Nova Scotia Utility and Review Board

IN THE MATTER OF Section 35A of *The Public Utilities Act*, R.S.N.S. 1989, c.380, as amended

- and -

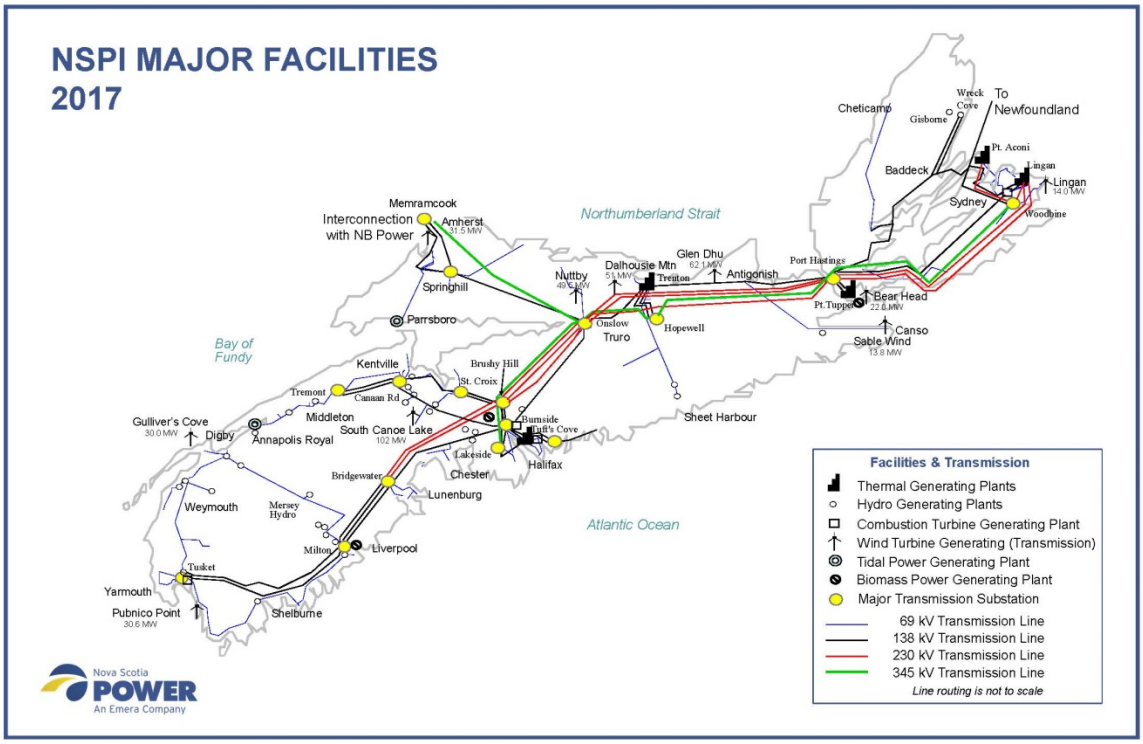
IN THE MATTER OF an Application by Nova Scotia Power Inc. for Approval of the **2018 Annual Capital Expenditure (ACE) Plan**

2018 ACE Plan

Date Filed: November 22, 2017

Nova Scotia Power

2018 Annual Capital Expenditure Plan



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EXECUTIVE SUMMARY

Nova Scotia Power Inc.'s (NS Power, Company) vision is to be a trusted, customer-focused, community-based organization that safely, efficiently and cost effectively delivers electricity to Nova Scotians. The investments proposed by NS Power in its 2018 ACE Plan are focused on the value provided to customers, whether through reliability of power production and delivery, through compliance with regulatory requirements including the adoption of clean, renewable energy, or through improvements to the customer experience. These investments are pursued only where needed in accordance with NS Power's asset management methodologies, grounded in affordability for customers.

In this Application, NS Power is requesting approval from the Board of 105 capital work orders and the 2018 capital routine program for an aggregate total of $204 million. The majority of capital work orders submitted for approval are less than $1 million each: 43 projects are forecast between $250,000 and $500,000, 34 are forecast between $500,000 and $1 million, and 28 exceed $1 million. The 2018 ACE Plan total budget is over $40 million less than the total budget in 2017. The 2018 total budget is also consistent with what NS Power forecasted in the 2017 ACE Plan application for anticipated necessary capital investment in 2018.

NS Power's ACE Plan Application is critical to NS Power's capital investments program as it provides customers, the Nova Scotia Utility and Review Board (Board, UARB), and other stakeholders with a comprehensive and transparent overview of the Company's capital investments for the year ahead. As with previous ACE Plans, NS Power's forecast capital spending in 2018 is focused on providing value to customers. The benefits and opportunities that are enabled by NS Power's 2018 capital program are:

- **The 2018 capital program reduces upward pressure on rates -** NS Power's capital investments for 2018 are projected to reduce upward pressure on rates and revenue requirement cumulatively over the next five years. This takes into account the additional fixed cost recovery as a result of customer growth achieved through the capital investments made to serve new customers.

- **The 2018 capital program is focused on maintaining safe and reliable service for customers -** The 2018 capital plan is required for sustaining and compliance capital work on the Company's system. These projects include rebuilding or refurbishing aging and deteriorated plant and equipment, compliance with Provincial regulations and continuing to improve the reliability of the distribution and transmission system for customers. The Performance Standards came into effect on January 1, 2017, and all transmission and distribution projects in the 2018 ACE Plan will contribute to meeting those metrics; as noted by NS Power during the Performance Standards proceeding, no additional capital investment beyond the regular sustaining capital investments NS Power makes through its ACE Plan program are required to meet these standards. In addition, the 2018 capital spending will include strategic projects, such as Advanced Metering Infrastructure (AMI Application) pending Board approval, the upgrade of NS Power's Transmission and Distribution Work and Asset Management System, and transmission upgrades required to integrate the Maritime Link.

- **The 2018 capital program continues to place a strong focus on improvements and efficiencies for customers through investment in Information Technology (IT)** – Increases in IT regulatory and legal compliance, technology turnover and obsolescence, and cyber-related threats continue to drive corresponding increases in IT-related capital investments. This trend related to IT investment began with NS Power's application for the Enterprise Resource Planning (ERP) project, and will continue with future strategic IT projects such as T&D Work & Asset Management in 2018 in accordance with NS Power's IT investment plan.[1] Accordingly, the 2018 ACE Plan includes several IT projects planned for subsequent submission.

- **The 2018 capital program enhances customer experience** – NS Power is committed to improving the customer experience and is doing so through valuable capital investments, largely in IT. Some customer experience projects have already been completed,

[1] 2017 ACE Plan, NSUARB IR-71 Attachment 1, M07745, January 5, 2017.

improving areas such as outage information and customer self-service. These investments will continue into 2018 and beyond.

- **The 2018 capital program is an investment in communities throughout Nova Scotia –** Each year the Company invests millions of dollars in capital assets in communities throughout the province where they are needed most. Transmission and distribution capital investments in 2018, for example, provide direct reliability benefits to all counties in which they are undertaken. For example, over $3 million will be invested in Yarmouth County, over $9 million in Halifax County, and over $12 million on Cape Breton Island. Millions in capital investments associated with the 2018 ACE Plan are distributed throughout all of Nova Scotia. These investments provide direct benefits to communities across the Province and the customers served in those communities. NS Power is committed to continued investment in all Nova Scotian communities now and into the future, providing customers with affordable, safe and reliable service.

- **The changing industry environmental landscape will result in innovative solutions that change the way NS Power serves customers into the future -** The Company and customers have undertaken a significant evolution over the last decade with the transition from fossil fuel based generation to renewable generation and through compliance with emissions hard caps. Since 2005, NS Power has tripled its renewable generation to 28 percent as of the end of 2016. Over the same period, greenhouse gas emissions were reduced by 34 percent. This reduction, in compliance with Provincial requirements, surpasses the Federal target of reducing CO2 emissions by 30 percent from 2005 levels by 2030. In addition, in 2016, installed wind generation on the NS Power system reached approximately 600 MW. NS Power remains on track to reach 40 percent renewable generation by 2020.

Given new Federal and Provincial carbon reduction requirements coming forward in the future, Nova Scotia will continue to make transitions into a cleaner future. In addition, the electric industry and electricity customers are together seeing change through opportunities presented through new technologies. The provision of electricity service

will look and feel different for customers in the future. A recent example of an innovative capital project brought forward by NS Power and approved by the UARB was the Intelligent Feeder project approved in 2017 which will explore the viability of grid scale battery storage systems, their value in supporting the integration of variable renewable energy, and the provision of other reliability services on the power system. Innovation projects will prepare NS Power for the future impact of renewable energy and evolving customer expectations; some will enable the Company to respond to Federal and Provincial environmental policy, while others will position the Company to bring improved solutions to customers to meet their needs and expectations in a changing electrical landscape.

- **The 2018 ACE Plan is designed to achieve improvements in regulatory efficiency** - The capital investments proposed in the ACE Plan are vetted and planned in accordance with the UARB-approved asset management ranking methodologies.[2] These are provided in the Capital Expenditure Justification Criteria (CEJC) which confirms proper prioritization of annual investments for customers pursuant to the approved ranking methodology. All projects within the 2018 ACE Plan are in compliance with the CEJC. In an effort to reduce the number of filings throughout 2018, and increase the transparency of the Company's 2018 planned capital expenditures, NS Power included a larger number of capital projects for approval in the 2018 ACE Plan. The 2017 ACE Plan included 71 projects for approval, compared to 105 in the 2018 ACE Plan. This reduces the number of projects forecast for subsequent approval throughout 2018. This effort will create better regulatory efficiency for the Board, regulatory participants and NS Power. In addition, prior to filing this Application, NS Power met with customer representatives to provide an overview of the 2018 ACE Plan. NS Power has made a "no surprises" commitment to interested parties that it will engage with them and seek their feedback in advance of all major filings before the UARB and has been doing so throughout the past year. NS Power is committed to continuing with this approach with a view to better transparency and

[2] Summary CEJC, approved by the UARB October 24, 2017, M08278.

mutual understanding of concerns and areas of interest, and of continuing to gain regulatory efficiencies for the Board and regulatory participants.

2018 ACE PLAN STRUCTURE

The 2018 Annual Capital Expenditure (ACE) Plan application is intended to provide the UARB, regulatory participants, and customers with a comprehensive and transparent view of NS Power's planned capital expenditures for 2018. The following provides an overview of how the 2018 ACE Plan is organized.

- **Section 1.0 - Introduction** - This section provides a high-level summary of the overall expenditures in the 2018 ACE Plan, including a breakdown of expenditures into various categories such as sustaining and strategic capital, as well as a forecast of expenditures in those categories for the next five years.

- **Section 2.0 - Asset Class Overview -** This section provides narratives for Generation, Transmission & Distribution, and General Plant asset classes, highlighting factors influencing capital investments in each area. It also provides descriptions of emerging trends influencing the Company's capital investments now and into the future. These include Innovation and Customer Experience initiatives.

- **Section 3.0 - 2017 ACE Plan Follow-Up -** This section addresses the status of items from the 2017 ACE Plan, including a list of capital items pending submission in 2017 from the 2017 ACE Plan, the 2017 ACE Plan deferred and cancelled items, and the outcome of the 2017 ACE Plan stakeholder engagement process. This section responds to the Board's 2017 ACE Plan directive to include a list of projects which appear as items for subsequent submission in a prior year's ACE Plan filing, which have not been submitted for approval at the time of an ACE Plan filing, but which NS Power intends to submit by the end of the calendar year.[3]

- **Section 4.0 - 2018 ACE Plan Summary -** This section provides a summary of all 2018 capital expenditures. These include the list of projects for which NS Power is seeking

[3] 2017 ACE Plan, UARB Order, M07745, April 4, 2017.

approval, the list of projects forecast for subsequent submission, the list of projects with a value of less than $250,000, and the list of projects for the Point Aconi Generating station. Capital projects under $250,000 and Point Aconi projects do not require UARB approval under the *Public Utilities Act*[4]; however, the Company has traditionally included them in its ACE Plan for information purposes and to provide a complete picture of all annual capital expenditures on NS Power's system.

- **Section 5.0 - Generation -** This section lists all Generation capital projects submitted for approval, as well as related carry-over spending. Generation assets generate electricity through a variety of methods and fuel sources, including hydro, coal, oil and gas, biomass, and wind.

- **Section 6.0 - Transmission -** This section lists all Transmission capital projects submitted for approval, as well as related carry-over spending. Transmission assets transmit electricity from the generation plants to the distribution system throughout the province. Transmission includes assets and equipment operating at 69 kV level or higher.

- **Section 7.0 - Distribution -** This section lists all Distribution capital projects submitted for approval, as well as related carry-over spending. Distribution assets include equipment for delivering electric energy from points on the transmission system to customers served at voltages below 69 kV.

- **Section 8.0 - General Plant -** This section lists all General Plant capital projects submitted for approval, as well as related carry-over spending. General Plant assets include computer infrastructure and communication equipment, which comprise the majority of capital expenditures incurred under this function. Other items such as office equipment, vehicles, construction equipment, buildings (except generating and substation facilities) are also included under this function.

[4] Public Utilities Act R.S.N.S., c.380, as amended s. 35 and 36.

- **Section 9.0 - Routine Capital Program -** This section lists all Routine Capital items, by Generation, Transmission, Distribution, and General Plant submitted for approval. Routine capital items are recurring annual expenditures for replacement of equipment (like-for-like replacement), additions to existing equipment base resulting from system growth, and addition of customers to the system.

- **Section 10.0 - Directives and Miscellaneous –** This section provides information from the Company in response to the various directives issued by the Board in respect to the Company's ACE Plan over the years as well as other miscellaneous information traditionally included in the Company's Application. The Board's directives include requests for information on revenue requirement impacts, transmission and distribution investment reliability impacts, and the ranking of projects submitted in the ACE Plan for approval.

The 2018 ACE Plan also includes the following information provided as separate appendices:

- **Confidentiality Matrix (Appendix A) -** The confidentiality matrix provides a listing of all capital items submitted for approval, their attachments, and their confidential status so that the Board may evaluate the confidential portions of the ACE Plan. As it does with all its filings, NS Power has minimized the information for which it seeks confidential treatment in this Application in order to facilitate the overall transparency of the ACE Plan.

- **Database of all 2018 ACE Plan projects in Excel format (Appendix B) -** A complete database of all 2018 ACE Plan projects is provided in Excel format. This provides the Board and interested parties a convenient reference of all expenditures in 2018, regardless of whether they are submitted for approval in the ACE Plan. Details include Capital Item Numbers (CI #s), names, functional class, and spend details.

- **Updated Q3 Capital Reports (Appendix C)** – NS Power's Q3 capital reports, initially submitted to the UARB on October 30, 2017, have been updated with 2018 ACE Plan

projects submitted for approval and subsequent submittal, and provided in Excel format. The updated Q3 capital reports provide the Board and stakeholders a comprehensive listing of the status of all "active" projects (i.e. those that have been submitted to the UARB or referenced on the ACE Plan subsequent submittal list, and are currently underway).

- **The Excel version of NS Power's Long-Term Capital Planning & Revenue Requirement table found in Section 10.1.1 (Appendix D)** - The Excel version of NS Power's Revenue Requirement table provides the Board and interested parties the data required to fully examine the calculation and assumptions used to calculate the revenue requirement associated with NS Power's ACE Plan expenditures.

1.0 INTRODUCTION

1.1 2018 ACE Plan Summary

The Company's overall 2018 capital budget (inclusive of capital projects under $250,000 and Point Aconi projects that do not require UARB approval, carryover spending, capital routines, and subsequent submittal items) is $355 million. NS Power is requesting UARB approval of 105 capital work orders and the 2018 capital routine program, for a total approval amount of $204 million.

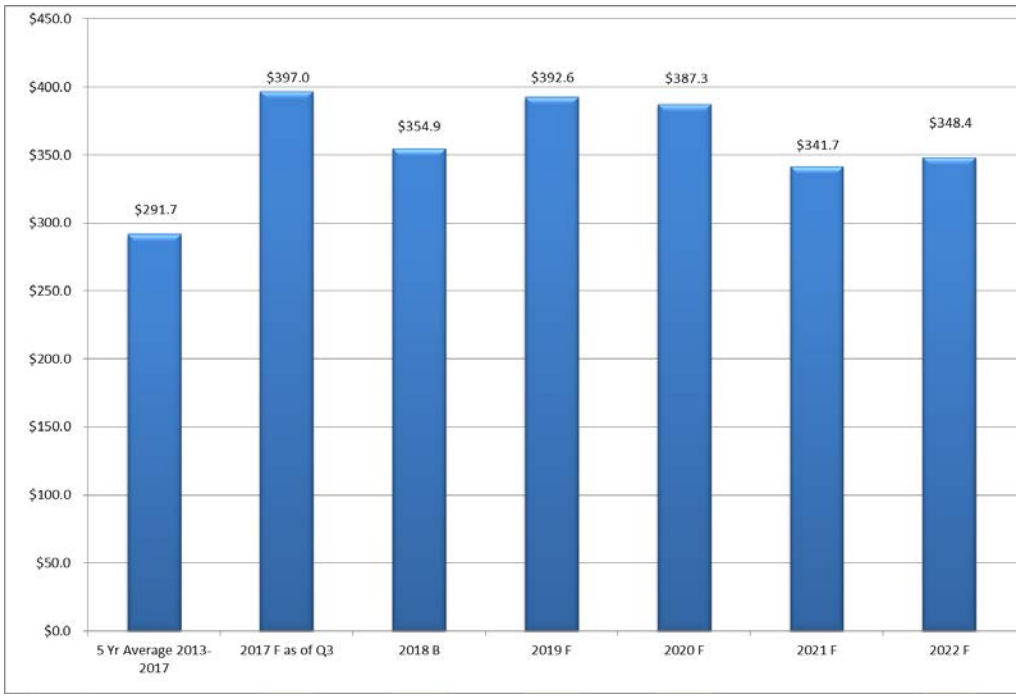
The increase in capital projects submitted for approval over the 2017 ACE Plan amount of projects submitted is due to NS Power's efforts to advance scoping of these projects that may have otherwise been previously included in the ACE Plan as subsequent submittal items. The 2018 ACE Plan forecasts only 24 projects for subsequent submittal during 2018 in the amount of $30 million, compared to 83 subsequent submittal items in 2017 in the amount of $109 million, a decrease in 59 capital work orders and $79 million. As a result, over 80 percent of 2018 capital work orders eligible for UARB submission are included in the 2018 ACE Plan for review and approval. In the 2017 ACE Plan, 71 capital work orders were submitted for approval. This effort to include more projects for approval is intended to provide greater transparency to customers, the Board and other stakeholders with respect to NS Power's overall planned capital expenditures for 2018. Including more projects in the ACE Plan for approval rather than for subsequent submittal later in the year is also intended to create regulatory efficiencies throughout the year by reducing the number of capital projects subsequently submitted to the Board for approval. All projects within the 2018 ACE Plan are compliant with the Board approved CEJC.

Capital expenditures in 2017, and those forecast for 2018, have increased compared to historical averages due to the inclusion of necessary strategic capital projects. Strategic capital investments are generally considered to be those investments that either add new utility assets or significantly change/replace current utility assets, or how the Company uses them. Strategic capital investments, such as the installation of AMI (pending Board

approval), the upgrade of the transmission and distribution (T&D) Work & Asset Management system, increased investment related to the Rights-of-Way widening program, and the completion of Maritime Link transmission system upgrades, require capital investments in 2018. Hydro infrastructure investment, which includes re-development of the Mersey Hydro System and a mid-life extension of NS Power's Wreck Cove Hydro Generating Station, will contribute to increases in Hydro capital expenditures in 2019 and beyond.

Figure 1 and **Figure 2** below illustrate NS Power's total capital budget for 2018 and forecast spend for 2019 through to 2022, as well as NS Power's total annual capital expenditures by function.

Figure 1: NS Power Total Capital Spend: Historical, Budget and Forecast ($M)



F = Forecast, B = Budget in above figure

Figure 2: Total Annual Capital Expenditures by Function ($M)

Year	Actuals 2013	2014	2015	2016	2017 Q3 F	2017 ACE Budget	ACE Plan 2018	Forecast 2019	2020	2021	2022
Generation	68.4	66.0	110.4	115.8	$124.4	$106.0	116.5	146.9	165.5	155.9	175.8
New Renewables	15.2	82.8	17.1	-	-	-	-	-	-	-	-
Transmission	31.0	51.0	54.4	57.5	90.4	91.2	$75.7	65.0	57.0	58.0	59.0
Distribution	62.9	52.8	62.5	68.8	76.1	83.9	$108.1	125.8	121.6	72.9	74.2
General Plant	29.9	21.7	27.1	66.5	106.0	116.9	$54.6	55.0	43.3	54.9	39.4
Total	**$207.4**	**$274.3**	**$271.5**	**$308.5**	**$397.0**	**$398.0**	**$354.9**	**$392.6**	**$387.3**	**$341.7**	**$348.4**

Note: Figures presented may include $0.1M in rounding differences on some line items.

Note: Includes Maritime Link Transmission Spend that is currently removed from rate base.

The Company's capital program continues to focus on sustaining capital assets, representing cost-effective investments to maintain system performance for customers. The emphasis continues to be on making timely investments based on equipment condition and criticality and maintaining the performance of assets for customers.

Generation, Transmission, Distribution and Information Technology projects in the 2018 ACE Plan are subject to the Board approved project selection and asset management methodologies pursuant to Section 6.2 of the CEJC. Only projects that provide the best value to customers are put forward for approval and completion. This year, NS Power expanded its formal asset management practice, creating a new asset management methodology for technically justified Information Technology projects, based closely on the Board-approved condition and criticality asset management methodology used to manage generation, transmission and distribution capital projects.

As shown in **Figure 3** and **Figure 4** below, NS Power's investments toward sustaining the Company's assets, customer driven investments, and investments required by regulatory or environmental standards are forecast to be relatively stable over the next five years.

Figure 3: Breakdown of Capital Forecast by Investment Type ($M)

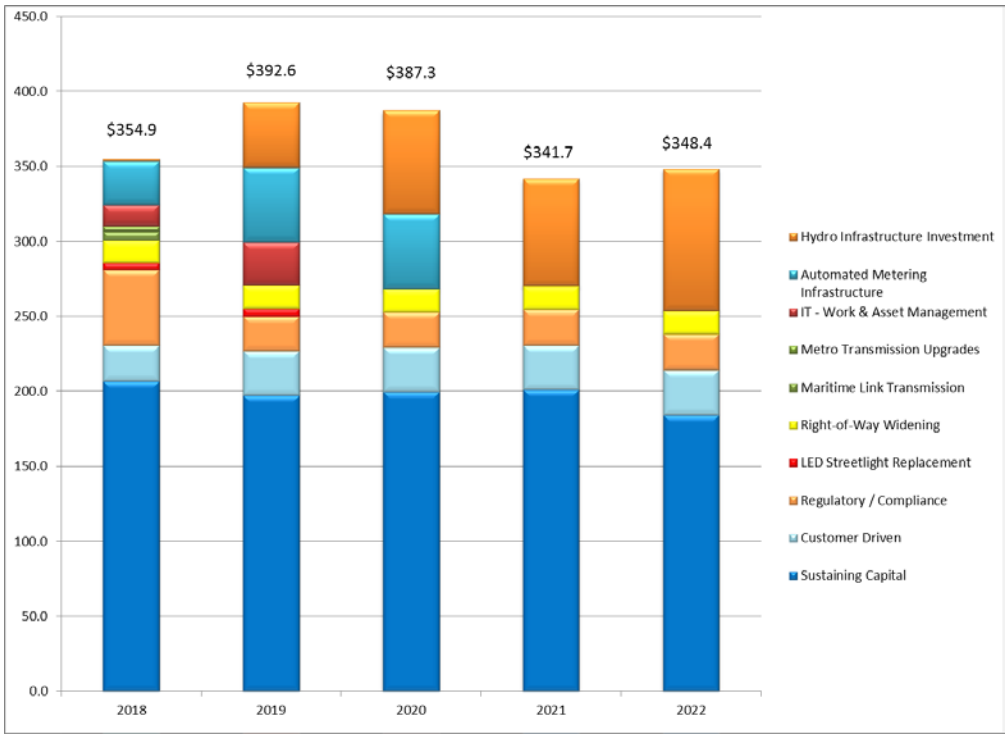


Figure 4: Breakdown of Capital Forecast by Investment Type ($M)

Investment Type[5]	2018	2019	2020	2021	2022
Sustaining Capital	207.0	197.2	199.7	201.0	184.1
Customer Driven	23.9	29.7	29.8	29.9	30.0
Regulatory / Compliance	50.0	23.0	23.5	23.9	24.4
LED Streetlight Replacement	4.8	5.5	0.0	0.0	0.0
Right-of-Way Widening	15.1	15.4	15.4	15.4	15.4
Maritime Link Transmission	5.8	0.0	0.0	0.0	0.0
Metro Transmission Upgrades	3.5	0.0	0.0	0.0	0.0
T&D Work & Asset Management	14.5	28.6	0.0	0.0	0.0
AMI / Smart Grid	29.0	50.0	50.0	0.0	0.0
Hydro Infrastructure Investment	1.2	43.2	69.0	71.5	94.5
	354.9	**392.6**	**387.3**	**341.7**	**348.4**

Note: Totals may be off slightly due to rounding.
Note: These figures are the Company's current forecast. The accuracy of these estimates will improve over time as new information informs the potential investments.

Section 10.1.1 of this Application (Impact of 2018 ACE Plan on Revenue Requirement and Affordability) shows that NS Power's capital expenditures for 2018 reduce upward pressure on rates and revenue requirement cumulatively over the next five years. This takes into account the additional fixed cost recovery as a result of customer growth achieved through these capital investments made to serve new customers.

1.2 Forecast Capital Spending

The 2018 ACE Plan and future ACE Plans will continue to focus on capital required to meet the company's obligations to provide customers with affordable, safe and reliable electricity service, together with larger strategic projects. However, changing environments and new emerging trends will influence NS Power's capital investments into the future. Furthermore, based on technological trends and customer expectations,

[5] The Sustaining, Customer Driven, and Regulatory/Compliance Capital portion of the annual forecast in 2018 – 2021 is more certain than the large scale strategic capital profile. The Sustaining Capital estimates are built up from well-established asset management and replacement programs. Strategic Capital reflects projections of spending in later years, and is based on estimates subject to change as project scope becomes better defined.

additional capital investments could be required to enable NS Power to meet customers' expectations for both service delivery and customer experience.

1.3 Impact of Performance Standards

The Performance Standards approved by the UARB relating to metrics in reliability and customer service are now in effect.[6] The majority of T&D projects in the 2018 ACE Plan will contribute to meeting these performance standards requirements; as noted by NS Power during the Performance Standards proceeding, no additional capital investment beyond the regular sustaining capital investments NS Power makes through its ACE Plan program are required to meet these standards. Please refer to Section 2.1.2 (Transmission and Distribution) and Section 10.1.7 (Impact of Reliability Projects) for further detail.

1.4 Generation Utilization and Optimization

In 2017, the UARB advised that it would be engaging Synapse Energy Economics Inc. (Synapse) to undertake an independent analysis of optimal utilization of generation resources and potential options that may be more economical for Nova Scotia ratepayers (the Generation Utilization and Optimization study or GUO study).[7] The scope of the exercise is not focused on near-term necessary and prudent capital generation investments required to serve customers. The ACE Plan process advances projects required to maintain safe, reliable and affordable electricity service. Sustaining the steam generation fleet through continued prudent and cost effective capital investment, in accordance with Board-approved methodologies established in the CEJC, is necessary to serve NS Power customers. Please refer to Section 2.1.1 (Generation).

[6] Performance Standards, UARB Order, M07387, December 20, 2016.
[7] Generation Utilization and Optimization Terms of Reference, July 7, 2017, (M08059).

1.5 Innovation Initiatives

Innovation capital projects refer to non-traditional capital investments that focus on technologies, solutions or enhancements in order to adapt to Federal and Provincial environmental policy, or to better meet customer needs and expectations within an evolving electricity sector.

With a view to minimizing the costs of innovation projects for customers, NS Power is seeking government funding for certain innovation projects. Please refer to Section 2.2.1 (Innovation Initiative) for further discussion on the innovation initiative.

1.6 Customer Experience Projects

Customers are now accustomed to advanced technologies - such as smart phones and software applications – and expect service providers to keep pace by offering services as conveniently as possible, which often requires the integration of new technologies when delivering services to customers.

NS Power has pursued improvements to customer interactions with the Company through customer experience initiatives. These initiatives are aimed at key customer interactions and improving the customer's overall experience with the Company during those interactions. Please refer to Section 2.2.2 (Customer Experience) for a discussion of this initiative.

1.7 Relief Sought from the Board

NS Power respectfully requests Board approval of the following, in accordance with Section 35A of the *Public Utilities Act*:

- 105 Capital Items with 2018 budget spending of $92 million and total project spending of $120 million (please refer to Section 4.2); and

- Capital routine programs with 2018 budget spending of $84 million (please refer to Section 9.1).

2.0 ASSET CLASS OVERVIEWS

2.1 Asset Class Overviews

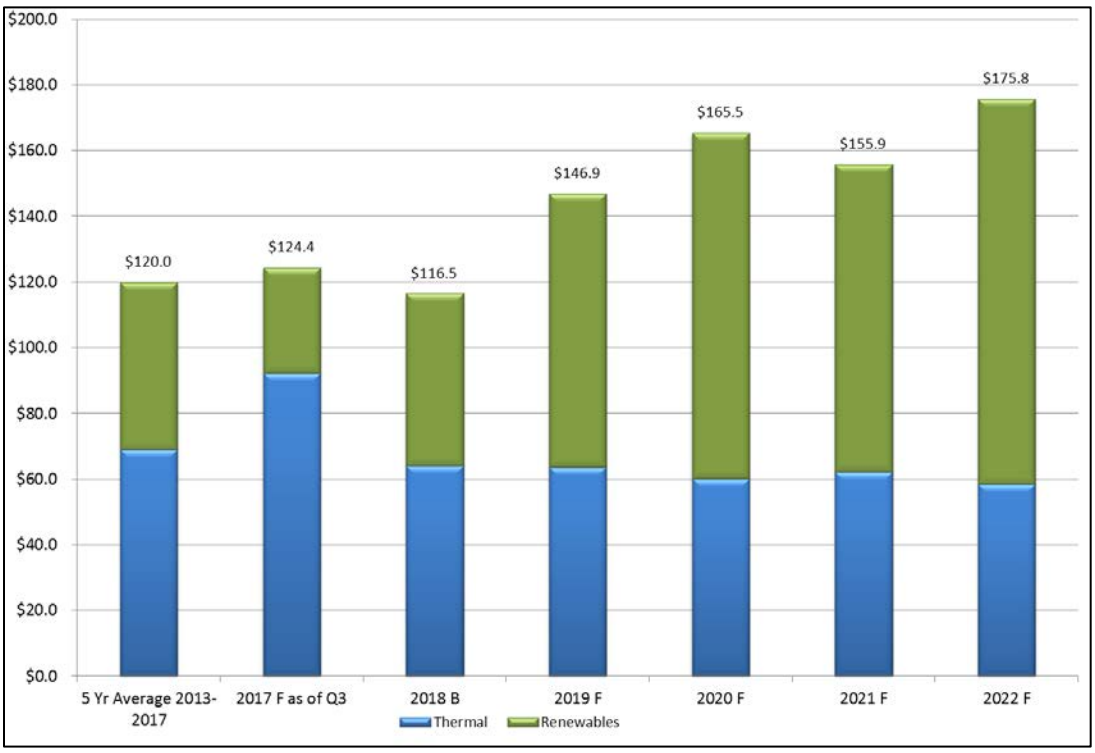
This section provides an overview of the traditional asset classes (generation, transmission and distribution, and general plant) and describes emerging trends that are influencing capital investment now and are expected to into the future.

NS Power's selection of capital investments for generation, transmission, distribution and information technology (which falls under general plant) is based on the methodologies described in Section 6.2 of the CEJC. This allows NS Power to determine how to best invest sustaining capital in assets critical to the safe and reliable delivery of electricity to NS Power customers.

2.1.1 Generation

Generation includes replacements and additions to NS Power's Thermal, Hydro, Wind, Tidal, Combustion Turbine and Biomass facilities. The increase in investment in future years from the 2017/2018 investment levels is largely attributable to the investment in the Mersey Hydro System Re-Development and the Wreck Cove Hydro System Life Extension & Modernization (LEM) projects. **Figure 5**, below, illustrates NS Power's capital spending on Generation, including historical, forecast and budget.

Figure 5: Generation Spend – Historical, Forecast and Budget ($M)



F = Forecast, B=Budget in above figure

Figures 6 and 7 provide a breakdown of the 2018 generation spend by investment type.

Figure 6: 2018 Thermal Spend by Investment Type

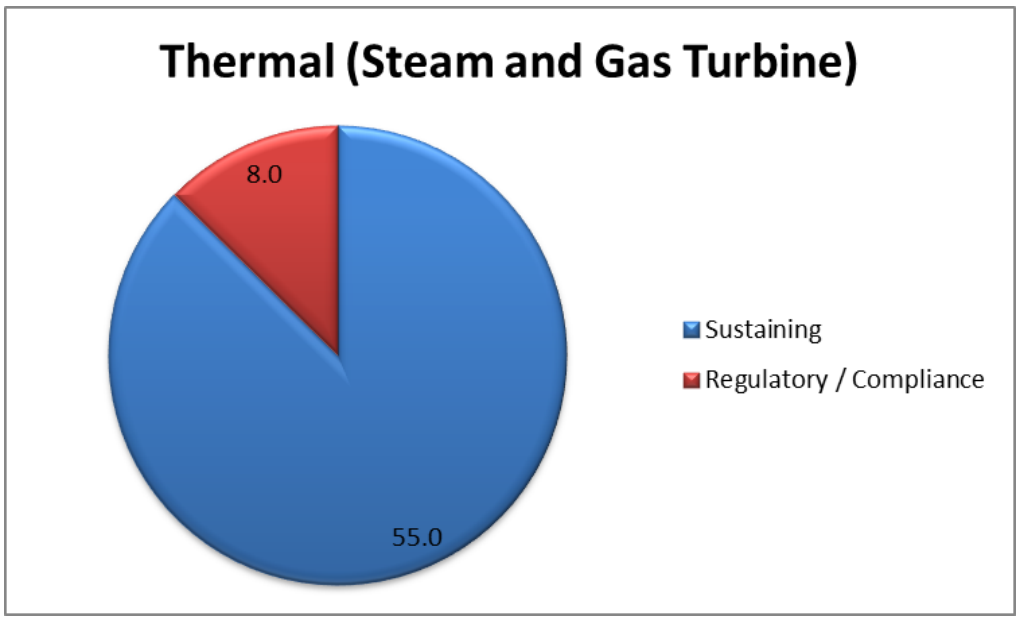
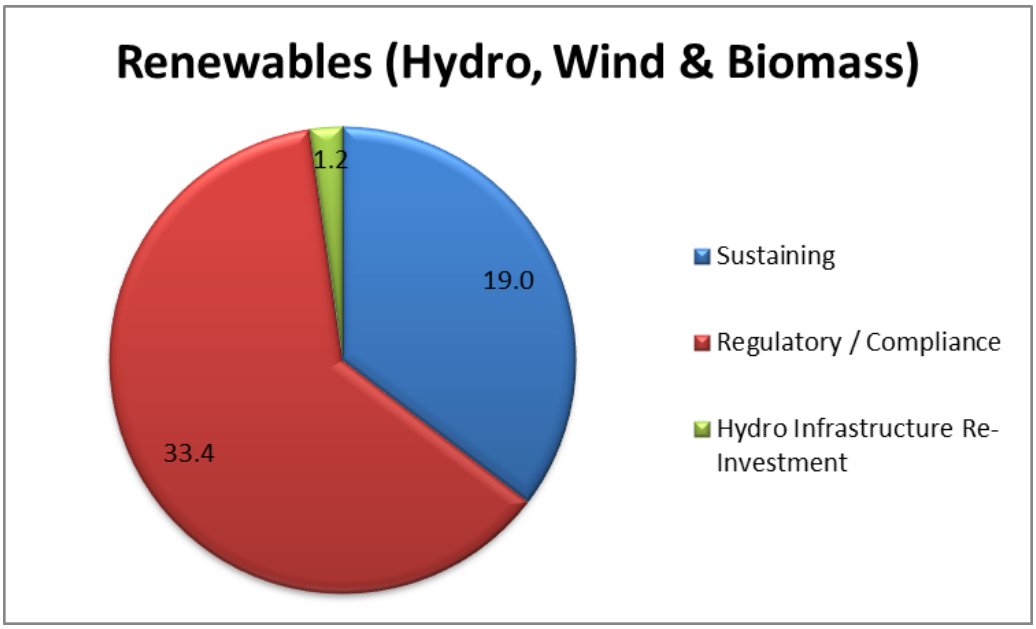


Figure 7: 2018 Renewable Generation Spend by Investment Type



As noted above, in May 2017, the UARB advised that it would be engaging Synapse to undertake an independent analysis of optimal utilization of generation resources and potential options that may be more economical for Nova Scotia ratepayers. Pursuant to

the Terms of Reference approved by the UARB on August 22, 2017, the objective of the GUO study is as follows:

> The main objective of the analysis will be to determine the extent to which it is cost-effective to ratepayers to retain NSPI's thermal fleet through 2030, and possibly beyond. Critically, this will require comparison of the costs of retention of the thermal fleet to alternative options. Alternative options will include some mix of thermal unit retirement (i.e., less than full retention of the fleet), capacity utilization and energy provision from the remaining portion of the thermal fleet, and capacity and energy supply (or avoidance of supply) from replacement resources (i.e., demand-side and supply side options). The analysis will strive to address all reasonable alternatives, including those that require transmission system reinforcement and/or expansion. The analysis will assess the sensitivity of the results to input assumptions that will exhibit different degrees of uncertainty.[8]

The GUO study is currently being prepared by Synapse which has indicated that it expects to file a report with the UARB in early 2018. NS Power understands the Board is anticipating a hearing process following the filing of the report. The scope of the exercise is not focused on near-term necessary and prudent capital generation investments required to serve customers. The ACE Plan process advances projects required to maintain service to customers for safe, reliable and affordable electricity service. The 2018 ACE Plan includes capital investments on steam related generation, totaling approximately $54.7 million in 2018 expenditures. Sustaining the steam generation fleet through continued prudent and cost effective capital investment, through Board-approved methodologies found in the CEJC, is necessary to serve NS Power customers. The capital investments provided in the 2018 ACE Plan are required to maintain the generating system for the safe and reliable provision of electricity to customers.

[8] Generation Utilization and Optimization, Terms of Reference, M08059, July 7, 2017.

NS Power's selection of generation related capital investment is based on an asset management approach as described in Section 6.2 of the CEJC. Asset Management enables NS Power to determine how to best mitigate risks arising from aging units, changes in unit utilization, and renewable integration using a range of measures.

The Company's asset health and risk profiling methodology determines the condition and criticality of equipment and allows the most appropriate risk mitigation strategy to be implemented, including effective investment of sustaining capital. This enables NS Power to have the information necessary to prioritize decisions to invest in assets only when necessary to maintain safety and reliability, while managing costs for customers.

Key elements of NS Power's asset management approach include:

- fleet-wide asset class programs;
- application of the latest technologies to enhance understanding of asset health;
- effective operational support tools and infrastructure; and
- risk-based inspection programs.

NS Power engages industry experts to augment the assessment of risks and mitigating measures for the generation fleet.

NS Power's generation asset management approach is focused on optimizing generation resources by mitigating risks through operating procedures, monitoring and assessing assets, and capital investment. The approach also focuses on continuing to develop and improve asset health profiling and risk assessment as the transformation of the utilization of the generating fleet continues. Coal fired generating units will retire in the future. Until that time, capital investments are still required to meet the electricity demands of NS Power customers, avoid customer interruptions, and adhere to safety and regulatory requirements. These capital investments are also frequently economically justified.

It is clear there are questions about the future of NS Power's steam fleet. Capital investment in NS Power's legacy steam fleet is essential to providing reliable electricity supply to customers while NS Power completes its transition to clean energy generation in the most cost effective manner for customers. The total energy production of the coal fleet declines year over year; however, the value that the coal fired units bring to the power system persists. Flexible unit operation responds to the need to integrate variable renewable generation on the power system. While valuable, flexibility does result in more unit starts, stops and load swings, which increase the wear on the units, which contributes to continued capital investments.

NS Power is confident that the level of investment proposed for these units in the 2018 ACE Plan is in the best interests of NS Power's customers and that these investments will

remain unchanged if, for example, the coal fired generating units are retired on an advanced timeline.

A large percentage of the generation projects included in the 2018 ACE Plan are required to be completed in order for NS Power to be in a position to operate these units. These projects are primarily safety-related (e.g. fire protection, high energy piping), a result of environmental regulations or requirements (e.g. ash site investment), or required to meet other regulatory requirements such as Department of Labour (DOL) codes (e.g. selective boiler tube replacement, due to minimum tube wall thickness requirements). NS Power will not be able to operate these units if these projects are not completed.

The Company acts proactively to mitigate risks on assets prior to failure and the associated outages or unit deratings. This is the most prudent approach to asset management and investment, which has been evident in sustained steam unit reliability (Derated Adjusted Forced Outage Rates (DAFOR)) despite the significant change in unit utilization triggered by renewables integration.

Alternative run to failure strategies will result in higher DAFOR, which increases the risk of safety issues, collateral component damage, potentially high cost replacement energy, and customer interruptions. If multiple failures were to occur at the same time, customers could experience service outages due to a generating capacity shortfall. A proactive approach to capital investment maintains operational reliability for the betterment of the power system. All projects included in the 2018 ACE Plan are required to be completed in order for the continued reliable operation of these units, even if changes to present utilization plans were to call for retirements on an advanced timeline.

Investment in coal fired units is based on condition assessments and associated maintenance strategy. Steam units typically require a planned major outage (such as a significant turbine or generator investment) every 8 to 10 years, depending on the unit's utilization. In situations where a plant may be anticipated for retirement beyond that

timeframe, investment is still warranted to allow for the safe and reliable operation of that unit through to the next planned major outage.

Many other steam generation projects are justified, in part, on economics. For these capital projects included in the 2018 ACE Plan, the majority of projects have a payback period of less than five years, with the longest payback period being 5.6 years, as outlined in Section 10.6 – Summary of Economically justified projects. That is, the benefit that customers receive in avoided replacement energy and repair cost savings over the first five years after completing that capital investment outweigh the total capital cost of the project. In other words, the capital investment is a more cost effective alternative than the "do nothing" alternative. In cases like this, if the currently forecasted unit retirement is outside the payback period window, then that investment is the proper decision.

As of the time of filing this Application, in the GUO study process, Synapse has proposed for comment by interested parties, two retirement tracks for coal-fleet retirement. Even under the most aggressive of the proposed retirement scenarios, investments will be required in the coal fleet to preserve the safe and reliable operation of the units to meet the needs of the system until such time that replacement capacity (be it supply side or demand side) is available.

In summary, all generation capital investments in the 2018 ACE Plan are required, regardless of the future retirement of units, to enable the safe and reliable operation of these units for customers over the near term. These projects are either required for regulatory compliance purposes, to maintain the reliable operation of the units, or are economically justified with payback to customers provided in less than 5 years in most cases.

Port Hawkesbury Biomass

As an outcome of the 2017 ACE Plan process, NS Power and interested parties agreed to take consideration of the projects proposed in relation to the Port Hawkesbury Biomass

(PHB) facility offline to a separate stakeholder consultation process. Following this consultation, NS Power reported to the Board and confirmed that the Consumer Advocate (CA), Small Business Advocate (SBA) and counsel to the IG (Industrial Group) advised that they did not oppose NS Power proceeding with the 2017 PHB Projects but reserved the right to further examine the usefulness of the PHB assets in future applications.[9] NS Power subsequently submitted CI 49499 for the 2017 PHB Boiler Refurbishment project for approval and the Board approved the CI, stating:

> The Board understands refurbishment of the boiler at the Port Hawkesbury Biomass ("PHB") Plant is a project that needs to be performed on an annual basis in order to maintain safe and reliable operation of this unit. NSPI stated that, in accordance with Section 5(2A) of the Renewable Electricity Regulations, it is required to maintain the PHB Plant as a base load cogeneration facility, and operate the plant on an economic dispatch basis or as required for system reliability.
>
> In accordance with the Consensus document, the Board withheld its approval of the PHB Plant projects in its 2017 ACE Plan Decision. The Board directed NSPI to advise, no later than August 4, 2017, whether the stakeholders have reached agreement on these projects.
>
> On June 21, 2017, NSPI provided an update on the stakeholder process related to the 2017 PHB Plant projects. NSPI stated in part:
>
> > The discussion with stakeholders on the 2017 PHB Projects took place on May 10, 2017, and was attended by the Consumer Advocate (CA), Small Business Advocate (SBA), and counsel to the Industrial Group (IG).
> >
> > The CA, SBA and counsel to the IG have advised that they do not oppose NS Power proceeding with the 2017 PHB Projects. Stakeholders have, however, indicated that they reserve the right to further examine the usefulness of the PHB assets in future applications.
>
> In its July 31, 2017, letter to the Board regarding the status of stakeholder discussions of issues outlined in Appendix "A" to the Consensus document, NSPI confirmed that the parties to the 2017 ACE Plan Proceeding were not opposing the 2017 PHB Plant capital expenditures.

[9] NS Power correspondence to UARB dated June 21, 2017 respecting 2017 PHB Capital Expenditures.

> Based on the above, the Board accepts this project is necessary and the corresponding cost is justified. Accordingly, this will confirm that the Board has approved NSPI's request in the amount of $593,740, with respect to this work order.[10]

The 2018 ACE Plan includes CI 51818 PHB Boiler Refurbishment for $440,315 for approval as well as five projects and three routine expenditures, each below the $250,000 threshold. These expenditures continue to be required in order to maintain safe and reliable operation of this unit to allow NS Power to comply with the Renewable Electricity Regulations. They are required to maintain the PHB plant as a base load cogeneration facility, and to continue to allow NS Power to operate the plant on an economic dispatch basis or as required for system reliability.

Wreck Cove Life Extension and Modernization

The Wreck Cove Hydro Generating Station was commissioned in 1978. It is NS Power's largest hydro generation station in terms of installed capacity and annual electricity production, providing approximately 330 GWh a year on average in valuable renewable generation. Existing condition assessments, conducted in 2012 and 2013 by external experts, concluded that there is considerable opportunity to improve equipment condition, enhance reliability, and invest in end of life equipment, preserving the Wreck Cove Hydro generating station and the renewable energy it produces.

The objective of the LEM initiative is to enable the Wreck Cove Generating station to continue to provide renewable generation and system stability value from a fleet portfolio perspective for the next 40 years. This will be done through:

- Upgrades, refurbishments and replacements necessary to retain existing MW peak capacity at minimum initial capital outlay.

[10] M08177 – UARB Approval of 2017 Capital Work Order (P-128.17), August 4, 2017 (P-128.17).

- Upgrades, refurbishments and replacements necessary to maximize the energy output while maintaining the geographic footprint of the system within the watershed and staying within current environmental regulatory constraints;

- Maintaining and/or exceeding typical annual generation profile with stable, reliable and smooth operation range from low to full load (0-110MW). Today, the units have a minimum operating limit of 45MW to mitigate turbine runner cavitation issues, but greater operating range would assist system operators in wind integration and load following activities;

- Investigating various turbine runner options to increase maximum peak output (MW) with an acceptable efficiency curve and favorable operating range.

There are no capital investments in the 2018 ACE Plan related to the Wreck Cove LEM initiative. However, related preliminary engineering will continue to occur in 2018 with corresponding capital work order submissions due to be submitted to the UARB as part of the 2019 ACE Plan.

Mersey Hydro System Re-Development

The Mersey Hydro System is comprised of twelve generating units, commissioned between 1929 and 1955. It is NS Power's second largest hydro system with a total capacity of approximately 45 MW and an average annual generation of 299 GWH.

Due to the age, condition and dam safety requirements of the Mersey Hydro System, it requires a re-development of the powerhouses, generating equipment and water retaining structures in order to continue the generation of renewable energy into the future. This re-development is currently planned to begin in 2018 (under CI 39472 Mersey Hydro System Re-Development) and will continue until 2029.

The broad scope of this re-development will include:

- Replacement of the six powerhouses on the Mersey System
- Replacement of the 12 generating units within those six powerhouses
- Refurbishment of the dams and water retaining structures
- Refurbishment of the water control structures (spillways and sluiceways)
- Refurbishment of five switchyards

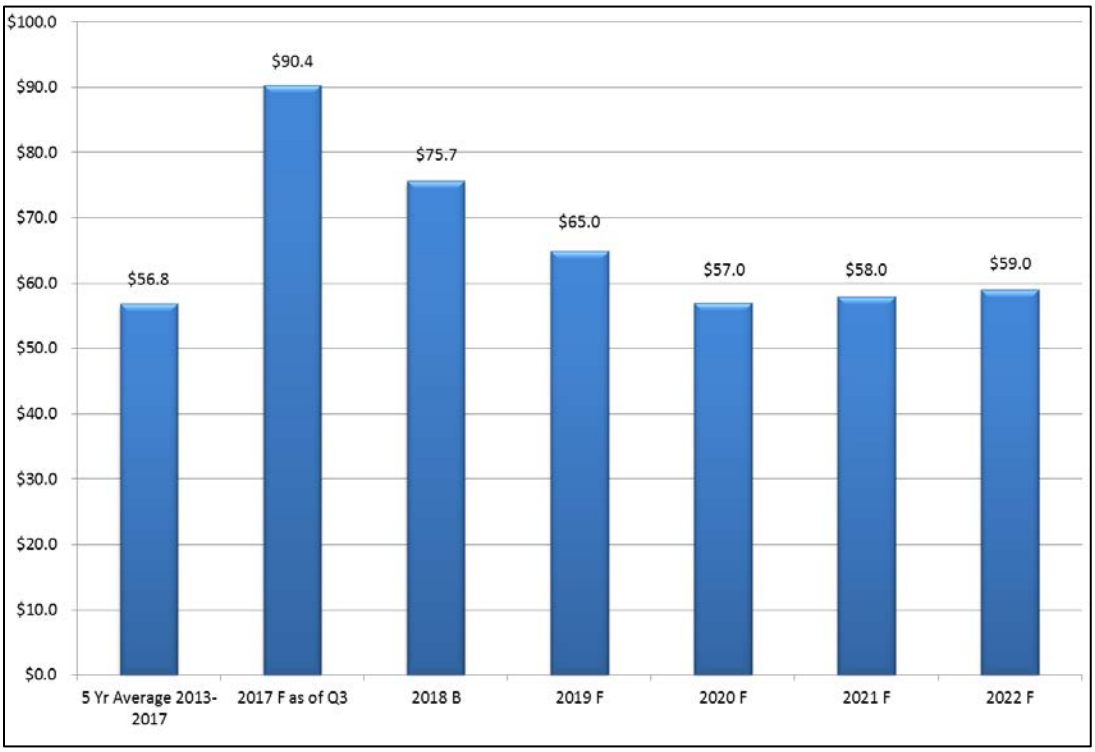
This re-development is expected to be completed over a 10 to 12 year timeframe, completing the construction on all components in a staged approach to mitigate the amount of lost generation due to construction. The current high-level estimate for the completion of the full scope listed above is approximately $500 - $600 million, based on a Class 5 estimate.

2.1.2 Transmission and Distribution

Transmission includes items for replacement, reinforcement or expansion of the transmission system, which transmits electrical energy from the generation plants to distribution substations throughout the province. Transmission includes assets and

equipment operating at 69 kV or higher. NS Power operates over 5,000 km of transmission circuits and related protection, controls and substation equipment. The decreased investment in 2018 is primarily driven by Maritime Link transmission work being largely completed in 2017. **Figure 8** below illustrates NS Power's capital spending on Transmission, including historical, forecast and budget.

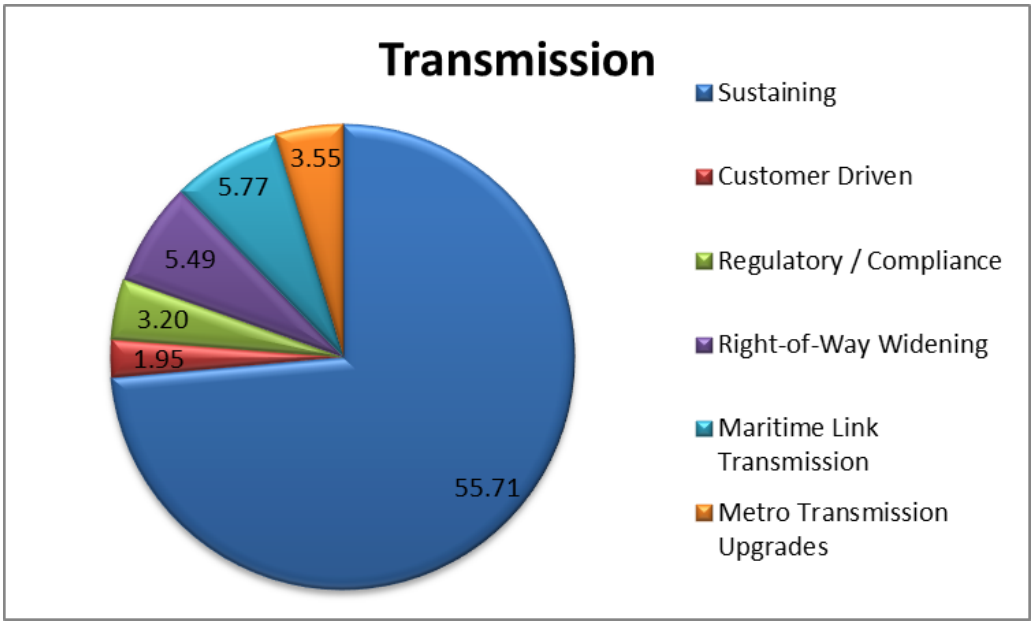
Figure 8: Transmission Spend – Historical, Forecast and Budget ($M)



F = Forecast, B=Budget in above figure

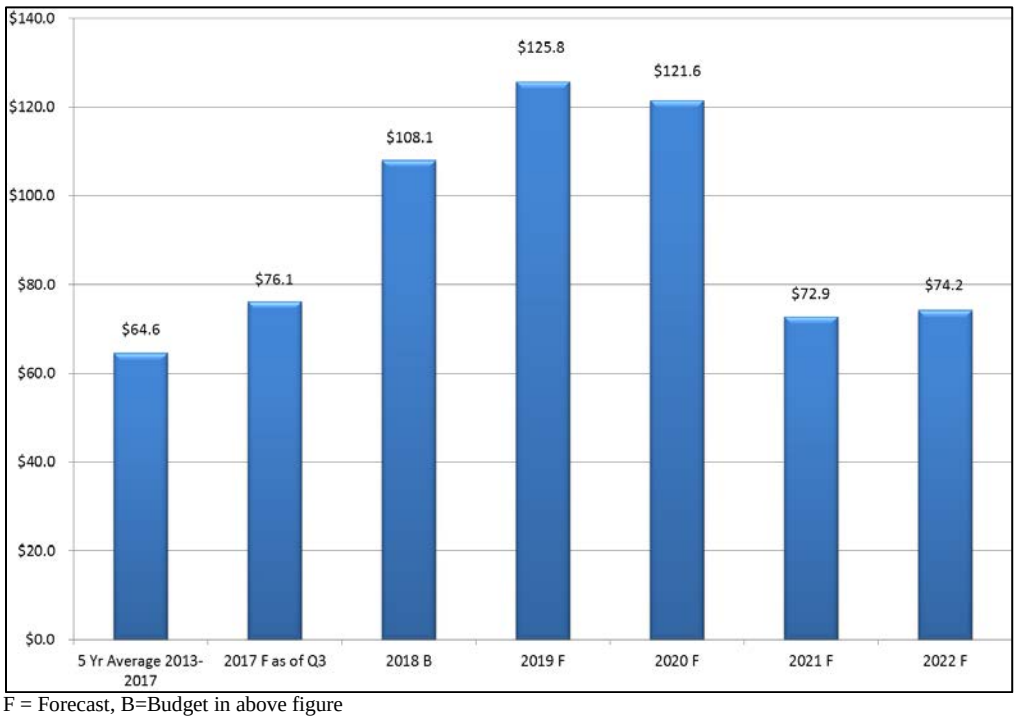
Figure 9 provides a breakdown of the 2018 transmission spend by investment type.

Figure 9: 2018 Transmission Spend by Investment Type



Distribution includes replacement of and additions to equipment for delivering electricity from points on the transmission system to customers served at voltages below 69 kV. NS Power operates 26,972 km of distribution circuits and related protection, controls and transformers. The increased investment levels in 2018-2020 are primarily due to forecast investment in the Advanced Metering Infrastructure project. **Figure 10** below illustrates NS Power's capital spending on Distribution, including historical, forecast and budget.

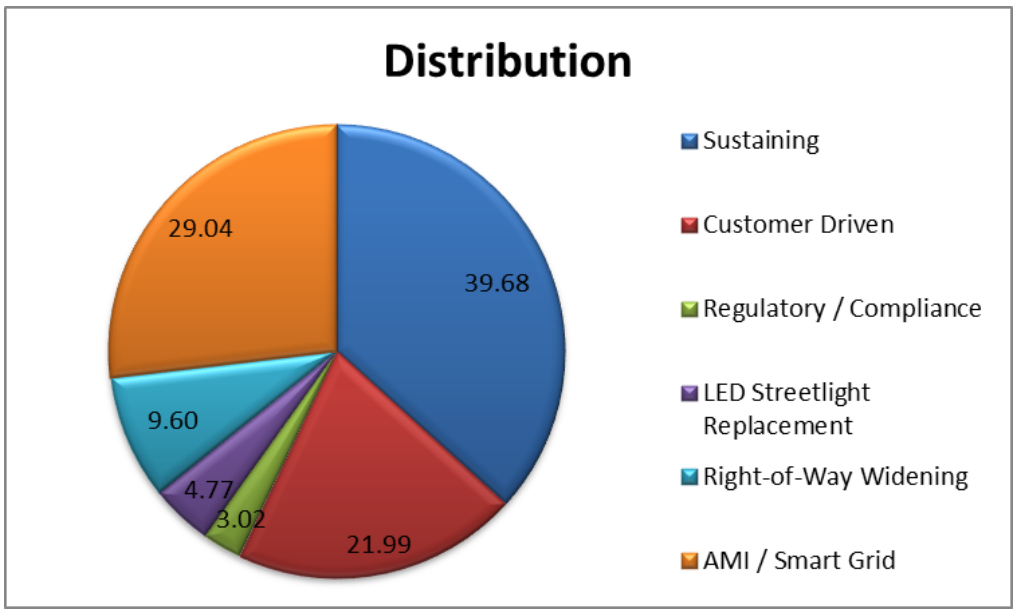
Figure 10: Distribution Spend – Historical, Forecast and Budget ($M)



F = Forecast, B=Budget in above figure

Figure 11 provides a breakdown of the 2018 distribution spend by investment type.

Figure 11: 2018 Distribution Spend by Investment Type



T&D investment in the 2018 ACE Plan is driven by the asset management approach as described in Section 6.2 of the CEJC. The asset management approach evaluates condition and criticality to determine the failure risk of different asset groups and provides priorities for the maintenance and replacement of these assets. NS Power's asset management strategy and inspection program results feed up into this selection process, aimed largely at sustaining capital investments. This provides NS Power the ability to appropriately invest in assets only where needed, keeping costs as low as possible for the benefit of our customers.

Inspection programs are established for Transmission Line, Substation and Distribution Line assets. The frequency for inspection varies by asset class and ranges from on-line monitoring to monthly or bi-annual assessments. The inspection results play an important role in identifying deteriorated equipment and are used to identify and prioritize capital projects. Regulatory and compliance requirements also drive T&D projects, such as the T&D polychlorinated biphenyl (PCB) contaminated equipment replacement projects included in the 2018 ACE Plan.

As noted above, the Performance Standards approved by the Board came into effect on January 1, 2017.[11] All T&D projects in the 2018 ACE Plan will contribute to meeting these performance standards targets. T&D projects in the 2018 ACE Plan are selected based on the asset management methodology pursuant to section 6.2 of the CEJC, guiding investments to where they are needed most. As noted by NS Power during the Performance Standards proceeding, no additional capital investment beyond the regular sustaining capital investments NS Power makes through its ACE Plan program are required to meet these standards.

Increases in storm reliability focused investments are being pursued as a result of weather events such as Post-Tropical Storm Arthur (PTSA). As a result of the findings of the PTSA proceeding, increases in the transmission and distribution right-of-way widening

[11] Performance Standards, UARB Order, M07387, December 20, 2016.

routines (T010 and D010, respectively) were proposed in the 2016 ACE Plan. This year, consistent with the 2017 ACE Plan and in accordance with the Board's 2016 ACE Plan Decision and Order, the investment related to transmission right-of-way widening has been separated into an individual capital work order for Board approval (CI 51969). The increased investment related to D010, the distribution right-of-way widening routine, has also been separated into an individual capital work order for Board approval (CI C0001950).

T&D capital expenditures in the 2018 ACE Plan are benefiting customers by focusing on sustaining capital to maintain the significant reliability gains achieved in recent years, and to improve storm related reliability through T010, CI 51969, CI C0001950 and D010.

Pole Testing

The UARB's decision with respect to CI 50772 – 37N-412 Glooscap Trail Rebuild provided as follows:

> In response to IR-3, NSPI stated that the average service life for distribution poles is 38 years; however, verification of the state of pole deterioration was based on visual inspection rather than on pole testing methods. The Board will address this issue separately at a later time.[12]

The UARB's decision with respect to CI 49862 – 50N-410 Trenton Rebuild also provided as follows:

> NSPI has stated that the existing poles are approximately 52 years old and have reached the end of their service life. In response to IR-3, NSPI stated that the average service life for distribution poles is 38 years, however, verification of the state of pole deterioration was based on visual inspection rather than on pole testing methods. The Board will address this issue separately at a later time.

[12] CI 50772 – 37N-412 Glooscap Trail Rebuild, UARB Decision Letter, M07997, August 21, 2017.

> NS Power's current practice for evaluating pole condition for replacement or upgrade is based on visual inspection by a Regional Planner qualified in assessing distribution assets. This visual inspection practice has served as an adequate method for evaluating poles, and feeds into the Board approved T&D asset management methodology as described in Section 6.2 of the CEJC.[13]

NS Power continually explores opportunities to supplement and improve upon its practices. As such, NS Power obtained four pole testing drills for distribution poles, one pole testing drill for transmission poles, and the supporting software. Preliminary trials were conducted in 2017 to examine how drilled pole testing might supplement NS Power's practice of visual inspections. NS Power will be developing engineering practices, work methods and associated processes to incorporate some measure of pole testing into the T&D inspection and capital management programs in 2018.

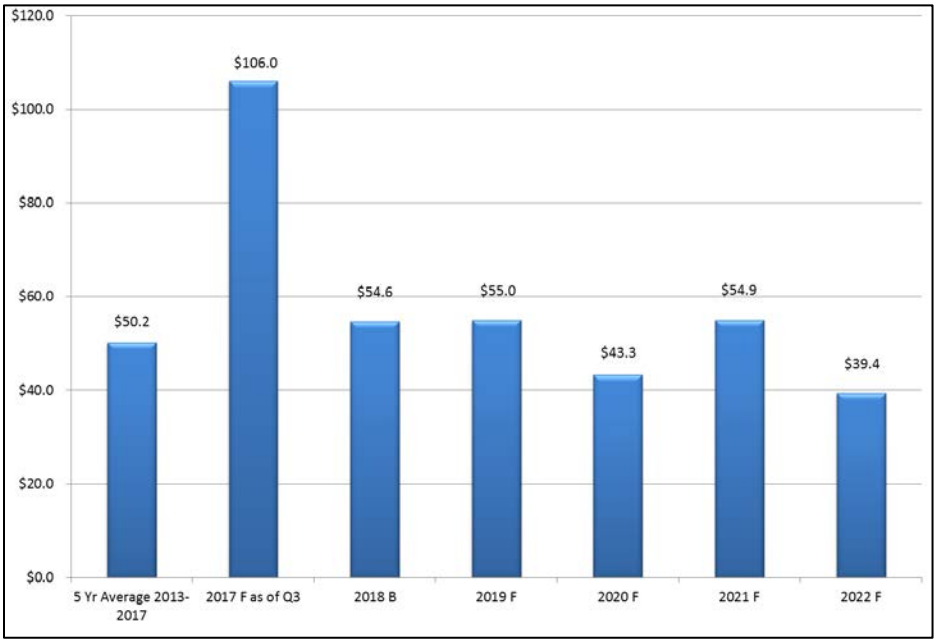
2.1.3 General Plant

General Plant includes information technology, computer infrastructure and communication equipment, which comprise the majority of capital expenditures incurred under this function. Other items such as office equipment, vehicles, and construction equipment are also included under this function.

The General Plant function also includes all buildings except generating and substation facilities. It primarily pertains to customer service, work depot and head office facilities. The increased investment in 2017 was driven by the Enterprise Resource Planning (ERP) project (CI 44671). **Figure 12** below illustrates NS Power's capital spending on General Plant, including historical, forecast and budget.

[13] CI 49862 – 50N-410 Trenton Rebuild, UARB Decision Letter, M07998, August 21, 2017.

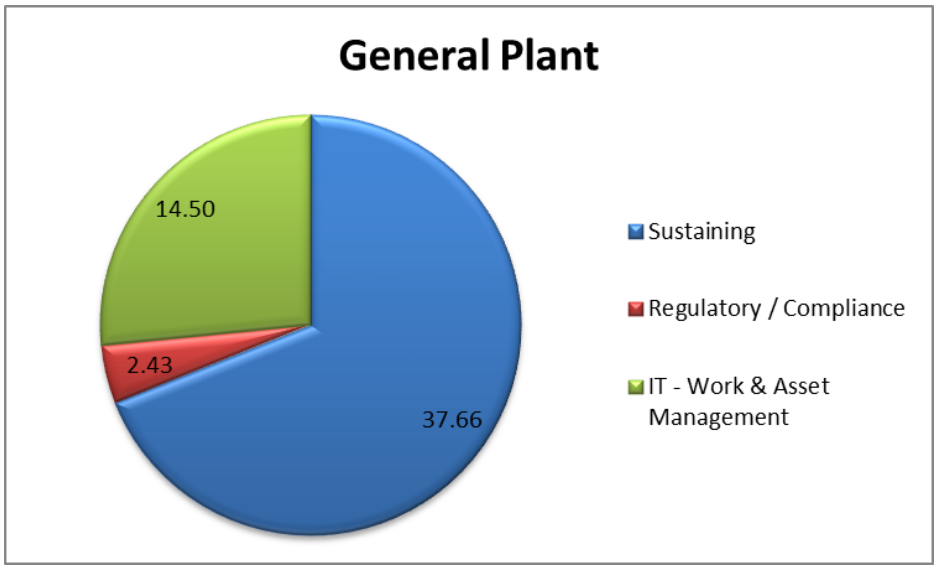
Figure 12: General Plant Spend – Historical, Forecast and Budget ($M)



F = Forecast, B=Budget in above figure

Figure 13 provides a breakdown of the 2018 general plant spend by investment type.

Figure 13: 2018 General Plant Spend by Investment Type



IT is the largest of asset investments in the General Plant category in the 2018 ACE Plan. NS Power has historically maintained relatively low investments on IT capital assets to the benefit of customers. These low cost investments were aligned to the conditions and requirements at that time – a period of relative stability with the information technology platforms which were managed to sustain them and extend their useful life to the maximum extent possible, as outlined in the information technology investment plan.[14]

Over the past several years, there has been an increase in technology requirements. Drivers influencing the pace of change in NS Power's technology requirements include:

1. An increase in customer expectations to access information, control services, and conduct business with NS Power through multiple technology platforms, making interactions with NS Power easier and quicker and enabling customers to conduct business with NS Power 24 hours a day, 7 days a week. Please refer to Section 2.2.2 below.

2. An increase in regulatory[15] and legal compliance requirements to implement new controls and provide information in more detail and in a timely manner.

3. An increase in the level of integration of business processes within the Company and with external businesses and agencies.

4. Software vendors increasing the frequency of new releases and expanding the amount of business functionality.

5. Acceleration in technology turnover has resulted in increased technology obsolescence.

[14] 2017 ACE Plan, NSUARB IR-71 Attachment 1, M07745, January 5, 2017.
[15] NS Power is required to comply with the NERC reliability standards that fall under the Critical Infrastructure Protection (CIP) program.

6. An increase in the volume and sophistication of cyber-related threats.

NS Power will need to continue to make more investments in its IT assets as a result of these changes.

NS Power adopted an IT asset management methodology and justification criteria for technically justified IT projects, which is based on the Board approved Generation, Transmission, and Distribution asset management methodology, both of which are found in section 6.2 of the CEJC. The IT asset management methodology evaluates assets on condition and criticality, providing a methodology for NS Power to prioritize and select those IT projects that are most needed at that time. NS Power also introduced new Technical, Customer Experience, and Economic sub-justifications to IT projects contained in section 17.13 of the CEJC.

NS Power has a number of major IT assets that are at or near end-of-life. For example, the Board approved ERP project (CI 44671), which is nearing completion, and is justified, in part, by the obsolescence of those assets and their criticality in running the day-to-day operations of the Company. Major IT projects and initiatives and their forecasted timelines are outlined in the **Figure 14** below.

Figure 14: Schedule of Major IT Projects

2014	2015	2016	2017	2018	2019	2020	2021	2022	
					Customer Information System (CIS)				**$40M**
			T&D Work & Asset Management						**$46M**
	Enterprise Resource Planning (ERP)								**$90M**
		CyberSecurity							**$15M**
Foundational IT Assets & Services									**$28M**

All of these large IT projects and initiatives are critical to the operation of the Company, many are highly complex, and have significant levels of uncertainty early in their development. NS Power is on track with this forecasted plan and expects to file the capital work order for the T&D Work and Asset Management Project in 2018.

As noted above, NS Power's IT capital expenditures over the next several years will be higher than the historical investment profile. These investments will address many of the aforementioned changes currently facing NS Power, and set the Company up for more regular, incremental IT upgrades to keep pace with the rapid evolution of technology and customer demands. NS Power has developed a governance model to manage these IT assets so that they are appropriately evaluated and justified, risks are mitigated, and are cost effective, providing clear benefits to customers.

2.2 Emerging Trends

In addition to the traditional capital asset classes and the factors influencing corresponding investments, innovation and customer experience projects will feature more prominently in NS Power's capital expenditures going forward.

2.2.1 Innovation Initiative

Innovation capital projects refer to non-traditional capital investments that focus on technologies, solutions or enhancements in order to adapt to Federal and Provincial environmental policy, or to better adapt to evolving customer needs and expectations within an equally evolving electricity sector. The value of these projects is expected to go beyond the assets themselves, providing NS Power with data and learnings on how best to tackle modern problems and how to best serve customers.

Projects aimed at adapting to environmental policy feature prominently in these investments. The Provincial and Federal governments are moving toward a low carbon future, putting in place increasing environmental policies. In Nova Scotia, the Renewable

Electricity Regulations prescribe that NS Power must provide 25 percent of energy from qualifying renewable resources, increasing to 40 percent in 2020.

On November 21, 2016, the Government of Canada announced that it would accelerate coal phase out, to be completed by 2030. An Agreement in Principle was signed between the Federal and Provincial governments to arrive at a modified Equivalency Agreement in order to continue coal unit operation past 2030 in Nova Scotia, to protect value for customers and acknowledge that they have already invested in advancing carbon reduction in this jurisdiction. On September 29, 2017, the Province of Nova Scotia introduced Bill No. 15 - An Act to Amend Chapter 1 of the Acts of 1994-95, the Environment Act which is enabling legislation needed to establish a cap and trade system within the province. The bill passed through the Nova Scotia Legislature and received Royal Assent on October 26, 2017.

NS Power is a part of this change. NS Power is integrating innovation technologies onto the grid through various capital projects for the benefit of customers. This is exemplified by NS Power's Intelligent Feeder Project (CI 49787), which was approved by the UARB on August 21, 2017. This project is exploring the viability of grid scale battery storage systems, their value in supporting the integration of variable renewable energy, and the provision of other reliability services on the power system. The Intelligent Feeder project will receive partial funding from government bodies: Sustainable Development Technology Canada is providing funding in the amount of approximately $625,000. This funding will significantly reduce the overall capital costs for NS Power's customers.

Another example is NS Power's application for approval of an Electric Vehicle Charging Station Network Pilot Project (CI 50295) which is before the Board as of the time of this Application. The purpose of the proposed Pilot Project is to enable NS Power to understand the impacts on its electrical system of the use of fast charging stations, which will inform future decisions to ensure grid stability as EV adoption increases. Approximately fifty percent of the proposed Pilot Project funding has been conditionally

approved to come from Natural Resources Canada, providing an opportunity for NS Power to examine EV fast charging stations at a lower cost for customers.

There is significant federal funding available to help public and private sectors enable new innovation opportunities to strengthen infrastructure and accelerate towards a low carbon future in line with Canada's environmental commitments.[16] NS Power is pursuing these opportunities to expand innovation programs and services, and leverage incremental benefits for customers while reducing costs for customers.

The value of grid innovation and new customer solutions projects is expected to go well beyond the physical assets themselves, providing NS Power with data and learnings on how best to tackle modern problems and how to best serve customers. The development of core knowledge related to new innovation solutions needs to be paired with the understanding of NS Power's existing system in order to determine the feasibility of integrating them into the grid and the best means to maximize customer benefits as NS Power adapts to the energy future.

2.2.2 Customer Experience

Customer expectations are changing. Rapid advances in technology, the offerings customers receive from other service providers, and the availability and control of information 24 hours a day are driving changes in customer expectations. The widespread adoption of smart phones is a prime example of how quickly technology can shape the way that we interact with each other and with our service providers.

Customers measure NS Power against other service offerings and businesses, many of whom have embraced technology to provide customers with better service and

[16] http://www.infrastructure.gc.ca/plan/placemat-tableausynthese-eng.html.
http://www.budget.gc.ca/2017/docs/plan/chap-02-en.html

experiences. Today's customers have access to web-available information and portals on the services they use, providing greater ease of access to their service providers and a better customer experience.

As described above, NS Power has historically kept IT investment relatively low in an effort to keep costs low for customers while mitigating risks related to cyber security, at a time when the pace of technology and customer expectations did not demand great investment. However, as customer expectations have changed, greater investment in IT assets to enhance the customer experience is warranted.

Accordingly, NS Power is committed to improving the customer experience, and is doing so through IT capital investments. Customers have advised NS Power through regular contact with the Company and transactional research (contacting customers for their feedback after a transaction with the Company) of their expectations and areas that could use some improvement. Customer experience capital investments are targeted to meet customer expectations regarding 1) keeping our commitments, 2) doing it right the first time, and 3) communicating proactively.

With these in mind, NS Power has identified eight key customer experiences for improvements through capital investment:

1. Customer Tree Trimming
2. Billing
3. Outage
4. Building & Wire Inspection
5. Reno & Wire Inspection
6. Streetlights
7. Arrears
8. Move in/Move out

Full end-to-end redesigns of the key experiences will be carried-out over the next three to five years in order to address process improvement opportunities.

NS Power has already completed or is currently executing several Board-approved customer experience projects, including:

- CI 48234 - Customer Support System Enhancement
- CI 46739 - IT - Outage Map Technology Upgrades
- CI 49212 - IT - My Account Single Sign-On
- CI 48238 - Customer Billing Experience Improvements
- CI 48236 - Customer Experience Self-Serve Development Phase 1

Remaining customer experience projects that form NS Power's overall customer experience initiative will be submitted for approval and execution in 2018, 2019 and 2020.

In order to aid the UARB and stakeholders in their review of customer experience projects, NS Power has added a "Customer Experience" sub-justification criteria under Section 17.13 Information Technology Application and Hardware System of the CEJC. Although certain customer experience projects may result in cost savings, these project are not based on economics – as stated above, their primary justification is the improvement of customers' experience with the Company.

NS Power is committed to keeping pace with our customers as the technology they use and their expectations continue to evolve. NS Power will keep pace and improve customer experience through the customer experience initiative, and the redesign of the eight key customer experiences. This will provide tangible, "front facing" benefits to our customers.

There are no customer experience capital projects submitted for approval in the 2018 ACE Plan. However, two customer experience projects are scheduled for submission separately

in 2018 as noted in Section 4.3 - 2018 ACE Plan Capital Items Forecast for Subsequent Approval.

3.0 2017 ACE PLAN FOLLOW-UP

Before providing in detail the 2018 ACE Plan capital expenditures in Sections 4.0 to 9.0, Section 3.0 addresses items from the 2017 ACE Plan. These items include a summary of the outcome of stakeholder engagement discussions, a list of subsequent submittal capital items from the 2017 ACE Plan that are planned to be submitted before year-end, as well as items from the 2017 ACE Plan that have been deferred or cancelled. This is a new section in the 2018 ACE Plan intended to provide additional clarity for the Board and stakeholders.

3.1 Stakeholder Engagement

NS Power engaged in stakeholder consultations as an outcome of the 2017 ACE Plan proceeding, consistent with years prior. In the 2017 ACE Plan Decision, the Board acknowledged that "[i]t is now undeniable that discussions between stakeholders have greatly improved the quality of NSPI's ACE Plan filings and allowed for their more efficient review",[17] and directed NS Power to lead the consultative process[18] on the 2017 ACE Plan Terms of Consensus items. Stakeholder consultation sessions were held throughout 2017, and a report regarding these was submitted to the UARB on September 5, 2017, along with a revised Detailed and Summary CEJC for the Board's information and approval, respectively. Highlights of those discussions and the report are provided below.

3.1.1 CEJC Updates

Revisions to the CEJC were proposed by NS Power for review by stakeholders. These revisions were discussed in detail during the 2017 stakeholder engagement sessions. The substantive revisions to the CEJC include the following:

[17] 2017 ACE Plan, UARB Decision, M07745, April 4, 2017, para 79.
[18] 2017 ACE Plan, UARB Decision, M07745, April 4, 2017 para 145.

- Information Technology Investment Governance – Language incorporated in sections 6.1, 6.2 and 17.13 describing the newly developed IT investment governance including investment planning process, prioritization, and investment justification criteria. This addresses the Board's 2017 ACE Plan Order directive #6 for the provision of an IT governance model.

- Scope Change Capital Work Orders – Revisions to sections 1.0, 10.0, 12.1 and 12.2 have been made to separate Scope Change capital work orders from ATO capital work orders. This reflects the mutually exclusive nature of Scope Change capital work orders and ATOs.

The revised Summary and Detailed CEJC were submitted to the UARB on September 5, 2017 for the UARB's approval and information, respectively. The Board approved the Summary CEJC on October 24, 2017.

3.1.2 Revenue Requirement

NS Power has continued to work with stakeholders and their consultants on the issue of the revenue requirement directive (Section 10.1.1). The 2017 ACE Plan Terms of Consensus (Terms of Consensus) provided the following:

> NS Power agrees to amend the stakeholder version of the Revenue Requirement table in the ACE Plan to address the CA's concerns. Parties agree to defer discussion of the specific amendments to a subsequent stakeholder analysis between NS Power and interested stakeholders, for implementation into the 2018 ACE Plan.[19]

The stakeholder version of the 2017 ACE Plan "Long-Term Capital Planning & Revenue Requirement" table was provided in Excel format to the consultants for the CA and SBA. The consultant for the CA subsequently provided suggested revisions and a corresponding mock-up of its version of the table using its methodology. This revised version of the

[19] 2017 ACE Plan, UARB Decision, M07745, April 4, 2017, Attachment 1 - Terms of Consensus, page 1 of 3.

stakeholder revenue requirement table has been incorporated into the 2018 ACE Plan alongside NS Power's table. This is in Section 8.1.1 – Impact of 2017 ACE Plan on Revenue Requirement and Affordability.

3.1.3 Replacement Energy Calculation (REC)

The 2017 ACE Plan Terms of Consensus provided the following:

> NS Power will consult with stakeholders on its replacement energy cost calculations for hydro and non-hydro generation, including discussions on locational costs, capacity factor and seasonal generation output. Parties agree no further amendments to the replacement energy cost calculation methodology are required at this time and to further discuss this issue as part of a subsequent stakeholder consultation process.[20]

NS Power and interested parties have not reached agreement on the overall REC calculation methodology. NS Power maintains its position as set out in Section 8.1.9 of the 2017 ACE Plan: NS Power's current Variable Dispatch REC calculation methodology is best suited for today's power system based on years of refinement and experience with other methodologies. NS Power is committed to further discussion on this topic with stakeholders as part of the 2018 ACE Plan proceeding.

NS Power proposed revisions to the calculation of the hydro generation component of the REC calculation methodology, which replaces hydro energy with only dispatchable Renewable Energy Standards (RES) compliant sources of electricity. NS Power submits that the proposed change to the hydro REC calculation methodology reflects the reality of RES compliance and is consistent with the stated approach filed with the 2017 ACE Plan engagement report. No parties have expressed opposition to the Company's proposed hydro generation replacement energy methodology.

[20] Ibid, page 1 of 3.

3.1.4 Projects Under $250,000

The 2017 ACE Plan Terms of Consensus provides the following:

> NS Power provided clarification regarding the number and selection of capital expenditures under $250,000 in the 2017 ACE Plan. NS Power agrees to the CA's recommendation for the Board to monitor the trend on these expenditures. The Parties also agree to further discuss the selection process for projects under $250,000 as part of a subsequent stakeholder consultation process.[21]

NS Power provided clarification to interested parties regarding the selection of projects under $250,000, and also proposed additional detail in the under $250,000 project list in future ACE Plans. Interested parties reviewed and provided feedback, including a request for historical information on those projects. NS Power and interested parties reached agreement on the final revised table which now includes:

- (i) the number of projects under $250,000 for the past five years per asset class; and (ii) the dollar value associated with each asset class;
- a brief description of the work to be completed under the project, and
- the ranking of the project pursuant to NS Power's asset management methodology.

Please refer to Section 4.4 for the new Capital Items under $250,000 table.

3.1.5 Information Technology Capital Investments

The 2017 ACE Plan Terms of Consensus provided:

[21] Ibid, page 2 of 3.

> NS Power agrees to hold a separate stakeholder session specifically with respect to providing additional information to stakeholders on the Company's future IT investments and overall IT strategy.[22]

The Board's Order approving the 2017 ACE Plan directed as follows:

> The Board directs NSPI to develop the new IT governance model as soon as possible and to file it with the Board once completed, and in any case, no later than with the next ACE Plan filing.[23]

In compliance with the 2017 ACE Plan Terms of consensus, NS Power held a technical conference regarding the Company's future IT investments and strategy on April 6, 2017.

With respect to the new IT governance model, pursuant to the Board's 2017 ACE Plan Order, NS Power developed a new IT investment governance methodology and incorporated it into the CEJC. The IT investment governance details and the corresponding revisions to the CEJC were presented to interested parties and Board staff.

This IT investment methodology is based on the current Board approved Generation, Transmission and Distribution asset management methodology pursuant to Section 6 of the Summary CEJC. The Company sought to provide clarity to interested parties and the Board by aligning its IT investment methodology with that of its existing Generation, Transmission, and Distribution methodology.

3.2 2017 Capital Items Pending Submission

The UARB provided the following directive in its 2017 ACE Plan Order:

> 9. The Board directs NSPI to include, as part of their annual ACE Plan submissions, a list of projects which appear as items for subsequent submission in a prior years' ACE Plan filing, which have not been

[22] Ibid, page 2 of 3.
[23] 2017 ACE Plan, UARB Order, M07745, April 4, 2017.

submitted for approval at the time of an ACE Plan filing, but which NSPI intends to submit by the end of the calendar year.[24]

Figure 15 identifies projects included in the 2017 ACE Plan as items for subsequent approval, but not yet submitted to the Board. NS Power anticipates these projects will be filed for approval in late 2017. These 2017 projects will carry over into 2018 and total $864,059 of 2018 forecast spending. These budget numbers were estimates at the time the 2017 ACE Plan was prepared and are subject to change when the scope and details of the projects are refined and provided for approval.

Figure 15: Pending 2017 Subsequent Submittal Items

CI #	Project Title	2018 Budget ($)	Project Total ($)
Gas Turbine			
49940	LM6000 TUC5 Control System Upgrade *This project includes the upgrade of the control system on the Tufts Cove Unit #5 LM6000.*	811,559	811,559
Total New Steam Spending for Subsequent Approval		**$811,559**	**$811,559**
General Plant			
48837	AMO Fleet Environmental Data Management *This project includes development and integration of an Environmental Data Management System to improve consistency, eliminate duplication and increase automation with respect to environmental reporting).*	52,500	259,380
Total New Wind Spending for Subsequent Approval		**$52,500**	**$259,380**
Total New Generation Spending for Subsequent Approval		**$864,059**	**$1,070,940**

3.3 2017 ACE Plan Subsequent Submittal List Status Update (Schedule C from 2017 ACE Plan Decision)

[24] 2017 ACE Plan, UARB Order, M07745, April 4, 2017.

Figure 16 below provides an update to Schedule C from the UARB's 2017 ACE Plan Decision.

Figure 16: Subsequent Submittal List Status Update

CI#	Project Title	2017 Budget ($)	Project Total ($)	2017 Budget ($)	Project Total ($)	Status
Generation						
39472	HYD Mersey Hydro System Re-Development	300,000	84,000,000	1,223,368	83,595,607	ACE 2018 Subsequent Submittal
29807	HYD - Tusket Falls Main Dam	3,697,643	9,940,664	633,477	18,157,609	Submitted, Awaiting UARB Review & Approval
47654	HYD - Gulch Penstock & Surge Tank Replacement	3,526,825	3,629,655	4,941,095	4,970,542	Approved
48533	HYD - Lequille Headpond Water Retaining Structures Refurbishment	1,809,228	1,919,166	4,209,710	4,472,369	Submitted in ACE 2018 for Approval
48052	HYD - Annapolis HVAC Upgrade	1,420,463	1,498,367	1,489,457	1,573,596	Approved
47648	HYD - Lequille Pipeline Replacement	1,329,928	1,384,448	1,099,345	1,121,253	Approved
47876	HYD - Lequille Overhaul	1,075,450	1,155,418	1,282,307	1,395,229	Approved
38931	HYD - HYD Harmony Site Stabilization	586,469	1,106,122	436,088	931,942	Submitted, Awaiting UARB Review & Approval
49596	HYD - Hells Gate 2 Overhaul	962,316	970,827	1,174,411	1,204,263	Approved
47678	Prince Mine Dam Decommissioning	761,647	819,451	725,992	815,792	Pt Aconi project
47682	HYD - Lequille Switchgear Replacement	651,251	698,659	761,326	776,391	Approved
48913	HYD - Tusket Facility Refurbishment	656,308	657,956	516,273	1,183,470	Submitted, Review Deferred
49835	HYD - Dive Site Risk Mitigation	315,851	650,533	-	-	Cancelled
49598	HYD - Gisborne Switchgear Replacement	593,754	623,814	747,450	747,450	Approved
47166	HYD - McAskill Brook Decommissioning	459,736	562,684	5,422	531,701	Deferred to 2019
48914	HYD - Malay Falls Facility Refurbishment	444,589	446,237	473,203	1,034,045	Submitted, Awaiting UARB Review & Approval
48396	HYD - Bridge Remediation	338,935	404,616	594,252	677,591	Submitted, Awaiting UARB Review & Approval
47660	HYD - Dickie Brook Controls Upgrade	94,032	307,251	228,354	863,451	ACE 2018 Subsequent Submittal
49039	HYD - Lequille Controls Upgrade	298,302	304,121	757,515	762,912	Approved
46499	Stator Rewind Kit Capital Spare	2,668,808	5,219,939	2,809,254	2,871,003	Approved
48893	TUC3 IP Turbine Refurbishment	4,338,274	4,798,475	4,788,455	4,871,454	Approved
47531	TRE6 Turbine Refurbishments	1,500,000	2,322,487	875,667	1,704,784	Approved
49438	LIN A Gallery Floor Replacement	593,814	593,814	591,761	591,761	Approved
49499	PHB - Boiler Refurbishment 2017	484,730	484,730	593,740	593,740	Approved
49111	POT - Air heater refurbishment	462,168	471,204	263,054	272,538	Approved
49538	TRE6 Generator Refurbishment	411,766	411,766	784,610	784,610	Approved
47553	TRE6 Turbine Main Valves	392,887	392,887	570,600	570,600	Approved
49674	TUC2 Boiler Selective Waterwall Tube Replacements	390,898	390,898	421,518	421,518	Approved

CI#	Project Title	2017 Budget ($)	Project Total ($)	2017 Budget ($)	Project Total ($)	Status
49060	POT - Condenser Dog Bone Expansion Joint Replacement	298,253	298,253	139,182	139,182	Now less than $250k
48868	AMO Fleet TWIP Upgrades	257,442	280,608	-	-	Cancelled
44776	CT - TUC#5 LM6000 Generator Stator Re-wedge	1,041,614	1,073,280	1,331,547	1,361,301	Approved
49273	CT-BGT2 Engine Refurbishment	908,102	1,019,832	2,036,393	2,170,157	Submitted, Awaiting UARB Review & Approval
49940	LM6000 TUC5 Control System Upgrade	1,018,769	1,018,769	811,559	811,559	Pending 2017 Subsequent Submittal
49594	LM6000 TUC5 Airhouse Upgrade	833,200	833,200	830,287	916,391	ACE 2018 Subsequent Submittal
49926	LM6000 TUC4 Airhouse Upgrade	815,633	815,633	417,303	417,303	Awaiting Submission, no 2018 Spend
49949	LM6000 TUC4 Control System Replacement	710,815	710,815	12,178	856,847	Deferred to 2019
47118	CT Tusket Hydraulic Starter	317,015	317,015	-	-	Cancelled
Transmission						
43678	Separate L8004/L7005 on Canso Crossing Double Circuit Tower(DCT)	13,892,444	16,183,691	16,663,946	19,251,601	Awaiting Submission, no 2018 Spend
45053	69Kv Structure Replacements West	321,656	4,818,017	-	4,818,017	Deferred to 2019
50342	Western Transmission System Voltage Support	300,000	4,000,000	-	-	Cancelled
49879	77V-T52 Replacement	746,631	775,082	766,073	772,208	Approved
50021	91H Tufts Cove Bus and Line Upgrades	417,178	417,178	-	200,000	Deferred to 2019
49928	3S Gannon Rd. Bus Reconfiguration	364,777	364,777	371,395	371,395	Approved
49922	Western Switching Upgrades	353,906	353,906	378,843	378,843	Approved
49929	Tap Changer Replacements	262,526	262,526	318,236	318,236	Approved
Distribution						
50343	Advanced Metering Infrastructure	11,352,709	111,707,380	-	-	Combined as part of 47124
47124	Advanced Metering Infrastructure	5,756,276	8,274,738	4,212,234	133,228,952	Submitted, Awaiting UARB Review & Approval
47776	111S Prime Brook Feeder Exits & Feeders	456,805	1,503,986	457,449	1,504,630	Approved
47787	2H Armdale New Feeder	1,253,299	1,285,679	988,498	988,498	Approved
47760	85S-402 Re-Insulate	499,495	1,259,666	665,520	1,551,859	Approved
44749	Tiverton Tower Refurbishment	689,416	1,058,200	132,611	1,465,132	Submitted, Awaiting UARB Review & Approval
50341	2017 Substation Recloser Replacements	577,388	577,388	604,889	604,889	Approved
49899	10H Halifax 4kV Conversion Year 4	254,608	254,608			Now less than $250k
General Plant						
46075	IT - Work & Asset Management	8,008,495	28,027,680	14,498,734	45,509,963	ACE 2018 Subsequent Submittal
43202	Replace Mobile Radio System	2,975,666	6,537,700	3,495,425	6,296,878	Approved
49857	IT - Storage Infrastructure Upgrade	945,955	5,045,955	1,753,387	1,901,189	Submitted, Awaiting UARB Review & Approval
49860	IT - Sharepoint Upgrade	1,971,915	4,021,915	1,737,452	3,903,594	Submitted, Awaiting UARB Review & Approval
49093	IT - Security Operations Center (SOC) and Security Information Event Monitoring (SIEM)	2,191,284	2,476,976	-	2,476,976	Deferred to 2019
49787	Intelligent Feeder/Storage Project (SDTC)	1,276,653	2,399,368	2,530,028	2,782,384	Approved

CI#	Project Title	2017 Budget ($)	Project Total ($)	2017 Budget ($)	Project Total ($)	Status
49859	IT - Windows Server 2008 Upgrade	158,886	2,069,258	-	2,069,258	Deferred to 2019
49855	Window 10 Migration Project	1,804,339	2,013,034	3,182,591	4,620,516	Submitted, Awaiting UARB Review & Approval
50153	Self Serve Development Phase 2	1,827,720	1,827,720	469,376	1,160,528	Submitted, Awaiting UARB Review & Approval
49094	IT - Identity Access Management Infrastructure	1,500,000	1,711,147	800,000	977,498	ACE 2018 Subsequent Submittal
49858	IT - Microsoft Exchange Upgrade	1,500,000	1,500,000	1,555,597	1,555,597	ACE 2018 Subsequent Submittal
48773	IT - VOIP Expansion to NSPI sites	1,400,000	1,499,731	253,858	1,708,923	Submitted, Awaiting UARB Review & Approval
49480	IT - Disaster Recovery	1,270,691	1,483,365	494,282	6,312,277	ACE 2018 Subsequent Submittal
49601	IT - Data loss Prevention	1,158,633	1,199,013	-	1,166,334	Deferred to 2019
49600	IT - Network Architecture Redesign	1,033,597	1,183,826	-	2,409,750	Deferred to 2019
49876	Real Time Economic Dispatch	816,638	1,161,618	-	1,161,618	Deferred to 2019
50112	Consolidated Customer Web Portal	770,977	770,977	654,004	1,190,588	ACE 2018 Subsequent Submittal
50113	Customer Experience - Streetlight improvements	679,394	679,394	366,223	875,836	Submitted, Awaiting UARB Review & Approval
47751	Dynamic Transmission Limits	524,616	537,466	-	537,466	Deferred to 2019
49603	IT - Patch Management	500,970	536,350	-	-	Cancelled
48238	Customer Billing Experience Improvements	124,280	490,878	162,279	405,324	Approved
48044	Bentley Nevada Upgrade and Integration to Fleet Monitoring	383,621	401,459	-	401,459	Deferred to 2019
48155	2016 SCADA Application Upgrade	261,387	400,688	261,387	400,688	Approved
50295	Electric Vehicle Infrastructure Deployment	300,000	400,000	415,068	419,908	Submitted, Awaiting UARB Review & Approval
50132	Joint Regulation	236,175	387,704	-	387,704	Deferred to 2019
49953	IT - CIS High Availability	354,578	354,578	437,788	519,023	Submitted, Awaiting UARB Review & Approval
50292	FAC - Kempt Road Depot Truck Bay	340,656	340,655	601,282	1,095,720	Submitted, Awaiting UARB Review & Approval
50115	Customer Support System Enhancement	310,647	332,847	-	-	Cancelled
48837	AMO Fleet Environmental Data Management	304,404	317,215	206,880	259,380	Pending 2017 Subsequent Submittal
49856	IT - ITSM Replacement	300,000	300,000	-	-	Cancelled

3.4 2017 ACE Capital Items Deferred / Cancelled

NS Power's list of deferred and cancelled capital work orders relative to the 2017 ACE Plan are noted in **Figure 17**. Given the timing of the filing of this Application, **Figure 17** does not include 2017 ACE Plan Subsequent Submittal items that are planned to be

submitted after this Application has been filed and prior to 2017 year-end and does not include additional 2018 expenditures.

Of the 65 projects listed, no projects were included in the 2017 ACE Plan for approval. 28 of these projects were listed in the 2017 ACE Plan subsequent submittal list, to be filed separately as individual capital items. The remaining 37 projects were listed in the 2017 ACE Plan as projects under $250,000.

These 65 projects were originally included in the 2017 ACE Plan with a forecasted spend of $31million in 2017. 17 of these projects have been cancelled, while 48 have been deferred to future years.

Figure 17: 2017 ACE Items – Deferred or Cancelled

CI#	Project Title	2017 ACE Project Total	Cancelled/ Deferred	Deferred To	Prior Approval	Prior ACE Plan Reference	2018 ACE Plan Reference
Generation							
39472	HYD Mersey Hydro System Re-Development *Further consultation with First Nations was required in 2017 in order to proceed with this project, pushing the start of this project to late 2018*	84,000,000	Deferred	2018		Subsequent Submittal	Subsequent Submittal
48533	HYD - Lequille Headpond Water Retaining Structures Refurbishment *Further analysis of the most recent flood study completed on Lequille is required to validate the dam classification.*	1,919,166	Deferred	2018		Subsequent Submittal	Request Approval
49594	LM6000 TUC5 Airhouse Upgrade *Vendor fabrication of components could not be completed to align with the planned TUC5 annual outage.*	833,200	Deferred	2018		Subsequent Submittal	Subsequent Submittal
49949	LM6000 TUC4 Control System	710,815	Deferred	2019		Subsequent	

CI#	Project Title	2017 ACE Project Total	Cancelled/ Deferred	Deferred To	Prior Approval	Prior ACE Plan Reference	2018 ACE Plan Reference
	Replacement					Submittal	
	Internal review of control systems is ongoing. NS Power expects to complete controls upgrade on TUC5 in 2018, and TUC4 in 2019.						
49835	HYD - Dive Site Risk Mitigation	650,533	Cancelled			Subsequent Submittal	
	Changes in procedure and dive requirements have mitigated the risk and negated the requirement for project.						
47166	HYD - McAskill Brook Decommissioning	562,684	Deferred	2019		Subsequent Submittal	
	Project delayed as engagement with First Nations is undertaken.						
47118	CT Tusket Hydraulic Starter	317,015	Cancelled			Subsequent Submittal	
	A new valve technology has led to the replacement of the air start system no longer being required.						
47660	HYD - Dickie Brook Controls Upgrade	307,251	Deferred	2018		Subsequent Submittal	Subsequent Submittal
	Project originally scheduled for a late 2017 start, has been pushed to a 2018 start as other control projects are being completed.						
48868	AMO Fleet TWIP Upgrades	280,608	Cancelled			Subsequent Submittal	
	This project was for a fleet wide upgrade. However, this is being split amongst the individual steam plants to better align with timing.						
49912	ICP - Armour Stone Refurbishment Phase 2	242,644	Cancelled			Less than $250k	
	This work is being completed under CI 49869 ICP Armour Stone Replacement U&U, approved on March 10, 2017.						
47834	ICP Ranger Motor Upgrade	242,512	Deferred	2018		Less than	Less than

CI#	Project Title	2017 ACE Project Total	Cancelled/ Deferred	Deferred To	Prior Approval	Prior ACE Plan Reference $250k	2018 ACE Plan Reference $250k
	This project is deferred to 2018 as conveyor modifications were found to be required prior to a motor upgrade.						
49452	LIN3 Heater Level Controls Upgrade *NS Power has deferred the planned outage on Lingan 3 in 2017; therefore this project will be completed in 2018.*	235,135	Deferred	2018		Less than $250k	Less than $250k
49874	CT-BGT Replace Halon Fire Protection *Fire protection at Tusket and Victoria Junction are being completed in 2017, which has reduced vendor availability to complete this work.*	226,366	Deferred	2019		Less than $250k	
47659	HYD - Fall River Controls Upgrade *Project originally scheduled for a late 2017 start, has been pushed to a 2018 start as other control projects are being completed..*	226,054	Deferred	2018		Less than $250k	Subsequent Submittal
49666	TUC1 South Boiler Feedpump Refurbishment *This project is deferred while NS Power addresses an issue on the north boiler feed pump which needs to be in operation to allow for the south boiler feed pump to come offline to complete this project.*	226,025	Deferred	2019		Less than $250k	
47655	HYD - Paradise Controls Upgrade *Project originally scheduled for a late 2017 start, has been pushed to a 2018 start as other control projects are being completed. Now included in ACE 2018 for approval.*	207,802	Deferred	2018		Less than $250k	Request Approval
49546	TRE6 FW Heater Level Control	187,434	Deferred	2018		Less than	Less than

CI#	Project Title	2017 ACE Project Total	Cancelled/ Deferred	Deferred To	Prior Approval	Prior ACE Plan Reference $250k	2018 ACE Plan Reference $250k
	Based on the daily monitoring of feedwater heater drain temperatures, the temperatures and level controls are stable. Therefore, this upgrade can be safely deferred to 2018.						
49547	TRE5 5-1 BFP Refurbishment *Condition assessments completed in 2017 determined the condition of the Boiler Feed Pumps allowed for this project to be safely deferred to 2018. Now included in ACE 2018 for approval.*	185,294	Deferred	2018		Less than $250k	Request Approval
49667	TUC1 Oil Purifier I&C Heater Replacement *This project is deferred while NS Power confirms that the technology installed on TUC3 works as expected. Once this is confirmed, this project will proceed.*	160,593	Deferred	2019		Less than $250k	
49991	TUC1 CEMS Replacement *Temporary repairs on TUC1 CEM allowed this project to be deferred to 2019 to allow for CEMS replacements on TUC3, 4 and 5 which were found to be higher priority,*	159,167	Deferred	2019		Less than $250k	
49676	TUC2 CEMS Replacement *This project is being deferred to 2018 to allow for CEMS replacements on TUC3, 4 and 5 which were found to be higher priority, Now included in ACE 2018 for approval.*	150,374	Deferred	2018		Less than $250k	Request Approval
45832	TUC6 Boiler Purge Credit *This project is dependent on similar work being implemented on TUC4 & 5, and those projects are still being developed.*	138,864	Deferred	2019		Less than $250k	
49654	TUC Refurbishment Gas Compressor 6A/6B	133,870	Cancelled			Less than $250k	

CI#	Project Title	2017 ACE Project Total	Cancelled/ Deferred	Deferred To	Prior Approval	Prior ACE Plan Reference	2018 ACE Plan Reference
	This project was initiated as a Steam project, however these compressors are better considered Gas Turbine projects related to the Tufts Cove 4 / 5 units, therefore two CIs (51731 and 51798) replaced this work. No change to the actual work completed.						
49711	TUC Low Load Oil Operation, Flue Gas monitoring *This project is cancelled as efforts are now focused on TUC3 low load operation*	130,429	Cancelled			Less than $250k	
49622	HYD - Fourth Lake PLC Upgrades *This project will now be completed as part of a larger Sissiboo River Controls Upgrade, currently planned for 2020.*	116,767	Cancelled			Less than $250k	
49456	LIN1 Electric Motor Refurbishment *Further analysis has shown the condition of the motors is such that investment is not required.*	113,171	Cancelled			Less than $250k	
49457	LIN3 Electric Motor Refurbishment *Further analysis has shown the condition of the motors is such that investment is not required.*	111,829	Cancelled			Less than $250k	
49670	TUC1 4kv/600V Breaker Replacement *Further analysis indicated the breakers scheduled for replacement can be safely deferred to 2018.*	104,851	Deferred	2018		Less than $250k	Less than $250k
49715	TUC Upgrade PLC Control Panel *Other DCS / PLC priorities are required to be completed prior to this project. Project can be safely deferred to 2019.*	99,875	Deferred	2019		Less than $250k	

CI#	Project Title	2017 ACE Project Total	Cancelled/ Deferred	Deferred To	Prior Approval	Prior ACE Plan Reference	2018 ACE Plan Reference
49699	TUC6 Access Doors *It has been determined that these areas do not require investment at this time. Current expectation is that it will be needed in 2019 as operating hours accumulate.*	64,304	Deferred	2019		Less than $250k	
49515	POT - Replacement of Graver valves and solenoids *Repairs completed on the existing valves and equipment mitigated the need for capital investment.*	59,496	Cancelled			Less than $250k	
49688	TUC3 Analytical Panel Upgrades *Further analysis of the Analytical Panel determined this project could be deferred until 2018*	55,050	Deferred	2018		Less than $250k	Less than $250k
49945	HYD - Malay Falls Switchgear Replacement *The amount included in the 2017 ACE Plan was for preliminary engineering which has been underway, with full construction scheduled for 2018. Now included in ACE 2018 for approval.*	54,729	Deferred	2018		Less than $250k	Request Approval
49700	TUC6 Vacuum Cooler *The condition of the vacuum cooler has allowed for a deferral to 2019. An inspection of the coating solution on the vacuum cooler completed in 2017 will further determine the required timing of the project.*	54,610	Deferred	2019		Less than $250k	
47909	TUC Nat Gas Valves Refurbishment *Further analysis of the natural gas valves indicated that this project could be safely deferred.*	54,153	Deferred	2019		Less than $250k	
49653	TUC Dehumidifier Air Unit *Due to the higher utilization of the TUC Units in 2017 than anticipated, the need for an additional dehumidifier is not*	51,073	Deferred	2019		Less than $250k	

CI#	Project Title	2017 ACE Project Total	Cancelled/ Deferred	Deferred To	Prior Approval	Prior ACE Plan Reference	2018 ACE Plan Reference
	required.						
49701	TUC6 Turbine Control Valves *As this turbine is of similar vintage to the Port Hawkesbury Biomass generating station, a determination of what is required on this turbine will be made based on the condition of the PHB turbine which will be assessed as part of the 2017 planned outage. This will determine the requirements of this project for 2019.*	50,584	Deferred	2019		Less than $250k	
49673	TUC1 Extraction Pump Rotork Valve Actuator *Further analysis indicated the Rotork Valve Actuator can be safely deferred to 2019.*	48,479	Deferred	2019		Less than $250k	
47907	TUC6 Vacuum Pumps' Seal Water Cooler Upgrade *The scope of this project will be completed as part of CI 49700 TUC6 Vacuum Cooler Upgrade.*	40,501	Cancelled			Less than $250k	
49932	CT - TUC 4 LM6000 Roof Skid Access *Further analysis determined additional requirements were required to the roof skid. Additional planning and a longer outage are required. Due to this change in project scope, the project is deferred to 2018.*	33,161	Deferred	2018		Less than $250k	Less than $250k
49933	CT - TUC 5 LM6000 Roof Skid Access *Further analysis determined additional requirements were required to the roof skid. Additional planning and a longer outage are required. Due to this change in project scope, the project is deferred to 2018.*	33,161	Deferred	2018		Less than $250k	Less than $250k
49959	CT - VJ Varec Gauges Upgrade/Refurbishment *Temporary repairs have been made to restore level indication which has allowed the deferral of this project to 2019.*	29,904	Deferred	2019		Less than $250k	

CI#	Project Title	2017 ACE Project Total	Cancelled/ Deferred	Deferred To	Prior Approval	Prior ACE Plan Reference	2018 ACE Plan Reference
Transmission							
45053	69kV Structure Replacements West *The planning study for this project is still underway and will be completed throughout 2018, leading to project construction in 2019.*	4,818,017	Deferred	2019		Subsequent Submittal	
50342	Western Transmission System Voltage Support *Further analysis completed in 2017 has shown this project is no longer required.*	4,000,000	Cancelled			Subsequent Submittal	
50021	91H Tufts Cove Bus and Line Upgrades *Further analysis of the engineering solutions was ompleted in 2017 and has shown this project can be safely deferred to 2019, and is also now under $250,000.*	417,178	Deferred	2019		Subsequent Submittal	
Distribution							
46305	103W-311G Gold River Reconductor - Phase 3 *This project was a duplicate of CI 43177, approved as part of ACE 2014, and completed in 2017*	118,563	Cancelled			Less than $250k	
General Plant							
46075	IT - Work & Asset Management *Project has been deferred to better align with availability of resources required to complete the work, and to finish the project scoping / detailed design. Project will be filed in 2018.*	28,027,680	Deferred	2018		Subsequent Submittal	Subsequent Submittal
49093	IT - Security Operations Center (SOC) and Security Information Event Monitoring (SIEM)	2,476,976	Deferred	2019		Subsequent Submittal	

CI#	Project Title	2017 ACE Project Total	Cancelled/ Deferred	Deferred To	Prior Approval	Prior ACE Plan Reference	2018 ACE Plan Reference
	Implementation of ERP resulted in constrained resources and NS Power chose to minimize the disruption to the business. Further evaluation revealed that this work could be deferred to 2019.						
49859	IT - Windows Server 2008 Upgrade *Implementation of ERP resulted in constrained resources and NS Power wanted to minimize disruption to the business. Further evaluation revealed that this work could be deferred to 2019.*	2,069,258	Deferred	2019		Subsequent Submittal	
49094	IT - Identity Access Management Infrastructure *Subsequent to the 2017 ACE Plan, NS Power reexamined the resource availability / requirements with the implementation of the ERP project in 2017 and determined that these projects would carry less risk during implementation if completed in 2018.*	1,711,147	Deferred	2018		Subsequent Submittal	Subsequent Submittal
49858	IT - Microsoft Exchange Upgrade *The assessment on whether this project will include an on-premises or a cloud solution is currently being completed which led the project to be deferred to 2018.*	1,500,000	Deferred	2018		Subsequent Submittal	Subsequent Submittal
49480	IT - Disaster Recovery *Project scoping had revealed that further work is required to determine the project requirements.*	1,483,365	Deferred	2018		Subsequent Submittal	Subsequent Submittal
49876	Real Time Economic Dispatch *Continued project planning is required in 2018 to understand the full scope of the RTED implementation, in particular, how to deal with transmission*	1,161,618	Deferred	2019		Subsequent Submittal	

CI#	Project Title	2017 ACE Project Total	Cancelled/ Deferred	Deferred To	Prior Approval	Prior ACE Plan Reference	2018 ACE Plan Reference
	constraints and locational reserves						
49601	IT - Data loss Prevention	1,199,013	Deferred	2019		Subsequent Submittal	
	Subsequent to the 2017 ACE Plan, NS Power reexamined this project and determined that this project could be safely deferred to 2019.						
49600	IT - Network Architecture Redesign	1,183,826	Deferred	2019		Subsequent Submittal	
	Subsequent to the 2017 ACE Plan, NS Power reexamined the resource availability / requirements with the implementation of the ERP project in 2017 and determined that these projects would carry less risk during implementation if completed in 2018						
50112	Consolidated Customer Web Portal	770,977	Deferred	2018		Subsequent Submittal	Subsequent Submittal
	Project has been deferred to allow for further scoping and customer engagement.						
47751	Dynamic Transmission Limits	537,466	Deferred	2019		Subsequent Submittal	
	Further analysis is required before this project is pursued.						
49603	IT - Patch Management	536,350	Cancelled			Subsequent Submittal	
	Project scoping has determined the solution for this project is not capital investment.						
48044	Bentley Nevada Upgrade and Integration to Fleet Monitoring	401,459	Deferred	2019		Subsequent Submittal	
	Operational Technology Infrastructure required for implementation delayed this project due to identified Cyber Security concerns. Once the infrastructure is deployed to ensure a secure gateway into the Plant environment, this project will be executed.						

CI#	Project Title	2017 ACE Project Total	Cancelled/ Deferred	Deferred To	Prior Approval	Prior ACE Plan Reference	2018 ACE Plan Reference
50132	Joint Regulation	387,704	Deferred	2019		Subsequent Submittal	
	Further analysis is required before this project is pursued.						
50115	Customer Support System Enhancement	332,847	Cancelled			Subsequent Submittal	
	Project has been cancelled as the scope has been consolidated into other customer experience capital projects.						
49856	IT - ITSM Replacement	300,000	Cancelled			Subsequent Submittal	
	Subsequent to the 2017 ACE Plan, NS Power reexamined the options to address this need and determined that a capital project is not necessary.						
49602	IT - Internal Vulnerability Assessment	238,543	Cancelled			Less than $250k	
	Project scoping has determined the solution for this project is not capital investment.						
49825	Radio Site Grounding Review & Upgrade	228,414	Deferred	2018		Less than $250k	Less than $250k
	This project is deferred as internal resources are focusing on other, higher priority, telecommunication projects.						
49832	Victoria Junction Substations Fiber Links	65,972	Deferred	2018		Less than $250k	Less than $250k
	This project is deferred as internal resources are focusing on other, higher priority, telecommunication projects.						

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4.0 2018 ANNUAL CAPITAL EXPENDITURE PLAN

4.1 Summary of Expenditures

Figure 18 below provides the proposed capital investment by category for NS Power's 2018 ACE Plan filing. This Application seeks UARB approval of the 2018 routine capital and other 2018 projects, which total approximately $176 million of forecast spending in 2018. Certain items do not require UARB approval, but are included in NS Power's annual capital plan for transparency and stakeholders' information. The 2018 ACE Plan budget also includes spending on multi-year projects that were previously approved by the UARB (Carryover Projects).

Figure 18: 2018 Capital Investments by Category

2018 ACE Spend	2018 UARB Approval Request ($M)	UARB Approval Not Required ($M)	Capital Items Forecast for Later Filing & Approval in 2017/2018 ($M)	Previously Approved Capital Projects with 2018 Carryover ($M)	2018 ACE Plan ($M)
Capital Item Approval Sought through the 2018 ACE Process (Including Routine Capital Projects)	175.9				**175.9**
2017 ACE Plan Items Pending Submission in 2017			0.9		**0.9**
Capital Items Submitted for Later Approval in 2018			29.8		**29.8**
2018 Carryover Projects				119.8	**119.8**
Capital Items Less Than $250K		17.9			**17.9**
Point Aconi Capital Spend		10.6			**10.6**
2018 ACE Plan	**$175.9**	**$28.6**	**$30.6**	**$119.8**	**$354.9**

Note: NS Power is seeking approval of $84 million of Routine spending in 2018.
Note: Figures presented in the ACE Plan document reflect rounding which may cause $0.1 million in rounding differences on some line items.

4.2 2018 ACE Plan Capital Items Submitted for Approval

Figure 19 below provides the list of new Capital Items for which NS Power seeks UARB approval in the 2018 ACE Plan, totaling approximately $176 million of spending in 2018, with a total forecast spend of approximately $204 million.

In an effort to reduce the number of filings throughout the year in 2018, and to increase transparency and review of capital projects during the 2018 ACE Plan proceeding, NS Power dedicated efforts to including more capital projects for approval in this year's ACE Plan, compared to 2017. The 2017 ACE Plan included 71 projects for approval, compared to 105 in the 2018 ACE Plan; an increase in 34 capital work orders. This has the effect of reducing the number of projects that would have otherwise been forecast for subsequent approval throughout 2018. This was made possible by initiating the capital work order development process earlier in the year.

Some of the new projects in the 2018 ACE Plan, including those noted in the table below, use a new Capital Item numbering system as a result of the ERP upgrade to the capital planning software program PowerPlan. The previous version of PowerPlan used a five digit system (e.g. CI 51236 - HYD - WRC Tailrace Rock Bolting), whereas the new version of PowerPlan uses an eight digit system (e.g. C0001419 - TRE HFO Refurbishment Phase 1). Going forward, new projects created in the new version of PowerPlan will use the eight digit CI system.

Figure 19: 2018 Capital Items Submitted for Approval

Tab #	CI#	Project Title	2018 Budget ($)	Project Total ($)
Hydro				
G01	51236	HYD - WRC Tailrace Rock Bolting	8,677,118	8,861,996
G02	48533	HYD Lequille Headpond Refurbishment	4,209,710	4,472,369
G03	49033	HYD WRC Tunnel T-2 Intake Replacement	2,525,419	2,851,582
G04	51235	HYD - WRC Main Access Rd Refurbishment	2,574,654	2,686,075
G05	51234	HYD - WRC HVAC Upgrade	266,738	1,876,537
G06	49943	HYD - Ruth Falls Facility Refurbishment	1,217,177	1,234,931
G07	49942	HYD - Tidewater Facility Refurbishment	1,230,442	1,234,178
G08	49946	HYD - Fourth Lake Overhaul	978,404	1,025,769

Tab #	CI#	Project Title	2018 Budget ($)	Project Total ($)
G09	49945	HYD - Malay Falls Switchgear Replacement	957,136	958,631
G10	52262	HYD - Hells Gate 1 Overhaul	854,993	854,993
G11	51972	HYD Nictaux Canal Embank Refurbishment	779,686	789,918
G12	51866	HYD - 4th Lake Penstock Refurbishment	663,326	696,963
G13	47655	HYD - Paradise Controls Upgrade	218,179	639,991
G14	49944	HYD - Dickie Brook Penstock Refurbishment	478,820	478,820
G15	48712	HYD - Dam Instrumentation Upgrade	395,505	476,207
G16	52018	HYD - RES Revenue Meter Replacement	368,897	378,248
Total New Hydro Spending			**26,396,205**	**$29,517,209**
Steam				
Boiler				
G17	51802	TRE5 Boiler Refurbishment 2018	1,212,228	1,212,228
G18	51805	LIN4 Boiler Refurbishment 2018	739,657	739,657
G19	47684	LIN3 Boiler Refurbishment 2018	739,657	739,657
G20	51825	POT Boiler Refurbishment 2018	568,740	568,740
G21	52252	LIN1 SH5 Tube Replacement	521,259	521,259
G22	52253	LIN3 Economizer Header Refurbishment	499,951	499,951
G23	51821	TRE5 Air Heater Refurbishment	487,376	487,376
G24	51824	LIN3 ID Fan Damper and VIV Refurbishment	443,311	443,311
G25	51818	PHB Boiler Refurbishment 2018	440,315	440,315
G26	51807	TUC2 Boiler Lower Vestibule Refurbishment	412,872	412,872
G27	51849	LIN3 RH Tube Replacement	399,546	399,546
G28	51850	LIN4 RH Tube Replacement	399,546	399,546
G29	49547	TRE5 5-1 BFP Refurbishment	345,523	345,523
G30	51857	TRE5 Burner Refurbishments 2018	332,497	332,497
Turbine				
G31	49534	TRE6 EHG/Turbine Controls Upgrade	2,507,264	2,725,344
G32	51820	TRE5 Reheat Turbine Valves	450,408	450,408
G33	51862	TRE6 Lube Oil Cooler Refurbihsment	341,769	341,769
G34	43429	TRE5 Lube Oil Cooler Retube	338,398	338,398
G35	51853	LIN3 Turbine Valve Refurb 2018	295,709	295,709
Generator				
G36	51803	TUC2 Generator Flux Probe Installation	840,158	840,158
Environmental				
G37	50577	TRE6 CEMS Replacement	715,562	715,562
G38	49676	TUC2 CEMS Replacement	380,140	380,140
Balance of Plant				
G39	51806	LIN Mill Refurbishment 2018	673,153	673,153
G40	52093	ICP Rail Crossing Refurbishment	592,402	592,402
G41	51811	LIN Reclaim Refurbishment Phase 2	534,666	534,666
G42	51815	LIN CW Pump Refurbishment 2018	520,436	520,436
G43	51861	TRE6 CW Screen Replacement 2018	513,192	513,192
G44	51816	TRE Asbestos Abatement 2018	509,035	509,035
G45	51835	TUC2 H2 Panel Upgrades	454,886	454,886
G46	51836	TRE5 Mill Refurbishments 2018	409,458	409,458
G47	47871	LIN Stack Re-Coating	381,034	381,034
G48	51839	LIN Coal Plant Structural Refurbishment	354,067	354,067
G49	51851	LIN CW Screen Refurbishment 2018	350,534	350,534
G50	C0001419	TRE HFO Refurbishment Phase 1	340,618	340,618
G51	51804	LIN3&4 ACW Duplex Strainer Replacement	333,808	333,808
G52	51852	POT Mill Refurbishment 2018	327,267	327,267
G53	52156	LIN Vaccuum Pump Upgrades	302,714	302,714
G54	51860	TRE5 PF Mill Line Replacement	258,761	258,761
Total New Steam Spending			**$20,267,916**	**$20,485,995**
Gas Turbine Generation				

Tab #	CI#	Project Title	2018 Budget ($)	Project Total ($)
G55	52143	LM6000 Engine 191-332 Hot Section	1,776,275	1,776,275
Total New Gas Turbine Spending			**1,776,275**	**1,776,275**
Total New Generation Spending			**$48,440,395**	**$51,779,479**
Transmission				
T01	51969	2018 Transmission ROW Widening 69kV	5,487,686	5,487,686
T02	51975	5P Mobile Substation Replacement	3,225,405	4,829,458
T03	52258	2018/2019 Isolated Structure Replacement	1,094,899	4,818,521
T04	51403	2018 PCB Removal Program	1,478,161	4,402,342
T05	51402	2018/2019 Sacrificial Anode Installation	703,416	3,023,668
T06	C0001900	Mount Hope 69-25kV Substation	1,397,158	2,982,338
T07	52314	1C-GT1/UT1 Replacement	1,162,188	2,032,393
T08	51398	2018/2019 Steel Tower Refurbishment	461,426	1,992,692
T09	52320	L6549 2018 Replacements & Upgrades	657,710	1,406,535
T10	51406	2018/2019 Transmission Switch & Breaker Replacement	1,311,498	1,405,891
T11	51405	2018 Wood Pole Retreatment Program	680,538	1,361,076
T12	48131	48H-T1 Replacement	648,122	1,281,449
T13	52328	56N-T1 Transformer Upgrades	703,817	1,279,271
T14	49779	L6537 Replacements and Upgrades	587,041	1,255,220
T15	49777	L7002 Replacements and Upgrades	437,128	926,777
T16	52241	16V-T2 Weymouth Hydro Transformer Replacement	889,253	889,253
T17	52102	L5014-2018 Replacements and Upgrades	849,700	849,700
T18	49788	L5564 Replacements and Upgrades	691,417	738,853
T19	52059	L5039 - 2018 Replacements and Upgrades	719,825	719,825
T20	49783	L5027A Replacements and Upgrades	648,292	648,292
T21	52119	L5054 2018 Replacements and Upgrades	560,143	560,143
T22	52238	2018/2019 Capacitor Bank Breaker Replacement	243,830	433,719
T23	43268	9W-B53 Tusket Replace Structure	375,523	375,523
T24	51797	2018 Oil Containment Program	331,507	331,507
T25	52305	2018 Substation Insulator Replacement	316,348	316,348
T26	51863	2018 Tap Changer Replacements	306,102	306,102
Total New Transmission Spending			**$25,968,132**	**$44,654,581**
Distribution				
D01	C0001950	New Distribution Rights-of-Way Ph 3	6,870,749	9,822,493
D02	52271	2018 Padmount Replacement	1,286,340	1,657,205
D03	51493	2018 PCB Pole Top Transformer Replacement	842,163	1,360,354
D04	52184	37N-412-Glooscap Trail Rebuild Phase 2	858,046	858,046
D05	52224	532N-Elm Street Conversion Phase 2	433,695	722,113
D06	C0001802	54C-211 Queen Street Conversion	705,316	705,316
D07	52185	50N-410 Rebuild Phase 2	695,098	695,098
D08	43218	88W-323A Tusket Islands Phase 3	347,162	654,721
D09	51400	2018 Sub Recloser Replacements	644,710	644,710
D10	52194	6S-223 Harold Street Conversion	642,368	642,368
D11	52200	65V-301 Brickton Reconductor	288,048	594,362
D12	52205	30N-412 Hwy 242 Fundy Shore Rebuild	536,670	536,670
D13	51744	30N-411 Maccan River Rebuild	473,044	473,044
D14	52204	87W-312G-Tancook Island Replacement	208,236	454,096
D15	52267	16W-302H-Brenton Rd Rebuild	258,839	387,767
D16	52207	678H-211 McNab's Island Replacement	162,232	350,176
D17	51500	2018 Pin Insulator Replacements	329,944	350,100
D18	52192	54H-303 Underground Device Replacement	289,957	309,230
D19	52206	20V-311-Bishop Ville Rd	303,533	303,533
D20	52186	4S Feeder Exit Cable Replacement Phase 1	276,129	293,509
D21	52208	3S Feeder Exit Cable Replacement Phase 2	293,228	293,228
D22	52201	55V-314GA-Welsford Reconductor	275,161	275,161

Tab #	CI#	Project Title	2018 Budget ($)	Project Total ($)
Total New Distribution Spending			**$17,020,666**	**$22,383,299**
General Plant				
GP01	52308	2018 RTU Replacement Program	298,792	988,056
GP02	52233	2018 Telecom Building Replacement	314,929	314,929
Total New General Plant Spending			**613,720**	**1,302,985**
Total New Capital Spending			**$92,042,914**	**$120,120,344**
Total Routine Capital Spending			**$83,861,643**	**$83,861,643**
Total Capital Items for which Approval is Sought			**$175,904,557**	**$203,981,987**

4.3 2018 ACE Plan Capital Items Forecast for Subsequent Approval

Figure 20 below identifies 2018 projects that are not yet ready for submission to the UARB, and that NS Power anticipates will be filed for review and approval throughout 2018. NS Power estimates approximately $30 million of spending in 2018 on these projects, which are currently estimated for total spending of approximately $152 million. The budget numbers indicated below are estimates as NS Power needs additional time to refine the specific project budget proposals. This section of NS Power's filing is designed to provide an indication of these anticipated 2018 projects.

As noted in Section 3.2 above, NS Power significantly increased the number of capital projects submitted for approval compared to 2017. This correspondingly reduces the number of projects forecast for subsequent approval throughout 2018. The 2017 ACE Plan included 83 projects for subsequent approval for a total 2017 spend of $109 million, compared to 24 in the 2018 ACE Plan for a total 2018 spend of $30 million; a decrease of 59 capital work orders and $79 million. This will reduce the regulatory burden for NS Power, the UARB and stakeholders throughout 2018.

Figure 20: 2018 Capital Items Forecast for Subsequent Submittal

CI#	Project Title	2018 Budget ($)	Project Total ($)
Hydro			
39472	HYD Mersey System Re-Development	1,223,368	83,595,607
	This project is the first phase of the re-development of the Mersey Hydro System and includes the replacement of the Big Falls PowerHouse and Lower Great Brook Dam Structure.		
48791	HYD - WRC Safety Standards Upgrades	440,182	1,019,928
	Project includes addition of alternate egress routes from lowest level of plant, higher capacity sump pumps, and a back-up power source for spherical valve closing.		
51775	HYD Fixed Ladder & Machine Guard	906,249	999,149
	Project includes installation of floor grating and shaft guards as well as increased instrumentation in the wheel pit area of the hydraulic turbine. It also will replace or modify ladders in order to meet regulation.		
47660	HYD - Dickie Brook Controls Upgrade	228,354	885,586
	This project will cover new instrumentation installations, Programmable Logic Controller (PLC) replacements, Distributed Control System (DCS) installation at the Dickie Brook Generating Station.		
52017	HYD ANN Exciter Replacement	465,855	473,350
	The replacement of the excitation system for the Annapolis tidal generation station.		
51772	HYD Arc Flash Mitigation	262,654	403,175
	This project includes mitigation measures to reduce or eliminate arc flash potential in hydro generating stations. This may include protection upgrades or switchgear modification or replacement.		
47659	HYD - Fall River Controls Upgrade	104,320	302,867
	This project will cover new instrumentation installations, Programmable Logic Controller (PLC) replacements, Distributed Control System (DCS) installation at the Fall River Generating Station.		
	Total New Hydro Spending for Subsequent Approval	**3,630,982**	**87,679,662**
Gas Turbine			
C0002978	CT's Motor Control Centre Upgrades	1,199,221	1,199,221
	This project includes the upgrade of the Motor Control Centre for the combustion turbine fleet.		
49594	LM6000 TUC5 Airhouse Upgrade	830,287	916,391
	This project includes the upgrade of the air house and its components on the Tufts Cove Unit #5 LM6000.		
	Total New Gas Turbine Spending for Subsequent Approval	**2,029,508**	**2,115,612**

CI#	Project Title	2018 Budget ($)	Project Total ($)
Steam			
51808	TUC HFO Piping Refurbishment	1,291,933	1,291,933
	This project includes the replacement of pipe supports on Heavy Fuel Oil (HFO) piping at the Tufts Cove Generating Station.		
52107	TUC6 CW Screen Replacement	1,000,676	1,029,787
	This project includes the replacement of the Cooling Water screens on the Tufts Cove #6 Generating Station		
52321	TUC3 Air Heater Refurbishment	535,728	570,623
	This project includes the refurbishment of the Air Heater on the Tufts Cove #3 Unit.		
	Total New Steam Spending for Subsequent Approval	**2,828,337**	**2,892,343**
	Total New Generation Spending for Subsequent Approval	**$8,488,827**	**$92,687,617**
Distribution			
47794	Heckman Island Underwater Cable Replacement *This project provides for the replacement of the underwater cable to Heckman's Island near Lunenburg. The targeted underwater cable has reached its end of life due to age, condition and risk. In addition, the load on this cable has increased since its original installation and the cable can no longer support cold load pick up.*	762,186	1,524,923
	Total New Distribution Plant Spending for Subsequent Approval	**762,186**	**1,524,923**
General Plant			
46075	IT - Work and Asset Management *This project will upgrade NS Power's Maximo and ESRI GIS systems to the current release from the vendor and integrate the Maximo system with the NS Power GIS system, enabling a spatial view of work and assets in Maximo on a platform that is supported by the vendor.*	14,498,734	45,509,963
49480	IT - Disaster Recovery *This project will review, design, and deploy the necessary infrastructure to ensure disaster recovery capabilities and processes are in place for all NS Power IT systems based on their classification of criticality.*	494,282	6,312,277
49858	IT - MS Exchange Upgrade *This project will upgrade the Microsoft Exchange environment as part of NS Power's technology lifecycle management. Microsoft Exchange 2010 is the platform that manages and delivers all email to NS Power employees, schedules calendars and manages contacts.*	1,555,597	1,555,597
50112	Customer Experience Consolidated Customer Web Portal	654,004	1,190,588

CI#	Project Title	2018 Budget ($)	Project Total ($)
	This project will develop a common strategy, development and execution plan for an enhanced online customer experience. The project will include solutions related to customer service requests, information requests and access and usage of MyAccount (existing customer online access tool), particularly as it relates to the AMI (Smart Meter) project. In addition, the Customer Portal project will be adaptable to include other online assets that currently exist or will be developed in future.		
49094	IT - Identity Access Mgmt Infrastructure *This project will assess, design, and deploy hardware and software related to controlled access and use of NS Power IT systems and applications.*	800,000	977,498
C0002241	IT-Generation Operation Upgrade *This is a required tool for the economic dispatch of the NS Power generation fleet. NS Power is currently operating on a legacy product that does not have the required support for an essential and required dispatch tool. This project will upgrade to the current version.*	511,673	511,673
52335	IT-Automate Manual Billing *This project will develop an application to enable large scale one-time uploading of transactions to customer accounts in CIS. This will include solutions for billing adjustments, payment adjustments, fixed charges, and account details. Some additional updates may be required in the existing CIS system to accommodate this application and process improvement.*	506,403	506,403
52337	IT-Group Billing Experience *This project will introduce fixes to the CIS group billing application to correct billing inaccuracies. The project will also develop, test, and implement a solution to allow Group Billing customers streamlined access to their consolidated invoices and individual bills for their accounts through MyAccount. In addition, the project will align internal processes to provide sustainable and consistent support to Group Billing customers.*	505,823	505,823
C0002130	ADMS Distribution Fault Location *This project provides for integration of the distribution fault location functionality into the ADMS system. This functionality will provide predictions on potential fault locations during outage events.*	473,660	473,660
C0002106	Vegetation Inventory System Upgrade *This project includes the upgrade to the current vegetation inventory system.*	260,172	260,172
C0002254	IT- MV90 Upgrade *MV 90 is an automatic meter reading system used for collecting meter reads from large industrial and load research customers. This project will upgrade this software to a supported version.*	254,062	254,062
	Total New General Plant Spending for Subsequent Approval	**20,514,410**	**$58,057,716**
	Total Capital Items for Subsequent Approval	**$29,765,423**	**$152,270,257**

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4.4 2018 ACE Plan Capital Items with Estimated Total Project Cost of Less Than $250,000

Figure 23 below sets out capital items with a total project cost of less than $250,000. In accordance with Section 35 of the *Public Utilities Act*, these projects do not require UARB approval but are provided for transparency and informational purposes.

The information in this section has been expanded in the 2018 ACE Plan in accordance with the agreement reached with stakeholders pursuant to NS Power's report provided to the UARB on September 5, 2017. Historical dollar values and numbers of projects are now provided in **Figures 21 and 22** below respectively. The table of projects under $250,000 now includes brief descriptions of all projects and rankings of those projects in accordance with NS Power's asset management methodology as described in section 6.2 of the CEJC. Compared to 2017, there are 35 fewer projects in NS Power's annual capital budget that fall below the $250,000 threshold, for a $3.6 million reduction from 2017 in total budget for projects in this category.

Figure 21: Historical Value of Projects Less Than $250,000

Function	2015	2016	2017	2018
Gas Turbine	0.6	0.6	1.7	1.2
Steam	8.4	12.2	16.0	12.5
Hydro	0.3	0.1	0.9	0.8
Transmission	0.8	0.6	0.1	0.2
Distribution	0.8	0.6	1.3	1.2
General Plant	1.4	1.2	1.6	1.9
Total	**$12.3**	**$15.3**	**$21.5**	**$17.9**

Note: Totals in the tables above may be off slightly due to rounding

Figure 22: Historical Number of Projects Less Than $250,000

Function	2015	2016	2017	2018
Gas Turbine	7	7	19	15
Steam	59	85	116	87
Hydro	2	1	8	7
Transmission	4	5	1	1
Distribution	4	4	9	6
General Plant	8	9	14	16
Total	**84**	**111**	**167**	**132**

Note: Totals in the tables above may be off slightly due to rounding

Figure 23: 2018 Capital Items with Estimated Total Project Cost of Less than $250,000

CI#	Project Title	2018 Budget ($)	Project Total ($)	Criticality	Condition	Ranking
Hydro						
C0002103	HYD WRC U1 WG Thrust Assembly	200,574	200,574	4	4	16
This project includes replacement of the Wreck Cove Unit 1 thrust assembly and spherical valve upstream seal						
52256	HYD WRC Helipad Construction	160,435	161,695	4	4	16
This project includes the construction of a helicopter landing area for life flight support services due to the remote location of the site.						
C0001578	HYD WRC Bus Duct Monitors	158,439	158,439	4	5	20
This project installs online monitoring of the Wreck Cove bus duct temperature.						
51848	HYD - ANN Warehouse Refurbishment	118,275	147,187	3	5	15
This project renovates an office area at the Annapolis Tidal Plant warehouse to provide material control, meeting space and a customer interaction point.						
C0002231	HYD DHA Purchase	50,000	50,000	4	4	16
This project procures portable dehumidification units for the Wreck Cove generator pits to minimize unit dryout on startup.						
51868	HYD - 4th Lake Butterfly Valve Refurbishment	48,006	48,174	5	3	15
This project is to modify the plant isolation valve with a lock-out mechanism on the 4th Lake generating unit on the Sissiboo Hydro System.						
47649	HYD - Salmon Tail Gate Pedestal Replacement	36,227	38,576	3	5	15
This project is to replace the sluice gate actuation pedestal, actuator and gate on the Black River Hydro System.						
Total Hydro Items Less Than $250,000		**$771,957**	**$804,645**			

CI#	Project Title	2018 Budget ($)	Project Total ($)	Criticality	Condition	Ranking
Steam						
52040	LIN Grating Refurb (Boiler House)	244,596	244,596	4	4	16
This project includes the refurbishment of grating in the Boiler house. Defects in grating represent a risk to plant safety.						
52037	LIN1 Main FW Control Valve & Actuator	241,216	241,216	4	4	16
This project includes the refurbishment of Lingan Unit 1 feedwater control valve and actuator. This valve controls the flow of water to the boiler.						
52035	LIN Plant Lighting Upgrade Phase 2	237,079	237,079	3	5	15
This project includes the replacement of out of service plant lighting with LED fixtures. The main driver to project is to improve lighting in high risk areas improving plant safety, with the added benefit of reducing station service requirements.						
49452	LIN3 FW Heater Level Controls Upgrade	236,285	236,285	4	4	16
This project includes the replacement of Obsolete Feedwater heater level controls with improved technology that reduces heat rate implications and damage mechanisms.						
47834	ICP Ranger Motor Upgrade	235,643	235,643	4	4	16
This project is the replacement of the vessel unloading conveyor belt. The conveyor is used to transport fuel from the vessel to the coal yard.						
52041	LIN Siding Refurbishment Phase 2	233,676	233,676	4	4	16
This project includes the select replacements of deteriorated siding containing asbestos. There is currently a risk of siding detaching from the building, impacting people and property.						
52101	ICP Rail Car Rebuild	233,505	233,505	4	4	16
This project includes the rebuilding of rail cars deteriorated from erosion and corrosion. The rail cars are part of the fuel delivery system.						
52097	ICP Water Truck	232,000	232,000	4	4	16
This project includes the replacement of the existing water truck. The water truck is used for dust control and debris cleaning of access roads.						
52222	TUC2 Breaker Replacements and Upgrade	229,831	229,831	3	5	15
This project includes the select replacement of obsolete breakers.						
52050	LIN4 Misc. Valve Refurbishment	223,217	223,217	3	5	15
This project includes the select refurbishment of defective valves. Valves are selected based on condition assessment and associated maintenance strategy						
52243	POT Asbestos Abatement	221,668	221,668	5	3	15
This project includes strategic abatement of asbestos from plant equipment						
52182	TRE5 Condenser Tubesheet Coating	220,699	220,699	4	4	16
This project includes the refurbishment of the condenser tube sheet coating to prevent exposure to seawater.						
52104	ICP Rail Car Truck Program	220,461	220,461	4	4	16
This project includes the refurbishment of the rail car trucks which can also be referred to as wheel assemblies.						
52062	LIN Forklift Replacement	219,740	219,740	3	5	15
This project includes the replacement of the forklift primarily used for removal of specification fuel from the coal feeders.						
52242	POT West CW Pump Overhaul	219,146	219,146	3	5	15
This project includes the refurbishment of the cooling water circulation pump based on condition assessment and recommended maintenance strategy.						
52197	TUC2 Main Feedwater Control Valve Refurbishment	216,249	216,249	4	4	16

CI#	Project Title	2018 Budget ($)	Project Total ($)	Criticality	Condition	Ranking
This project includes the refurbishment of the TUC 2 main feedwater control valve based on condition assessment and recommended maintenance strategy.						
52052	LIN1 Misc. Valve Refurbishment	214,536	214,536	3	5	15
This project includes the refurbishment of defective valves based on condition assessment and associated maintenance strategy						
52051	LIN3 Misc. Valve Refurbishment	213,302	213,302	3	5	15
This project includes the refurbishment of defective valves based on condition assessment and associated maintenance strategy.						
52049	LIN PF Line Replacement	212,325	212,325	3	5	15
This project includes the replacement of pulverized fuel piping. Pulverized fuel is transported from the mills to the boiler through this piping. Spool pieces are replacement due to erosion/corrosion.						
52053	LIN3 Air heater and Aux Air Dampers	212,031	212,031	4	4	16
This project includes the refurbishment of the boiler air preheater and associated dampers to improve control and support more flexible unit operation.						
52291	POT 4160V Motor Controls Upgrade	203,735	203,735	3	5	15
This project includes the upgrade of the push buttons on the motor control system to allow operation from the Main Operator Control System.						
C0002059	LIN - Exterior Security Light Upgrade	202,950	202,950	4	4	16
This project includes the addition of security lighting at Lingan Generating station to improve perimeter security based on NERC requirements						
52296	TUC Asbestos Abatement	200,000	200,000	5	3	15
This project includes strategic abatement of asbestos from plant equipment.						
52046	LIN Precipitator Controls Upgrade	197,953	197,953	4	5	20
This project includes the controls upgrade to static precipitators. Precipitators are used to remove particulates from stack emissions.						
51900	TRE5 PLC Upgrade WTP/Polisher	193,112	193,112	4	4	16
This project includes the upgrade of the plant water treatment and Polishing Control System. These systems are using to treat water to meet boiler and steam turbine requirements						
49546	TRE6 FW Heater Level Control	187,315	187,315	4	5	20
This project includes the replacement of obsolete feedwater heater level controls with improved technology that reduces heat rate implications and damage to mechanisms.						
52248	POT Boiler Gas Temp Monitors	182,984	182,984	3	5	15
This project includes the upgrade of boiler gas temperature indicators which are required for unit startup.						
52058	LIN3 ID Fan Shaft Refurbishment	179,967	179,967	4	4	16
This project includes the refurbishment of the ID fan shaft based on condition assessment. The refurbishment will remove corrosion sites extending the life of the fan.						
51854	PHB Conveyors and Handling Systems	176,943	176,943	3	5	15
This project includes the replacement of components on the secondary biomass fuel handling system, including wear components on a drag chain conveyor, belt conveyor, screws, and other fuel handling equipment						
52179	TRE5 Valve Refurbishments 2018	176,207	176,207	3	5	15
This project includes select valve refurbishments based on condition assessment and associated maintenance strategy.						
52177	TRE6 Valve Refurbishments 2018	176,141	176,141	3	5	15
This project includes select valve refurbishments based on condition assessment and associated maintenance strategy.						
52042	LIN Plant Heating Upgrade	171,552	171,552	3	5	15

CI#	Project Title	2018 Budget ($)	Project Total ($)	Criticality	Condition	Ranking
This project includes refurbishment of the plant heating system to provide adequate temperature control and freeze protection						
52038	LIN Precip Pressurizing Fan	168,048	168,048	4	4	16
This project includes the refurbishment of the static precipitator fan based on condition assessment. The fan is used to ensure adequate operating conditions of the precipitator cells.						
52043	LIN A Coal Chute Replacement	162,228	162,228	3	5	15
This project includes the replacement of the Lingan A coal chute due to erosion and corrosion based on condition assessment. The coal chute is part of the fuel delivery system.						
52239	TUC6 Main and Induction Stop Valve	160,053	160,053	4	4	16
This project includes the refurbishment of the main and induction steam valves based on recommended maintenance strategy. These valves ensure control of steam to the turbine.						
51394	LIN34 Control Panel Button Upgrade	125,816	154,864	4	5	20
This project includes the replacement of control panel switches and buttons that are defective and pose risk to operators and equipment.						
52249	POT Breaker Replacements / Upgrades	154,859	154,859	3	5	15
This project includes select refurbishment of electrical breakers based on condition assessment.						
52154	TRE Ash Site Management 2018	153,269	153,269	4	5	20
This project includes the intermediate cover of exposed ash, pending final capping. This is required to meet environmental compliance.						
52155	TRE6 Conveyor Refurbishment 2018	151,482	151,482	4	4	16
This project includes the refurbishment of conveyor components, including belts, pulleys, scrappers and structural/electrical components. This conveyor is part of the fuel delivery system.						
52175	TRE5 Mill Platform Access	151,402	151,402	4	4	16
This project includes the construction of a platform to support fuel mill access, improving mill maintenance safety						
52231	TUC6 Turbine Bypass Valve Refurbishment	151,072	151,072	4	4	16
This project includes of the refurbishment of the bypass valve. The bypass line is used during startup to meet turbine startup requirements						
52244	PHB Replace Mini-Bins	149,828	149,828	3	5	15
This project includes the refurbishment of the mini-bins which are part of the fuel delivery system.						
52300	TUC Facilities Upgrade Phase 2	149,504	149,504	4	4	16
This project includes the upgrade of existing plant infrastructure. Improved facilities for the women's and men's washrooms/locker rooms, etc.						
C0001538	LIN4 Sequence of Event Recorder	137,666	137,666	3	5	15
This project includes the installation of a sequence of events recorder to improve unit reliability and troubleshooting						
52121	LIN Boiler Fill Pump Suc. Repl. Phase 2	132,439	132,439	4	4	16
This project includes the replacement of deteriorated boiler fill piping with superior material that will allow for improved quality of makeup water. This system is used to fill the boiler during unit startup.						
52063	LIN Facilities Upgrade	131,777	131,777	3	5	15
This project includes the upgrade of the main lunch room, men's washroom and the control room washrooms.						
52048	LIN Contractor Trailer	130,486	130,486	4	4	16
This project includes the refurbishment of the Lingan washroom trailer exterior to the plant. This washroom is used for external contractors.						
52153	TRE5 Stack Refurbishment	127,579	127,579	4	4	16

CI#	Project Title	2018 Budget ($)	Project Total ($)	Criticality	Condition	Ranking
This project includes the refurbishment of Trenton 5 stack.						
52054	LIN BFP Discharge Valve (Capital Spare)	120,696	120,696	3	5	15
This project includes supply of a boiler feed pump discharge valve as a critical spare. This valve is part of the feedwater control system and is common to all four units at Lingan Generating Station.						
C0001498	ICP-#2 Gate Upgrade Phase 2	119,647	119,647	3	5	15
This project includes the upgrade of the coal chute gate. The gate is used to divide the fuel either into the coal yard or directly to the rail loading system.						
52251	POT Misc. Valve/Component Replacement	119,550	119,550	3	5	15
This project includes select valve refurbishment based on condition assessment and associated maintenance strategy.						
52240	TUC2 Stack Refurbishment	116,335	116,335	4	4	16
This project includes the refurbishment of TUC2 Stack. Activities include refurbishment of access platforms, stack top, protective coatings, and miscellaneous electrical components.						
52318	TUC CW Inlet Structural Steel Refurbishment	116,181	116,181	4	5	20
This project includes the refurbishment of structural steel due on the cooling water intakes.						
52292	TUC Heavy Fuel Oil Tank Dyke Refurbishment	110,668	110,668	5	4	20
This project includes the refurbishment of the heavy fuel oil tank dyke. The dyke is used to prevent oil from entering the environment.						
50855	TRE Chemical Storage Area	100,057	107,616	5	4	20
This project includes the upgrade of the chemical storage area to improve access and mitigate safety concerns. Ramps and grating will be installed to improve accessibility.						
49670	TUC1 4kv/600V Breaker Replacement	106,420	106,420	3	5	15
This project includes the select replacements of defective electrical breakers based on condition assessments.						
49451	LIN Fan Positioner Replacement	105,915	105,915	4	4	16
This project includes the replacement of the fan positioners from pneumatic to electric. The fans are used to control air flow into and out of the boiler.						
47674	POT - CW Pumphouse Motor Control Centre Upgrade	104,638	104,638	3	5	15
This project includes the upgrade of the cooling water pumphouse motor control center.						
52061	LIN 4160 600V Breaker Refurbishment	104,433	104,433	3	5	15
This project includes select replacements of defective electrical breakers based on condition assessments.						
52139	TRE Common Water Piping Replacement	103,524	103,524	3	5	15
Replacement of deteriorated piping on the common water system at Trenton Generating Station						
52140	TRE5 4 kV Motor Refurbishments 2018	101,780	101,780	3	5	15
Select refurbishment of 4160 V Motors based on condition assessment						
49657	TUC Sequence of Events Recorder SEL	101,586	101,586	3	5	15
This project includes the installation of a sequence of events recorder to improve performance monitoring and event response.						
52013	TRE Floor Plates/Grating Refurbishment	101,388	101,388	4	4	16
This project includes select refurbishment of pedestrian grating based on condition assessment.						
52276	TUC1 Obsolete Valve Replacement	101,355	101,355	3	5	15

CI#	Project Title	2018 Budget ($)	Project Total ($)	Criticality	Condition	Ranking
This project includes select replacement of defective and obsolete valves based on condition assessment and associated maintenance strategy						
52274	POT Coal Chute Refurbishments	100,440	100,440	4	4	16
Coal chute refurbishment due to erosion and corrosion based on condition assessment.						
52223	TUC1 Air Heater Roof Replacement	99,086	99,086	4	4	16
This project includes replacement of the air heater roof on the TUC1 Generating Unit.						
52138	TRE5 Conveyor Refurbishment 2018	98,389	98,389	4	4	16
This project includes refurbishment of conveyor components including belts, pulleys, etc.						
52257	TUC3 Breaker Replacements and Upgrade	98,105	98,105	3	5	15
This project includes select replacements of defective electrical breakers based on condition assessments.						
52152	TRE5 Relay Room Fire Protection	96,940	96,940	4	4	16
Fire protection improvements to Trenton 5 relay room based on insurance and industry recommendations.						
52036	LIN CW Screen Wash Piping Upgrade	95,138	95,138	4	4	16
This project includes upgrading the wash piping to improve removal of seawater debris from the circulating water screens. This circulating water is used to cool the condenser and auxiliary equipment.						
C0001158	ICP High Rail Truck Replacement	95,000	95,000	3	5	15
This project includes the replacement of the rail maintenance truck. This truck can be used on the railtrack and on highway						
52039	LIN Automated Sweeper	94,842	94,842	4	4	16
This project includes the replacement of the automated sweeper to improve housekeeping at Lingan. The sweeper is used to remove coal dust and other debris.						
51840	LIN C Belt Replacement	93,628	93,628	4	4	16
This project includes the replacement of the Lingan C coal belt which is part of the fuel delivery system.						
52137	TRE A Conveyor Structural Refurbishment	85,483	85,483	4	4	16
This project includes the structural refurbishment of the Trenton A coal conveyor which is part of the fuel delivery system.						
52245	PHB Trancel Screw Refurbishment	80,366	80,366	3	5	15
This project includes the refurbishment of trancel feed screws. Trancel screws feed fuel into the boiler.						
52298	TUC6 Auxiliary Cooling Piping Upgrade	74,526	74,526	4	4	16
Upgrade of TUC6 cooling water piping with superior materials that will resist corrosion from seawater.						
52047	LIN Diesel Light Oil Emergency Shutoff Valve Installation	67,410	67,410	4	4	16
This project includes installation of fast acting shut off valves on the light oil system that supplies emergency power generators.						
C0001303	PHB - HVAC System Upgrades 2018	66,262	66,262	4	5	20
This project includes upgrades to the HVAC system to ensure adequate temperature control of critical system environments						
52281	POT South Air Compressor Refurbishment	62,212	62,212	3	5	15
This project includes refurbishment of Point Tupper south air compressor based on condition assessment and associated maintenance strategy. The air compressor is required for control of pneumatic equipment						
52136	TRE5 Jacking Oil Pump Replacement	60,692	60,692	4	4	16

CI#	Project Title	2018 Budget ($)	Project Total ($)	Criticality	Condition	Ranking
This project includes the replacement of Trenton 5 jacking oil pump. The jacking oil pump is used to provide lubrication when the turbine is on turning gear.						
52280	PHB Rotary Valve Replacements	57,912	57,912	3	5	15
This project includes the replacement of rotary valves on the Port Hawkesbury Generation Unit						
52178	POT - Fuel Oil Supply Shutoff Valve Installation	54,857	54,857	4	4	16
This project includes installation of fast acting shut off valves on the light oil system that supplies emergency power generators.						
52135	TRE5 Nitrogen Generator Installation	54,471	54,471	3	5	15
This project includes the installation of a nitrogen generator to layup steam and water touched components improving plant layup and flexible unit operation.						
52120	TRE Fuel Oil Emerg Valve Fire Protection	50,866	50,866	4	4	16
This project includes installation of a fast acting shut off valve on the light oil system that supplies emergency power generators						
52266	TUC2 Oil Spill Containment	45,000	45,000	4	4	16
This project includes oil spill containment for TUC2 to prevent the spread of flammable lube oil in the event of a fire.						
52290	TUC1 Opacity Meter Replacement	40,000	40,000	4	4	16
This project includes the replacement of the TUC1 opacity meter based on condition. The Opacity Meter is used to ensure compliance against emissions requirements.						
49688	TUC3 Analytical Panel Upgrades	31,527	31,527	4	4	16
This project includes an upgrade to TUC3 cycle chemistry instrumentation including the addition of cation conductivity monitoring recommended by EPRI.						
Total Steam Items Less Than $250,000		**$12,540,895**	**$12,577,502**			
Gas Turbine						
49932	CT - TUC 4 LM6000 Roof Skid Access	176,559	176,559	3	5	15
This project includes constructing infrastructure to enable the CT staff to safely gain access to the generator and turbine vent fans for quarterly maintenance, annual maintenance, and possible motor or fan removals.						
49933	CT - TUC 5 LM6000 Roof Skid Access	176,559	176,559	3	5	15
This project includes constructing infrastructure to enable the CT staff to safely gain access to the generator and turbine vent fans for quarterly maintenance, annual maintenance, and possible motor or fan removals.						
52145	CT TUC 4 Thrust Balance Valve Replacement	157,285	157,285	4	4	16
This project includes the replacement of the thrust balance valve on TUC4.						
52149	CT TUC 5 Thrust Balance Valve Replacement	157,285	157,285	4	4	16
This project includes the replacement of the thrust balance Valve on TUC5.						
52115	CT VJ Fuel Level Monitoring Upgrade	82,285	82,285	4	4	16
This project includes the upgrade of the fuel level monitoring system at Victoria Junction to improve the Environmental Monitoring and Fuel Consumption Program.						
47812	BGT Fuel Tank 3 Refurbishment	72,091	72,091	4	4	16
This project includes the refurbishment of Burnside Fuel Tank 3. Activities include refurbishment of coating to prevent against corrosion.						
49970	CT - TUS Exhaust Stack Refurbishment	66,592	66,592	4	4	16
This project includes the refurbishment of the Tusket Combustion Turbine Stack.						

CI#	Project Title	2018 Budget ($)	Project Total ($)	Criticality	Condition	Ranking
52106	CT BGT Fuel Level Monitoring Upgrade	65,828	65,828	4	4	16
	This project includes the upgrade of the fuel level monitoring system at Burnside to improve the Environmental Monitoring and Fuel Consumption Program.					
47937	BGT1 Clutch Refurbishment	61,000	61,000	4	4	16
	This project includes the refurbishment of the clutch on the Burnside Unit 1 Turbine.					
52142	CT Tusket Plant Coating	43,885	43,885	4	4	16
	This project includes the re-coating of the Tusket Plant to prevent against corrosion					
52144	CT TUC 4 & 5 Engine Pad Installation	43,885	43,885	4	4	16
	This project includes installation of a pad that will enable the safe removal of the engine and reduce the safety and equipment risks while transferring from crane to shipping container.					
52159	CT VJ1 Varec Gauges Upgrades	35,000	35,000	4	4	16
	This project includes the upgrade of Varec gauges to meet calibration and reliability requirements					
52160	CT VJ2 Varec Gauges Upgrades	35,000	35,000	4	4	16
	This project includes the upgrade of Varec gauges to meet calibration and reliability requirements.					
C0002858	CT's TUS Operator Interface Upgrade	30,167	30,167	3	5	15
	This project includes upgrading the operator interface at Tusket to improve performance and reliability.					
C0002980	CT BGT Plenum Floor Refurbishment	28,879	28,879	4	4	16
	This project includes the refurbishment of the plenum floor at Burnside. This refurbishment will prevent flaking concrete from entering the unit and causing subsequent damage to the turbine.					
Total Gas Turbine Items Less Than $250,000		**$1,232,300**	**$1,232,300**			
Total Generation Items Less Than $250,000		**$14,545,152**	**$14,614,447**			
Transmission						
52261	83V-503 & 83V-504 - Bring Switches	212,968	212,968	3	5	15
	This project includes the relocation of two switches (83V-503 & 83V-504) to roadside for ease of access.					
Total Transmission Items Less Than $250,000		**$212,968**	**$212,968**			
Distribution						
51499	2018 Downline Recloser Replacements	245,928	245,928	5	4	20
	This project includes the replacement of downline reclosers and controls. Additional replacements include framing, switches, lightning arrestors, fuses, and transformers, where applicable.					
49898	15N-202 Victoria St Rebuild	242,253	242,253	4	4	16

CI#	Project Title	2018 Budget ($)	Project Total ($)	Criticality	Condition	Ranking
This project includes the replacement of deteriorated poles and conductor on sections of 15N-202 along Victoria St, Pleasant St, Muir St and King St in Truro.						
C0001798	Halifax 4kV Conversion Phase 5	218,971	218,971	5	4	20
This project is the fifth phase of a multi-phase project to convert the remaining 4kV distribution plant in peninsular Halifax to 25kV.						
52221	515S-311-Rebuild on Aliant poles	190,606	190,606	5	4	20
This project includes the rebuilding of the existing single phase feeder 515S-311 to roadside by utilizing existing joint use Aliant poles along the Cabot Trail in North River Centre.						
52306	5N-301 - Masstown Road Rebuild	165,446	165,446	4	4	16
This project includes the replacement of deteriorated poles and conductor on 5N-301 along Masstown Rd in Debert.						
52265	55V-322-English Mt Rd Reconfigure	157,022	157,022	4	5	20
This project includes the upgrade of approximately 420 meters of existing single-phase #4 copper conductor and fill in of 100 meters under L-5022 with three phase 336 ASC primary and 4/0 neutral conductor on feeder 55V-322 along English Mountain Rd in Coldbrook.						
Total Distribution Items Less Than $250,000		**$1,220,227**	**$1,220,227**			
General Plant						
C0001758	AMO CBT & Procedure Management Phase 3	213,866	231,446			
This project includes the expansion of the Competency Based Training and Procedure Management System into maintenance, chemical and environment streams.						
C0002058	Damage Assessment Enhancements	213,616	213,616			
This project will include the upgrade of damage assessment kits and enhancements to the accessibility of information collected through damage assessment.						
C0002256	IT- Customer Care & Billing Server-Migration	205,021	205,021	3	5	15
This project includes the upgrade of both server and operating system for hosting applications in use by the Customer Care and Billing Teams.						
49825	Radio Site Grounding Upgrade	181,197	181,197			
This project includes upgrades to grounding at NS Power telecom sites.						
52247	PTMT Water treatment Eyewash/Shower	154,857	154,857			
This project includes the installation of an eye wash station at the Point Tupper Marine Terminal.						
52334	IT-Meridium Upgrade	150,000	150,000	4	4	16
This project includes the upgrade of the currently used version of Meridium. Meridium is an asset management software solution.						
52310	Move RTU Circuits to New Backbone	149,819	149,819			
This project is to move approximately 8 RTUs over to the new Multiprotocol Label Switching (MPLS) network. It includes new routers, engineering design, and technician labour.						
50955	AMO NERC CIPv6 Compliance Upgrades	117,361	117,361			
This project includes infrastructure upgrades to comply with NERC CIP version 6 requirements that come into effect on September 1, 2018.						
C0002479	CIPv6 Electronic Security	102,055	102,055			

CI#	Project Title	2018 Budget ($)	Project Total ($)	Criticality	Condition	Ranking
This project includes the purchase and implementation of firewalls for the newly identified CIP Low Impact substations to comply with NERC CIP version 6 requirements that come into effect on September 1, 2018.						
50941	AMO Portal Development	102,031	102,031			
This project includes the development and implementation of IT infrastructure to facilitate connectivity between multiple asset management systems.						
52312	System Operations Phone Upgrade	90,511	90,511			
This project includes the upgrade of the existing System Operations Phone System (SOPS) to replace obsolete equipment and to allow expansion for new sites. Included in scope is the replacement/upgrade of the central phone switches at the ECC and the BCC, as well as an upgrade to the operator phones at both sites.						
50942	AMO Hydro Data Integration	61,219	61,219			
This project includes the integration of hydro system data into asset management systems. Activities will include IT infrastructure deployment to incorporate operational data into various groups including environment, Generation Asset Management and Energy Marketing.						
49832	Victoria Junction Substations Fiber Links	52,631	52,631			
This project includes installation of new Fiber links, from the 415S Victoria Junction Radio to the 2S Victoria Junction substations. This will improve the reliability and capability of the communications to these sites.						
51752	AMO Mobile Applications	51,021	51,021			
This project includes the development and deployment of an asset management mobile application.						
51753	AMO SWP Automation	51,021	51,021			
This project includes the deployment of safe work practices into operational technology solutions.						
50944	AMO RBI Program Phase 4	51,015	51,015			
This project is to advance the development of risk based inspections programs and infrastructure.						
Total General Plant Items Less Than $250,000		**$1,947,239**	**$1,964,820**			
Total Capital Items Less Than $250,000		**$17,925,586**	**$18,012,462**			

4.5 2018 ACE Plan Capital Items – Point Aconi Generating Station

Figure 24 below provides the Point Aconi capital projects for 2018. These projects do not require UARB Approval but are provided for transparency and informational purposes.

Figure 24: 2018 Capital Items – Point Aconi Generating Station

CI#	Project Title	2018 Budget ($)	Project Total ($)
51799	POA Boiler Refurbishment 2018	1,681,408	1,681,408
51800	POA Boiler Refractory 2018	799,984	799,984
51801	POA Air Heater Tube Replacement	574,681	574,681
51819	POA SH3 Tube Replacements	572,602	572,602
51855	POA LS System Refurbishment	328,667	328,667
51858	POA Coal System Refurbishment	269,172	269,172
52065	POA Boiler Arrowhead Replacement	256,851	256,851
52122	POA CW Screen Refurbishment 2018	251,164	251,164
52072	POA Ash System Refurbishment	238,262	238,262
52080	POA SA Compressor Upgrade	215,329	215,329
52078	POA Frontwall Pipe Replacement	203,622	203,622
52084	POA Turbine Hydraulic Controls	201,097	201,097
52073	POA LS Crusher Refurbishment	197,546	197,546
52071	POA Plant Lighting Upgrade	171,913	171,913
52082	POA Flame Scanners SUB Valve Train	166,872	166,872
52066	POA Expansion Joint Replacement	162,942	162,942
C0001438	POA - Coal Chute Refurbishment	158,542	158,542
52067	POA Valve Component Replacement	155,910	155,910
52070	POA Access Improvement	151,748	151,748
52079	POA BA Center Drain Valves	138,552	138,552
52083	POA Sequence of Events Recorder	124,385	124,385
52069	POA Fan Vibration Probe Upgrade	119,337	119,337
52077	POA Facilities Upgrades	119,323	119,323
47857	POA CW Valve Replacement	102,417	102,417
52064	POA - Boiler House Window Upgrade	92,614	92,614
52074	POA Floor Sweeper	90,879	90,879
52123	POA CW Screen Wash Pump Replacement	87,318	87,318
52087	POA Coal System Fire Detection	81,158	81,158
52086	POA Lube Oil Tank Fire Protection	67,872	67,872
52068	POA 4KV 600V Breaker Refurbishment	67,277	67,277
52075	POA Forklift Replacement	59,220	59,220
52085	POA Diesel Line Emergency Shutoff	51,134	51,134
Total Point Aconi New Spending		**$7,959,798**	**$7,959,798**
Point Aconi Carryover Spending		**$2,193,929**	**$7,917,954**
Point Aconi Routine Spending			
25647	POA DCMS Equipment Replacement	37,000	37,000

CI#	Project Title	2018 Budget ($)	Project Total ($)
21485	POA - Kelly Rock Limestone Quarry	22,000	22,000
21484	POA Plant Tools & Equipment	52,530	52,530
10718	POA - Routine Equipment Replacement	217,054	217,054
27858	POA Roofing Routine	109,713	109,713
33865	POA Heat Rate Routine	48,527	48,527
Point Aconi Routine Spending		**$486,824**	**$486,824**
Total Point Aconi Capital Spending		**$10,640,551**	**$16,364,575**

5.0 GENERATION

The focus for Generation capital investments in 2018 is investment in hydro infrastructure renewal and sustaining the current thermal asset base. The approximately $117 million Generation capital investment plan for 2018 is summarized in **Figure 25** below.

Figure 25: Summary of 2018 Generation Capital Investments ($ millions)

i	New 2018 capital spending for projects with total estimated project spending greater than $250,000 and for which approval is sought. (As provided in Section 5.2)	48.4
ii	2018 capital spending for projects with total estimated project spending greater than $250,000 for which approval will be sought subsequent to the filing of the 2018 ACE Plan. (As provided in Section 4.3)	8.5
iii	New capital spending for projects with total estimated spending less than $250,000 for which approval is not sought. (As provided in Section 4.4)	14.5
iv	2018 capital spending for projects included in the 2017 ACE Plan for which approval will be sought in late 2017 (As provided in Section 3.2).	0.8
v	Point Aconi Generating Station capital spending. (As provided in Section 4.5)	10.5
vi	Carry-over capital spending. (As provided in Section 5.1)	29.1
vii	Routine capital spending. (As provided in Section 9)	4.6
	Total 2018 Generation Capital Investment Plan	$116.5 M
	Request for ACE Approval (Items i and vii)	$53.0 M

Note: Totals may be off slightly due to rounding.
Note: Figures are noted in $millions.

5.1 Generation – Carry-over Capital Spending Summary

Figure 26: Generation Carry-over Capital Spending Summary

CI#	Project Title	Start Date	Final Date	Previous Expenditure ($)	2018 Budget ($)	Subsequent Spending ($)	Total Estimate ($)
Hydro Generation Plant							
16374	HYD Gaspereau Dam Safety	2007/05	2020/01	8,323,181	3,708,981	9,326,938	21,359,099
29807	HYD - Tusket Falls Main Dam	2008/01	2020/12	5,754,477	10,398,599	2,004,533	18,157,609
44978	HYD - Wreck Cove Controls Upgrade	2014/01	2019/04	3,591,421	1,117,205	-	4,708,626
47551	HYD - SHH Controls Upgrade	2015/07	2018/12	611,690	1,099,505	-	1,711,195
48396	HYD - Bridge Remediation	2016/02	2018/06	405,262	1,239,856	-	1,645,118
47163	HYD - Tusket Controls Upgrade	2015/03	2019/06	516,010	367,891	-	883,900
49039	HYD - Lequille Controls Upgrade	2016/03	2019/04	286,845	315,702	-	602,547
48631	HYD - Gulch Spillway Refurbishment	2015/12	2019/03	74,695	472,350	-	547,045
49598	HYD - Gisborne Switchgear Replacement	2016/06	2019/05	18,934	375,071	-	394,005
49634	HYD - Trout River Div. Screen Replacement	2016/06	2019/05	1,877	234,956	-	236,834
C0001458	HYD HMS Shop Expansion	2017/01	2019/04	30,435	198,776	-	229,212
46253	HYD - Lequille Tailrace Gate	2016/01	2018/06	64,514	150,640	-	215,154
52313	HYD - HG1 Crane Replacement	2017/01	2018/08	43,442	160,116	-	203,558
C0001459	HYD Annapolis Rip Rap Refurbishment	2017/01	2019/03	54,621	113,928	-	168,550
52255	HYD - Miller Lake Access Improvement	2017/07	2018/11	39,748	66,620	-	106,368
38931	HYD Harmony Partial Decommission	2009/11	2018/06	854,972	11,657	-	866,628
Total Hydro Generation Plant				**$20,672,124**	**$20,031,851**	**$11,331,471**	**$52,035,447**
Steam Generation Plant							
44267	TRE Trenton Ash Site Closure	2013/05	2018/12	7,211,521	1,823,288	-	9,034,809
46499	AMO Stator Rewind Kit Cap Spare	2016/02	2018/09	1,819,659	31,677	-	1,851,336
49707	TUC2 Generator Bushing Replacement	2017/03	2018/12	1,781	996,640	-	998,421
49897	POT - Fire system upgrades 2017	2017/04	2019/08	80,156	541,998	-	622,153
41511	TRE6 Condenser Waterbox/CW Piping Replacement	2017/05	2018/12	70,593	543,189	-	613,782
50020	LIN CEMS Replacement Phase 1	2017/05	2018/12	-	486,083	-	486,083
49316	TUC3 CEMS Replacement U&U	2016/07	2018/06	416,441	34,752	-	451,193
49132	PTMT Dock Winching and Access	2016/03	2018/12	29,669	394,449	-	424,118
52015	LIN2 UU Turbine Control Valve Refurbishment	2018/07	2018/12	-	241,020	-	241,020
49437	LIN Vacuum Pump Cooler Refurbishment	2017/04	2018/06	165,069	68,073	-	233,142
44727	TUC3 - DCS Upgrade Phase 3 Turbine	2017/07	2018/06	151,944	52,423	-	204,367
51356	TUC3 UU TG Fire System and Detection	2018/07	2019/06	-	178,573	14,350	192,923

CI#	Project Title	Start Date	Final Date	Previous Expenditure ($)	2018 Budget ($)	Subsequent Spending ($)	Total Estimate ($)
41229	LIN - Cable Spreading Rooms Fire Protection	2013/09	2018/12	37,542	149,951	-	187,493
46495	TUC3 - DCS Upgrade Phase 4 Boiler	2017/07	2018/12	118,444	50,998	-	169,442
51410	TUC U&U Wastewater Lagoon Refurbishment	2017/04	2018/12	126,025	54,857	-	180,882
49697	TUC2 - Replace Oil Purifier I&C Heater	2017/07	2018/07	17,756	84,933	-	102,689
49459	LIN34 HMI TSC Upgrades	2017/05	2018/12	-	97,760	-	97,760
49454	LIN3 Gen. Bus Duct Temp. Sensors	2017/01	2018/12	45,264	39,931	-	85,195
49514	POT - LP Heaters Level Controls	2017/02	2018/12	39,453	18,515	-	57,968
Total Steam Generation Plant				**$10,331,317**	**$5,889,108**	**$14,350**	**$16,234,775**
Gas Turbine Generation Plant							
33142	CT - BGT4 Unit Restoration	2014/11	2018/06	8,679,199	536,911	-	9,216,110
51526	CT's Tusket Replace Generator	2017/05	2018/12	1,414,181	1,679,586	-	3,093,767
51711	CT Burnside Unit 2 Generator Replacement	2017/06	2018/12	1,945,374	931,694	-	2,877,068
49973	CT - TUS Control Room Halon Replacement	2017/03	2018/05	150,922	71,246	-	222,168
Total Gas Turbine Generation Plant				**$12,189,677**	**$3,219,437**	**$0**	**$15,409,114**
Total Generation Carry Over Spending				**$43,193,118**	**$29,140,396**	**$11,345,821**	**$83,679,336**

5.2 Generation – New 2018 Capital Items for ACE Plan Approval

Figure 27: Generation - New 2018 Capital Items for ACE Plan Approval

Tab #	CI#	Project Title	2017 Budget	Project Total
	Hydro Generation Plant			
G01	51236	HYD - WRC Tailrace Rock Bolting	8,677,118	8,861,996
G02	48533	HYD Lequille Headpond Refurbishment	4,209,710	4,472,369
G03	49033	HYD WRC Tunnel T-2 Intake Replacement	2,525,419	2,851,582
G04	51235	HYD - WRC Main Access Rd Refurbishment	2,574,654	2,686,075
G05	51234	HYD - WRC HVAC Upgrade	266,738	1,876,537
G06	49943	HYD - Ruth Falls Facility Refurbishment	1,217,177	1,234,931
G07	49942	HYD - Tidewater Facility Refurbishment	1,230,442	1,234,178
G08	49946	HYD - Fourth Lake Overhaul	978,404	1,025,769
G09	49945	HYD - Malay Falls Switchgear Replacement	957,136	958,631
G10	52262	HYD - Hells Gate 1 Overhaul	854,993	854,993
G11	51972	HYD Nictaux Canal Embank Refurbishment	779,686	789,918

Tab #	CI#	Project Title	2017 Budget	Project Total
G12	51866	HYD - 4th Lake Penstock Refurbishment	663,326	696,963
G13	47655	HYD - Paradise Controls Upgrade	218,179	639,991
G14	49944	HYD - Dickie Brook Penstock Refurbishment	478,820	478,820
G15	48712	HYD - Dam Instrumentation Upgrade	395,505	476,207
G16	52018	HYD - RES Revenue Meter Replacement	368,897	378,248
		Total Hydro Generation Plant	**$26,396,205**	**$29,517,209**
		Steam Generation Plant		
Boiler				
G17	51802	TRE5 Boiler Refurbishment 2018	1,212,228	1,212,228
G18	51805	LIN4 Boiler Refurbishment 2018	739,657	739,657
G19	47684	LIN3 Boiler Refurbishment 2018	739,657	739,657
G20	51825	POT Boiler Refurbishment 2018	568,740	568,740
G21	52252	LIN1 SH5 Tube Replacement	521,259	521,259
G22	52253	LIN3 Economizer Header Refurbishment	499,951	499,951
G23	51821	TRE5 Air Heater Refurbishment	487,376	487,376
G24	51824	LIN3 ID Fan Damper and VIV Refurbishment	443,311	443,311
G25	51818	PHB Boiler Refurbishment 2018	440,315	440,315
G26	51807	TUC2 Boiler Lower Vestibule Refurbishment	412,872	412,872
G27	51849	LIN3 RH Tube Replacement	399,546	399,546
G28	51850	LIN4 RH Tube Replacement	399,546	399,546
G29	49547	TRE5 5-1 BFP Refurbishment	345,523	345,523
G30	51857	TRE5 Burner Refurbishments 2018	332,497	332,497
Turbine				
G31	49534	TRE6 EHG/Turbine Controls Upgrade	2,507,264	2,725,344
G32	51820	TRE5 Reheat Turbine Valves	450,408	450,408
G33	51862	TRE6 Lube Oil Cooler Refurbishment	341,769	341,769
G34	43429	TRE5 Lube Oil Cooler Retube	338,398	338,398
G35	51853	LIN3 Turbine Valve Refurb 2018	295,709	295,709
Generator				
G36	51803	TUC2 Generator Flux Probe Installation	840,158	840,158
Environmental				
G37	50577	TRE6 CEMS Replacement	715,562	715,562
G38	49676	TUC2 CEMS Replacement	380,140	380,140
Balance of Plant				
G39	51806	LIN Mill Refurbishment 2018	673,153	673,153
G40	52093	ICP Rail Crossing Refurbishment	592,402	592,402
G41	51811	LIN Reclaim Refurbishment Phase 2	534,666	534,666
G42	51815	LIN CW Pump Refurbishment 2018	520,436	520,436
G43	51861	TRE6 CW Screen Replacement 2018	513,192	513,192

Tab #	CI#	Project Title	2017 Budget	Project Total
G44	51816	TRE Asbestos Abatement 2018	509,035	509,035
G45	51835	TUC2 H2 Panel Upgrades	454,886	454,886
G46	51836	TRE5 Mill Refurbishments 2018	409,458	409,458
G47	47871	LIN Stack Re-Coating	381,034	381,034
G48	51839	LIN Coal Plant Structural Refurbishment	354,067	354,067
G49	51851	LIN CW Screen Refurbishment 2018	350,534	350,534
G50	C0001419	TRE HFO Refurbishment Phase 1	340,618	340,618
G51	51804	LIN3&4 ACW Duplex Strainer Replacement	333,808	333,808
G52	51852	POT Mill Refurbishment 2018	327,267	327,267
G53	52156	LIN Vacuum Pump Upgrades	302,714	302,714
G54	51860	TRE5 PF Mill Line Replacement	258,761	258,761
Total Steam Generation Plant			**$20,267,916**	**$20,485,995**
	Steam Generation Plant			
G55	52143	LM6000 Engine 191-332 Hot Section	1,776,275	1,776,275
Total Gas Turbine Generation Plant			**$1,776,275**	**$1,776,275**
Total Generation New Spending			**$48,440,395**	**$51,779,479**

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6.0 TRANSMISSION

The focus for Transmission capital investments in 2018 is on system reliability, as well as transmission required to integrate the Maritime Link. The approximately $76 million Transmission capital investment plan for 2018 is summarized in **Figure 28** below.

Figure 28: Summary of 2018 Transmission Capital Investments ($ million)

i	New 2018 capital spending for projects with total estimated project spend greater than $250,000 and for which approval is sought. (As provided in Section 6.2)	26.0
ii	2018 capital spending for projects with total estimated project spending greater than $250,000 for which approval will be sought subsequent to the filing of the 2018 ACE Plan. (As provided in Section 4.3)	0.0
iii	New capital spending for projects with total estimated spending less than $250,000 for which approval is not sought. (As provided in Section 4.4)	0.2
iv	Carry-over capital spending. (As provided in Section 6.1)	38.0
v	Routine capital spending. (As provided in Section 9)	11.5
vi	Total 2018 Transmission Capital Investment Plan	$75.7 M
	Request for ACE Approval (Items i and v)	$37.4 M

Note 1: Totals may be off slightly due to rounding.
Note 2: Figures are noted in $millions.

6.1 Transmission – Carry-over Capital Spending Summary

Figure 29: Transmission Carry-Over Capital Spending Summary

CI#	Project Title	Start Date	Final Date	Previous Expenditure	2018 Budget	Subsequent Spending	Total Estimate
Transmission Plant							
43324	L6513 Rebuild/upgrade Line Terminal	2013/01	2018/06	10,434,236	5,772,679	-	16,206,915
46591	88S Lingan Replace 230kV GIS	2014/11	2019/10	3,865,693	10,417,221	487,200	14,770,114

CI#	Project Title	Start Date	Final Date	Previous Expenditure	2018 Budget	Subsequent Spending	Total Estimate
48022	Spider Lake Substation Addition	2015/09	2018/12	4,129,010	3,547,876	-	7,676,886
47954	L7012 Replacements and Upgrades	2017/04	2018/11	1,847,922	2,345,236	-	4,193,158
49838	2017 Substation PCB Equip Replacement	2017/01	2019/06	2,845,978	1,001,403	261,210	4,108,591
46757	88S Lingan 230kV BPS Upgrades	2015/09	2018/12	2,887,931	390,479	-	3,278,410
49948	2017/2018 Isolated Structure Replacements	2017/06	2019/03	2,033,194	1,126,790	-	3,159,984
49793	L7011 Replacements and Upgrades	2017/04	2018/12	921,750	2,039,165	-	2,960,915
49789	L6515 Replacements and Upgrades	2016/12	2017/10	2,605,733	216,842	-	2,822,575
48061	New Mobile Substation 7.5MVA	2015/12	2018/12	826,631	1,983,761	-	2,810,393
51404	2018/2019 Steel Tower Life Extension	2017/07	2020/01	871,685	1,461,922	647,712	2,981,318
49815	2017 Steel Tower Refurbishment	2017/01	2019/06	897,524	1,079,482	-	1,977,006
49814	2017 Steel Tower Life Extension	2017/01	2018/12	1,555,043	202,455	-	1,757,498
51956	6P Mobile Substation Rewind	2017/09	2018/11	410,740	985,312	-	1,396,051
49790	L5505 Replacements and Upgrades	2018/02	2019/05	-	1,220,473	-	1,220,473
49778	L5535 Replacements and Upgrades	2017/07	2018/06	882,448	302,398	-	1,184,846
49774	L5527 Replacements and Upgrades	2017/04	2018/07	18,991	1,067,741	-	1,086,732
47131	L8001 Structure 58 Replacement	2015/04	2018/06	672,499	346,671	-	1,019,170
49775	L5004 Replacements and Upgrades	2016/12	2018/06	614,803	267,765	-	882,568
49776	L7008 Replacements and Upgrades	2017/02	2018/05	346,550	395,402	-	741,952
49879	77V-T52 Replacement	2016/09	2018/05	162,809	556,677	-	719,486
49821	Mersey River Hydro Spare Transformer	2017/01	2018/06	231,199	431,344	-	662,544
47915	L5053 Replacements and Upgrades	2017/03	2018/05	19,408	627,905	-	647,312
49798	2017 Capacitor Bank Breaker Replacement	2017/06	2018/06	133,673	249,565	-	383,238
				$39,215,448	**$38,036,565**	**$1,396,122**	**$78,648135**
Total Transmission Plant							
				$39,215,448	**$38,036,565**	**$1,396,122**	**$78,648135**
Total Transmission Carry Over Spending							

6.2 Transmission – New 2018 Capital items for ACE Plan Approval

Figure 30: Transmission – New 2018 Capital items for ACE Plan Approval

Tab #	CI#	Project Title	2017 Budget	Project Total
	Transmission Plant			
T01	51969	2018 Transmission ROW Widening 69kV	5,487,686	5,487,686
T02	51975	5P Mobile Substation Replacement	3,225,405	4,829,458
T03	52258	2018/2019 Isolated Structure Replacement	1,094,899	4,818,521
T04	51403	2018 PCB Removal Program	1,478,161	4,402,342
T05	51402	2018/2019 Sacrificial Anode Installation	703,416	3,023,668
T06	C0001900	Mount Hope 69-25kV Substation	1,397,158	2,982,338
T07	52314	1C-GT1/UT1 Replacement	1,162,188	2,032,393
T08	51398	2018/2019 Steel Tower Refurbishment	461,426	1,992,692
T09	52320	L6549 2018 Replacements & Upgrades	657,710	1,406,535
T10	51406	2018/2019 Transmission Switch & Breaker Replacement	1,311,498	1,405,891
T11	51405	2018 Wood Pole Retreatment Program	680,538	1,361,076
T12	48131	48H-T1 Replacement	648,122	1,281,449
T13	52328	56N-T1 Transformer Upgrades	703,817	1,279,271
T14	49779	L6537 Replacements and Upgrades	587,041	1,255,220
T15	49777	L7002 Replacements and Upgrades	437,128	926,777
T16	52241	16V-T2 Weymouth Hydro Transformer Replacement	889,253	889,253
T17	52102	L5014-2018 Replacements and Upgrades	849,700	849,700
T18	49788	L5564 Replacements and Upgrades	691,417	738,853
T19	52059	L5039 - 2018 Replacements and Upgrades	719,825	719,825
T20	49783	L5027A Replacements and Upgrades	648,292	648,292
T21	52119	L5054 2018 Replacements and Upgrades	560,143	560,143
T22	52238	2018/2019 Capacitor Bank Breaker Replacement	243,830	433,719
T23	43268	9W-B53 Tusket Replace Structure	375,523	375,523
T24	51797	2018 Oil Containment Program	331,507	331,507
T25	52305	2018 Substation Insulator Replacement	316,348	316,348
T26	51863	2018 Tap Changer Replacements	306,102	306,102
Total Transmission Plant			**$25,968,132**	**$44,654,581**
Total Transmission New Spending			**$25,968,132**	**$44,654,581**

7.0 DISTRIBUTION

The focus for Distribution capital investments in 2018 continues to reflect localized customer load growth and customer reliability, and the implementation of the AMI project. The approximately $108 million Distribution capital investment plan for 2018 is summarized in **Figure 31** below.

Figure 31: Summary of 2018 Distribution Capital Investments ($ million)

i	New 2018 capital spending for projects with total estimated project spend greater than $250,000 and for which approval is sought. (As provided in Section 7.2)	17.0
ii	2018 capital spending for projects with total estimated project spend greater than $250,000 for which approval will be sought subsequent to the filing of the 2017 ACE Plan. (As provided in Section 4.3)	0.8
iii	New capital spending for projects with total estimated spending less than $250,000 for which approval is not sought. (As provided in Section 4.4)	1.2
iv	Carry-over capital spending. (As provided in Section 7.1)	41.4
v	Routine capital spending. (As provided in Section 9)	47.7
	Total 2018 Distribution Capital Investment Plan	$108.1 M
	Request for ACE Approval (Items i and v)	$64.7 M

Note 1: Totals may be off slightly due to rounding.

Note 2: Figures are noted in $millions.

7.1 Distribution – Carry-over Capital Spending Summary

Figure 32: Distribution Carry-over Capital Spending Summary

CI#	Project Title	Start Date	Final Date	Previous Expenditure	2018 Budget	Subsequent Spending	Total Estimate
Distribution Plant							
47124	Advanced Meter Infrastructure	2015/01	2020/12	6,434,265	28,323,131	104,588,701	139,346,096
40320	LED Street Light Conversion	2012/07	2019/09	24,240,026	4,766,609	8,163,857	37,170,492
50796	New Distribution ROW Phase II	2017/01	2018/07	3,403,663	2,729,757	-	6,133,420
49787	Intelligent Feeder/Storage Project	2016/08	2019/12	2,068,198	717,742	106,047	2,891,988
44749	509V-301 Tower and Crossing Replacement	2013/10	2019/06	592,739	1,059,753	-	1,652,492
49919	2017 PCB Pole Top Trans. Replacement	2017/01	2018/07	1,234,700	349,725	-	1,584,425
49806	2017 Padmount Replacement Program	2017/01	2018/03	1,333,116	235,460	-	1,568,576
47760	85S-402 Re-Insulate	2015/12	2019/01	1,059,012	435,806	43,566	1,538,384
44826	2014 Build-to-Roadside	2014/03	2018/08	768,677	138,078	-	906,756
49841	23H-Rockingham Voltage Conversion	2017/01	2018/09	507,447	336,745	-	844,192
41350	16W-301 Hebron Rebuild Phase 2	2017/05	2019/12	36,180	383,790	416,112	836,082
47787	2H Armdale New Feeders	2017/07	2019/02	111,254	701,079	-	812,333
47765	58C-405 Belle Cote Phase 2	2015/12	2018/04	258,709	390,092	-	648,801
49311	93V-312 Lower Saulnierville Conduct	2016/08	2018/07	233,761	245,914	-	479,674
43177	103W-311 Gold River Reconductor Phase 3	2014/03	2018/05	380,177	41,484	-	421,662
49891	509V Recloser and Voltage Regulator	2017/05	2018/06	102,858	162,737	-	265,595
49056	65V-302HAA Old Liverpool Rd Rebuild	2016/06	2018/09	72,348	125,346	-	197,694
49957	93V Feeder Expansion	2017/04	2018/12	10,224	132,021	-	142,246
47777	70W-321 Wile Lake Road	2016/06	2018/12	7,790	94,089	-	101,879
Total Distribution Plant				**$42,855,143**	**$41,369,360**	**$113,318,283**	**$197,542,786**
Total Distribution Carry Over Spending				**$42,855,143**	**$41,369,360**	**$113,318,283**	**$197,542,786**

7.2 Distribution – New 2018 Capital Items for ACE Plan Approval

Figure 33: Distribution – New 2018 Capital Items for ACE Plan Approval

Tab #	CI#	Project Title	2018 Budget	Project Total
Distribution Plant				
D01	C0001950	New Distribution Rights-of-Way Ph 3	6,870,749	9,822,493
D02	52271	2018 Padmount Replacement	1,286,340	1,657,205
D03	51493	2018 PCB Pole Top Transformer Replacement	842,163	1,360,354
D04	52184	37N-412-Glooscap Trail Rebuild Phase 2	858,046	858,046
D05	52224	532N-Elm Street Conversion Phase 2	433,695	722,113
D06	C0001802	54C-211 Queen Street Conversion	705,316	705,316
D07	52185	50N-410 Rebuild Phase 2	695,098	695,098
D08	43218	88W-323A Tusket Islands Phase 3	347,162	654,721
D09	51400	2018 Sub Recloser Replacements	644,710	644,710
D10	52194	6S-223 Harold Street Conversion	642,368	642,368
D11	52200	65V-301 Brickton Reconductor	288,048	594,362
D12	52205	30N-412 Hwy 242 Fundy Shore Rebuild	536,670	536,670
D13	51744	30N-411 Maccan River Rebuild	473,044	473,044
D14	52204	87W-312G-Tancook Island Replacement	208,236	454,096
D15	52267	16W-302H-Brenton Rd Rebuild	258,839	387,767
D16	52207	678H-211 McNab's Island Replacement	162,232	350,176
D17	51500	2018 Pin Insulator Replacements	329,944	350,100
D18	52192	54H-303 Underground Device Replacement	289,957	309,230
D19	52206	20V-311-Bishop Ville Rd	303,533	303,533
D20	52186	4S Feeder Exit Cable Replacement Phase 1	276,129	293,509
D21	52208	3S Feeder Exit Cable Replacement Phase 2	293,228	293,228
D22	52201	55V-314GA-Welsford Reconductor	275,161	275,161
Total Distribution Plant			**$17,020,666**	**$22,383,299**
Total Distribution New Spending			**$17,020,666**	**$22,383,299**

8.0 GENERAL PLANT

General Plant capital investment in 2018 is primarily on Information Technology. The General Plant capital investment plan for 2018 is summarized in **Figure 34** below.

Figure 34: Summary of 2018 General Plant Capital Investments ($ million)

i	New 2018 capital spending for projects with total estimated project spend greater than $250,000 and for which approval is sought. (As provided in Section 8.2)	0.6
ii	2018 capital spending for projects with total estimated project spending greater than $250,000 for which approval will be sought subsequent to the filing of the 2017 ACE Plan. (As provided in Section 4.3)	20.5
iii	New capital spending for projects with total estimated spending less than $250,000 for which approval is not sought. (As provided in Section 4.4)	1.9
iv	2018 capital spending for projects included in the 2017 ACE Plan for which approval will be sought in late 2017. (As provided in Section 3.2)	0.1
v	Point Aconi Generating Station capital spending. (As provided in Section 4.5)	0.1
vi	Carry-over capital spending. (As provided in Section 8.1)	11.3
vii	Routine capital spending. (As provided in Section 9)	20.1
	Total 2018 General Plant Capital Investment Plan	$54.6 M
	Request for ACE Approval (Items i and vii)	$20.7 M

Note 1: Totals may be off slightly due to rounding.
Note 2: Figures are noted in $millions.

8.1 General Plant – Carry-over Capital Spending Summary

Figure 35: General Plant – Carry-over Capital Spending Summary

CI#	Project Title	Start Date	Final Date	Previous Expenditure	2018 Budget	Subsequent Spending	Total Estimate
43202	Replace Mobile Radio System	2012/11	2019/09	3,684,371	2,227,581	-	5,911,952
46338	2017 New RTU Deployment	2018/03	2018/12	-	599,994	-	599,994
46572	2017 RTU Replacements	2017/01	2018/12	170,402	360,655	-	531,057
Total Telecommunications				**$3,854,773**	**$3,188,230**	**$0**	**$7,043,003**
49855	IT - Desktop SW Modernization	2016/08	2018/07	3,268,859	1,736,019	-	5,004,877
49860	IT - Sharepoint Upgrade	2017/01	2019/01	1,737,452	2,166,142	-	3,903,594
47477	IT - Next Generation Firewall	2015/05	2018/03	3,547,479	57,796	-	3,605,275
46739	IT - Outage Map Technology Upgrades	2015/02	2018/06	2,542,920	353,000	-	2,895,920
48773	IT - VOIP Expansion	2016/01	2019/10	373,089	776,193	641,726	1,791,007
49857	IT - Storage Infrastructure Upgrade	2017/01	2018/01	1,254,597	330,000	-	1,584,597
51485	IT-Threat Management Gateway	2017/05	2018/08	595,329	176,274	-	771,603
49861	IT - PI System Upgrade	2017/01	2018/02	580,646	104,649	-	685,295
51481	IT CMS Upgrade	2017/05	2018/12	38,888	525,174	-	564,063
Total Computers				**$13,939,258**	**$6,225,248**	**$641,726**	**$20,806,231**
50153	Self Serve Dev Phase 2	2017/08	2018/06	538,826	601,775	-	1,140,601
50113	Customer Experience Streetlight Improvements	2017/01	2019/06	256,687	479,202	-	735,889
Total Customer Experience				**$795,513**	**$1,080,977**	**$0**	**$1,876,489**
50292	Kempt Road/Dartmouth East Truck Bay	2017/01	2018/05	618,017	528,138	-	1,146,155
49880	Meter Shop Test Console Replacement	2017/08	2018/04	205,000	205,000	-	410,000
50295	Electric Vehicle Charging Stations	2017/03	2018/08	426,012	23,829	-	449,841
48039	AMO Meridium 4.0	2017/10	2018/04	52,325	18,000	-	70,325
Total Other General Plant				**$1,301,354**	**$774,967**	**$0**	**$2,076,321**

CI#	Project Title	Start Date	Final Date	Previous Expenditure	2018 Budget	Subsequent Spending	Total Estimate
Total General Plant Carry Over Spending				**$19,890,897**	**$11,269,421**	**$641,726**	**$31,802,044**

8.2 General Plant – New 2018 Capital Items for ACE Plan Approval

Figure 36: General Plant – New 2018 Capital Items for ACE Plan Approval

Tab #	CI#	Project Title	2018 Budget	Project Total
Outage Performance				
GP01	52308	2018 RTU Replacement Program	298,792	988,056
GP02	52233	2018 Telecom Building Replacement	314,929	314,929
Total Outage Performance Spending			**$613,720**	**$1,302,985**
Total New General Plant Spending			**$613,720**	**$1,302,985**

9.0 ROUTINE CAPITAL PROGRAM

NS Power's routine capital program is for recurring annual expenditures of like-for-like replacement of equipment, additions to existing equipment base resulting from system growth, and addition of customers to the system. This section details all routine capital expenditures for Generation, Transmission, Distribution and General Plant asset classes. NS Power seeks UARB approval of the 2018 routine capital program in the amount of approximately $84 million.

9.1 Routine Capital Spending by Function Yr/Yr

Figure 37: Routine Capital Spending by Function Yr/Yr

	2016 Actual	2017 Budget	2017 Forecast	2018 ACE Plan
Generation				
Generation Equipment Replacements	3,413,611	3,382,030	3,595,812	3,747,051
Generation Other Hydro	477,186	402,705	440,869	532,616
Generation Other Thermal	379,345	289,096	293,240	300,319
	$4,270,142	**$4,073,830**	**$4,329,920**	**$4,579,986**
Transmission				
Transmission Substation Replacement, Add'ns/Mod'ns	3,006,060	3,070,404	2,757,403	3,070,000
Primary Equipment Spares	140,432	250,000	251,283	250,000
Protection Modification & Replacement	299,387	449,111	407,601	607,304
Transmission Line Replacement, Add'ns/Mod'ns	6,810,255	6,003,899	5,916,668	6,926,213
Transmission Right-of-Way Widening	6,004,868	598,698	598,358	599,751
	$16,261,003	**$10,372,112**	**$9,931,313**	**$11,453,268**
Distribution				
Meters	3,517,782	3,216,686	3,434,845	3,619,283
Distribution Upgrades and Replacement	22,542,033	20,263,362	21,737,542	21,551,891
New Customers	22,418,427	22,382,605	22,157,169	21,441,842
Joint Use	385,014	508,021	538,058	508,021
Distribution Right-of-Way Widening	807,288	598,698	572,051	600,095
	$49,670,544	**$46,969,372**	**$48,439,666**	**$47,721,132**

	2016 Actual	2017 Budget	2017 Forecast	2018 ACE Plan
General Plant				
Work Vehicles	7,110,720	7,898,672	7,915,787	8,649,700
Tools and Test Equipment	1,109,305	1,474,000	1,664,637	1,576,500
Telecommunications	824,189	796,387	792,292	870,899
Computing Asset Management	2,308,471	2,122,443	1,978,877	2,768,159
Property Improvements and Furniture	2,295,806	5,115,724	5,161,395	5,105,000
Other	1,316,203	1,345,438	1,171,420	1,137,000
	$14,964,695	**$18,752,665**	**$18,684,408**	**$20,107,257**

Total Routine Capital Spending	**$85,166,383**	**$80,167,979**	**$81,385,307**	**$83,861,643**

Note: The entire Routine program totals $84.5 million including Point Aconi routines. The totals presented above and in the following information do not include Point Aconi routines.

9.2 Routine Capital Spending Project Breakdown Yr/Yr

Figure 38: Routine Capital Spending Project Breakdown Yr/Yr

Project #	CI #	Project Title	2016 Actual	2017 Budget	2017 Forecast	2018 ACE Plan
G001	10634	CT - Routine Equipment Replacements	118,709	144,000	111,359	374,397
H001	11622	HYD - Routine Equipment Replacement	634,606	697,087	672,963	742,181
H004	27867	HYD-Roofing Routine	22,018	89,371	89,083	100,048
S001	23428	GS - Routine Capital	44,716	0	0	0
	10645	POT - Routine Equipment Replacement	315,816	266,813	263,169	270,546
	10673	TRE - Routine Equipment Replacement	593,455	377,929	626,303	377,287
	43646	PHB - Routine Equipment Replacement	199,254	170,000	141,197	170,331
	10621	TUC - Routine Equipment Replacement	432,358	327,423	339,992	270,697
	10626	LIN - Routine Equipment Replacement	409,488	383,162	349,518	376,624
S004	27856	TRE - Roofing Routine	336,585	100,000	122,153	104,857
	27855	POT - Roofing Routine	20,109	163,963	175,568	209,713
	27854	TUC - Roofing Routine	119,984	63,228	51,483	68,279
	C0002249	PHB - Roofing Routine	0	98,675	98,675	52,428
	27857	LIN - Roofing Routine	39,639	400,000	444,833	438,852
W001	41830	Wind - Routine Equipment Replacement	126,874	100,379	109,516	190,811
Generation Equipment Replacements Total			**$3,413,611**	**$3,382,030**	**$3,595,812**	**$3,747,051**
H005	35583	HYD - Oil Release Risk Assessment	317,958	218,370	260,660	350,091
H006	35584	HYD - Gate Refurbishment	159,228	184,335	180,209	182,525

		Generation Hydro Total	**$477,186**	**$402,705**	**$440,869**	**$532,616**
S005	33871	TUC-Heat Rate Routine	78,919	47,690	49,379	52,011
	33867	POT-Heat Rate Routine	126,414	84,967	74,823	92,094
	33869	TRE-Heat Rate Routine	87,310	80,000	59,563	80,000
	33863	LIN-Heat Rate Routine	86,703	76,439	109,475	76,215
Generation Thermal Total			**$379,345**	**$289,096**	**$293,240**	**$300,319**
T003	23120	Provincial-Trans Substation Primary	2,442,667	2,199,801	2,057,762	2,200,000
T004	23121	Provincial - Substation Additions & Replacements	563,393	870,603	699,640	870,000
Transmission Subs Replace, Adds/Mods Total			**$3,006,060**	**$3,070,404**	**$2,757,403**	**$3,070,000**
T018	14973	Primary Equipment Spares	140,432	250,000	251,283	250,000
Primary Equipment Spares Total			**$140,432**	**$250,000**	**$251,283**	**$250,000**
T016	14841	Protection Modification & Replacement	299,387	449,111	407,601	607,304
Protection Modification & Replacement Total			**$299,387**	**$449,111**	**$407,601**	**$607,304**
T001	23115	Provincial Transmission Line Replace	2,185,367	882,026	1,125,458	1,650,684
T011	23118	Provincial - Planned Trans Line Replacement	4,624,888	5,121,873	4,791,210	5,275,529
Transmission Line Replacements Total			**$6,810,255**	**$6,003,899**	**$5,916,668**	**$6,926,213**
T010	43827	Transmission Right-of-Way Widening	6,004,868	598,698	598,358	599,751
Transmission Right-of-Way Widening Total			**$6,004,868**	**$598,698**	**$598,358**	**$599,751**
D009	26496	Meter Routine	3,517,782	3,216,686	3,434,845	3,619,283
		Meters Total	**$3,517,782**	**$3,216,686**	**$3,434,845**	**$3,619,283**
D005	23158	Unplanned Replace Deteriorated	9,683,571	8,443,160	9,937,656	9,828,485
D006	23135	Regulatory Replacements - Province	1,838,784	1,078,010	1,078,918	1,320,085
D008	23361	Provincial Storm	4,011,924	2,418,069	2,444,549	2,942,145
D051	29038	System Performance Improvement Routine	407,628	599,717	699,543	508,772
D055	23137	Planned Replacement Of Distribution	6,600,126	7,724,405	7,576,877	6,952,404
Distribution Upgrades and Replacement Total			**$22,542,033**	**$20,263,362**	**$21,737,542**	**$21,551,891**
D004	26716	New Customer Upgrades	7,110,774	7,740,351	7,538,451	7,162,551
D018	23511	Primary Equipment Spares - Distribution	182,273	175,000	325,000	154,435
D061	39766	New Customers - Residential	9,128,056	8,422,167	8,671,178	8,597,052
D062	39770	New Customers - Commercial	5,997,324	6,045,087	5,622,541	5,527,804

New Customers Total			**$22,418,427**	**$22,382,605**	**$22,157,169**	**$21,441,842**
D007	23136	Contractual Replacements (Joint Use)	385,014	508,021	538,058	508,021
Joint Use Total			**$385,014**	**$508,021**	**$538,058**	**$508,021**
D010	23127	Provincially Widening	807,288	598,698	572,051	600,095
Right of Way Widening Total			**$807,288**	**$598,698**	**$572,051**	**$600,095**
P006	20945	Replacement and Additional Work Vehicles	249,260	210,202	145,855	220,000
P009	16192	Mobile Transformer & Track Routine	8,395	70,978	70,172	0
P063	39304	Class 3 Work Vehicle Replacements	296,226	335,000	547,464	463,000
P062	39305	Work Vehicle Replacements	4,496,857	5,429,993	5,671,659	5,986,200
P061	40236	Transportation Vehicle Replacements	2,059,982	1,852,500	1,480,638	1,980,500
Work Vehicles Total			**$7,110,720**	**$7,898,672**	**$7,915,787**	**$8,649,700**
P002/P016		Meter Shop - Tools and Equipment	1,033,869	1,384,000	1,574,274	1,486,500
P015	11611	Hydro Production Tools, Test Equipment	75,437	90,000	90,363	90,000
Tools and Test Equipment Total			**$1,109,305**	**$1,474,000**	**$1,664,637**	**$1,576,500**
P025	16365	Mobile Radio Routine	51,889	46,048	46,011	49,146
P027	16551	Telecommunication Radio and Fibre Optics	142,092	141,942	139,277	150,442
P028	16550	Telecommunication Systems Replace & Modifications	484,718	476,554	475,804	494,936
P814	38243	Telecommunications Spares	145,489	131,844	131,201	176,376
Telecommunications Total			**$824,189**	**$796,387**	**$792,292**	**$870,899**
P010	16073	SCADA Improvements Routine	144,960	131,525	110,088	113,189
P031	29114	NSPI Non-CGI Infrastructure	2,104,049	1,810,000	1,718,774	2,478,970
P040	28522	CT'S Dcms Routine	3,002	20,000	25,778	20,000
	25667	POT - DCMS Equipment Replacement Routine	5,931	30,000	27,544	31,000
	25626	TRE - DCMS Equipment Replacement Routine	11,454	40,000	29,428	40,000
	25646	TUC - DCMS Equipment Replacements Routine	37,935	60,917	66,491	50,000
	25668	LIN - DCMS Equipment Replacement Routine	1,140	30,000	775	35,000
Computing Asset Management Total			**$2,308,471**	**$2,122,443**	**$1,978,877**	**$2,768,159**
P001/P030		Property Improvement and Furniture	2,295,806	5,115,724	5,161,395	5,105,000
Property Improvement and Furniture Total			**$2,295,806**	**$5,115,724**	**$5,161,395**	**$5,105,000**
P012/P041		Other (HYD - Security Improvement & FAC - Land Acquisition)	670,703	623,267	542,895	450,000

P018	48158	Environment Equipment Replacement Routine	133,048	100,000	12,005	100,000
P816	38897	FAC Environmental Property Remediation Routine	215,936	216,733	210,261	198,500
P815	38896	FAC Environment Site Assess Routine	108,972	205,438	213,410	188,500
P032	38848	Purchasing Equip & Warehouse Routine	187,544	200,000	192,849	200,000
Other Total			**$1,316,203**	**$1,345,438**	**$1,171,420**	**$1,137,000**
Routine Capital Spending			**$85,166,383**	**$80,167,979**	**$81,385,307**	**$83,861,643**

9.3 2018 Routine Capital Spending Project Details

Transmission

Figure 39: Transmission Substation Replacements, Additions and Modifications

T003 Provincial: Transmission Substation Primary Equipment	**ACE 2018 Forecast**
Unplanned Failures	1,200,000
PT and CT Replacements	50,000
Battery Bank & Charger Replacements	50,000
Transformer Radiator Replacements	225,000
Transformer Cooler Replacements	125,000
Substation Fencing & Gravel Replacements	25,000
Footing Remediation	150,000
Substation Yard Lighting	35,000
Low Voltage Bus Pole Structure Replacements	95,000
Switch Frame Replacements	50,000
Replace 4kV Metering Unit	40,000
Re-gasket Transformers	100,000
89W Bus Upgrade	35,000
20N-T2 Retirement	20,000
Total T003 Provincial: Transmission Substation Primary Equipment	**$2,200,000**
T004 Provincial- Substation Additions & Replacements	
Unknown Additions	300,000
Install Animal Guards - Substations	40,000
Switch Upgrades	90,000
MOD Switch Upgrades	60,000
Transformer Refurbishment	200,000
Transformer Online Monitoring	80,000
Remote Video/Thermal Substation Monitoring	100,000
Total T004 Provincial- Substation Additions & Replacements	**$870,000**

Total Transmission Substation Replacements, Additions and Modifications	**$3,070,000**

Figure 40: Primary Equipment Spares

T018 Primary Equipment Spares	ACE 2018 Forecast
Spare Reactor for TCR at 120H	75,000
Spare Reactor for TSC1 at 120H	75,000
Spare Reactor for TSC2 at 120H	75,000
Spare Capacitors for 120H SVC	15,000
Miscellaneous	10,000
Total Primary Equipment Spares	**$250,000**

Figure 41: Protection Modification and Replacement

T016 Protection Modification & Replacement	ACE 2018 Forecast
Unplanned Relay Replacement	78,627
Replace Primary & Secondary Protection on L-6539 at 3S	81,367
Replace Primary & Secondary Protection on L-6538 at 3S	81,367
Replace Primary & Secondary Protection on L-6516 at 2S	81,367
Replace Primary & Secondary Protection on L-5035 at 43V	81,367
Replace SER at 1H	62,599
Replace SER at 91H	62,599
Replace 20V Differential Protection	78,011
Total Protection Modification & Replacement	**$607,304**

Figure 42: Transmission Line Replacement, Additions/Modifications

T001 Provincial Transmission Line Replacement (Unplanned)	
This routine is budgeted based on historical T001 investment	**$1,650,684**

T011 Provincial- Planned Transmission Line Replacement

LINE#	Description	ACE 2018 Forecast
L5004	99H Farrell ST-124H Akerley- 90H Sackville	210,034
L5003	40H Woodlawn to 58H Imperial	276,370
L5022	99H Farrell ST to 40H Woodlawn	162,305

L5023	L5053 tap to 52V Berwick	158,673
L5012	East River 86E (L5031 Tap) to 85W Canexel	284,696
L5014	99H Farrell ST to 62H Albro Lake	184,715
L5024A	91H Tufts Cove to 99H Ferrall ST	182,349
L5024B	50N Trento to 62N Stellerton	346,468
L5030	50N Trenton to 54N Ambercrombie PT	165,219
L5531	43V Cannan Road to 6V Hollow Bridge	308,353
L5538	95H Malay Falls to 96H Ruth Falls	216,946
L5549	30N Maccan to 17V Brownell ST	193,422
L5533	91H Tufts Cove to 90H Sackville	269,028
L5540	120H Brushy Hill to 131H Lucasville	208,832
L5565	90H Sackville to 131H Lucasville	308,086
L5573	50N Trenton to 79N Hopewell	356,372
L5579	90H Sackville to 120H Brushy Hill	207,981
L6518	90H Sackville to 104H Kempt Road	257,787
L6527	103H Lakeside to 129H Kearney Lake	156,879
L5547	91H Tufts Cove to 113H Dartmouth East	330,756
Various	1C PT Tupper to 47c Stora	490,258
T011 Provincial- Planned Transmission Line Replacement		**$5,275,529**
Transmission Line Replacement Total		**$6,926,213**

T010 – Provincial: Transmission Right of Way Widening

In its 2017 ACE Plan Order, the Board directed NS Power as follows:

> The Board directs NSPI to update the cost estimates for vegetation management and right-of-way widening projects in the 2018 ACE Plan (and future years) based on actual historical costs incurred for this project.[25]

NS Power confirms that the cost estimates for vegetation management and right-of-way widening projects in the 2018 ACE Plan are based on actual historical costs incurred. This forecast is also developed based on the known level of widening in the current year as set out in **Figure 40** below:

[25] 2017 ACE Plan, UARB Order, M07745, April 4, 2017.

Figure 43: T010 Forecast by Line

> 69 kV	
L6001	38,694
L6054	58,040
L6012	77,387
L6552	29,020
L6514	117,290
L6536	96,734
L7003	140,264
L7009	42,321
Total T010	**$599,751**

*Total above may be off slightly due to rounding

The Board's 2016 ACE Plan Order provided the following directive:

> The Board directs that the Routine for Transmission widening be treated as a separate project, and not a routine, in future ACE Plan Applications. NSPI is to provide an annual progress report on the expenditure, works undertaken, results achieved and future plans as part of the annual ACE Plan submissions.[26]

CI 51969 - 2018 Transmission Right-of-Way Widening 69kV is submitted in the 2018 ACE Plan in compliance with the Board's directive. With the addition of a separate capital work order for transmission Right-of-Way widening, the transmission vegetation management program is now carried-out under three broad initiatives:

1. Operating activities for transmission vegetation management
2. Capital Routine T010 - Transmission Right-of-Way Widening (for 138kV, 230kV and 345kV RoWs)
3. New Transmission Rights-of-Way Widening individual capital projects (i.e. CI 51969 for 69kV RoWs and subsequent phases)

[26] NS Power 2016 ACE Plan, UARB Order, M07176, June 8, 2016, page 2. NS Power's annual progress report on the expenditure, works undertaken, results achieved and future plans can be found in the 2018 ACE Plan Reliability Directive in section 10.1.7.

Capital routine T010 remains for the widening of 138kV, 230kV and 345kV rights-of-way. This is the traditional scope of T010, but it has also previously included 69kV rights-of-way which are now assumed under CI 51969 and subsequent phases. This was the scope of work included in the $43.2 million eight-year program ($5.4 million per year), which the UARB approved in principle and directed NS Power to include in ACE Plan filings for final approval.[27] The 69kV work was removed from T010 but the budget for T010 remains approximately the same due to increased NERC requirements at the other voltage levels (specifically 138kV).

[27] Review of Nova Scotia Power Inc.'s (NSPI) state of preparedness and response to Post-Tropical Storm Arthur, UARB Supplemental Decision, M06321, September 21, 2015, page 16. NS Power 2016 ACE Plan, UARB Decision, M07176, June 8, 2016, pages 26-28.

Distribution

Figure 44: Meters – D009 Meter Routine

Item#	Prg#	Meter Type	Meter Style	Description	2018 Forecast	Current Unit Cost	Capital for meters
1.0 Element, 120-240 volt							
1	294	Form 3S (5 jaw)	Itron Centron	240V, 10A, 2W, 5 Jaw, 4 dial	250	65.00	16,250.00
	220	Form 3S (5 Jaw)	Itron Sentinel	T/R, 2W, 4Jaw, TOU (KWH) c/w L.C. (ETS)	80	130.00	10,400.00
2	230	Form 3S (5 Jaw)	Itron Sentinel	T/R, 2W, 5Jaw, KW/KVA dmd	140	122.00	17,080.00
	239	Form 3S (5 Jaw)	Itron Sentinel	T/R, 2W, 5Jaw, TOU(KWH) c/w modem, L.P,L.C. (ETS)	0	350.00	0.00
	240	Form 3S (5 Jaw)	Itron Sentinel	T/R, 2W, 5Jaw, KW/KVA dmd, c/w modem, L.P.	0	325.00	0.00
3	296	Form 3S (5 Jaw)	Itron Sentinel	T/R, 2W, 5jaw, BID, TOU LC(ETS)	20	150.00	3,000.00
1.5 Element, 120-240 volt							
	N/A	C1S	Centron	240V, 200A, 3W,4 Jaw, 5 dial	22000	22.50	495,000.00
6	219	SS1S1T	Sentinel	S/C, 3W, 4Jaw, TOU(KWH) c/w L.C. (ETS)	700	130.00	91,000.00
7	231	SS1S2D	Sentinel	S/C, 3W, 4Jaw, KW/KVA dmd	672	110.00	73,920.00
8	232	SS1S2D	Sentinel	T/R, 3W, 4Jaw, KW/KVA dmd	0	125.00	0.00
	236	SS1S1L	Sentinel	S/C, 3W, 4Jaw, (KWH) c/w modem & L.P.	4	290.00	1,160.00
	241			S/C, 3W, 4Jaw, KW/KVA dmd,c/w modem,L.P.	0	350.00	0.00
	266			S/C, 3W, 4Jaw, (kWh), BID	200	130.00	26,000.00

Item#	Prg#	Meter Type	Meter Style	Description	2018 Forecast	Current Unit Cost	Capital for meters
	291			SC, 3W, 4Jaw, (kWh) TOU, BID, LC (ETS)	12	150.00	1,800.00
	292			S/C, 3W, 4Jaw, kWh/kW, BID	8	130.00	1,040.00
2.0 Element, 120-480 volt							
9	N/A	CN1S	Centron	120V,200A,3W,5Jaw(9o,clock pos:), 5 dial	1200	52.00	62,400.00
10	226	SS2S2D	Sentinel	S/C, 3W, 5Jaw(9 o,clock pos:) KW/KVA dmd,(Mult: 25)	60	110.00	6,600.00
	227	SS3S2D	Sentinel	T/R, 3W, 8Jaw, KW/KVA dmd, c/w KYZ pulses	0	160.00	0.00
11	233	SS2S1T	Sentinel	S/C, 3W, 5Jaw(9 o,clock pos:)TOU(KWH) c/w L.C.(ETS)	60	135.00	8,100.00
12	235	SS3S3L	Sentinel	T/R, 3W, 8Jaw, KW/KVA dmd, c/w modem, L.P.	4	290.00	1,160.00
	246			T/R, 3W, 8Jaw, KW/KVA dmd, c/w modem,L.P, KYZ	4	315.00	1,260.00
	254			S/C,3W, 5jaw(9 o,clock pos:)KW/KVA dmd, modem,LP,(Mult 25)	4	315.00	1,260.00
	271			T/R, 3W, 8 Jaw, kW/kVA dmd, Modem, LP (5-min int)	4	290.00	1,160.00
13	272	SS3S3L	Sentinel	T/R , 3W, 8Jaw, kW/kVA dwd, Modem, LP (5-min int) KYZ	0	425.00	0.00
27	297	SS3S2D	Sentinel	T/R, 3W, 8Jaw, KW/KVA dmd	100	116.00	11,600.00
2.5 Element, 120-347 volt							
14	281	SS5S0	Sentinal	T/R,4W, 13Jaw, 120-480V, 0.1-10A (KWH)	4	105.00	420.00
15	228	SS2S2D	Sentinel	T/R, 4W, 13Jaw, KW/KVA dmd	200	102.00	20,400.00
16	229	SS5S2D	Sentinel	T/R, 4W, 13Jaw, KW/KVA dmd, c/w KYZ	0	135.00	0.00

Item#	Prg#	Meter Type	Meter Style	Description	2018 Forecast	Current Unit Cost	Capital for meters
17	234	SS5S3L	Sentinel	T/R,4W, 13Jaw, KW/KVA dmd c/w modem, L.P.	8	315.00	2,520.00
18	273	SS5S3L	Sentinel	T/R, 4W, 13 Jaw, kW/kVA dmd, modem, LP (5 min int)	0	290.00	0.00
19	274	SS5S3L	Sentinel	T/R, 4W, 13 Jaw, kW/kVA dmd, modem, LP (5 min int), KYZ	0	350.00	0.00
	288			T/R, W, 13 Jaw, kW BID	8	140.00	1,120.00
3.0 Element, 120-347 volt							
20	247	SS4S0D	Sentinel	S/C, 4 W, 7Jaw, (KWH)	48	105.00	5,040.00
21	248	SS4S0	Sentinel	T/R, 4W, 13Jaw, (KWH)	0	105.00	0.00
22	218	SS4S3L	Sentinal	T/R, 4W, 13Jaw, KW/KVA dmd, c/w modem, L.P.	4	315.00	1,260.00
23	222	SS4S2D	Sentinel	S/C, 4W, 7Jaw, KW/KVA dmd, (Mult 25)	576	105.00	60,480.00
24	223	SS4S2D	Sentinel	T/R, 4W, 13Jaw, KW/KVA dmd	300	102.00	30,600.00
	225	SS4S2D	Sentinel	T/R,4W, 13Jaw, KW/KVA dmd, c/w KYZ	24	150.00	3,600.00
	243	SS4S3L	Sentinel	T/R, 4W, 13Jaw, KW/KVA, dmd, c/w modem, L.P, KYZ	4	350.00	1,400.00
25	275	SS4S3L	Sentinel	T/R, 4W, 13 Jaw, kW/kVA dmd, modem, LP (5 min int)	4	315.00	1,260.00
26	276	SS4S3L	Sentinel	T/R, 4W, 13 Jaw, kW/kVA dmd, modem, LP (5 min int), KYZ	0	400.00	0.00
	283			T/R, 4W, 13 Jak, kWh/kW, BID	20	128.00	2,560.00
	295			S/C, 4W, 7Jaw, kWh/kW, BID	20	128.00	2,560.00
	211			T/R, 4W, 13 Jaw, TOU, kWh	4	128.00	512.00
				TWACS Modules	100	26.00	2,600.00
				Total Meters	**26846**		**$966,522**

Misc Meters "ION"	5	8,000.00	**$40,000.00**
Cellular Meters	100	900.00	**$90,000.00**
CT and PT requirements			**$150,000.0**
Wire, Adapters and switches			**$90,000.00**
Total Materials			**$1,336,522**
Applied Overhead			**$1,282,103**
Labour			**$1,000,658**
D009 Meters Total			**$3,619,283**

Distribution Upgrades and Replacement

Figure 45: Distribution Upgrades and Replacement

		ACE 2018 Forecast
D005 Unplanned Replacement Deteriorated Equipment		
	The forecast was developed based on an estimated 3,655 person days of work at a unit cost of $2,689/person day	**$9,828,485**
D006 Regulatory Replacements		
	The forecast is developed based on past experiences or information from various government agencies. This amount could vary based on current year decisions by these agencies.	**$1,320,085**
D008 Provincial Storm		
	This forecast is developed based on past experience. There can be significant variation in this amount based on yearly storm activity.	**$2,942,145**
D051 System Performance Improvement		
	19W-311-Lighthouse Rte Rebuild	64,992
	22C-403-59C-401 Grand Anse Recloser Upgrade	80,000
	50W-412GA-Mill Village Build to Roadside	214,195
	57W-401-D417-010 Upgrade	45,000
	78W-301 Northwest Line Extension	29,585
	Various-2018 Transformer Animal Guard Additions	75,000
Total D051 System Performance Improvement		**$508,772**
D055 Planned Replacement of Distribution Equipment		
	Bin Work (Work resulting from NS Power's distribution line inspection program that has been identified as requiring follow up within one year.)	825,000
	Streetlight/service installation & removal (This funding is to support system upgrades required for street light installations and upgrades. This includes transformer installs, service upgrades and/or new pole installations.)	950,000
	Field Driven Work	625,000
	100C-422G-Reinsulate Phase 1	135,221
	102W-311G-Surette Cross Rd Rebuild	112,000
	102W-312-Tour Des Buttes Way	84,592
	126H-312-Marine Dr Reinsulate Phase 1	181,000
	126H-312-Marine Dr Reinsulate Phase 2	210,926
	129H-412 Bedford HWY Reconductor	56,500

D055 Planned Replacement of Distribution Equipment		
	13V-303-Lake Lemerchant Rebuild	125,000
	15S-301-Target Replacement	150,000
	20N-201-Charles & Academy St Rebuild	200,000
	21W-312-Lower Woods Harbour Reconductor	76,035
	2H-411-Cowie Hill UG system Replacement_Part 2	56,000
	36W-301G-Sable River Branch Crossing	74,220
	3S-302 -3S-405-Reconfigure and Removal	155,000
	4C-432-Saint Andrews Deteriorated Line	220,000
	50N-410GAA-Arbuckle Road Rebuild	70,000
	510W-211-Cresent Beach Rd Rebuild	80,705
	513V-311-Dakin Park Rd Rebuild	88,028
	514C-312-Lochaber Road Rebuild	59,000
	543C-211-Mauger Road Rebuild	145,000
	544W-311-Mt Pleasant Stepdown	20,000
	56N-414-ICP	35,000
	57S-401-Albert Bridge Rebuild	130,000
	62N-413-Sherbrooke Road Repole	95,223
	658V-211-Cortland Crescent Conversion	125,000
	65V-302GA-Forest Glade Repole	148,446
	663V-221-West Main St Reconductor	186,185
	67C-411H-Mabou Harbor Crossing	125,000
	67C-411-Reconductor Ceilidh Trail	195,000
	70V-311GA-Port Lorne Rebuild	139,432
	84W-302-King St, Chester Rebuild	85,000
	89W-303-Station Rd and Pinegrove Rd Line Extension	103,890
	92W-302-Valley Crescent Rebuild	85,000
	Various-2018 Manhole Cover Replacement	200,000
	Various-2018 Manhole Replacement	150,000
	Various-2018 Padmount Switch Replacement	200,000
	Various-2018 Vault Equipment replacement	250,000
Total D055 Planned Replacement of Distribution Equipment		**$6,952,403**

Distribution Upgrades and Replacement Total	**$21,551,890**

New Customers

Figure 46: New Customers

D004 New Customer Upgrades		**ACE 2018 Forecast**
	This forecast developed as a % of D061 and D062 net of capital contributions. In 2017 this is estimated to be 54%.	**$7,162,551**
D018 Primary Equipment Spares Distribution		

	This forecast is developed based on the probable amount of distribution spare equipment required during the year.	**$154,435**
D061 New Customers- Residential		
	This forecast is for the costs associated with new residential customers net of capital contributions. Costs include metered services, unmetered services, line extensions and underground services.	**$8,597,052**
D062 New Customers- Commercial		
	This forecast is for the costs associated with new commercial customers net of capital contributions. Costs include metered services, unmetered services, line extensions and underground services.	**$5,527,804**
Total New Customers		**$21,441,842**

Joint Use

Figure 47: Joint Use

Joint Use Total		**ACE 2018 Forecast**
	This forecast is developed based on prior spending levels for both Joint Use requests from Nova Scotia Power's Joint Use Partner, Bell Aliant, and communication utility requests.	**$508,021**
Distribution Total		**$47,121,036**

Distribution Right of Way Widening

In its 2017 ACE Plan Order, the Board directed NS Power as follows:

> The Board directs NSPI to update the cost estimates for vegetation management and right-of-way widening projects in the 2018 ACE Plan (and future years) based on actual historical costs incurred for this project.[28]

NS Power confirms that the cost estimates for vegetation management and right-of-way widening projects in the 2018 ACE Plan are based on actual historical costs incurred. This forecast is also developed based on the known level of widening in the current year.

[28] 2017 ACE Plan, UARB Order, M07745, April 4, 2017.

The spend in this Routine reflects the work that will be required to widen the following rights-of-way to standard.

Figure 48: Distribution Right of Way Widening

Feeder Section	Geographic Location	Length (Km)	Managed Length (Km)	Avg Cost per Km	Cost	Contract Overhead	Total Segment Cost
88H-402	Musquodboit	5.00	5.00	18,000	90,000	18,018	108,018
88H-401	Moose River	5.00	5.00	18,000	90,000	18,018	108,018
665H-311	Malay Falls	2.00	2.00	18,000	36,000	7,207	43,207
Provincial	Clear Cut Buffers (Other Forestry Operations) TBD	5.00	5.00	18,000	90,000	18,018	108,018
84W-301G	Chester-Vaughn (Highway 14)	6.60	3.00	18,000	54,000	10,811	64,811
103W-312	Chester-New Ross (Highway 12)	0.55	0.55	18,000	9,900	1,982	11,882
1V-443	New Ross (NewRossRoad-R414-001)	2.70	2.70	18,000	48,600	9,730	58,330
103H-432	Otter Lake	2.50	2.50	18,000	45,000	9,009	54,009
77V-302	Sissiboo Rd/North Range Cross/Doucetteville	2.50	2.03	18,000	36,495	7,306	43,802
Total Distribution Right of Way Widening							**$600,095**

Pursuant to CI 49611 - New Distribution Rights-of-Way Phase I, submitted to the UARB on November 1, 2016, Liberty's report on its review of NS Power's response to PTSA included a recommendation that for distribution rights-of-way NS Power should "develop a comprehensive plan for reclaiming and/or widening the overgrown ROW corridors".[29] In its Supplemental Decision on September 21, 2015, the Board directed NS Power as follows:

> [36] A circumstance where it will take 32 years for the distribution vegetation management program to become sustainable causes the Board significant concern.
> //

[29] Review of Nova Scotia Power Inc.'s (NSPI) state of preparedness and response to Post-Tropical Storm Arthur, M06321, Liberty Consulting Group, Comments on Review of NS Power's Storm Response, Exhibit A-4, September 9, 2014, page 7.

> [38] The Board is intrigued by the stakeholder discussion concerning innovative financing options and directs NSPI to pursue that issue and report back to the Board the results of those discussions. [30]

In response to the Board's concerns, and in order to further reduce the likelihood of tree contact related outages like those during the PTSA event, NS Power increased the budget for the D010 in the 2016 ACE Plan. NS Power's 2016 ACE Plan provided the following:

> NS Power is seeking approval as part of the 2016 ACE Plan of $3 million for the distribution widening routine, D010, in 2016. The $3 million comes from the portion of the annual $10.4 million that is spent on managing the vegetation in distribution ROWs to a sustainable state.[31]

In its 2016 ACE Plan Decision regarding D010, the Board directed NS Power as follows:

> …the Board assumes that NSPI has increased the distribution Routine budget by an amount of $2.4 million from the operating budget over the $600,000 in the 2015 ACE Plan. This means that NSPI is reducing its operating expenses by $2.4 million in 2016, thus increasing profits, with a corresponding increase in its rate base. This action will only increase rates which the Board does not approve. Accordingly, the Board reduces the routine budget for D010 to $600,000, to be in line with the 2015 ACE Plan amount.[32]

Consistent with the 2017 ACE Plan, for the 2018 ACE Plan, NS Power has not increased the budget for D010 in response to the PTSA findings. Rather, additional spending has been broken out into a separate capital work order, C0001950 - New Distribution Rights-of-Way Phase 3. The distribution vegetation management program is now carried-out under three broad initiatives:

[30] Review of Nova Scotia Power Inc.'s (NSPI) state of preparedness and response to Post-Tropical Storm Arthur, M06321, UARB Supplemental Decision, September 21, 2015, page 14. NS Power responded with its proposal to increase spend in D010 in the 2016 ACE Plan.
[31] 2016 ACE Plan, M07176, November 12, 2015, page 72.
[32] 2016 ACE Plan, UARB Decision, M07176, June 8, 2016, page 18.

1. Operating activities for distribution vegetation management
2. Capital Routine D010 - Distribution Right-of-Way Widening
3. New Distribution Rights-of-Way individual capital projects (i.e. C0001950 and subsequent phases)

No reductions in spend for operating activities have been transferred to fund either D010 or C0001950.

The scope of work completed under operating activities will continue to focus on existing right-of-way asset reclamation, urban cycle trimming in municipalities, reactive maintenance, hazard tree mitigation, vegetation removal during storm events, customer requested tree trimming, and maintaining sustainability of existing rights-of-way.

The scope of work completed under the D010 routine will continue to focus on widening of existing rights-of-way to the current standard beyond the Department of Nova Scotia Transportation and Infrastructure Renewal (NSTIR) right-of-way.

C0001950 and subsequent phases will establish new rights-of-way where none have previously existed.

General Plant

Figure 49: Work Vehicles

P006 Replacement and Additional Work Vehicles	**Quantity**	**Unit Price**	**ACE 2017 Forecast**
Reel and Pole Trailers	13	16,923	220,000
Total P006 Replacement and Additional Work Vehicles			**$220,000**
P061 Transportation Vehicle Replacements	60	35,342	2,120,500
		Salvage	-140,000
			$1,980,500

P062 Work Vehicle Replacements	20	312,310	6,246,200
		Salvage	-260,000
			$5,986,200
P063 Class 3 Work Vehicle Replacements	4	118,750	475,000
		Salvage	-12,000
			$463,000
Total Work Vehicles			**$8,649,700**

Figure 50: Tools and Test Equipment

Description	Quantity	Estimated Unit Cost	Estimated Total
Meter Shop Tools and Equipment			**$50,000**
Provincial Line Tools & Equipment			
Western Territory			$89,933
North Eastern Territory			43,516
Cape Breton Territory			63,824
Central Territory			203,075
T&D Asset			452,567
System Maintenance			232,086
P002 Tools and Equipment Total			**1,135,000**
P015 Hydro Production Tools & Test Equipment			**$90,000**
P016 Thermal Production Tools & Test Equipment			
POT Tools & Equipment			$75,000
TUC Tools & Equipment			76,500
TRE Tools & Equipment			80,000
LIN Tools & Equipment			51,000
CT Tools & Equipment			28,000
PHB Tools & Equipment			41,000
P016 Thermal Production Tools & Test Equipment Total			**$351,500**
Tools and Test Equipment Total			**$1,576,500**

Figure 51: Telecommunications

P025 Mobile Radio	ACE 2018 Forecast
Replacement Radio Equipment Hardware and Upgrades	16,432
Equipment repairs - Bell, Nova, etc. Standing POs	18,028
Miscellaneous Support for existing system	14,686
P025 Mobile Radio Total	**$49,146**
P027 Telecommunication Radio & Fibre Ops	
HVAC & Generator Upgrades - 2 sites	100,627
Radio Site repairs – Miscellaneous	24,823
Add Generator Alarms And Controls at various sites	5,501
Miscellaneous Replacements	19,491
P027 Telecommunication Radio & Fibre Ops Total	**$150,442**
P028 Telecommunication Systems Replace & Modifications	
Replace DPR and Tone Protection Equipment (as required)	51,700
Upgrade Site Access Equipment (as required)	27,848
RAL Move Circuits (ongoing)	30,193
Remove Old Bayly Multiplex Equipment (ongoing)	14,538
Backup Control Center Circuits	16,831
Backup Time Synch for Backup Control Centre	5,493
Battery Replacements Various Sites	18,248
Replace Miscellaneous Power Supplies	7,500
UPS Replacements Various Sites	7,500
Upgrade Ethernet Radios and Equipment (Wide Area Network -WAN)	28,874
Cable & Entrance Protection – Positron	17,250
Switched Communications - System Operations Phones	12,500
Replace Fibre Optic Equipment (NEC & ADC)	32,500
Install One Fibre Link from Substation to Radio Site	64,169
Network Monitoring - upgrade TMON alarming system	41,816
Alarm Commissioning for new sites into SCADA	41,816
Review and Update System Drawings and Records	29,499
Support Services for Newbridge Multiplex Network - Nokia/ALU	28,500
Tower Lighting Upgrades	18,161
P028 Telecommunication Systems Replace & Modifications Total	**$494,936**
P814 Telecommunications Spares	
Alcatel-Lucent MPR9500 Microwave Radio	50,000
Net Guardian Alarm Monitoring Equipment	15,000
7705 MPLS Router Spares	20,000
Ethernet Spares	5,976
MDS SD9, Transnet, INet	10,100
SEL 2505, 2506 Spares	10,100

RFL IMUX and 9745 Spares	25,100
Battery Charger Spare	10,100
RTU and Misc. Spares	30,000
P814 Telecommunications Spares Total	**$176,376**
Telecommunications Total	**$870,900**

Figure 52: Computing Asset Management

P010 SCADA Improvements			**ACE 2018 Forecast**
	This forecast is developed based on SCADA equipment/operator interfaces failures or modifications		
P010 SCADA Improvements Total			**$113,189**

P031 NSPI IT Infrastructure

Infrastructure Component	**Asset Management Plan**	**Volume to be Refreshed**	**ACE 2017 Forecast**
Voice and Data Network	Network Infrastructure & Equipment		125,000
Servers	Servers Refresh, Licenses, & Storage		425,000
Laptop and Desktop Computers, Personal Devices	Computers that have or will reach four (4) years old	**1,000**	1,366,970
	New laptop or desktop computers	60	72,000
	Mobile Devices	100	100,000
	Laptop/Desktop Mgmt Tool-capacity upgrade		100,000
	Software & software licenses		250,000
Power Supplies	Replaced after 10 years		10,000
Accessories	Accessories		30,000
P031 NSPI IT Infrastructure Total			**$2,478,970**
P040 DCMS Equipment Replacement			
	CT's DCMS Equipment Replacement		20,000
	POT DCMS Equipment Replacement		31,000
	TRE DCMS Equipment Replacement		40,000
	TUC DCMS Equipment Replacement		50,000
	LIN DCMS Equipment Replacement		35,000
			$176,000
Computing and Asset Management Total			**$2,768,159**

Figure 53: Property Improvement and Furniture

P001		ACE 2018 Forecast
	Building Protective Coatings	$50,000
	Roofing & Emergency Refurbishment	230,000
	Grading / Drainage	100,000
	Fencing	75,000
	Pole Brow	300,000
	General Refurbishment Work	551,000
	Asphalt / Paving	73,000
	Consulting	70,000
	HVAC Improvements	235,000
	Substations	35,000
	Generator	90,000
	Protective Signage	5,000
	Security Improvements	20,000
	1H General Refurbishments	271,000
	Substation / Depot Improvements	3,000,000
Property Improvement and Furniture Total		**$5,105,000**

Figure 54: Other

Other		
P012	HYD - Security Improvement	$400,000
P018	Environmental Equipment Replacement	100,000
P041	FAC - Land Acquisition Routine	50,000
P816	FAC - Environment Property Remediation	198,500
P815	FAC - Environment Site Assessment	188,500
P032	FAC - Equipment & Warehouse	200,000
Other Total		**$1,137,000**
General Plant Total		**$20,107,259**

10.0 DIRECTIVES AND MISCELLANEOUS

10.1 UARB ACE Plan Directives and Stakeholder Commitments

NS Power has received a number of Directives from prior ACE Plan Decisions. The Company has also made a number of commitments to interested parties. Responses to each of these Directives and commitments are provided below.

10.1.1 Impact of 2018 ACE Plan on Revenue Requirement and Affordability

Introduction

Revenue requirement and its effect on rates are well understood: increases in revenue requirement create upward pressure on rates. NS Power understands rate increases are of particular concern for customers; a concern which is frequently expressed in terms of affordability.

Over the years, the UARB has directed NS Power to provide information regarding the ACE Plan's revenue requirement impact. Directive 7 of the 2011 ACE Plan Decision and Directive 12 of the 2012 ACE Plan Decision direct NS Power to provide the estimated effect the ACE Plan may have on revenue requirement over the next five years. This information is provided in **Figure 55** below.

This information has been provided in prior ACE Plans and, through discussion and agreement with stakeholders as well as further direction from the UARB, has grown to include tables breaking out the revenue requirement impact of:

- Economically Justified capital investments (2013 CEJC stakeholder engagement);
- Current Asset capital investments (2014 stakeholder engagement);

- Work Support Facilities capital investments (UARB 2013 ACE Plan Decision Directive 13); and
- A version of NS Power's "Long-Term Capital Planning & Revenue Requirement" table incorporating stakeholder assumptions (2016 stakeholder engagement).

Considered as a whole, NS Power's assumptions and corresponding information provide the UARB and customers an impression of the impact NS Power's capital program is expected to have on revenue requirement and help inform discussions on affordability. The 2018 ACE Plan is focused on the provision of safe and reliable electric service, investing where required to best maintain the performance and reliability of the Company's assets, while minimizing upward pressure on rates.

The overall revenue requirement table, "Long-Term Capital Planning & Revenue Requirement" contained in **Figure 55** shows that NS Power's capital expenditures have a decreasing effect on NS Power's revenue requirement for customers over the next five years taking into account the contribution to fixed costs provided by new customer additions.

Overall Revenue Requirement

The overall revenue requirement calculation shows the effect on rate base and the effect on revenue requirement. The underlying assumption of this calculation is that, to the extent capital expenditures equal depreciation expense in a given year, there is no incremental effect on rate base or associated revenue requirement and therefore it is not included in the calculation.

The revenue requirement assessment incorporates the following inputs:

- Capital expenditures compared to forecast depreciation expense annually.

- Administrative overhead credit based on the proration of capital expenditures in excess of depreciation expense in each year.

- Depreciation expense of assets added during the examined timeframe based on the proportion of capital expenditures in excess of depreciation expense of all assets in each year.

- Incremental interest based on the cost of debt multiplied by the portion of debt to total capital of the incremental rate base.

- AFUDC based on the proportion of capital expenditures in excess of depreciation expense of all assets in each year.

- Income taxes based on the resultant effects and prorated Capital Cost Allowance for tax purposes.

- Net earnings based on the rate of return multiplied by the portion of equity to total capital of the incremental rate base.

- Additional fixed cost recovery received from customer growth achieved through capital investment to serve these customers.

Depreciation expense and additional fixed cost recoveries are delineated in the overall revenue requirement calculation.

This method does not address the revenue requirement effect should capital projects not be completed. Costs resulting from not completing certain projects include items such as increased operating costs, increased fuel costs, increased repair costs, and other risks or implications. The Economic Analysis Model used to decide whether an economically justified capital project is the best option for customers includes estimates of the avoided

expenses; these avoided cost benefits are not included in this revenue requirement calculation. The effect of economic projects and their savings is broken out separately in the subsequent section.

Figure 55: Long-Term Capital Planning & Revenue Requirement[33] ($ M)

NOVA SCOTIA POWER ($M)	2018 ACE	2019	2020	2021	2022
Estimated Spend Related to five-year Capital Plan					
Capital Expenditures (Spend)	$354.9	$392.6	$387.3	$341.7	$348.4
Less: Depreciation of all assets	208.4	216.1	224.5	232.4	240.2
Incremental Spend over Depreciation (Growth)	146.5	176.6	162.8	109.3	108.2
Incremental Spend as a portion of Total Spend	41.3%	45.0%	42.0%	32.0%	31.1%
New Incremental Regulated Capital Assets					
Beginning Balance	-	146.5	323.1	485.9	595.2
Capital Spend	354.9	392.6	387.3	341.7	348.4
Depreciation	208.4	216.1	224.5	232.4	240.2
Ending Balance	146.5	323.1	485.9	595.2	703.4
Average Incremental Net Book Value of projects in five-year plan	73.3	234.8	404.5	540.6	649.3
Capital Cost Allowance					
Depreciation of Assets added 2018-2022	4.5	15.8	25.4	26.4	32.1
Impact on Net Earnings					
Expenses					
OM&G	(3.5)	(7.0)	(10.5)	(14.0)	(17.5)
Administrative Overhead	(15.4)	(18.2)	(16.5)	(9.9)	(9.8)
Depreciation	1.4	5.0	8.2	8.8	10.9
Interest	2.6	8.4	14.5	19.4	23.3
AFUDC	(2.8)	(3.6)	(3.6)	(2.4)	(2.6)
Earnings before tax	(3.9)	(0.7)	5.3	14.4	18.0
Income Tax less Impact of Administrative Overhead	(3.0)	(4.7)	(4.8)	(1.7)	(1.8)
Income Tax Impact of Administrative Overhead	(3.3)	(4.0)	(3.6)	(2.1)	(2.1)
Net Earnings	$2.5	$7.9	$13.7	$18.2	$21.9

[33] This table does not include avoided costs related to economically justified projects.

NOVA SCOTIA POWER ($M)	2018 ACE	2019	2020	2021	2022
Incremental Revenue Requirement of five-year capital plan					
Including Fixed Cost Recovery:					
Incremental Revenue Requirement of five-year capital plan	(21.5)	(16.1)	(2.6)	16.3	22.4
Change in Incremental Revenue Requirement from Previous Year	(21.5)	5.4	13.6	18.9	6.1
Rate Impact of five-year capital Plan	-1.7%	-1.3%	-0.2%	1.3%	1.8%
Excluding Fixed Cost Recovery:					
Incremental Revenue Requirement of five-year capital plan	(18.0)	(9.1)	7.9	30.3	39.9
Change in Incremental Revenue Requirement from Previous Year	(18.0)	8.9	17.1	22.4	9.6
Rate Impact of five-year capital Plan	-1.4%	-0.7%	0.6%	2.4%	3.1%

The overall revenue requirement shown in **Figure 55**, in the line item "Incremental Revenue Requirement of five-year capital plan", shows a decreasing revenue requirement for years 2018 to 2022 as a result of the new capital investment. This is due to additional fixed cost recovery received from customer growth achieved through capital investments to serve these customers, Administrative Overhead and AFUDC credits related to construction of capital assets, and the income tax impact of new capital investment.

Stakeholder Revenue Requirement Table

In compliance with the 2016 ACE Plan Terms of Consensus and the subsequent stakeholder engagement process, NS Power has included an additional revenue requirement table using assumptions requested by stakeholders. The table shown in **Figure 56** below, first included in the 2017 ACE Plan, has evolved throughout the 2017 ACE Plan Stakeholder Engagement process. It includes the following significant differences from NS Power's "Long-Term Capital Planning & Revenue Requirement" table above:

- Elimination of the impact of additional fixed cost recovery as well as the administrative overhead and AFUDC credits from the revenue requirement calculation.

- Elimination of the application of the incremental spend as a portion of total spend percentage to the calculated depreciation expense and capital cost allowance in the revenue requirement calculation.

- Elimination of the reduction of depreciation of all assets in the calculation of New Incremental Regulated Capital Assets.

NS Power believes the assumptions reflected in the table shown in **Figure 56** do not accurately reflect the impact of the Company's capital program because:

- Including the reduction in fixed costs in the model demonstrates the decrease in revenue requirement for current customers related to having more customers connected and sharing the fixed costs.

- Including the AO and AFUDC credits in the calculation of revenue requirement is consistent with how rates are calculated and that the inclusion of these credits in the revenue requirement directive is appropriate.

- Since NS Power does not have the option to cease investment in its capital infrastructure at a sustaining level, a five year capital plan should be viewed in the context of costs that the capital program is driving in comparison to maintaining the assets.

Figure 56: Long-Term Capital Planning & Revenue Requirement (Stakeholder Table)

NOVA SCOTIA POWER ($M)	2018 ACE	2019	2020	2021	2022
Capital Expenditures (Spend)	$354.9	$392.6	$387.3	$341.7	$348.4
Less: Depreciation of all assets	208.4	216.1	224.5	232.4	240.2
Incremental Spend over Depreciation (Growth)	146.5	176.6	162.8	109.3	108.2

NOVA SCOTIA POWER ($M)	2018 ACE	2019	2020	2021	2022
Incremental Spend as a portion of Total Spend	41.3%	45.0%	42.0%	32.0%	31.1%
Revenue Requirement Calculation					
OM&G	-	-	-	-	-
Depreciation	3.4	11.1	19.5	27.4	35.2
Interest	6.4	19.8	33.8	46.8	59.2
AFUDC	-	-	-	-	-
Return on Equity	6.0	18.6	31.8	44.1	55.7
Income Tax less Impact of Administrative Overhead	(0.6)	(2.2)	(3.9)	(4.8)	(5.4)
Administrative Overhead	-	-	-	-	-
Income Tax Impact of Administrative Overhead	-	-	-	-	-
Incremental Revenue Requirement of five-year capital plan	**15.2**	**47.2**	**81.1**	**113.5**	**144.8**
Change in Incremental Revenue Requirement from Previous Year	15.2	32.1	33.9	32.4	31.3
Rate Impact of five-year capital Plan*	1.2%	3.7%	6.4%	8.9%	11.4%
RECAP					
Expenses					
OM&G	-	-	-	-	-
Administrative Overhead	-	-	-	-	-
Depreciation	3.4	11.1	19.5	27.4	35.2
Interest	6.4	19.8	33.8	46.8	59.2
AFUDC	-	-	-	-	-
Earnings before tax	5.4	16.4	27.8	39.3	50.3
Income Tax less Impact of Administrative Overhead	(0.6)	(2.2)	(3.9)	(4.8)	(5.4)
Income Tax Impact of Administrative Overhead	-	-	-	-	-
Net Earnings	$6.0	$18.6	$31.8	$44.1	$55.7
New Incremental Regulated Capital Assets					
Beginning Balance	-	354.9	747.5	1,134.9	1,476.6
Capital Spend	354.9	392.6	387.3	341.7	348.4
Ending Balance	354.9	747.5	1,134.9	1,476.6	1,825.0
Average Blance	177.5	551.2	941.2	1,305.7	1,650.8
Capital Cost Allowance					
Depreciation of Assets added 2018-2022	10.8	34.7	60.0	82.1	103.1

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Categories of Capital Expenditures and Revenue Requirement

Like the functional classes of capital expenditures noted throughout the ACE Plan, overall revenue requirement can be broken down into different sub-categories. A table breaking out "Current Asset Investment" is provided in **Figure 57**.

Current Asset Investment is made up of all capital investment on our current asset base which includes both compliance and sustaining capital projects. It does not include investment that creates new assets (e.g. customer growth and wind farms) or substantially alters current assets (e.g. transmission upgrades for Wind/Maritime Link).

Figure 57: Current Asset Investment

NOVA SCOTIA POWER ($M)	2018 ACE	2019	2020	2021	2022
Estimated Spend Related to five-year Capital Plan					
Capital Expenditures (Spend)	$257.0	$248.8	$223.1	$224.9	$208.5
Less: Depreciation of all assets	208.4	213.6	218.9	224.1	229.4
Incremental Spend over Depreciation (Growth)	48.6	35.2	4.2	0.9	(20.9)
Incremental Spend as a portion of Total Spend	18.9%	14.2%	1.9%	0.4%	-10.0%
Average Incremental Net Book Value of projects in five-year plan	24.3	66.2	85.9	88.5	78.4
Impact on Net Earnings					
Expenses					
OM&G					
Administrative Overhead	(4.3)	(3.4)	(0.5)	(0.1)	2.0
Depreciation	0.4	1.1	0.2	0.1	(2.3)
Interest	0.9	2.4	3.1	3.2	2.8
AFUDC	(1.0)	(0.6)	(0.1)	(0.0)	0.4
Earnings before tax	(1.1)	0.8	3.8	4.2	6.6
Income Tax less Impact of Administrative Overhead	(1.0)	(0.7)	1.0	1.3	3.5
Income Tax Impact of Administrative Overhead	(0.9)	(0.7)	(0.1)	(0.0)	0.4
Net Earnings	$0.8	$2.2	$2.9	$3.0	$2.6
Incremental Revenue Requirement of five-year capital plan					

Incremental Revenue Requirement of five-year capital plan	(5.1)	0.2	6.6	7.4	9.4
Change in Incremental Revenue Requirement from Previous Year	(5.1)	5.3	6.4	0.8	2.0
Rate Impact of five-year capital Plan	-0.4%	0.0%	0.5%	0.6%	0.7%

Compliance investment is required to meet a variety of regulatory requirements.

Sustaining investment includes projects in T&D, Work Support Facilities, and Generation necessary to sustain those assets:

- Sustaining investment in Work Support Facilities is based on technical, economic or regulatory requirements of the assets.

- Sustaining investment in our generation, transmission and distribution assets is done through our asset management program and developed through ongoing inspection programs and based on condition and criticality of the asset. Sustaining investments in generation are backed up with economic analysis stating it is more economical to complete this project compared to a "do nothing" option.

Current Asset Investments represent those projects that NS Power is required to complete to maintain system reliability and performance.

Reductions in NS Power's current asset investment in T&D assets could lead to a decrease in reliability. Likewise, reductions in current asset investment in generation assets, and corresponding economically justified projects, could lead to reduced generation performance and outages resulting in an increase in revenue requirement due to incurring expenses that would otherwise be avoided.

Effect of Economically Justified Projects

NS Power's overall revenue requirement, of which NS Power's capital revenue requirement is a part, is influenced by economically justified projects. Economically justified projects contribute to minimizing upward pressure on rates by keeping NS Power's overall revenue requirement lower than it otherwise would be.

Figure 58 below shows the effect of all new economically justified projects in the 2018 ACE Plan.

Figure 58: Economically Justified Projects

NOVA SCOTIA POWER ($MM)	2018	2019	2020	2021	2022
Capital Expenditures (Spend)	$12.0	$0.0	$0.0	$0.0	$0.0
Electric Revenue	($3.9)	($3.1)	($4.0)	($4.6)	($4.8)
Operating Expense	(1.0)	-	-	-	-
Avoided Expenses	(3.1)	(4.2)	(5.0)	(5.7)	(5.9)
Depreciation Expense	0.1	0.3	0.3	0.3	0.3
Interest	0.2	0.4	0.4	0.4	0.4
AFUDC	(0.1)	-	-	-	-
Earnings before taxes	(0.2)	0.3	0.4	0.4	0.4
Income taxes	(0.4)	(0.1)	(0.0)	(0.0)	0.0
Net Earnings	$0.2	$0.4	$0.4	$0.4	$0.4
Revenue Requirement of Capital Investment	($0.8)	$1.1	$1.1	$1.1	$1.1
Total Revenue Requirement	($3.9)	($3.1)	($4.0)	($4.6)	($4.8)

NS Power's revenue requirement in 2018 if NS Power did not pursue its economically justified capital projects, would be $3.9 million higher.

As shown in **Figure 58**, the avoided $3.9 million in Revenue Requirement is composed mostly of avoided expenses. These avoided expenses do not represent a reduction in NS Power's capital. Rather, they are primarily avoided replacement energy and repair costs, as shown in each economically justified project's Economic Analysis Model.

Upward pressure on rates caused by NS Power's overall revenue requirement is minimized when economically justified projects are completed as compared to not completing them.

Conclusion

NS Power's capital program for 2018 forecasts reduced upward pressure on rates and revenue requirement. In addition, over the next three years, NS Power's capital program is expected to reduce upward pressure on rates and revenue requirement when fixed cost recovery is taken into account, and will minimally impact rates and revenue requirements when it is not.

Investment in the Current Asset Base has a small impact on revenue requirement while still maintaining reliability and performance of assets, and is justified based on need or economics in accordance with the requirements of the CEJC.

Investment in economically justified projects minimizes upward pressure on overall revenue requirement and rates by avoiding considerable expenses primarily related to replacement energy and repairs that would otherwise be incurred.

NS Power recognizes that this describes the influence of our capital program only. NS Power also recognizes that all aspects of our business contribute to the complete picture of our revenue requirement in any given year. Those other aspects include, broadly, fuel costs, operating, maintenance, and general (OM&G) costs, and past investments.

The 2018 ACE Plan, as with prior ACE Plans, emphasizes affordability for customers by maintaining its focus on sustaining capital expenditures, and prudently maintaining NS Power's Generation, Transmission and Distribution systems.

Addendum: Work Support Facilities

In **Figure 59**, NS Power has broken out the revenue requirement effect of Work Support Facilities projects. Work Support Facilities projects, as set out in the CEJC, are those associated with building, facilities replacement, and modifications, telecontrol and telecommunications, and Information Technology.

Those Work Support Facilities projects that NS Power submits for approval either provide a clear benefit or are considered necessary pursuant to indvidual project justifications. For example, Information Technology related capital projects are frequently necessary due to a number of factors including obsolescence of previous technology, manufacturer support expiring, or improving work practices in line with industry trends and customer expectations. Capital work orders for Work Support Facilities will be assessed and submitted in accordance with the criteria found in the CEJC, and will describe the corresponding justification for the project, be it technical or economic.

Figure 59: Work Support Facilities

NOVA SCOTIA POWER ($M)	2018 ACE	2019	2020	2021	2022
Estimated Spend Related to five-year Capital Plan					
Capital Expenditures (Spend)	$53.4	$54.5	$55.6	$56.7	$57.8
Less: Depreciation of all assets	31.4	30.0	32.2	38.6	39.9
Incremental Spend over Depreciation (Growth)	22.1	24.5	23.4	18.1	18.0
Incremental Spend as a portion of Total Spend	41.3%	45.0%	42.0%	32.0%	31.1%
Average Incremental Net Book Value of projects in five-year plan	11.0	34.3	58.2	79.0	97.0

Impact on Net Earnings	1.7	5.4	9.2	12.7	16.4
Expenses					
OM&G					
Administrative Overhead	(1.1)	(1.2)	(1.2)	(0.9)	(0.9)
Depreciation	0.3	1.1	1.8	2.0	2.6
Interest	0.4	1.2	2.1	2.8	3.5
AFUDC	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Earnings before tax	(0.1)	0.6	1.5	2.6	3.2
Income Tax less Impact of Administrative Overhead	(0.2)	(0.3)	(0.3)	0.1	0.2
Income Tax Impact of Administrative Overhead	(0.2)	(0.3)	(0.3)	(0.2)	(0.2)
Net Earnings	$0.4	$1.2	$2.0	$2.7	$3.3
Incremental Revenue Requirement of five-year capital plan					
Incremental Revenue Requirement of five-year capital plan	(0.7)	1.4	3.9	6.3	8.2
Change in Incremental Revenue Requirement from Previous Year	(0.7)	2.1	2.5	2.3	1.9

Note: NS Power has not determined the future planned investments in Work Support Facilities beyond 2018. As such, the analysis assumes that the level of investment would increase by an inflation rate of 2 percent annually. The incremental spend as a portion of total spend is assumed to be the same as the entire capital program. The revenue requirement effect includes the same factors as those used in the Long-Term Capital Planning & Revenue Requirement table.

10.1.2 Sustaining Capital – 2018 ACE Plan Alignment with the Integrated Resource Plan (IRP)

The 2015 ACE Plan Terms of Consensus provide the following:

> NS Power will also engage with interested stakeholders on the issue of NS Power including information in future ACE Plans to show how its long-term planning assumptions regarding projections of sustaining capital investment in existing thermal plants presented in the IRP and future ACE Plans are consistent. This stakeholder consultation process will begin within 30 days of the Board issuing its decision in this matter.[34]

During the stakeholder consultation process in early 2015, NS Power discussed the issue of including information in future ACE Plans to show how its long-term planning assumptions regarding projections of sustaining capital investment in existing thermal plants presented in the IRP and future ACE Plans are consistent. A mock-up of this

[34] 2015 ACE Plan, Terms of Consensus Agreement, M06514/P-128.15, February 18, 2015, page 2.

commitment was provided to and agreed upon by stakeholders pursuant to NS Power's report submitted to the Board on June 30, 2015.[35] NS Power provides this information in **Figure 60** below.

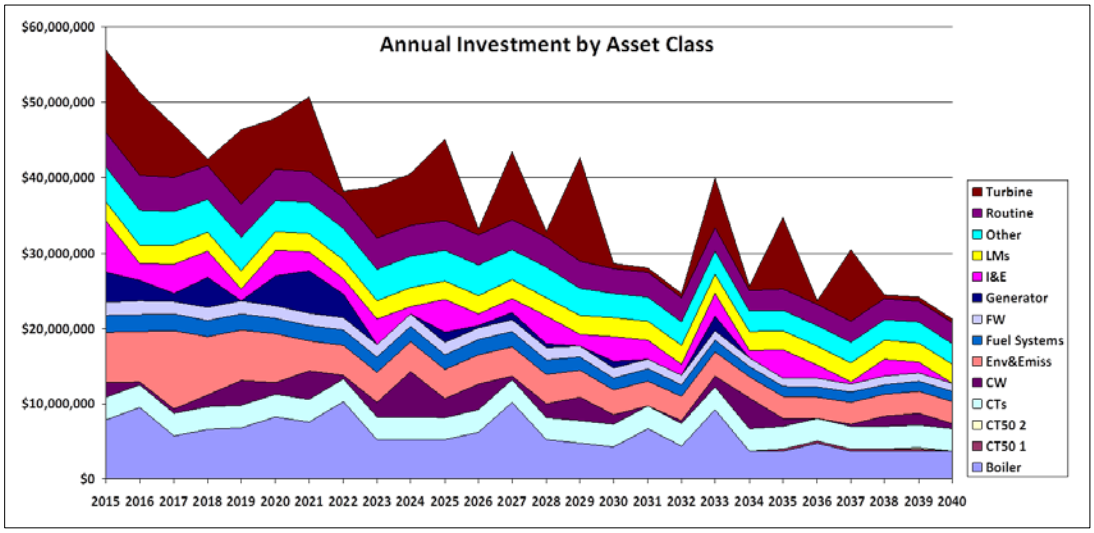
NS Power introduced sustaining capital assumptions for the thermal generating fleet for the first time in the 2014 IRP. This was made necessary by efforts to include unit retirement assumptions in the IRP analysis. The 2018 ACE Plan was derived using the same asset management practices used for the sustaining capital forecast assumptions for the 25 year planning period of the 2014 IRP.

When comparing a single capital year from an ACE Plan to a long term planning exercise such as the IRP, it is important to take into consideration the leveling of investment used for the 25 year capital forecast used within the IRP. Outside of major asset classes (turbines, generators, combustion turbines etc.), the investment in asset classes are levelized throughout the expected life of the associated generating unit. With respect to major asset classes it should be expected that the timing of investments will change from long term projections as annual assessments based on the latest operational information are essential to optimizing investment.

The capital investment forecast used in the 2014 IRP is shown in **Figure 60** below.

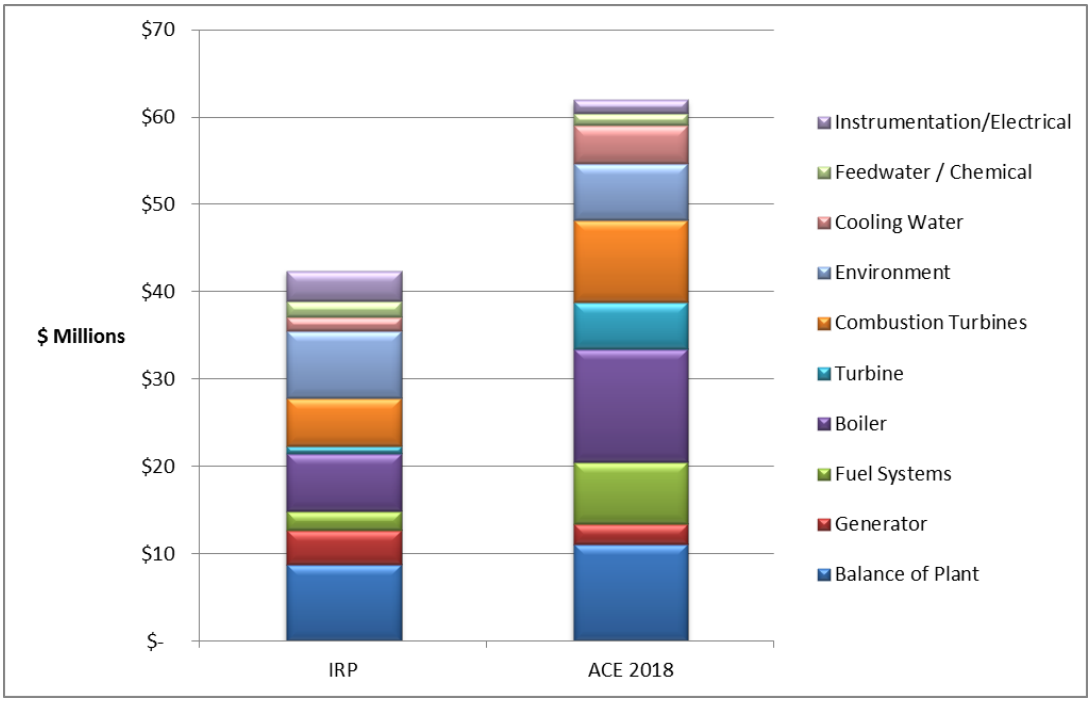
[35] 2015 ACE Plan Stakeholder Engagement Report, M06963, June 30, 2015.

Figure 60: 2014 IRP Sustaining Capital Forecast



As shown in **Figure 61**, NS Power has completed a more detailed, single year capital forecast; the 2018 capital forecast has changed as compared to the amount assumed in the 2014 IRP.

Figure 61: 2014 IRP vs. 2018 ACE Forecast Comparison by Asset Class



While the 2018 ACE Plan forecast is higher than the 2014 IRP forecast for 2018, the variance is largely due to the following factors:

- The 2014 IRP was completed using only 2014 dollars and did not include any form of inflation for future years and was at a time where the Canadian dollar was relatively on par with the US dollar. When applied to the 2014 IRP forecast, a conservative estimate of the increase in that forecast would be $7-10 million.

- 2018 also has a large investment in the combustion turbine units, which was included in the IRP forecast at $5.5 million levelized annually. The capital investment in 2018 is $10 million, largely due to the major components of the combustion turbine fleet requiring investment to continue reliable operation into the future. This increased investment of $4.5 million does not have an effect on alignment with the IRP as all Combustion Turbines are anticipated to operate

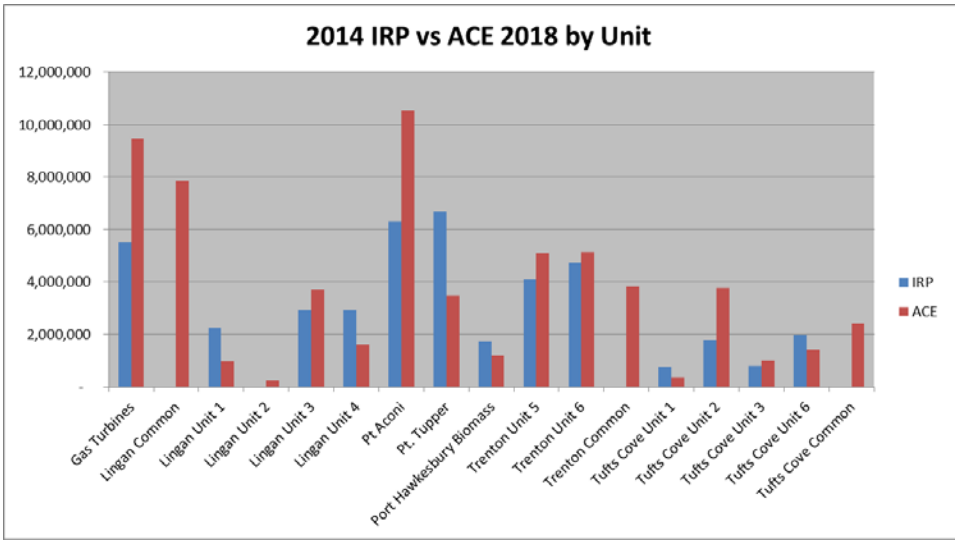
throughout the IRP Planning Period, an assumption that was common to all of the Resource Plans evaluated in the IRP.

- Another driver for this increase is the investment in Tufts Cove 2 and the Fleet Boiler Asset Class generally. Tufts Cove 2 utilization has continued to be greater than forecast in 2014 which drives added sustaining investment. Boiler related investments are greater than projected based on latest health assessments. Overall, this represents approximately $6 million of the increase from the IRP forecast for 2018.

- The remaining amount is due to an increase in the investment in boilers and balance of plant assets. The boiler investment across all units was levelized in the 2014 IRP. In actual practice, investments are planned to address specific requirements resulting from inspections and assessments, which will vary from the levelized IRP forecast. Balance of plant items would not have had a detailed future forecast in the IRP assumption development work. The condition of these assets was not understood as well as many of the complex asset classes (turbines, generators, etc) at the time of the IRP assumption development.

Figure 62 below provides a comparison of IRP assumed investments versus the 2018 ACE Plan forecast investments by generation unit.

Figure 62: 2014 IRP vs. 2018 ACE Forecast Comparison by Unit



Asset classes related to Lingan, Tufts Cove and Trenton Common include costs associated with ash and other elements of the station which are common to the generating units. While these are accounted for separately in the ACE Plan, the common costs were spread across the associated units in the IRP sustaining capital assumptions for the modeling purposes.

10.1.3 Summary of 2018 ACE Plan Capital Items Related to NERC and/or NPCC Standards

The UARB's 2011 ACE Plan Order Directive 9 provided as follows:

> NSPI is ordered to provide a summary sheet as part of future ACE Plan applications showing the list of projects, location, amounts and year in which each project related to NERC and/or NPCC standards is planned, in addition to the information currently provided.[36]

Figure 63 below is provided pursuant to the Board's directive.

[36] 2011 ACE Plan, UARB Order, NSUARB-P-128.11, June 23, 2011.

Figure 63: NERC and/or NPPC Capital Projects

CI#	Project Title	2018 ACE Plan	Total Estimate	2018 ACE Category
46757	88S Lingan 230kV BPS Upgrades	$390,479	$3,278,410	Carryover
50955	AMO NERC CIPv6 Compliance Upgrades	$117,361	$117,361	Less than $250k
C0002479	CIPv6 Electronic Security	$102,055	$102,055	Less than $250k
NERC and/or NPCC Compliance Total		**$609,895**	**$3,497,826**	

** The primary justification for the projects listed is compliance with NERC Standards and/or NPCC Criteria. Other capital projects (e.g. generation projects that preserve reserve margins or maintain Black-Start Capability) support NERC compliance but this is not presented as the primary project justification.*

10.1.4 Annual Ranking/Prioritization of Capital Projects

Pursuant to the UARB's 2011 ACE Plan directive 11 and 2013 ACE Plan directive 7, below is NS Power's capital project ranking criteria.

Pursuant to Section 6.1 of the CEJC, NS Power's Generation, Transmission and Distribtuion capital projects are ranked according to the following criteria:

- Health and Safety: Regulatory Requirements, Operating Permits, Protection of Equipment and Personnel Safety, and JOHSC actions.

- Environment/Regulatory Compliance: Renewable Energy Standards, Greenhouse Gas (GHG) Regulations, or Air Emission Regulations.

- Business Sustainability: SAIDI, SAIFI, CAIDI; unit reliability; system upgrade requirements; code requirements; NERC/NPCC Requirements, or economics (based on payback period, and revenue requirement); requirement to serve.

Technically justified IT projects are broadly ranked using the following criteria:

- Customer: service impacts to customers as a result of technical failure

- Finance: financial impacts to the Company as a result of technical failure

- Compliance: safety, environmental, security, legal or regulatory requirements (e.g. NERC/CIP and NI-52 compliance)

- Operating Sustainability: ability for NS Power staff or contractor to perform critical functions of the business.

NS Power's project ranking methodology is described in section 6.2 of the CEJC. This methodology uses a ranking matrix which results in a final ranking of 1 to 25. The ranking (also termed risk) is developed by determining the "Criticality" (ranked 1 to 5) and "Condition" (ranked 1 to 5) of each asset and multiplying the two to determine the overall risk.

Criticality and Condition values are typically influenced by one predominant factor and ranked accordingly. However, other factors may also influence the ranking of a project. In the event that multiple factors are present for a project, individual rankings will be taken into consideration in determining the overall Criticality rankings. For example, Health and Safety considerations for a project may warrant a Criticality ranking of serious (3), while Environmental considerations for the same project may also independently warrant a Criticality ranking of serious (3); this project may therefore warrant a higher Criticality ranking of 4 or 5 due to multiple influencing factors.

Multiple influencing factors, rankings, and the order of completion of projects ahead of others, are all subject to the evaluation and professional judgment of NS Power staff and third party industry experts.

Figures 64 to **68** below identify the projects included in the 2018 ACE Plan, their ranking category and ranking value, where applicable.

Generation

Figure 64: Hydro – 2018 ACE Plan Capital Item Rankings

CI#	Project Title	2018 ACE Budget	Ranking Category	Criticality	Condition	Ranking
39472	HYD Mersey System Re-Development	1,223,368	Business Sustainability	4	5	20
51236	HYD - WRC Tailrace Rock Bolting	8,677,118	Health & Safety	4	4	16
48533	HYD Lequille Headpond Refurbishment	4,209,710	Health & Safety	5	3	15
49033	HYD WRC Tunnel T-2 Intake Replacement	2,525,419	Health & Safety	4	4	16
51235	HYD - WRC Main Access Rd Refurbishment	2,574,654	Health & Safety	4	4	16
51234	HYD - WRC HVAC Upgrade	266,738	Business Sustainability	4	5	20
49943	HYD - Ruth Falls Facility Refurbishment	1,217,177	Health & Safety	3	5	15
49942	HYD - Tidewater Facility Refurbishment	1,230,442	Health & Safety	3	5	15
49946	HYD - Fourth Lake Overhaul	978,404	Business Sustainability	4	4	16
48791	HYD - WRC Safety Standards Upgrades	440,182	Health & Safety	5	4	20
51775	HYD Fixed Ladder & Machine Guard	906,249	Health & Safety	4	5	20
49945	HYD - Malay Falls Switchgear Replacement	957,136	Health & Safety	4	4	16
47660	HYD - Dickie Brook Controls Upgrade	228,354	Business Sustainability	4	5	20
52262	HYD - Hells Gate 1 Overhaul	854,993	Business Sustainability	4	4	16
51972	HYD Nictaux Canal Embank Refurbishment	779,686	Health & Safety	4	4	16
51866	HYD - 4th Lake Penstock Refurbishment	663,326	Business Sustainability	4	4	16
47655	HYD - Paradise Controls Upgrade	218,179	Business Sustainability	4	5	20
49944	HYD - Dickie Brook Penstock Refurbishment	478,820	Business Sustainability	4	4	16
48712	HYD - Dam Instrumentation Upgrade	395,505	Business Sustainability	4	4	16
52017	HYD ANN Exciter Replacement	465,855	Business Sustainability	4	4	16
51772	HYD Arc Flash Mitigation	262,654	Business Sustainability	4	5	20
52018	HYD - RES Revenue Meter Replacement	368,897	Business Sustainability	4	4	16
47659	HYD - Fall River Controls Upgrade	104,320	Business Sustainability	4	5	20
C0002103	HYD WRC U1 WG Thrust Assembly	200,574	Business Sustainability	4	4	16
52256	HYD WRC Helipad Construction	160,435	Health & Safety	4	4	16
C0001578	HYD WRC Bus Duct Monitors	158,439	Business Sustainability	4	5	20
51848	HYD - ANN Warehouse Refurbishment	118,275	Business Sustainability	3	5	15
C000223	HYD DHA Purchase	50,000	Business	4	4	16

CI#	Project Title	2018 ACE Budget	Ranking Category	Criticality	Condition	Ranking
1			Sustainability			
51868	HYD - 4th Lake Butterfly Valve Refurbishment	48,006	Business Sustainability	5	3	15
47649	HYD - Salmon Tail Gate Pedestal Replacement	36,227	Business Sustainability	3	5	15

Figure 65: Steam – 2018 ACE Plan Capital Item Rankings

CI	Project Title	2018 ACE Budget	Ranking Category	Criticality	Condition	Ranking
49534	TRE6 EHG/Turbine Controls Upgrade	2,507,264	Business Sustainability	4	4	16
51808	TUC HFO Piping Refurbishment	1,291,933	Environment	4	4	16
51802	TRE5 Boiler Refurbishment 2018	1,212,228	Business Sustainability	3	5	15
52107	TUC6 CW Screen Replacement	1,000,676	Business Sustainability	4	5	20
51803	TUC2 Generator Flux Probe Installation	840,158	Business Sustainability	3	5	15
51805	LIN4 Boiler Refurbishment 2018	739,657	Business Sustainability	3	5	15
47684	LIN3 Boiler Refurbishment 2018	739,657	Business Sustainability	3	5	15
50577	TRE6 CEMS Replacement	715,562	Environment	5	4	20
51806	LIN Mill Refurbishment 2018	673,153	Business Sustainability	3	5	15
52093	ICP Rail Crossing Refurbishment	592,402	Business Sustainability	4	4	16
52321	TUC3 Air Heater Refurbishment	535,728	Business Sustainability	4	4	16
51825	POT Boiler Refurbishment 2018	568,740	Business Sustainability	3	5	15
51811	LIN Reclaim Refurbishment Phase 2	534,666	Health & Safety	4	4	16
52252	LIN1 SH5 Tube Replacement	521,259	Business Sustainability	3	5	15
51815	LIN CW Pump Refurbishment 2018	520,436	Business Sustainability	3	5	15
51861	TRE6 CW Screen Replacement 2018	513,192	Business Sustainability	4	4	16
51816	TRE Asbestos Abatement 2018	509,035	Health & Safety	5	3	15
52253	LIN3 Economizer Header Refurbishment	499,951	Business Sustainability	4	5	20
51821	TRE5 Air Heater Refurbishment	487,376	Business Sustainability	4	4	16
51835	TUC2 H2 Panel Upgrades	454,886	Health & Safety	4	4	16
51820	TRE5 Reheat Turbine Valves	450,408	Health & Safety	4	4	16
51824	LIN3 ID Fan Damper and VIV Refurbishment	443,311	Business Sustainability	3	5	15

51818	PHB Boiler Refurbishment 2018	440,315	Business Sustainability	3	5	15
51807	TUC2 Boiler Lower Vestibule Refurbishment	412,872	Business Sustainability	4	4	16
51836	TRE5 Mill Refurbishments 2018	409,458	Business Sustainability	3	5	15
51849	LIN3 RH Tube Replacement	399,546	Business Sustainability	3	5	15
51850	LIN4 RH Tube Replacement	399,546	Business Sustainability	3	5	15
47871	LIN Stack Re-Coating	381,034	Health & Safety	4	4	16
49676	TUC2 CEMS Replacement	380,140	Environment	4	4	16
51839	LIN Coal Plant Structural Refurbishment	354,067	Health & Safety	4	4	16
51851	LIN CW Screen Refurbishment 2018	350,534	Business Sustainability	4	4	16
49547	TRE5 5-1 BFP Refurbishment	345,523	Business Sustainability	4	5	20
51862	TRE6 Lube Oil Cooler Refurbihsment	341,769	Environment	4	4	16
C0001419	TRE HFO Refurbishment Phase 1	340,618	Business Sustainability	4	4	16
43429	TRE5 Lube Oil Cooler Retube	338,398	Environment	4	5	20
51804	LIN3&4 ACW Duplex Strainer Replacement	333,808	Business Sustainability	4	4	16
51857	TRE5 Burner Refurbishments 2018	332,497	Business Sustainability	3	5	15
51852	POT Mill Refurbishment 2018	327,267	Business Sustainability	3	5	15
52156	LIN Vaccuum Pump Upgrades	302,714	Business Sustainability	3	5	15
51853	LIN3 Turbine Valve Refurb 2018	295,709	Health & Safety	4	4	16
51860	TRE5 PF Mill Line Replacement	258,761	Business Sustainability	3	5	15
52040	LIN Grating Refub (Boiler House)	244,596	Health & Safety	4	4	16
52037	LIN1 Main FW Control Valve & Actuator	241,216	Business Sustainability	4	4	16
52035	LIN Plant Lighting Upgrade Phase 2	237,079	Business Sustainability	3	5	15
49452	LIN3 FW Heater Level Controls Upgrade	236,285	Business Sustainability	4	4	16
47834	ICP Ranger Motor Upgrade	235,643	Business Sustainability	4	4	16
52041	LIN Siding Refurbishment Phase 2	233,676	Business Sustainability	4	4	16
52101	ICP Rail Car Rebuild	233,505	Business Sustainability	4	4	16
52097	ICP Water Truck	232,000	Environment	4	4	16
52222	TUC2 Breaker Replacements and Upgrade	229,831	Business Sustainability	3	5	15
52050	LIN4 Misc. Valve Refurbishment	223,217	Business Sustainability	3	5	15
52243	POT Asbestos Abatement	221,668	Health & Safety	5	3	15

52182	TRE5 Condenser Tubesheet Coating	220,699	Business Sustainability	4	4	16
52104	ICP Rail Car Truck Program	220,461	Business Sustainability	4	4	16
52062	LIN Forklift Replacement	219,740	Business Sustainability	3	5	15
52242	POT West CW Pump Overhaul	219,146	Business Sustainability	3	5	15
52197	TUC2 Main Feedwater Control Valve Refurbishment	216,249	Business Sustainability	4	4	16
52052	LIN1 Misc. Valve Refurbishment	214,536	Business Sustainability	3	5	15
52051	LIN3 Misc. Valve Refurbishment	213,302	Business Sustainability	3	5	15
52049	LIN PF Line Replacement	212,325	Business Sustainability	3	5	15
52053	LIN3 Air heater and Aux Air Dampers	212,031	Business Sustainability	4	4	16
52291	POT 4160V Motor Controls Upgrade	203,735	Business Sustainability	3	5	15
C0002059	LIN - Exterior Security Light Upgrade	202,950	Business Sustainability	4	4	16
52296	TUC Asbestos Abatement	200,000	Health & Safety	5	3	15
52046	LIN Precipitator Controls Upgrade	197,953	Environment	4	5	20
51900	TRE5 PLC Upgrade WTP/Polisher	193,112	Business Sustainability	4	4	16
49546	TRE6 FW Heater Level Control	187,315	Business Sustainability	4	5	20
52248	POT Boiler Gas Temp Monitors	182,984	Business Sustainability	3	5	15
52058	LIN3 ID Fan Shaft Refurbishment	179,967	Business Sustainability	4	4	16
51854	PHB Conveyors and Handling Systems	176,943	Business Sustainability	3	5	15
52179	TRE5 Valve Refurbishments 2018	176,207	Business Sustainability	3	5	15
52177	TRE6 Valve Refurbishments 2018	176,141	Business Sustainability	3	5	15
52042	LIN Plant Heating Upgrade	171,552	Business Sustainability	3	5	15
52038	LIN Precip Pressurizing Fan	168,048	Environment	4	4	16
52043	LIN A Coal Chute Replacement	162,228	Business Sustainability	3	5	15
52239	TUC6 Main and Induction Stop Valve	160,053	Business Sustainability	4	4	16
51394	LIN34 Control Panel Button Upgrade	125,816	Health & Safety	4	5	20
52249	POT Breaker Replacements / Upgrades	154,859	Business Sustainability	3	5	15
52154	TRE Ash Site Management 2018	153,269	Environment	4	5	20
52155	TRE6 Conveyor Refurbishment 2018	151,482	Business Sustainability	4	4	16
52175	TRE5 Mill Platform Access	151,402	Business Sustainability	4	4	16
52231	TUC6 Turbine Bypass Valve Refurbishment	151,072	Business Sustainability	4	4	16

52244	PHB Replace Mini-Bins	149,828	Business Sustainability	3	5	15
52300	TUC Facilities Upgrade Phase 2	149,504	Health & Safety	4	4	16
C0001538	LIN4 Sequence of Event Recorder	137,666	Business Sustainability	3	5	15
52121	LIN Boiler Fill Pump Suc. Repl. Phase 2	132,439	Business Sustainability	4	4	16
52063	LIN Facilities Upgrade	131,777	Business Sustainability	3	5	15
52048	LIN Contractor Trailer	130,486	Health & Safety	4	4	16
52153	TRE5 Stack Refurbishment	127,579	Business Sustainability	4	4	16
52054	LIN BFP Discharge Valve (Capital Spare)	120,696	Business Sustainability	3	5	15
C0001498	ICP-#2 Gate Upgrade Phase 2	119,647	Business Sustainability	3	5	15
52251	POT Misc. Valve/Component Replacement	119,550	Business Sustainability	3	5	15
52240	TUC2 Stack Refurbishment	116,335	Business Sustainability	4	4	16
52318	TUC CW Inlet Structural Steel Refurbishment	116,181	Business Sustainability	4	5	20
52292	TUC Heavy Fuel Oil Tank Dyke Refurbishment	110,668	Environment	5	4	20
50855	TRE Chemical Storage Area	100,057	Health & Safety	5	4	20
49670	TUC1 4kv/600V Breaker Replacement	106,420	Business Sustainability	3	5	15
49451	LIN Fan Positioner Replacement	105,915	Business Sustainability	4	4	16
47674	POT - CW Pumphouse Motor Control Centre Upgrade	104,638	Business Sustainability	3	5	15
52061	LIN 4160 600V Breaker Refurbishment	104,433	Business Sustainability	3	5	15
52139	TRE Common Water Piping Replacement	103,524	Business Sustainability	3	5	15
52140	TRE5 4 kV Motor Refurbishments 2018	101,780	Business Sustainability	3	5	15
49657	TUC Sequence of Events Recorder SEL	101,586	Business Sustainability	3	5	15
52013	TRE Floor Plates/Grating Refurbishment	101,388	Health & Safety	4	4	16
52276	TUC1 Obsolete Valve Replacement	101,355	Business Sustainability	3	5	15
52274	POT Coal Chute Refurbishments	100,440	Business Sustainability	4	4	16
52223	TUC1 Air Heater Roof Replacement	99,086	Business Sustainability	4	4	16
52138	TRE5 Conveyor Refurbishment 2018	98,389	Business Sustainability	4	4	16
52257	TUC3 Breaker Replacements and Upgrade	98,105	Business Sustainability	3	5	15
52152	TRE5 Relay Room Fire Protection	96,940	Business Sustainability	4	4	16
52036	LIN CW Screen Wash Piping Upgrade	95,138	Business Sustainability	4	4	16
C0001158	ICP High Rail Truck Replacement	95,000	Business Sustainability	3	5	15

52039	LIN Automated Sweeper	94,842	Health & Safety	4	4	16
51840	LIN C Belt Replacement	93,628	Business Sustainability	4	4	16
52137	TRE A Conveyor Structural Refurbishment	85,483	Business Sustainability	4	4	16
52245	PHB Trancel Screw Refurbishment	80,366	Business Sustainability	3	5	15
52298	TUC6 Auxiliary Cooling Piping Upgrade	74,526	Business Sustainability	4	4	16
52047	LIN Diesel Light Oil Emergency Shutoff Valve Installation	67,410	Health & Safety	4	4	16
C0001303	PHB - HVAC System Upgrades 2018	66,262	Business Sustainability	4	5	20
52281	POT South Air Compressor Refurbishment	62,212	Business Sustainability	3	5	15
52136	TRE5 Jacking Oil Pump Replacement	60,692	Business Sustainability	4	4	16
52280	PHB Rotary Valve Replacements	57,912	Business Sustainability	3	5	15
52178	POT - Fuel Oil Supply Shutoff Valve Installation	54,857	Health & Safety	4	4	16
52135	TRE5 Nitrogen Generator Installation	54,471	Business Sustainability	3	5	15
52120	TRE Fuel Oil Emerg Valve Fire Protection	50,866	Health & Safety	4	4	16
52266	TUC2 Oil Spill Containment	45,000	Environment	4	4	16
52290	TUC1 Opacity Meter Replacement	40,000	Environment	4	4	16
49688	TUC3 Analytical Panel Upgrades	31,527	Business Sustainability	4	4	16

Figure 66: Combustion Turbine – 2018 ACE Plan Capital Item Rankings

CI#	Project Title	2017 ACE Budget	Ranking Category	Criticality	Condition	Ranking
52143	LM6000 Engine 191-332 Hot Section	1,776,275	Business Sustainability	5	4	20
C0002978	CT's Motor Control Centre Upgrades	1,199,221	Business Sustainability	3	5	15
49594	LM6000 TUC5 Airhouse Upgrade	830,287	Business Sustainability	4	4	16
49940	LM6000 TUC5 Control System Upgrade	811,559	Business Sustainability	4	4	16
49932	CT - TUC 4 LM6000 Roof Skid Access	176,559	Business Sustainability	3	5	15
49933	CT - TUC 5 LM6000 Roof Skid Access	176,559	Business Sustainability	3	5	15
52145	CT TUC 4 Thrust Balance Valve Replacement	157,285	Business Sustainability	4	4	16
52149	CT TUC 5 Thrust Balance Valve Replacement	157,285	Business Sustainability	4	4	16
52115	CT VJ Fuel Level Monitoring Upgrade	82,285	Environment	4	4	16
47812	BGT Fuel Tank 3 Refurbishment	72,091	Environment	4	4	16
49970	CT - TUS Exhaust Stack Refurbishment	66,592	Business Sustainability	4	4	16
52106	CT BGT Fuel Level Monitoring Upgrade	65,828	Environment	4	4	16
47937	BGT1 Clutch Refurbishment	61,000	Business Sustainability	4	4	16

52144	CT TUC 4 & 5 Engine Pad Installation	43,885	Business Sustainability	4	4	16
52142	CT Tusket Plant Coating	43,885	Business Sustainability	4	4	16
52159	CT VJ1 Varec Gauges Upgrades	35,000	Business Sustainability	4	4	16
52160	CT VJ2 Varec Gauges Upgrades	35,000	Business Sustainability	4	4	16
C0002858	CT's TUS Operator Interface Upgrade	30,167	Business Sustainability	3	5	15
C0002980	CT BGT Plenum Floor Refurbishment	28,879	Business Sustainability	4	4	16

Transmission & Distribution

Figure 67: Transmission and Distribution – 2018 ACE Plan Capital Item Rankings

CI#	Project Title	2018 ACE Budget	Ranking Category	Criticality	Condition	Ranking
Transmission Capital Items Included in 2017 ACE Plan						
51969	2018 Transmission ROW Widening 69kV	5,487,686	Business Sustainability	4	4	16
51975	5P Mobile Substation Replacement	3,225,405	Business Sustainability	5	4	20
52258	2018/2019 Isolated Structure Replacement	1,094,899	Business Sustainability	4	5	20
51403	2018 PCB Removal Program	1,478,161	Environment	5	4	20
51402	2018/2019 Sacrificial Anode Installation	703,416	Business Sustainability	4	4	16
C0001900	Mount Hope 69-25kV Substation	1,397,158	Business Sustainability	5	3	15
52314	1C-GT1/UT1 Replacement	1,162,188	Business Sustainability	4	4	16
51398	2018/2019 Steel Tower Refurbishment	461,426	Business Sustainability	4	4	16
52320	L6549 2018 Replacements & Upgrades	657,710	Business Sustainability	4	4	16
51406	2018/2019 Transmission Switch & Breaker Replacement	1,311,498	Business Sustainability	4	5	20
51405	2018 Wood Pole Retreatment Program	680,538	Business Sustainability	4	4	16
48131	48H-T1 Replacement	648,122	Business Sustainability	4	4	16
52328	56N-T1 Transformer Upgrades	703,817	Business Sustainability	4	4	16
49779	L6537 Replacements and Upgrades	587,041	Business Sustainability	4	5	20
49777	L7002 Replacements and Upgrades	437,128	Business Sustainability	4	5	20
52241	16V-T2 Weymouth Hydro Transformer Replacement	889,253	Business Sustainability	4	4	16
52102	L5014-2018 Replacements and Upgrades	849,700	Business Sustainability	4	4	16
49788	L5564 Replacements and Upgrades	691,417	Business Sustainability	4	4	16
52059	L5039 - 2018 Replacements and Upgrades	719,825	Business Sustainability	4	4	16
49783	L5027A Replacements and Upgrades	648,292	Business Sustainability	4	5	20

CI#	Project Title	2018 ACE Budget	Ranking Category	Criticality	Condition	Ranking
52119	L5054 2018 Replacements and Upgrades	560,143	Business Sustainability	4	4	16
52238	2018/2019 Capacitor Bank Breaker Replacement	243,830	Business Sustainability	4	4	16
43268	9W-B53 Tusket Replace Structure	375,523	Business Sustainability	5	4	20
51797	2018 Oil Containment Program	331,507	Environment	4	4	16
52305	2018 Substation Insulator Replacement	316,348	Business Sustainability	4	4	16
51863	2018 Tap Changer Replacements	306,102	Business Sustainability	4	4	16
52261	83V-503 & 83V-504 - Bring Switches	212,968	Business Sustainability	3	5	15
Distribution Capital Items Included in 2017 ACE Plan						
C0001950	New Distribution Rights-of-Way Ph 3	6,870,749	Business Sustainability	4	4	16
52271	2018 Padmount Replacement	1,286,340	Business Sustainability	4	5	20
51493	2018 PCB Pole Top Transformer Replacement	842,163	Environment	5	4	20
47794	Heckman Island Underwater Cable Replacement	762,186	Business Sustainability	5	4	20
52184	37N-412-Glooscap Trail Rebuild Phase 2	858,046	Business Sustainability	5	4	20
52224	532N-Elm Street Conversion Phase 2	433,695	Business Sustainability	5	4	20
C0001802	54C-211 Queen Street Conversion	705,316	Business Sustainability	4	4	16
52185	50N-410 Rebuild Phase 2	695,098	Business Sustainability	5	4	20
43218	88W-323A Tusket Islands Phase 3	347,162	Business Sustainability	4	5	20
51400	2018 Sub Recloser Replacements	644,710	Business Sustainability	4	4	16
52194	6S-223 Harold Street Conversion	642,368	Business Sustainability	4	5	20
52200	65V-301 Brickton Reconductor	288,048	Business Sustainability	4	5	20
52205	30N-412 Hwy 242 Fundy Shore Rebuild	536,670	Business Sustainability	4	5	20
51744	30N-411 Maccan River Rebuild	473,044	Business Sustainability	5	4	20
52204	87W-312G-Tancook Island Replacement	208,236	Business Sustainability	5	4	20
52267	16W-302H-Brenton Rd Rebuild	258,839	Business Sustainability	4	5	20
52207	678H-211 McNab's Island Replacement	162,232	Business Sustainability	5	4	20
51500	2018 Pin Insulator Replacements	329,944	Business Sustainability	4	4	16
52221	515S-311-Rebuild on Aliant poles	190,606	Business Sustainability	5	4	20
52192	54H-303 Underground Device Replacement	289,957	Business Sustainability	5	4	20
52206	20V-311-Bishop Ville Rd	303,533	Business Sustainability	5	4	20
52186	4S Feeder Exit Cable Replacement Phase 1	276,129	Business Sustainability	5	4	20
52208	3S Feeder Exit Cable Replacement Phase 2	293,228	Business Sustainability	4	5	20
52201	55V-314GA-Welsford Reconductor	275,161	Business Sustainability	4	5	20
49898	15N-202 Victoria St Rebuild	242,253	Business	4	4	16

CI#	Project Title	2018 ACE Budget	Ranking Category	Criticality	Condition	Ranking
			Sustainability			
51499	2018 Downline Recloser Replacements	245,928	Business Sustainability	5	4	20
C0001798	Halifax 4kV Conversion Phase 5	218,971	Business Sustainability	5	4	20
52306	5N-301 - Masstown Road Rebuild	165,446	Business Sustainability	4	4	16
52265	55V-322-English Mt Rd Reconfigure	157,022	Business Sustainability	4	5	20

Information Technology – Capital Item Rankings

Figure 68: IT – 2018 ACE Plan Capital Item Rankings

CI#	Project Title	2018 ACE Budget	Ranking Category	Criticality	Condition	Ranking
46075	IT - Work and Asset Management	14,498,734	Business Sustainability	5	4	20
49480	IT - Disaster Recovery	494,282	Business Sustainability	5	3	15
49858	IT - MS Exchange Upgrade	1,555,597	Business Sustainability	4	4	16
49094	IT - Identity Access Mgmt Infrastructure	800,000	Business Sustainability	5	3	15
C0002241	IT-Generation Operation Upgrade	511,673	Business Sustainability	5	4	20
52335	IT-Automate Manual Billing	506,403	Business Sustainability	4	5	20
52337	IT-Group Billing Experience	505,823	Business Sustainability	3	5	15
C0002254	IT- MV90 Upgrade	254,062	Business Sustainability	3	5	15
C0002256	IT- Customer Care & Billing Server-Migration	205,021	Business Sustainability	3	5	15
52334	IT-Meridium Upgrade	150,000	Business Sustainability	4	4	16

10.1.5 2018 to 2022 Forecasted ACE Plan Expenditures by Functional Class and Spending Program

Pursuant to 2011 ACE Plan Directive 12, NS Power provides its forecast spend by functional class and spending program. Justifications for projects determined as capital investments are scoped on an annual basis. Capital investment on the basis of health and safety, environmental compliance and requirement to serve remains non-discretionary. **Figure 69** below identifies anticipated sustaining capital by function and specific notable investments included in this ACE Plan. Investment levels from 2018 to 2022 are subject to change based on operating conditions, updated asset assessments, regulatory directives, or legislation/regulations.

Sustaining capital funding levels represent typical annual investment by function in a given year to sustain the integrity of existing assets. Notable capital projections reflect specific projects. Included in these specific projects are transformative multi-year program investments and asset growth.

Figure 69: Forecasted ACE Plan Expenditures by Functional Class and Spending Program ($M)

	2018 ACE	2019	2020	2021	2022
Thermal Generation	54.7	54.0	50.4	52.2	48.4
Combustion Turbines	9.4	9.6	9.7	9.9	10.1
Hydro Generation	51.0	40.0	36.2	22.2	22.6
Wind Generation	0.2	0.1	0.1	0.1	0.1
Transmission	50.4	59.6	51.6	52.6	53.6
Distribution	64.7	60.3	61.6	62.9	64.2
General Plant	40.1	26.3	25.3	36.9	34.4
Total Base Capital Expenditure	**270.6**	**249.9**	**234.9**	**236.8**	**233.5**
General Plant:					
IT - CIS Replacement	0.0	0.0	18.0	18.0	5.0
IT - Work & Asset Management	14.5	28.6			
Distribution:					
Advanced Metering Infrastructure	28.3	50.0	50.0	0.0	0.0
Intelligent Feeder Project	0.7				
Distribution R.O.W Widening	9.6	10.0	10.0	10.0	10.0
LED Streetlights	4.8	5.5	0.0	0.0	0.0
Transmission:					
Maritime Link Transmission	5.8				
Metro Transmission Upgrades	3.5				
Transmission R.O.W Widening	5.4	5.4	5.4	5.4	5.4
Lingan GIS Replacement	10.4				

	2018 ACE	2019	2020	2021	2022
Hydro:					
Hydro Infrastructural Renewal					
Wreck Cove Overhaul		7.0	4.1	29.6	50.7
Annapolis Overhaul		3.1	3.1	3.1	1.5
Mersey Re-Development	1.2	33.2	61.8	38.8	42.3
Total Notable Capital	**84.4**	**142.7**	**152.4**	**104.9**	**114.9**
Total Annual Capital Investment	**354.9**	**392.6**	**387.3**	**341.7**	**348.4**

10.1.6 Routine Expenditures

The UARB's 2013 ACE Plan Order Directive 2 provided as follows:

> The Board directs NSPI, in the next ACE Plan application, to analyze the routine expenditures to determine what are the "like-for-like" totals. NSPI is further directed to explain why those totals, if they are similar in magnitude to the Board's analysis, are growing at an annual rate in excess of inflation.[37]

A summary of NS Power's total routine and like-for-like routine spending is provided in **Figure 70** below.

Figure 70: Annual Cost of Like for Like Routine Replacements

NOVA SCOTIA POWER ($M)	2014 Actual	2015 Actuals	2016 Actuals	2017 Forecast	2018 ACE Plan
Total Routine Spending	$68.2	$75.8	$85.2	$81.4	$84.0
Less:					
New Customers	20.9	24.1	22.4	22.2	21.4
System Growth and Performance	3.0	2.0	8.2	2.9	2.9
Other	0.7	1.0	1.4	1.2	1.4
Like-for-Like	44.6	47.9	53.1	55.1	58.3

[37] 2013 ACE Plan, UARB Order, NSUARB-P-128.13, June 4, 2013.

NOVA SCOTIA POWER ($M)	2014 Actual	2015 Actuals	2016 Actuals	2017 Forecast	2018 ACE Plan
Work Vehicles (Like-for-like)	2.4	6.2	7.1	7.9	8.6
Net (Like-for-like)	42.1	41.8	46.0	47.2	49.6

Note: Point Aconi amounts have been removed in order to reflect the spend totals that require UARB approval.

Routine classifications are determined by the primary classification of each routine project. If the majority of the work completed under the routine is like-for-like replacements, the routine is classified as like-for-like. New Customer routines, System Growth and Performance routines (such as heat rate, system improvement and right-of-way widening routines) and other routines (such as environmental assessment routines) were not included in the like-for-like totals.

NS Power addresses reactive items within routines by using the professional judgment of its personnel to assess the urgency of each job. At an overall routine level, NS Power actively evaluates and prioritizes work in order to manage costs within budget. Each month, NS Power monitors the activities within the routines to evaluate whether the work is necessary.

10.1.7 Impact of Reliability Projects

The UARB's 2013 ACE Plan Decision provided the following directive:

> …the Board expects NSPI to monitor the impact of the deferral of reliability projects in the original 2013 ACE Plan closely and to provide a report on the results in the next ACE Plan.[38]

Pursuant to NS Power's commitment noted in the 2015 ACE Plan Terms of Consensus, this directive is expanded to include additional information regarding continued sustaining capital investments and maintaining reliability performance.

[38] 2013 ACE Plan, UARB Decision, M05339, May 27, 2013, page 44, line 174.

The UARB's 2017 ACE Plan Order provided the following directive:

> The Board directs NSPI to identify and list any proposed capital investments related to performance standards established by the Board in future ACE Plan applications.[39]

All T&D projects in the 2018 ACE Plan will contribute to meeting these performance standards targets. T&D projects in the 2018 ACE Plan are selected based on the asset management methodology pursuant to section 6.2 of the CEJC, guiding investments to where they are needed most. As noted by NS Power during the Performance Standards proceeding, no additional capital investment beyond the regular sustaining capital investments NS Power makes through its ACE Plan program are required to meet these standards.

Finally, the UARB directed NS Power to continue providing the same information with respect to reliability and severe weather events notwithstanding the UARB's approval of the performance standards in 2017 and the Company's obligations to report on those standards:

> …[T]o what extent, if any, certain aspects of the information set out in Section 8.1.7 of the 2017 ACE Plan will be reproduced in the report required by the Performance Standards Decision remains to be seen.
>
> It is not clear such items as, for example, plans for replacement of aging transmission and distribution equipment, and storm performance information, beyond the 48-hour restoration metric, will be fully explored in the context of performance standard metrics reporting.
> As there is some uncertainty, and a part of the information provided in Section 8.1.7 is derived from an agreement between stakeholders, as part of the 2015 ACE Plan process, the Board will not direct any changes to the current ACE Plan reporting related to reliability as this time. The Board will monitor the ongoing relevancy of this part of the ACE Plan.

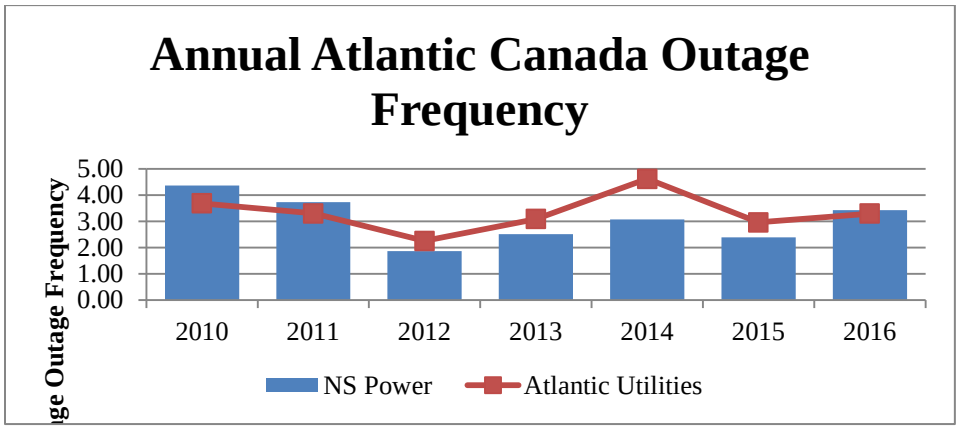
[39] 2017 ACE Plan, UARB Order, M07745, April 4, 2017.

The first report arising from the Performance Standards Decision is due March 31, 2018. Once that report has been filed and analyzed, the matter should be revisited in the context of a future ACE Plan. [40]

Reliability Statistics

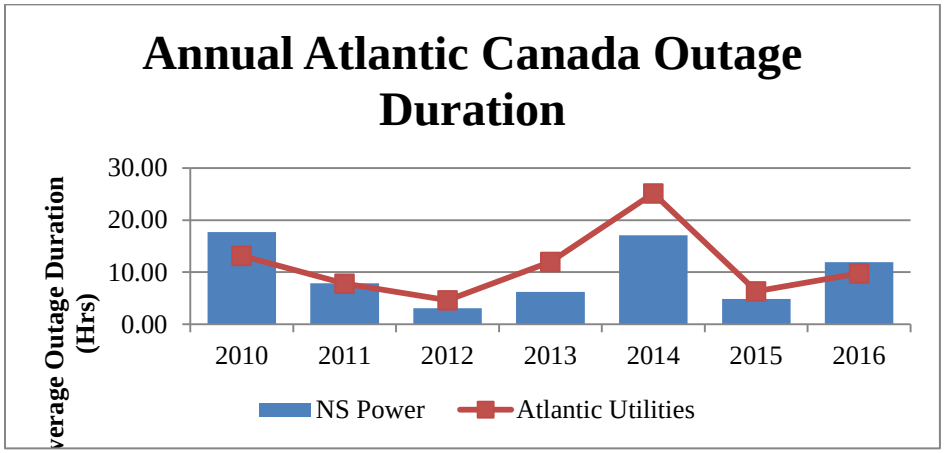
As shown in **Figures 71** and **72** below, with the exception of 2016 due to challenging weather conditions, NS Power's annual outage frequency and duration continues to be below the average of Atlantic Canada utilities. The data for 2014 is higher due to Post Tropical Storm Arthur, but NS Power is still below the average of the Atlantic Canadian utilities, as reported annually to the Canadian Electrictiy Association (CEA).

Figure 71: Annual Atlantic Canada Outage Frequency



[40] 2017 ACE Plan, UARB Decisions, M07745, April 4, 2017, para 98 to 101.

Figure 72: Annual Atlantic Canada Outage Duration



Figures 73 and 74 below represent NS Power's reliability statistics with Major and Extreme Events (such as Post-Tropical Storm Arthur and as defined by IEEE-1366) removed from the data. This shows a normalized comparison between yearly reliability performance. Similar to 2015, increases in 2016 were largely the result of a significant number of storm events, including heavy snowfall, leading to more frequent and longer smaller outages than would have been experienced in previous years, in turn leading to an increase in SAIFI and SAIDI. The 10 year trend shows overall reliability improvements for customers.

Figure 73: NS Power Annual SAIFI (Major/Extreme Events Excluded)

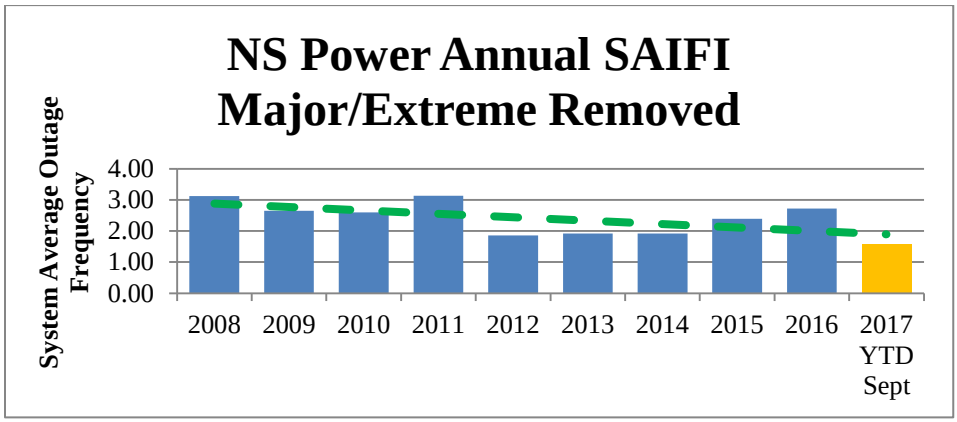
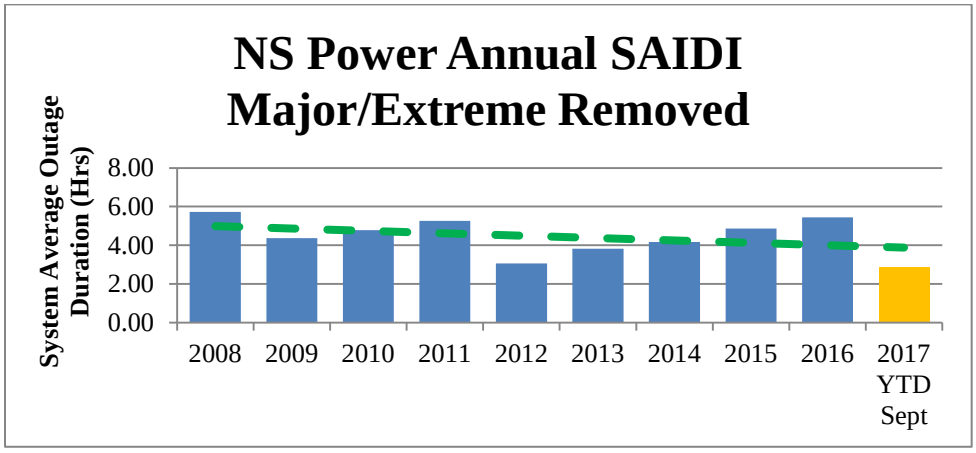


Figure 74: NS Power Annual SAIDI (Major/Extreme Events Excluded)



Figures 75 and 76 below represent NS Power's reliability statistics with Major and Extreme Events included.

Figure 75: NS Power Annual SAIFI (Major and Extreme Events Included)

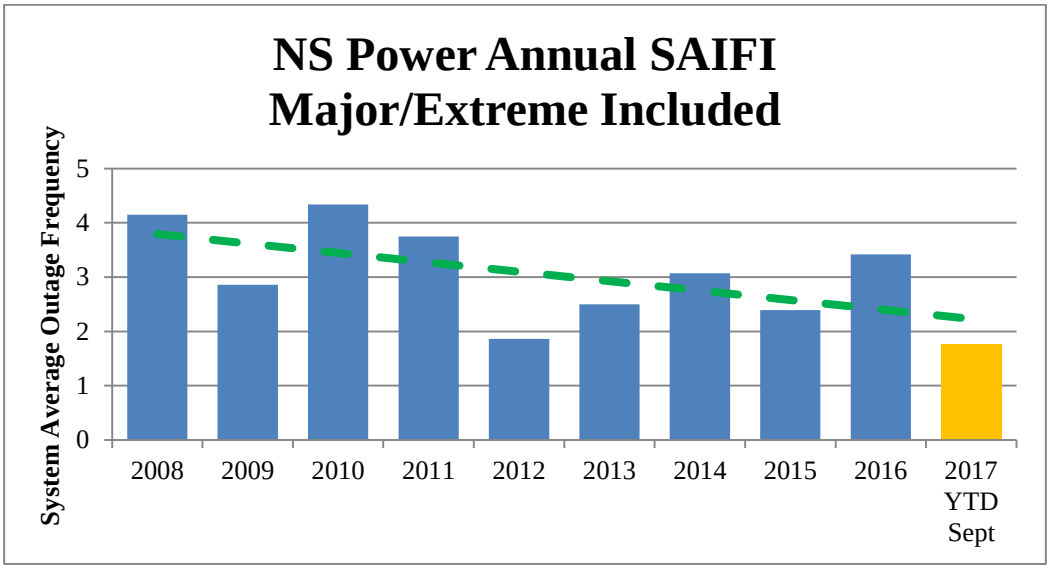
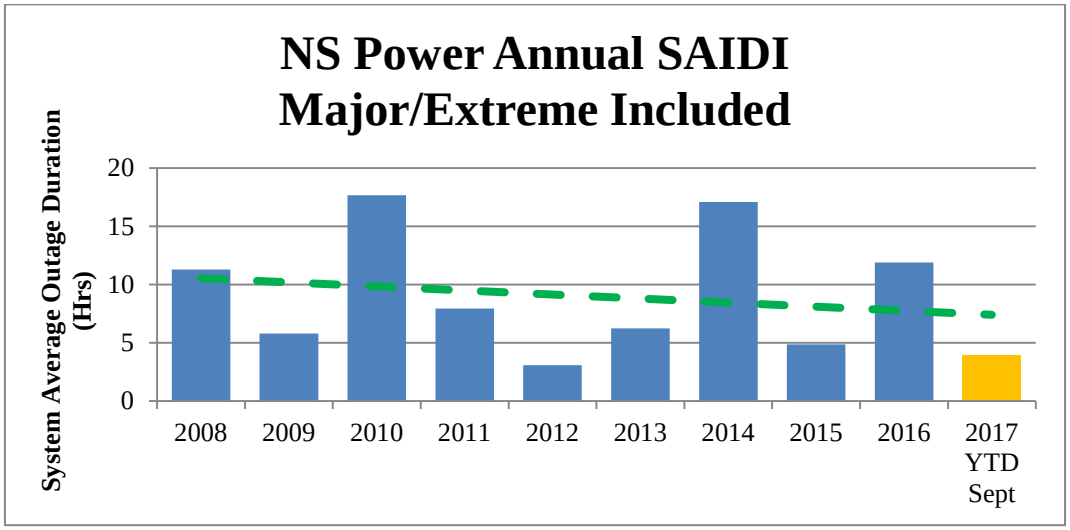


Figure 76: NS Power Annual SAIDI (Major and Extreme Events Included)



Outage Causes

Historically, two of the leading causes of NS Power customer outages for all days (storm and non-storm) are Defective Equipment and Tree Contacts. These outage causes and NS Power's associated investments are described in more detail below.

Defective Equipment

Figures 77 and **78** below show the reliability gains realized through upgrades and replacements of targeted distribution equipment resulting from the Reliability Investment Strategy. There has been an improvement in both customer interruptions and customer hours of interruption due to defective equipment.

The increased customer interruptions for 2016 is a result of a number of failures of a particular type of in-line disconnect switches in Metro Halifax. These resulted in high customer interruptions but short duration outages; as shown in the second chart, customer hours of interruptions in 2016 increased proportionally less, with in-line disconnects

representing 5.68 percent of defective equipment customer hours of interruption. Planned replacement of these devices to address reliabilty concerns continues.

Figure 77: Annual Defective Equipment – Customer Interruptions

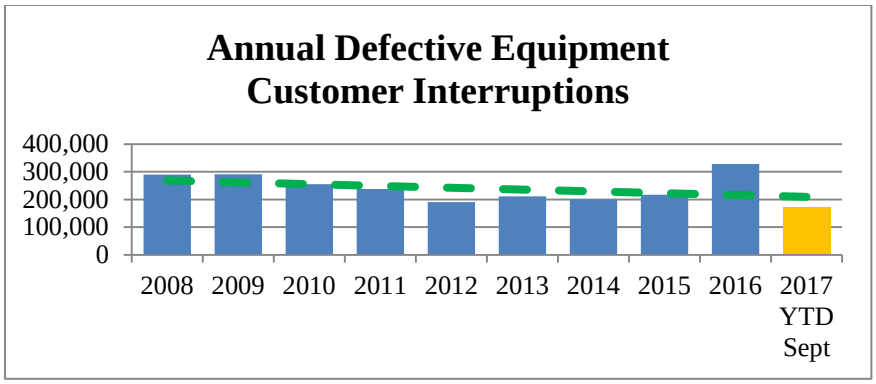
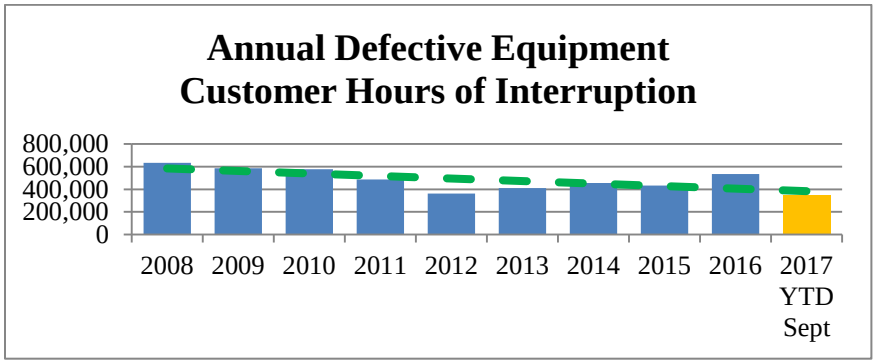


Figure 78: Annual Defective Equipment – Customer Hours of Interruption



Taking a further look into the 2016 reliability data, defective equipment outages can be classified by device type. This is shown in **Figure 79** below.

Figure 79: Customer Hours of Interruption

Customer Hours of Interruption		
Device Type	**2016**	**% of Hours**
Pin Insulator	127,005	23.71%
Primary Aerial Conductor	60,949	11.38%
Cutout	44,899	8.38%
U/G Primary Cable	31,767	5.93%
Inline Disconnect	30,424	5.68%
Wood Pole	21,890	4.09%
Polemount TX	21,014	3.92%
Lead	20,826	3.89%
Tie Wire	19,284	3.60%
Jumper	17,912	3.34%

All Distribution capital projects and Routines that replace deteriorated equipment will sustain system reliability and address the device failures referenced in the table above. The scope of the following capital projects also include elements that will result in improved reliability by improving outage response:

- CI 52185 - 50N-410 Rebuild Phase 2
- CI 52221 - 515S-311 Rebuild on Aliant Poles
- CI 52205 - 30N-412 Fundy Shore Rebuild

Tree Contacts

Tree Contacts are the largest source of outage hours for NS Power's customers. **Figures 80** and **81** below show both customer interruptions and customer hours of interruption due to tree contacts under normal and severe weather conditions.

Figure 80: Annual Tree Contact – Customer Interruptions

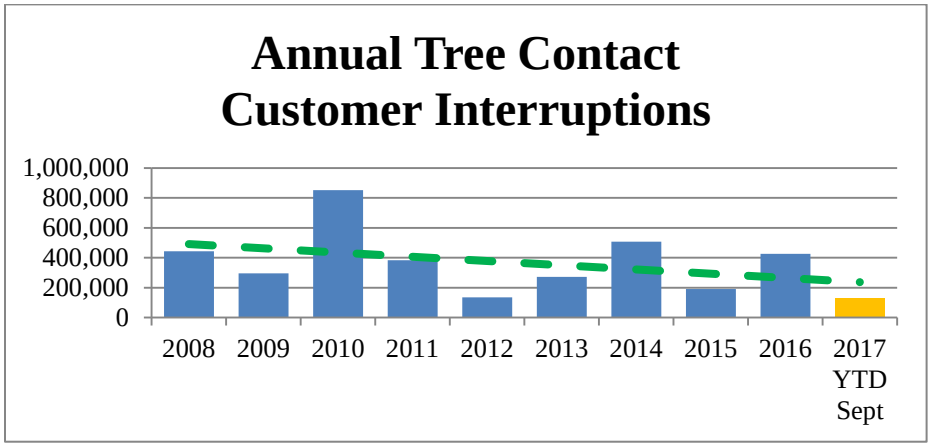
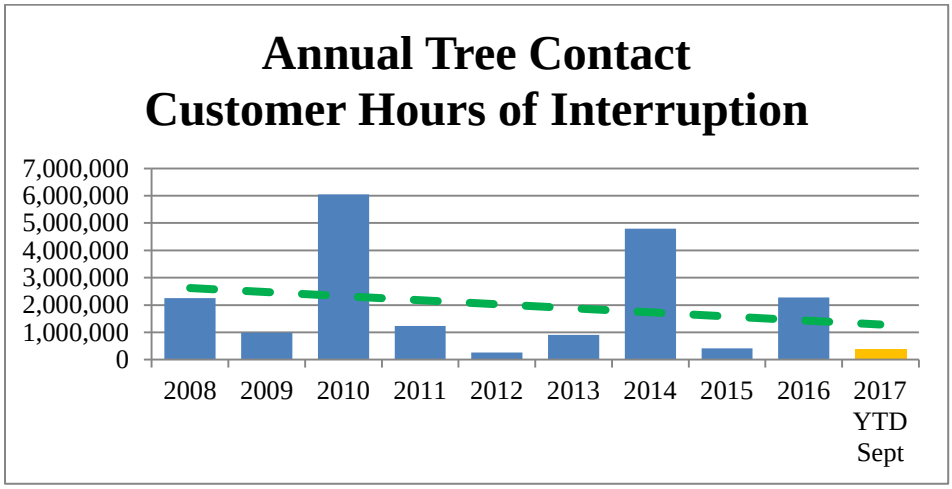


Figure 81: Annual Tree Contact – Customer Hours of Interruption



Figures 82 and **83** below show the data normalized with Major and Extreme Events removed. With these events removed, the data demonstrates the vegetative effects of major storms and their impact for months following the extreme event. There were 2 Extreme and 3 Major Event Days in 2016, and from January to September 2017 there have been 2 Major Event Days.

Figure 82: Annual Tree Contact – Customer Interruptions (Major/Extreme Events Removed)

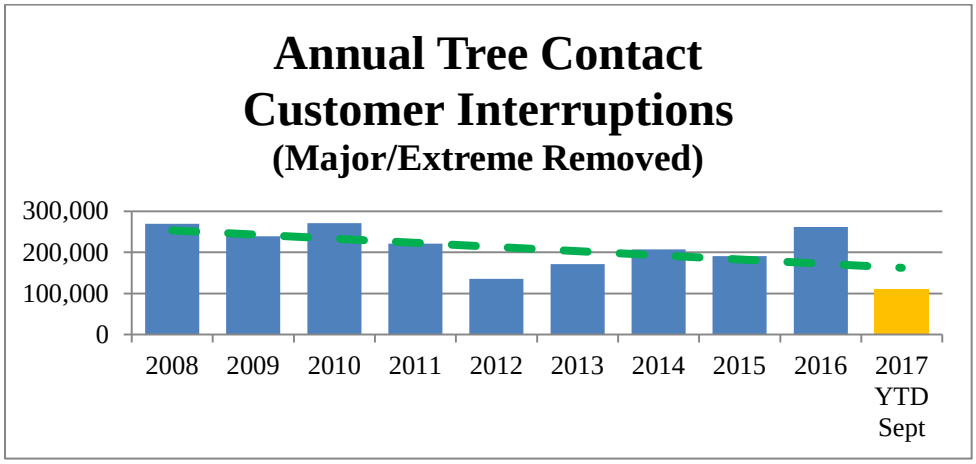
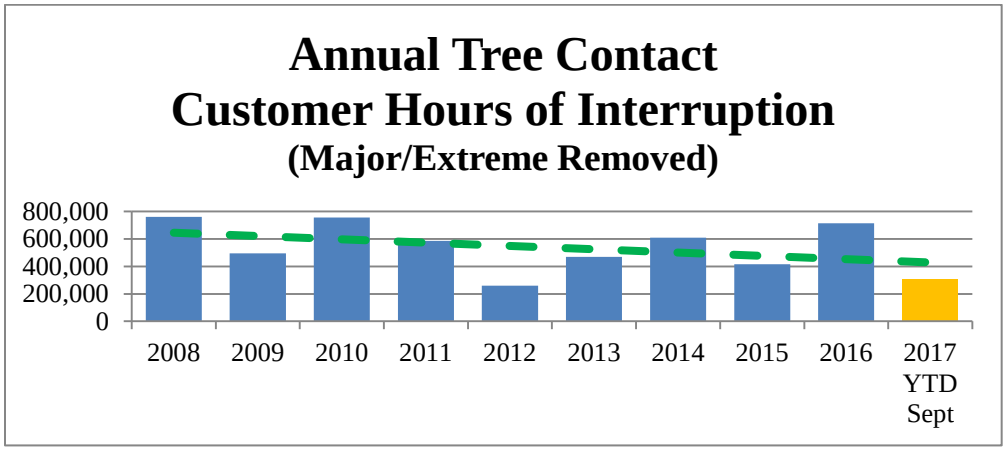


Figure 83: Annual Tree Contact – Customer Hours of Interruption (Major/Extreme Events Removed)



In a continued effort to minimize storm effects and overall reliability, NS Power has proposed the following spending in 2018 for Transmission and Distribution vegetation management. These targeted investments for managing vegetation aim to minimize outage frequency and duration, while seeking to improve access to the system.

- CI 50796 – New Distribution Rights-of-Way Phase II

- CI 51969 – 2018 Transmission Right-of-Way Widening 69kV
- D010 Distribution Right of Way Routine
- T010 Transmission Right of Way Routine

Update on storm performance and related capital investments

The effect of storms and storm response varies storm-to-storm and year-to-year. The wind speeds, rainfalls, time of year, time of day and weather forecast accuracy all contribute to a storm's impact.

NS Power uses the 2.5 Beta Method (IEEE-3366 Standard) to classify Major Event Days. The same methodology is applied to further classify storms for Storm Days (2.0 Beta) and Extreme Event Days (3.5 Beta).

As of August 31, 2017, NS Power experienced 4 storm days, and 2 major event days.

NS Power has the following capital programs for storm response and reactive work for 2018:

- D008 – Provincial Storm Distribution
- T001 – Transmission Line Unplanned

As noted above, NS Power continues to invest on vegetation management. These investments aim to minimize tree contact and maximize access to our Transmission and Distribution systems as provided for in routines T010 and D010, as well as capital work orders CI 51969 and CI 50796.

2017 Storm Performance vs. Previous Years

Figures 84 to 89 below show the count of the previously identified storm classifications, and their SAIFI and SAIDI contributions annually. They outline the frequency and impact of storm days to customers.

Figure 84: Count of Annual Storm Days

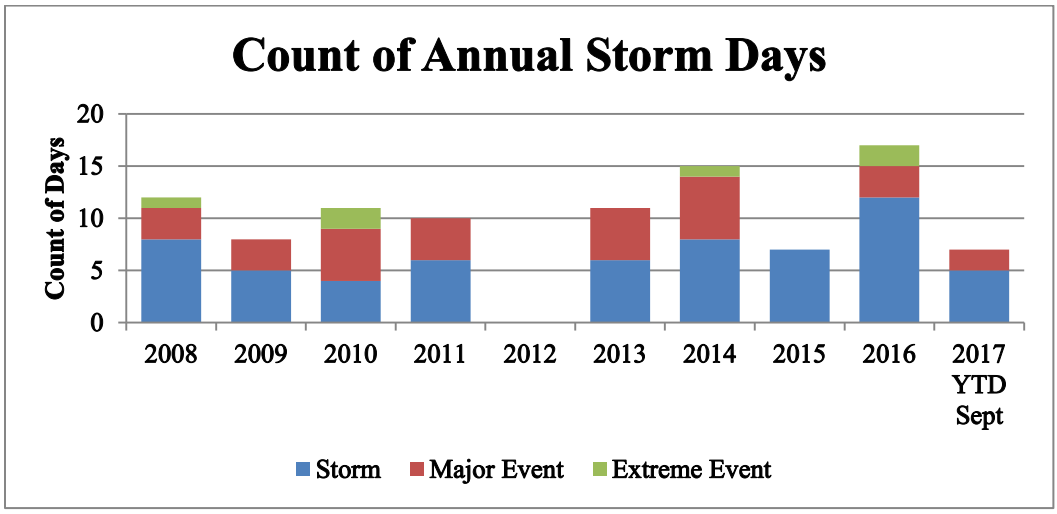


Figure 85: Count of Annual Storm Days – Sept YTD

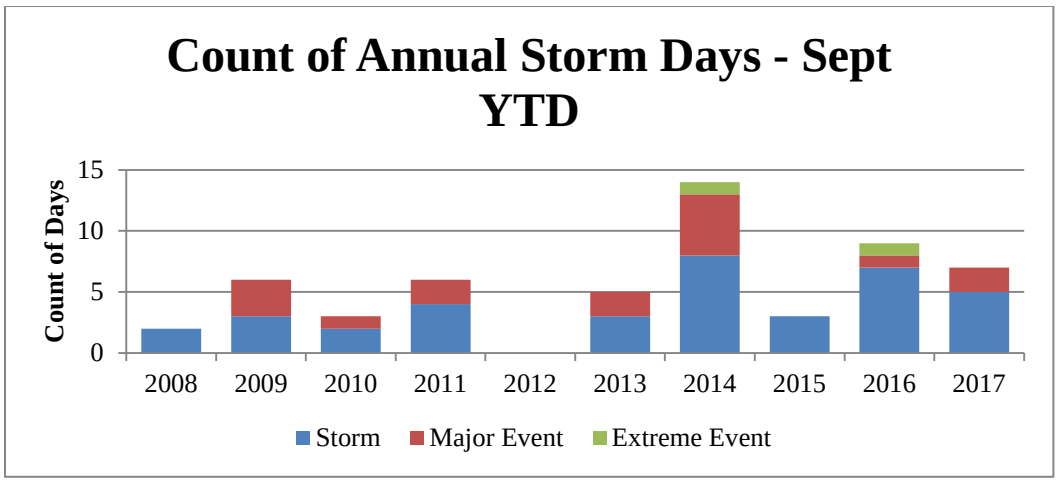


Figure 86: SAIFI- Storm Contribution

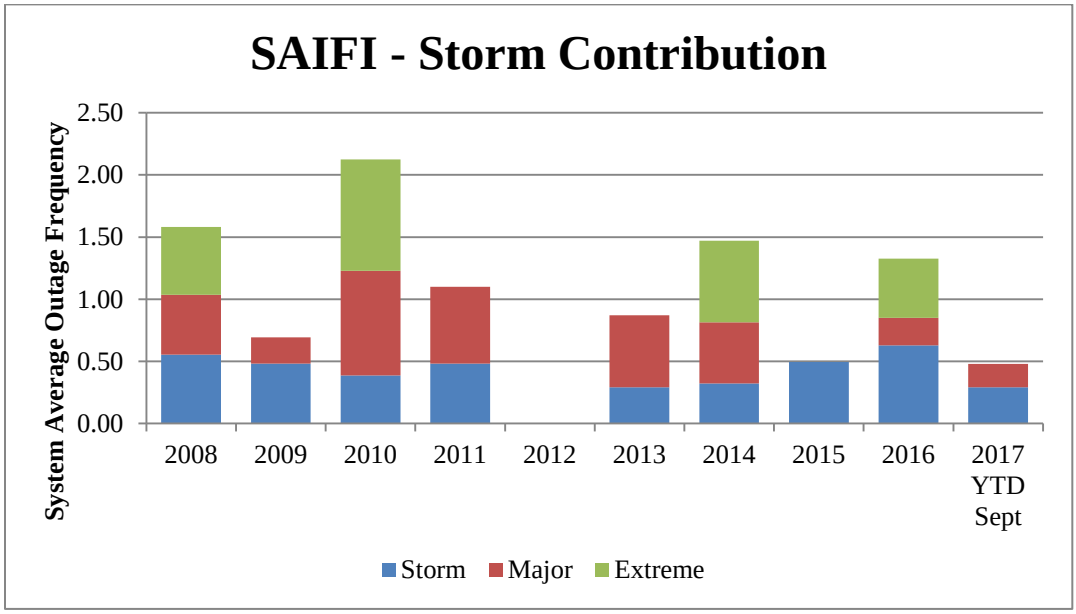


Figure 87: SAIFI Storm Contribution – Sept YTD

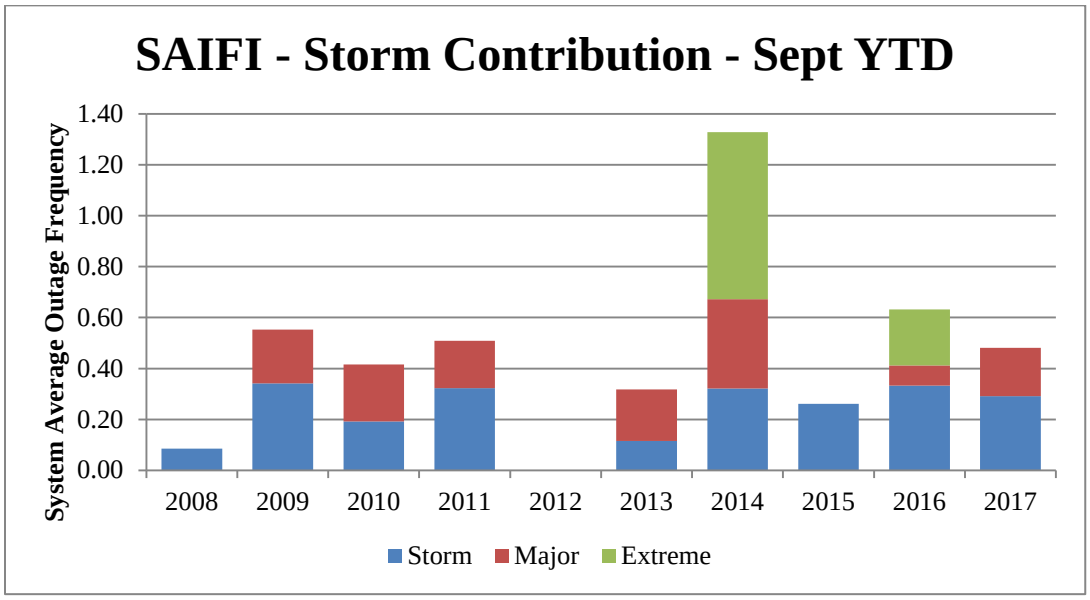


Figure 88: SAIDI – Storm Contribution

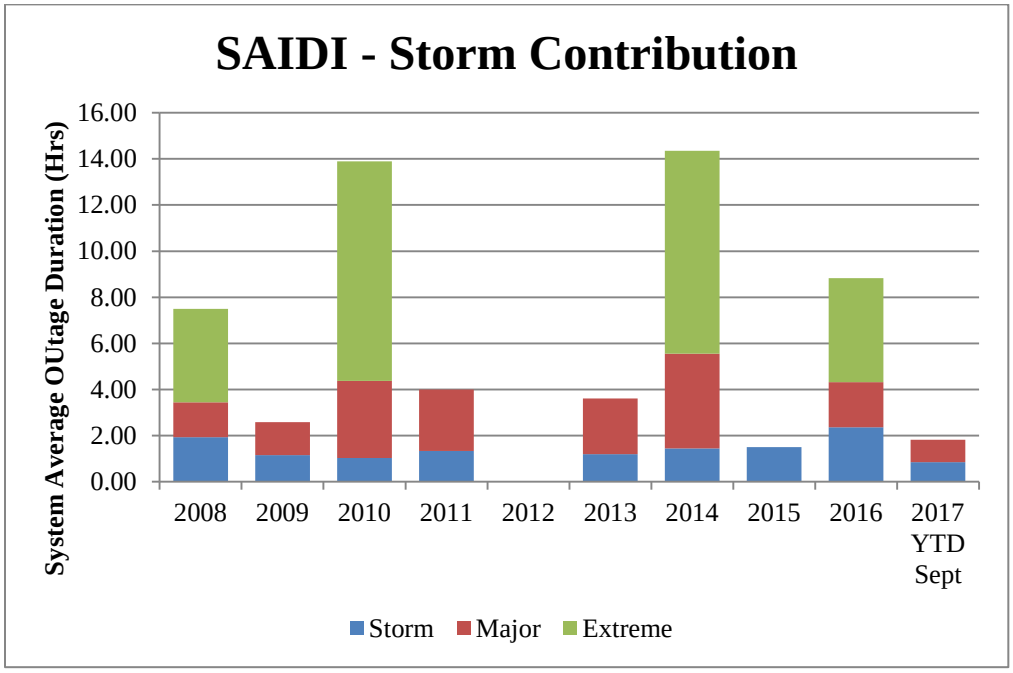
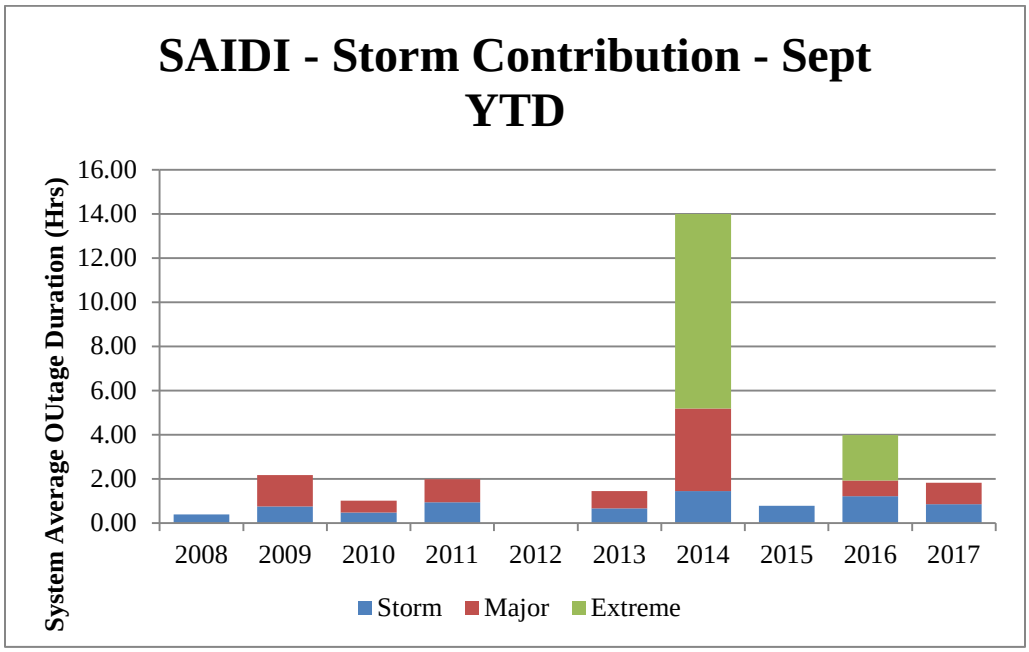


Figure 89: SAIDI Storm Contribution – Sept YTD



Note: 2012 experienced no severe weather days.

Figure 90 below provides detail on outage causes for the 6 severe weather days experienced so far in 2017.

Figure 90: Detail on Outage Causes for Severe Weather Days

		Storm	Major	Extreme	
CEA Cause Code	**Description**	**Hours of Interruption**	**Hours of Interruption**	**Hours of Interruption**	**% of Hours**
0	Unknown/Other	8,277	19,316	0	3%
1	Scheduled Outage	5,368	1,881	0	1%
2	Loss of Supply	44,455	55,296	0	12%
3	Tree Contacts	125,984	96,112	0	26%
4	Lightning	0	0	0	0%
5	Damaged Equipment	42,153	57,376	0	12%
6	Adverse Weather	121,619	213,902	0	39%
7	Adverse Environment	1,332	51,928	0	6%
8	Human Element	0	0	0	0%
9	Foreign Interference	2,058	2,471	0	1%
	Total	351,246	498,281	**0**	

26 percent of storm outages year to date in 2017 have been caused by tree contacts. While NS Power always strives to minimize tree caused outages, the importance is further stressed in storm conditions. Continued investment for vegetation management and right-of-way widening will help minimize these outages in all weather conditions.

The following capital projects are identified to address vegetation management and right-of-way widening for 2018:

- CI 50796 – New Distribution Rights-of-Way Phase II
- CI 51969 – 2018 Transmission Right-of-Way Widening 69kV
- D010 Distribution Right of Way Routine
- T010 Transmission Right of Way Routine

T010 and D010 Report

In the 2016 ACE Plan Order, the UARB directed as follows:

> The Board approves the 2016 Routine capital expenditures, with the exception of the Distribution ROW widening (D010) which is reduced to $600,000. The Board directs that the Routine for Transmission widening be treated as a separate project, and not a routine, in future ACE Plan Applications. NSPI is to provide an annual progress report on the expenditure, works undertaken, results achieved and future plans as part of the annual ACE Plan submissions.[41]

In accordance with the Board's directive, NS Power provides its progress report on D010 and T010 below as of September 30, 2017.

In its 2017 ACE Plan Order, the Board directed as follows:

> The Board directs NSPI to update the cost estimates for vegetation management and right-of-way widening projects in the 2018 ACE Plan (and future years) based on actual historical costs incurred for this project.[42]

NS Power confirms that the cost estimates for vegetation management and right-of-way widening projects in the 2018 ACE Plan are based on actual historical costs incurred.

[41] 2016 ACE Plan, UARB Order, M07176, June 8, 2016.
[42] 2017 ACE Plan, UARB Order, M07745, April 4, 2017.

Expenditures, Works Undertaken, and Results

The following progress was made on 69kV Transmission Widening under T010:

- 90 percent of planned work has been completed as of September 30, 2017
- 100 percent completion is forecasted for year end 2017
- Forecast year end spend is approximately $5,386,623
- Three substitutions have been made from the original plan, due to revised priorities:
    - L-5550 replaced with L-5532;
    - L-5055 replaced with L-5535;
    - L-5521 and L-5037 replaced with L-5533
    - L-5025 replaced with L-5029
- Savings in easement acquisition costs allowed for the additional completion of L-5500

The following progress was made on >69kV Transmission Widening under T010:

- 85 percent of planned work has been completed as of September 30, 2017
- 100 percent completion is forecast for year end 2017
- Forecast year end spend is approximately $576,292
- One substitution was made from the original plan, due to revised priorities:
    - L-6001 was replaced with L-6054

The following progress was made on Distribution Widening under D010:

- 95 percent of planned work has been completed
- Forecast year end spend is approximately $600,000

- Completed areas include:

  - 50N-410 Frasers Mountain, Magrath's Mountain and Brown Mills Road
  - 5N-301 Londonderry
  - 81N-412 Debert
  - 7N-302G/4N-311 Wentworth (Fountain Road) currently in progress

- Substitutions have been made from the original plan, due to revised priorities, including:

  - 62N-412 Park Falls Road
  - 77V-302 Acacia Valley Road
  - 57W-402 West Caledonia

Plans for Replacement of Aging T&D Equipment & Storm Performance

The 2015 ACE Plan Terms of Consensus included two commitments with respect to reliability:

> (4) As part of the reliability directive in future ACE Plans, NS Power will provide additional information regarding its plans for replacement of aging transmission and distribution equipment in accordance with the following recommendation on this matter made by the SBA's consultant, Mary Neal, at page 12 of her evidence in this proceeding dated January 16, 2015:
>
> "I recommend NSPI provide more information regarding its plans for replacement of aging transmission and distribution equipment to better show how it justified the target investments. This should include (where possible):
>
> - Descriptions of assets to be replaced and their ages,
> - Goals for strategic replacement programs, such as targets for age profiles of different asset classes,

- Expected improvements in asset age profiles due to each ACE Plan project involving replacement of transmission and distribution equipment considered at end-of-life,
- More detailed descriptions of how NSPI targets specific assets every year, whether based on age, performance degradation, or other factors, and
- Any recent, relevant inspection data"

(5) As part of the reliability directive in future ACE Plans, NS Power will provide an update on its storm performance and related capital investment strategies to improve storm performance.[43]

The Terms of Consensus were approved by the UARB on May 5, 2015. These are addressed below.

Plans for Replacement of Aging Transmission and Distribution Equipment

The multi-year Reliability Investment Strategy has resulted in a step-change towards improved reliability for NS Power customers. NS Power continually monitors outages and performance of transmission, substation and distribution assets, and future investments will continue at an appropriate level to ensure affordable and reliable service. To sustain these reliability performance improvements, NS Power follows its asset management principles to prioritize investments in T&D plant in accordance with Section 6.2 of the CEJC. The project ranking methodology found therein determines condition and criticality to rank projects for the replacement and refurbishment of T&D assets. This reduces the overall risk for the asset class.

Annual estimated replacement targets developed based on asset age profiles, and the Iowa Survivor curves for equipment failure are used to reduce the overall risk for each asset class. While the suitable investments for a specific asset class may vary from year to year depending on system performance, the estimated replacements analysis provides a

[43] 2015 ACE Plan, Terms of Consensus, M06514, February 18, 2015, page 2 of 5.

working range in which to evaluate the appropriateness of proposed sustaining capital investments.

NS Power uses a variety of factors to determine the specific assets targeted for replacement as part of the annual capital investment program. Generally, targeted assets have experienced degradation in performance manifesting in decreased reliability, increased maintenance frequency and cost, or reduced functionality. These effects are identified through reliability tracking, field inspections, and test results of the impacted assets. Criticality of the asset to continued operations of the NS Power system and any risks posed to people and the environment contribute to determining specific assets for replacement.

Asset age is a concern when the frequency of required maintenance is increased, the availability of replacement parts or critical spares is limited, or performance is negatively impacted. This information can be used to inform project prioritization. However, age profiles are used in concert with asset condition, performance, and legislated requirements; it is never the single determining element in an investment decision. Capital project justifications outline the reasoning behind a given replacement program considering all relevant elements.

In 2014, NS Power embarked on further formalizing the identification and prioritization of assets for replacement by creating a regimented framework to determine the condition, criticality, and risk individual assets within a given class pose to the NS Power system. While the risk score of an asset does not determine its suitability for replacement alone, it can aid in identifying assets requiring more detailed investigation by technical experts and subsequent risk mitigation activities.

The target ranges for T&D assets covered by this analysis is provided in **Figure 91** below.

Figure 91: Target Ranges for T&D Assets

	High Band Replacements	Low Band Replacements			
Asset Classification	**Quantity on Grid**	**Estimated Useful Life**	**Annual Replacements**	**Estimated Useful Life**	**Annual Replacements**
Distribution Conductor (km)	42,830	45	952	55	779
Distribution Structure	350,168	50	7,003	60	5,836
Pole Top Transformer	123,942	35	3,541	45	2,754
Underground Conductor (km)	784	45	17	55	14
Padmount Transformers	4,187	35	120	45	93
Transmission Conductor (km)	5,140	55	93	65	80
Transmission Structure	30,685	55	558	65	471
Substation Breakers	548	45	12	55	10
Substation Transformer	315	50	6	60	5

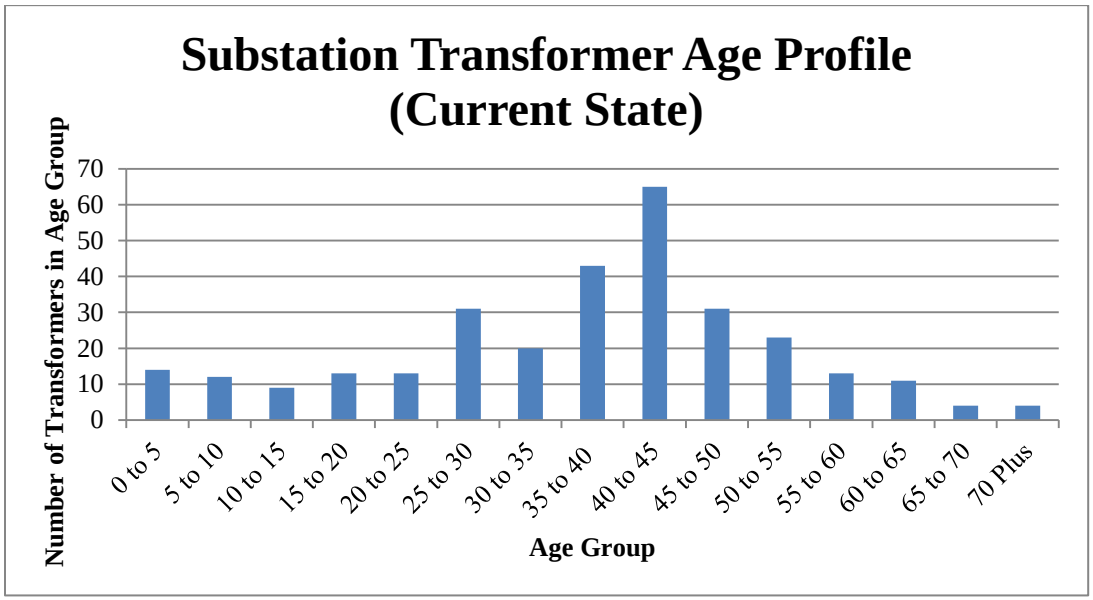
Age demographics information is presently not available for all transmission and distribution asset classes. Substation Transformers, Substation Breakers, Transmission Conductor, Downline Reclosers and Padmount Transformers are asset classes for which this information is available at this time. As asset information improves for individual asset classes, their age profiles provide a more complete picture of the current state across the T&D system.

As T&D equipment reaches end-of-life, capital investments are used to mitigate impacts related to aging infrastructure. Over time this will result in an overall positive shift in age profile towards a younger equipment fleet.

Substation Transformers

Figure 92 below shows the substation transformer age profile (current state).

Figure 92: Substation Transformers Age Profile (Current State)



- Expected useful life of 50-60 years depending on the transformer type, loading, and environmental conditions.

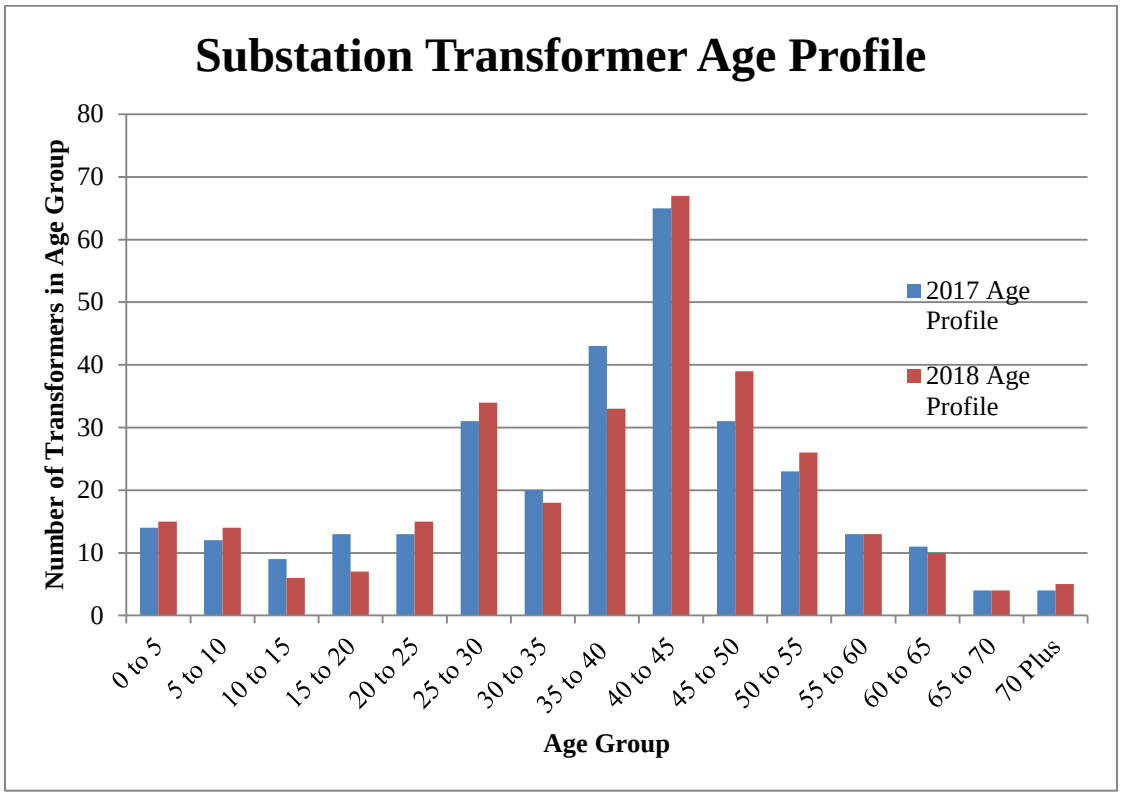
- Age Demographics – 18 percent of Transformers are beyond 50 years of service.

- Targeted number of replacements – 5 to 6 units per year.

- Changes to age demographics – As a result of the proposed 2018 capital investments in substation transformers, the age profile for this asset class will experience an increase of 1 percent in assets beyond 50 years of age. Age is only one of multiple factors in determining targeted assets in a given year. However, it is expected that over time an overall positive shift in age profile towards a

younger equipment fleet will occur. To support mitigation of risk associated with this asset class, continuation of the strategic transformer spares program and mobile substation program is planned. Proactive transformer replacements in future years will again focus on the overall condition of each unit and system criticality. **Figure 93** illustrates the overall change in asset age profile for Substation Transformers between 2017 and 2018.

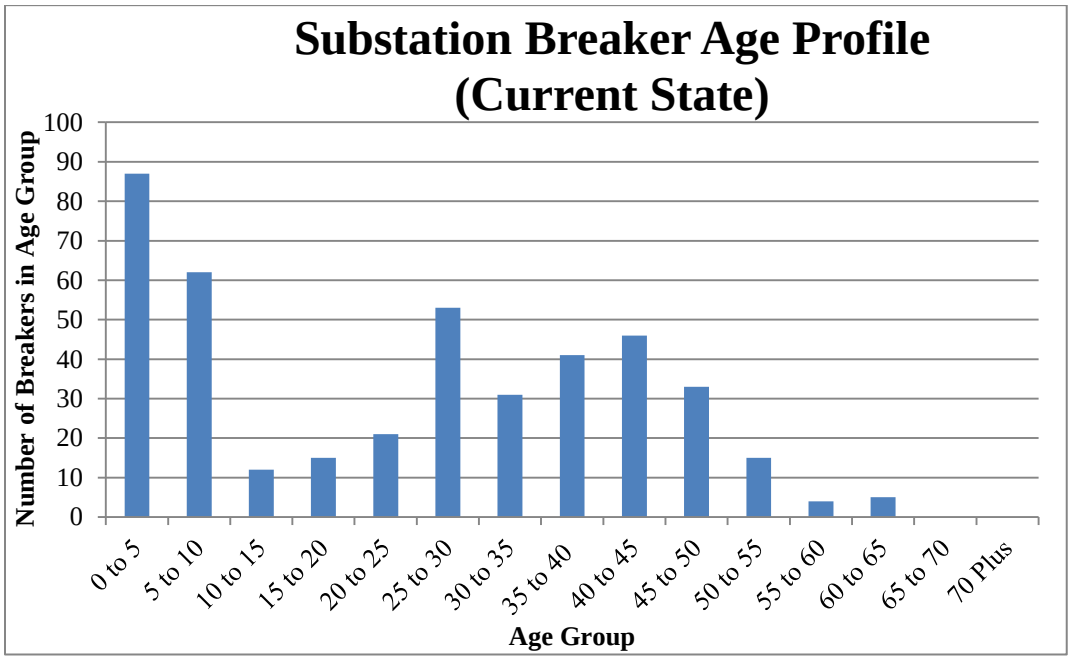
Figure 93: Substation Transformer Age Profile



Substation Breakers

Figure 94 below shows the substation breaker age profile (current state).

Figure 94: Substation Breakers Age Profile (Current State)



- Expected useful life of 45-55 years depending on the breaker type, operations count, and environmental conditions.

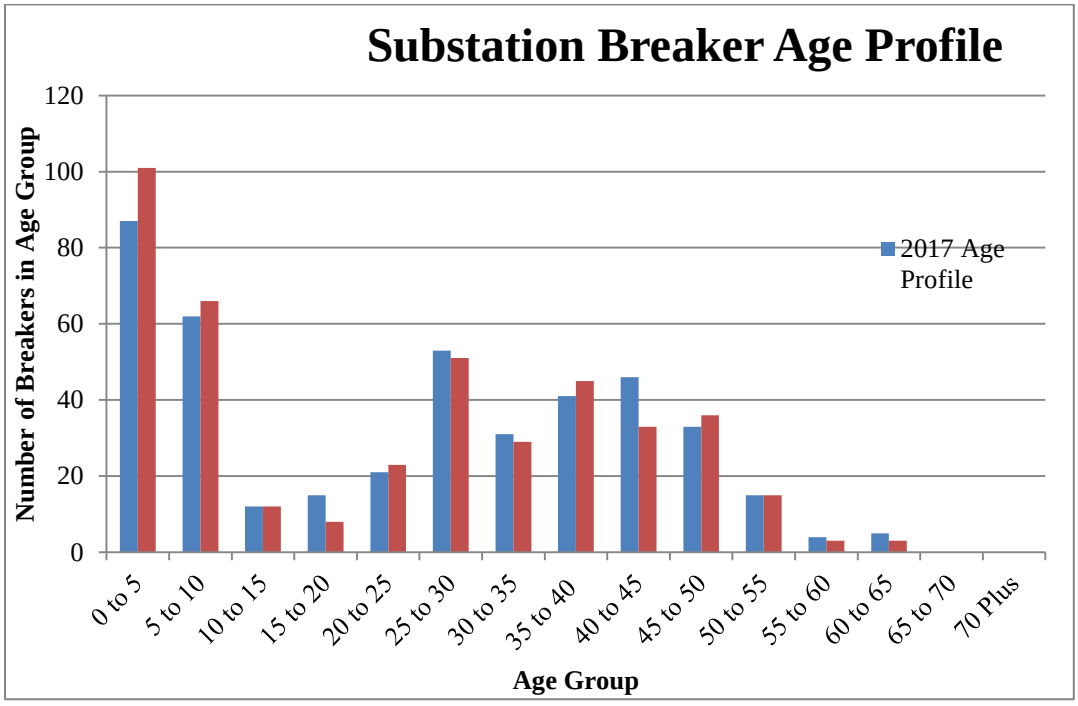
- Age Demographics – 13 percent of breakers are beyond 45 years of service.

- Targeted number of replacements – 10-12 units per year.

- Changes to age demographics – As a result of the proposed capital investments in Substation Breakers during 2018, the age profile for this asset class will maintain approximately the same percentage of assets beyond 45 years of age. Age is only one of multiple factors in determining targeted assets in a given year. However, it

is expected that over time an overall positive shift in age profile towards a younger equipment fleet will occur. To support mitigation of risk associated with this asset class, continuation of the strategic breaker spares program is planned. **Figure 95** illustrates the overall change in asset age profile for Substation Breakers between 2017 and 2018.

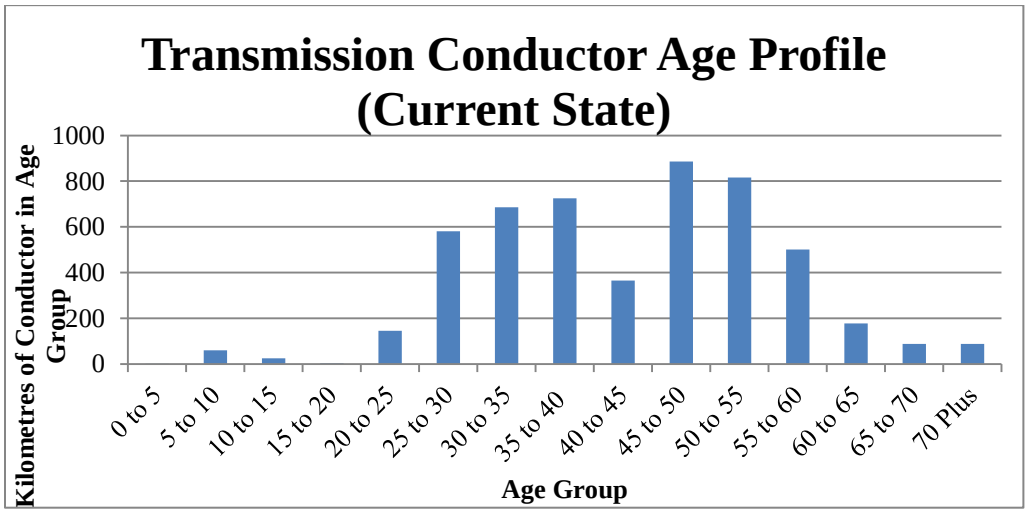
Figure 95: Substation Breaker Age Profile



Transmission Conductor

Figure 96 below shows the transmission conductor age profile (current state).

Figure 96: Transmission Conductor Age Profile (Current State)



- Expected useful life of 55-65 years depending on the conductor design and environmental conditions.

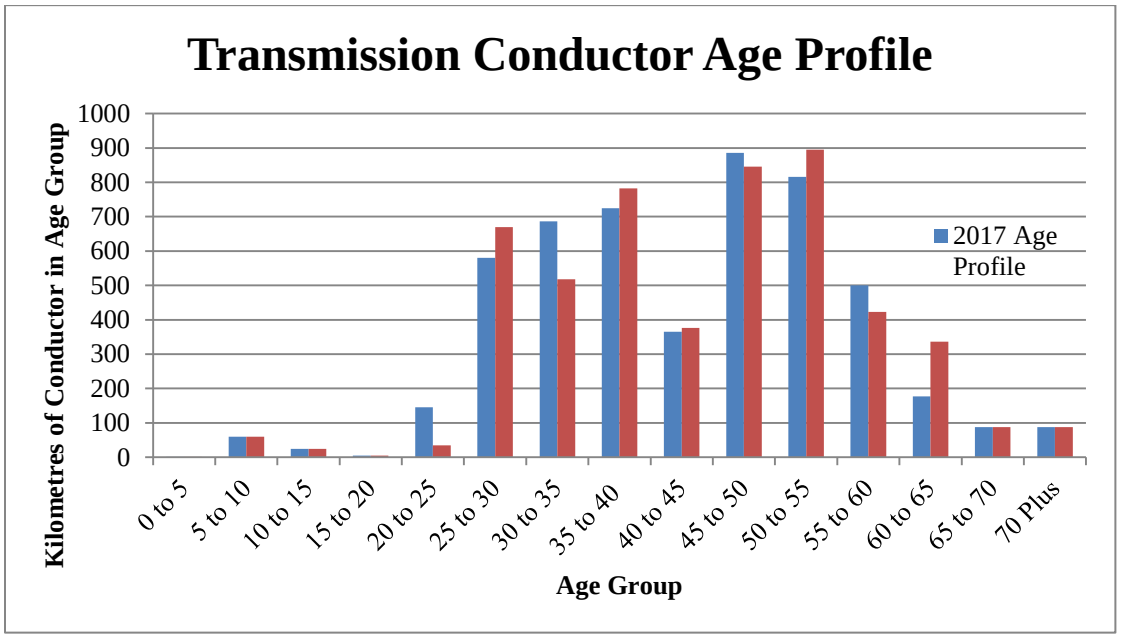
- Age Demographics – 16.6 percent of conductor is beyond 55 years of service.

- Targeted number of replacements – 79 to 93 km per year.

- Changes to age demographics – As a result of proposed capital investments in transmission conductor in 2018, the age profile for this asset class will experience an approximately 1.5 percent increase in assets beyond 55 years of age. Age is only one of multiple factors in determining targeted assets in a given year. However, it is expected that over time an overall positive shift in age profile towards a younger equipment fleet will occur. In order to help mitigate risks associated with transmission conduction, innovative testing of conductor over 60

years old is taking place to further assess condition as required. **Figure 97** illustrates the overall change in asset age profile for Transmission Conductor between 2017 and 2018.

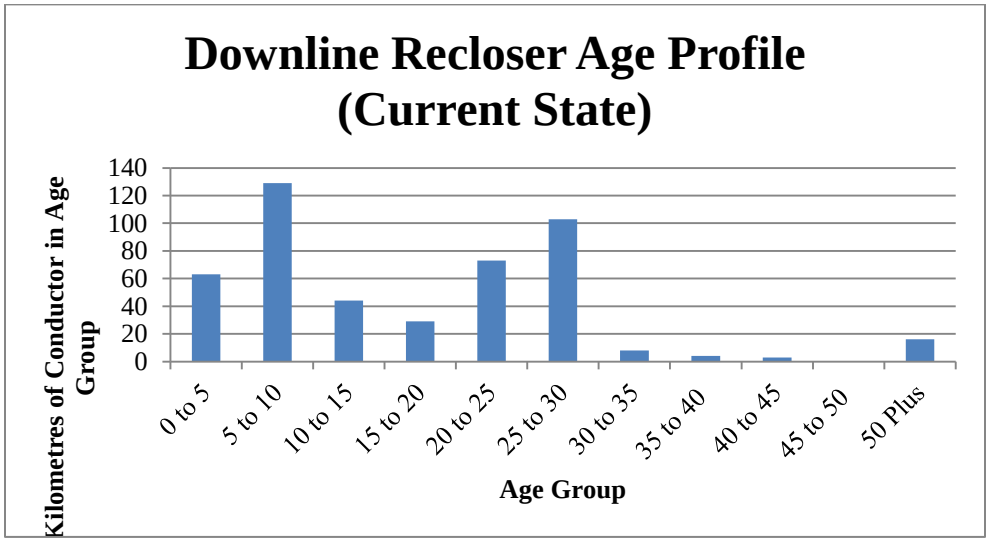
Figure 97: Transmission Conductor Age Profile



Downline Reclosers

Figure 98 below shows the downline reclosers age profile (current state).

Figure 98: Downline Reclosers Age Profile (Current State)



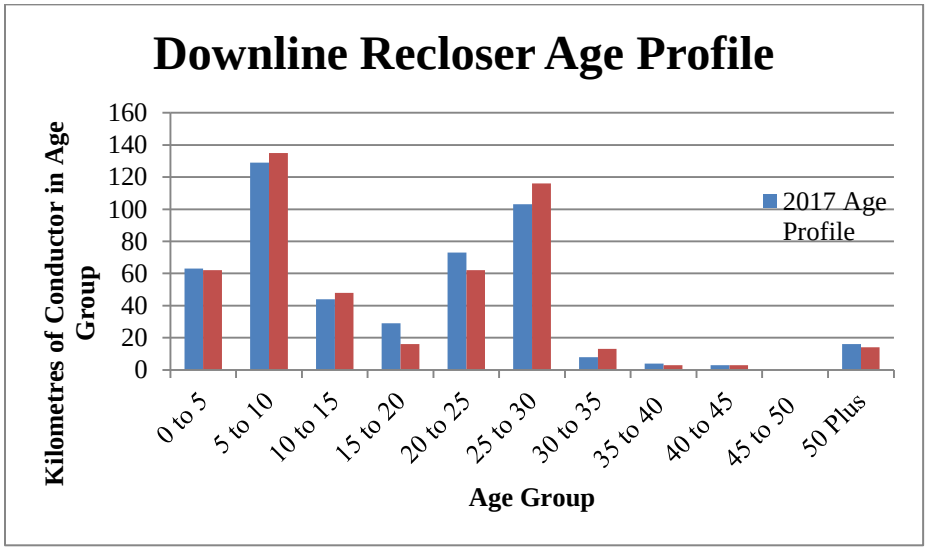
- Expected useful life of 30-40 years depending on the downline recloser design, loading, and environmental conditions.

- Age Demographics – 6.6 percent of Downline Reclosers are beyond 30 years of service.

- Targeted number of replacements – 16 to 21 units per year.

- Changes to age demographics – As a result of the proposed capital investments in Downline Reclosers during 2018, the age profile for this asset class will experience an approximately 0.5 percent increase in assets beyond 30 years of age. Age is only one of multiple factors in determining targeted assets in a given year. However, it is expected that over time an overall positive shift in age profile towards a younger equipment fleet will occur. To support mitigation of risk associated with this asset class, continuation of the strategic transformer Downline Recloser spares program is planned. **Figure 99** below illustrates the overall change in asset age profile for Downline Reclosers between 2017 and 2018.

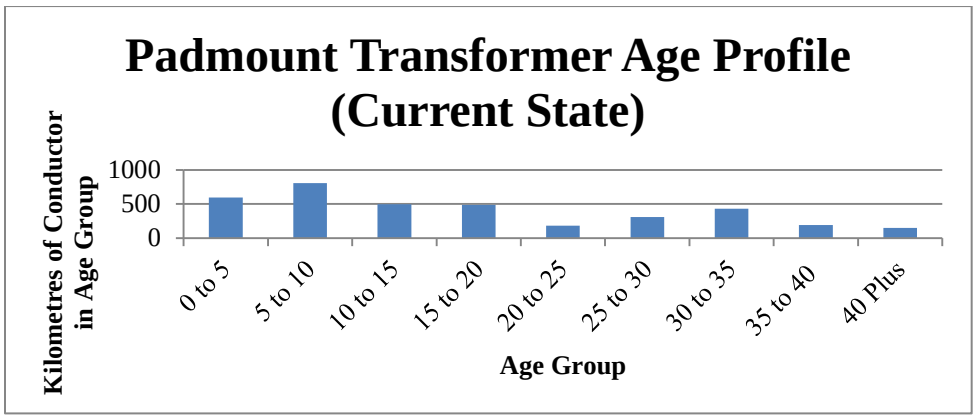
Figure 99: Downline Recloser Age Profile



Padmount Transformers

Figure 100 below shows the Padmount Transformer age profile (current state).

Figure 100: Padmount Transformers Age Profile (Current State)



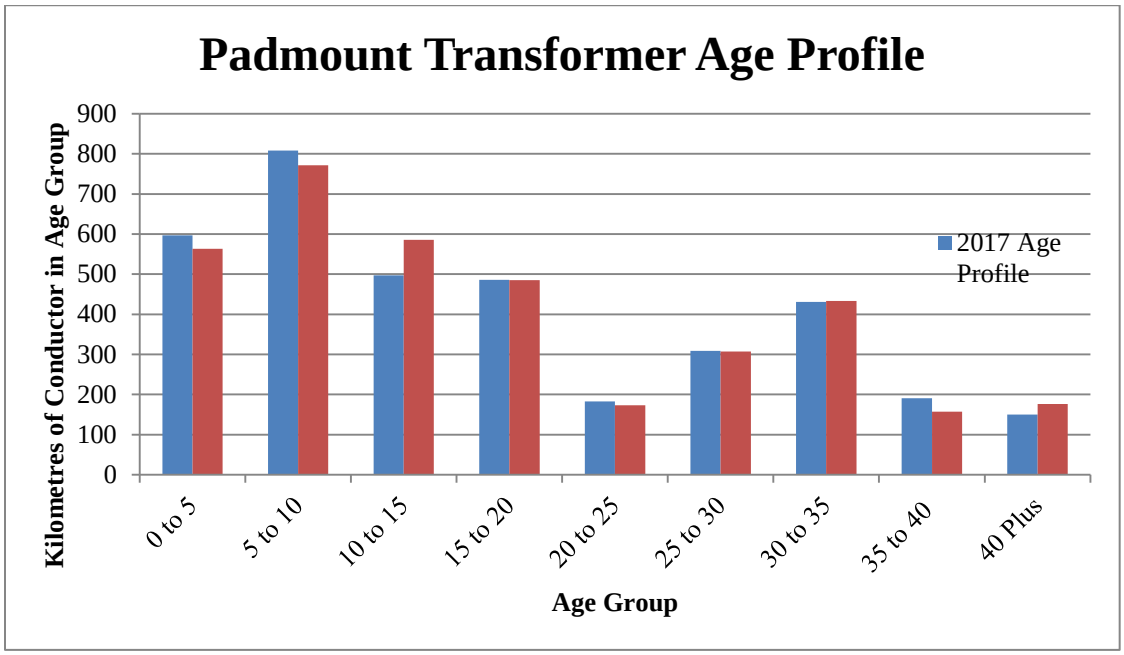
- Expected useful life of 35-45 years depending on the padmount design, loading, and environmental conditions.

- Age Demographics – 9.34 percent of padmounts are beyond 35 years of service.

- Targeted number of replacements – 93 to 120 units per year.

- Changes to age demographics – As a result of the proposed capital investments in Padmount Transformers during 2018, the age profile for this asset class will experience an approximately 0.2 percent reduction in assets beyond 35 years of age. **Figure 101** below illustrates the overall change in asset age profile for Padmount Transformers between 2017 and 2018.

Figure 101: Padmount Transformer Age Profile



10.2 2018 Capital Spending by Justification Criteria

Items in the 2018 ACE Plan have been developed in accordance with the CEJC. Definitions of the various criteria referenced in **Figure 102** below are included in the CEJC.

Figure 102: Capital Expenditures by Justification Criteria ($M)

Justification Criteria	2018 Budget	Projects included for Approval	Routine Spend for Approval	Less than $250K	2017 ACE Items for Filing in late 2017	Items for Subsequent Submission	Carryover	Pt. Aconi
Distribution System	75.0	16.2	44.1	1.2	0.0	0.8	12.7	0.0
Thermal	53.4	18.0	3.2	13.0	0.8	4.0	5.8	8.6
Work Support	53.4	0.6	19.0	1.9	0.1	20.5	11.3	0.0
Hydro	14.1	5.2	1.8	0.6	0.0	2.3	4.2	0.0
Health and Safety	43.1	24.2	0.0	0.7	0.0	1.3	16.8	0.0
Transmission Plant	72.9	24.2	11.5	0.2	0.0	0.0	37.0	0.0
Environmental	11.1	3.7	0.7	0.2	0.0	0.8	3.7	2.0
Metering Equipment	31.9	0.0	3.6	0.0	0.0	0.0	28.3	0.0
System Design	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Facilities/Land and Right-of-Way	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0
Total	**$354.9**	**$92.0**	**$83.9**	**$17.9**	**$0.9**	**$29.8**	**$119.8**	**$10.6**

Note: Details of justification sub-criteria are provided on the following section.
Note: Figures presented may include $0.1M in rounding differences on some line items

10.3 2018 Capital Spending by Justification Sub-Criteria

Figure 103 below provides 2018 capital spending by justification sub-criteria.

Figure 103: 2018 Capital Spending by Justification Sub-Criteria($M)

Justification Sub-Criteria	2018 Budget	Projects included for Approval	Routine Spend	Less than $250K	2017 ACE Items for Filing in late 2017	Items for Subsequent Submission	Carryover
Distribution System							
Requirement to Serve	36.7	0.0	36.0	0.0	0.0	0.0	0.7
Pole Strength	7.9	0.5	7.0	0.0	0.0	0.0	0.4
Joint Use Agreement	0.5	0.0	0.5	0.0	0.0	0.0	0.0
Deteriorated Conductor	5.8	4.3	0.0	0.8	0.0	0.0	0.8
Equipment Replacement	10.5	2.8	0.0	0.2	0.0	0.8	6.8
Outage Performance	10.3	6.9	0.6	0.0	0.0	0.0	2.9
Overloaded Equipment	0.1	0.0	0.0	0.0	0.0	0.0	0.1
Capacity	2.3	1.8	0.0	0.2	0.0	0.0	0.3
Other Distribution System	0.7	0.0	0.0	0.0	0.0	0.0	0.7
Total	**$75.0**	**$16.2**	**$44.1**	**$1.2**	**$0.0**	**$0.8**	**$12.7**
Work Support Facilities							
Buildings	$5.4	$0.0	$5.3	$0.1	$0.0	$0.0	$0.0
Furniture & Fixtures	0.2	0.0	0.0	0.2	0.0	0.0	0.0
Telecommunications	5.6	0.6	0.9	0.4	0.0	0.5	3.2

Computers / IT	29.7	0.0	2.6	0.7	0.1	20.0	6.2
Tools & Equipment	1.6	0.0	1.6	0.0	0.0	0.0	0.0
Vehicles	8.6	0.0	8.6	0.0	0.0	0.0	0.0
Equipment Replacement	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other General Plant	1.4	0.0	0.0	0.6	0.0	0.0	0.8
Total	**$52.3**	**$0.6**	**$19.0**	**$1.9**	**$0.1**	**$20.5**	**$10.2**

Note: Figures presented may include $0.1M in rounding differences on some line items

10.4 Quick Reference Sheet

2018 AFUDC Rate for Capital 6.96%

In the Board's Weighted Average Cost of Capital (WACC) and Allowance for Funds Used During Construction (AFUDC) Order dated January 12, 2017, the UARB directed NS Power as follows:

1. The WACC and AFUDC rates are established at 6.96%, effective February 1, 2017;
2. NSPI is directed to file an application for approval annually, no later than November 30, of the calculation of WACC/AFUDC, unless there is a general rate application in the same year, using the principles outlined in the Board's Decision.[44]

Consistent with the Board's Order, the 2018 ACE Plan projects use the Board's approved AFUDC rate of 6.96 percent.

An application for the calculation of the updated WACC/AFUDC rate will be filed by the Company by November 30, 2017.

[44] WACC/AFUDC Application, UARB Order, M07215, January 12, 2017, page 2.

2018 O/H Rates

Generation		**Customer Operations**		**Shared Services**	
PP Regular	21.97%	Regular	88.80%	IT	29.28%
Hydro	42.69%	Contract	18.97%		
Contractor	9.71%	Vehicle	40.87%		

The engineering and environmental support of capital projects previously recovered through the Project Support O/H rate are now captured through the Customer Operations Regular and PP Regular O/H rates.

10.5 2018 Depreciation Rates

Figure 104: 2018 Depreciation Rates

	2018
Steam Production Plant	
Lingan	
Lingan 1-2	4.12%
Lingan 3-4	2.28%
Lingan – Common	4.48%
Total Lingan	3.35%
Point Aconi 1	2.27%
Point Tupper	
Point Tupper 1 (Common)	3.97%
Point Tupper 2	2.82%
Total Point Tupper	2.89%
Trenton	
Trenton 5	3.10%
Trenton 6	2.34%
Trenton – Common	0.47%
Total Trenton	2.47%
Tufts Cove	
Tufts Cove 1	4.24%
Tufts Cove 2	3.68%
Tufts Cove 3	2.33%
Tufts Cove – Common	3.44%
Total Tufts Cove	3.27%
Port Hawkesbury Biomass	2.50%
Point Tupper Marine Terminal	4.06%
International Coal Pier	2.60%
General	2.82%
Total Steam Production Plant	**2.82%**

	2018
Hydro Production Plant	
Avon	3.02%
Bear River	1.80%
Black River	2.04%
Dickie Brook	3.16%
Fall River	1.82%
Harmony	4.55%
Lequille System	2.33%
Roseway	2.29%
Mersey	2.00%
St. Margaret's	2.85%

Sheet Harbour	3.38%
Tusket	2.64%
Wreck Cove System	1.67%
Annapolis Tidal	2.32%
General	2.10%
Total Hydro Production	**2.10%**

1

	2018
Other Production - Combustion Turbines	
Burnside	2.40%
Tusket	6.42%
Victoria Junction	3.17%
Tufts Cove Unit 4	2.55%
Tufts Cove Unit 5	2.77%
Tufts Cove Unit 6	3.03%
Wind Turbines	
Pre 2009 Wind	5.52%
Post 2009 Wind	4.0%
Transmission Plant	
Land Rights - Easements	1.26%
Station Equipment	2.14%
Towers & Fixtures	1.26%
Poles & Fixtures	4.32%
Overhead Conductors & Devices	1.96%
Underground Conduit	1.53%
Underground Conductors & Devices	2.61%
Roads, Trails & Bridges	1.74%
Total Transmission Plant	**2.35%**

2

	2018
Distribution Plant	
Land Rights - Easements, Surveys & Clearing	1.56%
Structures & Improvements	5.31%
Station Equipment	1.28%
SCADA Equipment	9.68%
Remote Monitoring Equipment	10.32%
Station Equipment – Miscellaneous	12.49%
Poles, Towers & Fixtures	3.79%
Overhead Conductors & Devices	3.33%
Underground Conduit	1.51%
Underground Conductors & Devices	3.17%
Line Transformers	4.09%
Services	5.33%
Meters	6.87%

Street Lighting & Signal Systems	5.33%
Total Distribution Plant	**3.89%**

1

	2018
General Plant	
Land Rights - General Plant	1.93%
Structures & improvements	2.85%
Office Furniture & Equipment	9.26%
Office Furniture & Equip - Comp Hardware	20.00%
Office Furniture & Equip - Comp Software	10.00%
Transportation Equipment	9.55%
Stores Equipment	14.97%
Communication Equipment	4.38%
Communication Equipment - SCADA Eq	1.33%
Remote Monitoring Equipment	10.27%
Miscellaneous Equipment	5.02%
Roads, Bridges & Traps (Kelly Rock)	2.58%
Mining Equipment (Kelly Rock)	2.92%
Total General Plant	**8.16%**

10.6 Summary of Economically Justified Projects

Figure 105: Summary of Economically Justified Projects

CI	Project	Alternative	Rank as Filed	As Filed	Capital Spend Increased 10%	Avoided Expenses Reduced 10%	Deferral of 1 year	Deferral of 2 years	Deferral of 3 years	Payback	Year 0 / 2017	Year 1 / 2018	Year 2 / 2019	Year 3 / 2020	Year 4 / 2021	Year 5 / 2022	Years 6 to end of life / 2023+	Total
47684	LIN3 Boiler Refurbishment 2018	Refurbish Boiler vs Replacement Energy Costs	1	-1,934,831	-1,868,066	-1,674,583	78,332	147,277	340,422	4.24	0	(154,207)	(51,259)	(149,246)	(221,414)	(240,545)	-1,118,160	-1,934,831
49547	TRE5 5-1 BFP Refurbishment	BFP Refurbishment vs Replacement Energy Costs	1	-327,380	-295,175	-262,437	34,795	86,581	193,997	3.78	0	(67,954)	(39,095)	(83,246)	(110,958)	(115,074)	88,947	-327,380
49944	HYD - Dickie Brook Penstock Refurbishment	Penstock Refurbishment vs Replacement Energy Costs	1	-6,609,928	-6,562,660	-5,901,667	59,745	126,239	214,972	4.84	0	(116,781)	(44,419)	(57,481)	(67,039)	(76,236)	-6,247,973	-6,609,928
49946	HYD - Fourth Lake Overhaul	Unit Overhaul vs Replacement Energy Costs	1	-2,561,127	-2,475,861	-2,219,748	159,642	295,392	446,903	5.69	(2,618)	(327,748)	(115,075)	(108,395)	(99,397)	(93,039)	-1,814,856	-2,561,127
51802	TRE5 Boiler Refurbishment 2018	Boiler Refurbishment vs Replacement Energy Costs	1	-3,734,052	-3,619,376	-3,245,970	126,339	323,729	573,301	5.00	0	-224,174	-153,472	-182,682	-183,759	-164,322	-2,825,642	-3,734,052
51804	LIN3&4 ACW Duplex Strainer Replacement	Strainer Replacement vs Replacement Energy Costs	1	-347,337	-316,503	-281,769	64,912	121,897	184,452	4.82	0	-94,135	-51,080	-47,749	-37,797	-47,332	-69,245	-347,337
51805	LIN4 Boiler Refurbishment 2018	Boiler Refurbishment vs Replacement Energy Costs	1	-1,856,093	-1,789,328	-1,603,719	79,539	147,139	336,992	4.28	0	-155,414	-50,143	-146,300	-219,781	-229,080	-1,055,374	-1,856,093
51806	LIN Mill Refurbishment 2018	Mill Refurbishment vs Replacement Energy Costs	1	-1,275,403	-1,214,427	-1,086,887	148,238	314,140	528,006	3.06	0	-223,482	-151,666	-175,075	-187,509	-220,406	-317,266	-1,275,403
51815	LIN CW Pump Refurbishment 2018	CW Pump Refurbishment vs Replacement Energy Costs	1	-803,201	-753,728	-673,408	101,500	222,485	382,578	3.33	0	-133,835	-110,506	-131,618	-132,363	-181,511	-113,367	-803,201
51821	TRE5 Air Heater Refurbishment	Air Heater Refurbishment vs Replacement Energy Costs	1	-2,693,655	-2,648,113	-2,378,747	217,302	426,460	715,353	1.84	0	-264,236	-202,190	-246,431	-262,442	-252,311	-1,466,044	-2,693,655
51824	LIN3 ID Fan Damper and VIV Refurbishment	Fan Dampe and VIV Refurb vs Replacement Energy Costs	1	-665,162	-624,580	-558,064	12,267	52,675	122,604	5.65	0	-51,539	-26,163	-49,410	-49,839	-101,256	-386,956	-665,162
51825	POT Boiler Refurbishment 2018	Boiler Refurbishment vs Replacement Energy Costs	1	-3,474,388	-3,419,790	-3,072,352	317,651	900,214	1,736,357	1.35	0	-349,869	-563,155	-746,276	-686,346	-755,547	-373,195	-3,474,388
51836	TRE5 Mill Refurbishments 2018	Mill Refurbishment vs Replacement Energy Costs	1	-306,842	-267,369	-236,685	225,165	667,035	618,506	1.17	0	-250,134	-424,595	31,333	29,238	27,225	280,091	-306,842
51851	LIN CW Screen Refurbishment 2018	CW Screen Refurbishment vs Replacement Energy Costs	1	-272,717	-242,404	-215,132	94,544	177,436	378,436	2.23	0	-149,505	-76,787	-168,620	-148,303	21,560	248,938	-272,717

CI	Project	Alternative	Rank as Filed	As Filed	Capital Spend Increased 10%	Avoided Expenses Reduced 10%	Deferral of 1 year	Deferral of 2 years	Deferral of 3 years	Payback	Year 0 / 2017	Year 1 / 2018	Year 2 / 2019	Year 3 / 2020	Year 4 / 2021	Year 5 / 2022	Years 6 to end of life / 2023+	Total
51852	POT Mill Refurbishment 2018	Mill Refurbishment vs Replacement Energy Costs	1	-449,711	-418,608	-373,637	60,398	198,732	465,779	1.84	0	-85,836	-125,588	-230,213	-258,493	20,894	229,526	-449,711
51861	TRE6 CW Screen Replacement 2018	CW Screen Replacement vs Replacement Energy Costs	1	-1,439,818	-1,374,231	-1,230,250	186,906	215,789	302,835	3.90	0	-224,380	-42,311	-69,861	-98,854	-114,393	-890,018	-1,439,818
51861	TRE6 CW Screen Replacement 2018	CW Screen Refurbishment vs Replacement Energy Costs	2	-642,736	-503,935	-439,662	152,955	148,958	203,780	23.00	0	-210,189	-64,831	-82,527	-102,182	-108,601	-74,406	-642,736
51866	HYD - 4th Lake Penstock Refurbishment	Pentosck Refurbishment vs Replacement Energy Costs	1	-10,525,324	-10,460,765	-9,408,233	129,408	319,038	596,931	2.80	(4718)	-215,372	-165,889	-227,599	-276,087	-320,615	-9,315,044	-10,525,324
52156	LIN 3&4 Condenser Vacuum Pump Replacement51404	Pump Upgrades vs Replacement Energy Costs	1	-373,854	-344,352	-306,966	35,677	81,454	142,158	5.39	0	-45,815	-39,074	-47,122	-24,242	-47,529	-170,073	-373,854
52252	LIN1 SH5 Tube Replacement	Tube Replacement vs Replacement Energy Costs	1	-2,075,515	-2,026,345	-1,818,794	77,406	247,535	448,184	2.80	0	-134,138	-141,346	-158,927	-140,964	-157,009	-1,343,130	-2,075,515
52253	LIN3 Economizer Header Refurbishment	Header Refurbishment vs Replacement Energy Costs	1	-2,380,122	-2,334,627	-2,096,615	97,544	184,441	406,147	3.26	0	-143,833	-77,880	-183,438	-262,716	-280,163	-1,432,091	-2,380,122
52262	HYD - Hells Gate 1 Overhaul	Overhaul vs Replacement Energy Costs	1	-4,132,042	-4,064,925	-3,651,721	80,793	167,167	280,519	5.49	0	-278,214	-59,491	-72,617	-81,784	-91,003	-3,548,933	-4,132,042
	Summary of all Economically Justified Projects		**1**	48,881,239	47,625,170	42,737,046	2,541,058	5,571,813	9,619,212	100	-7,336	-3,900,790	-2,776,016	-3,333,502	-3,623,030	-3,526,294	31,714,270	-48,881,239

1

CI Number: 51236

Title: HYD WRC Tailrace Tunnel Rock Bolting Phase 1

Start Date: 2017/04
In-Service Date: 2018/08
Final Cost Date: 2019/02
Function: Hydro
Forecast Amount: $8,861,996

DESCRIPTION:

This project includes clearing rock fall debris, and remediation and stabilization of the tailrace tunnel at the Wreck Cove Generation Station, which includes rock bolting, shotcreting, and mesh installation. This phase will complete work on approximately 284 metres (932 feet) of the tunnel.

The Wreck Cove Generating Station consists of several reservoirs, a head pond, penstock, underground powerhouse and tailrace tunnel. Wreck Cove is the largest hydroelectric plant in Nova Scotia, constructed from 1975-1978. The generating station includes two 109 MW generating units and produces approximately 330 GWh of energy annually. The Wreck Cove Generating Station is an integral part of NS Power's generation fleet as the hydro system has a fast response time and is able to "follow wind" as wind generation fluctuates.

The tailrace tunnel, extending from the draft tube manifold near the power house to the outlet at the Atlantic Ocean, is approximately 5600 ft (1706 m) long. It was constructed by drill and blast construction, with a design width of 20 ft (6.1 m) and a height to the crown of 20 ft (6.1 m). The crown of the tunnel was designed to be semi-circular with a radius of 10 ft (3.1 m). The tailrace tunnel is largely unsupported (approximately 66 percent unsupported), with localized zones of rock bolts and shotcrete completed over time in response to rock falls.

The Wreck Cove Generating Station tailrace tunnel is used to pass water from the hydro turbines to the Atlantic Ocean. It has experienced multiple rock falls, one of which resulted in a capacity derating of approximately 150 MW. The most recent rockfall occurred on March 11, 2015. A third-party consultant was hired to perform geotechnical evaluation of the tailrace tunnel, a visual inspection of the current condition of ground support in March, 2015, and a LiDAR survey in October 2015(Please refer to Attachment 3).

A total of 11 areas, listed in Attachment 3, Table 5-6, have been identified as potential areas of concern as a result of geotechnical evaluation of the tailrace tunnel. These areas vary from sections of previously supported ground to unsupported sections experiencing ongoing raveling of the rock mass.

The 2015 studies led to CI 47476 HYD – Wreck Cove Tailrace Rockfall U&U (approved by the UARB for $2,422,964 on September 9th, 2015). CI 47476 installed rock bolts and mesh throughout 252 feet of the mucking tunnel and 280 feet of the tailrace tunnel.

While the entire tunnel requires eventual stabilization of the crown and walls to mitigate the risk of future blockages, the scope of this project is to clear rock fall debris, and to remediate and stabilize approximately 932 ft (284 m) of the tailrace tunnel. This includes installing rock bolts, wire mesh and shotcrete in the walls and crown. This will provide additional support and minimize additional deterioration of the rock mass in the area. Phase 1 will be completed in 2018 in conjunction with a planned outage at Wreck Cove. Over the next several years, it is necessary to continue with the project, estimating another approximately $25 - 30 million to be confirmed upon further study during the completion of Phase 1 and alignment with upcoming outages.

Summary of Related CIs +/- 2 years:
2019 – 2021 CI TBD HYD WRC Tailrace Tunnel Rock Bolting Phase 2

Depreciation Class: Hydro Production Plant - Wreck Cove Hydro System

Estimated Life of the Asset: 40 Years

JUSTIFICATION:

Justification Criteria: Health & Safety

Why do this project?

Wreck Cove is the largest hydro facility in the NS Power fleet and is required to maintain a high level of reliability for system stability and NERC requirements (black start and 10 minute reserve).

A rock fall in the tailrace tunnel can reduce water discharge capacity from the generation units, which can result in derating the units to approximately 125-150 MW. A derating reduces the capability of the generating station to provide load support. Rock falls also pose a risk of causing unplanned outages at the Wreck Cove Generating Station. This unit is critical to supporting grid capacity and security.

In addition, depending on the water levels in the tailrace tunnel, a complete unit shut down may be required as a result of the Tailrace High Water Alarm. A tailrace rock fall can also pose a safety risk related to possible powerhouse flooding arising from a sudden blockage of the tailrace from a rock fall during unit operation. The only way to avoid the risk of rock fall is to proactively stabilize and remediate the tailrace tunnel through rock bolting and mesh installation.

This project is primarily justified on unit reliability, but secondarily supported for safety reasons.

Why do this project now?

At Wreck Cove, NS Power endeavors to ensure that a ground control procedure is prepared for all underground facilities to prevent rock falls. Furthermore, a third party consultant has informed NS Power that current industry practice for most operators and contractors is to avoid personnel working under unsupported ceilings. Based on observations during the LiDAR scan and on the mapping completed in 2015, the condition of the tunnel has deteriorated so that further instabilities are likely to occur with increasing frequency.

Why do this project this way?

This project is the only alternative to mitigate the risk of the derating that would occur in the event of another rock fall event. The do nothing alternative is not considered acceptable due to the importance of the generation at Wreck Cove and due to the safety concerns that a major rock fall event could create. The project will address the stability concerns for the crown and walls of the tunnel.

Pattern bolting, mesh and shotcrete methods are the most economic means of stabilizing and supporting the tailrace tunnel. There are other methods to stabilize and support, however the cost would be greater. Concrete slip-line methods (in which concrete is poured into a continuously moving form) would be one such method. As this is a water discharge tunnel and the life span of bolts and mesh would be affected by moisture the preferred approach is to use corrosion protection bolts and mesh for longer life span, as was done in 2015. Observations of moisture on the crown, shoulder and walls of the tunnel have caused increased deterioration towards the portal end causing support and stabilization installation to be required. Frequent inspections would be required to assess for signs of deterioration.

CI Number : 51236-H821 - HYD WRC Tailrace Tunnel Rock Bolting Phase 1 **Project Number** 51236-H821

Parent CI Number : -

Asset Location : 1361 - 1361 Wreck Cove Common Property **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	2700 - HGP - Waterways	8,861,996
	Total Cost:	8,861,996
	Original Cost:	

Capital Project Detailed Estimate

Location: Hydro
CI# : 51236
Title: HYD WRC Tailrace Tunnel Rock Bolting Phase 1
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Engineering	PD	103	$ 405	$ 41,746		
Hydro River Staff	PD	27	$ 365	$ 9,849		
Project Administration	PD	19	$ 223	$ 4,237		
Financial	PD	7	$ 223	$ 1,561		
Procurement	PD	10	$ 321	$ 3,210		
			Sub-Total	$ 60,604		
OT Labour						
OT Labour	PD	14	$ 730	$ 10,220		
			Sub-Total	$ 10,220		
Term Labour						
Term Labour	PD	9	$ 405	$ 3,645		
			Sub-Total	$ 3,645		
Travel Expense						
Travel / Accommodations	Lot	1	$ 5,000	$ 5,000		
			Sub-Total	$ 5,000		
Materials						
8' Bolts with 11'x5' galvanized mesh	per bolt	2,182	[redacted]		Cost Support Item #1 - Table 2.2 (Unit Price)	
10' Bolts with 11'x5' galvanized mesh	per bolt	110			Cost Support Item #1 - Table 2.2 (Unit Price)	
Cover Plates & Signage	Lot	1				
			Sub-Total	$ 1,869,600		
Contracts						
Remediation Contractor in 2018:						
Mobilization/Demobilization	Lot	1	[redacted]		Cost Support Item #1 - Table 2.2 (Unit Price)	
Dewatering and Installation/removal of gate	weeks	17			Cost Support Item #1 - Table 2.2 (Unit Price)	
Lighting and ventilation	weeks	17			Cost Support Item #1 - Table 2.2 (Unit Price)	
Shotcrete	m3	456			Cost Support Item #1 - Table 2.2 (Unit Price)	
Debris removal/clean-up following completion	Lot	1			Cost Support Item #1 - Table 2.2	
Portal Gate Works	Lot	1	[redacted]			
Contracted Site Manager	Lot	1				
Contracted Implementation PM	Hours	258				
Equipment Rental Rates						
Scooptram, 6 yd.	Month	2	[redacted]		Cost Support Item #2 - Page 2 - Monthly Rates	
Scissor Deck	Month	2			Cost Support Item #2 - Page 2 - Monthly Rates	
Compressor	Month	2			Cost Support Item #2 - Page 2 - Monthly Rates	
Passenger Van	Month	2			Cost Support Item #2 - Page 2 - Monthly Rates	
Pickup truck	Month	2			Cost Support Item #2 - Page 2 - Monthly Rates	
Hand Held Drills	Month	2			Cost Support Item #2 - Page 2 - Monthly Rates	
Shotcrete Machine	Month	2			Cost Support Item #2 - Page 2 - Monthly Rates	
Generator/Lighting	Month	2			Cost Support Item #2 - Page 2 - Monthly Rates	
Ventilation Fan	Month	2			Cost Support Item #2 - Page 2 - Monthly Rates	
Front End Loader	Month	2			Cost Support Item #2 - Page 2 - Monthly Rates	
Office Trailer	Month	2			Cost Support Item #2 - Page 2 - Monthly Rates	
Pumps	Month	2			Cost Support Item #2 - Page 2 - Monthly Rates	
Power Washer	Month	2			Cost Support Item #2 - Page 2 - Monthly Rates	
Telehandler	Month	2			Cost Support Item #2 - Page 2 - Monthly Rates	
Equipment Operating Rates						
Scooptram, 6 yd.	Hour	1152	[redacted]		Cost Support Item #2 - Page 2 - Operating Rates	
Scissor Deck	Hour	1152			Cost Support Item #2 - Page 2 - Operating Rates	
Compressor	Hour	1152			Cost Support Item #2 - Page 2 - Operating Rates	
Passenger Van	Hour	1152			Cost Support Item #2 - Page 2 - Operating Rates	
Pickup truck	Hour	1152			Cost Support Item #2 - Page 2 - Operating Rates	
Hand Held Drills	Foot	932			Cost Support Item #2 - Page 2 - Operating Rates	
Shotcrete Machine	Hour	1152			Cost Support Item #2 - Page 2 - Operating Rates	
Generator/Lighting	Hour	1152			Cost Support Item #2 - Page 2 - Operating Rates	
Front End Loader	Hour	1152			Cost Support Item #2 - Page 2 - Operating Rates	
Telehandler	Hour	1152			Cost Support Item #2 - Page 2 - Operating Rates	
Labour Rates						
4x Lead Construction Miner	Hour	4608	[redacted]		Cost Support Item #2 - Page 2 - Labour Rates	
4x Construction Miner	Hour	4608			Cost Support Item #2 - Page 2 - Labour Rates	
2x Project Superintendent	Hour	2304			Cost Support Item #2 - Page 2 - Labour Rates	
2x Mechanic	Hour	2304			Cost Support Item #2 - Page 2 - Labour Rates	
Safety Technicians dedicated to emergency response	Lot	1	[redacted]			
Misc. Site Services	Lot	1				
			Sub-Total	$ 5,215,531		
Consulting						
Rock Bolt Survey Update and Construction	Lot	1	[redacted]			
Pre-Construction Engineering and Procurement Support	Lot	1				
Construction Engineering Support and QA	Lot	1				
			Sub-Total	$ 388,858		
Meals & Entertainment						
Meals	Lot	1	$ 750	$ 750		
			Sub-Total	$ 750		
Other Goods & Services						
Contingency	%	10%	$ 7,554,208	$ 755,421		
			Sub-Total	$ 755,421		
Interest Capitalized						
AFUDC				$ 14,634		
				$ -		
			Sub-Total	$ 14,634		
Administrative Overhead						
Labour AO				$ 31,452		
Contract AO				$ 506,281		
				$ -		
			Sub-Total	$ 537,733		
			SUB-TOTAL (no AO, AFUDC)	$ 8,309,629		
			TOTAL (AO, AFUDC included)	$ 8,861,996		
Original Cost				$ -		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

BGC ENGINEERING INC.
AN APPLIED EARTH SCIENCES COMPANY
Suite 630 - 1718 Argyle Street
Halifax, NS Canada B3J 3N6
Telephone (902) 474-5925
Fax (902) 474-5929

August 31, 2017
Project No.: 1009005

Ray Sampson, P.Eng.
Project Manager - Nova Scotia Power Capital Projects
Nova Scotia Power Inc.
25 Lakeside Park Drive
Lakeside, NS B3T 1M9

Dear Mr. Sampson,

Re: Preliminary Cost Estimate for Support Works - Wreck Cove Tailrace Tunnel

1.0 INTRODUCTION

Nova Scotia Power Inc. (NSPI) is planning to carry out maintenance shutdowns and upgrades to the Wreck Cove Hydroelectric Generating Facility during the summer and fall months of 2018, 2019 and 2020. It is expected that these planned shutdowns will span a period of approximately four (4) to five (5) months for each of 2018 and 2019, and for a minimum period of two (2) months in 2020. As part of the planned maintenance/upgrade program, BGC Engineering Inc. (BGC) understands that NSPI may carry out the remaining support/stabilization works (approximately 1550 m of support to include bolts, mesh and shotcrete) to the Tailrace Tunnel. The intent of the works is to fully support the total length of the tunnel (approximately 1700 m). Of the 1700 m, approximately 90 m of tunnel was previously supported near the draft tube manifold (in 2015) and approximately 60 m of tunnel near the portal entrance was concrete-lined during the initial construction of the tunnel (circa mid-1970's).

As per our discussions and at the request of NSPI, BGC has prepared a preliminary cost estimate to assist with the planning and development of the proposed support/stabilization works. An estimated schedule to complete the support/stabilization works, during the scheduled shutdowns, is also provided.

2.0 PRELIMINARY COST ESTIMATE

For this preliminary cost estimate, the Tailrace Tunnel was subdivided into segments based on the NGI Q-Values (NGI, 2015) reported in the Tailrace Tunnel Inspection and LiDAR Survey Report (BGC 2016). The Q system is a rock mass classification system used to establish tunnel support requirements. The range of Q-values for the Tailrace Tunnel and the corresponding support/stabilization recommendations are provided in Table 2-1 below.

Table 2-1. Q-values and the corresponding support/stabilization measures.

Q-value range	Description	Bolt Lengths (m)	Min. Shotcrete Thickness (cm)	Approx. Length of Tunnel (m)
43 – 4.1	Pattern bolting and mesh	2.4	None	630
4.1 – 1.0	Pattern bolting, mesh and shotcrete	2.4	5	280
1.0 – 0.4	Pattern bolting, mesh and shotcrete	2.4	7.5	140
0.4 – 0.2	Pattern bolting, mesh and shotcrete	2.4	10	220
< 0.2	Pattern bolting, mesh and shotcrete	3.0	13	280

Note: the support/stabilization measures provided in Table 2-1 are preliminary, pending detailed design.

The tunnel lengths included in Table 2-1 also include areas with prior support/stabilization as some of these areas are showing signs of deterioration.

Preliminary cost estimates to complete the support/stabilization work for approximately 1550 m of Tailrace Tunnel are provided below in Table 2-2 below. The quantities provided in Table 2-2 are based on extrapolations of previously completed works carried out by Cementation Canada Inc. (Cementation) in 2015. This cost estimate provides a range of costs which varies depending on the final length of schedule (35 to 50 weeks) and on the quantity of bolts, mesh and shotcrete required. Quantities will be confirmed or revised during the detailed design phase.

Table 2-2. Preliminary Cost Estimates for Ground Support/Stabilization of Tailrace Tunnel.

Description	Unit	Qty.	Unit Price	Cost
Mobilization/Demobilization	LS	1 to 3	[redacted]	
Dewatering and installation/removal of gate	weeks	35 to 50		
Lighting and Ventilation	weeks	35 to 50		
8' Bolts with 11' x 5' galvanized mesh	per bolt	10,000 to 12,000		
10' Bolts with 11' x 5' galvanized mesh	per bolt	500 to 600		
Shotcrete	m^3	2,000 to 2,500		
Debris removal/clean-up following completion	LS	1		
Support Design, Engineering and Quality Assurance	LS	1		
			Total	[redacted]

Note: the costs provided in Table 2-2 exclude costs associated with supporting equipment (radios, pumps, generators, etc.) which may be required.

The above unit rates are based on the rates provided by Cementation as part of the 2015 support/stabilization works (see Schedule A attached). Two items to consider with regards to this cost estimate are: 1) an increase in unit rates may apply for future construction works carried out between 2018 to 2020; and 2) the work completed in 2015 included only a short section of the

tunnel (approximately 90 m of Tailrace Tunnel) and an extrapolation to the full tunnel length may not necessarily consider production efficiencies for a longer section of tunnel (approximately 1550 m), which could potentially lower the unit rates.

The cost estimates and quantities provided in Table 2-2 should be considered as preliminary. Following the completion of the design of support/stabilization for the Tailrace Tunnel, a refined cost estimate could be developed and provided to NSPI. The cost estimates provided above do not include a contingency to account for uncertainties such as variability of Contractor unit rates, refinement of quantities based on detailed design, impacts of schedule on costs, etc. BGC suggests that NSPI carry a contingency of 30 or 40% to account for such uncertainties.

3.0 SCHEDULE ESTIMATE

Based on the above quantities for bolts and shotcrete, the estimated schedule to complete the stabilization works is approximately 320 days. This estimate is based on the Contractor using similar methods and equipment used for the support/stabilization works completed in 2015. Table 3-1 below provides a summary of production rates for the installation of 2.4 m bolts, 3.0 m bolts and shotcrete. The production rates were estimated based on the support/stabilization works carried out in 2015.

Table 3-1. Estimated production rates

Activity	Production rate (24hr work day)	Estimated Time Required
2.4 m bolt scaling and installation	45 bolts per day	245 days
3.0 m bolt scaling and installation	43 bolts per day	15 days
Shotcrete	36 m^3 per day	60 days
	Total	320 days

Table 3-2 provides an estimate on the length of tunnel which could be supported during each of the respective maintenance/upgrade periods from 2018 to 2020.

Table 3-2. Estimated work completed during 2018, 2019 and 2020 construction seasons.

Construction Season	Months of Work	Station Start	Station End
2018	4.5	1+610 m	0+970 m
2019	4.5	0+970 m	0+330 m
2020	2	0+330 m	0+062 m

Note: Based on an average estimated advancement rate of 4.75 m / day. Station 1+610 m is where the 2015 support work finished and station 0+062 m is where the cast concrete section of the Tailrace Tunnel begins. Station 0+000 m is located at the Tailrace Portal.

Construction/design inputs used to develop the above noted schedule estimates are:

- Production rates used are based on support/stabilization works completed in the Tailrace Tunnel in 2015.
- Production rates assume construction activities are carried out on a 24-hour schedule (i.e. dayshift and nightshift).
- Bolting and shotcrete works cannot be completed concurrently (i.e. shotcrete is assumed to be completed towards the end of each construction season, once all bolting is installed).
- The following have not been included in the schedule:
    - Mobilization and demobilization,
    - Dewatering,
    - Ventilation and lighting installation, and
    - Mucking of Tailrace Tunnel before and after completion of construction.

Note, a potential reduction in the schedule could be realized should construction activities for bolting and shotcrete be carried out concurrently with one-another, potentially reducing the schedule estimate from 320 days to 260 days. Other potential reductions in schedule and/or efficiencies in production are possible depending on the resources/equipment put forth by the Contractor (eg. two crews working in parallel, working from both ends of the tunnel). BGC recommends that NSPI explore all options with the Contractor to optimize the schedule.

4.0 CLOSURE

BGC Engineering Inc. (BGC) prepared this document for the account of Nova Scotia Power Inc.. The material in it reflects the judgment of BGC staff in light of the information available to BGC at the time of document preparation. Any use which a third party makes of this document or any reliance on decisions to be based on it is the responsibility of such third parties. BGC accepts no responsibility for damages, if any, suffered by any third party as a result of decisions made or actions based on this document.

As a mutual protection to our client, the public, and ourselves, all documents and drawings are submitted for the confidential information of our client for a specific project. Authorization for any use and/or publication of this document or any data, statements, conclusions or abstracts from or regarding our documents and drawings, through any form of print or electronic media, including without limitation, posting or reproduction of same on any website, is reserved pending BGC's written approval. A record copy of this document is on file at BGC. That copy takes precedence over any other copy or reproduction of this document.

We trust that the information contained herein is sufficient for your current needs. If you have any questions, concerns or comments, please don't hesitate to contact us.

Yours sincerely,

BGC ENGINEERING INC.
per:

Scott Munro, M.Sc.E., P.Eng.
Senior Geotechnical Engineer

SM/JL/ec/cd

Attach: Schedule A Goods and Services – Cementation approved pricing

References:

BGC Engineering Inc. (2016). Wreck Cove Hydroelectric Generating Station – Tailrace Tunnel Inspection and LiDAR Survey Report. April 1, 2016.

Norwegian Geotechnical Institute (NGI), 2015. Using the Q-system. www.ngi.no.

Cementation

Additional Scope

Pricing

Evacuation Tunnel Ground Support

Item	Description	Unit	Qty	Unit Price	Total Price
8.1	**Mobilization**	**LS**	**1**	[redacted]	
8.2	**Relocate existing services for scissor lift to pass**	**LS**	**1**		
8.3	Install ventilation	**LS**	1		
8.4	Install air and water lines	**LS**	1		
8.5	**Knock down walls**	**LS**	**1**		
8.6	Move materials out of drift and cleanup	**LS**	1		
8.7	Setup scissor lift to bolt	**LS**	1		
8.8	**Install 2.4 m galvanized #7 Williams rebar assembly c/w screen and 2 ft split sets**	**per Bolt**	**318**		
8.9	**Bolt testing**	**LS**	**1**		
8.10	**Setup scaffolding far side of top wall**	**LS**	**1**		
8.11	Install bolts off scaffolding	per Bolt	15		
8.12	Remove air and water lines, fan and vent	**LS**	1		
8.13	Reinstall NSPI services to original state	**LS**	1		

Tailrace Tunnel Ground Support Towards Turbines

Item	Description	Unit	Qty	Unit Price	Total Price
9.1	**Mobilization**	**LS**	**1**	[redacted]	
9.2	Install 2.4 m galvanized #7 Williams rebar assembly c/w screen and 2 ft split sets	per Bolt	120		
9.3	Bolt testing	LS	1		

Notes:

1. The Contract pricing provided assumes that the total price is the sum of the products of the estimated quantities extended by the appropriate unit prices. The contract price will be the final sum of the products of the actual quantities incorporated in the work as confirmed by count and measurement and the appropriate unit prices together with any adjustments that are made in accordance with the provisions of the contract documents.
2. We have assumed that NSPI will complete any electrical work required.

Cementation

Labour Rates

Qty.	Position	Hourly Rate
Direct Labour		
2	Lead Construction Miner	[redacted]
2	Construction Miner	
Indirect Labour		
1	Project Superintendent	
1	Mechanic	

Note:

1. Extra Work Labour Rates: Supervision, indirect and direct labour rates have been provided for extra work labour rates. Supervision and indirect labour will be invoiced at the same proportion as direct labour, calculated on a per invoice basis. The proportion of direct cost plus may be expressed as a factor (a percentage), that will be applied to the total indirect hours for each classification.

Equipment Rental Rates

Description	Monthly	Operating*
Scooptram, 6 yd	[redacted]	
Scissor Deck		
Compressor		
Passenger Van		
Pickup Truck		
Hand Held Drills		
Shotcrete Machine		
Generator/Lighting		
Ventilation Fan		
Front End Loader		
Office Trailer		
Pumps		
Power Washer		
Telehandler		

*Note that fuel is included in the operating cost.

Notes:

1. Equipment costs have been broken down by rental and operating costs. The factor, as described in the labour rates will be applied to the rental rates. The operating rate will apply to any reported operating hours.
2. Any equipment identified as being provided from a third party will be invoiced for any and all delays that are a result of a lack of owner provided service or material.
3. We have assumed that after the tailrace gate has been set in position there will be no major inflows of water to handle. We have only priced in a small air pump in our submission.

BGC ENGINEERING INC.
AN APPLIED EARTH SCIENCES COMPANY

NOVA SCOTIA POWER

WRECK COVE HYDROELECTRIC GENERATING STATION

TAILRACE TUNNEL INSPECTION AND LIDAR SURVEY

PROJECT NO.: 1009-002 DATE: April 1, 2016
DOCUMENT NO.:

BGC ENGINEERING INC.
AN APPLIED EARTH SCIENCES COMPANY
Suite 630 - 1718 Argyle Street
Halifax, NS Canada B3J 3N6
Telephone (902) 474-5925
Fax (902) 474-5929

April 1, 2016
Project No.: 1009-002

Ms. Aileen Woodman, P.Eng.
Nova Scotia Power Incorporated
1223 Lower Water Street
Halifax, NS B3J 3S8

Dear Ms. Woodman,

Re: Wreck Cove Hydroelectric Generating Station – Tailrace Tunnel Inspection and LiDAR Survey Report

BGC Engineering Inc. (BGC) is pleased to provide Nova Scotia Power Inc. (NSPI) with this Tailrace Tunnel Inspection and LiDAR Survey Report for the Wreck Cove Hydroelectric Generating Station. Should you have any questions or comments, please contact me at your earliest convenience.

Yours sincerely,

BGC ENGINEERING INC.
per:

Scott Munro, M.Sc.E, P.Eng.
Senior Geotechnical Engineer

Tony L Gilman, M.Sc., P.Eng, P.Geo
Senior Rock Mechanics Engineer

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DRAWING 02 – TAILRACE TUNNEL INSPECTION AND LIDAR SURVEY (STATION 0+900 TO 1+700)

1.0 INTRODUCTION

On March 17, 2015, Nova Scotia Power Inc. (NSPI) contacted BGC Engineering Inc. (BGC) following a suspected rock fall in the tailrace tunnel at the Wreck Cove Generating Station, Wreck Cove, Nova Scotia. This rock fall was identified by a change in water elevation within the tailrace tunnel that was imposing a restriction on power generation. BGC was retained on March 20, 2015 to provide an initial geotechnical inspection (conducted on March 30, 2015) of the rock fall located near the upstream end of the tailrace tunnel. Due to high water levels and safety concerns this inspection terminated at the rock fall zone at Station 5+220 (measured from the outfall of the tailrace), or 280 ft downstream from the draft tube manifold.

Following this site visit, BGC provided guidance on the current stability of the rock mass where the rock fall zone had occurred, as well as recommendations for debris removal, and rock support design for remediation of the rock fall zone. NSPI remediated the rock fall zone between Stations 5+300 to 5+255 (i.e. 200 ft to 245 ft downstream from the draft tube manifold), completing the work on November 6, 2015.

In conjunction with the rock support recommendation for the rock fall zone, BGC recommended a visual geotechnical inspection of the entire tailrace tunnel and a Light Detection and Ranging (LiDAR) survey of the tunnel be conducted during the rock fall zone repair. That work was carried out at the same time as the above noted rock fall zone remediation work. This report presents: the results from BGC's visual geotechnical inspection of the tailrace tunnel; the methodology and results of a LiDAR survey of the tunnel; a discussion of potential instabilities within the tunnel; and recommendations for further work.

The purpose of this report is to provide a baseline of tunnel conditions that can be used to prioritize areas of the tunnel for future monitoring or stabilization work. The LiDAR data can be used in additional stability assessment of the tunnel, and can be used to compare against future LiDAR surveys to detect changes in condition such as rock fall that might otherwise not be detectable. This type of analysis can assist NSPI in the identification of zones within the tunnel that are actively failing. Additionally, the LiDAR data could be used to carry out a hydraulics assessment/model of the tailrace tunnel, and can be used to visualize rock fall accumulations or changes in rock fall on the tunnel floor.

2.0 SCOPE OF WORK

The scope of work for this project included a geotechnical assessment and 3D LiDAR scan of the full length of the tailrace tunnel (including the mucking tunnel). The geotechnical assessment included a visual inspection of the full length of the tailrace tunnel by a rock mechanics engineer and structural geology mapping to identify other active or potential rock fall hazard zones, and to conduct a visual assessment of past support/stabilization measures. The LiDAR data was collected at a resolution suitable for mapping discontinuity orientation, persistence and spacing, tunnel shape, cross sectional area, and over/under break with respect to design.

The LiDAR scan included:

- The full length of the tailrace tunnel (approximately 1700 m length) and mucking tunnel.
- Conversion of the LiDAR data into a 3D point cloud and a 3D surface model for future analysis and delivery to the client as a digital file. Additionally, NSPI was provided a computer program to visualize the 3D data.

3.0 BACKGROUND

3.1. General

The Wreck Cove hydroelectric generating station is located on the east side of Cape Breton, Nova Scotia, and consists of several reservoirs, a head pond, penstock, underground powerhouse and tailrace tunnel (Figure 2-1). Construction of the Wreck Cove Generating Station Facility and associated infrastructure was completed in 1978 and took three years to construct. The tailrace tunnel is approximately 5600 ft (1706 m) long, extending from the draft tube manifold near the power house to the outlet at the Atlantic Ocean. The entry to the tailrace tunnel is located approximately 900 ft (274 m) below surface (Golder, 1993). The invert level of the tailrace tunnel is 4 ft (1.2 m) above sea level (asl) at Station 5+500 (draft tube manifold) and -3 ft (-0.9 m) asl at the discharge to the Atlantic Ocean, with an approximate grade of -0.25%. The draft tubes at the inlet are orientated at approximately 145°. From this location the tailrace tunnel curves on a 120 ft (36.6 m) radius to a final orientation of 105°, continuing in this orientation until the outlet at the Atlantic Ocean (Golder, 1993).

The tailrace tunnel was constructed by drill and blast construction, with a design width of 20 ft (6.1 m) and a height to the crown of 20 ft (6.1 m). The crown of the tunnel was designed to be semi-circular with a radius of 10 ft (3.1 m). The tailrace tunnel is largely unsupported (approximately 66% unsupported), with localized zones of rock bolts and shotcrete.

3.2. Background Information Provided

Background information provided to BGC by NSPI and reviewed prior to the inspection included design and as-built drawings (Nenniger & Chenevert, 1978a through 1978f), and reports on previous work by Golder (1993) and Hatch (2009). Details of these references are provided in the Reference list at the back of this report.

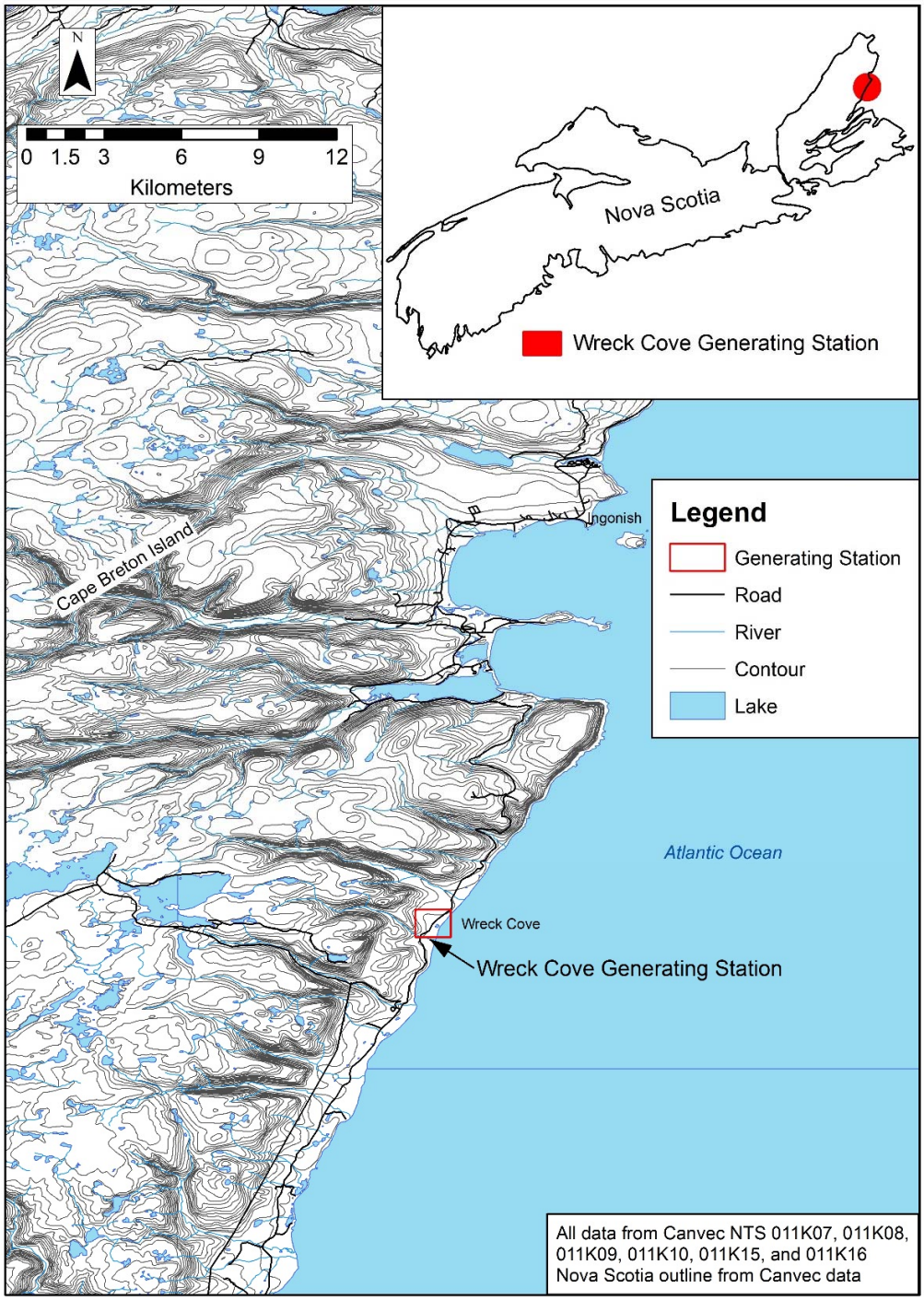


Figure 3-1: Project Location of the Wreck Cove Hydroelectric Generating Station, Wreck Cove, Nova Scotia. All data from Canvec NTS sheets.

3.3. Previous Studies

In 1991 a rock fall occurred in the tailrace tunnel. Golder Associates Ltd. (Golder) was retained to complete an inspection of this rock fall and provide NSPI with recommendations for rehabilitation of the tunnel. This inspection identified a rock fall in the vicinity of Station 4+500 (1000 ft or 305 m downstream from the draft tube manifold located at Station 5+500). As a result of this inspection, a rehabilitation program of debris removal, rock bolts and shotcrete was completed in that area of the tunnel in 1992. At this time the tunnel was pumped out and a full tunnel inspection was completed by Golder. This inspection resulted in the identification of a second rock fall at approximately Station 0+550 or 550 ft (229 m) upstream from the outlet. A rock reinforcement program was designed and remediation work was carried out between the outlet at the Atlantic Ocean up to approximately Station 0+900 (900 ft or 274 m upstream from the outlet) (Golder, 1993; Hatch, 2009).

In 2009 NSPI reported a rock fall, approximately 250 ft (76 m) downstream of the confluence of the mucking tunnel and the tailrace tunnel, near Station 5+250. At this time NSPI retained Hatch Consulting Ltd. (Hatch) to complete a full tunnel inspection, the results of which are contained within their WRC Tailrace Tunnel Inspection Report (Hatch, 2009). The primary focus of this inspection was on areas of identified rock falls and previously supported areas. Only a portion of the tunnel was inspected, as water levels in the lower portion of the tunnel were too high for a detailed inspection. Consequently, only the upper portion of the tunnel was mapped in detail. Hatch recommended remediation of the active rock fall area at approximately Station 4+500 (the area remediated by Golder in 1993). Hatch concluded that there were other areas of the tunnel downstream of the rock fall at Station 4+500 that would benefit from additional rock fall support, but otherwise the tunnel was performing adequately (Hatch, 2009).

4.0 SITE INVESTIGATIONS

4.1. General

A visual geotechnical inspection, structural geology mapping and LiDAR survey of the tailrace tunnel were completed over two site visits from October 19 to October 22, 2015 and from October 27 to October 30, 2015. This inspection was carried out by Tony Gilman, M.Sc., P.Eng, P.Geo of Terrane Geoscience Inc. (Terrane) under subcontract to BGC and Stephanie Bale, E.I.T., BGC. Additionally, on October 20, 2015, Mr. Gilman and Ms. Bale were accompanied by Scott Munro, P.Eng., and Matt Lato, PhD., P.Eng. from BGC, and Aileen Woodman, P.Eng., from NSPI. The LiDAR survey was completed by AllNorth Consultants Limited (AllNorth) by Carl Hovey and Stephen Rafuse of AllNorth.

Prior to the geotechnical inspection and LiDAR survey of the tailrace tunnel, the turbines were shut down and the water was pumped out of the tunnel. On October 19, 2015 before entering the tunnel, a kickoff meeting and safety orientation were given by NSPI personnel (Aileen Woodman and Paul MacKay). Since approximately 70% of the Wreck Cove tailrace tunnel is under unsupported ground, Tony Gilman, M.Sc., P.Eng, P.Geo, a rock mechanics specialist along with Stephanie Bale, E.I.T, inspected the tunnel ahead of the AllNorth crew and remained with them at all times during the LiDAR survey for safety.

From October 19 to October 22, 2015 LiDAR data was collected from Station 5+500 to Station 2+400. At this time surveying could not progress any further as water levels in the tunnel were up to 1.2 m in depth. To allow time to further lower the water level (i.e. dewatering), it was decided to postpone the inspection and surveying of the lower portion (i.e. Station 2+400 to the outlet) of the tunnel. From October 27 – October 30, 2015 the remaining portion of the tunnel from Station 2+400 to the outlet was inspected and surveyed.

4.2. Geologic Data Collection

A total of five days were spent in the field collecting geological data from Station 5+500 at the draft tube manifold to the outlet at the Atlantic Ocean. The main purpose of the geological data collection was to:

- Divide the tailrace tunnel into applicable structural domains;
- Characterize the main joint sets within each of the structural domains; and
- Collect geotechnical rock mass characteristics for use in completing a rock mass classification (Q-system) within the tailrace tunnel (NGI, 2015).

All geologic discontinuity orientation data was collected with a geologic compass as dip and dip direction with an -18.5° west declination. The structural geology discontinuity orientation data collected as part of this mapping is summarized in Appendix C.

4.2.1. Data for Q-system – Rock Mass Classification

The Q-system classification parameters are based on block size, shear strength (joint conditions), and active stresses (Barton, 1974; NGI, 2015). “Q” is defined as:

$$Q = (RQD/J_N) \times (J_R/J_A) \times (J_W/SRF)$$

Where:

RQD=Rock Quality Designation

J_N = Joint Set Number

J_R = Joint Roughness Number

J_A = Joint Alteration Number

J_W = Joint Water Reduction Factor

SRF = Stress Reduction Factor

The assessed values of the Q system input parameters and resulting Q value calculations for rock mass classification along the tunnel are summarized in Appendix A and on Drawing 01 and Drawing 02. Table 4-1 provides the descriptive correlation of rock mass quality with Q-system values.

Table 4-1: Correlation of numeric to descriptive rock mass quality from the Q-system.

Rockmass Quality	NGI-Q Range
Very Poor	<1.0
Poor	1 to 4
Fair	4 to 10
Good	10 to 40
Very Good	40 to 100
Extremely Good	>100

4.2.2. Historical Ground Support Conditions

In addition to the collection of structural geological data, the condition of existing ground support was also reviewed. Ground support conditions were noted through photographs and visual observations. Additionally, the resolution of the LiDAR survey, discussed below, can be used to provide further details about ground support conditions. However, such an exercise is beyond the scope of this work. Select photographs of ground support conditions can be found in Appendix B. Ground support condition observations are also summarized on Drawing 01 and Drawing 02.

4.3. LiDAR Surveying

LiDAR scans were conducted of the tailrace tunnel (approximately 5500 ft) as well as for the mucking tunnel (approximately 250 ft) that leads into the tailrace tunnel. Scans were completed using a tripod-mounted Leica C10 Scanner, the data were collected at a minimum point density of 10,000 points/m^2.

Scan stations were spaced approximately every 8 m along the length of each tunnel, and the LiDAR unit was positioned in the center of the tunnel to minimize occlusion (i.e. shadows in the data). A total of 230 scans were completed (including both the tailrace tunnel and mucking tunnel, as well as 4 scans outside of the tailrace portal). The LiDAR data was not georeferenced to a local or global coordinate system, however, this could be completed at a later date at the direction of NSPI.

The LiDAR point cloud of the Wreck Cove tailrace tunnel was converted to a 3-dimensional (3D) surface model for visualization and analysis. High resolution images of the tailrace tunnel are provided in Appendix D. These images are also included with the Q-system data and support review information on Drawings 01 and 02. Digital files and visualization software were provided to NSPI on November 25th 2015.

5.0 TAILRACE TUNNEL CONDITIONS

5.1. Geologic Setting

5.1.1. Regional Geologic Setting

The Wreck Cove Generating Station is located within the Cape Breton Highlands in an area characterized, geologically, by a complex assemblage of sedimentary, metamorphic, and igneous (plutonic and volcanic) rocks. These assemblages range in age from Late Proterozoic to Devonian (Barr and Raeside, 1986). These units are variably deformed and occur within and adjacent to north-south to northeast-southwest trending faults and shear zones (Barr et al., 1992). These faults and shear zones act as litho-tectonic terrane boundaries which divide the region into three major terranes. These are the Blair River Complex, the Aspy Terrane, and the Bras D'or Terrane (Barr and Raeside, 1986).

The Wreck Cove power generation site lies entirely within the Bras D'or Terrane. The Bras D'or Terrane extends across the east-central portion of the Cape Breton Highlands and is characterized by granite to granodiorite to diorite units of Cambrian age. In the Wreck Cove region the primary units are the Birch Plane granite and the Wreck Cove diorite. The primary faults in this region are oriented north-south to northeast-southwest with later east-west to northwest-southeast oriented faults offsetting most major units (Barr et al., 1992).

5.1.2. Tailrace Tunnel Geology

The Wreck Cove tailrace tunnel is underlain by rocks of the Birch Plain Granite (Barr et al., 1992). Mapping by NSPI includes granodiorite (black and pink), granite (red to pink), and diorite (Nenniger & Chenevert, 1978). Similarly as part of this inspection and mapping of the tailrace tunnel three primary lithologies were mapped within the tailrace tunnel, these are;

- Unit 1 - Fine to medium grained, occasionally coarse grained; massive to moderately well foliated; grey to dark grey; Diorite to Granodiorite.
- Unit 2 - Fine to medium grained, occasionally coarse grained; massive to moderately well foliated; pink; Granite to Granodiorite.
- Unit 3 – Fine- to medium-grained; sheared with very well-developed foliation; pink to grey; Sheared Granite to Granitic Gneiss.

In addition to the units described above, numerous mafic dykes and sills intrude and cross cut the local geology. These mafic dykes are often associated with intense hematite and chlorite alteration along the host rock dyke contact which allows the contacts to act as areas of weakness and/or fault zones. Many of the mapped fault zones coincide with areas where up to 30% of the host rock is intruded by dykes.

Faults within the tailrace tunnel are characterized by a dominantly north-south trending, steeply west dipping set and a less well developed near vertical east-west orientated fault set. These data are discussed in Section 5.3.

5.2. Structural Domains

The tailrace tunnel has been divided into four structural domains, based on areas with similar rock mass properties. Each of the structural domains is controlled variably by geology, faults/shear zones, joint alteration, past instabilities, and/or mafic dyke emplacement. The four structural domains within the tailrace tunnel are summarized below in Table 5-1; in Appendix A (Figure A1 and A2) with details of the Q-system rating, and Drawing 01 and Drawing 02 with respect to structural geology mapping and the LiDAR survey.

Table 5-1: Structural domains, Wreck Cove tailrace tunnel.

Domain	Description
1	Unit 1 and Unit 2; fine to medium grained, occasionally coarse grained; red, grey and dark grey; granite, granodiorite and diorite.
2	Unit 1 and Unit 2 that has been intruded by up to 30% mafic dykes.
3	Unit 3 – Fine- to medium-grained; sheared with very well developed foliation; pink to grey; sheared granite to granitic gneiss.
4	Fault/shear zones with ongoing ravelling; lithologically, often unit 3.

The structural domains summarized in Table 5-1, along with the discontinuity data summarized in Section 5.3, have been used as the basis for the rock mass classification using the Q-system described in Section 5.4.

5.3. Faults, Shear Zones, and Discontinuities

Geological mapping by Barr et al., (1992) indicates that a major north-south orientated fault zone passes through the Wreck Cove tailrace tunnel. Based on the scale of the Barr et al. (1992) mapping, it is difficult to locate accurately where this fault zone intersects the tunnel but it is interpreted, herein, that many of the mapped north-south faults and shear zones within the tailrace tunnel can be attributed to this system (see Drawings 01 and 02). Additionally, the north-south, steeply dipping faults and shear zones are structurally related to a shallower dipping, nearly north-south, oriented fault set that together have a tendency to produce large wedges in the tunnel crown. Figure 5-1 illustrates a schematic representation of this type of wedge. Throughout the tunnel, these fault sets are found to be related to each other through reverse fault kinematics, specifically SC fabric relationships which form from ductile deformation of rock masses, thereby providing insight into the strain history of a rock mass. The rock mass instability remediated by Golder in 1992 near Station 4+500 is interpreted by BGC to represent such a crown wedge failure based on the fault relationships in this area. Additionally, the recent failure at Station 5+300 to 5+255 is also interpreted to have been facilitated by this structural relationship. Stereonet data in Figure 5-2 illustrates these fault relationships. Note that stereonet data are presented with a magnetic declination of -18.5°, and are not biased corrected.

As illustrated in Figure 5-2, along with the dominantly north-south oriented faults, a less well represented fault set is present, orientated approximately east-west. Given the alignment of the tunnel (approximately east-west) it is possible that this set is under-represented in the data. Additionally, five other less well developed faults were mapped (Figure 5-2). These are interpreted as splays off of the main fault sets. They may be important local controlling structures, but are not systematically found throughout the tailrace tunnel.

A total of four main discontinuity sets were mapped within the tailrace tunnel (Figure 5-3). In addition to the four main discontinuity sets, several less well developed sets were also mapped (Figure 5-3). While the less well developed discontinuities may be important locally, generally, they are not considered to be dominant controlling structures.

The four main discontinuity sets are interpreted as genetically related conjugate or orthogonal sets (Table 5-2). Within each structural domain the exact number of discontinuity sets varied as summarized in Figures A1 and A2 (Appendix A) and Drawings 01 and 02. Table 5-2 below summarizes the main discontinuity sets and their average orientation within the tailrace tunnel.

Table 5-2: Primary mapped discontinuity sets, Wreck Cove tailrace tunnel.

Discontinuity Set	Description	Average Orientation (Dip/Dip Dir.)
1	S_1 – Primary discontinuity set	65°/265°
2	S_2 – Conjugate discontinuity set to S_1	52°/290°
3	S_3 – Secondary discontinuity set	62°/125°
4	S_4 – Orthogonal discontinuity set to S_3	57°/030°

5.4. Q-system Rock Mass Classification

The nature of the rock in the tailrace tunnel has been characterized through a combination of field mapping and visual observations. The rock mass is classified based on the classification system developed at the Norwegian Geotechnical Institute – Q (Q-system) method (Barton, 1974; NGI, 2015). This rock mass classification varies based on structural domain, and joint water conditions within the tailrace tunnel.

For the purposes of this study the rock mass has been divided into four structural domains as discussed in Section 4.1. The domains are divided based on geology, faults/shear zones, joint alteration, structural relationships, and/or mafic dyke emplacement. For each domain, a range of Q-system input values were assessed.

Table 5-3 summarizes the Q-system rock mass classification (Barton, 1974; NGI, 2015) values for each structural domain. Photos of general conditions in the tunnel can be found in Appendix B.

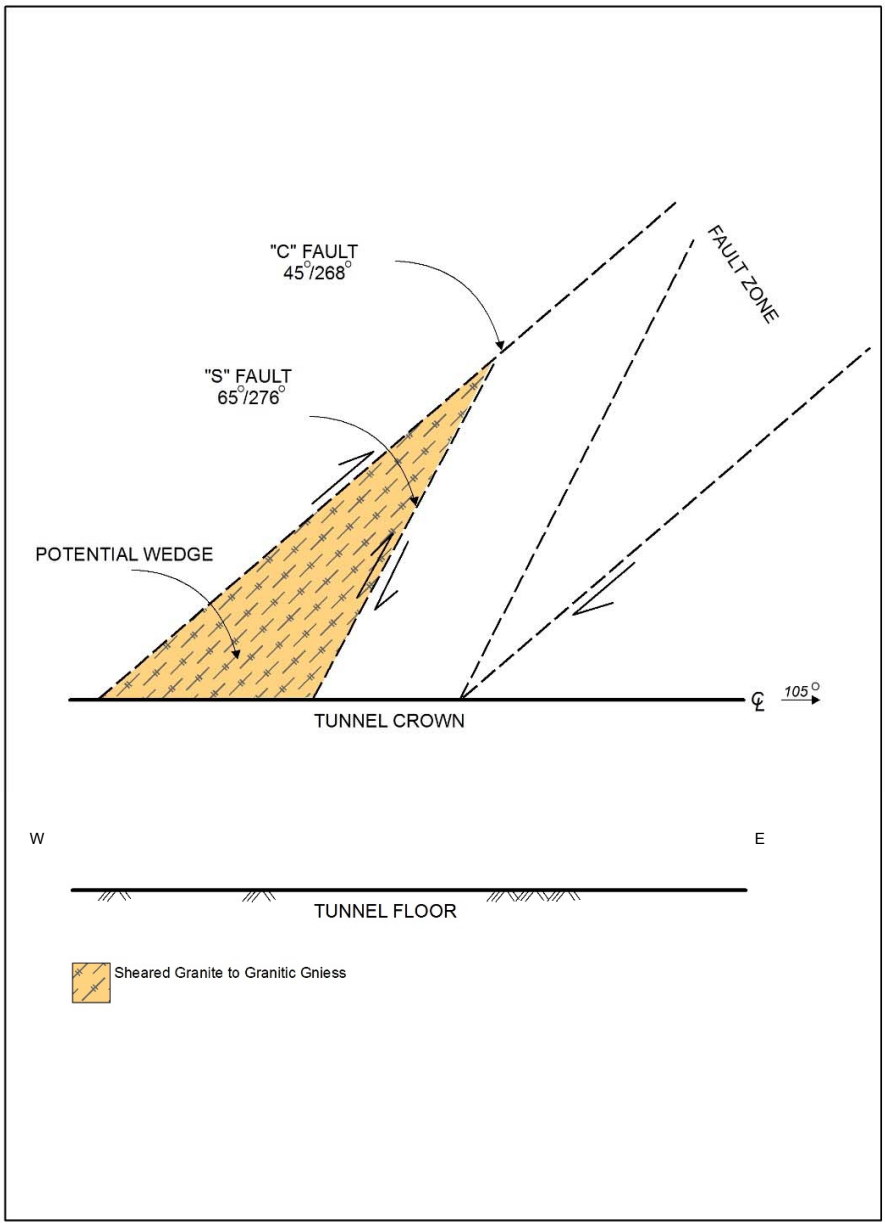
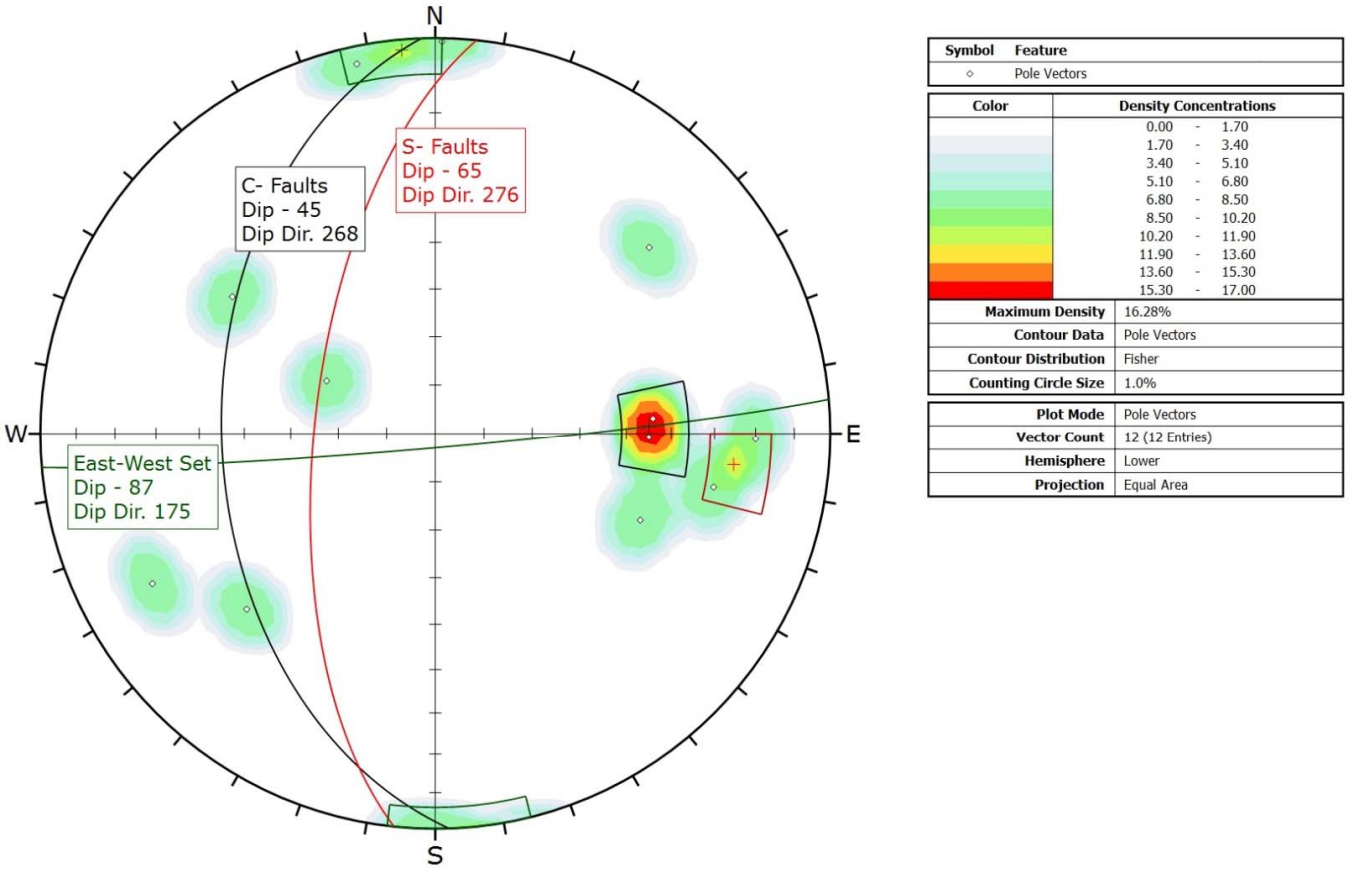


Figure 5-1: Schematic longitudinal section through the Wreck Cove tailrace, Not to scale, looking north, illustrating how faults commonly form large potential wedge failures in the tunnel crown.



Symbol	Feature
◇	Pole Vectors

Color	Density Concentrations
	0.00 - 1.70
	1.70 - 3.40
	3.40 - 5.10
	5.10 - 6.80
	6.80 - 8.50
	8.50 - 10.20
	10.20 - 11.90
	11.90 - 13.60
	13.60 - 15.30
	15.30 - 17.00

Maximum Density	16.28%
Contour Data	Pole Vectors
Contour Distribution	Fisher
Counting Circle Size	1.0%

Plot Mode	Pole Vectors
Vector Count	12 (12 Entries)
Hemisphere	Lower
Projection	Equal Area

Figure 5-2: Lower hemisphere, equal area, sterenonet plot displaying contours of the poles to mapped faults and their corresponding average orientation within the Wreck Cove tailrace tunnel. The tunnel orientation is approximately 105º

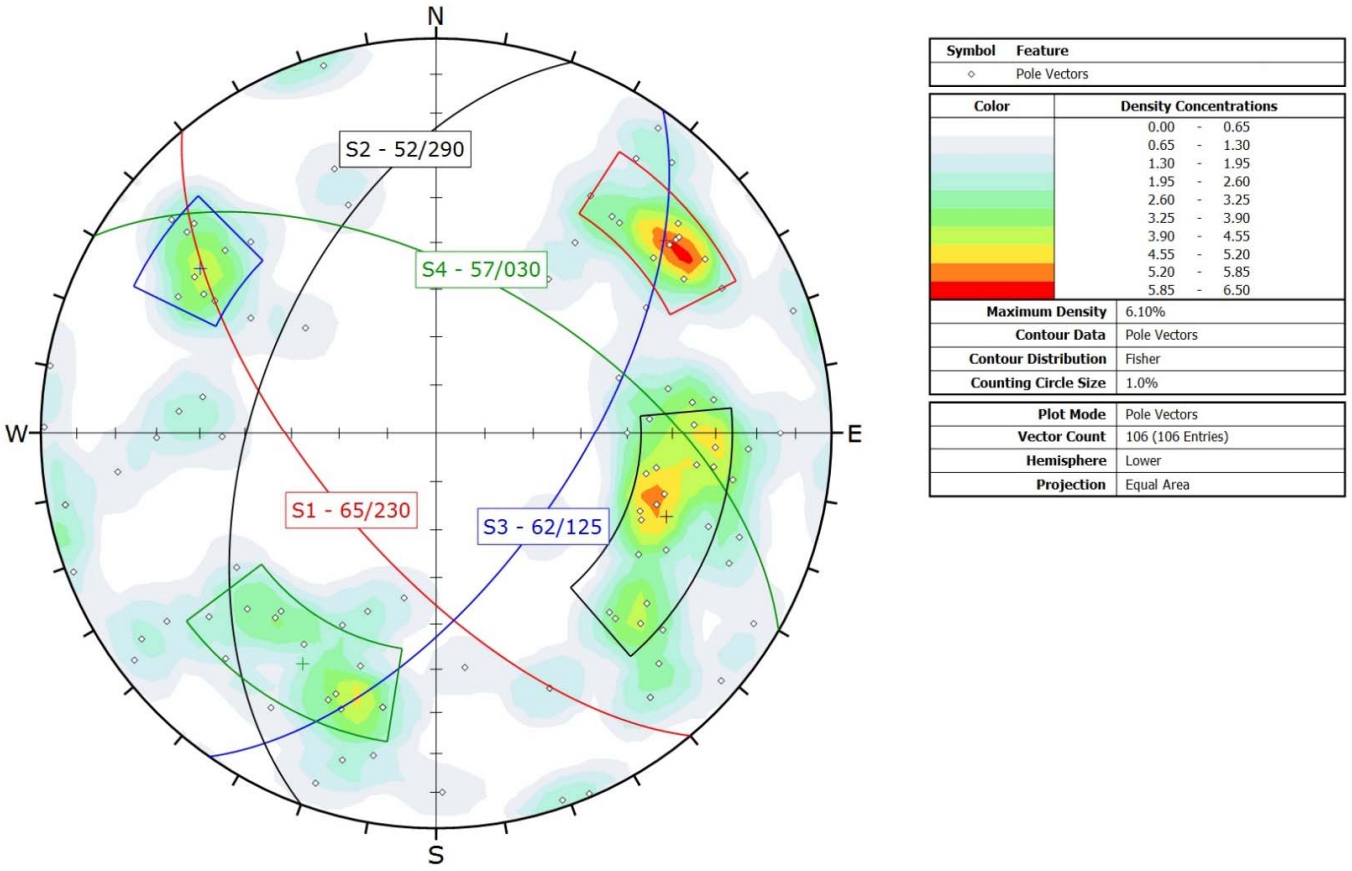


Figure 5-3: Lower hemisphere, equal area, stereonet plot displaying contours of the poles to mapped discontinuity sets and their corresponding average orientation (Dip and Dip Direction) within the Wreck Cove tailrace tunnel.

Table 5-3: Rock mass classification: NGI-Q-system, Wreck Cove tailrace tunnel.

Structural Domain	Description	NGI-Q		Rock Quality[1.]
		Min	Max	
1	Unit 1 and Unit 2: Fine to medium-grained, occasionally coarse grained; red, grey and dark grey; granite, granodiorite and diorite.	7	43	Fair to Very Good rock quality
2	Unit 1 and Unit 2 that has been intruded by up to 30% mafic dykes.	4.1	15	Fair to Good rock quality
3	Unit 3: Fine to medium-grained; sheared with very well developed foliation; pink to grey; sheared granite to granitic gneiss.	0.6	3	Poor to Very Poor rock quality
4	Areas of past rock fall and ongoing ravelling; lithologically, often Unit 3 and associated with fault/shear zones.	0.1	0.4	Very Poor rock quality

NOTES: 1. See Table 5-1 for a summary of rock mass quality descriptions based on Q-system values.

5.5. Ground Support Conditions

Several areas within the tailrace tunnel have been subject to ground support programs over the lifetime of the tunnel. These ground support programs started with the building of the tunnel (1975 to 1978) and have continued as necessary. Notably, two major rehabilitation programs of ground support were carried out under the direction of Golder in 1992 and 1993. Ground support within the tailrace tunnel consists of three main support types: 1.) rock bolts, 2.) rock bolts, mesh and shotcrete, and 3.) concrete lining (at the tunnel outlet and at the manifold).

As part of this geotechnical evaluation of the tailrace tunnel, a visual inspection of the current condition of ground support was carried out. In general, the condition of ground support was best between Station 5+500 to approximately Station 2+100 and progressively deteriorated downstream towards the outlet of the tunnel. Coincident with this deterioration is an increase in groundwater flowing into the tunnel from Station 5+500 to the outlet. Table 5-4 summarizes the condition of ground support sections within the tailrace tunnel. Photos of general conditions in the tailrace tunnel and the condition of ground support can be found in Appendix B. Drawings 01 and 02 also provide a summary of the ground support conditions within the tailrace tunnel.

Table 5-4: Ground support condition summary, Wreck Cove tailrace tunnel.

STATION[1.]		Support Type	Condition
From (ft)	To (ft)		
5+255	5+200	Shotcrete	Good condition.
4+800	4+750	Rock Bolts	Good condition.
4+550	4+500	Shotcrete	Area of rock fall remediated in 1992; minor seepage associated with bolts; minor deterioration of shotcrete, locally, at bolt locations.
4+175	4+150	Shotcrete	Good condition.
3+975	3+950	Shotcrete	Good condition; minor seepage associate with bolts.
2+950	2+900	Rock Bolts	Good condition.
2+750	2+675	Shotcrete	Good condition.
2+425	2+375	Shotcrete	Good condition; minor seepage associate with bolts.
2+150	1+825	Shotcrete	Generally in good condition, shotcrete only on walls (north and south); minor scour at the base.
1+725	1+675	Rock Bolts	Poor condition; bolts very corroded; coincident with a fault zone and very wet area with constant drips.
1+650	1+575	Shotcrete	Good condition with scour at the base; coincident with fault breccia zones.
1+475	1+410	Shotcrete	Good condition; minor seepage; minor scour at the base of the walls.
1+325	1+200	Rock Bolts	Poor condition; bolts very corroded; constant inflow of water in a stream.
1+285	1+275	Shotcrete	Moderate deterioration of shotcrete; scour at the base of the walls (north and south); seepage to constant drips associated with rock bolt locations.
1+155	1+150	Rock Bolts	Poor condition; bolts very corroded.
1+025	9+750	Shotcrete	Good condition; minor seepage associate with bolts.

NOTES: 1. Station 5+500 corresponds with the draft tube manifold at the inlet. The station numbers decrease downstream to the tunnel outlet at the Atlantic Ocean.

Table 5-5: Ground support condition summary, Wreck Cove tailrace tunnel (continued).

STATION[1.]		Support Type	Condition
From (ft)	To (ft)		
0+975	0+965	Rock Bolts	Poor condition; bolts very corroded; heavy inflow at bolts.
0+875	0+865	Shotcrete	Moderate deterioration of shotcrete; seepage to constant drips associated with rock bolt locations.
0+775	0+750	Rock Bolts	Poor condition; bolts very corroded; heavy inflow in this area.
0+625	0+075	Shotcrete	Moderate deterioration of shotcrete; to locally heavily deteriorated shotcrete; seepage to constant drips associated with rock bolt locations; scour at the base on both north and south walls.
0+075	0+075	Shotcrete	Very poor condition; at the interface between the cast concrete and the shotcrete a large wedge failure is developing; the shotcrete is heavily deteriorated to missing completely.
0+075	Outlet	Cast concrete	Good condition; minor seepage.

NOTES: 1. Station 5+500 corresponds with the draft tube manifold at the inlet. The station numbers decrease downstream to the outlet.

5.6. Rock Fall Areas of Concern

Drawings 01 and 02 summarize the tailrace tunnel geology (structure and lithology), ground support conditions, structural domains and Q-system ratings. Included on these figures are shaded relief images displaying the crown, north wall, and south wall of the tailrace tunnel from the LiDAR survey. Individual shaded relief images, taken at 200 m intervals, can be found in Appendix D.

Sections of the tunnel designated as Structural Domains 3 and 4 are composed of Q-system rock masses that are best described as poor to very poor rock quality (Table 5-3). These sections, particularly those within Domain 4 are characterized by areas of ongoing raveling and past failures that are structurally related to fault/shear zones often within Unit 3, are of concern for future rock fall. Table 5-6 focuses on specific areas of concern within the larger zones of poor rock mass quality.

Precise timing of instabilities are difficult to predict. However, it can be said with a high degree of confidence that some of these sections will lead to future, potentially large rock falls. These areas vary from sections of previously supported ground to un-supported sections experiencing ongoing raveling of the rock mass. A total of 11 areas have been identified as potential areas of concern. Table 5-5 summarizes these sections and provides recommendations, and photos in Appendix B highlight some of these potential problem areas. Sections are categorized as:

- No action required;
- Periodic visual review of condition; or
- Physical work recommendations to stabilize rock fall areas, repair or replace previous stabilization measures, or provide additional support to the tunnel.

Table 5-6: Areas of Concern, Wreck Cove Tailrace Tunnel.

From	To	Further Work Recommendations	Comments
4+550	4+500	Periodic visual inspection	This segment experienced a rock fall in 1991 and was the focus of a major rehabilitation, overseen by Golder in 1992. Shotcrete in this area shows seepage and minor deterioration.
4+450	4+300	Physical work recommended	This section is characterized by very poor rock mass quality with a large volume (1800 ft^3 or 50 m^3) of rock fall debris on the floor close to the north wall of the tunnel and a lesser amount on the floor close to the south wall of the tunnel. At station 4+300 there is evidence of ongoing failure of the rock mass with gravel to cobble size particles that appear to have fallen after the tunnel was drained for this review (i.e. they are very fresh).
3+475	3+450	Physical work recommended	Channel floor nearly continuously covered across from the north wall to the south wall with large (3 ft^3) blocks co-incident with a fault zone. Fresh, not stained rocks suggest recent (last 1 to 5 years) ongoing ravelling of the rock mass in this area.
3+275	3+275	Periodic visual inspection	Large historic wedge failure with a large rock block on the channel floor.
3+175	3+100	Physical work recommended	Recent (last 1 to 5 years) wedge failure with evidenced of fresh rock ravelling on the tunnel floor and open discontinuities in another wedge that is considered at high risk of failure.
2+400	2+400	Periodic visual inspection	South wall floor has fresh, un-weathered, small (0.5 ft^3) recent rock fall.
2+200	2+200	Periodic visual inspection	South wall floor has fresh, un-weathered, small (0.25 ft^3) recent rock fall co-incident with a fault zone.
1+800	1+700	Physical work recommended	This section contains numerous, historic, small, wedge failures co-incident with sheared granitic gneiss and areas of past rock bolt failure. Additionally, the remaining rock bolts are in very poor condition. Debris on the tunnel floor suggests ongoing, small scale, ravelling of the tunnel crown.
0+900	0+875	Physical work recommended	This section contains numerous, historic, small, wedge failures co-incident with a shear zone and areas of past rock bolt failure. Additionally, the remaining rock bolts are in very poor condition.
0+575	0+500	Physical work recommended	Fault zone with past rock bolting and numerous, large, historic wedge failures. This area was remediated in 1993 under the direction of Golder. Rock bolts in this section are in very poor condition (corroded) with evidence of recent (last 1-5 years) rock fall on the tunnel floor.
0+075	0+075	Physical work recommended	At the interface between the cast concrete at the outlet of the tailrace tunnel and the shotcrete placed within this region a wedge instability with evidence of ongoing ravelling is present.

6.0 CONCLUSIONS AND RECOMMENDATIONS

It is anticipated that the data included in this report will aid in the understanding of the rock mass conditions and will be a resource for future monitoring of tunnel rock mass stability as well as support planning and design. Future LiDAR data can be compared with the baseline survey in this report to identify rock fall release zones and additional debris accumulation on the tailrace tunnel floor.

Based on this review, we conclude:

- The last geotechnical review of the tailrace was carried out in June 2009 (Hatch, 2009), following a minor rock fall in the tunnel near the powerhouse (precise location unknown). The majority of tunnel was inspected at this time, except for the lower portion of the tunnel, where the collection of detailed measurements was not completed due to tidal action within the lower portion of the tunnel. The debris from this minor rock fall was mucked out, but no additional rock support was installed. Prior to this, the last physical work in the tunnel was a rock reinforcement program (wire mesh, rock bolts and shotcrete), following a large rock fall in 1991. This work was completed in 1992, along with a full inspection of the tunnel by Golder Associates (Golder, 1993).
- The condition of existing localized tunnel support measures qualitatively appears to worsen from inlet to outfall of the tunnel. This may be caused in part by increased seepage into the tunnel in the lower parts.
- There is insufficient data from past reviews to quantitatively assess frequency of rock fall in the tunnel. However, the evidence of debris on the tunnel floor indicates smaller rock fall (< 1 ft or 0.3 m in longest dimension) occur many times a year, with larger rock fall (> 1 ft or 0.3 m in longest dimension) occurring perhaps annually to once every five years.
- There is a reasonable risk of a sufficiently large rock fall restricting the tailrace and affecting plant generating capacity.
- Future rock fall frequency or magnitude may not be similar to that noted in the past. This is because the rock mass of the tunnel has been deteriorating since construction. It can be expected that over time, weathering will progressively reduce the strength along discontinuities, making rock fall more likely and possibly increasing the frequency of larger rock fall.

We recommend:

- Tunnel intervals in Table 5-5 designated as “requiring periodic visual inspection” be visually reviewed on a two to five year basis for ongoing evidence of instabilities of a magnitude that could affect plant operation. For practicality, it is anticipated that this would coincide with plant shutdowns as part of other planned repairs/maintenance activities. Visual review of these areas should be accompanied by LiDAR survey and that survey used relative to the 2015 survey to quantitatively assess the areas for rock mass changes.
- Tunnel intervals in Table 5-5 designated as “physical work recommended” should have stabilization designs prepared and implemented. This would involve further kinematic and numerical stability assessment and rock support design. The data from this 2015 work is

sufficient for this design. During design, where appropriate the rock mass classification should be refined to include data obtained from the LiDAR survey.

- The current ground support measures from station 1+000 to the cast concrete ground support at station 0+075 is generally in very poor condition. A ground support remediation program be should be designed and implemented for this segment of the tailrace tunnel.

7.0 CLOSURE

We trust the above satisfies your requirements at this time. Should you have any questions or comments, please do not hesitate to contact us.

Yours sincerely,

BGC ENGINEERING INC.
per:

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TG/SM/MAP/ec/md

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Nenniger & Chenevert, 1978. Surveyor Nenniger & Chenevert, 1978. Design and as-built drawings for the Wreck Cove Hydroelectric Project, provided in Adobe pdf format:

a. H085S1 1 111 00 001 – Power system penstock powerhouse, draft tube and tailrace – Grouting and Drainage (Adobe PDF file H085S1 1 111 00 001.pdf).
b. H085S1 1 626 00 001 – Tailrace Tunnel – Geotechnical Data – As Built (Adobe PDF file H085S1 1 626 00 001.pdf).
c. H085S1 1 626 00 006 – Detailed Geology of Tailrace Tunnel (Sheet 2 of 3) (Adobe PDF file H085S1 1 626 00 006.pdf).
d. H085S1 1 626 00 007 – Detailed Geology of Tailrace Tunnel (Sheet 3 of 3) (Adobe PDF file H085S1 1 626 00 007.pdf).
e. H085S1 1 110 00 030 – Power System and Details (Adobe PDF file H085S1 1 110 00 030.pdf).
f. H085S1 1 211 01 001 – Powerhouse and Manifolds General Layout of Excavation. (Adobe PDF file H085S1 1 211 01 001.pdf).

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APPENDIX A
Q-SYSTEM ROCK MASS CLASSIFICATION

Nova Scotia Power Inc.
Tailrace Tunnel Inspection and LiDAR Survey

TAILRACE TUNNEL CHAINAGE (FEET)

STATION[3.]	55+00	54+00	53+00	52+00	51+00	50+00	49+00	48+00	47+00	46+00	45+00	44+00	43+00	42+00	41+00	40+00	39+00	38+00	37+00	36+00	35+00	34+00	33+00	32+00	31+00	30+00	29+00	28+00	27+00	26+00

Lithology																														
Structural Domain	DOMAIN 1		4	DOMAIN 1		DOMAIN 2		DOMAIN 1		DOMAIN 4	DOMAIN 3	DOMAIN 4	3	DOMAIN 1					DOMAIN 3	4	DOMAIN 1	4	DOMAIN 1	4	1	DOMAIN 2				
Q-SYSTEM Max	29		0.4	29	43	14		29	43	0.4	3	0.4	3	43	23	35	2	0.4	29	0.4	29	0.4	29			14				
Q-SYSTEM Min	11		0.2	11	14	4.1		11	14	0.2	0.6	0.2	0.6	14	9	12	0.6	0.2	11	0.2	11	0.2	11			1				
RQD[1.]	65									33				65					33		65	33	65			65				
Jn[2.] Max	9	9	12	9	6	6	9	9	6	12	9	12	9	6	6	9	9	6	12	12	9	12	9	12	9	9				
Jn[2.] Min	12	12	12	12	9	9	12	12	9	12	12	12	12	9	9	12	12	9	12	12	12	12	12	12	12	12				
Jr[2.] Max	3		2	3		2		3		2	2	2	2	3					2	2	3	2	3	2	3	2				
Jr[2.] Min	2		1.5	2		1.5		2		1.5	1.5	1.5	1.5	2					1.5	1.5	2	1.5	2	1.5	2	1.5				
Ja[2.] Max	0.75		2	0.75		1		0.75		2	1	2	1	0.75					1	2	0.75	2	0.75	2	0.75	1				
Ja[2.] Min	1		3	1		2		1		3	3	3	3	1					3	3	1	3	1	3	1	2				
Jw[1.]	1																0.8		1											
SRF[1.]	1		7.5	1		1		1		7.5	2.5	7.5	2.5	1					2.5	7.5	1	7.5	1	7.5	1	1				

Domains

1		Fine to medium grained; massive; grey; Diorite/Granodiorite to Pink Granite
2		Fine to medium grained; massive; grey; Diorite/Granodiorite to Pink Granite intruded by up to 30% Mafic Dykes
3		Sheared/Faulted; grey to pink; granite to granitic gniess
4		Fault/shear Zones; lithologically often Unit 3

Q-SYSTEM - ROCK QUALITY	
0.1 - 1.0 - VERY POOR ROCK	
1- 4 - POOR ROCK	
4 - 10 - FAIR ROCK	
10 - 40 - GOOD ROCK	
40 - 100 - VERY GOOD ROCK	
>100 - EXTREMELY GOOD	N/A

NOTES:
1. VALUES IN Q THAT REPRESENT PROPERTIES OF THE ENTIRE ROCK MASS (i.e. RQD, J_W AND SRF) IN AN AREA WERE MEASURED/ESTIMATED BASED ON FILED OBSERVATIONS.
2. VALUES IN Q THAT REPRESENT THE INDIVIDUAL DISCONTINUITY CONDITIONS (i.e. Jn, J_r AND J_a) WERE GIVEN A RANGE TO ACCOUNT FOR VARIABLITY IN THE VARIOUS DISCONTINUITY SETS
3. STATION 0+00 IS LOCATED WITHIN THE CAST CONCRETE SECTION NEAR THE OUTLET

Figure A1 - Q-system calculation based on structural domains; Stations 5+500 to 2+600

Nova Scotia Power Inc.
Tailrace Tunnel Inspection and LiDAR Survey

TAILRACE TUNNEL CHAINAGE (FEET)

STATION[3]	26+00	25+00	24+00	23+00	22+00	21+00	20+00	19+00	18+00	17+00	16+00	15+00	14+00	13+00	12+00	11+00	10+00	9+00	8+00	7+00	6+00	5+00	4+00	3+00	2+00	1+00	0+00	
Lithology																				SHOTCRETE							CAST CONCRETE	
Structural Domain	DOMAIN 1		4	DOMAIN 1		4	DOMAIN 3			DOMAIN 4	3	DOMAIN 1	DOMAIN 2					4	3	DOMAIN 4	Shotcrete						Concrete	
Q-SYSTEM Max	29	19	0.2	19	29	0.4	3			0.2	1.5	19	15					0.2	1.5	0.2	Shotcrete						Concrete	
Q-SYSTEM Min	11	7	0.1	7	11	0.2	0.6			0.1	0.4	7	3					0.1	0.4	0.1	Shotcrete						Concrete	
RQD	66		33	66		33	33			33	33	66	66					33	33	33	Shotcrete						Concrete	
Jn Max	9		12	9		12	9			12	9	9	9					12	9	9	Shotcrete						Concrete	
Jn Min	12		12	12		12	12			12	12	12	12					12	12	12	Shotcrete						Concrete	
Jr Max	3		2	3		2	2			2	2	3	3					2	2	2	Shotcrete						Concrete	
Jr Min	2		1.5	2		1.5	1.5			1.5	1.5	2	1.5					1.5	1.5	1.5	Shotcrete						Concrete	
Ja Max	0.75		2	0.75		2	1			2	1	0.75	1					2	1	2	Shotcrete						Concrete	
Ja Min	1		3	1		3	3			3	3	1	2					3	3	3	Shotcrete						Concrete	
Jw	1		0.66			1				0.66											Shotcrete						Concrete	
SRF	1		7.5	1		7.5	2.5			7.5	2.5	1	1					7.5	2.5	7.5	Shotcrete						Concrete	

Domains

1		Fine to medium grained; massive; grey; Diorite/Granodiorite to Pink Granite
2		Fine to medium grained; massive; grey; Diorite/Granodiorite to Pink Granite intruded by up to 30% Mafic Dykes
3		Sheared/Faulted; grey to pink; granite to granitic gniess
4		Fault/shear zones; lithologically often Unit 3

Q-SYSTEM - ROCK QUALITY	
0.1 - 1.0 - VERY POOR ROCK	
1- 4 - POOR ROCK	
4 - 10 - FAIR ROCK	
10 - 40 - GOOD ROCK	
40 - 100 - VERY GOOD ROCK	
>100 - EXTREMELY GOOD	N/A

NOTES:
1. VALUES IN Q THAT REPRESENT PROPERTIES OF THE ENTIRE ROCK MASS (i.e. RQD, J_w AND SRF) IN AN AREA WERE MEASURED/ESTIMATED BASED ON FILED OBSERVATIONS.
2. VALUES IN Q THAT REPRESENT THE INDIVIDUAL DISCONTINUITY CONDITIONS (i.e. Jn, J, AND J_a) WERE GIVEN A RANGE TO ACCOUNT FOR VARIABLITY IN THE VARIOUS DISCONTINUITY SETS
3. STATION 0+00 IS LOCATED WITHIN THE CAST CONCRETE SECTION NEAR THE OUTLET

Figure A2 - Q-system calculation based on structural domains; Stations 2+600 to -0+000

APPENDIX B
TAILRACE TUNNEL INSPECTION - PHOTO LIBRARY

Station: 4+525

Description: Shotcrete not covering mesh with seepage at bolt locations

Mesh without shotcrete

Seepage at bolts

Station: 4+525

Description: Shotcrete not covering mesh

Mesh without shotcrete

Station: 4+500

Description: Shotcrete good condition floor north wall

Station: 4+500

Description: Deteriorating shotcrete

Station: 4+450

Description: Start of large debris pile

Station: 4+450

Description: Looking down tunnel at large debris pile

Station: 4+450

Description: Looking down tunnel at large debris pile

Station: 4+400

Description: Fault North wall

Station: 4+400

Description: Typical Crown

Station: 4+300

Description: Typical Crown

Station: 4+275

Description: Crown, previous wedge failure

Station: 4+275

Description: On going, fresh ravelling on floor

Station: 4+200

Description: Typical Crown

Station: 4+300

Description: Typical Crown

Station: 4+075

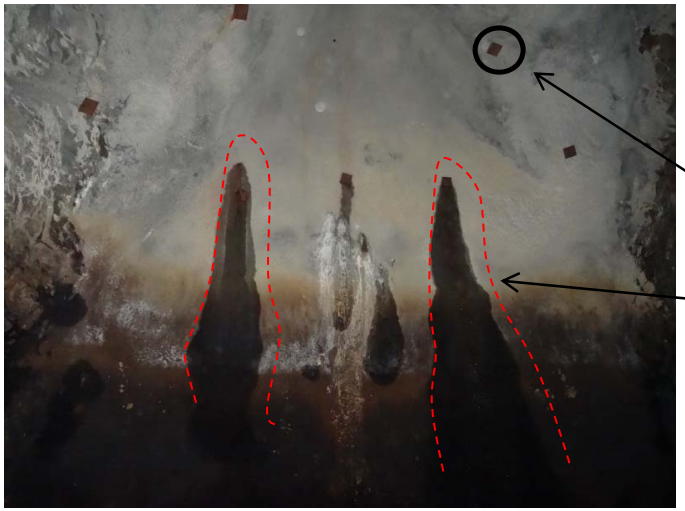
Description: Typical slightly weathered medium to coarse grained granite

Station: 4+050

Description: Seepage on crown

Station: 4+000

Description: Typical Crown



Station: 3+975

Description: Seepage through shotcrete corroded bolts

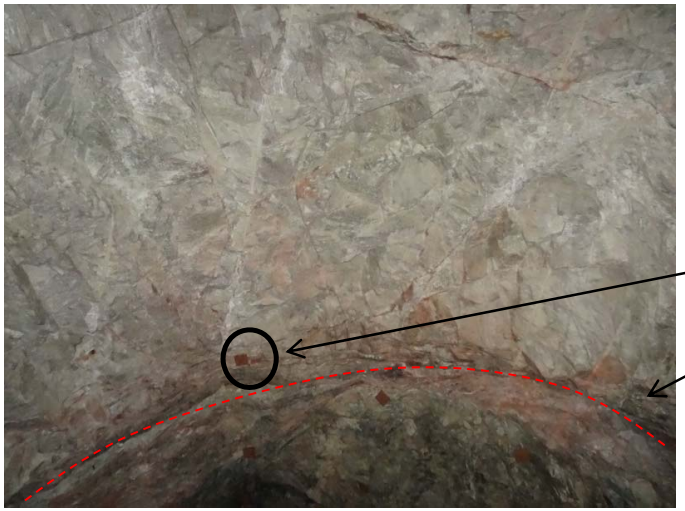
Corroded bolts

Seepage through shotcrete

Station: 3+950

Description: Corroded bolts

Corroded bolt

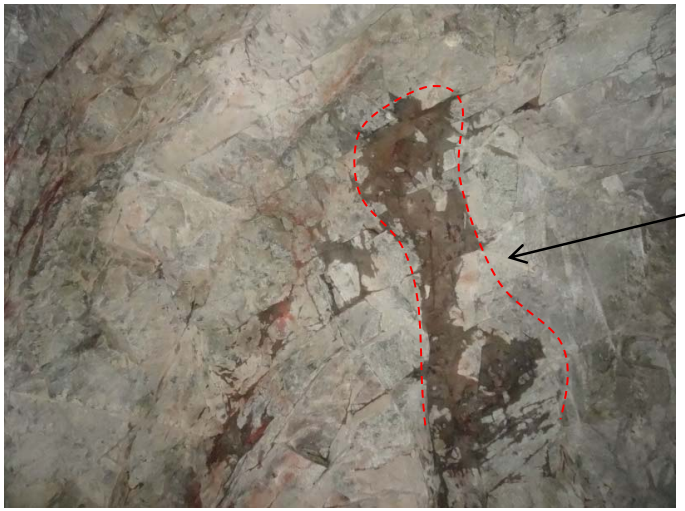


Station: 3+925

Description: Fault / shear zone corroded bolts

Corroded bolt

Fault/shear zone



Station: 3+900

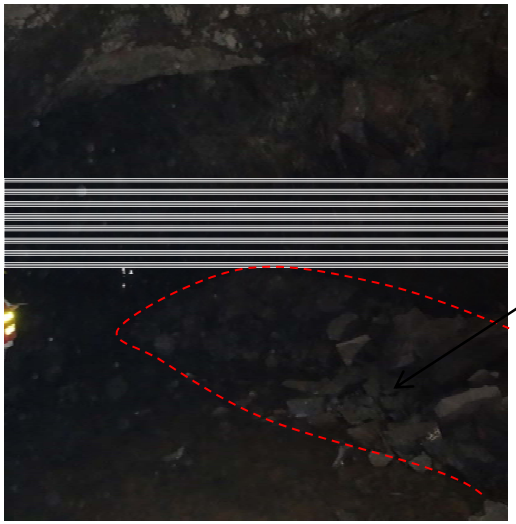
Description: Crown, seepage along discontinuities

Station: 3+825

Description: Potential Wedge

Station: 3+800

Description: Shear zone with hematite alteration (red staining) along discontinuity contact.



Station: 3+800

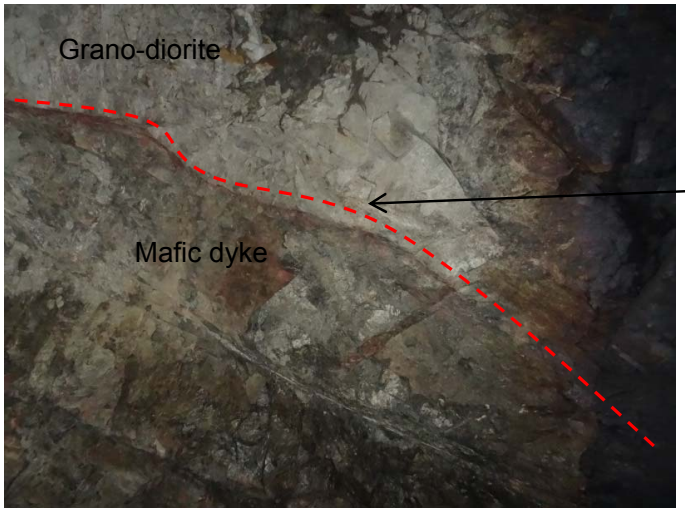
Description: Rock fall debris pile

Station: 3+800

Description: Typical Crown

Station: 3+700

Description: Crown, fault zone



Station: 3+650

Description: Contact between mafic dyke and grano-diorite, with red, hematite alteration.

Station: 3+625

Description: Seepage on wall

Station: 3+625

Description: Recently failed wedge

Station: 3+600

Description: Typical Crown

Station: 3+500

Description: Past Rock fall

Station: 3+500

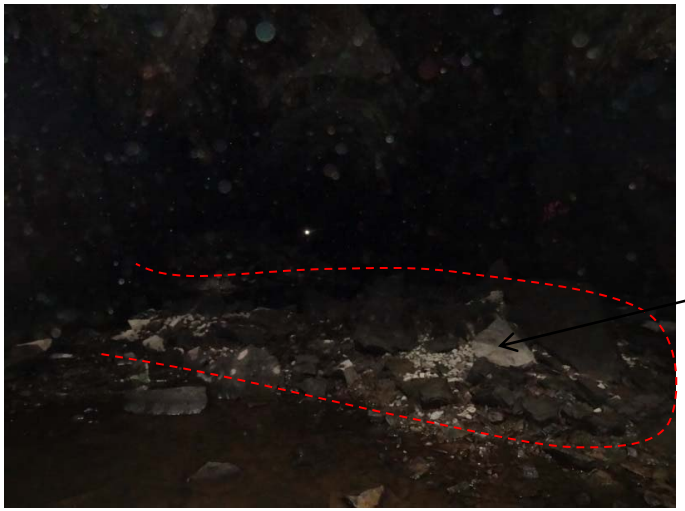
Description: Looking down tunnel at debris pile nearly crossing tunnel

Station: 3+500

Description: Typical Crown

Station: 3+450

Description: Shear zone



Station: 3+425

Description: Looking up tunnel at debris pile across tunnel, note fresh grey rock

Debris pile with freshly fallen (grey/white) rock

Station: 3+400

Description: Typical Crown

Station: 3+325

Description: Past Wedge Instability

Station: 3+300

Description: Large slab noted by Golder

Station: 3+300

Description: Typical Crown

Station: 3+200

Description: Rock slab

Station: 3+200

Description: Typical Crown

Station: 3+175

Description: Recently Fallen Rock slab

Station: 3+175

Description: Recently Fallen Rock slab

Station: 3+175

Description: Relatively fresh fallen rock

Station: 3+175

Description: Freshly fallen rock

Station: 3+175

Description: Fresh grano-diorite from recent fall

Station: 3+150

Description: Large wedge with assessed high likelihood of future failure

Station: 3+100

Description: Typical Crown

Station: 3+000

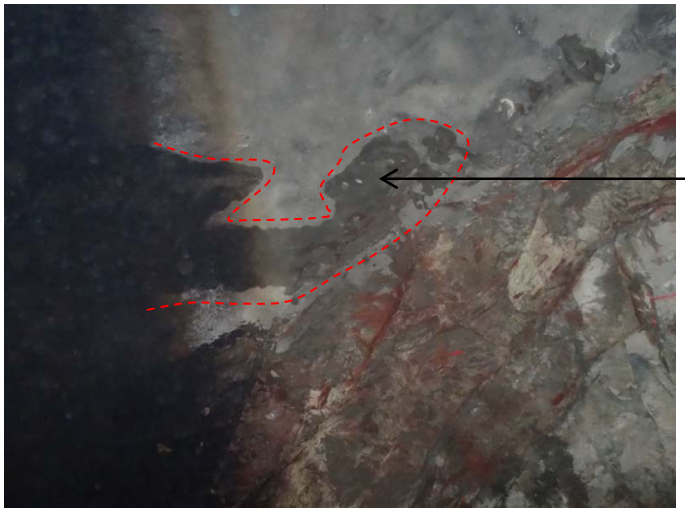
Description: Typical Crown

Station: 2+900

Description: Typical Crown

Station: 2+800

Description: Crown, corroded bolts

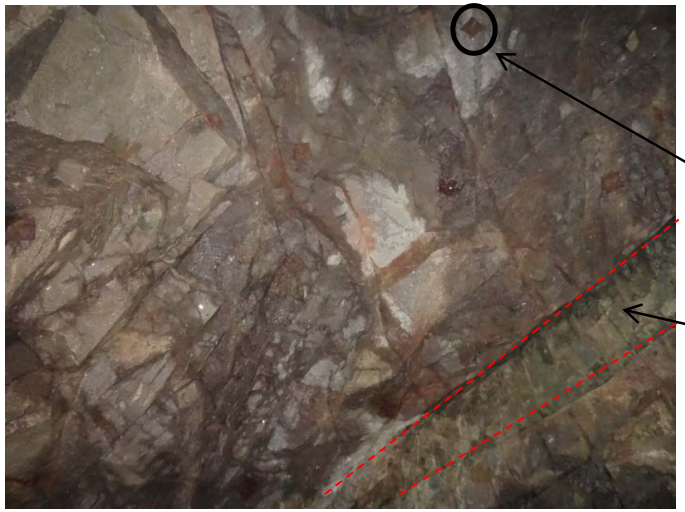


Station: 2+750

Description: Seepage through shotcrete

Station: 2+750

Description: Hydraulic blowout in shotcrete



Station: 2+750

Description: Mafic dyke and corroded bolts

Corroded bolts

Mafic dyke

Station: 2+600

Description: North wall small scale shear zone

Station: 2+600

Description: Crown shear zone

Station: 2+400

Description: South wall fresh rock fall

Station: 2+375

Description: South wall, fault zone, breccia, clay gouge matrix

Station: 2+200

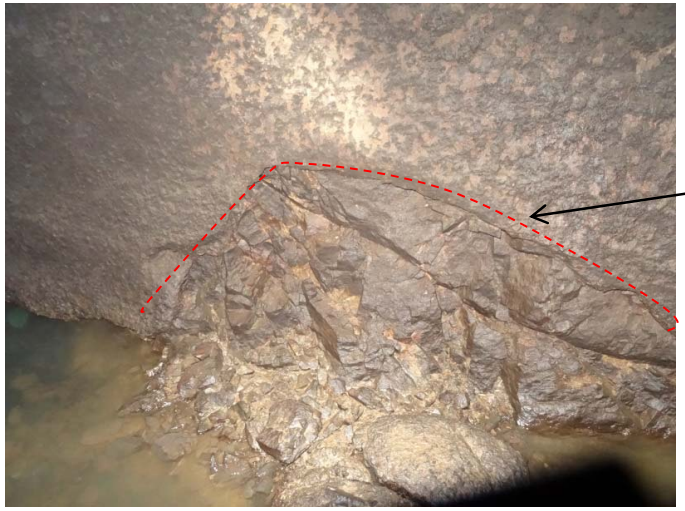
Description: Fresh fallen rock and a potential wedge failure with open joints.

Station: 2+200

Description: Debris pile, fresh rock

Station: 2+175

Description: Fault north wall, hematite alteration along fault



Station: 1+875

Description: Scour at base of shotcrete

Station: 1+850

Description: Dyke hematite alteration (red)

Station: 1+800

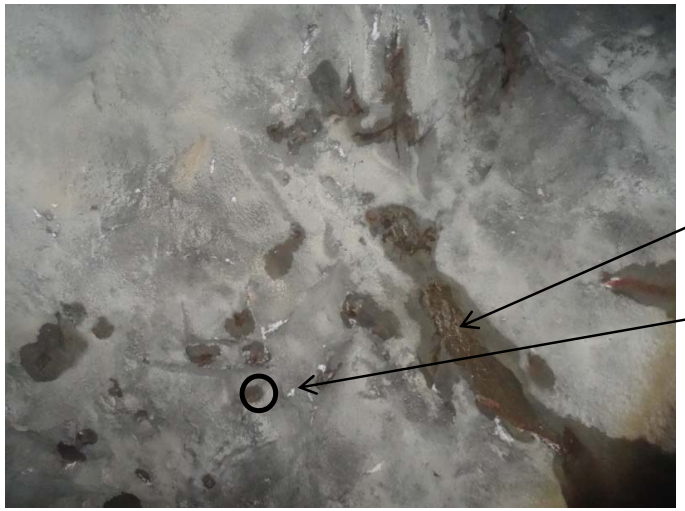
Description: South wall and crown recent wedge failure

Station: 1+750

Description: Area of past wedge failure from the crown and North wall looking West

Station: 1+625

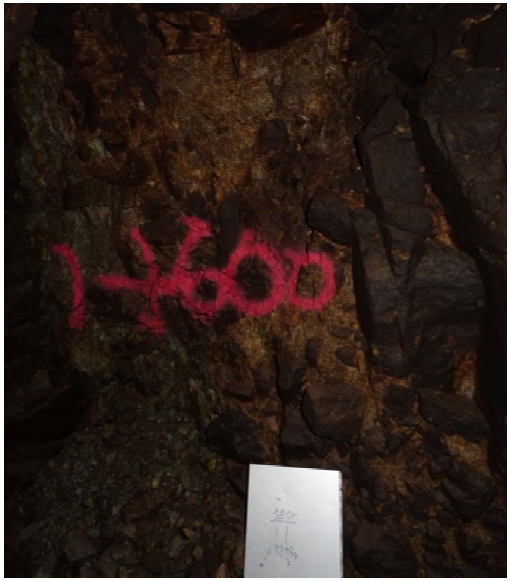
Description: Wall scour of the South wall near the floor



Station: 1+625

Description: Shotcrete with water seeping and dripping at bolts

Seepage at rock bolt



Station: 1+600

Description: North wall scour in shotcrete at fault zone

Station: 1+575

Description: Wall, Scour of a fault zone and ravelling

Station: 1+400

Description: South wall scour at a fault that is undercutting a potential slab failure

Station: 1+400

Description: South wall close up of a fault

Station: 1+300

Description: Typical crown

Station: 1+250

Description: Heavily corroded bolt at fault zone

Station: 1+200

Description: Crown, typical view

Station: 1+100

Description: Crown, typical view

Station: 1+050

Description: Crown shotcrete: good condition minor water seepage

Seepage

APPENDIX C
STRUCTURAL DATA FROM TAILRACE TUNNEL

Structural Geology Data - Compass Declination -18.5° W

Station Interval	Type	Dip (°)	Dip Direction (°)	Comments
55+00 - 54+00	S1	60	238	At the upstream manifold below the power house
54+00 - 53+00	S1	55	282	
54+00 - 53+00	J_1	80	240	
54+00 - 53+00	J_2	72	30	
53+00 - 52+00	S1	60	296	
53+00 - 52+00	J_2	55	66	
53+00 - 52+00		55	316	
52+00 - 51+00	S1	40	272	
52+00 - 51+00	J_1	85	270	
51+00 - 50+00	S1	67	250	
51+00 - 50+00	J_2	60	30	
50+00 - 49+00	J_1	85	235	
50+00 - 49+00	J_2	60	30	
50+00 - 49+00	S1	60	292	
49+00 - 48+00	S1	60	240	
49+00 - 48+00	J_2	45	45	
48+00 - 47+00	J_1	70	248	
48+00 - 47+00	J_2	63	70	
47+00 - 46+00	S1	50	304	
47+00 - 46+00	J_2	62	41	
47+00 - 46+00	J_2	60	40	
46+00 - 45+00	S1	62	308	
46+00 - 45+00	J_2	85	72	
45+00 - 44+00	J_1	70	308	lagre cavern location
45+00 - 44+00	J_2	50	60	
44+00 - 43+00	J_2	63	38	
44+00 - 43+00	S1	65	298	
43+00 - 42+00	J_1	76	289	
42+00 - 41+00	J_1	70	335	
42+00 - 41+00	J_2	60	108	
41+00 - 40+00		62	142	
41+00 - 40+00	S1	40	235	
40+00 - 39+00	S1	60	250	
40+00 - 39+00	J_2	52	37	
40+00 - 39+00	J_3	88	0	estimate from crown
39+00 - 38+00	S1	61	232	
39+00 - 38+00		70	150	
39+00 - 38+00		83	320	
39+00 - 38+00	J_3	87	182	estimate from crown
38+00 - 37+00	S1	65	250	
38+00 - 37+00	J_2	51	75	
38+00 - 37+00		75	340	
37+00 - 36+00	S1	52	258	
37+00 - 36+00		55	140	

Structural Geology Data - Compass Declination -18.5° W

Station Interval	Type	Dip (°)	Dip Direction (°)	Comments
37+00 - 36+00	J_3	75	340	
36+00 - 35+00	J_3	65	330	
36+00 - 35+00	S1	63	257	
36+00 - 35+00	J_2	88	88	
35+00 - 34+00		70	102	
35+00 - 34+00	S1	50	235	
35+00 - 34+00	J_3	55	335	
35+00 - 34+00	J_2	53	51	
34+00 - 33+00		63	137	
34+00 - 33+00	J_1	70	256	
34+00 - 33+00	J_1	75	235	
33+00 - 32+00	J_3	50	320	
33+00 - 32+00	S1	68	250	
33+00 - 32+00		60	150	
32+00 - 31+00	J_3	70	313	
32+00 - 31+00		52	178	
31+00 - 30+00	S1	55	287	
30+00 - 29+00	J_3	58	328	
29+00 - 28+00	J_3	53	335	
29+00 - 28+00	J_2	67	62	
28+00 - 27+00	J_3	60	332	
28+00 - 27+00	S1	68	292	
28+00 - 27+00	J_2	52	60	
27+00 - 26+00	S1	47	298	
27+00 - 26+00	J_2	75	35	
27+00 - 26+00		80	74	
26+00 - 25+00	S1	45	300	
26+00 - 25+00	Sz	47	312	
26+00 - 25+00		57	155	
26+00 - 25+00	J_3	80	18	
25+00 - 24+00		61	178	
25+00 - 24+00		70	148	
25+00 - 24+00	J_3	89	356	
24+00 - 23+00	S1	50	278	
24+00 - 23+00		46	141	
23+00 - 22+00	S1	60	282	
23+00 - 22+00		30	330	
23+00 - 22+00		35	30	
23+00 - 22+00		70	50	
22+00 - 21+00	S1	70	262	
22+00 - 21+00		55	114	
22+00 - 21+00		75	148	
19+00 - 18+00	J_3	85	330	
19+00 - 18+00		50	118	
18+00 - 17+00	S1	46	310	

Structural Geology Data - Compass Declination -18.5° W

Station Interval	Type	Dip (°)	Dip Direction (°)	Comments
18+00 - 17+00		35	148	
18+00 - 17+00		89	119	
16+00 - 15+00	S1	49	307	
16+00 - 15+00		45	108	
15+00 - 14+00	J_3	60	355	
15+00 - 14+00	J_2	85	98	
15+00 - 14+00	J_3	60	355	
15+00 - 14+00	J_2	85	98	
13+00 - 12+00	S1	45	285	
13+00 - 12+00	J_2	40	40	
12+00 - 11+00		58	140	
12+00 - 11+00		40	289	
12+00 - 11+00		50	12	
11+00 - 10+00	S1	56	296	
11+00 - 10+00	J_3	83	38	
11+00 - 10+00		89	110	
10+00 - 9+00	J_2	72	74	

APPENDIX D
TAILRACE TUNNEL LIDAR SLOPE SHADE IMAGES 0+000 to 1+700

Nova Scotia Power Inc.
Tailrace Tunnel Inspection and LiDAR Survey

April 1, 2016
Project No.: 1009-002

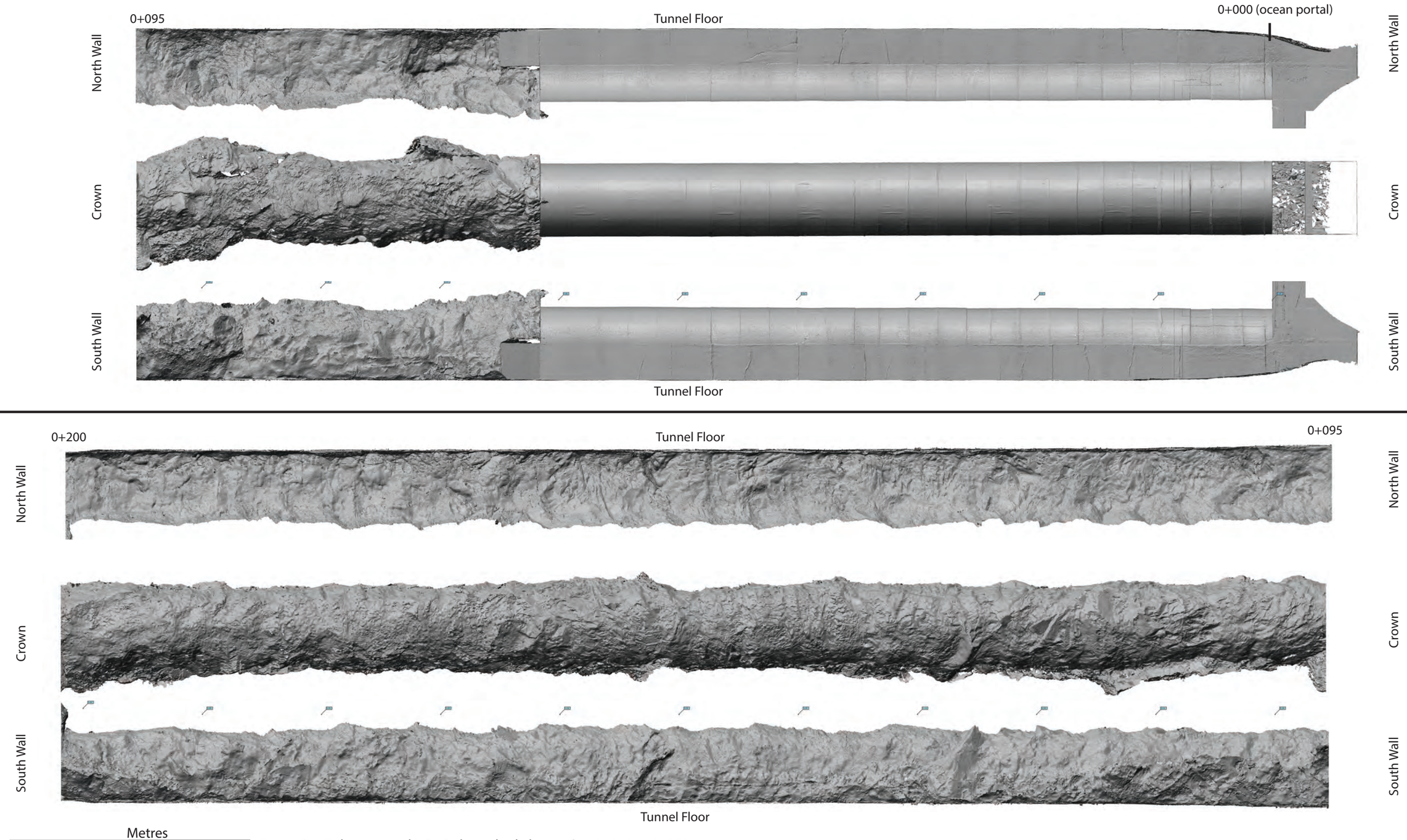


Figure D1: Tailrace tunnel LiDAR slope shade layout Sta. 0+000 to 0+200

Nova Scotia Power Inc.
Tailrace Tunnel Inspection and LiDAR Survey

April 1, 2016
Project No.: 1009-002

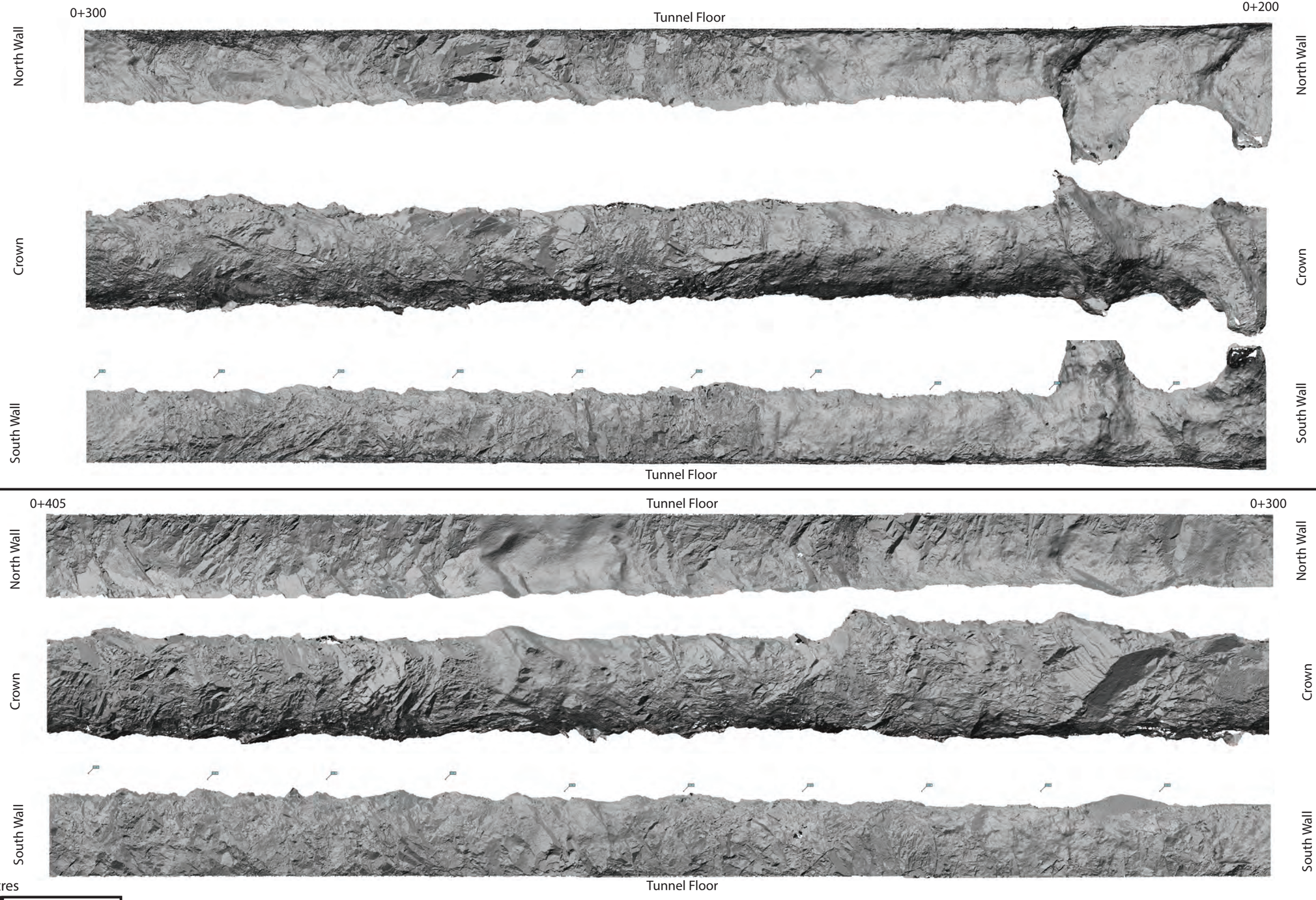


Figure B0: Tailrace tunnel LiDAR slope shade layout Sta. 0+200 to 0+400

Nova Scotia Power Inc.
Tailrace Tunnel Inspection and LiDAR Survey

April 1, 2016
Project No.: 1009-002

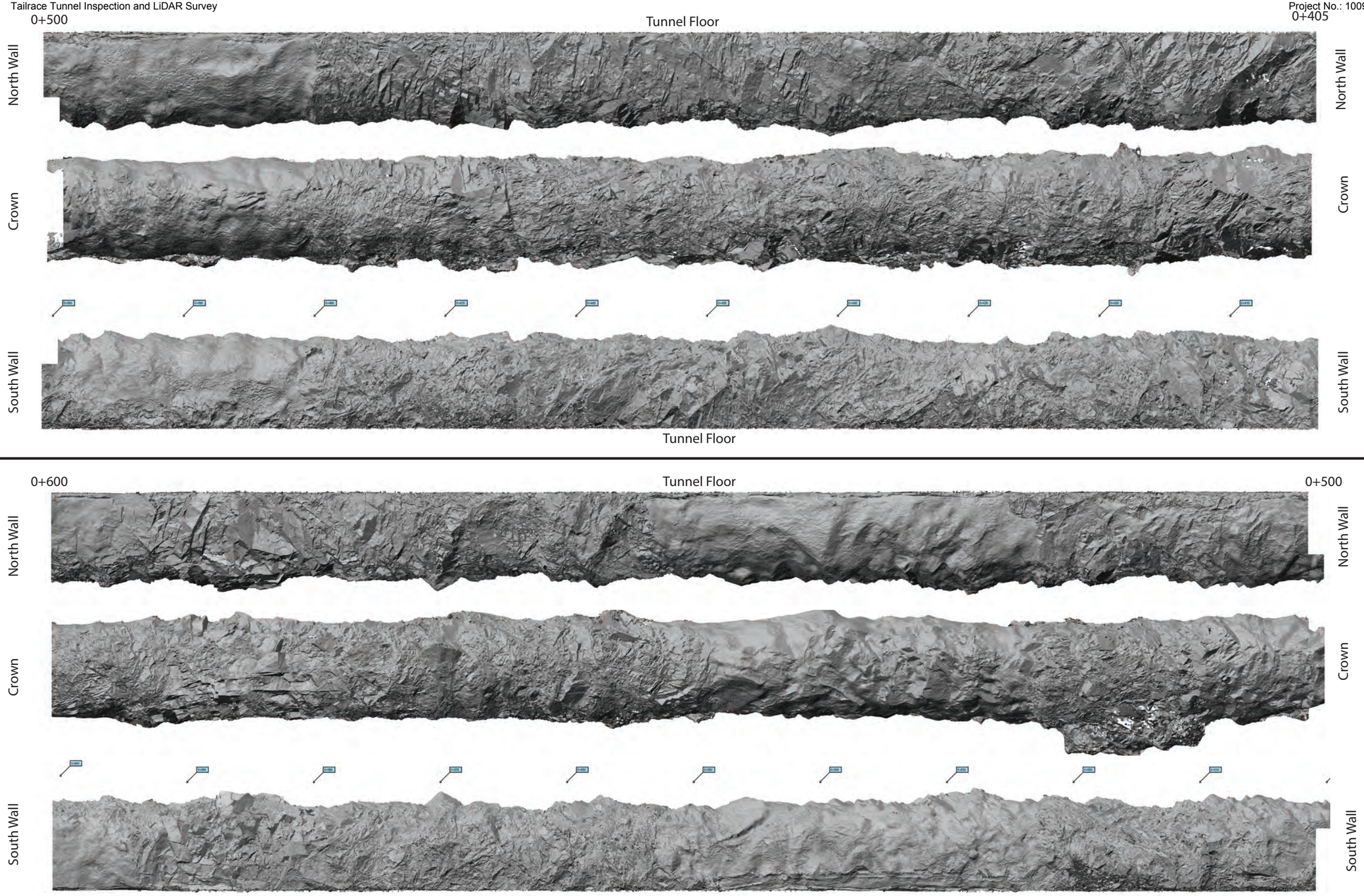


Figure D3: Tailrace tunnel LiDAR slope shade layout Sta. 0+400 to 0+600

Nova Scotia Power Inc.
Tailrace Tunnel Inspection and LiDAR Survey

April 1, 2016
Project No.: 1009-002

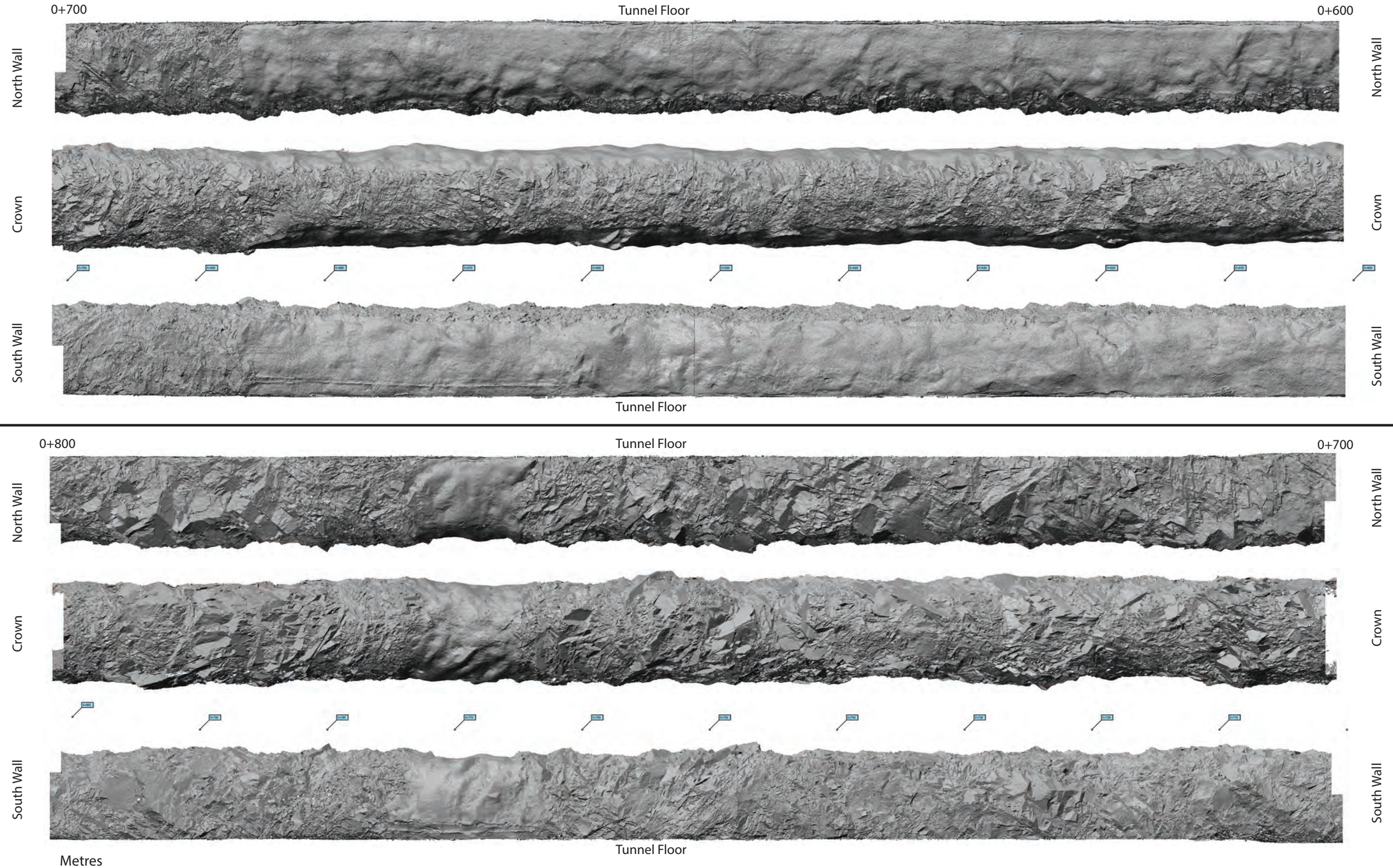


Figure D4: Tailrace tunnel LiDAR slope shade layout Sta. 0+600 to 0+800

Nova Scotia Power Inc.
Tailrace Tunnel Inspection and LiDAR Survey

April 1, 2016
Project No.: 1009-002

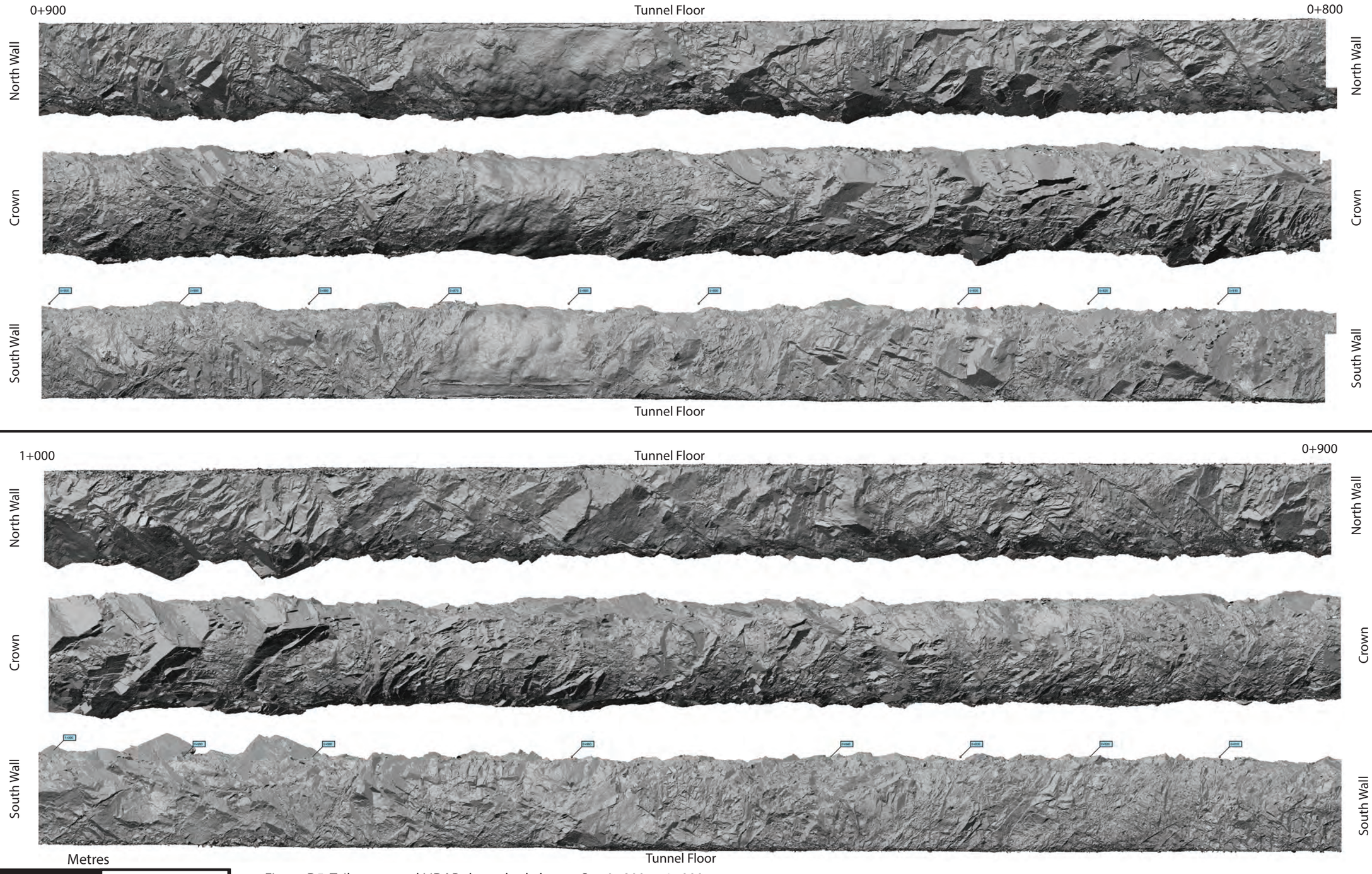


Figure D5: Tailrace tunnel LiDAR slope shade layout Sta. 0+800 to 1+000

Nova Scotia Power Inc.
Tailrace Tunnel Inspection and LiDAR Survey

April 1, 2016
Project No.: 1009-002

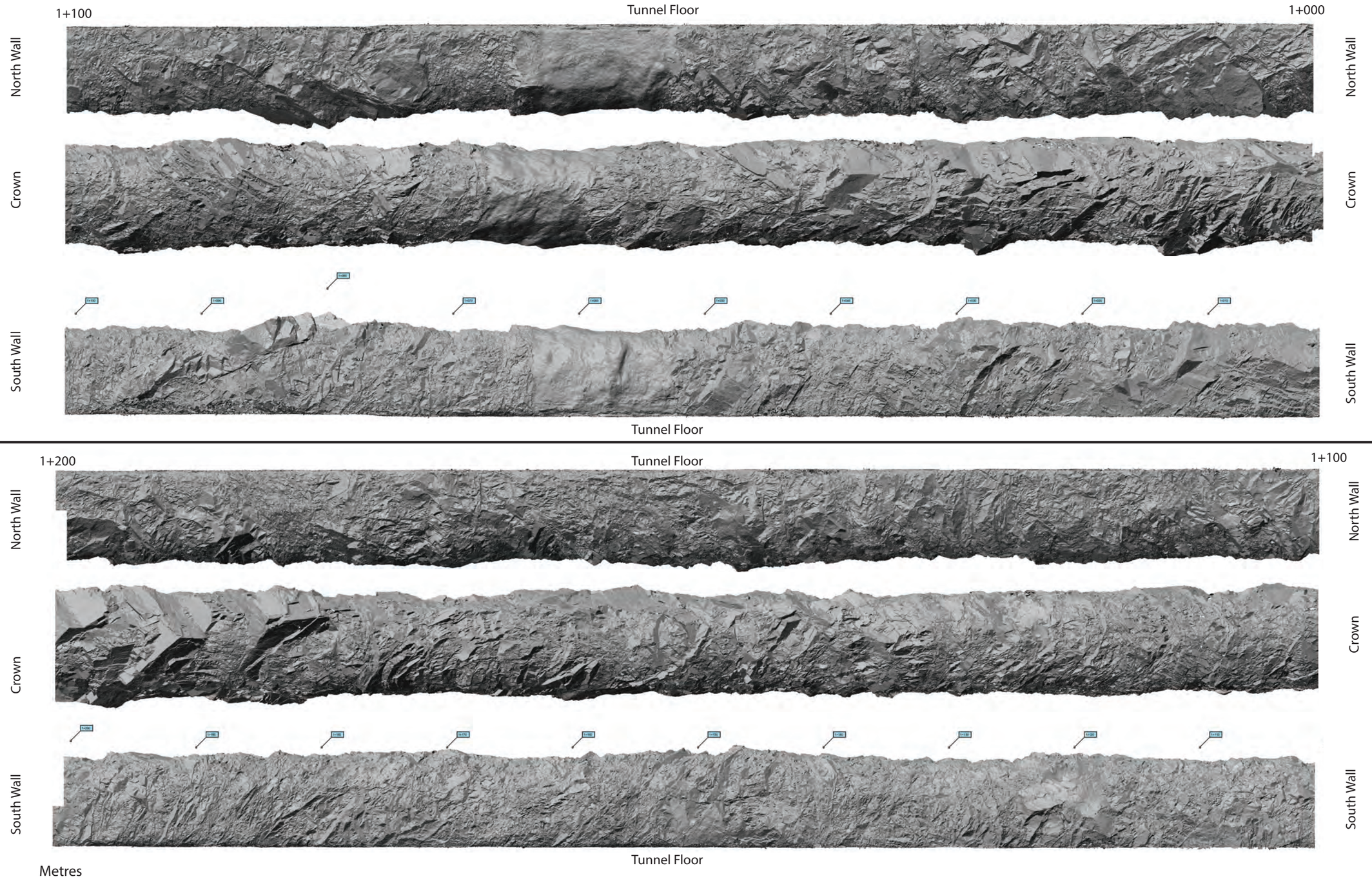
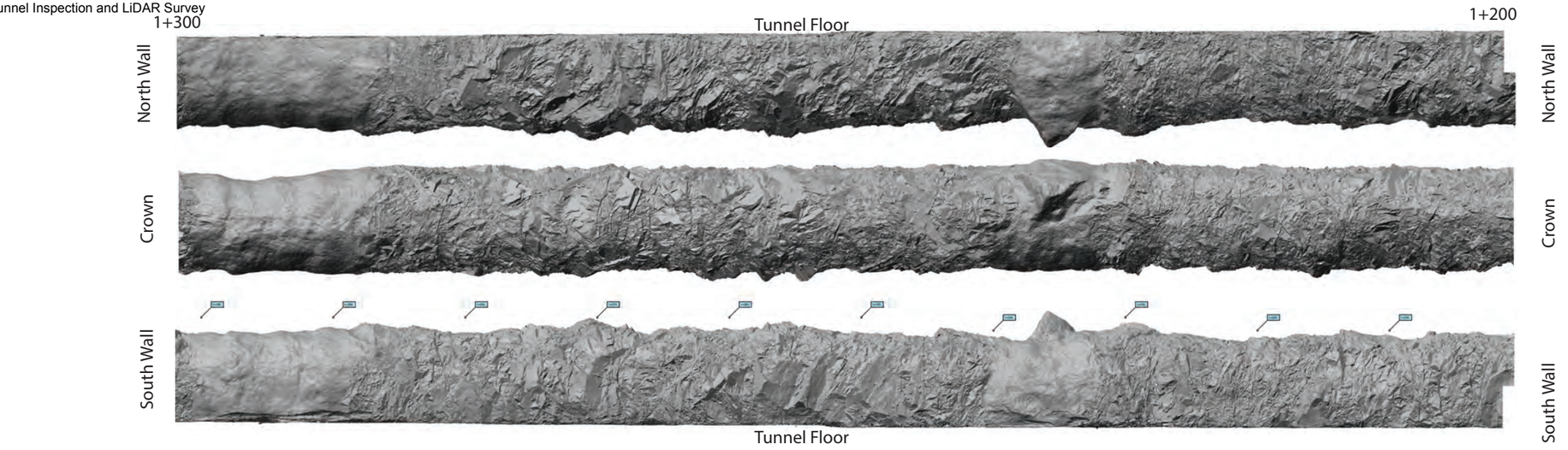
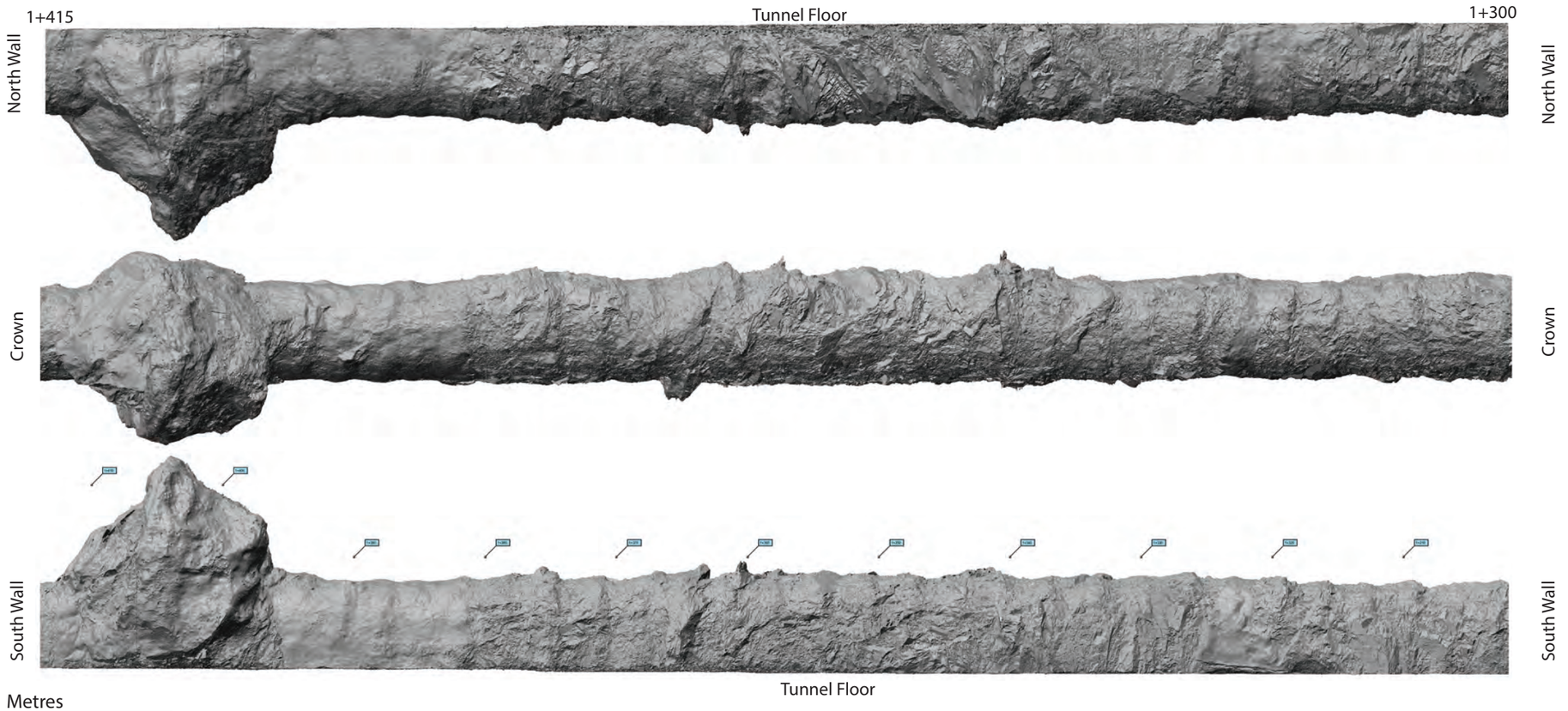


Figure D6: Tailrace tunnel LiDAR slope shade layout Sta. 1+000 to 1+200

Nova Scotia Power Inc.
Tailrace Tunnel Inspection and LiDAR Survey

April 1, 2016
Project No.: 1009-002





Metres
0 10 20

Figure D7: Tailrace tunnel LiDAR slope shade layout Sta. 1+200 to 1+400

Nova Scotia Power Inc.
Tailrace Tunnel Inspection and LiDAR Survey

April 1, 2016
Project No.: 1009-002

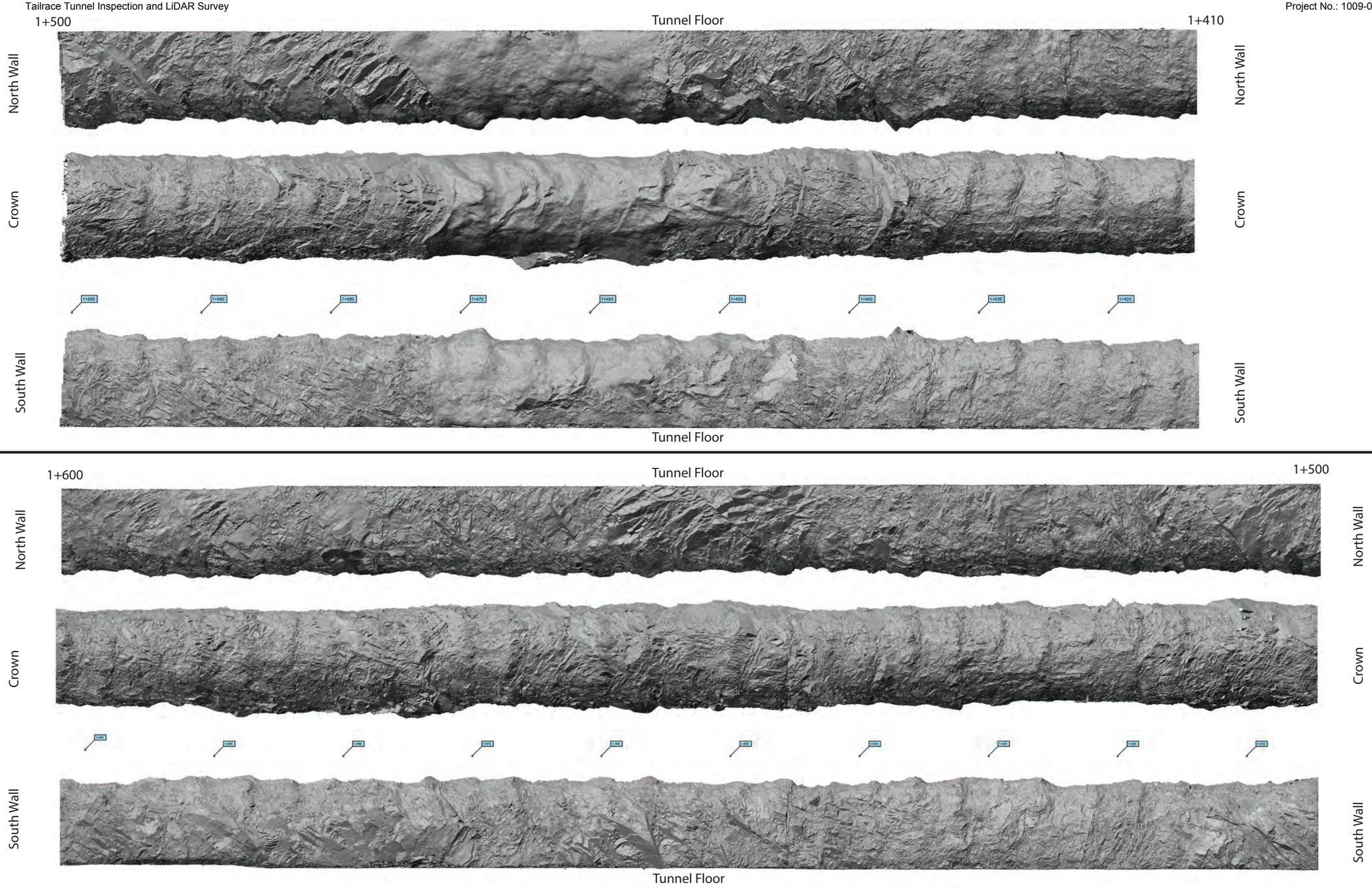
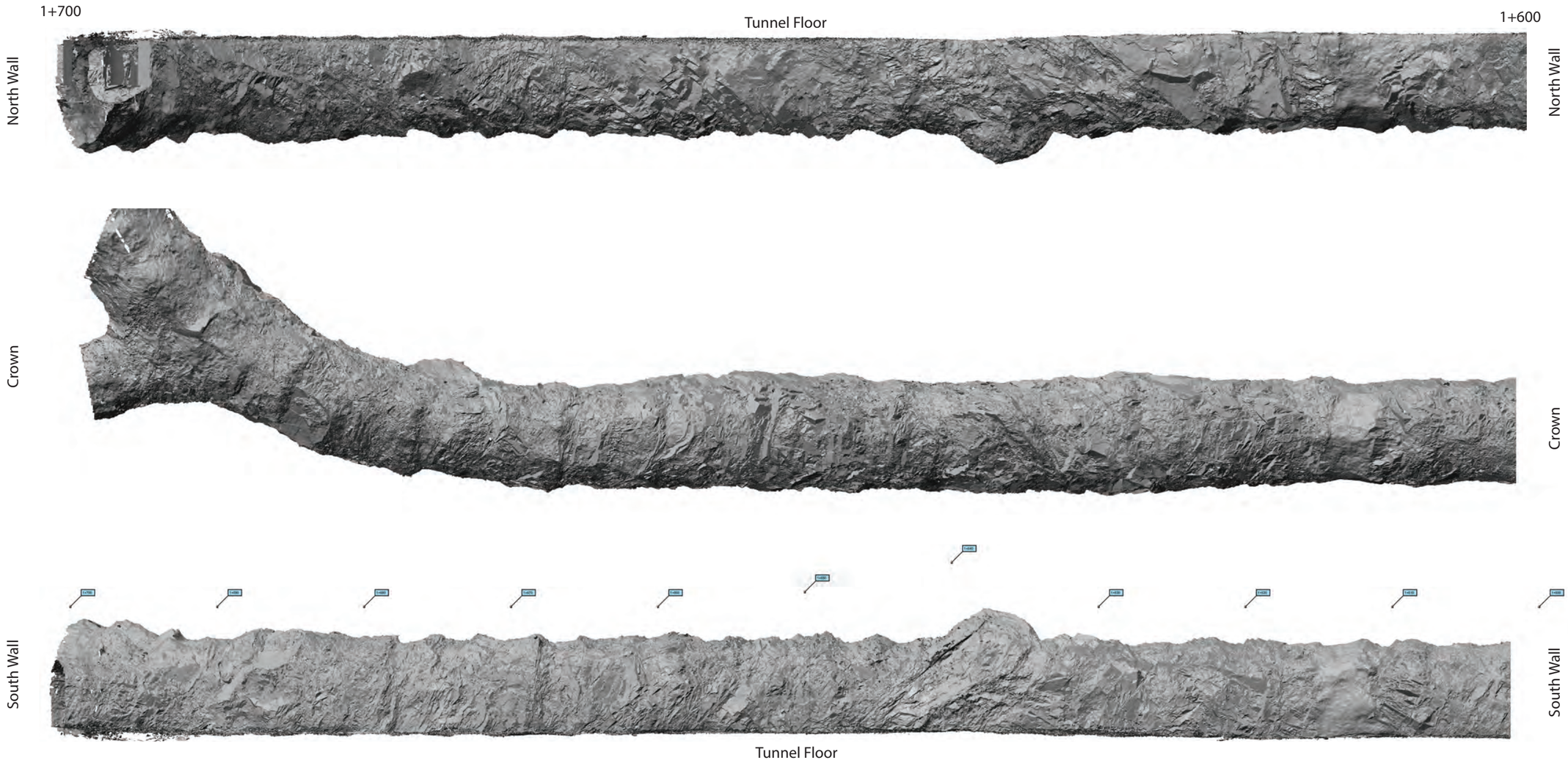


Figure D8: Tailrace tunnel LiDAR slope shade layout Sta. 1+400 to 1+600

Nova Scotia Power Inc.
Tailrace Tunnel Inspection and LiDAR Survey

April 1, 2016
Project No.: 1009-002



Metres
0 10 20

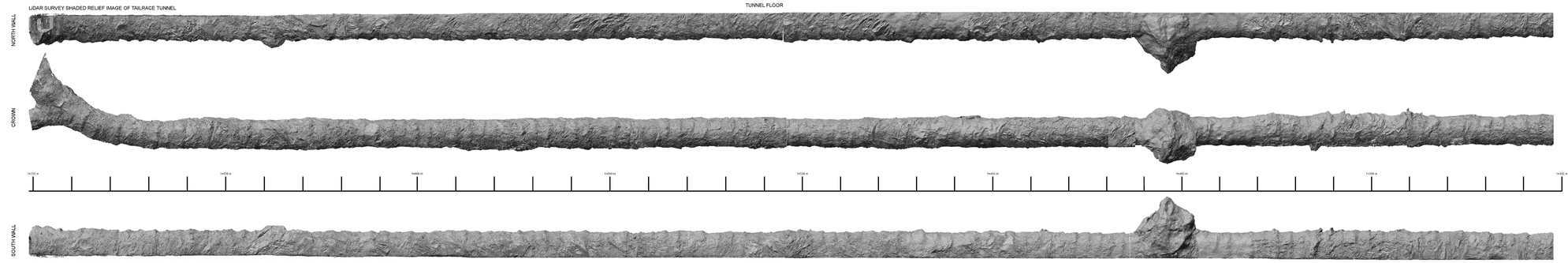
Figure D9: Tailrace tunnel LiDAR slope shade layout Sta. 1+600 to 1+700

DRAWINGS

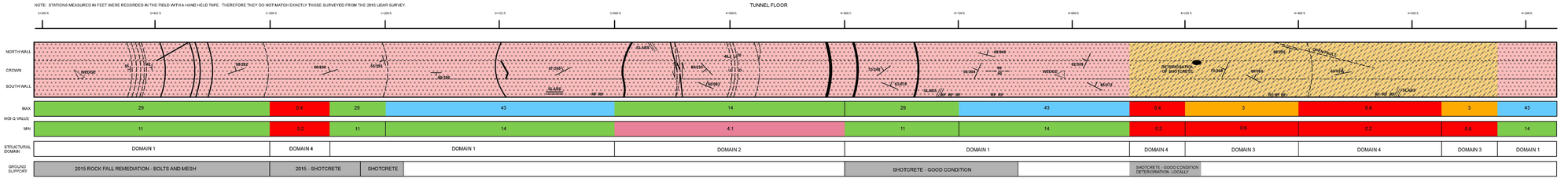
THIS BAR MEASURES 100 mm AT FULL SIZE. ALL SCALES REFERENCED TO FULL SIZE

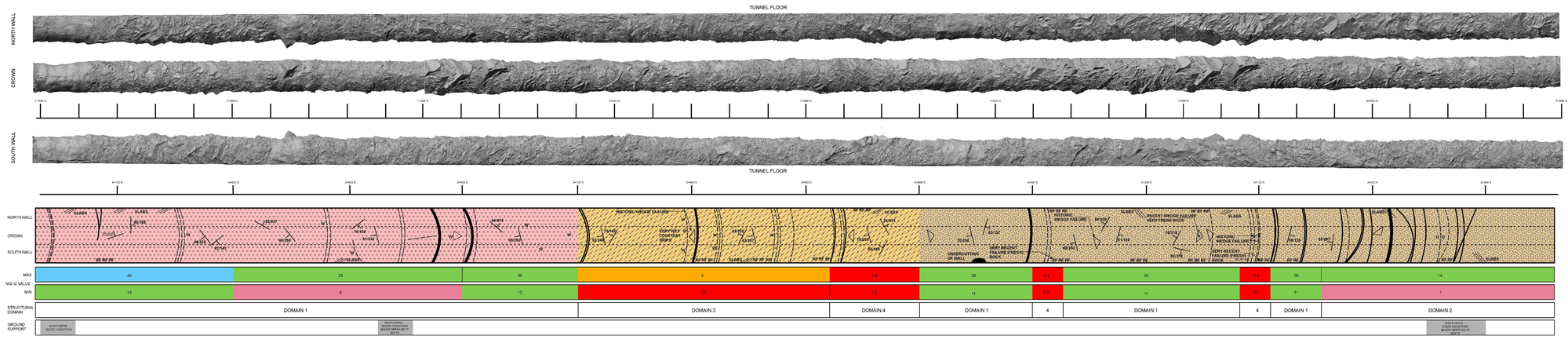
Y:\Projects\1009\002\GENERAL\CAD\PRODUCTION\REPORT\WRECK COVE HYDROELECTRIC GENERATING STATION\01-TAILRACE_TUNNEL_INSPECTION\LIDAR_SURVEY.dwg Layout: RM-E-SIZE Plot Date: oct 21 15 Time: 2:12

LIDAR SURVEY SHADED RELIEF IMAGE OF TAILRACE TUNNEL



NOTE: STATIONS MEASURED IN FEET WERE RECORDED IN THE FIELD WITH A HAND HELD TAPE. THEREFORE THEY DO NOT MATCH EXACTLY THOSE SURVEYED FROM THE 2015 LIDAR SURVEY.





LEGEND

LITHOLOGY

- Unit 1 - Fine to medium grained, occasionally coarse grained; massive to moderately well foliated; grey to dark grey; Diorite to Granodiorite.
- Unit 2 - Fine to medium grained, occasionally coarse grained; massive to moderately well foliated; pink; Granite to Grano-diorite.
- Unit 3 – Fine- to medium-grained; sheared with very well developed foliation; pink to grey; Sheared Granite to Granitic Gniess.

STRUCTURAL DOMAINS

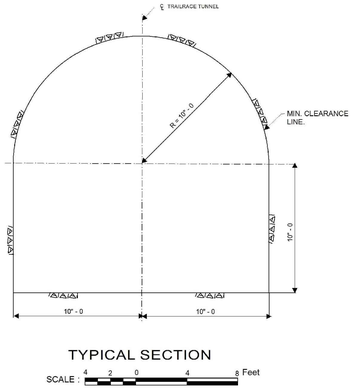
1. Unit 1 and Unit 2; fine to medium grained, occasionally coarse grained; red, grey and dark grey; granite, grano-diorite and diorite.
2. Unit 1 and Unit 2 that has been intruded by up to 30% mafic dykes.
3. Unit 3 – Fine- to medium-grained; sheared with very well developed foliation; pink to-grey; sheared granite to granitic gniess.
4. Fault/shear zones with ongoing ravelling; lithologically, often unit 3.

Q-SYSTEM ROCK QUALITY

- 40 - 100 - VERY GOOD ROCK
- 10 - 40 - GOOD ROCK
- 4 - 10 - FAIR ROCK
- 1- 4 - POOR ROCK
- 0.1 - 1.0 - VERY POOR ROCK

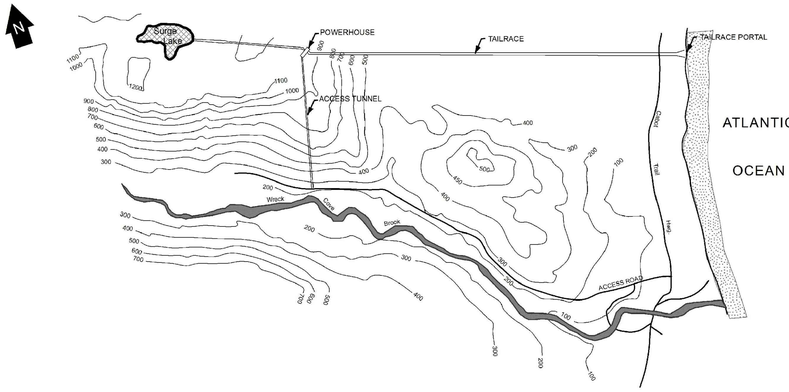
SYMBOLS

- MAFIC DYKE
- ROCK FALL DEBRIS ON FLOOR OF TUNNEL
- POTENTIAL FOR SMALL SCALE SLAB INSTABILITIES ALONG WALL
- FAULT OR SHEAR ZONE
- RELATIVE STRIKE-SLIP MOVEMENT ON FAULT
- RELATIVE REVERSE MOVEMENT ON FAULT
- DIP AND DIP DIRECTION OF DOMINANT DISCONTINUITY SETS
- W — WATER DRIPPING FROM CROWN



TYPICAL SECTION

SCALE : 4 2 0 4 8 Feet



LOCATION PLAN

SCALE: 800 400 0 800 1,600 Feet

SCALE 1" = 40'

40 0 40 80 120

FEET

THIS DRAWING MAY HAVE BEEN REDUCED OR ENLARGED.
ALL FRACTIONAL SCALE NOTATIONS INDICATED ARE BASED ON ORIGINAL FORMAT DRAWINGS. D

NOTES:

1. ALL DIMENSIONS ARE IN FEET UNLESS OTHERWISE NOTED.
2. THIS DRAWING MUST BE READ IN CONJUNCTION WITH BGC'S REPORT TITLED "WRECK COVE HYDROELECTRIC GENERATING STATION, TAILRACE TUNNEL INSPECTION AND LIDAR SURVEY", AND DATED DECEMBER 21, 2015.
3. UNLESS BGC AGREES OTHERWISE IN WRITING, THIS DRAWING SHALL NOT BE MODIFIED OR USED FOR ANY PURPOSE OTHER THAN THE PURPOSE FOR WHICH BGC GENERATED IT. BGC SHALL HAVE NO LIABILITY FOR ANY DAMAGES OR LOSS ARISING IN ANY WAY FROM ANY USE OR MODIFICATION OF THIS DOCUMENT NOT AUTHORIZED BY BGC. ANY USE OF OR RELIANCE UPON THIS DOCUMENT OR ITS CONTENT BY THIRD PARTIES SHALL BE AT SUCH THIRD PARTIES' SOLE RISK.

SCALE:	AS SHOWN
DATE:	DEC 2015
DRAWN:	TLG/HH/COC
CHECKED:	TLG
APPROVED:	SM

BGC ENGINEERING INC.
AN APPLIED EARTH SCIENCES COMPANY

CLIENT: Nova Scotia POWER An Emera Company

PROJECT: WRECK COVE HYDROELECTRIC GENERATING STATION, TAILRACE TUNNEL INSPECTION AND LIDAR SURVEY

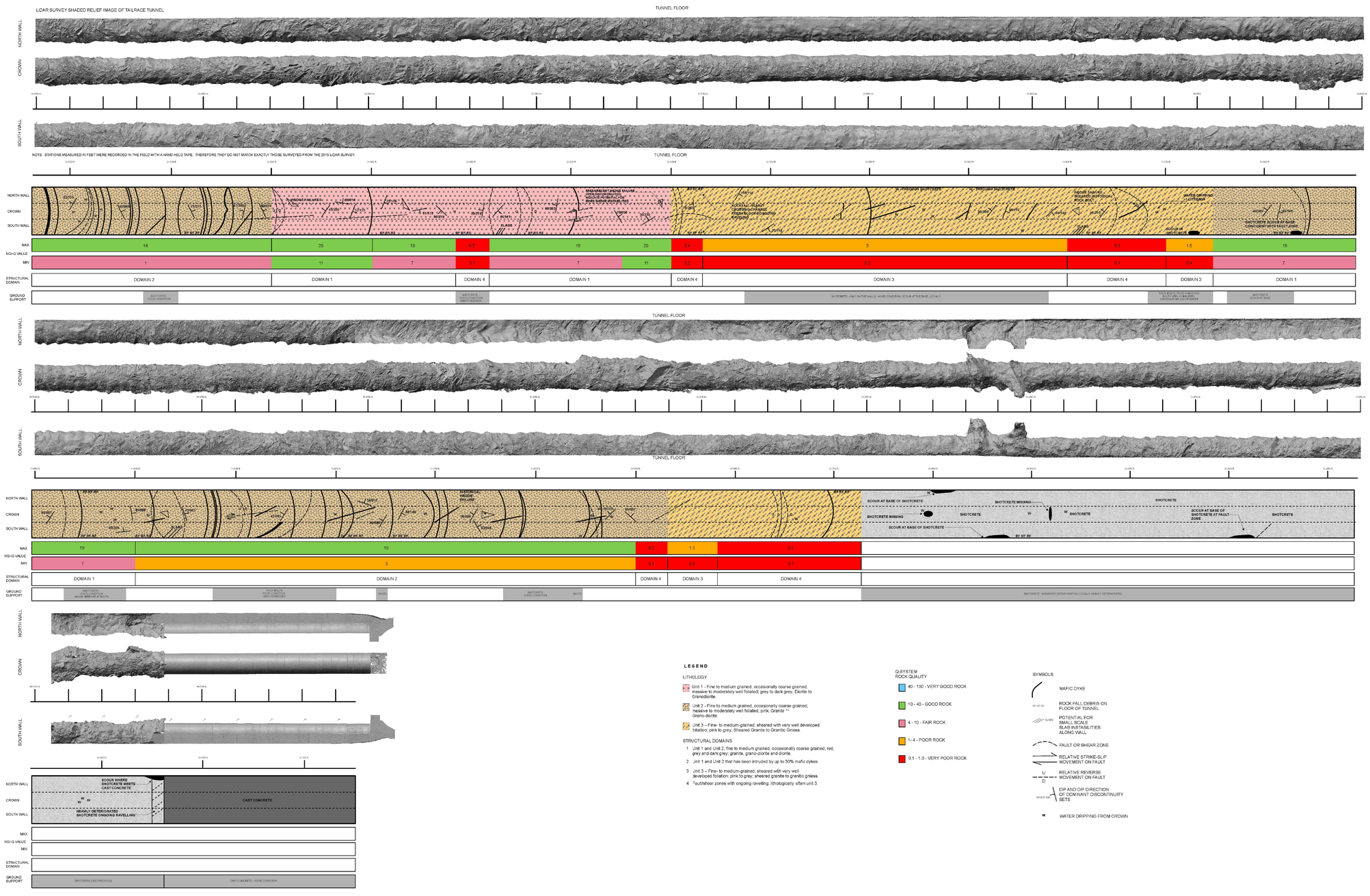
TITLE: SUMMARY OF MAPPING AND Q-SYSTEM DATA, SHEET 1 OF 2

PROJECT No.: 1009 002

DWG No.: 01

THIS BAR MEASURES 100mm AT FULL SIZE. ALL SCALES REFERENCED TO FULL SIZE

Y:\Projects\1009\002\GENERAL\CAD\PRODUCTION\REPORT\WRECK COVE HYDROELECTRIC GENERATING STATION\002-TAILRACE_TUNNEL_INSPECTION\LIDAR_SURVEY.dwg Layout: RM-E-SIZE Plot Date: dic 21 15 Time: 2:12



LEGEND

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- RELATIVE REVERSE MOVEMENT ON FAULT
- DIP AND DIP DIRECTION OF DOMINANT DISCONTINUITY SETS
- WATER DRIPPING FROM CROWN

SCALE 1" = 40'

40 0 40 80 120

FEET

THIS DRAWING MAY HAVE BEEN REDUCED OR ENLARGED. ~~ALL FRACTIONAL SCALE NOTATIONS INDICATED ARE~~ BASED ON ORIGINAL FORMAT DRAWINGS.

NOTES:

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SCALE:	AS SHOWN
DATE:	DEC 2015
DRAWN:	TLG/HH/COC
CHECKED:	TLG
APPROVED:	SM

BGC ENGINEERING INC.
AN APPLIED EARTH SCIENCES COMPANY

CLIENT: Nova Scotia POWER An Emera Company

PROJECT: WRECK COVE HYDROELECTRIC GENERATING STATION, TAILRACE TUNNEL INSPECTION AND LIDAR SURVEY

TITLE: SUMMARY OF MAPPING AND Q-SYSTEM DATA, SHEET 2 OF 2

PROJECT No.: 1009 002

DWG No.: 02

CI Number: 48533

Title: HYD Lequille Headpond Refurbishment

Start Date: 2015/12
In-Service Date: 2018/10
Final Cost Date: 2019/04
Function: Hydro
Forecast Amount: $4,472,369

DESCRIPTION:

This project includes the refurbishment of the dams and spillway structures at Lequille Headpond to meet the requirements of the latest Canadian Dam Association (CDA) Dam Safety Guidelines. This refurbishment includes the replacement of two existing tainter gates with a free overflow spillway and raising the headpond embankment dams, listed below, to ensure minimum freeboard is provided.

The Lequille Hydro System is located in Annapolis County, Nova Scotia. It was originally constructed in the late 1950s and early 1960s and underwent upgrades in 1967. The system includes three storage reservoirs: Dargie Lake, Grand Lake, and Lequille Headpond (Grand Lake Flowage). Water from the Lequille Headpond is diverted through a canal intake structure to the power canal. The power canal is approximately three miles long and terminates at the forebay, where a concrete intake structure conveys water via a 7 ft. diameter penstock to the powerhouse. The generating capacity from the Lequille System is 11 MW with a design discharge of 410 cfs.

The Lequille Headpond consists of four earthfill embankments including: the Main Dam, Wing Dams No. 3 and No. 4, and the right abutment to the intake structure, all of which can be found in Table 1 of the Executive Summary in the attached Dam Safety Review. There are two outlet structures: the tainter gates spillway and the canal intake structure. The Lequille spillway structure, which consists of a two bay concrete structure, is located to the east of the Main Dam. Water discharge is controlled by two manually operated tainter gates, which each measure approximately 24 ft. wide and 15 ft. high. The concrete structure is approximately 57 ft. wide and 18 ft. high and is abutted by compacted fill. Water passing through the spillway structure is diverted downstream via a channel that joins with the Lequille River, taking these flows out of the system.

Summary of Related CIs +/- 2 years:
2017 CI 47648 - HYD Lequille Pipeline Replacement - $1,121,253
2017 CI 47682 - HYD Lequille Switchgear Replacement - $776,391
2017 CI 46253 - HYD Lequille Tailrace Gate - $34,298
2017 CI 47876 - HYD Lequille Overhaul - $1,395,229

Depreciation Class: Hydro Production Plant- Lequille Hydro System- Lequille

Estimated Life of the Asset: 50 Years

JUSTIFICATION:

Justification Criteria: Health & Safety

Why do this project?

In 2011, NS Power carried out a Dam Safety Review (DSR) of its Lequille Hydro System in accordance with the CDA Dam Safety Guidelines. According to these guidelines, the Lequille Main Dam is classified as High, and, therefore, the inflow design flood is 1/3 between the 1/1000-year flood and the Probable Maximum Flood (PMF). The 2011 DSR (Attachment 2, findings summarized on Table 1, Pages v - vii), its 2016 Freeboard Addendum (Attachment 3), detail the deficiencies related to the Lequille Main Dam, Wing Dams 3 and 4, the Spillway Tainter Gates and Abutments, and the Canal Intake Structure and Abutments. It indicated that that the Lequille Headpond structures do not meet CDA requirements for both normal and minimum freeboard. A 2016 addendum (Attachment 3) to the 2011 DSR determined that, based on updated wind speeds, the normal freeboard was adequate, however the 2016 Flood Routing Analysis (Attachment 4), concluded that, at present,

the Lequille Headpond Main Dam does not have sufficient discharge capacity to meet the minimum freeboard requirements during the Inflow Design Flood (IDF).

The IDF water level and minimum freeboard requirement is a direct function of the ability of operations staff to access the site and make spillway gate adjustments on a frequent basis during a flood event. In 2016, IDF levels for several operating scenarios were calculated (Attachment 4). In all scenarios it was determined that minimum freeboard requirements at the Lequille Headpond were not met.

Why do this project now?

NS Power carries out dam safety projects on a priority basis based on risk. NS Power maintains a dam safety risk prioritization list of sites and assets to identify which projects should be considered for rehabilitation/redevelopment. NS Power's operating license is tied to its water control structures meeting the Canadian Dam Association (CDA) Guidelines. The dam prioritization is based on the Canadian Dam Association categories: life safety, environment, and economic/ infrastructure and includes assessment of sub-categories, including freeboard, stability, and condition, against CDA guidelines. The priority of the work at Lequille Headpond is based on the downstream risk if the dams should breach or overtop.

Why do this project this way?

The Lequille Headpond dams and spillway must be refurbished to meet the CDA Dam Safety Guidelines for minimum freeboard. To meet this requirement the discharge capacity of the spillway will be increased by replacing the existing spillway structure with a longer concrete free overflow spillway, and the crest of the main dam and wing dams will be raised.

CI Number : 48533-H751 - HYD Lequille Headpond Refurbishment **Project Number** 48533-H751

Parent CI Number : -

Asset Location : 1356 - 1356 Lequille, 11Mwh; 1968 on the Lequille River System **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	2800 - HGP - Dams & Spillways	4,417,513
Retirements	2800 - HGP - Dams & Spillways	54,857
	Total Cost:	4,472,369
	Original Cost:	529,352

Capital Project Detailed Estimate

Location: Hydro
CI# / FP#: 48533-H751
Title: HYD Lequille Headpond Refurbishment
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Hydro River Staff	day	16	$ 365	$ 6,000		
Environmental Staff	day	16	$ 405	$ 6,500		
Project Management	day	112	$ 405	$ 45,430		
Administrative support (no AO)	day	8	$ 365	$ 2,945		
T&D Labour	Lot	1	$ 30	$ 30		
			Sub-Total	$ 60,905		
Term Labour						
Hydro Term Labour	Lot	1	$ 134	$ 134		
			Sub-Total	$ 134		
Travel Expenses						
Travel	lot	1	$ 4,908	$ 4,908		
	lot			$ -		
			Sub-Total	$ 4,908		
Materials						
Cast in Place Concrete	%	60%	[redacted]		Cost Support #1 - Item 3.5	
Reinforcing Steel	lot	1			Cost Support #1 - Item 3.7	
Walkway	lot	1			Cost Support #1 - Item 3.8	
Dowels	lot	1			Cost Support #1 - Item 3.16	
				$ -		
			Sub-Total	[redacted]		
Contracts						
Construction	lot	1	[redacted]		Cost Support #1 - All remaining Items	
Project Manager Technical	PD	59	$ 750	$ 44,524		
Construction Supervision	PD	133	$ 750	$ 100,000		
Removals	lot	1	[redacted]		Cost Support #1 - Item 3.2	
	lot			$ -		
			Sub-Total	[redacted]		
Consulting						
Conceptual Design	lot	1	$ 45,798	$ 45,798		
Detailed Design	lot	1	$ 97,381	$ 97,381		
Assistance during construction	lot	1	$ 20,000	$ 20,000		
Miscellaneous	lot	1	$ 809	$ 809		
Environmental	lot	1	$ 10,828	$ 10,828		
			Sub-Total	$ 174,816		
Meals						
Meals	lot	1	$ 700	$ 700		
				$ -		
			Sub-Total	$ 700		
Other Goods and Services						
Contingency	%	15%	3,583,062	$ 537,354		
			Sub-Total	$ 537,354		
Vehicle Overhead						
Vehicle Allocated Costs		1	15	$ 15		
				$ -		
			Sub-Total	$ 15		
Interest Capitalized						
AFUDC				$ 68,567		
				$ -		
			Sub-Total	$ 68,567		
Administrative Overhead						
Labour AO				$ 28,387		
Contracts AO				$ 254,983		
			Sub-Total	$ 283,370		
			Sub-Total (no AO, AFUDC)	$ 4,120,416		
			TOTAL (AO, AFUDC included)	$ 4,472,369		
Original Cost				$ 529,352		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

Construction Cost Estimate

Rev A.

(Conceptual)

Date: 30-Aug-17

Project Name: Lequille Headpond Dams Refurbishment

Description: New 275 ft overflow spillway at existing sluiceway location, and raising earth embankments, abutments and canal. Accuracy = +/-40%

Item	Description	Estim. Quantity	Unit	Unit Price	Amount
1	**Contractor's Construction Indirects**				
1.1	Mobilization & Demobilization	1	LS	[redacted]	
1.2	Construction Facilities (office, site trailers, site services)	1	LS		
	Subtotal				
2	**General Items**				
2.1	Access Road Upgrading and Maintenance	1	LS		
2.2	Environmental Protection	1	LS		
2.3	Water Control	1	LS		
2.4	Cofferdam Construction (for new spillway)	1	LS		
	Subtotal				
3	**New 275 ft Concrete Overflow Spillway and Earth Abutments and Retaining wall**				
3.1	Clearing, Grubbing, and Stripping	3	acre		
3.2	Removal and Disposal of Existing Tainter Gates and Structure	1	LS		
3.3	Excavation - General	44500	yd^3		
3.4	Excavation - Rock	4000	yd^3		
3.5	Cast-in-Place Concrete (new overflow spillway and wing walls)	2100	yd^3		
3.6	Formwork	1720	yd^2		
3.7	Reinforcing Steel	207900	lb		
3.8	Walkway	1	LS		
3.9	Zone 1 - Impervious	10	yd^3		
3.10	Zone 3 - Filter	25	yd^3		
3.11	Zone 6 - Riprap Bedding	40	yd^3		
3.12	Zone 8 - Riprap	75	yd^3		
3.13	Road Topping	70	yd^3		
3.14	Channel slope protection	2000	yd^3		
3.15	Grout Curtain and Contact Grouting	1	LS		
3.16	Dowels (35M Dowels, 19 ft long, 15 ft in rock)	46	no.		
	Subtotal				
4	**Earthworks - Canal Intake Structure and Main Dam Raise**				
4.1	Clearing, Grubbing, and Stripping	0.5	acre		
4.2	Excavation - General	3150	yd^3		
4.3	Zone 1 - Impervious	120	yd^3		
4.4	Zone 3 - Filter	0	^{3}		
4.5	Zone 6 - Riprap Bedding	850	yd^3		
4.6	Zone 8 - Riprap	1700	yd^3		
4.7	Road Topping	1200	yd^3		
4.8	Raise stoplog structure	1	LS		
	Subtotal				
5	**Earthworks - Wing Dams 3 and 4 Raise**				
5.1	Clearing, Grubbing, and Stripping	0.3	acre		
5.2	Excavation - General	200	yd^3		
5.3	Zone 1 - Impervious	100	yd^3		
5.4	Zone 3 - Filter	0	^{3}		
5.5	Zone 6 - Riprap Bedding	1050	yd^3		
5.6	Zone 8 - Riprap	2100	yd^3		
5.7	Road Topping	1250	yd^3		
5.8	Maintain Operable Flow Passage to Town of Annapolis Watershed	1	LS		
	Subtotal				
Total Estimated Construction Cost without Contingency					

Exclusions:
- Engineering design and environmental studies
- Owner's engineering costs (project management, tendering, site supervision, QA testing)
- Owner's other costs (financing/IDC, taxes, land acquisition, legal surveys)
- Escalation beyond August 2017
- Mitigative measures for protection of archaeological areas or other sensitive areas (if applicable)
- moving power lines and poles (if applicable)

Available Information:
- Unit prices from recent NSPI penstock and dam refurbishment projects
- Actual pricing from similar dam refurbishment projects (by others)

Other Notes/Assumptions:
- Unit prices for concrete include formwork, reinforcing steel, dowels, excavation/backfill
- Surface preparation is considered incidental to the work (not a separate pay item)
- 4 month construction schedule
-Assumed bedrock and bathymetry (not currently available)

ACE 2018 CI 48533 Attachments 2 & 3 have been removed due to confidentiality.

Nova Scotia Power Inc.

Draft Report

For

Lequille Headpond Flood Routing Analysis

H351972-00000-220-230-0001
Rev. A
November 25, 2016

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Nova Scotia Power Inc.

Draft Report

For

Lequille Headpond Flood Routing Analysis

H351972-00000-220-230-0001
Rev. A
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Draft Report

Lequille Headpond Flood Routing Analysis

H351972-00000-220-230-0001

2016-11-25	A	Client Review	E. Neufeld	M. Orton	T. Chislett
DATE	REV.	STATUS	PREPARED BY	CHECKED BY	APPROVED BY

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1. Introduction

The Lequille Headpond Dams Refurbishment Project is being executed within Nova Scotia Power Inc.'s (NSPI) Annual Capital Expenditure (ACE) Plan. NSPI has retained Hatch to provide engineering services for the design of remedial measures for dam upgrades. The overall general arrangement for the Lequille Development is shown in Figure 1. The design criteria and extent of works for the remedial plan is highly dependent on the extreme flood water levels at the project site.

The headpond flood level analysis consists of the following tasks:

- confirm dam geometry
- review headpond inflow sequence
- review/revise the headpond storage curve
- review/revise the stage discharge curve for the spillway's tainter gates
- headpond flood routing analysis to assess the capability of the existing tainter gate spillway to pass the inflow design flood (IDF) without overtopping the embankments.

1.1 Reference Documents

The following reports are used for reference:

- "2011 Dam Safety Review Final Report", submitted by AMEC in 2015, (Amec 2015)
- "Addendum to Lequille Hydro System 2011 Dam Safety Review Final Report January 2015: Freeboard Re-assessment for the Lequille Headpond Dams", submitted by AMEC in 2016, (AMEC 2016)
- "Lequille Hydro System 1:100 Year Flood Estimates", submitted by AMEC in 2002, (AMEC 2002)

NSPI provided the following spreadsheet as part of the AMEC 2016 model results:

- "2016 AMEC Flood Routing Hydrographs.xlsx"

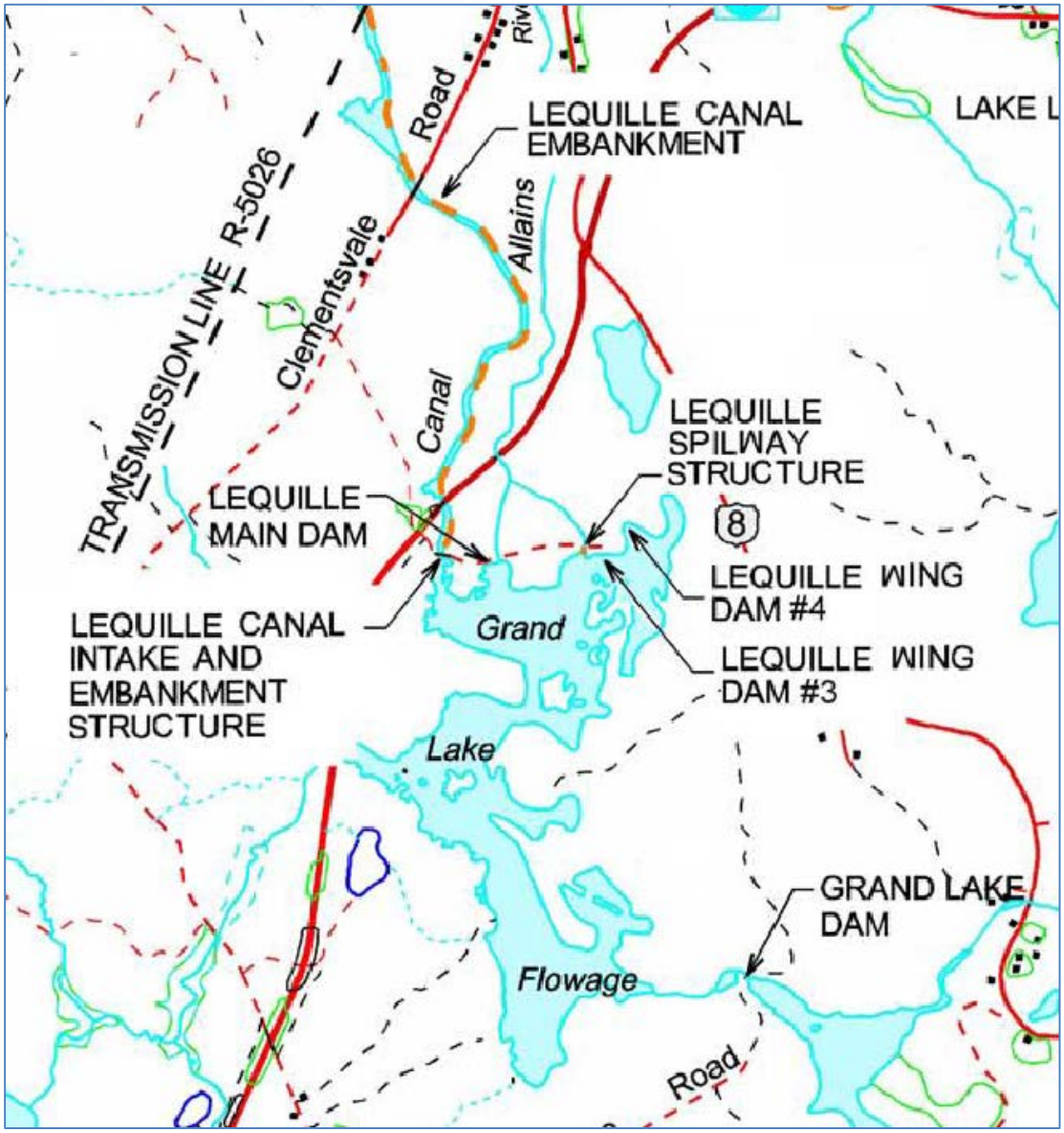

Figure 1: Lequille General Arrangement

2. Confirm Dam Geometry

LiDAR data for the project area was used to confirm the embankment elevations indicated in previous reports, in order to assess the freeboard available at the dams.

Using ArcMap, the following approximate crest elevations were confirmed:

- Main Dam = 123.9 m (406.5 ft)
- Spillway Embankment = 123.4 m (405.0 ft)
- Wing Dam #3 = 123.4 m (405.0 ft)
- Wing Dam #4 = 123.4 m (405.0 ft)
- Canal Intake Embankment = 123.9 m (406.5 ft)
- Canal Embankment = 123.4 m (405.0 ft)

The crest elevations for the Main Dam, Spillway Embankment, and Wing Dams and are consistent with those shown in drawings dating to 1966 and 1967, included in AMEC's 2015 report. However, the crest elevations for the Canal Intake Embankment and the Canal Embankment do not match the AMEC 2015 report. This inconsistency requires further investigation.

3. Review Headpond Inflow Sequence

Hatch reviewed the Headpond inflow sequence as provided in the "2016 AMEC Flood Routing Hydrographs.xlsx" spreadsheet. The magnitude of the inflow hydrograph peak appears reasonable, but this conclusion is qualified by the following:

- Hatch had no access to the model or the input values that generated the hydrograph.
- The format of the file "2016 AMEC Flood Routing Hydrographs.xlsx" appears to be from HEC-HMS, but the inflow peak (9,581 cfs) does not agree with the "Target High IDF Flows" value (10,591 cfs) from HEC-HMS in Table 3-7 (Figure 2). This casts a level of doubt on the validity of the routing in "2016 AMEC Flood Routing Hydrographs.xlsx".

Table 3-7 High IDF Ratios

Location	HMS Storm Centering	1/1000 Inflow (cfs)	PMP Inflow (cfs)	Target High IDF Flows (cfs)	High IDF HMS Ratio	Resulting HEC-RAS Inflow (cfs)
Grand Lake	Lequille Hydro System (SC1)	4755	18924	9478	0.50	9572
Lequille Headpond	Lequille Hydro System (SC1)	5576	20622	10591	0.51	9581
Dargie Lake	Dargie Lake (SC2)	741	3001	1494	0.50	1500

Figure 2: Table 3-7 from 2015 AMEC Report

- The AMEC 2015 report describes the development of the HEC-HMS model, but does not provide any values for the snowpack, PMP, etc.
- AMEC also compared the similarities of the 2015 PMF to the 1996 PMF. However, it is not mentioned that the 1996 PMF was from a Summer PMP, whereas the 2015 PMF was from a Spring PMP.
- The Lequille storage curve shown in the AMEC 2015 report appears to be the same as that used in the 1996 HEC-1 models and the 2002 DAMBRK models. However, the elevations and storages shown in "2016 AMEC Flood Routing Hydrographs.xlsx" do not agree with these storage curves. It is understood that the AMEC 2015 model included a Grand Lake dam break and that the AMEC 2016 model did not, which would explain the varying elevations. However a dam break would not affect the storage values in the headpond.

Hatch cannot confirm the accuracy of the Lequille Headpond inflow hydrograph without more details of the modeling and how/why the 1/3K-PMF target 10,591 cfs in Table 3-7 became 9,581 cfs in HEC-RAS, nor how/why the HEC-RAS inflow hydrograph was routed using HEC-HMS in "2016 AMEC Flood Routing Hydrographs.xlsx".

4. Review/Revise Headpond Storage Curve

The storage curves used by AMEC in 2002 and 2015 are very similar below el 395 ft, but differ above this elevation.

Using LiDAR data, the storage curve above el 398 ft was developed and compared to the storage curves used by AMEC in 2002 and 2015.

The LiDAR data closely matches the shape of the 2002 AMEC curve as shown in Figure 3.

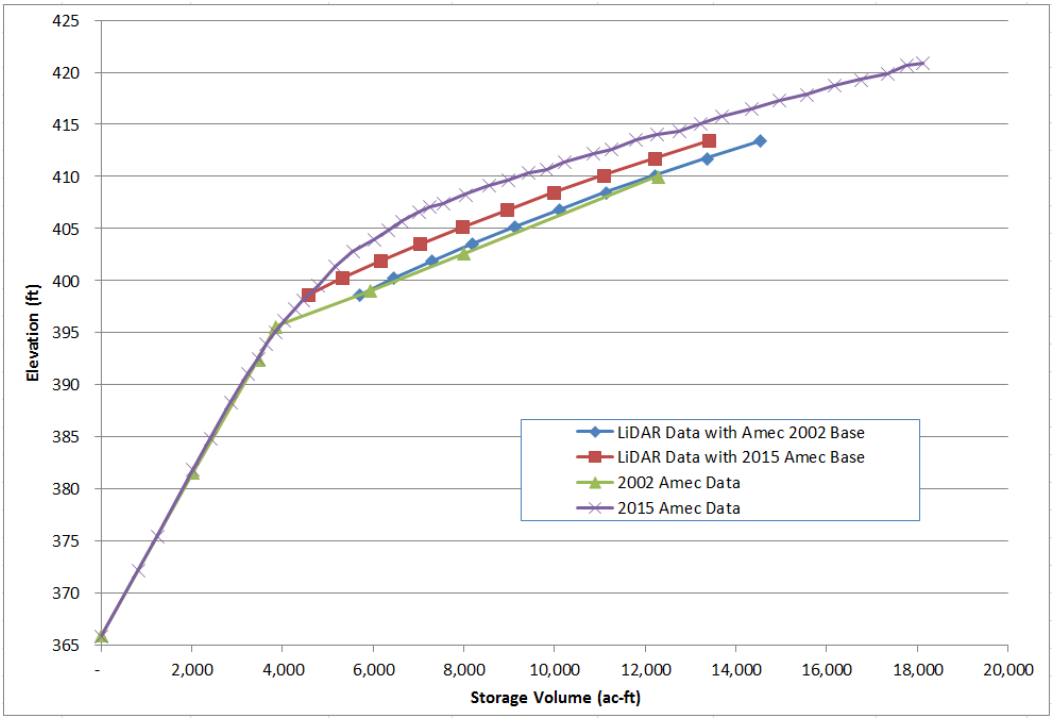

Figure 3: Storage-Elevation Curve Comparison

5. Review/Revise Tainter Gate Stage/Discharge Curve

The AMEC 2015 report assumed that the spillway tainter gates would open 7 ft. The stage/discharge curve provided in the report rises abruptly at around el 405 ft. The spillway embankments would be overtopped at el 405 ft, therefore an assumption may have been made that the flow through the gates would not increase with any additional head and all excess flow would pass over the embankments. It is not clear how this is handled in the AMEC analysis.

Hydraulic formulas indicate that the flow through the gate would continue to increase with an increase in head.

In discussion with NSPI operations staff during a site visit, Hatch learned that the likely maximum opening range of the tainter gates is 6 ft. It is understood that the lifting mechanism restricts the range of travel, and does not allow the gates to be raised past this point. It is believed that it may be possible to alter the lifting mechanism to open the gates to the trunion height of approximately 9 ft. This would require further study and design.

Hatch developed a stage/discharge curve for the tainter gates based on a maximum opening height of 6 ft, shown in Figure 4.

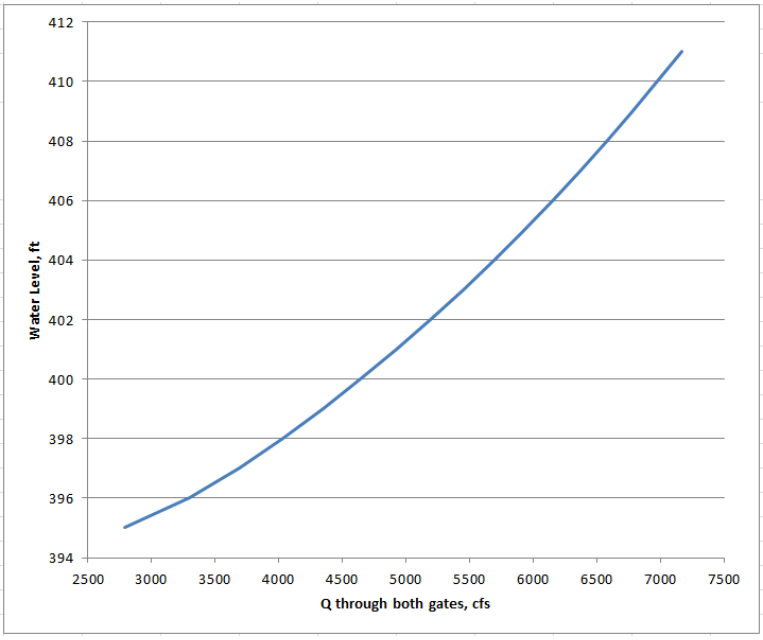

Figure 4: Hatch Stage/Discharge Curve for Tainter Gates with 6 ft Opening

Hatch also compared a stage/discharge curve for the tainter gates with openings of 7 ft with the AMEC 2015 stage/discharge curve, shown in Figure 5. It is assumed that the AMEC 2015 stage/discharge curve is for one gate only, and therefore it was doubled for this figure.

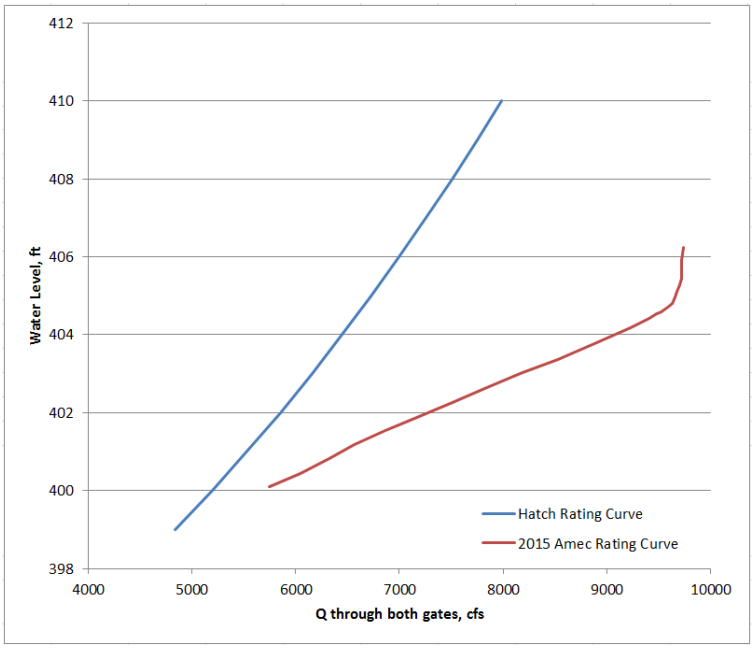

Figure 5: Comparison of Stage Discharge Curves with 7 ft Opening

The gates must be manually operated; therefore, Hatch developed a series of rating curves for a series of gate openings. It is assumed that NSPI operations staff would travel to the site and check the water levels periodically during a heavy rainfall event for the purpose of raising the gates as required to increase discharge capacity. The shape of these rating curves is similar to Figure 4.

6. Flood Routing Analysis

Using the dam confirmed dam crest elevations, inflow hydrograph, revised storage curve and revised stage discharge curves, Hatch has developed a series of flood routing analyses for the Lequille Headpond.

The dams were included in the routing analyses as possible discharge points should the water levels in the reservoir rise above their crests.

The peak headpond level is highly dependent on the ability of NSPI staff to access the site and operate the spillway structure (i.e. open the gates) during flood events. Less frequent gate openings will result in higher peak water levels.

Three scenarios were considered to assess the uncertainty of operator availability. These scenarios do not represent the full range of possible outcomes, but rather represent a reasonable range of outcomes given the manual nature of gate operation.

- **Scenario 1** – Operations staff visit the site and check the water levels once per day during a heavy rainfall event. The gates are opened when the headpond level exceeds the FSL of 400 ft. Subsequently, operations staff check water levels twice per day once the gates are opened 2 ft. It is assumed that operations staff can open the gates to their maximum level even after the spillway embankment is overtopped. The headpond elevation may drop below the FSL as the gates are opened in an effort to avoid overtopping the embankments.
- **Scenario 2** – Operations staff visit the site and check water levels once per day during a heavy rainfall event regardless of the gate opening, and open the gates when the water level exceeds 401 ft. It is assumed that operations staff can open the gates to their maximum level even after the spillway embankment is overtopped. The headpond is not intentionally drawn down below the FSL, however, this may still happen if sufficient drawdown occurs between checks on the water level.
- **Scenario 3** – The gates are only opened partially before the spillway embankment is overtopped and the operations staff are not able to gain safe access to the spillway for the purpose of opening the gates to their maximum height.

The headpond flood routing analysis was conducted for the spillway gates under the current maximum 6 ft gate opening, and again for a potential situation where the spillway gates are modified to allow them to open 9 ft. The results are summarized in Table 1.

Table 1: Summary of Peak Headpond Levels

Operating Scenario	Current Conditions (Max 6 ft Gate Opening)	Gate Expansion (Max 9 ft Gate Opening)
1 - Site visits up to twice per day - Begin gate operation at el 400 ft	407.2 ft	405.5 ft
2 - Site Visits once per day - Begin gate operation at el 401 ft	407.8 ft	406.3 ft
3 - Spillway gates are not opened more than 2 ft before embankment is overtopped	409.4 ft	409.4 ft

Note:

Main Dam crest elevation = 406.5 ft

Wing Dams crest elevation = 405.0 ft

6.1 Current Conditions

For the design flood provided, and at a maximum gate opening of 6 ft, overtopping of embankment structures would occur in all scenarios. However, the severity of flooding increases from Scenarios 1 to 3 as shown in Table 1 and Figures 7 to 9.

Depending on the operating scenario (i.e. frequency and extent of gate operations), the maximum headpond elevation would range from 407.2 ft to 409.4 ft. In all cases, this is above the crest elevations of the various embankment structures.

Inflow and outflow hydrographs are shown in Figure 6, with storage and elevation plots shown in Figures 7 to 9. The large increases and decreases in the outflow curve indicate where the gates were raised or lowered.

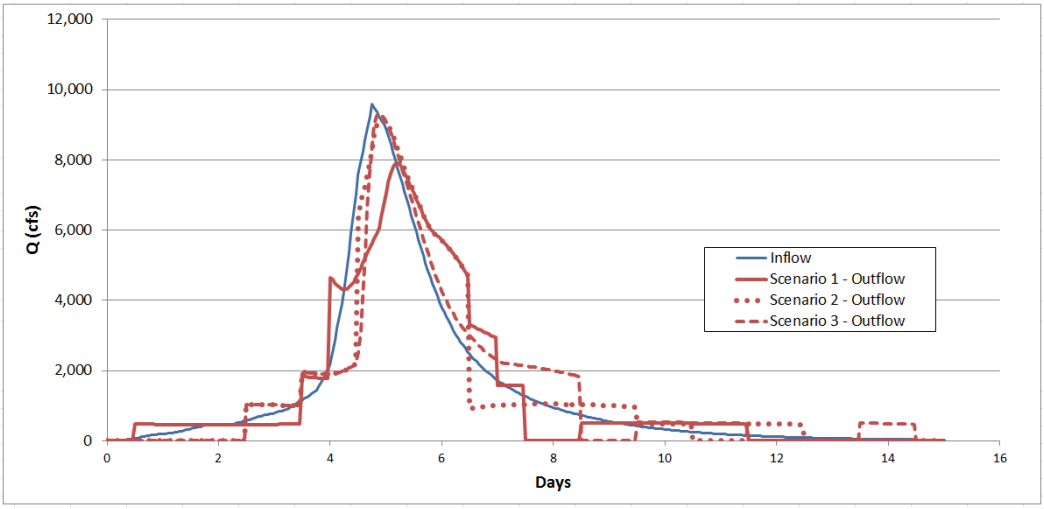

Figure 6: Current Conditions – Inflow and Outflow Hydrographs

In Figures 7 to 9, the storage volumes vary with the headpond elevation. Because the gates are operated manually, the headpond elevation and storage volumes are variable.

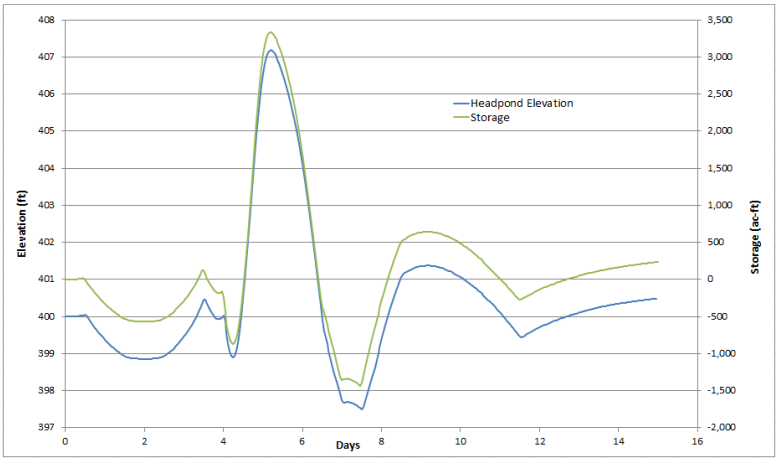

Figure 7: Current Conditions – Scenario 1 – Storage and Elevation Curves

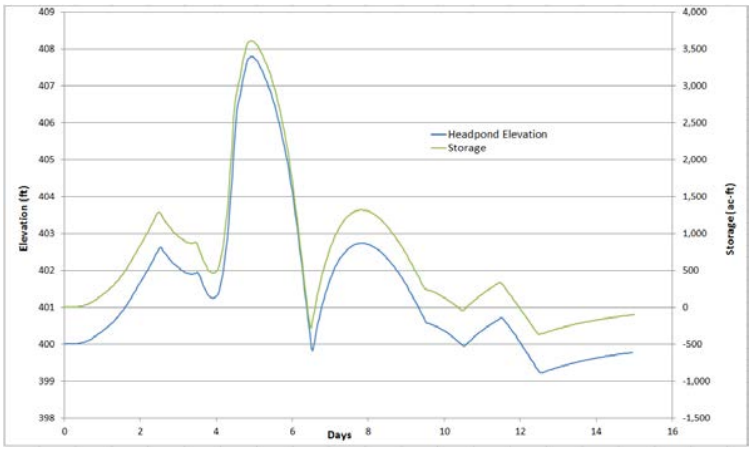

Figure 8: Current Conditions – Scenario 2 – Storage and Elevation Curves

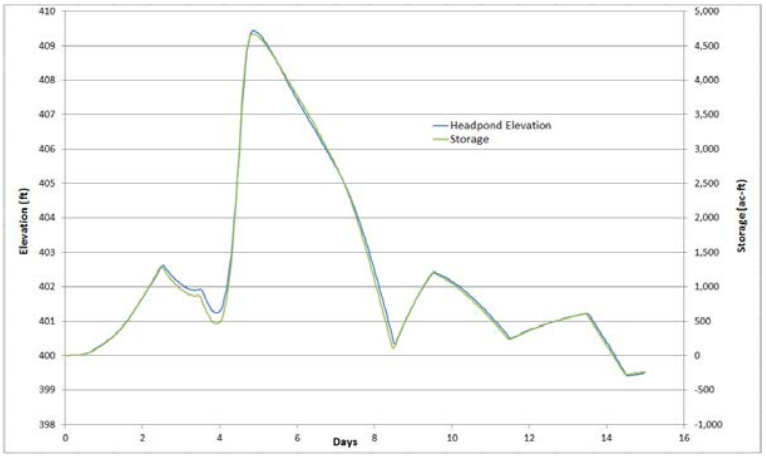

Figure 9: Current Conditions – Scenario 3 – Storage and Elevation Curves

6.2 Gate Expansion

For the design flood provided, and at a maximum gate opening of 9 ft, overtopping of embankment structures would still occur in all scenarios, but Scenarios 1 and 2 would be less severe than in the “Current Conditions” analysis. The magnitude of the Scenario 3 flooding would be unchanged, as the spillway embankments are overtopped prior to the gates being opened fully. Again, the severity of flooding increases from Scenarios 1 to 3 as shown in Table 1 and Figures 11, 12 and 9.

Depending on the operating scenario (i.e. frequency and extent of gate operations), the maximum headpond elevation would range from 405.5 ft to 409.4 ft. It should be noted that for Scenario 1, the available freeboard at the main dam (1.0 ft) is less than the required freeboard of 2.37 ft. Therefore freeboard requirements are not met.

Inflow and outflow hydrographs are shown in Figure 10, with storage and elevation plots shown in Figures 11 and 12. The storage and elevation plot for Scenario 3 is found in Figure 9.

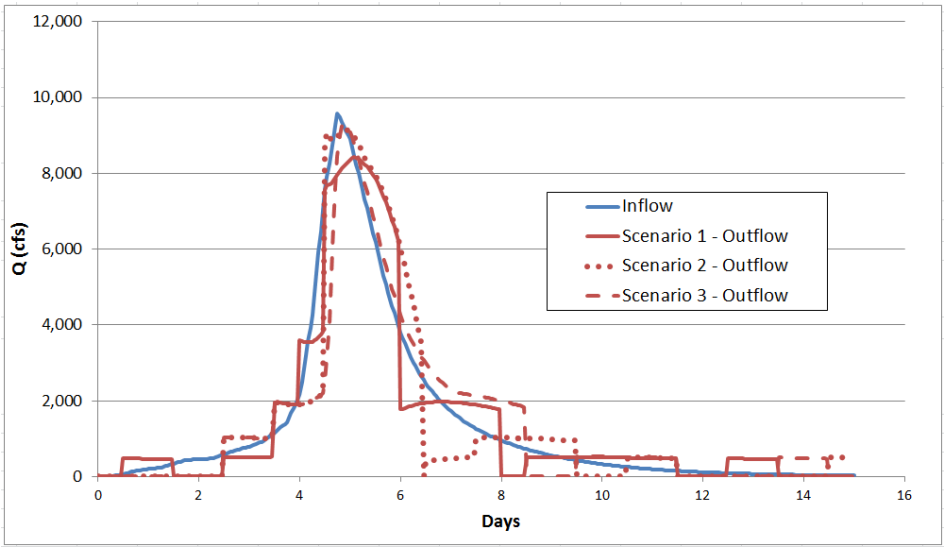

Figure 10: Gate Expansion - Inflow and Outflow Hydrographs

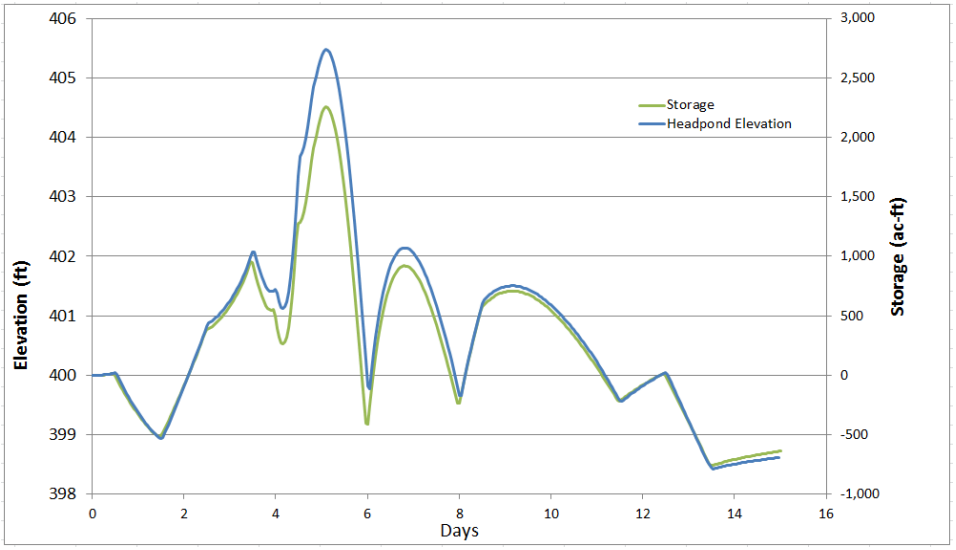

Figure 11: Gate Expansion – Scenario 1 – Storage and Elevation Curves

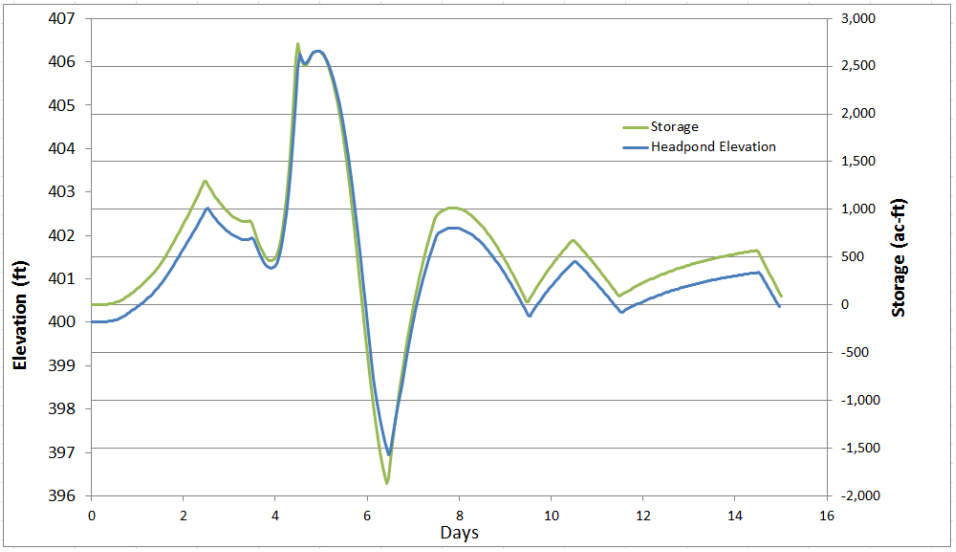

Figure 12: Gate Expansion – Scenario 2 – Storage and Elevation Curves

6.3 Comparison with AMEC 2015 Results

As a check, the Scenario 1 routing analysis was conducted again with the gates opened to a maximum of 7 ft in order to compare the results with the AMEC 2015/2016 model. The 2015 AMEC storage-elevation curve was used in order to keep as many variables consistent between the models as possible.

The inflow and outflow hydrographs are very similar, as seen in Figure 13. However, the storage volume and headpond elevation curves in Figure 14 are significantly different. The

model storage curve is smooth without the large dips shown by Hatch; presumably the HEC-RAS model adjusted the gate opening at relatively small time intervals to maintain the headpond elevation as constant as possible. However, since the gates are manually operated, it is not anticipated that the actual curve would be this smooth.

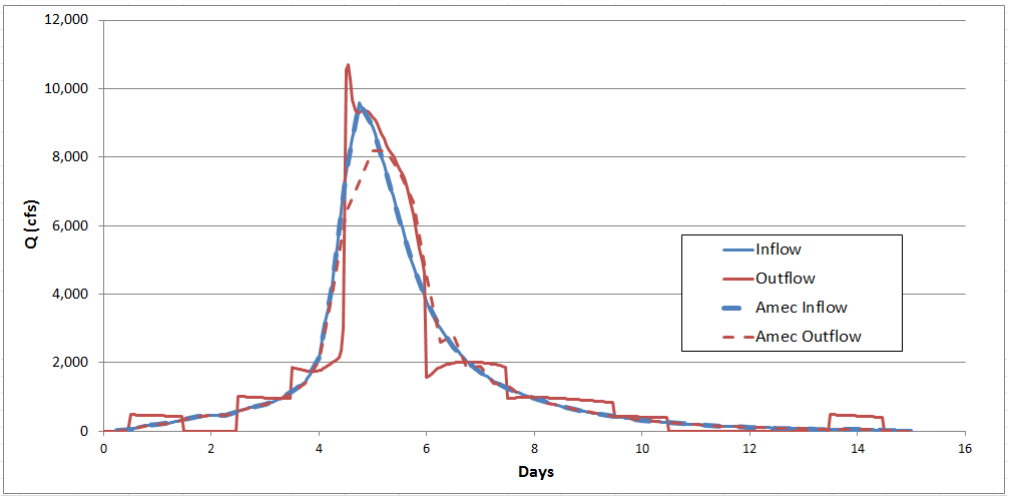

Figure 13: Comparison of Results - Inflow and Outflow Hydrographs

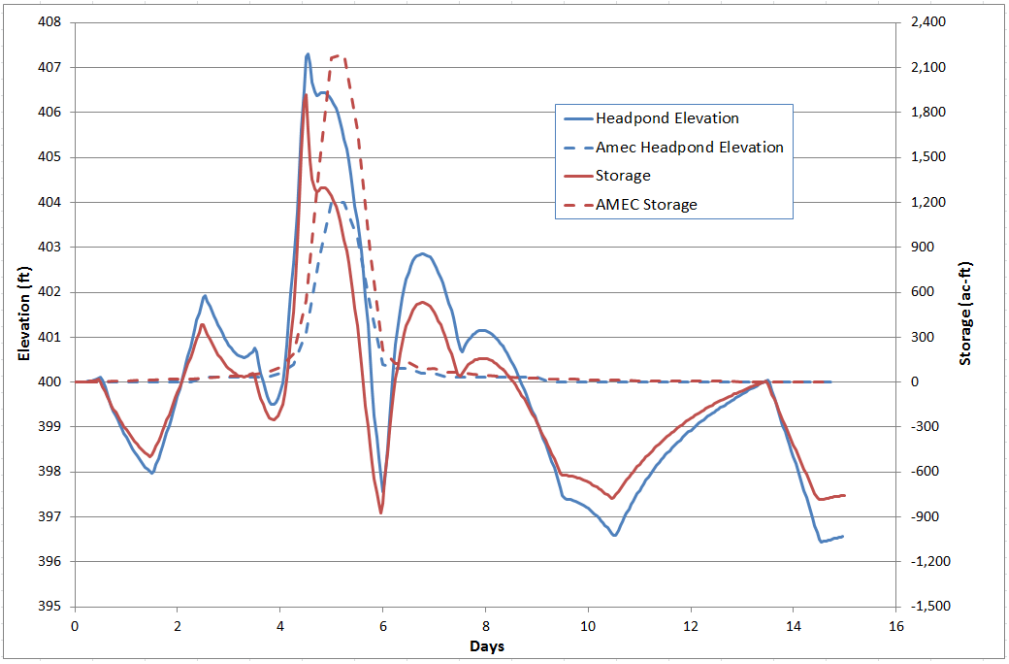

Figure 14: Comparison of Results - Storage and Elevation Curves

The Hatch maximum headpond elevation is 407.3 ft, exceeding the embankment crest elevations. The AMEC maximum headpond elevation is 404.0 ft, resulting in no overtopping.

Using the storage-elevation curve and tainter gate stage discharge curves from Appendix A of the AMEC 2015 report, the peak storage and outflow for a maximum water level of 404.0 ft are about 6,000 ac-ft and 4,600 cfs. However, the peak storage and outflow calculated by the model as shown in Figure 14 and in the "2016 AMEC Flood Routing Hydrographs.xlsx" spreadsheet are approximately 2,190 ac-ft (2,700,000 m^3) and 8,200 cfs (232 m^3/s), respectively. It is not understood how these values are obtained in the AMEC 2016 analysis, as they do not match the curves provided in the 2015 report.

7. Conclusion

The flood routing analysis carried out by Hatch indicates that the Lequille Headpond embankment crests will be overtopped in an extreme flood event, using the inflow hydrograph provided by AMEC, with a 6 ft maximum opening height of the spillway gates. The extent of dam overtopping is a direct function of the ability of operations staff to access the site and make spillway gate adjustments on a frequent basis during a flood event.

If the hoisting mechanism for spillway gates can be modified to allow for a 9 ft opening height, severity of overtopping will be lower than in the 6 ft gate opening case. However, overtopping will still occur when the effects of wind/wave action are considered. Again, the maximum headpond levels are highly dependent on gate operations during a flood event.

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HATCH

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St. John's, Newfoundland, Canada A1A 3W8
Tel: +1 (709) 754 6933

CI Number: 49033

Title: HYD WRC Tunnel T-2 Intake Gate and Hoist Replacement

Start Date: 2016/04
In-Service Date: 2018/10
Final Cost Date: 2019/04
Function: Hydro
Forecast Amount: $2,851,582

DESCRIPTION:

This project includes the replacement of the gate and hoist assembly, as well as its support structure at the Tunnel T-2 intake structure, located at the Wreck Cove Reservoir.

A third party assessment (Attachment 3), of the Tunnel T-2 intake completed in 2016/17 concluded that the gate and hoist assembly were unreliable. The inspection of the gate showed extensive cracking and noted that weld repairs may be required in the short-term to temporarily extend the life of the gate until its scheduled replacement in 2018. An unreliable gate system causes undue risk to the operation of the intake structure. The assessment recommended the replacement of the gate and hoist assembly, as well as the replacement of the deteriorated support structure and enclosure, which would not be suitable for the replacement gate and hoist arrangement.

Summary of Related CIs +/- 2 years:
2018 CI 51236 - HYD WRC Tailrace Tunnel Rock Bolting Phase 1 - $8,855,857

Depreciation Class: Hydro Production Plant- Wreck Cove Hydro System

Estimated Life of the Asset: 40 Years

JUSTIFICATION:

Justification Criteria: Health & Safety

Why do this project?

In 2012/13, KGS Group completed a study (Attachment 2, Section 4-1, Section 5-1) on the condition of the Tunnel T-2 intake and completed a condition assessment of the intake structure. The condition assessment recommended that further inspection, refurbishment and repair of the components would be required. Operation of the gate for full exposure to perform visual inspection above water was not possible at the time of this assessment due to a control system issue.

Detailed assessments of the Tunnel T-2 intake components were carried out in 2016/17 by Hatch. The assessment work was carried out in accordance with Canadian hydro utility best practices. The design of the intake structure will also be undertaken in accordance with the Canadian Dam Association (CDA) Dam Safety Guidelines.

For the Tunnel T-2 intake gate and support structure, the assessed deterioration was such that the replacement of all components is required to ensure reliable operation. Concrete ballast weight was added to the gate after the original construction, which would allow the existing gate to close under full flow; however, this can no longer be maintained due to hoist loading considerations and aged gate condition.

Why do this project now?

Detailed assessments of the Tunnel T-2 intake components were carried out in 2016/17 by Hatch. The assessed deterioration was such that the replacement of all components is required to ensure reliable operation. Due to the condition of the intake gate and support structure, completion of this project in 2018 is considered necessary. Additionally, the remediation of the tailrace tunnel (CI 51236), will be completed in 2018 and will require a plant outage lasting approximately two months. The generation system and Surge Lake will be drained to accommodate the tailrace work. Wreck Cove Reservoir, located upstream of the T2 intake gate, will also be temporarily lowered to accommodate isolation of the two main units for replacement of the intake. This temporary isolation is optimal to minimize leakage into Surge Lake, which will be dewatered for the tailrace work.

Why do this project this way?

Refurbishment and replacement options were reviewed and assessed as part of the third party study. Replacement with a new gate and hoist assembly and upgrades to the existing concrete structure were determined to be the more cost effective alternative. The refurbishment of Tunnel T-2 intake was considered to be a more expensive alternative due to the anticipated custom in-field modifications and associated increased schedule requirements.

The final design specification will provide:

- Methods to achieve successful water control during construction (i.e. cofferdam upstream or temporary steel framed and isolation gate with gasket mounted to structure);
- Modifications for the existing concrete structure and gate check, including demolition, to accommodate a replacement gate;
- Replacement of the deteriorated gate with a new vertical wheeled gate and wire rope hoist assembly of comparable or increased hoist capacity with capability to close under full flow;
- Demolish and refurbish the existing support structure and enclosure.

CI Number : 49033-H762 - HYD WRC Tunnel T-2 Intake Gate and Hoist Replacement **Project Number** 49033-H762

Parent CI Number : -

Asset Location : 1361 - 1361 Wreck Cove Common Property **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	2700 - HGP - Waterways	2,829,640
Retirements	2700 - HGP - Waterways	21,943
	Total Cost:	2,851,582
	Original Cost:	803,160

Capital Project Detailed Estimate

Location: Hydro
CI# : 49033
Title: HYD WRC Tunnel T-2 Intake Gate and Hoist Replacement
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Electrician	PD	16	$ 358	$ 5,733		
Engineering	PD	80	$ 405	$ 32,424		
CADD Operators	PD	3	$ 294	$ 882		
Hydro River Staff	PD	25	$ 365	$ 9,120		
Other (procurement, environmental, administration, cost analyst)	LOT	1	$ 9,104	$ 9,104		
			Sub-Total	$ 57,263		
OT Labour						
Hydro River Staff	LOT	1	$ 3,063	$ 3,063		
			Sub-Total	$ 3,063		
Term Labour						
Safety Specialist	Lot	1	$ 10,593	$ 10,593		
			Sub-Total	$ 10,593.00		
Travel Expense						
Vehicle/Accommodations	Lot	1	$ 7,766	$ 7,766		
			Sub-Total	$ 7,766		
Materials						
Gate / hoist and contractor supplied support structure, enclosure and access platform(s) components	Lot	70%	[redacted]		Cost Support 1 - 70% of Items 3.2 - 3.7, & 3.9	
Signage	Lot	1				
			Sub-Total	[redacted]		
Contracts						
Rescue Set Up Services for Confined Space or Forced Air	Lot	1	$ 150,000	$ 45,000		
Clearing	Lot	1	$ 3,000	$ 3,000		
Tunnel T2 Intake Replacement Works	Lot	1	[redacted]		Cost Support 1 - All items less Material portion above	
Gate Commissioning Support and Guide Installation Site Supervision	Lot	1				
Fencing Contractor	Lot	1	$ 7,500	$ 7,500		
Project Management	Month	48	$ 3,438	$ 165,000		
Pre-Construction Coordination and Construction Management	Lot	1	$ 90,000	$ 90,000		
2nd Construction Coordinator for Backshift	Lot	1	$ 75,000	$ 75,000		
Water Management Planning and Execution Support	Lot	1	$ 26,000	$ 26,000		
Misc. Supporting Contracts	Lot	1	$ 23,430	$ 23,430		
			Sub-Total	[redacted]		
Consulting						
Tunnel T-2 Intake Gate Assessment	lot	1	$ 78,746	$ 78,746		
Conceptual Design	lot	1	$ 11,242	$ 11,242		
Detailed Design / RFP Support	lot	1	$ 82,087	$ 82,087		
Construction Support	Mnth	6	$ 20,000	$ 120,000		
Stantec assessment of Portal Gate Storage	lot	1	$ 13,002	$ 13,002		
Surveys	lot	1	$ 37,500	$ 37,500		
			Sub-Total	$ 342,577		
Meals & Entertainment						
Meals	lot	1	$ 2,381	$ 2,381		
				$ -		
			Sub-Total	$ 2,381		
Other Goods & Services						
Contingency	%	20%	$ 1,839,063	$ 367,813		
				$ -		
			Sub-Total	$ 367,813		
AFUDC						
AFUDC				$ 68,405		
			Sub-Total	$ 68,405		
Administrative Overhead						
Hydro Reg. Labour AO				$ 41,236		
Thermal / Hydro Contracts AO				$ 128,455		
			Sub-Total	$ 169,691		
			SUB-TOTAL (no AO, AFUDC)	$ 2,613,486		
			TOTAL (AO, AFUDC included)	$ 2,851,582		
Original Cost				$ 803,160		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

HATCH

Preliminary Construction Cost Estimate
(Conceptual)

Rev A.
(Issued for Client Review)

Client: Nova Scotia Power Inc.
Project Name: Wreck Cove - T2 Intake Gate Assessment Project
Project Number: H351728
Project Duration: Assumed approx 6 months

Date: April 19, 2017
Prepared by: J. Atkinson, I. Maan, D. Pinese
Reviewed by: A. Bridgeman, M. Miller

Description: Conceptual Design Cost Estimate for Wreck Cove T2 Intake Gate Replacement and Modifications
Accuracy Range = ± 30%

Item	Description	Estim. Quantity	Unit	Unit Price	Amount
1	**Contractor's Construction Indirects**				
1.1	Construction Facilities, Mobilization & Demobilization	1	LS		
	Subtotal				
2	**General Items**				
2.1	Access Road and Laydown Area Improvements	1	LS		
2.2	Access Road Clearing	1	LS		
2.3	Environmental Management	1	LS		
2.4	Water Control	1	LS		
	Subtotal				
3	**T2 Intake Gate / Gatehouse**				
3.1	Removal of Existing Gate Equipment, Support Structure, Hoist, and Building	1	LS		
3.2	Supply and Installation Supervision of Gate (embedded parts not included)	1	LS		
3.3	Supply and Installation Supervision of Hoist	1	LS		
3.4	Supply and Installation Supervision of Superstruture	1	LS		
3.5	Supply and Installation Supervision of New Insulated Gate Enclosure	1	LS		
3.6	Supply and Installation Supervision of Stairway Structure	1	LS		
3.7	Installation of Gate Equipment (gate, support structure, hoist)	1	LS		
3.8	New Reinforced Concrete Slab	1	LS		
3.9	Concrete Dowelling of new support structure into new concrete slab	1	LS		
3.10	Miscellaneous Steel (grating for deck openings)	1	LS		
3.11	Upstream Steel Cofferdam - 1/2 to be reused as upstream curtain wall	1	LS		
3.12	Installation of Cofferdam	1	LS		
3.13	Divers for cofferdam Installation	1	LS		
3.14	Crane on site for 4 weeks	1	LS		
3.15	Remediation of gains (scaffolding, sandblast, paint)	1	LS		
3.16	Provision for Gate Manufacturer on site for 1 month	1	LS		
3.17	Commissioning	1	LS		
	Subtotal				
4	**Electrical**				
4.1	Electrical Works	1	LS		
4.2	Electrical Service Upgrade	1	LS		
4.3	Wreck Cove Intake and Foundation Grounding	1	LS		
4.4	CCTV Freeze Protection Camera	1	LS		
	Subtotal				
Total Estimated Construction Cost without Contingency					
Contingency (20%)					
Total Estimated Construction Cost					

Exclusions:

- Engineering design and environmental studies
- Owner's engineering costs (project management, tendering, site supervision, QA testing)
- Owner's other costs (financing/IDC, taxes, land acquisition, legal surveys)
- Construction Insurance and Bonds
- Escalation beyond September 2017
- Mitigation measures for protection of archaeological areas (if applicable)
- Concrete testing (Owner preference to coordinate)

Available Information:

- Cost estimates based on recent other NSPI projects (actuals and tendered)
- Budgetary quote received for major gate and hoist equipment

Other Notes/Assumptions:

- Contractor indirects such as site supervision, mob, demob, etc., assumed to be included in unit rates and LS costs (typical NSPI experience)
- Unit prices for concrete include formwork and reinforcing steel
- Cost estimate developed without comprehensive condition assessment of existing structures and site conditions
- Local contractor (minimal per diems)
- Existing structures assumed to be in acceptable condition for intended purpose
- Existing structures assumed to meet stability requirements
- Bedrock presumed to be sound and in good condition (geotech inspection required before foundation construction)
- Bedrock can be removed using excavator with rock breaker
- Road access and possible laydown areas on project site assumed to be in reasonable condition (some improvements needed) for construction equipment and crane access
- Concrete surface preparation is considered incidental to the work (not a separate pay item)
- Dewatering managed by NSPI (outage planned)
- Grounding requirements based on standard design supplier requirements
- CCTV Camera included for visual inside gate well to monitor freeze protection
- All ladder and fall arrest systems by suppliers
- 6 month construction schedule

NOVA SCOTIA POWER CORPORATION

WRECK COVE GENERATING STATION

CONDITION ASSESSMENT

FINAL REPORT

APRIL 2013

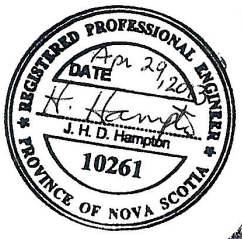
NOVA SCOTIA POWER
An Emera Company

Wreck Cove GS

Condition Assessment

Submitted by:

Mike Markovich – Project Manager and Lead Mechanical Engineer



Holly Hampton – Lead Civil Engineer

Adam Pawlikewich – Lead Electrical Engineer

Approved by:

Stefan Kohnen - KGS Group - Regional Manager

Acknowledgments

The following persons contributed information for this report:

Nova Scotia Power Incorporated

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Electrical Technician: Terry Grant

Heavy Equipment Technician: Glen Cantwell

Senior Specialist Engineer: Ellis O'Neil

Other Plant Staff: Alistair MacInnis, Blair MacNeil

Superintendent (retired): Keith Hawley

Staff Located Elsewhere

Senior Manager Capital Planning: Jamie MacDonald

Senior Electrical Engineer: Charles Hooper

Senior Electrical Engineer (retired): Daniel Brennan

Senior Mechanical Engineer: Tim Gillis

Mechanical Engineer: Martin Huntley

Electrical Engineer: Adam Lusk

Maintenance Specialist (retired): Malcolm Kaiser

The condition assessment was performed by the following team from KGS Group:

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Fady Takla

Mechanical Investigators

Mike Markovich (Lead)

John Barbour

Rudy Derksen

Electrical Investigators

Adam Pawlikewich (Lead)

Monish Bhowmik

Condition Assessment Project Manager

Mike Markovich

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1 EXECUTIVE SUMMARY

This report summarizes the results of the Condition Assessment carried out at Wreck Cove GS in 2011 to 2012. The scope of the assessment included the Civil (not including geotechnical), Mechanical and Electrical (including protections & controls) assessments.

The table at the end of the Executive Summary summarizes the assessment results in these three disciplines. The distribution of the expenditures in future years is shown in Section 9.

The 2012 Condition Assessment of Wreck Cove addressed the powerhouse equipment and systems, the access tunnel portal, the structures and equipment for water control at the entrance to tunnel T-2, at the inlet to the penstock and at the tailrace tunnel outlet, the penstocks and the standby diesel generator.

Certain component parts of the Wreck Cove facility were outside the scope of the 2012 assessment, including the storage dams, tunnels T-1, T-2, the powerhouse access tunnel and the tailrace tunnel, Gisborne Generating Station, the main output transformers and the associated 144 kV conductors, the switchyard, the Administration Building and all surface facilities such as dykes, roads, communication tower, storage buildings and other miscellaneous buildings. Assessments for dam safety and assessments of these assets may result in identification of additional projects requiring funding which is not included here.

The following summarizes the identified Opportunities and Issues and the Recommended Viability Expenditures from this current Condition Assessment of 2011-2012.

While Viability Expenditures are intended to maintain the production, safety and environmental capabilities at an acceptable level, Opportunities are typically activities which permit enhancement of the asset and which provide value over and above the status quo. Issues are potential obstacles to effective operation of the asset, which if not addressed effectively, may impede the full use of the asset in the future or somehow diminish its capability. Either may require detailed analysis to determine the best path forward from several potential solutions.

Opportunities

- Turbine Uprating: Turbine runner uprating should be investigated prior to the next round of major overhauls of the turbines and generators, and if found to be justified, the installation of the runners should be coordinated with the outages for the proposed generating unit major overhauls. The potential benefits could include a combination of increased capacity (5% to 10% may be possible), improved operating power range and increased efficiency (up to 2% may be possible). The estimated cost of replacement runners is $5.55 million. If capacity is significantly increased, an assessment of the capacity of electrical equipment such as generators, bus duct, transformers and conductors will be required. As well, the hydraulic capacity of tunnel T-2 will need to be considered in the calculation of benefits.

- Plant Efficiency Testing: There is no recent report of plant efficiency testing and the operation of the plant may use predicted design information or test results from the 1978 commissioning of the generating units. Efficiency tests would provide up-to-date actual efficiency versus power for one unit and for both units across the full range of operating power outputs. The information would allow for optimization of the use of the plant, aid in determining if the penstocks have higher losses than when new, and would provide baseline information to support a decision on turbine runner replacements. The estimated cost of the testing is $250k.

Issues

- Worker Refuge Facility: The existing refuge facility is of unknown effectiveness, limited in terms of capacity and not quickly accessible to persons working on lower floors. As egress out of the powerhouse is limited to one path and as that path is close to the largest potential fire source (the oil in the underground step-up transformers), appropriately designed and adequate capacity refuge facilities are required. For the existing work crew and for the anticipated increased worker presence during the implementation of the Life Extension and Modernization program, new refuge facilities are required. See Section 7 of this report for further details.

- Maintenance Inspection and Testing: The present periodic maintenance inspection and testing program and procedures should be reviewed and expanded to achieve improved

monitoring and outage record reporting for critical plant components. The process should involve both the existing maintenance resources at Wreck Cove and external engineers with hydroelectric plant maintenance expertise. The findings of the inspection and testing activities need to be documented and securely filed for future use, and resources need to be provided to ensure this can be effectively done.

- Preparation for Life Extension and Modernization: In order to carry out the Life Extension and Modernization program for Wreck Cove, considerable advance planning and site infrastructure improvements will be required. Initiation of the planning and installation of a project management team will need to be achieved in the near future.
    - As much of the replacement equipment and repair work is custom tailored for the site (common for large hydro plants) considerable lead time is required for engineering and manufacturing. Sequencing of work in the powerhouse to minimize unit and complete plant outages will require careful advance planning.
    - The location of the plant and the limited access to the underground powerhouse, where much of the work will be done, will require provision of a surface storage/workshop facility, worker support facilities and access tunnel traffic control.

Further details on Opportunities and Issues can be found in Section 7 of this report.

Recommended Viability Expenditures

Viability expenditures are those investments required to sustain the productive operation of the installed asset. Expenditures totalling $68.1 million have been identified over the next 30 years, of which $66.7 million is required over the next 10 years.

The major individual expenditures over the next 30 years, defined as those investments individually requiring more than $500k to carry out, are summarized in the following table. Costs include engineering, supply, delivery, installation, testing, commissioning and contingency, as well as an allowance for owner costs to manage the activities.

SUMMARY OF 2011 - 2012 CONDITION ASSESSMENT MAJOR (>$500k) EXPENDITURES

Engineering Discipline	Component	Assessment Results	Cost for Remedial Work (in 2012 $M)	Recommended Year(s) for Remedial Work
Civil	Life Safety	Detailed study and subsequent improvements	$5.35	2013-2016
Mechanical *	Turbines	Install uprated runners with wide operation range	$5.55	2015-2018
Mechanical	Turbines and Generators	Major mechanical overhauls	$5.00	2017-2018
Mechanical	Cooling Water System	Replace piping, valves & instrumentation (requires further assessment)	$1.80	2019
Mechanical	Powerhouse Crane	Replace control system	$0.55	2015
Mechanical	Fire Detection and Alarm Systems	Replace all systems	$0.55	2015
Electrical	Generators and Exciters	Refurbish generators and replace exciters	$30.00	2017-2018
Electrical	Excitation Transformers	Replace	$0.55	2021
Electrical	AC Station Service	Replace	$2.90	2019
Electrical	Protections	Replace	$3.05	2016-2017
Electrical	Control Systems	Replace	$2.75	2016
Electrical	Lighting Systems	Replace	$0.65	2016
		Table Total	**$58.7 ** **	

* This item is an Opportunity, rather than viability-driven. It is included in the listing here because of its significant cost.

** See third and fourth paragraph of Executive Summary for important information regarding this total.

2 INTRODUCTION

This report summarizes the results of the Condition Assessment carried out by KGS Group at Wreck Cove GS in 2011 and 2012.

The objectives of the condition assessment are:

- To provide a thorough, multi-disciplinary systems-based assessment of the physical condition of the Wreck Cove Generating Station and its associated structures.
- To document the present condition of the hydro generating facility for use as part of an asset management program so that proper scheduling of replacement and maintenance of items can be achieved.
- To provide comprehensive documentation of any deficiencies found or improvements required to modernize the facility to present day standards i.e. to scope a Life Extension and Modernization (LEM) program for Wreck Cove.

In addition, design adequacy reviews of several aspects of the station were performed, including:

- T-2 Adit and drain piping adequacy to perform its intended function
- Ungated intake structure
- Co-location of power conductors and back-up power in access tunnel
- Life safety assessment
- Sump and pump systems capacities
- Protection relays

The scope of the project included a visual inspection by civil (except geotechnical), mechanical, electrical, and the protection and control experts at the generating station, a review of existing documentation such as drawings, manuals, inspection and maintenance reports and interviews with Nova Scotia Power staff familiar with the plant, its maintenance history and current problems. The assessment scope covered all equipment and structures from the T-2 Tunnel Intake to the Tailrace Tunnel Outlet Structure. The main output transformers, the 144 kV conductors to the switchyard and the switchyard (except for the standby diesel generator set) were not part of the scope, nor were the other site buildings, roads and associated surface

structures, except for the fire protection tanks and deep well pumps, and the Access Tunnel Portal structure and equipment.

The condition of the plant has not been previously assessed in the same comprehensive manner.

During the course of the condition assessment, two important requirements for the Wreck Cove facility were identified by Nova Scotia Power to the assessment team:

1. In future, the Wreck Cove units would be called upon to operate over a wide range of loads to compensate for variability in wind turbine output to the electrical grid.
2. Based on the Nova Scotia Government's Electricity Act, Nova Scotia Power is required to meet two targets for the percentage of renewable capacity in their fleet: years 2015 up to 2020: 25% and from year 2020 onward: 40%

These requirements will have a strong influence on the reliability level required from the Wreck Cove generators and on the timing of major refurbishment work, and have been considered in recommending the schedule for the major refurbishment activities.

This assessment report consists of two volumes: Volume 1 includes the results of the assessments with supporting photographs, recommended actions, including estimated costs and proposed implementation schedule, and a summary of investment cash flows looking out 30 years. The recommendations in the report consist of four general classes:

- Maintenance activities such as periodic inspections and tests, for which no estimated costs are shown, as it is assumed these activities are funded in the annual maintenance program.
- Maintenance and/or diagnostic activities which involve resources from outside the Wreck Cove maintenance crew, such as Non-Destructive Examination (NDE) services. Cost estimates for these are provided and are based on performing a number of inspection activities in a group, such as NDE inspection of a number of turbine and generator components during an annual unit outage.
- Engineering studies and assessments which are recommended in order to arrive at the optimum solution. These are provided with judgement-based cost estimates, which consider the likely effort involved.
- Major refurbishment and replacement recommendations, such as turbine generator mechanical overhauls, for which an estimate is provided, along with an estimate sheet in

Volume 2 of the report. In some cases, major equipment suppliers have provided budgetary information for supply and install portions of the estimate.

Volume 2 contains appendices containing the supporting check sheet documentation, additional photos, and estimate sheets for those recommended actions whose individual estimated cost exceeds $250k.

The report identifies issues and opportunities at the generating station, provides an assessment of the station condition and identifies future actions required to support long term reliable and safe operation of the station.

3 THE FACILITY

Wreck Cove GS is a two-unit 200 MW hydroelectric station located on the east coast of Cape Breton Island, northwest of Sydney. The facility was placed into service in 1978, and is controlled from the Nova Scotia Power Incorporated Energy Control Centre in Halifax.

The assessment of the Wreck Cove GS facility includes the following structures:

- Wreck Cove Reservoir
- Tunnel T-2 Intake with Gate
- 3590 m long Tunnel T-2
- Surge Lake Reservoir
- Penstock Intake Structure
- 495.9 m (1627 ft) long Concrete Lined Penstock and Bifurcation
- Steel Lined Horizontal Penstocks
- Underground Powerhouse and 561 m (1842 ft) Access Tunnel
- 1702 m (5585 ft) Tailrace Tunnel and Exit Portal with Gate

The powerhouse contains the following major equipment:

- Two 6 ft diameter Turbine Shutoff Valves
- Two Vertical Shaft Francis Turbines
- Two Vertical Shaft Synchronous Generators
- Cabinet Type Mechanical-Hydraulic Governors
- Static Excitation Systems
- Powerhouse Crane
- Auxiliary Mechanical and Electrical Systems
- Two Step-up Power Transformers
- Life Safety Refuge Chamber

The scope of assessment specifically excluded:

- Wreck Cove Reservoir (and other reservoirs and associated dams)
- Tunnel T-1
- Gisborne Generating Station
- Step-up Power Transformers

- 144 kV Power Conductors
- Switchyard (except for Standby Diesel Generator)
- the Administration Building
- all surface facilities such as roads, storage and other miscellaneous buildings

UNIT CHARACTERISTICS

	Unit 1	Unit 2
First Year of Operation	1978	1978
Generator Rating (MVA @ 0.9pf, 90C rise)	111.1	111.1
Generator Manufacturer	Canadian General Electric	Canadian General Electric
Excitation Type	Static	Static
Speed (rpm)	450	450
Turbine Capacity (hp @ 1150 ft head)	138,000	138,000
Turbine Manufacturer	Mitsubishi Heavy Industries	Mitsubishi Heavy Industries
Turbine Type	Vertical Francis	Vertical Francis
Type of Spiral Case	Steel Spiral	Steel Spiral
Type of Draft Tube	Elbow	Elbow

4 CIVIL CONDITION ASSESSMENT

GENERAL

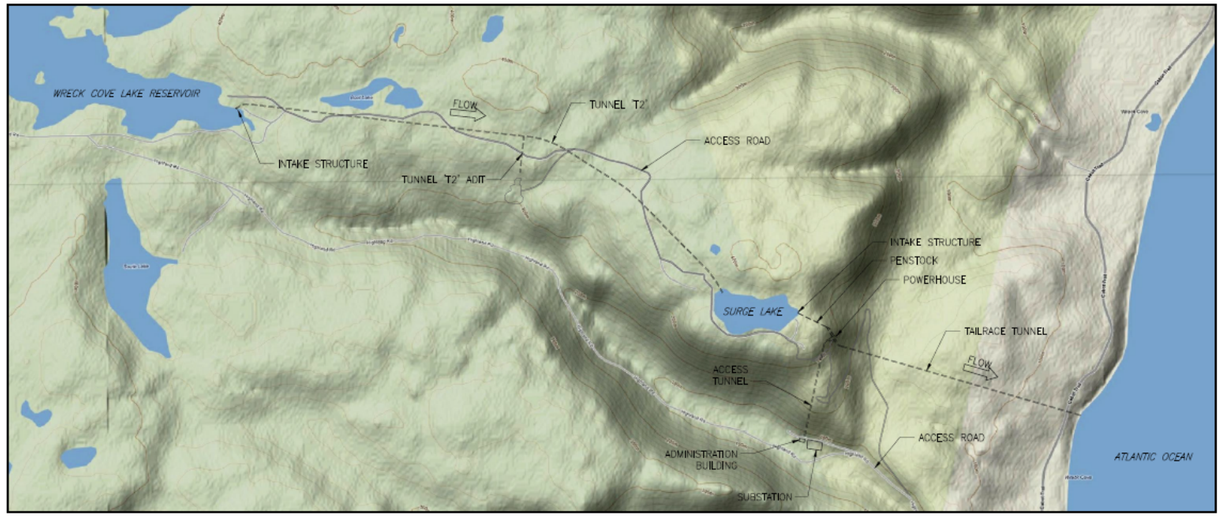
The general arrangement of the Wreck Cove GS is shown in Figure 4-1.

The following components were included in the civil condition assessment:

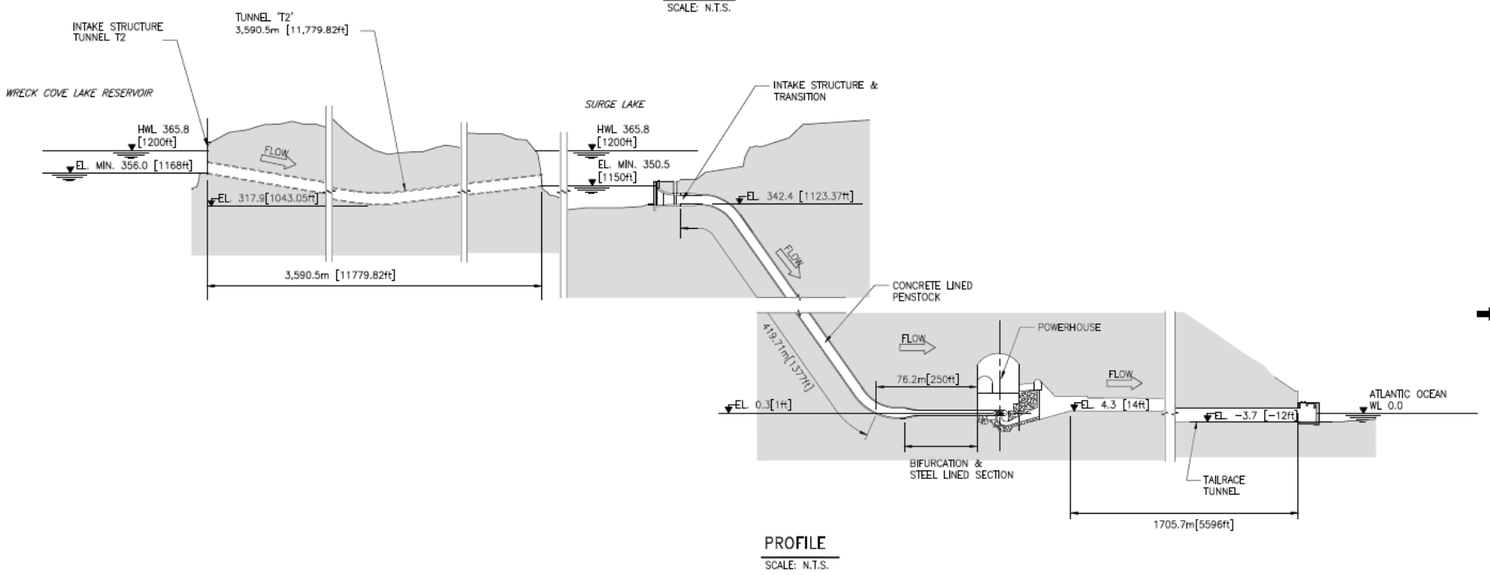
- tunnel T-2 Intake Structure
- tunnel T-2 Adit
- powerhouse
- powerhouse access tunnel Portal building
- penstock intake structure at Surge Lake
- penstock from Surge Lake
- draft tubes and spiral cases of turbines
- tailrace tunnel exit structure and gate storage structure

A general description, condition assessment, and recommendations follow for each of the above components.

In this report, when referring to the location of intake and tailrace components, “right” and “left” is referenced to looking downstream.



PLAN
SCALE: N.T.S.



PROFILE
SCALE: N.T.S.

NOTES:

1. ALL DIMENSIONS IN MILLIMETRES AND ALL ELEVATIONS IN METRES UNLESS OTHERWISE NOTED.

REFERENCE DRAWINGS:

1. GENERAL LAYOUT (H-085S1-1-111-00-033)
2. EMERGENCY PREPAREDNESS PLAN SYSTEM LAYOUT (FIGURE 11.1b)
3. PROJECT PLAN (WCP PROJECT O&M MANUAL – PLATE 1)
4. CROSS SECTION OF PROJECT (WCP PROJECT O&M MANUAL–PLATE 2)

NO.	YY/MM/DD	DESCRIPTION	BY
A	YY/MM/DD	DESCRIPTION	XXX

REVISIONS / ISSUE

CLIENT: NOVA SCOTIA POWER An Emera Company

PROJECT: WRECK COVE HYDRO SYSTEM

DWG. DESCRIPTION: GENERAL ARRANGEMENT EXISTING CONDITIONS PLAN AND PROFILE

DESIGN BY:	XXX	DATE (YY/MM/DD):	YY/MM/DD
DESIGN CHECK:	XXX	DATE:	YY/MM/DD
DRAWN BY:	XXX	DATE:	YY/MM/DD
DWG CHECK:	XXX	DATE:	YY/MM/DD

KGS GROUP CONSULTING ENGINEERS

DWG. NO.: 11-2242-01 | 1 | REV.: A

Figure 4-1: General Arrangement

4.1 TUNNEL T-2 INTAKE STRUCTURE

Description

Water is carried from Wreck Cove Reservoir to the forebay, located at Surge Lake, by Tunnel T-2. The intake of Tunnel T-2 is equipped with a wheeled vertical lift gate to cut off the flow to the power system when necessary (see Photo 4.1-1). The structure also comprises of a metal clad gate house building supported on a steel superstructure, which houses the hoist and associated mechanical equipment.

Since the entrance to the penstock at Surge Lake does not have a gate to stop flow to the powerhouse, the intake gate at the entrance to Tunnel T-2 essentially acts as the headgate to the Wreck Cove Generating Station. This gate is intended for operation in the fully open or fully closed position only. The gate is raised by an electrically operated wire rope hoist that can be controlled either locally or remotely from the Wreck Cove Administration Building. There is no provision for automatic operation in the event of an emergency.

Photo 4.1-1: Tunnel T-2 Intake Structure

Tunnel T-2 is unlined except where concrete lining or shotcreting was required due to poor bedrock conditions. The tunnel has an inverted “U” section, 3.96 m (13 ft) wide by 3.96 m (13 ft)

high and a length of 3,590 m (11,780 ft). According to the Operations and Maintenance Manual WRC-GEN-GEN-OMS-1978-46, the design maximum conveyance capacity of Tunnel T-2 is 32.4 m^3/s (1,145 ft^3/s), which is about the rated discharge capacity of one Wreck Cove generator.

Assessment

This assessment of the Tunnel T-2 Intake structure included a visual inspection of the above water components, review of Engineering Inspection Reports, and interviews with maintenance staff. Assessment details are organized under four sub-headings below: Concrete Structure, Miscellaneous Components, Gate House Building and Safety.

Concrete Structure

Based upon the visual inspection, the concrete structure is in good condition. Minor spalling was observed near the gains on the piers and deck (see Photos 4.1-2 and 4.1-3 and Volume 2 photos. Some minor shrinkage cracks were noticed (see Volume 2 photos) 410-7). No concrete repairs have been carried out to-date nor are any repairs currently required to be carried out.

Photo 4.1-2: Tunnel T-2 Intake Structure – Minor Concrete Spalling on Pier

Photo 4.1-3: Tunnel T-2 Intake Structure – Spalling on Deck

The concrete / rock interfaces at the right and left foundation abutments and right wingwall are tight with no evidence of leakage. (see Photo 4.1-4 and Volume 2 photos).

No dive inspection was carried out to inspect the concrete below the water surface, however, based upon the condition of the concrete above and at the waterline it is expected that the concrete is sound and in good condition.

Photo 4.1-4: Tunnel T-2 Intake Structure – Tight Concrete / Rock Interface

Miscellaneous Components

Based upon visual inspection, the steel gains are in good condition but some surface corrosion was evident (see Photo 4.1-5).

Photo 4.1-5: Tunnel T-2 Intake Structure – Minor Corrosion of the Gain

There are no trash racks installed at the Tunnel T-2 Intake Structure and ingestion of trash was not seen to be a problem at Wreck Cove GS.

Gate House Building

Based upon visual inspection, interviews with maintenance staff and a 2009 Engineering Inspection Report (WRC-WRC-G-RP-2009-24 *Incomplete Report*), the steel Gate House Building and the steel superstructure are in good condition (see Photo 4.1-6)). The steel frame superstructure supporting the Gate House Building appears to be in good condition, but the paint is flaking / peeling and some corrosion is evident but no loss of sectional area was observed due to the corrosion (see Photo 4.1-7). A single bolt is missing from the downstream cross-braces as noted in the Engineering Inspection Report (2009). The steel ladder and safety cage are in good condition. The condition of the protective coating is similar to that of the steel substructure; minor surface corrosion was also observed in the ladder, cage and platform/handrail assembly. Volume 2 contains additional photos showing the gate house building.

The locking mechanism on the man door accessing the Gate Hoist Building is malfunctioning.

Photo 4.1-6: Tunnel T-2 Intake Structure – Gate House Superstructure

Photo 4.1-7: Tunnel T-2 Intake Structure – Corrosion of the Structural Members

Roof Leakage

In June 2012, a detailed inspection of the steel roof was carried out by Roofchek. The roof system and flashings were found to be showing moderate wear and were in need of service and or repair to achieve their expected service life. At the time of the KGS Group inspections in June 2012 and August 2012, the roof was noted to have an active leak and water infiltration was dripping onto an electrical box in the gate hoist house (see Photos 4.1-8 and 4.1-9). The water infiltration was assessed to be coming in from the roof hatch due to deteriorated / debonded caulking.

Photo 4.1-8: Tunnel T-2 Intake Structure – Observed Roof Leakage

Photo 4.1-9: Water Leakage Dripping onto Equipment

Safety

Prior to 2010 the only protection to personnel and the public from falling into the water were the existing handrails. The handrails are secure and have little to no corrosion.

New public safety fencing (approximately 2.1 m (7 ft) high) with a lockable gate was installed in 2010 (see Photos 4.1-10 to 4.1-12). The fencing was installed around the intake structure and along the wing walls to prevent unauthorized access to the structure and to improve protection to personnel and the public from falling into the water.

Photo 4.1-10: Tunnel T-2 Intake Structure – New Public Fencing Extending to the Left

Photo 4.1-11: Tunnel T-2 Intake Structure – New Public Fencing Extending to the Right

Photo 4.1-12: Tunnel T-2 Intake Structure – New Lockable Gate Enclosing the Structure

Warning signs are posted to increase public safety (see Photo 4.1-13). The signs appear to meet the 2011 Canadian Dam Association (CDA) Signage for Public Safety Around Dams Technical Bulletin standards except that they are deficient in that an “emergency call” number is

not provided on the signs. When any of the signs require replacement they should be replaced with signs that have an “emergency call” number on them and they should be designed in accordance with the CDA Signage for Public Safety Around Dams Technical Bulletin standards.

Photo 4.1-13: Tunnel T-2 Intake Structure – Warning Signs

Currently no public safety booms are installed upstream of the intake structure nor is the intake structure equipped with trash racks. In accordance with the CDA 2011 Guidelines for Public Safety Around Dams, the head pond upstream of the intake structure is considered to be a “dangerous zone” as serious injury or death could occur if swimmers or boaters come too close to the intake structure when the gate is open. Safety booms should be installed upstream of the intake structure to act a physical barrier to delineate this dangerous water area. The safety booms can be seasonal or all season and the booms should be installed and orientated to aid self-rescue of stranded swimmers and boaters. NSP may prefer to install all season booms to save having to take the booms out of the water in the fall and redeploy them in the spring. In addition, with the seasonal booms the periods when the booms are not deployed and before ice has formed on the water, the public are at risk to the danger of the intake structure. However, initial material and construction costs are higher for all season booms compared to seasonal booms because they must be designed for ice loads. Furthermore, maintenance costs also tend to be higher for all season booms because they are subjected to harsher environmental

conditions (i.e., ice) and are in the water year round versus only half of the year with the seasonal booms. Popular seasonal and all season booms used at hydroelectric sites are the "Tuffboom" and "Boat Buster", respectively. Both are supplied by Worthington Inc. The safety fencing should also be extended to the boom anchor points.

Recommendations

- Continue to periodically, visually monitor the concrete for evidence of deterioration and spalling and waterline erosion.
- Carry out minor patching repairs to the spalled concrete within the next 10 years. Other than the minor patch work no concrete repairs are recommended for the next 30 years. Cost for the patch work is estimated to be $50k.
- Remove deteriorated paint and corrosion and apply a protective coating to the Gate Hoist Building structural steel superstructure as well as gains. This work should be performed within the next 5 years to maintain the integrity of the structure. The estimated cost for this work is $30k.
- Repair the failed caulking around the roof hatch within the next year. Consideration should be given to replacing the failed caulking with grade mastic and mesh. A protective coating should then be installed over the repair. The estimated cost for this work is $6k.
- Install an all season safety boom in 2013, at an estimated cost of $130k.
- Include funds in the maintenance budget for boom maintenance in the amount of $5k every 3 years.
- Extend the safety fencing to the boom anchor points in 2013 at an estimated cost of $70k.
- Provide two additional public safety signs on the land side of the fencing in 2013, at an estimated cost of $1k

4.2 TUNNEL T-2 ADIT

Description

Tunnel T-2 is unlined except where concrete lining or shotcreting was required due to poor rock conditions, for mining safety or to ensure the long-term stability of the rock walls. The tunnel has an inverted "U" section 3.96 m (13 ft) base x 3.96 m (13 ft) high. Tunnel T-2 Adit's design function, once Wreck Cove began operations, is to drain Tunnel T-2 for inspection or maintenance purposes, if required.

Figure 4.2-1 shows a plan and profile of the Tunnel T-2 and the location of the Adit. The information shown in Figure 4.2-1 is based on Nova Scotia Power Drawing: Geotechnical Data, Tunnel T-2 -H-085S1-1-628-00-014. The Tunnel T-2 Adit is located approximately 1,884 m± (6,180 ft±) from the Tunnel T-2 Intake Structure at the Wreck Cove Reservoir and the approximate elevation is 329 m± (1080 ft±). The lowest indicated elevation of Tunnel T-2 is 320 m (1050 ft).

The Adit has an inverted "U" section measuring approximately 4.50 m± (14.7 ft±) high by 3.65 m± (12 ft±) wide. Shotcreting was applied to the arched section of the Adit for a minimum length of approximately 6.10 m (20 ft) at a distance of approximately 21.34 m (70 ft) from the perpendicular intersection of the Adit with Tunnel T-2.

According to the Nova Scotia Power Drawing: Tunnel T-2 Adit - H-085S1-1-628-09-001, and the Wreck Cove Power Project Operations and Maintenance Manual (WRC-GEN-GEN-OMS-1978-46), a concrete plug was constructed at the end of the T-2 Adit near its junction with the T-2 Tunnel. A drainage line was embedded within the concrete plug with two valves located just outside the plug. Historically, dewatering of Tunnel T-2 for inspection and/or maintenance was accomplished by opening these drain valves. However, as a result of numerous rock falls associated with structural instability, the T-2 Adit has been deemed unsafe and no entry into the Adit is permitted.

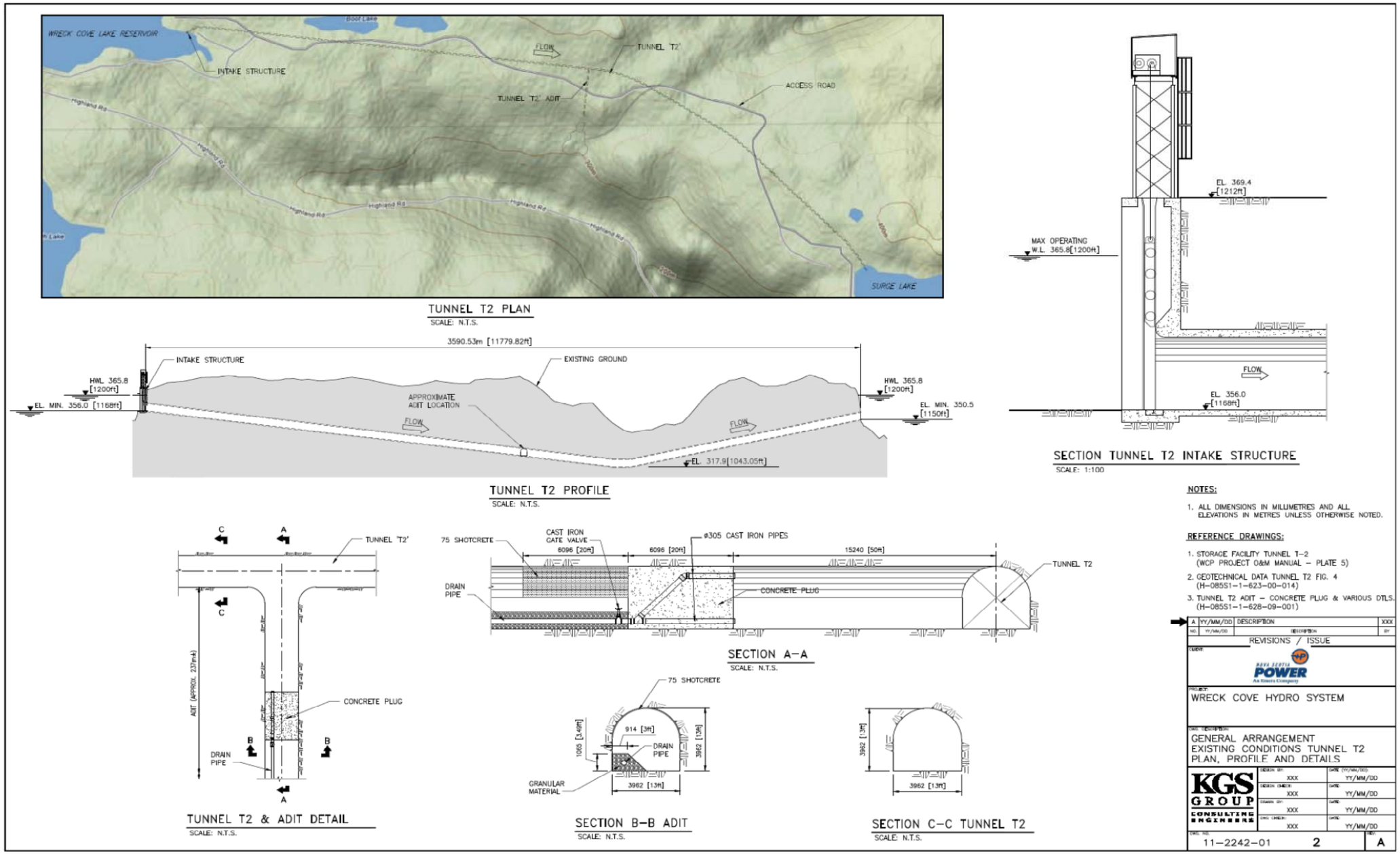


Figure 4.2-1: General Plan and Section of Tunnel T-2 and Adit

Assessment

This assessment of the Tunnel T-2 Adit involved a limited visual inspection of the outlet, review of the Operations and Maintenance Manual (1978) and interviews with maintenance staff. Assessment details are organized under two sub-headings below: Safety and Design Adequacy.

Safety

In the late 1990's the Adit was inspected and evidence of rock falls was found for an approximate 180 m length of the tunnel. A mining contractor was then hired to reinforce the areas susceptible to rock fall but only after a few days into the work the contractor deemed the Adit to be unsafe to work in because of the numerous rock falls associated with structural instability. Since then there has been no access or further assessment of the condition of the Adit.

KGS Group's visual inspection of the T-2 Adit was limited to the outlet. The corrugated steel outlet section appears to be in good condition. The steel corrugated pipe is closed-off using a wire mesh secured to a wooden frame (see Photos 4.2-1 to 4.2-3). The wire mesh has been separated from the frame at the ground level, making the tunnel accessible by unauthorized persons. Damage to the wire may be an act of vandalism or may have been caused by an animal. A caution sign is placed on the wire mesh indicating that a space assessment is required before entry.

The upstream end of the corrugated steel pipe outlet appeared sealed off by a wooden barricade.

The Adit outlet appeared dry with only ponding as a result of precipitation (i.e., no signs of leakage from the upstream Tunnel T-2). Therefore, the concrete plug appears to be effective in containing the water in Tunnel T-2.

Photo 4.2-1: Outlet of Tunnel T-2 Adit

Photo 4.2-2: No Access Permitted into Adit

Photo 4.2-3: Corrugated Steel Outlet of Adit Appears to be in Good Condition

Design Adequacy

To dewater the Tunnel T-2 for inspection or maintenance activities, it is necessary to bring the level of Surge Lake below the level of the tunnel outlet invert elevation which is at El. 352 m (1155.0 ft). This is accomplished by closing Tunnel T-2 gate and passing water out through the units to lower Surge Lake. Then, historically, T-2 Tunnel dewatering has been accomplished by opening the drain valve installed near the concrete plug at Tunnel T-2 Adit. In the mid 1990's, Tunnel T-2 was last drained by this method and the operation took about 6 days.

Because access into the Adit is not permitted, the condition of the rock walls and roof, concrete plug, valve and drainage piping could not be assessed. The condition of these components at this time is unknown. However, based upon the visual inspection of the Adit outlet the concrete plug, the pressurized pipe and the valve in the closed position do not appear to be noticeably leaking.

Dewatering options that could be considered for further study include:

- Dewater with a pump from the Tunnel T-2 exit.

- Construct a vertical shaft above the T-2 Tunnel, to be used for dewatering. Ideally the shaft would be drilled near the lowest elevation point in the tunnel where this coincides with the least amount of drilling and pumping to discharge the water is required.
- Construct a vertical shaft through the rock above the Adit to access the valve and/or to dewater the tunnel through the shaft.
- Rehabilitate the Adit to make it safe for entry.

In the short term, if need be, consideration can be given to carrying out an inspection of Tunnel T-2 without it being dewatered. This could be achieved using an underwater ROV to video film the inside of the tunnel (and inspect the drainage pipe penetration into the tunnel).

With entry now not permitted into the Adit, there is no access to operate the 35 year old valve to dewater the Tunnel T-2. Whether the valve is operable after being unused for 20 years is also unknown. Currently the Adit is not serving its intended function nor has Nova Scotia Power established an alternative method to safely dewater the tunnel in a reasonable time. Until a solution is identified and implemented, there remains the risk of a failure of the pressurized piping, which would require a significant plant outage to address.

Recommendations

- Within the next two years, inspect the inside of the Adit with a remotely operated tracked vehicle (ROV) to determine the condition, feasibility and the extent of repairs required to make the Adit safe for entry. The estimated cost for the inspection and assessment is $50k.
- In parallel with the inspection and condition assessment work, undertake a engineering study to investigate alternative means to de-water the tunnel, including the alternative of making the Adit safe, if found to be feasible, at an estimated study cost of $30k. All alternatives should assume that the present valve and pressurized pipe penetration into Tunnel T-2 will need to be permanently sealed. Any alternative using the Adit for drainage should assume that a new valve and pipe penetration into Tunnel T-2 are required.
- Allow funding in the capital budget in 2016 to provide a means of draining Tunnel T-2 and sealing off the existing pipe penetration. For the purpose of providing an estimate, the solution of drilling a 1.5 m diameter vertical shaft 60 m long through the rock into the tunnel near the Adit is assumed, with an estimated cost of $325k for design and drilling. In the

event an alternative tunnel dewatering system is not selected, or if its implementation is deferred some years beyond 2016, seal the drainage piping by 2016.

4.3 PENSTOCK INTAKE STRUCTURE AT SURGE LAKE

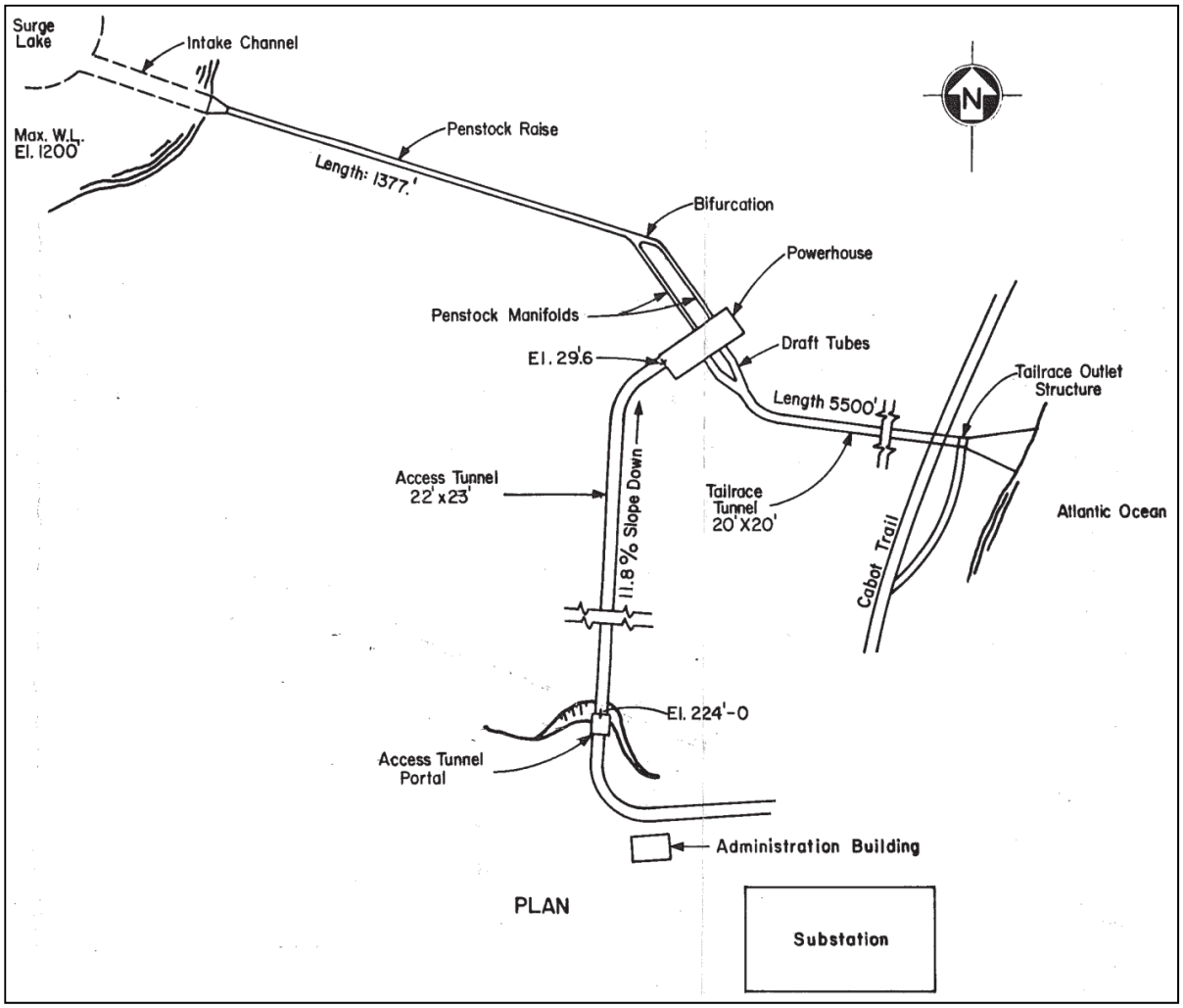


Figure 4.3-1: General Arrangement of Wreck Cove Facility
(Extracted from Plate 6 from the Wreck Cove Power Project - Operation and Maintenance Manual)

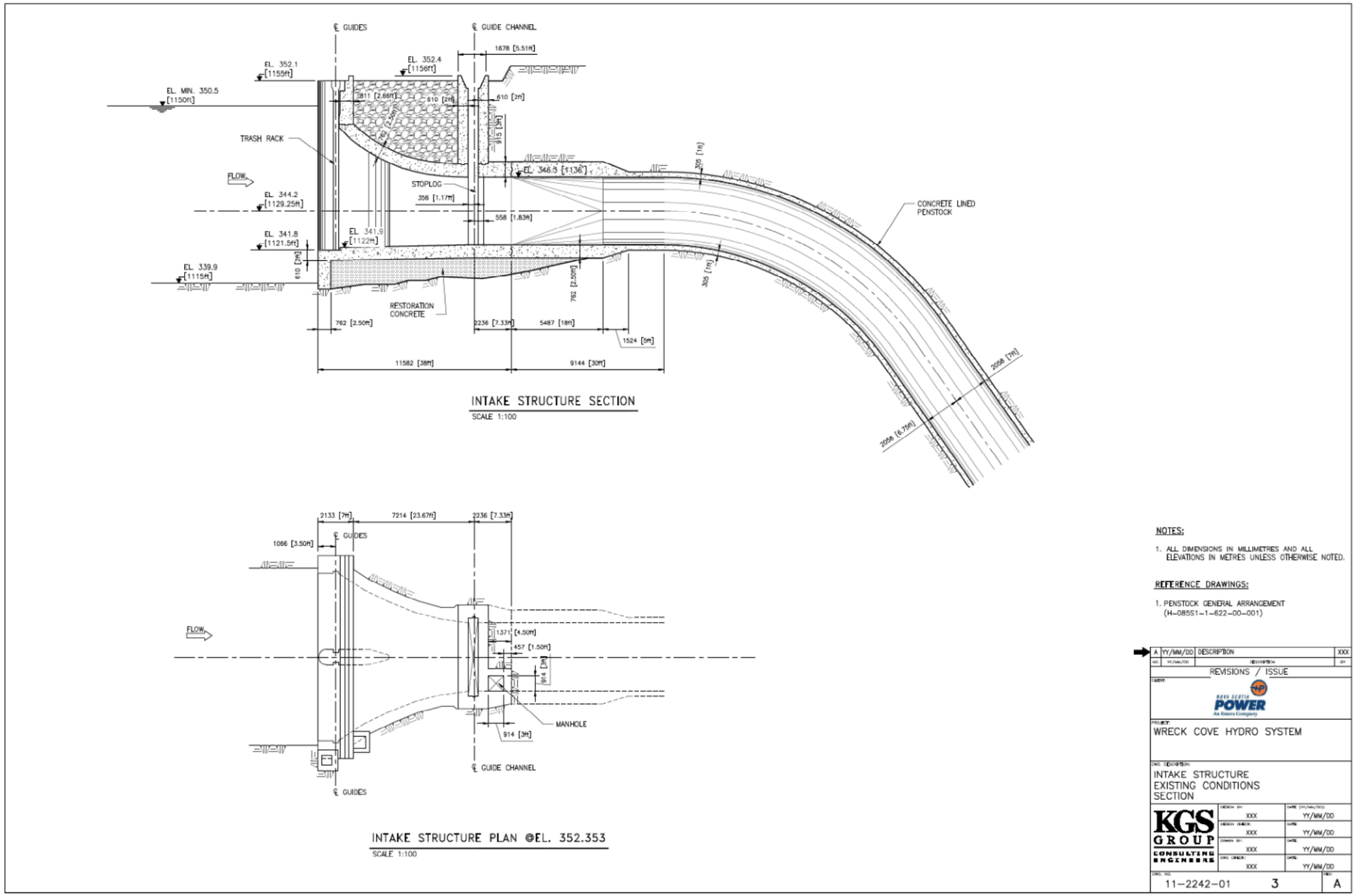


Figure 4.3-2: Cross-Section of Penstock at Intake Structure

Description

From the intake at Surge Lake, the water is led to the turbines by a single underground concrete lined penstock tunnel which bifurcates at the powerhouse level at El. 0.305 m (1 ft). The reinforced concrete intake structure is entirely submerged under normal operating conditions (maximum operating water level is El. 365.8 m (1,200 ft)). Two trashrack elements, 4.57 m (15 ft) wide by 6.71 m (22 ft) high, are installed at the intake portal. The intake to the penstock is ungated; however, steel stoplogs are provided to permit dewatering of the penstock. To install the stoplogs, Surge Lake must first be lowered by passing much of the water through the turbines and the rest through a drain line in the bottom of the lake through Dam D11-2, which is controlled by a valve located at the toe of the dam.

Manual raking of the trashracks and placement of the stoplogs with a mobile crane have to be carried out from the deck of the intake structure at El. 352.0 m (1,155.0 ft) with the level of Surge Lake drawn down to El. 350.5 m (1,150.0 ft). Figures 4.3-1 and 4.3-2 show the general layout and cross sections of the penstock including the intake structure.

The entire steel trashrack assembly consists of two sets of identical racks, left and right of the intake centre line. A total of four panels are located at each side, stacked in the trashrack checks from sill elevation to near the top of the intake structure. All trashracks are designed to be removed for access into the penstock or for maintenance, by a small mobile crane or moderately large boom truck.

Assessment

At the time of the KGS Group site visit, September 2012, the penstock intake structure could not be visually inspected because it was below the water level.

During a planned outage and when Surge Lake was drawn down in 2009, the intake structure including the trash racks were inspected. The inspection consisted mainly of a visual examination including an assessment of the remaining / residual protective coating on the trash rack panel units and an approximation of material loss due to corrosion (Report No. WRC-WRC-TR-RP-2009-26). The trashrack panel assemblies were found to be in overall good condition with some limited metal loss in areas where the original protective coating had significantly degraded or was found to be non-existent. No distortion or structural damage to the trashrack frame and bars was noted.

The protective coating is original and has exceeded its normal service life expectancy, with loss of coating in several areas. Now that the metal is exposed in multiple locations, metal loss rates and general structural degradations will be expected to accelerate and spread quickly over each of the steel trashrack panels. Photos 4.3-1 to 4.3-3 are photos extracted from the 2009 Trashrack Inspection Report.

Photo 4.3-1: Upper Trashrack Panel (Photo from 2009 Trashrack Inspection Report)

Photo 4.3-2: Trashrack Lower Corner (Photo from 2009 Trashrack Inspection Report)

Photo 4.3-3: Trashrack Bars are True and Corners / Edges are Square
(Photo from 2009 Trashrack Inspection Report)

The trashrack checks embedded parts were found to be in good condition, but with surface corrosion starting to spread over the exposed surfaces (see Photo 4.3-4,).

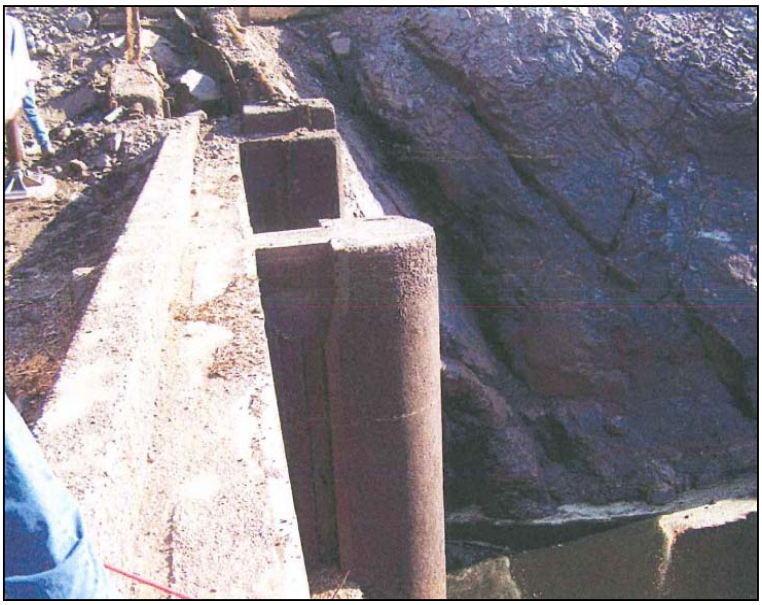


Photo 4.3-4: Surface Corrosion Evident on Trashrack Checks
(Photo from 2009 Trashrack Inspection Report)

KGS Group is in agreement with the recommendation provided in the 2009 Trashrack Inspection Report to carry out remedial work on the trashracks and trashrack checks as part of the next major planned plant outage or sooner. The following remedial work is recommended:

- Remove the trashracks from the checks.
- Thoroughly blast clean (in accordance with the manufacturer's requirements for the selected new protective coating).
- Following the initial blast cleaning, a visual examination should be carried out to identify areas / locations on the racks and / or embedded parts that require structural repair (i.e., welding).
- Following any repairs, if required, the rack panels should be finish blasted and re-coated with an appropriate protective coating such as a two-part epoxy coating system.

Photo 4.3-5: Surge Lake Penstock Inlet Sectional Gates

The penstock inlet sectional gates appear to be in good condition and have performed well. No work is required, other than touching up areas where the protective coating is lost or damaged.

Recommendations

- Refurbish the trashracks at an estimated cost of $110k. The refurbishment of the trashracks should be carried out no later than 2018. Refurbishment is estimated to be less costly than replacement ($220k).

4.4 PENSTOCK FROM SURGE LAKE

Description

The penstock is 495.9 m (1627 ft) long with a total gross head of 365.5 m (1199 ft). According to the construction drawings, starting at the intake, the penstock includes the following (see Figure 4.3-1 and 4.3-2):

- a transition section
- an upper elbow
- an inclined section 400.8 m (1,315 ft) long sloped at 55° to the horizontal
- a lower elbow

- a bifurcation
- a manifold
- two horizontal penstocks, penstocks 1 and 2, each 45.7 m (150 ft) long.

According to the 2009 Hatch Review of Penstock Inspection Report the penstock has the following characteristics:

- The inclined penstock is 4.11 m (13.5 ft) in diameter at the top and 3.51 m (11.5 ft) in diameter at the bottom.
- The thickness of the concrete liner for the inclined penstock varies from 305 mm (1.0 ft) to 840 mm (2.75 ft).
- The inclined penstock concrete liner is non-reinforced and the concrete to bedrock contact was pressure grouted.
- The transition, bifurcation and manifold are reinforced concrete.
- The horizontal penstocks are steel and concrete lined. The steel lined section is approximately 2.44 m (8.0 ft) in diameter and the minimum concrete thickness is 610 mm (2.0 ft).

Assessment

General

During the planned outage in 2009 the penstock was dewatered for an inspection by Remote Access Technology (RAT) and Hatch reviewed the RAT Inspection Report and interviewed the RAT inspector (Hatch, Review of Penstock Inspection Report, 2009). Based on the RAT Inspection Report (RAT, Penstock Inspection, 2009) and Hatch's review, in general, the penstock was found to be in sound condition and performing satisfactorily. Particular observations made by RAT and interpretations of the observations are as follows:

- Features which might suggest overstressing of the concrete such as offsets (i.e., displacement along cracks and joints, or longitudinally oriented cracks in the penstock concrete) were not observed.
- Typical cracking was noted throughout the concrete penstock. The cracks were noted to be a maximum of 3.5 m to 4.5 m (11.5 ft to 14.8 ft) in length and formed no discernable pattern.
- RAT identified construction joints at 3.05 m (10 ft) intervals. However, according to Nova Scotia Power Drawing H-085S1-1-622-00-004, the construction joints are generally at a

spacing upwards of 15.2 m (50 ft). Therefore, most of the construction joints reported by RAT may actually be shrinkage joints.

- RAT identified black “silt like” material up to 20 mm (0.8 inches) thick coating the inside of the entire penstock. This material is most likely algae with possibly some fine sediment which has deposited over 30+ years of operation.
- Full round continuous, near normal to the penstock centreline, white traces spaced at a moderate frequency were noted by RAT. The traces were approximately 50 mm to 75 mm (2 to 3 inches) wide. Occasional relatively wide (up to 600 mm (2 ft)) and long white plumes extending from the white traces were noted. The white traces and plumes are most likely due to leakage water through shrinkage cracks and cold joints. The leakage water carries soluble materials such as carbon dioxide and calcium hydroxide, the latter derived from the concrete to produce the insoluble calcium carbonate deposits on the inside of the penstock. The shrinkage cracks and calcium carbonate deposits are not uncommon for penstock concrete liners. The inferred cracks and joints would appear to have little or no structural impact. They do however cause leakage. The white traces and plumes suggest that the leakage is inward directed.
- The presence of calcium carbonate deposits and the black coating (and irregularity of the black coating thickness) could possibly cause increased head loss and reduced power generation. Locally damaged joints / cracks could also cause some head loss.
- There is a remote possibility that the deposits consist of silica gel, in which case, this would suggest alkali aggregate reaction and could lead to progressive deterioration in the concrete.

Steel Penstock Thickness Measurements - Unit 1

Steel penstock wall thickness readings were taken where the penstock emerges from the upstream wall of the powerhouse, about 7 m (20 feet) upstream of the spherical valve. The outer surface was covered with precipitated material carried by drainage water from the gap between the concrete and the steel penstock wall. According to drawing H08551-9622-00-005 the wall thickness in this area is 41.3 mm (1-5/8 in).

Several areas were scraped clean and ultrasonic thickness readings were taken. The readings were between 41.2 and 41.7 mm (1.62 and 1.64 in). The wall thickness is acceptable.

Photo 4.4-1: Location of Penstock Thickness Reading

As this section of the penstock was watered up, the interior surface could not be inspected. However the short length of penstock downstream of the spherical valve was inspected and found to be in excellent condition. There was no erosion or damage evident.

Recommendations

- The penstock steel plate in the powerhouse in the area where the thickness measurement was taken is in good condition. Starting in 2013, perform more extensive ultrasonic thickness testing every 5 years. Estimated cost is $5k for two penstocks.
- During the next planned penstock dewatering, take core samples of the concrete liner and carry out laboratory tests to rule out the remote possibility of alkali aggregate reaction. The estimated cost to sample and test the concrete liner is approximately $20k. For budgeting purposes, assume this coring / testing activity will take place within the next 10 years.
- By 2014 carry out a (desk-top) assessment of the potential head losses and energy production losses due to the algae, calcium carbonate deposits, and surface irregularities to determine if power wash cleaning of the inside surface of the penstock is warranted. The estimated cost of a power wash is $500k and each gain of 0.1 % in plant efficiency would yield 260 MWh per year of added energy. The estimated cost for this assessment is $12k.

4.5 SPIRAL CASE

See Section 5.3 Turbine for the assessment of the spiral cases.

4.6 DRAFT TUBE

Description

The draft tubes are steel lined in the high water velocity area from the discharge ring to the elbow transition, after which the walls are unlined concrete.

The draft tube liner is made of 20 mm (0.8 inches) thick mild steel. At the upper end, the liner is attached to the stainless steel erection ring, which forms the stationary part of the runner band bottom seal. An air pipe behind the liner feeds air to the three legged air admission tripod.

There have been periodic cavitation pitting repairs made to the draft tube liner, especially in the area of the air admission piping. No repairs were needed during the September 2012 outage on Unit 2, or the November 2012 outage on Unit 1.

Air is admitted into the draft tube via turbovent operation and through the draft tube tripod pipes (see Photo 4.6-1). The turbovent air admission is controlled from the operating ring while the tripod air is admitted on demand, depending on the amount of negative pressure in the draft tube.

Photo 4.6-1: Unit 1 Air Admission Tripod

Assessment – Unit 2 Draft Tube Liner

Information for the assessment was obtained from visual inspection, ultrasonic testing, hammer tap testing and from discussions with maintenance staff.

The draft tube liner was visually inspected down to the level of the draft tube platform.

The stainless steel erection ring is in very good condition, with no damage observed. It is shown in the runner cavitation photos.

The air admission tripod legs have caused cavitation putting damage downstream of where they connect to the draft tube walls. See Photo 4.6-1 showing the stainless steel overlay on the draft tube liner used to repair the cavitation damage. This is a typical problem with these tripods, and the ongoing damage has been successfully repaired. Noted during the inspection was some ongoing mild cavitation damage at the junction between the stainless overlay and the mild steel wall. This should be repaired within about 2 years. It is of interest that galvanic damage of this type has been observed at another station where the draft tube liner could be in contact with salt water.

Testing done during the 2012 Unit 2 outage has confirmed that the air supply pipe leading to the east tripod leg (upstream is assumed to be north) has broken behind the draft tube liner. Water in the draft tube enters the tripod piping and goes out though the break beside the draft tube door and runs down the steps. This break should be repaired to prevent erosion of the concrete and rusting behind draft tube. The water flowing out of the draft tube also is a slipping hazard.

Photo 4.6-2: Water Leakage to the Left of Unit 2 Draft Tube Door

Ultrasonic thickness measurements of the draft tube liner were taken at various locations but concentrating on the areas where the tripod legs pass through the draft tube liner. The measured thicknesses were between 17.5 mm to 20.75 mm (0.70 to 0.83 in). The design thickness is 20 mm (0.79 in). The thickness readings were written on the draft tube liner and photographed. No significantly thinned areas were discovered.

The bond between the concrete and the back of the draft tube liner was checked by hammer tapping. About 30% of the liner is not bonded, mainly around the tripod pipes. Anecdotal evidence from the plant staff says the concrete in this area was poured from the top. This can

leave voids around piping and stiffeners. This condition is not unusual, and no remedial action is required unless fatigue cracks occur in the draft tube liner.

The draft tube door bolts were visually inspected for signs of cracking and damaged threads and found to be in good condition. The threaded holes in the draft tube liner also are in good condition.

Assessment – Unit 1 Draft Tube Liner

The draft tube liner was visually inspected down to the level of the draft tube platform.

The stainless steel erection ring is in good condition. It has some patches of mild cavitation pitting at various locations around the ring, as seen in the runner cavitation pitting photos.

The air admission tripod legs have caused cavitation pitting where they connect to the draft tube walls. This is a common problem with these tripods. The ongoing damage has been successfully repaired with welded stainless steel overlay. The photo below shows the stainless steel overlay on the draft tube liner where the pipe is attached.

Photo 4.6-3: Unit 1 Draft Tube Liner Thickness Readings and White Circled Hollow Area

A detailed inspection of the Unit 2 draft tube liner, including thickness testing, was carried out in 2009 (WRC-WRC-DT-RP-2009-32). The inspection found no significant liner thickness loss, with measurements ranging between 19.65 mm (0.77 in) to 20.0 mm (0.79 in), with a design thickness of 20 mm (0.79 in).

During the unit inspection, ultrasonic thickness measurements of the draft tube liner were taken by KGS Group at various locations but concentrating on the areas where the tripod legs pass through the draft tube liner. The measured thicknesses were between 19.3 mm to 20.5 mm (0.760 to 0.810 in). The design thickness is 20 mm (0.79 in). Thicker readings probably are due to weld repairs and the different speed of sound in stainless steel. The thickness readings were written on the draft tube liner and photographed. No significantly thinned areas were discovered.

The bond between the concrete and the back of the draft tube liner was checked by hammer tapping. About 80% of the liner is not bonded. This condition is not unusual, and no remedial action is required unless fatigue cracks occur in the draft tube liner.

The draft tube door bolts were visually inspected for signs of cracking and damaged threads and were found to be in good condition. The threaded holes in the draft tube liner also are in good condition.

In September 2012, when Unit 1 was in operation, a small amount of leakage was observed coming from the concrete near the draft tube door. This is much less severe than the leakage in the same area of Unit 2.

Assessment – Unlined Concrete

The concrete walls of the draft tube could not be visually inspected due to access limitations. However, in 2009, Remote Access Technology (RAT) conducted a visual inspection of the Unit 2 draft tube liner (Ref: RAT 2009, Report No. WRC-WRC-DT-RP-2009-32, “Visual & Non Destructive Testing Inspection Report”). RAT observed 2 locations with cracks and one location with a hole in the concrete wall (max 250 mm in depth) of the draft tube unit located next to the steel / concrete interface area.

No record or staff recollection of a similar inspection of Unit 1 could be located.

Recommendations

- Continue to repair any draft tube liner cavitation pitting damage during the yearly maintenance outages. Repair the present minor damage within two years.
- Refurbish the Unit 2 tripod air system within 8 months. Cost is estimated to be $40k.
- Investigate the Unit 1 draft tube water leakage in 2013 at an estimated cost of $10k.
- During the next scheduled outages of each unit, the condition of the unlined draft tube concrete sections should be inspected and assessed. Estimated cost for each unit inspection and assessment is $5k per unit.
- Repair the observed 250 mm deep hole in the concrete wall of Unit 2 draft tube by 2018.

4.7 TAILRACE

Description

Water from the draft tube of each turbine discharges into a tailrace manifold and then into the tailrace tunnel. Sufficient steel stoplogs, handled by an overhead monorail hoist, are provided for use at the draft tube outlets for dewatering one turbine for maintenance.

The unlined tailrace tunnel is 1,702 m (5,585 ft) long with a 6.10 m (20 ft) by 6.10 m (20 ft) inverted “U” section. The tailrace discharges directly into the Atlantic Ocean.

A reinforced concrete portal structure is constructed at the tailrace tunnel outlet (see Figure 4.7.1). Closure of the tailrace tunnel from the ocean is carried out by placing a bulkhead gate by mobile crane in the portal structure embedded guides. The gate is a 6.91 m wide by 6.30 m high (22 ft 8 in by 20 ft 8 in) structural steel gate with a 9.5 mm (0.375 inch) skin plate on the upstream side, and four hydraulically operated cylinders (one at each corner) to ensure positive sealing when the gate is in position. The gate is stored vertically on a purpose-built reinforced concrete frame located away from, but nearby the tailrace outlet structure, within 15 m (49.2 ft) of the ocean.

An opening is provided in the deck of the portal structure, upstream of the gate gains, for limited vehicle access and removal of muck in case of rock falls in the tunnel.

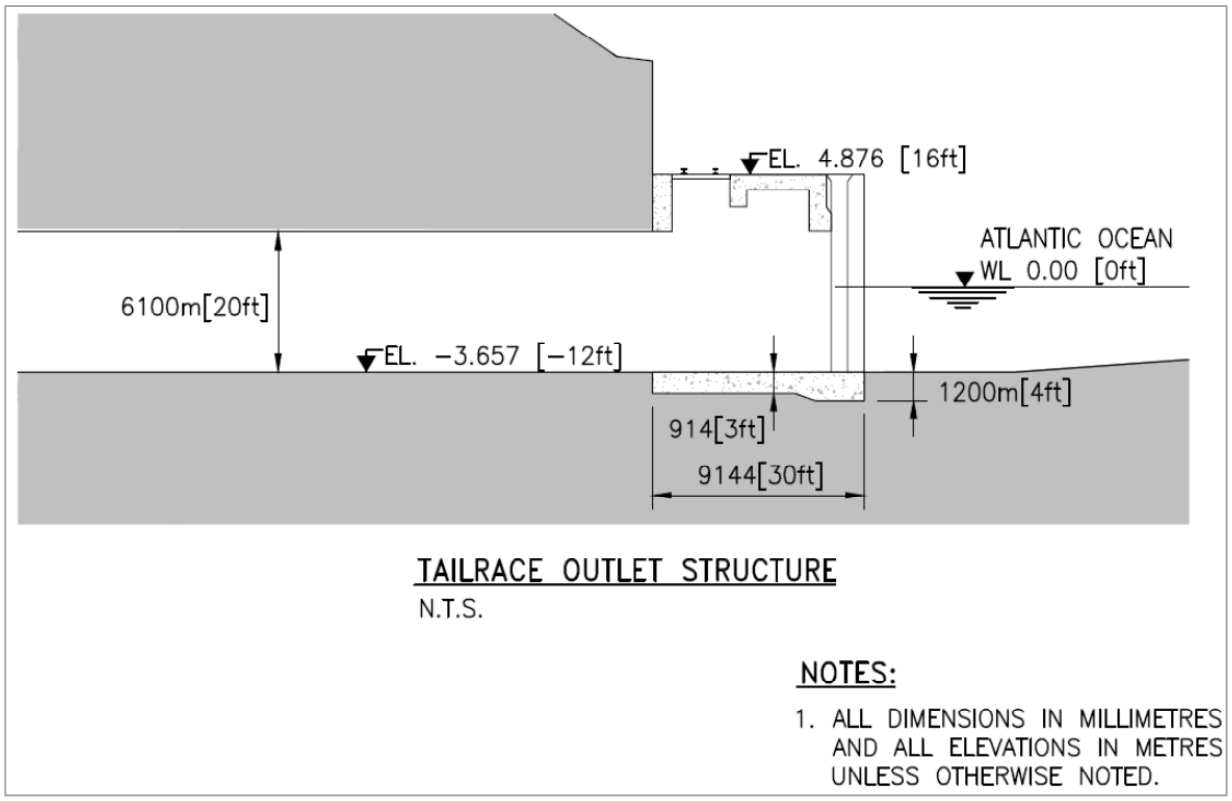


Figure 4.7-1: Tailrace Outlet Structure

Assessment

The assessment of the tailrace and flow control equipment at the outlet of the draft tubes and outlet of the tailrace tunnel included a visual inspection from the decks of the structures carried out by KGS Group on August 29 and 30, 2012 of the following structural components:

- Concrete structure above the waterline at the outlet of the draft tube
- Draft tube stoplog gains and monorail hoist
- Concrete structure above the waterline at the outlet of the tailrace tunnel
- Concrete supporting structure for the tailrace bulkhead gate at the outlet of the tailrace tunnel
- Tailrace bulkhead gate and concrete structure for storing the gate
- Opening and grating system in the deck of the tailrace outlet portal structure.

The reports that were reviewed include:

- Nova Scotia Power November 2008 Engineering Inspection Report: “Wreck Cove Tailrace Outlet Bulkhead Gate” (Report No.: WRC-WRC-G-RP-2008-23, E. O’Neil).
- Nova Scotia Power November 2009 Engineering Inspection Report: “Wreck Cove Tailrace Tunnel” (Report No.: WRC-WRC-T-RP-2009-25, E. O’Neil).
- Hatch September 2009 “Wreck Cove Hydro System – Tailrace Inspection Report” (Report No.: WRC-WRC-TR-RP-2009-38).

Photo 4.7-1: Tailrace Manifold - Deck Area over Draft Tubes

Outlets of Draft Tubes

Based on the visual inspection the following was concluded (see Photos 4.7-1 to 4.7-11):

- The concrete deck and concrete gain structures are in good condition.
- The steel frame for the monorail hoist appears to be structurally sound. The steel frame has a protective coating that is performing well. There is no evidence of any significant peeling or corrosion of the steel.
- The steel safety railing is in satisfactory condition but the protective coating has deteriorated and been lost in some areas and the steel has started to corrode.
- The rock above the deck has been stabilized with a combination of shotcrete, rock anchors and wire mesh. There was no evidence of falling rock from above the deck area.

Photo 4.7-2: Tailrace Manifold - Deck and Railing over Draft Tubes at Unit 1 End

Photo 4.7-3: Monorail for Draft Tube Sectional Gates

Photo 4.7-4: Outlet and Gains of Draft Tube

Photo 4.7-8: Outlet of Draft Tube

Photo 4.7-10: Tailrace Manifold - Deck and Railing Over Unit 2 Draft Tube

Photo 4.7-11: Rock Bolts and Wire Mesh to Stabilize Rock at Tailrace Manifold

Tailrace Tunnel Portal Structure and Bulkhead Gate

In November 2008, Nova Scotia Power engineers carried out an assessment of the tailrace tunnel portal structure and the tailrace outlet bulkhead gate. The 2008 assessment determined the following:

- The tailrace tunnel portal structure was in good condition and appeared to have had some recent restoration work completed on it
- The bulkhead gate was badly corroded and inoperable
- The hydraulic cylinders used to ensure positive sealing of the gate were inoperable
- The operability of the gate valve in the gate was unknown
- The functionality of the lifting sling was suspect
- The means for securing the gate in the vertical position did not meet current seismic design standards, and was likely not designed to resist the significant horizontal loadings resulting from the accumulation of snow behind the gate at the toe of the slope of the adjacent embankment.

Photo 4.7-12: Overview of Tailrace Bulkhead Gate in 2008 (photo extracted from Nova Scotia Power Report No.: WRC-WRC-G-RP-2008-23).

As a result of the assessment, the following rehabilitation work was completed (see Photos 4.7-13 to 4.7-17):

- The gate was sandblasted and recoated.
- The rubber seals were replaced.
- The hydraulic cylinders and hydraulic lines were refurbished.
- The gate valve in the gate was refurbished.

- The earth embankment behind the gate storage frame was stabilized by placing new concrete between the earth embankment and storage frame.
- The anchorage system for holding the gate in the vertical position in the storage frame was modified.

Photo 4.7-13: Refurbished Tailrace Bulkhead Gate and Storage Structure

Photo 4.7-14: Refurbished Tailrace Bulkhead Gate on Storage Structure

Photo 4.7-15: Refurbished Tailrace Bulkhead and Storage Structure

Photo 4.7-16: Tailrace Bulkhead Gate Storage Structure

Photo 4.7-17: Tailrace Bulkhead Gate Storage Structure

In general, based on the KGS Group August 29, 2012 inspection, the concrete tailrace tunnel portal structure was found to be in good condition (see Photos 4.7-18 to 4.7-24). Some surface corrosion was evident on the embedded steel gain liners. Minor concrete spalling was noted on the top surface of the “left” gain.

The grating and I-beam system for access to the tunnel for removal of muck was found to be in good condition with only minor corrosion of the anchor rods and nuts which secure the grating to the I-beams (see Photo 4.7-25).

The I-beams located downstream of the outlet structure, which were used for electrical grounding, are corroding. Refer to Section 6.16 Station Grounding System for further assessment / recommendations of the grounding I-beams.

Safety

The tailrace area is accessed via a locked gate in a chain link security fence around the area (see Photos 4.7-26 and 4.7-27). However, it is possible for the public to trespass and enter the area from the beach rock outcrops immediately downstream of the handrails.

Warning signs are posted to increase public safety at the locked gate entrance. The signs appear to meet the 2011 CDA Signage for Public Safety Around Dams Technical Bulletin standards except that they are deficient in that an “emergency call” number is not provided on the signs. No signage was provided on the downstream side of the tailrace portal structure.

Photo 4.7-18: Tailrace Outlet Portal Structure

Photo 4.7-19: Tailrace Outlet Portal Structure

Photo 4.7-20: Tailrace Outlet Portal Structure Retaining Wall

Photo 4.7-21: Gain of Tailrace Outlet Portal Structure

Photo 4.7-22: Minor Corrosion on Steel Liner of South Gain

Photo 4.7-23: Tailrace Outlet Portal Structure

Photo 4.7-24: Minor Corrosion on Steel Liner of North Gain

Photo 4.7-25: Tailrace Outlet Structure – Tunnel Access Cover

Photo 4.7-26: Tailrace Outlet Portal Area Fencing

Photo 4.7-27: Tailrace Outlet Portal Area Fencing

Tailrace Tunnel

A major rehabilitation program involving shotcrete, and mesh and rock bolts was performed in 1992 and 1993 to stabilize the existing failures and reinforce potential new failures. At the time

of the KGS Group tailrace inspection, no access was available to inspect inside of the tunnel. However, in 2009 a cursory tunnel inspection was carried out by Nova Scotia Power (NSP Report No. WRC-WRC-T-RP-2009-25) and a rockfall was found to have occurred approximately 70 m downstream of the concrete draft tube manifold. A few minor rock falls were also noted.

Following the cursory inspection, a detailed inspection was carried out by Hatch in September 2009 (Nova Scotia Power Report No. WRC-WRC-TR-RP-2009-38). This inspection indicated the following:

- The tunnel is in granite and altered granite which is closely jointed and sheared. As a result, the rock mass was classified as being of poor to fair rock quality with local sections being very poor and should have been supported during construction with systematic bolting, shotcrete and ribs in areas to provide long term performance.
- Rock failures have occurred locally in the zones of poorest rock quality since construction. The rock failures may have been caused by alternate wetting and drying of the walls under tidal effects.
- No deterioration of the repairs carried out in 1992 / 1993 was noted. The major rock fall and possibly a few minor rock falls noted during the 2009 inspections have occurred subsequent to the 1992 / 1993 repairs.

There is presently no means to conveniently and accurately measure the tailrace tunnel hydraulic losses. If instruments were available at both ends of the tunnel, these could be used as a means of monitoring for evidence of accumulating rock fall effects, provided the readings were correlated with the discharge from the two turbines.

Recommendations - Outlets of Draft Tubes

- No significant draft tube outlet concrete repairs are expected to be required over the next 30 years other than potentially some minor patching of the concrete. Allow $50k in the budget for the minor repairs to be carried out between years 2037 and 2042**.**
- The safety railings on the draft tube deck will require sandblasting (or corrosion removed by other means) and repainting within the next 10 years at an estimated cost of $15k.
- The steel frame for the draft tube sectional gates monorail hoist may need to be repainted within the next 20 years. Allow $20k for this task.

- Continue to monitor the condition of the rock and shotcrete above the deck area and on an ongoing basis scale and/or install rock anchors as required. Allow $5k every 5 years for these activities.

Recommendations - Tailrace Outlet Portal Structure and Gate Support Structure

- No significant tailrace tunnel outlet structure concrete repairs are expected to be required over the next 30 years other than minor patchwork. Allow $60k between years 2022 and 2042**.**
- The embedded steel gain liners will be required to be sandblasted and repainted within the next 15 years at an estimated cost of $40k.
- When any of the public safety warning signs are required to be replaced, they should be replaced with signs that have an “emergency call” number on them and they should be designed in accordance with the CDA Signage for Public Safety Around Dams Technical Bulletin standards. The signs are expected to be replaced with the next 15 years at a cost of approximately $4k.
- Install public safety signage on the downstream side of the tailrace portal structure. This new signage should be installed within the next year and be in accordance with the CDA standards. The estimated cost is $5k.
- Extend the fencing along the downstream side of the tailrace deck to prevent the public from accessing the tailrace area immediately downstream of the handrail on the right side of the deck. The estimated cost is $15k and the work should be completed in 2013.
- Nova Scotia Power should confirm that a structural analysis was carried out for the design of the new anchorage system that was installed in 2011 for storing the gate in its vertical position and that the anchorage system does meet all applicable loading conditions (including seismic). If an analysis has not been carried out it should be completed within the next year. The cost for the analysis is estimated to be $20k.

Recommendations - Tailrace Tunnel

- By 2018, it would be prudent to repair the major rock fall found during the 2009 inspections to avoid risk of continuing rock fall. The estimated cost for this repair work is $100k.
- Provide instrumentation to allow the periodic measurement and recording of water levels at the inlet and outlet of the tailrace tunnel. Monitoring the hydraulic loss will provide an indication of the cumulative effects of rockfalls on the tunnel’s hydraulic performance.

Assuming this is done with staff gauges, the estimated cost is $5k and the work should be done by 2014.

4.8 POWERHOUSE

Description

The underground powerhouse (see Photos 4.8.1 and 4.8.2) is located 274.3 m (900 ft) below the surface and houses the turbine shutoff valves, turbines, generators, step up transformers and auxiliary equipment. The main powerhouse cavern measures 51.8 m (170 ft) long, 18.3 m (60 ft) wide and 16.2 m (53 ft) high above generator floor level at El. 29 ft-6 in. The turbines and generators are enclosed in reinforced concrete unit blocks with access from the floors at El. 14 ft-6 in, El. 5 ft-0 in and El. -10 ft-0 in. Steel columns and runway girders support the 150 tonne (165 ton) capacity overhead bridge crane. The powerhouse cavern roof and walls are supported by rock bolts and shotcrete.

Photo 4.8-1: General View of the Main Powerhouse Level

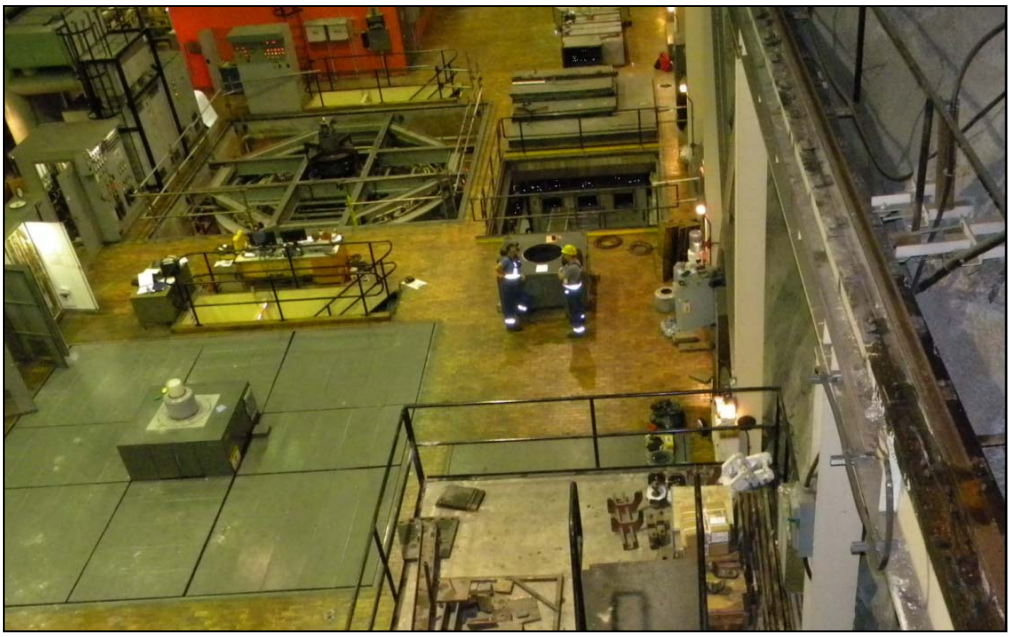


Photo 4.8-2: View of the Main Powerhouse from Crane Level

Assessment

The assessment of the powerhouse included:

- A cursory visual inspection of the structural condition of the main powerhouse cavern at and above the generator floor level
- Life safety review of the powerhouse

General Structural Condition of Powerhouse

Based on a cursory visual inspection of the main powerhouse cavern, the structural components including the steel crane columns, concrete floor, floor tiles, and shotcrete appear to be performing satisfactorily. However, leakage through the rock and shotcrete is a maintenance concern (see Photos 4.8.3 to 4.8.7).

The shotcrete is in good condition but in some areas there is evidence of efflorescence (i.e., white deposits of calcium carbonate ($CaCO_3$)) on the surface of the shotcrete. The efflorescence is a result of leakage from the rock causing calcium hydroxide ($Ca(OH)_2$) to be leached out from the shotcrete and react with calcium dioxide to form the white deposits. In general this amount of efflorescence is not a concern for the performance of the shotcrete. The

efflorescence can also be coming from the rock itself. In isolated areas stalactites have started to form.

In addition to the efflorescence on the shotcrete, additional evidence of past and active leakage were noted: water stains on the floor tiles in localized areas; and water, actively dripping from the ceiling. Currently, Nova Scotia Power is addressing the leakage by the following means:

- Suspended steel pans have been installed in the ceiling at several of the leakage locations to catch the leakage.
- Near the northeast end of the powerhouse, an approximate 75 mm diameter hole exists in the ceiling through the full depth of the rock. The hole provides access for feeding communication cabling into the powerhouse. This hole is acting as a vertical drain for the water leakage in the bedrock. The leakage from the hole is currently being collected by means of a semi-circle steel drain pipe with its inlet end fastened to the ceiling and its outlet end connected to a pvc drain pipe that leads to gutter floor drain (see Photo 4.8-8). A tarp is also installed in this area to prevent any leakage that is not collected with the drain pipe system from falling on personnel (see Photos 4.8-9 and 4.8-10). The tarp also directs the leakage to the floor drain.
- Critical crane components such as motors have been provided with temporary covers to protect against water entering into the motor housings.

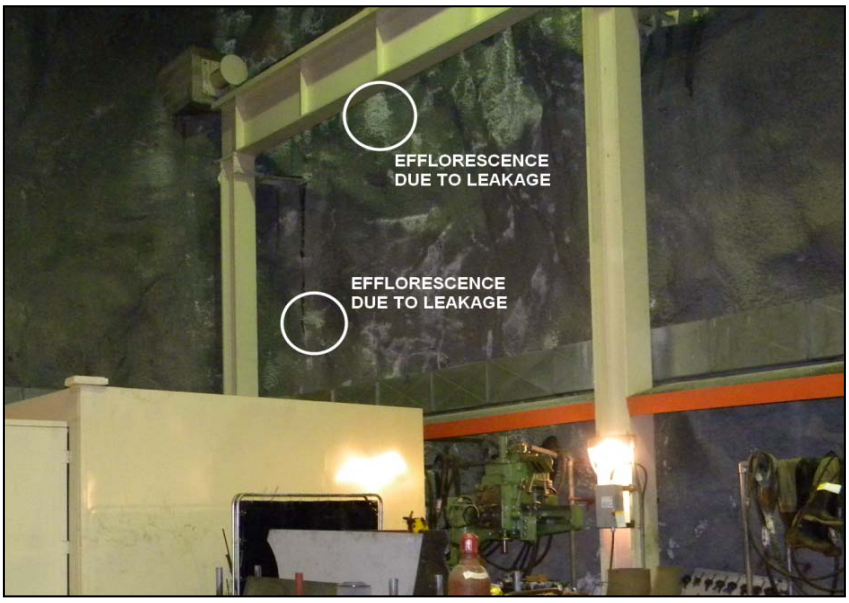


Photo 4.8-3: Walls of Powerhouse are Shotcreted – Note Efflorescence

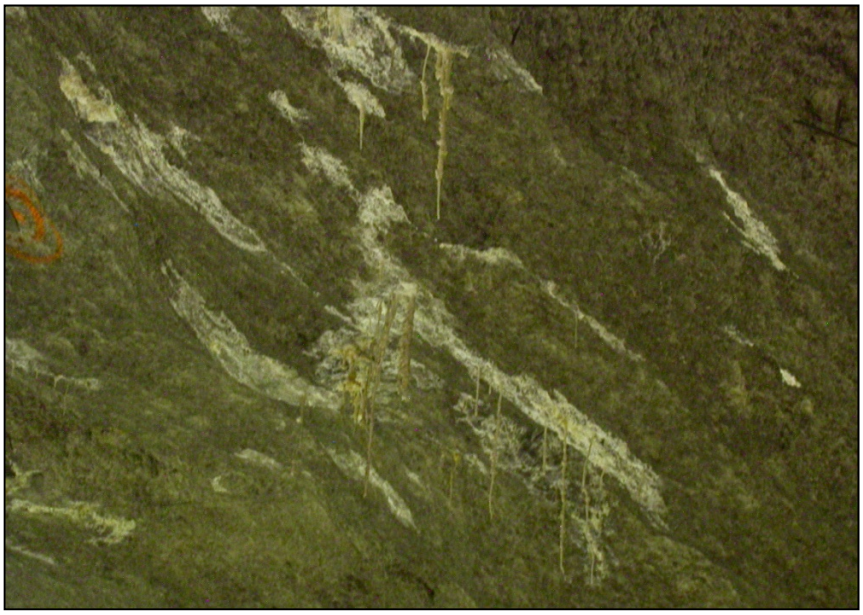


Photo 4.8-4: In a Few Localized Areas Stalactites are Forming

Photo 4.8-5: Northeast End of Powerhouse
Garbage Pails Used to Catch Leakage from Ceiling

Photo 4.8-6: Note Active Leaks and Water Staining on Tiles

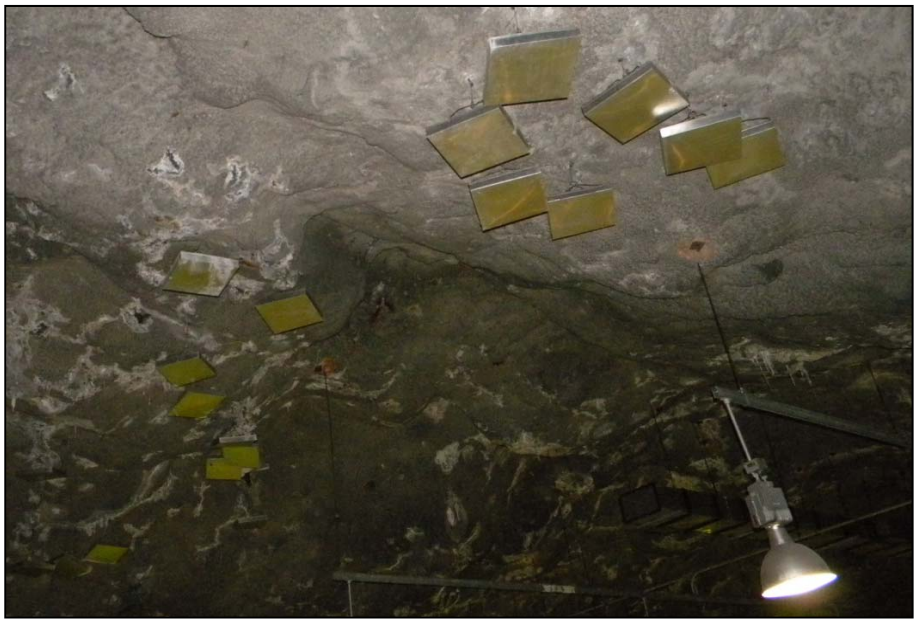


Photo 4.8-7: Note Steel Pans Suspended from Ceiling to Catch Leakage

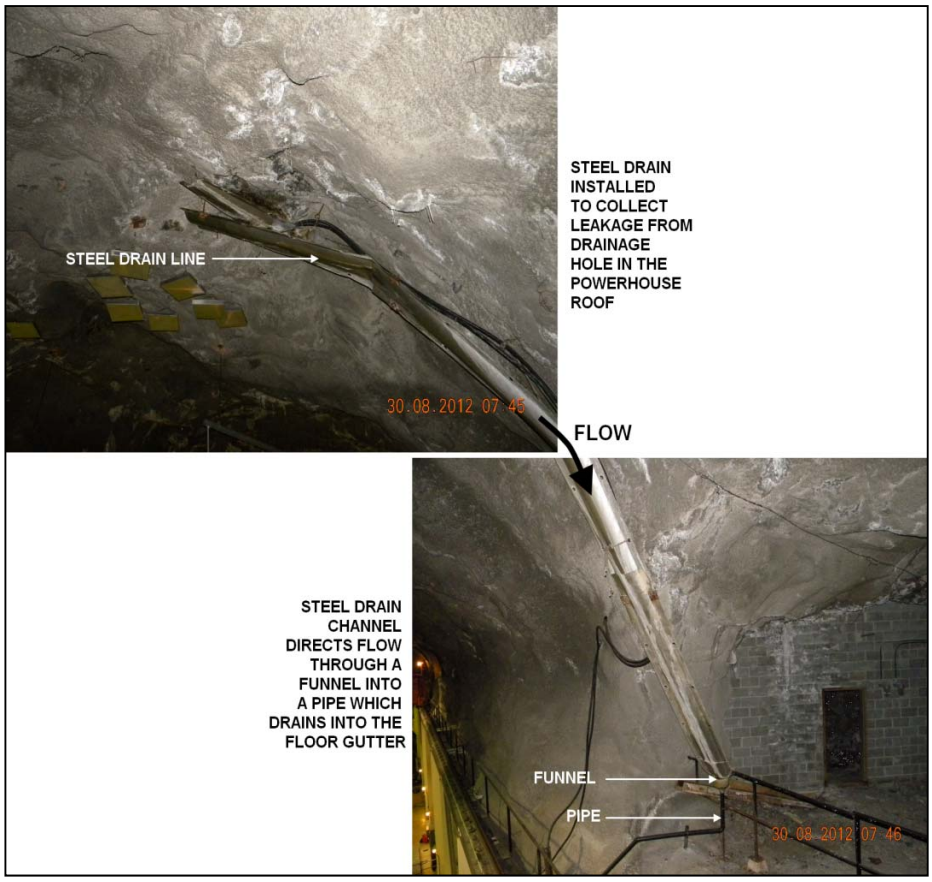


Photo 4.8-8: Steel Drain System Installed to Direct Water Leakage From Hole in Ceiling into the Floor Gutter

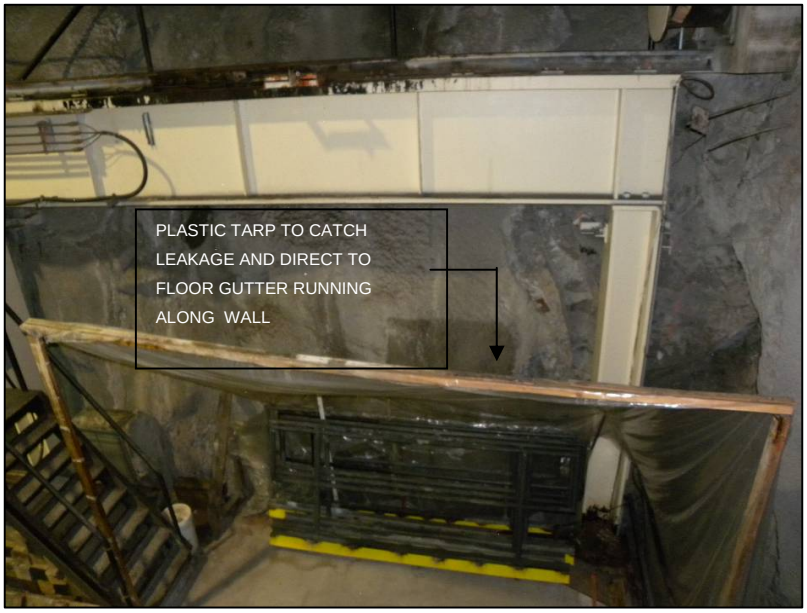


Photo 4.8-9: Plastic Tarp Catches Leakage

Photo 4.8-10: Plastic Tarp Catches Leakage

Powerhouse Crane Rails

In 2011 some crane rail bolts were reported to be broken (see Photo 4.8-11). Nova Scotia Power personnel have since replaced these broken bolts and currently the crane rails appear to be in satisfactory condition. No broken bolts have been reported since the broken bolts were replaced.

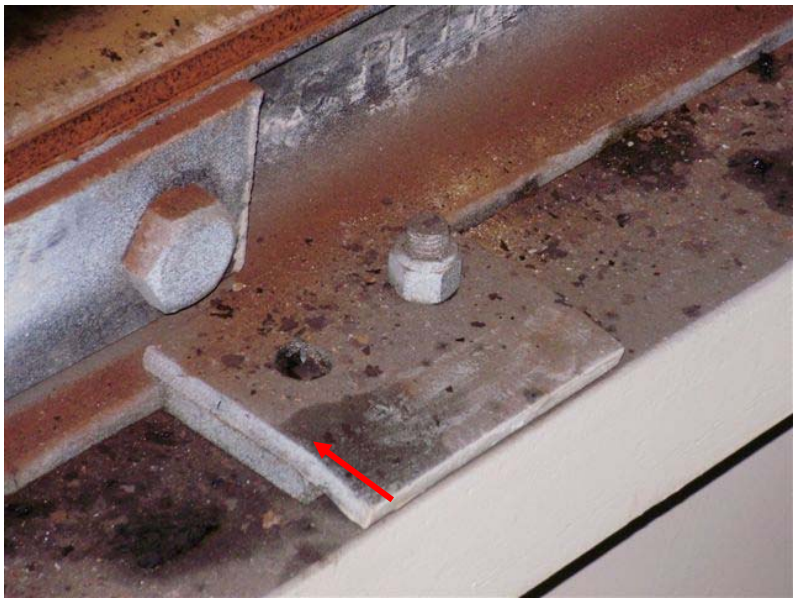


Photo 4.8-12 – July 2011 Photo of Crane Rail Bolt Sheared Below the Rail Clamp

Recommendations

- Investigate and evaluate within the next 2 years more efficient means to deal with the leakage issue such as installing a ceiling leakage collection drainage system. The estimated cost for the engineering study is $30k. Allow approximately $200k in the budget for years 2016 and 2017 to install a system to handle the leakage.
- Provide a budget allowance of $110k to repaint the columns and crane in 20 years.
- Provide an annual allowance of $10k for miscellaneous items such as repairing / replacing individual tiles, patching concrete and shotcrete, adding / replacing rock anchors, repainting and repairing handrails, etc. This annual allowance would also include for monitoring and removing the stalactites to avoid the potential for them to fall on persons working below.
- In 2013 a survey of the alignment of the crane rails should be carried out to determine if any misalignment issues could have contributed to the failure of the bolts. The estimated cost for this work is $10k.
- Every two years starting in 2013, inspect the condition of the crane rails and bolts to ensure that failure of the crane bolts is not an ongoing issue.

Powerhouse Egress and Life Safety Systems

Unrelated to the existing condition of the plant, KGS Group was asked to review and comment on the life safety systems for the powerhouse. In doing this, the following items were considered:

- Current Building Codes
- Life safety systems in the original design
- Previous assessment performed by Landsirkjun Power in May of 2011
- Assessment of the site
- Review of the existing drawings
- Check of safety practices in the industry, specific to underground powerhouses

Original Life Safety Features of the Powerhouse

Area of Refuge

There is a note on the original design documents to use the (mucking tunnel) chamber near the powerhouse end of the access tunnel as a refuge area. This chamber had been constructed;

however, the doors to the chamber are no longer functional, lighting within the space is no longer functional and there are no emergency supplies stored in the area. Original plans indicate that a shaft to the surface was to be used to provide an air supply to the area of refuge. This air supply has not been installed. The borehole to the surface carries power supply and radio communication cabling and has been sealed at the top, where it emerges from the rock.

This tunnel area of refuge has an access near the entrance to the power house and one from the crane access level. Neither of these access points is quickly accessible from within the various floors of the powerhouse.

Photo 4.8-14: Interior of Entrance to Original Refuge Tunnel

Smoke Control System

The original powerhouse design includes a smoke control system which shuts down normal ventilation, opens the access tunnel portal door and starts a high volume fan intended to evacuate smoke from the powerhouse to the tailrace tunnel and out to atmosphere at the tunnel exit. The effectiveness of this system has not been tested, and is subject to the AC station service and control conductors withstanding a fire.

Egress

There is only one path of human egress from the powerhouse. This path is via the main access tunnel. While at first glance, the tailrace tunnel might be seen as an alternate means of egress, under certain sea conditions, there is inadequate clearance to the tunnel roof, and if the smoke extraction system functions as intended, the airspace above the water will be filled with smoke and gaseous combustion products.

Emergency Lighting

There is some emergency lighting provided which is supplied from the DC station battery.

Exit Signage

There is no original exit signage provided to guide occupants to safety.

Fire Protection

The original fire protection for the facility consists of fire hose cabinets and portable fire extinguishers at several locations in the powerhouse, and deluge systems covering the main output transformers and the generators. These systems are in place and functional.

Fall Protection

The access ladder on the powerhouse crane and the walkways of the crane expose workers to significant risk of falling due to awkward ladder location, railings with large openings and unguarded line shafts. The access ladders and fall protection would be considered insufficient by modern standards. Improvements to the ladder, screening the railings and guarding the drive shafts would reduce the risks significantly.

Powerhouse Life Safety Additions/Enhancements

Supplemental Area of Refuge

Nova Scotia Power has added a steel enclosure on the powerhouse floor as an area of refuge for staff in case of an emergency. While the enclosure does contain some equipment necessary in case of fire, it does not appear adequate to provide a safe area of refuge for staff.

In an environment where a permanent area of refuge is not possible due to time constraints, some allowances can be made in mining for temporary areas of refuge. These systems would typically have fire ratings, and significant closures as shown in Photo 4-8-17. See also Section 7 Opportunities and Issues, for further information. These types of systems would require the eventual installation of a permanent area of refuge.

Photo 4.8-15 – Present Refuge Enclosure

Photo 4.8-16: Interior of Present Refuge Enclosure

Photo 4.8-17: Typical Modern Refuge Enclosure

Fall Protection

Fall risks relating to powerhouse crane operation have been somewhat reduced with the provision of radio controls. Risks associated with access to the crane and the crane rails for inspection and maintenance are unchanged from original.

Powerhouse Life Safety Risks

There are several items which are a significant risk to life safety within any powerhouse which can be mitigated by the design of the powerhouse itself. The key items are typically:

- Risk of fire (causing risk of burns, smoke inhalation and suffocation)
- Risk of flood
- Risk of falling from any elevated level

These risks have not been adequately addressed at Wreck Cove GS. Further, an additional risk of having a vehicle accident in the access tunnel blocking egress and entry is also an issue.

Risk of Fire

In addition to having significant sources for ignition, and plenty of oxygen, Wreck Cove GS has significant other sources of fuel. Some of the fuel sources such as the power transformers are not readily removable. There is, however, significant accumulation of combustible load in the powerhouse which should be removed and stored in a surface storage building. Prime

examples of this are the storage of many boxes of rags adjacent to the steel refuge enclosure, and wood blocking stored in various locations in the powerhouse.

Risk of Flood - Penstock Rupture

The spherical valves that join the penstocks to the turbine spiral cases are at El. 1 ft-0 in and are located in a room at the north side of powerhouse (see Figure 4.8-1). Should the short exposed section of penstock upstream of a turbine shut-off valve rupture, the powerhouse would be quickly flooded (see Photos 4.8-18 and 4.8-19). The only means to stop the flooding would be to drop the intake gate at Tunnel T-2 Intake and attempt to drain Surge Lake and the penstocks through one or both turbines. Due to the time required, it is likely that the powerhouse and its equipment would be severely damaged and persons working in the powerhouse would be at great personal risk, before the flow could be stopped.

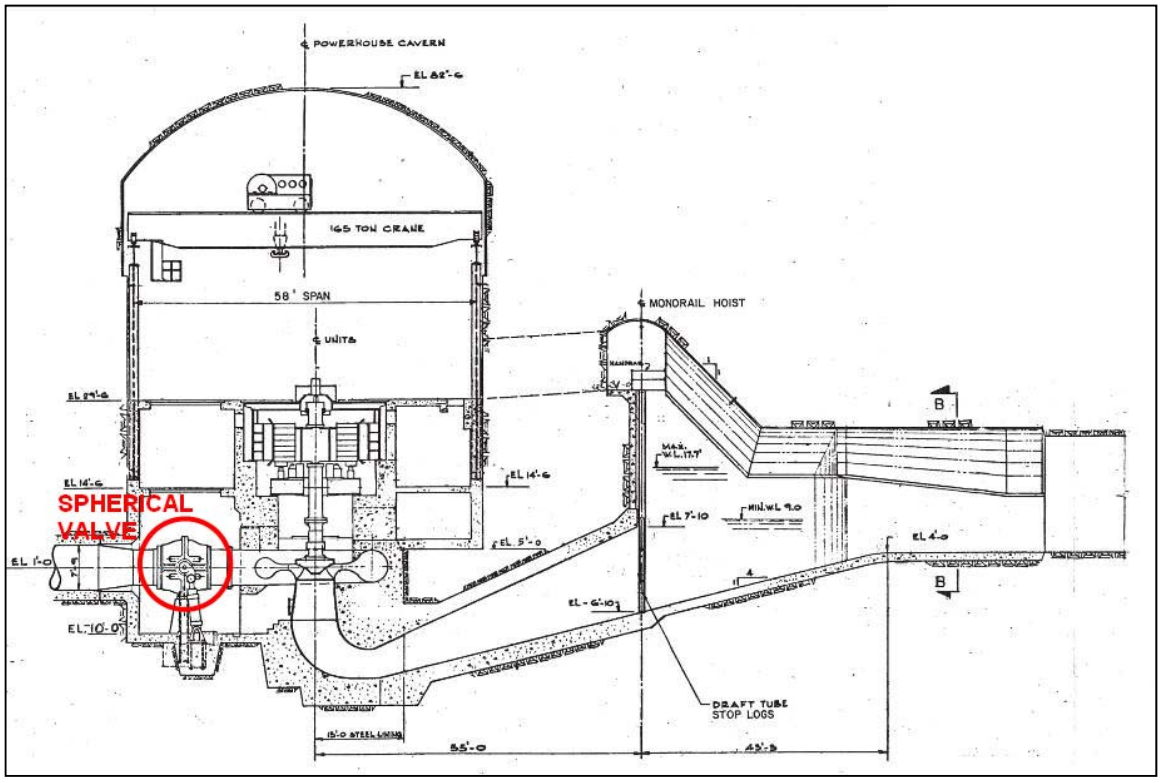


Figure 4.8-1: Cross Section of Powerhouse
(extracted from Plate 7 from the Wreck Cove Power Project - Operation and Maintenance Manual)

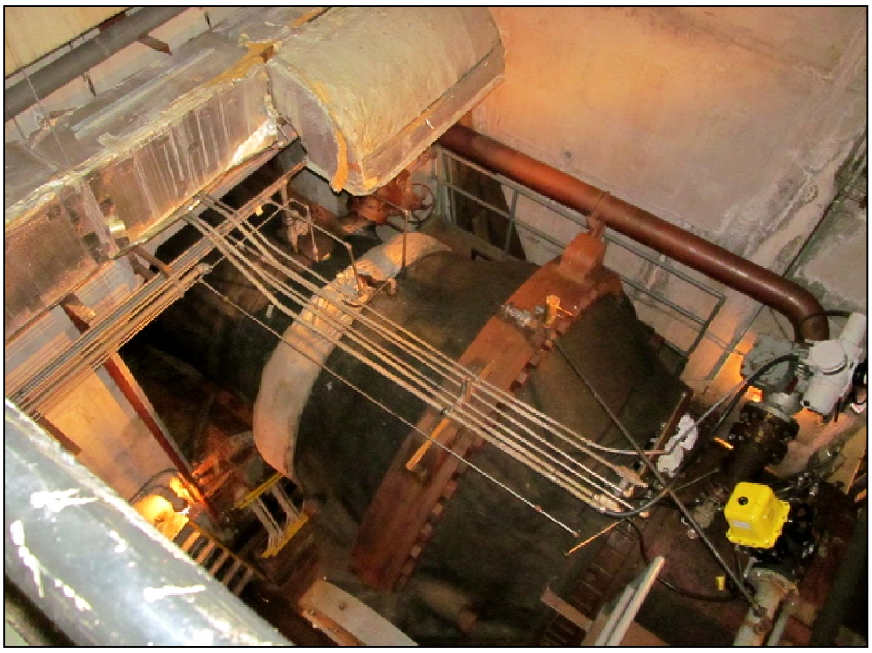


Photo 4.8-18: Penstock Valve – View from El. 14 ft-6 in Floor

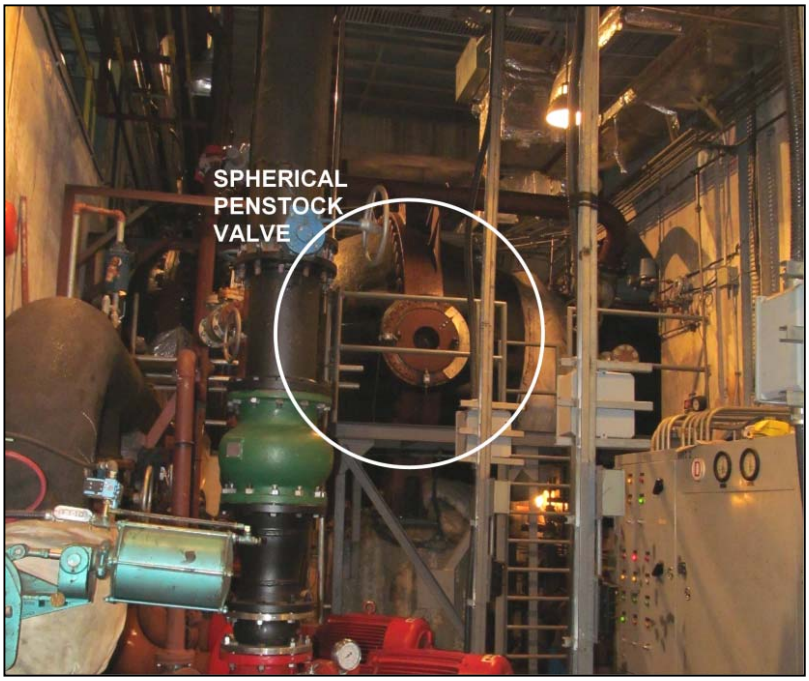


Photo 4.8-19: Penstock Valve in Background

Risk of Flood - Blockage of Tailrace Tunnel

Should the tailrace tunnel become blocked or partially blocked due to a large mass of rock falling from the tunnel surface the powerhouse would be flooded if the units are not shut down.

Currently in the draft tube gallery, there is instrumentation that monitors the water level, alarms when the water level rises above acceptable levels and shuts down the generators at an extreme high level (see Photo 4.8-20). As noted in Section 6.13, this monitoring and alarm equipment is severely corroded, the monitoring function does not work and it is not tested periodically. Currently, this is the only means for notifying personnel when the tailrace water level is at an unsafe level.

Photo 4.8-20: Instrumentation for Monitoring Tailrace Water Level

The access to egress at Wreck Cove GS, as well as the other life safety items requires urgent action. It is recommended that Nova Scotia Power immediately address the short term life safety issues by installing a more appropriate short term refuge facility and by removing all non-operating essential combustible load, including spare oil, wood blocking and wood crated parts, rags and boxes of components.

Additionally, to reduce worker exposure, any work which does not need to be performed inside the powerhouse, such as workshop work, should be done at the surface.

A check with several organizations operating or designing underground power stations indicates two common practices: two independent exits must be provided or if only one exit is possible, the powerhouse must be provided with refuge facilities. A study of risks is typically performed to identify the type and potential impact of risk involved. Some utilities have retrofitted improvements to smoke extraction systems to ensure the access tunnel is effectively cleared of smoke and fumes. Dedicated communication paths to the safety refuge is a common requirement. It is also common to place the step-up transformers outdoors or if underground, in a separate cavern from the powerhouse cavern.

According to the 2010 National Building Code (NBC), buildings for industrial occupancy (i.e., such as the type of occupancy in the Wreck Cove powerhouse) shall have at least 2 exits for every floor intended for occupancy. The only exception to this requirement is if the building has a floor area of 200 m^2 or less for a floor area without a sprinkler system and 300 m^2 or less for a floor area with a sprinkler system (NBC Division B, Section 3.4.2.1). The Wreck Cove powerhouse main floor does not have a sprinkler system and has a floor area of approximately 916 m^2 (17.7 m x 51.8 m). Thus, the means of egress from the powerhouse do not meet the NBC requirements. Although not likely to be a governing document, the Nova Scotia Underground Mining Regulations (2011) made under Section 82 of the Occupational Health and Safety Act (Part 3, Sections 148 to 154 provide useful guidance on design and maintenance of refuges.

Nova Scotia Power should undertake a detailed engineering study to assess the risks and to provide options to improve the access to egress, and upgrading as required of any permanent areas of refuge, improvements to control of water flow into the turbines, and improvements to ventilation and smoke extraction. It is anticipated that this would provide Nova Scotia Power with options for life safety improvements within the plant. There would have to be negotiation with the authorities having jurisdiction, and possibly the mines branch. Following the study, it is anticipated that Nova Scotia Power would proceed with a formal life safety upgrade. This upgrade could be on the order of $5-$15 million; however, without a detailed plan, there is a great degree of variability on the cost of the necessary enhancements.

As Nova Scotia Power has indicated that they are in the early stages of planning for a life extension program for the plant, it is highly advised that all life safety concerns be addressed prior to having large work crews in the plant. There have fortunately not been any significant issues to date, but, KGS Group would consider it of very high risk to proceed with significant refurbishment work in the powerhouse without first upgrading the life safety systems.

Recommendations

- The equipment and alarm system for monitoring the tailrace water level should be regularly tested to ensure that it functions satisfactorily and if necessary it should be refurbished or replaced.
- Provide a new short term refuge facility for present staff levels by 2014. Estimated cost is $150k for a 6 person 24 hour design.
- Plan on providing two additional short term facilities or a permanent refuge facility for the increased worker levels anticipated when major work starts in the powerhouse. Assumed cost is $300k in 2016.
- Reduce worker exposure in the powerhouse by having any work which does not need to be performed inside the powerhouse, such as workshop work, done at the surface.
- Reduce the amount of combustible material stored in the powerhouse (oil, wood, rags), by removing it to a surface storage/workshop building located in the vicinity of the present Administration Building. Consider allowing only diesel engine vehicles into the access tunnel, to reduce the amount of readily flammable fuel in the powerhouse area. A basic surface storage/workshop building is estimated to cost $425k and should be planned in 2013 for implementation in 2014.
- Carry out a formal, comprehensive, detailed life safety and equipment protection engineering risk analysis, to identify failure modes and risks and to identify and assess solutions. The scope should include falling, fire and flooding risks, and should be undertaken in 2013, with a view to completing implementation prior to major equipment replacement with the anticipated increase in worker numbers in the powerhouse. The estimated study cost is $250k, and a budgetary allowance of $5M is recommended in 2015 and 2016 for implementation, with a small allowance of $100k split between 2013 and 2014 for improvements which can be implemented quickly.
- Particular urgent attention should be given to the risk assessment associated with the absence of head gates at the penstock inlet structure, as the absence of effective mean of

quickly stopping water flows in an emergency can lead to injury, fatalities and extensive plant destruction (e.g. Kainji in Nigeria, 2000 and Sayano-Shushenskaya in Russia, 2009). The study should address providing head gates at the penstock inlet structure, with an alarm system that would alert the operators that there is an issue with the penstocks (i.e., large drop in pressure) and which would have the capability to close the head gates automatically or by remote control in an emergency situation. The engineering study costs are included above.

4.9 POWERHOUSE ACCESS TUNNEL

Description

Access to the powerhouse is provided by a 561.4 m (1842 ft) long tunnel 7.01 m (23 ft) wide by 6.71 m (22 ft) high. The 144 kV power cables are located in trenches under the sidewalk on either side of the tunnel roadway. Control cables, ventilation duct and piping for firefighting and potable water are installed on the west side-wall of the tunnel. The Portal building, at the entrance of the access tunnel, is fitted with a portal door and contains heating and ventilation and station service equipment in the Portal building's mechanical room.

Assessment

The assessment of the powerhouse access tunnel included:

- A visual inspection of the portal structure at the entrance to the powerhouse access tunnel.
- Visual inspection of the power cables, ventilation duct, and piping for the firefighting and potable water system.
- Design adequacy review of having the main power supply and back-up power supply routed in close proximity to each other in the powerhouse access tunnel. In addition to the visual inspection for this review, available documents were reviewed and discussions were held with station maintenance staff.

Portal Building

The portal building (see Photos 4.9-1 to 4.9-3) consists of two levels and is a steel clad structure with concrete walls and concrete ceiling for the first level at the interface between the steel cladding and the rock tunnel. The upper level is the mechanical room where the ventilation and heating system is housed.

Photo 4.9-1: Powerhouse Access Tunnel Portal Building

Photo 4.9-2: Powerhouse Access Tunnel Looking Out

Photo 4.9-3: Powerhouse Access Tunnel Concrete Section

Tunnel Entrance Level (First Level)

The steel cladding is in good condition and the steel supporting frame is structurally sound. The steel frame is painted but in some areas the paint is flaking and minor to moderate corrosion is evident (see Photos 4.9-4 and 4.9-5).

Corrosion is evident at a location where a drainage pipe penetrates through the steel cladding of the first level ceiling (see Photos 4.9-6 and 4.9-7). The remainder of the steel cladding ceiling is in excellent condition.

The concrete walls and concrete ceiling are in excellent condition.

Photo 4.9-4: Portal Building Structural Steel

Photo 4.9-5: Portal Building Structural Steel

Photo 4.9-6: Powerhouse Access Tunnel Ceiling

Photo 4.9-7: Powerhouse Access Tunnel – Corrosion Detail

The steel overhead door is in excellent condition (see Photo 4.9-8).

Photo 4.9-8: Powerhouse Access Tunnel Door

The concrete foundation plinth appears to be in good condition. However, vertical expansion joints on either side of the overhead door are not sealed thus leaving these joints exposed to water penetration and potential freeze/thaw damage in the winter months (see Photos 4.9-9 to 4.9-11).

Photo 4.9-9: Portal Building Plinth Open Joint Locations

The asphalt tunnel entrance roadway is in good condition.

Photo 4.9-10: Portal Building Plinth - Detail

Photo 4.9-11: Powerhouse Access Tunnel Plinth Expansion Joint Missing Sealant

Fallen rocks were noted between the right side (referenced looking into the entrance) of the Portal structure and the gabion retaining wall (see Photo 4.9-12). Falling rocks and

accumulation of the rocks against the cladding could eventually damage the cladding. Falling rocks in this vicinity could also pose a safety hazard to staff and the public.

Photo 4.9-12: Fallen Rock beside Portal Building

Mechanical Equipment Room

The staircase and railing up to the mechanical equipment room are in good condition but the paint is worn and flaking in some areas. There is evidence of minor corrosion and pitting in some of the areas where the paint has flaked off. There are fallen rocks which have collected on the stairs creating a tripping hazard (see Photos 4.9-13 and 4.9-14).

Photo 4.9-13: Portal Building – Stairs to Mechanical Equipment Room

Photo 4.9-14: Portal Building – Accumulated Debris on Stairs

Photo 4.9-15: Close up of Top of Exposed Cliff

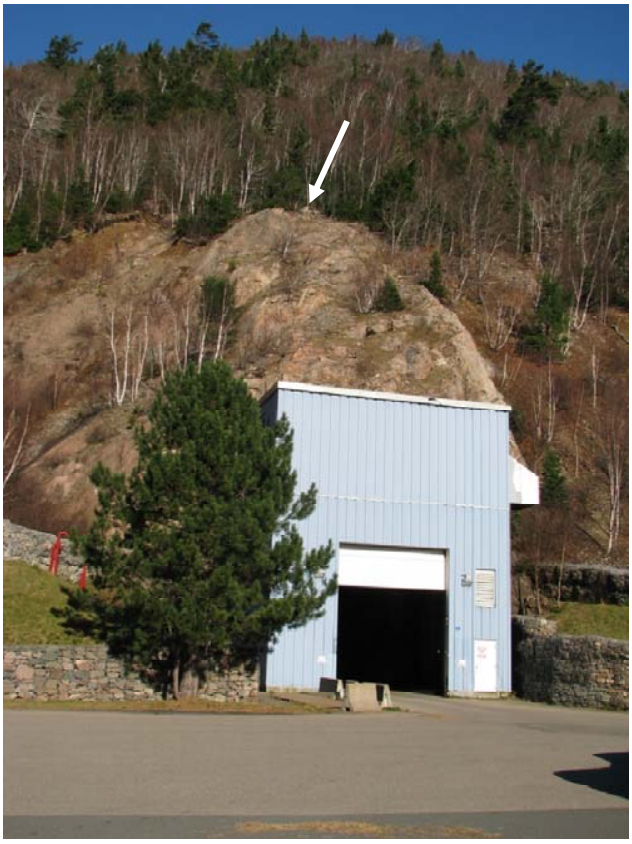


Photo 4.9-16: Arrow Shows Location of Photo 4.9-15

The steel cladding, steel support frame, and concrete floor are all in good condition (see Photo 4.9-17). The concrete floor has only some minor hairline cracks. Some minor surface wear of the paint and very minor localized corrosion of the steel support frame was noted.

Photo 4.9-17: Portal Building – Mechanical Equipment Room

Recommendations

- Sandblast and re-paint the corroded areas of the portal building steel support frame and cladding within the next 10 years to prevent any significant corrosion to occur that could compromise the structural integrity of the portal structure. Repair/patching of the steel ceiling at the location where the steel has corroded and steel has been lost should also be carried out at the same time as the sandblasting and re-painting repair if not before. The estimated cost to complete this work is $25k.
- Seal the expansion joints of the concrete foundation plinth within the next year at an estimated cost of $2k.
- As a regular maintenance item clear debris that accumulates on the staircase to eliminate this tripping hazard.
- Sandblast and re-paint the staircase and railing up to the mechanical equipment room within the next 5 years. The estimated cost to complete this work is $17k.
- Carry out an investigation to determine where the rock that is accumulating between the portal structure and the gabion wall is falling from and then assess and implement means to

prevent the rock from falling in the future. The cost of the study is estimated to be $10k and it should be carried out in 2013.

- Until a means has been implemented to prevent the rock from falling, a maintenance program should be implemented to remove the fallen rock between the portal structure and the gabion wall on an on-going basis. Provide an annual allowance of $4k for this work.
- Provide an allowance of $25k to sandblast and re-paint the steel structural frame in the mechanical equipment room in approximately 15 years.
- Provide an allowance of $20k to surface prepare and repaint the exterior of the portal structure in approximately 15 years.

4.10 POWERHOUSE ACCESS TUNNEL FEEDERS

Description

There are two types of feeders installed in the access tunnel at Wreck Cove. There are 600 V and 25 kV station service feeders installed in cable tray which feed power to the station service. There are also two sets of 144 kV high voltage oil insulated cables, which are installed under concrete covers and buried in sand, and which transport the power from the transformers out to the switchyard (see Photo 4.9-16).

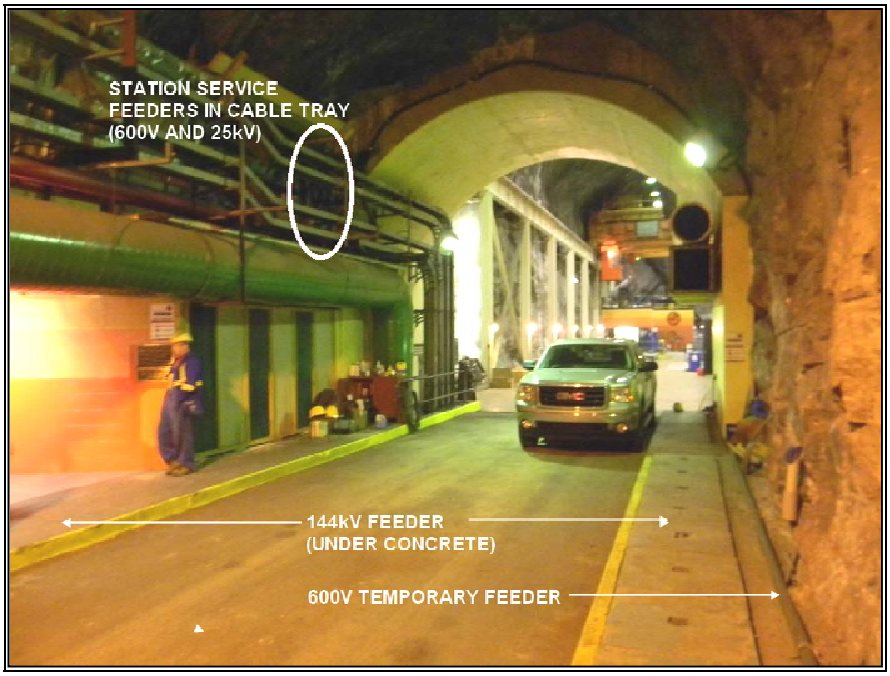


Photo 4.9-16: Tunnel Feeder Arrangements

The 600 V station service feeder consists of 2-3/C 500 MCM cables installed in cable trays which run at high level on the west side of the access tunnel. This main service feeder is fed from the service switchboard in the Diesel Generator Building, and extends to connect to the auxiliary service switchboard on Powerhouse El.14 ft 6 in floor.

The 25 kV feeder, which consists of a 3/C #3/0 AWG cable is installed in another level of the same group of trays as the 600 V feeder. This feeder connects to Transformer AT-1 which then also feeds the auxiliary service switchboard on Powerhouse El.14 ft 6 in floor. The transformer is mounted adjacent to this switchgear.

The two 144 kV feeders are installed in two trenches on opposite sides of the access tunnel. The feeders are paper insulated and jacketed cables. The oil filled power cables are managed by the distribution business part of Nova Scotia Power.

There is one additional Teck 90 cable which is no longer in use. This cable was installed while there was some temporary work being done in the tunnel, because there was concern that a vehicle accident may impact the main station service cables.

The 144 kV feeders are not part of the responsibility of the local Wreck Cove generation maintenance group, and they were not included as part of the scope of this condition assessment. Nova Scotia Power has contacted the original equipment manufacturer, which has recommended inspection and testing, which will cost $80k.

Assessment

The existing station service cables were visually inspected and interviews with staff were undertaken to review their history.

There are no apparent issues with the cables themselves. Having all cables installed in cable trays protects the cables well from minor incidental damage and as such they are in good condition. Unfortunately, having all cables in one exposed location on a common set of cable trays allows for the possibility of one major event such as a vehicle collision with the cable trays causing significant damage and cutting all feeders at once. This risk was clearly registered previously when a temporary cable was installed for some work in the tunnel.

A separately protected path should be established from the main portal entrance, down the access tunnel to the powerhouse. While the risk of a significant issue is increased when construction is underway or when large equipment is transported down the access tunnel, any vehicle traffic down the access tunnel could pose a risk, such as a collision with the feeders. Protection against vehicle fire should be considered, but the risk may not be reduced unless the feeders are buried in a medium such as sand.

The cables which are installed, if not damaged, would have an additional 20-30 years of life, but should begin to be tested on a regular basis.

Recommendations

- A plan should be developed for one of the main station service feeders to be installed in an alternate configuration. This work should be performed before any large equipment is transported down the access tunnel to the powerhouse. The high voltage 25 kV cable has the smallest profile and could be more easily protected from vehicle impact on the opposite side of the tunnel in a location similar to that of the temporary cable. The estimated cost for this work, assuming use of Jersey barriers, is $450k and it should be carried out within 5 years. In comparison, the cost of constructing a new cable tunnel, which would relocate the feeders completely away from vehicle traffic, is estimated at $6.05M.

5 MECHANICAL CONDITION ASSESSMENT

GENERAL

The following components were included in the mechanical condition assessment:

- Tunnel T2 Intake Equipment
- Tunnel T2 Adit Drain Valve & Piping
- Turbine Shutoff Valves
- Turbines
- Turbine Regulating Equipment
- Generator Mechanical
- Tailrace Equipment
- Ancillary Equipment
- Heating, Ventilation & Air Conditioning
- Compressed Air Systems
- Fire Protection and Detection System
- Sump Systems (Drainage And Dewatering)
- Domestic Water & Sewage System
- Surge Lake Drain Valves

A general description, condition assessment, and recommendations follow for each of the above components.

5.1 TUNNEL T-2 INTAKE EQUIPMENT

Mechanical

Description

The intake for Tunnel T-2 is provided with a single vertical lift gate 4725 mm high x 4623 mm wide (15 ft 6 in x 15 ft 2 in), equipped with 4 rollers per side and a dedicated electric motor driven wire rope hoist, of kN (41,000 lb) capacity.

The hoist is located in an elevated metal clad enclosure supported by a steel superstructure.

Photo 5.1-1: Tunnel T2 Intake Gate Hoist

Heating systems for the gate body and gains were provided in the original design. The gate is filled with concrete ballast to achieve a 15,900 kg (35,000 lb) weight.

T-2 intake gate is the first means upstream of the turbine shutoff valves where water flow to the powerhouse can be easily interrupted. As such it is an essential device both as an emergency gate and for isolation when inspection or maintenance of T-2 Tunnel, the penstocks or the turbine shut off valves is needed.

Assessment

Inspection of the hoist included visual inspection and discussion with plant maintenance staff. The gate was not operated at the time of the inspection. Inspection of the gate was visual mainly from the intake structure concrete deck and from the adjacent shore, while visual hoist inspection was performed from the deck of the metal clad enclosure.

The intake gate was used in 2009 and at that time there was no problem in closing the gate and it sealed well. No periodic testing program, such as lowering the gate under control of the fan brake is performed.

A recent incident of the gate freezing to the gains has been addressed with the installation of a new bubbler system.

The gate body and gain heating systems have deteriorated and are no longer functioning.

The top cover of the gate, which appears to shield an extensive gate body heating array, is surficially corroded over much of its surface. The gasket is cracking and coming out of its joint, and several of the fastening bolts are missing.

Photo 5.1-2: T-2 Intake Gate – East Side

Photo 5.1-3: T-2 Intake Gate – Top Cover and Gasket

At the time of the inspection, the gate could not be operated (except possibly for manual dropping under fan brake control) as the hoist control systems had failed.

The lintel seal on the gate was in good condition, with little abrasive wear evident.

Photo 5.1-4: T-2 Intake Gate – Lintel Seal

Photo 5.1-5: T-2 Intake Gate – Seal Corner

Other gate components were not accessible and could not be assessed. This includes structural members, skin plate, main rollers, side rollers, bumpers, side and bottom seals.

As the hoist includes a fan brake, it is assumed the gate can be lowered without external power. However, it is not known if the gate will close completely under full flow conditions or how well it seals, as no periodic testing is conducted.

The solenoid activated brake drum is rusted, indicating infrequent use and excess humidity in the hoist house.

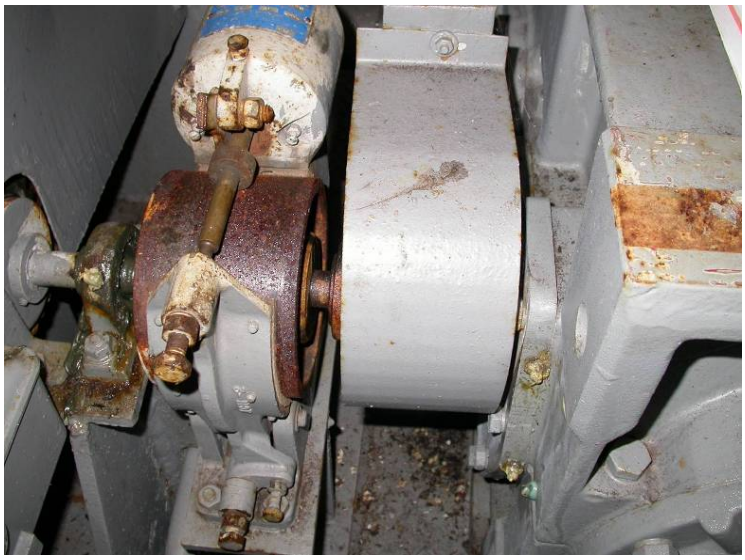


Photo 5.1-6: Tunnel T2 Intake Gate Solenoid Brake

The fan brake inlet is screened and clear of any material that could reduce its braking effect and the rotor blades were intact and not bent. The wire ropes are positively clipped to the drum. No significant signs of lubricant leakage due to failed bearing seals were evident.

Photo 5.1-7: Tunnel T2 Intake Gate Air Brake Fan Rotor and Inlet Screen

The visible part of the wire rope on the drum appeared to be in good condition, with no observed frayed wires and adequate lubrication. The wire rope was well secured to the drum and the hoist was firmly attached to its mounting frame.

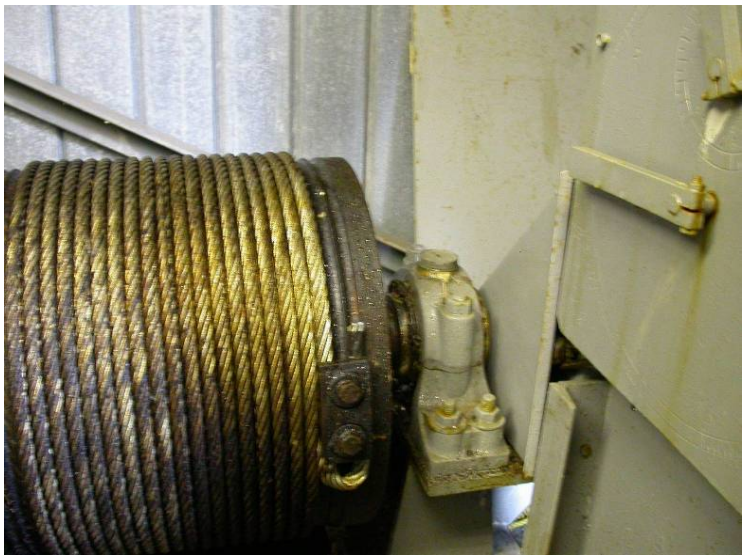


Photo 5.1-8: Tunnel T2 Intake Gate Hoist Drum and Bearing

Since the intake gate is the only ready means of isolation of Tunnel T-2, Surge Lake and the penstocks, its effective operation is imperative. Therefore, further assessment, with inspection and testing is required to confirm the gate's effectiveness.

Recommendations

- Conduct a thorough assessment of gate condition by removing the top covers, and progressively raising and stopping the gate to allow for checking of the main and guide rollers for seizing/free rotation. At the same time check the condition of the skin plate and welds, visible structural members, side and bottom seals and seal clamping plates and fasteners, and the integrity of side roller assemblies and bumpers. If possible to access, also inspect the condition of the roller and seal path surfaces. From this inspection establish the scope and timing of a gate refurbishment. The cost of the assessment is estimated at $15k and it should be completed by 2013.
- Carry out a detailed inspection of the hoist, pulley block, holding brake, and wire rope and replace all lubricants. Depending on the findings, an overhaul may be required, not based on high usage, but because of long periods of inactivity may have resulted in corrosion of items such as anti-friction bearings. Cost of inspection is estimated at $5k, and this should be completed in 2013, before the first gate test.
- Following a review of available documentation, and discussions with original engineers and gate supplier if possible, establish and execute a periodic gate testing procedure. Ideally,

this should involve closure under flow conditions, unless reasons are found to avoid such a test. Investigation cost is estimated at $12k and timing would be by 2014.

- Plan for a gate refurbishment in 2015 to include recoating of the gate body, replacement of roller bushings and hoist bearings replacement. The exact scope will be determined by the above inspections and test. Cost is estimated to be $150k.

Photo 5.1-9: T-2 Intake Gate – Pulley Block Cover

Photo 5.1-10: T-2 Intake Gate – New Enclosure for Bubbler System Compressor

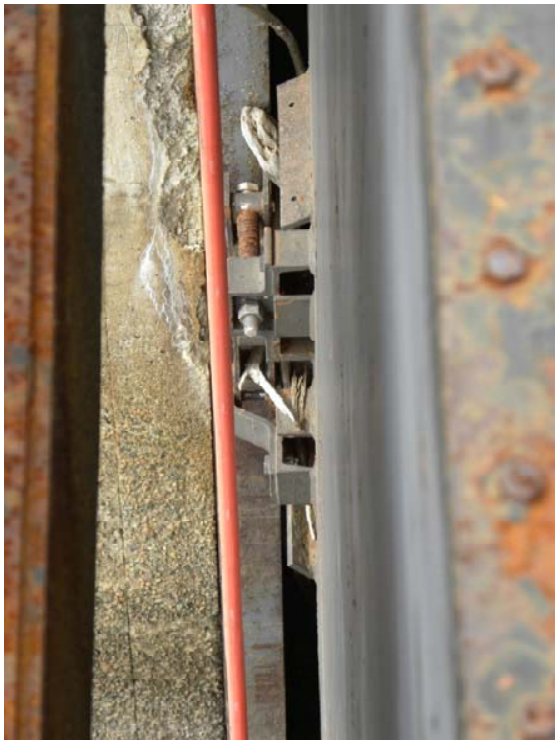


Photo 5.1-11: T-2 Intake Gate – Side Guides (Red Hose is Bubbler Air Supply)

Electrical

Description

There are a number of small electrical systems at the Tunnel T-2 Intake hoist house. These systems include:

- Power distribution
- Grounding
- Gain Heating
- Bubbler / Level System
- Hoisting system
- Local lighting

Electrically, the Tunnel T-2 intake is serviced overhead from a three phase pole mounted transformer bank. The distribution system for the T-2 intake is at 600 V. A 5 kVA dry-type transformer provides power to the 120 V convenience receptacles and lighting.

Photo 5.1-12: Pole Mounted Transformers, Hoist House Connection and 5 kVA Transformer

Located within the hoist house there is a 600 V distribution panel, a 120 V distribution panel, a control panel for the 2.3 kW (3 hp) gate hoist motor, controls and a communication uplink to provide water level indication to the control building, T12 style fluorescent lights, an electric industrial style force flow heater, and convenience receptacles.

On the exterior of the building there are incandescent light fixtures, and the intake gate gains were provided with gain heaters.

Assessment

The 600 V equipment and the hoist controls have a number of abandoned conduits and there are items which have been tagged as not functional. Further, the access around the 600 V equipment makes it difficult to work on the equipment safely. When the 600 V and control equipment is replaced, re-arrangement of panels can provide for improved accessibility.

Photo 5.1-13: Cut and Removed Copper Grounding and MI Heating cable.

Various materials stored in the hoist building could be stored on shelving to improve the situation. See Photo 5.1-1 for equipment and panel layout and spare material storage conditions.

There appear to be a number of systems which have been damaged over the years which have not been repaired or replaced. A number of the exposed systems have been significantly vandalized. The following items have been totally broken by vandalism or removed during theft:

- All grounding conductors for the system have been cut off and removed up to within 3 m (10 ft) of grade
- All Mineral Insulated (MI) style gain heaters have been cut / damaged and partially removed
- The roll up conductor system which fed the gate body heating appears to be disconnected.

The expanded fencing may provide protection against future vandalism attempts, but if still found to be inadequate, enhanced security measures such as video surveillance may be required.

The exterior lighting system was not functional at the time of the inspection. The interior lighting had one fixture which was not functional and another that had either lamps or ballasts failing.

The communications systems and the bubbler system for water level monitoring are not in properly enclosed cabinetry.

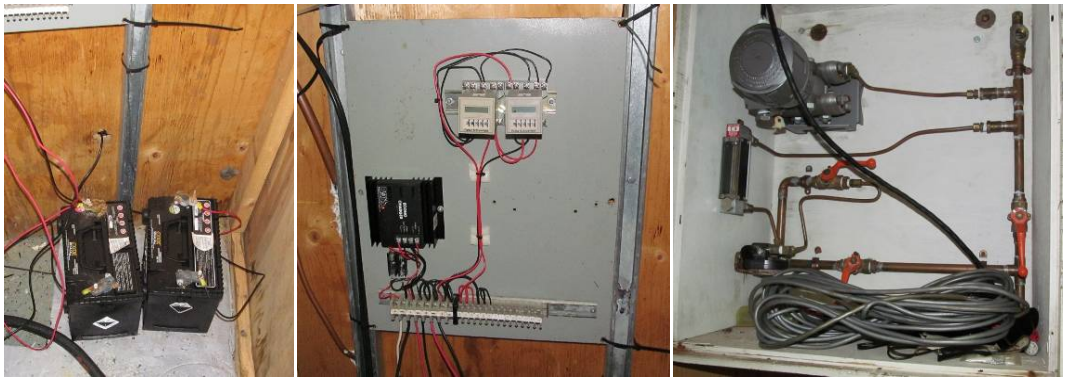


Photo 5.1-14: Exposed Mounting of Batteries, Controls and Bubbler System

The hoist controls for the T-2 intake gate are enclosed in one electrical enclosure. The enclosure is tagged on the lower pushbutton “Do not operate.” It is not clear how functional the

controls are at the time of the inspection. The electrical controls allow for remote or local operation; however, the controls have been left on local operation and the tag on the lower operation indicates there may be some issues needing attention.

The hoist drive equipment appears to be functional and was successfully operated in 2009. However, given the condition of the T-2 intake electrical equipment as a whole, it is not anticipated that long-term reliability can be expected.

As this gate is the only protection in place to address a breach of the Surge Lake dyke or the penstock or the failure of one of the turbine shutoff valves, the operation, condition and remote control capability of this gate should be considered to be critical since considerable time is required for an operator to reach the headworks and initiate the gate drop.

The T-2 tunnel intake electrical equipment is generally in a state of disrepair. Given the condition of the equipment and the difficulty in working on equipment within the hoist house, it is recommended that the electrical components of the complete T-2 intake structure be replaced.

All equipment which has been damaged or removed should be assessed to determine its necessity. The following systems may need to be replaced or reinstated:

- Grounding
- Gain heating (unless the recently installed bubbler system proves to be successful)
- Power to the gate body
- Exterior lighting
- Hoist controls
- Trip activation controls

Recommendations

- It is anticipated that the following work will be done as a package.
  - All electrical and control equipment should be replaced.
  - Given the remoteness of the location and the presence of vandalism, it is recommended that Nova Scotia Power replace all electrical systems with more vandal resistant equipment. All abandoned or obsolete equipment at the site should be removed and all new equipment should be designed to be contained in a limited number of panels which can be installed in a way to improve serviceability.

- It is recommended that all lighting be replaced or returned to a working condition.
- It is recommended that all electrical equipment be installed in enclosures.
- Provide storage shelving in the hoist house to store replacement parts, lubricant, wipers and similar materials.
- Provide for remote gate closure, to be used in the event of an emergency.

Estimated cost is $140k (does not include gate body or guide heating) and the work should be carried out within 2013.

5.2 TUNNEL T-2 ADIT DRAIN VALVE AND ASSOCIATED PIPING

Description

Draining of Tunnel T-2 was provided for in the original design of Wreck Cove through provision of a drain connection pipe through the concrete plug where Tunnel T-2 Adit joins Tunnel T-2. In the Adit, a drain valve and piping were installed to carry the drainage water to the open end of the Adit. From this point, the drainage would run on the surface and eventually enter into Wreck Cove Brook.

According to retired plant staff, there are two valves in series (drawing H-085S1-1-628-09-001 shows only one) and the drain pipe is exposed in some sections and not entirely covered in sand.

Assessment

In the 1980's, a mining contractor was engaged to enter the T-2 Adit and re-inforce the rock in areas where rockfalls had previously been experienced. The contractor reported that the rock conditions in the Adit had deteriorated significantly and the Adit was no longer safe to work in. Consequently, Nova Scotia Power closed the T-2 Adit entrance with a chain link enclosure and has not allowed workers or contractors to enter the Adit since then.

These actions have rendered the drain valve inaccessible and effectively made the drainage system unusable. Further, the condition of the 35 year old drain valve(s), which have not been operated in 20 years, and the pressurized piping on the Tunnel T-2 side of the valve(s) is unknown. There is a risk, of unknown degree which is increasing with time, that a pipe failure could release an uncontrolled water jet driven by a pressure head of 47.9 m (157 ft) into the Adit. This pipe failure leakage would be very difficult to stop, would entail a full plant outage and

access to the interior of Tunnel T-2 to carry out.

An assessment of the condition and functionality of the valve(s) and piping cannot be carried out until T-2 Adit is made safe or an alternate route of accessing the valve(s) and piping is provided, such as a vertical shaft. Ultimately it can be assumed because of corrosion potential, that the existing pipe penetration will need to be sealed and if T-2 Tunnel drainage through the T-2 Adit is selected as the best dewatering alternative, a new penetration and valves will be required. If another alternative for dewatering is selected, the pipe penetration will still need to be sealed.

Recommendations

- Carry out an inspection on the condition of the valve and piping, using an unmanned remotely operated tracked vehicle. Co-ordinate this work with a geotechnical inspection and assessment of alternatives for the T-2 Adit (see report Section 4.2 Tunnel T-2 Adit for further details). While it will not be possible to test operate the valve(s), the inspection will provide information on the exterior surface condition of the pressurized piping, which will indicate the urgency of sealing the penetration. As well, the inspection will provide information on the condition of any exposed piping downstream of the valve(s), to develop a better estimate of the cost of restoring the Adit as a tunnel drainage solution.
- Whichever alternative is selected for Tunnel T-2 dewatering, the existing piping penetration will need to be sealed and if the T-2 Adit is the preferred solution, a new piping penetration and new valves will be needed. Funding to seal the existing piping is included in the recommendation for a Tunnel T-2 dewatering solution in the Civil section of the report (see report Section 4.2 Tunnel T-2 Adit for further details).

5.3 TURBINE SHUTOFF VALVES

Description

The two spiral case inlet 1828 mm (72 in) spherical turbine shutoff valves are used to isolate the unit spiral cases from the station's single penstock at a point downstream of the bifurcation. They close as part of the unit shut down sequence.

The valves are designed for a maximum head of 366 m (1200 ft). The maximum design leakage when closed is 9.1 L/min (2 Igpm). The original design closing time using penstock water pressure was 90 seconds. According to the station operating manual, the valves are designed

to close under full head with the wicket gates fully open (see Valve Manual page 3:12). According to the original bid specification, the valves shall be able to close against a maximum flow of 35.8 m^3/s (1265 ft^3/s). There is approximately 907 t (2 million lb) of force on a closed valve due to hydrostatic load.

The valves were originally operated using water pressure from the penstock. Early in the station life, this system became unreliable as dirt in the water clogged the control valve orifices. About 20 years ago the water pressure based operating system was replaced with a hydraulic oil system. The two 11 kW (15 hp) pumping systems supply oil at 2413 kPa (350 psi) to the valves' hydraulic operating cylinders. Unit 1 valve has the original operating cylinder, whereas Unit 2 has a new cylinder installed a few years ago, and the original cylinder is still available. The two hydraulic systems are independent, have no provision for cross connection, and do not have sufficient accumulator tank storage capacity to close a valve in an emergency without AC power.

Hydraulic pressure is required to operate the valves in both the closing and opening directions, and there is no closing counterweight provided. A locking system is provided on the operating lever.

Photo 5.3-1: Hydraulic Pressure Unit for Turbine Shutoff Valve (one of two)

The turbine shutoff valve seal operation is unchanged from the original arrangement. Water at penstock pressure is used to operate the upstream and downstream valve seals. The downstream seal closes at each shutdown. The upstream seal is used only when maintenance is done on the valve or on the turbine generator. The downstream seals of Unit 1 valve were replaced during the November 2012 outage.

The shut off valve bypass line is 203 mm (8 inch) Schedule 80 pipe having a nominal wall thickness of 12.7 mm (0.50 in). The downstream end has a motorized ball valve and the upstream end has a manually operated gate valve. The downstream valve is used for normal unit shutdowns and the upstream valve is used for longer unit isolations. According to station staff, the downstream valves' motors and gear boxes were replaced a few years ago as the original drives had insufficient torque. The upstream manual valves are very difficult to close completely. A bar has to be inserted in the hand wheel spokes to provide the necessary extra leverage.

Photo 5.3-2: Unit 1 Bypass Line
Downstream Motorized Valve

Photo 5.3-3: Unit 1 Bypass Line
Upstream Manual Valve

In 1997, the bypass piping wall thickness of both valves was measured ultrasonically. The readings varied from 13.59 to 11.36 mm (0.535 to 0.447 in) for Unit 1 valve bypass line and 13.82 to 11.74 mm (0.544 to 0.462 in) for the Unit 2 valve bypass line. The thicknesses were again measured during this inspection. The readings varied from 15.24 to 11.93 mm (0.600 to 0.470 in) for Unit 1 and 15.24 to 12.19 mm (0.600 to 0.480 in) for Unit 2. The readings greater than 12.7 mm (0.50 in) are not unusual as Schedule 80 elbows often are made from Schedule

100 material with the ends turned down. The Schedule 80 pipe has a maximum allowable working pressure of 12400 kPa (1800 psi). The maximum design head during a load rejection is 4140 kPa (600 psi). Note that the actual pressure limit will be governed by the flanged connections and will be much lower.

In 2008, the nozzle downstream of the motorized bypass valve of Unit 2 was found to have cavitation pitting over an internal area of 33 cm x 30 cm, with a maximum depth of one half the 25 mm wall thickness. The nozzle is part of the spherical valve downstream extension piece of the spherical turbine shut off valve. The downstream extension piece was removed, and the nozzle was repaired and provided with a cavitation resistant 308 stainless steel internal surface. (See Alstom report 001, April 2008 and drawing H-085S1-4-414-00-003.) Unit 1 was subsequently inspected and was repaired by the Hydro Maintenance Shop personnel.

In 2009 the cast iron trunnion glands and gland liners of both valves were replaced. A five month station outage was required; Surge Lake and the penstock had to be drained for this work, as the valve position safety locking system is disabled when the operating lever is removed. The downstream seals of Unit 1 valve have also been replaced. Although not known for certain, the upstream seal O-rings may be original from 1978.

Station maintenance staff advised that some years ago a small leak at one of the valve main seals initiated severe penstock pressure oscillations. After this incident, penstock pressure and valve motion switches were installed to detect this type of event. If a pressure oscillation occurs, an alarm sounds and the bypass motorized valve and the downstream seal opens.

According to station maintenance staff, the air relief valves were recently replaced because of lack of spare parts for the original ones.

Also, maintenance staff advised that during a recent hot summer the water filter on the Unit 1 penstock water line to the valve seal became plugged with algae growth, and the valve seals could not be applied. This event is said to have happened only once.

Assessment – Unit 2 Valve

Unit 2 valve was the first of the two valves to be inspected and is the first to be discussed. Most of the Unit 2 comments also apply to Unit 1 valve. Specific issues for Unit 1 valve are given separately.

The valve was closed during the inspection and because of the maintenance work on Unit 2 it could not be operated. From inside the spiral case the downstream end of the valve could be observed. No reports of valve maintenance and repair work were found, so the valve history was gathered in discussions with the station staff. The valve operating data was taken from the original bid specification, the manufacturer's manual and the station operating manual.

The Unit 2 turbine shutoff valve appears to be in good condition. It operates well and no recent maintenance issues have occurred. When viewed from the spiral case, with the upstream seal sealing off the penstock, only very minor leakage was observed inside the spiral case at the downstream flange of Unit 2 valve.

The bypass line motorized valve and the new air release valve appear to be in good condition. The bypass line manual valve is very difficult to close completely. This is an issue for safety and for unit isolation. If the station lost electrical power, the manual valve would have to be closed to stop unit rotation.

The 1997 valve bypass piping wall thickness measurements given above showed a maximum wall loss of about 10%. Considering the limited number of test points in each inspection, the bypass piping lowest wall thickness readings taken during the 2012 inspection indicate no change from the 1997 readings.

According to the station staff the hydraulic operating system for the valve is in good condition. It has one small accumulator that could not supply sufficient oil for valve closure. No regular oil analysis is done.

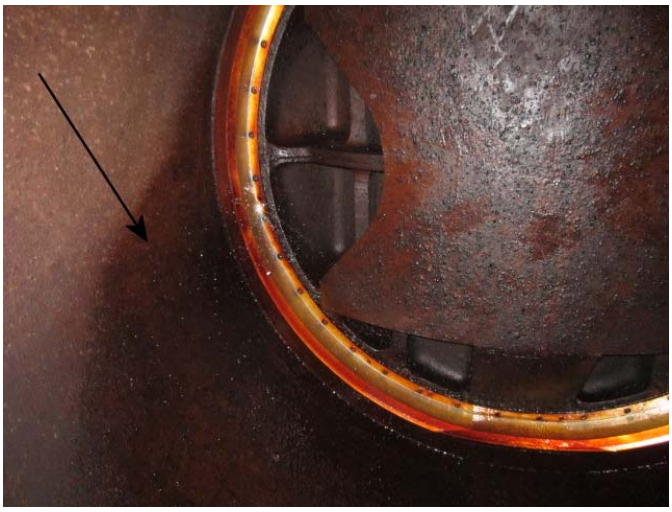


Photo 5.3-4: Closed Unit 2 Turbine Shutoff Valve
Slight leakage is wetting the spiral case walls (arrow).

Assessment - Unit 1 Valve

Unit 1 valve is in approximately the same good condition as Unit 2 valve. Specific items for this valve are as follows.

The difficulty in closing the bypass line manual valve also applies to Unit 1.

Considering the limited number of test points in each inspection, the bypass piping lowest wall thickness readings taken during the 2012 inspection indicate no change from the 1997 readings.

The hydraulically powered valve operating system is working well, although Unit 1 operating cylinder has some minor leakage at the cylinder rod seal.

The sliding flange of the downstream water seal has very slight leakage, probably due to a combination of O ring seal wear and slight corrosion of the metal sealing surfaces for the O ring.

An inspection of the valve from inside the Unit 1 scroll case showed only minor leakage similar to that of Unit 2.

Assessment – Both Valves

Given the cavitation pitting experienced on the nozzle downstream of the Unit 2 motorized bypass valve, this area will need periodic inspection to ensure that pitting has not resumed.

If a hydraulic hose to the servomotor fails, the valve may move very quickly open or closed. The hydraulic oil schematic drawing indicates flow controlling orifices are in the lines at the cylinders. Their presence and the orifice sizes should be confirmed.

If station electrical service and the manually operated diesel back up are unavailable the valves cannot be operated. A closing system not requiring AC electric power should be installed. This system would include additional oil accumulator tanks, and DC control valves, both to close the turbine shutoff valve and also to provide water pressure for seal operation.

Photo 5.3-5: Unit 1 Valve Sliding Flange
Slight leakage is dripping from the bottom (arrow).

Unless dictated otherwise by the engineering review of safety codes and industry practices (see next paragraph), no major work on the valves is expected over the next thirty years except for possible replacement of the main seals of each valve.

While the turbine shutoff valves are in good condition, operating and safety standards have evolved since Wreck Cove was commissioned, particularly with respect to the adequacy of a single isolation barrier to protect workers. Therefore, the valve design and operation requires an engineering review. Some issues to be considered are listed below.

- When a turbine is dewatered the valve's upstream isolation seal is the only water barrier. It is not physically locked in place but is held by water pressure. If the other unit had a load rejection, the penstock pressure fluctuations may affect the water tightness of the seal.
- If one of the three O rings on the upstream seal were to fail, while the scroll case door is open or the downstream extension piece is removed, the powerhouse would quickly flood. These O rings are likely original (1978) and cannot be replaced without draining Surge Lake.
- Is the present closing speed appropriate for emergency protection service?
- Should the seals operation be converted to oil pressure rather than penstock water pressure?
- The acceptable present day safety practice and procedures for personnel working behind such a valve, as a single barrier isolation.
- The acceptable practices and procedures used within other hydro and thermal plants in Nova Scotia Power and in other utilities with hydro stations. An informal survey of five hydro stations by Nova Scotia Power indicates locking devices on the operating arm are typically provided and lockable upstream seals are often used.

Recommendations

- Perform an analysis of the oil in the hydraulic operating system every two years.
- Repair or replace the upstream manual valves in the bypass lines of both units by 2014. Replacement cost: $10k for two valves.
- Annually inspect the nozzles on the downstream side of the motorized bypass valves for evidence of cavitation pitting and repair as necessary.
- Every 5 years, measure the wall thickness of the valves' bypass piping. This could be done during the yearly outage. If the wall thickness decreases to 80% of nominal, replace the piping. Inspection cost: $4k for two units every 5 years.
- In 2013, perform an NDE check of the turbine shut off valve stems using ultrasonic means. Review valve drawings and determine if there is any evidence of cracking in the stems. Inspection cost is estimated to be $2 k per valve.
- Confirm if the upstream seal O-rings are original and if found to be so or if indeterminate, plan to replace the O-rings within three years.
- Perform an engineering review by 2014 of the potential safety issues, looking at industry current best practices. Cost is estimated to be $25k.

- Install turbine shutoff valve closing systems which are independent of AC station service power in 2013. This could be achieved by modifying the existing hydraulic systems, and the cost is estimated at $25k per unit.
- Confirm the pressure, size, location and security of the orifices in the supply to the turbine shut off valve servomotors. This should be done in 2013 and the estimated cost is $2k per servomotor.

Turbine Shutoff Valve Spare Parts

Description

The following parts are available:

- Two sets of upstream and downstream seals
- One valve operating cylinder (stored at Nova Scotia Power central shop)

Assessment

The seals are important spares as they are long delivery items and critical to unit operation. At present, they are lying unprotected on top of a crate where there is a chance they could be damaged. A nick or dent could seriously affect their sealing capability.

The shut off valve body dimensions in the vicinity of the seals are different for Unit 1 and Unit 2, due to machining differences and this requires that the seals be of slightly different dimensions to properly fit. It is likely that this is not reflected in record drawings, but may be noted in recent purchase orders. As well, the O ring sizes and material specifications for the downstream seals are different from those shown on record drawings.

Photo 5.3-6: Spare Turbine Shutoff Valve Seals on Top of a Crate

Recommendations

- Store the spare valve seals securely in a purpose made wooden crate
- Purchase a set of trunnion seals ($1k). This will minimize outage time if they have to be replaced.
- Purchase a spare hydraulic pump and motor ($1.5k). If a pump fails, the generating unit cannot be operated.
- Confirm that drawings and specifications are available for ordering new turbine shutoff valve main water seals (upstream and downstream) and new trunnion seals.
- Amend the record drawings to show the difference in size between the seals of Unit 1 and Unit 2, and the correct O ring dimensions and materials.

5.4 TURBINES

Description

The units were commissioned in 1978, and until recently were used for peaking, with a load factor of about 18%. Now the unit operations have changed to tracking the wind turbine load and acting as reserve power. The units often operate at low power but not below 45 MW. Below this level, station staff report that draft tube noise increases markedly. This is typical for Francis turbines which exhibit draft tube hydraulic instability below 50 to 60% power and are not generally designed to operate below that level.

The cumulative operating hours on each unit from start of operation in 1978 were not available.

A yearly two week maintenance outage is scheduled for each unit although grid supply constraints sometimes cancel or shorten the planned outage times.

The Mitsubishi Francis turbines are rated 102,950 kW (138,000 hp) at 355 m (1166 ft) head and operate at 450 r/min. The runner band outside diameter is 2640 mm (104 in). Since their commissioning in 1978 the turbines have operated very reliably. The original runners are still performing well. The normal wicket gate closing time is 13 seconds. The spherical turbine shutoff valve takes three minutes to close and begins closure when the unit has slowed to 375 r/min.

In 1996, Unit 2 was dismantled to repair the runner band lower seal which was rubbing on the discharge ring liner. In 2009 Unit 2 had about 5 shear pin failures. The upper wicket gate bushings and the operating ring bearings were replaced which stopped the shear pin breakages.

The units do not creep when they are stopped. The turbine shutoff valve closes as part of the shut down sequence so there is almost no head of water in the spiral case. If creep is detected, the turbine shutoff valve repeats its closure sequence.

In 2011 Unit 1 was out of service to repair the governor.

During the 2012 outages the turbines were dewatered and the spiral case door opened for inspection and for maintenance work by the station staff. The draft tube platform also was installed.

Assessment

Unit 2 was the first of the two units to be inspected and reported on so it is the first to be discussed. Most of the Unit 2 issues also apply to Unit 1.

The turbine operating data was taken from the Mitsubishi turbine manual [1978] and the station operating manual [1978].

The turbine history was obtained from the station staff, and job safety analysis forms that had been filled out for past maintenance work.

From the information available and the visual inspections, both the turbines appear to be in good mechanical condition except for the problem of wicket gates rubbing against the head cover, the spots of cavitation pitting through the head cover stainless overlay and cavitation on the Unit 1 wicket gates. The turbine runner blades have no significant cavitation damage or visible cracks. Considering the turbines have now seen 34 years of service, a major overhaul or refurbishment will be needed in the next 5 to 10 years.

At the present time, due to the lack of comprehensive historical inspection and maintenance information and trending analysis, complete information needed to fully assess turbine condition is not available. The timing for such a major refurbishment would be best determined by implementing a more comprehensive periodic inspection and monitoring program, such as has been initiated with Acuren Ltd. on oil analysis, and shaft vibration analysis.

Other than externally discernible turbine condition, there are other scenarios, alone or in combination, which can determine the optimum time to perform a major overhaul:

- The condition of some components cannot be fully determined without partial or nearly complete disassembly. This would include such items as the head cover, the stay ring seats for the head cover and bottom ring and the wicket gate stems and lower bushings. The typical time between overhauls varies from 25-40 years (the large variability owing to the fact that hydraulic turbine designs are highly site-specific) and Wreck Cove is now in the upper middle of this time range.
- The need to perform major generator work, such as winding replacement, which presents the opportunity to carry out a major overhaul on the turbine for little incremental outage cost.
- Upgrading of the turbine (usually involving a runner replacement) may be planned and this requires virtually complete disassembly of the generator and turbine.
- The units will be experiencing a change in service conditions, with more exposure to such mechanisms as fatigue induced cracking on critical components, as the units operate over a broad load range and spend less time at or near the optimum design load. This is likely to be the case with Wreck Cove units being used more for load following, as the wind turbine presence in Nova Scotia increases. In this case, a major overhaul would be prudently performed in advance to help avoid unplanned outages.

The operation of the Wreck Cove turbines at relatively low loads such as 40 MW, results in hydraulic flow instability in the draft tube, which is evidenced by a loud hammering noise and vibration, especially noticeable when standing near the draft tube access door.

The vibration of the draft tube liner is induced by the hydraulic conditions and has likely contributed to the failure of the tripod air supply pipe and may be loosening the liner within the concrete. The vibration may also be imposing added loading to other turbine parts such as the runner blades and the guide bearing.

Francis type hydraulic turbines typically have a rough zone of operation in the low to middle power range, within which they are not intended to operate for long periods. When starting and loading such turbines, it is usually recommended to pass through the rough zone quickly and to limit excursions into this zone. Operation within this zone is believed to be a contributing factor to the failure of the Sayano Shushenskaya turbine in Russia in 2009, and as such, extended operation within the rough zone should be carefully considered prior to long term use of the Wreck Cove turbines at low loads. As hydraulic turbines are custom engineered for the site conditions and for other owner requirements, it is not possible to identify for all turbines a general rule for load ranges within which the hydraulic instability and associated vibration is so severe as to preclude operation and avoid the accumulation of long term damage.

Although it was not located, there may be in Nova Scotia Power records, a copy of the model test report, which would have been conducted in the course of the design of the Mitsubishi turbines. If not available, it might be possible to obtain a copy from Mitsubishi or from SNC Lavalin, the successor company of the original engineers for Wreck Cove.

A review of the model test report and a program of vibration testing on the turbines, at various loads, would provide essential information to define the rough load range and aid in identifying and assessing the potential unintended consequences of operation in the rough load range. The final aspect would be to define operating rules to avoid undue exposure to the excessively rough zone.

Recommendations

- Consider new runners engineered to potentially provide a capacity increase, higher efficiency and a wide range of stable operation. Estimated cost is $5.55M for two runners. Installation would be during turbine overhauls.
- To ensure long term unit reliability a comprehensive monitoring program should be established, with the following mechanical elements:
  - Install a shaft vibration analysis system that will give trending data on shaft runout, shaft orbit, and changes in the characteristic frequencies of the unit components
  - Record the bearing temperatures and institute a temperature analysis and trending system.
  - Continue to carry out yearly inspections but review what is to be inspected, based on the new operating conditions. Emphasize the close inspection of components susceptible to fatigue cracking, specifically the generator rotor and the turbine runner. Non destructive examination by LPI, MPI, and UT methods are recommended for critical areas.
  - Ensure the annual inspection and operation records are documented and available over the long term to allow for trending analysis.
- The following repair work is required to be done within the next 5 years (funds are included in the major overhaul recommendation below):
  - Plan to take the turbines out of service for rehabilitation of the wicket gates, to stop the top of the wicket gates rubbing on the head cover.
  - During the same outage repair the cavitation on the headcover, discharge ring and runner.
- Carry out major overhauls on each turbine concurrently with generator refurbishment or replacement. The estimated cost is $2.5 M per unit in 2017 and 2018.
- Undertake an engineering study to review model test information and to conduct a vibration test program on the Wreck Cove turbines, to establish the extent of the rough load range and to assess the risks of extended and periodic operation within such rough load range. This work should be undertaken in 2013, with a view to completing the vibration tests and the assessment by 2014. The estimated cost for this engineering study is $150k, including the vibration test work for one unit.

Turbine Shaft, Bearing and Shaft Seal

Description

The turbine shaft is 686 mm (27 in) diameter and 2286 mm (90 in) long. The babbitted turbine bearing does not have a cooling coil. Instead, the cooling water is pumped through the hollow bearing shoes. The shaft seal has three rows of carbon segments and an inflatable maintenance seal.

The runouts at the turbine bearings are discussed with the generator shaft turnouts in the Generator shaft section of the report.

Assessment – Unit 2 Turbine Shaft

The turbine shaft appears to be in good condition, based on a limited visual inspection.

Recent plant records of the combined generator and turbine shaft runouts are given below.

Table 5.4-1: Unit 2 Shaft Runout in 2012 (mils peak to peak)

Power MW	Turbine Guide A	Turbine Guide B	Lower Generator Guide A	Lower Generator Guide B	Upper Generator Guide A	Upper Generator Guide B
45	3	3	9	7	9	9
92	1	1	7	7	10	9

A and B represent orthogonal axis readings at the bearings

ISO standard 7919-5 (2005) gives shaft runout recommendations for this type and speed of unit. It allows up to 240 µm (0.010 in.) peak to peak runout at the optimum design point, usually at the best efficiency output. The turbine shaft runout is acceptable but the generator shaft runout is at the upper limit.

When the unit is running at 92 MW it is close to the efficiency point where turbine shaft runout should be, and is, at a minimum. However as the load increases, the generator shaft runout does not change with increasing magnetic force. This indicates the generator shaft runout probably is caused by mechanical unbalance. This problem is being investigated separately.

The Unit 2 turbine bearing is said to be in good condition. The design radial clearance is 0.33 to 0.38 mm (0.013 to 0.015 in). According to station staff, the only wipe that occurred was when a spare was installed that had too small an inside diameter. The bearing shoe cooling system works well. The condition of the bearing oil is not known, but the Acuren oil analysis program will cover this bearing. The bearing temperatures range from 35 to 60°C depending on the load. The 60°C temperature is somewhat higher than normal. This may be due to slight bearing damage or the shaft may be running hard over on one side of the bearing. This latter issue could be due to slight shaft misalignment.

The shaft seal consists of three rows of spring loaded carbon segments. It is reported to be in good condition. The tailwater level is nominally one foot above the centre line of the distributor so the seal acts against only a small differential pressure.

The shaft seal also incorporates an inflatable rubber maintenance seal. These seals are intended to be used to block the water flow while the carbon segments are being replaced. However, this work is done infrequently and almost always during a unit outage when the turbine is dewatered. This type of inflatable seal is always exposed to water and dirt and may rub on the shaft. Because of this environment at other utilities they are known to have deteriorated and failed during or shortly after inflation. This seal has not been used for many years as it is not required for its intended function.

Assessment – Unit 1 Turbine Shaft

The turbine shaft appears to be in good condition, based on a limited visual inspection. The combined generator and turbine shaft runouts are given below.

Table 5.4-2: Unit 1 Shaft Runout in 2012 (mils peak to peak)

Power MW	Turbine Guide A	Turbine Guide B	Lower Generator Guide A	Lower Generator Guide B	Upper Generator Guide A	Upper Generator Guide B
45	5	5	6	4	11	11
101	2	1	6	5	10	10

A and B represent orthogonal axis readings at the bearings

ISO standard 7919-5 (2005) gives shaft runout recommendations for this type and speed of unit. It allows up to 240 µm (0.010 in.) peak to peak runout at the optimum design point, usually at

the best efficiency output. The turbine shaft runout is acceptable but the generator shaft runout is slightly over the upper limit. The large difference in runout between the lower and upper generator guide bearings suggests the upper generator shaft may not be concentric with the lower generator shaft.

When the unit is running at 101 MW, it is close to the efficiency point where turbine shaft runout should be, and is, at a minimum level. However as the load increases, the generator shaft runout does not change with increasing magnetic force. This indicates the generator shaft runout probably is caused by mechanical unbalance. This problem is being investigated for both Units 1 and 2.

The Unit 1 turbine bearing is said to be in good condition. The design radial clearance is 0.33 to 0.38 mm (0.013 to 0.015 in). The bearing shoe cooling system works well. The condition of the bearing oil is not known, but the Acuren oil analysis program will cover this bearing. Bearing temperatures are similar to Unit 2, ranging from 35 to 59°C. The latter temperature is higher than expected.

The carbon segment shaft seal is reported to be in good condition. The tailwater level is nominally one foot above the centre line of the distributor, so the seal acts against only a small differential pressure.

As with Unit 2, the inflatable seal has not been used for many years as the carbon seal replacement procedure does not require its use.

Recommendations

- Remove the inflatable shaft seals from service. The estimated cost is $6k per unit and as this is not a critical item, it has been scheduled for 2015.
- Every two years filter the turbine bearing oil to remove dirt and especially any water. A filter medium that specifically removes water should be used.
- Using the shaft vibration probe outputs, review the shaft orbits to see if the shaft is over to one side of the bearing. This could cause high running temperatures and may be due to shaft misalignment.
- Check the calibration of the Bently Nevada vibration monitors to ensure the read outs are valid. This should be done in 2013.

- During the next outage (2013), perform an NDE examination of turbine shaft critical areas. Estimated cost is $2k per unit.

Turbine Runners

Description

The turbines have 19 blade martensitic CA6NM stainless steel runners. The band outside diameter is 2640 mm (103.94 in). Because of the high head, both the top and bottom of the runner band have sealing surfaces. In the past, damage in this area has caused or extended some outages. In 1998 the runner band of Unit 1 was rubbing on the discharge ring liner. A CGE report in file [1998] describes building up the runner band and cleaning up the discharge ring by in situ machining. The runner seals are simple cylindrical and not a labyrinth type.

Table 5.4-3: Design Runner Seal Radial Clearances

Location	Radial Clearance
Outer crown	1.5 mm (0.060 in)
Inner crown	1.27 mm (0.050 in)
Band top (lower seal)	1.5 mm (0.060 in)
Band bottom (discharge ring seal)	1.27 mm (0.050)

Taken from Dwg: H-085S1-9-411-00-002

The minor amounts of cavitation pitting experienced on the runners are weld repaired during the normal yearly outages. 309L stainless steel applied with the TIG welding process is used as the filler material. The surface is then blended and polished with a flap sander.

Assessment – Unit 2 Runner

The original stainless steel runner is in very good condition and has required no major repairs.

Table 5.4-4: Unit 2 Runner: Measured Clearances - September 2012

Location	Upper Seal (Outer Crown)	Lower Seal	Discharge Ring Seal
Design clearance	1.5mm (0.060 in)	1.5 mm (0.060 in)	1.27 mm (0.050 in)
Upstream	0.039	0.056	0.039
Right	0.048	0.045	0.034
Downstream	0.044	0.071	0.052
Left	0.043	0.044	0.038

All measurements in inches

These clearances are acceptable.

The 2012 inspection of Unit 2 runner exhibited very minor cavitation pitting as follows:

- At the blade trailing edges at the runner crown
- At the inside of the band at the bottom
- Some minor cavitation on one blade on the suction side

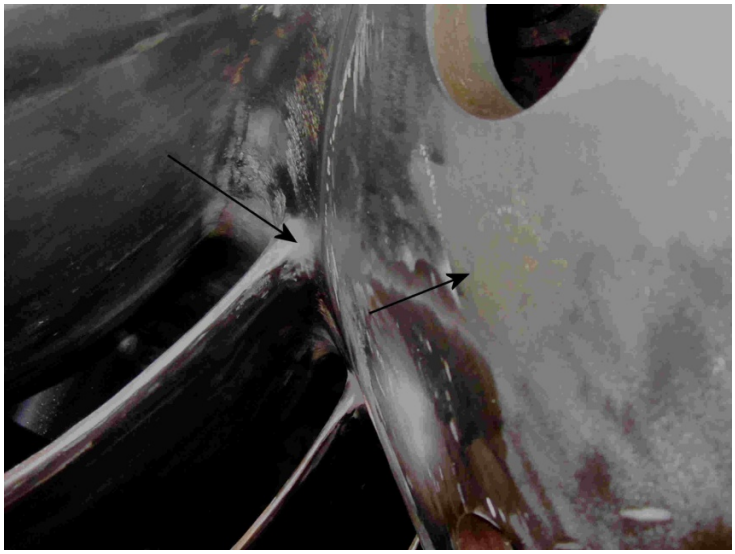


Photo 5.4-1: Unit 2 Cavitation Pitting on the Top of Blade at the Trailing Edge (left arrow) and Minor Cavitation at the Vent on the Runner Cone (right arrow)

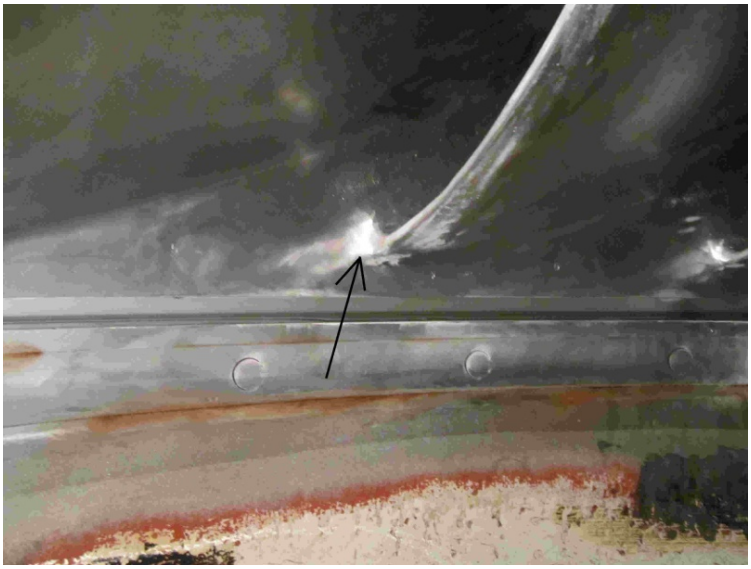


Photo 5.4-2: Unit 2 Cavitation Pitting on Blade Trailing Edge at the Runner Band (arrow)

Also, in Photos 5.4-2 and 5.4-3, note the excellent pit free condition of the erection ring.

Figure 5.4-3: Unit 2 Cavitation Pitting to be Repaired on the Blade Suction Side

The surface roughness of the cavitated areas was comparable to 220 grit sandpaper. No cracks were observed in the visual inspection. The runner could only be inspected from the draft tube as the wicket gates were closed while governor maintenance was being done.

It is fortunate that the runner has not cavitated badly as access through the openings between the blades and between the wicket gates is very tight. For major repairs the runner would have to be removed from the turbine.

Assessment – Unit 1 Runner

The original stainless steel runner is in good condition, although it has more cavitation pitting damage than Unit 2 runner. No cracks were observed. No major repairs have been required.

Table 5.4-5: Unit 1 Runner: Measured runner clearances - November 2012

Location	Upper Seal (Outer Crown)	Lower Seal	Discharge Ring Seal
Design clearance	1.5 mm (0.060 in)	1.5 mm (0.060 in)	1.25 mm (0.050 in)
Upstream	0.038	0.070	NA
Right	0.032	0.068	NA
Downstream	0.030	0.065	NA
Left	0.042	0.065	NA

All measurements in inches; NA = not available

These clearances are acceptable.

At this inspection the Unit 1 runner exhibits minor cavitation pitting in the following areas:

- The blade trailing edges at the runner crown
- Minor cavitation on the runner cone
- The blade to band joints at the trailing edges
- Cavitation patches on the suction side of the blades
- Some minor cavitation patches on the erection ring

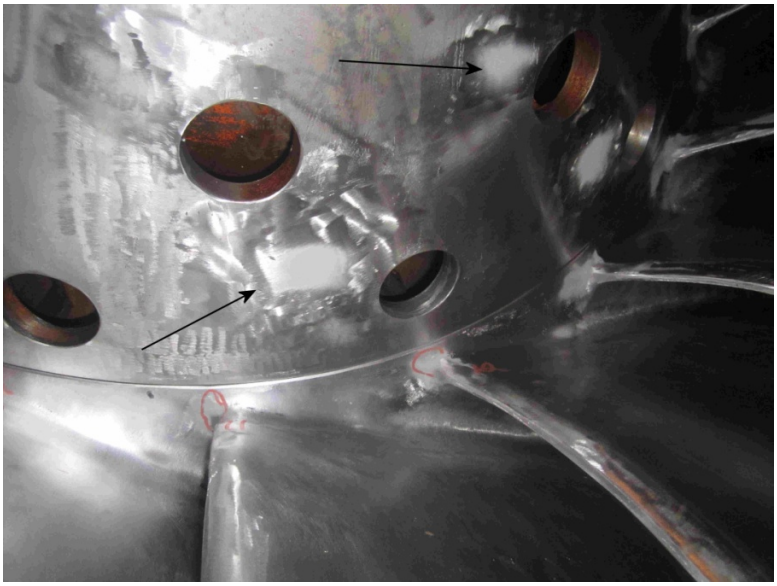


Photo 5.4-4: Unit 1 Cavitation Pitting on the Blade Top at the Trailing Edges (orange circled grey areas) and Minor Cavitation on the Runner Cone (arrows)

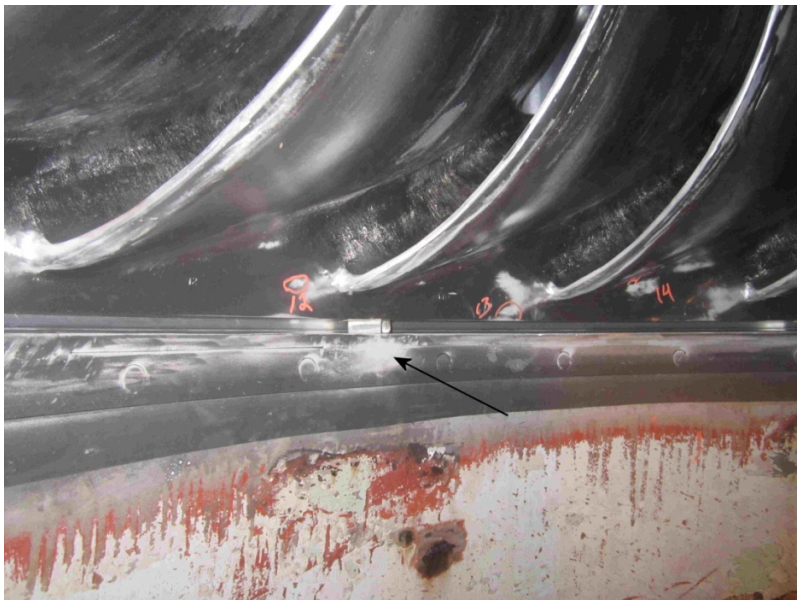


Photo 5.4-5: Unit 1 Cavitation Pitting on the Blade Trailing Edges (circled in orange) and an Example Patch of Cavitation Pitting on the Erection Ring (arrow)

Figure 5.4-6: Unit 1 Cavitation Pitting on the Suction Side of the Blade and an Example Patch of Cavitation Pitting on the Erection Ring

The surface roughness of the cavitation affected areas is comparable to 220 grit sandpaper. No cracks were observed in the visual inspection.

Recommendations

- Continue to keep the runners in their present good condition, with the periodic repairs to the minor cavitation pitting so the damage does not increase.
- Measure the runner crown and band seal clearances every 2 years starting in 2013.
- Every two years non-destructively inspect the runner for cracks, particularly at the blade and band welds, starting in 2013. The estimated cost is $3k per unit.

Wicket gates and top and bottom sealing surfaces

Description

The wicket gates are stainless steel and are 325 mm (12.8 in) high. Because of the high head their top and bottom clearances are each only 0.25 mm (0.010 in). The gate stems have bronze bearings of SAE 660 material. According to station staff the upper bushings were replaced in 2009 (See the wicket gate linkage section below).

The head cover surface above the wicket gates top ends is an overlay of 304 stainless steel 3 mm (0.12 in) thick. A similar overlay surface is on the bottom ring.

Assessment – Unit 2 Wicket Gates

Based on a visual inspection limited by the difficult access, the wicket gates are in reasonable condition. On the gates themselves, some slight surface discolouration and old polishing marks were noted, but no cavitation or erosion was evident. In fact numbers written on the gates last year (2011) with yellow marker are clearly visible.

Photo 5.4-7: Unit 2 Wicket Gates Seen through the Stay Vanes

The following damage was observed:

- Many small indentations downstream of the gate leading edges
- Small horizontal wear lines on the gate leading edges
- Patches of cavitation damage on the headcover beside the wicket gate tops.
- Severe rubbing of the top of the wicket gates on the headcover at the position where the gates are nearly closed.

The wicket gates upper seal packing is in good condition as indicated by only a small amount of leakage into the turbine pit. As discussed below, the lower gate stem bushing O ring seal is probably damaged and leaking.

The wicket gate bushings could not be observed. They are similar to SAE 660 tin bronze, a commonly used material for wicket gate bushings. It has a history of successful operation at many utilities. The upper bushings were replaced in 2009 which appeared to stop a shear pin failure issue. This suggests the clearances may be excessive. The condition of the bottom bushings is not known although, as suggested below, they may be damaged.

The leading edges on the inner side of almost all the gates have many small indentations (see the photo below). The station staff believes this damage occurred in 2009, after Surge Lake had been dewatered and dried out, and that stones on the lake bed became loose and on start-up

were carried into the penstocks and through the turbines. The station staff had a typical one inch size stone that had been found in the cooling water strainer.

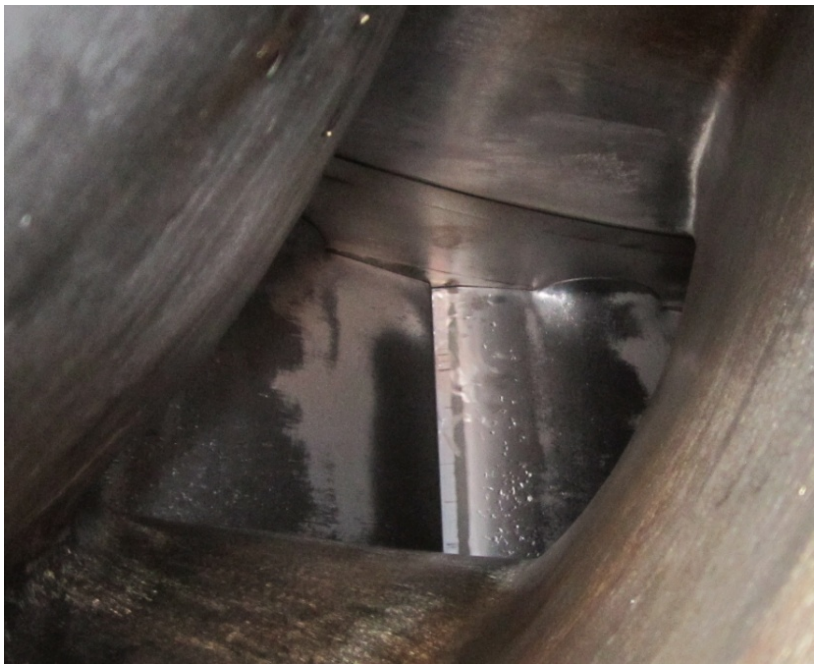


Photo 5.4-8: Unit 2 Wicket Gates Showing Indentation Damage on Leading Edges

The wicket gate surfaces on the inner side near the trailing edges are dulled but do not appear to be pitted. Theses areas may become pitted in the future.

The gate top and bottom design clearances are 0.254 mm (0.010 in) for a total of 0.51 mm (0.020 in) clearance. Measured clearances taken previously at different times give total clearances of approximately 0.762 mm (0.030 in). The current readings are given in Table 5.4-4. The vertical clearances and total clearances are acceptable although as discussed below, severe rubbing is occurring.

The gate side clearances are listed in Table 5.4-5 below. The allowable clearance is unknown but for this high head unit it probably is 0.00 mm. Using this criteria, six sets of clearances are unacceptable.

When the gates were in the closed position no rubbing marks or erosion was seen on the facing plates adjacent to at the top and bottom of the gates. However after the inspection, the gates were moved to the open position. The following damage could then be seen.

- Patches of cavitation erosion damage on the headcover beside the wicket gate tops.
- Severe rubbing of the top of the wicket gates on the headcover at the position where the gates are nearly closed.

Photos of the damage are shown below. Unit 1 has similar damage. The photos of Unit 1 show the damage more clearly.

Photo 5.4-9: Unit 2 Cavitation Hole in Stainless Overlay (arrow)

Photo 5.4-10: Unit 2 Galling Rub Marks on the Headcover above the Wicket Gates

The cavitation damage on the headcover probably occurs at low wicket gate positions when the water flow is disturbed. The damage is being repaired on an ongoing basis by welding and grinding. However because of extremely limited access, this machined surface can not be returned to original condition, and further cavitation damage will occur.

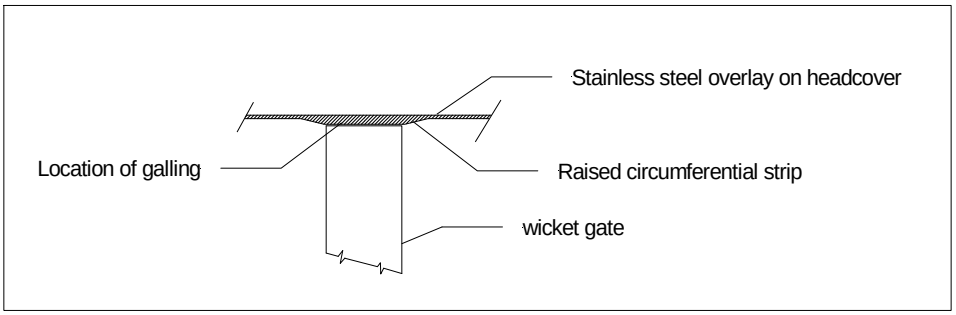


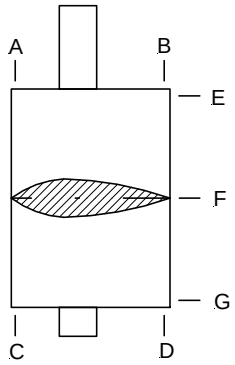
Figure 5.4-1: Location of the Rubbing Wear on the Headcover

The badly worn areas on the underside of the headcover are on the 304 stainless welded overlay. These rub marks are curved, and therefore are related to motion of the gate. If they were straight they could have been caused by erosion. The wear is almost entirely on the circumferential strip of the headcover that is raised above the rest of the surface. The surface appears to be typical of galling wear between the two surfaces. On the Unit 1 photos the build up of metal typical of galling can be seen.

For two surfaces to undergo galling they must be pushed against each other while relative motion is taking place. This force could be supplied by a build up of head pressure under the lower wicket gate stem. If the O ring seal at the lower stem has failed there could be up to 3600 kg (8000 lb) of force pushing a gate upwards. In addition, the gate thrust washer may be worn or not designed to withstand a large upward force. This would explain why the galling can occur even though the measured top and bottom gate clearances are within specification.

The damage also may be connected with the gate stem bushing greasing amount and interval. The greasing is done manually on a weekly basis. Typically the wicket gate bushings at a high head plant might be greased every three hours of running time. Lack of grease may have damaged the gate lower stem O ring seal.

Table 5.4-6: Unit 2 Wicket Gate Top and Bottom Clearances- September 2012

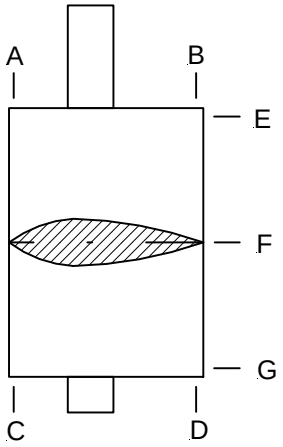


Gate #	Top A	Top B	Bottom C	Bottom D	Total A+C	Total B+D
1	0.011	0.010	0.011	0.011	0.022	0.021
2	0.014	0.017	0.008	0.006	0.022	0.023
3	0.011	0.011	0.007	0.006	0.018	0.017
4	0.010	0.012	0.009	0.007	0.019	0.019
5	0.008	0.009	0.008	0.007	0.016	0.016
6	0.007	0.007	0.012	0.013	0.019	0.020
7	0.010	0.009	0.011	0.010	0.021	0.019
8	0.013	0.012	0.004	0.006	0.017	0.018
9	0.009	0.006	0.008	0.014	0.017	0.020
10	0.011	0.009	0.008	0.012	0.019	0.021
11	0.012	0.009	0.010	0.012	0.022	0.021
12	0.011	0.013	0.008	0.006	0.019	0.019
13	0.016	0.015	0.003	0.004	0.019	0.019
14	0.003	0.002	0.018	0.019	0.021	0.021
15	0.013	0.011	0.008	0.008	0.021	0.019
16	0.011	0.011	0.006	0.007	0.017	0.018
17	0.012	0.011	0.010	0.008	0.022	0.019
18	0.010	0.009	0.008	0.009	0.018	0.018
19	0.013	0.012	0.007	0.007	0.020	0.019
20	0.008	0.008	0.009	0.009	0.017	0.017
21	0.013	0.010	0.007	0.009	0.020	0.019
22	0.012	0.008	0.008	0.011	0.020	0.019
23	0.013	0.011	0.010	0.012	0.023	0.023
24	0.013	0.011	0.009	0.010	0.022	0.021

Design clearances: 0.25 mm (0.010 in) at each end. All measurements are in inches.

These clearances are considered acceptable, and the uniform heel and toe values indicate good head cover and bottom ring alignment.

Table 5.4-7: Unit 2 Wicket Gate Side Clearances- September 2012



Gate #	Top E	Middle F	Bottom G
24-1	0.042	0.040	0.040
1-2	0,003	0	0
2-3	0.006	0.006	0,008
3-4	0	0	0
4-5	0	0	0
5-6	0	0	0
6-7	0	0	0
7-8	0	0	0.002
8-9	0	0	0
9-10	0	0	0
10-11	0	0	0.002
11-12	0	0	0
12-13	0.015	0.015	0.015
13-14	0	0	0
14-15	0	0	0
15-16	0	0	0
16-17	0	0	0
17-18	0	0	0
18-19	0	0	0
19-20	0.005	0.005	0.004
20-21	0	0	0
21-22	0.010	0.009	0.008
22-23	0	0	0
23-24	0.018	0.018	0.018

All measurements are in inches.

These values are considered acceptable.

Assessment – Unit 1 Wicket Gates

The following damage was found on Unit 1 wicket gates. It is very similar to the damage found on Unit 2, except that the Unit 1 wicket gates had some minor cavitation pitting, not found on Unit 2. Generally, the damage appears to be slightly greater on Unit 1 than on Unit 2.

Damage found:

- Cavitation on the suction side of the wicket gates
- A small number of indentations downstream of the gate leading edges
- Small horizontal wear lines on the gate leading edges
- Patches of cavitation damage on the headcover beside the wicket gate tops.
- Severe rubbing of the top of the wicket gates on the headcover at the position where the gates are nearly closed.
- Patches of cavitation damage on the discharge ring beside the wicket gate bottoms

Photo 5.4-11: Unit 1 Wicket Gates: Cavitation Pitting on the Suction Side

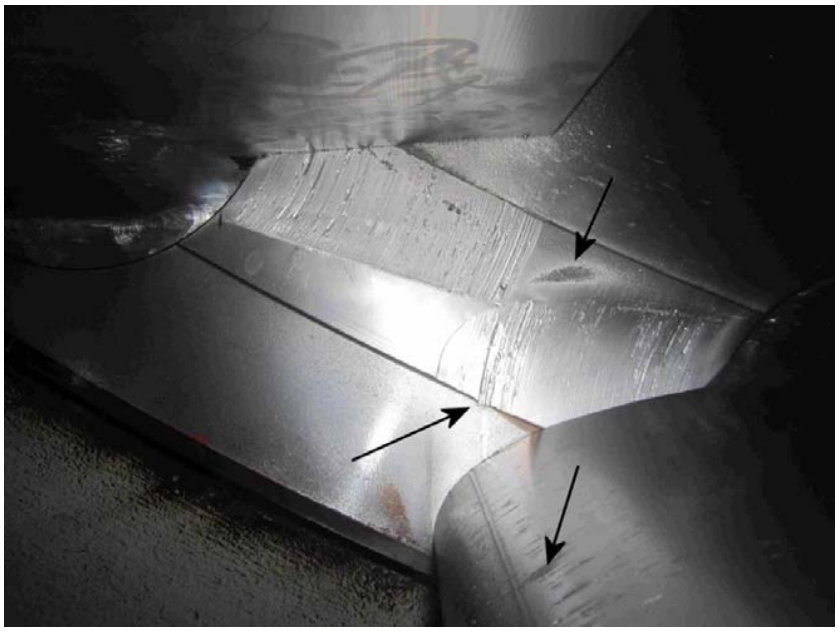


Photo 5.4-12: Unit 1 Underside of Headcover Showing Galling Wear Caused by the Wicket Gates

In the photo above observe the gate leading edge erosive wear lines (lower arrow), the deformed metal indicative of galling (middle arrow), and the patch of cavitation pitting (upper arrow), directly downstream of the water flow when the gates are open about 10%.

Photo 5.4-13: Unit 1: Patch of Cavitation Pitting on Bottom Ring Beside Wicket Gates

Photo 5.4-14: Unit 1 Wicket Gate Suction Side
Note horizontal wear lines on leading edge and cavitation pitting near trailing edge.

The cavitation pitting on the suction side of the wicket gates is about 1.6 mm (1/16 in) deep. Most of the gates are cavitated in a similar manner. It would be interesting to see any photos of this area taken before the mode of operation changed. The present partial gate operation may be increasing the rate of cavitation pitting.

The wear lines on the gate leading edges probably are “wire drawing” caused by leakage when the scroll case is at head pressure and the gates are closed. This could occur while the turbine shutoff valve is open during shutdown and start up

As with Unit 2, the cavitation pitting damage on the headcover probably occurs at low wicket gate positions when the water flow is disturbed. The damage is being repaired on an ongoing basis by welding and grinding. However because of the extremely limited access, this machined surface will not be returned to its original condition. Further cavitation pitting damage will occur.

The rubbing of the wicket gates on the headcover is similar to that of Unit 2. It probably also is caused by a build up of head pressure under the wicket gates’ lower stems because the O ring seal has failed. The deformed metal in the rubbing area, characteristic of galling, can be seen in

the above photograph. Like unit 2, the top and bottom clearance readings have been normal. Gate clearance measurements on Unit 1 in 2011 give total clearances between about 0.64 and 0.76 mm (0.025 and 0.030 in). The readings taken during this outage are given in Tables 5.4-8 and 5.4-9.

The patches of cavitation on the discharge ring are relatively minor. They probably are caused by extended part load operation.

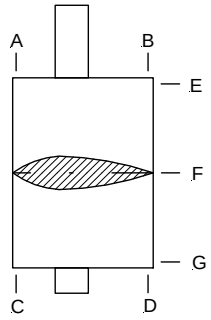
The wicket gate bushings are said to be in good condition although on Unit 1 they are the original bushings. As previously discussed in Unit 2 comments, the lower stem bushing O ring probably is damaged and leaking so the bushing itself may be damaged.

The wicket gates upper seal packing is in good condition as station staff reported only a small amount of leakage into the turbine pit.

As discussed with Unit 2, the damage also may be connected with the gate stem bushing greasing amount and interval. Lack of grease may have damaged the gate lower stem O ring seal.

The wicket gate bushings are greased on a weekly basis. This may be insufficient. For a high head station, a major utility standard recommends a 3 hour operating time greasing interval.

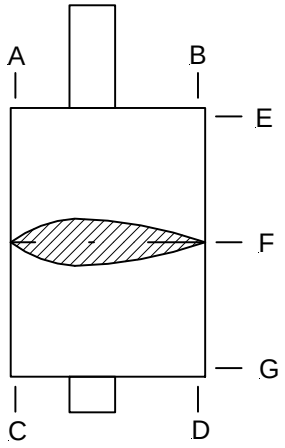
Table 5.4-8: Unit 1: Wicket Gate Top and Bottom Clearances – November 2012



Gate #	Top A	Top B	Bottom C	Bottom D	Total A+C	Total B+D
1	0.018	0.018	0.009	0.010	0.027	0.028
2	0.016	0.019	0.014	0.014	0.030	0.032
3	0.023	0.020	0.007	0.006	0.030	0.026
4	0.012	0.012	0.010	0.011	0.022	0.023
5	0.022	0.015	0.007	0.007	0.029	0.022
6	0.023	0.021	0.004	0.004	0.027	0.025
7	0.009	0.008	0.011	0.015	0.020	0.024
8	0.012	0.012	0.005	0.009	0.017	0.021
9	0.019	0.019	0.006	0.007	0.025	0.026
10	0.016	0.016	0.006	0.009	0.022	0.025
11	0.019	0.017	0.006	0.006	0.025	0.024
12	0.019	0.017	0.006	0.008	0.025	0.025
13	0.014	0.013	0.010	0.010	0.024	0.023
14	0.013	0.011	0.017	0.017	0.030	0.027
15	0.017	0.016	0.011	0.011	0.028	0.026
16	0.015	0.016	0.004	0.004	0.019	0.020
17	0.018	0.015	0.010	0.015	0.028	0.030
18	0.016	0.015	0.004	0.004	0.020	0.019
19	0.023	0.017	0.004	0.004	0.027	0.021
20	0.017	0.015	0.004	0.004	0.021	0.019
21	0.026	0.023	0.004	0.005	0.030	0.028
22	0.025	0.023	0.003	0.004	0.028	0.027
23	0.022	0.018	0.010	0.010	0.032	0.028
24	0.018	0.014	0.009	0.010	0.027	0.024

Design clearances: 0.25 mm (0.010 in) at each end. All measurements are in inches.

Table 5.4-9: Unit 1 Wicket Gate Side Clearances – November 2012



Gate #	Top E	Middle F	Bottom G
24-1	0.000	NA	000.0
1-2	0.000	NA	000.0
2-3	0.000	NA	000.0
3-4	0.000	NA	000.0
4-5	0.000	NA	000.0
5-6	0.000	NA	000.0
6-7	0.000	NA	000.0
7-8	0.000	NA	000.0
8-9	0.000	NA	000.0
9-10	0.000	NA	000.0
10-11	0.000	NA	000.0
11-12	0.000	NA	000.0
12-13	0.000	NA	000.0
13-14	0.000	NA	000.0
14-15	0.000	NA	000.0
15-16	0.000	NA	000.0
16-17	0.000	NA	000.0
17-18	0.000	NA	000.0
18-19	0.000	NA	000.0
19-20	0.000	NA	000.0
20-21	0.000	NA	000.0
21-22	0.000	NA	000.0
22-23	0.000	NA	000.0
23-24	0.000	NA	000.0

All measurements are in inches

Recommendations

- Use dial indicators to measure upward movement of several wicket gates when the turbine is dewatered and when it is watered up. The dial indicators should be supported on the pit wall or on the turbine shaft and read against the top of the upper stems. If the gates raise

when the turbine is watered up then the lower stem seals probably have failed. This test should be performed in 2013 and the cost is $2k per unit.

- Inspect and document with photos the wicket gate surfaces and the surrounding area during each yearly outage. Look for surface damage and signs of rubbing at the top and bottom of the gates.
- Continue the yearly repairs to the wicket gate cavitation damaged surfaces until permanent repairs can be done.
- Review the type of grease used, and the greasing timing and amount. Install automatic greasing systems in 2013. Cost $10k per unit.
- Monitor the wicket gates upper stem area for seal leakage. Replace the packing during a yearly maintenance outage if excessive leakage occurs. Cost: $5k (materials)
- Within one year, carry out an axial ultrasonic examination of the upper wicket gate stems to determine if cracking has occurred where the stems join the blade. Estimated cost is $2k per unit.
- Within 5 years overhaul the wicket gates and repair the headcover and discharge ring surface damage.

Spiral case

Description

The spiral case and stay vanes are made of heavy cast steel segments bolted together at radial joints. The spiral case door opens inward, and is held closed by the water pressure, not by the bolts. The 12 stay vanes are the normal high head configuration, that is, long in the direction of flow and short vertically. The spherical shut off valve is immediately upstream of the spiral case.

Assessment – Unit 2 Spiral Case

The spiral case is in good condition. No cavitation or erosion was observed and almost all of the paint is intact. No leakage was seen at any of the spiral case casting joints. (If there is leakage out of the spiral case, when it is dewatered inward leakage often occurs at the outward leakage points.)

The stay vanes are in good condition. All of the vanes were visually inspected. No cracks were observed and the paint is mostly intact except for some of the leading and trailing edges which

are bare metal. The leading edges themselves are in good condition with almost no erosion, scale build up or other damage.

Photo 5.4-15: Unit 2: Stay Vane Trailing Edge Devoid of Paint

Where the stay ring abuts the bottom ring, at several locations around the circumference the bottom ring is up to about 6 mm (¼ in) higher than the stay ring. This step would be expected to cause turbulence and possibly erosion or cavitation, but no damage was observed.

Photo 5.4-16: Unit 2: Step at the Joint between Stay Ring and Bottom Ring (arrow)

Where the headcover abuts the upper stay ring there are some brown surface markings on the stainless steel cover plate. This appears to be only minor surface erosion.

The spiral case door bolts and the matching bolt holes in the spiral case were visually inspected. No cracks or damaged threads were observed.

Assessment – Unit 1 Spiral Case

The spiral case is in good condition. No cavitation or erosion was observed and almost all of the paint is intact. No leakage was seen at any of the spiral case casting joints.

The stay vanes are in good condition. All of the vanes were visually inspected. No cracks were observed and the paint is mostly intact except for the leading and trailing edges which have some bare metal. The leading edges are in good condition with almost no erosion, scale build up or other damage.

Photo 5.4-17: Unit 1: Stay Vane Leading Edges with Some Bare Areas

As for Unit 2, where the stay ring abuts the bottom ring, at several locations around the circumference the bottom ring is up to about 6 mm (¼ in) higher than the stay ring. This step would be expected to cause turbulence and possibly erosion or cavitation, but no damage was observed.

The spiral case door bolts and the matching bolt holes in the spiral case were visually inspected. No cracks or damaged threads were observed.

Recommendations

- Visually inspect the spiral case at each annual maintenance outage. Look for any erosion damage and for any cracking at the top and bottom of the stay vanes. For suspect indications and not less than every two years perform magnetic particle non destructive examination. Cost: $3k per unit.

Draft Tube Liner (and Air Admission Tripod)

See Section 4.6 Draft Tube, in the Civil Assessment part of this report.

Headcover

Description

The headcover is fabricated of welded mild steel. All of the water sealing connections and flanges have O ring seals. The design is such that outer bolt circle transfers the hydraulic loads to the stay ring but it is not the water sealing surface. The sealing surface is at a slightly smaller radius at a lower elevation. See Drawing H-085S1-9-411-00-002.

At each of the frequent unit stops and starts, the spiral case pressure changes from atmospheric pressure to full head. As a result, the headcover and specifically the outer flange stud bolts will have been subjected to cyclic axial and flexural loading. The material and preload on these bolts is not known. There is no record of them being inspected.

The pipe plugs in the headcover have been known to fail resulting in severe leaking. One such plug hole was welded closed during this outage.
There are no headcover sump pumps. Any leakage drains to the station sump.

The turbovent air intake system is controlled by a cam on the operating ring. It appears to be working satisfactorily.

Assessment

The head covers were observed but could not be examined closely. The water sealing appears to be good as no leakage was evident. The outer flange stud bolts could not be closely examined. There is no record of them being inspected.

The pipe plugs in the headcover occasionally leak so welded replacements are installed.
The headcover water-side damage caused by the wicket gates rubbing is discussed in the wicket gate section of this report.

Recommendations

- Inspect all the stud bolts on the head cover outer flange of both turbines in 2013, then every 5 years. This would include an ultrasonic test, visual inspection and a representative check of the applied torque. The required torque should be determined by a mechanical engineer. Estimated NDE cost is $3k per unit.
- During the next turbine disassembly clean, degrease and blast clean the headcover and NDE check all welds and the flange around the stud holes for cracking. Estimated cost is $10k per unit.

Servomotors and Linkages

Description

The wicket gate servomotors appear to be in good condition. The piston rod packing on both units has been leaking and was to be replaced.

Station staff reported that in 2009, Unit 2 experienced 5 shear pin breakages. The operating ring journal bearing, the upper wicket gate bushings and the link bushings were replaced, and no further shear pin breakages occurred. The wicket gate bushings are similar to SAE 660 tin bronze, according to station staff.

During the 2012 visit some of the 2009 broken shear pins were examined. The fractures appear to be caused by overload and not by fatigue. It is surmised the loose clearances in worn bearings concentrated the loads on a few gates, which then caused the shear pin failures. The

unit has a shear pin failure alarm system, which alarms on a pin failure but does not identify the failed pin.

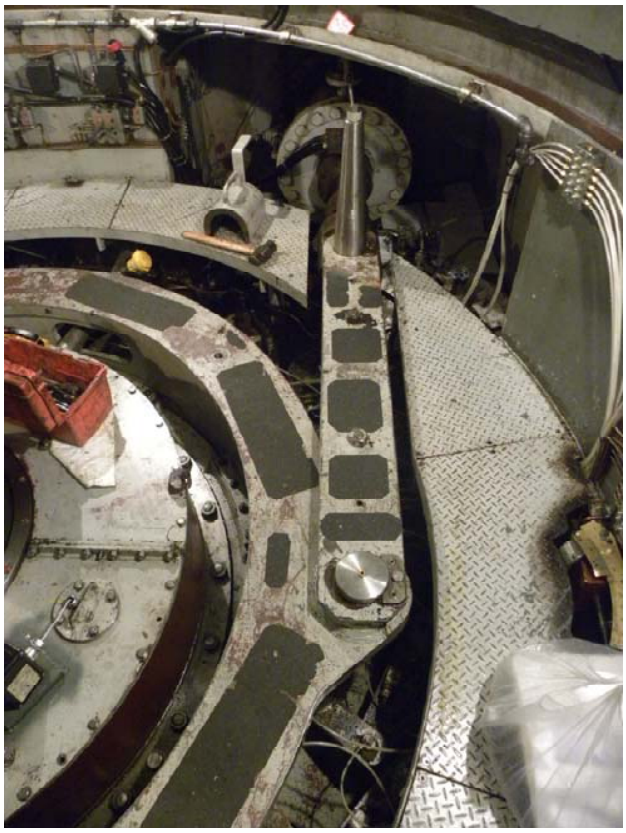


Photo 5.4-18: Top of Turbine No.2

Although the wicket gates are rubbing, the extra forces are not causing shear pin breakage. This probably is because the rubbing is only occurring between about zero and 10% gate opening on the raised circumferential strips on the headcover. At this point the hydraulic forces may be low.

Photo 5.4-19: Unit 2 - Turbine Gate Linkages, Shear Pin and Alarm

Assessment – Unit 2 Servomotors

The servomotors appear to be in good condition. The piston rod surfaces are relatively free from scratches and wear although there is some oil leakage from the piston rod packing. During this outage the staff planned to replace the rod seals. However the pin connecting the rod to the operating ring could not be removed so the work was postponed.

The operating ring, gate links, link pins and shear pins appear to be in good condition. No problems have been reported since the 2009 bushing repairs.

The greasing system for the wicket gates and links is a standard commercial design. It manually delivers a set amount of grease to each bushing. Greasing is done on a weekly basis, and may be insufficient. A major utility standard for high head stations recommends a 3 hour operating time greasing interval.

Assessment – Unit 1 Servomotors

The servomotors appear to be in good condition. The piston rod surfaces are relatively free from scratches and wear although there is some oil leakage from the piston rod packing.

The operating ring, gate links, link pins and shear pins appear to be in good condition. No problems have been reported.

As with Unit 2, the greasing system for the wicket gates and links is a standard manually operated commercial design and may not be delivering sufficient grease. It delivers a set amount of grease to each bushing. Greasing is done on a weekly basis, and may be insufficient. A major utility standard for high head stations recommends a 3 hour operating time greasing interval.

Recommendations

- Consider installing piston rod lip seals having joints on their circumference. They can be easily installed without dismantling the servomotor rod end fittings.
- Every year measure the governor pump cycling time with the wicket gates not moving. An increase in the cycling time may indicate wear of the servomotor piston rings, or governor control valve internal leakage.
- As with the wicket gates, increase the greasing frequency for the operating ring and linkages and adjust the quantity of grease injected to avoid extraneous grease accumulating on the head cover. It will be important to assess the greasing frequency as the turbine wicket gates will be more active when the generator load will be continually changing to follow system wind load variations.

Turbine Spare Parts

Description

The following turbine parts are on site:

- 3 wicket gates
- 3 wicket gate arms and shear pin levers
- Shear pins
- Three turbine bearings
- Servomotor rod seals

Assessment

The above spare parts are normally on hand at most stations. They are specific to the units and are the most important ones to have on site. They often are required on short notice and have a long delivery.

Photo 5.4-20: Spare Turbine and Upper Guide Bearings Sitting on Runner Plate

Photo 5.4-21: Spare Wicket Gate Fittings

Most of the spare parts are stored in crates. The wicket gate arms and levers on the floor and the loose shear pins should be tagged and shelved. The wicket gate arm bores on the floor should be measured to make sure they are not used ones which are worn oversize.

Recommendations

- The following spare parts should be acquired by 2014 as they may be needed at short notice.
  - Carbon seal segments and their springs
  - At least 5 wicket gate water seals per unit (upper and lower)

  The estimated cost is $8k.
- Sources for the following parts should be found, and drawings and specifications should be prepared:
  - Servomotor cast iron piston rings
  - Bearing re-babbitting companies. Re-babbitting specifications should be prepared
  - O rings for the headcover flanges. These may be non standard items
  - Magnetrol level switch parts or replacement units

5.5 TURBINE REGULATING EQUIPMENT

Description

The governors are Woodward cabinet actuators. These governors are known to be very reliable, and many similar ones are in very good condition after 60 years of operation with regular maintenance. This type of governor can meet the North American Electric Reliability Corporation (NERC) compliance test standards of a frequency range between 59.4 and 60.6 Hz with a 0.06% deadband. Nova Scotia Power is a member of NERC through the Northeast Power Coordinating Council, Inc.

Photo 5.5-1: Governors

The oil system for each governor includes the oil sump within the governor cabinet, two IMO screw pumps also within the governor cabinet, and the accumulator tank one floor above. The system working pressure is 2068 kPa (300 psig) and there is no connection between the oil systems of the two governors.

Replacement parts for this type of Woodward governor are readily available from several sources.

Assessment

This assessment applies to both governors.

Controls

Based on discussions with maintenance staff, the governors are reliable with very little maintenance being required. An outside contractor (American Governor) usually has been brought in when governor work is done. There is no record of the governor being tested for compliance with the NERC standards. These tests are done by a specialized testing company.

No reports of load rejection testing were found. The unit parameters for a load rejection are given below.

Table 5.5-1: Unit Load Rejection Parameters

Parameter	Value	Source
Generator maximum (r/min)	780	Nova Scotia Power RFP documentation
Turbine maximum (r/min)	780	Mitsubishi manual
Maximum design overspeed during a load rejection	35% with a 7 second wicket gate closing time	Mitsubishi manual
Maximum penstock pressure for a load rejection of both turbines together	4177 kPa (606 psi)	Mitsubishi manual

The governor dashpot settings are not known. Usually they are set at a compromise between reasonable response time and governor stability. They would be reviewed as part of the governor compliance testing.

The main valve dither could not be observed and information was not available. Typically it would be about 0.102 mm (0.004 in). The dither also would be reviewed during compliance testing.

The condition of the pilot and control valves is not known, but staff reported no related governor control issues such as servomotor hunting.

The governor pump cycling time has not been measured but is said to be at least about 20 minutes. The cycling time is good indication of any internal leakage of the oil system. The procedure is carried out with the wicket gates at a fixed position. Typically the period would be greater than 5 minutes. If the cycling period is under five minutes or is decreasing over the test periods then the servomotor piston rings or the governor main control valve clearances may be excessive.

Oil Pumps

The IMO screw pumps are known in the utility industry to be reliable. They have been the standard Woodward governor pump for many years.

As well as being on lead-lag configuration the two pumps often are operated alternatively as lead to equalize their running time. However this also means they will fail at about the same time. A better approach is to operate them on a 75/25 % basis so the time to failure will be very different.

As the pumps are 35 years old finding spare parts may be difficult.

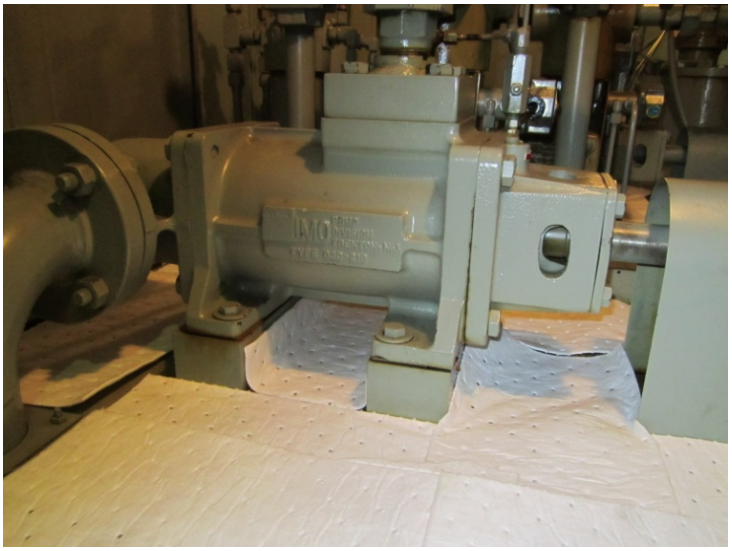


Photo 5.5-2: Governor Oil System IMO Oil Pump

Accumulator Tanks

The accumulator tanks and their equipment appear to be in good condition. A pressure switch was replaced on Unit 2 tank during the inspection outages. The tanks' access hole is of such a large size that an internal inspection could be done without entering the tank. The Nova Scotia Department of Labour pressure vessel inspection certificate is on the wall beside the tanks. The next inspection is due in 2015.

The pressure relief valves were lift tested in 2011. As lift testing can result in ongoing valve leakage, instead of lift testing, it may be cost effective to install new or refurbished valves.
Air make up to the accumulator tanks is manually carried out once a week.

The Magnetrol level switches are original so parts will probably become difficult to find. Newer combined level indicator and switches are good replacements.

Photo 5.5-3: Governor Accumulator Tanks - Note the Large Access Hatch

As the compressed air in the top of the accumulator tank may contain moisture, there can be a long term issue with internal rusting and wall thickness loss.

The air make up compressor does not have a downstream air cooler. If it is continuously running to fill a de-pressurized accumulator tank the supply line can become quite hot. If procedural changes can not resolve this concern an air cooler could be added. The air storage tank is manually blown down on a weekly basis, as there is no timed blow down valve.

Recommendations

- Carry out compliance testing of the governor within the next two years and at the same time review the dashpot settings. The estimated cost of the testing is $42k per unit.
- After generator refurbishment or replacement is completed (2018), carry out a load rejection test on each unit under the supervision of experienced engineers (hydraulic, mechanical and electrical disciplines). The incremental procedure in the CEATI “Mechanical Overhaul Guide for Hydroelectric Turbine Generators” should be followed. See the turbine shutoff valve section of this report for load rejection test comments. This test is not recommended at present due to the risk associated with operating the rotors above synchronous speed. Estimated cost is $20k per unit.

- Within 2 years and thereafter every 5 years, inspect the interior of the accumulator tank and ultrasonically measure the wall thickness.

Governor System Spare Parts

Description

The following spare parts are available on site:

- Oil filters
- Pressure switches
- Governor pilot valve
- Permanent magnet generator
- O ring, seal kits

Assessment

Very few spare parts are required for governors other than those mentioned above. If replacement pumps of a different design are required, there will be some re-engineering required for mounting, proper elevation relative to oil surface and piping connections.

Recommendations

- Investigate the parts availability for the Magnetrol level switches. If parts are difficult to find, install modern combined level indicators and switches.
- Investigate the availability of the governor oil pump replacement parts 2013. They may be very long delivery or no longer be available.

5.6 GENERATOR- MECHANICAL

General Description

The generators were designed and manufactured by Canadian General Electric (CGE), are rated for 111 MVA, and operate at 450 r/min. After commissioning in 1978, the generators of both units (floating rim design) had ongoing rotor unbalance and vibration problems which caused the units to trip off-line. In 1998 the Unit 2 rotor spider to rim connection was modified by CGE to increase its stiffness. Extra rim keys were added at the top and bottom of the rotor, but the floating rim design was retained. See Photo 5.6-3. The guide bearing radial clearance also was reduced to 0.229 mm (0.009 in).

In 2002 Unit 1 had the same rotor rim key modifications as Unit 2. It also had new adjustable wedge type stator soleplate keys installed, replacing the rectangular keys. Unit 2 also was to have this soleplate modification but the work was not done; the keys are on site but were not installed. Both the stator frames do not appear free to move radially: the new stator soleplate keys on Unit 2 seem to be too thick. This lack of radial freedom can result in loss of air gap uniformity, from a thermal ratcheting effect.

This work appeared to solve the unbalance problem and no rotor balancing has been required for at least 10 years. Current shaft runouts are on the borderline of acceptable runout as given in ISO guidelines. Aside from the rotor modification work, the only outages have been for yearly scheduled maintenance.

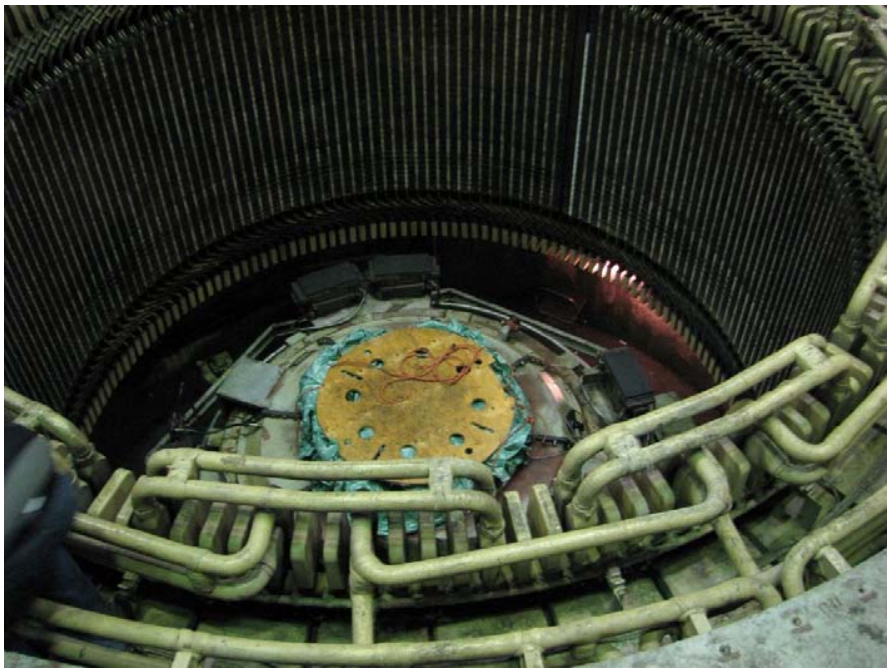


Photo 5.6-1: Unit 1 Stator

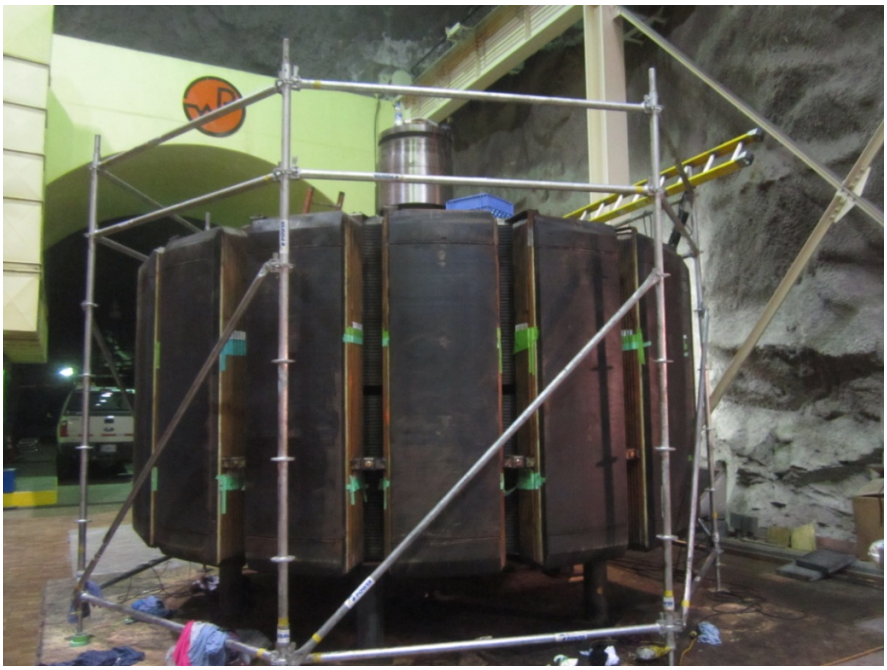


Photo 5.6-2: Unit 1 Rotor

During the KGS Group inspection in September 2012, Unit 2 had the generator top covers removed but the rotor in place. The surface air coolers had been removed for maintenance so the stator frame in that area could be inspected. The generator operating data was taken from the manufacturer's manual and the station operating manual. The generator history was obtained from the station staff, two reports [Report by Power Engineering Company on problems with rotor balancing: 1996 and Report by GE Hydro on modifications to Unit 2 rotor: 1998], and job safety analysis forms that had been filled out for past maintenance work.

During the Unit 2 outage in September 2012 the station staff found loose inter-pole support braces on the rotor. The rotor was removed to repair these items and Power Engineering Company was asked to review the generator condition in detail and define the scope of repairs needed. A summary of their November 20, 2012 report is included below.

Because of the problems with Unit 2, for the November 2012 outage of Unit 1, the rotor was removed. Similar problems with the inter-pole support braces were found. Power Engineering is also preparing an inspection report of this unit.

Summary of Power Engineering Company Report on Unit 2 Generator

Power Engineering Company found the following problems:

- The rotor mechanical stiffness is marginal due to specific design features.
- 30 of the 32 field coil braces are loose and the rotor has damage associated with vibration and unbalanced magnetic forces.
- The stator frame components have cracked welds. The core has waviness and signs of fretting at the splits.
- Many slot wedges are loose.

History of this Type of CGE Generator

The CGE rotors of the 1970's tended to have the following deficiencies:

- The use of two lamination doughnuts with rim clamping studs having clearance holes instead of reamed fitted holes has allowed large plastic deformation of the rim laminations. The rotor "floating rim" design gives no radial constraining stiffness to the rim lamination doughnuts.
- These floating rim units are very difficult to keep in balance. Misaligned rim doughnuts, high vibration, fretting and wear of rotor to shaft keys are the "norm" for CGE floating rim generators of this era.
- Nearly all CGE hydro units supplied around this period with resinous ground-wall insulated stator coils suffered from coil looseness and partial discharges. CGE generator stator coils were prone to becoming "loose" in the stator slots owing to use of a new semi-conductive room temperature curing silicone (CRTV) side packing.

The rotor and stator modifications implemented at Wreck Cove in 1998 and 2002 were partially successful; however they did not overcome all of the design problems nor address the component aging processes.

Power Engineering Company Recommendations

Wreck Cove generators' condition and age indicates that their reliability is expected to be much lower in the forthcoming years, and major work is required to prevent long unplanned failures. The rotor stiffness is seen as a significant weak component. Should the rotor fail in a sudden manner, major consequential damage to the stator would occur. Due to the small population of similar CGE rotors, failure mode and remaining life cannot be precisely predicted.

An economic analysis should be made to determine whether to:

a) Install a new generator or
b) Refurbish and modify the present generator.

New generator issues to be considered:

- The new generators must fit into existing foundations.
- The site work will be done in a subterranean power plant, with access limitations.
- Generators produced overseas require increased quality assurance vigilance.
- The expertise required to write a specification specifically for this site may not be readily available within Nova Scotia Power.

Generator refurbishment scope would include:

- Install new stator windings.
- Install redesigned rotor spiders, with increased stiffness.
- Modify the stator sole plate guide keys, and realign the stators.
- Repair the damaged core insulation and repack the stator core splits.
- Re-insulate the field poles.
- Replace most of the auxiliary equipment and controls.

Table 5.6-1: Power Engineering Company Generator Rehabilitation Work Priorities

Component	Rectify Deficiency Immediately or Before September 2013	Rectify Deficiency Between September 2013 & September 2017
Stator Winding	Schedule an outage to assess stator winding condition by NDT methods (Slot Discharge via Corona Probe and DC Hipot Tests).	Based on winding age and history of OEM's winding insulation system lifetime (for this type of winding), and NDT results, order & install a complete stator winding. NDT results will revise priority.
Stator Frame and Core	Obtain spare bars from a reputable coil manufacturer, and winding supplies. When materials are delivered to Wreck Cove schedule an outage to repack the stator core splits (requires some winding bars removal and rewinding at core splits).	

Component	Rectify Deficiency Immediately or Before September 2013	Rectify Deficiency Between September 2013 & September 2017
Stator Frame and Core	Retrofit existing adjustable radial keys to the stator soleplates (8), install shims in the frame-to-soleplates interface, realign stator frame so stator core satisfies CEA profile tolerances. This will mean that the unit will be realigned (adjust guide bearing bracket centres and thrust bearing level)	Unit centreline alignment maybe repeated during turbine generator rehabilitation.
Rotor Rim and Spider		Correct the rotor spider-to-rim alignment so rotor pole profile satisfies CEA tolerances. Realignment of the rim 'donuts' will require that the field poles be removed and spline drive keys be replaced. If performed with a generator rehabilitation would involve manufacturing of a new rotor spider.
Auxiliary systems	Eliminate oil & water leak problems in bearing housings and heat exchangers. Eliminate carbon dust contamination problems.	
Field Pole and Coils		Test rotor field coils, re-insulate and reinstall. Activity should be coordinated with rotor rim and spider alignment correction.
Bolted joints and assemblies.	Apply approved safety locking systems on all fasteners in the unit before unit is return to service in October, 2012.	
Rehabilitate turbine and generator		Turbine and generator rehabilitation shall satisfy relevant IEC and IEEE Standards.

Overview of Recommendations for Generators

- Implement the Acuren shaft runout trending program and the Power Engineering Company unbalanced magnetic pull (UMP) system by March 2013. Review the data on a monthly basis.
- Carry out the rotor and stator testing program recommended by Power Engineering Company, and KGS Group.
- Perform a rotational alignment check on both units in 2013 and re-centre the stators relative to the rotors.

- Review the two options in the Power Engineering report: to replace the generator or perform a major refurbishment, and based on the results of these inspections and the soon to be obtained test data, establish a date for a refurbishment of the generator and the scope of work to be done. This review should be done in 2013. The estimated cost of refurbishment of two generators is $30M and to recognize site work space constraints, these costs are shown equally split between 2017 and 2018. Note: these costs are included in the Electrical Assessment section of this report.

Generator Components

Generator Rotors

Description

The 16 pole rotor has an eight arm spider connected to the rim with 16 keys at the top and 16 at the bottom. The 8 additional keys between the spider arms at the top and bottom were added in 1998 for Unit 2 and in 2002 for Unit 1.

Photo 5.6-3: Unit 2 Rotor Extra Keys Added Between the Arms (arrow)

Assessment - Unit 2 Rotor

All of the top rotor rim keys were inspected for signs of fretting. The bottom keys were not accessible. No red powder (a product of fretting) was observed. Thus it is unlikely fretting is occurring indicating no excessive movement of the rim.

Photo 5.6-4: Unit 2 Rotor Rim Support Block
(arrow indicates the high stress location)

Critically stressed areas of the rotor were visually inspected for signs of cracking. These are the rotor arm to hub welds and the rim support blocks. No cracking at the arms was observed although the access for inspection at the rim is limited. The rotor rim support blocks were inspected at their inside corners, which is a known location for a crack to start. No cracks were observed in visual inspection.

After the rotor was removed, the detailed assessment by Power Engineering found the following rotor issues.

- Loose inter-pole coil braces
- Movement in the doughnut erection key assemblies
- Cracked locking welds on rotor spline keys
- Signs of possible overheating
- The rotor circularity and concentricity is within CEATI guidelines for operating units but above the commissioned unit tolerances

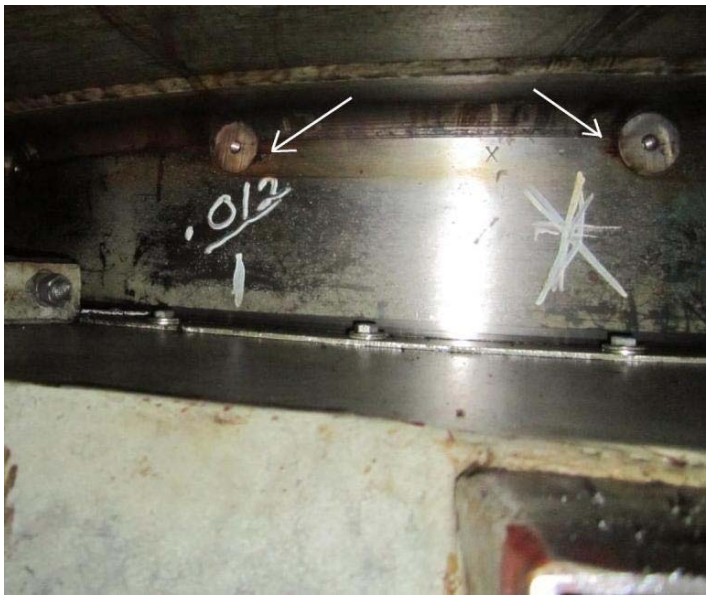


Photo 5.6-5: Unit 2 Rotor to Shaft Dowels (arrows)

The radial dowels between the rotor and the generator shaft are showing signs of minor fretting. This is a typical occurrence with CGE units of this vintage. After the inspection, when the rotor was removed some of the radial dowel caps screws were said to be broken. During the next overhaul the dowel holes should be re-machined and new dowels fitted.

The rotor is coated with a film of oil probably from the thrust bearing which has collected dust from the brakes and the carbon brushes. About 5 years ago the generator was cleaned by dry ice blasting, a process which will remove dry dirt but is not very effective in removing oil. The brake pad material needs to be confirmed as non asbestos.

The lower fan blades on the rotor could not be observed as the covers were in place.

The 32 brake track segments have minor patches of overheating and small areas of thermal checking. Visual inspection found no cracks. The track segment bolts are outside the sweep of the brake pads so cracking at the bolt holes is unlikely to occur. Brakes come on at 45 rpm in the shutdown sequence.

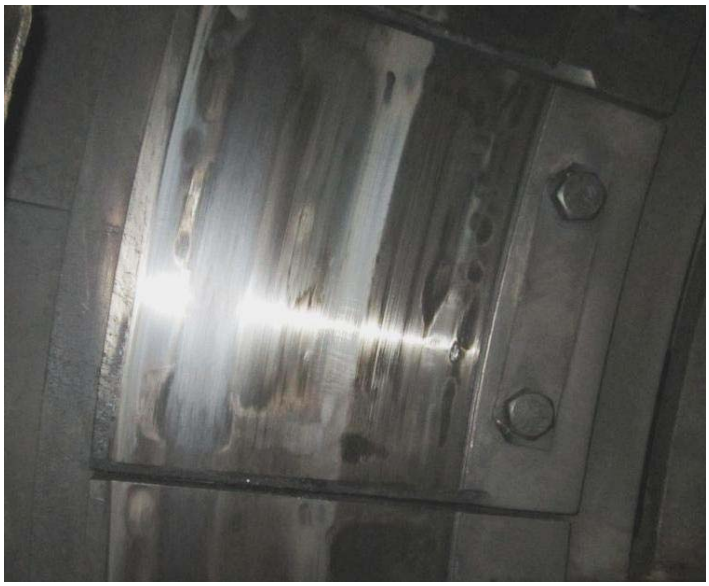


Photo 5.6-6: Unit 2 Brake Track Segment

Assessment - Unit 1 Rotor

During the November 2012 KGS Group inspection visit the Unit 1 rotor was out of the stator. Power Engineering Company had inspected it and was assisting with high priority repair work. In general the issues with Unit 1 are the same as those of Unit 2. Power Engineering Company will be issuing a report on their findings and the remedial work required.

Photo 5.6-7: Unit 1: Rotor Radial Dowels

Because the Unit 1 rotor was removed, the radial dowels between the rotor and the generator shaft were accessible. They are showing signs of fretting, which is a typical occurrence with CGE units of this vintage. No action is recommended at this time. During the next overhaul the dowels should be re-fitted.

Photo 5.6-8: Unit 1: Very Large Balance Weight

The rotor spider was visually examined. No weld cracks were observed. An extremely large balance weight is installed and its own mass may be contributing to the changes in the rim shape.

The 32 brake track segments are in similar condition as those of Unit 2. They have minor patches of overheating and small areas of thermal checking. Visual inspection found no cracks but some surface damage. The track segment bolts are outside the sweep of the brake pads so cracking at the bolt holes is unlikely to occur.

Photo 5.6-9: Unit 1 Brake Track Segment with Minor Surface Damage

Recommendations - Both Rotors

- Implement the Power Engineering Company UMP system by March 2013. Review this data on a monthly basis for any changes and trends. Estimated equipment cost is $40k per unit.
- In 2013 review the condition of the rotors as found from inspections and tests and plan future repairs.
- Non-destructively inspect the rotor brake tracks every five years starting in 2013. Estimated cost is $2k per unit.
- During the next unit overhauls, machine the radial dowel holes and replace the dowels. Funds for this are included in Section 5.4 Turbines, as part of a major turbine and generator mechanical refurbishment.

Generator Stators

Description

The stator frames are welded steel plate design constructed in two pieces. In 1998 and 2002, when the rotor unbalance problems were being addressed, the two stator frame splits were reinforced with welded plates. This was an attempt to stop any relative movement in this area. At the same time, key bars were found to be broken in this area as well.

As part of the rotor modification work in 1998 and 2002, it was understood that CGE would modify the stator soleplates to allow radial movement. This was done for Unit 1 in 1998, but for unknown reasons the modification work on Unit 2 was not done. The keys are stored on site.

Photo 5.6-10: Unit 2 Stator Frame Split - the Modifications are Painted Red

Photo 5.6-11: Unit 2 Greased Stator Soleplates having the Original Rectangular Keys

Assessment – Unit 2 Stator

The stator frame was visually inspected at one of the splits using the access provided while a surface air cooler was removed. The one stator split that was visible had plates welded across it and the stator bars in the immediate vicinity had been braced with welded-on plates.

After the rotor was removed, the detailed assessment by Power Engineering Company found the following stator issues:

- Several of the J type damper brackets have failed
- The new soleplate keys in Unit 2 appear to be incorrectly installed (too thick) and do not allow radial displacement.
- Core waviness near the stator splits
- Core mechanical damage at the splits
- Loose slot wedges
- The stator and rotor concentricity and circularity are below CEATI guidelines for intervention on an operating unit but do not meet new unit standards.
- Dirt and oil in the ventilation slots

Assessment - Unit 1 Stator

A detailed assessment by Power Engineering was carried out. From on site discussions with the Power Engineering staff, Unit 1 has the same issues as Unit 2, except that the stator has the original rectangular keys in place.

Recommendations - Both Stators

- In 2013 plan the work and timing of repairs and refurbishment, including consultation with the OEM.
- In 2013 repack the stator cores at the splits, install the soleplate radial keys in Unit 1 and rectify the soleplate radial keys problem in Unit 2. Estimated cost is $100k per unit.

Main Bracket

Description

The four arm main bracket is of welded construction and supports the thrust bearing as well as the brakes. The eight air operated brakes are mounted on top of the arms, two per arm. Each

brake has a limit switch to indicate if a brake is not retracted. The thrust bearing high pressure oil lift system is also mounted on one of the bracket arms.

In 2010 pad eyes were welded to the bottom of the lower bracket arms. They are attachment points for the chain falls used to lift the turbine bearing.

Assessment – Unit 2

The arm welds were visually inspected for cracking. No cracks were found. The brake pads appear to be in good condition. They are about 38 mm (1 ½ in) thick. They are said to be the non asbestos type but this should be confirmed.

Assessment – Unit 1

The arm welds were visually inspected for cracking. No cracks were found. The brake pads appear to be in good condition. They are about 38 mm (1 ½ in) thick. They look to be the non asbestos type but this should be confirmed.

Recommendations

- Confirm that the brake pads are made of non asbestos material. Replace the pads if they are asbestos based.
- Measure the brake pad thickness every five years. Replace any pads less than 25 mm (1 in) thick.

Surface Air Coolers

Description

Each unit has four vertical surface air coolers, with finned tubing made of standard copper nickel alloy. During the 2012 outages the coolers were removed for repair and cleaning. Water leaks had been observed at the gasket between the water box and the cooler body. New sealant was applied and at the same time the tubes were rodded out. According to station staff these coolers were previously repaired about 15 years ago.

Several years ago, the surface air cooler water piping was found to have severe internal build up with the pipes' clear inside diameters being reduced in some places to only about 19 mm (¾ in). The pipes were replaced.

The cooling water for each generator comes directly from the strainer through an air powered shut off valve then a throttling valve. The single water supply line splits into two lines each going to two coolers. Flow meters on each of the lines alarm at a low flow of 909 L/min (200 IGPM).

Assessment

Only minor tube fouling was found during the 2012 cooler repairs. The water boxes have significant corrosion especially at the usual location where the copper nickel tubes are swaged into the steel water box. Cooler life could be extended for a short time by epoxy coating the water box interiors.

Photo 5.6-12: Unit 2 Surface Air Cooler Water Box Interior

Recommendations

- Record the surface air cooler cooling water flows monthly.
- NDE inspect the cooling water piping every 10 years. Replace the piping within the generators in 30 years: $54k per unit
- Replace the surface air coolers within 5 years: $148k per unit

Generator Shafts

Description

The 686 mm (27 in) diameter generator shafts are of the usual CGE design where the top of the shaft forms the thrust block. The rotors are concentrically aligned to the top of the shaft by radial dowels.

The shaft runouts at the upper guide bearing, the thrust bearing and the turbine bearing are monitored by a Bently Nevada vibration monitoring system. The two units have Bently Nevada non contact eddy current shaft runout sensors connected to a common readout and alarm panel. As with the oil analysis, a pilot program developed by Acuren is being implemented to record and track the shaft runout of the two units.

Assessment – Unit 2

Based on visual inspection, the generator shaft is in good condition. See the rotor assessment section in section 5.6 Generator – Mechanical for comments on the dowels at the rotor to shaft connection.

Recent data on the combined generator and turbine shaft runouts in 2012 is given below.

Table 5.6-2: Unit 2 Generator and Turbine Shaft Runout (inches peak to peak)

Power MW	Turbine Guide A	Turbine Guide B	Lower Generator Guide A	Lower Generator Guide B	Upper Generator Guide A	Upper Generator Guide B
45	0.003	0.003	0.009	0.007	0.009	0.009
92	0.001	0.001	0.007	0.007	0.010	0.009

A and B represent orthogonal axis readings at the bearings.

ISO standard 7919-5 (2005) gives shaft runout recommendations for this type and speed of unit. It allows up to 240 µm (0.010 in.) peak to peak runout at the optimum design point, usually at the best efficiency output. The turbine shaft runout is acceptable but the generator shaft runout is at the upper limit and is therefore of concern.

When the unit is running at 92 MW, it is likely close to the best efficiency point where turbine shaft runout should be, and is, at a minimum. The readings show that as the load increases, the

generator shaft runout does not change with the increasing magnetic force. This indicates the generator shaft runout probably is caused by mechanical unbalance or shaft misalignment. The same issue exists on Unit 1 and therefore the runout problem should be investigated on both units.

The frequencies in the shaft runout signal often can be analysed to identify the source of excessive vibration. Table 5.6-3 is a reference for the characteristic frequencies of the Wreck Cove units.

Table 5.6-3: Characteristic Frequencies of the Wreck Cove Units

Source	Frequency(Hz)			Comment
Turbine				
Runner blades	142.5			rps x number of runner blades
Wicket gates	180.0			rps x number of wicket gates
Interaction of wicket gates with runner blades	684.0			(rps x blades x gates)/(blades – gates)
Reingans frequency- draft tube instability	1.9	to	2.5	~1/3 to ¼ rps
Once per revolution frequency	7.5			1 x rps
Generator				
Magnetic interaction of rotor with changed air gap at stator vertical joints	15.0			rps x number of stator vertical joints
Air gap problems	120.0			Rps x number of rotor poles
Rotor arms	120.0			Rps x number of rotor spider arms
Air gap problems	Values not known			Rps x number of stator slots
Shaft, coupling mis-alignment, shaft resonance	7.5	and	15	1 x rps, 2 x rps
Mechanical, generator magnetic, or hydraulic unbalance	7.5			1 x rps
Thrust bearing interaction	105.0			rps x number of thrust shoes
Interaction between the thrust shoes and the joints of split thrust bearing runner plates	210.0			rps x 2 x number of thrust shoes
Interaction between guide bearing pads and shaft	120.0			rps x number of guide bearing pads
One brake shoe rubbing brake track	240.0			rps x number of brake track segments
One brake track segment hitting each brake pad	60.0			rps x number of brake shoes
Stator problems such as loose core bolts or shorted field pole	120.0			For 60 Hz generator

Assessment – Unit 1

Based on visual inspection, the generator shaft is in good condition. See the rotor assessment section in section 5.6 Generator – Mechanical for comments on dowels at the rotor to shaft connection.

The combined generator and turbine shaft runouts in 2012 are given below.

Table 5.6-4: Unit 1 Generator and Turbine Shaft Runout (inches peak to peak)

Power MW	Turbine Guide A	Turbine Guide B	Lower Generator Guide A	Lower Generator Guide B	Upper Generator Guide A	Upper Generator Guide B
45	0.006	0.005	0.006	0.004	0.011	0.011
101	0.002	0.001	0.006	0.005	0.010	0.010

A and B represent orthogonal axis readings at the bearings.

ISO standard 7919-5 (2005) gives shaft runout recommendations for this type and speed of unit. It allows up to 240 µm (0.010 in.) peak to peak runout at the optimum design point, usually at the best efficiency output. The turbine shaft runout is acceptable but the generator shaft runout is slightly over the upper limit. The large difference in runout between the lower and upper guide bearings suggests the upper generator shaft may not be concentric with the lower generator shaft.

Like Unit 2, as the load increases, the generator shaft runout does not change with the increasing magnetic force. This indicates the generator shaft runout probably is caused by mechanical unbalance or shaft misalignment.

When the unit is running at 86 MW it is likely close to the best efficiency point where turbine shaft runout is at a minimum level. As the load increases from 45 to 106 MW, the generator shaft runout does not change with increasing magnetic force. This indicates the high generator shaft runout probably is caused by mechanical unbalance. The runout problem should be investigated for both Units 1 and 2.

Recommendations

- The shaft runout data collection and analysis program proposed by Acuren should be implemented and applied over the long term, to check for developing problems.
- The calibration of the Bently Nevada vibration monitoring system should be checked to ensure it is working correctly.

- The reason for the high runout levels at the lower and upper guide bearings of both units should be analyzed in 2013 as to cause and then addressed. Estimated study cost is $10k/unit.
- During the next outage (2013), perform an NDE examination of generator shaft critical areas. Estimated cost is $2k per unit.

Generator Shaft Bearings

Description

The generator bearing arrangement is a modified umbrella type having an upper guide bearing above the rotor and a combined thrust and guide bearing below the rotor.

The upper guide bearing is a two segment babbitted bearing. The thrust bearing is a CGE spring mattress arrangement having 14 babbitted segments. The lower guide bearing is a babbitted 16 segment arrangement using the side of the thrust bearing runner plate as the journal surface. The thrust bearing runner plate is made of mild steel. According to the station staff, the units are operating with their original thrust bearings.

In the past, oil analysis had only been carried out infrequently. A pilot program with Acuren Ltd. is now in place that covers oil sampling techniques, installation of collection points, analysis and trending.

According to station staff the thrust and guide bearing oil coolers were replaced about four years ago.

Assessment – Unit 2

Information for the assessment came from a review of manuals, external visual inspection and discussion with maintenance staff. None of the bearings were dismantled for inspection. The bearings have operated reliably and there is no history of frequent thrust bearing wipes.

Unit 2 thrust bearing runs at a significantly higher temperature than that of Unit 1. according to plant staff, these relative operating temperatures have been consistent for many years.

Table 5.6-5: Unit 2 Bearing Temperatures - Degrees C

Power MW	Turbine Metal	Turbine Guide Bearing	Lower Generator Guide	Thrust	Upper Generator Guide	Date
45	35	39	55	85	44	12/12/2011
92	39	42	62	88	48	14/5/2012
Unit 1 - 91*	59	47	46	67	44	12/6/2012

*Unit 1 data given for comparison

It is possible that the thrust segments of Unit 2 may have been slightly damaged at some time in the past because of a minor wipe, which could account for the higher operating temperature. Unit 2 thrust bearing temperature is currently quite high but in the short term is acceptable on the grounds that the bearing has operated for some years with no increase in temperature; however, if the bearing temperatures increase any further, the thrust segments should be replaced with the spare set. With this design of bearing the thrust shoes can be removed and replaced without dismantling the unit. An inspection should be arranged to investigate the cause of this condition.

The thrust bearing high pressure oil lift system is said to be working well. It is a typical CGE design, although there is no oil filter in the system. As the oil is introduced directly onto the thrust segment babbitt surface, a filter would prevent the introduction of dirt in a critical area. The filter also is a useful inspection point to see if any babbitt particles or other debris is in the oil pot. The filter would be located upstream of the pressure switch.

However, if these units will be experiencing frequent (daily, for instance) starts and stops, they could be candidates for having PTFE coated thrust segments installed. PTFE material is more tolerant of thermal crowning and no time is required for stabilization between start up and shut down. PTFE segments also do not require high pressure oil lift and the existing system could be abandoned.

Unit 2 – Thrust Bearing High Pressure Oil Lift System

At the upper guide bearing, carbon dust from the brush gear is about 5 mm deep on the top cover and on the felt seal. As the felt seal wears, this dust could enter the bearing oil and cause lubricant performance degradation.

Photo 5.6-13: Upper Guide Bearing with Carbon Dust on the Top Cover

The three Magnetrol level switches sensing oil level in the bearings are reported to be operating reliably. It is likely they will have to be replaced within the next thirty years ($3k).

Oil has collected on the top cover of the thrust bearing oil pot, and some oil is dripping into the turbine pit. The rotor also has an oily film on its surfaces. The source of the oil appears to be leakage at the seal at the top of the thrust bearing oil pot. Further seals adjustments can be attempted although for complete elimination of the problem, a vacuum demisting unit may have to be installed. The amount of oil loss from the thrust bearing is relatively small and the station staff report only very minor amounts of makeup oil are required.

The bearings are in good condition. They will require only routine maintenance over the next 30 years.

Assessment – Unit 1

Information for the assessment came from a review of manuals, external visual inspection and discussion with maintenance staff. The upper guide bearing was on the floor and could be inspected. It is in good condition with only minor scratches. The bearings have operated reliably and there is no history of frequent thrust bearing wipes.

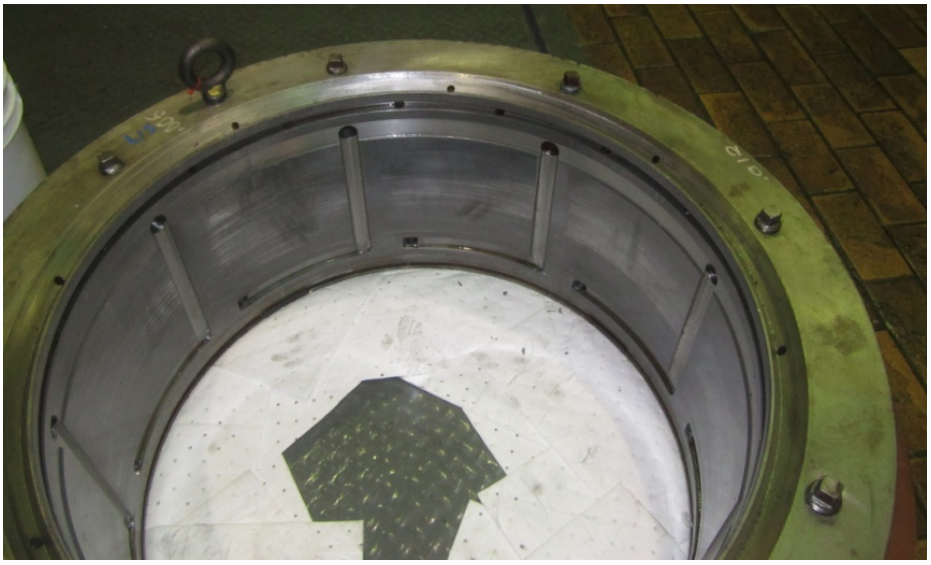


Photo 5.6-14: Unit 1 Upper Guide Bearing

Table 5.6-6: Unit 1 Bearing Temperatures - Degrees C

Power MW	Turbine Metal	Turbine Guide Bearing	Lower Generator Guide	Thrust	Upper Generator Guide	Date
46	61	50	51	64	45	13/7/2012
91	59	47	46	67	44	12/6/2012
100	61	49	50	64	44	3/7/2012

The above operating temperatures are acceptable.

Table 5.6-7: Unit 1 Upper Guide Bearing Clearances - November 2012

Location	Clearance - inches
US	0.011
US north	0.004
North	0.000 – 0.003
DS north	0.000 – 0.003
DS	0.007
DS south	0.014
South	0.017
US south	0.016

US = upstream; DS = downstream

The sums across the bearing diameters are all about 0.45 mm (0.018”). The design clearance is not known but it should be about this value.

The thrust bearing high pressure oil lift system is said to be working well. It is a typical CGE design, although there is no oil filter in the system. As the oil is introduced directly onto the thrust segment Babbitt surface, a filter would prevent the introduction of dirt in a critical area. The filter also is a useful inspection point to see if any Babbitt particles or other debris is in the oil pot. The filter would be located upstream of the pressure switch.

The level switches sensing oil level in the bearings are reported to be operating reliably. It is likely they will have to be replaced within the next ten to twenty years ($3k)

With the possible exception of the Unit 2 thrust bearing, the bearings of both units are in good condition. They will require only routine maintenance over the next 30 years, unless it is discovered during a major overhaul that the Babbitt bond is below standard, or during a thrust bearing inspection of Unit 2 that the babbitt surfaces are damaged.

Recommendations

- Filter the thrust and guide bearing oil every two years. This period may change depending on the Acuren oil analysis program findings.
- The thrust bearing temperatures should be periodically recorded and the data reviewed on a six month basis. If at some time a continual temperature increase is noted, the thrust segments should be replaced with the spare ones. Rebabbitting cost: $30k
- Clean the top cover of the upper guide bearing yearly to prevent the carbon dust from mixing with the oil.
- Install an oil filter in the high pressure oil lift systems by 2014 ($1k per unit)
- Re-adjust the oil pot seals. If the leakage cannot be reduced to an acceptable level, install a vacuum demisting unit in 2013 ($15k per unit)
- Check the condition of the Unit 2 thrust bearing by removing two segments for visual inspection in 2013. If the surface shows no sign of damage, check the calibration of the temperature measuring system.
- Allow funds in the program to replace the thrust and guide bearing cooling coils within about 20 years at their anticipated end of service life ($20k per unit).

Generator Mechanical Spare Parts

Description

The following generator mechanical spare parts are on site.

- One upper guide bearing
- One set of thrust bearing pads
- One thrust bearing runner plate (two piece)
- One set of lower guide bearing pads

These are parts specific to the two units and normally are of the same dimensions for each set of units. These components are the most important ones to have on site, and they often are required on short notice.

Assessment

The parts listed above are the normal on-site generator parts carried by most generating stations. The following spare parts also should be kept at the station to keep unplanned outage times to a minimum.

- High pressure oil lift pump and motor ($600)
- High pressure oil lift pressure switches

Other mechanical parts such as seals and bushings are available on short notice. The bearings are stored in crates and are well protected. The runner plate is lying on the floor wrapped in greased paper.

Recommendations

- By 2014, the runner plate should be coated with anti-rust compound, wrapped in protective paper and stored in a crate. The journal surface flatness tolerance is 0.013 mm (0.0005 in), so to prevent distortion, the plate must be evenly supported. Estimated cost is $3k.
- Non-destructively, by UT method, inspect the spare set of thrust pads in 2013 to confirm their babbitt bond is acceptable. If the pads are to be installed, their flatness must first be checked on a surface plate.
- By 2014, suppliers for the following parts should be found, and drawings and specifications should be prepared. This will reduce the delivery time when the parts are required. Estimated cost is $10k.
    - Bearing re-babbitting companies (prepare, in advance, specifications for rebabbitting and machining)
    - Magnetrol level switch parts or replacement switch units
    - Brake pads (one set of 8 pads) non asbestos type
    - Surface air coolers (one set of 4)
    - Thrust and upper guide bearing cooling coils (one of each)

Cooling Water System

Description

There are two cooling water systems. The main system draws water from one or both turbine draft tubes, and has three 56 kW (75 hp) end suction Armstrong centrifugal pumps, two on

primary service and one on standby. Each has a capacity of 8,720 L/min (2,300 USgpm) at 36.6 m (120 ft) head. They provide flow for the following applications:

- Generator guide and thrust bearings 523 L/min (115 Igpm) per unit
- Generator air coolers 4,360 L/min (960 Igpm) per unit
- Main transformers 772 L/min (170 Igpm) per unit

Photo 5.6-15: Cooling Water Piping (note deteriorated insulation)

These pumps at one time also provided condenser cooling water to two mechanical air conditioning units located on El. 14.5 ft. However these units have not been in operation for many years. The system includes two large basket strainers, one ahead of the water supply to each generator.

Photo 5.6-16: Main Cooling Water Pumps

There are also two smaller 3.7 kW (5 hp) cooling water pumps drawing water from the same draft tube suction header as the three 56 kW (75 hp) pumps. They provide bearing cooling water during generator/turbine start-up. After the generator(s) has started, the small pumps shut down and the larger main cooling water pumps supply all requirements including the larger quantities of flow needed by the generator surface air coolers.

Cooling water from this pumped cooling system is discharged to the station tailrace.

The second cooling water supply system, which is no longer in use, drew water from turbine #2 penstock, just upstream of the turbine shutoff valve. Pressure was first reduced from 520 psi to 200 psi for the turbine shaft seals, and from 520 psi to 90 psi for other service. Continuing problems with the pressure reduction valves required high maintenance effort and led to the system being abandoned many years ago, in favour of the system using cooling water pumps.

Piping is steel throughout. Much of the piping is covered in a thin black spray-on protective insulation covering that provides protection against rust and also some protection against condensation.

Assessment

The assessment is based on information collected from visual inspection of the cooling water system and interviews with plant maintenance and operating staff.

Most of the cooling water piping for both systems is original piping. However the 62 mm (2.5 in) and smaller piping was recently replaced and was available for inspection in the generating station yard (see photos in Appendix 1C). The inside of this piping system had extensive build-up and blistering taking place. Maintenance personnel noted the remaining original piping is continuing to perform well. There has been no pinhole leakage noted in this larger size (6 in, 8 in, and 16 in) piping.

The original heat exchangers for the upper guide and the thrust and lower guide bearings were replaced as follows:

- Unit 1 – upper guide and lower guide and thrust bearing cooling coils in 2008
- Unit 2 - upper guide cooling coil in 2007; lower guide and thrust bearing cooling coil in 2008

The generator surface air cooler water boxes have all been replaced, and the heat exchangers' tubes and tube sheets were considered by maintenance staff to be in poor condition.

The three 56 kW (75 hp) cooling water pumps and related isolation and check valves were replaced 5 years ago.

Recommendations

- In 2014, perform ultrasonic testing to confirm the level of wear or deterioration of the cooling water piping. Carry out visual checks of some extracted pipe sections to obtain additional information to decide on the need and timing to replace this piping. Estimated cost is $20k.
- At the same time install air vents on both ends of the draft tube pump suction header. This would make air removal more effective and reliable regardless of which draft tube is being used to draw water from, or which pump is being run.
- Replace piping larger than 76 mm (3 in) (piping smaller than 76 mm size was previously replaced) on both units' cooling water piping systems. Pending further information on piping condition, it is recommended that funding for the piping replacement be scheduled for 2019. Estimated cost for this work is $1.8M, which covers piping, valves, instrumentation, hangers

and insulation and allows for the congested work area and the need to keep at least one unit available to operate during the replacement.

5.7 TAILRACE EQUIPMENT

Description

The tailrace tunnel outlet is provided with a structural steel 6909 mm x 6706 mm (20 ft 8 in x 22 ft) vertical lift bulkhead gate. It is stored adjacent to the tailrace outlet structure and installation of the gate is with a mobile crane into steel gains in the outlet structure. The gate has no rollers. Once in place, hydraulic cylinders integral to the gate are used to press the gate upstream within the gains to achieve effective contact of the seals on the tunnel side of the gate to the seal surface. The gate has an integral priming valve to refill the tunnel prior to gate removal.

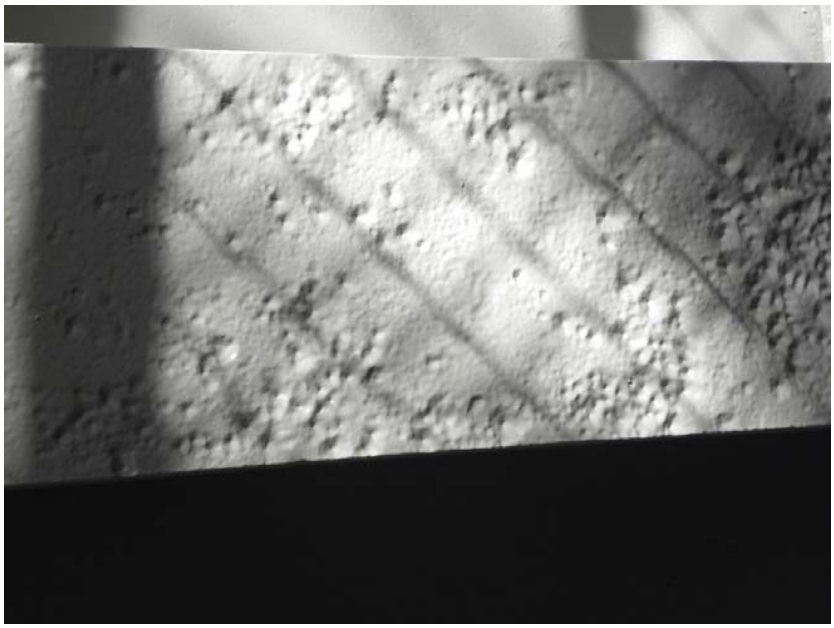


Photo 5.7-1: Tailrace Tunnel Outlet Gate Horizontal Member Prior Corrosion Pitting

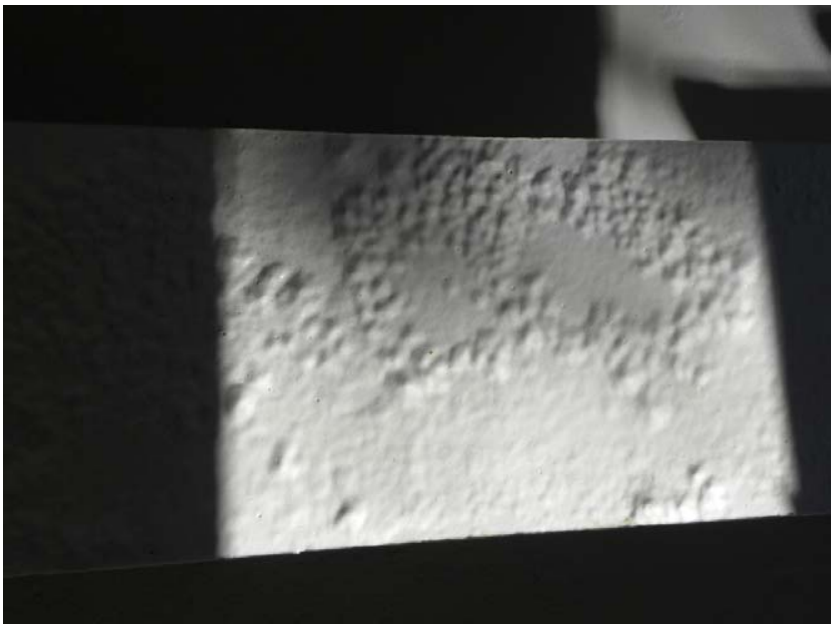


Photo 5.7-2: Tailrace Tunnel Outlet Gate Prior Corrosion Pitting

Photo 5.7-3: Tailrace Tunnel Outlet Gate Prior Corrosion Pitting

Assessment

Information for the assessment of the gate came from review of drawings, visual inspection from ground level and from the concrete deck of the gate storage structure, and from discussion with plant maintenance staff.

In late 2011, the gate were blasted clean and recoated with a marine enamel and the mechanical parts of the gate were replaced or refurbished. At the time of inspection (September 2012), several locations of coating failure by cracking and rust were evident. Extensive pitting, presumably from long term corrosion were visible as the light-coloured enamel made these very evident.

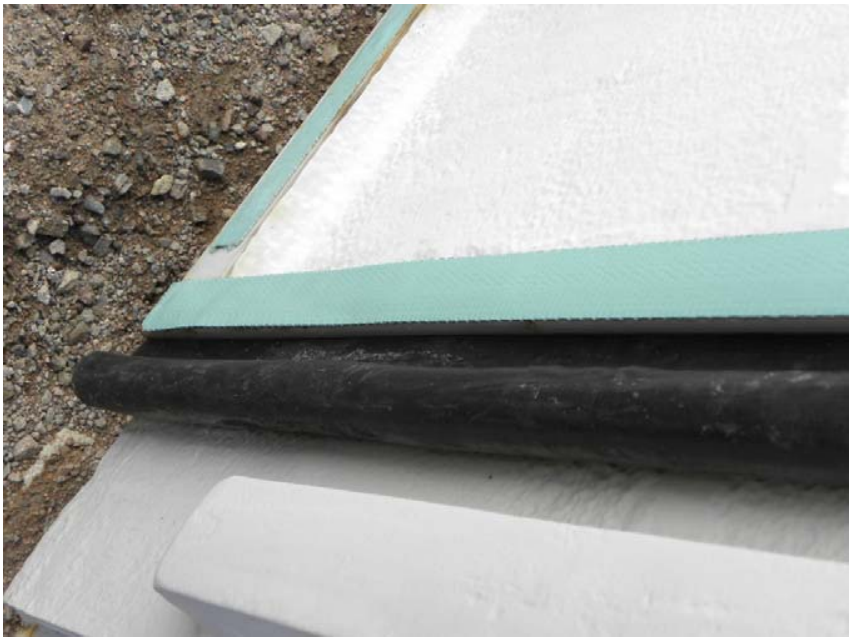


Photo 5.7-4: Tailrace Tunnel Outlet Gate Side Seal

A check of the side seals (J type) position relative to the adjacent bearing bars indicated that the seals might not contact the sealing surface of the gains until differential water pressure from the sea side loads the seals. It was later confirmed that the gains have sealing bars which about 10 mm thick and thus the seals should make full contact without differential pressure.

During the inspection, it was noticed that wave action had placed cobblestones into the area of the tailrace tunnel outlet structure's northerly gains to a depth of approximately two metres. Much of this material would need to be cleared to allow the gate to reach the sill, and close the outlet.

Recommendations

- Develop a detailed installation plan for the tailrace tunnel outlet gate that deals with removal of the cobblestones obstructing the north side gains. This should be completed before major refurbishment work in the powerhouse or tunnel begins. This study is estimated to cost $10k and should be performed in 2013.
- Monitor the condition of the coating on the tailrace tunnel outlet gate periodically, to track the failure of the coating, touching up the coating as found necessary. This work is estimated to cost $2k per year and should be performed annually.
- Perform a stress and deflection analysis on the gate which considers the loss of metal from major members. While the results are not expected to condemn the gate, they will be useful in a future decision to refurbish or replace the gate. This should be done by 2017 and is estimated to cost $15k.

Tailrace (Draft Tube) Sectional Gates and Storage Carriage Equipment

Description

The four sections of draft tube sectional gates are stored on a custom made steel carriage, which is manually moved to place each log under the monorail hoist. It runs on short steel rails embedded in the concrete floor. No inspection reports or maintenance records were available for review.

Assessment

The carriage is in good condition with no work required except for routine greasing of the chain drive and the wheel bearings.

The gears on the manual chain drive are uncovered and could be a pinch point for the fingers of the person turning the operating handle.

The sectional gates were reported to be in good condition. They install without difficulty and seal well in both turbines' draft tube gains.

Photo 5.7-6: Tailrace Log Storage Carriage

Recommendations

- Install a guard on the chain drive of the draft tube gates storage carriage to prevent the operator's fingers from being trapped. ($1k in 2013)

5.8 ANCILLARY EQUIPMENT (CRANES, MONORAILS)

Description

A 1.8 tonne (2 ton) Coffing hoist in the tailrace service gallery is used to raise and lower stop logs to isolate either of the turbine draft tubes. The hoist runs on a monorail to permit it to service both draft tubes.

The tailrace hoist was replaced about 12 years ago. In addition, the monorail's support system was changed to support the system from the floor instead of from the ceiling structure. The main disconnect switch was also recently replaced.

Photo 5.8-1: Monorail Hoist in Tailrace Service Gallery

The main power house crane is original equipment. It is a Richard Wilcox 150 tonne (165 ton) unit with an auxiliary 22.7 tonne (25 ton) hoist, and has a span of 17.7 m (58 ft). No record of a full load test in the original commissioning of the crane could be found.

Photo 5.8-2: Powerhouse Bridge Crane

The electrical systems for the powerhouse crane are essentially original to the plant and were operated from the crane cab. The powerhouse crane controls have been expanded to include a remote control about 4 years ago. The original crane controls are of a wound rotor motor type.

Assessment

The assessment is based on information collected from visual inspection of the cranes, interviews with plant maintenance staff, and review of an inspection report on file at the plant.

The tailrace hoist and related electrical systems are relatively new and in good condition. No problems were noted from discussions with plant maintenance staff.

The powerhouse crane is inspected annually by Atlantic Crane & Material Handling. Their most recent inspection report provided is dated May 25, 2011. A letter from Nova Scotia Power to Atlantic Crane dated August 15, 2011, indicates action planned on various miscellaneous issues that Atlantic Crane had raised. The issues raised have since been addressed.

These items included providing protective covering over drive motors to prevent water dripping from the ceiling above from damaging the motors. In addition a number of the crane rail tie down bolts had failed or gone missing. A bolt inventory was taken and the failed or missing bolts have been replaced. In addition a letter from Breton ND Testing dated 3 Oct 2011 indicates that magnetic particle testing of a sample of the rail tie down bolts was completed and no concerns were noted. A Log Book is kept that lists crane activities and repair work completed.

The addition of the wireless control appears to have introduced sudden stop issues with the movement of the crane. Maintenance staff noted that when the controls are released, the crane stops abruptly enough that the hook and any attached loads could swing. It would appear adding a slower speed drive would not necessarily address this issue, nor achieve precise load spotting control.

The existing crane controls have effectively reached the end of their useful life. Crane controls typically have an expected lifespan of 30-40 years. The current configuration of the controls has operational issues with the movement capability of the crane during a lift.

Recommendations

- The electrical systems for the powerhouse crane should be upgraded with a modern crane control system. This work would be typical to this vintage of crane. This work should also be done to resolve the quick stop issue of the crane movement. It is estimated that the upgrade would cost $550k, and this work should be performed within the next 3 years or prior to any major plant work requiring intense use of this crane. A full load test of the crane should be performed with the new controls.

5.9 HEATING VENTILATION & AIR CONDITIONING (HVAC) SYSTEM

Description

The station HVAC system was designed to provide heated fresh air and recirculation ventilation air to the powerhouse, provide any space heating required and also provide supplementary cooling which may be required when the generators are running or when space cooling is required for maintenance works that may be taking place. A system overview is presented in Figure 5.9-1 below.

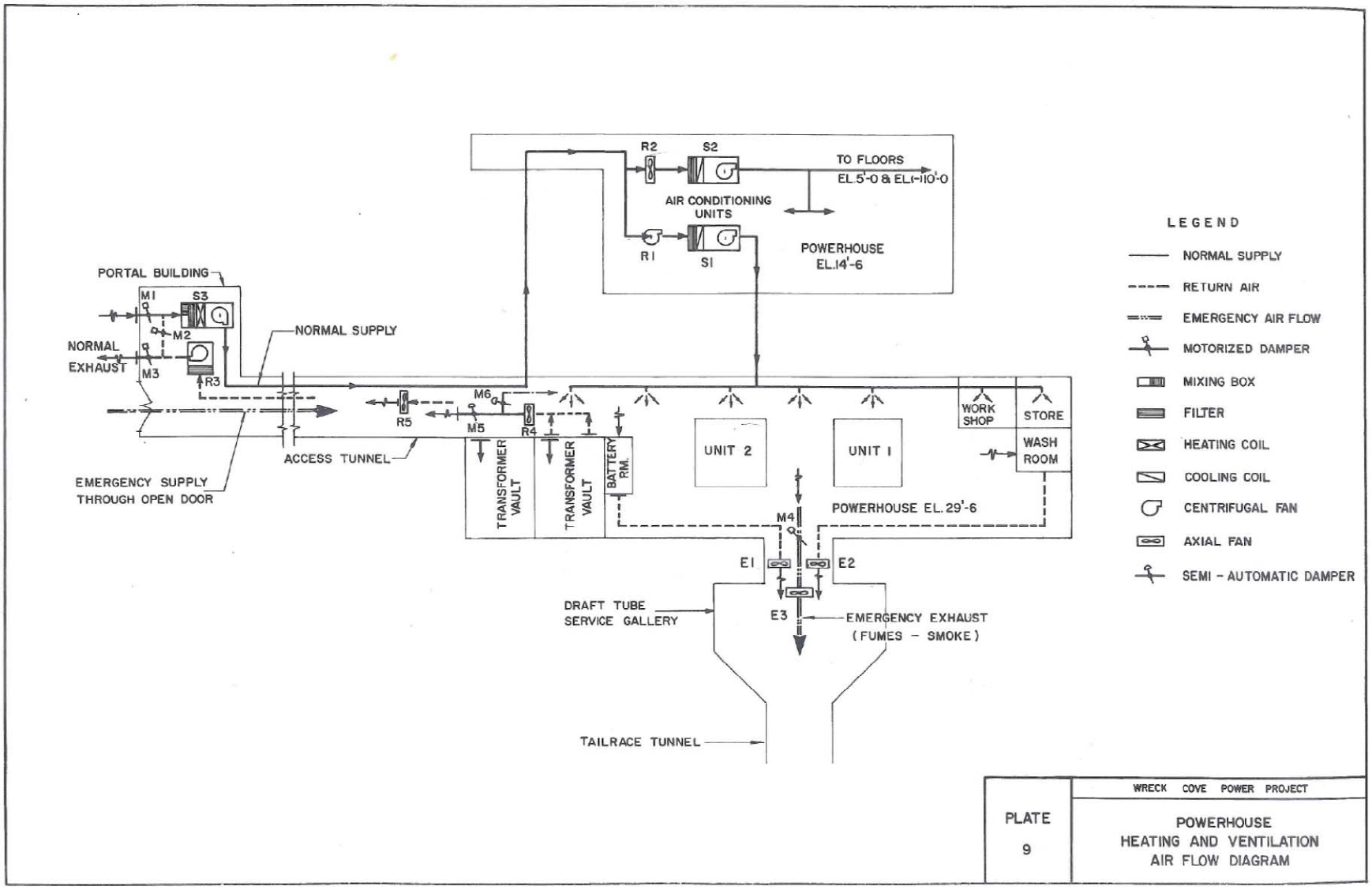


Figure 5.9-1: HVAC Schematic

In overview, the system operates as follows. There is one main supply fan and one return fan in the Portal Building located at the powerhouse access tunnel entrance. The supply fan (S3) draws in a mixture of return air from the powerhouse access tunnel, and fresh outside air, and delivers this mixed air stream via a 864 mm (34 in) diameter spiral steel duct down the access tunnel back to the powerhouse. The air stream is heated as required by an electric heating coil located in the Portal Building before being returned to the powerhouse.

Photo 5.9-1: Supply & Return Air Ductwork Located in Portal Building

The return fan (R3) draws air from the powerhouse up the access tunnel back into the Portal Building where a portion is vented to the outside and the remainder is directed to the inlet side of supply fan S3 for return to the powerhouse.

In winter the outside air is limited to about 1/3 of the air delivered to the powerhouse to limit air heating costs. In summer the outside air is increased to 100% and then the full 600 m^3/min (21,200 cfm) supply air to the powerhouse is available to cool and dehumidify the powerhouse.

Photo 5.9-2: Supply Air Duct to Powerhouse

When the supply air from fan S3 arrives at the powerhouse it is directed to two separate air handling systems. Each includes a return fan (R1 and R2) that mixes some of the S3 supply air with powerhouse return air and circulates it through the powerhouse. One powerhouse ventilation system with fans R1 and S1 ventilates the main powerhouse at El. 29.5 ft. The second ventilation system with fan R2 and S2 ventilates the powerhouse lower levels El. 14.5 ft, El. 5 ft, and El. -10.0 ft.

Each recirculation system also includes a packaged mechanical/refrigeration cooling unit which was intended to cool and to some degree dehumidify the powerhouse area that it serves. These packaged units were cooled using water supplied by the cooling water system, which was then discharged to the tailrace. The two packaged refrigeration units experienced recurring problems and eventually were abandoned, but left in place.

Before powerhouse return air enters the access tunnel on its way back to the Portal Building, one return fan R4 draws a portion of the powerhouse air through the transformer vaults before

discharging into the access tunnel. A second return fan R5 draws air from high level in the main powerhouse and also discharges into the access tunnel.

Photo 5.9-3: Powerhouse and Transformer Vault Exhaust Ductwork to Return Air Tunnel

Outside air brought into the powerhouse by the ventilation system mostly travels back up the access tunnel, through the Portal Building return air fan to the outside. The remainder is discharged to the tailrace service gallery by two small exhaust fans E1 and E2, which draw exhaust air from the battery room and washroom, both located at powerhouse El. 29.5 ft.

In the event of a fire emergency, the normal operation of the HVAC system is shutdown and replaced by a high rate smoke removal system. The Portal outside tunnel access door at grade is opened to allow outside air into the access tunnel. A large emergency exhaust fan E3 located in the tailrace service gallery is started. It then draws outside air down the access tunnel into the powerhouse. The emergency exhaust fan draws powerhouse air and smoke from El. 29.5 ft through automatic damper M-4 located just upstream of fan E3, and discharges into the partially water filled 1.7 km (5,585 ft) long tailrace tunnel and eventually to the outdoors at the tunnel outlet.

Mechanical HVAC Controls

The controls for the HVAC systems and the miscellaneous other auxiliary systems such as cooling water are gathered together in one panel on the main floor of the powerhouse. The HVAC portion of the controls was originally designed and installed by Honeywell and is essentially a pneumatic control system. The remainder of controls are essentially relay based controls and manual on/off switches. Much of the functionality of the systems has deteriorated over the years. Some critical alarms have been relayed to the plant SCADA system. Much of the operations of the original ancillary controls and monitoring has deteriorated over the years and has not been well documented.

Photo 5.9-4: Emergency Smoke Exhaust Fan on Tailrace Deck

Assessment

The assessment is based on information collected from visual inspection of the HVAC system, interviews with plant maintenance and operating staff, review of limited existing drawings and review of the Wreck Cove Risk Assessment Report prepared by Landsvirkjun Power in 2011.

The main ventilation system equipment is all original.

The ventilation system in the Portal Building, including the ductwork, dampers, heating coil and fans are in good condition. No operational issues were noted. Similarly the 864 mm (34 in) supply air duct running down the tunnel is in generally good condition. There are a few areas where tunnel water leakage has caused ductwork corrosion beyond normal.

Similarly ductwork, fans and dampers in the powerhouse are in good condition given their age, and are working well. No significant condition related concerns were noted.

However the cooling units S1 and S2 have had significant operational issues, many related to freon refrigerant leakage. This resulted in high costs for frequent repairs over many years. As a result, they were shut down over 20 years ago and are currently not operational. Currently when space cooling is required, the ventilation system is adjusted to bring in 100% outside air and all return air is exhausted. This would increase outside air brought into the powerhouse for cooling from a normal level of 204 m^3/min (7,200 cfm) to 600 m^3/min (21,200 cfm).

Powerhouse space temperatures in winter are acceptable. However, in summer, temperatures in the powerhouse when maintenance work is being performed, can get uncomfortably warm. To ease the situation, the tailrace service gallery doors were previously opened on occasion, which allowed cool, but moist and salty air into the powerhouse. This air was then drawn up the access tunnel by fan R3, and discharged out at the portal building. This did relieve the excessively warm working conditions somewhat but is no longer permitted due to concerns for corrosion of steel components in the powerhouse. The present practice of having the portal building vehicle door fully open provides some, but not complete relief from the heat. Unfortunately, there are no records of temperatures and humidities in the powerhouse along with outdoor temperatures and humidities.

Photo 5.9-5: Ventilation Air Cooling Compressors at El. 14 ft – 6 in

In the past Nova Scotia Power decided not to replace the existing mechanical space cooling units (S1 and S2) due to high failure rates and repair costs. The estimated loss of cooling capacity is 400 kW. If the units are not to be replaced to improve the space temperature and humidity conditions, then the units should be removed as they are currently contributing to ventilation system pressure drop. Note also that operation of fans S1 and S2 are likely not necessary if the cooling units are removed. With these two units removed, there would be more free floor space, and less electrical energy used to circulate air. Removal of these units would include removal of the associated water cooling piping as well.

The following option could be tried to further reduce warm space temperature conditions in summer and reduce the need to open the tailrace doors to allow cool but moist, salty corrosive air into the powerhouse. Shut down the existing supply and return fans in the portal building, open the access tunnel main door to allow outside air in, and turn on the emergency exhaust fan E3 in the tailrace service gallery and draw maximum outside air for cooling and dehumidification into the powerhouse. Based on the original design figures, this arrangement would draw twice as much outside air (40,000 cfm) into the powerhouse than normal summer

system operation would. It would also provide a higher level of assurance that the emergency exhaust system will actually be able to draw significant air volumes of outside air down the access tunnel and out the tailrace tunnel. This option could allow unauthorized access to the powerhouse, and thus if found to be successful, a perforated type of overhead door would need to be installed at the Portal Building to supplement the existing door.

The lower level (El. -10.0 ft) is experiencing very moist conditions. As a result, mechanical systems, including piping, and valves are rusting at an accelerated rate. A major source of the moisture is from turbine draft tube leakage running across the walls and floor into the drain system. In addition, the piping and valves are moist from condensate as they are not well insulated, the water inside is cold, and the ventilation at this level is inadequate.

According to the original design drawings, outside air that ends up in the lower levels for dehumidification is 22.6 m^3/min (800 cfm), which is cut to 1/3 at the recirculation units S1 and S2 again for a net fresh air during winter of about 8.5 m^3/min (300 cfm). This is an extremely low ventilation rate if this fresh air is to achieve any dehumidification in this area.

The ventilation air that is presently directed down to the El.-10.0 ft level is discharged vertically at a high level (El. 11.0 ft), 6.4 m (21 ft) above the floor level. It appears that with this arrangement, there is little ventilation (dehumidification) air reaching most of this space. An electric heating coil was installed in the duct supplying air to this lower level in an effort to dehumidify this space, but is not effective due to the high air discharge elevation and increased humidity load.

Aside from finding ways to reduce turbine and other water leakage at the El. -10 ft level, suggestions to improve the high humidity situation at this level include the following:

- Insulate as much of the existing cooling water piping at this level as possible, including penstocks.
- **Spring, summer and fall** – Bring the maximum amount of outside air into the powerhouse by opening the portal building vehicle access door to permit air into the station, and then using the emergency smoke removal fan E3 to draw the air through the powerhouse and out

the tailrace tunnel. This may require some changes to the existing control system, or manual operation of certain systems.

- Extend the supply air duct closer to the floor level at El. -10 ft, to discharge not at ceiling level, but nearer to floor level.
- Install ceiling propeller fans to create turbulent air movement in the pump room air at El. -10 ft.
- **Winter** - Provide a 170 m^3/min (6,000 cfm) exhaust fan to draw the somewhat moist air from the El. -10 ft level and exhaust it into the tailrace service gallery. (Normally this 170 m^3/min (6,000 cfm), according to original drawings, would flow up the powerhouse access tunnel to the outside.)
- As for spring, summer and fall operation, use the proposed ceiling fans to create air movement in the pump room El. -10 ft.

The Landsvirkjun Power report also raises concerns as to whether or not the existing smoke removal system will actually work when the need arises (see report pages 26, 33 and 59, item 4). Their concern is that the stack effect of hot air associated with a fire rising up the access tunnel would work against the emergency ventilation fan, and may overpower it. Landsvirkjun Power recommend test operation of the system and a comprehensive review to ensure the system will deliver the design results under emergency conditions.

KGS Group support this concern. Periodically running this emergency exhaust system during normal operation to improve cooling and dehumidification in the powerhouse might be useful in helping insure the system will be effective when required in an emergency.

Also, KGS Group has some concerns that the HVAC system controls are nearing the end of their useful life. Modern digital controls would allow better control and reporting capability. Replace the HVAC system controls with modern digital controls. Estimated cost is $150k. The costs of electrical upgrades to this control system are reflected in the Electrical Assessment section of this report, under Protection and Controls Systems.

Recommendations

- In 2013, install thermometers and hygrometers at several locations in the powerhouse and outdoors and monitor and record the conditions on a weekly basis and more frequently when tests to improve cooling are being performed. The data collected is important to determine the extent of the cooling problem and will assist in devising the optimum solution. The estimated cost is $5k.
- No major replacement is foreseen over the next 30 years on the supply and exhaust fans in the portal building mechanical room. However, due to the criticality of these fans and dampers, a set of spare bearings, drive belts and drive motors for each fan and a replacement set of motorized dampers and motors should be acquired by 2014 at an estimated cost of $56k.
- Adjust the ventilation system operation in summer to operate the emergency smoke removal system to maximize the amount of outside air brought into the powerhouse for cooling and dehumidification. Monitor temperatures and humidity levels in the powerhouse to check effectiveness. If the operation of the emergency smoke removal fan is unacceptable due to high noise levels, adjust the intake damper M1 in the portal building to full open, close damper M2. Monitor temperatures and humidity levels in the powerhouse to check effectiveness. These two tests should help establish whether mechanical cooling needs to be reinstated.
- Bring El. -10 ft supply air ductwork down closer to floor level and provide propeller fans for the El. -10.0 ft level to improve dehumidification and reduce rusting of piping and equipment. Estimated cost $15k.
- Pending successful results of the summer ventilation tests, remove the mechanical cooling units S1 and S2, and related cooling water piping. If the test fails, replacement of the mechanical cooling units would be required. Estimated cost for either solution is $150k.
- Whether the abandoned mechanical cooling system is to be revived or removed, remove the poor condition fibreglass insulation and re-route the ductwork located downstream of air handling units S1 and S2. This section of ductwork obstructs the hatchway when major work is performed on the turbine generators. Estimated cost is $10k.
- Add insulation to cold water piping and the penstocks at the El. -10.0 ft level. The cost is in the cooling water piping system replacement.

5.10 COMPRESSED AIR SYSTEMS

Description

There are two compressed air systems, both located in the powerhouse on floor El. 14.5 ft. The high pressure system provides 2068 kPa (300 psi) air to the turbine governor oil pressure system. A second low pressure compressed air system provides service air at 689 kPa (100 psi) to plant services, generator brakes, turbine shaft maintenance seals, and turbine grease pumps.

The governor air system consists of two 7.5 kW (10 hp), 0.6 m^3/min (20.9 scfm) Atlantic Compressed Air Ltd. reciprocating air compressors, complete with intercoolers and aftercoolers, and a 0.85 cubic metre (30 cubic foot) air receiver (Tank A). They operate to top up the governor air tanks weekly (manually performed), and typically run for about 5 minutes per week. These compressors were replaced about 2007.

Photo 5.10-1: High Pressure Air Compressors

The service air system consists of a single 2.8 m^3/min (100 scfm), 30 kW (40 hp) Sulair air compressor (new in 2009), which includes an aftercooler and two air receivers. The 2.55 cubic

metre (90 cubic foot) air receiver (tank C) is intended for service air and cooling water system control valves. The service air system supplies various control valves and service air hoses located on floors El. 29.5 ft, El. 14.4 ft, El. 5 ft, and El. -10 ft. The smaller receiver (tank B) is reserved for the generator brake air. All compressors are serviced by Atlantic Compressors Ltd.

Photo 5.10-2: Low Pressure Compressor

Photo 5.10-3: Compressed Air Receivers (Left to Right A, B & C)

The high pressure governor compressed air system is linked by a cross connection and a pressure reducing valve to the generator brake air system. This normally closed cross connection provides backup air to the brake system if service air is not available.

Both high and low pressure piping systems are galvanized steel with screwed fittings.

Assessment

The assessment is based on information collected from visual inspection of the compressed air system and interviews with plant maintenance staff.

The two high pressure reciprocating compressors are new and in very good condition. The service air compressor is 3 years old and also in very good condition.

The receiver tanks were certified by the Nova Scotia Department of Labour in 2009.

Piping in both high and low pressure systems was randomly visually inspected and is in good condition.

The service air system refrigerated air dryer has not been working for some time and should be replaced.

On the service air system, a control valve actuator pilot valve was venting compressed air continuously. Service air piping has not been checked for leaks for some time.

On the piping system, the site staff noted the following items related to an upgrade on the piping system functionality:

1. Piping around the receiver tanks should be reworked to permit each receiver tank to be individually isolated while permitting the remaining tanks to stay operational. This would assist in periodic relief valve testing activities.
2. Currently the service air refrigerated air dryer (which is not working) only addresses the control valve compressed air, and not the shop air and generator brake system. It was noted that in the powerhouse lower levels, air tools often contained significant moisture. Piping should be revised to pass air for these services through the refrigerated air dryer as well.

Recommendations

- Inspect the service air system for leaks and repair as required
- To upgrade the functionality and reliability of the service air system, while simplifying maintenance, redesign the compressed air piping to allow individual tank isolation and replace the service air refrigerated dryer. Estimated cost is $20k and the work should be carried out within 3 years.
- In 2013, install a timed blow down valve on the compressed air storage tanks which supply the governor and power tools ($10k).
- In 2013, install an automatic air make up system for the governor accumulator tanks ($15k per unit).

5.11 FIRE PROTECTION AND DETECTION SYSTEM

Description

Components which make up the fire protection systems for the Wreck Cove GS site include four automatic deluge systems (two for the unit transformers and two for the generators), a fire detection and alarm system and fire extinguishers and hose cabinets in the powerhouse.

Mechanical

Water for the fire protection system is obtained from two wells located behind the Quonset building. The pumps are 4 kW (5 hp) each and each can deliver an estimated 151 L/min (40 USgpm). The pumps are used to keep two 113,560 L (30,000 US gallon) steel storage tanks located adjacent to the Portal Building full, to provide the station with the water required for a fire emergency. The pumps start and stop automatically based on level sensors in the storage tanks. The storage tanks are covered with soil and are not visible.

Photo 5.11-1: Fire Protection Well No. 1

Photo 5.11-2: Fire Protection Well No. 2

From the storage tanks, water is carried via an 203 mm (8 in) steel pipe down the 561 m (1842 ft) long access tunnel into the powerhouse. In the powerhouse the fire protection water services the generator and transformer deluge systems. Additional photos of the fire protection water piping systems are included in Appendix 1B.

Additional fire protection systems in the access tunnel and powerhouse include dry chemical type 4.5 kg (10 lb) class ABC fire extinguishers. They are UC rated 4A-30BC complete with nozzle, shut-off valves, pressurized cartridges and pressure gauge.

There are also fire hose stations equipped with 38 mm (1.5 in) Lexan electric fog nozzles and complete with 23.9 m (75 ft) of 38 mm (1.5 in) hose. They are located along the west side of the generator floor level and on the south side of the generator enclosures at the turbine floor level, as well as along the west side of the access tunnel.

Photo 5.11-3: Typical Powerhouse Fire Hose Station and Extinguisher

Each of the two generators has an automatic deluge system which consists of two deluge sprinkler rings with nozzles. One ring is mounted above the stator and one below. Water is

admitted to the deluge system by a solenoid valve which is activated by a local deluge control panel. (The triggers for the deluge control panel are a smoke detector and the generator differential trip signal which must be activated in combination).

Each of the two power transformers has an automatic deluge system consisting of a sprinkler loop located around the top of the transformer and above the oil reservoir. Water is admitted to the deluge system by a solenoid valve which is activated via a control panel by a temperature sensitive detector. A timer controls the duration of the deluge to about 5 minutes. If the temperature sensor indicates the temperature is still high, the deluge will be restarted.

The water flow requirement of the fire protection system is as follows:

1. Fire hoses – 379 L/min (100 USgpm) each;
2. Generator deluge at 345 to 380 kPa (50 to 60 psi) – 946 L/min (250 USgpm) per unit;
3. Transformer deluge at 345 to 380 kPa (50 to 60 psi) – 1552 L/min (410 USgpm) per unit.

The deluge systems are tested annually, with measures to divert water so as not to wet the generators.

In addition, the fire protection system described above is supplemented by an underground life support refuge gallery. The gallery had been sealed at both ends as intended, but has deteriorated and is no longer a suitable refuge area. See Section 4.8 Powerhouse, which deals in more detail with Powerhouse Life Safety matters.

The powerhouse also has a smoke detection system, and provisions in the powerhouse ventilation system for the emergency supply of fresh outside air and exhaust of smoke and fumes out through the tailrace tunnel. The smoke exhaust system is described in more detail in the Heating, Ventilation and Air Conditioning section of this report.

The local fire department is a volunteer organization (the North Shore Volunteer Fire Department) and has no specific training related to Wreck Cove fire fighting.

Electrical Components

The main electrical components which relate to fire protection are the controls and the main fire alarm panel.

The two generator deluge systems each have new Siemens Fire Alarm Control panels installed (Photo 5.11-4) to control the operation of the deluge system. These control panels are connected to the unit protections to monitor the status of the generator and verify that the unit has tripped if there is to be water sprayed on the units.

Photo 5.11-4: Generator Deluge Control Panel

The generator deluge systems are configured with Siemens smoke detectors (Photo 5.11-5) located within the generator enclosures. The systems are programmed so that if there is smoke detected within the enclosure and the unit has tripped offline from a differential protection trip, then the generator deluge system will operate. The generator deluge is limited in the amount of time that it will be operating.

Photo 5.11-5: Generator Deluge Smoke Detector

The generator deluge systems report back to the plant SCADA system as to the status of the fire protection.

The deluge control panels (Photo 5.11-6) for the transformers are the original control panels which have had some maintenance repairs over time, but are essentially original.

Photo 5.11-6: Transformer Deluge Control Panels

The transformer deluge is controlled via pneumatic heat detectors which trigger a pressure switch to initiate transformer deluge. These then trigger electrical solenoids which provide pilot water to the transformer deluge valves. There is no de-energizing of the transformers as a pre-condition for deluge operation.

The valves for this system are electrically held and fail to the open position.

The main fire alarm panel is an older Edwards conventional zone panel. There are a limited number of heat detection devices, smoke detectors in critical areas and pull stations around the powerhouse which will trigger a plant alarm. This alarm will trigger plant evacuation as well as initiate the smoke evacuation system portion of the HVAC system.

In order to indicate that there is a plant fire, there are bells throughout the plant to indicate the presence of fire.

Assessment

The assessment is based on information collected from visual inspection of the fire protection system, interviews with plant maintenance and operating staff, and a review of the Wreck Cove Risk Assessment Report dated 2011. In general, the fire protection systems are for asset protection rather than for life safety. The systems in place are typical for generating stations of this significance, but as noted below improvements are recommended along with replacement of key components.

Mechanical

The fire protection system wells, water storage tanks and piping down to the powerhouse are original equipment and therefore 35 years old. The water level in the tanks is checked manually on a weekly basis, but the supply pumps are not monitored for hours of operation, and are not periodically tested. It is not certain that both pumps are in good working order. To the knowledge of plant personnel, the pumps have never been overhauled. There are no indications that water is being lost from the system, that is, level checks do not seem to indicate that the

tanks are leaking. However given their age and the fact they cannot be easily inspected, it is prudent to check their condition.

There does not appear to be a recent study indicating how the station conforms to NFPA 851, Recommended Practice for Fire Protection for Hydroelectric Generating Stations - 2005. Neither is there a report from the insurer indicating any current concerns with the system as it is. However the Risk Assessment Report prepared by Landsvirkjun Power in May 2011 identifies that NFPA 851 recommends that the water storage capacity should be 568,000 L (150,000 US gal), instead of the current 227,000 L (60,000 US gal).

The transformer deluge system was inadvertently triggered about 10 years ago and at that time the system worked.

Electrical

The Siemens deluge control panels which have been installed for the generators are new (within one year), appropriate for the task and in good condition.

Typically on larger capacity hydro turbines (such as those at Wreck Cove GS), there would be some additional redundancies/ features built into the deluge system. Those of note are:

1. An additional interlock from the unit protections to ensure that the unit is absolutely offline.
2. A parallel deluge valve to ensure that at least one valve operates when the system is required to discharge.
3. Formally monitored sprinkler valves for the system to ensure that no valves which should be closed or open can be left in the improper state without triggering supervisory alarms.

The deluge systems are also not tied into the plant fire alarm system to trigger evacuation of the plant in case of fire.

The transformer deluge systems are reaching the end of their useful life and have shown signs of deterioration. An overheated solenoid has already caused a fire within one of the panels.

Photo 5.11-7: Transformer Deluge Control Showing Indications of Internal Fire

As a final item, the Edwards fire alarm system has reached the end of its useful life. While appropriate for the era in which it was designed, fire alarm systems from this time have the following issues:

1. Parts are no longer readily available or reliable.
2. Typically the audibility is poor, and given the requirement in many areas of the plant for hearing protection, the lack of visible alarms would likely result in no indication to the powerhouse occupants.
3. There is no proper enunciator at the Portal Building, which means that there is a requirement to get all the way to the fire prior to understanding the fire condition of the powerhouse.
4. There is no general alarm when there is a flow related to a fire hose.

Adding to the complexity of the operation of the Wreck Cove GS, is the single path of egress and generally poor exiting guidance. While not a replacement for additional exits, the addition of Early Warning Smoke detection systems is often used in facilities where exiting can be

difficult or damage to assets can be significant. This option should be reviewed for the Wreck Cove GS.

Recommendations

Mechanical

- To establish their remaining life, arrange for inspection and wall thickness testing of the existing tanks and related piping from the well pumps to the storage tanks and also the piping and valves from the storage tanks into the powerhouse and to the generator and transformer fire protection systems. Based on the results of this testing, a plan for remedial work can be developed. Estimated investigation cost is $20k in 2013.
- Address the current shortfall in the required water storage capacity. Current total storage capacity in the two tanks is 227,000 L (60,000 US gallons) versus an NFPA 851 requirement for 568,000 L (150,000 US gallons). Perform a study to investigate alternatives before implementing. Estimated cost to investigate the work described is $40k.
- The two water supply wells should have vegetation removed from the immediate vicinity and fence post markers with identification tags placed to clearly identify the well locations. Estimated cost $2k.
- Confirm that both well pumps are capable of operation and are in good working order. This can be achieved by flushing the fire protection supply line to the powerhouse with a flow rate not less than the transformer deluge capacity of 1552 L/min (410 USgpm), which will also remove any loose corrosion particulate matter from the supply line. Repeat this flush every two years.

Electrical

- The generator and transformer deluge systems should be tied to the station fire alarm system to ensure that there is proper evacuation in the case of a fire. The estimated cost is $10k and this work should be completed by 2014 or before major refurbishment work in the powerhouse is begun.
- The transformer deluge control panels should be replaced with modern systems, at an estimated cost of $40k, and should be completed within the next 2 years
- The main plant fire alarm system should be replaced. This should include:
    - A system with new audible devices, including the addition of strobe indication.

- A proper enunciator installed in an area where a fire can be safely responded to.
- Some review of early detection and more detailed annunciation that could be used in areas of refuge. This is further addressed in the report section called Issues and Opportunities.

The estimated cost is $550k and the work should be completed within the next 2 years and before major work in the powerhouse begins.

5.12 SUMP SYSTEMS (DRAINAGE AND DEWATERING)

Description

The powerhouse has both a general drainage system and a dewatering system that is used to empty the turbine water passages below the tailrace water level, when required for turbine inspection and maintenance. Both systems pump to the tailrace.

The powerhouse drainage system has a 13,250 L (3,500 US gallon) sump. It collects water from various drains and all groundwater leakage into the powerhouse. This sump has two drainage pumps P4 and P5. P4 is a non-clog sump pump, and P5 is a self priming sump pump. They each have a capacity of 1325 L/min (350 USgpm) at 27.4 m (90 ft) head and are float controlled.

The drainage sump has a check valve protected overflow that discharges excess flow into the adjacent dewatering sump where the two dewatering pumps are available to assist with additional pumping capacity if required. The drainage sump does not have any oil containment or removal systems.

Photo 5.12-1: Drainage Sump Pumps P5 at Left & P4 at Right

Note that the transformer vault drains, which are intended primarily for the fire protection deluge system, discharge directly to the tailrace and not to the drainage sump. In the event of a major transformer oil spill due to a tank rupture, how much of the oil would remain in the transformer room is not known, as there is only a plumbing-type inverted trap system to retain an oil-over-water situation.

None of the major oil containing equipment is provided with secondary oil containment. This includes the governor accumulator tanks, governor sump tanks, and turbine shutoff valves accumulator tanks and the valve operating cylinders. The oil storage area includes a plastic type secondary containment, but it is inadequate for the volumes of oil stored during major work and therefore oil drums are placed outside the containment. The headcover of the turbines, where governor oil, or generator or turbine bearing oil might spill to, drains by gravity to the station sump, which has no provision for oil recovery.

Photo 5-12-2: Pressure Unit with No Secondary Containment

Photo 5-12-3: Accumulator Tanks with No Secondary Containment

Photo 5-12-3: Oil Storage Exceeds Secondary Containment Area

The draft tube dewatering sump has a capacity of 18,900 L (5,000 US gallons) and is connected to the draft tubes by two 203 mm (8 in) pipes. It has two vertical turbine style pumps, a 30 kW (40 hp) unit with a capacity of 3785 L/min (1,000 USgpm) at 27.4 m (90 ft) head (P2), and a 15 kW (20 hp) unit with 1325 L/min (350 USgpm) capacity at 27.4 m (90 ft) head (P1). A float level control system is used to start and stop the pumps.

Photo 5.12-4: Dewatering Sump Pumps P1 & P2

Assessment

The assessment is based on information collected from visual inspection of the dewatering system, interviews with plant maintenance staff, and review of equipment literature.

Both drainage system sump pumps P4 and P5 were replaced in the fall of 2011. P5 is in very good condition. However pump P4 ran dry because the floats did not shut the pump down. As a result P4 has a high vibration level. Current plans are to replace this pump and keep refurbish the existing damaged pump to serve as a backup.

On the dewatering system, the more frequently used smaller pump P1 was replaced in October 2011 (the existing pump motor was reused).

The larger pump P2 is original from 1977. It is now drawing low amperage suggesting that its impeller may be worn. In addition, its upper bearing is making noise and needs to be replaced. Since P2 represents 74% of the total dewatering sump pumping capacity, it should be replaced or repaired soon.

The consequences of P2 at 3785 L/min (1,000 USgpm) capacity failing are that:

- it would take longer to dewater the draft tube and related systems with only P1 at 1325 L/min (350 USgpm) capacity in operation
- in the event of a leak such as occurred with the spherical valve trunnion seal, the powerhouse could flood, and
- in some cases, an inadequate pumping capacity can hinder achieving a seal on the draft tube gates, extending the isolation time.

Also should P2 fail when needed, the extended generator outage time would add significantly to the real cost of an unplanned pump replacement.

The pump discharge piping for both systems (some of which is visible and some of which is in concrete), should be ultrasonically inspected to check their condition and to assist in establishing when replacement is required. This piping system should be retained until it demonstrates it is no longer able to carry the flow being pumped, or it begins to leak.

Secondary oil containment should be provided around floor mounted equipment which contain stored oil, to intercept any leakage before it goes to the station sump or the tailrace. The oil storage area secondary containment should be sized to accommodate the peak oil volumes kept on site during turbine generator maintenance, while any infrequently used lubricants should be moved out of the powerhouse.

The drainage sump systems should be provided with an oil detection and oil skimmer system with alarm and interlock control to prevent pumping below a set level (oil-water interface) if oil is detected. Care must be taken to ensure the design would not flood the El. -10 ft floor.

Recommendations

- Replace pump P4. This work was completed in late 2012.
- Replace or rebuild dewatering pump P2 in 2013. Replacement cost is estimated to be $3k.
- Take representative thickness tests on the pump discharge piping to obtain a general indication of its thickness and an indication as to its remaining life. Based on the results of this testing, determine if piping replacement is warranted. Estimated study cost is $10k.
- By 2014 provide secondary oil containment around floor mounted equipment containing oil and match the size of the containment area for the level of stored oil needed during turbine generator maintenance. Remove any infrequently used lubricants outside of the powerhouse. Estimated cost is $30k.
- By 2014 install an oil detection and skimmer system with alarm and pump interlock control on the station sump at an estimated cost of $25k.
- Carry out a study on the routing of all plant and equipment drains to determine which drain directly to the tailrace. Determine what action, if any, is required to avoid or capture potential spills. Study cost is $40k and it should be completed by 2013.

5.13 DOMESTIC WATER AND WASTEWATER SYSTEM

Description

Water for domestic use in the powerhouse is obtained from the fire protection system. The water was originally drawn from the fire protection tanks and travelled via a 50 mm (2 in) steel

pipe down the access tunnel to the powerhouse. This 50 mm piping was abandoned and the domestic water is now connected to the fire protection supply pipe, near where it enters the powerhouse. There is no connection to the domestic water well, which supplies only the administration building.

Where the access tunnel connects to the powerhouse, the water passes through a pressure reducing station and is stored in a 136 L (36 US gallon) galvanized steel storage tank. Inside the powerhouse, the domestic water piping is generally copper.

The system has no treatment facility and supplies water to the following fixtures or applications:

1. Service sink
2. Water closet
3. Urinal
4. Hot water tank
5. Hose connections in the powerhouse.

The hose connections are used for general washing including floors and vehicles.

Photo 5.13-1: Urinal and Water Closet

This system is not potable and is not used for drinking water; which is provided by bottled water.

Wastewater from the various plumbing fixtures drains via PVC piping to a fibreglass holding tank installed in 1997/98 in the powerhouse lower level. This tank is pumped out by truck 2 to 3 times a year.

Photo 5.13-2: Fibreglass Sewage Holding Tank

Assessment

The assessment is based on information collected from visual inspection of the systems and interviews with plant maintenance staff.

The copper piping is original and has received little attention since being installed. Not critical to station operation, it could be run as long as possible to get maximum value from the existing system.

Concerns with this system were not noted. It appears to be working well. It may be best to continue using the system as is and making repairs to the system when the need arises.

The wastewater piping system is original, in good condition, and not in need of attention. The fibreglass tank is relatively new and should last another 30 years.

Monitor the system and repair components as the need arises. Replace the plumbing fixtures and system components such as the well pump, hot water tank, or sink faucets as required.

Recommendations

No recommendations

5.14 SURGE LAKE DRAIN VALVES

Description

Embedded in the Dam D11-2 on the south side of Surge Lake is a drain pipe terminating in two valves, which is designed to permit the lowering of Surge Lake water level below the bottom of the penstock inlet structure, if necessary. The valve arrangement consists of two butterfly valves in series, with the downstream valve controlling flow and the upstream being normally fully open. The arrangement is similar to that located at dam D4, where the valves control the riparian outflow from Gisborne Lake.

On July 25, 2012, a major leak at dam D4 was detected. After investigation, the leak was determined to be caused by the downstream butterfly valve disc, which had become loose on its stem. The loose disc was able to quickly turn on its stem and closed suddenly due to imbalanced upstream downstream forces. This created a water hammer effect which ruptured the pipe flanges and the valve body of the upstream valve, resulting in an increased release of water downstream. Owing to the lack of accurate as-built drawings, significant difficulty was encountered in safely stopping the flow, which was eventually achieved by plugging the pipe at the inlet end.

Assessment

The piping and valve system at the toe of the Surge Lake Dam D11-2 is believed to be of a very similar design, except for pipe and valve diameter, to that of Dam D4. Although the valves are the same age, the service is different and the exposure to vibration caused by throttling is much

less. However, the valves have not been removed and inspected in detail since installation, and may be suffering from corrosion at the disc/stem connection.

As the condition of the valve disc/stem bolting cannot be checked without removing the valve from the piping, a check should be performed and a new valve installed or the existing one repaired.

Recommendations

- Remove both valves of the Surge Lake drain piping and inspect for disc to stem bolting damage and security. Plan to repair or replace the valves, depending on the findings. This work should be carried out by 2014 and is estimated to cost $20k, assuming only some minimal difficulty in closing off the pipe inlet, so that both valves can be checked.

Photo 5.14-1 Surge Lake Drain Pipe Inlet

6 ELECTRICAL CONDITION ASSESSMENT

GENERAL

The following components were included in the electrical condition assessment:

- Generators (Electrical)
- Excitation Systems
- Isolated Phase Bus Duct
- Excitation Transformer
- AC Station Service System, including:
  - Station Service Transformers
  - Auxiliary Service Transformers
  - AC Switchgear
  - Auto Transfer Control
  - MCC's and Panel Boards
  - Cable and Bus
  - Standby Diesel Generator
- Protection and Controls Systems
- Station DC Power System
- Station Grounding System
- Station Lighting System

A general description, condition assessment, and recommendations follow for each of the above components.

The assessment of the following systems' electrical supply and controls are included in the Mechanical Assessment section of this report:

- Tunnel T-2 Intake Gate
- Heating, Ventilation and Air Conditioning
- Fire Protection

The following components at Wreck Cove were not in the scope of the assessment:

- Main Output Transformers

- High Voltage Conductors to Switchyard
- Switchyard

6.1 GENERATORS (ELECTRICAL)

Description

Wreck Cove Generating Station contains two vertical shaft, umbrella type, synchronous generators manufactured by Canadian General Electric (CGE) Company in 1976. These units have a guide bearing above the rotor and a combined thrust and guide bearing located below the rotor. Each unit is recessed into a concrete housing.

The generators are nameplate rated for 111 MVA, 13.8 kV, 4,648 A, 450 rpm, and 90°C temperature rise with a maximum design over speed of 780 rpm. The nameplate overload capacity is 116 MVA. As Wreck Cove has been operated as a peaking power plant, these generators have very rarely operated at their nominal rating.

The generator rotor is a fabricated assembly consisting of a hub, a spider, a built-up rim fitted with field poles and a brake ring on the underside. The rim is piled in two sections which are clamped vertically by through studs and are keyed to the spider by dovetail keys. The Wreck Cove generator rim is a floating rim design.

The field winding includes 16 interconnected field poles. Each of the field poles around the circumference of the rim are mounted with dovetails locked in place in the rim by sixteen tapered pole keys driven in at assembly.

The stator assembly was manufactured in two sections and is supported on the foundation at eight equally spaced points around the periphery of the frame on sole plates grouted into the concrete. Radial keys on the sole plates permit the radial freedom necessary for the thermal expansion and contraction of the frame.

The stator winding consists of single turn Roebel bars with two parallel circuits per phase. Packing and tight wedges restrain the bars throughout the length of the slot. The bars are

formed of several conductors in parallel, arranged to form a rectangular cross-section. Each conductor is insulated with polyester glass. The formed rectangular bar is wound with ground insulation consisting of epoxy impregnated mica paper tape which is heat cured and then covered with a glass tape saturated with conductive paint and an outer coating of conducting room temperature vulcanizing (CRTV) silicone rubber.

Generator cooling is provided by four finned air-to-water heat exchangers located within the generator housing, through which the air of the machine is passed and then re circulated.

After investigation of the available records at site the following historical significant activities were recorded for Unit 2:

- 1994 - Air Gap measurements on Unit 2. The results of this measurement were not available in the files.
- 1996 – During this annual shutdown which occurred in September, a significant amount of work was performed on Unit 2 including:
  - Inspection of the wedging of the stator winding bars and new wedges were installed in the stator slots at the splits.
  - Verification of the rotor winding insulation condition and torque level at the DC bus jumpers
  - Verification of the rotor pole wedges and tightness
  - Replacement of short brushes on the slip rings
  - Visual inspection of ring bus jumpers, pole caps and coupling capacitors for damage to epoxy
  - Modification of the mounting system for the fibreglass cover for the generator neutral connections.
  - Measurements of the stator to rotor air gap. No measurement data is available on file.
  - Electrical tests on the stator and rotor. However, no measurement data is available on file.
- 2011 – During this outage some electrical tests were performed on the generator such as dielectric test and a polarization index test. The generator rotor was also tested for rotor impedance and capacitance. All test results indicated the rotor and stator were in good condition electrically.

No similar chronology for historical significant activities could be compiled for Unit 1.

Assessment

Assessment of the condition of the generators is mainly based on visual inspection, review of test records, review of the inspection report provided by Power Engineering Company and interviews with the plant maintenance staff. Inspection of the components involved identification of visual evidence of looseness, overheating, electrical deterioration, mechanical damage, dusting, fretting corrosion and other conditions that could lead to more extensive problems.

The records of electrical tests performed during the outage September 2012 Unit 2 were also reviewed as a part of the assessment.

At the time of the Unit 1 assessment in November 2012, the rotor of Unit 1 was already out for detail inspection by Nova Scotia Power. As both units at Wreck Cove GS are identical, most of the electrical issues are identical in nature.

The details of the assessment are outlined below.

Stator Winding – Unit 2

At the time of the KGS Group inspection the generator rotor was in position so it was not possible to view the entire circumference of the stator windings. Visual inspection of the generator stator revealed evidence of extensive oil contamination within the generator housing. Although the review of the generator test report from the 2011 outage does not indicate any noticeable insulation degradation of the stator winding, long term contamination by oil can lead to a decrease in reliability by several means:

- Stator contamination can foster electrical tracking which can lead to phase to ground and phase to phase faults.
- Oil based contamination can leach into the core and cause inter-laminar looseness and, in some cases, inter-laminar abrasion. Loss of inter-laminar insulation can cause core hot spots which accelerate stator winding aging.

- Stator winding contamination in the end winding area can produce alternative electrical conduction paths between the end-winding and ground.
- Oil on the winding can increase the risk of fire.

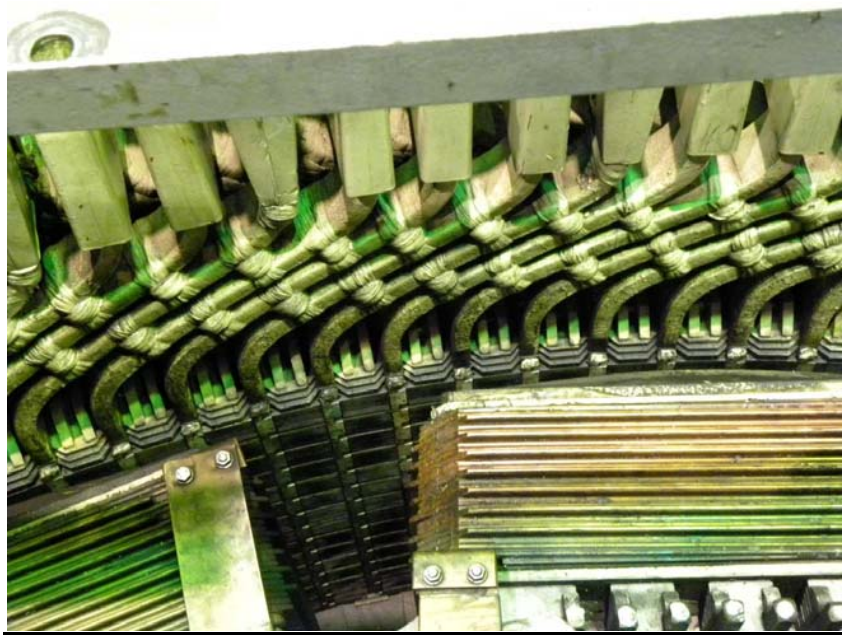


Photo 6.1-1: Evidence of Oil Contamination within the Stator Winding

With the amount of oil and dust contamination present, it was not possible to see any white powder which is evidence of partial discharge activity and no previous partial discharge test records were available with the maintenance records. Interviews with the maintenance staff revealed that there was provision for online partial discharge measurement in the past but this system has not been functional for several years and has been mostly removed.

Photo 6.1-2: Provisions for Partial Discharge Probes

Based on our initial discussions there were no signs that there were loose, broken or cracked slot wedges. Follow up conversation revealed that there were some loose elements found within the generator and the Power Engineering report reveals there are loose wedges in various slot locations and at the stator splits. These loose elements are a concern.

A visual inspection of the stator windings with the rotor in place showed no evidence of unusual conditions. Items reviewed were the migration of the fillers, indication of overheating, partial discharge activity or any mechanical damage.

Later when the rotor was removed for the Power Engineering inspection it became evident that repacking of the stator core splits is required. As a consequence some degree of winding replacement will be required at the core splits.

Visual inspection of the end winding area did not reveal any concerns. There is no evidence of erosion, overheating, partial discharge activity or corona activity at the end winding area except for a few scratches from assembly and dismantling of the top shrouds.

Photo 6.1-3: Scratches on the End Windings

Photo 6.1-4: Top of Stator Windings

From the dielectric test results performed on 31st August 2012 if was observed that the Polarization Index (P.I.) was above 2.5. As per IEEE 43, this P.I. value is within the acceptable range. It is important to note that this value was achieved with heavy surface contamination. Even though the stator winding condition is not poor, considering the age of the generator it may be prudent to plan for re-winding of the stator within the next five years. This would extend the electrical life of this unit by 20 to 30 years.

As a part of the life extension and modernization of Wreck Cove GS, it is recommended that a rewinding program be initiated. The scheduling of the rewinding process will depend on the results of the other evaluating tests such as partial discharge tests, DC hipot tests done at reduced voltage and off-line corona probe tests.

Given the age of the stator winding (35 years) it very difficult to predict the number of years this unit will operate reliably without rewinding. To avoid a lengthy forced outage due to winding failure, it is prudent to re-wind by the year 2017.

Stator Frame and Core – Unit 2

The stator frame is fabricated of steel plate. Visual inspection revealed no noted cracks, broken welds or distortion in the structure and no unusual water leakage was observed from the cooler tubes or cooler piping. The stator frame uses separate sole plates for anchoring to the foundation. Radial keys are incorporated not only to resist torque but also to allow thermal

expansion and contraction of the stator. Visually no abnormality was observed in these components.

Visual inspection of the stator core was limited by excessive amounts of oil and dust residue on the core surfaces. From our preliminary inspection no unusual core waviness was observed; however, the Power Engineering inspection with the rotor removed detected core waviness near the stator core splits. There is migration of insulation of the core split packing which is a factor and contributed to the stator profile out of tolerance. The migrated core packing may have been dissolved by continuous exposure to lubricating oil mixture. It is uncertain whether there are any hot spots within the stator core. The temperature records obtained from site do not indicate any issues with core hot spots.

Even though this situation does not pose an immediate risk for operation, it is recommended to perform a detailed assessment of the stator core as soon as possible, ideally at the 2013 outage, and at the same time the following tests on the stator core should be performed:

- Through check of the core tightness
- Stator Core Loop Test
- ELCID Test

These tests are recommended to determine whether there are any underlying hot spots within the stator core and to better understand the condition of the inter-laminar insulation.

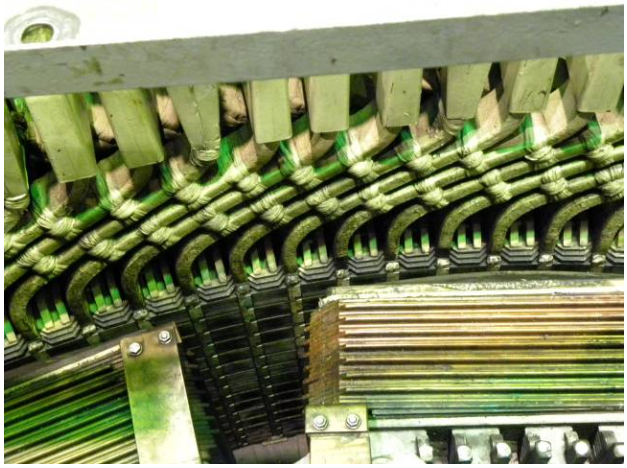


Photo 6.1-6: Stator Core

Photo 6.1-7: Stator Frame and Core

Rotor – Unit 2

The rotor condition assessment is subdivided into:

- Rotor coils, poles and damper winding
- Collector and brush assembly.

The following items were inspected visually on the rotor coils and poles where accessible. With the rotor in the machine, these items are essentially a spot check:

- Evidence of dusting or erosion
- Improper locking or looseness in field coil braces and their hardware
- Insulation fretting, cracks or breaks
- Evidence of overheating
- Moisture, oil, dirt or other contamination
- Mechanical damage of any kind
- Looseness or fretting in the dovetail key assembly.

The damper windings of these units were not visible for inspection as these are closely integrated with the construction of the poles.

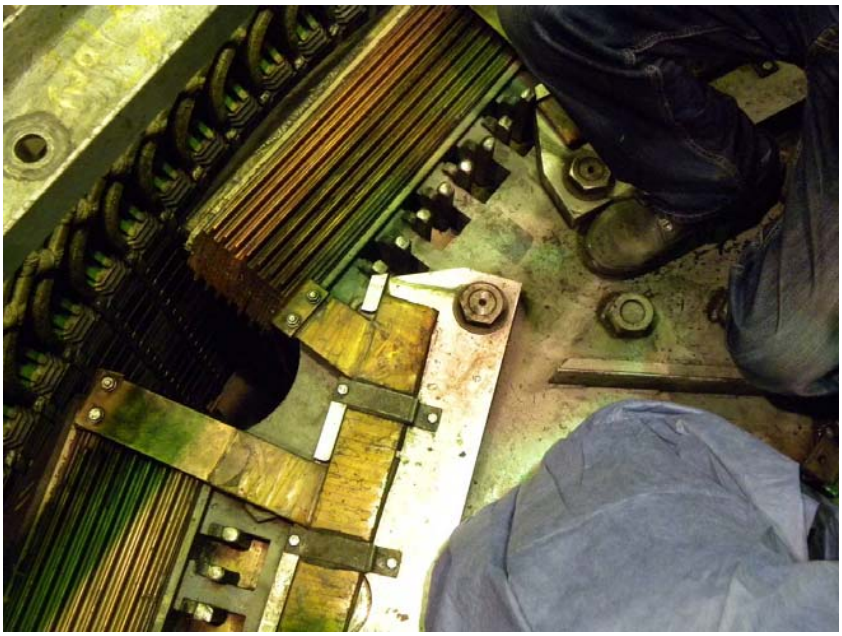


Photo 6.1-11: Rotor Poles

While there are no immediate major issues which were visually observed, during this inspection for the above items, an ongoing deficiency was identified in the form of a recurring generator field ground problem. At the time of the inspection the maintenance staff was working to rectify the generator field ground issue.

Subsequent to KGS's inspection, Nova Scotia Power performed additional assessments on the field poles and noted that there was looseness or fretting in the dovetail keys and the field coil braces were found extremely loose. Nova Scotia Power has indicated that a detailed review and corrective measure of these issues are underway.

The generator field copper bars are routed through a vertical shaft section from the slip ring housing and then connect with the main rotor leads. The picture below shows the mechanical arrangement of the rotor field connections, where it can be seen that the copper bars and their associated joints are insulated with mica tape.

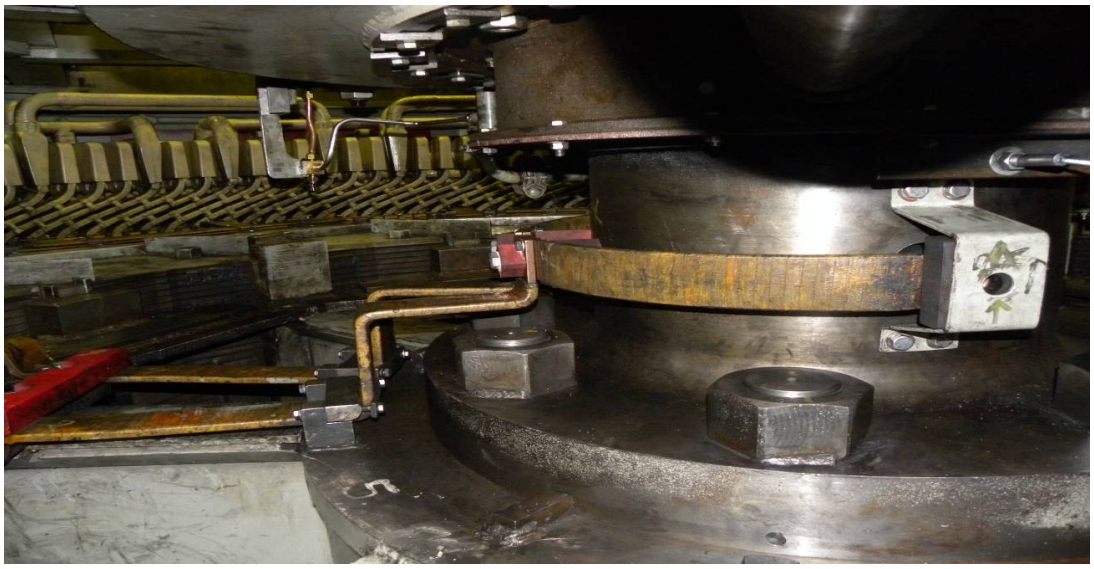


Photo 6.1-12: Arrangement of Generator Rotor Leads

This configuration can allow carbon dust from the collector ring assemblies to work its way into the rotor area. We suspect that the oil contamination could carry some of this carbon dust to the small cracks and cause ground faults. Another possibility for ground issues is the accumulation of excessive carbon dust within the vertical section of buswork which could produce ground tracking. Carbon dust from brushes can find its way through the small pockets where the field copper bars are routed.

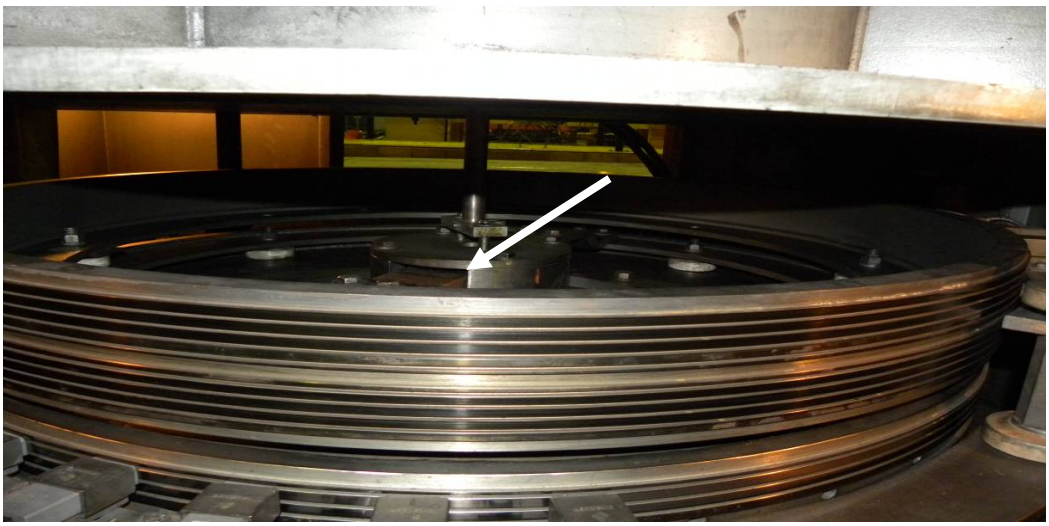


Photo 6.1-13: Rotor Leads Routing through a Small Pocket near Slip Ring Housing

This issue also could be linked to the excessive vibration of the unit. The field pole ground issue has a long history at the plant, and has reportedly caused many outages. The unit trip settings for the ground fault level have been adjusted to a setting which is not the recommended nominal value to help compensate. This field ground issue should be considered to be a major ongoing issue as it could lead to significant and long term outages. It is recommended that Nova Scotia Power plan to resolve this issue in the 2013 outage.

Rotor pole assemblies are original. Based on experience with other utilities in Canada, generator poles of similar manufacture continue to operate with minimal problems for much longer than the 36 years of this unit, provided they are free of contamination. While the contamination does not appear to be as severe as found on the stator, any amount of oil contamination on the poles can lead to faults. The critical issue with the oil and moisture contamination is that, in the course of time, contaminated oil might find a path into cracks, carbonize and provide a tracking path to ground, or could lead to looseness of the wedging. According to recent test records as well as the AC pole drop test there is no indication of any shorted turns in the field coils. Even though no unusual condition exists on the pole windings, considering the age of the units, it is prudent to re-insulate the poles at the same time when the stator rewinding is initiated.

The brush and the slip ring arrangements were visually inspected. No excessive wear or deterioration of the surface was found on the collector rings and there was no abnormal surface colour which would indicate excessive heating. There is no substantial evidence of brush chipping or accumulation of excessive carbon dust on the collector insulation.

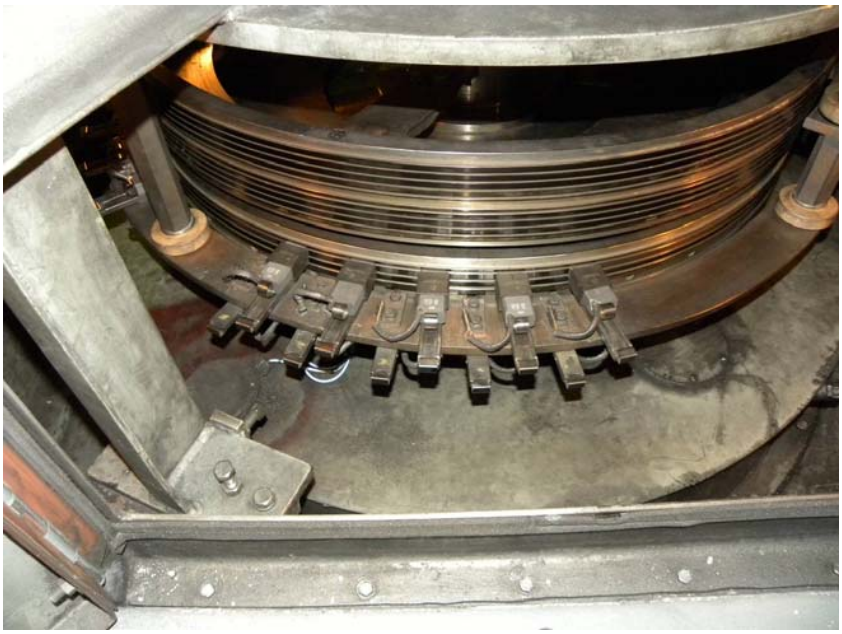


Photo 6.1-14: Slip Ring Housing with Arrangement of Brushes

Based on the present condition, operation for the next 20 years is expected, provided a regular maintenance program is performed.

Air Gap Measurements

The air gap analysis is covered within the generator mechanical assessment section of this report. Review of the Power Engineering Company report reveals that the air gap variation due to stator eccentricity and the rotor non-circularity is progressing. Remedial action should be taken in accordance with the recommendations specified in their report.

Discussion with the maintenance staff revealed that there had been a recommendation from the OEM to increase the temperature of the stator to reduce the vibration issues. However the control of flow of cooling water to the stator surface air coolers using an updated control valve design did not function adequately. We recommend this issue be investigated to find the underlying rationale.

Photo 6.1-8: Surface Air Coolers

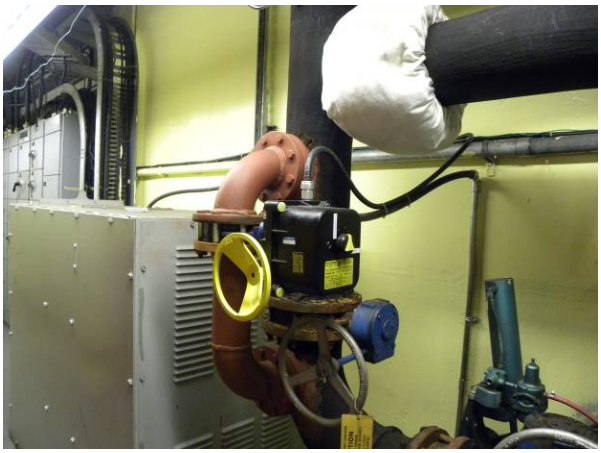


Photo 6.1-9: Keystone Water Flow Control Valves

Stator Winding – Unit 1

At the time of the inspection the generator rotor was out and the generator stator was open for inspection.

Visual inspection of the generator stator revealed evidence of extensive oil contamination within the generator housing.

Photo 6.1-10: Generator Oil Contamination within the Stator Winding

Excessive oil contamination within the stator area can foster electrical tracking which can lead to phase to ground and phase to phase faults. Oil based contamination can leach into the core and cause inter-laminar looseness and, in some cases, inter-laminar abrasion. Loss of inter-laminar insulation can cause core hot spots which accelerate stator winding aging.

Stator winding contamination in the end winding area can produce alternative electrical conduction paths between the end-winding and ground.

As the time of the KGS Group inspection, no partial discharge test results were available at site and as a consequence it was not possible to determine the present condition of the winding. Interviews with the maintenance staff did not reveal any unusual behaviour with the stator winding. However, given the level of contamination, it is anticipated that there would be issues if the information was available.

During the time of the inspection, Nova Scotia Power was inspecting the stator wedges and was in the process of replacing some of the loose wedges.

As with Unit 2, the Power Engineering Company Unit 1 report identified that once the unit was inspected in detail, repacking of the stator core splits is required. As a consequence some degree of winding replacement will be required at and around the core split.

Visual inspection of the end winding did not reveal any unusual condition or concerns. There is no evidence of erosion, overheating or partial discharge activity or corona activity at the end winding area except for few a scratches from assembly and dismantling of the top shrouds.

With the limited data available on the condition of the stator winding, it is difficult to predict with any accuracy the number of years this unit will operate trouble free without re-winding of the stator. However considering the winding age, and to avoid a forced outage due to stator failure, it is prudent to re-wind within five years.

Stator Frame and Core – Unit 1

Visual inspection of the stator core revealed excessive amount of oil and dust residue on the core surfaces. This contamination has the potential to cause ongoing damage.

Even though from the visual inspection no unusual core waviness was observed for the Unit 1 stator core, it is believed that there is certain amount of core-waviness near the core splits.

There is migration of insulation of the core split packing which is a factor and contributed to the stator profile out of tolerance. It is possible that the migrated core packing has been dissolved by continuous exposure to lubricating oil mixture.

While the temperature records obtained from site do not indicate any hot spot issues with the core, it is recommended to perform a detailed assessment of the stator core as soon as possible, ideally at the next outage, and at the same time perform the following:

- Thorough check of core tightness
- Stator Core Loop Test
- ELCID Test

These tests are recommended to determine whether there are any underlying hot spots within the stator core and to better understand the condition of the inter-laminar insulation.

Industry standard in normal operating conditions is that a stator core for this type of unit would be acceptable for a long period of time and replacement would not be initiated when the stator winding is replaced. For the Wreck Cove generators, without the above mentioned testing, it is difficult to determine if core replacement should be initiated on the first rewind or if the core can continue to operate reliably for another 20 to 30 years.

Based on the life extension and modernization it is prudent to plan and include costs for the core replacement in the budget with the rewind, until more detailed test results can be obtained.

Air Gap Measurements

The air gap analysis is covered within the generator mechanical assessment section of this report. Based on the recommendation of Power Engineering Company, Nova Scotia Power have installed UMP sensors, which when the monitoring equipment is installed will provide continuous online monitoring of the unbalanced magnetic pull in the air gap.

Rotor – Unit 1

The rotor condition assessment is subdivided into rotor coils, poles and damper winding and the collector and brush assembly. At the time of the inspection (November 2012) the rotor of Unit 1 was already taken out and Nova Scotia Power was performing remedial work.

Visual inspection of the poles revealed oil and dirt contamination on the surface of the pole bodies. Even though this contamination is not as severe as found in the stator, any amount of oil contamination on the poles can lead to significant issues. The rotor needs to be properly cleaned.

Photo 6.1-15: View Showing Dirt Deports on the Field Coil Connections

There is no sign or evidence of overheating in the pole bodies or overheating at the axial ends of the pole pieces.

A detailed inspection of the rotor by Nova Scotia Power revealed loose inter-pole braces, which were corrected before the unit's return to service.

Photo 6.1-16: Interpole Braces

No insulation fretting, cracks or breaks were observed on any of the rotor coils. There was no mechanical damage observed.

Maintenance personnel indicated that there were similar field ground fault issues in Unit 1 as identified in Unit 2 but less severe.

A more thorough inspection by Nova Scotia Power revealed that there is looseness or fretting in the dovetail key assembly.

A discussion with the maintenance personnel did not reveal any issues, based on the insulation resistance measurement and AC pole drop test. But considering the age of the unit, it is prudent to consider re-insulation of the poles at the same time as stator re-winding.

The brush and slip ring arrangements were inspected. No excessive wear or deterioration of the surface was found on the collector rings. There was no abnormal surface colour that would indicate excessive heating. There is no substantial evidence of brush chipping or accumulation of excessive dust on the collector insulation.

Photo 6.1-17: Brush Gear Assembly

Recommendations

The recommendations for the generators are based on generator refurbishment. Depending on the results of further testing and inspections, generator replacement may be a preferred solution.

- A thorough detailed investigation should be done to find the cause of the persistent Unit 1 and Unit 2 field grounds, involving the OEM or third party expert in the process. This should be done in 2013 at an estimated cost of $100k.
- Rectify the loose stator wedges on both units in 2013, estimated at $100k.
- The OEM proposed solution for improved temperature control and potential vibration reduction should be reviewed to understand the rationale. If warranted, a solution should be implemented with the unit re-wind. The assessment should be performed by 2014 and the estimated cost is $10k.
- Re-implement the online partial discharge monitoring system on both units, which will require installation of new partial discharge (PD) couplers to obtain PD readings and an associated data acquisition device for analysis. If this is not feasible in the short term, then a periodic partial discharge measurement program should be initiated to monitor the stator insulation condition. The cost of this work is estimated at $65k and it should be done in 2013.

- Install the permanent continuous UMP monitoring system on both units in 2013. The cost estimate is $80k.
- The rotor pole drop test should be performed annually on both units to determine the rotor field turns insulation health. Shorted turns can cause vibration, and unbalanced stresses on the generator stator core, frame and rotor.
- A generator dielectric test should be performed annually on both stator windings to determine and track stator winding insulation condition.
- Generator visual inspection should be done annually with specific attention to the common degradation problems:
  - Loose wedges
  - Loose field coil braces
  - Evidence of any partial discharge
  - Evidence of any overheating

  To perform this inspection the rotor and stator should be in a clean and oil-free state.
- Perform the following testing in 2013 on both units to establish overall electrical condition of the generators. Budgetary cost is $200k.
  - Partial Discharge testing
  - DC Hipot test (Reduced Voltage) with DC ramp tester
  - Corona Probe test
  - ELCID test
- After the UMP based monitoring systems are installed, monitor and review the air gap of the units. An air gap that does not stay within acceptable tolerances can cause undue stresses on components such as the stator and rotor, brackets and bearings and in extreme cases a stator and rotor collision could occur. The air gap of a hydro generator is ultimately determined by the circularity and concentricity of the rotor and stator.
- Rewind the stators and re-insulate the pole windings within the next five years. The cost of re-winding including pole insulation is $3.2M per unit with 3-4 months downtime per unit to execute the work. It is anticipated that this work would be done in 2017 and 2018. The funds are included in the generator refurbishment recommendation below.
- Before initiating a re-winding program, it is recommended to perform more in-depth inspection of the stator core by performing in-depth visual inspection, and an ELCID test to check for any hot-spots within the stator core. Normally stator cores of this type of generator

are not changed at the time of the first re-winding of the stator. With the already identified stator core issues and with the oil contamination, it is recommended to perform required tests soon, as the stator core may require replacement, along with the winding. The cost estimate to replace the stator core is $2.4M/unit, to be done at the same time as the re-wind in 2017 and 2018. The funds are included in the generator refurbishment recommendation below.

- Replace the rotors with new rotors having improved mechanical rigidity. Assuming the shaft, thrust bearing and bracket can be reused, the estimated cost is $7.9M per unit. The funds are included in the generator refurbishment recommendation below.
- Including excitation system replacement, the estimate for generator and refurbishment is estimated at $30M including costs related to removal of existing equipment, installation, contingency and commissioning. These refurbishments are shown equally split between the years 2017 and 2018. There could be some cost reduction depending on the condition of the stator frame and core as determined after further testing and inspection.

Generator Spare Parts

The following generator spare parts were found in the inventory:

- 4 spare stator winding bars
- Spare stator winding connections
- Unfinished flat bar for rotor field connections
- One spare pole coil

Photo 6.1-18: Stator Winding Bars

Photo 6.1-19: Spare Pole Coil

Photo 6.1-20: Stator Winding Connections, Flat Bar for Rotor Field Connections

Recommendations

It is recommended to keep the following minimum level of spares on hand:

- 12 top bars
- 12 bottom bars
- Wedges for 12 slots
- Fillers (Top, Centre & Bottom) for 12 slots
- One of each type of stator winding connection
- Winding material for 12 slots
- The spare pole coil should be tested in 2013

Estimated cost is $200k and these should be acquired in 2013.

6.2 EXCITATION SYSTEMS

Description

Wreck Cove is equipped with Unitrol static excitation systems of 1976 vintage. The system is configured as a shunt field static excitation scheme and the complete installation is divided into four principal sections:

- Semi-conductor rectifiers (SCR's) stage
- Excitation start-up and field discharge equipment
- Automatic and operational control unit
- Excitation transformer

The necessary excitation power is taken from the generator itself. It is fed through the excitation transformer to the SCR stage and eventually to the generator field via a DC field circuit breaker. Figure 6.2-1 below shows a schematic of the exciter arrangement.

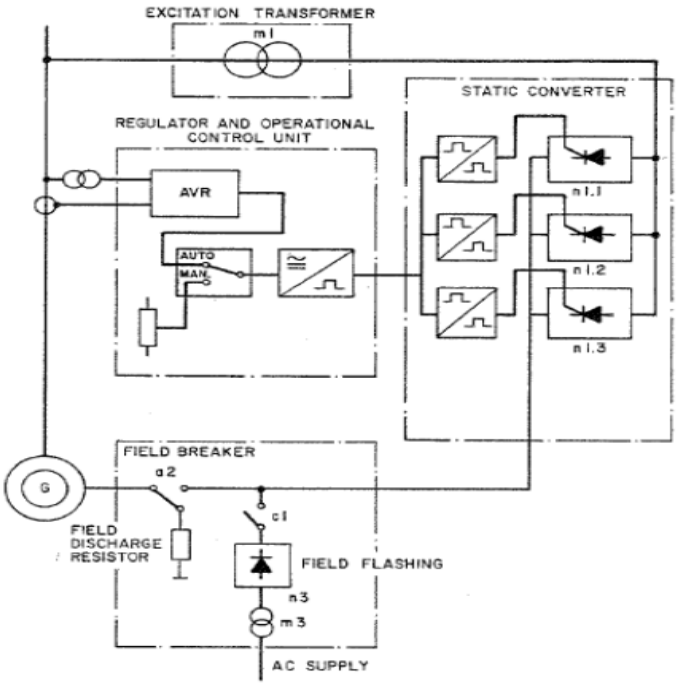


Figure 6.2-1: Exciter Schematic

With several converters connected in parallel the control electronics are arranged in racks of a separate hinged frame to add greater redundancy.

The SCR output stage bridge consists of three parallel bridges, each having six thyristors in 3-phase bridge connections. Each parallel bridge is controlled by a final pulse stage, and is cooled by one fan. There are protection devices integrated with the excitation system for protection of the thyristor bridges.

The automatic unit consists of the voltage regulator type UN 2010. There are also over excitation and under excitation limiters which act in conjunction with the AVR. The rotor current limiter is UN1024 type while the rotor angle limiter is UN 1043 type. The rotor angle limiter works in the opposite direction and if the angle becomes too large, the field voltage is raised to avoid generator slip.

This Unitrol exciter control module is equipped with a grid control module which is of type UN 1001. This module provides the interface for automatic and manual operation.

Assessment

Condition assessment of the static exciter involved interviews with the operations and maintenance staff, spare parts assessment, visual inspections and a review of the test records.

The excitation equipment is original which makes it more than 35 years old. According to the present industry norms, the maximum operating life of such equipment would be approximately 40 years. The operating life of these exciters has essentially been reached.

Photo 6.2-1: Exciter Front View

Photo 6.2-2: Exciter Converter Section

Although the excitation systems have operated without any major issues, recently intermittent “conduction failure” alarms have been recorded for the Unit 2 excitation system. This issue could be a sign of impending failure. As these units are often operated at partial load, this would have helped maintain the lifespan of the exciter equipment over time; however they have reached the end of their expected life.

Interviews with the maintenance staff did not reveal any other major problems; however, given the age of the equipment, a major failure could be expected anytime. Moreover, such failure could cause a prolonged unit downtime, since the availability of OEM spare parts and technical support is poor to not available.

A thorough visual inspection was performed on the control section, the converter section and on the protection devices. No major issues were detected.

The field circuit breaker was visually inspected. No unusual deposits or any arcing indication was observed on the contacts and within the arcing chamber.

Photo 6.2-3: Field Breaker Section of the Static Exciter

Although the protection relays of the exciters are original, these are still in good condition. Maintenance personnel revealed no major issues with these relays.

Photo 6.2-4: Protection Relays within Static Exciter

The static exciters should be replaced within the next five years before they reach the end of their service life.

The replacement should be held until Nova Scotia Power decides what course of action (replacement or refurbishment) will be taken for the generators. As such the exciter replacement budget has been placed in 2017 and 2018.

It is anticipated that there would be an outage of approximately 1 month per unit while the excitation system is changed out.

The spare parts were reviewed. Most of the spare electronic card modules are also over 35 years old and no valid test or verification has been done to ensure that these spare parts are still useful. After a review with the original equipment manufacturer, it is evident that availability of spare parts and technical support on older model of Unitrol exciters is extremely limited or non-existent.

The dry type excitation transformer is in good condition. See Section 6.4 Excitation Transformer for further information. Note that any significant uprating of the turbine generators would likely require these transformers to be replaced.

Recommendations

- Based on the age of the equipment and declining support from the manufacturer, it is recommended to initiate the process of replacing these exciters, as they have reached end of life. It is estimated that these costs are $750k per unit, and the replacements would be done in 2017 and in 2018, when major generator work is proposed. These funds are included in the generator refurbishment recommendation estimate in Section 6.1 Generators.
- The existing spare parts should be checked to ensure that these are still functional. This process should be initiated soon to avoid any unexpected downtime. This check is estimated at $20k and should be done in 2013.

6.3 ISOLATED PHASE BUS DUCT (GENERATOR OUTPUT)

Description

The generators, station auxiliary transformers, excitation transformers and main output transformers are interconnected by a 15 kV air insulated, isolated phase bus (IPB) system. This is original to the station and was manufactured in 1977. In general, the IPB is mounted overhead.

The IPB is naturally air cooled with dust tight aluminium enclosures. Conductors are formed of aluminium tubing and all conductors are mounted coaxially inside the housings and supported radially by porcelain insulators at various points along the bus. Expansion of the conductors is accommodated using laminated expansion joints. Flexible braid connectors are used at the transformer and generator terminals. The following are the major bus sections of the isolated phase bus ducts:

- Bus section from generators to the main output transformers
- Bus section from the generator to the auxiliary transformers
- Bus section from the generator to the excitation transformers

The continuous current rating of the IPB is believed to be designed to a conductor temperature of 105°C or 65°C raise over 40°C ambient.

The basic methodology of forming the ground bus is shown in Figure 6.3-1 below. On the ground enclosure, all split covers are solidly connected to their mating enclosure, thus forming a continuous conductor to prevent longitudinal circulating currents.

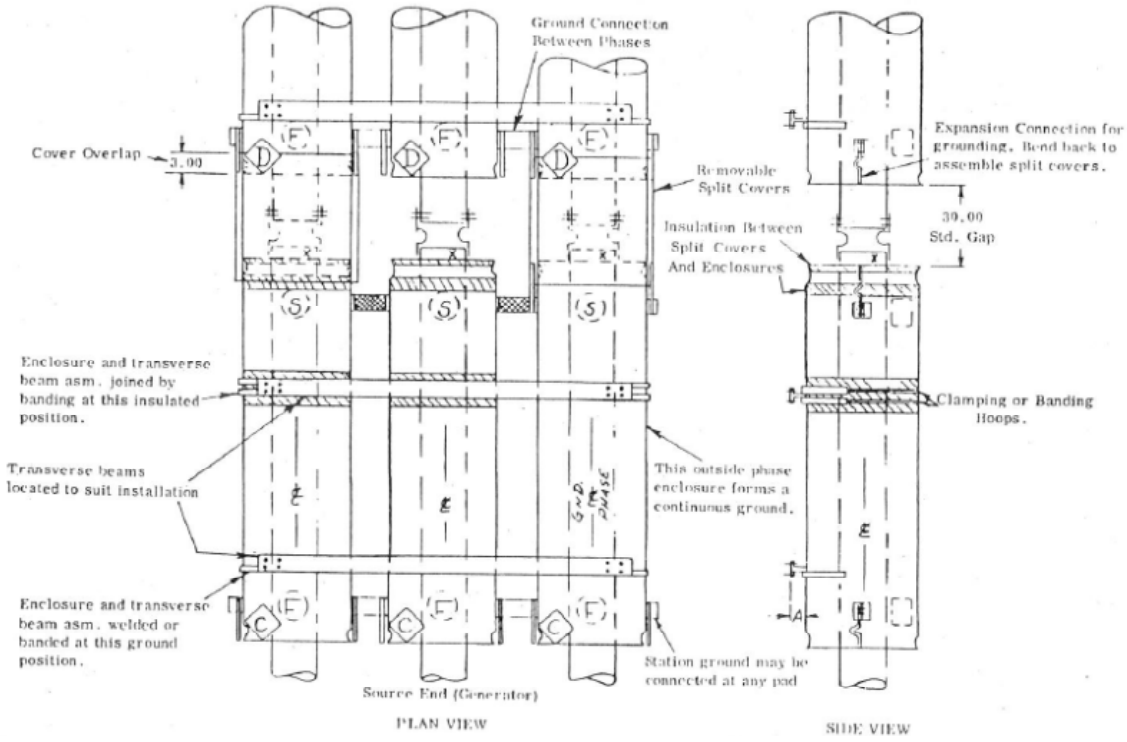


Figure 6.3-1 Bus Duct Ground

One end of the transverse mounting beams is insulated from the mounting structure. This insulation breaks up longitudinal circulating current paths through the structure.

In addition to the basic enclosure system, potential transformers are included within the isolated phase bus duct system. The potential transformer cubicle is of the swing-out type.

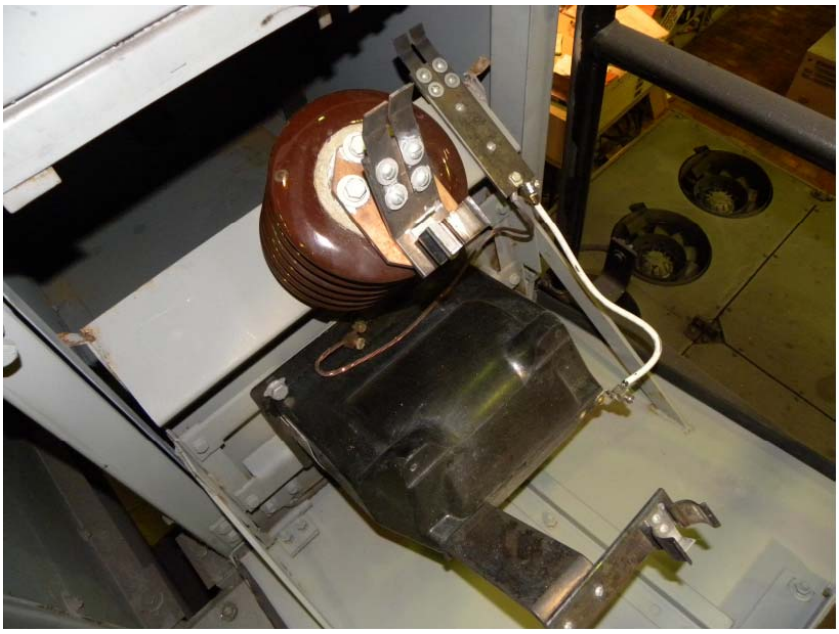


Photo 6.3-1: Swing-out PT Cubicle

Swinging the units out isolates the transformer and fuses by disconnecting the transformer primary and secondary connections and momentarily grounds the high potential side, permitting safe removal of the current limiting fuses. All transformer secondary leads terminate at the terminal board.

No significant historical event record was found relating to the isolated phase bus ducts.

Assessment

Condition assessment of the IPB involved mainly visual inspection as there were no recent thermography reports available, interviews with the maintenance staff, review of any available information and review of available spare parts.

Visual inspection of the IPB did not reveal any issues. At the time of the outage the sections of the bus between the generator and auxiliary transformer and the short section at the excitation transformer were accessible for inspection. The insulators were found clean, enclosures were defect free, and the conductors and flexible connections were secure with no visible signs of stress and overheating.

Photo 6.3-2: Isolated Phase Bus Ducts Routing

Photo 6.3-3: Clean and Defect Free Insulators

Photo 6.3-4: Isolated Ducts with Flexible Braids

No substantial maintenance records were available at the time of the inspection, however a detail discussion with maintenance personnel does not indicate any past or present issues with the isolated phase bus ducts.

The insulation test results obtained from the 2011 outage were reviewed and the insulation appears to be within acceptable limits. A copy of the test results are included below.

Phase "R"

Time	KV	Current	Resistance
1	5	.2uA	25GΩ
2	10	.4 "	25 "
3	15	.7 "	21.4 "
4	20	1.9 "	10.5 "
5	25	8 "	3.1 "
6	30	18 "	1.67 "
7	35	38 "	921 MΩ
8	40	74 "	540 "
9	45	145 "	310 "
10	50	230 "	217 "

Phase "Y"

Time	KV	Current	Resistance
1	5	.2uA	25GΩ
2	10	.4 "	25 "
3	15	.7 "	21.4 "
4	20	1.3 "	15.4 "
5	25	4.2 "	5.95 "
6	30	10.4 "	2.88 "
7	35	27 "	1.296 "
8	40	64 "	625 MΩ
9	45	135 "	333 "
10	50	240 "	208 "

Phase "B"

Time	KV	Current	Resistance
1	5	.3uA	16GΩ
2	10	.7 "	14 "
3	15	1 "	15 "
4	20	1.6 "	12.5 "
5	25	2.6 "	9.6 "
6	30	9.2 "	3.26 "
7	35	23 "	1.52 "
8	40	65 "	615 MΩ
9	45	123 "	366 "
10	50	220 "	227 "

Figure 6.3-2: Unit 2 Bus Duct Insulation Test Results

No thermal scan reports were available at site for review. Interview with the maintenance staff reveals that previously thermal scanning was performed but no conclusive results were available on the basis of such reports. This is reasonably to be expected. As the plant typically does not operate at full capacity and only during peaking times, the opportunities of operating the plant to reveal an overheating location are minimal.

Spare consumables such as gaskets etc. could be available locally but no inventory was found for the non-routinely replaced spares. The manufacturer documentation recommends that these items be kept in stock and on hand.

The IPB appears to be in good condition and a continued reliable life span of 30 more years can be expected, provided no overheating issue is observed. Any issues are best mitigated by a program of maintenance and monitoring. Note that a significant uprating of the turbine generators may require the IPB to be upgraded.

Recommendations

- A regular maintenance and monitoring program inclusive of visual inspection, cleaning and testing should be established to monitor the condition of the IPB on a regular basis. The manufacturer literature recommends that at minimum an annual inspection be performed on the bus.
- An operating temperature study of the IPB system should be performed at a time when the associated unit is running as close to peak load as possible. Allow $50k in 2014.
- Spare flexible connections and insulators should be procured and stocked at the station. Allow $150k in 2014 for spare parts procurement. It is important that these spares are available in hand otherwise a small failure could lead to a major unit outage.

6.4 EXCITATION TRANSFORMERS

This section covers the excitation transformers, which supply AC electrical power to the G1 and G2 static excitation systems. The station service transformers are assessed in Section 6.5 AC Station Service System.

Description

The power stage of both the G1 and G2 static excitation systems are supplied by dry-type power transformers. These transformers are original and were manufactured in 1976 by Federal Pioneer. They are located on the powerhouse floor adjacent to the excitation systems. The primary sides of these transformers are connected to the generator terminals via a tap off the isolated phase bus duct while their secondary is connected to the AC side of the static exciter bridge by cable. These transformers are housed in individual ventilated steel enclosures. Both the transformers are identical and are rated 475 kVA, 13.8 kV/220 V and the cooling is natural convection cooling.

Each transformer has three 100:5 current transformers which are installed around the high voltage side. The CT's are used in each transformer for the over-current protection scheme. Both transformers are equipped with auxiliary devices to monitor the winding temperature and annunciation is provided in the event that temperature rises above the pre-set value.

Interviews with the maintenance personnel did not reveal any major historical events.

Assessment

Condition assessment involved external visual inspection, spare parts review and interviews with operating and maintenance staff.

The transformers and their enclosures are free of evidence of overheating or stress. The maintenance staff did not identify any issues with excitation transformer operation. As such, the excitation transformers appear to be in very good condition.

There is no spare unit available on site. Although the condition of the transformer may be good for many further years of operation, if there is a significant failure requiring replacement, the lead time for the procurement of a new transformer is typically six months and requires some planning time. In order to mitigate this risk, a rigorous monitoring and maintenance program should be in place.

Provided there are no new issues revealed in the ongoing detailed testing and cleaning of the transformers, reliable operation for the next 10 years can be expected. This would take the transformers to the end of their expected life. Note that a decision to significantly uprate the turbine generators may require replacement of these transformers.

Recommendations

- Regular maintenance which includes visual inspection and cleaning should be done every year.
- All the routine tests including a thermographic scan should be performed every two years. Estimated cost is $9k.

- The transformers should be replaced at the end of their expected life which would be approximately 2022. There may be a requirement to change the transformers with the excitation systems, if the units are uprated, as the logistics may be appealing. Replacement should include all the associated cable between the exciter and the transformer. Cost estimate is $550k for both.

6.5 AC STATION SERVICE SYSTEM

General

The powerhouse AC station service provides AC power for starting and running of the unit auxiliary equipment, lighting and motor loads. Emergency power is provided from a dedicated diesel generator in the event of complete loss of power. The DC station service system, consisting of a single battery bank and charger, provides power for control, protection and annunciation systems. The single line diagram A-135-05-061 provides an overview of the Wreck Cove AC station service arrangement.

The AC station service system consists of the following:

- Powerhouse unit service transformers and associated switchboards
- Powerhouse auxiliary service transformer and its associated switchboard
- Diesel building auxiliary service transformer and its associated switchboard
- Motor control centre
- Distribution panels
- Cable and buss
- Standby Diesel Generator
- Tunnel T-2 Gate AC System

The assessment of the AC electrical equipment for Tunnel T-2 intake gate is grouped with the Mechanical Assessment of the gate in this report. See Section 5.1 Tunnel T-2 Intake Equipment.

6.6 STATION SERVICE TRANSFORMERS

Description

There are two 500 kVA, 13.8 kV to 600 V dry–type unit service transformers, each of which are fed from its associated generator terminals and provide power to the unit switchboards and to the unit service MCCs. The unit transformers are original and were manufactured in 1975 by Westinghouse. Both the transformers are connected in wye to delta configuration and equipped with off-load tap changers. The protection of the unit transformers is via over-current protection relays which are connected with protection class CT's located at the 13.8 kV side of the transformer.

Assessment

The condition assessment involved exterior visual inspection and interviews with the maintenance staff.

External visual inspection revealed no major issues. Some degree of dust accumulation was apparent. The transformers and their enclosures appear to be in good condition, free of evidence of overheating and stress.

During the inspection there did not appear to be any unusual conditions such as vibration related noises, and interviews with the maintenance staff did not reveal any concerns with these transformers.

The transformers have adequate grounding and auxiliary devices to monitor transformer condition. The over-current protection of both the transformers is adequate for protection of such sizes of transformer. Both transformers are adequately sized based on the present loading condition. As there is no identified requirement for significant system changes, it is anticipated that the transformers will operate well to the end of their expected life of 40 years.

The transformers are in fair condition and suitable for operation until the time when the AC station service system upgrade is recommended in 2019.

Recommendations

- As no up to date test results were available during this inspection, it is recommended to perform insulation resistance tests in 2013.
- A regular yearly maintenance, including thorough cleaning, and periodic test is recommended to be performed to keep the units in operation.
- The transformers should be replaced during station service life extension upgrade by the year 2019. The replacement cost of the transformers is included in Section 6.8 AC Switchgear.

6.7 AUXILIARY SERVICE TRANSFORMERS

Description

In addition to the unit service transformers, there are two 500 kVA auxiliary transformers AT-1 and AT-2. The primary sides of these transformers are connected to the 25 kV distribution system at the 144 kV switchyard. These transformers feed power to the powerhouse auxiliary service switchboard for normal operation, as well as to the diesel generating building auxiliary service switchboard and provide standby and emergency power to the powerhouse, portal building and switchyard.

One of the auxiliary transformers (AT-1) is located within the powerhouse and is close coupled with the powerhouse auxiliary service switchboard. This transformer is a dry-type transformer rated at 500 kVA, 25 kV-600 V and is equipped with 4 X ± 2.5% off-load tap changer. This transformer is a May and Christie GmbH unit manufactured in 1977. The other auxiliary transformer which is located in the 144 kV switchyard is an oil filled, sealed tank transformer manufactured by Carte Electric (AT-2). Transformer AT-2 feeds power to the emergency power switchboard located within the diesel generator building.

Assessment

The condition assessment of the auxiliary transformers involved exterior visual inspection, and interviews with the maintenance staff. The inspection was limited to the transformers and the downstream low voltage systems. The 25 kV equipment located within the switchyard, such as

the reclosers are not part of the assessment, although it was noted that these reclosers have recently been replaced.

External visual inspection revealed no major issues other than a certain level of dust accumulation. This is true for both the oil filled and dry-type units. The transformers and their enclosures appear to be in good condition and free of evidence of overheating and stress. As the dry-type transformer is ventilated, dust accumulation could become an issue over time and should be addressed.

At the time of the inspection, no test records were available for either auxiliary transformer and discussion with the maintenance staff did not reveal any major issues. Recent test records would better indicate any underlying issues with the transformers, but from our visual inspection and discussion with staff it is reasonable to conclude that the transformers will perform satisfactorily until they reach the end of their life. These transformers would typically have a similar lifespan to the station service gear and should be replaced at a similar time.

There is no sizing issue based on the present loading condition. However, a load reassessment is recommended ahead of the AC station service upgrade process. To assist in this Nova Scotia Power should begin a regular load monitoring program to provide a factual basis for sizing replacement transformers.

Recommendations

- Development of an annual maintenance and testing program is recommended. Included in this program should be cleaning of the dry-type transformer, visual inspection, thermographic scanning, testing of oil from the oil-filled transformer and dielectric testing.
- As there were no recent test results available during the inspection, it is recommended to perform a dielectric test on the transformers in 2013.
- Replace both the transformers and their associated disconnect switches by the year 2019 which is the life expectancy of the associated switchgear. The cost of the replacement is included in Section 6.8 AC Switchgear.
- Nova Scotia Power should begin a regular load monitoring program in 2013, to provide a factual basis for sizing replacement transformers.

6.8 AC SWITCHGEAR

This section covers the 600 V AC switchgear including breakers, enclosures, bus-work, instrument transformers and transfer scheme.

Description

The AC distribution system consists of four metal enclosed switchgear assemblies which are, with the exception of the diesel generator building equipment, closed coupled with their respective transformers. These switchgear assemblies are known operationally as unit service switchgear, service switchgear and auxiliary service switchgear. All switchgear is of identical design and was manufactured by Westinghouse, and placed into service in 1978, making all switchgear 35 years of age.

Each unit service switchgear is connected with its associated 500 kVA unit service transformer for normal operation and to the auxiliary service switchboard for starting of the units. Each unit service switchgear feeds power to the station auxiliaries through a station service MCC. The unit service switchgear and the unit service MCCs are interconnected with cables. The unit transformer and the unit switchgear are close coupled. The switchgear assemblies are ventilated and metal enclosed, but not of arc resistant construction.

Each unit service assembly has bare copper bus work and two air circuit breakers: one incoming main breaker and one tie breaker. Main and tie breakers are interlocked to prevent paralleling of two power supplies. The switchgear bus is rated at 600 V, 600 A while the breakers are 600 A, 3 pole, and 600 VAC. While not available on the nameplate, the interrupting rating of similar equipment is 35 kA and this equipment is anticipated to be the same.

The breakers installed within the unit service switchgear are Westinghouse DS type draw-out style air circuit breakers which use atmospheric air and arc chutes for current interruption. The breakers are equipped with solid state LSI trip units. The breakers can be operated locally from the breaker front and from the switchgear control switches or automatically by remote control in

accordance with a transfer scheme. All operation is electrically interlocked to prevent 'make before break' operation. The service and auxiliary service switchgear assemblies are similar to the unit service switchgear described above.

The auxiliary service switchgear, fed from AT-1 auxiliary service transformer, feeds power to auxiliary service MCC for normal operation of the units and as well supplies power to each unit service switchgear for unit start up. The service switchgear located inside the diesel generating building fed from auxiliary service transformer AT-2 provides power for normal operation and is also an interconnect point for the diesel generator. This service switchgear supplies power for lighting and other services in the switchyard control building, the administration building and the portal building.

The rating and the breaker types of both switchgear assemblies are same as the unit service switchgear mentioned above.

Assessment

Condition assessment of the switchgear and its internal components involved visual inspection, review of maintenance records, interviews with maintenance staff, and spare parts assessment.

The switchgear is original and 35 years of age. Well maintained switchgear has a life expectancy of 30 to 40 years. The number of operations and service duty can factor in to increase or decrease the expected life; however, in general 40 years is a reasonable estimate.

None of the switchgear at Wreck Cove GS is of arc-resistant construction. A strong emphasis by many utilities has been placed on switching out equipment with arc-resistant switchgear to reduce personnel safety hazards. Also, with older equipment, there is a likelihood of increased arc flash events due to mechanical or electrical failure, which can be a safety issue for the plant personnel.

A rating and adequacy study was not conducted in this assessment; however, there have been no significant changes in the AC station service load which would expose the equipment to duties beyond its original required capabilities.

Based on the external visual inspection, no obvious sign of moisture ingress, stress or damage to assemblies was found. Also there is no evidence of excessive contact wear.

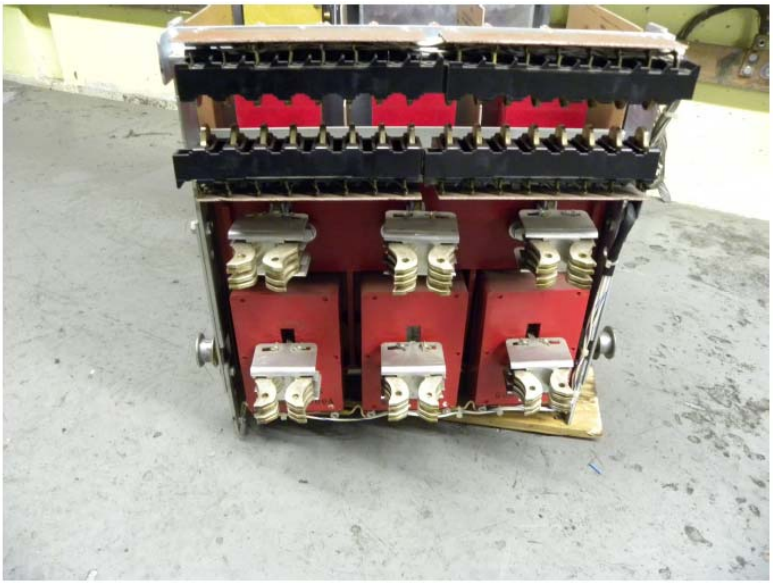


Photo 6.8-1: Circuit Breaker Contacts

At the time of the inspection, no test results or infra-red thermography reports were available for review and analysis. There also does not appear to be a program in place to routinely exercise the breakers in the systems. The maintenance records did not show any substantial test reports such as timing tests, closure tests, etc.

Discussion with the maintenance personnel revealed that there have been some recent reliability issues with the switchgear. The transfer to the tie breaker in the auxiliary switchboard did not occur during a power outage and consequently there was full blackout condition while a generating unit was in operation. This is a major concern as this situation could damage the major equipment and cause significant downtime and cost. After investigation, it was found that the closing coil was burnt out and the breaker operating mechanism was not moving properly (sticky). The circuit breaker was eventually sent to the Siemens Moncton switchgear facility for repair

A failure of this type is likely a symptom of older switchgear and these types of events typically increase over time as the switchgear approaches the end of its life.

There are operational safety issues associated with the switchgear. There are currently no shutter doors in the breaker cell to cover the live stab once a breaker is removed from the cell. While typical for this vintage, this can expose personnel to significant electrical hazards.

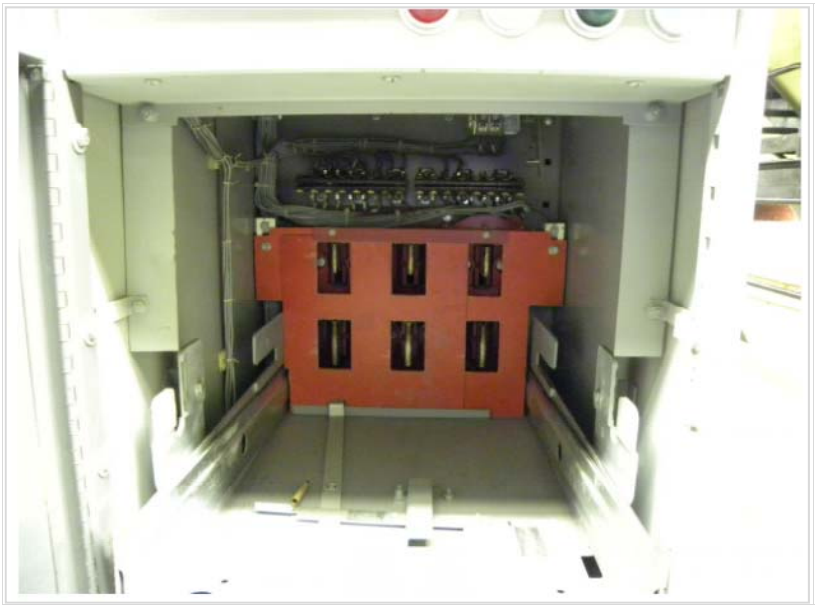


Photo 6.8-2: No Shutter within the Breaker Cell

There has been no arc-flash hazard analysis study done on the station service system. Switchgear and the assemblies are not equipped with arc-flash hazard warning signs / labels which are becoming an industry standard. A formal documented system of equipment labelling, identifying protection requirements is needed. Procedures should be established for labelling, wearing personal protective equipment, and safe work/lockout schemes if equipment needs to be worked on while live. Failure to perform the study and establish correct procedures can expose the maintenance personnel to significant hazards.

KGS did not find any substantial spare parts availability at site. Since this particular type of switchgear is no longer in production, availability of spare parts will become an issue if there are failures. To keep these running, refurbishment by the OEM may be the most practical solution.

With the present assessed condition, the 600 V switchgear may be reliably operable for the next 10 years. However, given the recent failure and considering all aspects of the operational safety and reliability we recommend replacement of all 600 V switchgear by the end of 2019.

Recommendations

- Perform infra-red scans on all 600 V switchgear no later than 2013 at an estimated cost of $15k.
- Initiate a refurbishment program with the OEM to maintain the reliability of the breakers until such time as they are replaced in 2019. Allow $15k per year for this work.
- It is strongly recommended to perform an arc flash and protection co-ordination study on the entire 600 V AC station service system in 2013 to determine the possible level of arc energy at the switchgear locations. The cost estimate for the study is $50k.
- As there are no recent test results available, the following tests should be performed by 2014 on the 600 V switchgear, at a cost of $35k:
  - High voltage AC dielectric tests on wiring and bus bar
  - Contact resistance measurement of the breakers
  - Partial discharge (corona)
  - Secondary AC current injection to verify (LSI) breaker trip settings
  - DC protective circuits check
  - CT & PT transformation ratio check
- The 600 V switchgear should be replaced in 2019. The cumulative budgetary price for upgrade of the overall AC station service is $2.9M. This budget price includes switchgear and other accessories such as feeder cables and cable trays. The new switchgear should be of the arc resistant type. In the meantime, the 600 V AC breakers should be refurbished depending on the test program results recommended above.

6.9 AUTO TRANSFER CONTROL

Description

The auto-transfer is a relay-based logic transfer scheme which is integrated into the switchgear and provides ‘break-before-make’ transfer of the station service loads. There are several

scenarios under which the transfer scheme operates. Refer to the station service single line diagram (A-135-05-061) to aid in understanding the transfer process.

Under normal operating conditions, when a generator is in operation, the unit service switchgear is fed from the unit service transformer. During unit start-up, the station service power is fed from the auxiliary service switchboard. After synchronization of a generator, the 144 kV breaker closes and a transfer occurs from the auxiliary service switchboard source to the unit transformer source. This process initiates opening of the tie breaker and closure of the main breaker. Each of the unit service switchboards is connected to its associated unit service transformer by its main breaker. The main and the tie breakers are interlocked so that only one breaker is closed at one time. The transfer is only possible if the selector switch is in “auto” position. All breakers are supplied with external breaker position indication lights; breaker closed indication light is red and breaker opened indication light is green.

When loss of voltage on a unit service transformer occurs, the undervoltage relay will open the main line breaker and close the tie line breaker and a transfer from unit service to auxiliary service will take place. After restoration of the normal power to the unit transformer, the tie line breaker in the auxiliary service switchboard opens and main line breaker is closed.

During the condition when the auxiliary service station supply fails (AT-1), the associated main breaker opens automatically and the tie breaker closes, and hence the unit service switchboard will be fed by (AT-2) transformer located in the switchyard. The same procedure applies in the case of AT-2 failure and power will be fed by the AT-1 transformer. Refer to the station service single line diagram for more details.

In the case of losing both auxiliary transformers (AT-1 and AT-2), meaning complete loss of station service power, emergency power is fed from the 200 kW diesel generator. Transfer to diesel generator is done manually. The 400 A disconnect switch located in the auxiliary service MCC will open upon sensing a drop in line voltage and must be reset manually, as the diesel generator is only sized to pick up critical loads, not all loads.

Assessment

The assessment of the auto-transfer scheme involved discussion with the maintenance staff and review of any records available on site.

Discussion with the maintenance staff reveals that there has been some modification in the present auto-transfer scheme, but no formal drawings were found to identify the changes made to the original transfer scheme concept. Some sketches of how the transfer scheme appears to operate have been prepared by operational staff to help in trouble shooting when transfers are required.

No maintenance records were available to demonstrate that the auto-transfer scheme is tested on a regular basis.

Discussion with the maintenance staff did reveal that there has been at least one failure of the transfer scheme as outlined in the discussion of the unit service switchgear above. Other than that, there have not been any significant issues with the operation of the auto-transfer scheme. However, it is essential that an updated drawing of the auto-transfer scheme is made available, together with a description of its operation. A written procedure to implement the transfer manually should also be prepared.

The scheme discussed is fairly simple in nature and is comprised of components which can be replaced as required. The present condition of the transfer scheme components and their remaining life is difficult to determine. However, at 35 years of age, it is reasonable to forecast increased rates of component failure.

As the AC station service system is reaching the end of its life, it is reasonable to assume that the auto-transfer scheme condition is adequate to provide service over the limited remaining lifetime of the switchgear, at which point it would be replaced.

Recommendations

- To ensure reliable operation of the system, detailed regular maintenance should be performed on the transfer equipment.

- The voltage relays and timers utilized by the auto-transfer system should be cleaned, tested and calibrated in 2013.
- Starting in 2013, test the auto transfer system on an annual basis, prepare a written procedure for the manual transfer and update/revise original drawings to reflect the present arrangement.
- The complete auto-transfer system together with the AC station service switchgear should be replaced during the station service upgrade. Cost of the upgrade is included within the AC Switchgear section.

6.10 MCC'S AND PANEL BOARDS

Description

Electrically, downstream of the unit and auxiliary service switchboards are the unit service MCCs, auxiliary service MCCs and distribution panels. There are several motor control centres as follows:

- Unit 1 service MCC
- Unit 2 service MCC
- Auxiliary service MCC
- Portal building MCC
- And numerous 600 V, 120 V/ 208 V distribution panels.

Assessment

The MCC's and most of the 600 V distribution panels and are original to the station (1978). The system is still operational but almost at the end of life. It is suitable for operation until the time of the station service upgrade which should be scheduled for the near future.

It was noted that there is significant dirt and debris build-up on and in some of the equipment, especially in the portal building equipment. While this equipment may be maintained until the station service upgrade, it should all be thoroughly cleaned.

Photo 6.10-1: Distribution Panels

Photo 6.10-2: MCC

Recommendations

- A thorough cleaning of all electrical equipment should be carried out in 2013 and then every 3 – 5 years.
- All MCC and distribution panels should be replaced at the time of station service upgrade in 2019. Budgetary costs for the replacement are included in the station service upgrade cost associated with the AC Switchgear.

6.11 CABLE AND BUS

Description

The cables are primarily original to the construction of the station and are typically an armoured cable or tray cable construction. Some of the cable trays were found to be overfilled.

Photo 6.11-1: Cable Tray Over Filled

Photo 6.11-2: Cable Runs

Photo 6.11-3: Incoming Feeder from Switchgear to MCC

Assessment

Discussion with the maintenance staff did not reveal any issues with the condition of the cables. Cabling of this age can reasonably be expected to have life beyond its current 35 years, provided the cables are not reconfigured. Changes which require the cables to be moved and/or reconnected can be a concern, as the insulation can become brittle over time and is easily damaged by reconfiguration at equipment.

While the cabling itself will likely last until the station service upgrade, it is anticipated that the re-use of the cabling would be extremely difficult and as such, the cabling should be changed out with the upgrade of the associated system.

Recommendations

- Cables should be reviewed regularly to ensure there has been no mechanical damage, otherwise, cabling should be changed out when the associated system is changed out.

6.12 STANDBY DIESEL GENERATOR

Photo 6.12-1: Diesel Genset – West Side

Photo 6-12.2: Diesel Genset – East Side

As part of the station service supply, a diesel generator is provided in a building adjacent to the plant switchyard. The diesel generator consists of a Cummins model NT855-G six cylinder turbocharged diesel engine connected to a Brown Boveri Canada 200 kW/250 kVA generator. The genset is original to the plant and was placed into service in 1978. The auxiliary equipment for the generator includes:

- A diesel day-tank (approximately 900 L)
- Two diesel fill pumps for the day-tank
- A double wall bulk storage tank (25,000 L)
- A battery charger
- An auxiliary in flow type block heater
- Full controls to allow the breaker to synchronize and close

Photo 6.12-3: Outdoor Bulk Storage Tank

Photo 6.12-4: Diesel Day Tank and Pumps

Photo 6.12-5: Partially Failed Battery Charger

Photo 6.12-6: Generator Controls and Station Service Equipment

The generator is interconnected to the 600 A service switchboard in the diesel generator building. The switchboard is covered in the AC station service assessment section of this report.

There are a number of other miscellaneous ancillary items including the building itself, the building heating, lighting and local 120 V distribution which are incidental to the generator. These are all original equipment dating to 1978.

Assessment

The engine heating system shows signs of repair over the years and it is reported that the parts for the generator are becoming increasingly difficult to acquire. As the generator is a critical piece of equipment, lack of available spare parts is a concern and should be a reason for planning replacement of the diesel generator.

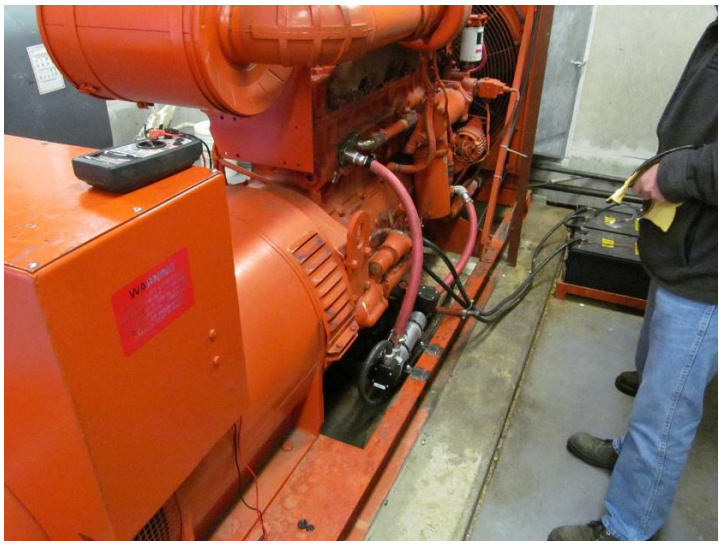


Photo 6.12-7: Auxiliary Inline Heater Installed on Engine

The existing battery charging system has partially failed. The onsite review revealed that it cannot be left on the battery, and it has to be manually turned on and off.

The diesel generator undergoes regular testing and maintenance by Atlantic Tractors and Equipment Ltd. The last two inspection reports were reviewed as part of this assessment. The equipment itself still appears to perform well.

The diesel generator is approaching the end of its useful life and, given the difficulty in sourcing spare parts, it should be scheduled for replacement. It was noted that the generator is already

slated for replacement in 2013. Diesel generators sets typically have a service life expectancy of approximately 30-40 years, and thus replacement at this time is not unusual.

The building itself and its heating, grounding and local distribution system are in reasonable condition given their age. They should continue to be maintained.

The building lighting should be reviewed for replacement as part of the overall lighting upgrades which will eventually be required in the powerhouse and access tunnel.

Recommendations

- The existing diesel generator, including all directly related auxiliaries (day-tank, batteries, charger, generator controls etc.) should be replaced except for the bulk storage tank, the building and the building slab. It is anticipated that this will cost approximately $300k. Replacement does not include the station service distribution portion, as this is addressed elsewhere in this report. It is recommended that Nova Scotia Power proceed with the planned replacement within the next five years. (Note – the project was proceeding in 2013.)
- Provide secondary oil containment around the outdoor bulk fuel storage tank in 2013. Estimated cost is $25k.

6.13 PROTECTION AND CONTROLS SYSTEMS

6.13.1 Protections

The assessment of the protection system includes the generator protections, transformer protections, station service transformer protections, low voltage bus protections, cables, wiring and instrument transformers.

Description

The protection system consists of 1970's vintage electromechanical relays manufactured by Westinghouse. The powerhouse equipment protection relays are installed in a section within the unit control board where the control, indication and metering is on the front of the panel and protective relays are on the back of the panel.

Photo 6.13-1: Electromechanical Protection Relay Arrangement

The line protection relays are the only exception; they are located within the switchyard control building and are not part of the scope of this assessment.

Generator Protections

The generators are protected by discrete electromechanical relays of 1970's vintage. They consist of hardwired primary and auxiliary discrete relays, flush mounted on the panels along with the auxiliary tripping relays and other ancillary components. The fuses and links are mounted on the same panel as the protection relays. The generator protection implemented with single a electromechanical relay is not redundant, meaning that there is no redundant "A" and "B" protection or dual DC supply configuration in this plant.

The protection elements provided for generator protection are as follows:

- Generator voltage restrained over-current 51 VR
- Generator phase unbalance 50/ 51 U
- Generator over-voltage 59
- Generator field ground 64
- Generator P.T. unbalance 60

- Generator differential 87 G
- Generator negative sequence 46
- Generator loss of field 40
- Generator grounding transformer over-current 50 G
- Generator ground over-voltage 59 G
- Generator transformer differential 87 GT
- Generator reverse power 32

Main Output Transformers Protections

The primary protection of the main output transformers is provided by a set of three-phase differential relays. Additional system ground protection is provided by an inverse timed over-current relay connected to the neutral of the transformers. The transformers are also protected by gas relays which detect rapid rate of internal pressure rise. In addition to the transformer protection, a secondary protection for the 144 kV oil filled cable is provided with an HCB-1 pilot wire scheme. The following protection elements are presently configured for the transformers and 144 kV line protection:

- Main transformer restricted ground fault 87 NG
- Main transformer overfluxing 59/81
- Main transformer neutral displacement current 59 ND
- Main transformer neutral over-current 51 G
- 144 kV cable, pilot wire 87 PW

Station Service Transformers Protections

The dry type station service transformers, both unit transformers and the excitation transformers are protected by a set of three electromechanical relays providing timed and instantaneous over-current protection. The protection elements are as follows:

- Unit transformer over-current 50 / 51 UT
- Excitation transformer over-current 50 / 51 ET

The low voltage bus protection is implemented with Westinghouse over-voltage relays and these relays are original and of 1975 vintage.

The location of the protection CT's and PT's are shown in the protection single line diagram 13-4700-11.

Operation of the protective devices on the generator system will result in tripping the unit offline (removing it from service). Fortunately, with the system configuration, a warning in the form of an alarm will typically be given before the tripping function occurs (an example would be the case of transformer high temperature).

The present configuration of the protection system is divided into two main categories: "lock-out" and "non-lockout trip".

The non-lockout tripping includes all non-ordinary conditions and faults which do not warrant a visit to the plant before re-starting of the machine. Non-lockout tripping includes:

- Generator loss of field
- Generator negative sequence
- Generator over-voltage
- Fail to start
- Volts / Hertz over-excitation
- Generator reverse power

The non-lockout relay (94) will do the following actions:

- Trip the main circuit breaker
- Trip the field breaker
- De-energize the shutdown solenoid
- Block auto-start

When the generator has slowed and the wicket gates have closed, the 94 relay will reset itself and reset the auto-start system. The generator may then be restarted from any location.

Lock-out tripping includes all scenarios that are considered critical enough to require investigation before restating the generator. There are three different lockout relays implemented in Wreck Cove GS.

The first lockout relay (86-1) will be operated from the following relays and devices:

- Generator differential
- Main transformer neutral over-current
- Main transformer sudden gas pressure
- Main transformer winding temperature extremely high
- Main transformer oil level extremely low
- Generator phase unbalance
- Generator ground over-voltage
- 144 kV cable pilot wire differential protection
- Neutral displacement voltage
- Generator field ground
- Generator rotor (field) over-voltage
- Exciter AC supply failure
- Exciter thyristor gate control failure
- Failure of two exciter power stages
- Exciter changeover switch off

The second lock-out (86-2) will be operated from the following relays and devices:

- Transformer restricted earth fault
- Unit overall differential
- Unit service transformer over-current
- Unit service transformer temperature extremely high
- Generator back-up voltage restrained over-current
- Generator grounding transformer over-current
- Exciter over-current and over temperature
- Over speed
- Cable oil pressure low
- Trash rack differential high

The third lock-out (86-3) will be operated from the following:

- Generator upper guide bearing temperature extremely high
- Generator lower guide bearing temperature extremely high
- Thrust bearing temperature extremely high
- Unit service failure
- Unit vibration
- Governor oil pressure extremely low
- Governor oil level extremely low
- Gate cable failure
- Tailrace level extremely high

Operation of these lock out relays will prevent the generator from restarting. In this case the operated relay opens the main starting circuit and cannot be reset without manual intervention.

The generator differential protection also provides additional output to the fire protection system. If smoke is detected in parallel with this trip in a generator, the generator deluge system is activated. For further explanation of this, see the Fire Protection section, in the Mechanical Assessment part of this report.

Assessment

The assessment of the protection system included visual inspection, discussion with the maintenance staff, review of the maintenance and test records and KGS Group's experience with similar facilities. The findings summarized below are applicable to all protection equipment covered in this section.

The protections are not duplicated at any point. Protection redundancy or A/B redundancy is typically implemented in modern facilities of this size. Having properly planned duplicate protection in place can significantly help to increase the overall maintainability and reliability of the station. Currently, the failure of a single discrete relay may result in long outages, or worse yet, fail to protect the unit and possibly cause extensive damage.

The age of the protections in place also poses issues. Re-verification of the electromechanical relays is becoming increasingly challenging. Due to the age of the relays, recalibration of the

internal mechanical components in order to obtain the designed time current characteristics should be performed on a regular basis. This is a time consuming and often difficult task.

There are insufficient detailed test records available at site to demonstrate that there is adequate testing done on the instrument transformers such as saturation, accuracy, ratio, and insulation resistance verification.

The cables associated with the protection and control system enclosures contain asbestos which, while typical of this vintage of plant, poses significant health concerns and makes any work or repair required with this cabling or enclosure very difficult. Any work would require asbestos containment enclosures, management and disposal plans, respirators and other associated safety gear, as work with the cabling can cause the asbestos to become friable and airborne.

Photo 6.13-2: Cables within P&C Panel

Photo 6.13-3: Wiring within P&C Panel

There are dedicated breakers for both protection and control within the DC distribution panel. Inspection of the protection and control cables reveals that there is sufficient separation of DC power between the protection and control circuits.

A visual inspection of the cables and wires of the protection system shows that many of these are significantly worn and moreover most of the cables contain asbestos. In the near future this is likely to become an unworkable condition both from a personnel health and an operational viewpoint.

The protection CT's and the PT's are original but still in reasonable condition. They can likely be maintained in operation until a major protections upgrade is undertaken. The only issue with the present arrangement is that there are only single CTs and PTs available for protection. This will cause an issue for any future protection upgrade plans which consider A/B style redundant protections. While these instruments could be shared in redundant schemes, it is ideal to have redundant instruments as well.

Photo 6.13-4: Generator Neutral CT's

Photo 6.13-5: Generator Line Side CT's

When reviewing the generator protection scheme, the existing configuration lacks the protection items that 40 years ago were not recognized to be a problem (i.e. out of step protection, inadvertent energization, etc). System protections and operating conditions for hydroelectric stations in general have drastically changed in that time. The requirements for a present day generator protection system demand a lot more than what was installed 40 years ago. These types of upgrades to a modern configuration would typically be done as part of an overall generator protections upgrade, which has not been performed at this site.

Visual inspection and discussion with the maintenance personnel did not reveal any major issues with the generator protections at this time.

Functionally no issues were reported on the generator mechanical protection and most of the protective devices such as level switches which trigger generator mechanical protections appear to be in good condition.

The transformer protection relays are all old electromechanical relays and are of 1976 vintage. There is no reported functionality issue with the relays but it is recommended to replace these relays with newer multifunction relays as the electromechanical relays are no longer in production and any failure could result in a prolonged downtime of the plant.

The station service and low voltage protection relays are effectively in the same condition and the same issues apply.

Discussion with the maintenance personnel indicate that it is a separate testing group in Nova Scotia Power is responsible for the relay testing and maintenance of the protection relays.

Spare parts are typically a critical issue for relays of older vintage. Discussion with the supplier indicates that availability of spare parts for the electromechanical relays at Wreck Cove would be limited or non-existent.

Recommendations

- Continue with maintenance and calibration of the existing protection systems until the existing system is replaced.
- Given the age of the existing protections and lack of manufacturer support, a plant wide upgrade is in order. As part of this upgrade, it would be anticipated that the entire system should be reviewed to see how the more modern protection schemes could benefit plant reliability and long term maintenance. It is recommended that this upgrade be performed in the year 2016 and the estimated cost is $1.53M per unit, including engineering. Considerations for the upgrade should include:
  - Optimum method of project roll out to minimize outage lengths
  - Methods of encapsulating and removing asbestos from the existing system
  - Options for redundant protection schemes using modern multifunction digital relays
  - Locations and configuration of new equipment

- Integration with future station service switchyard protections
- Anticipated design time is likely on the order of 12-15 months
- Installation time could be in excess of 6 months including an outage of each unit which could be on the order of 1 month
- It is anticipated that station controls upgrades would be performed in parallel with this work
- This work would be done to accommodate the generator replacement or refurbishment.
- Allow for an initial period of low reliability and retain the manual control capability that now exists to assist with this phase.
- Ensure that maintenance persons with the appropriate education and training are in place for maintaining the new technology equipment.

6.13.2 Control System

This section covers all the control systems related to plant / generator control, SCADA RTU and its associated communications, start-stop controls, synchronizers, governor controls, metering, generator and station auxiliaries and miscellaneous items such as: generator and transformer deluge systems, water level gauging, tunnel T-2 gate controls, turbine shut-off valve controls and sump level control.

Plant Control, SCADA RTU and Communications

Description

The control of generating units, reservoir gates, and substation can be performed from two locations: the unit control board at the powerhouse and the Energy Control Centre (ECC) located at Halifax. Historically, a control panel in the Administration Building control room could be used for unit control, but this system is no longer in use.

Photo 6.13-6: Control and Protection Cubicle Front View

Photo 6.13-7: Control and Protection Cabinet Internal View

The unit control board within the powerhouse is located adjacent to each individual unit. This panel is a duplex switchgear control panel with control, indication and metering located at the front with the protective relays mounted on the back of the panel. The controls are hardwired

and date back to the original design and construction of the station (1976). The control system is designed around relay based logic control circuits.

The operator interface for local control consists of control switches, timers, electromechanical relays and speed switches, analog and digital panel meters which are used locally to start, stop, synchronize and load generators. The control circuits interact with each unit's electromechanical flyball centrifugal governor and static excitation system as well as the other generator auxiliary systems required to safely start, stop and control the generator. Synchronizing is performed by auto synchronizer. The Unit 2 auto-synchronizer module is integrated within the exciter control panels while the Unit 1 is equipped with a newly installed Basler auto-synchronizer. The system is composed mostly of the original control circuit components from 1976. Adjacent to the old unit control boards there is a PLC based supervisory system which, with its HMI may be used for monitoring of vibration levels, temperatures and flows. This supervisory system is interfaced with the plant control through SER panel's repeater contacts. Discussions with the protection and control staff reveal that even though this supervisory system is available, it is not used for day to day operation and maintenance.

Earlier there was a fibre optic link between this plant supervisory system and the control equipment located within the administrative building, this link is no longer functional. The unit annunciation mounted on the front panel of the unit control board provides most visual alarms. Pre-start condition can be checked by a manually operated pre-start check switch.

In remote mode, the central SCADA system located at Halifax interacts with the generator hardwired control circuits to allow remote operators to start, stop and to perform a variety of plant control items. A remote terminal unit (RTU) located at the powerhouse connects the powerhouse unit control to the master SCADA control station. The powerhouse RTU is an ACS NTU 7510a RTU and communication with the remote SCADA is based on microwave communication. This remote interface provides the system operators with capability for telemetering and remote control. All critical operating functions can effectively be carried out on a continuous basis without manual intervention at the Wreck Cove GS itself.

Status and condition of systems and units, water levels, etc., are monitored and operators can start, load and stop the generators as required. There is a similar ACS NTU 7510a based remote terminal unit (RTU) within the substation premises which allows the system operators at Halifax to monitor and initiate tripping or closing of the 144 kV line breakers. The reservoir water level information is telemetered to Halifax but no remote control of the reservoir gates is available.

Photo 6.13-8: SCADA RTU within the Powerhouse

A supervisory system for remote monitoring of the reservoir gates and supervisory water level indication is in place at Wreck Cove station. This supervisory system includes a master station at the administration building and a remote station located in the gate control structure. This system used to be a Motorola based system that has recently been changed to a PLC (SCADA PAC) based system. The remote station communicates with the master control station through radio communication while the master station communicates with the RTU located at the 144 kV substation.

The SCADA system at Halifax receives supervisory data related to reservoir water level and gate opening indication through the substation RTU. A discussion about this system reveals that there was once fibre optic communication link between the powerhouse and this supervisory

master station which would allow viewing of data such as the generator temperatures and other basic plant parameters. However that communication link is no longer functional. Effectively, the control of the reservoir gates is done at locally at each gate while remote control is presently disabled.

Photo 6.13-9: Master Station

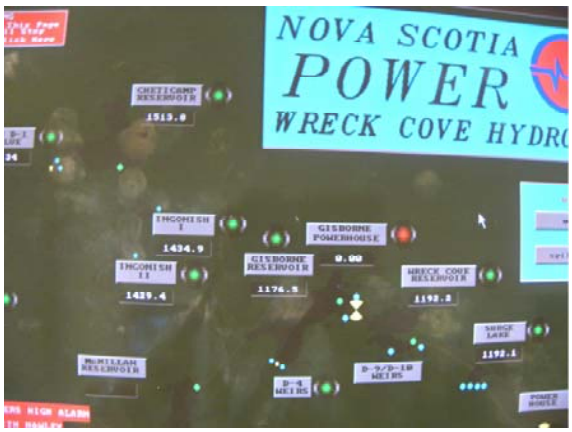


Photo 6.13-10: Water Level Screen

For event recording there are dedicated panels within the powerhouse which house the equipment for the Sequence of Event Recorders (SER). (There is also a similar unit at the substation control building.) These units record the time and event and provide multiplying contacts for local and remote annunciation and display.

The SER in the powerhouse is connected to a printer which captures all event records and also provides contacts for the unit annunciator, the station service annunciator in the powerhouse and to the SCADA system.

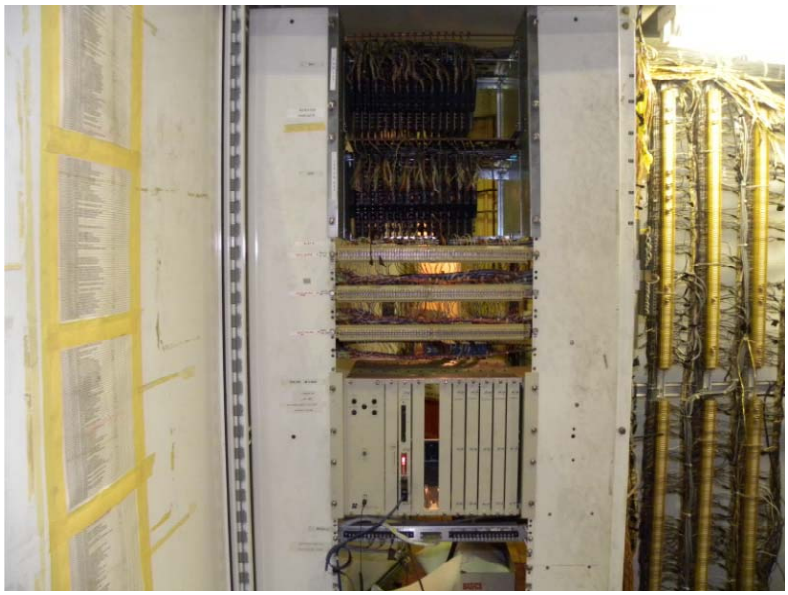


Photo 6.13-11: Sequence of Events Recorder Adjacent to Power Control Cabinets

Assessment

The assessment was performed on the basis of visual inspection, discussion with the maintenance staff and review of the maintenance records.

The existing unit control boards are original and have effectively reached the end of their expected life. Most of the controls are relay based which are becoming obsolete.

All the control wiring within the control panel contains asbestos and requires significant training and preparation to make any changes, so as not to not pose a health related risk for the maintenance personnel.

It has been reported by the station maintenance personnel that the SCADA RTU has been problematic for many years. There are reported intermittent issues with the control cards that cause problems with the configuration stored in memory. Once the configuration is corrupted on the control board, the operator is unable to operate the relays associated with that control board. This can effectively stop plant operation until the issue is resolved. In order to address these technical issues with the RTU, a specialized maintenance crew has to travel from Sydney to Wreck Cove.

The sequence of event recorder is also reaching the end of its life and is based on old technology. Even though the system is working, it is also effectively obsolete when compared with modern day systems.

A system of this type would typically be replaced after approximately 25-30 years. The existing system has already outlasted that estimate. With care the system could be maintained until the overall protections and controls upgrade, but the operational issues may require that the timeline for the overall upgrades be shortened.

A limited stock of spare auxiliary relays, time delay relays, etc. are available at site. However, the available stock is not sufficient to address all the needs in case of significant system failure. Availability of spare parts could be an issue and could potentially cause extended unit downtime.

KGS Group recommends that Nova Scotia Power plan for an upgrade of the Wreck Cove control system to completely replace the installed system with a modern PLC based control systems with two new unit controllers for each unit and one plant controller for other common plant related activity. This configuration would be typical for a facility of this significance; however a detail finalized configuration will be determined during a definition study on the overall plant protection and control systems. See the considerations under

Recommendations

- The problem with the SCADA RTU should be investigated in more detail. Even though replacement of faulty modules within the RTU is acceptable to continue with the operation, procurement and installation of a new RTU is strongly recommended at the time of the control system upgrade. The cost is included within the budget estimated below.
- The upgrade of the control system is recommended for the year 2016. The budgetary cost of replacement is approximately $2.5M. In addition, a design allowance and investigations required for planning of $250k should be included in the year 2014. The upgrade of the control system has to be initiated together with the protection upgrade so that all the technical interfaces between these two systems can be addressed at the same time to

minimize complications. See Control System recommendations for considerations that may apply to Protections replacement.

Start – Stop Control

Description

The units at Wreck Cove GS can be started and stopped in the following control modes:

- Local-Manual
- Local-Automatic
- Remote-Automatic

Sequentially controlled events are laid out within the control board relay logic to allow starting and stopping of the units either locally and or remotely from the Energy Control Centre. The pre-start checks include:

- Penstock readiness, confirmation of minimum lake water level
- Verification of the turbine spherical valve status and, unit circuit breaker status etc.
- Availability of AC and DC station services
- Readiness of thrust bearing oil lift pump, transformer oil pump, turbine spherical valve, generator brakes and voltage regulator
- Shutdown solenoid readiness within the governor cubicle
- Dashpot bypass condition at the governor cubicle
- Readiness of governor oil pumps and
- Readiness of cooling water pumps.

The selector switch 43CS on the unit control board allows local–manual, local-automatic and remote SCADA start-up and shutdown. During the start-up, after all the start-up preconditions are met, initiation of start command will pick up the starting relay (1X). This relays starts the “Incomplete Sequence” timer which is set for a time slightly longer than the expected longest sequencing time of the unit.

This timer (48) seals and picks-up the starting auxiliary relay (1Y). The starting auxiliary relay (1Y) will be energized through the timer contact and eventually a number of cascaded auxiliary relays are activated based on starting conditions and then the unit will be started.

The shutdown is configured as normal-manual, normal-automatic, emergency and protection shutdown. Initiation of emergency shutdown will activate the lockout relay which will trip the unit circuit breaker and close the turbine spherical valve. In case of emergency shutdown, the unit is locked out and requires someone to visit the powerhouse to reset the relays for unit re-starting.

Protection shutdown is initiated by lockout relays triggered by electrical and mechanical protections. The electrical and mechanical shutdown is further segregated as non-lockout shutdown and lock-out shutdown.

Assessment

No major issues were observed relating to the plant start-stop control. The emergency and protection shutdowns are adequate for the plant operation. Discussions with the maintenance staff did not reveal any substantial issues with the plant start-stop control.

The present start-stop control is adequate for the immediate future, until the upgrade of the control system.

Recommendations

- The start-stop control should be upgraded as part of the new PLC based control systems. The budgetary price for the plant start-stop control upgrade is included in the control system budget.

Synchronizers

Description

The Wreck Cove plant does not contain a generator circuit breaker for each unit and the synchronization of the units is performed at the 144 kV level. The generator side PT is compared with the 144 kV bus PT for synchronization.

Photo 6.13-12: Upgraded Auto-Synchronizer

The Unit 2 auto-synchronization devices are within the excitation panel while the Unit 1 auto-synchronizer has been changed recently to a Basler BE1 – 25A based auto-synchronizer.

Assessment

The Basler auto-synchronizer is typical of a more modern system and is adequate for future operation of the system. Generally as these electronic synchronizers have a life expectancy of approximately 20 years, the newer synchronizer is good for operation for the next 10-15 years. Typically this component would be replaced or re-integrated with the overall protection and control upgrade.

The Unit 2 auto–synchronizer which is within the exciter control panel will have to be replaced during the protection and control upgrade.

Recommendations

- The new synchronization system should be integrated with the overall plant controls and protections upgrade. Funds for the synchronizer replacement are included in the controls budget.

Governor Controls

Description

The governors are hydraulic based mechanical governors manufactured by the Woodward Governor Company. The main electrical and control systems/devices supporting the two turbine governor systems are as follows:

- Permanent magnet generator (PMG): Generator speed sensing is performed by a permanent magnet generator fixed to the generator shaft near the top of the unit. The AC signal originating from the PMG is cable connected to a synchronous motor located in the cabinet actuator which is used to drive the governor flyballs.
- Pump power supplies: The governor oil system include two pumps per unit. Each are provided with power supplies from the AC station service unit switchboard and is furnished with a 3-pole disconnect located in one of the lower compartments of the cabinet actuator assembly. These are original to the station (1976).
- Oil pressure and level measurement: The governor oil system accumulator tanks are provided with oil pressure and level switches to perform a variety of functions such as generator mechanical protections, pump control etc. There are float actuated level switches on each accumulator tank. The level and pressure switches are used for generator mechanical protection.
- Oil sump high and low level detection: Each governor oil sump is furnished with float actuated level switches: one for low level detection and one for high level detection.
- Wicket gate position switches: The governor systems are equipped with cam driven, gate position switches which provide gate position information to the generator control systems. The switches are located on linkages within the cabinet actuator and are original to the station (1976).
- Gate position potentiometers: gate position and gate limit sensing, for purposes of generator control and operator indication is performed by potentiometers installed on the governor linkages.
- Governor terminal racks: All control and low power cables for the governor system route through the governor terminal racks. The racks are in a lower compartment, which are an integral part of the cabinet actuators.

Photo 6.13-13: Cabinet Actuator Governor

Photo 6.13-14: Woodward Mechanical Governor

Assessment

The majority of the electrical equipment related to the governor is in good condition. There have been minimal reported issues with the governor system and with thorough maintenance an additional 20 years of reliable operation can be expected.

The frequency response of such mechanical governor is suitable for control of the unit in many operating conditions.

A subset of the components such as the disconnect switches, pumps, internal actuator cabinet wiring, the potentiometers in the wicket gate/gate limit position detection, gate position switches and solenoid valves should be considered replaceable items and should be reviewed for replacement over the course of the next 5 – 10 years.

Currently, there is a brake solenoid valve in Unit 1 governor, which is reported to be sticky. This needs to be checked and replaced, if this situation persists.

Photo 6.13-15: Brake Solenoid Valve

The following spares were found available within the plant maintenance group.

- 2 Motors (speed adjustment motor and limiter motor)
- 1 PMG with a set of speed switches
- 1 Governor pump motor
- No spares were available for the pressure switches

Recommendations

- Generally, this vintage of Woodward governor system has a long history of reliability. Many of the minor electrical items should be assessed for replacement. This is effectively routine maintenance. Components such as the pumps, internal actuator cabinet wiring, potentiometers in the wicket gate/gate limit position detection, gate position switches and solenoid valves should be replaced in a continuous fashion. A program of upgrades should be reviewed costing approximately $ 20k per year and running five years. It is anticipated that this should start within ten years.
- As a part of the life extension program for the governors it is recommended:
  - To perform a major overhaul in the year 2018 and then every 20 years. The cost of a major overhaul is $30k per unit. It is anticipated that this overhaul would be done in conjunction with the unit overhaul.
  - To perform minor overhauls every 5 years in between the two major overhauls. The budgetary cost of minor overhauls is $15k per unit.
- Minor governor maintenance should be done as a part of regular maintenance activity. Lumpsum budgetary estimate is $2k per year.
- Most of the major spare parts and the spares for the accumulator level and pressure measurements system should be procured. The budgetary cost of such spares procurement is $20k. This should be initiated in 2014.
- The faulty brake solenoid should be replaced or repaired in 2013, at an estimated cost of $5k.

Metering

Description

The metering provided for each unit is located on the powerhouse unit control board. The transducers used for the purposes of metering are original to the station (1976). The following metering is located in the unit control board:

- Kilowatt hour meter
- Megawatts
- Megavars
- AC volts

- AC amperes
- DC (field) amperes
- Frequency
- Gate position
- Gate limit
- Speed droop

The metering indication provided to the SCADA system is based on an old analog system, and includes the following indications for each unit:

- Megawatts
- Megavars
- Kilowatt hours
- Voltages
- Gate position
- Gate limit
- Frequency

Assessment

While there are no visible signs of degradation or unusual conditions, the metering systems and their associated transducers are reaching the end of their expected life. The present style and method of metering would typically be replaced with a control system upgrade to a modern metering arrangement.

Photo 6.13-16: Unit Control Board Metering

Photo 6.13-17: Analog Metering Circuitry for SCADA

Currently, the system used to transmit plant MW and MVARs to remote SCADA is an analog based system. A more modern system would use digital interconnections to monitor and transmit this data.

Recommendations

- As the metering system is important to the remote and local operation of the plant, it is recommended that the current system be replaced as it has reached the end of its useful life. The costs to replace this system have been included in the control upgrade costs.

Station and Generator Auxiliaries

Description

The generator auxiliary systems include the following items:

- Cooling water system
- Heating and ventilation systems
- Bearing oil level measurement
- Temperature monitoring
- High pressure oil lift pump system
- Other generator related auxiliary systems

Cooling Water System

The cooling water system provides cooling water to the following electrical and mechanical equipment:

- Generator surface air coolers and guide and thrust bearings
- Turbine bearing and seals
- Main power transformers
- Heating and ventilating air conditioning units (refrigeration units are no longer in service)

The control panel CP1 located within the powerhouse centralizes and integrates control and operation of the cooling water system in the powerhouse and also provides local indication of various alarm conditions. The cooling water section of CP1 provides selection of the operating and standby pumps and local indication of the status of all remotely controlled valves and pumps. There are three centrifugal pumps configured to have two running and one in standby when pumps are in the automatic mode. Time delay and control/alarm relays for the various cooling water system components are contained within the panel CP1. Panel CP1 also houses

alarm relays and provides local indication of alarm conditions for penstock low pressure, high penstock cooling water pressure, high water level in the valve gallery, brake and service air receiver high pressure, fire protection system low water pressure and main cooling water header flow.

Photo 6.13-18: CP1 Panel Internal View

Heating Ventilation and Air Conditioning System

The powerhouse heating ventilating, and air conditioning system is designed to provide fresh air and to evacuate smoke in the event of fire. Control panel CP2, located in the Portal building mechanical room, provides selection of control mode and indication of the operation of air handling units. Local manual or remote automatic control can be selected at the CP2 panel.

Photo 6.13-19: CP2 Panel in Portal Building

Bearing Oil Level Measurement

The lubrication oil in the turbine bearing oil reservoir and in the thrust/generator guide oil reservoir of each generating unit is measured and high or low level alarms are generated in response to abnormal conditions.

Guide/thrust low and high oil level alarms are generated by a float actuated level switch. These switches are original to the station (1978).

Temperature Monitoring

The following temperatures are monitored for the generator mechanical protections and annunciations:

- The stator of each generator contains temperature measurement RTDs for measurement of winding and core temperature
- Bearing temperatures

A new (4-5 years old) panel containing temperature transducers and a SCADA Pack based IO module is used to interface with the generator temperature sensors for supervisory information, as well as for mechanical protections.

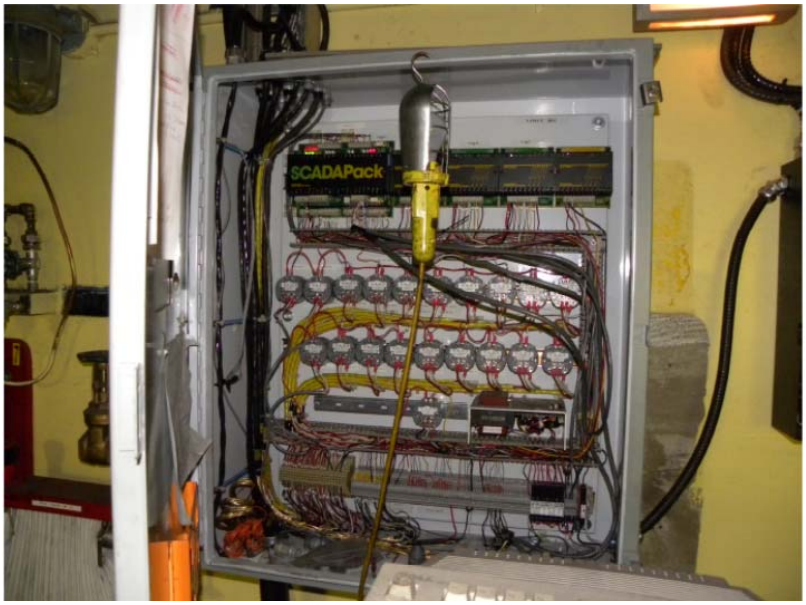


Photo 6.13-20: New Temperature Monitoring Interface Module with Transducers

High Pressure Lift Oil System

Each generator is equipped with a high pressure lift oil system which is used to provide thrust bearing lubrication during unit starts and stops. The system is controlled by the generator speed switch and consists of an electrical motor driven pump, a power supply and a pressure switch,

Assessment

Panel CP1 is old and has effectively reached the end of its useful life. While it is relatively reliable in operation, limited indication and difficult trouble shooting would suggest that it should be replaced. Essentially, the features within panel CP1 would typically be incorporated into the plant PLC with a controls upgrade.

Panel CP2 has also effectively reached the end of its useful life. While it may provide reliable operation for the next several years, it should be assessed for replacement when HVAC systems undergo major renewals. The system will likely provide reliable service for the next ten years.

The new temperature monitoring panel functions will be taken over by the proposed new control system and can be abandoned at that time, likely before it reaches end of life.

The generator temperature monitoring system is modern and good operation can be expected for the next 10 years.

Recommendations

- It is recommended that the control panels CP1 and CP2 be considered for upgrade at the same time as the systems or equipment that they are related to or services are upgraded. While the estimated cost to upgrade CP1 has been included with the controls upgrade, the cost to upgrade the HVAC controls / CP2 is estimated to be approximately $150k and the work should be planned for 2016.

Other Generator Related Auxiliary Systems

Description

Among the other generator related auxiliary systems, are:

- Digital speed switch
- Rotor creep detector
- Thrust bearing water in oil detector
- Brake pad position detection
- Generator vibration monitoring system which is based on a Bentley Nevada system. There is also a vibration analysis system provided in the Wreck Cove plant.

Assessment

Discussion with the maintenance staff did not reveal any major issues with the present instrumentation for the listed systems. As part of a plant control system upgrade, further assessment would be made to identify the instrumentation requirements to match the upgrade.

Recommendations

- Perform a thorough analysis of the compatibility of the plant control instrumentation with respect to modernization of the plant control system. It is anticipated that many of these instruments would be replaced at the time of a controls upgrade, but they could be done at

any time. A lump sum instrument replacement budget for these items is $100k, and the work should be planned for 2016.

Miscellaneous Controls

Description

Included in this section are the following controls:

- Water level gauging
- Tunnel T-2 gate control
- Tailrace manifold water level gauging
- Turbine shut-off valves controls
- Sump level controls
- Deluge systems controls (see Mechanical Assessment section 5.11 Fire Protection and Detection System for details)

Water Level Gauging

There are several water level gauge sites in the Wreck Cove water system where Nova Scotia Power owned water level gauges are installed. The water elevation readings from these gauges are used for Wreck Cove operational purposes.

The lake levels are measured using underwater sensors which respond to changes in lake level. The supervisory system located at the local station transmits the level information to the master station through a VHF radio communication link. The lake and reservoir level is measured for McMillan, Gisborne, Wreck Cove and also at Surge Lake. All the level information is available at the master station located in the Administration Building and also at Halifax through the RTU located at the substation.

Tunnel T-2 Intake Gate Control

The control systems for the Tunnel T-2 gate are included with the mechanical assessment of the gate. See Section 5.1 Tunnel T-2 Intake Equipment for further information.

Tailrace Manifold Gauging

Wreck Cove was originally provided with a tailrace water level monitoring device, an alarm for high level and a lockout which would shut down the turbine generators on extreme high level. This equipment is mounted on the draft tube deck adjacent to Unit 1 draft tube outlet.

Photo 6.13-21: Tailrace Water Level Alarm and Trip

Photo 6.13-22: Floats for Tailwater Alarm and Trip

Turbine Shut-off Valves Controls

The electronic part of the turbine shut-off valve controls was changed recently and discussion with the maintenance personnel indicates that the system is working well.

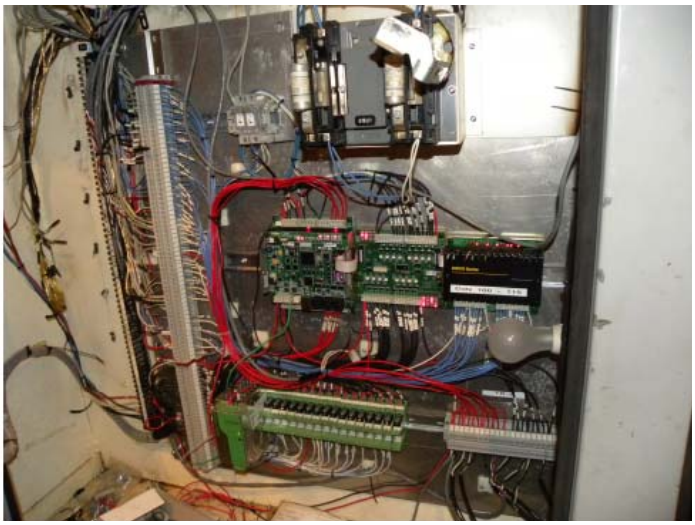


Photo 6.13-23: New Electronic Modules for Shut-off Valve Control

Sump Level Controls

The sump pumps are controlled by level switches installed within the sump. The power for the sump pumps is fed from the auxiliary service MCC while the control panel is located near the pumps. The picture below shows the present condition of the sump pump control panel. It is evident from the picture that there is the possibility of water ingress inside the panel as the panels are located very near a leak running on the wall.

Photo 6.13-24: Sump Pump Control Panel

Photo 6.13-25: Sump Pump

Assessment

The water level gauging system and the associated supervisory system is appropriate and acceptable for operation for the next 10 years.

The tailwater level instrumentation is significantly corroded and the level monitoring function no longer works. The alarm and lockout functions are not tested on a regular basis but when last tested, the alarm functioned as intended and the lockout (with wiring to generating unit controls disconnected to avoid trips) worked as well.

The sump pump control panels are in an inappropriate location and water ingress issues could occur at any time. An outage of the sump pumps could lead to larger issues within the plant.

The newly introduced control cards and electronic system for control of the turbine shut-off valves is good for operation for the next 15 years, at which time it should be replaced.

Recommendations

- Institute a periodic testing program for the tailrace water level alarm and lockout functions, as these functions are very important for worker safety and plant protection.
- Re-instate the tailrace water level monitoring function and connect to SCADA for transmission to the Energy Control Centre in 2014 at an estimated cost of $25k.
- Replace the tailrace water level alarm and lockout system within 3 years at an estimated cost of $15k.

- Replacement of the reservoir water level gauging system is estimated at $38k and should be performed in 2022.
- The sump pump control system should be upgraded within the next five years, including, relocation of the panel to a dry area. The budgetary cost for this work is $18k and it is allowed for in 2016.
- Replace turbine shut-off valve controls with a PLC based system in 2027 at a cost of $50k for two units.

6.14 STATION DC POWER SYSTEM

Description

Wreck Cove GS has a single station DC system, consisting of a single battery bank and charger/inverter system as well as a DC distribution system.

The original DC system failed in 2011 and the inverter was replaced. The new system is a Staticon Stativolt Plant Inverter System rated at 120 VDC and 75 A. The batteries have also been replaced as of December 2011 with a 60 cell bank of GNB Absolyte GP batteries.

Photo 6.14-1: Station Battery Bank

The power distribution centre is the original DC distribution panel. The panel has exposed buswork under the access panel.

Assessment

As the inverter and battery have been recently replaced, they are in good condition. The typical lifespan for batteries in a powerhouse DC system is 10 years. Inverters would typically have a 25 year life span.

The distribution panel has likely reached the end of its useful life and has significant exposed bus-work and poor internal barriers which are not advisable for safe work in a modern facility. The existing power distribution panel should be replaced with the remainder of the equipment.

As the DC system provides critical control power for plant operation, utilities typically install a complete parallel redundant DC system. The current system has no redundancy and as such, any work which must be performed, or any failures which occur, cause complete plant outages.

Recommendations

- The power distribution panel for the DC system is a potential hazard given its exposed buswork. Covers to ensure there is no access issues with the door open could help to reduce this risk, however, as parts of the DC system have substantially been upgraded, the distribution panel should be upgraded as well, to return the entire system to a like new condition. An upgrade to the distribution panel would be done with a distribution panel with visible contacts and would cost $15k and should be preformed in 2014.
- Should Nova Scotia Power wish to increase the reliability of the DC system to attain a more standard configuration with redundant DC supplies, a second battery system and inverter could be installed. An additional battery system would cost $135k. This work would typically be done with station protections and controls upgrades and has been included in 2016.

6.15 STATION GROUNDING SYSTEM

Description

The station grounding system is essentially as installed during the construction of the plant. Drawings H-085S1-3-211-06-001 to H-085S1-3-211-06-007 shows the original as-built drawings of the station grounding system. Much of this grounding system is embedded into the structure itself.

A review of the site showed that the original station grounding system is fully intact. The original grounding system consists of several copper busses which interconnect loops of 250 MCM copper conductor. While there is some sign that the cabling has been moved around over time during construction and operation of the plant, there is little evidence of deterioration of the grounding system or conductors in the powerhouse.

Ocean Ground at Tailrace Tunnel Outlet

There is a heavy ground conductor which extends from the station switchyard, on the overhead line out to the area where the tailrace tunnel discharges into the ocean. This heavy ground was extended out to two large steel I-beams in the water, and was apparently used as a ground electrode at some point in time. The bare conductor which was installed to connect this ground has been stolen and the ground is no longer connected. It is not clear what the intent of the ground was or what system it was tied to. This ground is outside the scope of this Wreck Cove GS plant assessment; however, as there was a significant ground in place which has been removed, its requirement should be revisited and it should be repaired if found to be required.

Assessment

The original ground installed in the powerhouse appears through visual inspection to be in good condition. There are some areas where the strands of the ground conductors are slightly unwound (“bird caging”). However, there is no sign that this is causing any problems and it is likely that this has been present since construction.

In general it is anticipated that the grounding system will provide an additional 40 years of service. It is not clear what level of step or touch potential (personal potential) studies were

done at the time of the grounding installation. Review of these items would require the performance of a modern grounding study, involving both site investigation and tests and specialized computer analysis. Given the advancement of grounding analysis tools over the last 40 years, however, Nova Scotia Power should undertake a full grounding study including step-touch potential analysis.

As maintenance staff has expressed concerns about the state of the grounds immersed in the tailrace, Nova Scotia Power has decided to undertake an initial investigation in 2014.

Recommendations

- Perform a grounding study within in the next ten years. The cost is anticipated at $95k, and this amount has been included in the year 2020.
- While it is not clear how much grounding modification would result from the study, $150k in grounding upgrades has been identified for 2021 as a reasonable estimate.

6.16 STATION LIGHTING SYSTEM

Description

There are three items reviewed as part of the station lighting. These items are general area lighting, emergency lighting and exit signage/lighting.

Plant General Area Lighting

The majority of the lighting throughout the plant is primarily original lighting fixtures, dating from 1978. There have been a few fixtures upgraded in the access tunnel as existing fixtures have failed.

The original lighting in the plant uses mercury vapour HID fixtures for the larger areas and T12 style fluorescent lighting for the majority of the remaining areas. There are some areas which also have large incandescent lamps.

In the main powerhouse area, where the fixtures are suspended on a strut system from the ceiling of the cavern, the supports for the lighting and the conduits supplying power are showing

significant signs of deterioration and have failed in a few areas. There are also a number of areas where the fixtures cannot be readily reached for repair.

In the tunnel portion of the plant which could be used as a refuge area, the lighting and supports are deteriorated to the point of being no longer functional.

As the lighting installed in the plant is nearing forty years old, it has reached the end of its useful life. The fixtures are also significantly less efficient than modern fixtures.

Given the age of the fluorescent fixtures, it is likely that there are ballasts containing PCB's. While not a significant risk, these need to be disposed of properly when they are replaced.

Photo 6.17-1: Typical Powerhouse Area Lighting Fixture Suspended from Strut

Photo 6.17-2: Lighting Support Deteriorated and Fixtures Misaligned as Supports Break

Photo 6.17-3: Typical Fluorescent Area Lighting (Incandescent Fixture in Background)

Plant General Emergency Lighting

Emergency lighting throughout the powerhouse is typically provided using incandescent fixtures and DC power from the station DC system. Emergency lights are placed at key areas, but do not clearly illuminate the path of egress.

There are a few unitized emergency lights in the plant. The main area is in the current “refuge chamber”.

Exit Signage

There is currently no illuminated exit signage in the plant. There are some signs which indicate “Fire Hose” which could be confused for exit signs, but these do not indicate the path of egress.

Assessment

Plant General Area Lighting

The lighting throughout the powerhouse and access tunnel has effectively reached the end of its useful life. Many of the lamps in use will become increasingly more difficult to obtain and are significantly less efficient than modern lighting. The mounting for much of the lighting in the main powerhouse area is significantly deteriorated and should be replaced or repaired. Some

replacement of lighting supports was carried out late in 2012, but the same fixtures were returned to service.

In general, the lighting levels are adequate, but the lighting systems should be replaced.

Plant General Emergency Lighting

Many utilities have begun to get away from emergency lighting which is sourced from the plant DC battery. There are several reasons for this:

1. Lighting loads are more significantly wired throughout the plant than most other DC loads and can introduce a much larger risk into the DC system which is a critical system for control and operation of the plant.
2. The DC systems used for plant lighting are typically not listed/rated to be used as emergency lighting systems.
3. Where emergency lighting systems are upgraded to meet modern requirements, the additional load on the station DC system is often more than the utility would like to add to their station DC system.
4. As the emergency lighting system becomes a more tested/monitored system, it is desirable to decouple the emergency lighting from the station DC to more easily allow testing/repair.

While the existing DC emergency lighting system is functional, it does not provide adequate illumination to meet good egress requirements.

Exit Signage

Given the underground nature of this plant, with limited egress, the lack of illuminated exit signs significantly contributes to workplace life safety risks.

General Lighting Co-ordination

When all lighting systems require upgrades as is the case with Wreck Cove, the lighting upgrades should take into consideration the following items which can help provide the long term operability, maintenance and the day to day operation of the plant:

- Placement of emergency lighting circuits relative to regular lighting. By coordinating these systems, modern techniques such as UPS for lighting can be used which can help minimize the re-wiring of the systems and reduce maintenance compared to two separate systems.
- As there are a number of lighting technologies available today which can be used, they should be assessed with the long term operation of the facilities. Estimates for the lighting

replacements are based on using T5HO high-bay fixtures and standard industrial fixtures in the lower levels. Depending on the location, LED fixtures, which have a long mean time before failure or maintenance is required, could also be reviewed for use in areas where access for maintenance is more difficult.

Recommendations

Plant General Area Lighting

- The lighting throughout the plant should be replaced within the next two to three years, along with the supporting structures where they show signs of corrosion. The main areas where lighting should be upgraded along with their estimated cost include:

Access Tunnel	$205k
Plant Main Area	$220k
Plant Auxiliary Areas	$180k
Plant Refuge Tunnel area	$45k
TOTAL	$650k

This amount has been included in 2016 as its implementation would benefit generating unit overhaul activities.

Plant General Emergency Lighting

- A modern emergency lighting system should be installed which clearly illuminates the paths of egress. This should be installed in conjunction with exit signage and phosphorescent paint striping on the floor, which helps evacuation to occur down the correct route. This new modern emergency lighting system would be DC, but separate from the station DC system.

  The cost of the emergency lighting system would be approximately $195k, and should be done by 2014 as it improves safety for plant staff.

Exit Signage

- Given that there a multiple circular routes and effectively only one exit, exit signs and phosphorescent paint striping on the floor should be installed to clearly indicate the directions of exit. The cost of the exit signs is included with the above item. If an exit

signage system is installed as a separate item, with standalone battery units, the cost of this work would be approximately $20k and should be done by 2014 as it reduces life safety risks for plant staff. These would essentially be self contained exit signs which would have internal chargers and batteries and would connect to AC station service.

7 OPPORTUNITIES AND ISSUES

Opportunities

1. Turbine Upgrading

For many years Wreck Cove operated to help meet daily peak loads, and this has required the units to operate in a relatively narrow power range of relatively high efficiency for a limited number of hours per year (approximately 18 % of the time). For some years, Wreck Cove was also required to respond to very large and sudden steel mill load changes at Sydney.

The future operational requirements for Wreck Cove GS will involve providing support for the grid with quickly varying MW as the capacity of wind-powered generation rises and falls with the prevailing wind speeds. This operating scenario will require the units to operate over a large range of power outputs and likely for many more hours per year. At the same time, Nova Scotia Power is obligated to meet increasingly demanding targets for the amount of renewable capacity supplying the grid. Wreck Cove may be able to contribute to these targets, by increasing the capacity of the units, primarily through upgrading of turbines by runner replacement.

Turbine upgrades by runner replacement should be investigated prior to any planned major unit overhauls, and co-ordinated with these overhauls. Upgrading is a widely practiced solution to extract energy gains by installing new higher efficiency runners, usually with slightly higher capacity as well. These improvements are available as the result of improved design tools and high precision manufacturing processes.

To satisfy the combined requirements of increased capacity and a broader range of stable outputs is a challenging task and will require a design/development program involving both computerized fluid dynamics studies and precision scale model testing, to attain the design characteristics required. The source of supply can include the original equipment supplier, but is best expanded to include large reputable suppliers such as Andritz, Alstom and Voith. The essential need is for a supplier with strong design credentials and modern design tools and extensive experience with high head Francis turbines.

Other considerations for this opportunity include:

- Efficiency gains could potentially justify at least some of the cost of the new runners.
- Air admission requirements for partial load operation consistent with modern installations should be investigated during the engineering phase for new runners.
- The potential to improve the geometry of the wicket gates and the draft tube should be considered in the engineering phase.
- Comparison model testing of the existing and future runners should be performed.
- The turbine hydraulic model and runner from the 1970's may be reusable and should result in some cost savings for the engineering phase.
- Depending on the capacity gain available, other power components will need to be assessed for upgrading/replacement, including generator windings, exciter, breakers, IPB, and main output transformers.
- A limiting feature of Wreck Cove appears to be the hydraulic capacity of Tunnel T-2 to supply adequate water to Surge Lake to run two units at full load for a sustained period.
- The installation of the new runners should be coordinated with the future major unit overhauls, rewinding and electrical equipment replacements.

The estimated cost of supplying two replacement runners, including hydraulic model development is $5.55M, and the time required from preparing specifications to runner delivery would be 2 ½ to 3 years.

Photo 7.0-1: Turbine Hydraulic Model at Wreck Cove

2. Plant Efficiency Tests

It appears that the present overall efficiency at various loads for the Wreck Cove Facility is not known. No performance testing has been carried out since original commissioning when Mitsubishi performed a test, likely for the purpose of demonstrating compliance with turbine specifications. The test report was not available and may no longer exist. NS Power should consider performing a series of unit and turbine performance tests to determine:

a) Overall plant and individual unit efficiency for all loads
b) Penstock losses
c) Turbine efficiency as a baseline for turbine upgrading

The cost of the test program is estimated to be $250k, and would need to be performed by a company specialized in this type of testing.

In the event that runner replacement does not proceed, having the test results would assist in optimizing the operation of the Wreck Cove units.

Issues

1. Worker Refuge Facility

In the original design of Wreck Cove, a basic worker refuge area was provided in the form of a modified mucking tunnel, upstream of the powerhouse cavern. Over the years, the tunnel refuge has not been maintained and at some point a steel refuge chamber was installed. The design requirements for the refuge chamber are unknown. It appears to have space for about 4-6 persons, but for what time period or against what event is not clear.

The capacity and location will be inadequate during the LEM site work phase, when large numbers of persons will be working in the plant.

A combination of modern refuge enclosure(s) and fire safety modifications within the powerhouse would provide better protection for persons working on various plant floors.

Photo 7.0-2: Exterior of Present Refuge Enclosure

Photo 7.0-3: Interior of Present Refuge Enclosure

The following photos and text describe a modern refuge recently purchased by B.C. Hydro for one of its underground hydro stations. The supplier of the information and photos below and of the B.C. Hydro refuge is Mine ARC Company.

Photo 7.0-4: Modern Refuge Enclosure

This unit was custom built to customer specifications and features:

- 4 person occupancy / 24 hour stand-alone operation.

- Built-up wall construction using 1/4" steel exterior panel, 1" Promat calcium silicate fire resistant material and 1/8" steel inner panel.
- Airlock system for flushing prior to entry into chamber including compressed breathing air cylinders and push-button activated flushing.
- Air scrubbing of CO2 and CO
- On board oxygen supply with medical grade oxygen regulator.
- Powerless design using liquid CO2 to propel scrubbing fan and provide cooling and dehumidifying within refuge interior (we can also Engineer electrically-operated designs).
- External lockable liquid CO2 cylinder bay.
- Wheel package for transport with lifting and towing eyes, forklift slots, etc.
- Rechargeable power packs for lighting, emergency strobe light and interior lighting.
- Digital hygrometer/thermometer for managing scrubber/air conditioning system.
- Manual gas monitoring of O2, CO2 and CO within refuge chamber.
- Communications connections with ability to power radio off battery packs.
- Seating, scrubbing chemicals, emergency food and water.
- Chemical toilet and fire extinguisher.
- Incoming compressed air line with three stage filter pack, auto-drains to exterior, regulator and auto muffler.

For budgetary purposes a 6 person refuge chamber of similar design will be in the $90k range – however it is best for us to examine the exact needs of the facility prior to providing any costing. If you foresee the value in it, I will be happy to fly up to visit with you and your customer to do a site visit, examine their needs and provide an informal presentation/discussion on the subject – please let me know.

4
HYGROMETER
HANDLE
PURE OXYGEN
ROTATE HANDLE SLOWLY
EMERGENCY DRINKING WATER
EMERGENCY FOOD RATIONS

KEEP CLEAR FOR ABSORBER CARTRIDGE INSTALLATION
7 CO2 CHEMICAL MARCSORB 1500
8 CO CHEMICAL MARCSORB 1000
10:12

PUSH TO FLUSH AIRLOCK
EMERGENCY USE ONLY
2
13, 14
DANGER
NO SMOKING
PURE OXYGEN
DANGER
LEAK TEST

mineARC
SYSTEMS
7
CO2 CHEMICAL
MARCISORB 1500
CO CHEMICAL
MARCISORB 1000
10-12

2. Maintenance Inspection and Testing Program

The present periodic maintenance inspection and testing program for major equipment and for auxiliary systems and equipment should be reviewed, updated and expanded with the assistance of engineers familiar with hydro plant equipment. Inspection and test procedures with records sheets for ease of recording the findings should be prepared.

Adequate resources should be provided within the Wreck Cove maintenance crew to ensure that the inspection and test findings are documented in retrievable reports, and are available for trend analysis, monitoring and general reference.

3. Preparations for Life Extension and Modernization

In order to carry out the refurbishment of the Wreck Cove Facility in the safest, cost effective and outage schedule effective way, several enhancements and additions to infrastructure will be needed. This includes:

- Surface storage/workshop building for major equipment components and workspace
- Management of traffic in the powerhouse access tunnel, including parking at the powerhouse end
- Provision of worker facilities – accommodations, food and parking
- Life safety enhancements such as refuge areas, improved access to egress, refurbishment of lighting and ventilation improvements
- Updating of powerhouse crane controls

Furthermore, planning for the LEM will need to address:

- Long lead time for activities such as engineering and procurement for major equipment and systems, much of which is custom designed,
- Optimum sequencing and overlap for integrating various equipment replacement and refurbishment activities, and
- Whether a potential additional access tunnel to the powerhouse is necessary.

Supporting Information

The following pages contain information related to the opportunities and Issues discussed in this section of the report.

Mike Markovich

From: Girard Gilles [Gilles.Girard@andritz.com]
Sent: November-21-12 12:14
To: Mike Markovich
Cc: Pomeroy Keith
Subject: RE: Wreck Cove

Hello Mike,

In response to your email below and the one that you sent to Keith Pomeroy, I am pleased to provide you with a rough budget price for the supply of replacement runners for the NS Power Wreck Cove project:

- First runner: $ 1,415,000.00
- Second runner: $ 1,215,000.00

Your email also asked for model testing and these days a fully homologous model test cost approximately $ 1.5 Million. However, if the model assembly can be provided and if it can be used as is without modification / refurbishment to the assembly or to the test stand, the model development price could be reduced approximately by $ 400,000.00 to $ 450,000.00

This budget pricing is non binding and its sole and exclusive purpose is to provide KGS / Nova Scotia Power with preliminary information on costs for the Wreck Cove Replacement Runner Project for the Wreck Cove project. This proposal does no create any binding obligations, legal or equitable, on the part of either Andritz Hydro Canada Inc. or KGS / Nova Scotia Power to (i) execute a final agreement for the Wreck Cove Replacement Runner Project, (ii) attempt to reach an agreement on the proposed terms of a final agreement for the Wreck Cove Replacement Runner Project or (iii) otherwise. Neither Andritz Canada Inc. nor KGS / Nova Scotia Power assumes any binding obligations (including in relation to budget price) regarding the Wreck Cove Replacement Runner Project unless and until a mutually agreed contract is executed by both parties pursuant to all required corporate authorizations

As I mentioned in a previous email, this should not be construed as an engagement from Andritz Hydro to provide new and improved replacement runners for Wreck Cove and in the event of a contract complete water passages dimensions will have to be provided

I hope the above will be useful

Best regards

Gilles

From: Mike Markovich [mailto:MMarkovich@kgsgroup.com]
Sent: Friday, November 16, 2012 4:14 PM
To: Girard Gilles
Cc: 'Mike Markovich'
Subject: RE: Wreck Cove

Hello Gilles – I've attached the full email I sent to Keith. It has all the information you need, except I don't have the runner weight.

Yes for your stainless question.

Two runners are required.

1

Yes, it is understood the limitations of your budgetary price and that there is no commitment on Andritz or affirmation that an improved runner could be designed without extensive model testing and analysis.

Have a good weekend, Gilles.

Mike Markovich P Eng
Senior Mechanical Engineer & Project Manager
KGS Group
ph: 905.848.6031
4310 Sherwoodtowne Blvd., Suite 402
Mississauga, Ont. L4Z 4C4

From: Girard Gilles [mailto:Gilles.Girard@andritz.com]
Sent: November-16-12 15:14
To: Mike Markovich (mmarkovich@kgsgroup.com)
Cc: Pomeroy Keith
Subject: Wreck Cove

Hello Mike,

Keith Pomeroy forwarded your request for a rough budgetary price for a runner replacement at Wreck Cove.

In order to be able to provide you with a budget price, can you provide me with the following runner information:

Throat diameter
Distributor height
Runner weight
Net head

I presume that you would want a stainless steel runner.

With regard to potential performance enhancement, unless we are given all the unit water passages information (dimensions), at this time, we cannot presume that we could achieve increases in output and efficiency nor can we state with any degree of certainty if we could improve on the already large operating range of these machines.

Therefore, the budgetary price that we will provide must not be viewed as a firm engagement of Andritz Hydro that we could deliver an improved runner (output, efficiency and operating range) as is implied in your email to Keith without doing model testing and more detailed analysis of the existing machine.

Gilles

##########

This message and any attachments are solely for the use of the intended recipients. They may contain privileged and/or confidential information or other information protected from disclosure. If you are not an intended recipient, you are hereby notified that you received this email in error and that any review, dissemination, distribution or copying of this email and any attachment is strictly prohibited. If you have received this email in error, please contact the sender and delete the message and any attachment from your system.

Thank You.

##########

Mike Markovich

From: Albert Mikhail [albert.mikhail@hppe.com]
Sent: January-16-13 00:08
To: 'Mike Markovich'
Cc: albert.mikhail@hppe.com
Subject: RE: Performance Tests

Importance: High

Hello Mike

Here is the update

	THERMODYNAMICS	ACCOUSTIC
ONE UNIT	$78,870.00	$81,740.00
SECOND UNIT SAME TRIP	$71,640.00	$77,940.00
TWO UNITS SAME TRIP AFTER TESTING EACH UNIT	$29,740.00	$29,740.00
ONE TRIP - TOTAL TESTING EACH UNIT AND THEN BOTH UNITS SAME TIME	$180,250.00	$189,420.00
ONE TRIP SETUP TWO UNITS AND TESTING ONE UNIT THEN TESTING BOTH UNITS AT THE SAME TIME	$171,706.00	$176,872.00

Albert Mikhail P.Eng.
Principal Engineer
HydroPower Performance Engineering Inc.
Mobile (416) 558-1641

From: Scott Parsons
To: mmarkovich@kgsgroup.com
Cc: Steve.Edwards@weirgroup.ca; Alan Roth; jason.heilman@weirgroup.com; Marc Chenier; agamig@verizon.net; mark.self@weirgroup.com
Subject: NS Power Wreck Cove Assesment
Date: Tuesday, April 10, 2012 2:00:21 PM

Mike:

Good afternoon, we had a meeting with NS Power (Tim Gillis & Malcolm Kaiser) about three weeks ago regarding this project. Both Tim and Malcolm were visiting the Weir American Hydro facility in Montreal.

At that time they had indicated that you were assigned as the contact within KGS for this project. NS Power has provided us with some additional info as well and we will review to determine if the the info supplied was sufficient to review for the efficiency assessment for runner upgrade.

Regards
Scott

Scott Parsons
Account Manager Atlantic Canada

Weir Canada Inc / Weir American Hydro
201 Brownlow Ave. Suite 44
Dartmouth, Nova Scotia B3B 1W2
Ph: 902-468-6103
Cell: 902-240-1558
Fax: 902-468-6108
Montreal: 514-366-0907 Ext 2221

E-Mail: scott.parsons@weirgroup.com

From: Steve Edwards <steve.edwards@weirgroup.ca>
To: Jason Heilman <jheilman@ahydro.com>
Cc: George Agami <agamig@verizon.net>, alan.roth@weirgroup.com, mark.self@weirgroup.com
Date: 04/10/2012 12:31 PM
Subject: Fwd: Upgrade Runner

Hi Jason,

This one is for George (Nova Scotia Power). Please ask someone to respond to Mike Markovich and have them copy me on the first round.

Thanks,

Steve

-------- Original Message --------
Subject: Upgrade Runner
Date: Tue, 10 Apr 2012 11:41:54 -0400
From: Mike Markovich <MMarkovich@kgsgroup.com>
To: 'Steve' <steve.edwards@weirgroup.ca>
CC: 'Mike Markovich' <MMarkovich@kgsgroup.com>

Steve – we are performing a condition assessment of a plant for NS Power (one of your clients, I understand). They are not presently planning on a runner replacement (to my knowledge), but as part of our work we are investigating the merits at a concept study level. Power gain is not as valuable as an efficiency gain.

Could you please provide a budgetary price for design and manufacture, and a performance curve (hill chart or, for the rated head, an efficiency vs power curve or an efficiency and power vs discharge curve) for two replacement stainless steel runners, with cones, as follows:

Two vertical shaft units
Rated Head 1150 ft
Speed 450 rpm
Runner Crown OD 2640 mm
Runner Inlet Edge Diameter 2600 mm
Distributor Height 326.5 mm
Runner Band OD 2120 mm
Runner Outlet Diameter (Throat) 1990 mm
Distributor Centreline (relative to tailwater) 4 ft below tailwater
Plant Elevation Sea level

Present unit is rated for 138,000 hp at 1150 ft. Head range is 1121 ft to 1166 ft. The unit has 24 wicket gates on 3000 mm circle and runner has 19 blades.

If you need other information, please call or e mail. Would you be able to respond by end of April or early May?

Thanks, Steve.

Mike Markovich P Eng
Senior Mechanical Engineer & Project Manager
KGS Group
ph: 905.848.6031
4310 Sherwoodtowne Blvd., Suite 402
Mississauga, Ont. L4Z 4C4

From: Scott Parsons
To: mmarkovich@kgsgroup.com
Cc: Alan Roth; jason.heilman@weirgroup.com; Steve.Edwards@weirgroup.ca; Marc Chenier
Subject: NS Power Wreck Cove
Date: Thursday, June 21, 2012 6:05:31 AM
Attachments: Wreck Cove Prel Performance.pdf

Mike:

Attached are some notes and preliminary design review that has been conducted by Bob Rittase our chief hydraulic engineer.
Jason Heilman and myself met with NS Power Tim Gillis and Ellis O'Neil earlier this week regarding Wreck Cove and other ongoing projects we have with NS Power.
Tim has invited us to come to Wreck Cove during the scheduled outages for these units in August and September.
If you have any questions or if you could also provide additional direction please don't hesitate to contact us.

Regards
Scott

Scott Parsons
Account Manager Atlantic Canada

Weir American Hydro
201 Brownlow Ave. Suite 44
Dartmouth, Nova Scotia B3B 1W2
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Cell: 902-240-1558
Fax: 902-468-6108
Montreal: 514-366-0907 Ext 2221

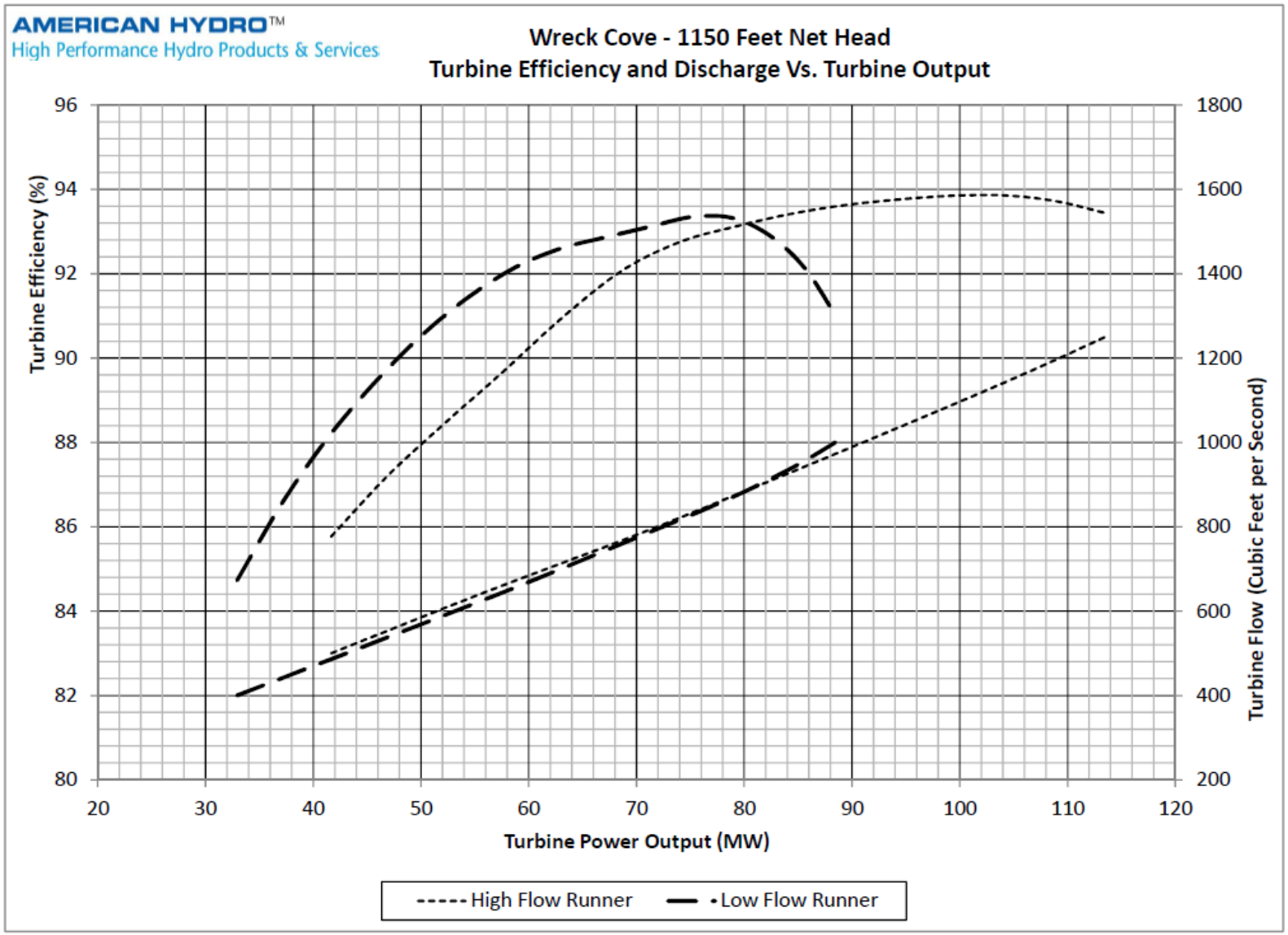
E-Mail: scott.parsons@weirgroup.com

I tried coming up with a "mismatched units" scenario for Wreck Cove and was not too successful. The upgrade potential of the units is only slightly over 10% without cavitation. The attached performance comparison shows two machines with one designed for a higher flow and one designed for a lower flow maintaining the existing capacity of 200 MW for the plant. The low flow runner improves efficiency at part load but not significantly since the curve shapes on these machines are relatively flat. Also, the low flow runner at Nq=25 has a lower peak efficiency than the high flow runner.

Overall, there are no fundamental problems with the existing hydraulic design. We could possibly develop an air admission system to replace the existing frame in the draft tube cone but this might present some mechanical problems and does not appear to require a runner replacement. If their existing aeration system allows them to operate to very low loads, this is likely not a very good alternative.

Bob

Robert A. Rittase
Chief Hydraulic Engineer


AMERICAN HYDRO™
High Performance Hydro Products & Services
Wreck Cove - 1150 Feet Net Head
Turbine Efficiency and Discharge Vs. Turbine Output
Turbine Efficiency (%)
96
94
92
90
88
86
84
82
80
1800
1600
1400
1200
1000
800
600
400
200
Turbine Flow (Cubic Feet per Second)
20
30
40
50
60
70
80
90
100
110
120
Turbine Power Output (MW)
High Flow Runner
Low Flow Runner

From: Girard Gilles
To: Mike Markovich
Subject: RE: Budgetary Estimate for Two New Generators
Date: Thursday, February 14, 2013 10:11:44 AM

Mike,

I was finally able to find recent reference project and I am pleased to provide you with the following:

The estimated selling price for 1 unit of 111 MVA, 450 rpm, 13.8 kV is 13.5 M CAD including installation

Hope this will help

Gilles

From: Girard Gilles
Sent: Wednesday, February 06, 2013 2:01 PM
To: 'Mike Markovich'
Subject: RE: Budgetary Estimate for Two New Generators

Mike,

Just a quick word to tell you that I did not forget about your request. I am trying to find a recent close reference of a similar generator in order to develop a budget price for Wreck Cove Generator. We have nothing recent in Canada or North America but we have asked our friends in Europe if they have something close.

As soon as we hear from them, I should be able to derive a budget price for Wreck Cove

Regards

Gilles

From: Mike Markovich [mailto:MMarkovich@kgsgroup.com]
Sent: Friday, January 18, 2013 9:19 AM
To: Girard Gilles
Cc: Pomeroy Keith; mmarkovich@kgsgroup.com
Subject: Budgetary Estimate for Two New Generators

Hello Gilles:

Nova Scotia Power is in the early stages of planning for major refurbishments at Wreck Cove GS. It would be very helpful and appreciated if you could provide me with a budgetary price estimate to design, supply, install and commission two new generators, to fit onto existing turbines, having the following specs;

111 MVA with overload rating of 116 MVA
13.8 kV
450 rpm
780 rpm runaway

Also, if the scope of work was only to replace the rotor spider and the stator cores and windings, would the price be significantly reduced? The existing generators are CGE of 1978 vintage, and presumably the stator frames, shafts and bearings could be reused.

Thanks for your assistance on this, Gilles. Please note that a lot of detailed effort on this is not required, as it is mainly to plan a budget for the next 5 to 7 years.

Mike Markovich P Eng
Senior Mechanical Engineer & Project Manager
KGS Group
ph: 905.848.6031
4310 Sherwoodtowne Blvd., Suite 402
Mississauga, Ont. L4Z 4C4

8 REFERENCES

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Drawings

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23. Powerhouse - General Layout. 1976. H-085S!-1-211-00-003.

24. General Layout. 1978 : s.n. H-085S1-1-111-00-033.

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27. Tailrace Outlet. 1976. H-085S1-1-626-00-002.

28. Geotechnical Data - Tunnel T-2 (Fig. 4). H-085S1--1-628-00-014.

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34. Spherical valve - General Arrangement. 1975. H-085S1-2-410-09-001.

35. Nova Scotia Power Wreck Cove Hydro System – Emergency Preparedness Plan. Figure 11.1b.

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47. Report by GE Hydro on modifications to unit 2 rotor: 1998

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49. NSPI Plant condition assessment Request for Proposal: 2011

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54. Powerhouse H.V.A.C. Layout at EL. 29'-6. 1977. H-085S1-2-732-00-002.

55. Arrangement of Compressed Air Piping (1/2). 1976. H-085S1-9-411-00-087.

56. Powerhouse Cooling Water & Dewatering System Instruments Flow Sheet. 1977. H-085S1-4-211-00-002.

57. 72" Dia. Spherical Valve Assembly. 1976. H-085S1-9-414-00-035.

58. Auxiliary Cooling Water Flow Diagram. 1996. H-085S1-2-712-51-001.

59. Powerhouse Fire Protection Equipment Layout. 1977. H-085S1-2-714-00-002.

60. Access Tunnel Fire Protection Equipment Layout. 1976. H-085S1-2-714-00-004.

61. Powerhouse Cooling Water & Dewatering System Flow Sheet. 1977. H-085S1-2-717-00-001.

62. Sectional Assembly of Vertical Francis Turbine. 1970. H-085S1-9-411-00-002.

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64. Powerhouse Clear Water & Transformed Oil Drainage System Flow Sheet. 1976. H-085S1-2-155-00-001.

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66. Main Single Line Equipment Diagram. 1977. H-085S1-3-211-02-002.

67. Powerhouse Lighting Fixture & Panel Schedules. 1977. H-085S1-3-211-06-013.

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71. Wiring Diagram for #11-330 165/25 Ton Cap. Overhead Crane. 1976. H-085S1-9-771-34-003.

72. Schematic Wiring Diagram for #11-330 165/25 Ton Cap. Crane. 1976. H-085S1-9-771-34-004.

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76. Unit No 1 - AC Schematic Diagram - Generator Relaying & Metering Current Circuits. 2006. A-085S1-3-211-03-001 (Rev AB1).

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9 STATEMENT OF LIMITATIONS AND CONDITIONS

9.1 THIRD PARTY USE OF REPORT

This report has been prepared for the Client to whom this report has been addressed and any use a third party makes of this report, or any reliance on or decisions made based on it, are the responsibility of such third parties. KGS Group accepts no responsibility for damages, if any, suffered by any third party as a result of decisions made or actions undertaken based on this report.

9.2 SCOPE OF 2012 ASSESSMENT

The 2012 Condition Assessment of Wreck Cove addressed the powerhouse equipment and systems, the access tunnel portal, the structures and equipment for water control at the entrance to tunnel T-2, at the inlet to the penstock and at the tailrace tunnel outlet, the penstocks and the standby diesel generator.

Certain component parts of the Wreck Cove facility were outside the scope of the 2012 assessment, including the storage dams, tunnels T-1, T-2, the powerhouse access tunnel and the tailrace tunnel, Gisborne Generating Station, the main output transformers and the associated 144 kV conductors, the switchyard, the Administration Building and all surface facilities such as dykes, roads, communication tower, storage buildings and other miscellaneous buildings. Assessments for dam safety and assessments of these assets may result in identification of additional projects requiring funding which is not included here.

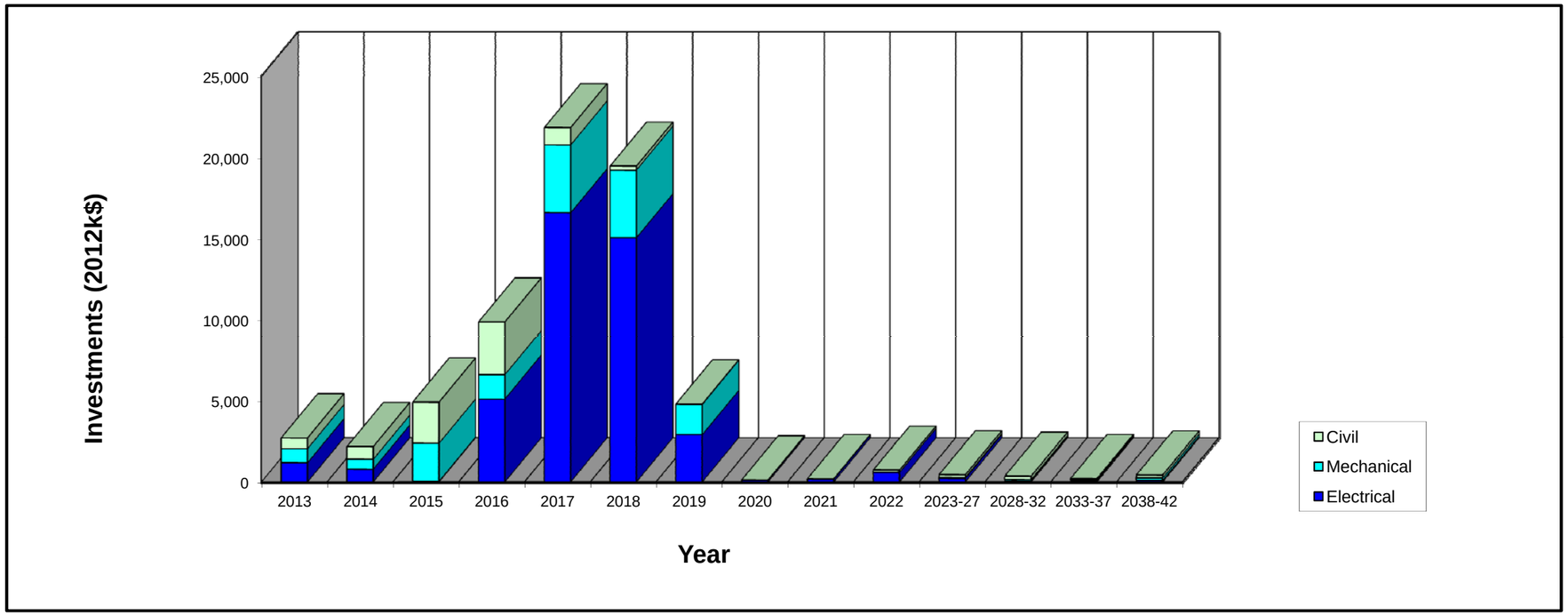
FACILITY & DISCIPLINE SUMMARY SHEETS

Condition Assessment
Facility Summary Sheet
WRECK COVE GS

All Disciplines (except for geotechnical)

Thirty year total (2012 k$)	$68,104	Five year total (2012 k$)	$41,433
Ten year total (2012 k$)	$66,695	One year total (2012 k$)	$2,695

Discipline \ Year	All Years	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023-27	2028-32	2033-37	2038-42
Totals	**68,104**	**2,695**	**2,167**	**4,901**	**9,841**	**21,829**	**19,455**	**4,784**	**113**	**189**	**721**	**435**	**350**	**201**	**423**
Civil	9,263	648	771	2,514	3,244	1,061	234	19	14	14	129	158	204	74	179
Mechanical	15,924	870	609	2,346	1,502	4,187	4,174	1,854	2	14	2	60	88	60	156
Electrical	42,917	1,177	787	41	5,095	16,581	15,047	2,911	97	161	590	217	58	67	88



Notes: *1. Added costs potentially in the range of 10 million dollars may be identified in a detailed life safety study recommended to be undertaken.*
2. The 2012 Condition Assessment of Wreck Cove addressed the powerhouse equipment and systems, the access tunnel portal, the structures and equipment for water control at the entrance to tunnel T-2, at the inlet to the penstock and at the tailrace tunnel outlet, the penstocks and the standby diesel generator. Certain component parts of the Wreck Cove facility were outside the scope of the 2012 assessment, including the storage dams, tunnels T-1, T-2, the powerhouse access tunnel and the tailrace tunnel, Gisborne Generating Station, the main output transformers and the associated 144 kV conductors, the switchyard, the Administration Building and all surface facilities such as dykes, roads, communication tower, storage buildings and other miscellaneous buildings. Assessments for dam safety and assessments of these assets may result in identification of additional projects requiring funding which is not included here.

Wreck Cove Condition Assessment - Condition Rating Scale

Rating	Condition Description	Details	Remediation Timetable
4	Good	Only minor deterioration or defects are evident.	20 plus years (2034 & beyond)
3	Fair	Moderate deterioration. Function is still adequate.	7-20 years (2021 to 2033)
2	Poor	Serious deterioration of at least some portions of the equipment. Function is inadequate. OR: Additional inspection, testing and assessment required in near future, to more fully define condition.	2-7 years (2015 to 2020)
1	Unacceptable	Extensive deterioration. Barely functional. Urgent need for remediation. OR: Additional inspection, testing and assessment urgently required to more fully define condition.	0-2 years (2013 to 2014)

Notes:

1. The basis year for this table is the end of 2012, by which time the assessment of equipment and structures was completed.
2. Condition considers physical deterioration and general adequacy for functional, safety and environmental adequacy.
3. In some cases, additional inspection, testing, investigation or assessment activites are recommended to better define condition and to aid in selecting or refining the best solution.
4. The condition rating scale is based on a similar table used by a large Canadian electrical utility.
5. The term MTCE is used to identify routine/periodic maintenance program recommendations. These are not condition ratable.

Condition Assessment Discipline Summary Sheet

WRECK COVE GS

***Civil** (except Geotechnical)*

Thirty year total (2012 k$) $9,263
Ten year total (2012 k$) $8,648

(costs in 2012 k$)

		Condition Rating	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023-2027	2028-2032	2033-2037	2038-2042	TOTAL 2013-2042
TOTALS			**648**	**771**	**2,514**	**3,244**	**1,061**	**234**	**19**	**14**	**14**	**129**	**158**	**204**	**74**	**179**	**9,263**
TUNNEL T2 INTAKE STRUCTURE			207	0	0	5	30	0	5	0	0	55	5	10	10	5	332
TUNNEL T2 ADIT			0	80	0	325	0	0	0	0	0	0	0	0	0	0	405
PENSTOCK INTAKE STRUCTURE AT SURGE LAKE			0	0	0	0	0	110	0	0	0	0	0	0	0	0	110
PENSTOCK FROM SURGE LAKE			5	12	0	0	0	5	0	0	0	20	5	5	5	5	62
SPIRAL CASE			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DRAFT TUBE			50	10	0	0	0	0	0	0	0	0	0	0	0	0	60
TAILRACE			50	0	0	0	0	105	0	0	0	15	49	25	5	115	364
POWERHOUSE			20	40	10	110	110	10	10	10	10	10	50	160	50	50	650
POWERHOUSE EGRESS AND LIFE SAFETY			300	625	2,500	2,800	0	0	0	0	0	0	0	0	0	0	6,225
POWERHOUSE ACCESS TUNNEL			16	4	4	4	921	4	4	4	4	29	49	4	4	4	1,055
POWERHOUSE ACCESS TUNNEL FEEDERS			0	0	0	0	450	0	0	0	0	0	0	0	0	0	450
DETAILED SUMMARIES																	
TUNNEL T2 INTAKE STRUCTURE			**207**	**0**	**0**	**5**	**30**	**0**	**5**	**0**	**0**	**55**	**5**	**10**	**10**	**5**	**332**
	Continue to periodically, visually monitor the concrete for evidence of deterioration and spalling and waterline erosion.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Carry out minor patching repairs to the spalled concrete within the next 10 years. Other than the minor patch work no concrete repairs are recommended for the next 30 years. Cost for the patch work is estimated to be $50k.	3	0	0	0	0	0	0	0	0	0	50	0	0	0	0	50
	Remove deteriorated paint and corrosion and apply a protective coating to the Gate Hoist Building structural steel superstructure as well as gains. This work should be performed within the next 5 years to maintain the integrity of the structure. The estimated cost for this work is $30k.	2	0	0	0	0	30	0	0	0	0	0	0	0	0	0	30
	Repair the failed caulking around the roof hatch within the next year. Consideration should be given to replacing the failed caulking with grade mastic and mesh. A protective coating should then be installed over the repair. The estimated cost for this work is $6k.	1	6	0	0	0	0	0	0	0	0	0	0	0	0	0	6
	Install an all season safety boom in 2013, at an estimated cost of $130k.	1	130	0	0	0	0	0	0	0	0	0	0	0	0	0	130
	Include funds in the maintenance budget for boom maintenance in the amount of $5k every 3 years.	MTCE	0	0	0	5	0	0	5	0	0	5	5	10	10	5	45
	Extend the safety fencing to the boom anchor points in 2013 at an estimated cost of $70k.	1	70	0	0	0	0	0	0	0	0	0	0	0	0	0	70
	Provide two additional public safety signs on the land side of the fencing in 2013, at an estimated cost of $1k.	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1
TUNNEL T2 ADIT			**0**	**80**	**0**	**325**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**405**
	Within the next two years, inspect the inside of the Adit with a remotely operated tracked vehicle (ROV) to determine the condition, feasibility and the extent of repairs required to make the Adit safe for entry. The estimated cost for the inspection and assessment is $50k.	1	0	50	0	0	0	0	0	0	0	0	0	0	0	0	50
	In parallel with the inspection and condition assessment work, undertake a engineering study to investigate alternative means to de-water the tunnel, including the alternative of making the Adit safe, if found to be feasible, at an estimated study cost of $30k. All alternatives should assume that the present valve and pressurized pipe penetration into Tunnel T-2 will need to be permanently sealed. Any alternative using the Adit for drainage should assume that a new valve and pipe penetration into Tunnel T-2 are required.	1	0	30	0	0	0	0	0	0	0	0	0	0	0	0	30
	Allow funding in the capital budget in 2016 to provide a means of draining Tunnel T-2 and sealing off the existing pipe penetration. For the purpose of providing an estimate, the solution of drilling a 1.5 m diameter vertical shaft 60 m long through the rock into the tunnel near the Adit is assumed, with an estimated cost of $325k for design and drilling. In the event an alternative tunnel dewatering system is not selected, or if its implementation is deferred some years beyond 2016, seal the drainage piping by 2016.	2	0	0	0	325	0	0	0	0	0	0	0	0	0	0	325
PENSTOCK INTAKE STRUCTURE AT SURGE LAKE			**0**	**0**	**0**	**0**	**0**	**110**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**110**
	Refurbish the trashracks at an estimated cost of $110k. The refurbishment of the trashracks should be carried out no later than 2018. Refurbishment is estimated to be less costly than replacement ($220k).	2	0	0	0	0	0	110	0	0	0	0	0	0	0	0	110
PENSTOCK FROM SURGE LAKE			**5**	**12**	**0**	**0**	**0**	**5**	**0**	**0**	**0**	**20**	**5**	**5**	**5**	**5**	**62**
	The penstock steel plate in the powerhouse in the area where the limited thickness measurements were taken is in good condition. Starting in 2013 perform more extensive ultrasonic thickness testing every 5 years. Estimated cost $5k for two penstocks.	MTCE	5	0	0	0	0	5	0	0	0	0	5	5	5	5	30
	During the next planned penstock dewatering, take core samples of the concrete liner and carry out laboratory tests to rule out the remote possibility of alkali aggregate reaction. The estimated cost to sample and test the concrete liner is approximately $20k. For budgeting purposes, assume this coring / testing activity will take place within the next 10 years.	3	0	0	0	0	0	0	0	0	0	20	0	0	0	0	20

Condition Assessment Discipline Summary Sheet

WRECK COVE GS

***Civil** (except Geotechnical)*

Thirty year total (2012 k$) $9,263
Ten year total (2012 k$) $8,648

(costs in 2012 k$)

		Condition Rating	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023-2027	2028-2032	2033-2037	2038-2042	TOTAL 2013-2042
	By 2014 carry out a (desk-top) assessment of the potential head losses and energy production losses due to the algae, calcium carbonate deposits, and surface irregularities to determine if power wash cleaning of the inside surface of the penstock is warranted. The estimated cost for this assessment would be approximately $12k.	1	0	12	0	0	0	0	0	0	0	0	0	0	0	0	12
SPIRAL CASE			**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	See under Turbine in the Mechanical spreadsheet for the projects related to spiral cases.	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DRAFT TUBE			**50**	**10**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**60**
	Continue to repair any draft tube liner cavitation pitting damage during the yearly maintenance outages. Repair the present minor damage within two years.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Refurbish the Unit 2 tripod air system within 8 months. Cost is estimated to be $40k.	1	40	0	0	0	0	0	0	0	0	0	0	0	0	0	40
	Investigate the Unit 1 draft tube water leakage in 2013 at an estimated cost of $10k.	1	10	0	0	0	0	0	0	0	0	0	0	0	0	0	10
	During the next scheduled outages for each unit, the condition of the unlined draft tube concrete sections should be inspected and assessed. Estimated cost for each unit inspection and assessment is $5k per unit.	MTCE	0	10	0	0	0	0	0	0	0	0	0	0	0	0	10
	Repair the observed 250 mm deep hole in the concrete wall of Unit 2 draft tube by 2018.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TAILRACE			**50**	**0**	**0**	**0**	**0**	**105**	**0**	**0**	**0**	**15**	**49**	**25**	**5**	**115**	**364**
	No significant draft tube deck and outlet concrete repairs are expected to be required over the next 30 years other than potentially some minor patching of the concrete. Allow $50k in the budget for the minor repairs to be carried out between years 2037 and 2042.	*4*	0	0	0	0	0	0	0	0	0	0	0	0	0	50	50
	The safety railings on the draft tube deck will require sandblasting (or corrosion removed by other means) and repainting within the next 10 years at an estimated cost of approximately $15k.	3	0	0	0	0	0	0	0	0	0	15	0	0	0	0	15
	The steel frame for the draft tube sectional gates monorail hoist may need to be repainted within the next 20 years. Allow $20k for this task.	3	0	0	0	0	0	0	0	0	0	0	0	20	0	0	20
	Continue to monitor the condition of the rock and shotcrete above the draft tube deck area and on an ongoing basis, scale and/or install rock anchors as required. Allow $5k every 5 years for these activities.	MTCE	5	0	0	0	0	5	0	0	0	0	5	5	5	5	30
	No significant tailrace tunnel outlet structure concrete repairs are expected to be required over the next 30 years other than minor patchwork. Allow $60k between years 2022 and 2042.	4	0	0	0	0	0	0	0	0	0	0	0	0	0	60	60
	The embedded steel gain liners will be required to be sandblasted and repainted within the next 15 years at an estimated cost of $40k.	3	0	0	0	0	0	0	0	0	0	0	40	0	0	0	40
	When any of the public safety warning signs are required to be replaced, they should be replaced with signs that have an “emergency call” number on them and they should be designed in accordance with the CDA Signage for Public Safety Around Dams Technical Bulletin standards. The signs are expected to be replaced with the next 15 years at a cost of approximately $4k.	MTCE	0	0	0	0	0	0	0	0	0	0	4	0	0	0	4
	Install public safety signage on the downstream side of the tailrace portal structure. This new signage should be installed within the next year and be in accordance with the CDA standards. The estimated cost is $5k.	1	5	0	0	0	0	0	0	0	0	0	0	0	0	0	5
	Extend the fencing along the downstream side of the tailrace deck to prevent the public from accessing the tailrace area immediately downstream of the handrail on the right side of the deck. The estimated cost is $15k and the work should be completed in 2013.	1	15	0	0	0	0	0	0	0	0	0	0	0	0	0	15
	NSP should confirm that a structural analysis was carried for the design of the new anchorage system that was installed in 2011 for storing the gate in its vertical position and that the anchorage system does meet all applicable loading conditions (including seismic). If an analysis has not been carried out it should be completed within the next year. The cost for the analysis is estimated to be $20k.	1	20	0	0	0	0	0	0	0	0	0	0	0	0	0	20
	By 2018, it would be prudent to repair the major rock fall found during the 2009 tunnel inspections to avoid risk of continuing rock fall. The estimated cost for this repair work is $100k.	2	0	0	0	0	0	100	0	0	0	0	0	0	0	0	100
	Provide instrumentation to allow the periodic measurement and recording of water levels at the inlet and outlet of the tailrace tunnel. Monitoring the hydraulic loss will provide an indication of the cumulative effects of rockfalls on the tunnel’s hydraulic performance. Assuming this is done with staff gauges, the estimated cost is $5k and the work should be done by 2014.	1	5	0	0	0	0	0	0	0	0	0	0	0	0	0	5
POWERHOUSE			**20**	**40**	**10**	**110**	**110**	**10**	**10**	**10**	**10**	**10**	**50**	**160**	**50**	**50**	**650**
	Investigate and evaluate within the next 2 years more efficient means to deal with the leakage issue such as installing a ceiling leakage collection drainage system. The estimated cost for the study is $30k. Allow approximately $200k in the budget for years 2016 and 2017 to install a system to handle the leakage.	2	0	30	0	100	100	0	0	0	0	0	0	0	0	0	230
	Provide a budget allowance of $110k to repaint the supporting columns and crane in 20 years.	3	0	0	0	0	0	0	0	0	0	0	0	110	0	0	110

Condition Assessment Discipline Summary Sheet

WRECK COVE GS

***Civil** (except Geotechnical)*

Thirty year total (2012 k$) $9,263
Ten year total (2012 k$) $8,648

(costs in 2012 k$)

		Condition Rating	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023-2027	2028-2032	2033-2037	2038-2042	TOTAL 2013-2042
	Provide an annual allowance of $10k for miscellaneous items such as repairing / replacing individual tiles, patching concrete and shotcrete, adding / replacing rock anchors, repainting and repairing handrails, etc. This annual allowance would also include for monitoring and removing the stalactities to avoid the potential for them to fall on persons working below.	MTCE	10	10	10	10	10	10	10	10	10	10	50	50	50	50	300
	In 2013 a survey of the alignment of the crane rails should be carried out to determine if any misalignment issues could have contributed to the failure of the bolts. The estimated cost for this work is $10k.	1	10	0	0	0	0	0	0	0	0	0	0	0	0	0	10
	Every two years starting in 2013, inspect the condition of the crane rails and bolts to ensure that failure of the crane bolts is not an ongoing issue.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
POWERHOUSE EGRESS AND LIFE SAFETY			**300**	**625**	**2,500**	**2,800**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**6,225**
	The equipment and alarm system for monitoring the tailrace water level should be regularly tested to ensure that it functions satisfactorily and if necessary it should be refurbished or replaced.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Provide a new short term refuge facility for present staff levels by 2014. Estimated cost is $150k for a 6 person 24 hour design.	1	0	150	0	0	0	0	0	0	0	0	0	0	0	0	150
	Plan on providing two additional short term facilities or a permanent refuge facility for the increased worker levels anticipated when major work starts in the powerhouse. Assumed cost is $300k in 2016.	2	0	0	0	300	0	0	0	0	0	0	0	0	0	0	300
	Reduce worker exposure in the powerhouse by having any work which does not need to be performed inside the powerhouse, such as workshop work, done at the surface.	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Reduce the amount of combustible material stored in the powerhouse (oil, wood, rags), by removing it to a surface storage/workshop building located in the vicinity of the present Administration Building. Consider allowing only diesel engine vehicles into the access tunnel, to reduce the amount of readily flammable fuel in the powerhouse area. A basic surface storage/workshop building is estimated to cost $425k and should be planned in 2013 for implementation in 2014.	1	0	425	0	0	0	0	0	0	0	0	0	0	0	0	425
	Carry out a formal, comprehensive, detailed life safety and equipment protection engineering risk analysis, to identify failure modes and risks and to identify and assess solutions. The scope should include falling, fire and flooding risks, and should be undertaken in 2013, with a view to completing implementation prior to major equipment replacement with the anticipated increase in worker numbers in the powerhouse. The estimated study cost is $250k, and a budgetary allowance of $5M is recommended in 2015 and 2016 for implementation, with a small allowance of $100k split between 2013 and 2014 for improvements which can be implemented quickly.	1	300	50	2,500	2,500	0	0	0	0	0	0	0	0	0	0	5,350
	Particular urgent attention should be given to the risk assessment associated with the absence of head gates at the penstock inlet structure, as the absence of effective mean of quickly stopping water flows in an emergency can lead to injury, fatalities and extensive plant destruction (e.g. Kainji in Nigeria, 2000 and Sayano-Shushenskaya in Russia, 2009). The study should address providing head gates at the penstock inlet structure with an alarm system that would alert the operators that there is an issue with the penstocks (i.e., large drop in pressure) and which would have the capability to close the head gates automatically or by remote control in an emergency situation. The engineering study costs are included above.	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
POWERHOUSE ACCESS TUNNEL			**16**	**4**	**4**	**4**	**921**	**4**	**4**	**4**	**4**	**29**	**49**	**4**	**4**	**4**	**1,055**
	Sandblast and re-paint the corroded areas of the portal building steel support frame and cladding within the next 10 years to prevent any significant corrosion to occur that could compromise the structural integrity of the portal structure. Repair/patching of the steel ceiling at the location where the steel has corroded and steel has been lost should also be carried out at the same time as the sandblasting and re-painting repair if not before. The estimated cost to complete this work is $25k.	3	0	0	0	0	0	0	0	0	0	25	0	0	0	0	25
	Seal the expansion joints of the concrete foundation plinth within the next year at an estimated cost of $2k.	1	2	0	0	0	0	0	0	0	0	0	0	0	0	0	2
	As a regular maintenance item clear debris that accumulates on the staircase to eliminate this tripping hazard.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Sandblast and re-paint the staircase and railing up to the mechanical equipment room within the next 5 years. The estimated cost to complete this work is $17k.	2	0	0	0	0	17	0	0	0	0	0	0	0	0	0	17
	Carry out an investigation to determine where the rock that is accumulating between the portal structure and the gabion wall is falling from and then assess and implement means to prevent the rock from falling in the future. The cost of the study is estimated to be $10k and it should be carried out in 2013.	1	10	0	0	0	0	0	0	0	0	0	0	0	0	0	10
	Until a means has been implemented to prevent the rock from falling, a maintenance program should be implemented to remove the fallen rock between the portal structure and the gabion wall on an on-going basis. Provide an annual allowance of $4k for this work.	MTCE	4	4	4	4	4	4	4	4	4	4	4	4	4	4	56

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Condition Assessment Discipline Summary Sheet

WRECK COVE GS

***Civil** (except Geotechnical)*

Thirty year total (2012 k$) $9,263
Ten year total (2012 k$) $8,648

(costs in 2012 k$)

		Condition Rating	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023-2027	2028-2032	2033-2037	2038-2042	TOTAL 2013-2042
	Provide an allowance of $25k to sandblast and re-paint the steel structural frame in the mechanical equipment room in approximately 15 years.	3	0	0	0	0	0	0	0	0	0	0	25	0	0	0	25
	Provide an allowance of $20k to surface prepare and repaint the exterior of the portal structure in approximately 15 years.	3	0	0	0	0	0	0	0	0	0	0	20	0	0	0	20
POWERHOUSE ACCESS TUNNEL FEEDERS			**0**	**0**	**0**	**0**	**450**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**450**
	A plan should be developed for one of the main station service feeders to be installed in an alternate configuration. This work should be performed before any large equipment is transported down the access tunnel to the powerhouse. The high voltage 25 kV cable has the smallest profile and could be more easily protected from vehicle impact on the opposite side of the tunnel in a location similar to that of the temporary cable. The estimated cost for this work, assuming use of Jersey barriers, is $450k and it should be carried out within 5 years. In comparison, the cost of constructing a new cable tunnel, which would relocate the feeders completely away from vehicle traffic, is estimated at $6.05M.	2	0	0	0	0	450	0	0	0	0	0	0	0	0	0	450

Condition Assessment Discipline Summary Sheet

WRECK COVE GS

Mechanical

Thirty year total (2012 k$) $15,924
Ten year total (2012 k$) $15,560

(costs in 2012 k$)

		Condition Rating	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023-2027	2028-2032	2033-2037	2038-2042	TOTAL 2013-2042
TOTALS			**870**	**609**	**2,346**	**1,502**	**4,187**	**4,174**	**1,854**	**2**	**14**	**2**	**60**	**88**	**60**	**156**	**15,924**
TUNNEL T2 INTAKE EQUIPMENT			170	12	150	0	0	0	0	0	0	0	0	0	0	0	332
TUNNEL T2 ADIT DRAIN VALVE & PIPING			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TURBINE SHUTOFF VALVES			40	35	0	0	0	4	0	0	0	0	4	4	4	4	95
TURBINES			105	108	1,074	1,500	4,022	4,016	12	0	12	0	42	30	42	30	10,993
TURBINE REGULATING EQUIPMENT			0	84	0	0	0	0	40	0	0	0	0	0	0	0	124
GENERATOR MECHANICAL			373	32	0	0	148	152	1,800	0	0	0	4	44	4	112	2,669
TAILRACE EQUIPMENT			13	2	2	2	17	2	2	2	2	2	10	10	10	10	86
ANCILLARY EQUIPMENT (CRANES, MONORAILS)			0	0	550	0	0	0	0	0	0	0	0	0	0	0	550
HEATING, VENTILATION & AIR CONDITIONING			5	231	0	0	0	0	0	0	0	0	0	0	0	0	236
COMPRESSED AIR SYSTEMS			50	0	20	0	0	0	0	0	0	0	0	0	0	0	70
FIRE PROTECTION AND DETECTION SYSTEM			62	50	550	0	0	0	0	0	0	0	0	0	0	0	662
SUMP SYSTEMS (DRAINAGE AND DEWATERING)			53	55	0	0	0	0	0	0	0	0	0	0	0	0	108
DOMESTIC WATER & SEWAGE SYSTEM			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SURGE LAKE DRAIN VALVES			0	20	0	0	0	0	0	0	0	0	0	0	0	0	20
DETAILED SUMMARIES																	
TUNNEL T2 INTAKE EQUIPMENT			**170**	**12**	**150**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**332**
	Conduct a thorough assessment of gate condition by removing the top covers, and progressively raising and stopping the gate to allow for checking of the main and guide rollers for seizing/free rotation. At the same time check the condition of the skin plate and welds, visible structural members, side and bottom seals and seal clamping plates and fasteners, and the integrity of side roller assemblies and bumpers. If possible to access, also inspect the condition of the roller and seal path surfaces. From this inspection establish the scope and timing of a gate refurbishment. The cost of the assessment is estimated at $15k and it should be completed by 2013.	1	15	0	0	0	0	0	0	0	0	0	0	0	0	0	15
	Carry out a detailed inspection of the hoist, pulley block, holding brake, and wire rope and replace all lubricants. Depending on the findings, an overhaul may be required, not based on high usage, but because of long periods of inactivity may have resulted in corrosion of items such as anti-friction bearings. Cost of inspection is estimated at $5k per gate, and this should be completed in 2013, before the first gate test.	1	10	0	0	0	0	0	0	0	0	0	0	0	0	0	10
	Following a review of available documentation, and discussions with original engineers and gate supplier if possible, establish and execute a periodic gate testing procedure. Ideally, this should involve closure under flow conditions, unless reasons are found to avoid such a test. Investigation cost is estimated at $12k and timing would be by 2014.	1	0	12	0	0	0	0	0	0	0	0	0	0	0	0	12
	Plan for a gate refurbishment in 2015 to include recoating of the gate body, replacement of roller bushings and hoist bearings replacement. The exact scope will be determined by the above inspections and test. Cost is estimated to be $150k.	2	0	0	150	0	0	0	0	0	0	0	0	0	0	0	150
	It is anticipated that the following work will be done in as a package. • All electrical and control equipment should be replaced. • Given the remoteness of the location and the presence of vandalism, it is recommended that NSP replace all electrical systems with more vandal resistant equipment. All abandoned or obsolete equipment at the site should be removed and all new equipment should be designed to be contained in a limited number of panels which can be installed in a way to improve serviceability. • It is recommended that all lighting be replaced or returned to a working condition. • It is recommended that all electrical equipment be installed in enclosures. • Provide for remote gate closure, to be used in the event of an emergency. This should be done in 2013 at an estimated cost of $5k. Estimated cost is $140k (does not include gate body or guide heating) and the work should be carried out within 2013.	1	145	0	0	0	0	0	0	0	0	0	0	0	0	0	145
TUNNEL T2 ADIT DRAIN VALVE & PIPING			**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Carry out an inspection on the condition of the valve and piping, using an unmanned remotely operated tracked vehicle. Co-ordinate this work with a geotechnical inspection and assessment of alternatives for the T-2 Adit (see report Section 4.2 Tunnel T-2 Adit for further details). While it will not be possible to test operate the valve(s), the inspection will provide information on the exterior surface condition of the pressurized piping, which will indicate the urgency of sealing the penetration. As well, the inspection will provide information on the condition of any exposed piping downstream of the valve(s), to develop a better estimate of the cost of restoring the Adit as a tunnel drainage solution.	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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Condition Assessment Discipline Summary Sheet

WRECK COVE GS

Mechanical

Thirty year total (2012 k$) $15,924
Ten year total (2012 k$) $15,560

(costs in 2012 k$)

		Condition Rating	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023-2027	2028-2032	2033-2037	2038-2042	TOTAL 2013-2042
	Whichever alternative is selected for Tunnel T-2 dewatering, the existing piping penetration will need to be sealed and if the T-2 Adit is the preferred solution, a new piping penetration and new valves will be needed. Funding to seal the existing piping is included in the recommendation for a Tunnel T-2 dewatering solution in the Civil section of the report (see report Section 4.2 Tunnel T-2 Adit for further details).	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TURBINE SHUTOFF VALVES			**40**	**35**	**0**	**0**	**0**	**4**	**0**	**0**	**0**	**0**	**4**	**4**	**4**	**4**	**95**
	Perform an analysis of the oil in the hydraulic operating system every two years.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Repair or replace the upstream manual valves in the bypass lines of both units by 2014. Replacement cost: $10k for two valves.	1	0	10	0	0	0	0	0	0	0	0	0	0	0	0	10
	Annually inspect the nozzles on the downstream side of the motorized bypass valves for evidence of cavitation pitting and repair as necessary.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Every 5 years, measure the wall thickness of the valves' bypass piping. This could be done during the yearly outage. If the wall thickness decreases to 80% of nominal, replace the piping. Inspection cost: $4k for two units every 5 years	1	4	0	0	0	0	4	0	0	0	0	4	4	4	4	24
	In 2013, perform an NDE check of the turbine shut off valve stems using ultrasonic means. Review valve drawings and determine if there is any evidence of cracking in the stems. Inspection cost is estimated to be $2 k per valve.	1	4	0	0	0	0	0	0	0	0	0	0	0	0	0	4
	Confirm if the upstream seal O-rings are original and if found to be so or if indeterminate, plan to replace the O-rings within three years.	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Perform an engineering review by 2014 of the potential safety issues, looking at industry current best practices. Cost is estimated to be $25k.	1	0	25	0	0	0	0	0	0	0	0	0	0	0	0	25
	Install a turbine shutoff valve closing system which are independent of AC station service power in 2013. This could be achieved by modifying the existing systems, and the cost is estimated at$25k per unit.	1	25	0	0	0	0	0	0	0	0	0	0	0	0	0	25
	Confirm the pressure, size, location and security of the orifices in the supply to the turbine shut off valve servomotors. This should be done in 2013 and the estimated cost is $2k per servomotor.	1	4	0	0	0	0	0	0	0	0	0	0	0	0	0	4
	Store the spare valve seals securely in a purpose made wooden crate.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Purchase a set of trunnion seals ($1k). This will minimise outage time if they have to be replaced.	MTCE	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1
	Purchase a spare hydraulic pump and motor ($1.5k). If a pump fails, the generating unit could not be operated.	MTCE	2	0	0	0	0	0	0	0	0	0	0	0	0	0	2
	Confirm that drawings and specifications are available for ordering new turbine shutoff valve main water seals (upstream and downstream) and new trunnion seals.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Amend the record drawings to show the difference in size between the seals of Unit 1 and Unit 2, and the correct O ring dimensions and materials.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TURBINES			**105**	**108**	**1,074**	**1,500**	**4,022**	**4,016**	**12**	**0**	**12**	**0**	**42**	**30**	**42**	**30**	**10,993**
	Consider new runners engineered to potentially provide a capacity increase, higher efficiency and a wide range of stable operation. Estimated cost is $5.55M for two runners. Installation would be during turbine overhauls.	2	0	0	1,050	1,500	1,500	1,500	0	0	0	0	0	0	0	0	5,550
	To ensure long term unit reliability a comprehensive monitoring program should be established, with the following mechanical elements: 1. Install a shaft vibration analysis system that will give trending data on shaft runout, shaft orbit, and changes in the characteristic frequencies of the unit components 2. Record the bearing temperatures and institute a temperature analysis and trending system. 3. Continue to carry out yearly inspections but review what is to be inspected, based on the new operating conditions. Emphasize the close inspection of components susceptible to fatigue cracking, specifically the generator rotor and the turbine runner. Non destructive examination by LPI, MPI, and UT methods are recommended for critical areas. 4. Ensure the annual inspection and operation records are documented and available over the long term to allow for trending analysis.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	The following repair work is required to be done within the next 5 years (funds are included in the major overhaul recommendation below): 1. Plan to take the turbine out of service for rehabilitation of the wicket gates, to stop the top of the wicket gates rubbing on the head cover 2. During the same outage repair the cavitation on the headcover, discharge ring and runner.	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Carry out major overhauls on each turbine concurrently with generator refurbishment/replacement. The estimated cost is $2.5 M per unit in 2017 and 2018, co-ordinated with the generator refurbishment work.	*2*	0	0	0	0	2,500	2,500	0	0	0	0	0	0	0	0	5,000

Condition Assessment Discipline Summary Sheet

WRECK COVE GS

Mechanical

Thirty year total (2012 k$) $15,924
Ten year total (2012 k$) $15,560

(costs in 2012 k$)

		Condition Rating	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023-2027	2028-2032	2033-2037	2038-2042	TOTAL 2013-2042
	Undertake an engineering study to review model test information and to conduct a vibration test program on the Wreck Cove turbines, to establish the extent of the rough load range and to assess the risks of extended and periodic operation within such rough load range. This work should be undertaken in 2013, with a view to completing the vibration tests and the assessment by 2014. The estimated cost for this engineering study is $150k, including the vibration test work for one unit.	1	50	100	0	0	0	0	0	0	0	0	0	0	0	0	150
	Remove the inflatable shaft seals from service. The estimated cost is $6k per unit and as this is not a critical item, it has been scheduled for 2015.	2	0	0	12	0	0	0	0	0	0	0	0	0	0	0	12
	Every two years filter the turbine bearing oil to remove dirt and especially any water. A filter medium that specifically removes water should be used.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Using the shaft vibration probe outputs, review the shaft orbits to see if the shaft is over to one side of the bearing. This could cause high running temperatures and may be due to shaft misalignment.	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Check the calibration of the Bently Nevada vibration monitors to ensure the read outs are valid. This should be done in 2013.	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	During the next outage (2013), perform an NDE examination of turbine shaft critical areas. Estimated cost is $2k per unit.	1	4	0	0	0	0	0	0	0	0	0	0	0	0	0	4
	Continue to keep the runners in their present good condition, with the periodic repairs to the minor cavitation pitting so the damage does not increase.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Measure the runner crown and band seal clearances every 2 years starting in 2013.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Every two years non-destructively inspect the runner for cracks, particularly at the blade and band welds, starting in 2013. The estimated cost is $3k per unit.	1	6	0	6	0	6	0	6	0	6	0	18	12	18	12	90
	Use dial indicators to measure upward movement of several wicket gates when the turbine is dewatered to when it is watered up. The dial indicators should be supported on the pit wall or on the turbine shaft and read against the top of the upper stems. If the gates rise when the turbine is watered up then the lower stem seal probably have failed. This test should be performed in 2013 and the cost is $2k per unit.	1	4	0	0	0	0	0	0	0	0	0	0	0	0	0	4
	Inspect and document with photos the wicket gate surfaces and the surrounding area during each yearly outage. Look for surface damage and signs of rubbing at the top and bottom of the gates.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Continue the yearly repairs to the wicket gate cavitation damaged surfaces until permanent repairs can be done.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Review the type of grease used, and the greasing timing and amount. Install an automatic greasing system in 2013. Cost $10k per unit.	1	20	0	0	0	0	0	0	0	0	0	0	0	0	0	20
	Monitor the wicket gates upper stem area for seal leakage. Replace the packing during a yearly maintenance outage if excessive leakage occurs. Cost: $5k (materials)	1	5	0	0	0	0	0	0	0	0	0	0	0	0	0	5
	Within one year, carry out an axial ultrasonic examination of the upper wicket gate stems to determine if cracking has occurred where the stems join the blade. Estimated cost is $2k per unit.	1	4	0	0	0	0	0	0	0	0	0	0	0	0	0	4
	Within 5 years overhaul the wicket gates and repair the headcover and discharge ring surface damage. Funds are included in the major overhaul entry in this section.	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Visually inspect the spiral case at each annual maintenance outage. Look for any erosion damage and for any cracking at the top and bottom of the stay vanes. For suspect indications and not less than every two years perform magnetic particle non destructive examination. Cost: $3k per unit.	1	6	0	6	0	6	0	6	0	6	0	18	12	18	12	90
	Inspect all the stud bolts on the head cover outer flange of both turbines in 2013, then every 5 years This would include an ultrasonic test, visual inspection and a representative check of the applied torque. The required torque should be determined by a mechanical engineer. Estimated NDE cost is $3k per unit.	1	6	0	0	0	0	6	0	0	0	0	6	6	6	6	36
	During the next turbine disassembly clean, degrease and blast clean the headcover and NDE check all welds and the flange around the stud holes for cracking. Estimated cost is $10k per unit.	2	0	0	0	0	10	10	0	0	0	0	0	0	0	0	20
	Consider installing piston rod lip seals having joints on their circumference. They can be easily installed without dismantling the servomotor rod end fittings.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Every year measure the governor pump cycling time with the wicket gates not moving. An increase in the cycling time may indicate wear of the servomotor piston rings, or governor control valve internal leakage.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	As with the wicket gates, increase the greasing frequency for the operating ring and linkages and adjust the quantity of grease injected. to avoid extraneous grease accumulating on the head cover. It will be important to assess the greasing frequency as the turbine wicket gates will be more active when the generator load will be continually changing to follow system wind load variations.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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Condition Assessment Discipline Summary Sheet

WRECK COVE GS

Mechanical

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	The following spare parts should also be acquired by 2014 as they may be needed at short notice. • Carbon seal segments and their springs • At least 5 wicket gate water seals per unit (upper and lower) The estimated cost is $8k.	1	0	8	0	0	0	0	0	0	0	0	0	0	0	0	8
	Sources for the following parts should be found, and drawings and specifications should be prepared: • Servomotor cast iron piston rings • Bearing re-babbitting companies. Re-babbitting specifications should be prepared • O rings for the headcover flanges. These may be non standard items • Magnetrol level switch parts or replacement units	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TURBINE REGULATING EQUIPMENT			**0**	**84**	**0**	**0**	**0**	**0**	**40**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**124**
	Carry out compliance testing of the governor within the next two years and at the same time review the dashpot settings. The estimated cost of the testing is $42k per unit.	1	0	84	0	0	0	0	0	0	0	0	0	0	0	0	84
	After generator refurbishment or replacement is completed (2018), carry out a load rejection test on each unit under the supervision of experienced engineers (hydraulic, mechanical and electrical disciplines). The incremental procedure in the CEATI "Mechanical Overhaul Guide for Hydroelectric Turbine Generators" should be followed. See the turbine shutoff valve section of this report for load rejection test comments. This test is not recommended at present due to the risk associated with operating the rotors above synchronous speed. Estimated cost is $20k per unit.	2	0	0	0	0	0	0	40	0	0	0	0	0	0	0	40
	Within 2 years and thereafter every 5 years, inspect the interior of the accumulator tank and ultrasonically measure the wall thickness.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Investigate the parts availability for the Magnetrol level switches. If parts are difficult to find, install modern combined level indicators and switches.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Investigate the availability of the governor oil pump replacement parts in 2013. They may be very long delivery or no longer be available.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GENERATOR MECHANICAL			**373**	**32**	**0**	**0**	**148**	**152**	**1,800**	**0**	**0**	**0**	**4**	**44**	**4**	**112**	**2,669**
	Implement the Acuren shaft runout trending program and the Power Engineering Company unbalanced magnetic pull (UMP) system by March 2013. Review the data on a monthly basis.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Carry out the rotor and stator testing program recommended by Power Engineering Company, and KGS Group	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Perform a rotational alignment check on both units in 2013 and re-centre the stators relative to the rotors.	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Review the two options in the Power Engineering Company report: to replace the generator or perform a major refurbishment, and based on the results of these inspections and the soon to be obtained test data, establish a date for a refurbishment of the generator and the scope of work to be done. This review should be done in 2013. The estimated cost of refurbishment of two generators is $30M and to recognize site work space constraints, these costs are shown equally split between 2017 and 2018. Note: these costs are included in the Electrical Assessment section of this report.	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Implement the Power Engineering Company UMP system by March 2013. Review this data on a monthly basis for any changes and trends. Estimated equipment cost is $40k per unit.	1	80	0	0	0	0	0	0	0	0	0	0	0	0	0	80
	In 2013 review the condition of the rotors as found from inspections and tests and plan future repairs.	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Non-destructively inspect the rotor brake tracks every five years starting in 2013. Estimated cost is $2k per unit.	1	4	0	0	0	0	4	0	0	0	0	4	4	4	4	24
	During the next unit overhauls, machine the radial dowel holes and replace the dowels. Funds for this are included under Turbines, above, as part of a major turbine overhaul and generator mechanical refurbishment.	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	In 2013 plan the work and timing of repairs and refurbishment, including consultation with OEM.	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	In 2013 repack the stator cores at the splits, install the soleplate radial keys in Unit 1 and rectify the soleplate radial keys problem in Unit 2. Estimated cost is $100k per unit.	1	200	0	0	0	0	0	0	0	0	0	0	0	0	0	200
	Confirm that the brake pads are made of non asbestos material. Replace the pads if they are asbestos based.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Measure the brake pad thickness every five years. Replace any pads less than 25 mm (1 in) thick.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Record the surface air cooler cooling water flows monthly.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	NDE inspect the cooling water piping every 10 years. Replace the piping within the generators in 30 years: $54k per unit	4	0	0	0	0	0	0	0	0	0	0	0	0	0	108	108
	Replace the surface air coolers within 5 years: $148k per unit	2	0	0	0	0	148	148	0	0	0	0	0	0	0	0	296
	The shaft runout data collection and analysis program proposed by Acuren should be implemented and applied over the long term, to check for developing problems.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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WRECK COVE GS

Mechanical

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	The calibration of the Bently Nevada vibration monitoring system should be checked to ensure it is working correctly.	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	The reason for the high runout levels at the lower and upper guide bearings of both units should be analyzed in 2013 as to cause and then addressed. Estimated cost is $10k/unit.	1	20	0	0	0	0	0	0	0	0	0	0	0	0	0	20
	During the next outage (2013), perform an NDE examination of generator shaft critical areas. Estimated cost is $2k per unit.	1	4	0	0	0	0	0	0	0	0	0	0	0	0	0	4
	Filter the thrust and guide bearing oil every two years. This period may change depending on the Acuren oil analysis program findings.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	The thrust bearing temperatures should be recorded and the data reviewed on a six month basis. If at some time a continual temperature increase is noted, the thrust segments should be replaced with the spare ones. Rebabbitting cost: $30k	1	30	0	0	0	0	0	0	0	0	0	0	0	0	0	30
	Clean the top cover of the upper guide bearing yearly to prevent the carbon dust from mixing with the oil.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Install an oil filter in the high pressure oil lift systems by 2014 ($1k per unit).	1	0	2	0	0	0	0	0	0	0	0	0	0	0	0	2
	Re-adjust the oil pot seals. If the leakage cannot be reduced to an acceptable level, install a vacuum demisting unit in 2013 ($15k per unit).	1	30	0	0	0	0	0	0	0	0	0	0	0	0	0	30
	Check the condition of the Unit 2 thrust bearing by removing two segments for visual inspection in 2013. If the surface shows no sign of damage, check the calibration of the temperature measuring system.	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Allow funds in the program to replace the thrust and guide bearing cooling coils within about 20 years at their anticipated end of service life ($20k per unit).	4	0	0	0	0	0	0	0	0	0	0	0	40	0	0	40
	By 2014, the runner plate should be coated with anti-rust compound, wrapped in protective paper and stored in a crate. The journal surface flatness tolerance is 0.013 mm (0.0005 in), so to prevent distortion, the plate must be evenly supported. Estimated cost is $3k.	1	3	0	0	0	0	0	0	0	0	0	0	0	0	0	3
	Non-destructively by UT method inspect the spare set of thrust pads in 2013 to confirm their babbitt bond is acceptable. If the pads are to be installed, their flatness must first be checked on a surface plate.	1	2	0	0	0	0	0	0	0	0	0	0	0	0	0	2
	By 2014, suppliers for the following parts should be found, and drawings and specifications should be prepared. This will reduce the delivery time when the parts are required. Estimated cost is $10k. • Bearing re-babbitting companies (prepare, in advance, specifications for rebabbitting and machining) • Magnetrol level switch parts or replacement switch units • Brake pads (one set of 8 pads) non asbestos type • Surface air coolers (one set of 4) • Thrust and upper guide bearing cooling coils (one of each)	MTCE	0	10	0	0	0	0	0	0	0	0	0	0	0	0	10
	In 2014, perform ultrasonic testing to confirm the level of wear or deterioration of the cooling water piping. Carry out visual checks of some extracted pipe sections to obtain additional information to decide on the need and timing to replace this piping. Estimated cost is $20k.	1	0	20	0	0	0	0	0	0	0	0	0	0	0	0	20
	At the same time install air vents on both ends of the draft tube pump suction header. This would make air removal more effective and reliable regardless of which draft tube is being used to draw water from, or which pump is being run.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Replace piping larger than 76 mm (3 in) (piping smaller than 76 mm size was previously replaced) on both units' cooling water piping systems. Pending further information on piping condition, it is recommended that funding for the piping replacement be scheduled for 2019. Estimated cost for this work is $1.8M, which covers piping, valves, instrumentation, hangers and insulation and allows for the congested work area and the need to keep at least one unit available to operate during the replacement.	3	0	0	0	0	0	0	1,800	0	0	0	0	0	0	0	1,800
TAILRACE EQUIPMENT			**13**	**2**	**2**	**2**	**17**	**2**	**2**	**2**	**2**	**2**	**10**	**10**	**10**	**10**	**86**
	Develop a detailed plan for the installation of the tailrace tunnel outlet gate that deals with removal of the cobblestones obstructing the north side gains. This should be completed before major refurbishment work in the powerhouse or tunnel begins. This study is estimated to cost $10k and should be performed in 2013.	1	10	0	0	0	0	0	0	0	0	0	0	0	0	0	10
	Monitor the condition of the coating on the tailrace tunnel outlet gate periodically, to track the failure of the coating, touching up the coating as found necessary. This work is estimated to cost $2k per year and should be performed annually.	MTCE	2	2	2	2	2	2	2	2	2	2	10	10	10	10	60
	Perform a stress and deflection analysis on the gate which considers the loss of metal from major members. While the results are not expected to condemn the gate, they will be useful in a future decision to refurbish or replace the gate. This should be done by 2017 and is estimated to cost $15k.	2	0	0	0	0	15	0	0	0	0	0	0	0	0	0	15

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	Install a guard on the chain drive of the draft tube gates storage carriage to prevent the operator's fingers from being trapped. ($1k in 2013)	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1
ANCILLARY EQUIPMENT (CRANES, MONORAILS)			**0**	**0**	**550**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**550**
	The electrical systems for the powerhouse crane should be upgraded with a modern crane control system. This work would be typical to this vintage of crane. This work should also be done to resolve the quick stop issue of the crane movement. It is estimated that the upgrade would cost on the order of $550k, and this work should be performed within the next 3 years or prior to any major plant work requiring intense use of this crane. A full load test of the crane should be performed with the new controls.	2	0	0	550	0	0	0	0	0	0	0	0	0	0	0	550
HEATING, VENTILATION & AIR CONDITIONING			**5**	**231**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**236**
	In 2013, install thermometers and hygrometers at several locations in the powerhouse and outdoors and monitor and record the conditions on a weekly basis and more frequently when tests to improve cooling are being performed. The data collected is important to determine the extent of the cooling problem and will assist in devising the optimum solution. The estimated cost is $5k.	1	5	0	0	0	0	0	0	0	0	0	0	0	0	0	5
	No major replacement is foreseen over the next 30 years on the supply and exhaust fans in the portal building mechanical room. However, due to the criticality of these fans and dampers, a set of spare bearings, drive belts and drive motors for each fan and a replacement set of motorized dampers and motors should be acquired by 2014 at an estimated cost of $56k.	1	0	56	0	0	0	0	0	0	0	0	0	0	0	0	56
	Adjust the ventilation system operation in summer to operate the emergency smoke removal system to maximize the amount of outside air brought into the powerhouse for cooling and dehumidification. Monitor temperatures and humidity levels in the powerhouse to check effectiveness. If the operation of the emergency smoke removal fan is unacceptable due to high noise levels, adjust the intake damper M1 in the portal building to full open, close damper M2. Monitor temperatures and humidity levels in the powerhouse to check effectiveness. These two tests should help establish whether mechanical cooling needs to be reinstated.	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Bring El. -10 ft supply air ductwork down closer to floor level and provide propeller fans for the El. -10.0 ft level to improve dehumidification and reduce rusting of piping and equipment. Estimated cost $15k.	1	0	15	0	0	0	0	0	0	0	0	0	0	0	0	15
	Pending successful results of the summer ventilation tests, remove the mechanical cooling units S1 and S2, and related cooling water piping. If the test fails, replacement of the mechanical cooling units would be required. Estimated cost for either solution is $150k.	1	0	150	0	0	0	0	0	0	0	0	0	0	0	0	150
	Whether the abandoned mechanical cooling system is to be revived or removed, remove the poor condition fibreglass insulation and re-route the ductwork located downstream of air handling units S1 and S2. This section of ductwork obstructs the hatchway when major work is performed on the turbine generators. Estimated cost is $10k.	1	0	10	0	0	0	0	0	0	0	0	0	0	0	0	10
	Add insulation to cold water piping and the penstocks at the El. -10.0 ft level. The cost is in the cooling water piping system replacement.	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
COMPRESSED AIR SYSTEMS			**50**	**0**	**20**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**70**
	Inspect the service air system for leaks and repair as required	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	To upgrade the functionality and reliability of the service air system, while simplifying maintenance, redesign the compressed air piping to allow individual tank isolation and replace the service air refrigerated dryer. Estimated cost is $20k and the work should be carried out within 3 years.	2	0	0	20	0	0	0	0	0	0	0	0	0	0	0	20
	In 2013, install a timed blow down valve on the compressed air storage tanks which supply the governor and power tools ($10k).	1	20	0	0	0	0	0	0	0	0	0	0	0	0	0	20
	In 2013, install automatic air make up systems for the governor accumulator tanks ($15k per unit).	1	30	0	0	0	0	0	0	0	0	0	0	0	0	0	30
FIRE PROTECTION AND DETECTION SYSTEM			**62**	**50**	**550**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**662**
	To establish their remaining life, arrange for inspection and wall thickness testing of the existing tanks and related piping from the well pumps to the storage tanks and also the piping and valves from the storage tanks into the powerhouse and to the generator and transformer fire protection systems. Based on the results of this testing, a plan for remedial work can be developed. Estimated investigation cost is $20k in 2013.	1	20	0	0	0	0	0	0	0	0	0	0	0	0	0	20
	Address the current shortfall in the required water storage capacity. Current total storage capacity in the two tanks is 227,000 L (60,000 US gallons) versus an NFPA 851 requirement for 568,000 L (150,000 US gallons). Perform a study to investigate alternatives before implementing. Estimated cost to investigate the work described is $40k	1	40	0	0	0	0	0	0	0	0	0	0	0	0	0	40
	The two water supply wells should have vegetation removed from the immediate vicinity and fence post markers with identification tags placed to clearly identify the well locations. Estimated cost $2k.	1	2	0	0	0	0	0	0	0	0	0	0	0	0	0	2

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(costs in 2012 k$)

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	Confirm that both well pumps are capable of operation and are in good working order. This can be achieved by flushing the fire protection supply line to the powerhouse with a flow rate not less than the transformer deluge capacity of 1552 L/min (410 USgpm), which will also remove any loose corrosion particulate matter from the supply line. Repeat this flush every two years.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	The generator and transformer deluge systems should at least be tied to the station fire alarm system to ensure that there is proper evacuation in the case of a fire. The estimated cost is $10k and this work should be completed by 2014 or before major refurbishment work in the powerhouse is begun.	1	0	10	0	0	0	0	0	0	0	0	0	0	0	0	10
	The transformer deluge control panels should be replaced with modern systems, at an estimated cost of $40k, and should be completed within the next 2 years	1	0	40	0	0	0	0	0	0	0	0	0	0	0	0	40
	The main plant fire alarm system should be replaced. This should include: • A system with new audible devices, including the addition of strobe indication. • A proper enunciator installed in an area where a fire can be safely responded to. • Some review of early detection and more detailed annunciation that could be used in areas of refuge. This is further addressed in the report section called Issues and Opportunities. The estimated cost is $550k and the work should be completed within the next 2 years and before major work in the powerhouse begins.	2	0	0	550	0	0	0	0	0	0	0	0	0	0	0	550
SUMP SYSTEMS (DRAINAGE AND DEWATERING)			**53**	**55**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**108**
	Replace or rebuild dewatering pump P2 in 2013. Replacement cost is estimated to be $3k.	1	3	0	0	0	0	0	0	0	0	0	0	0	0	0	3
	Take representative thickness tests on the pump discharge piping to obtain a general indication of its thickness and an indication as to its remaining life. Based on the results of this testing, determine if piping replacement is warranted. Estimated study cost is $10k.	1	10	0	0	0	0	0	0	0	0	0	0	0	0	0	10
	By 2014 provide secondary oil containment around floor mounted equipment containing oil and match the size of the containment area for the level of stored oil needed during turbine generator maintenance. Remove any infrequently used lubricants outside of the powerhouse. Estimated cost is $30k.	1	0	30	0	0	0	0	0	0	0	0	0	0	0	0	30
	By 2014 install an oil detection and skimmer system with alarm and pump interlock control on the station sump at an estimated cost of $25k.	1	0	25	0	0	0	0	0	0	0	0	0	0	0	0	25
	Carry out a study on the routing of all plant and equipment drains to determine which drain directly to the tailrace. Determine what action, if any, is required to avoid or capture potential spills. Study cost is $40k and it should be completed by 2013.	1	40	0	0	0	0	0	0	0	0	0	0	0	0	0	40
DOMESTIC WATER & SEWAGE SYSTEM			**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	No recommendations.	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SURGE LAKE DRAIN VALVES			**0**	**20**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**20**
	Remove both valves of the Surge Lake drain piping and inspect for disc to stem bolting damage and security. Plan to repair or replace the valves, depending on the findings. This work should be carried out by 2014 and is estimated to cost $20k, assuming only some minimal difficulty in closing off the pipe inlet, so that both valves can be checked.	1	0	20	0	0	0	0	0	0	0	0	0	0	0	0	20

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Condition Assessment Discipline Summary Sheet

WRECK COVE GS

Electrical

Thirty year total (2012 k$) $42,917
Ten year total (2012 k$) $42,487

(costs in 2012 k$)

		Condition Rating	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023-2027	2028-2032	2033-2037	2038-2042	TOTAL 2013-2042
TOTALS			**1,177**	**787**	**41**	**5,095**	**16,581**	**15,047**	**2,911**	**97**	**161**	**590**	**217**	**58**	**67**	**88**	**42,917**
GENERATORS (ELECTRICAL)			745	10	0	0	15,000	15,000	0	0	0	0	0	0	0	0	30,755
EXCITATION SYSTEMS			20	0	0	0	0	0	0	0	0	0	0	0	0	0	20
ISOLATED PHASE BUS DUCT			0	200	0	0	0	0	0	0	0	0	0	0	0	0	200
EXCITATION TRANSFORMERS			0	0	9	0	9	0	9	0	9	550	27	18	27	18	676
AC STATION SERVICE SYSTEM			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
STATION SERVICE TRANSFORMERS			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AUXILIARY SERVICE TRANSFORMERS			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AC SWITCHGEAR			80	50	15	15	15	15	2,900	0	0	0	0	0	0	0	3,090
AUTO TRANSFER CONTROL			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MCC'S AND PANEL BOARDS			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CABLE AND BUS			0	0	0	0	0	0	0	0	0	0	0	0	0		0
STANDBY DIESEL GENERATOR			325	0	0	0	0	0	0	0	0	0	0	0	0	0	325
PROTECTION AND CONTROLS SYSTEM			7	297	17	4,295	1,557	32	2	2	2	40	190	40	40	70	6,591
STATION DC POWER SYSTEM			0	15	0	135	0	0	0	0	0	0	0	0	0	0	150
STATION GROUNDING SYSTEM			0	0	0	0	0	0	0	95	150	0	0	0	0	0	245
STATION LIGHTING SYSTEM			0	215	0	650	0	0	0	0	0	0	0	0	0	0	865
DETAILED SUMMARIES																	
GENERATORS (ELECTRICAL)			**745**	**10**	**0**	**0**	**15,000**	**15,000**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	30,755
	A thorough detailed investigation should be done to find the cause of the persistent Unit 1 and Unit 2 field grounds, involving the OEM or third party expert in the process. (This should be done in 2013 at an estimated cost of $100k).	1	100	0	0	0	0	0	0	0	0	0	0	0	0	0	100
	Rectify the loose stator wedges on both units in 2013 estimated at $100k.	1	100	0	0	0	0	0	0	0	0	0	0	0	0	0	100
	The OEM proposed solution for improved temperature control and potential vibration reduction should be reviewed to understand the rationale. If warranted, a solution should be implemented with the unit re-wind. The assessment should be performed by 2014 and the estimated cost is $10k.	1	0	10	0	0	0	0	0	0	0	0	0	0	0	0	10
	Re-implement the online partial discharge monitoring system on both units, which will require installation of new partial discharge (PD) couplers to obtain PD readings and associated data acquisition device for analysis. If this is not feasible in the short term then a periodic partial discharge measurement program should be initiated to monitor the stator insulation condition. The cost of this work is estimated at $65k and it should be done in 2013.	1	65	0	0	0	0	0	0	0	0	0	0	0	0	0	65
	Install the permanent continuous UMP monitoring system on both units in 2013. The cost estimate is $80k	1	80	0	0	0	0	0	0	0	0	0	0	0	0	0	80
	The rotor pole drop test should be performed annually on both units to determine the rotor field turns insulation health. Shorted turns can cause vibration, unbalanced stresses on the generator stator core, frame and rotor.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	A generator dielectric test should be performed annually on both stator windings to determine and tract stator winding insulation condition.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Generator visual inspection should be done annually with specific attention to the common degradation problems: • Loose wedges • Loose field coil braces • Evidence of any partial discharge • Evidence of any overheating To perform this inspection the rotor and stator should be in a clean and oil-free state.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Perform the following testing in 2013 on both units to establish overall electrical condition of the generators. Budgetary cost is $200k. • Partial Discharge testing • DC Hipot test (Reduced Voltage) with DC ramp tester • Corona Probe test • ELCID test	1	200	0	0	0	0	0	0	0	0	0	0	0	0	0	200
	After the UMP based air gap monitoring system is installed, monitor and review the air gap of the unit. An air gap that does not stay within acceptable tolerances can cause undue stresses on components such as the stator and rotor, brackets and bearings and in extreme cases a stator and rotor collision could occur. The air gap of a hydro generator is ultimately determined by the circularity and concentricity of the rotor and stator.	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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Condition Assessment Discipline Summary Sheet

WRECK COVE GS

Electrical

Thirty year total (2012 k$) $42,917
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(costs in 2012 k$)

		Condition Rating	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023-2027	2028-2032	2033-2037	2038-2042	TOTAL 2013-2042
	Rewind the stators and re-insulate the pole windings within the next five years. The cost of re-winding including pole insulation is $3.2M per unit with 3-4 months downtime per unit to execute the work. It is anticipated that this work would be done in 2017 and 2018. The funds are included in the generator refurbishment recommendation below.	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Before initiating a re-winding process, it is recommended to perform more in-depth inspection of the stator core by performing in-depth visual inspection, and an Elcid test to check for any potential hot-spots within the stator core. In normal cases stator cores of this type of generator should be changed at the time of the second re-winding of the stator, but with the already identified stator core issues and with all the oil contamination issues, it is recommended to perform required tests soon as the stator core may require replacement, along with the winding. The cost estimate to replace the stator core is $2.4M/unit, to be done at the same time as the re-wind in 2017 and 2018. The funds are included in the generator refurbishment recommendation below.	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Replace the rotors with new rotors having improved mechanical rigidity. Assuming the shaft, thrust bearing and bracket can be reused, the estimated cost is $7.9M per unit. The funds are included in the generator refurbishment recommendation below.	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Including excitation system replacement, the estimate for generator and refurbishment is estimated at $30M including costs related to removal of existing equipment, installation, contingency and commissioning. These refurbishments are shown equally split between the years 2017 and 2018. There could be some cost reduction depending on the condition of the stator frame and core as determined after further testing and inspection.	2	0	0	0	0	15,000	15,000	0	0	0	0	0	0	0	0	30,000
	It is recommended to keep the following minimum level of spares on hand: • 12 top bars and 12 bottom bars • Wedges for 12 slots • Fillers (Top, Centre & Bottom) for 12 slots • One of each type of stator winding connection • Winding material for 12 slots • The spare pole coil should be tested in 2013. Estimated cost is $200k and these should be acquired in 2013.	1	200	0	0	0	0	0	0	0	0	0	0	0	0	0	200
EXCITATION SYSTEMS			**20**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	20
	Based on the age of the equipment and declining support from the manufacturer, it is recommended to initiate the process of replacing these exciters, as they have reached end of life. It is estimated that these costs are $750k per unit, and the replacements would be done in 2017 and in 2018, when major generator work is proposed. These funds are included in the generator refurbishment recommendation estimate under Generators, above.	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	The existing spare parts should be checked to ensure that these are still functional. This process should be initiated soon to avoid any unexpected downtime. This check is estimated at $20k and should be done in 2013.	1	20	0	0	0	0	0	0	0	0	0	0	0	0	0	20
ISOLATED PHASE BUS DUCT			**0**	**200**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	200
	A regular maintenance and monitoring program inclusive of visual inspection, cleaning and testing should be established to monitor the condition of the IPB on a regular basis. The manufacturer literature recommends that at minimum an annual inspection be performed on the bus.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	An operating temperature study of the IPB system should be performed at a time when the associated unit is running as close to peak load as possible. Allow $50k in 2014.	1	0	50	0	0	0	0	0	0	0	0	0	0	0	0	50
	Spare flexible connections and insulators should be procured and stocked at the station. Allow $150k in 2014 for spare parts procurement. It is important that these spares are available in hand otherwise a small failure could lead to a major unit outage.	1	0	150	0	0	0	0	0	0	0	0	0	0	0	0	150
EXCITATION TRANSFORMERS			**0**	**0**	**9**	**0**	**9**	**0**	**9**	**0**	**9**	**550**	**27**	**18**	**27**	**18**	676
	Regular maintenance which includes visual inspection and cleaning should be done every year.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	All the routine tests including a thermographic scan should be performed every two years. Estimated cost is $9k.	MTCE	0	0	9	0	9	0	9	0	9	0	27	18	27	18	126
	The transformers should be replaced at the end of their expected life which would be approximately 2022. There may be a requirement to change the transformers with the excitation systems, if the units are uprated, as the logistics may be appealing. Replacement should include all the associated cable between the exciter and the transformer. Cost estimate is $550k for both.	3	0	0	0	0	0	0	0	0	0	550	0	0	0	0	550
AC STATION SERVICE SYSTEM			**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	0
	See individual components below.	NA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
STATION SERVICE TRANSFORMERS			**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	0

Condition Assessment Discipline Summary Sheet

WRECK COVE GS

Electrical

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Ten year total (2012 k$) $42,487

(costs in 2012 k$)

		Condition Rating	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023-2027	2028-2032	2033-2037	2038-2042	TOTAL 2013-2042
	As no up to date test results were available during this inspection, it is recommended to perform insulation resistance tests in 2013.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	A regular yearly maintenance, including thorough cleaning, and periodic test is recommended to be performed to keep the units in operation.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	The transformers should be replaced during station service life extension upgrade by the year 2019. The replacement cost of the transformers is included in AC Switchgear, below.	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AUXILIARY SERVICE TRANSFORMERS			**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	0
	Development of an annual maintenance and testing program is recommended. Included in this program should be cleaning of the dry-type transformer, visual inspection, thermographic scanning, testing of oil from the oil-filled transformer and dielectric testing.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	As there were no up to date test results available during the inspection, it is recommended to perform at least an insulation resistance test on the transformers in 2013.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Replace both the transformers and their associated disconnect switches by the year 2019 which is the life expectancy of the associated switchgear. The cost of the replacement is included in AC Switchgear, below.	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Nova Scotia Power should begin a regular load monitoring program in 2013, to provide a factual basis for sizing replacement transformers.	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AC SWITCHGEAR			**80**	**50**	**15**	**15**	**15**	**15**	**2,900**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	3,090
	Perform infra-red scans on all switchgear no later than 2013 at an estimated cost of $15k.	1	15	0	0	0	0	0	0	0	0	0	0	0	0	0	15
	Initiate a refurbishment program with the OEM to maintain the reliability of the breakers until such time as they are replaced in 2019. Allow $15k per year for this work.	1	15	15	15	15	15	15	0	0	0	0	0	0	0	0	90
	It is strongly recommended to perform an arc flash and protection co-ordination study on the entire station service system in 2013 to determine the possible level of arc energy at the switchgear locations. The cost estimate for the study is $50k.	1	50	0	0	0	0	0	0	0	0	0	0	0	0	0	50
	As there are no recent testing results available, the following tests should be performed by 2014 on the 600 V switchgear, at a cost of $35k: • High voltage AC dielectric tests on wiring and bus bar • Contact resistance measurement of the breakers • Circuit breaker timing test • Current transformer (CT) polarity check • Partial discharge (corona) • Secondary AC current injection • DC protective circuits check • CT & PT transformation ratio check	1	0	35	0	0	0	0	0	0	0	0	0	0	0	0	35
	The 600 V switchgear should be replaced in 2019. The cumulative budgetary price for upgrade of the overall AC station service is $2.9M. This budget price includes switchgear and other accessories such as feeder cables and cable trays. The new switchgear should be of the arc resistant type. In the meantime, AC breakers should be refurbished depending on the test program results	3	0	0	0	0	0	0	2,900	0	0	0	0	0	0	0	2,900
AUTO TRANSFER CONTROL			**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	0
	To ensure reliable operation of the system, detailed regular maintenance should be performed on the transfer equipment.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	The voltage relays and timers utilized by the auto-transfer system should be cleaned, tested and calibrated in 2013.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Starting in 2013, test the auto transfer system on an annual basis, prepare a written procedure for the manual transfer and update/revise original drawings to reflect the present arrangement.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	The complete auto-transfer system together with the AC station service switchgear should be replaced during the station service upgrade. Cost of the upgrade is included within the AC Switchgear section, above.	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MCC'S AND PANEL BOARDS			**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	0
	A thorough cleaning of all electrical equipment should be carried out in 2013 and then every 3 – 5 years.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	All MCC and distribution panels should be replaced at the time of station service upgrade in 2019. Budgetary costs for the replacement are included in the station service upgrade cost associated with the AC Switchgear, above.	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CABLE AND BUS			**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	0
	Cables should be reviewed regularly to ensure there has been no mechanical damage, otherwise, cabling should be changed out when the associated system is changed out.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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Condition Assessment Discipline Summary Sheet

WRECK COVE GS

Electrical

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STANDBY DIESEL GENERATOR			**325**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	325
	The existing diesel generator, including all directly related auxiliaries (day-tank, batteries, charger, generator controls etc.) should be replaced except for the bulk storage tank, the building and the building slab. It is anticipated that this will cost approximately $300k. Replacement does not include the station service distribution portion, as this is addressed elsewhere in this report. It is recommended that NSP proceed with the planned replacement within the next five years. NSP has indicated that they are proceeding in 2013.	1	300	0	0	0	0	0	0	0	0	0	0	0	0	0	300
	Provide secondary oil containment around the outdoor bulk fuel storage tank in 2013. Estimated cost is $25k.	1	25	0	0	0	0	0	0	0	0	0	0	0	0	0	25
PROTECTION AND CONTROLS SYSTEM			**7**	**297**	**17**	**4,295**	**1,557**	**32**	**2**	**2**	**2**	**40**	**190**	**40**	**40**	**70**	6,591
	Continue with maintenance and calibration of the existing protection systems until the existing system is replaced.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Given the age of the existing protections and lack of manufacturer support, a plant wide upgrade is in order. As part of this upgrade, it would be anticipated that the entire system should be reviewed to see how the more modern protection schemes could benefit plant reliability and long term maintenance. It is recommended that this upgrade be performed in the year 2016 and the estimated cost is $1.53M per unit, including engineering. Considerations for the upgrade should include: • Optimum method of project roll out to minimize outage lengths • Methods of encapsulating and removing asbestos from the existing system • Options for redundant protection schemes using modern multifunction digital relays • Locations and configuration of new equipment • Integration with future station service switchyard protections • Anticipated design time is likely on the order of 12-15 months • Installation time could be in excess of 6 months including an outage of each unit which could be on the order of 1 month • It is anticipated that station controls upgrades would be performed in parallel with this work • This work would be done to accommodate the generator replacement or refurbishment. • Allow for an initial period of low reliability and retain the manual control capability that now exists to assist with this phase.	2	0	0	0	1,525	1,525	0	0	0	0	0	0	0	0	0	3,050
	The problem with the SCADA RTU should be investigated in more detail. Even though replacement of faulty modules within the RTU is acceptable to continue with the operation, procurement and installation of new a RTU is strongly recommended at the time of the control system upgrade. The cost is included within the control system budget estimate below.	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	The upgrade of the control system is recommended for the year 2016. The budgetary cost of replacement is approximately $2.5M. in addition, a design allowance and investigations required for planning of $250k should be included in the year 2014. The upgrade of the control system has to be initiated together with the protection upgrade so that all the technical interfaces between these two systems can be addressed at the same time to minimize complications. See Control System recommendations for considerations that may apply to Protections replacement.	2	0	250	0	2,500	0	0	0	0	0	0	0	0	0	0	2,750
	The start-stop control should be upgraded as part of the new PLC based control systems. The budgetary price for the plant start-stop control upgrade is included in the control system budget, above.	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	The new synchronization system should be integrated with the overall plant controls and protections upgrade. Funds for the synchronizer replacement are included in the controls systems budget, above.	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Generally, this vintage of Woodward governor system has a long history of reliability. Many of the minor electrical items should be assessed for replacement. This is effectively routine maintenance. Components such as the pumps, internal actuator cabinet wiring, potentiometers in the wicket gate/gate limit position detection, gate position switches and solenoid valves should be replaced in a continuous fashion. A program of upgrades should be reviewed costing approximately $ 20k per year and running five years. It is anticipated that this should start within ten years.	3	0	0	0	0	0	0	0	0	0	0	100	0	0	0	100

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(costs in 2012 k$)

		Condition Rating	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023-2027	2028-2032	2033-2037	2038-2042	TOTAL 2013-2042
	As a part of the life extension program for the governors it is recommended: • To perform a major overhaul in the year 2018 and then every 20 years. The cost of a major overhaul is $30k per unit. It is anticipated that this overhaul would be done in conjunction with the unit overhauls, in 2017 and 2018. • Perform minor overhauls every 5 years in between the two major overhauls. The budgetary cost of minor overhauls is $15k per unit.	2	0	0	0	0	30	30	0	0	0	0	30	30	30	60	210
	Minor governor maintenance should be done as a part of regular maintenance activity. Lumpsum budgetary estimate is $2k per year.	MTCE	2	2	2	2	2	2	2	2	2	2	10	10	10	10	60
	Most of the major spare parts and the spares for the accumulator level and pressure measurements system should be procured. The budgetary cost of such spares procurement is $20k. This should be initiated in 2014	1	0	20	0	0	0	0	0	0	0	0	0	0	0	0	20
	The faulty brake solenoid should be replaced or repaired in 2013, at an estimated cost of $5k.	MTCE	5	0	0	0	0	0	0	0	0	0	0	0	0	0	5
	As the metering system is important to the remote and local operation of the plant, it is recommended that the current system be replaced as it has reached the end of its useful life. The costs to replace this system have been included in the control upgrade costs.	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	It is recommended that the control panels CP1 and CP2 be considered for upgrade at the same time as the systems or equipment that they are related to or service are upgraded. While the estimated cost to upgrade CP1 has been included with the controls upgrade, the cost to upgrade the HVAC controls / CP2 is estimated to be approximately $150k and the work should be planned for 2016.	2	0	0	0	150	0	0	0	0	0	0	0	0	0	0	150
	Perform a thorough analysis of the compatibility of the plant control instrumentation with respect to modernization of the plant control system. It is anticipated that many of these instruments would be replaced at the time of a controls upgrade, but they could be done at any time. A lump sum instrument replacement budget for these items is $100k, and the work should be planned for 2016	2	0	0	0	100	0	0	0	0	0	0	0	0	0	0	100
	Institute a periodic testing program for the tailrace water level alarm and lockout functions, as these functions are very important for worker safety and plant protection.	MTCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Re-instate the tailrace water level monitoring function and connect to SCADA for transmission to the Energy Control Centre in 2014 at an estimated cost of $25k.	1	0	25	0	0	0	0	0	0	0	0	0	0	0	0	25
	Replace the tailrace water level alarm and lockout system within 3 years at an estimated cost of $15k.	2	0	0	15	0	0	0	0	0	0	0	0	0	0	0	15
	Replacement of the reservoirs water level gauging system is estimated at $38k and should be performed in 2022.	3	0	0	0	0	0	0	0	0	0	38	0	0	0	0	38
	The sump pump control system should be upgraded within the next five years, Including, relocation of the panel to a dry area. The budgetary cost for this work is $18k and it is allowed for in 2016	2	0	0	0	18	0	0	0	0	0	0	0	0	0	0	18
	Replace turbine shut-off valve controls with a PLC based system in 2027 at a cost of $50k for two units.	3	0	0	0	0	0	0	0	0	0	0	50	0	0	0	50
STATION DC POWER SYSTEM			**0**	**15**	**0**	**135**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	150
	The power distribution panel for the DC system is a potential hazard given its exposed buswork. Covers to ensure there is no access issues with the door open could help to reduce this risk, however, as parts of the DC system have substantially been upgraded, the distribution panel should be upgraded as well, to return the entire system to a like new condition. An upgrade to the distribution panel would be done with a distribution panel with visible contacts and would cost $15k and should be performed in 2014.	1	0	15	0	0	0	0	0	0	0	0	0	0	0	0	15
	Should NSP wish to increase the reliability of the DC system to attain a more standard configuration with redundant DC supplies, a second battery system and inverter could be installed. An additional battery system would cost $135k. This work would typically be done with station protections and controls upgrades and has been included in 2016.	2	0	0	0	135	0	0	0	0	0	0	0	0	0	0	135
STATION GROUNDING SYSTEM			**0**	**0**	**0**	**0**	**0**	**0**	**0**	**95**	**150**	**0**	**0**	**0**	**0**	**0**	245
	Perform a grounding study within in the next ten years. The cost is anticipated at $95k, and this amount has been included in the year 2020.	3	0	0	0	0	0	0	0	95	0	0	0	0	0	0	95
	While it is not clear how much grounding modification would result from the study, $150k in grounding upgrades has been identified for 2021 as a reasonable estimate.	3	0	0	0	0	0	0	0	0	150	0	0	0	0	0	150
STATION LIGHTING SYSTEM			**0**	**215**	**0**	**650**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	865
	The lighting throughout the plant should be replaced within the next two to three years, along with the supporting structures where they show signs of corrosion. The main areas where lighting should be upgraded along with their estimated cost include: Access Tunnel: $205k; Plant Main Area: $220k; Plant Auxiliary Areas: $180k; Plant Refuge Tunnel Area: $45k, for a total of $650k. This amount has been included in 2016 as it would benefit general unit overhaul activities.	2	0	0	0	650	0	0	0	0	0	0	0	0	0	0	650

Condition Assessment Discipline Summary Sheet

WRECK COVE GS

Electrical

Thirty year total (2012 k$) $42,917
Ten year total (2012 k$) $42,487

(costs in 2012 k$)

		Condition Rating	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023-2027	2028-2032	2033-2037	2038-2042	TOTAL 2013-2042
	A modern emergency lighting system should be installed which clearly illuminates the paths of egress. This should be installed in conjunction with the exit signage which helps evacuation to occur down the correct route. This new modern emergency lighting system would be DC, but separate from the station DC system. The cost of the emergency lighting system would be approximately $195k, and should be done by 2014 as it improves safety for plant staff.	1	0	195	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	195
	Given that there a multiple circular routes and effectively only one exit, exit signs and phosphorescent paint on the floor should be installed to clearly indicate the directions of exit. The cost of the system is included with the above item. If an exit signage system is installed as a separate item, with standalone battery units, the cost of this work would be approximately $20k, and should be done by 2014 as it improves safety for plant staff.. As separate items, these would essentially be self contained exit signs which would have internal chargers and batteries and would connect to AC station service.	1	0	20	0	0	0	0	0	0	0	0	0	0	0	0	20

EXCERPT FROM SUMMARY SHEETS FOR YEAR 2013

WRECK COVE GS

2013-04-23

Condition Assessment Summary

2013 Recommended Activities

(costs in 2012 k$)

*Note: items showing no funds in 2013 are assumed to be covered with existing maintenance funding or internal engineering studies and assessments funding.

Component or System	Recommended Projects	Condition Rating	2013	2014	2015	2016	2017
CIVIL							
TUNNEL T2 INTAKE STRUCTURE			**207**	**0**	**0**	**0**	**0**
	Continue to periodically, visually monitor the concrete for evidence of deterioration and spalling and waterline erosion.	MTCE	0	0	0	0	0
	Repair the failed caulking around the roof hatch within the next year. Consideration should be given to replacing the failed caulking with grade mastic and mesh. A protective coating should then be installed over the repair. The estimated cost for this work is $6k.	1	6	0	0	0	0
	Install an all season safety boom in 2013, at an estimated cost of $130k.	1	130	0	0	0	0
	Extend the safety fencing to the boom anchor points in 2013 at an estimated cost of $70k.	1	70	0	0	0	0
	Provide two additional public safety signs on the land side of the fencing in 2013, at an estimated cost of $1k.	1	1	0	0	0	0
TUNNEL T2 ADIT			**0**	**0**	**0**	**0**	**0**
	No 2013 recommendations	-	0	0	0	0	0
PENSTOCK INTAKE STRUCTURE AT SURGE LAKE			**0**	**0**	**0**	**0**	**0**
	See Powerhouse Egress and Life Safety section below	-	0	0	0	0	0
PENSTOCK FROM SURGE LAKE			**5**	**0**	**0**	**0**	**0**
	The penstock steel plate in the powerhouse in the area where the limited thickness measurements were taken is in good condition. Starting in 2013 perform more extensive ultrasonic thickness testing every 5 years. Estimated cost $5k for two penstocks.	MTCE	5	0	0	0	0
SPIRAL CASE			**0**	**0**	**0**	**0**	**0**
	See Turbines section below.	-	0	0	0	0	0
DRAFT TUBE			**50**	**10**	**0**	**0**	**0**
	Continue to repair any draft tube liner cavitation pitting damage during the yearly maintenance outages. Repair the present minor damage within two years.	MTCE	0	0	0	0	0
	Refurbish the Unit 2 tripod air system within 8 months. Cost is estimated to be $40k.	1	40	0	0	0	0
	Investigate the Unit 1 draft tube water leakage in 2013 at an estimated cost of $10k.	1	10	0	0	0	0
	During the next scheduled outages for each unit, the condition of the unlined draft tube concrete sections should be inspected and assessed. Estimated cost for each unit inspection and assessment is $5k per unit.	MTCE	0	10	0	0	0
TAILRACE			**50**	**0**	**0**	**0**	**0**
	Continue to monitor the condition of the rock and shotcrete above the draft tube deck area and on an ongoing basis, scale and/or install rock anchors as required. Allow $5k every 5 years for these activities.	MTCE	5	0	0	0	0
	Install public safety signage on the downstream side of the tailrace portal structure. This new signage should be installed within the next year and be in accordance with the CDA standards. The estimated cost is $5k.	1	5	0	0	0	0
	Extend the fencing along the downstream side of the tailrace deck to prevent the public from accessing the tailrace area immediately downstream of the handrail on the right side of the deck. The estimated cost is $15k and the work should be completed in 2013.	1	15	0	0	0	0

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2013-04-23

Condition Assessment Summary

2013 Recommended Activities

(costs in 2012 k$)

*Note: items showing no funds in 2013 are assumed to be covered with existing maintenance funding or internal engineering studies and assessments funding.

Component or System	Recommended Projects	Condition Rating	2013	2014	2015	2016	2017
	NSP should confirm that a structural analysis was carried for the design of the new anchorage system that was installed in 2011 for storing the gate in its vertical position and that the anchorage system does meet all applicable loading conditions (including seismic). If an analysis has not been carried out it should be completed within the next year. The cost for the analysis is estimated to be $20k.	1	20	0	0	0	0
	Provide instrumentation to allow the periodic measurement and recording of water levels at the inlet and outlet of the tailrace tunnel. Monitoring the hydraulic loss will provide an indication of the cumulative effects of rockfalls on the tunnel's hydraulic performance. Assuming this is done with staff gauges, the estimated cost is $5k and the work should be done by 2014.	1	5	0	0	0	0
POWERHOUSE			**20**	**10**	**10**	**10**	**10**
	Provide an annual allowance of $10k for miscellaneous items such as repairing / replacing individual tiles, patching concrete and shotcrete, adding / replacing rock anchors, repainting and repairing handrails, etc. This annual allowance would also include for monitoring and removing the stalactities to avoid the potential for them to fall on persons working below.	MTCE	10	10	10	10	10
	In 2013 a survey of the alignment of the crane rails should be carried out to determine if any misalignment issues could have contributed to the failure of the bolts. The estimated cost for this work is $10k.	1	10	0	0	0	0
	Every two years starting in 2013, inspect the condition of the crane rails and bolts to ensure that failure of the crane bolts is not an ongoing issue.	MTCE	0	0	0	0	0
POWERHOUSE EGRESS AND LIFE SAFETY			**300**	**475**	**2,500**	**2,500**	**0**
	The equipment and alarm system for monitoring the tailrace water level should be regularly tested to ensure that it functions satisfactorily and if necessary it should be refurbished or replaced.	MTCE	0	0	0	0	0
	Reduce worker exposure in the powerhouse by having any work which does not need to be performed inside the powerhouse, such as workshop work, done at the surface.	1	0	0	0	0	0
	Reduce the amount of combustible material stored in the powerhouse (oil, wood, rags), by removing it to a surface storage/workshop building located in the vicinity of the present Administration Building. Consider allowing only diesel engine vehicles into the access tunnel, to reduce the amount of readily flammable fuel in the powerhouse area. A basic surface storage/workshop building is estimated to cost $425k and should be planned in 2013 for implementation in 2014.	1	0	425	0	0	0
	Carry out a formal, comprehensive, detailed life safety and equipment protection engineering risk analysis, to identify failure modes and risks and to identify and assess solutions. The scope should include falling, fire and flooding risks, and should be undertaken in 2013, with a view to completing implementation prior to major equipment replacement with the anticipated increase in worker numbers in the powerhouse. The estimated study cost is $250k, and a budgetary allowance of $5M is recommended in 2015 and 2016 for implementation, with a small allowance of $100k split between 2013 and 2014 for improvements which can be implemented quickly.	1	300	50	2,500	2,500	0

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2013-04-23

Condition Assessment Summary

2013 Recommended Activities

(costs in 2012 k$)

*Note: items showing no funds in 2013 are assumed to be covered with existing maintenance funding or internal engineering studies and assessments funding.

Component or System	Recommended Projects	Condition Rating	2013	2014	2015	2016	2017
	Particular urgent attention should be given to the risk assessment associated with the absence of head gates at the penstock inlet structure, as the absence of effective mean of quickly stopping water flows in an emergency can lead to injury, fatalities and extensive plant destruction (e.g. Kainji in Nigeria, 2000 and Sayano-Shushenskaya in Russia, 2009). The study should address providing head gates at the penstock inlet structure with an alarm system that would alert the operators that there is an issue with the penstocks (i.e., large drop in pressure) and which would have the capability to close the head gates automatically or by remote control in an emergency situation. The engineering study costs are included above.	1	0	0	0	0	0
POWERHOUSE ACCESS TUNNEL			**16**	**4**	**4**	**4**	**4**
	Seal the expansion joints of the concrete foundation plinth within the next year at an estimated cost of $2k.	1	2	0	0	0	0
	As a regular maintenance item clear debris that accumulates on the staircase to eliminate this tripping hazard.	MTCE	0	0	0	0	0
	Carry out an investigation to determine where the rock that is accumulating between the portal structure and the gabion wall is falling from and then assess and implement means to prevent the rock from falling in the future. The cost of the study is estimated to be $10k and it should be carried out in 2013.	1	10	0	0	0	0
	Until a means has been implemented to prevent the rock from falling, a maintenance program should be implemented to remove the fallen rock between the portal structure and the gabion wall on an on-going basis. Provide an annual allowance of $4k for this work.	MTCE	4	4	4	4	4
POWERHOUSE ACCESS TUNNEL FEEDERS			**0**	**0**	**0**	**0**	**0**
	No 2013 recommendations	-	0	0	0	0	0
MECHANICAL							
TUNNEL T2 INTAKE EQUIPMENT			**170**	**0**	**0**	**0**	**0**
	Conduct a thorough assessment of gate condition by removing the top covers, and progressively raising and stopping the gate to allow for checking of the main and guide rollers for seizing/free rotation. At the same time check the condition of the skin plate and welds, visible structural members, side and bottom seals and seal clamping plates and fasteners, and the integrity of side roller assemblies and bumpers. If possible to access, also inspect the condition of the roller and seal path surfaces. From this inspection establish the scope and timing of a gate refurbishment. The cost of the assessment is estimated at $15k and it should be completed by 2013.	1	15	0	0	0	0
	Carry out a detailed inspection of the hoist, pulley block, holding brake, and wire rope and replace all lubricants. Depending on the findings, an overhaul may be required, not based on high usage, but because of long periods of inactivity may have resulted in corrosion of items such as anti-friction bearings. Cost of inspection is estimated at $5k per gate, and this should be completed in 2013, before the first gate test.	1	10	0	0	0	0

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2013-04-23

Condition Assessment Summary

2013 Recommended Activities

(costs in 2012 k$)

*Note: items showing no funds in 2013 are assumed to be covered with existing maintenance funding or internal engineering studies and assessments funding.

Component or System	Recommended Projects	Condition Rating	2013	2014	2015	2016	2017
	It is anticipated that the following work will be done in as a package. • All electrical and control equipment should be replaced. • Given the remoteness of the location and the presence of vandalism, it is recommended that NSP replace all electrical systems with more vandal resistant equipment. All abandoned or obsolete equipment at the site should be removed and all new equipment should be designed to be contained in a limited number of panels which can be installed in a way to improve serviceability. • It is recommended that all lighting be replaced or returned to a working condition. • It is recommended that all electrical equipment be installed in enclosures. • Provide for remote gate closure, to be used in the event of an emergency. This should be done in 2013 at an estimated cost of $5k. Estimated cost is $140k (does not include gate body or guide heating) and the work should be carried out within 2013.	1	145	0	0	0	0
TUNNEL T2 ADIT DRAIN VALVE & PIPING			**0**	**0**	**0**	**0**	**0**
	No 2013 recommendations	-	0	0	0	0	0
TURBINE SHUTOFF VALVES			**40**	**0**	**0**	**0**	**0**
	Perform an analysis of the oil in the hydraulic operating system every two years.	MTCE	0	0	0	0	0
	Annually inspect the nozzles on the downstream side of the motorized bypass valves for evidence of cavitation pitting and repair as necessary.	MTCE	0	0	0	0	0
	Every 5 years, measure the wall thickness of the valves' bypass piping. This could be done during the yearly outage. If the wall thickness decreases to 80% of nominal, replace the piping. Inspection cost: $4k for two units every 5 years	1	4	0	0	0	0
	In 2013, perform an NDE check of the turbine shut off valve stems using ultrasonic means. Review valve drawings and determine if there is any evidence of cracking in the stems. Inspection cost is estimated to be $2 k per valve.	1	4	0	0	0	0
	Confirm if the upstream seal O-rings are original and if found to be so or if indeterminate, plan to replace the O-rings within three years.	1	0	0	0	0	0
	Install a turbine shutoff valve closing system which are independent of AC station service power in 2013. This could be achieved by modifying the existing systems, and the cost is estimated at$25k per unit.	1	25	0	0	0	0
	Confirm the pressure, size, location and security of the orifices in the supply to the turbine shut off valve servomotors. This should be done in 2013 and the estimated cost is $2k per servomotor.	1	4	0	0	0	0
	Store the spare valve seals securely in a purpose made wooden crate.	MTCE	0	0	0	0	0
	Purchase a set of trunnion seals ($1k). This will minimise outage time if they have to be replaced.	MTCE	1	0	0	0	0
	Purchase a spare hydraulic pump and motor ($1.5k). If a pump fails, the generating unit could not be operated.	MTCE	2	0	0	0	0
	Confirm that drawings and specifications are available for ordering new turbine shutoff valve main water seals (upstream and downstream) and new trunnion seals.	MTCE	0	0	0	0	0
	Amend the record drawings to show the difference in size between the seals of Unit 1 and Unit 2, and the correct O ring dimensions and materials.	MTCE	0	0	0	0	0

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2013-04-23

Condition Assessment Summary

2013 Recommended Activities

(costs in 2012 k$)

*Note: items showing no funds in 2013 are assumed to be covered with existing maintenance funding or internal engineering studies and assessments funding.

Component or System	Recommended Projects	Condition Rating	2013	2014	2015	2016	2017
TURBINES			**105**	**100**	**12**	**0**	**12**
	To ensure long term unit reliability a comprehensive monitoring program should be established, with the following mechanical elements: 1. Install a shaft vibration analysis system that will give trending data on shaft runout, shaft orbit, and changes in the characteristic frequencies of the unit components 2. Record the bearing temperatures and institute a temperature analysis and trending system. 3. Continue to carry out yearly inspections but review what is to be inspected, based on the new operating conditions. Emphasize the close inspection of components susceptible to fatigue cracking, specifically the generator rotor and the turbine runner. Non destructive examination by LPI, MPI, and UT methods are recommended for critical areas. 4. Ensure the annual inspection and operation records are documented and available over the long term to allow for trending analysis.	MTCE	0	0	0	0	0
	Undertake an engineering study to review model test information and to conduct a vibration test program on the Wreck Cove turbines, to establish the extent of the rough load range and to assess the risks of extended and periodic operation within such rough load range. This work should be undertaken in 2013, with a view to completing the vibration tests and the assessment by 2014. The estimated cost for this engineering study is $150k, including the vibration test work for one unit.	1	50	100	0	0	0
	Every two years filter the turbine bearing oil to remove dirt and especially any water. A filter medium that specifically removes water should be used.	MTCE	0	0	0	0	0
	Using the shaft vibration probe outputs, review the shaft orbits to see if the shaft is over to one side of the bearing. This could cause high running temperatures and may be due to shaft misalignment.	1	0	0	0	0	0
	Check the calibration of the Bently Nevada vibration monitors to ensure the read outs are valid. This should be done in 2013.	1	0	0	0	0	0
	During the next outage (2013), perform an NDE examination of turbine shaft critical areas. Estimated cost is $2k per unit.	1	4	0	0	0	0
	Continue to keep the runners in their present good condition, with the periodic repairs to the minor cavitation pitting so the damage does not increase.	MTCE	0	0	0	0	0
	Measure the runner crown and band seal clearances every 2 years starting in 2013.	MTCE	0	0	0	0	0
	Every two years non-destructively inspect the runner for cracks, particularly at the blade and band welds, starting in 2013. The estimated cost is $3k per unit.	1	6	0	6	0	6
	Use dial indicators to measure upward movement of several wicket gates when the turbine is dewatered to when it is watered up. The dial indicators should be supported on the pit wall or on the turbine shaft and read against the top of the upper stems. If the gates rise when the turbine is watered up then the lower stem seal probably have failed. This test should be performed in 2013 and the cost is $2k per unit.	1	4	0	0	0	0
	Inspect and document with photos the wicket gate surfaces and the surrounding area during each yearly outage. Look for surface damage and signs of rubbing at the top and bottom of the gates.	MTCE	0	0	0	0	0

WRECK COVE GS

2013-04-23

Condition Assessment Summary

2013 Recommended Activities

(costs in 2012 k$)

*Note: items showing no funds in 2013 are assumed to be covered with existing maintenance funding or internal engineering studies and assessments funding.

Component or System	Recommended Projects	Condition Rating	2013	2014	2015	2016	2017
	Continue the yearly repairs to the wicket gate cavitation damaged surfaces until permanent repairs can be done.	MTCE	0	0	0	0	0
	Review the type of grease used, and the greasing timing and amount. Install an automatic greasing system in 2013. Cost $10k per unit.	1	20	0	0	0	0
	Monitor the wicket gates upper stem area for seal leakage. Replace the packing during a yearly maintenance outage if excessive leakage occurs. Cost: $5k (materials)	1	5	0	0	0	0
	Within one year, carry out an axial ultrasonic examination of the upper wicket gate stems to determine if cracking has occurred where the stems join the blade. Estimated cost is $2k per unit.	1	4	0	0	0	0
	Visually inspect the spiral case at each annual maintenance outage. Look for any erosion damage and for any cracking at the top and bottom of the stay vanes. For suspect indications and not less than every two years perform magnetic particle non destructive examination. Cost: $3k per unit.	1	6	0	6	0	6
	Inspect all the stud bolts on the head cover outer flange of both turbines in 2013, then every 5 years. This would include an ultrasonic test, visual inspection and a representative check of the applied torque. The required torque should be determined by a mechanical engineer. Estimated NDE cost is $3k per unit.	1	6	0	0	0	0
	Consider installing piston rod lip seals having joints on their circumference. They can be easily installed without dismantling the servomotor rod end fittings.	MTCE	0	0	0	0	0
	Every year measure the governor pump cycling time with the wicket gates not moving. An increase in the cycling time may indicate wear of the servomotor piston rings, or governor control valve internal leakage.	MTCE	0	0	0	0	0
	As with the wicket gates, increase the greasing frequency for the operating ring and linkages and adjust the quantity of grease injected. to avoid extraneous grease accumulating on the head cover. It will be important to assess the greasing frequency as the turbine wicket gates will be more active when the generator load will be continually changing to follow system wind load variations.	MTCE	0	0	0	0	0
TURBINE REGULATING EQUIPMENT			**0**	**0**	**0**	**0**	**0**
	Investigate the parts availability for the Magnetrol level switches. If parts are difficult to find, install modern combined level indicators and switches.	MTCE	0	0	0	0	0
	Investigate the availability of the governor oil pump replacement parts in 2013. They may be very long delivery or no longer be available.	MTCE	0	0	0	0	0
GENERATOR MECHANICAL			**370**	**0**	**0**	**0**	**0**
	Implement the Acuren shaft runout trending program and the Power Engineering Company unbalanced magnetic pull (UMP) system by March 2013. Review the data on a monthly basis.	MTCE	0	0	0	0	0
	Carry out the rotor and stator testing program recommended by Power Engineering Company, and KGS Group	1	0	0	0	0	0
	Perform a rotational alignment check on both units in 2013 and re-centre the stators relative to the rotors.	1	0	0	0	0	0

WRECK COVE GS

2013-04-23

Condition Assessment Summary

2013 Recommended Activities

(costs in 2012 k$)

*Note: items showing no funds in 2013 are assumed to be covered with existing maintenance funding or internal engineering studies and assessments funding.

Component or System	Recommended Projects	Condition Rating	2013	2014	2015	2016	2017
	Review the two options in the Power Engineering Company report: to replace the generator or perform a major refurbishment, and based on the results of these inspections and the soon to be obtained test data, establish a date for a refurbishment of the generator and the scope of work to be done. This review should be done in 2013. The estimated cost of refurbishment of two generators is $30M and to recognize site work space constraints, these costs are shown equally split between 2017 and 2018. Note: these costs are included in the Electrical Assessment section of this report.	1	0	0	0	0	0
	Implement the Power Engineering Company UMP system by March 2013. Review this data on a monthly basis for any changes and trends. Estimated equipment cost is $40k per unit.	1	80	0	0	0	0
	In 2013 review the condition of the rotors as found from inspections and tests and plan future repairs.	1	0	0	0	0	0
	Non-destructively inspect the rotor brake tracks every five years starting in 2013. Estimated cost is $2k per unit.	1	4	0	0	0	0
	In 2013 plan the work and timing of repairs and refurbishment, including consultation with OEM.	1	0	0	0	0	0
	In 2013 repack the stator cores at the splits, install the soleplate radial keys in Unit 1 and rectify the soleplate radial keys problem in Unit 2. Estimated cost is $100k per unit.	1	200	0	0	0	0
	Confirm that the brake pads are made of non asbestos material. Replace the pads if they are asbestos based.	MTCE	0	0	0	0	0
	Record the surface air cooler cooling water flows monthly.	MTCE	0	0	0	0	0
	The shaft runout data collection and analysis program proposed by Acuren should be implemented and applied over the long term, to check for developing problems.	MTCE	0	0	0	0	0
	The calibration of the Bently Nevada vibration monitoring system should be checked to ensure it is working correctly.	1	0	0	0	0	0
	The reason for the high runout levels at the lower and upper guide bearings of both units should be analyzed in 2013 as to cause and then addressed. Estimated cost is $10k/unit.	1	20	0	0	0	0
	During the next outage (2013), perform an NDE examination of generator shaft critical areas. Estimated cost is $2k per unit.	1	4	0	0	0	0
	Filter the thrust and guide bearing oil every two years. This period may change depending on the Acuren oil analysis program findings.	MTCE	0	0	0	0	0
	The thrust bearing temperatures should be recorded and the data reviewed on a six month basis. If at some time a continual temperature increase is noted, the thrust segments should be replaced with the spare ones. Rebabbitting cost: $30k	1	30	0	0	0	0
	Clean the top cover of the upper guide bearing yearly to prevent the carbon dust from mixing with the oil.	MTCE	0	0	0	0	0
	Re-adjust the oil pot seals. If the leakage cannot be reduced to an acceptable level, install a vacuum demisting unit in 2013 ($15k per unit).	1	30	0	0	0	0
	Check the condition of the Unit 2 thrust bearing by removing two segments for visual inspection in 2013. If the surface shows no sign of damage, check the calibration of the temperature measuring system.	1	0	0	0	0	0

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2013 Recommended Activities

(costs in 2012 k$)

*Note: items showing no funds in 2013 are assumed to be covered with existing maintenance funding or internal engineering studies and assessments funding.

Component or System	Recommended Projects	Condition Rating	2013	2014	2015	2016	2017
	Non-destructively by UT method inspect the spare set of thrust pads in 2013 to confirm their babbitt bond is acceptable. If the pads are to be installed, their flatness must first be checked on a surface plate.	1	2	0	0	0	0
TAILRACE EQUIPMENT			**13**	**2**	**2**	**2**	**2**
	Develop a detailed plan for the installation of the tailrace tunnel outlet gate that deals with removal of the cobblestones obstructing the north side gains. This should be completed before major refurbishment work in the powerhouse or tunnel begins. This study is estimated to cost $10k and should be performed in 2013.	1	10	0	0	0	0
	Monitor the condition of the coating on the tailrace tunnel outlet gate periodically, to track the failure of the coating, touching up the coating as found necessary. This work is estimated to cost $2k per year and should be performed annually.	MTCE	2	2	2	2	2
	Install a guard on the chain drive of the draft tube gates storage carriage to prevent the operator's fingers from being trapped. ($1k in 2013)	1	1	0	0	0	0
ANCILLARY EQUIPMENT (CRANES, MONORAILS)			**0**	**0**	**0**	**0**	**0**
	No 2013 recommendations	-	0	0	0	0	0
HEATING, VENTILATION & AIR CONDITIONING			**5**	**0**	**0**	**0**	**0**
	In 2013, install thermometers and hygrometers at several locations in the powerhouse and outdoors and monitor and record the conditions on a weekly basis and more frequently when tests to improve cooling are being performed. The data collected is important to determine the extent of the cooling problem and will assist in devising the optimum solution. The estimated cost is $5k.	1	5	0	0	0	0
	Adjust the ventilation system operation in summer to operate the emergency smoke removal system to maximize the amount of outside air brought into the powerhouse for cooling and dehumidification. Monitor temperatures and humidity levels in the powerhouse to check effectiveness. If the operation of the emergency smoke removal fan is unacceptable due to high noise levels, adjust the intake damper M1 in the portal building to full open, close damper M2. Monitor temperatures and humidity levels in the powerhouse to check effectiveness. These two tests should help establish whether mechanical cooling needs to be reinstated.	1	0	0	0	0	0
COMPRESSED AIR SYSTEMS			**50**	**0**	**0**	**0**	**0**
	Inspect the service air system for leaks and repair as required	MTCE	0	0	0	0	0
	In 2013, install a timed blow down valve on the compressed air storage tanks which supply the governor and power tools ($10k).	1	20	0	0	0	0
	In 2013, install automatic air make up systems for the governor accumulator tanks ($15k per unit).	1	30	0	0	0	0
FIRE PROTECTION AND DETECTION SYSTEM			**62**	**0**	**0**	**0**	**0**
	To establish their remaining life, arrange for inspection and wall thickness testing of the existing tanks and related piping from the well pumps to the storage tanks and also the piping and valves from the storage tanks into the powerhouse and to the generator and transformer fire protection systems. Based on the results of this testing, a plan for remedial work can be developed. Estimated investigation cost is $20k in 2013.	1	20	0	0	0	0

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Condition Assessment Summary

2013 Recommended Activities

(costs in 2012 k$)

*Note: items showing no funds in 2013 are assumed to be covered with existing maintenance funding or internal engineering studies and assessments funding.

Component or System	Recommended Projects	Condition Rating	2013	2014	2015	2016	2017
	Address the current shortfall in the required water storage capacity. Current total storage capacity in the two tanks is 227,000 L (60,000 US gallons) versus an NFPA 851 requirement for 568,000 L (150,000 US gallons). Perform a study to investigate alternatives before implementing. Estimated cost to investigate the work described is $40k	1	40	0	0	0	0
	The two water supply wells should have vegetation removed from the immediate vicinity and fence post markers with identification tags placed to clearly identify the well locations. Estimated cost $2k.	1	2	0	0	0	0
	Confirm that both well pumps are capable of operation and are in good working order. This can be achieved by flushing the fire protection supply line to the powerhouse with a flow rate not less than the transformer deluge capacity of 1552 L/min (410 USgpm), which will also remove any loose corrosion particulate matter from the supply line. Repeat this flush every two years.	MTCE	0	0	0	0	0
SUMP SYSTEMS (DRAINAGE AND DEWATERING)			**53**	**0**	**0**	**0**	**0**
	Replace or rebuild dewatering pump P2 in 2013. Replacement cost is estimated to be $3k.	1	3	0	0	0	0
	Take representative thickness tests on the pump discharge piping to obtain a general indication of its thickness and an indication as to its remaining life. Based on the results of this testing, determine if piping replacement is warranted. Estimated study cost is $10k.	1	10	0	0	0	0
	Carry out a study on the routing of all plant and equipment drains to determine which drain directly to the tailrace. Determine what action, if any, is required to avoid or capture potential spills. Study cost is $40k and it should be completed by 2013.	1	40	0	0	0	0
DOMESTIC WATER & SEWAGE SYSTEM			**0**	**0**	**0**	**0**	**0**
	No 2013 recommendations	-	0	0	0	0	0
SURGE LAKE DRAIN VALVES			**0**	**0**	**0**	**0**	**0**
	No 2013 recommendations	-	0	0	0	0	0
ELECTRICAL							
GENERATORS (ELECTRICAL)			**745**	**0**	**0**	**0**	**0**
	A thorough detailed investigation should be done to find the cause of the persistent Unit 1 and Unit 2 field grounds, involving the OEM or third party expert in the process. (This should be done in 2013 at an estimated cost of $100k).	1	100	0	0	0	0
	Rectify the loose stator wedges on both units in 2013 estimated at $100k.	1	100	0	0	0	0
	Re-implement the online partial discharge monitoring system on both units, which will require installation of new partial discharge (PD) couplers to obtain PD readings and associated data acquisition device for analysis. If this is not feasible in the short term then a periodic partial discharge measurement program should be initiated to monitor the stator insulation condition. The cost of this work is estimated at $65k and it should be done in 2013.	1	65	0	0	0	0
	Install the permanent continuous UMP monitoring system on both units in 2013. The cost estimate is $80k	1	80	0	0	0	0

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Condition Assessment Summary

2013 Recommended Activities

(costs in 2012 k$)

*Note: items showing no funds in 2013 are assumed to be covered with existing maintenance funding or internal engineering studies and assessments funding.

Component or System	Recommended Projects	Condition Rating	2013	2014	2015	2016	2017
	The rotor pole drop test should be performed annually on both units to determine the rotor field turns insulation health. Shorted turns can cause vibration, unbalanced stresses on the generator stator core, frame and rotor.	MTCE	0	0	0	0	0
	A generator dielectric test should be performed annually on both stator windings to determine and tract stator winding insulation condition.	MTCE	0	0	0	0	0
	Generator visual inspection should be done annually with specific attention to the common degradation problems: • Loose wedges • Loose field coil braces • Evidence of any partial discharge • Evidence of any overheating To perform this inspection the rotor and stator should be in a clean and oil-free state.	MTCE	0	0	0	0	0
	Perform the following testing in 2013 on both units to establish overall electrical condition of the generators. Budgetary cost is $200k. • Partial Discharge testing • DC Hipot test (Reduced Voltage) with DC ramp tester • Corona Probe test • ELCID test	1	200	0	0	0	0
	After the UMP based air gap monitoring system is installed, monitor and review the air gap of the unit. An air gap that does not stay within acceptable tolerances can cause undue stresses on components such as the stator and rotor, brackets and bearings and in extreme cases a stator and rotor collision could occur. The air gap of a hydro generator is ultimately determined by the circularity and concentricity of the rotor and stator.	1	0	0	0	0	0
	It is recommended to keep the following minimum level of spares on hand: • 12 top bars and 12 bottom bars • Wedges for 12 slots • Fillers (Top, Centre & Bottom) for 12 slots • One of each type of stator winding connection • Winding material for 12 slots • The spare pole coil should be tested in 2013. Estimated cost is $200k and these should be acquired in 2013.	1	200	0	0	0	0
EXCITATION SYSTEMS			**20**	**0**	**0**	**0**	**0**
	The existing spare parts should be checked to ensure that these are still functional. This process should be initiated soon to avoid any unexpected downtime. This check is estimated at $20k and should be done in 2013.	1	20	0	0	0	0
ISOLATED PHASE BUS DUCT			**0**	**0**	**0**	**0**	**0**
	A regular maintenance and monitoring program inclusive of visual inspection, cleaning and testing should be established to monitor the condition of the IPB on a regular basis. The manufacturer literature recommends that at minimum an annual inspection be performed on the bus.	MTCE	0	0	0	0	0

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Condition Assessment Summary

2013 Recommended Activities

(costs in 2012 k$)

*Note: items showing no funds in 2013 are assumed to be covered with existing maintenance funding or internal engineering studies and assessments funding.

Component or System	Recommended Projects	Condition Rating	2013	2014	2015	2016	2017
EXCITATION TRANSFORMERS			**0**	**0**	**9**	**0**	**9**
	Regular maintenance which includes visual inspection and cleaning should be done every year.	MTCE	0	0	0	0	0
	All the routine tests including a thermographic scan should be performed every two years. Estimated cost is $9k.	MTCE	0	0	9	0	9
AC STATION SERVICE SYSTEM			**0**	**0**	**0**	**0**	**0**
	See individual components below.	-	0	0	0	0	0
STATION SERVICE TRANSFORMERS			**0**	**0**	**0**	**0**	**0**
	As no up to date test results were available during this inspection, it is recommended to perform insulation resistance tests in 2013.	MTCE	0	0	0	0	0
	A regular yearly maintenance, including thorough cleaning, and periodic test is recommended to be performed to keep the units in operation.	MTCE	0	0	0	0	0
AUXILIARY SERVICE TRANSFORMERS			**0**	**0**	**0**	**0**	**0**
	Development of an annual maintenance and testing program is recommended. Included in this program should be cleaning of the dry-type transformer, visual inspection, thermographic scanning, testing of oil from the oil-filled transformer and dielectric testing.	MTCE	0	0	0	0	0
	As there were no up to date test results available during the inspection, it is recommended to perform at least an insulation resistance test on the transformers in 2013.	MTCE	0	0	0	0	0
	Nova Scotia Power should begin a regular load monitoring program in 2013, to provide a factual basis for sizing replacement transformers.	1	0	0	0	0	0
AC SWITCHGEAR			**80**	**15**	**15**	**15**	**15**
	Perform infra-red scans on all switchgear no later than 2013 at an estimated cost of $15k.	1	15	0	0	0	0
	Initiate a refurbishment program with the OEM to maintain the reliability of the breakers until such time as they are replaced in 2019. Allow $15k per year for this work.	1	15	15	15	15	15
	It is strongly recommended to perform an arc flash and protection co-ordination study on the entire station service system in 2013 to determine the possible level of arc energy at the switchgear locations. The cost estimate for the study is $50k.	1	50	0	0	0	0
AUTO TRANSFER CONTROL			**0**	**0**	**0**	**0**	**0**
	To ensure reliable operation of the system, detailed regular maintenance should be performed on the transfer equipment.	MTCE	0	0	0	0	0
	The voltage relays and timers utilized by the auto-transfer system should be cleaned, tested and calibrated in 2013.	MTCE	0	0	0	0	0
	Starting in 2013, test the auto transfer system on an annual basis, prepare a written procedure for the manual transfer and update/revise original drawings to reflect the present arrangement.	MTCE	0	0	0	0	0
MCC'S AND PANEL BOARDS			**0**	**0**	**0**	**0**	**0**
	A thorough cleaning of all electrical equipment should be carried out in 2013 and then every 3 – 5 years.	MTCE	0	0	0	0	0
CABLE AND BUS			**0**	**0**	**0**	**0**	**0**

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Condition Assessment Summary

2013 Recommended Activities

(costs in 2012 k$)

*Note: items showing no funds in 2013 are assumed to be covered with existing maintenance funding or internal engineering studies and assessments funding.

Component or System	Recommended Projects	Condition Rating	2013	2014	2015	2016	2017
	Cables should be reviewed regularly to ensure there has been no mechanical damage, otherwise, cabling should be changed out when the associated system is changed out.	MTCE	0	0	0	0	0
STANDBY DIESEL GENERATOR			**325**	**0**	**0**	**0**	**0**
	The existing diesel generator, including all directly related auxiliaries (day-tank, batteries, charger, generator controls etc.) should be replaced except for the bulk storage tank, the building and the building slab. It is anticipated that this will cost approximately $300k. Replacement does not include the station service distribution portion, as this is addressed elsewhere in this report. It is recommended that NSP proceed with the planned replacement within the next five years. NSP has indicated that they are proceeding in 2013.	1	300	0	0	0	0
	Provide secondary oil containment around the outdoor bulk fuel storage tank in 2013. Estimated cost is $25k.	1	25	0	0	0	0
PROTECTION AND CONTROLS SYSTEM			**7**	**2**	**2**	**2**	**2**
	Continue with maintenance and calibration of the existing protection systems until the existing system is replaced.	MTCE	0	0	0	0	0
	The problem with the SCADA RTU should be investigated in more detail. Even though replacement of faulty modules within the RTU is acceptable to continue with the operation, procurement and installation of new a RTU is strongly recommended at the time of the control system upgrade. The cost is included within the control system budget estimate below.	1	0	0	0	0	0
	Minor governor maintenance should be done as a part of regular maintenance activity. Lumpsum budgetary estimate is $2k per year.	MTCE	2	2	2	2	2
	The faulty brake solenoid should be replaced or repaired in 2013, at an estimated cost of $5k.	MTCE	5	0	0	0	0
	Institute a periodic testing program for the tailrace water level alarm and lockout functions, as these functions are very important for worker safety and plant protection.	MTCE	0	0	0	0	0
STATION DC POWER SYSTEM			**0**	**0**	**0**	**0**	**0**
	No 2013 recommendations	-	0	0	0	0	0
STATION GROUNDING SYSTEM			**0**	**0**	**0**	**0**	**0**
	No 2013 recommendations	-	0	0	0	0	0
STATION LIGHTING SYSTEM			**0**	**0**	**0**	**0**	**0**
	No 2013 recommendations	-	0	0	0	0	0

2012 Wreck Cove Condition Assessment

Notes:

1. Added costs potentially in the range of 10 million dollars may be identified in a detailed life safety study recommended to be undertaken in 2013.

2. The 2012 Condition Assessment of Wreck Cove addressed the powerhouse equipment and systems, the access tunnel portal, the structures and equipment for water control at the entrance to tunnel T-2, at the inlet to the penstock and at the tailrace tunnel outlet, the penstocks and the standby diesel generator.
Certain component parts of the Wreck Cove facility were outside the scope of the 2012 assessment, including the storage dams, tunnels T-1, T-2, the powerhouse access tunnel and the tailrace tunnel, Gisborne Generating Station, the main output transformers and the associated 144 kV conductors, the switchyard, the Administration Building and all surface facilities such as dykes, roads, communication tower, storage buildings and other miscellaneous buildings. Assessments for dam safety and assessments of these assets may result in identification of additional projects requiring funding which is not included here.

2012 Wreck Cove Condition Assessment - Condition Rating Scale

Rating	Condition Description	Details	Remediation Timetable
4	Good	Only minor deterioration or defects are evident.	20 plus years (2034 & beyond)
3	Fair	Moderate deterioration. Function is still adequate.	7-20 years (2021 to 2033)
2	Poor	Serious deterioration of at least some portions of the equipment. Function is inadequate. OR: Additional inspection, testing and assessment required in near future, to more fully define condition.	2-7 years (2015 to 2020)
1	Unacceptable	Extensive deterioration. Barely functional. Urgent need for remediation. OR: Additional inspection, testing and assessment urgently required to more fully define condition.	0-2 years (2013 to 2014)

Notes:

1. The basis year for this table is the end of 2012, by which time the assessment of equipment and structures was completed.

2. Condition considers physical deterioration and general adequacy for functional, safety and environmental adequacy.

3. In some cases, additional inspection, testing, investigation or assessment activities are recommended to better define condition and to aid in selecting or refining the best solution.

4. The condition rating scale is based on a similar table used by a large Canadian electrical utility.

5. The term MTCE is used to identify routine/periodic maintenance program recommendations. These are not condition rateable.

EXCERPT FROM SUMMARY SHEETS FOR YEAR 2014 - 2017

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Condition Assessment Summary

2014 to 2017 Recommended Activities

(See also 2013 Recommended Activities document)

(costs in 2012 k$)

*Note: items showing no funds in 2014-2017 are assumed to be covered with existing maintenance funding or internal engineering studies and assessments funding.

Component or System	Recommended Projects	Condition Rating	2013	2014	2015	2016	2017	2018
CIVIL								
TUNNEL T2 INTAKE STRUCTURE			**0**	**0**	**0**	**5**	**30**	**0**
	Remove deteriorated paint and corrosion and apply a protective coating to the Gate Hoist Building structural steel superstructure as well as gains. This work should be performed within the next 5 years to maintain the integrity of the structure. The estimated cost for this work is $30k.	2	0	0	0	0	30	0
	Include funds in the maintenance budget for boom maintenance in the amount of $5k every 3 years.	MTCE	0	0	0	5	0	0
TUNNEL T2 ADIT			**0**	**80**	**0**	**325**	**0**	**0**
	Within the next two years, inspect the inside of the Adit with a remotely operated tracked vehicle (ROV) to determine the condition, feasibility and the extent of repairs required to make the Adit safe for entry. The estimated cost for the inspection and assessment is $50k.	1	0	50	0	0	0	0
	In parallel with the inspection and condition assessment work, undertake a engineering study to investigate alternative means to de-water the tunnel, including the alternative of making the Adit safe, if found to be feasible, at an estimated study cost of $30k. All alternatives should assume that the present valve and pressurized pipe penetration into Tunnel T-2 will need to be permanently sealed. Any alternative using the Adit for drainage should assume that a new valve and pipe penetration into Tunnel T-2 are required.	1	0	30	0	0	0	0
	Allow funding in the capital budget in 2016 to provide a means of draining Tunnel T-2 and sealing off the existing pipe penetration. For the purpose of providing an estimate, the solution of drilling a 1.5 m diameter vertical shaft 60 m long through the rock into the tunnel near the Adit is assumed, with an estimated cost of $325k for design and drilling. In the event an alternative tunnel dewatering system is not selected, or if its implementation is deferred some years beyond 2016, seal the drainage piping by 2016.	2	0	0	0	325	0	0
PENSTOCK INTAKE STRUCTURE AT SURGE LAKE			**0**	**0**	**0**	**0**	**0**	**0**
	No 2014 to 2017 recommendations	-	0	0	0	0	0	0
PENSTOCK FROM SURGE LAKE			**0**	**12**	**0**	**0**	**0**	**0**
	By 2014 carry out a (desk-top) assessment of the potential head losses and energy production losses due to the algae, calcium carbonate deposits, and surface irregularities to determine if power wash cleaning of the inside surface of the penstock is warranted. The estimated cost for this assessment would be approximately $12k.	1	0	12	0	0	0	0
SPIRAL CASE			**0**	**0**	**0**	**0**	**0**	**0**
	No 2014 to 2017 recommendations	-	0	0	0	0	0	0
DRAFT TUBE			**0**	**0**	**0**	**0**	**0**	**0**
	No 2014 to 2017 recommendations	-	0	0	0	0	0	0
TAILRACE			**0**	**0**	**0**	**0**	**0**	**0**
	No 2014 to 2017 recommendations	-	0	0	0	0	0	0
POWERHOUSE			**0**	**30**	**0**	**100**	**100**	**0**
	Investigate and evaluate within the next 2 years more efficient means to deal with the leakage issue such as installing a ceiling leakage collection drainage system. The estimated cost for the study is $30k. Allow approximately $200k in the budget for years 2016 and 2017 to install a system to handle the leakage.	2	0	30	0	100	100	0

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Condition Assessment Summary

2014 to 2017 Recommended Activities

(See also 2013 Recommended Activities document)

(costs in 2012 k$)

*Note: items showing no funds in 2014-2017 are assumed to be covered with existing maintenance funding or internal engineering studies and assessments funding.

Component or System	Recommended Projects	Condition Rating	2013	2014	2015	2016	2017	2018
POWERHOUSE EGRESS AND LIFE SAFETY			**0**	**150**	**0**	**300**	**0**	**0**
	Provide a new short term refuge facility for present staff levels by 2014. Estimated cost is $150k for a 6 person 24 hour design.	1	0	150	0	0	0	0
	Plan on providing two additional short term facilities or a permanent refuge facility for the increased worker levels anticipated when major work starts in the powerhouse. Assumed cost is $300k in 2016.	2	0	0	0	300	0	0
POWERHOUSE ACCESS TUNNEL			**0**	**0**	**0**	**0**	**917**	**0**
	Sandblast and re-paint the staircase and railing up to the mechanical equipment room within the next 5 years. The estimated cost to complete this work is $17k.	2	0	0	0	0	17	0
POWERHOUSE ACCESS TUNNEL FEEDERS			**0**	**0**	**0**	**0**	**450**	**0**
	A plan should be developed for one of the main station service feeders to be installed in an alternate configuration. This work should be performed before any large equipment is transported down the access tunnel to the powerhouse. The high voltage 25 kV cable has the smallest profile and could be more easily protected from vehicle impact on the opposite side of the tunnel in a location similar to that of the temporary cable. The estimated cost for this work, assuming use of Jersey barriers, is $450k and it should be carried out within 5 years. In comparison, the cost of constructing a new cable tunnel, which would relocate the feeders completely away from vehicle traffic, is estimated at $6.05M.	2	0	0	0	0	450	0
MECHANICAL								
TUNNEL T2 INTAKE EQUIPMENT			**0**	**12**	**150**	**0**	**0**	**0**
	Following a review of available documentation, and discussions with original engineers and gate supplier if possible, establish and execute a periodic gate testing procedure. Ideally, this should involve closure under flow conditions, unless reasons are found to avoid such a test. Investigation cost is estimated at $12k and timing would be by 2014.	1	0	12	0	0	0	0
	Plan for a gate refurbishment in 2015 to include recoating of the gate body, replacement of roller bushings and hoist bearings replacement. The exact scope will be determined by the above inspections and test. Cost is estimated to be $150k.	2	0	0	150	0	0	0
TUNNEL T2 ADIT DRAIN VALVE & PIPING			**0**	**0**	**0**	**0**	**0**	**0**
	Carry out an inspection on the condition of the valve and piping, using an unmanned remotely operated tracked vehicle. Co-ordinate this work with a geotechnical inspection and assessment of alternatives for the T-2 Adit (see report Section 4.2 Tunnel T-2 Adit for further details). While it will not be possible to test operate the valve(s), the inspection will provide information on the exterior surface condition of the pressurized piping, which will indicate the urgency of sealing the penetration. As well, the inspection will provide information on the condition of any exposed piping downstream of the valve(s), to develop a better estimate of the cost of restoring the Adit as a tunnel drainage solution.	2	0	0	0	0	0	0
	Whichever alternative is selected for Tunnel T-2 dewatering, the existing piping penetration will need to be sealed and if the T-2 Adit is the preferred solution, a new piping penetration and new valves will be needed. Funding to seal the existing piping is included in the recommendation for a Tunnel T-2 dewatering solution in the Civil section of the report (see report Section 4.2 Tunnel T-2 Adit for further details).	2	0	0	0	0	0	0
TURBINE SHUTOFF VALVES			**0**	**35**	**0**	**0**	**0**	**0**
	Repair or replace the upstream manual valves in the bypass lines of both units by 2014. Replacement cost: $10k for two valves.	1	0	10	0	0	0	0

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Condition Assessment Summary

2014 to 2017 Recommended Activities

(See also 2013 Recommended Activities document)

(costs in 2012 k$)

*Note: items showing no funds in 2014-2017 are assumed to be covered with existing maintenance funding or internal engineering studies and assessments funding.

Component or System	Recommended Projects	Condition Rating	2013	2014	2015	2016	2017	2018
	Perform an engineering review by 2014 of the potential safety issues, looking at industry current best practices. Cost is estimated to be $25k.	1	0	25	0	0	0	0
TURBINES			**0**	**8**	**1,062**	**1,500**	**4,010**	**4,010**
	Consider new runners engineered to potentially provide a capacity increase, higher efficiency and a wide range of stable operation. Estimated cost is $5.55M for two runners. Installation would be during turbine overhauls.	2	0	0	1,050	1,500	1,500	1,500
	The following repair work is required to be done within the next 5 years (funds are included in the major overhaul recommendation below): 1. Plan to take the turbine out of service for rehabilitation of the wicket gates, to stop the top of the wicket gates rubbing on the head cover 2. During the same outage repair the cavitation on the headcover, discharge ring and runner.	2	0	0	0	0	0	0
	Carry out major overhauls on each turbine concurrently with generator refurbishment/replacement. The estimated cost is $2.5 M per unit in 2017 and 2018, co-ordinated with the generator refurbishment work.	*2*	0	0	0	0	2,500	2,500
	Remove the inflatable shaft seals from service. The estimated cost is $6k per unit and as this is not a critical item, it has been scheduled for 2015.	2	0	0	12	0	0	0
	Within 5 years overhaul the wicket gates and repair the headcover and discharge ring surface damage. Funds are included in the major overhaul entry in this section.	2	0	0	0	0	0	0
	During the next turbine disassembly clean, degrease and blast clean the headcover and NDE check all welds and the flange around the stud holes for cracking. Estimated cost is $10k per unit.	2	0	0	0	0	10	10
	The following spare parts should also be acquired by 2014 as they may be needed at short notice. • Carbon seal segments and their springs • At least 5 wicket gate water seals per unit (upper and lower) The estimated cost is $8k.	1	0	8	0	0	0	0
	Sources for the following parts should be found, and drawings and specifications should be prepared: • Servomotor cast iron piston rings • Bearing re-babbitting companies. Re-babbitting specifications should be prepared • O rings for the headcover flanges. These may be non standard items • Magnetrol level switch parts or replacement units	MTCE	0	0	0	0	0	0
TURBINE REGULATING EQUIPMENT			**0**	**84**	**0**	**0**	**0**	**0**
	Carry out compliance testing of the governor within the next two years and at the same time review the dashpot settings. The estimated cost of the testing is $42k per unit.	1	0	84	0	0	0	0
	Within 2 years and thereafter every 5 years, inspect the interior of the accumulator tank and ultrasonically measure the wall thickness.	MTCE	0	0	0	0	0	0
GENERATOR MECHANICAL			**3**	**32**	**0**	**0**	**148**	**148**
	During the next unit overhauls, machine the radial dowel holes and replace the dowels. Funds for this are included under Turbines, above, as part of a major turbine overhaul and generator mechanical refurbishment.	2	0	0	0	0	0	0
	Measure the brake pad thickness every five years. Replace any pads less than 25 mm (1 in) thick.	MTCE	0	0	0	0	0	0
	Replace the surface air coolers within 5 years: $148k per unit	2	0	0	0	0	148	148
	Install an oil filter in the high pressure oil lift systems by 2014 ($1k per unit).	1	0	2	0	0	0	0

WRECK COVE GS

2013-04-23

Condition Assessment Summary

2014 to 2017 Recommended Activities

(See also 2013 Recommended Activities document)

(costs in 2012 k$)

*Note: items showing no funds in 2014-2017 are assumed to be covered with existing maintenance funding or internal engineering studies and assessments funding.

Component or System	Recommended Projects	Condition Rating	2013	2014	2015	2016	2017	2018
	By 2014, the runner plate should be coated with anti-rust compound, wrapped in protective paper and stored in a crate. The journal surface flatness tolerance is 0.013 mm (0.0005 in), so to prevent distortion, the plate must be evenly supported. Estimated cost is $3k.	1	3	0	0	0	0	0
	By 2014, suppliers for the following parts should be found, and drawings and specifications should be prepared. This will reduce the delivery time when the parts are required. Estimated cost is $10k. • Bearing re-babbitting companies (prepare, in advance, specifications for rebabbitting and machining) • Magnetrol level switch parts or replacement switch units • Brake pads (one set of 8 pads) non asbestos type • Surface air coolers (one set of 4) • Thrust and upper guide bearing cooling coils (one of each)	MTCE	0	10	0	0	0	0
	In 2014, perform ultrasonic testing to confirm the level of wear or deterioration of the cooling water piping. Carry out visual checks of some extracted pipe sections to obtain additional information to decide on the need and timing to replace this piping. Estimated cost is $20k.	1	0	20	0	0	0	0
	At the same time install air vents on both ends of the draft tube pump suction header. This would make air removal more effective and reliable regardless of which draft tube is being used to draw water from, or which pump is being run.	MTCE	0	0	0	0	0	0
TAILRACE EQUIPMENT			**0**	**0**	**0**	**0**	**15**	**0**
	Perform a stress and deflection analysis on the gate which considers the loss of metal from major members. While the results are not expected to condemn the gate, they will be useful in a future decision to refurbish or replace the gate. This should be done by 2017 and is estimated to cost $15k.	2	0	0	0	0	15	0
ANCILLARY EQUIPMENT (CRANES, MONORAILS)			**0**	**0**	**550**	**0**	**0**	**0**
	The electrical systems for the powerhouse crane should be upgraded with a modern crane control system. This work would be typical to this vintage of crane. This work should also be done to resolve the quick stop issue of the crane movement. It is estimated that the upgrade would cost on the order of $550k, and this work should be performed within the next 3 years or prior to any major plant work requiring intense use of this crane. A full load test of the crane should be performed with the new controls.	2	0	0	550	0	0	0
HEATING, VENTILATION & AIR CONDITIONING			**0**	**231**	**0**	**0**	**0**	**0**
	No major replacement is foreseen over the next 30 years on the supply and exhaust fans in the portal building mechanical room. However, due to the criticality of these fans and dampers, a set of spare bearings, drive belts and drive motors for each fan and a replacement set of motorized dampers and motors should be acquired by 2014 at an estimated cost of $56k.	1	0	56	0	0	0	0
	Bring El. -10 ft supply air ductwork down closer to floor level and provide propeller fans for the El. -10.0 ft level to improve dehumidification and reduce rusting of piping and equipment. Estimated cost $15k.	1	0	15	0	0	0	0
	Pending successful results of the summer ventilation tests, remove the mechanical cooling units S1 and S2, and related cooling water piping. If the test fails, replacement of the mechanical cooling units would be required. Estimated cost for either solution is $150k.	1	0	150	0	0	0	0

WRECK COVE GS

2013-04-23

Condition Assessment Summary

2014 to 2017 Recommended Activities

(See also 2013 Recommended Activities document)

(costs in 2012 k$)

*Note: items showing no funds in 2014-2017 are assumed to be covered with existing maintenance funding or internal engineering studies and assessments funding.

Component or System	Recommended Projects	Condition Rating	2013	2014	2015	2016	2017	2018
	Whether the abandoned mechanical cooling system is to be revived or removed, remove the poor condition fibreglass insulation and re-route the ductwork located downstream of air handling units S1 and S2. This section of ductwork obstructs the hatchway when major work is performed on the turbine generators. Estimated cost is $10k.	1	0	10	0	0	0	0
COMPRESSED AIR SYSTEMS			**0**	**0**	**20**	**0**	**0**	**0**
	To upgrade the functionality and reliability of the service air system, while simplifying maintenance, redesign the compressed air piping to allow individual tank isolation and replace the service air refrigerated dryer. Estimated cost is $20k and the work should be carried out within 3 years.	2	0	0	20	0	0	0
FIRE PROTECTION AND DETECTION SYSTEM			**0**	**50**	**550**	**0**	**0**	**0**
	The generator and transformer deluge systems should at least be tied to the station fire alarm system to ensure that there is proper evacuation in the case of a fire. The estimated cost is $10k and this work should be completed by 2014 or before major refurbishment work in the powerhouse is begun.	1	0	10	0	0	0	0
	The transformer deluge control panels should be replaced with modern systems, at an estimated cost of $40k, and should be completed within the next 2 years	1	0	40	0	0	0	0
	The main plant fire alarm system should be replaced. This should include: • A system with new audible devices, including the addition of strobe indication. • A proper enunciator installed in an area where a fire can be safely responded to. • Some review of early detection and more detailed annunciation that could be used in areas of refuge. This is further addressed in the report section called Issues and Opportunities. The estimated cost is $550k and the work should be completed within the next 2 years and before major work in the powerhouse begins.	2	0	0	550	0	0	0
SUMP SYSTEMS (DRAINAGE AND DEWATERING)			**0**	**55**	**0**	**0**	**0**	**0**
	By 2014 provide secondary oil containment around floor mounted equipment containing oil and match the size of the containment area for the level of stored oil needed during turbine generator maintenance. Remove any infrequently used lubricants outside of the powerhouse. Estimated cost is $30k.	1	0	30	0	0	0	0
	By 2014 install an oil detection and skimmer system with alarm and pump interlock control on the station sump at an estimated cost of $25k.	1	0	25	0	0	0	0
DOMESTIC WATER & SEWAGE SYSTEM			**0**	**0**	**0**	**0**	**0**	**0**
	No 2014 to 2017 recommendations	-	0	0	0	0	0	0
SURGE LAKE DRAIN VALVES			**0**	**20**	**0**	**0**	**0**	**0**
	Remove both valves of the Surge Lake drain piping and inspect for disc to stem bolting damage and security. Plan to repair or replace the valves, depending on the findings. This work should be carried out by 2014 and is estimated to cost $20k, assuming only some minimal difficulty in closing off the pipe inlet, so that both valves can be checked.	1	0	20	0	0	0	0
ELECTRICAL								
GENERATORS (ELECTRICAL)			**0**	**10**	**0**	**0**	**15,000**	**15,000**
	The OEM proposed solution for improved temperature control and potential vibration reduction should be reviewed to understand the rationale. If warranted, a solution should be implemented with the unit re-wind. The assessment should be performed by 2014 and the estimated cost is $10k.	1	0	10	0	0	0	0

WRECK COVE GS

2013-04-23

Condition Assessment Summary

2014 to 2017 Recommended Activities

(See also 2013 Recommended Activities document)

(costs in 2012 k$)

*Note: items showing no funds in 2014-2017 are assumed to be covered with existing maintenance funding or internal engineering studies and assessments funding.

Component or System	Recommended Projects	Condition Rating	2013	2014	2015	2016	2017	2018
	Rewind the stators and re-insulate the pole windings within the next five years. The cost of re-winding including pole insulation is $3.2M per unit with 3-4 months downtime per unit to execute the work. It is anticipated that this work would be done in 2017 and 2018. The funds are included in the generator refurbishment recommendation below.	2	0	0	0	0	0	0
	Before initiating a re-winding process, it is recommended to perform more in-depth inspection of the stator core by performing in-depth visual inspection, and an Elcid test to check for any potential hot-spots within the stator core. In normal cases stator cores of this type of generator should be changed at the time of the second re-winding of the stator, but with the already identified stator core issues and with all the oil contamination issues, it is recommended to perform required tests soon as the stator core may require replacement, along with the winding. The cost estimate to replace the stator core is $2.4M/unit, to be done at the same time as the re-wind in 2017 and 2018. The funds are included in the generator refurbishment recommendation below.	2	0	0	0	0	0	0
	Replace the rotors with new rotors having improved mechanical rigidity. Assuming the shaft, thrust bearing and bracket can be reused, the estimated cost is $7.9M per unit. The funds are included in the generator refurbishment recommendation below.	2	0	0	0	0	0	0
	Including excitation system replacement, the estimate for generator and refurbishment is estimated at $30M including costs related to removal of existing equipment, installation, contingency and commissioning. These refurbishments are shown equally split between the years 2017 and 2018. There could be some cost reduction depending on the condition of the stator frame and core as determined after further testing and inspection.	2	0	0	0	0	15,000	15,000
EXCITATION SYSTEMS			**0**	**0**	**0**	**0**	**0**	**0**
	Based on the age of the equipment and declining support from the manufacturer, it is recommended to initiate the process of replacing these exciters, as they have reached end of life. It is estimated that these costs are $750k per unit, and the replacements would be done in 2017 and in 2018, when major generator work is proposed. These funds are included in the generator refurbishment recommendation estimate under Generators, above.	2	0	0	0	0	0	0
ISOLATED PHASE BUS DUCT			**0**	**200**	**0**	**0**	**0**	**0**
	An operating temperature study of the IPB system should be performed at a time when the associated unit is running as close to peak load as possible. Allow $50k in 2014.	1	0	50	0	0	0	0
	Spare flexible connections and insulators should be procured and stocked at the station. Allow $150k in 2014 for spare parts procurement. It is important that these spares are available in hand otherwise a small failure could lead to a major unit outage.	1	0	150	0	0	0	0
EXCITATION TRANSFORMERS			**0**	**0**	**0**	**0**	**0**	**0**
	No 2014 to 2017 recommendations	-	0	0	0	0	0	0
AC STATION SERVICE SYSTEM			**0**	**0**	**0**	**0**	**0**	**0**
	See individual components below.	-	0	0	0	0	0	0
STATION SERVICE TRANSFORMERS			**0**	**0**	**0**	**0**	**0**	**0**
	No 2014 to 2017 recommendations	-	0	0	0	0	0	0
AUXILIARY SERVICE TRANSFORMERS			**0**	**0**	**0**	**0**	**0**	**0**
	No 2014 to 2017 recommendations	-	0	0	0	0	0	0

WRECK COVE GS

2013-04-23

Condition Assessment Summary

2014 to 2017 Recommended Activities

(See also 2013 Recommended Activities document)

(costs in 2012 k$)

*Note: items showing no funds in 2014-2017 are assumed to be covered with existing maintenance funding or internal engineering studies and assessments funding.

Component or System	Recommended Projects	Condition Rating	2013	2014	2015	2016	2017	2018
AC SWITCHGEAR			**0**	**35**	**0**	**0**	**0**	**0**
	As there are no recent testing results available, the following tests should be performed by 2014 on the 600 V switchgear, at a cost of $35k: • High voltage AC dielectric tests on wiring and bus bar • Contact resistance measurement of the breakers • Circuit breaker timing test • Current transformer (CT) polarity check • Partial discharge (corona) • Secondary AC current injection • DC protective circuits check • CT & PT transformation ratio check	1	0	35	0	0	0	0
AUTO TRANSFER CONTROL			**0**	**0**	**0**	**0**	**0**	**0**
	No 2014 to 2017 recommendations	-	0	0	0	0	0	0
MCC'S AND PANEL BOARDS			**0**	**0**	**0**	**0**	**0**	**0**
	No 2014 to 2017 recommendations	-	0	0	0	0	0	0
CABLE AND BUS			**0**	**0**	**0**	**0**	**0**	**0**
	No 2014 to 2017 recommendations	-	0	0	0	0	0	0
STANDBY DIESEL GENERATOR			**0**	**0**	**0**	**0**	**0**	**0**
	No 2014 to 2017 recommendations	-	0	0	0	0	0	0
PROTECTION AND CONTROLS SYSTEM			**0**	**295**	**15**	**4,293**	**1,555**	**30**
	Given the age of the existing protections and lack of manufacturer support, a plant wide upgrade is in order. As part of this upgrade, it would be anticipated that the entire system should be reviewed to see how the more modern protection schemes could benefit plant reliability and long term maintenance. It is recommended that this upgrade be performed in the year 2016 and the estimated cost is $1.53M per unit, including engineering. Considerations for the upgrade should include: • Optimum method of project roll out to minimize outage lengths • Methods of encapsulating and removing asbestos from the existing system • Options for redundant protection schemes using modern multifunction digital relays • Locations and configuration of new equipment • Integration with future station service switchyard protections • Anticipated design time is likely on the order of 12-15 months • Installation time could be in excess of 6 months including an outage of each unit which could be on the order of 1 month • It is anticipated that station controls upgrades would be performed in parallel with this work • This work would be done to accommodate the generator replacement or refurbishment. • Allow for an initial period of low reliability and retain the manual control capability that now exists to assist with this phase. • Ensure that maintenance persons with the appropriate education and training are in place	2	0	0	0	1,525	1,525	0
	The upgrade of the control system is recommended for the year 2016. The budgetary cost of replacement is approximately $2.5M. in addition, a design allowance and investigations required for planning of $250k should be included in the year 2014. The upgrade of the contro system has to be initiated together with the protection upgrade so that all the technical interfaces between these two systems can be addressed at the same time to minimize complications. See Control System recommendations for considerations that may apply to Protections replacement.	2	0	250	0	2,500	0	0

WRECK COVE GS

2013-04-23

Condition Assessment Summary

2014 to 2017 Recommended Activities

(See also 2013 Recommended Activities document)

(costs in 2012 k$)

*Note: items showing no funds in 2014-2017 are assumed to be covered with existing maintenance funding or internal engineering studies and assessments funding.

Component or System	Recommended Projects	Condition Rating	2013	2014	2015	2016	2017	2018
	The start-stop control should be upgraded as part of the new PLC based control systems. The budgetary price for the plant start-stop control upgrade is included in the control system budget, above.	2	0	0	0	0	0	0
	The new synchronization system should be integrated with the overall plant controls and protections upgrade. Funds for the synchronizer replacement are included in the controls systems budget, above.	2	0	0	0	0	0	0
	As a part of the life extension program for the governors it is recommended: • To perform a major overhaul in the year 2018 and then every 20 years. The cost of a major overhaul is $30k per unit. It is anticipated that this overhaul would be done in conjunction with the unit overhauls, in 2017 and 2018. • Perform minor overhauls every 5 years in between the two major overhauls. The budgetary cost of minor overhauls is $15k per unit.	2	0	0	0	0	30	30
	Most of the major spare parts and the spares for the accumulator level and pressure measurements system should be procured. The budgetary cost of such spares procurement is $20k. This should be initiated in 2014	1	0	20	0	0	0	0
	It is recommended that the control panels CP1 and CP2 be considered for upgrade at the same time as the systems or equipment that they are related to or service are upgraded. While the estimated cost to upgrade CP1 has been included with the controls upgrade, the cost to upgrade the HVAC controls / CP2 is estimated to be approximately $150k and the work should be planned for 2016.	2	0	0	0	150	0	0
	Perform a thorough analysis of the compatibility of the plant control instrumentation with respect to modernization of the plant control system. It is anticipated that many of these instruments would be replaced at the time of a controls upgrade, but they could be done at any time. A lump sum instrument replacement budget for these items is $100k, and the work should be planned for 2016	2	0	0	0	100	0	0
	Re-instate the tailrace water level monitoring function and connect to SCADA for transmission to the Energy Control Centre in 2014 at an estimated cost of $25k.	1	0	25	0	0	0	0
	Replace the tailrace water level alarm and lockout system within 3 years at an estimated cost of $15k.	2	0	0	15	0	0	0
	Replacement of the reservoirs water level gauging system is estimated at $38k and should be performed in 2022.	3	0	0	0	0	0	0
	The sump pump control system should be upgraded within the next five years, Including, relocation of the panel to a dry area. The budgetary cost for this work is $18k and it is allowed for in 2016	2	0	0	0	18	0	0
STATION DC POWER SYSTEM			**0**	**15**	**0**	**135**	**0**	**0**
	The power distribution panel for the DC system is a potential hazard given its exposed buswork. Covers to ensure there is no access issues with the door open could help to reduce this risk, however, as parts of the DC system have substantially been upgraded, the distribution panel should be upgraded as well, to return the entire system to a like new condition. An upgrade to the distribution panel would be done with a distribution panel with visible contacts and would cost $15k and should be performed in 2014.	1	0	15	0	0	0	0
	Should NSP wish to increase the reliability of the DC system to attain a more standard configuration with redundant DC supplies, a second battery system and inverter could be installed. An additional battery system would cost $135k. This work would typically be done with station protections and controls upgrades and has been included in 2016.	2	0	0	0	135	0	0

WRECK COVE GS

2013-04-23

Condition Assessment Summary

2014 to 2017 Recommended Activities

(See also 2013 Recommended Activities document)

(costs in 2012 k$)

*Note: items showing no funds in 2014-2017 are assumed to be covered with existing maintenance funding or internal engineering studies and assessments funding.

Component or System	Recommended Projects	Condition Rating	2013	2014	2015	2016	2017	2018
STATION GROUNDING SYSTEM			**0**	**0**	**0**	**0**	**0**	**0**
	No 2014 to 2017 recommendations	-	0	0	0	0	0	0
STATION LIGHTING SYSTEM			**0**	**215**	**0**	**650**	**0**	**0**
	The lighting throughout the plant should be replaced within the next two to three years, along with the supporting structures where they show signs of corrosion. The main areas where lighting should be upgraded along with their estimated cost include: Access Tunnel: $205k; Plant Main Area: $220k; Plant Auxiliary Areas: $180k; Plant Refuge Tunnel Area: $45k, for a total of $650k. This amount has been included in 2016 as it would benefit general unit overhaul activities.	2	0	0	0	650	0	0
	A modern emergency lighting system should be installed which clearly illuminates the paths of egress. This should be installed in conjunction with the exit signage which helps evacuation to occur down the correct route. This new modern emergency lighting system would be DC, but separate from the station DC system. The cost of the emergency lighting system would be approximately $195k, and should be done by 2014 as it improves safety for plant staff.	1	0	195	**0**	**0**	**0**	**0**
	Given that there a multiple circular routes and effectively only one exit, exit signs and phosphorescent paint on the floor should be installed to clearly indicate the directions of exit. The cost of the system is included with the above item. If an exit signage system is installed as a separate item, with standalone battery units, the cost of this work would be approximately $20k, and should be done by 2014 as it improves safety for plant staff.. As separate items, these would essentially be self contained exit signs which would have internal chargers and batteries and would connect to AC station service.	1	0	20	0	0	0	0

2012 Wreck Cove Condition Assessment

Notes:

1. Added costs potentially in the range of 10 million dollars may be identified in a detailed life safety study recommended to be undertaken in 2013.

2. The 2012 Condition Assessment of Wreck Cove addressed the powerhouse equipment and systems, the access tunnel portal, the structures and equipment for water control at the entrance to tunnel T-2, at the inlet to the penstock and at the tailrace tunnel outlet, the penstocks and the standby diesel generator.

Certain component parts of the Wreck Cove facility were outside the scope of the 2012 assessment, including the storage dams, tunnels T-1, T-2, the powerhouse access tunnel and the tailrace tunnel, Gisborne Generating Station, the main output transformers and the associated 144 kV conductors, the switchyard, the Administration Building and all surface facilities such as dykes, roads, communication tower, storage buildings and other miscellaneous buildings. Assessments for dam safety and assessments of these assets may result in identification of additional projects requiring funding which is not included here.

2012 Wreck Cove Condition Assessment - Condition Rating Scale

Rating	Condition Description	Details	Remediation Timetable
4	Good	Only minor deterioration or defects are evident.	20 plus years (2034 & beyond)
3	Fair	Moderate deterioration. Function is still adequate.	7-20 years (2021 to 2033)
2	Poor	Serious deterioration of at least some portions of the equipment. Function is inadequate. OR: Additional inspection, testing and assessment required in near future, to more fully define condition.	2-7 years (2015 to 2020)
1	Unacceptable	Extensive deterioration. Barely functional. Urgent need for remediation. OR: Additional inspection, testing and assessment urgently required to more fully define condition.	0-2 years (2013 to 2014)

Notes:

1. The basis year for this table is the end of 2012, by which time the assessment of equipment and structures was completed.

2. Condition considers physical deterioration and general adequacy for functional, safety and environmental adequacy.

3. In some cases, additional inspection, testing, investigation or assessment activities are recommended to better define condition and to aid in selecting or refining the best solution.

4. The condition rating scale is based on a similar table used by a large Canadian electrical utility.

5. The term MTCE is used to identify routine/periodic maintenance program recommendations. These are not condition rateable.

Report

Wreck Cove - T2 Intake Gate Assessment

H351728-00000-200-230-0001

2017-09-13	**A**	**Client Review**	**A. Bridgeman, D. Pinese, O. Belashov**	**J. Westermann**	**A. Bridgeman**
DATE	**REV.**	**STATUS**	**PREPARED BY**	**CHECKED BY**	**APPROVED BY**
				Discipline Lead	**Functional Manager**

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Disclaimer

This report was prepared for Nova Scotia Power Inc. (the "Client") by Hatch Ltd. (the "CONSULTANT") and is subject to the following limitations, qualifications and disclaimers:

1. The report is intended for the exclusive use of the Client and it may not be used or relied upon in any manner for or for any purpose whatsoever by any other party.
2. The report is for the Wreck Cover Life Extension and Modernization Project (the "Project"). Data required to support detailed engineering assessments have not always been available and in such cases engineering judgments have been made which may subsequently turn out to be inaccurate. There are, therefore, risks inherent in the Project which are outlined in the report. The CONSULTANT accepts no liability beyond using reasonable diligence, professional skill and care in preparing the report in accordance with the standard of care, skill, and diligence expected of professional engineering firms performing substantially similar work at the time such work is performed, based on the circumstances the CONSULTANT knew or ought to have known based on the information it had at the date the report was written and after due inquiry based on that information.
3. The CONSULTANT shall not be responsible or liable for any interpretation or recommendation made by others, including any determination in respect of any sale by the Client or any purchase by any third party or any valuation in respect of the Project based in whole or in part on the data, interpretations and/or recommendations generated by the CONSULTANT in the report.
4. The investigation described in the report is based solely upon site visits by the CONSULTANT, and the information received from the Client.
5. The report speaks only as of its date and to conditions observed at that time, which conditions may change (or may have changed) by virtue of the passage of time or due to direct or indirect human intervention causing any one or more changes in plans or procedures or due to other factors.
6. The report does not extend to any latent defect or other deficiency in the Project which could not have been reasonably discoverable or discovered by such observation, with the exception of any latent defect or other such deficiency of which the CONSULTANT had actual knowledge.
7. The report is to be read in conjunction with all other data and information received and referenced in paragraph 4 and all correspondence between the Client and the CONSULTANT. Except as stated in the report, the CONSULTANT has not made any independent verification of such data and information and does not have responsibility for the accuracy or completeness thereof.

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Executive Summary

Nova Scotia Power Inc. (NSPI) engaged Hatch Ltd. (Hatch) to assess the condition of the gate equipment installed at the T2 Intake of the Wreck Cove Generating Station (GS). The objectives of the study were:

- perform a thorough assessment of gate condition
- complete an inspection of the hoist equipment, including electrical power systems
- conduct a cursory design review on the principle dimensions of the gate
- based on the results of the inspection and design review, establish the scope and timing of gate refurbishment or replacement, including sketches of the conceptual design
- develop a feasibility study level cost estimate for refurbishment or replacement of the gate, hoist, and hoist support structure, including ancillary equipment.

The site was visited by Hatch mechanical and electrical engineers in August and November 2016. The condition assessment noted that the gate skinplates (upstream and downstream) were in good condition, but the wheel boxes have several weld cracks. Water was noted to have penetrated the gate body and scaling was observed on interior steel surfaces during a borescope inspection. The gates seals were deteriorated and noted to be in poor condition. The gate wheels, embedded parts, hoist, and hoist enclosure were noted to be in fair condition.

A cursory design review was conducted on the gate, however, due to the unusual design of the gate, and cracked welds observed, a more detailed analysis was conducted using Finite Element Analysis (FEA) to assess the gate structural integrity. The FEA analysis was conducted under maximum hydrostatic pressure conditions using the Allowable Stress Design (ASD) method under the guidelines from the USACE ETL 1110-2-584 Design of Hydraulic Steel Structures publication. FEA results showed that the maximum stresses on the loaded gate structure did not exceed the allowable stress of 19.8 ksi.

A structural model of the hoist support structure was completed using SAP2000 software. The subsequent analysis showed that the support beams and columns are able to withstand the anticipated loads in accordance with CSA S16-09, Limit States Design of Steel Structures.

Calculations were performed to assess the hoist capacity and determine if the gate weight is sufficient to allow for gate closure. Both the original design conditions (water tight gate body, buoyancy forces) and current existing conditions (water allowed to infiltrate gate) were assessed. The hoist was found to be slightly undersized for the current condition of water infiltration and it is recommended to increase the hoist capacity during any future refurbishment or replacement project.

The gate electrical system is generally in poor condition and in need of an upgrade due to the deterioration that has taken place. There were numerous deficiencies noted during the site investigation. Only local control of the gate hoist is currently available.

As a base case, it is recommended to replace the T2 Intake gate, hoist, hoist support structure, and hoist enclosure. The major reasons for hoist replacement rather than refurbishment are to minimize the duration of a station outage, maintain flexibility within the short seasonal construction window, maximize the equipment life extension gain, and take advantage of the preassembled nature of the new equipment. An estimated cost for the equipment replacement scope of work is $990,000.

1. Introduction

Nova Scotia Power Inc. (NSPI) engaged Hatch Ltd. (Hatch) to assess the condition of the intake gate equipment at the T2 Intake at the Wreck Cove Generating Station (GS). This work was undertaken on the basis of the Hatch proposal dated May 3, 2016.

The objectives of the Tunnel T2 Intake Gate Assessment are to accomplish the following:

- perform a thorough assessment of gate condition
- complete an inspection of the hoist equipment, including electrical power systems
- conduct a cursory design review on the principle dimensions of the gate
- based on the inspection and design review, establish the scope and timing of gate refurbishment or replacement, including sketches of the conceptual design
- develop a feasibility study level cost estimate for refurbishment or replacement of the gate, hoist, and hoist support structure, including ancillary equipment.

The purpose of this report is to communicate the Hatch findings from the gate inspections completed at site and during the desktop analyses. Recommendations on how to proceed with the T2 Intake equipment are included in this analysis, as well as a cost estimate for the base case scenario.

2. Background and Site Description

This section provides a brief background to the history of the project, and a site description of the Wreck Cove Facility.

2.1 Background

A comprehensive condition assessment of the station was completed in 2011 and 2012. Various recommendations were provided, including estimated expenditures to maintain the facility as well as consideration of opportunities to improve plant performance and reliability in preparation for life extension and modernization.

For the current phase of the project, NSPI has engaged Hatch to conduct engineering services specific to the improvement of the existing Tunnel T2 Intake Gate and associated equipment.

2.1.1 Tunnel T2 Intake Gate Equipment Assessment

The project objectives for the T2 Intake Area of the Wreck Cove site are:

- conduct a detailed assessment of gate and hoist equipment condition
- based on findings, establish the scope and timing of a gate equipment refurbishment or replacement program.

2.2 Description of the Wreck Cove Facility

A schematic of the Wreck Cove Facility (from Wreck Cove Lake to the underground Powerhouse) can be seen in Figure 2-1. The general features (from upstream to downstream) of the Wreck Cove GS are as follows:

- Wreck Cove Lake Reservoir
- Tunnel T2 intake structure with wheeled intake gate
- Tunnel T2, 3590 m long
- Surge Lake
- Surge Lake penstock intake structure
- concrete lined penstock, 496 m long
- bifurcation and steel lined horizontal penstocks
    - two 6 ft dia spherical turbine inlet shutoff valves
    - 200 MW underground powerhouse (placed in service in 1978)
    - tailrace tunnel, 1705 m long.

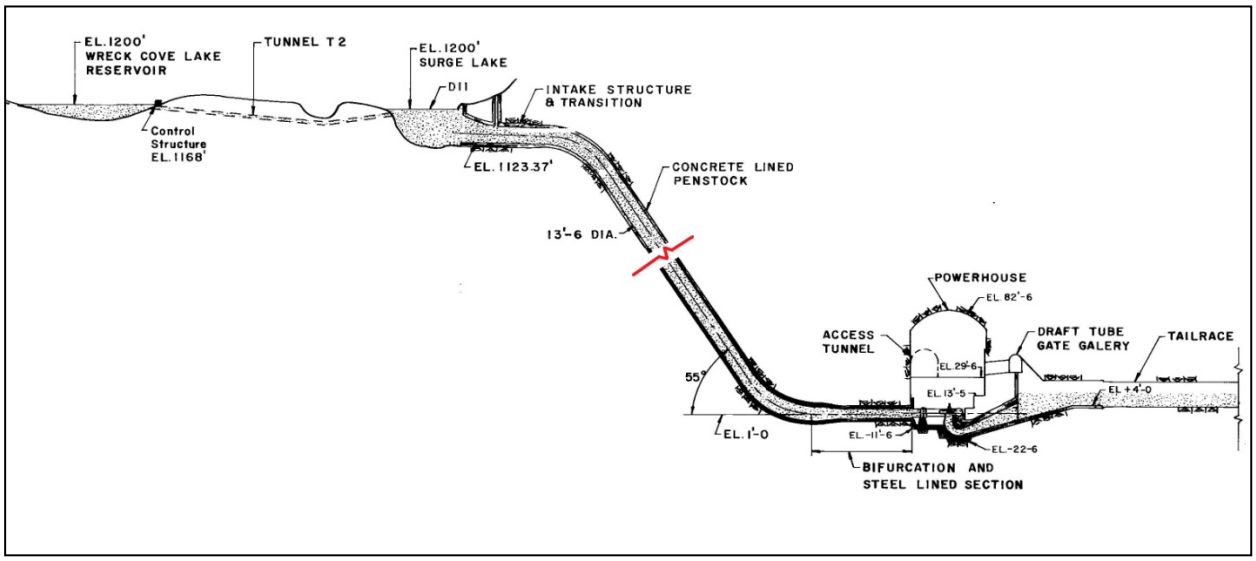

Figure 2-1: **Schematic of the Wreck Cove Facility (Ref. Drawing No. H-085S1-1-111-00-033)**

2.2.1 T2 Intake Control Structure

The T2 intake structure controls the flow of water from the Wreck Cove Lake Reservoir to Surge Lake. The control structure is equipped with a single vertical lift wheeled gate (4.725 m high x 4.623 m wide, 35,000 lb, four wheels per side), operated by a motor-driven wire rope hoist mounted on an elevated steel superstructure, enclosed with a metal-clad building.

The T2 intake gate acts as a headgate for the Wreck Cove GS (the penstock intake at Surge Lake does not currently have a gate). The T2 intake gate is currently the only shutoff device available to stop water flow upstream of turbine inlet valves. The gate is intended for operation in the fully open or closed position, and currently has no electrical controls for remote or automatic emergency closure.

The general arrangement of the T2 intake control structure can be seen in Figure 2-2.

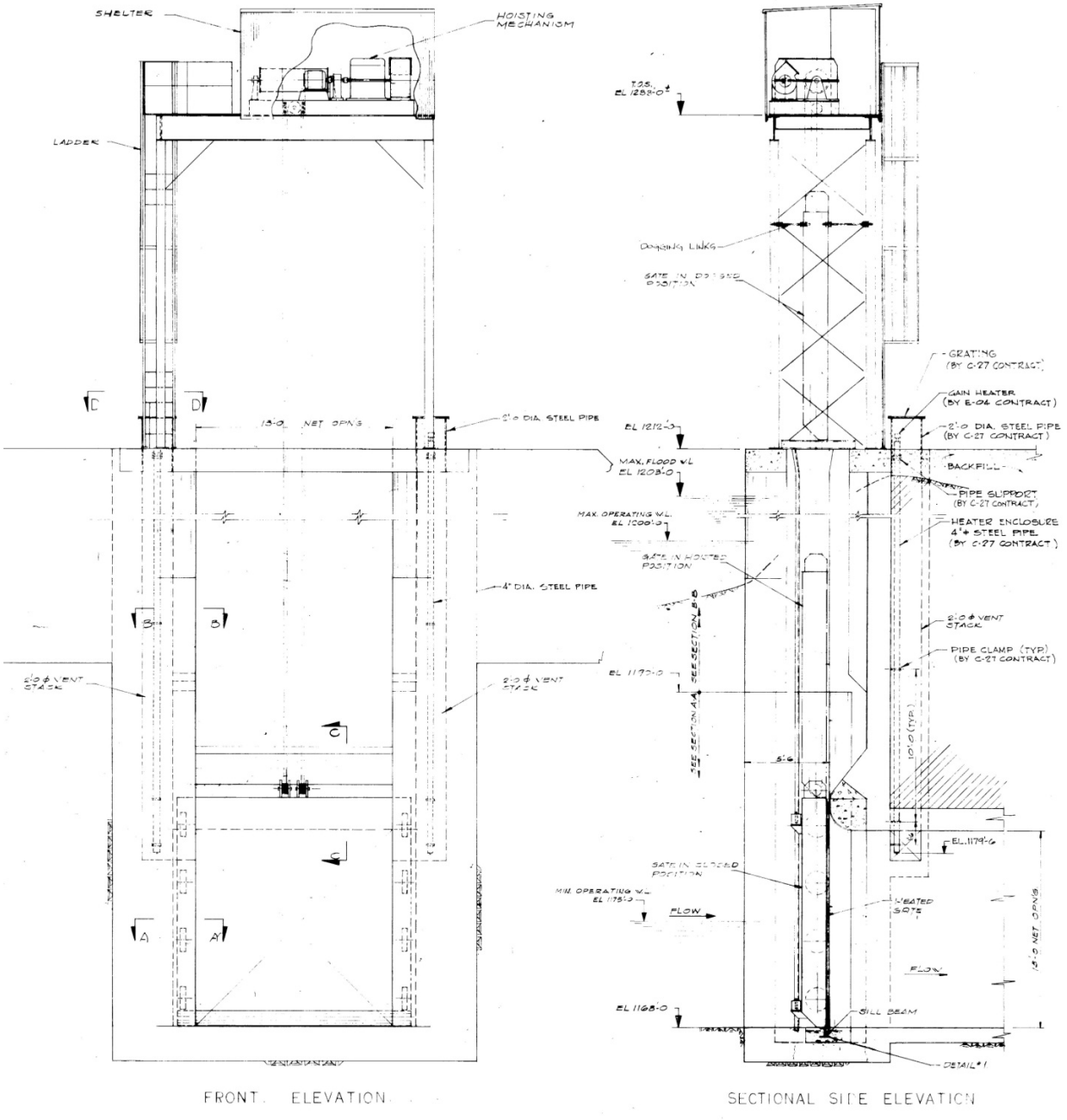

Figure 2-2: General Arrangement of the T2 Intake Gate (Ref. Drawing No. H-085S1-2-628-00-001)

3. Methodology

3.1 Gate Condition Assessment

3.1.1 Data Review

A desktop data review was carried out as part of the condition assessment. NSPI provided various studies and drawings for each piece of equipment which were available prior to the site visit.

In addition to the review of drawings and previous reports, the following NSPI staff, with previous experience working at these facilities, were interviewed during the site visit:

- Ray Sampson – Senior Engineer
- Tim Hawley – Electrical Technician
- Dan _____ – Mechanical Technician.

3.1.2 Site Visit

The site inspection team was composed of professional engineers from Hatch with extensive experience in similar work on other projects. They were accompanied during the visit by NSPI staff. The Hatch team included:

- Jonathan Atkinson – Senior Mechanical Engineer
- Leonardo Chacon – Senior Electrical Engineer
- Jerry Westermann – Mechanical Engineering Consultant
- Andrew Bridgeman – Mechanical Engineer.

Two inspections were carried out; the first on August 20, 2016, and the second on November 5, 2016. The purpose of the second inspection was to verify the interior condition of the welds, and verify wheel alignment.

3.1.3 Condition Assessment

Standardized condition assessment check sheets were used to collect data and record the perceived condition of the intake structure equipment. The condition rating was determined based on a visual inspection of each component (looking for obvious irregularities), information gathered during data review, and information received from NSPI staff during and after the site inspections.

Data recorded on the check sheets consist of nameplate information, overhaul/rehab history, condition ratings and notes for sub-components, photographs, and an overall condition rating. A copy of the inspection check sheets can be found in Appendix A.

4. Tunnel T2 Intake Gate Assessment

Hatch completed an assessment of the major components at the T2 intake and generated condition assessment check sheets for each component assessed.

It is noted that the perceived condition was based on a combination of the general overall visual condition of each component, O&M history, reported condition and concerns discussed with NSPI, as well as historical data. Detailed inspection and testing of components (e.g., performance testing, oil samples, electrical tests, etc.) were not completed as part of the assessment, and the overall condition was assessed based on the discipline engineer's experience with hydro power components and in discussion and agreement with NSPI staff.

4.1 Gate and Hoist Condition

Detailed inspection check sheets for equipment assessed during the site visit can be found in Appendix A. A summary of the observations is provided in the following subsections.

4.1.1 Gate Body

The gate skinplates (upstream and downstream) are in good condition. Plate thickness measurements were taken on the skinplates and indicated that there has been little or no loss of material in relation to the original drawing dimensions. The coating system on the gate body is generally in fair condition, with surface corrosion and pitting on less than 10% of the skinplate surfaces.

Many cracked welds were identified around the wheel boxes during the inspection. Detailed crack mapping can be seen in Appendix B, with accompanying photographs of the cracks. It is expected that the cracks were caused by water infiltration behind the wheel boxes, followed by freeze-thaw cycles, however, the exact cause has not been determined.

The gate was originally designed to be water tight and heated, however the heating system has failed (reported to have failed approximately 25 years ago), and the power supply to the gate has been removed. The cable access holes have not been plugged after the heating system was removed and currently water is allowed to freely enter the gate body. The gate top cover gasket was also found to be severely deteriorated and is no longer maintaining a seal.

The inside surfaces of the gate body were inspected with a borescope camera. Significant scaling was evident throughout the gate interior as a result of water infiltration.

4.1.2 Gate Seals

The gate seals were found to be in poor condition. Minor tearing of the fluorocarbon film was evident, and the rubber seal material was deteriorated.

The coating system on the seal clamp bars is failing and significant corrosion was observed throughout.

4.1.3 Gate Wheels

The gate wheels were found to be in fair condition. All wheels could be turned by hand, indicating that they are freely rotating. Significant corrosion was identified on all wheels, including the axle cover plates and keeper plates.

4.1.4 Embedded Parts

The visible portion of the embedded parts was in fair condition. Minor paint deterioration and corrosion were visible above water level. A subsequent ROV inspection of embedded parts below the water surface completed after the site visit, showed that the condition of the embedded parts is fair.

There are three gain heater conduits on each side of the gate slot (one upstream, two downstream); however, all gain heaters have failed and are no longer operational.

4.1.5 Hoist and Hoist House

The hoist and hoist house were visually inspected and found to be in fair condition. Various deficiencies were identified during the inspection, and are summarized below:

- main brake reported to be slipping, NSPI currently dogs the gate in place rather than relying on brake
- no remote or automatic emergency closure capabilities are present on the hoist
- fan brake damper is fully closed – fan brake damper should be fixed in place to ensure proper closing speed
- minor surface corrosion on hoist drum
- roof leaks in building onto various pieces of equipment.

The hoist was also inspected by Hercules on October 31, 2016, who identified various deficiencies, mostly related to limit switches. The Hercules inspection letter can be seen in Appendix C.

4.1.6 Operational Tests

During the site inspection, functional testing was performed on the gate. The gate was fully closed and opened under balanced head conditions. The tunnel was not dewatered during the testing to observe leakage; however, it was reported by operators that the tunnel was drained last fall and minimal leakage was observed on the gate.

4.2 Intake Gate Finite Element Analysis (FEA)

Finite Element Analysis (FEA) was conducted using ANSYS Workbench R15.0 for the Wreck Cove T2 Intake Gate to assess the gate structural integrity.

4.2.1 FEA Methodology and Model

Allowable Stress Design (ASD) method was adopted using guidelines from USACE ETL 1110-2-584 Design of Hydraulic Steel Structures publication. Observed cracks in the end beam welds were not modelled as it was assumed that these would be repaired.

The FEA model (Appendix D, Figure D-5) geometry is illustrated in the details shown in Figure D-6. The gate plates were modelled using 4 node SHELL181 elements while the axles were modelled using 8 node SOLID185 elements (Figure D-7). The number of elements is 121,300; the number of nodes is 124,500. Continuous mesh was used between all plates forming the gate structure.

To connect the solid-meshed axles (wheels and sheave block) to the shell-meshed gate no-separation contacts allowing sliding were used. Such contact type is considered adequate for the axle-plate interaction and significantly reduces the required solving time. The wheel axles consist of three different diameters. To attach the three axle components to each other bonded contacts were used (Figure D-10).

A single load combination with a number of loading scenarios was used. Multiple load scenarios were considered based on discussions with NSPI to help determine if a misaligned wheel could have caused overstress. The load combination is LC1 = 1.0D + 1.0H, where D is the gate weight of 35,000 lbf (Figure D-13) and H is the hydrostatic pressure corresponding to the maximum operating water level of 1200.0 ft elevation (32 ft of hydrostatic head at the gate sill). Hydrostatic pressure, assuming water is inside the gate, was applied as illustrated in Figure D-14. The loading scenarios are as follows:

- LS1 All wheels are in contact with the wheel track (Figure D-12a)
- LS2 The pair of upper most wheels (01) is not in contact with the wheel track (Figure D-12b)
- LS3 The pair of 02 wheels is not in contact with the wheel track (Figure D-12c)
- LS4 The pair of 03 wheels is not in contact with the wheel track (Figure D-12d)
- LS5 The pair of bottom most wheels (04) is not in contact with the wheel track (Figure D-12e)

For all loading scenarios above the gate was assumed to be supported by the wire rope with U_y=0 (vertical direction) constraint applied at the sheave axle (Figure D-11). In order to reduce computational time, only half of the gate was modelled due to symmetry about the middle X-Y plane. Symmetry boundary conditions were applied as shown in (Figure D-11).

Steel material properties were assigned to all elements with E = 200 GPa, ρ = 7850 kg/m^3,

v = 0.3. Nominal plate thicknesses are shown on Figure D-6.

For all loading scenarios 1/16 in. corrosion allowance was subtracted from all plates except for the 1/2 in. main girder webs and 1/2 in. inner end plates where 1/8 in. was subtracted. The adopted corrosion allowances are consistent with the results of Hatch's site inspection.

4.2.2 FEA Model Results

The gate structure is fabricated out of G40.21-44T steel with 44 ksi yield strength (per H-085S1-9-625-00-048 drawings). The allowable stress per ETL 1110-2-584 is 44 ksi/ (1.67*1.33) = 19.8 ksi where 1.33 is the allowable stress modifier for emergency closure gates and 1.67 is the allowable stress design safety factor.

The deflection criterion is taken from ETL 1110-2-584. The main girder deflection in the middle of the gate is limited to 1/800 times the span and the skinplate deflection is limited to 0.4 times the plate thickness. 178 in./800 = 0.222 in. where 178 in. is the distance between the wheels. 0.4*0.625 in. = 0.25 in. where 0.625 in. is the skinplate thickness.

The FEA results are summarized in Table 4-1 below. The results show that the stress levels in the gate do not exceed the allowable of 19.8 ksi.

The wheel axles were analyzed using reaction forces from the FEA model and analytical methods. Although the axle material is not known both shear and bending stresses in the wheel axles are low.

Main girder web to skinplate weld capacity was checked using nodal forces from the FEA model. The existing welds on both the upstream and downstream sides were determined to have a sufficient capacity to resist the applied loads. It should be noted that the present weld condition is unknown.

End plate to skinplate weld capacity was checked using nodal forces from the FEA model. The welds connecting the end beam plates should be repaired and their size increased to 3/8 in. using matching electrode.

4.2.3 FEA Conclusions and Recommendations

Based on the results of the assessment, Hatch concludes:

- The gate load-carrying components (gate leaf, wheel axles, skinplate-to-end-plate welds in the end beams, main-girder-web-to-skinplate welds) investigated in this study show that these components have sufficient capacity to resist forces corresponding to the maximum operating water level (el 1200 ft).

Hatch recommends the following:

- The welds connecting the end beam plates shall be repaired and their original size increased to 3/8 in. using matching electrodes.
- It is assumed that the gate will not be restored to its original completely sealed configuration. Therefore, drain holes shall be provided to avoid water entrapment and recurring issues with cracked welds.

Table 4-1: FEA Results – Summary Table

Loading Scenario	Girder Deflection [in]	Skinplate Deflection [in]	Misaligned Wheel Deflection[in]	Upstream Skinplate σ_{vm} [psi]	Downstream Skinplate σ_{vm} [psi]	Main Girder Bending σ_y[psi]	End Beam σ_{vm} [psi]	End Beam Bending σ_y [psi]
LS1	0.113	0.045	0.0	10,530	16,520	7,120	8,680	5040
LS2	0.181	0.045	0.092	10,860	18,100	8,130	15,990	15,300
LS3	0.109	0.046	0.023	11,860	17,200	6,880	12,050	10,100
LS4	0.118	0.037	0.022	10,440	16,500	7,020	9,820	8,390
LS5	0.171	0.070	0.073	11,080	17,300	7,820	16,420	15,020

Notes:
1. The allowable stress is 19,800 psi
2. The allowable girder deflection in the middle of the gate is 0.222 in.
3. The allowable skinplate deflection is 0.25 in.
4. The wheel axle eccentricity intended for wheel alignment is 0.125 in., Ref [2].

4.2.4 FEA References

The following references were used to create and analyze the FEA model of the T2 Intake Gate:

[1] H-085S1-2-628-00-001 drawing

[2] H-085S1-9-625-00-047 drawing

[3] H-085S1-9-625-00-048 drawing

[4] H-085S1-9-625-00-049 drawing

[5] H-085S1-9-625-00-081 drawing

[6] H-085S1-9-625-00-082 drawing

[7] USACE ETL 1110-2-584 Design of Hydraulic Steel Structures.

4.3 Hoist Superstructure Assessment

4.3.1 Inspection

Only one serious structural deficiency was noted during the inspection. On the downstream side of the structure, a bolt connecting cross bracing is missing, as seen in Figure 4-1.

The missing bolt in the cross bracing should be replaced immediately using a structural bolt with diameter to match the original bolt. The bolt material is to be ASTM A325, the nut and washer are to be ASTM A563 and ASTM F436, respectively.

Figure 4-1: Missing Bolt in Cross Brace on Downstream Side

From an earlier assessment by Hercules, the existing ladder may not be constructed in accordance to current code standards. This should be confirmed by NSPI.

4.3.2 Structural Assessment

Based on existing drawings, a computer model of the hoist building and support structure was created using SAP2000 software. The model was analyzed primarily to determine the capacity of the support columns. It was also possible to determine the capacity of the hoist equipment support beams using this model. A graphic of this model is included below:

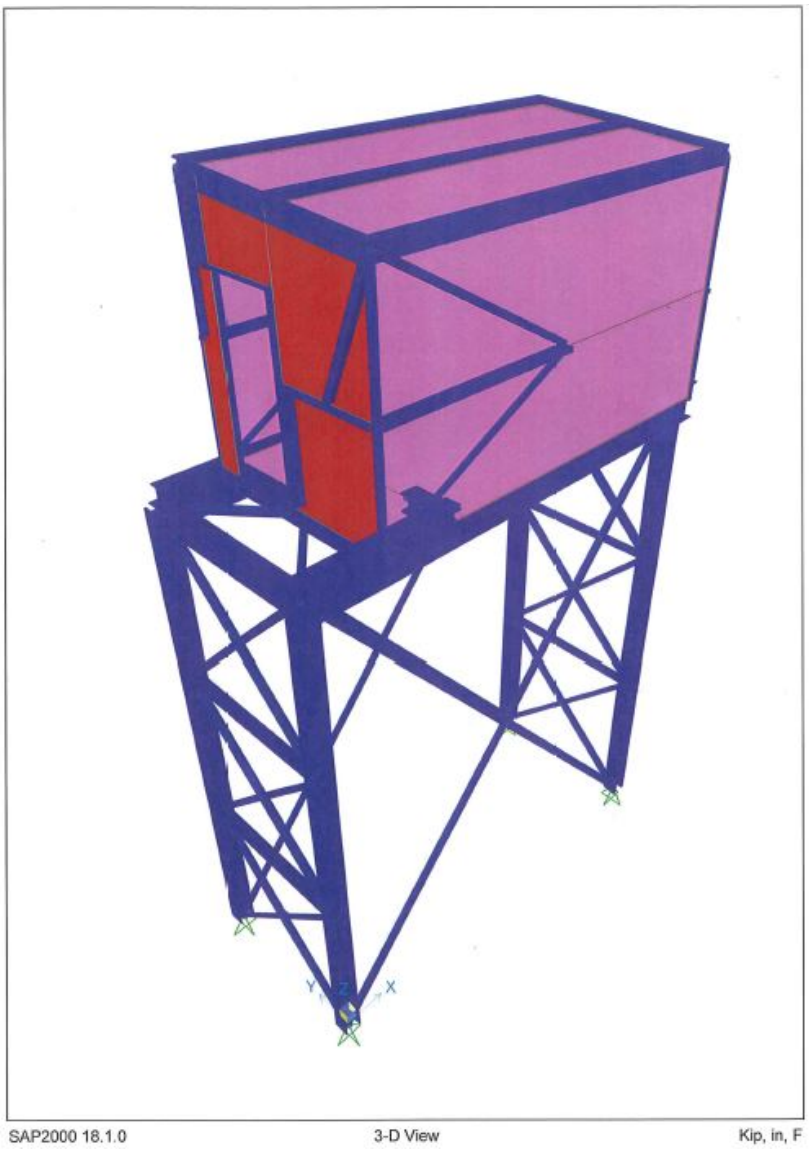

Figure 4-2: SAP2000 Hoist Support Structure Model

The results of this analysis indicate that the hoist equipment support beams and columns are below capacity in accordance with CSA S16-09, Limit States Design of Steel Structures.

The complete superstructure assessment results are in Appendix E.

4.4 Hoist Capacity Calculation

Calculations were performed to assess the hoist capacity and determine if the gate weight is sufficient to allow for gate closure. Both the original design conditions (water tight gate body, buoyancy forces) and current existing conditions (water allowed to infiltrate gate) were assessed. The calculations can be seen in Appendix F.

The analysis considered the following forces acting on the gate during hoisting and lowering operations:

- seal friction
- wheel bearing friction
- wheel sliding resistance
- downpull
- buoyancy
- gravity.

The results of the design review are as follows:

- In an analysis neglecting downpull forces and considering the full buoyancy forces of the original design conditions of the gate, the gate has enough weight to lower under gravity. This assessment considers that all wheels are rotating freely and that the fluorocarbon film on the seals is intact.
- The hoist has 134% of the required capacity to lift the gate to the prime position, with full head acting on the upstream side of the gate considering the original design conditions (water tight gate, high buoyancy forces).
- The hoist has 101% of the required capacity to lift the gate to the prime position, with full head acting on the upstream side of the gate considering the as-found conditions (water filled gate).

Typically, hoists are sized to have a capacity not less than 110% of the calculated required capacity. Therefore, in the as-found conditions the hoist is slightly undersized. Raising the gate to the prime position is a short operation which is done very infrequently, and operating the hoist in the as-found condition is not considered to be a concern. However, it is recommended that the hoist capacity be increased during the gate and hoist refurbishment/replacement project.

4.5 Electrical Review

4.5.1 Description

Power supply for the Tunnel T2 Intake Gate is taken from a 25 kV transmission line that runs from the Wreck Cove Switchyard parallel to the T2 Intake access road. At the end of the transmission line are three 25/0.6 kV single phase transformers that are installed for servicing the intake electrical equipment.

Electrical equipment is installed in the hoist house and consists of one energy meter, 600 V AC and 120 V AC distribution panels, disconnect switch, 5 kVA lighting transformer, hoist control panel, RTU for remote communication, heaters and enclosure lighting.

At the gate deck level, electrical equipment was originally installed to supply power for gate and gain heaters and bubbler system.

4.5.2 Assessment

In general, all the electrical equipment at the hoist house and gate deck level are original and are in need of an upgrade. Gate local controls were modernized in 2012, but operation is only available locally. In addition, the hoist building roof is damaged and it leaks, exposing the electrical equipment to water.

The following list summarizes the electrical deficiencies observed during the site inspection:

- Heater for hoist building is suspected to be inoperable due to roof water leakage.
- Enough fluorescent lamps are installed but few are in operation.
- There is no provision for voice communication.
- All the building structure electrical grounds have been deliberately removed, apparently by vandals.
- An RTU is installed inside an inadequate wooden cabinet with exposed batteries.
- According to handwritten notes in the RTU Panel, the following signals are available: gate open limit, gate close limit, gate trouble alarm, intrusion alarm, gate local control, gate raise, gate lower and gate stop. Operations personnel reported that the gate is only operated locally and no remote supervision is currently available.
- A pressure transducer is installed for reservoir water level measurement; however, it is not clear how this signal is transmitted to the powerhouse/ECC.
- All cables for the gate and gain heaters have been removed.
- Cables at deck level for pressure transducer and gate docking position limit switch are not protected with conduits.

During the site inspection, the gate was operated for mechanical assessment and measurement. The motor seems to operate normally; however, functional verification of limit switches was not confirmed.

Pictures of the above-mentioned deficiencies and others are indicated in Gate Electrical Check Sheets in Appendix A.

5. Recommendations

5.1 Life Extension Alternatives

Two life extension alternatives were evaluated for the Wreck Cove Intake; refurbishment and replacement. The scope of work for each alternative is explained in further detail in the Section 5.1.1 and Section 5.1.2

5.1.1 T2 Intake Replacement Alternative

Replacement would involve removing the existing equipment and installing new equipment. This alternative would result in higher capital costs than a refurbishment scope, however the overall construction schedule would be compressed, minimizing outage duration and lost generation revenues.

The following items would be included in the base case scope of work:

- removal of existing gate, hoist, hoist enclosure, and hoist support structure
- cleaning and refurbishment of the existing gate guide embedded parts
- new downstream sealing vertical wheeled gate installed inside of the existing gate slots using the existing sealing surfaces and embedded parts
- new steel hoist support structure installed at deck level and would facilitate removal of the gate from the gate slots
- new wire rope gate hoist installed inside of a new heated hoist enclosure that is mounted on top of the new hoist support structure
- new heated enclosure installed at deck level on the downstream side of the vertical gate to facilitate air entrance and exhaust [required during penstock filling (air escape) and penstock dewatering (air entrance)]
    - Note that there is currently a vent stack shown on the T2 Intake Gate design drawings. This arrangement will be investigated and confirmed or recommended to be refurbished or replaced during the detailed design phase based on the air demand requirements
- new winter season timber isolation beams to shield the gate guide area from ice cover (installed on the upstream side of the gate guides).

This concept uses well-established technologies that are typically installed at similar hydro facilities and are in-line with prudent utility practice.

It is recommended to review the air venting requirements and the capability of the existing vent stack as part of the next phase of the project. This analysis will determine the vent surface area required based on the demands of the T2 tunnel during load rejections at the Wreck Cove GS. Due to the presence of Surge Lake, it is not anticipated that a load rejection

at the Powerhouse would affect the assets at the T2 intake, but this should be confirmed during the detailed design phase.

A similar hoist arrangement concept could be applied to the penstock intake at Surge Lake which would facilitate uniformity for spare parts and operation procedures.

5.1.2 T2 Intake Refurbishment Alternative

Refurbishment of the gate and hoist equipment is a potential option for extending the life of the equipment. The refurbishment would be at a lower capital cost than full replacement, however extensive site work would be required resulting in a longer outage and higher cost due to lost revenues.

The following sections contain lists of the rehabilitation measures proposed for the gates, embedded parts, hoist, and hoist support structure.

5.1.3 Gate

- Blast clean and paint gate body.
- Replace seals.
- Replace seal clamp bars, and refurbish backing bars.
- Replace all seal bolting with stainless steel bolts.
- Remove, refurbish, re-assemble, install, and adjust main roller assemblies.
- Remove gate heater components to the extent possible.
- Drill water drain holes on the upstream side of the gate and the enclosed compartments in the end beams.
- Repair cracks in end beams and wheel boxes.
- Replace and weld top covers on to gate.
- Refurbish lateral guide rollers.
    - Replace springs and roller bushings.
    - Consider re-installation and possible design modification of lateral guide roller protective covers.
- Replace lateral bumpers with fixed bronze bumpers.
- Replace deformed end plates.
- Design and install a gate well heating system to prevent the gate from freezing in place.
- Cleaning and refurbishment of the existing gate guide embedded parts.

5.1.4 Hoist

- Replace hoist motor.
- Replace and commission main brake and brake drum.
  - Brake to include manual release lever.
- Replace fan brake.
- Inspect and lubricate bearings.
- Conduct oil analysis of gearbox, and inspect gearbox (seals, bearings, gears).
- Replace load block sheave assemblies, consider self-lubricated bushings.
- Replace upper sheaves and equalizer, including load sensing pin.
- Install wire rope retention device on load block sheaves.
- Inspect and NDE hoist drum.
- Mechanically clean and paint hoist support frame, and perform NDE on structural welds.
- Install machinery guards to protect personnel from exposed hoist drum and other exposed rotating equipment.

5.1.5 Electrical

Considering the conditions of the electrical equipment it is recommended that the following work be completed:

- replace all the electrical equipment including 600 VAC and 120 VAC distribution panels, lighting transformer, internal and external lighting
- replace hoist control panel, including provisions for remote supervision and control
- replace hoist house heater
- reinstall ground cables
- replace gain heaters, including cables and controls
- evaluate conditions of main power supply cables coming from transformer bank
- install means for voice communication
- replace rotary control system, to include the following:
  - normal closed
  - prime position

- normal open position
- maintenance position

- install new digital position encoder
- replace hoist over travel limit switch
- install load cell for slack for and hoist overload conditions.

5.1.6 Hoist House and Structural

- Repair water leakage in hoist house roof.
- Consider vent fan on humidistat control.
- Provide screening.
- Install missing bolt in support cross bracing.
- Blast clean and paint superstructure.
- Consider access safety issues, and ensure ladder, platforms and handrails meet current OHS requirements. Consider installation of a staircase.

5.1.7 Gate Well Heating Arrangement

Regardless of the recommended alternative, a gate well heating arrangement is suggested to reduce the probability of having the gate frozen in the gains.

The original design of the gate incorporated an upstream and downstream skinplate, an air tight sealed gate body, and internal gate heaters. As described in Section 4.1.1, this arrangement has failed. The heaters are no longer functional, and cracked welds have allowed for water to infiltrate the gate body.

Both refurbishment and replacement alternatives do not recommend reinstating gate body heating arrangement, but instead recommend providing an upstream barrier to the gate well to close off the upstream wall, and heating the enclosed area. The proposed arrangement would include the following components:

- upstream guides, embedded into the existing concrete structure
- upstream timber beam isolation wall, installed in the new guides to shield the gate guide area from ice, and minimize heat loss from the area
- gate slot cover to minimize heat loss from the area
- radiant heaters hanging from the gate deck.

The proposed arrangement can be seen below in Figure 5-1.

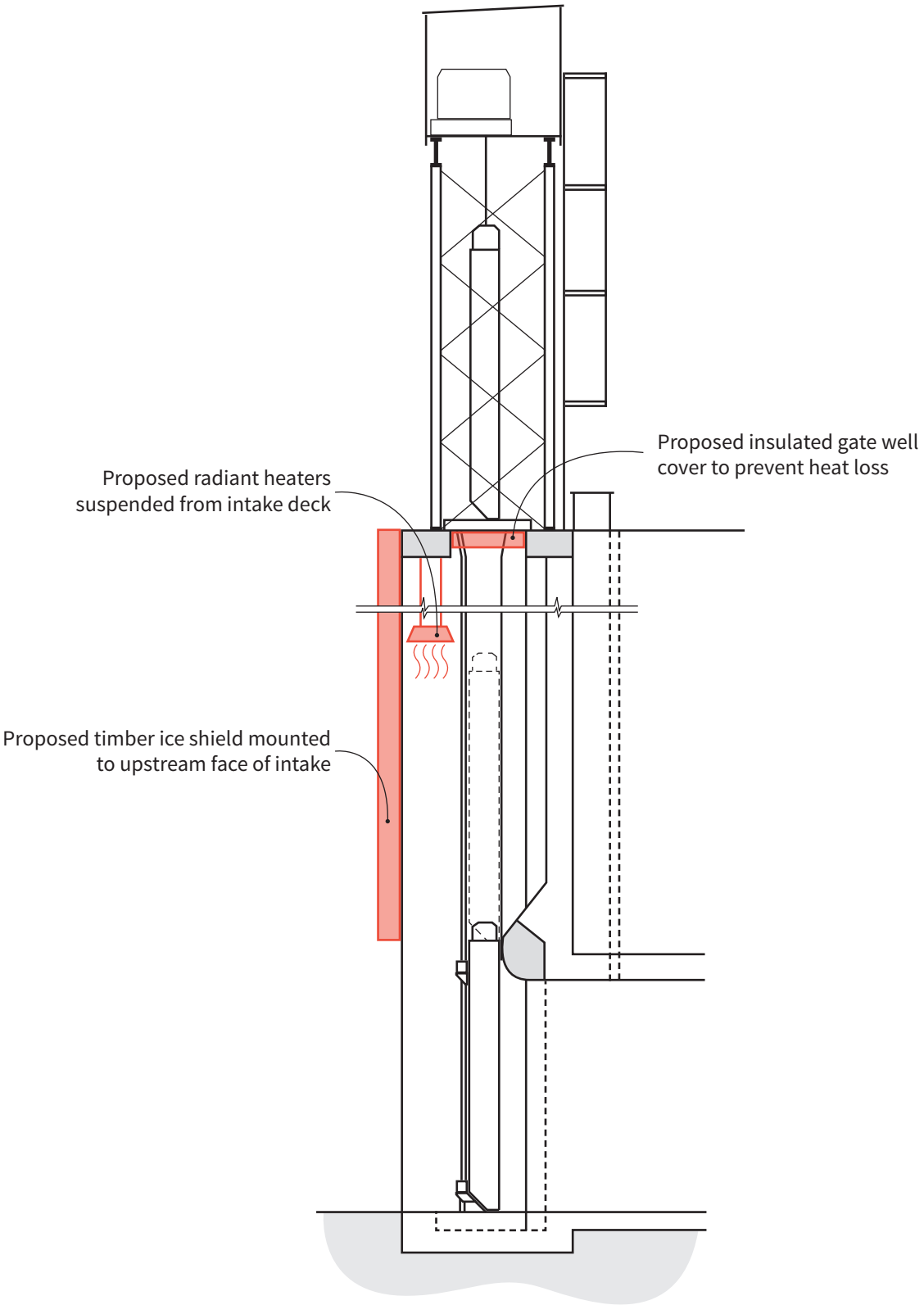

Figure 5-1
Nova Scotia Power Inc.
Wreck Cove – T2 Intake Gate Assessment
Proposed Gate Well Heating Arrangement

HATCH

5.2 Recommended Alternative

Replacement of the major components will provide the maximum duration of life extension and lessen the overall construction schedule. Once the existing equipment is removed the new equipment can be installed resulting in a more efficient project and minimizing station downtime and lost generation. A Preliminary Construction Cost Estimate was prepared for the T2 Intake equipment replacement and can be found in Section 5.3.

The scope of work for gate and hoist replacement was developed based on observations made during the site inspection and conversations with NSPI site operations and engineering staff.

If replacement of the T2 Intake equipment is not a preferred solution for NSPI, then refurbishment is an option. While refurbishment will have a lower capital cost, the major drawbacks of this option are the extended duration of the site work that would be required (resulting in higher outage costs) and the challenges of working at site with limited laydown areas. In order to minimize the station outage, the project would need to be completed on an accelerated schedule. Costs for the refurbishment option were not estimated, but gate refurbishments can typically be between 40% to 70% of gate replacement cost. Refurbishments of the hoist, superstructure, and hoist house are typically between 20% to 50% of replacement costs.

5.3 Replacement Cost Estimate

The estimated project cost for the Wreck Cove – T2 Intake Gate Assessment Project is $990,000 in 2017 Canadian dollars (CAD) and is subject to certain qualifications, assumptions and exclusions further explained in this section.

This preliminary Construction Cost Estimate is considered to have an accuracy range of ±30%

The cost estimate can be found in Appendix G of this report.

5.3.1 Estimate Methodology

The cost estimates were developed based on unit costs obtained from previous NSPI projects as well budgetary quotes for the major equipment. A copy of the budgetary quote provided by Canmec can be found in Appendix H.

5.3.2 Scope of Estimate

5.3.2.1 Qualifications and Assumptions

The Construction Cost Estimate was compiled based on the following parameters:

- an estimate base date of August 2017
- all prices are in CAD
- cost estimate was developed without comprehensive condition assessment of existing structures and site conditions

- existing structures assumed to meet stability requirements
- existing structures assumed to be in acceptable condition for intended purpose
- costs were provided based on local contractor (minimal per diems)
- road access and possible laydown areas on the project site assumed to be in reasonable condition for construction equipment and crane access (allowance provided for minimal improvements)
- dewatering managed by NSPI (outage planned)
- grounding requirements based on standard design supplier requirements
- CCTV camera included for visual inside intake to monitor freeze protection
- all ladder and fall arrest systems by suppliers
- 6-month project schedule.

5.3.3 Exclusions

- Geotechnical investigations or environmental studies.
- Improvements to the existing ventilation shaft.
- Owner's Costs (project management, tendering, site supervision, QA testing, financing/IDC, taxes, land acquisition, legal services).
- Construction insurance and bonds.
- Escalation beyond 2017.
- Mitigation measure for protection of archaeological areas (if applicable).
- Concrete testing (Owner preference to coordinate).
- Risk allowance.
- Sales tax and import duties unless specifically included.
- Schedule acceleration costs.
- Schedule delays and associated costs, such as those caused by:
  - unexpected site conditions
  - unidentified ground conditions
  - labor disputes.

- Force majeure.
- Permitting.
- Development fees and approval costs of statutory authorities.

5.3.4 Contingencies

Contingencies are provisions for project costs which will occur, but which cannot be defined insufficient detail for estimating purposes due to the lack of complete, accurate and detailed information, as well as the limited engineering, which has been performed. The addition of contingency is required in order to determine the most likely cost of the project. Based on Hatch's experience on similar projects, the contingency for the project was assessed at 20% of construction direct and indirect costs.

6. Conclusions and Recommendations

The condition of the Tunnel T2 gate, hoist, and superstructure has been assessed by a team of Hatch mechanical and electrical engineers. Detailed condition assessment checksheets are provided in Appendix A and a summary of major findings is provided in Section 4. In addition to the site assessment, desktop calculations were preformed to assess the hoist, superstructure, and gate components. A summary of findings from the desktop calculations is provided below:

- The hoist equipment support beams and columns are below capacity in accordance with CSA S16-09, Limit States Design of Steel Structures.
- The hoist capacity is sufficient when considering the original design (sealed gate cavity with large buoyancies forces); however, it is slightly undersized for the current conditions of the gate (water allowed to enter and fill the gate cavity). This is not considered to be a major concern; however, during refurbishment/replacement it is suggested that the hoist capacity be increased.
- The gate load-carrying components (gate leaf, wheel axles, skinplate-to-end-plate welds in the end beams, main-girder-web-to-skinplate welds) were investigated and these components have sufficient capacity to resist forces corresponding with the maximum operating water level (el 1200 ft).

Cracked welds were identified on the end beams and around the wheel boxes, which require immediate attention. It is presumed that these failures were initiated by water infiltration into the gate, resulting in freeze thaw damage. A preliminary scope of suggested repairs was provided to NSPI in November 2016 to address these concerns, which can be seen in Appendix I.

Due to the age of the existing T2 Intake equipment, site access challenges, seasonal construction schedule, desire to minimize station downtime, and the limited equipment life extension gained by a refurbishment project, it is recommended to replace the T2 Intake gate, hoist, hoist support structure, and hoist enclosure. In addition, there may be a requirement to add a ventilation enclosure on the downstream side of the gate slots if it is confirmed that the existing vent shaft cannot transport the required air supply to the tunnel during penstock filling or emptying. A general base scope of work for gate and hoist replacement was developed based on observations made during the site inspection and conversations with NSPI site operations and engineering staff. The scope of work for replacement project is presented in Section 5. A cost estimate for the T2 Intake equipment replacement base scope of work is provided in Appendix G.

Appendix A
T2 Intake Conditions Assessment Checksheets

Condition Assessment Checklist

Intake and Spillway Gate Hoist				
Site Name	Wreck Cove T2 Intake			
Date of Inspection	August 20, 2016			
Weather	Cloudy/Light Rain 20°C			
Upstream Water Level	Not confirmed			
Description of Item	**Equipment Data/O&M Data and Year**			
Gate data: **(record source if not seen on equipment)**	**Type** **(tainter, vertical lift)**	**W x H**	**Side Seals**	**Lintel seal**
H-085S1-9-625-00-053	Vertical	13' x 13' Clear opening	Rubber w flouro-carbon	Rubber w flouro-carbon
Hoist data: **(record source if not seen on equipment)**	**Design/actual speeds (lower/raise)**	**Capacity**	**Motor hp**	**Torque switch**
H-085S1-9-625-00-053	2.42 fpm lifting 2.8 fpm lowering	41000 lb rated 98000 lb stall	3 hp	
	Hoist in open or enclosed	**Hoist supplier/year installed**		**Lift**
	Enclosed	1976		1212' top of deck 1168' sill
Hoist arrangement [drums (no./dia./no. wraps/left & rh grooving on drums?), hoist rope or chain, no. falls, no. sheaves (upper/lower)]: Single drum with gearbox, motor and wire rope. LH/RH common drum.				
Operating problems reported (jamming, jerkiness, noisy, stalling, slow, vibration).	None reported.			
Hoist system - inspection frequency - year overhauled - overhaul details	Annual inspection by Hercules (maybe bi-annual for gate). Believe only good for 5 years. Only wire rope has been recently replaced (otherwise maybe 15 years ago was replaced). Last decal on hoist suggests last inspection in 2009. Controls done recently (approximately 2 years ago), but unsure of scope.			

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Intake and Spillway Gate Hoist	
Major repairs, modifications	None – appears original (other than controls).
Maintenance problems	Brake slipping – possible asbestos in pads. NSPI currently looking at replacing brake. Last Sept/Oct when Surge Lake was drained, motor thermals were tripping out (suspect when gate under head).
Drawings/manuals-record location (site, office, both)	Stored in site office.

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Nova Scotia Power Inc.
Wreck Cover - Assessment and Improvements
H351728

Engineering Checklist
Mechanical Engineering
Condition Assessment Checklist

Item	Rating	Reason for Rating
Couplings, Shafts and Bearings	☐ 1 ☒ 2 ☐ 3 ☐ 4	No issues reported.
Gear Reducer, V-Belts and Sheaves	☐ 1 ☒ 2 ☐ 3 ☐ 4	Don't think any oil samples done.
Open Gearing	☐ 1 ☐ 2 ☐ 3 ☐ 4	N/A
Main Brake and Fan Brake	☐ 1 ☐ 2 ☒ 3 ☐ 4	Slippage; No lever on brake. No issues with fan brake reported – damper is closed. Appears rust build-up inside fan housing.
Hoist Drum	☐ 1 ☒ 2 ☐ 3 ☐ 4	Some surface corrosion, grooves appear ok, new rope.
Wire Rope Sheaves and Wire Ropes	☒ 1 ☒ 2 ☐ 3 ☐ 4	Rope recently replaced (1.5 months), believe Hercules looked at sheaves, etc. Sheaves show signs of surface corrosion.
Hoist Support Structure	☐ 1 ☐ 2 ☒ 3 ☐ 4	Some rusting, bolt mission on brace on downstream side. Roof leaks in building onto various equipment.
Platforms, Stairs, Ladders, Handrails, Toeplates	☐ 1 ☐ 2 ☒ 3 ☐ 4	No issues. General surface corrosion. Mentioned that ladders don't meet current requirements.
Joints, Rivets, Welds, Anchor Bolts, Misc. Steel Bolting	☐ 1 ☒ 2 ☐ 3 ☐ 4	Bolt missing on cross bracing.
Hoist system performance reported	☐ 1 ☒ 2 ☐ 3 ☐ 4	Other than brake, no issues. Thermal overload in Oct 2015.
Gate hoist enclosure heater	☐ 1 ☐ 2 ☐ 3 ☐ 4	Thermostat control. No issues reported but unsure if it works.
Other	☐ 1 ☐ 2 ☐ 3 ☐ 4	Appears that mechanical rotary counter provides position indication to RTU. Rotary cam – one abandoned, one wired to gate panel (8 wires with one pair spare and three connected in panel).
Additional information (Test results, Photographs, Notes, Sketches, etc)	• In past remote control ability, but never remotely operated. • In winter concerns regarding freezing, so local control only. • Believe only way to E-drop is to manually open brake (no lever – need to use screwdriver) to close on fan brake control. Handle missing?	

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Item	Rating	Reason for Rating
	• Have portable hydraulic power pack but not large enough to operate gate – fitting on hoist shaft is there if required. • No back-up generator, hand crank only. • Leakage into roof onto equipment. • Controls replaced after KGS inspection. • Believe status signals are slack, hoist overtravel, rotary cam for elevation, remote gate position and false alarm to local control center (radio link). • Spares not known. Used to have spare wire rope (suspect can get on short notice but made to length). • 25 kV line on poles, stepped to 600 V at site (transmission between Wreck Cove and Gisbourn). • Not aware if dam safety requirements qualify gate for Dam Safety Purposes. • NSPI not sure of procedure to raise gate by hand crank. o Clutch considered hand brake.	

Rating	Condition Description	Details
1	Good	Only minor deterioration or defects are evident.
2	Fair	Moderate deterioration. Function is adequate.
3	Poor	Serious deterioration of at least some parts. Function is inadequate.
4	Unacceptable	Extensive deterioration. Barely functional. May be unsafe to operate.

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Intake Hoist Photographs

Photo 1: Intake hoist assembly	

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Intake Hoist Photographs

Photo 2: Hoist Drum	
Photo 3: Wire rope equalizer sheave	

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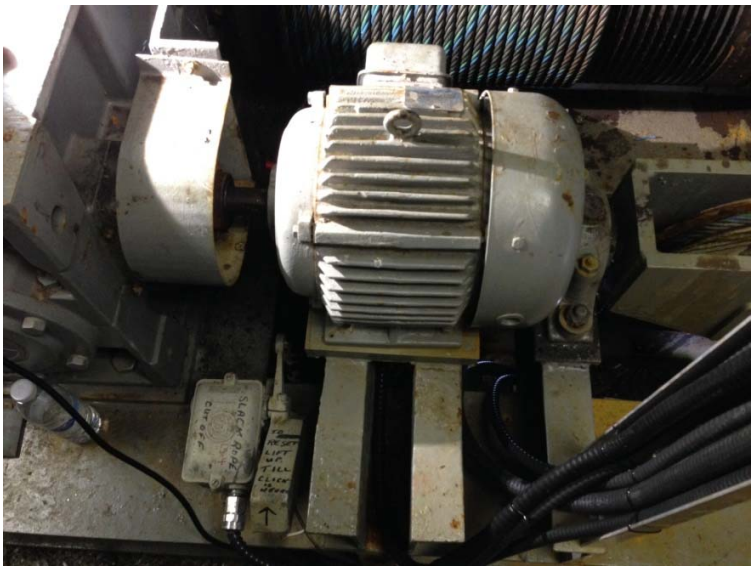
Intake Hoist Photographs

Photo 4: Hoist motor	
Photo 5: Hoist motor nameplate	

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Intake Hoist Photographs

Photo 6: Fan brake with damper fully closed	
Photo 7: Hoist speed reducer	

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Intake Hoist Photographs

Photo 8: Speed reducer nameplate

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Intake Hoist Photographs

Photo 9: Hoist brake	
Photo 10: Hoist enclosure electric heater	

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Intake Hoist Photographs

Photo 11: Downstream side of hoist superstructure	

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Intake Hoist Photographs

Photo 12: Upstream side of hoist superstructure	

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Intake Hoist Photographs

Photo 13: Missing bolt on cross brace	

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Condition Assessment Checklist

Vertical Lift Gate (1 of 6) Gate General			
Site Name	Wreck Cove T2 Intake		
Date of Inspection	August 20, 2016		
Weather	Cloudy/Light Rain 20°C		
Upstream Water Level	Not confirmed		
Description of Item	**Equipment Data/O&M Data and Year**		
Gate data **(record source if not seen on equipment)**	**Skinplate location (u/s, d/s):**	**Width:**	**Height:**
	Double Skinplate	13' net opening	13' net opening
H-085S1-2-628-00-001 H-085S1-9-625-00-047	**Side/bottom seals – type/material**	**Gate supplier:**	**Year installed:**
	J-type rubber (side) with flouro-carbon. Double stem rubber (lintel) with flouro-carbon Stainless steel (sill).	Marine Steel Foundaries Ltd.	Approximately 1977.
Operating problems reported (jamming, jerkiness, noisy, slow, vibration)	Very rarely operated – maybe 1x per year, and only if penstock (at Surge Lake intake) needs to be dewatered. Otherwise, no issues are known.		
Gate maintenance: - inspection frequency - year overhauled - overhaul details	Typically inspected 1x per year by Hercules (hoist only). Gate structure and superstructure not inspected regularly. Wire rope replaced recently (in past year). Annual NSPI inspection – pull up and look at rollers, sheaves, etc. Rubber seals never been replaced. Gate never been touched – controls recently replaced in last 3 years.		
Major repairs, modifications	Gain heaters and gate heaters failed and removed from service. (Reported to have failed ~ 25 years ago).		
Maintenance problems	Hold brake concerns with holding gate in the open position.		
Drawings/manuals-record location (site, office, both)	Drawings located in site office.		
Other	When tunnel closed last fall, tunnel partially drained, minimal leakage presumed on gate as there was no flow at D/S tunnel when closed.		

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Gate General Photographs

Photo 1: Downstream	

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Gate General Photographs

Photo 2: Upstream	

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Gate General Photographs

Photo 3: Upstream	

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Gate General Photographs

Photo 4: Gate Slot	
Photo 5: Gate Slot	

Rating	Condition Description	Details
1	Good	Only minor deterioration or defects are evident.
2	Fair	Moderate deterioration. Function is adequate.
3	Poor	Serious deterioration of at least some parts. Function is inadequate.
4	Unacceptable	Extensive deterioration. Barely functional. May be unsafe to operate.

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Vertical Lift Gate (2 of 6)
Gate Leaf

Site Name	Wreck Cove T2 Intake
Date of Inspection	August 20, 2016
Weather	Cloudy/Light Rain 20°C
Upstream Water Level	Not confirmed

Item	Rating	Reason for Rating
Skinplate	☐ 1 ☒ 2 ☐ 3 ☐ 4	Some paint system failure, and localized pitting on upstream and downstream skinplate surface
Main Girders	☐ 1 ☐ 2 ☐ 3 ☐ 4	Appears ½" plate webs Not visible – upstream and downstream skinplates fully enclose girders
Stiffeners and End Girders	☐ 1 ☐ 2 ☐ 3 ☒ 4	End girders show sever signs of cracking around wheel boxes
Gate Internal Steelwork	☐ 1 ☐ 2 ☐ 3 ☐ 4	Not visible
Bottom Lip	☐ 1 ☒ 2 ☐ 3 ☐ 4	Not visible (below deck)
Insulation and Cladding	☐ 1 ☐ 2 ☐ 3 ☐ 4	N/A
Bumpers	☐ 1 ☒ 2 ☐ 3 ☐ 4	Side bumpers show signs of corrosion on sliding surface. Unable to inspect sliding pivot surface. Lateral guide roller assemblies show signs of paint failure and minor corrosion, rollers in good condition.
Joints (Rivets, Welds and Bolts)	☐ 1 ☐ 2 ☒ 3 ☐ 4	Welds around wheel boxes are severely cracked.
Other	☐ 1 ☐ 2 ☐ 3 ☐ 4	

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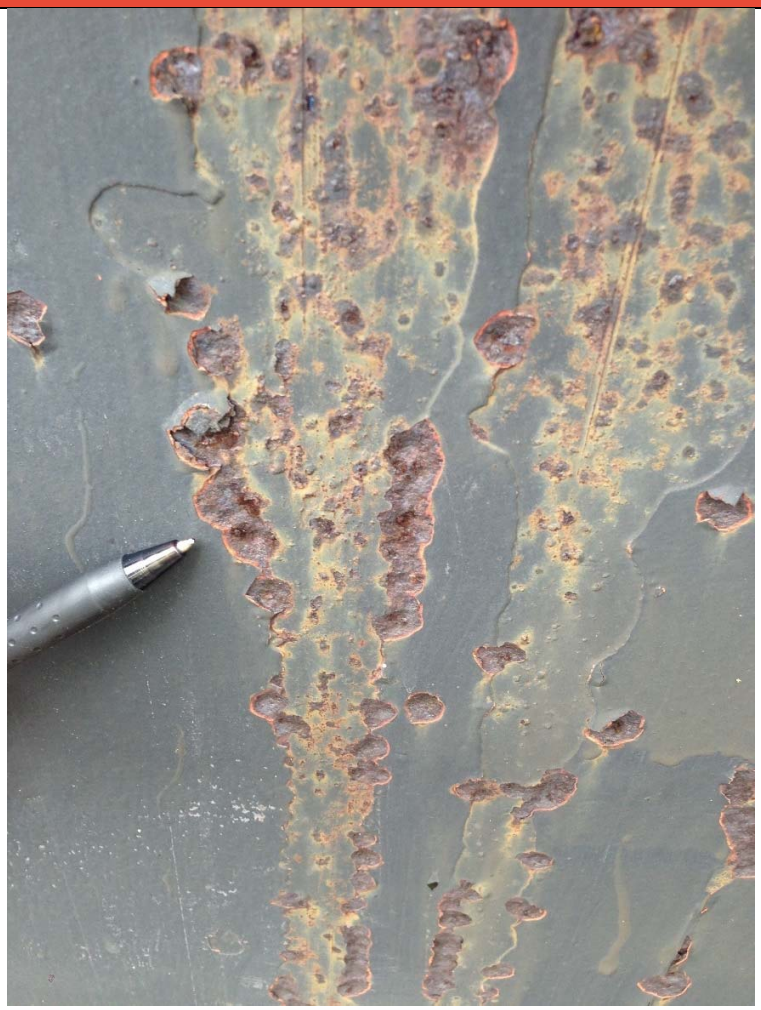
Gate Leaf Photographs

Photo 1: Skinplate paint failure and pitting	

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Gate Leaf Photographs

Photo 2: Side Bumper	

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Gate Leaf Photographs

Photo 3: Side Bumper	

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Gate Leaf Photographs

Photo 4: Side Rollers	

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Gate Leaf Photographs

Photo 5: Bottom Lip	

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Gate Leaf Photographs

Photo 6: Cracking on end beams around wheel boxes	

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Gate Leaf Photographs

Photo 7: Cracking on end beams around wheel boxes	

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Gate Leaf Photographs

Photo 8: Cracking on end beams around wheel boxes

Rating	Condition Description	Details
1	Good	Only minor deterioration or defects are evident.
2	Fair	Moderate deterioration. Function is adequate.
3	Poor	Serious deterioration of at least some parts. Function is inadequate.
4	Unacceptable	Extensive deterioration. Barely functional. May be unsafe to operate.

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Vertical Lift Gate (3 of 6)
Wheels and Rollers

Site Name:	Wreck Cove T2 Intake
Date of Inspection:	August 20, 2016
Weather:	Cloudy/Light Rain 20°C
Upstream Water Level:	Not confirmed
Number of Gate Wheels:	**4 per side**
Diameter:	**15”**

Item	Rating	Reason for Rating
Gate Wheels H-085S1-9-625-0047	☐ 1 ☒ 2 ☐ 3 ☐ 4	Eight rollers total, no reported issues. Corrosion on wheels. Roller ability to spin (view from D/S): • L1 (top): stiff to spin • L2: stiff to spin • L3: Okay • L4 (bottom): Okay • R1 (top): Okay • R2: Okay • R3: Okay • R4 (bottom): Okay. Wheel box welds cracked at connection with downstream skinplate
Axles, Bushings, Keeper Plates and Thrust Washers for Gate Wheels	☐ 1 ☒ 2 ☐ 3 ☐ 4	Keeper plates, and cover plates significantly corroded.
Side Guide Rollers	☐ 1 ☒ 2 ☐ 3 ☐ 4	Rollers appear in satisfactory condition. Minor paint failure and corrosion on support steel. Noted gaps on rollers during raise/lower (suspect some adjustment required).
Axles, Bushings, Keeper Plates and Thrust Washers for Side Guide Rollers	☐ 1 ☒ 2 ☐ 3 ☐ 4	Rollers rotating freely.
Other	☐ 1 ☐ 2 ☐ 3 ☐ 4	

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Wheels and Rollers Photographs

Photo 1: Corrosion on wheels, keeper plates and cover plates	

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Photo 2: Evidence of wheels sliding (not rotating freely). Cracks visible around wheel box welds	

Rating	Condition Description	Details
1	Good	Only minor deterioration or defects are evident.
2	Fair	Moderate deterioration. Function is adequate.
3	Poor	Serious deterioration of at least some parts. Function is inadequate.
4	Unacceptable	Extensive deterioration. Barely functional. May be unsafe to operate.

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Vertical Lift Gate (4 of 6)
Gate Seals, Seal Path and Roller Path

Site Name:	Wreck Cove T2 Intake
Date of Inspection:	August 20, 2016
Weather:	Cloudy/Light Rain 20°C
Upstream Water Level:	Not confirmed
Type of Seals:	**Huntington rubber seals / Stainless steel lintel**
Location of Side Seal:	**Downstream skinplate**

Item	Rating	Reason for Rating
Side Seals and Path H-085S1-9-625-00-047	☐ 1 ☐ 2 ☒ 3 ☐ 4	Seals material is deteriorating – minor tearing of fluoro-carbon film. Seal clamp bars corroded. Huntington No. 2314, with 0.08” thick fluoro-carbon film. Seal path 304 SS, 3/8” plate
Lintel Seal and Seal Path H-085S1-9-625-00-047	☐ 1 ☐ 2 ☒ 3 ☐ 4	Seals material is deteriorating – minor tearing of fluoro-carbon film. Seal clamp bars corroded. Huntington No. 2284 with 0.06” thick flouro-carbon film. Seal path 304 SS, 3/8” plate
Bottom Seal and Sill Beam	☐ 1 ☐ 2 ☐ 3 ☐ 4	Stainless steel seal – ½” plate Embedded beam with stainless steel top plate. Not visible during inspection
Roller Path and Gains	☐ 1 ☒ 2 ☐ 3 ☐ 4	Minor paint deterioration and corrosion visible above water level. Roller on 1” thick plate.

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Gate Seals, Seal Path and Roller Path Photographs

Photo 1: Minor damage on lintel seal and side seal	

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Photo 2: Lintel Seal	

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Photo 3: Side Seals	

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Photo 4: Roller path and gains	

Rating	Condition Description	Details
1	Good	Only minor deterioration or defects are evident.
2	Fair	Moderate deterioration. Function is adequate.
3	Poor	Serious deterioration of at least some parts. Function is inadequate.
4	Unacceptable	Extensive deterioration. Barely functional. May be unsafe to operate.

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Vertical Lift Gate (5 of 6)
Heaters and Miscellaneous

Site Name:	Wreck Cove T2 Intake
Date of Inspection:	August 20, 2016
Weather:	Cloudy/Light Rain 20°C
Upstream Water Level:	Not confirmed

Item	Rating	Reason for Rating
Gate Heaters H-085S1-2-628-00-001	☐ 1 ☐ 2 ☐ 3 ☒ 4	Heater tubes in gate all failed, and not operational. Heaters may still be in gate.
Gain Heaters	☐ 1 ☐ 2 ☐ 3 ☒ 4	3 gain heater conduits (1 U/S, 2 D/S), all failed and not operational. Appears air vent heaters (unsure if operational).
Gate Hoist Enclosure Heater	☐ 1 ☒ 2 ☐ 3 ☐ 4	Electric coil, ceiling mounted heater
Forebay Ice Prevention System (record type)	☐ 1 ☐ 2 ☒ 3 ☐ 4	Bubbler installed in 2010, but shortly after shut down. Intent was to prevent freezing in. Had some “piping” issues on dams on Surge Lake (need gate to dewater Surge Lake). Reported that gate froze in place in approx. 2006/07. Gate could not move, wire rope came off drum, some slack in rope, left site, gate slipped on brake and gate closed remaining of way and Surge Lake drained until head pond alarm.

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Heaters and Miscellaneous Photographs

Photo 1: Gate hoist enclosure heater	
Photo 2: Gain heater slots	

Rating	Condition Description	Details
1	Good	Only minor deterioration or defects are evident.
2	Fair	Moderate deterioration. Function is adequate.
3	Poor	Serious deterioration of at least some parts. Function is inadequate.
4	Unacceptable	Extensive deterioration. Barely functional. May be unsafe to operate.

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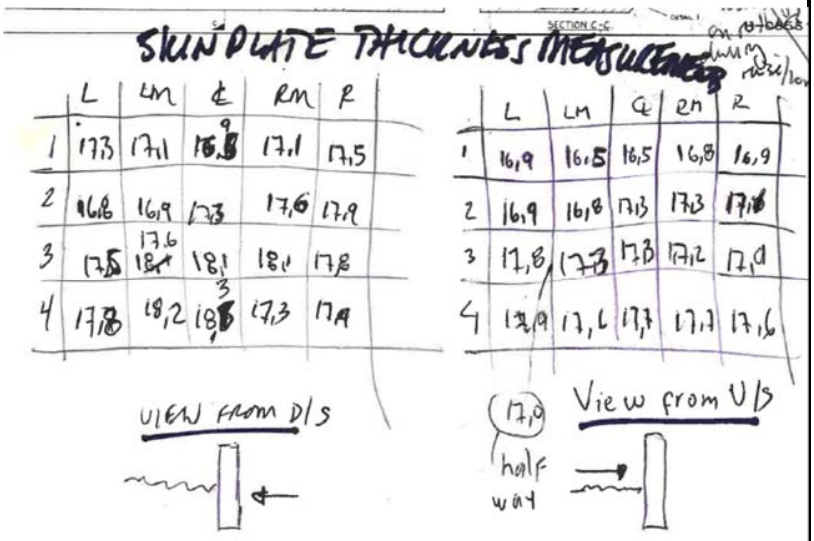
Nova Scotia Power Inc.
Wreck Cover - Assessment and Improvements
H351728

Engineering Checklist
Mechanical Engineering
Condition Assessment Checklist

Vertical Lift Gate (6 of 6)
Additional Info

Additional information (Test results, Photographs, Notes, Sketches, etc)	Typically, gate is opened approx. 4" – 6" to start tunnel rewater. Wait 15 to 20 mins and continue opening. 1145 cfs at full head (34.2 cms). Head pond pressure transducer moved over to 24" drain valve on D11 (on Surge Lake). Moved away from gate. Wreck Cove Lake is at Gate house. Microwave from here to Ragged Lake (is ECC). **Skinplate Thickness Measurements** L = Left; LM = Left Middle; CL = centerline; RM = right middle; R = right. 1 = Upper Roller, 2 = 2nd Roller, 3 = 3rd Roller, 4 = Bottom Roller. 

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Condition Assessment Checklist

Condition Assessment Checklist		
Site Name	Wreck Cove Control Structure T2 Intake Gate	
Date of Inspection	August 20, 2016	
Weather	Cloudy/Light Rain 20°C	
Equipment Cubicles, Enclosure Building Identification		
Item	**Rating**	**Reason for Rating**
Component Labelling	☐ 1 ☒ 2 ☐ 3 ☐ 4	In general most of the components/ devices have handwritten identification. Labels missing for 600 & 220/120 VAC Distribution Panels
Nameplate	☐ 1 ☒ 2 ☐ 3 ☐ 4	No nameplate found for the hoist building and distribution panels
Cleanliness, External Damage	☐ 1 ☐ 2 ☐ 3 ☒ 4	Hoist building roof is leaking. A thorough cleanup is required in the building
Connections, Mounting	☒ 1 ☒ 2 ☐ 3 ☐ 4	In general electrical panels are properly secured and mounted
Evidence of Overheated or Damaged Components	☒ 1 ☐ 2 ☐ 3 ☐ 4	No damaged reported for electrical equipment
Moisture Entry, Corrosion	☐ 1 ☐ 2 ☐ 3 ☒ 4	Hoist building roof leaking
Protective Devices, Fusing	☒ 1 ☐ 2 ☐ 3 ☐ 4	Gate/hoist motor control panel modernized in 2012. Rotating limit switch was replaced but box is opened and cut cables exposed.
Heaters	☐ 1 ☐ 2 ☐ 3 ☒ 4	O&M personnel suspect that heater for hoist building is not working due to roof water leakage.
Lighting	☐ 1 ☐ 2 ☐ 3 ☒ 4	Enough fluorescent lamps installed but few working.
Security/Locks	☒ 1 ☐ 2 ☐ 3 ☐ 4	Building is properly secured with locks
Spares	☐ 1 ☐ 2 ☐ 3 ☒ 4	O&M personnel reported that no spares are available.
Voice Communications	☐ 1 ☐ 2 ☐ 3 ☒ 4	No phone available
Drawings and Manuals	☐ 1 ☐ 2 ☐ 3 ☐ 4	TBC

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Condition Assessment Checklist

Additional information	1) All the building structure grounds have been deliberately removed by vandalism. 2) RTU installed for remote communication. According to handwritten notes in the RTU the following signals are available: gate open limit, gate close limit, gate trouble alarm, intrusion alarm, gate local control, gate raise, gate lower and gate stop. O&M reported that the gate is only operated locally and no remote control is functioning. Need to confirm which remote supervision is actually working. 3) Pressure transducer installed for reservoir water level measurement. Need to confirm how this signal is reported to powerhouse/ECC 4) According to sticker on 600VAC DP, the last inspection of the hoist was performed by the company Atlantic in May/2009.

Rating	Condition Description	Details
1	Good	Only minor deterioration or defects are evident.
2	Fair	Moderate deterioration. Function is adequate.
3	Poor	Serious deterioration of at least some parts. Function is inadequate.
4	Unacceptable	Extensive deterioration. Barely functional. May be unsafe to operate.

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Intake Building/Equipment Photographs

Photo 1: Intake hoist building	
Photo 2: Intake Distribution Panels and Gate Control Panel	

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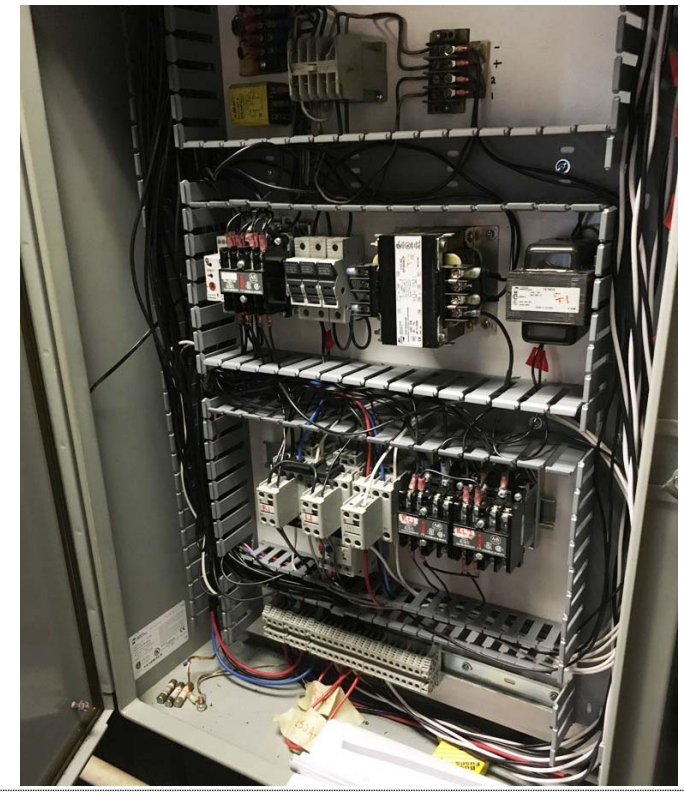
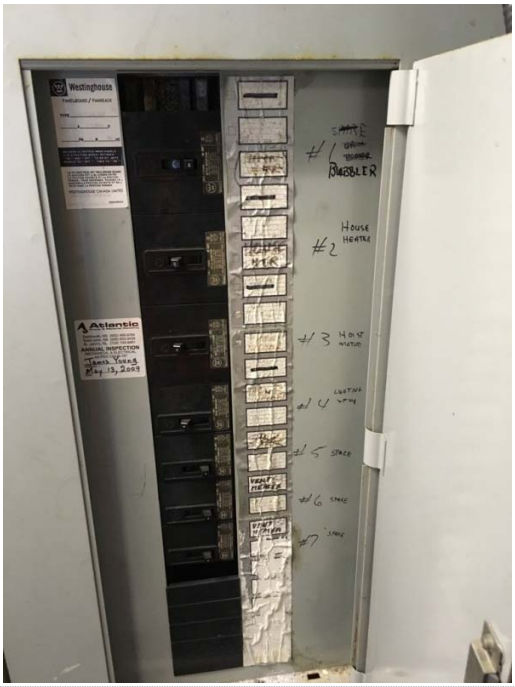
Photo 3: Internal view Gate Control Panel	
Photo 4: 600 VAC Gate Distribution Panel	

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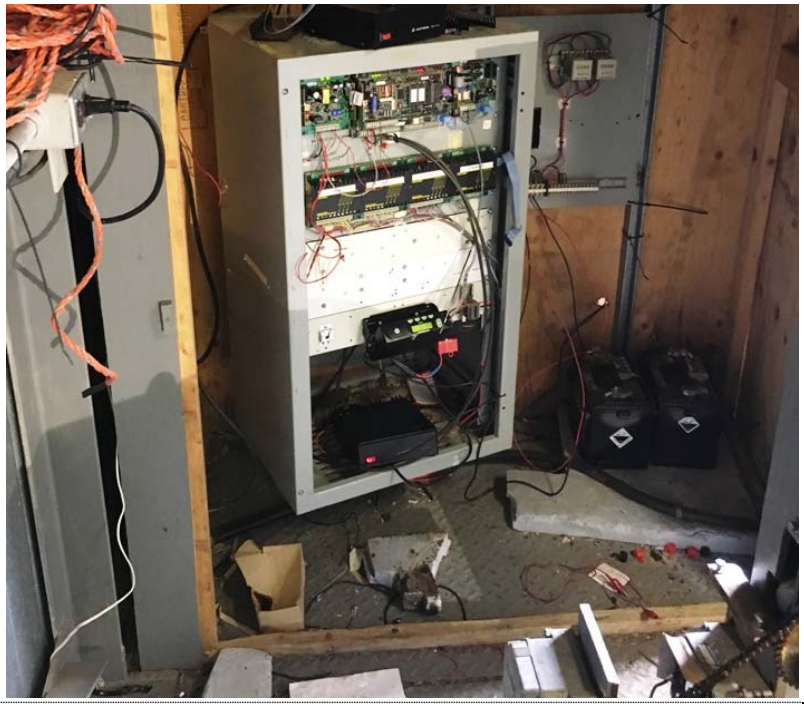
Photo 5: Intake RTU for remote monitoring	
Photo 6: Ground deliberately removed in all hoist structure columns	

Ver: 04.02

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Photo 7: Embedded tail for bonding to ground intake equipment deliberately cut	
Photo 8:Heater for hoist building presumably not working due to roof water leakage	

Ver: 04.02

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Photo 9: Lighting in hoist building. Several lamps not working	
Photo 10: Last inspection of intake equipment in May/2009	

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Intake and Spillway Gate Hoist Condition Assessment Checklist

Site Name	Wreck Cove Control Structure T2 Intake Gate
Date of Inspection	August 20, 2016
Weather	Cloudy/Light Rain 20°C

Motor, Brake, Gearbox Heater Identification

Item	Rating	Reason for Rating
Component Label, Nameplates	☐ 1 ☒ 2 ☐ 3 ☐ 4	Nameplate for motor and brakes covered with paint
Cleanliness, External Damage	☐ 1 ☐ 2 ☐ 3 ☒ 4	Cleanup is required, rust found in fan brake
Connections, Mounting	☒ 1 ☐ 2 ☐ 3 ☐ 4	No issues found/reported
Evidence of Overheating or Damaged Components	☒ 1 ☐ 2 ☐ 3 ☐ 4	No issues found/reported
Moisture Entry, Corrosion	☐ 1 ☐ 2 ☐ 3 ☒ 4	Hoist building roof leaking, corrosion in fan brake
Motor (check for unusual noises, vibration)	☒ 1 ☐ 2 ☐ 3 ☐ 4	Motor operation is normal. Motor current measurement could not be taken
Motor Heater	☐ 1 ☐ 2 ☐ 3 ☐ 4	(N/A)
Gearbox Heater	☐ 1 ☐ 2 ☐ 3 ☐ 4	(N/A)
Break Solenoid	☒ 1 ☐ 2 ☐ 3 ☐ 4	No issues found/reported
Drawings and Manuals	☐ 1 ☐ 2 ☐ 3 ☐ 4	
Additional information		

Rating	Condition Description	Details
1	Good	Only minor deterioration or defects are evident.
2	Fair	Moderate deterioration. Function is adequate.
3	Poor	Serious deterioration of at least some parts. Function is inadequate.
4	Unacceptable	Extensive deterioration. Barely functional. May be unsafe to operate.

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Hoist Motor & Brake Photographs

Photo 11: Motor hoist nameplate	
Photo 12: Solenoid for gate brake	

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Intake and Spillway Gate Hoist Condition Assessment Checklist

Site Name	Wreck Cove Control Structure T2 Intake Gate
Date of Inspection	August 20, 2016
Weather	Cloudy/Light Rain 20°C

Cable Identification

Item	Rating	Reason for Rating
Armoured Cable		
Corrosion	☒ 1 ☐ 2 ☐ 3 ☐ 4	No issues found/reported. Teck cables installed in hoist building recently for gate controls
Signs of deterioration	☒ 1 ☐ 2 ☐ 3 ☐ 4	No issues found/reported.
Clamps are secure	☒ 1 ☐ 2 ☐ 3 ☐ 4	No issues found/reported.
Cleanlines-potheads and terminators	☒ 1 ☐ 2 ☐ 3 ☐ 4	No issues found/reported.
Signs of distortion from cold flow or overheating	☒ 1 ☐ 2 ☐ 3 ☐ 4	No issues found/reported.
Thermoplastic Covered Cable		
Cleanliness-freedom from excessive dirt and moisture, drain holes clear	☐ 1 ☐ 2 ☐ 3 ☒ 4	Cables at deck label for pressure transducer and gate docking position limit switch are not protected with conduits. Refer to pictures
Sheath-if multi-conductor and shielded, check that shield is grounded	☐ 1 ☐ 2 ☐ 3 ☐ 4	Not verified
Additional information	1) All cables for gate and gain heaters have been removed 2) All cables without identification labels	

Rating	Condition Description	Details
1	Good	Only minor deterioration or defects are evident.
2	Fair	Moderate deterioration. Function is adequate.
3	Poor	Serious deterioration of at least some parts. Function is inadequate.
4	Unacceptable	Extensive deterioration. Barely functional. May be unsafe to operate.

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Intake Cables Photographs

Photo 13: Cables for gain and gate heaters cut	
Photo 14: Cables for gain and gate heaters cut	

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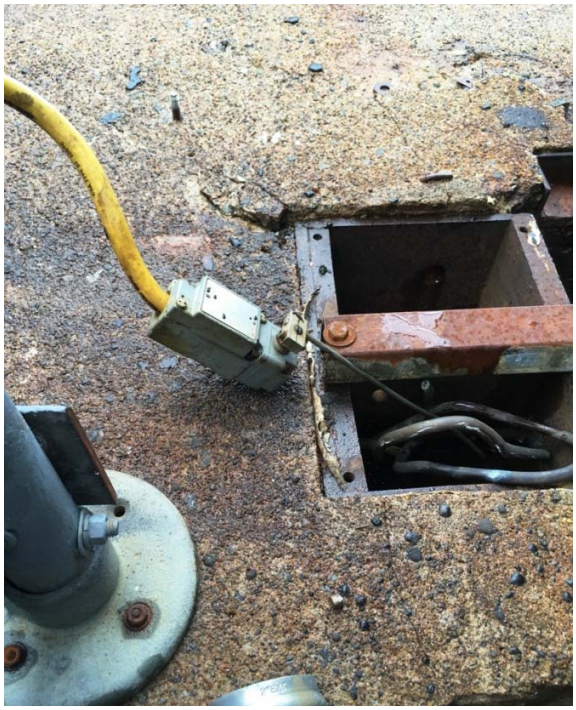
Photo 15: Cable for water level transducer not properly installed and protected	
Photo 16: Cable for gate dogging position not protected	

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Intake and Spillway Gate Hoist Condition Assessment Checklist

Site Name	Wreck Cove Control Structure T2 Intake Gate
Date of Inspection	August 20, 2016
Weather	Cloudy/Light Rain 20°C

Overhead Line Identification

Item	Rating	Reason for Rating
Conductor Sag and Condition	☒ 1 ☐ 2 ☐ 3 ☐ 4	No issues found/reported.
Guy Wires and Anchors	☒ 1 ☐ 2 ☐ 3 ☐ 4	No issues found/reported.
Supporting Members (poles, etc)	☒ 1 ☐ 2 ☐ 3 ☐ 4	No issues found/reported.
Insulators	☒ 1 ☐ 2 ☐ 3 ☐ 4	No issues found/reported.
Fuses	☒ 1 ☐ 2 ☐ 3 ☐ 4	No issues found/reported.
Other – Pole-mounted Devices/Equipment/Hardware (describe)	☒ 1 ☐ 2 ☐ 3 ☐ 4	No issues found/reported.
Encroachment of Vegetation	☒ 1 ☐ 2 ☐ 3 ☐ 4	No issues found/reported.
Security or routing	☒ 1 ☐ 2 ☐ 3 ☐ 4	No issues found/reported.
Additional information	1) Power supply to intake gate is taken from a 25kV transmission line that runs from the Wreck Cove switchyard parallel to the access road to the Intake area. At the end of the transmission line a 3 single phase transformer bank is installed. The line and transformer bank is not under the jurisdiction of Wreck Cove GS staff. 2) It is suspected that one or two of the transformers were changed since they are not similar. 3) Low voltage cables from the transformer bank seems to have the cable jacket frayed. Refer to picture 18 below. 4) Emergency power supply not available for gate operation.	

Rating	Condition Description	Details
1	Good	Only minor deterioration or defects are evident.
2	Fair	Moderate deterioration. Function is adequate.
3	Poor	Serious deterioration of at least some parts. Function is inadequate.
4	Unacceptable	Extensive deterioration. Barely functional. May be unsafe to operate.

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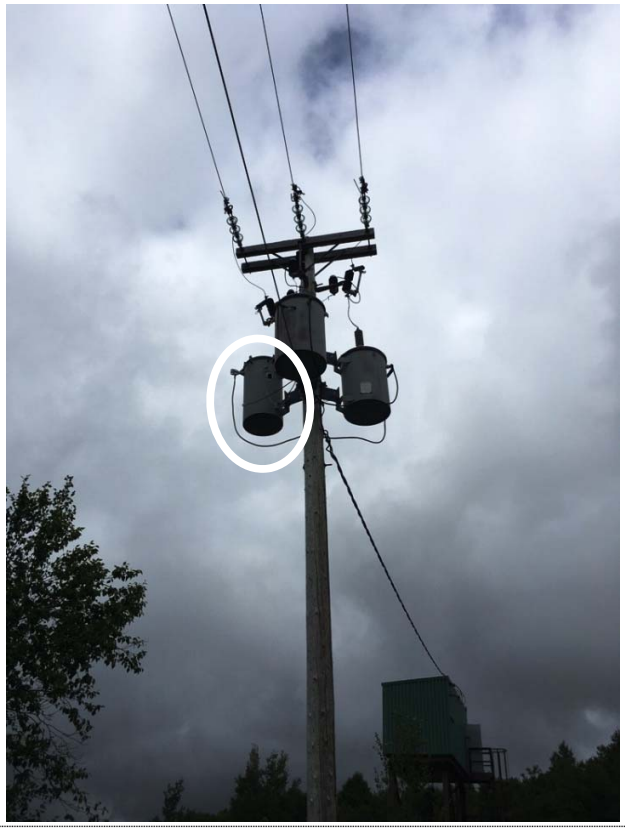
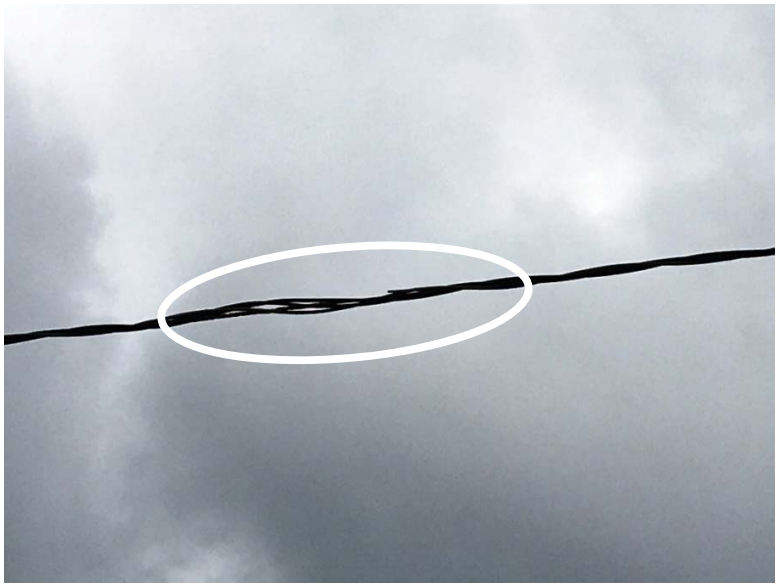
Intake Power Supply Photographs

Photo 17: Transformer bank for intake power supply. Note transformers that probably was changed	
Photo 18: Low voltage cables from transformer with frayed jacket	

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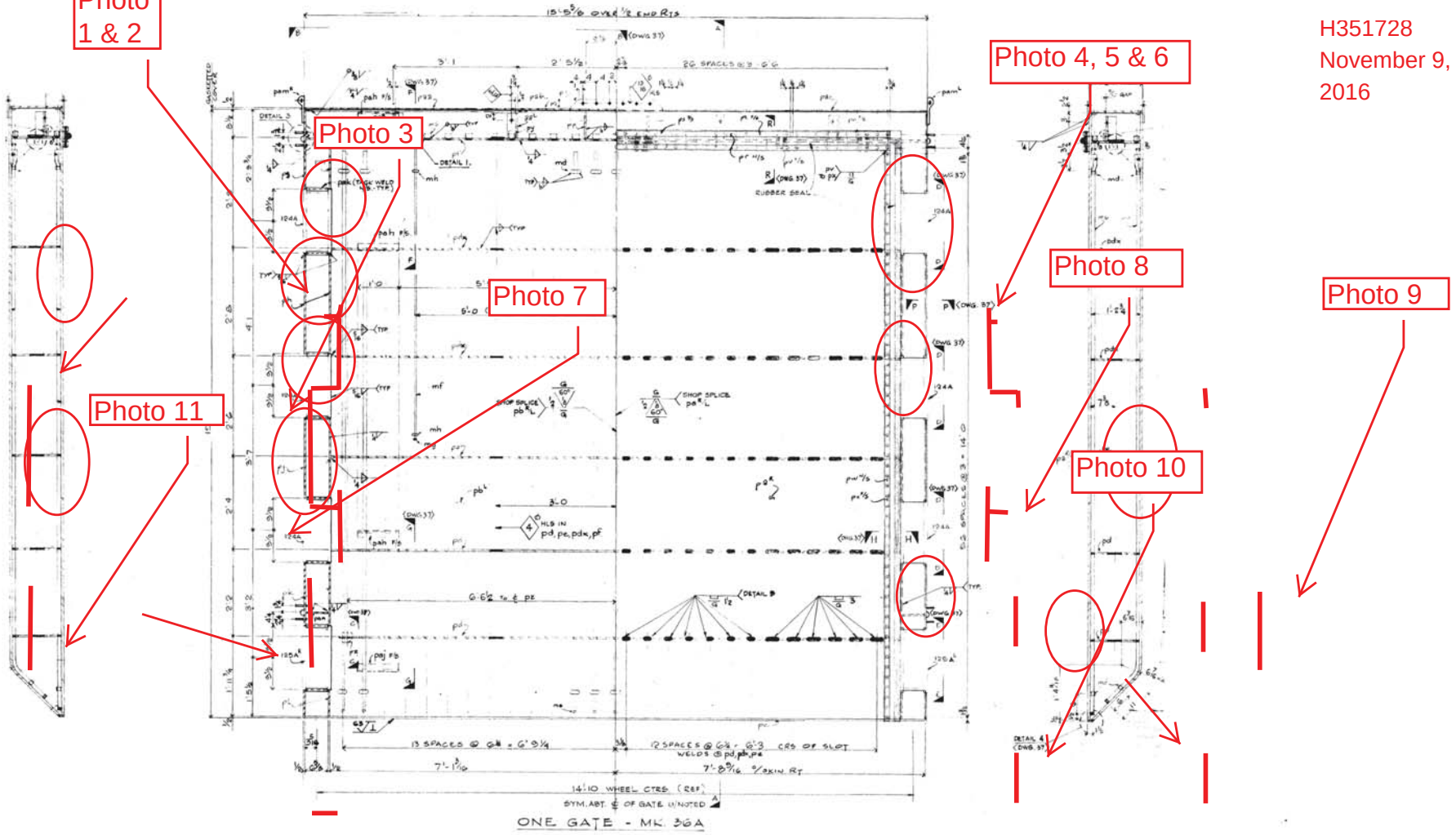
Appendix B
Gate Crack Mapping

Wreck Cove T2 Intake Gate - Mapping of Cracks
(based on inspections by Hatch in Aug and Nov 2016)



H351728
November 9, 2016

Photo 1

Photo 2

Photo 3

Photo 4

Photo 5

Photo 6

Photo 7

Photo 8
Potential Cracking

Photo 9

Photo 10

Photo 11

Appendix C
Hercules Hoist Inspection

HERCULES SLR inc
INSPECTION & TRAINING DIVISION
520 WINDMILL ROAD, DARTMOUTH, NOVA SCOTIA, B3B 1B3
PHONE: 902-482-3120 FAX: 902-482-3030

Nova Scotia Power
42338 Cabot Trail
Wreck Cove, Nova Scotia, B0C1H0

November 17, 2016

Attention: Ray Sampson

Reference: Inspection of Wreck Cove, T2 Inlet

Ray/Paul,

Please see our technician's findings below from the inspection at Wreck Cove T2 Inlet on Oct 31 2016

In order for this unit to be certified this year the following issues would need to be addressed:

1) Main rotary upper limit is not setup
2) Secondary rotary upper limit is completely disconnected (not hooked up)
3) Secondary limit installed by NSP at the gate (gate comes up and hits limit arm) is not functional
4) Extreme upper limit is not working

The slack rope switch was adjusted at time of inspection.

As a follow up to our conversation about long term use vs a complete replacement we would also recommend that at minimum the unit is completely rewired with a new brake drum and assembly installed, replacement of sheaves and bearings (complete with block heaters), and a load limiter installed. (Based on available parts) Although we feel this unit is mechanical sound, we recommend a discussion with the manufacturer to determine availability of parts and if any parts are obsolete.

It's also worth noting that our tech was informed onsite that the gate was cracked and can fill up with water. Please advise that this could cause the hoist/brake to be overloaded if the assumed weight is much higher than anticipated.

Yours truly,

James Jardine
Crane Service Coordinator

Appendix D
Gates Stress Analysis (FEA)

D.1 FEA Model Setup

Graphical representations of the FEA model definition as described in Section 4.2.1 are presented in this section.

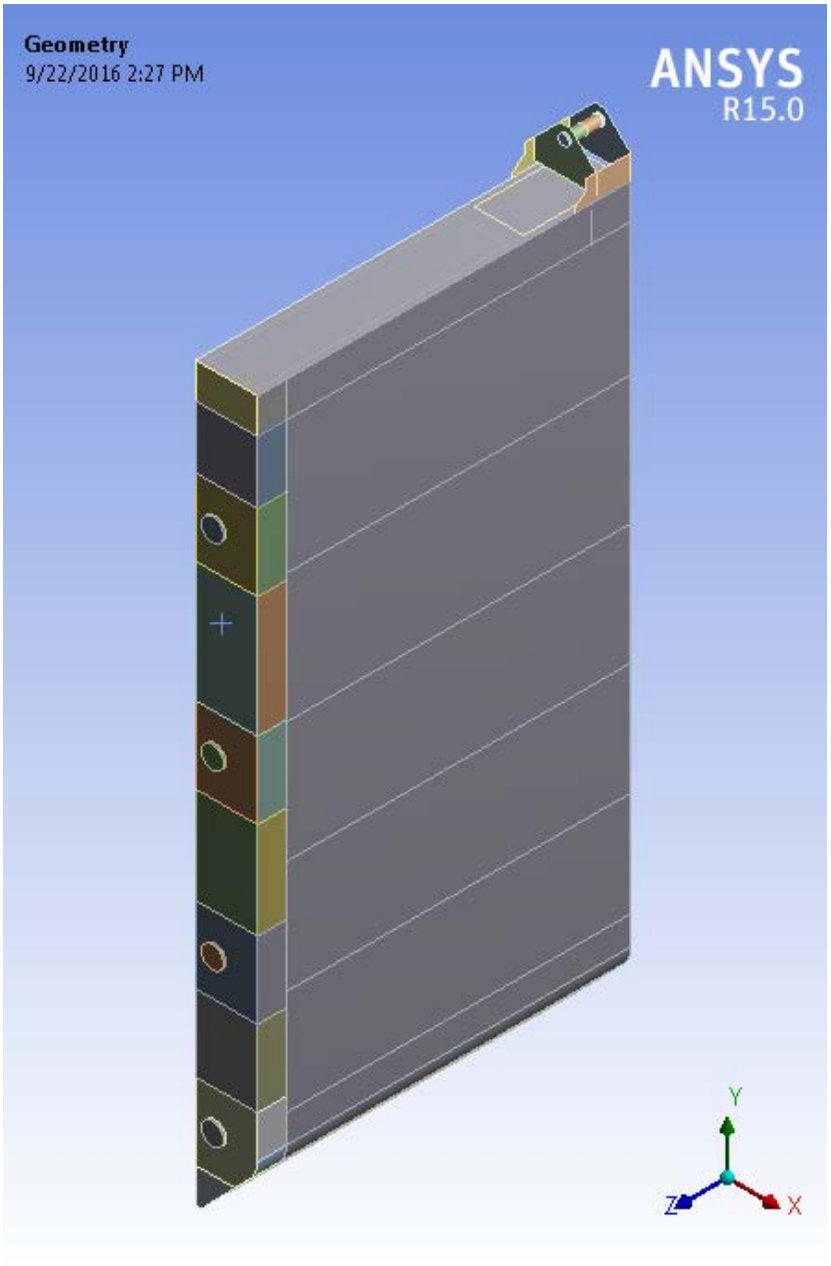
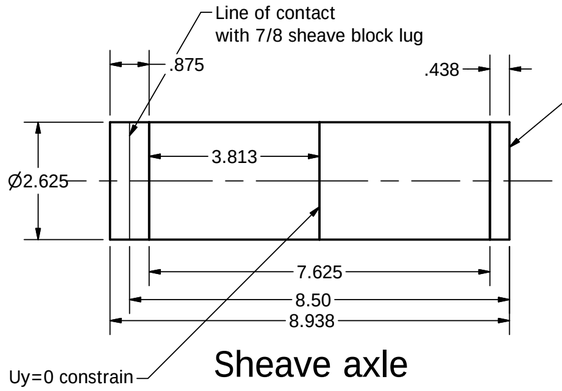


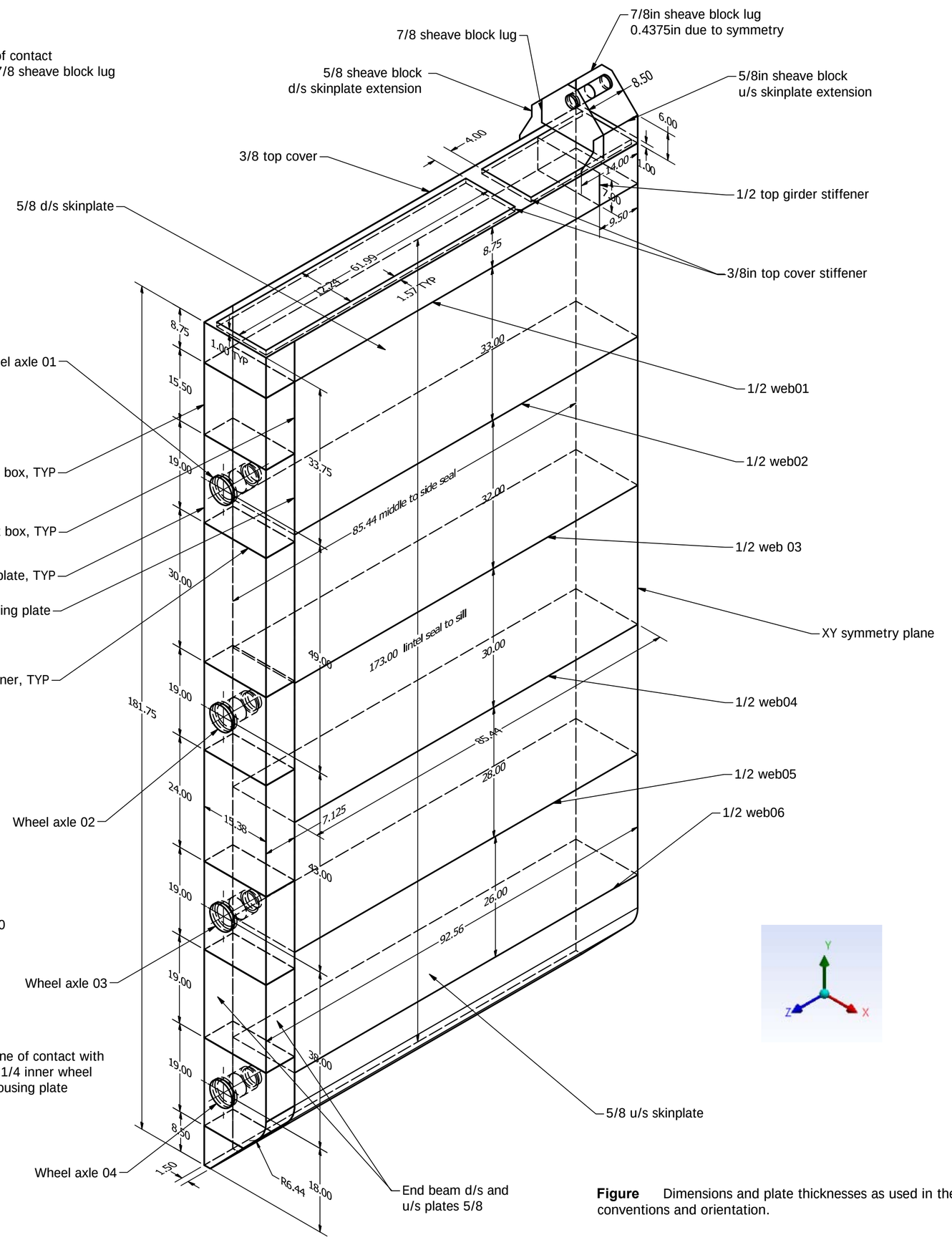
Figure D1: Intake Gate Finite Element Model

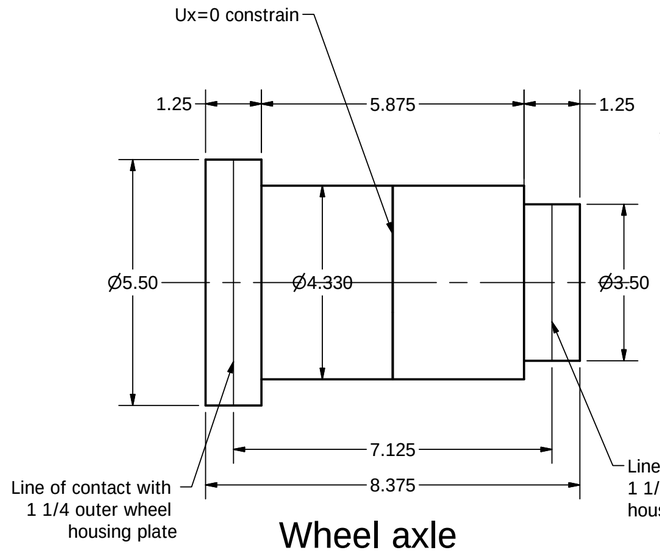
Due to symmetry, only half of the gate was modeled.



Sheave axle

All dimensions and plate thicknesses in inches





Wheel axle

Figure Dimensions and plate thicknesses as used in the FEA model. Name conventions and orientation.

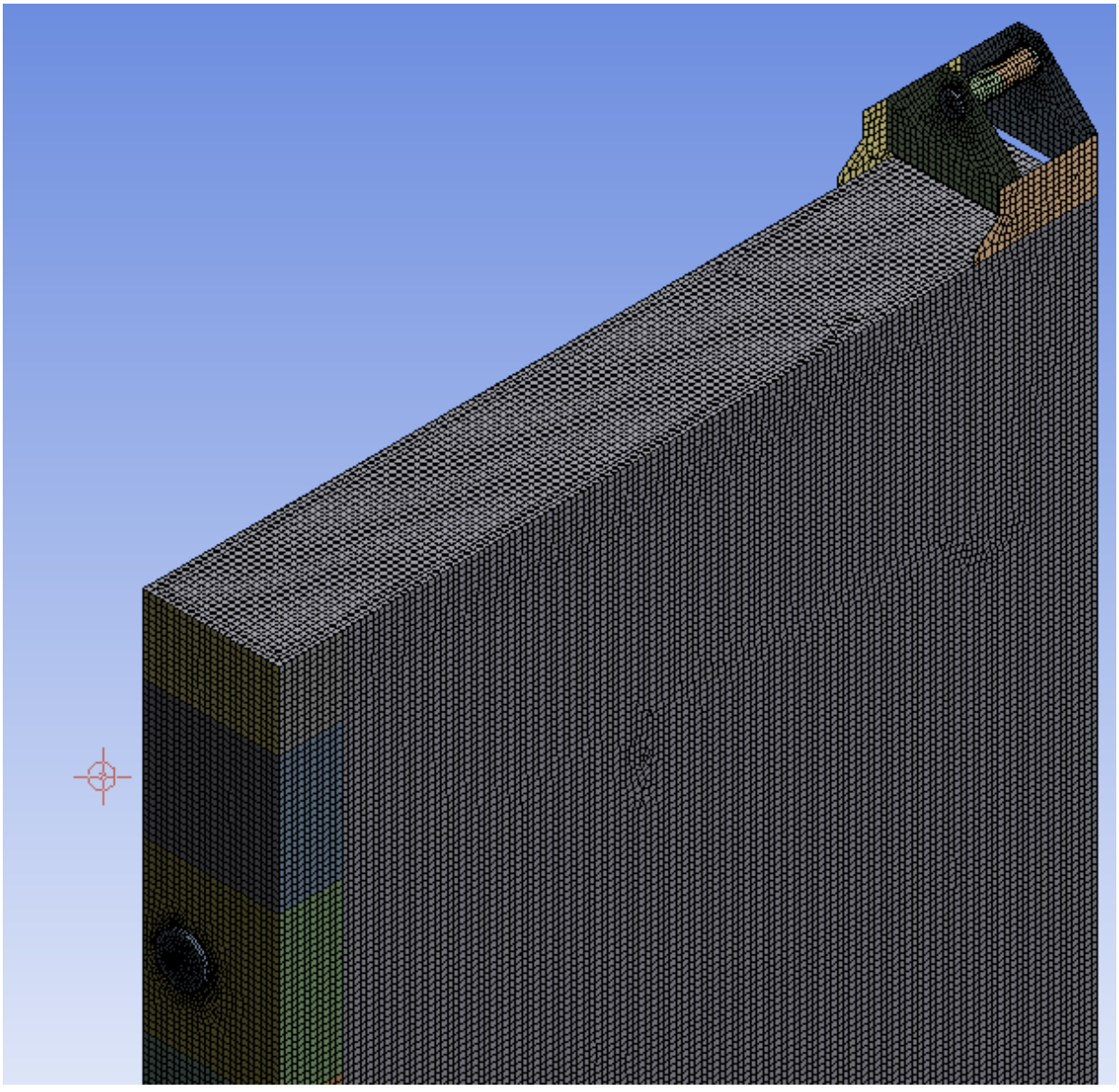


Figure D3: Finite Element Model Mesh

The gate plates were meshed with 4-node SHELL181 elements. The axles were meshed with 8-node SOLID185 hexahedron elements.

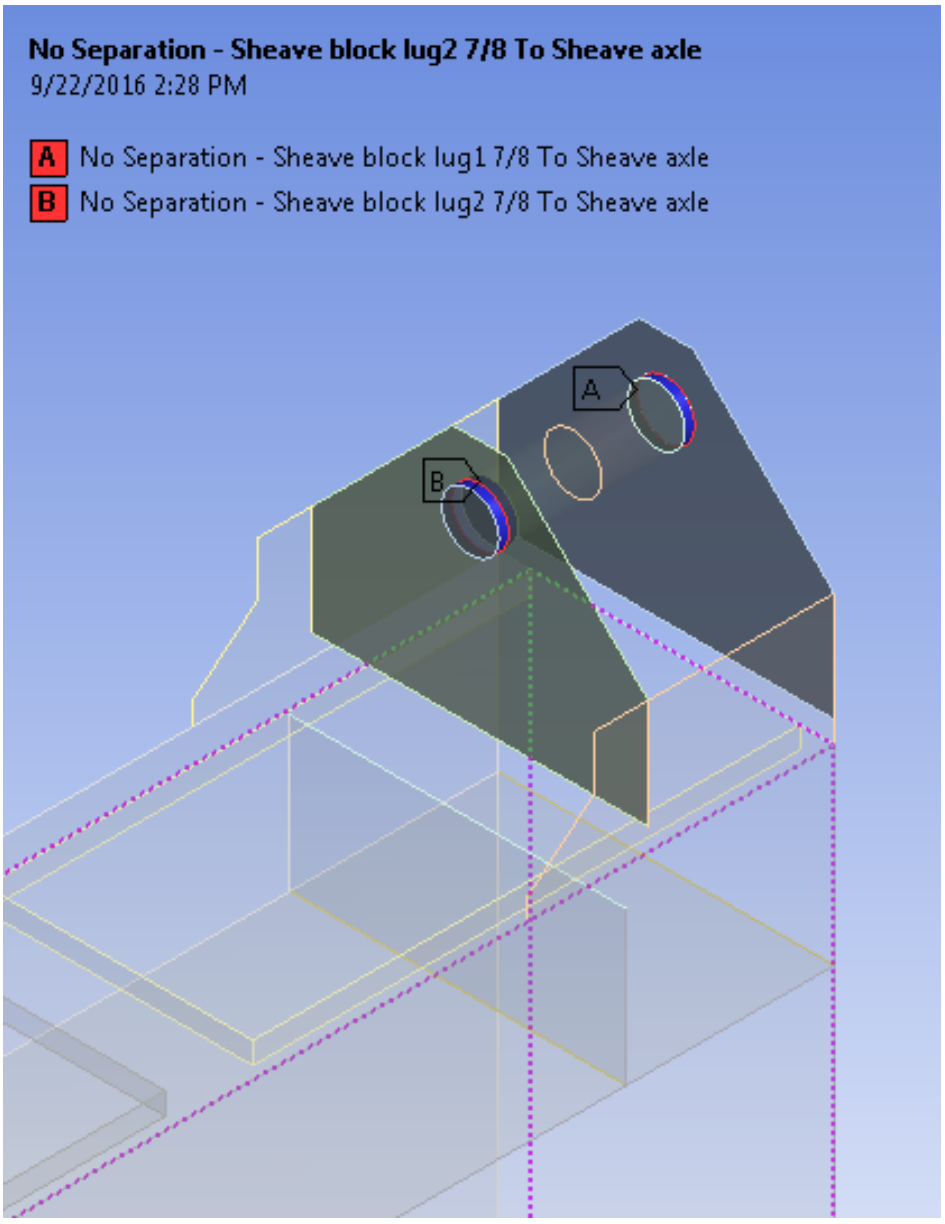


Figure D4: Contact Model Between Sheave Block Lugs and the Sheave Axle

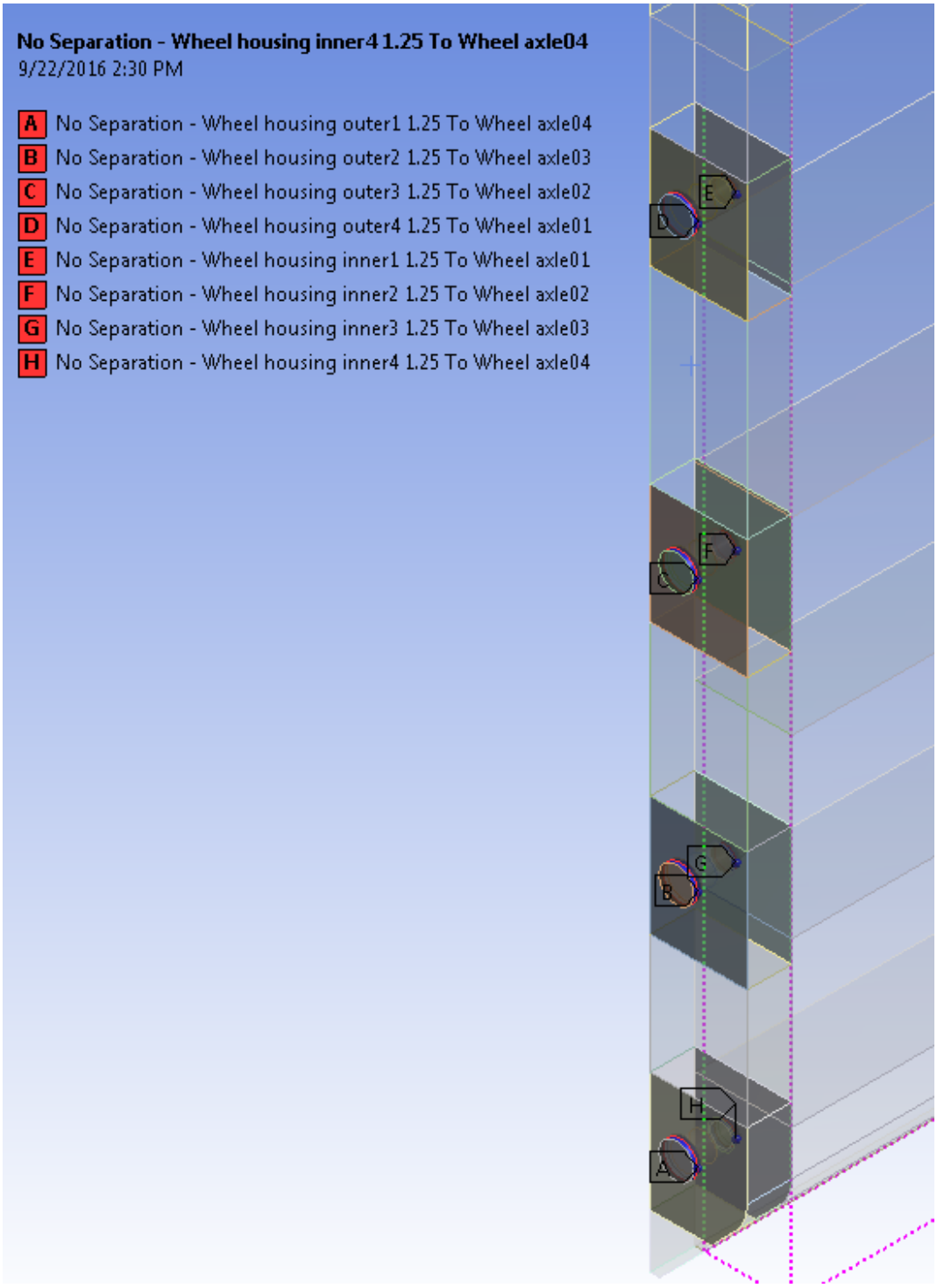


Figure D5: Contact Model Between the Wheel Housing End Plates and Wheel Axles

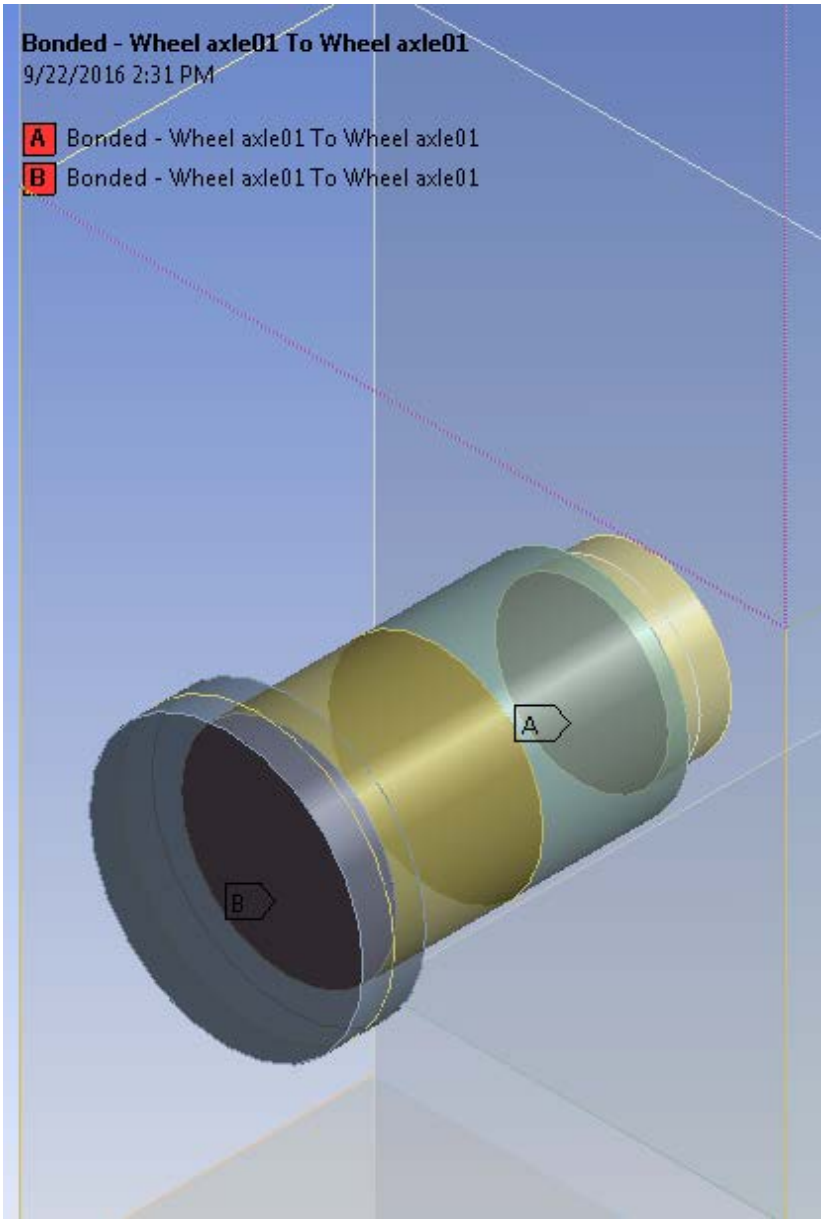


Figure D6: Bonded Contacts in the Wheel Axles to Join Between Different Diameters

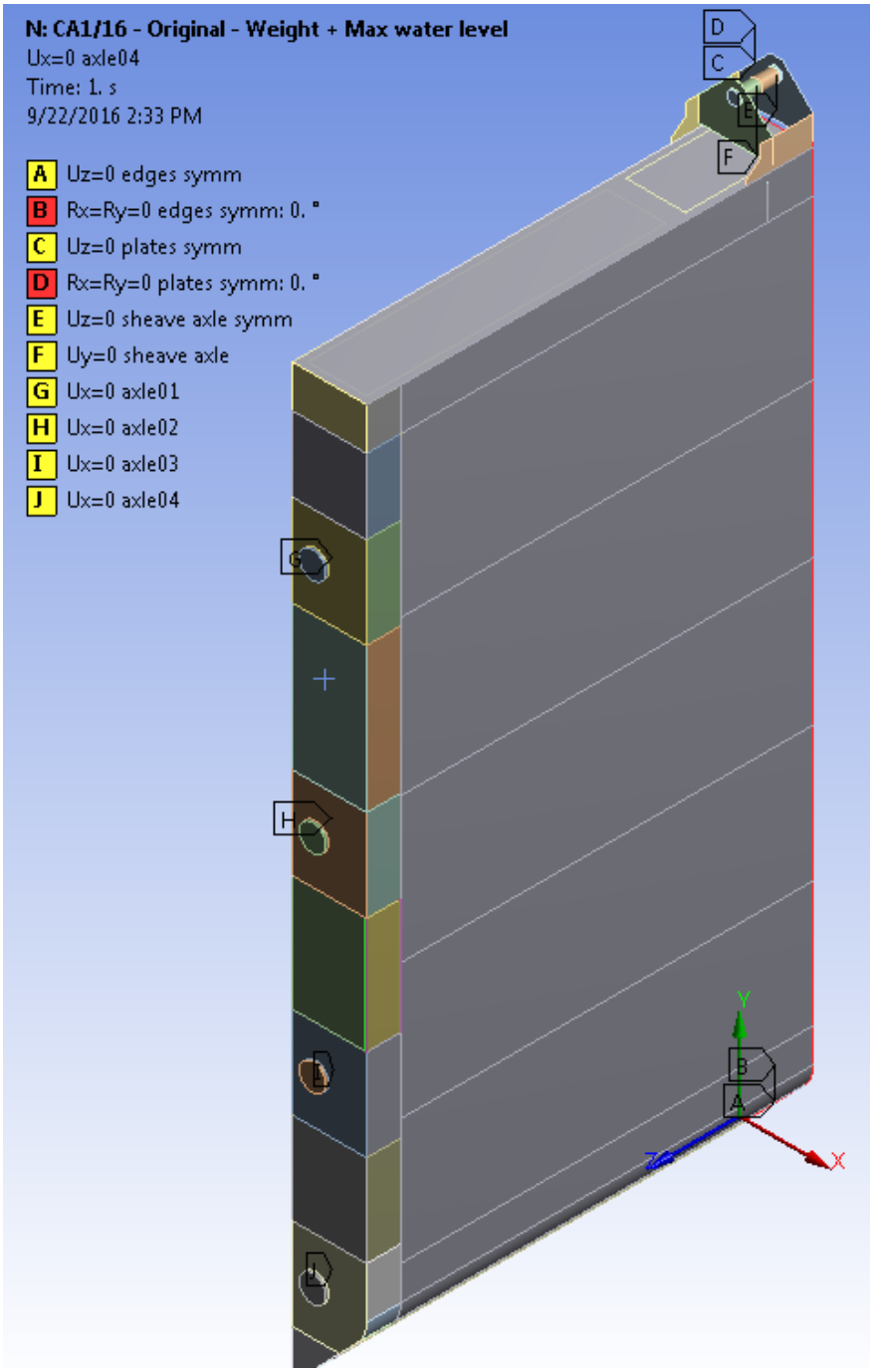


Figure D7: Boundary Conditions

Ux = 0 in the middle of wheel axles. Uy = 0 in the quarter distance of sheave axle. Uz = 0 and Rx = Ry = 0 in the middle of the gate (symmetry plane boundary conditions).

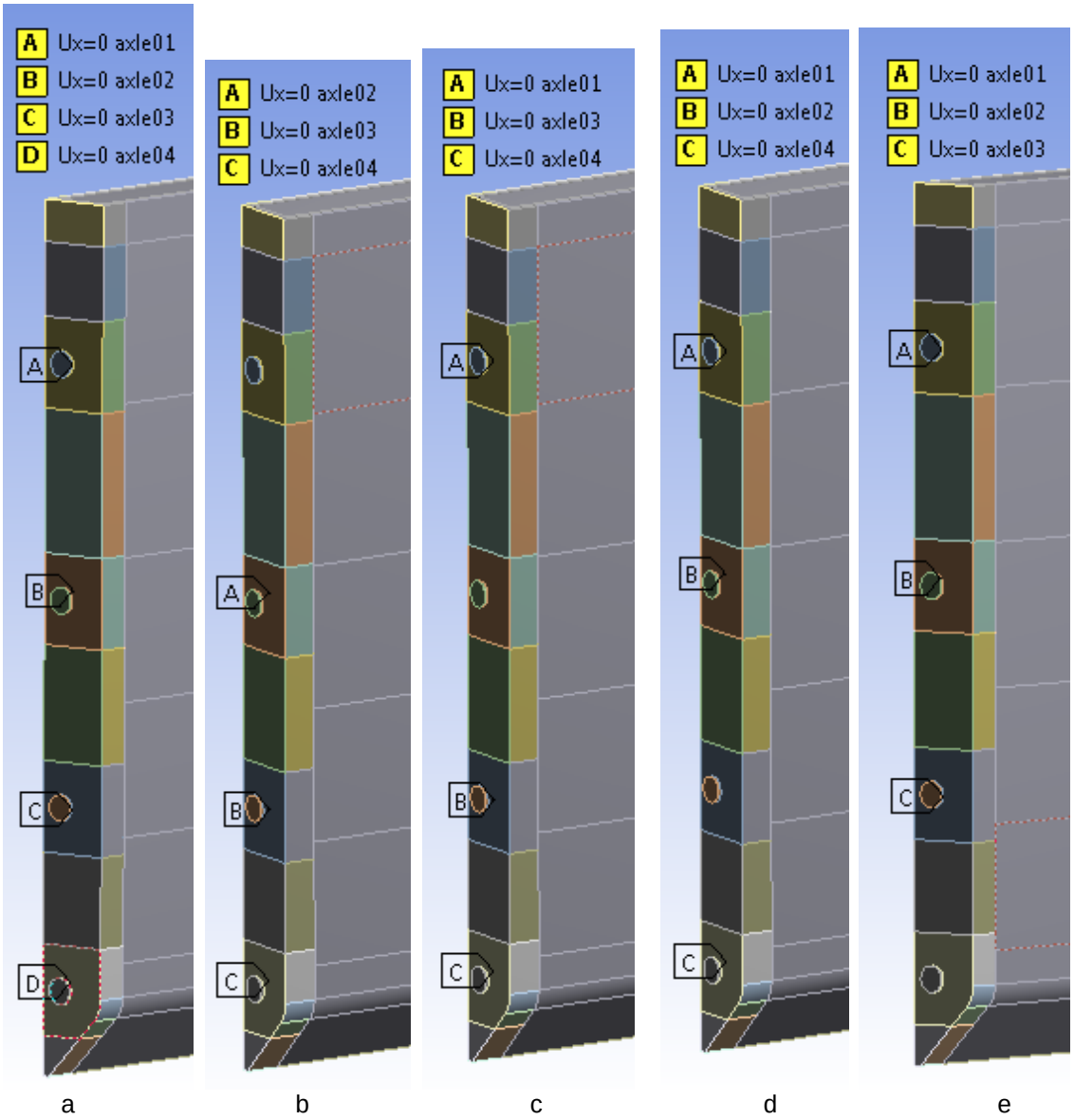


Figure D8: Wheel Axle Constrains to Simulate No-Contacting Wheel

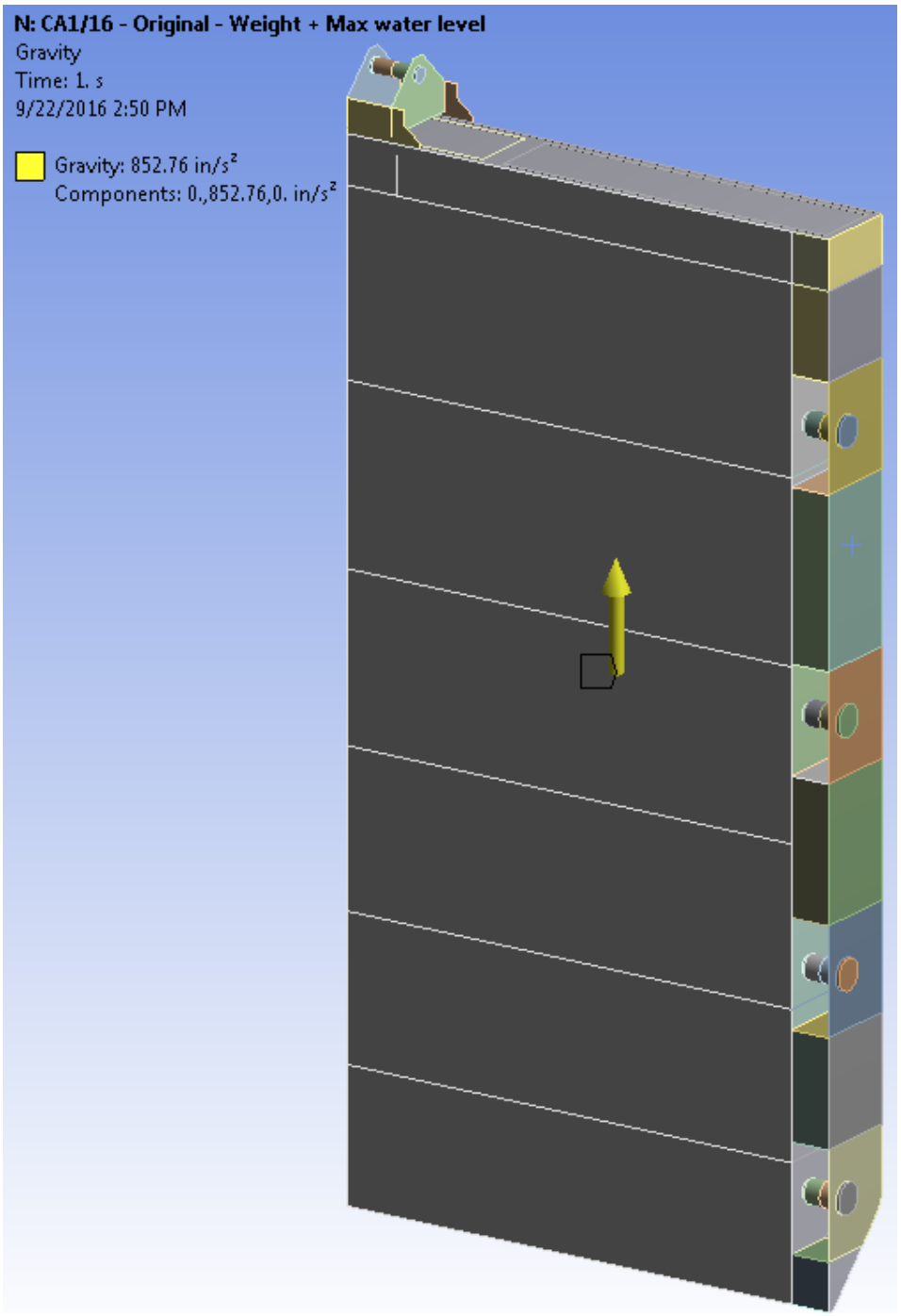


Figure D9: Gravity Load (D)

2.256*g was applied on the gate to match the 35,000 lbf weight specified on Drawing H08551-9625-00-081 to make up for the concrete ballast and corrosion allowance.

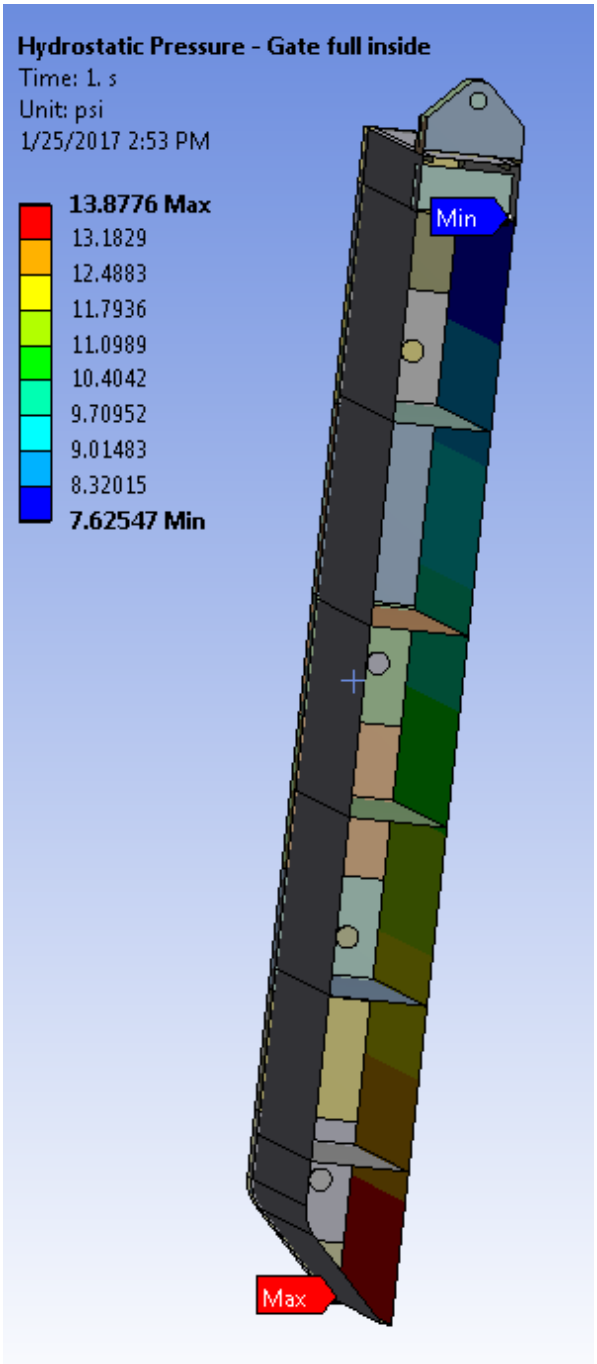


Figure D10: Hydrostatic Pressure (H) with Water Inside the Gate

D.2 FEA Results

Graphical representations of the FEA results presented in Error! Reference source not found. for the various loading scenarios are presented in this section.

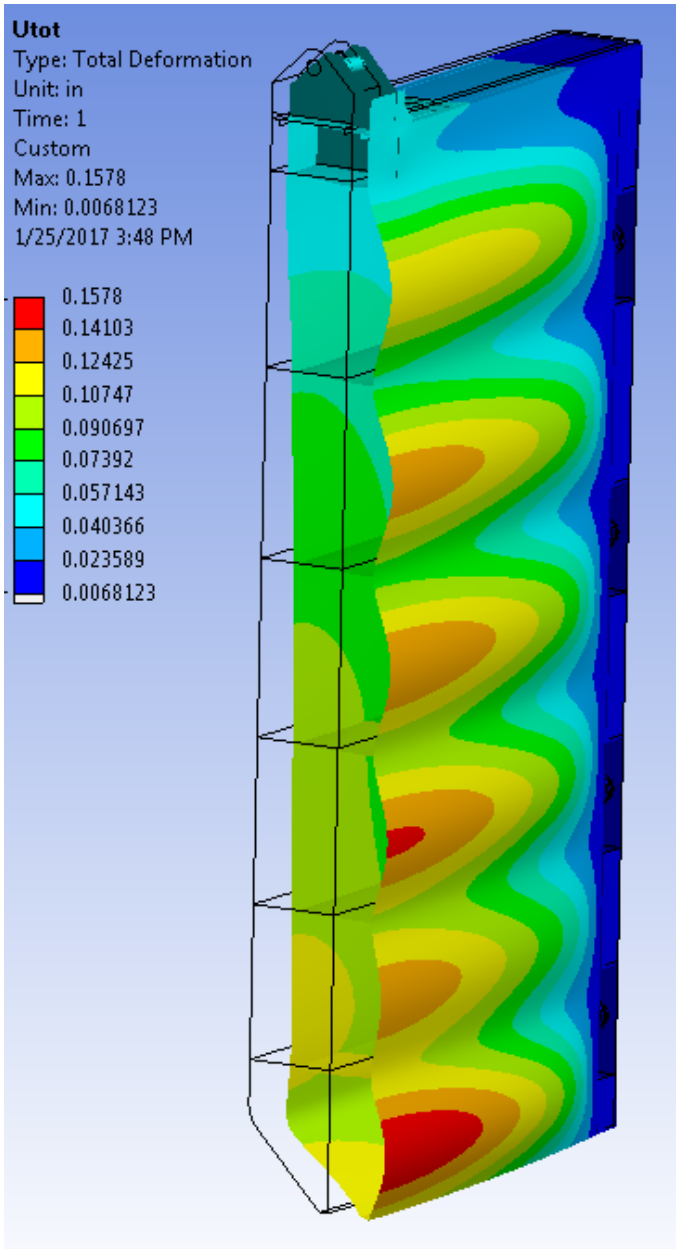


Figure D11: LS1 – Deflection

Max deflection of 0.113 in. occurs in web06 in the gate middle. Max skinplate deflection 0.158 - 0.113 = 0.045 in.

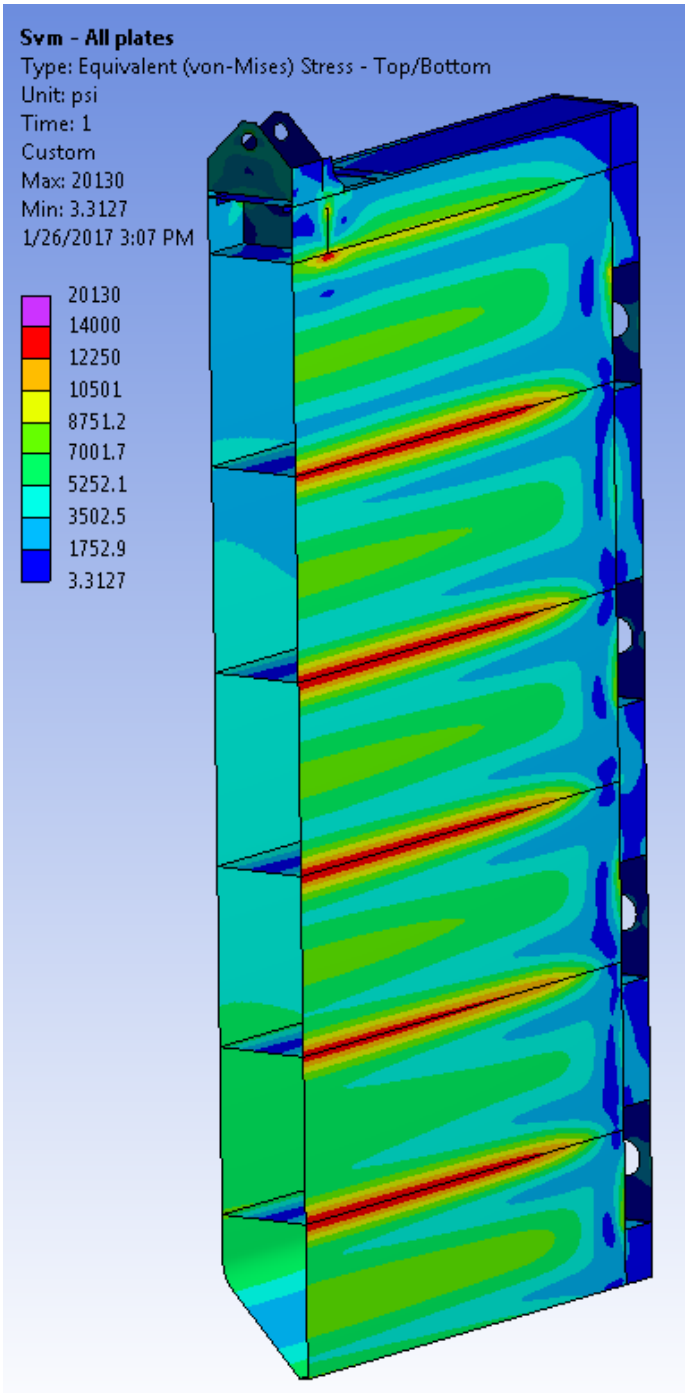


Figure D12: LS1 – Von Mises Stress

Max of 20,130 psi occurs in the corner of the Girder 01 stiffener. Elsewhere in the gate the stresses are below 14,000 psi. Allowable 19,800 psi.

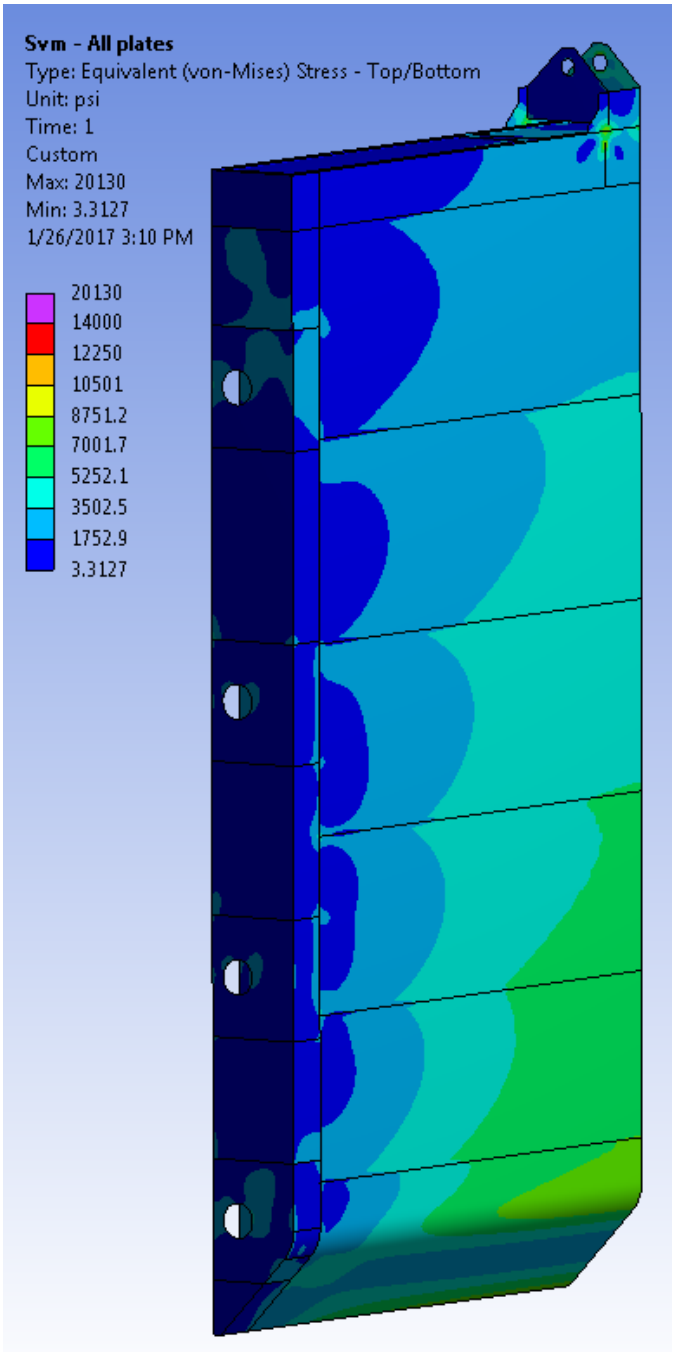


Figure D13: LS1 – Von Mises Stress

Max of 20,130 psi occurs in the corner of the Girder 01 stiffener. Elsewhere in the gate the stresses are below 14,000 psi. Allowable 19,800 psi.

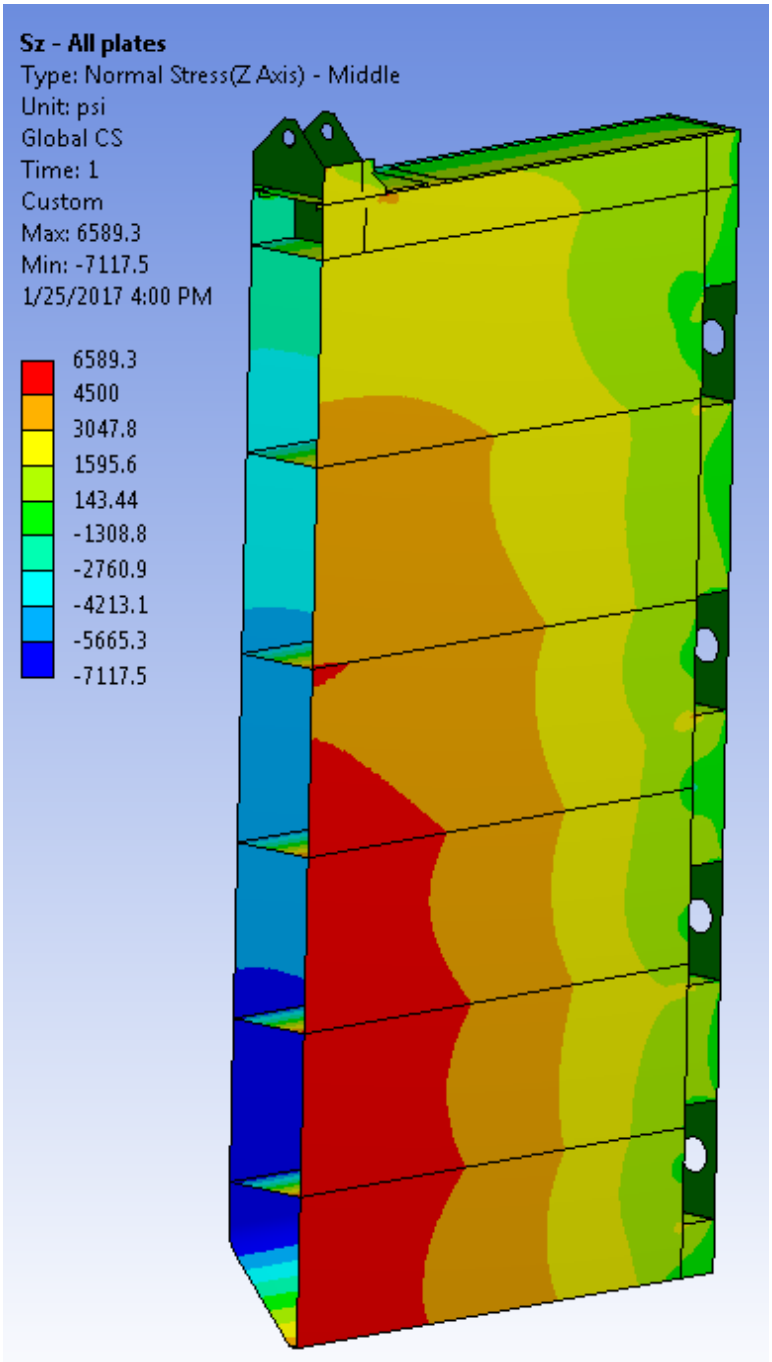


Figure D14: LS1 – Major Bending Stress σ_z

Max of 7,117 psi (compression) occurs in the upstream skinplate in the middle of gate at Girder 06. Allowable 19,800 psi.

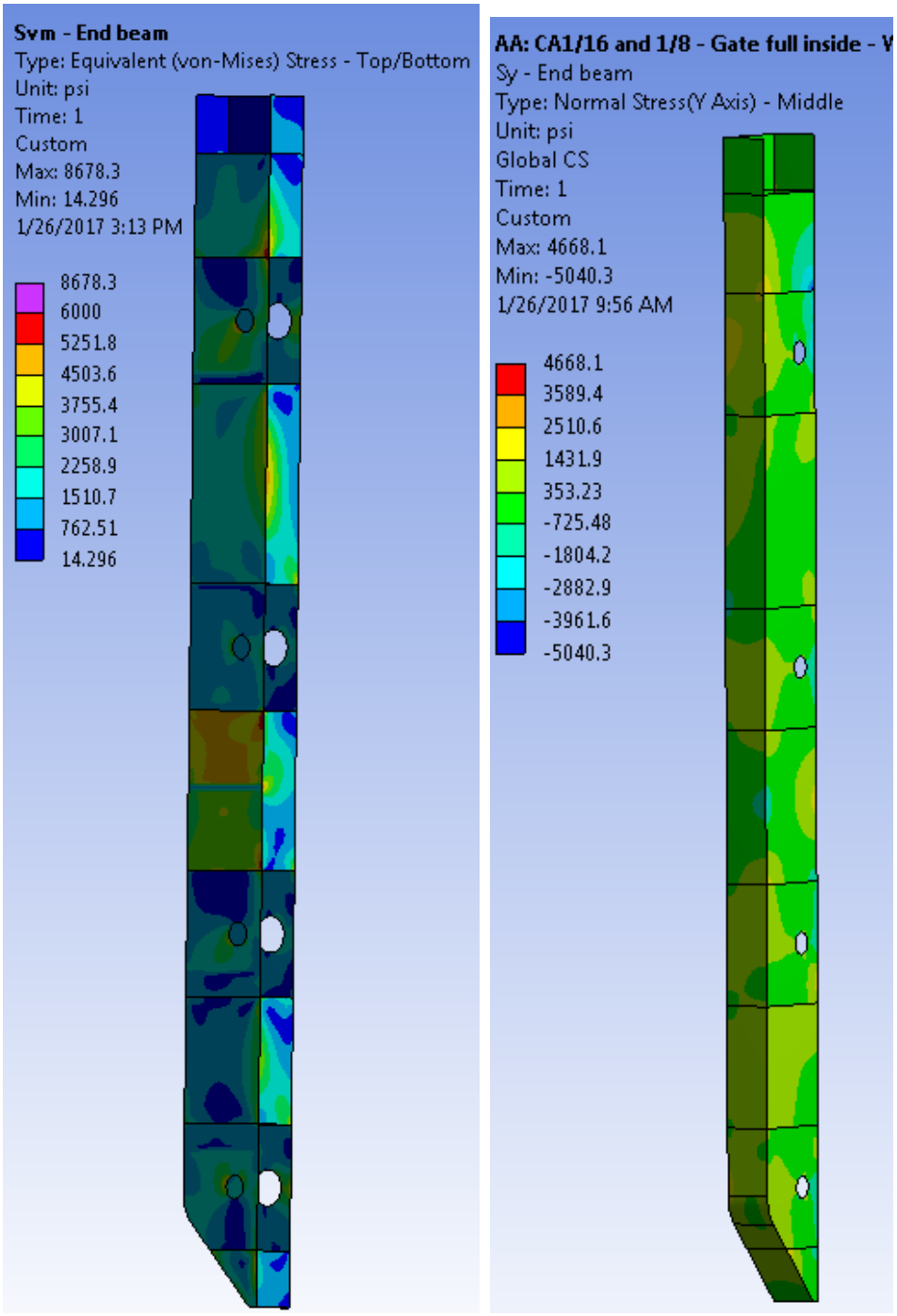


Figure D15: LS1 – Von Mises Stress (a) and Bending Stress σ_y (b) in the end Beam

Max 8,678 psi and 5,040 psi, respectively. Allowable 19,800 psi.

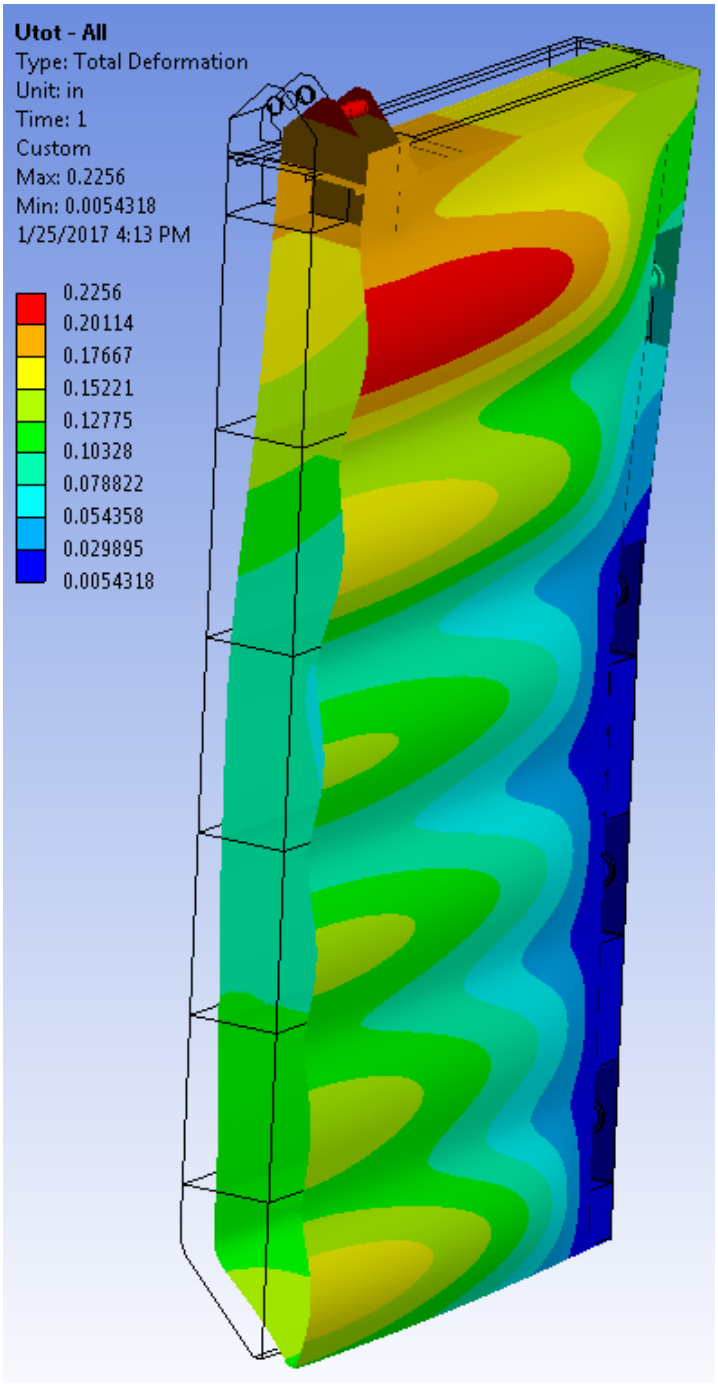


Figure D16: LS2 – Deflection

Max deflection of 0.181 in occurs in web01 in the gate middle. Max skinplate deflection 0.226 - 0.181 = 0.045 in.

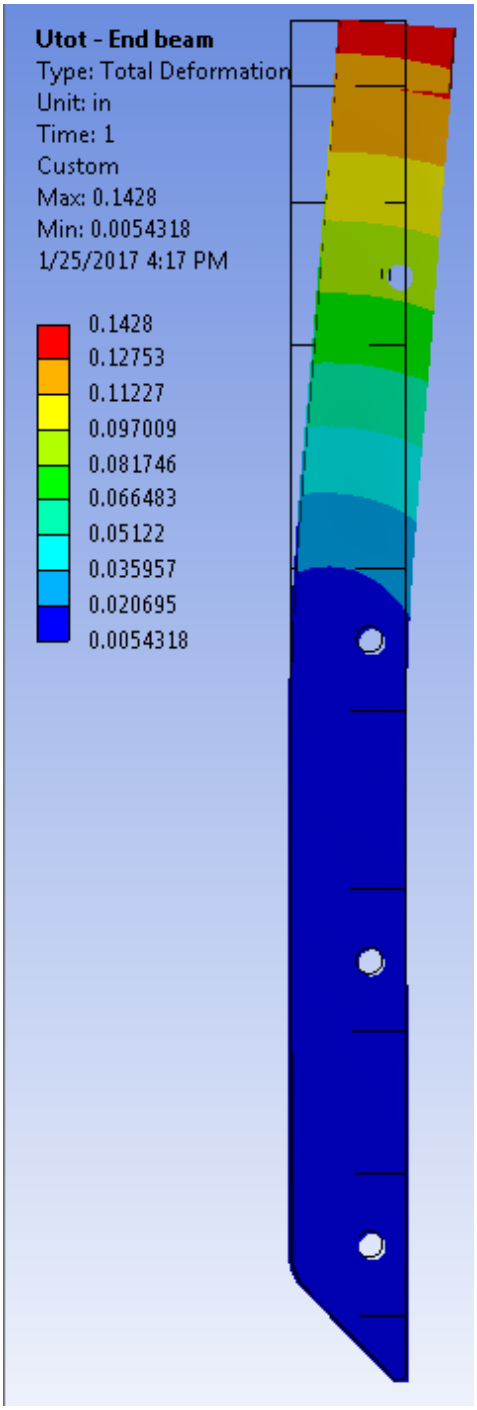


Figure D17: LS2 – End Beam Deflection

Max deflection at the top wheel (wheel 01) is 0.092 in.

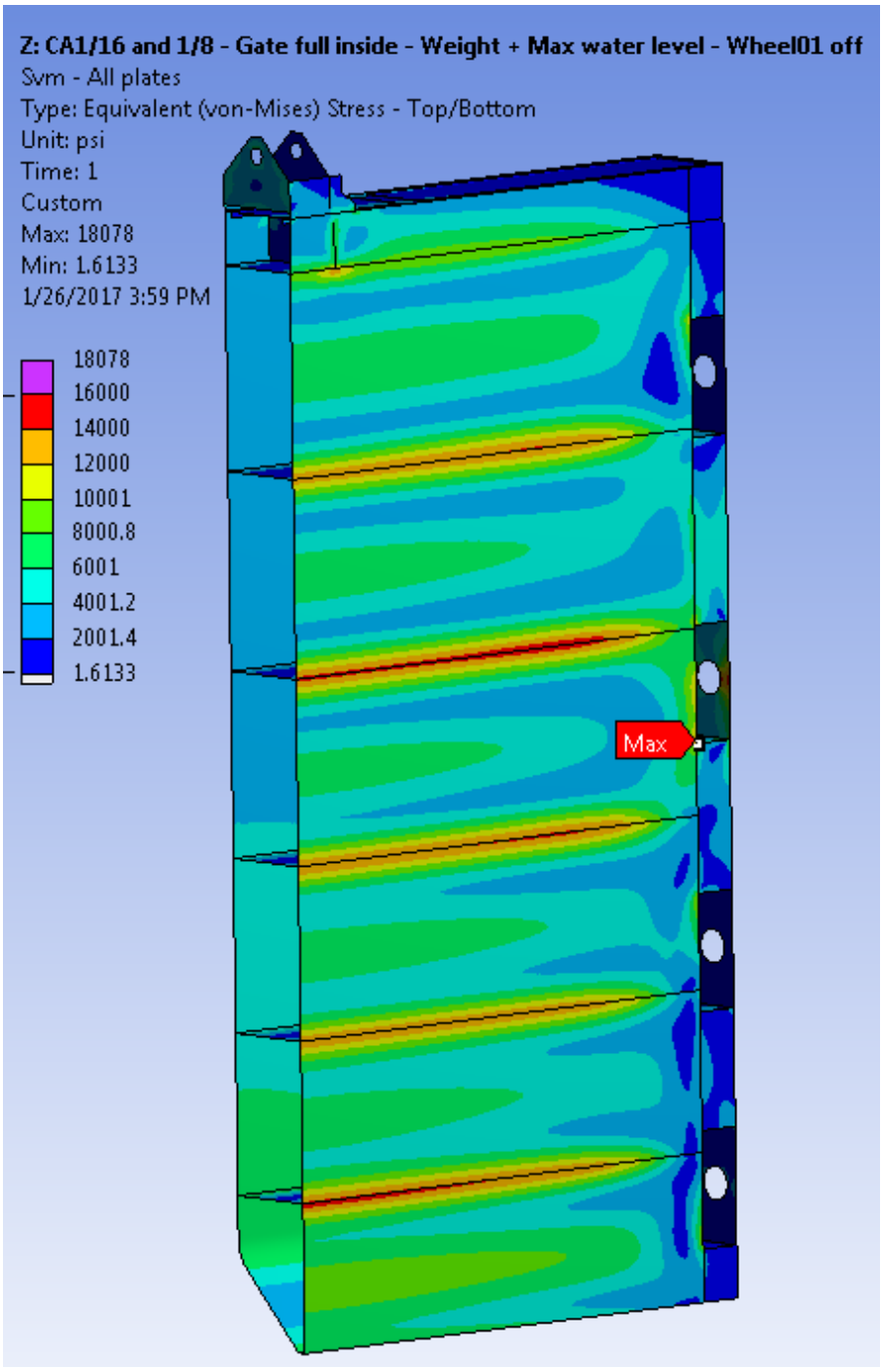


Figure D18: LS2 – Von Mises Stress

Max of 18,078 psi occurs as a stress concentration in the downstream skinplate in the vicinity of Wheel 02. Elsewhere in the gate the stresses are below 16,000 psi allowable 19,800 psi.

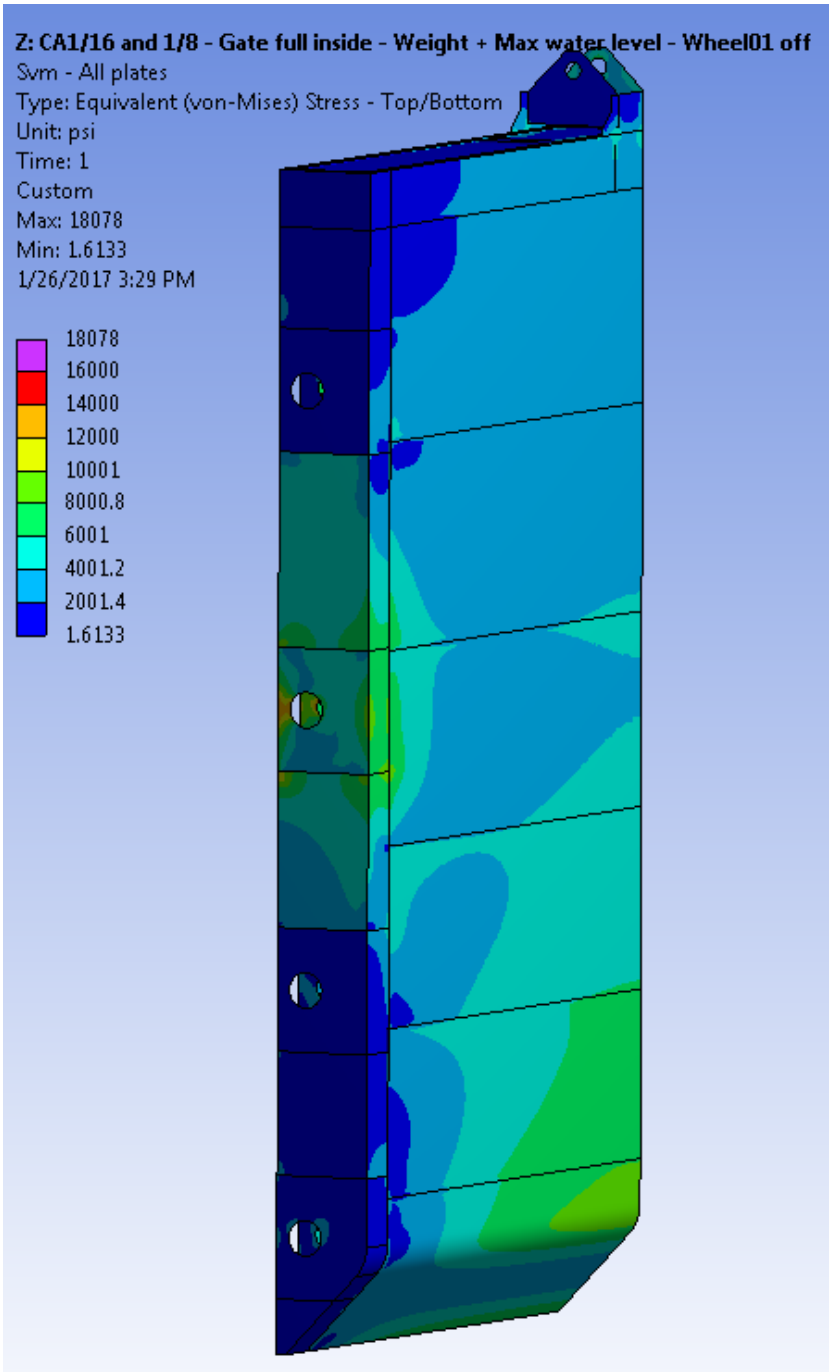


Figure D19: LS2 – Von Mises Stress

Max of 18,078 psi occurs as a stress concentration in the skinplate in the vicinity of Wheel 02. Elsewhere in the gate the stresses are below 16,000 psi allowable 19,800 psi.

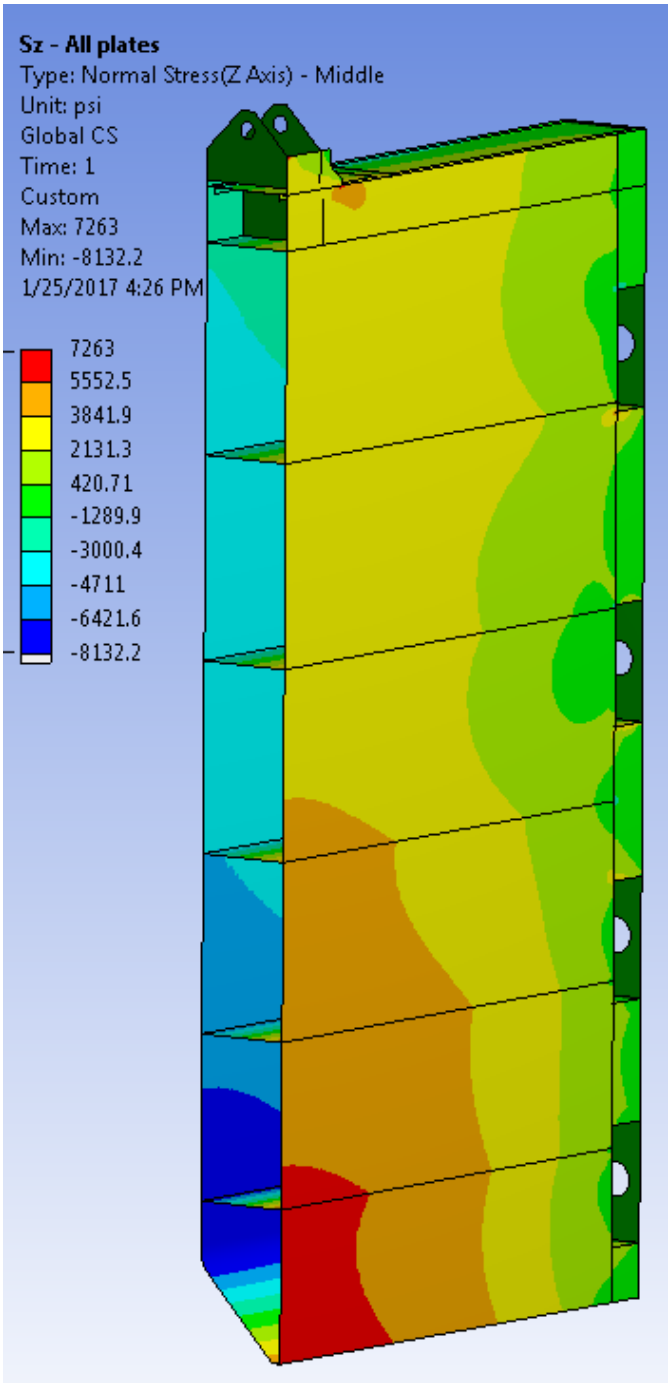
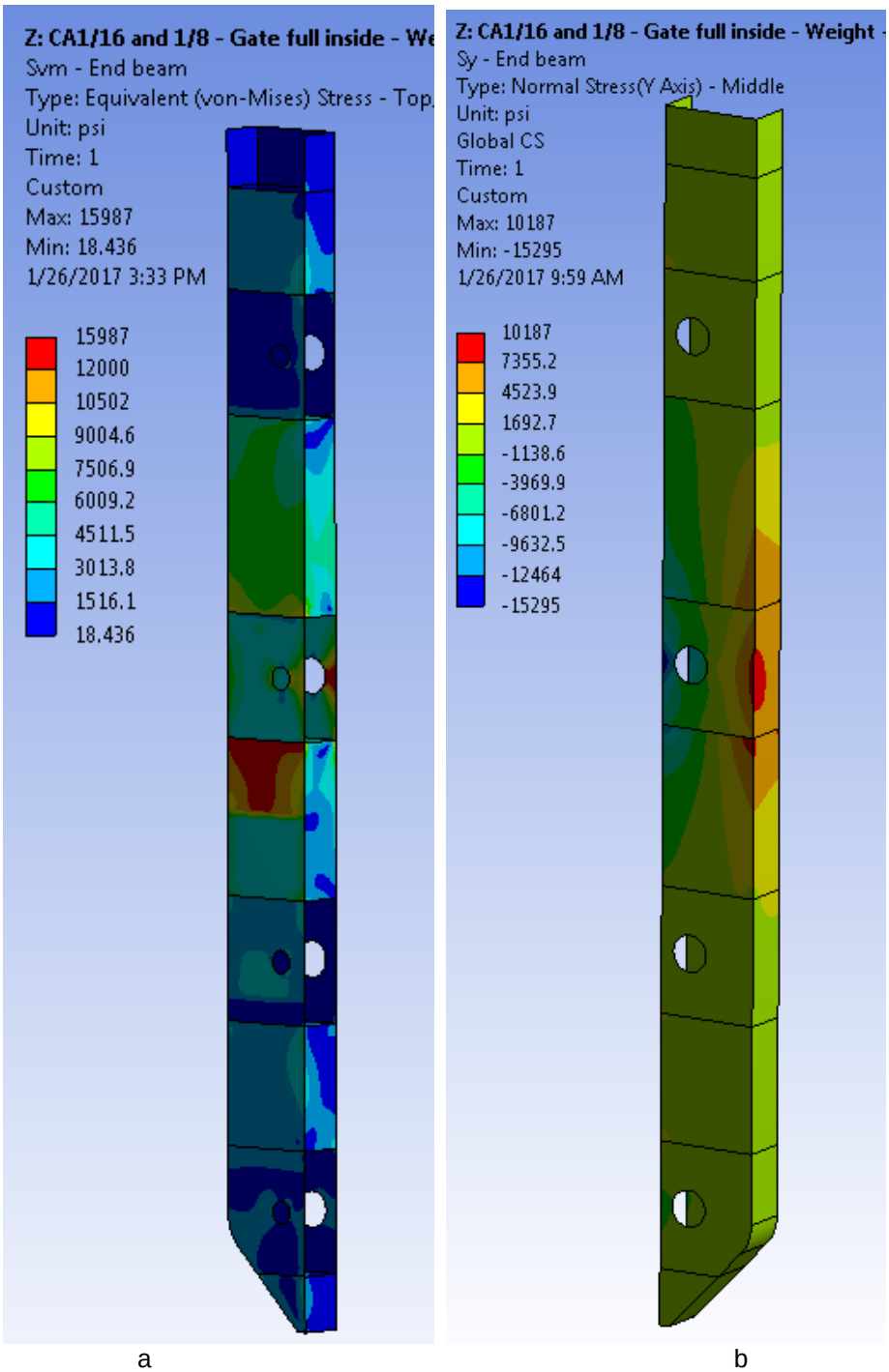


Figure D20: LS2 – Major Bending Stress, σz

Max of 8,132 psi (compression) occurs in the upstream skinplate in the middle of gate at girder 06. Allowable 19,800 psi.



a b

Figure D21: LS2 – Von Mises Stress (a) and Bending Stress σ_y (b) in the End Beam

Max 15,987 psi and 15,295 psi (compression), respectively. Allowable 19,800 psi.

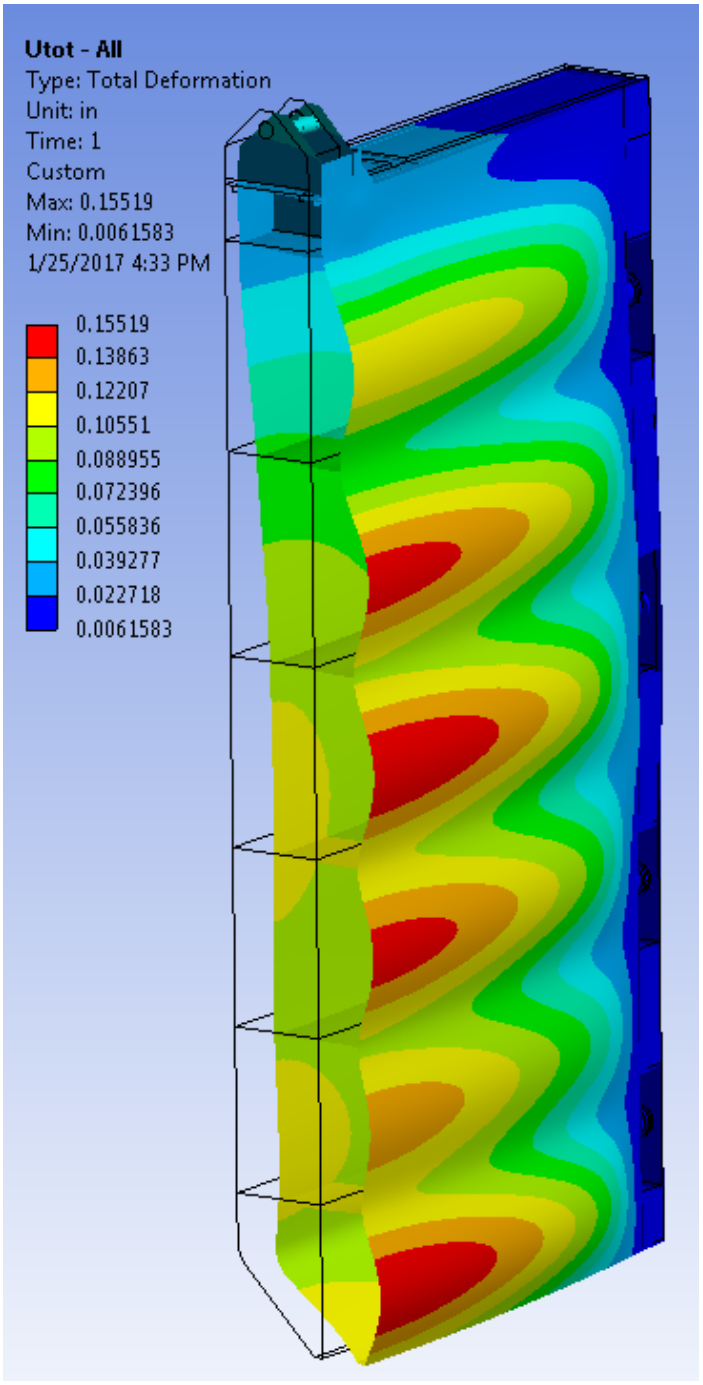


Figure D22: LS3 – Deflection

Max deflection of 0.109 in occurs in web04 in the gate middle. Max skinplate deflection 0.155 - 0.109 = 0.046 in.

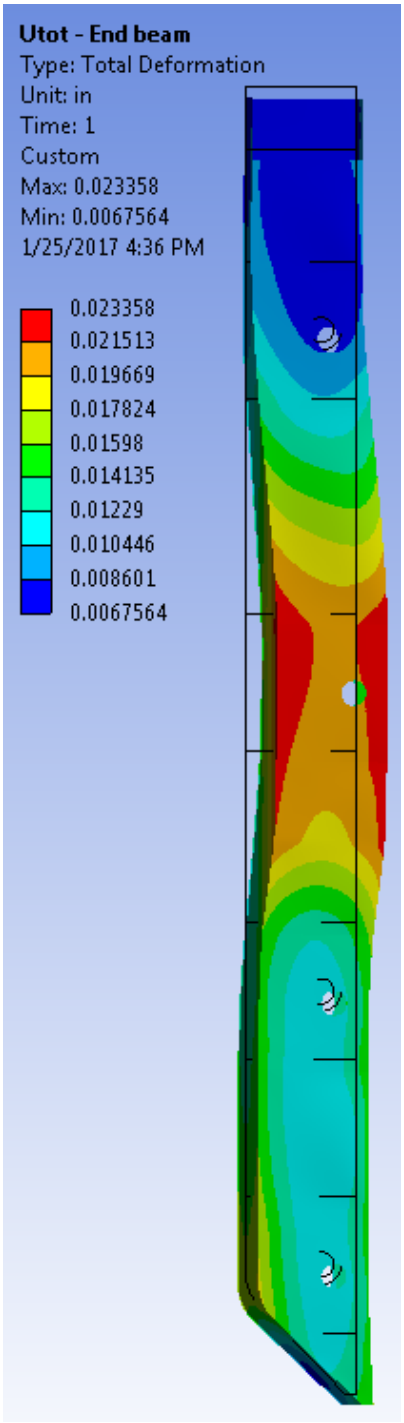


Figure D23: LS3 – End Beam Deflection

Max deflection at wheel 02 is 0.023 in.

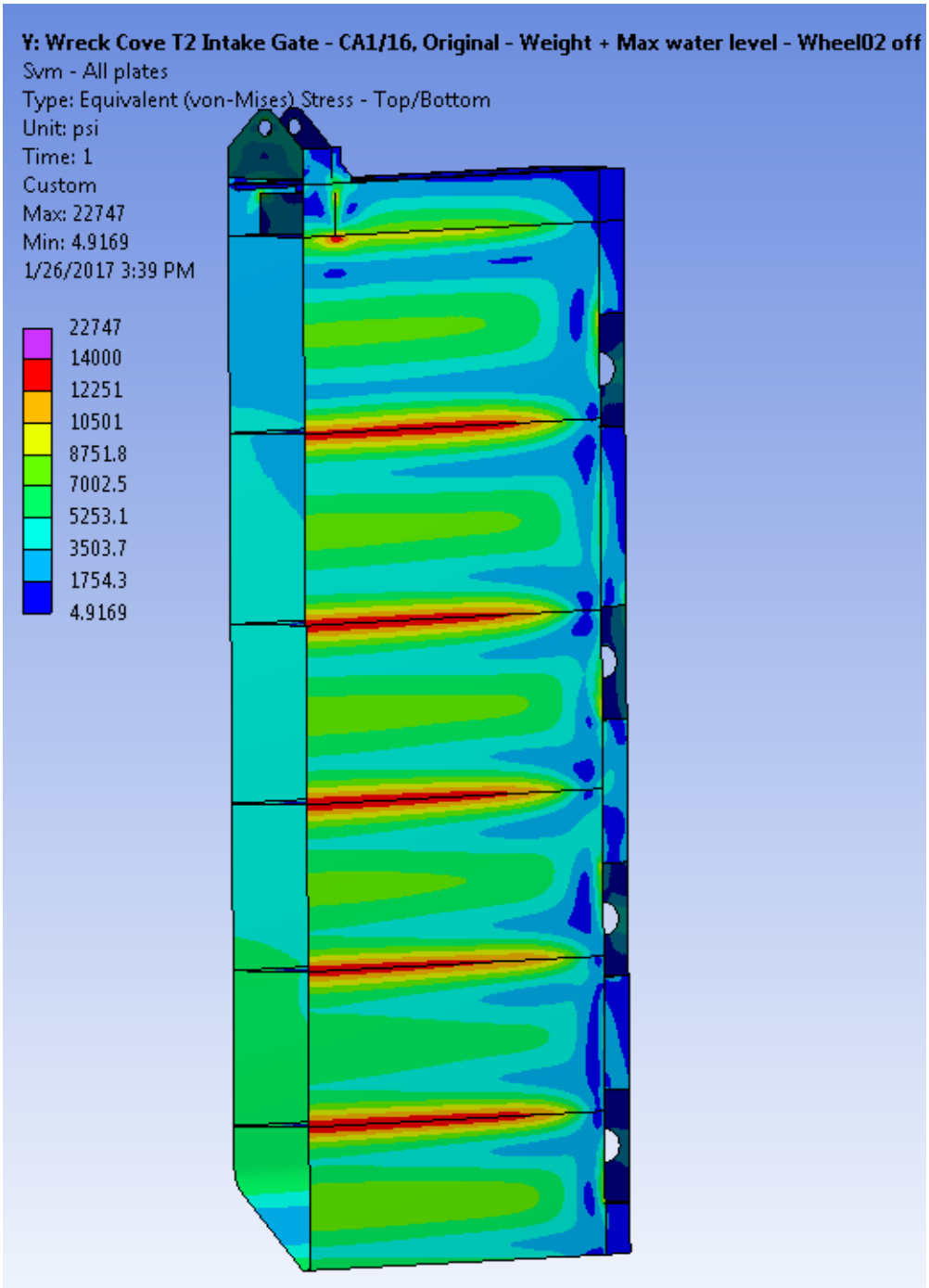


Figure D24: LS3 – Von Mises Stress

Max of 22,747 psi occurs in the corner of the Girder 01 stiffener. Elsewhere in the gate the stresses are below 14,000 psi. Allowable 19,800 psi.

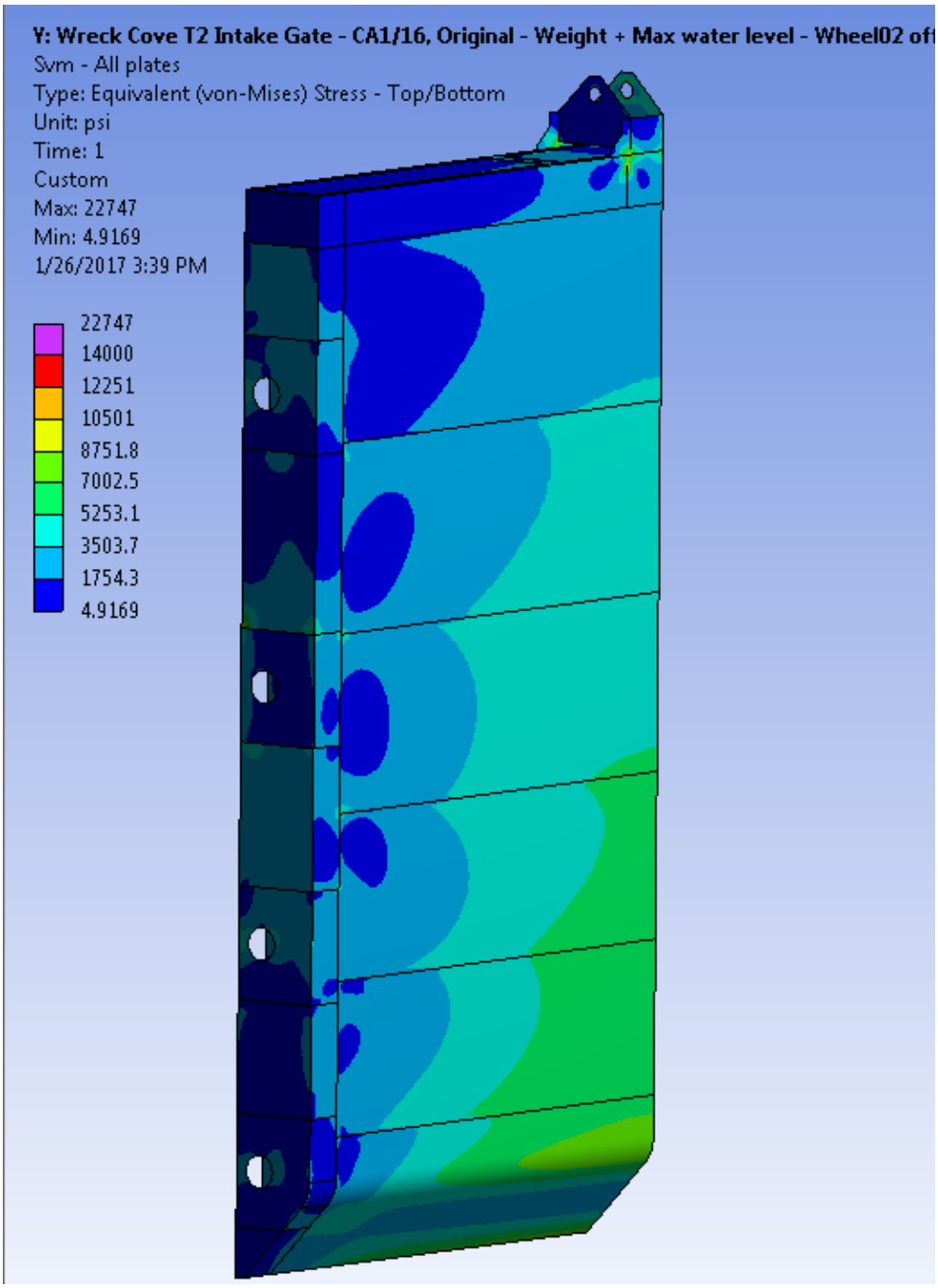


Figure D25: LS3 – Von Mises Stress

Max of 22,747 psi occurs in the corner of the Girder 01 stiffener. Elsewhere in the gate the stresses are below 14,000 psi. Allowable 19,800 psi.

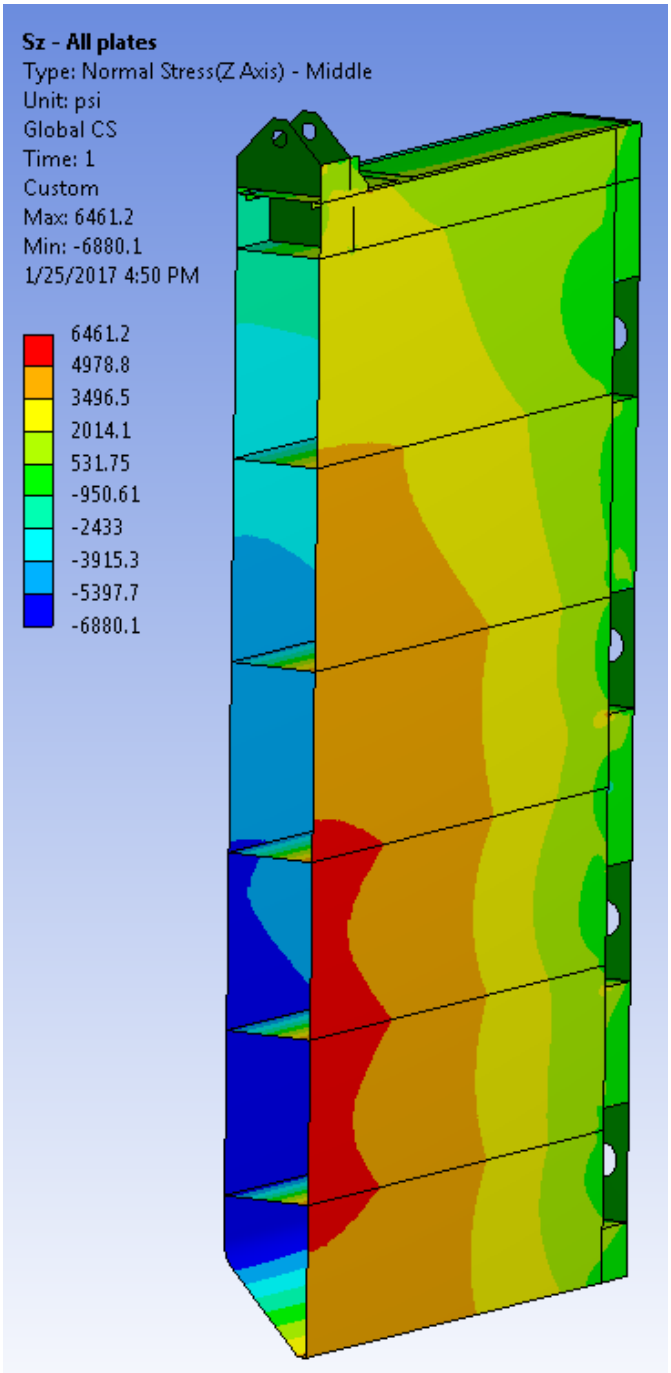
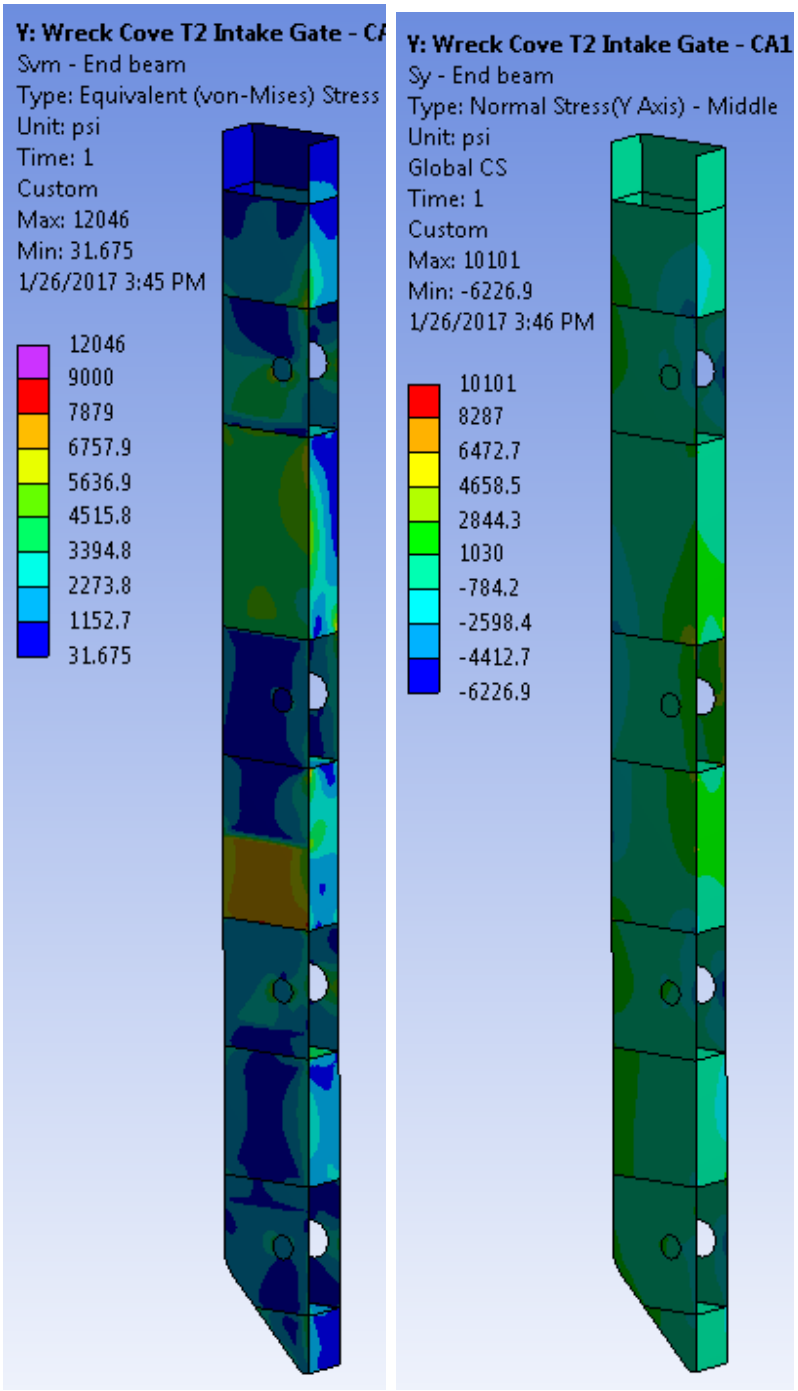


Figure D25: LS3 – Major Bending Stress, σ_z

Max of 6,880 psi (compression) occurs in the upstream skinplate in the middle of gate at girder 06. Allowable 19,800 psi.



a b

Figure D26: LS3 – Von Mises Stress (a) and Bending Stress σ_y (b) in the End Beam

Max 12,046 psi and 10,101 psi, respectively. Allowable 19,800 psi.

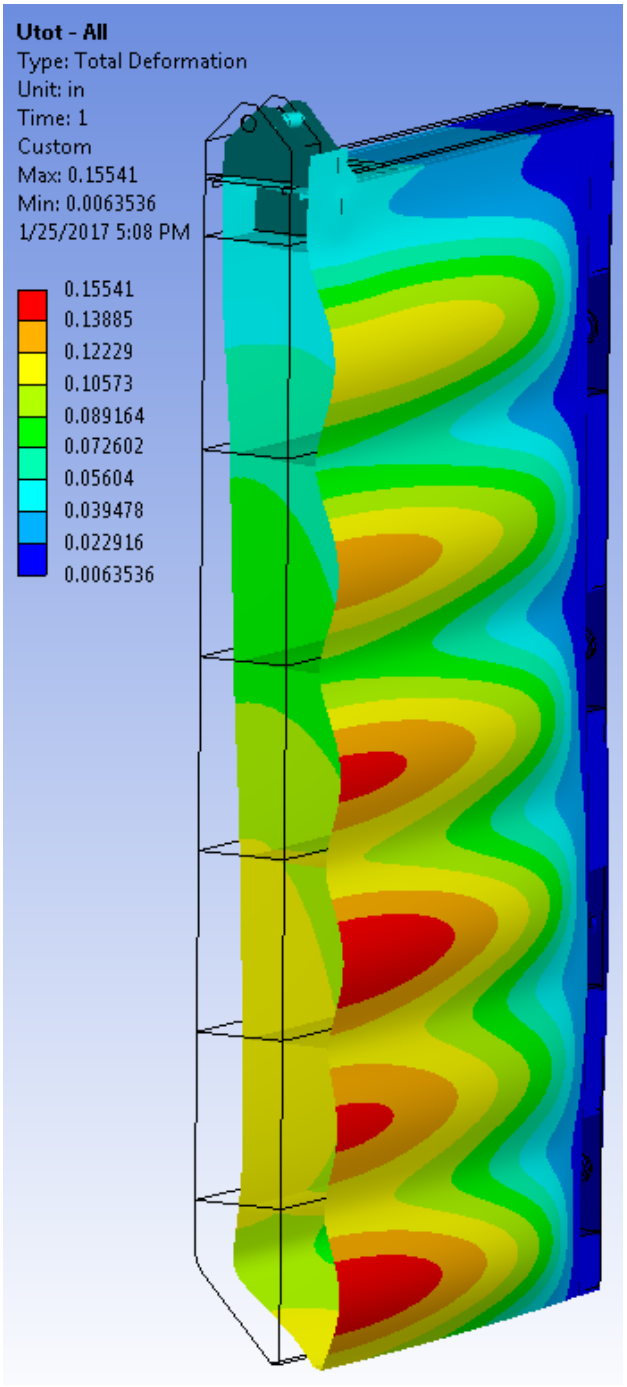


Figure D27: LS4 – Deflection

Max deflection of 0.118 in. occurs in web05 in the gate middle. Max skinplate deflection 0.155 - 0.118 = 0.037 in.

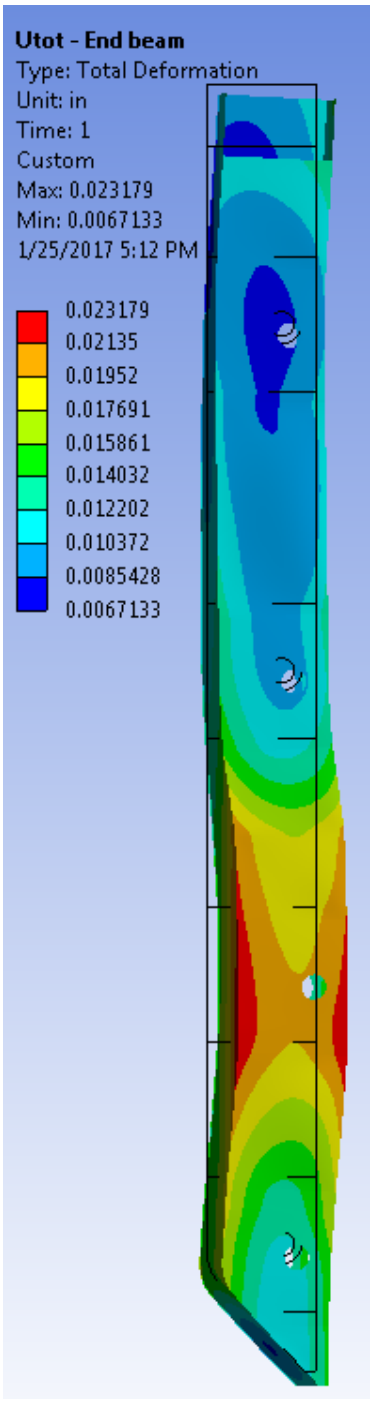


Figure D28: LS4 – End Beam Deflection

Max deflection at wheel 03 is 0.022 in.

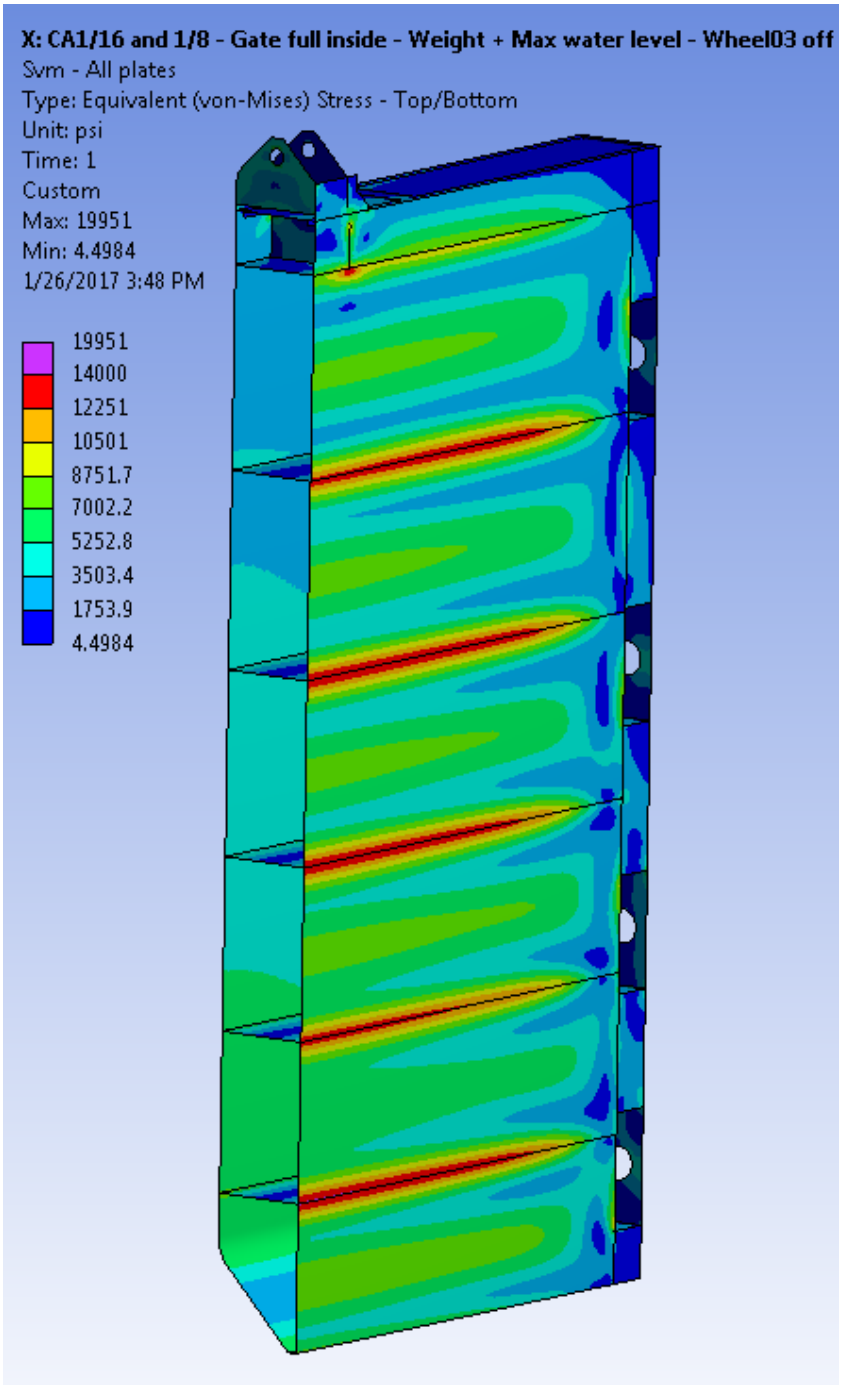


Figure D29: LS4 – Von Mises Stress

Max of 19,951 psi occurs in the corner of the Girder 01 stiffener. Elsewhere in the gate the stresses are below 14,000 psi. Allowable 19,800 psi.

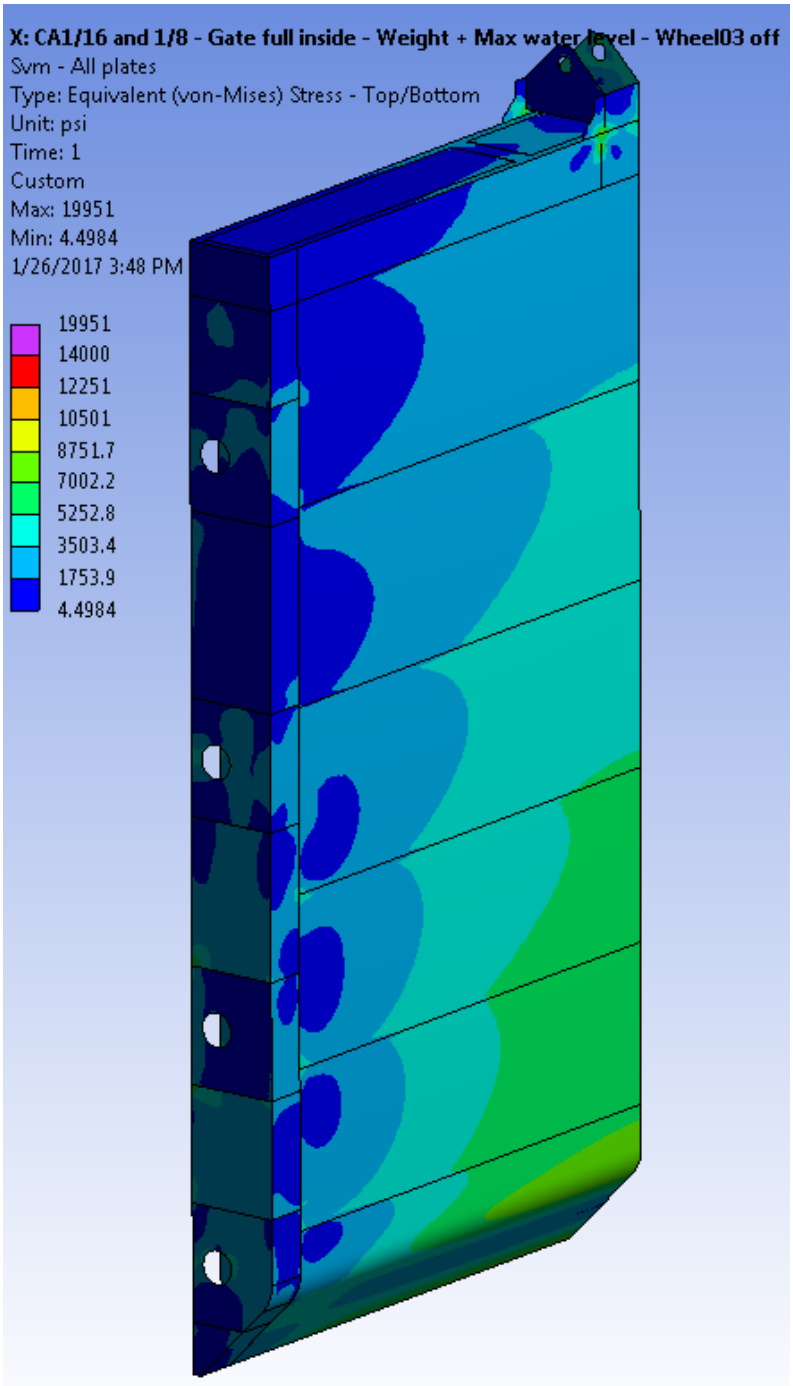


Figure D30: LS4 – Von Mises Stress

Max of 19,951 psi occurs in the corner of the Girder 01 stiffener. Elsewhere in the gate the stresses are below 14,000 psi. Allowable 19,800 psi.

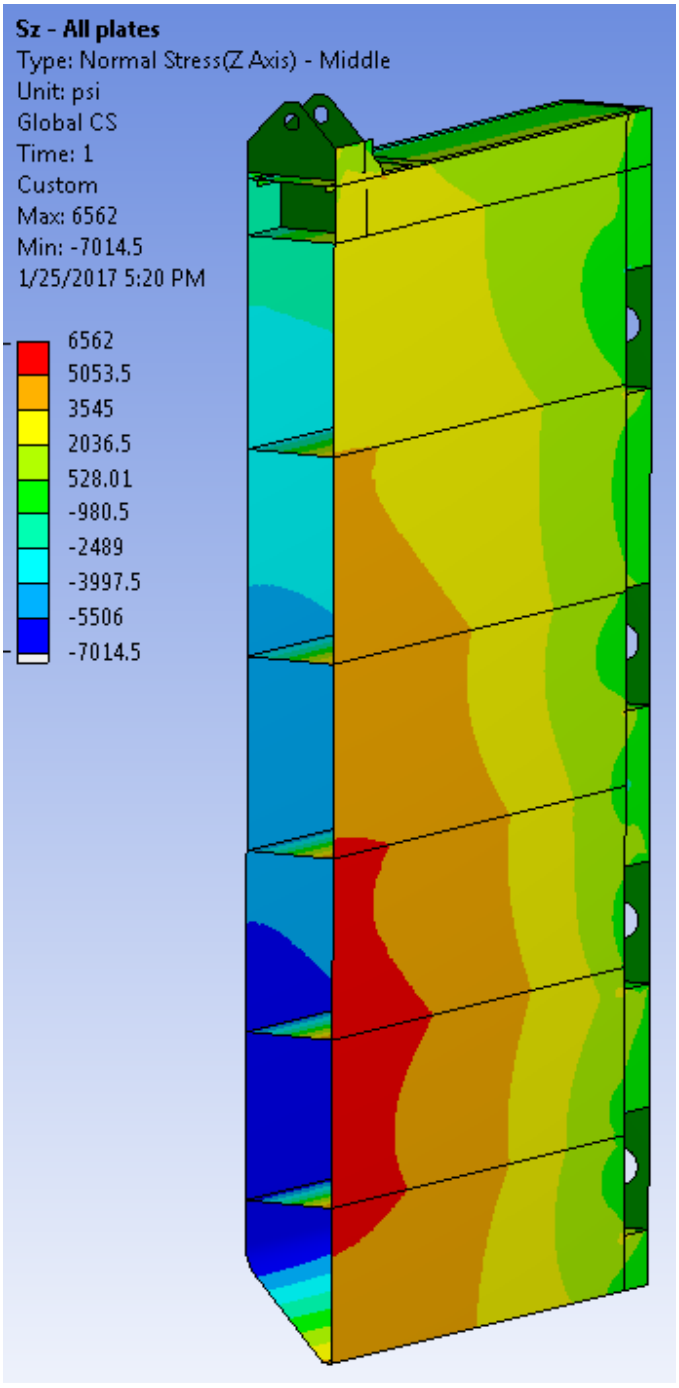
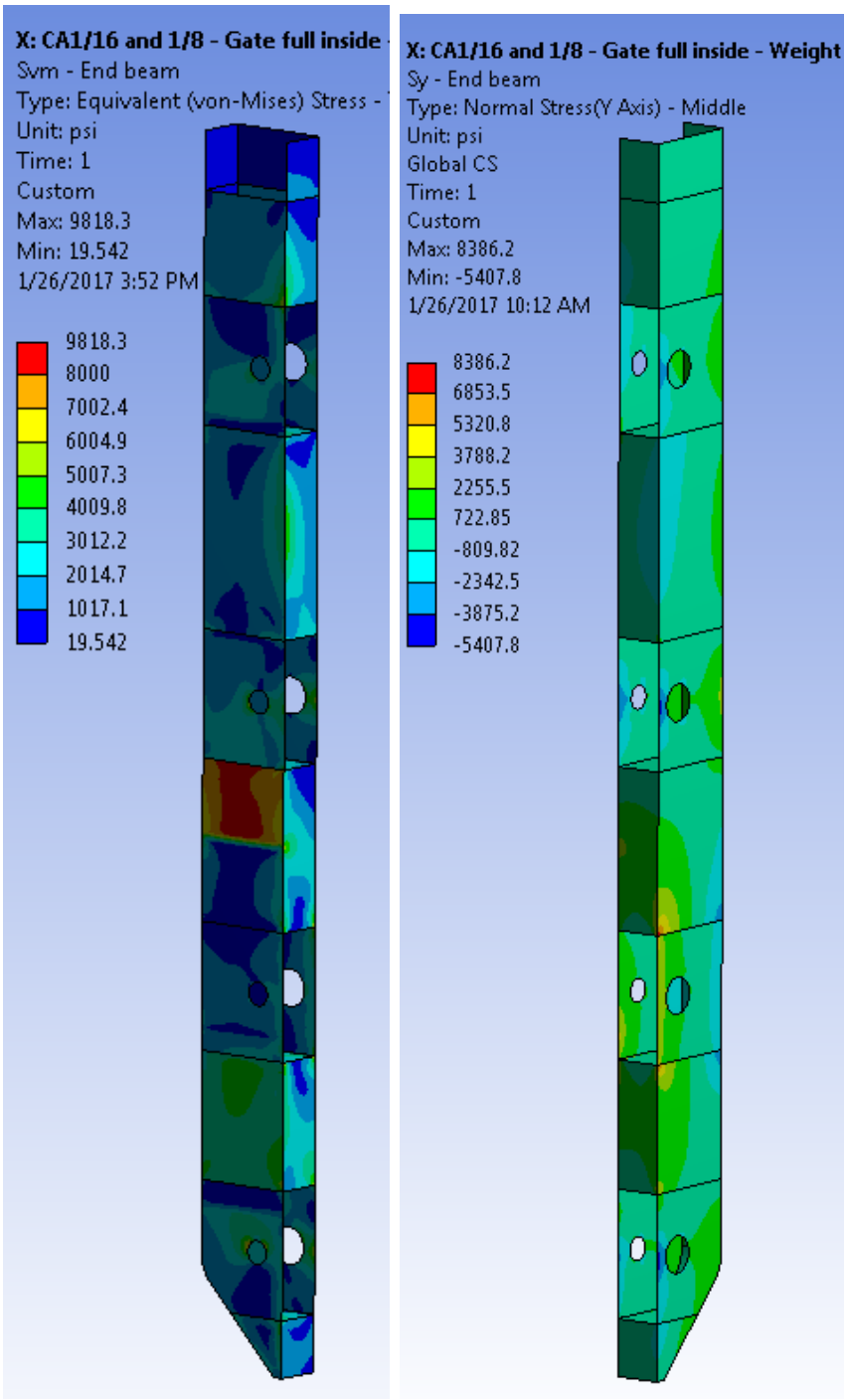


Figure D31: LS4 – Major Bending Stress, σ_z

Max of 7,014 psi (compression) occurs in the upstream skinplate in the middle of gate at girder 06. Allowable 19,800 psi.



a b

Figure D32: LS4 – Von Mises Stress (a) and Bending Stress σ_y (b) in the End Beam

Max 9,818 psi and 8,386 psi, respectively. Allowable 19,800 psi.

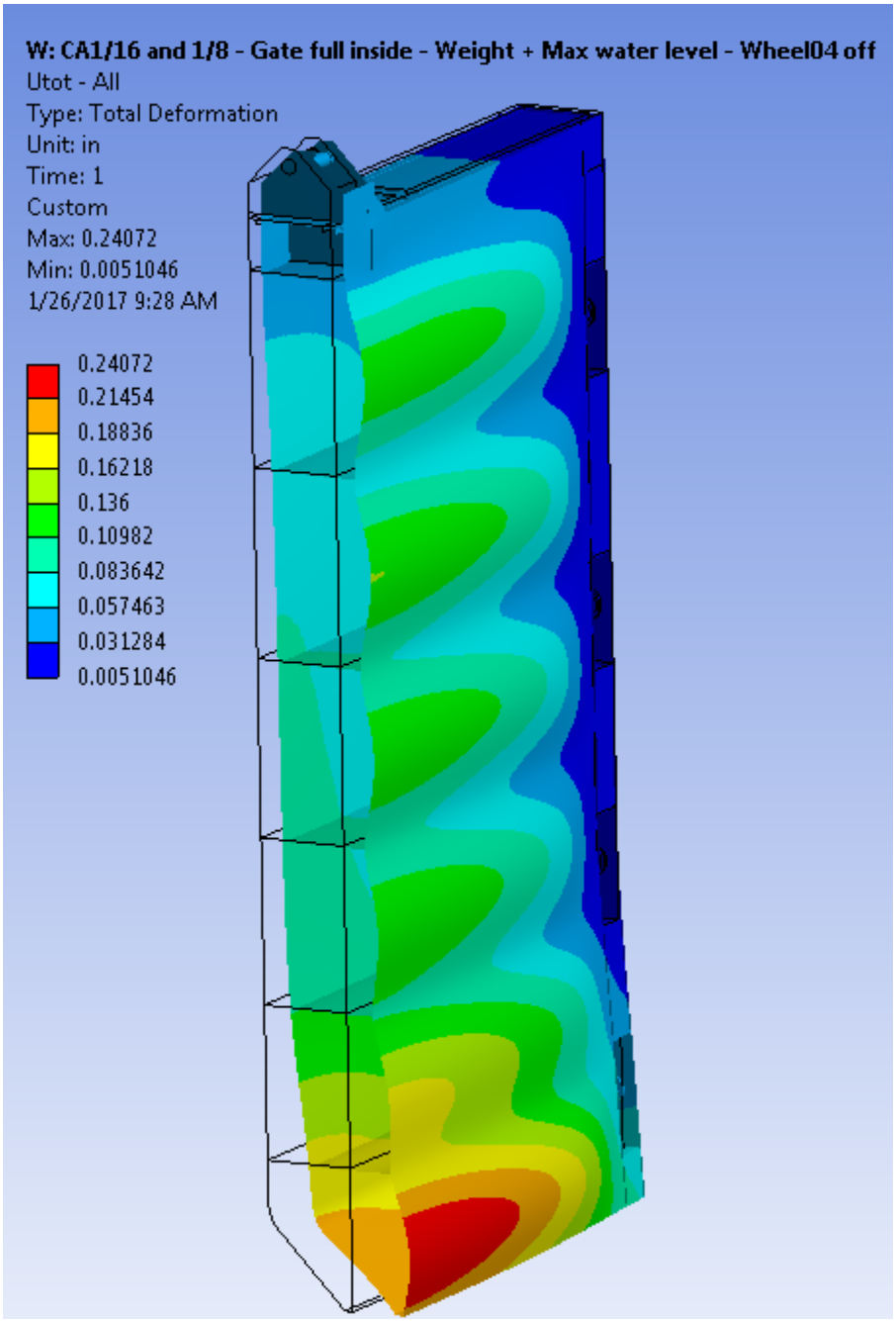


Figure D33: LS5 – Deflection

Max deflection of 0.171 in. occurs in web06 in the gate middle. Max skinplate deflection 0.241 - 0.171 = 0.070 in.

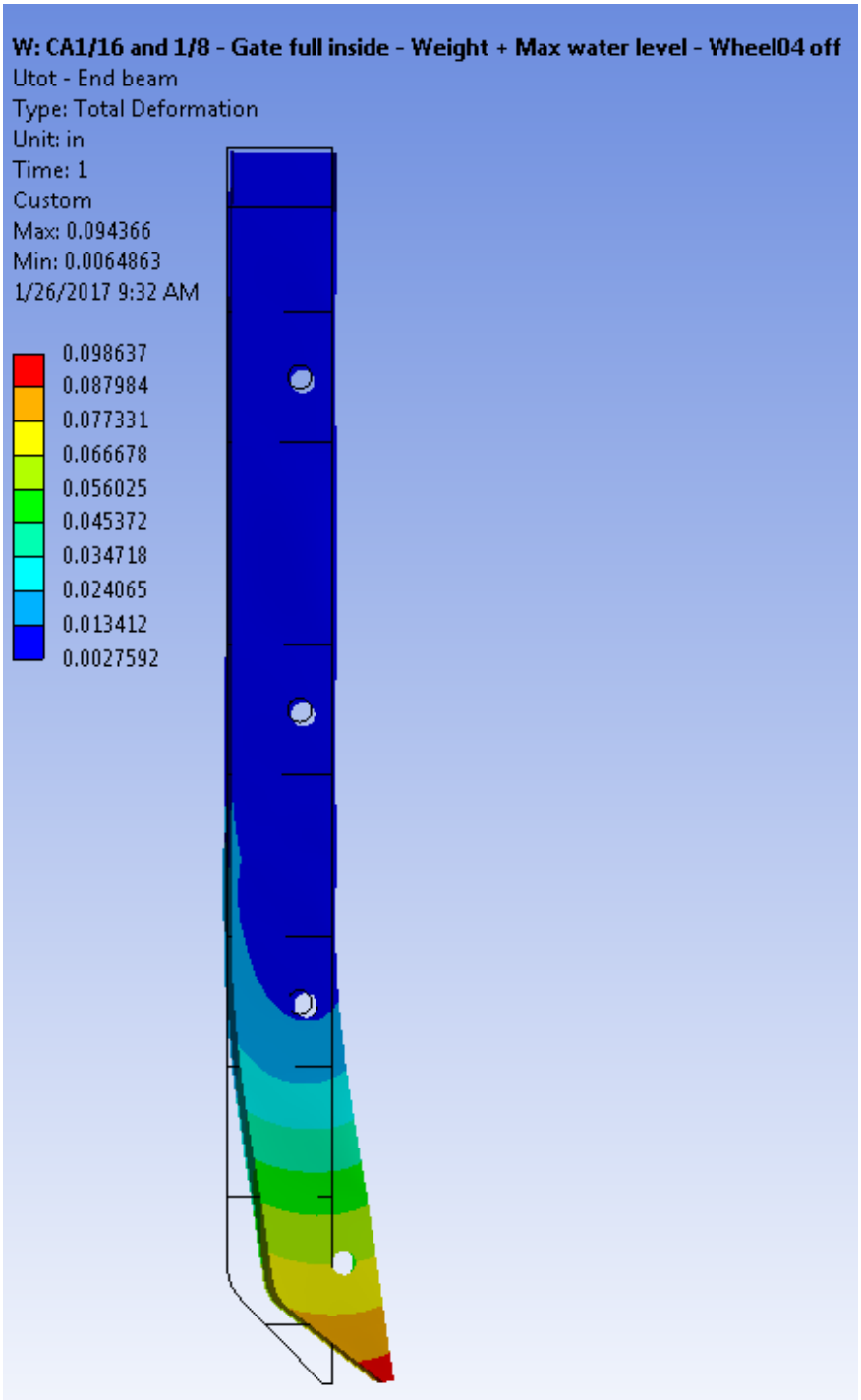


Figure D34: LS5 – End Beam Deflection

Max deflection at wheel 04 is 0.073 in.

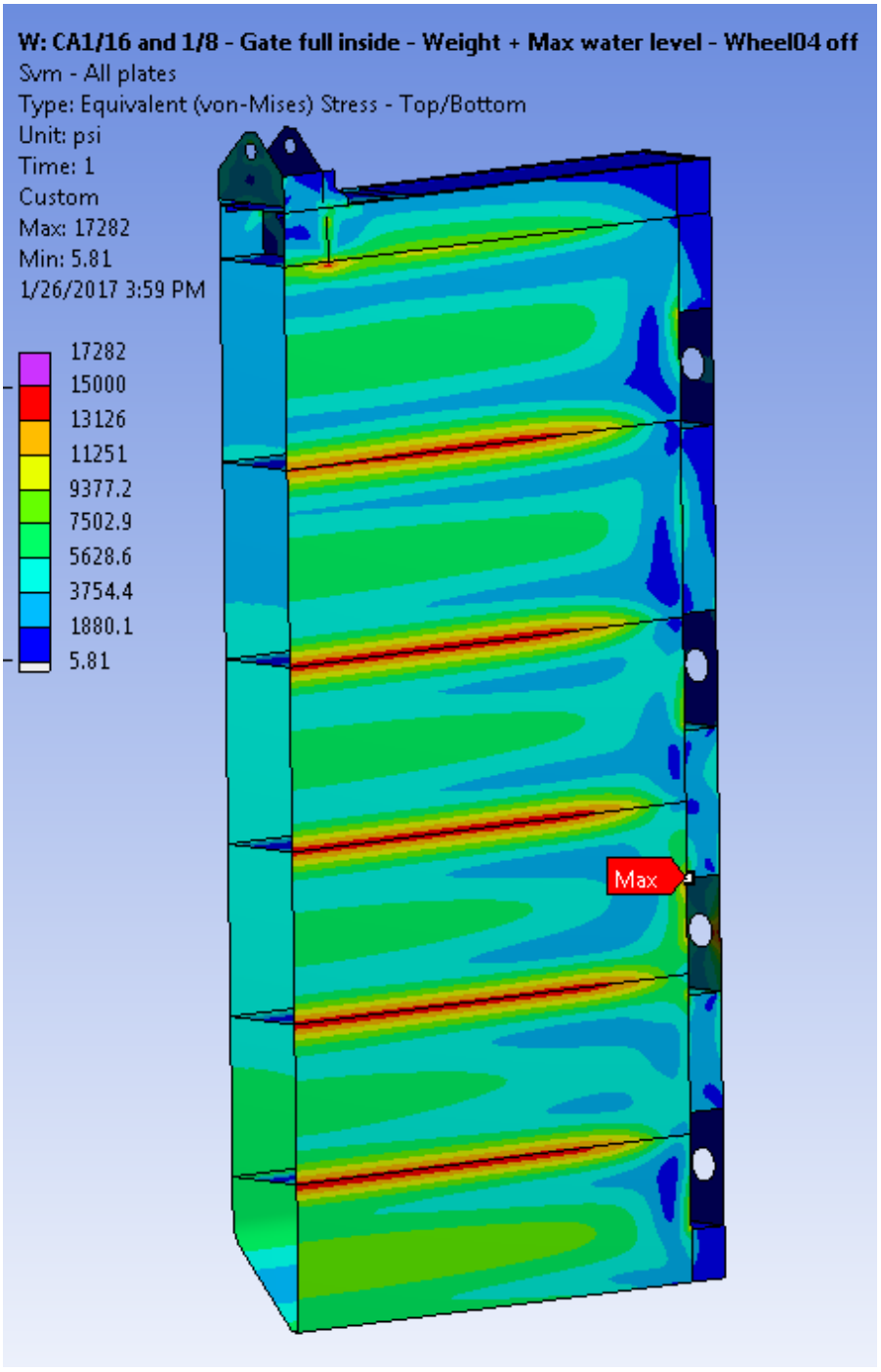


Figure D35: LS5 – Von Mises Stress

Max of 17,282 psi occurs as a stress concentration in the downstream skinplate in the vicinity of Wheel 03. Elsewhere in the gate the stresses are below 15,000 psi Allowable 19,800 psi.

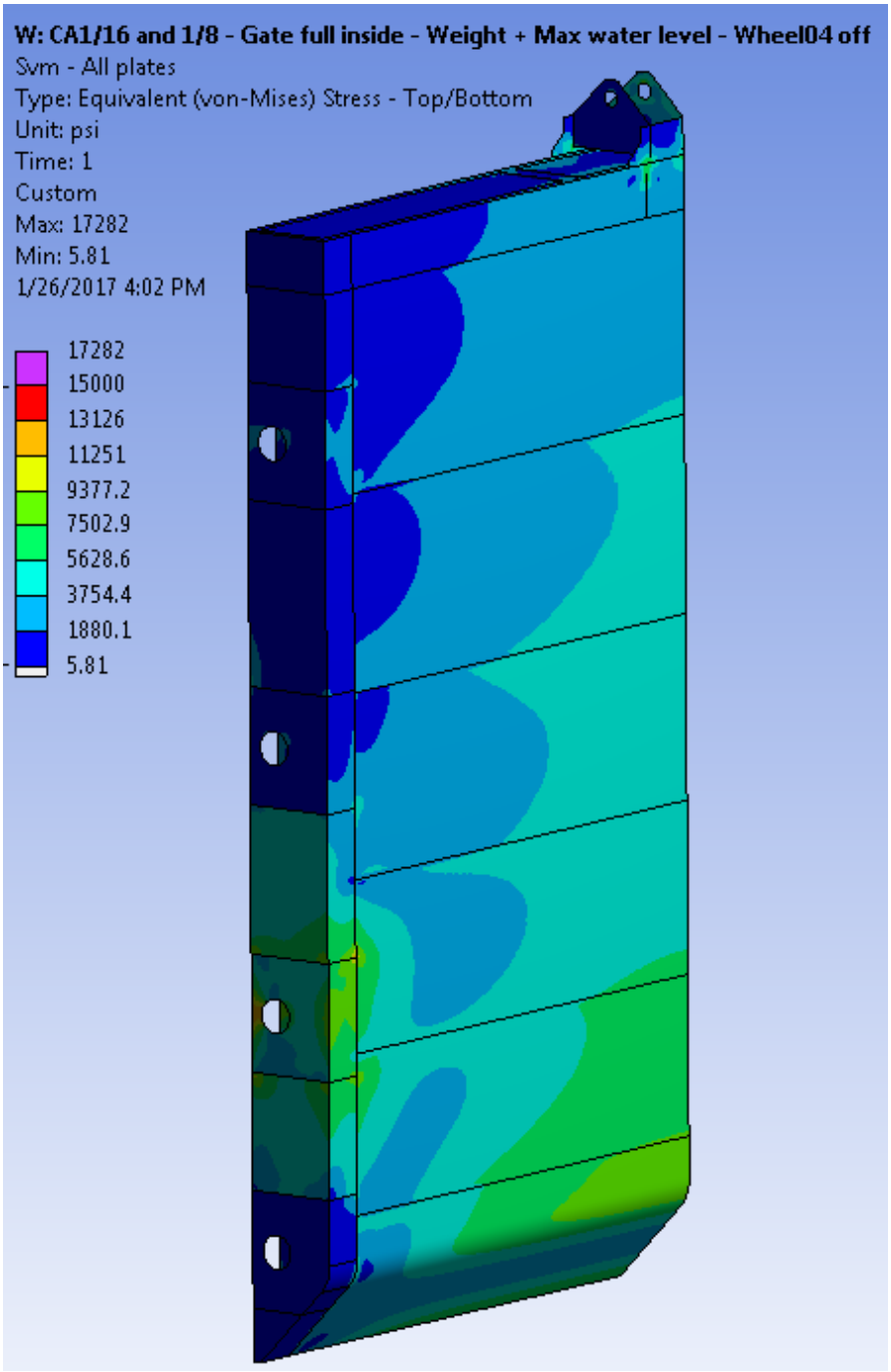


Figure D36: LS5 – Von Mises Stress

Max of 17,282 psi occurs as a stress concentration in the downstream skinplate in the vicinity of Wheel 03. Elsewhere in the gate the stresses are below 15,000 psi Allowable 19,800 psi.

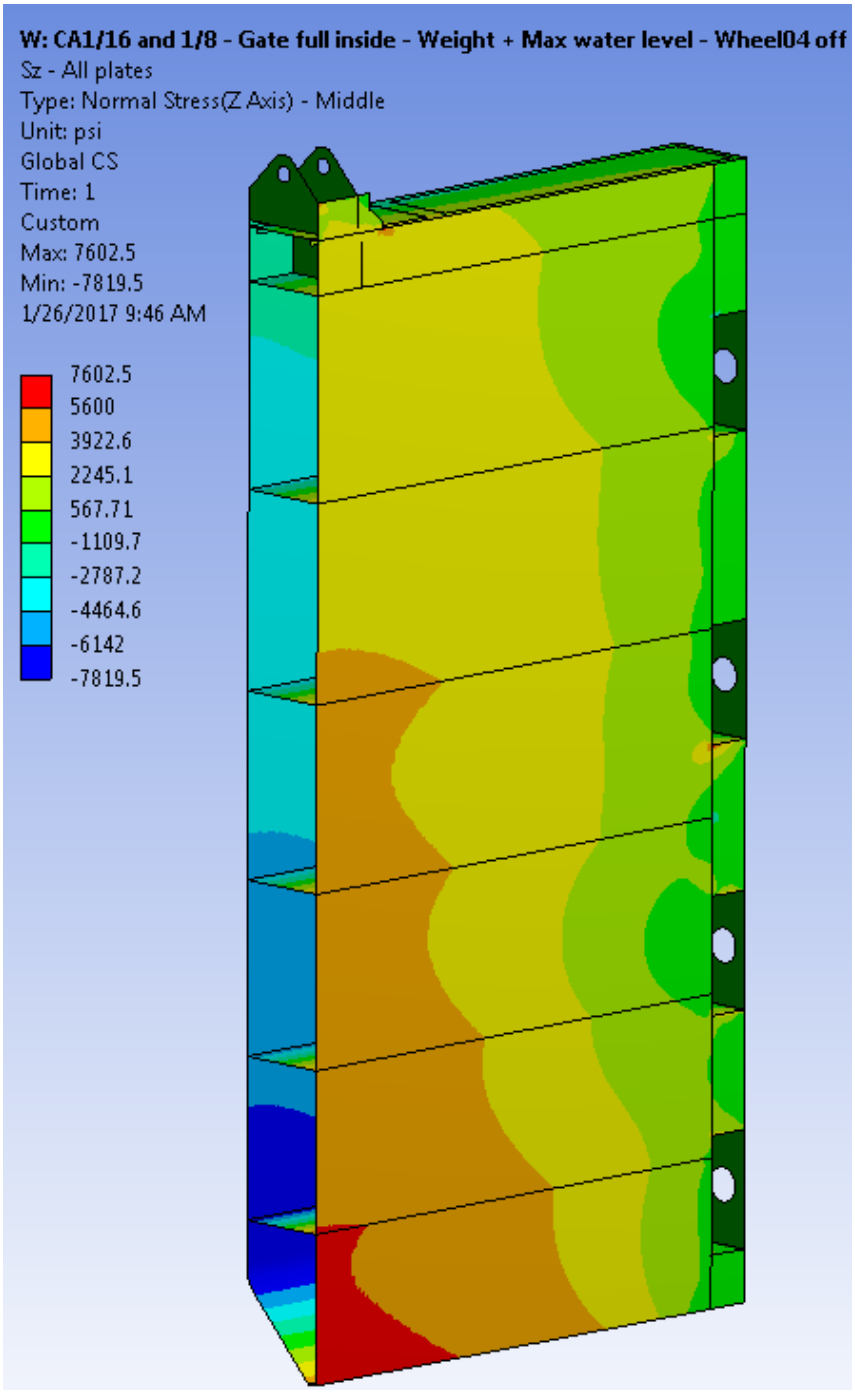
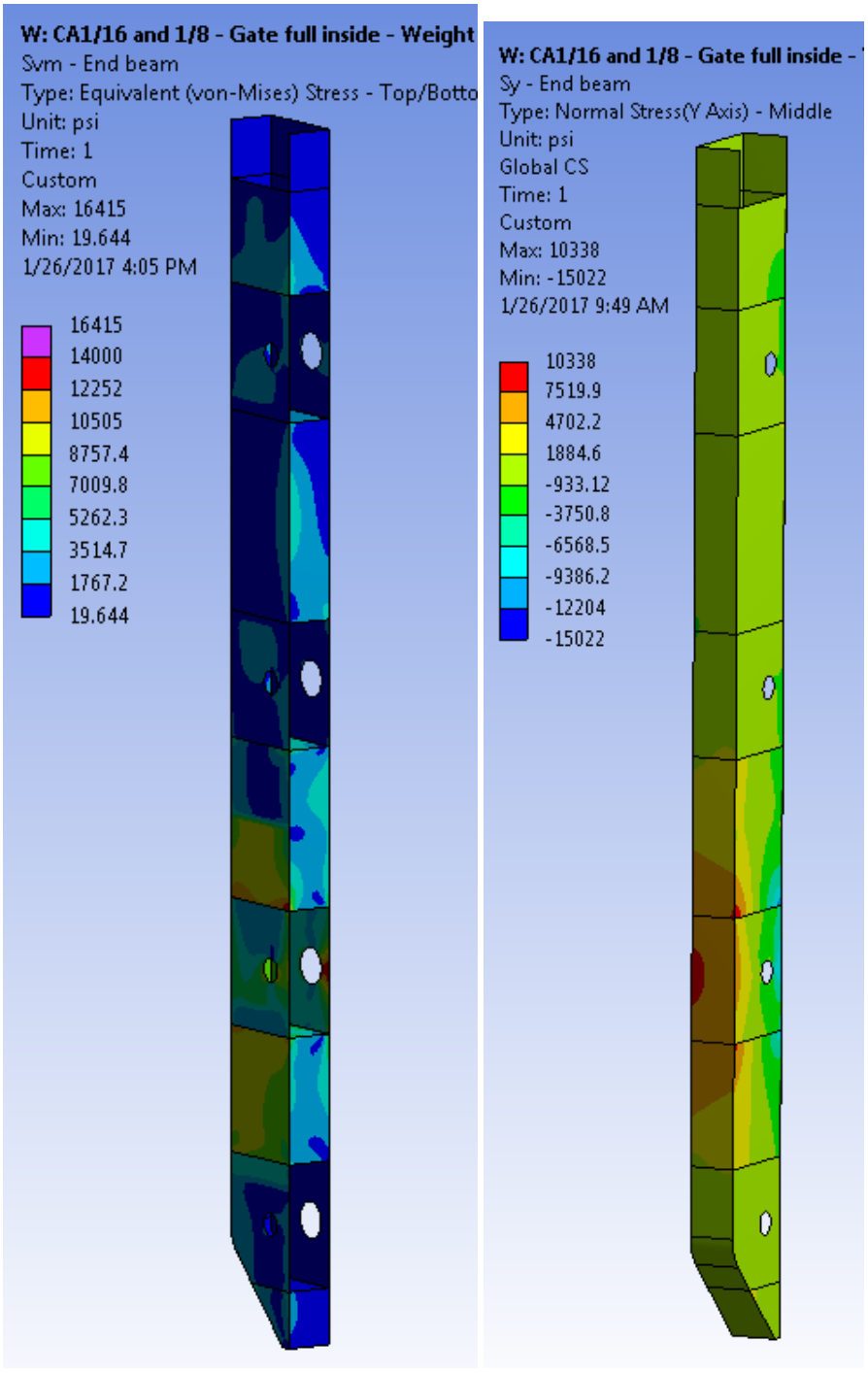


Figure D37: LS5 – Major Bending Stress, σ_z

Max of 7,819 psi (compression) occurs in the upstream skinplate in the middle of gate at Girder 06. Allowable 19,800 psi.



a b

Figure D38: LS5 – Von Mises Stress (a) and Bending Stress σ_y (b) in the End Beam

Max 16,415 psi and 15,022, respectively. Allowable 19,800 psi.

D3 - Wheel Axels Stress Check

Wreck Cove T2 Intake Gate - Wheel axles stress check

Calculation Cover Sheet

Customer:	Nova Scotia Power
Project Title:	Wreck Cove Generating Station Dam Safety Assessment
Discipline:	Mechanical
Calculation No.:	H351728-00000-200-230-0002-App A **File No:** **Number of Sheets:** 6
Description:	Wreck Cove T2 Intake Gate - Wheel axles stress check
Category of calculation verification required *tick box*	☑ 1 ☐ 2 ☐ 3 ☐ 4
Prepared by:	O.Belashov **Date:** 06Feb2017
Print Name >	Oleg Belashov
Preliminary Review by:	**Date:** 06Feb2017
Print Name >	Val Kovalishyn
Can the calculation now be released for work?	☑ Yes ☐ No **To the Client?** ☑ Yes ☐ No
Checked by: by:	**Date:** 06Feb2017
Print Name >	Val Kovalishyn
Reviewed by:	**Date:**
Print Name >	
Approved by:	**Date:**
Print Name >	

General Notes: Internal rev A-03

Revisions

Rev.	Date	Prepared by	Checked by	Approved by	Description
A	06Feb2017	O. Belashov OB	V. Kovalishyn	J.Atkinson	

Superseded by Calculation No. **Date:**

Reason voided:

Calculation Descriptions and Assumptions

1. The axle material cannot be read from H085S1-9-625-00-082 drawing due to poor quality of the scan
2. Reaction forces are take from the FEA study Ref 2

References

1. H085S1-9-625-00-082 drawings .
2. H351728-00000-200-230-0002, Finite Element Analyses.

HATCH™

1) Input Data

$h_{seal} := 173in$ Sill to lintel distance

$w_{seal} := 2 \cdot 85.438in = 170.88 \cdot in$ Side seal to side seal distance

$EL_{max} := 1200ft$ Max operating water elevation

$EL_{sill} := 1168ft$ Sill elevation

$g := 9.81 \frac{m}{s^2}$ Same g value as used in FEA to define hydrostatic pressure

$\rho := 1000 \frac{kg}{m^3}$ Water density

Wheel reaction forces from FEA study of Ref 2

$R_w :=$

LS1	LS2	LS3	LS4	LS5
40808	0	54915	36807	33077
35649	113490	0	58907	11035
35891	9578	63618	0	114800
46567	35850	40383	63201	0

$R_w := R_w \cdot lbf$

$i := 0 .. rows(R_w) - 1$

$j := 0 .. cols(R_w) - 1$

2) Reaction force verification

$H_{sill} := EL_{max} - EL_{sill} = 32 \cdot ft$ Hydrostatic head at the sill

$H := w_{seal} \cdot \int_{H_{sill}-h_{seal}}^{H_{sill}} \rho \cdot g \cdot y \, dy = 317832 \cdot lbf$ Total hydrostatic force on the gate

$H_{FE_j} := 2 \sum R_w^{\langle j \rangle}$ Total hydrostatic force from FEA for each loading scenario

$H_{FE} := H_{FE}^T$

$H_{FE} =$

LS1	LS2	LS3	LS4	LS5
317830	317836	317832	317830	317824

$\cdot lbf$ FEA

$H = 317832 \cdot lbf$ Analytical. In very close agreement with FEA

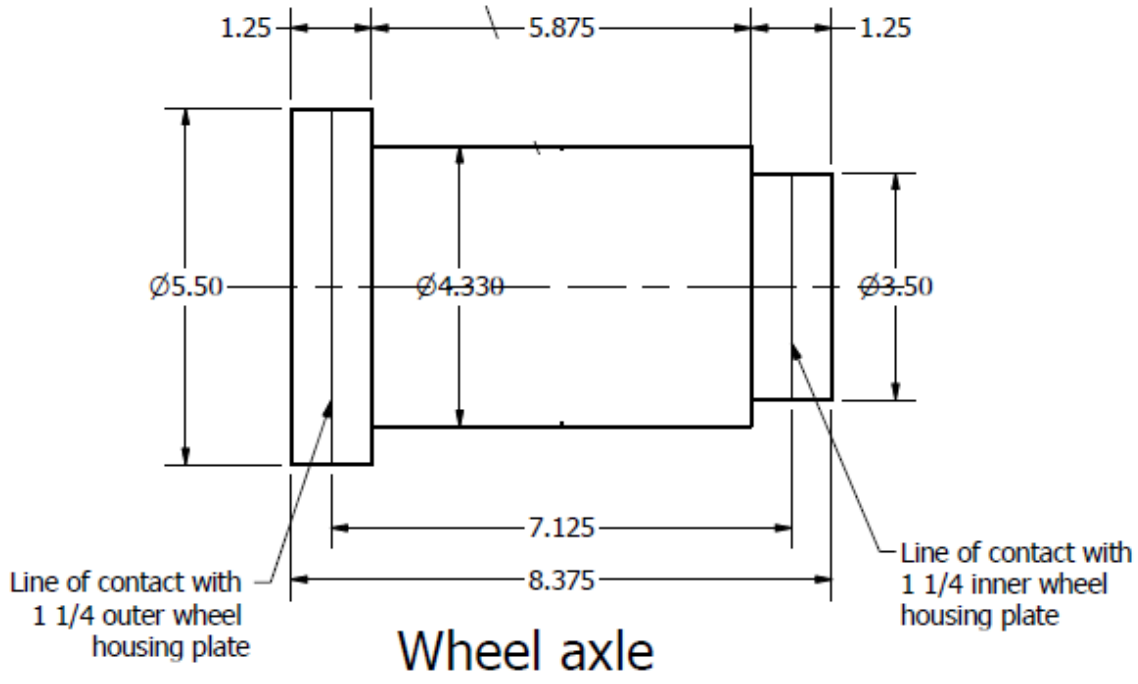
3) Wheel axle stresses

$d_1 := 4.33in$ Axle diameter in the middle

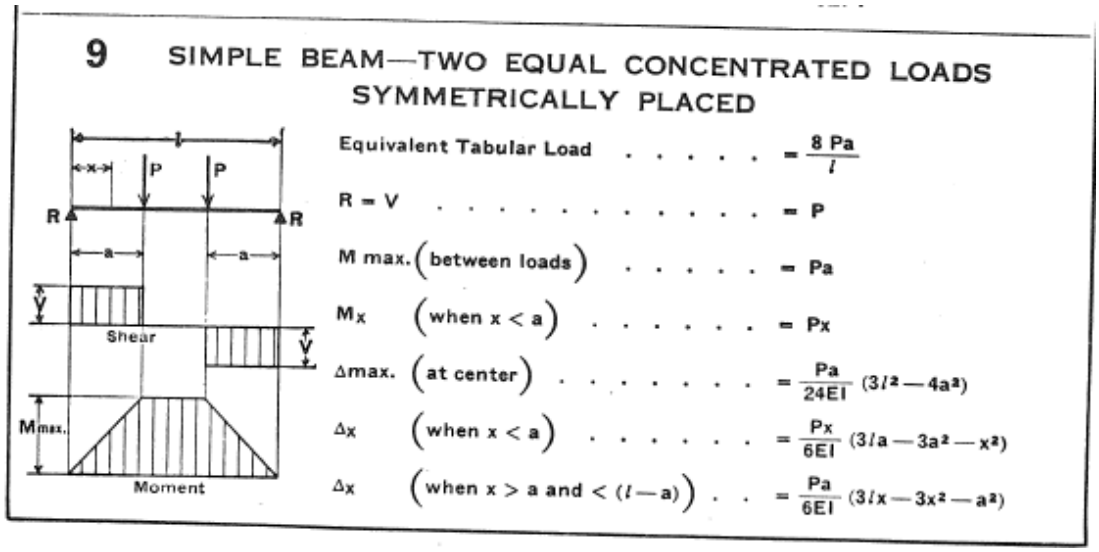
$d_2 := 3.5in$ Axle diameter at the inner end plate

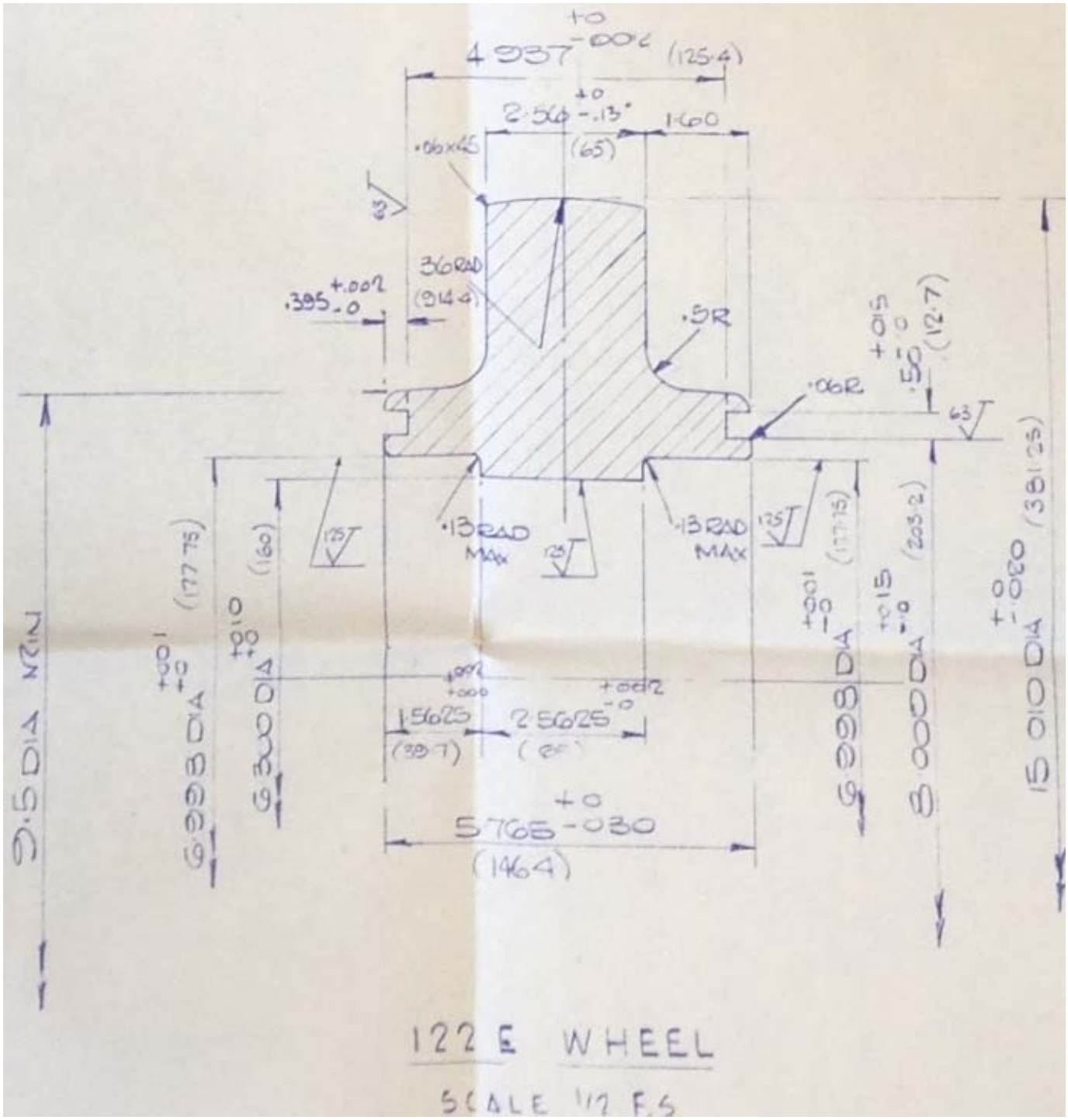
$L := 7.125in$ Distance between end plates

$a := 0.8in + \frac{1.25in}{2} = 1.43 \cdot in$ Distance between the middle of end plate to the middle of roller bearing. There are two roller bearing per wheel



Wheel axle




4.937 +0 -.002 (125.4)
2.56 +0 -.13 (65)
1.60
.06x45
36 RAD (914.4)
.395 +.002 -0
.5R
.06R
.13 RAD MAX
.13 RAD MAX
1.5625 (39.7)
2.5625 +.002 -0
5.765 +0 -.030 (146.4)
9.5 DIA MIN
6.998 DIA
6.300 DIA
6.998 DIA
8.000 DIA
15.010 DIA
122 E WHEEL
SCALE 1/2 F.S

$A_2 := \pi \cdot \frac{d_2^2}{4} = 9.62 \cdot in^2$ Cross section area at the inner end plate

$I_1 := \pi \cdot \frac{d_1^4}{64} = 17.26 \cdot in^4$ Moment of inertia in the middle

$S_1 := \frac{I_1}{0.5 \cdot d_1} = 7.97 \cdot in^3$ Section modulus in the middle

$M_{i,j} := 0.5 \cdot R_{w_{i,j}} \cdot a$ Bending moment in the middle

$\sigma_{i,j} := \frac{M_{i,j}}{S_1}$ Bending stress in the middle

$\tau_{i,j} := \frac{4}{3} \cdot \frac{0.5 \cdot R_{w_{i,j}}}{A_2}$ Shear stress at the inner end plate

$\sigma =$

LS1	LS2	LS3	LS4	LS5
3648	0	4909	3290	2957
3187	10146	0	5266	986
3209	856	5687	0	10263
4163	3205	3610	5650	0

$\cdot psi$

$\tau \cdot \sqrt{3} =$

4898	0	6591	4417	3970
4278	13621	0	7070	1324
4308	1150	7635	0	13778
5589	4303	4847	7585	0

$\cdot psi$

Both bending and shear stress in the wheel axles are low. Although the axle material is not known it can be concluded the the wheel axles have sufficient capacity

D4 - Main Girder Weld Capacity Check

Wreck Cove T2 Intake Gate - Girder Weld Capacity Check

Calculation Cover Sheet

Client:	Nova Scotia Power				
Project Title:	Wreck Cove T2 Intake				
Discipline:	Mechanical/Structural				
Calculation No.:	H351728-00000-200-230-0002-App B	**File No:**		**Number of Sheets:** 37	
Description:	Wreck Cove T2 Intake Gate - Girder Weld Capacity Check				
Category of calculation verification required *tick box*	☑ 1	☐ 2	☐ 3	☐ 4	
Prepared by:	O.Belashov		**Date:**	24Jan2017	
Print Name >	Oleg Belashov				
Preliminary Review by:			**Date:**	24Jan2017	
Print Name >	Val Kovalishyn				
Can the calculation now be released for work?	☑ Yes ☐ No	**To the Client?**	☑ Yes ☐ No		
Checked by:			**Date:**	24Jan2017	
Print Name >	Val Kovalishyn				
Reviewed by:			**Date:**		
Print Name >					
Approved by:			**Date:**	24Jan2017	
Print Name >	Jonathan Atkinson				

General Notes:
Internal Rev A-02

Revisions

Rev.	Date	Prepared by	Checked by	Approved by	Description
A	24Jan2017	O. Belashov OB	V. Kovalishyn	J. Atkinson	

Superseded by Calculation No. **Date:**

Reason voided:

CALCULATIONS

Calculation description

1. This calculation checks the capacity of the girder welds at the the web-skinplate interface on both the downstream and upstream sides
2. One loading scenario LS1, corresponding to max normal hydrostatic pressure with water inside the gate where all wheels are in contact with the wheel track (Ref 3), is considered.
3. Nodal forces acting on the webs are extracted from the FEA model of Ref 3

References

1. ETL 1110-2-584, Design of Hydraulic Steel Structures, June 2014
2. Mechanical Engineering Design, Shigley
3. H351728-00000-200-230-0002, Finite Element Analyses

1) Input Parameters

$\alpha := 1.33$ Gate performance factor, Ref 1

$fa_{1\_4} := 3.18 \frac{kip}{in}$ Fillet weld capacity for E60XX electrode for 1/4in weld, Ref 2

$fa := \frac{2 \cdot fa_{1\_4}}{\alpha} = 4.782 \cdot \frac{kip}{in}$ Allowable weld capacity for E60XX electrode for double 1/4in fillet weld

Table 9–6

Allowable Steady Loads and Minimum Fillet Weld Sizes

Schedule A: Allowable Load for Various Sizes of Fillet Weld

	Strength Level of Weld Metal (EXX)						
	60*	70*	80	90*	100	110*	120
	Allowable shear stress on throat, ksi (1000 psi) of fillet weld or partial penetration groove weld						
$\tau =$	18.0	21.0	24.0	27.0	30.0	33.0	36.0
	Allowable Unit Force on Fillet Weld, kip/linear in						
†$f =$	12.73h	14.85h	16.97h	19.09h	21.21h	23.33h	25.45h

Leg Size h, in *	Allowable Unit Force for Various Sizes of Fillet Welds kip/linear in						
1	12.73	14.85	16.97	19.09	21.21	23.33	25.45
7/8	11.14	12.99	14.85	16.70	18.57	20.41	22.27
3/4	9.55	11.14	12.73	14.32	15.92	17.50	19.09
5/8	7.96	9.28	10.61	11.93	13.27	14.58	15.91
1/2	6.37	7.42	8.48	9.54	10.61	11.67	12.73
7/16	5.57	6.50	7.42	8.35	9.28	10.21	11.14
3/8	4.77	5.57	6.36	7.16	7.95	8.75	9.54
5/16	3.98	4.64	5.30	5.97	6.63	7.29	7.95
1/4	3.18	3.71	4.24	4.77	5.30	5.83	6.36
3/16	2.39	2.78	3.18	3.58	3.98	4.38	4.77
1/8	1.59	1.86	2.12	2.39	2.65	2.92	3.18
1/16	0.795	0.930	1.06	1.19	1.33	1.46	1.59

*Fillet welds actually tested by the joint AISC-AWS Task Committee.
†$f = 0.707h\,\tau_{all}$

Figure 1: Fillet weld capacity from Ref 1

$n_s := 12$ Number of spacings in the stitch weld ranging from the inner end plate to the middle of the gate

$Ls1 := 3in$ Length of one stitch in the interval marked as 1 in Figure 2

$Ls2 := 1.5in$ Length of one stitch in the interval marked as 2 in Figure 2

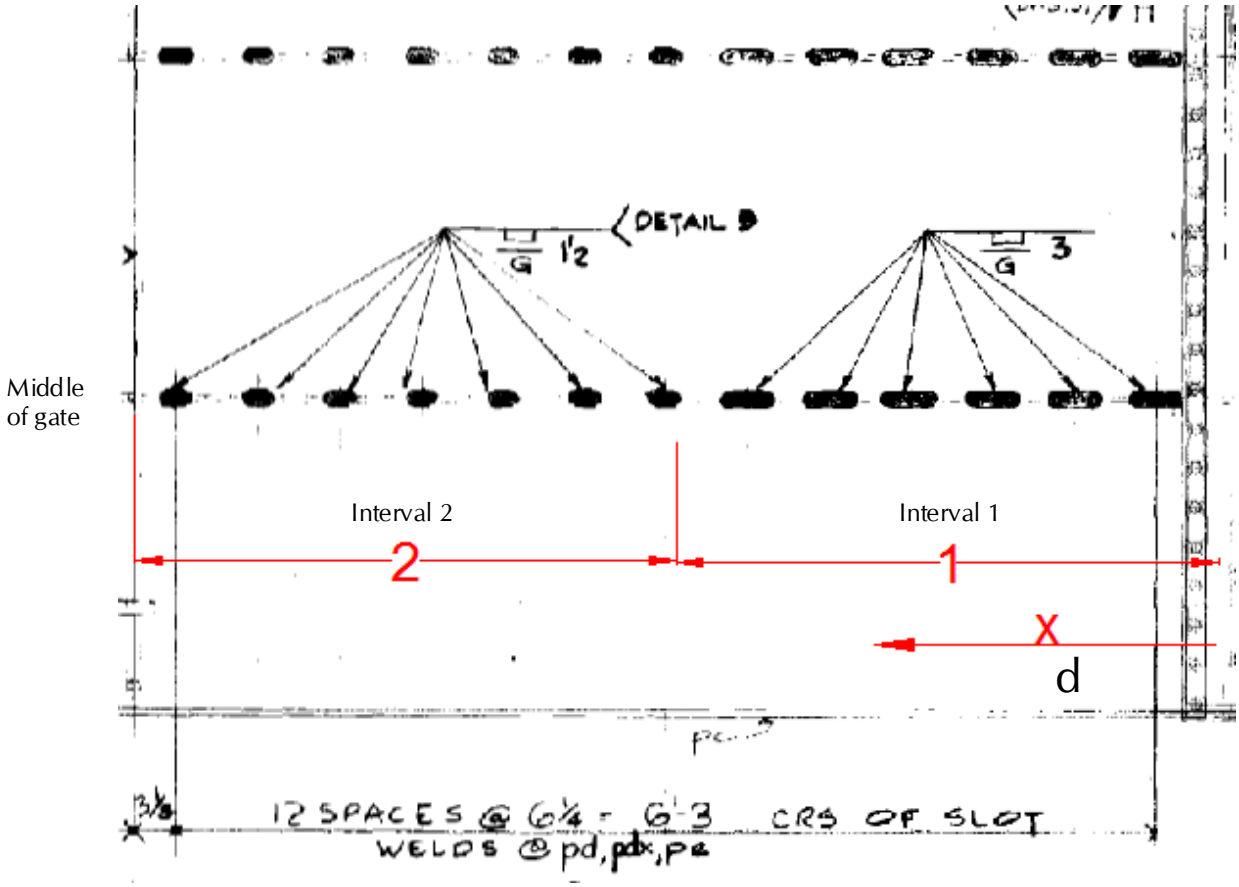


Figure 2: Stitch weld on the downstream side. The upstream weld is continuous 1/4in fillet weld on both sides of the web

2) Input Data From FEA - Nodal Forces

The data below represents nodal forces (Ref 3) at the web-skinplate interface (both upstream and downstream) from loading scenario LS1 corresponding to max normal hydrostatic pressure with water inside the gate where all wheels are in contact with the wheel track.

G1US :=

	0	1	2	3
	d[in]	Fx[lbf]	Fx[lbf]	Fx[lbf]
0	0	-141.71	5.268	-127.75
1	0.697	-29.56	4.794	-293.95
2	1.393	-24.092	1.537	...

G1DS :=

Girder 1

	0	1	2	3
	d[in]	Fx[lbf]	Fx[lbf]	Fx[lbf]
0	0	-130.23	14.696	79.303
1	0.697	-52.07	32.799	253.53
2	1.393	-36.65	15.032	...

G2US :=

	0	1	2	3
0	0	-434.29	-2.849	-524.97
1	0.7	-363	-42.401	-701.71
2	1.401	-228.71	-11.712	...

G2DS :=

Girder 2

	0	1	2	3
0	0	-380.88	1.39	383.91
1	0.7	-361.85	27.582	608.38
2	1.401	-231.58	7.031	...

G3US :=

	0	1	2	3
0	0	-454.64	8.969	-496.16
1	0.7	-346.39	-16.691	-751.29
2	1.401	-201.83	-2.529	...

G3DS :=

Girder 3

	0	1	2	3
0	0	-422.97	-8.178	429.73
1	0.7	-352.15	0.103	705.37
2	1.401	-202.41	2.073	...

G4US :=

	0	1	2	3
0	0	-673.38	-4.721	-757.12
1	0.7	-233.41	-12.878	-870.41
2	1.401	-97.908	-2.643	...

G4DS :=

Girder 4

	0	1	2	3
0	0	-700.76	14.016	770.12
1	0.7	-226.01	7.315	862.54
2	1.401	-72.341	1.959	...

G5US :=

	0	1	2	3
0	0	-475.04	-8.659	-576.68
1	0.7	-394.77	3.768	-754.56
2	1.401	-258.56	-1.062	...

G5DS :=

Girder 5

	0	1	2	3
0	0	-456.63	4.603	477.04
1	0.7	-425.72	-11.397	694.89
2	1.401	-279.93	-2.093	...

G6US :=

	0	1	2	3
0	0	-426.23	-5.667	-505.27
1	0.7	-360.31	21.033	-701.84
2	1.401	-241.22	3.458	...

G6DS :=

Girder 6

	0	1	2	3
0	0	-432.99	5.028	451.33
1	0.7	-404.46	-25.041	689.08
2	1.401	-270.25	-3.066	...

3) Weld check - Girder 1

Girder1 - Upstream weld

Location := "Girder1 - Upstream weld "

Data := G1US

$n := rows(Data) = 124$ Number of rows

Read data from FEA

$d := Data^{\langle 0 \rangle} \cdot in$ $Fx := Data^{\langle 1 \rangle} \cdot lbf$ $Fy := Data^{\langle 2 \rangle} \cdot lbf$ $Fz := Data^{\langle 3 \rangle} \cdot lbf$

$F := \sqrt{Fx^2 + Fy^2 + Fz^2}$ Total force

$i := 0 .. n - 2$

$\Delta d := 0$

$\Delta d_i := d_{i+1} - d_i$

Check if the intervals can be considered equal

$min(\Delta d) = 0.68 \cdot in$ $max(\Delta d) = 0.70 \cdot in$ $Stdev(\Delta d) = 0.006 \cdot in$ OK, to be considered equal

$\Delta d := mean(\Delta d) = 0.69 \cdot in$

Extrapolate force values for the first and last data points

$i := 1 .. n - 2$

$d_{temp} := 0$ $F_{temp} := 0$

$d_{temp_{i-1}} := d_i$ $F_{temp_{i-1}} := F_i$

$F_0 := linterp(d_{temp}, F_{temp}, d_0)$

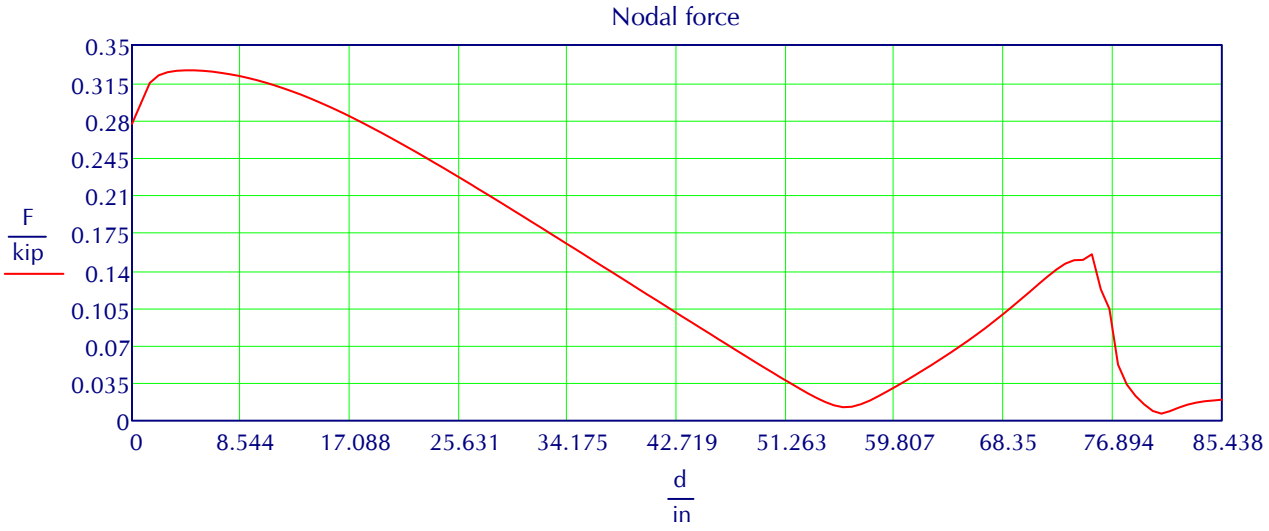
$F_{n-1} := linterp(d_{temp}, F_{temp}, d_{n-1})$

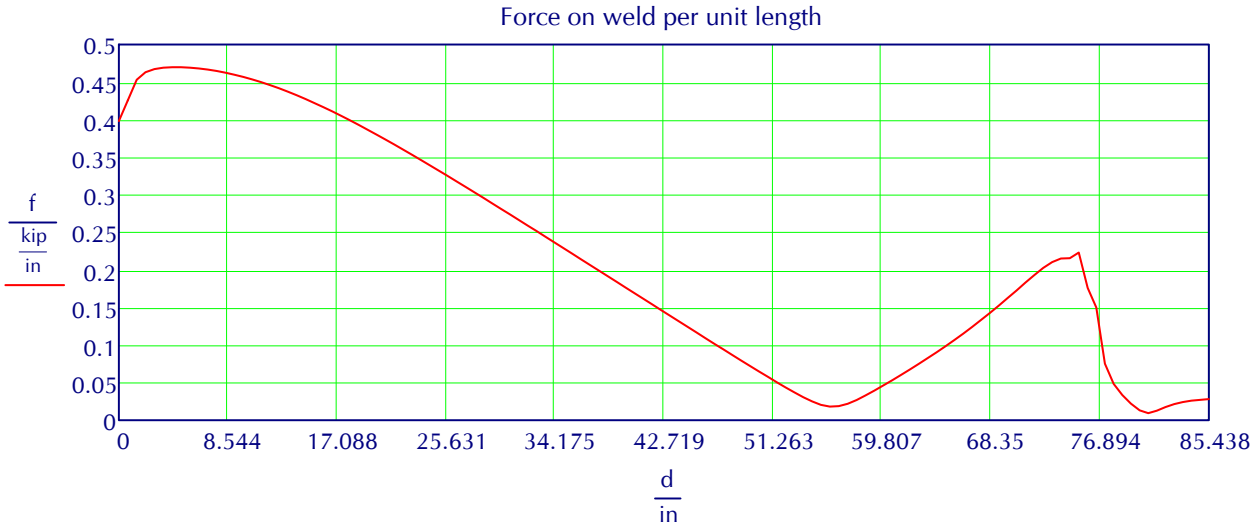
$f := \frac{F}{\Delta d}$ Force on the weld per unit length

$f_{max} := max(f) = 0.470 \cdot \frac{kip}{in}$

$\frac{f_{max}}{fa} = 0.10 < 1.0$ Demand\capacity ratio for Location = "Girder1 - Upstream weld " where $fa = 4.78 \cdot \frac{kip}{in}$

Location = "Girder1 - Upstream weld "





Girder1 - Downstream weld

Location := "Girder1 - Downstream weld"

Data := G1DS

n := rows(Data) = 124 Number of rows

Read data from FEA

$d := Data^{\langle 0 \rangle} \cdot in$ $Fx := Data^{\langle 1 \rangle} \cdot lbf$ $Fy := Data^{\langle 2 \rangle} \cdot lbf$ $Fz := Data^{\langle 3 \rangle} \cdot lbf$

$F := \sqrt{Fx^2 + Fy^2 + Fz^2}$ Total force

$i := 0 .. n - 2$

$\Delta d := 0$

$\Delta d_i := d_{i+1} - d_i$

Check if the intervals can be considered equal

$\min(\Delta d) = 0.68 \cdot in$ $\max(\Delta d) = 0.70 \cdot in$ $Stdev(\Delta d) = 0.006 \cdot in$ OK, to be considered equal

$\Delta d := mean(\Delta d) = 0.69 \cdot in$

Extrapolate force values for the first and last data points

$i := 1 .. n - 2$

$d_{temp} := 0$ $F_{temp} := 0$

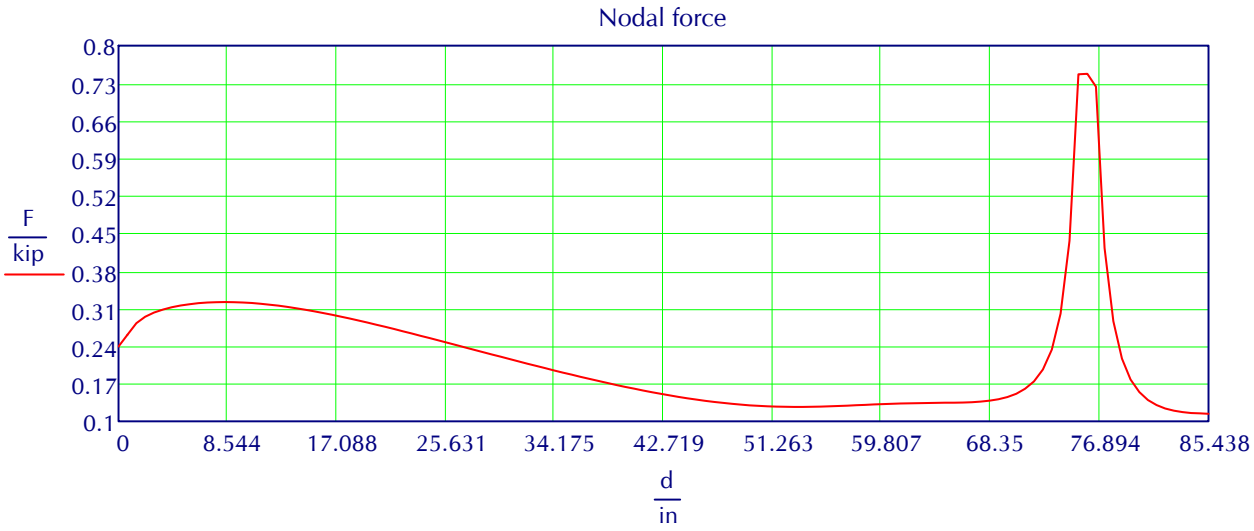
$d_{temp_{i-1}} := d_i$ $F_{temp_{i-1}} := F_i$

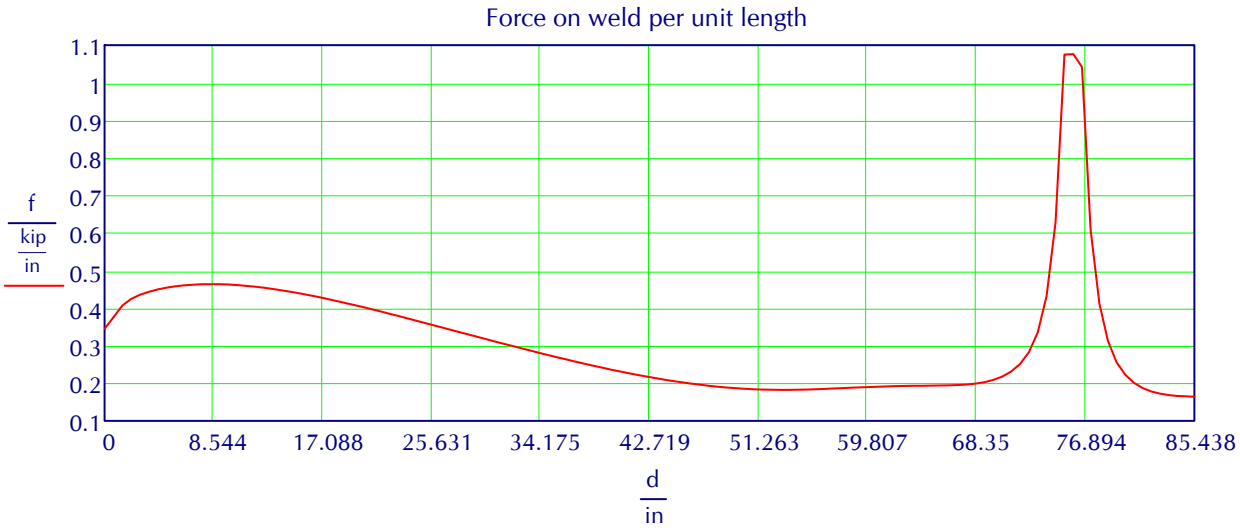
$F_0 := linterp(d_{temp}, F_{temp}, d_0)$

$F_{n-1} := linterp(d_{temp}, F_{temp}, d_{n-1})$

$f := \frac{F}{\Delta d}$ Force on the weld per unit length

Location = "Girder1 - Downstream weld"





The spike at d = 75in is due to the gusset plate at this location

However the weld on the downstream side is not continuous (Figure 2). A single stitch is conservatively assumed to have the capacity of 1/4 double fillet weld.

Weld capacity calculation for the 3in stitch weld

$i := 0 .. \frac{n}{2}$

$F1 := 0$

$F1_i := F_i$

$F_{max} := \max(F1) = 0.32 \cdot kip$

$n_{max} := match(F_{max}, F)_0 = 12$ Find where the nodal force is max along Interval 1 as shown in Figure 2

$d_{max} := d_{n_{max}} = 8.36 \cdot in$

$\Delta w := \frac{\max(d)}{n_s} = 7.12 \cdot in$ One stitch is to withstand force from $\Delta w = 7.12 \cdot in$

$Fs1 := \int_{d_{max}-0.5\cdot\Delta w}^{d_{max}+0.5\cdot\Delta w} linterp(d, f, x)\, dx = 3.280 \cdot kip$ Max force per single 3in stitch

$fs1 := \frac{Fs1}{Ls1} = 1.09 \cdot \frac{kip}{in}$ Required min weld capacity for a single stitch

$\frac{fs1}{fa} = 0.23 \quad < 1.0$ Demand\capacity ratio for Location = "Girder1 - Downstream weld" for the 3in stitch weld where $fa = 4.78 \cdot \frac{kip}{in}$

Weld capacity calculation for the 1.5in stitch weld

$i := \frac{n}{2} .. n - 1$

$F2 := 0$

$F2_{i-\frac{n}{2}} := F_i$

$F_{max} := \max(F2) = 0.75 \cdot kip$ Find where nodal force is max along Interval 2 as shown in Figure 2

$n_{max} := match(F_{max}, F)_0 = 109$

$d_{max} := d_{n_{max}} = 75.94 \cdot in$

$Fs2 := \int_{d_{max}-0.5\cdot\Delta w}^{d_{max}+0.5\cdot\Delta w} linterp(d, f, x)\, dx = 4.320 \cdot kip$ Max force per single 1.5in stitch

$fs2 := \frac{Fs2}{Ls2} = 2.88 \cdot \frac{kip}{in}$ Required min weld capacity for a single stitch

$\frac{fs2}{fa} = 0.60 \quad < 1.0$ Demand\capacity ratio for Location = "Girder1 - Downstream weld" for the 1.5in stitch weld where $fa = 4.78 \cdot \frac{kip}{in}$

in

4) Weld check - Girder 2

Girder2 - Upstream weld

Location := "Girder2 - Upstream weld "

Data := G2US

n := rows(Data) = 123 Number of rows

Read data from FEA

$d := Data^{\langle 0 \rangle} \cdot in$ $Fx := Data^{\langle 1 \rangle} \cdot lbf$ $Fy := Data^{\langle 2 \rangle} \cdot lbf$ $Fz := Data^{\langle 3 \rangle} \cdot lbf$

$F := \sqrt{Fx^2 + Fy^2 + Fz^2}$ Total force

$i := 0 .. n - 2$

$\Delta d := 0$

$\Delta d_i := d_{i+1} - d_i$

Check if the intervals can be considered equal

$\min(\Delta d) = 0.70 \cdot in$ $\max(\Delta d) = 0.70 \cdot in$ $Stdev(\Delta d) = 0.000 \cdot in$ OK, to be considered equal

$\Delta d := mean(\Delta d) = 0.70 \cdot in$

Extrapolate force values for the first and last data points

$i := 1 .. n - 2$

$d_{temp} := 0$ $F_{temp} := 0$

$d_{temp_{i-1}} := d_i$ $F_{temp_{i-1}} := F_i$

$F_0 := linterp(d_{temp}, F_{temp}, d_0)$

$F_{n-1} := linterp(d_{temp}, F_{temp}, d_{n-1})$

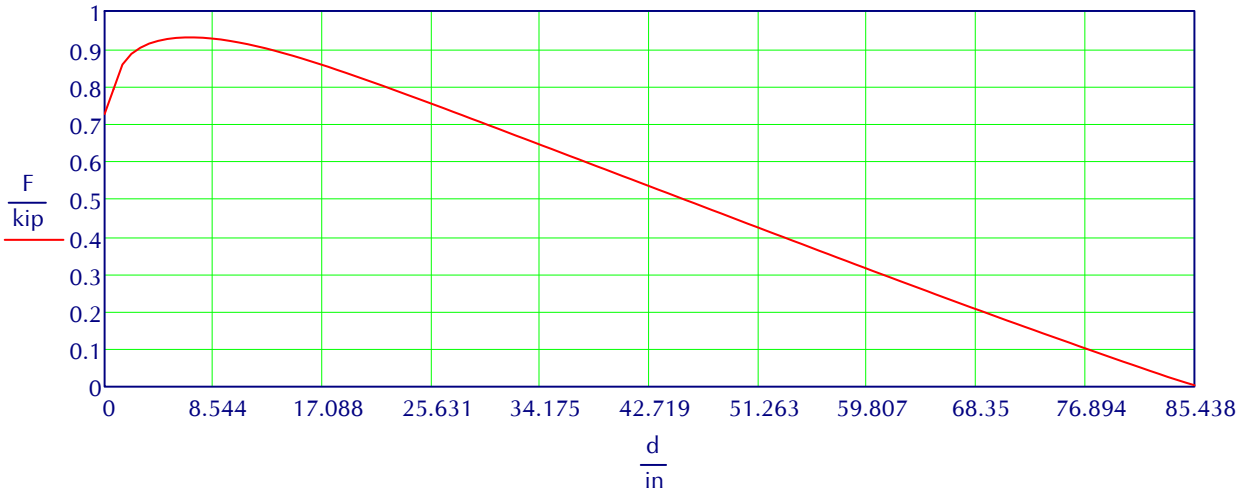
$f := \frac{F}{\Delta d}$ Force on the weld per unit length

$f_{max} := \max(f) = 1.327 \cdot \frac{kip}{in}$

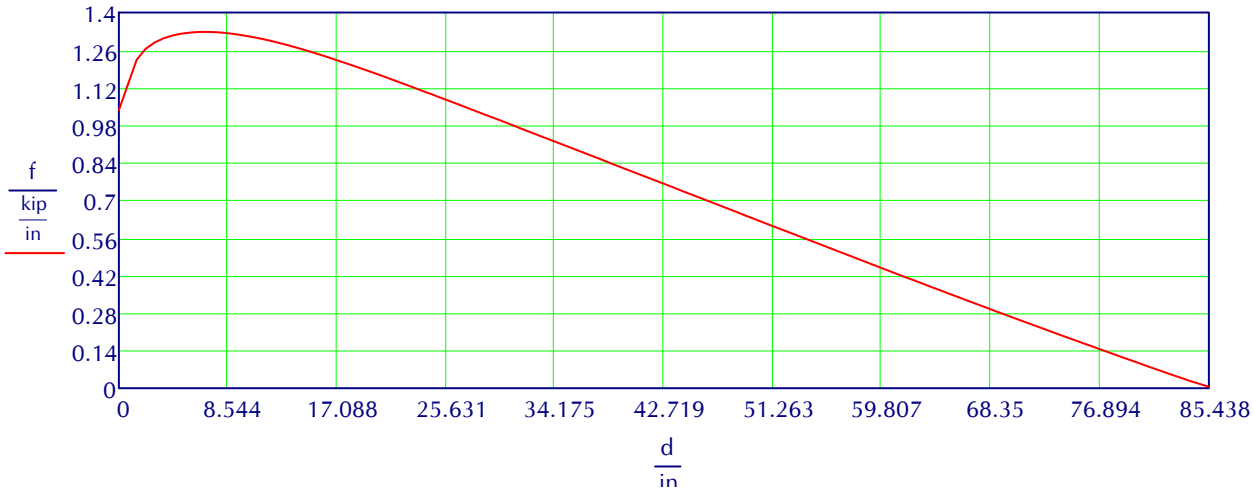
$\frac{f_{max}}{fa} = 0.28 < 1.0$ Demand/capacity ratio for Location = "Girder2 - Upstream weld " where $fa = 4.78 \cdot \frac{kip}{in}$

Location = "Girder2 - Upstream weld "

Nodal force



Force on weld per unit length



...

Girder2 - Downstream weld

Location := "Girder2 - Downstream weld"

Data := G2DS

n := rows(Data) = 123 Number of rows

Read data from FEA

$d := Data^{\langle 0 \rangle} \cdot in$ $Fx := Data^{\langle 1 \rangle} \cdot lbf$ $Fy := Data^{\langle 2 \rangle} \cdot lbf$ $Fz := Data^{\langle 3 \rangle} \cdot lbf$

$F := \sqrt{Fx^2 + Fy^2 + Fz^2}$ Total force

i := 0 .. n − 2

Δd := 0

$\Delta d_i := d_{i+1} - d_i$

Check if the intervals can be considered equal

$\min(\Delta d) = 0.70 \cdot in$ $\max(\Delta d) = 0.70 \cdot in$ $Stdev(\Delta d) = 0.000 \cdot in$ OK, to be considered equal

$\Delta d := mean(\Delta d) = 0.70 \cdot in$

Extrapolate force values for the first and last data points

i := 1 .. n − 2

$d_{temp} := 0$ $F_{temp} := 0$

$d_{temp_{i-1}} := d_i$ $F_{temp_{i-1}} := F_i$

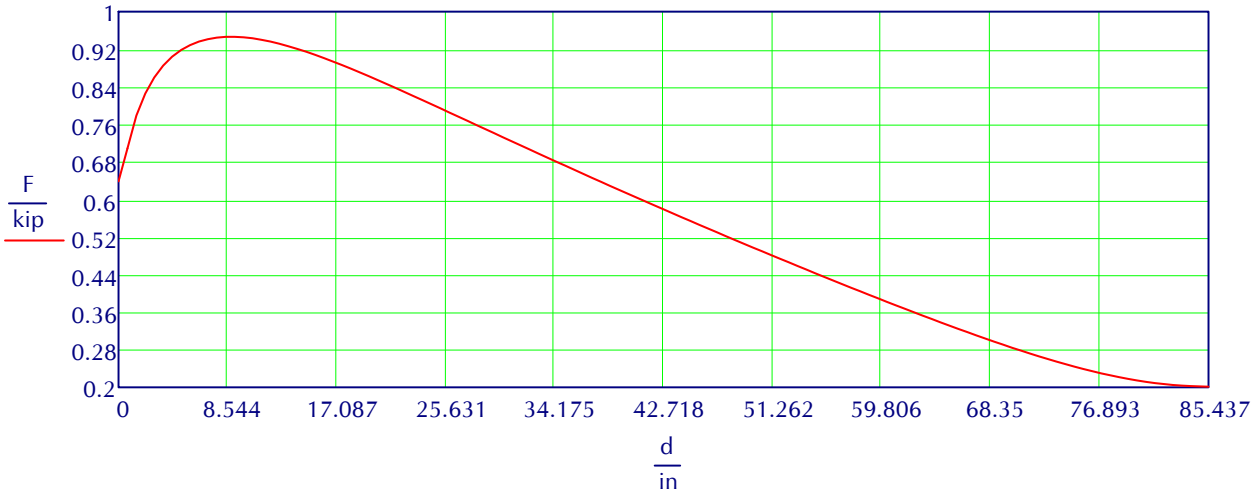
$F_0 := linterp(d_{temp}, F_{temp}, d_0)$

$F_{n-1} := linterp(d_{temp}, F_{temp}, d_{n-1})$

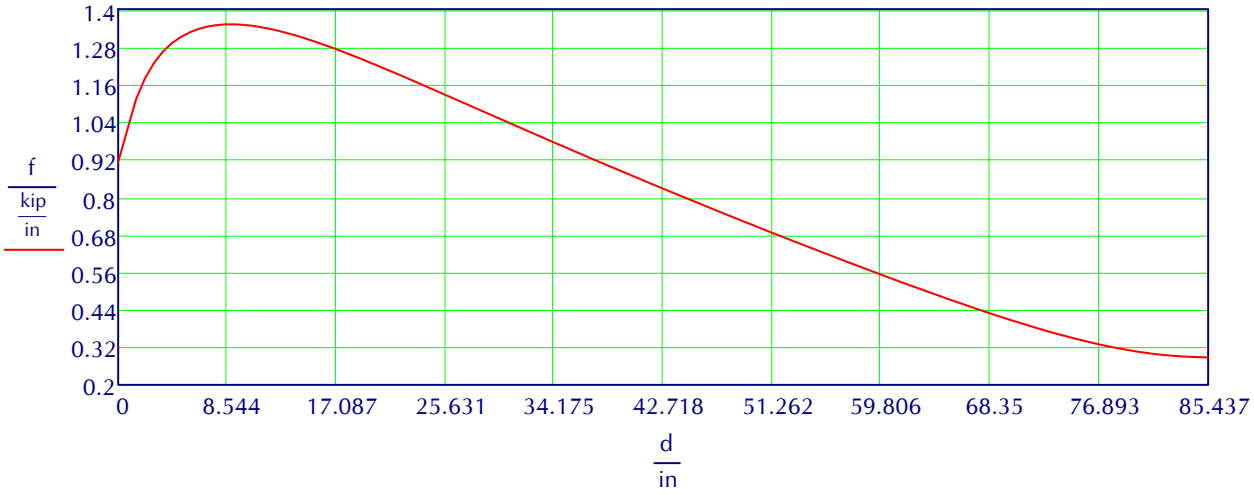
$f := \frac{F}{\Delta d}$ Force on the weld per unit length

Location = "Girder2 - Downstream weld"

Nodal force



Force on weld per unit length



However the weld on the downstream side is not continuous (Figure 2). A single stitch is conservatively assumed to have the capacity of 1/4 double fillet weld.

Weld capacity calculation for the 3in stitch weld

$i := 0 .. \frac{n}{2}$

$F1 := 0$

$F1_i := F_i$

$F_{max} := \max(F1) = 0.95 \cdot kip$

$n_{max} := match(F_{max}, F)_0 = 13$ Find where the nodal force is max along Interval 1 as shown in Figure 2

$d_{max} := d_{n_{max}} = 9.1 \cdot in$

$\Delta w := \frac{\max(d)}{n_s} = 7.12 \cdot in$ One stitch is to withstand force from $\Delta w = 7.12 \cdot in$

$Fs1 := \int_{d_{max}-0.5\cdot\Delta w}^{d_{max}+0.5\cdot\Delta w} linterp(d, f, x)\, dx = 9.562 \cdot kip$ Max force per single 3in stitch

$fs1 := \frac{Fs1}{Ls1} = 3.19 \cdot \frac{kip}{in}$ Required min weld capacity for a single stitch

$\frac{fs1}{fa} = 0.67 < 1.0$ Demand\capacity ratio for Location = "Girder2 - Downstream weld" for the 3in stitch weld where $fa = 4.78 \cdot \frac{kip}{in}$

Weld capacity calculation for the 1.5in stitch weld

$d_{max} := \frac{\max(d)}{2} = 42.72 \cdot in$ Location where nodal force is max along Interval 2 as shown in Figure 2

$Fs2 := \int_{d_{max}}^{d_{max}+\Delta w} linterp(d, f, x)\, dx = 5.461 \cdot kip$ Max force per single 1.5in stitch

$fs2 := \frac{Fs2}{Ls2} = 3.64 \cdot \frac{kip}{in}$ Required min weld capacity for a single stitch

$\frac{fs2}{fa} = 0.76 < 1.0$ Demand/capacity ratio for Location = "Girder2 - Downstream weld" for the 1.5in stitch weld where $fa = 4.78 \cdot \frac{kip}{in}$

5) Weld check - Girder 3

Girder3 - Upstream weld

Location := "Girder3 - Upstream weld "

Data := G3US

n := rows(Data) = 123 Number of rows

Read data from FEA

$d := Data^{\langle 0 \rangle} \cdot in$ $Fx := Data^{\langle 1 \rangle} \cdot lbf$ $Fy := Data^{\langle 2 \rangle} \cdot lbf$ $Fz := Data^{\langle 3 \rangle} \cdot lbf$

$F := \sqrt{Fx^2 + Fy^2 + Fz^2}$ Total force

$i := 0 .. n - 2$

$\Delta d := 0$

$\Delta d_i := d_{i+1} - d_i$

Check if the intervals can be considered equal

$\min(\Delta d) = 0.70 \cdot in$ $\max(\Delta d) = 0.70 \cdot in$ $Stdev(\Delta d) = 0.000 \cdot in$ OK, to be considered equal

$\Delta d := mean(\Delta d) = 0.70 \cdot in$

Extrapolate force values for the first and last data points

$i := 1 .. n - 2$

$d_{temp} := 0$ $F_{temp} := 0$

$d_{temp_{i-1}} := d_i$ $F_{temp_{i-1}} := F_i$

$F_0 := linterp(d_{temp}, F_{temp}, d_0)$

$F_{n-1} := linterp(d_{temp}, F_{temp}, d_{n-1})$

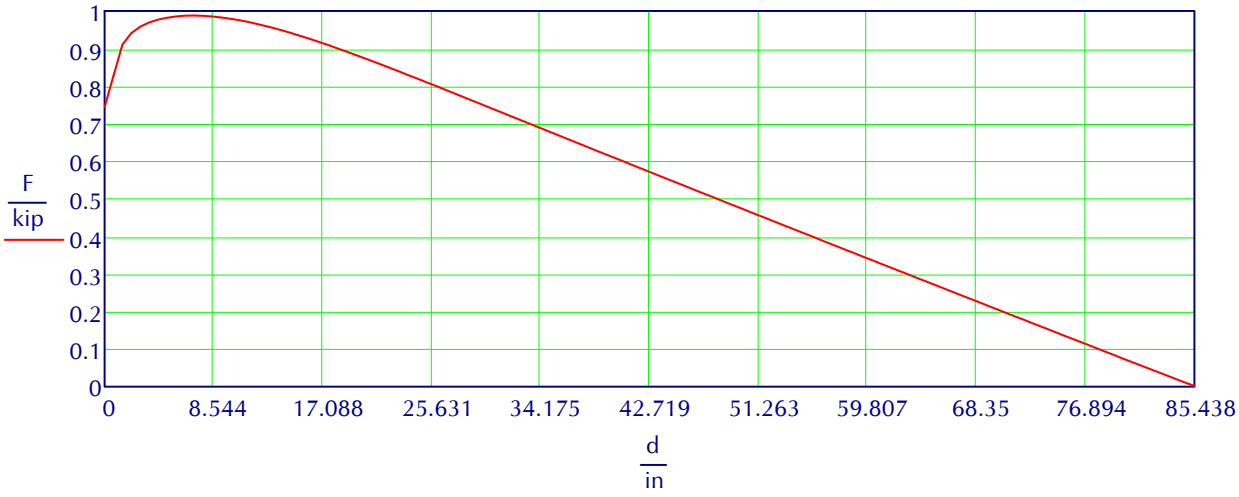
$f := \frac{F}{\Delta d}$ Force on the weld per unit length

$f_{max} := \max(f) = 1.410 \cdot \frac{kip}{in}$

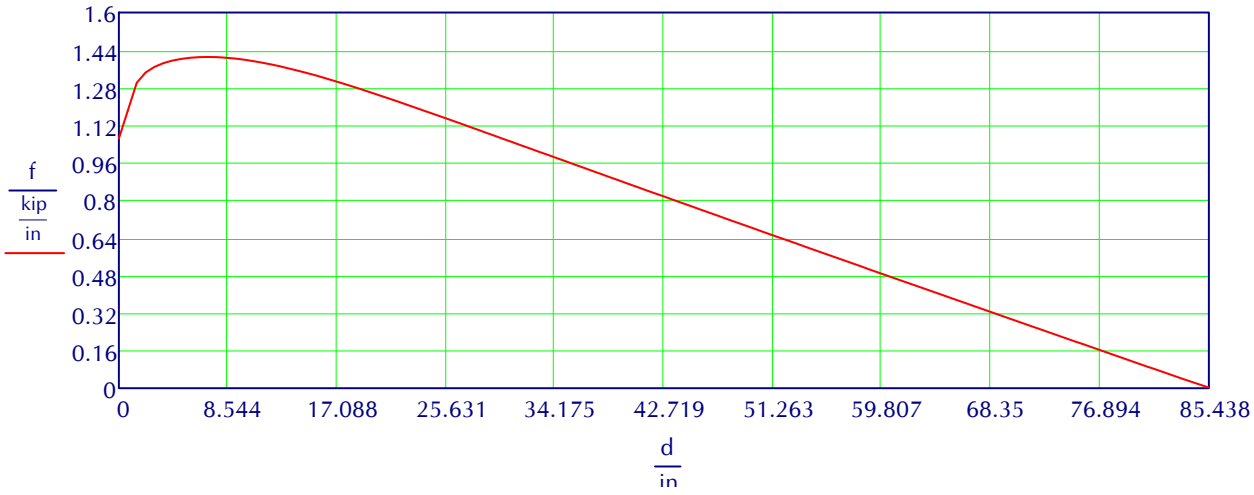
$\frac{f_{max}}{fa} = 0.29 < 1.0$ Demand/capacity ratio for Location = "Girder3 - Upstream weld " where $fa = 4.78 \cdot \frac{kip}{in}$

Location = "Girder3 - Upstream weld "

Nodal force



Force on weld per unit length



...

Girder3 - Downstream weld

Location := "Girder3 - Downstream weld"

Data := G3DS

n := rows(Data) = 123 Number of rows

Read data from FEA

$d := Data^{\langle 0 \rangle} \cdot in$ $Fx := Data^{\langle 1 \rangle} \cdot lbf$ $Fy := Data^{\langle 2 \rangle} \cdot lbf$ $Fz := Data^{\langle 3 \rangle} \cdot lbf$

$F := \sqrt{Fx^2 + Fy^2 + Fz^2}$ Total force

$i := 0 .. n - 2$

$\Delta d := 0$

$\Delta d_i := d_{i+1} - d_i$

Check if the intervals can be considered equal

$\min(\Delta d) = 0.70 \cdot in$ $\max(\Delta d) = 0.70 \cdot in$ $Stdev(\Delta d) = 0.000 \cdot in$ OK, to be considered equal

$\Delta d := mean(\Delta d) = 0.70 \cdot in$

Extrapolate force values for the first and last data points

$i := 1 .. n - 2$

$d_{temp} := 0$ $F_{temp} := 0$

$d_{temp_{i-1}} := d_i$ $F_{temp_{i-1}} := F_i$

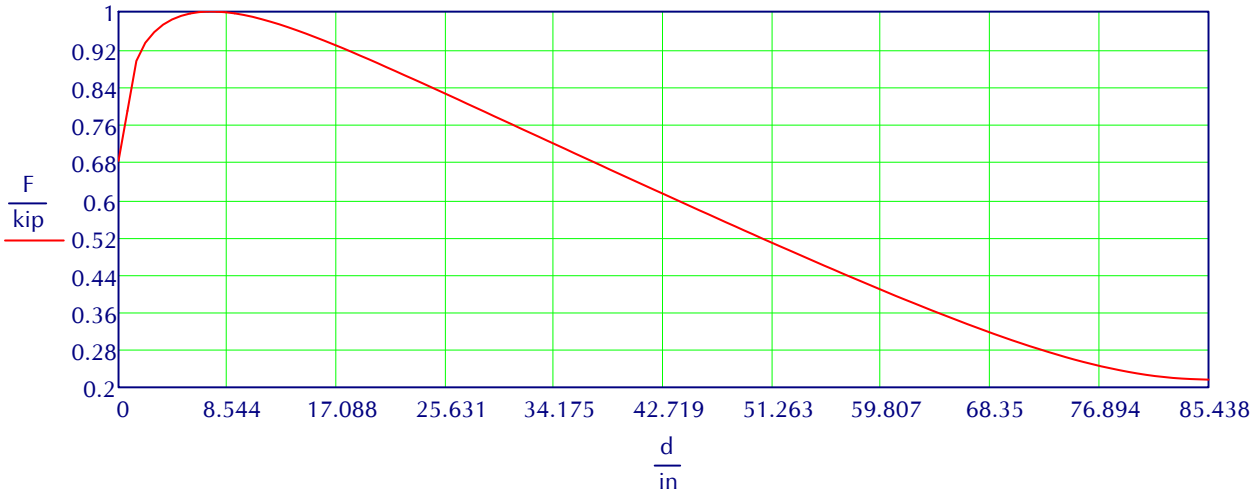
$F_0 := linterp(d_{temp}, F_{temp}, d_0)$

$F_{n-1} := linterp(d_{temp}, F_{temp}, d_{n-1})$

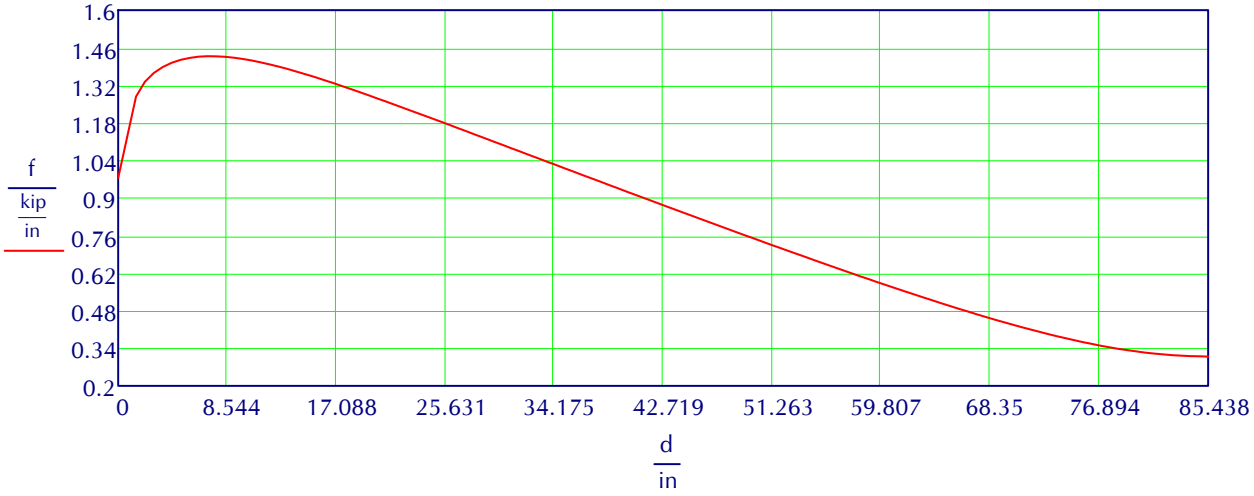
$f := \frac{F}{\Delta d}$ Force on the weld per unit length

Location = "Girder3 - Downstream weld"

Nodal force



Force on weld per unit length



However the weld on the downstream side is not continuous (Figure 2). A single stitch is conservatively assumed to have the capacity of 1/4 double fillet weld.

Weld capacity calculation for the 3in stitch weld

$i := 0 .. \frac{n}{2}$

$F1 := 0$

$F1_i := F_i$

$F_{max} := \max(F1) = 1 \cdot kip$

$n_{max} := match(F_{max}, F)_0 = 10$ Find where the nodal force is max along Interval 1 as shown in Figure 2

$d_{max} := d_{n_{max}} = 7 \cdot in$

$\Delta w := \frac{\max(d)}{n_s} = 7.12 \cdot in$ One stitch is to withstand force from $\Delta w = 7.12 \cdot in$

$Fs1 := \int_{d_{max}-0.5 \cdot \Delta w}^{d_{max}+0.5 \cdot \Delta w} linterp(d, f, x)\, dx = 10.098 \cdot kip$ Max force per single 3in stitch

$fs1 := \frac{Fs1}{Ls1} = 3.37 \cdot \frac{kip}{in}$ Required min weld capacity for a single stitch

$\frac{fs1}{fa} = 0.70 < 1.0$ Demand\capacity ratio for Location = "Girder3 - Downstream weld" for the 3in stitch weld where $fa = 4.78 \cdot \frac{kip}{in}$

Weld capacity calculation for the 1.5in stitch weld

$d_{max} := \frac{\max(d)}{2} = 42.72 \cdot in$ Location where nodal force is max along Interval 2 as shown in Figure 2

$Fs2 := \int_{d_{max}}^{d_{max}+\Delta w} linterp(d, f, x)\, dx = 5.770 \cdot kip$ Max force per single 1.5in stitch

$fs2 := \frac{Fs2}{Ls2} = 3.85 \cdot \frac{kip}{in}$ Required min weld capacity for a single stitch

$\frac{fs2}{fa} = 0.80 < 1.0$ Demand/capacity ratio for Location = "Girder3 - Downstream weld" for the 1.5in stitch weld where $fa = 4.78 \cdot \frac{kip}{in}$

6) Weld check - Girder 4

Girder4 - Upstream weld

Location := "Girder4 - Upstream weld "

Data := G4US

n := rows(Data) = 123 Number of rows

Read data from FEA

$d := Data^{\langle 0 \rangle} \cdot in$ $Fx := Data^{\langle 1 \rangle} \cdot lbf$ $Fy := Data^{\langle 2 \rangle} \cdot lbf$ $Fz := Data^{\langle 3 \rangle} \cdot lbf$

$F := \sqrt{Fx^2 + Fy^2 + Fz^2}$ Total force

$i := 0 .. n - 2$

$\Delta d := 0$

$\Delta d_i := d_{i+1} - d_i$

Check if the intervals can be considered equal

$\min(\Delta d) = 0.70 \cdot in$ $\max(\Delta d) = 0.70 \cdot in$ $Stdev(\Delta d) = 0.000 \cdot in$ OK, to be considered equal

$\Delta d := mean(\Delta d) = 0.70 \cdot in$

Extrapolate force values for the first and last data points

$i := 1 .. n - 2$

$d_{temp} := 0$ $F_{temp} := 0$

$d_{temp_{i-1}} := d_i$ $F_{temp_{i-1}} := F_i$

$F_0 := linterp(d_{temp}, F_{temp}, d_0)$

$F_{n-1} := linterp(d_{temp}, F_{temp}, d_{n-1})$

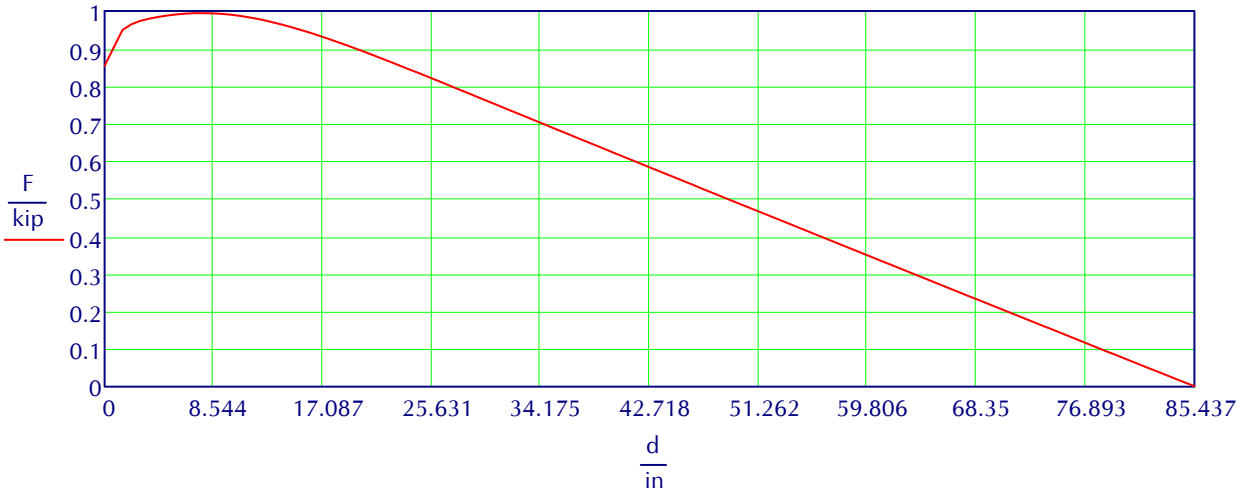
$f := \frac{F}{\Delta d}$ Force on the weld per unit length

$f_{max} := \max(f) = 1.419 \cdot \frac{kip}{in}$

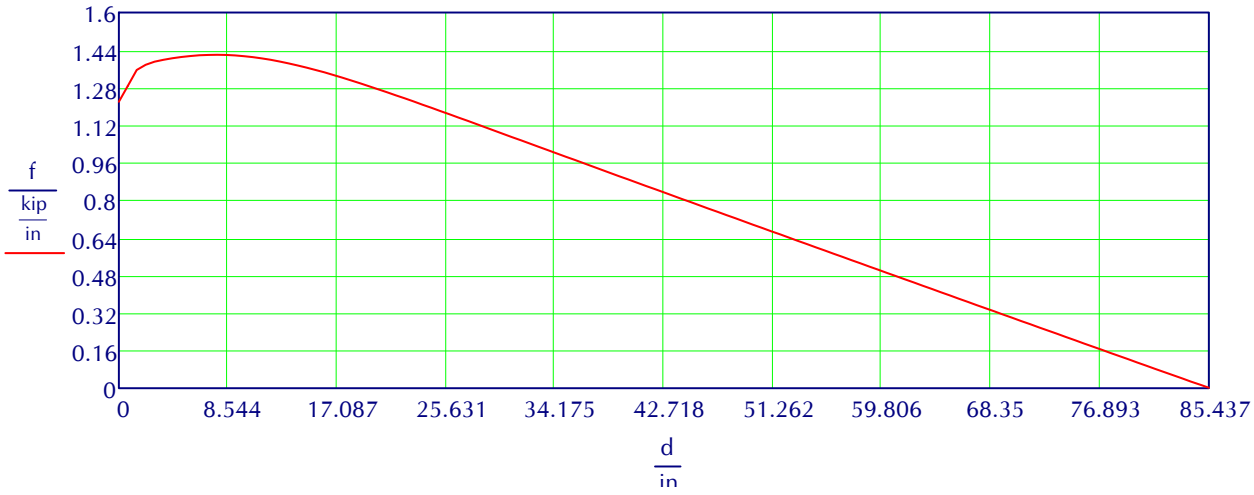
$\frac{f_{max}}{fa} = 0.30 < 1.0$ Demand/capacity ratio for Location = "Girder4 - Upstream weld " where $fa = 4.78 \cdot \frac{kip}{in}$

Location = "Girder4 - Upstream weld "

Nodal force



Force on weld per unit length



...

Girder4 - Downstream weld

Location := "Girder4 - Downstream weld"

Data := G4DS

n := rows(Data) = 123 Number of rows

Read data from FEA

$d := Data^{\langle 0 \rangle} \cdot in$ $Fx := Data^{\langle 1 \rangle} \cdot lbf$ $Fy := Data^{\langle 2 \rangle} \cdot lbf$ $Fz := Data^{\langle 3 \rangle} \cdot lbf$

$F := \sqrt{Fx^2 + Fy^2 + Fz^2}$ Total force

$i := 0 .. n - 2$

$\Delta d := 0$

$\Delta d_i := d_{i+1} - d_i$

Check if the intervals can be considered equal

$min(\Delta d) = 0.70 \cdot in$ $max(\Delta d) = 0.70 \cdot in$ $Stdev(\Delta d) = 0.000 \cdot in$ OK, to be considered equal

$\Delta d := mean(\Delta d) = 0.70 \cdot in$

Extrapolate force values for the first and last data points

$i := 1 .. n - 2$

$d_{temp} := 0$ $F_{temp} := 0$

$d_{temp_{i-1}} := d_i$ $F_{temp_{i-1}} := F_i$

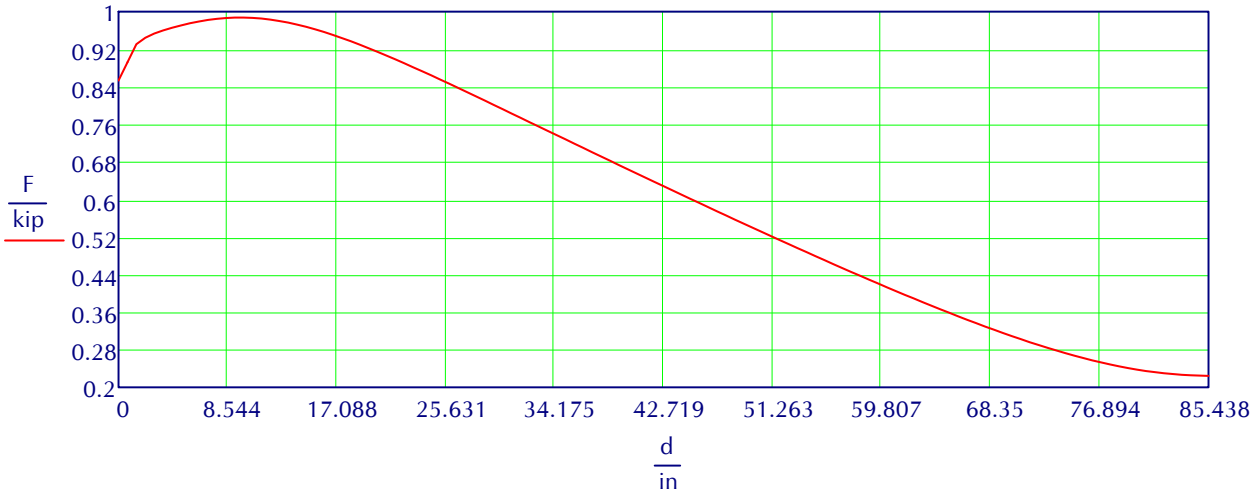
$F_0 := linterp(d_{temp}, F_{temp}, d_0)$

$F_{n-1} := linterp(d_{temp}, F_{temp}, d_{n-1})$

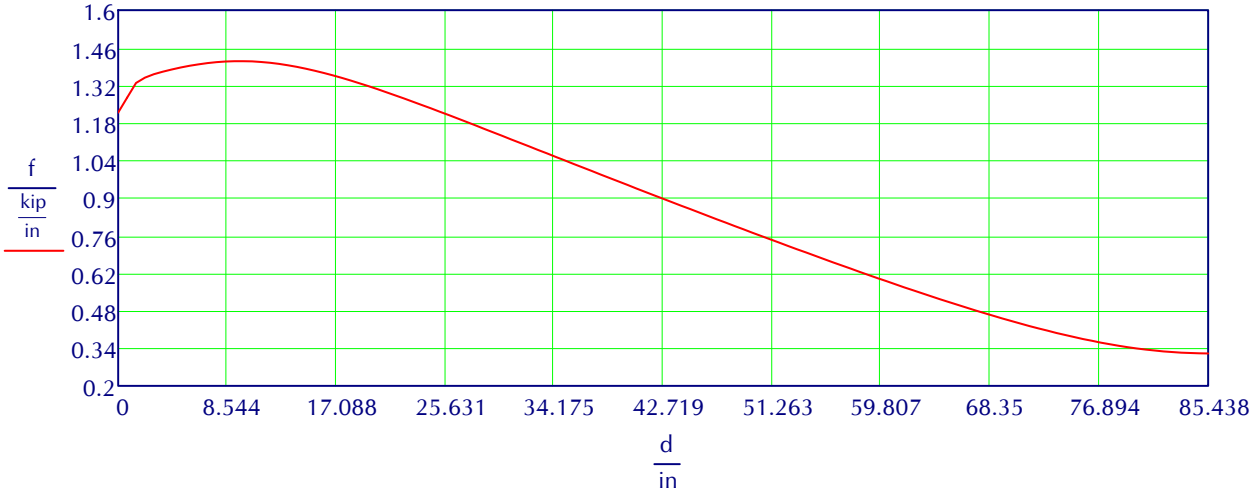
$f := \frac{F}{\Delta d}$ Force on the weld per unit length

Location = "Girder4 - Downstream weld"

Nodal force



Force on weld per unit length



However the weld on the downstream side is not continuous (Figure 2). A single stitch is conservatively assumed to have the capacity of 1/4 double fillet weld.

Weld capacity calculation for the 3in stitch weld

$i := 0 .. \frac{n}{2}$

$F1 := 0$

$F1_i := F_i$

$F_{max} := \max(F1) = 0.99 \cdot kip$

$n_{max} := match(F_{max}, F)_0 = 14$ Find where the nodal force is max along Interval 1 as shown in Figure 2

$d_{max} := d_{n_{max}} = 9.8 \cdot in$

$\Delta w := \frac{\max(d)}{n_s} = 7.12 \cdot in$ One stitch is to withstand force from $\Delta w = 7.12 \cdot in$

$Fs1 := \int_{d_{max}-0.5 \cdot \Delta w}^{d_{max}+0.5 \cdot \Delta w} linterp(d, f, x)\, dx = 10.001 \cdot kip$ Max force per single 3in stitch

$fs1 := \frac{Fs1}{Ls1} = 3.33 \cdot \frac{kip}{in}$ Required min weld capacity for a single stitch

$\frac{fs1}{fa} = 0.70 < 1.0$ Demand\capacity ratio for Location = "Girder4 - Downstream weld" for the 3in stitch weld where $fa = 4.78 \cdot \frac{kip}{in}$

Weld capacity calculation for the 1.5in stitch weld

$d_{max} := \frac{\max(d)}{2} = 42.72 \cdot in$ Location where nodal force is max along Interval 2 as shown in Figure 2

$Fs2 := \int_{d_{max}}^{d_{max}+\Delta w} linterp(d, f, x)\, dx = 5.924 \cdot kip$ Max force per single 1.5in stitch

$fs2 := \frac{Fs2}{Ls2} = 3.95 \cdot \frac{kip}{in}$ Required min weld capacity for a single stitch

$\frac{fs2}{fa} = 0.83 < 1.0$ Demand/capacity ratio for Location = "Girder4 - Downstream weld" for the 1.5in stitch weld where $fa = 4.78 \cdot \frac{kip}{in}$

7) Weld check - Girder 5

Girder5 - Upstream weld

Location := "Girder5 - Upstream weld "

Data := G5US

n := rows(Data) = 123 Number of rows

Read data from FEA

$d := Data^{\langle 0 \rangle} \cdot in$ $Fx := Data^{\langle 1 \rangle} \cdot lbf$ $Fy := Data^{\langle 2 \rangle} \cdot lbf$ $Fz := Data^{\langle 3 \rangle} \cdot lbf$

$F := \sqrt{Fx^2 + Fy^2 + Fz^2}$ Total force

$i := 0 .. n - 2$

$\Delta d := 0$

$\Delta d_i := d_{i+1} - d_i$

Check if the intervals can be considered equal

$\min(\Delta d) = 0.70 \cdot in$ $\max(\Delta d) = 0.70 \cdot in$ $Stdev(\Delta d) = 0.000 \cdot in$ OK, to be considered equal

$\Delta d := mean(\Delta d) = 0.70 \cdot in$

Extrapolate force values for the first and last data points

$i := 1 .. n - 2$

$d_{temp} := 0$ $F_{temp} := 0$

$d_{temp_{i-1}} := d_i$ $F_{temp_{i-1}} := F_i$

$F_0 := linterp(d_{temp}, F_{temp}, d_0)$

$F_{n-1} := linterp(d_{temp}, F_{temp}, d_{n-1})$

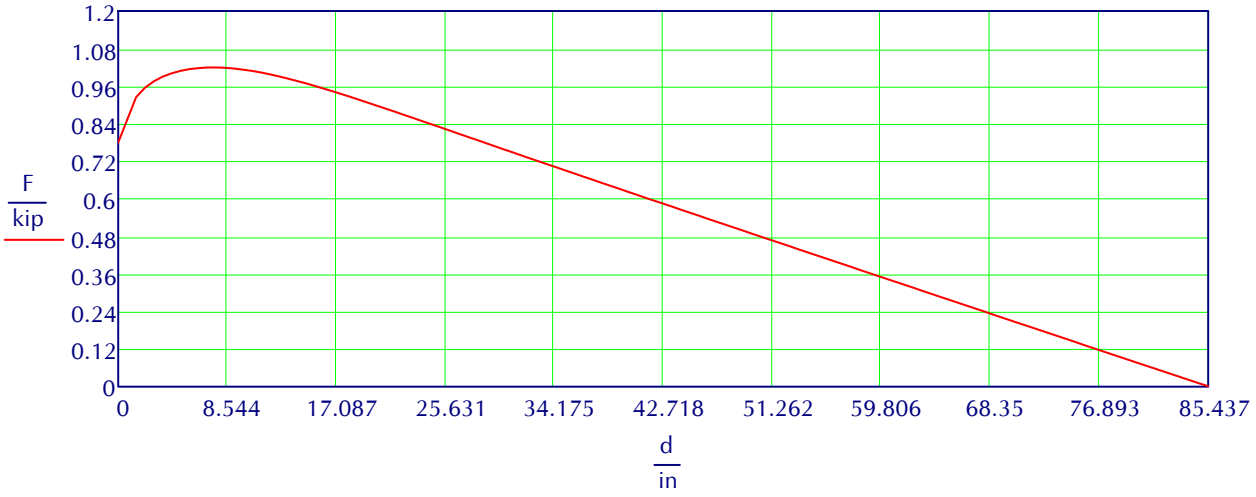
$f := \frac{F}{\Delta d}$ Force on the weld per unit length

$f_{max} := \max(f) = 1.455 \cdot \frac{kip}{in}$

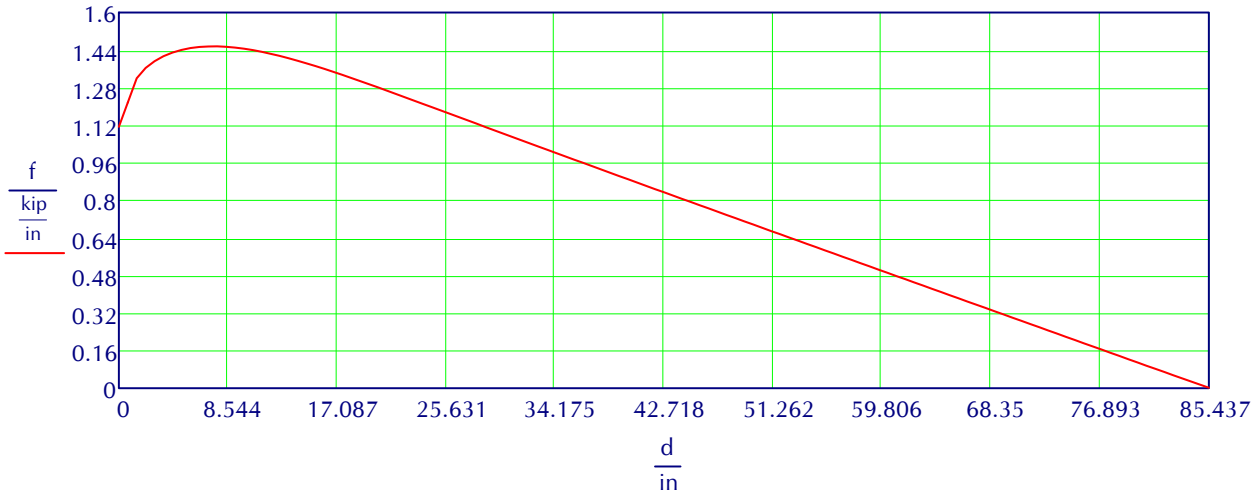
$\frac{f_{max}}{fa} = 0.30 < 1.0$ Demand/capacity ratio for Location = "Girder5 - Upstream weld " where $fa = 4.78 \cdot \frac{kip}{in}$

Location = "Girder5 - Upstream weld "

Nodal force



Force on weld per unit length



Girder5 - Downstream weld

Location := "Girder5 - Downstream weld"

Data := G5DS

n := rows(Data) = 123 Number of rows

Read data from FEA

$d := Data^{\langle 0 \rangle} \cdot in$ $Fx := Data^{\langle 1 \rangle} \cdot lbf$ $Fy := Data^{\langle 2 \rangle} \cdot lbf$ $Fz := Data^{\langle 3 \rangle} \cdot lbf$

$F := \sqrt{Fx^2 + Fy^2 + Fz^2}$ Total force

$i := 0 .. n - 2$

$\Delta d := 0$

$\Delta d_i := d_{i+1} - d_i$

Check if the intervals can be considered equal

$\min(\Delta d) = 0.70 \cdot in$ $\max(\Delta d) = 0.70 \cdot in$ $Stdev(\Delta d) = 0.000 \cdot in$ OK, to be considered equal

$\Delta d := mean(\Delta d) = 0.70 \cdot in$

Extrapolate force values for the first and last data points

$i := 1 .. n - 2$

$d_{temp} := 0$ $F_{temp} := 0$

$d_{temp_{i-1}} := d_i$ $F_{temp_{i-1}} := F_i$

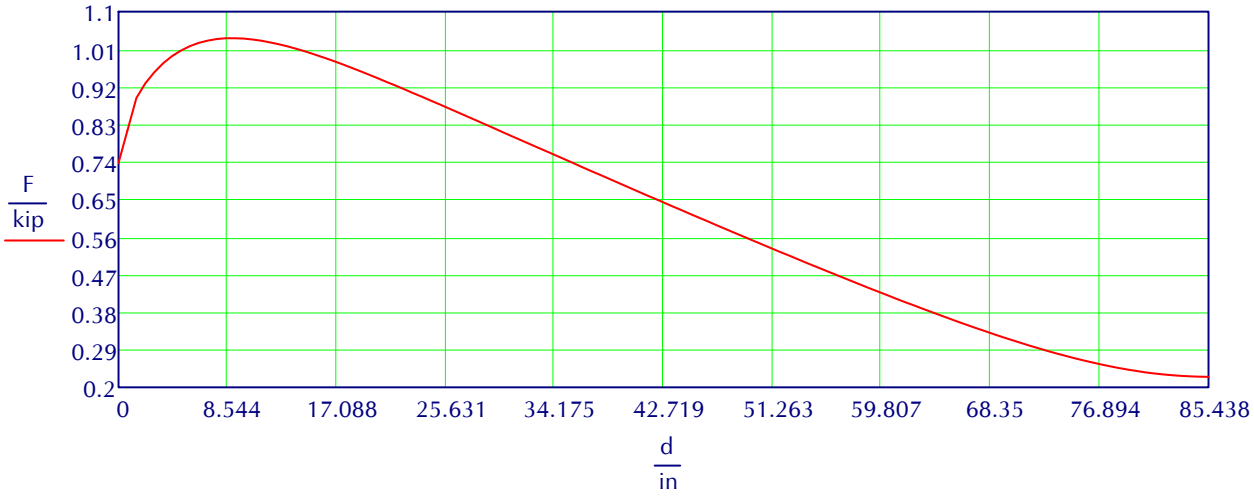
$F_0 := linterp(d_{temp}, F_{temp}, d_0)$

$F_{n-1} := linterp(d_{temp}, F_{temp}, d_{n-1})$

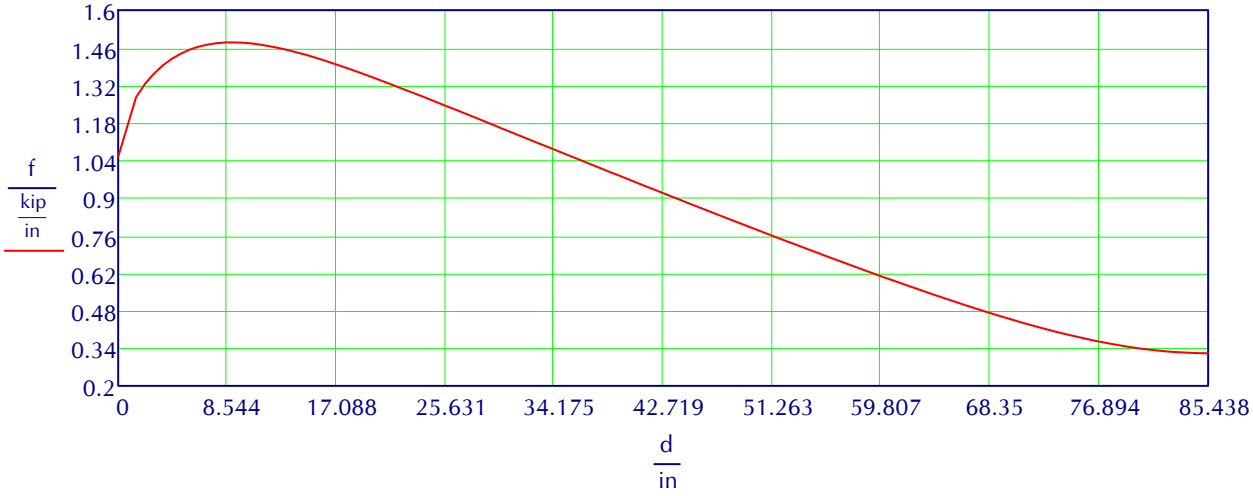
$f := \frac{F}{\Delta d}$ Force on the weld per unit length

Location = "Girder5 - Downstream weld"

Nodal force



Force on weld per unit length



However the weld on the downstream side is not continuous (Figure 2). A single stitch is conservatively assumed to have the capacity of 1/4 double fillet weld.

Weld capacity calculation for the 3in stitch weld

$i := 0 .. \frac{n}{2}$

$F1 := 0$

$F1_i := F_i$

$F_{max} := \max(F1) = 1.04 \cdot kip$

$n_{max} := match(F_{max}, F)_0 = 13$ Find where the nodal force is max along Interval 1 as shown in Figure 2

$d_{max} := d_{n_{max}} = 9.1 \cdot in$

$\Delta w := \frac{\max(d)}{n_s} = 7.12 \cdot in$ One stitch is to withstand force from $\Delta w = 7.12 \cdot in$

$Fs1 := \int_{d_{max}-0.5 \cdot \Delta w}^{d_{max}+0.5 \cdot \Delta w} linterp(d, f, x)\, dx = 10.474 \cdot kip$ Max force per single 3in stitch

$fs1 := \frac{Fs1}{Ls1} = 3.49 \cdot \frac{kip}{in}$ Required min weld capacity for a single stitch

$\frac{fs1}{fa} = 0.73 < 1.0$ Demand\capacity ratio for Location = "Girder5 - Downstream weld" for the 3in stitch weld where $fa = 4.78 \cdot \frac{kip}{in}$

Weld capacity calculation for the 1.5in stitch weld

$d_{max} := \frac{\max(d)}{2} = 42.72 \cdot in$ Location where nodal force is max along Interval 2 as shown in Figure 2

$Fs2 := \int_{d_{max}}^{d_{max}+\Delta w} linterp(d, f, x)\, dx = 6.059 \cdot kip$ Max force per single 1.5in stitch

$fs2 := \frac{Fs2}{Ls2} = 4.04 \cdot \frac{kip}{in}$ Required min weld capacity for a single stitch

$\frac{fs2}{fa} = 0.84 < 1.0$ Demand/capacity ratio for Location = "Girder5 - Downstream weld" for the 1.5in stitch weld where $fa = 4.78 \cdot \frac{kip}{in}$

8) Weld check - Girder 6

Girder6 - Upstream weld

Location := "Girder6 - Upstream weld "

Data := G6US

$n := rows(Data) = 123$ Number of rows

Read data from FEA

$d := Data^{\langle 0 \rangle} \cdot in$ $Fx := Data^{\langle 1 \rangle} \cdot lbf$ $Fy := Data^{\langle 2 \rangle} \cdot lbf$ $Fz := Data^{\langle 3 \rangle} \cdot lbf$

$F := \sqrt{Fx^2 + Fy^2 + Fz^2}$ Total force

$i := 0 .. n - 2$

$\Delta d := 0$

$\Delta d_i := d_{i+1} - d_i$

Check if the intervals can be considered equal

$min(\Delta d) = 0.70 \cdot in$ $max(\Delta d) = 0.70 \cdot in$ $Stdev(\Delta d) = 0.000 \cdot in$ OK, to be considered equal

$\Delta d := mean(\Delta d) = 0.70 \cdot in$

Extrapolate force values for the first and last data points

$i := 1 .. n - 2$

$d_{temp} := 0$ $F_{temp} := 0$

$d_{temp_{i-1}} := d_i$ $F_{temp_{i-1}} := F_i$

$F_0 := linterp(d_{temp}, F_{temp}, d_0)$

$F_{n-1} := linterp(d_{temp}, F_{temp}, d_{n-1})$

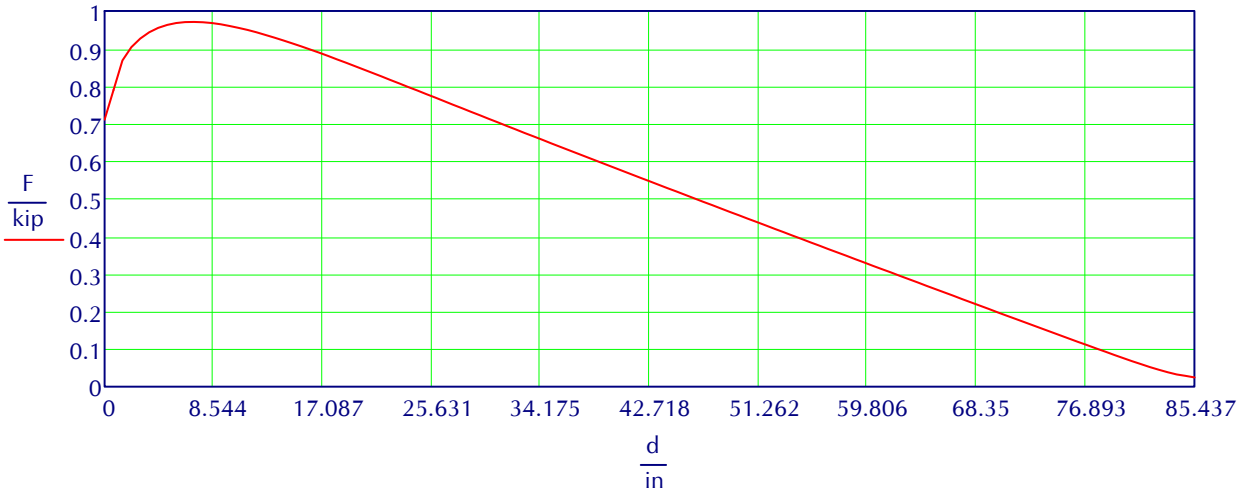
$f := \frac{F}{\Delta d}$ Force on the weld per unit length

$f_{max} := max(f) = 1.386 \cdot \frac{kip}{in}$

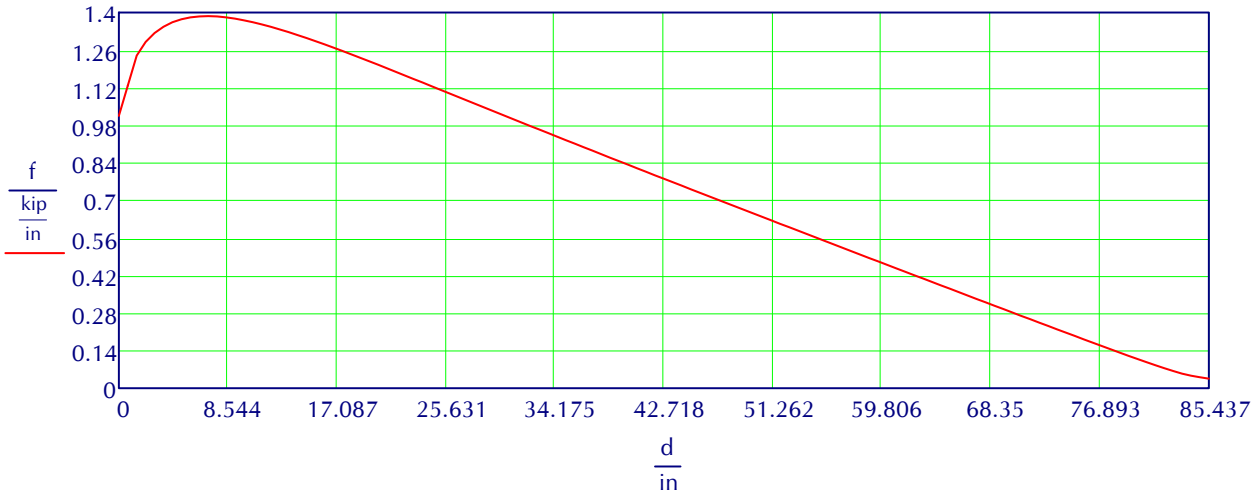
$\frac{f_{max}}{fa} = 0.29 < 1.0$ Demand/capacity ratio for Location = "Girder6 - Upstream weld " where $fa = 4.78 \cdot \frac{kip}{in}$

Location = "Girder6 - Upstream weld "

Nodal force



Force on weld per unit length



Girder6 - Downstream weld

Location := "Girder6 - Downstream weld"

Data := G6DS

n := rows(Data) = 123 Number of rows

Read data from FEA

$d := Data^{\langle 0 \rangle} \cdot in$ $Fx := Data^{\langle 1 \rangle} \cdot lbf$ $Fy := Data^{\langle 2 \rangle} \cdot lbf$ $Fz := Data^{\langle 3 \rangle} \cdot lbf$

$F := \sqrt{Fx^2 + Fy^2 + Fz^2}$ Total force

$i := 0 .. n - 2$

$\Delta d := 0$

$\Delta d_i := d_{i+1} - d_i$

Check if the intervals can be considered equal

$\min(\Delta d) = 0.70 \cdot in$ $\max(\Delta d) = 0.70 \cdot in$ $Stdev(\Delta d) = 0.000 \cdot in$ OK, to be considered equal

$\Delta d := mean(\Delta d) = 0.70 \cdot in$

Extrapolate force values for the first and last data points

$i := 1 .. n - 2$

$d_{temp} := 0$ $F_{temp} := 0$

$d_{temp_{i-1}} := d_i$ $F_{temp_{i-1}} := F_i$

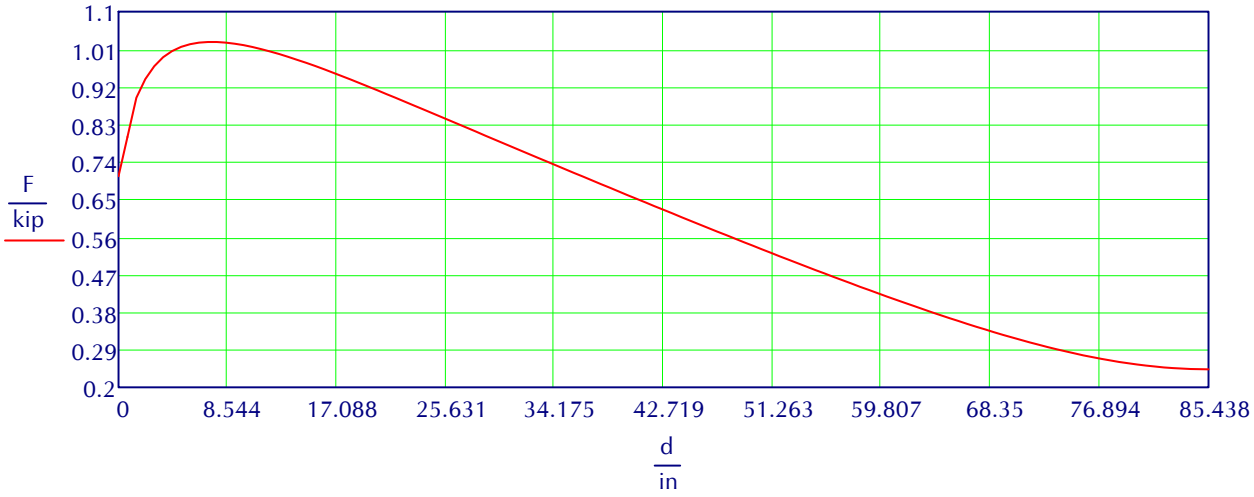
$F_0 := linterp(d_{temp}, F_{temp}, d_0)$

$F_{n-1} := linterp(d_{temp}, F_{temp}, d_{n-1})$

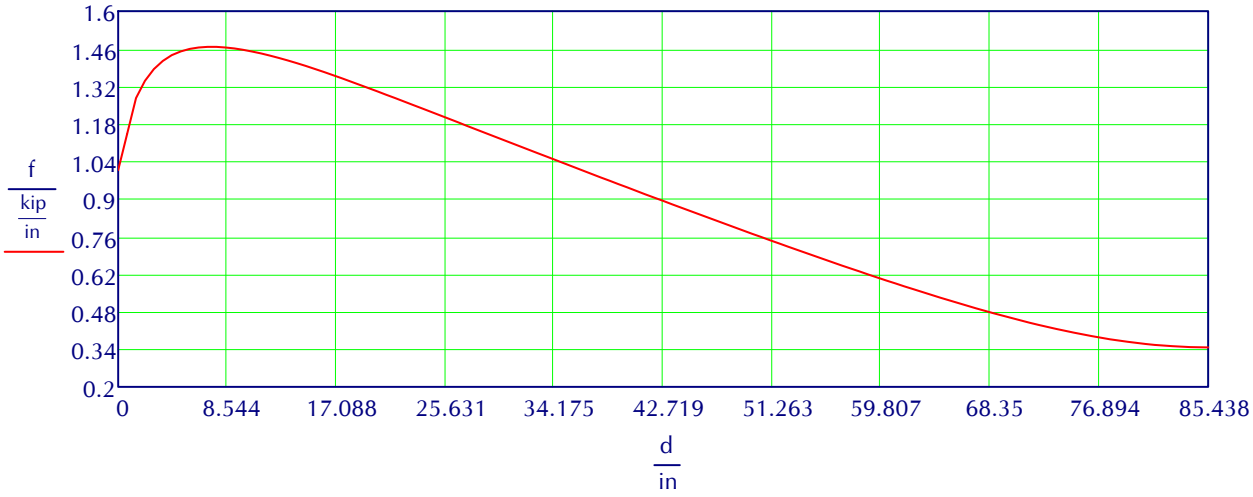
$f := \frac{F}{\Delta d}$ Force on the weld per unit length

Location = "Girder6 - Downstream weld"

Nodal force



Force on weld per unit length



However the weld on the downstream side is not continuous (Figure 2). A single stitch is conservatively assumed to have the capacity of 1/4 double fillet weld.

Weld capacity calculation for the 3in stitch weld

$i := 0 .. \frac{n}{2}$

$F1 := 0$

$F1_i := F_i$

$F_{max} := \max(F1) = 1.03 \cdot kip$

$n_{max} := match(F_{max}, F)_0 = 10$ Find where the nodal force is max along Interval 1 as shown in Figure 2

$d_{max} := d_{n_{max}} = 7 \cdot in$

$\Delta w := \frac{\max(d)}{n_s} = 7.12 \cdot in$ One stitch is to withstand force from $\Delta w = 7.12 \cdot in$

$Fs1 := \int_{d_{max}-0.5\cdot\Delta w}^{d_{max}+0.5\cdot\Delta w} linterp(d, f, x)\, dx = 10.358 \cdot kip$ Max force per single 3in stitch

$fs1 := \frac{Fs1}{Ls1} = 3.45 \cdot \frac{kip}{in}$ Required min weld capacity for a single stitch

$\frac{fs1}{fa} = 0.72 \quad < 1.0$ Demand\capacity ratio for Location = "Girder6 - Downstream weld" for the 3in stitch weld where $fa = 4.78 \cdot \frac{kip}{in}$

Weld capacity calculation for the 1.5in stitch weld

$d_{max} := \frac{\max(d)}{2} = 42.72 \cdot in$ Location where nodal force is max along Interval 2 as shown in Figure 2

$Fs2 := \int_{d_{max}}^{d_{max}+\Delta w} linterp(d, f, x)\, dx = 5.906 \cdot kip$ Max force per single 1.5in stitch

$fs2 := \frac{Fs2}{Ls2} = 3.94 \cdot \frac{kip}{in}$ Required min weld capacity for a single stitch

$\frac{fs2}{fa} = 0.82 \quad < 1.0$ Demand/capacity ratio for Location = "Girder6 - Downstream weld" for the 1.5in stitch weld where $fa = 4.78 \cdot \frac{kip}{in}$

8) Summary

Main girder welds at the web-skinplate interface at both the upstream and downstream sides have adequate capacity

D5 - End Beam Weld Capacity Check

Wreck Cove T2 Intake Gate - End Beam Weld Capacity Check

Calculation Cover Sheet

Client:	Nova Scotia Power
Project Title:	Wreck Cove T2 Intake
Discipline:	Mechanical/Structural
Calculation No.:	H351728-00000-200-230-0002-App C
File No:	
Number of Sheets:	49
Description:	Wreck Cove T2 Intake Gate – End Beam Weld Capacity Check
Category of calculation verification required *tick box*	☑ 1 ☐ 2 ☐ 3 ☐ 4
Prepared by:	O.Belashov
Date:	24Jan2017
Print Name >	Oleg Belashov
Preliminary Review by:	
Date:	24Jan2017
Print Name >	Val Kovalishyn
Can the calculation now be released for work?	☑ Yes ☐ No
To the Client?	☑ Yes ☐ No
Checked by:	
Date:	24Jan2017
Print Name >	Val Kovalishyn
Reviewed by:	
Date:	
Print Name >	
Approved by:	
Date:	24Jan2017
Print Name >	Jonathan Atkinson

General Notes:
Internal Rev A-02

Revisions

Rev.	Date	Prepared by	Checked by	Approved by	Description
A	24Jan2017	O. Belashov OB	V. Kovalishyn	J. Atkinson	

Superseded by Calculation No. **Date:**

Reason voided:

Superseded by Calculation No. **Date:**
Reason voided:

CALCULATIONS

Calculation description

1. This calculation checks the capacity of end beam welds connecting the 5/8in skinplate to the 1/2in and 1 1/4in end plates.
2. Five loading scenario including max normal hydrostatic pressure with water inside the gate (Ref 3) were considered. The five loading scenarios are as follows: LS1 =all wheels in contact with the wheel track; LS2 =Wheel 01 not in contact with the wheel track; LS3 =Wheel 02 not in contact with the wheel track; LS4 =Wheel 03 not in contact with the wheel track; LS5 =Wheel 04 not in contact with the wheel track;
3. Nodal forces acting on the inner and outer end plates were extracted from the FEA model of Ref 3

References

1. EETL 1110-2-584, Design of Hydraulic Steel Structures, June 2014
2. Mechanical Engineering Design, Shigley
3. H351728-00000-200-230-0002, Finite Element Analyses

1) Input Parameters

$\alpha := 1.33$ Gate performance factor, Ref 1

$fa_{3\_8} := 4.77 \frac{kip}{in}$ Fillet weld capacity for E60XX electrode for 3/8in weld, Ref 2

$fa := \frac{fa_{3\_8}}{\alpha} = 3.586 \cdot \frac{kip}{in}$ Allowable weld capacity for E60XX electrode for 3/8in fillet weld

Table 9–6

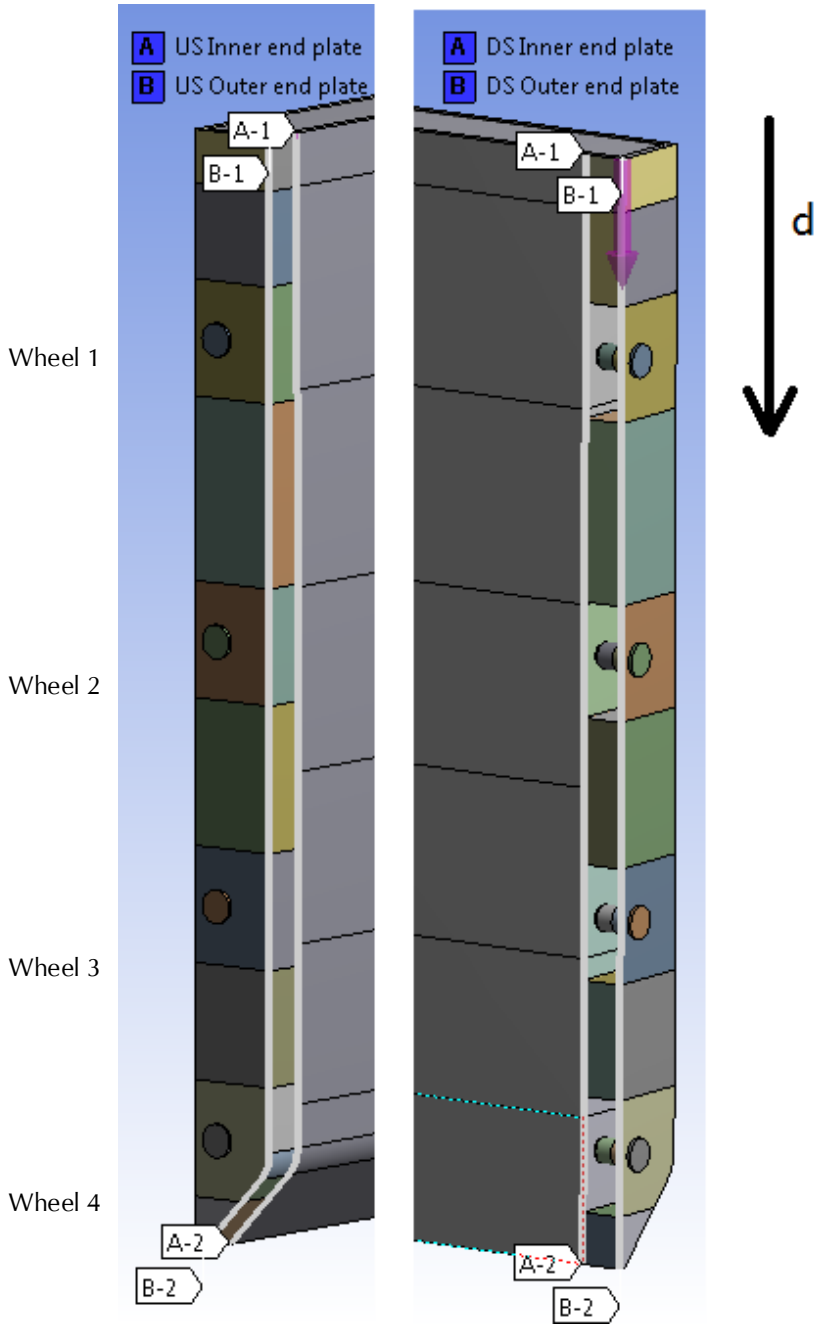
Allowable Steady Loads and Minimum Fillet Weld Sizes

Schedule A: Allowable Load for Various Sizes of Fillet Weld

	Strength Level of Weld Metal (EXX)						
	60*	70*	80	90*	100	110*	120
	Allowable shear stress on throat, ksi (1000 psi) of fillet weld or partial penetration groove weld						
$\tau =$	18.0	21.0	24.0	27.0	30.0	33.0	36.0
	Allowable Unit Force on Fillet Weld, kip/linear in						
†$f =$	12.73h	14.85h	16.97h	19.09h	21.21h	23.33h	25.45h
Leg Size h, in	Allowable Unit Force for Various Sizes of Fillet Welds kip/linear in						
1	12.73	14.85	16.97	19.09	21.21	23.33	25.45
7/8	11.14	12.99	14.85	16.70	18.57	20.41	22.27
3/4	9.55	11.14	12.73	14.32	15.92	17.50	19.09
5/8	7.96	9.28	10.61	11.93	13.27	14.58	15.91
1/2	6.37	7.42	8.48	9.54	10.61	11.67	12.73
7/16	5.57	6.50	7.42	8.35	9.28	10.21	11.14
3/8	4.77	5.57	6.36	7.16	7.95	8.75	9.54
5/16	3.98	4.64	5.30	5.97	6.63	7.29	7.95
1/4	3.18	3.71	4.24	4.77	5.30	5.83	6.36
3/16	2.39	2.78	3.18	3.58	3.98	4.38	4.77
1/8	1.59	1.86	2.12	2.39	2.65	2.92	3.18
1/16	0.795	0.930	1.06	1.19	1.33	1.46	1.59

*Fillet welds actually tested by the joint AISC-AWS Task Committee.
†$f = 0.707h\,\tau_{all}$

Figure 1: Fillet weld capacity from Ref 2



End plate nom thickness
Upstream side

	dist from top	t plate
$t_{US} :=$	−0.001	0.5
	8.75	0.5
	24.25	1.25
	43.25	0.5
	73.25	1.25
	92.25	0.5
	116.25	1.25
	135.25	0.5
	154.25	1.25
	175.276	0.5

in

End plate nom thickness
Downstream side

	dist from top	t plate
$t_{DS} :=$	−0.001	0.5
	8.75	0.5
	24.25	1.25
	43.25	0.5
	73.25	1.25
	92.25	0.5
	116.25	1.25
	135.25	0.5
	154.25	1.25
	173.25	0.5

in

Figure 2: Paths along the edges of the end plates on upstream and downstream side of the gate. Four paths were created: Upstream Inside end plate (USI), Upstream Outside end plate (USO), Downstream Inside end plate (DSI), Downstream outside end plate (DSO)

2) Input Data From FEA - Nodal Forces

The data below represents nodal forces (Ref 3) at the web-skinplate interface (both upstream and downstream) from loading scenario LS1 corresponding to max normal hydrostatic pressure with water inside the gate where all wheels are in contact with the wheel track.

AllUSI :=

	d[in]	Fx[lbf]	Fx[lbf]	Fx[lbf]
0	0	0	0	0
1	0.673	0	0	0
2	1.346	0	0	0
3	2.019	0	0	...

AllDSI :=

	d[in]	Fx[lbf]	Fx[lbf]	Fx[lbf]
0	0	0	0	0
1	0.673	0	0	0
2	1.346	0	0	0
3	2.019	0	0	...

AllUSO :=

	0	1	2	3
0	0	16.444	9.338	-0.179
1	0.672	4.662	26.339	-5.932
2	1.345	2.758	38.709	-2.584
3	2.018	1.614	47.821	...

AllDSO :=

	0	1	2	3
0	0	18.966	16.869	-2.053
1	0.673	4.852	46.811	4.36
2	1.346	2.872	70.709	2.468
3	2.019	1.93	88.109	...

W1USI :=

	0	1	2	3
0	0	0	0	0
1	0.673	0	0	0
2	1.346	0	0	0
3	2.019	0	0	0

W1DSI :=

	0	1	2	3
0	0	0	0	0
1	0.673	0	0	0
2	1.346	0	0	0
3	2.019	0	0	0

W1USO :=

	0	1	2	3
0	0	-5.707	-2.333	-0.265
1	0.672	-2.461	-5.471	0.841
2	1.345	-0.735	-7.526	0.097
3	2.018	0.045	-8.397	-0.199

W1DSO :=

	0	1	2	3
0	0	-1.735	-8.322	-2.694
1	0.673	-2.369	-23.934	-3.104
2	1.346	-0.804	-38.205	-0.455
3	2.019	0.272	-49.456	0.285

W2USI :=

	0	1	2	3
0	0	0	0	0
1	0.673	0	0	0
2	1.346	0	0	0
3	2.019	0	0	0

W2DSI :=

	0	1	2	3
0	0	0	0	0
1	0.673	0	0	0
2	1.346	0	0	0
3	2.019	0	0	0

W2USO :=

	0	1	2	3
0	0	23.175	12.932	-0.168
1	0.672	6.798	36.17	-8.01
2	1.345	3.81	53.011	-3.408
3	2.018	2.091	65.222	-1.856

W2DSO :=

	0	1	2	3
0	0	25.215	-19.419	-1.821
1	0.673	7.021	-53.663	6.667
2	1.346	3.986	-80.428	3.372
3	2.019	2.435	-99.654	2.052

W3USI :=

	0	1	2	3
	d[in]	Fx[lbf]	Fx[lbf]	Fx[lbf]
0	0	0	0	0
1	0.673	0	0	0
2	1.346	0	0	0
3	2.019	0	0	0

W3DSI :=

	0	1	2	3
	d[in]	Fx[lbf]	Fx[lbf]	Fx[lbf]
0	0	0	0	0
1	0.673	0	0	0
2	1.346	0	0	0
3	2.019	0	0	0

W3USO :=

	0	1	2	3
0	0	15.929	8.982	-0.154
1	0.672	4.546	25.304	-5.741
2	1.345	2.691	37.183	-2.504
3	2.018	1.577	45.946	-1.421

W3DSO :=

	0	1	2	3
0	0	18.561	-16.754	-2.135
1	0.673	4.729	-46.458	4.118
2	1.346	2.792	-70.237	2.37
3	2.019	1.89	-87.57	1.586

W4USI :=

	0	1	2	3
0	0	0	0	0
1	0.673	0	0	0
2	1.346	0	0	0
3	2.019	0	0	0

W4DSI :=

	0	1	2	3
0	0	0	0	0
1	0.673	0	0	0
2	1.346	0	0	0
3	2.019	0	0	0

W4USO :=

	0	1	2	3
0	0	8.075	5.142	-0.279
1	0.672	1.844	15.066	-3.46
2	1.345	1.401	22.38	-1.615
3	2.018	1.022	28.014	-1.02

W4DSO :=

	0	1	2	3
0	0	10.956	-13.428	-2.128
1	0.673	2.011	-37.719	1.714
2	1.346	1.468	-57.716	1.438
3	2.019	1.31	-72.601	1.165

3) Weld check - All wheels in contact

All wheels in contact - US inner plate

Name := "All wheels in contact - US inner plate"

Data := AllUSI

n := rows(Data) = 268 Number of rows

Read data from FEA

d := $Data^{\langle 0 \rangle}$·in Fx := $Data^{\langle 1 \rangle}$·lbf Fy := $Data^{\langle 2 \rangle}$·lbf Fz := $Data^{\langle 3 \rangle}$·lbf

Assign end plate thickness

k := 0 t := 0

i := 0 .. n − 1

k_i := reverse(match(1 , $t_{US}^{\langle 0 \rangle}$ < d_i))$_0$

t_i := $\left(t_{US}^{\langle 1 \rangle}\right)_{(k_i)}$ End plate thickness along d

F := $\sqrt{Fx^2 + Fy^2 + Fz^2}$ Total nodal force

Intervals

i := 0 .. n − 2

Δd := 0

Δd_i := $d_{i+1} - d_i$

Adjust intervals

i := 0 .. n − 3

Δd1 := 0

$\Delta d1_i$:= 0.5·Δd_i + 0.5·Δd_{i+1}

i := 0 .. n − 1

Δd2 := 0

$\Delta d2_i$:= 0

$\Delta d2_0$:= 0.5·Δd_0

$\Delta d2_{n-1}$:= 0.5·Δd_{n-2}

i := 0 .. n − 3

$\Delta d2_{i+1}$:= $\Delta d1_i$

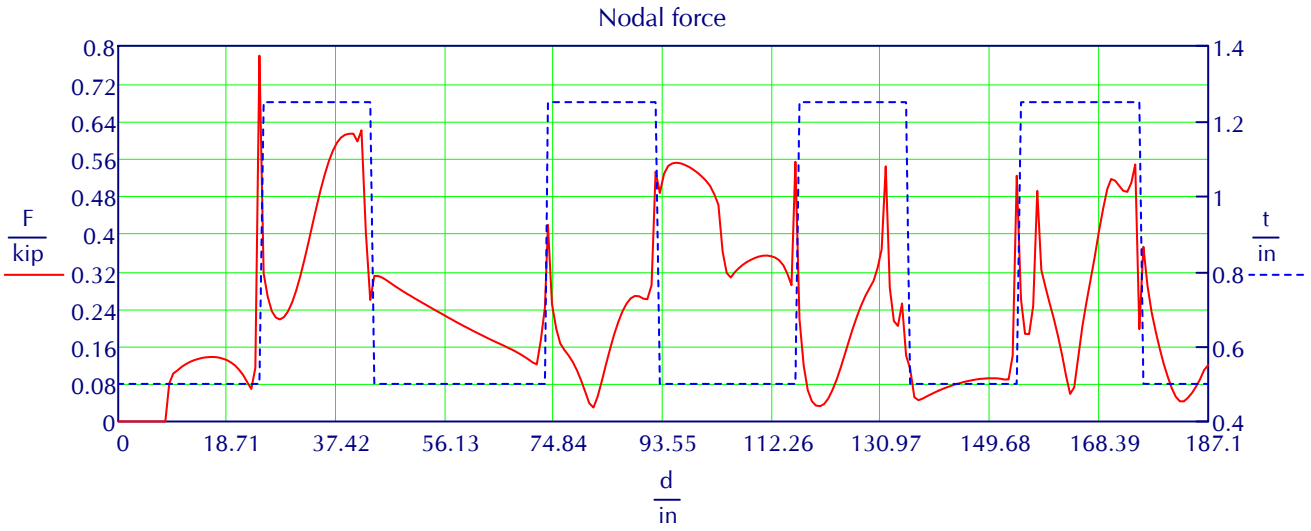
Δd := Δd2 Adjusted intervals

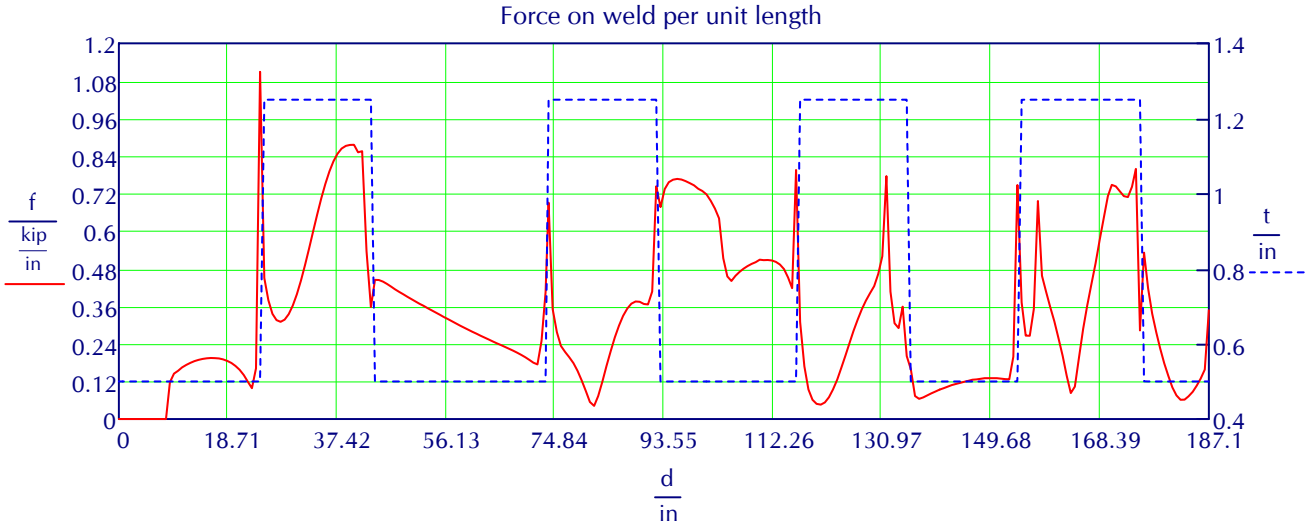
$f := \frac{F}{\Delta d}$ Force on the weld per unit length

$f_{max} := \max(f) = 1.109 \cdot \frac{kip}{in}$

$\frac{f_{max}}{fa} = 0.31 \quad < 1.0$ Demand\capacity ratio for Name = "All wheels in contact - US inner plate" where $fa = 3.59 \cdot \frac{ki}{ir}$

Name = "All wheels in contact - US inner plate"





All wheels in contact - DS inner plate

Name := "All wheels in contact - DS inner plate"

Data := AllDSI

n := rows(Data) = 260 Number of rows

Read data from FEA

$d := Data^{\langle 0 \rangle} \cdot in$ $Fx := Data^{\langle 1 \rangle} \cdot lbf$ $Fy := Data^{\langle 2 \rangle} \cdot lbf$ $Fz := Data^{\langle 3 \rangle} \cdot lbf$

Assign end plate thickness

k := 0 t := 0

i := 0 .. n − 1

$k_i := reverse\left(match\left(1, t_{DS}^{\langle 0 \rangle} < d_i\right)\right)_0$

$t_i := \left(t_{DS}^{\langle 1 \rangle}\right)_{(k_i)}$ End plate thickness along d

$F := \sqrt{Fx^2 + Fy^2 + Fz^2}$ Total nodal force

Intervals

i := 0 .. n − 2

Δd := 0

$\Delta d_i := d_{i+1} - d_i$

Adjust intervals

i := 0 .. n − 3

Δd1 := 0

$\Delta d1_i := 0.5 \cdot \Delta d_i + 0.5 \cdot \Delta d_{i+1}$

i := 0 .. n − 1

Δd2 := 0

$\Delta d2_i := 0$

$\Delta d2_0 := 0.5 \cdot \Delta d_0$

$\Delta d2_{n-1} := 0.5 \cdot \Delta d_{n-2}$

i := 0 .. n − 3

$\Delta d2_{i+1} := \Delta d1_i$

Δd := Δd2 Adjusted intervals

$f := \frac{F}{\Delta d}$ Force on the weld per unit length

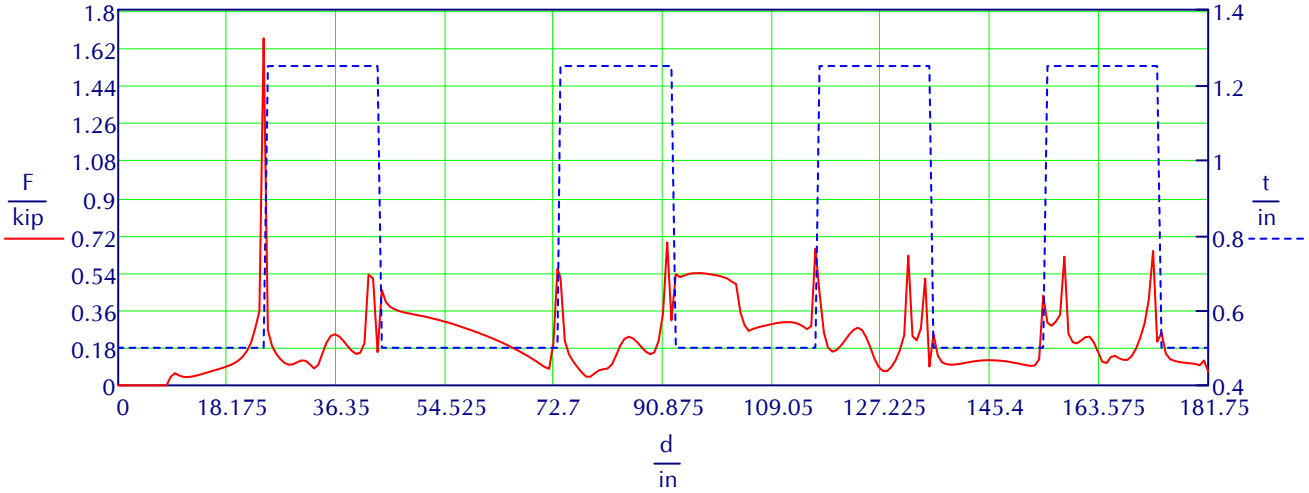
Δd

$f_{max} := \max(f) = 2.367 \cdot \frac{kip}{in}$

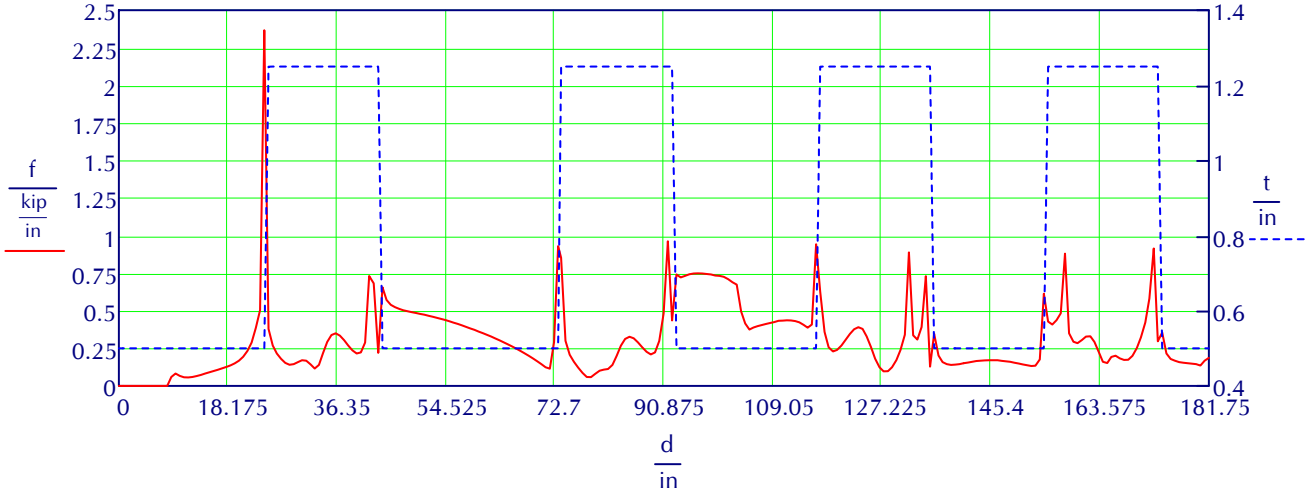
$\frac{f_{max}}{fa} = 0.66 \quad < 1.0$ Demand\capacity ratio for Name = "All wheels in contact - DS inner plate" where $fa = 3.59 \cdot \frac{ki}{in}$

Name = "All wheels in contact - DS inner plate"

Nodal force



Force on weld per unit length



All wheels in contact - US outer plate

Name := "All wheels in contact - US outer plate"

Data := AllUSO

n := rows(Data) = 268 Number of rows

Read data from FEA

$d := Data^{\langle 0 \rangle} \cdot in$ $Fx := Data^{\langle 1 \rangle} \cdot lbf$ $Fy := Data^{\langle 2 \rangle} \cdot lbf$ $Fz := Data^{\langle 3 \rangle} \cdot lbf$

Assign end plate thickness

k := 0 t := 0

i := 0 .. n − 1

$k_i := reverse\left(match\left(1, t_{US}^{\langle 0 \rangle} < d_i\right)\right)_0$

$t_i := \left(t_{US}^{\langle 1 \rangle}\right)_{(k_i)}$ End plate thickness along d

$F := \sqrt{Fx^2 + Fy^2 + Fz^2}$ Total nodal force

Intervals

i := 0 .. n − 2

Δd := 0

$\Delta d_i := d_{i+1} - d_i$

Adjust intervals

i := 0 .. n − 3

Δd1 := 0

$\Delta d1_i := 0.5 \cdot \Delta d_i + 0.5 \cdot \Delta d_{i+1}$

i := 0 .. n − 1

Δd2 := 0

$\Delta d2_i := 0$

$\Delta d2_0 := 0.5 \cdot \Delta d_0$

$\Delta d2_{n-1} := 0.5 \cdot \Delta d_{n-2}$

i := 0 .. n − 3

$\Delta d2_{i+1} := \Delta d1_i$

Δd := Δd2 Adjusted intervals

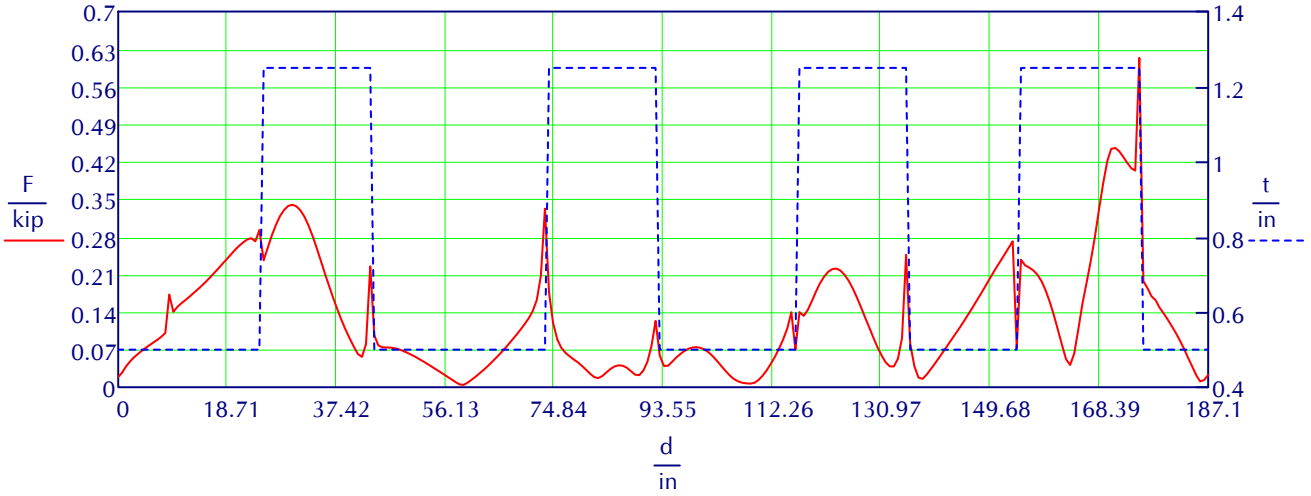
$f := \frac{F}{\Delta d}$ Force on the weld per unit length

$f_{max} := \max(f) = 0.883 \cdot \frac{kip}{in}$

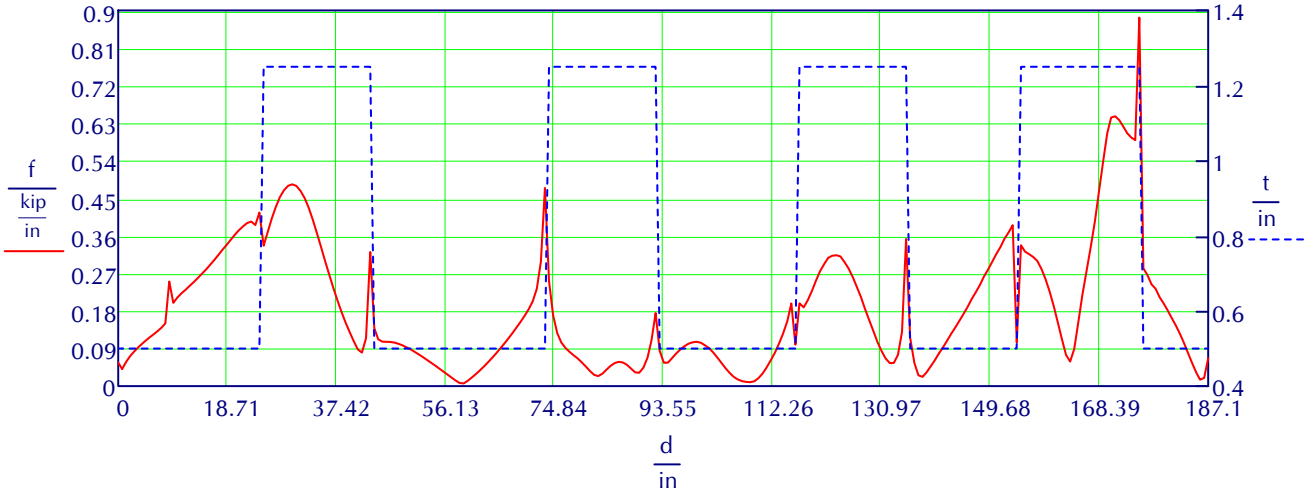
$\frac{f_{max}}{fa} = 0.25 \quad < 1.0$ Demand\capacity ratio for Name = "All wheels in contact - US outer plate" where fa = 3.59·ki/in

Name = "All wheels in contact - US outer plate"

Nodal force



Force on weld per unit length



All wheels in contact - DS outer plate

Name := "All wheels in contact - DS outer plate"

Data := AllDSO

$n := rows(Data) = 264$ Number of rows

Read data from FEA

$d := Data^{\langle 0 \rangle} \cdot in$ $Fx := Data^{\langle 1 \rangle} \cdot lbf$ $Fy := Data^{\langle 2 \rangle} \cdot lbf$ $Fz := Data^{\langle 3 \rangle} \cdot lbf$

Assign end plate thickness

k := 0 t := 0

i := 0 .. n − 1

$k_i := reverse\left(match\left(1, t_{DS}^{\langle 0 \rangle} < d_i\right)\right)_0$

$t_i := \left(t_{DS}^{\langle 1 \rangle}\right)_{(k_i)}$ End plate thickness along d

$F := \sqrt{Fx^2 + Fy^2 + Fz^2}$ Total nodal force

Intervals

i := 0 .. n − 2

Δd := 0

$\Delta d_i := d_{i+1} - d_i$

Adjust intervals

i := 0 .. n − 3

Δd1 := 0

$\Delta d1_i := 0.5 \cdot \Delta d_i + 0.5 \cdot \Delta d_{i+1}$

i := 0 .. n − 1

Δd2 := 0

$\Delta d2_i := 0$

$\Delta d2_0 := 0.5 \cdot \Delta d_0$

$\Delta d2_{n-1} := 0.5 \cdot \Delta d_{n-2}$

i := 0 .. n − 3

$\Delta d2_{i+1} := \Delta d1_i$

Δd := Δd2 Adjusted intervals

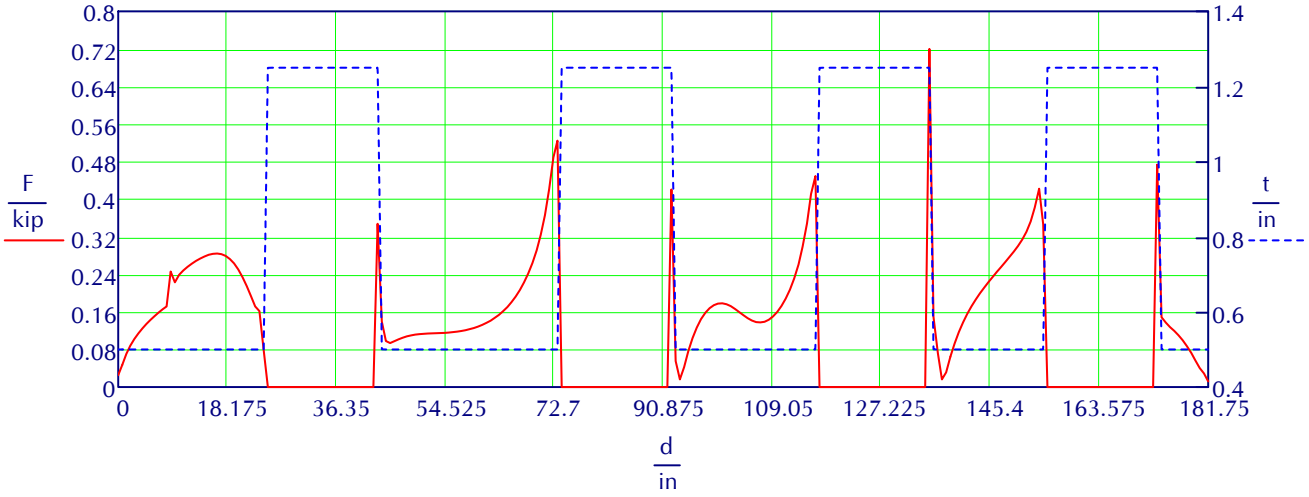
$f := \frac{F}{\Delta d}$ Force on the weld per unit length

$f_{max} := \max(f) = 1.036 \cdot \frac{kip}{in}$

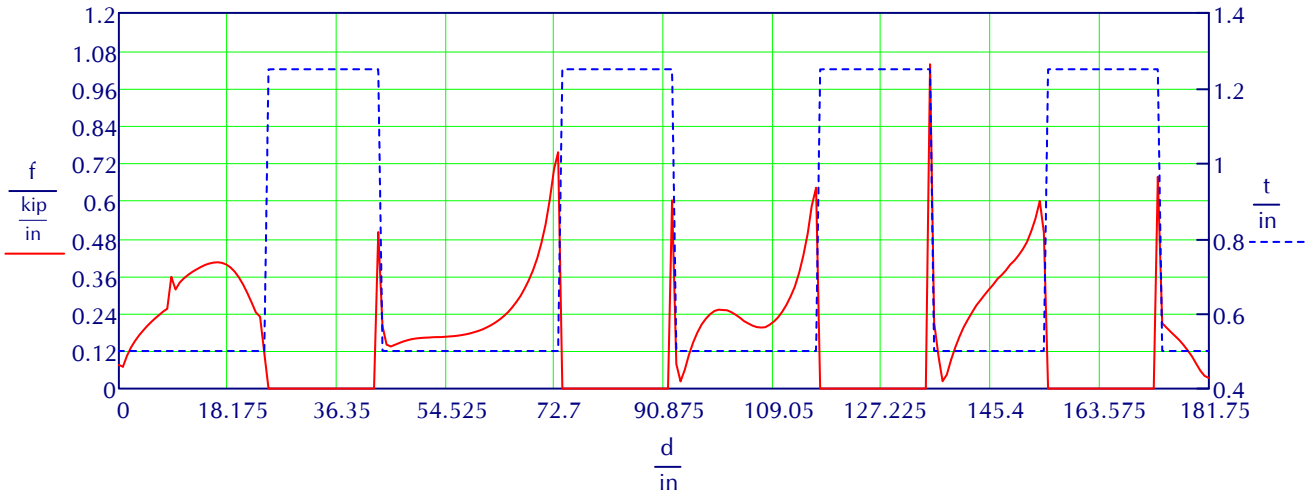
$\frac{f_{max}}{fa} = 0.29 \quad < 1.0$ Demand\capacity ratio for Name = "All wheels in contact - DS outer plate" where fa = $3.59 \cdot \frac{ki}{ir}$

Name = "All wheels in contact - DS outer plate"

Nodal force



Force on weld per unit length



4) Weld check - Wheel 1 not in contact

Wheel 1 not in contact - US inner plate

Name := "Wheel 1 not in contact - US inner plate"

Data := W1USI

n := rows(Data) = 268 Number of rows

Read data from FEA

$d := Data^{\langle 0 \rangle} \cdot in$ $Fx := Data^{\langle 1 \rangle} \cdot lbf$ $Fy := Data^{\langle 2 \rangle} \cdot lbf$ $Fz := Data^{\langle 3 \rangle} \cdot lbf$

Assign end plate thickness

k := 0 t := 0

i := 0 .. n − 1

$k_i := reverse\left(match\left(1, t_{US}^{\langle 0 \rangle} < d_i\right)\right)_0$

$t_i := \left(t_{US}^{\langle 1 \rangle}\right)_{(k_i)}$ End plate thickness along d

$F := \sqrt{Fx^2 + Fy^2 + Fz^2}$ Total nodal force

Intervals

i := 0 .. n − 2

Δd := 0

$\Delta d_i := d_{i+1} - d_i$

Adjust intervals

i := 0 .. n − 3

Δd1 := 0

$\Delta d1_i := 0.5 \cdot \Delta d_i + 0.5 \cdot \Delta d_{i+1}$

i := 0 .. n − 1

Δd2 := 0

$\Delta d2_i := 0$

$\Delta d2_0 := 0.5 \cdot \Delta d_0$

$\Delta d2_{n-1} := 0.5 \cdot \Delta d_{n-2}$

i := 0 .. n − 3

$\Delta d2_{i+1} := \Delta d1_i$

Δd := Δd2 Adjusted intervals

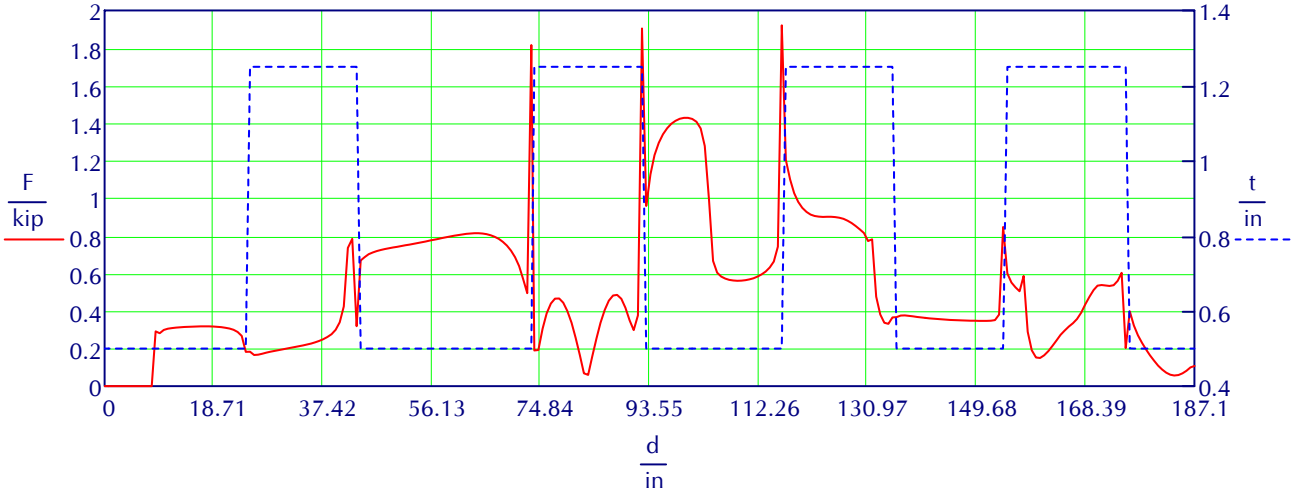
$f := \frac{F}{\Delta d}$ Force on the weld per unit length

$f_{max} := \max(f) = 3.031 \cdot \frac{kip}{in}$

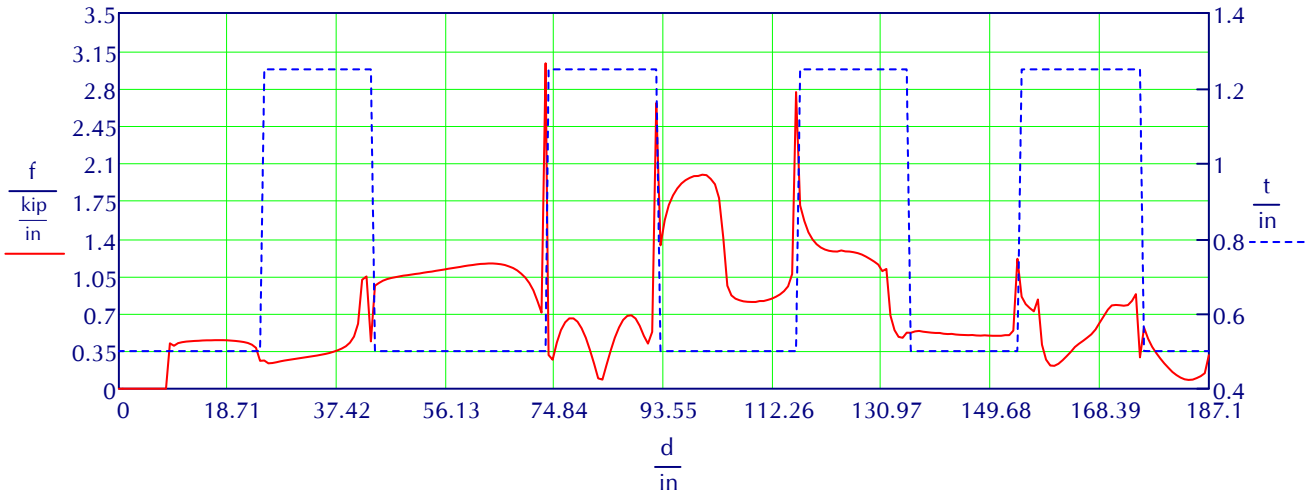
$\frac{f_{max}}{fa} = 0.85 < 1.0$ Demand\capacity ratio for Name = "Wheel 1 not in contact - US inner plate" where fa = 3.59

Name = "Wheel 1 not in contact - US inner plate"

Nodal force



Force on weld per unit length



Wheel 1 not in contact - DS inner plate

Name := "Wheel 1 not in contact - DS inner plate"

Data := W1DSI

$n := rows(Data) = 260$ Number of rows

Read data from FEA

$d := Data^{\langle 0 \rangle} \cdot in$ $Fx := Data^{\langle 1 \rangle} \cdot lbf$ $Fy := Data^{\langle 2 \rangle} \cdot lbf$ $Fz := Data^{\langle 3 \rangle} \cdot lbf$

Assign end plate thickness

$k := 0$ $t := 0$

$i := 0 .. n - 1$

$k_i := reverse\left(match\left(1, t_{DS}^{\langle 0 \rangle} < d_i\right)\right)_0$

$t_i := \left(t_{DS}^{\langle 1 \rangle}\right)_{(k_i)}$ End plate thickness along d

$F := \sqrt{Fx^2 + Fy^2 + Fz^2}$ Total nodal force

Intervals

$i := 0 .. n - 2$

$\Delta d := 0$

$\Delta d_i := d_{i+1} - d_i$

Adjust intervals

$i := 0 .. n - 3$

$\Delta d1 := 0$

$\Delta d1_i := 0.5 \cdot \Delta d_i + 0.5 \cdot \Delta d_{i+1}$

$i := 0 .. n - 1$

$\Delta d2 := 0$

$\Delta d2_i := 0$

$\Delta d2_0 := 0.5 \cdot \Delta d_0$

$\Delta d2_{n-1} := 0.5 \cdot \Delta d_{n-2}$

$i := 0 .. n - 3$

$\Delta d2_{i+1} := \Delta d1_i$

$\Delta d := \Delta d2$ Adjusted intervals

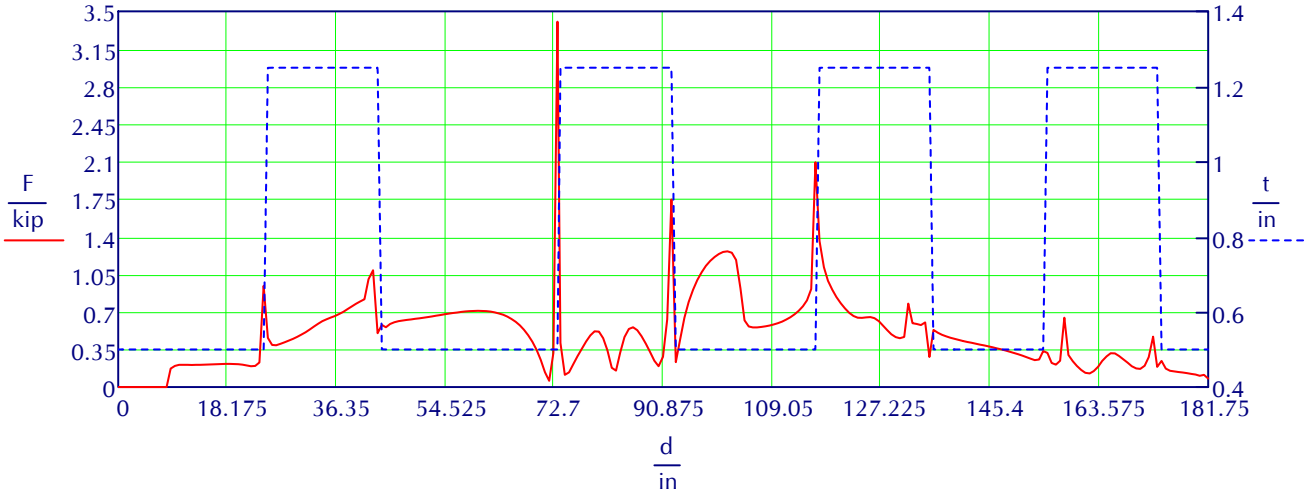
$f := \frac{F}{\Delta d}$ Force on the weld per unit length

$f_{max} := \max(f) = 5.681 \cdot \frac{kip}{in}$

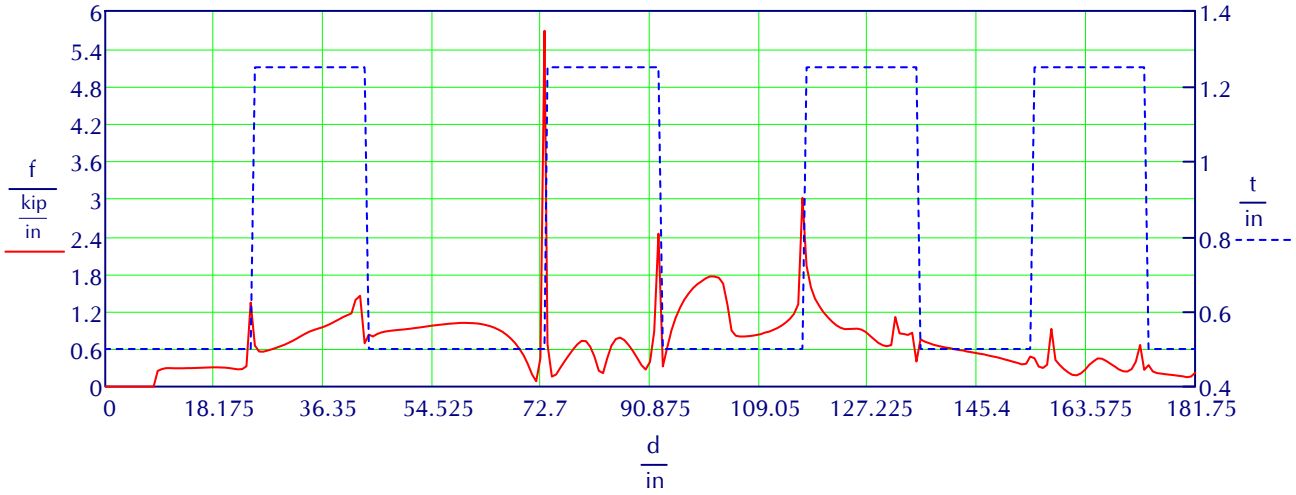
$\frac{f_{max}}{fa} = 1.58 \quad < 1.0$ Demand\capacity ratio for Name = "Wheel 1 not in contact - DS inner plate" where fa = 3.59

Name = "Wheel 1 not in contact - DS inner plate"

Nodal force



Force on weld per unit length



There is a small section that will be overloaded but it is not a concern since the stress will be redistributed

Wheel 1 not in contact - US outer plate

Name := "Wheel 1 not in contact - US outer plate"

Data := W1USO

$n := rows(Data) = 268$ Number of rows

Read data from FEA

$d := Data^{\langle 0 \rangle} \cdot in$ $Fx := Data^{\langle 1 \rangle} \cdot lbf$ $Fy := Data^{\langle 2 \rangle} \cdot lbf$ $Fz := Data^{\langle 3 \rangle} \cdot lbf$

Assign end plate thickness

$k := 0$ $t := 0$

$i := 0 .. n - 1$

$k_i := reverse\left(match\left(1 , t_{US}^{\langle 0 \rangle} < d_i\right)\right)_0$

$t_i := \left(t_{US}^{\langle 1 \rangle}\right)_{(k_i)}$ End plate thickness along d

$F := \sqrt{Fx^2 + Fy^2 + Fz^2}$ Total nodal force

Intervals

$i := 0 .. n - 2$

$\Delta d := 0$

$\Delta d_i := d_{i+1} - d_i$

Adjust intervals

$i := 0 .. n - 3$

$\Delta d1 := 0$

$\Delta d1_i := 0.5 \cdot \Delta d_i + 0.5 \cdot \Delta d_{i+1}$

$i := 0 .. n - 1$

$\Delta d2 := 0$

$\Delta d2_i := 0$

$\Delta d2_0 := 0.5 \cdot \Delta d_0$

$\Delta d2_{n-1} := 0.5 \cdot \Delta d_{n-2}$

$i := 0 .. n - 3$

$\Delta d2_{i+1} := \Delta d1_i$

$\Delta d := \Delta d2$ Adjusted intervals

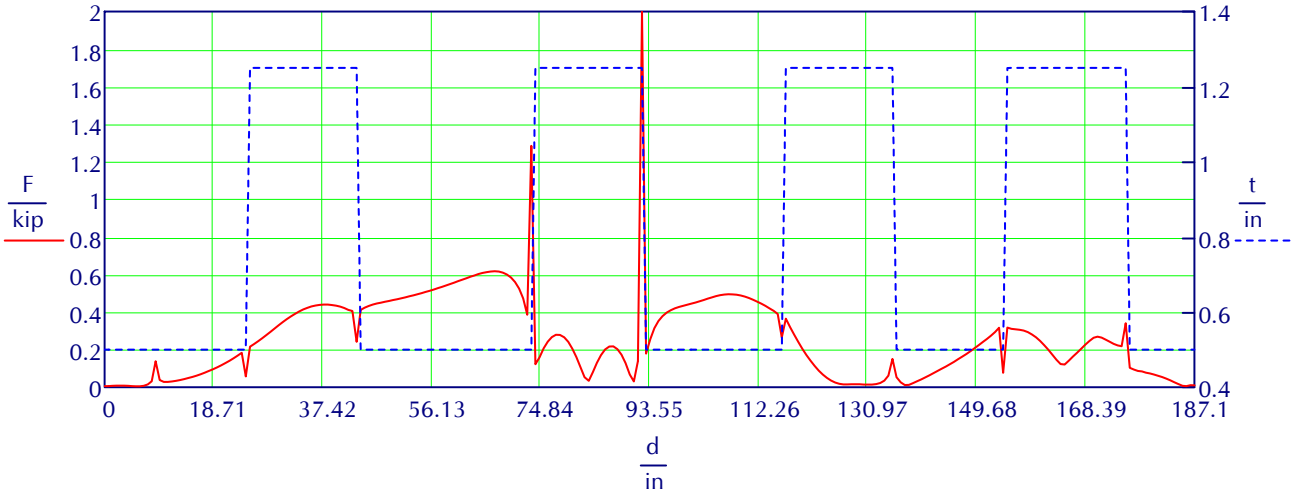
$f := \frac{F}{\Delta d}$ Force on the weld per unit length

$f_{max} := \max(f) = 2.833 \cdot \frac{kip}{in}$

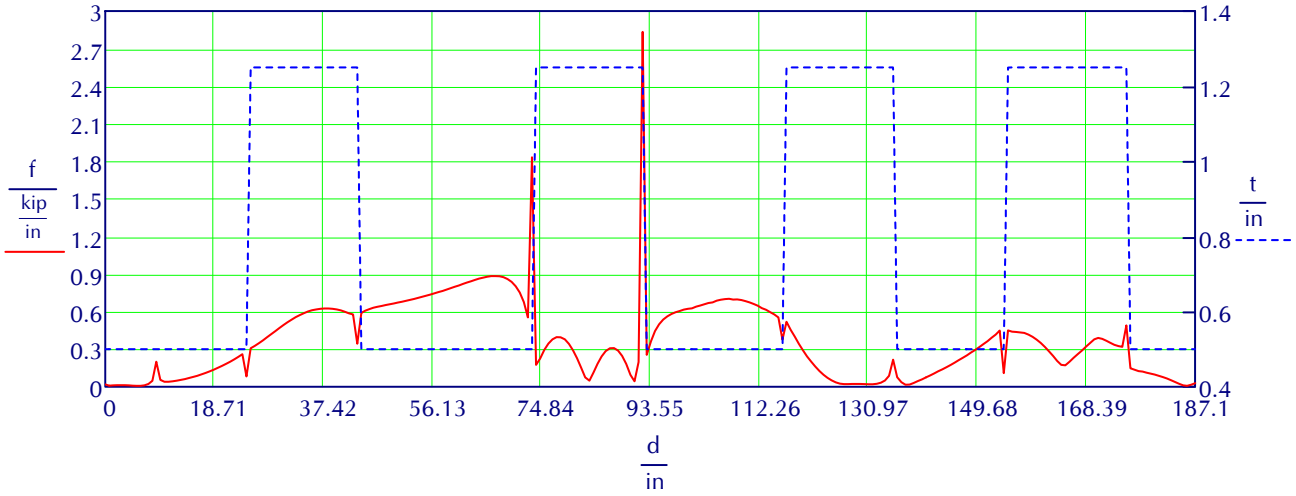
$\frac{f_{max}}{fa} = 0.79 \quad < 1.0$ Demand\capacity ratio for Name = "Wheel 1 not in contact - US outer plate" where fa = 3.59

Name = "Wheel 1 not in contact - US outer plate"

Nodal force



Force on weld per unit length



Wheel 1 not in contact - DS outer plate

Name := "Wheel 1 not in contact - DS outer plate"

Data := W1DSO

n := rows(Data) = 264 Number of rows

Read data from FEA

$d := Data^{\langle 0 \rangle} \cdot in$ $Fx := Data^{\langle 1 \rangle} \cdot lbf$ $Fy := Data^{\langle 2 \rangle} \cdot lbf$ $Fz := Data^{\langle 3 \rangle} \cdot lbf$

Assign end plate thickness

k := 0 t := 0

i := 0 .. n − 1

$k_i := reverse\left(match\left(1, t_{DS}^{\langle 0 \rangle} < d_i\right)\right)_0$

$t_i := \left(t_{DS}^{\langle 1 \rangle}\right)_{(k_i)}$ End plate thickness along d

$F := \sqrt{Fx^2 + Fy^2 + Fz^2}$ Total nodal force

Intervals

i := 0 .. n − 2

Δd := 0

$\Delta d_i := d_{i+1} - d_i$

Adjust intervals

i := 0 .. n − 3

Δd1 := 0

$\Delta d1_i := 0.5 \cdot \Delta d_i + 0.5 \cdot \Delta d_{i+1}$

i := 0 .. n − 1

Δd2 := 0

$\Delta d2_i := 0$

$\Delta d2_0 := 0.5 \cdot \Delta d_0$

$\Delta d2_{n-1} := 0.5 \cdot \Delta d_{n-2}$

i := 0 .. n − 3

$\Delta d2_{i+1} := \Delta d1_i$

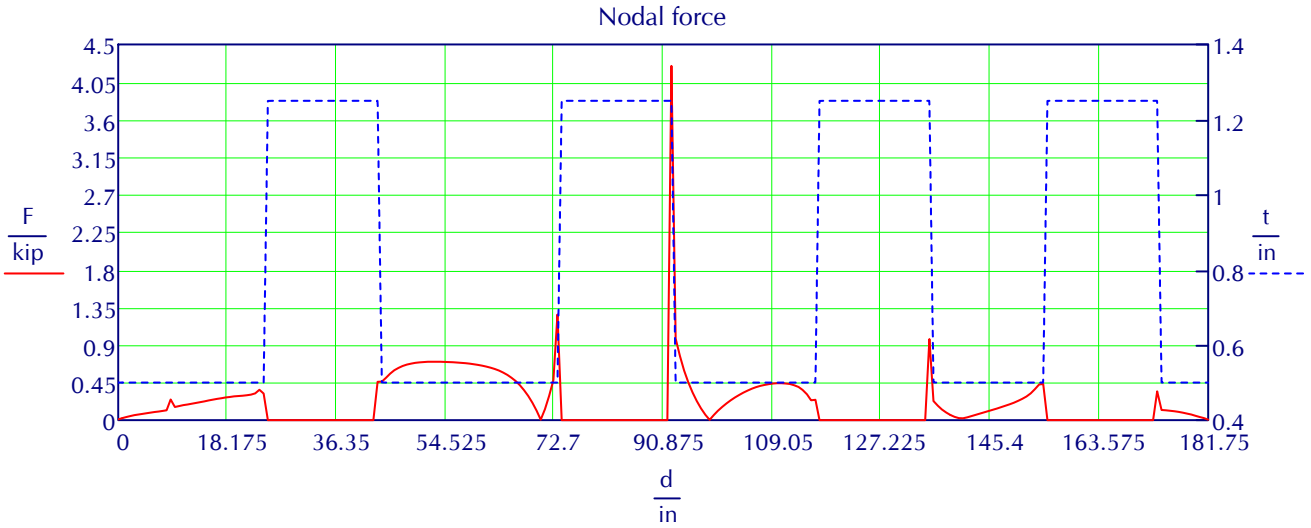
Δd := Δd2 Adjusted intervals

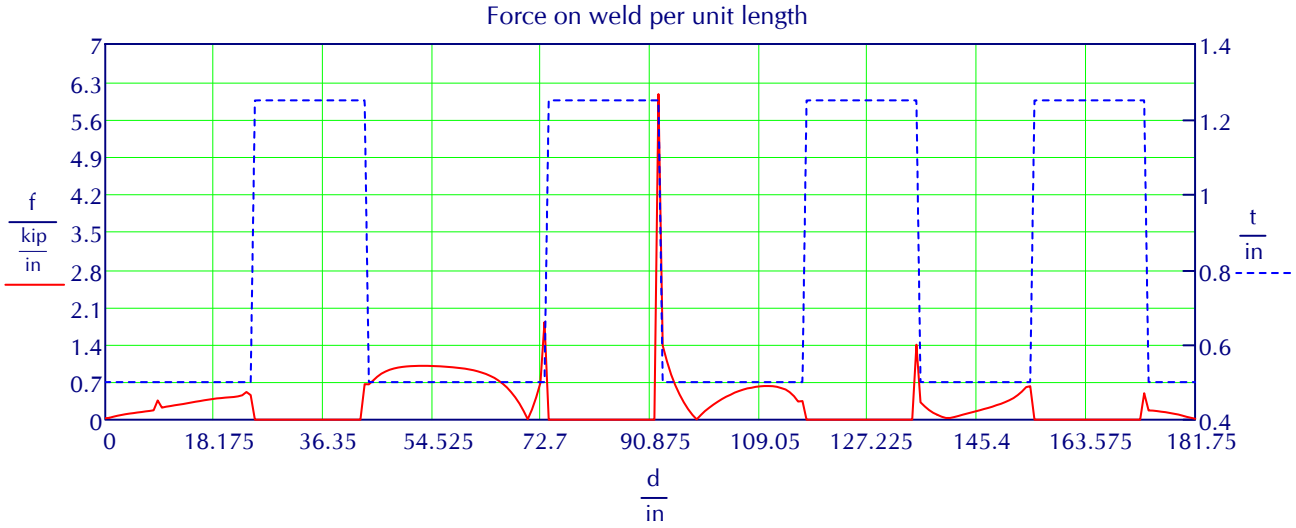
$f := \frac{F}{\Delta d}$ Force on the weld per unit length

$f_{max} := \max(f) = 6.067 \cdot \frac{kip}{in}$

$\frac{f_{max}}{fa} = 1.69 \quad < 1.0$ Demand\capacity ratio for Name = "Wheel 1 not in contact - DS outer plate" where fa = 3.59

Name = "Wheel 1 not in contact - DS outer plate"





There is a small section that will be overloaded but it is not a concern since the stress will be redistributed

5) Weld check - Wheel 2 not in contact

Wheel 2 not in contact - US inner plate

Name := "Wheel 2 not in contact - US inner plate"

Data := W2USI

n := rows(Data) = 268 Number of rows

Read data from FEA

$d := Data^{\langle 0 \rangle} \cdot in$ $Fx := Data^{\langle 1 \rangle} \cdot lbf$ $Fy := Data^{\langle 2 \rangle} \cdot lbf$ $Fz := Data^{\langle 3 \rangle} \cdot lbf$

Assign end plate thickness

k := 0 t := 0

i := 0 .. n − 1

$k_i := reverse\left(match\left(1, t_{US}^{\langle 0 \rangle} < d_i\right)\right)_0$

$t_i := \left(t_{US}^{\langle 1 \rangle}\right)_{(k_i)}$ End plate thickness along d

$F := \sqrt{Fx^2 + Fy^2 + Fz^2}$ Total nodal force

Intervals

i := 0 .. n − 2

Δd := 0

$\Delta d_i := d_{i+1} - d_i$

Adjust intervals

i := 0 .. n − 3

Δd1 := 0

$\Delta d1_i := 0.5 \cdot \Delta d_i + 0.5 \cdot \Delta d_{i+1}$

i := 0 .. n − 1

Δd2 := 0

$\Delta d2_i := 0$

$\Delta d2_0 := 0.5 \cdot \Delta d_0$

$\Delta d2_{n-1} := 0.5 \cdot \Delta d_{n-2}$

i := 0 .. n − 3

$\Delta d2_{i+1} := \Delta d1_i$

Δd := Δd2 Adjusted intervals

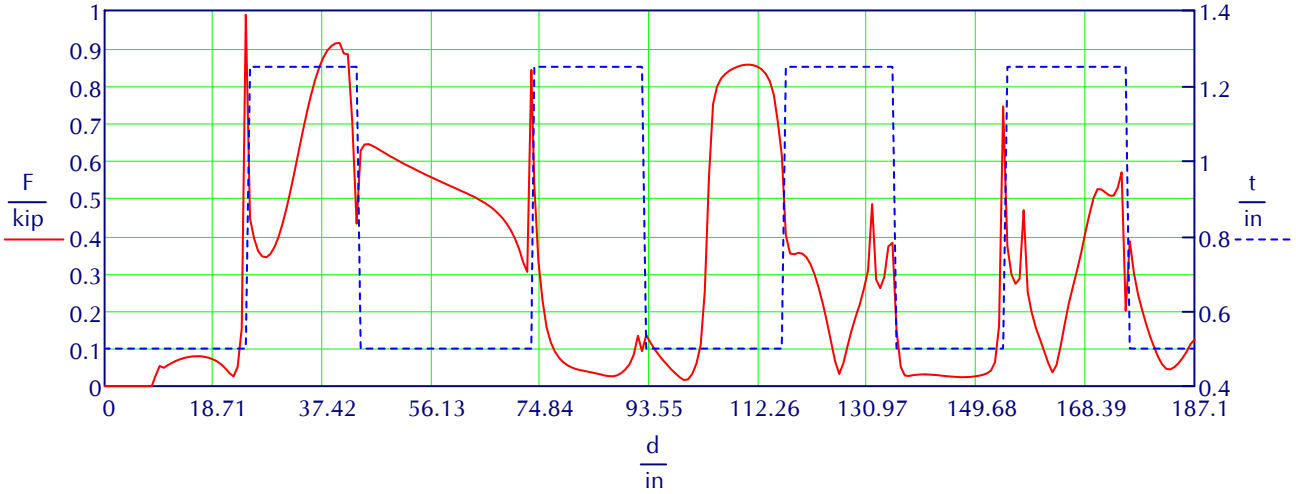
$f := \frac{F}{\Delta d}$ Force on the weld per unit length

$f_{max} := \max(f) = 1.407 \cdot \frac{kip}{in}$

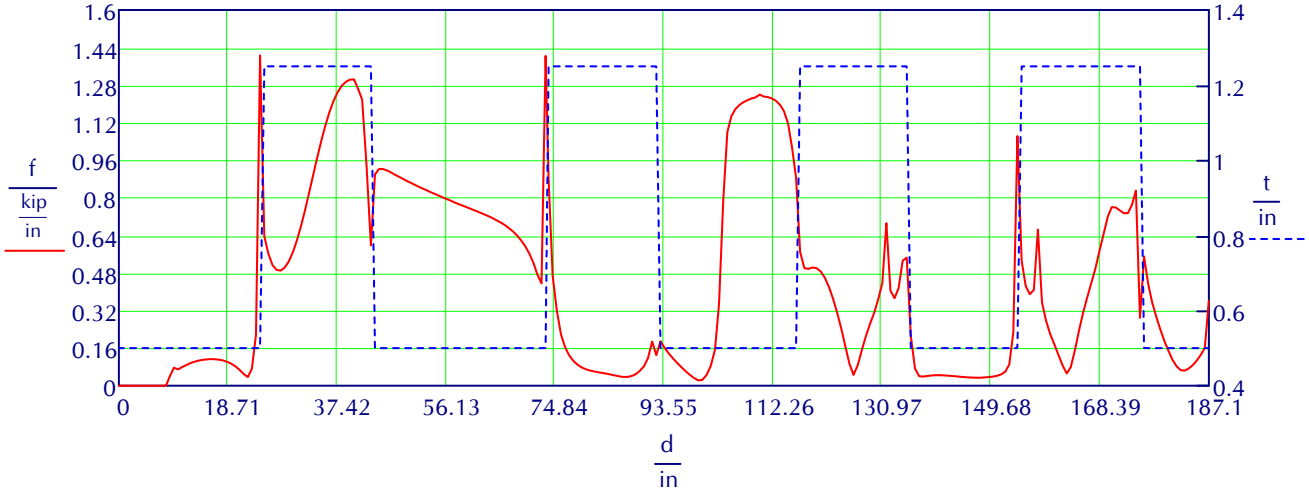
$\frac{f_{max}}{fa} = 0.39 \quad < 1.0$ Demand\capacity ratio for Name = "Wheel 2 not in contact - US inner plate" where fa = 3.59

Name = "Wheel 2 not in contact - US inner plate"

Nodal force



Force on weld per unit length



Wheel 2 not in contact - DS inner plate

Name := "Wheel 2 not in contact - DS inner plate"

Data := W2DSI

n := rows(Data) = 260 Number of rows

Read data from FEA

$d := Data^{\langle 0 \rangle} \cdot in$ $Fx := Data^{\langle 1 \rangle} \cdot lbf$ $Fy := Data^{\langle 2 \rangle} \cdot lbf$ $Fz := Data^{\langle 3 \rangle} \cdot lbf$

Assign end plate thickness

k := 0 t := 0

i := 0 .. n − 1

$k_i := reverse\left(match\left(1, t_{DS}^{\langle 0 \rangle} < d_i\right)\right)_0$

$t_i := \left(t_{DS}^{\langle 1 \rangle}\right)_{(k_i)}$ End plate thickness along d

$F := \sqrt{Fx^2 + Fy^2 + Fz^2}$ Total nodal force

Intervals

i := 0 .. n − 2

Δd := 0

$\Delta d_i := d_{i+1} - d_i$

Adjust intervals

i := 0 .. n − 3

Δd1 := 0

$\Delta d1_i := 0.5 \cdot \Delta d_i + 0.5 \cdot \Delta d_{i+1}$

i := 0 .. n − 1

Δd2 := 0

$\Delta d2_i := 0$

$\Delta d2_0 := 0.5 \cdot \Delta d_0$

$\Delta d2_{n-1} := 0.5 \cdot \Delta d_{n-2}$

i := 0 .. n − 3

$\Delta d2_{i+1} := \Delta d1_i$

Δd := Δd2 Adjusted intervals

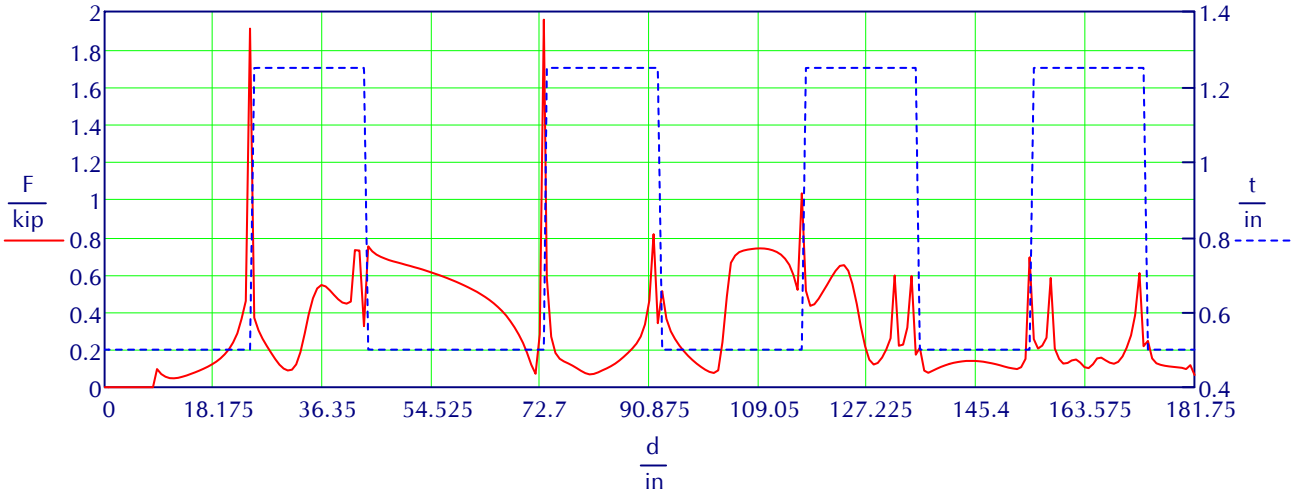
$f := \frac{F}{\Delta d}$ Force on the weld per unit length

$f_{max} := \max(f) = 3.267 \cdot \frac{kip}{in}$

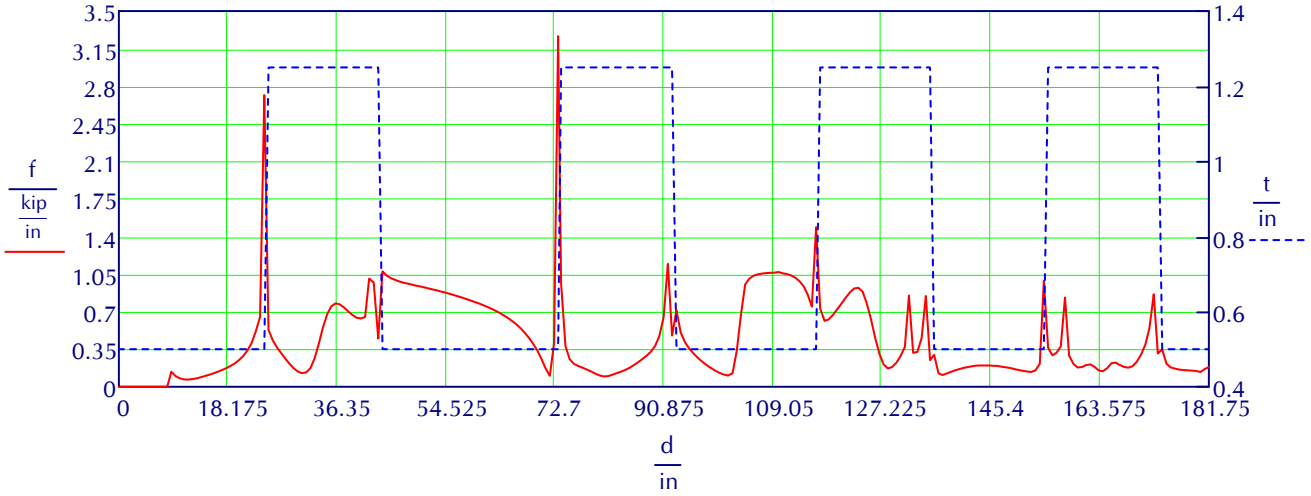
$\frac{f_{max}}{fa} = 0.91 \quad < 1.0$ Demand\capacity ratio for Name = "Wheel 2 not in contact - DS inner plate" where fa = 3.59

Name = "Wheel 2 not in contact - DS inner plate"

Nodal force



Force on weld per unit length



Wheel 2 not in contact - US outer plate

Name := "Wheels 2 not in contact - US outer plate"

Data := W2USO

n := rows(Data) = 268 Number of rows

Read data from FEA

$d := Data^{\langle 0 \rangle} \cdot in$ $Fx := Data^{\langle 1 \rangle} \cdot lbf$ $Fy := Data^{\langle 2 \rangle} \cdot lbf$ $Fz := Data^{\langle 3 \rangle} \cdot lbf$

Assign end plate thickness

k := 0 t := 0

i := 0 .. n − 1

$k_i := reverse\left(match\left(1, t_{US}^{\langle 0 \rangle} < d_i\right)\right)_0$

$t_i := \left(t_{US}^{\langle 1 \rangle}\right)_{(k_i)}$ End plate thickness along d

$F := \sqrt{Fx^2 + Fy^2 + Fz^2}$ Total nodal force

Intervals

i := 0 .. n − 2

Δd := 0

$\Delta d_i := d_{i+1} - d_i$

Adjust intervals

i := 0 .. n − 3

Δd1 := 0

$\Delta d1_i := 0.5 \cdot \Delta d_i + 0.5 \cdot \Delta d_{i+1}$

i := 0 .. n − 1

Δd2 := 0

$\Delta d2_i := 0$

$\Delta d2_0 := 0.5 \cdot \Delta d_0$

$\Delta d2_{n-1} := 0.5 \cdot \Delta d_{n-2}$

i := 0 .. n − 3

$\Delta d2_{i+1} := \Delta d1_i$

Δd := Δd2 Adjusted intervals

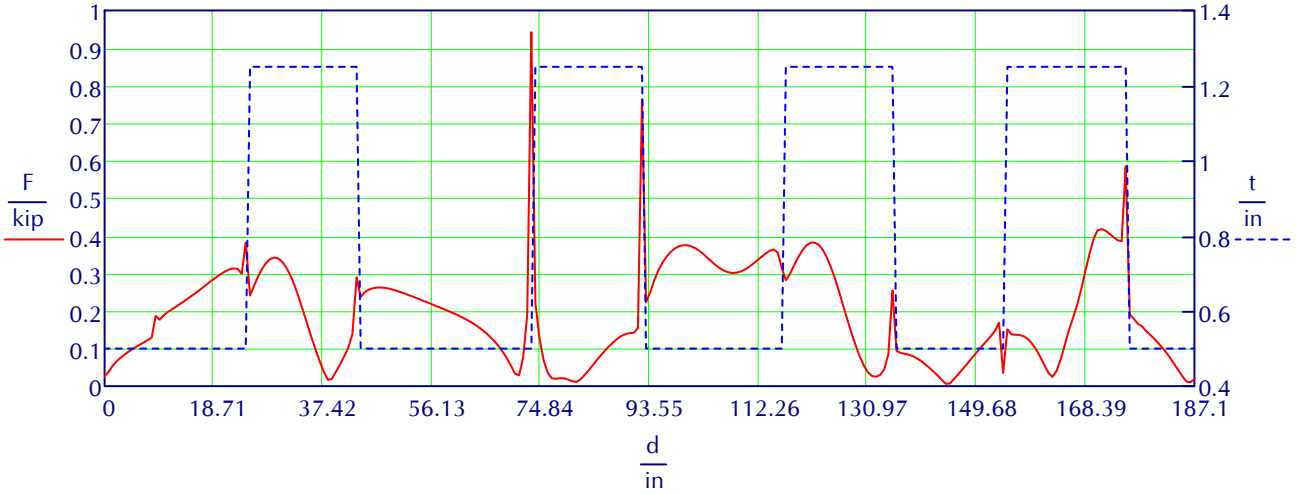
$f := \frac{F}{\Delta d}$ Force on the weld per unit length

$f_{max} := \max(f) = 1.345 \cdot \frac{kip}{in}$

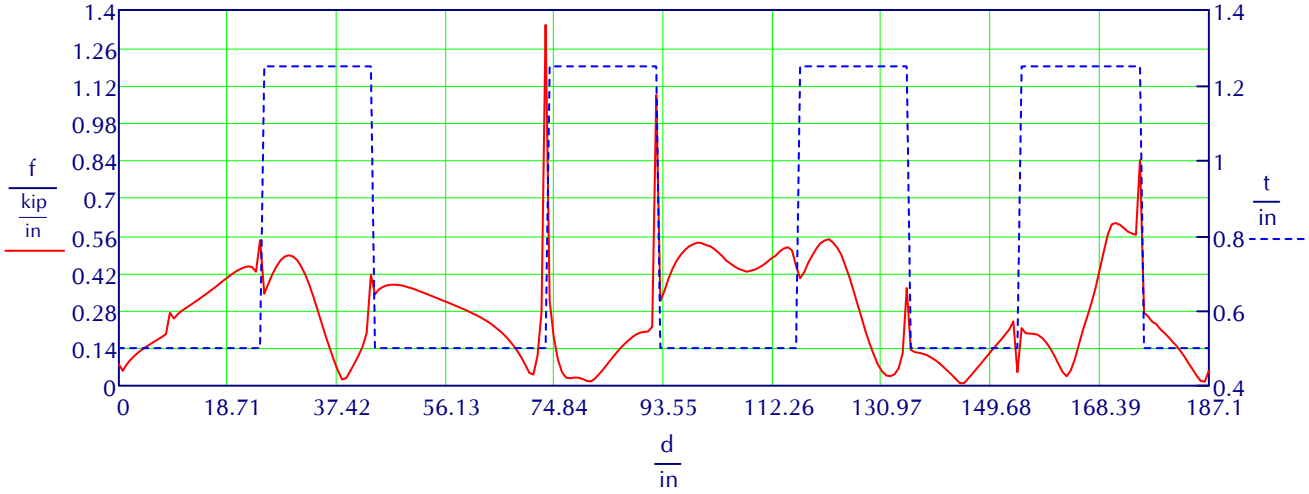
$\frac{f_{max}}{fa} = 0.37 < 1.0$ Demand\capacity ratio for Name = "Wheels 2 not in contact - US outer plate" where fa = 3.59

Name = "Wheels 2 not in contact - US outer plate"

Nodal force



Force on weld per unit length



Wheel 2 not in contact - DS outer plate

Name := "Wheel 2 not in contact - DS outer plate"

Data := W2DSO

n := rows(Data) = 264 Number of rows

Read data from FEA

$d := Data^{\langle 0 \rangle} \cdot in$ $Fx := Data^{\langle 1 \rangle} \cdot lbf$ $Fy := Data^{\langle 2 \rangle} \cdot lbf$ $Fz := Data^{\langle 3 \rangle} \cdot lbf$

Assign end plate thickness

k := 0 t := 0

i := 0 .. n − 1

$k_i := reverse\left(match\left(1, t_{DS}^{\langle 0 \rangle} < d_i\right)\right)_0$

$t_i := \left(t_{DS}^{\langle 1 \rangle}\right)_{(k_i)}$ End plate thickness along d

$F := \sqrt{Fx^2 + Fy^2 + Fz^2}$ Total nodal force

Intervals

i := 0 .. n − 2

Δd := 0

$\Delta d_i := d_{i+1} - d_i$

Adjust intervals

i := 0 .. n − 3

Δd1 := 0

$\Delta d1_i := 0.5 \cdot \Delta d_i + 0.5 \cdot \Delta d_{i+1}$

i := 0 .. n − 1

Δd2 := 0

$\Delta d2_i := 0$

$\Delta d2_0 := 0.5 \cdot \Delta d_0$

$\Delta d2_{n-1} := 0.5 \cdot \Delta d_{n-2}$

i := 0 .. n − 3

$\Delta d2_{i+1} := \Delta d1_i$

Δd := Δd2 Adjusted intervals

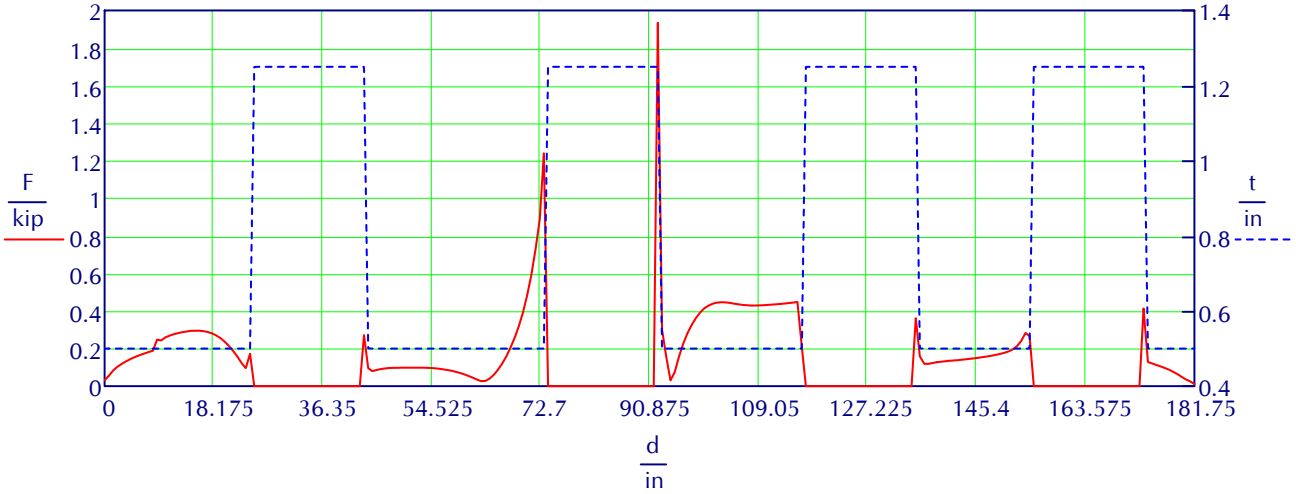
$f := \frac{F}{\Delta d}$ Force on the weld per unit length

$f_{max} := \max(f) = 2.765 \cdot \frac{kip}{in}$

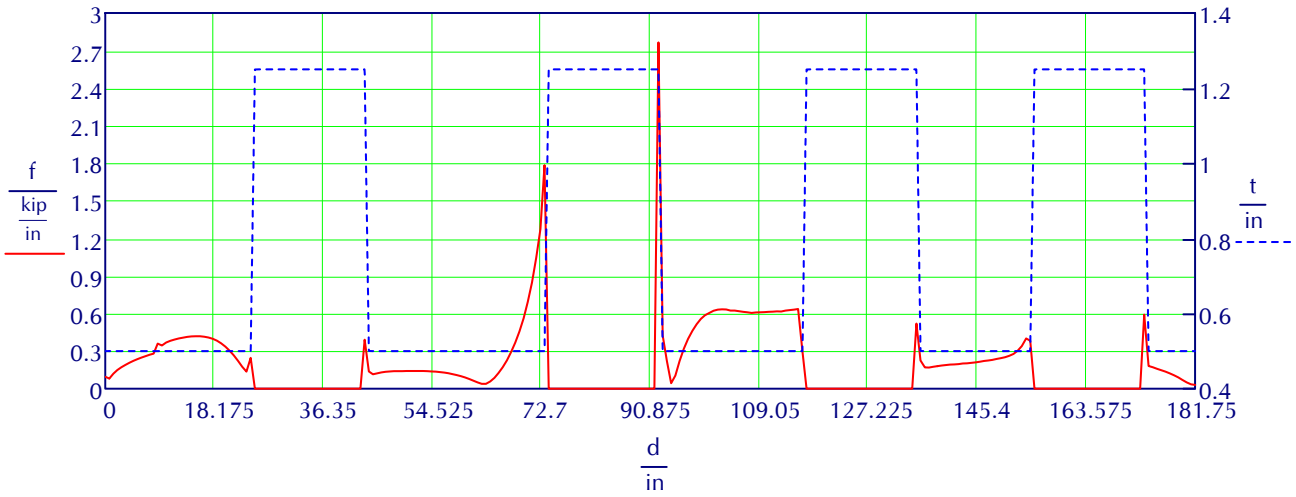
$\frac{f_{max}}{fa} = 0.77 \quad < 1.0$ Demand\capacity ratio for Name = "Wheel 2 not in contact - DS outer plate" where fa = 3.59

Name = "Wheel 2 not in contact - DS outer plate"

Nodal force



Force on weld per unit length



5) Weld check - Wheel 3 not in contact

Wheel 3 not in contact - US inner plate

Name := "Wheel 3 not in contact - US inner plate"

Data := W3USI

n := rows(Data) = 268 Number of rows

Read data from FEA

d := $Data^{\langle 0 \rangle}$·in Fx := $Data^{\langle 1 \rangle}$·lbf Fy := $Data^{\langle 2 \rangle}$·lbf Fz := $Data^{\langle 3 \rangle}$·lbf

Assign end plate thickness

k := 0 t := 0

i := 0 .. n − 1

$k_i := reverse\left(match\left(1, t_{US}^{\langle 0 \rangle} < d_i\right)\right)_0$

$t_i := \left(t_{US}^{\langle 1 \rangle}\right)_{(k_i)}$ End plate thickness along d

$F := \sqrt{Fx^2 + Fy^2 + Fz^2}$ Total nodal force

Intervals

i := 0 .. n − 2

Δd := 0

$\Delta d_i := d_{i+1} - d_i$

Adjust intervals

i := 0 .. n − 3

Δd1 := 0

$\Delta d1_i := 0.5 \cdot \Delta d_i + 0.5 \cdot \Delta d_{i+1}$

i := 0 .. n − 1

Δd2 := 0

$\Delta d2_i := 0$

$\Delta d2_0 := 0.5 \cdot \Delta d_0$

$\Delta d2_{n-1} := 0.5 \cdot \Delta d_{n-2}$

i := 0 .. n − 3

$\Delta d2_{i+1} := \Delta d1_i$

Δd := Δd2 Adjusted intervals

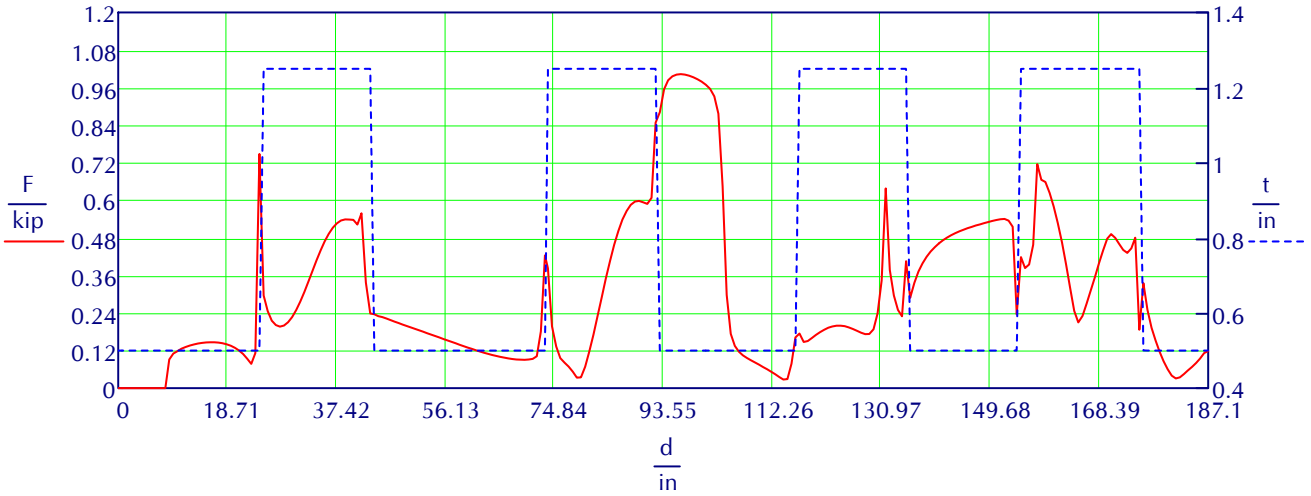
$f := \frac{F}{\Delta d}$ Force on the weld per unit length

$f_{max} := \max(f) = 1.396 \cdot \frac{kip}{in}$

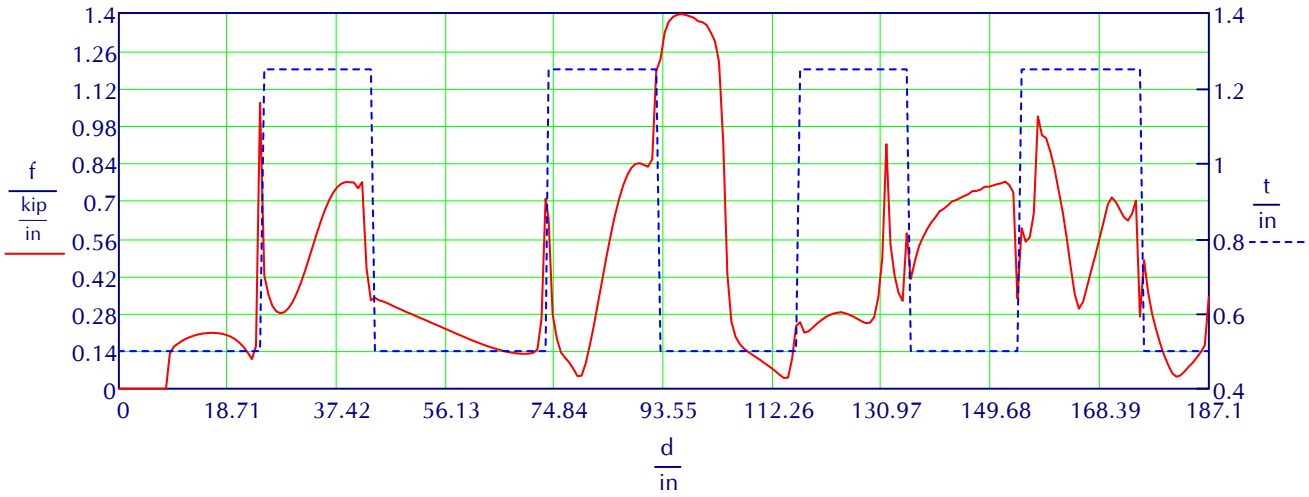
$\frac{f_{max}}{fa} = 0.39 \quad < 1.0$ Demand\capacity ratio for Name = "Wheel 3 not in contact - US inner plate" where fa = 3.59

Name = "Wheel 3 not in contact - US inner plate"

Nodal force



Force on weld per unit length



Wheel 3 not in contact - DS inner plate

Name := "Wheel 3 not in contact - DS inner plate"

Data := W3DSI

$n := rows(Data) = 260$ Number of rows

Read data from FEA

$d := Data^{\langle 0 \rangle} \cdot in$ $Fx := Data^{\langle 1 \rangle} \cdot lbf$ $Fy := Data^{\langle 2 \rangle} \cdot lbf$ $Fz := Data^{\langle 3 \rangle} \cdot lbf$

Assign end plate thickness

$k := 0$ $t := 0$

$i := 0 .. n - 1$

$k_i := reverse\left(match\left(1, t_{DS}^{\langle 0 \rangle} < d_i\right)\right)_0$

$t_i := \left(t_{DS}^{\langle 1 \rangle}\right)_{(k_i)}$ End plate thickness along d

$F := \sqrt{Fx^2 + Fy^2 + Fz^2}$ Total nodal force

Intervals

$i := 0 .. n - 2$

$\Delta d := 0$

$\Delta d_i := d_{i+1} - d_i$

Adjust intervals

$i := 0 .. n - 3$

$\Delta d1 := 0$

$\Delta d1_i := 0.5 \cdot \Delta d_i + 0.5 \cdot \Delta d_{i+1}$

$i := 0 .. n - 1$

$\Delta d2 := 0$

$\Delta d2_i := 0$

$\Delta d2_0 := 0.5 \cdot \Delta d_0$

$\Delta d2_{n-1} := 0.5 \cdot \Delta d_{n-2}$

$i := 0 .. n - 3$

$\Delta d2_{i+1} := \Delta d1_i$

$\Delta d := \Delta d2$ Adjusted intervals

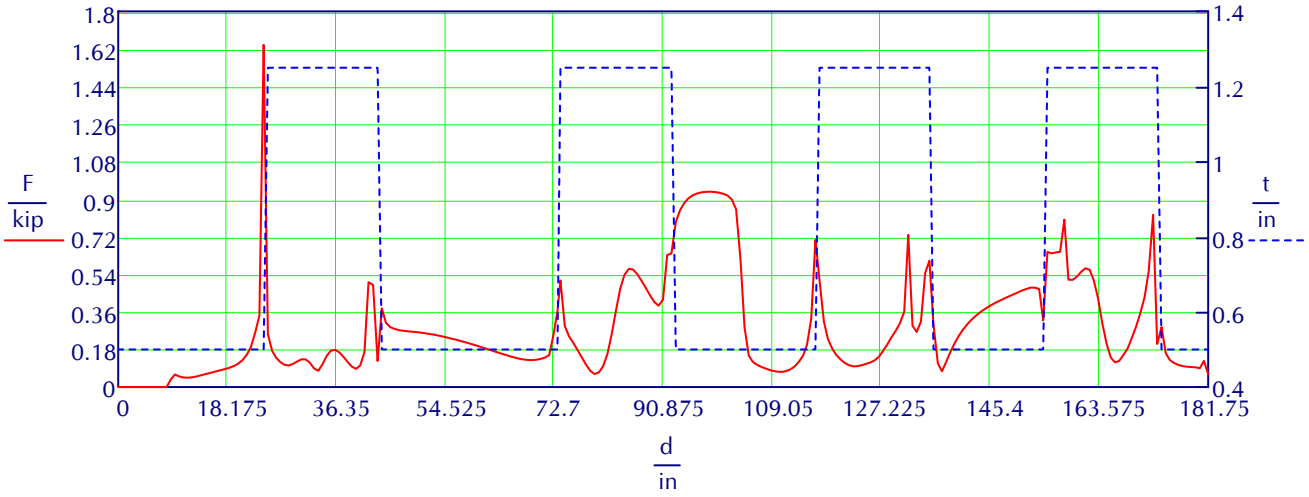
$f := \frac{F}{\Delta d}$ Force on the weld per unit length

$f_{max} := \max(f) = 2.333 \cdot \frac{kip}{in}$

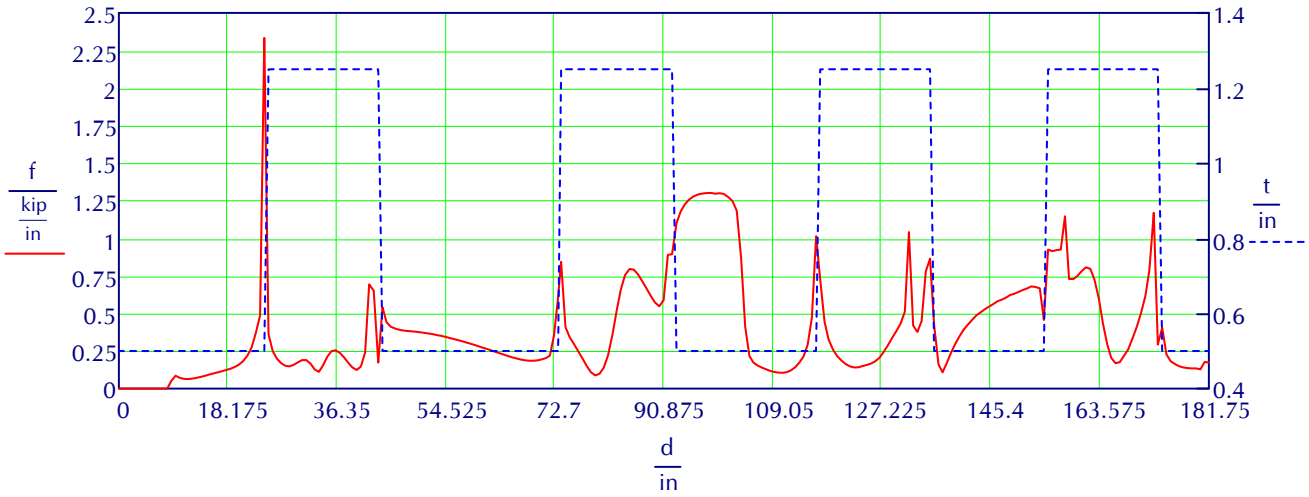
$\frac{f_{max}}{fa} = 0.65 \quad < 1.0$ Demand\capacity ratio for Name = "Wheel 3 not in contact - DS inner plate" where fa = 3.59

Name = "Wheel 3 not in contact - DS inner plate"

Nodal force



Force on weld per unit length



Wheel 3 not in contact - US outer plate

Name := "Wheel 3 not in contact - US outer plate"

Data := W3USO

n := rows(Data) = 268 Number of rows

Read data from FEA

$d := Data^{\langle 0 \rangle} \cdot in$ $Fx := Data^{\langle 1 \rangle} \cdot lbf$ $Fy := Data^{\langle 2 \rangle} \cdot lbf$ $Fz := Data^{\langle 3 \rangle} \cdot lbf$

Assign end plate thickness

k := 0 t := 0

i := 0 .. n − 1

$k_i := reverse\left(match\left(1, t_{US}^{\langle 0 \rangle} < d_i\right)\right)_0$

$t_i := \left(t_{US}^{\langle 1 \rangle}\right)_{(k_i)}$ End plate thickness along d

$F := \sqrt{Fx^2 + Fy^2 + Fz^2}$ Total nodal force

Intervals

i := 0 .. n − 2

Δd := 0

$\Delta d_i := d_{i+1} - d_i$

Adjust intervals

i := 0 .. n − 3

Δd1 := 0

$\Delta d1_i := 0.5 \cdot \Delta d_i + 0.5 \cdot \Delta d_{i+1}$

i := 0 .. n − 1

Δd2 := 0

$\Delta d2_i := 0$

$\Delta d2_0 := 0.5 \cdot \Delta d_0$

$\Delta d2_{n-1} := 0.5 \cdot \Delta d_{n-2}$

i := 0 .. n − 3

$\Delta d2_{i+1} := \Delta d1_i$

Δd := Δd2 Adjusted intervals

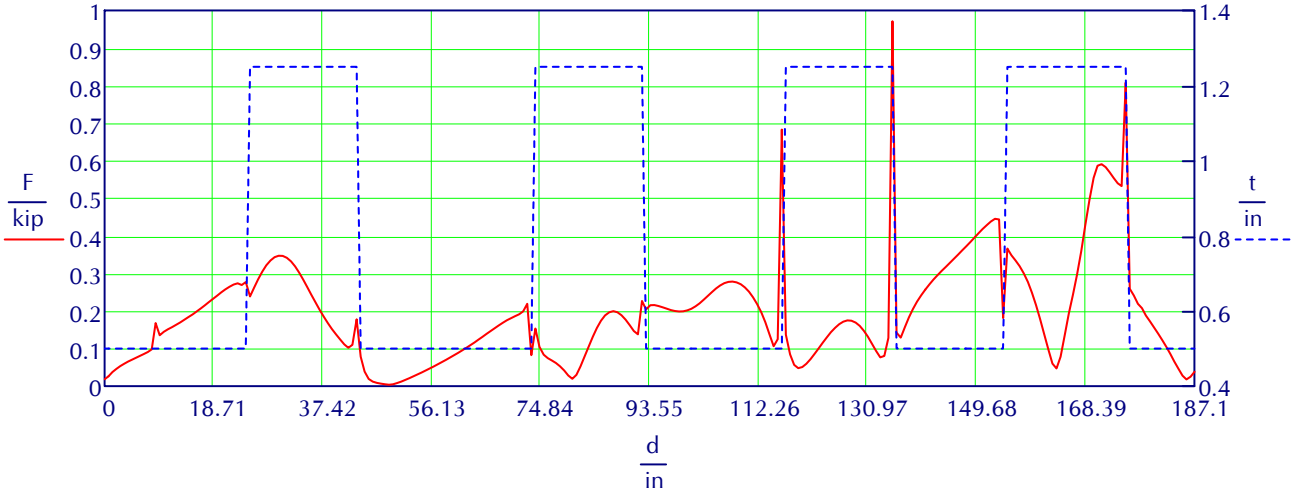
$f := \frac{F}{\Delta d}$ Force on the weld per unit length

$f_{max} := \max(f) = 1.387 \cdot \frac{kip}{in}$

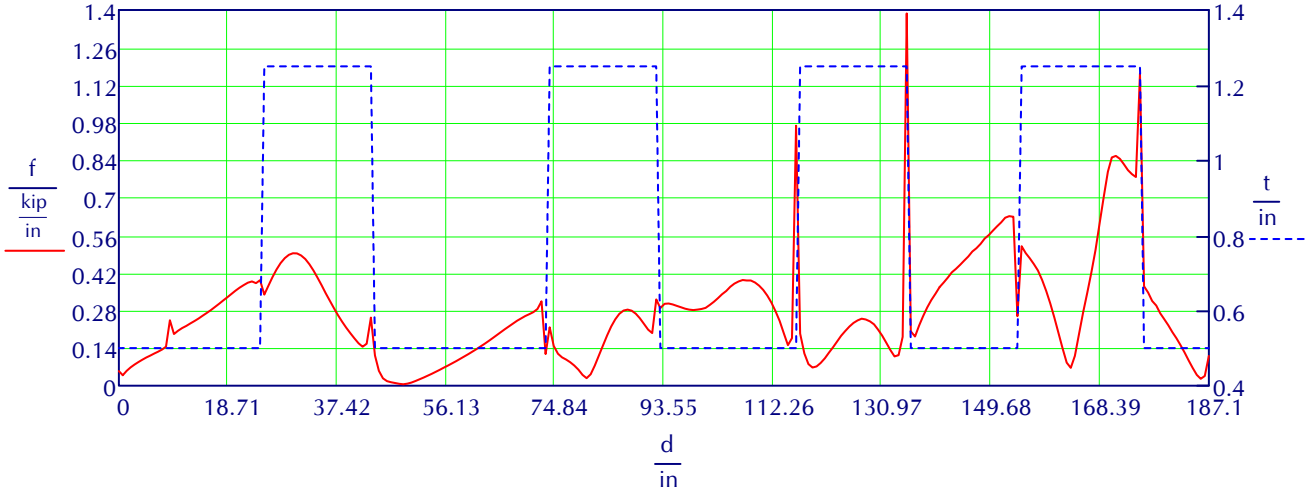
$\frac{f_{max}}{fa} = 0.39 \quad < 1.0$ Demand\capacity ratio for Name = "Wheel 3 not in contact - US outer plate" where fa = 3.59

Name = "Wheel 3 not in contact - US outer plate"

Nodal force



Force on weld per unit length



Wheel 3 not in contact - DS outer plate

Name := "Wheel 3 not in contact - DS outer plate"

Data := W3DSO

n := rows(Data) = 264 Number of rows

Read data from FEA

$d := Data^{\langle 0 \rangle} \cdot in$ $Fx := Data^{\langle 1 \rangle} \cdot lbf$ $Fy := Data^{\langle 2 \rangle} \cdot lbf$ $Fz := Data^{\langle 3 \rangle} \cdot lbf$

Assign end plate thickness

k := 0 t := 0

i := 0 .. n − 1

$k_i := reverse\left(match\left(1, t_{DS}^{\langle 0 \rangle} < d_i\right)\right)_0$

$t_i := \left(t_{DS}^{\langle 1 \rangle}\right)_{(k_i)}$ End plate thickness along d

$F := \sqrt{Fx^2 + Fy^2 + Fz^2}$ Total nodal force

Intervals

i := 0 .. n − 2

Δd := 0

$\Delta d_i := d_{i+1} - d_i$

Adjust intervals

i := 0 .. n − 3

Δd1 := 0

$\Delta d1_i := 0.5 \cdot \Delta d_i + 0.5 \cdot \Delta d_{i+1}$

i := 0 .. n − 1

Δd2 := 0

$\Delta d2_i := 0$

$\Delta d2_0 := 0.5 \cdot \Delta d_0$

$\Delta d2_{n-1} := 0.5 \cdot \Delta d_{n-2}$

i := 0 .. n − 3

$\Delta d2_{i+1} := \Delta d1_i$

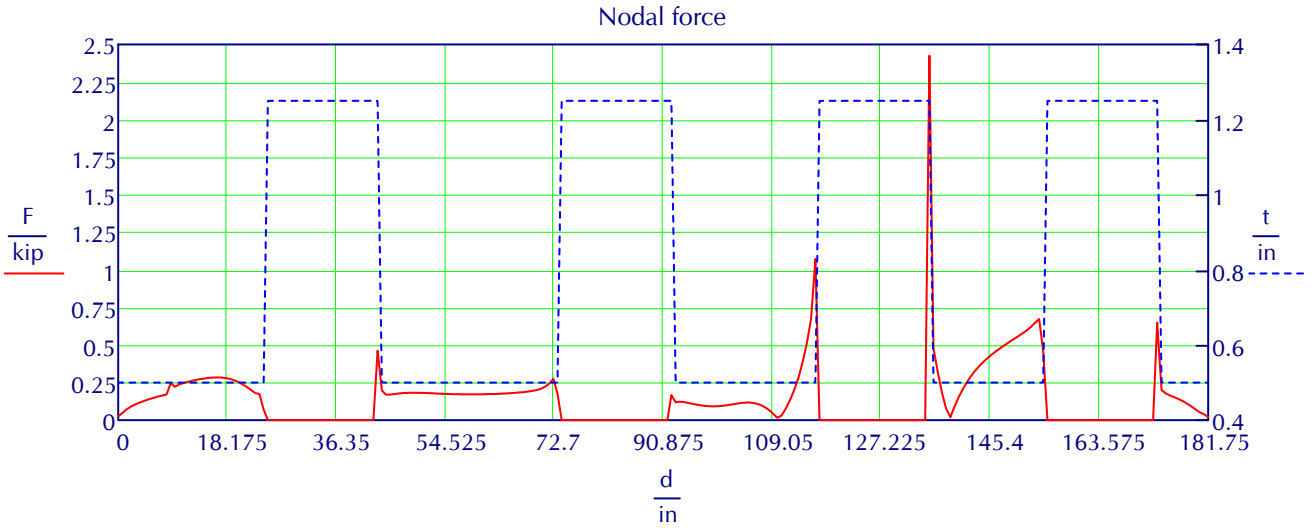
Δd := Δd2 Adjusted intervals

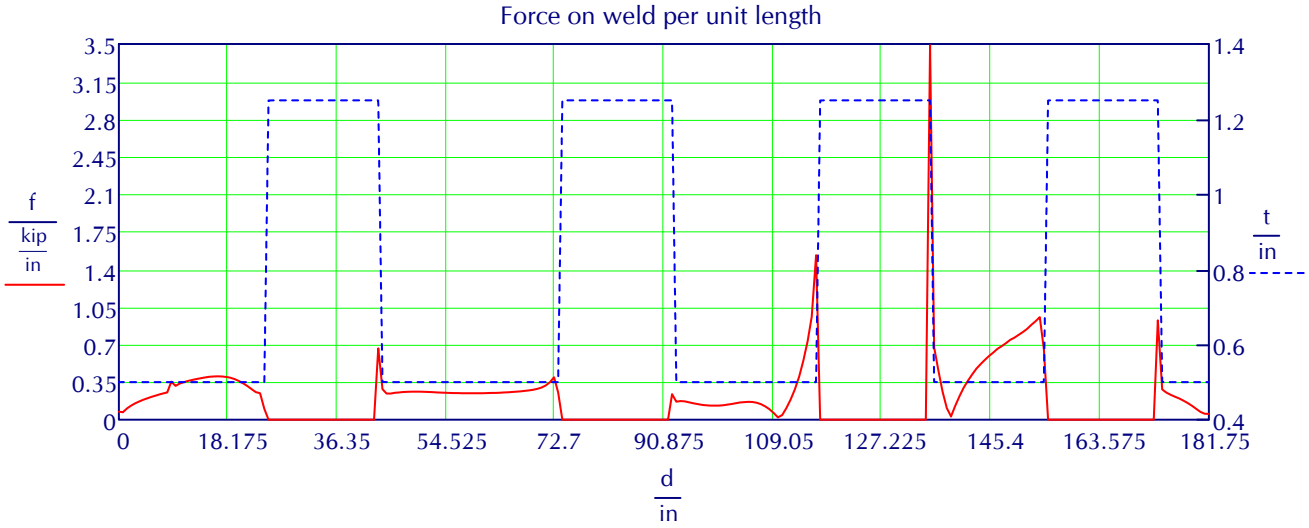
$f := \frac{F}{\Delta d}$ Force on the weld per unit length

$f_{max} := \max(f) = 3.489 \cdot \frac{kip}{in}$

$\frac{f_{max}}{fa} = 0.97 \quad < 1.0$ Demand\capacity ratio for Name = "Wheel 3 not in contact - DS outer plate" where fa = 3.59

Name = "Wheel 3 not in contact - DS outer plate"





6) Weld check - Wheel 4 not in contact

Wheel 4 not in contact - US inner plate

Name := "Wheel 4 not in contact - US inner plate"

Data := W4USI

n := rows(Data) = 268 Number of rows

Read data from FEA

$d := Data^{\langle 0 \rangle} \cdot in$ $Fx := Data^{\langle 1 \rangle} \cdot lbf$ $Fy := Data^{\langle 2 \rangle} \cdot lbf$ $Fz := Data^{\langle 3 \rangle} \cdot lbf$

Assign end plate thickness

k := 0 t := 0

i := 0 .. n − 1

$k_i := reverse\left(match\left(1, t_{US}^{\langle 0 \rangle} < d_i\right)\right)_0$

$t_i := \left(t_{US}^{\langle 1 \rangle}\right)_{(k_i)}$ End plate thickness along d

$F := \sqrt{Fx^2 + Fy^2 + Fz^2}$ Total nodal force

Intervals

i := 0 .. n − 2

Δd := 0

$\Delta d_i := d_{i+1} - d_i$

Adjust intervals

i := 0 .. n − 3

Δd1 := 0

$\Delta d1_i := 0.5 \cdot \Delta d_i + 0.5 \cdot \Delta d_{i+1}$

i := 0 .. n − 1

Δd2 := 0

$\Delta d2_i := 0$

$\Delta d2_0 := 0.5 \cdot \Delta d_0$

$\Delta d2_{n-1} := 0.5 \cdot \Delta d_{n-2}$

i := 0 .. n − 3

$\Delta d2_{i+1} := \Delta d1_i$

Δd := Δd2 Adjusted intervals

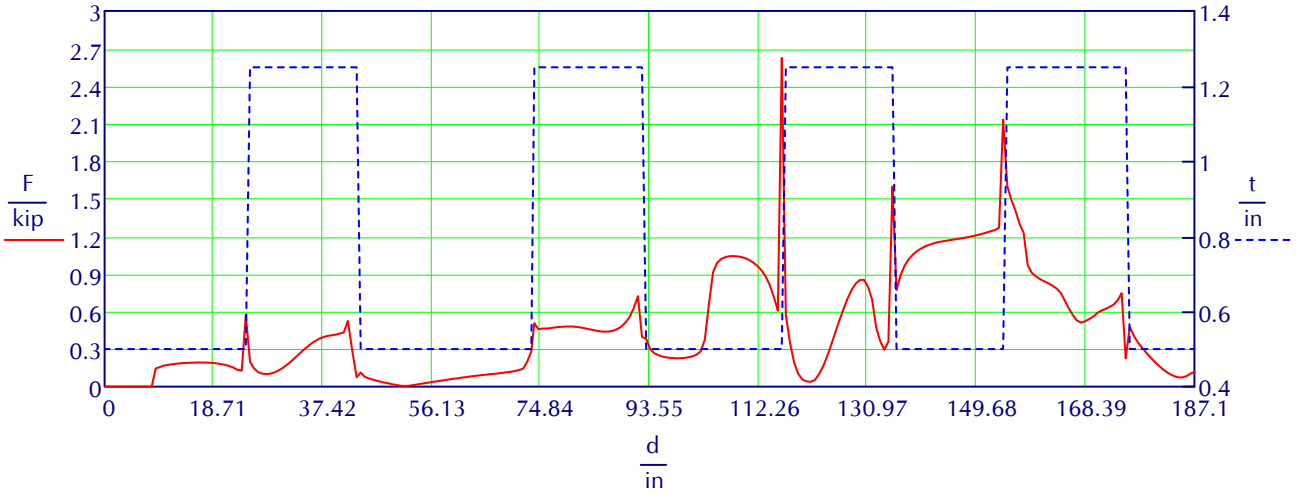
$f := \frac{F}{\Delta d}$ Force on the weld per unit length

$f_{max} := \max(f) = 3.777 \cdot \frac{kip}{in}$

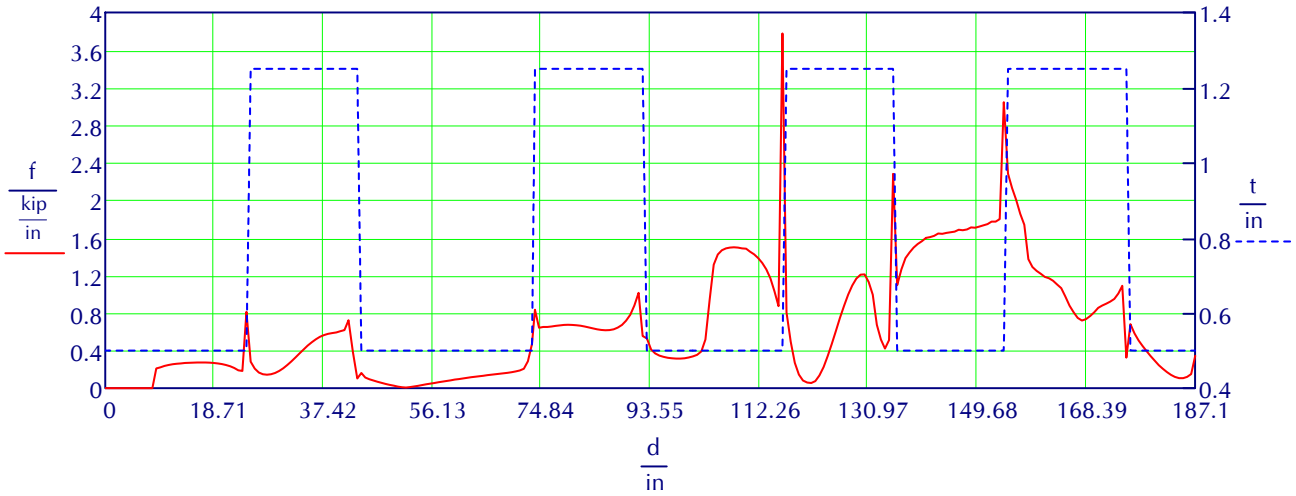
$\frac{f_{max}}{fa} = 1.05 < 1.0$ Demand\capacity ratio for Name = "Wheel 4 not in contact - US inner plate" where fa = 3.59

Name = "Wheel 4 not in contact - US inner plate"

Nodal force



Force on weld per unit length



There is a small section that will be overloaded but it is not a concern since the stress will be redistributed

Wheel 4 not in contact - DS inner plate

Name := "Wheel 4 not in contact - DS inner plate"

Data := W4DSI

n := rows(Data) = 260 Number of rows

Read data from FEA

$d := Data^{\langle 0 \rangle} \cdot in$ $Fx := Data^{\langle 1 \rangle} \cdot lbf$ $Fy := Data^{\langle 2 \rangle} \cdot lbf$ $Fz := Data^{\langle 3 \rangle} \cdot lbf$

Assign end plate thickness

k := 0 t := 0

i := 0 .. n − 1

$k_i := reverse\left(match\left(1, t_{DS}^{\langle 0 \rangle} < d_i\right)\right)_0$

$t_i := \left(t_{DS}^{\langle 1 \rangle}\right)_{(k_i)}$ End plate thickness along d

$F := \sqrt{Fx^2 + Fy^2 + Fz^2}$ Total nodal force

Intervals

i := 0 .. n − 2

Δd := 0

$\Delta d_i := d_{i+1} - d_i$

Adjust intervals

i := 0 .. n − 3

Δd1 := 0

$\Delta d1_i := 0.5 \cdot \Delta d_i + 0.5 \cdot \Delta d_{i+1}$

i := 0 .. n − 1

Δd2 := 0

$\Delta d2_i := 0$

$\Delta d2_0 := 0.5 \cdot \Delta d_0$

$\Delta d2_{n-1} := 0.5 \cdot \Delta d_{n-2}$

i := 0 .. n − 3

$\Delta d2_{i+1} := \Delta d1_i$

Δd := Δd2 Adjusted intervals

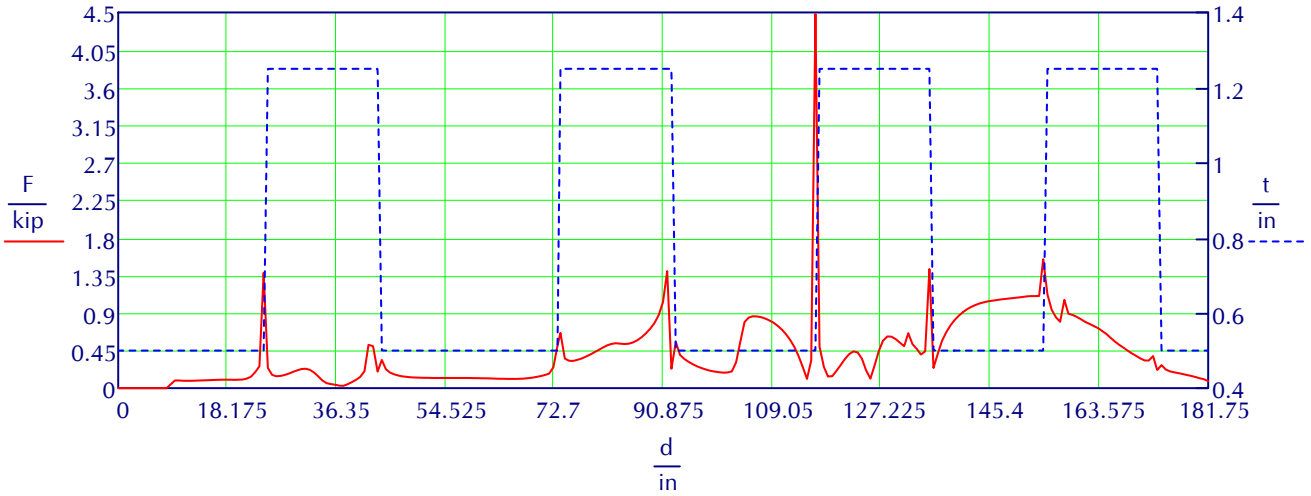
$f := \frac{F}{\Delta d}$ Force on the weld per unit length

$f_{max} := \max(f) = 6.449 \cdot \frac{kip}{in}$

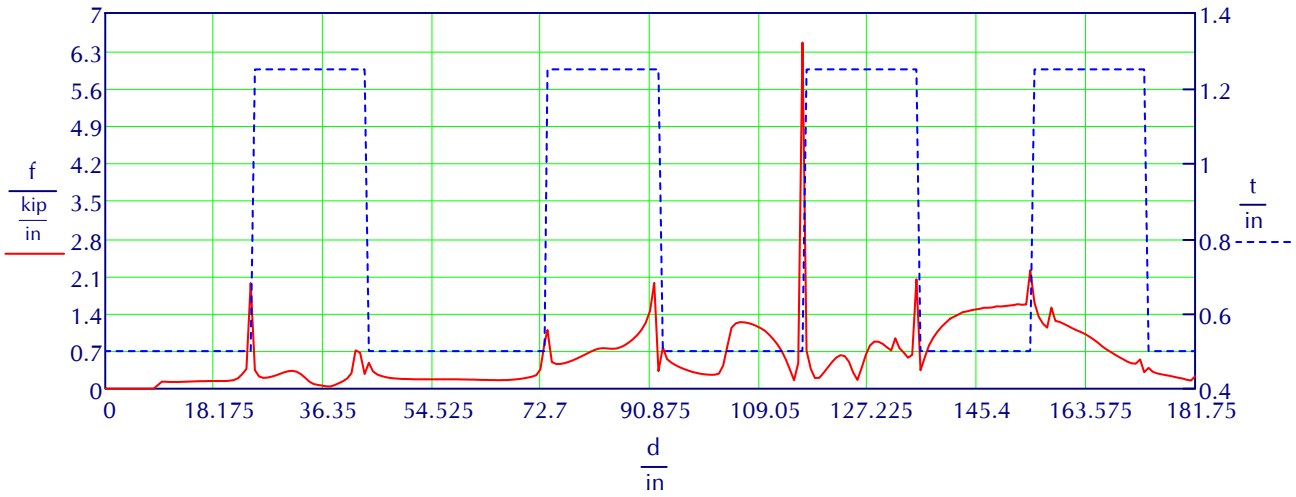
$\frac{f_{max}}{fa} = 1.80 \quad < 1.0$ Demand\capacity ratio for Name = "Wheel 4 not in contact - DS inner plate" where fa = 3.59

Name = "Wheel 4 not in contact - DS inner plate"

Nodal force



Force on weld per unit length



There is a small section that will be overloaded but it is not a concern since the stress will be redistributed

Wheel 4 not in contact - US outer plate

Name := "Wheel 4 not in contact - US outer plate"

Data := W4USO

$n := rows(Data) = 268$ Number of rows

Read data from FEA

$d := Data^{\langle 0 \rangle} \cdot in$ $Fx := Data^{\langle 1 \rangle} \cdot lbf$ $Fy := Data^{\langle 2 \rangle} \cdot lbf$ $Fz := Data^{\langle 3 \rangle} \cdot lbf$

Assign end plate thickness

$k := 0$ $t := 0$

$i := 0 .. n - 1$

$k_i := reverse\left(match\left(1, t_{US}^{\langle 0 \rangle} < d_i\right)\right)_0$

$t_i := \left(t_{US}^{\langle 1 \rangle}\right)_{(k_i)}$ End plate thickness along d

$F := \sqrt{Fx^2 + Fy^2 + Fz^2}$ Total nodal force

Intervals

$i := 0 .. n - 2$

$\Delta d := 0$

$\Delta d_i := d_{i+1} - d_i$

Adjust intervals

$i := 0 .. n - 3$

$\Delta d1 := 0$

$\Delta d1_i := 0.5 \cdot \Delta d_i + 0.5 \cdot \Delta d_{i+1}$

$i := 0 .. n - 1$

$\Delta d2 := 0$

$\Delta d2_i := 0$

$\Delta d2_0 := 0.5 \cdot \Delta d_0$

$\Delta d2_{n-1} := 0.5 \cdot \Delta d_{n-2}$

$i := 0 .. n - 3$

$\Delta d2_{i+1} := \Delta d1_i$

$\Delta d := \Delta d2$ Adjusted intervals

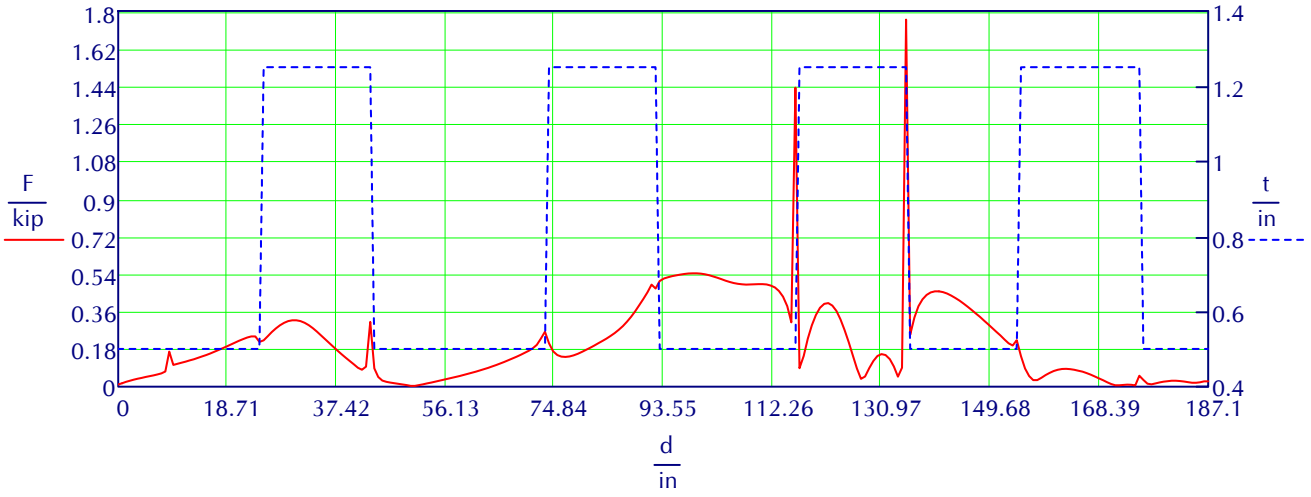
$f := \frac{F}{\Delta d}$ Force on the weld per unit length

$f_{max} := \max(f) = 2.511 \cdot \frac{kip}{in}$

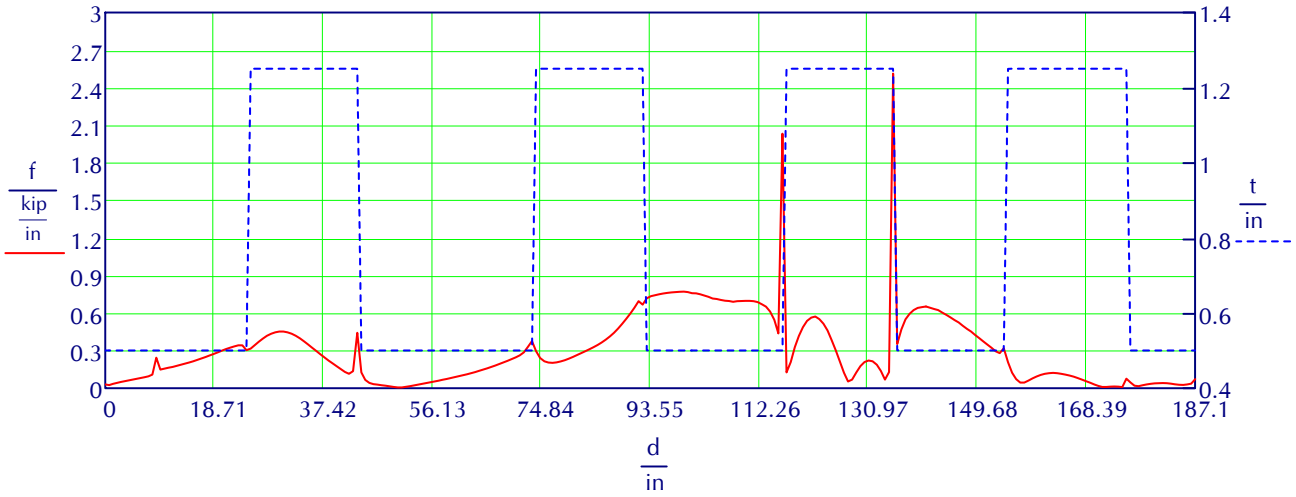
$\frac{f_{max}}{fa} = 0.70 < 1.0$ Demand\capacity ratio for Name = "Wheel 4 not in contact - US outer plate" where fa = 3.59·

Name = "Wheel 4 not in contact - US outer plate"

Nodal force



Force on weld per unit length



Wheel 4 not in contact - DS outer plate

Name := "Wheel 4 not in contact - DS outer plate"

Data := W4DSO

n := rows(Data) = 264 Number of rows

Read data from FEA

$d := Data^{\langle 0 \rangle} \cdot in$ $Fx := Data^{\langle 1 \rangle} \cdot lbf$ $Fy := Data^{\langle 2 \rangle} \cdot lbf$ $Fz := Data^{\langle 3 \rangle} \cdot lbf$

Assign end plate thickness

k := 0 t := 0

i := 0 .. n − 1

$k_i := reverse\left(match\left(1, t_{DS}^{\langle 0 \rangle} < d_i\right)\right)_0$

$t_i := \left(t_{DS}^{\langle 1 \rangle}\right)_{(k_i)}$ End plate thickness along d

$F := \sqrt{Fx^2 + Fy^2 + Fz^2}$ Total nodal force

Intervals

i := 0 .. n − 2

Δd := 0

$\Delta d_i := d_{i+1} - d_i$

Adjust intervals

i := 0 .. n − 3

Δd1 := 0

$\Delta d1_i := 0.5 \cdot \Delta d_i + 0.5 \cdot \Delta d_{i+1}$

i := 0 .. n − 1

Δd2 := 0

$\Delta d2_i := 0$

$\Delta d2_0 := 0.5 \cdot \Delta d_0$

$\Delta d2_{n-1} := 0.5 \cdot \Delta d_{n-2}$

i := 0 .. n − 3

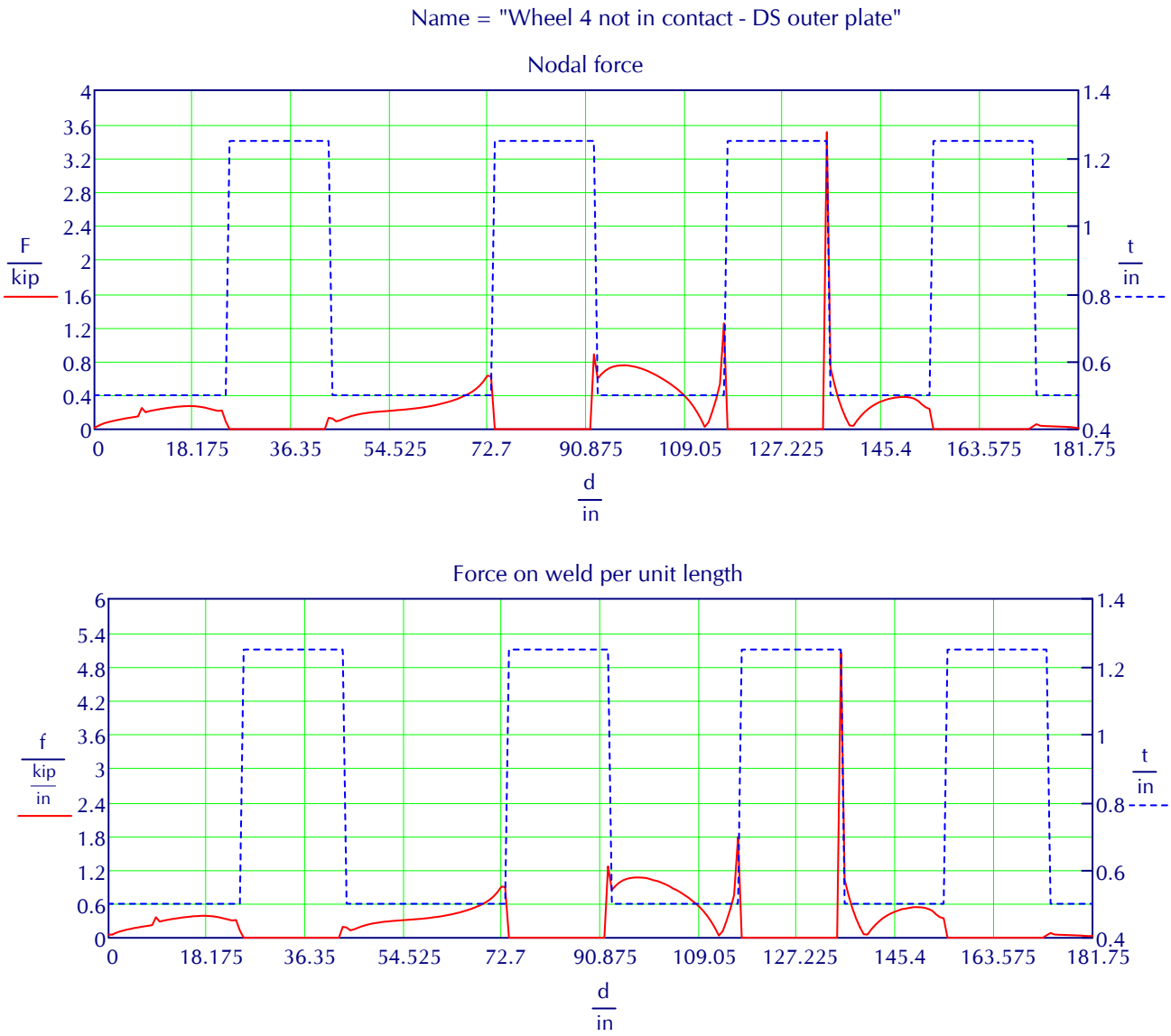
$\Delta d2_{i+1} := \Delta d1_i$

Δd := Δd2 Adjusted intervals

$f := \frac{F}{\Delta d}$ Force on the weld per unit length

$f_{max} := \max(f) = 5.043 \cdot \frac{kip}{in}$

$\frac{f_{max}}{fa} = 1.41 \quad < 1.0$ Demand\capacity ratio for Name = "Wheel 4 not in contact - DS outer plate" where fa = 3.59



There is a small section that will be overloaded but it is not a concern since the stress will be redistributed

7) Summary

The results above show that the 3/8in E60 fillet weld to connect the 5/8in upstream and downstream skinplates to the inner and outer end plates is sufficient.
A localized overstress may occur in the welds if Wheel 1 or Wheel 4 are not in contact with the wheel track, however the extent of the overstressed weld is very small and therefore is not a concern.

Appendix E
Hoist Superstructure Assessment

HATCH | CALCULATION SHEET | SHEET NO. 1 OF

DESCRIPTION	PROJECT NO	MADE BY	CHECKED BY
NSP - WRECK COVE HOIST SUPPORT STRUCTURE	351728	P. MICHALKO DATE 26 SEPT 16	GLENDENNING G. DATE SEPT 27/16

SCOPE:

VERIFY ADEQUACY OF HOIST FLOOR SUPPORT BEAMS AND COLUMNS FOR CURRENT GATE LIFTING FORCES.

ARRG'T:

FOR COPIES OF RELEVANT DWGS, SEE PGS. 2 THRU 5

LOADING:

THE MANDATE IS TO CONSIDER DEAD LOADS AND NORMAL AND JAMMED GATE LIFTING LOADS ONLY. LIVE LOAD WILL BE VERY MINIMAL

FOR NORMAL LIFTING, JAMMED GATE AND HOIST FRAME LOADS, REFER TO PG. 6 PREPARED BY HATCH MECHANICAL.

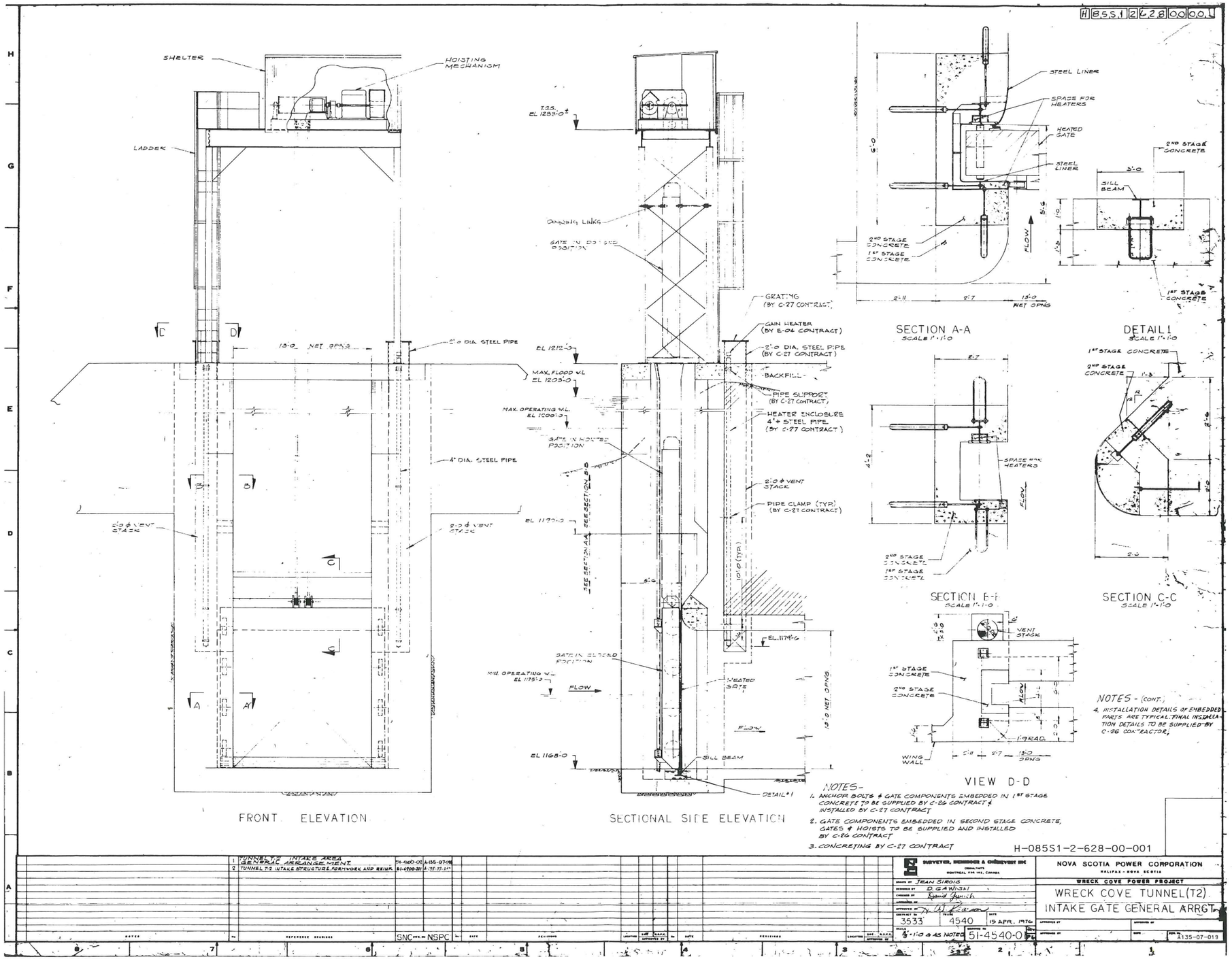
ANALYSIS:

ANALYZE USING A SAP MODEL. EVEN THOUGH THE INVESTIGATION IS LIMITED TO THE HOIST FLOOR AND SUPPORT COLUMNS, MODEL THE ENTIRE STRUCTURE INCLUDING 5/16" FLOOR PLATE AND THIN GAGE SHEETING.

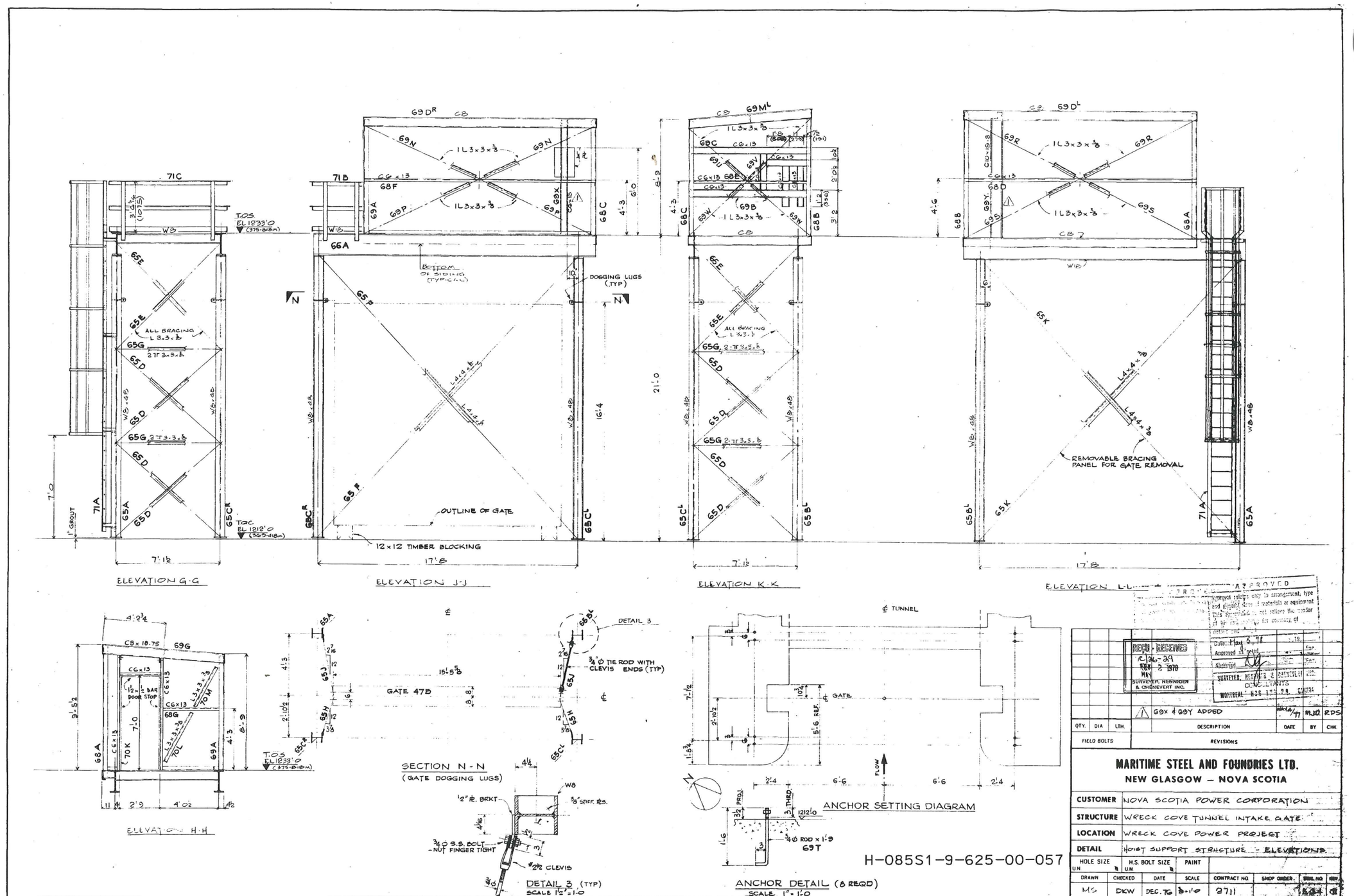
- FOR OVERALL MODEL, REFER TO PG. 7
- FOR PARTIAL " " " PG. 8 (UP TO HOIST FLOOR ONLY)
- FOR GRAPHIC SHOWING HOIST FLOOR, REFER TO PG. 9
- FOR GRAPHIC SHOWING APPLIED LOADING, NORMAL LIFT, REFER TO Pg 10
- " " " " " JAMMED " " TO PG. 11
- " " " S16.1 UTILIZATION, " TO PG. 12
- " " " MAX. GIRDER DEFLECTION, " TO PG. 13

→ CONTINUED PG. 14

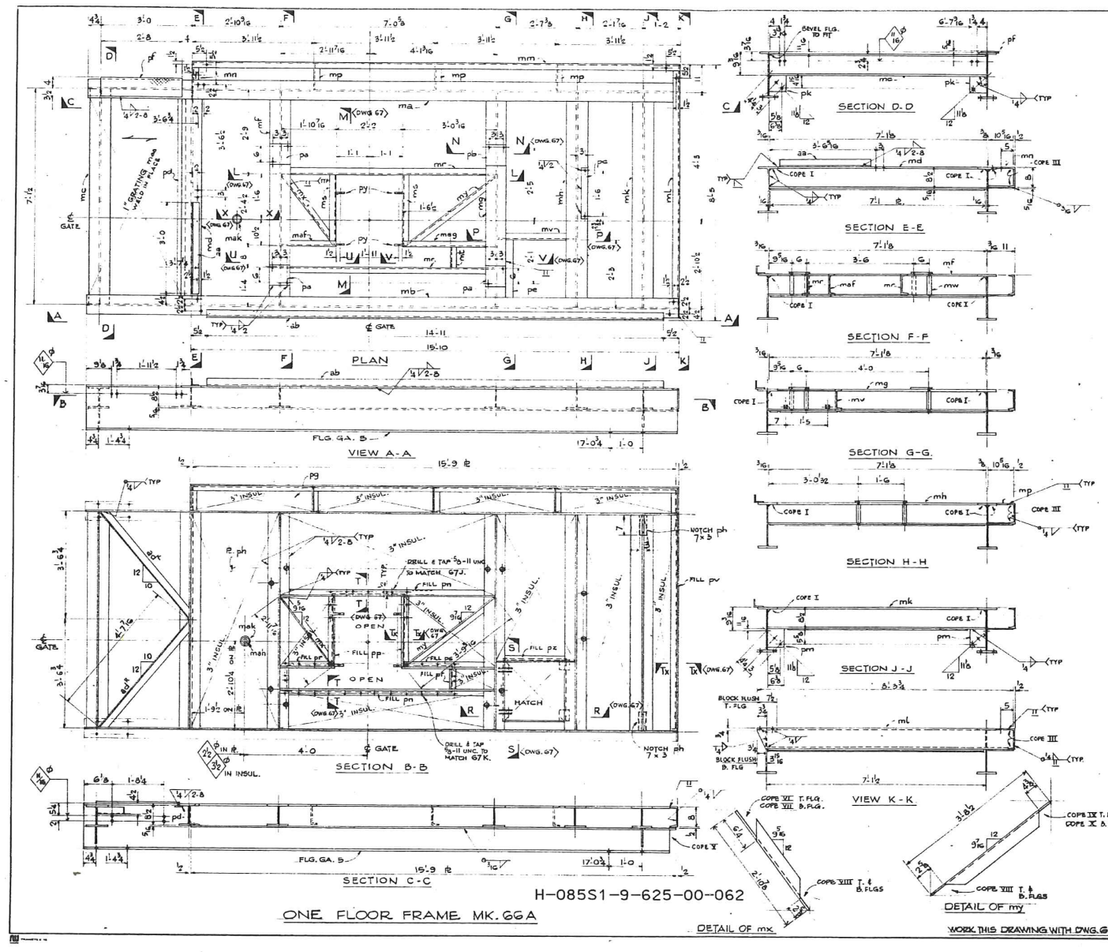
Pg. 2


H 8 5 S 1 2 6 2 8 0 0 0 0 1
SHELTER
HOISTING MECHANISM
LADDER
FRONT ELEVATION
SECTIONAL SIDE ELEVATION
SECTION A-A
SCALE 1"=1'-0
DETAIL 1
SCALE 1"=1'-0
SECTION B-B
SCALE 1"=1'-0
SECTION C-C
SCALE 1"=1'-0
VIEW D-D
STEEL LINER
SPACE FOR HEATERS
HEATED GATE
2ND STAGE CONCRETE
1ST STAGE CONCRETE
SILL BEAM
GRATING (BY C-27 CONTRACT)
GAIN HEATER (BY E-04 CONTRACT)
2'-0 DIA. STEEL PIPE (BY C-27 CONTRACT)
BACKFILL
PIPE SUPPORT (BY C-27 CONTRACT)
HEATER ENCLOSURE 4"+ STEEL PIPE (BY C-27 CONTRACT)
PIPE CLAMP (TYP.) (BY C-27 CONTRACT)
2'-0 DIA. STEEL PIPE
4" DIA. STEEL PIPE
2'-0 ϕ VENT STACK
MAX. FLOOD W.L. EL 1203'-0
MAX. OPERATING W.L. EL 1200'-0
MIN. OPERATING W.L. EL 1175'-0
EL 1168'-0
EL 1179'-6
FLOW
WING WALL
NOTES - (CONT.)
4. INSTALLATION DETAILS OF EMBEDDED PARTS ARE TYPICAL. FINAL INSTALLATION DETAILS TO BE SUPPLIED BY C-26 CONTRACTOR.
NOTES-
1. ANCHOR BOLTS & GATE COMPONENTS EMBEDDED IN 1ST STAGE CONCRETE TO BE SUPPLIED BY C-26 CONTRACT & INSTALLED BY C-27 CONTRACT
2. GATE COMPONENTS EMBEDDED IN SECOND STAGE CONCRETE, GATES & HOISTS TO BE SUPPLIED AND INSTALLED BY C-26 CONTRACT
3. CONCRETING BY C-27 CONTRACT
H-085S1-2-628-00-001
1 TUNNEL T-2 INTAKE AREA GENERAL ARRANGEMENT
2 TUNNEL T-2 INTAKE STRUCTURE, FORMWORK AND REINF.
SURVEYER, NEMBOSE & CHEVEYRE INC
NOVA SCOTIA POWER CORPORATION
HALIFAX - NOVA SCOTIA
WRECK COVE POWER PROJECT
WRECK COVE TUNNEL (T2)
INTAKE GATE GENERAL ARRGT.
JEAN SIROIS
D. GAWISH
3533
4540
15 APR. 1976
51-4540-01
A135-07-019
SNC NSPC

Pg. 3


ELEVATION G-G
ELEVATION J-J
ELEVATION K-K
ELEVATION L-L
ELEVATION H-H
SECTION N-N
(GATE DOGGING LUGS)
DETAIL 3 (TYP)
SCALE 1½" = 1'-0
ANCHOR SETTING DIAGRAM
ANCHOR DETAIL (8 REQD)
SCALE 1" = 1'-0
H-085S1-9-625-00-057
MARITIME STEEL AND FOUNDRIES LTD.
NEW GLASGOW – NOVA SCOTIA
CUSTOMER NOVA SCOTIA POWER CORPORATION
STRUCTURE WRECK COVE TUNNEL INTAKE GATE
LOCATION WRECK COVE POWER PROJECT
DETAIL HOIST SUPPORT STRUCTURE - ELEVATIONS
69X & 69Y ADDED
DRAWN MS
CHECKED DKW
DATE DEC. 76
SCALE 3"=1'-0
CONTRACT NO. 2711
REMOVABLE BRACING PANEL FOR GATE REMOVAL
OUTLINE OF GATE
12 x 12 TIMBER BLOCKING
DOGGING LUGS (TYP)
BOTTOM OF SIDING (TYPICAL)
ALL BRACING
GATE 47B
¾"Ø TIE ROD WITH CLEVIS ENDS (TYP)
¾"Ø S.S. BOLT - NUT FINGER TIGHT
#2½ CLEVIS
APPROVED
REC'D - RECEIVED
SURVEYER, NENNIGER & CHENEVERT INC.
MONTREAL

Pg. 9



H-085S1-9-625-00-062

ONE FLOOR FRAME MK. GGA

BILL OF MATERIAL

ITEM	MARK	QTY.	DESCRIPTION	WT./FT.	LENGTH FT.	LENGTH IN.	WEIGHT	REMARKS
1	GGA	ONE	FLOOR FRAME					
2								
3	ma	1	W 10/6 x 7⅝ x ⅜	55	19	2¼	1055	S40.21-44T
4	mb	1	W 10/6	55	19	2¼	1055	do
5	mc	1	W 8½ x 6⅝ x ⅜	48	7	1⅛	341	do
6	md	1	W 8½	48	7	1⅛	341	do
7	mf	1	W 8½	48	7	1⅛	341	do
8	mg	1	W 8½	48	7	1⅛	341	do
9	mh	1	W 8½	48	7	1⅛	341	do
10	mk	1	W 8½	48	7	1⅛	341	do
11	ml	1	C 8 x 2⅜ x ½	18.75	8	3.4	156	do
12	mm	1	C 8	18.75	15	10	297	do
13	mn	1	C 8	18.75	10⅝		196	do
14	mp	3	C 8	18.75	10⅝		468	do
15	mr	2	C 8	18.75	7 10¾		284	do
16	ms	2	C 8	18.75	2 4		87	do
17	mt	1	C 8	18.75	8		12	do
18	pa	5	PL. 8 x ½	13.6	8		272	do
19	pb	1	PL. 8 x ½	13.6	8		9	do
20	pc	1	PL 2 x ½	3.4	1	8	6	do
21	pd	1	BAR 3 x ⅜	3.83	6	6	25	do
22	pe	1	BAR 3 x ⅜	3.83	1	11¼	7	do
23	pf	1	CHNO PL 7.7 x ⅜	12	2	8	23	A36
24	pg	1	PL 9 x ⅝	5.56	15	9	151	S40.21-44T
25	ph	1	PL 25 x ⅝	20.31	19	9	1422	do
26	pk	2	PL 6¼ x ⅜	7.97		5⅞	5	do
27	pm	2	PL 6⅝ x ⅜	8.13		6⅛	5	do.
28	pn	1	L 3 x 3 x ⅜	7.2	3	0	22	do.
29	pb	1	L 3 x 3 x ⅜	7.2	14	11	107	do.
30								
31	adf	2	L 3 x 3 x ⅜	7.2	4	7⅝	67	do
32	pz	1	FILL PL 2 x ½	3.4	1	11½	9	do
33	mak	1	STD. PIPE 3 ϕ	7.58		7½	6	A53 GR. B
34								
35								
36								
37								
38								
39	mv	1	C 5	6.75	2	7	49	do
40	mw	10	STD. PIPE 1 ϕ	1.68		7½	10	A53-GR.B
41	mx	1	C 8	18.75	2	10⅝	55	S40.21-44T
42	my	1	C 8	18.75	3	8½	71	do
43	pw	4	PL ½ x 5⅝	1.99		4⅝	3	do
44	px	2	PL ½ x 5⅝	1.99		2⅛	1	do
45	pn	2	FILL PL 2 x ½	3.4	6	4½	43	do
46	pp	2	FILL PL 2 x ½	3.4	2	2½	15	do
47	pt	1	FILL PL 2 x ½	3.4	1	6⅝	5	do
48	ps	1	FILL PL 2 x ½	3.4	2	7⅝	9	do
49	pf	1	FILL PL 2 x ½	3.4		8½	2	do
50	pv	1	FILL PL 2 x ½	3.4	7	1½	324	do
51	py	4	PL 5 x ⅜	7.65		5½	71	do
52	mss	1	GRATING 3'-0 (1x¾ BAR)	G	G		141	S.S. TYPE
53	mab	1	CHAIN ⅜ PROOF COIL	-	3	0		
54	mac	2	BUTT HINGES 4 x 4	-				
55	mad	2	ROD ⅜ ϕ	1.5		2½	1	S.S. 304
56	mae	2	FLAT WASH ⅜ ϕ	-				A307
57	-	128	SF. 3" INSULATION					PAINTING MARINE PRIME SYSTEM
58	maf	1	C 8	18.75	1	10¼	39	S40.21-44T
59	mag	1	C 8	18.75	3	0	56	do
60	mah	1	GROMMET #AN931-D20-60					

12	⅝	1¾
8	¾	2¼
20	⅝	2
10	¾	12
QTY.	DIA.	LTH.
FIELD BOLTS		

APPROVED

Approval relates only to arrangement, type and general size of material or equipment. This approval does not relieve the vendor of his responsibility for accuracy of details and fitting.

RECD - RECEIVED
JAN 1978
SURVEYER, NENNIGER & CHEVERIE INC.

Date: Mar 31 78
Approved as noted
Approved: [signature]

NO.	DESCRIPTION	BY	DATE
	ADDITIONAL MARKING		

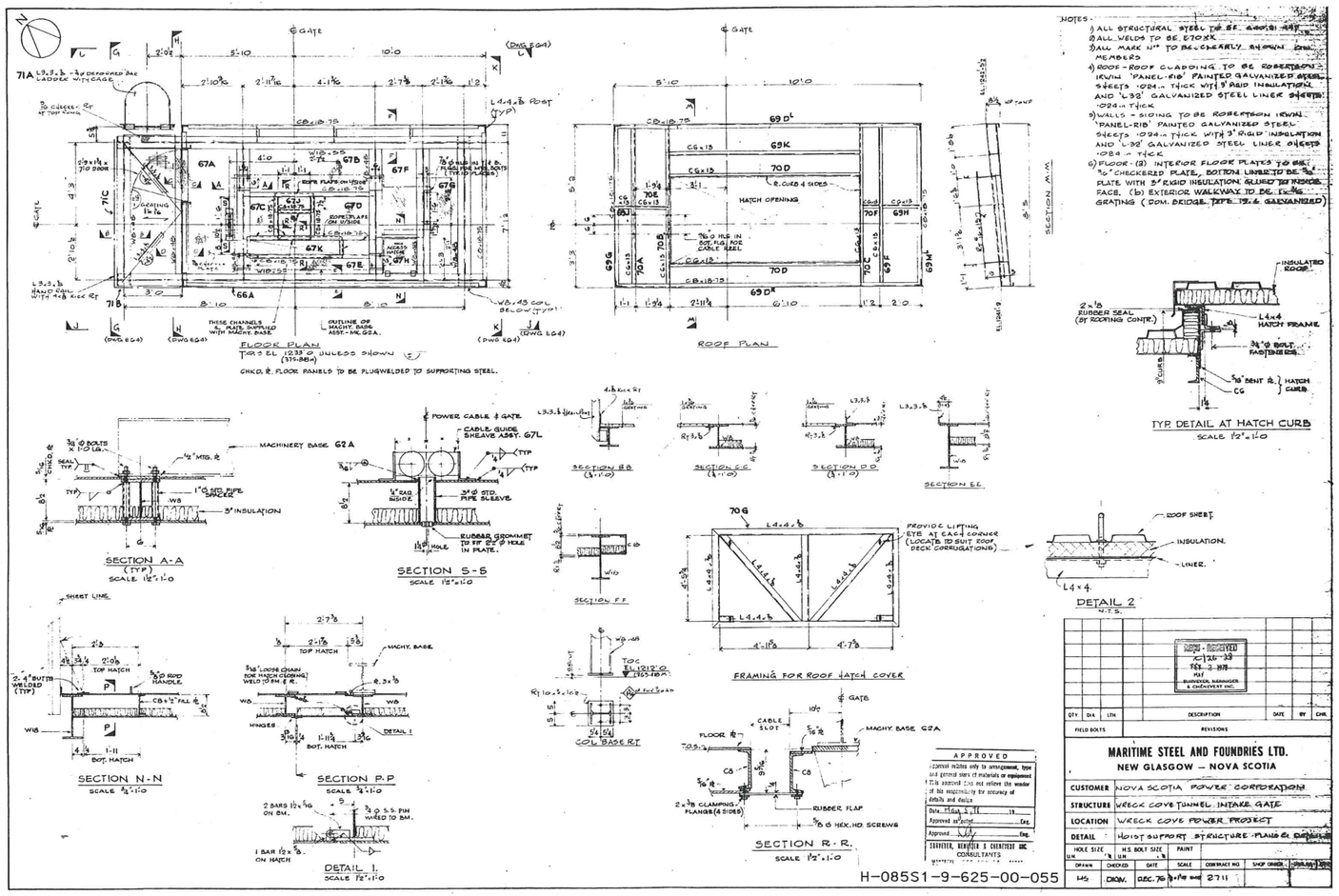
MARITIME STEEL AND FOUNDRIES LTD.
NEW GLASGOW – NOVA SCOTIA

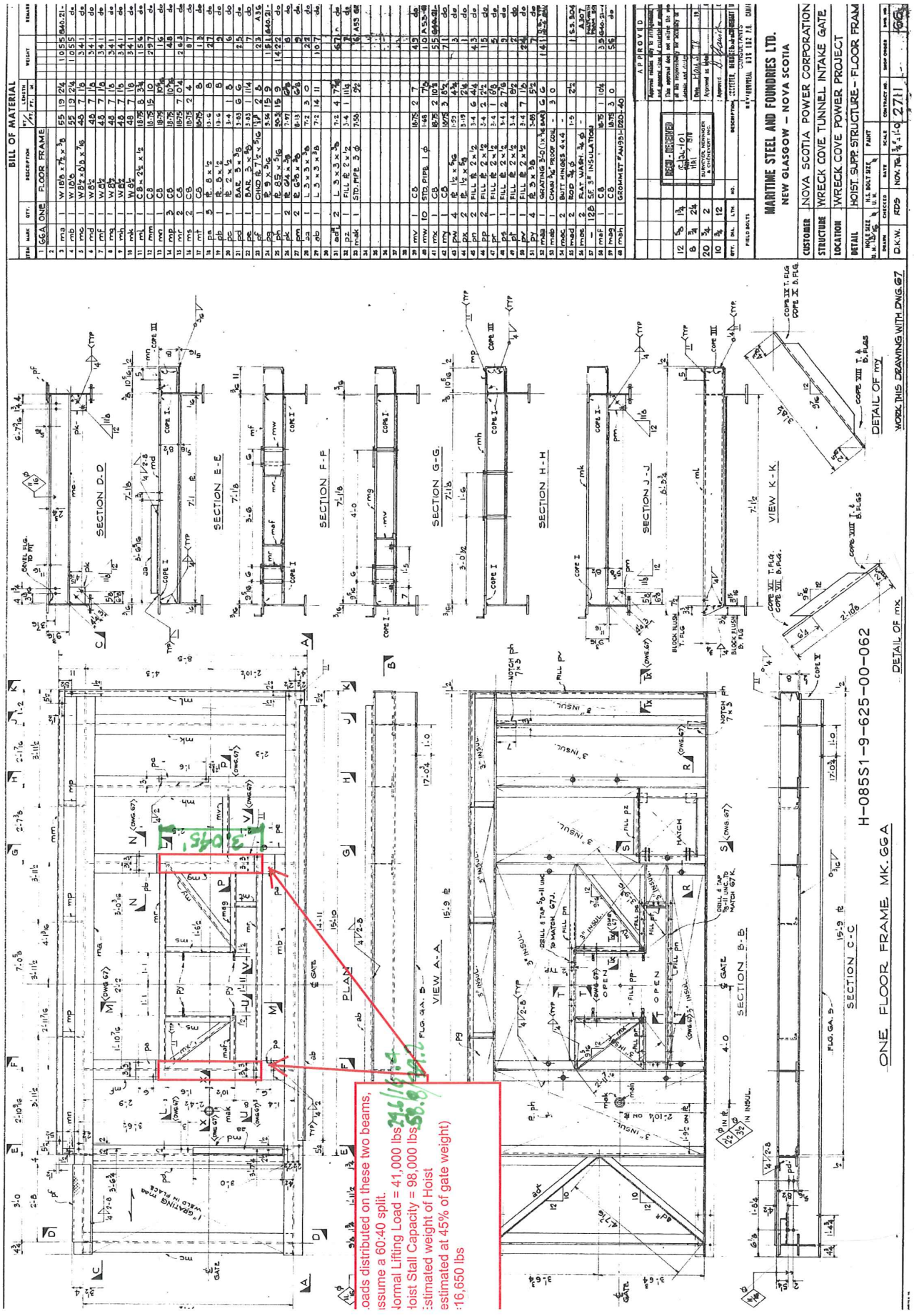
CUSTOMER	NOVA SCOTIA POWER CORPORATION
STRUCTURE	WRECK COVE TUNNEL INTAKE GATE
LOCATION	WRECK COVE POWER PROJECT
DETAIL	HOIST SUPP. STRUCTURE – FLOOR FRAME.

HOLE SIZE	H.S. BOLT SIZE	PAINT
⅞ in.	¾ U.N.	

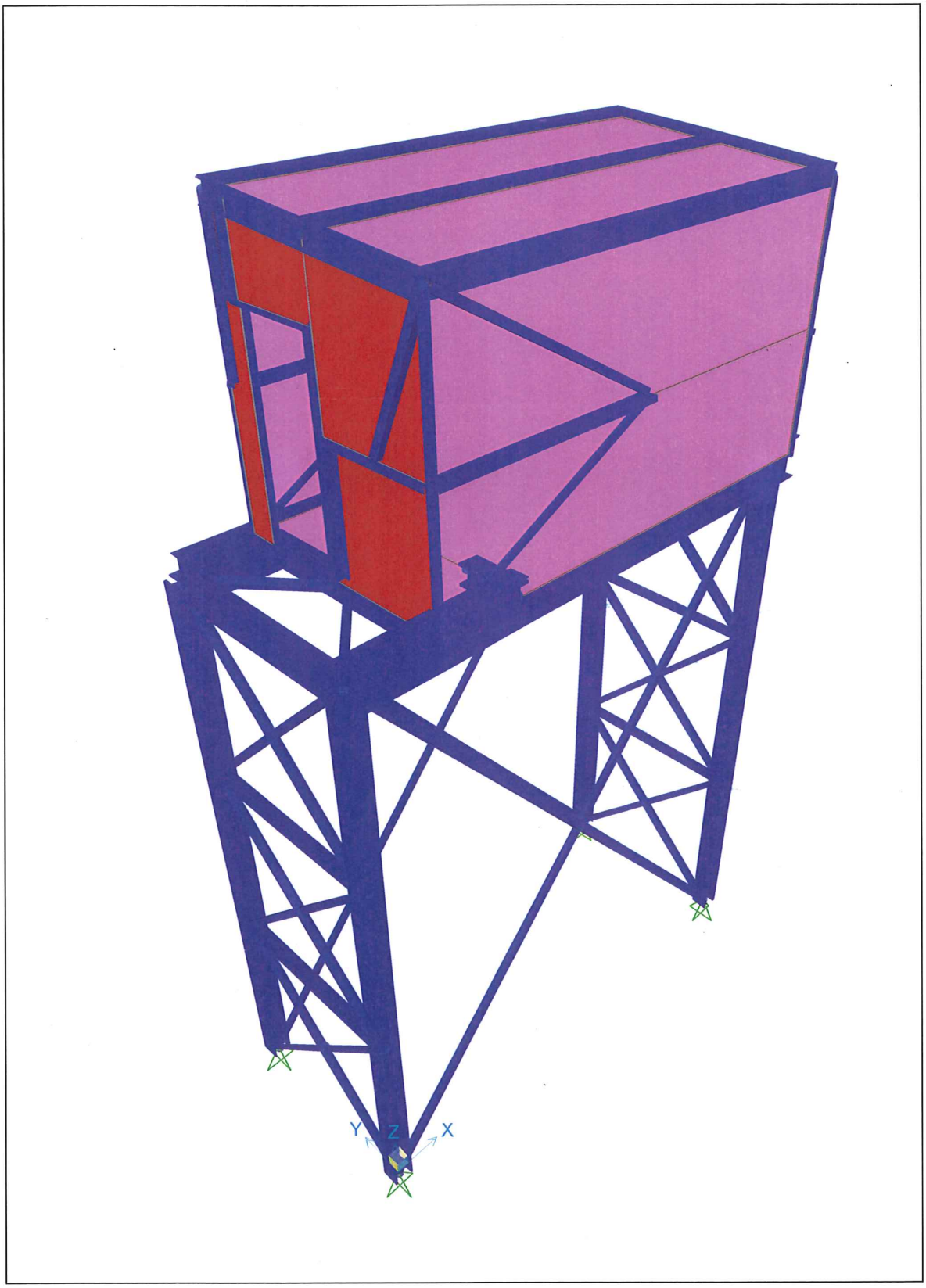
DRAWN	CHECKED	DATE	SCALE	CONTRACT NO.	SHOP ORDER	DWG. NO.	REV.
D.K.W.	KDS	NOV. 76	¾"=1'-0	2711		GG. 0	

Pg. 5


FLOOR PLAN
ROOF PLAN
SECTION M-M
TYP. DETAIL AT HATCH CURB
SECTION A-A
SECTION S-S
SECTION B-B
SECTION C-C
SECTION D-D
SECTION E-E
SECTION F-F
FRAMING FOR ROOF HATCH COVER
DETAIL 2
SECTION N-N
SECTION P-P
DETAIL 1
COL. BASE RT.
SECTION R-R
APPROVED
MARITIME STEEL AND FOUNDRIES LTD.
NEW GLASGOW – NOVA SCOTIA
CUSTOMER NOVA SCOTIA POWER CORPORATION
STRUCTURE WRECK COVE TUNNEL INTAKE GATE
LOCATION WRECK COVE POWER PROJECT
DETAIL HOIST SUPPORT STRUCTURE PLANS & DETAILS
H-085S1-9-625-00-055

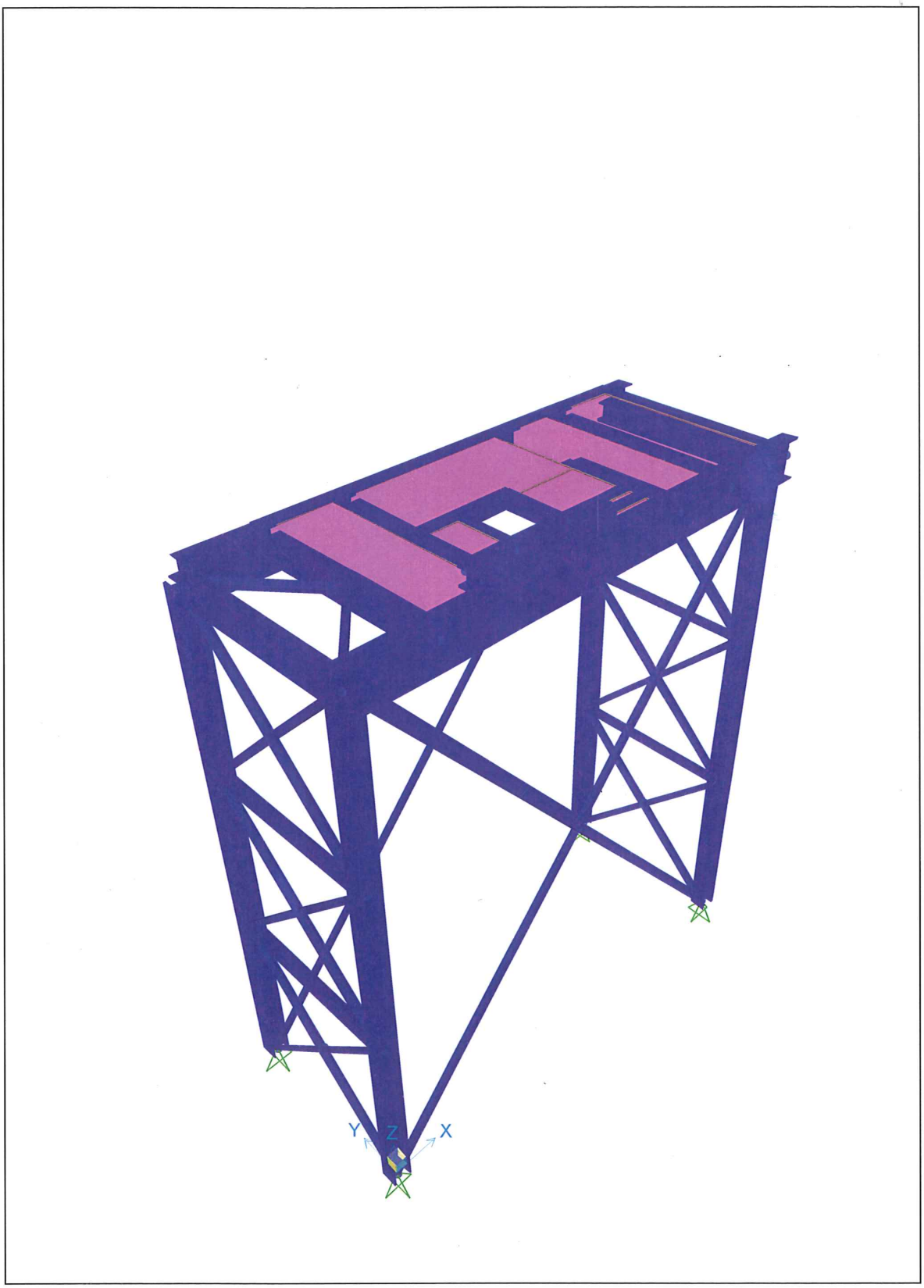

MARITIME STEEL AND FOUNDRIES LTD.
NEW GLASGOW – NOVA SCOTIA
CUSTOMER NOVA SCOTIA POWER CORPORATION
STRUCTURE WRECK COVE TUNNEL INTAKE GATE
LOCATION WRECK COVE POWER PROJECT
DETAIL HOIST SUPP. STRUCTURE – FLOOR FRAM
BILL OF MATERIAL
APPROVED
SECTION D-D
SECTION E-E
SECTION F-F
SECTION G-G
SECTION H-H
SECTION J-J
VIEW K-K
DETAIL OF mx
WORK THIS DRAWING WITH DWG. 67
PLAN
VIEW A-A
SECTION B-B
SECTION C-C
ONE FLOOR FRAME MK. GGA
H-085S1-9-625-00-062
Loads distributed on these two beams,
assume a 60:40 split.
Normal Lifting Load = 41,000 lbs
Hoist Stall Capacity = 98,000 lbs
Estimated weight of Hoist
Estimated at 45% of gate weight)
16,650 lbs

Gate Hoist Structure.sdb 27/09/2016 Pg 7



SAP2000 18.1.0 3-D View Kip, in, F

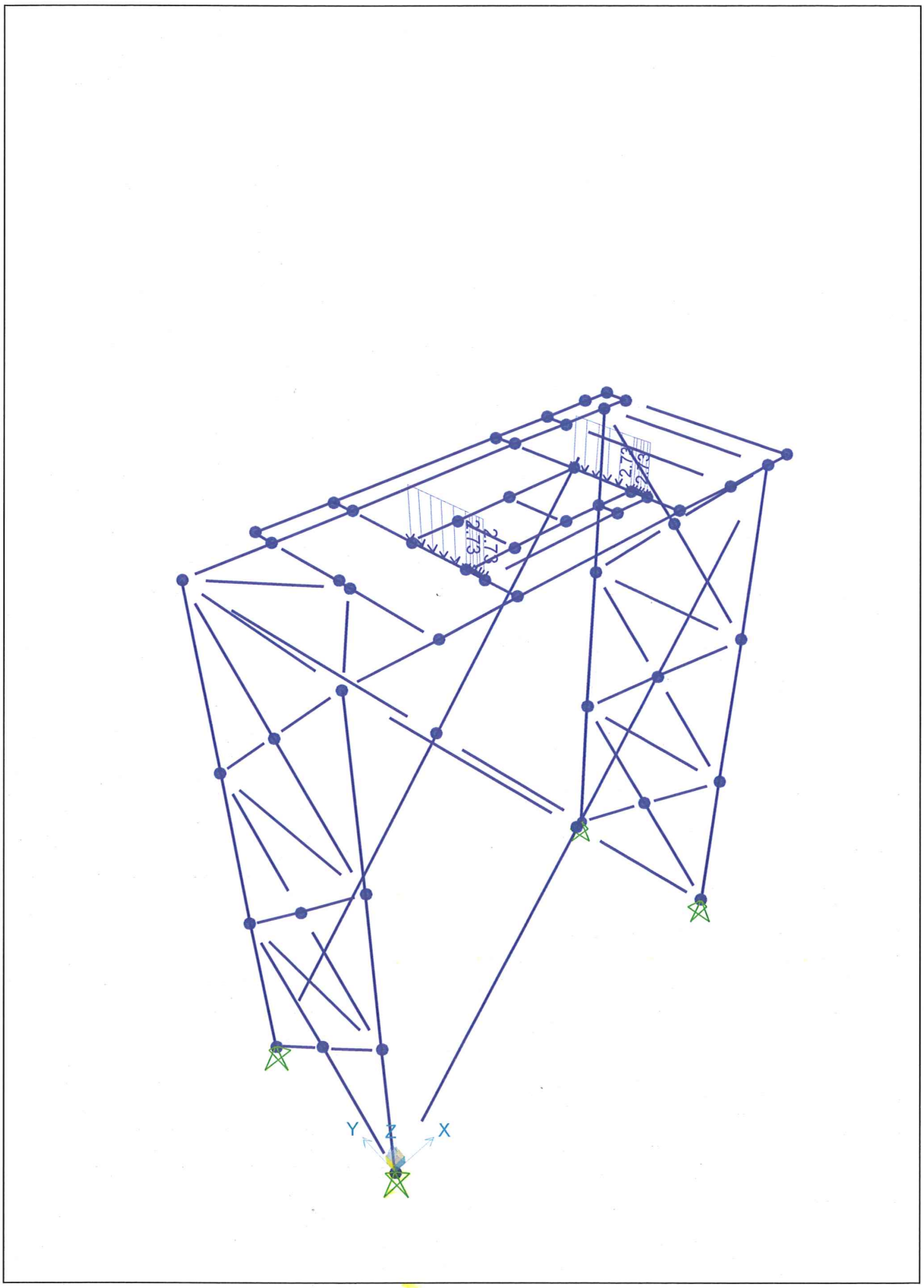
Gate Hoist Structure.sdb 27/09/2016 6.8



SAP2000 18.1.0 3-D View Kip, in, F

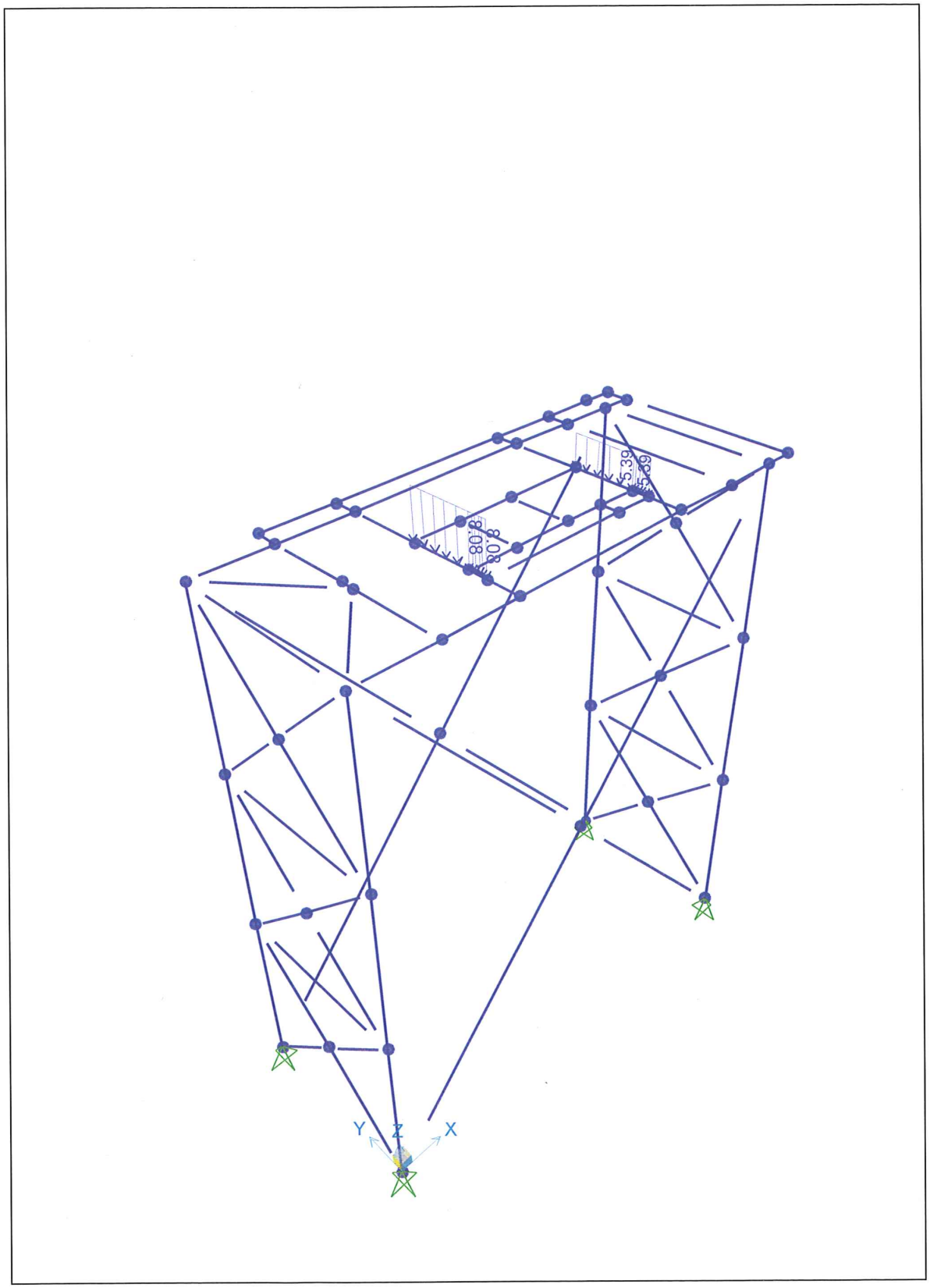
Pg. 9

Gate Hoist Structure.sdb 28/09/2016



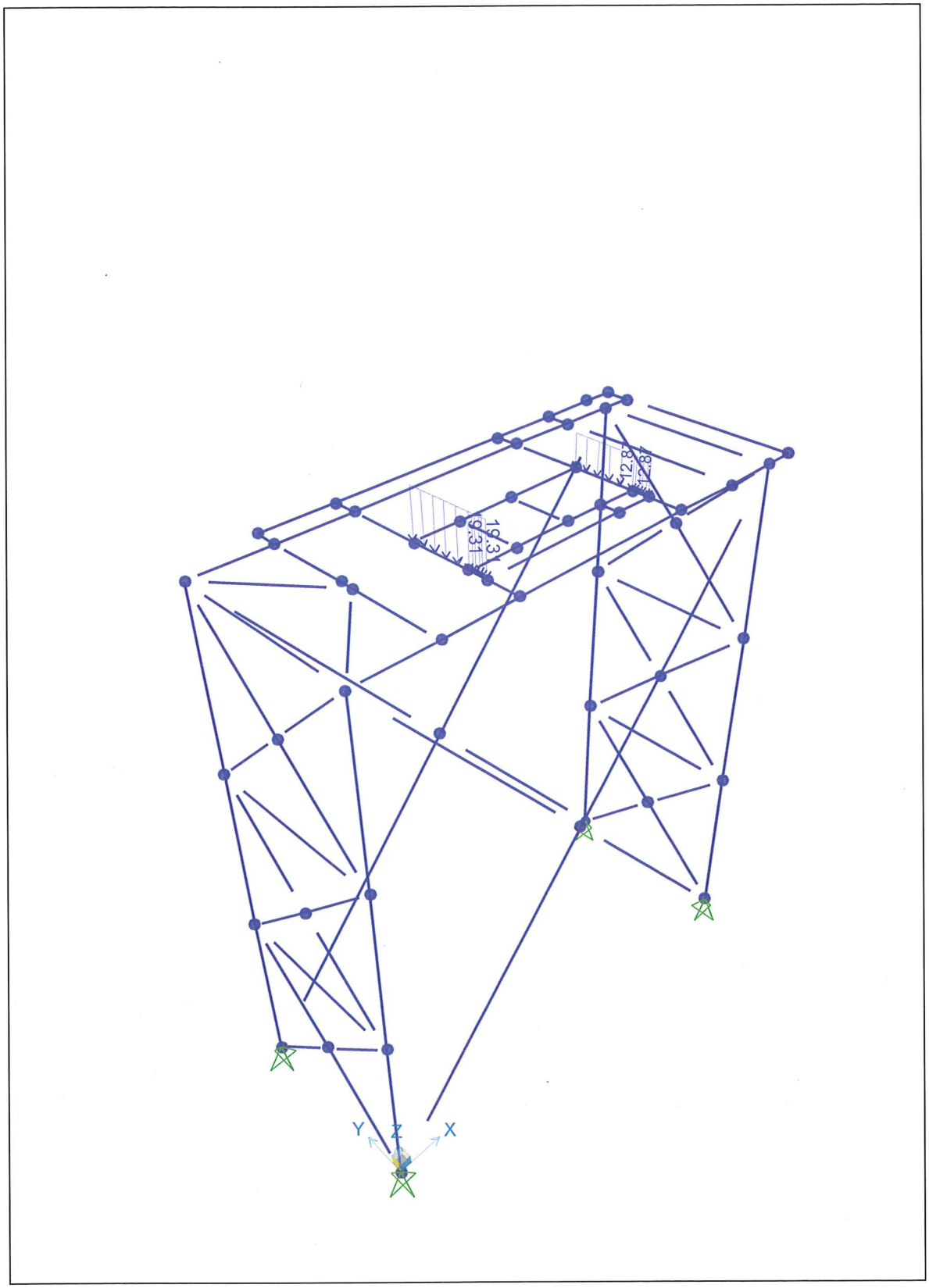
SAP2000 18.1.0 Frame Span Loads (DEAD) (As Defined) Kip, ft, F

Gate Hoist Structure.sdb 27/09/2016 fy.10



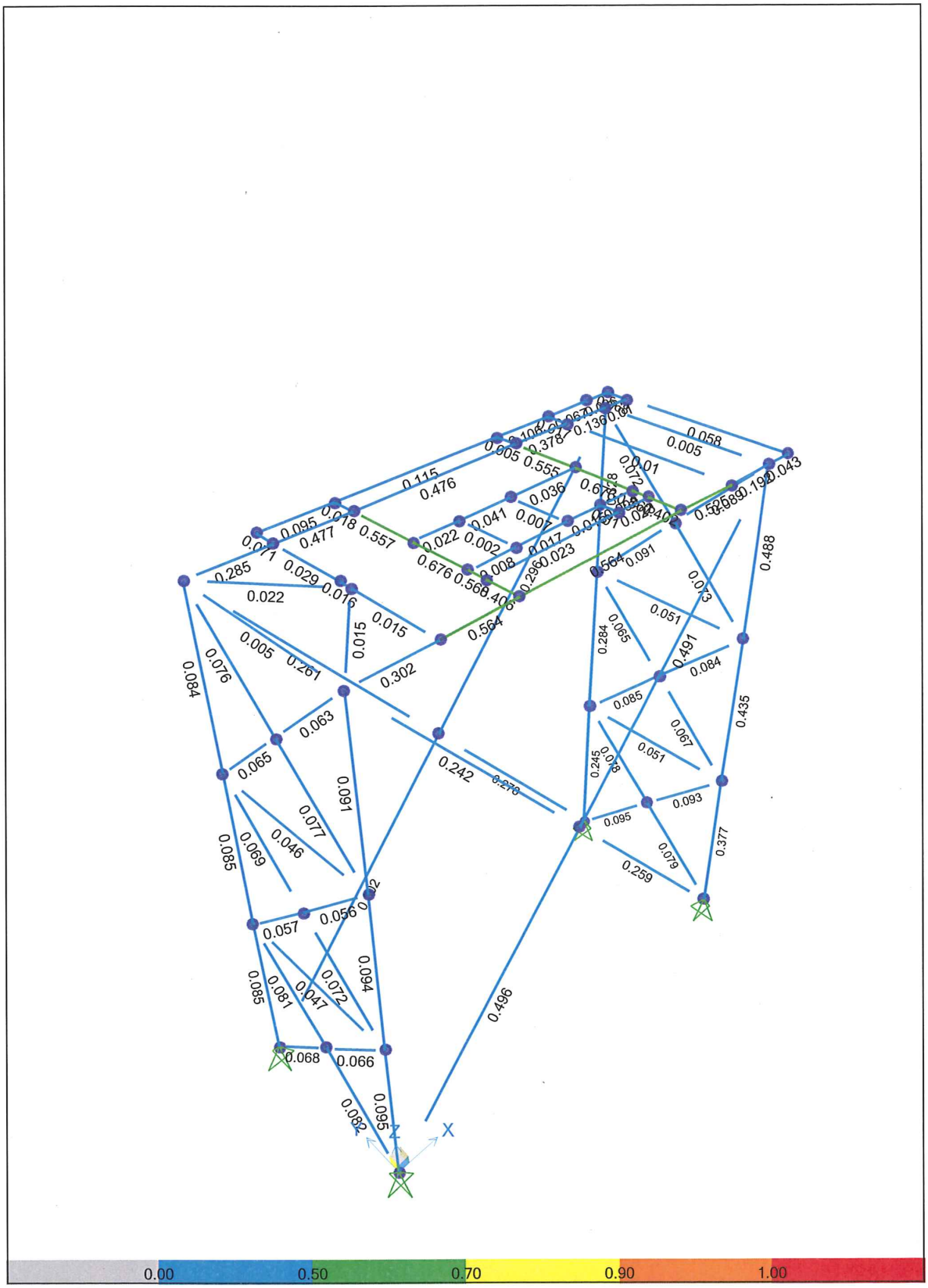
SAP2000 18.1.0 Frame Span Loads (NORMAL LEFT) (As Defined) Kip, ft, F

Gate Hoist Structure.sdb 27/09/2016 B.11

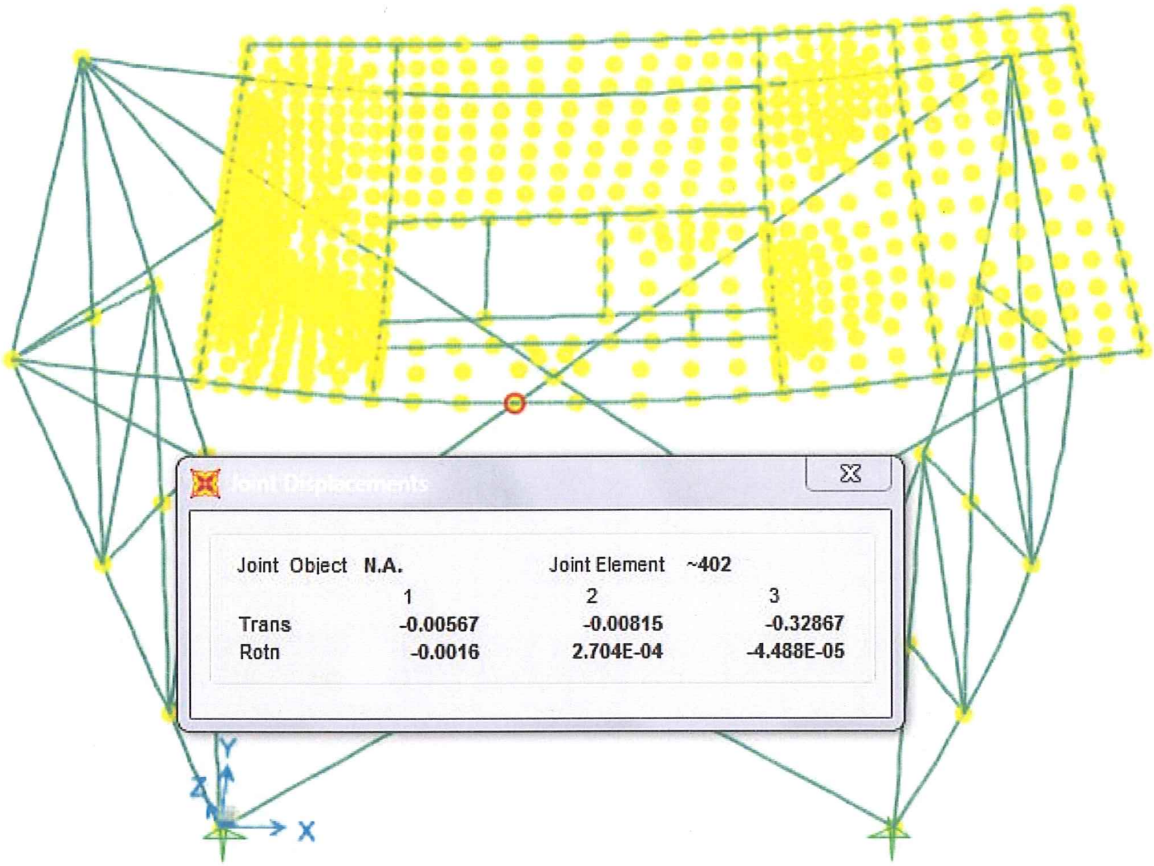


SAP2000 18.1.0 Frame Span Loads (JAMMED LEFT) (As Defined) Kip, ft, F

Gate Hoist Structure.sdb 27/09/2016 Pg. 12



B.13


Joint Displacements
Joint Object N.A.
Joint Element ~402
1
2
3
Trans
-0.00567
-0.00815
-0.32867
Rotn
-0.0016
2.704E-04
-4.488E-05
Y
Z
X

HATCH	CALCULATION SHEET		SHEET NO. 14 OF
DESCRIPTION: NSP - WRECK COVE HOIST SUPPORT STRUCTURE	PROJECT NO: 351728	MADE BY: P. MICHALKO DATE: 26 SEP '16	CHECKED BY: D. GLENDENNING DATE: SEPT 27/16.

RESULTS:

ALL HOIST BEAMS AND COLUMNS ARE BELOW FULL UTILIZATION IN ACCORDANCE WITH S16.1.

FOR DEFLECTION INDICATED ON PG. 12; (JAMMED LIFTING CASE)

$\delta = .33$ in ; $L = 17.67$ ft $= 212$ in ON W18X55

$\therefore \frac{L}{\delta} = \frac{212}{.33} = 642$ $\therefore$ O.K. FOR DEFLECTION

DESIGN REVIEW:

DESIGN REVIEWED USING INDEPENDENT HAND CALCS BY D. GLENDENNING.

REFER TO PGS. 15 & 16 FOR REVIEW NOTES

HATCH

CALCULATION SHEET

SHEET NO. 15 OF

DESCRIPTION	PROJECT NO	MADE BY	CHECKED BY
N.S. POWER - WRECK COVE - HOIST STRUCTURE CHECK BEAMS AND COLUMNS.	H351728	GLENDENNING. DATE SEPT 27/16	D. MICHALYUO DATE 27 SEP 16

DEAD LOAD (SELF WEIGHT OF STRUCTURE, INCLUDING 16.65^K HOIST) = 34^K

∴ D.L. PER COLUMN = 34/4 = 8.5^K × 1.25 = 10.63^K = C_{fD}

LIVE LOAD : NORMAL LIFTED LOAD = 41^K 60% TO ONE END = 24.6^K + .5(16.65) = 32.93^K

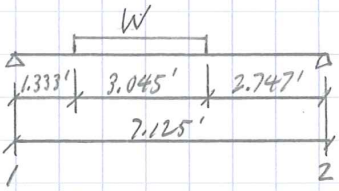
40% TO OTHER END = 16.4^K + 8.33 = 24.73^K

HOIST STALL CAPACITY = 98^K 60% TO ONE END = 58.8^K + 8.33^K = 67.13^K } GOVERNS

40% TO OTHER END = 39.2^K + 8.33^K = 47.53^K }

ALL STRUCTURAL STEEL IS G40.21 : F_y = 44 KSI

CHECK W8×48 : L = 7.125'



$W_{f\,max} = (58.8^{83.2} \times 1.5) + .5(16.65^{10.4} \times 1.25) = 98.6^K$

$R_{f1} = \frac{98.6}{7.125}\left(\frac{3.045}{2} + 2.747\right) = 59.1^K$

$R_{f2} = 98.6 - 59.1 = 39.5^K$

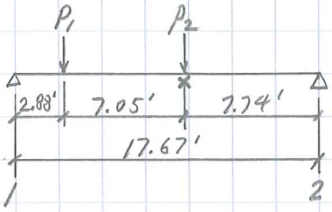
$M_{f\,max}$ AT $X = 1.333 + \frac{59.1}{98.6} = 1.932'$ FROM R_{f1}

$= \frac{98.6}{3.045}\left(\frac{1.932^2 - 1.333^2}{2}\right) = 31.67^{IK}$

FOR W8×48 : M_r AT 7.125' = 162^{IK} >> 31.67^{IK} OK

W8×48 IS ADEQUATE.

CHECK W18×55 : L = 17.67'



$P_{f1} = 59.1^K$ $P_{f2} = \frac{47.53}{67.13} \times 59.1 = 41.9^K$

$R_{f1} = \frac{(41.9 \times 7.74) + (59.1 \times 14.79)}{17.67} = 67.82^K$

$R_{f2} = (59.1^{101} + 41.9) - 67.82 = 33.18^K$

$M_{f\,max} = 33.18 \times 7.74 = 257^{IK}$

FOR W18×55 : M_r AT 7.05' = 333^{IK} > 257^{IK} OK

W18×55 IS ADEQUATE

HATCH

CALCULATION SHEET

SHEET NO. 16 OF

DESCRIPTION	PROJECT NO	MADE BY	CHECKED BY
N.S. POWER - WRECK COVE - HOIST STRUCTURE CHECK BEAMS AND COLUMNS.	H351728	GLENDENNING. DATE SEPT 27/16	P. MICHALKO DATE 27 SEP '16

CHECK W8x48 COLUMNS : $L_x = 19.5'$, $L_y = 19.5/3 = 6.5'$ $K_x = K_y = 1.0$

$C_{FD} = 10.63^K$ $r_x = 3.61"$, $r_y = 2.08"$, $A = 14.1\ in^2$

$C_{FL} = 67.82^K$ (CONSERVATIVE)

$C_F = 78.45^K$

$\frac{K_x L_x}{r_x} = \frac{1.0 \times 19.5 \times 12}{3.61} = 65 \rightarrow Cr/A = 28.8^{KSI}$

$\frac{K_y L_y}{r_y} = \frac{1.0 \times 6.5 \times 12}{2.08} = 38$ $\therefore Cr = 28.8 \times 14.1 = 406^K \gg 78.45^K$ OK

W 8x48 COLUMNS ARE ADEQUATE

Appendix F
Hoist Capacity Assessment

HATCH

Client: Nova Scotia Power

Project Title: Wreck Cove T2 Intake Assessment **Project No: H351728**

Discipline: Mechanical

Calculation No.: H351728-00000-200-202-0001 **File No:** **Number of Sheets:** 7

Description: Combines hydrostatic loads and friction loads to estimate required hoist capacity for gate, and determines if the gate weight is sufficent to ensure gate will close.

Category of calculation verification required ○ 1 ◉ 2 ○ 3 ○ 4

Prepared by: Andrew Bridgeman (Print Name) **Date:** September 20, 2016

Review by: Daniel Flores (Print Name) **Date:** August 30, 2017

Can the calculation now be released for work? ◉ Yes ○ No **To the Client?** ◉ Yes ○ No

General Notes:

Revisions:

Rev.	Date	Prepared by	Checked by	Approved by	Description
0	10/20/2016	A. Bridgeman	D. Flores	A. Bridgeman	

Superseded by Calculation No. **Date:**

Reason voided:

HOIST CAPACITY CALCULATIONS: TAILRACE BULKHEAD

Calculation description

1. Combines hydrostatic loads and friction loads to estimate required hoist capacity for gate, and determines if the gate weight is sufficent to ensure gate will close.

Assumptions

1. Estimation of gate weight known

References

Drawings:
H-085S1-9-625-00-047
H-085S1-9-625-00-048
H-085S1-9-625-00-049
H-085S1-9-625-00-050
H-085S1-9-625-00-053
H-085S1-2-628-00-001

OPERATING LOADS

Gate Data

Gate Width	$B := 15.5ft$
Gate Height	$h_{gate} := 15.146ft = 181.75 \cdot in$
Gate Thickness	$d := 16in$
Wet Gate Height	$Hgate := 15.146ft$
Max Headwater Level	$HW_{max} := 1203ft = 366.67\,m$
Sill Elevation	$H_{sill} := 1168ft = 356.01\,m$
Max Head	$H_{max} := HW_{max} - H_{sill} = 10.67\,m$

OPERATING LOADS

Parameters

Width between seals	$Ws := 178in = 4.52\,m$
Width between load blocks	$Ww := 186in = 4.72\,m$
Total length of seal	$L_{seal} := h_{gate} \cdot 2 = 9.23\,m$
Total length of top seal	$L_{top} := B = 4.72\,m$
Seal projection from clamp	$b_{seal} := 44.4mm$
distance from center of rotation to embedded part	$a_{seal} := 30mm$
Seal stem thickness	$t_{seal} := 0.563in = 14.3 \cdot mm$
Seal friction coefficient (PTFE on steel)	$\mu_{seal} := .1$
Youngs modulus	$E_{st} := 30000000psi$
Density of water	$\rho := 1000 \frac{kgf}{m^3}$
Density of steel	$\rho_{st} := 7860 \frac{kgf}{m^3}$
Density of concrete	$\rho_c := 2400 \frac{kgf}{m^3}$

Hydrostatic Load $HL := Hgate \cdot \left(H_{max} - \frac{Hgate}{2} \right) \cdot \rho \cdot Ws = 1711.12 \cdot kN$

Wheel Friction

Friction in the bearing due to the total wheel load produces a frictional resistance of E_1 as follows:

Wheel Axle Diameter $da := 4in = 0.1\,m$

Wheel Radius $r_w := 15\frac{in}{2} = 0.19\,m$

Coefficient of dynamic wheel friction $\mu := .003$ (Roller Bearing - Ref. Erbisti)

Total static wheel friction $E_1 := \mu \cdot \frac{da \cdot HL}{2 \cdot r_w} = 1.37 \cdot kN$

Sliding Resistance

Flattening of the wheel contact area produces a resistance to rolling, E_2, as follows.

Ref. Machinery's Handbook," 26th. edition; page 191

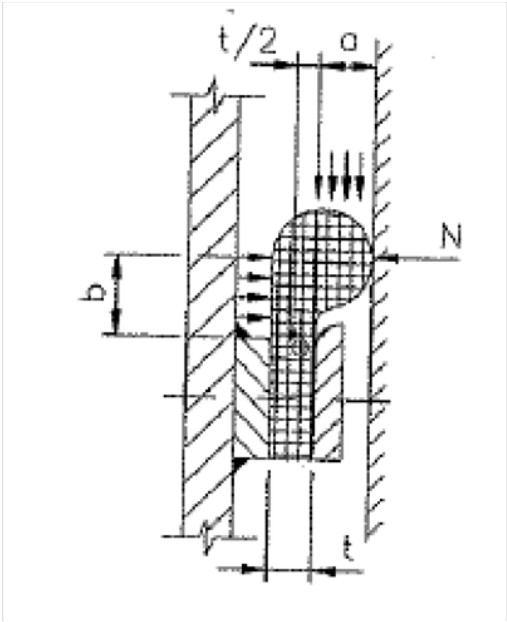
Resistance to rolling factor $f := 0.02in$ (for iron on iron)

Resistance to sliding $E_2 := HL \cdot \frac{f}{r_w}$ $E_2 = 5 \cdot kN$

Seal Friction

The rubber seals provide a frictional resistance of E3. The wall reaction creates friction forces. Therefore, E3 can be computed as follows:

Ref. "Design of Hydraulic Gates," by Paulo C.F. Erbisti; page 228



Average head on side seal $H_{seal} := H_{max} - \frac{Hgate}{2} = 8.36\,m$

Head on lintel seal $H_{lintel} := H_{max} - Hgate = 6.05\,m$

Water pressure on side seal $p_{side} := H_{seal} \cdot \rho = 81.98 \cdot \frac{kN}{m^2}$

Water pressure on top seal $p_{top} := H_{lintel} \cdot \rho = 59.34 \cdot \frac{kN}{m^2}$

Normal force on side seal $N_{seal} := \frac{p_{side} \cdot L_{seal}}{2 \cdot b_{seal}} \cdot \left(b_{seal}^{\,2} + a_{seal}^{\,2} + a_{seal} \cdot t_{seal} \right)$

Normal force on top seal $N_{top} := \frac{p_{top} \cdot L_{top}}{2 \cdot b_{seal}} \cdot \left(b_{seal}^{\,2} + a_{seal}^{\,2} + a_{seal} \cdot t_{seal} \right)$

$N_{seal} = 28.13 \cdot kN$

$N_{top} = 10.42 \cdot kN$

Seal friction due to head $E_3 := \mu_{seal} \cdot \left(N_{seal} + N_{top} \right) = 3.86 \cdot kN$

Precompression unit force (for 3 mm preset) according to Figure 9.2 in Erbisti:

Precompression of J Seal	$F_{sealpc} := 62.7\frac{kgf}{m}$	$F_{sealpc} = 3.51\cdot\frac{lbf}{in}$
Precompression of Bulb Seal	$F_{bulbpc} := 483\frac{kgf}{m}$	
precompression force	$N_{sealpc} := L_{seal}\cdot F_{sealpc} + L_{top}\cdot F_{bulbpc} = 28.05\cdot kN$	
Seal friction due to precompression	$E_{3pc} := \mu_{seal}\cdot N_{sealpc} = 2.81\cdot kN$	
Total seal friction	$E_{3t} := E_3 + E_{3pc} = 6.66\cdot kN$	

Total friction $E := E_1 + E_2 + E_{3t}$ $E = 13\cdot kN$

Weight of gate $A := (35000)lb\cdot g = 155.69\cdot kN$ *as per gate drawings*

Wire Rope moves up and down along with the gate. So, its weight shall be added.

$W_R := 100kg$

$A := A + W_R\cdot g = 156.67\cdot kN$

Buoyancy

Hydrostatic Forces Acting on the Top and Bottom of the Gate Due to the enclosed gate body, there are hydrostatic pressures acting on the top and bottom of the gate

First, calulate the buoyancy of the gate in the as-designed condition of the gate. This assumes all seal welds are intact, and the gate body is water tight. This force will be used when considering the lowering forces, since the gate body will be full of air, and only slowly fill with water as it is submerged.

Gate volume $V_g := d\cdot Ws\cdot h_{gate} = 8.48\,m^3$

Buoyancy Force (assuming gate cavity empty) $F_{b1} := V_g\cdot\rho = 83.18\cdot kN$

Second, calculate the buoyancy of the gate in the as-found condition, where the seals are no longer intact and the gate body will fill with water. This force will be used when calculating required hoist power.

Gate weight (steel) (estimate from vertgate + 10%) $W_s := 15000lb\cdot 1.1 = 1.65\times 10^4\cdot lb$

Weight of Concrete (Estimate) $W_c := 35000lb - W_s = 1.85\times 10^4\cdot lb$

Volume of Steel $V_s := \frac{W_s\cdot g}{\rho_{st}} = 0.95\,m^3$

Volume of concrete $V_c := \frac{W_c \cdot g}{\rho_c} = 3.5\,m^3$

Height of concrete (to check against drawing) $h_c := \frac{V_c}{14.75in \cdot 170.375in} = 7.08 \cdot ft$

Plug location on gate appears to be located at approximately 8.5 ft. Concrete fill level assumed to be within 0.5ft of the plug level. Since the bottom of the gate is angled, estimated height of concrete (and therefore volume of concrete) appears to be correct.

Buoyancy Force (Assuming gate cavity full of water) $F_{b2} := (V_s + V_c) \cdot \rho = 43.63 \cdot kN$

The gate weight is usually required to exceed resistance to lowering by 115% minimum.

Required gate weight $A_{req} := 115 \cdot \% \cdot (E + F_{b1})$

or:

$A_{req} = 110.14 \cdot kN$ $A = 156.67 \cdot kN$

$A_{req} < A = 1$ Okay

Under emergency drop conditions, the gate has enough weight to lower under its own weight, provided that the wheels are rotating freely, and Fluoro-carbon film on the seals is intact.

Downpull Estimate from Vertgate (during cracking)

$dp_{crack} := 8384lbf = 37.29 \cdot kN$

$dp_{max} := 17845lbf = 79.38 \cdot kN$

Original Hoist Requirements $F_{hoistorig} := A + E + dp_{crack} - F_{b1} = 123.37 \cdot kN$

Hoist requirement = Weight of gate + friction forces + downpull - buoyancy (assuming gate water tight)

The current condition of the gate allows for the upper portion of the gate to be filled with water. Originally full buoyancy forces would have acted on the gate assuming water tight welds, however with water infiltration, the buoyances forces are lower, and the hoist is required to lift the weight of water which has filled the cavity.

Calculate required capacity of the hoist to crack the gate $F_{hoistFinal} := A + E + dp_{crack} - F_{b2} = 162.93 \cdot kN$ answer

Calculate required capacity of the hoist to lift the gate in balanced head conditions

Lifting force in equalized conditions $F_{hoistEqual} := A + E_{3pc} - F_{b2} = 115.85 \cdot kN$ answer

Estimate the actual hoist capacity based on nameplate conditions and assumed hoist efficiency:

Actual Hoist Capacity

Hoisting Speed $v := 2.4 \frac{ft}{min}$

Hoist Efficiency $\eta_{hoist} := 90\%$ (Assumed sheave + gearbox efficiency)

Hoist Power $P_h := 3hp$

Lifting Capactiy of Hoist $F_{hoistcalc} := P_h \cdot \frac{\eta_{hoist}}{v} = 165.14 \cdot kN$

Calculate the capacity factor of the hoist for all three loading scenarios:

$$CF_{orig} := \frac{F_{hoistcalc}}{F_{hoistorig}} = 1.34$$

$$CF_{final} := \frac{F_{hoistcalc}}{F_{hoistFinal}} = 1.01$$

$$CF_{equal} := \frac{F_{hoistcalc}}{F_{hoistEqual}} = 1.43$$

Typically, hoist are designed to be at least 110% of the calculated required capacity. Based on this critera, the hoist capacity is sufficient for the original design conditions, and for lifting the gate under equilized head in the current conditions, however it is slightly undersized for cracking the gate in the current conditions (not water tight, water allowed to fill cavity reducing buoyancy forces).

Appendix G
T2 Intake Cost Estimate

HATCH

Preliminary Construction Cost Estimate
(Conceptual)

Rev A.
(Issued for Client Review)

Client: Nova Scotia Power Inc.
Project Name: Wreck Cove - T2 Intake Gate Assessment Project
Project Number: H351728
Project Duration: Assumed approx 6 months

Date: April 19, 2017
Prepared by: J. Atkinson, I. Maan, D. Pinese
Reviewed by: A. Bridgeman, M. Miller

Description: Conceptual Design Cost Estimate for Wreck Cove T2 Intake Gate Replacement and Modifications
Accuracy Range = ± 30%

Item	Description	Estim. Quantity	Unit	Unit Price	Amount
1	**Contractor's Construction Indirects**				
1.1	Construction Facilities, Mobilization & Demobilization	1	LS	$20,000	$20,000
	Subtotal				**$20,000**
2	**General Items**				
2.1	Access Road and Laydown Area Improvements	1	LS	$25,000	$25,000
2.2	Access Road Clearing	1	LS	$10,000	$10,000
2.3	Environmental Management	1	LS	$5,000	$5,000
2.4	Water Control	1	LS	$5,000	$5,000
	Subtotal				**$45,000**
3	**T2 Intake Gate / Gatehouse**				
3.1	Removal of Existing Gate Equipment, Support Structure, Hoist, and Building	1	LS	$30,000	$30,000
3.2	Supply and Installation Supervision of Gate (embedded parts not included)	1	LS	$125,000	$125,000
3.3	Supply and Installation Supervision of Hoist	1	LS	$225,000	$225,000
3.4	Supply and Installation Supervision of Superstruture	1	LS	$75,000	$75,000
3.5	Supply and Installation Supervision of New Insulated Gate Enclosure	1	LS	$35,000	$35,000
3.6	Supply and Installation Supervision of Stairway Structure	1	LS	$10,000	$10,000
3.7	Installation of Gate Equipment (gate, support structure, hoist)	1	LS	$100,000	$100,000
3.8	New Reinforced Concrete Slab	1	LS	$15,000	$15,000
3.9	Concrete Dowelling of new support structure into new concrete slab	1	LS	$6,500	$6,500
3.1	Miscellaneous Steel (grating for deck openings)	1	LS	$10,000	$10,000
3.11	Supply and Installation of Wood Timbers for Ice Prevention	1	LS	$36,000	$36,000
	Subtotal				**$667,500**
4	**Electrical**				
4.1	Electrical Works	1	LS	$65,000	$65,000
4.2	Electrical Service Upgrade	1	LS	$7,500	$7,500
4.3	Wreck Cove Intake and Foundation Grounding	1	LS	$10,000	$10,000
4.4	CCTV Freeze Protection Camera	1	LS	$10,000	$10,000
	Subtotal				**$92,500**
Total Estimated Construction Cost without Contingency					**$825,000**
Contingency (20%)					**$165,000**
Total Estimated Construction Cost					**$990,000**

Exclusions:

- Engineering design and environmental studies
- Owner's engineering costs (project management, tendering, site supervision, QA testing)
- Owner's other costs (financing/IDC, taxes, land acquisition, legal surveys)
- Construction Insurance and Bonds
- Escalation beyond September 2017
- Mitigation measures for protection of archaeological areas (if applicable)
- Concrete testing (Owner preference to coordinate)

Available Information:

- Cost estimates based on recent other NSPI projects (actuals and tendered)
- Budgetary quote received for major gate and hoist equipment

Other Notes/Assumptions:

- Contractor indirects such as site supervision, mob, demob, etc., assumed to be included in unit rates and LS costs (typical NSPI experience)
- Unit prices for concrete include formwork and reinforcing steel
- Cost estimate developed without comprehensive condition assessment of existing structures and site conditions
- Local contractor (minimal per diems)
- Existing structures assumed to be in acceptable condition for intended purpose
- Existing structures assumed to meet stability requirements
- Bedrock presumed to be sound and in good condition (geotech inspection required before foundation construction)
- Bedrock can be removed using excavator with rock breaker
- Road access and possible laydown areas on project site assumed to be in reasonable condition (some improvements needed) for construction equipment and crane access
- Concrete surface preparation is considered incidental to the work (not a separate pay item)
- Dewatering managed by NSPI (outage planned)
- Grounding requirements based on standard design supplier requirements
- CCTV Camera included for visual inside gate well to monitor freeze protection
- All ladder and fall arrest systems by suppliers
- 6 month construction schedule

Appendix H
Budgetary Quote

Wreck Cove GS – Gate Equipment

Request for Budget Quote

1. Item 1 – T2 Intake Gate Equipment

1.1 Description

The T2 intake gate at the Wreck Cove Generating Station in Nova Scotia controls the water passage between the Wreck Cove reservoir and Surge Lake. Nova Scotia Power Inc. (NSPI) is considering replacement/refurbishment of the T2 intake gate equipment.

There are no plans to replace the existing embedded parts as an underwater ROV inspection suggests that the embedded parts are in acceptable condition.

Hoist arrangements being considered are:

- Superstructure mounted wire rope hoist
- Superstructure with deck mounted wire rope hoist.

If the hoist is installed at deck elevation, the wire ropes will run from the hoist drum up at an angle to sheaves/pulleys located on the gate support structure above the gate slot. The deck mounted hoist location has value as it allows for a shorter tower structure and for better access to the hoist during maintenance activities.

1.2 Scope of Supply

If possible, please provide pricing for the items listed below based on a superstructure mounted wire rope hoist.

Please also comment on the feasibility of mounting the wire rope hoist at deck elevation.

Description	Weight or Capacity (kg)	Budget Price ($CAN)
Vertical wheeled intake gate		
Wire rope hoist		
Steel superstructure with ladder access		
Insulated hoist enclosure		
Staircase access (alternate to ladder access)		

1.3 Design Requirements

General design requirements as per below.

Description	Requirement
Maximum Headwater Level	1200 ft
Sill Elevation	1168 ft
Deck Elevation	1212 ft
Approximate Lift Height	45 ft (bottom of gate should be 6 in. higher than deck elevation when in maintenance position)
Seal Location	Downstream
Water Passage Clear Height	12 ft – 0 in.
Water Passage Clear Width	13 ft – 0 in.
Gate Center-to-Center Main Rollers	14 ft. – 10 in.
Existing Seals	Sill seal – metal to metal type Side seals – rubber J bulb type Lintel seal – rubber centre bulb type
Lifting/Lowering Speed (minimum)	Existing: 2.4 ft per minute Proposed: 3.0 ft per minute
Emergency Closure Speed (minimum) under self-weight using fan brake	Existing: 5.0 ft per minute Proposed: Average of 6.0 ft per minute and not more than 3 times rated speed
Ladder or Stairs	To meet applicable health and safety requirements
Rated Capacity of Hoist	Not less than 133% of calculated required capacity
Self-weight of Gate	To exceed forces resisting closure by a minimum of 25%
Gate Corrosion Allowance	1/16 in. on all surfaces exposed to water

1.4 Reference Drawings

The following reference drawings are attached.

Drawing Number	Title
H-085S1-9-625-00-047	Wreck Cove Tunnel Intake Gate – General Arrangement of Gate and Seals
H-085S1-9-625-00-050	Wreck Cove Tunnel Intake Gate – General Arrangement of Embedded Parts
H-085S1-9-625-00-053	Wreck Cove Tunnel Intake Gate – Hoist Drive General Arrangement
H-085S1-9-625-00-057	Wreck Cove Tunnel Intake Gate – Hoist Support Structure - Elevations
H-085S1-2-628-00-001	Wreck Cove Tunnel Intake Gate – Intake Gate General Arrangement

1.5 Reference Photos

Photo 1 – T2 Hoist Support Structure and Enclosure

Photo 2 – T2 Hoist Support Structure and Enclosure

Photo 3 – T2 Gate Intake Structure

2. Item 2 – Penstock Intake Gate Equipment

2.1 Description

A submerged penstock intake is used to transport water from Surge Lake to the Wreck Cove Powerhouse. The submerged penstock intake currently uses stoplogs (sectional gates) for penstock and powerhouse isolation (requires dewatering of Surge Lake and installation by boom truck). Proposed changes to the penstock intake include construction of a concrete gate tower/well (or steel structure) that will facilitate installation of a vertical wheeled gate. The wheeled gate will replace the stoplogs as the primary penstock/powerhouse isolation mechanism. The overall scope of the new intake area at Surge Lake includes:

- Extension of intake structure (by others) upstream to allow for installation of a concrete or steel gate tower (by others) for new vertical downstream stealing gate
    - If concrete, the tower will enclose the gate path to facilitate heating at the water surface
    - If steel, the wire ropes will be shielded and within a heated space to prevent freezing at the water surface
- Installation of an access bridge to the gate tower (by others).

Similar to the T2 intake gate, hoist arrangements being considered are:

- Superstructure mounted wire rope hoist
- Superstructure with deck mounted wire rope hoist.

If the hoist is installed at deck elevation, the wire ropes will run from the hoist drum up at an angle to sheaves/pulleys located on the gate support structure above the gate slot. The deck mounted hoist location has value as it allows for a shorter tower structure and for better access to the hoist during maintenance activities.

2.2 Scope of Supply

If possible, please provide pricing for the items listed below based on a superstructure mounted wire rope hoist.

Please also comment on the feasibility of mounting the wire rope hoist at deck elevation.

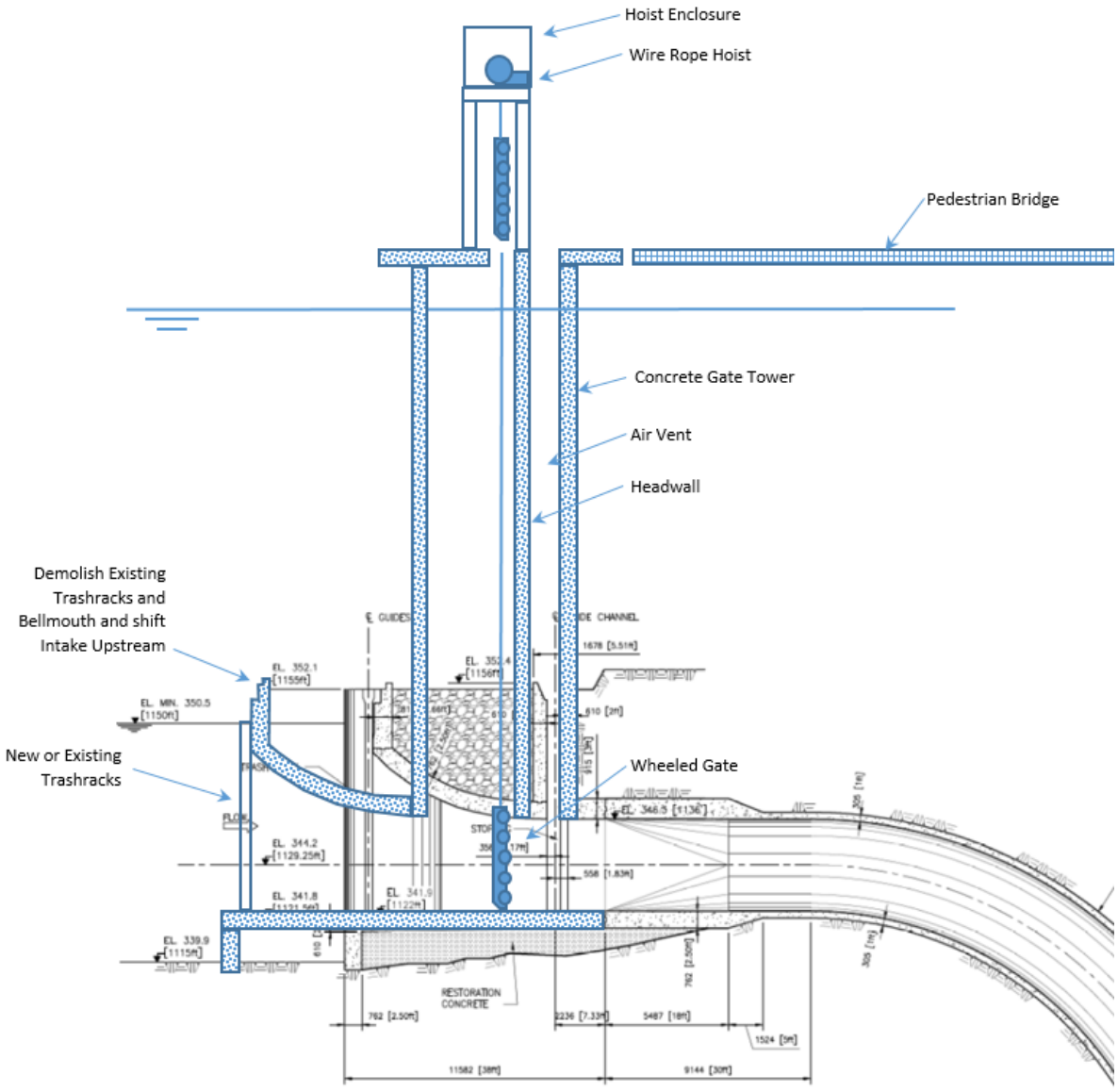
Description	Weight or Capacity (kg)	Budget Price ($CAN)
Vertical wheeled intake gate		
Wire rope hoist		
Steel superstructure with ladder access		
Insulated hoist enclosure		
Staircase access (alternate to ladder access)		

2.3 Design Requirements

General design requirements as per below.

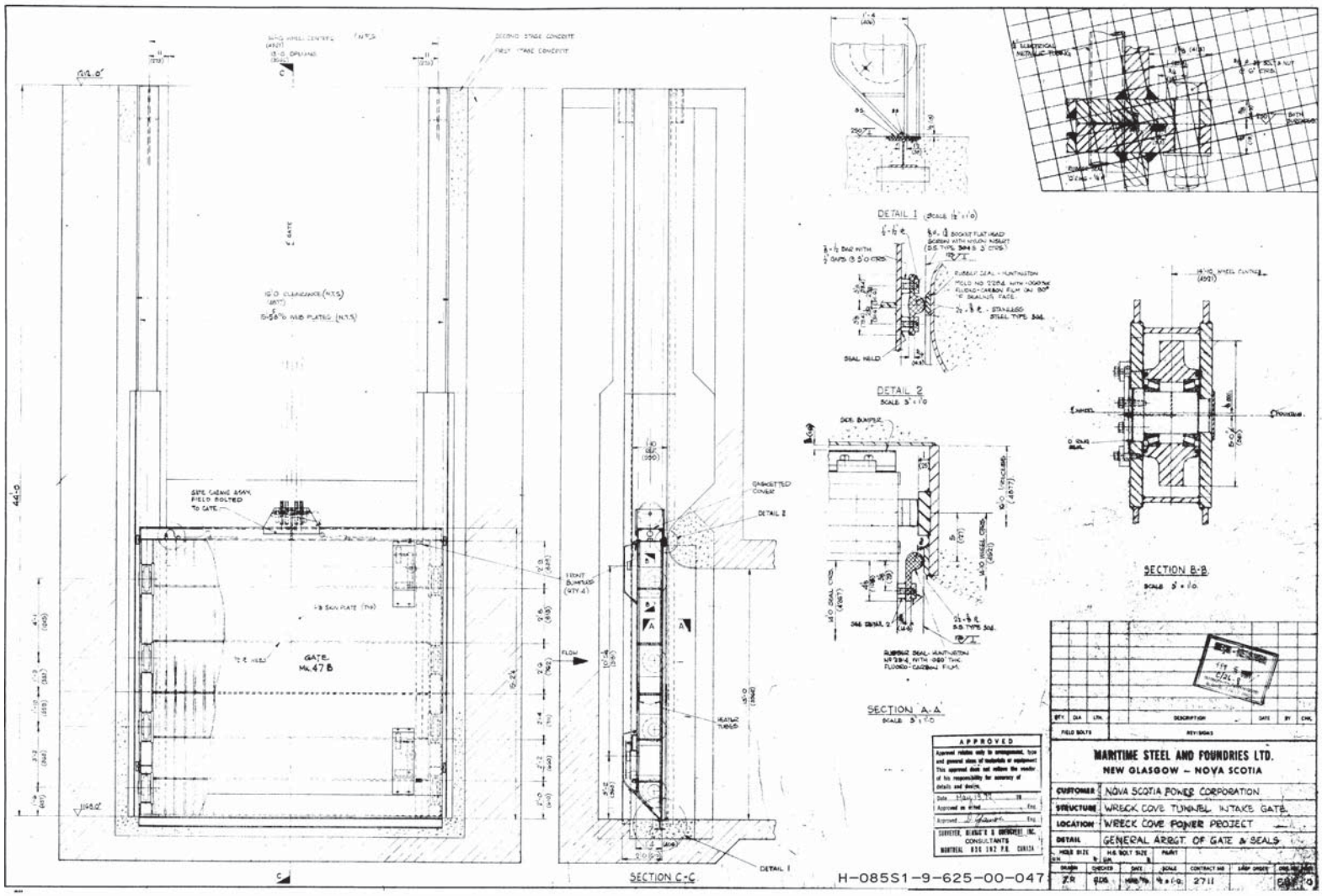
Description	Requirement
Maximum Headwater Level	1200 ft
Sill Elevation	1121.5 ft
Deck Elevation	1212 ft (assumed to be similar to T2 intake)
Approximate Lift Height	To be determined by gate designer (bottom of gate should be 6 in. higher than deck elevation when in maintenance position)
Seal Location	Downstream
Water Passage Clear Height	Approx 14 ft – 6 in.
Water Passage Clear Width	Approx 13 ft – 0 in.
Gate Dimensions	To be determined by gate designer
Seals	Sill seal – metal to metal type (or that recommenced by designer) Side seals – rubber J bulb type Lintel seal – rubber centre bulb type
Lifting/Lowering Speed (minimum)	Proposed: 3.0 ft per minute
Emergency Closure Speed (minimum) under self-weight using fan brake	Proposed: Average of 6.0 ft per minute and not more than 3 times rated speed
Ladder or Stairs	To meet applicable health and safety requirements
Rated Capacity of Hoist	Not less than 133% of calculated required capacity
Self-weight of Gate	To exceed forces resisting closure by a minimum of 25%
Gate Corrosion Allowance	1/16 in. on all surfaces exposed to water

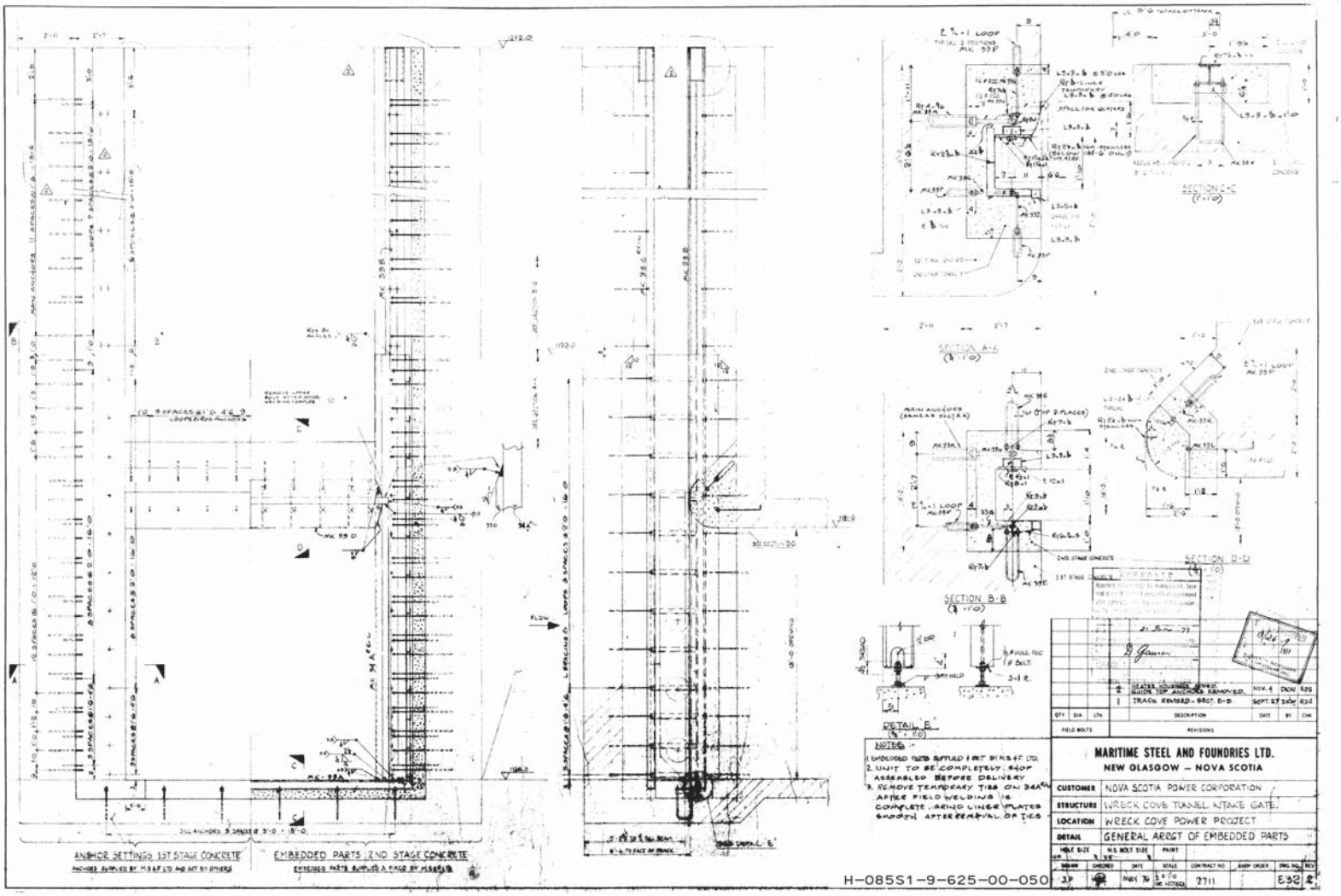
2.4 Reference Drawings (see sketch below)

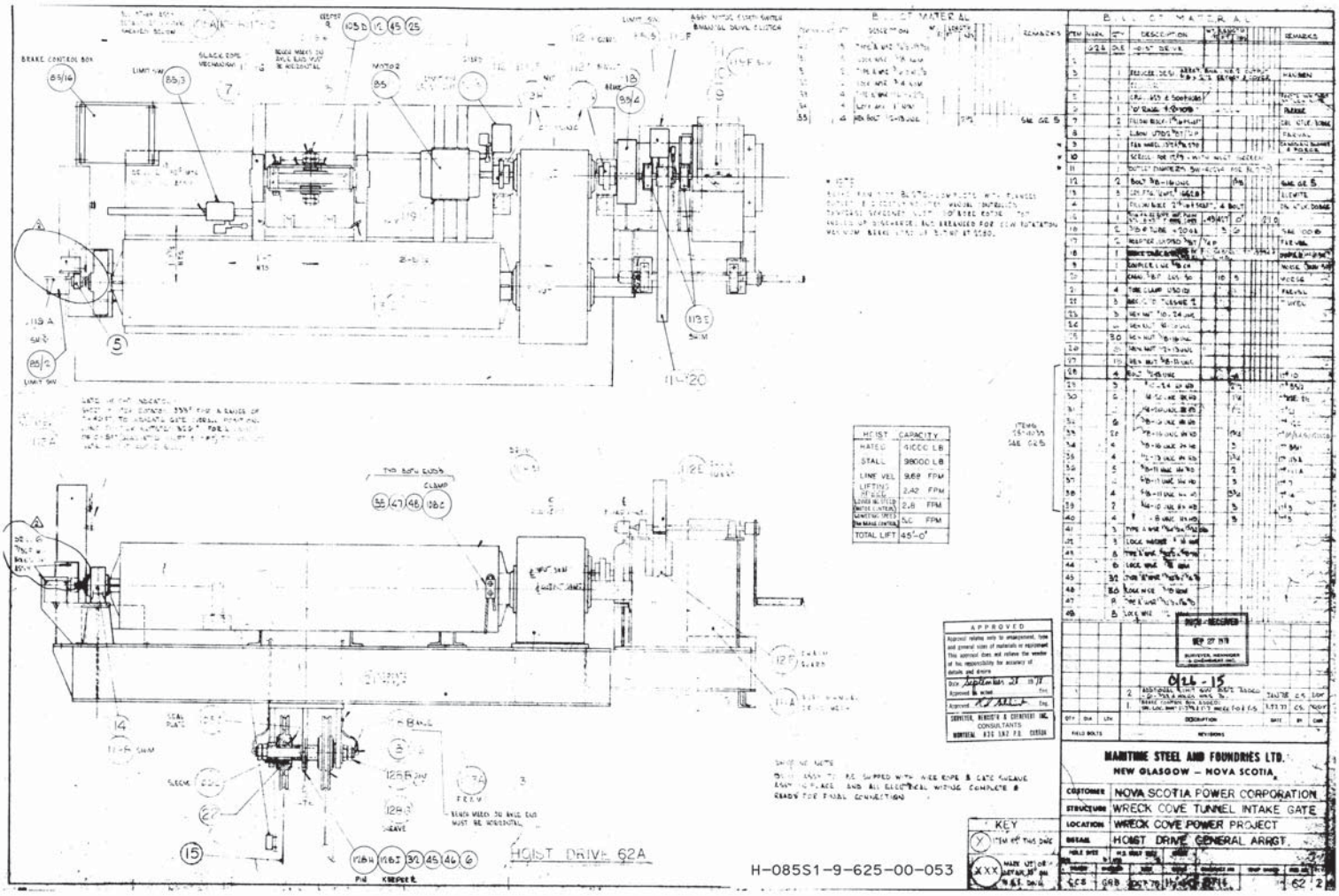


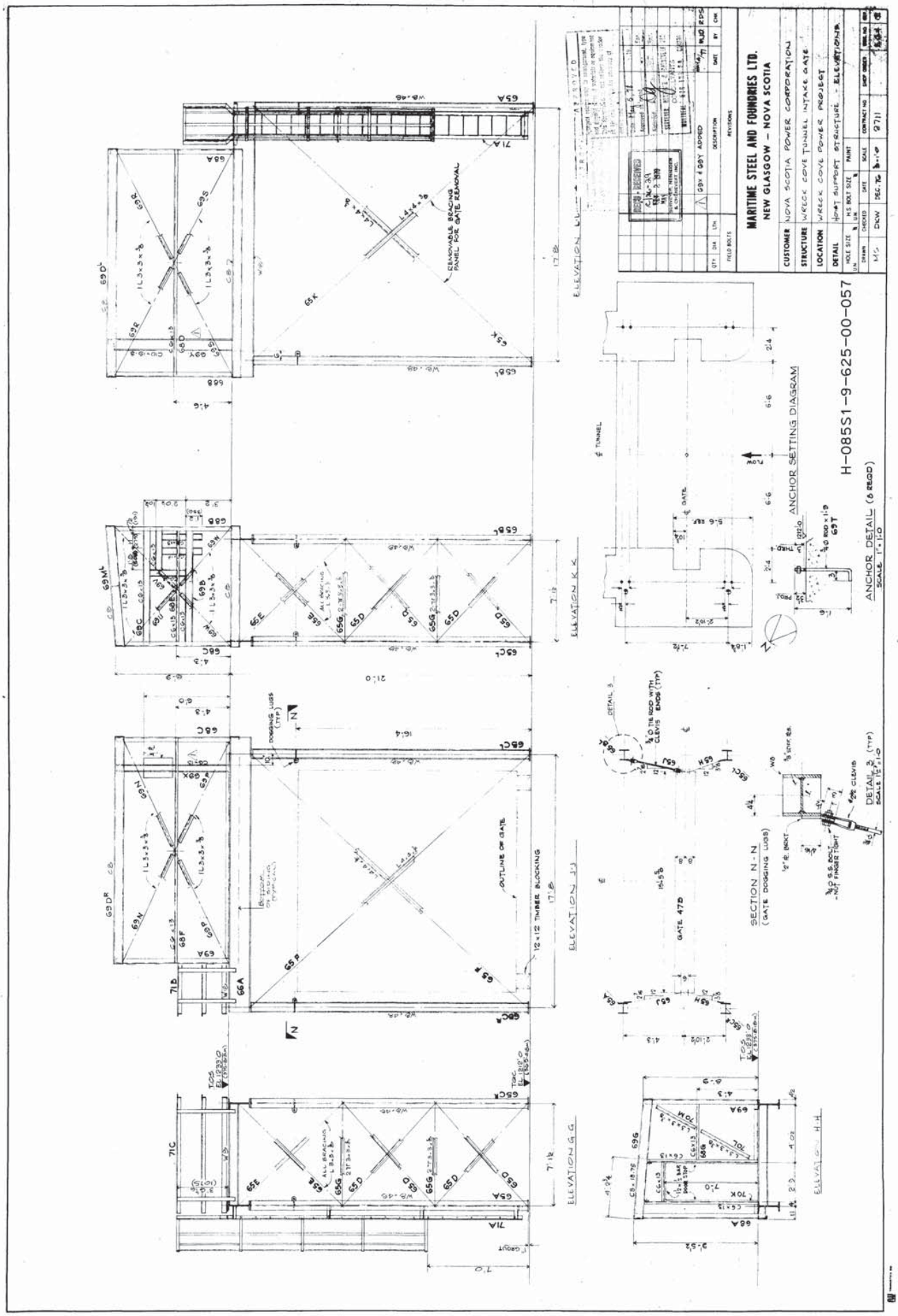
2.5 Reference Photos

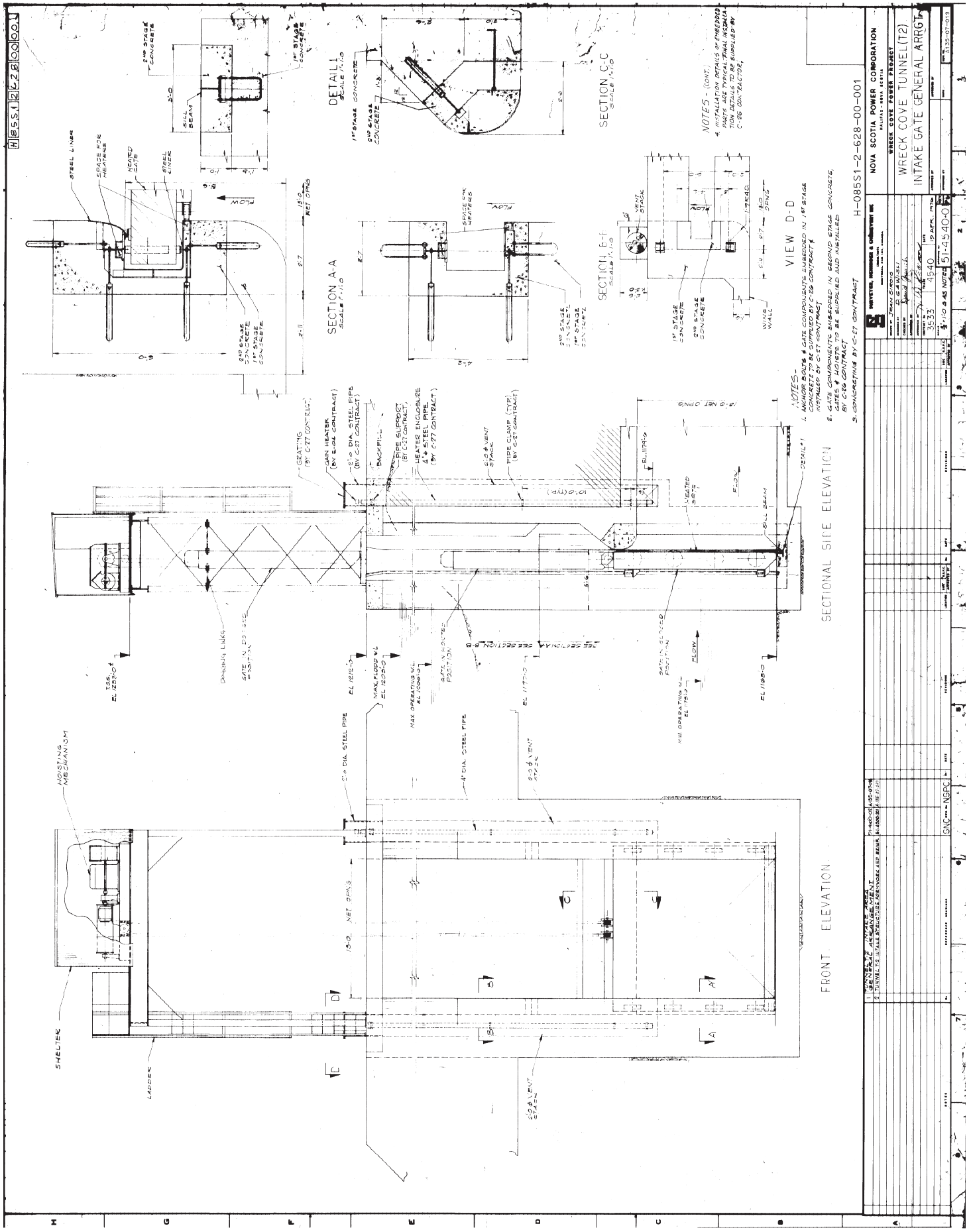
Photo 1 – Penstock Intake (dewatered)


DETAIL 1
DETAIL 2
SECTION A-A
SECTION B-B
SECTION C-C
GATE Mk.47B
MARITIME STEEL AND FOUNDRIES LTD.
NEW GLASGOW – NOVA SCOTIA
CUSTOMER NOVA SCOTIA POWER CORPORATION
STRUCTURE WRECK COVE TUNNEL INTAKE GATE
LOCATION WRECK COVE POWER PROJECT
DETAIL GENERAL ARRGT OF GATE & SEALS
H-085S1-9-625-00-047


ANCHOR SETTINGS 1ST STAGE CONCRETE
EMBEDDED PARTS 2ND STAGE CONCRETE
SECTION C-C
SECTION A-A
SECTION D-D
SECTION B-B
DETAIL E
NOTES
MARITIME STEEL AND FOUNDRIES LTD.
NEW GLASGOW – NOVA SCOTIA
CUSTOMER NOVA SCOTIA POWER CORPORATION
STRUCTURE WRECK COVE TUNNEL ATAKE GATE.
LOCATION WRECK COVE POWER PROJECT
DETAIL GENERAL ARRGT OF EMBEDDED PARTS
H-085S1-9-625-00-050


HOIST DRIVE 62A
H-085S1-9-625-00-053
MARITIME STEEL AND FOUNDRIES LTD.
NEW GLASGOW — NOVA SCOTIA
CUSTOMER NOVA SCOTIA POWER CORPORATION
STRUCTURE WRECK COVE TUNNEL INTAKE GATE
LOCATION WRECK COVE POWER PROJECT
DETAIL HOIST DRIVE GENERAL ARRGT.
HOIST CAPACITY
RATED 4000 LB
STALL 98000 LB
LINE VEL 9.69 FPM
TOTAL LIFT 45'-0"
APPROVED
KEY


MARITIME STEEL AND FOUNDRIES LTD.
NEW GLASGOW – NOVA SCOTIA
CUSTOMER NOVA SCOTIA POWER CORPORATION
STRUCTURE WRECK COVE TUNNEL INTAKE GATE
LOCATION WRECK COVE POWER PROJECT
DETAIL HOIST SUPPORT STRUCTURE - ELEVATIONS
H-085S1-9-625-00-057
ANCHOR SETTING DIAGRAM
ANCHOR DETAIL (6 REQD)
SECTION N-N
(GATE DOGGING LUGS)
ELEVATION G-G
ELEVATION J-J
ELEVATION K-K
ELEVATION L-L
ELEVATION H-H
REMOVABLE BRACING PANEL FOR GATE REMOVAL
OUTLINE OF GATE
12 x 12 TIMBER BLOCKING
DOGGING LUGS (TYP)
GATE 47B
DETAIL 3 (TYP)
DETAIL 3


H-085S1-2-628-00-001
NOVA SCOTIA POWER CORPORATION
WRECK COVE POWER PROJECT
WRECK COVE TUNNEL (T2)
INTAKE GATE GENERAL ARRGT
SECTION A-A
SECTION B-B
SECTION C-C
DETAIL
VIEW D-D
SECTIONAL SIDE ELEVATION
FRONT ELEVATION
NOTES-
1. ANCHOR BOLTS & GATE COMPONENTS EMBEDDED IN 1ST STAGE CONCRETE TO BE SUPPLIED BY C-26 CONTRACT & INSTALLED BY C-27 CONTRACT
2. GATE COMPONENTS EMBEDDED IN SECOND STAGE CONCRETE, GATE & HOISTS TO BE SUPPLIED AND INSTALLED BY C-26 CONTRACT
3. COORDINATION BY C-27 CONTRACT
NOTES - (CONT.)
4. INSTALLATION DETAILS OF EMBEDDED ANCHOR BOLTS & FINAL ALIGNMENT TO BE SUPPLIED BY C-26 CONTRACTOR.
GRATING (BY C-27 CONTRACT)
DAM HEATER (BY C-24 CONTRACT)
6'-0" DIA. STEEL PIPE (BY C-27 CONTRACT)
BACKFILL
PIPE SUPPORT (BY C-27 CONTRACT)
HEATER ENCLOSURE
4'-6" STEEL PIPE (BY C-27 CONTRACT)
SLOT VENT STACK
PIPE CLAMP (TYP.) (BY C-27 CONTRACT)
HOISTING MECHANISM
SHELTER
LADDER
SLOT VENT
EL 1128.0
EL 1117.0
MAX. FLOOD W.L. EL 1128.0
MAX. OPERATING W.L. EL 1108.5
MIN. OPERATING W.L. EL 1093.5
GATE IN POSITION
GATE IN SLOT
DRAWING LINKS
SEE SECTION A-A
SEE SECTION B-B
FLOW
SPACE FOR HEATERS
HEATED GATE
STEEL LINER
SILL BEAM
1ST STAGE CONCRETE
2ND STAGE CONCRETE
VENT STACK
WING WALL
13.0 NET OPNG
15.0 NET OPNG
EL 1128.0
EL 1112.5
EL 1108.5
EL 1093.5
EL 1117.0
EL 1128.0
SLOT VENT
SILL BEAM
HEATED GATE
DETAIL
SCALE 1:10
SECTION A-A
SCALE 1:10
SECTION B-B
SCALE 1:10
SECTION C-C
SCALE 1:10
VIEW D-D
SCALE 1:10
SECTIONAL SIDE ELEVATION
SCALE 1:10
FRONT ELEVATION
SCALE 1:10
GENERAL ARRANGEMENT
TUNNEL T2 - INTAKE STRUCTURE, ADIT, WORKS AND REMARKS
SNC-LAVALIN NSPC
DESIGNED
DRAWN
CHECKED
APPROVED
DATE
SCALE
PROJECT
DRAWING
REVISIONS

CANMEC INDUSTRIEL

Transmission ( ) By Mail
( ) By Fax
(x) By Email

Chicoutimi, May 17th 2017,

Client : Hatch

Att: Mr. Jonathan Atkinson.

Your Reference :
Our Reference : GCS-17-196

Copy : Mr. Éric Tremblay, V-P Canmec

Request for Budget Quote-Wreck Cove GS-Gate Equipment

Dear Sir,

It's a pleasure to submit you our **Budgetary price proposal** #GCS-17-196 for the Fabrication of (2) Gates equipment for the Wreck Cove GS project in accordance with your request.

Please refer to the notes and conditions hereafter.

We are looking forward to receiving a favorable answer from you.

Sincerely yours,

Guy Ouellet, P.Eng., Estimator
Canmec Industriel

Canmec Industriel 1750 La Grande Chicoutimi (Qc) G7K 1H7 Tel : (418) 543-9151 Fax : 418-543-5564 www.canmec.com

CANMEC INDUSTRIEL

1. Main drawings and reference specifications used for this proposal

REFERENCE DOCUMENTS AND SPECIFICATIONS:

Item	Document Number	Rev.	Description
#1	H351728-00000-620-070-0001	0001	Request for Budget Quote-Wreck Cove GS-Gate Equipment

2. Included

a. Engineering and Fabrication of item 1 T2 Intake Gate Equipment and Item 2 Penstock intake Gate including Vertical wheeled gate, Wire rope hoist, steel superstructure, insulated hoist enclosure and staircase access.

b. Main Material: CSA G40.21 300W, 350W

Note: Imperial equivalents for plate thickness and profile have been considered in this quotation.

c. Welding procedures as CSA W47.1 and W59.

d. NDT: VT 100%, MT 10%

e. Shop drawings

f. Complete quality control documentation Inspection and Test Plan, inspection reports, mill tests, certification of conformity and all other relevant documents

g. Sandblasting and painting: SSPC SP-10, Interseal 670 HS, 2 layers 8mils/each

h. FCA Chicoutimi, QC

i. Manufacturing schedule including milestones for fabrication and testing will be provided after purchase order.

3. Excluded

a. Transportation to the site.

b. Unloading on site

c. All applicable taxes.

d. Additional storage in case of delay.

4. Other Technical Informations

a. Qualification of quality inspectors as per CGSB 48.9712-2000, Level II. (Canadian General Standards Board).Qualification of welders as per CWB (Canadian Welding Bureau).

b. Welding operations will be performed as per CSA W47.1 Div. 1 and CSA W59

CANMEC INDUSTRIEL

5. Others Commercial Information

Before the contract is awarded and a formal Purchase Order is issued, a formal pre-production meeting must be held in order to discuss the following issues.

a. Review of all technical aspects including drawings and manufacturing details.

b. Review of potential minor modifications.

c. Our standard warranty regarding raw materials and workmanship is valid for (12) months following the components are ready for pick-up at Canmec's facility.

d. Main steel price based on 0.55$/pound, can be readjusted if there price increase at the time of the purchasing activities.

e. Cancellation charges/ Delays

In the case of an order cancellation or a delay cause by the contractor of the owner, the total material and labor costs at this time including profits will be charged to client.

f. Delivery: to be discussed, 16-20 weeks approx.

g. Liquidated damages : no liquidated damages for this quotation

6. Price

Item 1-T2 Intake Gate Equipment

Description	Weight or Capacity (kg)	Budget Price ($CAN)
Vertical wheeled intake gate	10,000	125,000$
Wire rope hoist	30,000	225,000$
Steel superstructure with ladder access	8000	75,000$
Insulated hoist enclosure	-	35,000$
Staircase access (alternate to ladder access)	2,500	10,000$
	Total	**470,000$**

Item 2- Penstock Intake Gate Equipment

Description	Weight or Capacity (kg)	Budget Price ($CAN)
Vertical wheeled intake gate	16,000	195,000$
Wire rope hoist	30,000	225,000$
Steel superstructure with ladder access	8,000	75,000$
Insulated hoist enclosure	-	35,000$
Staircase access (alternate to ladder access)	2,500	10,000$
	Total	**540,000$**

CANMEC INDUSTRIEL

7. Terms of payment

a) 20% with purchase order, net 45 days.

b) 30% at material receiving, net 45 days.

c) 40% according to manufacturing progress (each month), net 45 days.

d) 10% after ready to ship is completed each unit, net 45 days.

8. Limitation of liability

Notwithstanding anything to the contrary in the contractual documents, exchange of correspondence or exchange of pre-contractual documents, the liability of the contractor, including that of its subcontractors and suppliers, and their respective officers, directors, agents and employees, with regard to any claim arising from the execution of the present contract, including any penalty, if applicable, and with regard to any claim arising from the performance or non-performance of any obligation in connection with the contract or the performance of any service or work outside the contract, in the context of the execution of such contract, whether such claim is based on contract, warranty, civil right or extra-contractual liability (including a claim based on negligence but excluding fraud), or for any other cause, shall not exceed, in the aggregate, including any insured part, one hundred percent (100 %) of the contract value, including claims for damages, loss of profits, loss of revenue or the loss of both; for loss related to plant shutdown or to the inability to operate the plant to its normal level of productivity; for the increased expenses of operation or for any indirect damage.

This limitation of liability and prosecution, to the benefit of the contractor, shall apply to contractual matters as well as to extra-contractual matters and shall remain valid and fully enforceable after termination of the contract and notably, for the period in which warranties provided by any applicable law or regulation apply.

Should you have questions, please do not hesitate to communicate with us.

Best regards,

Guy Ouellet P.Eng., Estimator
Canmec Industriel

Appendix I
Interim Repair Email

From: Atkinson, Jonathan
Sent: Wednesday, November 09, 2016 7:05 PM
To: SAMPSON, RAY
Cc: Bridgeman, Andrew; Westermann, Jerry; Belashov, Oleg; 351728
Subject: Wreck Cove T2 Intake Gate - Status Update and Recommendations for Interim Repair
Attachments: Wreck Cove T2 Intake Gate - Mapping of Cracks in Welds.pdf

Hi Ray,

We are currently in the process of preparing the inspection summary report and suggested refurbishment/replacement scope for the T2 intake gate. However, based on the cracked welds found on the gate during the initial site inspection and recent site inspection (to inspect the interior of gate with borescope and measure wheel alignment), we suggest that an interim repair be completed to ensure reliable use of the gate for isolation purposes. Please find below a brief status update of the inspections and analysis performed to date as well as recommendations.

The following inspections have been completed:

- Initial inspection completed on Aug 20, 2016. Results of initial inspections will be included in the summary report.
- Recent inspection completed to attempt to inspect the interior of the gate via select drilled holes with borescope completed on Nov 5, 2016. Inspection went well. There was a significant amount of scaling throughout, so it was difficult to determine the condition of the welds inside the gate. The scaling was consistent with the top of the gate however (below covers), and after removing debris and scaling, the welds appeared to be in good shape (possible indication that interior welds not inspected and interior welds where ballast located could be in similar condition).

The following analysis activities have been completed to date:

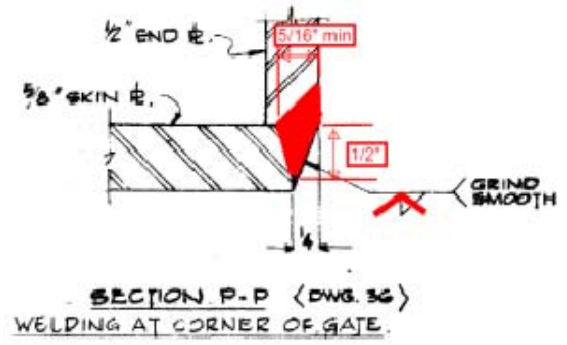
- Hoist capacity is adequate, and the gate should lower in full flow conditions considering all static & dynamic forces acting on the gate.
- Hoist superstructure columns were found to be adequate to take all expected hoisting loads, and the stall torque of the hoist.
- Gate finite element analysis (FEA) determined that all gate stresses are within allowable for the original gate design. The original end beam welds appear to have an adequate capacity given all wheels are in contact with the wheel path. However, if one of the wheels is not in contact with the wheel path the end beam welds at the above or below adjacent wheel may be overstressed.
- Currently, some welds on the gate have failed (we suspect likely due to freeze thaw issues and possible overstress of welds as per above) and the gate is no longer under the same conditions it was designed for:
    - Gate heating system has failed and been abandoned
    - Gate cavity was originally water tight, and now water can fill the gate cavity.

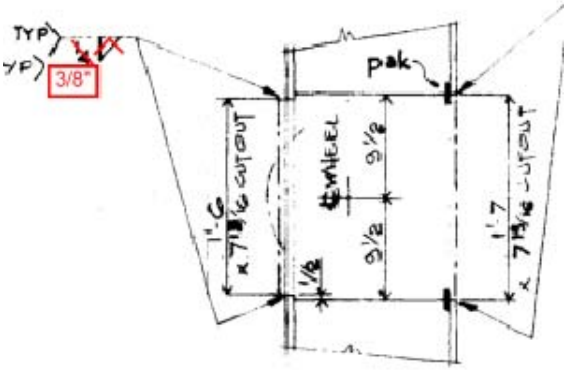
Until a refurbishment approach/strategy can be further developed, the following recommendations are suggested in the short-term to ensure reliable use of the gate for isolation purposes:

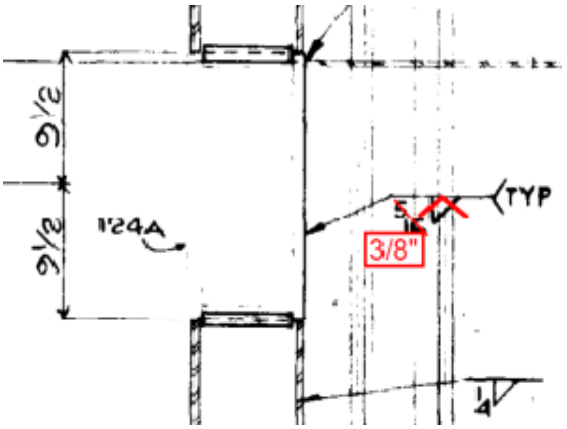
- Repair the damaged welds as per the original design but using a minimum weld size of 5/16” (E70 electrode) for end box weld repairs, and 3/8” (E70 electrode) for wheel box weld repairs. Remove material to sound metal by gouging or grinding. Use Vee preparation to achieve minimum desired weld size.
- Slightly deformed plates may be left as-is until gate refurbishment, unless the deformations affect the weld procedure, or are anticipated to affect gate operational clearances with the embedded parts.

- Consider drilling holes through the skinplate and end plates to allow for water drainage since the gate is currently not water tight. Location of holes to be determined.
- Touch up paint around welds and drain holes to prevent corrosion using a compatible coating system.

We have attached a PDF file that maps general gate cracking locations and have included below a few excerpts (three images) of the original gate drawings with mark-ups of weld details that can be used to approach local fabricators for possible pricing for the repairs.







Please let us know your thoughts and please don't hesitate to call to further discuss any of above and next steps.

Regards,
Jon

Jonathan Atkinson, P.Eng., M.Eng.
Project Manager / Water Power

Tel: +1 780 392 1244
9888 Jasper Avenue NW, Suite 1100, Edmonton
Alberta Canada T5J 5C6

CI Number: 51235

Title: HYD Wreck Cove Main Access Road Refurbishment

Start Date: 2017/06
In-Service Date: 2018/10
Final Cost Date: 2019/04
Function: Hydro
Forecast Amount: $2,686,075

DESCRIPTION:

This project is for the design and refurbishment of a section of the main access road (Highland Road) to the Wreck Cove Generating Station. Highland Road connects Highway 312 Cabot Trail to the Wreck Cove Generating Station, and is the property of NS Power.

The section of road was originally constructed in 1978 and underwent asphalt and settlement repairs in 1997. To extend the life of the roadway and to ensure safe access to the Hydro System the road requires refurbishments. This includes improvements to the road surface and drainage system, replacement of the guard rails and protection from potential rock falls. The embankment also requires repairs.

Summary of Related CIs +/- 2 years
2016 CI 50151 WRC Main Access Road Bridge Replacement $716,508

Depreciation Class: Hydro Production Plant- Wreck Cove Hydro System

Estimated Life of the Asset: 50 Years

JUSTIFICATION:

Justification Criteria: Health & Safety

Why do this project?

This project is for the design and rehabilitation of a section of the main access road (Highland Road) to the Wreck Cove Generating Station. Highland Road was originally constructed in 1978 and underwent asphalt and settlement repairs in 1997. Required repairs include improvements to the road surface and drainage system, replacement of the guard rails and protection from potential rock falls. Currently, the outside lane of the access road is restricted due to potential for slope failure, as this road has a steep slope on one side, where rock falls could take place. Heavy equipment (loaders, snow plows, etc.) carrying significant loads can be required on the site and the access road requires upgrades to be able to safely handle this equipment.

Why do this project now?

A recent road inspection (Attachment 1) indicated that the asphalt has deteriorated in places, the guard rail has shifted in some areas, and a significant quantity of loose rock has fallen onto the roadway and into the ditch. Additional loose rock threatens the safety of the roadway, due to falling rock. The inspection also recommended a lane closure for a section of the access road.

Why do this project this way?

Road upgrades are required to provide safe access to the Wreck Cove Generating Station. The only feasible option is to resurface the access road, replace the guardrail and refurbish the failed slope section.

CI Number : 51235-H823 - HYD Wreck Cove Main Access Road Refurbishment

Project Number 51235-H823

Parent CI Number :

Asset Location : 1361 - 1361 Wreck Cove Common Property

Budget Version 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0300 - HGP - Bldg.,Struct.Grnd.	2,292,946
Retirements	0300 - HGP - Bldg.,Struct.Grnd.	393,129
	Total Cost:	2,686,075
	Original Cost:	763,838

Capital Project Detailed Estimate

Location: Hydro
FP# / P# 51235
Title HYD Wreck Cove Main Access Road Refurbishment
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Hydro River Staff - Construction	day	35	365	$ 12,768		
Engineering Staff	day	59	405	$ 24 026		
Environmental Staff	day	20	332	$ 6,642		
			Sub-Total	$ 43,436		
Travel Expenses						
Site Visit	Weeks	18	$ 150	$ 2,700		
			Sub-Total	$ 2,700		
Materials						
Road Surface Rehabilitation	%	50%	[redacted]		Cost Support #1 - Page 3	
Guiderail Replacement	Lot	1			Cost Support #1 - Page 3	
Drainage Reinstatement	%	25%			Cost Support #1 - Page 3	
Downslope Embankment Stabilization	%	50%			Cost Support #1 - Page 3 (Low Cost)	
			Sub-Total			
Contracts						
Upslope Remediation	Lot	1	[redacted]		Cost Support #1 - Page 3 (High Cost)	
Road Surface Rehabilitation	%	50%			Cost Support #1 - Page 3	
Drainage Reinstatement	%	75%			Cost Support #1 - Page 3	
Downslope Embankment Stabilization	%	50%			Cost Support #1 - Page 3 (Low Cost)	
			Sub-Total			
Consulting						
Downslope Embankment Geotechnical Investigation	Lot	1	[redacted]		Cost Support #1 - Page 3	
Road Assessment	Lot	1	$ 26,802	$ 26,802		
Construction Management	Month	4	$ 3 000	$ 12 000		
			Sub-Total	[redacted]		
Meals						
Site Visit	week	16	$ 75	$ 1,200		
			Sub-Total	$ 1,200		
Other Goods and Services						
Contingency	%	[redacted]		$ 214,960		
			Sub-Total	$ 214,960		
Interest Capitalized						
AFUDC				$ 29,948		
			Sub-Total	$ 29,948		
Administrative Overhead						
Labor AO				$ 19,640		
Contract AO				$ 139,289		
			Sub-Total	$ 158,930		
			Sub-Total (no AO, AFUDC)	$ 2,497,198		
			TOTAL (AO, AFUDC included)	$ 2,686,075		
Original Cost				$ 763,838		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

Stantec

Memo

To:	Colin MacDonald, P.Eng.	From:	Maureen Matthew, P.Geo.
	Nova Scotia Power Inc.		Stantec Consulting Ltd.
File:	Wreck Cove Main Access Road Assessment Project No. 121620755	Date:	August 11, 2017

Reference: Wreck Cove Main Access Road Assessment
Class D Cost Estimate for Upgrades and Maintenance

INTRODUCTION

Stantec Consulting Ltd. (Stantec) was retained by Nova Scotia Power Inc. (NSPI) to provide consulting engineering services for the Wreck Cove Main Access Road Assessment, at the Wreck Cove Hydro Station, Cape Breton, NS.

NSPI has identified that the main access road (Highland Road) requires upgrading to extend the service life and improve safety along the main access to the Wreck Cove Hydro Station. Components of the road that have been identified for assessment include: the asphalt driving surface, guard rails, road drainage system, overburden slopes and rock cuts (upslope), and the downslope embankment.

Stantec understands that NSPI requires a cost estimate for the recommended remedial measures to upgrade Highland Road for 2018 capital expenditure planning. This memo will be followed by a full Condition Assessment Report that provides details on the work completed, site conditions, engineering analyses, and recommendations for remediation. However, in consideration of NSPI's requirement for cost estimates for internal planning purposes, this memo is provided with Class D cost estimates on all recommended component upgrades in advance of the full report.

ASSESSMENT SUMMARY

Upslope Remediation

An evaluation of the upslope overburden slopes and rock cuts has been carried out. The road has been subdivided into sections of high, moderate, and low risk associated with rock slope/soil instabilities that may impact the road.

Two options for remediation of the upslope area are provided for consideration:

- Concrete Barrier option (low cost) to include:
  - Installation of a concrete jersey barrier along the high-risk sections of the road;
  - Installation of rock anchors in select areas to stabilize larger rock blocks;
  - Manual scaling of the rock face and slope crest along the entire road length; and
  - Clearing the catchment ditch of accumulated debris along the entire road length.

Reference: Wreck Cove Main Access Road Assessment
Class D Cost Estimate for Upgrades and Maintenance

- Rock Slope Netting option (high cost) to include:
  - Installation of a secured rock slope drapery system over the high-risk section of the road;
  - Installation of rock anchors in select areas to stabilize larger rock blocks;
  - Manual scaling of the rock face and slope crest along the entire road length; and
  - Clearing the catchment ditch of accumulated debris along the entire road length.

Option 1 (low cost) can be constructed by a local experienced contractor. Based on our analyses, this measure can provide over 90% catchment of anticipated rock fall events, with some requirement for ongoing maintenance and ditch clean out. Option 2 (higher cost) will require installation by a specialized contractor, however, the slope will be more actively stabilized and rockfall events minimized.

Road Surface Rehabilitation

A visual assessment and intrusive investigation was carried out to assess the condition of the road surface and subgrade. The results of the investigation and subsequent laboratory testing and analysis indicate that the existing road structure does not meet the required strength for a 20-year pavement design for the anticipated traffic loadings. The pavement design was carried out in accordance with the 1993 AASHTO Guide for the Design of Pavement Structures.

Stantec recommends a full depth reconstruction for the entire length of the study section. Full depth reconstruction will address the inadequate strength of the existing pavement structure, the lack of drainage observed, and the potential realignment and/or widening.

Civil Engineering Assessment

Stantec's civil engineering team has completed an assessment of the roadway alignment, guardrail condition, and drainage features as part of the project. Based on the results of the site visit and review, the following components are proposed for remediation:

- Guiderail Replacement to include:
  - Removal of existing double wire guide rail system; and
  - Installation of W-beam guide rail.

- Drainage Reinstatement to include:
  - Clearing vegetation and debris within 3 culverts;
  - Replacement of 2 culverts;
  - Repair of downstream outlet area of 1 culvert; and
  - Ditch regrading and reinstatement.

Downslope Embankment Assessment

Assessment of the downslope embankment was not included as part of the original scope of work. During the initial site visits, tension cracks were observed in the road surface near the crest of the downslope embankment. The presence of these cracks indicated potential slope instability, however, the mechanism of failure is currently unknown.

Stantec

August 11, 2017
Colin MacDonald, P.Eng.

Reference: Wreck Cove Main Access Road Assessment
Class D Cost Estimate for Upgrades and Maintenance

An additional site reconnaissance was completed by senior geotechnical personnel and a proposal for further geotechnical investigation and stability analysis has been provided to NSPI. The investigation will be required prior to developing recommendations for remediation. The cost of this additional work is included in the attached Class D cost estimate, Table 1.

As the downslope stability has not been fully assessed at this time, a conceptual remedial approach has been utilized for the purpose of the cost estimate for the Highland Road upgrade. The concept assumes that each area of potential downslope instability is stabilized using a retaining wall. A general cost estimate for this approach is provided in Table 1.

Table 1 Class D Cost Estimate for Highland Road Upgrades

Remediation Component	Class D Cost Estimate (excl. HST)	
	Option 1 (Low Cost)	Option 2 (High Cost)
Upslope Remediation	[redacted]	
Road Surface Rehabilitation		
Guiderail Replacement		
Drainage Reinstatement		
Downslope Embankment Geotechnical Investigation		
Downslope Embankment Stabilization (Conceptual)[1]		
TOTAL CLASS D (LOW COST)		
TOTAL CLASS D (HIGH COST)		

Note: 1) The cost estimate associated with downslope embankment stabilization is based on a conceptual remedial model and has not been verified by a geotechnical investigation, analysis and design. Subject to change.

We trust this information meets your present requirements. If you have any questions or concerns on the information provided, please do not hesitate to contact the undersigned at your convenience.

STANTEC CONSULTING LTD.

MC Matthew

Maureen Matthew, M.Sc., P.Geo.
Engineering Geologist
Phone: (902) 468-7777
Fax: (902) 468-9009
Maureen.Matthew@stantec.com

Stantec Consulting Ltd.
102-40 Highfield Park Drive, Dartmouth NS B3A 0A3

August 3, 2017
File: 121620755

Attention: Mr. Colin MacDonald, P.Eng., Civil Project Engineer
Nova Scotia Power Hydro and Wind Energy
1223 Lower Water Street
Halifax NS B3J 3S8

Dear Mr. MacDonald,

Reference: Highland Road Geotechnical Embankment Fill Slope Stability Review Site Reconnaissance, Wreck Cove Main Access Road Assessment, Nova Scotia

Stantec Consulting Ltd. (Stantec) has performed a site reconnaissance comprising a visual review of the crest area of the current Highland Road embankment surface for evidence of potential critical global instability associated with the roadway embankment fill. This letter reports the findings of our visual review along with recommendation and associated estimated costs to conduct further detailed *in situ* investigation, monitoring, and analyses of critical areas identified for potential global instability.

We understand the roadway was constructed circa 1978 and the asphalt along the southern lane has been subsequently resurfaced. We understand that no deep-seated slope failures are known to have occurred within the embankment along the roadway alignment.

The visual review was completed on July 19, 2017. The road surface and southern shoulder were visually reviewed for evidence of longitudinal cracking and anomalies of sloughing and/or excessive settlement/depressions which could suggest potential slope instability. During our visual review, four locations were identified as showing some indication of potential slope instability. The general locations of the four areas, indicated as Site 1 to Site 4, are shown on the attached Figure No. 1. Also attached are photos of each site area. Longitudinal cracking in the asphalt surface and significant tipping of the guiderail post down slope were observed in each of these areas. The length of each area was approximately 14 m at Site 1, 27 m at Site 2, 19 m at Site 3 and 90 m at Site 4.

The asphalt cracking and guiderail tipping may be a result of shallow localized displacement of the embankment fill or possibly more critical deeper seated global slope instability. We therefore recommend that a more detailed slope stability assessment and evaluation of these areas be undertaken to assess the cause. As previously noted in our July 6, 2017 email correspondence, immediate precautionary measures are recommended at Site 3, at least until the more detailed assessment and evaluation is completed which will provide a better understanding of the cause of the asphalt cracking and settlement in this area.

For the more detailed slope stability assessment and evaluation, topographic survey of the slope cross-sections, a series of boreholes, some fitted with slope inclinometer casings for monitoring lateral ground movement, and slope stability modeling are recommended. The recommended work scope for the program comprises:

- Detailed topographic cross-sections that extend across the crest of the road embankment and out beyond the toe of slope at each of the four site locations.

Reference: Highland Road Geotechnical Embankment Fill Slope Stability Review Site Reconnaissance, Wreck Cove Main Access Road Assessment, Nova Scotia

- A series of fully sampled geotechnical boreholes put down into bedrock at Sites 1, 3 and 4. Boreholes are recommended within each road shoulder at each site. One borehole is also recommended at the slope toe of Site 1, which is accessible from the lower road. The boreholes will provide information on the subsurface embankment conditions which will be utilized to develop the slope stability model.
- Installation of slope inclinometer casings within the southern shoulder boreholes at Site 1, 3 and 4 along with a longer-term monitoring program. The inclinometer casings will provide a means of monitoring for deeper lateral ground movement. Measurements can be taken over time to observe ground displacement relative from the time of initial installation. An initial baseline set of slope inclinometer measurements will be completed following installation. Subsequent monitoring will be completed on a quarterly basis for a year and then semi-annually for a year (initial monitoring event plus 6 additional monitoring events).
- Installation of standpipe for groundwater level measurement and monitoring in all other boreholes. The location of the groundwater table will be utilized in the slope stability modelling.
- Engineering analysis principally comprising slope stability assessment using Geo-Slope's Slope/W software program with models developed from the borehole and topographic survey data.
- A geotechnical engineering report detailing all findings and comments/recommendations on the slope stability of each Site.
- A brief letter report will be provided subsequent to the geotechnical report following the obtainment of each slope inclinometer data set.

Estimate of probable costs to complete the work scope outline herein is summarized as follows:

Topographical Cross-Section Survey
Traffic Control, Four Days (3rd Party)
Drill Rig Rental and Operation, Four Days (3rd Party)
Field Supplies (inclinometer casing, standpipe, well covers)
Field Technician for Planning, Coordinating and Drilling, Five Days
Slope Inclinometer Measurements (6 events) and Reporting
Project Management, Engineering and Reporting

TOTAL (excluding HST) [redacted]

Stantec will engage Design Point Engineering & Surveying to completed the topographic cross-sections at each site.

Prior to mobilizing to the site to conduct the boreholes, Stantec will require confirmation from NSPI that no underground utilities are present in the immediate area of the proposed borehole locations.

All boreholes would be laid out, surveyed, and logged in the field by Stantec geotechnical personnel. Boreholes would be advanced using a geotechnical drill rig operated by a locally subcontracted geotechnical drilling company. Soils would be sampled throughout the borehole depth and bedrock would be cored using diamond bit rotary methods. Upon completion of the

Reference: Highland Road Geotechnical Embankment Fill Slope Stability Review Site Reconnaissance, Wreck Cove Main Access Road Assessment, Nova Scotia

boreholes, slope inclinometer casings and stand pipes will be installed as previously noted. The casings and standpipes will be cut-off near flush with the ground surface.

We would require up to about 2 weeks' lead time to conduct planning and utility locates prior to commencing surveying and drilling of the boreholes. We estimate that up to four days will be required to complete drilling of the seven boreholes. Following completion of the field work, we would be able to complete and issue a geotechnical report within three weeks.

This letter was prepared by Brian T. Grace, P.Eng., and reviewed by Mark Bochmann, P.Eng. We trust that the information contained in this report is adequate for your present purposes. If you have any questions about the contents of the report or if we can be of any other assistance please contact us at your convenience.

Yours truly,

STANTEC CONSULTING LTD.

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Attachments: Figure No. 1, Road Embankment Stability Review Locations
Photo Pages (4)

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2017/07/25 2:35 PM By: Pinnell, Brian

ORIGINAL SHEET - ISO A3

JULY, 2017
121620755

Stantec

102 - 40 HIGHFIELD PARK DRIVE,
DARTMOUTH, NS
www.stantec.com

Legend
★ REVIEW LOCATION

0 50 100 200m
BAR SCALE
1:5000

Notes
REFERENCE: GOOGLE EARTH 2017

Client/Project
NSPI
WRECK COVE MAIN ACCESS ROAD ASSESSMENT
ROAD EMBANKMENT STABILITY REVIEW, WRECK COVE, NS

Figure No.
1

Title
ROAD EMBANKMENT STABILTY
REVIEW LOCATIONS

Photo No. 1: Site 1 West Looking East

Photo No. 2: Site 1 Toe Area

Photo No. 3: Site 2 West Looking East

Photo No. 4: Site 2 East Looking West

Photo No. 5: Site 3 West Looking East

Photo No. 6: Site 3 East Looking West

Photo No. 7: Site 4 West Looking East

Photo No. 8: Site 4 East Looking West

CI Number: 51234

Title: HYD Wreck Cove HVAC Upgrade

Start Date: 2017/04
In-Service Date: 2019/08
Final Cost Date: 2020/02
Function: Hydro
Forecast Amount: $1,876,537

DESCRIPTION:

This project will upgrade the Heating, Ventilation and Air Conditioning (HVAC) system of the Wreck Cove Hydro Generating Station, replacing two dehumidification units, which no longer operate as intended. Additionally, NS Power will upgrade several fans; install new fans for un-serviced areas and a system to measure the quality of the air inside the plant. This will address the year round humidity issues in the plant, and the replacement unit's ability to measure air quality will improve the safety of operations.

NS Power has operated the hydroelectric station at Wreck Cove since 1978, producing approximately 330 GWh annually. Wreck Cove is a very important plant for wind following, peak capacity and fast response on the system.

Summary of Related CIs +/- 2 years:
No other projects in 2016, 2017, 2018, 2019 and 2020

Depreciation Class: Hydro Production Plant- Wreck Cove Hydro System

Estimated Life of the Asset: 40 Years

JUSTIFICATION:

Justification Criteria: Hydro, Wind and Biomass

Why do this project?

The original HVAC system is 40 years old and has undergone multiple repairs since the early 1990s. The HVAC system is important for efficient operation of the plant. Potential operational problems such as deterioration from high temperature and humidity are minimal with a functional air quality system. As well, being an underground facility, the quality of the air can be measured using mining air quality measurement equipment that follows mining air standards. The upgrade will include two air handler units (AHU) with dehumidification capacity, and fans and ducts to distribute fresh air to the underground powerhouse. The main supply fans will be located in the access tunnel portal building on the surface. These fans supply a mix of outside and recycled air through ductwork to the power plant, which then returns air back up the access tunnel for re-mixing. Please refer to Attachment 1 for a report on temperature and humidity at the Wreck Cove Hydro Station.

Why do this project now?

Major life extension work is currently planned for the Wreck Cove site in the next 3-4 years. Upgrades will address issues with the generating equipment within the plant, mitigate roof leakage, and improve working conditions in the plant to comply with regulatory requirements and current standards. The HVAC of the plant must be upgraded to ensure equipment maintenance efforts and plant working conditions are addressed before major reinvestment work begins. More workers are expected to occupy the space underground to support capital work activities.

Why do this project this way?

The existing AHUs will move air, but no longer dehumidify. Refurbishment of these units is costly and difficult due to their age. As such, installation of new and more efficient units is the desirable option. To optimize the use of those units, some fans must also be upgraded. As well, to comply with standards for underground facilities, it is necessary to install an air quality measuring system.

CI Number : 51234-H822 - HYD Wreck Cove HVAC Upgrade **Project Number** 51234-H822

Parent CI Number : -

Asset Location : 1361 - 1361 Wreck Cove Common Property **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0300 - HGP - Bldg.,Struct.Grnd.	1,872,499
Retirements	0300 - HGP - Bldg.,Struct.Grnd.	4,038
	Total Cost:	1,876,537
	Original Cost:	541,207

Capital Project Detailed Estimate

Location: Hydro
FP# / P#: 51234
Title: HYD Wreck Cove HVAC Upgrade
Execution Year: 2018-2019

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Hydro River Staff - Construction	day	35	365	$ 12,768		
Engineering Staff	day	94	405	$ 38,053		
			Sub-Total	$ 50,820		
Travel Expenses						
Site Visit	Week	23	$ 300	$ 6,900		
			Sub-Total	$ 6,900		
Materials						
Dehumidification Air handling units (2)	Ea	2	$ 500,000	$ 1,000,000		CI 48052 - Annapolis HVAC Upgrade
HVAC Control Panel	Lot	1	$ 43,500	$ 43,500		
Air Quality Monitoring System	Lot	1	$ 75,000	$ 75,000		
			Sub-Total	$ 1,118,500		
Contracts						
Installation of Dehumidification AHU	Lot	1	$ 50,000	$ 50,000		
Upgrades to the HVAC System	Lot	1	$ 50,000	$ 50,000		CI 48052 - Annapolis HVAC Upgrade
Inspection contract	Lot	1	$ 46,000	$ 46,000		
HVAC Control Panel	Lot	1	$ 13,343	$ 13,343		
Air Quality Monitoring System	Lot	1	$ 75,000	$ 75,000		
			Sub-Total	$ 234,343		
Consulting						
STANTEC - Roof leakage	Lot	1	$ 49,158	$ 49,158		
STANTEC - HVAC upgrades design	Lot	1	$ 62,300	$ 62,300		
Trimac - HVAC panel design	Lot	1	$ 6,781	$ 6,781		
			Sub-Total	$ 118,239		
Meals						
Site Visit	Weeks	23	$ 150	$ 3,450		
			Sub-Total	$ 3,450		
Other Goods and Services						
Contingency	%	15%	$ 1,532,253	$ 229,838		
			Sub-Total	$ 229,838		
Interest Capitalized						
AFUDC				$ 69,425		
			Sub-Total	$ 69,425		
Administrative Overhead						
Labour AO				$ 23,555		
Contracts AO				$ 21,466		
			Sub-Total	$ 45,021		
			Sub-Total (no AO, AFUDC)	$ 1,762,091		
			TOTAL (AO, AFUDC included)	$ 1,876,537		
Original Cost				$ 541,207		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

NSPI Wreck Cove Power Plant
Temperature and Relative Humidity Readings
Draft Report

Source: https://www.nspower.ca

170421.00RE01 ● Draft Report ● October 2017

Prepared for:

Nova Scotia POWER
An Emera Company

Prepared by:

CBCL LIMITED
Consulting Engineers

Issued for Review	T. Watson	10/12/17	M. Casimirri
Issue or Revision	***Reviewed By:***	***Date***	***Issued By:***

CBCL LIMITED
Consulting Engineers

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EXECUTIVE SUMMARY

In September 2017, CBCL Limited was engaged to deploy temperature and relative humidity (RH) loggers in five different areas at the Wreck Cove Power Plant. Such areas included the main level, second level, third level, fourth level, and the generator. Data loggers were deployed in specific locations in each of the aforementioned areas at the request of the NS Power representative. Temperature and RH levels were recorded from September 20, 2017 until October 3, 2017. The collected data was assessed according to ASHRAE Standard 55-2013 to determine if the average conditions comply with the acceptable ranges of operative temperature and humidity for people in typical clothing and activity level at the plant.

According to the results from the different assessments, four (4) of the five (5) areas comply with ASHRAE 55-2013. Only one of the areas, Area 4 on the fourth level, does not meet the standard requirements. Lower temperature conditions and higher relative humidity in this area could be addressed by reviewing the heating and dehumidification provided for this space. Table 0.1 shows a summary of the findings for each of the five areas under study.

Table 0.1: Summary – Analytical Comfort Zone Method ASHRAE 55-2013

VARIABLES	VARIABLES	PMV	PPD	SENSATION	SET	COMPLIES
AREA #1 MAIN LEVEL – AVERAGE T °C	22.6	0.24	6%	Neutral	26.3°C	Yes
AREA #1 MAIN LEVEL – AVERAGE %RH	56.0					
AREA #2 SECOND LEVEL – AVERAGE T °C	22.1	0.15	5%	Neutral	26°C	Yes
AREA #2 SECOND LEVEL – AVERAGE %RH	58.7					
AREA #3 THIRD LEVEL – AVERAGE T °C	21.5	0.04	5%	Neutral	25.5°C	Yes
AREA #3 THIRD LEVEL – AVERAGE %RH	62.3					
AREA #4 FOURTH LEVEL – AVERAGE T °C	17.5	-0.75	17%	Slightly Cool	21.7°C	No
AREA #4 FOURTH LEVEL – AVERAGE %RH	81.6					
AREA #5 GENERATOR – AVERAGE T °C	23.5	0.35	7%	Neutral	26.5°C	Yes
AREA #5 GENERATOR – AVERAGE %RH	40.2					

It is worth mentioning that indoor temperature and RH levels are most likely to be higher during the warmest periods in July and August. Also, an assessment that includes mean radiant temperature and air speed measurements, as well as occupant surveys (according to ASHRAE 55-2013 section 7) would

yield better information to determine the thermal comfort conditions in these areas. Nevertheless, ambient temperatures ranged from a high of 27.4°C to a low of 0°C for the testing period. A wide range of ambient conditions were monitored and the space dry bulb temperature represents a reasonable approximation for the operative temperature in the spaces with low air speeds and minimal radiant heat.

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Appendices

A Area #1 – Recorded Temperature and Relative Humidity

B Area #2 – Recorded Temperature and Relative Humidity

C Area #3 – Recorded Temperature and Relative Humidity

D Area #4 – Recorded Temperature and Relative Humidity

E Area #5 – Recorded Temperature and Relative Humidity

CHAPTER 1 OVERVIEW

1.1 Purpose of Study

Five different areas at the Wreck Cove Power Plant were selected, by NS Power personnel, to record the temperature and relative humidity (RH) levels for at least seven consecutive days. The objectives of this study were:

- To deploy temperature and RH loggers.
- To create graphs and tables that include the collected data for each one of the areas under study.
- To determine if the average conditions in each area are within the acceptable ranges of operative temperature and RH for people in typical clothing and activity level at the plant, according to ASHRAE Standard 55-2013.

Mr. Paul Breski (NSPI) was on site to escort CBCL staff through the power plant during the walkthrough portion of the site visit and the deployment of the data loggers.

1.2 Studied Areas

The five areas under study included the main level, second level, third level, fourth level, and the generator. Data loggers were installed in specific locations in each of the aforementioned areas as requested by the NS Power representative.

1.3 Methodology

The methodology to complete this study is described as follows:

- Data loggers were installed in specific locations in each of the areas as per NS Power personnel request.
- Temperature and RH was recorded every ten minutes, starting at 18:00 hours on September 20, 2017.
- Logging devices were removed on October 4, 2017.
- The study considered the data recorded until October 3, 2017 at 18:00 hours.
- Graphs showing the recorded data and the outside conditions from the Ingonish Beach RSC weather station were created for each area.
- Tables showing the maximum, minimum, and average temperatures and RHs were created.

- Average conditions for each area were assessed with the CBE/ASHRAE Thermal Comfort Tool according to the ASHRAE 55-2013 acceptable thermal environment conditions. Mean radiant temperature, air speed, metabolic rate, and clothing level were assumed to complete the assessment.

1.4 Temperature and RH Loggers Summary

Temperature and humidity levels in each area were recorded with the following equipment:

- HOBO U12-012 temperature/RH/light logger
- HOBO UX100-003 temperature/RH logger
- HOBO U14-001 temperature/RH logger
- MTP ST-171s temperature/RH logger

According to information provided by HOBO manuals, "*the U family of data loggers offers reliability and convenient monitoring for applications that require higher accuracy, better resolution, more memory, or USB connectivity for fast data readout to your computer*"[1].

[1] http://www.onsetcomp.com/files/manual_pdfs/13416-A-MAN-U14-00x.pdf. Retrieved on 05-Oct-2017, 05-Oct-2017, Halifax NS.

CHAPTER 2 STANDARD

2.1 Overview

The six factors in steady state that shall be addressed when defining conditions for acceptable thermal comfort include:

- Metabolic rate (met)
- Clothing insulation (clo)
- Air temperature
- Radiant temperature
- Air speed
- Humidity

ASHRAE 55-2013 provides the conditions for acceptable thermal environments, which involves the use of the ASHRAE thermal sensation scale (refer to Table 2.1). This scale assigns words describing the thermal sensation felt by a person to a corresponding number.

Table 2.1: Thermal Sensation Scale

3	Hot
2	Warm
1	Slightly warm
0	Neutral
-1	Slightly cool
-2	Cool
-3	Cold

The ASHRAE thermal sensation scale is part of the "Analytical Comfort Zone Method". This method applies to all spaces where occupants have activity levels that translate in average metabolic rates between 1.0 and 2 met, where clothing is worn that provides 1.5 clo or less of thermal insulation, and where the average air speed is between 0.15 m/s (30 fpm) and 1.2 m/s (240 fpm).

The standard includes energy balance equations that have been developed to use the predicted mean vote (PMV) index. The PMV index forecasts the mean response of a large group of people following the ASHRAE thermal sensation scale. The predicted percentage dissatisfied (PPD) index is related to the PMV. ISO Standard 7730 includes a computer listing for allowing the calculation of PMV and PPD for a large range of variables. The recommended PPD and PMV range for typical applications are presented in Table 2.2. These values are the basis for the graphical and analytical comfort zone methods used in ASHRAE Standard 55-2013.

Table 2.2: Acceptable Thermal Environment for General Comfort

PPD	PMV RANGE
<10	-0.5 < PMV < +0.5

ASHRAE permits the use of the Thermal Comfort Tool to comply with the Analytical Comfort Zone Method. The Thermal Comfort Tool provides user friendly interface for calculating PPD and PMV values for certain conditions. The tool is available at the Center for the Built Environment (CBE), University of California Berkeley website.

CHAPTER 3 ANALYSIS

3.1 Assumptions

The recorded air temperature and RH in each area, as well as mean radiant temperature, air speed, metabolic rate (met), and clothing insulation (clo) are considered in the Comfort Thermal Tool to assess the acceptable thermal environment conditions. Out of these variables, only air temperature and RH were measured, the other factors were given assumed values as follows:

- Mean radiant temperature (tr): ASHRAE 55-2013, section 7.2.2.1.a. indicated that mean radiant temperature should be measured, unless it can be otherwise demonstrated that tr is within 1°C (2°F) of air temperature (ta). For the purpose of the study, it will be assumed that tr=ta and the locations of sensors were generally positioned to avoid the impact of radiant heat.
- Air speed: Calculations were completed on the assumption of still air conditions, reference figure 5.3.3A from ASHRAE 55-2013, reproduced below.

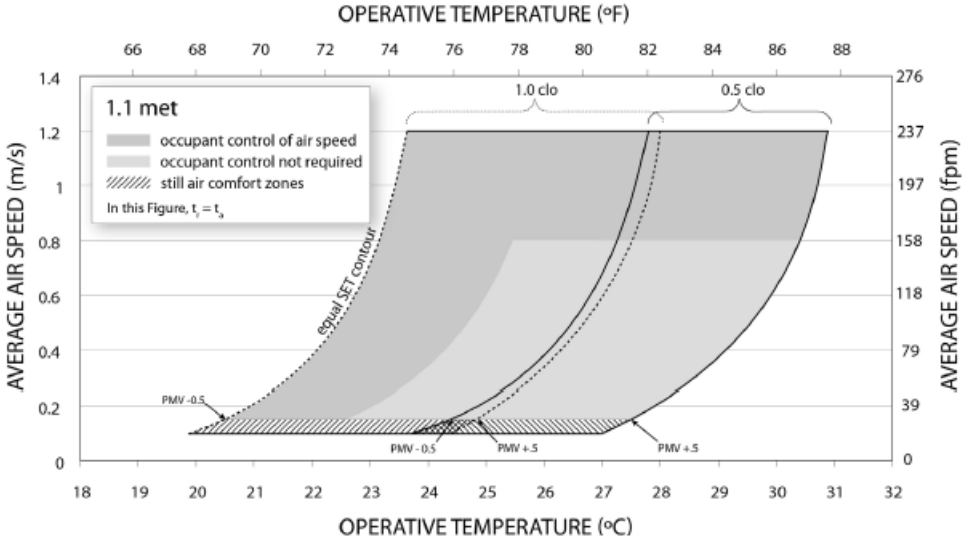

FIGURE 5.3.3A Acceptable ranges of operative temperature (t_o) and average air speed (V_a) for the 1.0 and 0.5 clo comfort zone presented in Figure 5.3.1.1, at humidity ratio 0.010.

Figure 3.1: Figure 5.3.3A – ASHRAE 55-2013

- Metabolic rate (met): Considering table 5.2.1.2 from ASHRAE 55-2013, met for light activity in the electrical industry is 2.0, whereas for a standing person met is 1.2. Considering the different activity levels at the power plant, an average met of 1.6 was used.
- Clothing insulation (clo): The clo value was estimated to be ABC based on ambient conditions at 06:00 hours, figure 5.2.2.2 from ASHRAE 55-2013, and the assumption that working conditions allow for some flexibility to match clothing to the working environment.

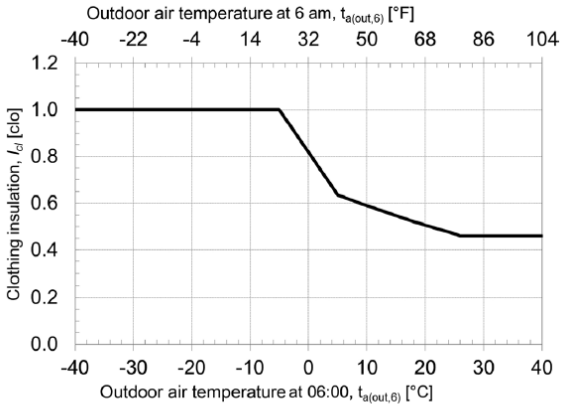

FIGURE 5.2.2.2 Representative clothing insulation (I_{cl}) as a function of outdoor air temperature at 06:00 a.m.

Figure 3.2: Figure 5.2.2.2 – ASHRAE 55-2013

3.2 Area #1 – Main Level

The temperature and humidity logger was installed on a column as per the client's suggestion. The following pictures illustrate the location of the data logger.

Figure 3.3: Area #1 Main Level – Location of Data Logger HOBO1

Table 3.1 includes the maximum, minimum, and average temperature and RH recorded in Area #1, as well as the outside condition during the same period of time. Appendix A presents a graph with the recorded data, which shows a slight change in temperature but significant RH variation throughout the one week period between September 20, 2017 and September 27, 2017. The change in indoor relative humidity was probably a result of large ambient temperature changes and steady interior temperatures during the test period.

Table 3.1: Temperature and RH Readings in Area #1

VARIABLES	MAX	DATE	MIN	DATE	AVG
OUTSIDE AIR TEMP °C	26.9	26/09/2017 12:00	1.3	01/10/2017 4:00	13.1
OUTSIDE %RH	92	22/09/2017 6:00	25	23/09/2017 10:00	73.6
AREA #1 MAIN LEVEL - T °C	23.2	26/09/2017 14:00	21.3	21/09/2017 13:00	22.6
AREA #1 MAIN LEVEL. - %RH	76.4	28/09/2017 6:00	36.9	03/10/2017 15:00	56.0

The ASHRAE Thermal Comfort Tool was used to determine if the average conditions in this area comply with ASHRAE 55-2013 according to the "Analytical Comfort Zone Method". The results are presented in Table 3.2. The Standard Effective Temperature (SET) model in the Thermal Comfort Tool was only used to evaluate comfort for air speed above 0.2 m/s (40 fpm).

Table 3.2: Area #1 – Analytical Comfort Zone Method ASHRAE 55-2013

VARIABLES	VARIABLES	PMV	PPD	SENSATION	SET	COMPLIES
AREA #1 MAIN LEVEL – AVERAGE T °C	22.6	0.24	6%	Neutral	26.3°C	Yes
AREA #1 MAIN LEVEL. – AVERAGE %RH	56.0					

According to the assumed mean radiant temperature, air speed, met, clo, and the average temperature and RH for this area, it was determined that the average conditions comply with ASHRAE standard 55-2013. Recorded data indicated that RH was higher than 60% for about 24% of the time. ASHRAE Standard 62 generally requires that for air conditioned spaces (it does not apply in non-air conditioned spaces), the relative humidity should be controlled to a maximum of 65%.

Figure 3.4, from the Thermal Comfort Tool, depicts the acceptable range of operative temperature and humidity for this area considering the average temperature and RH. Mean radiant temperature, air speed, met, and clo were assumed to be as described in Section 3.1 of this report. Figure 3.4 shows that the operating condition lies within the envelope of an acceptable thermal environment.

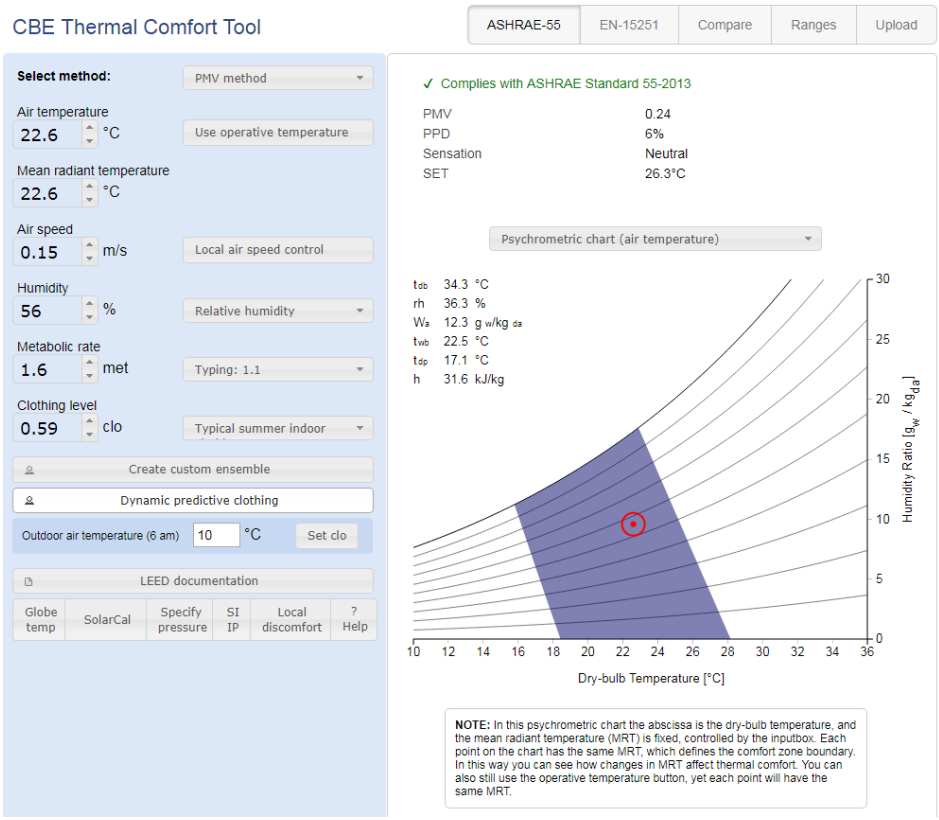

Figure 3.4: Area #1 – Acceptable Range of Operative Temperature and Humidity for the Average Conditions – ASHRAE Thermal Comfort Tool

3.3 Area #2 – Second Level

The temperature and humidity loggers were installed on the wall as per the client's suggestion. The photographs in Figure 3.5 show the location of the data loggers.

Figure 3.5: Area #2 Second Level – Location of Data Loggers HOBO2 and HOBO4

Table 3.3 includes the maximum, minimum, and average temperature and RH recorded in Area #2, as well as the outside condition during the same period of time. Appendix B presents a graph with the recorded data, which shows slight changes in temperature and significant RH variation throughout the one week period between September 20, 2017 and September 27, 2017. The change in indoor relative humidity was probably a result of large ambient temperature changes and steady interior temperatures during the test period.

Table 3.3: Temperature and RH Readings in Area #2

VARIABLES	MAX	DATE	MIN	DATE	AVG
OUTSIDE AIR TEMP °C	26.9	26/09/2017 12:00	1.3	01/10/2017 4:00	13.1
OUTSIDE %RH	92	22/09/2017 6:00	25	23/09/2017 10:00	73.6
AREA #2 SECOND LEVEL – T °C - 2	22.7	01/10/2017 16:50	20.7	23/09/2017 15:20	22.1
AREA #2 SECOND LEVEL. – %RH - 2	75.3	20/09/2017 19:50	38.9	03/10/2017 15:00	58.7

The ASHRAE Thermal Comfort Tool was used to determine if the maximum, minimum, and average conditions in this area comply with ASHRAE 55-2013 according to the "Analytical Comfort Zone Method". The results are presented in Table 3.4. The Standard Effective Temperature (SET) model in the Thermal Comfort Tool was only used to evaluate comfort for air speed above 0.2 m/s (40 fpm).

Table 3.4: Area #2 – Analytical Comfort Zone Method ASHRAE 55-2013

VARIABLES	VARIABLES	PMV	PPD	SENSATION	SET	COMPLIES
AREA #2 SECOND LEVEL – AVERAGE T °C	22.1	0.15	5%	Neutral	26°C	Yes
AREA #2 SECOND LEVEL – AVERAGE %RH	58.7					

According to the assumed mean radiant temperature, air speed, met, clo, and the average temperature and RH for this area, it was determined that the average conditions comply with the standard.

Recorded data indicated that the RH was higher than 60% for about 43% of the time. ASHRAE Standard 62 generally requires that for air conditioned spaces (it does not apply in non-air conditioned spaces), the relative humidity should be controlled to a maximum of 65%.

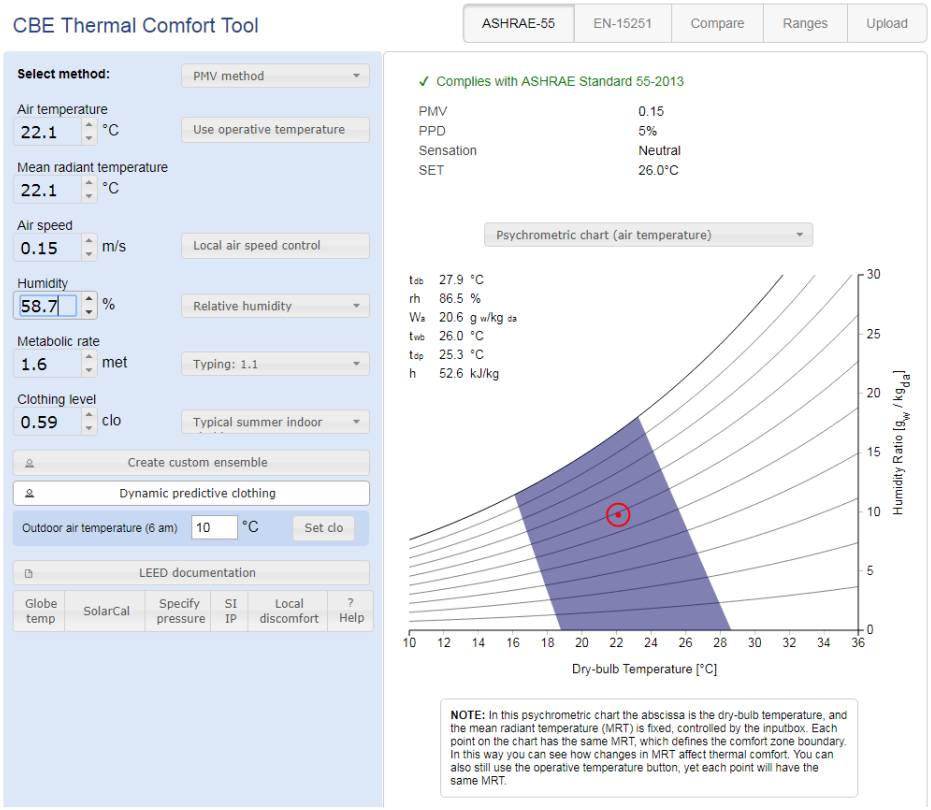

Figure 3.6: Area #2 – Acceptable Range of Operative Temperature and Humidity for the Average Conditions – ASHRAE Thermal Comfort Tool

Figure 3.6, from the Thermal Comfort Tool, depicts the acceptable range of operative temperature and humidity for this area considering the average temperature and RH. Mean radiant temperature, air speed, met, and clo were assumed to be as described in Section 3.1 of this report. Figure 3.6 shows that the operating condition lies within the acceptable thermal environment limits.

3.4 Area #3 – Third Level

The temperature and humidity loggers were installed on the wall above the entrance to the turbine pit as per the client's suggestion. The following photographs show the location of the data loggers.

Figure 3.7: Area#3 Third Level – Location of Data Loggers HOBO3 and HOBO5

Table 3.5 includes the maximum, minimum, and average temperature and RH recorded in Area #3, as well as the outside condition during the same period of time. Appendix C presents a graph with the recorded data, which shows slight changes in temperature and significant RH variation throughout the one week period between September 20, 2017 and September 27, 2017. The change in indoor relative humidity was probably a result of large ambient temperature changes and steady interior temperatures during the test period.

Table 3.5: Temperature and RH Readings in Area #3

VARIABLES	MAX	DATE	MIN	DATE	AVG
OUTSIDE AIR TEMP °C	26.9	26/09/2017 12:00	1.3	01/10/2017 4:00	13.1
OUTSIDE %RH	92	22/09/2017 6:00	25	23/09/2017 10:00	73.6
AREA #3 THIRD LEVEL – T °C - 3	22.8	03/10/2017 13:00	18.7	25/09/2017 11:00	21.5
AREA #3 THIRD LEVEL – %RH - 3	83.4	26/09/2017 18:40	39.3	03/10/2017 13:20	62.3

The ASHRAE Thermal Comfort Tool was used to determine if the maximum, minimum, and average conditions in this area comply with ASHRAE 55-2013 according to the "Analytical Comfort Zone Method". The results are presented in Table 3.6. The Standard Effective Temperature (SET) model in the Thermal Comfort Tool was only used to evaluate comfort for air speed above 0.2 m/s (40 fpm).

Table 3.6: Area #3 – Analytical Comfort Zone Method ASHRAE 55-2013

VARIABLES	VARIABLES	PMV	PPD	SENSATION	SET	COMPLIES
AREA #3 THIRD LEVEL – AVERAGE T °C	21.5	0.04	5%	Neutral	25.5°C	Yes
AREA #3 THIRD LEVEL – AVERAGE %RH	62.3					

According to the assumed mean radiant temperature, air speed, met, clo, and the average temperature and RH for this area, it was determined that the average conditions comply with the standard. Recorded data indicated that the RH was higher than 60% for about 82% of the time. ASHRAE Standard 62 generally requires that for air conditioned spaces (it does not apply in non-air conditioned spaces), the relative humidity should be controlled to a maximum of 65%.

Figure 3.8, from the Thermal Comfort Tool, depicts the acceptable range of operative temperature and humidity for this area considering the average temperature and RH. Mean radiant temperature, air speed, met, and clo were assumed to be as described in Section 3.1 of this report. Figure 3.8 shows that the operating condition lies within the acceptable thermal environment limits.

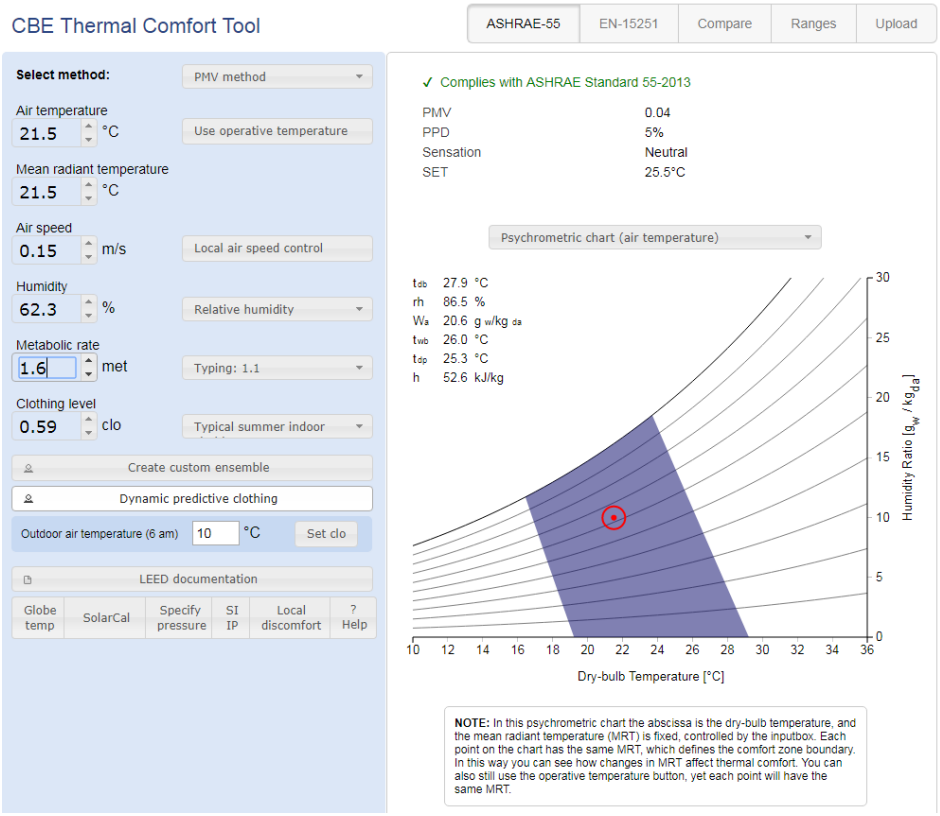

Figure 3.8: Area #3 – Acceptable Range of Operative Temperature and Humidity for the Average Conditions – ASHRAE Thermal Comfort Tool

3.5 Area #4 – Fourth Level

The temperature and humidity loggers were installed in the basement where the intake valves are located as per the client's suggestion. The following photographs show the location of the data loggers.

Figure 3.9: Area #4 Fourth Level – Location of Data Loggers HOBO1 and MTP1

Table 3.7 includes the maximum, minimum, and average temperature and RH recorded in Area #4, as well as the outside condition during the same period of time. Appendix D presents a graph with the recorded data, which shows slight changes in temperature and RH throughout the one week period between September 20, 2017 and September 27, 2017. The change in indoor relative humidity was probably a result of large ambient temperature changes and steady interior temperatures during the test period.

Table 3.7: Temperature and RH Readings in Area #4

VARIABLES	MAX	DATE	MIN	DATE	AVG
OUTSIDE AIR TEMP °C	26.9	26/09/2017 12:00	1.3	01/10/2017 4:00	13.1
OUTSIDE %RH	92	22/09/2017 6:00	25	23/09/2017 10:00	73.6
AREA #4 FOURTH LEVEL – T °C - 1	19.0	21/09/2017 5:50	15.6	23/09/2017 15:00	17.5
AREA #4 FOURTH LEVEL – %RH - 1	86.9	28/09/2017 5:40	72.6	03/10/2017 7:00	81.6

The ASHRAE Thermal Comfort Tool was used to determine if the maximum, minimum, and average conditions in this area comply with ASHRAE 55-2013 according to the "Analytical Comfort Zone Method". The results are presented in Table 3.8. The Standard Effective Temperature (SET) model in the Thermal Comfort Tool was used to evaluate comfort for air speed above 0.2 m/s (40 fpm).

Table 3.8: Area #4 – Analytical Comfort Zone Method ASHRAE 55-2013

VARIABLES	VARIABLES	PMV	PPD	SENSATION	SET	COMPLIES
AREA #4 FOURTH LEVEL – AVERAGE T °C	17.5	-0.75	17%	Slightly Cool	21.7°C	Do not
AREA #4 FOURTH LEVEL – AVERAGE %RH	81.6					

According to the assumed mean radiant temperature, air speed, met, clo, and the average temperature and RH for this area, it was determined that the average conditions do not comply with the standard. Occupants might find this area slightly cool. Recorded data indicated that the RH was higher than 80% for about 86% of the time. ASHRAE Standard 62 generally requires that for air conditioned spaces (it does not apply in non-air conditioned spaces), the relative humidity should be controlled to a maximum of 65%.

Figure 3.10, from the Thermal Comfort Tool, depicts the acceptable range of operative temperature and humidity for this area considering the average temperature and RH. Mean radiant temperature, air speed, met, and clo were assumed to be as described in Section 3.1 of this report. Figure 3.10 shows that the operating condition lies outside the acceptable thermal environment limits.

Lower temperature conditions and higher relative humidity in this area could be addressed by reviewing the heating and dehumidification provided for this space.

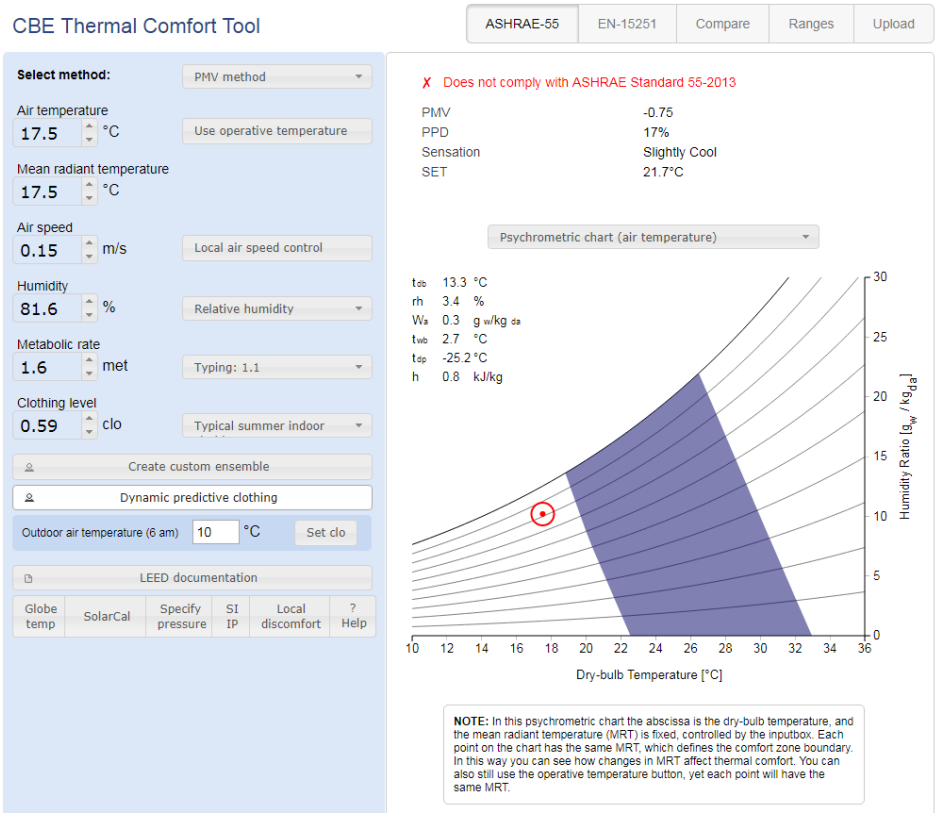

Figure 3.10: Area #4 – Acceptable Range of Operative Temperature and Humidity for the Average Conditions – ASHRAE Thermal Comfort Tool

3.6 Area #5 – Generator

The temperature and humidity logger was installed inside the generator room next to the entrance door as per the client's suggestion. The following photographs show the location of the data logger.

Figure 3.11: Area #5 Generator – Location of Data Logger HOBO7

Table 3.9 includes the maximum, minimum, and average temperature and RH recorded in Area #5, as well as the outside condition during the same period of time. Appendix E presents a graph with the recorded data, which shows slight changes in temperature and significant RH variation throughout the one week period between September 20, 2017 and September 27, 2017. The change in indoor relative humidity was probably a result of large ambient temperature changes and steady interior temperatures during the test period.

Table 3.9: Temperature and RH Readings in Area #5

VARIABLES	MAX	DATE	MIN	DATE	AVG
OUTSIDE AIR TEMP °C	26.9	26/09/2017 12:00	1.3	01/10/2017 4:00	13.1
OUTSIDE %RH	92	22/09/2017 6:00	25	23/09/2017 10:00	73.6
AREA #5 GENERATOR – T °C	25.2	26/09/2017 14:00	20.9	21/09/2017 13:00	23.5
ARE A#5 GENERATOR – %RH	75.1	28/09/2017 6:00	18.9	03/10/2017 15:00	40.2

The ASHRAE Thermal Comfort Tool was used to determine if the maximum, minimum, and average conditions in this area comply with ASHRAE 55-2013, according to the "Analytical Comfort Zone Method". The results are presented in Table 3.10. The Standard Effective Temperature (SET) model in the Thermal Comfort Tool was used to evaluate comfort for air speed above 0.2 m/s (40 fpm). ASHRAE Standard 62 generally requires that for air conditioned spaces (it does not apply in non-air conditioned spaces), the relative humidity should be controlled to a maximum of 65%.

Table 3.10: Area #5 – Analytical Comfort Zone Method ASHRAE 55-2013

VARIABLES	VARIABLES	PMV	PPD	SENSATION	SET	COMPLIES
AREA #5 GENERATOR – AVERAGE T °C	23.5	0.35	7%	Neutral	26.5°C	Yes
AREA #5 GENERATOR – AVERAGE %RH	40.2					

According to the assumed mean radiant temperature, air speed, met, clo, and the average temperature and RH for this area, it was determined that the average conditions do not comply with the standard. Recorded data indicated that the RH was higher than 60% for about 8% of the time.

Figure 3.12, from the Thermal Comfort Tool, depicts the acceptable range of operative temperature and humidity for this area considering the average temperature and RH. Mean radiant temperature, air speed, met, and clo were assumed to be as described in Section 3.1 of this report. Figure 3.12 shows that the operating condition lies within the acceptable thermal environment limits.

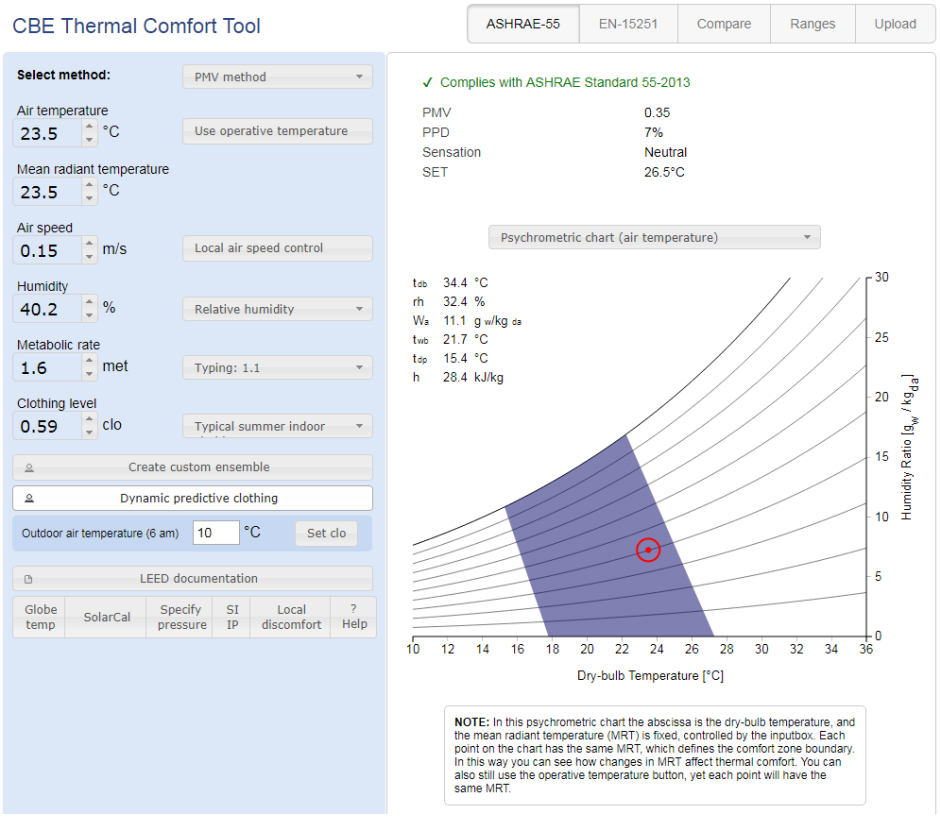

Figure 3.12: Area#5 - Acceptable Range of Operative Temperature and Humidity for the Average Conditions – ASHRAE Thermal Comfort Tool

CHAPTER 4 FINDINGS

According to the results from the different assessments, four (4) of the five (5) areas comply with ASHRAE 55-2013. Only one of the areas, Area #4 Fourth Level, does not meet the standard requirements. Table 4.1 presents a summary of the findings for the five areas.

Table 4.1: Summary – Analytical Comfort Zone Method ASHRAE 55-2013

VARIABLES	VARIABLES	PMV	PPD	SENSATION	SET	COMPLIES
AREA #1 MAIN LEVEL – AVERAGE T °C	22.6	0.24	6%	Neutral	26.3°C	Yes
AREA #1 MAIN LEVEL – AVERAGE %RH	56.0					
AREA #2 SECOND LEVEL – AVERAGE T °C	22.1	0.15	5%	Neutral	26°C	Yes
AREA #2 SECOND LEVEL – AVERAGE %RH	58.7					
AREA #3 THIRD LEVEL – AVERAGE T °C	21.5	0.04	5%	Neutral	25.5°C	Yes
AREA #3 THIRD LEVEL – AVERAGE %RH	62.3					
AREA #4 FOURTH LEVEL – AVERAGE T °C	17.5	-0.75	17%	Slightly Cool	21.7°C	Not
AREA #4 FOURTH LEVEL – AVERAGE %RH	81.6					
AREA #5 GENERATOR – AVERAGE T °C	23.5	0.35	7%	Neutral	26.5°C	Yes
AREA #5 GENERATOR – AVERAGE %RH	40.2					

Regarding RH, Area#4 showed RH levels higher than 80% for over 86% for the time between September 20, 2017 and October 3, 2017, which results in thermal discomfort. Lower temperature conditions and higher relative humidity in this area could be addressed by reviewing the heating and dehumidification provided for this space. Upper humidity levels are established in consideration of dry skin, respiratory health, eye irritation, microbial growth, and other moisture related phenomena. When the Graphical Comfort Zone Method is applied, the humidity ration should be maintain below or at 0.012kgw/kg dry air, equivalent to a water vapour pressure of 1.910 kPa (0.277 psi) at standard pressure or a dew-point temperature of 16.8 °C (62.2°F). There are no established lower level humidity limits for thermal comfort; ASHRAE 55-2013 does not specify a minimum humidity level. However, low humidity effects on skin and mucus membranes may place limits on the acceptability of very low humidity for some occupants.[2]

[2] ASHRAE 55-2013

The effect of thermal radiation asymmetry, drafts, vertical air temperature differences, floor surface temperatures, RH, occupant activity levels, and clothing insulation levels define the thermal comfort in any space. Also, outside air condition will play a role in indoor comfort levels. Therefore, changes to any of these variables will affect the thermal sensations felt by an occupant in a given space.

It is worth mentioning that indoor temperature and RH levels are most likely to be higher during the warmest periods in July and August. Also, an assessment that includes mean radiant temperature and air speed measurements, as well as occupant surveys (according to ASHRAE 55-2013 section 7) would yield better information to determine the thermal comfort conditions in these areas. Nevertheless, it is believed that the measurements obtained and the reporting period offer a good representation of the general conditions in the space.

4.1 Closure

We trust this report satisfies your current requirements at this time. Please feel free to contact us at your earliest convenience should you have any questions or concerns.

Yours truly,

CBCL Limited

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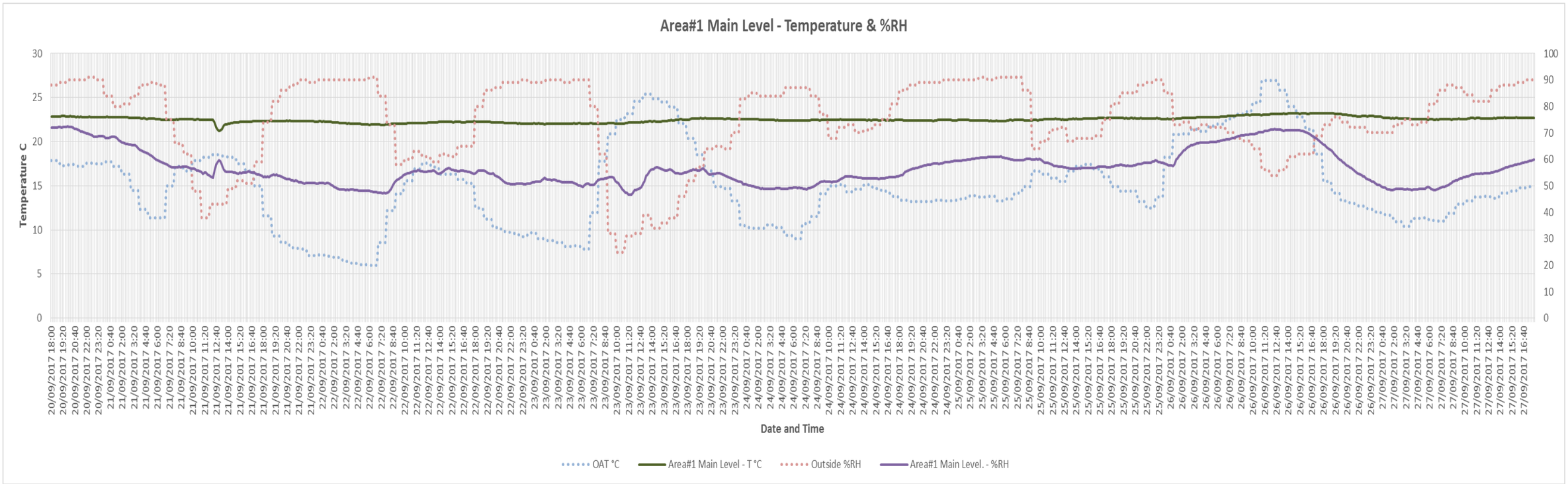
APPENDIX A

Area #1 – Recorded Temperature and Relative Humidity


Area#1 Main Level - Temperature & %RH
Temperature C
30
25
20
15
10
5
0
100
90
80
70
60
50
40
30
20
10
0
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20/09/2017 19:20
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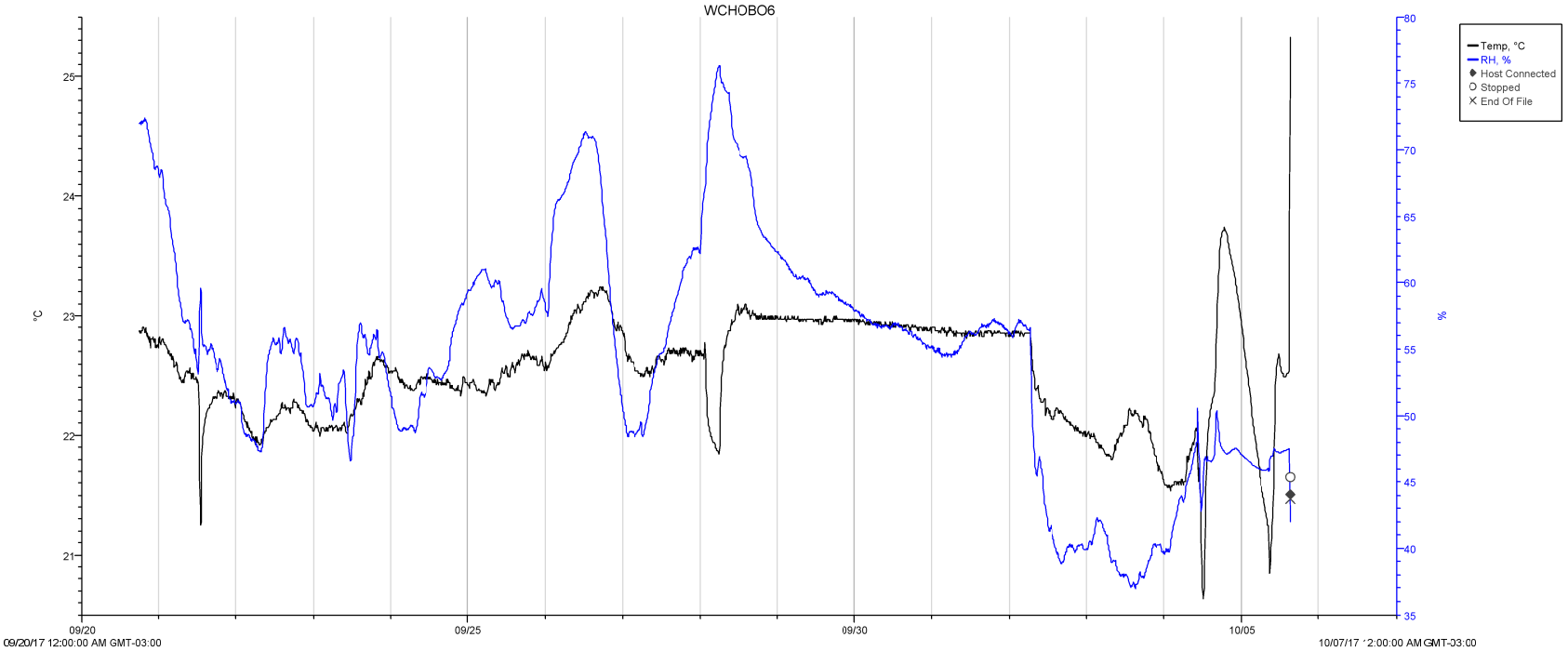
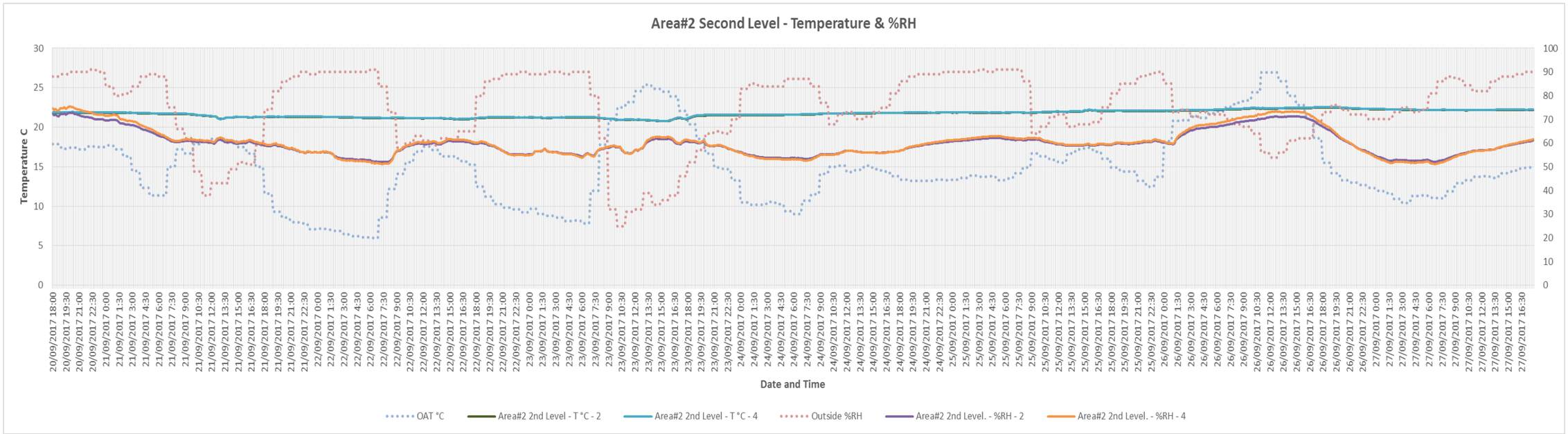
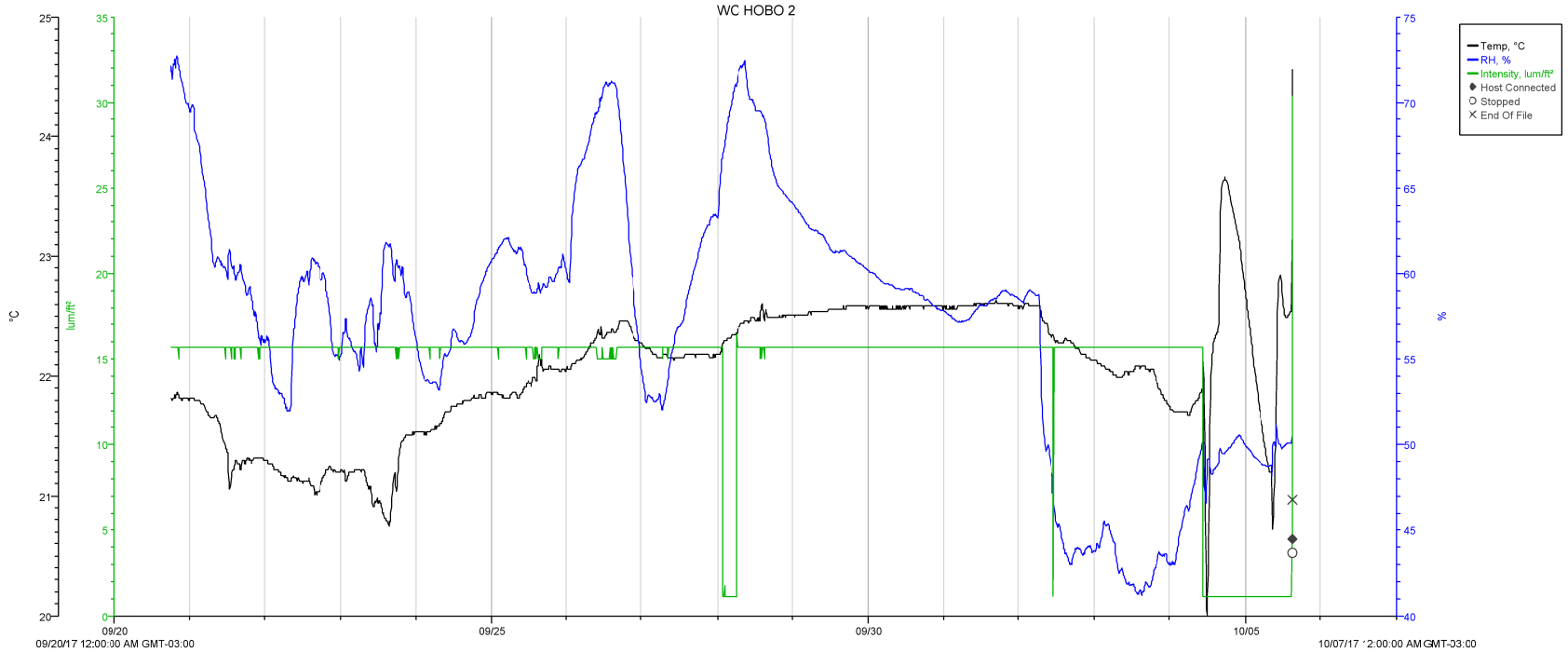
27/09/2017 14:00
27/09/2017 15:20
27/09/2017 16:40
Date and Time
OAT °C
Area#1 Main Level - T °C
Outside %RH
Area#1 Main Level. - %RH

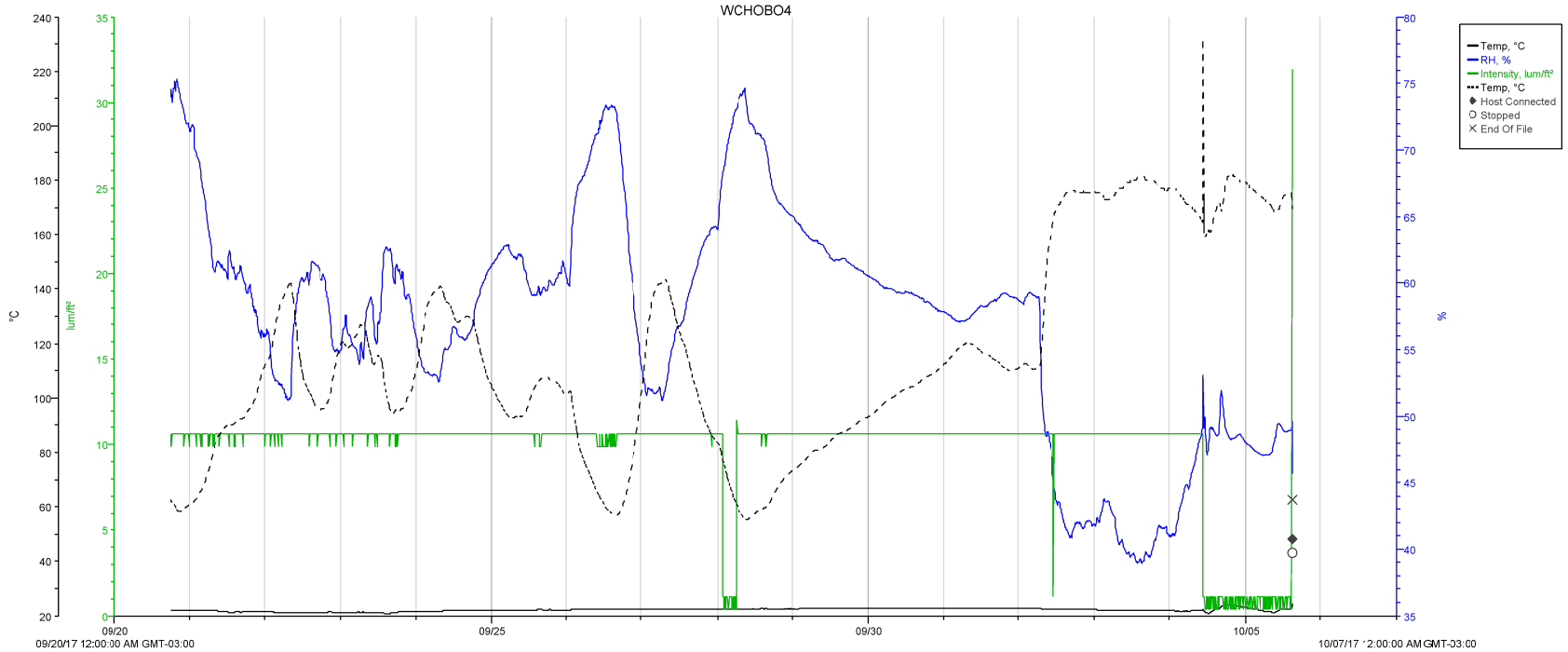

WCHOBO6
°C
%
25
24
23
22
21
80
75
70
65
60
55
50
45
40
35
09/20
09/25
09/30
10/05
09/20/17 12:00:00 AM GMT-03:00
10/07/17 12:00:00 AM GMT-03:00
Temp, °C
RH, %
Host Connected
Stopped
End Of File

APPENDIX B

Area #2 – Recorded Temperature and Relative Humidity

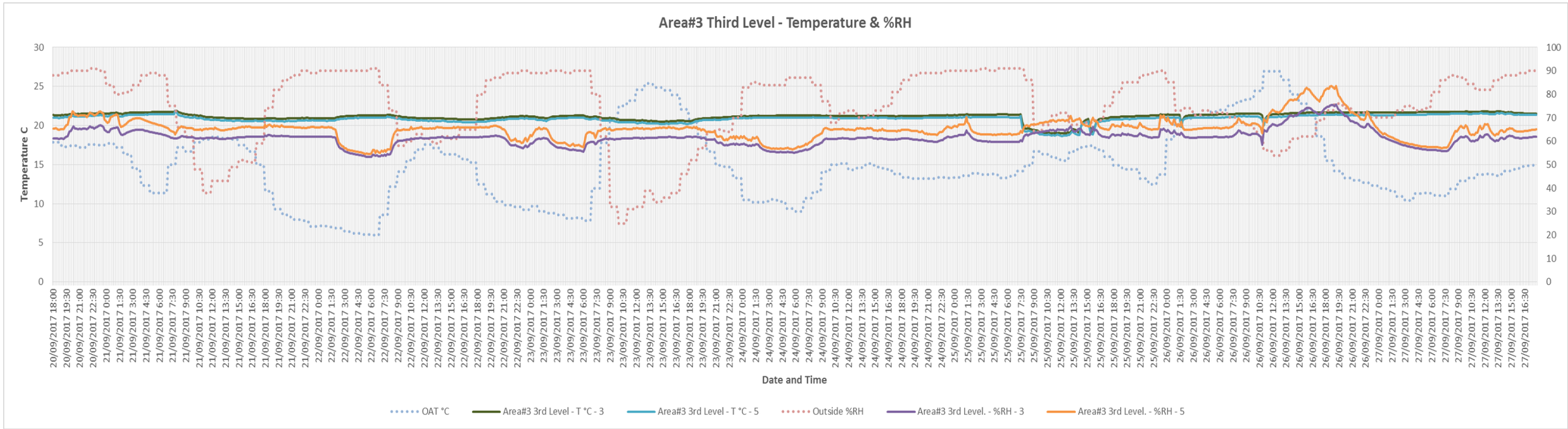

Area#2 Second Level - Temperature & %RH
Temperature C
Date and Time
OAT °C
Area#2 2nd Level - T °C - 2
Area#2 2nd Level - T °C - 4
Outside %RH
Area#2 2nd Level. - %RH - 2
Area#2 2nd Level. - %RH - 4


WC HOBO 2
°C
lum/ft²
%
Temp, °C
RH, %
Intensity, lum/ft²
Host Connected
Stopped
End Of File
09/20
09/25
09/30
10/05
09/20/17 12:00:00 AM GMT-03:00
10/07/17 12:00:00 AM GMT-03:00


WCHOBO4
°C
lum/ft²
%
Temp, °C
RH, %
Intensity, lum/ft²
Temp, °C
Host Connected
Stopped
End Of File
09/20
09/25
09/30
10/05
09/20/17 12:00:00 AM GMT-03:00
10/07/17 12:00:00 AM GMT-03:00

APPENDIX C

Area #3 – Recorded Temperature and Relative Humidity


Area#3 Third Level - Temperature & %RH
Temperature C
30
25
20
15
10
5
0
100
90
80
70
60
50
40
30
20
10
0
20/09/2017 18:00
20/09/2017 19:30
20/09/2017 21:00
20/09/2017 22:30
21/09/2017 0:00
21/09/2017 1:30
21/09/2017 3:00
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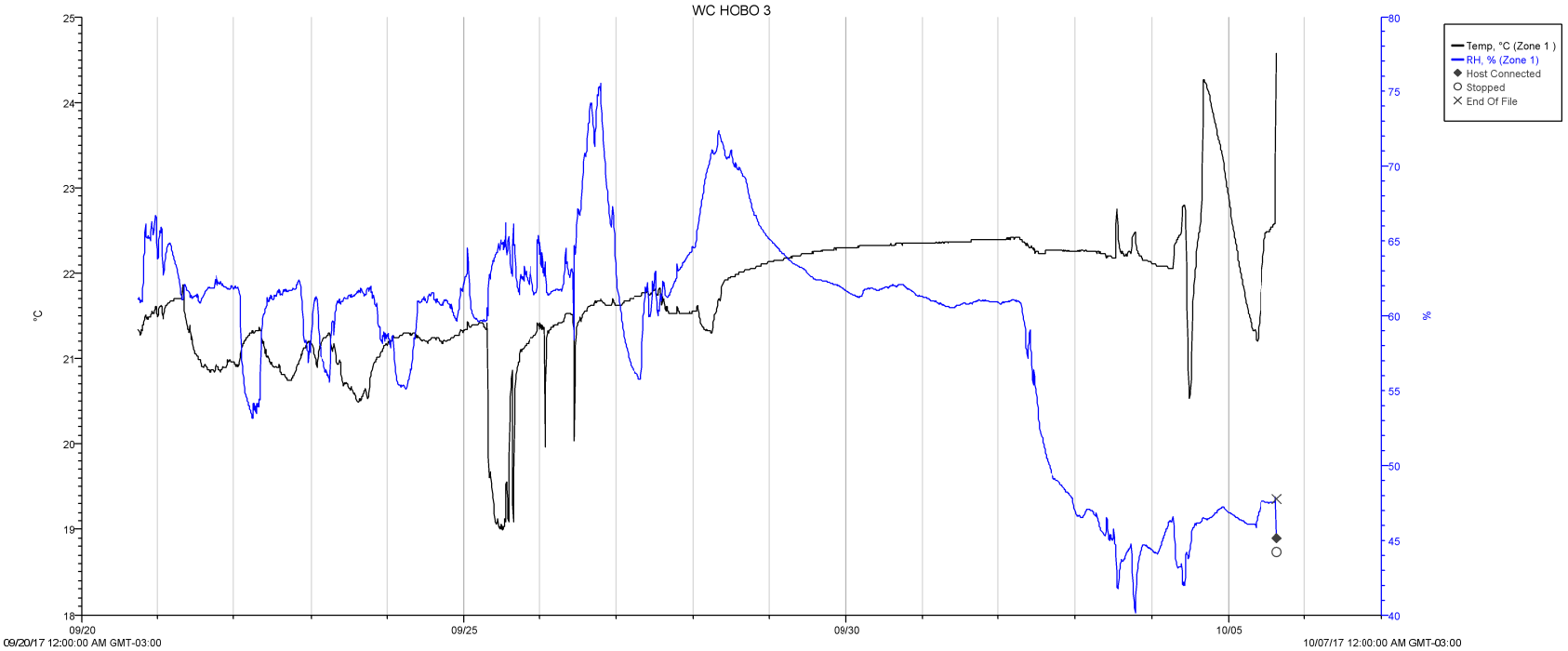
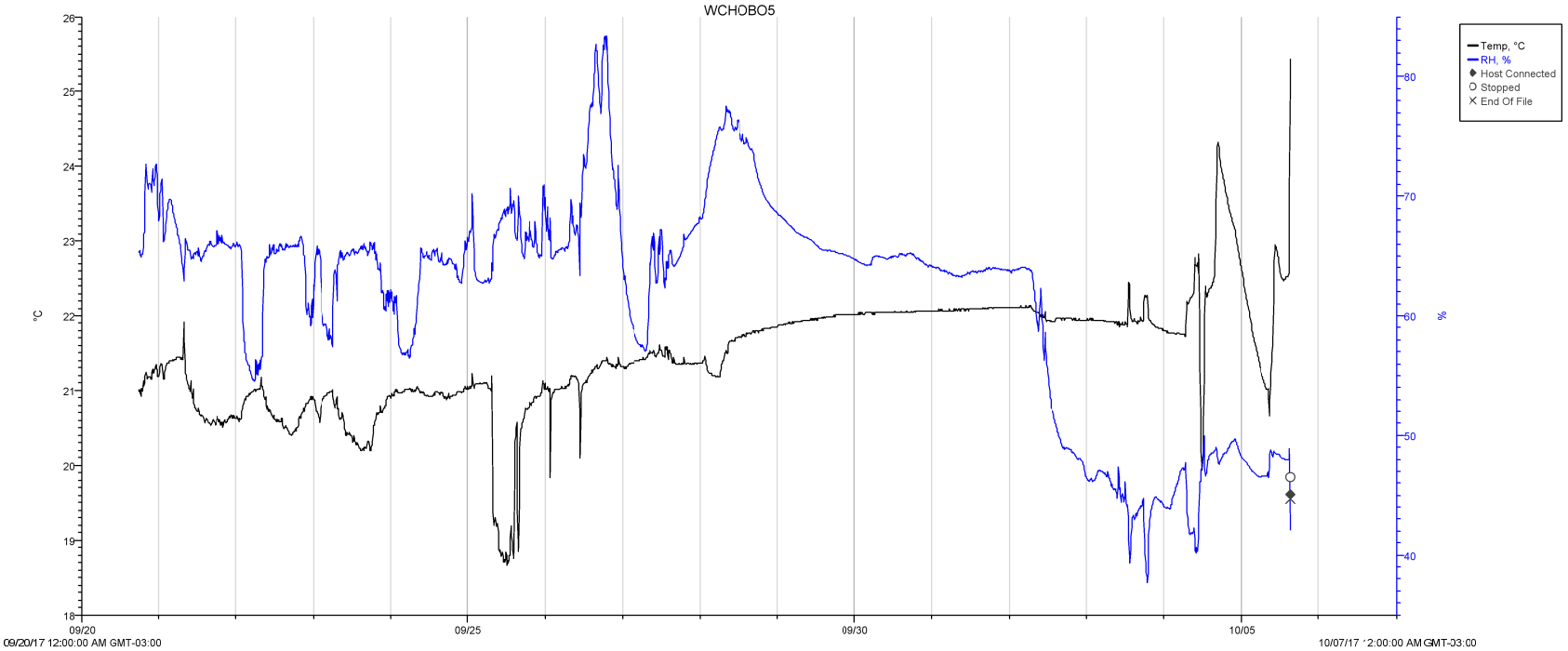
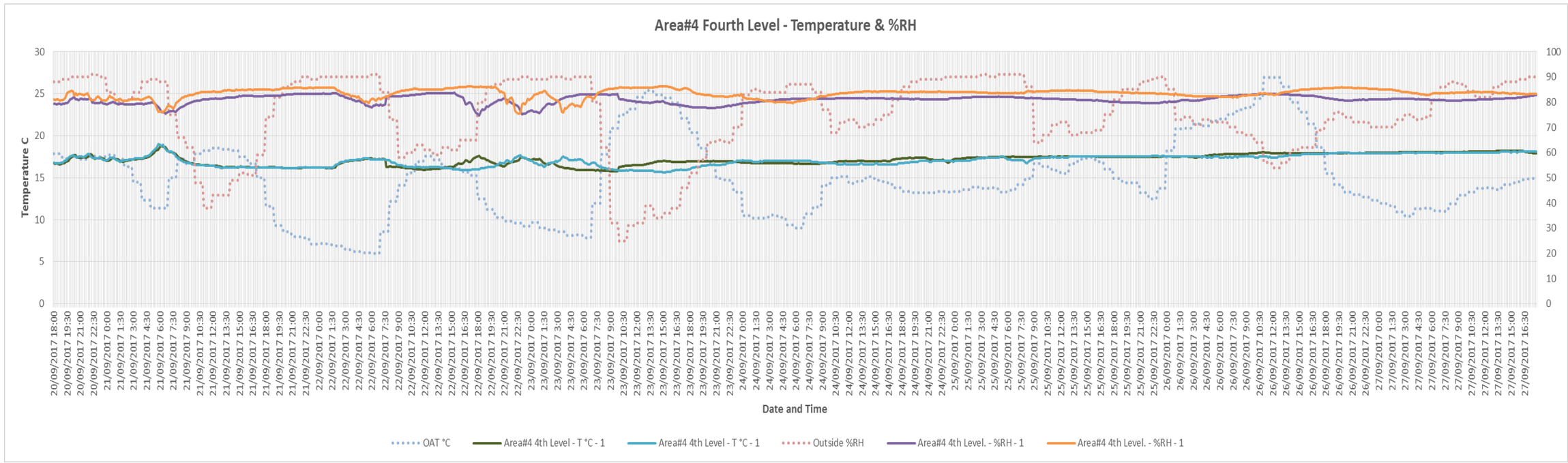
27/09/2017 10:30
27/09/2017 12:00
27/09/2017 13:30
27/09/2017 15:00
27/09/2017 16:30
Date and Time
OAT °C
Area#3 3rd Level - T °C - 3
Area#3 3rd Level - T °C - 5
Outside %RH
Area#3 3rd Level. - %RH - 3
Area#3 3rd Level. - %RH - 5


WC HOBO 3
°C
%
25
24
23
22
21
20
19
18
80
75
70
65
60
55
50
45
40
09/20
09/25
09/30
10/05
09/20/17 12:00:00 AM GMT-03:00
10/07/17 12:00:00 AM GMT-03:00
Temp, °C (Zone 1)
RH, % (Zone 1)
Host Connected
Stopped
End Of File


WCHOBO5
°C
%
Temp, °C
RH, %
Host Connected
Stopped
End Of File
09/20
09/25
09/30
10/05
09/20/17 12:00:00 AM GMT-03:00
10/07/17 12:00:00 AM GMT-03:00

APPENDIX D

Area #4 – Recorded Temperature and Relative Humidity


Area#4 Fourth Level - Temperature & %RH
Temperature C
30
25
20
15
10
5
0
100
90
80
70
60
50
40
30
20
10
0
20/09/2017 18:00
20/09/2017 19:30
20/09/2017 21:00
20/09/2017 22:30
21/09/2017 0:00
21/09/2017 1:30
21/09/2017 3:00
21/09/2017 4:30
21/09/2017 6:00
21/09/2017 7:30
21/09/2017 9:00
21/09/2017 10:30
21/09/2017 12:00
21/09/2017 13:30
21/09/2017 15:00
21/09/2017 16:30
21/09/2017 18:00
21/09/2017 19:30
21/09/2017 21:00
21/09/2017 22:30
22/09/2017 0:00
22/09/2017 1:30
22/09/2017 3:00
22/09/2017 4:30
22/09/2017 6:00
22/09/2017 7:30
22/09/2017 9:00
22/09/2017 10:30
22/09/2017 12:00
22/09/2017 13:30
22/09/2017 15:00
22/09/2017 16:30
22/09/2017 18:00
22/09/2017 19:30
22/09/2017 21:00
22/09/2017 22:30
23/09/2017 0:00
23/09/2017 1:30
23/09/2017 3:00
23/09/2017 4:30
23/09/2017 6:00
23/09/2017 7:30
23/09/2017 9:00
23/09/2017 10:30
23/09/2017 12:00
23/09/2017 13:30
23/09/2017 15:00
23/09/2017 16:30
23/09/2017 18:00
23/09/2017 19:30
23/09/2017 21:00
23/09/2017 22:30
24/09/2017 0:00
24/09/2017 1:30
24/09/2017 3:00
24/09/2017 4:30
24/09/2017 6:00
24/09/2017 7:30
24/09/2017 9:00
24/09/2017 10:30
24/09/2017 12:00
24/09/2017 13:30
24/09/2017 15:00
24/09/2017 16:30
24/09/2017 18:00
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24/09/2017 21:00
24/09/2017 22:30
25/09/2017 0:00
25/09/2017 1:30
25/09/2017 3:00
25/09/2017 4:30
25/09/2017 6:00
25/09/2017 7:30
25/09/2017 9:00
25/09/2017 10:30
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25/09/2017 22:30
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26/09/2017 1:30
26/09/2017 3:00
26/09/2017 4:30
26/09/2017 6:00
26/09/2017 7:30
26/09/2017 9:00
26/09/2017 10:30
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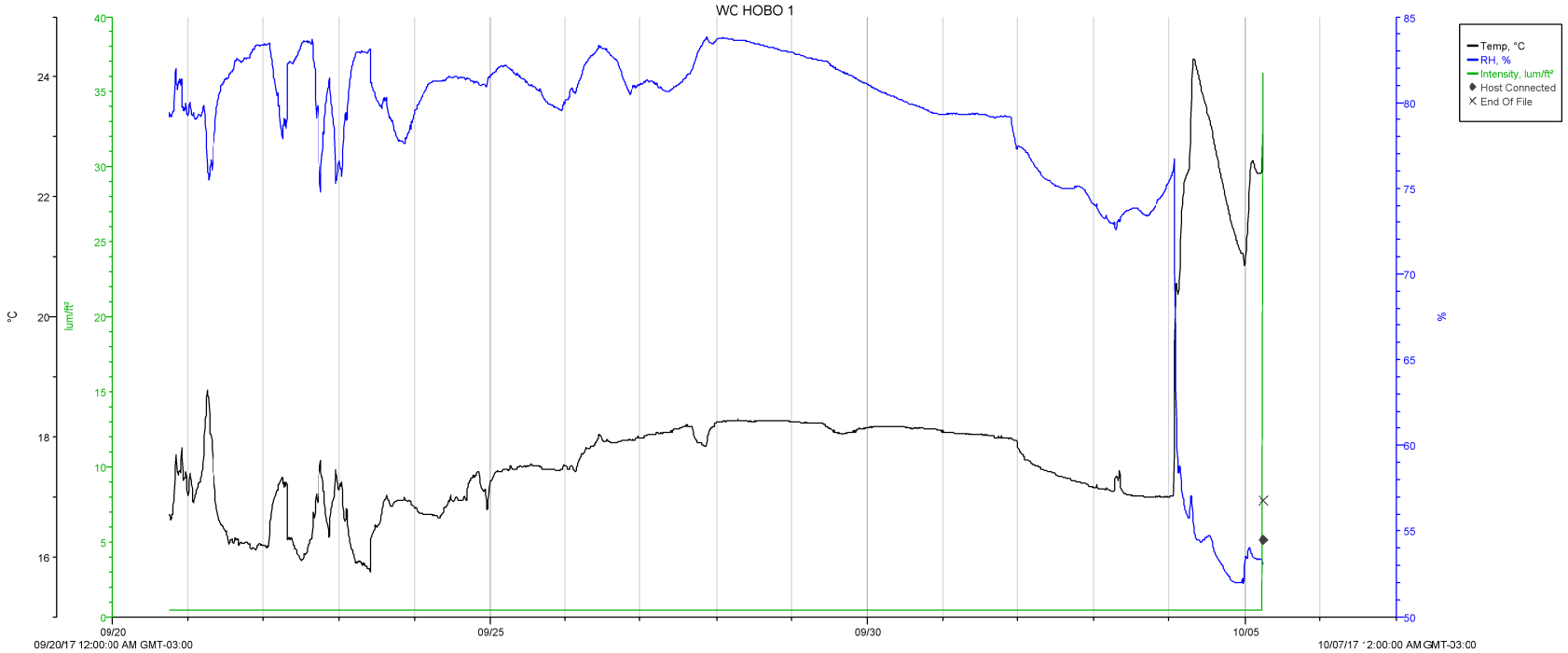
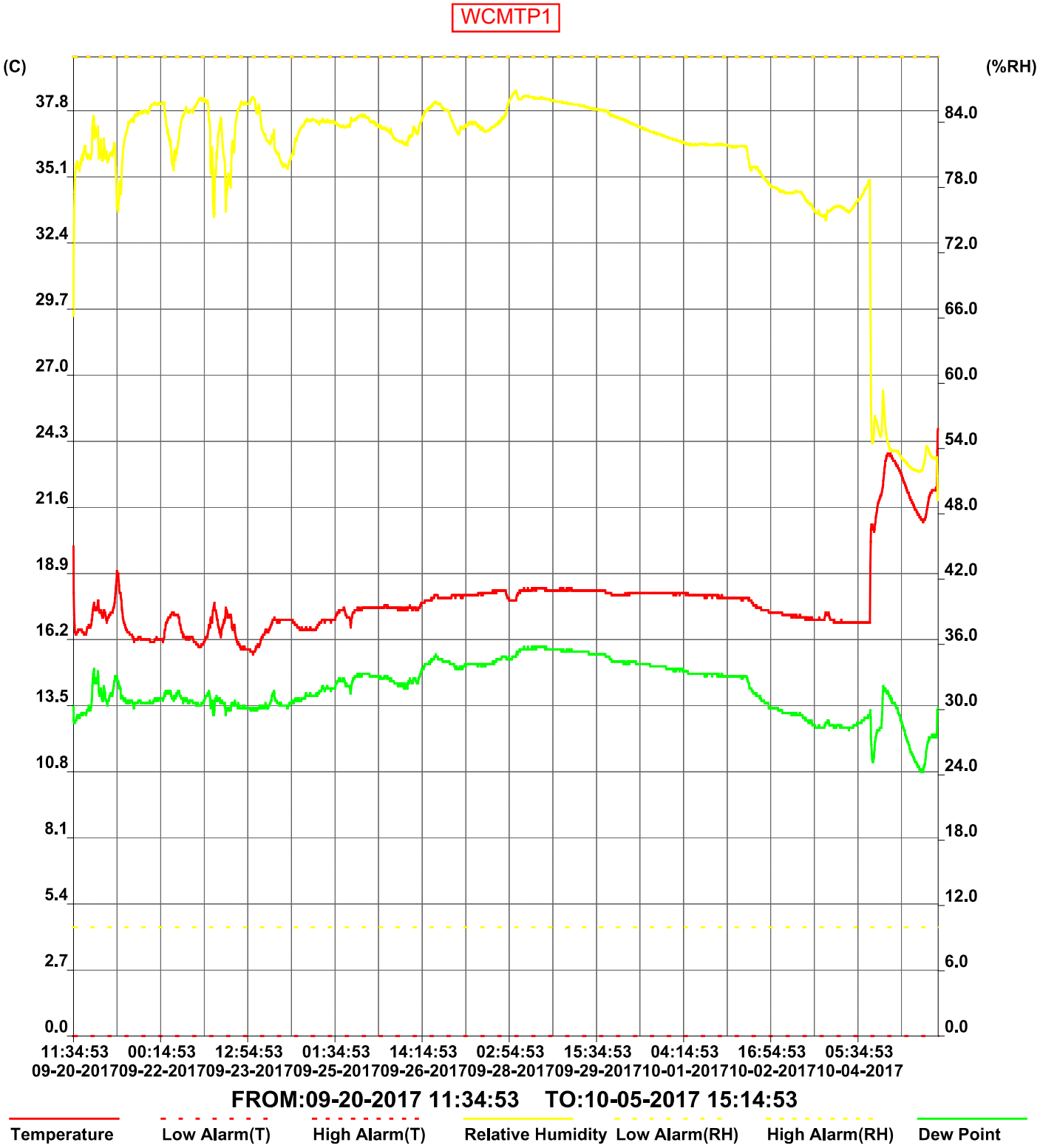
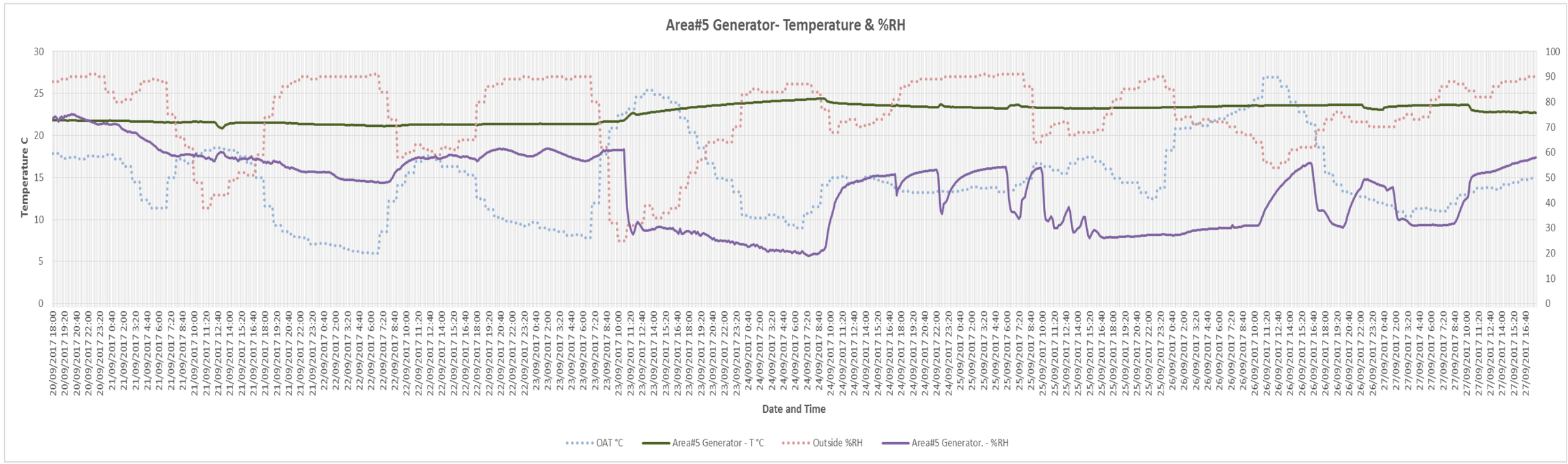
26/09/2017 13:30
26/09/2017 15:00
26/09/2017 16:30
26/09/2017 18:00
26/09/2017 19:30
26/09/2017 21:00
26/09/2017 22:30
27/09/2017 0:00
27/09/2017 1:30
27/09/2017 3:00
27/09/2017 4:30
27/09/2017 6:00
27/09/2017 7:30
27/09/2017 9:00
27/09/2017 10:30
27/09/2017 12:00
27/09/2017 13:30
27/09/2017 15:00
27/09/2017 16:30
Date and Time
OAT °C
Area#4 4th Level - T °C - 1
Area#4 4th Level - T °C - 1
Outside %RH
Area#4 4th Level. - %RH - 1
Area#4 4th Level. - %RH - 1

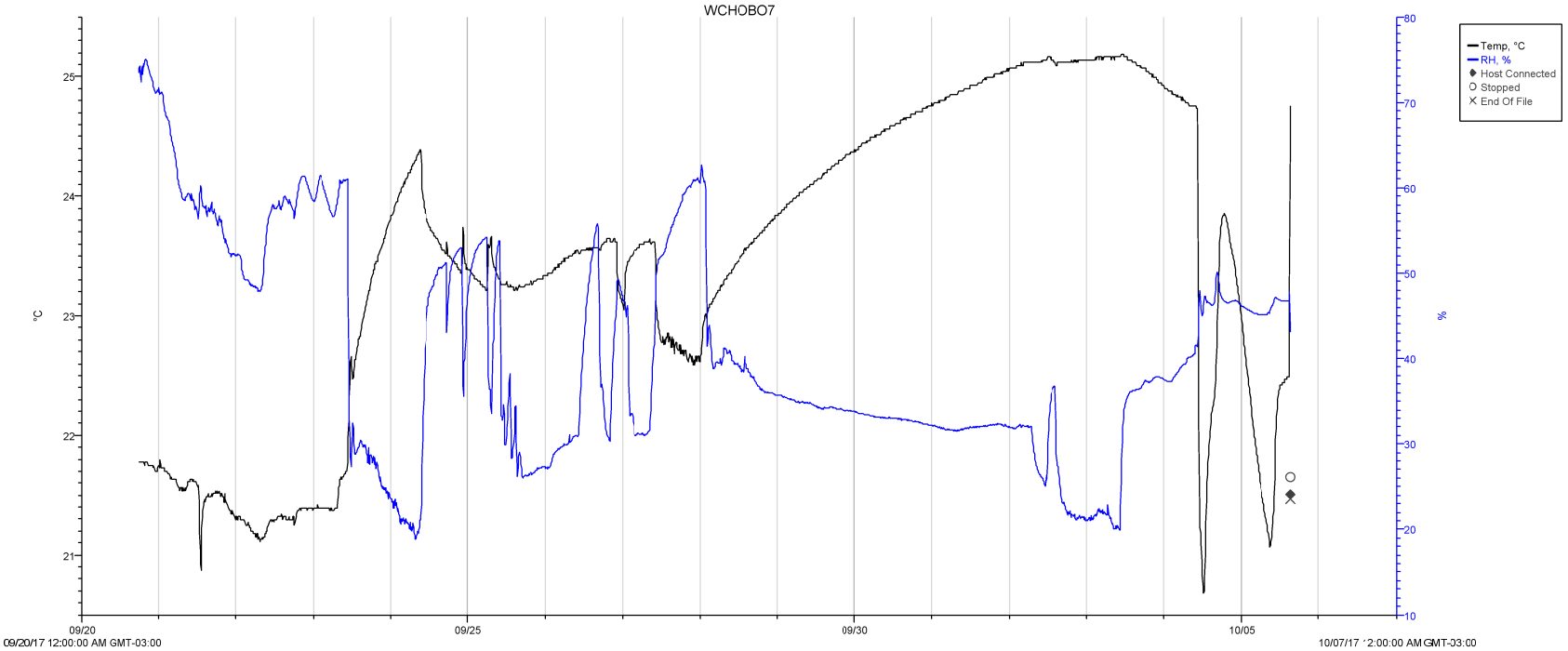

WC HOBO 1
°C
lum/ft²
%
Temp, °C
RH, %
Intensity, lum/ft²
Host Connected
End Of File
09/20
09/25
09/30
10/05
09/20/17 12:00:00 AM GMT-03:00
10/07/17 12:00:00 AM GMT-03:00


WCMTP1
(C)
(%RH)
37.8
35.1
32.4
29.7
27.0
24.3
21.6
18.9
16.2
13.5
10.8
8.1
5.4
2.7
0.0
84.0
78.0
72.0
66.0
60.0
54.0
48.0
42.0
36.0
30.0
24.0
18.0
12.0
6.0
0.0
11:34:53 00:14:53 12:54:53 01:34:53 14:14:53 02:54:53 15:34:53 04:14:53 16:54:53 05:34:53
09-20-201709-22-201709-23-201709-25-201709-26-201709-28-201709-29-201710-01-201710-02-201710-04-2017
FROM:09-20-2017 11:34:53 TO:10-05-2017 15:14:53
Temperature
Low Alarm(T)
High Alarm(T)
Relative Humidity
Low Alarm(RH)
High Alarm(RH)
Dew Point

APPENDIX E

Area #5 – Recorded Temperature and Relative Humidity


Area#5 Generator- Temperature & %RH
Temperature C
Date and Time
OAT °C
Area#5 Generator - T °C
Outside %RH
Area#5 Generator. - %RH


WCHOBO7
Temp, °C
RH, %
Host Connected
Stopped
End Of File
°C
%
25
24
23
22
21
80
70
60
50
40
30
20
10
09/20
09/25
09/30
10/05
09/20/17 12:00:00 AM GMT-03:00
10/07/17 12:00:00 AM GMT-03:00

CI Number: 49943

Title: HYD Ruth Falls Facility Refurbishment

Start Date: 2017/05
In-Service Date: 2018/07
Final Cost Date: 2019/01
Function: Hydro
Forecast Amount: $1,234,931

DESCRIPTION:

This project will address areas of the Ruth Falls Powerhouse in need of refurbishment, including the windows, garage door and main door, ventilation louvers, the deteriorating stucco cladding, floors which are cracking and have spalling concrete, and the exterior drainage system. The scope of work includes exterior and interior work and hazmat remediation due to removal of lead paint. These items pose safety and security risks and must be addressed to restore security and safety to the powerhouse.

Summary of Related CIs +/- 2 years:
No other projects in 2016, 2017, 2018, 2019 and 2020

JUSTIFICATION:

Justification Criteria: Health & Safety

Why do this project?

The Ruth Falls Powerhouse has been in service since 1925 and many of its components have deteriorated to the point that safety and security concerns within the plant need to be mitigated. These components must be addressed to restore the safety and security of the powerhouse. Refurbishing and upgrading the powerhouse will increase the service life of the building and prevent rain infiltration related equipment failures and accelerated deterioration of the building.

The Ruth Falls Powerhouse is a long term facility with no plans for retirement in the long term future.

This project is primarily justified on safety, while secondarily justified on maintaining unit reliability.

Why do this project now?

The Ruth Falls Powerhouse was built in 1925 and many of its assets have deteriorated. A third party assessment of the plant in September 2017 concluded that the overall condition of the building is fair with some items of concern. Please refer to Partially Confidential Attachment 1 for more detail. Potential for water to enter the buildings is also a threat to the electrical components of the system.

Why do this project this way?

Replacing deteriorated components, recoating the interior and exterior of the buildings and providing much needed repairs to walls, windows, floors and ceilings will stop possible water infiltration and increase the service life of the structures while improving safety and decreasing risk to the equipment.

CI Number : 49943-H811 - HYD - Ruth Falls Facility Refurbishment **Project Number** 49943-H811

Parent CI Number : -

Asset Location : 1359 - 1359 Ruth Falls Common Property **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0300 - HGP - Bldg.,Struct.Grnd.	903,597
Retirements	0300 - HGP - Bldg.,Struct.Grnd.	331,333
	Total Cost:	1,234,931
	Original Cost:	156,922

Capital Project Detailed Estimate

Location: Hydro
FP# / P#: 49943
Title: HYD Ruth Falls Facility Refurbishment
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Hydro River Staff - Construction	day	15	365	$ 5,472		
Engineering Staff	day	29	405	$ 11,830		
Environmental Staff	day	6	332	$ 1,993		
			Sub-Total	$ 19,295		
Travel Expenses						
Site Visit	Month	3	$ 600	$ 1,800		
			Sub-Total	$ 1,800		
Materials						
Exterior Windows and Doors	Lot	1	[redacted]		Cost Support #1 - Items 4 & 5	
			Sub-Total	[redacted]		
Contracts						
Construction Costs	Lot	1	[redacted]		Cost Support #1 - Items 1 & 20	
Contractor Overhead and Fees	Lot	1			Cost Support #1 - Item 18	
Exterior Work	Lot	1			Cost Support #1 - Items 3, 6 & 7	
Interior Work	Lot	1			Cost Support #1 - Items 8 - 17	
Hazmat Remediation	Lot	1			Cost Support #1	
			Sub-Total	[redacted]		
Consulting						
Construction Management	Month	3	$ 3,000	$ 9,000		
Design and Specification	Lot	1	$ 8,940	$ 8,940		
			Sub-Total	$ 17,940.00		
Meals and Entertainment						
Site Visit	Month	3	$ 300	$ 900		
			Sub-Total	$ 900		
Other Goods and Services						
Contingency	%	[redacted]				
			Sub-Total	[redacted]		
Interest Capitalized						
AFUDC				$ 4,583		
			Sub-Total	$ 4,583		
Administrative Overhead						
Labour AO				$ 8,468		
Contract AO				$ 81,395		
			Sub-Total	$ 89,863		
			Sub-Total (no AO, AFUDC)	$ 1,140,485		
			TOTAL (AO, AFUDC included)	$ 1,234,931		
Original Cost				$ 156,922		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CBCL LIMITED
Consulting Engineers

OPINION OF PROBABLE CONSTRUCTION COST
Ruth Falls NSPI Powerhouse Renovations
Ruth Falls, NS

DATE:	29/08/2017
CBCL FILE No.:	170222.00
PREPARED BY:	ADT
EST. DESCRIPTION :	Class C

No.	DESCRIPTION
	CONSTRUCTION COSTS
1	Mobilization, Bonds, Insurance, Pre-Construction Management
2	Hazmat Abatement (Separate Contract)
	EXTERIOR WORK
3	Concrete / Masonry Walls Cladding Repairs & Paint
4	Exterior Doors & Paint Steel Rollup Door
5	Exterior Windows
6	Exterior Stairs & Railings
7	Exterior Lighting East Side
	INTERIOR WORK
8	Floors
9	Interior Walls Main Floor Area (F)
10	Interior Walls Washroom (F)
11	Interior Walls Lower Floor
12	Interior Walls Lower Floor Washroom
13	Interior Walls Stairwell South
14	Ceilings Main, Lower, Washrooms, Stairs Levels
15	Stairs Main Level, South, Lower Level over Pipes
16	Lighting Fixtures
17	Design Development Contingency Allowance - Note 1
	SUB-TOTAL - DIRECT CONSTRUCTION C
18	Contractor Overhead and Fees
	SUB-TOTAL - DIRECT and INDIRECT COSTS without CONTIN
19	Construction Contingency - Note 2
20	Location Factor - Note 4
21	Escalation / Inflation (Based on 2017 Dollars) - Note 3
	TOTAL - DIRECT & INDIRECT CONSTRUCTION COSTS with CONTINGENCY w
	HST (NS)
	TOTAL - CONSTRUCTION COSTS wi

DRAFT

[redacted]

Separate Class D Budget:
Item # 2 - Hazmat Abatement Order of Magnitude

THIS OPINION OF PROBABLE COSTS IS PRESENTED ON THE BASIS OF EXPERIENCE, QUALIFICATIONS, AND BEST JUDGEMENT. IT HAS BEEN PREPARED IN ACCORDANCE WITH ACCEPTABLE PRINCIPLES AND PRACTICES. MARKET TRENDS, NON-COMPETITIVE BIDDING SITUATIONS, UNFORESEEN LABOUR AND MATERIAL ADJUSTMENTS AND THE LIKE ARE BEYOND THE CONTROL OF CBCL LIMITED. AS SUCH WE CANNOT WARRANT OR GUARANTEE THAT ACTUAL COSTS WILL NOT VARY FROM THE OPINION PROVIDED.

Note 1	A Design Development Contingency is to allow for increases of qty's; material costs; as the work is better defined
Note 2	A Construction Contingency is to allow for C.O. cost of additional work over and above the contract Awarded price.
Note 3	The Escalation/Inflation allowance is for increases in construction costs from time the budget to Tender Call
Note 4	The Location Factor is for variances between construction costs at the location of the project & historical costs data

Form CBCL 035.Rev 2

170222.00 ~ Class C Ruth Falls Powerhouse Renos 29-08-2017_at.xlsx

CI Number: 49942

Title: HYD Tidewater Facility Refurbishment

Start Date: 2017/10
In-Service Date: 2018/07
Final Cost Date: 2019/01
Function: Hydro
Forecast Amount: $1,234,178

DESCRIPTION:

This project will address areas of the Tidewater Powerhouse in need of refurbishment, including the windows, garage door and main door, ventilation louvers, the deteriorating stucco cladding, floors which are cracking and have spalling concrete, and the exterior drainage system. The scope of work includes exterior and interior work and hazmat remediation due to removal of lead paint. These items pose safety and security risks and must be addressed to restore security and safety to the powerhouse.

Summary of Related CIs +/- 2 years:
No other projects in 2016, 2017, 2018, 2019 and 2020

JUSTIFICATION:

Justification Criteria: Health & Safety

Why do this project?

The Tidewater Powerhouse was built in 1922 and many of its components have deteriorated to the point that safety and security concerns within the plant need to be mitigated. These components must be addressed to restore the safety and security of the powerhouse. Refurbishing and upgrading the powerhouse will increase the service life of the building and prevent rain infiltration related equipment failures and accelerated deterioration of the building.

Tidewater generating station is a long term facility with no plans for retirement in the long term future.

This project is primarily justified on safety, while secondarily justified on maintaining unit reliability.

Why do this project now?

Hydro facilities were evaluated in 2011 as a fleet and prioritized for investment timing. Many aspects of the Tidewater Powerhouse have deteriorated. Water is entering the building through exterior cracks and the ventilation is inadequate, as the facility deteriorates water contact with sensitive electrical components increases. The work must be completed now to prevent further deterioration of the structures and ensure facility life into the future.

Why do this project this way?

The windows and doors in the powerhouse are in such condition that refurbishment is not an option. Recoating the interior and exterior of the buildings and providing much needed repairs to walls, floors and ceilings, will stop water infiltration and increase the service life of the structures while improving safety and decreasing risk of water damage to the equipment.

CI Number : 49942 - HYD - Tidewater Facility Refurbishment **Project Number** 49942

Parent CI Number : -

Asset Location : 1360 - 1360 Tide Water Common Property **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0300 - HGP - Bldg.,Struct.Grnd.	902,845
Retirements	0300 - HGP - Bldg.,Struct.Grnd.	331,333
	Total Cost:	1,234,178
	Original Cost:	156,922

Capital Project Detailed Estimate

Location: Hydro
FP# / P#: 49942
Title: HYD Tidewater Facility Refurbishment
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Hydro River Staff - Construction	day	15	365	$ 5,472		
Engineering Staff	day	29	405	$ 11,830		
Environmental Staff	day	6	332	$ 1,993		
			Sub-Total	$ 19,295		
Travel Expenses						
Site Visit	Month	3	$ 600	$ 1,800		
			Sub-Total	$ 1,800		
Materials						
Exterior Windows and Doors	Lot	1	[redacted]		Cost Support #1 - Items 4 & 5	
			Sub-Total	[redacted]		
Contracts						
Construction Costs	Lot	1	[redacted]		Cost Support #1 - Items 1 & 20	
Contractor Overhead and Fees	Lot	1			Cost Support #1 - Item 18	
Exterior Work	Lot	1			Cost Support #1 - Items 3, 6 & 7	
Interior Work	Lot	1			Cost Support #1 - Items 8 - 17	
Hazmat Remediation	Lot	1			Cost Support #1	
			Sub-Total	[redacted]		
Consulting						
Construction Management	Month	3	$ 3,000	$ 9,000		
Design and Specification	Lot	1	$ 8,940	$ 8,940		
			Sub-Total	$ 17,940		
Meals and Entertainment						
Site Visit	Month	3	$ 300	$ 900		
			Sub-Total	$ 900		
Other Goods and Services						
Contingency	%	[redacted]		$ 143,550		
			Sub-Total	$ 143,550		
Interest Capitalized						
AFUDC				$ 3,838		
			Sub-Total	$ 3,838		
Administrative Overhead						
Labour AO				$ 8,461		
Contract AO				$ 81,395		
			Sub-Total	$ 89,856		
			Sub-Total (no AO, AFUDC)	$ 1,140,485		
			TOTAL (AO, AFUDC included)	$ 1,234,178		
Original Cost				$ 156,922		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CBCL LIMITED
Consulting Engineers

OPINION OF PROBABLE CONSTRUCTION COST
Ruth Falls NSPI Powerhouse Renovations
Ruth Falls, NS

DATE:	29/08/2017
CBCL FILE No.:	170222.00
PREPARED BY:	ADT
EST. DESCRIPTION :	Class C

No.	DESCRIPTION
	CONSTRUCTION COSTS
1	Mobilization, Bonds, Insurance, Pre-Construction Management
2	Hazmat Abatement (Separate Contract)
	EXTERIOR WORK
3	Concrete / Masonry Walls Cladding Repairs & Paint
4	Exterior Doors & Paint Steel Rollup Door
5	Exterior Windows
6	Exterior Stairs & Railings
7	Exterior Lighting East Side
	INTERIOR WORK
8	Floors
9	Interior Walls Main Floor Area (F)
10	Interior Walls Washroom (F)
11	Interior Walls Lower Floor
12	Interior Walls Lower Floor Washroom
13	Interior Walls Stairwell South
14	Ceilings Main, Lower, Washrooms, Stairs Levels
15	Stairs Main Level, South, Lower Level over Pipes
16	Lighting Fixtures
17	Design Development Contingency Allowance - Note 1
	SUB-TOTAL - DIRECT CONSTRUCTION C
18	Contractor Overhead and Fees
	SUB-TOTAL - DIRECT and INDIRECT COSTS without CONTING
19	Construction Contingency - Note 2
20	Location Factor - Note 4
21	Escalation / Inflation (Based on 2017 Dollars) - Note 3
	TOTAL - DIRECT & INDIRECT CONSTRUCTION COSTS with CONTINGENCY w/
	HST (NS)
	TOTAL - CONSTRUCTION COSTS wi

DRAFT

[redacted]

Separate Class D Budget:
Item # 2 - Hazmat Abatement Order of Magnitude

THIS OPINION OF PROBABLE COSTS IS PRESENTED ON THE BASIS OF EXPERIENCE, QUALIFICATIONS, AND BEST JUDGEMENT. IT HAS BEEN PREPARED IN ACCORDANCE WITH ACCEPTABLE PRINCIPLES AND PRACTICES. MARKET TRENDS, NON-COMPETITIVE BIDDING SITUATIONS, UNFORESEEN LABOUR AND MATERIAL ADJUSTMENTS AND THE LIKE ARE BEYOND THE CONTROL OF CBCL LIMITED. AS SUCH WE CANNOT WARRANT OR GUARANTEE THAT ACTUAL COSTS WILL NOT VARY FROM THE OPINION PROVIDED.

Note 1	A Design Development Contingency is to allow for increases of qty's; material costs; as the work is better defined
Note 2	A Construction Contingency is to allow for C.O. cost of additional work over and above the contract Awarded price.
Note 3	The Escalation/Inflation allowance is for increases in construction costs from time the budget to Tender Call
Note 4	The Location Factor is for variances between construction costs at the location of the project & historical costs data

Form CBCL 035.Rev 2

170222.00 ~ Class C Ruth Falls Powerhouse Renos 29-08-2017_at.xlsx

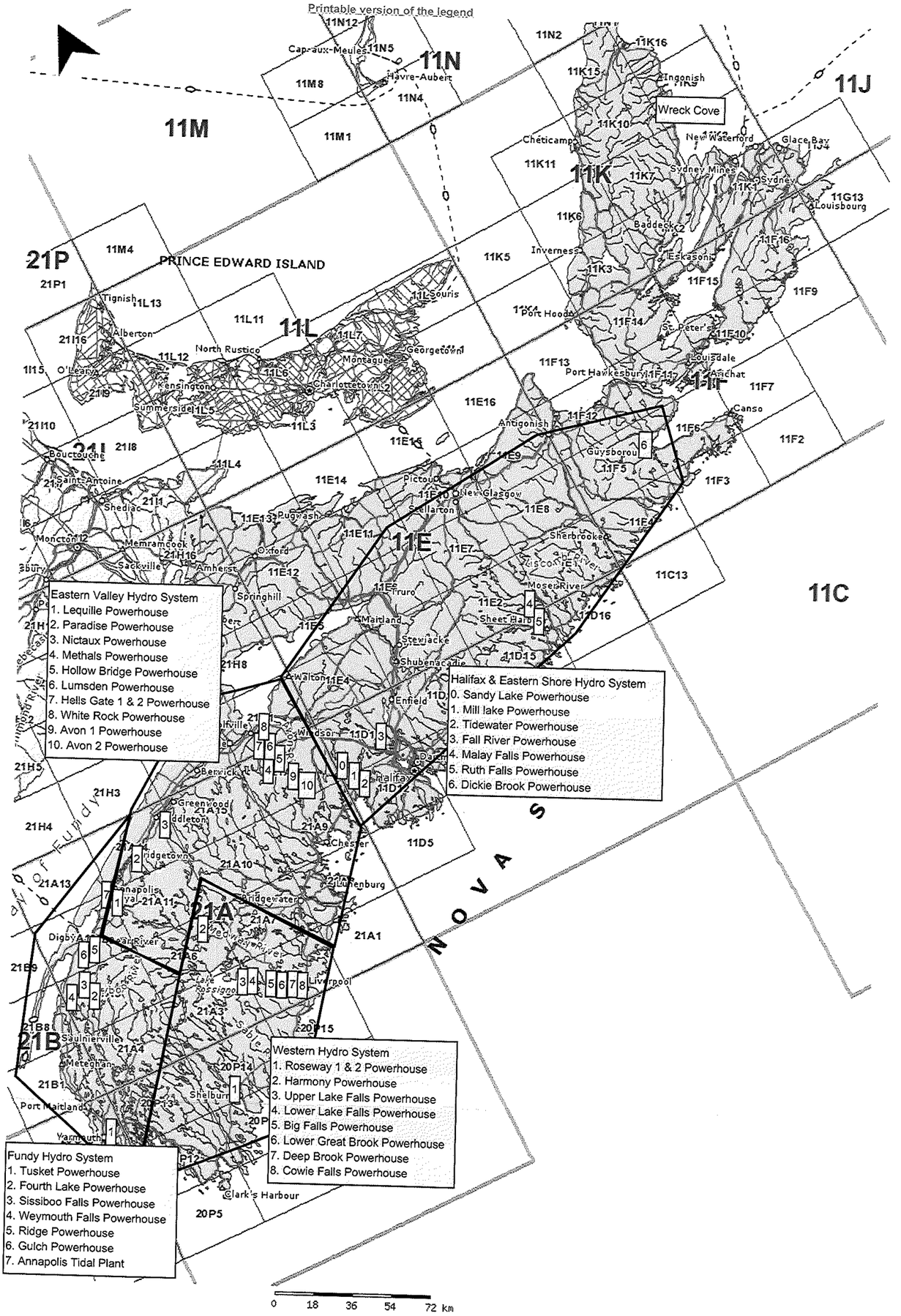
HYD-GEN-PH-AG-2012-404

NOVA SCOTIA POWER
An Emera Company

NSPI Powerhouse Condition Surveys

Halifax and Eastern Shore Hydro System

POWERHOUSE
LOCATION MAPS



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Date Filed: November 22, 2017 Page 1277 of 2371 REDACTED

ACE 2018 CI 44942 Attachment 2 Page 3 of 91

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Toporama – Topographic Maps

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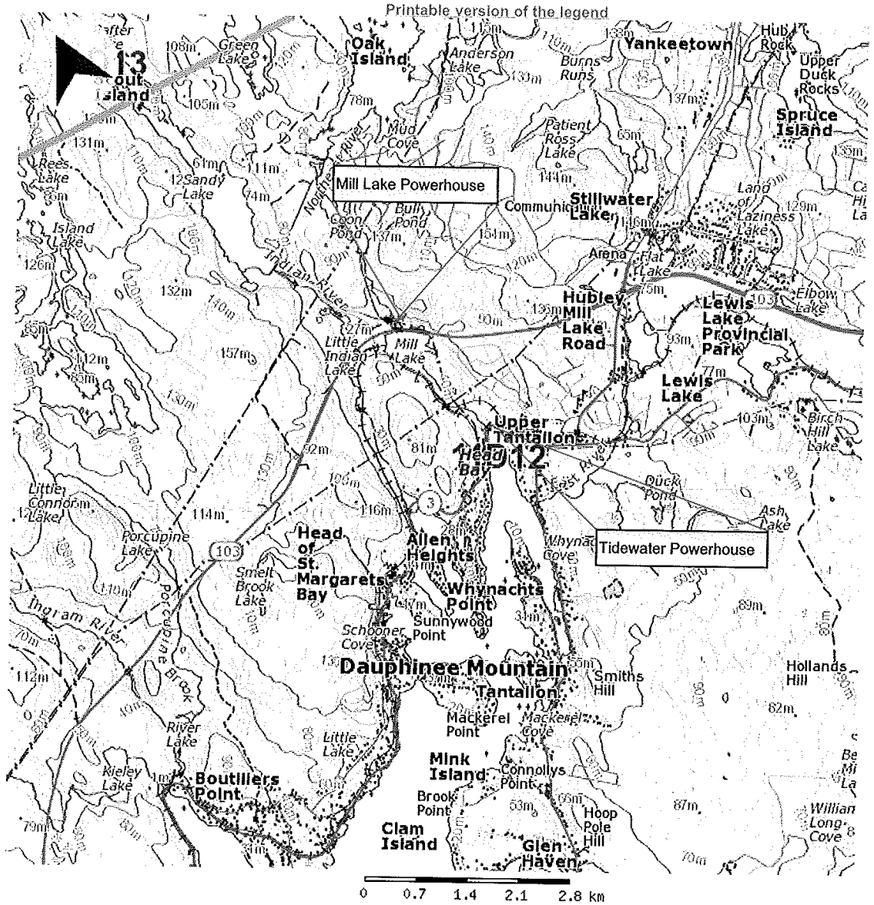

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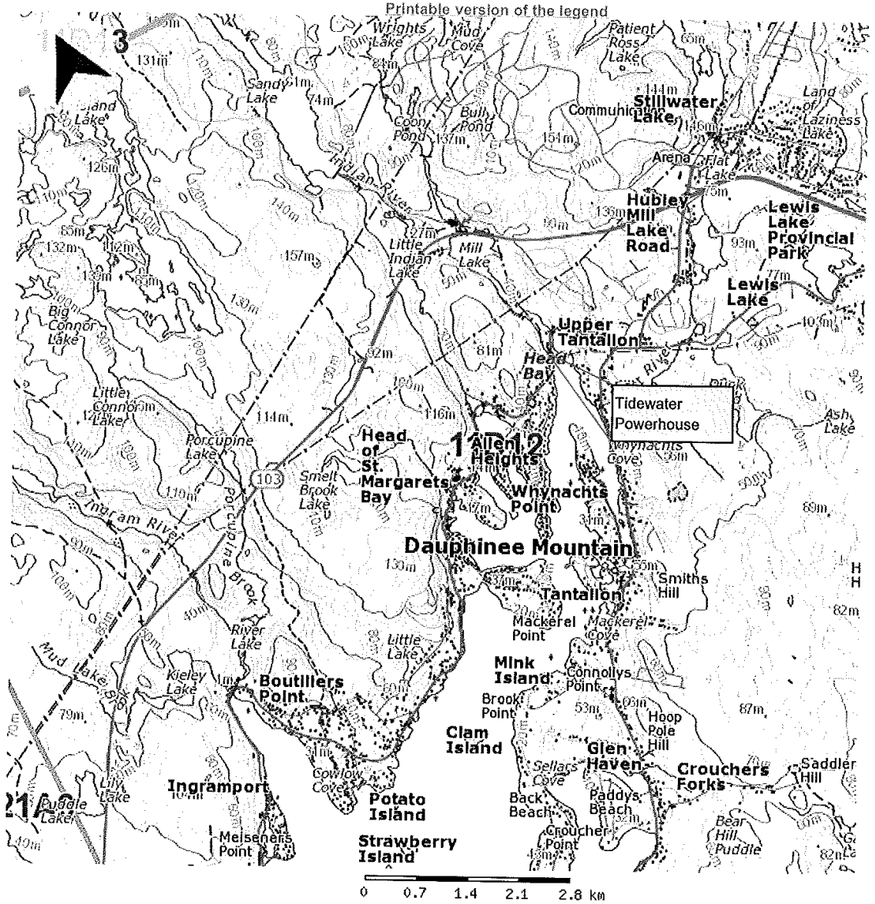
Printable version of the legend



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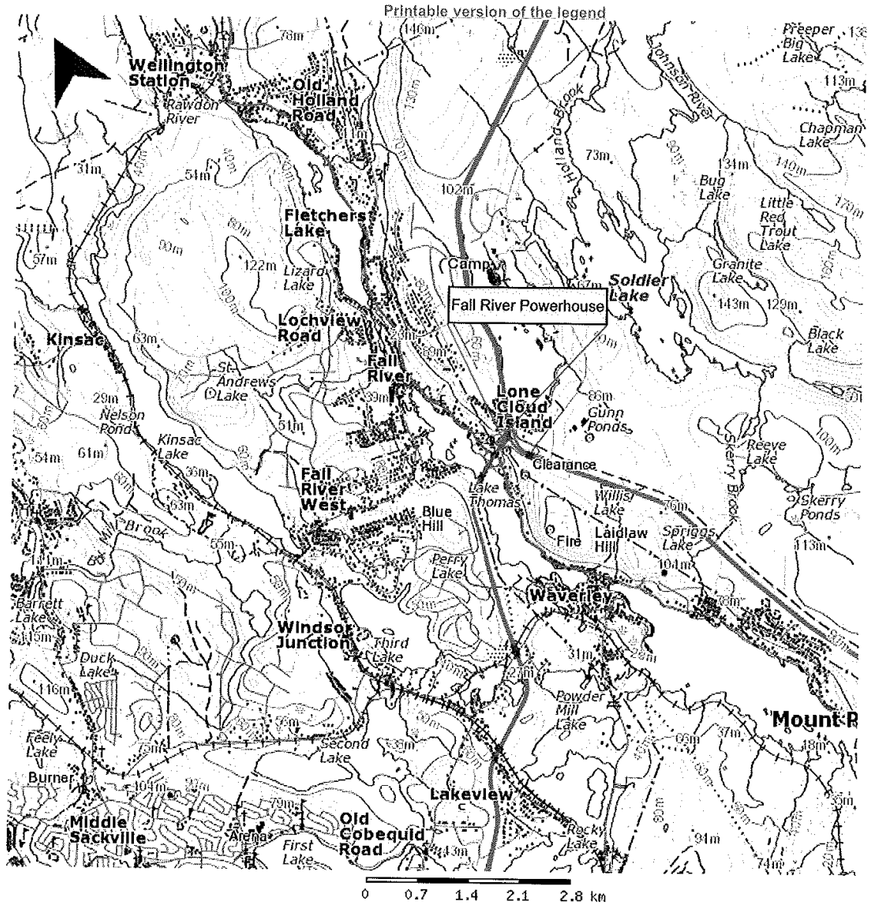
Toporama – Topographic Maps



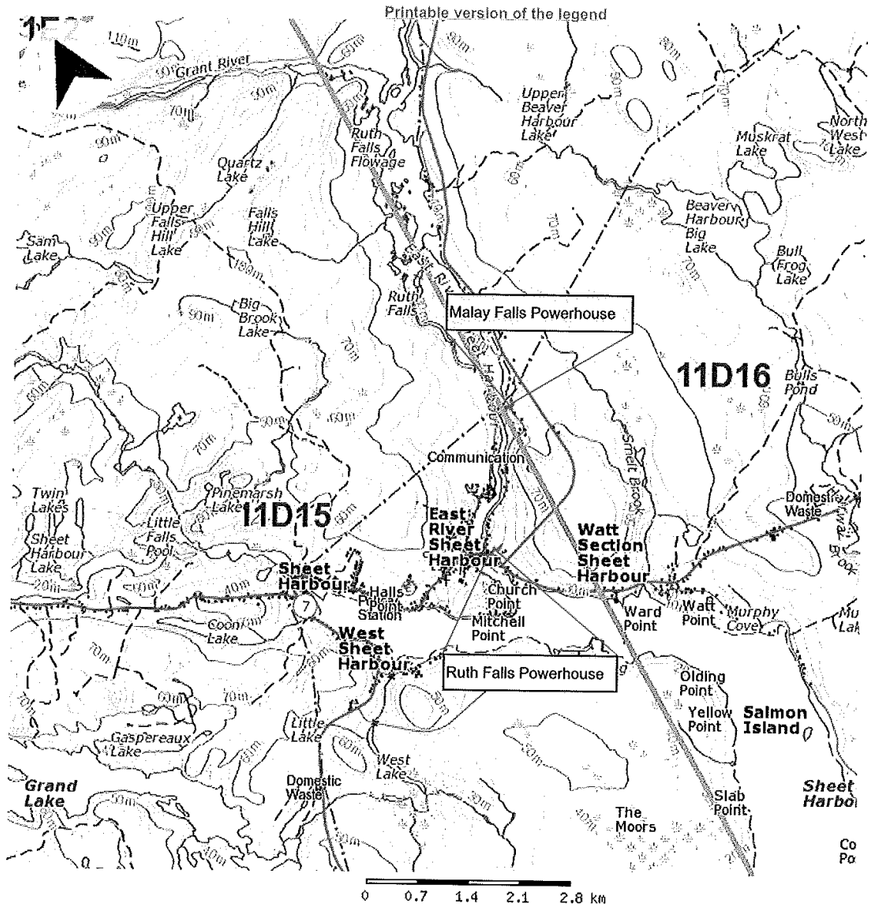
Natural Resources Canada | Ressources naturelles Canada

The Atlas of Canada

Print Map

Return

Toporama – Topographic Maps



Natural Resources Canada | Ressources naturelles Canada

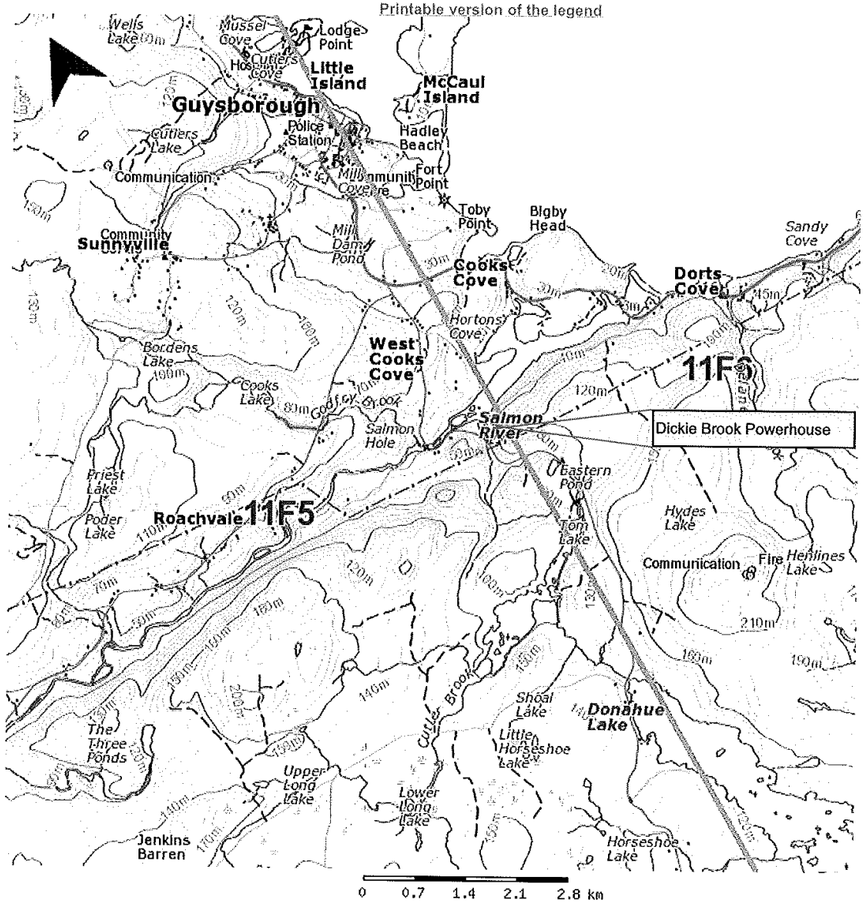
The Atlas of Canada

Print Map

Return

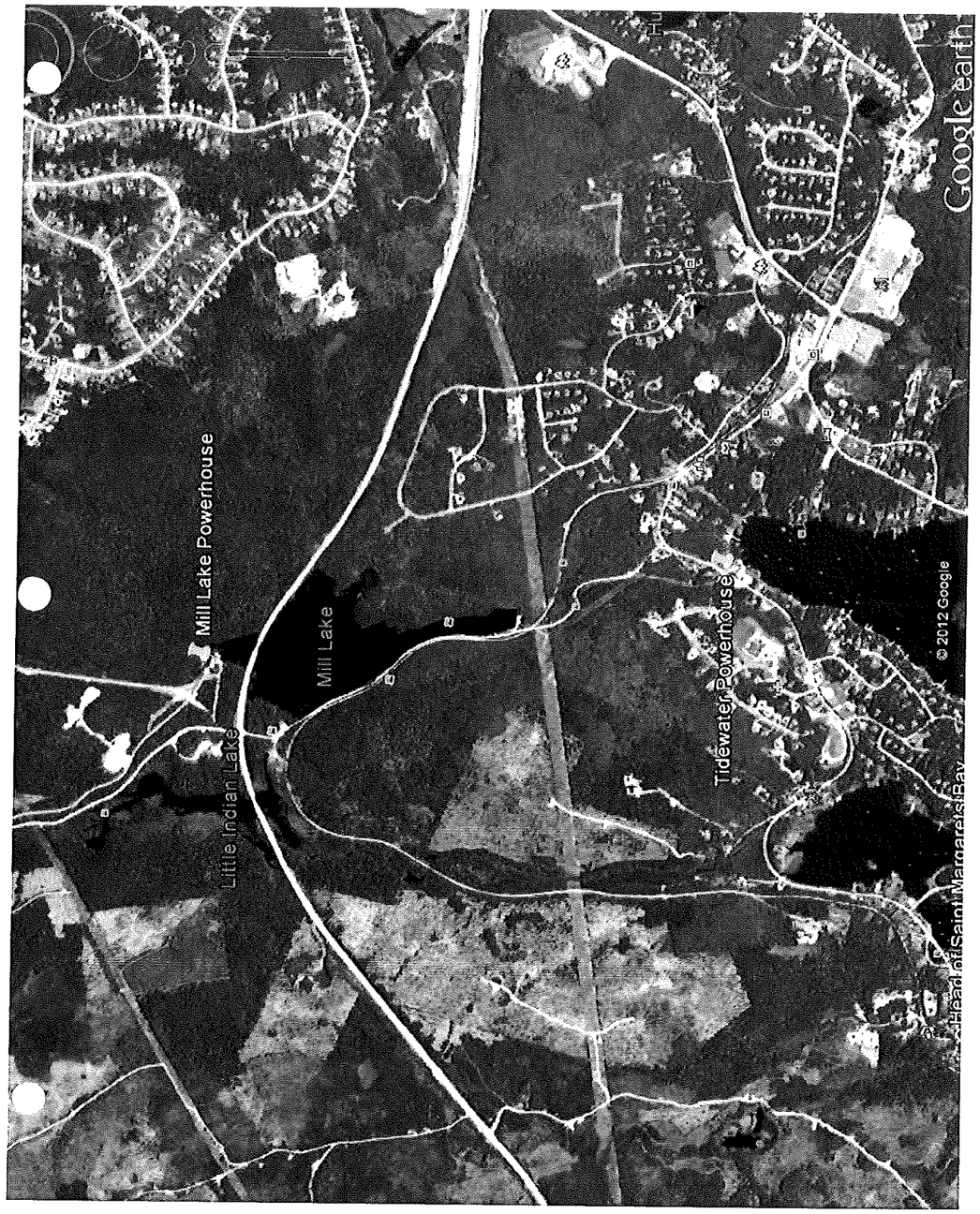
Toporama – Topographic Maps

Printable version of the legend



Halifax and Eastern Shore Hydro System

	Location	Zone	Easting	Northing
1.	Mill Lake Powerhouse	20T	429010.00 m E	4951306.00 m N
2.	Tidewater Powerhosue	20T	429373.53 m E	4949059.40 m N
3.	Fall River Powerhouse	20T	452167.00 m E	4961704.00 m N
4.	Malay Falls Powerhouse	20T	540672.00 m E	4981686.00 m N
5.	Ruth Falls Powerhouse	20T	539532.00 m E	4975800.00 m N
6.	Dickie Brook Powerhouse	20T	617251.59 m E	5022729.96 m N


Mill Lake Powerhouse
Mill Lake
Little Indian Lake
Tidewater Powerhouse
Google earth
© 2012 Google

Google earth
Fall River Powerhouse
Lake Thomas
© 2012 Google

Malay Falls Powerhouse
Malay Falls
Beaver Harbour Big Lake
Ruth Falls Powerhouse
Sheet Harbour
Google earth
© 2012 Cnes/Spot Image
© 2012 Google

West Cooks Cove
Cooks Cove
Dickie Brook Powerhouse
Google earth
© 2012 Cnes/Spot Image
© 2012 Google
Image © 2012 GeoEye

NOVA SCOTIA POWER
An Emera Company

NSPI Powerhouse Condition Survey

November 3, 2011

Halifax and Eastern Shore Hydro System

Mill Lake

351 Mersey Road, St. Margaret's Bay, Nova Scotia

Mill Lake - Halifax and Eastern Shore Hydro

Date	November 3, 2011
Inspector (s):	G. Webber
NSPI Site representative	M. MacCormick
Address:	351 Mersey Road, St. Margaret's Bay, Nova Scotia

Inspection Method: Visual inspection of building drainage, exterior/interior architectural/structural features, lighting, ventilation and louvres.

Inspection Procedure: Received site orientation from NSPI personnel; examined building perimeter at grade level to identify any drainage issues; examined building exterior to determine condition of exterior finishes, including window/doors/area lighting and exterior louvres. Examined exterior roof line with binoculars to identify any noticeable defects. Entered building examined interior floors, walls, underside of roof structure, windows and doors, and noted condition and operation of lighting and ventilation. Noted and photographed areas of interest.

Equipment used: Sony digital Camera and Binoculars, PPE (personal protection equipment), where/as required.

Overall Comments: Powerhouse exterior and interior in generally fair to good shape with some defects as noted on following evaluation sheets.
Exterior concrete walls require repairs and repainting.
New garage door should be installed.
Additional ventilation should be installed in the Generator area.

Mill Lake - Halifax and Eastern Shore Hydro

U - Unacceptable F - Fair
P - Poor G - Good

Exterior Elements	Location Identification	Description	Photo ID	Condition				Remediation Period (Years)			
				U	P	F	G	0-2	2-7	7-20	20+
Building Perimeter Drainage	North	Intake	14				X				X
	South	To Lake	10								
Comments: No problems; building is higher than grading.											
Exterior Walls/ Cladding	North	Painting/caulking	14 - 17			X	X		X		
	East	Painting	18 - 20			X	X		X		
	South	Wall crack repairs/painting	1 - 9			X	X	X	X		
	West	Concrete and glass block glazing repairs	10 - 13, 21			X	X	X	X		
Comments: Painted concrete walls. 3 wall cracks in the east side wing of the South Elevation and one above the window in the centre (11). General painting is required. Recaulk the north wall control joints (14, 17).											
Exterior Doors	North	Painted metal swing garage door	16		X	X			X		
	West	2 Painted metal man doors at lower level (repaint)	10, 13				X				X
Comments: Painted metal swing garage doors should be replaced.											
Windows	South	Glass block with operable aluminum single glazed window inserts	2			X				X	
	East, West, North	Industrial painted metal with single glazing	15, 19, 21			X	X	X			
Comments: Check pointing of glass block and repoint as required. West wall glass block - numerous broken and plywood over, needs repairs (12, 21).											
Exterior Louvres	North	Aluminum louvre and window screens	17			X				X	
	East, West	Window screens, small power operated louvres	10, 19			X			X		
Comments: Replace small louvres. Additional power operated louvres should be installed. Window screens need repair.											
Exterior Lighting	North	1 Sodium light beside garage door	16				X				X
	West	1 Sodium above man door	10				X				X
	SW Corner	Power pole area light					X				X
Comments:											

Date Filed: November 22, 2017
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REDACTED

ACE 2018 CI 44942 Attachment 2 Page 17 of 91

Mill Lake - Halifax and Eastern Shore Hydro

U - Unacceptable F - Fair
P - Poor G - Good

Interior Elements	Location Identification	Description	Photo ID	Condition				Remediation Period (Years)			
				U	P	F	G	0-2	2-7	7-20	20+
Floors	Main Level	Clay quarry tile	23				X				X
	Mezzanine	Painted concrete, touch-up					X				X
	Lower Level	Concrete stair/steps need repair	28		X			X			
Comments:											
Interior Walls	North	Caulk joint replacement	22				X				X
	East		26				X				X
	South	Mezzanine control area	27				X				X
	West	Glass block repairs	21		X	X		X			
Comments: Painted concrete and concrete block walls. Northwest corner spall repair required (25).											
Roof Structure (Underside Only)		Painted concrete	24				X				X
Comments: Small area repainting.											
Interior Lighting	Generator Room	Wall mounted, 6 sodium lights in main area	22, 26				X				X
	Control Room	Fluorescent in mezzanine control area	27				X				X
Comments: 1 sodium light is burned out.											
Building Ventilation and Louvres	East, West	2 Exhaust fans (1 operating)	21, 27			X	X	X			X
	North	1 aluminum louvre	17				X				X
	North, East, West	Screens in windows (2 East/West, 4 North)	15, 19		X			X			
Comments: More power ventilation is required for Generator area.											

Date Filed: November 22, 2017 Page 1292 of 2371 REDACTED

ACE 2018 CI 44942 Attachment 2 Page 18 of 91

Mill Lake - Halifax and Eastern Shore Hydro System - Photographs

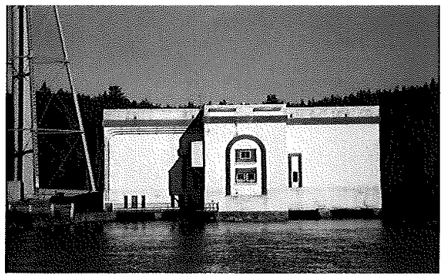


Photo #1 South Elevation, concrete repairs and painting required.

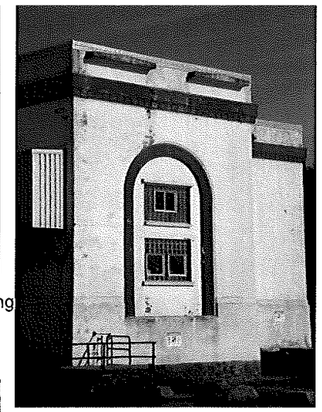


Photo #2 South Elevation, concrete repairs and painting required.

Photo #3 South Elevation, concrete repairs and painting required.

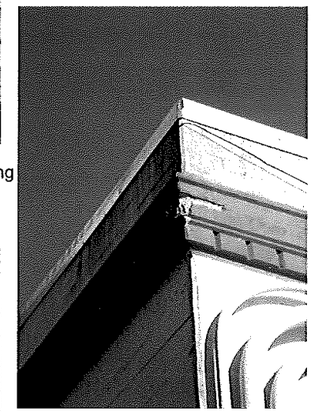


Photo #4 South Elevation, concrete repairs and painting required.

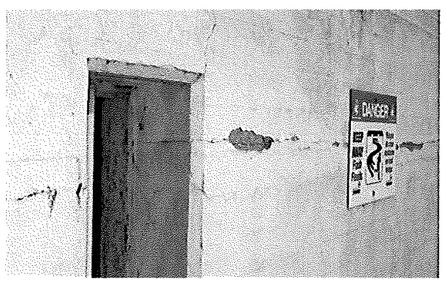


Photo #5 South Elevation, concrete repairs and painting required.

Mill Lake - Halifax and Eastern Shore Hydro System - Photographs

Photo #6 South Elevation, concrete repairs and painting required.

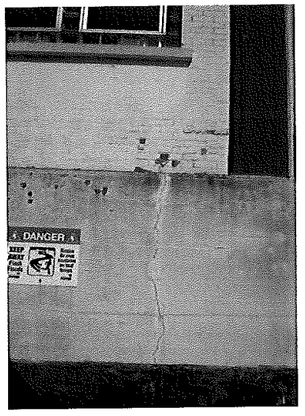


Photo #7 South Elevation, concrete repairs and painting required.

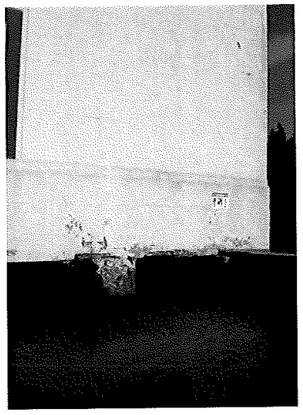


Photo #8 South Elevation, concrete repairs and painting required. (37)

Photo #9 South Elevation, concrete repairs and painting required.

Photo #10 West Elevation, concrete repairs required.

Mill Lake - Halifax and Eastern Shore Hydro System - Photographs

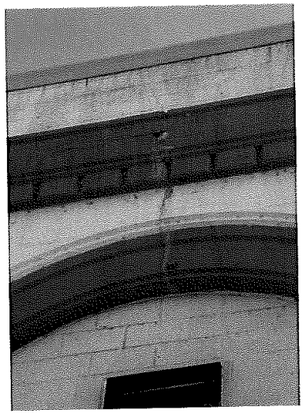


Photo #11 West Elevation, concrete repairs and glazing required.

Photo #12 West Elevation, concrete repairs and plywood over glass block.

Photo #13 West Elevation, concrete repairs and painting required. Also repaint both metal man doors at the lower level.

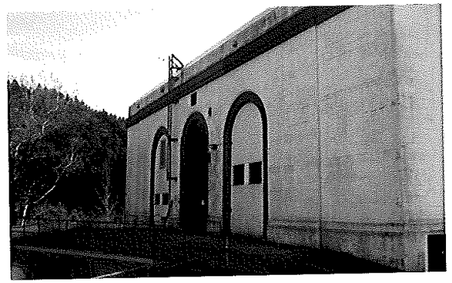


Photo #14 North Elevation, painting and caulking required.

Mill Lake - Halifax and Eastern Shore Hydro System - Photographs

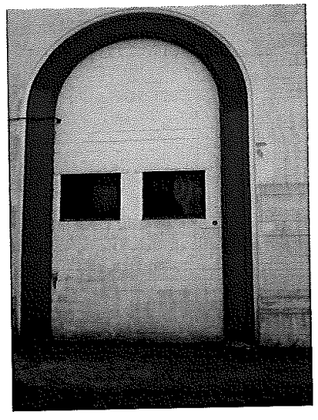


Photo #15 North Elevation, painting and caulking required.

Photo #16 North Elevation, painting and caulking required.

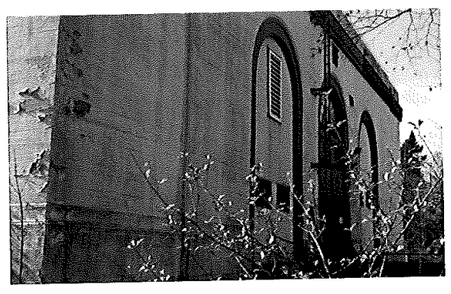


Photo #17 North Elevation, painting and caulking required.

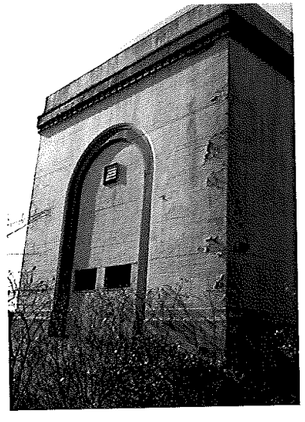


Photo #18 East Elevation, painting required.

Mill Lake - Halifax and Eastern Shore Hydro System - Photographs

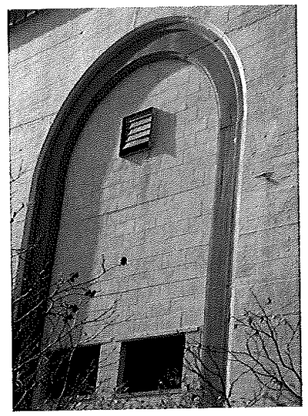


Photo #19 East Elevation, painting required.

Photo #20 East Elevation, painting required.

Photo #21 West Elevation, repair glass block glazing.

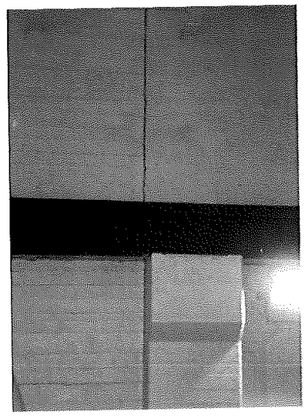


Photo #22 North Elevation, caulk joint replacement required.

Mill Lake - Halifax and Eastern Shore Hydro System - Photographs

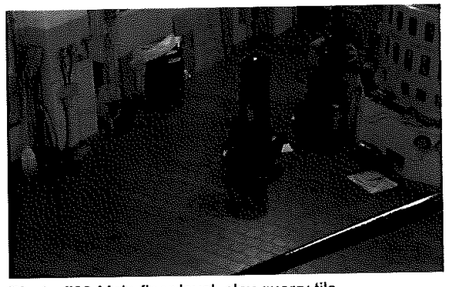


Photo #23 Main floor level, clay quarry tile.

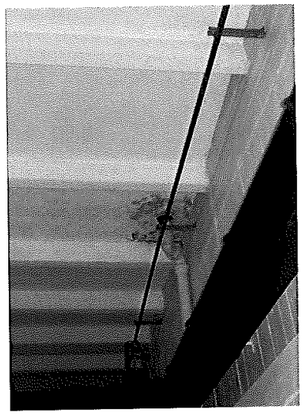


Photo #24 Painted concrete roof structure.

Photo #25 Northwest Corner, spall repair.

Photo #26 East Elevation, Generator Room.

Mill Lake - Halifax and Eastern Shore Hydro System - Photographs

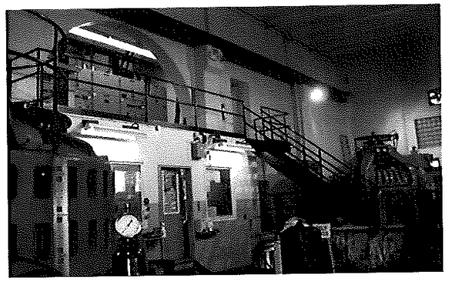
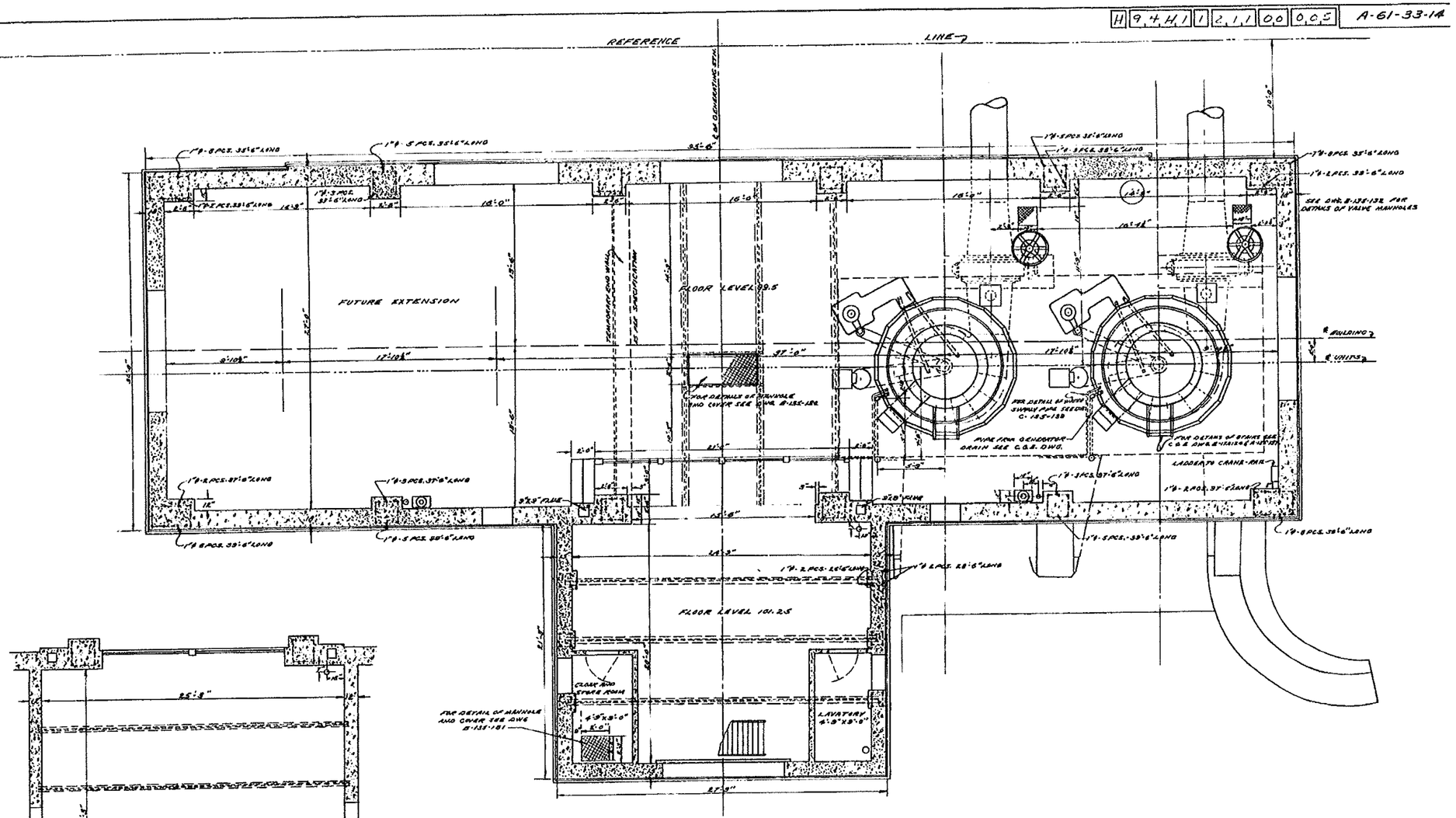


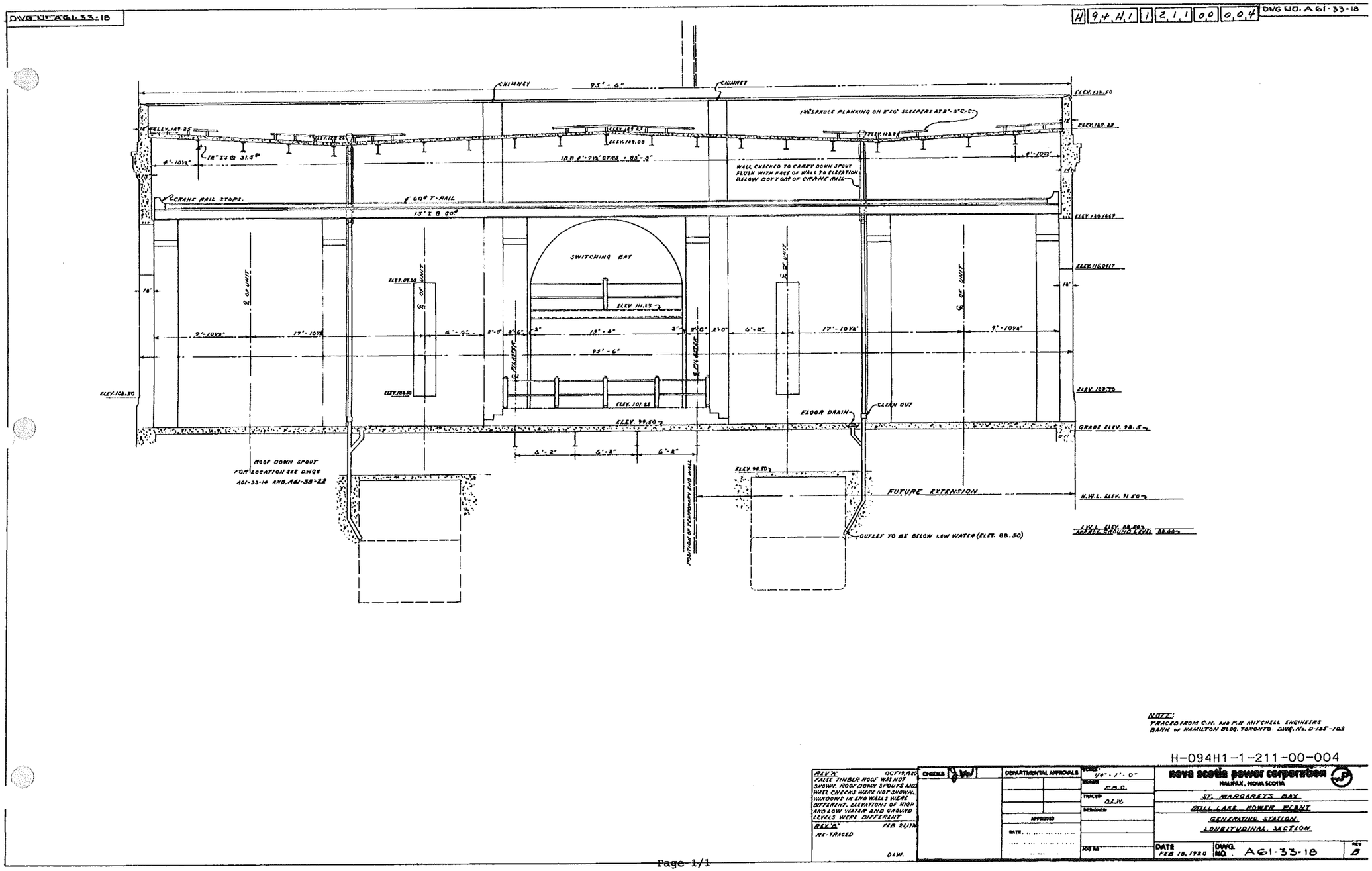
Photo #27 South Elevation, mezzanine control area, repaint concrete floor.

Photo #28 Lower floor level, repair concrete stair/steps and repaint.

A-61-33-14

H 9 4 H 1 1 2 1 1 0 0 0 0 5 A-61-33-14

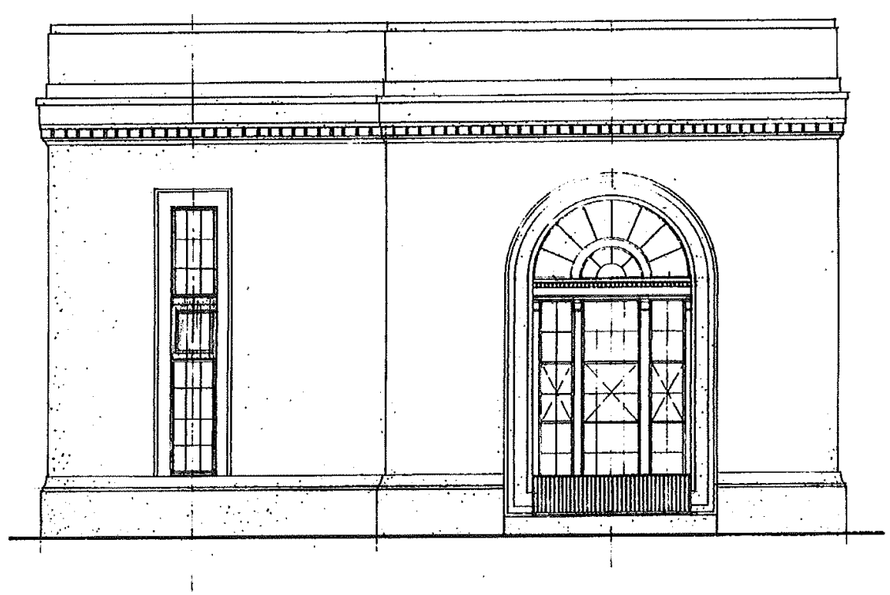

REFERENCE LINE
FUTURE EXTENSION
FLOOR LEVEL 101.25
FLOOR LEVEL 99.5
CLEAR 2000 STORE ROOM
LAVATORY
LADDER TO CRANE BAR
FOR DETAIL OF MANHOLE AND COVER SEE DWG B-135-181
SEE DWG B-135-132 FOR DETAILS OF VALVE MANHOLES
PIPE FROM GENERATOR DRAIN SEE C.G.S. DWG.
FOR DETAILS OF SERVICE AND COVER SEE DWG B-135-180
FOR DETAIL OF WATER SUPPLY PIPE SEE DWG C-185-138
FOR DETAILS OF STRUT SEE C.G.S. DWG B-113138 & B-113137
CENTRE LINE OF BUILDING
CENTRE LINE OF COLUMNS
1"ø-8 PCS. 35'6" LONG
1"ø-5 PCS. 35'6" LONG
1"ø-3 PCS. 35'6" LONG
1"ø-2 PCS. 35'6" LONG
1"ø-2 PCS. 22'6" LONG
1"ø-3 PCS. 37'6" LONG
1"ø-2 PCS. 37'6" LONG
1"ø-2 PCS. 33'6" LONG
1"ø-8 PCS. 33'6" LONG
1"ø-5 PCS. 33'6" LONG
1"ø-3 PCS. 33'6" LONG
1"ø-2 PCS. 33'6" LONG
1"ø-8 PCS. 35'6" LONG
1"ø-5 PCS. 35'6" LONG
1"ø-3 PCS. 37'6" LONG
1"ø-2 PCS. 37'6" LONG
1"ø-2 PCS. 22'6" LONG
1"ø-3 PCS. 37'6" LONG
1"ø-2 PCS. 37'6" LONG
1"ø-8 PCS. 35'6" LONG
1"ø-5 PCS. 35


DWG No. A61-33-18
H 94 H1 1 211 00 004
DWG NO. A61-33-18
CHIMNEY
95'-6"
CHIMNEY
ELEV. 133.50
ELEV. 129.25
ELEV. 129.00
18 @ 4'-7½" CTRS = 83'-3"
WALL CHECKED TO CARRY DOWN SPOUT FLUSH WITH FACE OF WALL TO ELEVATION BELOW BOTTOM OF CRANE RAIL
CRANE RAIL STOPS.
60# T-RAIL
15" I @ 60#
SWITCHING BAY
ELEV. 111.25
ELEV. 101.25
ELEV. 99.50
ELEV. 102.50
ELEV. 102.50
ELEV. 102.50
ELEV. 115.0417
ELEV. 129.1667
9'-10½"
17'-10½"
6'-0"
15'-6"
95'-6"
FLOOR DRAIN
CLEAN OUT
GRADE ELEV. 98.5
ROOF DOWN SPOUT FOR LOCATION SEE DWGS A61-33-14 AND A61-33-22
POSITION OF TEMPORARY END WALL
FUTURE EXTENSION
H.W.L. ELEV. 91.50
OUTLET TO BE BELOW LOW WATER (ELEV. 88.50)
NOTE:
TRACED FROM C.H. AND P.H. MITCHELL ENGINEERS
BANK OF HAMILTON BLDG. TORONTO DWG. No. D-135-103
H-094H1-1-211-00-004
REV "A" OCT 19, 1920
FALSE TIMBER ROOF WAS NOT SHOWN. ROOF DOWN SPOUTS AND WALL CHECKS WERE NOT SHOWN. WINDOWS IN END WALLS WERE DIFFERENT. ELEVATIONS OF HIGH AND LOW WATER AND GROUND LEVELS WERE DIFFERENT
REV "B" FEB 21, 1920
RE-TRACED
D.L.W.
CHECKS
DEPARTMENTAL APPROVALS
APPROVED
DATE
SCALE 1/8" = 1'-0"
DRAWN F.B.C.
TRACED D.L.W.
DESIGNED
JOB NO.
nova scotia power corporation
HALIFAX, NOVA SCOTIA
ST. MARGARETS BAY
MILL LAKE POWER PLANT
GENERATING STATION
LONGITUDINAL SECTION
DATE FEB 18, 1920
DWG. NO. A61-33-18
REV B

Page 1/1

DWG. NO. A61-33-17

H 9,4,H,1 1 2,1,1 0,0 0,0,3 DWG. NO. A61-33-17



·EAST·ELEVATION·
·SCALE·1/4"·1'-0"

·WEST·ELEVATION·
SCALE·1/4"·1'-0"

·NOTE·
FROM·DRAWING BY·C.H & P.H. MITCHELL, ENGINEERS·DATED MAR·9·1920·PLAN No·D135·109

H-094H1-1-211-00-003

REFERENCE DRAWINGS	DWG. NO.

·REVISION "A"
REDRAWN·FEB·18/74

CHECKS JNW

DEPARTMENTAL APPROVALS

APPROVED

DATE

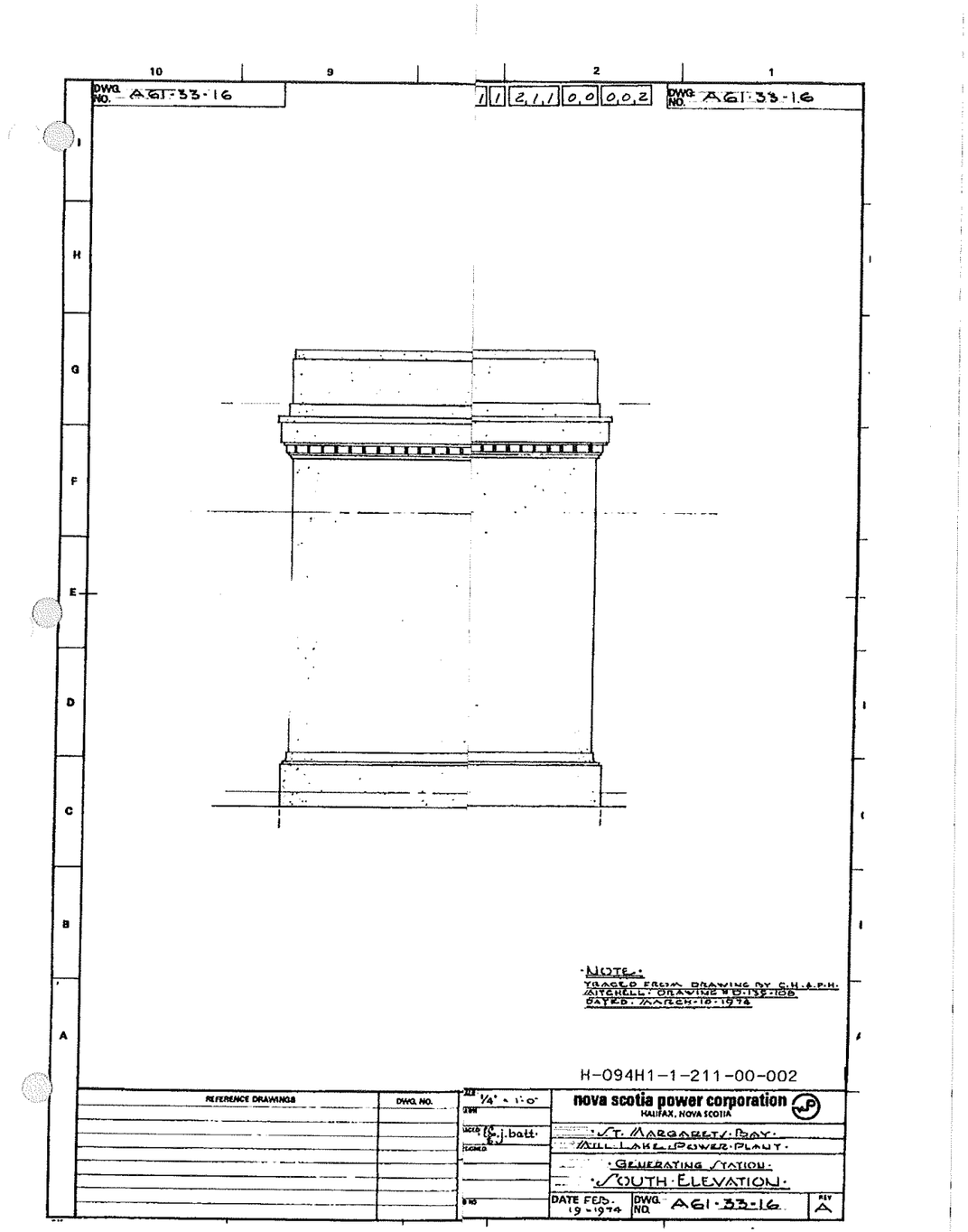
SCALE 1/4"·1'-0"
DRAWN
TRACED E.J. batt.
DESIGNED
JOB NO

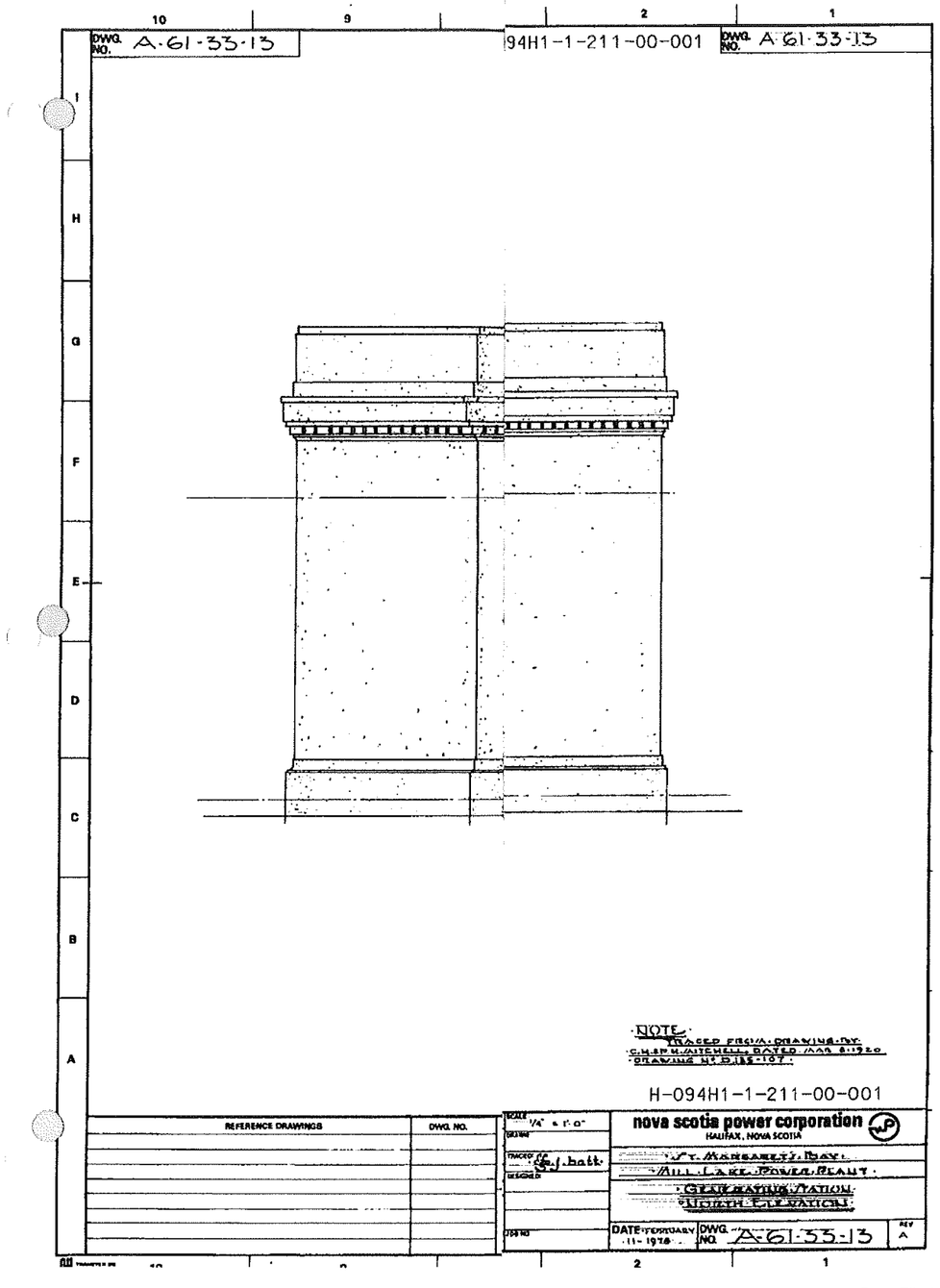
nova scotia power corporation
HALIFAX, NOVA SCOTIA

·ST·MARGARETS·BAY·
·MILL·LAKE·POWER·PLANT·
·GENERATING·STATION·
·EAST & WEST·ELEVATIONS·

DATE·FEB. 18·1974 DWG. NO. A61-33-17 REV A

Page 1/1


10
9
2
1
DWG NO. AGI-33-16
1 1 2,1,1 0,0 0,0,2
DWG NO. AGI-33-16
H
G
F
E
D
C
B
A
NOTE:
TRACED FROM DRAWING BY C.H.&P.H. MITCHELL. DRAWING NO. 135-106 DATED. MARCH-10-1974
H-094H1-1-211-00-002
REFERENCE DRAWINGS
DWG. NO.
1/4" = 1'-0"
D.J.batt
nova scotia power corporation
HALIFAX, NOVA SCOTIA
ST. MARGARETS BAY
MILL LAKE POWER PLANT
GENERATING STATION
SOUTH ELEVATION
DATE FEB. 19-1974
DWG. NO. AGI-33-16
REV A


10
9
2
1
DWG. NO. A-61-33-13
94H1-1-211-00-001
DWG. NO. A-61-33-13
I
H
G
F
E
D
C
B
A
NOTE
TRACED FROM DRAWING BY
C.H. & W. MITCHELL DATED MAR 8 1920
DRAWING NO. 185-107.
H-094H1-1-211-00-001
REFERENCE DRAWINGS
DWG. NO.
SCALE 1/4" = 1'-0"
DRAWN
TRACED G.J. batt.
DESIGNED
JOB NO
nova scotia power corporation
HALIFAX, NOVA SCOTIA
ST. MARGARETS BAY
MILL LAKE POWER PLANT
GENERATING STATION
NORTH ELEVATION
DATE FEBRUARY 11-1976
DWG. NO. A-61-33-13
REV A

NOVA SCOTIA POWER
An Emera Company

NSPI Powerhouse Condition Survey

November 3, 2011

Halifax and Eastern Shore Hydro System

Tidewater

5546 St. Margaret's Bay Road
Head of St. Margaret's Bay, Nova Scotia

Tidewater - Halifax and Eastern Shore Hydro

Date	November 3, 2011
Inspector (s):	G. Webber
NSPI Site representative	M. MacCormick
Address:	5546 St. Margaret's Bay Road Head of St. Margaret's Bay, Nova Scotia

Inspection Method: Visual inspection of building drainage, exterior/interior architectural/structural features, lighting, ventilation and louvres.

Inspection Procedure: Received site orientation from NSPI personnel; examined building perimeter at grade level to identify any drainage issues; examined building exterior to determine condition of exterior finishes, including window/doors/area lighting and exterior louvres. Examined exterior roof line with binoculars to identify any noticeable defects. Entered building examined interior floors, walls, underside of roof structure, windows and doors, and noted condition and operation of lighting and ventilation. Noted and photographed areas of interest.

Equipment used: Sony digital Camera and Binoculars, PPE (personal protection equipment), where/as required.

Overall Comments: Powerhouse exterior and interior in generally fair to good shape with defects as noted on following evaluation sheets.
All exterior concrete walls require some concrete repairs, caulking of control joints and wall penetrations, and painting of entire building to minimize water infiltration.
Additional ventilation should be installed in the Generator area.

Tidewater - Halifax and Eastern Shore Hydro

U - Unacceptable F - Fair
P - Poor G - Good

Exterior Elements	Location Identification	Description	Photo ID	Condition				Remediation Period (Years)			
				U	P	F	G	0-2	2-7	7-20	20+
Building Perimeter Drainage	North to South	South, water/bayside	1, 9				X				X
Comments: No perimeter drainage problems as building is higher than perimeter grading. Storm surge effects basement level with ±2 feet of water at worst condition. Roof drains require cleaning out. Rain gutters required at office building.											
Exterior Walls/Cladding	North		9 - 17			X			X		
	East		8			X			X		
	South	3 cracks/1 caulk control joint	1 - 7			X			X		
	West		18			X			X		
Comments: Exterior walls are painted concrete and brick. Minor amounts of crack repairs; control joint and wall penetrations require caulking; and general painting of entire building.											
Exterior Doors	North	2 metal pivoted garage doors with man door inset	11, 15		X			X			
Comments: Replace the doors.											
Windows	South, West	Dozen broken glass blocks	6			X		X			X
	East, North	Painted metal frames, single glazed	8, 12				X				X
Comments: Glass block windows. Replace broken glass blocks and check pointing of all units for minor repointing.											
Exterior Louvres	South	4 Aluminum louvres with hoods	1				X				X
	North	3 Small exhaust fans and 2 open window screens	9		X	X		X		X	
	East	1 Small louvre	8			X				X	
	West	Operable window in glass block window	18			X				X	
Comments: Additional ventilation should be installed in Generator area, and screens replaced with louvres.											
Exterior Lighting	North	Power pole area light					X				X
	North	3 wall mounted lights	11, 15				X				X
Comments:											

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Tidewater - Halifax and Eastern Shore Hydro

U - Unacceptable F - Fair
P - Poor G - Good

Interior Elements	Location Identification	Description	Photo ID	Condition				Remediation Period (Years)			
				U	P	F	G	0-2	2-7	7-20	20+
Floors	Main Level	Clay quarry tile	21				X				X
	Garage	Concrete needs painting	20			X			X		
	Upper Mezz.	Touch-up painted concrete					X			X	
Comments:											
Interior Walls	North	NE and SE corner painting and crack above Generator Room garage door (28)	19, 28			X					X
	East		22				X				X
	South		23 - 25, 27			X	X	X		X	
	West						X				X
Comments: Painted concrete and concrete block walls. Caulked control joint is open through the wall so daylight can be seen (23), replace joint inside and outside.											
Roof Structure (Underside Only)	Main Level	Painted concrete	26 - 28				X				X
	Upper Mezz. Garage	Repair damaged painted board finish	29			X		X			X
Comments: One horizontal crack in roof slab (south to north) in Generator area (26).											
Interior Lighting	Main Gen. Area	4 Sodium lights, wall mounted	27				X				X
	Upper Mezz. Control	Fluorescent					X				X
	Upper Mezz. Garage	2 Sodium lights	29				X				X
Comments:											
Building Ventilation and Louvres	South	4 Aluminum louvres	27				X				X
	North	3 Exhaust fans and 2 open window screens	28				X	X			X
	East	1 Small louvre	8			X				X	
	West	Operable window in glass block window	18			X				X	
Comments: Additional ventilation should be installed in Generator area. Replace open screens with louvres.											

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Tidewater - Halifax and Eastern Shore Hydro System - Photographs

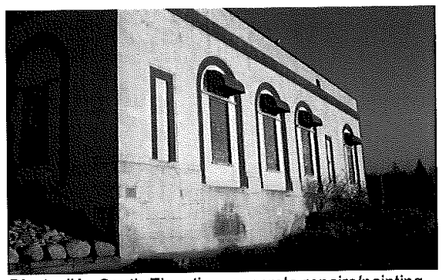


Photo #1 South Elevation, concrete repairs/painting required.

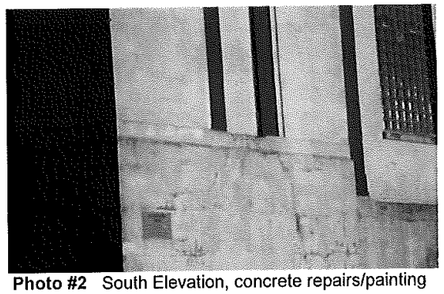


Photo #2 South Elevation, concrete repairs/painting required.

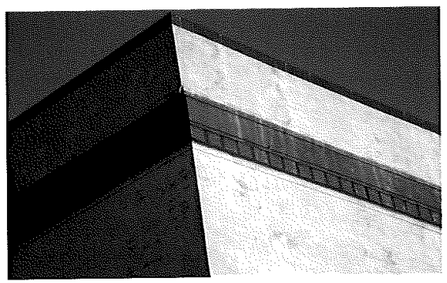


Photo #3 South Elevation, concrete repairs/painting required.

Photo #4 South Elevation, concrete repairs/painting required.

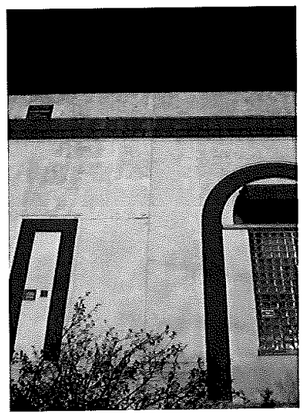


Photo #5 South Elevation, concrete repairs/painting and control joint repair required.

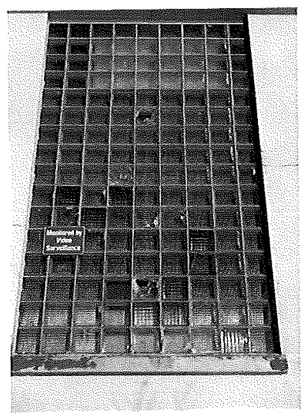


Photo #6 South Elevation, replace broken glass blocks and check pointing.

Tidewater - Halifax and Eastern Shore Hydro System - Photographs

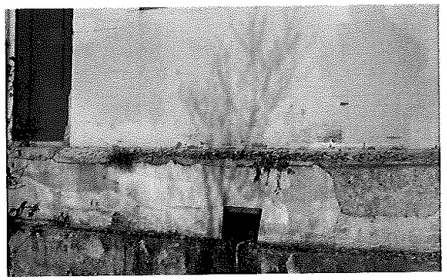


Photo #7 South Elevation, concrete repairs/painting required.

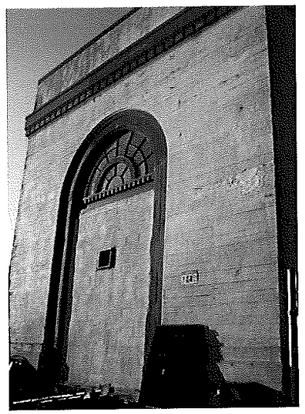


Photo #8 East Elevation, concrete repairs/painting required.

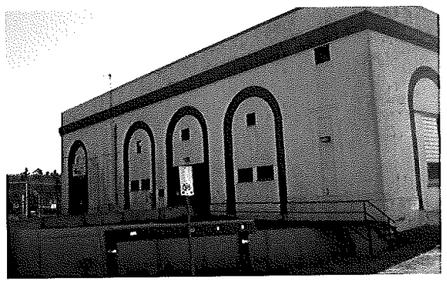


Photo #9 North Elevation, concrete repairs/painting required.

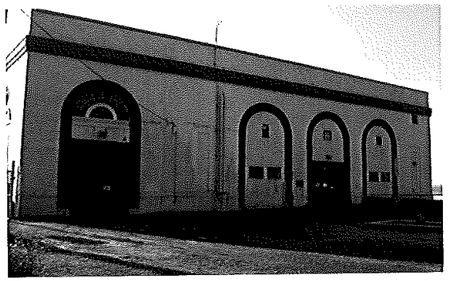


Photo #10 North Elevation, concrete repairs required.

Photo #11 North Elevation, replace garage doors.

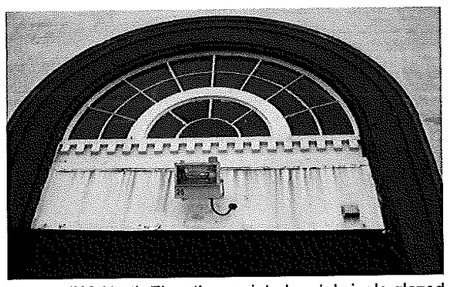


Photo #12 North Elevation, painted metal single glazed window; wall mounted light above garage door.

Tidewater - Halifax and Eastern Shore Hydro System - Photographs

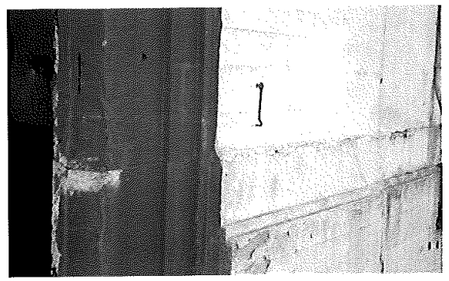


Photo #13 North Elevation, concrete repairs/painting required.

Photo #14 North Elevation, caulk control joints.

Photo #15 North Elevation, replace garage doors.

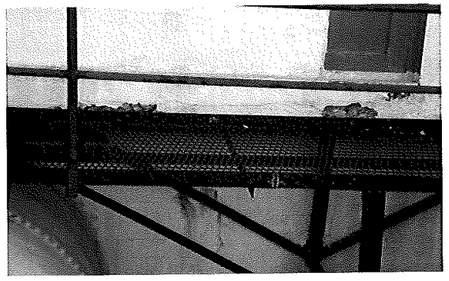


Photo #16 North Elevation, concrete repairs/painting required.

Photo #17 North Elevation, concrete repairs/painting required.

Tidewater - Halifax and Eastern Shore Hydro System - Photographs

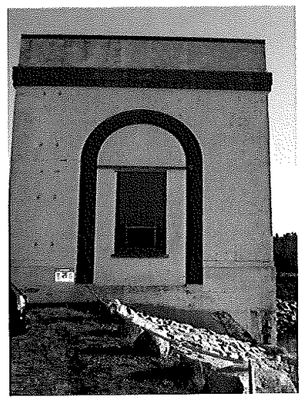


Photo #18 West Elevation, concrete/ painting repairs required.

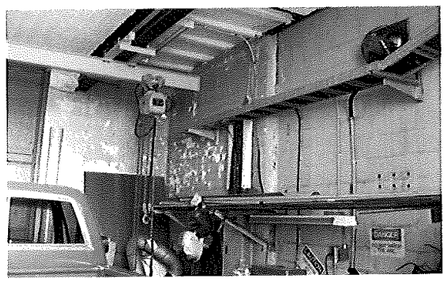


Photo #19 Northeast Corner, painting required.

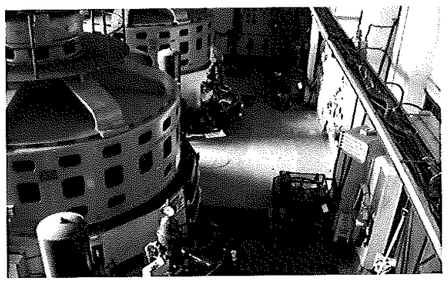


Photo #21 Main floor level, clay quarry tile.

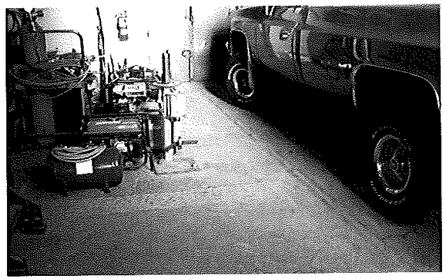


Photo #20 Concrete garage floor requires painting.

Photo #22 East Elevation, crack above window requires repair.

Tidewater - Halifax and Eastern Shore Hydro System - Photographs

Photo #23 South Elevation, replace control joint inside and outside.

Photo #24 South Elevation, evidence of moisture penetration.

Photo #25 South Elevation, evidence of moisture penetration.

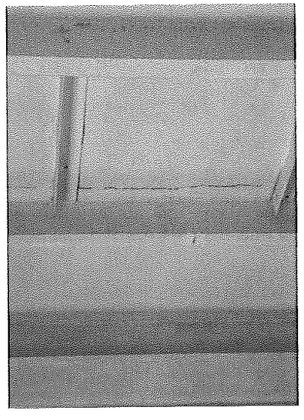


Photo #26 Main roof structure, repair the horizontal crack in the roof slab (south to north) in the Generator area.

Photo #27 Main Generator Area, 4 wall mounted sodium lights.

Tidewater - Halifax and Eastern Shore Hydro System - Photographs

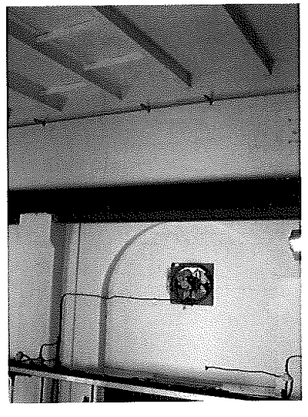


Photo #28 North Elevation, repair crack above Generator Room garage door.

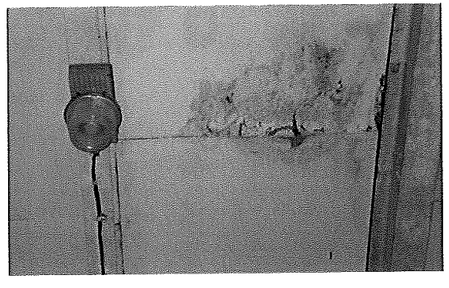
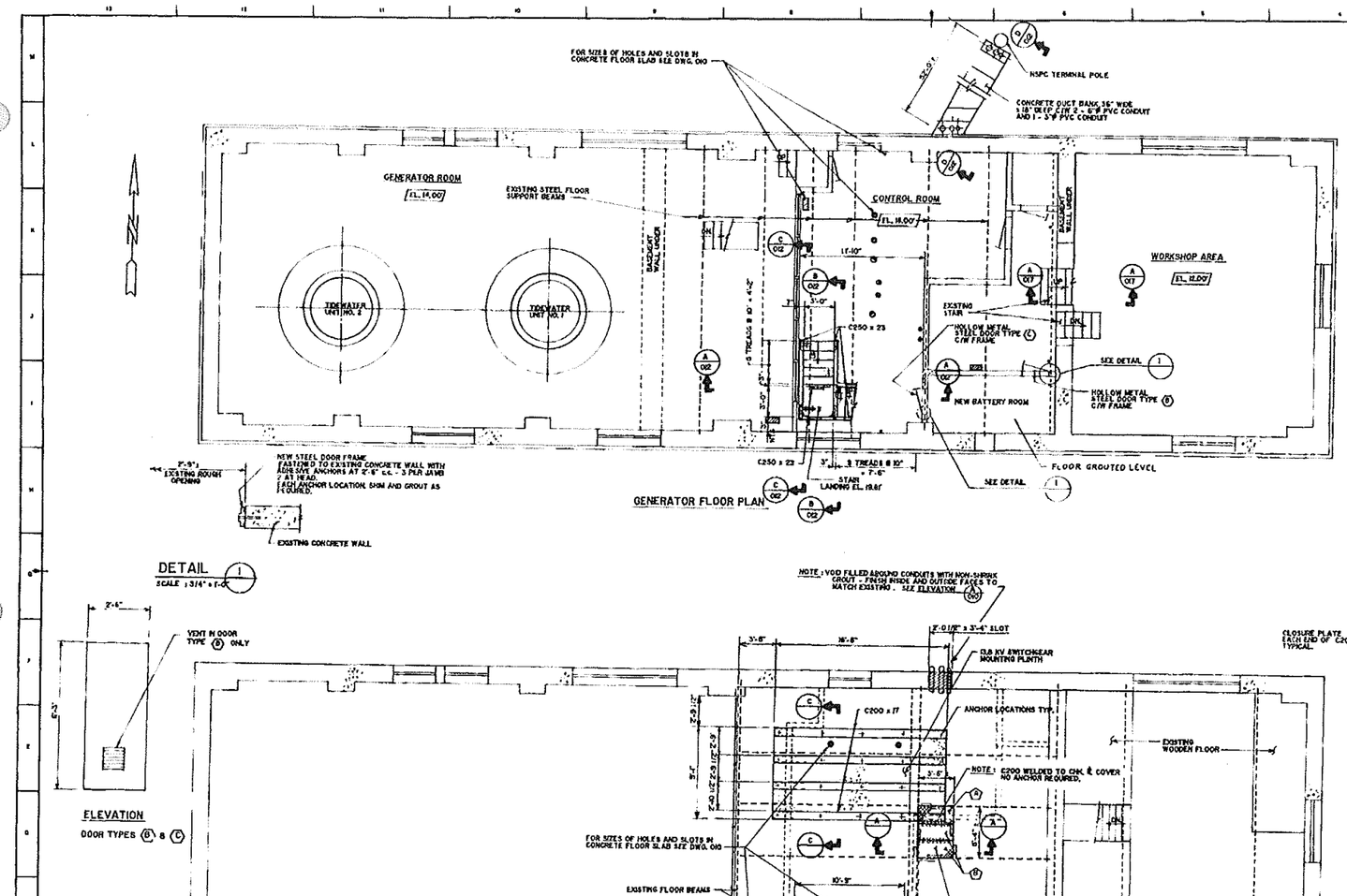


Photo #29 Garage/Mezzanine, repair damaged board finish.

DWG H092H1121100011



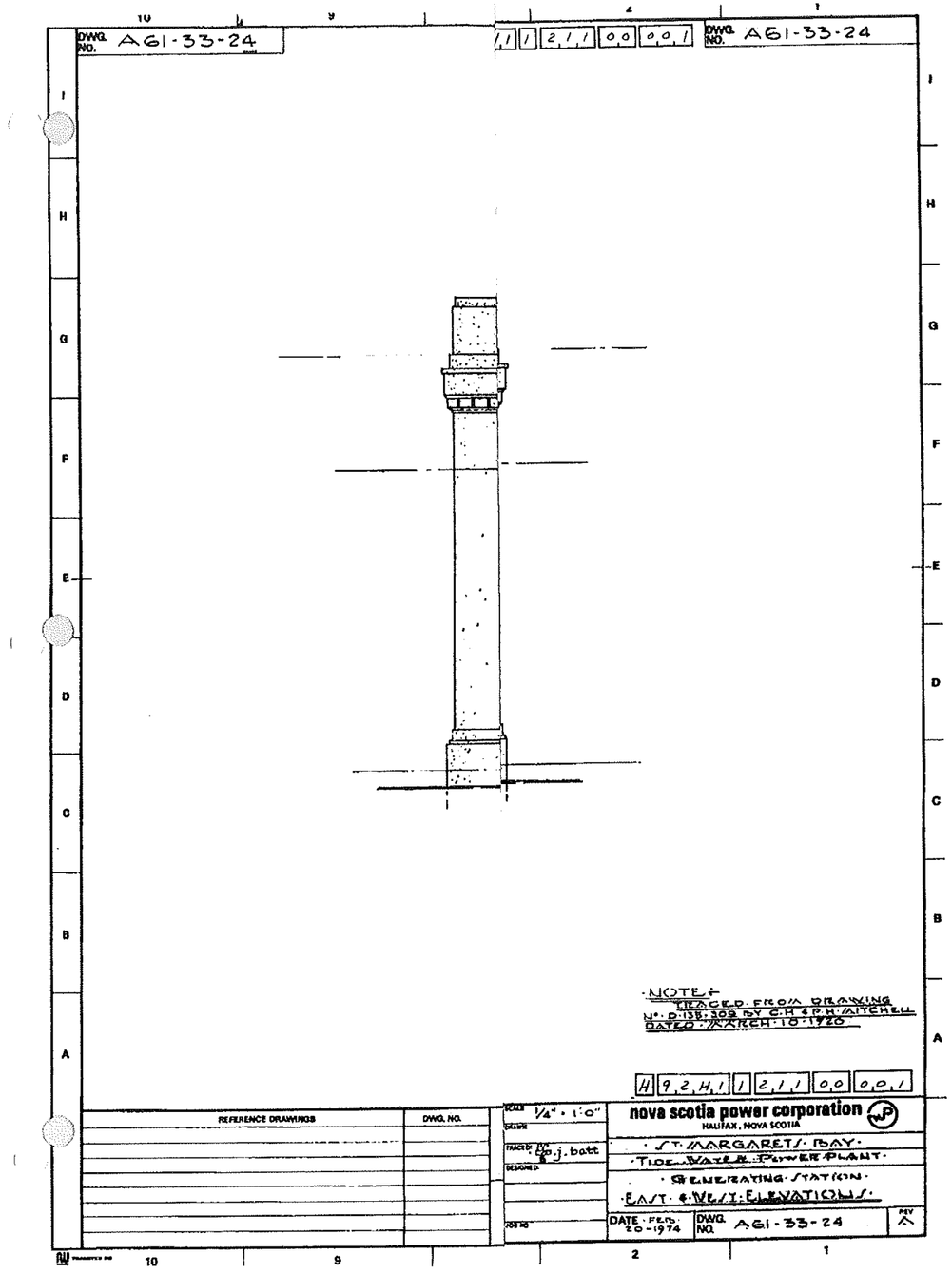
AS BUILT

TIDEWATER DEVELOPMENT FOUNDATION SECTIONS	H092H1121100011
TIDEWATER DEVELOPMENT FOUNDATION PLAN & SECTIONS	H092H1121100006
TIDEWATER DEVELOPMENT SECTIONS OF OPERATIONS OFFICE	H092H1121100008

REFERENCE DRAWINGS — DRAWING NUMBER

C	REVISED AS BUILT	BY: DJC	DATE: 87 06 28	BY: DJC DATE: 89 05 09
B	ISSUED FOR CONSTRUCTION	BY: DJC	DATE: 87 01 12	
A	ISSUED FOR TENDER CONTRACT NO. E-01			

nova scotia power corporation
HALIFAX NOVA SCOTIA
HALIFAX AREA
92H TIDEWATER HYDRO
GENERATOR AND GALLERY FLOOR PLANS SECTIONS AND DETAILS
DWG NO H092H1121100011 REV C
JOB NO 33072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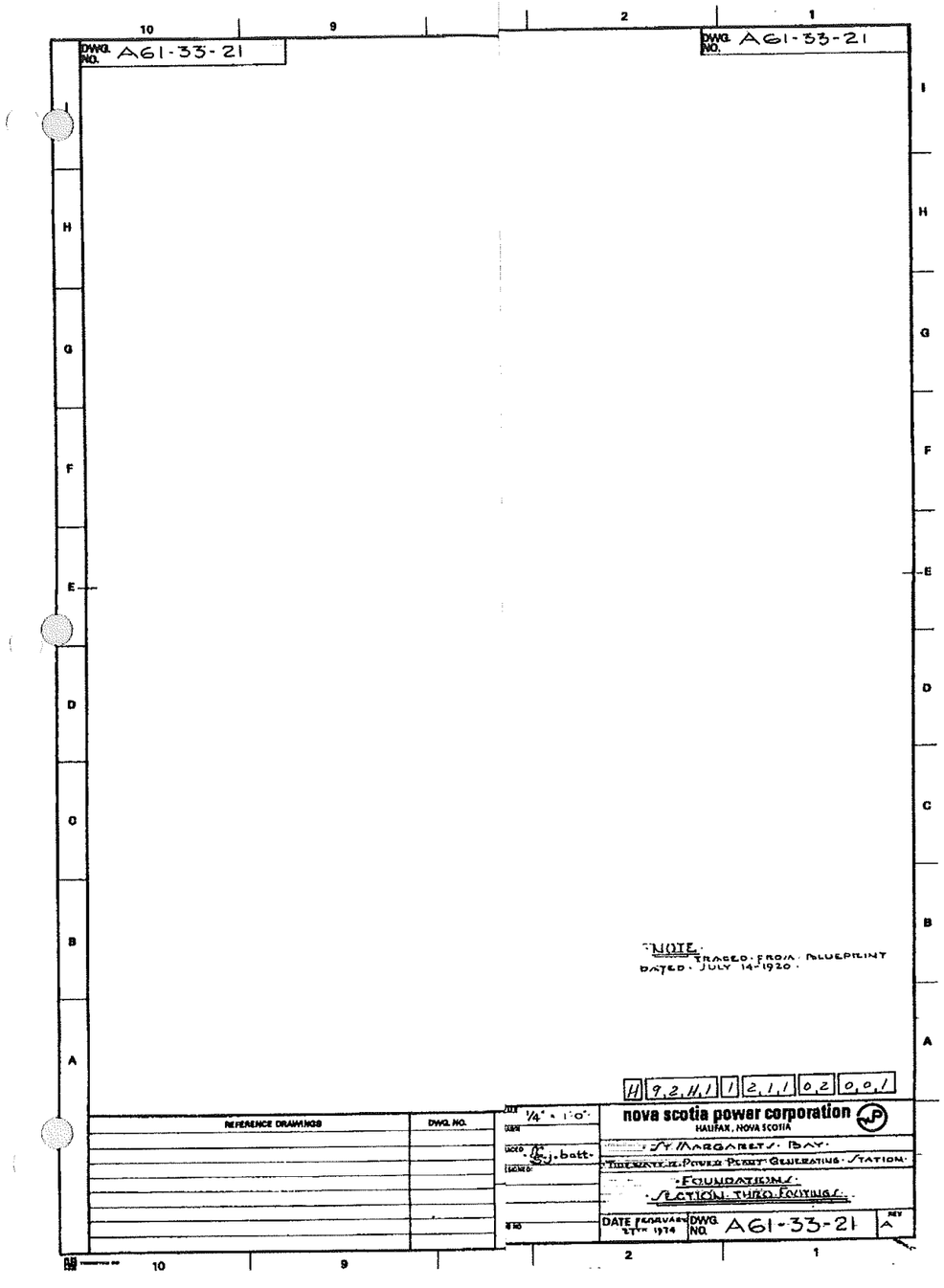
DESIGNED
JOB NO
nova scotia power corporation
HALIFAX, NOVA SCOTIA
ST. MARGARETS BAY
TIDE WATER POWER PLANT
GENERATING STATION
EAST & WEST ELEVATIONS
DATE FEB 20-1974
DWG. NO. A61-33-24
REV
10 9 2 1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nova scotia power corporation
HALIFAX, NOVA SCOTIA
ST MARGARETS BAY
THERMAL POWER PLANT GENERATING STATION
FOUNDATIONS
SECTION THRO FOOTINGS
DATE FEBRUARY 27TH 1974
DWG. NO. A61-33-21
REV A

NOVA SCOTIA POWER
An Emera Company

NSPI Powerhouse Condition Survey

October 28, 2011

Halifax and Eastern Shore Hydro System

Fall River

67 Ray's Lane, Fall River, Nova Scotia

Fall River - Halifax and Eastern Shore Hydro

Date	October 28, 2011
Inspector (s):	G. Webber
NSPI Site representative	M. MacCormick
Address:	67 Ray's Lane, Fall River, Nova Scotia

Inspection Method: Visual inspection of building drainage, exterior/interior architectural/structural features, lighting, ventilation and louvres.

Inspection Procedure: Received site orientation from NSPI personnel; examined building perimeter at grade level to identify any drainage issues; examined building exterior to determine condition of exterior finishes, including window/doors/area lighting and exterior louvres. Examined exterior roof line with binoculars to identify any noticeable defects. Entered building examined interior floors, walls, underside of roof structure, windows and doors, and noted condition and operation of lighting and ventilation. Noted and photographed areas of interest.

Equipment used: Sony digital Camera and Binoculars, PPE (personal protection equipment), where/as required.

Overall Comments: Powerhouse exterior and interior in generally good shape with some defects as noted on following evaluation sheets.
Exterior painting of the building would add longevity to the structure.

Fall River - Halifax and Eastern Shore Hydro

U - Unacceptable F - Fair
P - Poor G - Good

Exterior Elements	Location Identification	Description	Photo ID	Condition				Remediation Period (Years)			
				U	P	F	G	0-2	2-7	7-20	20+
Building Perimeter Drainage	East to West	Dug in embankment	5, 6				X				X
Comments: North roof gutter rusted through, requires replacement (4). South roof gutter totally rusted through, requires replacement (8).											
Exterior Walls/ Cladding	North	Front NE corner trim repair and dented siding to left of man door (11)	1, 3 - 5, 10			X	X			X	
	East		6			X	X			X	
	South		7, 8			X	X			X	
	West		2			X	X			X	
Comments: Prefinished metal siding. Metal flashing at base of South wall (10'±) was unpainted, now rusting and requires painting (9). Recaulk wall penetrations. Gutters require replacement. Future repainting of all the siding will add longevity to the building.											
Exterior Doors	North	Section insulation overhead door	1, 3			X				X	
	North	Painted metal insulation man door	1				X			X	
Comments: Bottom section of overhead door has been dented inward (3), but door still operates properly (by manual chain hoisting). Both doors should be repainted.											
Windows	None										
Comments:											
Exterior Louvres	West	1 Aluminum louvre	2				X				X
	Roof	Automatic exhaust louvre					X				X
Comments:											
Exterior Lighting	Area	Power pole at Northeast corner					X				X
Comments:											

Date Filed: November 22, 2017

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Fall River - Halifax and Eastern Shore Hydro

U - Unacceptable F - Fair
P - Poor G - Good

Interior Elements	Location Identification	Description	Photo ID	Condition				Remediation Period (Years)			
				U	P	F	G	0-2	2-7	7-20	20+
Floors	Main Level		15				X				X
Comments: Epoxy painted concrete.											
Interior Walls	North						X				X
	East						X				X
	South		13				X				X
	West		14				X				X
Comments: Prefinished metal liner panel to 10' (then just metal building vapour barriered insulation). Tape penetrations through building insulation vapour barrier.											
Roof Structure (Underside Only)		Exposed vapour barrier over insulation	12				X				X
Comments: Tape penetrations through building insulation vapour barrier.											
Interior Lighting		4 Sodium lights	12				x				X
Comments:											
Building Ventilation and Louvres	West	Aluminum louvre	2, 14				X				X
	Roof	Automatic exhaust louvre					X				X
Comments:											

Date Filed: November 22, 2017 Page 1323 of 2371 REDACTED

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Fall River - Halifax and Eastern Shore Hydro System - Photographs

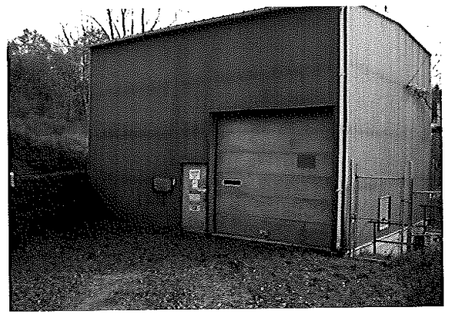


Photo #1 North Elevation.

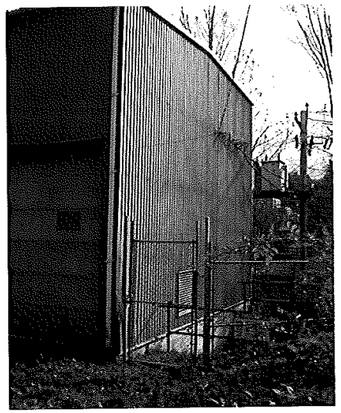


Photo #2 West Elevation.

Photo #3 North Elevation, repair bottom section of overhead door where it is dented inward and repaint.

Photo #4 North Elevation, the roof gutter is rusted through and requires replacement.

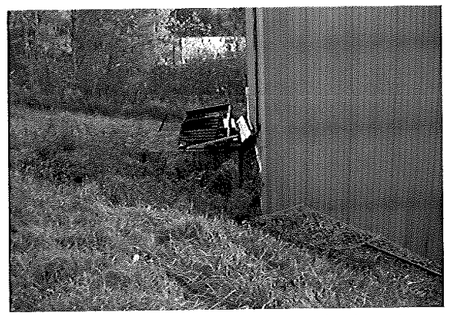


Photo #5 Northeast Corner, dug-in embankment, drainage East to West.

Fall River - Halifax and Eastern Shore Hydro System - Photographs

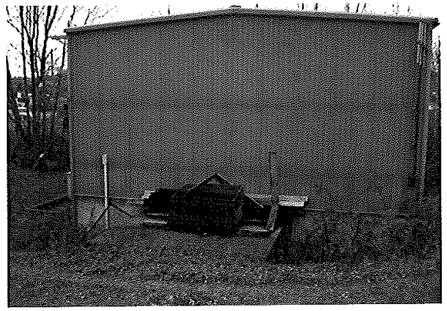


Photo #6 East Elevation.

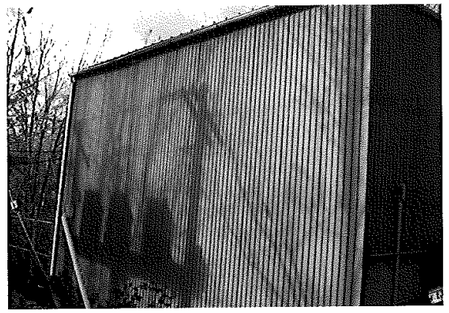


Photo #7 South Elevation.

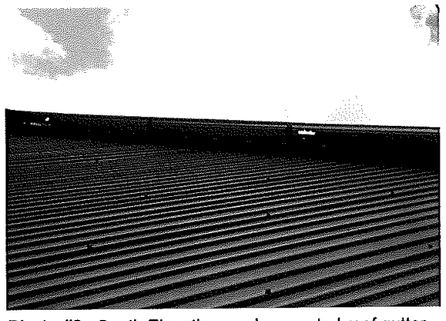


Photo #8 South Elevation, replace rusted roof gutter.

Photo #9 Metal flashing at the base of the South wall is rusted and requires painting.

Photo #10 Northeast Corner, repair trim.

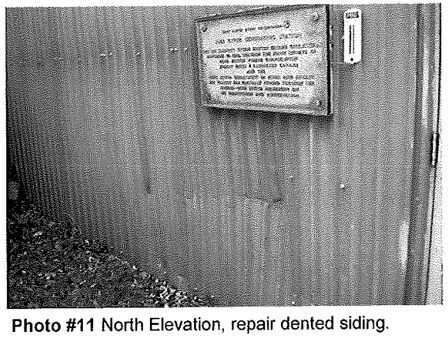


Photo #11 North Elevation, repair dented siding.

Fall River - Halifax and Eastern Shore Hydro System - Photographs

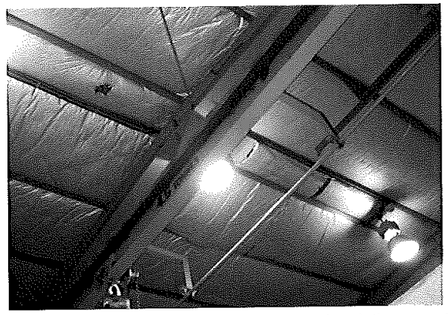


Photo #12 Exposed vapour barrier over insulation, repair penetrations through vapour barrier.

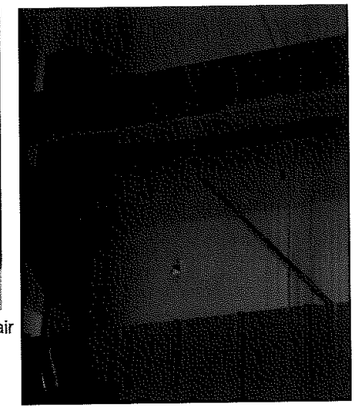


Photo #13 South Elevation, repair penetrations through vapour barrier.

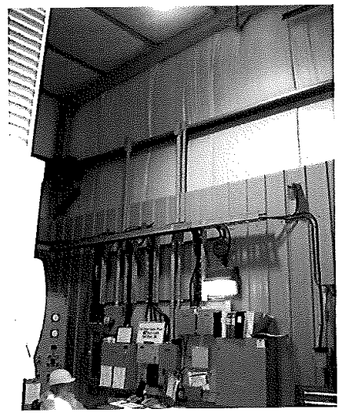


Photo #14 West Elevation, prefinished metal line panel to 10' then just metal building vapour barrier insulation).

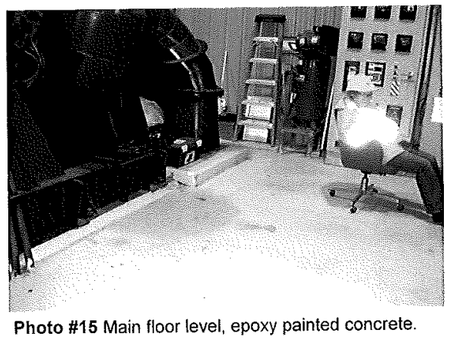
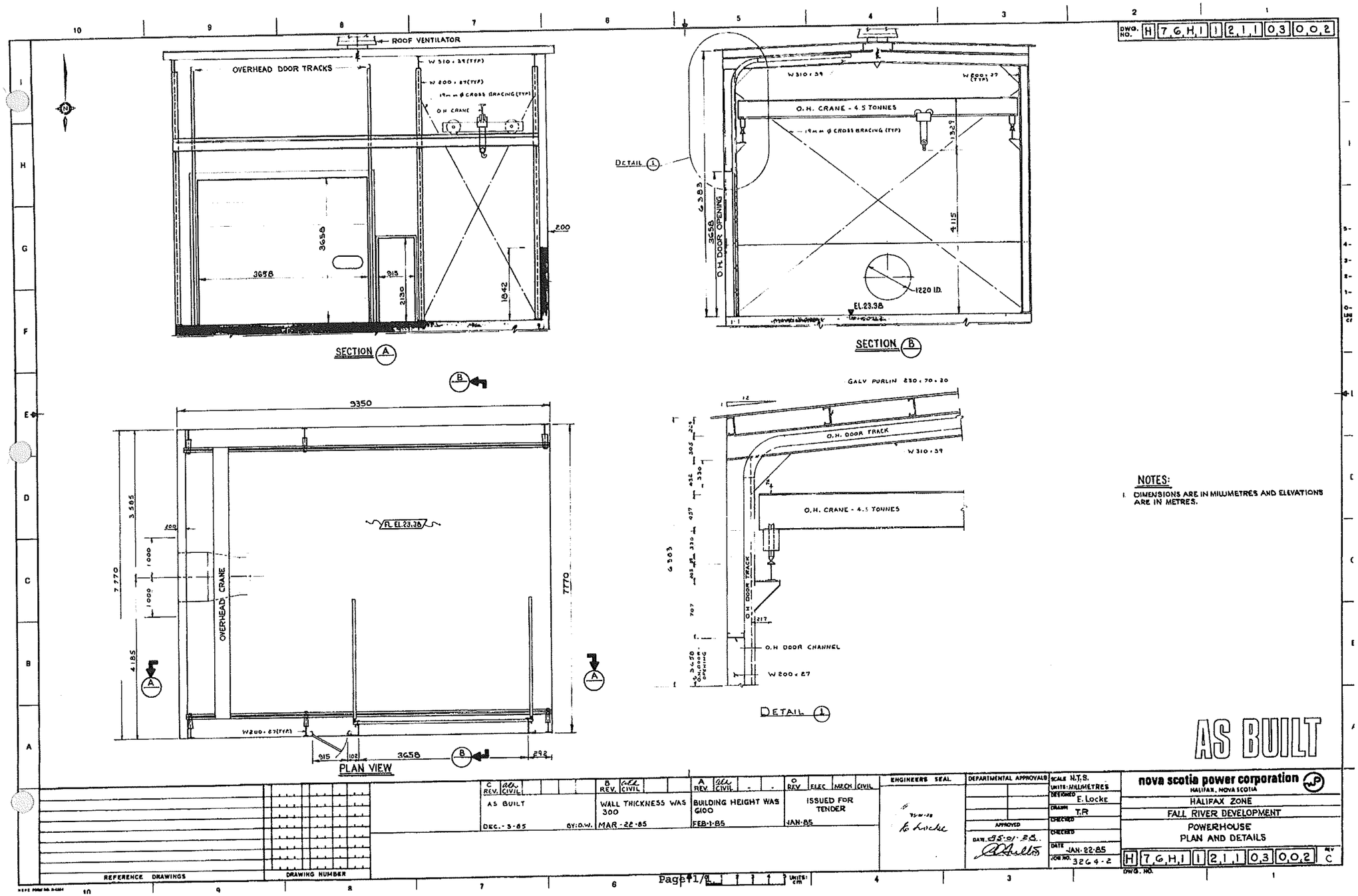
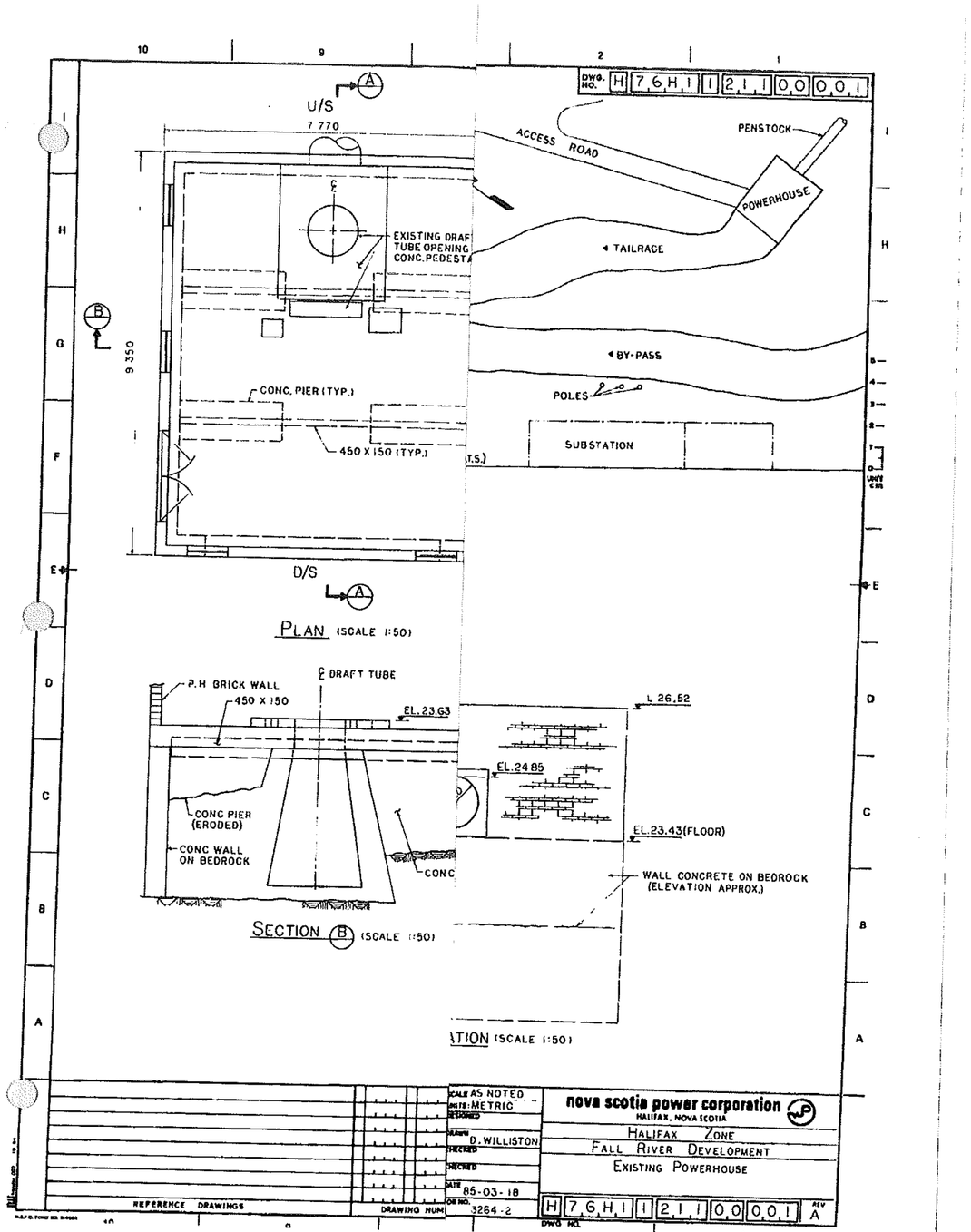
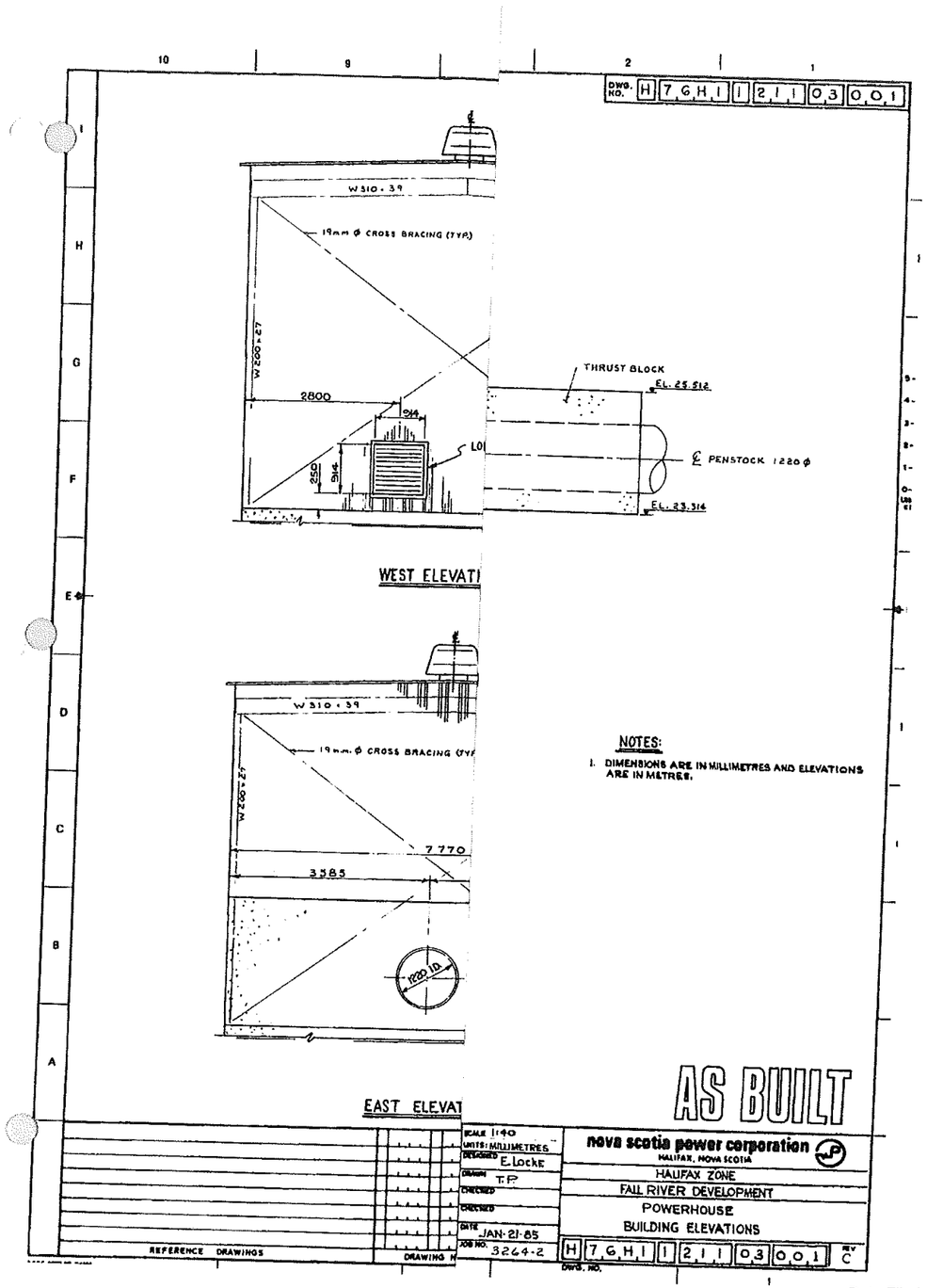


Photo #15 Main floor level, epoxy painted concrete.


DWG. NO. H 7 6 H 1 1 2 1 1 0 3 0 0 2
ROOF VENTILATOR
OVERHEAD DOOR TRACKS
W 310 x 39 (TYP)
W 200 x 27 (TYP)
19mm ϕ CROSS BRACING (TYP)
O.H. CRANE
3658
3658
915
2130
1842
200
SECTION A
DETAIL 1
6383
3658
O.H. DOOR OPENING
O.H. CRANE - 4.5 TONNES
19mm ϕ CROSS BRACING (TYP)
1329
4115
1220 I.D.
EL.23.38
SECTION B
9350
3585
7770
4185
1000
1000
OVERHEAD CRANE
FL. EL.23.38
7770
W200 x 27 (TYP)
915
102
3658
292
PLAN VIEW
GALV PURLIN 230 x 70 x 20
O.H. DOOR TRACK
W 310 x 39
O.H. CRANE - 4.5 TONNES
O.H. DOOR TRACK
O.H. DOOR CHANNEL
W 200 x 27
DETAIL 1
NOTES:
1. DIMENSIONS ARE IN MILLIMETRES AND ELEVATIONS ARE IN METRES.
AS BUILT
C REV. CIVIL
AS BUILT
DEC.-3-85
BY: D.W.
B REV. CIVIL
WALL THICKNESS WAS 300
MAR-22-85
A REV. CIVIL
BUILDING HEIGHT WAS 6100
FEB-1-85
O REV ELEC MECH CIVIL
ISSUED FOR TENDER
JAN-85
ENGINEERS SEAL
DEPARTMENTAL APPROVALS
APPROVED
DATE 85-01-28
SCALE N.T.S.
UNITS: MILLIMETRES
DESIGNED E. Locke
DRAWN T.R
CHECKED
DATE JAN-22-85
JOB NO. 3264-2
nova scotia power corporation
HALIFAX, NOVA SCOTIA
HALIFAX ZONE
FALL RIVER DEVELOPMENT
POWERHOUSE
PLAN AND DETAILS
H 7 6 H 1 1 2 1 1 0 3 0 0 2
REV C
DWG. NO.
REFERENCE DRAWINGS
DRAWING NUMBER
Page 1/1
UNITS: cm


DWG. NO. H 7 6 H 1 1 2 1 1 0 0 0 0 1
U/S
7 770
ACCESS ROAD
PENSTOCK
POWERHOUSE
TAILRACE
BY-PASS
POLES
SUBSTATION
EXISTING DRAFT TUBE OPENING CONC. PEDESTA
CONC. PIER (TYP.)
450 X 150 (TYP.)
9 350
D/S
PLAN (SCALE 1:50)
℄ DRAFT TUBE
P.H BRICK WALL
450 X 150
EL. 23.63
L 26.52
EL. 24.85
EL. 23.43 (FLOOR)
CONC PIER (ERODED)
CONC WALL ON BEDROCK
WALL CONCRETE ON BEDROCK (ELEVATION APPROX.)
SECTION B (SCALE 1:50)
ATION (SCALE 1:50)
SCALE AS NOTED
UNITS: METRIC
DRAWN
CHECKED D. WILLISTON
CHECKED
DATE 85-03-18
JOB NO. 3264-2
nova scotia power corporation
HALIFAX, NOVA SCOTIA
HALIFAX ZONE
FALL RIVER DEVELOPMENT
EXISTING POWERHOUSE
H 7 6 H 1 1 2 1 1 0 0 0 0 1
REV A
DWG NO.
REFERENCE DRAWINGS
DRAWING NUM


10
9
2
1
DWG. NO. H 7 6 H 1 1 2 1 1 0 3 0 0 1
H
G
F
E
D
C
B
A
W 310 • 39
19mm ϕ CROSS BRACING (TYP.)
W 260 • 27
2800
914
914
250
THRUST BLOCK
EL. 25.512
℄ PENSTOCK 1220 ϕ
EL. 23.314
WEST ELEVATI
W 310 • 39
19 m.m. ϕ CROSS BRACING (TYP
W 260 • 27
7770
3585
1220 ID.
EAST ELEVAT
NOTES:
1. DIMENSIONS ARE IN MILLIMETRES AND ELEVATIONS ARE IN METRES.
AS BUILT
REFERENCE DRAWINGS
DRAWING N
SCALE 1:40
UNITS: MILLIMETRES
DESIGNED E. Locke
DRAWN T.P.
CHECKED
CHECKED
DATE JAN. 21-85
JOB NO. 3264-2
nova scotia power corporation
HALIFAX, NOVA SCOTIA
HALIFAX ZONE
FALL RIVER DEVELOPMENT
POWERHOUSE
BUILDING ELEVATIONS
H 7 6 H 1 1 2 1 1 0 3 0 0 1
DWG. NO.
REV C

NOVA SCOTIA POWER
An Emera Company

NSPI Powerhouse Condition Survey

October 31, 2011

Halifax and Eastern Shore Hydro System

Malay Falls

293 Malay Falls Road, Sheet Harbour, Nova Scotia

Malay Falls - Halifax and Eastern Shore Hydro

Date	October 31, 2011
Inspector (s):	G. Webber
NSPI Site representative	M. MacCormick
Address:	293 Malay Falls Road, Sheet Harbour, Nova Scotia

Inspection Method: Visual inspection of building drainage, exterior/interior architectural/structural features, lighting, ventilation and louvres.

Inspection Procedure: Received site orientation from NSPI personnel; examined building perimeter at grade level to identify any drainage issues; examined building exterior to determine condition of exterior finishes, including window/doors/area lighting and exterior louvres. Examined exterior roof line with binoculars to identify any noticeable defects. Entered building examined interior floors, walls, underside of roof structure, windows and doors, and noted condition and operation of lighting and ventilation. Noted and photographed areas of interest.

Equipment used: Sony digital Camera and Binoculars, PPE (personal protection equipment), where/as required.

Overall Comments: Powerhouse exterior and interior in generally poor to fair shape with defects as noted on following evaluation sheets. Major exterior amounts of stucco and painting required on all elevations.
Major amounts of repairs and painting required on interior East wall and southeast corner as well as smaller areas on other walls where water penetration has taken place.
Steel pivoted garage door requires replacement or painting at minimum.

Malay Falls - Halifax and Eastern Shore Hydro

U - Unacceptable F - Fair
P - Poor G - Good

Exterior Elements	Location Identification	Description	Photo ID	Condition				Remediation Period (Years)			
				U	P	F	G	0-2	2-7	7-20	20+
Building Perimeter Drainage	East to West		3				X				X
Comments: East elevation subjected to additional water/snow build up for water infiltration. Further drainage work should be undertaken.											
Exterior Walls/ Cladding	North		4, 5			X			X		
	East		3, 6		X			X			
	South		1, 7, 8		X			X			
	West		2, 9			X			X		
Comments: Painted stucco over clay speed tile and concrete pilasters. Major amounts of stucco and painting required, all walls.											
Exterior Doors	South	Steel pivoted garage door	8			X			X		
	South, East	Aluminum man doors	3, 7, 15				X				X
Comments: Steel pivoted garage door requires replacement or painting at minimum (8). Water leakage at East wall man door/glass block area (15).											
Windows	East, North, West	Glass block	2, 3, 5				X				X
Comments: Paint the wooden windows on North and West wall lower floor level (2).											
Exterior Louvres	South	1 Aluminum louvre	1			X				X	
	North	2 Operable windows, 1 aluminum louvre	4, 5			X				X	
	West	3 Aluminum louvres	2, 9			X				X	
Comments:											
Exterior Lighting	SE Corner	Power pole area light					X				X
Comments:											

Date Filed: November 22, 2017 Page 1333 of 2371 REDACTED

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Malay Falls - Halifax and Eastern Shore Hydro

U - Unacceptable F - Fair
P - Poor G - Good

Interior Elements	Location Identification	Description	Photo ID	Condition				Remediation Period (Years)			
				U	P	F	G	0-2	2-7	7-20	20+
Floors	Main Level	Minor repairs/painting	10				X				X
Comments: Epoxy paint over clay quarry tile and concrete.											
Interior Walls	North						X				X
	East	Stucco/paint at southeast end	11			X			X		
	South	Stucco/paint at southeast end	11				X				X
	West	Stucco/paint at northwest end	12, 14			X			X		
Comments: Painted stucco over clay speed tile and concrete. Stucco/painting of interior walls in progress.											
Roof Structure (Underside Only)		Painted stucco	13				X				X
Comments:											
Interior Lighting		5 Sodium lights	13				X				X
Comments:											
Building Ventilation and Louvres	South	1 Aluminum louvre	1			X				X	
	North	2 Operable windows, 1 aluminum louvre	4, 5			X				X	
	West	3 Aluminum louvres	12 - 14			X				X	
Comments:											

Date Filed: November 22, 2017 Page 1334 of 2371 REDACTED

ACE 2018 CI 44942 Attachment 2 Page 60 of 91

Malay Falls - Halifax and Eastern Shore Hydro System - Photographs

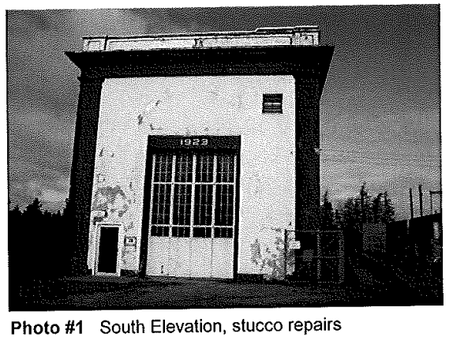


Photo #1 South Elevation, stucco repairs and painting required.

Photo #2 West Elevation, stucco repairs and painting required.

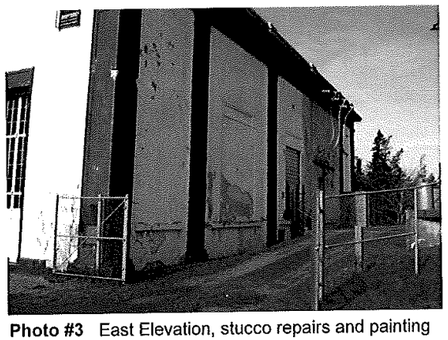


Photo #3 East Elevation, stucco repairs and painting required.

Photo #4 North Elevation, stucco repairs and painting required.

Malay Falls - Halifax and Eastern Shore Hydro System - Photographs

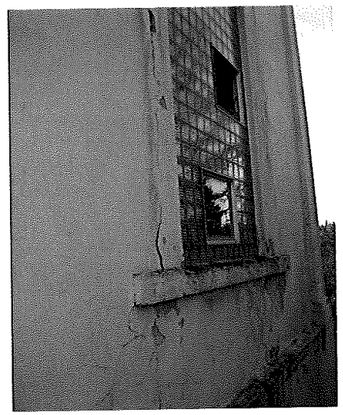


Photo #5 North Elevation, stucco repairs and painting required.

Photo #6 East Elevation, stucco repairs and painting required.

Photo #8 South Elevation, steel pivotted garage door requires replacement or painting at minimum.

Photo #7 South Elevation, stucco repairs and painting required.

Malay Falls - Halifax and Eastern Shore Hydro System - Photographs

Photo #9 West Elevation, stucco repairs and painting required.

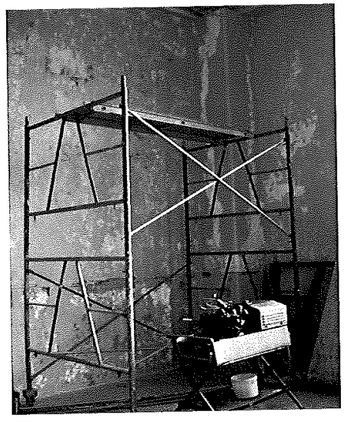


Photo #11 East Elevation, stucco repairs and painting required at southeast end.

Photo #10 Main floor level requires minor repairs and painting.

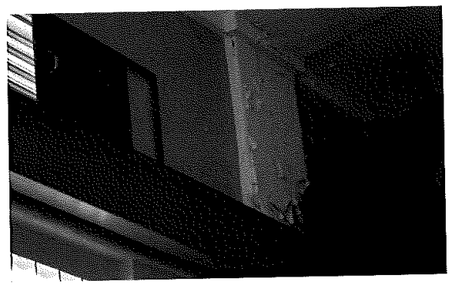


Photo #12 West Elevation, stucco repairs and painting required at northwest end.

Photo #13 Roof Structure, painted stucco ceiling.

Malay Falls - Halifax and Eastern Shore Hydro System - Photographs

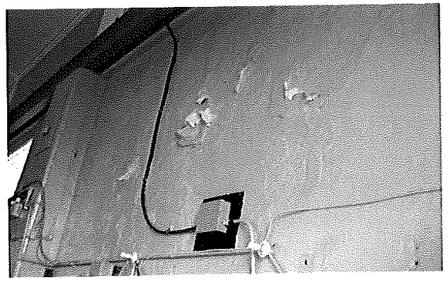
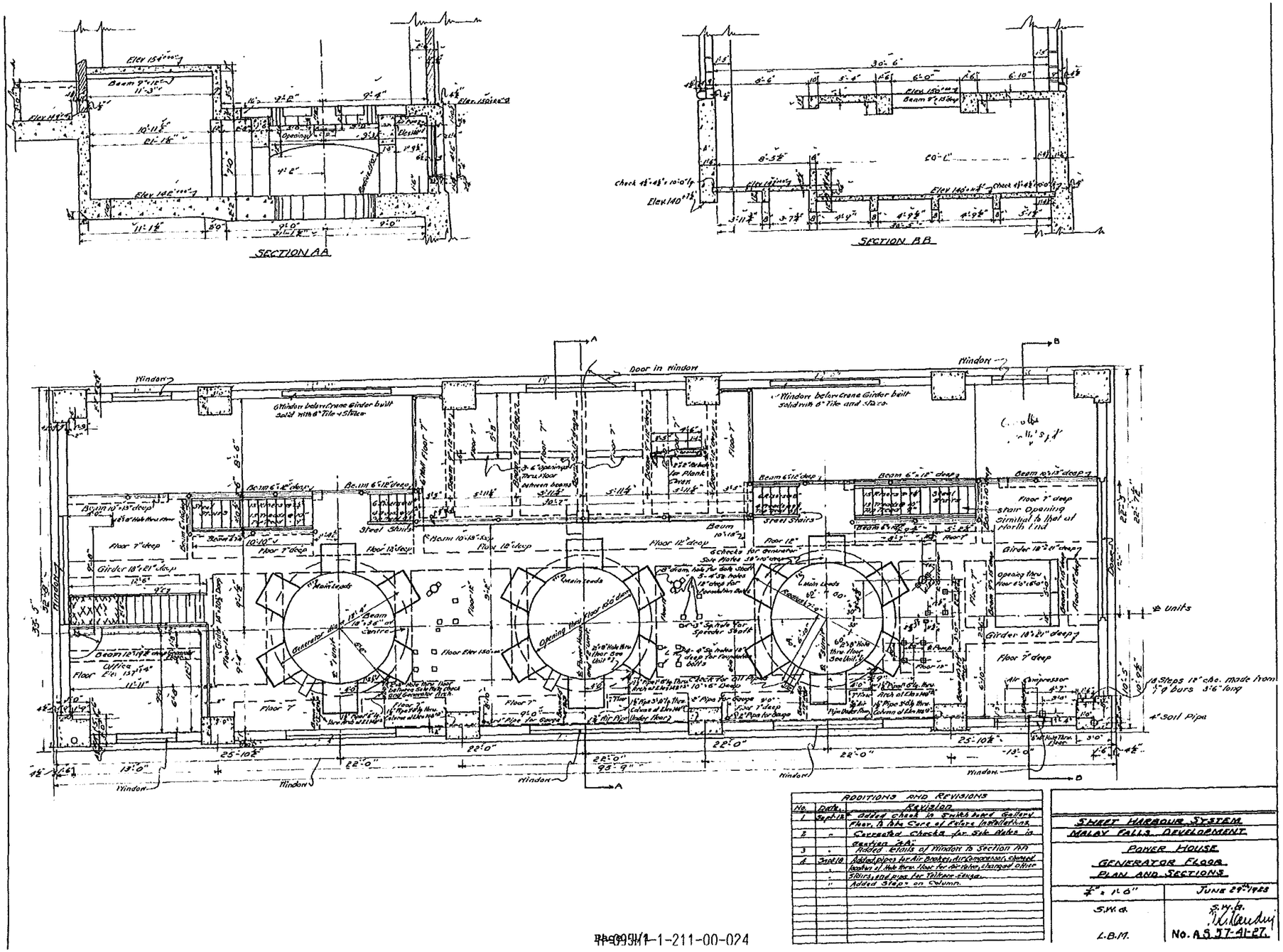
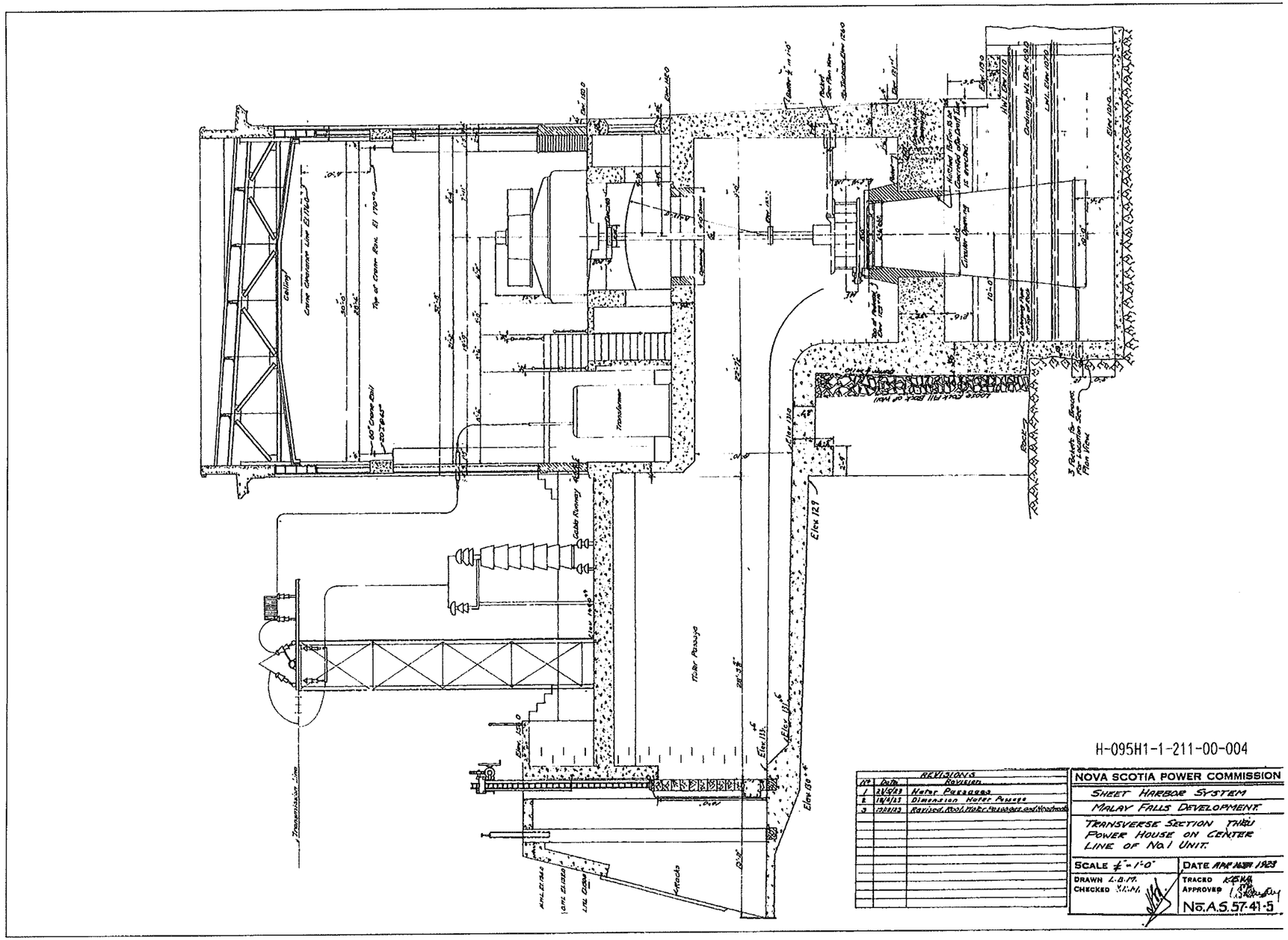


Photo #14 West Elevation, stucco repairs and painting required.

Photo #15 East Elevation, water leakage at east wall man door/glass block area.



Date Filed: November 22, 2017 Page 1339 of 2371 REDACTED


Ceiling
Crane Clearance Line El 176.0
Top of Crane Rail El 170'-0"
Transformer
Cable Runway
Water Passage
Transmission Line
Elev 129
Elev 130'-6"
Elev 113'-6"
Elev 110'-0"
Elev 131'-0"
Elev 131'-6"
Elev 132'-0"
Elev 132'-6"
Elev 133'-0"
Elev 133'-6"
Elev 134'-0"
Elev 134'-6"
Elev 135'-0"
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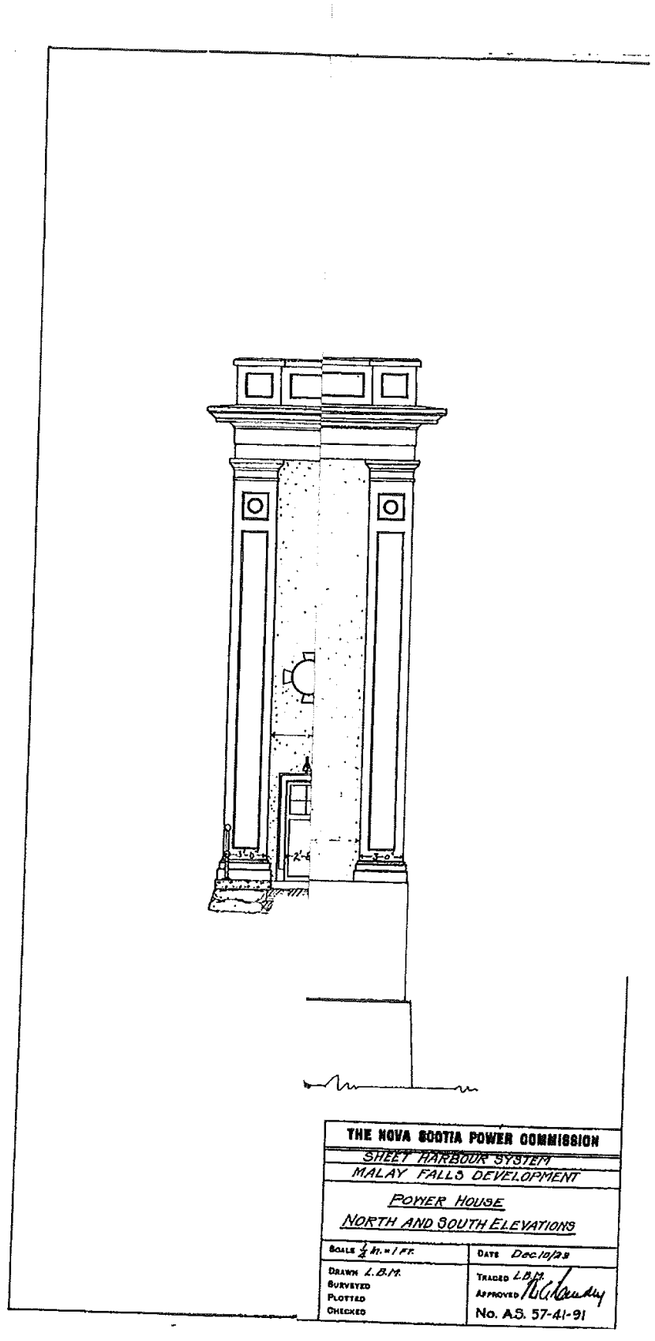
Elev 140'-6"
Elev



THE NOVA SCOTIA POWER COMMISSION

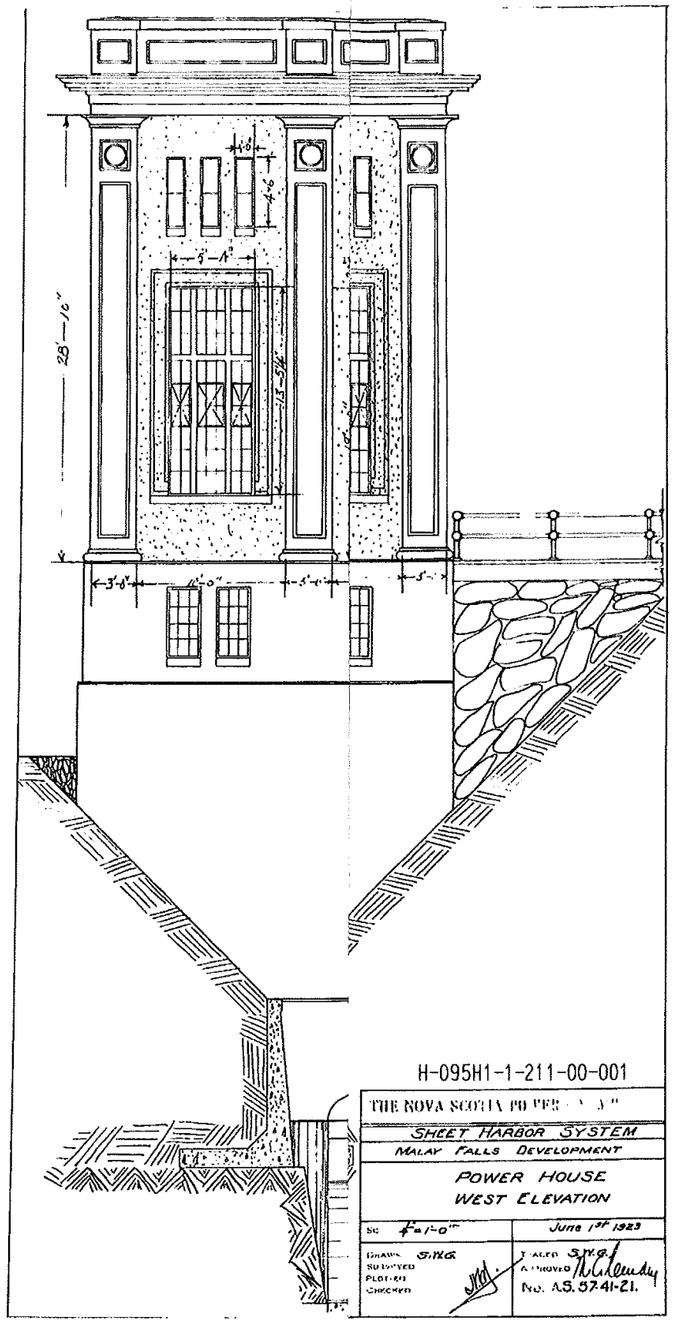
SHELT HARBOUR SYSTEM

MALAY FALLS DEVELOPMENT

POWER HOUSE

NORTH AND SOUTH ELEVATIONS

SCALE ½ IN. = 1 FT.	DATE Dec 10/28
DRAWN L.B.M.	TRACED L.B.M.
SURVEYED	
PLOTTED	APPROVED R.C. Laundy
CHECKED	No. A.S. 57-41-91


H-095H1-1-211-00-001
THE NOVA SCOTIA POWER
SHEET HARBOR SYSTEM
MALAY FALLS DEVELOPMENT
POWER HOUSE
WEST ELEVATION
June 1st 1923
No. A.S. 57-41-21.

5. RUTH FALLS

NOVA SCOTIA POWER
An Emera Company

NSPI Powerhouse Condition Survey

October 31, 2011

Halifax and Eastern Shore Hydro System

Ruth Falls

116 Powerhouse Road, East Side East River
Sheet Harbour, Nova Scotia

Ruth Falls - Halifax and Eastern Shore Hydro

Date	October 31, 2011
Inspector (s):	G. Webber
NSPI Site representative	M. MacCormick
Address:	116 Powerhouse Road, East Side East River Sheet Harbour, Nova Scotia

Inspection Method: Visual inspection of building drainage, exterior/interior architectural/structural features, lighting, ventilation and louvres.

Inspection Procedure: Received site orientation from NSPI personnel; examined building perimeter at grade level to identify any drainage issues; examined building exterior to determine condition of exterior finishes, including window/doors/area lighting and exterior louvres. Examined exterior roof line with binoculars to identify any noticeable defects. Entered building examined interior floors, walls, underside of roof structure, windows and doors, and noted condition and operation of lighting and ventilation. Noted and photographed areas of interest.

Equipment used: Sony digital Camera and Binoculars, PPE (personal protection equipment), where/as required.

Overall Comments: Powerhouse exterior and interior in generally fair to good shape with defects as noted on following evaluation sheets.
Pilaster cracks are exhibited on the West Elevation which will require caulked control joints being installed.
Concrete and painting repairs on all exterior walls in numerous areas and caulking of control joints/cracks are required. Interior wall repairs required in similar locations as cracks and water infiltration also evident.
Movement of interior/exterior concrete walls at pilasters evident at interior basement foundation level (some cracks are just separate concrete pours with ties between and some others are just cracks).

Ruth Falls - Halifax and Eastern Shore Hydro

U - Unacceptable F - Fair
P - Poor G - Good

Exterior Elements	Location Identification	Description	Photo ID	Condition				Remediation Period (Years)			
				U	P	F	G	0-2	2-7	7-20	20+
Building Perimeter Drainage	East to West		5				X				X
Comments: No problems.											
Exterior Walls/ Cladding	North	Minor cracking/painting	5, 7				X		X		
	East	Repairs above overhead door	3, 4, 21			X	X	X			
	South	Cracks at pilasters and joint repairs required	1, 9, 11, 20, 21		X	X		X			
	West	Cracks at pilasters, caulked control joints required	2, 6, 20		X	X		X			
Comments: Painted concrete with brick pilasters. Concrete and painting repairs on exterior in numerous areas and caulking of control joints/cracks. Pilaster cracks evident from interior side of west wall, repairs required (12 to 16). Also SE and SW upper corners (20, 21). South Elevation concrete blockwork requires repointing and painting (1).											
Exterior Doors	East	Rolling overhead steel door	4, 8				X				X
	East	Painted metal man door	4				X				X
Comments:											
Windows	East, West, North	Wooden single glazed windows	2, 4 - 6, 19			X	X			X	X
Comments: Single glazed wood windows, painting required as a minimum. West: Also glass block window in good shape. North: Just glass block windows (7) in good shape (3 total, broken).											
Exterior Louvres	North, South	Aluminum louvres	1, 5				X				X
	West	2 Aluminum Louvres, 2 open fibre screens in windows	6, 19		X			X			X
Comments: Fibre screens should be replaced with louvres.											
Exterior Lighting	NE Corner	Building area light	3, 5				X				X
	SE	Power pole area light					X				X
Comments: Exterior light at main man door/overhead door should be installed.											

Date Filed: November 22, 2017 Page 1346 of 2371 REDACTED

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Ruth Falls - Halifax and Eastern Shore Hydro

U - Unacceptable F - Fair
P - Poor G - Good

Interior Elements	Location Identification	Description	Photo ID	Condition				Remediation Period (Years)			
				U	P	F	G	0-2	2-7	7-20	20+
Floors	Main Level	4" x 4" quarry tile	11				X				X
Comments: Floors are quarry tile over concrete. Flooring infill required around generator No. 3 unit (11).											
Interior Walls	North						X				X
	East	Repairs above overhead door	17			X			X		X
	South	Crack at pilasters SE end					X		X		X
	West	Cracks at pilasters & NW corner	12		X	X			X	X	
Comments: West wall has vertical cracks beside each pilaster, repairs required (12 to 16). Movement of interior/exterior concrete walls at pilaster evident at interior basement foundation level (22 to 24), but are separate concrete pours with ties between/some just cracks. Interior repairs should only follow after exterior work completed.											
Roof Structure (Underside Only)		Painted plaster	18				X			X	
Comments: One crack across ceiling, to be repaired.											
Interior Lighting		6 Sodium lights	18				X				X
		(one shade/reflector missing)									
Comments:											
Building Ventilation and Louvres	North, South	Aluminum louvres	1, 5				X				X
	West	2 Aluminum Louvres, 2 open fibre screens in windows	19	X			X	X			X
	North, West	2 Operable windows	6, 7				X				X
Comments: Fibre screens should be replaced with louvres, to prevent water infiltration.											

Date Filed: November 22, 2017 Page 1347 of 2371 REDACTED

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Ruth Falls - Halifax and Eastern Shore Hydro System - Photographs

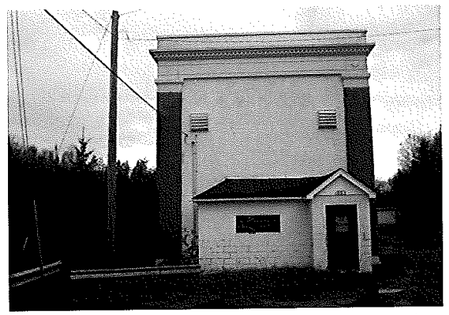


Photo #1 South Elevation, touch-up paint on exterior.

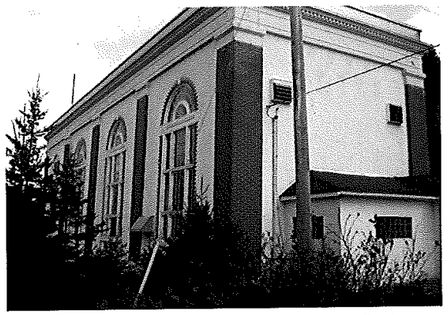


Photo #2 West Elevation, repair cracks at pilasters.

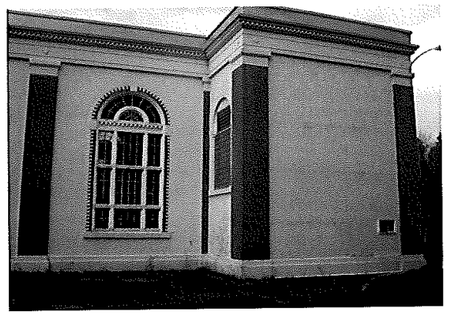


Photo #3 East Elevation.

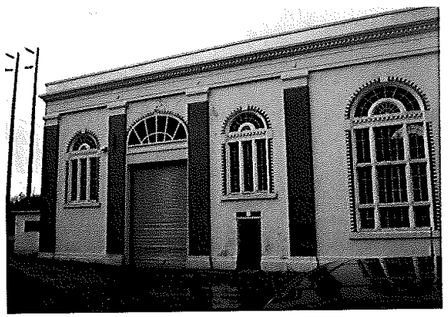


Photo #4 East Elevation, repair area above overhead door.

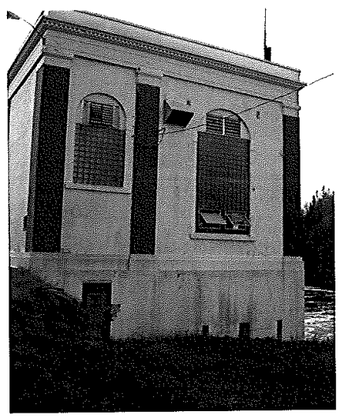


Photo #5 North Elevation, repair cracking.

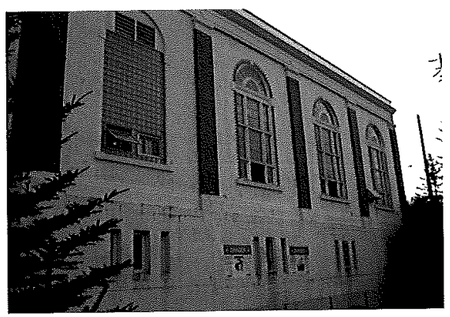


Photo #6 West Elevation, concrete repairs required.

Ruth Falls - Halifax and Eastern Shore Hydro System - Photographs

Photo #7 North Elevation, repair cracking.

Photo #8 East Elevation, rolling overhead steel door.

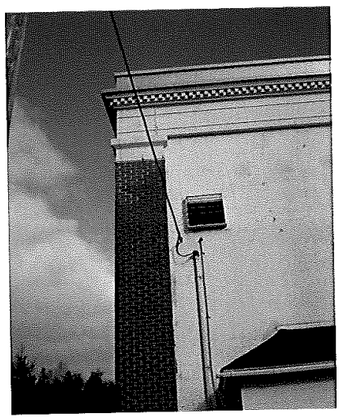


Photo #9 South Elevation, repair cracking and joints.

Photo #10 South Elevation, repair cracking and joints.

Photo #11 Flooring infill required around Generator No. 3 unit.

Ruth Falls - Halifax and Eastern Shore Hydro System - Photographs

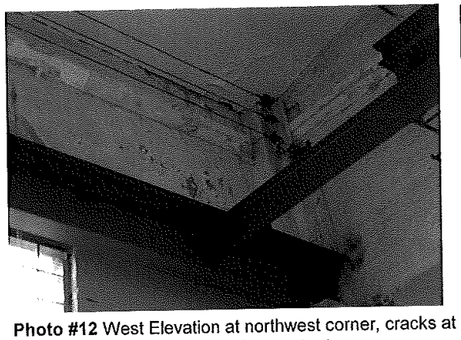


Photo #12 West Elevation at northwest corner, cracks at pilasters and repairs required.

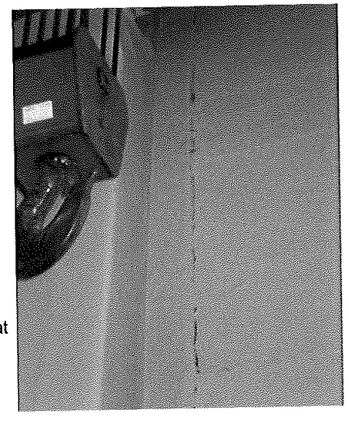


Photo #13 West Elevation, cracks at pilasters, repairs required.

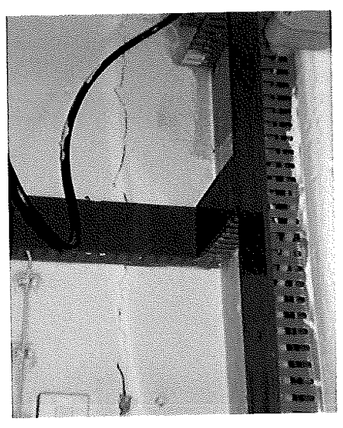


Photo #14 West Elevation, cracks at pilasters, repairs required.

Photo #15 West Elevation, cracks at pilasters, repairs required.

Ruth Falls - Halifax and Eastern Shore Hydro System - Photographs

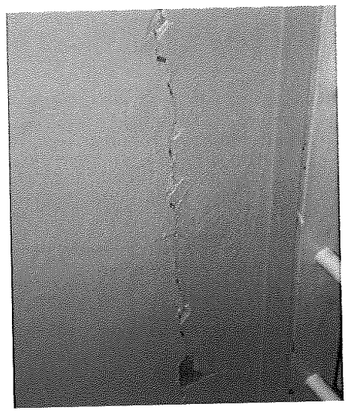


Photo #16 West Elevation, cracks at pilasters, repairs required.

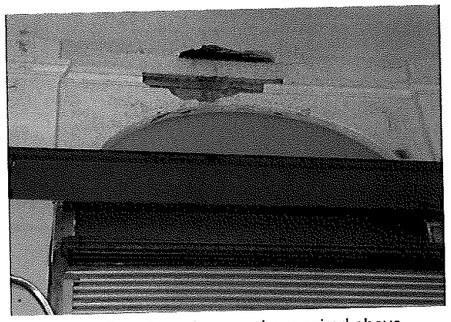


Photo #17 East Elevation, repairs required above overhead door.

Photo #19 West Elevation, fibre screen.

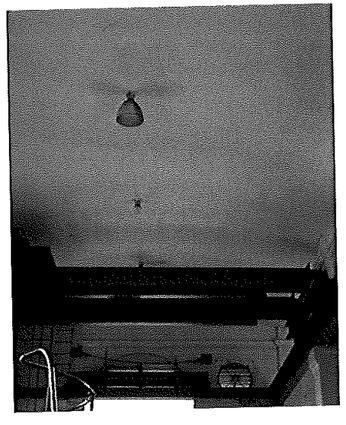


Photo #18 Repair the crack across the painted plaster ceiling.

Ruth Falls - Halifax and Eastern Shore Hydro System - Photographs

Photo #20 Southeast corner, crack repairs required.

Photo #21 Southwest corner, crack repairs required.

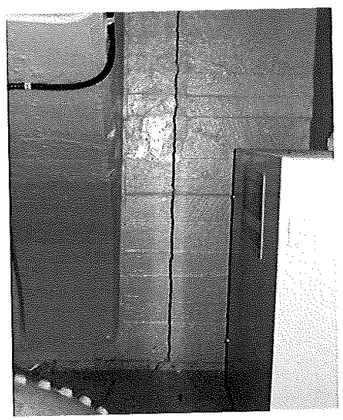


Photo #22 Movement of interior/exterior concrete walls at pilaster evident at interior basement foundation level (separate concrete pours with ties between).

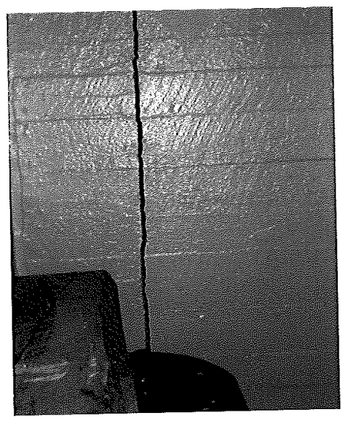
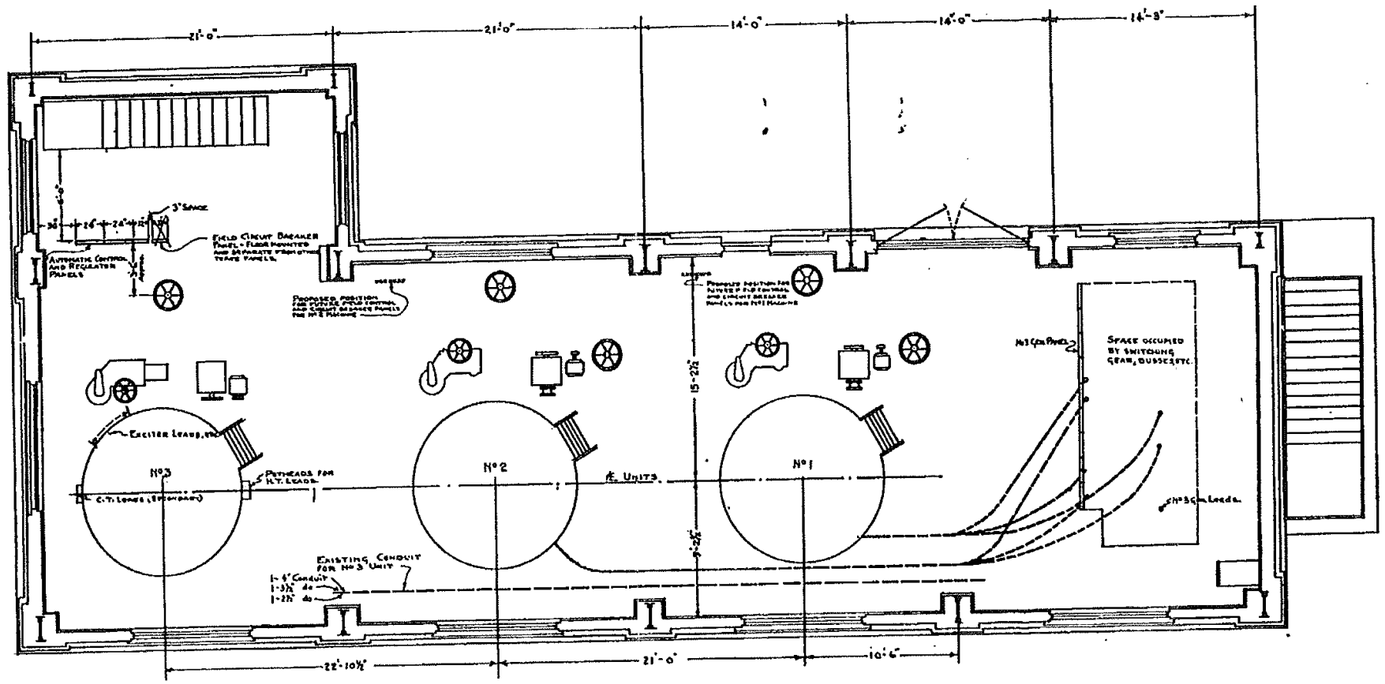


Photo #23 Movement of interior/exterior concrete walls at pilaster evident at interior basement foundation level (separate concrete pours with ties between).

Ruth Falls - Halifax and Eastern Shore Hydro System - Photographs

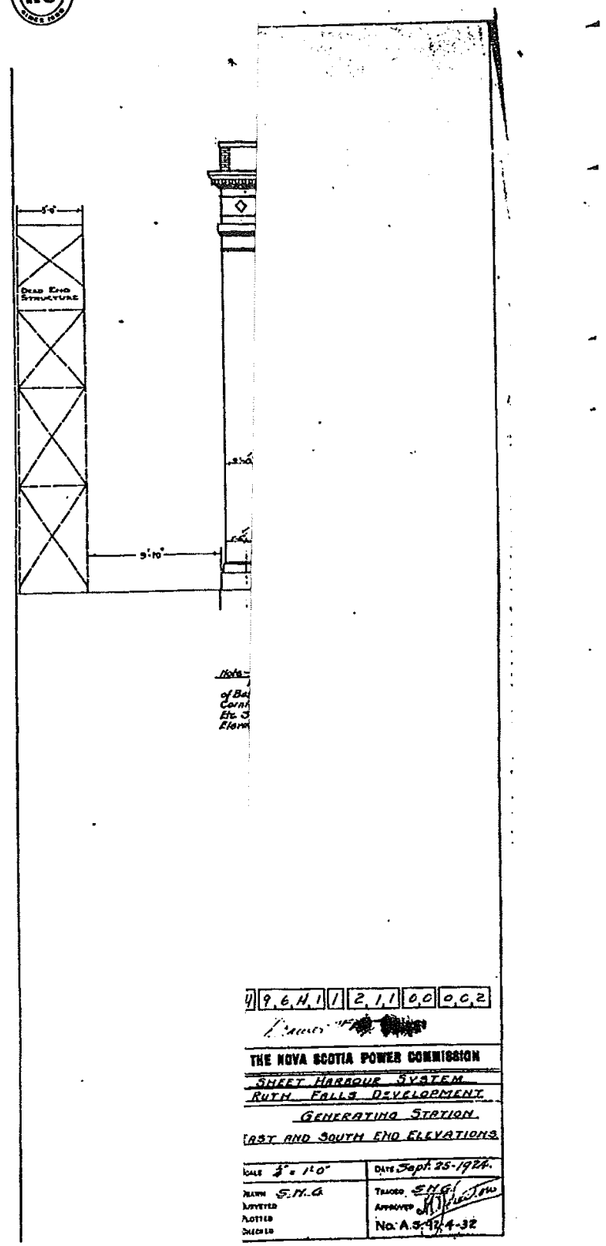
Photo #24 Movement of interior/exterior concrete walls at pilaster evident at interior basement foundation level (separate concrete pours with ties between).

DETAILS PLAN OF GENERATOR FLOOR



GENERATOR FLOOR.

| | | |

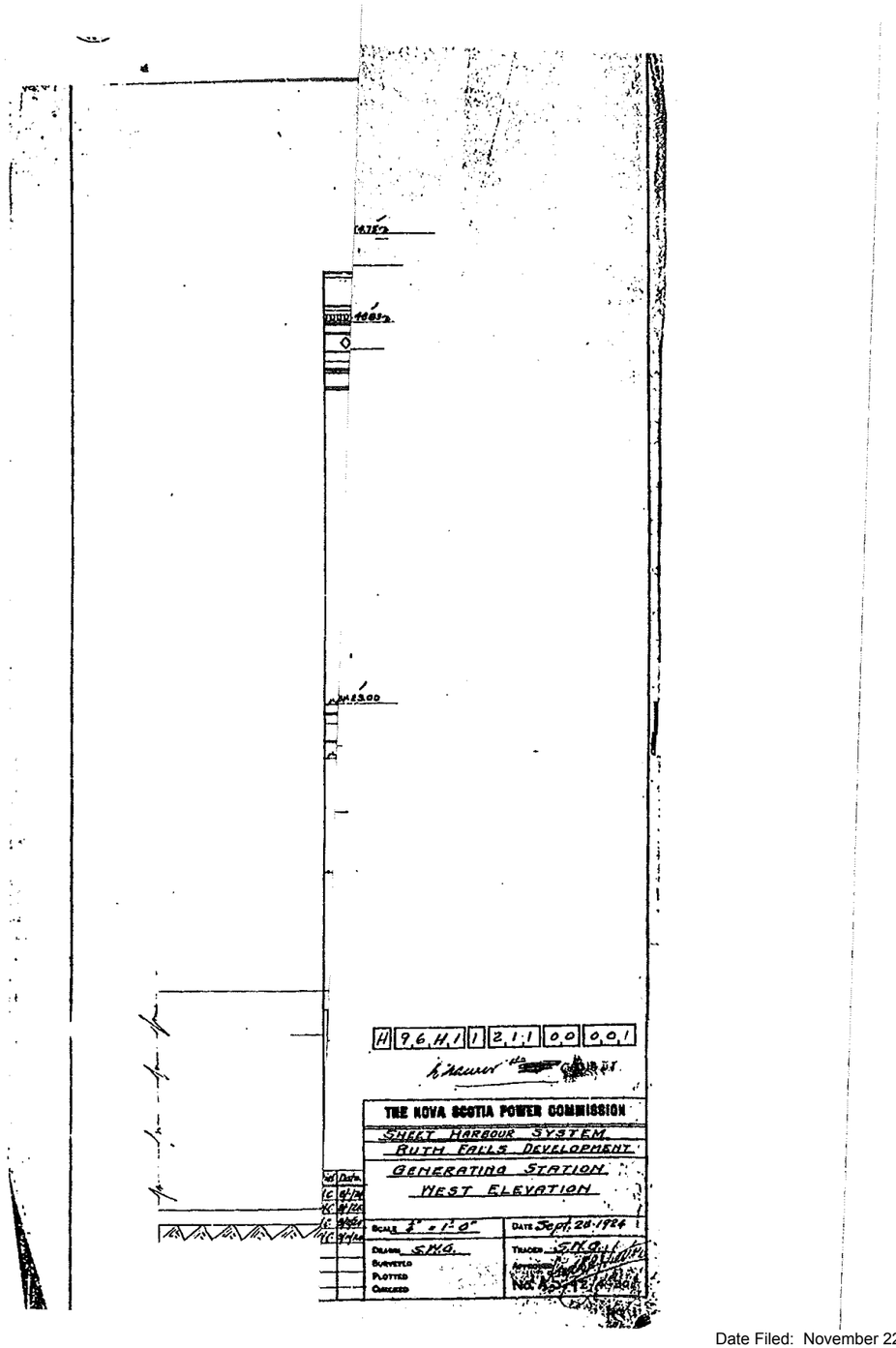


4	9,6,4,1	1	2,1,1	0,0	0,0,2	

THE NOVA SCOTIA POWER COMMISSION

SHEET HARBOUR SYSTEM
RUTH FALLS DEVELOPMENT
GENERATING STATION
EAST AND SOUTH END ELEVATIONS

SCALE 1/8" = 1'-0"	DATE Sept. 25-1924.
DRAWN S.H.G.	TRACED S.H.G.
SURVEYED	APPROVED
PLOTTED	No. A.S.-92-4-32
CHECKED	


H 9,6,H,1 1 2,1:1 0,0 0,0,1
THE NOVA SCOTIA POWER COMMISSION
SHEET HARBOUR SYSTEM
RUTH FALLS DEVELOPMENT
GENERATING STATION
WEST ELEVATION
SCALE 3/8" = 1'-0"
DATE Sept. 20-1926
DRAWN S.M.G.
TRACED S.M.G.
SURVEYED
PLOTTED
CHECKED

NOVA SCOTIA POWER
An Emera Company

NSPI Powerhouse Condition Survey

October 31, 2011

Halifax and Eastern Shore Hydro System

Dickie Brook

19 Mountain Road, West Cooks Cove
Guysborough County, Nova Scotia

Dickie Brook - Halifax and Eastern Shore Hydro

Date	October 31, 2011
Inspector (s):	G. Webber
NSPI Site representative	M. MacCormick
Address:	19 Mountain Road, West Cooks Cove Guysborough County, Nova Scotia
Inspection Method:	Visual inspection of building drainage, exterior/interior architectural/structural features, lighting, ventilation and louvres.
Inspection Procedure:	Received site orientation from NSPI personnel; examined building perimeter at grade level to identify any drainage issues; examined building exterior to determine condition of exterior finishes, including window/doors/area lighting and exterior louvres. Examined exterior roof line with binoculars to identify any noticeable defects. Entered building examined interior floors, walls, underside of roof structure, windows and doors, and noted condition and operation of lighting and ventilation. Noted and photographed areas of interest.
Equipment used:	Sony digital Camera and Binoculars, PPE (personal protection equipment), where/as required.
Overall Comments:	Powerhouse exterior and interior in generally good shape with some defects as noted on following evaluation sheets. Replace both doors or as a minimum repainting is required. Touch-up paint including trim and soffits/fascias, and caulked joints required on all elevations. All windows require painting.

Dickie Brook - Halifax and Eastern Shore Hydro

U - Unacceptable F - Fair
P - Poor G - Good

Exterior Elements	Location Identification	Description	Photo ID	Condition				Remediation Period (Years)			
				U	P	F	G	0-2	2-7	7-20	20+
Building Perimeter Drainage	East to West	Slopes to East side of building	3				X				X
Comments: No problems evident.											
Exterior Walls/Cladding	North	Painted concrete (painted siding upper)	4				X				X
	East	Painted concrete	3				X				X
	South	Painted siding	1				X				X
	West	Painted concrete	2				X				X
Comments: Exterior walls are painted masonite siding on South and North upper portion. Painted concrete on East and West, also North lower portion. Touch-up paint including trim and soffits/fascias, and caulked joints required on all elevations.											
Exterior Doors	South	Painted wood pivoted garage door complete with man door inset	1, 9			X		X			
	North	Painted wood door	4		X			X			
Comments: Replace both doors or as a minimum repainting is required. South man door in garage door needs repair at threshold (binds), same with North man door.											
Windows	East, West	Painted wood windows with single glazing	2, 3, 5			X	X	X			
Comments: All windows require painting.											
Exterior Louvres	East, West	2 Aluminum louvres	5, 11				X				X
	North, South	1 Aluminum louvre, power operated	7, 9				X				X
Comments:											
Exterior Lighting	Area	SW corner power pole light					X				X
Comments:											

Date Filed: November 22, 2017 Page 1360 of 2371 REDACTED

ACE 2018 CI 44942 Attachment 2 Page 86 of 91

Dickie Brook - Halifax and Eastern Shore Hydro

U - Unacceptable F - Fair
P - Poor G - Good

Interior Elements	Location Identification	Description	Photo ID	Condition				Remediation Period (Years)			
				U	P	F	G	0-2	2-7	7-20	20+
Floors	Main Level	Epoxy painted concrete	6			X				X	
Comments: Repainting could be done.											
Interior Walls	North	Painted concrete (painted siding upper)					X				X
	East	Painted concrete	10				X				X
	South	Painted wood	9				X				X
	West	Painted concrete	11				X				X
Comments:											
Roof Structure (Underside Only)		Painted wood decking	7				X				X
Comments:											
Interior Lighting	Control Area	9 Fluorescent lights	8				X				X
	Generator Area	3 Sodium lights (disconnected)	7	X				X			
		5 Others with wiring hanging down (not capped off) (disconnected)	7	X				X			
Comments: Remove redundant fixtures and wiring.											
Building Ventilation and Louvres	East	2 Aluminum louvres	10				X				X
	West	2 Aluminum louvres	11				X				X
	North, South	1 Louvre each end	7, 9				X				X
Comments:											

Date Filed: November 22, 2017 Page 1361 of 2371 REDACTED

ACE 2018 CI 44942 Attachment 2 Page 87 of 91

Dickie Brook - Halifax and Eastern Shore Hydro System - Photographs

Photo #1 South Elevation, paint siding, trim, soffits/ fascias and garage doors. Caulk joints.

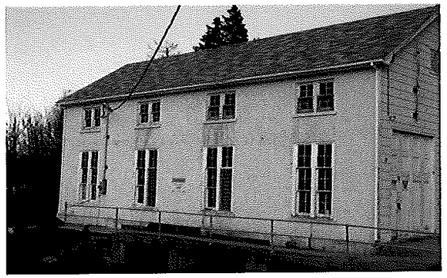


Photo #2 West Elevation, paint siding, trim, and soffits/fascias. Caulk joints.

Photo #3 East Elevation, paint siding, trim, and soffits/fascias. Caulk joints.

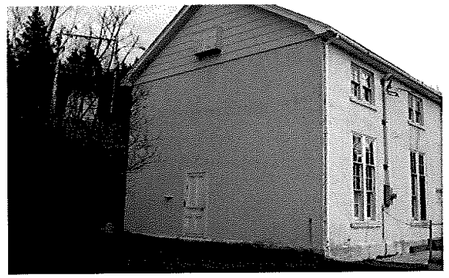


Photo #4 North Elevation, man door requires repair (as does man door in garage door).

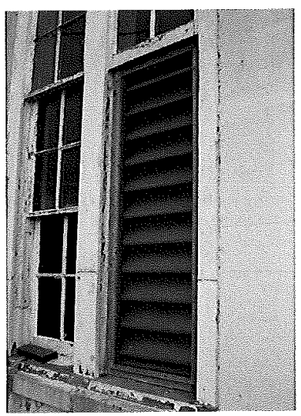


Photo #5 West Elevation, paint wood window frames.

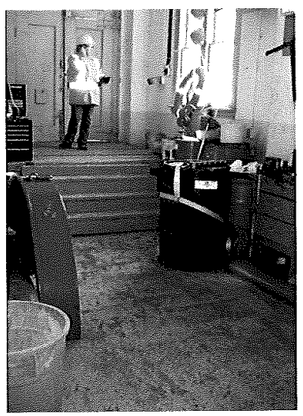


Photo #6 Main floor level, repaint concrete floor.

Dickie Brook - Halifax and Eastern Shore Hydro System - Photographs

Photo #7 Roof Structure, painted wood decking.

Photo #8 East Elevation, painted concrete interior wall, fluorescent lights.

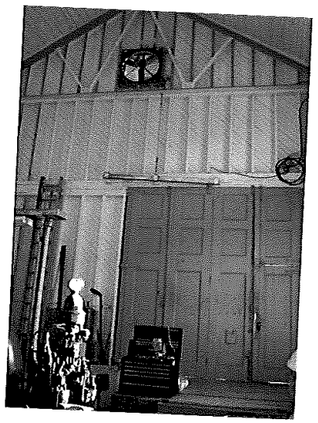


Photo #9 South Elevation, painted wood interior wall.

Photo #10 East Elevation, painted concrete interior wall.

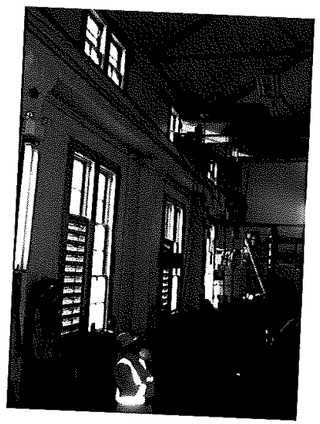
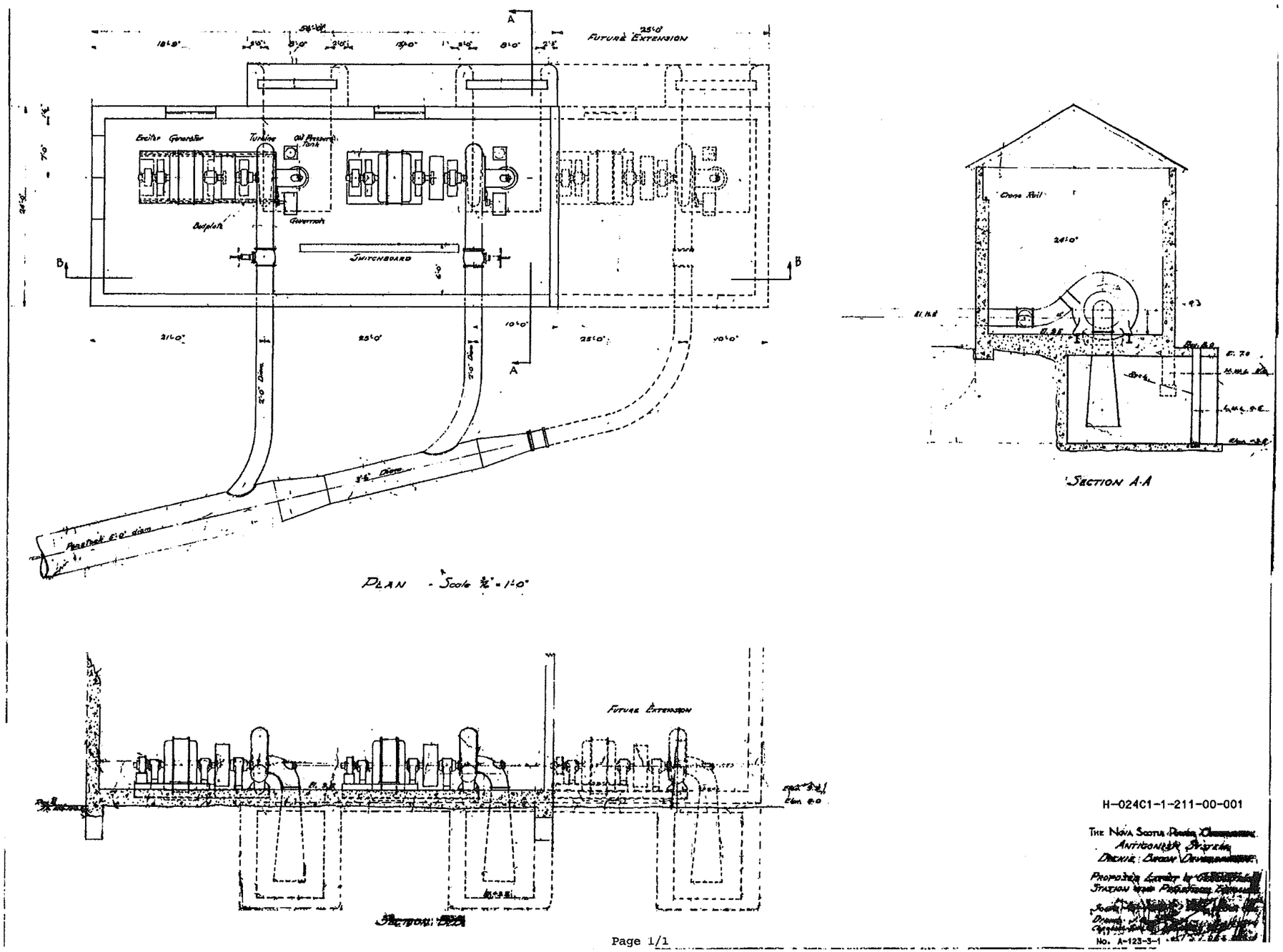
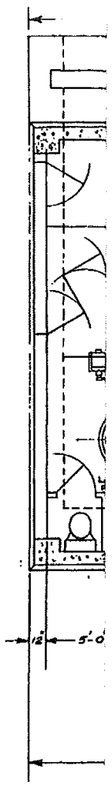


Photo #11 West Elevation, painted concrete wall.


Future Extension
Exciter Generator
Turbine
Oil Pressure Tank
Bedplate
Governors
Switchboard
Penstock 6'-0" diam
Plan - Scale 3/8" = 1'-0"
Crane Rail
Section A-A
Future Extension
Section B-B
H-024C1-1-211-00-001
The Nova Scotia Power Corporation
Antigonish System
Drexie Bacon Development
Proposed Layout of Generating Station with Pressure Tunnel
No. A-123-3-1



24C1-1-211-00-007

NOVA SCOTIA POWER COMMISSION
HALIFAX, NOVA SCOTIA
E BROOK DEVELOPMENT
ANTIGONISH SYSTEM
FLOOR PLAN
OF
NERATING STATION

CI Number: 49946

Title: HYD Fourth Lake Overhaul

Start Date: 2017/10
In-Service Date: 2018/11
Final Cost Date: 2019/05
Function: Hydro
Forecast Amount: $1,025,769

DESCRIPTION:

This project will replace the mechanical turbine shaft seal, the internal seals of the turbine runner, the blades of the runner, and refurbish the case of the unit and the runner oil seals.

Fourth Lake Plant is a single unit hydro plant on the Sissiboo River Hydro System. The Kaplan turbine has a capacity of 3 MW, and the plant has an average yearly production of 10.2 GWh. The unit is limited to 75 percent of its maximum capacity (2.25MW of the 3MW nameplate capacity) as a result of turbine cavitation issues.

Summary of Related CIs +/- 2 years:
2018 – CI 51866 – Fourth Lake Penstock Refurbishment $697,090

Depreciation Class: Hydro Production Plant- Bear River Hydro System

Estimated Life of Asset: 25 Years

JUSTIFICATION:

Justification Criteria: Hydro, Wind & Biomass Energy

Sub Criteria: Equipment Replacement / Refurbishment

Why do this project?

Completion of this project will both increase the efficiency of the unit, and mitigate the risk of future unplanned outages due to cavitation issues. This project will increase the plant's output by 25 percent, increase renewable generation (both energy and capacity) and lessens the use of more expensive generation sources. Substitution of the turbine shaft seal will minimize or mitigate oil leak risk. All other minor components identified during the overhaul as deficient will also be replaced or refurbished. This unit provides important water management for the Sissiboo River Hydro System and serves as the source water for the remaining units on the system. Increasing the output of this unit will increase the run flexibility of the remaining units on the system and provide a positive economic benefit.

Why do this project now?

The project is part of a plan to refurbish units on the Sissiboo River System. All other units on the river system have been overhauled. The work is being completed concurrently with a penstock refurbishment in order to minimize the unit's downtime. The unit contributes to grid stability in the western end of the province and the energy production contributes to renewable electricity targets. Restoring the unit to full rated output contributes firm capacity to the power system and enhances the operational flexibility of the entire river system.

Why do this project this way?

There are two major objectives included in this project scope:

- the turbine runner blade replacement, and
- the turbine shaft seal replacement.

Under the turbine runner blade replacement, two options were considered regarding the unit's cavitation issue: replacement of the entire unit with a new unit, or blade replacement with an augmented blade profile. Unit replacement was not selected as it is a significantly higher cost option and would require significant civil modifications to the plant. The return to full rated capacity can be achieved with a blade profile redesign. This is the most economical way to restore full operational capacity to the unit.

Three options were considered for repairing turbine shaft seal leaks: (1) replacement of the unit in whole with a redesigned unit, (2) replacement of the seal with a redesigned hydrostatic pressure seal, or (3) replacement of the seal with a redesigned mechanical pressure seal. The replacement of the unit in whole was not selected due to the reasons discussed above. The redesigned hydrostatic pressure seal was not chosen as a seal replacement option as the existing seal uses hydrostatic pressure which is prone to pressure fluctuations, due to flow velocity, resulting in leaks and unreliable performance. The redesigned mechanical pressure seal is the preferred solution as it will guarantee the shaft seal.

CI Number : 49946 - HYD Fourth Lake Overhaul **Project Number** 49946

Parent CI Number : -

Asset Location : 1364 - 1364 Fourth Lake, 3 Mwh; 1983 on Sissiboo River **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	2400 - HGP - Turbine (Hydro)	973,718
Retirements	2400 - HGP - Turbine (Hydro)	52,051
	Total Cost:	1,025,769
	Original Cost:	450,375

Capital Project Detailed Estimate

Location: Hydro
CI# / FP#: 49946
Title: HYD Fourth Lake Overhaul
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Hydro River Staff - Construction	day	160	$ 365	$ 58,366		
Engineering Staff	day	104	$ 405	$ 42,152		
Hydro River Staff - Removal	day	40	$ 365	$ 14,591		
			Sub-Total	$ 115,109		
Term Labour						
Hydro River Staff - Construction	day	240	$ 365	$ 87,549		
Hydro River Staff - Removal	day	60	$ 365	$ 21,887		
			Sub-Total	$ 109,436		
Travel Expenses						
Site Visit - Engineering	Week	30	$ 150	$ 4,500		
Temporary Report Point	Month	6	$ 1,500	$ 9,000		
			Sub-Total	$ 13,500		
Materials						
Design / Fabrication of new Shaft Seal	Lot	1	[redacted]		Cost Support #1 - Page 11 - Seal AC Type Seal System, plus Service Kit A & B,	
Design / fabrication of new blades	Lot	1				42666 - Tusket 2 Overhaul
Misc Materials	Month	5	$ 10,000	$ 50,000		
			Sub-Total	$ 430,095		
Contracts						
Refurb / Modifications to the case of the unit	Month	5	$ 10,000	$ 50,000		
Additional work on the runner (oil seals)	Month	5	$ 5,000	$ 25,000		
Misc Contracts	Month	5	$ 6,000	$ 30,000		
			Sub-Total	$ 105,000		
Consulting						
Design and Quality Control Support	Month	5	$ 4,000.00	$ 20,000		
			Sub-Total	$ 20,000		
Meals & Entertainment						
Site Visit - Engineering	Week	32	$ 75.00	$ 2,400		
Meals due to site being Temporary Report Point	Month	6	$ 3,000	$ 18,000		
			Sub-Total	$ 20,400		
Other Goods & Services						
Contingency	%	10%	$ 813,540	$ 81,354		
			Sub-Total	$ 81,354		
Interest Capitalized						
AFUDC				$ 24,260		
				$ -		
			Sub-Total	$ 24,260		
Administrative Overhead						
Labour AO				$ 96,416		
Contract AO				$ 10,199		
			Sub-Total	$ 106,615		
			Sub-Total (no AO, AFUDC)	$ 894,894		
			TOTAL (AO, AFUDC included)	$ 1,025,769		
Original Cost				$ 450,375		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

HYD Fourth Lake Overhaul
Summary of Alternatives

Division :	Power Production	**Date :**	**17-Nov-17**
Department :	Hydro	**CI Number:**	49946
		Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank (based on PV of RR)	IRR	Disc Pay
A	Unit Overhaul vs Replacement Energy Costs	5.88%	-2,561,127	2,026,542	1	22.14%	5.7 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

Recommendation :

It is recommended to complete this project in order to achieve the efficiency improvements.

Notes/Comments :

Unit Overhaul vs Replacement Energy Costs

The capital includes the mechanical turbine shaft seal, the internal seals of the runner, the blades of the runner and complete a general mechanical refurbishment. The avoided expense calculator assumes a 25% generation loss for the life of the unit. The 11yr average generation of Fourth Lake Plant is 10.2 GWh.

Test 2

Test 3

Test 4

HYD Fourth Lake Overhaul
Summary of Sensitivities

Nova Scotia POWER
An Emera Company

Division :	Power Production
Department :	Hydro

Date :	**10-Nov-17**
CI Number:	49946
Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Unit Overhaul vs Replacement Energy Costs	5.88%	-2,561,127	2,026,542	1	22.14%	5.7 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

	Alternative Variance on Capital Spend	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Unit Overhaul vs Replacement Energy Costs	10%	-2,475,861	1,954,970	1	20.08%	6.4 years
B	Test 2	10%	0	0	2	#NUM!	0.0 years
C	Test 3	10%	0	0	2	#NUM!	0.0 years
D	Test 4	10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		85,266	-71,571	0	-2.06%	0.7 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

	Alternative Variance on Avoided Expenses	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Unit Overhaul vs Replacement Energy Costs	-10%	-2,219,748	1,752,316	1	19.88%	6.5 years
B	Test 2	-10%	0	0	2	#NUM!	0.0 years
C	Test 3	-10%	0	0	2	#NUM!	0.0 years
D	Test 4	-10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		341,379	-274,226	0	-2.26%	0.8 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

Alternative Variance on Avoided Expenses - Change in Revenue Requirement		PV of Revenue Requirement	PV of Revenue Requirement	PV of Revenue Requirement	Delay?
	Yrs Delay:	1	2	3	
	A	159,642	295,392	446,903	No
	B	0	0	0	No
	C	0	0	0	No
	D	0	0	0	No

HYD Fourth Lake Overhaul
Avoided Cost Calculations

Division :	Power Production	**Date :**	10-Nov-17
Department :	Hydro	**CI Number:**	49946
		Project No. :	

Unit Overhaul vs Replacement Energy Costs

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	1	1	1	1		
Probability of Occurance (%)	100%	100%	100%	100%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	2550.0	2550.0				
Duration (Hours or Years)	1	1				
Totals	$213,045	$212,353	$0	$0	$213,045	$212,353
Total Capital Cost of Alternative						$1,025,769

Test 2

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

Test 3

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

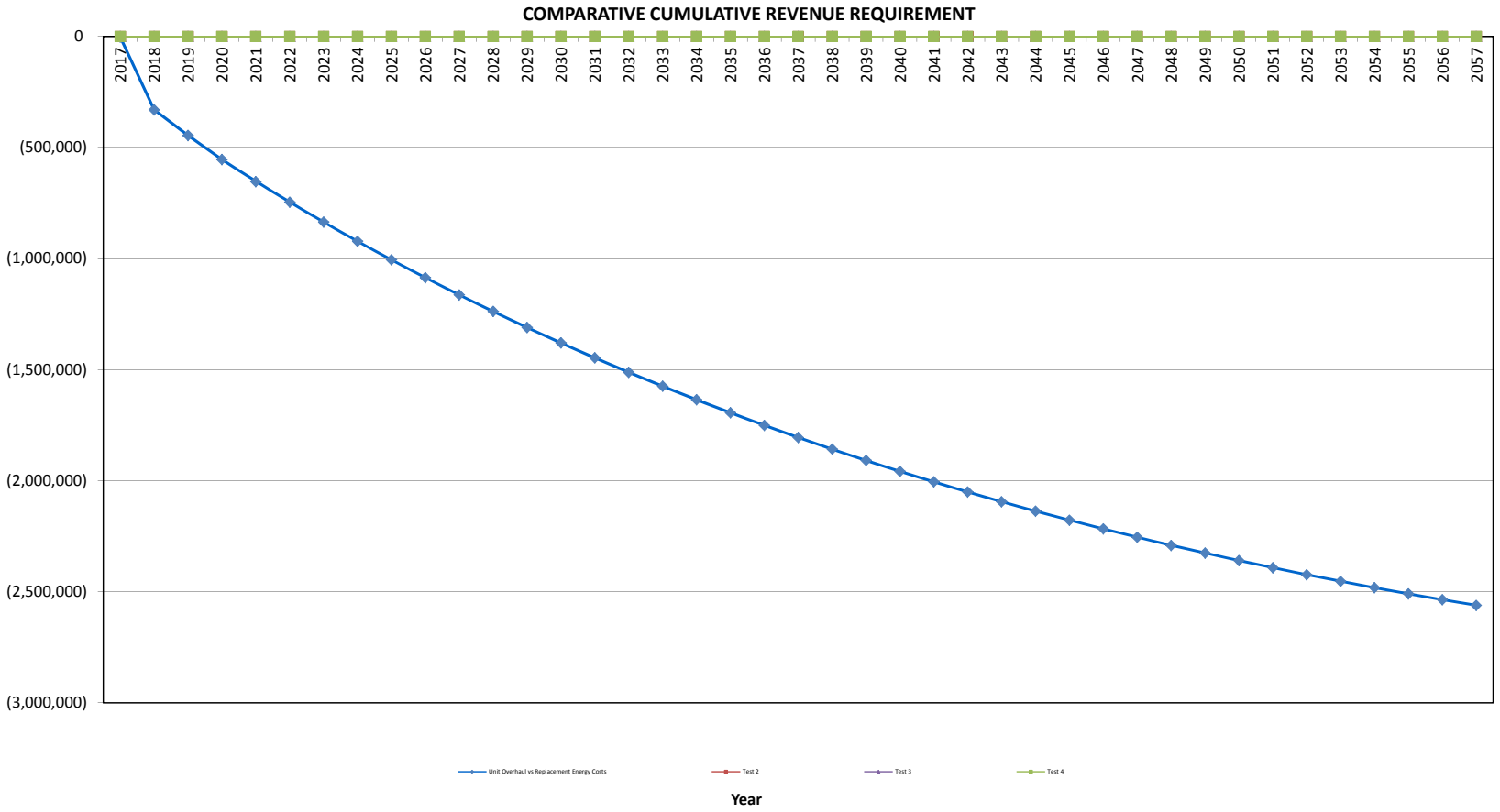
Test 4

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

HYD Fourth Lake Overhaul

Unit Overhaul vs Replacement Energy Costs

Year	Total Revenue	Operating Costs	Avoided Expenses	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	PV of CF	Discount Factor	CNPV
2017	-	-	-	(44,209.6)	-	-	(44,209.6)	-	(44,209.6)	(44,209.6)	1.00	(44,209.6)
2018	-	-	213,045.3	(874,944.9)	35,795.8	888,524.1	(661,899.7)	(54,947.3)	(716,847.0)	(677,037.2)	0.94	(721,246.8)
2019	-	-	212,353.0	-	68,727.9	814,883.4	212,353.0	(44,523.8)	167,829.2	149,706.2	0.89	(571,540.6)
2020	-	-	214,334.9	-	63,229.6	747,134.0	214,334.9	(46,842.6)	167,492.3	141,108.4	0.84	(430,432.2)
2021	-	-	212,577.5	-	58,171.3	684,804.5	212,577.5	(47,865.9)	164,711.6	131,059.5	0.80	(299,372.7)
2022	-	-	213,331.5	-	53,517.6	627,461.4	213,331.5	(49,542.3)	163,789.2	123,088.0	0.75	(176,284.8)
2023	-	-	217,598.1	-	49,236.2	574,705.7	217,598.1	(52,192.2)	165,405.9	117,399.8	0.71	(58,884.9)
2024	-	-	221,950.1	-	45,297.3	526,170.5	221,950.1	(54,762.4)	167,187.7	112,074.5	0.67	53,189.6
2025	-	-	226,389.1	-	41,673.5	481,518.1	226,389.1	(57,261.8)	169,127.3	107,078.5	0.63	160,268.1
2026	-	-	230,916.9	-	38,339.6	440,437.9	230,916.9	(59,699.0)	171,217.9	102,382.1	0.60	262,650.1
2027	-	-	235,535.2	-	35,272.4	402,644.1	235,535.2	(62,081.5)	173,453.8	97,959.0	0.56	360,609.2
2028	-	-	240,245.9	-	32,450.6	367,873.9	240,245.9	(64,416.5)	175,829.4	93,786.0	0.53	454,395.2
2029	-	-	245,050.9	-	29,854.6	335,885.2	245,050.9	(66,710.8)	178,340.0	89,842.5	0.50	544,237.7
2030	-	-	249,951.9	-	27,466.2	306,455.6	249,951.9	(68,970.6)	180,981.3	86,109.8	0.48	630,347.5
2031	-	-	254,950.9	-	25,268.9	279,380.4	254,950.9	(71,201.4)	183,749.5	82,571.7	0.45	712,919.1
2032	-	-	260,049.9	-	23,247.4	254,471.2	260,049.9	(73,408.8)	186,641.2	79,213.4	0.42	792,132.5
2033	-	-	265,250.9	-	21,387.6	231,554.8	265,250.9	(75,597.6)	189,653.3	76,021.7	0.40	868,154.2
2034	-	-	270,555.9	-	19,676.6	210,471.7	270,555.9	(77,772.6)	192,783.4	72,984.8	0.38	941,139.0
2035	-	-	275,967.1	-	18,102.5	191,075.2	275,967.1	(79,938.0)	196,029.0	70,092.2	0.36	1,011,231.2
2036	-	-	281,486.4	-	16,654.3	173,230.4	281,486.4	(82,098.0)	199,388.5	67,334.1	0.34	1,078,565.4
2037	-	-	287,116.1	-	15,321.9	156,813.2	287,116.1	(84,256.2)	202,859.9	64,702.0	0.32	1,143,267.3
2038	-	-	292,858.5	-	14,096.2	141,709.4	292,858.5	(86,416.3)	206,442.2	62,187.9	0.30	1,205,455.2
2039	-	-	298,715.6	-	12,968.5	127,813.9	298,715.6	(88,581.6)	210,134.0	59,784.7	0.28	1,265,239.9
2040	-	-	304,689.9	-	11,931.0	115,030.0	304,689.9	(90,755.3)	213,934.7	57,485.8	0.27	1,322,725.7
2041	-	-	310,783.7	-	10,976.5	103,268.9	310,783.7	(92,940.2)	217,843.5	55,285.4	0.25	1,378,011.1
2042	-	-	316,999.4	-	10,098.4	92,448.6	316,999.4	(95,139.3)	221,860.1	53,177.9	0.24	1,431,189.0
2043	-	-	323,339.4	-	9,290.5	82,494.0	323,339.4	(97,355.1)	225,984.3	51,158.3	0.23	1,482,347.2
2044	-	-	329,806.2	-	8,547.3	73,335.7	329,806.2	(99,590.3)	230,215.9	49,222.0	0.21	1,531,569.2
2045	-	-	336,402.3	-	7,863.5	64,910.1	336,402.3	(101,847.0)	234,555.3	47,364.7	0.20	1,578,934.0
2046	-	-	343,130.4	-	7,234.4	57,158.5	343,130.4	(104,127.7)	239,002.6	45,582.6	0.19	1,624,516.5
2047	-	-	349,993.0	-	6,655.7	50,027.1	349,993.0	(106,434.6)	243,558.4	43,871.8	0.18	1,668,388.3
2048	-	-	356,992.8	-	6,123.2	43,466.2	356,992.8	(108,769.6)	248,223.2	42,229.0	0.17	1,710,617.3
2049	-	-	364,132.7	-	5,633.4	37,430.1	364,132.7	(111,134.8)	252,997.9	40,651.0	0.16	1,751,268.2
2050	-	-	371,415.3	-	5,182.7	31,877.0	371,415.3	(113,532.1)	257,883.2	39,134.8	0.15	1,790,403.1
2051	-	-	378,843.6	-	4,768.1	26,768.1	378,843.6	(115,963.4)	262,880.2	37,677.7	0.14	1,828,080.7
2052	-	-	386,420.5	-	4,386.6	22,067.9	386,420.5	(118,430.5)	267,990.0	36,277.0	0.14	1,864,357.7
2053	-	-	394,148.9	-	4,035.7	17,743.7	394,148.9	(120,935.1)	273,213.8	34,930.2	0.13	1,899,287.9
2054	-	-	402,031.9	-	3,712.8	13,765.4	402,031.9	(123,478.9)	278,553.0	33,635.1	0.12	1,932,923.0
2055	-	-	410,072.5	-	3,415.8	10,105.5	410,072.5	(126,063.6)	284,009.0	32,389.4	0.11	1,965,312.4
2056	-	-	418,274.0	-	3,142.6	6,738.3	418,274.0	(128,690.7)	289,583.2	31,191.1	0.11	1,996,503.4
2057	-	-	426,639.5	-	2,891.1	3,640.5	426,639.5	(131,362.0)	295,277.5	30,038.1	0.10	2,026,541.6
Total	**-**	**-**	**11,944,348.0**	**(919,154.5)**	**861,646.0**		**11,025,193.5**	**(3,435,637.6)**	**7,589,555.9**	**2,026,541.6**		


COMPARATIVE CUMULATIVE REVENUE REQUIREMENT
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Unit Overhaul vs Replacement Energy Costs
Test 2
Test 3
Test 4
Year

WÄRTSILÄ – SEALS & BEARINGS PROPOSAL

TECHNICAL AND BUDGETARY PROPOSAL FOR:

Nova Scotia Power – Fourth Lake Power Generating Plant

SEAL Upgrade

NOVA SCOTIA POWER

An Emera Company

Created By: Wärtsilä Seals & Bearings

Date: Wednesday, 08 June 2016

WÄRTSILÄ

Proposal Details

Design, Manufacture, Supply, Installation and Commissioning support of new seal arrangement and control systems as part of unit refurbishment.

CLIENT:	Nova Scotia Power Inc. P.O. Box 910 Halifax, NS B3J 2W5
REF:	Fourth Lake.
CONFIDENTIALITY:	The proposal is submitted by Wärtsilä UK Ltd – Seals and Bearings, to fulfil the request for a solution proposal for the replacement of the Bulb Type turbine shaft seal currently installed at the Fourth Lake Power Plant. Intellectual property (IP) in the seal design remains vested in Wärtsilä. The information herein may not be used for any other purposes, reproduced in whole or in part, or passed to any other organisation without the specific permission in writing of the proposal manager.
Validity:	120 DAYS
REF #:	TD-17296
Proposal Manager:	Mr James Robb – Consulting Engineer (Energy) James.robb@wartsila.com Wärtsilä UK Ltd – Seals and Bearings
Tel:	+44 (0)2392 391681
Approvals:	Wärtsilä UK LTD holds the following approvals: ISO 9001: 2008 ISO 14001: 2004 OHSA 18001: 2007 ALL CURRENT AND VALID UNTIL 7TH MARCH 2015 Copies of all certificates are included in Appendix A

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- Executive Summary 4
- Focus 4
- Technical Proposal 5
- Commercial Proposal 10
- Appendix A – References 12
- Appendix B – Wear Down Controller 14

Executive Summary

Wärtsilä Seals & Bearings is a global organisation and is a service division of the Wärtsilä Corporation; with service centres and operations in 170 locations and 60 countries.

The companies that make up the S&B division have a combined experience in excess of 100 years in the design, manufacture, installation and lifecycle management of shaft seals and bearing solutions. Financial performance of both the division, and the parent corporation, is consistent with, or ahead of, the market segments in which it operates; both currently and historically. All relevant information is in the public domain.

The portfolio of both product and service offerings are extensive and comprise of a tailored series of standard solutions available alongside customer designs and installations where a bespoke requirement is specified.

There is a high level of vertical integration within the five facilities (UK x 2, Spain, Sweden, Japan and China) including foundries, moulding, design, manufacture and test/validation. The supporting supply chain is well managed and has been developed over time.

Focus

Wärtsilä Seals & Bearings will utilise proven technologies to provide a technical solution in support of the Nova Scotia Power request for issues experienced on the fourth lake turbine shaft seals turbine shaft seals.

From the information supplied the current arrangements utilise Bestobel mechanical face type seals.

The requirement is to propose an alternative proven seal design from our product portfolio capable of operating in the same conditions but with improvements in performance (reduced leakage), to eliminate the loss of bearing lubrication oil during certain operations and reductions in through life cost.

The seals would be designed, manufactured and tested in the UK.

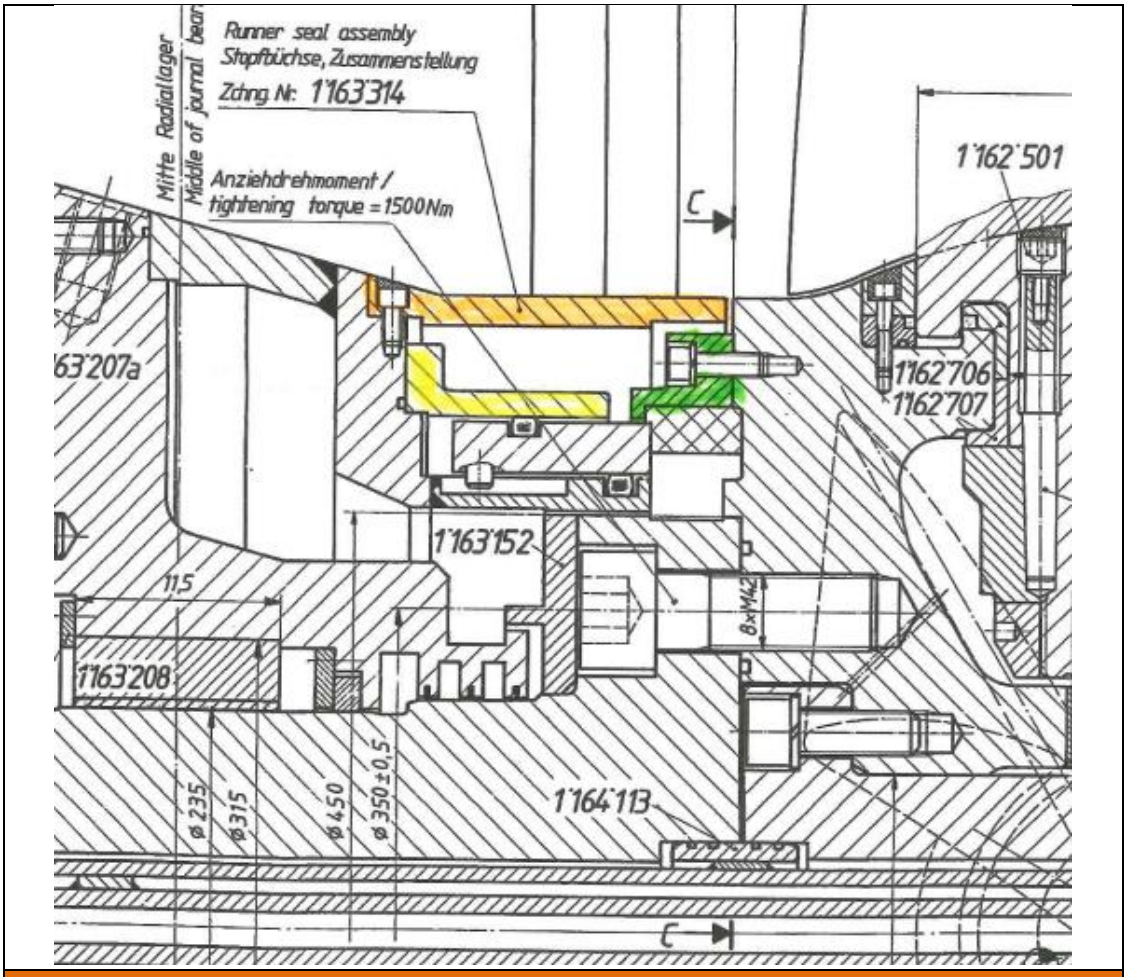
Lifecycle support for any installation would be provided through both Wärtsilä Canada and Wärtsilä UK as appropriate.

WÄRTSILÄ – SEALS & BEARINGS PROPOSAL

-TECHNICAL-

Fourth Lake HEP

Technical Summary

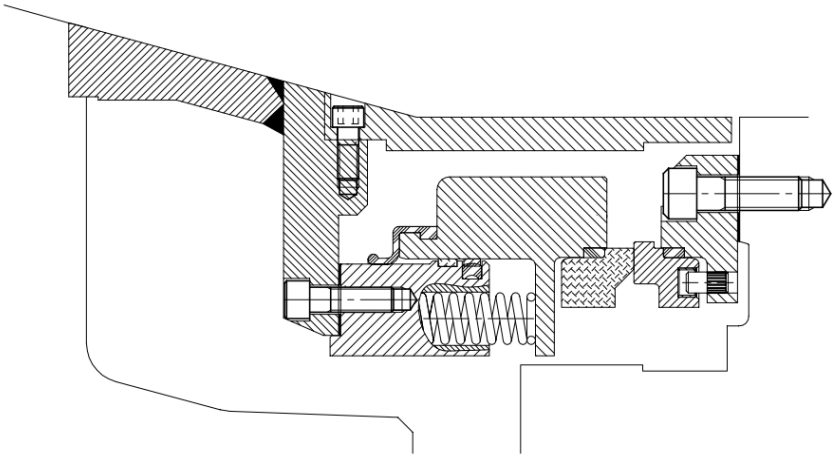


Current Installed Mechanical Seal – Unit 2

The seal currently fitted is a hydraulically activated mechanical face type seal, manufactured by Sterling Mechanical Seals and were the original seal type fitted. It is understood that NS Power have been experiencing significant loss of bearing oil, occurring during certain operations (Possibly during shut-down due to partial external vacuum pressure).

The request received during a meeting with NS power Technical representatives was to propose a suitable alternative solution that would help overcome these issues, and also help to improve overall mechanical performance of the shaft seal.

Technical Offering



Cross section of AC type shaft seal – H31421-01

The 'A' series seal range is a Mechanical Face Type Seal consisting of a multi segment stationary Seat element, which seals against a segmented rotating Face component. The seal would be mounted between the stationary shroud ring and the runner Hub of the turbine (no drilling into or welding of the shaft is necessary).

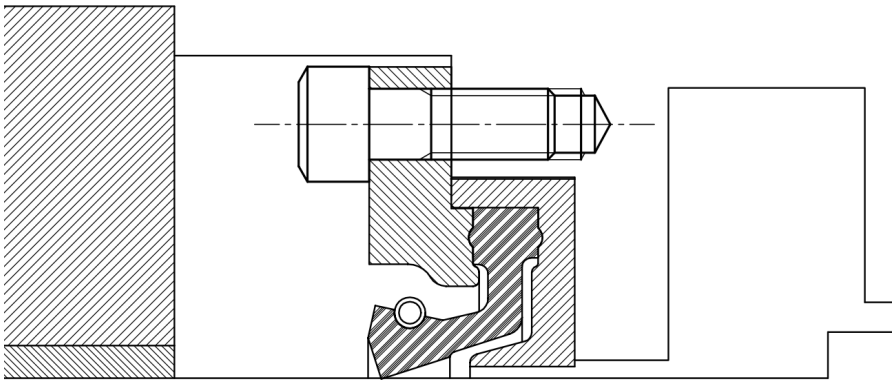
The hydraulically balanced seal design maintains contact between the Rotating Seat element and the stationary Face element by means of helical coil springs and hydraulic force provided by OD water Pressure. The helical springs in the seal, allow the Face and Seat to remain in contact throughout the operation of the Turbine (allowing for the required axial shaft movement specified) and self-adjust to compensate for any wear experienced over a 5-10 year service period. The Balance factor applied would be set during the detail design phase of an order to ensure that the contact scenario accounts for the possibility of external vacuum pressure, to ensure seal integrity is maintained and the vacuum pressure is not experience across the Bussing & Labyrinth seals protecting the bearing oil.

The AC Type configuration is an O/D pressurised seal, derived from Wartsila Submarine seal technology is able to cope with high service pressures exceeding that specified, while maintaining low leakage and low interface wear. The seals are also designed to operate bi-directionally with no loss in performance in either clockwise or counter-clockwise directions.

The seal will also be fitted with an inductive proximity sensor, which will allow for interface wear measurements to be taken. The sensor can either be wired directly into the plants SCADA system (requires a 9 – 30V power supply and produces a 4-20ma signal), or monitored remotely by a control box supplied by Wartsila (See Appendix C). The control box also allows for a 4-20ma signal feed for Scada connectivity.

The seal proposed is manufactured from a combination of corrosion resistant materials such as Bronzes, Stainless Steels and composites. It can be designed to interface with the existing seal mounting arrangement however due to the current set-up being integral to the existing seal, some modification to the shroud ring (see H31421-01) will be required to allow for the stationary assembly of new seal to be mounted. This work can be carried out by Wartsila on request, alternatively, the required modification detail can be supplied if local machining resource is preferred.

Bearing Oil Retention



Seal Ring Option – H31421-01

Although we are fully confident that the Seal will alleviate the Oil Leakage issues, one aspect of the current installed design which differs from similar configurations seen is the bushing used to restrict the bearing oil. In other configurations a lip seal has been used; understanding that loss of lubrication must occur via the Bushing & Labyrinth seal, a recommendation would be that modifying the arrangement to incorporate a seal ring would give significant improvements in performance over the existing arrangement.

To install a seal ring in this location, it would be possible to design an insert to provide the correct housing profile, and for the retaining ring to fit the existing PCD. As the required dimensions are not detailed on the drawings provided, and as it is understood that now detail drawings exist, if this modification were to be carried out, detailed inspection would need to be carried out prior to production of the required components.

Spares

Typical service cycles for the 'AC' type seal arrangement are based on intermediate (as required/predicted) and recommended 10 year intervals, components replaced at each service interval are as follows:

Shaft Seal

Service Kit "A" – intermediate service

- Face (split) Assy [inclusive of o-cords & sealing strips]
- Seat (split) Assy [inclusive of o-cords & sealing strips]
- Compression Tooling

Service Kit "B" – 10 year service

As Service Kit "A" including:

- Helical Springs
- Secondary Seal O-cord & Bearing Ring
- Mounting Gaskets (Split)
- All Elastomer components
- Fasteners

Technical Offering – Future Development

Wärtsilä specializes in the design and manufacture of a multitude of structural composites. These composites can be used to manufacture water lubricated guide bearing housings and housings for shaft seals.

The use of our in-house manufactured and developed composite materials not only has the potential for cost saving on volume production designs but offers a substantial saving on weight. This reduction in component weight can shorten installation and overhaul times and directly reduce costs and possible down time with no reduction in performance. Field service and initial installation is also made safer through increased ease of handling through the substantial weight reductions achieved.

Working closely with customer design teams we could [and have on other installations] reduce the component count within the seals construction; this saves weight, cost and time to the benefit of the overall product cost and performance.

WÄRTSILÄ – SEALS & BEARINGS PROPOSAL

-COMMERCIAL-

Fourth Lake HEP

Commercial proposal

Scope of supply:

The commercial offer is based on the supply of one [1] AC type seal and supporting wear down system:

Seal System Budgetary Offer:

1 X Seal AC Type Seal System (Including Wear down Controller)	@ CAD ($)	[redacted]
Spares:		
Service Kit 'A' - Intermediate	@ CAD (£)	
Service Kit 'B' - Major Overhaul (10 years)	@ CAD (£)	

This offer is subject to our standard terms, conditions and payment terms.

Delivery is EXW - Portsmouth UK

Shipping can be arranged at an additional cost and will be shipped to customers preferred location, such costs can be agreed at when PO is ready to be placed.

Lead-times of all components is 20 weeks from the point of ordering.

Product packaging will be in line with international freight requirements and will ensure that the risk of damage is transit in minimised.

Installation and commissioning at Customer site – can be supplied on request.

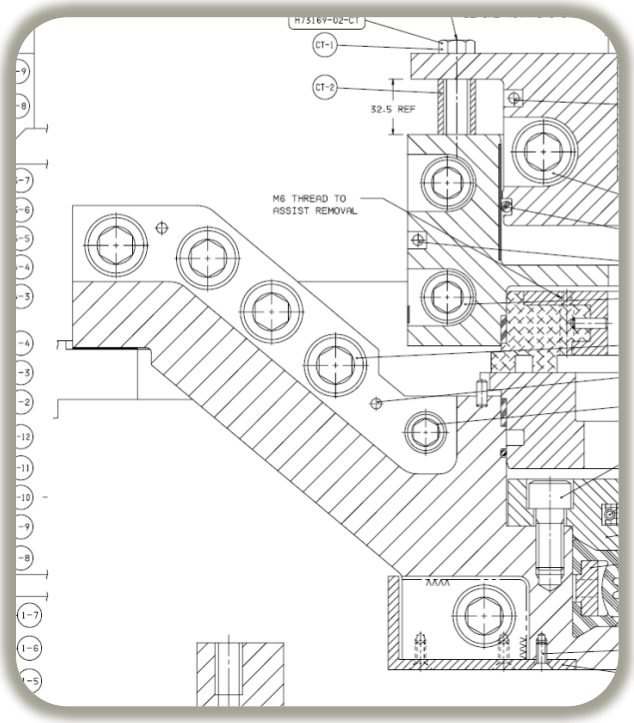
Appendix A – References

As well as numerous marine installations that currently utilise the proposed seal type, the following are examples of Hydro & other Industrial applications where Wartsila Seal technology has been installed.

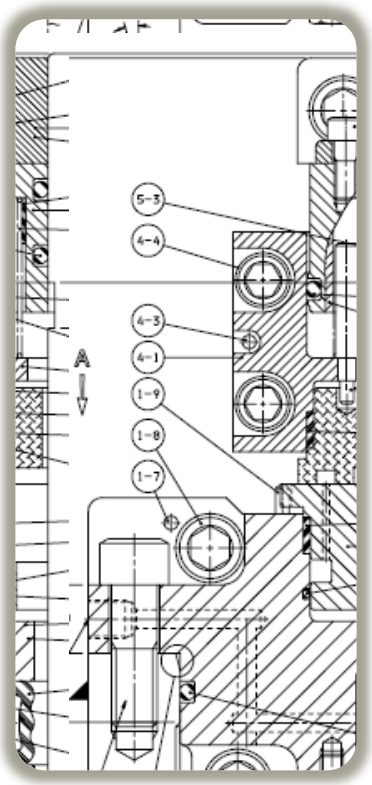
Aqaba Power Plant	CW Pumps	H71036	175	A6
Blackpoint Power Station	CW Pumps	H72565-01	150	AL
Castle Peak A Power Station	CW Pumps	H70796	270	MY
Castle Peak B Power Station	CW Pumps	H70797	460	MY
Cordemais Power Plant	CW Pumps 4/5	H71828-01	496	AR
Cordemais Power Plant	CW Pumps	H74186-02	496	AK
Dahanu Thermal Power Station	Volute Pumps	H72148	265	AK
Daya Bay Bop PS (Guang Dong)	CW Pumps	H71128	460	MY
Deer Island	Kaplan	H72907-01	250	AL
Diablo Canyon	CW Pumps	H71283	406.4	A5
Heysham I power station	CW Pumps	H41397	292.1	MZ
Heysham II	CW Pumps	H44273	350	MY
Heysham II	CW Pumps	H75697-01	350	MY
Hinkley Point B Power Station	CW Pumps	H71201	285.75	AF
Minidoka - Units 8	H-Kaplan	H30477-01	400	AL
Minidoka - Units 9	H-Kaplan	H30478-01	560	AR
Peterhead Power Station	CW Pump	H72005	266.7	MY
Pulau Seraya Steam Power Station	CW Pumps	H70167	240	MY
Rihand 1 Power Station	CW Pump	H70526	305	MY
Torness Power Station	CW Pumps	H72516-01	350	MY
Waitaki Hydro Plant	Francis	H72399-01	584.2	AS
Warsak 1 & 4	Francis	H73169-01	787.4	AR
Warsak 5 & 6	Francis	H73169-02	787.4	AR
Wylfa Power Station	CW Pumps	H70384	457.2	MY

Appendix C – References *(cont.)*

Installation	Warsak
Application	Hydro Turbine
Type	Francis
Manufacturer	Voith
Project Type	Retrofit
Shaft Diameter	787.4 mm
Pressure	4.9 Bar
Abrasives	Yes (Quartz)
Years of Service	18 Years



Installation	Cordemais
Application	Cooling water Pump
Type	Vertical Volute
Manufacturer	Unknown
Project Type	Retrofit (Packed Gland)
Shaft Diameter	496 mm
Pressure	1.8 Bar
Abrasives	Yes (Very High Sand Loading)
Years of Service	27 Years



Before

After

Appendix B – Wear Down Monitoring

WUK – SEALS & BEARINGS

INTERFACE WEAR DOWN GAUGE SYSTEM

PRINCIPAL OF OPERATION, SPECIFICATIONS AND INSTALLATION DETAILS

TD-16596 ISSUE A

AUTHOR: J. ROBB *20 AUGUST 2015*

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WÄRTSILÄ

Principal of operation, specifications and installation details

TD-16596

Interface wear down gauge system

- ***What does it do****?*
  - *Indicates the interface wear (or any other line shaft bearing if access permits) by measuring the shaft drop (by virtue of face wear) over time.*

- ***How does it do it****?*
  - *Via an inductive proximity sensor mounted on the seal Face Carrier Assy. The signal is transmitted to a digital control unit via a dedicated cable assembly.*

- ***How is the wear rate displayed?***
  - *The wear rate in millimetres is displayed on a digital display Unit, located in a convenient location near the Turbine.*
  - *Measurement is indicated after establishing a new / as installed datum of the seat in relation to the face carrier.*
  - *All resultant wear is indicated from this established datum.*
  - *The user can easily programme 'wear milestones,' which in turn alter the digital display colour, providing an instant warning of wear limits reached (green, amber, red and flashing red).*
  - *The maximum measured interface wear is 10mm.*

- ***Advantages:***
  - *Actual interface wear is indicated on the digital control unit, physical measurement does not need to be conducted.*
  - *The power supply only needs to be connected when a wear reading is required.*
  - *Indicative future bearing wear can be predicted if wear to date vs. time is analysed.*

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Bearing Wear down gauge system

- ***Standard supply***
  - *1 off wear down (WDG) module*
  - *1 off cable assembly (various standard cable lengths are available – 300m max)*
  - *1 off Digital display unit*
  - *1 off Technical manual on CD*
  - *Loose items pack comprising;*
    - *1 off Delrin distance setting block*
    - *1 off enclosure key – for the digital control unit enclosure lock*
    - *30cc pot of 'Vibratite' thread locking compound*

Packing case size:
460x460x330mm
Typical kit gross weight: 9kg

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TD-16596

Key system specifications

- ***Electrical supplies (to Digital control unit)***
  - 100-240Vac, 50Hz / 60Hz single phase supply; live, neutral and earth
  - Output supply to WDG module: 24Vdc (derived from within the Digital display unit)
  - Output from WDG to digital control unit: 4-20mA (non linear; correction coefficient applied by virtue of shaft line / bearing journal material)

- ***Internal protection ratings***
  - WDG module: **IP67**
  - Digital display unit: **IP65**; although it shall be mounted inside the hull of the vessel

- ***Electrical approvals***
  - Complies with the Low Voltage directive 2006/95/EC
  - Complies with the EMC directive 2004/108/EC
  - The digital display unit and WDG module are CE marked accordingly

CE

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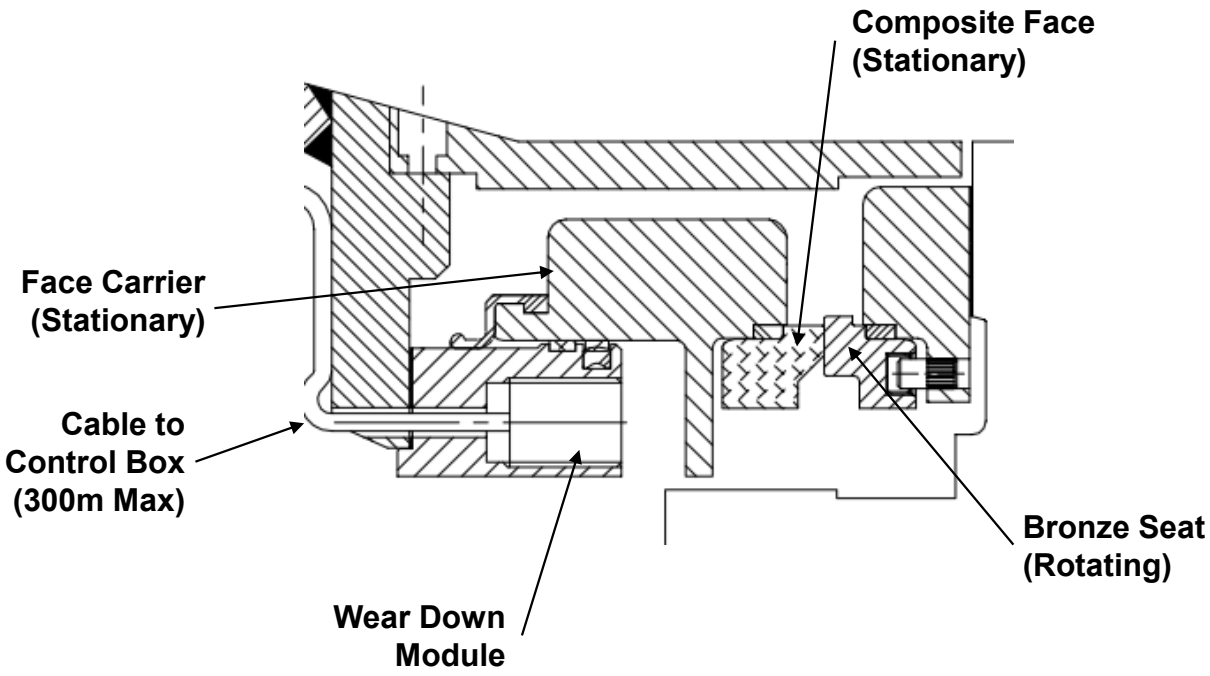
Principal of operation, specifications and installation details

TD-16596

Mounting arrangement for the interface wear down module



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Principal of operation, specifications and installation details

TD-16596

Wear down gauge (WDG) Module

- *IP67 construction (submersible)*
- *Input supply: 24Vdc*
- *Output signal: 4-20mA*
- *Operating temperature range: -5°C to +40°C*
- *Mass: 0.170kg*
- *Principal metallic parts: Chrome Plated Brass*
- *Working range (bearing wear): 0-10mm; measured as Face wear*
- *Recommended installed distance from shaft (new seal condition): 0.5" – set via a dedicated distance setting block (supplied).*
- *Mounted in dedicated location on seal Face Carrier*
- *No user serviceable parts*
- *Compatible with a range of metallic Seat materials*

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Principal of operation, specifications and installation details

TD-16596

Digital display unit

- Panel mounted inside the vessel hull on a suitable bulkhead / wall
- Input supply: 100-240Vac, 50Hz / 60Hz single phase supply; live, neutral and earth
- Installation inputs (for optional display of shaft hours run): 24Vdc, 0V
- Mass: 5.9kg
- IP 65 construction
- External dimensions: 300mm x 200mm x 160mm
- Supplied with 3 off Nickel plated cable glands; 7mm OD maximum cable diameter
- Operational temperature range: +5°C to +40°C
- Internal fuses: 3A for the PLC unit, 2A for the Power supply unit. 5mm diameter x 20mm long cartridge quick acting type.
- WDG and respective Digital display unit are a matched pair (calibrated together)

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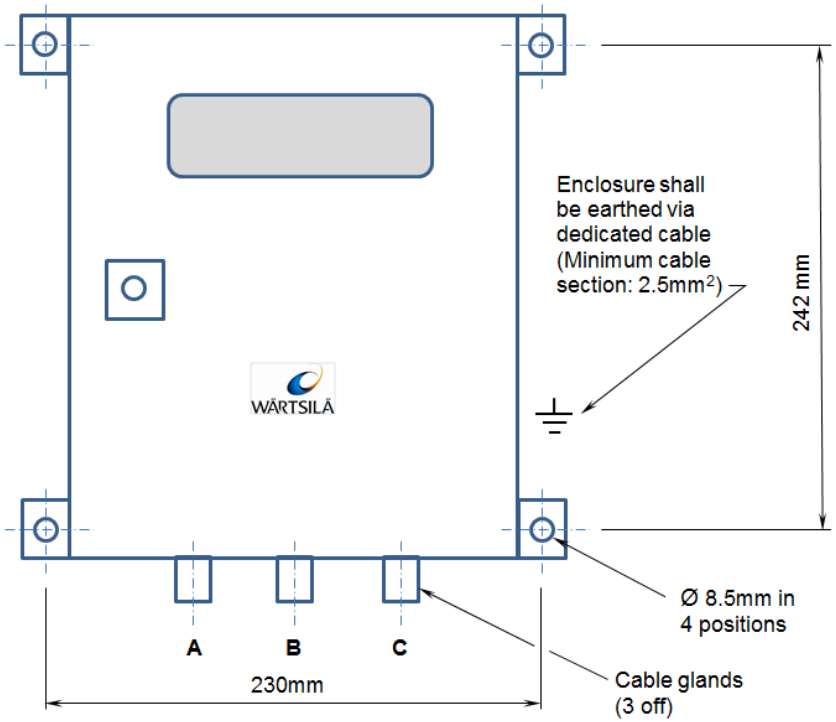
Principal of operation, specifications and installation details

TD-16596

Digital display unit
(continued)



Cable gland position	Cable function / remarks
A	***Input supply***; 100-230Vac, 50-60Hz, single phase. 2 core plus earth
B	***WDG input***; 3 core screened cable
C	***Optional*** Turbine shaft run input (24Vdc) *or* piggy back output (4-20mA) to Plants SCADA System. Use of these signals is at user's discretion
Gland details: Cable outside diameter range: 3.50 – 7.00mm. Nut / body hexagon: 20mm A/F	

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CI Number: 49945

Title: HYD Malay Falls Switchgear Replacement

Start Date: 2017/12
In-Service Date: 2018/08
Final Cost Date: 2019/02
Function: Hydro
Forecast Amount: $958,631

DESCRIPTION:

This project will replace the existing switchgear with modern arc-flash rated switchgear integrating with modern controls and interfaces.

The Malay Falls Generation Station is a powerhouse with three identical units located on the Sheet Harbour Hydro System. On average, the three units are rated at 1.5 MW and annually produce 13.5 GWh of renewable electricity on average.

Summary of Related CI's +/- 2 years
2016 CI 47551 - Sheet Harbour Controls Upgrade - $1,749,212
2017 CI 48914 - HYD Malay Falls Facility Refurbishment - $1,034,045

JUSTIFICATION:

Justification Criteria: Health & Safety

Why do this project?

The current switchgear requires manual racking of the breakers every time the unit requires safe work permit isolation (multiple times a year, per unit) which includes a significant arc-flash hazard for the hydro operator and risk of damage to the equipment. The project is being undertaken to eliminate the arc-flash hazard for personnel safety and improved reliability of the unit breakers.

This project is primarily justified on health and safety, and secondarily on unit reliability.

Why do this project now?

The switchgear in the Malay Falls plant is 34 years old, near the end of its design life. The design of the breakers presents an arc-flash risk with every manual racking operation. The switchgear breakers, and other components of the switchgear, are in poor condition and require replacement. One of the three generator breakers, an integral component of the switchgear, was sent to the OEM in 2016 for maintenance and was determined to be in poor condition.

Why do this project this way?

Replacing rather than refurbishing aging switchgear has been the standard in Hydro for years to bring this equipment up to modern safety standards. By replacing the switchgear it will improve the safety and reliability of the plant. Refurbishment of the switchgear is not considered feasible due to the age and technology of the current equipment.

CI Number : 49945 - HYD - Malay Falls Switchgear Replacement **Project Number** 49945

Parent CI Number : -

Asset Location : 1359 - 1359 Malay Falls Common Property **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	2300 - HGP - Power Equip.-Station S	938,219
Retirements	2300 - HGP - Power Equip.-Station S	20,412
	Total Cost:	958,631
	Original Cost:	454,006

Capital Project Detailed Estimate

Location: Hydro
FP# / P#: 49945
Title: HYD Malay Falls Switchgear Replacement
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Hydro River Staff - Construction	PD	55	$ 358	$ 19,670		
Engineering Staff	PD	69	$ 397	$ 27,418		
Hydro River Staff - Removal	PD	20	$ 358	$ 7,153		
			Sub-Total	$ 54,240		
Term Labour						
Hydro River Staff - Construction	PD	220	$ 358	$ 78,679		
Hydro River Staff - Removal	PD	20	$ 358	$ 7,153		
			Sub-Total	$ 85,832		
Travel Expense						
Site Visits	Week	20	$ 150	$ 3,000		
Temporary Report Point	Month	3	$ 2,000	$ 6,000		
			Sub-Total	$ 9,000		
Materials						
Switchgear for 3 units	ea	3	$ 133,000	$ 399,000		23125 Sissiboo Electrical
Cabling	Lot	1	$ 100,000	$ 100,000		17581 Weymouth Electrical
Misc Electrical supplies	Lot	1	$ 50,000	$ 50,000		
			Sub-Total	$ 549,000		
Contracts						
Misc Contracts	Lot	1	$ 30,000	$ 30,000		23125 Sissiboo Electrical 17581 Weymouth Electrical
			Sub-Total	$ 30,000		
Consulting						
Switchgear design	Lot	1	$ 45,000	$ 45,000		23125 Sissiboo Electrical
Switchgear Commissioning	Lot	1	$ 30,000	$ 30,000		17581 Weymouth Electrical
			Sub-Total	$ 75,000		
Meals						
Site Visits	Week	20	$ 75	$ 1,500		
Temporary Report Point	Month	3	$ 1,000	$ 3,000		
			Sub-Total	$ 4,500		
Other Goods & Services						
Contingency	%	10%	$ 807,572	$ 80,757		
			Sub-Total	$ 80,757		
Interest Capitalized						
AFUDC				$ 7,582		
			Sub-Total	$ 7,582		
Administrative Overhead						
Labour AO				$ 59,805		
Contract AO				$ 2,914		
			Sub-Total	$ 62,719		
			Sub-Total (no AO, AFUDC)	$ 888,330		
			TOTAL (AO, AFUDC included)	$ 958,631		
Original Cost				$ 454,006		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 52262

Title: HYD – Hells Gate #1 Overhaul

Start Date:	2018/01
In-Service Date:	2018/11
Final Cost Date:	2019/05
Function:	Hydro
Forecast Amount:	$854,993

DESCRIPTION:

This project includes disassembly of Hells Gate Unit 1, wicket gate replacement, remediation of cavitation spots on scroll case, head cover and linkage refurbishment and unit reassembly. The project also includes general unit refurbishment of all worn items, replacement of protective coatings and repair of damaged components.

Hells Gate is a Hydro Generating Plant operating on the Black River system. The Hells Gate Unit 1 is rated at 3.6 MW and produces 19.1 GWh/year.

Summary of Related CIs +/- 2 years:
No other projects in 2016, 2017, 2018, 2019 or 2020

JUSTIFICATION:

Justification Criteria: Hydro

Sub Criteria: Equipment Replacement / Refurbishment

Why do this project?

Components of Hells Gate Unit 1 require refurbishment or replacement. The unit has cavitation on wicket gates, scroll case, and stay vanes. This damage is causing excessive leakage of the wicket gates and decreasing efficiency of the turbine. The governor also needs maintenance to repair oil leaks. The head cover needs refurbishment to address erosion, and gaps that have formed that allow water past the wicket gates.

Why do this project now?

The Hells Gate unit is in poor condition. If not addressed in 2018, forced outages are likely to occur. This disrupts unit reliability and availability and can lead to replacement energy costs. The attached economic analysis shows that the costs of mitigating the risks around the wicket gates and other components will avoid more expensive replacement energy costs.

Why do this project this way?

Refurbishing this unit is the most economical way to maintain reliability. Replacement of specific worn components under an overall refurbishment is significantly more economic than unit replacement. To maximize output of the unit, the refurbishment will be timed to minimize spilled water (lost generation). Additionally, replacement parts will be of higher quality than original parts, which will reduce maintenance costs in the future.

CI Number : 52262 - HYD - Hells Gate #1 Overhaul

Project Number 52262

Parent CI Number : -

Asset Location : 1352 - 1352 Hells Gate 1, 3 Mwh; 1931 on Black River System

Budget Version 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	2400 - HGP - Turbine (Hydro)	792,532
Retirements	2400 - HGP - Turbine (Hydro)	62,461
	Total Cost:	854,993
	Original Cost:	580,610

Capital Project Detailed Estimate

Location: Hydro
CI# / FP#: 52262
Title: HYD Hells Gate #1 Overhaul
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
Hydro River Staff - Construction	day	200	365	$ 72,957		
Engineering Staff	day	97	405	$ 39,315		
Hydro River Staff - Removal	day	40	365	$ 14,591		
			Sub-Total	$ 126,863		
Term Labor						
Hydro River Staff - Construction	day	400	$ 365	$ 145,915		
Hydro River Staff - Removal	day	80	$ 365	$ 29,183		
			Sub-Total	$ 175,098		
Travel						
Crew Temporary Report Point	Lot	1	$ 21,800	$ 21,800		
			Sub-Total	$ 21,800		
Materials						
Bearings	Lot	1	$ 25,000	$ 25,000		
Misc. Materials (bushings, pins, fasteners)	Month	10	$ 5,000	$ 50,000		
Wicket Gate Replacement	Lot	1	$ 80,000	$ 80,000		
			Sub-Total	$ 155,000		
Contracts						
Misc. Contracts	Month	10	$ 5,000	$ 50,000		
Head Cover Refurbishment	Lot	1	$ 50,000	$ 50,000		
Scroll Case Recoating	Lot	1	$ 35,000	$ 35,000		
			Sub-Total	$ 135,000		
Consulting						
Quality Inspections	Month	6	$ 2,000	$ 12,000		
			Sub-Total	$ 12,000		
Meals & Entertainment						
Site Visit - Engineer	Month	8	$ 250	$ 2,000		
Crew Temporary Report Point	Month	6	$ 1,500	$ 9,000		
			Sub-Total	$ 11,000		
Other Goods & Services						
Contingency	%	10%	$ 636,761	$ 63,676		
			Sub-Total	$ 63,676		
Interest Capitalized						
AFUDC				$ 12,539		
				$ -		
			Sub-Total	$ 12,539		
Administrative Overhead						
Labor AO				$ 128,904		
Contract AO				$ 13,113		
			Sub-Total	$ 142,017		
			Sub-Total (no AO, AFUDC)	$ 700,437		
			TOTAL (AO, AFUDC included)	$ 854,993		
Original Cost				$ 580,610		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

HYD – Hells Gate #1 Overhaul
Summary of Alternatives

Division :	Power Production	**Date :**	**19-Nov-17**
Department :	Hydro	**CI Number:**	52262
		Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank (based on PV of RR)	IRR	Disc Pay
A	Overhaul vs Replacement Energy Costs	5.88%	-4,132,042	3,414,947	1	26.91%	5.5 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

Recommendation :

Complete the overhaul to avoid the replacement energy costs.

Notes/Comments :

Overhaul vs Replacement Energy Costs

The project compares the refurbishment of the Hells Gate 1 unit including, wicket gate replacement, headcover and scroll case refurbishment and bushing and bearing replacement. The avoided costs are assumed to be a unit outage that lasts 3 months, which is the estimated time to disassemble the unit to repair/ replace a wicket gate. The wicket gates are severely cavitated and require replacement. The wicket gates are original from 1930.

Test 2

Test 3

Test 4

HYD – Hells Gate #1 Overhaul
Summary of Sensitivities

Division :	Power Production
Department :	Hydro

Date :	**19-Nov-17**
CI Number:	52262
Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Overhaul vs Replacement Energy Costs	5.88%	-4,132,042	3,414,947	1	26.91%	5.5 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

	Alternative Variance on Capital Spend	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Overhaul vs Replacement Energy Costs	10%	-4,064,925	3,359,729	1	24.98%	6.0 years
B	Test 2	10%	0	0	2	#NUM!	0.0 years
C	Test 3	10%	0	0	2	#NUM!	0.0 years
D	Test 4	10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		67,117	-55,218	0	-1.93%	0.5 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

	Alternative Variance on Avoided Expenses	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Overhaul vs Replacement Energy Costs	-10%	-3,651,721	3,018,235	1	24.78%	6.0 years
B	Test 2	-10%	0	0	2	#NUM!	0.0 years
C	Test 3	-10%	0	0	2	#NUM!	0.0 years
D	Test 4	-10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		480,322	-396,713	0	-2.12%	0.5 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

Alternative Variance on Avoided Expenses - Change in Revenue Requirement		PV of Revenue Requirement	PV of Revenue Requirement	PV of Revenue Requirement	Delay?
	Yrs Delay:	1	2	3	
	A	80,793	167,167	280,519	No
	B	0	0	0	No
	C	0	0	0	No
	D	0	0	0	No

HYD – Hells Gate #1 Overhaul
Avoided Cost Calculations

Division :	Power Production	**Date :**	**19-Nov-17**
Department :	Hydro	**CI Number:**	52262
		Project No. :	

Overhaul vs Replacement Energy Costs

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	1	1	1	1		
Probability of Occurance (%)	30%	35%	30%	35%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	1592.0	1592.0				
Duration (Hours or Years)	3	3				
Totals	$119,706	$139,204	$0	$0	$119,706	$139,204
Total Capital Cost of Alternative						$854,993

Test 2

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

Test 3

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

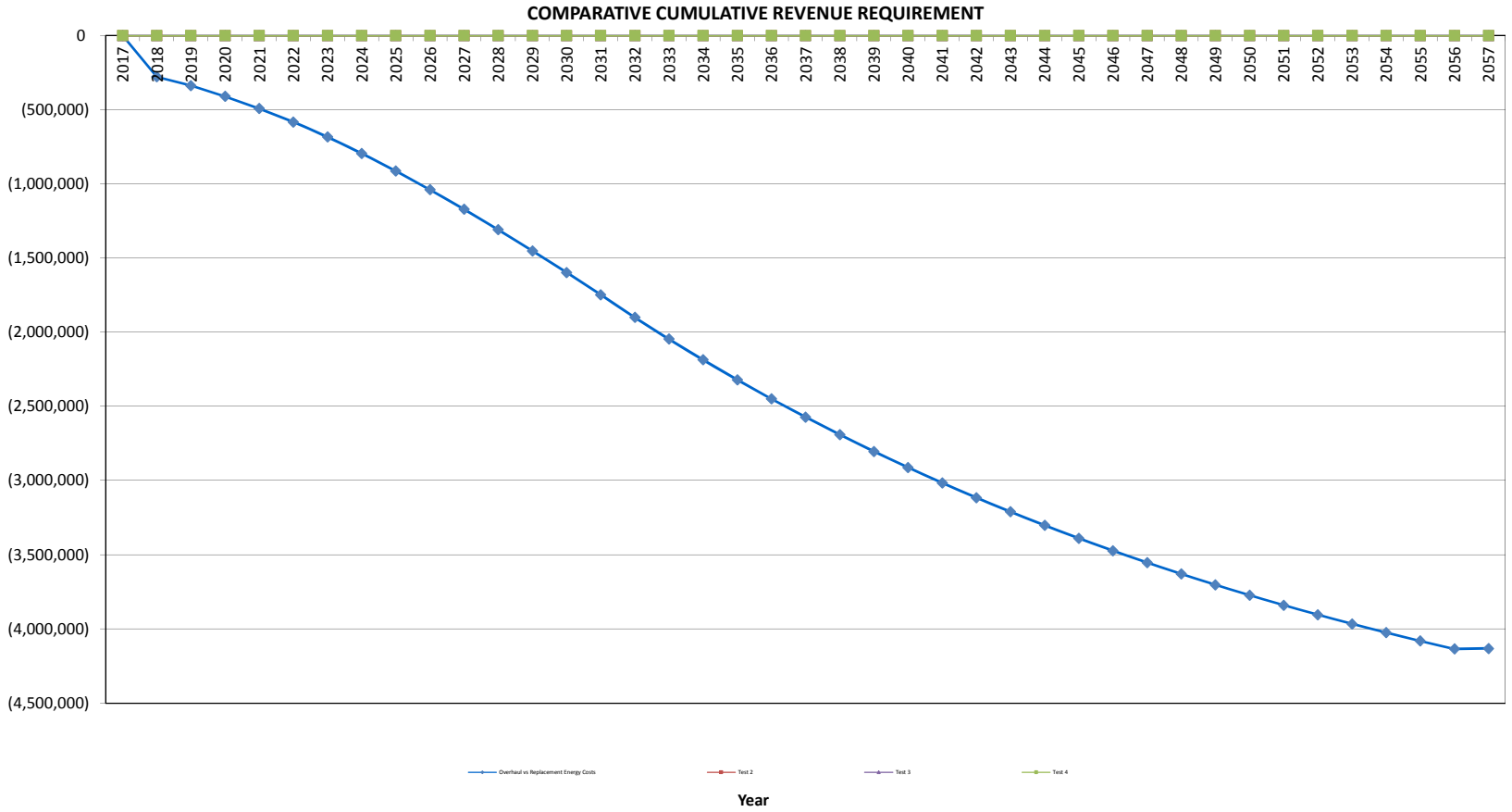
Test 4

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

HYD – Hells Gate #1 Overhaul

Overhaul vs Replacement Energy Costs

Year	Total Revenue	Operating Costs	Avoided Expenses	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	PV of CF	Discount Factor	CNPV
2017	-	-	-	-	-	-	-	-	-	-	1.00	-
2018	-	-	119,706.4	(712,976.4)	28,017.5	711,616.3	(593,270.0)	(28,423.6)	(621,693.6)	(587,168.1)	0.94	(587,168.1)
2019	-	-	139,203.7	-	53,793.6	651,278.6	139,203.7	(26,477.1)	112,726.5	100,553.8	0.89	(486,614.3)
2020	-	-	160,574.7	-	49,490.1	595,767.9	160,574.7	(34,436.2)	126,138.4	106,268.8	0.84	(380,345.5)
2021	-	-	179,165.3	-	45,530.9	544,698.1	179,165.3	(41,426.7)	137,738.6	109,597.4	0.80	(270,748.2)
2022	-	-	199,778.7	-	41,888.4	497,713.8	199,778.7	(48,946.0)	150,832.7	113,351.1	0.75	(157,397.1)
2023	-	-	224,151.7	-	38,537.3	454,488.3	224,151.7	(57,540.4)	166,611.2	118,255.3	0.71	(39,141.7)
2024	-	-	249,419.7	-	35,454.4	414,720.9	249,419.7	(66,329.3)	183,090.4	122,734.9	0.67	83,593.2
2025	-	-	275,608.8	-	32,618.0	378,134.8	275,608.8	(75,327.1)	200,281.6	126,803.0	0.63	210,396.2
2026	-	-	302,745.6	-	30,008.6	344,475.6	302,745.6	(84,548.5)	218,197.1	130,473.9	0.60	340,870.1
2027	-	-	330,857.7	-	27,607.9	313,509.2	330,857.7	(94,007.5)	236,850.3	133,762.6	0.56	474,632.7
2028	-	-	359,973.2	-	25,399.2	285,020.0	359,973.2	(103,717.9)	256,255.3	136,684.6	0.53	611,317.3
2029	-	-	390,121.0	-	23,367.3	258,810.0	390,121.0	(113,693.6)	276,427.3	139,256.0	0.50	750,573.2
2030	-	-	421,330.6	-	21,497.9	234,696.8	421,330.6	(123,948.1)	297,382.5	141,492.8	0.48	892,066.0
2031	-	-	453,632.7	-	19,778.1	212,512.7	453,632.7	(134,494.9)	319,137.7	143,411.2	0.45	1,035,477.2
2032	-	-	487,058.2	-	18,195.8	192,103.3	487,058.2	(145,347.3)	341,710.9	145,027.3	0.42	1,180,504.6
2033	-	-	496,799.4	-	16,740.2	173,326.6	496,799.4	(148,818.4)	347,981.0	139,486.7	0.40	1,319,991.2
2034	-	-	506,735.4	-	15,401.0	156,052.1	506,735.4	(152,313.7)	354,421.7	134,178.7	0.38	1,454,169.9
2035	-	-	516,870.1	-	14,168.9	140,159.5	516,870.1	(155,837.4)	361,032.7	129,090.9	0.36	1,583,260.8
2036	-	-	527,207.5	-	13,035.4	125,538.3	527,207.5	(159,393.4)	367,814.1	124,212.0	0.34	1,707,472.9
2037	-	-	537,751.6	-	11,992.5	112,086.9	537,751.6	(162,985.3)	374,766.3	119,531.4	0.32	1,827,004.2
2038	-	-	548,506.7	-	11,033.1	99,711.5	548,506.7	(166,616.8)	381,889.9	115,039.1	0.30	1,942,043.4
2039	-	-	559,476.8	-	10,150.5	88,326.2	559,476.8	(170,291.2)	389,185.6	110,726.2	0.28	2,052,769.5
2040	-	-	570,666.3	-	9,338.4	77,851.7	570,666.3	(174,011.6)	396,654.7	106,584.0	0.27	2,159,353.6
2041	-	-	582,079.7	-	8,591.4	68,215.2	582,079.7	(177,781.4)	404,298.3	102,604.8	0.25	2,261,958.3
2042	-	-	593,721.3	-	7,904.1	59,349.5	593,721.3	(181,603.3)	412,117.9	98,780.9	0.24	2,360,739.3
2043	-	-	605,595.7	-	7,271.7	51,193.2	605,595.7	(185,480.4)	420,115.3	95,105.6	0.23	2,455,844.9
2044	-	-	617,707.6	-	6,690.0	43,689.3	617,707.6	(189,415.5)	428,292.1	91,572.3	0.21	2,547,417.2
2045	-	-	630,061.7	-	6,154.8	36,785.8	630,061.7	(193,411.2)	436,650.6	88,174.7	0.20	2,635,591.8
2046	-	-	642,663.0	-	5,662.4	30,434.5	642,663.0	(197,470.2)	445,192.8	84,907.1	0.19	2,720,499.0
2047	-	-	655,516.2	-	5,209.4	24,591.4	655,516.2	(201,595.1)	453,921.1	81,764.1	0.18	2,802,263.0
2048	-	-	668,626.6	-	4,792.7	19,215.6	668,626.6	(205,788.5)	462,838.1	78,740.3	0.17	2,881,003.3
2049	-	-	681,999.1	-	4,409.3	14,270.0	681,999.1	(210,052.9)	471,946.2	75,831.0	0.16	2,956,834.3
2050	-	-	695,639.1	-	4,056.5	9,720.0	695,639.1	(214,390.6)	481,248.5	73,031.4	0.15	3,029,865.7
2051	-	-	709,551.9	-	3,732.0	5,534.0	709,551.9	(218,804.2)	490,747.7	70,337.1	0.14	3,100,202.8
2052	-	-	723,742.9	-	3,433.4	1,682.9	723,742.9	(223,295.9)	500,447.0	67,743.9	0.14	3,167,946.8
2053	-	-	738,217.8	-	3,158.8	(1,860.2)	738,217.8	(227,868.3)	510,349.5	65,247.8	0.13	3,233,194.6
2054	-	-	752,982.1	-	2,906.1	(5,119.8)	752,982.1	(232,523.6)	520,458.5	62,845.0	0.12	3,296,039.6
2055	-	-	768,041.8	-	2,673.6	(8,118.6)	768,041.8	(237,264.1)	530,777.6	60,531.7	0.11	3,356,571.3
2056	-	-	783,402.6	-	2,459.7	(10,877.5)	783,402.6	(242,092.3)	541,310.3	58,304.6	0.11	3,414,875.9
2057	-	-	-	-	2,262.9	(13,415.7)	-	701.5	701.5	71.4	0.10	3,414,947.3
Total	**-**	**-**	**19,406,890.6**	**(712,976.4)**	**674,413.7**		**18,693,914.2**	**(5,807,067.9)**	**12,886,846.4**	**3,414,947.3**		


COMPARATIVE CUMULATIVE REVENUE REQUIREMENT
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Overhaul vs Replacement Energy Costs
Test 2
Test 3
Test 4
Year

CI Number: 51972

Title: HYD Nictaux Canal Embankment Upgrade

Start Date:	2017/09
In-Service Date:	2018/08
Final Cost Date:	2019/02
Function:	Hydro
Forecast Amount:	$789,918

DESCRIPTION:

The project includes adding a drainage system and stability berm to the toe of the Nictaux Canal to increase canal stability. As well, the 5.2 kilometer driving surface on the canal crest will be refurbished.

The Nictaux Canal begins at the left abutment of the Nictaux Main Dam and extends for 5.2 kilometers towards the Nictaux Intake Structure. It is thought to have been constructed by placement of the excavated soil and rock from the canal channel 60 to 70 years ago. The canal has a maximum height of approximately 60 feet and a design crest elevation of 493.5 feet. Modifications to the canal are necessary to meet Canadian Dam Association recommended safety standards for slope stability. The downstream slope will require flattening by the addition of a berm to meet the steady state, flood and pseudo-static flood cases.

Summary of Related CIs +/- 2 years:
2016 – CI 47396 – HYD Nictaux Powerhouse Dam Refurbishment $1,792,968

JUSTIFICATION:

Justification Criteria: Health & Safety

Why do this project?

The project is being completed to minimize the risk of a stability failure of the structure. The stability deficiency has been monitored for over 20 years and the risk associated with stability failure has increased as shown in a stability analysis completed in 2017. The stability analysis is presented as Confidential Attachment 1.

The canal crest is not at a consistent elevation or width and is heavily rutted. The crest also has no crowning, which is preventing adequate drainage from the top of the dam and allowing material from the dam crest to erode and cause dangerous road conditions next to a water body. Canal crest refurbishment was indicated as a required action in the last dam safety review received in 2015 and was planned to coincide with stability refurbishments.

Why do this project now?

The canal requires repairs to reduce risks to dam safety. The work is being done now as part of the risk prioritization of dam safety work.

Why do this project this way?

The addition of a toe berm will restore the required factor of safety to the structure. The toe berm can be added to the existing structure without interruption of plant operations or environmental impact. This is the simplest option to correct the deficiencies. The alternative option considered was reconstruction of the dam. The reconstruction option was ruled out due to increased scope, outage requirement and cost.

CI Number : 51972-H847 - HYD Nictaux Canal Embankment Upgrade

Project Number 51972-H847

Parent CI Number : -

Asset Location : 1362 - 1362 Nictaux, 7 Mwh; 1954

Budget Version 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	2700 - HGP - Waterways	767,976
Retirements	2700 - HGP - Waterways	21,943
	Total Cost:	789,918
	Original Cost:	154,121

Capital Project Detailed Estimate

Location: Hydro
FP# / P#: 51972
Title: HYD Nictaux Canal Embankment Upgrade
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Hydro River Staff - Construction	day	20	365	$ 7,296		
Engineering Staff	day	24	405	$ 9,727		
Environmental Staff	day	16	332	$ 5,313		
			Sub-Total	$ 22,337		
Travel Expenses						
Site Visits	Month	4	$ 400	$ 1,600		
			Sub-Total	$ 1,600		
Materials						
Perforated Pipe	Lin. Ft	160	[redacted]		Totals are 50% of Costs to split between Materials and Contracts	49633 - Trout River Canal Refurbishment
Toe Drain	Cu. Ft	38979				
Stability Berm	Cu. Ft	94037				
Seeding	Sq Ft	12181				
Road Re-cresting	km	5.6				51771 - Wreck Cove Tailrace Road Refurbishment
			Sub-Total	[redacted]		
Contracts						
Perforated Pipe	Lin. Ft	160	[redacted]		Totals are 50% of Costs to split between Materials and Contracts	49633 - Trout River Canal Refurbishment
Toe Drain	Cu. Ft	38979				
Stability Berm	Cu. Ft	94037				
Seeding	Sq Ft	12181				
Mobilization / Demobilization	lot	1				
Environmental Control	lot	1				
Road Re-cresting	km	5.6				51771 - Wreck Cove Tailrace Road Refurbishment
			Sub-Total	[redacted]		
Consulting						
Engineering Fees (IFC's, QTY's, Site Visit, etc)	Lot	1	$ 30,000	$ 30,000		
Environmental Studies (archaeology, wetlands, etc)	Lot	1	$ 11,000	$ 11,000		
			Sub-Total	$ 41,000		
Meals and Entertainment						
Site Visits	Month	4	$ 400	$ 1,600		
			Sub-Total	$ 1,600		
Other Goods and Services						
Contingency	%	10%	$ 691,412	$ 69,141		
			Sub-Total	$ 69,141		
Interest Capitalized						
AFUDC				$ 3,288		
				$ -		
			Sub-Total	$ 3,288		
Administrative Overhead						
Labour AO				$ 9,535		
Contract AO				$ 16,542		
			Sub-Total	$ 26,077		
			Sub-Total (no AO, AFUDC)	$ 760,553		
			TOTAL (AO, AFUDC included)	$ 789,918		
Original Cost				$ 154,121		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

ACE 2018 CI 51972 Attachment 1
has been removed due to confidentiality.

CI Number: 51866

Title: HYD Fourth Lake Penstock Refurbishment

Start Date: 2017/09
In-Service Date: 2018/09
Final Cost Date: 2019/03
Function: Hydro
Forecast Amount: $696,963

DESCRIPTION:

The Fourth Lake Penstock is a concrete pipe with steel liner that passes through an earth filled dam. The steel liner is degrading and losing thickness as a result of erosion and pitting and is suffering from protective coating loss. This project will remediate the pitting and erosion damage, install steel plates and inject concrete where necessary, and recoat the penstock to protect the liner and extend its useful life.

Summary of Related CIs +/- 2 years:
2018 – 49946 Fourth Lake Overhaul $1,025,769

JUSTIFICATION:

Justification Criteria: Hydro, Wind and Biomass

Why do this project?

Pitting and erosion poses a risk to the integrity of the penstock. The main risk is not a loss of the penstock but rather the water released from the penstock will remove dam materials surrounding the penstock and contribute to a potential dam failure mode. NS Power assessed this penstock pipe in 2011 and made recommendations for steel and concrete refurbishment at that time.

This project is primarily justified on unit reliability and secondarily on positive economics.

Why do this project now?

Damage was observed in an inspection in 2011 and NS Power has monitored the progression of the pitting and erosion over the last 6 years, in order to defer the investment. The timing of the project is to take advantage of a combined outage with CI 49946 Fourth Lake Overhaul, minimizing unit down time. It is recommended that the damaged areas berefurbished now by installing new steel plates and injecting concrete where necessary as well as recoating the penstock to prevent any further material loss and additional risk to the dam.

Why do this project this way?
Other option considered include the replacement of the pipeline with a material that does not experience corrosion or require recoating. Replacing the penstock was not considered to be the best alternative as it is more expensive not considered necessary at this time. The best approach is to refurbish the damaged areas of the penstock, adding steel plates, injecting concrete and recoating the penstock where necessary.

CI Number : 51866 - HYD Fourth Lake Penstock Refurbishment **Project Number** 51866

Parent CI Number : -

Asset Location : 1364 - 1364 Fourth Lake, 3 Mwh; 1983 on Sissiboo River **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	2700 - HGP - Waterways	675,021
Retirements	2700 - HGP - Waterways	21,943
	Total Cost:	696,963
	Original Cost:	329,337

Capital Project Detailed Estimate

Location: Hydro
CI# / FP#: 51866
Title: HYD Fourth Lake Penstock Refurbishment
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Hydro River Staff - Construction	day	80	365	$ 29,183		
Engineering Staff	day	65	405	$ 26,345		
			Sub-Total	$ 55,528		
Travel Expenses						
Site Visits	Week	28	150	$ 4,200		
			Sub-Total	$ 4,200		
Contracts						
Blast and Recoat Penstock	sqft	20500	$ 20	$ 410,000		43136
Penstock Repairs	Lot	1	$ 50,000	$ 50,000		
			Sub-Total	$ 460,000		
Consulting						
Inspection during the work (contract)	Month	5	$ 5,000	$ 25,000		
Penstock Inspection	lot	1	$ 20,000	$ 20,000		
			Sub-Total	$ 45,000		
Meals						
Site Visits	week	28	75	$ 2,100		
			Sub-Total	$ 2,100		
Other Goods and Services						
Contingency	%	10%	$ 566,828	$ 56,683		
			Sub-Total	$ 56,683		
Interest Capitalized						
AFUDC				$ 4,322		
			Sub-Total	$ 4,322		
Administrative Overhead						
Labour AO				$ 24,451		
Contracts AO				$ 44,680		
			Sub-Total	$ 69,131		
			Sub-Total (no AO, AFUDC)	$ 623,511		
			TOTAL (AO, AFUDC included)	$ 696,963		
Original Cost				$ 329,337		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

HYD Fourth Lake Penstock Refurbishment
Summary of Alternatives

Division :	Power Production	**Date :**	**19-Nov-17**
Department :	Hydro	**CI Number:**	51866
		Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank (based on PV of RR)	IRR	Disc Pay
A	Penstock Refurbishment vs Replacement Energy Costs	5.88%	-10,525,324	8,679,663	1	55.51%	2.8 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

Recommendation :

It is recommended to complete this penstock refurbishment in order to avoid replacement energy costs.

Notes/Comments :

Penstock Refurbishment vs Replacement Energy Costs

This considers the capital cost of the penstock refurbishment, and the avoided replacement energy costs that would occur as a result of a penstock failure.

Test 2

Test 3

Test 4

HYD Fourth Lake Penstock Refurbishment
Summary of Sensitivities

Nova Scotia POWER An Emera Company

Division :	Power Production	**Date :**	**15-Nov-17**
Department :	Hydro	**CI Number:**	51866
		Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Penstock Refurbishment vs Replacement Energy	5.88%	-10,525,324	8,679,663	1	55.51%	2.8 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

	Alternative Variance on Capital Spend	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Penstock Refurbishment vs Replacement Energy	10%	-10,460,765	8,627,652	1	51.14%	3.0 years
B	Test 2	10%	0	0	2	#NUM!	0.0 years
C	Test 3	10%	0	0	2	#NUM!	0.0 years
D	Test 4	10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		64,559	-52,011	0	-4.37%	0.2 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

	Alternative Variance on Avoided Expenses	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Penstock Refurbishment vs Replacement Energy	-10%	-9,408,233	7,759,686	1	50.71%	3.1 years
B	Test 2	-10%	0	0	2	#NUM!	0.0 years
C	Test 3	-10%	0	0	2	#NUM!	0.0 years
D	Test 4	-10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		1,117,091	-919,977	0	-4.80%	0.3 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

Alternative Variance on Avoided Expenses - Change in Revenue Requirement		PV of Revenue Requirement	PV of Revenue Requirement	PV of Revenue Requirement	Delay?
	Yrs Delay:	1	2	3	
	A	129,408	319,038	596,931	No
	B	0	0	0	No
	C	0	0	0	No
	D	0	0	0	No

HYD Fourth Lake Penstock Refurbishment
Avoided Cost Calculations

Division :	Power Production	**Date :**	**15-Nov-17**
Department :	Hydro	**CI Number:**	51866
		Project No. :	

Penstock Refurbishment vs Replacement Energy Costs

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	1	1	1	1		
Probability of Occurance (%)	20%	30%	20%	30%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	10200.0	10200.0				
Duration (Hours or Years)	1	1				
Totals	$170,436	$254,824	$0	$0	$170,436	$254,824
Total Capital Cost of Alternative						$696,963

Test 2

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

Test 3

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

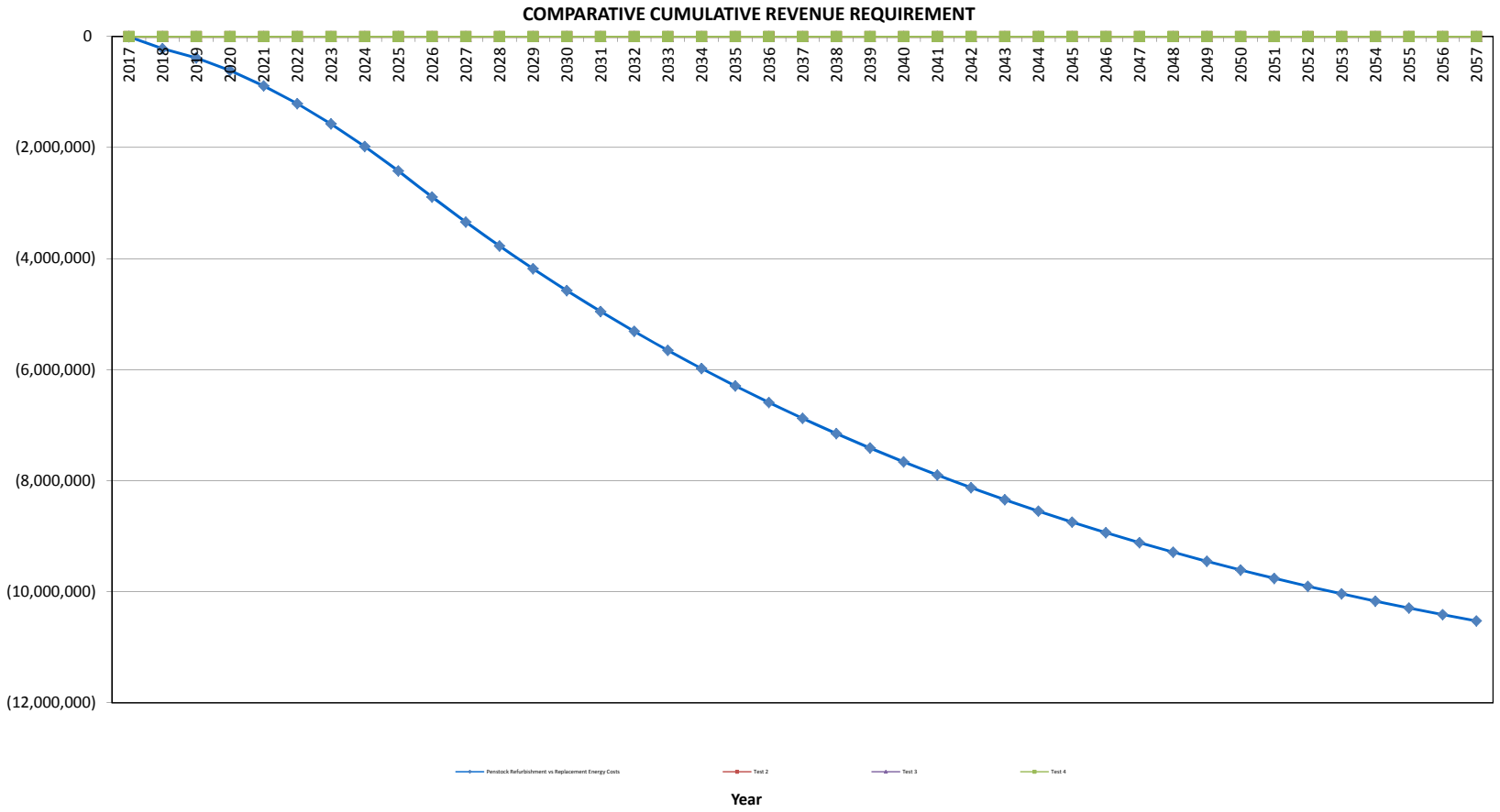
Test 4

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

HYD Fourth Lake Penstock Refurbishment

Penstock Refurbishment vs Replacement Energy Costs

Year	Total Revenue	Operating Costs	Avoided Expenses	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	PV of CF	Discount Factor	CNPV
2017	-	-	-	(29,429.9)	-	-	(29,429.9)	-	(29,429.9)	(29,429.9)	1.00	(29,429.9)
2018	-	-	170,436.2	(598,402.7)	12,470.2	630,950.0	(427,966.4)	(48,969.5)	(476,935.9)	(450,449.5)	0.94	(479,879.4)
2019	-	-	254,823.6	-	24,441.6	604,882.4	254,823.6	(71,418.4)	183,405.2	163,600.2	0.89	(316,279.2)
2020	-	-	342,935.8	-	23,464.0	579,857.6	342,935.8	(99,036.3)	243,899.5	205,479.8	0.84	(110,799.4)
2021	-	-	425,155.0	-	22,525.4	555,833.7	425,155.0	(124,815.2)	300,339.8	238,977.6	0.80	128,178.2
2022	-	-	511,995.6	-	21,624.4	532,770.8	511,995.6	(152,015.1)	359,980.6	270,526.2	0.75	398,704.5
2023	-	-	609,274.8	-	20,759.4	510,630.4	609,274.8	(182,439.8)	426,835.0	302,953.8	0.71	701,658.3
2024	-	-	710,240.4	-	19,929.0	489,375.6	710,240.4	(213,996.5)	496,243.8	332,657.7	0.67	1,034,316.0
2025	-	-	815,000.8	-	19,131.9	468,971.0	815,000.8	(246,719.4)	568,281.4	359,792.4	0.63	1,394,108.5
2026	-	-	923,667.6	-	18,366.6	449,382.6	923,667.6	(280,643.3)	643,024.3	384,505.0	0.60	1,778,613.4
2027	-	-	942,140.9	-	17,631.9	430,577.7	942,140.9	(286,597.8)	655,543.1	370,221.8	0.56	2,148,835.2
2028	-	-	960,983.8	-	16,926.6	412,525.0	960,983.8	(292,657.7)	668,326.1	356,480.0	0.53	2,505,315.2
2029	-	-	980,203.4	-	16,249.6	395,194.5	980,203.4	(298,825.7)	681,377.7	343,258.1	0.50	2,848,573.3
2030	-	-	999,807.5	-	15,599.6	378,557.1	999,807.5	(305,104.4)	694,703.1	330,535.5	0.48	3,179,108.7
2031	-	-	1,019,803.7	-	14,975.6	362,585.3	1,019,803.7	(311,496.7)	708,307.0	318,292.5	0.45	3,497,401.3
2032	-	-	1,040,199.7	-	14,376.6	347,252.3	1,040,199.7	(318,005.2)	722,194.6	306,510.4	0.42	3,803,911.7
2033	-	-	1,061,003.7	-	13,801.5	332,532.6	1,061,003.7	(324,632.7)	736,371.0	295,171.1	0.40	4,099,082.7
2034	-	-	1,082,223.8	-	13,249.5	318,401.8	1,082,223.8	(331,382.0)	750,841.8	284,257.3	0.38	4,383,340.0
2035	-	-	1,103,868.3	-	12,719.5	304,836.1	1,103,868.3	(338,256.1)	765,612.1	273,752.5	0.36	4,657,092.4
2036	-	-	1,125,945.6	-	12,210.7	291,813.1	1,125,945.6	(345,257.8)	780,687.8	263,640.8	0.34	4,920,733.3
2037	-	-	1,148,464.5	-	11,722.3	279,311.0	1,148,464.5	(352,390.1)	796,074.4	253,907.2	0.32	5,174,640.5
2038	-	-	1,171,433.8	-	11,253.4	267,309.0	1,171,433.8	(359,655.9)	811,777.9	244,537.0	0.30	5,419,177.5
2039	-	-	1,194,862.5	-	10,803.3	255,787.1	1,194,862.5	(367,058.4)	827,804.1	235,516.4	0.28	5,654,693.9
2040	-	-	1,218,759.8	-	10,371.1	244,726.0	1,218,759.8	(374,600.5)	844,159.3	226,831.8	0.27	5,881,525.7
2041	-	-	1,243,135.0	-	9,956.3	234,107.4	1,243,135.0	(382,285.4)	860,849.6	218,470.5	0.25	6,099,996.2
2042	-	-	1,267,997.7	-	9,558.0	223,913.6	1,267,997.7	(390,116.3)	877,881.4	210,420.2	0.24	6,310,416.5
2043	-	-	1,293,357.6	-	9,175.7	214,127.5	1,293,357.6	(398,096.4)	895,261.2	202,669.1	0.23	6,513,085.6
2044	-	-	1,319,224.8	-	8,808.7	204,732.8	1,319,224.8	(406,229.0)	912,995.8	195,205.7	0.21	6,708,291.3
2045	-	-	1,345,609.3	-	8,456.3	195,713.9	1,345,609.3	(414,517.4)	931,091.9	188,019.3	0.20	6,896,310.6
2046	-	-	1,372,521.4	-	8,118.1	187,055.8	1,372,521.4	(422,965.0)	949,556.4	181,099.3	0.19	7,077,409.9
2047	-	-	1,399,971.9	-	7,793.4	178,744.0	1,399,971.9	(431,575.3)	968,396.5	174,435.6	0.18	7,251,845.5
2048	-	-	1,427,971.3	-	7,481.6	170,764.7	1,427,971.3	(440,351.8)	987,619.5	168,018.7	0.17	7,419,864.3
2049	-	-	1,456,530.7	-	7,182.4	163,104.5	1,456,530.7	(449,298.0)	1,007,232.7	161,839.3	0.16	7,581,703.6
2050	-	-	1,485,661.4	-	6,895.1	155,750.8	1,485,661.4	(458,417.6)	1,027,243.8	155,888.4	0.15	7,737,592.0
2051	-	-	1,515,374.6	-	6,619.3	148,691.2	1,515,374.6	(467,714.1)	1,047,660.4	150,157.4	0.14	7,887,749.4
2052	-	-	1,545,682.1	-	6,354.5	141,914.0	1,545,682.1	(477,191.6)	1,068,490.5	144,638.2	0.14	8,032,387.6
2053	-	-	1,576,595.7	-	6,100.3	135,407.8	1,576,595.7	(486,853.6)	1,089,742.1	139,322.8	0.13	8,171,710.4
2054	-	-	1,608,127.6	-	5,856.3	129,161.9	1,608,127.6	(496,704.1)	1,111,423.5	134,203.6	0.12	8,305,914.0
2055	-	-	1,640,290.2	-	5,622.0	123,165.9	1,640,290.2	(506,747.1)	1,133,543.1	129,273.2	0.11	8,435,187.2
2056	-	-	1,673,096.0	-	5,397.2	117,409.7	1,673,096.0	(516,986.6)	1,156,109.3	124,524.7	0.11	8,559,711.9
2057	-	-	1,706,557.9	-	5,181.3	111,883.7	1,706,557.9	(527,426.8)	1,179,131.1	119,951.3	0.10	8,679,663.2
Total	**-**	**-**	**44,690,936.1**	**(627,832.6)**	**499,160.0**		**44,063,103.5**	**(13,699,450.6)**	**30,363,652.9**	**8,679,663.2**		


COMPARATIVE CUMULATIVE REVENUE REQUIREMENT
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Penstock Refurbishment vs Replacement Energy Costs
Test 2
Test 3
Test 4
Year

CI Number: 47655

Title: HYD Paradise Controls Upgrades

Start Date: 2016/07
In-Service Date: 2019/09
Final Cost Date: 2020/03
Function: Hydro
Forecast Amount: $639,991

DESCRIPTION:

This project will provide new instrumentation installations, Programmable Logic Controller (PLC) replacements, and Distributed Control System (DCS) installation at the Paradise Generation Station. Paradise River System is a hydro system consisting of one generating station with a single unit. The design and installation of a modern control system will follow standards developed at the Nictaux and Wreck Cove hydro facilities.

This will result in an improved communication system for dam and environmental monitoring as well as generator condition monitoring and control. This project is in line with NS Power's strategy for risk based investment, consistent with the CEJC asset management ranking methodology, and informs our asset management condition assessments for Paradise hydro assets.

The PLC is a digital computer used for automation of electromechanical processes, such as switches, motor start/stop control, or light fixtures. The components to be replaced as part of this project include the main microprocessors, input/output modules, communication backplanes and programing software.

Summary of Related CIs +/- 2 years:
No other projects in 2016, 2017, 2018, 2019 or 2020

JUSTIFICATION:

Justification Criteria: Hydro

Why do this project?

Automating this plant will allow for central control of the unit and advanced data acquisition to monitor unit health. With a modern control system, unit operation and efficiency can be closely monitored and problems more effectively diagnosed.

Why do this project now?

NS Power is completing control upgrades at remote hydro facilities to gain the benefit of more centralized control. This will allow a more planned approach to operation and maintenance, as well as provide central control of unit dispatch and water control.

Generation from NS Power's legacy hydro facilities qualify under the provisions of the Nova Scotia Renewable Electricity Regulations. Generation from hydro facilities is an important part of NS Power's compliance plan to generate 40 percent of electricity from renewable energy sources in 2020.

Why do this project this way?

The new equipment will communicate with the existing Input/Output (I/O) subsystems and upgrade the capacity of the control system so as not to be limited in the number of sensors and points of control. This will allow NS Power to retain the I/O modules and chassis where warranted, or to migrate, dependent on the evaluation inherent in the review process, and avoid having to rewire and re-commission field systems involving many cables. In addition, the new PLC line retains much of the same programming format as the older system. Standardization will allow technicians to troubleshoot problems and/or modify logic on multiple systems, reducing training and start-up costs.

NS Power is completing this project in alignment with its Asset Management Office guidelines and the standards developed during the Nictaux (CI 45115) and Wreck Cove (CI 44978) Control Upgrade projects. Completing the project in this manner will allow process and equipment consistency across automation sites, as well as allow for sharing of resources and creation of a repository of spare parts. This project facilitates increased data acquisition that will support data-driven decision making on maintenance and capital investments.

CI Number : 47655-H758 - HYD - Paradise Controls Upgrade **Project Number** 47655-H758

Parent CI Number : -

Asset Location : 1358 - 1358 Paradise, 4 Mwh; 1950 on Nictaux River System **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	2200 - HGP - Elec Contr.Equip.	624,375
Retirements	2200 - HGP - Elec Contr.Equip.	15,615
	Total Cost:	639,991
	Original Cost:	462,607

Capital Project Detailed Estimate

Location: Hydro
FP# / P#: 47655
Title: HYD Paradise Controls Upgrade
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Hydro River Staff - Construction	day	65	$ 365	$ 23,611		
Engineering Staff	day	44	$ 405	$ 17,833		
Hydro River Staff - Removal	day	10	$ 365	$ 3,648		
			Sub-Total	$ 45,092		
Term Labour						
Hydro River Staff - Construction	day	45	$ 365	$ 16,446		
Hydro River Staff - Removal	day	20	$ 365	$ 7,296		
			Sub-Total	$ 23,741		
Travel Expenses						
Site Visits	Lot	1	4822	$ 4,822		
			Sub-Total	$ 4,822		
Materials						
Plant Control and Protection System	Lot	1	$ 80,000	$ 80,000		44978 WRC Controls Upgrade, 49039 Lequille Controls Upgrade
Wireless Radio Communication Network	Lot	1	$ 15,000	$ 15,000		
PLC Base Radio End point control	Lot	1	$ 15,000	$ 15,000		
Digital Governor Upgrade	Lot	1	$ 75,000	$ 75,000		
Misc Materials	Lot	1	$ 15,000	$ 15,000		
			Sub-Total	$ 200,000		
Contracts						
Misc Contracts	Lot	1	$ 15,000	$ 15,000		
			Sub-Total	$ 15,000		
Consulting						
Control System Design	Lot	1	$ 150,620	$ 150,620		44978 WRC Controls Upgrade, 49039 Lequille Controls Upgrade
Plant Control and Protection System	Lot	1	$ 10,000	$ 10,000		
Wireless Radio Communication Network	Lot	1	$ 10,000	$ 10,000		
PLC Base Radio End point control	Lot	1	$ 15,000	$ 15,000		
Commissioning Services	Lot	1	$ 30,000	$ 30,000		
Digital Governor Upgrade	Lot	1	$ 25,000	$ 25,000		
			Sub-Total	$ 240,620		
Meals						
Site Visits	Lot	1	$ 2,250	$ 2,250		
			Sub-Total	$ 2,250		
Other Goods & Services						
Contingency	%	10%	$ 531,525	$ 53,153		
			Sub-Total	$ 53,153		
Interest Capitalized						
AFUDC				$ 24,408		
			Sub-Total	$ 24,408		
Administrative Overhead						
Labour AO				$ 29,448		
Contract AO				$ 1,457		
			Sub-Total	$ 30,905		
			Sub-Total (no AO, AFUDC)	$ 584,678		
			TOTAL (AO, AFUDC included)	$ 639,991		
Original Cost				$462,607		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 49944

Title: HYD - Dickie Brook Penstock Refurbishment

Start Date:	2018/01
In-Service Date:	2018/09
Final Cost Date:	2019/03
Function:	Hydro
Forecast Amount:	$478,820

DESCRIPTION:

This project includes the replacement of approximately 60 penstock pedestal liners as well as spot coating sections of the penstock on the Dickie Brook Hydro system.

Dickie Brook is a two unit hydro plant located in Guysborough County. It has two 1.5 MW units that produce 8.4 GWh annually and contributes to renewable electricity generation requirements.

Summary of Related CIs +/- 2 years
2019 CI 47660 HYD Dickie Brook Controls Upgrade $TBD

JUSTIFICATION:

Justification Criteria: Hydro, Wind & Biomass Energy

Why do this project?

The Dickie Brook steel section of penstock was installed in 1989. Recent inspections have indicated that the penstock's protective coating is deteriorating near the pedestals, as has the liner material between the pedestals and the penstock. If left unaddressed, corrosion of the penstock will occur, leading to more extensive repairs or replacement being required. By refurbishing the coating and liner, further deterioration can be avoided for a more cost effective solution.

Why do this project now?

A 2016 penstock inspection identified (Attachment 1) areas of significant coating failure. It also indicated that the liners between the pedestals and penstock have deteriorated. The pedestal liners provide a slip surface for the penstock. Without these liners the pipe is subject to substantial friction between the steel pipe and the concrete pedestals as the penstock expands and contracts. To prevent further deterioration the project needs to be completed in 2018.

Why do this project this way?

The most economic method to address this deficiency is to replace the pedestal liners with a long lasting material and to recoat areas that have experienced deterioration. NS Power explored other options, including replacing the pipe, however replacing the pipe is a more expensive option and not considered necessary at this time.

CI Number : 49944 - HYD - Dickie Brook Penstock Refurbishment **Project Number** 49944

Parent CI Number : -

Asset Location : 1353 - 1353 Dickie Brook Common Property **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account		Forecast Amount
Additions	2700 - HGP - Waterways		447,004
Retirements	2700 - HGP - Waterways		31,817
		Total Cost:	478,820
		Original Cost:	392,304

Capital Project Detailed Estimate

Location: Hydro
CI# / FP#: 49944
Title: HYD Dickie Brook Penstock Refurbishment
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Hydro River Staff - Construction	day	62	365	$ 22,617		
Engineering Staff	day	46	405	$ 18,482		
			Sub-Total	$ 41,099		
Travel Expense						
Site Visits	Lot	1	$ 1,300	$ 1,300		
			Sub-Total	$ 1,300		
Materials						
Penstock Liners	Lot	1	$ 90,000	$ 90,000		44887 Sissiboo Pipeline
Misc Materials	Lot	1	$ 15,000	$ 15,000		
			Sub-Total	$ 105,000		
Contracts						
Penstock Liner Installation	Lot	1	$ 150,000	$ 150,000		44887 Sissiboo Pipeline
Penstock Coating Refurbishment	Lot	1	$ 75,000	$ 75,000		
			Sub-Total	$ 225,000		
Consulting						
Project Support Staff	Lot	1	$ 15,000	$ 15,000		
Coatings Inspection	Lot	1	$ 6,000	$ 6,000		
			Sub-Total	$ 21,000		
Meals						
Site Visits	Lot	1	$ 650	$ 650		
			Sub-Total	$ 650		
Other Goods & Services						
Contingency	%	10%	$ 394,049	$ 39,405		
			Sub-Total	$ 39,405		
Interest Capitalized						
AFUDC				$ 5,968		
				$ -		
			Sub-Total	$ 5,968		
Administrative Overhead						
Labour AO				$ 17,545		
Contracts AO				$ 21,854		
			Sub-Total	$ 39,399		
			Sub-Total (no AO, AFUDC)	$ 433,454		
			TOTAL (AO, AFUDC included)	$ 478,820		
Original Cost				$ 392,304		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

HYD Dickie Brook Penstock Refurbishment
Summary of Alternatives

Division :	Power Production	**Date :**	**17-Nov-17**
Department :		**CI Number:**	
		Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank (based on PV of RR)	IRR	Disc Pay
A	Penstock Refurbishment vs Replacement Energy Costs	5.88%	-6,609,928	5,713,209	1	34.97%	4.8 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

Recommendation :

It is recommended to complete the penstock refurbishment

Notes/Comments :

Penstock Refurbishment vs Replacement Energy Costs

The capital pays for the replacement of approximately 60 penstock pedestal liners. The assumptions in the avoided expense calculator assume a forced outage due to penstock breach of 3 months. The probabilty of failure is considered high due to the number of possible failure locations. Once probabilty reaches 100% the number of failures in a year increase to an estimate of 5/year. A leak in the penstock would cause a forced outage for both units in the Dickie Brook Plant.

Test 2

Test 3

Test 4

HYD Dickie Brook Penstock Refurbishment
Summary of Sensitivities

Nova Scotia POWER An Emera Company

Division :	Power Production	**Date :**	**13-Nov-17**
Department :		**CI Number:**	
		Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Penstock Refurbishment vs Replacement Energy	5.88%	-6,609,928	5,713,209	1	34.97%	4.8 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

	Alternative Variance on Capital Spend	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Penstock Refurbishment vs Replacement Energy	10%	-6,562,660	5,676,851	1	32.68%	5.3 years
B	Test 2	10%	0	0	2	#NUM!	0.0 years
C	Test 3	10%	0	0	2	#NUM!	0.0 years
D	Test 4	10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		47,269	-36,358	0	-2.30%	0.4 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

	Alternative Variance on Avoided Expenses	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Penstock Refurbishment vs Replacement Energy	-10%	-5,901,667	5,105,530	1	32.45%	5.3 years
B	Test 2	-10%	0	0	2	#NUM!	0.0 years
C	Test 3	-10%	0	0	2	#NUM!	0.0 years
D	Test 4	-10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		708,261	-607,679	0	-2.53%	0.5 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

Alternative Variance on Avoided Expenses - Change in Revenue Requirement		PV of Revenue Requirement	PV of Revenue Requirement	PV of Revenue Requirement	Delay?
	Yrs Delay:	1	2	3	
	A	59,745	126,239	214,972	No
	B	0	0	0	No
	C	0	0	0	No
	D	0	0	0	No

HYD Dickie Brook Penstock Refurbishment
Avoided Cost Calculations

Division :	Power Production	**Date :**	13-Nov-17
Department :		**CI Number:**	
		Project No. :	

Penstock Refurbishment vs Replacement Energy Costs

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	1	1	1	1		
Probability of Occurance (%)	50%	60%	50%	60%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	697.0	697.0				
Duration (Hours or Years)	3	3				
Totals	$87,349	$104,478	$0	$0	$87,349	$104,478
Total Capital Cost of Alternative						$479,190

Test 2

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

Test 3

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

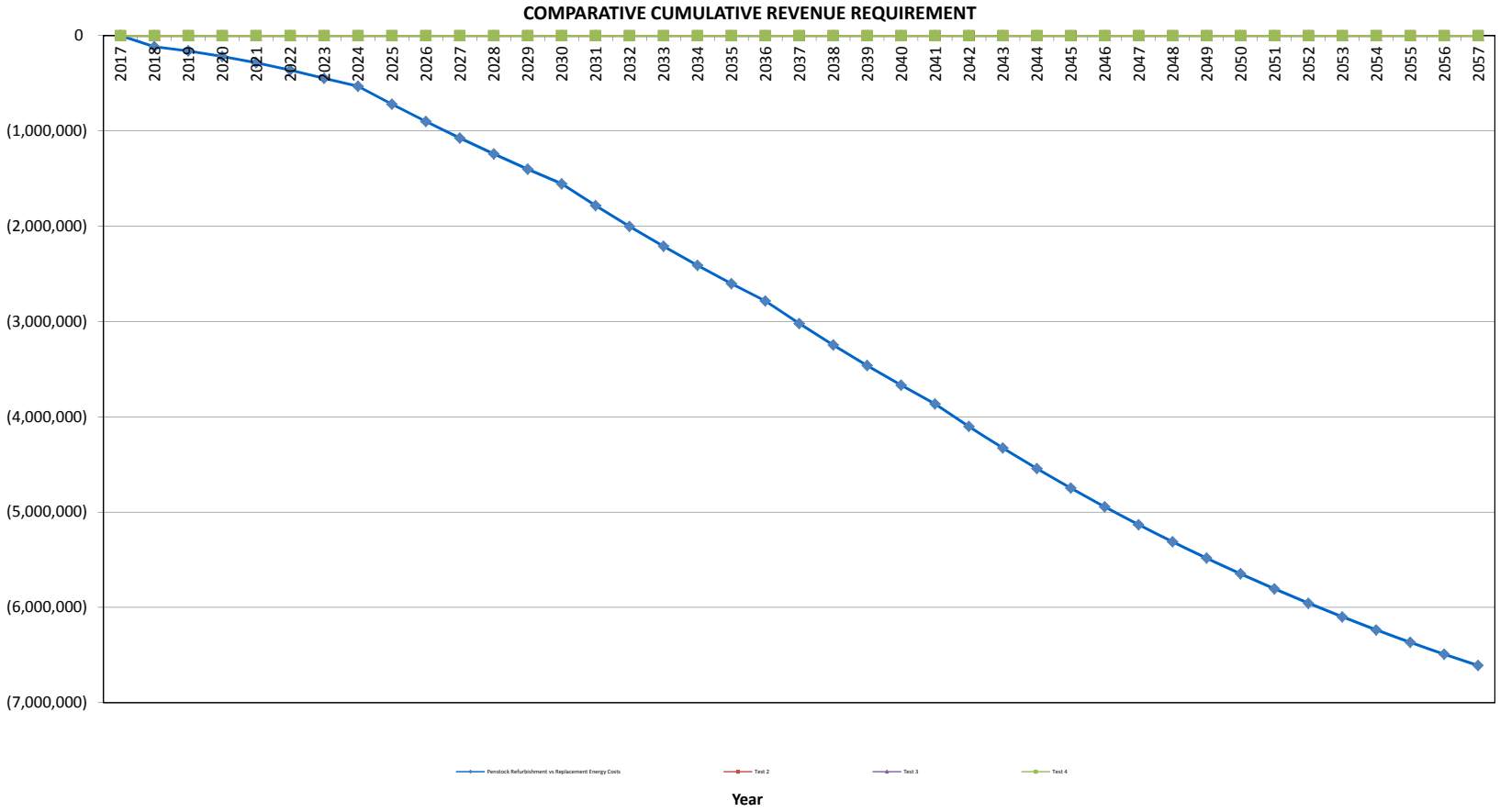
Test 4

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

HYD Dickie Brook Penstock Refurbishment

Penstock Refurbishment vs Replacement Energy Costs

Year	Total Revenue	Operating Costs	Avoided Expenses	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	PV of CF	Discount Factor	CNPV
2017	-	-	-	-	-	-	-	-	-	-	1.00	-
2018	-	-	87,348.6	(439,790.8)	8,669.1	436,131.4	(352,442.3)	(24,390.6)	(376,832.9)	(355,905.7)	0.94	(355,905.7)
2019	-	-	104,477.7	-	16,991.4	418,213.4	104,477.7	(27,120.8)	77,356.9	69,003.5	0.89	(286,902.1)
2020	-	-	123,028.2	-	16,311.7	401,012.1	123,028.2	(33,082.1)	89,946.1	75,777.6	0.84	(211,124.6)
2021	-	-	139,450.8	-	15,659.3	384,498.8	139,450.8	(38,375.4)	101,075.4	80,424.8	0.80	(130,699.8)
2022	-	-	157,438.7	-	15,032.9	368,646.1	157,438.7	(44,145.8)	113,292.9	85,139.9	0.75	(45,559.9)
2023	-	-	178,430.5	-	14,431.6	353,427.4	178,430.5	(50,839.7)	127,590.8	90,559.9	0.71	45,000.0
2024	-	-	181,999.1	-	13,854.3	338,817.6	181,999.1	(52,124.9)	129,874.2	87,061.3	0.67	132,061.3
2025	-	-	371,278.1	-	13,300.1	324,792.1	371,278.1	(110,973.2)	260,305.0	164,805.2	0.63	296,866.6
2026	-	-	378,703.7	-	12,768.1	311,327.6	378,703.7	(113,440.0)	265,263.7	158,618.0	0.60	455,484.5
2027	-	-	386,277.8	-	12,257.4	298,401.7	386,277.8	(115,946.3)	270,331.5	152,671.3	0.56	608,155.8
2028	-	-	394,003.3	-	11,767.1	285,992.9	394,003.3	(118,493.2)	275,510.1	146,955.0	0.53	755,110.8
2029	-	-	401,883.4	-	11,296.4	274,080.3	401,883.4	(121,082.0)	280,801.4	141,459.5	0.50	896,570.3
2030	-	-	409,921.1	-	10,844.6	262,644.3	409,921.1	(123,713.7)	286,207.4	136,175.7	0.48	1,032,746.0
2031	-	-	627,179.2	-	10,410.8	251,665.8	627,179.2	(191,198.2)	435,981.0	195,917.2	0.45	1,228,663.2
2032	-	-	639,722.8	-	9,994.4	241,126.4	639,722.8	(195,215.8)	444,507.0	188,655.6	0.42	1,417,318.7
2033	-	-	652,517.3	-	9,594.6	231,008.5	652,517.3	(199,306.0)	453,211.2	181,667.7	0.40	1,598,986.4
2034	-	-	665,567.6	-	9,210.8	221,295.4	665,567.6	(203,470.6)	462,097.0	174,942.9	0.38	1,773,929.3
2035	-	-	678,879.0	-	8,842.4	211,970.8	678,879.0	(207,711.4)	471,167.6	168,470.8	0.36	1,942,400.2
2036	-	-	692,456.6	-	8,488.7	203,019.2	692,456.6	(212,030.0)	480,426.5	162,241.6	0.34	2,104,641.8
2037	-	-	941,740.9	-	8,149.1	194,425.6	941,740.9	(289,413.5)	652,327.5	208,059.2	0.32	2,312,701.0
2038	-	-	960,575.7	-	7,823.2	186,175.8	960,575.7	(295,353.3)	665,222.4	200,389.2	0.30	2,513,090.2
2039	-	-	979,787.3	-	7,510.2	178,256.0	979,787.3	(301,405.9)	678,381.4	193,004.5	0.28	2,706,094.7
2040	-	-	999,383.0	-	7,209.8	170,653.0	999,383.0	(307,573.7)	691,809.3	185,894.3	0.27	2,891,988.9
2041	-	-	1,019,370.7	-	6,921.4	163,354.1	1,019,370.7	(313,859.3)	705,511.4	179,048.1	0.25	3,071,037.0
2042	-	-	1,299,697.6	-	6,644.6	156,347.1	1,299,697.6	(400,846.4)	898,851.2	215,446.5	0.24	3,286,483.5
2043	-	-	1,325,691.6	-	6,378.8	149,620.4	1,325,691.6	(408,987.0)	916,704.6	207,523.4	0.23	3,494,007.0
2044	-	-	1,352,205.4	-	6,123.6	143,162.8	1,352,205.4	(417,285.3)	934,920.0	199,893.3	0.21	3,693,900.3
2045	-	-	1,379,249.5	-	5,878.7	136,963.5	1,379,249.5	(425,744.9)	953,504.5	192,545.2	0.20	3,886,445.5
2046	-	-	1,406,834.5	-	5,643.5	131,012.2	1,406,834.5	(434,369.2)	972,465.3	185,468.5	0.19	4,071,913.9
2047	-	-	1,434,971.2	-	5,417.8	125,298.9	1,434,971.2	(443,161.5)	991,809.6	178,653.0	0.18	4,250,566.9
2048	-	-	1,463,670.6	-	5,201.1	119,814.2	1,463,670.6	(452,125.5)	1,011,545.0	172,089.1	0.17	4,422,656.0
2049	-	-	1,492,944.0	-	4,993.0	114,548.8	1,492,944.0	(461,264.8)	1,031,679.2	165,767.3	0.16	4,588,423.3
2050	-	-	1,522,802.9	-	4,793.3	109,494.1	1,522,802.9	(470,583.0)	1,052,219.9	159,678.6	0.15	4,748,101.9
2051	-	-	1,553,258.9	-	4,601.6	104,641.5	1,553,258.9	(480,083.8)	1,073,175.2	153,814.4	0.14	4,901,916.3
2052	-	-	1,584,324.1	-	4,417.5	99,983.1	1,584,324.1	(489,771.0)	1,094,553.1	148,166.2	0.14	5,050,082.5
2053	-	-	1,616,010.6	-	4,240.8	95,511.0	1,616,010.6	(499,648.6)	1,116,362.0	142,726.1	0.13	5,192,808.6
2054	-	-	1,648,330.8	-	4,071.2	91,217.8	1,648,330.8	(509,720.5)	1,138,610.3	137,486.4	0.12	5,330,295.0
2055	-	-	1,681,297.4	-	3,908.3	87,096.3	1,681,297.4	(519,990.6)	1,161,306.8	132,439.5	0.11	5,462,734.5
2056	-	-	1,714,923.4	-	3,752.0	83,139.6	1,714,923.4	(530,463.1)	1,184,460.3	127,578.4	0.11	5,590,312.9
2057	-	-	1,749,221.9	-	3,601.9	79,341.3	1,749,221.9	(541,142.2)	1,208,079.7	122,896.1	0.10	5,713,209.0
Total	**-**	**-**	**36,396,855.5**	**(439,790.8)**	**347,007.3**		**35,957,064.7**	**(11,175,453.0)**	**24,781,611.7**	**5,713,209.0**		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Penstock Refurbishment vs Replacement Energy Costs
Test 2
Test 3
Test 4
Year

Nova Scotia Power Inc.

Assessment Summary

For

Dickie Brook Existing Steel Penstock Assessment

H340552-0000-50-124-0001
Rev. 2
January 25, 2013

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Nova Scotia Power Inc.

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Nova Scotia Power Inc.
Dickie Brook Existing Steel Penstock Assessment

Assessment Summary

2013-01-25	2	Re-issued for information	K. Savoury	R. Hibbs	G. Saunders	
2012-12-20	1	Re-issued for information	K. Savoury	R. Hibbs	G. Saunders	
2012-11-01	0	Issued for Information	K. Savoury	R. Hibbs	G. Saunders	
Date	**Rev.**	**Status**	**Prepared By**	**Checked By**	**Approved By**	**Approved By**
			HATCH			**Client**

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Appendices

Appendix A Calculations
Appendix B Reference Drawings

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1. Introduction

In July 2012, Hatch was engaged by Nova Scotia Power Inc. (NSPI) to perform a design assessment of existing steel penstock at Dickie Brook Generating Station.

This report summarizes the results of the assessment. Calculations are presented in Appendix A.

2. Brief History

The Dickie Brook Generating Station was built in the 1940's and consists of two horizontal Francis turbines rated at 1450 hp each. The powerhouse is located at the end of a 3700 ft long pipeline and penstock which is equipped with a 73 ft high simple surge tank. The upstream section is approximately 2900 ft of HDPE pipeline and the remaining downstream section is steel penstock. The HDPE pipeline was installed in 2008, replacing old woodstave penstock; the steel penstock was installed in the late 1980's.

In December 2011, NSPI experienced a failure at the transition from steel to HDPE. In reaction to this failure, NSPI decided that a design assessment of the existing steel penstock was required to determine if it could have contributed to the failure in any way and to determine if there were other concerns with the steel portion of the penstock.

3. Basis of Assessment

This assessment is a desktop exercise based on the reference drawings in Appendix B.

This assessment did not include any seismic, snow, wind or ice loads.

This assessment was completed per the guidelines of the American Society of Civil Engineers ASCE Manuals and Reports on Engineering Practice No. 79 Steel Penstocks.

The following components were excluded from this assessment:

- Concrete foundations
- HDPE pipeline to steel penstock transition joint
- Penstock bifurcation
- Thrust block at the penstock bifurcation

4. Original Design Parameters

The original design parameters as presented on the reference drawings are:

- Internal Static Design Pressure: 126 psig
- Internal Water Hammer Design Pressure: 158 psig

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- Internal Exceptional Water Hammer Design Pressure: 252 psig
- Installation Temperature: 73 ºF (23 ºC)
- Operating Temperature: 32 to 73 ºF (0 to 23 ºC)
- Design Temperature: 32 to 111 ºF (0 to 44 ºC)
- Service: Water
- Radiography: Full
- Corrosion Allowance: None

5. Existing Steel Penstock

The existing steel penstock is constructed from CSA G40.21 260W carbon steel. It has an outside Diameter (OD) of 60 inches and a total length of 796 ft. It is constructed of 12 assembled sections. Each assembled section is constructed from six 11 ft long courses. Some courses are mitred to create the penstock profile. There is a strap anchor 2 ft from the downstream end of each assembly (every 6 courses). Each assembly has two intermediate saddle supports with a maximum unsupported length of 19 ft.

6. Findings

6.1 Original Design Parameters Assessment

Compared to the transient analysis completed by Hatch in 2008, the static design pressure and water hammer design pressure as presented above are adequate. The static design pressure is calculated based on the change in elevation from maximum head pond elevation to the turbine centerline elevation. The water hammer design pressure is calculated based on the change in elevation from the top of the surge tank to the turbine centerline elevation. The exceptional water hammer design pressure is presumed to be the resultant transient pressure if the surge tank failed to operate properly.

The design and operating temperature lower limit of 32 ºF is valid as long as the penstock is watered up and operational. When the penstock is dewatered, the penstock temperature can drop to the outside temperature. Even with the penstock watered up and the outside temperature less than 32º F, there will be a temperature gradient across the penstock shell. This lower temperature will have very little effect on the system since the expansion joints between each anchor will accommodate the additional thermal contraction. The transition from steel to woodstave during the original construction was an overlapped joint that acted as an expansion joint.

6.2 Allowable Stress

The yield stress for 260 W is 36,000 psi and the tensile stress is 58,000 psi.

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The allowable stress for the normal operating condition is 19,330 psi; calculated as the lesser of 2/3 yield stress (24,000 psi) or 1/3 tensile stress (19,330 psi).

The allowable stress for the emergency condition is 29,000psi; calculated as the allowable stress under the normal operating condition multiplied by the corresponding K factor (1.5) from Table 3-4, ASCE Practice No. 79.

The allowable stress for the exceptional condition is 48,330psi; calculated as the allowable stress under the normal operating condition multiplied by the corresponding K factor (2.5) from Table 3-4, ASCE Practice No. 79.

6.3 Minimum Shell Thickness for Shipping and Handling

The minimum shell thickness that was required for shipping and handling is 0.207". The actual penstock thickness is 0.313".

The maximum stress that would have been in the shell if it was empty resting on a flat surface and supporting itself is calculated to be 7,288 psi.

6.4 Hoop Stress Due to Internal Pressure

The minimum shell thickness required for hoop stress due to internal pressure is 0.193". The actual penstock thickness is 0.313".

The hoop stress due to internal pressure is equal to:

- 11,970 psi from internal static design pressure (normal operating condition)
- 15,010 psi from water hammer design pressure (emergency condition)
- 23,940 psi from exceptional water hammer design pressure (exceptional condition)

6.5 Internal Vacuum

To avoid buckling due to full internal vacuum, the D/t ratio should be less than 158. In this case, the D/t ratio is equal to 192 and thus the penstock cannot withstand full internal vacuum. However, the shell thickness and diameter can withstand vacuum up to -9.3 psig. 2

6.6 Longitudinal Stress

6.6.1 Beam Action

With a maximum unsupported length of 19 ft, the maximum longitudinal stress due to beam action caused by the self weight of the penstock, weight of the water, pressure thrust forces during the exceptional condition and expansion joint frictional forces is 1,922 psi.

The pressure thrust force is a result of the mitres in the penstock. The maximum mitre width on each penstock section in the downward direction across any span is 5/8" (1" in upward direction). The maximum moment occurs when this mitre is located at the mid-span of the supports. With an exceptional water hammer design pressure of 252 psi, this mitre causes a pressure thrust force of 14,918 lbs downwards. 2

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The mitres also create thrust forces as a result the expansion joint frictional forces. The frictional force at the expansion joint is based on ASCE Manuals and Reports on Engineering Practice No. 79 – Steel Penstocks which assumes the frictional force at the expansion joint to be equal to 500 lbs per inch of diameter. For a 60 inch expansion joint, the frictional force equals 30,000 lbs. The resultant lateral force at the mitre, due to the expansion joint frictional force is 628 lbs downwards.

Any mitres in the upward direction would simply counteract the weight of the water and penstock.

6.6.2 Penstock Buckling Due to Axial Compression

The maximum axial compressive stress due to the weight of the penstock, the frictional force at the expansion joint and the frictional force at the intermediate supports, with downstream anchorage, is 664 psi. △2

The allowable compressive stress is 12,000 psi.

6.6.3 Longitudinal Strain/Stress Due to Poisson's Effect

Radial expansion due to internal pressure will cause longitudinal contraction, which is known as Poisson's effect. Since this penstock is fixed at one end and free to slide on the other, the longitudinal strain/stress due to Poisson's effect results from the force required to overcome friction in the expansion joint, 561 psi. △2

6.6.4 Temperature Stresses

Circumferential thermal stresses develop as a result of a temperature gradient across the shell thickness. The maximum circumferential thermal stress is calculated to be 5,544psi. △2

The maximum longitudinal thermal stress results from the force required to overcome friction in the expansion joint and at the intermediate supports, 561psi.

6.7 Combined Stresses

The principle stresses that result from the above combined stresses conditions is as followed:

- 18,900 psi for the normal operating condition (19,330 psi allowable) △2
- 21,930 psi for the emergency condition (29,000 psi allowable) △2
- 30,860 psi for the exceptional condition (48,330 psi allowable) △2

6.8 Penstock Anchors

The construction of this penstock is similar to Figure 8-3 Arrangement (B) in ASCE Manuals and Reports on Engineering Practice No. 79 – Steel Penstocks. It is made up of 66 ft long sections with an anchor on the downstream end and an expansion joint on the upstream end of each section, i.e., fixed on one end and free to slide on the other end once overcoming the expansion joint frictional force. The maximum axial load on any anchor due to the weight of the penstock plus the frictional force in the intermediate supports and expansion joint is equal to 38,920 lbs, occurring at the maximum incline of the penstock. The anchor is constructed from a strap that is tightened down with four 1 ¼" diameter anchor bolts wet torque to △2

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150 ft-lbs each. Approximating the clamping force from one anchor bolt to be 55,000 lbs and assuming a coefficient of friction of 0.8 between the strap and penstock, the axial load required to overcome friction at each anchor is 176,000 lbs. The penstock is adequately anchored with each anchor having a maximum utilization of 22 percent.

6.9 Penstock Profile

△2

An analysis was performed to determine the effects of thermal contraction/expansion on the penstock due to its mitred profile. The analysis was performed on the penstock assembly with the largest mitres (1"). The effects of thermal contraction/ expansion on all penstock assemblies with smaller mitres will be less.

The analysis revealed that, due to axial contraction/expansion, the penstock will want to displace vertically 0.001" to 0. 018" at the support locations. These vertical displacements are well within construction tolerances so it was concluded that thermal contraction/ expansion has no adverse effects on the penstock due to its profile.

7. Conclusions

Hatch conducted an assessment of the steel penstock at the NSPI Dickie Brook Generating Station. The assessment has found that the governing case for design is normal static head and portions of the penstock are near the limit of capacity, but otherwise the existing steel penstock was adequately designed.

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Appendix A

Calculations

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CLIENT NAME: **Nova Scotia Power Inc.**

PROJECT AND SITE: **Dickie Brook GS**

PROJECT NUMBER: **H340552**
DISCIPLINE: **60 Piping**
CALCULATION NO: **H340552-0000-60-125-0001**
CALCULATION TITLE: **Design Assessment of Existing Steel Penstock**

24/Jan/13	1	Reissued for Information	K. Savoury	G. Saunders	R. Hibbs	
03/Dec/12	0	Issued for Information	K. Savoury	G. Saunders	R. Hibbs	
04/Oct/12	A	Issued For Review	K. Savoury	R. Hibbs	R. Hibbs	
DATE	**REV**	**STATUS**	**AUTHOR**	**CHECKED**	**APPROVED**	**APPROVED**
HATCH						**CLIENT**

Date Filed: November 22, 2017 Page 1519 of 2371 REDACTED

CALCULATIONS

Design Parameters (from reference drawings):

$OD := 60$ Outside diameter, in

$t_{actual} := \frac{5}{16} = 0.313$ Penstock thickness, in

$ID := OD - 2 \cdot t_{actual} = 59.375$ Inside diameter, in

$P_{normal} := 126$ Static pressure, psi

$P_{emergency} := 158$ Full surge tank, psi

$P_{exceptional} := 252$ Exceptional water hammer condition, psi

From ASCE Manuals and Reports on Engineering Practice No. 79 - Steel Penstocks

3.4.10 Basic Allowable Stress Intensity (S)

Penstock Shell Material: 260W (A36)

$S_T := 58000$ Tensile Stress

$S_Y := 36000$ Yield Stress

S is the lesser of the following:

$S := \frac{2}{3} \cdot S_Y = 2.400 \times 10^4$

$S := \frac{1}{3} \cdot S_T = 1.933 \times 10^4$

3.5.1 Weld Joint Reduction Factor (E)

All welds are fully radiographed. From Table 3-3 for 100% RT,

$E := 1.00$

3.5.2 Allowable Stress Increase Factor (K)

From Table 3-4, Allowable stress intensity K factors:

$K_{normal} := 1.0$

$K_{emergency} := 1.5$

$K_{exceptional} := 2.5$

Which gives the allowable design stress of:

$S_{normal} := S \cdot K_{normal} = 1.933 \times 10^{4}$

$S_{emergency} := S \cdot K_{emergency} = 2.900 \times 10^{4}$

$S_{exceptional} := S \cdot K_{exceptional} = 4.833 \times 10^{4}$

4.1.2.1 Minimum Shell Thickness for Shipping and Handling

$D_{nom} := 59.7$ Nominal Penstock Diameter, in

Using the Bureau of Reclamation formula:

$$t_{min} := \frac{D_{nom} + 20}{400} = 0.199$$

Using the Pacific Gas and Electric Company (PG&E) formula

$$t_{min} := \frac{D_{nom}}{288} = 0.207$$

Determine the maximum stress (S_{max}) if the shell is resting on a flat surface and supporting itself:

$$R_{nom} := \frac{D_{nom}}{2} = 29.850$$

$W := 0.284$ density of steel, lb/in^3

$t_{actual} = 0.313$

$$S_{max} := \frac{9 \cdot R_{nom}^{2} W}{t_{actual}} = 7287.851$$ Equation 4-3

4.1.2.2 Hoop Stress Due to Internal Pressure

For normal operating condition:

$P_{normal} = 126.000$

$S_{normal} = 1.933 \times 10^{4}$

$r := \frac{ID}{2} = 29.688$

$E = 1.000$

$t_{normal} := \frac{P_{normal} \cdot r}{S_{normal} \cdot E} = 0.193$

For emergency operating condition

$P_{emergency} = 158.000$

$S_{emergency} = 2.900 \times 10^{4}$

$r = 29.688$

$E = 1.000$

$t_{emergency} := \frac{P_{emergency} \cdot r}{S_{emergency} \cdot E} = 0.162$

For exceptional operating condition

$P_{exceptional} = 252.000$

$S_{exceptional} = 4.833 \times 10^{4}$

$r = 29.688$

$E = 1.000$

$$t_{exceptional} := \frac{P_{exceptional} \cdot r}{S_{exceptional} \cdot E} = 0.155$$

Therefore the normal operating condition governs for required thickness.

$t_{normal} = 0.193$

$t_{actual} = 0.313$

With the above actual thickness, the hoop stress due to internal pressure is equal to:

For normal operating condition:

$$S_{Hnormal} := \frac{P_{normal} \cdot r}{t_{actual} \cdot E} = 1.197 \times 10^4$$

For emergency operating condition:

$$S_{Hemergency} := \frac{P_{emergency} \cdot r}{t_{actual} \cdot E} = 1.501 \times 10^4$$

For exceptional operating condition:

$$S_{Hexceptional} := \frac{P_{exceptional} \cdot r}{t_{actual} \cdot E} = 2.394 \times 10^4$$

Internal vacuum Considerations

From AWWA Manual M11, Steel Pipe - A Guide for Design and Installation

For buckling failure equation (4-4) gives

$$P_c := 50200000 \cdot \left(\frac{t_{actual}}{ID} \right)^3 \cdot \frac{lb}{in^2} = 7.319 \cdot \frac{lb}{in^2}$$

Where Pc is the external gauge pressure for buckling failure.

4.1.2.3 Longitudinal Stresses

(1) Beam Action

$r = 29.688$

$S_{mod} := \pi \cdot r^2 \cdot t_{actual} \cdot in^3 = 865.261 \cdot in^3$ Section modulus of penstock

$OD = 60.000$

$ID = 59.375$

$A := \frac{\pi \cdot (OD^2 - ID^2)}{4} \cdot in^2 = 58.598 \cdot in^2$ Cross sectional area of penstock

$\rho_{water} := 64.2 \frac{lb}{ft^3}$ Density of water

$W_{water} := \frac{\pi \cdot (ID \cdot in)^2}{4} \cdot \rho_{water} = 1234.439 \cdot \frac{lb}{ft}$ Linear weight of water in the penstock

$\rho_{steel} := 490 \frac{lb}{ft^3}$ Density of steel

$W_{steel} := \rho_{steel} \pi (D_{nom} \cdot in) \cdot (t_{actual} \cdot in) = 199.438 \cdot \frac{lb}{ft}$ Linear weight of steel penstock

$W_{total} := W_{water} + W_{steel} = 1433.877 \cdot \frac{lb}{ft}$ Total linear weight

$L_{support} := 19ft$ Maximum Span between supports

The maximum moment due to the linear weight of water and steel penstock (uniformly distributed load), M_{B1}, occurs at the midspan and is equal to:

$M_{B1} := \frac{W_{total} \cdot L_{support}^2}{8} = 7.764 \times 10^5 \cdot in \cdot lb$ Maximum bending moment at supports

The maximum miter in the downward direction across any span is a 5/8" miter. The miter results in pressure thrust, T. The maximum moment due to the pressure thrust occurs when the miter is located at half the span. This resultant moment M_{B2} is equal to:

$ID = 59.375$

$A_{ID} := \frac{\pi \cdot ID^2}{4} = 2768.835$

$\varphi := 0.60deg$ Angle in penstock with 5/8" miter

$P_{normal} = 126.000$

$T_{\varphi normal} := 2P_{normal} \cdot A_{ID} \cdot \sin(\varphi) \cdot lb = 7306.651 \cdot lb$

$P_{emergency} = 158.000$

$T_{\varphi emergency} := 2P_{emergency} \cdot A_{ID} \cdot \sin(\varphi) \cdot lb = 9162.308 \cdot lb$

$P_{exceptional} = 252.000$

$T_{\varphi exceptional} := 2P_{exceptional} \cdot A_{ID} \cdot \sin(\varphi) \cdot lb = 1.461 \times 10^4 \cdot lb$

$$M_{B2} := \frac{T_{\varphi exceptional} \cdot L_{support}}{4} = 8.330 \times 10^5 \cdot in \cdot lb$$

The expansion joint frictional force, $W_{EJ,}$ also results in a moment due to the miter.

ASCE Manuals and Reports on Engineering Practice No. 79 - Steel Penstocks, Pg. 353 assumes the frictional force at the expansion joint equals 500lbs/dia. inch. Assuming the same value for this asssessement gives a total frictional force at the expansion joint equal to:

$$W_{EJ} := 500 \frac{lb}{in} \cdot 60in = 3.000 \times 10^4 \cdot lb$$

This resultant laterial force, T_{Ej}, at the miter is equal to:

$T_{EJ} := 2 \cdot W_{EJ} \cdot \sin(\varphi) = 628.307 \cdot lb$

The maximum moment due to the T_{EJ} occurs when the miter is located at half the span.

$$M_{B3} := \frac{T_{EJ} \cdot L_{support}}{4} = 3.581 \times 10^4 \cdot in \cdot lb$$

The expansion joint arrangement also results in a longitudinal force in the penstock as the pressure acts on the exposed ends of the penstock wall in the expansion joint. Similarly to pressure thrust, this longitudinal force has a resultant lateral force due to the miter. The longitudinal force, F_{long}, the resultant lateral force, $F_{lateral}$ and the moment, M_{B4} due to the resultant lateral force is equal to:

$F_{long} := \pi \cdot ID \cdot t_{actual} \cdot P_{exceptional} = 1.469 \times 10^4$

$F_{lateral} := 2 \cdot F_{long} \cdot \sin(\varphi) \cdot lb = 307.648 \cdot lb$

$$M_{B4} := \frac{F_{lateral} \cdot L_{support}}{4} = 1.754 \times 10^4 \cdot in \cdot lb$$

The Maximum longitudinal stress intensity due to beam action is equal to:

$$S_L := \frac{M_{B1} + M_{B2} + M_{B3} + M_{B4}}{S_{mod}} = 1921.677 \cdot \frac{lb}{in^2}$$

(2) Stiffener ring restraint

Not applicable. No stiffener rings on penstock.

(3) Buckling due to Axial Compression

$W_{steel} = 199.438 \cdot \frac{lb}{ft}$ Total linear weight of steel penstock

$L_{anchor} := 66ft$ Distance between anchors

$W_{penstock} := W_{steel} \cdot L_{anchor} = 1.316 \times 10^4 \cdot lb$ Total weight of penstock between anchors

$\theta := 27.3deg$ Max. incline of any penstock section

$W_{Axial} := \sin(\theta) \cdot W_{penstock} = 6037.161 \cdot lb$ Total axial self weight of penstock contributing to buckling

$W_{EJ} = 3.000 \times 10^4 \cdot lb$ Frictional force in expansion joint

$\rho_{water} = 64.200 \cdot \frac{lb}{ft^3}$ Density of water

$W_{ww} := W_{penstock} + \frac{\pi \cdot ID^2}{4} \cdot L \cdot \rho_{water} = 1.944 \times 10^4 \cdot lb$ Water filled weight of penstock assembly

Assuming one intermediate support under each penstock can section (for a total of 5 intermediate supports), and one anchor, the total load on the intermediate supports will be approximetaly 5/6 W_{ww}. The normal load from this is:

$F_N := \frac{5}{6} W_{ww} \cdot \cos(\theta) = 1.440 \times 10^4 \cdot lb$ Normal force on intermediate suppports as a result of water filled weight of penstock assembly

$\mu_{support} := 0.2$ Coefficient of friction for teflon on steel

$W_{support} := F_N \cdot \mu_{support} = 2879.181 \cdot lb$ Force to overcome friction on five intermediate supports

The total axial compression contributing to buckling is:

$W_{anchor} := W_{Axial} + W_{EJ} + W_{support} = 3.892 \times 10^4 \cdot lb$ Max. total axial load in penstock contributing to buckling

Maximum axial compressive stress due to the weight of the penstock, friction between the penstock and intermedial saddles and expansion joint forces with downstream anchorage, is equal to:

$$S_{axial} := \frac{W_{anchor}}{A} = 664.123 \cdot \frac{lb}{in^2}$$

Safe compressive stress that can be carried without buckling failure by wrinkling is given by the lesser of:

(i) for general buckling

$$S_{allow} := \min\left[1.5 \cdot \left(10^6\right) \cdot \frac{t_{actual}}{r}, \frac{1}{3} \cdot S_Y\right] = 1.200 \times 10^4$$

(ii) for local buckling

$$S_{allow} := \min\left[1.8 \cdot \left(10^6\right) \cdot \frac{t_{actual}}{r}, \frac{1}{2} \cdot S_Y\right] = 1.800 \times 10^4$$

(4) Longitudinal strain/stress

For a penstock restrained axially,

$S_H := S_{Hexceptional} = 2.394 \times 10^4$ hoop stress due to internal pressure, psi

$\mu := 0.303$ Poissons ratio 0.303 for steel

$S_{LP1} := \mu \cdot S_H = 7254$ longitudinal stress from Poisson's effect, psi

In this case, since there is an expansion joint, the longitudinal stress resulting from friction in the expansion joint and friction on the intermediate supports is

$W_{EJ} = 3.000 \times 10^4 \cdot lb$

$W_{support} = 2879.181 \cdot lb$

$$S_{EJ} := \frac{W_{EJ} + W_{support}}{A} = 561 \cdot \frac{lb}{in^2}$$

Therefore the maximum longitudinal stress from Poisson's effect is equal to $S_{EJ,}$ the stress resulting from the friction in the expansion joint and the intermediate supports.

(5) Temperature stresses

The maximum temperature gradient across the penstock shell occurs when:

$T_i := 32$ Assumed minimum inside temperature

$T_o := 73$ Maximum operating temperature as defined on drawing H-024C1-9-001-00-002.

$\Delta T := T_o - T_i = 41$ Extreme temperature range excluding boundary layers

$\alpha := 6.5 \times 10^{-6}$ Coefficient of thermal expansion

$E_Y := 29000000$ Young's modulus of steel

$\mu = 0.303$ Poisson's ration for steel

The circumferencial stress resulting from a temperature gradient across the penstock is equal to:

$$S_{CT} := \frac{\Delta T \cdot \alpha \cdot E_Y}{2 \cdot (1 - \mu)} \cdot \frac{lb}{in^2} = 5544 \cdot \frac{lb}{in^2}$$ (Equation 4-17)

The axial load imposed due to thermal expansion/contraction will be the resistance to sliding in the expansion joint and intermediate supports.

$W_{EJ} = 3.000 \times 10^4 \cdot lb$

$W_{support} = 2879.181 \cdot lb$

$S_{EJ} = 561 \cdot \frac{lb}{in^2}$

4.1.3 Loading Combinations

(1) For normal operating condition:

$S_{1normal} := S_{Hnormal} \cdot \frac{lb}{in^2} + S_{CT} = 1.751 \times 10^4 \cdot \frac{lb}{in^2}$ Circumferential membrane stress due to pressure and temperature

$S_{2normal} := -(S_L + S_{EJ}) = -2483 \cdot \frac{lb}{in^2}$ Longitudinal membrane stress (compressive)

$S_{3normal} := -\left(\frac{P_{normal}}{2}\right)\cdot\frac{lb}{in^2} = -63.000\cdot\frac{lb}{in^2}$

Compressive stress in the penstock from pressure (assumed to vary linearly from P on the inside to 0psi on the outside for an average compressive stress of P/2.

The equivalent stress is equal to (Equation 3-2):

$$S_{enormal} := \left[0.5\left[\left(S_{1normal} - S_{2normal}\right)^2 + \left(S_{2normal} - S_{3normal}\right)^2 + \left(S_{3normal} - S_{1normal}\right)^2\right]\right]^{0.5} = 1.890\times 10^4\cdot\frac{lb}{in^2}$$

The allowable under normal operating conditions is equal to:

$$S_{normal} = 1.933\times 10^4$$

(2) For emergency operating condition:

$S_{1emergency} := S_{Hemergency}\cdot\frac{lb}{in^2} + S_{CT} = 2.055\times 10^4\cdot\frac{lb}{in^2}$

Circumferential membrane stress due to pressure and temperature

$S_{2emergency} := -\left(S_L + S_{EJ}\right) = -2483\cdot\frac{lb}{in^2}$

Longitudinal membrane stress (compressive)

$S_{3emergency} := -\left(\frac{P_{emergency}}{2}\right)\cdot\frac{lb}{in^2} = -79.000\cdot\frac{lb}{in^2}$

Compressive stress in the penstock from pressure (assumed to vary linearly from P on the inside to 0psi on the soutside for an average compressive stress of P/2.

The equivalent stress is equal to:

$$S_{eemergency} := \left[0.5\left[\left(S_{1emergency} - S_{2emergency}\right)^2 + \left(S_{2emergency} - S_{3emergency}\right)^2 + \left(S_{3emergency} - S_{1emergency}\right)^2\right]\right]^{0.5}$$

$$S_{eemergency} = 2.193\times 10^4\cdot\frac{lb}{in^2}$$

The allowable under normal operating conditions is equal to:

$$S_{emergency} = 2.900\times 10^4$$

(3) For exceptional operating condition:

$S_{1excep} := S_{Hexceptional}\cdot\frac{lb}{in^2} + S_{CT} = 2.948\times 10^4\cdot\frac{lb}{in^2}$

Circumferential membrane stress due to temperature and pressure

$S_{2excep} := -\left(S_L + S_{EJ}\right) = -2483\cdot\frac{lb}{in^2}$

Longitudinal membrane stress (compressive)

$S_{3excep} := -\left(\frac{P_{exceptional}}{2}\right)\cdot\frac{lb}{in^2} = -126.000\cdot\frac{lb}{in^2}$

Compressive stress in the penstock from pressure (assumed to vary linearly from P on the inside to 0psi on the soutside for an average compressive stress of P/2.

The equivalent stress is equal to:

$$S_{eexcep} := \left[0.5\left[\left(S_{1excep} - S_{2excep}\right)^2 + \left(S_{2excep} - S_{3excep}\right)^2 + \left(S_{3excep} - S_{1excep}\right)^2\right]\right]^{0.5}$$

$$S_{eexcep} = 3.086 \times 10^4 \cdot \frac{lb}{in^2}$$

The allowable under normal operating conditions is equal to:

$$S_{exceptional} = 4.833 \times 10^4$$

8.2 Anchors for Penstocks

Reference Figrue 8-3 Penstock Loads Affecting Anchors

Arrangement (B) Penstock with Sleeve Couplings

The penstock is made up of six 11 ft long sections anchored on the downstream end with an expansion joint on the upstream end. Essensially, fixed on one end and free to slide in the expansion joint on the other once overcoming the friction force in the intermediate supports and the expansion joint. Therefore, the axial load on the anchor is equal to the weight of the penstock plus the frictional forces in the interdiate support and the expansion joint.

$W_{Axial} = 6037.161 \cdot lb$ Total axial load on anchor due to weight of penstock.

$W_{EJ} = 3.000 \times 10^4 \cdot lb$ Total load to overcome friction in expansion joint

$W_{support} = 2879.181 \cdot lb$ Total load to over friction at intemediate supports

The total axial load on the anchor is:

$$W_{anchor} = 3.892 \times 10^4 \cdot lb$$

Note: The weight of the water is carried by the downstream anchor.

Shear strength of bolts

$F_{clamping} := 55000lb$ Approx. clamping load from one 1 1/4" anchor bolt wet torqued to 150 ft-lbs wet

$N_{clamping} := 4 \cdot F_{clamping} = 2.200 \times 10^5 \cdot lb$ Normal force generated from torquing four anchor bolts

$\mu_{steel} := 0.8$ Coefficient of friction for steel on steel

$F_f := \mu_{steel} \cdot N_{clamping} = 1.760 \times 10^5 \cdot lb$ Axial frictional resistance at anchor.

In summary,

$W_{anchor} = 3.892 \times 10^{4} \cdot lb$

$F_f = 1.760 \times 10^{5} \cdot lb$

The maximum axial load on any one anchor, W_{anchor}, is less than the axial load required to overcome friction at the anchor, F_f, thus the penstock is adaquately restrained. The incline at all other penstock sections is less than θ as presented above, thus W_A at the remaining anchor locations will be less.

9.1 Mechancial Expansion Joints

$L := 792 \ in$	Distance between expansion joints, 66ft
$\alpha := 6.5 \times 10^{-6}$	Coefficient of thermal expansion
$T_{installation} := 73.4$	Installation temperature, 23 deg C, 73.4 deg F
$\Delta T_1 := 111 - 73.4 = 37.600$	ΔT for Max. design temperature, 44 deg C, 111 deg F
$\Delta_1 := L \cdot \alpha \cdot \Delta T_1 = 0.194$	Thermal expansion, in

The expansion joint gap of 1" during installation is adaquate.

Appendix B

Reference Drawings

Safety • Quality • Sustainability • Innovation

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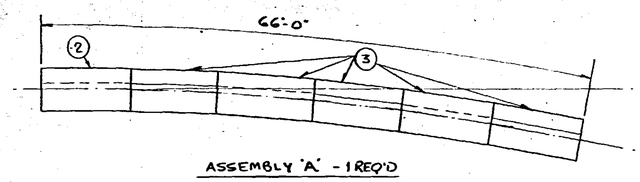

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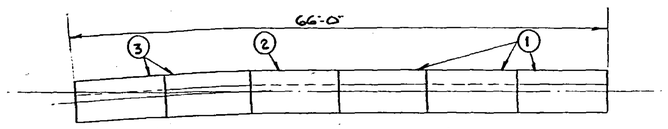

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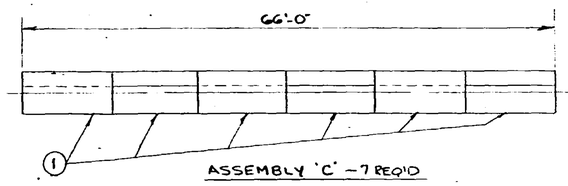

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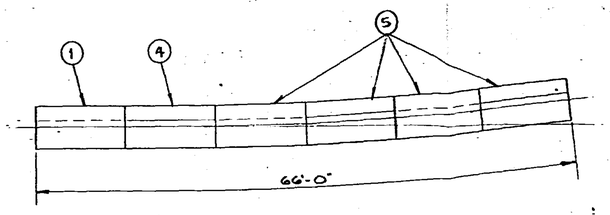

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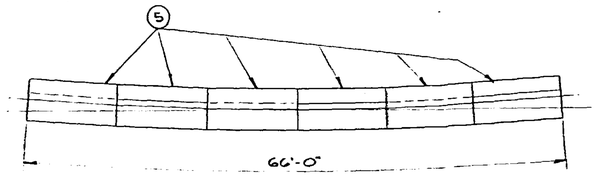

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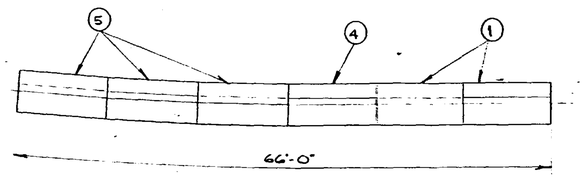

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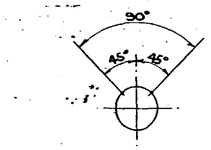
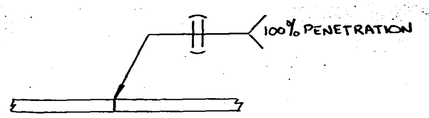


HORIZ. WELDS TO RUN 90° APART TYPICAL



TYPICAL WELD FOR BOTH CIRC. & HORIZ SEAMS

DESIGN CONDITIONS:

DESIGN AND CONSTRUCTION OF PIPING IN ACCORDANCE WITH AWWA STANDARDS C200, AND NSPC DOCUMENT 3254E SECTION 01500.

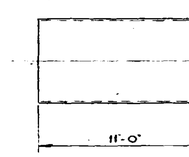
DESIGN PRESSURE: INTERNAL STATIC PRESSURE 126 PSI.
INTERNAL NORMAL WATER HAMMER 158 PSI.
INTERNAL EMERGENCY WATER HAMMER 252 PSI.

SERVICE: FRESH WATER
RADIOGRAPHY: FULL
CORROSION ALLOWANCE: NONE
INSTALLATION TEMPERATURE: 23°C (NOMINAL)
OPERATING TEMPERATURE: 0 TO 23°C
DESIGN TEMPERATURE: 0 TO 49°C

NOTES:

1. MATERIAL - CSA G40.21 260W
2. ALL WELDING TO BE IN ACCORDANCE WITH SEC. IX OF A.S.M.E. BOILER & PRESSURE VESSEL CODE.
3. ALL PIPING LONGITUDINAL AND CIRCUMFERENTIAL JOINTS TO BE FULLY RADIOGRAPHED IN ACCORDANCE WITH UW-11 OF ABOVE CODE. ACCEPTANCE CRITERIA PER UW-51.
4. TOLERANCES:
   - MISMATCH 1/32"
   - DIAMETER (AS MEASURED WITH CIRCUM. TAPE) ±1/8"
   - OUT OF ROUND ±1/2"
   - LENGTH ±1/4"
   - STRAIGHTNESS 1/8" IN 10 FEET
5. PROTECTIVE COATING FOR THE PIPE INTERIOR & EXTERIOR TO MEET THE REQUIREMENT OF AWWA C210.
   - BLAST TO BE NEAR WHITE AS PER SSPC-SP10.
   - TWO COATS BAR RUST OF TOTAL DFT OF NOT LESS THAN 185 MILS.

NOTE: BLAST AND COATING TO BE PROVIDED BY BLACK & MACDONALD.



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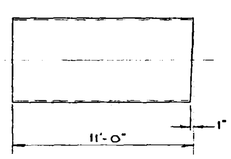

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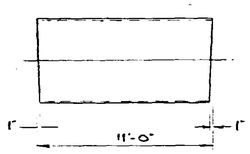

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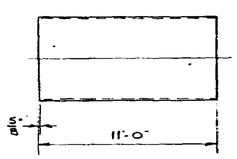

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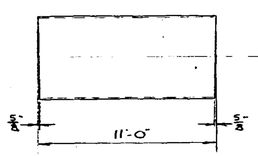

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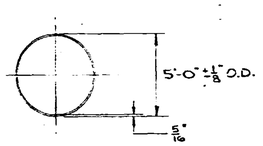
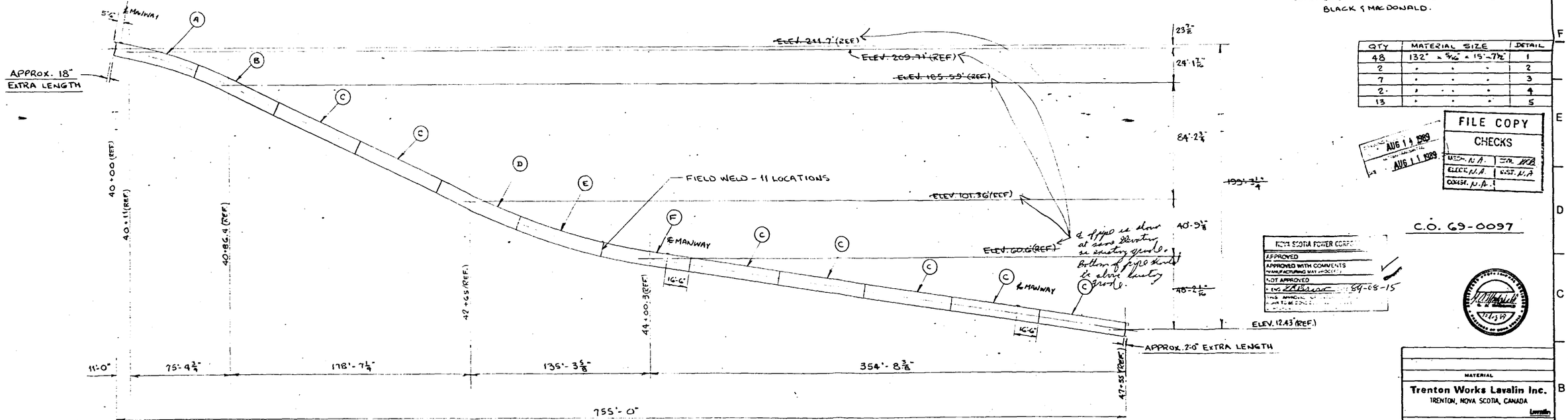


TYPICAL END VIEW



QTY	MATERIAL SIZE	DETAIL
48	132" ø x 5/16" x 15'-7 1/2"	1
2	" " "	2
7	" " "	3
2	" " "	4
13	" " "	5

FILE COPY
CHECKS
MECH. N.A. | STR. N.A.
ELECT. N.A. | INST. N.A.
CORR. N.A.
AUG 19 1989
AUG 11 1989

C.O. 69-0097

NOVA SCOTIA POWER CORP.
APPROVED
APPROVED WITH COMMENTS
MANUFACTURING MAY PROCEED
NOT APPROVED
ENG. [signature] 89-08-15

H-024C1-9-001-00-002

REV	BY	DATE	REVISION
B	[signature]	Aug. 10/89	REVISED TO AGREE WITH APPROVAL NOTES.
A	[signature]	JULY 25/89	MANWAY LOCATIONS ADDED

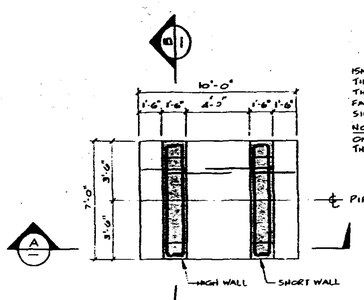
MATERIAL
Trenton Works Lavalin Inc.
TRENTON, NOVA SCOTIA, CANADA
Lavalin

DICKIE BROOK
5'-0" DIA. PIPE LINE

DRAWN BY: [signature] | TRACED BY | CHECKED BY
CORRECT | APPROVED

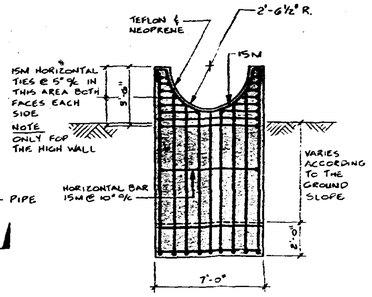
SCALE: 1" = 10'-0" = 60
DATE: JULY 25/89
DRAWING: A118 F 755

ACE 2018 C3 49944 Attachment 9 Page 26 of



PLAN

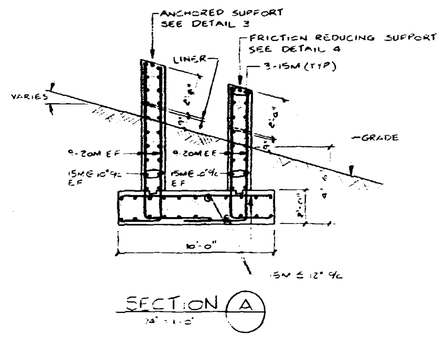
1/4" = 1'-0"



SECTION B

1/4" = 1'-0"

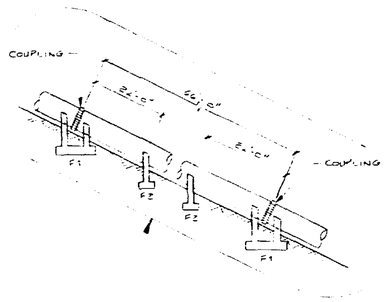
NOTE : REBAR COVER TO BE : 2" ABOVE GRADE
3" BELOW GRADE.

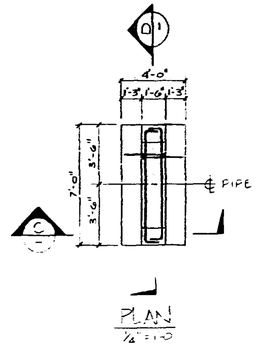


SECTION A

1/2" = 1'-0"

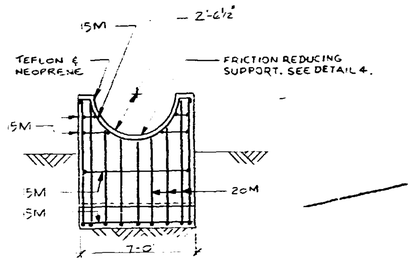
FOOTING "F1"





PLAN

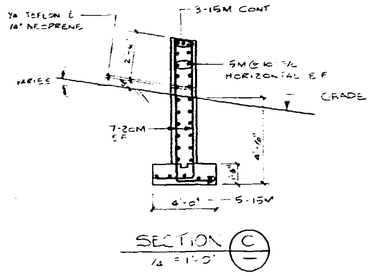
1/2" = 1'-0"



SECTION D

1/2" = 1'-0"

NOTE : REBAR COVER TO BE : 2" ABOVE GRADE
3" BELOW GRADE

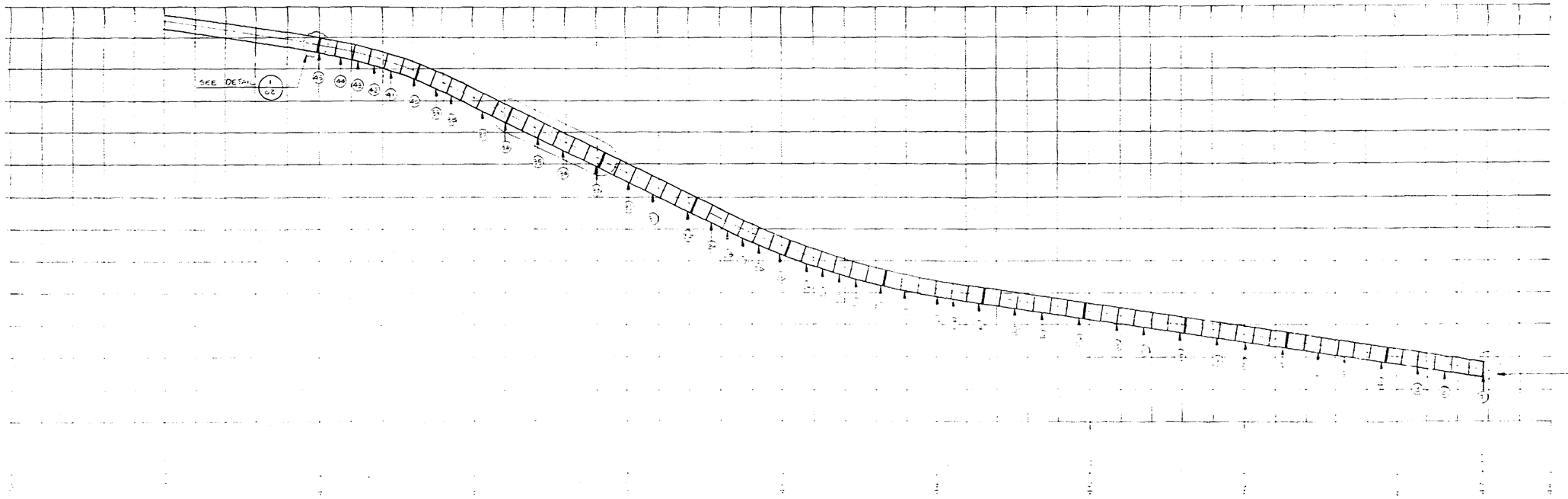


SECTION C

1/2" = 1'-0"

FOOTING F2

SUPPORT	TYPE	CHAINAGE	ELEVATION
1	F1	4705.00	8.94
2	F2	4731.25	13.38
3	F2	4713.39	18.97
4	F1	4689.64	25.42
5	F2	4665.89	32.86
6	F2	4646.03	39.45
7	F1	4624.28	45.89
8	F2	4600.53	53.34
9	F2	4582.66	58.92
10	F1	4556.92	66.37
11	F2	4535.17	73.81
12	F2	4517.32	79.49
13	F1	4493.57	87.85
14	F2	4469.81	95.29
15	F2	4451.96	100.86
16	F1	4428.21	109.32
17	F2	4411.88	115.69
18	F2	4400.95	119.27
19	F2	4379.29	126.36
20	F1	4363.14	131.30
21	F2	4347.12	136.56
22	F2	4336.50	139.51
23	F2	4325.95	142.41
24	F2	4315.47	145.56
25	F1	4299.66	150.66
26	F2	4284.50	156.41
27	F2	4274.35	160.50
28	F2	4264.30	164.82
29	F2	4254.35	169.36
30	F1	4239.43	176.52
31	F2	4217.79	186.69
32	F2	4201.51	195.69
33	F2	4179.87	209.05
34	F2	4158.22	219.42
35	F2	4141.95	227.22
36	F1	4120.31	237.56
37	F2	4104.19	244.72
38	F2	4093.55	249.23
39	F2	4075.71	256.94
40	F1	4059.67	263.39
41	F2	4045.27	269.92
42	F2	4034.96	274.73
43	F2	4024.34	279.06
44	F2	4013.72	283.59
45	F1	3998.00	292.06



PROFILE

1/50" = 1'-0"

No.	REVISION	DATE	BY
	AS BUILT DRAWINGS		

REFERENCE DRAWINGS

DESIGNED BY	S.R./B.L.	
DRAWN BY	B.L./ S.	Sept 89 Siyuda
CHECKED BY	S.R./B.L.	
APPROVED BY	NSPC	
ISSUED FOR DATE		

PLANT — PROJECT NO. 84

CONSTRUCTION

FENCO SHAWINIGAN ENGINEERING (1985) LIMITED

HALIFAX, NOVA SCOTIA

Black & McDonald

PROJECT TITLE

NOVA SCOTIA POWER CORPORATION
[illegible] RIVER HYDRO PLANT
PENSTOCK REPLACEMENT

DRAWING TITLE

PENSTOCK ANCHOR, EXPANSION JOINT AND INTERMEDIATE FOOTING LOCATIONS ON PIPE PROFILE

SCALE AS NOTED

DRAWING NUMBER 58480-01 REV

FILE COPY
CHECKS

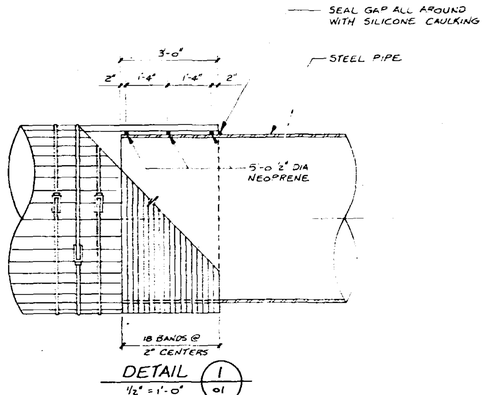
MECH.	CIVIL
ELECT.	INST.
CONST.	

SEP 07 1989

H-024C1-9-001-00-004

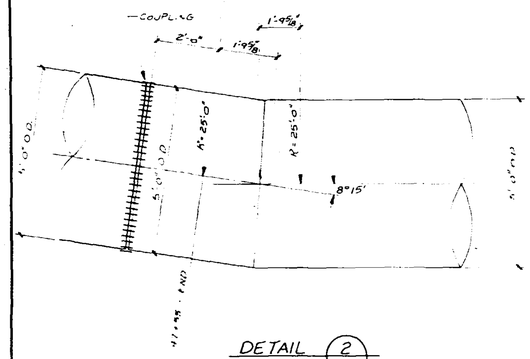
Date Filed: November 22, 2017 Page 1004 of 2371 REDACTED

ACE 2018 CD 49944 Attachment 1 Page 27 of



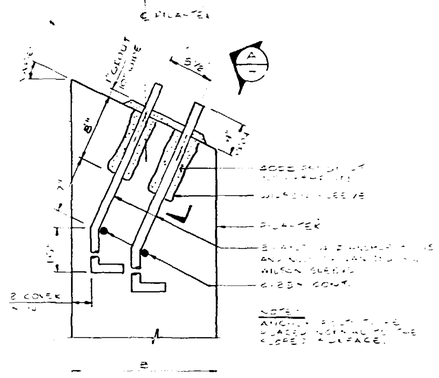
DETAIL (1) 01
1/2" = 1'-0"

TYPICAL WOODSTAVE TO STEEL PIPE CONNECTION

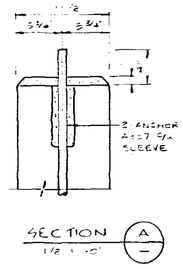


DETAIL (2) 01
1/2" = 1'-0"

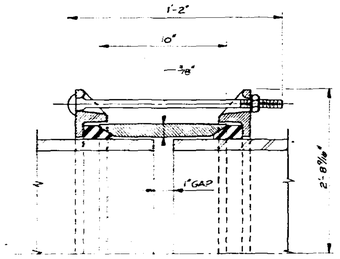
STEEL THIMBLE PIECE CONNECTION AT 47+55



ANCHOR BOLT DETAIL
1/2" = 1'-0"

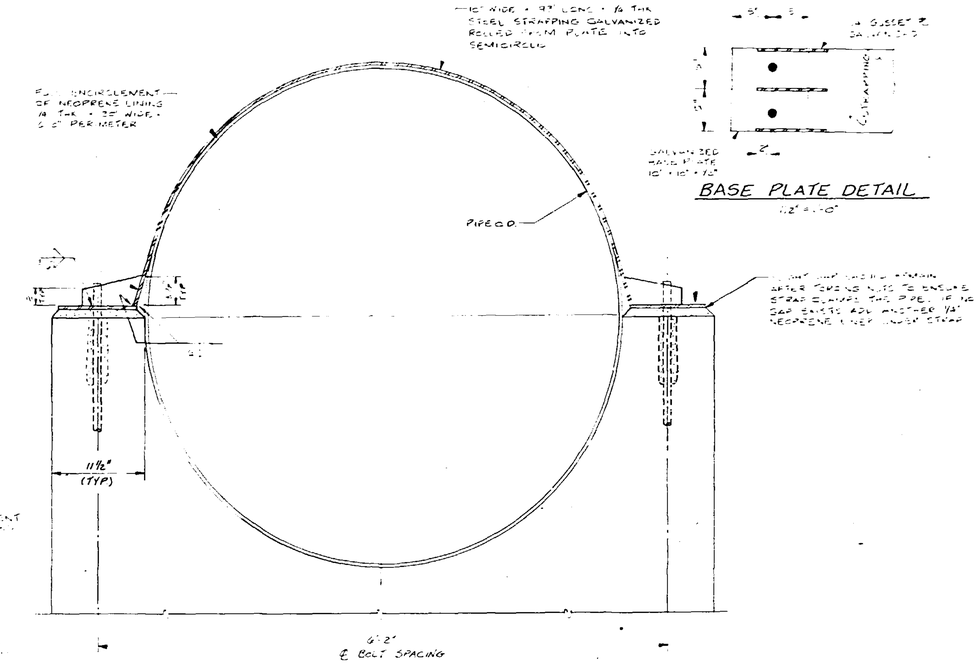


SECTION (A) —
1/2" = 1'-0"



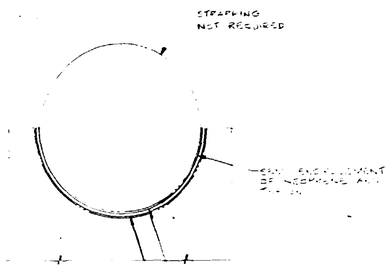
COUPLING DETAIL
NTS

BASE PLATE DETAIL
1/2" = 1'-0"



DETAIL (3) 01
1 1/2" = 1'-0"

ANCHORING STRAP CONNECTION AND SADDLE LINING AT UPPER LEG OF F1



DETAIL (4) 01

GENERAL NOTES:

1) All NSPC Technical Specifications in the Dickie Brook Hydro Plant Tender document for Penstock Replacement are to be adhered to.
2) All work and materials shall conform to the requirements set out in the 1985 National Building Code.
3) The Steel Penstock has been designed in accordance with the A.W.W.A. Steel Pipe - A Guide for Design and Installation, Manual M11.
4) A Subsurface investigation report has been carried out. Refer to report No. 5556, dated August 1, 1989 by Jacques, Whitford and Associates Ltd.
5) The Contractor shall examine all drawings, check all dimensions and report any discrepancies before proceeding with the work.
6) Pipe fabrication details are specified on Trenton Works drawing A118 F 755.

PIPE NOTES:

1) Pipe Couplings are to be Dresser style 200, 60" OD x 3/8" x 10" centre ring. Wetted components shall be protected as per interior of the pipe. Exterior components shall be protected as per exterior of the pipe. An expansion gap of 1" between the butt ends of the pipe should be allowed and must be maintained at 1" after the coupling compression nuts are fully torqued to manfacturer's specifications.
2) The longitudinal seam weld of the pipe should be ground flush with the pipe surface where it is located within the couplings seals. This will prevent leakage at the seal.
3) The 1 1/4" ϕ UNC bolts used to compress the circumferential strap to the pipe shall be wet torqued to 150 ft-lbs. An anti-galling compound should be applied to the threads.
4) Pipe welds should not be supported within a restraint cradle.
5) The pipe support with the Anchor Straps has one 1/4" thick neoprene lining. Additional neoprene linings may be required.
6) The pipe supports designed to reduce friction has a top lining of 1/4" teflon and a bottom lining of 1/4" neoprene.
7) Neoprene linings shall be 70 Durometer and conform to ASTM Grade D2000 to 6KBC715.

CONCRETE NOTES

1) All concrete, concrete material, forms and concrete practice shall conform to CAN3-A23.1-M77 unless noted otherwise.
2) All concrete compressive strength shall be 4000 psi (27 MPa) and shall have 6% ± 1% entrained air. This cement shall have fly ash of 20% by weight.
3) No admixture shall be used without prior approval from the Engineer. The use of admixtures must comply with CAN3-A23.1-M77.
4) Do not place any concrete without prior approval of Engineer.
5) All concrete shall be tested in accordance with CAN3-A23.1-M77.
6) For compressive strength testing of concrete a minimum of 3 cylinders (12" x 6" Dia.) are required for:
   a) Each day pour
   b) each type or grade of concrete
   c) each change of supplier
   d) each 50 yd.³ or fraction thereof for footings, found wall and slabs
   e) additional test specimens shall be taken whenever required by the Manager to verify the concrete quality
7) Take at least one slump test with each compress. strength test.
8) Take at least one entrain. test wih each compress. strength test.
9) All mix designs shall conform to CAN3-A23.1-M77.
10) No chlorides permitted to be added to concrete mix.
11) Where construction joints are required. The splice length is 30 x Bar ϕ minimum. A 2" x 6" keyway laying normal to pipe axis shall be provided.

REINFORCING STEEL

1) All reinf. steel shall have a minimum yield strength of 60 KSI (400 MPa).
2) All reinf. steel shall be detailed, fabricated, placed and supported in accordance with reinf. steel institute of Ontario, 1983 and CAN3-G30.5-84.
3) All reinf. shall be lapped a minimum class "C" tension splice, 40N otherwise.

No.	Revision	Date	By

REFERENCE DRAWINGS

DESIGNED BY	SR/BL	
DRAWN BY	DAW	SEP 89
CHECKED BY	SR BL	S Rajadurai
APPROVED BY	NSPC	
ISSUED DATE	01-09-89	

DATE: SEPTEMBER 05/89

PROJECT NO.: CONSTRUCTION

FENCO SHAWINIGAN ENGINEERING (1985) LIMITED

HALIFAX, NOVA SCOTIA

CLIENT: Erving Mfg. Limited

NOVA SCOTIA POWER CORPORATION
DICKIE BROOK HYDRO PLANT
PENSTOCK REPLACEMENT

DRAWING TITLE:
PENSTOCK
CONNECTION DETAILS
SADDLE LINER DETAILS

SCALE: AS NOTED

DRAWING NO.: 5547-02 | REV.

H-024C1-9-001-00-005

Date Filed: November 22, 2017 Page 1026 of 2371 REDACTED

Suite E200, Bally Rou Place, 370 Torbay Rd.
St. John's, Newfoundland, Canada A1A 3W8
Tel (709) 754 6933 ◆ Fax (709) 754 2717

CI Number: 48712

Title: HYD Dam Instrumentation Upgrade

Start Date: 2016/06
In-Service Date: 2018/04
Final Cost Date: 2019/05
Function: Hydro
Forecast Amount: $476,349

DESCRIPTION:

This project includes installation of new piezometers, which have reached the end of their expected service life. Piezometers provide quantifiable information to help better define risk within a dam structure, at hydro sites throughout Nova Scotia. They include:

Black River Hydro System
Forks Dam
Black River Lake Dam
Lumsden Dam

Sissiboo Hydro System
Fourth Lake Wing Dam #1
Fourth Lake Wing Dam #2
Sissiboo Falls
Weymouth Main Dam

Nictaux Hydro System
Nictaux Intake
Curl Hole Dam

Wreck Cove Hydro System
Wreck Cove Dam D1
Wreck Cove Dam D6
Wreck Cove Dam D7

Bear River Hydro System
Gulch Main Dam

Summary of Related CIs +/- 2 years:
No other projects in 2016, 2017, 2018, 2019 and 2020

JUSTIFICATION:

Justification Criteria: Hydro, Wind and Biomass

Why do this project?

The piezometers installed on hydro dams throughout the province have exceeded their expected service lives, with many having been in service for 20 years or more. Upgrading NS Power's instrumentation will improve dam safety by providing surveillance of the structures to better meet the recommendations contained in the Canadian Dam Association (CDA) Dam Safety Guidelines. Many of the dams and spillways have known deficiencies, and instrumentation on these structures provides valuable information when completing surveillance of the condition of these structures. Instrumentation monitoring complements information from visual inspections and helps understand the condition of the structures. Piezometers provide quantifiable information to better define risk within a dam structure, including an indication of the condition of the interior of the structures, and could help provide advance warning of a problem with the structure.

Why do this project now?

This project is proposed to be completed in 2018 to mitigate the risk that the current piezometers will not provide the necessary information on the condition of the dam structures. The risk associated with NS Power's dam structures varies from low to extreme, according to CDA Guidelines Dam Classification system. Structures with known deficiencies must be monitored until repairs can be completed, while others should be monitored as good practice as recommended by CDA Guidelines.

This project is considered in-service when the first piezometer in installed (April 2018), therefore the forecasted final cost date (May 2019) is six months after the final piezometer is installed (November 2018).

Why do this project this way?

Replacing the piezometers is the only option as they cannot be repaired. In order to ensure NS Power's instrumentation monitoring program can improve dam safety by providing surveillance of the structures, the piezometers must be replaced.

CI Number : 48712-H761 - HYD - Dam Instrumentation Upgrade **Project Number** 48712-H761

Parent CI Number : -

Asset Location : 1370 - 1370 Hydro General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	2800 - HGP - Dams & Spillways	470,721
Retirements	2800 - HGP - Dams & Spillways	5,486
	Total Cost:	476,207
	Original Cost:	248,647

Capital Project Detailed Estimate

Location: Hydro
FP# / P#: 48712
Title: HYD Dam Instrumentation Upgrade
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Hydro River Staff - Construction	day	34	365	$ 12,403		
Engineering Staff	day	68	405	$ 27,567		
Environmental Staff	day	37	332	$ 12,287		
			Sub-Total	$ 52,257		
Term Labour						
Hydro River Staff - Construction	day	62	$ 365	$ 22,499		
				$ -		
			Sub-Total	$ 22,499		
Travel Expenses						
Site Visit	Month	8.5	$ 1,000	$ 8,500		
Investigation Site Visits	lot	1	$ 1,802	$ 1,802		
			Sub-Total	$ 10,302		
Materials						
Instrumentation	ea	16	[redacted]		Cost Support #1	
Investigation Materials	lot	1				
			Sub-Total	$ 38,669		
Contracts						
Piezometers	ea	16	[redacted]		Cost Support #1	
Survey	ea	11			Cost Support #1	
Investigation Contracts	lot	1				
			Sub-Total	$ 189,364		
Consulting						
Specifications and Design	ea	16	[redacted]		Cost Support #1	
Project Management	Month	8				
Scope Determination	lot	1	$ 25,000	$ 25,000		
			Sub-Total	$ 81,000		
Meals						
Site Visit	Month	8.5	$ 200	$ 1,700		
Investigation Site Visit	lot	1	$ 322	$ 322		
			Sub-Total	$ 2,022		
Other Goods and Services						
Contingency	%	10%	$ 228,033	$ 22,803		
				$ -		
			Sub-Total	$ 22,803		
Interest Capitalized						
AFUDC				$ 6,517		
				$ -		
			Sub-Total	$ 6,517		
Administrative Overhead						
Labour AO				$ 34,554		
Contract AO				$ 16,221		
			Sub-Total	$ 50,775		
			Sub-Total (no AO, AFUDC)	$ 418,916		
			TOTAL (AO, AFUDC included)	$ 476,207		
Original Cost				$248,647		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

Structure / Hydro System	Instrumentation	Piezometers	Survey	Specification & Design	Total	# of Piezometers
Forks Dam, Black River System						
Black River Lake, Black River System						
Lumsden, Black River System						2
Fourth Lake Wing Dam #2, Sissiboo River System						2
Nictaux - Intake						2
Wreck Cove D1						
Wreck Cove D6						
Wreck Cove D7						
Fourth Lake Wing Dam #1						2
Sissiboo Falls						3
Weymouth Main Dam						1
Gulch, Bear River						1
Nictaux Curl Hole Dam						3
Total						

Each Piezometer includes the following:	
Instrumentation	
Piezometer Equipment	
Specifications & Design	
Total	

* Please refer to Cost Support 2 for the Third Party estimate.

MEMORANDUM

TO: Melanie Scholten, Nova Scotia Power Inc.

FROM: Chris Vella, Kleinschmidt Associates Canada Inc.

CC: Jonathan Lorette, Nova Scotia Power Inc.

DATE: August 30, 2017

RE: 2018 Priority List for Repair or Refurbishment of Piezometers

At the request of Nova Scotia Power Inc. (NSPI), the NSPI piezometer registry and piezometer monitoring data have been reviewed by Kleinschmidt Associates Canada Inc. (Kleinschmidt). A preliminary list of recommendations for maintenance or new installations are included in the table below for budgetary purposes, and should be included in maintenance work plans for 2018.

Recommendations were prioritized utilizing the dams hazard classification from current NSPI Dam Safety Reports, such that dams with a higher hazard classification receive attention first. This list should not be considered a complete representation of recommendations for all hydro systems and all dams. A complete list of recommendations for all hydro systems will be provided at the conclusion of our review and after discussions with NSPI engineers and operators.

STRUCTURE/ HYDRO SYSTEM	HAZARD CLASSIFICATION	RECOMMENDATIONS	OPINION OF PROBABLE COST ESTIMATE
Forks Dam, Black River System	Extreme	The piezometers were noted to be in good condition and the readings were within limits, but it was not clear to the operator if the piezometer height above ground was accounted for in the measurements. Survey of the top of the piezometer is required to confirm elevations, and review of piezometer monitoring procedure is recommended.	[redacted]
Black River Lake, Black River	Extreme	There is indication that some of piezometers at the toe have been raised. Recommend discussion with the operator and review piezometer monitoring procedure. A survey is required to confirm elevations of the existing piezometers.	
Lumsden, Black River	Extreme	Crest piezometers are buried, therefore recommend installation of two new piezometers at the crest in the same area as existing piezometers.	
Fourth Lake Wing Dam #2, Sissiboo	Very High	The inspection revealed the piezometers to be in good condition along the crest and halfway down the dam. Two piezometers are located at the toe, but are in poor condition and the labels have been switched. Upon review of the site data, it is recommended to confirm the lake elevation and confirm with survey the elevations of the piezometers. It was noted that the piezometer measurements exceeded that of the lake elevations in some cases. Installation of two new piezometers is recommended.	

STRUCTURE/ HYDRO SYSTEM	HAZARD CLASSIFICATION	RECOMMENDATIONS	OPINION OF PROBABLE COST ESTIMATE
Nictaux - Intake	Very High	The piezometers readings are very close to or at the tip readings. It appears that these piezometers may be dry or plugged. There are no other piezometers located at the intake; therefore, recommend replacement of two piezometers.	[redacted]
Wreck Cove D1	High	The dam was raised by 3.5 feet. It is recommended that the piezometer elevations be confirmed.	
Wreck Cove D6	High	Piezometers at the toe are either plugged or buried. Survey is recommended to confirm piezometers elevations.	
Wreck Cove D7	High	The dam was raised by 1.7 feet. A survey is required to confirm piezometer elevations.	
Fourth Lake Wing Dam #1	High	The data was reviewed and some piezometer readings were found to be higher than the lake elevation which is physically not possible. Recommend installation of two new piezometers.	
Sissiboo Falls	High	It was noted in the registry that there are eleven broken piezometers. Three are operational. Recommend installation of at least three, with two piezometers on the crest close to the intake.	
Weymouth Main Dam	High	Recheck elevations of piezometers on dam crest. Install one new piezometer on the crest of the dam.	
Gulch, Bear River	High	Install one new piezometer at the toe. Existing piezometer is dry.	
Nictaux Curl Hole Dam	High	Install three new piezometers. No monitoring at the toe of the dam and crest elevation readings indicate one piezometer may be dry and some of the elevations are higher than the lake elevation.	
TOTAL			

Note: The costs reflect purchase and installation of vibrating wire piezometers as an alternative to standpipe piezometers. The survey costs were estimated as $5,000 per site and $10,000 in Cape Breton.

The notes from NSPI operators taking the piezometer measurements indicate there may be manholes without covers, missing locks on the manholes, drainage issues, and piezometers in poor physical condition, which were not included in the above recommendations as these are general maintenance issues.

CI Number: 52018

Title: HYD Renewable Energy Generation Meter Upgrade

Start Date: 2017/09
In-Service Date: 2018/12
Final Cost Date: 2019/06
Function: Hydro
Forecast Amount: $378,248

DESCRIPTION:

This project includes the replacement of the generation meters across the hydro fleet for measuring station service usage and net plant output.

Present generation measurement and reporting on hydro generation units is done by monthly manual readings in the plants. This project will install meters that can automatically collect accurate generation data for continuous reporting and store the data in a central location. This project will eliminate manual generation readings and mitigate the risk of recording errors.

Summary of Related CIs +/- 2 years:
No other projects in 2016, 2017, 2018, 2019 or 2020

JUSTIFICATION:

Justification Criteria: Hydro, Wind and Biomass

Why do this project?

The existing meters are of varying age and should be replaced in order to mitigate the risk of discrepancies between the amount of electricity generated from the unit and the generation transmitted to the electrical grid (total generation, less station service) energy usage. The measured readings are taken as the correct value, but the integrity of the transmitted data must be improved and collected centrally to mitigate the risk of recording errors. Replacement of the meters will ensure accurate measurement of renewable energy generation, using revenue meter accuracy standards set by Measurement Canada as a guideline.

Why do this project now?

Upgrading the meters in 2018 will mitigate the risk of inaccuracies in NS Power's renewable generation reporting.

Why do this project this way?

Installing standardized meters across Hydro will allow for a common calibration schedule and method. It will also reduce costs associated with an inventory of spare parts. Currently, not every plant has a station service meter. This has a potential to introduce errors in energy usage reporting. Of the meters installed currently, none are capable of establishing communications with the central storage PI Historian server. Communication with the PI server would allow for more reliable and continuous recording of generation data.

CI Number : 52018 - HYD Renewable Energy Generation Meter Upgrade **Project Number** 52018

Parent CI Number : -

Asset Location : 1370 - 1370 Hydro General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account		Forecast Amount
Additions	2300 - HGP - Power Equip.-Station S		375,928
Retirements	2300 - HGP - Power Equip.-Station S		2,320
		Total Cost:	378,248
		Original Cost:	264,053

Capital Project Detailed Estimate

Location: Hydro
FP# / P#: 52018
Title: HYD Renewable Energy Generation Meter Upgrade
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Engineering Staff	day	63	405	$ 25,534		
Environmental Staff	day	112	332	$ 37,194		
Hydro River Staff	day	56	365	$ 20,428		
			Sub-Total	$ 83,157		
Travel Expenses						
Site Visit	Month	8	$ 400	$ 3,200		
			Sub-Total	$ 3,200		
Materials						
Energy usage meters	Ea	84	$ 1,333	$ 112,000		CI 49039 - Lequille Controls Upgrade
Current transformers	Ea	44	$ 1,136	$ 50,000		
Potential transformers	Ea	44	$ 1,136	$ 50,000		
			Sub-Total	$ 212,000		
Meals and Entertainment						
Site Visit	Month	8	$ 100	$ 800		
			Sub-Total	$ 800		
Other Goods & Services						
Contingency	%	10%	$ 299,156	$ 29,916		
			Sub-Total	$ 29,916		
Interest Capitalized						
AFUDC				$ 13,117		
				$ -		
			Sub-Total	$ 13,117		
Administrative Overhead						
Labour AO				$ 36,059		
				$ -		
			Sub-Total	$ 36,059		
			Sub-Total (no AO, AFUDC)	$ 329,072		
			TOTAL (AO, AFUDC included)	$ 378,248		
Original Cost				$ 264,053		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 51802

Title: TRE5 Boiler Refurbishment 2018

Start Date: 2018/05
In-Service Date: 2018/06
Final Cost Date: 2018/12
Function: Steam
Forecast Amount: $1,212,228

DESCRIPTION:

The scope of work for this project is to refurbish and replace deteriorated boiler tubes, tube bends and shields on the Trenton Unit 5 boiler as part of the planned unit outage in 2018. The scope of this project is determined as part of the annual boiler condition data collection and analysis, however current projections are based on an estimate of 20 tube cut-outs, 200 shields and 80 alignment brackets. This effort includes evaluation and prioritization of activities to be undertaken during the annual outage. Protective erosion shields identified as missing or degraded will be replaced with new shields. Tubes and bends will be replaced in the areas where the thickness readings are below American Society of Mechanical Engineers (ASME) specifications and Nova Scotia Labour and Advanced Education (NSLAE) regulations. This tolerance maximizes the economic tube life while maintaining boiler reliability.

Summary of Related CIs +/- 2 years:
2016 CI 47552 TRE5 Boiler Refurbishments 2016 $2,429,444
2017 CI 49536 TRE5 Boiler Refurbishments 2017 $717,589
2019 CI TBD TRE5 Boiler Refurbishment $TBD
2020 CI TBD TRE5 Boiler Refurbishment $TBD

Depreciation Class: Steam Production Plant - Trenton Unit 5

Estimated Life of the Asset: 17 years

JUSTIFICATION:

Justification Criteria: Thermal

Sub Criteria: Equipment Replacement / Refurbishment

Why do this project?

Ongoing asset management activities have identified the requirement for boiler component replacement to maintain the long term reliability of the boiler and mitigate the risk of unplanned outages due to tube leaks. Boiler tube failures represent the industry's single largest source of outages for steam-based generation. NS Power has a long history of managing this issue with comprehensive boiler inspection and proportional investment programs to match the various failure mechanisms.

This project is primarily justified on unit reliability, and secondarily justified on economics.

Why do this project now?

To mitigate the risk of unplanned outages, annual boiler refurbishment activities are required. Some of the tubes to be inspected and replaced are difficult to access and sufficient time during a planned outage is required to complete refurbishment or replacements. The annual planned outage duration will afford the time necessary to assess, locate and replace the tubes and shields.

Why do this project this way?

Replacing deteriorated boiler tubes, tube bends and shields will mitigate the risk of tube leaks and minimize the number of unplanned outages. Based on boiler assessments, these upgrades are necessary to maintain reliable operation of the boiler. Refurbishment of these components is not an option once they are outside acceptable tolerances because there is industry code and legislative requirements governing allowable tolerances.

CI Number : 51802 - TRE5 Boiler Refurbishment 2018 **Project Number** 51802

Parent CI Number : -

Asset Location : 1165 - 1165 Trenton Unit 5; Commissioned 1969, 160 Mwh **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account		Forecast Amount
Additions	1300 - SGP - Boiler		1,102,515
Retirements	1300 - SGP - Boiler		109,713
		Total Cost:	1,212,228
		Original Cost:	145,642

Capital Project Detailed Estimate

Location: Trenton Generating Station
CI# : 51802
Title: TRE5 Boiler Refurbishment 2018
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Engineering	PD	20	$ 405	$ 8,106		
Maintenance Trades	PD	8	$ 365	$ 2,918		
Utility worker	PD	60	$ 240	$ 14,411		
Power Engineer	PD	30	$ 390	$ 11,711		
Electrician	PD	4	$ 358	$ 1,433		
			Sub-Total	$ 38,580		
OT Labour						
Utility worker	PD	20	$ 480	$ 9,607		
				$ -		
			Sub-Total	$ 9,607		
Term Labour						
Utility worker	PD	60	$ 240	$ 14,411		
				$ -		
			Sub-Total	$ 14,411		
Materials						
Boiler Tubes	ea	20	$ 1,500	$ 30,000		
Contractor Materials	lot	1	$ 20,000	$ 20,000		
Shields	ea	200	$ 100	$ 20,000		
Alignment Brackets	ea	80	$ 953	$ 76,280		
			Sub-Total	$ 146,280		
Contracts						
Inspection	lot	1	$ 120,000	$ 120,000		CI49536
Boiler Refurbishment	lot	1	$ 475,000	$ 475,000		CI49536
Supervision	lot	1	$ 80,000	$ 80,000		CI49536
Vacuum Services	lot	1	$ 50,000	$ 50,000		
			Sub-Total	$ 725,000		
OT Meals						
Meals	lot	1	$ 1,000	$ 1,000		
			Sub-Total	$ 1,000		
Consulting						
Boiler Assessment	lot	1	$ 142,541	$ 142,541		
			Sub-Total	$ 142,541		
Rentals						
Misc. Equipment	lot	1	$ 5,000	$ 5,000		
			Sub-Total	$ 5,000		
Other Goods & Services						
Contingency	%	5%	$ 933,877	$ 46,694		
			Sub-Total	$ 46,694		
Administrative Overhead						
Thermal Reg. Labour AO				$ 12,696		
Thermal / Hydro Contracts AO				$ 70,419		
			Sub-Total	$ 83,115		
			SUB-TOTAL (no AO, AFUDC)	$ 1,129,113		
			TOTAL (AO, AFUDC included)	$ 1,212,228		
Original Cost				$ 145,642		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

TRE5 Boiler Refurbishment 2018
Summary of Alternatives

Division :	Power Production	**Date :**	**17-Nov-17**
Department :	Trenton	**CI Number:**	51802
		Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank (based on PV of RR)	IRR	Disc Pay
A	Boiler Refurbishment vs Replacement Energy Costs	5.88%	-3,734,052	2,836,799	1	30.22%	5.0 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

Recommendation :

It is recommended to complete this project based on the economic analysis.

Notes/Comments :

Boiler Refurbishment vs Replacement Energy Costs

This model compares the refurbishment costs to the replacement energy costs associated with unplanned outages due to tube leaks in the boiler. Assumptions are that there will be two tube leaks in 2018, with increasing likelihood of failure in subsequent years. The unit would be down an average of 96 hours to perform repairs such that the unit could be returned to service. The failure rate considers the age of the boiler (1969).

Test 2

Test 3

Test 4

TRE5 Boiler Refurbishment 2018
Summary of Sensitivities

Nova Scotia POWER An Emera Company

Division :	Power Production
Department :	Trenton

Date :	**13-Nov-17**
CI Number:	51802
Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Boiler Refurbishment vs Replacement Energy Cos	5.88%	-3,734,052	2,836,799	1	30.22%	5.0 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

	Alternative Variance on Capital Spend	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Boiler Refurbishment vs Replacement Energy Cos	10%	-3,619,376	2,749,697	1	27.69%	5.4 years
B	Test 2	10%	0	0	2	#NUM!	0.0 years
C	Test 3	10%	0	0	2	#NUM!	0.0 years
D	Test 4	10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		114,676	-87,103	0	-2.53%	0.4 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

	Alternative Variance on Avoided Expenses	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Boiler Refurbishment vs Replacement Energy Cos	-10%	-3,245,970	2,466,017	1	27.44%	5.4 years
B	Test 2	-10%	0	0	2	#NUM!	0.0 years
C	Test 3	-10%	0	0	2	#NUM!	0.0 years
D	Test 4	-10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		488,082	-370,783	0	-2.78%	0.4 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

Alternative Variance on Avoided Expenses - Change in Revenue Requirement		PV of Revenue Requirement	PV of Revenue Requirement	PV of Revenue Requirement	Delay?
	Yrs Delay:	1	2	3	
	A	126,339	323,729	573,301	No
	B	0	0	0	No
	C	0	0	0	No
	D	0	0	0	No

TRE5 Boiler Refurbishment 2018
Avoided Cost Calculations

Division :	Power Production	**Date :**	**13-Nov-17**
Department :	Trenton	**CI Number:**	51802
		Project No. :	

Boiler Refurbishment vs Replacement Energy Costs

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			80,000	83,224		
Events/Outages (#)	2	3	2	3		
Probability of Occurance (%)	100%	100%	100%	100%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	160.0	160.0				
Duration (Hours or Years)	96	96				
Totals	$32,011	$39,875	$160,000	$249,672	$192,011	$289,547
Total Capital Cost of Alternative						$1,212,228

Test 2

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

Test 3

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

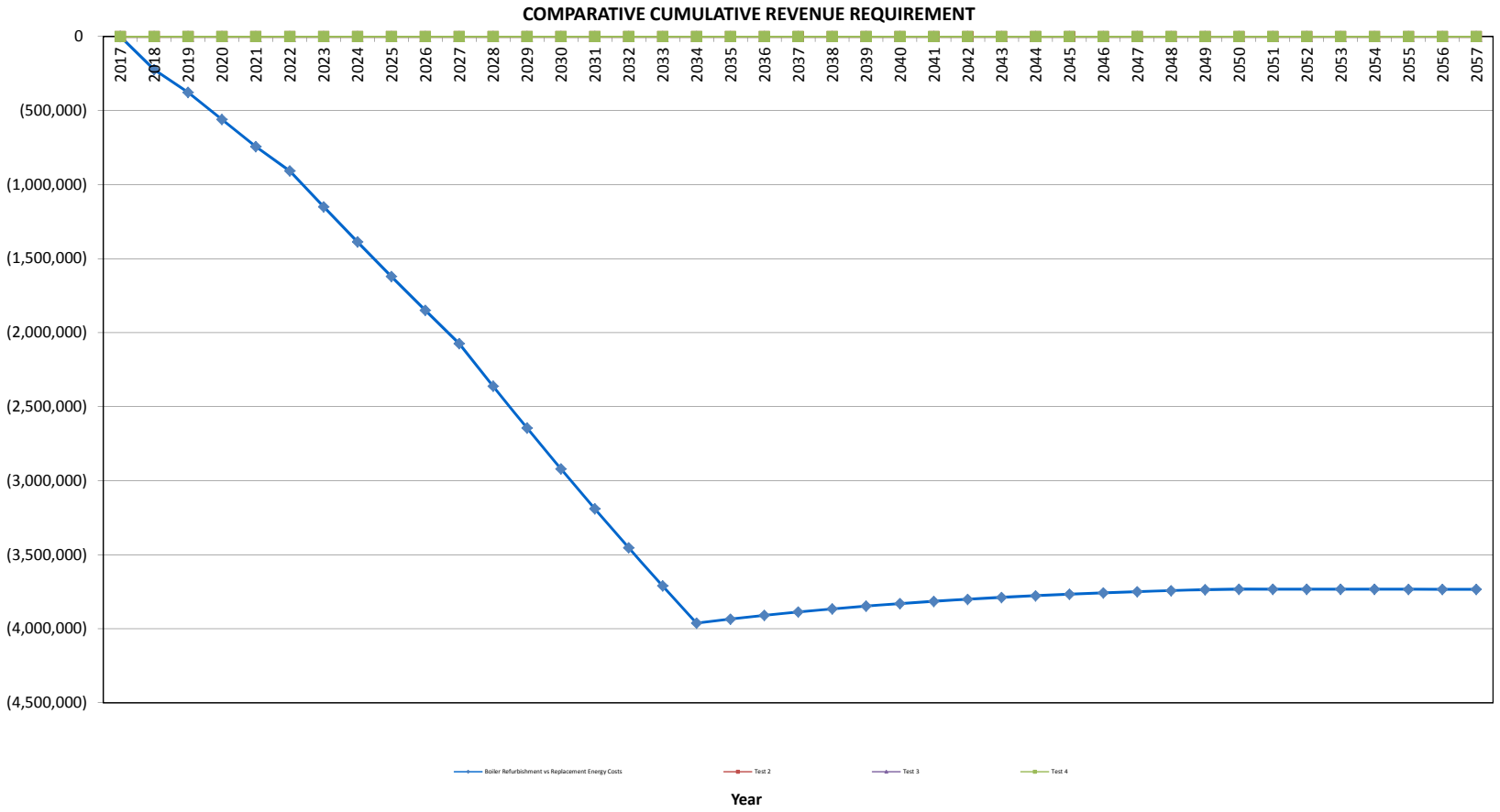
Test 4

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

TRE5 Boiler Refurbishment 2018

Boiler Refurbishment vs Replacement Energy Costs

Year	Total Revenue	Operating Costs	Avoided Expenses	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	PV of CF	Discount Factor	CNPV
2017	-	-	-	-	-	-	-	-	-	-	1.00	-
2018	-	-	192,011.3	(1,129,112.7)	45,164.5	1,106,888.0	(937,101.3)	(45,522.5)	(982,623.8)	(928,054.2)	0.94	(928,054.2)
2019	-	-	289,546.5	-	86,715.9	1,016,342.2	289,546.5	(62,877.5)	226,669.0	202,192.2	0.89	(725,862.1)
2020	-	-	337,509.6	-	79,778.6	933,040.1	337,509.6	(79,896.6)	257,613.0	217,033.1	0.84	(508,829.0)
2021	-	-	354,222.2	-	73,396.3	856,402.1	354,222.2	(87,056.0)	267,166.2	212,581.6	0.80	(296,247.4)
2022	-	-	343,262.2	-	67,524.6	785,895.1	343,262.2	(85,478.7)	257,783.6	193,725.0	0.75	(102,522.4)
2023	-	-	474,444.9	-	62,122.6	721,028.8	474,444.9	(127,819.9)	346,625.0	246,023.3	0.71	143,500.9
2024	-	-	491,848.6	-	57,152.8	661,351.7	491,848.6	(134,755.7)	357,092.9	239,377.7	0.67	382,878.6
2025	-	-	509,919.4	-	52,580.6	606,448.8	509,919.4	(141,775.0)	368,144.4	233,080.9	0.63	615,959.5
2026	-	-	528,683.4	-	48,374.1	555,938.1	528,683.4	(148,895.9)	379,787.6	227,099.1	0.60	843,058.5
2027	-	-	548,168.0	-	44,504.2	509,468.3	548,168.0	(156,135.8)	392,032.2	221,402.4	0.56	1,064,461.0
2028	-	-	710,501.7	-	40,943.9	466,716.1	710,501.7	(207,562.9)	502,938.7	268,263.7	0.53	1,332,724.6
2029	-	-	736,766.2	-	37,668.4	427,384.0	736,766.2	(216,720.3)	520,045.9	261,983.8	0.50	1,594,708.4
2030	-	-	764,041.8	-	34,654.9	391,198.5	764,041.8	(226,109.9)	537,931.9	255,944.7	0.48	1,850,653.2
2031	-	-	792,368.3	-	31,882.5	357,907.9	792,368.3	(235,750.6)	556,617.7	250,127.8	0.45	2,100,781.0
2032	-	-	821,787.2	-	29,331.9	327,280.5	821,787.2	(245,661.1)	576,126.0	244,516.7	0.42	2,345,297.7
2033	-	-	852,341.3	-	26,985.4	299,103.2	852,341.3	(255,860.4)	596,481.0	239,096.8	0.40	2,584,394.4
2034	-	-	884,075.6	-	24,826.5	273,180.2	884,075.6	(266,367.2)	617,708.4	233,855.0	0.38	2,818,249.4
2035	-	-	-	-	22,840.4	249,331.0	-	7,080.5	7,080.5	2,531.7	0.36	2,820,781.1
2036	-	-	-	-	21,013.2	227,389.8	-	6,514.1	6,514.1	2,199.8	0.34	2,822,980.9
2037	-	-	-	-	19,332.1	207,203.8	-	5,993.0	5,993.0	1,911.4	0.32	2,824,892.4
2038	-	-	-	-	17,785.5	188,632.7	-	5,513.5	5,513.5	1,660.9	0.30	2,826,553.3
2039	-	-	-	-	16,362.7	171,547.4	-	5,072.4	5,072.4	1,443.1	0.28	2,827,996.4
2040	-	-	-	-	15,053.7	155,828.8	-	4,666.6	4,666.6	1,254.0	0.27	2,829,250.4
2041	-	-	-	-	13,849.4	141,367.7	-	4,293.3	4,293.3	1,089.6	0.25	2,830,339.9
2042	-	-	-	-	12,741.4	128,063.5	-	3,949.8	3,949.8	946.7	0.24	2,831,286.7
2043	-	-	-	-	11,722.1	115,823.7	-	3,633.9	3,633.9	822.6	0.23	2,832,109.3
2044	-	-	-	-	10,784.4	104,563.0	-	3,343.2	3,343.2	714.8	0.21	2,832,824.1
2045	-	-	-	-	9,921.6	94,203.2	-	3,075.7	3,075.7	621.1	0.20	2,833,445.2
2046	-	-	-	-	9,127.9	84,672.2	-	2,829.6	2,829.6	539.7	0.19	2,833,984.9
2047	-	-	-	-	8,397.6	75,903.6	-	2,603.3	2,603.3	468.9	0.18	2,834,453.8
2048	-	-	-	-	7,725.8	67,836.6	-	2,395.0	2,395.0	407.5	0.17	2,834,861.2
2049	-	-	-	-	7,107.8	60,414.9	-	2,203.4	2,203.4	354.0	0.16	2,835,215.3
2050	-	-	-	-	6,539.1	53,586.9	-	2,027.1	2,027.1	307.6	0.15	2,835,522.9
2051	-	-	-	-	6,016.0	47,305.2	-	1,865.0	1,865.0	267.3	0.14	2,835,790.2
2052	-	-	-	-	5,534.7	41,526.0	-	1,715.8	1,715.8	232.3	0.14	2,836,022.5
2053	-	-	-	-	5,092.0	36,209.1	-	1,578.5	1,578.5	201.8	0.13	2,836,224.3
2054	-	-	-	-	4,684.6	31,317.6	-	1,452.2	1,452.2	175.4	0.12	2,836,399.6
2055	-	-	-	-	4,309.8	26,817.5	-	1,336.0	1,336.0	152.4	0.11	2,836,552.0
2056	-	-	-	-	3,965.0	22,677.3	-	1,229.2	1,229.2	132.4	0.11	2,836,684.4
2057	-	-	-	-	3,647.8	18,868.3	-	1,130.8	1,130.8	115.0	0.10	2,836,799.4
Total	**-**	**-**	**9,631,498.2**	**(1,129,112.7)**	**1,087,162.5**		**8,502,385.6**	**(2,648,744.1)**	**5,853,641.5**	**2,836,799.4**		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Boiler Refurbishment vs Replacement Energy Costs
Test 2
Test 3
Test 4
Year

CI Number: 51805

Title: LIN4 Boiler Refurbishment 2018

Start Date: 2018/03
In-Service Date: 2018/04
Final Cost Date: 2018/10
Function: Steam
Forecast Amount: $739,657

DESCRIPTION:

The scope of work for this project is to refurbish and replace deteriorated boiler tubes, tube bends and shields on the Lingan Unit 4 boiler as part of the planned unit outage in 2018. The scope of this project is determined as part of the annual boiler condition data collection and analysis. This effort includes evaluation and prioritization of activities to be undertaken during the annual outage. Protective erosion shields identified as missing or degraded will be replaced with new shields. Tubes and bends will be replaced in the areas where the thickness readings are below American Society of Mechanical Engineers (ASME) specifications and with Nova Scotia Labour and Advanced Education (NSLAE) regulations. This tolerance maximizes the economic tube life while maintaining boiler reliability.

Summary of Related CIs (+/- 2 years):
2016 CI 47664 LIN4 Boiler Div. Wall Replacement $ 684,118
2016 CI 47663 LIN4 SH5 Boiler Tube Replacement $615,510
2019 CI TBD LIN4 Boiler Refurbishment 2019 $TBD

JUSTIFICATION:

Justification Criteria: Thermal

Sub Criteria: Equipment Replacement / Refurbishment

Why do this project?

On-going asset management activities have identified the requirement for boiler component replacement to maintain the long term reliability of the boiler and mitigate the risk of unplanned outages due to tube leaks. Boiler tube failures represent the industry's single largest source of outages for steam based generation. NS Power has a long history of managing this issue with comprehensive boiler inspection and proportional investment programs to match the various failure mechanisms.

This project is primarily justified on unit reliability, and secondarily supported by positive economics.

Why do this project now?

In order to mitigate the risk of an unplanned outage, annual boiler refurbishment activities are required. Some of the tubes to be inspected and replaced are difficult to access and sufficient time during a planned outage is required to complete repairs or replacements. The annual planned outage duration will afford the time necessary to assess, locate and replace tubes and shields.

Why do this project this way?

Replacing deteriorated tubes, tube bends and shields will mitigate the risk of tube leaks and minimize the number of unplanned outages. Based on boiler assessments, these upgrades are necessary to maintain reliable operation of the boiler. Refurbishment of these components is not an option once they are outside acceptable tolerances because there are industry codes and legislative requirements governing allowable tolerances.

CI Number : 51805 - LIN4 Boiler Refurbishment 2018 **Project Number** 51805

Parent CI Number : -

Asset Location : 1134 - 1134 Lingan Unit 4; Commissioned 1984, 160 Mwh **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	1300 - SGP - Boiler	566,897
Retirements	1300 - SGP - Boiler	172,760
	Total Cost:	739,657
	Original Cost:	271,201

Capital Project Detailed Estimate

Location: Steam
CI# : 51805
Title: LIN4 Boiler Refurbishment 2018
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Utility worker	PD	20	$ 240	$ 4,804		
			Sub-Total	$ 4,804		
Term Labour						
Utility worker	PD	60	$ 240	$ 14,411		
				$ -		
			Sub-Total	$ 14,411		
Materials						
Boiler Tubes	lot	1	$ 15,000	$ 15,000		47666
Boiler Shields	lot	1	$ 15,000	$ 15,000		47666
Misc Consumables	lot	1	$ 6,000	$ 6,000		
				$ -		
			Sub-Total	$ 36,000		
Contracts						
Boiler Refurbishment Contractor	lot	1	$ 560,000	$ 560,000		47666
Industrial Cleaning Services	lot	1	$ 60,000	$ 60,000		
				$ -		
			Sub-Total	$ 620,000		
Administrative Overhead						
Labour AO				$ 4,221		
Contract AO				$ 60,221		
			Sub-Total	$ 64,442		
			SUB-TOTAL (no AO, AFUDC)	$ 675,215		
			TOTAL (AO, AFUDC included)	$ 739,657		
Original Cost				$ 283,936		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

LIN4 Boiler Refurbishment
Summary of Alternatives

Division :	Power Production	**Date :**	**17-Nov-17**
Department :	Lingan	**CI Number:**	51805
		Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank (based on PV of RR)	IRR	Disc Pay
A	Boiler Refurbishment vs Replacement Energy Costs	5.88%	-1,856,093	1,336,784	1	36.00%	4.3 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

Recommendation :

NS Power recommends completing this project in order to maintain boiler reliability.

Notes/Comments :

Boiler Refurbishment vs Replacement Energy Costs

It is assumed as time passes, the frequency and probabilty of tube failures increases.

Test 2

Test 3

Test 4

LIN4 Boiler Refurbishment
Summary of Sensitivities

Nova Scotia POWER An Emera Company

Division :	Power Production
Department :	Lingan

Date :	**14-Nov-17**
CI Number:	51805
Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Boiler Refurbishment vs Replacement Energy Cos	5.88%	-1,856,093	1,336,784	1	36.00%	4.3 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

	Alternative Variance on Capital Spend	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Boiler Refurbishment vs Replacement Energy Cos	10%	-1,789,328	1,284,697	1	32.76%	4.6 years
B	Test 2	10%	0	0	2	#NUM!	0.0 years
C	Test 3	10%	0	0	2	#NUM!	0.0 years
D	Test 4	10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		66,764	-52,088	0	-3.23%	0.3 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

	Alternative Variance on Avoided Expenses	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Boiler Refurbishment vs Replacement Energy Cos	-10%	-1,603,719	1,151,018	1	32.44%	4.6 years
B	Test 2	-10%	0	0	2	#NUM!	0.0 years
C	Test 3	-10%	0	0	2	#NUM!	0.0 years
D	Test 4	-10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		252,374	-185,766	0	-3.56%	0.3 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

Alternative Variance on Avoided Expenses - Change in Revenue Requirement		PV of Revenue Requirement	PV of Revenue Requirement	PV of Revenue Requirement	Delay?
	Yrs Delay:	1	2	3	
	A	79,539	147,139	336,992	No
	B	0	0	0	No
	C	0	0	0	No
	D	0	0	0	No

LIN4 Boiler Refurbishment
Avoided Cost Calculations

Division :	Power Production	**Date :**	**14-Nov-17**
Department :	Lingan	**CI Number:**	51805
		Project No. :	

Boiler Refurbishment vs Replacement Energy Costs

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			87,200	90,691		
Events/Outages (#)	1	1	1	1		
Probability of Occurance (%)	100%	100%	100%	100%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	154.0	154.0				
Duration (Hours or Years)	96	96				
Totals	$30,991	$28,074	$87,200	$90,691	$118,191	$118,765
Total Capital Cost of Alternative						$739,656

Test 2

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

Test 3

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

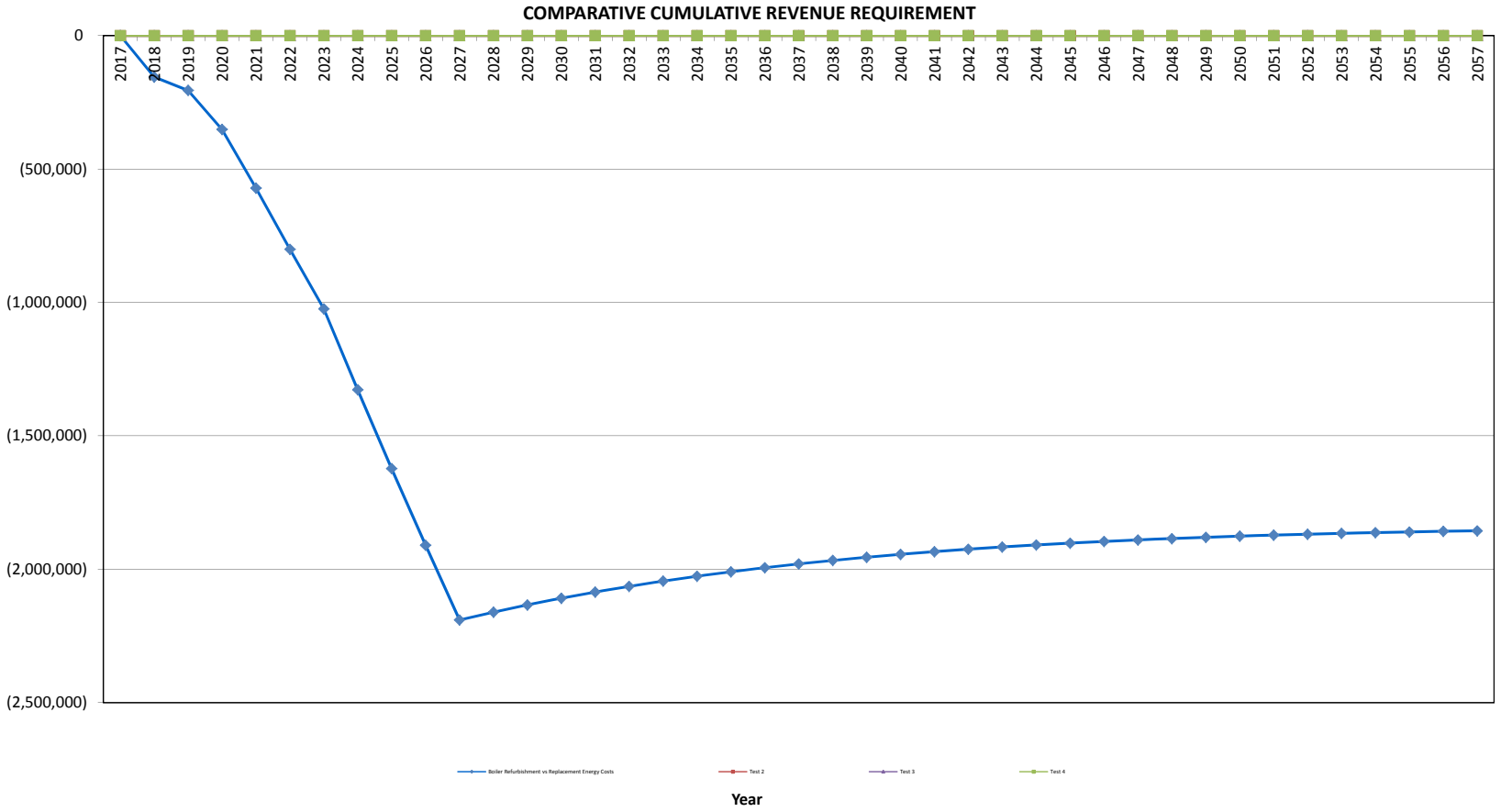
Test 4

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

LIN4 Boiler Refurbishment

Boiler Refurbishment vs Replacement Energy Costs

Year	Total Revenue	Operating Costs	Avoided Expenses	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	PV of CF	Discount Factor	CNPV
2017	-	-	-	-	-	-	-	-	-	-	1.00	-
2018	-	-	118,190.5	(675,214.2)	27,008.6	665,991.5	(557,023.7)	(28,266.4)	(585,290.1)	(552,786.3)	0.94	(552,786.3)
2019	-	-	118,765.3	-	51,856.5	611,165.6	118,765.3	(20,741.7)	98,023.5	87,438.5	0.89	(465,347.8)
2020	-	-	240,909.7	-	47,707.9	560,725.8	240,909.7	(59,892.5)	181,017.2	152,502.8	0.84	(312,845.0)
2021	-	-	349,878.0	-	43,891.3	514,321.1	349,878.0	(94,855.9)	255,022.1	202,918.7	0.80	(109,926.3)
2022	-	-	383,110.3	-	40,380.0	471,628.8	383,110.3	(106,246.4)	276,863.9	208,063.9	0.75	98,137.6
2023	-	-	396,904.1	-	37,149.6	432,351.9	396,904.1	(111,523.9)	285,380.2	202,553.7	0.71	300,691.3
2024	-	-	548,292.3	-	34,177.6	396,217.2	548,292.3	(159,375.6)	388,916.8	260,710.9	0.67	561,402.2
2025	-	-	568,101.3	-	31,443.4	362,973.2	568,101.3	(166,364.0)	401,737.4	254,349.4	0.63	815,751.6
2026	-	-	588,660.5	-	28,927.9	332,388.7	588,660.5	(173,517.1)	415,143.4	248,240.6	0.60	1,063,992.2
2027	-	-	609,999.1	-	26,613.7	304,251.0	609,999.1	(180,849.5)	429,149.7	242,364.7	0.56	1,306,357.0
2028	-	-	-	-	24,484.6	278,364.4	-	7,590.2	7,590.2	4,048.6	0.53	1,310,405.5
2029	-	-	-	-	22,525.8	254,548.6	-	6,983.0	6,983.0	3,517.8	0.50	1,313,923.4
2030	-	-	-	-	20,723.8	232,638.1	-	6,424.4	6,424.4	3,056.7	0.48	1,316,980.1
2031	-	-	-	-	19,065.9	212,480.5	-	5,910.4	5,910.4	2,656.0	0.45	1,319,636.0
2032	-	-	-	-	17,540.6	193,935.4	-	5,437.6	5,437.6	2,307.8	0.42	1,321,943.8
2033	-	-	-	-	16,137.4	176,874.0	-	5,002.6	5,002.6	2,005.3	0.40	1,323,949.1
2034	-	-	-	-	14,846.4	161,177.5	-	4,602.4	4,602.4	1,742.4	0.38	1,325,691.5
2035	-	-	-	-	13,658.7	146,736.7	-	4,234.2	4,234.2	1,514.0	0.36	1,327,205.5
2036	-	-	-	-	12,566.0	133,451.2	-	3,895.4	3,895.4	1,315.5	0.34	1,328,521.0
2037	-	-	-	-	11,560.7	121,228.5	-	3,583.8	3,583.8	1,143.1	0.32	1,329,664.0
2038	-	-	-	-	10,635.8	109,983.6	-	3,297.1	3,297.1	993.2	0.30	1,330,657.2
2039	-	-	-	-	9,785.0	99,638.3	-	3,033.3	3,033.3	863.0	0.28	1,331,520.2
2040	-	-	-	-	9,002.2	90,120.6	-	2,790.7	2,790.7	749.9	0.27	1,332,270.1
2041	-	-	-	-	8,282.0	81,364.4	-	2,567.4	2,567.4	651.6	0.25	1,332,921.7
2042	-	-	-	-	7,619.4	73,308.6	-	2,362.0	2,362.0	566.2	0.24	1,333,487.8
2043	-	-	-	-	7,009.9	65,897.4	-	2,173.1	2,173.1	491.9	0.23	1,333,979.8
2044	-	-	-	-	6,449.1	59,079.0	-	1,999.2	1,999.2	427.4	0.21	1,334,407.2
2045	-	-	-	-	5,933.2	52,806.1	-	1,839.3	1,839.3	371.4	0.20	1,334,778.6
2046	-	-	-	-	5,458.5	47,035.0	-	1,692.1	1,692.1	322.7	0.19	1,335,101.4
2047	-	-	-	-	5,021.8	41,725.6	-	1,556.8	1,556.8	280.4	0.18	1,335,381.8
2048	-	-	-	-	4,620.1	36,840.9	-	1,432.2	1,432.2	243.7	0.17	1,335,625.4
2049	-	-	-	-	4,250.5	32,347.1	-	1,317.6	1,317.6	211.7	0.16	1,335,837.1
2050	-	-	-	-	3,910.4	28,212.7	-	1,212.2	1,212.2	184.0	0.15	1,336,021.1
2051	-	-	-	-	3,597.6	24,409.1	-	1,115.3	1,115.3	159.8	0.14	1,336,181.0
2052	-	-	-	-	3,309.8	20,909.8	-	1,026.0	1,026.0	138.9	0.14	1,336,319.8
2053	-	-	-	-	3,045.0	17,690.4	-	944.0	944.0	120.7	0.13	1,336,440.5
2054	-	-	-	-	2,801.4	14,728.6	-	868.4	868.4	104.9	0.12	1,336,545.4
2055	-	-	-	-	2,577.3	12,003.7	-	799.0	799.0	91.1	0.11	1,336,636.5
2056	-	-	-	-	2,371.1	9,496.8	-	735.0	735.0	79.2	0.11	1,336,715.7
2057	-	-	-	-	2,181.4	7,190.4	-	676.2	676.2	68.8	0.10	1,336,784.5
Total	**-**	**-**	**3,922,811.2**	**(675,214.2)**	**650,127.9**		**3,247,597.0**	**(1,014,531.8)**	**2,233,065.1**	**1,336,784.5**		


COMPARATIVE CUMULATIVE REVENUE REQUIREMENT
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Boiler Refurbishment vs Replacement Energy Costs
Test 2
Test 3
Test 4
Year

CI Number: 47684

Title: LIN3 - Boiler Refurbishment 2018

Start Date:	2018/03
In-Service Date:	2018/04
Final Cost Date:	2018/10
Function:	Steam
Forecast Amount:	$739,657

DESCRIPTION:

The scope of work for this project is to refurbish and replace deteriorated boiler tubes, tube bends and shields on the Lingan Unit 3 boiler as part of the planned unit outage in 2018. The scope of this project is determined as part of the annual boiler condition data collection and analysis. This effort includes evaluation and prioritization of activities to be undertaken during the annual outage. Protective erosion shields identified as missing or degraded will be replaced with new shields. Tubes and bends will be replaced in the areas where the thickness readings are below American Society of Mechanical Engineers (ASME) specifications and with Nova Scotia Labour and Advanced Education (NSLAE) regulations. This tolerance maximizes the economic tube life while maintaining boiler reliability.

Summary of Related CIs (+/- 2 years):
2019: CI TBD LIN3 Boiler Refurbishment 2019 $TBD
2020: CI TBD LIN3 Boiler Refurbishment 2020 $TBD

JUSTIFICATION:

Justification Criteria: Thermal

Why do this project?

On-going asset management activities have identified the requirement for boiler component replacement to maintain the long term reliability of the boiler and mitigate the risk of unplanned outages due to tube leaks. Boiler tube failures represent the industry's single largest source of outages for steam based generation. NS Power has a long history of managing this risk with comprehensive boiler inspection and investment programs to match the various failure mechanisms.

This project is primarily justified on unit reliability, and secondarily supported by positive economics.

Why do this project now?

In order to mitigate the risk of an unplanned outage, boiler refurbishment activities are required in 2018. Some of the tubes to be inspected and replaced are difficult to access and sufficient time during a planned outage is required to complete repairs or replacements. The annual planned outage duration will afford the time necessary to assess, locate and repair tubes and shields.

Why do this project this way?

Replacing deteriorated tubes, tube bends and shields will mitigate the risk of tube leaks and minimize the number of unplanned outages. Based on boiler assessments, these upgrades are necessary to maintain reliable operation of the boiler. Refurbishment of these components is not an option once they are outside acceptable tolerances because there is industry code and legislative requirements governing allowable tolerance.

CI Number : 47684 - LIN3 - Boiler Refurbishment 2018 **Project Number** 47684

Parent CI Number : -

Asset Location : 1133 - 1133 Lingan Unit 3; Commissioned 1983, 164Mwh **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	1300 - SGP - Boiler	566,897
Retirements	1300 - SGP - Boiler	172,760
	Total Cost:	739,657
	Original Cost:	271,201

Capital Project Detailed Estimate

Location: Steam
CI# : 47684
Title: LIN3 - Boiler Refurbishment 2018
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Utility worker	PD	20	$ 240	$ 4,804		
			Sub-Total	$ 4,804		
Term Labour						
Utility worker	PD	60	$ 240	$ 14,411		
			Sub-Total	$ 14,411		
Materials						
Boiler Tubes	lot	1	$ 15,000	$ 15,000		47666
Boiler Shields	lot	1	$ 15,000	$ 15,000		47666
Misc Consumables	lot	1	$ 6,000	$ 6,000		
			Sub-Total	$ 36,000		
Contracts						
Boiler Refurbishment Contractor	lot	1	$ 560,000	$ 560,000		47666
Industrial Cleaning Services	lot	1	$ 60,000	$ 60,000		
			Sub-Total	$ 620,000		
Administrative Overhead						
Thermal Reg. Labour AO				$ 4,221		
Thermal / Hydro Contracts AO				$ 60,221		
			Sub-Total	$ 64,442		
			SUB-TOTAL (no AO, AFUDC)	$ 675,215		
			TOTAL (AO, AFUDC included)	$ 739,657		
Original Cost				$ 271,201		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

LIN3 Boiler Refurbishment
Summary of Alternatives

Division :	Power Production	**Date :**	**17-Nov-17**
Department :	Lingan	**CI Number:**	47684
		Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank (based on PV of RR)	IRR	Disc Pay
A	Refurbishment Boiler vs Replacement Energy Costs	5.88%	-1,934,831	1,395,318	1	36.77%	4.2 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

Recommendation :

NS Power recommends completing this project to maintain boiler reliaiblity on the basis of favourable economic analysis.

Notes/Comments :

Refurbishment Boiler vs Replacement Energy Costs

It is assumed as time passes the frequency and probabilty of tube failures increases.

Test 2

Test 3

Test 4

LIN3 Boiler Refurbishment
Summary of Sensitivities

Nova Scotia POWER An Emera Company

Division :	Power Production
Department :	Lingan

Date :	**10-Nov-17**
CI Number:	47684
Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Refurbishment Boiler vs Replacement Energy Cos	5.88%	-1,934,831	1,395,318	1	36.77%	4.2 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

	Alternative Variance on Capital Spend	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Refurbishment Boiler vs Replacement Energy Cos	10%	-1,868,066	1,343,230	1	33.51%	4.5 years
B	Test 2	10%	0	0	2	#NUM!	0.0 years
C	Test 3	10%	0	0	2	#NUM!	0.0 years
D	Test 4	10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		66,765	-52,088	0	-3.26%	0.3 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

	Alternative Variance on Avoided Expenses	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Refurbishment Boiler vs Replacement Energy Cos	-10%	-1,674,583	1,203,698	1	33.18%	4.5 years
B	Test 2	-10%	0	0	2	#NUM!	0.0 years
C	Test 3	-10%	0	0	2	#NUM!	0.0 years
D	Test 4	-10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		260,248	-191,620	0	-3.59%	0.3 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

Alternative Variance on Avoided Expenses - Change in Revenue Requirement		PV of Revenue Requirement	PV of Revenue Requirement	PV of Revenue Requirement	Delay?
	Yrs Delay:	1	2	3	
	A	78,332	147,277	340,422	No
	B	0	0	0	No
	C	0	0	0	No
	D	0	0	0	No

LIN3 Boiler Refurbishment
Avoided Cost Calculations

Division :	Power Production	**Date :**	**10-Nov-17**
Department :	Lingan	**CI Number:**	47684
		Project No. :	

Refurbishment Boiler vs Replacement Energy Costs

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			87,200	90,691		
Events/Outages (#)	1	1	1	1		
Probability of Occurance (%)	100%	100%	100%	100%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	154.0	154.0				
Duration (Hours or Years)	96	96				
Totals	$29,699	$29,351	$87,200	$90,691	$116,899	$120,041
Total Capital Cost of Alternative						$739,657

Test 2

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

Test 3

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

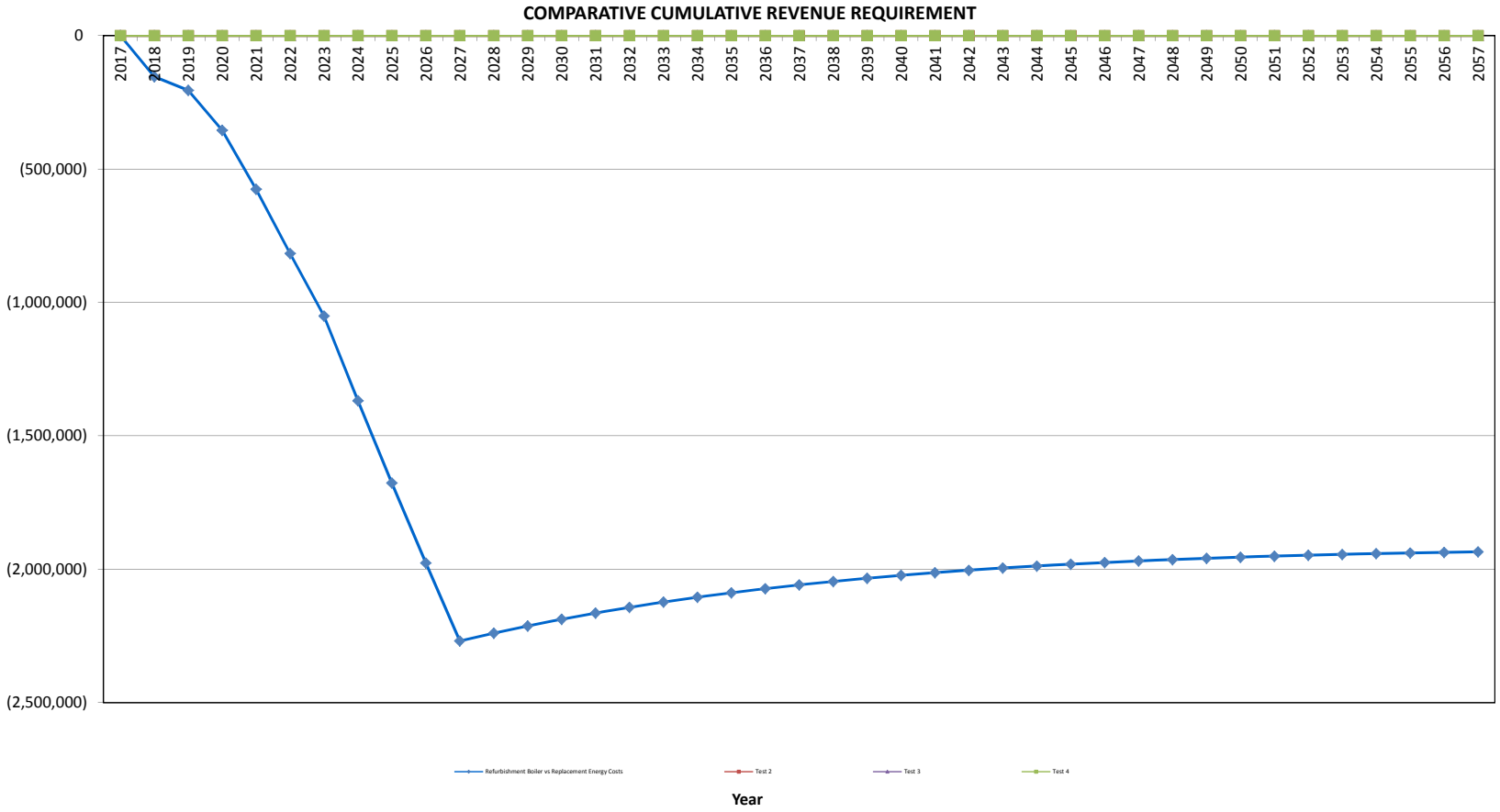
Test 4

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

LIN3 Boiler Refurbishment

Refurbishment Boiler vs Replacement Energy Costs

Year	Total Revenue	Operating Costs	Avoided Expenses	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	PV of CF	Discount Factor	CNPV
2017	-	-	-	-	-	-	-	-	-	-	1.00	-
2018	-	-	116,899.3	(675,215.0)	27,008.6	665,992.3	(558,315.7)	(27,866.1)	(586,181.8)	(553,628.5)	0.94	(553,628.5)
2019	-	-	120,041.4	-	51,856.5	611,166.3	120,041.4	(21,137.3)	98,904.1	88,223.9	0.89	(465,404.5)
2020	-	-	244,514.3	-	47,708.0	560,726.4	244,514.3	(61,010.0)	183,504.3	154,598.2	0.84	(310,806.3)
2021	-	-	352,015.9	-	43,891.3	514,321.7	352,015.9	(95,518.6)	256,497.3	204,092.5	0.80	(106,713.8)
2022	-	-	399,159.5	-	40,380.0	471,629.3	399,159.5	(111,221.6)	287,937.9	216,386.0	0.75	109,672.2
2023	-	-	413,274.3	-	37,149.6	432,352.4	413,274.3	(116,598.7)	296,675.7	210,570.9	0.71	320,243.1
2024	-	-	570,555.8	-	34,177.7	396,217.6	570,555.8	(166,277.2)	404,278.6	271,008.7	0.67	591,251.8
2025	-	-	590,810.1	-	31,443.5	362,973.6	590,810.1	(173,403.7)	417,406.5	264,269.9	0.63	855,521.7
2026	-	-	611,823.5	-	28,928.0	332,389.1	611,823.5	(180,697.6)	431,125.9	257,797.5	0.60	1,113,319.2
2027	-	-	633,625.4	-	26,613.7	304,251.4	633,625.4	(188,173.6)	445,451.8	251,571.4	0.56	1,364,890.6
2028	-	-	-	-	24,484.6	278,364.7	-	7,590.2	7,590.2	4,048.6	0.53	1,368,939.2
2029	-	-	-	-	22,525.9	254,548.9	-	6,983.0	6,983.0	3,517.8	0.50	1,372,457.1
2030	-	-	-	-	20,723.8	232,638.4	-	6,424.4	6,424.4	3,056.7	0.48	1,375,513.7
2031	-	-	-	-	19,065.9	212,480.7	-	5,910.4	5,910.4	2,656.0	0.45	1,378,169.7
2032	-	-	-	-	17,540.6	193,935.6	-	5,437.6	5,437.6	2,307.8	0.42	1,380,477.5
2033	-	-	-	-	16,137.4	176,874.2	-	5,002.6	5,002.6	2,005.3	0.40	1,382,482.8
2034	-	-	-	-	14,846.4	161,177.7	-	4,602.4	4,602.4	1,742.4	0.38	1,384,225.2
2035	-	-	-	-	13,658.7	146,736.8	-	4,234.2	4,234.2	1,514.0	0.36	1,385,739.1
2036	-	-	-	-	12,566.0	133,451.3	-	3,895.5	3,895.5	1,315.5	0.34	1,387,054.7
2037	-	-	-	-	11,560.7	121,228.6	-	3,583.8	3,583.8	1,143.1	0.32	1,388,197.7
2038	-	-	-	-	10,635.8	109,983.7	-	3,297.1	3,297.1	993.2	0.30	1,389,190.9
2039	-	-	-	-	9,785.0	99,638.4	-	3,033.3	3,033.3	863.0	0.28	1,390,053.9
2040	-	-	-	-	9,002.2	90,120.7	-	2,790.7	2,790.7	749.9	0.27	1,390,803.8
2041	-	-	-	-	8,282.0	81,364.5	-	2,567.4	2,567.4	651.6	0.25	1,391,455.4
2042	-	-	-	-	7,619.4	73,308.7	-	2,362.0	2,362.0	566.2	0.24	1,392,021.5
2043	-	-	-	-	7,009.9	65,897.4	-	2,173.1	2,173.1	491.9	0.23	1,392,513.5
2044	-	-	-	-	6,449.1	59,079.0	-	1,999.2	1,999.2	427.4	0.21	1,392,940.9
2045	-	-	-	-	5,933.2	52,806.1	-	1,839.3	1,839.3	371.4	0.20	1,393,312.3
2046	-	-	-	-	5,458.5	47,035.0	-	1,692.1	1,692.1	322.7	0.19	1,393,635.1
2047	-	-	-	-	5,021.8	41,725.6	-	1,556.8	1,556.8	280.4	0.18	1,393,915.5
2048	-	-	-	-	4,620.1	36,840.9	-	1,432.2	1,432.2	243.7	0.17	1,394,159.1
2049	-	-	-	-	4,250.5	32,347.1	-	1,317.6	1,317.6	211.7	0.16	1,394,370.8
2050	-	-	-	-	3,910.4	28,212.7	-	1,212.2	1,212.2	184.0	0.15	1,394,554.8
2051	-	-	-	-	3,597.6	24,409.1	-	1,115.3	1,115.3	159.8	0.14	1,394,714.7
2052	-	-	-	-	3,309.8	20,909.8	-	1,026.0	1,026.0	138.9	0.14	1,394,853.5
2053	-	-	-	-	3,045.0	17,690.4	-	944.0	944.0	120.7	0.13	1,394,974.2
2054	-	-	-	-	2,801.4	14,728.5	-	868.4	868.4	104.9	0.12	1,395,079.1
2055	-	-	-	-	2,577.3	12,003.7	-	799.0	799.0	91.1	0.11	1,395,170.2
2056	-	-	-	-	2,371.1	9,496.8	-	735.0	735.0	79.2	0.11	1,395,249.4
2057	-	-	-	-	2,181.4	7,190.4	-	676.2	676.2	68.8	0.10	1,395,318.2
Total	**-**	**-**	**4,052,719.5**	**(675,215.0)**	**650,128.5**		**3,377,504.6**	**(1,054,803.2)**	**2,322,701.4**	**1,395,318.2**		


COMPARATIVE CUMULATIVE REVENUE REQUIREMENT
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Refurbishment Boiler vs Replacement Energy Costs
Test 2
Test 3
Test 4
Year

CI Number: 51825

Title: POT Boiler Refurbishment 2018

Start Date:	2018/03
In-Service Date:	2018/04
Final Cost Date:	2018/10
Function:	Steam
Forecast Amount:	$568,740

DESCRIPTION:

The scope of work for this project is to repair and replace tubes, tube bends and shields on the Point Tupper boiler as part of a planned outage in 2018. The scope of this project is determined as part of the annual boiler condition data collection and analysis. This effort includes evaluation and prioritization of activities to be undertaken during the annual outage. Protective erosion shields identified as missing or degraded will be replaced with new shields. Tubes and bends will be replaced in the areas where the wall thickness readings are below American Society of Mechanical Engineers (ASME) specifications and Nova Scotia Labour and Advanced Education (NSLAE) regulations. Adherence to this tolerance maximizes the tube life while maintaining boiler reliability.

Summary of Related CIs +/- 2 years:
2016 CI 47719 POT - Unit 2 Boiler Refurbishment 2016 $240,083
2017 CI 49419 POT Boiler Refurbishment 2017 $969,292
2019 CI TBD POT - Boiler Refurbishment 2019 $TBD
2020 CI TBD POT - Boiler Refurbishment 2020 $TBD

JUSTIFICATION:

Justification Criteria: Thermal

Sub Criteria: Equipment Replacement / Refurbishment

Why do this project?

Ongoing asset management activities have identified the requirement for boiler component replacement to maintain the reliability of the boiler and mitigate the risk of unplanned outages due to tube leaks. Boiler tube failures represent the industry's single largest source of outages for steam-based generation. NS Power has a long history of managing this issue with comprehensive boiler inspection and proportional investment programs to address the various failure mechanisms.

This project is being undertaken primarily to prevent boiler failure and preserve the unit's availability, and is secondarily supported by positive economics.

Why do this project now?

In order to mitigate the risk of unplanned outages, annual boiler refurbishment activities are required. Some of the tubes to be inspected and replaced are difficult to access and sufficient time during a planned outage is required to complete refurbishment or replacements. The annual planned outage duration will afford the time necessary to assess, locate and repair tubes and shields.

Why do this project this way?

Replacing deteriorated tubes, tube bends and shields will mitigate the risk of tube leaks and minimize the number of unplanned outages. Based on boiler assessments, these upgrades are necessary to maintain reliable operation of the boiler. Refurbishment of these components is not an option once they are outside acceptable tolerances. For tubes, wall thickness tolerances are established by industry standard (ASME) and governed by legislative requirements. Tube shield replacement is determined by inspector assessment of the degree of deterioration.

CI Number : 51825 - POT Boiler Refurbishment 2018 **Project Number** 51825

Parent CI Number : -

Asset Location : 1152 - 1152 Point Tupper Unit 2 **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	1300 - SGP - Boiler	459,027
Retirements	1300 - SGP - Boiler	109,713
	Total Cost:	568,740
	Original Cost:	226,395

Capital Project Detailed Estimate

Location: **Pt Tupper**
CI# : 51825
Title: POT Boiler Refurbishment 2018
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Electrician	PD	2	$ 358	$ 717		
Maintenance Trades	PD	2	$ 365	$ 730		
Power Engineer	PD	16	$ 390	$ 6,246		
Utility worker	PD	10	$ 240	$ 2,402		
			Sub-Total	$ 10,094		
OT Labour						
Utility worker	PD	12	$ 480	$ 5,764		
Operators	PD	12	$ 358	$ 4,299		
			Sub-Total	$ 10,064		
Term Labour						
Utility worker	PD	42	$ 240	$ 10,087		
				$ -		
			Sub-Total	$ 10,087		
Travel Expense						
Travel	lot	1	$ 1,000	$ 1,000		
				$ -		
			Sub-Total	$ 1,000		
Materials						
Boiler tubing, shields, pins, etc.	lot	1	$ 80,000	$ 80,000		
			Sub-Total	$ 80,000		
Contracts						
Boiler tube replacement and refurbishment	lot	1	$ 245,000	$ 245,000		
			Sub-Total	$ 245,000		
Freight						
Freight	lot	1	$ 1,000	$ 1,000		
			Sub-Total	$ 1,000		
OT Meals						
OT Meals	lot	1	$ 500	$ 500		
			Sub-Total	$ 500		
Consulting						
Boiler Assessment	lot	1	$ 139,285	$ 139,285		
			Sub-Total	$ 139,285		
Rentals						
Rentals	lot	1	$ 5,000	$ 5,000		
			Sub-Total	$ 5,000		
Meals & Entertainment						
Meals	lot	1	$ 1,000	$ 1,000		
			Sub-Total	$ 1,000		
Other Goods & Services						
Contingency	%	10%	$ 363,745	$ 36,375		
				$ -		
			Sub-Total	$ 36,375		
Administrative Overhead						
Labour AO				$ 5,539		
Contract AO				$ 23,797		
			Sub-Total	$ 29,336		
			SUB-TOTAL (no AO, AFUDC)	$ 539,405		
			TOTAL (AO, AFUDC included)	$ 568,740		
Original Cost				$ 226,395		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

POT Boiler Refurbishment
Summary of Alternatives

Division :	Power Production	**Date :**	**17-Nov-17**
Department :	Pt. Tupper	**CI Number:**	51825
		Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank (based on PV of RR)	IRR	Disc Pay
A	Boiler Refurbishment vs Replacement Energy Costs	5.88%	-3,474,388	2,468,054	1	198.21%	1.4 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

Recommendation :

This project is recommended to proceed based upon strong economics and reliability of the Point Tupper Generating Station.

Notes/Comments :

Boiler Refurbishment vs Replacement Energy Costs

This analysis considers the capital cost to refurbish the boiler and the replacement energy and repair costs that would be incurred from tube leaks if this project is not completed.

Test 2

Test 3

Test 4

POT Boiler Refurbishment
Summary of Sensitivities

Nova Scotia POWER An Emera Company

Division :	Power Production
Department :	Pt. Tupper

Date :	**14-Nov-17**
CI Number:	51825
Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Boiler Refurbishment vs Replacement Energy Cos	5.88%	-3,474,388	2,468,054	1	198.21%	1.4 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

	Alternative Variance on Capital Spend	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Boiler Refurbishment vs Replacement Energy Cos	10%	-3,419,790	2,426,443	1	168.63%	1.5 years
B	Test 2	10%	0	0	2	#NUM!	0.0 years
C	Test 3	10%	0	0	2	#NUM!	0.0 years
D	Test 4	10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		54,597	-41,611	0	-29.58%	0.1 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

	Alternative Variance on Avoided Expenses	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Boiler Refurbishment vs Replacement Energy Cos	-10%	-3,072,352	2,179,637	1	165.89%	1.5 years
B	Test 2	-10%	0	0	2	#NUM!	0.0 years
C	Test 3	-10%	0	0	2	#NUM!	0.0 years
D	Test 4	-10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		402,036	-288,417	0	-32.32%	0.1 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

Alternative Variance on Avoided Expenses - Change in Revenue Requirement		PV of Revenue Requirement	PV of Revenue Requirement	PV of Revenue Requirement	Delay?
	Yrs Delay:	1	2	3	
	A	317,651	900,214	1,736,357	No
	B	0	0	0	No
	C	0	0	0	No
	D	0	0	0	No

POT Boiler Refurbishment
Avoided Cost Calculations

Nova Scotia POWER An Emera Company

Division :	Power Production	**Date :**	**14-Nov-17**
Department :	Pt. Tupper	**CI Number:**	51825
		Project No. :	

Boiler Refurbishment vs Replacement Energy Costs

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			59,400	61,782		
Events/Outages (#)	4	7	4	7		
Probability of Occurance (%)	100%	100%	100%	100%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	150.0	150.0				
Duration (Hours or Years)	60	60				
Totals	$129,239	$262,650	$237,600	$432,472	$366,839	$695,122
Total Capital Cost of Alternative						$568,740

Test 2

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

Test 3

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

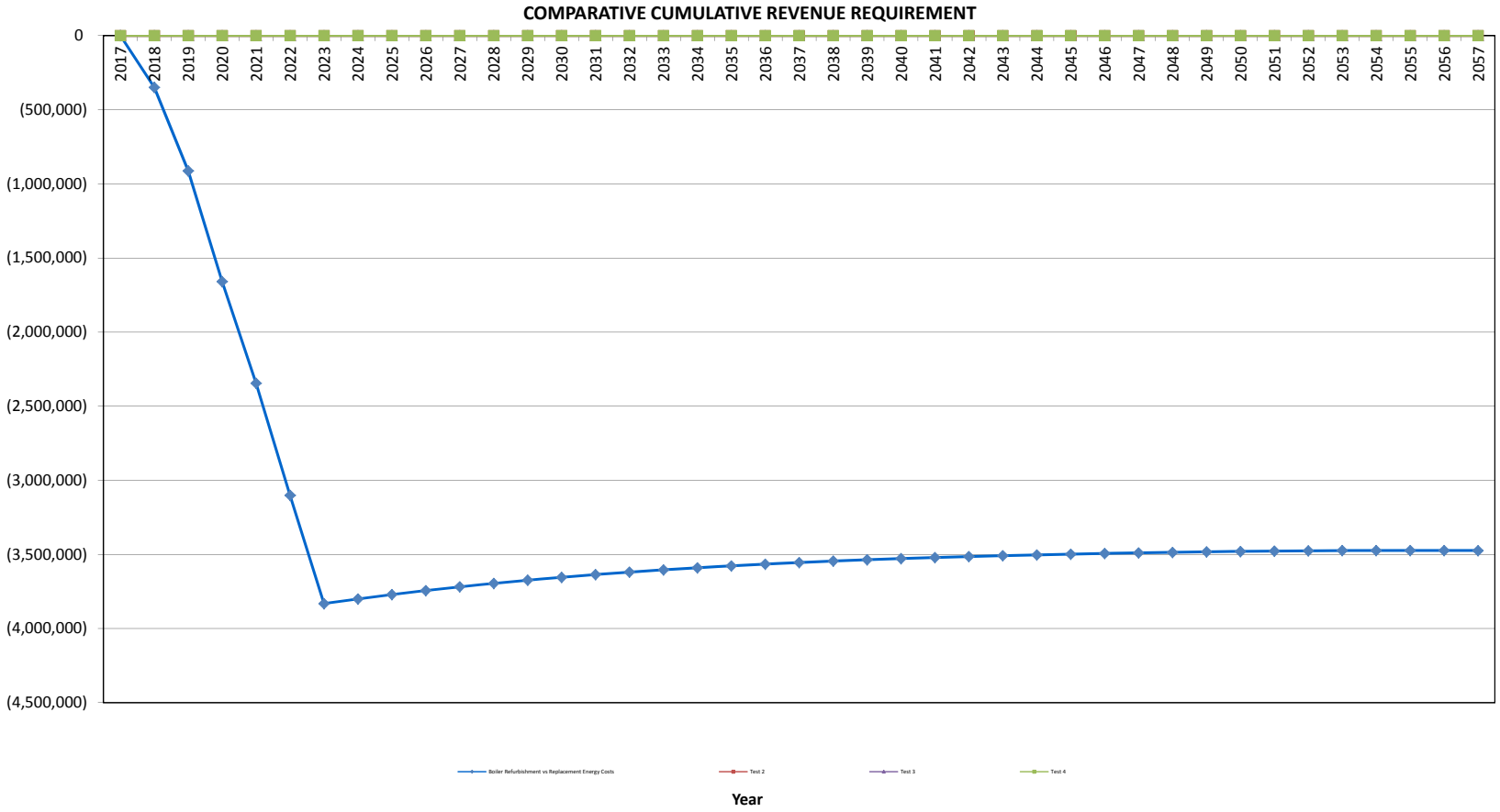
Test 4

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

POT Boiler Refurbishment

Boiler Refurbishment vs Replacement Energy Costs

Year	Total Revenue	Operating Costs	Avoided Expenses	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	PV of CF	Discount Factor	CNPV
2017	-	-	-	-	-	-	-	-	-	-	1.00	-
2018	-	-	366,839.5	(539,404.8)	21,576.2	525,925.2	(172,565.3)	(107,031.6)	(279,596.9)	(264,069.6)	0.94	(264,069.6)
2019	-	-	695,122.3	-	41,426.3	483,147.2	695,122.3	(202,645.8)	492,476.5	439,296.4	0.89	175,226.8
2020	-	-	964,197.6	-	38,112.2	443,791.3	964,197.6	(287,086.5)	677,111.1	570,450.7	0.84	745,677.6
2021	-	-	949,348.9	-	35,063.2	407,584.0	949,348.9	(283,428.6)	665,920.3	529,866.6	0.80	1,275,544.1
2022	-	-	1,108,670.4	-	32,258.2	374,273.2	1,108,670.4	(333,687.8)	774,982.6	582,401.2	0.75	1,857,945.4
2023	-	-	1,144,814.4	-	29,677.5	343,627.3	1,144,814.4	(345,692.4)	799,121.9	567,191.2	0.71	2,425,136.5
2024	-	-	-	-	27,303.3	315,433.0	-	8,464.0	8,464.0	5,673.9	0.67	2,430,810.4
2025	-	-	-	-	25,119.0	289,494.3	-	7,786.9	7,786.9	4,930.1	0.63	2,435,740.5
2026	-	-	-	-	23,109.5	265,630.7	-	7,163.9	7,163.9	4,283.8	0.60	2,440,024.3
2027	-	-	-	-	21,260.8	243,676.2	-	6,590.8	6,590.8	3,722.2	0.56	2,443,746.5
2028	-	-	-	-	19,559.9	223,478.1	-	6,063.6	6,063.6	3,234.3	0.53	2,446,980.7
2029	-	-	-	-	17,995.1	204,895.8	-	5,578.5	5,578.5	2,810.3	0.50	2,449,791.0
2030	-	-	-	-	16,555.5	187,800.0	-	5,132.2	5,132.2	2,441.9	0.48	2,452,232.9
2031	-	-	-	-	15,231.1	172,072.0	-	4,721.6	4,721.6	2,121.8	0.45	2,454,354.6
2032	-	-	-	-	14,012.6	157,602.2	-	4,343.9	4,343.9	1,843.6	0.42	2,456,198.3
2033	-	-	-	-	12,891.6	144,289.9	-	3,996.4	3,996.4	1,601.9	0.40	2,457,800.2
2034	-	-	-	-	11,860.2	132,042.7	-	3,676.7	3,676.7	1,391.9	0.38	2,459,192.1
2035	-	-	-	-	10,911.4	120,775.2	-	3,382.5	3,382.5	1,209.5	0.36	2,460,401.6
2036	-	-	-	-	10,038.5	110,409.1	-	3,111.9	3,111.9	1,050.9	0.34	2,461,452.5
2037	-	-	-	-	9,235.4	100,872.3	-	2,863.0	2,863.0	913.1	0.32	2,462,365.6
2038	-	-	-	-	8,496.6	92,098.5	-	2,633.9	2,633.9	793.4	0.30	2,463,159.1
2039	-	-	-	-	7,816.9	84,026.6	-	2,423.2	2,423.2	689.4	0.28	2,463,848.5
2040	-	-	-	-	7,191.5	76,600.4	-	2,229.4	2,229.4	599.0	0.27	2,464,447.5
2041	-	-	-	-	6,616.2	69,768.3	-	2,051.0	2,051.0	520.5	0.25	2,464,968.1
2042	-	-	-	-	6,086.9	63,482.8	-	1,886.9	1,886.9	452.3	0.24	2,465,420.3
2043	-	-	-	-	5,599.9	57,700.1	-	1,736.0	1,736.0	393.0	0.23	2,465,813.3
2044	-	-	-	-	5,152.0	52,380.0	-	1,597.1	1,597.1	341.5	0.21	2,466,154.8
2045	-	-	-	-	4,739.8	47,485.6	-	1,469.3	1,469.3	296.7	0.20	2,466,451.5
2046	-	-	-	-	4,360.6	42,982.7	-	1,351.8	1,351.8	257.8	0.19	2,466,709.3
2047	-	-	-	-	4,011.8	38,840.0	-	1,243.6	1,243.6	224.0	0.18	2,466,933.4
2048	-	-	-	-	3,690.8	35,028.7	-	1,144.2	1,144.2	194.6	0.17	2,467,128.0
2049	-	-	-	-	3,395.6	31,522.4	-	1,052.6	1,052.6	169.1	0.16	2,467,297.1
2050	-	-	-	-	3,123.9	28,296.5	-	968.4	968.4	147.0	0.15	2,467,444.1
2051	-	-	-	-	2,874.0	25,328.7	-	890.9	890.9	127.7	0.14	2,467,571.8
2052	-	-	-	-	2,644.1	22,598.4	-	819.7	819.7	111.0	0.14	2,467,682.7
2053	-	-	-	-	2,432.6	20,086.5	-	754.1	754.1	96.4	0.13	2,467,779.2
2054	-	-	-	-	2,237.9	17,775.5	-	693.8	693.8	83.8	0.12	2,467,862.9
2055	-	-	-	-	2,058.9	15,649.4	-	638.3	638.3	72.8	0.11	2,467,935.7
2056	-	-	-	-	1,894.2	13,693.4	-	587.2	587.2	63.2	0.11	2,467,999.0
2057	-	-	-	-	1,742.7	11,893.9	-	540.2	540.2	55.0	0.10	2,468,053.9
Total	**-**	**-**	**5,228,993.0**	**(539,404.8)**	**519,364.1**		**4,689,588.2**	**(1,459,984.9)**	**3,229,603.3**	**2,468,053.9**		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Boiler Refurbishment vs Replacement Energy Costs
Test 2
Test 3
Test 4
Year

CI Number: 52252

Title: LIN1 SH5 Tube Replacement

Start Date:	2018/10
In-Service Date:	2018/10
Final Cost Date:	2019/04
Function:	Steam
Forecast Amount:	$521,259

DESCRIPTION:

This project includes the replacement of 44 tube cut-outs in the Lingan Unit 1 Superheater 5. As per the inspection data from the 2015 and 2017 planned outages, approximately 78 tubes were at or below minimum allowable tube thickness, per the NS Department of Labor. During the 2017 Lingan Unit 1 outage, approximately 34 tube cutouts were replaced on Superheater #5. This left 44 tubes to be replaced during the next planned outages.

Summary of Related CIs (+/- 2 years):
2017 CI 49433 LIN1 SH5 Boiler Tube Replacement $848,377

JUSTIFICATION:

Justification Criteria: Thermal

Sub Criteria: Equipment Replacement / Refurbishment

Why do this project?

Erosion of boiler tubes will lead to leaks, requiring the boiler to come offline for repairs. Superheat tubes exhibiting erosion beyond the minimum allowable wall thickness for the boiler pressure and temperature must be refurbished to mitigate unplanned outages and comply with industry guidelines.

This project is being undertaken primarily to preserve the unit's availability, and is secondarily supported by positive economics.

Why do this project now?

In order to mitigate the risk of an unplanned outage, boiler refurbishment activities are required in 2018. Some of the tubes to be inspected and replaced are difficult to access and sufficient time during a planned outage is required to complete repairs or replacements. The annual planned outage duration will afford the time necessary to assess, locate and repair tubes and shields.

Why do this project this way?

Replacing these tube cut outs will mitigate the risk of tube leaks and minimize the number of unplanned outages. Based on assessments, these upgrades are necessary to maintain reliable operation of the boiler. Refurbishment of these components is not an option since the existing tube material has reached creep failure conditions and cannot be weld overlayed. New tube material with remaining creep life must be utilized to prevent the probability of tube failures. Creep damage is a function of operating conditions and boiler tube thickness.

CI Number : 52252 - LIN1 SH5 Tube Replacement

Project Number 52252

Parent CI Number : -

Asset Location : 1131 - 1131 Lingan Unit 1; Commissioned 1979, 164Mwh

Budget Version 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	1300 - SGP - Boiler	425,192
Retirements	1300 - SGP - Boiler	96,067
	Total Cost:	521,259
	Original Cost:	108,824

Capital Project Detailed Estimate

Location: Steam
CI# : 52252
Title: LIN1 SH5 Tube Replacement
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
Electrician	PD	8	$ 358	$ 2,866		
Maintenance Trades	PD	8	$ 365	$ 2,918		
Utility worker	PD	20	$ 240	$ 4,804		
			Sub-Total	$ 10,588		
Term Labor						
Utility worker	PD	80	$ 240	$ 19,214		
				$ -		
				$ -		
			Sub-Total	$ 19,214		
Materials						
Boiler Tube	lot	1	$ 18,000	$ 18,000		
Boiler Shields	lot	1	$ 8,000	$ 8,000		
Miscellaneous Consumables	lot	1	$ 4,000	$ 4,000		
				$ -		
			Sub-Total	$ 30,000		
Contracts						
Boiler Maintenance Contractor	lot	1	$ 380,000	$ 380,000		
			Sub-Total	$ 380,000		
Other Goods & Services						
Contingency	%	10%	$ 380,000	$ 38,000		
				$ -		
			Sub-Total	$ 38,000		
Administrative Overhead						
Labor AO				$ 6,547		
Contracts AO				$ 36,909		
			Sub-Total	$ 43,456		
			SUB-TOTAL (no AO, AFUDC)	$ 477,802		
			TOTAL (AO, AFUDC included)	$ 521,259		
Original Cost				$ 108,824		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

LIN1 SH5 Tube Replacement
Summary of Alternatives

Division :	Power Production	**Date :**	**17-Nov-17**
Department :	Lingan	**CI Number:**	52252
		Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank (based on PV of RR)	IRR	Disc Pay
A	Tube Replacement vs Replacement Energy Costs	5.88%	-2,075,515	1,522,221	1	51.52%	2.8 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

Recommendation :

NS Power recommends completing this project to maintain reliability in the SH5 section of the boiler.

Notes/Comments :

Tube Replacement vs Replacement Energy Costs

It is estimated it will take approximately 96 hours to repair a tube leak in SH5. As time passes, the frequency and probability of leaks in this section of the boiler will increase.

Test 2

Test 3

Test 4

LIN1 SH5 Tube Replacement
Summary of Sensitivities

Nova Scotia POWER
An Emera Company

Division :	Power Production	**Date :**	**14-Nov-17**
Department :	Lingan	**CI Number:**	52252
		Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Tube Replacement vs Replacement Energy Costs	5.88%	-2,075,515	1,522,221	1	51.52%	2.8 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

	Alternative Variance on Capital Spend	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Tube Replacement vs Replacement Energy Costs	10%	-2,026,345	1,485,362	1	46.93%	3.1 years
B	Test 2	10%	0	0	2	#NUM!	0.0 years
C	Test 3	10%	0	0	2	#NUM!	0.0 years
D	Test 4	10%	0	0	2	#NUM!	0.0 years
Change:	**A**		49,169	-36,859	0	-4.59%	0.3 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

	Alternative Variance on Avoided Expenses	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Tube Replacement vs Replacement Energy Costs	-10%	-1,818,794	1,333,140	1	46.47%	3.1 years
B	Test 2	-10%	0	0	2	#NUM!	0.0 years
C	Test 3	-10%	0	0	2	#NUM!	0.0 years
D	Test 4	-10%	0	0	2	#NUM!	0.0 years
Change:	**A**		256,721	-189,081	0	-5.05%	0.3 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

Alternative Variance on Avoided Expenses - Change in Revenue Requirement		PV of Revenue Requirement	PV of Revenue Requirement	PV of Revenue Requirement	Delay?
	Yrs Delay:	1	2	3	
	A	77,406	247,535	448,184	No
	B	0	0	0	No
	C	0	0	0	No
	D	0	0	0	No

LIN1 SH5 Tube Replacement
Avoided Cost Calculations

Nova Scotia POWER An Emera Company

Division :	Power Production	**Date :**	14-Nov-17
Department :	Lingan	**CI Number:**	52252
		Project No. :	

Tube Replacement vs Replacement Energy Costs

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			91,040	94,686		
Events/Outages (#)	1	2	1	2		
Probability of Occurance (%)	100%	100%	100%	100%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	154.0	154.0				
Duration (Hours or Years)	96	96				
Totals	$16,141	$29,351	$91,040	$189,372	$107,181	$218,723

Total Capital Cost of Alternative	$521,259

Test 2

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0

Total Capital Cost of Alternative	$0

Test 3

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0

Total Capital Cost of Alternative	$0

Test 4

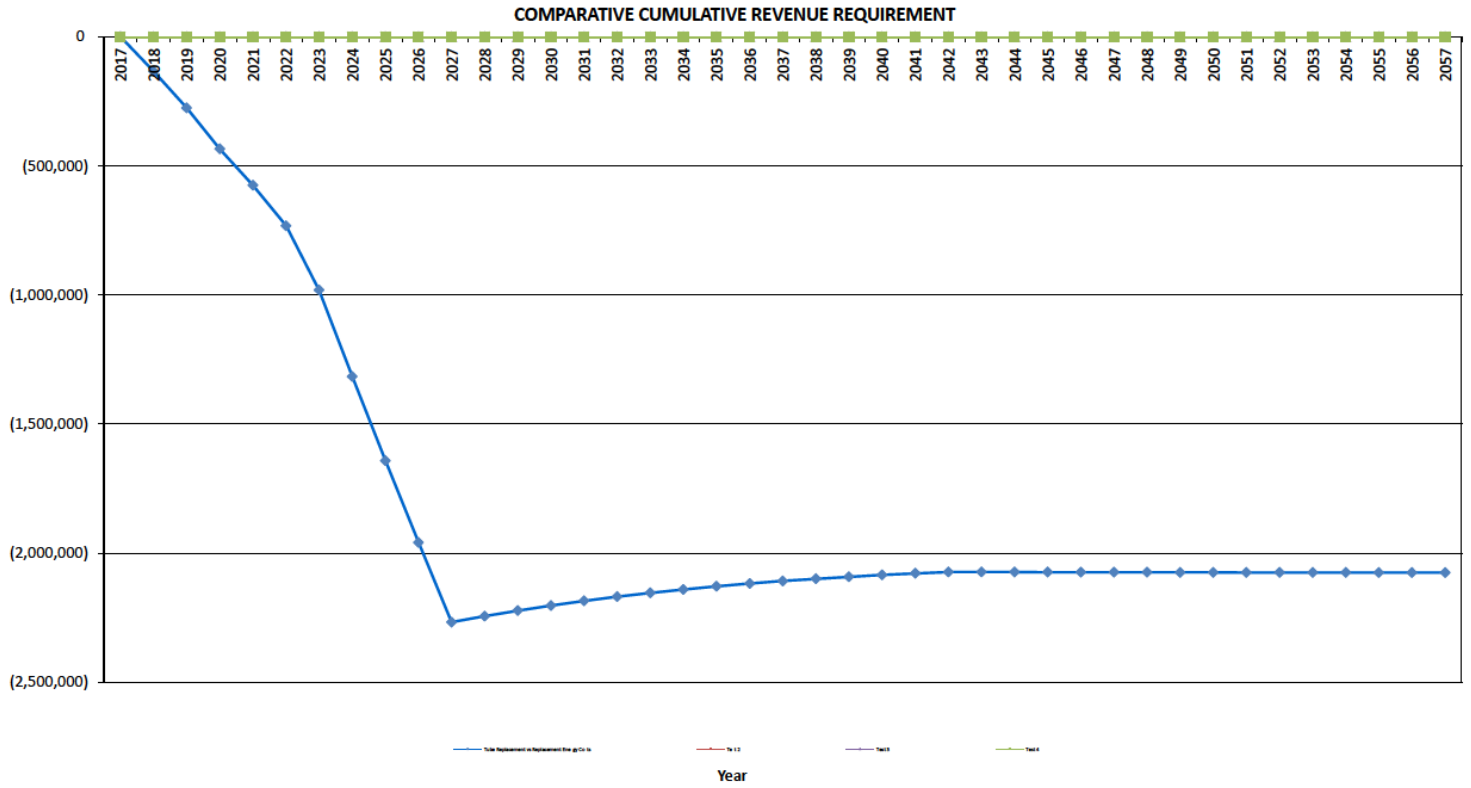
	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0

Total Capital Cost of Alternative	$0

LIN1 SH5 Tube Replacement

Tube Replacement vs Replacement Energy Costs

Year	Total Revenue	Operating Costs	Avoided Expenses	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	PV of CF	Discount Factor	CNPV
2017	-	-	-	-	-	-	-	-	-	-	1.00	-
2018	-	-	107,180.9	(477,802.3)	19,112.1	470,684.2	(370,621.4)	(27,301.3)	(397,922.8)	(375,824 3)	0.94	(375,824.3)
2019	-	-	218,722.5	-	36,695.2	431,986.5	218,722.5	(56,428.5)	162,294.1	144,768.7	0.89	(231,055.6)
2020	-	-	251,025.1	-	33,759.6	396,384.6	251,025.1	(67,352.3)	183,672.8	154,740.1	0.84	(76,315.4)
2021	-	-	240,475.7	-	31,058.8	363,630.9	240,475.7	(64,919.2)	175,556.4	139,688.6	0.80	63,373.2
2022	-	-	275,104.7	-	28,574.1	333,497.5	275,104.7	(76,424.5)	198,680.2	149,308.7	0.75	212,681.8
2023	-	-	427,317.1	-	26,288.2	305,774.7	427,317.1	(124,319.0)	302,998.2	215,058.4	0.71	427,740.2
2024	-	-	590,036.0	-	24,185.1	280,269.8	590,036.0	(175,413.8)	414,622.3	277,942.6	0.67	705,682.8
2025	-	-	611,077.3	-	22,250.3	256,805.3	611,077.3	(182,536.4)	428,540.9	271,319.4	0.63	977,002.2
2026	-	-	632,909.5	-	20,470.3	235,217.9	632,909.5	(189,856.1)	443,053.3	264,929.7	0.60	1,241,931.9
2027	-	-	655,563.2	-	18,832.7	215,357.5	655,563.2	(197,386.5)	458,176.8	258,758 0	0.56	1,500,689.9
2028	-	-	-	-	17,326.1	197,086.0	-	5,371.1	5,371.1	2,864 9	0.53	1,503,554.8
2029	-	-	-	-	15,940.0	180,276.1	-	4,941.4	4,941.4	2,489 3	0.50	1,506,044.1
2030	-	-	-	-	14,664.8	164,811.1	-	4,546.1	4,546.1	2,163 0	0.48	1,508,207.1
2031	-	-	-	-	13,491.6	150,583.2	-	4,182.4	4,182.4	1,879.4	0.45	1,510,086.6
2032	-	-	-	-	12,412.3	137,493.6	-	3,847.8	3,847.8	1,633.1	0.42	1,511,719.6
2033	-	-	-	-	11,419.3	125,451.2	-	3,540.0	3,540.0	1,419 0	0.40	1,513,138.6
2034	-	-	-	-	10,505.7	114,372.1	-	3,256.8	3,256.8	1,233 0	0.38	1,514,371.6
2035	-	-	-	-	9,665.3	104,179.4	-	2,996.2	2,996.2	1,071 3	0.36	1,515,442.9
2036	-	-	-	-	8,892.1	94,802.1	-	2,756.5	2,756.5	930 9	0.34	1,516,373.8
2037	-	-	-	-	8,180.7	86,175.0	-	2,536.0	2,536.0	808 9	0.32	1,517,182.7
2038	-	-	-	-	7,526.2	78,238.0	-	2,333.1	2,333.1	702 8	0.30	1,517,885.5
2039	-	-	-	-	6,924.1	70,936.0	-	2,146.5	2,146.5	610.7	0.28	1,518,496.2
2040	-	-	-	-	6,370.2	64,218.2	-	1,974.8	1,974.8	530.6	0.27	1,519,026.8
2041	-	-	-	-	5,860.6	58,037.8	-	1,816.8	1,816.8	461.1	0.25	1,519,487.9
2042	-	-	-	-	5,391.7	52,351.8	-	1,671.4	1,671.4	400.6	0.24	1,519,888.5
2043	-	-	-	-	4,960.4	47,120.7	-	1,537.7	1,537.7	348.1	0.23	1,520,236.6
2044	-	-	-	-	4,563.6	42,308.1	-	1,414.7	1,414.7	302 5	0.21	1,520,539.1
2045	-	-	-	-	4,198.5	37,880.5	-	1,301.5	1,301.5	262 8	0.20	1,520,801.9
2046	-	-	-	-	3,862.6	33,807.1	-	1,197.4	1,197.4	228.4	0.19	1,521,030.3
2047	-	-	-	-	3,553.6	30,059.6	-	1,101.6	1,101.6	198.4	0.18	1,521,228.7
2048	-	-	-	-	3,269.3	26,611.9	-	1,013.5	1,013.5	172.4	0.17	1,521,401.1
2049	-	-	-	-	3,007.8	23,440.0	-	932.4	932.4	149 8	0.16	1,521,551.0
2050	-	-	-	-	2,767.1	20,521.8	-	857.8	857.8	130 2	0.15	1,521,681.1
2051	-	-	-	-	2,545.8	17,837.1	-	789.2	789.2	113.1	0.14	1,521,794.3
2052	-	-	-	-	2,342.1	15,367.2	-	726.1	726.1	98 3	0.14	1,521,892.5
2053	-	-	-	-	2,154.7	13,094.9	-	668.0	668.0	85.4	0.13	1,521,977.9
2054	-	-	-	-	1,982.4	11,004.3	-	614.5	614.5	74 2	0.12	1,522,052.1
2055	-	-	-	-	1,823.8	9,081.0	-	565.4	565.4	64 5	0.11	1,522,116.6
2056	-	-	-	-	1,677.9	7,311.6	-	520.1	520.1	56 0	0.11	1,522,172.6
2057	-	-	-	-	1,543.6	5,683.7	-	478.5	478.5	48.7	0.10	1,522,221.3
Total	**-**	**-**	**4,009,412.1**	**(477,802.3)**	**460,050.5**		**3,531,609.7**	**(1,100,302.1)**	**2,431,307.6**	**1,522,221.3**		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CI Number: 52253

Title: LIN3 Economizer Header Refurbishment

Start Date: 2018/03
In-Service Date: 2018/03
Final Cost Date: 2018/09
Function: Steam
Forecast Amount: $499,951

DESCRIPTION:

The scope of work for this project is to refurbish the economizer inlet header through the replacement of the economizer header inlet T and attached economizer tubes at the T section on Lingan Unit 3.

The economizer inlet header distributes the feedwater entering the boiler through the economizer tube bank. A tube from each platen of the lower economizer is connected to the header. The feedwater enters the header through the main feedwater pipe attached to the center of the header forming a T section. This section has experienced flow accelerated corrosion (FAC).

Summary of Related CIs (+/- 2 years):
No other projects in 2016, 2017, 2018, 2019 & 2020

JUSTIFICATION:

Justification Criteria: Thermal

Sub Criteria: Equipment Replacement / Refurbishment

Why do this project?

In 2017, a tube leak developed at the economizer header in the T section to the feedwater inlet. The header and tubing in this area were found to exhibit material loss. The economizer header has thinned in the T connection to the main feedwater line due to FAC. During FAC, iron ions from the mild steel piping or tubing dissolve in the passing feedwater. The rate of FAC is dependent on temperature being between 120 and 205°C, geometry of the piping or tubing, plain or low alloy carbon steel metallurgy, dissolved oxygen concentration, and ph. The section proposed to be replaced operates in the FAC temperature range, and is a susceptible steel metallurgy.

There is known material loss due to FAC in the economizer header at the T connection to the feedwater inlet. The thin material creates a potential leak site within the boiler. A tube or header leak in the economizer area will force the unit off line and cause water to leak into the air heater directly below, plugging off the air heater baskets and forcing an air heater clean.

This project is primarily justified on unit reliability, while secondarily supported by positive economics.

Why do this project now?

This project must be completed in 2018 in order to mitigate the risk of tube and header failures due to the known material loss on the economizer header at the T connection to the feedwater inlet pipe and the attached economizer tubes in that area of the header. This project is also supported by industry codes and best practices.

Why do this project this way?

Replacement of the T section and attached economizer tubes affected by the FAC will allow the remainder of the header to stay in service avoiding the extra cost of replacing the whole header. The condition of the T section and economizer tubes does not allow for refurbishment.

CI Number : 52253 - LIN3 Economizer Header Refurbishment **Project Number** 52253

Parent CI Number : -

Asset Location : 1133 - 1133 Lingan Unit 3; Commissioned 1983, 164Mwh **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	1300 - SGP - Boiler	406,555
Retirements	1300 - SGP - Boiler	93,395
	Total Cost:	499,951
	Original Cost:	150,926

Capital Project Detailed Estimate

Location: Steam
CI# : 52253
Title: LIN3 Economizer Header Refurbishment
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Utilityworker	PD	25	$ 240	$ 6,004		
			Sub-Total	$ 6,004		
Term Labour						
Utilityworker	PD	40	$ 240	$ 9,607		
				$ -		
			Sub-Total	$ 9,607		
Materials						
Economizer Tubes	lot	1	$ 6,000	$ 6,000		
Economizer Header T	$	1	$ 20,000	$ 20,000		
			Sub-Total	$ 26,000		
Contracts						
Boiler Maintenance Contractor	$	1	$ 340,000	$ 340,000		
Heat Treatment Contractor	$	1	$ 40,000	$ 40,000		
			Sub-Total	$ 380,000		
Other Goods & Services						
Contingency	%	10%	$ 380,000	$ 38,000		
				$ -		
			Sub-Total	$ 38,000		
Administrative Overhead						
Labour AO				$ 3,430		
Contracts AO				$ 36,909		
			Sub-Total	$ 40,339		
			SUB-TOTAL (no AO, AFUDC)	$ 459,612		
			TOTAL (AO, AFUDC included)	$ 499,951		
Original Cost				$ 150,926		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

LIN3 Economizer Header Refurbishment
Summary of Alternatives

Division :	Power Production	**Date :**	**19-Nov-17**
Department :	Lingan	**CI Number:**	52253
		Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank (based on PV of RR)	IRR	Disc Pay
A	Header Refurbishment vs Replacement Energy Costs	5.88%	-2,380,122	1,732,912	1	57.14%	3.3 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

Recommendation :

NS Power recommends completing this project in order to maintain boiler reliability.

Notes/Comments :

Header Refurbishment vs Replacement Energy Costs

It is assumed as time passes, the frequency and probabilty of tube/header failure increases.

Test 2

Test 3

Test 4

LIN3 Economizer Header Refurbishment
Summary of Sensitivities

Division :	Power Production
Department :	Lingan

Date :	**19-Nov-17**
CI Number:	52253
Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Header Refurbishment vs Replacement Energy C	5.88%	-2,380,122	1,732,912	1	57.14%	3.3 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

	Alternative Variance on Capital Spend	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Header Refurbishment vs Replacement Energy C	10%	-2,334,627	1,697,456	1	52.28%	3.4 years
B	Test 2	10%	0	0	2	#NUM!	0.0 years
C	Test 3	10%	0	0	2	#NUM!	0.0 years
D	Test 4	10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		45,496	-35,456	0	-4.86%	0.2 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

	Alternative Variance on Avoided Expenses	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Header Refurbishment vs Replacement Energy C	-10%	-2,096,615	1,524,165	1	51.79%	3.5 years
B	Test 2	-10%	0	0	2	#NUM!	0.0 years
C	Test 3	-10%	0	0	2	#NUM!	0.0 years
D	Test 4	-10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		283,508	-208,747	0	-5.34%	0.2 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

Alternative Variance on Avoided Expenses - Change in Revenue Requirement		PV of Revenue Requirement	PV of Revenue Requirement	PV of Revenue Requirement	Delay?
	Yrs Delay:	1	2	3	
	A	97,544	184,441	406,147	No
	B	0	0	0	No
	C	0	0	0	No
	D	0	0	0	No

LIN3 Economizer Header Refurbishment
Avoided Cost Calculations

Division :	Power Production	**Date :**	**19-Nov-17**
Department :	Lingan	**CI Number:**	52253
		Project No. :	

Header Refurbishment vs Replacement Energy Costs

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			97,200	101,091		
Events/Outages (#)	1	1	1	1		
Probability of Occurance (%)	100%	100%	100%	100%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	154.0	154.0				
Duration (Hours or Years)	96	96				
Totals	$29,699	$29,351	$97,200	$101,091	$126,899	$130,441
Total Capital Cost of Alternative						$499,951

Test 2

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

Test 3

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

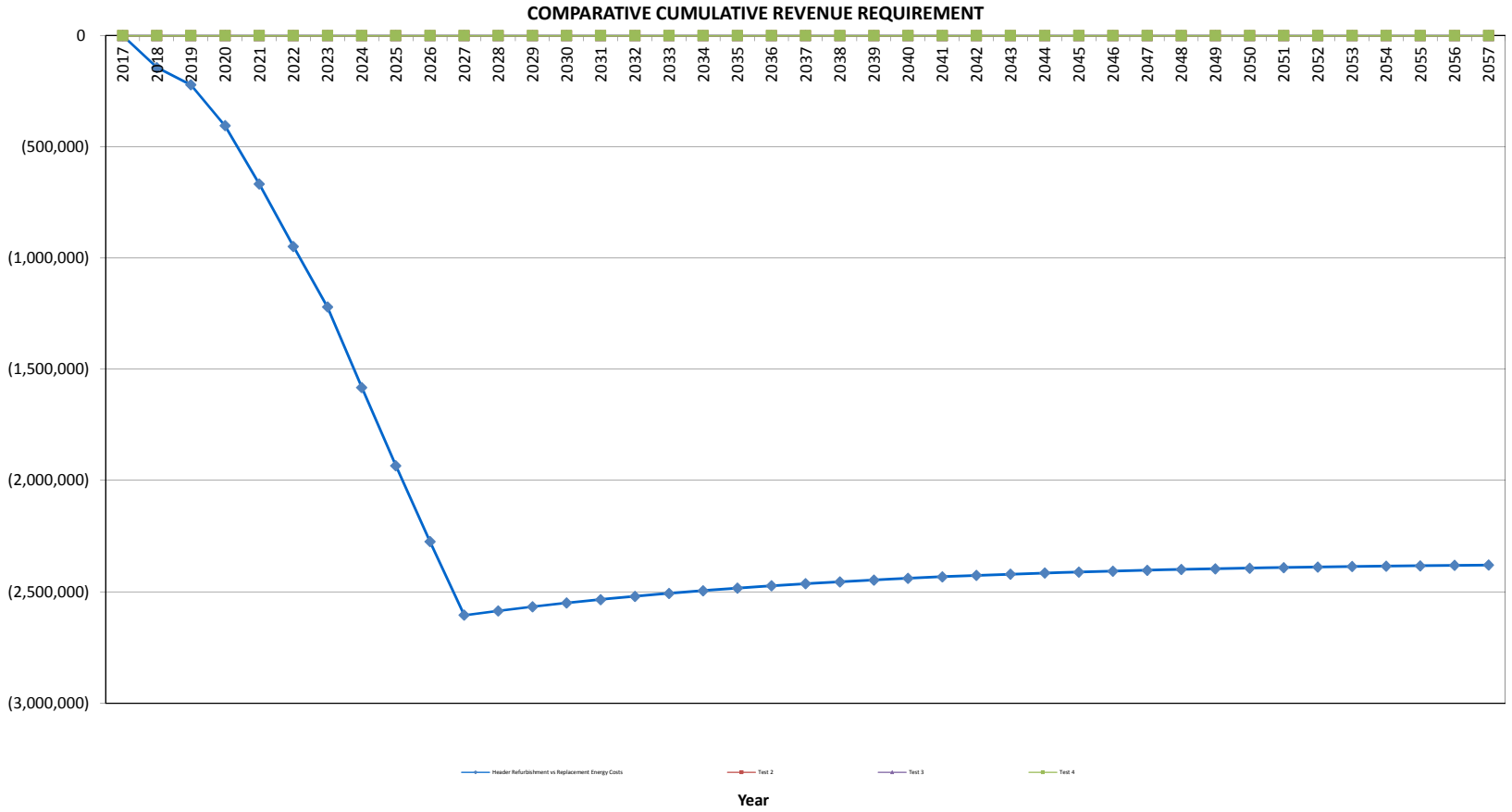
Test 4

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

LIN3 Economizer Header Refurbishment

Header Refurbishment vs Replacement Energy Costs

Year	Total Revenue	Operating Costs	Avoided Expenses	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	PV of CF	Discount Factor	CNPV
2017	-	-	-	-	-	-	-	-	-	-	1.00	-
2018	-	-	126,899.3	(459,611.6)	18,384.5	452,360.7	(332,712.3)	(33,639.6)	(366,351.9)	(346,006.7)	0.94	(346,006.7)
2019	-	-	130,441.4	-	35,298.2	415,203.7	130,441.4	(29,494.4)	100,947.0	90,046.2	0.89	(255,960.5)
2020	-	-	266,146.3	-	32,474.3	381,019.2	266,146.3	(72,438.3)	193,708.0	163,194.6	0.84	(92,765.9)
2021	-	-	385,761.8	-	29,876.4	349,569.6	385,761.8	(110,324.5)	275,437.3	219,162.9	0.80	126,397.0
2022	-	-	434,255.3	-	27,486.3	320,635.9	434,255.3	(126,098.4)	308,156.9	231,580.6	0.75	357,977.6
2023	-	-	449,773.9	-	25,287.4	294,016.9	449,773.9	(131,590.8)	318,183.1	225,836.2	0.71	583,813.8
2024	-	-	621,168.6	-	23,264.4	269,527.4	621,168.6	(185,350.3)	435,818.3	292,151.4	0.67	875,965.2
2025	-	-	643,447.4	-	21,403.2	246,997.1	643,447.4	(192,833.7)	450,613.7	285,294.2	0.63	1,161,259.4
2026	-	-	666,566.3	-	19,691.0	226,269.2	666,566.3	(200,531.3)	466,034.9	278,671.8	0.60	1,439,931.2
2027	-	-	690,557.8	-	18,115.7	207,199.5	690,557.8	(208,457.1)	482,100.8	272,269.2	0.56	1,712,200.4
2028	-	-	-	-	16,666.4	189,655.4	-	5,166.6	5,166.6	2,755.8	0.53	1,714,956.2
2029	-	-	-	-	15,333.1	173,514.8	-	4,753.3	4,753.3	2,394.6	0.50	1,717,350.8
2030	-	-	-	-	14,106.5	158,665.5	-	4,373.0	4,373.0	2,080.6	0.48	1,719,431.4
2031	-	-	-	-	12,978.0	145,004.1	-	4,023.2	4,023.2	1,807.9	0.45	1,721,239.3
2032	-	-	-	-	11,939.7	132,435.7	-	3,701.3	3,701.3	1,570.9	0.42	1,722,810.2
2033	-	-	-	-	10,984.5	120,872.7	-	3,405.2	3,405.2	1,365.0	0.40	1,724,175.1
2034	-	-	-	-	10,105.8	110,234.7	-	3,132.8	3,132.8	1,186.0	0.38	1,725,361.2
2035	-	-	-	-	9,297.3	100,447.8	-	2,882.2	2,882.2	1,030.5	0.36	1,726,391.7
2036	-	-	-	-	8,553.5	91,443.9	-	2,651.6	2,651.6	895.5	0.34	1,727,287.2
2037	-	-	-	-	7,869.2	83,160.2	-	2,439.5	2,439.5	778.1	0.32	1,728,065.2
2038	-	-	-	-	7,239.7	75,539.3	-	2,244.3	2,244.3	676.1	0.30	1,728,741.3
2039	-	-	-	-	6,660.5	68,528.0	-	2,064.8	2,064.8	587.4	0.28	1,729,328.7
2040	-	-	-	-	6,127.7	62,077.6	-	1,899.6	1,899.6	510.4	0.27	1,729,839.2
2041	-	-	-	-	5,637.5	56,143.3	-	1,747.6	1,747.6	443.5	0.25	1,730,282.7
2042	-	-	-	-	5,186.5	50,683.7	-	1,607.8	1,607.8	385.4	0.24	1,730,668.1
2043	-	-	-	-	4,771.6	45,660.8	-	1,479.2	1,479.2	334.9	0.23	1,731,002.9
2044	-	-	-	-	4,389.8	41,039.8	-	1,360.8	1,360.8	291.0	0.21	1,731,293.9
2045	-	-	-	-	4,038.6	36,788.5	-	1,252.0	1,252.0	252.8	0.20	1,731,546.7
2046	-	-	-	-	3,715.6	32,877.3	-	1,151.8	1,151.8	219.7	0.19	1,731,766.4
2047	-	-	-	-	3,418.3	29,279.0	-	1,059.7	1,059.7	190.9	0.18	1,731,957.3
2048	-	-	-	-	3,144.8	25,968.5	-	974.9	974.9	165.9	0.17	1,732,123.1
2049	-	-	-	-	2,893.3	22,922.9	-	896.9	896.9	144.1	0.16	1,732,267.2
2050	-	-	-	-	2,661.8	20,120.9	-	825.2	825.2	125.2	0.15	1,732,392.5
2051	-	-	-	-	2,448.9	17,543.1	-	759.1	759.1	108.8	0.14	1,732,501.3
2052	-	-	-	-	2,252.9	15,171.5	-	698.4	698.4	94.5	0.14	1,732,595.8
2053	-	-	-	-	2,072.7	12,989.7	-	642.5	642.5	82.1	0.13	1,732,677.9
2054	-	-	-	-	1,906.9	10,982.4	-	591.1	591.1	71.4	0.12	1,732,749.3
2055	-	-	-	-	1,754.3	9,135.7	-	543.8	543.8	62.0	0.11	1,732,811.3
2056	-	-	-	-	1,614.0	7,436.7	-	500.3	500.3	53.9	0.11	1,732,865.2
2057	-	-	-	-	1,484.9	5,873.6	-	460.3	460.3	46.8	0.10	1,732,912.1
Total	**-**	**-**	**4,415,018.1**	**(459,611.6)**	**442,535.5**		**3,955,406.5**	**(1,231,469.6)**	**2,723,936.9**	**1,732,912.1**		


COMPARATIVE CUMULATIVE REVENUE REQUIREMENT
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Header Refurbishment vs Replacement Energy Costs
Test 2
Test 3
Test 4
Year

CI Number: 51821

Title: TRE5 Air Heater Drive Assembly and Seal Refurbishment

Start Date: 2018/06
In-Service Date: 2018/07
Final Cost Date: 2019/01
Function: Steam
Forecast Amount: $487,376

DESCRIPTION:

This project includes the refurbishment of the air heater driver assembly components, such as gear drive assembly, pin rack and seals for Trenton Unit 5 air heaters.

The air heaters consist of two units that exchange heat between the exhaust flue gas and the incoming combustion air for the unit by means of continuously rotating heat transfer elements known as baskets. To efficiently operate an air heater of this design, the air heater assemblies are rotated with a drive system.

The drive system consists of a large gear that meshes with a pin rack. The replacement of the cold-end baskets in 2016 (CI 46352) during the annual outage noted mechanical defects in the gear drive and pin rack assembly. Further inspection of this assembly indicated that this gear and pin rack have worn through the hardened layer and are at risk of failure. Also, through inspection it was determined that the sealing angle on the hot end of the air heater has a worn groove, making sealing difficult. This results in air leakage and reduced performance from the air heater. Lastly, issues with the rotor structure were noted during the 2016 inspection that will be remediated as part of this project.

Summary of Related CIs +/- 2 years:
2016 CI 46352 - TRE 5Air Heater Refurbishment - $1,088,844

JUSTIFICATION:

Justification Criteria: Thermal

Sub Criteria: Equipment Replacement/Refurbishment

Why do this project?

The air heaters are part of the original design of the plant (1969). Their function is to recover heat transfer from outgoing flue gas to incoming combustion air. In 2016, the two drive assemblies for the air heaters were found to be deteriorated. These units are required to rotate the air heaters for heat transfer. Additionally, seals on the hot end of the air heater were worn. That will also be addressed under this capital item. The seals are important to prevent air leakages that reduce air heater performance.

Why do this project now?

Regular assessment by NS Power and the OEM indicated the condition of the components is such that replacement is required at this time to provide reliable performance of the unit. Risk profiling (compared to similar equipment in NS Power's fleet) provides guidance on the timing of refurbishment.

Why do this project this way?

Air heater drive refurbishment would be substantially less costly than replacement. As the air rotates during operation, this work must be completed during a unit outage. Typically, the duration of the work is greater than 2 weeks, depending on scope. It is not effective to have an issue advance to critical between outage intervals. Execution of the project as defined is the only alternative to risking an eventual failure of the air heater drives and to avoid a forced outage and replacement energy costs. Addressing the seals will remove leakage paths and improve air heater efficiency and performance.

CI Number : 51821 - TRE5 Air Heater Drive Assembly and Seal Refurbishment **Project Number** 51821

Parent CI Number : -

Asset Location : 1165 - 1165 Trenton Unit 5; Commissioned 1969, 160 Mwh **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	1700 - SGP - Draft Equip./Stacks	409,351
Retirements	1700 - SGP - Draft Equip./Stacks	78,025
	Total Cost:	487,376
	Original Cost:	62,464

Capital Project Detailed Estimate

Location: Trenton Generating Station
CI# : 51821
Title: TRE5 Air Heater Drive Assembly and Seal Refurbishment
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Mech (Welders)	PD	20	$ 364.79	$ 7,296		
Utility	PD	14	$ 240.18	$ 3,363		
Power Engineer	PD	30	$ 390.38	$ 11,711		
Electricians	PD	4	$ 358.28	$ 1,433		
			Sub-Total	$ 23,803		
OT Labour						
Mech (Millwrights)	PD	4	$ 729.58	$ 2,918		
Utility	PD	4	$ 780.76	$ 3,123		
			Sub-Total	$ 6,041		
Term Labour						
Mech (Millwrights)	PD	10	$ 364.79	$ 3,648		
Utility	PD	14	$ 240.18	$ 3,363		
			Sub-Total	$ 7,010		
Materials						
Pin Rack	lot	1	[redacted]		Cost Support 1	
Bull Gear	lot	1			Cost Support 1	
Misc Mechanical Materials	lot	1				
			Sub-Total	$ 60,340		
Contracts						
Installation labour	PD	200	$ 1,000	$ 200,000		CI 46352
Supervision	PD	1	$ 100,000	$ 100,000		
Project Manager	lot	1	$ 20,000	$ 20,000		
			Sub-Total	$ 320,000		
OT Meals						
Meals	lot	1	$ 500	$ 500		
			Sub-Total	$ 500		
Phones						
Mobile Phones	lot	1	$ 150	$ 150		
			Sub-Total	$ 150		
Rentals						
Trailer rentals	lot	1	$ 2,000	$ 2,000		
Misc equipment	lot	1	$ 10,000	$ 10,000		
			Sub-Total	$ 12,000		
Other Goods & Services						
Contingency	%	5%	$ 380,340	$ 19,017		
				$ -		
			Sub-Total	$ 19,017		
Administrative Overhead						
Labour AO				$ 7,433		
Contract AO				$ 31,082		
			Sub-Total	$ 38,514		
			SUB-TOTAL (no AO, AFUDC)	$ 448,862		
			TOTAL (AO, AFUDC included)	$ 487,376		
Original Cost				$ 62,464		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

TRE5 Air Heater Drive Assembly and Seal Refurbishment
Summary of Alternatives

Division :	Power Production	**Date :**	**19-Nov-17**
Department :	Trenton	**CI Number:**	51821
		Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank (based on PV of RR)	IRR	Disc Pay
A	Air Heater Refurbishment vs Replacement Energy & Repair Costs	5.88%	-2,693,655	1,969,106	1	89.50%	1.8 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

Recommendation :

Based on a favourable economic analysis, the air heater refurbishment is recommended

Notes/Comments :

Air Heater Refurbishment vs Replacement Energy & Repair Costs

This scenario measures the cost of refurbishments versus the replacement energy and repair costs associated with an unplanned outage due to air heater failure. This model assumes a 50% chance of occurrence within the first year, increasing in probability thereafter. This model also assumes that, on average, the unplanned outage would be a full unit outage (160MW) which would last 3 weeks (504 hours) in order to complete repairs so that the unit can return to service.

Test 2

Test 3

Test 4

TRE5 Air Heater Drive Assembly and Seal Refurbishment
Summary of Sensitivities

Division :	Power Production
Department :	Trenton
Date :	**15-Nov-17**
CI Number:	51821
Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Air Heater Refurbishment vs Replacement Energy	5.88%	-2,693,655	1,969,106	1	89.50%	1.8 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

	Alternative Variance on Capital Spend	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Air Heater Refurbishment vs Replacement Energy	10%	-2,648,113	1,934,480	1	78.26%	2.0 years
B	Test 2	10%	0	0	2	#NUM!	0.0 years
C	Test 3	10%	0	0	2	#NUM!	0.0 years
D	Test 4	10%	0	0	2	#NUM!	0.0 years
	Change: **A**		45,542	-34,626	0	-11.24%	0.2 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

	Alternative Variance on Avoided Expenses	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Air Heater Refurbishment vs Replacement Energy	-10%	-2,378,747	1,737,569	1	77.20%	2.1 years
B	Test 2	-10%	0	0	2	#NUM!	0.0 years
C	Test 3	-10%	0	0	2	#NUM!	0.0 years
D	Test 4	-10%	0	0	2	#NUM!	0.0 years
	Change: **A**		314,908	-231,537	0	-12.31%	0.2 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

Alternative Variance on Avoided Expenses - Change in Revenue Requirement		PV of Revenue Requirement	PV of Revenue Requirement	PV of Revenue Requirement	Delay?
	Yrs Delay:	1	2	3	
	A	217,302	426,460	715,353	No
	B	0	0	0	No
	C	0	0	0	No
	D	0	0	0	No

TRE5 Air Heater Drive Assembly and Seal Refurbishment
Avoided Cost Calculations

Division :	Power Production	**Date :**	**15-Nov-17**
Department :	Trenton	**CI Number:**	51821
		Project No. :	

Air Heater Refurbishment vs Replacement Energy & Repair Costs

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			426,000	434,520		
Events/Outages (#)	1	1	1	1		
Probability of Occurance (%)	50%	55%	50%	55%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	160.0	160.0				
Duration (Hours or Years)	504	504				
Totals	$42,015	$38,379	$213,000	$238,986	$255,015	$277,365
Total Capital Cost of Alternative						$487,376

Test 2

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

Test 3

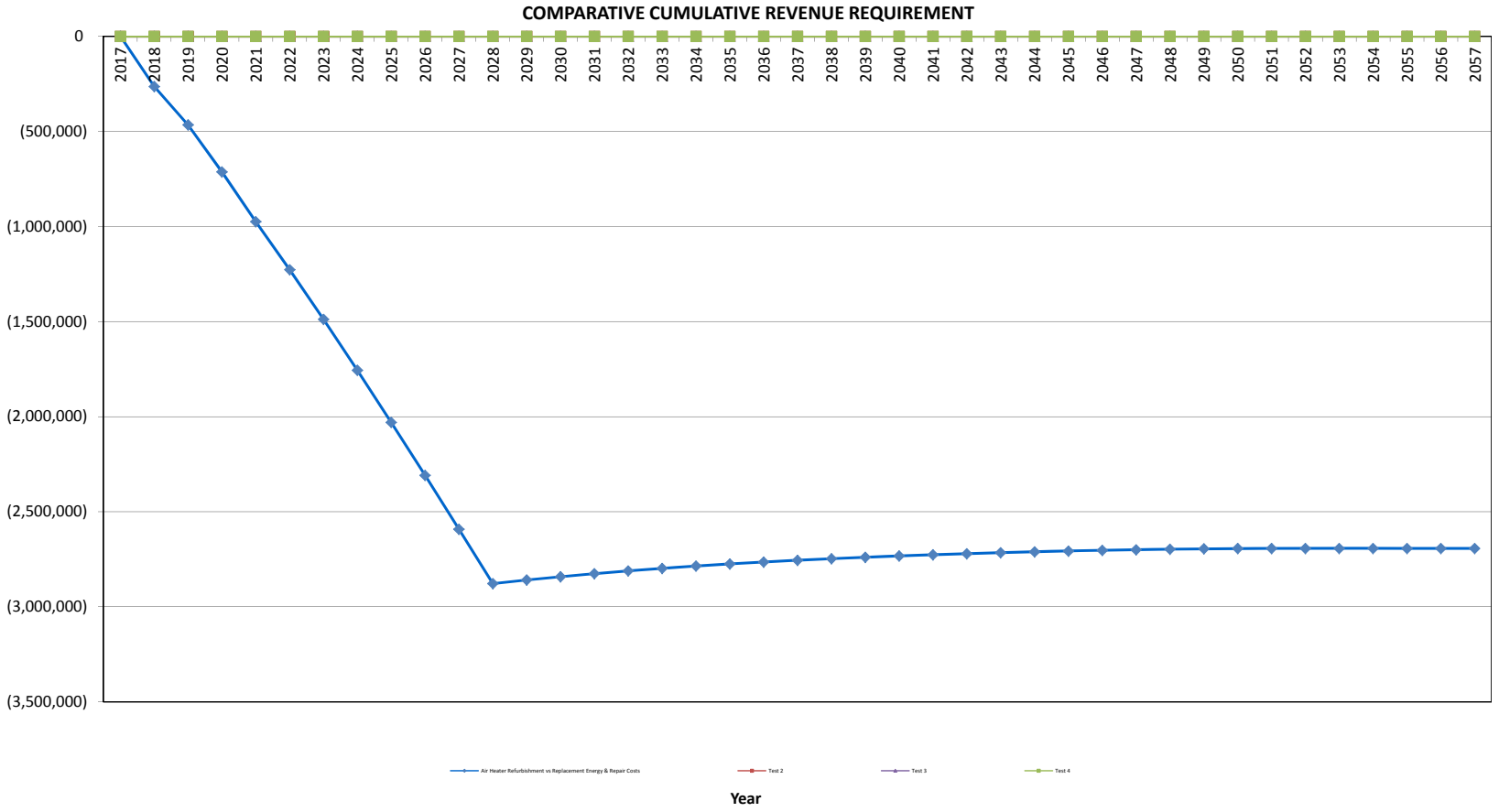
	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

Test 4

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

TRE5 Air Heater Drive Assembly and Seal Refurbishment
Air Heater Refurbishment vs Replacement Energy & Repair Costs

Year	Total Revenue	Operating Costs	Avoided Expenses	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	PV of CF	Discount Factor	CNPV
2017	-	-	-	-	-	-	-	-	-	-	1.00	-
2018	-	-	255,014.9	(448,861.6)	17,954.5	441,537.1	(193,846.7)	(73,488.7)	(267,335.5)	(252,489.1)	0.94	(252,489.1)
2019	-	-	277,365.2	-	34,472.6	405,289.8	277,365.2	(75,296.7)	202,068.5	180,248.1	0.89	(72,241.0)
2020	-	-	347,590.8	-	31,714.8	371,942.3	347,590.8	(97,921.6)	249,669.2	210,340.7	0.84	138,099.7
2021	-	-	389,422.6	-	29,177.6	341,262.5	389,422.6	(111,675.9)	277,746.6	221,000.4	0.80	359,100.1
2022	-	-	398,942.0	-	26,843.4	313,037.2	398,942.0	(115,350.6)	283,591.4	213,119.6	0.75	572,219.7
2023	-	-	435,986.6	-	24,695.9	287,069.9	435,986.6	(127,500.1)	308,486.5	218,953.8	0.71	791,173.5
2024	-	-	474,353.4	-	22,720.2	263,179.9	474,353.4	(140,006.3)	334,347.2	224,130.1	0.67	1,015,303.6
2025	-	-	514,080.5	-	20,902.6	241,201.2	514,080.5	(152,885.2)	361,195.4	228,681.3	0.63	1,243,984.9
2026	-	-	555,207.0	-	19,230.4	220,980.8	555,207.0	(166,152.7)	389,054.3	232,640.2	0.60	1,476,625.1
2027	-	-	597,772.9	-	17,692.0	202,378.0	597,772.9	(179,825.1)	417,947.8	236,038.4	0.56	1,712,663.6
2028	-	-	641,819.3	-	16,276.6	185,263.4	641,819.3	(193,918.2)	447,901.1	238,907.0	0.53	1,951,570.5
2029	-	-	-	-	14,974.5	169,518.0	-	4,642.1	4,642.1	2,338.5	0.50	1,953,909.1
2030	-	-	-	-	13,776.5	155,032.2	-	4,270.7	4,270.7	2,032.0	0.48	1,955,941.1
2031	-	-	-	-	12,674.4	141,705.3	-	3,929.1	3,929.1	1,765.6	0.45	1,957,706.7
2032	-	-	-	-	11,660.5	129,444.5	-	3,614.7	3,614.7	1,534.2	0.42	1,959,240.8
2033	-	-	-	-	10,727.6	118,164.6	-	3,325.6	3,325.6	1,333.0	0.40	1,960,573.9
2034	-	-	-	-	9,869.4	107,787.1	-	3,059.5	3,059.5	1,158.3	0.38	1,961,732.2
2035	-	-	-	-	9,079.9	98,239.8	-	2,814.8	2,814.8	1,006.4	0.36	1,962,738.6
2036	-	-	-	-	8,353.5	89,456.3	-	2,589.6	2,589.6	874.5	0.34	1,963,613.1
2037	-	-	-	-	7,685.2	81,375.4	-	2,382.4	2,382.4	759.9	0.32	1,964,373.0
2038	-	-	-	-	7,070.4	73,941.0	-	2,191.8	2,191.8	660.3	0.30	1,965,033.2
2039	-	-	-	-	6,504.7	67,101.4	-	2,016.5	2,016.5	573.7	0.28	1,965,606.9
2040	-	-	-	-	5,984.4	60,809.0	-	1,855.2	1,855.2	498.5	0.27	1,966,105.4
2041	-	-	-	-	5,505.6	55,019.9	-	1,706.7	1,706.7	433.1	0.25	1,966,538.6
2042	-	-	-	-	5,065.2	49,694.0	-	1,570.2	1,570.2	376.4	0.24	1,966,914.9
2043	-	-	-	-	4,660.0	44,794.1	-	1,444.6	1,444.6	327.0	0.23	1,967,242.0
2044	-	-	-	-	4,287.2	40,286.2	-	1,329.0	1,329.0	284.2	0.21	1,967,526.1
2045	-	-	-	-	3,944.2	36,139.0	-	1,222.7	1,222.7	246.9	0.20	1,967,773.0
2046	-	-	-	-	3,628.6	32,323.5	-	1,124.9	1,124.9	214.5	0.19	1,967,987.6
2047	-	-	-	-	3,338.4	28,813.3	-	1,034.9	1,034.9	186.4	0.18	1,968,174.0
2048	-	-	-	-	3,071.3	25,583.9	-	952.1	952.1	162.0	0.17	1,968,335.9
2049	-	-	-	-	2,825.6	22,612.9	-	875.9	875.9	140.7	0.16	1,968,476.7
2050	-	-	-	-	2,599.5	19,879.5	-	805.9	805.9	122.3	0.15	1,968,599.0
2051	-	-	-	-	2,391.6	17,364.8	-	741.4	741.4	106.3	0.14	1,968,705.2
2052	-	-	-	-	2,200.2	15,051.3	-	682.1	682.1	92.3	0.14	1,968,797.6
2053	-	-	-	-	2,024.2	12,922.8	-	627.5	627.5	80.2	0.13	1,968,877.8
2054	-	-	-	-	1,862.3	10,964.6	-	577.3	577.3	69.7	0.12	1,968,947.5
2055	-	-	-	-	1,713.3	9,163.1	-	531.1	531.1	60.6	0.11	1,969,008.1
2056	-	-	-	-	1,576.2	7,505.7	-	488.6	488.6	52.6	0.11	1,969,060.7
2057	-	-	-	-	1,450.1	5,980.9	-	449.5	449.5	45.7	0.10	1,969,106.4
Total	**-**	**-**	**4,887,555.2**	**(448,861.6)**	**432,185.0**		**4,438,693.6**	**(1,381,164.8)**	**3,057,528.8**	**1,969,106.4**		


COMPARATIVE CUMULATIVE REVENUE REQUIREMENT
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Air Heater Refurbishment vs Replacement Energy & Repair Costs
Test 2
Test 3
Test 4
Year

Quotation (Aftermarket)

ISO 9001:2008 Certified

Attention:	Mr. Darryl Myette	From:	Phillip Edgerton
Company/Representative:	Trenton Thermal Generating Station	Phone:	919-324-2388
Plant/Site:	Trenton Thermal Generating Station	Email:	phillip.edgerton@howden.com
Your Reference:			
Our Reference:	Secondary APHs (782 / 1101)	Fax:	866-810-9419
Market:	Power	Quote #:	HNAGAT.AFM.001233/A
General Assembly Drawing:		Date:	1/3/2017

Howden North America presents our offer as follows:

Item	Part Number	Description	Qty	Price Each	Lead Time to Ship
1	24VIR Pin Rack	Pin Rack Assembly	1	[redacted]	[redacted]
2	D-1-01626 - 14	36T Pinion with Taperlock Bushing	1	[redacted]	[redacted]

Prices are in CAD

Freight:	EXW (Origin) Incoterms 2010. No Freight Allowed.

This quote is subject only to Howden North America's Standard Terms and Conditions of Sale, (available at www.howden.com). Unless otherwise negotiated and agreed to by HNA in writing, no other terms shall apply regardless of any statement on Buyer's documents to the contrary.

Howden North America does not accept Liquidated Damages or in place warranty as standard business practice.

*If quoted lead time does not meet your requirements, please advise.

For Prepay and Charge orders, there will be a 4% charge of the net selling price applied to Buyer's invoice as a separate item to cover the standard transportation and handling expenses to the first North American destination. This does not apply to overseas or expedited shipments. In addition, any expense incurred by Seller because of special delivery arrangements requested by Buyer shall be billed to Buyer. Howden does not provide copies of freight invoices.

Pricing does not include Federal, State, Local, or Export taxes or duties.

Payment Terms are Net Thirty (30) days from invoice date, which is based on the freight terms quoted above.

Quote expires 30 days from noted and is subject to customer credit approval.

Minimum order value is $350.00.

Non inventory parts are not returnable; returned inventory parts are subject to restocking charges.

Quoted lead time is based upon material availability and factory loading at time of quotation, and may be subject to adjustment at order placement/acknowledgement.

If you have any questions, please contact us.

Sincerely,

Phillip Edgerton

CI Number: 51824

Title: LIN3 ID Fan Damper and VIV Refurbishment

Start Date: 2018/03
In-Service Date: 2018/04
Final Cost Date: 2018/10
Function: Steam
Forecast Amount: $443,311

DESCRIPTION:

This project covers the refurbishment of the Lingan Unit 3 Induced Draft (ID) fan damper and variable inlet vanes (VIVs). This includes the replacement of the bearings, bushings and seals to allow for controlled movement of the damper and vanes.

The ID fans are part of the boiler combustion control process. The flue gas flow from the boiler is controlled by the ID fan dampers and VIVs. The ID Fan, VIVs and dampers are required to be in working order to allow the fan to adjust to changing unit load. If the VIVs are unable to operate, a unit trip is likely. If the VIVs seize and the unit does not trip, load will be limited and heat rate will be negatively impacted. In addition, sticking VIVs can increase exhaust gas opacity which must be controlled as part of the Lingan Operating Permit. If the VIVs are not in working order, Supervisory Control and Data Acquisition (SCADA) control of the unit is limited, affecting its ability to change output to serve variable customer demand and balance wind generation.

Summary of Related CI's +/- 2 years:
No other projects in 2016, 2017, 2018, 2019 or 2020

JUSTIFICATION:

Justification Criteria: Thermal

Sub Criteria: Equipment Replacement / Refurbishment

Why do this project?

The ID fan, VIVs and dampers are required to be in good working order and able to be automatically adjusted as the needs of the boiler change. Currently the bearings, bushings and seals require replacement to allow for controlled movement. This project will prevent related outages and deratings.

This project is primarily justified on unit reliability, but secondarily justified on environmental factors and economics.

Why do this project now?

This project needs to be completed in 2018 due to the deteriorated condition of the ID fan VIVs and dampers. The ID fan is a critical piece of equipment to the operation of the boiler; the unit outage in 2018 will allow the work to be completed in a planned manner. As the demands on the boiler change and it is required to change load more frequently to meet system conditions, the ID fans must be in good working order to successfully accommodate the need for flexible unit operation.

Why do this project this way?

Due to the deteriorated condition, replacement of the moving components (bearings, bushings and seals) is the only option to allow the dampers and VIVs to operate correctly.

CI Number : 51824 - LIN3 ID FAN Damper and VIV Refurbishment

Project Number 51824

Parent CI Number : -

Asset Location : 1133 - 1133 Lingan Unit 3; Commissioned 1983, 164Mwh

Budget Version 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	1700 - SGP - Draft Equip./Stacks	425,015
Retirements	1700 - SGP - Draft Equip./Stacks	18,295
	Total Cost:	443,311
	Original Cost:	167,433

Capital Project Detailed Estimate

Location: Lingan Generating Station
CI# : 51824
Title: LIN3 ID Fan Damper and VIV Refurbishment
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Engineering	PD	2	$ 397	$ 795		
Maintenance Trades	PD	80	$ 358	$ 28,611		
Power Plant Technician	PD	30	$ 375	$ 11,238		
Utility worker	PD	19	$ 235	$ 4,356		
			Sub-Total	$ 45,000		48438
OT Labour						
Maintenance Trades	PD	56	$ 715	$ 40,000		
			Sub-Total	$ 40,000		48438
Term Labour						
Maintenance Trades	PD	224	$ 358	$ 80,000		
			Sub-Total	$ 80,000		48438
Materials						
Damper and VIV Bushing, Bearings and Seals	Lot	1	$ 180,000	$ 180,000		
Damper positioners	Lot	1	$ 40,000	$ 40,000		
Misc. Consumables	Lot	1	$ 10,000	$ 10,000		
			Sub-Total	$ 230,000		48438
Contracts						
Fan Casing Repair	Lot	1	$ 5,000	$ 5,000		
Industrial Cleaning	Lot	1	$ 7,000	$ 7,000		
Trucking Transportation	Lot	1	$ 3,000	$ 3,000		
			Sub-Total	$ 15,000		48438
Administrative Overhead						
Labour AO				$ 31,854		
Contract AO				$ 1,457		
			Sub-Total	$ 33,311		
			SUB-TOTAL (no AO, AFUDC)	$ 410,000		
			TOTAL (AO, AFUDC included)	$ 443,311		
Original Cost				$ 167,433		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

LIN3 ID Fan Damper and VIV Refurbishment
Summary of Alternatives

Division :	Power Production	**Date :**	**18-Nov-17**
Department :	Lingan	**CI Number:**	51824
		Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank (based on PV of RR)	IRR	Disc Pay
A	Fan Damper and VIV Refurb vs Replacement Energy Costs	5.88%	-665,162	473,347	1	24.20%	5.7 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

Recommendation :

NS Power recommends completing this project to ensure opacity remains under control, the boiler can be controlled by SCADA to meet changing power demands, and the plant is able to avoid unit trips and reduced heat rate performance on Unit 3.

Notes/Comments :

Fan Damper and VIV Refurb vs Replacement Energy Costs

The ID Fan, VIVs and Dampers are required to be in working order to allow the fan to adjust to changing load demands. If the VIVs are unable to operate, a unit trip is likely. If the VIVs stick and the unit does not trip, load will be limited and heat rate will be negatively impacted. In addition, sticking VIVs can increase opacity, which must be controlled as part of the Lingan Operating Permit. If the VIVs are not in working order, the amount of SCADA control is limited, affecting Lingan's ability to change output to meet power demands.

Test 2

Test 3

Test 4

LIN3 ID Fan Damper and VIV Refurbishment
Summary of Sensitivities

Nova Scotia POWER An Emera Company

Division :	Power Production
Department :	Lingan

Date :	**14-Nov-17**
CI Number:	51824
Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Fan Damper and VIV Refurb vs Replacement Ene	5.88%	-665,162	473,347	1	24.20%	5.7 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

	Alternative Variance on Capital Spend	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Fan Damper and VIV Refurb vs Replacement Ene	10%	-624,580	441,719	1	21.80%	6.0 years
B	Test 2	10%	0	0	2	#NUM!	0.0 years
C	Test 3	10%	0	0	2	#NUM!	0.0 years
D	Test 4	10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		40,582	-31,629	0	-2.40%	0.3 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

	Alternative Variance on Avoided Expenses	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Fan Damper and VIV Refurb vs Replacement Ene	-10%	-558,064	394,384	1	21.55%	6.0 years
B	Test 2	-10%	0	0	2	#NUM!	0.0 years
C	Test 3	-10%	0	0	2	#NUM!	0.0 years
D	Test 4	-10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		107,098	-78,963	0	-2.64%	0.4 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

Alternative Variance on Avoided Expenses - Change in Revenue Requirement		PV of Revenue Requirement	PV of Revenue Requirement	PV of Revenue Requirement	Delay?
	Yrs Delay:	1	2	3	
	A	12,267	52,675	122,604	No
	B	0	0	0	No
	C	0	0	0	No
	D	0	0	0	No

LIN3 ID Fan Damper and VIV Refurbishment
Avoided Cost Calculations

Division :	Power Production	**Date :**	**14-Nov-17**
Department :	Lingan	**CI Number:**	51824
		Project No. :	

Fan Damper and VIV Refurb vs Replacement Energy Costs

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			8,500	8,842		
Events/Outages (#)	1	2	1	2		
Probability of Occurance (%)	100%	100%	100%	100%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	154.0	154.0				
Duration (Hours or Years)	80	80				
Totals	$24,749	$48,918	$8,500	$17,685	$33,249	$66,602
Total Capital Cost of Alternative						$443,311

Test 2

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

Test 3

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

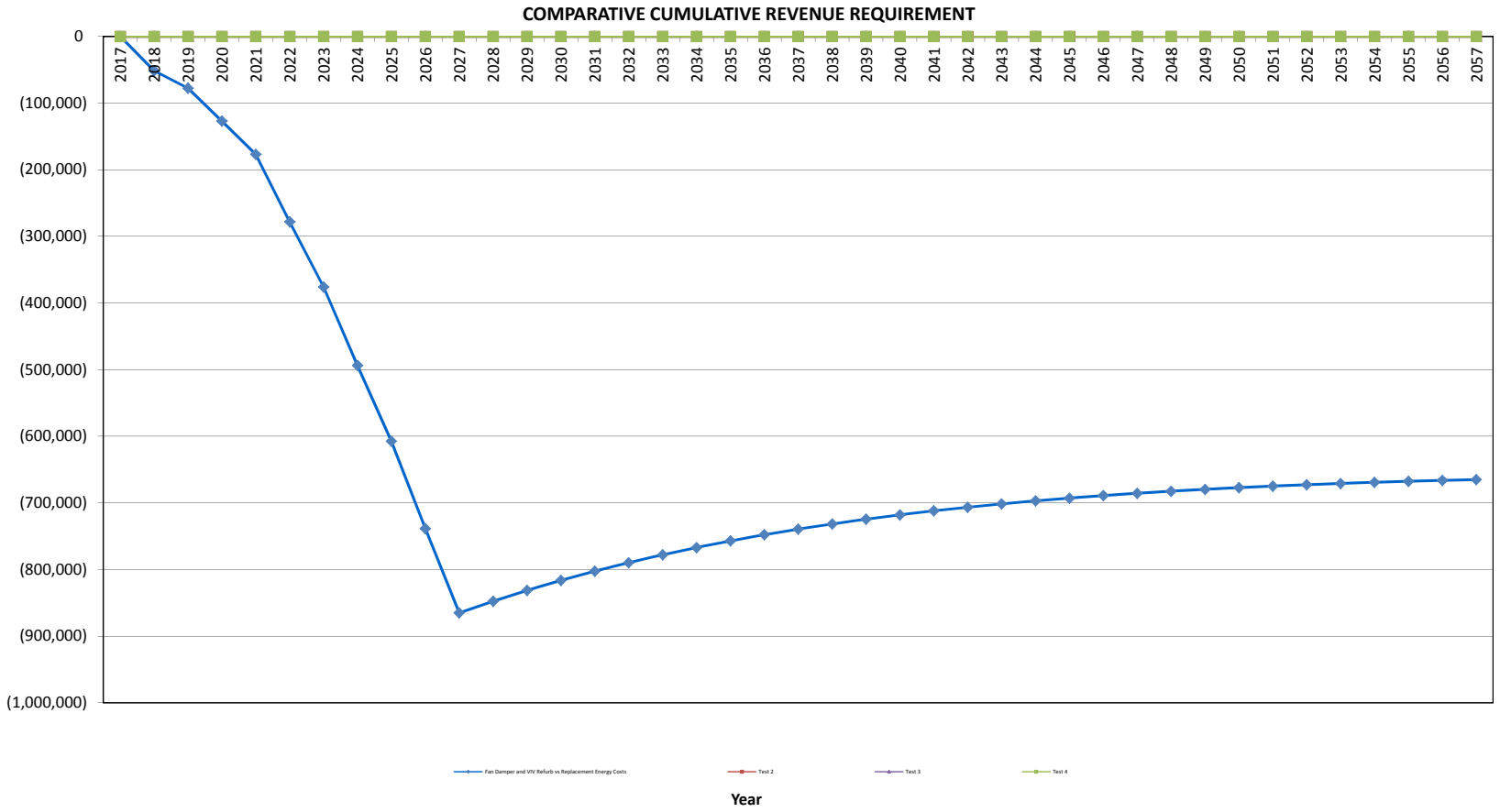
Test 4

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

LIN3 ID Fan Damper and VIV Refurbishment

Fan Damper and VIV Refurb vs Replacement Energy Costs

Year	Total Revenue	Operating Costs	Avoided Expenses	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	PV of CF	Discount Factor	CNPV
2017	-	-	-	-	-	-	-	-	-	-	1.00	-
2018	-	-	33,249.4	(410,000.0)	16,400.0	402,793.7	(376,750.6)	(5,223.3)	(381,973.9)	(360,761.2)	0.94	(360,761.2)
2019	-	-	66,602.3	-	31,488.0	369,770.8	66,602.3	(10,885.4)	55,716.9	49,700.3	0.89	(311,060.9)
2020	-	-	97,434.9	-	28,969.0	339,389.6	97,434.9	(21,224.4)	76,210.4	64,205.6	0.84	(246,855.3)
2021	-	-	102,413.7	-	26,651.4	311,439.0	102,413.7	(23,486.3)	78,927.4	62,801.8	0.80	(184,053.5)
2022	-	-	179,058.6	-	24,519.3	285,724.4	179,058.6	(47,907.2)	131,151.4	98,560.6	0.75	(85,492.9)
2023	-	-	183,649.3	-	22,557.8	262,067.0	183,649.3	(49,938.4)	133,710.9	94,903.7	0.71	9,410.8
2024	-	-	226,047.0	-	20,753.2	240,302.2	226,047.0	(63,641.1)	162,405.9	108,869.0	0.67	118,279.8
2025	-	-	231,878.9	-	19,092.9	220,278.6	231,878.9	(65,963.7)	165,915.3	105,044.9	0.63	223,324.7
2026	-	-	277,527.0	-	17,565.5	201,856.9	277,527.0	(80,588.1)	196,938.9	117,762.3	0.60	341,087.0
2027	-	-	284,732.8	-	16,160.2	184,908.9	284,732.8	(83,257.5)	201,475.3	113,784.3	0.56	454,871.3
2028	-	-	-	-	14,867.4	169,316.7	-	4,608.9	4,608.9	2,458.4	0.53	457,329.6
2029	-	-	-	-	13,678.0	154,971.9	-	4,240.2	4,240.2	2,136.1	0.50	459,465.7
2030	-	-	-	-	12,583.8	141,774.7	-	3,901.0	3,901.0	1,856.1	0.48	461,321.8
2031	-	-	-	-	11,577.1	129,633.3	-	3,588.9	3,588.9	1,612.7	0.45	462,934.5
2032	-	-	-	-	10,650.9	118,463.2	-	3,301.8	3,301.8	1,401.3	0.42	464,335.9
2033	-	-	-	-	9,798.8	108,186.6	-	3,037.6	3,037.6	1,217.6	0.40	465,553.5
2034	-	-	-	-	9,014.9	98,732.3	-	2,794.6	2,794.6	1,058.0	0.38	466,611.5
2035	-	-	-	-	8,293.7	90,034.2	-	2,571.1	2,571.1	919.3	0.36	467,530.8
2036	-	-	-	-	7,630.2	82,032.0	-	2,365.4	2,365.4	798.8	0.34	468,329.6
2037	-	-	-	-	7,019.8	74,670.0	-	2,176.1	2,176.1	694.1	0.32	469,023.7
2038	-	-	-	-	6,458.2	67,897.0	-	2,002.1	2,002.1	603.1	0.30	469,626.8
2039	-	-	-	-	5,941.6	61,665.8	-	1,841.9	1,841.9	524.0	0.28	470,150.8
2040	-	-	-	-	5,466.2	55,933.0	-	1,694.5	1,694.5	455.3	0.27	470,606.1
2041	-	-	-	-	5,028.9	50,658.9	-	1,559.0	1,559.0	395.6	0.25	471,001.8
2042	-	-	-	-	4,626.6	45,806.8	-	1,434.3	1,434.3	343.8	0.24	471,345.6
2043	-	-	-	-	4,256.5	41,342.8	-	1,319.5	1,319.5	298.7	0.23	471,644.3
2044	-	-	-	-	3,916.0	37,235.9	-	1,214.0	1,214.0	259.6	0.21	471,903.8
2045	-	-	-	-	3,602.7	33,457.6	-	1,116.8	1,116.8	225.5	0.20	472,129.3
2046	-	-	-	-	3,314.5	29,981.5	-	1,027.5	1,027.5	196.0	0.19	472,325.3
2047	-	-	-	-	3,049.3	26,783.5	-	945.3	945.3	170.3	0.18	472,495.6
2048	-	-	-	-	2,805.4	23,841.4	-	869.7	869.7	148.0	0.17	472,643.5
2049	-	-	-	-	2,581.0	21,134.6	-	800.1	800.1	128.6	0.16	472,772.1
2050	-	-	-	-	2,374.5	18,644.4	-	736.1	736.1	111.7	0.15	472,883.8
2051	-	-	-	-	2,184.5	16,353.4	-	677.2	677.2	97.1	0.14	472,980.9
2052	-	-	-	-	2,009.8	14,245.7	-	623.0	623.0	84.3	0.14	473,065.2
2053	-	-	-	-	1,849.0	12,306.6	-	573.2	573.2	73.3	0.13	473,138.5
2054	-	-	-	-	1,701.1	10,522.6	-	527.3	527.3	63.7	0.12	473,202.1
2055	-	-	-	-	1,565.0	8,881.3	-	485.1	485.1	55.3	0.11	473,257.5
2056	-	-	-	-	1,439.8	7,371.4	-	446.3	446.3	48.1	0.11	473,305.5
2057	-	-	-	-	1,324.6	5,982.2	-	410.6	410.6	41.8	0.10	473,347.3
Total	**-**	**-**	**1,682,593.8**	**(410,000.0)**	**394,767.2**		**1,272,593.8**	**(399,226.3)**	**873,367.6**	**473,347.3**		


COMPARATIVE CUMULATIVE REVENUE REQUIREMENT
0
(100,000)
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Fan Damper and VAV Refurb vs Replacement Energy Costs
Test 2
Test 3
Test 4
Year

CI Number: 51818

Title: PHB Boiler Refurbishment 2018

Start Date:	2018/08
In-Service Date:	2018/09
Final Cost Date:	2019/03
Function:	Steam
Forecast Amount:	$440,315

DESCRIPTION:

Refurbishment of sections of the Port Hawkesbury Biomass (PHB) boiler is required to maintain reliable operation of the co-generation unit. Due to the volume of biomass fuel that passes through the boiler, it has many erosion susceptible areas including conveyors, feed screws and reciprocating grates. This project falls within the projected sustaining capital investment for the biomass plant. Similar to the boilers on coal-fired units, the biomass boiler will require refurbishment and select component replacements over its life in response to continuous exposure to elevated temperatures, temperature cycling, erosion and corrosion.

Specifically, replacements will be made on the boiler's fuel insertion screw conveyors, boiler reciprocating grate, and pressure parts. On the electrostatic precipitator, the collecting system alignment will be improved and casing repairs undertaken to reduce air ingress.

Summary of Related CIs +/- 2 years:
2016 CI 47613 PHB - Boiler Refurbishment 2016 $572,360
2017 CI 49499 PHB - Boiler Refurbishment 2017 $593,740
2019 CI TBD PHB Boiler Refurbishment 2019 $TBD
2020 CI TBD PHB Boiler Refurbishment 2020 $TBD

JUSTIFICATION:

Justification Criteria: Thermal

Sub Criteria: Equipment Replacement/Refurbishment

Why do this project?

Legislation:

NS Power is required to maintain PHB unit as a base load cogeneration facility, and operate the plant on an economic dispatch basis or as required for system reliability. PHB capital projects and routines are designed to maintain PHB unit in that capacity. Section 5(2A) of the Renewable Electricity Regulation provide as follows:

> 5(2A) NSPI must maintain the Port Hawkesbury biomass power generation plant available as a base load cogeneration facility and NSPI must operate the plant on an economic dispatch basis or as required for system reliability."

Renewable Energy Standards:

The PHB generation station was designed to meet requirements under the Renewable Energy Standards, providing ready and reliable renewable energy, while contributing to system stability. The Port Hawkesbury Biomass Cogeneration facility is the only NS Power-owned renewable resource whose output can be increased to meet RES obligations in the event of a low wind/hydro output year. Continued investment in the biomass facility diversifies NS Power's energy portfolio in renewables, and will contribute to RES requirements of 40% of NS Power's electric sales being from renewable energy sources in 2020.

Contractual Obligations:

The PHB arrangement was designed and approved as a cogeneration operation. The boiler's steam output is for the purpose of producing renewable electrical energy and supplying Port Hawkesbury Paper's (PHP) mill steam requirements.

As a cogeneration facility, the biomass unit is highly integrated into the operation of the paper mill. NS Power and PHP entered into a Shared Services and Steam Supply Agreement dated September 28, 2012 (the Agreement). Within the Agreement, NS Power agreed to provide steam and related services to PHP over the term of the contract.

Asset Condition:

Ongoing asset management activities identified the requirement for boiler component replacement to maintain the near term and long term reliability of the boiler, and mitigate the risk of unplanned outages due to tube leaks. Due to the biomass that passes through the boiler, it has many areas susceptible to erosion including conveyors, feed screws and reciprocating grates.

Why do this project now?

Some of the boiler tubes and other equipment to be inspected and replaced are difficult to access. This project is required to be completed during an outage of sufficient duration to complete the necessary work. The planned outage for the biomass boiler in 2018 will be of sufficient duration to complete the work.

Why do this project this way?

Completing this work in this manner is the only feasible way to allow for reliable and efficient operation of the boiler. Refurbishing the boiler through component replacement is a more cost effective alternative than full boiler replacement.

CI Number : 51818 - PHB Boiler Refurbishment 2018 **Project Number** 51818

Parent CI Number : -

Asset Location : 1401 - 1401 Port Hawkesbury Biomass **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	1300 - SGP - Boiler	364,498
Retirements	1300 - SGP - Boiler	75,817
	Total Cost:	440,315
	Original Cost:	288,814

Capital Project Detailed Estimate

Location: Port Hawkesbury Biomass
CI# : 51818
Title: PHB Boiler Refurbishment 2018
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Utility worker	PD	40	$ 240	$ 9,607		
			Sub-Total	$ 9,607		
OT Labour						
Utility worker	PD	10	$ 480	$ 4,804		
			Sub-Total	$ 4,804		
Term Labour						
Utility worker	PD	10	$ 240	$ 2,402		
			Sub-Total	$ 2,402		
Materials						
Grates, stationary	ea	100	$ 678	$ 67,800		
Grates, reciprocating	ea	100	$ 872	$ 87,200		
Grates parts - beams, sliders, wear plates, etc.	lot	1	$ 10,000	$ 10,000		
Structural steel, steel plate, etc.	lot	1	$ 7,000	$ 7,000		
Precipitator rotary valves	ea	4	$ 17,000	$ 68,000		
Valve actuator	ea	1	$ 10,000	$ 10,000		
			Sub-Total	$ 250,000		
Contracts						
Boiler refurbishment services provider	lot	1	$ 115,000	$ 115,000		
Non-destructive testing	lot	1	$ 5,000	$ 5,000		
			Sub-Total	$ 120,000		
Other Goods & Services						
Contingency	%	10%	$ 386,812	$ 38,681		
			Sub-Total	$ 38,681		
Administrative Overhead						
Labour AO				$ 3,166		
Contract AO				$ 11,656		
			Sub-Total	$ 14,821		
			SUB-TOTAL (no AO, AFUDC)	$ 425,494		
			TOTAL (AO, AFUDC included)	$ 440,315		
Original Cost				$ 462,436		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 51807

Title: TUC2 Boiler Lower Vestibule Refurbishment

Start Date: 2018/03
In-Service Date: 2018/06
Final Cost Date: 2018/12
Function: Steam
Forecast Amount: $412,872

DESCRIPTION:

This project will remove and replace four sloped floor tubes which allow access to filler blocks in the Tufts Cove Unit 2 boiler.

The furnace floor and the side walls of the Tufts Cove Unit 2 boiler are composed of membrane tube surfaces. The intersection of the floor and wall is sealed using filler blocks in order to make the furnace flue gas tight.

Summary of Related CIs +/- 2 years:
2017 CI 49674 - TUC2 Boiler Waterwall Tube Replacement - $421,518

JUSTIFICATION:

Justification Criteria: Thermal

Sub Criteria: Equipment Replacement / Refurbishment

Why do this project?

During the 2017 annual inspection of the Tufts Cove Unit 2 boiler furnace, it was noted that the majority of filler blocks at the described seal locations have corroded, which compromises the integrity of the gas seal along the length of the intersecting tube surfaces. Failure of this seal would allow flue gases to enter the header vestibule below the furnace with potential resultant corrosion damage to headers and tubing located in this vestibule, as well as potential release of flue gas leakage into the operating area of the Tufts Cove Unit 2 boilerhouse. In addition to flue gas leakage, the compromised filler blocks create a pocket for oil ash to accumulate and, with moisture addition, develop a corrosion cell resulting in damage to the associated tube surfaces. Selected damaged filler blocks were removed during the 2017 outage and the pocket cleaned out for inspection. Significant corrosion damage was found at these locations, highlighting a need for this project.

This project is required to maintain reliability of the Tufts Cove Unit 2 boiler, and mitigate the risk to operations personnel.

Why do this project now?

This project is required in 2018 to maintain the reliability of the Tufts Cove Unit 2 boiler. Investigated areas of the subject seal in 2017 found corrosion damage and wall loss to the underlying tube surfaces.

Why do this project this way?

Removal and replacement of the floor tubes is the only feasible solution in order to mitigate the risks associated with the lower vestibule. The tubes and membranes have deteriorated to the point where they cannot be refurbished by weld overlay and require new material in order to ensure the integrity of the seals.

CI Number : 51807 - TUC2 Boiler Lower Vestibule Refurbishment **Project Number** 51807

Parent CI Number : -

Asset Location : 1172 - 1172 Tufts Cove Unit 2; Commissioned 1972, 97 Mwh **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	1300 - SGP - Boiler	350,698
Retirements	1300 - SGP - Boiler	62,175
	Total Cost:	412,872
	Original Cost:	55,546

Capital Project Detailed Estimate

Location: Steam
CI# : 51807
Title: TUC2 Boiler Lower Vestibule Refurbishment
Execution Year: 2017

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Electrician	PD	10	$ 358	$ 3,583		
Engineering	PD	10	$ 405	$ 4,053		
Maintenance Trades	PD	10	$ 365	$ 3,648		
Power Engineer	PD	2	$ 390	$ 781		
Utility worker	PD	60	$ 240	$ 14,411		
			Sub-Total	$ 26,475		
OT Labour						
Utility worker	PD	12	$ 480	$ 5,760		
			Sub-Total	$ 5,760		
Materials						
Misc	lot	1	$ 3,000	$ 3,000		
			Sub-Total	$ 3,000		
Contracts						
Replace Filler Blocks and Necessary Tubes	lot	1	[redacted]		Cost Support #1 - Page 5	
Scaffolding in Vestibule	lot	1				
Vacuum ash	lot	1	$ 15,000	$ 15,000		
Non Destructive Examination	lot	1	$ 20,000	$ 20,000		
			Sub-Total	$ 311,138		
Rentals						
Trailer	ea	1	$ 3,000	$ 3,000		
				$ -		
			Sub-Total	$ 3,000		
Other Goods & Services						
Contingency	%	10%	$ 251,138	$ 25,114		
			Sub-Total	$ 25,114		
Interest Capitalized						
AFUDC				$ 1,716		
			Sub-Total	$ 1,716		
Administrative Overhead						
Labour AO				$ 6,449		
Contract AO				$ 30,221		
			Sub-Total	$ 36,670		
			SUB-TOTAL (no AO, AFUDC)	$ 374,487		
			TOTAL (AO, AFUDC included)	$ 412,872		
Original Cost				$ 55,546		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

babcock & wilcox power generation group canada
479 Rothesay Ave. • Saint John, New Brunswick, CA • (506) 633-2880 • Fax (506) 633-1353

June 2, 2017

NSPI – Tuft's Cove
315 Windmill Rd.
Dartmouth, NS
B3A 1H3

Attention: Kevin Thompson

Reference: TUC2 – Remove and Replace Lower Furnace Filler Blocks
B&W PGG Proposal No. TP001012 Rev. 00

Dear Kevin,

B&W PGG is pleased to provide the following budget pricing to remove and replace (R&R) the filler blocks in the lower furnace of Tufts Cove Unit #2 (TUC2) which were found during a recent inspection to have burned through. The purpose of the filler blocks is to maintain a gas-tight seal to the lower vestibule, and although the seal is not significantly compromised as only minor leakage was observed, there are two issues which should be investigated: cracking in the filler blocks which has begun to propagate into the pressure part welds, and tube wall loss due to corrosion from moisture entering the void between the floor tubes and the wall tubes, likely during out-of-service periods.

Two options are given for your consideration:

1. Remove and replace the entire filler block in 164 locations, exposing the wall tube surface for dye penetrant and ultrasonic thickness testing, and then completing any identified repairs. This option involves removing at least one (1) floor tube from each corner of the boiler, from the tan of the front / rearwall bend to the tan of the hopper bend. This has the added benefit of addressing pitting damage found on the outer sides of the floor tubes in question by replacing them with new material. B&W recommends this option.

2. Remove and replace only the top portion of the filler block in 164 locations. This option will provide a seal preventing any gas leaks into the lower vestibule and further corrosion in the existing void, and allow dye penetrant inspection on the hot side only to evaluate crack propagation. It would not be possible to perform thickness checks on the wall tubes, making this the less preferred option from a reliability standpoint.

There are a total of 170 filler blocks in the lower furnace, however six (6) were installed along with a new five (5) tube panel during the last maintenance outage, thus, a maximum of 164 blocks require attention. After an initial cleaning, it is likely that a small number of blocks will be found intact, and if a dye penetrant inspection shows no cracking and the block thickness is acceptable, those blocks will be left in place unless NSPI would like them replaced as well. It is expected that fewer than 20 blocks will be in acceptable condition to leave in place, based on the previous inspection.

B&W Scope of Work:

- Supply labor, supervision, tools, site facilities, and material as required to perform the following:
  - Site set-up
  - Remove floor tubes immediately adjacent to the sidewall, as required
  - Remove 164 filler blocks
  - Prepare tube surfaces for inspection
  - Complete identified repairs
  - Install 164 new filler blocks following inspection
  - Fit and weld new floor tubes and membrane
  - Replace floor tube to sidewall seal
  - Clean-up work site, pack and ship tools

Customer Supply:

- Supply gas testing and confined space watch as necessary
- Supply scaffolding and scaffolding erection if required
- Washing of the boiler prior to work
- (550V/ 220V and 110V) power supply to active work areas and trailers
- Electrical hook-up of welding machines
- Lunchroom and washroom facilities
- Use of plant hoist and / or elevator for movement of men and equipment
- Free unobstructed access to work areas at all times
- Area adjacent to boiler house for B&W trailers and materials.
- Scrap bins and scrap removal
- Repair or removal of any asbestos insulation in the work areas
- Removal and replacement of insulation and lagging if necessary
- Allow use of plant fork lift
- Site safety orientations
- New tube material, already on-site
- Supply of NDE services for UT, LPI, and Radiography

Estimated Prices:

Babcock & Wilcox PGG Canada is pleased to provide the following budget pricing for the supply of supervision, labor, tools, equipment, material, and consumables to carry out the filler block removal and replacement described above:

Option 1: Complete R&R of 164 Filler Blocks..... [redacted]

Option 2: R&R of Top Portion Only..... [redacted]

This proposal is issued for budgetary purposes and includes a 5% contingency amount to cover additional items such as minor scope change, delays etc. and these amounts will only be charged if additional manpower or time is required for the completion of the work.

Basis of Pricing

- Price in Canadian dollars.
- All applicable taxes are extra.
- Field Service personnel availability subject to workload commitments and subject prior to sale.
- Based on B&W's standard quality and manufacturing standards.
- Standard lead-times for materials.
- Accuracy of estimate +/- 10%
- Schedule is based on working ten (10) hour shifts, Monday – Thursday.
- Overtime, holiday, or weekend time is not included.

Commercial Terms and Conditions:

Commercial terms and conditions shall be in accordance with the terms mutually agreed upon for the shutdown, prior to the shutdown date.

Construction Pricing Notes:

1. The construction price provided above is based on construction union labor rates in effect until July 1, 2017. If work is performed during a period in which the union rates or government assessments increase under the applicable labor union agreement, all such increases will be to the Purchasers account.

2. The construction prices for maintenance work provided herein are estimated only and not given by B&W PGG Canada as an offer, nor as a term of any contract, nor as an undertaking that the estimated prices will be the final prices. All work will be charged based on the actual time taken in accordance with our cost plus field Construction Terms and Conditions, Form F-143-B3.

3. The price for maintenance work provided above includes an estimated amount for travel time, fares, and daily subsistence costs as stipulated in the current boilermaker agreement. These costs will be charged only if applicable.

4. We have assumed that all insulation is free of asbestos. If asbestos removal is required, then the costs and time associated with the disposal to meet provincial regulations will be charged at an extra to the contract, as well as any delays or standby time resulting from the presence and removal of asbestos.

5. All taxes extra as applicable.

Thank you for giving us the opportunity of estimating this work. If you have any questions, please call me at (506) 651-0619.

Regards,

Devin Ring
Field Service Engineer
Babcock & Wilcox PGG Canada Corp.

Attached:
Summary of costs
Construction estimate bar charts
F143-B3 - Construction Rate Sheet

babcock & wilcox canada ltd.

Customer: NSPI - Tuft's Cove Generating Station
Location: Dartmouth, NS
Boiler Type: TUC2 El Paso Radiant
Scope: Option 1: R&R Complete Filler Block
Estimator: Devin Ring & Reg MacCarthy
Shutdown Shifts: 24 (4 x 10 hrs)
Proposal #: TP001012

PROJECT ESTIMATE

NOVA SCOTIA POWER
An Emera Company

LABOUR	Hours
BWC Support Staff	
ST & OT	232.00
TT ,Fares, & Subsistence	4.00
Subtotal	236.00
Union Supervision	
ST & OT	232.00
TT, Fares & Subsistence	8.00
Subtotal	240.00
Union Labour	
ST & OT	1,856.00
TT, Fares & Subsistence	64.00
Subtotal	1,920.00
Total Labour	**2,396.00**

RENTALS
Cranes
Tractors and Floats
Fork Lift
Boom Truck
Trailers
1/2 ton truck
Air compressor c/w fuel
Two (2) way radios
Air tuggers
Office and lunch room furniture
Welding machines (automatics)
Plasma cutters
XX
Total Rentals

SUB-CONTRACTS
Welders tests (D.O.L.)
Scaffolding
Insulation & Lagging
NDT
Stress Relieving
Coverall cleaning
Surveying
Engineering (A/E)
Scrap removal
Touch-up painting
Refractories
Piping
xx
Misc.
Total Sub-Contracts

TRANSPORTATION
Tool freight
Transportation for tool van
Total Transportation

MISC. MATERIAL
Fax / phone / copier
Fire blanket
Planks / plywood
Stainless steel / alloy consumables
Builder's Risk Insurance
XX
Misc. steel / material
Total Misc. Material

CONSTRUCTION CONTINGENCY @ 5.
CAMBRIDGE SUPPLIED MATERIAL
TOTAL PROJECT (SUPPLY & INSTALL)

[redacted]

babcock & wilcox canada ltd.

Customer: NSPI - Tuft's Cove Generating Station
Location: Dartmouth, NS
Boiler Type: TUC2 El Paso Radiant
Scope: Option 2: R&R Partial Filler Block
Estimator: Devin Ring & Reg MacCarthy
Shutdown Shifts: 12 (4 x 10 hrs)
Proposal #: T

PROJECT ESTIMATE

NOVA SCOTIA POWER An Emera Company

LABOUR	Hours
BWC Support Staff	
ST & OT	175.00
TT ,Fares, & Subsistence	8.00
Subtotal	183.00
Union Supervision	
ST & OT	135.00
TT, Fares & Subsistence	8.00
Subtotal	143.00
Union Labour	
ST & OT	960.00
TT, Fares & Subsistence	64.00
Subtotal	1,024.00
Total Labour	**1,350.00**

RENTALS
Cranes
Tractors and Floats
Fork Lift
Boom Truck
Trailers
1/2 ton truck
Air compressor c/w fuel
Two (2) way radios
Air tuggers
Office and lunch room furniture
Welding machines (automatics)
Plasma cutters
XX
Total Rentals

SUB-CONTRACTS
Welders tests (D.O.L.)
Scaffolding
Insulation & Lagging
NDT
Stress Relieving
Coverall cleaning
Surveying
Engineering (A/E)
Scrap removal
Touch-up painting
Refractories
Piping
xx
Misc.
Total Sub-Contracts

TRANSPORTATION
Tool freight
Transportation for tool van
Total Transportation

MISC. MATERIAL
Fax / phone / copier
Fire blanket
Planks / plywood
Stainless steel / alloy consumables
Builder's Risk Insurance
XX
Misc. steel / material
Total Misc. Material

CONSTRUCTION CONTINGENCY @
CAMBRIDGE SUPPLIED MATERIAL
TOTAL PROJECT (SUPPLY & INSTAL

[redacted]

6/2/2017

Babcock & Wilcox PGG Canada

Customer: NSPI Tufts Cove
Description Of Work: Remove and Replace 4 floor tubes and 164 filler blocks
Date: June 2, 2017

Day:	M	T	W	T	M	T	W	T	M	T	W	T	M	T	W	T	M	T	W	T	M	T	W	T
Shift #:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Scope of Work	Week 1				Week 2				Week 3				Week 4				Week 5				Week 6			
Site orientations and tool set up	[redacted]																							
Cut membrane and remove slope tube at sidewall																								
Grind prep splits																								
Gouge out 164 filler blocks																								
Grind prep 164 areas of block removals																								
Fit and weld 164 new filler blocks																								
Fit and weld 4 slope tubes																								
Fit membrane at slope tube [2@ each side seal 1 @																								
Weld out hot side																								
Weld out cold side [stitch at side seal]																								
Demob																								
Foreman																								
Total Manpower:																								
Shift																								

Notes:

Based on working 10 hour shifts, 4 crews of 2 Boilermakers each

6/2/2017

Babcock & Wilcox PGG Canada

Customer: NSPI Tufts Cove
Description Of Work: Remove and replace 164 filler blocks hot side only
Date: June 2, 2017

Day:	M	T	W	T	M	T	W	T	M	T	W	T	M	T	W	T	M	T	W	T	M	T	W	T
Shift #:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Scope of Work	Week 1				Week 2				Week 3				Week 4				Week 5				Week 6			
Site orientations and tool set up	[redacted]																							
Remove 164 filler blocks above slope tubes																								
Grind prep areas of removal																								
Fit 164 filler blocks [top side only]																								
Weld out 164 filler blocks																								
Foreman																								
Total Manpower:																								
Shift																								

Notes:

Based on working 10 hour shifts, 4 crews of 2 Boilermakers each

CI Number: 51849

Title: LIN3 RH Tube Replacement

Start Date:	2018/03
In-Service Date:	2018/04
Final Cost Date:	2018/10
Function:	Steam
Forecast Amount:	$399,546

DESCRIPTION:

The scope of work for this project is to replace reheat tube bends that pass through the waterwall and connect to the reheat header. These bends are subject to systematic soot blowing which is required for the removal of ash build up on the reheat tubes. The soot blowing causes erosion on the tube bends as they enter the waterwall opening on route to the reheat header. Over years of operation, the tube bends required pad welding during each planned outage to rebuild the tube wall thickness. Pad welded repairs are more susceptible to future tube failures and pulls due to thermal stresses. The future planned operational state of the Unit 3 boiler will see increased cycling which will increase potential thermal stresses on these pad weld repairs. The location of these tubes passing through the waterwall into a header vestibule could allow an external boiler steam leak to occur if the tubes fail. The reheat tube replacement will be completed in a phased approach enabling the work to be completed over regular planned shutdown intervals.

Summary of Related CIs (+/- 2 years):
2019 CI TBD LIN3 RH Tube Replacement 2019 $TBD
2020 CI TBD LIN3 RH Tube Replacement 2020 $TBD

JUSTIFICATION:

Justification Criteria: Health & Safety

Why do this project?

This project needs to be completed to reduce the risk of reheat boiler tube leaks in the area where the tubes exit the waterwall on route to the reheat header. A leak on a reheat tube bend in this area could allow steam to leak into the header vestibule external to the boiler, potentially causing waterwall damage. External boiler steam leaks can lead to serious safety hazards for plant personnel.

This project is primarily justified on safety, and secondarily justified on unit reliability.

Why do this project now?

In order to mitigate the risk of an external steam leak and unplanned outage, reheat tube replacement activities are required.

Why do this project this way?

Replacing the deteriorated tube bends will mitigate the risk of tube leaks and minimize the number of unplanned outages. Based on boiler assessments, these upgrades are necessary to maintain reliable operation of the boiler. Refurbishment of these components is not an option due the failure modes present in the pad welded tubes.

CI Number : 51849 - LIN3 RH Tube Replacement **Project Number** 51849

Parent CI Number : -

Asset Location : 1133 - 1133 Lingan Unit 3; Commissioned 1983, 164Mwh **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	1300 - SGP - Boiler	326,401
Retirements	1300 - SGP - Boiler	73,146
	Total Cost:	399,546
	Original Cost:	133,316

Capital Project Detailed Estimate

Location: Steam
CI# : 51849
Title: LIN3 RH Tube Replacement
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Utility worker	PD	20	$ 240	$ 4,804		
			Sub-Total	$ 4,804		
Term Labour						
Utility worker	PD	60	$ 240	$ 14,411		
			Sub-Total	$ 14,411		
Materials						
Boiler Tubes	lot	1	$ 30,000	$ 30,000		
Misc Consumables	lot	1	$ 6,000	$ 6,000		
			Sub-Total	$ 36,000		
Contracts						
Boiler Maintenance Contractor	lot	1	$ 280,000	$ 280,000		
Industrial Cleaning Services	lot	1	$ 30,000	$ 30,000		
			Sub-Total	$ 310,000		
Administrative Overhead						
Labour AO				$ 4,221		
Contract AO				$ 30,110		
			Sub-Total	$ 34,331		
			SUB-TOTAL (no AO, AFUDC)	$ 365,215		
			TOTAL (AO, AFUDC included)	$ 399,546		
Original Cost				$ 133,316		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 51850

Title: LIN4 RH Tube Replacement

Start Date:	2018/04
In-Service Date:	2018/04
Final Cost Date:	2018/10
Function:	Steam
Forecast Amount:	$399,546

DESCRIPTION:

The scope of work for this project is to replace reheat tube bends that pass through the waterwall and connect to the reheat header. These bends are subject to systematic soot blowing which is required for the removal of ash build up on the reheat tubes. The soot blower action causes erosion on the tube bends as they enter the waterwall opening on route to the reheat header. Over years of operation the tube bends required pad welding to rebuild the tube wall thickness during each planned outage. Pad welded repairs are more susceptible to future tube failures due to thermal stresses. The future planned operational state of the Unit 4 boiler will see increased cycling which will increase potential thermal stresses on these pad weld repairs. The location of these tubes passing through the waterwall into a header vestibule could allow an external boiler steam leak to occur. The reheat tube replacement will be undertaken in a phased approach enabling the work to be completed over regular planned shutdown intervals.

Summary of Related CIs (+/- 2 years):
2019 CI TBD LIN4 RH Tube Replacement 2019 $TBD
2020 CI TBD LIN4 RH Tube Replacement 2020 $TBD

JUSTIFICATION:

Justification Criteria: Health & Safety

Why do this project?

This project needs to be completed to reduce the risk of reheat boiler tube leaks in the area where the tubes exit the waterwall on route to the reheat header. A leak on a reheat tube bend in this area could allow steam to leak into the header vestibule external to the boiler. External boiler steam leaks can lead to serious safety hazards for plant personnel.

Why do this project now?

In order to mitigate the risk of external steam leaks and unplanned outages, reheat tube replacement activities are required. This project needs to be completed now due to future increased thermal cycling of Unit 4.

Why do this project this way?

Replacing the deteriorated tube bends will mitigate the risk of tube leaks and minimize the number of unplanned outages. Due to the level of deterioration, refurbishment of these components is not an option to mitigate the risk of an external boiler steam leak.

CI Number : 51850 - LIN4 RH Tube Replacement **Project Number** 51850

Parent CI Number : -

Asset Location : 1134 - 1134 Lingan Unit 4; Commissioned 1984, 160 Mwh **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	1300 - SGP - Boiler	326,400
Retirements	1300 - SGP - Boiler	73,146
	Total Cost:	399,546
	Original Cost:	133,316

Capital Project Detailed Estimate

Location: Steam
CI# : 51850
Title: LIN4 RH Tube Replacement
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Utilityworker	PD	20	$ 240	$ 4,804		
			Sub-Total	$ 4,804		
Term Labour						
Utilityworker	PD	60	$ 240	$ 14,411		
			Sub-Total	$ 14,411		
Materials						
Boiler Tubes	Lot	1	$ 30,000	$ 30,000		
Misc Consumables	Lot	1	$ 6,000	$ 6,000		
			Sub-Total	$ 36,000		
Contracts						
Boiler Contractor	Lot	1	$ 280,000	$ 280,000		
Industrial Cleaning Services	Lot	1	$ 30,000	$ 30,000		
			Sub-Total	$ 310,000		
Administrative Overhead						
Labour AO				$ 4,221		
Contract AO				$ 30,110		
			Sub-Total	$ 34,331		
			SUB-TOTAL (no AO, AFUDC)	$ 365,214		
			TOTAL (AO, AFUDC included)	$ 399,546		
Original Cost				$ 133,316		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 49547

Title: TRE5 5-1 BFP Refurbishment

Start Date: 2018/05
In-Service Date: 2018/06
Final Cost Date: 2018/12
Function: Steam
Forecast Amount: $345,523

DESCRIPTION:

The scope of this project is to refurbish the 5-1 Boiler Feed Pump (BFP) cartridge and bearings on Trenton Unit 5.

Trenton Unit 5 high pressure feed water system supplies treated water to the boiler. The deaerator storage tank supplies the suction to the two boiler feed pumps, which pump the feed water through three high-pressure heaters and on to the boiler. The two 50 percent duty BFPs are Byron Jackson 9 stage, double case pumps with a capacity of 1,260 US gallons per minute and are each driven by a 2,500 horsepower (HP) drive motors.

The BFP consists of an outer casing which incorporates connections for the suction and discharge piping. The cartridge is in the inner casing that houses the pump impeller shaft. This configuration allows for easier access to remove the cartridge (pump) for repair and maintenance.

The cartridges are refurbished based on condition assessments. A spare cartridge is maintained ready for use in case of failure of one of the two operating pumps because the unit can only operate at partial level with one pump. The spare cartridge will be installed on 5-1 BFP, and the removed cartridge will be refurbished along with out of tolerance journal bearings for inspection and refurbishment as part of this capital project.

Summary of Related CIs +/- 2 years:
2017 CI 51571 TRE5 4kV Motor Refurbishment U&U $105,172

JUSTIFICATION:

Justification Criteria: Thermal

Sub Criteria: Equipment Replacement/Refurbishment

Why do this project?

As part of the Asset Management program at the Trenton Generating Station, the inspection and overhaul of 5-1 BFP is scheduled for 2018 based on the condition assessment. The pump was last inspected and overhauled in 2012 and the intent is to disassemble the pump, replace the cartridge with a spare unit and refurbish the cartridge and bearings. The refurbishment of the removed cartridge is part of this capital project.

For the Unit 5 boiler to run at full load, both BFPs must be running. If one BFP is forced out of service, the average unit output drops by approximately 75 MW. Therefore, it is imperative that the spare cartridge be overhauled in a proactive manner before an in-service failure occurs.

This project is primarily justified on unit reliability, and secondarily supported by positive economics.

Why do this project now?

As part of the Asset Management assessment at Trenton, 5-1 BFP is recommended for an overhaul in 2018. This refurbishment will ensure the long-term reliability of the unit, while minimizing risk of failure and maintenance costs. Failure to institute the overhaul of this pump could jeopardize unit output.

Why do this project this way?

The only alternative to this project is a full replacement of the pump cartridge, which is more costly than this refurbishment project, and is not considered necessary at this time.

CI Number : 49547 - TRE5 5-1 BFP Refurbishment **Project Number** 49547

Parent CI Number : -

Asset Location : 1165 - 1165 Trenton Unit 5; Commissioned 1969, 160 Mwh **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	1600 - SGP - Feed Water Sys.	321,129
Retirements	1600 - SGP - Feed Water Sys.	24,394
	Total Cost:	345,523
	Original Cost:	49,348

Capital Project Detailed Estimate

Location: Trenton Generating Station
CI# : 49547
Title: TRE5 5-1 BFP Refurbishment
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Engineering	PD	5	$ 405	$ 2,027		
Maintenance Trades	PD	40	$ 365	$ 14,591		
Power Engineer	PD	10	$ 390	$ 3,904		
Power Plant Technician	PD	10	$ 382	$ 3,821		
Utility worker	PD	20	$ 240	$ 4,804		
			Sub-Total	$ 29,146		
OT Labour						
Maintenance Trades	PD	10	$ 730	$ 7,300		
			Sub-Total	$ 7,300		
Term Labour						
Maintenance Trades	PD	35	$ 365	$ 12,768		
			Sub-Total	$ 12,768		
Travel Expense						
Travel		1	$ 2,000	$ 2,000		
			Sub-Total	$ 2,000		
Materials						
Misc. Materials (Gaskets, Dowel pins, Spacers, etc)	lot	1	$ 13,500	$ 13,500		
Volute Refurbishment Materials	lot	1	$ 35,438	$ 35,438		
			Sub-Total	$ 48,938		
Contracts						
Volute Refurbishment	lot	1	$ 77,088	$ 77,088		
Motor Refurbishment	lot	1	$ 90,000	$ 90,000		
Technician - Disassembly/Inspection	lot	1	$ 9,000	$ 9,000		
Technician - Reassembly (On-Site)	lot	1	$ 11,250	$ 11,250		
			Sub-Total	$ 187,338		
Freight						
Shipping	lot	2	$ 3,000	$ 6,000		
			Sub-Total	$ 6,000		
OT Meals						
OT Meals	lot	1	$ 200	$ 200		
			Sub-Total	$ 200		
Other Goods & Services						
Contingency	%	10%	$ 236,276	$ 23,628		
				$ -		
			Sub-Total	$ 23,628		
Administrative Overhead						
Labour AO				$ 10,009		
Contracts AO				$ 18,196		
			Sub-Total	$ 28,206		
			SUB-TOTAL (no AO, AFUDC)	$ 317,317		
			TOTAL (AO, AFUDC included)	$ 345,523		
Original Cost				$ 49,348		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

TRE5 5-1 BFP Refurbishment
Summary of Alternatives

Nova Scotia POWER An Emera Company

Division :	Power Production	**Date :**	**18-Nov-17**
Department :	Trenton	**CI Number:**	49547
		Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank (based on PV of RR)	IRR	Disc Pay
A	BFP Refurbishment vs Replacement Energy Costs	5.88%	-327,380	222,235	1	27.30%	3.8 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

Recommendation :

It is recommended to complete the BFP refurbishment

Notes/Comments :

BFP Refurbishment vs Replacement Energy Costs

The capital costs are for the refurbishment of the 5-1 BFP motor and cartridge. The avoided expense calculator assumes the unit is de-rated to 50% capacity for 4 weeks while either the motor or the cartridge are sent for refurbishment in the event of a failure. The probability of failure includes the possibility of either the pump or motor failing. The probability of failure increases year over year due to the continuous use of the equipment.

Test 2

Test 3

Test 4

TRE5 5-1 BFP Refurbishment
Summary of Sensitivities

Nova Scotia POWER An Emera Company

Division :	Power Production
Department :	Trenton

Date :	**10-Nov-17**
CI Number:	49547
Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	BFP Refurbishment vs Replacement Energy Cost	5.88%	-327,380	222,235	1	27.30%	3.8 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

	Alternative Variance on Capital Spend	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	BFP Refurbishment vs Replacement Energy Cost	10%	-295,175	197,756	1	23.27%	4.0 years
B	Test 2	10%	0	0	2	#NUM!	0.0 years
C	Test 3	10%	0	0	2	#NUM!	0.0 years
D	Test 4	10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		32,205	-24,479	0	-4.03%	0.3 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

	Alternative Variance on Avoided Expenses	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	BFP Refurbishment vs Replacement Energy Cost	-10%	-262,437	175,533	1	22.86%	4.1 years
B	Test 2	-10%	0	0	2	#NUM!	0.0 years
C	Test 3	-10%	0	0	2	#NUM!	0.0 years
D	Test 4	-10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		64,943	-46,702	0	-4.43%	0.3 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

Alternative Variance on Avoided Expenses - Change in Revenue Requirement		PV of Revenue Requirement	PV of Revenue Requirement	PV of Revenue Requirement	Delay?
	Yrs Delay:	1	2	3	
	A	34,795	86,581	193,997	No
	B	0	0	0	No
	C	0	0	0	No
	D	0	0	0	No

TRE5 5-1 BFP Refurbishment
Avoided Cost Calculations

Division :	Power Production	**Date :**	**10-Nov-17**
Department :	Trenton	**CI Number:**	49547
		Project No. :	

BFP Refurbishment vs Replacement Energy Costs

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			117,280	121,978		
Events/Outages (#)	1	1	1	1		
Probability of Occurance (%)	30%	45%	30%	45%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	80.0	80.0				
Duration (Hours or Years)	720	720				
Totals	$18,006	$22,429	$35,184	$54,890	$53,190	$77,320
Total Capital Cost of Alternative						$345,523

Test 2

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

Test 3

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

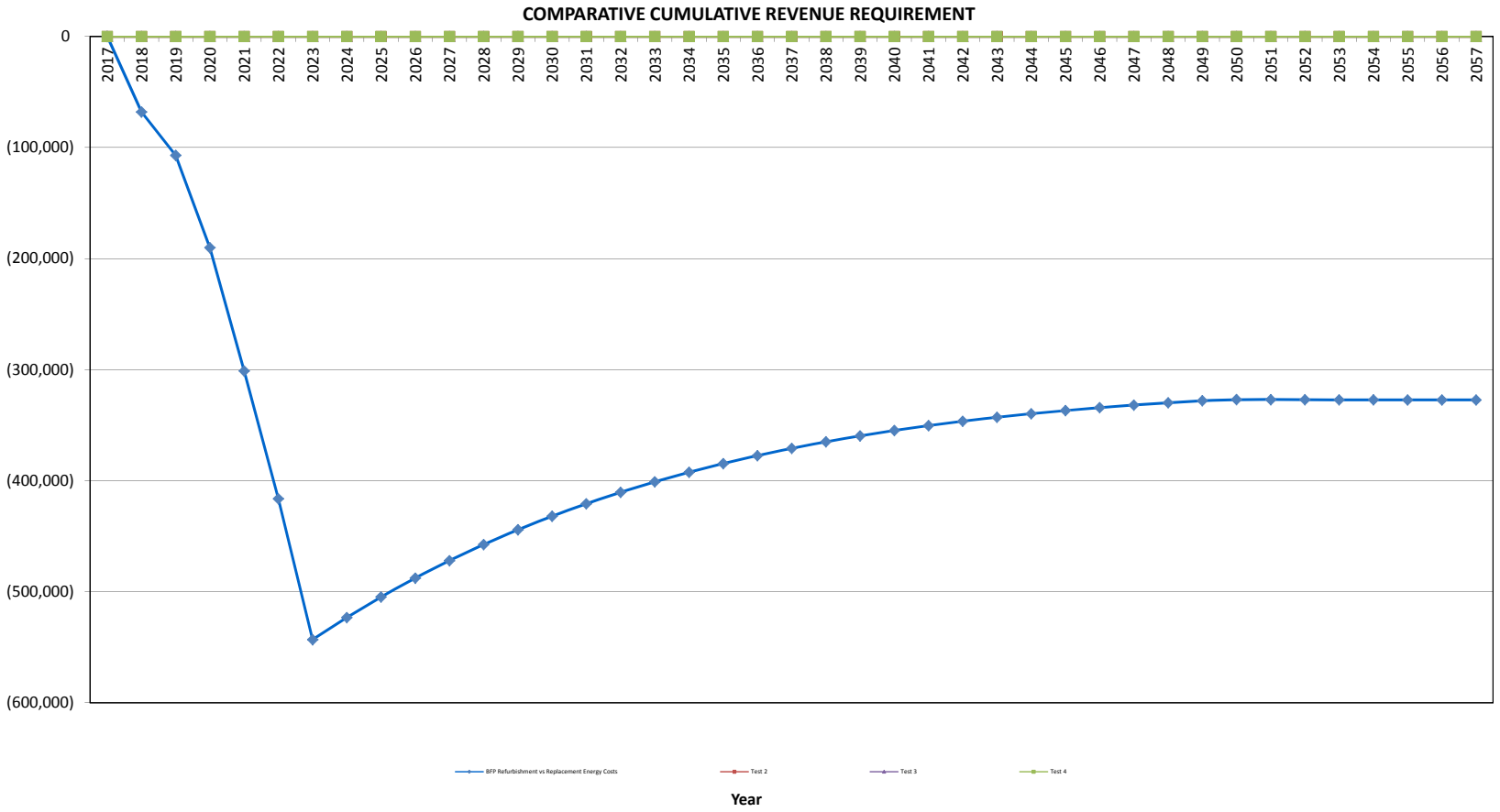
Test 4

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

TRE5 5-1 BFP Refurbishment

BFP Refurbishment vs Replacement Energy Costs

Year	Total Revenue	Operating Costs	Avoided Expenses	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	PV of CF	Discount Factor	CNPV
2017	-	-	-	-	-	-	-	-	-	-	1.00	-
2018	-	-	53,190.4	(317,317.0)	12,692.7	312,409.1	(264,126.6)	(12,554.3)	(276,680.9)	(261,315.5)	0.94	(261,315.5)
2019	-	-	77,319.6	-	24,369.9	286,739.4	77,319.6	(16,414.4)	60,905.2	54,328.3	0.89	(206,987.2)
2020	-	-	134,450.5	-	22,420.3	263,123.3	134,450.5	(34,729.3)	99,721.1	84,012.8	0.84	(122,974.4)
2021	-	-	177,729.7	-	20,626.7	241,396.5	177,729.7	(48,701.9)	129,027.8	102,666.2	0.80	(20,308.2)
2022	-	-	193,452.5	-	18,976.6	221,407.9	193,452.5	(54,087.5)	139,364.9	104,733.1	0.75	84,424.9
2023	-	-	221,998.9	-	17,458.5	203,018.3	221,998.9	(63,407.5)	158,591.3	112,563.0	0.71	196,987.9
2024	-	-	-	-	16,061.8	186,099.9	-	4,979.2	4,979.2	3,337.8	0.67	200,325.7
2025	-	-	-	-	14,776.8	170,535.0	-	4,580.8	4,580.8	2,900.2	0.63	203,225.9
2026	-	-	-	-	13,594.7	156,215.2	-	4,214.4	4,214.4	2,520.0	0.60	205,745.9
2027	-	-	-	-	12,507.1	143,041.1	-	3,877.2	3,877.2	2,189.7	0.56	207,935.6
2028	-	-	-	-	11,506.5	130,920.9	-	3,567.0	3,567.0	1,902.6	0.53	209,838.2
2029	-	-	-	-	10,586.0	119,770.3	-	3,281.7	3,281.7	1,653.2	0.50	211,491.5
2030	-	-	-	-	9,739.1	109,511.7	-	3,019.1	3,019.1	1,436.5	0.48	212,927.9
2031	-	-	-	-	8,960.0	100,073.8	-	2,777.6	2,777.6	1,248.2	0.45	214,176.1
2032	-	-	-	-	8,243.2	91,391.0	-	2,555.4	2,555.4	1,084.5	0.42	215,260.7
2033	-	-	-	-	7,583.8	83,402.8	-	2,351.0	2,351.0	942.4	0.40	216,203.0
2034	-	-	-	-	6,977.1	76,053.6	-	2,162.9	2,162.9	818.8	0.38	217,021.9
2035	-	-	-	-	6,418.9	69,292.4	-	1,989.9	1,989.9	711.5	0.36	217,733.4
2036	-	-	-	-	5,905.4	63,072.1	-	1,830.7	1,830.7	618.2	0.34	218,351.6
2037	-	-	-	-	5,432.9	57,349.4	-	1,684.2	1,684.2	537.2	0.32	218,888.8
2038	-	-	-	-	4,998.3	52,084.5	-	1,549.5	1,549.5	466.8	0.30	219,355.5
2039	-	-	-	-	4,598.4	47,240.8	-	1,425.5	1,425.5	405.6	0.28	219,761.1
2040	-	-	-	-	4,230.6	42,784.6	-	1,311.5	1,311.5	352.4	0.27	220,113.5
2041	-	-	-	-	3,892.1	38,684.9	-	1,206.6	1,206.6	306.2	0.25	220,419.7
2042	-	-	-	-	3,580.8	34,913.2	-	1,110.0	1,110.0	266.1	0.24	220,685.8
2043	-	-	-	-	3,294.3	31,443.2	-	1,021.2	1,021.2	231.2	0.23	220,917.0
2044	-	-	-	-	3,030.8	28,250.8	-	939.5	939.5	200.9	0.21	221,117.8
2045	-	-	-	-	2,788.3	25,313.8	-	864.4	864.4	174.5	0.20	221,292.4
2046	-	-	-	-	2,565.2	22,611.8	-	795.2	795.2	151.7	0.19	221,444.0
2047	-	-	-	-	2,360.0	20,125.9	-	731.6	731.6	131.8	0.18	221,575.8
2048	-	-	-	-	2,171.2	17,838.9	-	673.1	673.1	114.5	0.17	221,690.3
2049	-	-	-	-	1,997.5	15,734.8	-	619.2	619.2	99.5	0.16	221,789.8
2050	-	-	-	-	1,837.7	13,799.1	-	569.7	569.7	86.5	0.15	221,876.3
2051	-	-	-	-	1,690.7	12,018.2	-	524.1	524.1	75.1	0.14	221,951.4
2052	-	-	-	-	1,555.4	10,379.8	-	482.2	482.2	65.3	0.14	222,016.7
2053	-	-	-	-	1,431.0	8,872.5	-	443.6	443.6	56.7	0.13	222,073.4
2054	-	-	-	-	1,316.5	7,485.8	-	408.1	408.1	49.3	0.12	222,122.7
2055	-	-	-	-	1,211.2	6,210.0	-	375.5	375.5	42.8	0.11	222,165.5
2056	-	-	-	-	1,114.3	5,036.3	-	345.4	345.4	37.2	0.11	222,202.7
2057	-	-	-	-	1,025.2	3,956.4	-	317.8	317.8	32.3	0.10	222,235.0
Total	**-**	**-**	**858,141.4**	**(317,317.0)**	**305,527.6**		**540,824.4**	**(171,310.3)**	**369,514.2**	**222,235.0**		


COMPARATIVE CUMULATIVE REVENUE REQUIREMENT
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(300,000)
(400,000)
(500,000)
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BFP Refurbishment vs Replacement Energy Costs
Test 2
Test 3
Test 4
Year

CI Number: 51857

Title: TRE5 Burner Refurbishments 2018

Start Date:	2018/06
In-Service Date:	2018/06
Final Cost Date:	2018/12
Function:	Steam
Forecast Amount:	$332,497

DESCRIPTION:

The scope of this project is to replace the impellers and complete the refurbishment of the burner front registers and associated refractory on Trenton Unit #5.

NS Power coal fired units use burner assemblies which deliver and distribute pulverized coal and combustion air to the boiler combustion zone. These burner assemblies include ductwork (and support structures), air registers, coal nozzles and associated pneumatic control mechanisms. The delivery elements are subjected to erosion and corrosion as a result of transporting a fuel/air mixture at high velocity. The components nearer the boiler front are subjected deterioration due to heat and erosion.

The burner fronts external to the boiler in the wind box area were inspected by NS Power in 2017 and were determined to require significant refurbishment in 2018 based on condition. The burner condition has a direct impact on unburned carbon, oxygen levels, and boiler temperatures, which all have an effect on unit heat rate and life consumption. This project will see the replacement of 16 impellers, 16 burner registers and the refractory on the burner front.

Summary of Related CIs (+/- 2 years):
CI 46358 TRE5 Burner Refurbishments $207,190

JUSTIFICATION:

Justification Criteria: Health & Safety

Why do this project?

Refurbishment is required to maintain the burner system in a safe and effective operating condition, as burner performance and integrity deteriorates over time. Supporting structures, seal mechanisms and the integrity of ducts and registers will deteriorate and this increases the risk of burner fires (outside the combustor) creating a safety concern to plant personnel. Additionally, burner distribution to the combustor and fuel/air mix will become less uniform as elements in the burner system deteriorate, resulting in a less efficient use of fuel.

Why do this project now?

Inspections completed by NS Power indicate that the components are in poor condition and that refurbishment is required to ensure the reliability and performance of the generating unit. As the burner system is essential to boiler operation, this work must be completed during a unit outage.

Why do this project this way?

A combination of component refurbishment and replacement will be included in the refurbishment. Some register dampers and linkages will be replaced based on condition. Supporting structures are typically refurbished in place. Both replacement and refurbishment are options on the various elements to optimize refurbishment cost and sustain burner system performance. When the condition of the component allows, refurbishment is generally the more cost effective alternative. In cases where the condition does not allow for refurbishment, the component is replaced.

CI Number : 51857 - TRE5 Burner Refurbishments 2018 **Project Number** 51857

Parent CI Number : -

Asset Location : 1165 - 1165 Trenton Unit 5; Commissioned 1969, 160 Mwh **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	1300 - SGP - Boiler	308,104
Retirements	1300 - SGP - Boiler	24,394
	Total Cost:	332,497
	Original Cost:	47,108

Capital Project Detailed Estimate

Location: Trenton Generating Station
CI# : 51857
Title: TRE5 Burner Refurbishments 2018
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
Maintenance Trades	PD	120	$ 365	$ 43,774		
Power Engineer	PD	10	$ 390	$ 3,904		
Power Plant Technician	PD	5	$ 382	$ 1,911		
Utility worker	PD	20	$ 240	$ 4,804		
			Sub-Total	$ 54,392		
OT Labor						
Maintenance Trades	PD	10	$ 730	$ 7,296		
			Sub-Total	$ 7,296		
Term Labor						
Maintenance Trades	PD	100	$ 365	$ 36,479		
			Sub-Total	$ 36,479		
OT Meals						
OT Meals	lot	1	$ 200	$ 200		
			Sub-Total	$ 200		
Materials						
Impellers	lot	16	$ 940	$ 15,040		
Liners	lot	1	$ 7,500	$ 7,500		
Burners	lot	16	$ 1,875	$ 30,000		
Miscellaneous Materials	lot	1	$ 10,000	$ 10,000		
Refractory	lot	1	$ 30,000	$ 30,000		
			Sub-Total	$ 92,540		
Contracts						
Vacuum Services	lot	1	$ 5,000	$ 5,000		
Project Supervision	lot	1	$ 10,000	$ 10,000		
Install Refractory	lot	1	$ 70,000	$ 70,000		
			Sub-Total	$ 85,000		
Other Goods & Services						
Contingency	%	10%	$ 275,707	$ 27,571		
				$ -		
			Sub-Total	$ 27,571		
Administrative Overhead						
Labor AO				$ 20,764		
Contract AO				$ 8,256		
			Sub-Total	$ 29,020		
			SUB-TOTAL (no AO, AFUDC)	$ 303,477		
			TOTAL (AO, AFUDC included)	$ 332,497		
Original Cost				$ 47,108		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 49534

Title: TRE6 Turbine Controls Upgrade

Start Date: 2017/07
In-Service Date: 2018/11
Final Cost Date: 2020/04
Function: Steam
Forecast Amount: $2,725,344

DESCRIPTION:

The scope of work for this project includes the design, procurement and installation of replacements for the Trenton 6 turbine controls. The turbine controls consist of an Electro-Hydraulic Governor (EHG), Automatic Run-up System (ARU), turbine protection systems, and the turbine auxiliary equipment controls. The project includes the procurement of the replacement controls system in 2018, with the installation taking place in 2019 during the Unit 6 outage. The procurement of the controls system in 2018 will provide a critical spare leading up to the installation of the system in 2019.

Trenton Unit 6 is a 170 MW coal-fired power plant, with a steam turbine, commissioned in 1991. The EHG is a dedicated control system designed to process instantaneous plant data and control the speed and operation of the turbine.

An ARU involves the monitoring of critical turbine data to control starting, acceleration rates, holds, differential expansion and to monitor vibration levels. It assists operators in the safe and efficient starting and shutting down of the turbine.

Turbine protection systems read and monitor field instrumentation and give warnings or implement automatic shut-down in cases of abnormal conditions to protect personnel and equipment.

Turbine auxiliary equipment refers to supplemental equipment that aids in running the turbine. Some examples include oil lubricating pumps, turning gear, cooling water pumps, gland steam valves, and seal oil pumps.

The turbine controls were supplied as original equipment when the unit was constructed in 1990 and commissioned in 1991. As with all microprocessor-based equipment, the 25 year in-service duration has created obsolescence issues as technology has progressed past what was available in 1990. The original equipment manufacturer (OEM) has stated that most components of the turbine controls are no longer supported and some have time-limited support. Their recommendation is to replace / upgrade these systems. Please refer to Attachment 2, section 4.

Summary of Related CIs +/- 2 years:
No other projects 2016, 2017, 2018, 2019 or 2020.

Depreciation Class: Steam Production Plant - Trenton Unit 6

Estimated Life of the Asset: 25 years

JUSTIFICATION:

Justification Criteria: Thermal

Sub Criteria: Equipment Replacement/Refurbishment

Why do this project?

The controls system for Trenton Unit 6 generator is now obsolete. The OEM no longer supports the components of the turbine controls and some have time-limited support. The unit cannot run without this critical system in place. It is critical to the safe operation and protection of the turbine. In the event a failure was to occur, a replacement turbine control system would require approximately 13 months to procure and install.

Why do this project now?

A technical proposal from Hitachi has indicated that the current turbine controls are no longer supported. In the event of a failure, the obsolescence of the current turbine run-up system would make it difficult to source replacement parts. Procurement of the replacement components in 2018 will allow for appropriate planning and coordination for the installation with the Unit 6 outage planned for 2019, while also ensuring the replacement parts are available in advance of the 2019 outage should a failure occur prior to that planned outage window. The 2019 outage window would be the opportune time to complete this project without incurring replacement energy costs.

Why do this project this way?

Replacement of these components is the only alternative as the current components are no longer supported, and a full control system replacement is significantly more costly and not required at this time.

CI Number : 49534-SI63 - TRE6 Turbine Controls Upgrade **Project Number** 49534-SI63

Parent CI Number : -

Asset Location : 1166 - 1166 Trenton Unit 6; Commissioned 1991, 170 Mwh **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	1100 - SGP - Plant Control and Inst	2,700,950
Retirements	1100 - SGP - Plant Control and Inst	24,394
	Total Cost:	2,725,344
	Original Cost:	1,724,045

Capital Project Detailed Estimate

Location: **Trenton Generating Station**
CI# : 49534
Title: TRE6 Turbine Controls Upgrade
Execution Year: 2018-2019

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Electrician	PD	120	$ 358	$ 42,994		
Engineering	PD	135	$ 405	$ 54,716		
Power Engineer	PD	5	$ 390	$ 1,952		
Power Plant Technician	PD	3	$ 382	$ 1,146		
Utility worker	PD	2	$ 240	$ 480		
CADD Operators	PD	4	$ 294	$ 1,176		
			Sub-Total	$ 102,465		
OT Labour						
Electrician	PD	20	$ 717	$ 14,331		
			Sub-Total	$ 14,331		
Travel Expense						
Engineering Travel Expense	lot	1	$ 10,000	$ 10,000		
			Sub-Total	$ 10,000		
Materials						
Control Panel Materials	lot	1	[redacted]		Cost support 1 item 1	
Misc Materials	each	1	$ 5,000	$ 5,000		
			Sub-Total	[redacted]		
Contracts						
Site Service for assessment Oct 2017	lot	1	$ 40,000	$ 40,000		
Installation/Commissioning	lot	1	[redacted]		Cost support 1 - Item 2	
Supervision	lot	1	$ 10,000	$ 10,000		
			Sub-Total	[redacted]		
OT Meals						
OT Meals	lot	20	$ 15	$ 300		
				$ -		
			Sub-Total	$ 300		
Other Goods & Services						
Contingency	%	2%	$ 2,570,796	$ 51,416		
				$ -		
			Sub-Total	$ 51,416		
Interest Capitalized						
AFUDC				$ 34,723		
				$ -		
			Sub-Total	$ 34,723		
Administrative Overhead						
Labour AO				$ 24,084		
Contract AO				$ 34,025		
			Sub-Total	$ 58,109		
			SUB-TOTAL (no AO, AFUDC)	$ 2,632,512		
			TOTAL (AO, AFUDC included)	$ 2,725,344		
Original Cost				$ 1,724,045		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

Data Validation
002 Overtime Labour
004 Term Labour
011 Travel Expenses
013 Other Contracts
028 Consulting
041 Meals and Entertainment

QUOTATION

Mitsubishi Hitachi Power Systems Canada, Ltd.
Power Division
460-10655 Southport Road S. W.
Calgary, AB
Canada T2W 4Y1
Telephone: (403) 278-1881
Fax: (403) 278-1810

Date: September 14, 2017

Our Ref. No.: QT-10820
Revision: 2
Sales Inquiry No.: PENDING
Final Customer: XTN6

Dear Kevin Macdonald:
NOVA SCOTIA POWER INC.
Trenton Generating Station
108 Power Plant Road
Trenton, NS B0K 1X0
CANADA

In accordance with your request we are pleased to quote as follows:

DELIVERY: APPROX. 13.5 MONTHS AFTER RECEIPT OF ORDER

PAYMENT: Net 30

Item	Quantity	Description	Unit Price	Total Price CDN$
1	1	CONTROL PANEL MATERIALS REFER TO ATTACHED DOCUMENT TC-16-018 REV2 Replacement of TCP components including; EHG/HITASS CUBICLES (4) AUX. LOGIC CUBICLES (2) TRANSDUCER PANEL (1) ENGINEERING WORK STATION (EWS) HUMAN MACHINE INTERFACE (HMI) X 2 COMMUNICATIONS CABLES (lengths to be confirmed by the customer) EWS AND HMI SOFTWARE Supply scope includes up to 3 DAYS of factory acceptance testing. Does not include any expenses for the customer or customer's inspector to witness these tests. Includes supply of fibre optic cables between control panels and to the EWS and HMIs. Customer to provide required cable lengths. Cable between existing cabinets and existing operator console will not be required for the upgraded system. OUT OF SCOPE: Manpower for the installation support, testing, and commissioning. Manpower for disconnection and removal of existing panels. Manpower for installation and reconnection of new panels and computers. SITE TRAINING is not included in this scope. SPARE PARTS are not included in this scope. Customer to provide power supply (120VAC) and desk/cabinet space for the EWS and HMI computers and their LAN boxes. Existing cable will be reused as much as possible. If cable length is a problem or if cables are damaged during construction the customer will be responsible for new cables. Customer shall provide cable for Modbus communication.	[redacted]	

2	1	SITE LABOUR The upgrade requires the following TAs to be dispatched for the installation support, testing, and commissioning. The following are included in this proposal; ASSEMBLY TA x 2 for up to 9 Days INSPECTION QA TA for up to 16 Days DESIGN TA for up to 9 Days MHPSC ENGINEER for up to 20 Days Additional time required on site due to delays caused by NSPI or its contractors will be billed at extra hours worked and standard rates in effect at time of work. OUT OF SCOPE: Manpower for disconnection and removal of existing panels. Manpower for installation and reconnection of new panels and computers. SITE TRAINING is not included in this scope.	[redacted]
		TOTAL	[redacted]

OTHER TERMS AND CONDITIONS:
Please take note of the following remarks that form part of our offer:

1) GST and any applicable Provincial Sales tax not included.
2) Terms: Net 30 days.
3) Validity: This quotation is valid until December 15, 2017.
4) All parts quoted are DDP Site (INCOTERMS 2010).
5) Delivery/Schedule:
- Delivery is subject to availability of material and resources at time of order.
- Delivery is to be confirmed after receipt of order.
- Pricing reflects lead time for manufacture & delivery as quoted.
6) Pricing is based on order of all items quoted. Pricing is subject to change for partial orders.
7) Items to be manufactured to OEM manufacturing drawings, and with OEM material.
8) Order cannot be accepted or placed until after receipt of acceptable PO. Acceptable PO must have pricing and terms that conform to this quote.
9) All PO's issued toward this quote must reference the appropriate Mitsubishi Hitachi Power Systems Canada quote number.
10) In accordance with MHPS Standard Terms & Conditions for Parts & Services Rev.20160503.

Rev.1 - Reduced pricing offered based on receiving a formal order in October 2016 and work being completed within 2017.

Rev 2 - Split quote material and labor into separate line items.

Sheldon Merkosky, General Manager

Taite Purnell, General Manager

HITACHI
Hitachi, Ltd., Infrastructure Systems Division
Turbine Control System
D-EHG/HITASS/AUX.

Date:Jun.25, 2016
Ref. No. TC-16-018

http://www.hitachi.co.jp/Div/omika/index.html

Rev.2

Customer: NOVA SCOTIA POWER CORPORATION
TRENTON GENERATING STATION UNIT NO.6
150MW STEAM TURBINE GENERATOR SET

OFFER SPECIFICATION of
Turbine Control System Upgrading
(D-EHG/HITASS/AUX. Control Panel)

Ref. No. TC-16-018

HITACHI
Inspire the Next

HITACHI

Hitachi, Ltd., Infrastructure Systems Division
Turbine Control System

Date:Jun.25, 2016
Ref. No. TC-16-018

http://www.hitachi.co.jp/Div/omika/index.html

Rev.2

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1.2 Maintenance cost and reliability ····· 3

2. Upgrading method ····· 3

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7. Estimated Modification Period at site ····· 4

Attachments

Comparison for each upgrading	attachment-1
Major Equipment Support Status(Existing HIACS-3000 system)	attachment-2
Bill of materials	attachment-3
Layout drawing of Controller Upgrading	attachment-4
Specification of Controller Module	attachment-5
Network Type: Micro-Sigma 1000	attachment-6
Specification of EWS	attachment-7

HITACHI
Hitachi, Ltd., Infrastructure Systems Division
Turbine Control System
D-EHG/HITASS/AUX.

Date:Jun.25, 2016
Ref. No. TC-16-018

http://www.hitachi.co.jp/Div/omika/index.html

Rev.2

0. Summary

Hitachi would like to thank NSPC/TRENTON#6 Power Station for giving us the opportunity to submit this proposal.
As in line with any electronic products, some of the components in HIACS-3000 system have been outdated and supply for the fresh replacement modules are not possible.
Further to HIACS-3000 system, Hitachi has developed HISEC-04M/R900 controller series featuring 32 bit RISC(Reduced Instruction Set Computer) Power PC CPU and 1000Mbps communication network.
The following page or later summarizes our proposals in accordance with the result of our study.

Ref.No. TC-16-018

Upgrading for Turbine Control System at Trenton Generating Station Unit No.6 (1/2)

We would like to explain about upgrading for the existing "HIACS-3000" system that we have considered how to renew or retrofit in Turbine Control System(TCS:EHG and HITASS system).

1. Examination of upgrading for EHG/HITASS/AUX.

1.1 Upgrading for the existing "HIACS-3000" system

The existing EHG, HITASS, AUX. and EWS are constructed by HIACS-3000 based on our former control system, not latest our system.

Between EHG, HITASS, AUX. and EWS are connected by the transmission lines based on CV-network and have the interface by transmitting the data through CV-network. Moreover the existing EWS which maintenance and monitors the data is connected by PADT adapter through CV-network, and is common equipment among EHG ,HITASS and AUX. controllers etc..

Therefore, in case of considering upgrade for the existing HIACS-3000 system, it is important for EHG, HITASS, AUX. and EWS to evaluate the upgrade not separate but whole system.

And it is necessary to decide the retrofit range with the surrounding of the existing controller parts available.

1.2 Maintenance cost and reliability

Generally the service life of electronic equipment is said to be some 15 years. Service lives of individual parts or components are not equal, and reliability of the total system can be effectively maintained by replacing parts with relatively short lives.

Alternatively you can perform system maintenance to a considerable extent at the beginning of the wear failure period that follows the 15 year's occasional failure period.

This method may reduce total maintenance cost compared with a series of minor maintenance services performed from time to time.

Otherwise, in case of considering the maintenance and serviceability with regard to the whole system of your EHG/HITASS/AUX. controller and EWS based on HIACS-3000 system, we need to consider the following items comprehensively and build maintenance plan that has the considerationbalance of cost and reliability.

1)Life of electronic equipment using the existing EWS and EHG/HITASS/AUX. control panel

2)Considering alternative parts or equipments

3)Improvement of maintainability

4)Upgrading or adding new some functions

In the above present situation, the facility of your Trenton Generating Station Unit No.6 produced at 1990 is now in the shifting point from the occasional failure to the wear failure period.

By mean of keeping the reliability for the whole equipment or system, we think the replacement of some parts or component is effective support, especially for main parts like CPU, PS(power supply),EWS and PIO etc. based on the module in HIACS-3000 system.

However, more devices used the existing controller become unavailable.

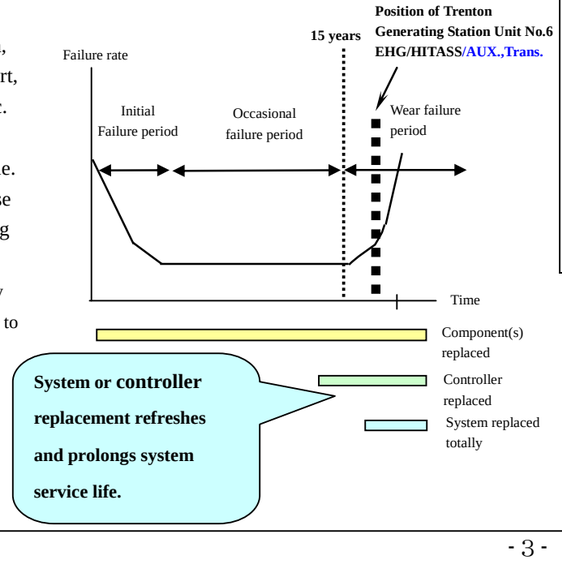
And it is impossible to deliver or repair devices or components, because there aren't any alternative devices using network and CPU in the existing HIACS-3000 system.

Considering the circumstances mentioned above, in present serviceability surrounding, we considered upgrading method for EWS etc., which gives priority to the following items.

*1)25 years have passed since production of EHG/HITASS/AUX. at Trenton Generating Station Unit No.6.

*2)Whether or not to keep the serviceability regarding HIACS-3000 controller.

*3)Economic evaluation through the whole maintenance.
(total cost of the whole maintenance in future)



2. Upgrading method

We considered the Upgrading for the whole EHG/HITASS,AUX. Control panel with EWS and Operator Control Panel.

3. Comparison for each upgrading (refer to attachment-1)

Table.1 comparison of upgrading summary

ITEM	DESCRIPTION
Upgrading range	EWS , Operator Control Panel and whole EHG/HITASS/AUX. control panel, Transducer panel
Control system after upgrading	HISEC-04M/R900 Series (our latest system)
Upgrading parts	1)EWS : Dell PC(Windows XP) ⇒HP or Dell PC(Windows 7) (generally) 2)Replacing the control panel entirely (our latest model on HSC4000/7000 PIO)
Upgrading Work	・Manufacture of new EHG/HITASS/AUX. control panel, Transducer panel and test ・Construction at site
Development factor	- (apply our Upgrading system)
Improvement	1)EWS function *Logic and PIO monitor based on CAD *Fulfilling support function used as regular inspection (Simulated input or operation etc.) 2)Transmission rate 500kbps ⇒ 1000Mbps 3)Upgrading for CPU, PIO and periphery circuit with power Supply module.

Ref.No. TC-16-018

Upgrading for Turbine Control System at Trenton Generating Station Unit No.6 (2/2)

4. Major Equipment Support Status (Existing HIASC-3000)

The table on attachment-2 shows maintenance condition of the existing main parts in your EHG/HITASS/AUX. control panel.

Hitachi stopped already manufacture of controllers HIACS-3000(our former control system) using at Trenton Generating Station Unit No.6, especially CPU in closely relation to EWS, because the electronic components are out of manufacturing by vendor or phase out according to technology progress. And it is difficult for us to repair as part or device level, too.

5. Evaluation for each upgrading

We considered and estimated the merit or effectiveness of each upgrading cases with our actual performance and experience as follows, according to the maintenance in future and the risk of progress schedule(modification work, test etc.,.) and verification check when upgrading, especially at site

Table.2 Evaluation for each upgrading

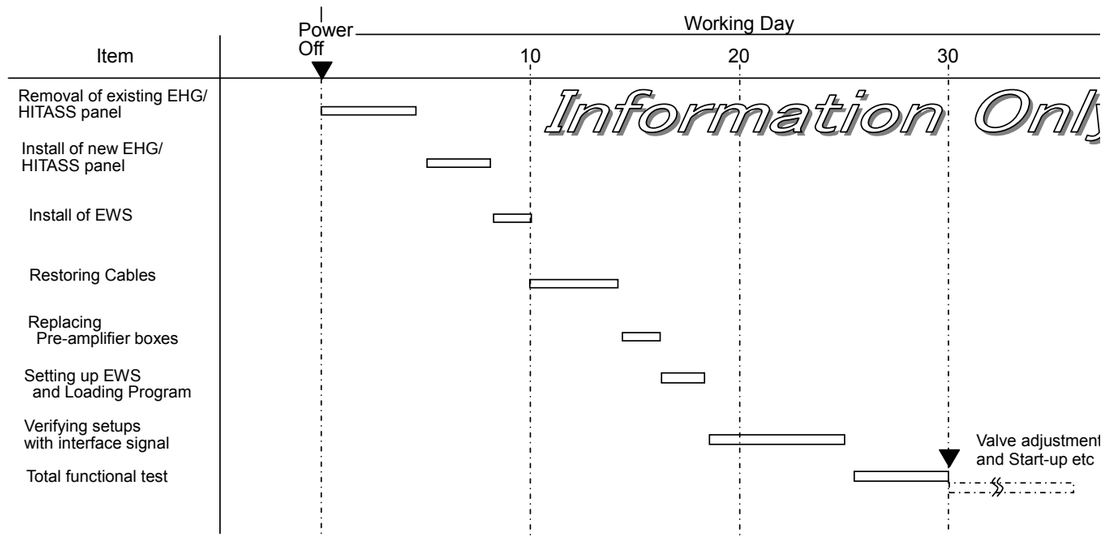
ITEM	Whole system upgrading
Modification work and verification items when upgrading	(Factory) ・Manufacture of new EHG/ HITASS/AUX. control panel with Conversion of logic from the existing ones to Upgrading system. ・Check of all functions and interfaces with between EWS,HMI and controller etc. in EHG/HITASS/AUX. control panel. (Site) ・Removal work of the existing EWS with the related cables. ・Removal work of the existing EHG/HITASS/AUX. control panel, Operator Control panel. ・Installation work of new EHG/HITASS/AUX. control panel, EWS and HMI ・Installation work of new trans-mission cables etc. for EWS and HMI. ・Total functional test
Merit or effectiveness	・Improvement of function according to upgrading System. .(refer to table.1) ・Feasible to keep serviceability as new system.

6. Conclusion

In accordance with the result of mentioned above our study, we would like to recommend the upgrading for the whole EHG/HITASS/AUX. control panel, Transducer panel with EWS.

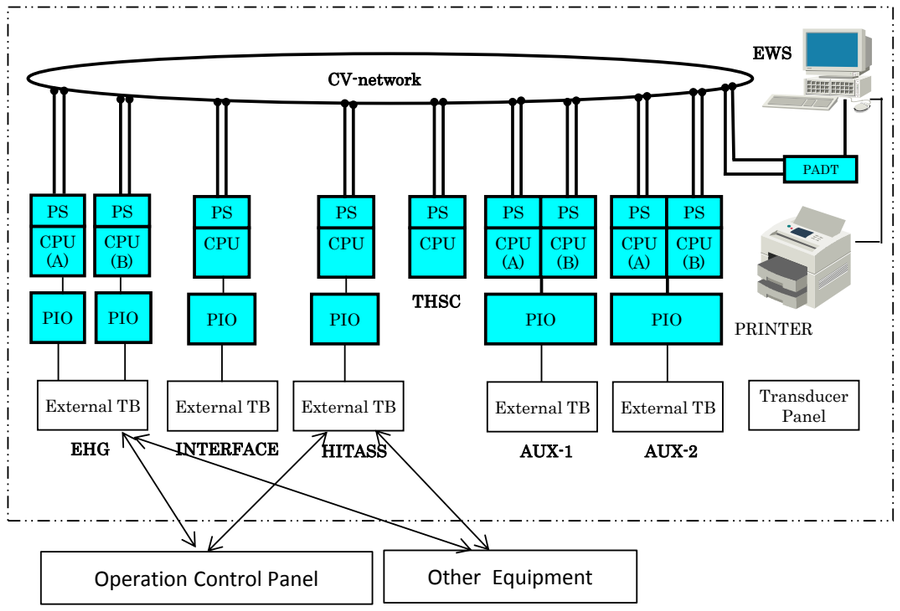
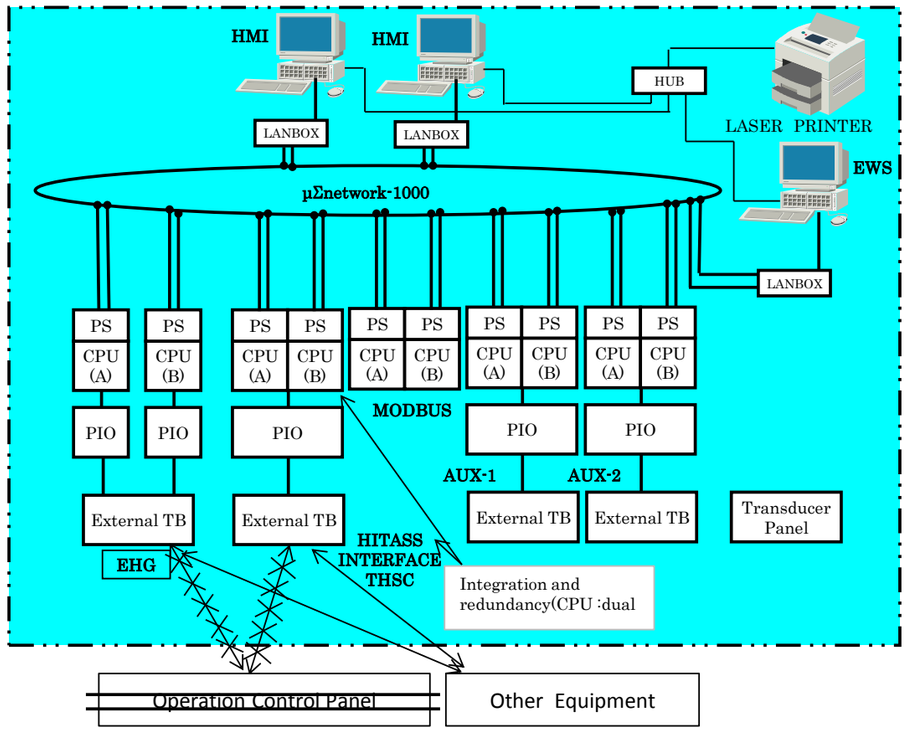
7. Estimated Modification Period at site (Information)

Following shows estimated modification period only from our experience.



Comparison for upgrading

Attachment-1(1/6)

ITEM	Exisiting	Upgrading the whole EHG/HITASS/AUX.
Upgrading range	 Exsiting (1)Network:CV-network (2)Power Supply(PS):Type:AVR600,AVR601 and PD5000 (3)CPU/PIO :CPU(H-3000),PIO:HSC4000 PIO (4)EWS: PC,PADT,PRINTER(A4 SIZE)	 Whole upgrading (1)Network:µΣnetwork-1000 (2)EHG/HITASS/AUX.Panel:Uprading the whole EHG/HITASS/AUX. panel note1:Integration and Redundancy for Interface, HITASS and THSC controllers note2:Addition of MODBUS controller note3:As for "External TB", apply the settings to the same type,wiring and location of existing EHG/HITASS/AUX. panel. (3)EWS: Upgrading EWS system(PC,LAN-BOX),PRINTER(A4 SIZE) (4)HMI: Upgrading HMI system(PC,LAN-BOX,HUB) (5)Transducer Panel:Upgrading the whole Transducer panel
Base plate of panel	–	Reuse
Panel	–	Renewal(Panel size is the same as existing one)
Modification work at site (EHG/HITASS/AUX. panel)	–	1)EWS equipment:Remove the existing EWS and install new EWS PC with transmission cables. 2)Remove work of the existing EHG/HITASS/AUX. panel, Transducer panel and Operator Control Panel. 3)Installation work of new EHG/HITASS/AUX. panel,Transducer panel and HMI PC with transmission cables.
Remark (Risk against upgrading etc.)	–	This upgrading has a risk against the progress schedule at site, because of the concentration of construction, modification work and test at site.

Attachment-1 (2/6)

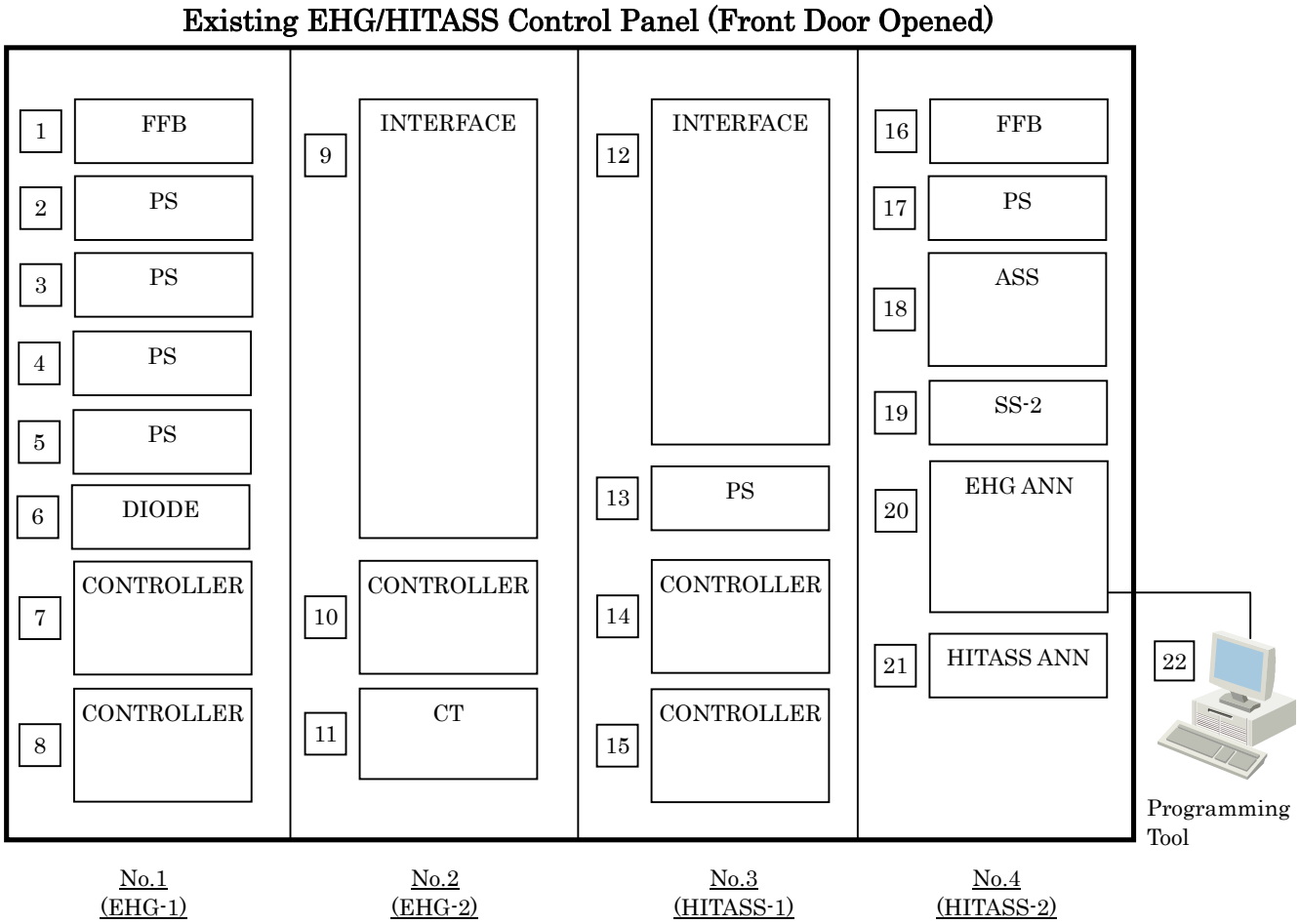
Table-3 Up Grading Procedure

Equipment	Status of Parts Supply	Whole system Up-grading	Remarks
Power Supply	No	✓	To the latest version of HIACS Power Supply equipment.
Controller	No	✓	To the latest version of HIACS controller.
Process I/O module	Partially No	✓	To the latest version of HIACS I/O.
Programming Tool (Personal Computer)	No	✓	Vender oriented MS-DOS PC → Windows 7 PC
Relay Unit etc.	Yes	✓	
Cabinet / Internal Wiring	—	✓	

Note: ✓ mark shows up grading

Attachment-1(3/6)

Fig. –1 Scope of up grading (Panel Image)



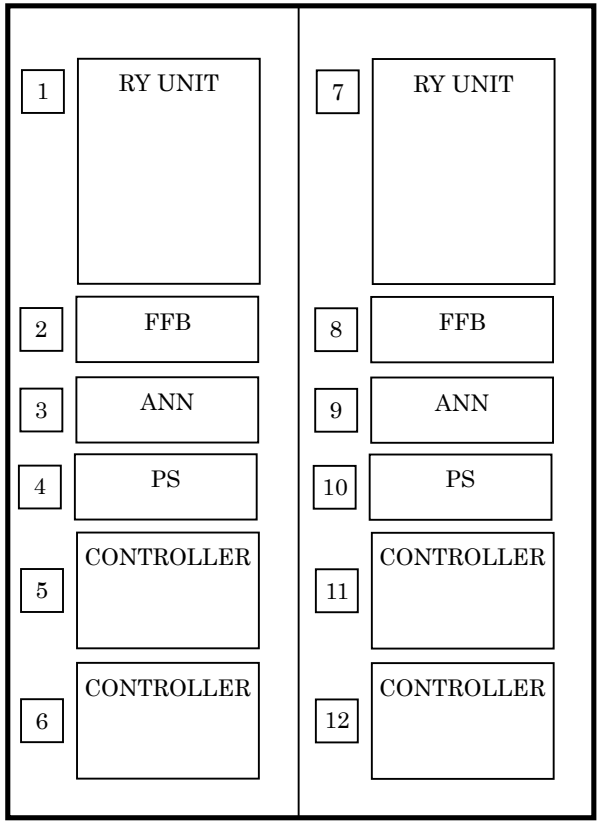
Scope of up grading

INDEX	DESCRIPTION
1	FFB Unit
2	EHG Control PS-1
3	EHG Control PS-2
4	Interface PS-1
5	Interface PS-2
6	DIODE Unit
7	EHG(A) Controller + I/O
8	EHG(B) Controller + I/O
9	Interface Unit
10	Interface Controller +I/O
11	CT Unit
12	Interface Unit
13	HITASS CPU PS
14	HITASS Controller +I/O
15	THSC Controller
16	FFB Unit
17	Control PS
18	ASS Unit
19	SS-2 Unit
20	EHG ANN Unit
21	HITASS ANN Unit
22	Programming Tool

Attachment-1(4/6)

Fig. –2 Scope of up grading (Panel Image)

Existing AUX. Control Panel (Front Door Opened)



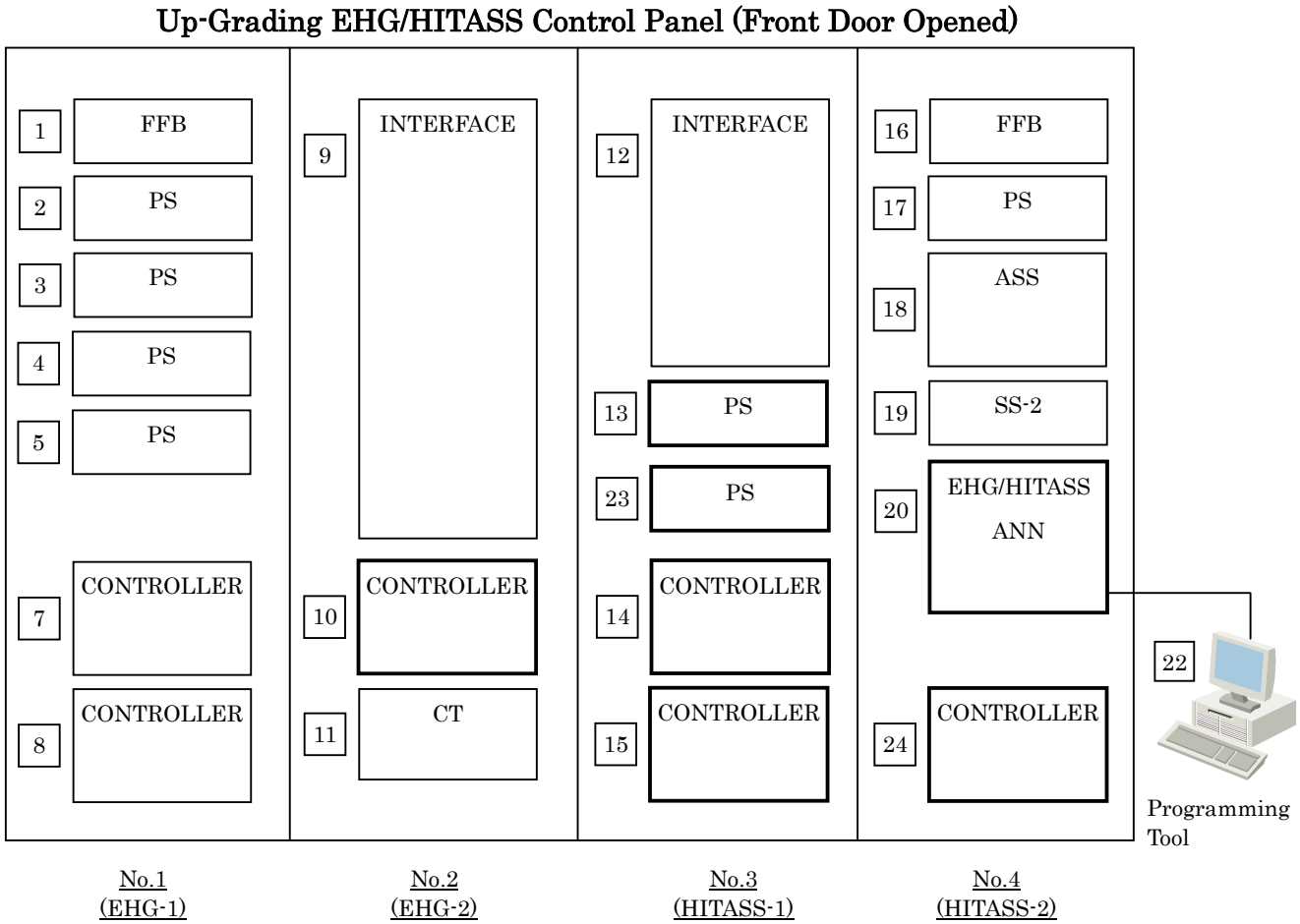
:Up-Grading Range

Scope of up grading

INDEX	DESCRIPTION
1	RY Unit
2	FFB Unit
3	ANN Unit
4	24V,48V DC P.S.
5	PLC-1 Controller + I/O
6	PLC-1 I/O
7	RY Unit
8	FFB Unit
9	ANN Unit
10	24V,48V DC P.S.
11	PLC-1 Controller + I/O
12	PLC-1 I/O

Attachment-1(5/6)

Fig. –3 Scope of up grading (Panel Image)



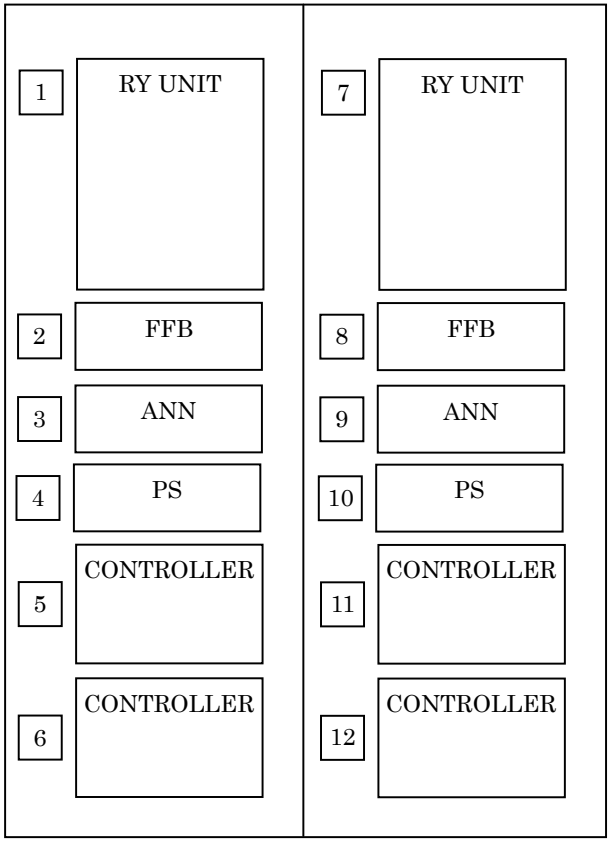
Scope of up grading

INDEX	DESCRIPTION
1	FFB Unit
2	EHG Control PS-1
3	EHG Control PS-2
4	Interface PS-1
5	Interface PS-2
6	
7	EHG(A) Controller + I/O
8	EHG(B) Controller + I/O
9	Interface Unit
10	PLU/BUG Unit
11	CT Unit
12	Interface Unit
13	HITASS CPU PS-1
14	HITASS Controller +I/O
15	HITASS Controller +I/O
16	FFB Unit
17	Control PS
18	ASS Unit
19	SS-2 Unit
20	EHG/HITASS ANN Unit
21	
22	Programming Tool
23	HITASS CPU PS-2
24	MODBUS Controller

Attachment-1(6/6)

Fig. –4 Scope of up grading (Panel Image)

Up-Grading AUX. Control Panel (Front Door Opened)



Scope of up grading

INDEX	DESCRIPTION
1	RY Unit
2	FFB Unit
3	ANN Unit
4	24V,48V DC P.S.
5	PLC-1 Controller + I/O
6	PLC-1 I/O
7	RY Unit
8	FFB Unit
9	ANN Unit
10	24V,48V DC P.S.
11	PLC-2 Controller + I/O
12	PLC-2 I/O

Attachment-2(1/2)

Major Equipment Support Status (Existing HIACS-3000 system using Trenton Generating Station Unit No.6)

Category	No.	Existing Equipment		Quantity / Unit							Existing Status of Parts Supply	
		Item	Type	EHG	HITASS	Interface	THSC	PADT	AUX.	Total	Code	Description
Power Supply	1	Power Supply Unit	PD5000	4	2				2	8	AM	Type PE6000
	2	Input	MPD050A	4	2				2	8	AM	Type MPE060A
	3	Output 5VDC	MPD100A		1					1	AM	Type MPE111A
	4	Output +/-15VDC	MPD300A	6	2					8	AM	Type MPE310A or MPE710A
	5	Output 24VDC(48VDC)	MPD400A	8	4				6	18	AM	Type MPE411A
	6											
	7	Slot	AVR600B	2		1	1		4	8	X	
	8	Slot	AVR601B	2		1	1		4	8	X	
	9											
	10											
Controller	11	Controler module for HIACS-3000	LPC133A	2	1	1	1		4	9	X	
	12	Padt Adapter	LCP132A					1		1	X	
	13											
	14											
	15											
	16											
	17											
	18											
	19											
	20											
	21											
	22											
	23											
	24											
Process I/O Module	25	Digital Input	LPD200A	4	4	2			1	11	A	Type LYD000A
	26	Digital Output	LPD150A	4	6	3				13	A	Type LYD105A
	27	Analog Input	LPA200A	2		2				4	A	Type LYA200A
	28	THC AI	LPA210A		2	2				4	AM	Type LYA210A:Req'd Hardware & Software Modification
	29	Analog Output	LPA300A	2	1	1				4	A	Type LYA300A
	30	Pulse Train Input	LPT020A	6						6	AM	Type LYT000A:Req'd Hardware & Software Modification
	31	DCM	LPF230A						16	16	X	
	32	CV-IF	LNT240A						2	2	X	
	33	PI/O CE	LCE250A						2	2	A	Type LCE250B
	34	Unit Driver	LUD060A						2	2	A	Type LUD070A
	35	Digital Output	LPD301A						4	4	A	Type LYD301A
	36											
	37											
	38											
	39											
	40											

Note
Code A; Alternative equipment is available
Code AM; Alternative equipment is available but modification work is required
Code R; Repair is in service
Code S ; Existing equipment is still available
Code X; Discontinued

Attachment-2(2/2)

Category	No.	Existing Equipment		Quantity / Unit							Existing Status of Parts Supply	
		Item	Type	EHG	HITASS	Interface	THSC		AUX.	Total	Code	Description
Peripheral Discrete Module	41	BUG	HFV102A	3						3	X	
	42	PLU	AUD001A	3						3	X	
	43	AMP	AOA110A	3						3	X	
	44	Hg RY	ARY110B	3						3	X	
	45	mA/V	ACV001A	7						7	X	
	46	V/mA	AVC000C	7	8					15	X	
	47	Hg RY	ARY010A	4						4	X	
	48	Rectifier	ASA301B	3						3	X	
	49	OSC	KOA041D	2						2	S	
	50	SERVO	ASA505A	4						4	X	
	51	Pre Amp.	LTC064A	3						3	AM	LTC080A
	52											
	53											
	54											
	55											
Others	56	Maintenance tool	B16(Windows XP)	1						1	X	
	57											
	58											
	59	Speed Pick up	4-0076	3						3	A	MP-988
	60	Valve Position Detector	GM7896-6	3						3	S.A,AM	(Equiv, as it is)
	61	Relay,Fuse,Connector				1			1	2	S.A,AM	(Equiv, as it is)
	62											
	63											
	64											
	65											
	66											
	67											
	68											
	69											
	70											

Note

Code A; Alternative equipment is available
Code AM; Alternative equipment is available but modification work is required
Code R; Repair is in service
Code S ; Existing equipment is still available
Code X; Discontinued

Attachment-3(1/3)

Bill of materials(EHG/HITASS CUBICLE)

Existing Equipment						Upgrading Equipment						Description
Category	No.	Item	Type	Maker	Quantity	Category	No.	Item	Type	Maker	Quantity	
FFB Unit	1	FFB Unit	-	Hitachi	1	FFB Unit	1	FFB Unit	-	Hitachi	1	
EHG Control PS-1	1	Power Supply Unit	PD5000	Hitachi	1	EHG Control PS-1	1	Power Supply Unit	PE6000	Hitachi	1	
	2	Input	MPD050A	Hitachi	1		2	Input	MPE060A	Hitachi	1	
	3	Output +/-15VDC	MPD300A	Hitachi	3		3	Output +/-15VDC	MPE710A	Hitachi	2	
	4	Output 24VDC(48VDC)	MPD400A	Hitachi	1		4	Output 24VDC(48VDC)	MPE411A	Hitachi	1	
EHG Control PS-2	1	Power Supply Unit	PD5000	Hitachi	1	EHG Control PS-2	1	Power Supply Unit	PE6000	Hitachi	1	
	2	Input	MPD050A	Hitachi	1		2	Input	MPE060A	Hitachi	1	
	3	Output +/-15VDC	MPD300A	Hitachi	3		3	Output +/-15VDC	MPE710A	Hitachi	2	
	4	Output 24VDC(48VDC)	MPD400A	Hitachi	1		4	Output 24VDC(48VDC)	MPE411A	Hitachi	1	
Interface PS-1	1	Power Supply Unit	PD5000	Hitachi	1	Interface PS-1	1	Power Supply Unit	PE6000	Hitachi	1	
	2	Input	MPD050A	Hitachi	1		2	Input	MPE060A	Hitachi	1	
	3	Output +/-15VDC	MPD400A	Hitachi	4		3	Output +/-15VDC	MPE411A	Hitachi	4	
Interface PS-2	1	Power Supply Unit	PD5000	Hitachi	1	Interface PS-1	1	Power Supply Unit	PE6000	Hitachi	1	
	2	Input	MPD050A	Hitachi	1		2	Input	MPE060A	Hitachi	1	
	3	Output +/-15VDC	MPD400A	Hitachi	4		3	Output +/-15VDC	MPE411A	Hitachi	4	
DIODE Unit	1	DIODE Unit	-	Hitachi	1	-	1	-	-	-	-	
EHG(A) Controller +I/O	1	Controller Rack	HSC4010	Hitachi	1	EHG(A) Controller +I/O	1	Controller Rack	HSC4010	Hitachi	1	
	2	Slot	AVR600B	Hitachi	1		2	Slot	AVR680A	Hitachi	2	
	3	Slot	AVR601B	Hitachi	1		3	-	-	-	-	
	4	Controller module for HIACS-3000	LPC133A	Hitachi	1		4	Controller module for HIACS	LPU802A	Hitachi	1	
	5	Pulse Train Input	LPT020A	Hitachi	3		5	Pulse Train Input	LYT000A	Hitachi	1	
	6	Analog Input	LPA200A	Hitachi	1		6	Analog Input	LYA200A	Hitachi	-	
	7	Analog Output	LPA300A	Hitachi	1		7	Analog Output	LYA300A	Hitachi	1	
	8	Digital Input	LPD200A	Hitachi	2		8	Digital Input	LYD000A	Hitachi	2	
	9	Digital Output	LPD150A	Hitachi	2		9	Digital Output	LYD105A	Hitachi	2	
	10	-	-	-	-		10	Analog Input	LYA000A	Hitachi	1	
	11	-	-	-	-		11	LVDT	AEH020A	Hitachi	1	
	12	-	-	-	-		12	SERVO	AEH000A	Hitachi	1	
EHG(B) Controller +I/O	1	Controller Rack	HSC4010	Hitachi	1	EHG(B) Controller +I/O	1	Controller Rack	HSC4010	Hitachi	1	
	2	Slot	AVR600B	Hitachi	1		2	Slot	AVR680A	Hitachi	2	
	3	Slot	AVR601B	Hitachi	1		3	-	-	-	-	
	4	Controller module for HIACS-3000	LPC133A	Hitachi	1		4	Controller module for HIACS	LPU802A	Hitachi	1	
	5	Pulse Train Input	LPT020A	Hitachi	3		5	Pulse Train Input	LYT000A	Hitachi	1	
	6	Analog Input	LPA200A	Hitachi	1		6	Analog Input	LYA200A	Hitachi	-	
	7	Analog Output	LPA300A	Hitachi	1		7	Analog Output	LYA300A	Hitachi	1	
	8	Digital Input	LPD200A	Hitachi	2		8	Digital Input	LYD000A	Hitachi	2	
	9	Digital Output	LPD150A	Hitachi	2		9	Digital Output	LYD105A	Hitachi	2	
	10	-	-	-	-		10	Analog Input	LYA000A	Hitachi	1	
	11	-	-	-	-		11	LVDT	AEH020A	Hitachi	1	
	12	-	-	-	-		12	SERVO	AEH000A	Hitachi	1	
Inteface Unit	1	BUG	HFV102A	Hitachi	3	Inteface Unit	1	PLU/BUG	AEH011A	Hitachi	3	
	2	PLU	AUD001A	Hitachi	3		2					
	3	AMP	AOA110A	Hitachi	4		3	-	-	-	-	
	4	Hg RY	ARY110B	Hitachi	3		4	-	-	-	-	
	5	mA/V	ACV001A	Hitachi	7		5	-	-	-	-	
	6	V/mA	AVC000C	Hitachi	7		6	Transducer	(Later)	(Later)	(Later)	
	7	Hg RY	ARY010A	Hitachi	4		7	Amp RY	ASA600A	Hitachi	2	
	8	Rectifier	ASA301B	Hitachi	3		8	-	-	-	-	
	9	OSC	KOA041D	Hitachi	2		9	-	-	-	-	
	10	SERVO	ASA505A	Hitachi	4		10	-	-	-	-	
	11	-	-	-	-		11	Controller Rack	HSC4010	Hitachi	1	
	12	-	-	-	-		12	Slot	AVR680A	Hitachi	2	

Attachment-3(2/3)

Bill of materials(EHG/HITASS CUBICLE)

Existing Equipment						Upgrading Equipment						Description
Category	No.	Item	Type	Maker	Quantity	Category	No.	Item	Type	Maker	Quantity	
Interface Controller +I/O	1	Controller Rack	HSC4010	Hitachi	1	-	1	-	-	-	Integration	
	2	Slot	AVR600B	Hitachi	1		2	-	-	-		
	3	Slot	AVR601B	Hitachi	1		3	-	-	-		
	4	Controller module for HIACS-3000	LPC133A	Hitachi	1		4	-	-	-		
	5	Analog Input	LPA200A	Hitachi	2		5	-	-	-		
	6	Analog Output	LPA300A	Hitachi	1		6	-	-	-		
	7	Digital Input	LPD200A	Hitachi	2		7	-	-	-		
	8	Digital Output	LPD150A	Hitachi	3		8	-	-	-		
Interface Unit	1	V/mA	AVC000C	Hitachi	2	Interface Unit	1	V/mA	AVC000C	Hitachi	-	
HITASS Power Supply	1	Power Supply Unit	PD5000	Hitachi	1	HITASS Power Supply (1)	1	Power Supply Unit	PE6000	Hitachi	1	
	2	Input	MPD050A	Hitachi	1		2	Input	MPE060A	Hitachi	1	
	3	Output 5VDC	MPD100A	Hitachi	1		3	Output 5VDC	MPE111A	Hitachi	1	
	4	Output +/-15VDC	MPD300A	Hitachi	1		4	Output +/-15VDC	MPE310A	Hitachi	1	
	5	Output 24VDC(48VDC)	MPD400A	Hitachi	1		5	Output 24VDC(48VDC)	MPE411A	Hitachi	1	
-	1	-	-	-	-	HITASS Power Supply (2)	1	Power Supply Unit	PE6000	Hitachi	1	Redundancy
	2	-	-	-	-		2	Input	MPE060A	Hitachi	1	
	3	-	-	-	-		3	Output 5VDC	MPE111A	Hitachi	1	
	4	-	-	-	-		4	Output +/-15VDC	MPE310A	Hitachi	1	
	5	-	-	-	-		5	Output 24VDC(48VDC)	MPE411A	Hitachi	1	
HITASS Controller +I/O	1	Controller Rack	HSC4010	Hitachi	1	HITASS Controller +I/O	1	Controller Rack	HSC4010	Hitachi	1	
	2	Controller module for HIACS-3000	LPC133A	Hitachi	1		2	Controller module for HIACS	LPU802A	Hitachi	2	Integration and Redundancy for Interface,HITASS and THSC Controller
	3	THC AI	LPA210A	Hitachi	2		3	THC AI	LYA210A	Hitachi	2	
	4	Analog Output	LPA300A	Hitachi	1		4	Analog Output	LYA300A	Hitachi	1	
	5	Digital Input	LPD200A	Hitachi	4		5	-	-	-	-	
	6	Digital Output	LPD150A	Hitachi	5		6	-	-	-	-	
	7	-	-	-	-		7	Analog Input	LYA000A	Hitachi	2	
	8	-	-	-	-		8	Analog Output	LYA300A	Hitachi	2	
	9	-	-	-	-		9	Controler module for HIACS	LCE250B	Hitachi	1	
-	1	-	-	-	-	HITASS Controller +I/O	1	Controller Rack	HSC4010	Hitachi	1	
	2	-	-	-	-		2	Digital Input	LYD000A	Hitachi	6	
	3	-	-	-	-		3	Digital Output	LYD105A	Hitachi	8	
	4	-	-	-	-		4	Unit Driver	LUD070A	Hitachi	1	
THSC Controller +I/O	1	Controller Rack	HSC4010	Hitachi	1	-	1	-	-	-	Integration	
	2	Slot	AVR600B	Hitachi	1		2	-	-	-		
	3	Slot	AVR601B	Hitachi	1		3	-	-	-		
	4	Controller module for HIACS-3000	LPC134A	Hitachi	1		4	-	-	-		
FFB Unit	1	FFB Unit	-	Hitachi	1	FFB Unit	1	FFB Unit	-	Hitachi	1	
Control PS	1	Power Supply Unit	PD5000	Hitachi	1	Control PS	1	Power Supply Unit	PE6000	Hitachi	1	
	2	Input	MPD050A	Hitachi	1		2	Input	MPE060A	Hitachi	1	
	3	Output +/-15VDC	MPD300A	Hitachi	1		3	Output +/-15VDC	MPE310A	Hitachi	1	
	4	Output 24VDC(48VDC)	MPD400A	Hitachi	3		4	Output 24VDC(48VDC)	MPE411A	Hitachi	3	
ASS Unit	1	ASS Unit	-	Hitachi	1	ASS Unit	1	ASS Unit	-	Hitachi	1	
SS-2 Unit	1	SS-2 Unit	-	Hitachi	1	SS-2 Unit	1	SS-2 Unit	-	Hitachi	1	
EHG ANN Unit	1	EHG ANN Unit	-	Hitachi	1	EHG/HITASS ANN Unit	1	EHG/HITASS ANN Unit	-	Hitachi	1	
HITASS ANN Unit	1	HITASS ANN Unit	-	Hitachi	1	-	1	-	-	-	-	
-	1	-	-	-	-	MODBUS Controller	1	Controller Rack	HSC4010	Hitachi	1	
	2	-	-	-	-		2	Slot	AVR680A	Hitachi	2	
	3	-	-	-	-		3	Controller module for HIACS	LPU802A	Hitachi	2	
	4	-	-	-	-		4	Digital Input	LYD000A	Hitachi	1	
	5	-	-	-	-		5	Digital Output	LYD105A	Hitachi	1	
Others	1	Maintenance tool	Dell PC	Hitachi	1	Others	1	Maintenance tool	HP or Dell PC	HP	1	
	2	-	-	-	-		2	LAN-BOX	H-7628-52	Hitachi	1	For Maintenance tool
	3	Pre Amp.	LTC064A	Hitachi	3		3	Pre Amp.	LTC080A	Hitachi	-	The other order
	4	Speed Pick up	4-0076	Sanken Airpacks	3		4	Speed Pick up	MP-988	Ono soki	-	The other order
	5	Valve Position Detector	GM-series	Kavlico	3		5	Valve Position Detector	GM-series	Kavlico	-	The other order
	6	Relay,Fuse,Connector					6	Relay,Fuse,Connector			1 Set	

Attachment-3(3/3)

Bill of materials(AUX. LOGIC CUBICLE)

Existing Equipment						Upgrading Equipment						Description
Category	No.	Item	Type	Maker	Quantity	Category	No.	Item	Type	Maker	Quantity	
RY Unit	1	RY Unit	-	Hitachi	1	**RY Unit**	1	RY Unit	-	Hitachi	1	
FFB Unit	1	FFB Unit	-	Hitachi	1	**FFB Unit**	1	FFB Unit	-	Hitachi	1	
ANN Unit	1	ANN Unit	-	Hitachi	1	**ANN Unit**	1	ANN Unit	-	Hitachi	1	
AUX Control PS-1	1	Power Supply Unit	PD5000	Hitachi	1	**AUX Control PS-1**	1	Power Supply Unit	PD5000	Hitachi	1	
	2	Input	MPD050A	Hitachi	1		2	Input	MPD050A	Hitachi	1	
	4	Output 24VDC(48VDC)	MPD400A	Hitachi	3		4	Output 24VDC(48VDC)	MPD400A	Hitachi	3	
PLC-1 Controller +I/O	1	Controller Rack	HSC4010	Hitachi	1	**PLC-1 Controller +I/O**	1	Controller Rack	HSC4010	Hitachi	1	
	2	Slot	AVR600B	Hitachi	1		2	Slot	AVR680A	Hitachi	2	
	3	Slot	AVR601B	Hitachi	1		3	-	-	-	-	
	4	Controller module for HIACS-3000	LPC133A	Hitachi	1		4	Controller module for HIACS	LPU802A	Hitachi	1	
	5	DCM	LPF230A	Hitachi	3		5	DCM	LPF230*	Hitachi	3	Renewal or new manufacture
	6	CV-IF	LNT240A	Hitachi	1		6	-	-	-	-	
	7	CE	LCE250A	Hitachi	1		7	CE	LCE250B	Hitachi	1	
PLC-1 +I/O	1	Controller Rack	HSC4010	Hitachi	1	**PLC-1 +I/O**	1	Controller Rack	HSC4010	Hitachi	1	
	2	Slot	AVR600B	Hitachi	1		2	Slot	AVR680A	Hitachi	2	
	3	Slot	AVR601B	Hitachi	1		3	-	-	-	-	
	4	DCM	LPF230A	Hitachi	5		4	DCM	LPF230*	Hitachi	5	Renewal or new manufacture
	5	DI	LPD200A	Hitachi	1		5	DI	LYD000A	Hitachi	1	
	6	DO	LPD301A	Hitachi	1		6	DO	LYD301A	Hitachi	1	
	7	UD	LUD060A	Hitachi	1		7	UD	LUD070A	Hitachi	1	
RY Unit	1	RY Unit	-	Hitachi	1	**RY Unit**	1	RY Unit	-	Hitachi	1	
FFB Unit	1	FFB Unit	-	Hitachi	1	**FFB Unit**	1	FFB Unit	-	Hitachi	1	
ANN Unit	1	ANN Unit	-	Hitachi	1	**ANN Unit**	1	ANN Unit	-	Hitachi	1	
AUX Control PS-2	1	Power Supply Unit	PD5000	Hitachi	1	**AUX Control PS-1**	1	Power Supply Unit	PD5000	Hitachi	1	
	2	Input	MPD050A	Hitachi	1		2	Input	MPD050A	Hitachi	1	
	4	Output 24VDC(48VDC)	MPD400A	Hitachi	3		4	Output 24VDC(48VDC)	MPD400A	Hitachi	3	
PLC-2 Controller +I/O	1	Controller Rack	HSC4010	Hitachi	1	**PLC-2 Controller +I/O**	1	Controller Rack	HSC4010	Hitachi	1	
	2	Slot	AVR600B	Hitachi	1		2	Slot	AVR680A	Hitachi	2	
	3	Slot	AVR601B	Hitachi	1		3	-	-	-	-	
	4	Controller module for HIACS-3000	LPC133A	Hitachi	1		4	Controller module for HIACS	LPU802A	Hitachi	1	
	5	DCM	LPF230A	Hitachi	3		5	DCM	LPF230*	Hitachi	3	Renewal or new manufacture
	6	CV-IF	LNT240A	Hitachi	1		6	-	-	-	-	
	7	CE	LCE250A	Hitachi	1		7	CE	LCE250B	Hitachi	1	
PLC-2 +I/O	1	Controller Rack	HSC4010	Hitachi	1	**PLC-2 +I/O**	1	Controller Rack	HSC4010	Hitachi	1	
	2	Slot	AVR600B	Hitachi	1		2	Slot	AVR680A	Hitachi	2	
	3	Slot	AVR601B	Hitachi	1		3	-	-	-	-	
	4	DCM	LPF230A	Hitachi	5		4	DCM	LPF230*	Hitachi	5	Renewal or new manufacture
	6	DO	LPD301A	Hitachi	3		6	DO	LYD301A	Hitachi	3	
	7	UD	LUD060A	Hitachi	1		7	UD	LUD070A	Hitachi	1	
Others	1	Relay,Fuse,Connector	Dell PC	Hitachi	1	**Others**	1	Relay,Fuse,Connector			1 Set	

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Attachment-4(1/7)

Layout drawing of EHG/HITASS Controller Upgrading (Existing & After Upgrading) (1/2)

------- *Existing* -------

Panel No. EHG-1
System EHG(A) CPU(same as EHG(B) CPU)

Slot No.	0	1	2	3	4	5	6	7	8	9	A	B	C	D	E	F	Z
HSC4010 Type	AVR600B		AVR601B		LCP133A		LPT020A	LPT020A	LPT020A	LPA200A	LPA300A	LPD200A	LPD200A	LPD150A	LPD150A		
Rack Type Name	AVR		AVR		CPU		PTI	PTI	PTI	AI	AO	DI	DI	DO	DO		

------- *After Upgrading* -------

Panel No. EHG-1
System EHG(A) CPU(same as EHG(B) CPU)

Slot No.	0	1	2	3	4	5	6	7	8	9	A	B	C	D	E	F	Z
HSC4010 Type	AVR680A		AVR680A		LPU802A		LYT000A	AEH000A	AEH020A	LYA000A	LYA300A	LYD000A	LYD000A	LYD105A	LYD105A		
Rack Type Name	AVR		AVR		CPU		PTI	SERVO	LVDT	AI	AO	DI	DI	DO	DO		

Panel No. EHG-2
System PLU/BUG UNIT

Slot No.	0	1	2	3	4	5	6	7	8	9	A	B	C	D	E	F	Z
HSC4010 Type	AVR680A		AVR680A				AEH011A				AEH011A				AEH011A		
Rack Type Name	AVR		AVR				PLU/BUG				PLU/BUG				PLU/BUG		

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Attachment-4(2/7)

Layout drawing of EHG/HITASS Controller Upgrading (Existing & After Upgrading) (2/2)

------- Existing -------

Panel No. EHG-2
System INTERFACE CPU

Slot No.	0	1	2	3	4	5	6	7	8	9	A	B	C	D	E	F	Z
HSC4010 Type	AVR600B		AVR601B		LCP133A		LPA200A	LPA200A	LPA300A	LPD200A	LPD200A		LPD150A	LPD150A	LPD150A		
Rack Type Name	AVR		AVR		CPU		AI	AI	AO	DI	DI		DO	DO	DO		

Panel No. HITASS-1
System HITASS CPU

Slot No.	0	1	2	3	4	5	6	7	8	9	A	B	C	D	E	F	Z
HSC4010 Type	LCP133A			LPA210A	LPA210A		LPA300A	LPD200A	LPD200A	LPD200A	LPD200A	LPD150A	LPD150A	LPD150A	LPD150A	LPD150A	
Rack Type Name	CPU			AI	AI		AO	DI	DI	DI	DI	DO	DO	DO	DO	DO	

Panel No. HITASS-1
System THSC CPU

Slot No.	0	1	2	3	4	5	6	7	8	9	A	B	C	D	E	F	Z
HSC4010 Type	AVR600B		AVR601B		LCP133A												
Rack Type Name	AVR		AVR		CPU												

Integration and Redundancy for Interface, HITASS and THSC contollers.

------- After Upgrading -------

Panel No. HITASS-1
System HITASS CPU

Slot No.	0	1	2	3	4	5	6	7	8	9	A	B	C	D	E	F	Z
HSC4010 Type	LPU802A		LPU802A			LYA210A	LYA210A				LYA000A	LYA000A		LYA300A	LYA300A		LCE250B
Rack Type Name	CPU		CPU		SLD	AI	AI	SLD			AI	AI		AO	AO		CE

Panel No. HITASS-1
System HITASS PI/O

Slot No.	0	1	2	3	4	5	6	7	8	9	A	B	C	D	E	F	Z
HSC4010 Type	LYD000A	LYD000A	LYD000A	LYD000A	LYD000A	LYD000A		LYD105A	LYD105A	LYD105A	LYD105A	LYD105A	LYD105A	LYD105A	LYD105A		LUD070A
Rack Type Name	DI	DI	DI	DI	DI	DI		DO	DO	DO	DO	DO	DO	DO	DO		UD

Panel No. HITASS-2
System MODBUS CPU

Slot No.	0	1	2	3	4	5	6	7	8	9	A	B	C	D	E	F	Z
HSC4010 Type	AVR680A		AVR680A		LPU802A		LPU802A				LYD000A		LYD105A				
Rack Type Name	AVR		AVR		CPU		CPU				DI		DO				

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Attachment-4(3/7)

Layout drawing of EHG/HITASS Controller Upgrading(Power Supply Unit) (Existing & After Upgrading) (1/2)

------- *Existing* -------

Panel No. EHG-1
System EHG Control PS-1(same as Control PS-2)

		Input Unit	Output 1	Output 2	Output 3	Output 4
Rack Type PD-5000	Type	MPD050A	MPD300A	MPD300A	MPD300A	MPD400A
	Name		+/-15V	+/-15V	+/-15V	24V

Panel No. EHG-1
System Interface PS-1(same as Interface PS-2)

Slot No.		Input Unit	Output 1	Output 2	Output 3	Output 4
Rack Type PD-5000	Type	MPD050A	MPD400A	MPD400A	MPD400A	MPD400A
	Name		24V	24V	48V	48V

------- *After Upgrading* -------

Panel No. EHG-1
System EHG Control PS-1(same as PS-2)

		Input Unit	Output 1	Output 2	Output 3	Output 4	Output 5
Rack Type PE-6000	Type	MPE060A	MPE710A	MPE710A		MPE411A	
	Name		+/-15V	+/-15V		24V	

Panel No. EHG-1
System Interface PS-1(same as PS-2)

Slot No.		Input Unit	Output 1	Output 2	Output 3	Output 4	Output 5
Rack Type PE-6000	Type	MPE060A	MPE411A	MPE411A	MPE411A	MPE411A	
	Name		24V	24V	48V	48V	

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Attachment-4(4/7)

Layout drawing of EHG/HITASS Controller Upgrading(Power Supply Unit) (Existing & After Upgrading) (2/2)

------- *Existing* -------

Panel No. HIATSS-1
System HITASS CPU PS

		Input Unit	Output 1	Output 2	Output 3	Output 4
PD-5000 Rack Type	Type	MPD050A	MPD100A	MPD310A	MPD400A	
	Name		5V	+/-15V	24V	

Panel No. HITASS-2
System Control PS

Slot No.		Input Unit	Output 1	Output 2	Output 3	Output 4
PD-5000 Rack Type	Type	MPD050A	MPD400A	MPD300A	MPD400A	MPD400A
	Name		24V	+/-15V	24V	48V

------- *After Upgrading* -------

Panel No. HITASS-1
System HITASS CPU PS-1(same as PS-2)

		Input Unit	Output 1	Output 2	Output 3	Output 4	Output 5
PE-6000 Rack Type	Type	MPE060A	MPE111A	MPE310A	MPE411A		
	Name		5V	+/-15V	24V		

Panel No. HITASS-2
System Control PS

Slot No.		Input Unit	Output 1	Output 2	Output 3	Output 4	Output 5
PE-6000 Rack Type	Type	MPE060A	MPE411A	MPE310A	MPE411A	MPE411A	
	Name		24V	+/-15V	24V	48V	

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Attachment-4(5/7)

Layout drawing of AUX. Controller Upgrading (Existing & After Upgrading) (1/2)

------- Existing -------

Panel No. AUX-1
System PLC GROUP-1

Slot No.	0	1	2	3	4	5	6	7	8	9	A	B	C	D	E	F	Z
HSC4010 Type	AVR600B		AVR601B		LCP133A		LCP133A		LPF230A	LPF230A	LPF230A					LNT240A	LCE250A
Rack Type Name	AVR		AVR		CPU		CPU		DCM	DCM	DCM					CVIF	CE

Panel No. AUX-1
System PLC GROUP-1

Slot No.	0	1	2	3	4	5	6	7	8	9	A	B	C	D	E	F	Z
HSC4010 Type	AVR600B		AVR601B		LPF230A	LPF230A	LPF230A	LPF230A	LPF230A						LPD200A	LPD301A	LUD060A
Rack Type Name	AVR		AVR		DCM	DCM	DCM	DCM	DCM						DI	DO	UD

------- After Upgrading -------

Panel No. AUX-1
System PLC GROUP-1

Slot No.	0	1	2	3	4	5	6	7	8	9	A	B	C	D	E	F	Z
HSC4010 Type	AVR680A		AVR680A		LPU802A		LPU802A		LYD000A	LYD000A	LYD000A	LYD000A					LCE250B
Rack Type Name	AVR		AVR		CPU		CPU		DI	DI	DI	DI					CE

Panel No. AUX-1
System PLC GROUP-1

Slot No.	0	1	2	3	4	5	6	7	8	9	A	B	C	D	E	F	Z
HSC4010 Type	AVR680A		AVR680A		LYD110A	LYD110A	LYD110A	LYD110A		LYD105A	LYD105A	LYD105A	LYD105A		LYD000A	LYD110A	LUD070A
Rack Type Name	AVR		AVR		DO	DO	DO	DO		DO	DO	DO	DO		DI	DO	UD

To 6/7

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Attachment-4(6/7)

Layout drawing of AUX. Controller Upgrading (Existing & After Upgrading) (2/2)

------- *Existing* -------

Panel No. AUX-2
System PLC GROUP-2

Slot No.	0	1	2	3	4	5	6	7	8	9	A	B	C	D	E	F	Z
HSC4010 Type	AVR600B		AVR601B		LCP133A		LCP133A		LPF230A	LPF230A	LPF230A					LNT240A	LCE250A
Rack Type Name	AVR		AVR		CPU		CPU		DCM	DCM	DCM					CVIF	CE

Panel No. AUX-2
System PLC GROUP-2

Slot No.	0	1	2	3	4	5	6	7	8	9	A	B	C	D	E	F	Z
HSC4010 Type	AVR600B		AVR601B		LPF230A	LPF230A	LPF230A	LPF230A	LPF230A					LPD301A	LPD301A	LPD301A	LUD060A
Rack Type Name	AVR		AVR		DCM	DCM	DCM	DCM	DCM					DO	DO	DO	UD

------- *After Upgrading* -------

From 5/7

Panel No. AUX-2
System PLC GROUP-2

Slot No.	0	1	2	3	4	5	6	7	8	9	A	B	C	D	E	F	Z
HSC4010 Type	AVR680A		AVR680A						LYD000A	LYD000A	LYD000A	LYD000A					LUD070A
Rack Type Name	AVR		AVR						DI	DI	DI	DI					UD

Panel No. AUX-2
System PLC GROUP-2

Slot No.	0	1	2	3	4	5	6	7	8	9	A	B	C	D	E	F	Z
HSC4010 Type	AVR680A		AVR680A		LYD110A	LYD110A	LYD110A	LYD110A		LYD105A	LYD105A	LYD105A	LYD105A	LYD110A	LYD110A	LYD110A	LUD070A
Rack Type Name	AVR		AVR		DO	DO	DO	DO		DO	DO	DO	DO	DO	DO	DO	UD

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Attachment-4(7/7)

Layout drawing of AUX. Controller Upgrading(Power Supply Unit) (Existing & After Upgrading) (1/1)

------- *Existing* -------

Panel No. AUX-1
System AUX Control PS-1

		Input Unit	Output 1	Output 2	Output 3	Output 4
PD-5000 Type		MPD050A	MPD400A	MPD400A		MPD400A
Rack Type	Name		48V	48V		24V

Panel No. AUX-2
System AUX Control PS-2

Slot No.		Input Unit	Output 1	Output 2	Output 3	Output 4
PD-5000 Type		MPD050A	MPD400A	MPD400A		MPD400A
Rack Type	Name		48V	48V		24V

------- *After Upgrading* -------

Panel No. AUX-1
System AUX Control PS-1

		Input Unit	Output 1	Output 2	Output 3	Output 4	Output 5
PE-6000 Type		MPE060A	MPE411A	MPE412A		MPE411A	
Rack Type	Name		48V	48V		24V	

Panel No. AUX-2
System AUX Control PS-2

Slot No.		Input Unit	Output 1	Output 2	Output 3	Output 4	Output 5
PE-6000 Type		MPE060A	MPE411A	MPE412A		MPE411A	
Rack Type	Name		48V	48V		24V	

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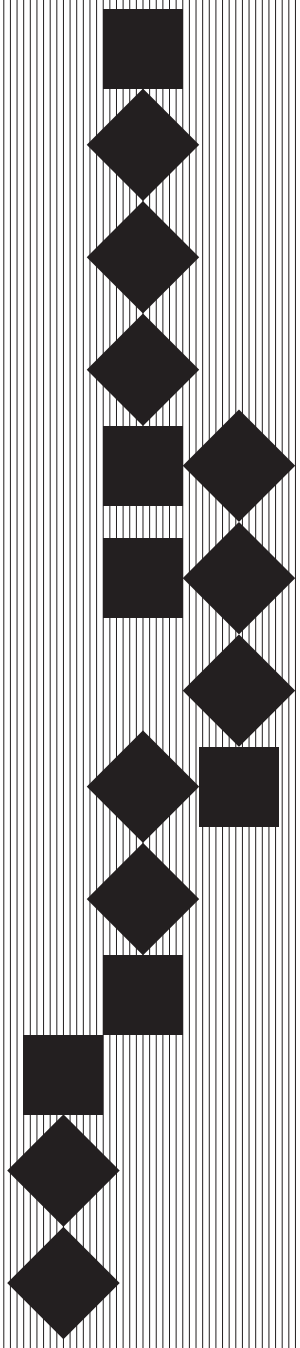
Attachment-5

HS-61-1011

HISEC 04/R900

GENERAL DESCRIPTION OF THE R900C CONTROLLER



SYSTEM MANUAL

CHAPTER 1 OVERVIEW

1.1 Overview

The R900C controller is a high-performance compact programmable controller. A CPU with network capability is mounted on the same unit as an HSC4000/HSC7000 series PI/O.
Some of the features of the R900C controller are listed below:

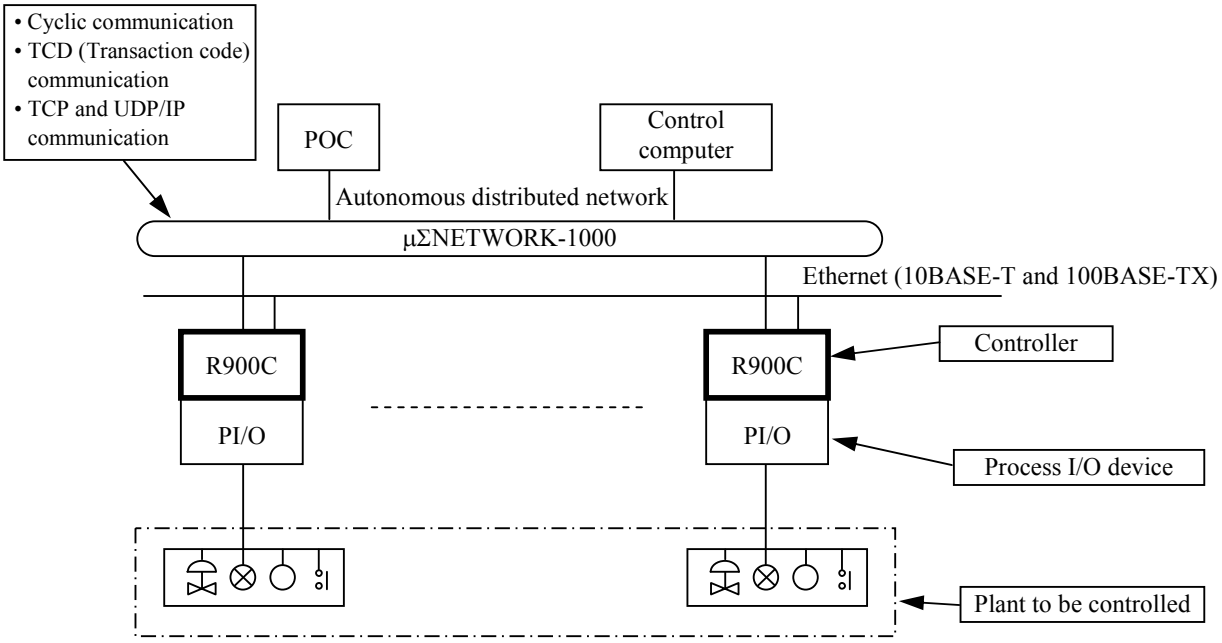
- By supporting the DCM bus, the R900C controller has increased its processing power, can support duplexed CPUs, and so on. The R900C controller is capable of accommodating conventional communication adapter cards mainly in consideration of replacing existing programmable controllers in Japan.
- R.Link/ES is a newly developed field bus that can support duplexed lines, star topologies using hub devices, and large-scale systems. The transmission speed is up to 20 Mbps. Online collection of RAS information is possible by using hardware copy to facilitate failure analysis.
- The R900C controller supports PI/Os from HSC900 series, HSC7000 series, and HSC4000 series and can accommodate various types of systems.
- A CPU with built-in CF-ROM can store user programs.

  A CPU with two processors can process the control and communication routines separately and simultaneously.
  Moreover, CPUs are equipped with highly reliable memory supporting 1-bit error correction with ECC.
- The R900C controller has software compatibility with the R900 controller. Therefore, the R900C controller can use software that has been developed for the R900 controller.
- CPU and PI/O modules can be mounted on the same unit. You can build a compact and highly reliable system.
- A CPU can be directly connected to a control LAN which can be either μΣNETWORK-1000 or Ethernet (10BASE-T and 100BASE-TX).

1.2 System Configuration Examples

- Using μΣNETWORK-1000

  Figure 1-1 shows a configuration example of an application of the R900C controller when μΣNETWORK-1000 is used. The μΣNETWORK-1000 version of the R900C controller uses μΣNETWORK-1000 as an autonomous distributed network and can be used as a part of a control system together with a control computer and a process operator's console. In addition, Ethernet (10BASE-T and 100BASE-TX) can be used at the same time as a standard feature of the CPU.

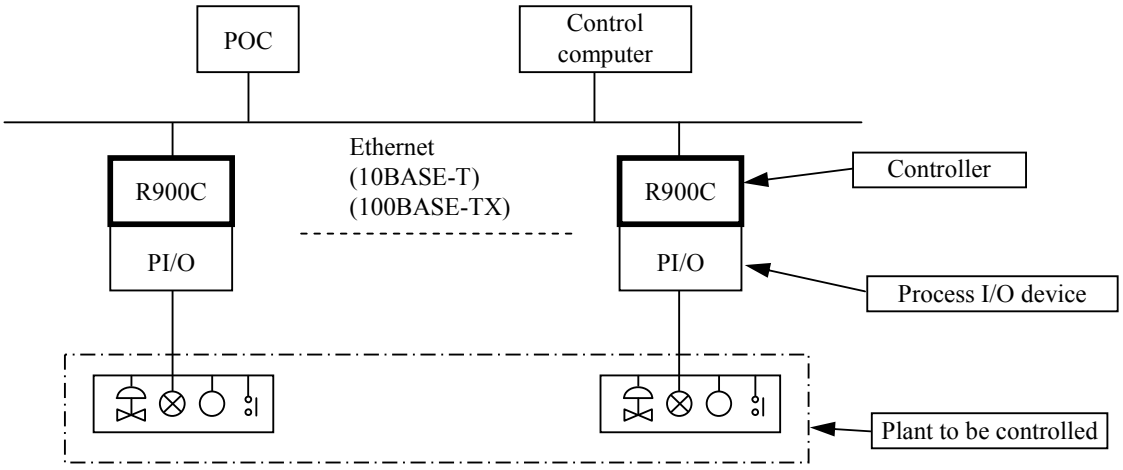


The maximum number of R900C controllers in one control system is 128 in the case of μΣNETWORK-1000. Note that this number might be reduced due to limitations of the system software.

POC: Process Operator's Console
Control computer: RS90 or others
PI/O: Process Input/Output

Figure 1-1 Configuration Example of an Application System using the R900C Controller (When connected to μΣNETWORK-1000)

- Using Ethernet
  Figure 1-2 shows a configuration example of an application of the R900C controller when Ethernet is used.
  The Ethernet version of the R900C controller supports international standard IEEE 802.3 CSMA/CD LAN (Ethernet) and can accommodate various types of system configurations.
  Note that this network is used as a control LAN and cannot be connected to a general network directly.



The maximum number of R900C controllers in one control system differs depending on the system software.

POC: Process Operator's Console
Control computer: RS90 or others
PI/O: Process Input/output

Figure 1-2 Configuration Example of an Application System using the R900C Controller (When connected to Ethernet)

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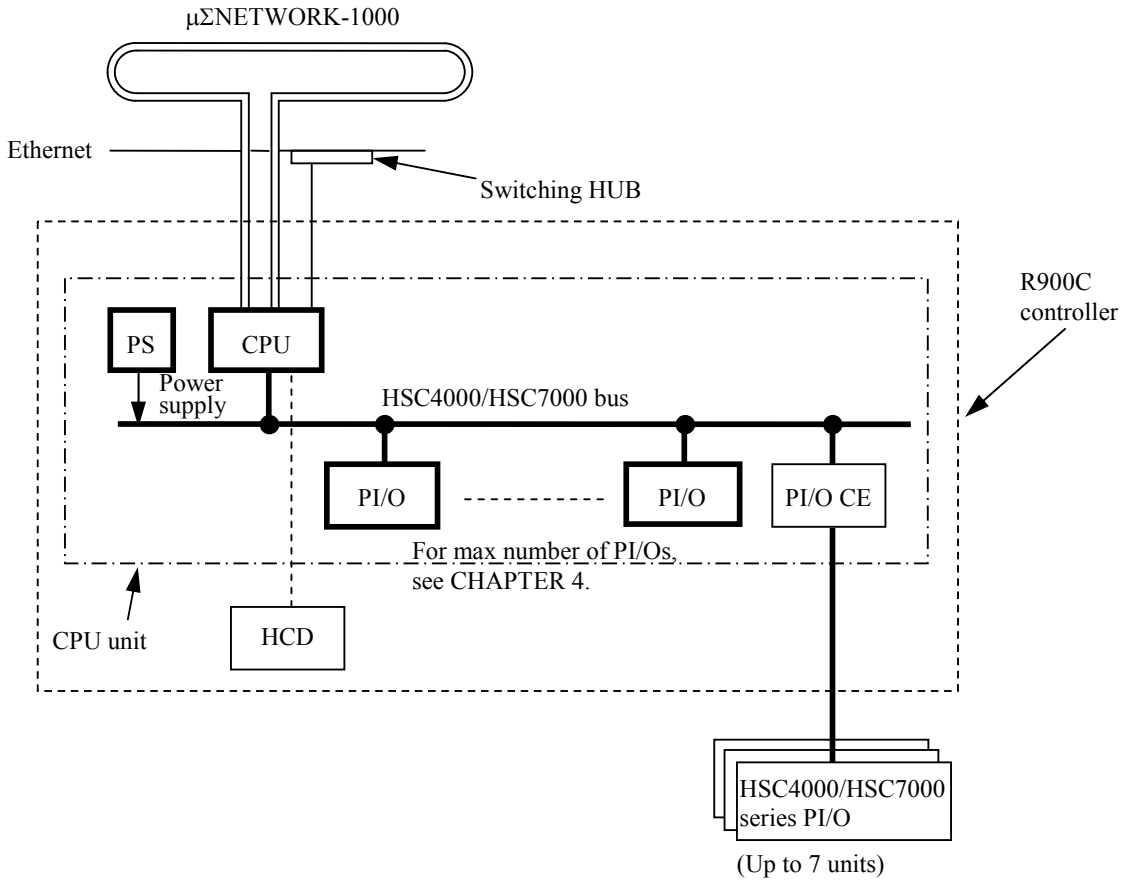
CHAPTER 2 HARDWARE CONFIGURATION

2.1 Single Controller Configuration

Figure 2-1 shows an example of hardware configuration with a single controller.



(Note 1) The units shown as a box with a bold border ▭ indicate a minimum configuration of the R900C.
(Note 2) The HCD is connected when you diagnose equipment failure with the test and maintenance program (T&M).

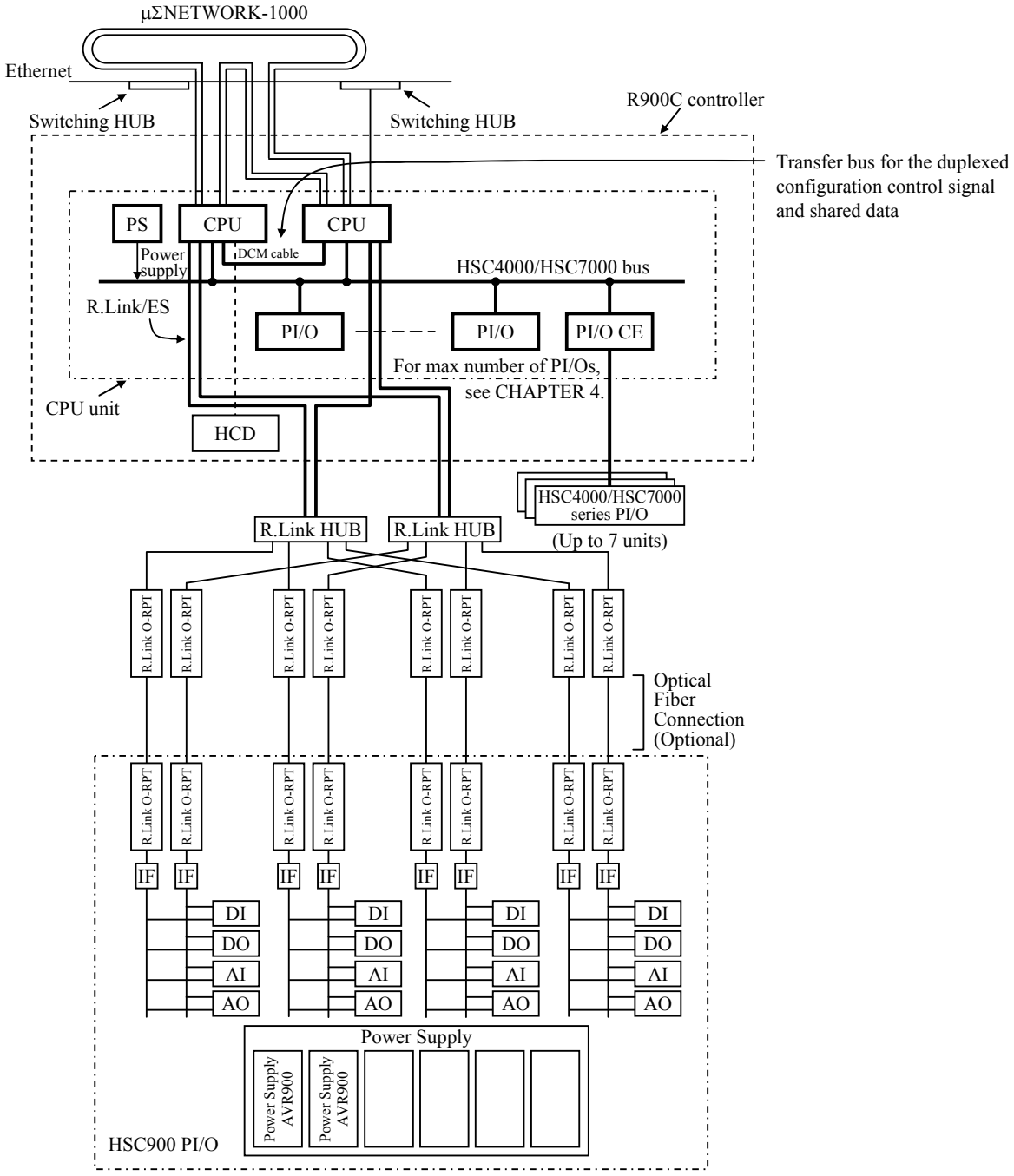
CPU: Central Processing Unit
PS: Power Supply
PI/O: Process Input/Output
PI/O CE: PI/O Control Electronics
HCD: HITACHI Conservation Device

Figure 2-1 Single Controller Hardware Configuration

2.2 Duplexed Controller Configuration

Figure 2-2 shows an example of a hardware configuration for the R900C controller where CPUs and R.Link/ES lines are duplexed.

- You can connect HSC900 series PI/Os to the R900C through R.Link/ES HUBs.
- When you need duplexed CPUs, connect the two CPUs with a duplexed common memory (DCM) cable to allow duplexed configuration control and memory duplication processing. Which of the two CPUs is selected as a master is determined by using the duplexed configuration control signal on the DCM cable.



(Note) The units shown as a box with a bold border ☐ indicate a minimum configuration of the R900C.
CPU: Central Processing Unit
PS: Power Supply
PI/O: Process Input/Output
PI/O CE: PI/O Control Electronics
HCD: HITACHI Conservation Device
DCM cable: Duplex Common Memory bus cable
A cable for both the control signal for the duplexed configuration and the common control data bus between the active and standby CPUs.
R.Link HUB: R.Link/ES HUB
DCM: Duplexed Common Memory
R.Link O-RPT: R.Link/ES Optical Repeater
IF: PI/O Inter-face
DI: Digital Input
DO: Digital Output
AI: Analog Input
AO: Analog Output

Figure 2-2 Duplexed Controller Hardware Configuration

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CHAPTER 3 LIST OF R900C CONTROLLER PRODUCTS

The R900C controller is built into the same unit as HSC4000 and HSC7000 PI/O modules.
The following is a typical configuration.

- Integrated with HSC4000 and HSC7000 (typical example)

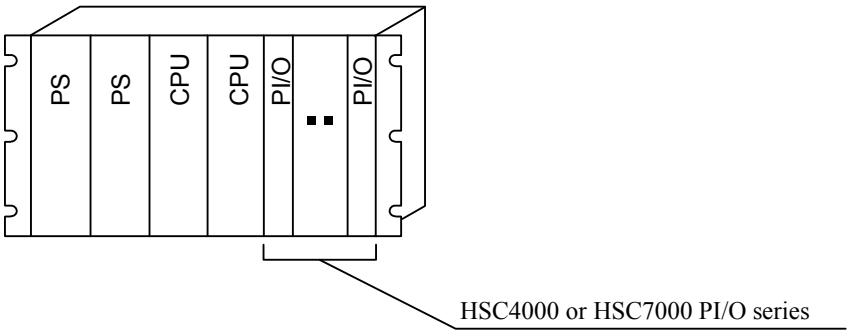


Figure 3-1 Typical Integrated with HSC4000 and HSC7000 Configuration

For information about which modules can be used in the above configuration, see “Table 3-1 List of Basic Modules Used in The Integrated Configuration with HSC4000 and HSC7000”.

3.1 List of Basic Modules Used in the Integrated Configuration with HSC4000 and HSC7000

Table 3-1 shows the list of basic modules used in an integrated configuration with HSC4000 and HSC7000.

If you want to use a module not in the list, contact our sales representative.

Table 3-1 List of Basic Modules Used in an Integrated Configuration with HSC4000 and HSC7000

Model	Module type	TYPE	Description	Current consumption (A) at rated voltage (+5 V)	Manual number	Note
LPU800A	CPU	-	R900C CPU 64 MB with ROM card µΣNETWORK-1000 version (multi-mode fiber)	4.6		
LPU801A	CPU	-	R900C CPU 64 MB without ROM card µΣNETWORK-1000 version (multi-mode fiber)	4.4		
LPU802A	CPU	-	R900C CPU 64 MB with ROM card µΣNETWORK-1000 version (single-mode fiber)	4.7		
LPU803A	CPU	-	R900C CPU 64 MB without ROM card µΣNETWORK-1000 version (single-mode fiber)	4.5		
HSC6853	BATT	-	Battery pack for backing up the CPU main memory	-		
HDC4940	CNEC	-	DCM cable 15 cm	-		
HSC7200	UNIT	-	Used as both CPU unit and PI/O unit	-		
HSC4700	UNIT	-	Single-CPU system unit. Supporting both power supply modules and power supply units.	-		
HSC4701	UNIT	-	Single-CPU system unit. Supporting power supply units only.	-		
HSC4710	UNIT	-	Duplexed-CPU system unit. Supporting both power supply modules and power supply units.	-		
HSC4010	UNIT	-	Used as both CPU unit and PI/O unit	-		Only for replacement or a special system
HSC4010A	UNIT	-	Used as both CPU unit and PI/O unit. Earthquake-resistant structure.	-		Only for replacement or a special system
HSC4301	UNIT	-	CPU unit	-		Only for replacement or a special system
HSC4302	UNIT	-	CPU unit	-		Only for replacement or a special system
HSC4303	UNIT	-	CPU unit	-		Only for replacement or a special system
HSC4311	UNIT	-	CPU unit. 2-compartment unit.	-		Only for replacement or a special system
HSC4304	UNIT	-	CPU unit	-		
LCE250A	CE	-	CE for connecting PI/O units	1.10	OM-5451E	For replacement only. Not to be used for a new system.
LCE250B	CE	-	CE for connecting PI/O units	3.00	HS-64-X297	
LUD070A	UD	-	PI/O unit driver for the HSC4000 bus	2.30	OM-5446E	
LUD060A	UD	-	PI/O unit driver	2.50	OM-5486E	For replacement only. Not to be used for a new system.
LUD700A	UD	-	PI/O unit driver for the HSC7000/HSC4000 bus	0.65	HS-64-X260	
LUD730A	UD	-	PI/O unit driver for the triplexed system	-	HS-64-X250	
PE6000	PS	-	Power supply unit	-	Y-64-X030	
AVR680A	PS	-	Power supply module. Input: Shared DC/AC input, 100/110/125 V. Output: +5 V: 2 to 15 A, ±15 V: 0 to ±1 A, +24 V: 0 to 3 A.	-	Y-64-X025	

(Note) The manual numbers shown in the table are subject to change without prior notice.

The 'X' is replaced with the revision number.

CHAPTER 4 HARDWARE SPECIFICATIONS

4.1 System Environment Specifications

Table 4-1 lists of the environment specifications of the R900C controller.

Table 4-1 Environment Specifications of the R900C Controller

Item		Specification
Temperature	Power on	0 to 55°C (0 to 40□C outside the rack)
	Power off	-20 to 70°C
Humidity	Power on	10 to 90%RH (non-condensing)
	Power off	
Vibration resistance		4.9 m/s^2 [0.5 G (between 10 Hz and 55 Hz)]
Shock resistance		Horizontal: 49 m/s^2 (5 G). Vertical: 98 m/s^2 (10 G)
Dielectric strength (between primary and secondary power supplies)		2000 VAC/minute
Grounding		Class D grounding (*1) (previously known as the third class grounding) (Less grounding resistance than 100 ohms)
Operating ambient air		Dust: 0.1 mg/m^3
Barometric pressure		Normal atmospheric pressure where the altitude is 1000 m or less
Corrosive gas		JEITA IT-1004 class B (*2)
Salt damage		0.05 mg/cm^3 or less
Burning resistance		Slow burning (self-extinguishing)

(*1) Class D grounding is defined in the Technical Standard for Electrical Facilities of Japan.
This standard states that the grounding resistance must be 100 ohms or less for equipment operating on 300 VAC or less, and 500 ohms or less for devices that shut down automatically within 0.5 seconds when shorting occurs in low tension lines.

(*2) Classification of the corrosive gas environment
Classification of the corrosive gas environment is determined by the interactive factors of the atmospheric corrosion, namely corrosive gas, temperature, humidity, and pollution severity. Each factor is evaluated and given an evaluation point. The classification is based on the sum of all evaluation points as follows.

Class	Total evaluation points
Class A	≤ 9
Class B	10 to 25
Class S_1	26 to 36
Class S_2	37 to 50
Class S_3	≥ 51

4. HARDWARE SPECIFICATIONS

The following table shows how each factor is evaluated.

Environment factor \ Category			1		2		3		4	
			Measured value	Evaluation point	Measured value	Evaluation point	Measured value	Evaluation point	Measured value	Evaluation point
Average annual temperature (°C)		A	≤ 20	1	≤ 25	2	≤ 30	4	> 30	8
Average annual humidity (%RH)		B	≤ 50	1	≤ 60	8	≤ 75	16	> 75	24
Gas (ppm)	SO_2	C1	≤ .04	1	≤ .08	3	≤ .2	6	≤ 5	9
	NO_2	C2	≤ .02	1	≤ .05	3	≤ .1	6	≤ 5	9
	H_2S	C3	≤ .003	1	≤ .01	8	≤ .1	14	≤ 10	20
	$C1_2$	C4	≤ .002	1	≤ .01	10	≤ .1	20	≤ 1	30
	NH_3	C5	≤ .1	1	≤ 1	2	≤ 10	4	≤ 100	8
Pollution severity (equivalent salinity) (mg/cm^2)		D	≤ .03	1	≤ .06	8	≤ .12	16	> .12	24

Total evaluation points = A + B + C1 + C2 + C3 + C4 + C5 + D

NOTICE

If you use the R900C controller at a lower or upper limit value in the specifications for a long time, the reliability of the controller will be compromised.
Except for a temporary malfunction of an air conditioner and similar occasions, use the controller at a normal temperature and at a normal relative humidity.

4.2 Rack Specifications (for Informational Purposes Only)

The rack used for mounting an R900C controller needs to have a fan installed at the door or must have air intake and exhaust holes at the door and at the top. The rack specifications described here are for informational purposes only. You need to take the actual usage, module/unit configuration, and other factors into account and set up the rack so that the specifications described in "Table 4-1 Environment Specifications of the R900C Controller" are met.

4.2.1 Rack with a fan

The following figure shows an example of installing a fan in the door of the rack.

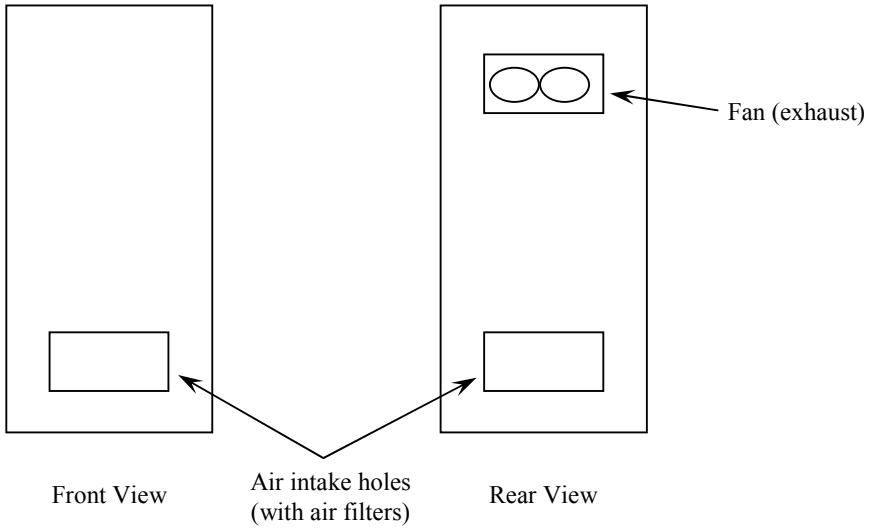


Figure 4-1 Rack Specifications (with a Fan)

NOTICE
If a rack has an air exhaust hole at its top, protection from objects and droplets of water falling from the above is required.

4.2.2 Rack without a fan

The following figure shows an example of air intake and exhaust holes in the door and at the top of the rack.

If the rack has an air intake and an exhaust hole at the top, protection from objects and droplets of water falling from the above is required.

The dimensions shown here are for informational purposes only. You need to modify them according to the actual usage, module/unit configuration, and other factors.

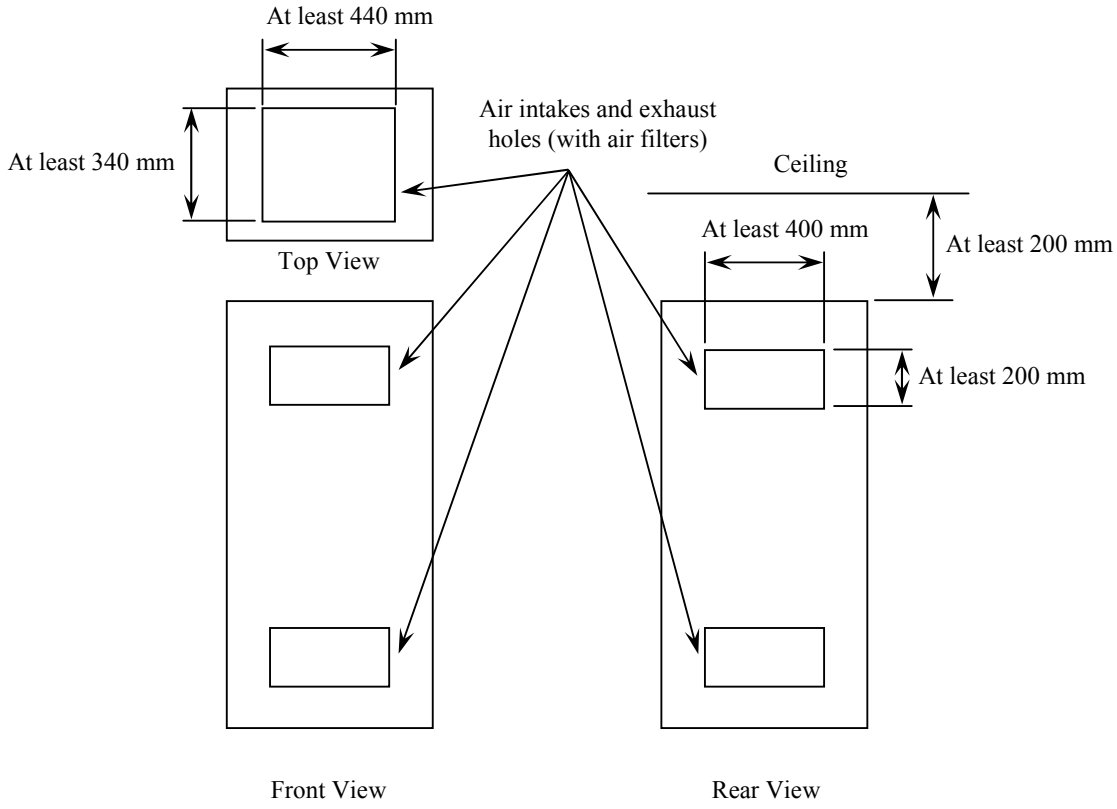


Figure 4-2 Rack Specifications (without a Fan)

4.3 CPU Specifications

4.3.1 CPU modules

Table 4-2 CPU Modules

Model	Main memory	μΣNETWORK-1000	DCM	CF-ROM	μΣNETWORK-1000 cable
LPU800A	64 MB	Supported	Supported	Built in	Multi-mode optical fiber
LPU801A				None	
LPU802A				Built in	Single-mode optical fiber
LPU803A				None	

4.3.2 LPU800A/LPU801A/LPU802A/LPU803A

- Functions and names of components
  LPU800A/LPU802A (with a CF-ROM)

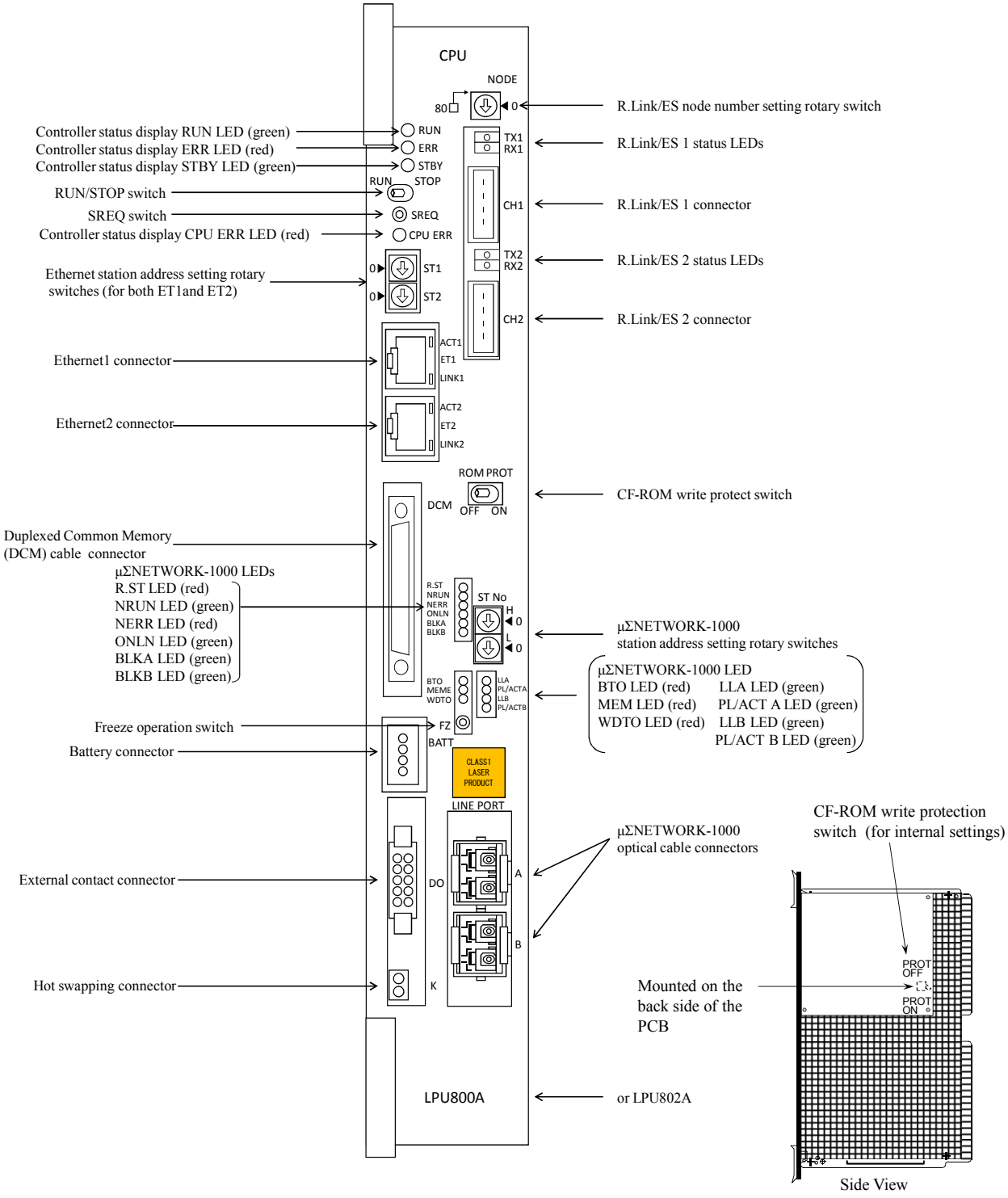


Figure 4-3 External View of LPU800A/LPU802A

LPU801A/LPU803A (without CF-ROM)

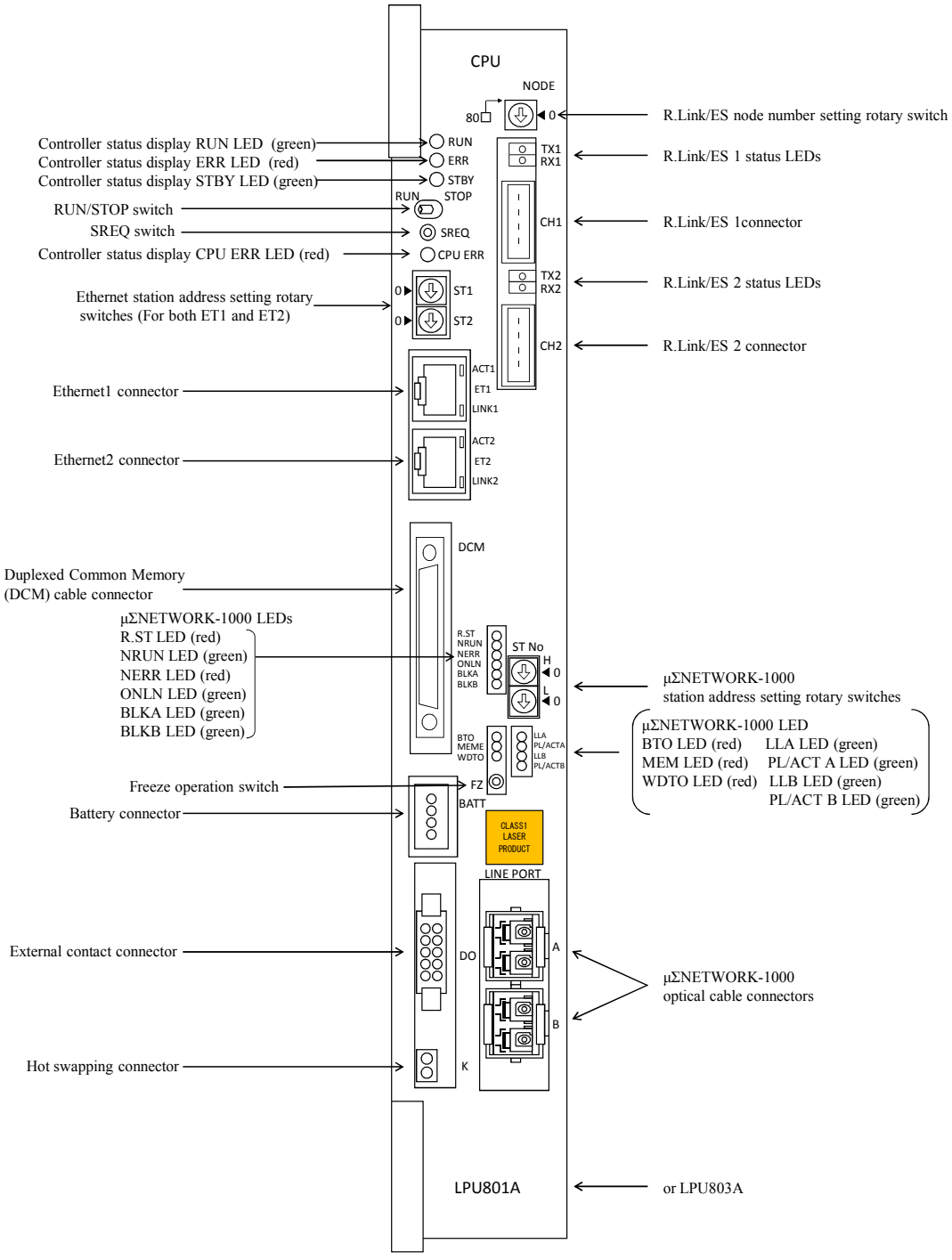


Figure 4-4 External View of LPU801A/LPU803A

• CPU function block (common for LPU800A/LPU801A/LPU802A/LPU803A)

Switch name	Function	Use	Note
RUN/STOP (Toggle Switch)	When the switch is changed from STOP to RUN, the CPU is reset and then starts. When the switch is changed from RUN to STOP, the CPU transitions to the STOP state. In normal operation, set the switch to RUN.	• Use this switch to reset and start the CPU. (From STOP to RUN) • Use this switch to stop the CPU when it is in the RUN state. (From RUN to STOP)	If you want to initialize and start the CPU in the RUN state, change the switch from RUN to STOP and then back to RUN.
SREQ (Push Switch)	In the RUN state: This switch is used to switch between the active system and the standby system. A CPU becomes a standby system when the switch on the CPU is pressed. (Standby request) In the STOP state: 1. If "PROT" is ON, the CPU resets and then stops. (Special reset) 2. If "PROT" is OFF, the contents of the main memory are saved to the ROM and then the CPU stops. (Save request)	In the RUN state: Use this switch when you want to switch between the active and standby systems of a duplexed system. For example, for maintenance.	If you press this switch while in the STOP state, the CPU is reset.
ST1 and ST2 (Rotary Switch)	Those switches configure the station address of the control LAN.		
NODE (Rotary Switch)	This switch configures the node number for R.Link/ES.		

Controller status display LEDs

LED name	Color	State	
		ON	OFF
RUN	Green	Indicates the operational state of the CPU. For details, see "CHAPTER 7 DESCRIPTION OF OPERATION".	
ERR	Red		
STBY	Green		
CPU ERR	Red		

Ethernet status LEDs

LED name	Color	State	
		ON	OFF
ACT1 and 2	Green	Transmitting	Not transmitted
LINK1 and 2	Green	LINK is normal	LINK has an error (cable disconnection, power shutdown)

R.Link/ES line status LEDs

LED name	Color	State	
		ON	OFF
TX1 and 2	Green	Transmitting	Not transmitting
RX1 and 2	Green	Receiving	Not receiving

Connector name	Function
ET1 ET2 Ethernet connector	Used for connecting to Ethernet (10BASE-T and 100BASE-TX). The connection is used for the control LAN. (Note) You cannot connect it to a general LAN. Those ports are also used for connecting maintenance tools.
Duplexed Common Memory (DCM) cable connector	Used for connecting a DCM cable. This connection enables duplexed configuration control and the duplication of shared data between CPUs.
BATT battery connector	Used for connecting a backup battery for the contents of the main memory and RTC. Replace the battery when the power is on.
DO external contact connector	Those external output contacts indicate the operational status of the CPU. (Contact name: PCSOK, MRUN, and SRUN) PCSOK: The controller is working properly. MRUN: Running as a master (active) system (PI/O access is possible.) SRUN: Running as a standby system (PI/O access is not possible.)
K hot swapping connector	Used for hot swapping.
CH1 CH2 R.Link/ES connector	Used for connecting an R.Link/ES cable.

Specifications specific to LPU800A/LPU802A

Switch name	Function	Use	Note
ROM PROT OFF/ON (Toggle Switch) (Note) Two locations on the front and back.	When the switch is ON, “ROM PROT” is enabled. When the switch is OFF, “ROM PROT” is disabled. In normal operation, set this setting to ON (protected).	The software uses this switch to know whether writing to the CF-ROM is prohibited. In normal operation, the program should not be saved; therefore, this switch must be ON.	The setting of this switch is effective only when “PROT OFF” is selected by the protection switch for internal settings on the CF-ROM. If “PROT ON” is selected by the protection switch for internal settings, the ROM protection switch on the panel has no effect, and the ROM is always protected. You need to remove the PI to change the protection switch for internal settings.

4. HARDWARE SPECIFICATIONS

• Network interface (NCP-E) block

Switch name	Function	Use	Note
H and L (Rotary Switches)	These switches configure a station address.		Those switches have the same functions as the H and L switches and the FZ switch of the R700 NCP-E (LNC600/LNC601).
FZ (Push Switch)	Press this switch to save error information to nonvolatile memory and stop the network interface.	When you replace the module due to a failure, press this switch before the replacement. Saving the information takes about two minutes. Do not turn off the power during this period.	

LED name	Color	State		Corresponding LED in R700 NCP-E (LNC600/LNC601)
		ON	OFF	
R.ST	Red	The CPU is in the reset state. (Lit also during hot swapping.)	The CPU is not in the reset state.	-
NRUN	Green	Initialization of the NCP-E block is complete. Communication is possible.	Initialization of the NCP-E block is not complete. Communication is stopped.	Same function as RUN.
NERR	Red	An error has occurred in the NCP-E block.	No error has occurred in the NCP-E block.	Same function as ERR.
ONLN	Green	Startup process of the NCP-E block initiated by the host CPU of the NCP-E block is complete. (The LED flashes if a duplicate station address is detected and connection to the permanent ring (trunk line) is terminated before initialization is requested from the host CPU.)	The NCP-E block has not started. Or the NCP-E block has been shut down.	Same function as the LED with the same name.
BLKA	Green	The LINE A port of the NCP-E block is in the blocking state.	The LINE A port of the NCP-E block is in the forwarding state.	
BLKB	Green	The LINE B port of the NCP-E block is in the blocking state.	The LINE B port of the NCP-E block is in the forwarding state.	
BTO	Red	Internal bus timeout error has occurred in the NCP-E block.	The error to the left has not occurred.	
MEME	Red	SRAM parity error has occurred in the NCP-E block.	The error to the left has not occurred.	
WDTO	Red	WDT timeout error has occurred in the NCP-E block.	The error to the left has not occurred.	
LLA	Green	A logical link has been established for the LINE A port of the NCP-E block.	A logical link is disconnected for the LINE A port of the NCP-E block.	
PL/ACTA	Green	A physical link has been established for the LINE A port of the NCP-E block. (This LED flashes when data is received or transmitted at the LINE A port.)	A physical link is disconnected for the LINE A port of the NCP-E block.	
LLB	Green	A logical link has been established for the LINE B port of the NCP-E block.	Logical link is disconnected for the LINE B port of the NCP-E block.	
PL/ACTB	Green	A physical link has been established for the LINE B port of the NCP-E block. (This LED flashes when data is received or transmitted at the LINE B port.)	Physical link is disconnected for the LINE B port of the NCP-E block.	

Connector name	Function	Note
A B Optical cable connector	Used for connecting a network cable.	Those connectors have the same functions as the connectors of the R700 NCP-E (LNC600/LNC601) with the same names.

NOTICE

Never press the freeze operation (FZ) switch except when you replace a module. If you press the switch by mistake, the network interface stops unexpectedly.

● Module specifications

• CPU function block

Item	Specification
Processor	32-bit RISC processor: SH4(SH7751) 160 MHz, SH4(SH7751R) 240 MHz
Main memory	64 MB with ECC
Main memory Battery backup time	120 hours after the power is turned off (minimum guaranteed hours)
Battery charging time	6 hours or less after the power is turned on
External contact outputs	Three DO contacts (PCSOK, MRUN, and SRUN)
Clock function	RTC (external component) (Precision: ±4 seconds/day at 25°C)
Timer	• Fixed interval timer • Programmable timer • Watchdog timer
Compatibility	Software compatible with the R900 CPU
Maximum number of modules that can be mounted	Two
Hot swapping	Supported

• Network interface block (1/2)

(1) Ethernet

Item	Specification
Network type	Star topology
Transmission speed	10 Mbps / 100 Mbps
Transmission line	Twisted-pair metal cable (category 5 or better)
Transmission distance	Distance between nodes: Up to 30 m
Maximum number of nodes that can be connected	255 (recommendation: 32 or less)
Access method	CSMA/CD
Communication function	• TCD (Transaction code) communication • Remote CPU control • Packet communication
Network management	• Network configuration management • Failure information management

• Network interface block (2/2)
(2) NCP-E

Item	Specifications	
	LPU800A and 801A	LPU802A and 803A
Network type	Bidirectional full-duplex ring topology	
Transmission speed	1 Gbps	
Transmission medium	Multi-mode fiber (MMF)	Single-mode fiber (SMF)
Distance between stations	Up to 550 m	Up to 10 km
Total loop length	Cyclic communication is not used: Up to 500 km Cyclic communication is used: Up to 100 km	
Maximum number of devices that can be connected	μΣNETWORK-1000 station (LANBOX+NCP-E+μΣNETWORK-1000NIC): Up to 128 (total number of control and information systems) • If computers are connected to control system branch ports at a LANBOX, the total number of those connected computers and the μΣNETWORK-1000 stations must not exceed 128. • There is no limitation on the number of computers connected to information system branch ports at a LANBOX.	
Network configuration method	Proprietary network configuration method (Network configuration time (for a single failure): 500 ms or less)	
Communication functions	• TCD (transaction code) communication • Remote CPU control • Cyclic communication Maximum transfer memory capacity: 1 MB Memory transfer cycle: Between 1 ms and 1000 ms • TCP and UDP/IP communication	
Network management	• Network configuration management • Failure information management	
Compatibility	Software/Hardware compatible with the NCP-E (LNC600)	Software/Hardware compatible with the NCP-E (LNC6001)

• CF-ROM block

Item	Specification
Interface	CF-ROM interface
Capacity	64 MB (same as the main memory) (for long-term memory backup)
ROM write/read time	LPU800A and 802A: About 6 minutes (or less)

<Explanation of the operation of a CPU for each combination of switches>

Operation for each combination of the RUN/STOP switch, SREQ switch, and ROM PROT switch

Switch operation			Description of the operation
RUN/STOP switch (Toggle Switch)	SREQ switch (Push Switch)	ROM PROT switch (Toggle Switch)	
STOP to RUN	-	-	Reset and start the CPU. (*)
RUN	ON	-	The CPU transitions to a standby system. (This has no effect for a single-CPU system.)
RUN to STOP	-	-	The CPU transitions to the stop state.
STOP	ON	ON	The CPU stops after reset.
STOP	ON	OFF	The contents of memory are saved in the ROM card.

(*) If you want to reset and start the CPU in the RUN state, change the switch from “RUN” to “STOP” and then back to “RUN”.
If the software has already issued a remote STOP request, you cannot start the CPU by changing the switch to “RUN”. You also need to generate a remote RUN request from software. (See CHAPTER 7.)

NOTICE
Do not change multiple switches at the same time. If you do, a malfunction of this module may result.

4. HARDWARE SPECIFICATIONS

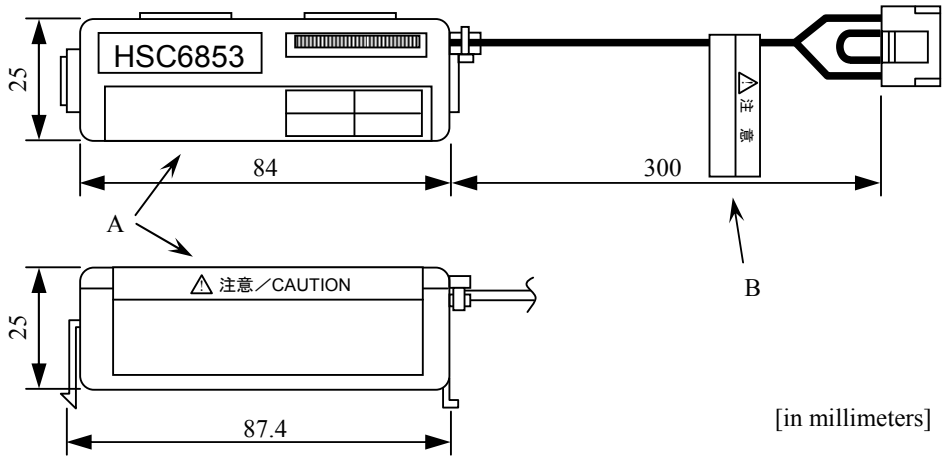
4.3.3 Battery

(1) Model: HSC6853

This is a rechargeable battery used specifically for backing up the memory and a real-time clock (RTC) in the CPU module.

This battery is automatically recharged when the power is turned on and monthly after that.

(a) Main specifications



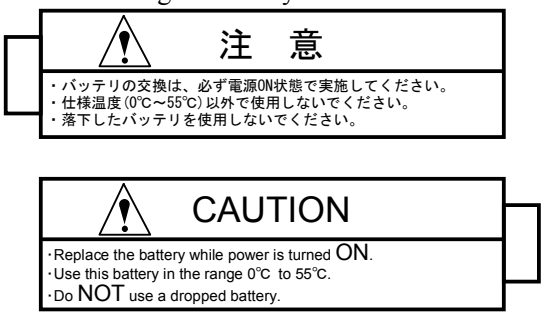
[in millimeters]

Item	Specifications
Service life (*)	Two years or 300 charge/discharge cycles, whichever comes first
External dimensions of the casing [mm]	84 (W) × 25 (D) × 25 (H) (See the figure above.)
Cable length [mm]	300 (See the figure above.)
Battery backup time	120 hours after the power is cut off
Operating ambient temperature	0 to 55°C
Storage temperature	-20 to 35°C

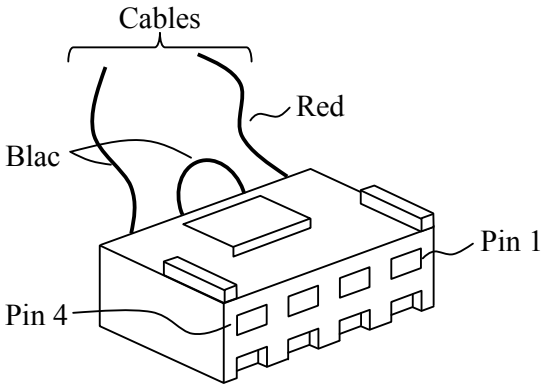
(*) The expiration date is clearly indicated on the casing of the battery.

A: Label with the caution for installing the battery and the expiration date of the battery

B: Label with the caution for using the battery



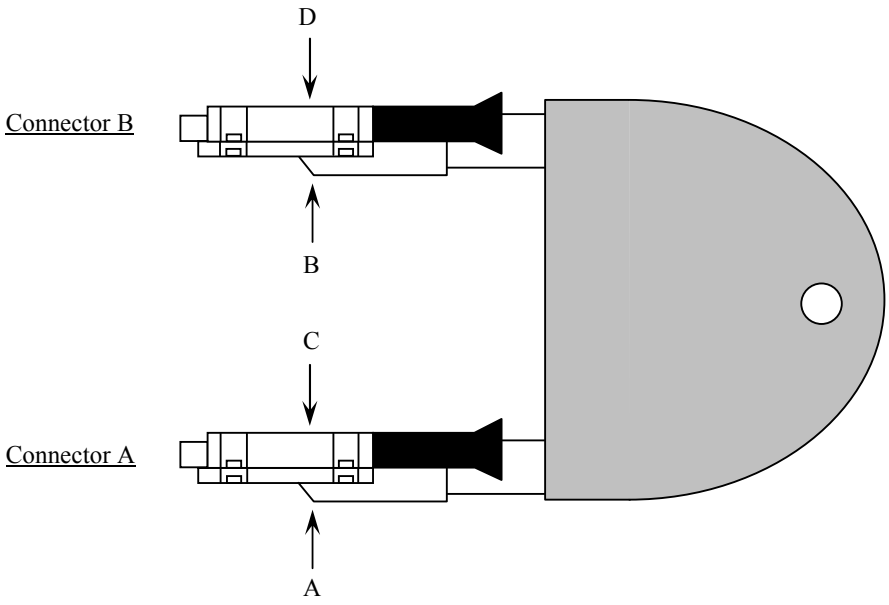
(b) Specifications of the connector

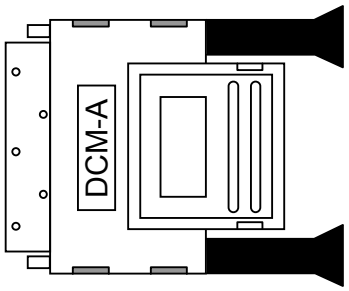


Pin 1: (+)
Pin 2: Connected to pin 3.
Pin 3: Connected to pin 2.
Pin 4: (-)

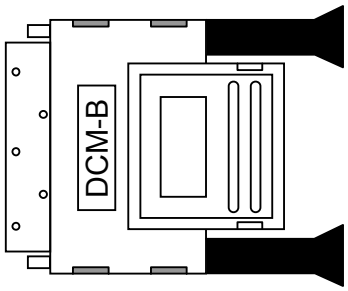
4. HARDWARE SPECIFICATIONS

4.3.4 DCM cable
Model: HDC4940
(1) Main specifications

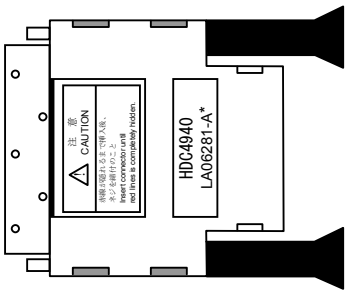




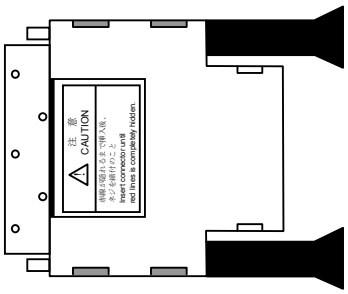
Viewed from A



Viewed from B



Viewed from C



Viewed from D

NOTICE

- By connecting CPUs with a Duplexed Common Memory (DCM) cable, you can control data duplication between CPUs and master-standby arbitration.
- When the two CPUs are turned on at the same time after a momentary power failure or other reason, the CPU connected to connector A of the DCM cable has precedence to become a master.
- Before installing a DCM cable, clean the contacts of both the cable connector and the connector at the board (CPU) side with a dust blower.
  For information about how to clean the contacts, see “9.2.3 Cleaning the contacts of the DCM connectors”.
- Make sure you do not apply too much pressure on a DCM cable including the cover when you connect and remove the cable.
- Fully insert a DCM cable. Confirm that the red lines on the stickers attached to the cable connectors are all concealed.
  Then tighten the screws securely.

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Attachment-6

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Equipment Specifications ; Network System

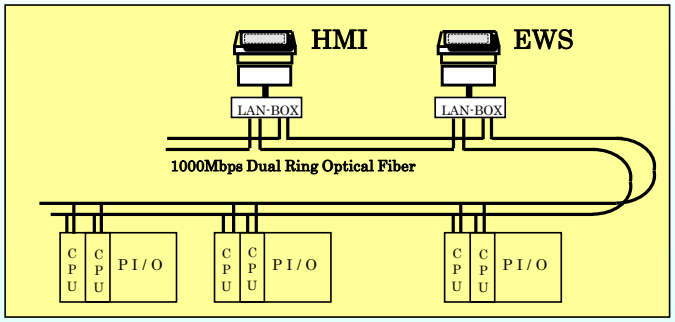
Attachment-6

Main Network Type: Micro Sigma 1000

As a transmission access method, Micro Sigma Network-1000 adopts FDDI (Fiber Distributed Data Interface) based on the token passing procedure standardized by IEEE 802.5.

The Micro Sigma Network-1000 has the following features.

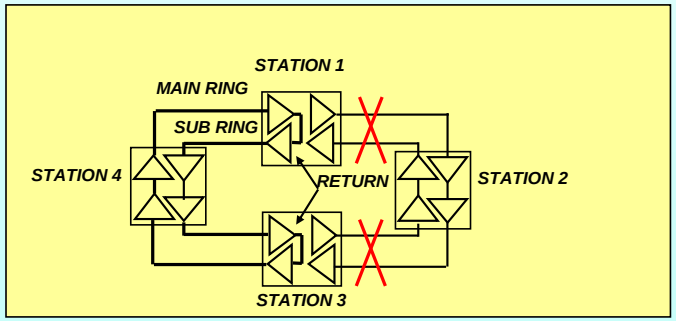
- Powerful transmission speed with 1000Mbps.
- High degree of availability (fault-tolerance) by Loop-Blocking function.
- Transmission media using optical fiber



Network Micro Sigma 1000

■ Specification of Micro Sigma 1000 network

Technical Data	
Item	**Specifications**
Network topology	Duplicated Ring
Network media	Optical fiber (GI-50/125,SM-10/125,SM-9.5/125 micron)
Network speed	1000Mbps
Network cable length	Total length Max.100km, Node to Node 550m
Communication protocol	IEEE802.3z (Token passing)
Max. number of controller	EWS + controller + HMI =< 128 station
Re – configuration function	Auto re-configuration
Transmission table	None (auto addressing)
Others	Instruction manual of EWS



Loop Blocking

Even if both rings cut -out, loop back path will be generated. When it returns to normal, communication is resumed automatically.

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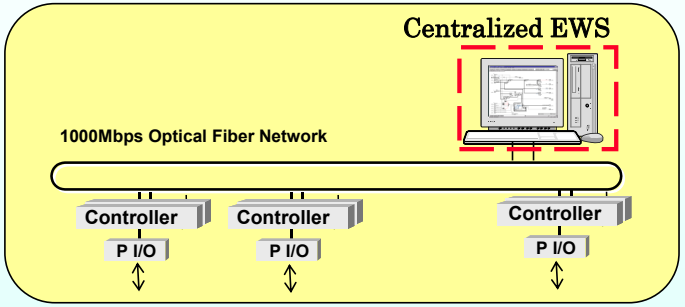
Equipment Specifications ; EWS (1)

Attachment-7

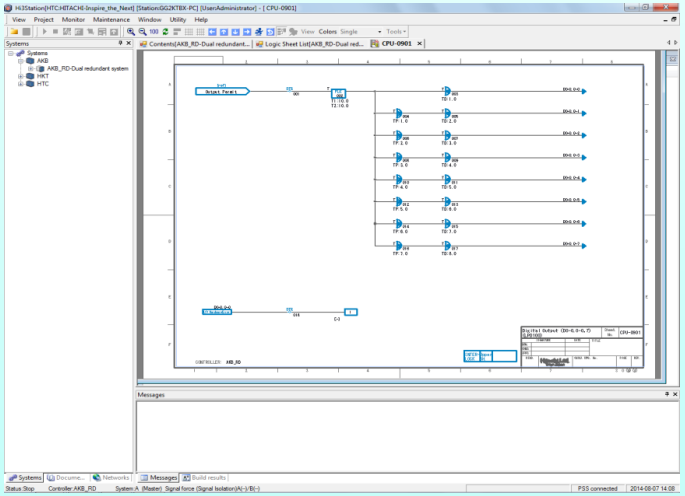
EWS Type: H-EWS

The HIACS/TCS Engineering Work Station (EWS) is designed to release the the thermal power plant engineer from complicated programming techniques using Windows based powerful CAD (Computer Aided Design) and hierarchical function.



Major Function

- ◆ Program maintenance
  - ➢ Program edit, Remote loading, Comparison
- ◆ Parameter tuning
  - ➢ On-line, Off-line remote tuning
- ◆ Monitoring
  - ➢ Screen monitoring (Logical, numerical on logic diagram)
  - ➢ Data trending (on-line, historical trend)
- ◆ Data analysis
  - ➢ Error data collection (Controller, Network)
  - ➢ Application data recording (Specified point)
- ◆ Document printing
  - ➢ Print out program as complete logic diagram



Sample of Logic Diagram on EWS screen

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Equipment Specifications ; EWS (2)

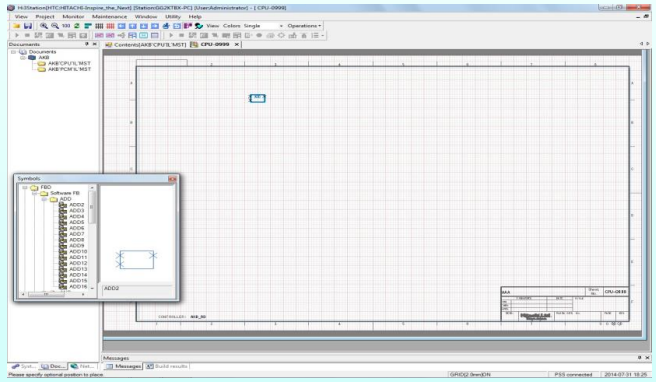
Attachment-7

Program Maintenance

Powerful CAD system offers intuitive operation & error free design.

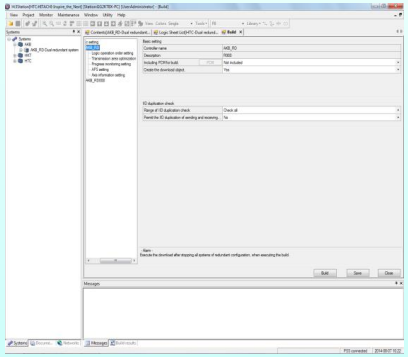
Programming

Windows like Drag & Drop operation from macro library



Compile

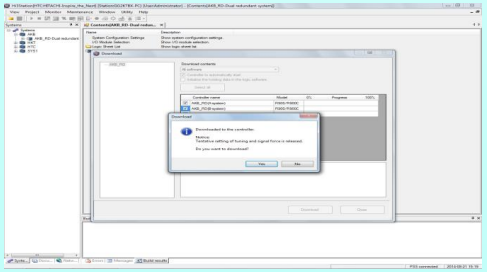
Combo box operation



Most programming errors are eliminated by the prodigious error check function.

Loading

Combo box operation
Remote Down Loading



Other utilities

- On-line Compare
- On-line version check

others ...

Documentation

- Direct print-out as complete logic diagram
- Generate various Lists
- Able to output drawing data by AutoCAD format

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Equipment Specifications ; EWS (3)

Attachment-7

Monitoring & Tuning

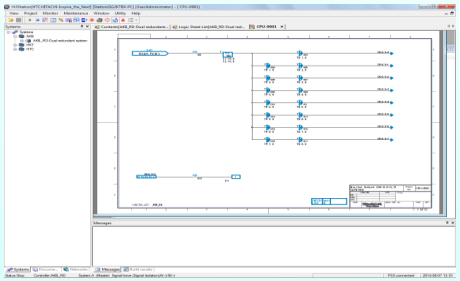
Multi-Window / Multi function offers effective monitoring.

Monitoring

On-Line Logic Monitoring

Binary Logic
- Black / Red display

Numerical
- Engineering unit display

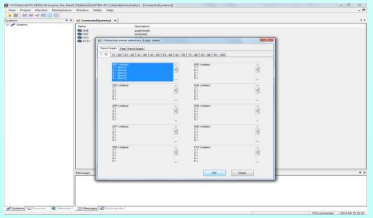


Multi Window On-Line Monitoring

Trending

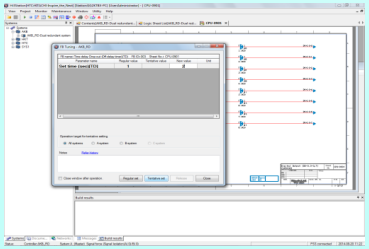
On-Line and Historical Data Trending

Recording time specified historic data recall



Output to spreadsheet form to external memory

Tuning



Multi Window Tuning box

On-Line tuning can be performed during monitoring

- Parameter reasonableness verifying
- Operation recording
- Password protection

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Equipment Specifications ; EWS (4)

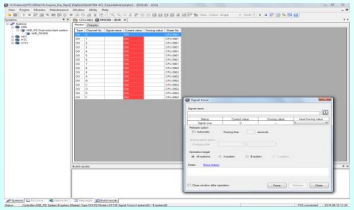
Attachment-7

Surveillance & Debugging

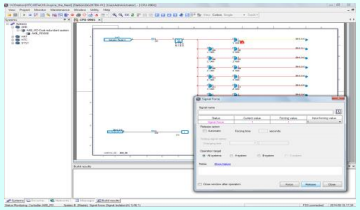
Other functions for customer's effective maintenance work

Data substitution

Able to set substitute data forcedly for system debugging



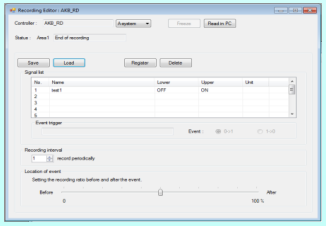
I/O table



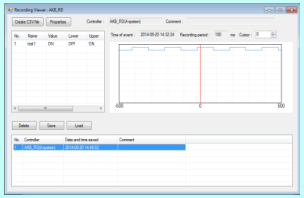
Logic diagram

Event Recording

Condition triggered ultra-high speed (synchronous with logic execution cycle) data recording



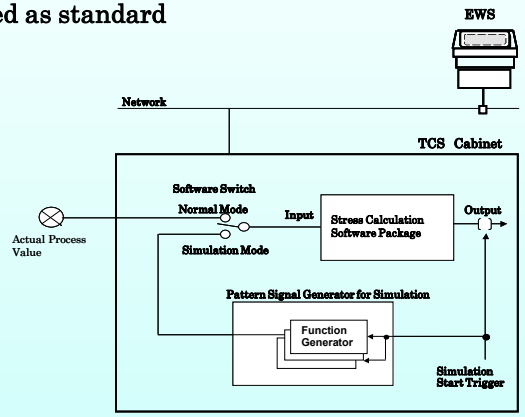
Recoding data spec. table



Recall to chart display or output to spreadsheet form

Simulation & Valve lift adjustment

Simulation software (turbine model) is equipped as standard



Result of simulation can be Monitored by EWS

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Equipment Specifications ; EWS (5)

Attachment-7

■ Functional Specifications

Technical Data			
	Item		Specifications
Monitor	Logic monitor	Data refresh rate	1 s
		Numerical expression	Engineering value (floating point)
	Real time Trending	Number of collection point	10 points x 100 group
		Data points / graph	10 points
		Data sampling interval	More than logic execution cycle
	Historical trending	Number of collection point	1000 points
		Data points / graph	10 points
		Data sampling interval	More than logic execution cycle
		Continuous trending time	2 weeks
Program Maintenance	Logic modification		Drag & drop base (CAD)
	Program / parameter compare		On-line & off-line
	Program loading		Remote loading
	Program dump		Remote dump
	Logic diagram printing		A4 size (Reduction size)
	Controller status display / control		Remote operation with pass-word protection
Tuning	On line tuning		Engineering value (floating point)
	Parameter list display / printing		Engineering value (floating point)
	Tuning history display / printing		Time and data (previous and new)
Others	CPU load factor measurement		Graph and numerical value display
	Error log collection		Automatic error data collection

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CI Number: 51820

Title: TRE5 Turbine Reheat Valve Refurbishment

Start Date:	2018/05
In-Service Date:	2018/06
Final Cost Date:	2018/12
Function:	Steam
Forecast Amount:	$450,408

DESCRIPTION:

This project addresses the component replacement of the turbine reheat steam valves on the Trenton Generating Station's Unit 5 Turbine. This will include replacement or refurbishment of valve stems and bushings, hydraulic valves and control oil pressure regulators. The scope of work also includes replacement of the bolts and studs on the reheat valves.

The primary function of the reheat valves is to regulate the steam flow to the turbine, and thus control the power output of the steam turbine generator. These valves are critical components of the steam turbine. Their functionality and reliability are necessary to the safe operation of the unit.

Summary of Related CIs +/- 2 years:
No other projects in 2016, 2017, 2018, 2019 and 2020

JUSTIFICATION:

Justification Criteria: Health & Safety

Why do this project?

Maintenance intervals on these valves are a function of the unit's Utilization Factor and expected future utilization. Annual planning efforts consider these factors to determine the timing and scope of the Turbine Valve refurbishment. This Risk Based approach has determined that these valve refurbishments should be scheduled in 2018.

Why do this project now?

Completing this project as part of the 2018 planned outage will mitigate the risk of unplanned outages. It will address possible valve failures, which could occur by operating the unit with out of tolerance components (physical dimensions have worn past OEM standards). A valve failure could lead to a potential over-speed event, which would put NS Power personnel in the plant at risk and would include significant damage to the turbine and other plant equipment.

Why do this project this way?

The refurbishment work is in accordance with best practices and consistent with NS Power's past practice. Total valve replacement is a more expensive option and not considered necessary at this time.

CI Number : 51820 - TRE5 Turbine Reheat Valve Refurbishments **Project Number** 51820

Parent CI Number : -

Asset Location : 1165 - 1165 Trenton Unit 5; Commissioned 1969, 160 Mwh **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account		Forecast Amount
Additions	1000 - SGP - Turbo Gen.Instal.		432,113
Retirements	1000 - SGP - Turbo Gen.Instal.		18,295
		Total Cost:	450,408
		Original Cost:	63,199

Capital Project Detailed Estimate

Location: Trenton Generating Station
CI# : 51820
Title: TRE5 Turbine Reheat Valve Refurbishment
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Engineering	PD	10	$ 405	$ 4,053		
Maintenance Trades	PD	50	$ 365	$ 18,239		
Power Engineer	PD	10	$ 390	$ 3,904		
Utilityworker	PD	40	$ 240	$ 9,607		
			Sub-Total	$ 35,803		
OT Labour						
Maintenance Trades	PD	10	$ 729.57	$ 7,296		
Utilityworker	PD	20	$ 480.36	$ 9,607		
			Sub-Total	$ 16,903		
Term Labour						
Maintenance Trades	PD	50	$ 365	$ 18,239		
Utilityworker	PD	30	$ 240	$ 7,205		
			Sub-Total	$ 25,445		
Materials						
Reheat Valve Parts	lot	1	$ 150,000	$ 150,000		CI 46465
Misc Parts (Seals/Studs/Nuts)	lot	1	$ 37,510	$ 37,510		CI 46465
			Sub-Total	$ 187,510		
Contracts						
External Machining Services	lot	1	$ 20,000	$ 20,000		
Service Supervisor	lot	1	$ 50,000	$ 50,000		
External Supervision	lot	1	$ 15,000	$ 15,000		
Insulation Services	lot	1	$ 5,000	$ 5,000		
Inspection Services	lot	1	$ 25,000	$ 25,000		
			Sub-Total	$ 115,000		
OT Meals						
OT Meals	lot	1	$ 200	$ 200		
				$ -		
			Sub-Total	$ 200		
Rentals						
Misc equipment/trailers	lot	1	$ 5,000	$ 5,000		
				$ -		
			Sub-Total	$ 5,000		
Other Goods & Services						
Contingency	%	10%	$ 380,661	$ 38,066		
				$ -		
			Sub-Total	$ 38,066		
Administrative Overhead						
Labour AO				$ 15,312		
Contract AO				$ 11,170		
			Sub-Total	$ 26,481		
			SUB-TOTAL (no AO, AFUDC)	$ 423,927		
			TOTAL (AO, AFUDC included)	$ 450,408		
Original Cost				$ 63,199		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 51862

Title: TRE6 Lube Oil Cooler Refurbishment

Start Date: 2018/01
In-Service Date: 2018/09
Final Cost Date: 2019/03
Function: Steam
Forecast Amount: $341,769

DESCRIPTION:

The scope of this project is to replace the existing tube bundles in the turbine lube oil coolers on Trenton Unit 6 with upgraded metallurgy that is more resistant to erosion and corrosion.

The lube oil coolers are required to cool the lube oil that services the Unit 6 turbine. There are currently two lube oil coolers associated with Trenton Unit 6 that have been in place since commissioning in 1991. These coolers consist of lube oil from the turbine which runs on the outside of the tubes and cooling water, drawn from the East River, inside the tubes. The heat transfer occurs between the tubes from lube oil to the water, which helps to maintain the lube oil at an appropriate operating temperature. Under section 35 of the Canadian Federal Fisheries Act (1985) "No person shall deposit…a deleterious substance of any type in waters frequented by fish…." Where a deleterious substance is "any substance that, if added to any water, would degrade or alter….the quality of that water so that it is rendered or is likely to be rendered deleterious to fish or fish habitat…."

As part of the cooler maintenance strategy Trenton 6 turbine lube oil coolers were eddy current tested (measures tube condition) on two occasions, once in 2011 and once in 2017. Eddy current results indicated approximately 6 percent of the tubes were exhibiting pitting in excess of 60 percent of wall thickness. Following the recent eddy current testing in 2017, several tubes have subsequently required plugs to mitigate potential leaks. Additionally, all tubes exhibited pitting in excess of 20 percent, and the expectation is that the tubes will continue to degrade as the unit moves to increasingly more flexible operation. The coolers are currently suitable for use. However, as their condition continues to deteriorate, the risk of an environmental incident (i.e. an oil release into the environment) increases.

Summary of Related CIs +/- 2 years:
No other projects in 2016, 2017, 2018, 2019 and 2020

JUSTIFICATION:

Justification Criteria: Environment

Why do this project?

Eddy current testing of the Trenton 6 Turbine lube oil coolers indicates that the tubes are deteriorating, exposing the unit to the risk of an oil release into the environment. Replacing the tubes will increase the heat exchanger surface area and an upgraded material will allow the unit to be run securely for the projected remaining life of the unit.

Why do this project now?

Eddy current testing of the Trenton 6 Turbine lube oil coolers indicates that the tubes are deteriorating (all tubes have greater than or equal to 20 percent wall loss), exposing the unit to the risk of an oil release into the environment.

To mitigate the risk of an unplanned outage, replacing the tubes in 2018, coincidental with the planned outage, will provide the most effective method of operating the unit.

Why do this project this way?

Refurbishment of coolers by replacing the bundles is less costly than complete unit replacement. Time requirements associated with refurbishing the existing bundles is10-12 weeks. Replacing the bundles allow for the purchase of the tube bundles in advance of the outage, thus minimizing the amount of time the unit is unavailable.

CI Number : 51862 - TRE6 Lube Oil Cooler Refurbishment **Project Number** 51862

Parent CI Number : -

Asset Location : 1166 - 1166 Trenton Unit 6; Commissioned 1991, 170 Mwh **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	1000 - SGP - Turbo Gen.Instal.	329,573
Retirements	1000 - SGP - Turbo Gen.Instal.	12,197
	Total Cost:	341,769
	Original Cost:	208,148

Capital Project Detailed Estimate

Location: Trenton Generating Plant
CI# : 51862
Title: TRE6 Lube Oil Cooler Refurbishment
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Maintenance Trades	PD	80	$ 365	$ 29,183		
Power Engineer	PD	10	$ 390	$ 3,904		
Utilityworker	PD	30	$ 240	$ 7,206		
Utilityworker (crane)	PD	5	$ 294	$ 1,470		
			Sub-Total	$ 41,763		CI 43429
OT Labour						
Maintenance Trades	PD	5	$ 730	$ 3,648		
			Sub-Total	$ 3,648		
Term Labour						
Maintenance Trades	PD	10	$ 365	$ 3,648		
			Sub-Total	$ 3,648		
Materials						
Misc Materials	lot	1	$ 5,000	$ 5,000		
Tube Bundles	lot	2	$ 20,000	$ 40,000		CI 43429
Fabrication of tube bundles	lot	1	$ 162,954	$ 162,954		CI 43429
			Sub-Total	$ 207,954		
Contracts						
External Supervision	lot	1	$ 10,000	$ 10,000		
			Sub-Total	$ 10,000		
OT Meals						
OT Meals	lot	1	$ 200	$ 200		
			Sub-Total	$ 200		
Consulting						
Design	lot	1	$ 30,000	$ 30,000		
			Sub-Total	$ 30,000		
Other Goods & Services						
Contingency	%	10%	$ 297,212	$ 29,721		
				$ -		
			Sub-Total	$ 29,721		
Interest Capitalized						
AFUDC				$ 3,488		
				$ -		
			Sub-Total	$ 3,488		
Administrative Overhead						
Labour AO				$ 10,377		
Contract AO				$ 971		
			Sub-Total	$ 11,348		
			SUB-TOTAL (no AO, AFUDC)	$ 326,934		
			TOTAL (AO, AFUDC included)	$ 341,769		
Original Cost				$ 208,148		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 43429

Title: TRE5 Turbine Lube Oil Cooler Refurbishment

Start Date: 2018/02
In-Service Date: 2018/06
Final Cost Date: 2018/12
Function: Steam
Forecast Amount: $338,398

DESCRIPTION:

There are currently two turbine lube oil coolers associated with Trenton Unit 5 that are original to the plant. These coolers are designed with oil flowing over the outside of the tubes and cooling water, drawn from the East River, passing inside the tubes. A tube leak releases oil into the environment so condition monitoring is of utmost importance. Between 2011 and 2016 the Trenton 5 turbine lube oil coolers were tested to determine wall thickness on three occasions. Eddy current is a technology used to determine tube condition. The results indicated that tubes were exhibiting pitting in excess of 90 percent of wall thickness. These tubes have been proactively plugged to prevent oil leakage. Additionally, virtually all tubes exhibited pitting in excess of 20 percent, leading to the expectation that the tubes will continue to degrade. While the coolers are currently suitable for use, their condition continues to deteriorate, which warrants risk mitigation.

The scope of this project is to replace the existing tube bundles in the lube oil coolers on Trenton Unit 5 with materials that are compatible with stop/start operation. This mode of operation exposes the tubes to higher corrosion rates. The return cooler channels will be replaced, the inlet channels will be refurbished for extended life, and the discharge covers will be replaced. Replacing the tubes will allow the unit to be run reliably for the projected remaining life of the unit and avoid discharge of oil into the environment.

Summary of Related CIs +/- 2 years:
No other projects in 2016, 2017, 2018, 2019 and 2020

JUSTIFICATION:

Justification Criteria: Environment

Why do this project?

Condition testing of the Trenton 5 Turbine lube oil coolers indicates that the tubes are deteriorating to minimal recommended wall thickness. The tubes must be replaced to prevent risk of oil release into the environment.

Why do this project now?
This project needs to be completed in 2018 in order to mitigate the increasing risk of tube failure and oil release into the environment. The planned replacement of the tubes during the next scheduled outage will have the least impact on the reliability of the unit.

Why do this project this way?

The project will lower the risk of oil release from the turbine lube oil coolers. Corrosion resistant materials selected for the tubes will align with the increased start/stop operations that exacerbate corrosion. Time requirements associated with refurbishing the existing bundles is 10-12 weeks. Replacing the bundles allows for the purchase of the tube bundles in advance of the outage, thus minimizing the amount of time the unit is unavailable.

Rebuilding and re-coating the inlet channels will allow for continued use without full replacement, but the discharge covers are excessively corroded and need to be replaced.

CI Number : 43429 - TRE5 Turbine Lube Oil Cooler Refurbishment **Project Number** 43429

Parent CI Number : -

Asset Location : 1165 - 1165 Trenton Unit 5; Commissioned 1969, 160 Mwh **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	1000 - SGP - Turbo Gen.Instal.	326,201
Retirements	1000 - SGP - Turbo Gen.Instal.	12,197
	Total Cost:	338,398
	Original Cost:	50,936

Capital Project Detailed Estimate

Location: Trenton Generating Plant
CI# : 43429
Title: TRE5 Turbine Lube Oil Cooler Refurbishment
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Maintenance Trades	PD	80	$ 365	$ 29,183		
Power Engineer	PD	5	$ 390	$ 1,952		
Utility worker	PD	30	$ 240	$ 7,205		
Utility worker (crane)	PD	5	$ 294	$ 1,470		
			Sub-Total	$ 39,811		
OT Labour						
Maintenance Trades	PD	5	$ 730	$ 3,648		
			Sub-Total	$ 3,648		
Term Labour						
Maintenance Trades	PD	10	$ 365	$ 3,648		
			Sub-Total	$ 3,648		
Materials						
Discharge Heads	ea	2	$ 10,000	$ 20,000		
Misc Materials	lot	1	$ 5,000	$ 5,000		
2 x Cu/Ni Tube bundles	lot	1	[redacted]		Cost Support #1 - Item 1 Alt	
Fabrication of Tube Bundles	lot	1	[redacted]		Cost Support #1 - Item 2	
Escalation (2014-2017) @ 2.5% / Year	lot	1	$ 11,391	$ 11,391		
			Sub-Total	$ 217,651		
Contracts						
Refurbish Inlet heads	ea	2	$ 5,000	$ 10,000		
External Supervision	lot	1	$ 10,000	$ 10,000		
			Sub-Total	$ 20,000		
OT Meals						
Meals	lot	1	$ 500	$ 500		
				$ -		
			Sub-Total	$ 500		
Consulting						
Design	lot	1	$ 10,000	$ 10,000		
				$ -		
			Sub-Total	$ 10,000		
Other Goods & Services						
Contingency	%	10%	$ 295,257	$ 29,526		
				$ -		
			Sub-Total	$ 29,526		
Interest Capitalized						
AFUDC				$ 1,725		
			Sub-Total	$ 1,725		
Administrative Overhead						
Labour AO				$ 9,948		
Contract AO				$ 1,943		
			Sub-Total	$ 11,890		
			SUB-TOTAL (no AO, AFUDC)	$ 324,783		
			TOTAL (AO, AFUDC included)	$ 338,398		
Original Cost				$ 50,936		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

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QUOTATION 5047

TO : Fred Jordan Company: Nova Scotia Power From: Barney Helton

TEL.: 902-396-9182 Pages: 1 0f 1

EMAIL: fred.jordan@nspower.ca Date: March 3, 2014 Ref.: Your January 20, 2014, Email

ITEM	QTY	UNITS	DESCRIPTION	UNIT PRICE	TOTAL
			Redesigned Replacement Turbine Lube Oil Cooler Tube Bundles for Nova Scotia Power Trenton Generating Station, Unit 5. Original manufacturer C.A. Parsons & Co., NSPC Drawing No. A-050N5-9-091-62-014		
1	1	Lot	Tubes (2 sets of 1.002 tubes each set), 1/2" OD x 18 BWG, ASTM B111, C443, Admiralty Brass.	[redacted]	[redacted]
1 Alt.	1	Lot	Tubes (2 sets of 1.002 tubes each set), 1/2" OD x 18 BWG, ASTM B111, C706, 90 /10 Cu Ni.	[redacted]	[redacted]
2	1	Lot	Fabricate and furnish two (2) replacement Turbine Lube Oil Cooler Tube Bundles having 1,002 tubes each (tubes priced separately, see items 1 & 1 Alt.), Naval Brass (Copper Alloy C464, ASTM B171) tubesheets, carbon steel baffles, tie rods and spacers, special shipping / handling cradles. Bundles to be redesigned and fabricated to the appropriate TEMA and HEI standards with expanded tube to tubesheet joints and tie-rod and spacer support for baffles. RetubeCo to provide a custom fabricated steel shipping / handling / storage cradle with wooden crate (cover) for each bundle. To be submitted for approval/record: "As-Built" Dimensional Assembly Drawing, Certified Material Test Reports, Final Hydrostatic Test and Inspection Report.	[redacted]	[redacted]
NOTES:			**Validity Date:** 30 day **Delivery Date:** 13 to 15 weeks ARO (note 1.) **Payment Terms:** net 30 **FOB:** Ooltewah TN, 37363 (note 3.) **Taxes not included ***	SUBTOTAL	Dependent on Tube Selection
1. Based on expected tube delivery from mill of 9 to 11 weeks ARO.				* TAX	
2. Final documents will be submitted 3 to 4 weeks after shipment of bundles.				SHIPPING & HANDLING	
3. Shipping of replacement tube bundle to be provided by Nova Scotia Power.				OTHER	
				TOTAL	

IMPORTANT:** ***Does not include taxes, duties, etc. related to shipment to Canada.

CONFIDENTIALITY NOTICE

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CI Number: 51853

Title: LIN3 Turbine Valve Refurbishment 2018

Start Date: 2018/03
In-Service Date: 2018/04
Final Cost Date: 2018/10
Function: Steam
Forecast Amount: $295,709

DESCRIPTION:

This project will refurbish the upper and lower turbine main steam control valves (CV) , the left and right combined reheat valves (CRV), and the turbine main stop valve (MSV) on Lingan Unit 3.

The CV's regulate the steam flow to the turbine, and thus control the power output of the steam turbine generator. The CRV's protect against destructive over speeds on unit trips and offer back-up protection for the steam turbine in the event of unit trip. The MSV ceases steam flow to the turbine promptly during an emergency trip. All of these valves are critical components of the safe operation of the steam turbine, their functionality and reliability are crucial to the operation of Unit 3.

Summary of Related CIs +/- 2 years:
2016 CI 47863 - LIN4 Turbine Valve Refurbishment - $204,548
2017 CI 47960 - LIN1 Control Valve Rebuild - $237,623

JUSTIFICATION:

Justification Criteria: Health & Safety

Why do this project?

The CV, CRV, and MSV are critical to the safe operation of the turbine. Failure of these components to operate as required could lead to various levels of damage to the turbine, up to and including failure. In the event of a failure to the main stop or control valves, the turbine could go into overspeed, leading to unit failure and putting plant personnel at significant safety risk.

The turbine valves must be refurbished to avoid valve malfunctioning issues during operation. Thermal maintenance practices determine the maintenance schedule and are developed to avoid valve issues during operation which could potentially harm the turbine.

This project is primarily justified by safety concerns in the event of an unplanned failure, and secondarily justified by unit reliability.

Why do this project now?

Maintenance intervals on these valves are a function of the unit's Utilization Factor and expected future utilization. Annual planning efforts consider these factors to determine the timing and scope of the Turbine Valve refurbishment. This Risk Based approach has determined that these valve refurbishments should be scheduled in 2018.

Why do this project this way?

Disassembly and inspection during an outage is the only method of assessing the condition and all the failure mechanisms associated with these valves.

CI Number	: 51853	- LIN3 Turbine Valve Refurbishment 2018	**Project Number**	51853
Parent CI Number	:	-		
Asset Location	: 1133	- 1133 Lingan Unit 3; Commissioned 1983, 164Mwh	**Budget Version**	2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	1000 - SGP - Turbo Gen.Instal.	241,398
Retirements	1000 - SGP - Turbo Gen.Instal.	54,311
	Total Cost:	295,709
	Original Cost:	159,000

Capital Project Detailed Estimate

Location: Lingan Generating Station
CI# : 51853
Title: LIN3 Turbine Valve Refurbishment 2018
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
Maintenance Trades	PD	125	$ 358	$ 44,704		
Utility worker	PD	40	$ 235	$ 9,419		
			Sub-Total	$ 54,123		
OT Labor						
Maintenance Trades	PD	40	$ 715	$ 28,611		
				$ -		
			Sub-Total	$ 28,611		
Term Labor						
Maintenance Trades	PD	125	$ 358	$ 44,704		
Utility worker	PD	60	$ 235	$ 14,113		
				$ -		
			Sub-Total	$ 58,817		
Materials						
Valve Components	ea.	1	$ 90,000	$ 90,000		
				$ -		
			Sub-Total	$ 90,000		
Contracts						
Valve machining	ea.	1	$ 13,000	$ 13,000		
Inspection	ea.	1	$ 20,000	$ 20,000		
				$ 33,000		
Administrative Overhead						
Labor AO				$ 27,953		
Contract AO				$ 3,205		
			Sub-Total	$ 31,159		
			SUB-TOTAL (no AO, AFUDC)	$ 264,551		
			TOTAL (AO, AFUDC included)	$ 295,709		
Original Cost				$ 159,000		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 51803

Title: TUC2 Generator Flux Probe Installation

Start Date: 2018/03
In-Service Date: 2018/06
Final Cost Date: 2018/12
Function: Steam
Forecast Amount: $840,158

DESCRIPTION:

This project involves the installation of the generator flux probe for on-line condition monitoring of the Tufts Cove Unit 2 Generator Rotor. The flux probe provides on-line monitoring for the progression of rotor shorted turns. Shorted rotor turns occur as insulation ages, resulting in increased excitation current to achieve the same flux. Generators require rotor rewinding as the number of shorted turns progresses.

The Tufts Cove Unit 2 generator is a 100 MW nominally rated unit that has been in service since 1970. It is driven by the Tufts Cove Unit 2 Steam Turbine. It operates at 3,600 RPM, and is a hydrogen cooled unit.

Summary of Related CIs +/- 2 years:
No other projects in 2016, 2017, 2018, 2019 or 2020

JUSTIFICATION:

Justification Criteria: Thermal

Why do this project?

The installation of the flux probe is required to permit on-line monitoring for rotor shorted turns detection and provides essential diagnostic information for assessing rotor winding condition. The potential for shorted turns increases as the unit experiences more start-stops and load cycling. Flux probes have been installed at Lingan Units 3 and 4, Point Aconi, Trenton 6, and Point Tupper in line with NS Power's fleet maintenance strategy for rotor condition monitoring. Without completing this project, NS Power will not be able to effectively determine when the generator rotor requires a rewind. A lack of understanding of condition of the rotor, which is used to determine appropriate timing of a potential rotor rewind, could lead to a failure and outages.

Why do this project now?

To effectively monitor the condition of the rotor, a flux probe must be installed. The Tufts Cove Unit 2 rotor is 47 years old and requires enhanced monitoring to predict advancement of shorted turns. NS Power has been installing flux probes on generators because of the increased potential for shorted turns as units age and to support the more flexible operations now expected from the thermal fleet.

Why do this project this way?

NS Power's thermal fleet units are required to operate in more flexible modes due to the increasing amount of intermittent renewable generation on the Nova Scotia grid. Installing a flux probe to monitor the progress of shorted turns (which are driven by more flexible unit utilization) is a standard industry practice, and recommended by the Electric Power Research Institute (EPRI). This online monitoring will support the generator rotor rewind interval and subsequent outage planning. There are no other industry acceptable methods to monitor generator rotor shorted turns.

CI Number : 51803 - TUC2 Generator Flux Probe Installation **Project Number** 51803

Parent CI Number : -

Asset Location : 1172 - 1172 Tufts Cove Unit 2; Commissioned 1972, 97 Mwh **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	1000 - SGP - Turbo Gen.Instal.	799,533
Retirements	1000 - SGP - Turbo Gen.Instal.	40,625
	Total Cost:	840,158
	Original Cost:	126,711

Capital Project Detailed Estimate

Location: Steam
CI# : 51803
Title: TUC2 Generator Flux Probe Installation
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Electrician	PD	30	$ 358	$ 10,748		
Engineering	PD	15	$ 405	$ 6,080		
Maintenance Trades	PD	45	$ 365	$ 16,415		
Utility worker	PD	20	$ 240	$ 4,804		
			Sub-Total	$ 38,047		
OT Labour						
Maintenance Trades	PD	30	$ 730	$ 21,900		
Utility worker	PD	20	$ 480	$ 9,600		
			Sub-Total	$ 31,500		
Materials						
Miscellaneous Siemens parts	lot	1	[redacted]		Cost Support #1 - Items 0001-0007	
Misc General	lot	1				
				$ -		
			Sub-Total	[redacted]		
Contracts						
Flux Probe Installation	lot	1	[redacted]		Cost Support #2 - Item 02b	
ITP Prep, reports, mobilization	lot	1			Cost Support #2 - Item 1 (50%, as costs shared with CI 49707	
				$ -		
			Sub-Total	[redacted]		
Interest Capitalized						
AFUDC				$ 6,458		
				$ -		
			Sub-Total	$ 6,458		
Administrative Overhead						
Labour AO				$ 11,818		
Contract AO				$ 64,834		
			Sub-Total	$ 76,652		
			SUB-TOTAL (no AO, AFUDC)	$ 757,047		
			TOTAL (AO, AFUDC included)	$ 840,158		
Original Cost				$ 126,711		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

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Ref: **Our SF171127719**
NOVA SCOTIA POWER NSP-TCU2 Generator Inspection Spares Proposal

Date: **30 AUG 2017**

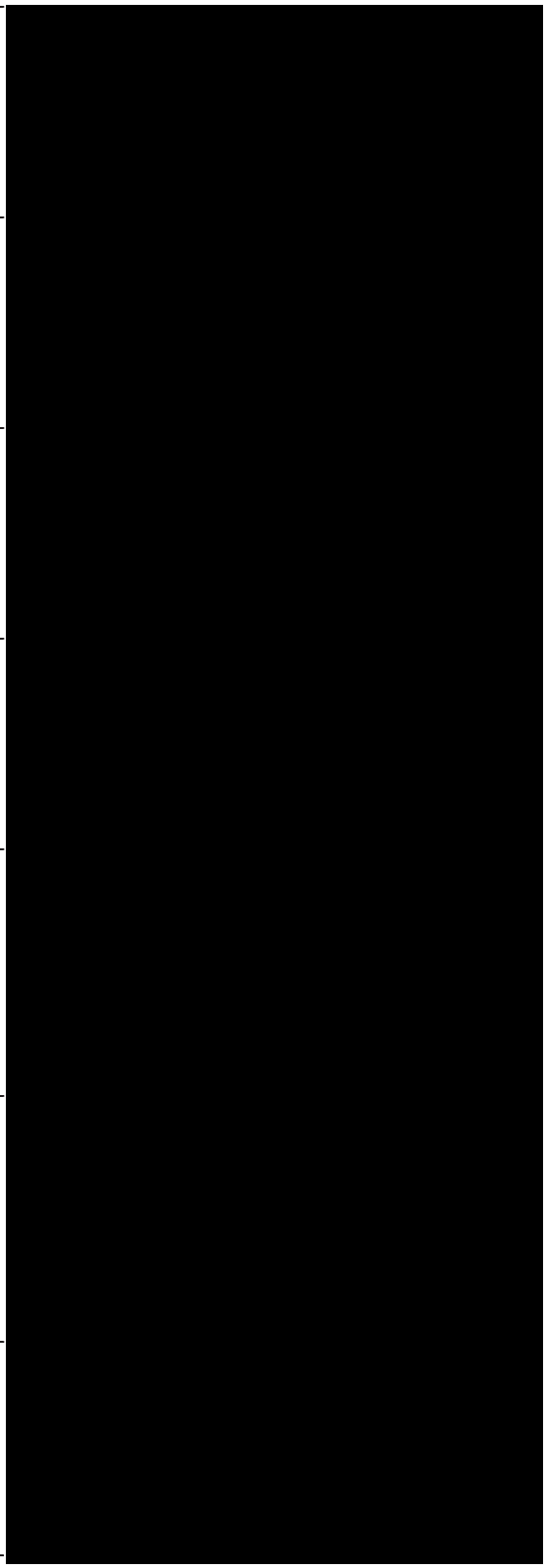
To: **Cletus MacIsaac**
c.c.: **Blaize McNeil, Tim Gillis, Greg Carlin.**

Subject: **PROPOSAL FOR 2018 OUTAGE GENERATOR INSPECTION SPARE PARTS**

With reference to requirement identified during discussions between Siemens and NSPI for Generator Inspection spare parts 2018 Outage, we are pleased to provide the following proposal for your consideration.

RFQ ITEM	DESCRIPTION	UNIT PRICE CDN $	Total Price CDN $	EST DELIVERY (ARO)
0001	O-Ring (supplied as cord) 2-off O-Rings (now 9.5MM dia cord +/- 0.18MM). Supplied with a minimum order quantity of 25MTRS in 5MTRS lengths. With following configuration: Assembly Drawing No.:[redacted] Detail Drawing No.:[redacted] QTY: 2 PCS	[redacted]		
0002	Cup Packing Ring With following configuration: Assembly Drawing No.: SL25842.010 Detail Drawing No.: 493S126 QTY: 2 PCS			
0003	Diaphragm EE With following configuration: Assembly Drawing No.: SL25842.090 Detail Drawing No.: 493U1510 QTY: 1 PC			
0004	Diaphragm TE With following configuration: Assembly Drawing No.: SL25842.091 Detail Drawing No.: 493U1511 QTY: 1 PC			
0005	1/2" Spring Lock-washer With following configuration: Assembly Drawing No.: SL24717.007 Detail Drawing No.: 21175715 QTY: 102 PCS			

0006	5/8" Spring Lock-washer With following configuration: Assembly Drawing No.: SL24717.009 Detail Drawing No.: 21175717 QTY: 127 PCS
0007	1.1/4" BSF Securing Bolt With following configuration: Assembly Drawing No.: SL24717.021 Detail Drawing No.: 406U1396 QTY: 6 PCS
0008	Cooler Gasket Fixed End With following configuration: Assembly Drawing No.: SL25699.028 Detail Drawing No.: 456M8522 QTY: 4 PCS
0009	Cooler Gasket Flexible End With following configuration: Assembly Drawing No.: SL25699.029 Detail Drawing No.: 456M8812 QTY: 4 PCS
0010	Replacement Up-shaft lead tube (existing design) With following configuration: Assembly Drawing No.: TBA Detail Drawing No.: TBA QTY: 1 PC
0011	Replacement Up-shaft lead tube (modified design) With following configuration: Assembly Drawing No.: TBA Detail Drawing No.: TBA QTY: 1 PC
0012	Radial Pins (existing design) With following configuration: Assembly Drawing No.: TBA Detail Drawing No.: TBA QTY: 4 PCS



0013	Radial Pins (Modified design) With following configuration: Assembly Drawing No.: TBA Detail Drawing No.: TBA QTY: 4 PCS	[redacted]
	TOTAL PROPOSAL PRICE	[redacted]

Prices: Price shown is in Canadian funds, include any import duties that may be applicable, FOB NSPI Tufts Cove GS, but do not include any taxes. Price shown is also based on the quantities quoted. Should the order quantity differ from the quoted quantity, we reserve the right to amend the prices.

Location of Supply: Siemens PLC UK.
A Division of Siemens Power Generation
Newcastle Upon Tyne, UK.

Validity: This proposal is valid for a period of 60 days from date of submission, unless extended, modified or withdrawn by Siemens Energy Services and limits acceptance to the terms set forth herein. The return of a purchase order or any other reasonable manner of acceptance communicated to Siemens during such validity period will be sufficient to form an agreement on the terms and conditions of this offer.

Due to recent significant movements in material costs and availability, our offer is subject to review beyond the validity period.

Environmental, Health & Safety:

This offer is based on Siemens' "Zero Harm" program and in accordance with COR Certification Requirements. Siemens EHS program is outlined in a Priority One Plan for each site.

Quality Program:

This offer is based on a Quality Program in accordance with ISO 9001:2015.

Terms of Payment:

Net 30 days. Overdue accounts will be charged a 2% per month carrying Charge.

Conditions of Sale:

As per Siemens Canada's terms and conditions for supply of parts and components Standard except as modified in this proposal.

Limitation of Liability: Notwithstanding any other provisions of this Contract, in no event shall the aggregate liability of Siemens Canada or its affiliates, partners and subcontractors exceed the final agreed Contract Price or any agreed increase to the Contract Price.

Siemens obligation to fulfill this agreement is subject to the proviso that the fulfillment is not prevented by any impediments arising out of national or international foreign trade and customs requirements or any embargos [or other sanctions].

Feel free to contact us should you have any questions. We look forward to receive your purchase order.

Regards,

IJAZ IMRAN
Digitally signed by IJAZ IMRAN
DN: cn=IJAZ IMRAN, o=Siemens, email=imran.ijaz@siemens.com
Reason: I have reviewed this document
Location: Oakville
Date: 2017.08.30 13:58:59 -04'00'

RIEMSCHNEIDER JAN-ERIK
Digitally signed by RIEMSCHNEIDER JAN-ERIK
DN: cn=RIEMSCHNEIDER JAN-ERIK, o=Siemens, email=jan-erik.riemschneider@siemens.com
Date: 2017.08.30 14:12:23 -04'00'

Senior Management Approval

Imran Ijaz
Manager – Parts Sales
Siemens Canada Limited
Power Generation Services Division
imran.ijaz@siemens.com

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PROPOSAL SF171127646 – NOVA SCOTIA POWER

TUC2 2018 Generator Inspection

		Signature and Date:
Prepared by:	**Jordan O`Brien Project Manager**	O'BRIEN JORDAN Digitally signed by O'BRIEN JORDAN DN: cn=O'BRIEN JORDAN, o=Siemens, email=jordan.obrien@siemens.com Date: 2017.09.19 15:11:49 -04'00'
Reviewed by:	**Chris Holloway Sales Manager**	HOLLOWAY CHRIS Digitally signed by HOLLOWAY CHRIS DN: cn=HOLLOWAY CHRIS, o=Siemens, email=chris.holloway@siemens.com Date: 2017.09.19 16:44:17 -02'30'
Approved by:	**Dilshan Canagasaby Sales Director**	CANAGASABY DILSHAN Digitally signed by CANAGASABY DILSHAN DN: cn=CANAGASABY DILSHAN, o=Siemens, email=dilshan.canagasaby@siemens.com Reason: I am approving this document Date: 2017.09.19 16:23:21 -04'00'

Siemens Canada Limited
Power Generation Services
1577 North Service Road East
Oakville, Ontario
L6H 0H6 / Canada

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PROPOSAL SF171127646 – NOVA SCOTIA POWER

TUC2 2018 Generator Inspection

Foreword

The work scope outlined in this proposal is to provide NSP with Generator Inspection and Overhaul for Tufts Cove`s Unit 2.

This "**Budgetary"** Pricing and the information contained herein are provided for informational & planning purposes only. The budgetary pricing submitted in this proposal is on a Time and Material basis. In case the work scope changes, new requirements will be addressed via SDIR with resultant price adjustments. Except for provisions regarding confidentiality, this proposal does not create any legal obligations between Siemens and any Purchaser. For greater certainty, it does not constitute an offer to provide any goods or services or to enter into a contract. No binding commitment or obligation exists unless and until the parties execute and deliver a binding written contract. Any future definitive agreement and discussion between Siemens and the Purchaser is subject to the approval of Siemens' management and compliance with all required regulatory and legal approvals.

No work will commence until a firm service Purchase Order has been issued to Siemens.

1.0 Work Scope

1.1 Base Scope

The base scope will be comprised of terminal bushing replacement. Assumptions made for terminal bushing replacement is that the machine is opened and ready to accept new bushings, rotor is out, and the station can supplement the crew with 3 electricians per shift:

A) Terminal Bushings

- Test and replace bushings:
  - Remove bushings.
  - Lower all Terminal plates, remove gaskets, and clean surfaces.
  - Fit new gaskets and refit terminal plates.
  - Fit new terminal bushings with new 'O' rings.
  - Re-insulate bushing to lead.
  - Diagnostic test - Partial discharge.
  - Carry out IR & PI test on winding.
  - Refit neutral Star connection.

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B) Rotor Flux Probe Installation

- Remove Generator Rotor
- Carry out IR & PI test on winding.
- Establish Clean Conditions for Stator Work.
- Winding slot wedge tightness checks.
- El-Cid Test.
- Stator end winding inspection.
- Core bore and Mazak spacer inspection.
- Inspect winding clamp studs.
- Carryout checks - core ventilation, core spacer bar security, and core tightness.
- Carryout inspections - stator casing, grounding strap for tightness & overheating, and thermocouple & RTD cables & support conduit.
- Carryout Thermocouple & RTD's electrical tests.
- Install new Flux Probe, and pressure test.
- Install Generator Rotor

C) Rotor Inspection (NSP requested scope)

- Receive rotor and place it on stands.
- Carryout visual and borescope inspections, and electrical tests.
- Removal and inspection of up shaft lead (U.S.L), radial pins.
- Dismantle, clean and prep for NDE inspections to be carried out by NSP third-party vendor: radial pins, fan hub & blades, shafts, slots and wedges.
- Fit U.S.L & radial pins, and carry out air test.
- Final electrical tests.

Note: To be provided by Nova Scotia Power:

- Three (3) electricians per shift during 3.5 weeks.
- Crane support.
- Two (2) millwrights per shift.
- Welders
- NDE of welds
- Scaffold Support

1.2 Optional Scopes

D) Radial Pin and Up Shaft Lead Upgrade

Detailed scope for this option is being developed and technical solution will be submitted to NSP. Pricing will be provided once scope is discussed and agreed upon.

E) End cap in-situ inspection (Rotor in stands, retaining rings on Rotor)

Mobilize Siemens personnel and equipment to site to perform end cap inspection.

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2.0 Duration

The duration for execution of the Base Scope is estimated in a total of **6.5 weeks,** including strip down and rebuild in a 1x6x10h shift pattern, and including 3.5 weeks in a 2x6x10h shift for the Inspections.

3.0 Pricing

To complete the work scope as outlined above we present the following pricing:

Item	Description	Contract Type	Total Price (CAD)
01	ITP Prep, planning, report writing, and mobilization. *Note: equals cancellation fee up until final mobilization.*	Fixed	[redacted]
02a	Siemens support - Terminal Bushing Replacement 1.1 (A) 2x Siemens Elec. TFA – 1 per shift for 3 weeks 6x Siemens Winders – 3 per shift for 3 weeks	T&M	
02b	Siemens Support - Rotor Flux Probe Installation 1.1 (B) 1 x Mech. TFA for 6.5 weeks 1 x Elect TFA for 2 weeks 3 x Winders for 1.5 weeks 1 x Foreman – 1 per shift for 6.5 weeks 3 x Millwrights – day shift for 6.5 weeks Electrical tooling	T&M	
02c	Siemens Support – Rotor Inspection 1.1 (C) 1 x Elect TFA for 0.5 weeks 1 x Winders for 1.5 weeks	T&M	
03	Option 1.2a : Radial Pin and Up Shaft Lead Like for Like 1x Siemens Winders – 1 per shift for 1.5 weeks Machining of shaft and pins Option 1.2a : Radial Pin and Up Shaft Lead Upgrade 1x Siemens Winders – 1 per shift for 1.5 weeks Machining of shaft and pins Modification of rotor plug for sealing	T&M	
04	Option 2: End cap in-situ inspection. Estimated total duration – 4x 12h days + mob/demob.	T&M	

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Prices are a T&M estimate based on expected 2018 rates. The updated 2018 rate sheets for both Siemens and subcontractors` personnel will be released once available.

Prices include time and expenses (air fares, travel time, all local accommodations, local travel, shift premiums and overtime premiums) for Siemens personnel, and are valid only for the release of work per this proposal. Trades' Travel, Room and Board charges are excluded from the price. TRB will be invoiced at cost at completion of the work.

Prices do not include any extra or discovery work, which will be addressed through a strip down Inspection Report.

Pricing for items 1, 2a, and 2b above have been priced considering synergies of having the scopes performed concurrently. If all scopes are not awarded together then pricing is no longer valid.

4.0 Quality Program

This budgetary offer is based on a Quality Program in accordance with ISO 9001:2015.

5.0 Environmental, Health & Safety

This budgetary offer is based on Siemens' "Zero Harm" program and in accordance with COR Certification Requirements. Siemens EHS program is outlined in a Priority One Plan for each site.

6.0 Confidentiality

The information contained in this proposal and all related documents is proprietary and confidential information that belongs to SIEMENS. This information is being disclosed to you for the specific purpose of your evaluation of SIEMENS as a contractor for a particular project. By reviewing the information contained in these documents, you agree to be bound to a confidentiality obligation with respect to this information. Specifically, you hereby agree that (1) you will treat this information with the same level of care as you treat your own proprietary information; (2) you will not disclose this information to third parties without the prior written consent of SIEMENS; and (3) you will not use this information for any purpose beyond evaluating SIEMENS as a contractor and/or contracting with SIEMENS for the particular project quoted herein.

CI Number: 50577

Title: TRE6 CEMS Replacement

Start Date: 2017/06
In-Service Date: 2018/08
Final Cost Date: 2019/02
Function: Steam
Forecast Amount: $715,562

DESCRIPTION:

The scope of work of this project includes the purchase, installation and certification testing of new continuous emission monitoring system (CEMS) equipment for the Unit 6 stack at the Trenton Generating Station. This new CEMS will be a Dilution Extractive Unit capable of dual range measurements.

The current CEMS that monitors sulfur dioxide (SO_2) and nitrogen oxide (NOx) for Trenton Unit 6 has surpassed its expected useful life and requires replacement. It was installed in 2001 and the recommended useful life of the equipment is 10 years. NS Power has been informed by the manufacturer that, the support for the current system can no longer be guaranteed as of June 30, 2017, as much of the equipment has become obsolete. The existing in-situ monitoring system will be replaced by a dilution extractive monitoring unit, which will allow for a better range for measurement of NOx and SO_2 at Trenton Unit 6 to ensure compliance with the provincial Air Emission Regulations.

Summary of Related CIs +/- 2 years:
No other projects in 2016, 2017, 2018, 2019 or 2020

JUSTIFICATION:

Justification Criteria: Environmental

Why do this project?

NS Power is required to operate and maintain a CEMS to continuously monitor the level of SO_2 and NOx in the flue gas emissions at each thermal generating facility, including Trenton, as per the facility's Operating Approval.[1] The CEMS on Trenton Unit 6 has limited spare parts, is no longer supported by the manufacturer, and must be replaced to ensure the Operating Approval is maintained.

Why do this project now?

The Trenton 6 CEMS is no longer supported by the manufacturer and if a failure occurred, limited spare parts are available, through either NS Power or the manufacturer. The CEMS requires replacement at this time to mitigate the risk of failure and allow the facility to remain in compliance with its Operating Approval. The existing system is showing signs of deterioration and this replacement will mitigate the risk of failure.

Why do this project this way?

Replacement of the CEMS is the only option due to the obsolescence of the existing equipment. The recommended approach is to replace the in-situ CEMS with a Dilution Extractive Unit capable of dual range measurements. This is a new monitoring system that the NS Power fleet has recently implemented at other plants / units (Tufts Cove and Trenton #5 Generating Stations), which will provide better information to NS Power's technical and operating staff for reporting to Nova Scotia Environment. By moving to a standardized system across the fleet, NS Power can also develop an inventory of common spare parts.

Other benefits to using the dilution extractive system rather than the in-situ CEMS include:

[1] The Operating Approval references federal guidelines: Environment Canada, Environmental Protection Series, *Protocols and Performance Specifications for Continuous Monitoring of Gaseous Emissions from Thermal Power Generation, Report EPS 1/PG/7*, (December 2005).

- Dual range measurement for concentrations of NOx and SO_2 since the ranges for the two parameters have a large scale difference.
- Installing a dual range system allows for flexibility with future fuel blends and does not limit Sulfur measurement.
- Dilution Extractive units provide the capability of measuring CO_2. With the current Federal and Provincial focus on CO_2, accurately measuring emissions is an improvement on NS Power's current mass balance approach.

NS Power considers the Teledyne CEMS the best alternative as it is currently used on units at other locations in the fleet. NS Power is familiar with this equipment and has been satisfied with the customer service and technical support.

CI Number : 50577-SI43 - TRE6 CEMS Replacement **Project Number** 50577-SI43

Parent CI Number : -

Asset Location : 1166 - 1166 Trenton Unit 6; Commissioned 1991, 170 Mwh **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account		Forecast Amount
Additions	0700 - SGP - Environmental		703,348
Retirements	0700 - SGP - Environmental		12,214
		Total Cost:	715,562
		Original Cost:	113,333

Capital Project Detailed Estimate

Location: **Trenton Generating Station**
CI# : 50577
Title: TRE6 CEMS Replacement
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Electrician	PD	10	$ 358	$ 3,583		
Engineering	PD	5	$ 405	$ 2,027		
Maintenance Trades	PD	45	$ 365	$ 16,415		
Power Engineer	PD	3	$ 390	$ 1,171		
Power Plant Technician	PD	10	$ 382	$ 3,821		
Utility worker	PD	20	$ 240	$ 4,804		
			Sub-Total	$ 31,821		CI 49551
OT Labour						
Electrician	PD	4	$ 716	$ 2,864		
			Sub-Total	$ 2,864		CI 49551
Term Labour						
Electrician	PD	150	$ 358	$ 53,742		
Maintenance Trades	PD	45	$ 365	$ 16,415		
			Sub-Total	$ 70,158		CI 49551
Materials						
Cables/Electrical Materials	ea	1	$ 15,000	$ 15,000		
Miscellaneous Consumables	ea	1	$ 5,000	$ 5,000		
TML-675 Continuous Emission Monitoring System	ea	1	$ 71,880	[redacted]	Cost Support 1 - Item A	
Allen Bradley Logic Controller	ea	1	$ 23,168	[redacted]	Cost Support 1 - Item C	
CO Analyzer Addition	ea	1	$ 12,725	[redacted]	Cost Support 1 - Item A-1	
CO2 Analyzer Addition	ea	1	$ 11,870	[redacted]	Cost Support 1 - Item A-2	
O2 Analyzer Addition	ea	1	$ 5,220	[redacted]	CI 49551	
Dilution Sample Umbilical	ft	300	$ 40	[redacted]	Cost Support 1 - Item D	
UltraFlow 150 Flow Monitor	ea	1	$ 24,585	[redacted]	Cost Support 1 - Item E	
Calibration Accessories	ea	1	$ 11,172	[redacted]	Cost Support 1 - Item F	
Standard Model CEM Shelter	ea	1	$ 61,812	[redacted]	Cost Support 1 - Item G	
Scroll Enclosed Air Compressor	ea	2	$ 9,380	[redacted]	Cost Support 1 - Item H	
USD to CDN Exchange Rate	%	30%	$ 253,192			
Platform for CEMS Access	ea	1	$ 4,000	$ 4,000		
Transformer	ea	1	$ 4,000	$ 4,000		
DCS Materials	lot	1	$ 5,000	$ 5,000		
			Sub-Total	$ 362,150		
Contracts						
Compressor Building Layout/Design, Platform Design	lot	1	$ 5,000	$ 5,000		
Project Manager	lot	1	$ 15,000	$ 15,000		
Factory Acceptance Test	lot	1	$ 3,855	[redacted]	Cost Support 1 - Item J	
System Start Up	lot	1	$ 10,765	[redacted]	Cost Support 1 - Item L	
Basic Training Course	lot	1	$ 9,455	[redacted]	Cost Support 1 - Item N	
CSA Inspection	lot	1	$ 7,143	[redacted]	CI 49551	
USD to CDN Exchange Rate	%	30%	$ 31,218	[redacted]		
Insulation	lot	1	$ 3,000	$ 3,000		
Construct Compressor Building/Foundation	lot	1	$ 50,000	$ 50,000		
HVAC for Compressor Room	lot	1	$ 5,000	$ 5,000		
Air Testing Services	lot	1	$ 15,000	$ 15,000		
Sheet Metal	lot	1	$ 5,000	$ 5,000		
			Sub-Total	$ 138,583		
Freight						
Shipping	lot	1	$ 4,500	$ 4,500		
				$ -		
				$ -		
			Sub-Total	$ 4,500		
Rentals						
Staging	lot	1	$ 2,500	$ 2,500		
Man lift	lot	1	$ 2,000	$ 2,000		
			Sub-Total	$ 4,500		
Other Goods & Services						
Contingency	%	10%	$ 605,575	$ 60,558		
				$ -		
			Sub-Total	$ 60,558		
Interest Capitalized						
AFUDC				$ 4,252		
			Sub-Total	$ 4,252		
Administrative Overhead						
Labour AO				$ 22,781		
Contract AO				$ 13,397		
			Sub-Total	$ 36,178		
			SUB-TOTAL (no AO, AFUDC)	$ 675,133		
			TOTAL (AO, AFUDC included)	$ 715,562		
Original Cost				$ 113,333		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

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Quote# 1705003

May 11, 2017

Nova Scotia Power
Trenton Generating Station
108 Power Plant Road
Trenton, NS B0K-1X0

Reference: Dilution CEMS for Unit 6

Dear Danya MacGillivray,

Teledyne Monitor Labs is pleased to provide Quotation No. 1705003 for our ML675 CEM System, Equipment, and Services. This proposal's competitive pricing is based on the entire package. TML has grouped various components in the item column below for comparison purposes. The purchase or exclusion of individual items must be discussed with TML.

The ML675 Extractive Monitoring System combines the benefits of field-proven extractive technology with innovative, flexible design to satisfy a vast range of process monitoring and compliance needs. Each extractive system is a pre-engineered package of high quality components, designed to economically and reliably meet specific application requirements.

If you have any questions regarding this quotation, please contact our Regional Sales Manager, Mr. Rob Bott, at 303-792-4200.

Sincerely,

Ryan Silkworth
Application Engineer

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Quote# 1705003

Teledyne Monitor Labs, a business unit of Teledyne Instruments, Inc.
35 Inverness Drive East
Englewood, Colorado, USA 80112-5189
+1-303-792-3300 Fax +1-303-799-1409
www.teledyne-ml.com

REPRESENTATIVE
Mr. Rob Bott Office: 303-792-4200 Fax: 303-799-1409 rbott@teledyne.com

CUSTOMER NAME & ADDRESS	QUOTE DATE	APPROXIMATE SHIP DATE
Nova Scotia Power Trenton Generating Station 108 Power Plant Road Trenton, NS B0K-1X0 Reference: Dilution CEMS for Unit 6 Attention: Danya MacGillivray	May 11, 2017	Dependent on Purchase Order Acceptance
	QUOTE NUMBER	**SHIP TERMS**
	1705003	FOB: Origin, PP&A EXW: Origin
	QUOTE VALID FOR	**TERMS OF PAYMENT**
	90 Days	30 Days

ITEM	QTY	DESCRIPTION OF ARTICLES AND/OR SERVICES	UNIT PRICE	AMOUNT
A	1	**TML-675 Continuous Emission Monitoring System** for the **single** point **Dilution Extractive** measurement of ***NO_X and SO_2***. Includes the following: ➢ T100 T SERIES® SO_2 Analyzer ➢ T200 T-SERIES® NO_X Analyzer ➢ 316 SS Dilution Extractive Probe with 316 SS Straw ➢ Open Rack Mounting ➢ Complete Sample Transport, Air Cleanup and Conditioning System ➢ Controller/PLC for System Sequencing and Control (detail below) ➢ Instrument Air Regulation and Distribution ➢ Automatic Probe Calibration with Multi-Valve Manifold ➢ Automatic Back Purge with Valve ➢ Two (2) sets of Standard Drawings and Two (2) Standard Manuals (on CD) ➢ System Integration and Factory Test ➢ Project management and Engineering	[redacted]	[redacted]
A-1	1	***Optional CO Analyzer Addition to 675 System Above*** ➢ T300 T-SERIES® CO Analyzer	[redacted]	***Optional***
A-2	1	***Optional CO_2 Analyzer Addition to 675 System Above*** ➢ T360 T-SERIES® CO_2 Analyzer	[redacted]	***Optional***

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ITEM	QTY	DESCRIPTION OF ARTICLES AND/OR SERVICES	UNIT PRICE	AMOUNT
		Option: Choose *One (1)* Controller/PLC Below		
B	1	**Teledyne Monitor Labs C3i/o® Controller** for System Sequencing and Control Includes the following: ➢ Data Buffering with RegPerfect® ➢ Modbus Communications ➢ CEMS Controller ➢ 8 Digital Inputs ➢ 8 Digital Outputs ➢ 4 Analog Inputs **(Qty 2)** ➢ 2 Analog Outputs **(Qty 2)** ➢ 19" Rack Mount Control Panel **Note:** CEMS to DCS communication available via Modbus/TCP	Included in Item (A) Above	Included in Item (A) Above
C	1	**Allen Bradley CompactLogix Programmable Logic Controller** Includes the following: ➢ L-3 Controller Dual Ethernet & 2MB Memory Processor ➢ Power Supply ➢ MVI69 Serial Communication Module ➢ Protocol Converter (Modbus) ➢ 16-channel digital input module **(Qty 1)** ➢ 16-channel digital output module **(Qty 1)** ➢ 4-channel analog input module **(Qty 1)** ➢ 4-channel analog output module **(Qty 1)** ➢ Panel View 600® display ➢ RS Logix Programming Software ➢ PLC Programming Labor **Please note:** Specific module and configuration may change after final engineering is complete. This proposal assumes all customer-supplied inputs are linear and compatible with required unit of measure.	[redacted] Adder to Item (A)	**Optional**

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ITEM	QTY	DESCRIPTION OF ARTICLES AND/OR SERVICES	UNIT PRICE	AMOUNT
D	Feet	**DILUTION SAMPLE UMBILICAL** The system is designed to use a seven-core sample transport bundle to carry the diluted gas sample from the probe to the cabinet for analysis. Within this bundle, a ⅜" PFA Teflon line transports the diluted sample, a 1/4" PFA Teflon line transports calibration gas, a 1/4" Teflon line supplies the dilution eductor vacuum indication, one 1/4" Teflon line carries bypass eductor air to the probe, a 1/4" Teflon line supplies backflush air, a 1/4" Teflon line carries the orifice pressure indication and finally, a 1/4" Teflon line transports dilution air to the probe. The entire bundle is encased in a rugged, fire-retardant PVC sheath to facilitate installation. Since any moisture is diluted with dry air, only freeze protection for the diluted sample line is supplied. This includes self-regulating heating element(s) located inside the sample bundle, which will operate at approximately 50F. **The quoted price is for lengths greater than 100 feet. Pricing for lengths less than 100 feet are subject to higher pricing per foot, and may require site-specific information.	[redacted] per foot	TBD
E	1	**UltraFlow™ 150 Flow Monitor** Monitor Includes: ➢ Dual 50 kHz Transducer Assemblies ➢ Transducer Interface Enclosure (TIE) ➢ Enhanced Remote Panel (ERP) ➢ Single 110CFM Purge Blower w/ Weather Cover ➢ Zero (0) feet of Data Cable **Long Range (20kHz) or Extended Range (14kHz) Transducers may be required per TML review of site-specific Installation Checklist. Dual 42CFM Blowers are required in this configuration.	[redacted]	[redacted]
F	Lot	**Calibration Accessories** Includes: ➢ Stainless Steel Regulators **(Qty 6)** ➢ Bottle Rack (6 Bottle Capacity) **(Qty 1)** ***Teledyne Monitor Labs has provided our best estimate of gas requirements at the time of quotation. Additional gases may be required after permit review and final engineering is complete but are not part of this proposal.*	[redacted]	[redacted]

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Quote# 1705003

ITEM	QTY	DESCRIPTION OF ARTICLES AND/OR SERVICES	UNIT PRICE	AMOUNT
G	1	**Standard Model CEMS Shelter** 8'W(OD) x 10'L(OD) x 8'H(ID) For placement in a general area classification. Channel skid base, galv. steel framing. white 24GA pre-finished steel interior & exterior cladding with finished stainless steel trim. White duro-last roofing system. Aluminum tread plate flooring. 3x7 insulated steel door with stainless steel hinges. Insulation. Built to the most current local and/or state building code applicable to factory built structures. **Note:** Item includes assembly and engineering labor to install the CEMS, and all accessories, for easy field installation. Also Includes: ➢ Power distribution including lights and receptacles ➢ HVAC 24k BTU, 5k Heat, thermostat, disc. sw ➢ Load Center, 100A, 3PH, 30 POS, NEMA 1 *typical* ➢ Surge Suppressor 3PH *typical* ➢ Disconnect Switch, Non-fused, NEMA 3R *typical* ➢ Single Doors Access (Panic Bar, 12x21 Window Tempered Glass, Automatic Hydraulic Closer) ➢ Interior Partition Wall, alike cladding (bottle bay) ➢ Double Doors access to Bottle Bay ➢ Ground Pad, Copper, NEMA 2-hole, bonded to frame ➢ Exterior light, LED wall pack 25W, 120V ➢ Smoke Alarm, Fire Extinguisher ➢ Canopy 24" projection 7-8 ft. width ➢ Exit Sign, Emergency Light, Battery Backup **Teledyne Monitor Labs has provided our best estimate of gas requirements at the time of quotation. Specific components and configuration may change after final engineering is complete.	[redacted]	[redacted]
H	1	**Scroll Enclosed Air Compressor** Model Number SES0208 Scroll Enclosure 2 HP system, complete with one 2-HP oil-less scroll compressors, mounted inside of a rigid steel enclosure. Enclosure to have a powder coat finish, and shall include sound deadening insulation. Noise levels shall not exceed 49 dBA with all compressor units in operation. Each compressor pump has a 1750-rpm, ODP motor, V-belt drive, and air-cooled aftercooler. Twin tower, heatless, desiccant air dryer is provided with integrated water separation/pre-filter and 1-micron final filtration. Dryer requires separate 115V power supply. Adjustable output pressure regulator is provided with gauge and installed downstream of the final filter.	[redacted]	[redacted]

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ITEM	QTY	DESCRIPTION OF ARTICLES AND/OR SERVICES	UNIT PRICE	AMOUNT
I	1	**RegPerfect® CEMS Compliance Data Acquisition and Handling System** Includes the following: ➢ RAID-1 Hot-Plug Tower Server Hardware ➢ Intel® Xeon® Quad Core Processor, 2.4 GHz or better ➢ 146/300 GB 15K RPM SCSI hard drive **(Qty 4)** ➢ 16 GB RAM ➢ CD/DVD-ROM ➢ 500 GB External Hard Drive Backup ➢ Network, video, and sound cards ➢ Tower Case with power supply ➢ Two (2) Year Extended On-Site Hardware Warranty ➢ UPS PRO 420 Power Back Up ➢ Keyboard, mouse ➢ 24" LCD Monitor ➢ HP LaserJet 2 Pro ➢ Microsoft Windows® Server (CAL=5) ➢ Microsoft SQL® (CAL=5) ➢ Microsoft Office® Home and Business	[redacted]	[redacted]
I-1	1	**Client Workstation Tower Hardware** Includes the following: ➢ Intel i7® Processor Mother Board ➢ 450 GB hard drive ➢ 4 GB RAM ➢ DVD +/-RW, 8X ➢ Network, video, and sound cards ➢ Mid-Tower case ➢ UPS 300 Power Back Up ➢ Keyboard, mouse ➢ 24" LCD monitor ➢ Windows® ➢ Microsoft Office® Home and Business ➢ RegPerfect® software, configuration and test	[redacted]	***Optional***

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ITEM	QTY	DESCRIPTION OF ARTICLES AND/OR SERVICES	UNIT PRICE	AMOUNT
I-2	1	**TML RegPerfect® Proprietary Server Software License for Windows®** ➢ Spotlight Real-time Graphical Interface and Data Display ➢ Alarm User Interface (Included in Spotlight) ➢ Trending Interface (Included in Spotlight) ➢ Browser Enabled Report Interface ➢ Data Base Editor ➢ Windows® Integrated Security ➢ RegPerfect® software, configuration and testing **Regulatory Disclaimer:** The proposal includes a RegPerfect® Client and/or Server license to meet the specific regulatory recordkeeping and reporting requirements identified in the bid specification. If a valid site-specific operating permit was not provided in the bid specification, TML reserves the right to review the permit, when provided, to determine if additional costs may be necessary to configure the RegPerfect® software to meet the applicable recordkeeping and reporting requirements. A purchase or contract change order may be required for the costs associated with any additional configuration work required to meet the applicable recordkeeping and reporting requirements not originally identified in the bid specification. **Configuration Disclaimer:** ***Configuration Disclaimer for VOC, PM, PM10, HAPS, NH_3, NH_3 Slip, NO_X, SO_2, CO:*** When there is not an instrument input or measured analog signal to the PLC or DAS, TML specifies that all parameter limits comply with the facility permit by annual or other scheduled facility compliance testing by customer unless estimation formulas are specified by the customer. These parameters will not be recorded or reported by the TML DAHS and are not included as a part of this quotation. **Configuration Requirement for RegPerfect®**: A high-speed connection of 1.5MB/sec is required for configuration via remote support. A phone modem is not considered high speed and would require a site visit and additional charges. A site visit would typically be shown as a separate line item in this proposal.	Included in Item (I) Above	Included in Item (I) Above

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Quote# 1705003

ITEM	QTY	DESCRIPTION OF ARTICLES AND/OR SERVICES	UNIT PRICE	AMOUNT
J	1	**Factory Acceptance Test (FAT)** ***One (1)*** day at Teledyne Monitor Labs' factory for customer personnel to confirm operation of the entire, integrated system. A Factory Witness Test protocol will be submitted for customer reference two (2) weeks prior to the test. Teledyne Monitor Labs' Quality Control and Assurance Department will submit a certified FAT report with the delivery of the CEMS. Customer is responsible for travel and expenses.	[redacted]	***Optional***
K	1	**Installation Supervision** ***One (1)*** plant visit with ***two (2)*** days on-site by a TML Certified Field Service Engineer to oversee and checkout equipment installation. **Please Note:** Fixed price is based upon one (1) trip with a site time of up to sixteen (16) hours (eight hours = one day) during normal business hours. The Service Department requires a minimum of three (3) weeks written notification prior to the actual date that Installation Supervision is desired. Failure to provide proper written notification may result in additional charges for Installation Supervision services. Any hours over the allotted time will be billed at standard general service rates. Delays resulting in additional time and/or expenses will be billed at standard general service rates. In addition, be aware that delays may result in the need for a return trip to the site. Expenses and Travel Time for a return trip will be charged to the customer and scheduling for such a trip will depend on Engineer availability. If this Service is not scheduled within six (6) months of System shipment, additional charges may apply. If the customer requests a schedule change after a firm date for services has been set, there may be additional costs associated with changes in travel arrangements.	[redacted] Price Per Mobilization [redacted] Price Per Day On-Site	[redacted] ***Optional***

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Quote# 1705003

ITEM	QTY	DESCRIPTION OF ARTICLES AND/OR SERVICES	UNIT PRICE	AMOUNT
L	1	**System Startup** during ***one (1)*** plant visit with ***five (5)*** days on-site by a TML Certified Field Service Engineer. Includes the following services: 1. **Installation Checkout:** Inspect all aspects of the installation and note or direct correction of errors in installation. 2. **System Inspection:** Examine the internal workings of the system to determine if damage occurred during shipment and installation. 3. **System Startup:** Supervise the application of electrical power and other utilities; test all system functions and observe on-line operation. 4. During the startup period Teledyne Monitor Labs' field personnel will familiarize the purchaser's operating and maintenance personnel with the basics of proper operating and preventative maintenance procedures. This familiarization is *not a substitute* for formal classroom system training for either the hardware or software. **NOTES:** **A)** Labor to correct customer installation errors shall be billed at actual time and materials at prevailing service rates when work is performed. **B)** Fixed price is based upon ***one (1)*** trip with a site time of up to ***forty (40)*** hours (eight hours = one day) during normal business hours. Waiting time due to client delays shall be billed in addition to the fixed price at prevailing service rates. In addition, be aware that delays may result in the need for a return trip to the site. Expenses and Travel Time for a return trip will be charged to the customer and scheduling for such a trip will depend on Engineer availability. If this Service is not scheduled within six (6) months of System shipment, additional charges may apply. **C)** Teledyne Monitor Labs requires a minimum of four (4) weeks notification prior to Startup. Failure to provide proper written notification may result in additional charges. **D)** If the customer requests a schedule change after a firm date for services has been set, there may be additional costs associated with changes in travel arrangements.	[redacted] Price Per Mobilization [redacted] Price Per Day On-Site	[redacted]

TELEDYNE MONITOR LABS
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Quote# 1705003

ITEM	QTY	DESCRIPTION OF ARTICLES AND/OR SERVICES	UNIT PRICE	AMOUNT
M	1	**Certification Test Assistance** of Teledyne Monitor Labs CEM System ***for SO_2, NO_X, CO, CO_2, and Flow.*** TML will provide a technician and regulatory **support** during the On-Site Reference Method testing to assist with documentation, data reduction and verification, relative accuracy, and calibration drift test assistance, according to procedures and specifications of the Code of Federal Regulations, ***Title 40, Part 75, Appendix A, or Title 40, Part 60, Appendix B, Performance specifications 1, 2, 3, 4, 5, & 6,*** as applicable to above system. The pricing quoted for Certification Test Assistance is a one-time charge with any retesting required due to the fault of our instrument performed at no additional charge for our services, provided the following: 1. This service assumes a Teledyne Monitor Labs Field Service Engineer already performed the system Startup, and the system has run for approximately 14 days to ensure stability. 2. The Customer will contract a qualified Stack Sampler to perform Reference Method testing for the CEMS Certification. Testing for each source to occur in one business calendar day during normal business hours. Our price is based upon ***one (1)*** mobilization with up to ***thirty-two (32) hours*** on-site. Delays, other than those caused by Teledyne Monitor Labs, during testing which result in additional Teledyne Monitor Labs Field Service Engineering hours or expenses that are beyond the scope will be billed to the customer at Teledyne Monitor Labs general service rates. 3. Others to provide all calibration gases for CEMS certification. 4. Ongoing QA/QC activities (Annual RATAs) not included. 5. Customer is responsible for providing adequate facilities (i.e. electricity, port, & platforms) required during the testing period. 6. If the customer requests a schedule change after a firm date for services has been set, there may be additional costs associated with changes in travel arrangements. 7. TML Requests a 30-day notice prior to the certification date to schedule a field service technician and stack sampler. 8. Others are responsible for providing the relative accuracy, ***P75 linearity, cycle time response,*** and drift test assessment, expressed in units of the reporting standard, in a report format ready for submittal to the applicable regulatory agencies. Any additional costs for additional time, retesting, and mobilizations by the stack sampler or others will be borne by others. 9. Certification needs to be scheduled within 90 days from completion of Startup; otherwise additional trip charges may apply for pre-cert. CEM system check out and calibration.	[redacted]	***Optional***

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ITEM	QTY	DESCRIPTION OF ARTICLES AND/OR SERVICES	UNIT PRICE	AMOUNT
N	1	**Basic Training Course** We are proposing a ***three (3)*** day On-Site training course held at customer's plant site. The price includes transportation and expenses for the instructor, course materials for up to ***ten (10)*** participants, and will utilize the customer's instruments. The customer will have the responsibility of providing an adequate classroom facility for the On-Site training course. This training class is designed to give your personnel basic operation and theoretical knowledge of the system quoted, and will cover each system component in as much depth as time permits. Arrangements for this training class should be made at least 60 days in advance with Teledyne Monitor Labs. **Factory Instrument Specific Training Courses**. Teledyne Monitor Labs also regularly offers a variety of in-depth instrument-specific training classes on individual system components at our facility. Participants in on-site training will receive a discounted price for factory classroom training classes. These training courses cover theory of operation, troubleshooting, circuit and system functions, maintenance, repair procedures, and actual “hands-on” training. Course dates can be arranged with Teledyne Monitor Labs' Training Department at 1-800-422-1499. **Please Note:** Tuition fees are fully refundable for any cancellation of registration received 30 days prior to class date. Since we keep our class sizes to a minimum to provide maximum value to our clients, cancellation charges of 25% will be applied for cancellations under 30 days and full tuition is due for cancellation under seven (7) days. If the customer requests a schedule change after a firm date for services have been set, there may be additional costs associated with changes in travel arrangements.	[redacted]	[redacted]

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CI Number: 49676

Title: TUC2 CEMS Replacement

Start Date:	2018/01
In-Service Date:	2018/07
Final Cost Date:	2019/01
Function:	Steam
Forecast Amount:	$380,140

DESCRIPTION:

The scope of work for this project includes the purchase and installation of a new Continuous Emissions Monitoring System (CEMS) on Unit #2 at Tufts Cove Generating Station. The new CEMS will be an extractive unit capable of measuring Sulphur Dioxide (SO_2), Nitrogen Oxides (NO_x), Carbon Dioxide (CO_2), Carbon Monoxide (CO), and Oxygen (O_2).

The CEMS that monitors SO_2 and NO_x at Tufts Cove has surpassed its expected useful life and requires replacement. The current CEMS is a Teledyne SM8175 and was installed in 2003. The expected lifespan of the equipment is 10 years.

The CEMS is no longer reliable and has required repairs several times over recent years, including repairs for issues related to on-board sensors, optic alignment, calibration mechanisms, and remote electronics.

Summary of Related CIs +/- 2 years:

No other projects in 2016, 2017, 2018, 2019 and 2020

JUSTIFICATION:

Justification Criteria: Environment

Why do this project?

NS Power is required to operate and maintain a CEMS to continuously monitor the emissions of SO_2 and NO_x in the flue gas at Tufts Cove as per the Operating Approval. The CEMS at Tufts Cove has surpassed its expected useful life and has also recently experienced technical issues. A replacement CEMS is required to ensure the facility continues to operate in compliance with the Operating Approval. NS Power has been informed by the manufacturer that parts and service for the CEMS are available on a “best effort basis” as much of the equipment has become obsolete.

Why do this project now?

The Tufts Cove CEMS has surpassed its expected lifespan and recently experienced technical issues. The CEMS requires replacement at this time to allow the facility to continue operation in compliance with the Operating Approval. Recent failures involved parts that are no longer being manufactured. The instrumentation technicians have made repairs with miscellaneous parts, which may prove unreliable. If the CEMS fails, the Unit cannot run.

Why do this project this way?

An alternative type of monitoring system, predictive emission monitoring system (PEMS), was trialed for Units 1-3 but it was not able to be certified on heavy fuel oil (HFO). The Tufts Cove units would not be able to burn Heavy Fuel Oil (HFO) without a monitoring system that is certified on HFO such as the CEMS being installed.

Full replacement of the CEMS is the only technically viable option (see above) due to the obsolescence of the existing equipment. The recommended approach is to replace the current CEMS with an extractive unit capable of dual range measurements. This is a new monitoring system that the NS Power fleet has begun implementing at other plants, most recently on Tufts Cove LM6000 Units #4 and #5, through CI 50017 TUC4 U&U CEMS Installation and CI 50018 TUC5 U&U CEMS Installation, both approved by the UARB on June 30, 2017. By moving to a standardized system across the fleet, NS Power can develop a repository of spare parts.

Other considerations for using the extractive system instead of the current system include:

- Dual range measurement for concentrations of NO_x and SO_2, since the ranges for the two parameters is a large scale difference.
- Installing a dual range system allows for flexibility with future fuel blends and does not limit the sulfur content in fuel.
- Extractive units provide the capability of measuring CO_2. With the current Federal and Provincial focus on CO_2, accurately measuring emissions is an improvement on NS Power's current mass balance approach.
- Extractive units also provide the capability of measuring CO and O_2. The O_2 monitoring is critical for flow measurement as it is based on fuel consumption. This eliminates the need to install and service a new flow meter inside the stack.

The extractive Teledyne CEMS is the best alternative among the CEMs as the Company currently uses these systems at other locations in the fleet. NS Power is familiar with the equipment and has been satisfied with the customer service and technical support. This type of replacement will continue on other units across the fleet that have not already been replaced in 2017 / 2018.

The CEMS being installed at Tufts Cove Unit #2 is a slightly different model than is being installed at the Trenton Generating Station, due to the different fuel sources used in generation. Trenton's use of coal leads to the requirement to dilute the sulphur in the flue in order to complete the testing, while sulphur is not an issue in the Tufts Cove units, which burn natural gas / oil, therefore a dilution system is not required. While these systems are slightly different, shared technical learnings between each is applicable and allows for a centralized repository of spare parts for both types of CEMS.

CI Number	: 49676	- TUC2 CEMS Replacement	**Project Number**	49676
Parent CI Number	:	-		
Asset Location	: 1172	- 1172 Tufts Cove Unit 2; Commissioned 1972, 97 Mwh	**Budget Version**	2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account		Forecast Amount
Additions	0700 - SGP - Environmental		372,119
Retirements	0700 - SGP - Environmental		8,021
		Total Cost:	380,140
		Original Cost:	293,296

Capital Project Detailed Estimate

Location: Steam
CI# : 49676
Title: TUC2 CEMS Replacement
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Electrician	PD	35	$ 358	$ 12,540		
Engineering	PD	20	$ 405	$ 8,106		
Maintenance Trades	PD	70	$ 365	$ 25,535		
Power Engineer	PD	8	$ 390	$ 3,123		
Utility worker	PD	10	$ 240	$ 2,402		
			Sub-Total	$ 51,706		
Term Labour						
Electrician	PD	130	$ 358	$ 46,577		
				$ -		
			Sub-Total	$ 46,577		
Freight						
Freight	Lot	1	$ 5,500	$ 5,500		
USD to CDN Exchange Rate	%	33%	$ 5,500	$ 1,815		
			Sub-Total	$ 7,315		
Materials						
TML CEMS Extractive incl SO2, NOx, CO, CO2 & O2 sensors	Lot	1	[redacted]		Cost Support # 1 - Item A	
TML Heated Sample Line ($47.50/ft x 200 ft)	Foot	200			Cost Support # 1 - Item C	
USD to CDN Conversion	%	32%				
Structural Steel & Piping Materials	lot	1	$ 2,000	$ 2,000		
Materials for New Breeching Test Ports	lot	1	$ 1,000	$ 1,000		
Electrical Materials	lot	1	$ 5,000	$ 5,000		
Calibration Gas	lot	1	$ 5,000	$ 5,000		
				$ -		
				$ -		
			Sub-Total	$ 131,709		
Contracts						
Stack Testing	lot	1	$ 15,000	$ 15,000		
Scaffolding & Sheet Metal	lot	1	$ 20,000	$ 20,000		
Engineering (Electrical & Structural Engineering Design)	lot	1	$ 10,000	$ 10,000		
Project Management & Supervision	lot	1	$ 22,000	$ 22,000		
DCS Design and Programming	lot	1	$ 12,500	$ 12,500		
Mobile Crane Services	lot	1	$ 5,000	$ 5,000		
Mobilization + 3 Days on Site	Lot	1	[redacted]		[redacted]	
USD to CDN Conversion	USD	32%				
High angle confined space rescue services	lot	1	$ 7,000	$ 7,000		
High Pressure Wash Cleaning	lot	1	$ 5,000	$ 5,000		
			Sub-Total	$ 105,365		
Interest Capitalized						
AFUDC				$ 5,644		
				$ -		
			Sub-Total	$ 5,644		
Administrative Overhead						
Labour AO				$ 21,591		
Contract AO				$ 10,234		
				$ -		
			Sub-Total	$ 31,825		
			SUB-TOTAL (no AO, AFUDC)	$ 342,672		
			TOTAL (AO, AFUDC included)	$ 380,140		
Original Cost				$ 293,296		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

TELEDYNE MONITOR LABS
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Quote #1704052-3

August 16, 2017

Nova Scotia Power
Tufts Generating Station
315 Windmill Road
Dartmouth, Nova Scotia
Canada B3J 2W5

Dear Mr. Nowlan,

Teledyne Monitor Labs is pleased to provide Quotation No. 1704052-3 for our ML660 CEM System, Equipment, and Services for Unit 3. This proposal's competitive pricing is based on the entire package. TML has grouped various components in the item column below for comparison purposes. The purchase or exclusion of individual items must be discussed with TML.

If you have any questions regarding this quotation, please contact our Vice President of Sales, Mr. Rob Bott at (303) 792-4200.

Sincerely,

Ryan Silkworth
Quotation Engineer

Seller's Offer, and any order issued by Buyer to Seller for the goods and/or services specified herein, is strictly limited to Seller's Terms and Conditions of Sale, which can be found at www.teledyne-ml.com.

TELEDYNE MONITOR LABS
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Quote #1704052-3

Teledyne Monitor Labs, a business unit of Teledyne Instruments, Inc.
35 Inverness Drive East
Englewood, Colorado, USA 80112-5189
+1-303-792-3300 Fax +1-303-799-1409
www.teledyne-ml.com

REPRESENTATIVE
Robert (Rob) Bott Vice President of Sales Phone: (303) 792-4200 E-mail: rbott@teledyne.com

CUSTOMER NAME & ADDRESS	QUOTE DATE	APPROXIMATE SHIP DATE
Nova Scotia Power Tufts Generating Station 315 Windmill Road Dartmouth, Nova Scotia Canada B3J 2W5 Attn: Karl Nowlan	August 16, 2017	Dependent on order acceptance
	QUOTE NUMBER	**F.O.B. POINT**
	1704052-3	Englewood, PP&A
	QUOTE VALID FOR	**TERMS OF PAYMENT**
	90 Days	30 Days

ITEM	QTY	DESCRIPTION OF ARTICLES AND/OR SERVICES	UNIT PRICE	AMOUNT
A	1	**TML-660 Continuous Emission Monitoring System** for the **single point** measurement of **NO_x, SO_2, CO, CO_2, & O_2**. Includes the following: ➢ T100 /CO_2 T-SERIES® SO_2 Analyzer w/ CO_2 Sensor **(Qty 1)** ➢ T200 /O_2 T-SERIES® NO_x Analyzer w/ O_2 Sensor **(Qty 1)** ➢ T300 T-SERIES® CO Analyzer **(Qty 1)** ➢ 316 SS Extractive Probe with 316 SS Straw ➢ Open Rack Mounting ➢ Complete Sample Transport and Conditioning System ➢ System Controller for Sequencing and Control (detailed below in Item B) ➢ Instrument Air Regulation and Distribution ➢ Automatic Probe Calibration with Multi-Valve Manifold ➢ Automatic Back Purge with Valve ➢ Valves for Manual Calibration at the Cabinet ➢ System Integration, Factory Testing, and Project Management ➢ Project Engineering with Two (2) sets of Standard Drawings and Two (2) Standard Manuals (on CD)	[redacted]	[redacted]
B	1	**Teledyne Monitor Labs C3i/o® Controller** for System Sequencing and Control ➢ Data Buffering with RegPerfect® ➢ Modbus Communications ➢ 8 Digital Inputs & 8 Digital Outputs ➢ 4 Analog Inputs **(Qty. 2)** ➢ 2 Analog Outputs **(Qty. 2)** ➢ 19” Rack Mount Control Panel **Note:** CEMS to DCS communication available via Modbus/TCP	Included in Item (A) Above	Included in Item (A) Above

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TELEDYNE MONITOR LABS
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Quote #1704052-3

ITEM	QTY	DESCRIPTION OF ARTICLES AND/OR SERVICES	UNIT PRICE	AMOUNT
C	200 Feet	**Heated Sample Line (HSL)** and unheated Probe Support Bundle (PSB) are in one (1) sheath. Heated sample line includes **two (2)** ⅜" Stainless Steel tube for sample transport, and a spare maintained at high temperatures with a constant watt density heating element. Probe support bundle includes **one (1)** ¼" Polyethylene tube for back purge, **one (1)** ¼" PFA Teflon tube for calibration gas transport, **one (1)** 14 AWG Triad for probe heater power, and **three (3)** 16 AWG twisted pair for low probe temperature alarm, back flush, and a spare. The HSL and PSB are contained in a fire retardant polyurethane sheath. **The quoted price is for lengths greater than 100 feet. Pricing for lengths less than 100 feet are subject to higher per foot pricing, and may require site-specific information.	[redacted] per foot	[redacted]
D	1	**Standard 8'W (OD) x 10'L (OD) x 8'H (ID) CEMS Shelter** For placement in a general area classification. Channel skid base, galv. steel framing. White 24GA pre-finished steel interior & exterior cladding with mill finished aluminum trim. White duro-last roofing system. Aluminum tread plate flooring. 3x7 insulated steel door with stainless steel hinges. R21 Insulation. Built to the most current local and/or state building code applicable to factory built structures. ***This item includes engineering, design, and assembly labor.*** The CEM System, and all accessories, are installed in the shelter for easy field installation. Includes: ➢ Power Distribution Including Lights and Receptacles ➢ Load Center 100A, 3 PH NEMA 1 ➢ HVAC with Upgraded Coated Coils ➢ Single Doors Access (Panic Bar, 12x21 Window Tempered Glass, Automatic Hydraulic Closer) ➢ Smoke and Carbon Monoxide Alarm ➢ Bulkhead Panel, Fixed Plate up to 12" H x 18" W (Alum.) ➢ Ground Pad, Copper, NEMA 2-hole, bonded to frame ➢ Exit Sign / Emergency Light & Fire Extinguisher	[redacted]	[redacted]

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Quote #1704052-3

ITEM	QTY	DESCRIPTION OF ARTICLES AND/OR SERVICES	UNIT PRICE	AMOUNT
E	1	**System Startup** of (Item A) CEMS during ***one (1)*** plant visit with up to ***two (2)*** days on-site by a TML Certified Field Service Engineer. Includes the following services: 1. **Installation Checkout:** Inspect all aspects of the installation and note or direct correction of errors in installation. 2. **System Inspection:** Examine the internal workings of the system to determine if damage occurred during shipment and installation. 3. **System Startup:** Supervise the application of electrical power and other utilities. Test all system functions and observe on-line operation. 4. During the startup period Teledyne Monitor Labs' field personnel will familiarize the purchaser's operating and maintenance personnel with the basics of proper operating and preventative maintenance procedures. This familiarization is *not a substitute* for formal classroom system training for either the hardware or software. **NOTES:** **A)** Labor to correct customer installation errors shall be billed at actual time and materials at prevailing service rates when work is performed. **B)** Fixed price is based upon ***one (1)*** trip with a site time of up to ***sixteen (16)*** hours (eight hours = one day) during normal business hours. Waiting time due to client delays shall be billed in addition to the fixed price at prevailing service rates. In addition, be aware that delays may result in the need for a return trip to the site. Expenses and Travel Time for a return trip will be charged to the customer and scheduling for such a trip will depend on Engineer availability. If this Service is not scheduled within six (6) months of System shipment, additional charges may apply **C)** Teledyne Monitor Labs requires a minimum of four (4) weeks notification prior to Start-up. Failure to provide proper written notification may result in additional charges. **D)** If the customer requests a schedule change after a firm date for services has been set, there may be additional costs associated with changes in travel arrangements	Per Mobilization [redacted] Per Day On-Site [redacted]	[redacted]

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Quote #1704052-3

ITEM	QTY	DESCRIPTION OF ARTICLES AND/OR SERVICES	UNIT PRICE	AMOUNT
F	1	**CSA Inspection**	[redacted]	[redacted]
G	1	**Basic Training Course** A ***Three (3)*** day on-site training course held at customer's plant site. The instruction price includes transportation and expenses for the instructor, course materials for up to ten (10) participants, and will utilize the customer's instruments. The customer will have the responsibility of providing an adequate classroom facility for the On-Site training course. This training class is designed to give your personnel basic operation and theoretical knowledge of the system quoted, and will cover each system component in as much depth as time permits. Arrangements for this training class should be made at least 60 days in advance with Teledyne Monitor Labs. **Factory Instrument Specific Training Courses**. In-depth, focused training classes on the individual system components are held regularly at our facility. Participants in on-site training receive a discounted price for factory classroom training. Teledyne Monitor Labs offers a variety of instrument-specific courses at our facilities. These training courses cover theory of operation, troubleshooting, circuit and system functions, maintenance, repair procedures, and actual “hands-on” training. Course dates can be arranged with Teledyne Monitor Labs' Training Department at 1-800-422-1499. **Please Note:** Tuition fees are fully refundable for any cancellation of registration received 30 days prior to class date. Since we keep our class sizes to a minimum to provide maximum value to our clients, cancellation charges of 25% will be applied for cancellations under 30 days and full tuition is due for cancellation under seven (7) days. If the customer requests a schedule change after a firm date for services have been set, there may be additional costs associated with changes in travel arrangements.	[redacted]	[redacted]
H	1	**Addition of Unit 3 to RegPerfect® CEMS Compliance System** Additional remote software programming labor to add Unit 3 CEM systems to existing on-site RegPerfect system	[redacted]	[redacted]

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TELEDYNE MONITOR LABS
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Quote #1704052-3

TELEDYNE MONITOR LABS' TERMS OF PAYMENT:

- 40% of contract price on submittal of drawings for review.
- 40% of contract price on shipment of equipment.
- 20% of contract price on startup, but not to exceed 90 days after receipt of equipment.

Payment terms for all invoices are NET 30 days from the date of the invoice. Unless otherwise agreed to in writing, payments for drawing submittals must be received by Teledyne Monitor Labs prior to shipment of equipment. Late payment will be considered a breach of contract and Teledyne reserves the right in such instances to cease activity until payment issues are resolved.

NOTE: Prices do not include sales tax. Sales tax will be added to each invoice as a separate line item unless the customer provides Teledyne with a sales and use tax certificate.

PLEASE NOTE: Spare parts ordered after delivery of the instrumentation quoted herein should be based on the final system design and spare parts lists provided with manuals and final drawings.

REGARDING MAINTENANCE AGREEMENT PURCHASES:
If an order resulting from this quotation includes an on-going maintenance agreement for hardware, software, or both, payment for the maintenance agreement(s) may be broken out from the contract price and billing schedule above and billed separately as services are performed.

Maintenance agreement contracts do not include the supply of spare or replacement parts. Spare or replacement parts are billed separately to the holder of the maintenance agreement. For that reason it is recommended that maintenance agreements be purchased by the end user of the equipment rather than an intermediary such as a construction or engineering firm.

The system description and product brochures provided herein describe in detail the instruments/systems included in this proposal. The descriptions are accurate to the best of our knowledge as of the date of this proposal; however, as additional information is obtained, variations may be required to enhance system performance. Teledyne Monitor Labs reserves the right to make changes in the design and construction of any system as it deems appropriate to meet the performance requirements of the application, with proper notification given to customer. Any changes made by Teledyne Monitor Labs will conform to U.S. EPA reference or equivalency method designations where applicable.

Other terms and conditions of sale, including warranty terms, are included with this quotation and can be found at our web site: www.teledyne-ml.com

Successful start-up shall be the criteria of acceptance, with such start-up defined as calibration of each gas parameter with zero and span gas.

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CI Number: 51806

Title: LIN Mill Refurbishment 2018

Start Date: 2018/03
In-Service Date: 2018/10
Final Cost Date: 2019/04
Function: Steam
Forecast Amount: $673,153

DESCRIPTION:

Lingan Generating Station has sixteen Raymond Bowl style mills used to pulverize coal for combustion in the boiler. Two of the sixteen mills have components that have reached the end of their expected useful lives and require replacement. Based on experienced wear characteristics, component failures will occur if not replaced. The consequence of such a failure could include unplanned unit derating.

This capital item includes the replacement of welded steel rollers and tables with ceramic wear components, worm gear and shaft, vertical shaft and other non-repairable mill components. As part of the planned outage in 2018, a condition assessment during teardown will determine which components must be replaced. In future, Additional capital investment on the Lingan mills will be required to extend asset life and ensure the reliability of this equipment is maintained.

These mills service all units at the Lingan generating station. The current expectation is that this project will not include the refurbishment of any mills on Unit #2. However, if mills on Unit #2 are found to require refurbishment in 2018, investment on Unit #2 could still be the best option. All four units at Lingan are similar and, as such, the components refurbished on this coal mill can be transferred to any of the other Lingan coal mills when Lingan Unit #2 is retired. This includes welded steel rollers and tables with ceramic wear components, worm gear and shaft, vertical shaft and other components that will be addressed in this capital item. The useful life of these coal mill components is more than double the payback period shown in the Economic Analysis Model providing a significant benefit to all of the coal mills at Lingan.

Summary of Related CIs +/- 2 years:
2016 CI 47505 - LIN Mill Refurbishment 2016 - $749,183
2017 CI 49431 - LIN Mill Refurbishment 2017 - $665,839
2019 CI TBD - LIN Mill Refurbishment 2019 - $TBD
2020 CI TBD - LIN Mill Refurbishment 2020 - $TBD

JUSTIFICATION:

Justification Criteria: Thermal

Sub Criteria: Equipment Replacement / Refurbishment

Why do this project?

This project is being completed to mitigate the risk of mill failure. A mill failure could limit the ability of the unit to reach rated generation depending on the fuel blend. Mills are required to be available full time between planned outages in order to maintain unit performance at rated capacity. The replacement of mechanical components and the upgrading of the ceramic surfaces are necessary to achieve the most economic operation of the unit.

This project is being undertaken primarily to prevent unit deratings, and is secondarily supported by positive replacement energy cost economics

Why do this project now?

A total of sixteen coal mills are installed on the four units at Lingan. An orderly approach to mill refurbishment manages the availability of the assets and supports the operation of the generating units that they serve. Operating and maintenance experience with the mills has identified several areas of concern that need to be addressed in order for the mills to meet availability targets. Replacement parts are now needed due to age and wear of many of the components. During periods of lower load it is possible to take one of four mills out of service without affecting generation. Isolated repairs and minor refurbishment are not typically possible for the mills. To access components and complete the required equipment replacement, it is necessary to disassemble the mill and therefore an overall refurbishment is more effective, as compared to isolated repairs.

Why do this project this way?

A phased approach to upgrading the mills allows for scheduled outages of selected mills, reducing the risk of extended unplanned outages. By planning refurbishments in a given year the refurbishment efforts can be made more efficient, with dedicated labour and parts available as required.

CI Number : 51806 - LIN Mill Refurbishment 2018 **Project Number** 51806

Parent CI Number : -

Asset Location : 1138 - 1138 Lingan Common Plant **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account		Forecast Amount
Additions	1800 - SGP - Fuel Hndlg.Coal		628,242
Retirements	1800 - SGP - Fuel Hndlg.Coal		44,911
		Total Cost:	673,153
		Original Cost:	514,626

Capital Project Detailed Estimate

Location: Lingan Generating Station
CI# / FP#: 51806
Title: LIN Mill Refurbishment 2018
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Maintenance Trades	PD	306	$ 358	$ 109,490		
Utility worker	PD	95	$ 235	$ 22,332		
			Sub-Total	$ 131,822		
Term Labour						
Maintenance Trades	PD	160.00	$ 358	$ 57,221		47505, 49431
			Sub-Total	$ 57,221		
Materials						
OEM and Locally Manufactured Parts	ea	1	$ 430,000	$ 430,000		47505, 49431
			Sub-Total	$ 430,000		
Interest Capitalized						
AFUDC				$ 12,581		
			Sub-Total	$ 12,581		
Administrative Overhead						
Labour AO				$ 41,529		
			Sub-Total	$ 41,529		
			SUB-TOTAL (no AO, AFUDC)	$ 619,043		
			TOTAL (AO, AFUDC included)	$ 673,153		
Original Cost				$ 514,626		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

LIN Mill Refurbishment
Summary of Alternatives

Division :	Power Production	**Date :**	**17-Nov-17**
Department :	Lingan	**CI Number:**	51806
		Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank (based on PV of RR)	IRR	Disc Pay
A	Mill Refurbishment vs Replacement Energy Costs	5.88%	-1,275,403	876,275	1	40.72%	3.1 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

Recommendation :

NS Power recommends completing this project to help avoid mill related deratings.

Notes/Comments :

Mill Refurbishment vs Replacement Energy Costs

The failure scenario is loss of a mill during peak unit load. With current coal blends (low sulf., low BTU), all four mills are required for peak load. A derate of approx 20 MW is expected if a mill is not available. A significant mill repair, including material lead time is 2 - 4 weeks. This scenario assumes the mill is unavailable for 4 weeks for teardown and materials lead time.

Test 2

Test 3

Test 4

LIN Mill Refurbishment
Summary of Sensitivities

Nova Scotia POWER An Emera Company

Division :	Power Production	**Date :**	**14-Nov-17**
Department :	Lingan	**CI Number:**	51806
		Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Mill Refurbishment vs Replacement Energy Costs	5.88%	-1,275,403	876,275	1	40.72%	3.1 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

	Alternative Variance on Capital Spend	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Mill Refurbishment vs Replacement Energy Costs	10%	-1,214,427	827,332	1	35.84%	3.4 years
B	Test 2	10%	0	0	2	#NUM!	0.0 years
C	Test 3	10%	0	0	2	#NUM!	0.0 years
D	Test 4	10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		60,976	-48,943	0	-4.88%	0.3 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

	Alternative Variance on Avoided Expenses	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Mill Refurbishment vs Replacement Energy Costs	-10%	-1,086,887	739,704	1	35.35%	3.4 years
B	Test 2	-10%	0	0	2	#NUM!	0.0 years
C	Test 3	-10%	0	0	2	#NUM!	0.0 years
D	Test 4	-10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		188,516	-136,570	0	-5.37%	0.3 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

Alternative Variance on Avoided Expenses - Change in Revenue Requirement		PV of Revenue Requirement	PV of Revenue Requirement	PV of Revenue Requirement	Delay?
	Yrs Delay:	1	2	3	
	A	148,238	314,140	528,006	No
	B	0	0	0	No
	C	0	0	0	No
	D	0	0	0	No

LIN Mill Refurbishment
Avoided Cost Calculations

Division :	Power Production	**Date :**	**14-Nov-17**
Department :	Lingan	**CI Number:**	51806
		Project No. :	

Mill Refurbishment vs Replacement Energy Costs

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			161,800	165,036		
Events/Outages (#)	2	2	2	2		
Probability of Occurance (%)	50%	60%	50%	60%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	20.0	20.0				
Duration (Hours or Years)	672	672				
Totals	$26,999	$32,019	$161,800	$198,043	$188,799	$230,062
Total Capital Cost of Alternative						$673,153

Test 2

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

Test 3

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

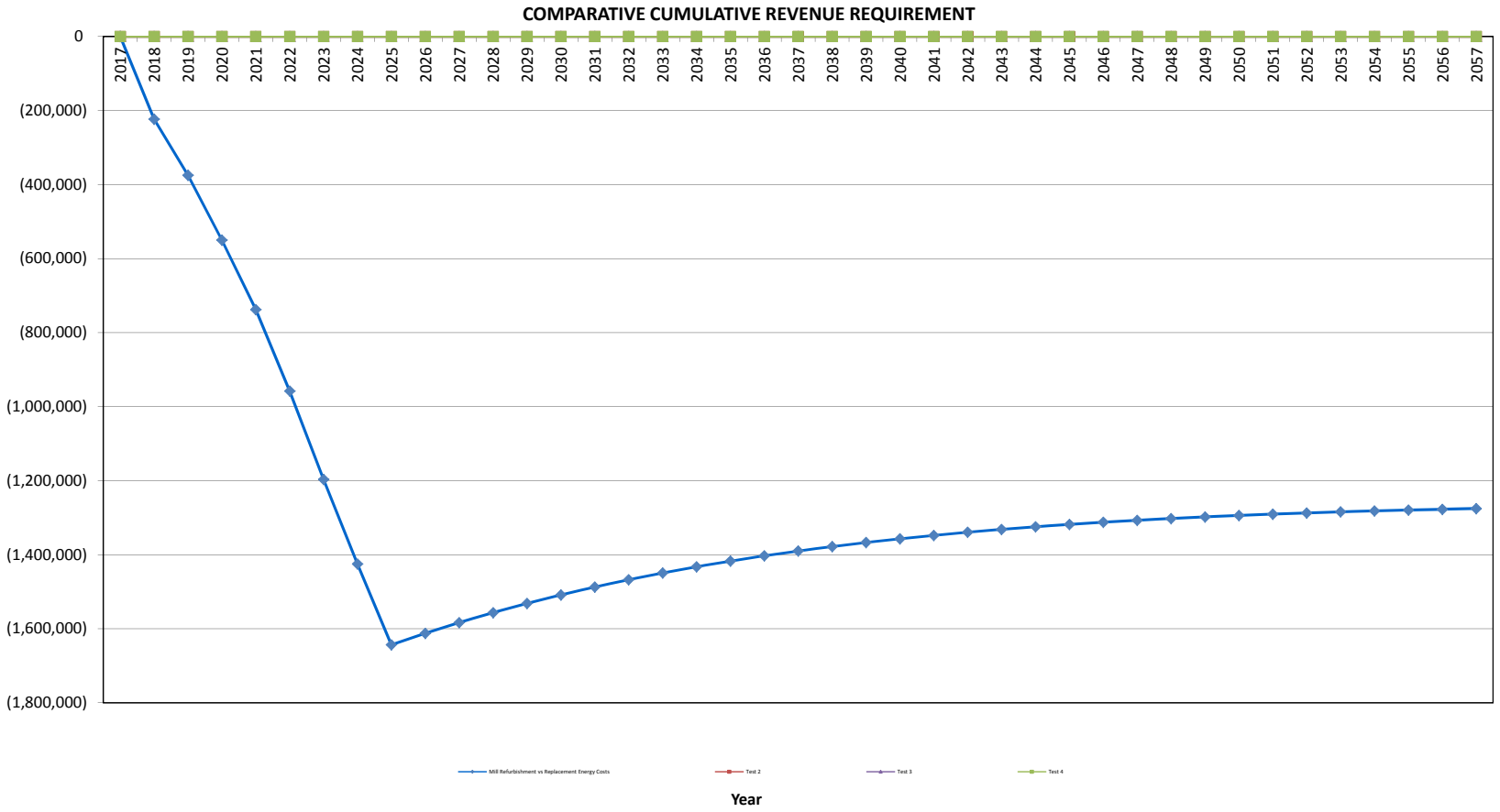
Test 4

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

LIN Mill Refurbishment

Mill Refurbishment vs Replacement Energy Costs

Year	Total Revenue	Operating Costs	Avoided Expenses	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	PV of CF	Discount Factor	CNPV
2017	-	-	-	-	-	-	-	-	-	-	1.00	-
2018	-	-	188,799.3	(631,624.0)	24,761.7	605,743.5	(442,824.6)	(50,851.7)	(493,676.3)	(466,260.2)	0.94	(466,260.2)
2019	-	-	230,061.9	-	47,542.5	556,287.3	230,061.9	(56,581.0)	173,480.9	154,747.6	0.89	(311,512.6)
2020	-	-	271,225.9	-	43,739.1	510,787.7	271,225.9	(70,520.9)	200,705.0	169,089.4	0.84	(142,423.3)
2021	-	-	302,712.6	-	40,240.0	468,927.9	302,712.6	(81,366.5)	221,346.1	176,123.0	0.80	33,699.8
2022	-	-	366,021.5	-	37,020.8	430,417.0	366,021.5	(101,990.2)	264,031.3	198,420.1	0.75	232,119.9
2023	-	-	414,824.4	-	34,059.1	394,987.0	414,824.4	(118,037.2)	296,787.2	210,650.0	0.71	442,770.0
2024	-	-	423,120.9	-	31,334.4	362,391.3	423,120.9	(121,453.8)	301,667.1	202,222.9	0.67	644,992.9
2025	-	-	431,583.3	-	28,827.6	332,403.3	431,583.3	(124,854.3)	306,729.0	194,197.4	0.63	839,190.3
2026	-	-	-	-	26,521.4	304,814.3	-	8,221.6	8,221.6	4,916.2	0.60	844,106.5
2027	-	-	-	-	24,399.7	279,432.5	-	7,563.9	7,563.9	4,271.8	0.56	848,378.3
2028	-	-	-	-	22,447.7	256,081.2	-	6,958.8	6,958.8	3,711.8	0.53	852,090.1
2029	-	-	-	-	20,651.9	234,598.0	-	6,402.1	6,402.1	3,225.2	0.50	855,315.3
2030	-	-	-	-	18,999.8	214,833.5	-	5,889.9	5,889.9	2,802.4	0.48	858,117.6
2031	-	-	-	-	17,479.8	196,650.1	-	5,418.7	5,418.7	2,435.0	0.45	860,552.7
2032	-	-	-	-	16,081.4	179,921.4	-	4,985.2	4,985.2	2,115.8	0.42	862,668.5
2033	-	-	-	-	14,794.9	164,531.0	-	4,586.4	4,586.4	1,838.4	0.40	864,506.9
2034	-	-	-	-	13,611.3	150,371.8	-	4,219.5	4,219.5	1,597.4	0.38	866,104.4
2035	-	-	-	-	12,522.4	137,345.4	-	3,881.9	3,881.9	1,388.0	0.36	867,492.4
2036	-	-	-	-	11,520.6	125,361.0	-	3,571.4	3,571.4	1,206.1	0.34	868,698.5
2037	-	-	-	-	10,599.0	114,335.5	-	3,285.7	3,285.7	1,048.0	0.32	869,746.4
2038	-	-	-	-	9,751.0	104,191.9	-	3,022.8	3,022.8	910.6	0.30	870,657.0
2039	-	-	-	-	8,971.0	94,859.9	-	2,781.0	2,781.0	791.2	0.28	871,448.2
2040	-	-	-	-	8,253.3	86,274.4	-	2,558.5	2,558.5	687.5	0.27	872,135.7
2041	-	-	-	-	7,593.0	78,375.7	-	2,353.8	2,353.8	597.4	0.25	872,733.1
2042	-	-	-	-	6,985.6	71,109.0	-	2,165.5	2,165.5	519.1	0.24	873,252.1
2043	-	-	-	-	6,426.7	64,423.6	-	1,992.3	1,992.3	451.0	0.23	873,703.2
2044	-	-	-	-	5,912.6	58,273.0	-	1,832.9	1,832.9	391.9	0.21	874,095.0
2045	-	-	-	-	5,439.6	52,614.5	-	1,686.3	1,686.3	340.5	0.20	874,435.6
2046	-	-	-	-	5,004.4	47,408.6	-	1,551.4	1,551.4	295.9	0.19	874,731.4
2047	-	-	-	-	4,604.1	42,619.2	-	1,427.3	1,427.3	257.1	0.18	874,988.5
2048	-	-	-	-	4,235.7	38,213.0	-	1,313.1	1,313.1	223.4	0.17	875,211.9
2049	-	-	-	-	3,896.9	34,159.2	-	1,208.0	1,208.0	194.1	0.16	875,406.0
2050	-	-	-	-	3,585.1	30,429.8	-	1,111.4	1,111.4	168.7	0.15	875,574.7
2051	-	-	-	-	3,298.3	26,998.7	-	1,022.5	1,022.5	146.5	0.14	875,721.2
2052	-	-	-	-	3,034.5	23,842.1	-	940.7	940.7	127.3	0.14	875,848.6
2053	-	-	-	-	2,791.7	20,938.1	-	865.4	865.4	110.6	0.13	875,959.2
2054	-	-	-	-	2,568.4	18,266.3	-	796.2	796.2	96.1	0.12	876,055.3
2055	-	-	-	-	2,362.9	15,808.3	-	732.5	732.5	83.5	0.11	876,138.9
2056	-	-	-	-	2,173.9	13,547.0	-	673.9	673.9	72.6	0.11	876,211.5
2057	-	-	-	-	2,000.0	11,466.5	-	620.0	620.0	63.1	0.10	876,274.5
Total	**-**	**-**	**2,628,349.9**	**(631,624.0)**	**596,043.8**		**1,996,725.9**	**(630,014.9)**	**1,366,711.0**	**876,274.5**		


COMPARATIVE CUMULATIVE REVENUE REQUIREMENT
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Mill Refurbishment vs Replacement Energy Costs
Test 2
Test 3
Test 4
Year

CI Number: 52093

Title: ICP Rail System Refurbishment Program 2018

Start Date: 2018/05
In-Service Date: 2018/08
Final Cost Date: 2019/02
Function: Steam
Forecast Amount: $592,402

DESCRIPTION:

This project is for the refurbishment of the rail system between the International Coal Pier and the Lingan Generating Station. The refurbishments will include two rail crossing rehabilitations, 800 track tie replacements, track surfacing, and rail bridge refurbishments. Coal is delivered to the Lingan Generating Station via a 15.5 mile track owned by NS Power. The condition of the track has deteriorated over time due to rail traffic and exposure to the elements. Public safety on and around the rail system is monitored and regulated by Transport Canada. These refurbishments are necessary to ensure the track continues to meet Transport Canada regulations.

Summary of Related CIs +/- 2 years:
2017 CI 49913 ICP Railway Tie Upgrade Program - $149,894
2017 CI 49313 ICP Mile 8.0 Track Replacement - $240,653
2019 CI TBD ICP Rail System Refurbishment 2019 $TBD

JUSTIFICATION:

Justification Criteria: Health & Safety

Why do this project?

This project needs to be completed to ensure the safe operation of the Sydney Coal Railway through the communities of Sydney and New Waterford on route to the Lingan Generating Station. These refurbishments will mitigate the risk of potential train derailments and ensure Transport Canada Regulations are met. Please see Attachment 1 for Transport Canada's notification.

The two rail crossings require refurbishment due to pavement deterioration and height differentials between the track and road surfaces. This is caused by the yearly freeze thaw cycle and track settling, creating a road hazard to passenger vehicles.

This project is required in order to replace 800 deteriorated track ties which degrade over time due to rot and need to be maintained to avoid failure and potential derailments.

Track surfacing is required to ensure the track ties are level, preventing highs and lows which could lead to derailments caused by severe track height differences.

The rail bridges degraded over time as a result of the deterioration of the abutments. This resulted through the loss of riprap protection to timber cribbing and structural steel degradation. Installation of new riprap on miles 8.95 and 8.21 is required to avoid undermining of the abutments. Structural repairs to the anchor bolts on mile 0.10 are required to maintain a positive bridge anchor and the support stringers on mile 0.46 require reinforcement to correct structure cracks and maintain structural integrity.

Why do this project now?

This project needs to be completed now as the condition of the track has deteriorated over time due to rail traffic and natural deterioration from exposure to the elements. The rail system is monitored and regulated by Transport Canada for public safety. These refurbishments are required to help ensure the track continues to meet Transport Canada regulations.

Why do this project this way?

Completing refurbishment activities over a number of years allows for little to no delivery disruption and maintains track safety compared to wholesale rail tie, track, or bridge replacements, which are not considered necessary at this time.

CI Number : 52093 - ICP Rail System Refurbishment Program 2018 **Project Number** 52093

Parent CI Number : -

Asset Location : 1114 - 1114 International Coal Pier **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0300 - SGP - Bldg.,Struct.Grnd.	482,689
Retirements	0300 - SGP - Bldg.,Struct.Grnd.	109,713
	Total Cost:	592,402
	Original Cost:	215,470

Capital Project Detailed Estimate

Location: Steam
CI# : 52093
Title: ICP Rail System Refurbishment Program 2018
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
Engineering	PD	15	$ 405	$ 6,080		
			Sub-Total	$ 6,080		
Materials						
Track Ties	Ea.	800	$ 72	$ 57,200		49913
Switch Ties	Ea.	200	$ 260	$ 52,000		49913
80ft 115lb Rail	Ea.	20	$ 2,600	$ 52,000		49313
Track Spikes	lot	1	$ 6,240	$ 6,240		49313
Rip Rap	lot	1	$ 5,000	$ 5,000		
Rail Seal and Clips	lot	1	$ 9,000	$ 9,000		
				$ -		
			Sub-Total	$ 181,440		
Contracts						
Rail Crossing Rehabilitation	lot	2	$ 25,000	$ 50,000		49313
Paving	lot	2	$ 15,000	$ 30,000		
Track Surfacing	lot	1	$ 90,000	$ 90,000		
Track Tie Installation	lot	1	$ 55,000	$ 55,000		49913
Bridge Rip Rap Installation	lot	1	$ 5,000	$ 5,000		
Bridge Anchor Bolt Replacement	lot	1	$ 10,000	$ 10,000		
Bridge Stringer Refurbishment	lot	1	$ 80,000	$ 80,000		
			Sub-Total	$ 320,000		
Other Goods & Services						
Contingency	%	10%	$ 501,440	$ 50,144		
				$ -		
			Sub-Total	$ 50,144		
Interest Capitalized						
AFUDC				$ 2,322		
				$ -		
			Sub-Total	$ 2,322		
Administrative Overhead						
Labor AO				$ 1,336		
Contract AO				$ 31,082		
			Sub-Total	$ 32,417		
			SUB-TOTAL (no AO, AFUDC)	$ 557,664		
			TOTAL (AO, AFUDC included)	$ 592,402		
Original Cost				$ 215,470		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

Transport Canada / Transports Canada

Atlantic Region
Surface Branch P.O. Box 42
Moncton, NB E1C 8K6

Our file: RSIG - 2982978

LETTER OF CONCERN

May 12, 2017

Mr. Johnny Walker
Maintenance Manager
Sydney Coal Railway
1139 Grand Lake Road
Sydney, Nova Scotia
B1M 1A2

Subject: Bridge Inspections- Victoria Subdivision

Dear Mr. Walker,

I am a Railway Safety Inspector designated by the Minister of Transport under subsection 27(1) of the *Railway Safety Act* (RSA).

On May 09 I performed inspections of Sydney Coal Railway and identified concerns as detailed in the attached appendix. In particular, please indicate how the railway intends to address issues related to fatigue cracking noted on several stringers on the loading dock structure at Mile 0.46 Victoria Subdivision.

Please advise this office in writing no later than May 27, 2017, how you intend to address these concerns.

Canada

Transport Canada / Transports Canada

Transport Canada Rail Safety - Bridge Inspection Report

Railway Company	Sydney Coal Railway	Summary	2017-05-08 to 2017-05-10, Atlantic Region, Reference #s: 2979819,2980308	TC Inspector	Marc Cormier

Concerns

Location	Other Authority	Description	Corrective Action	Ref. #
Railway Bridge: Mile 0.11, Victoria Subdivision (Sydney Coal)	Sydney Coal Railway	Railway Bridge: Site Observations Details: Concern with: Bridge - Walkways, Handrails, Refuge Bay, Fall Protection Devices for Inspections Comments: Walkway planks do not extend far enough beyond the ends of the bridge (abrupt drop-off) creating a condition that could affect the safety of railway workers.	Response to Transport Canada: - Enter corrective action here - Effective As Of: - If not immediate, enter implementation date here -	2979863
Railway Bridge: Mile 0.46, Victoria Subdivision (Sydney Coal)	Sydney Coal Railway	Railway Bridge: Site Observations Details: Concern with: Bridge - Walkways, Handrails, Refuge Bay, Fall Protection Devices for Inspections Comments: Concerns regarding: conditions that could affect the safety of railway workers and loading dock workers; (1) Coal spillage on south side walkway platform creating a tripping hazard and (2) Damaged stairway grating (stair treads) on the access stairs (ocean side, low mileage end of the bridge creating a trip and fall hazard , .	Response to Transport Canada: - Enter corrective action here - Effective As Of: - If not immediate, enter implementation date here -	2979923

Canada

Transport Canada Rail Safety - Bridge Inspection Report

Concerns				
Location	**Other Authority**	**Description**	**Corrective Action**	**Ref. #**
Railway Bridge: Mile 0.46, Victoria Subdivision (Sydney Coal)	Sydney Coal Railway	Railway Bridge: Site Observations Details: Concern with: Falling Debris Comments: Concerns regarding: conditions that exists that could affect the safety of railway and dock workers. Coal spillage on walkways and stairs could result in debris falling on employees working below the loading dock..	Response to Transport Canada: - Enter corrective action here - Effective As Of: - If not immediate, enter implementation date here -	2979925
Railway Bridge: Mile 0.46, Victoria Subdivision (Sydney Coal)	Sydney Coal Railway	Railway Bridge: Site Observations Details: Concern with: Superstructure - Main Members Comments: Concerns noted regarding the fatigue cracking on stringers.	Response to Transport Canada: - Enter corrective action here - Effective As Of: - If not immediate, enter implementation date here -	2979927
Railway Bridge: Mile 11.1, Victoria Subdivision (Sydney Coal)	Sydney Coal Railway	Railway Bridge: Site Observations Details: Concern with: Approaches - Low Mileage Comments: Several approach ties on the low mileage end of the bridge are in poor condition.	Response to Transport Canada: - Enter corrective action here - Effective As Of: - If not immediate, enter implementation date here -	2980265

CI Number: 51811

Title: LIN Reclaim Feeder Refurbishment Phase 2

Start Date: 2018/07
In-Service Date: 2018/10
Final Cost Date: 2019/04
Function: Steam
Forecast Amount: $534,666

DESCRIPTION:

This project is Phase 2 of the refurbishment of the Lingan coal reclaim feeder through component replacement. Phase 1 included the refurbishment of the 1A feeder. Phase 2 will continue with the next three most degraded reclaim, vibratory, feeders, based on the results of assessments to be done in 2018. Phase 3 is expected to take place in 2019, and focus on an additional three of Lingan's 12 feeders. The work is completed in phases as there is limited time to complete work on a continuously running facility.

This project (Phase 2) includes the replacement of the three vibratory feeder and support structures at the Lingan live coal storage reclaim due to the degradation of those assets.

The Lingan live storage coal operation has six reclaim locations (A to F) with two parallel reclaim feeders at each location. These vibratory feeders are located in a conveyer tunnel below the coal pile base. The vibratory feeders draw coal from the pile and deliver it to a conveyer which carries the coal to the plant conveyance systems. Numerous feeders are active at any given time to provide sufficient coal supply to the plant and to allow blending of up to six different coal types.

Personnel must access the feeder locations for various maintenance and inspection activities and, as such, it is important that support structures are stable and feeder housings do not allow coal spillage. Repair of reclaim feeders in situ is possible with appropriate safe guards, however is not desired due to the hazardous coal tunnel location and constricted work area.

Summary of Related CIs +/- 2 years:
2017 CI 49436 - LIN Reclaim Feeder Replacement $233,494
2019 CI TBD - LIN Reclaim Refurbishment Phase 3 $TBD

JUSTIFICATION:

Justification Criteria: Health & Safety

Why do this project?

Feeder 1A was refurbished in 2017 based on the evident deterioration of its components, as shown in the pictures below. The three feeders planned for refurbishment as part of this project are in similar deteriorated condition. Because of the condition, refurbishment is recommended. A significant failure in one feeder would allow coal from the pile above to flow into the reclaim tunnel, leading to safety risks to plant personnel. Additionally, availability of all six reclaims is necessary for the plant to supply the prescribed blend of fuel necessary for unit loading and environmental targets.

This project is primarily driven by safety reasons, however is secondarily justified on unit reliability.

Why do this project now?

Allowing the three planned feeders and support structures to continue to deteriorate increases the risk of a structural failure which would be difficult to safely access and repair in situ. Doing the extraction and replacement in lower load, dry summer months is preferable.

Why do this project this way?

The feeder structure and support mechanism have had repairs and metal replacements over time. These repairs were temporary in nature, and further repairs are not deemed feasible as they cannot be made structurally sound. Removing and replacing isolated components in situ may be possible but would present worker risk due to the constrained work area and coal dust hazards. In the repair in situ scenario, the A belt would have to be out of service for the duration of the work. It is preferable to remove the grizzly and chutes and extract the complete assembly by crane. The new assembly will be placed from above, limiting work in the tunnel and belt down time. The extracted feeder and support structure will be examined and further determination made regarding whether refurbishment or re-engineering options for use as a spare are feasible.

Feeder 1A

Feeder 1A – Main Pan

Feeder 1A - Deteriorated Framing

CI Number : 51811 - LIN Reclaim Feeder Refurbishment Phase 2 **Project Number** 51811

Parent CI Number : -

Asset Location : 1138 - 1138 Lingan Common Plant **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	1800 - SGP - Fuel Hndlg.Coal	469,751
Retirements	1800 - SGP - Fuel Hndlg.Coal	64,915
	Total Cost:	534,666
	Original Cost:	131,370

Capital Project Detailed Estimate

Location: Steam
CI# : 51811
Title: LIN Reclaim Feeder Refurbishment Phase 2
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Electrician	PD	30	$ 358	$ 10,748		
Maintenance Trades	PD	60	$ 365	$ 21,887		
Utility worker	PD	30	$ 240	$ 7,205		
			Sub-Total	$ 39,841		
OT Labour						
Maintenance Trades	PD	20	$ 729.57	$ 14,591		
			Sub-Total	$ 14,591		
Term Labour						
Maintenance Trades	PD	90	$ 365	$ 32,831		
Utility worker	PD	60	$ 240	$ 14,411		
			Sub-Total	$ 47,241		
Materials						
Replacement Vibrator Feeder	USD	3	$ 56,000	$ 168,000		49436
Exchange USD to CDN	%	30%	$ 168,000	$ 50,400		
Feeder Support Structure	$	3	$ 8,000	$ 24,000		49436
Impact Bed	$	3	$ 6,000	$ 18,000		
Misc. Consumables	$	3	$ 3,200	$ 9,600		
			Sub-Total	$ 270,000		
Contracts						
Chute Refurbishment	$	3	$ 30,000	$ 90,000		
Crane Services	$	5	$ 5,000	$ 25,000		
			Sub-Total	$ 115,000		
Other Goods & Services						
Contingency	%	10%	$ 115,000	$ 11,500		
			Sub-Total	$ 11,500		
Interest Capitalized						
AFUDC				$ 4,589		
			Sub-Total	$ 4,589		
Administrative Overhead						
Labour AO				$ 20,733		
Contract AO				$ 11,170		
			Sub-Total	$ 31,903		
			SUB-TOTAL (no AO, AFUDC)	$ 498,174		
			TOTAL (AO, AFUDC included)	$ 534,666		
Original Cost				$ 131,370		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 51815

Title: LIN CW Pump Refurbishment 2018

Start Date: 2018/03
In-Service Date: 2018/10
Final Cost Date: 2019/04
Function: Steam
Forecast Amount: $520,436

DESCRIPTION:

This project is for refurbishment of one of eight Cooling Water (CW) pumps at the Lingan Generating Station. As pump performance deteriorates, the CW flow becomes insufficient to maintain cooling in the condenser and auxiliary cooling equipment, resulting in efficiency and production losses. The pump that is selected for refurbishment is identified during the 2018 unit outages. Lingan Unit 2 is not expected to undergo a CW pump refurbishment, but if required, the risk of stranded investment is minimal due to the applicability of common components across all four units.

The refurbishment includes: resurfacing and rebuilding of worn, corroded and damaged surfaces. A new sleeveless, chromed stainless pump shaft and new marine bearings will be installed. The refurbishment project also includes the installation of an additional bearing on the pump shaft. This bearing will help to maintain alignment and reduces the movement of the pump shaft if misalignment occurs, improving pump reliability.

Summary of Related CIs +/- 2 years:
2016 CI 47507 LIN CW Pump Rebuild 2016 $441,560
2017 CI 49430 LIN CW Pump Refurbishment 2017 $516,270
2019 CI TBA LIN CW Pump Refurbishment $TBD
2020 CI TBA LIN CW Pump Refurbishment $TBD

JUSTIFICATION:

Justification Criteria: Thermal

Sub Criteria: Equipment Replacement / Refurbishment

Why do this project?

Each generating unit is equipped with two CW pumps that supply cooling water to each unit's condenser as well as other auxiliary equipment. Adequate condenser cooling is necessary to ensure proper condenser vacuum, which is a major contributor to unit efficiency. During the cooler months, one CW pump per operating unit is capable of providing adequate condenser cooling. During warmer months, both pumps are required. If one of a unit's two pumps is unavailable during the warmer months, the unit's heat rate or ability to generate full load is restricted due to higher seawater temperatures. The loss of both pumps would lead to an unplanned outage. Therefore, the reliability and availability of these pumps is critical to plant operation. The CW pumps are subject to solid particle erosion and corrosion from sand entrainment effects related to their salt water environment (which includes sea water, kelp, eel grass and other sea debris). These deterioration mechanisms are managed through periodic overhauls.

This project is being undertaken primarily to prevent unit deratings and preserve the unit’s availability, and is secondarily supported by positive economics.

Why do this project now?

Health assessments are determined from pump performance, condition based assessment and operating hours. A typical operating period between pump refurbishments is partly dependent upon the unit's utilization. Several pumps are approaching an actionable risk threshold and refurbishment should be completed in order to adequately mitigate the risk. Final determination of which pump is to be refurbished will be based on the latest performance and condition based monitoring (CBM) results. Additionally, CW Pump refurbishment has a lead time of upwards of six months, therefore proactive planning for these refurbishments is necessary to avoid lengthy unit deratings from unplanned failures.

Why do this project this way?

Compared to options such as full replacement or operating the pump until failure, the most economic and efficient solution is to rebuild deteriorated CW pumps. New pumps have an 11 month lead time and cost approximately 50 percent more than refurbishment.

CI Number : 51815 - LIN CW Pump Refurbishment 2018 **Project Number** 51815

Parent CI Number : -

Asset Location : 1138 - 1138 Lingan Common Plant **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	1400 - SGP - Circ.Water Sys.	508,240
Retirements	1400 - SGP - Circ.Water Sys.	12,197
	Total Cost:	520,436
	Original Cost:	395,173

Capital Project Detailed Estimate

Location: Steam
CI# : 51815
Title: LIN CW Pump Refurbishment 2018
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Electrician	PD	18	$ 351	$ 6,323		
Engineering	PD	4	$ 397	$ 1,589		
Maintenance Trades	PD	90	$ 358	$ 32,187		
			Sub-Total	$ 40,099		
Term Labour						
Maintenance Trades	PD	84	$ 358	$ 30,041		
				$ -		
				$ -		
			Sub-Total	$ 30,041		
Materials						
CW Pump Refurbishment	Lot	1	$ 400,000	$ 400,000		47507
			Sub-Total	$ 400,000		
Contracts						
Machining Contractor	Lot	1	$ 10,000	$ 10,000		
			Sub-Total	$ 10,000		
Freight						
Transportation & Shipping	Lot	1	$ 20,000	$ 20,000		
			Sub-Total	$ 20,000		
Interest Capitalized						
AFUDC				$ 3,916		
			Sub-Total	$ 3,916		
Administrative Overhead						
Labour AO				$ 15,408		
Contract AO				$ 971		
			Sub-Total	$ 16,380		
			SUB-TOTAL (no AO, AFUDC)	$ 500,140		
			TOTAL (AO, AFUDC included)	$ 520,436		
Original Cost				$ 395,173		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

LIN CW Pump Refurbishment
Summary of Alternatives

Division :	Power Production	**Date :**	**17-Nov-17**
Department :	Lingan	**CI Number:**	51815
		Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank (based on PV of RR)	IRR	Disc Pay
A	CW Pump Refurbishment vs Replacement Energy Costs	5.88%	-803,201	547,596	1	35.76%	3.3 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

Recommendation :

NS Power recommends completing this project to avoid any potential of a unit derating.

Notes/Comments :

CW Pump Refurbishment vs Replacement Energy Costs

If the CW pump fails, the whole unit will lose approximately 40 MW capacity for as long as 10 weeks depending on the severity of the damage when the pump fails.

Test 2

Test 3

Test 4

LIN CW Pump Refurbishment
Summary of Sensitivities

Nova Scotia POWER An Emera Company

Division :	Power Production
Department :	Lingan

Date :	**14-Nov-17**
CI Number:	51815
Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	CW Pump Refurbishment vs Replacement Energy	5.88%	-803,201	547,596	1	35.76%	3.3 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

	Alternative Variance on Capital Spend	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	CW Pump Refurbishment vs Replacement Energy	10%	-753,728	508,644	1	31.18%	3.6 years
B	Test 2	10%	0	0	2	#NUM!	0.0 years
C	Test 3	10%	0	0	2	#NUM!	0.0 years
D	Test 4	10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		49,473	-38,952	0	-4.58%	0.3 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

	Alternative Variance on Avoided Expenses	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	CW Pump Refurbishment vs Replacement Energy	-10%	-673,408	453,884	1	30.72%	3.6 years
B	Test 2	-10%	0	0	2	#NUM!	0.0 years
C	Test 3	-10%	0	0	2	#NUM!	0.0 years
D	Test 4	-10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		129,793	-93,712	0	-5.04%	0.3 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

Alternative Variance on Avoided Expenses - Change in Revenue Requirement		PV of Revenue Requirement	PV of Revenue Requirement	PV of Revenue Requirement	Delay?
	Yrs Delay:	1	2	3	
	A	101,500	222,485	382,578	No
	B	0	0	0	No
	C	0	0	0	No
	D	0	0	0	No

LIN CW Pump Refurbishment
Avoided Cost Calculations

Division :	Power Production	**Date :**	**14-Nov-17**
Department :	Lingan	**CI Number:**	51815
		Project No. :	

CW Pump Refurbishment vs Replacement Energy Costs

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			197,760	205,718		
Events/Outages (#)	1	1	1	1		
Probability of Occurance (%)	40%	50%	40%	50%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	40.0	40.0				
Duration (Hours or Years)	1680	1680				
Totals	$53,999	$66,706	$79,104	$102,859	$133,103	$169,564
Total Capital Cost of Alternative						$520,436

Test 2

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

Test 3

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

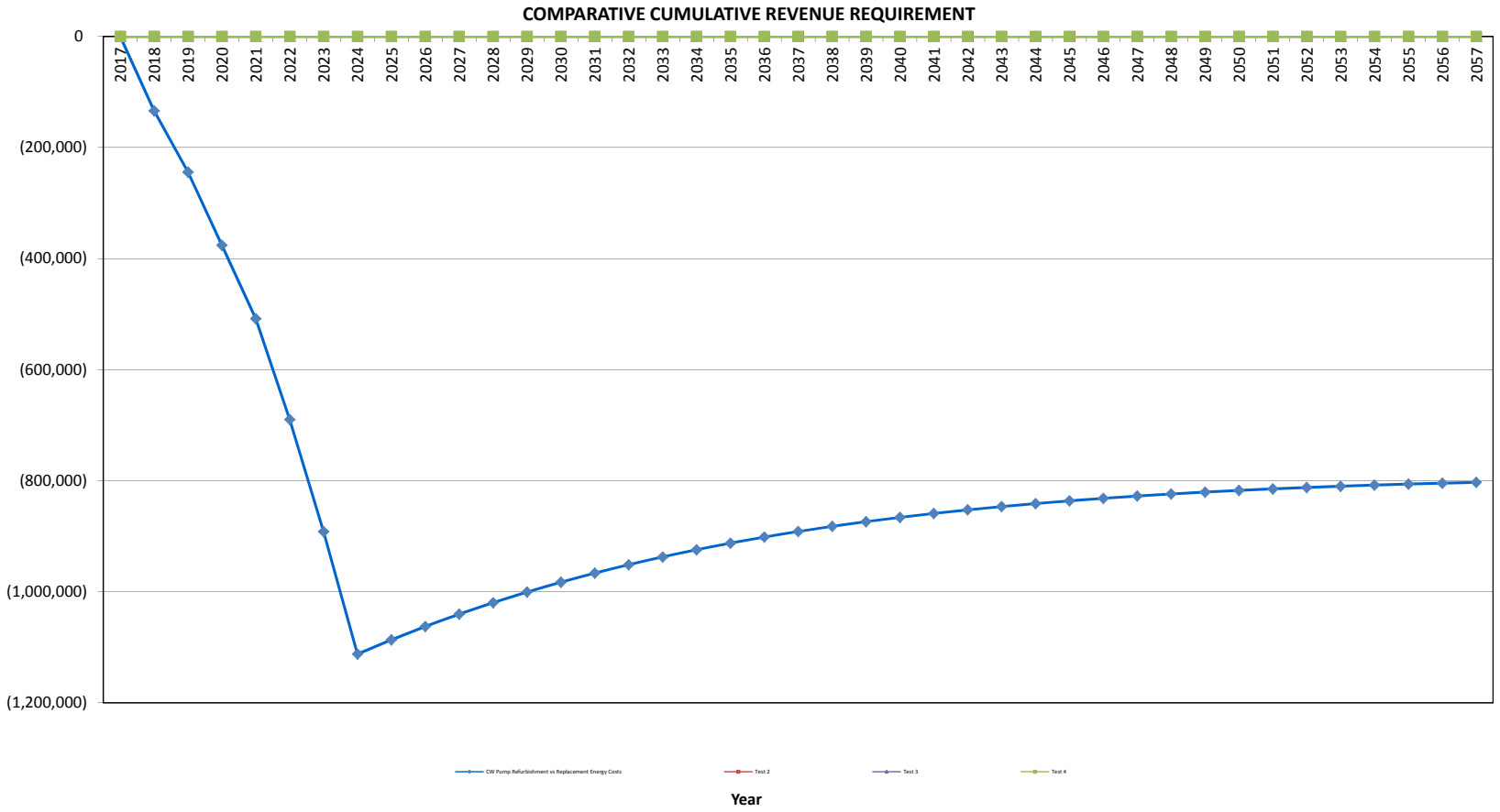
Test 4

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

LIN CW Pump Refurbishment

CW Pump Refurbishment vs Replacement Energy Costs

Year	Total Revenue	Operating Costs	Avoided Expenses	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	PV of CF	Discount Factor	CNPV
2017	-	-	-	-	-	-	-	-	-	-	1.00	-
2018	-	-	133,102.7	(504,056.7)	20,005.6	484,655.6	(370,954.1)	(35,060.1)	(406,014.2)	(383,466.4)	0.94	(383,466.4)
2019	-	-	169,564.4	-	38,410.8	445,490.0	169,564.4	(40,657.6)	128,906.8	114,986.8	0.89	(268,479.6)
2020	-	-	204,585.2	-	35,337.9	409,457.7	204,585.2	(52,466.7)	152,118.6	128,156.4	0.84	(140,323.1)
2021	-	-	217,046.0	-	32,510.9	376,308.0	217,046.0	(57,205.9)	159,840.1	127,183.3	0.80	(13,139.8)
2022	-	-	298,081.7	-	29,910.0	345,810.2	298,081.7	(83,133.2)	214,948.5	161,534.3	0.75	148,394.5
2023	-	-	346,266.6	-	27,517.2	317,752.3	346,266.6	(98,812.3)	247,454.3	175,635.1	0.71	324,029.6
2024	-	-	397,310.5	-	25,315.8	291,939.0	397,310.5	(115,318.3)	281,992.1	189,033.8	0.67	513,063.4
2025	-	-	-	-	23,290.6	268,190.8	-	7,220.1	7,220.1	4,571.2	0.63	517,634.6
2026	-	-	-	-	21,427.3	246,342.4	-	6,642.5	6,642.5	3,972.0	0.60	521,606.6
2027	-	-	-	-	19,713.1	226,241.9	-	6,111.1	6,111.1	3,451.3	0.56	525,057.8
2028	-	-	-	-	18,136.1	207,749.4	-	5,622.2	5,622.2	2,998.8	0.53	528,056.6
2029	-	-	-	-	16,685.2	190,736.3	-	5,172.4	5,172.4	2,605.7	0.50	530,662.4
2030	-	-	-	-	15,350.4	175,084.3	-	4,758.6	4,758.6	2,264.1	0.48	532,926.5
2031	-	-	-	-	14,122.4	160,684.5	-	4,377.9	4,377.9	1,967.3	0.45	534,893.8
2032	-	-	-	-	12,992.6	147,436.6	-	4,027.7	4,027.7	1,709.4	0.42	536,603.2
2033	-	-	-	-	11,953.2	135,248.6	-	3,705.5	3,705.5	1,485.3	0.40	538,088.5
2034	-	-	-	-	10,996.9	124,035.6	-	3,409.0	3,409.0	1,290.6	0.38	539,379.1
2035	-	-	-	-	10,117.2	113,719.6	-	3,136.3	3,136.3	1,121.4	0.36	540,500.6
2036	-	-	-	-	9,307.8	104,228.9	-	2,885.4	2,885.4	974.4	0.34	541,475.0
2037	-	-	-	-	8,563.2	95,497.5	-	2,654.6	2,654.6	846.7	0.32	542,321.7
2038	-	-	-	-	7,878.1	87,464.6	-	2,442.2	2,442.2	735.7	0.30	543,057.3
2039	-	-	-	-	7,247.9	80,074.3	-	2,246.8	2,246.8	639.2	0.28	543,696.6
2040	-	-	-	-	6,668.0	73,275.2	-	2,067.1	2,067.1	555.4	0.27	544,252.0
2041	-	-	-	-	6,134.6	67,020.1	-	1,901.7	1,901.7	482.6	0.25	544,734.7
2042	-	-	-	-	5,643.8	61,265.4	-	1,749.6	1,749.6	419.4	0.24	545,154.0
2043	-	-	-	-	5,192.3	55,971.0	-	1,609.6	1,609.6	364.4	0.23	545,518.4
2044	-	-	-	-	4,776.9	51,100.2	-	1,480.8	1,480.8	316.6	0.21	545,835.0
2045	-	-	-	-	4,394.8	46,619.1	-	1,362.4	1,362.4	275.1	0.20	546,110.1
2046	-	-	-	-	4,043.2	42,496.5	-	1,253.4	1,253.4	239.0	0.19	546,349.2
2047	-	-	-	-	3,719.7	38,703.6	-	1,153.1	1,153.1	207.7	0.18	546,556.9
2048	-	-	-	-	3,422.2	35,214.2	-	1,060.9	1,060.9	180.5	0.17	546,737.4
2049	-	-	-	-	3,148.4	32,004.0	-	976.0	976.0	156.8	0.16	546,894.2
2050	-	-	-	-	2,896.5	29,050.5	-	897.9	897.9	136.3	0.15	547,030.4
2051	-	-	-	-	2,664.8	26,333.4	-	826.1	826.1	118.4	0.14	547,148.8
2052	-	-	-	-	2,451.6	23,833.6	-	760.0	760.0	102.9	0.14	547,251.7
2053	-	-	-	-	2,255.5	21,533.8	-	699.2	699.2	89.4	0.13	547,341.1
2054	-	-	-	-	2,075.0	19,418.0	-	643.3	643.3	77.7	0.12	547,418.8
2055	-	-	-	-	1,909.0	17,471.4	-	591.8	591.8	67.5	0.11	547,486.3
2056	-	-	-	-	1,756.3	15,680.6	-	544.5	544.5	58.6	0.11	547,544.9
2057	-	-	-	-	1,615.8	14,033.0	-	500.9	500.9	51.0	0.10	547,595.9
Total	**-**	**-**	**1,765,957.1**	**(504,056.7)**	**481,558.6**		**1,261,900.4**	**(398,163.6)**	**863,736.8**	**547,595.9**		


COMPARATIVE CUMULATIVE REVENUE REQUIREMENT
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CW Pump Refurbishment vs Replacement Energy Costs
Test 2
Test 3
Test 4
Year

CI Number: 51861

Title: TRE6 CW Screen Replacement 2018

Start Date: 2018/08
In-Service Date: 2018/08
Final Cost Date: 2019/02
Function: Steam
Forecast Amount: $513,192

DESCRIPTION:

The scope of this project includes the replacement of one circulating water (CW) travelling screen for Trenton Unit #6.

There are two travelling screens on Unit #6 at the Trenton Generating Station. The self-cleaning screens remove debris (seaweed and eel grass) from the incoming sea water before it enters the CW pump and cooling systems. Each of the screen's bottom and intermediate sections are submerged in salt seawater while the upper drive sections are above the water level but are subjected to salt spray. The bottom section of the screens includes the lower shoe assembly and support structure. The top sections are comprised of the drive sprocket assembly and the support structure. The intermediate sections span vertically between the bottom and top sections and support the entire structures.

Summary of Related CIs +/- 2 years:
No related project in 2016, 2017, 2018, 2019 or 2020

JUSTIFICATION:

Justification Criteria: Thermal

Sub Criteria: Equipment Replacement / Refurbishment

Why do this project?

Based on condition assessments, debris is passing through degraded or non-functioning traveling screen panels resulting in downstream fouling of strainers at Circulating water (CW) and Auxiliary (ACW) locations. Fouling increases the risk of unit derating or forced outages due to inadequate cooling capacity. Fouling also results in high mechanical loading on the screens and circulating water pumps, increasing the deterioration of equipment. This high loading causes component failure at the screens and CW pumps and increases the risk of derating due to lack of cooling water.

This project is primarily justified on unit reliability, and secondarily supported by positive economics.

Why do this project now?

Based on the condition assessment and associated maintenance strategy elements, the screen has been identified for replacement.

The replacement/refurbishment of at least one of the two screens this year is important as it is tied to CW pump reliability. In order to avoid damage to the CW pumps, the screens must be in working condition in order to prevent ingress of materials to the CW pumps. Warmer cooling water during the summer months requires that both CW pumps are fully operational to deliver adequate cooling.

Why do this project this way?

Replacement of the existing travelling screen with a new one constructed of composite/stainless materials is more cost effective than refurbishment because the new screen will allow for a longer maintenance interval between refurbishments. Due to the corrosive nature of the environment and the design of the existing system, the current reinvestment interval on the existing system, based on historical operation, is two years. The expected reinvestment interval on the new composite system is five years, dependent upon unit utilization. The replacement screen system is designed using non-metallic baskets (high strength composite material) and stainless steel fasteners, making it more corrosion resistant than the current screen. The replacement system is also designed using an external drive motor and gear box (which rotates the screens) where the drive chain and sprockets are not in the salt water spray environment.

Please refer to the attached Economic Analysis Model that indicates replacement is the more cost effective alternative.

CI Number : 51861 - TRE6 CW Screen Replacement 2018 **Project Number** 51861

Parent CI Number : -

Asset Location : 1166 - 1166 Trenton Unit 6; Commissioned 1991, 170 Mwh **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	1400 - SGP - Circ.Water Sys.	488,798
Retirements	1400 - SGP - Circ.Water Sys.	24,394
	Total Cost:	513,192
	Original Cost:	313,751

Capital Project Detailed Estimate

Location: Trenton Generating Station
CI# : 51861
Title: TRE6 CW Screen Replacement 2018
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Maintenance Trades	PD	80	$ 365	$ 29,183		
Power Engineer	PD	10	$ 390	$ 3,904		
Utility worker	PD	20	$ 240	$ 4,804		
			Sub-Total	$ 37,890		
OT Labour						
Maintenance Trades	PD	10	$ 729.57	$ 7,296		
			Sub-Total	$ 7,296		
Term Labour						
Maintenance Trades	PD	80	$ 365	$ 29,183		
Utility worker	PD	10	$ 240	$ 2,402		
			Sub-Total	$ 31,585		
Materials						
CW Screen	lot	1	[redacted]		Cost Support #1	
USD to CDN Conversion	lot	30%				
Misc	lot	1	$ 5,000	$ 5,000		
			Sub-Total	[redacted]		
Contracts						
Supervision	PD	20	$ 455	$ 9,100		
Divers	lot	1	$ 25,000	$ 25,000		
Vacuum Services	lot	1	$ 15,000	$ 15,000		
			Sub-Total	$ 49,100		
OT meals						
OT meals	each	10	$ 15	$ 150		
			Sub-Total	$ 150		
Other Goods & Services						
Contingency	%	5%	[redacted]			
				$ -		
			Sub-Total	[redacted]		
Administrative Overhead						
Labour AO				$ 16,064		
Contract AO				$ 4,769		
			Sub-Total	$ 20,833		
			SUB-TOTAL (no AO, AFUDC)	$ 492,359		
			TOTAL (AO, AFUDC included)	$ 513,192		
Original Cost				$ 313,751		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

TRE6 CW Screen Replacement 2018
Summary of Alternatives

Nova Scotia POWER An Emera Company

Division :	Power Production	**Date :**	**19-Nov-17**
Department :		**CI Number:**	
		Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank (based on PV of RR)	IRR	Disc Pay
A	CW Screen Replacement vs Replacement Energy Costs	5.88%	-1,439,818	1,056,287	1	33.77%	3.9 years
B	CW Screen Refurbishment vs Replacement Energy Costs	5.88%	-642,736	369,581	2	20.27%	23.0 years
C	Test 3	5.88%	0	0	3	#NUM!	0.0 years
D	Test 4	5.88%	0	0	3	#NUM!	0.0 years

Recommendation :

Purchase of a new screen is the more economic alternative.

Notes/Comments :

CW Screen Replacement vs Replacement Energy Costs

Capital costs are for the purchase and installation of a new travelling screen with expected reinvestment every 5 years.

CW Screen Refurbishment vs Replacement Energy Costs

Costs include those associated with continuing ongoing refurbishment of existing system every 2 years for 10 years, at which time a new screen would have to be purchased. The investment every two years increase due to the aging components. Future cost of the screen system were calculated using 2% inflation and the annual maintenance cost was calculated assuming 10% increase year over year.

Test 3

Test 4

TRE6 CW Screen Replacement 2018
Summary of Sensitivities

Nova Scotia POWER An Emera Company

Division :	Power Production	**Date :**	**15-Nov-17**
Department :		**CI Number:**	
		Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	CW Screen Replacement vs Replacement Energy	5.88%	-1,439,818	1,056,287	1	33.77%	3.9 years
B	CW Screen Refurbishment vs Replacement Ener	5.88%	-642,736	369,581	2	20.27%	23.0 years
C	Test 3	5.88%	0	0	3	#NUM!	0.0 years
D	Test 4	5.88%	0	0	3	#NUM!	0.0 years

	Alternative Variance on Capital Spend	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	CW Screen Replacement vs Replacement Energy	10%	-1,374,231	1,003,860	1	29.76%	4.3 years
B	CW Screen Refurbishment vs Replacement Ener	10%	-503,935	253,552	2	13.06%	16.1 years
C	Test 3	10%	0	0	3	#NUM!	0.0 years
D	Test 4	10%	0	0	3	#NUM!	0.0 years
	Change:						
	A		65,587	-52,426	0	-4.01%	0.4 years
	B		138,801	-116,029	0	-7.21%	-6.9 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

	Alternative Variance on Avoided Expenses	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	CW Screen Replacement vs Replacement Energy	-10%	-1,230,250	898,232	1	29.37%	4.3 years
B	CW Screen Refurbishment vs Replacement Ener	-10%	-439,662	216,594	2	12.51%	16.3 years
C	Test 3	-10%	0	0	3	#NUM!	0.0 years
D	Test 4	-10%	0	0	3	#NUM!	0.0 years
	Change:						
	A		209,569	-158,055	0	-4.40%	0.4 years
	B		203,075	-152,987	0	-7.76%	-6.7 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

Alternative Variance on Avoided Expenses - Change in Revenue Requirement	Yrs Delay:	PV of Revenue Requirement 1	PV of Revenue Requirement 2	PV of Revenue Requirement 3	Delay?
	A	186,906	215,789	302,835	No
	B	152,955	148,958	203,780	No
	C	0	0	0	No
	D	0	0	0	No

TRE6 CW Screen Replacement 2018
Avoided Cost Calculations

Division :	Power Production	**Date :**	15-Nov-17
Department :		**CI Number:**	
		Project No. :	

CW Screen Replacement vs Replacement Energy Costs

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			35,760	37,193		
Events/Outages (#)	1	1	1	1		
Probability of Occurance (%)	50%	75%	50%	75%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	154.0	154.0				
Duration (Hours or Years)	336	336				
Totals	$214,566	$63,288	$17,880	$27,895	$232,446	$91,183

Total Capital Cost of Alternative	$813,192

CW Screen Refurbishment vs Replacement Energy Costs

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			35,760	36,475		
Events/Outages (#)	1	1	1	1		
Probability of Occurance (%)	50%	75%	50%	75%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	154.0	154.0				
Duration (Hours or Years)	336	336				
Totals	$214,566	$63,288	$17,880	$27,356	$232,446	$90,644

Total Capital Cost of Alternative	$2,118,033

Test 3

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0

Total Capital Cost of Alternative	$0

Test 4

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0

Total Capital Cost of Alternative	$0

TRE6 CW Screen Replacement 2018

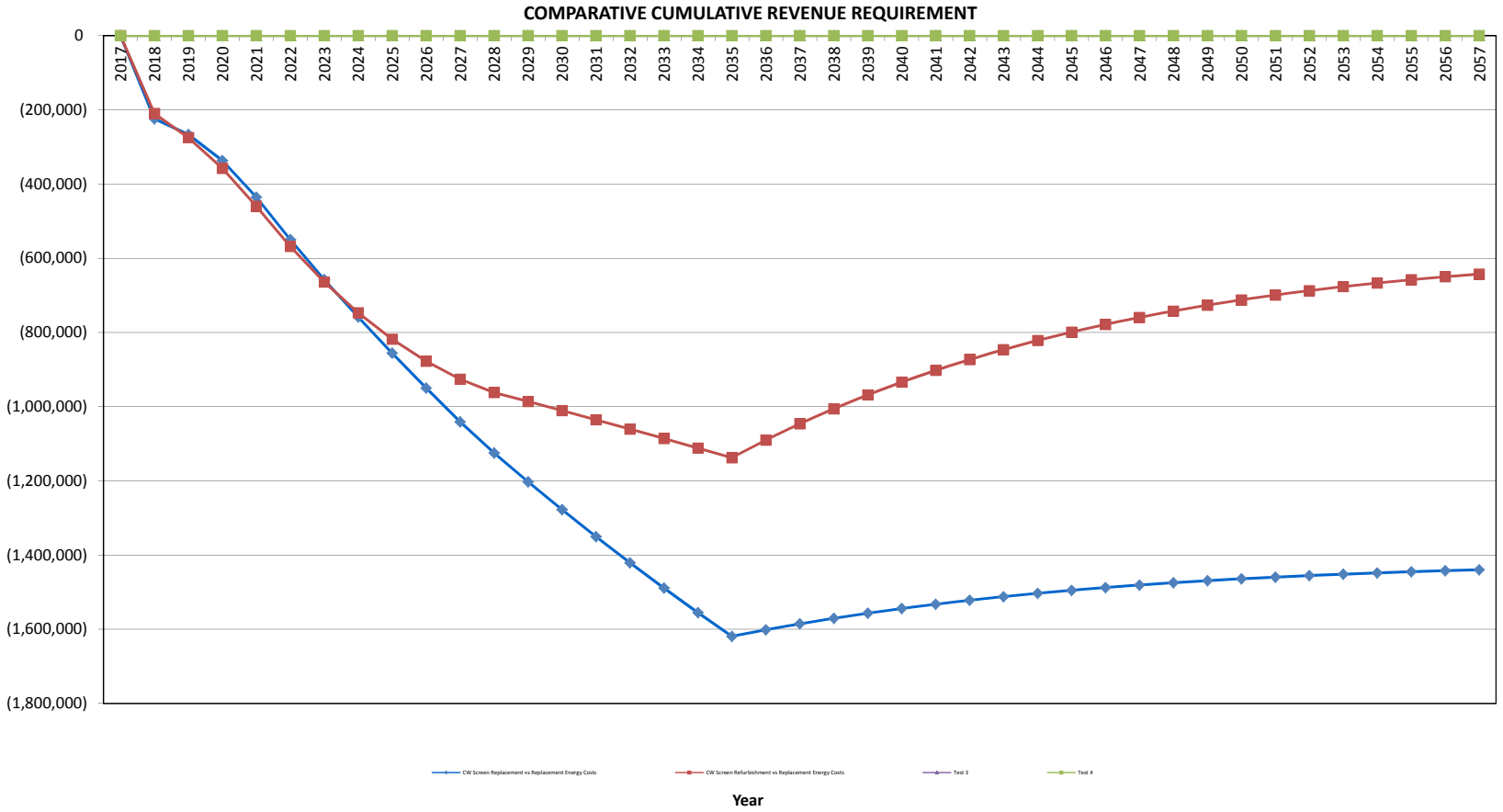
CW Screen Replacement vs Replacement Energy Costs

Year	Total Revenue	Operating Costs	Avoided Expenses	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	PV of CF	Discount Factor	CNPV
2017	-	-	-	-	-	-	-	-	-	-	1.00	-
2018	-	-	232,446.0	(492,359.3)	19,694.4	478,414.8	(259,913.3)	(65,953.0)	(325,866.3)	(307,769.5)	0.94	(307,769.5)
2019	-	-	91,182.6	-	37,813.2	439,641.6	91,182.6	(16,544.5)	74,638.1	66,578.3	0.89	(241,191.2)
2020	-	-	128,621.7	-	34,788.1	403,970.3	128,621.7	(29,088.4)	99,533.3	83,854.5	0.84	(157,336.7)
2021	-	-	172,766.9	-	32,005.1	371,152.7	172,766.9	(43,636.2)	129,130.8	102,748.1	0.80	(54,588.5)
2022	-	-	203,672.5	-	29,444.7	340,960.5	203,672.5	(54,010.6)	149,661.9	112,471.3	0.75	57,882.7
2023	-	-	208,585.6	(100,000.0)	35,089.1	405,183.7	108,585.6	(53,783.9)	54,801.7	38,896.5	0.71	96,779.2
2024	-	-	213,630.5	-	32,282.0	372,269.0	213,630.5	(56,218.0)	157,412.5	105,521.7	0.67	202,300.9
2025	-	-	218,811.3	-	29,699.4	341,987.5	218,811.3	(58,624.7)	160,186.6	101,417.9	0.63	303,718.8
2026	-	-	224,132.2	-	27,323.5	314,128.5	224,132.2	(61,010.7)	163,121.5	97,540.7	0.60	401,259.5
2027	-	-	229,597.3	-	25,137.6	288,498.2	229,597.3	(63,382.5)	166,214.8	93,870.7	0.56	495,130.2
2028	-	-	235,211.0	(200,000.0)	39,126.6	448,918.4	35,211.0	(60,786.2)	(25,575.2)	(13,641.6)	0.53	481,488.6
2029	-	-	240,978.0	-	35,996.5	412,504.9	240,978.0	(63,544.3)	177,433.7	89,385.9	0.50	570,874.5
2030	-	-	246,902.9	-	33,116.7	379,004.6	246,902.9	(66,273.7)	180,629.2	85,942.3	0.48	656,816.8
2031	-	-	252,990.5	-	30,467.4	348,184.2	252,990.5	(68,982.2)	184,008.4	82,688.0	0.45	739,504.8
2032	-	-	259,246.0	-	28,030.0	319,829.5	259,246.0	(71,677.0)	187,569.1	79,607.2	0.42	819,112.0
2033	-	-	265,674.5	-	25,787.6	293,743.1	265,674.5	(74,364.9)	191,309.6	76,685.6	0.40	895,797.6
2034	-	-	272,281.4	-	23,724.6	269,743.7	272,281.4	(77,052.6)	195,228.8	73,910.7	0.38	969,708.2
2035	-	-	279,072.3	-	21,826.6	247,664.2	279,072.3	(79,746.2)	199,326.1	71,271.1	0.36	1,040,979.3
2036	-	-	-	-	20,080.5	227,351.1	-	6,225.0	6,225.0	2,102.2	0.34	1,043,081.5
2037	-	-	-	-	18,474.1	208,663.0	-	5,727.0	5,727.0	1,826.6	0.32	1,044,908.1
2038	-	-	-	-	16,996.1	191,470.0	-	5,268.8	5,268.8	1,587.2	0.30	1,046,495.3
2039	-	-	-	-	15,636.4	175,652.4	-	4,847.3	4,847.3	1,379.1	0.28	1,047,874.4
2040	-	-	-	-	14,385.5	161,100.2	-	4,459.5	4,459.5	1,198.3	0.27	1,049,072.7
2041	-	-	-	-	13,234.7	147,712.2	-	4,102.8	4,102.8	1,041.2	0.25	1,050,113.9
2042	-	-	-	-	12,175.9	135,395.3	-	3,774.5	3,774.5	904.7	0.24	1,051,018.6
2043	-	-	-	-	11,201.8	124,063.7	-	3,472.6	3,472.6	786.1	0.23	1,051,804.7
2044	-	-	-	-	10,305.7	113,638.6	-	3,194.8	3,194.8	683.1	0.21	1,052,487.8
2045	-	-	-	-	9,481.2	104,047.5	-	2,939.2	2,939.2	593.5	0.20	1,053,081.3
2046	-	-	-	-	8,722.7	95,223.7	-	2,704.0	2,704.0	515.7	0.19	1,053,597.0
2047	-	-	-	-	8,024.9	87,105.8	-	2,487.7	2,487.7	448.1	0.18	1,054,045.1
2048	-	-	-	-	7,382.9	79,637.4	-	2,288.7	2,288.7	389.4	0.17	1,054,434.5
2049	-	-	-	-	6,792.3	72,766.4	-	2,105.6	2,105.6	338.3	0.16	1,054,772.8
2050	-	-	-	-	6,248.9	66,445.1	-	1,937.2	1,937.2	294.0	0.15	1,055,066.8
2051	-	-	-	-	5,749.0	60,629.5	-	1,782.2	1,782.2	255.4	0.14	1,055,322.2
2052	-	-	-	-	5,289.1	55,279.2	-	1,639.6	1,639.6	221.9	0.14	1,055,544.2
2053	-	-	-	-	4,865.9	50,356.9	-	1,508.4	1,508.4	192.9	0.13	1,055,737.0
2054	-	-	-	-	4,476.7	45,828.3	-	1,387.8	1,387.8	167.6	0.12	1,055,904.6
2055	-	-	-	-	4,118.5	41,662.1	-	1,276.7	1,276.7	145.6	0.11	1,056,050.2
2056	-	-	-	-	3,789.1	37,829.1	-	1,174.6	1,174.6	126.5	0.11	1,056,176.7
2057	-	-	-	-	3,485.9	34,302.8	-	1,080.6	1,080.6	109.9	0.10	1,056,286.7
Total	**-**	**-**	**3,975,803.3**	**(792,359.3)**	**752,271.1**		**3,183,443.9**	**(999,295.0)**	**2,184,149.0**	**1,056,286.7**		

TRE6 CW Screen Replacement 2018

CW Screen Refurbishment vs Replacement Energy Costs

Year	Total Revenue	Operating Costs	Avoided Expenses	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	PV of CF	Discount Factor	CNPV
2017	-	-	-	-	-	-	-	-	-	-	1.00	-
2018	-	-	232,446.0	(200,000.0)	8,000.0	200,000.0	32,446.0	(69,578.3)	(37,132.2)	(35,070.1)	0.94	(35,070.1)
2019	-	-	90,644.4	-	15,360.0	176,640.0	90,644.4	(23,338.2)	67,306.3	60,038.2	0.89	24,968.1
2020	-	-	127,143.6	(242,000.0)	33,491.2	385,148.8	(114,856.4)	(29,032.2)	(143,888.7)	(121,222.9)	0.84	(96,254.8)
2021	-	-	170,483.1	-	30,811.9	354,336.9	170,483.1	(43,298.1)	127,185.0	101,200.0	0.80	4,945.1
2022	-	-	200,535.8	(292,820.0)	51,772.6	595,384.3	(92,284.2)	(46,116.6)	(138,400.8)	(104,008.5)	0.75	(99,063.4)
2023	-	-	204,546.5	-	47,630.7	547,753.6	204,546.5	(48,643.9)	155,902.6	110,654.7	0.71	11,591.3
2024	-	-	208,637.4	(354,312.2)	72,165.3	829,900.5	(145,674.8)	(42,306.4)	(187,981.1)	(126,013.4)	0.67	(114,422.1)
2025	-	-	212,810.2	-	66,392.0	763,508.5	212,810.2	(45,389.6)	167,420.6	105,997.9	0.63	(8,424.2)
2026	-	-	217,066.4	(428,717.8)	95,378.1	1,096,848.2	(211,651.4)	(37,723.4)	(249,374.7)	(149,117.0)	0.60	(157,541.2)
2027	-	-	221,407.7	-	87,747.9	1,009,100.3	221,407.7	(41,434.6)	179,973.2	101,640.9	0.56	(55,900.3)
2028	-	-	225,835.9	(600,183.0)	128,742.7	1,480,540.6	(374,347.1)	(30,098.9)	(404,446.0)	(215,728.4)	0.53	(271,628.7)
2029	-	-	230,352.6	-	118,443.3	1,362,097.4	230,352.6	(34,691.9)	195,660.7	98,568.1	0.50	(173,060.6)
2030	-	-	234,959.6	-	108,967.8	1,253,129.6	234,959.6	(39,057.5)	195,902.2	93,209.1	0.48	(79,851.6)
2031	-	-	239,658.8	-	100,250.4	1,152,879.2	239,658.8	(43,216.6)	196,442.2	88,275.4	0.45	8,423.8
2032	-	-	244,452.0	-	92,230.3	1,060,648.9	244,452.0	(47,188.7)	197,263.3	83,721.6	0.42	92,145.4
2033	-	-	249,341.0	-	84,851.9	975,797.0	249,341.0	(50,991.6)	198,349.4	79,507.5	0.40	171,652.9
2034	-	-	254,327.9	-	78,063.8	897,733.2	254,327.9	(54,641.9)	199,686.0	75,598.1	0.38	247,250.9
2035	-	-	259,414.4	-	71,818.7	825,914.6	259,414.4	(58,154.7)	201,259.7	71,962.5	0.36	319,213.4
2036	-	-	-	-	66,073.2	759,841.4	-	20,482.7	20,482.7	6,917.1	0.34	326,130.5
2037	-	-	-	-	60,787.3	699,054.1	-	18,844.1	18,844.1	6,010.3	0.32	332,140.8
2038	-	-	-	-	55,924.3	643,129.8	-	17,336.5	17,336.5	5,222.4	0.30	337,363.2
2039	-	-	-	-	51,450.4	591,679.4	-	15,949.6	15,949.6	4,537.8	0.28	341,901.0
2040	-	-	-	-	47,334.4	544,345.0	-	14,673.6	14,673.6	3,942.9	0.27	345,843.9
2041	-	-	-	-	43,547.6	500,797.4	-	13,499.8	13,499.8	3,426.0	0.25	349,269.9
2042	-	-	-	-	40,063.8	460,733.6	-	12,419.8	12,419.8	2,976.9	0.24	352,246.8
2043	-	-	-	-	36,858.7	423,874.9	-	11,426.2	11,426.2	2,586.7	0.23	354,833.5
2044	-	-	-	-	33,910.0	389,964.9	-	10,512.1	10,512.1	2,247.6	0.21	357,081.1
2045	-	-	-	-	31,197.2	358,767.7	-	9,671.1	9,671.1	1,952.9	0.20	359,034.0
2046	-	-	-	-	28,701.4	330,066.3	-	8,897.4	8,897.4	1,696.9	0.19	360,730.9
2047	-	-	-	-	26,405.3	303,661.0	-	8,185.6	8,185.6	1,474.5	0.18	362,205.4
2048	-	-	-	-	24,292.9	279,368.1	-	7,530.8	7,530.8	1,281.2	0.17	363,486.6
2049	-	-	-	-	22,349.5	257,018.7	-	6,928.3	6,928.3	1,113.2	0.16	364,599.8
2050	-	-	-	-	20,561.5	236,457.2	-	6,374.1	6,374.1	967.3	0.15	365,567.1
2051	-	-	-	-	18,916.6	217,540.6	-	5,864.1	5,864.1	840.5	0.14	366,407.6
2052	-	-	-	-	17,403.2	200,137.4	-	5,395.0	5,395.0	730.3	0.14	367,137.9
2053	-	-	-	-	16,011.0	184,126.4	-	4,963.4	4,963.4	634.6	0.13	367,772.4
2054	-	-	-	-	14,730.1	169,396.3	-	4,566.3	4,566.3	551.4	0.12	368,323.8
2055	-	-	-	-	13,551.7	155,844.6	-	4,201.0	4,201.0	479.1	0.11	368,802.9
2056	-	-	-	-	12,467.6	143,377.0	-	3,864.9	3,864.9	416.3	0.11	369,219.2
2057	-	-	-	-	11,470.2	131,906.8	-	3,555.7	3,555.7	361.7	0.10	369,580.9
	-	**-**	**3,824,063.4**	**(2,118,033.0)**	**1,986,126.1**		**1,706,030.4**	**(569,760.6)**	**1,136,269.9**	**369,580.9**		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CW Screen Replacement vs Replacement Energy Costs
CW Screen Refurbishment vs Replacement Energy Costs
Test 3
Test 4
Year

MACGILLIVRAY, DANYA

From: LEWIS, JACK
Sent: Tuesday, August 29, 2017 4:25 PM
To: MACGILLIVRAY, DANYA
Subject: FW: Nova Scotia Power Trenton 6 Screen Replacement
Attachments: Dual Flow Information_Drawings_95926.pdf

Importance: High

Screen quote

From: Ian Johnston [mailto:ianjohnston@aps.ns.ca]
Sent: Tuesday, August 29, 2017 4:08 PM
To: LEWIS, JACK
Cc: Cernanec, Scott; Hettie Sacre
Subject: RE: Nova Scotia Power Trenton 6 Screen Replacement
Importance: High

This is an external email - exercise caution

Hi Jack,

Please review the e-mail below from Scott at Evoqua which contains high level preliminary budget pricing for (1) replacement dual flow screen to match your existing.

Is this sufficient at this time?

If you have any questions or need anything else please let us know.

Thanks,
Ian

Ian Johnston - Technical Sales Rep.
APS **Atlantic Purification Systems Ltd.**
10 Ferguson Road, Dartmouth, NS B3A 4M1
902-469-2806 ext.115 (office)
902-499-5553 (cell)
ianjohnston@aps.ns.ca

www.aps.ns.ca | LinkedIn

From: Cernanec, Scott [mailto:scott.cernanec@evoqua.com]
Sent: Tuesday, August 29, 2017 3:56 PM
To: Ian Johnston <ianjohnston@aps.ns.ca>
Cc: Cernanec, Scott <scott.cernanec@evoqua.com>
Subject: RE: Nova Scotia Power Trenton 6 Screen Replacement
Importance: High

Hi Ian,

Here is a very rough budgetary number to replace a screen: [redacted] **USD**.

This is a 6' x 27' dual flow screen to match the current one (see attached sales drawing).

Included:

1. HSC (fiberglass) baskets
2. Zinc sacrificial anodes, as with current screen

Not included:

1. Labour to install, supervise or commission
2. Controls (assume re-use of existing)

Let me know if you have any questions.

Scott Cernanec
Technical Sales Manager (Canada) – Intake Products

Evoqua Water Technologies Ltd.
Mobile: 226-378-8525
scott.cernanec@evoqua.com

From: Ian Johnston [mailto:ianjohnston@aps.ns.ca]
Sent: Monday, August 28, 2017 12:04 PM
To: Cernanec, Scott <scott.cernanec@evoqua.com>; Hediger, Robert B <robert.b.hediger@evoqua.com>

Cc: Hettie Sacre <hettie@aps.ns.ca>
Subject: FW: Nova Scotia Power Trenton 6 Screen Replacement

Scott / Bob:

Another NSP plant in Trenton, NS is looking to replace their dual intake travelling water screens. They want to replace (1) in 2018 and need budget pricing. Original drawing is attached with design information. Please provide a high level budget number, per their request below.

Please confirm receipt and expected turnaround.

Thanks,
Ian

Ian Johnston - Technical Sales Rep.
APS **Atlantic Purification Systems Ltd.**
10 Ferguson Road, Dartmouth, NS B3A 4M1
902-469-2806 ext.115 (office)
902-499-5553 (cell)
ianjohnston@aps.ns.ca
www.aps.ns.ca | LinkedIn

From: LEWIS, JACK [mailto:Jack.Lewis@nspower.ca]
Sent: Monday, August 28, 2017 12:04 PM
To: Ian Johnston <ianjohnston@aps.ns.ca>
Subject: Nova Scotia Power Trenton 6 Screen Replacement

Hi Ian,

Thanks for the discussion a few minutes ago. I have attached the drawing we have of the existing Unit 6 traveling water screens. The screens are currently a dual flow design entering the outsides and exiting through the center.

We would like to have a budgetary price for the replacement of one traveling screen for 2018. It may not matter at this point but we would like a change in the current design from the internal drive to an external drive where the drive chain and sprockets are not in the salt water spray environment.

Thanks again

Jack Lewis, P.Eng | Reliability Engineer | Nova Scotia Power | Trenton Generating Station
T: 902-755-5811 x4263 | C: 902-759-1667 | F: 902-755-3722 | E: jack.lewis@nspower.ca

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CI Number: 51816

Title: TRE Asbestos Abatement 2018

Start Date:	2018/02
In-Service Date:	2018/10
Final Cost Date:	2019/04
Function:	Steam
Forecast Amount:	$509,035

DESCRIPTION:

Unit 5 of the Trenton Generating Station has been in operation since 1969. Much of the insulation used during the construction of Unit 5 was asbestos-based. Trenton Units 3 and 4 were also constructed when asbestos was prevalent for industrial insulating purposes. Much of the asbestos from these two units has been removed over the years, though some remains. The asbestos remaining in these areas continues to be inspected and is included in the Trenton asbestos monitoring plan. NS Power has been completing asbestos abatement at the Trenton Generating Station as part of a multi-year plan. This project continues the removal of asbestos contaminated insulation materials from the Trenton Generating Station that may become exposed through regular operation, maintenance activities and equipment vibration.

The scope of this project is to conduct asbestos abatement in multiple areas of the Trenton Generating Station, in accordance with the Occupational Health and Safety Act (OHSA) and the Department of Labour's "Asbestos in the Workplace" guide which states:

> Where asbestos is present or believed to be present in a workplace to which the Occupational Health and Safety Act applies, the owner of the building and any employer whose workplace in the building may contain asbestos have a duty under the Act to take all reasonable precautions to ensure the health and safety of persons at or near that workplace.

The utilization of Trenton 5 will continue to decrease as more of NS Power's electricity requirements are met by renewable sources. Lower operating hours will increase unit cycling causing more thermal pipe expansion and deteriorating of asbestos insulation.

The 2018 project will continue the abatement effort with the following activities:

- <u>Abatement of Unit 5 High Energy Piping:</u>

  During the planned outage for Unit 5 in 2018, asbestos abatement will be completed on select areas of high energy piping and infrastructure. The exact areas for abatement have not been determined and will be established based on monitoring of the asbestos inventory to concentrate on piping that is prone to large movement during boiler starts and stops, thereby identified as piping that is the most susceptible to repeated deterioration of the asbestos encapsulation. These measures will be taken to properly mitigate the potential spread of asbestos fibers throughout the boiler house. The scope of work generally includes scaffolding to access the piping, installation of temporary enclosure over the entire area, the removal and disposal of asbestos-contaminated insulation, and re-insulation of the piping with asbestos-free insulation. This abatement work must be done while the unit is offline.

<u>Balance of Plant Encapsulation/Abatement:</u>

Over the course of 2018, regular inspections of the asbestos inventory will be conducted. The inspections will enable NS Power to identify deficiencies and to complete the balance of plant repairs/encapsulation/cleanup for unplanned miscellaneous asbestos issues as they are identified through day to day plant activities and operations.

- Unit 5 Outage Support:

  Based on previous experience, it is evident that despite regular inspection and encapsulation, some affected areas remain mostly undiscovered until such time that maintenance is required. With the increased amount of maintenance that occurs with a planned outage, NS Power will have asbestos abatement support available to monitor and complete encapsulation/abatement as required during the outage.

A breakdown of the approximate abatement/encapsulation costs by scope is as follows:

Project	Estimated Contract Cost
U5 High Energy Piping – Type 3 enclosure and abatement	$300K
U5 Boilerhouse – Quarterly Inspections and encapsulation (Q1 through Q4)	$100K
U5 Balance of plant – Unplanned	$60K
U5 2018 Outage Support – Miscellaneous Items	$50K

Summary of Related CIs +/- 2 years:
2016 CI 47600 TRE Asbestos Abatement (2016) $2,096,391
2017 CI 49553 TRE Asbestos Abatement 2017 $728,886
2019 CI TBD TRE Asbestos Abatement 2019 $TBD
2020 CI TBD TRE Asbestos Abatement 2020 $TBD

JUSTIFICATION:

Justification Criteria: Health & Safety

Why do this project?

Exposure of asbestos fibers poses a health risk to plant personnel. Degenerated asbestos insulation causes maintenance delays, increased down time and increased operating costs. Asbestos abatement and encapsulation are required to remove or mitigate health hazards to plant personnel associated with exposure to asbestos fibers. This project is in accordance with the Occupational Health and Safety Act (OHSA) and the Department of Labour's "Asbestos in the Workplace" guide:

The removal of asbestos-based insulation at the Trenton Generation Station is being completed in a multi-phase program based on risk, Joint Occupational Health and Safety Committee (JOSHC) recommendations, and equipment replacement requirements and planned outages.

Why do this project now?

The abatement and encapsulation work completed in this project is required to safely continue to operate the plant and to execute planned outage work (in some cases), as well as plan for future maintenance work. The operation of the unit will continue to vary due to decreased utilization and capacity as more of NS Power's electricity requirements are met by renewable sources. With more stops and starts occurring on the unit, the level of vibrations and potential for asbestos disturbances will increase.

In accordance with the Occupational Health and Safety Act (OHSA) and the Department of Labor's "Asbestos in the Workplace" guide, the Trenton Station has an asbestos management plan in place to manage the risks and protect the employees. This management plan includes an inventory of the asbestos containing insulation, which requires inspection on a regular basis. Subsequent to the inspections, any necessary encapsulation/abatement is completed.

Why do this project this way?

The scope of work itself is driven by safety compliance. A continued effort is required to monitor, remove and encapsulate asbestos containing materials. Ongoing inspection and selective abatement based on condition and wear are the best options to reduce further disruption and lost production due to repairs/maintenance that will be required in this area now and in the future.

CI Number : 51816 - TRE Asbestos Abatement 2018 **Project Number** 51816

Parent CI Number : -

Asset Location : 1168 - 1168 Trenton Common Property **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0300 - SGP - Bldg.,Struct.Grnd.	103,492
Retirements	0300 - SGP - Bldg.,Struct.Grnd.	405,543
	Total Cost:	509,035
	Original Cost:	15,758

Capital Project Detailed Estimate

Location: Trenton Generating Station
CI# : 51816
Title: TRE Asbestos Abatement 2018
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Utility	PD	80	240	$ 19,214		
Power Plant Tech (Chem)	PD	5	382	$ 1,911		
				$ -		
			Sub-Total	$ 21,125		
OT Labour						
Utility	PD	20	480	$ 9,607		
			Sub-Total	$ 9,607		
Term Labour						
Utility	PD	80	240	$ 19,214		
				$ -		
			Sub-Total	$ 19,214		
Materials						
Misc materials	lot	1	$ 500	$ 500		
			Sub-Total	$ 500		
Contracts						
Asbestos Abatement U5 High Energy Piping	lot	1	$ 160,000	$ 160,000		CI 47600/49553
Asbestos Abatement Balance of plant	lot	1	$ 50,000	$ 50,000		CI 47600/49553
U5 outage Abatement Support	lot	1	$ 25,000	$ 25,000		CI 47600/49553
Staging setup and inspection	lot	1	$ 50,000	$ 50,000		CI 47600/49553
Re-insulation	lot	1	$ 50,000	$ 50,000		CI 47600/49553
Supervision	lot	1	$ 25,000	$ 25,000		CI 47600/49553
Abatement Third Party Expert	lot	1	$ 15,000	$ 15,000		CI 47600/49553
				$ -		
			Sub-Total	$ 375,000		
OT Meals						
Meals	lot	1	$ 500	$ 500		
			Sub-Total	$ 500		
Freight						
Shipping	lot	1	$ 1,000	$ 1,000		
			Sub-Total	$ 1,000		
Rentals						
Staging	lot	1	$ 10,000	$ 10,000		
Misc.	lot	1	$ 5,000	$ 5,000		
			Sub-Total	$ 15,000		
Other Goods & Services						
Contingency	%	5%	$ 414,947	$ 20,747		
			Sub-Total	$ 20,747		
Administrative Overhead						
Thermal Reg. Labour AO				$ 9,917		
Thermal / Hydro Contracts AO				$ 36,424		
			Sub-Total	$ 46,341		
			SUB-TOTAL (no AO, AFUDC)	$ 462,694		
			TOTAL (AO, AFUDC included)	$ 509,035		
Original Cost				$ 15,758		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 51835

Title: TUC2 Hydrogen Panel Replacement

Start Date: 2018/01
In-Service Date: 2018/06
Final Cost Date: 2018/12
Function: Steam
Forecast Amount: $454,886

DESCRIPTION:

This project includes the replacement of the Tufts Cove 2 hydrogen gas panel station. This hydrogen panel is original to the Tufts Cove 2 generating station, is approximately 47 years old, and has reached the end of its expected useful life. As the hydrogen panel has aged, the system has experienced failures in components (valves, sensors, and piping connections) which can lead to unsafe working conditions due to the hazardous properties of hydrogen gas.

Hydrogen is used as the medium to ensure adequate cooling of the generator stator and associated equipment. The hydrogen panel is designed to control the flow of hydrogen gas and to monitor and regulate the gas purity in the system.

Summary of Related CIs +/- 2 years:
No other projects in 2016, 2017, 2018, 2019 and 2020

JUSTIFICATION:

Justification Criteria: Health & Safety

Why do this project?

As the Hydrogen Panel is original to the unit, the system has experienced failures in components (valves, sensors, and piping connections). This can lead to hydrogen gas releases causing unit shutdown until the leak is repaired, as well as unsafe working conditions. The system continues to deteriorate and needs replacement to ensure reliable generator cooling and to maintain the integrity of the hydrogen system.

This project is required to maintain the safe operation of the unit and to preserve the unit's performance.

Why do this project now?

This hydrogen panel is original to the Tufts Cove #2 generating station, is approximately 47 years old, and has reached the end of its expected useful life. As the hydrogen panel has aged, the plant has experienced failures in components (valves, sensors, and piping connections) which can lead to unsafe working conditions. As the system continues to age, the likelihood of a more significant system failure (larger releases of hydrogen) increases, thereby increasing risk to a level where mitigating actions are required.

Why do this project this way?

The method of resolving hydrogen panel leaks to date has been to repair or replace valve components, instrument components and piping elements as they fail. As the equipment ages and begins to deteriorate, this approach is less effective, resulting in a greater probability of significant failure. System replacement is the recommended approach to mitigate this risk.

CI Number : 51835 - TUC2 Hydrogen Panel Replacement **Project Number** 51835

Parent CI Number : -

Asset Location : 1172 - 1172 Tufts Cove Unit 2; Commissioned 1972, 97 Mwh **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	1000 - SGP - Turbo Gen.Instal.	448,787
Retirements	1000 - SGP - Turbo Gen.Instal.	6,098
	Total Cost:	454,886
	Original Cost:	70,561

Capital Project Detailed Estimate

Location: Tufts Cove
CI# : 51835
Title: TUC2 Hydrogen Panel Replacement
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
Electrician	PD	36	$ 358	$ 12,898		
Engineering	PD	30	$ 405	$ 12,159		
Maintenance Trades	PD	30	$ 365	$ 10,944		
Power Plant Technician	PD	10	$ 382	$ 3,821		
Utility worker	PD	5	$ 240	$ 1 201		
CADD Operators	PD	5	$ 294	$ 1,470		
			Sub-Total	$ 42,493		
Materials						
Hydrogen Control Panel	ea.	1	[redacted]		Cost Support #1 - Items 1 & 2	
USD to CDN Conversion	%	32%				
Misc. Pipe, Cable, Tubing, Instruments	lot	1				
			Sub-Total	$ 350,770		
Contracts						
Scaffolding	lot	1	[redacted]			
Hydrogen Control Panel -Commissioning	lot	1			Cost Support #1 - Items 3 & 4	
USD to CDN Conversion	%	32%				
			Sub-Total	$ 22,840		
Consulting						
Engineering project management	lot	1	$ 15,000	$ 15,000		
			Sub-Total	$ 15,000		
Freight						
Shipping	ea.	1	$ 5,000	$ 5,000		
			Sub-Total	$ 5,000		
Interest Capitalized						
AFUDC				$ 7,229		
				$ -		
			Sub-Total	$ 7,229		
Administrative Overhead						
Labor AO				$ 9,335		
Contract AO				$ 2,218		
			Sub-Total	$ 11,553		
			SUB-TOTAL (no AO, AFUDC)	$ 436,103		
			TOTAL (AO, AFUDC included)	$ 454,886		
Original Cost				$ 70,561		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

e|one Generating Solutions
UTILITY SYSTEMS
2773 Balltown Road Niskayuna, NY 12309
Phone: (518) 346-6161 Fax: (518) 346-4382

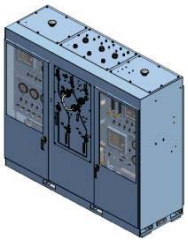
QUOTATION

Number: 2017.07.14_TuftsCove_GAS_01_MEW
Channel: Direct

Thank you for your interest in Environment One, its products and services. We are pleased to offer this quotation for your consideration.

TITLE PASSES AT SELLER'S DOCK

TO:		DATE	July 14, 2017	
	Karl Nowlan	REFERENCE	Site Visit	
	Sr. Electrical Engineer	PRICES	EXWorks	**Niskayuna, NY**
	Tufts Cove Generating Station	**TERMS***	Net 30	
	Nova Scotia Power	SHIPMENT	12-18	weeks ARO
phone:	902 428 7673	VALIDITY	30 DAYS	
e-mail:	karl.nowlan@nspower.com	FREIGHT	Not Included	

ITEM	QUANTITY	PART#	DESCRIPTION	UNIT PRICE (USD)	EXT PRICE (USD)
1	1	to be assigned	GAS Station in enclosed frame, including: Generator Gas Analyzer (GGA) Generator Gas Manifold (GGM) 2 Annunciation Display (points to be determined) Auxiliary Panels (gages, transmitters, switches) *(please reference preliminary P&ID and outline)* *Marking: class1, div2, groupB(h2)* *intent for SCA or equal,* *CNR* 	[redacted]	
2	1	to be assigned	CRN Cost	[redacted]	
3	5	day(s)	Per day rate for E/One Technician: System start-up, commissioning, and training of site personnel. Equipment must be piped in and wired prior to E/One's arrival for start-up support. **PLEASE NOTE THAT OUR FIELD SERVICE GROUP REQUIRES A MINIMUM 6-8 WEEKS ADVANCE NOTICE TO EFFECTIVELY PLAN FOR OUR PERSONNEL TO BE ON SITE. SHORT-CYCLING THIS NOTICE PERIOD CAN/WILL RESULT IN AN "EXPEDITE" PREMIUM OF 15%. WORK IS SCHEDULED ON A FIRST COME, FIRST SERVE BASIS – WE APPRECIATE YOUR CONSIDERATION OF THIS AND THE OPPORTUNITY TO MEET YOUR NEEDS.**	[redacted]	[redacted]
4	1	trip(s)	Actual travel and living (transportation, meals, lodging, etc.), as well as any additional expenses incurred due to contractual obligations in support of system start-up, will be invoiced separately at cost + 20% (administrative expenses) and 2 travel days at $500 per day. Documented verification of the expenditures will be provided with the invoice.	*Approximately*	[redacted]

***Request for terms other than the terms specified on this quotation may result in additional cost.**

E/One is not responsible for any taxes, VAT, GST, duties or misc. fees (where not required by law).
NAFTA Certificate cannot be provided. Chamber of Commerce stamped Certificates of Origin are at extra cost.

This quotation is subject to Environment One's Standard Terms and Conditions (D029). Terms and Conditions can be accessed at the following address: http://eone.com/utility-systems/regions/us/sales/
Such Terms and Conditions are incorporated by this reference. If you are unable to locate these Terms and Conditions on the website, please contact Environment One in writing.

U.S. export control laws apply to the products and technologies covered by this Order. Export or re-export of these products or technologies may require the prior approval of the U.S. government in accordance with the Export Administration Regulations, and OFAC rules, and customer agrees to notify Environment One Corporation, Inc. of any such intended export or re-export. Diversion contrary to U.S. law is prohibited.

HAZARDOUS AREA CLASSIFICATION - Check One

3rd Party Certification		If 3rd Party Certification then include the product category and product marking in this quote.
Designed by E/One to meet intent	X	
Not Applicable		

If an order is placed against this quote, E/One will confirm that the destination is not on the entity list at www.bis.doc.gov prior to shipment release.

Environment One, Utility Systems Business is an ISO9001 certified organization.

For and on Behalf of Environment One Corporation
Mark Williams 401-489-5225
VIA EMAIL: mwilliams@eone.com

D149
Issue07/JLF
Jan-14

This document contains confidential and proprietary information and must be treated as such.

CI Number: 51836

Title: TRE5 Mill Refurbishments 2018

Start Date: 2018/06
In-Service Date: 2018/06
Final Cost Date: 2018/12
Function: Steam
Forecast Amount: $409,458

DESCRIPTION:

This project will re-establish original equipment manufacturer (OEM) tolerances on the Trenton 5 coal mills and include replacement of worn components on two of the four Unit 5 coal mills at the Trenton Generating Station. Trenton Generating Station Unit 5 uses four Babcock & Wilcox EL-70 coal mills to pulverize coal for combustion in the boiler. The mills were originally installed and commissioned in 1969, and have been in service since that time.

Refurbishment of these mills is scheduled based on unit utilization and the condition assessment coinciding with planned unit outages. The 5-2 and 5-4 mills were last refurbished in late 2015 and early 2016, respectively. As part of the planned outage, a condition assessment during teardown will determine components to be refurbished.

Scope for this project generally includes refurbishment to the housing unit and liners, grinding rings, springs, spindles, swing valves, and replacement of the grinding media.

Summary of Related CIs +/- 2 years:
2016 CI 47599 - TRE5 5-4 Mill Refurbishments - $157,232
2016 CI 49548 - TRE5 PA 5-1 Mill Refurbishment - $224,615
2017 CI 49549 - TRE5 5-3 Mill Refurbishment 2017 - $180,147
2019 CI TBD - TRE5 Mill Refurbishments 2019 - $TBD
2020 CI TBD - TRE5 Mill Refurbishments 2020 - $TBD

JUSTIFICATION:

Justification Criteria: Thermal

Sub Criteria: Equipment Replacement / Refurbishment

Why do this project?

This project is being completed to mitigate the risk of mill failure. A mill failure could limit the ability of the unit to reach fully rated generator output depending on the fuel blend in service. It is imperative that the mills are available full time between planned outages in order to maintain unit performance at rated capacity. The replacement of mechanical components and the upgrading of the ceramic surfaces are necessary to achieve the most economic operation of the unit.

This project is being undertaken to prevent unit deratings, and is supported by positive replacement energy cost economics.

Why do this project now?

The plant requires a high degree of mill efficiency and availability to deliver economic electricity generation. This requires a well-executed mill program to maintain high mill availability. The 2018 Unit 5 planned outage is expected to be a four week outage. This will provide the ideal timeframe to complete the refurbishment of the 5-2 and 5-4 mills in a planned and cost effective manner.

Why do this project this way?

Improving mill availability has economic benefit, however, that benefit has to be achieved through good maintenance practice. Replacement parts are now required due to age and wear on many of the mill components. Re-establishing original equipment manufacturer tolerances and replacement of worn components will prevent degradation in plant performance and sustain high capacity factors. A phased approach to reinvesting in the mills allows for scheduled outages of selected mills, which will reduce the risk of extended unplanned outages. By planning refurbishments and replacements in a given year, efforts can be made more efficient with dedicated labour and parts available as required.

CI Number : 51836 - TRE5 Mill Refurbishments 2018 **Project Number** 51836

Parent CI Number : -

Asset Location : 1165 - 1165 Trenton Unit 5; Commissioned 1969, 160 Mwh **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	1800 - SGP - Fuel Hndlg.Coal	377,746
Retirements	1800 - SGP - Fuel Hndlg.Coal	31,712
	Total Cost:	409,458
	Original Cost:	348,441

Capital Project Detailed Estimate

Location: Trenton Generating Station
CI# : 51836
Title: TRE5 Mill Refurbishments 2018
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Engineering	PD	10	$ 405	$ 4,053		
Maintenance Trades	PD	70	$ 365	$ 25,535		
Power Engineer	PD	5	$ 390	$ 1,952		
Utility worker	PD	20	$ 240	$ 4,804		
Supervision	PD	25	$ 365	$ 9,120		
			Sub-Total	$ 45,463		
OT Labour						
Maintenance Trades	PD	8	$ 730	$ 5,837		
Utility worker	PD	8	$ 480	$ 3,843		
			Sub-Total	$ 9,679		
Term Labour						
Maintenance Trades	PD	70	$ 365	$ 25,535		
Utility worker	PD	30	$ 240	$ 7,205		
			Sub-Total	$ 32,740		
Materials						
Complete Set of Mill Parts	Ea	2	$ 121,437	$ 242,873		CI 49548 - 49549
Miscellaneous Parts and Materials	Ea	2	$ 7,500	$ 15,000		CI 49548 - 49549
Mill oil	Ea	2	$ 2,500	$ 5,000		
			Sub-Total	$ 262,873		
Contracts						
Machining/Fabrication	Ea	2	$ 10,000	$ 20,000		
Vacuum services	Ea	2	$ 5,000	$ 10,000		
			Sub-Total	$ 30,000		
OT Meals						
OT Meals	lot	1	$ 200	$ 200		
			Sub-Total	$ 200		
Freight						
Shipping	lot	1	$ 2,950	$ 2,950		
			Sub-Total	$ 2,950		
Other Goods & Services						
Contingency	%	5%	$ 87,883	$ 4,394		
				$ -		
			Sub-Total	$ 4,394		
Administrative Overhead						
Labour AO				$ 18,243		
Contract AO				$ 2,914		
			Sub-Total	$ 21,157		
			SUB-TOTAL (no AO, AFUDC)	$ 388,301		
			TOTAL (AO, AFUDC included)	$ 409,458		
Original Cost				$ 348,441		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

TRE5 Mill Refurbishment 2018
Summary of Alternatives

Division :	Power Production	**Date :**	**19-Nov-17**
Department :	Trenton	**CI Number:**	51836
		Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank (based on PV of RR)	IRR	Disc Pay
A	Mill Refurbishment vs Replacement Energy Costs	5.88%	-306,842	192,729	1	86.39%	1.2 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

Recommendation :

It is recommended to refurbish two of the four TRE5 mills. By conducting this project during the planned outage, replacement energy costs and down time during peak demand months are avoided. This is supported by favorable economic analysis data.

Notes/Comments :

Mill Refurbishment vs Replacement Energy Costs

This analysis compares the option of refurbishment versus failure. A failure would incur replacement energy cost associated with a derate of the Unit (40MW) while refurbishment is completed, and would have a risk of inflicting additional damage to the mill.

Test 2

Test 3

Test 4

TRE5 Mill Refurbishment 2018
Summary of Sensitivities

Nova Scotia POWER An Emera Company

Division :	Power Production	**Date :**	**14-Nov-17**
Department :	Trenton	**CI Number:**	51836
		Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Mill Refurbishment vs Replacement Energy Costs	5.88%	-306,842	192,729	1	86.39%	1.2 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

	Alternative Variance on Capital Spend	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Mill Refurbishment vs Replacement Energy Costs	10%	-267,369	162,775	1	59.28%	1.3 years
B	Test 2	10%	0	0	2	#NUM!	0.0 years
C	Test 3	10%	0	0	2	#NUM!	0.0 years
D	Test 4	10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		39,472	-29,955	0	-27.12%	0.1 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

	Alternative Variance on Avoided Expenses	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Mill Refurbishment vs Replacement Energy Costs	-10%	-236,685	143,502	1	56.84%	1.3 years
B	Test 2	-10%	0	0	2	#NUM!	0.0 years
C	Test 3	-10%	0	0	2	#NUM!	0.0 years
D	Test 4	-10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		70,157	-49,228	0	-29.56%	0.1 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

Alternative Variance on Avoided Expenses - Change in Revenue Requirement		PV of Revenue Requirement	PV of Revenue Requirement	PV of Revenue Requirement	Delay?
	Yrs Delay:	1	2	3	
	A	225,165	667,035	618,506	No
	B	0	0	0	No
	C	0	0	0	No
	D	0	0	0	No

TRE5 Mill Refurbishment 2018
Avoided Cost Calculations

Division :	Power Production	**Date :**	**14-Nov-17**
Department :	Trenton	**CI Number:**	51836
		Project No. :	

Mill Refurbishment vs Replacement Energy Costs

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			218,400	227,151		
Events/Outages (#)	2	2	2	2		
Probability of Occurance (%)	50%	100%	50%	100%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	40.0	40.0				
Duration (Hours or Years)	1008	1008				
Totals	$42,015	$69,780	$218,400	$454,303	$260,415	$524,083
Total Capital Cost of Alternative						$409,458

Test 2

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

Test 3

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

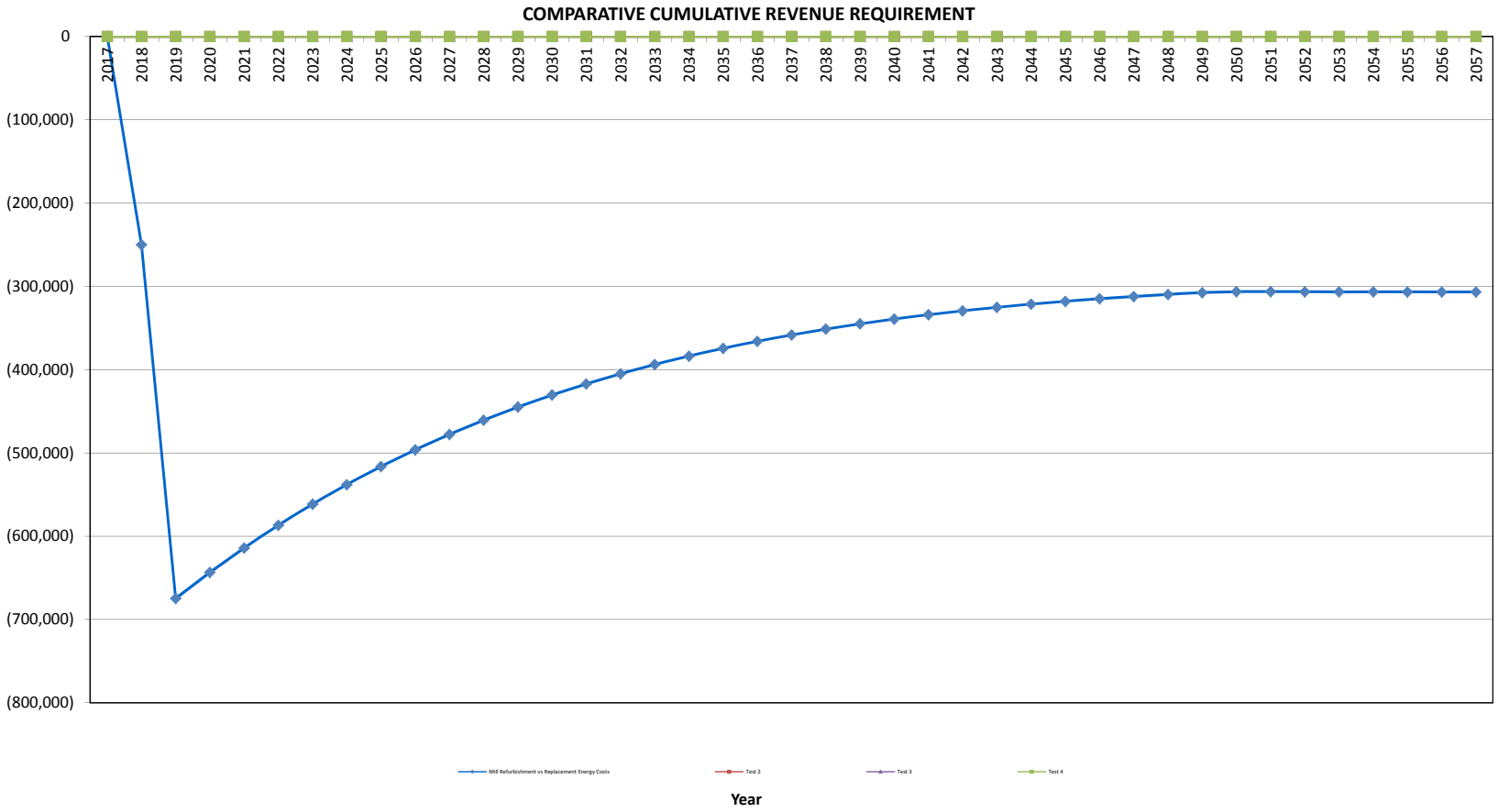
Test 4

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

TRE5 Mill Refurbishment 2018

Mill Refurbishment vs Replacement Energy Costs

Year	Total Revenue	Operating Costs	Avoided Expenses	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	PV of CF	Discount Factor	CNPV
2017	-	-	-	-	-	-	-	-	-	-	1.00	-
2018	-	-	260,414.9	(388,301.0)	15,532.0	378,608.3	(127,886.1)	(75,913.7)	(203,799.8)	(192,481.9)	0.94	(192,481.9)
2019	-	-	524,083.2	-	29,821.5	347,811.8	524,083.2	(153,221.1)	370,862.1	330,814.5	0.89	138,332.6
2020	-	-	-	-	27,435.8	319,479.1	-	8,505.1	8,505.1	7,165.4	0.84	145,498.0
2021	-	-	-	-	25,240.9	293,413.0	-	7,824.7	7,824.7	6,226.0	0.80	151,724.0
2022	-	-	-	-	23,221.7	269,432.2	-	7,198.7	7,198.7	5,409.9	0.75	157,133.9
2023	-	-	-	-	21,363.9	247,369.9	-	6,622.8	6,622.8	4,700.7	0.71	161,834.5
2024	-	-	-	-	19,654.8	227,072.5	-	6,093.0	6,093.0	4,084.4	0.67	165,919.0
2025	-	-	-	-	18,082.4	208,399.0	-	5,605.6	5,605.6	3,549.0	0.63	169,468.0
2026	-	-	-	-	16,635.8	191,219.3	-	5,157.1	5,157.1	3,083.8	0.60	172,551.7
2027	-	-	-	-	15,305.0	175,414.0	-	4,744.5	4,744.5	2,679.5	0.56	175,231.2
2028	-	-	-	-	14,080.6	160,873.1	-	4,365.0	4,365.0	2,328.2	0.53	177,559.5
2029	-	-	-	-	12,954.1	147,495.5	-	4,015.8	4,015.8	2,023.0	0.50	179,582.5
2030	-	-	-	-	11,917.8	135,188.1	-	3,694.5	3,694.5	1,757.8	0.48	181,340.4
2031	-	-	-	-	10,964.4	123,865.3	-	3,399.0	3,399.0	1,527.4	0.45	182,867.7
2032	-	-	-	-	10,087.2	113,448.3	-	3,127.0	3,127.0	1,327.2	0.42	184,194.9
2033	-	-	-	-	9,280.2	103,864.6	-	2,876.9	2,876.9	1,153.2	0.40	185,348.1
2034	-	-	-	-	8,537.8	95,047.7	-	2,646.7	2,646.7	1,002.0	0.38	186,350.1
2035	-	-	-	-	7,854.8	86,936.1	-	2,435.0	2,435.0	870.7	0.36	187,220.8
2036	-	-	-	-	7,226.4	79,473.5	-	2,240.2	2,240.2	756.5	0.34	187,977.3
2037	-	-	-	-	6,648.3	72,607.8	-	2,061.0	2,061.0	657.3	0.32	188,634.6
2038	-	-	-	-	6,116.4	66,291.4	-	1,896.1	1,896.1	571.2	0.30	189,205.8
2039	-	-	-	-	5,627.1	60,480.4	-	1,744.4	1,744.4	496.3	0.28	189,702.1
2040	-	-	-	-	5,177.0	55,134.2	-	1,604.9	1,604.9	431.2	0.27	190,133.3
2041	-	-	-	-	4,762.8	50,215.7	-	1,476.5	1,476.5	374.7	0.25	190,508.0
2042	-	-	-	-	4,381.8	45,690.6	-	1,358.3	1,358.3	325.6	0.24	190,833.6
2043	-	-	-	-	4,031.2	41,527.6	-	1,249.7	1,249.7	282.9	0.23	191,116.5
2044	-	-	-	-	3,708.7	37,697.7	-	1,149.7	1,149.7	245.8	0.21	191,362.3
2045	-	-	-	-	3,412.0	34,174.1	-	1,057.7	1,057.7	213.6	0.20	191,575.9
2046	-	-	-	-	3,139.1	30,932.4	-	973.1	973.1	185.6	0.19	191,761.5
2047	-	-	-	-	2,887.9	27,950.0	-	895.3	895.3	161.3	0.18	191,922.8
2048	-	-	-	-	2,656.9	25,206.3	-	823.6	823.6	140.1	0.17	192,062.9
2049	-	-	-	-	2,444.4	22,682.0	-	757.8	757.8	121.8	0.16	192,184.7
2050	-	-	-	-	2,248.8	20,359.7	-	697.1	697.1	105.8	0.15	192,290.4
2051	-	-	-	-	2,068.9	18,223.1	-	641.4	641.4	91.9	0.14	192,382.4
2052	-	-	-	-	1,903.4	16,257.5	-	590.1	590.1	79.9	0.14	192,462.2
2053	-	-	-	-	1,751.1	14,449.2	-	542.8	542.8	69.4	0.13	192,531.6
2054	-	-	-	-	1,611.0	12,785.5	-	499.4	499.4	60.3	0.12	192,591.9
2055	-	-	-	-	1,482.1	11,254.9	-	459.5	459.5	52.4	0.11	192,644.3
2056	-	-	-	-	1,363.6	9,846.7	-	422.7	422.7	45.5	0.11	192,689.9
2057	-	-	-	-	1,254.5	8,551.2	-	388.9	388.9	39.6	0.10	192,729.4
Total	**-**	**-**	**784,498.0**	**(388,301.0)**	**373,874.4**		**396,197.0**	**(127,293.3)**	**268,903.7**	**192,729.4**		


COMPARATIVE CUMULATIVE REVENUE REQUIREMENT
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Mill Refurbishment vs Replacement Energy Costs
Test 2
Test 3
Test 4
Year

CI Number: 47871

Title: LIN Stack Re-Coating

Start Date:	2018/07
In-Service Date:	2018/08
Final Cost Date:	2019/02
Function:	Steam
Forecast Amount:	$381,034

DESCRIPTION:

The chimney stacks discharge boiler gases from the combustion process in a Thermal Plant. Lingan Generating Station has two chimney stacks that are approximately 152 meters (500ft) high. They are exposed to all coastal winter conditions. The exterior protective coating protects the stacks outer surface from deteriorating. This project is for the replacement of the Lingan North and South chimney stack protective coating from the top of both stacks, down to the 200' level, based on condition assessment.

Summary of Related CIs +/- 2 years
2016 CI 47868 LIN Stack Lighting Replacement $241,895

JUSTIFICATION:

Justification Criteria: Health and Safety

Why do this project?

The Lingan chimney stack protective coating is losing its effectiveness. Over time, moisture from rain water and salt air permeates the surface of the concrete. This moisture can lead to surface spalling (flaking) as a result of freeze-thaw cycles or as the moisture causes the steel reinforcement in the stack to corrode and expand. By replacing the protective coating, the risk of concrete and other materials falling from the stack is minimized, which will reduce safety concerns for personnel and equipment below. An inspection (Attachment 2) has identified a deteriorating condition that poses a safety risk.

Why do this project now?

The protective coating will continue to deteriorate if not replaced in 2018. This continued deterioration can lead to stack structural concrete damage if not addressed. NS Power safely deferred this project in 2016 and 2017 but the protective coating now requires repairs to mitigate safety concerns for personnel.

Why do this project this way?

Replacement of the protective coating is the only option to mitigate the safety risk associated with the deterioration of the stack.

CI Number : 47871 - LIN Stack Re-Coating

Project Number 47871

Parent CI Number : -

Asset Location : 1138 - 1138 Lingan Common Plant

Budget Version 2018 Ace Plan

Capital Item Accounts

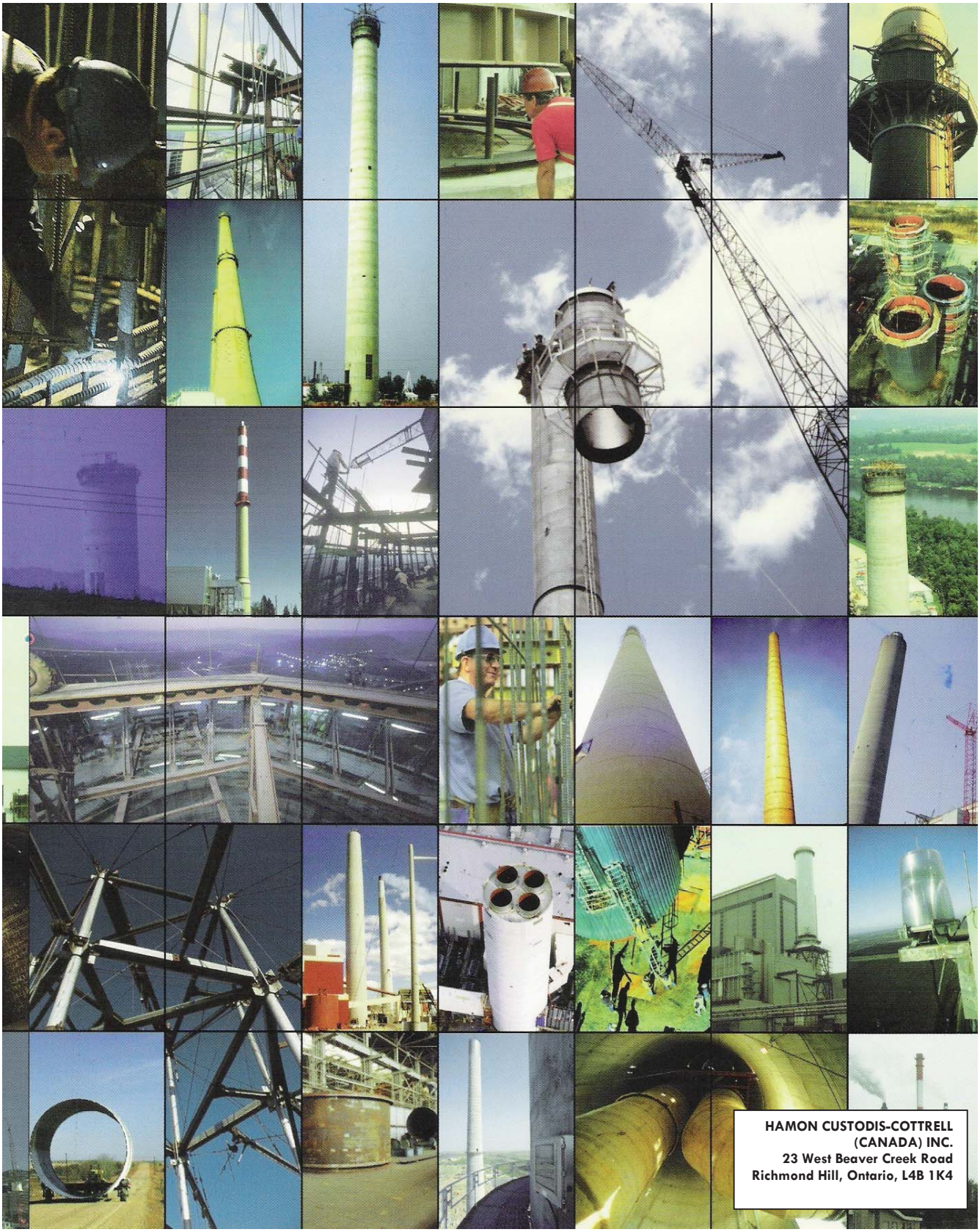
Exp. Type	Utility Account	Forecast Amount
Additions	1700 - SGP - Draft Equip./Stacks	381,034
	Total Cost:	381,034
	Original Cost:	184,935

Capital Project Detailed Estimate

Location: Steam
CI# : 47871
Title: LIN Stack Re-Coating
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Electrician	PD	8	$ 351	$ 2,810		
Engineering	PD	5	$ 397	$ 1,987		
Utility worker	PD	65	$ 235	$ 15,203		
			Sub-Total	$ 20,000		
Term Labour						
Utility worker	PD	65	$ 235	$ 15,203		
			Sub-Total	$ 15,203		
Contracts						
Stack Coating	Lot	1	[redacted]		Cost Support Item #1	
Stack Rigging Inspection	Lot	1				
				$ -		
			Sub-Total	$ 250,976		
Other Goods & Services						
Contingency	%	25%	$ 250,976	$ 62,744		
				$ -		
			Sub-Total	$ 62,744		
Administrative Overhead						
Labour AO				$ 7,733		
Contract AO				$ 24,377		
			Sub-Total	$ 32,111		
			SUB-TOTAL (no AO, AFUDC)	$ 348,923		
			TOTAL (AO, AFUDC included)	$ 381,034		
Original Cost				$ 184,935		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.



Hamon Custodis-Cottrell (Canada) Inc. RFP. P-16-114

Nova Scotia Power-Lingan G.S.

Matt Hannam

FILE. 285-13-14

May 31st 2016

HAMON CUSTODIS-COTTRELL CANADA, INC.

Ref: ***285/13/14*** *May 31, 2016*

NOVA SCOTIA POWER INC.
2599 Hinchey Avenue,
Lingan, Nova Scotia,
B1H 5E6.
Attention: *Matt Hannam | Procurement Lead* *matt.hannam@nspower.ca*

Subject: ***LINGAN GENERATING STATION CHIMNEY PAINTING- UNITS 1&2, 3&4***

Further to your recent request, we are submitting our FIRM pricing for the painting the top 300' of the (2) chimneys at the Lingan Generating Station. This proposal reflects painting ONE chimney at a time. If both chimneys are required to be painted at the same time, there may be a price impact. Please refer to enclosed schedule as part of 11.3 PROJECT PLAN. The scope of work is to consist of the following:

1. Mobilize.
2. Mechanically clean and paint the top 300' of the South chimney with first, primer coat. (Interseal 670HS)
3. Paint the top 300' of the South chimney with a second, top coat, light buff colour. (Interthane 990)
4. Mechanically clean and paint the top 300' of the North chimney with first, primer coat (Interseal 670HS)
5. Paint the top 300' of the North chimney with a second, top coat, light buff colour. (Interthane 990)
6. Demobilize.

PRICE: [redacted]
Complete for labour, equipment and materials.
HST: Not included

PAYMENT: Refer to attached "10HCCC T&C for sale - site work"

CONDITIONS: - The following pricing conditions are to be included on all resulting purchase orders.

a) The prices are based on work performed during normal working hours with the chimney OUT OF OPERATION.

b) The following to be accomplished by the Owner before crew's arrival:
- Leave the access door open to cool down and purge the chimney
- Provide power - 240V, 20A, 1Ph. (3 prong, twist-lock) within 50' of chimney base.

23 West Beaver Creek Road
Unit 2/3
Richmond Hill, Ontario L4B 1K4
Canada

Telephone
905.771.0234
Fax
905.771.9730

E-mail: info.hccc@hamon.com
Web: www.hamon.com

c) Any lost time due to emergency, plant activity including smoke interference or other works by contractors/owner which causes HC crew(s) to be delayed will be charged on a time and material basis.

d) Proposal is subject to review of the terms and conditions or that applicable terms and conditions shall be negotiated by the parties. This proposal is not an acceptance of clients/owners terms and conditions.

e) Protection of Equipment and Property
Owner is responsible to protect or relocate automobiles and/or equipment from airborne particles (i.e. concrete splatter, curing compound, paint, etc.) resulting from chimney construction. HC disclaims any liability due to damage to vehicles or equipment.

f) Owner to provide and remove bin for disposal of empty paint cans and used painting equipment.

****

SAFETY:

*Safety is of prime importance to our Corporation and will not be compromised under any conditions. Ensuring a safe work environment is the responsibility of both the **owner** and the **contractor**. The Industrial Health and Safety Regulations consider the interior of chimneys as **CONFINED SPACE**. Our Corporate Safety Program ensures the provision of trained personnel and specialized equipment for gas monitoring and evacuation of workers.*

All Hamon Custodis employees are trained in FALL ARREST, WHMIS, FIRST AID, CPR, and CONFINED SPACE ENTRY. For inspections, our crews are equipped with the following:

- *Personal protection equipment*
  - *Dust masks*
  - *Safety hats*
  - *Safety boots*
  - *Hearing protection*
  - *Gloves*
  - *Goggles*
- *Safety lines*
- *Fall arrest equipment*
- *Full body harness*
- *Portable lights*
- *Quick descent devices for emergency escape*
- *Emergency air packs*
- *Gas monitors*
- *Communication equipment*

We remain at your service and look forward to hearing from you.

Thank you for considering Hamon Custodis.
Sean Taylor - Sean.Taylor@hamon.com
(905)-771-0234 ext.3
HAMON CUSTODIS COTTRELL CANADA INC.

INSPECTION REPORT

500'-0" Concrete Chimney
Units 3 & 4

Nova Scotia Power
Lingan, NS.

Job No. S-1450/ File No. 285/14
April 2015

Hamon Custodis performed an inspection on the 500'-0" Concrete Chimney (units 3 & 4) in April 2015. The purpose of this inspection was to determine current conditions of the structure. Plant personnel did not express any specific concerns regarding the chimney.

The inspections consisted of visual observations of the exterior of the concrete column from three drops via power climbing equipment rigged from the top of the chimney, three drops in the interior of the steel liner via powered climbing equipment, and three drops in the annulus utilizing powered climbing equipment, platforms, and permanent ladder. A comprehensive set of Ultrasonic Thickness Measurement readings were taken on the steel liner interior wall and are attached in chart form.

Videos were taken and are referenced.

Repairs performed at the time of this inspection:

- None

Section 1: Unit Description

Section 2: Inspection Observations

Section 3: Ultrasonic Thickness Measurements

Section 4: Recommendations

HAMON CUSTODIS
Aftermarket Services
23–2 West Beaver Creek Rd.
Richmond Hill, ON L4B 1K4
ph: 905 771 0234

HAMON CUSTODIS

LINGAN, NS
3&4 CHIMNEY
APRIL 2015
S-1450 / 285/14

Description

Construction:	492'-0" x 24'-7 ¼" Top OD, reinforced concrete column with one independent CSA G40.21.M carbon steel liner. Concrete column is 492'-0" in height with a base OD of 45'-7 ¼". and a top OD of 24'-7 ¼". Column contains a 316L stainless steel weather hood with a stainless steel hatch door. G40.21.M carbon steel liner is 461'-6" x 15'-6" ID. Base of the liner is located at elevation 38'-6". Top 32'-9 ½" of liner is fabricated from 316L stainless steel plate. Liner is supported from foundation by two conical supports anchored into the reinforced concrete foundation at elevation 0'-0". Liner contains 316L stainless steel weather hood at elevation 492' -0".
Ladder:	Annular Space contains a permanent column mounted, galvanized steel ladder with a Latchways V-Xtenda ⅜" safety cable from elevation 0'-0" to 492'-0".
Platforms:	Seven (7) interior (annulus space) platform locations. One (1) 270° CEMS platform at elevation 239'-9"; One (1) full 360° bumper platform at elevation 325'-0"; One (1) full 360° bumper balcony at elevation 469'-0"; One (1) 320° AOL balcony at elevation 482'-0"; Three (3) partial rest platforms at elevations 37'-0", 136'-0", and 360'-6".
Breeching Ducts:	Two (2) 10'-3" x 19'-8 ¼" breeching ducts located North & South, with a bottom sill at elevation 37'-0".
LPS:	Two (2) interior (annulus space) copper downlead cables, North & South. Full length of cables are bare copper with a protective coating applied.
AOL:	Four (4) white flashing obstruction lights at AOL platform, 90° apart, North; East; South; West;, elevation 487'-0".
Access Doors:	6'-0" x 7'-0" double man door in column base, elevation 0'-0", East; 2'-0" X 2'0" breeching access door has been welded and sealed by customer, North; no current access to breeching or liner without cutting a new opening.

Note - This inspection is an indication of the inspector's opinion of the condition of the structure resulting from his best efforts to gain safe access to remote areas of the chimney as of the date of this report. No warranty or guarantee of the conditions described in this report is expressed or implied by the inspector to anyone requesting, authorizing or interested in this report. The inspector, Hamon Custodis, Inc., will not be held liable or responsible for defects not uncovered in the inspection due to obscurity, inaccessibility, and/or changes in the condition of the structure. In addition, this inspection did not include a review pertaining to compliance with any state or local building codes. In no event shall liability extend beyond the fee for services provided.

HAMON CUSTODIS

LINGAN, NS
3&4 CHIMNEY
APRIL 2015
S-1450 / 285/14

Liner: 461'-6" x 15'-6" ID, independent G40.21.M carbon steel liner supported from foundation by two carbon steel, conical supports anchored into the reinforced concrete, foundation at elevation 0'-0" ; Top 32'-9 ½" of liner fabricated from 316L stainless steel; 316L Stainless steel exterior hood, elevation 492'-0"; Test Port penetrations located between elevations 243'-9" & 253'-9"; 2'-0" x 2'-0" Clean-out door located at base; North, has been welded shut. Exterior full height of liner is covered with two (2) layers of 3" insulation with galvanized wire mesh retainer below the weatherhood. Liner protrudes 6'-6" above top of reinforced concrete column and has eight (8), equally spaced lightning rods, ¾" diameter; protruding 4'-0" above top of liner.

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HAMON CUSTODIS

Observations

Concrete Column Exterior:

1. Parged concrete veneer near top of the construction opening has cracked and broken away from areas exposing cinder block wall behind. 20' East. (Ref. video – LinganGS.Exterior.2015.. (1))

2. Numerous areas of "honeycombing" were observed above concrete cold joints at various elevations. This particular honeycombing is a condition that originated at the time of chimney construction and is attributed to poor concrete vibration. Many of these areas contain loose aggregate that is easily removed by hand. This honeycombing in the concrete is an entrance point for rain water into the chimney's annulus. Various elevations, East, South & West. (Ref. video – LinganGS.Exterior.2015.. (2),(3),(4),(17),(18),(30))

3. Six (6) small areas of spalling concrete, approximately 4"x 4" were noticed around a platform window on the west side. Some of the affected areas were found to have loose concrete around the spall. Loose concrete was removed from surrounding areas exposing the horizontal rebar in all six (6) locations. 250' West. (Ref. video – LinganGS.Exterior.2015.. (29))

4. Black, protective paint on a window frame and steel covering on the east side was found to be moderately deteriorated. Paint coverage is estimated to be near 50% with moderate amounts of rusted steel being exposed where paint has peeled and flaked away. 250' East. (Ref. video – LinganGS.Exterior.2015.. (5))

5. Grey paint protecting the concrete shell from elevation 250'-300' is badly stained from rain water and residue from the top of the chimney, however paint coverage is satisfactory with no signs of cracking or peeling in the protective coating. 300' East & West. (Ref. video – LinganGS. Exterior.2015.. (6),(28))

6. Beige paint protecting the concrete shell from elevation 300'-492' was found to be cracked and peeling badly in numerous areas. Initial areas of peeling paint were found at approximately 350' and continued to the 450' elevation with the west side found to have the highest number of affected areas. The protective covering can easily be removed by hand and breaks off in small sheets. The largest area of peeling found during the inspection was approximately 10"x 46". 350'-450' East, South & West. (Ref. video - LinganGS.Exterior.2015.. (8),(9),(10),(19),(20),(21),(24),(25),(26),(27))

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Breeching Ducts:

7. Steel support beams underneath the south breeching duct were observed to have mild paint deterioration near connection plate to concrete shell and along edges of beam flanges. 35' South. (Ref. video – LinganGS.Exterior.2015.. (12))

8. Corrugated steel siding and tin flashing on the bottom of the south breeching duct shows signs of deterioration in small areas around the edges. Heavy rust and scaling were observed in those isolated areas. 35' South. (Ref. video – LinganGS.Exterior.2015.. (13))

9. Top 6'x 2' of corrugated steel siding has completely deteriorated on south-west side of breeching duct exposing insulation underneath and a 6" gap between interior siding. This gap provides a clear view of the west breeching wall and access to the void between the breeching wall and corrugated siding. 60' South. (Ref. video – Lingan.Exterior.2015.. (14))

10. Breeching support Beams in annulus were noticed to have the web of the beams insulated around north breeching duct, however there is no insulation present around the south breeching duct. Two (2) areas, 2'x 4' of the top ply of insulation were also found to be missing underneath the south breeching duct. 35' East & South-West. (Ref. video – LinganGS.Annulus.2015.. (12),(23))

11. Two (2) areas of insulation, approximately 10"x 28" and 10"x 16", are missing on top of the south breeching duct exposing the steel wall underneath. The 10"x 28" area looks to have deteriorated as a result of water dripping from above. 75' East. (Ref. video – LinganGS. Annulus.2015.. (22))

Ladder:

12. The permanent ladder mounted to the interior (annulus) wall from elevation 0'-0" to the top of the column, elevation 492'-0", appears in satisfactory condition. The galvanized coating on the ladder and stand-offs is wearing thin throughout the height of the ladder, leaving behind a light surface rust. At' 65', a single ½" connection bolt was found to be missing. Lights alongside the ladder are not functioning in many locations. Various elevations North. (Ref. video – LinganGS.Annulus.2015.. (24),(25),(26),(37))

13. The Latchways V-Xtenda ⅜" safety cable secured to the permanent ladder was found to be in fine condition and considered up to code and safe for use. In certain locations a minute amount of discolouration was observed on the cable. The discolouration looks to be burn marks, possibly falling slag from hot work performed at higher elevations in the past. 200' North. (Ref. video – LinganGS. Annulus.2015.. (27))

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Platforms:

14. The protective coating covering the steel components on the 270° CEMS platform at the 239'-9" elevation is showing signs of significant deterioration. Paint coverage is estimated at a mere 15-20% and is flaking and peeling in those locations. A moderate amount of rusting, pitting and scaling was observed on platform components such as knee braces, stringers, toeboards and grating. Obsolete power cables were found to be hanging loosely underneath the platform in two locations. 250' East, South-West & North. (Ref. video – LinganGS. Annulus.2015.. (7),(8),(20),(28))

15. The protective coating covering the window frames and steel coverings at the CEMS platform is showing signs of significant deterioration. Paint coverage on the west side window is estimated at approximately 60% whereas the coverage on the north and east windows is negligible, approximately 10%. Moderate-heavy rust and scale were noticeable on unprotected steel. 250' East, North & West. (Ref. video – LinganGS.Annulus.2015.. (29),(30))

16. All platform components on the 360° bumper platform at the 325'-0" elevation are showing little to no signs of deterioration. The galvanized coating is largely intact, platform connections and anchoring are in place and look properly torqued. Mild amounts of wear were noticed on the bumper pads connected to the steel liner. 325' (Ref. video – LinganGS.Annulus.2015.. (5),(17),(32))

17. All balcony components on the 360° bumper balcony at the 469'-0" elevation are showing little to no signs of deterioration. A minimal amount of rust is noticeable on the balcony grating, knee braces, etc., however these rust stains likely originate from the AOL balcony above in which the protective coating is severely deteriorated and the balcony components are showing mild-moderate amounts of rust and scale. Paint coverage on the AOL balcony at 482'-0" is estimated to be 10%. Steel bumpers and bumper pads are showing significant amounts of wear, the steel liner moves notably in high winds, as shown in the video, and creates an enormous impact on this bumper system. 469' East, South-West & North. (Ref. video – LinganGS. Annulus.2015.. (1),(13),(38))

18. All interior lights on the 320° AOL balcony at the 482'-0" elevation were not functioning. The liner insulation and wire mesh retainer is disturbed in large areas along the stiffener ring exposing bare steel. The AOL mounting doors are showing moderate amounts of paint deterioration, mild amounts of rusted steel were visible in unprotected areas. 485'. (Ref. video – LinganGS.Annulus.2015.. (39),(40))

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LPS:

19. The two (2) copper downlead cables (North & South) are in satisfactory condition. The black protective coating on both cables was found to be in fair condition with minimal amounts of deterioration. A single anchor was found to be broken on the south downlead cable at an elevation of 20'. Other interior steel components such as weatherhood, balconies, ladder, platforms, etc. were all observed to be sufficiently grounded into the LPS. Various elevations East, South-West & North. (Ref. video – LinganGS.Annulus .2015.. (11),(21),(31))

AOL:

20. Four (4) aircraft obstruction lights (AOL) located on the North, East, South & West sides of the concrete column at the 487'-0" elevation are all properly mounted with all connecting hardware observed to be in satisfactory condition. The AOL on the North side is not functioning, while the other three are functioning properly. 487'

Access Doors:

21. A 6'-0"x 7'-0" double man door provides access into the annulus on the east side of the concrete shell at 0'-0". The door is in good working condition with minimal amounts of surface rust on the door frame and door itself. 0' East.

22. A 2'-0" x 2'-0" access door into the north breeching duct is shown on the construction drawings at 37'-0". In actuality this door has been welded shut and sealed with a ⅜" steel plate. Since there are no other ways to access the liner, a 2'x 2' hole was cut in the south breeching wall at 37' and promptly welded back into place after the interior inspection. 37' North & South.

23. A 2'-6" x 3'-0" stainless steel roof hatch is located at elevation 492'-0" and is in good working order. The locking mechanism currently being used is a length of chain wrapped around the hatch handle and a ladder rung fastened together by a carabiner. 492' North-West.

Liner Interior:

24. Ultrasonic Thickness measurement readings were taken along the full height of the carbon steel liner plates at regular intervals above and below horizontal weld locations. The Ultrasonic Thickness measurement readings taken identify that the stack plates show minimal to no loss of steel thickness. The chart below provides elevations, orientations, thickness readings and designed plate thickness. Various elevations North, South-East & South-West. (Ref. videos – LinganGS.Interior.2015.. (1),(2),(4),(6),(13),(18),(20),(22), (25))

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LINGAN, NS
3&4 CHIMNEY
APRIL 2015
S-1450 / 285/14

ULTRASONIC MEASUREMENTS

ELEVATION	NORTH	SOUTH EAST	SOUT WEST	DESIGN
70’	.365 & .355	.370 & .365	.360 & .335	.375
85’	.330 & .331	.333 & .337	.331	.375
100’	.325 & .322	.331 & .331	.337>.339	.312
115’	.319	.328	.322	.312
130’	.316 & .312	.319 & .324	.325	.312
145’	.237 & .237	.232 & .242	.240 & .239	.250
160’	.239	.237	.237 & .248	.250
180’	.232 & .235	.229	.235	.250
200’	.227 & .232	.232 & .237	.232 & .227	.250
215’	.229	.234	.240 & .229	.250
230’	.237 & .234	.237 & .237	.230	.250
250’	.223 & .227	.223 & .225	.225 & .237	.250
270’	.230	.229	.232	.250
285’	.227 & .232	.230 & .232	.226 & .231	.250
300’	.232 & .242	.227 & .232	.232 & .237	.250
315’	.228	.235	.239	.250
330’	.232 & .232	.232 & .237	.239	.250
350’	.237 & .240	.229	.232 & .237	.250
370’	.231	.227 & .237	.235	.250
385’	.232	.225	.232	.250

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400’	.237 & .242	.232 & .230	.227 & .237	**.250**
420’	.227	.232	.233 & .237	**.250**
435’	.227 & .232	.228	.230	**.250**
450’	.237 & .232	.232 & .237	.232 & .232	**.250**
465’	.225	.227	.229	**.250**
480’	.27 & .269	.270 & .268	.280 & .273	**.250 -SS**
500’	.278 & .273	.273 & .278	.273 & .282	**.250 -SS**

Decimal		Fraction
.3750	=	3/8”
.3125	=	5/16”
.2500	=	1/4”
.2344	=	15/64”
0.2188	=	7/32”

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25. Horizontal welds were visually inspected at the same intervals as ultrasonic tests were taken. The majority of welds were found to be mildly rusted with slight pitting in and around the weld. No visible signs of excessive wear, cracking or distortion were observed in these areas. Various elevations North, South-East & South-West. (Ref. video – LinganGS.Interior.2015.. (7),(12),(14),(16),(26))

26. The majority of the liner wall is covered in a light, powdery residue with exception of areas in proximity of the breechings, 70'-90' where the wall is covered in an oily residue and at the 500' elevation where the top 2'- 0" has a 6" accumulation. Most of this accumulation is localized on the north side of the liner wall. Various elevations North, South-East & South-West. (Ref. video – LinganGS.Interior.2015.. (3),(9),(17),(19)

27. Minor bulging was observed throughout height of liner. Bulging is localized to areas around plate seams and can be attributed to fitting liner plates together at the time of construction. Various elevations North, South-East & South-West. (Ref. video – LinganGS.Interior. 2015.. (8),(11),(21),(24))

28. Test Probe entering the liner from the CEMS platform at 250' on the north side is in fine condition. The 4" gas sampling port on the south-west side has been filled with insulation while the port on the south-east side is open with a clear view into the annulus. A light accumulation of residue was found inside the port holes and on top of the probe. 250' North, South-East & South-West. (Ref. video – LinganGS.Interior. 2015.. (5),(15),(23)

29. Extreme corrosion of the stainless steel was observed in a 4" ring, completely encircling the very top of the liner wall, elevation 500'-0". A small bulge was found on the north wall at approximately 485'-0". Evidence indicates this bulge possibly originated from complications in fitting the stiffener ring on the exterior liner wall. 495' North & South-East. (Ref. video – LinganGS.Interior.2015.. (10),(27))

Liner Exterior:

30. Insulation and wire mesh retainer were observed during the inspection of the annulus. In general, both were found to be in fine condition with very few locations of broken mesh or disturbed insulation. Various elevations East, South-West & North. (Ref. video – LinganGS.Annulus.2015.. (2),(9),(10),(16))

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Annulus:

31. The annulus area located between the interior of the concrete column and the exterior of the steel liner is in fair condition. Areas with moisture leaking through the concrete are identified throughout the full height of the column at "cold joint" locations. These locations are visible from the white stain they leave on the wall. During a storm fresh rain water can be observed seeping into annulus through these cold joints. Various elevations throughout annulus. (Ref. video – LinganGS.Annulus.2015.. (4),(15),(33))

32. On all three sides that inspections were performed, numerous concrete spall areas were found above the 290'- 0" elevation. Many of these spalls can be attributed to lack of concrete coverage between the inside face of rebar and the form work during the time of construction. Concrete spalling was also observed near cold joints where water has been seeping into the annulus from the outside. Loose concrete was found in these particular areas since the water affecting the area tends to speed up the spalling process. All loose concrete found was removed at the time of this inspection. Above 290' East, South-West & North. (Ref. video – LinganGS.Annulus.2015. (3),(18),(34),(35),(36))

33. A 500lbs. capacity davit at 265'- 0" was inspected during the south-west inspection drop. The davit is used to hoist material to the CEMS platform and is mounted to the concrete shell on two hinge plates. The steel components of the davit show significant signs of rusting and pitting. A welding rod has been used in place of a cotter pin as the locking mechanism on the upper hinge plate. Anchor bolts are all in place with good embedment and look to be properly torqued. 265' South-West. (Ref. video – LinganGS.Annulus.2015.. (6))

Weatherhood:

34. A thorough inspection was performed on top of the weatherhood at 492'-0", Ultrasonic tests were taken on the exterior liner wall and on the top of the stainless steel plate that makes up the hood. The readings taken identify that the hood plates show minimal to no loss of steel thickness and are provided below. During the inspection significant ice build-up was observed primarily on the north-east side and on lightning rods. Ice was built-up to a maximum of 4" in certain areas. Two (2) lightning points have been removed leaving six (6) left. The top two rungs on the ladder used to access the weatherhood from the AOL balcony are badly deformed and make it difficult to climb into the annulus. 492'. (Ref. video – LinganGS.Exterior.2015.. (33))

35. Looking across to units 1 & 2 it can be seen that all lightning points are in place and look to be solid. The stainless steel hood looks to have a protective coating that is severely deteriorated, the coating on the west side is peeling badly. 492'. (Ref. video – LinganGS.Exterior. 2015.. (23))

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Weatherhood Ultrasonic Measurements

Location	Liner Wall	Design	Hood Plate	Design
North	---	**.187**	.312	**.312**
East	.184 .183	**.187**	.330	**.312**
South	.183	**.187**	.312 .326	**.312**
West	.185	**.187**	.307	**.312**

Decimal		Fraction
.3750	=	3/8"
.3125	=	5/16"
.2500	=	1/4"
.2344	=	15/64"
0.2188	=	7/32"

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Recommendations

Exterior:

1. All flaking and peeling paint should be mechanically removed on units 1&2 chimney and units 3&4 chimney. Two (2) coats of protective paint should be applied from the 280' – 500' elevations on both chimneys to help prevent damage and weathering to the concrete shell and for esthetics.

2. Cut 6" ring away of corroded stainless steel all around top of liner, elevation 500', to prevent pieces from falling.

3. Remove remaining lightning points from 500'. The protruding steel liner and lightning points provides a redundancy in the LPS, therefore the lighting points can be removed. With the ice build-up observed during this inspection, it may cause an increased falling object hazard.

4. Repair areas of missing siding on the West side of the South breeching duct. Exposed breeching areas are subject to weather damage and increased rates of corrosion.

Interior:

5. Install a 3'-0" x 3'-0" clean out door at 37' either on north breeching duct or south duct in order to access interior of liner. Use of a high quality gasket is encouraged to prevent gas leakage.

Annulus:

6. Mechanically remove peeling paint from platform components at 250' and 482'. Apply protective coatings to both platforms to help reduce the effect of rusting and scaling on steel members.

7. Remove obsolete wiring from 250' CEMS platform and tidy up areas where power cords are hanging loosely. This is a working platform and proper housekeeping should be kept in mind.

8. Gaskets should be installed on the four (4) window frames at the 250' CEMS platform to prevent water from seeping in and running down the concrete shell wall.

9. Replace damaged insulation on top on south breeching duct to prevent bare steel from becoming a hot spot and therefore accelerating corrosion in those areas.

10. Replace light bulbs along permanent ladder and at AOL balcony. If lights are non-functional, replace fixtures.

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11. Replace bulb in AOL at 482' on north side. If the AOL is still non-functional, further troubleshooting on this fixture may be required.

12. Replace the top 10' of ladder leading from the AOL balcony at 482' to access the weatherhood at elevation 492'. The top two rungs of this ladder are badly deformed and create a hazard to any persons climbing into the annulus from the weatherhood.

13. Repair all concrete spall areas from the 290' to 492' elevations. The affected areas found during this inspection will continue to spall creating the danger of falling concrete inside the annulus.

14. All leaking "cold joint" areas in the concrete column need to be cleaned of all loose cement and debris, and repaired with the appropriate products to prevent further moisture intrusion.

Exterior and interior inspections should be performed on a regularly scheduled basis or sooner should circumstances dictate. A thorough inspection should be performed to monitor the stack's structural condition and the findings compared to previous inspection reports.

Thank you for choosing Hamon Custodis,
Over 100 Years of Chimney construction.

Sean Taylor
Hamon Custodis-Cottrell Canada, INC.
Sales Representative
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Fax: 905-771-9730
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CI Number: 51839

Title: LIN Coal Plant Structural Refurbishment Phase 4

Start Date: 2018/04
In-Service Date: 2018/08
Final Cost Date: 2019/02
Function: Steam
Forecast Amount: $354,067

DESCRIPTION:

This project is Phase 4 of the refurbishment of the structural system in the Lingan coal reclaim. This project is required as a result of the damage caused by corrosion of the conveyer system over time. The structural refurbishment will address the associated safety concerns related to corrosion damage of the support structures while ensuring the coal handling demands are met in a safe and reliable manner.

Coal is delivered to bunkers in the Lingan Plant through a coal conveyor system. An integral part of the conveyor system is the support structure and roller support system. The conveyor system's structural support has experienced damage over time as a result of the corrosive nature of the coal and the high humidity to which it is subjected. This project will continue the refurbishment of the structural system in the coal reclaim, B coal conveyor, and E gallery.

Phase 1 (completed in 2015) focused on the coal system conveyor support structures mainly in coal reclaim (D belts), and the B belt which travels outside along the coal pile. Phase 2 (completed in 2016), focused on the refurbishment of the structural system in the coal reclaim and crusher building. Phase 3 (completed in 2017) focused primarily on the conveyor structure, roller and roller frame replacements. Phase 4 will continue to the focus on conveyor structure and rollers. It is estimated that this work will continue for the next 3 to 5 years. The work needs to be phased because the coal system is operated daily and the work is aligned with time available during non-operating periods.

Summary of Related CIs +/- 2 years:
2016 CI 47510 LIN Coal Plant Structural Refurbishment Phase 2 $359,425
2017 CI 49427 LIN Coal Plant Structural Refurbishment Phase 3 $365,003
2019 CI TBA LIN Coal Plant Structural Refurbishment Phase 5 $TBD
2020 CI TBA LIN Coal Plant Structural Refurbishment Phase 6 $TBD

JUSTIFICATION:

Justification Criteria: Health & Safety

Why do this project?

Coal is delivered into the Lingan Plant through a coal conveyor system. An integral part of the conveyor system is the support structure and roller support system. The corrosive nature of the coal and the high humidity conditions that exist in the conveyor system galleries, lead to corrosion damage of the support structure over time, resulting in safety concerns. The conveyor support structure must be maintained in good condition in order to allow safe operation of the coal handling equipment and reliable performance of the generating units at Lingan.

This project is being undertaken primarily to address safety concerns, and is secondarily undertaken to maintain unit availability.

Why do this project now?

Based on the deteriorated condition of the structural system, the conveyor support structure must be refurbished to address safety concerns related to the corrosion damage that the support structures have suffered over time. This will allow the coal system to meet the coal handling demands of the plant in a safe and reliable manner. If this project is not completed in 2018, the safe operation of the coal system and reliable supply of coal to the generating units will be at risk.

Why do this project this way?

Refurbishment of the support structure is the only option to allow coal supply to the plant to continue, as a full replacement is not necessary and would require a full plant shutdown. Typically, coal is hoisted one shift per day during off-peak season, which allows for refurbishment work to be conducted on the non-hoisting shifts. Retirement of the structure is not feasible, as the coal system is required to operate all four Lingan units.

CI Number : 51839 - LIN Coal Plant Structural Refurbishment Phase 4 **Project Number** 51839

Parent CI Number : -

Asset Location : 1138 - 1138 Lingan Common Plant **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	1800 - SGP - Fuel Hndlg.Coal	305,280
Retirements	1800 - SGP - Fuel Hndlg.Coal	48,787
	Total Cost:	354,067
	Original Cost:	86,314

Capital Project Detailed Estimate

Location: Steam
CI# : 51839
Title: LIN Coal Plant Structural Refurbishment Phase 4
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
Maintenance Trades	PD	350	$ 365	$ 127,675		
Utility worker	PD	120	$ 240	$ 28,821		
			Sub-Total	$ 156,497		
Term Labor						
Maintenance Trades	PD	80	$ 365	$ 29,183		
				$ -		
			Sub-Total	$ 29,183		
Materials						
Structural Steel	Lot	1	$ 30,000	$ 30,000		49427
Troughing Roller	Lot	600	$ 54	$ 32,640		
Trough Roller Support	Lot	250	$ 217	$ 54,250		
Miscellaneous Consumables	Lot	1	$ 9,000	$ 9,000		
			Sub-Total	$ 125,890		
Interest Capitalized						
AFUDC				$ 1,707		
			Sub-Total	$ 1,707		
Administrative Overhead						
Labor AO				$ 40,790		
			Sub-Total	$ 40,790		
			SUB-TOTAL (no AO, AFUDC)	$ 311,570		
			TOTAL (AO, AFUDC included)	$ 354,067		
Original Cost				$ 86,314		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 51851

Title: LIN CW Screen Refurbishment 2018

Start Date: 2018/04
In-Service Date: 2018/10
Final Cost Date: 2019/04
Function: Steam
Forecast Amount: $350,534

DESCRIPTION:

The scope of this project includes work to be completed on two Cooling Water (CW) screens in 2018, based on condition assessments completed in 2018. There are eight travelling screens (two per unit) at the Lingan Generating Station. The self-cleaning screens remove debris from the incoming seawater before it enters the cooling water (CW) pump and downstream cooling systems, including unit condensers.

The travelling screen assemblies consist of bottom, top and intermediate sections. The bottom section includes the tail sprocket assembly and support structure. The top section is comprised of the drive sprocket assembly and the support structure. The intermediate section spans vertically between the bottom and top sections, and supports the entire structure. The bottom and intermediate sections are submerged in seawater, and the upper sections are wetted components, and in a salt spray environment.

Seasonally, during periods of low seaweed loading in the cooling water intake, screens can be taken out of service and refurbished with no impact to production. Screens are selected for refurbishment based on performance, condition and operational strategy for the unit.

Each generating unit is equipped with two CW travelling screens. Current expectation is that this project will not include the refurbishment of the screens on Unit 2. However, if screens on Unit 2 were found to require refurbishment in 2018, investment on Unit 2 could still be the best option. All four units at Lingan are similar and as such, the components refurbished or replaced on the CW travelling screens can be transferred to any of the other Lingan CW travelling screens when Lingan Unit 2 is retired.

Summary of Related CIs +/- 2 years:
2016 47506 LIN CW Screen Refurbishment 2016 $666,401
2017 49434 LIN CW Screen Refurbishment 2017 $347,062
2019 CI TBD LIN CW Screen Refurbishment 2019 $TBD

JUSTIFICATION:

Justification Criteria: Thermal

Sub Criteria: Equipment Replacement / Refurbishment

Why do this project?

Debris (Eel grass/seaweed) passing through degraded or non-functioning travelling screen panels results in downstream fouling of equipment at CW and Auxiliary CW locations. This increases the risk of unit de-rating or forced outages due to inadequate cooling capacity, particularly during the late summer and fall. The degree of eel grass fouling also results in high mechanical loading on the screens and drive systems and on the circulating water pumps. This high loading causes component failure at the screens and CW pumps and increases the risk of unit derating or forced outages due to insufficient cooling water flow.

This project is being undertaken primarily to prevent unit deratings and preserve the unit's availability, and is secondarily supported by positive economics.

Why do this project now?

The screens have degraded over time due to wear and corrosion and are in need of refurbishment. Completing this project will reduce existing issues with the circulating water system during periods of heavy seaweed and debris. This will reduce the risk of unit de-ratings and subsequent associated replacement energy costs.

Why do this project this way?

The screens operate in a harsh seawater environment and have experienced related corrosion and wear. The most cost effective solution is to replace the corroded and worn components, as opposed to replacing the complete screen assembly. Primary components to be refurbished include the top drives (sprocket refurbishment, bearing replacement, shaft refurbishment, top boot replacement with stainless steel material), intermediate section (guides, supports and screen panels replacement) and lower section (sprocket refurbishment, bearing replacement, shaft refurbishment, bottom boot replacement with stainless steel material).

CI Number : 51851 - LIN CW Screen Refurbishment 2018 **Project Number** 51851

Parent CI Number : -

Asset Location : 1138 - 1138 Lingan Common Plant **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	1400 - SGP - Circ.Water Sys.	325,055
Retirements	1400 - SGP - Circ.Water Sys.	25,478
	Total Cost:	350,534
	Original Cost:	252,621

Capital Project Detailed Estimate

Location: Lingan Generating Station
CI# / FP#: 51851
Title: LIN CW Screen Refurbishment 2018
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Electrician	PD	8	$ 351	$ 2,810		
Maintenance Trades	PD	230	$ 358	$ 82,256		
Utility worker	PD	25	$ 235	$ 5,887		
			Sub-Total	$ 90,953		
Term Labour						
Maintenance Trades	PD	162	$ 358	$ 57,937		
			Sub-Total	$ 57,937		
Materials						
Top boot screen components	lot	2	$ 21,000	$ 42,000		
Screen Section Panels - stainless	lot	2	$ 30,000	$ 60,000		
Bottom Boot screen components	lot	2	$ 19,000	$ 38,000		
			Sub-Total	$ 140,000		49434
Contracts						
Machining	lot	2	$ 10,000	$ 20,000		
			Sub-Total	$ 20,000		
Interest Capitalized						
AFUDC				$ 6,994		
			Sub-Total	$ 6,994		
Administrative Overhead						
Labour AO				$ 32,708		
Contract AO				$ 1,943		
			Sub-Total	$ 34,651		
			SUB-TOTAL (no AO, AFUDC)	$ 308,889		
			TOTAL (AO, AFUDC included)	$ 350,534		
Original Cost				$ 252,621		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

LIN CW Screen Refurbishment 2018
Summary of Alternatives

Division :	Power Production	**Date :**	**17-Nov-17**
Department :	Lingan	**CI Number:**	51851
		Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank (based on PV of RR)	IRR	Disc Pay
A	CW Screen Refurbishment vs Replacement Energy Costs	5.88%	-272,717	163,680	1	34.35%	2.2 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

Recommendation :

NS Power recommends completing this project to avoid unit de-rating or outages due to inadequate cooling capacity.

Notes/Comments :

CW Screen Refurbishment vs Replacement Energy Costs

It is assumed that if a CW screen fails, it can repaired to allow it to operate. If the screen is taken out of service, it is assumed that one CW pump may have to come out of service and it is estimated it may cause generation reduction of 20 MW until a repair is made to return the screen to service.

Test 2

Test 3

Test 4

LIN CW Screen Refurbishment 2018
Summary of Sensitivities

Nova Scotia POWER An Emera Company

Division :	Power Production	**Date :**	**15-Nov-17**
Department :	Lingan	**CI Number:**	51851
		Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	CW Screen Refurbishment vs Replacement Energ	5.88%	-272,717	163,680	1	34.35%	2.2 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

	Alternative Variance on Capital Spend	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	CW Screen Refurbishment vs Replacement Energ	10%	-242,404	139,191	1	27.12%	2.4 years
B	Test 2	10%	0	0	2	#NUM!	0.0 years
C	Test 3	10%	0	0	2	#NUM!	0.0 years
D	Test 4	10%	0	0	2	#NUM!	0.0 years
	Change: **A**		30,313	-24,489	0	-7.23%	0.2 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

	Alternative Variance on Avoided Expenses	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	CW Screen Refurbishment vs Replacement Energ	-10%	-215,132	122,823	1	26.41%	2.5 years
B	Test 2	-10%	0	0	2	#NUM!	0.0 years
C	Test 3	-10%	0	0	2	#NUM!	0.0 years
D	Test 4	-10%	0	0	2	#NUM!	0.0 years
	Change: **A**		57,585	-40,857	0	-7.94%	0.2 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

Alternative Variance on Avoided Expenses - Change in Revenue Requirement	Yrs Delay:	PV of Revenue Requirement 1	PV of Revenue Requirement 2	PV of Revenue Requirement 3	Delay?
	A	94,544	177,436	378,436	No
	B	0	0	0	No
	C	0	0	0	No
	D	0	0	0	No

LIN CW Screen Refurbishment 2018
Avoided Cost Calculations

Division :	Power Production	**Date :**	**15-Nov-17**
Department :	Lingan	**CI Number:**	51851
		Project No. :	

CW Screen Refurbishment vs Replacement Energy Costs

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			89,160	90,943		
Events/Outages (#)	1	1	1	1		
Probability of Occurance (%)	100%	100%	100%	100%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	20.0	20.0				
Duration (Hours or Years)	672	672				
Totals	$26,999	$26,682	$89,160	$90,943	$116,159	$117,625

Total Capital Cost of Alternative	**$350,534**

Test 2

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0

Total Capital Cost of Alternative	**$0**

Test 3

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0

Total Capital Cost of Alternative	**$0**

Test 4

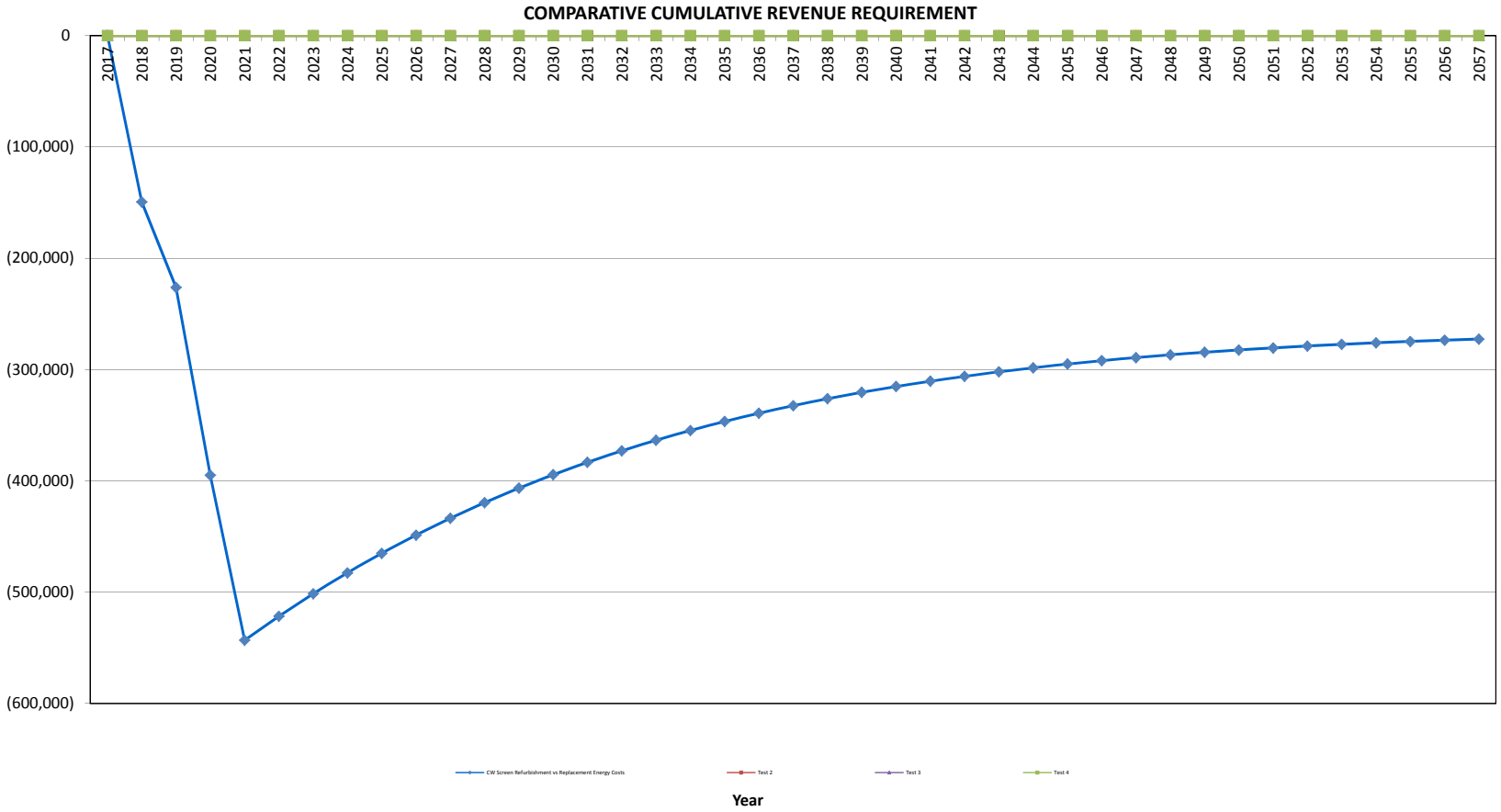
	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0

Total Capital Cost of Alternative	**$0**

LIN CW Screen Refurbishment 2018

CW Screen Refurbishment vs Replacement Energy Costs

Year	Total Revenue	Operating Costs	Avoided Expenses	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	PV of CF	Discount Factor	CNPV
2017	-	-	-	-	-	-	-	-	-	-	1.00	-
2018	-	-	116,159.3	(315,882.9)	12,355.6	306,097.3	(199,723.6)	(32,179.2)	(231,902.8)	(219,024.2)	0.94	(219,024.2)
2019	-	-	117,625.5	-	23,722.7	280,777.9	117,625.5	(29,109.9)	88,515.6	78,957.3	0.89	(140,066.9)
2020	-	-	236,316.2	-	21,824.9	257,484.1	236,316.2	(66,492.3)	169,823.9	143,072.8	0.84	3,005.9
2021	-	-	224,218.5	-	20,078.9	236,053.7	224,218.5	(63,283.3)	160,935.2	128,054.7	0.80	131,060.5
2022	-	-	-	-	18,472.6	216,337.8	-	5,726.5	5,726.5	4,303.5	0.75	135,364.0
2023	-	-	-	-	16,994.8	198,199.2	-	5,268.4	5,268.4	3,739.3	0.71	139,103.3
2024	-	-	-	-	15,635.2	181,511.6	-	4,846.9	4,846.9	3,249.1	0.67	142,352.5
2025	-	-	-	-	14,384.4	166,159.1	-	4,459.2	4,459.2	2,823.2	0.63	145,175.7
2026	-	-	-	-	13,233.6	152,034.7	-	4,102.4	4,102.4	2,453.1	0.60	147,628.8
2027	-	-	-	-	12,174.9	139,040.3	-	3,774.2	3,774.2	2,131.5	0.56	149,760.3
2028	-	-	-	-	11,200.9	127,085.5	-	3,472.3	3,472.3	1,852.1	0.53	151,612.4
2029	-	-	-	-	10,304.9	116,087.0	-	3,194.5	3,194.5	1,609.3	0.50	153,221.7
2030	-	-	-	-	9,480.5	105,968.5	-	2,938.9	2,938.9	1,398.3	0.48	154,620.0
2031	-	-	-	-	8,722.0	96,659.4	-	2,703.8	2,703.8	1,215.0	0.45	155,835.0
2032	-	-	-	-	8,024.3	88,095.0	-	2,487.5	2,487.5	1,055.7	0.42	156,890.8
2033	-	-	-	-	7,382.3	80,215.8	-	2,288.5	2,288.5	917.3	0.40	157,808.1
2034	-	-	-	-	6,791.7	72,966.9	-	2,105.4	2,105.4	797.1	0.38	158,605.2
2035	-	-	-	-	6,248.4	66,297.9	-	1,937.0	1,937.0	692.6	0.36	159,297.8
2036	-	-	-	-	5,748.5	60,162.5	-	1,782.0	1,782.0	601.8	0.34	159,899.6
2037	-	-	-	-	5,288.7	54,517.9	-	1,639.5	1,639.5	522.9	0.32	160,422.5
2038	-	-	-	-	4,865.6	49,324.8	-	1,508.3	1,508.3	454.4	0.30	160,876.9
2039	-	-	-	-	4,476.3	44,547.2	-	1,387.7	1,387.7	394.8	0.28	161,271.7
2040	-	-	-	-	4,118.2	40,151.8	-	1,276.6	1,276.6	343.0	0.27	161,614.7
2041	-	-	-	-	3,788.8	36,108.1	-	1,174.5	1,174.5	298.1	0.25	161,912.8
2042	-	-	-	-	3,485.7	32,387.8	-	1,080.6	1,080.6	259.0	0.24	162,171.8
2043	-	-	-	-	3,206.8	28,965.2	-	994.1	994.1	225.0	0.23	162,396.8
2044	-	-	-	-	2,950.3	25,816.4	-	914.6	914.6	195.5	0.21	162,592.4
2045	-	-	-	-	2,714.2	22,919.4	-	841.4	841.4	169.9	0.20	162,762.3
2046	-	-	-	-	2,497.1	20,254.3	-	774.1	774.1	147.6	0.19	162,909.9
2047	-	-	-	-	2,297.3	17,802.3	-	712.2	712.2	128.3	0.18	163,038.2
2048	-	-	-	-	2,113.5	15,546.5	-	655.2	655.2	111.5	0.17	163,149.7
2049	-	-	-	-	1,944.5	13,471.2	-	602.8	602.8	96.9	0.16	163,246.5
2050	-	-	-	-	1,788.9	11,561.9	-	554.6	554.6	84.2	0.15	163,330.7
2051	-	-	-	-	1,645.8	9,805.3	-	510.2	510.2	73.1	0.14	163,403.8
2052	-	-	-	-	1,514.1	8,189.3	-	469.4	469.4	63.5	0.14	163,467.4
2053	-	-	-	-	1,393.0	6,702.5	-	431.8	431.8	55.2	0.13	163,522.6
2054	-	-	-	-	1,281.6	5,334.7	-	397.3	397.3	48.0	0.12	163,570.5
2055	-	-	-	-	1,179.0	4,076.3	-	365.5	365.5	41.7	0.11	163,612.2
2056	-	-	-	-	1,084.7	2,918.6	-	336.3	336.3	36.2	0.11	163,648.4
2057	-	-	-	-	997.9	1,853.5	-	309.4	309.4	31.5	0.10	163,679.9
Total	**-**	**-**	**694,319.5**	**(315,882.9)**	**297,413.1**		**378,436.6**	**(123,041.0)**	**255,395.6**	**163,679.9**		


COMPARATIVE CUMULATIVE REVENUE REQUIREMENT
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CW Screen Refurbishment vs Replacement Energy Costs
Test 2
Test 3
Test 4
Year

CI Number: C0001419

Title: TRE (Bunker C) HFO Refurbishment Project Phase 1

Start Date: 2018/01
In-Service Date: 2018/10
Final Cost Date: 2019/04
Function: Steam
Forecast Amount: $340,618

DESCRIPTION:

Units 5 and 6 at the Trenton Generating Station have boilers that are front-fired to burn coal, with HFO as a backup. The HFO for both units is stored in an above ground storage tank on site. The storage tank was constructed in 1968, and when filled to capacity, will provide enough fuel for one unit to operate (exclusively on HFO) at full load for approximately six days. Availability of HFO is critical to allow uninterrupted operation of the plant in the event that coal becomes unavailable. Firing HFO can also sustain unit output if solid fuel is wet during winter months.

The Heavy Fuel Oil (HFO) system at the Trenton Generating Station will be refurbished in a phased approach over the next several years because the completing all the work in one year would hamper plant production. Phase 1 of this project will restore full functionality and increase reliability of the HFO system by replacing the steam piping from the plant to the HFO tank suction heaters and rebuilding the Unit 6 HFO pump.

The project includes replacement of the entire steam and condensate line from the plant tie-point, out to the HFO tank suction heaters. The current steam line has degraded such that an increased number of failures would be expected. This phase of the project also includes a rebuild of the Unit 6 HFO forwarding pump, with plans to reuse this pump during the 2019 TRE Bunker C (HFO) System Refurbishment Phase 2 (CI 50632).

The scope of work for Phase 2 is to refurbish a major portion of the Trenton Heavy Fuel Oil (HFO) piping and pumping system. The project would include replacement of the large portion of the pump and piping system from the storage tank containment berm through to the outlet area of the HFO heaters. The major equipment for replacement would be the main oil forwarding pumps, recirculation pump, suction strainers, valves and line heater system components, as well as piping, heat-tracing, instrumentation and controls replacement.

Summary of Related CIs +/- 2 years:
2019 CI 50632 - TRE Bunker C (HFO) Refurbishment Phase 2 - $TBD

JUSTIFICATION:

Justification Criteria: Thermal

Sub Criteria: Equipment Replacement / Refurbishment

Why do this project?

The purpose of this project is to complete replacement work of the HFO steam piping to provide additional heat input to the HFO system and allow it to be pumped properly. The Unit 6 pump rebuild will increase reliability of the system by restoring the pump to like-new operation. This will mitigate reliability risks for ongoing operation of the HFO System.

Why do this project now?

The HFO system at Trenton has become increasingly unreliable in recent years, due to equipment age and degradation. The steam piping is not providing heat to the system as required. If the HFO is not heated properly it can result in flow related issues which lead to increased wear and tear to pumping equipment. Temporary repairs and measures have been made to extend the life, but these are no longer feasible on a go forward. The above failure increases the risk of HFO system unavailability during an unexpected coal interruption.

Why do this project this way?

In the past, when leaks or equipment malfunctions have occurred, temporary repairs have been completed on the HFO system. However, the age and overall condition of the HFO system is such that replacement is the only option. Completion of this particular phase begins to mitigate the risk of failure and also reduces the scope of work required in the next phase when construction is limited by a short unit maintenance outage.

CI Number : C0001419 - TRE (Bunker C) HFO Refurbishment Project Phase 1 **Project Number** C0001419

Parent CI Number : -

Asset Location : 1168 - 1168 Trenton Common Property **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	1900 - SGP - Fuel Hndlg.Oil	335,739
Retirements	1900 - SGP - Fuel Hndlg.Oil	4,879
	Total Cost:	340,618
	Original Cost:	49,624

Capital Project Detailed Estimate

Location: Trenton Generating Station
CI# : C0001419
Title: TRE (Bunker C) HFO Refurbishment Project Phase 1
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
Electrician	PD	14	$ 358	$ 5,016		
Maintenance Trades	PD	15	$ 365	$ 5,472		
Power Plant Technician	PD	6	$ 382	$ 2,293		
Engineering	PD	15	$ 405	$ 6,080		
			Sub-Total	$ 18,860		
Travel Expense						
Site Visits	Lot	1	$ 2,000	$ 2,000		
			Sub-Total	$ 2,000		
Materials						
HFO Pump (#6 rebuild)	Lot	1	$ 5,000	$ 5,000		
Valves, Meters, Pipe Accessories	Lot	1	$ 4,000	$ 4,000		
Piping	Lot	1	$ 20,000	$ 20,000		
Electrical Components and Cable	Lot	1	$ 2,500	$ 2,500		
Instrumentation Components	Lot	1	$ 1,500	$ 1,500		
Controls	Lot	1	$ 2,000	$ 2,000		
Civil / Structural	Lot	1	$ 5,000	$ 5,000		
Heat Trace & Insulation	Lot	1	$ 25,000	$ 25,000		
Insulation	Lot	1	$ 16,119	$ 16,119		
				$ -		
			Sub-Total	$ 81,119		
Contracts						
Constr - Mobilization / Demob	Lot	1	$ 10,000	$ 10,000		
Constr - Piping / Mechanical / OH	Lot	1	$ 33,600	$ 33,600		
Constr - Civil / Structural	Lot	1	$ 8,000	$ 8,000		
Constr - Heat Trace	Lot	1	$ 25,000	$ 25,000		
Constr - Insulation	Lot	1	$ 56,000	$ 56,000		
Constr - Supervision/Commissioning	Lot	1	$ 25,000	$ 25,000		
Constr - Commissioning Field Support	Lot	1	$ 10,000	$ 10,000		
			Sub-Total	$ 167,600		
Consulting						
Eng. - Detailed Design	Lot	1	$ 15,000	$ 15,000		
Constr - Engineering Support	Lot	1	$ 2,000	$ 2,000		
			Sub-Total	$ 17,000		
Meals & Entertainment						
Site Visits	Lot	1	$ 500	$ 500		
				$ -		
			Sub-Total	$ 500		
Other Goods & Services						
Contingency	%	10%	$ 287,079	$ 28,708		
				$ -		
			Sub-Total	$ 28,708		
Interest Capitalized						
AFUDC				$ 4,408		
				$ -		
			Sub-Total	$ 4,408		
Administrative Overhead						
Labor AO				$ 4,143		
Contracts AO				$ 16,279		
			Sub-Total	$ 20,422		
			SUB-TOTAL (no AO, AFUDC)	$ 315,787		
			TOTAL (AO, AFUDC included)	$ 340,618		
Original Cost				$ 49,624		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 51804

Title: LIN ACW Duplex Strainer Replacement

Start Date: 2018/05
In-Service Date: 2018/08
Final Cost Date: 2019/02
Function: Steam
Forecast Amount: $333,808

DESCRIPTION:

This project will replace the duplex auxiliary circulating water (ACW) strainers on Lingan Units 3 and 4, which are required to provide back-up service to the automated self-cleaning strainers. The ACW strainers provide treated seawater for cooling of different applications and are integral to and maximizing unit availability and performance.

Summary of Related CIs +/- 2 years:
No other projects in 2016, 2017, 2018, 2019 and 2020

JUSTIFICATION:

Justification Criteria: Thermal

Sub Criteria: Equipment Replacement / Refurbishment

Why do this project?

Problems have occurred with the ACW strainers allowing debris to pass through the filter and plug off the ACW coolers; starving the cooling water supply and preventing the cooling of critical pieces of equipment such as the turbine lube oil. Although the strainers are primarily back-ups for the automated self-cleaning strainers, they are required to supplement in the summer and fall when there are large quantities of organic debris, and to provide primary straining capabilities when servicing the automated self-cleaning strainers. This project will increase the reliability of the station by providing a more reliable and low-maintenance ACW supply.

This project is primarily justified on unit reliability, but secondarily supported by positive economics.

Why do this project now?

This project must be completed in 2018 to reduce the risk of efficiency and production loss due to damaged ACW strainers and plugged ACW coolers. There is evidence of increased organic debris (eel grass) loading on the circulating water system over the last few years related to natural conditions in Lingan Bay and Indian Bay.

Why do this project this way?

Performance continues to degrade with the age of the current ACW strainers. Repairs to the strainers have not been successful in preventing debris from passing through, therefore replacement is necessary at this time. This is the most reliable way to maintain the ACW system at its full capacity.

CI Number : 51804 - LIN ACW Duplex Strainer Replacement **Project Number** 51804

Parent CI Number : -

Asset Location : 1133 - 1133 Lingan Unit 3; Commissioned 1983, 164Mwh **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account		Forecast Amount
Additions	1400 - SGP - Circ.Water Sys.		305,848
Retirements	1400 - SGP - Circ.Water Sys.		27,959
		Total Cost:	333,808
		Original Cost:	218,160

Capital Project Detailed Estimate

Location: Steam
CI# : 51804
Title: LIN ACW Duplex Strainer Replacement
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Engineering	PD	20	$ 405	$ 8,106		
Maintenance Trades	PD	80	$ 365	$ 29,183		
Power Plant Technician	PD	20	$ 382	$ 7,642		
Utility worker	PD	24	$ 240	$ 5,764		
			Sub-Total	$ 50,695		
OT Labour						
Maintenance Trades	PD	32	$ 730	$ 23,346		
			Sub-Total	$ 23,346		
Term Labour						
Maintenance Trades	PD	80	$ 365	$ 29,183		
			Sub-Total	$ 29,183		
Materials						
ACW Strainer	Ea	2	$ 72,000	$ 144,000		41275
Piping and Fittings	Ea	2	$ 15,000	$ 30,000		
			Sub-Total	$ 174,000		
Other Goods & Services						
Contingency	%	20%	$ 174,000	$ 34,800		
			Sub-Total	$ 34,800		
Interest Capitalized						
AFUDC				$ 1,671		
				$ -		
			Sub-Total	$ 1,671		
Administrative Overhead						
Labour AO				$ 20,112		
			Sub-Total	$ 20,112		
			SUB-TOTAL (no AO, AFUDC)	$ 312,025		
			TOTAL (AO, AFUDC included)	$ 333,808		
Original Cost				$ 218,160		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

LIN ACW Duplex Strainer Replacement
Summary of Alternatives

Division :	Power Production	**Date :**	**17-Nov-17**
Department :	Lingan	**CI Number:**	51804
		Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank (based on PV of RR)	IRR	Disc Pay
A	Strainer Replacement vs Replacement Energy Costs	5.88%	-347,337	234,968	1	23.55%	4.8 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

Recommendation :

The plant recommends completing this project to avoid unplanned loss of generation due to a lack of ACW supply.

Notes/Comments :

Strainer Replacement vs Replacement Energy Costs

If the ACW strainer fails inservice and allows debris past the strainers, this could result in plugged equipment coolers and create an overheating scenario, damaging equipment bearings etc. It would take a minimum of 120 hours to return the unit back to service.

Test 2

Test 3

Test 4

LIN ACW Duplex Strainer Replacement
Summary of Sensitivities

Nova Scotia POWER An Emera Company

Division :	Power Production
Department :	Lingan

Date :	**13-Nov-17**
CI Number:	51804
Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Strainer Replacement vs Replacement Energy Co	5.88%	-347,337	234,968	1	23.55%	4.8 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

	Alternative Variance on Capital Spend	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Strainer Replacement vs Replacement Energy Co	10%	-316,503	210,740	1	20.27%	5.3 years
B	Test 2	10%	0	0	2	#NUM!	0.0 years
C	Test 3	10%	0	0	2	#NUM!	0.0 years
D	Test 4	10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		30,834	-24,228	0	-3.28%	0.5 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

	Alternative Variance on Avoided Expenses	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Strainer Replacement vs Replacement Energy Co	-10%	-281,769	187,243	1	19.94%	5.4 years
B	Test 2	-10%	0	0	2	#NUM!	0.0 years
C	Test 3	-10%	0	0	2	#NUM!	0.0 years
D	Test 4	-10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		65,568	-47,725	0	-3.61%	0.6 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

Alternative Variance on Avoided Expenses - Change in Revenue Requirement		PV of Revenue Requirement	PV of Revenue Requirement	PV of Revenue Requirement	Delay?
	Yrs Delay:	1	2	3	
	A	64,912	121,897	184,452	No
	B	0	0	0	No
	C	0	0	0	No
	D	0	0	0	No

LIN ACW Duplex Strainer Replacement
Avoided Cost Calculations

Division :	Power Production	**Date :**	**13-Nov-17**
Department :	Lingan	**CI Number:**	51804
		Project No. :	

Strainer Replacement vs Replacement Energy Costs

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			47,600	49,515		
Events/Outages (#)	1	1	1	1		
Probability of Occurance (%)	100%	100%	100%	100%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	154.0	154.0				
Duration (Hours or Years)	120	120				
Totals	$37,124	$36,688	$47,600	$49,515	$84,724	$86,203
Total Capital Cost of Alternative						$333,808

Test 2

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

Test 3

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

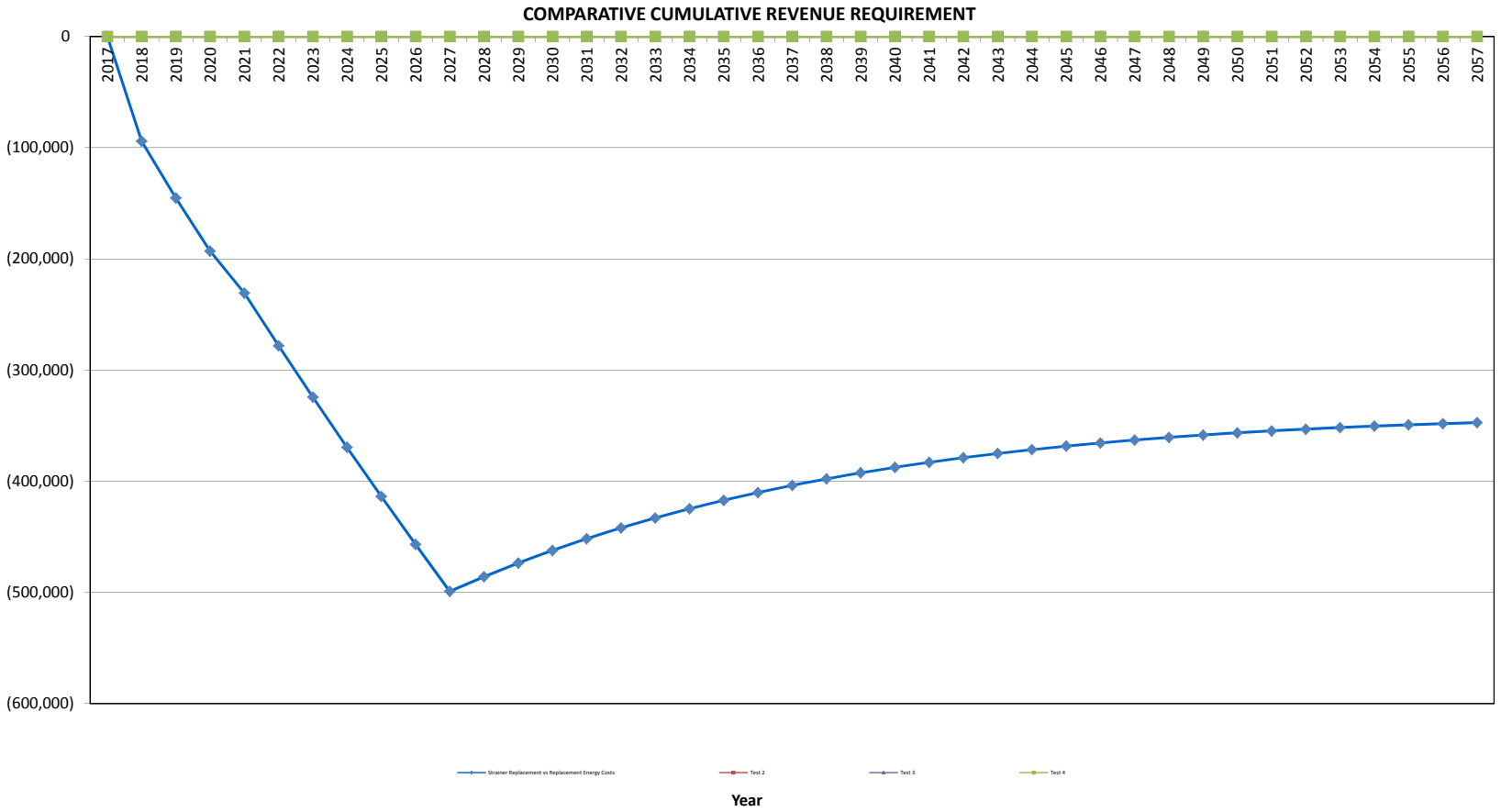
Test 4

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

LIN ACW Duplex Strainer Replacement

Strainer Replacement vs Replacement Energy Costs

Year	Total Revenue	Operating Costs	Avoided Expenses	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	PV of CF	Discount Factor	CNPV
2017	-	-	-	-	-	-	-	-	-	-	1.00	-
2018	-	-	84,724.1	(313,695.5)	12,481.0	305,094.6	(228,971.4)	(22,395.4)	(251,366.8)	(237,407.2)	0.94	(237,407.2)
2019	-	-	86,203.2	-	23,963.5	280,204.4	86,203.2	(19,294.3)	66,908.9	59,683.7	0.89	(177,723.5)
2020	-	-	86,426.7	-	22,046.4	257,305.3	86,426.7	(19,957.9)	66,468.8	55,998.5	0.84	(121,725.1)
2021	-	-	77,630.8	-	20,282.7	236,238.2	77,630.8	(17,777.9)	59,852.9	47,624.4	0.80	(74,100.7)
2022	-	-	94,520.7	-	18,660.1	216,856.5	94,520.7	(23,516.8)	71,003.9	53,359.6	0.75	(20,741.1)
2023	-	-	97,538.7	-	17,167.3	199,025.3	97,538.7	(24,915.1)	72,623.6	51,545.9	0.71	30,804.8
2024	-	-	100,662.5	-	15,793.9	182,620.6	100,662.5	(26,309.3)	74,353.2	49,842.8	0.67	80,647.6
2025	-	-	103,895.9	-	14,530.4	167,528.2	103,895.9	(27,703.3)	76,192.6	48,239.3	0.63	128,886.9
2026	-	-	107,243.1	-	13,368.0	153,643.3	107,243.1	(29,101.3)	78,141.8	46,726.0	0.60	175,612.8
2027	-	-	110,708.4	-	12,298.5	140,869.1	110,708.4	(30,507.1)	80,201.3	45,294.2	0.56	220,907.0
2028	-	-	-	-	11,314.6	129,116.9	-	3,507.5	3,507.5	1,870.9	0.53	222,777.9
2029	-	-	-	-	10,409.5	118,304.9	-	3,226.9	3,226.9	1,625.6	0.50	224,403.5
2030	-	-	-	-	9,576.7	108,357.8	-	2,968.8	2,968.8	1,412.5	0.48	225,816.1
2031	-	-	-	-	8,810.6	99,206.5	-	2,731.3	2,731.3	1,227.4	0.45	227,043.4
2032	-	-	-	-	8,105.7	90,787.3	-	2,512.8	2,512.8	1,066.5	0.42	228,109.9
2033	-	-	-	-	7,457.3	83,041.6	-	2,311.8	2,311.8	926.7	0.40	229,036.5
2034	-	-	-	-	6,860.7	75,915.6	-	2,126.8	2,126.8	805.2	0.38	229,841.7
2035	-	-	-	-	6,311.8	69,359.6	-	1,956.7	1,956.7	699.6	0.36	230,541.3
2036	-	-	-	-	5,806.9	63,328.2	-	1,800.1	1,800.1	607.9	0.34	231,149.2
2037	-	-	-	-	5,342.3	57,779.2	-	1,656.1	1,656.1	528.2	0.32	231,677.5
2038	-	-	-	-	4,914.9	52,674.2	-	1,523.6	1,523.6	459.0	0.30	232,136.4
2039	-	-	-	-	4,521.8	47,977.6	-	1,401.7	1,401.7	398.8	0.28	232,535.2
2040	-	-	-	-	4,160.0	43,656.7	-	1,289.6	1,289.6	346.5	0.27	232,881.8
2041	-	-	-	-	3,827.2	39,681.5	-	1,186.4	1,186.4	301.1	0.25	233,182.9
2042	-	-	-	-	3,521.0	36,024.3	-	1,091.5	1,091.5	261.6	0.24	233,444.5
2043	-	-	-	-	3,239.4	32,659.6	-	1,004.2	1,004.2	227.3	0.23	233,671.8
2044	-	-	-	-	2,980.2	29,564.2	-	923.9	923.9	197.5	0.21	233,869.4
2045	-	-	-	-	2,741.8	26,716.3	-	850.0	850.0	171.6	0.20	234,041.0
2046	-	-	-	-	2,522.4	24,096.4	-	782.0	782.0	149.1	0.19	234,190.1
2047	-	-	-	-	2,320.6	21,686.0	-	719.4	719.4	129.6	0.18	234,319.7
2048	-	-	-	-	2,135.0	19,468.4	-	661.8	661.8	112.6	0.17	234,432.3
2049	-	-	-	-	1,964.2	17,428.2	-	608.9	608.9	97.8	0.16	234,530.1
2050	-	-	-	-	1,807.1	15,551.3	-	560.2	560.2	85.0	0.15	234,615.2
2051	-	-	-	-	1,662.5	13,824.5	-	515.4	515.4	73.9	0.14	234,689.0
2052	-	-	-	-	1,529.5	12,235.8	-	474.1	474.1	64.2	0.14	234,753.2
2053	-	-	-	-	1,407.1	10,774.3	-	436.2	436.2	55.8	0.13	234,809.0
2054	-	-	-	-	1,294.6	9,429.7	-	401.3	401.3	48.5	0.12	234,857.4
2055	-	-	-	-	1,191.0	8,192.6	-	369.2	369.2	42.1	0.11	234,899.5
2056	-	-	-	-	1,095.7	7,054.5	-	339.7	339.7	36.6	0.11	234,936.1
2057	-	-	-	-	1,008.1	6,007.4	-	312.5	312.5	31.8	0.10	234,967.9
Total	**-**	**-**	**949,554.0**	**(313,695.5)**	**300,432.0**		**635,858.5**	**(201,227.8)**	**434,630.7**	**234,967.9**		


COMPARATIVE CUMULATIVE REVENUE REQUIREMENT
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Strainer Replacement vs Replacement Energy Costs
Test 2
Test 3
Test 4
Year

CI Number: 51852

Title: POT Coal Mill Refurbishment 2018

Start Date: 2018/09
In-Service Date: 2018/11
Final Cost Date: 2019/05
Function: Steam
Forecast Amount: $327,267

DESCRIPTION:

Point Tupper Unit 2 has four Raymond Bowl style mills to pulverize coal for combustion in the boiler. One of the four mills has components that have reached the end of their expected useful life and require replacement. Based on experienced wear characteristics, component failures will occur if not replaced. The consequence of such a failure could include unit derating.

This capital item includes the replacement of welded steel rollers and tables with ceramic wear components, and other non-repairable mill components. As part of the planned outage for the mill in 2018, a condition assessment during teardown will determine components to be replaced. In future, additional capital investment of the mills will be required to extend asset life and maintain the reliability of this equipment.

Summary of Related CIs +/- 2 years:
2016 CI 47662 POT - Coal Mill Overhauls 2016 $324,874
2017 CI 49463 POT - Coal Mill Overhauls 2017 $328,410
2019 CI TBD POT Coal Mill Overhauls 2019 $TBD
2020 CI TBD POT Coal Mill Overhauls 2020 $TBD

JUSTIFICATION:

Justification Criteria: Thermal

Sub Criteria: Equipment Replacement / Refurbishment

Why do this project?

This project is being completed to mitigate the risk of mill failure. A mill failure could limit the ability of the unit to generate at full capacity depending on the fuel blend. Mills are required to be available full time between planned outages in order to maintain unit performance at rated capacity.

This project is being undertaken primarily to prevent unit deratings, and is secondarily supported by positive economics.

Why do this project now?

Operating and maintenance experience with the mills has identified several areas of concern that need to be addressed in order for the mills to meet availability targets. Replacement parts are now needed due to age and wear on many of the components. During periods of lower load it is possible to take one of four mills out of service without affecting generation. Isolated repairs and minor refurbishment are not typically possible for the mills. It is often necessary to disassemble major components and therefore an overall refurbishment versus isolated repairs is more effective.

Why do this project this way?

A phased approach to reinvesting in the mills allows for scheduled outages of selected mills and reduces the risk of extended unplanned outages. By planning replacements in a given year, efforts can be made more efficient with dedicated labour and parts available as required.

CI Number : 51852 - POT Coal Mill Refurbishment 2018 **Project Number** 51852

Parent CI Number : -

Asset Location : 1152 - 1152 Point Tupper Unit 2 **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	1800 - SGP - Fuel Hndlg.Coal	283,334
Retirements	1800 - SGP - Fuel Hndlg.Coal	43,933
	Total Cost:	327,267
	Original Cost:	309,864

Location: Pt. Tupper
CI# / FP#: 51852
Title: POT Coal Mill Refurbishment 2018
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Electrician	PD	2	$ 351	$ 703		
Maintenance Trades	PD	40	$ 358	$ 14,305		
Power Plant Technician	PD	10	$ 375	$ 3,746		
Utility worker	PD	50	$ 235	$ 11,773		
			Sub-Total	$ 30,527		
OT Labour						
Electrician	PD	1	$ 703	$ 703		
Maintenance Trades	PD	2	$ 715	$ 1,431		
Power Plant Technician	PD	1	$ 749	$ 749		
Utility worker	PD	1	$ 471	$ 471		
			Sub-Total	$ 3,353		
Term Labour						
Maintenance Trades	PD	100	$ 358	$ 35,763		
			Sub-Total	$ 35,763		
Travel Expense						
Travel	lot	1	$ 1,000	$ 1,000		
			Sub-Total	$ 1,000		
Materials						
Mill rolls	lot	1	$ 33,000	$ 33,000		
Grinding table	lot	1	$ 33,000	$ 33,000		
Rejects table	lot	1	$ 6,000	$ 6,000		
Roll seals	lot	1	$ 2,000	$ 2,000		
Main table seals	lot	1	$ 2,000	$ 2,000		
Riffle boxes	lot	1	$ 6,000	$ 6,000		
Scraper assemblies	lot	2	$ 2,500	$ 5,000		
Mill side liners	lot	1	$ 10,000	$ 10,000		
Rejects side liners	lot	1	$ 10,000	$ 10,000		
Exhauster periphery liners	lot	1	$ 12,000	$ 12,000		
Door assemblies	lot	3	$ 3,000	$ 9,000		
Trunion bushings	lot	1	$ 3,500	$ 3,500		
Bowl ring extension	lot	1	$ 5,000	$ 5,000		
Exhauster fan	lot	1	$ 5,000	$ 5,000		
Exhauster bearings	lot	1	$ 2,000	$ 2,000		
Feeder parts	lot	1	$ 10,000	$ 10,000		
Transition piece	lot	1	$ 15,000	$ 15,000		
Coal pipe	lot	1	$ 6,000	$ 6,000		
Lubricating oil	lot	1	$ 4,500	$ 4,500		
Misc. and consumables	lot	1	$ 10,000	$ 10,000		
			Sub-Total	$ 189,000		
Contracts						
Cranes, etc.	lot	1	$ 3,000	$ 3,000		
			Sub-Total	$ 3,000		
Overtime Meals						
Overtime meals	lot	1	$ 1,000	$ 1,000		
			Sub-Total	$ 1,000		
Freight & Delivery						
Freight (015)	lot	1	$ 5,000	$ 5,000		
			Sub-Total	$ 5,000		
Rentals						
Rentals	lot	1	$ 1,000	$ 1,000		
				$ -		

				Sub-Total	$ 1,000		
	Meals & Entertainment						
	Meals	lot	1	$ 1,000	$ 1,000		
				Sub-Total	$ 1,000		
	Other Goods & Services						
	Contingency	%	15%	$ 266,644	$ 39,997		
					$ -		
				Sub-Total	$ 39,997		
	Interest Capitalized						
	AFUDC				$ 1,404		
				Sub-Total	$ 1,404		
	Administrative Overhead						
	Labour AO				$ 14,931		
	Contract AO				$ 291		
				Sub-Total	$ 15,223		
				SUB-TOTAL (no AO, AFUDC)	$ 310,641		
				TOTAL (AO, AFUDC included)	$ 327,267		
	Original Cost				$ 309,864		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

POT Mill Refurbishment 2018
Summary of Alternatives

Division :	Power Production	**Date :**	**19-Nov-17**
Department :	Pt. Tupper	**CI Number:**	51852
		Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank (based on PV of RR)	IRR	Disc Pay
A	Mill Refurbishment vs Replacement Energy Costs	5.88%	-449,711	300,060	1	52.85%	1.8 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

Recommendation :

This project is recommended to proceed in order to avoid unit deratings.

Notes/Comments :

Mill Refurbishment vs Replacement Energy Costs

The capital costs are for labour and materials to refurbish the coal mill. The likelihood of failure is based on historical experience and that the mill components are high wear items in an erosive environment.

Test 2

Test 3

Test 4

POT Mill Refurbishment 2018
Summary of Sensitivities

Nova Scotia POWER An Emera Company

Division :	Power Production
Department :	Pt. Tupper

Date :	**15-Nov-17**
CI Number:	51852
Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Mill Refurbishment vs Replacement Energy Costs	5.88%	-449,711	300,060	1	52.85%	1.8 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

	Alternative Variance on Capital Spend	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Mill Refurbishment vs Replacement Energy Costs	10%	-418,608	275,964	1	44.75%	2.0 years
B	Test 2	10%	0	0	2	#NUM!	0.0 years
C	Test 3	10%	0	0	2	#NUM!	0.0 years
D	Test 4	10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		31,103	-24,096	0	-8.11%	0.2 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

	Alternative Variance on Avoided Expenses	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Mill Refurbishment vs Replacement Energy Costs	-10%	-373,637	245,958	1	43.94%	2.0 years
B	Test 2	-10%	0	0	2	#NUM!	0.0 years
C	Test 3	-10%	0	0	2	#NUM!	0.0 years
D	Test 4	-10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		76,074	-54,102	0	-8.91%	0.2 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

Alternative Variance on Avoided Expenses - Change in Revenue Requirement		PV of Revenue Requirement	PV of Revenue Requirement	PV of Revenue Requirement	Delay?
	Yrs Delay:	1	2	3	
	A	60,398	198,732	465,779	No
	B	0	0	0	No
	C	0	0	0	No
	D	0	0	0	No

POT Mill Refurbishment 2018
Avoided Cost Calculations

Division :	Power Production	**Date :**	**15-Nov-17**
Department :	Pt. Tupper	**CI Number:**	51852
		Project No. :	

Mill Refurbishment vs Replacement Energy Costs

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			27,090	28,179		
Events/Outages (#)	2	4	2	4		
Probability of Occurance (%)	100%	100%	100%	100%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	50.0	50.0				
Duration (Hours or Years)	72	72				
Totals	$25,848	$60,034	$54,181	$112,715	$80,029	$172,750
Total Capital Cost of Alternative						$327,267

Test 2

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

Test 3

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

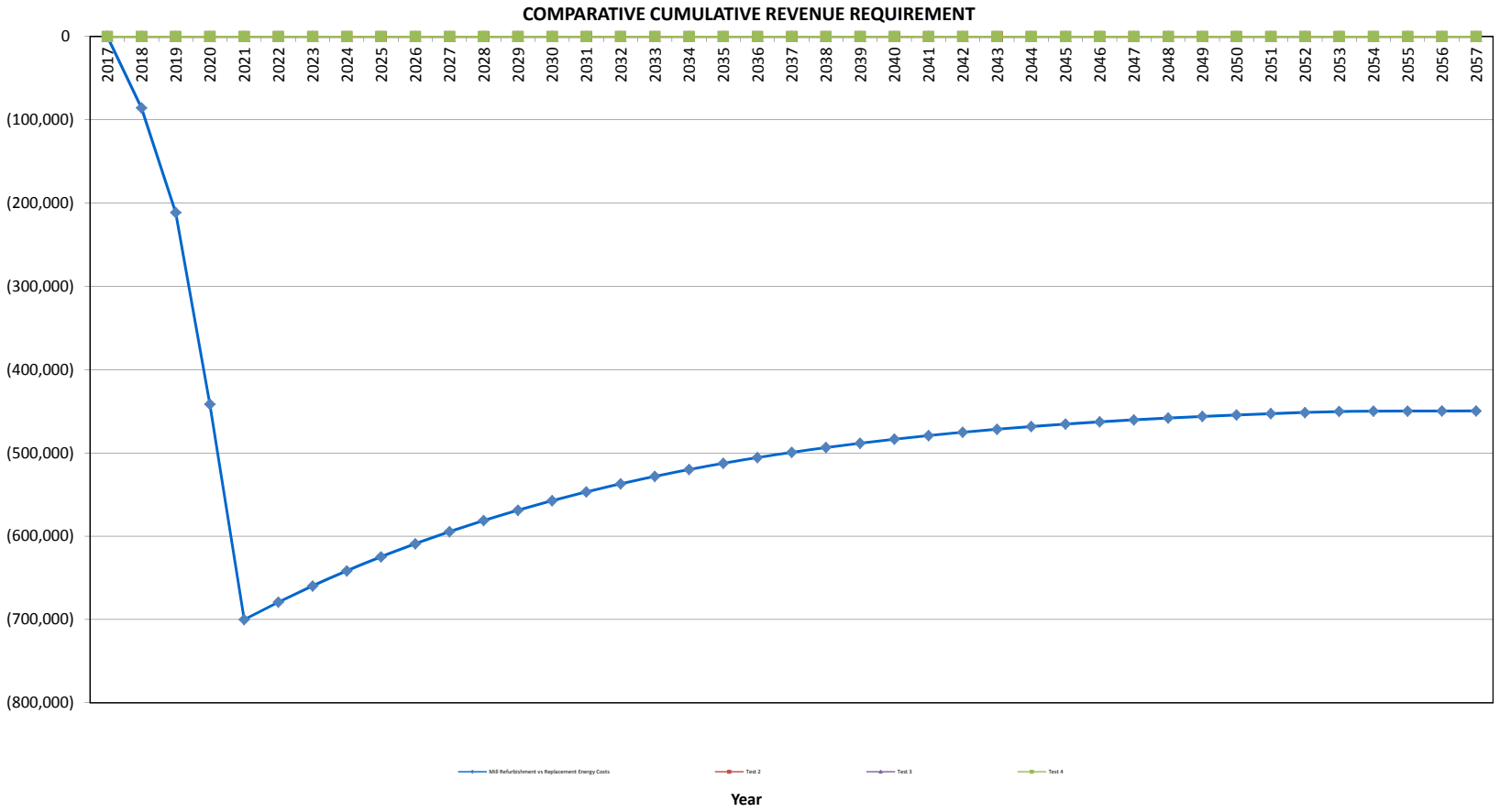
Test 4

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

POT Mill Refurbishment 2018

Mill Refurbishment vs Replacement Energy Costs

Year	Total Revenue	Operating Costs	Avoided Expenses	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	PV of CF	Discount Factor	CNPV
2017	-	-	-	-	-	-	-	-	-	-	1.00	-
2018	-	-	80,028.7	(312,044.5)	12,425.6	302,416.5	(232,015.8)	(20,957.0)	(252,972.8)	(238,924.1)	0.94	(238,924.1)
2019	-	-	172,749.7	-	23,857.2	277,857.8	172,749.7	(46,156.7)	126,593.0	112,922.9	0.89	(126,001.2)
2020	-	-	310,903.9	-	21,948.6	255,263.8	310,903.9	(89,576.1)	221,327.7	186,463.6	0.84	60,462.4
2021	-	-	367,582.0	-	20,192.7	234,477.4	367,582.0	(107,690.7)	259,891.3	206,793.1	0.80	267,255.5
2022	-	-	-	-	18,577.3	215,353.9	-	5,759.0	5,759.0	4,327.9	0.75	271,583.4
2023	-	-	-	-	17,091.1	197,760.2	-	5,298.3	5,298.3	3,760.5	0.71	275,343.9
2024	-	-	-	-	15,723.8	181,574.0	-	4,874.4	4,874.4	3,267.6	0.67	278,611.5
2025	-	-	-	-	14,465.9	166,682.8	-	4,484.4	4,484.4	2,839.2	0.63	281,450.7
2026	-	-	-	-	13,308.7	152,982.8	-	4,125.7	4,125.7	2,467.0	0.60	283,917.7
2027	-	-	-	-	12,244.0	140,378.9	-	3,795.6	3,795.6	2,143.6	0.56	286,061.3
2028	-	-	-	-	11,264.4	128,783.2	-	3,492.0	3,492.0	1,862.6	0.53	287,923.9
2029	-	-	-	-	10,363.3	118,115.2	-	3,212.6	3,212.6	1,618.4	0.50	289,542.3
2030	-	-	-	-	9,534.2	108,300.6	-	2,955.6	2,955.6	1,406.3	0.48	290,948.6
2031	-	-	-	-	8,771.5	99,271.3	-	2,719.2	2,719.2	1,221.9	0.45	292,170.5
2032	-	-	-	-	8,069.8	90,964.2	-	2,501.6	2,501.6	1,061.7	0.42	293,232.2
2033	-	-	-	-	7,424.2	83,321.7	-	2,301.5	2,301.5	922.5	0.40	294,154.8
2034	-	-	-	-	6,830.3	76,290.7	-	2,117.4	2,117.4	801.6	0.38	294,956.4
2035	-	-	-	-	6,283.8	69,822.1	-	1,948.0	1,948.0	696.5	0.36	295,652.9
2036	-	-	-	-	5,781.1	63,871.0	-	1,792.1	1,792.1	605.2	0.34	296,258.1
2037	-	-	-	-	5,318.6	58,395.9	-	1,648.8	1,648.8	525.9	0.32	296,784.0
2038	-	-	-	-	4,893.1	53,358.9	-	1,516.9	1,516.9	456.9	0.30	297,240.9
2039	-	-	-	-	4,501.7	48,724.9	-	1,395.5	1,395.5	397.0	0.28	297,637.9
2040	-	-	-	-	4,141.6	44,461.5	-	1,283.9	1,283.9	345.0	0.27	297,982.9
2041	-	-	-	-	3,810.2	40,539.3	-	1,181.2	1,181.2	299.8	0.25	298,282.7
2042	-	-	-	-	3,505.4	36,930.8	-	1,086.7	1,086.7	260.5	0.24	298,543.2
2043	-	-	-	-	3,225.0	33,611.0	-	999.7	999.7	226.3	0.23	298,769.5
2044	-	-	-	-	2,967.0	30,556.8	-	919.8	919.8	196.7	0.21	298,966.1
2045	-	-	-	-	2,729.6	27,746.9	-	846.2	846.2	170.9	0.20	299,137.0
2046	-	-	-	-	2,511.3	25,161.8	-	778.5	778.5	148.5	0.19	299,285.5
2047	-	-	-	-	2,310.4	22,783.5	-	716.2	716.2	129.0	0.18	299,414.5
2048	-	-	-	-	2,125.5	20,595.5	-	658.9	658.9	112.1	0.17	299,526.6
2049	-	-	-	-	1,955.5	18,582.5	-	606.2	606.2	97.4	0.16	299,624.0
2050	-	-	-	-	1,799.0	16,730.6	-	557.7	557.7	84.6	0.15	299,708.6
2051	-	-	-	-	1,655.1	15,026.8	-	513.1	513.1	73.5	0.14	299,782.2
2052	-	-	-	-	1,522.7	13,459.3	-	472.0	472.0	63.9	0.14	299,846.1
2053	-	-	-	-	1,400.9	12,017.2	-	434.3	434.3	55.5	0.13	299,901.6
2054	-	-	-	-	1,288.8	10,690.5	-	399.5	399.5	48.2	0.12	299,949.8
2055	-	-	-	-	1,185.7	9,469.9	-	367.6	367.6	41.9	0.11	299,991.8
2056	-	-	-	-	1,090.9	8,347.0	-	338.2	338.2	36.4	0.11	300,028.2
2057	-	-	-	-	1,003.6	7,313.9	-	311.1	311.1	31.6	0.10	300,059.8
Total	**-**	**-**	**931,264.2**	**(312,044.5)**	**299,099.4**		**619,219.7**	**(195,971.1)**	**423,248.6**	**300,059.8**		


COMPARATIVE CUMULATIVE REVENUE REQUIREMENT
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Mill Refurbishment vs Replacement Energy Costs
Test 2
Test 3
Test 4
Year

CI Number: 52156

Title: LIN 3&4 Condenser Vacuum Pump Replacement

Start Date: 2018/08
In-Service Date: 2018/09
Final Cost Date: 2019/03
Function: Steam
Forecast Amount: $302,714

DESCRIPTION:

This project is for the replacement of three condenser vacuum pumps. The condenser vacuum pump creates a vacuum in the condenser which removes air and any non-condensable gases and assists in drawing steam through the condenser as it exits the last stage of the low pressure section of the turbine. If the operating vacuum pump fails, or does not work properly, the loss of vacuum on the condenser results in higher unit heat rate as steam cannot exit the turbine at the required rate. There are two vacuum pumps per unit; each pump in good working order is sufficient to operate the unit at full load. An inspection of selected vacuum pumps by the OEM (see Attachment 1) showed that the 4B, 3B and 4A vacuum pumps were only able to operate at approximately 50% of rated capacity due to wear and, as such, must be replaced to restore reliability of the condensing system.

Summary of Related CIs +/- 2 years:
2017 CI 49437 - LIN Vacuum Pump Cooler Refurbishment - $282,034

JUSTIFICATION:

Justification Criteria: Thermal

Sub Criteria: Equipment Replacement / Refurbishment

Why do this project?

Condenser vacuum pumps are critical pieces of equipment and are required to allow the unit to operate efficiently. Three pumps are at or below 50% of rated capacity and must be replaced. If the vacuum pumps are not working properly, there is a loss of efficiency as air and non-condensable gases cannot be removed from the condenser at the required rate, preventing the unit from operating properly. If both pumps fail in the same timeframe, the unit cannot operate until one pump is returned to service.

This project is primarily justified on unit reliability, and secondarily supported by positive economics due to a loss of heat rate efficiency through the poor performance of a degraded vacuum pump.

Why do this project now?

The three pumps identified are operating at or below 50 percent of rated capacity and need to be replaced in 2018 to improve the efficiency and maintain the reliability of the units. All vacuum pumps are interchangeable across the Lingan units.

Why do this project this way?

Refurbishment costs are approximately 75percent of replacement costs, however refurbishment requires the pump to be sent to the vendor for approximately 8 weeks, during which time the associated operating unit will be at risk if the vacuum pump in service fails or trips. Replacement pumps are generally available in stock from the manufacturer, reducing the plant's operating risk. Replacement further mitigates the risk of unit unavailability.

CI Number : 52156 - LIN 3&4 Condenser Vacuum Pump Replacement **Project Number** 52156

Parent CI Number : -

Asset Location : 1134 - 1134 Lingan Unit 4; Commissioned 1984, 160 Mwh **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	1400 - SGP - Circ.Water Sys.	290,013
Retirements	1400 - SGP - Circ.Water Sys.	12,701
	Total Cost:	302,714
	Original Cost:	127,799

Capital Project Detailed Estimate

Location: Steam
CI# : 52156
Title: LIN 3&4 Condenser Vacuum Pump Replacement
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
Electrician	PD	20	$ 351	$ 7,025		
Engineering	PD	2	$ 397	$ 795		
Maintenance Trades	PD	30	$ 358	$ 10,729		
			Sub-Total	$ 18,549		
Term Labor						
Maintenance Trades	PD	15	$ 358	$ 5,365		
				$ -		
			Sub-Total	$ 5,365		
Materials						
Misc. Consumable	Ea.	1	[redacted]			
Condenser Vacuum Pump Replacement	Ea.	3				
			Sub-Total	$ 263,548		
Freight						
Transportation & Shipping	Lot	1	$ 10,000	$ 10,000		
			Sub-Total	$ 10,000		
Administrative Overhead						
Labor AO				$ 5,253		
			Sub-Total	$ 5,253		
			SUB-TOTAL (no AO, AFUDC)	$ 297,461		
			TOTAL (AO, AFUDC included)	$ 302,714		
Original Cost				$ 127,799		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

LIN Condenser Vacuum Pump Replacement
Summary of Alternatives

Division :	Power Production	**Date :**	**19-Nov-17**
Department :	Lingan	**CI Number:**	52156
		Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank (based on PV of RR)	IRR	Disc Pay
A	Pump Replacement vs Replacement Energy Costs	5.88%	-373,854	263,015	1	21.85%	5.4 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

Recommendation :

NS Power recommends replacing the vacuum pumps to ensure reliability of the operating unit.

Notes/Comments :

Pump Replacement vs Replacement Energy Costs

This alternative considers Lingan experiencing a vacuum pump failure where a degraded vacuum pump would have to be operated on the unit, resulting in a loss of 5MW of generation. The likelihood of this occuring will increase over time as the condition of the current pumps deteriorate.

Test 2

Test 3

Test 4

LIN Condenser Vacuum Pump Replacement
Summary of Sensitivities

Nova Scotia POWER An Emera Company

Division :	Power Production	**Date :**	**19-Nov-17**
Department :	Lingan	**CI Number:**	52156
		Project No. :	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Pump Replacement vs Replacement Energy Cost	5.88%	-373,854	263,015	1	21.85%	5.4 years
B	Test 2	5.88%	0	0	2	#NUM!	0.0 years
C	Test 3	5.88%	0	0	2	#NUM!	0.0 years
D	Test 4	5.88%	0	0	2	#NUM!	0.0 years

	Alternative Variance on Capital Spend	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Pump Replacement vs Replacement Energy Cost	10%	-344,352	240,068	1	19.27%	5.9 years
B	Test 2	10%	0	0	2	#NUM!	0.0 years
C	Test 3	10%	0	0	2	#NUM!	0.0 years
D	Test 4	10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		29,503	-22,947	0	-2.59%	0.5 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

	Alternative Variance on Avoided Expenses	Variance (%)	PV of Revenue Requirement	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Pump Replacement vs Replacement Energy Cost	-10%	-306,966	213,767	1	19.01%	6.0 years
B	Test 2	-10%	0	0	2	#NUM!	0.0 years
C	Test 3	-10%	0	0	2	#NUM!	0.0 years
D	Test 4	-10%	0	0	2	#NUM!	0.0 years
	Change:						
	A		66,888	-49,248	0	-2.85%	0.6 years
	B		0	0	0	#NUM!	0.0 years
	C		0	0	0	#NUM!	0.0 years
	D		0	0	0	#NUM!	0.0 years

Alternative Variance on Avoided Expenses - Change in Revenue Requirement		PV of Revenue Requirement	PV of Revenue Requirement	PV of Revenue Requirement	Delay?
	Yrs Delay:	1	2	3	
	A	35,677	81,454	142,158	No
	B	0	0	0	No
	C	0	0	0	No
	D	0	0	0	No

LIN Condenser Vacuum Pump Replacement
Avoided Cost Calculations

Division :	Power Production	**Date :**	**19-Nov-17**
Department :	Lingan	**CI Number:**	52156
		Project No. :	

Pump Replacement vs Replacement Energy Costs

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	1	1	1	1		
Probability of Occurance (%)	60%	80%	60%	80%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	5.0	5.0				
Duration (Hours or Years)	8760	8760				
Totals	$52,793	$69,564	$0	$0	$52,793	$69,564
Total Capital Cost of Alternative						$302,714

Test 2

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

Test 3

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

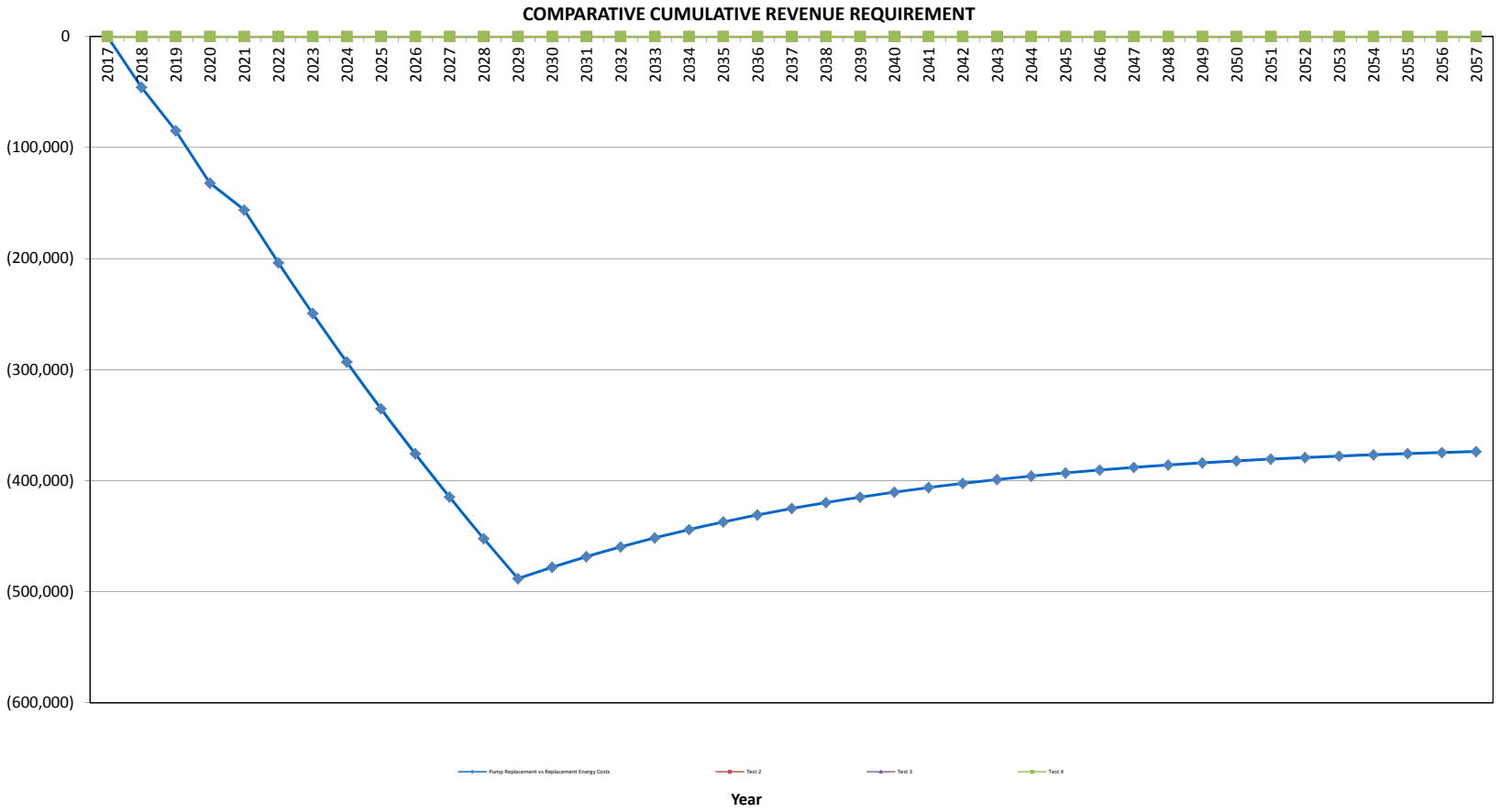
Test 4

	Avoided Replacement Energy Costs		Avoided Unplanned Repair Costs		Total Annual Avoided Costs	
Year	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**
Replacement Energy Cost ($/MWh)	[redacted]					
Repair Cost ($)			0	0		
Events/Outages (#)	0	0	0	0		
Probability of Occurance (%)	0%	0%	0%	0%		
Capacity Factor (%)	[redacted]					
Energy Replaced (MW)	0.0	0.0				
Duration (Hours or Years)	0	0				
Totals	$0	$0	$0	$0	$0	$0
Total Capital Cost of Alternative						$0

LIN Condenser Vacuum Pump Replacement

Pump Replacement vs Replacement Energy Costs

Year	Total Revenue	Operating Costs	Avoided Expenses	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	PV of CF	Discount Factor	CNPV
2017	-	-	-	-	-	-	-	-	-	-	1.00	-
2018	-	-	52,793.3	(297,460.9)	11,898.4	287,012.4	(244,667.6)	(12,677.4)	(257,345.0)	(243,053.4)	0.94	(243,053.4)
2019	-	-	69,564.5	-	22,845.0	263,925.3	69,564.5	(14,483.0)	55,081.5	49,133.5	0.89	(193,919.9)
2020	-	-	82,763.9	-	21,017.4	242,685.2	82,763.9	(19,141.4)	63,622.5	53,600.5	0.84	(140,319.5)
2021	-	-	57,005.0	-	19,336.0	223,144.3	57,005.0	(11,677.4)	45,327.6	36,066.8	0.80	(104,252.7)
2022	-	-	91,927.1	-	17,789.1	205,166.7	91,927.1	(22,982.8)	68,944.3	51,811.8	0.75	(52,440.9)
2023	-	-	93,765.6	-	16,366.0	188,627.3	93,765.6	(23,993.9)	69,771.8	49,521.8	0.71	(2,919.1)
2024	-	-	95,641.0	-	15,056.7	173,411.0	95,641.0	(24,981.1)	70,659.8	47,366.9	0.67	44,447.8
2025	-	-	97,553.8	-	13,852.2	159,412.0	97,553.8	(25,947.5)	71,606.3	45,335.6	0.63	89,783.4
2026	-	-	99,504.9	-	12,744.0	146,533.0	99,504.9	(26,895.9)	72,609.0	43,417.5	0.60	133,200.9
2027	-	-	101,494.9	-	11,724.5	134,684.3	101,494.9	(27,828.8)	73,666.1	41,603.4	0.56	174,804.3
2028	-	-	103,524.8	-	10,786.5	123,783.5	103,524.8	(28,748.9)	74,776.0	39,884.9	0.53	214,689.2
2029	-	-	105,595.3	-	9,923.6	113,754.7	105,595.3	(29,658.2)	75,937.1	38,254.9	0.50	252,944.1
2030	-	-	-	-	9,129.7	104,528.2	-	2,830.2	2,830.2	1,346.6	0.48	254,290.7
2031	-	-	-	-	8,399.3	96,039.9	-	2,603.8	2,603.8	1,170.1	0.45	255,460.8
2032	-	-	-	-	7,727.4	88,230.6	-	2,395.5	2,395.5	1,016.7	0.42	256,477.5
2033	-	-	-	-	7,109.2	81,046.1	-	2,203.9	2,203.9	883.4	0.40	257,360.9
2034	-	-	-	-	6,540.5	74,436.3	-	2,027.5	2,027.5	767.6	0.38	258,128.5
2035	-	-	-	-	6,017.2	68,355.4	-	1,865.3	1,865.3	667.0	0.36	258,795.4
2036	-	-	-	-	5,535.8	62,760.8	-	1,716.1	1,716.1	579.5	0.34	259,375.0
2037	-	-	-	-	5,093.0	57,613.9	-	1,578.8	1,578.8	503.6	0.32	259,878.5
2038	-	-	-	-	4,685.5	52,878.7	-	1,452.5	1,452.5	437.6	0.30	260,316.1
2039	-	-	-	-	4,310.7	48,522.3	-	1,336.3	1,336.3	380.2	0.28	260,696.3
2040	-	-	-	-	3,965.8	44,514.5	-	1,229.4	1,229.4	330.4	0.27	261,026.6
2041	-	-	-	-	3,648.6	40,827.2	-	1,131.1	1,131.1	287.0	0.25	261,313.7
2042	-	-	-	-	3,356.7	37,435.0	-	1,040.6	1,040.6	249.4	0.24	261,563.1
2043	-	-	-	-	3,088.2	34,314.1	-	957.3	957.3	216.7	0.23	261,779.8
2044	-	-	-	-	2,841.1	31,442.9	-	880.7	880.7	188.3	0.21	261,968.1
2045	-	-	-	-	2,613.8	28,801.4	-	810.3	810.3	163.6	0.20	262,131.7
2046	-	-	-	-	2,404.7	26,371.2	-	745.5	745.5	142.2	0.19	262,273.9
2047	-	-	-	-	2,212.3	24,135.4	-	685.8	685.8	123.5	0.18	262,397.4
2048	-	-	-	-	2,035.3	22,078.5	-	631.0	631.0	107.3	0.17	262,504.8
2049	-	-	-	-	1,872.5	20,186.1	-	580.5	580.5	93.3	0.16	262,598.1
2050	-	-	-	-	1,722.7	18,445.2	-	534.0	534.0	81.0	0.15	262,679.1
2051	-	-	-	-	1,584.9	16,843.5	-	491.3	491.3	70.4	0.14	262,749.5
2052	-	-	-	-	1,458.1	15,369.9	-	452.0	452.0	61.2	0.14	262,810.7
2053	-	-	-	-	1,341.5	14,014.2	-	415.9	415.9	53.2	0.13	262,863.9
2054	-	-	-	-	1,234.1	12,767.0	-	382.6	382.6	46.2	0.12	262,910.1
2055	-	-	-	-	1,135.4	11,619.6	-	352.0	352.0	40.1	0.11	262,950.2
2056	-	-	-	-	1,044.6	10,563.9	-	323.8	323.8	34.9	0.11	262,985.1
2057	-	-	-	-	961.0	9,592.7	-	297.9	297.9	30.3	0.10	263,015.4
Total	**-**	**-**	**1,051,134.2**	**(297,460.9)**	**286,409.2**		**753,673.3**	**(237,064.7)**	**516,608.6**	**263,015.4**		


COMPARATIVE CUMULATIVE REVENUE REQUIREMENT
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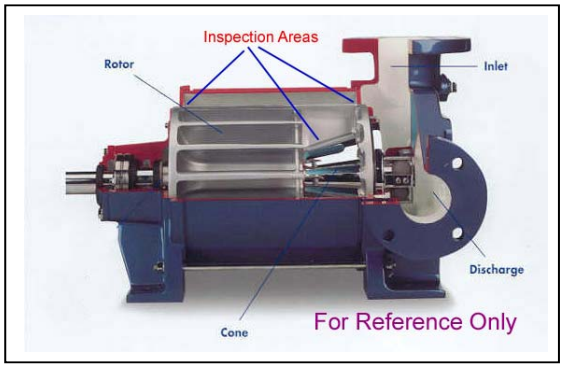
Pump Replacement vs Replacement Energy Costs
Test 2
Test 3
Test 4
Year



May 11th 2017

Nova Scotia Power
Lingan Generating station
2599 Hunchey Ave.
Lingan, NS

Attention : Blair Finlayson

Reference: **Fiber scope inspection of Nash vacuum pumps on Condensers**

Inspection Date: March 28th 2017

Blair,

The following report is based on my findings from a Fiberscope inspection of your Nash Condenser exhaust vacuum pumps. This inspection was performed with the motors locked out utilizing a digital Fiber scope to visually inspect all critical dimensions of the vacuum pumps, and record the digital photographs displayed in this report.

Observations and recommendations: As you will notice with the pictures below, three (3) pumps show signs of wear. I strongly believe this is due to a combination of factors; cavitation, seal water temperature and possibly sea water contamination from the heat exchangers. The rotors are severely worn beyond repair. Cone edges have some wear as well but could possibly be salvaged by means of stainless steel cladding. Some of the units have advanced pitting on the heads and body areas. I strongly recommend investigating the quality of the seal water. (IE: temperatures, PH, possible contamination, etc.) As well, I would review the start-up procedure since I believe on some occasions the pumps are started-up slightly flooded and some units need a constant make up (garden hose for seal water!!!) since the solenoid valves are not functioning properly. I would inspect/ repair these as well and add them to a preventive maintenance program and furthermore, shorten the timeline for the internal videoscope inspections in order to detect any operational issues.

Sincerely,

Eric Sabourin
Nash Field Service Technician
C-450.370.2586
@-Eric.Sabourin@gardnerdenver.com

Pump #	Pump Size	Test/Serial Number	Equipment Number	Service/ Application	Pump RPM	Estimated Capacity	Motor HP
1	AT-2004 E	82U0485	#1 A	Condenser Exhauster Vacuum Pump	500	85-90%	100

Idle end: surface corrosion on all internal surfaces. Clearances between the head shroud and rotor shroud is widening with time & age.

Idle end: pitted head shroud.

Idle end: close-up axial view of a rotor blade on first stage end. Tight clearance at the cone.

2nd stage: good measurement between the cone and rotor, considerable rust on all surfaces.

2nd stage: rotor is in good condition.

Was only able to inspect idle end since the drive end plug was seized and broken.

Pump #	Pump Size	Test/Serial Number	Equipment Number	Service/ Application	Pump RPM	Estimated Capacity	Motor HP
2	AT-2004 E	78U3097	#1 B	Condenser Exhauster Vacuum Pump	500	75-80%	100

Idle end: surfaces are somewhat acceptable, light corrosion but not reducing pump output.

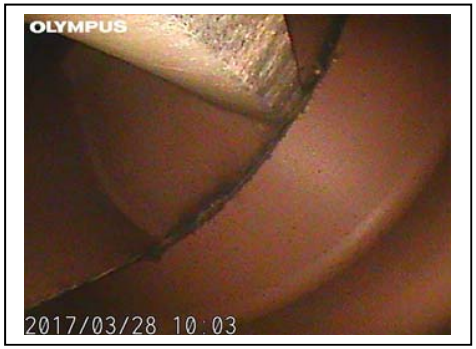
Idle end: clearance is widening between both shrouds, reduced capacity due to this wear.

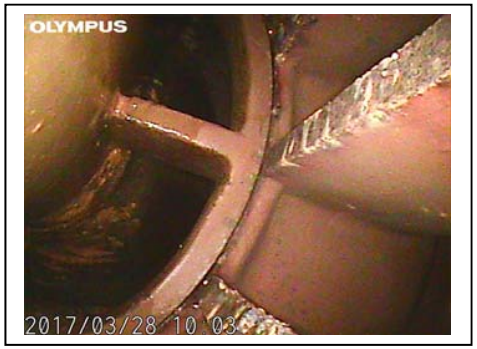
Idle end: start of wear (cavitation?) on backside of rotor blade. To monitor on next inspection.

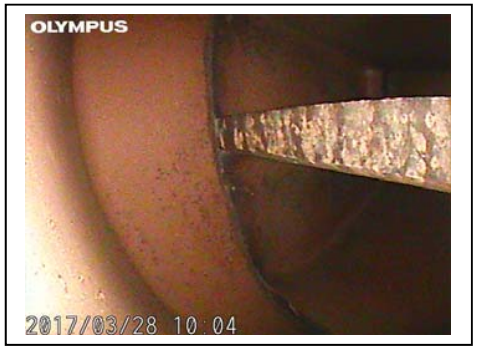
2nd stage: scaling on all surfaces.

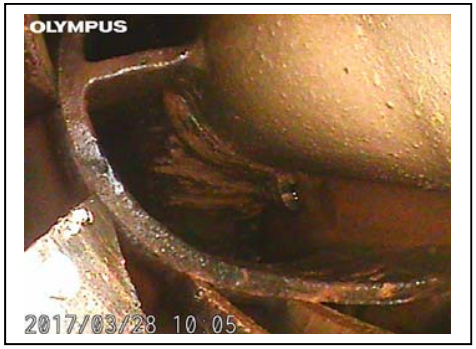
2nd stage: rotor is grooved but tight clearance at the cone.

Pump #	Pump Size	Test/Serial Number	Equipment Number	Service/ Application	Pump RPM	Estimated Capacity	Motor HP
3	AT-2006	132320807 Repaired 2/ 13	#2 B	Condenser Exhauster Vacuum Pump	500	90%	100





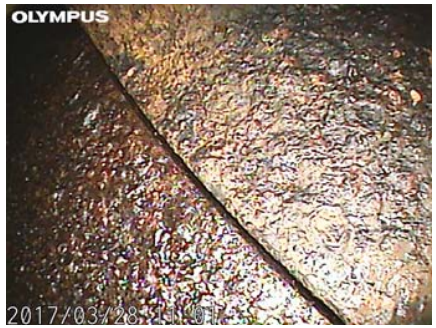




This unit is in near new condition. No wear to report and surfaces are clean and smooth.

Pump #	Pump Size	Test/Serial Number	Equipment Number	Service/ Application	Pump RPM	Estimated Capacity	Motor HP
4	AT-2004 E	79U1285	#3 A	Condenser Exhauster Vacuum Pump	500	80%	100

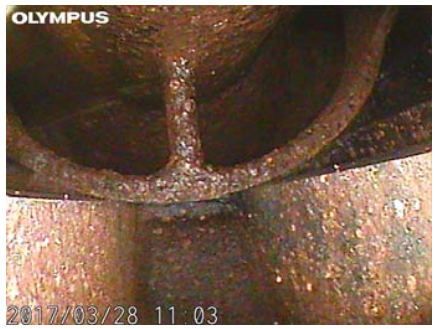
Rotor blades are in acceptable condition. Some pitting and corrosion on the surface but, not greatly reducing performance for now.



Rotor diameter and shroud measurements have reduced from wear. We will monitor on next inspection.

Center shroud clearance s tight.

Pitting has started on the backside of the rotor on the 1st stage. Not alarming for now.



Axial view between two rotor blades in the 1nd stage idle end.. All is good.

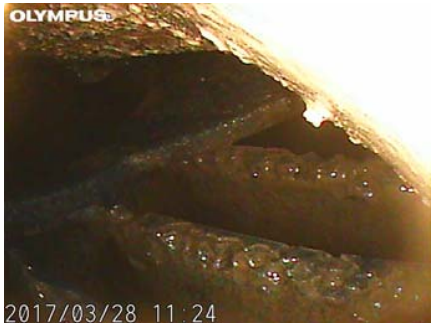
Was not able to inspect the 2nd stage since the inspection plug is broken.

Pump #	Pump Size	Test/Serial Number	Equipment Number	Service/ Application	Pump RPM	Estimated Capacity	Motor HP
5	AT-2006	122205768 Repaired 7/ 12	#4 B	Condenser Exhauster Vacuum Pump	500	**Below 50%**	100

Severe cavitation wear on all rotor blades.

From another angle, blades are completely worn at the tapers.

3 blades are shown here at the taper area. Advanced wear on all blades.



Axial view of worn blades due to cavitation.

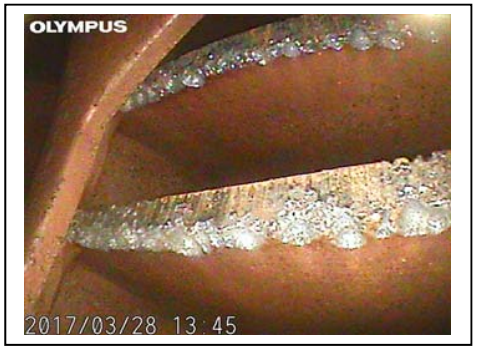
Idle end wear on rotor.

2nd stage rotor has rounded blade tips as well.!!

Pump #	Pump Size	Test/Serial Number	Equipment Number	Service/ Application	Pump RPM	Estimated Capacity	Motor HP
6	AT-2006	15K059102001001 Repaired 2015	#3 B	Condenser Exhauster Vacuum Pump	500	50-60%	100

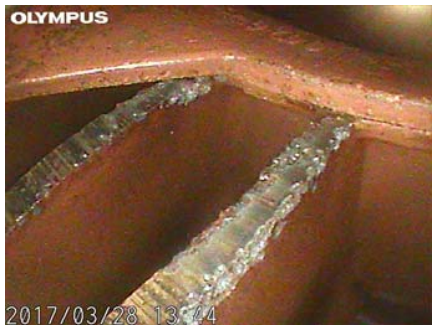
2nd stage rotor is still in near new condition.

Backside of rotor blades are worn from cavitation.



Close-up view of wear on tapers.

Pitted surfaces on the heads and body area. Not severe at this point. Surfaces still have the primmer..!!



Worn blades from cavitation.

Close-up view of jagged edges on rotor blades to the left of the picture.

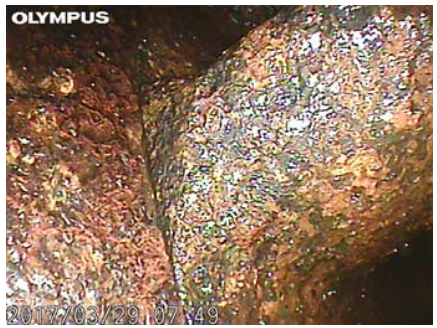
Pump #	Pump Size	Test/Serial Number	Equipment Number	Service/ Application	Pump RPM	Estimated Capacity	Motor HP
7	AT-2004 E	82U3903	#4 A	Condenser Exhauster Vacuum Pump	500	50-60%	100

Worn and pitted rotor blade tip on the OD

Severely pitted blade at the hub location.

Pitted tip and rounded edges on all rotor blades.

An actual piece missing from the blade taper. Worn from cavitation and/ or water quality or Sea water contamination.



2nd stage is severely corroded. Seen here at the shroud of the head.

2nd stage rotor has some wear on the taper.

CI Number: 51860

Title: TRE5 Pulverizer Fuel Line Refurbishment

Start Date: 2018/06
In-Service Date: 2018/07
Final Cost Date: 2019/01
Function: Steam
Forecast Amount: $258,761

DESCRIPTION:

This project will reline the eroded pulverizer fuel (PF) line elbows on Trenton Unit 5, which will improve the level of safety in the mill bay and burner front areas.

Trenton Unit 5 relies on coal as a fuel source. Coal arrives at the plant in a state that requires processing prior to entry into the boiler. Trenton Unit 5 has four solid fuel pulverizers, which supply pulverized fuel (PF) to the boiler burners. Each pulverizer supplies fuel to the four corners of the boiler at one burner level, giving a total of four PF lines per mill, or 16 PF lines per unit. Due to continual exposure to abrasive PF, the interior surfaces of these lines (notably the elbows) have eroded, resulting in reduced wall thickness in areas. When excessive erosion occurs, a hole develops in the pipe. The result is a continuous "spray" of coal dust. This dust can ignite if a source of excessive heat or open flame is present. The dust is also an air contaminant. To avoid the risk of PF leaks, these lines need to be refurbished.

Summary of Related CIs +/- 2 years:
No other projects in 2016, 2017, 2018, 2019 and 2020

JUSTIFICATION:

Justification Criteria: Health and Safety

Why do this project?

Due to continual exposure to abrasive PF, the interior surfaces of these lines have become eroded, resulting in reduced wall thickness in areas. If the lines are not refurbished, the plant risks frequent PF leaks as holes develop in eroded sections of PF lines. Holes in the PF lines results in a "spray" of pulverized coal within the plant. Excessive dust is a lung irritant, as well as an ignition source if excessive heat or open flame is present. The PF line refurbishment will improve the level of safety in the mill bay and burner front areas.

Why do this project now?

The internal erosion in many areas of the PF lines has reached the point where refurbishment is required due to increasing risk of PF leaks. Routine maintenance has been carried out in the past to extend their useful lives but refurbishment is now recommended.

Why do this project this way?

The plant proposes to refurbish the lines by replacing deteriorated sections of PF line. Refurbishment through selective replacement of components is a more cost effective solution than replacing the entire line.

CI Number : 51860 - TRE5 Pulverizer Fuel Line Refurbishment **Project Number** 51860

Parent CI Number : -

Asset Location : 1165 - 1165 Trenton Unit 5; Commissioned 1969, 160 Mwh **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	1800 - SGP - Fuel Hndlg.Coal	227,274
Retirements	1800 - SGP - Fuel Hndlg.Coal	31,487
	Total Cost:	258,761
	Original Cost:	34,390

Capital Project Detailed Estimate

Location: **Trenton Generating Station**
CI# : 51860
Title: TRE5 Pulverizer Fuel Line Refurbishment
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
Maintenance Trades	PD	20	$ 358	$ 7,153		
Power Engineer	PD	2	$ 383	$ 765		
Utility worker	PD	25	$ 235	$ 5,887		
			Sub-Total	$ 13,805		
OT Labor						
Maintenance Trades	PD	4	$ 715	$ 2,861		
Utility worker	PD	2	$ 471	$ 942		
			Sub-Total	$ 3,803		
Term Labor						
Maintenance Trades	PD	150	$ 358	$ 53,645		CI 47875
Utility worker	PD	120	$ 235	$ 28,171		CI 47875
			Sub-Total	$ 81,816		
Materials						
PF Line Replacement Pipe	Lot	1	$ 100,000	$ 100,000		CI 47875
Misc. Consumables and Materials	Lot	1	$ 5,000	$ 5,000		
			Sub-Total	$ 105,000		
Contracts						
Supervision	Lot	1	$ 10,000	$ 10,000		
			Sub-Total	$ 10,000		
OT Meals						
Meals	Lot	1	$ 500	$ 500		
			Sub-Total	$ 500		
Other Goods & Services						
Contingency	%	10%	$ 214,424	$ 21,442		
			Sub-Total	$ 21,442		
Administrative Overhead						
Labor AO				$ 21,424		
Contract AO				$ 971		
			Sub-Total	$ 22,395		
			SUB-TOTAL (no AO, AFUDC)	$ 236,366		
			TOTAL (AO, AFUDC included)	$ 258,761		
Original Cost				$ 34,390		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 52143

Title: LM6000 - 191-332 Hot Section Engine Refurbishment

Start Date: 2018/04
In-Service Date: 2018/05
Final Cost Date: 2018/11
Function: Gas Turbine
Forecast Amount: $1,776,275

DESCRIPTION:

This project includes the hot section refurbishment, through component replacement, of Engine 191-332 from the LM6000 Combustion Turbine Units. Engine 191-332 was first installed in the Tufts Cove Unit 4 enclosure in July 2003.

The hot section refurbishment includes replacements of the following components:

High Pressure Turbine Assembly:
- Stage 1 and 2 disks equipped with blades
- Stage 1 and 2 nozzle assemblies
- Shaft assembly
- Seal assemblies
- Combustor assembly

In addition to the hot section, as the engine is disassembled, components other than the hot section specific materials will be exposed. These will be inspected against OEM and industry experts limits and tolerances to determine if additional refurbishment activities are required.

An LM6000 engine is made up of a hot section (Low Pressure Turbine, High Pressure Turbine and Combuster end of the engine), and a cold section (High Pressure Compressor, Low Pressure Compressor and inlet end of the engine).

A hot section refurbishment was last completed on this engine in 2010. An engine refurbishment completed on 191-332 in 2015 (CI 46713 TUC5 LM6000 – Engine 191-332 Refurbishment, approved by the UARB on April 27, 2015) did not include refurbishment on the components included in this project.

The costs associated with this project have been reduced by [redacted] as a result of commercial negotiations related to CI 47331 LM6000 – 191-253 Engine Refurbishment. NS Power has worked with the OEM to understand Engine 191-253 previous reliability concerns and consequently has reached settlement on a cost reduction for the purchase of hot section components for two LM6000 engines. The two purchases are being completed as part of this project, and as part of CI 52008 LM6000 Engine 191-253 Refurbishment P&A, intended to be filed with the UARB in Q4 2017. Please refer to Confidential Attachment 1 for details on the settlement agreement.

NS Power, along with its third party experts, has experience with the expected costs of most goods and services that are required on the LM6000 units, and is confident that the "unreduced" price, as quoted, was representative of market value. This experience has been gained through prior capital projects on these units, where NS Power has purchased similar engine components. Additionally, NS Power received information from another vendor on the cost of similar components, which provided further confidence that the unreduced price was fair.

Summary of Related CIs +/- 2 years:
2017 CI 52008 LM6000 Engine 191-253 Hot Section Engine Refurbishment P&A $2,291,984

Depreciation Class: Gas Turbines – Tufts Cove CT Unit 4

Estimated Life of the Asset: 8-10 years

JUSTIFICATION:

Justification Criteria: Thermal

Why do this project?

The hot section refurbishment will be completed at this time based on the current equipment condition, forecast unit utilization, and OEM prescribed reinvestment intervals.

The hot section is among the higher stressed areas of the engine due to the temperatures, pressures, and rotational forces to which these components are subjected during operation. As a result of these stresses, the hot section requires refurbishment at shorter intervals than other engine components. This project needs to be completed in order to ensure the engine is in serviceable condition for operation through the next major reinvestment interval.

Why do this project now?

Based on the condition of Engine 191-332, forecast unit utilization, and OEM prescribed reinvestment intervals, NS Power considers this refurbishment to be required in 2018. Additionally, by completing this project in 2018, NS Power is able to take advantage of cost reductions as detailed in the proceeding for CI 47331 and Attachment 1.

Why do this project this way?

Refurbishment of this engine through component replacement is the most cost-effective alternative, as a full engine replacement is significantly more costly and not considered to be required at this time.

CI Number : 52143 - LM6000 - 191-332 Hot Section Engine Refurbishment **Project Number** 52143

Parent CI Number : -

Asset Location : 1174 - 1174 Tufts Cove 4 LM6000, 47 Mwh **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account		Forecast Amount
Additions	3000 - GTG - Gas Turbine Engines		1,769,692
Retirements	3000 - GTG - Gas Turbine Engines		6,583
		Total Cost:	1,776,275
		Original Cost:	907,273

Capital Project Detailed Estimate

Location: Gas Turbine
CI# : 52143
Title: LM6000 - 191-332 Hot Section Engine Refurbishment
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Engineering	PD	12	$ 405	$ 4,864		
Gas Turbine Operators	PD	15	$ 358	$ 5,374		
			Sub-Total	$ 10,238		
OT Labour						
Gas Turbine Operators OT	PD	5	$ 716	$ 3,580		
			Sub-Total	$ 3,580		
Term Labour						
Gas Turbine Operators Term	PD	11	$ 358	$ 3,938		
			Sub-Total	$ 3,938		
Travel Expense						
Travel Expense	Lot	1	$ 5,000	$ 5,000		
			Sub-Total	$ 5,000		
Materials						
GE Supply Hot Section	Lot	1	[redacted]		Cost Support #1	
US to CDN Exchange	%	22%				
GT Disassembly and Reassembly	Lot	1			Cost Support #2 - Item 1	
US to CDN Exchange	%	22%				
Engine Test	Lot	1			Cost Support #2 - Item 5	
US to CDN Exchange	%	22%				
Engine Storage	Lot	1			Cost Support #2 - Item 6	
US to CDN Exchange	%	22%				
			Sub-Total	$ 1,485,350		
Contracts						
Loading and unloading engine	Lot	1	$ 12,000	$ 12,000		
Load Testing Lifting Gear	Lot	1	$ 5,000	$ 5,000		
Scaffolding	Lot	1	$ 15,000	$ 15,000		
			Sub-Total	$ 32,000		
OT Meals						
Gas Turbine Operator OT Meals	Lot	5	$ 15	$ 75		
			Sub-Total	$ 75		
Freight						
Transporting Engine	Lot	1	$ 32,300	$ 32,300		
Transportation of Hot Section	Lot	1	$ 2,000	$ 2,000		
			Sub-Total	$ 34,300		
Consulting						
Shop Supervision	Lot	1	$ 15,000	$ 15,000		
US to CDN Exchange	%	22%	$ 15,000	$ 3,300		
Acuren	Lot	1	$ 15,000	$ 15,000		
			Sub-Total	$ 33,300		
Meals & Entertainment						
Meals	Lot	1	$ 1,000	$ 1,000		
			Sub-Total	$ 1,000		
Other Goods & Services						
Contingency	%	10%	$ 1,608,781	$ 160,878		
			Sub-Total	$ 160,878		
Administrative Overhead						
Labour AO				$ 3,507		
Contracts AO				$ 3,108		
			Sub-Total	$ 6,616		
			SUB-TOTAL (no AO, AFUDC)	$ 1,769,659		
			TOTAL (AO, AFUDC included)	$ 1,776,275		
Original Cost				$ 907,273		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

ACE 2018 CI 52143 Attachment 1
has been removed due to confidentiality.

TRANSCANADA TURBINES

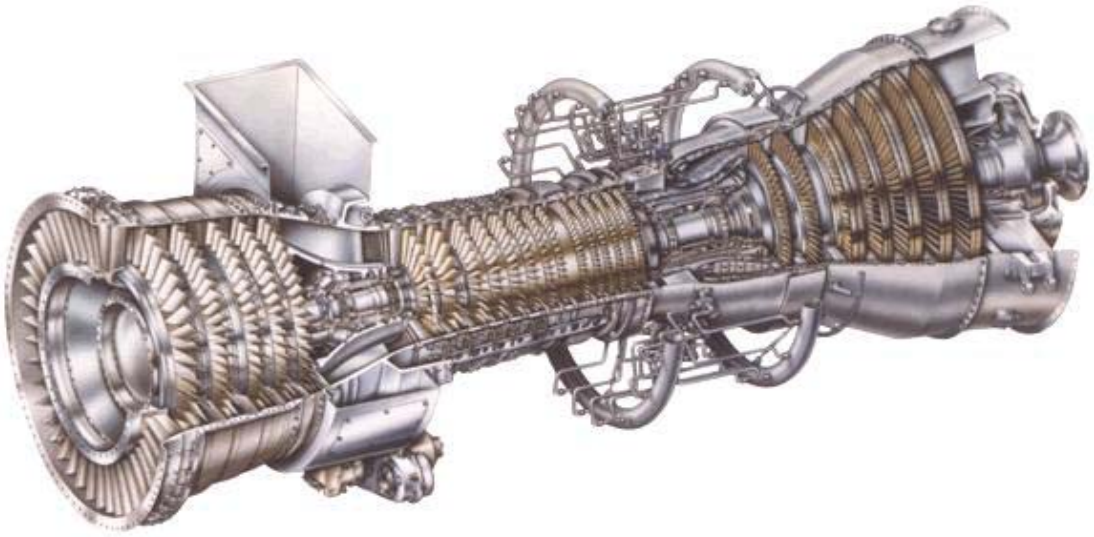
TransCanada Turbines Ltd.
998 Hamilton Boulevard N.E.
Airdrie, Alberta, Canada
T4A 0K8
Telephone: (403) 420-4200
Fax: (403) 420-4300
Toll Free: 1-877-219-5800

Nova Scotia Power

LPT Repairs Engine SN 191-253

Proposal Number: RFQ-17-0116

LM6000PC



Submitted by: TransCanada Turbines
Date: July 27, 2017

TRANSCANADA TURBINES

NSPI

Proprietary Information

This Proposal is issued 'without prejudice' and is the property of TransCanada Turbines. This Proposal contains information that is confidential, privileged, and/or proprietary. This Proposal is intended only for the person or persons who are explicitly addressed below. The Proposal may not be copied or used for any purpose other than that for which it is supplied, in whole or in part, without the express written permission of TransCanada Turbines.

July 27, 2017

Nova Scotia Power
2 Vidito Drive
Dartmouth, NS, Canada, B3B 1P9

To: Mr. Dean Webb

CC: Sharmilla Tymchen
Frank Henry
Marcus Nichols

Subject: LPT Repairs Engine SN 191-253
Proposal: RFQ-17-0116

TransCanada Turbines Ltd. . (TCT) is pleased to provide Nova Scotia Power Inc.(Customer), with this proposal for Depot Work consisting of LPT repairs on Engine SN 191-253 on (1) LM6000 gas turbine..

This proposal has been prepared in good faith, and TransCanada Turbines requests that Nova Scotia Power Inc. hold the contents of this and all supporting documentation confidential. TransCanada Turbines looks forward to working with Nova Scotia Power Inc. Should you have any questions concerning the proposal or the scope of the project, please contact me at the information listed below.

This proposal, RFQ-17-0116 dated July 27, 2017 is valid for 30 days from the date of issuance.

Sincerely,

Ron Inzana

Ron Inzana
Regional Sales Manager Eastern US & Eastern Canada
Email: ron_inzana@tcturbines.com
Phone / Cell: 518-796-0588

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TRANSCANADA TURBINES

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TRANSCANADA TURBINES

NSPI

History of Project

Nova Scotia Power Inc. has just completed SL6000-11-01-R1 and has found the LPT S5 blades on engine S/N 191-253 to be out of limits, which has rendered the engine unserviceable.

Work Scope

1. GT Disassembly and Reassembly
2. Replace hot section with Customer Owned Property (COP)
3. LPT Module Disassembly
4. Rotable Exchange Set of LPT Stage 5 Blades
5. Engine Test
6. Engine Storage (Option)

Project Schedule

Turnaround Time (TAT) using in stock rotables would be thirty (30) days from induction.

Scope of Supply & Pricing

Item	*Qty*	*Description*	***Price***
1	1	GT Disassembly and Reassembly	[redacted]

~ Induct engine into depot and take photos of as-received condition
~ Complete incoming borescope inspection
~ Disassemble GT as required to replace HPT and combustor
~ Includes labor and consumables for GT disassembly and reassembly
~ Work performed per Industrial Repair Manual (IRM) GEK 98492
~ Check balance LPC

Item	*Qty*	*Description*	***Price***
2	1	LPT Module	[redacted]

~ Remove TRF
~ Remove stage 5 disk assembly
~ Replace LPT stage 5 blades with rotable set provided by TCT
~ Rebuild LPT and balance
~ Includes labor and consumables for LPT module reassembly

Item	*Qty*	*Description*	***Price***
3	1	Rotable Exchange Set of LPT Stage 5 Blades	[redacted]

~ TCT will provide rotable set of stage 5 LPT blades in exchange for removed set
~ Rotable set is SB 295 compliant
~ SB 295 – Redesigned LPT Rotor Stage 5 Blade with Improved Durability
~ TCT to retain ownership of removed blades

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TRANSCANADA TURBINES

NSPI

Item	*Qty*	*Description*	***Price***
5	1	Engine Test ~ Engine performance test completed at TCT LM6000 test cell ~ Record test results and analyze with TCT engineering ~ Complete post-test borescope inspection ~ Prepare engine for shipment back to site ~ Price includes labor and fuel	[redacted]

Item	*Qty*	*Description*	***Price***
6	1	Engine Storage ($2,500.00 per/month) ~ Monthly storage fee at TCT Depot ~ Include storage and preservation per WP 3011	[redacted]

Price Items 1, 2, 3, 4 and 5 (Does not include storage Item 6) [redacted]

Additional Notes

Note 1: **Availability**
All required parts, technicians and tooling are subject to availability. Availability must be confirmed by Customer with TCT, prior to the issuance of a purchase order.

Note 2: **Currency**
All quoted amounts are in United States Dollars (USD).

Note 3: **Scrap**
All parts from Customer's engine which are replaced and declared as scrap, will be disposed of by TCT. If Customer wishes to retain any parts declared as scrap, Customer is required to inform TCT prior to the commencement of services. Customer will be responsible for all costs associated with the preservation, crating, shipment and/or storage of these items.

Note 4: **Terms of Payment**
Payment for the Services quote per this Proposal shall be in accordance with Article 5.3 of the pending Master Service Agreement.

Note 5: **Labor Costs**
The labor totals contained within this proposal are estimates only. The actual labor time and cost may be greater or less than the estimated time, based on the condition of the gas turbine.

Note 6: **Taxes and Duties**
All federal, municipal, provincial, state, sales and use tax charges will be the responsibility of the Customer, unless a Tax Exemption Certificate is provided to TCT.

Note 7: **Service Rates for Extra Work**
Any work outside the above listed work scope will be deemed as "extra work" and will be charged per the 2017 Services rates as set forth in Schedule B of the Master Service Agreement.

Note 8: **Reporting**
TCT will assign a project manager at the time of Purchase Order issue. TCT will provide weekly status updates to Customer, including digital photos. An interim report will be delivered to customer approximately 15 days after induction. Interim report will include inspection findings, workscope revisions (as required) and any revisions to the estimated invoice total. Customer will be informed of

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any required or recommended workscope revisions. During the weeks when TCT is awaiting material from subcontractors or building the engine, an e-mail providing status updates will be issued. All of the above will be included in the "Final Report" which TCT will submit to Customer several weeks following the completion of the work and return of the engine. Additionally, TCT can comply with any special reporting requirements of Customer

Note 9: **General Terms and Conditions of Sale**

All works performed pursuant to this Proposal RFQ-17-0116, shall be subject to the terms and conditions set forth in Master Service Agreement pending execution by the parties. In the event of any conflict between the terms and conditions set forth in this proposal, and the Master Service Agreement, the terms in this proposal shall take precedence.

Validity

This proposal is valid for 30 days from July 27, 2017.

Attachments:

A) Master Service Agreement

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CI Number: 51969

Title: 2018 Transmission Right-of-Way Widening 69kV

Start Date: 2018/01
In-Service Date: 2018/01
Final Cost Date: 2019/06
Function Class: Transmission
Forecast Amount: $5,487,686

DESCRIPTION:

This project will widen rights-of-way to reduce the occurrence of edge and off right-of-way tree contacts by increasing the separation between trees and transmission lines. The vegetation management practices performed under NS Power's maintenance program target vegetation within the rights-of-way and maintain existing, sustainable rights-of-way. These activities prevent tree growth from causing outages, but do not address edge or off right-of-way trees.

This is year three of the eight year 69 kV Transmission Right-of-Way Widening Plan accepted by the UARB through the Post Tropical Storm Arthur review process. Increasing the right-of-way width for 69 kV transmission lines to 30-40 meters where possible will significantly reduce the risk of trees contacting power lines during storms. Approximately 240 km of transmission right-of-way is targeted for widening in 2018.

The 69 kV transmission lines and the length of line currently planned for widening in 2018 are shown in the table below. The transmission lines completed can be expected to vary as further inspections, and changes in prioritization occur throughout 2018.

Line #	Length of Line to be Widened (km)
L-5017	26.2
L-5534	12.4
L-5572	16.8
L-5573	19.8
L-5022	22.2
L-5019	6.2
L-5028	30.3
L-5532	28.0
L-5535	35.0
L-5015	31.8
L-5016	11.2
TOTAL	**240.0**

*Costs in table above do not include Labor, Travel & Admin. Overheads

Summary of Related CIs +/- 2 years:
2016 T010 Provincial Transmission Right of Way Widening - $5,999,956
2017 CI 49992 - 2017 Transmission Right of Way Widening 69kV - $5,400,855
2019 CI TBD - 2019 Transmission Right of Way Widening 69kV - $TBD
2020 CI TBD - 2020 Transmission Right of Way Widening 69kV - $TBD

JUSTIFICATION:

Justification Criteria: Transmission Plant

Depreciation Class: –Transmission Plant- Land Rights- Easements

Why do this project?

NS Power's standard right-of-way width for a 69 kV transmission line was 20 meters. Given the power line structure is usually in the centre of the right-of-way, this resulted in a cleared area of 10m on each side of the centre line. The distance between the forest edge and conductor varies, depending on structure type. While this distance provides ample clearance for the safe maintenance and operation of all types of structures, it is not wide enough to prevent many tree species that are tall enough to span the entire right-of-way width from making contact with the power lines when they fall. Increasing the right-of-way width to 30-40 meters, where possible, for 69 kV transmission lines, will significantly reduce the risk of trees contacting the power lines during storms.

Why do this project now?

This is year three of the eight year 69 kV Transmission Right-of-Way Widening Plan. The transmission lines targeted for widening in 2018 are based on the prioritization outlined in the Widening Plan.

This project is deemed in-service when the first transmission right-of-way is widened (January 2018), therefore the Final Cost date (June 2019) is six months after the last right-of-way is completed on this project (December 2018).

Why do this project this way?

Prioritizing the widening of the 69 kV transmission rights-of-way based on customer count and redundancy will provide the largest reliability benefit.

CI Number : 51969 - 2018 Transmission Right-of-Way Widening 69kV **Project Number** 51969

Parent CI Number : -

Asset Location : 1455 - 1455 Transmission Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0200 - TP - Land Rights	5,487,686
	Total Cost:	5,487,686
	Original Cost:	

Capital Project Detailed Estimate

Location: Transmission
CI# / FP#: 51969
Title: 2018 Transmission Right-of-Way Widening 69kV
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
T&D Labor - Site Supervision	PD	206	$ 389	$ 80,000		
			Sub-Total	$ 80,000		
Travel Expense						
Travel		1	$ 10,000.00	$ 10,000		
			Sub-Total	$ 10,000		
Contracts						
Tree Trimming	Lot	1	$ 4,449,670	$ 4,449,670		
			Sub-Total	$ 4,449,670		
Vehicle Overhead						
Vehicle Allocated Costs				$ 32,693		
			Sub-Total	$ 32,693		
Administrative Overhead						
Labor AO				$ 71,042		
Contract AO				$ 844,280		
			Sub-Total	$ 915,323		
			SUB-TOTAL (no AO, AFUDC)	$ 4,539,670		
			TOTAL (AO, AFUDC included)	$ 5,487,686		
Original Cost						

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 51975

Title: 5P Mobile Substation Replacement

Start Date: 2018/01
In-Service Date: 2019/06
Final Cost Date: 2019/12
Function: Transmission
Forecast Amount: $4,829,458

DESCRIPTION:

The scope of this project is to purchase a new 25 MVA (Mega Volt-ampere) mobile substation to replace the 5P mobile substation currently in the NS Power mobile fleet. This type of mobile substation is used for maintenance, capital projects, reactive reliability response and as a back up to the 6P mobile substation. A mobile substation is a trailer mounted transformer with associated equipment that can be deployed on short notice for maintenance or power restoration purposes.

Summary of Related CIs +/- 2 years:
2016 CI 48061 New Mobile Substation 7.5MVA $2,390,744
2017 CI 51956 6P Mobile Substation Rewind $1,516,121

Depreciation Class: Transmission Plant – Station Equipment

Estimated Life of the Asset: 40 Years

JUSTIFICATION:

Justification Criteria: Transmission Plant

Sub Criteria: Equipment Replacement

Why do this project?

NS Power has two 25MVA mobile substations in its mobile fleet (5P and 6P), and it is NS Power's practice to always have one available for reactive deployment. The 5P mobile substation was purchased in 1979 and is nearing the end of its expected useful life. This mobile substation has been increasingly unavailable for periods of time because of trailer repairs, oil leaks and transformer failures. When the 5P mobile is unavailable for use, the 6P mobile substation has to be kept available for reactive reliability response, which can result in the delay of planned capital or maintenance work.

Why do this project now?

This project needs to be completed now to better facilitate maintenance and capital programs as the existing 5P mobile substation is experiencing reliability issues, and to mitigate the risk of a mobile not being available for reactive reliability response.

Why do this project this way?

Purchasing a new mobile substation to replace the 5P mobile is the best option given the age and condition of the existing unit. An alternative to purchasing a new mobile substation to replace 5P would be to rewind the 5P mobile substation transformer. The rewind would be approximately half of the cost of a new mobile substation; however it would only result in a new transformer. All of the many other physical components of the mobile substation would still be near the end of the expected useful life, including the trailer itself.

CI Number : 51975 - 5P Mobile Substation Replacement **Project Number** 51975

Parent CI Number : -

Asset Location : 1455 - 1455 Transmission Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	4400 - TP - Substn.Transf.	4,805,514
Retirements	4400 - TP - Substn.Transf.	23,945
	Total Cost:	4,829,458
	Original Cost:	1,459,193

Capital Project Detailed Estimate

Location: Transmission

CI# : 51975
Title: 5P Mobile Substation Replacement
Execution Year: 2018-2019

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
T&D Labour - PLT	PD	25	$ 372	$ 9,141		
T&D Labour - Design	PD	30	$ 386	$ 11,660		
Procurement / Financial Support	PD	1	$ 4,860	$ 4,860		
T&D Labour - Commissioning	PD	41	$ 372	$ 15,356		
			Sub-Total	$ 41,017		
Materials						
25MVA Mobile Substation c/w RTU and On- Line Gas Monitoring	Lot	1	$ 4,050,000	$ 4,050,000		
			Sub-Total	$ 4,050,000		
Contracts						
Old Transformer and Oil Transport	Lot	1	$ 2,480	$ 2,480		
			Sub-Total	$ 2,480		
Consulting						
Inspection and Witnessing of Tests	Lot	1	$ 40,000	$ 40,000		
			Sub-Total	$ 40,000		
Other Goods & Services						
Contingency	%	10%	$ 4,133,497	$ 413,350		
			Sub-Total	$ 413,350		
Vehicle Overhead						
Vehicle AO				$ 16,762		
				-		
			Sub-Total	16,762		
Interest Capitalized						
AFUDC				$ 228,955		
			Sub-Total	$ 228,955		
Administrative Overhead						
Labour AO				$ 36,424		
Contract AO				$ 471		
			Sub-Total	$ 36,895		
			SUB-TOTAL (no AO, AFUDC)	$ 4,546,847		
			TOTAL (AO, AFUDC included)	$ 4,829,458		
Original Cost				$ 1,459,193		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 52258

Title: 2018/2019 Isolated Transmission Structure Replacements

Start Date: 2018/06
In-Service Date: 2018/08
Final Cost Date: 2020/03
Function Class: Transmission
Forecast Amount: $4,818,521

DESCRIPTION:

This is a multi-year project with work planned to be completed in 2018 and 2019. This program is designed to use helicopters to conduct maintenance work on transmission structures located in isolated or environmentally sensitive areas that are very difficult to access using traditional construction methods. Utilizing helicopters to complete this work will reduce environmental impact and permitting times, reduce equipment and material mobilization challenges, lessen the costs of site access, reduce the planned outage time required to complete maintenance work, and reduce land access challenges. Completion of the maintenance work on these isolated structures using traditional construction methods would require significant resources to build bridges and lay environmental matting to access the structures, adding to project time and costs.

The project scope includes:

L5530B – 36W Green Harbour to 46W Broad River (73 structures):
- Structure Replacements: 10 structures
- Timber/Arm & Insulator Replacements: 57 structures
- Insulator Replacement: 4 structures
- Other Deteriorated Assets: 2 structures

L5549 – 30N Maccan to 19N Hickman Street (21 structures):
- Structure Replacements: 21 structures

L6020 – 30W Souriquois to 50W Milton (49 structures):
- Structure Replacements: 30 structures
- Timber/Arm & Insulator Replacements: 19 structures

L6531 – 50W Milton to 99W Bridgewater (8 structures):
- Structure Replacements: 3 structures
- Timber/Arm Replacements: 5 structures

Summary of Related CIs +/- 2 years:
2017 CI 49948 2017/2018 Isolated Structure Replacements $3,822,487
2019 CI TBD 2019/2020 Isolated Structure Replacements $TBD
2020 CI TBD 2020/2021 Isolated Structure Replacements $TBD

Depreciation Class: Transmission Plant- Poles and Fixtures
Transmission Plant- Overhead Conductors and Devices

Estimated Life of Asset: 45 years

JUSTIFICATION:

Justification Criteria: Transmission Plant

Why do this project?

The transmission inspection program identified deteriorated assets that require replacement to avoid transmission interruptions. Not completing this project would compromise the reliable operation of these lines.

Why do this project now?

This work has been prioritized based on transmission inspection results and is required to mitigate the risks to the reliable operation of these transmission lines. Access to these isolated structures is very difficult and the cost to build the required environmental bridges and lay environmental matting for site access is prohibitive. Therefore, past work has been completed using only small off-road vehicles. As a result, it has not been possible to use standard materials and equipment to complete the repairs, and, as such, temporary repairs have been completed on multiple structures in these areas. The temporary repairs that have been made must be replaced with permanent standard construction structures.

This project is forecast to be in-service once the first structure is replaced (August 2018), therefore the forecast Final Cost date (March 2020) is six months after the last structure is forecasted to be replaced (September 2019).

Why do this project this way?

This program targets isolated structure refurbishment and replacements on L5530B, L5549, L6020 and L6531. These lines require a large quantity of environmental matting and bridges for structure access by land. The cost of over-land access methods exceeds the cost of completing the work by helicopter. The following table compares the contract costs for performing the work with a helicopter and using traditional methods.

Line (# Structures)	**Contract Cost Comparison ($000s)**		
	Helicopter Costs	**Traditional Methods Environmental Matting Costs**	**Variance**
L5530B (73 structures)	$411	$900	$(489)
L5549 (21 structures)	$459	$600	$(141)
L6020 (49 structures)	$866	$1,000	$(134)
L6531 (8 structures)	$143	$220	$(77)
TOTAL	**$1,880**	**$2,720**	**$(840)**

This comparison demonstrates the cost benefit of using helicopters to complete the maintenance work on the isolated structures. In addition, once this program is established, the method of conducting work by helicopter will be available for use for reactive outage restoration, resulting in decreased outage times.

Replacing the existing deteriorated assets is more cost effective than rebuilding the entire line. Gaining access and completing the work from a helicopter for the identified structures on L5530B, L5549, L6020 and L6531 will result in lower costs than traditional work methods and will reduce permitting times, reduce equipment and material mobilization challenges, lessen the costs of site access, allow for faster completion of the work, and reduce land access challenges.

The contracts portion of this project will be sourced through NS Power's existing Power Line Technician (PLT) Service Agreement with Emera Utility Services. This is aligned with NS Power's workforce planning model which is designed to optimize the allocation and execution of PLT resources among work requirements.

CI Number : 52258 - 2018/2019 Isolated Transmission Structure Replacements **Project Number** 52258

Parent CI Number : -

Asset Location : 1455 - 1455 Transmission Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	3500 - TP - Wood Poles	3,910,485
Additions	3800 - TP - Insulators	133,469
Additions	3900 - TP - O/H Cond.	549,776
Retirements	3500 - TP - Wood Poles	168,465
Retirements	3800 - TP - Insulators	56,326
	Total Cost:	4,818,521
	Original Cost:	796,473

Capital Project Detailed Estimate

Location: **Transmission**
CI# / FP#: 52258
Title: 2018/2019 Isolated Transmission Structure Replacements
Execution Year: 2018-2019

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
T&D Labour - Electrician/Technician	PD	10	$ 366	$ 3,759		
T&D Labour - Site Supervision	PD	146	$ 389	$ 56,983		
Procurement / Financial Support	Lot	1	$ 6,458	$ 6,458		
			Sub-Total	$ 67,200		
Materials						
Poles	Lot	1	$ 296 310	$ 296 310		
Insulators	Lot	1	$ 26 210	$ 26 210		
Conductor	Lot	1	$ 399	$ 399		
			Sub-Total	$ 322 918		
Contracts						
Contract Line Work	Hrs	[redacted]		1 417 761		
Flagging	Lot	1	14 000	14 000		
Pole Haulage	Lot	1	32 400	32 400		
Waste Disposal	Lot	1	15,000	15,000		
Helicopter Services - L5530B	Lot	1	410,947	410,947		
Helicopter Services - L5549	Lot	1	459,320	459,320		
Helicopter Services - L6020	Lot	1	865,920	865,920		
Helicopter Services - L6531	Lot	1	143,392	143,392		
Survey	Lot	1	5,000	5,000		
			Sub-Total	$ 3,363,740		
Other Goods & Services						
Contingency	%	10%	$ 3,363,740	$ 336,374		
			Sub-Total	$ 336,374		
Vehicle Overhead						
Vehicle Allocated Costs				$ 27,462		
			Sub-Total	$ 27,462		
Administrative Overhead						
Labour AO				$ 59,676		
Contract AO				$ 638,236		
			Sub-Total	$ 697,912		
Interest Capitalized						
AFUDC				$ 2 915		
			Sub-Total	$ 2,915		
			SUB-TOTAL (no AO, AFUDC)	$ 4 090 232		
			TOTAL (AO, AFUDC included)	$ 4,818,521		
Original Cost				$ 796,473		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 51403

Title: 2018/2019 Substation Polychlorinated Biphenyl (PCB) Equipment Removal

Start Date: 2018/03
In-Service Date: 2018/03
Final Cost Date: 2020/05
Function Class: Transmission
Amount: $4,402,342

DESCRIPTION:

This project will replace substation devices that have polychlorinated biphenyl (PCB) levels of 50 mg/kg or more to comply with 2008 Federal Environmental PCB Regulations. PCB sampling of all accessible substation equipment was completed in previous year projects and the focus is now on equipment removal.

A portion of the capital costs associated with this capital item will contribute toward settling the Company's Asset Retirement Obligation for PCB contaminated oil.

Summary of Related CIs +/- 2 years:
2016 CI 48066 2016/2017 Substation PCB Equipment Removal $3,500,427
2017 CI 49838 2017/2018 Substation PCB Equipment Removal $4,127,023
2019 CI TBD 2019/2020 Substation PCB Equipment Removal $TBD
2020 CI TBD 2020/2021 Substation PCB Equipment Removal $TBD

Depreciation Class: Transmission Plant – Overhead Conductors and Devices
Transmission Plant – Station equipment

Estimated Useful Life: 40 Years

JUSTIFICATION:

Justification Criteria: Environmental

Why do this project?

This project is required to enable NS Power to comply with the revised 2008 PCB Regulations as set by the Federal Government, which includes a deadline of 2025 for the elimination of all equipment containing PCBs in concentrations at or above 50 mg/kg.

Why do this project now?

This project must be completed to comply with the replacement of all applicable PCB contaminated substation equipment before the 2025 deadline.

This project is deemed in-service when the first device is removed (March 2018), and the Final Cost Date (May 2020) is listed as six months after the last device is removed (November 2019).

Why do this project this way?

The replacement of equipment containing greater than 50 mg/kg concentration of PCBs must be planned over a period of several years to manage outages effectively and comply with the 2008 Federal PCB Regulations.

CI Number : 51403 - 2018/2019 Substation Polychlorinated Biphenyl (PCB) Equipment Removal **Project Number** 51403

Parent CI Number : -

Asset Location : 1455 - 1455 Transmission Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0300 - TP - Bldg.,Struct.Grnd.	135,503
Additions	2200 - TP - Elec Contr.Equip.	298,043
Additions	3900 - TP - O/H Cond.	140,313
Additions	4300 - TP - Substn Dev.	2,319,631
Additions	4400 - TP - Substn.Transf.	1,338,302
Retirements	4300 - TP - Substn Dev.	170,549
	Total Cost:	4,402,342
	Original Cost:	785,476

Capital Project Detailed Estimate

Location: Transmission
CI# / FP#: 51403
Title: 2018/2019 Substation Polychlorinated Biphenyl (PCB) Equipment Removal
Execution Year: 2018-2019

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
T&D Labor - Electrician/Technician	PD	620	$ 366	$ 226,691		
T&D Labor - Site Supervision	PD	23	$ 389	$ 8,966		
T&D Labor - Engineering Design	PD	628	$ 386	$ 242,408		
T&D Drafting Labor	PD	453	$ 284	$ 128,652		
			Sub-Total	$ 606,717		
Travel Expense						
Miscellaneous Travel	Lot	1	$ 500	$ 500		
			Sub-Total	$ 500		
Materials						
Connectors, Ground Connectors, Nuts, Jumpers, etc.	Lot	1	$ 15,035	$ 15,035		
Control Cables, Junction Boxes	Lot	1	$ 60,180	$ 60,180		
138 kV Circuit Breakers	Ea.	5	$ 93,445	$ 467,225		
138 kV Surge Arrester	Ea.	3	$ 9,000	$ 27,000		
69 kV Circuit Breakers	Ea.	7	$ 68,073	$ 476,508		
69 kV Surge Arrester	Ea.	6	$ 1,200	$ 7,201		
HV Bushings	Ea.	80	$ 10,000	$ 800,000		
			Sub-Total	$ 1,853,148		
Contracts						
Civil Contracts - Foundations, Conduit, etc.	Lot	1	$ 81,000	$ 81,000		
Labor (Overhead Conductors/Equipment)	PD	53	$ 800	$ 42,000		
Labor (138 kV and 69kV Circuit Breaker)	hr.	4500	$ 100	$ 450,000		
Boom/Crane Rental	hr.	72	$ 250	$ 18,000		
Mobile Transport	Lot	6	$ 1,000	$ 6,000		
Labor - Conductors	hr.	210	$ 100	$ 21,000		
Labor - Commissioning	hr.	870	$ 100	$ 87,000		
			Sub-Total	$ 705,000		
Other Goods & Services						
Contingency	%	10%	$ 3,164,865	$ 316,486.50		
				\		
			Sub-Total	$ 316,486		
Vehicle Overhead						
Vehicle AO				$ 247,941		
			Sub-Total	$ 247,941		
Administrative Overheads						
Labor AO				$ 538,783		
Contract AO				$ 133,767		
			Sub-Total	$ 672,550		
			SUB-TOTAL (no AO, AFUDC)	$ 3,481,851		
			TOTAL (AO, AFUDC included)	$ 4,402,342		
Original Cost				$ 785,476		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 51402

Title: 2018/2019 Sacrificial Anode Installation Program

Start Date: 2018/01
In-Service Date: 2018/01
Final Cost Date: 2020/06
Function Class: Transmission
Amount: $3,023,668

DESCRIPTION:

This project will systematically install sacrificial anodes, highly active metals used for cathodic protection, on steel transmission structures and key tower anchors which have been identified as corroding or at a high risk for corrosion. This program, along with the inspection of transmission steel towers and the steel tower refurbishment, will identify and address corrosion issues on steel assets throughout the province.

Summary of Related CIs +/- 2 years:
2016 CI 48116 2016 Sacrificial Anode Installation Program $970,909
2017 CI 49813 2017 Sacrificial Anode Installation Program $1,532,340
2020 CI TBD 2020/2021 Sacrificial Anode Installation Program $TBD

Depreciation Class: Transmission Plant – Towers and Fixtures

Estimated Useful Life: 15-20 years

JUSTIFICATION:

Justification Criteria: Transmission Plant

Why do this project?

Based on transmission line inspections, the age of NS Power infrastructure and the corrosion rate of steel once galvanization is breached, sacrificial anodes, which have proven effective in other jurisdictions to protect steel transmission structure assets and slow the rate of corrosion, have been recommended as a corrosion solution by NS Power's Transmission & Distribution engineering group.

Why do this project now?

Based on the age of NS Power's steel transmission structure assets, the galvanization is at or near the end of its anticipated life. Cathodic protection, provided by the installation of sacrificial anodes, will extend the life of the steel structure.

This project is deemed in-service when the first anode is installed (January 2018), therefore the Final Cost Date (June 2020) is listed as six months after the last anode is installed (December 2019).

Why do this project this way?

The installation of sacrificial anodes protects the existing assets once the galvanization is ineffective, deferring costly replacement.

The contracts portion of this project will be sourced through NS Power's existing Power Line Technician (PLT) Service Agreement with Emera Utility Services. This is aligned with NS Power's workforce planning model, which is designed to optimize the allocation and execution of PLT resources among work requirements.

CI Number : 51402-T969 - 2018/2019 Sacrificial Anode Installation Program **Project Number** 51402-T969

Parent CI Number : -

Asset Location : 1455 - 1455 Transmission Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	3700 - TP - Steel Towers	3,023,668
	Total Cost:	3,023,668
	Original Cost:	

Capital Project Detailed Estimate

Location: **Transmission**
CI# / FP#: 51402
Title: 2018/2019 Sacrificial Anode Installation Program
Execution Year: 2018/2019

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
T&D Labor - Site Supervision	PD	128	$ 385	$ 49,280		
Procurement / Financial Support	Lot	1	$ 2,866	$ 2,866		
				$ -		
			Sub-Total	$ 52,146		
Materials						
Anodes & Test Stations	EA	950	$ 151	$ 143,450		
				$ -		
			Sub-Total	$ 143,450		
Contracts						
Contract Line Work	EA	1	$ 2,000,000	$ 2,000,000		
Contract Supervision	EA	1	$ 100,000	$ 100,000		
				$ -		
			Sub-Total	$ 2,100,000		
Consulting						
External Program Consulting	Lot	1	$ 50,000	$ 50,000		
				$ -		
			Sub-Total	$ 50,000		
Meals & Entertainment						
Meals	Lot	1	$ 2,000	$ 2,000		
				$ -		
			Sub-Total	$ 2,000		
Other Goods & Services						
Contingency	%	10%	$ 2,100,000	$ 210,000		
				$ -		
			Sub-Total	$ 210,000		
Vehicle Overhead						
Vehicle AO				$ 21,310		
			Sub-Total	$ 21,310		
Administrative Overhead						
Labor AO				$ 46,308		
Contract AO				$ 398,454		
			Sub-Total	$ 444,762		
			SUB-TOTAL (no AO, AFUDC)	$ 2,557,596		
			TOTAL (AO, AFUDC included)	$ 3,023,668		
Original Cost						
				$ -		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: C0001900

Title: Mount Hope 69-25kV Substation

Start Date: 2018/01
In-Service Date: 2019/11
Final Cost Date: 2020/05
Function: Transmission
Forecast Amount: $2,982,338

DESCRIPTION:

This project includes the construction of a new 69-25kV substation in the Mount Hope area. As outlined in planning study report # 57-2016-TSMG (please refer to Attachment 1), capacity for contingency conditions are nearing limits at the 113H Dartmouth East substation. It is recommended that a 69-25kV pad-mount substation with a single 25kV feeder be constructed in the Mount Hope area. This new substation will provide necessary load relief to two of the most heavily loaded Dartmouth East feeders 113H-434 and 113H-443.

Summary of Related CIs +/- 2 years:
No other projects in 2016,2017,2018,2019 and 2020

Depreciation Class: Transmission Plant- Station Equipment
Transmission Plant- Underground Conductors and Devices
Transmission Plant- Poles and Fixtures
Transmission Plant- Overhead Conductors and Devices

Estimated Life of the Asset: 40 Years

JUSTIFICATION:

Justification Criteria: Transmission Plant

Why do this project?

Installation of a new 12MVA, 69-25kV pad-mount substation near the junction of 69kV lines L-5011 and L-5012 is needed to provide load relief on Dartmouth East feeders 113H-434 and 113H-443. Failure to complete this project will result in continuing loading violations that exceed the normal operating limit of 325A on these Dartmouth East feeders. This overloading would have a direct impact on customer reliability during contingency situations that require load transfer to adjoining substations.

Why do this project now?

Dartmouth East feeders 113H-434 and 113H-443 are presently experiencing load violations that exceed the normal operating limit. Without a new pad-mount substation, these customers are at risk of experiencing extended outages during peak load due to the restricted ability to transfer load to adjoining substations.

Why do this project this way?

Installation of a new pad-mount substation in the Mount Hope area as recommended in the Planning Study is an alternative to the construction of a new substation at Harbour East. This option is recommended due to its lower development cost (approximately $10 million less expensive), smaller footprint, compatibility of its appearance amongst local development and fast implementation. Due to the low site development cost, a pad-mount substation could easily be expanded or relocated to meet future load growth.

CI Number : C0001900 - Mount Hope 69-25kV Substation

Project Number C0001900

Parent CI Number : -

Asset Location : 1455 - 1455 Transmission Plant General

Budget Version 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0300 - TP - Bldg.,Struct.Grnd.	229,431
Additions	0700 - TP - Environmental	45,780
Additions	2200 - TP - Elec Contr.Equip.	53,427
Additions	2300 - TP - Power Equip.-Station S	12,632
Additions	3500 - TP - Wood Poles	60,205
Additions	3900 - TP - O/H Cond.	34,232
Additions	4300 - TP - Substn Dev.	37,911
Additions	4400 - TP - Substn.Transf.	2,393,044
Additions	4600 - TP - U/G Conductor	41,482
Additions	6100 - TP - Switched Telecomm. Sys	74,194
	Total Cost:	2,982,338
	Original Cost:	

Capital Project Detailed Estimate

Location: **Transmission**
CI# : C0001900
Title: Mount Hope 69-25kV Substation
Execution Year: 2018-2019

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
T&D Labour - PLT	PD	25	$ 372	$ 9,152		
T&D Labour - Electrician/Technician	PD	72	$ 366	$ 26,325		
T&D Labour - Site Supervision	PD	9	$ 389	$ 3,501		
T&D Labour - Design	PD	231	$ 386	$ 88,973		
T&D Labour - Site Supervision	PD	13	$ 389	$ 5,106		
T&D Labour - Drafting	PD	56	$ 284	$ 15,904		
			Sub-Total	$ 148,961		
OT Labour						
T&D Labour - Electrician/Technician	PD	15	$ 731	$ 11,081		
			Sub-Total	$ 11,081		
Term Labour						
T&D Labour - Design	PD	261	$ 386	$ 100,875		
			Sub-Total	$ 100,875		
Travel Expense						
Travel	Lot	1	$ 2,208	$ 2,208		
			Sub-Total	$ 2,208		
Materials						
Buildings, Structures and Grounds	Lot	1	$ 9,505	$ 9,505		
Environmental	Lot	1	$ 11,700	$ 11,700		
Control Equipment	Lot	1	$ 21,700	$ 21,700		
Station Service	Lot	1	$ 5,850	$ 5,850		
Wood Poles	Lot	1	$ 32,000	$ 32,000		
Substation Devices	Lot	1	$ 18,380	$ 18,380		
Padmount Substation	Lot	1	$ 1,300,000	$ 1,300,000		
Underground Conductors	Lot	1	$ 23,150	$ 23,150		
Communication Equipment	Lot	1	$ 40,000	$ 40,000		
			Sub-Total	$ 1,462,285		
Contracts						
Civil	Lot	1	$ 146,731	$ 146,731		
Civil Field Supervision	Lot	1	$ 3,850	$ 3,850		
Transformer (Transport/Offload/Assembly)	Lot	1	$ 80,400	$ 80,400		
Control Equipment Assembly	Lot	1	$ 10,000	$ 10,000		
Overhead 25kV Line Extension	Lot	1	$ 15,000	$ 15,000		
Survey, Mapping, Land Acquisition	Lot	1	$ 185,000	$ 185,000		
				$ -		
				$ -		
			Sub-Total	$ 440,981		
Consulting						
Padmount Substation FAT	Lot	1	$ 20,000	$ 20,000		
				$ -		
			Sub-Total	$ 20,000		
Meals & Entertainment						
Meals	Lot	1	$ 700	$ 700		
	Lot			$ -		
			Sub-Total	$ 700		
Other Goods & Services						
Contingency		10%	$ 2,063,308	$ 206,342		
			Sub-Total	$ 206,342		
Vehicle Overhead						
Vehicle AO				$ 104,362		
			Sub-Total	$ 104,362		
Interest Capitalized						
AFUDC				$ 174,090		
			Sub-Total	$ 174,090		
Administrative Overhead						
Labour AO				$ 226,781		
Contract AO				$ 83,672		
			Sub-Total	$ 310,453		
			SUB-TOTAL (no AO, AFUDC)	$ 2,393,432		
			TOTAL (AO, AFUDC included)	$ 2,982,338		
Original Cost				$ -		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

Nova Scotia POWER
An Emera Company

Harbour East Substation

Review of Requirements and Options

Report # 57-2016-TSMG

Principal Investigator
John Fraser, P.Eng

2017-02-28

T&D Technical Services
Nova Scotia Power Inc.

Document Approval

Role	Name	Signature	Date (yyyy/mm/dd)
Owner	Tim Leopold	Tim Leopold	2017/03/04

Revision Record

Rev. #	Date (yyyy/mm/dd)	Changes	Authors	Reviewers
0	2017/01/20	Initial draft	John Fraser	
1	2017/02/28	First draft for review	John Fraser	

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Executive Summary

This study revisits the question of whether a new Harbour East substation located in the Eastern passage area is needed within the next 10 year planning horizon – either for reasons of off-loading the 69 kV Dartmouth Loop or to meet load capacity requirements in the east Dartmouth and Eastern Passage areas – and if not needed what capacity requirements are needed.

The conclusion of this study is that within the 10 year time horizon studied there is sufficient capacity available on the Dartmouth 69 kV loop and on feeders supplying the Eastern passage area to meet forecast requirements. Further, growth requiring the construction of Harbour East substation to provide additional transformation capacity in the Eastern Passage area has not materialized nor is it expected to appear within the planning horizon of this study. The reasons for this are complex and are explored in depth in this report. The findings of this load investigation may have more broad application across the NS Power system.

Capacity for contingency conditions is nearing limits at the 113H Dartmouth East substation. It is recommended that a 69-26.4 kV padmount power transformer substation with a single 25 kV feeder be constructed in the Mount Hope area. With minor feeder reconfigurations this new substation and feeder would provide necessary load relief to two of the most heavily loaded Dartmouth East feeders: 113H-434 and 113H-443, one of which (113H-434) serves load in the Eastern Passage area. With the low load growth forecast for the area this substation will provide the required capacity to meet the currently forecasted load growth.

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1.0 Introduction

1.1 Scope

This study was initiated to review the findings of the original study that recommended Harbour East substation and the subsequent addendums to it and reconsider potential solutions in light of higher than originally estimated project costs and changing load growth patterns. Additionally, the study will review loading on the Dartmouth 69 kV Loop, exploring options to extend its capacity.

1.2 History

The requirement for the construction of a new Harbour East substation to serve the growing load of Eastern passage had its earliest roots in two studies conducted in the 1990s. The first, Report # 171-0194-H27 "Distribution Planning Report, Dartmouth District" by Kevin Kilfoil published in 1994, rated the construction of a new substation in Eastern Passage as a close second-best option to installing a second transformer at Albro Lake substation to serve the growing Dartmouth load (this option was actually pursued).

The second, Report # 198-0799-H35 "Cole Harbour/Eastern Passage Load Growth Report" by Larry O'Keefe published in 1999 also considered a new substation in Eastern Passage as an option but concluded that express feeders from East Dartmouth were the most economically favorable option for supplying the area.

In 2006, Report # 232-1105-H38 – "Sub-Transmission and Distribution Planning Study, Dartmouth 25 kV System" was prepared by John Charlton. In the report's discussion of issues it is stated that:

> "It becomes evident as load is scaled over the 15 year time frame of this report that express feeders into the Eastern Passage area from the Dartmouth East substation will eventually become impractical due to the parasitic load each feeder has to supply before reaching the load centre in Eastern Passage, and due to the limited number of access routes between the two areas. It is likely, therefore, that NSPI will need to establish a new substation within Eastern Passage at some point shortly after 2020/21."

The report also stated that:

> "The future of the 69kV sub-transmission system within Dartmouth was beyond the scope of this report. As such, a Transmission System study of the Loop is recommended within the next 5 years to address this issue. The long lead time is required to allow time to develop a strategy for upgrading this loop, or for developing an alternate right of way for new transmission assets to replace the loop."

Acting on this recommendation the Dartmouth 69 kV Loop Planning Study (Report # 255-087-H41) was initiated and completed by Joy Brake in 2007. That study forecast capacity violations on the Dartmouth 69 kV Loop as early as the 2012/13 peak and on the Dartmouth East substation feeders as early as the 2011/12 peak. The study recommended:

"• 2008 – Develop an express feeder from 113H-Dartmouth East to relieve loading on the 58H-Imperial Oil transformer 58H-T3
• 2008 to 2010 – Acquire ROW for a 138kV H-frame construction transmission corridor from 113H-Dartmouth East to Eastern Passage. Acquire land for a substation in Eastern Passage.
• 2011 – Construct a 138kV transmission line from 113H-Dartmouth East to the Eastern Passage substation site.
• 2011 – Construct a 138/25kV substation with 4 feeder exits in Eastern Passage
• 2011 – Reconfigure 58H-Imperial Oil and 113H-Dartmouth East feeder circuits as necessary to develop feeders from the new substation."

The estimated cost in 2007 of the recommended work was $9.7 Million.

The study also looked to the future opportunity to develop a transmission connection from Eastern Passage to Water Street so it further recommended:

"• Use double circuit monopole construction instead of H-frame for the new transmission line from 113H-Dartmouth East to the Eastern Passage substation.
• Acquire ROW from the Eastern Passage substation to the Halifax Harbour to facilitate a future Halifax/Dartmouth 138kV loop."

The additional cost of these items was estimated in 2007 $ at $6.6 Million, bringing the total for implementing all recommendations to 2007 $16.3 Million.

Work on implementing these recommendations began almost immediately. Consultations were initiated in 2009 with HRM staff in regard to the routing of a transmission line through lands that included parkland and other land owned by the municipality. Design work for the transmission line and substation was initiated under preliminary work order T731 and acquisition of ROW and a substation site proceeded under a preliminary work order against 2011 capital budget item CI # 38849. The development of the recommended express feeder along Bissett Road to relieve load on 58H-T3 was completed in 2010 under Distribution CI # 34602.

Following a community consultation process initiated in 2010, a great deal of public malcontent with the originally-planned cross country transmission route from East Dartmouth to Eastern Passage surfaced. In response, NS Power together with HRM established a Public Advisory Committee co-chaired by Terry Toner to explore viable options to that route. In November 2011 the Committee produced a report that recommended a roadside route that followed Main Street, Forest Hills Parkway, Cole Harbour Road and Bissett Road to a takeoff location where it then crosses forested land to a new substation site on Caldwell Road south of Hines Rd. The line design would be single circuit rather than the original plan for a double circuit.

Budget items were included in the 2012 Capital Budget for the transmission line ROW and substation site ($179,680), construction of a transmission line ($7,859,669), termination of the line at East Dartmouth ($788,149) and construction of the Harbour East substation ($3,490,007).

Since the 2007 study a number of addendums to the study were completed in 2012, 2013, 2015 and 2016. Other than the broader scopes of the two updates undertaken in 2012, all subsequent updates explored only the timing of the construction of the new substation at

Harbour East or opportunities for expenditures that would defer the in-service date of that substation.

With the recommendation by HRM Planning to HRM council in early March 2012 to accept the transmission line route proposed by the Public Advisory Committee: (https://www.halifax.ca/boardscom/swrac/documents/HarbourEastTransmissionLineUpdate.pdf), an update in March 2012 by Joy Brake of her original 2007 study was prepared to confirm the project timing. This update concluded that with the voltage conversion and transfer of load to 113H Dartmouth East and 139H Dartmouth Crossing, loading on the Dartmouth Loop was no longer an issue. However, due to continued forecasted loading criteria violations at 113H Dartmouth East and on the Dartmouth Crossing feeder 139H-414 across Lake Charles (which backfeeds toward Dartmouth East), the study re-confirmed the need for the Harbour East option with an in-service date of 2012/13 load peak. Design and ROW acquisition activities for the new line and substation proceeded and the preparation of revised estimates for the transmission line were initiated based on the approved route.

In May 2012, after the official approval for the new transmission line route was secured from HRM, Imperial Oil issued an announcement that they would seek a purchaser for their Eastern Passage refinery or would consider a reduction in operations to a tank farm. Following that announcement a follow-up review of the original study was undertaken by James MacQueen with a report issued in September 2012. The review assumed that with the refinery shutdown there would be a 15 MVA reduction in peak load on the Dartmouth Loop but also assumed offsetting load increases due to new loads in the Eastern Passage area (Shearwater and a new sewage treatment plant). The study evaluated alternatives that would have added new transformer capacity at East Dartmouth and Imperial Oil but concluded that the construction of Harbour East was the best option.

A year later on June 19 2013 Imperial Oil announced the closure of refining operations at its Eastern passage refinery to be implemented later that year, converting its operations to a terminal facility. The closure would result in a reduction of peak load from approximately 25 MVA to approximately 2.5 MVA with the loss of jobs. This change freed up approximately 23 MVA of capacity on the Dartmouth Loop thereby eliminating immediate contingency capacity concerns and allowing the possibility of supplying more distribution load from existing substations.

With the more certain future load forecast for the refinery operations another addendum to the original study was undertaken by James MacQueen and a report released in August 2013. The study was undertaken to determine what actions could be taken to defer the in-service date of the Harbour East substation until the 2015/16 winter peak. The report recommended changing out the 58H-T3 transformer from 15/20.8 MVA to a spare 15/20/25 MVA unit available from 22C Cleveland substation and the addition of a spare 7.5/10/12.5 MVA 25 kV transformer at 40H Woodlawn. The result of these changes, implemented under U&U Work Orders, revised the in-service date for Harbour East to be prior to the 2017/2018 winter peak.

Two additional study addendums were produced. The first addendum in 2015 by Brendon Henderson was prompted in part by delays in obtaining the desired Right-of-

Way due to land parcel ownership challenges. It reported that the growth rate for East Dartmouth had dropped from 1.8% to 1.5% and even though higher losses would be experienced in the interim, economics favoured a further deferral of Harbour East to an in-service of prior to the 2018/2019 peak. Among the report recommendations it is stated that:

> "Transmission line construction begins in 2016, allowing 2 years for completion. This will be double circuit monopole construction as per original study. There will be flexibility to use this line as a 25kV express feeder from 113H-Dartmouth East, if required before the substation is in service."

It is observed that although the original J. Brake report and the 2015 addendum both recommended a double circuit line, the agreement that came out of the community consultation process in 2012 was for the construction of a single circuit line. The rationale for a single circuit was that the 138 kV transmission circuit would eventually looped through Water Street via an underwater cable. This would satisfy the looping criteria as Harbour East load grew without needing a second circuit from Dartmouth East. Reviewing the transmission line cost estimates it is noted that the most recent estimates were prepared for a single circuit line.

The cost of a double circuit transmission line along the original route was estimated at $7.15 Million. Adopting the new route recommended by the Public Advisory Committee and adjusting for the additional design and construction restrictions imposed by HRM caused the line cost to increase. In the discussion of the HRM Planning recommendation in March 2012 it was reported that:

> "As a final comment, Nova Scotia Power estimates the cost of this transmission project to be approximately $12.0 million. The estimate for the original transmission line, as proposed 18 months ago, was $20.0 million. Assuming that these figures represent similar scope of work, the end result is a project which has support from the community and a 40% savings."

The most recent cost estimate as of July 2016 is $16.8 Million for a single circuit line – well above the original estimate. The transmission estimate figures are also very much different from the assumptions contained in the HRM staff report.

The most recent addendum, produced in 2016, was also by Brendon Henderson. That update was prompted by a very significant increase in the estimated cost of the new transmission line from East Dartmouth to supply the new Harbour East substation. The update explored the possibility of deferring Harbour East by one additional year in order to undertake a new study that would examine the many changes in transmission and distribution systems and customer load growth since Harbour East was initially approved and recommend what capacity options should be followed. The update identified that there had been a break in the upward trend of load growth in East Dartmouth and as a result violation of contingency capacity on the Dartmouth 25 kV system would not be expected till the winter of 2021, providing enough time to complete a new study. The results of that new study are what are reported in this document.

1.3 Findings of Preliminary Investigations

Other planners have identified a shift away from historical growth rates that used to fit an exponential model and a move more recently towards growth rates that are noticeably linear in character. Even more recent load patterns display little or no load growth at all, and in some instances a decline in load. These finding suggest that there are entirely new drivers of electrical demand and energy consumption at play in the community. This area will require close assessment of load forecasts to ensure capacity expansions are made with the best interests of customers and with the appropriate timing. Considerations should include opportunities to plan targeted programs like DSM, battery storage, solar power, etc. that could potentially offer more cost-effective alternatives.

As far back as 1994 general load growth was being estimated at 3.9% with a low and high range of 1.9% and 6%. By 1999 the growth rate for the Eastern Passage area was estimated to be lower at 2.7% with growth in the Colby area at 2.5%. The 1999 forecast employed estimates of population increase, growth in the number of dwellings and amount of land available for development together with average demand per customer as a means of improving both load forecast accuracy with respect to demand and where the demand would be located.

In his 2006 study J. Charlton broke down load forecasts into greater detail based on an analysis of a 10 year load history from 1995 to 2004. The same growth rates were reported by J Brake in her 2007 study. Reported growth rates were as follows:

Station/System	2004 Peak MVA	1995-04 Growth %
58H 25 kV	23	3.18
113H	80	2.49
Dartmouth 25 kV	140	3.05
Dartmouth 12 kV	88	0.47*
69 kV Loop	107	1.80

* 1.3% from 1998 to 2004

Table 1 Load Growth Rates from Charlton and Brake Studies

With adjustments for the reduction of load at Imperial Oil and assumptions about load increases at Shearwater and a new sewage treatment plant in Eastern Passage the first two Joy Brake report addendums employed the same load growth projections, stating:

> "The current loading on the 25kV distribution system in Dartmouth is continuing to grow, with new developments planned for the foreseeable future. These new developments will increase loading throughout the extent of the current 25kV distribution system."

In Addendum #3 prepared in 2015 by Brendon Henderson, all area load data was updated to the 2014-15 peak and a revised linear growth rate was calculated to be 1.5%, down from 1.8%. In forecasting the peak requirements for Eastern Passage an increased load was projected for 12 Wing Shearwater using the same estimate of approximately 5 MVA as had been included in earlier studies. In preparing this current study 12 Wing Shearwater was contacted and they confirmed that development at the Base, to date, implements all planned development for the foreseeable future. Halifax Water

Commission has indicated they do not have any plans to increase the capacity of the sewage treatment plant in Eastern Passage beyond what was put in place with the $64 Million upgrade completed in 2014 or to construct a new plant in the area. HRM's area plan limits new developments to those that will either have on-site disposal or will be in designated serviced lot areas that do not result in an increase in the existing treatment plant capacity. Therefore, no further load increases for 12 Wing or for a sewage treatment plant will be included in this report's forecast for the Eastern Passage load.

For Addendum #4 prepared in 2016, Brendon Henderson performed a great deal of analysis of substation transformer and feeder loads. Peak load data for all 25 kV load in Dartmouth was temperature normalized and the resulting plot of peak loads from 2009 to 2016 revealed no growth in peak load whatsoever despite increases in the number of customers throughout the period. The report observed:

> "it is clear that anticipated growth has not materialized in East Dartmouth. Since customer base has grown, it can be assumed that the way existing customers use electricity has changed. That is, energy consumers have become more efficient or have taken measures that reduce their contribution to peak. This could be explained by several things:
> - Efficiency One's DSM efforts
> - Conversions to oil or natural gas heating
> - Technology shift to energy efficient devices
> - Uptake of time-of-day rates
> - Major changes by large customer(s)"

The report also undertook to adjust the forecast load of the Dartmouth 25 kV system. The adjustment accounts for the DSM savings forecast estimates provided by Efficiency One and for an estimate of the impact of heat pump installations under a new NS Power program "Heat Pumps Set You Free" (http://heatpumpssetyoufree.ca/). However, despite the observation of changed customer usage patterns, the forecast in the report continued to project load using the historical growth rate of 1.5%, adjusting the forecasted load by the amount of load impact estimated for the heat pump and DSM programs.

This study agrees with the observation that the way customers use electricity has changed. Further investigation is recommended to determine the broad range of factors underlying customer electrical load in general and the influence these factors will have on future growth.

1.4 Equipment Loading Assumptions

This study is performed using the following equipment loading assumptions:

- **Distribution Circuits** – Normal operating limit of 325 Amps (as per Section 17.9 of the Capital Expenditure Justification Criteria); up to the equipment rating (typically 450 to 600 Amps) under contingency conditions.
- **Transmission Circuits** – Summer ratings calculated at +30 C with 2 ft/s wind; Winter rating calculated at +5 C with 2 ft/s wind as set forth in IEEE Standard for Calculation the Current-Temperature of Bare Overhead Conductors, IEEE 738™-2006. In addition to conductor ampacity and line operating temperature design considerations, circuit capacity may also be limited by line switch rating or line

metering limitations. Capacities of 69 kV lines in the Dartmouth area are summarized in Appendix A.

- **Substation Transformers** – 133% of top nameplate rating during winter peak under normal daily loading cycle.
- **Mobile Transformers** – 100% of top nameplate rating.

2.0 Investigations of Factors Affecting Load

Consideration was given to factors that influence future load growth on the system, many of which are interrelated in a number of ways. The changes over time that result in load growth trends arise both within the base of existing customers and with the addition of new customers. It can be stated that 99% of the customers that we will be supplying on the system next year are currently supplied by the system today. Even a small reduction in useage by the existing customer base could entirely overcome any growth from the addition of new customers. Consequently much can be achieved for improving load forecasts through understanding factors and trends affecting all customers, existing and new, but particularly focusing on factors affecting the existing customer base.

The following lists items that will be investigated and commented on in some level of detail:

- New customer growth
- Population demographics
- Commercial and industrial developments
- Demand Side Management – organic (naturally-occurring) and programmatic
- Building standards
- Natural Gas
- Solar – thermal and electric
- Heat pumps
- Electro-Thermal Storage and Time-of-Use
- Energy retrofits
- Electric vehicles
- Battery energy storage
- Distributed generation
- Conservation Voltage Reduction
- Environment – carbon pricing
- Global warming

2.1 New Customer Growth

Past studies contained information on population growth estimates and customer counts. The 1999 report by Larry O'Keefe showed a current residential dwelling growth rate for Eastern Passage of 2.7% with a population growth rate of 2.58%. The difference between the two growth rates indicates a trend of fewer residents per dwelling, a fact that over time has implications in regard to average electrical use per residential dwelling. Forecasts of future load that are based on a constant average load per dwelling will

overestimate demand. There are other factors that alter the average use per dwelling to consider as well. These will be discussed in greater detail in following sections of this report.

Population Growth Rate, Canada, Provinces and Territories, 2006 to 2011 and 2011 to 2016, %		
	2006 to 2011	**2011 to 2016**
Canada	5.9	5
Newfoundland and Labrador	1.8	1.0
Prince Edward Island	3.2	1.9
Nova Scotia	0.9	0.2
New Brunswick	2.9	-0.5
Quebec	4.7	3.3
Ontario	5.7	4.6
Manitoba	5.2	5.8
Saskatchewan	6.7	6.3
Alberta	10.8	11.6
British Columbia	7.0	5.6
Yukon	11.6	5.8
Northwest Territories	0.0	0.8
Nunavut	8.3	12.7

Table 2 Canadian Population Growth 2016 Stats Canada

The most recent census statistics document continued slow growth in the Nova Scotia population. Statistics from the 2016 Census reveal that the Nova Scotia population growth over the past 5 years was the second lowest in Canada. From 2006 to 2011 growth was 0.9% and from 2011 to 2016 it was only 0.2%.

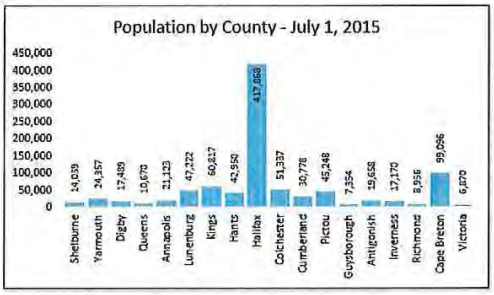


Figure 2 Population by County 2015

Statistics Canada projects future population levels under a number of scenarios and most of those scenarios show only minimal growth or even a decline in the population. Within the province there is a great disparity of population levels. In recent years Halifax County has grown largely at the expense of population loss in other areas of the province due to a migration of the population to the urban area and surrounds. This needs to be taken into account when using population growth rates to estimate load growth.

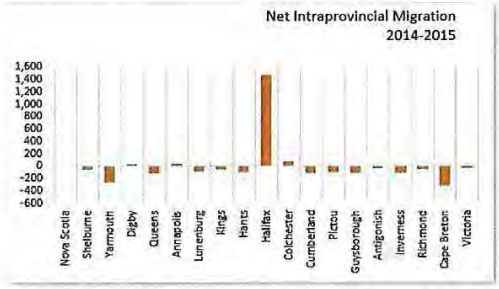


Figure 1 NS Intraprovincial Migration 2014-05

Across the province the low and declining population growth rate has also been observed as a decrease in the number of new customers added to the system each year. In the

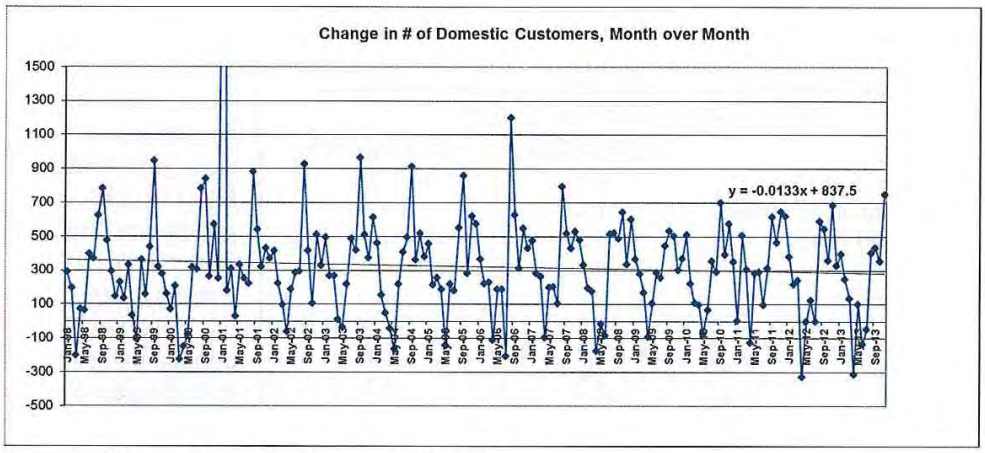


Figure 3 NS Power Customer Counts 1998 to 2013

period January 1998 to November 2014 the average count of domestic customers being added to the system declined approximately 5 customers per month each year. This decline can be anticipated to level off some number of years in the future, a projection that will be better understood after some further investigation of the population demographics which will be covered in the following section.

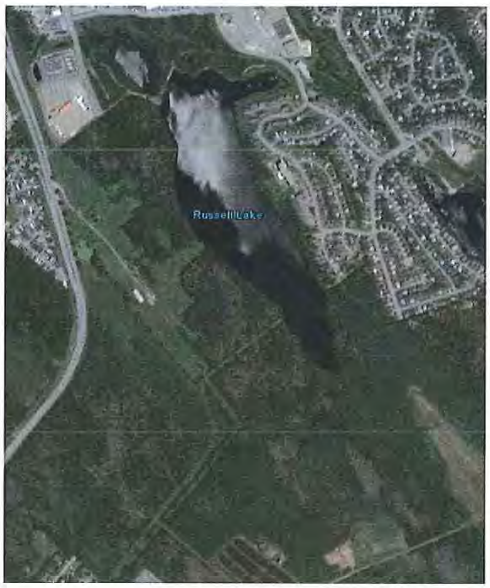


Figure 4 Russell Lake West: July 2, 2005

residential subdivision developments in Dartmouth, for example developments like Colby Village or Portland Hills. One of the largest of the recent localized

In recent years the majority of the growth in HRM has been outside the study area, mostly in the Rockingham and Kearney Lake areas. Aside from some localized developments, there have been no large scale

Figure 5 Russell Lake West: October 13, 2010

developments has been Russell Lake West in the area of Baker Drive and Mount Hope to the northwest of the Imperial Oil and 12 Wing Shearwater lands. Development had begun in late 2005 and continues to date.

The before and after satellite images above show the scale of the development, including a new exit from the 111 Circumferential Highway and the largely vacant adjacent lands owned by Imperial Oil and DND. The development consists of a mix of residential

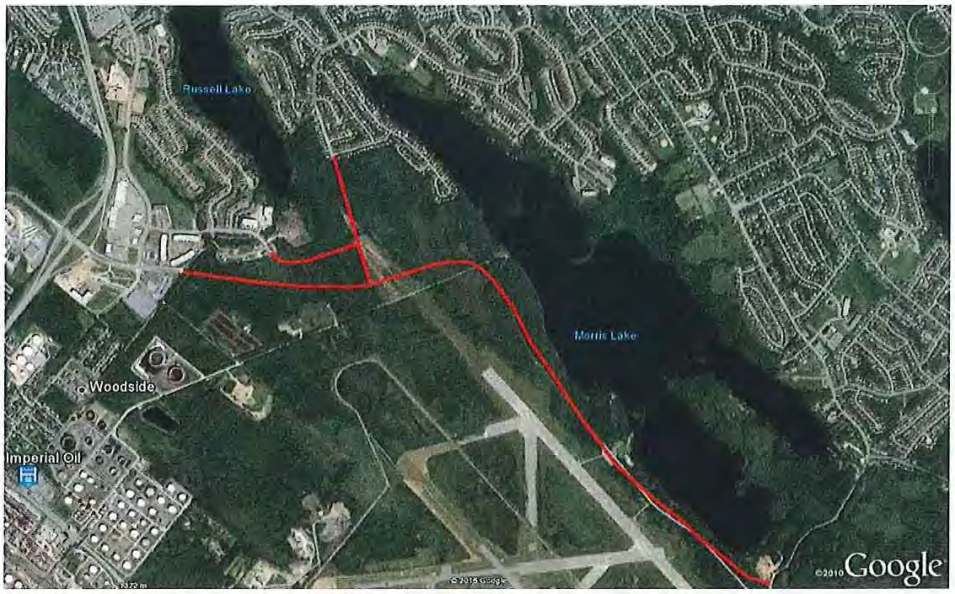


Figure 6 Planned Route of Mt Hope to Caldwell Road Connector

housing, apartment buildings and commercial space. Highway alignments for future developments are apparent in the images.

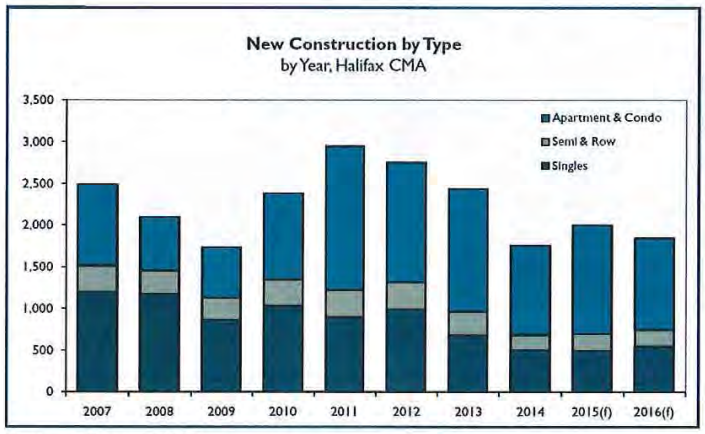
With past plans to close 12 Wing Shearwater airbase there had been plans to build a connector road from the new Mount Hope intersection off the Circumferential Highway 111 to Caldwell Road, south of Morris Lake. That plan was put temporarily on hold following a change in plans for 12 Wing Shearwater. The base will remain open as a training and maintenance base for the new fleet of Cormorant helicopters (replacing the Sea Kings). No further developments beyond what are already in place have been announced for the base so HRM is still pursuing a possible agreement with the military for approval of a highway route through the DND lands: (http://www.halifax.ca/council/agendasc/documents/160405ca1413.pdf) . Should the highway alignment gain approval and proceed the additional traffic capacity into Eastern Passage could offer a stimulus for development

Although statistics for the 2016 census are not yet available, data from the 2011 Census indicates a large difference between Nova Scotia and Canadian averages with respect to certain types of housing. Nova Scotia has higher proportions of single detached houses and lower proportions of multi-unit row houses and apartments. There are indications that this differential is changing, as is reflected in recent housing market statistics.

Structural Type of Dwelling (Stats Canada 2011 Census)	Nova Scotia		Canada	
	Number	%	Number	%
Total - Structural type of dwelling	390,280	100.0	13,320,615	100.0
Single-detached house	260,435	66.7	7,329,150	55.0
Semi-detached house	19,450	5.0	646,240	4.9
Row house	9,175	2.4	791,600	5.9
Apartment, building that has five or more stories	17,880	4.6	1,234,770	9.3
Apartment, building that has fewer than five stories	56,485	14.5	2,397,555	18.0
Apartment, duplex	11,970	3.1	704,485	5.3
Other single-attached house	705	0.2	33,310	0.3
Movable dwelling	14,175	3.6	183,510	1.4

Table 3 Canadian and Nova Scotia Dwelling Type from Stats Canada

Statistics from Canada Mortgage and Housing show a pattern of change in the housing market in the Halifax area over the past 8 years. In 2007 the majority of the homes constructed were single detached or semi-detached and row housing. By 2014 this had transitioned over to the majority of new housing units being apartments and condominiums. The same trend can also be observed in HRM building permit approvals. These trends will continue to move the housing types closer to that of the national average. It is a trend that can be expected to continue into the future. The reasons for this expectation will be better understood after considering the demographics of the Nova Scotia population.



Source and Forecast: CMHC

Figure 8 Halifax Home Construction Dwelling Type 2007 to 16

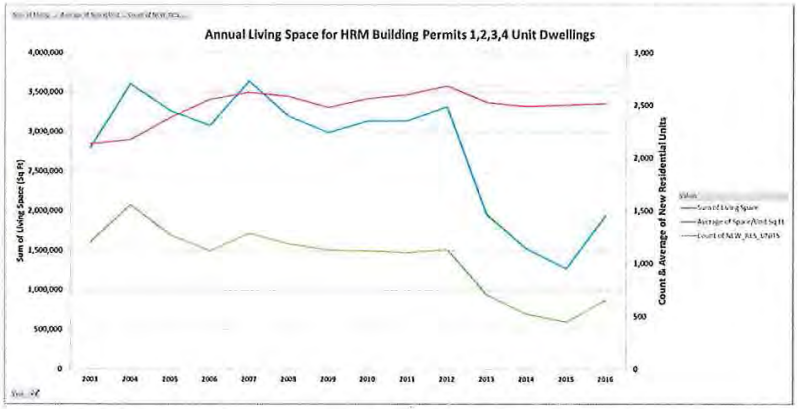


Figure 7 HRM Build Permits - Annual Living Space Approved

This shift in dwelling type is relevant to load forecasting. Energy useage per dwelling is very dependent

on the type of dwelling as well as its heating source.

It is fortunate that as a legacy of past times when NS Power had different electrical rates for all-electric and non-all-electric customers, coding for the two sub-groups of customers exists in the Customer Information System (CIS). Therefore, electrical consumption data for these sub-groups can be separately extracted from the CIS. The results of an analysis of the observed consumption patterns will be presented and discussed later in the report in Section 3 - Analysis of Load Data.

Caution in employing some CIS data is warranted as there is no general process by which changes to the customer's installed heating system is accurately tracked and the corresponding rate code updated in CIS. Some rate category changes are captured when customers participate in certain NS Power programs like the Electro-Thermal Storage (ETS) or other time-of-use metered programs or they install heat pumps (financed by NS Power) or gain approval for interconnection of solar electric panels or other generation sources. However, should the customer have made their own changes away from electric heat, for instance to natural gas, or installing electric heating systems like heat pumps, they may still be coded with their original rate category.

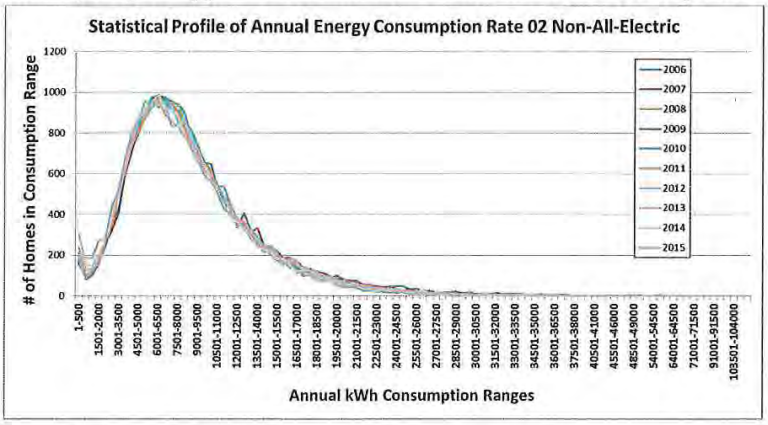


Figure 9 Non-All-Electric Premise kWh Consumption Ranges

The potential for that situation to exist in any given sample of customers could be best exemplified in the Figure 9 above. This shows that over the past 10 years the majority of premise annual energy consumption levels fall in the range of 3,000 to 12,500 kWh per year with the greatest concentration around the 6,000 to 7,000 kWh range. In most years around 950 homes on average have consumption levels that exceed 18,000 kWh, a level typically considered to be that of an all-electric premise. As a consequence, the average electrical energy consumption of Rate 02 homes, rather than being around the 6,500 kWh range calculates to be in the 8,750 range.

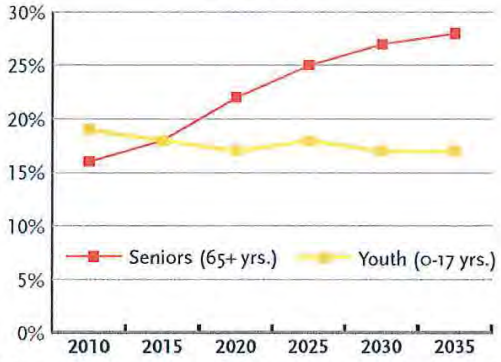
New customer growth is guided by municipal development plans and bylaws that restrict what development can take place. An investigation into the impact of new customer growth on electrical load employing spatial load forecasting techniques was to have been part of the overall review of the area, guiding both this subtransmission review and a distribution feeder planning study for the area. The spatial load forecast and the distribution feeder planning study remain to be completed.

As a consequence, the approach to completing this study was modified to accommodate the loss of that valuable input. One of the outcomes of modifying the approach is that

there will be more emphasis on qualitative findings rather than quantitative findings guiding the report recommendations.

2.2 Population Demographics

The demographics of the Nova Scotia population have contributed to the pattern of electrical load in the province. Statistics from the 2016 Census reveal that the Nova Scotia population growth over the past 5 years was the second lowest in Canada. From 2006 to 2011 growth was 0.9% and from 2011 to 2016 it was only 0.2%. Declining population was recognized by the Ivany Report "Now or Never: An Urgent Call to Action for Nova Scotians" as a significant factor in declining economic activity in the province. The demographic structure of that population over time is also significant.



Projected Population Change 2009 to 2034
by Region and Age Group

	< 20 Yrs	20—64 Yrs	> 64 Yrs	Total Population
Province	-30%	-21%	+41%	-4%
Cape Breton	-29%	-26%	+44%	-13%
Northern	-26%	-20%	+50%	-10%
Valley	-4%	-2%	+42%	-6%
Southwest	-37%	-9%	+40%	-6%
HRM	-2%	-13%	+49%	+1%

Source: Nova Scotia Department of Finance

Figure 10 Nova Scotia's Changing Age Profile and Projections

Statistics Canada projects future population levels under a number of scenarios. Most of those scenarios indicate minimal growth or potentially a decline in the Nova Scotia population. Further, all scenarios show an increase in the average age of Nova Scotians. Increased average age of the population is another feature of demographics important to load forecasting.

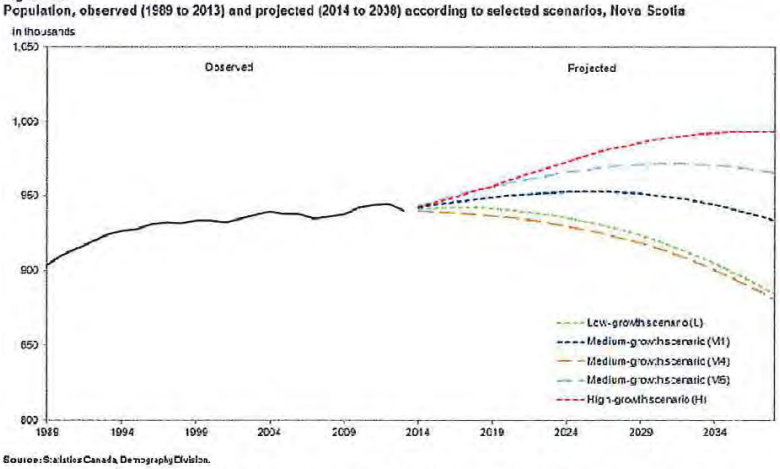


Figure 11 Stats Canada NS Population Projection Model Scenarios

As the "Baby Boom" generation moves through the various age

groups they contributed to consumer spending, employment growth and new residential development. Currently the peak of the Baby Boomers is around age 55 to 59 years old. The leading edge of that generation, however, is around 65 to 69 years old and that point brings into play a number of factors to consider in respect to electricity useage.

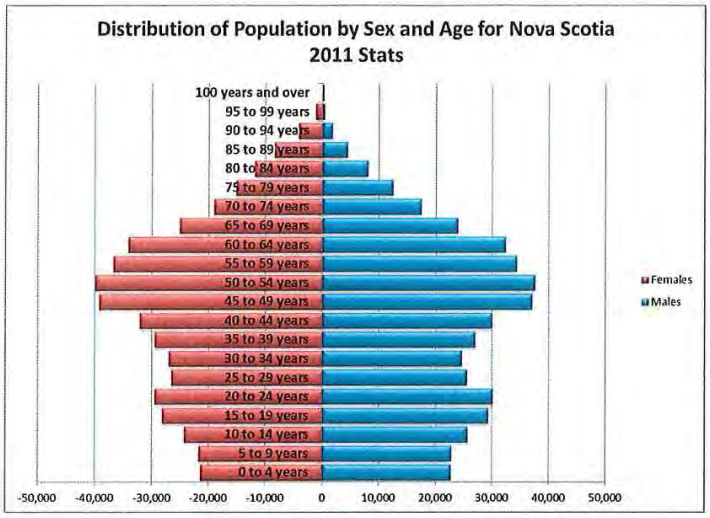


Figure 12 NS Population Pyramid - Figures from Stats Canada

Baby Boomers are in the midst of accelerating retirement numbers. Retirees are at home a greater portion of their time where they tend to seek warmth and comfort in their home. They are less likely to use daytime setbacks for their thermometers (or even to have automated setback thermostats) and are more likely to keep their home temperatures higher and consistent throughout the day. Both of these choices increase energy consumption. On the other hand, reaching retirement age generally means that children are usually no longer living in the same household. Rather, they have likely taken up new residences of their own thereby reducing the home energy consumption. It cannot easily be determined which of these factors might have the greater impact.

This Baby Boom generation is the wealthiest in Canadian history. In retirement their lifestyles will most certainly be quite different from the generation preceding them. Much of the wealth of this generation is locked up in the value of their homes – typically single detached homes. To access that wealth many in this generation would have a tendency, as they age, to sell those homes and downsize to an apartment or condominium to live out their remaining healthy years. Another incentive for this action is that it enables the

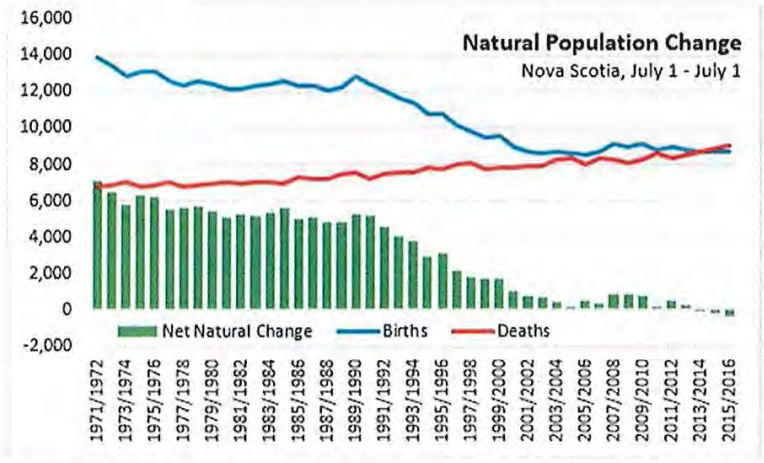


Figure 13 NS Natural Population Change 1971-2016, Births and Deaths

opportunity to travel, as selling their home provides the income to afford travel as well as the ability to leave their residence behind with fewer challenges to secure, maintain and insure it while they are away.

The increased numbers of single detached dwellings available on the market will likely depress new housing starts in this housing category while increasing further the demand for and construction of apartments and condominiums. This trend is already apparent in the shift in the types of housing being constructed in the Halifax area and this shift has been recognized in HRM's Municipal Planning Strategy (http://www.halifax.ca/regionalplanning/documents/RegionalMunicipalPlanningStrategy.pdf Pg. 15). The province' birth rate is now lower than the death rate, setting the stage for accelerated change in this area.

2.3 Commercial and Industrial Development

The largest amount of commercial development taking place in the region is the construction of apartment buildings. This construction is mostly concentrated on the Halifax Peninsula and west Bedford with a smaller number in central Dartmouth. Only a single development with two apartment buildings for Eastern Passage and one additional development with two apartment buildings adjacent to Lake Loon have been proposed for the Dartmouth - Eastern Passage area. This is reflective of the low demand for new housing and overall low growth expectations in general projected for the area by developers.

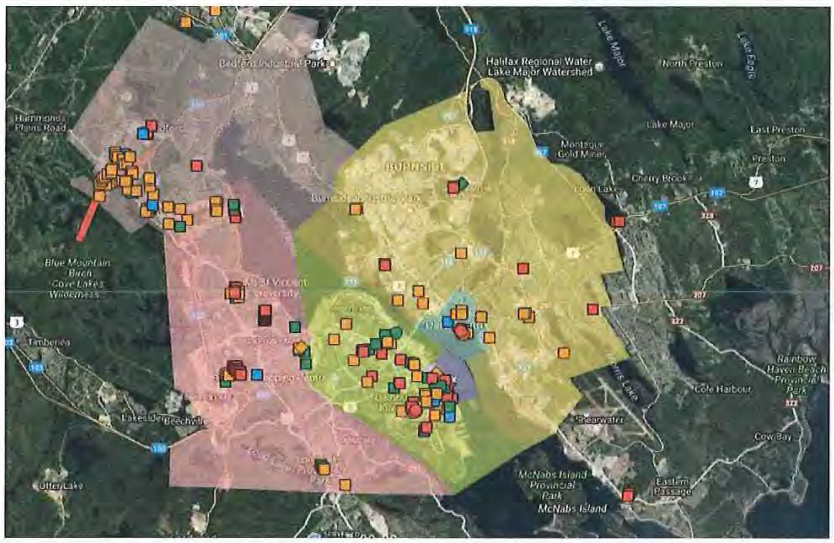


Figure 14 New Apartment Buildings Proposed for the Halifax Metro Area

RED (Red) - Proposed/Planned
ORANGE (Orange) - Approved/In Sales/Site Prep/Recently Approved
GREEN (Green) - Under Construction (Foundation to First Occupancy)
BLUE (Blue) - Recently Completed (Stays in this category for six months following completion of construction)
PURPLE (Purple) - Rejected/Abandoned/Outdated/Expired (Stays in this category for six months following announcement date)

Figure 15 HRM Active Land Use Planning Applications Awaiting Approval

Active land use planning applications before HRM staff for discretional approval also tell a similar story of negligible amounts of development in the Eastern Passage and Cole Harbour areas.

With low expectations for new housing growth in Eastern Passage there is little incentive for commercial development. HRM planning is directed towards increased densification of housing and is aimed at the area inside the Circumferential Highway. This type of development is already occurring in such areas as Kings Wharf in downtown Dartmouth and is further anticipated to occur in the Wyse Road area near the MacDonald Bridge. This is an area identified in HRM's Draft Centre Plan for development (http://centreplan.ca/).

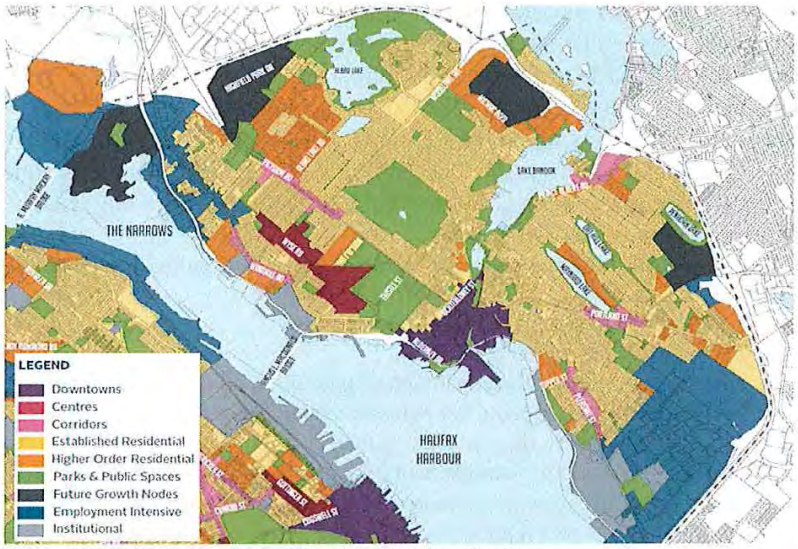


Figure 16 HRM Active Land Use Planning Applications

An additional factor affecting the Eastern passage area is accessibility. There is only one main artery road (Pleasant St.) and only two secondary routes (Caldwell Rd. and Bissett Rd./Cow Bay Rd.) into the area. That may change if HRM gains approval for a new connector road from Mount Hope, but it is not seen to be a growth factor within the ten year horizon of this planning review, particularly considering that Eastern Passage is not identified as a significant urban growth centre in HRM's new Regional Plan (http://www.halifax.ca/regionalplanning/FinalRegPlan.php).

Similarly, access is an important consideration for industrial development. The port facilities in the Eastern Passage area are mostly for automobile imports and petroleum product storage. Together with a functioning military airbase (12 Wing Shearwater) they provide valuable economic activity. There are no announced plans for any further industrial development in the area; new industrial developments are focused on areas like Burnside Industrial Park and to a lesser degree the Woodside Industrial park. However, a study is under way by the Halifax Port Authority charting out the strategic direction for the port and consideration of moving one or both container terminals to the Dartmouth area is one alternative under review. Any plan to do this would not be within the timeframe of this study so no allowance is being made in any load forecasts.

2.4 Demand Side Management (DSM)

One definition for Demand Side Management (DSM) is that it is the modification of consumer demand for energy through various methods such as financial incentives and behavioral change through education. DSM initiatives can become clouded by the actions and results of government programs and policies that modify the marketplace. As such they may become encompassed in what is thought of as DSM.

In its 2015 Decision for approval of the first Supply Agreement for electricity efficiency and conservation activities between EfficiencyOne and Nova Scotia Power, the NS Utility and Review Board (NSUARB or the Board) referenced the 2014 Electricity Efficiency and Conservation Restructuring Act. The 2014 Act provided for significant changes to DSM programming by amending the Public Utilities Act and repealing the 2009 Electricity Nova Scotia Corporation Act. The revised Public Utilities Act now states that electricity efficiency and conservation activities are defined in the following way:

> "79A In this Section and Sections 79B to 79V,
>
> (b) 'electricity efficiency and conservation activities" means activities, programs or plans relating to
>
> (i) the efficient use of electricity,
>
> (ii) the conservation of electricity,
>
> (iii) the alteration of the consumption pattern of an end-user of electricity that has the effect of reducing demand during Nova Scotia Power Incorporated's periods of highest demand,
>
> (iv) the utilization or management by Nova Scotia Power Incorporated of its electrical system in a more cost-effective manner,
>
> (v) the delivery of a reduction in the amount of electrical energy or capacity that Nova Scotia Power Incorporated would otherwise be required to supply to its customers, or
>
> (vi) any other prescribed activities, plans or programs;"

The Board in its Decision further went on to state that "*The Board uses the terms DSM and electricity efficiency and conservation activities interchangeably in this Decision.*" This terminology continues to cloud the definition of DSM.

A useful way to view the world of savings in respect to consumer demand for energy is to think of it in terms of "organic" (or all-natural) DSM and programmatic (targeted or directed) DSM. The organic portion of DSM is the portion of energy saving that is accomplished without specific intent through consumers' purchases of new or

replacement electrical devices that are inherently more energy efficient – either as a result of efficiency standards mandated by government decrees (e.g. phase out of incandescent

Average Annual Energy Consumption of New Major Appliances (in kWh/yr)	1990	1997	2001	2010
Refrigerators (467.3 – 521.1 L [16.5 – 18.4 cu. ft.])				
Standard top-mounted	1044	664	572	427
ENERGY STAR qualified	–	–	440	369
Freezers				
Standard chest	658	342	337	295[1]
Cooking appliances Ranges (76 cm [30-in.])				
Self-cleaning	727	759	741	530
Non-self-cleaning	786	780	786	499
Dishwashers				
Standard	1026	649	634	310
ENERGY STAR qualified	–	–	534	309
Clothes washers				
Standard (top-loading)	1218	930	905	319
ENERGY STAR qualified	–	–	304	148
Clothes dryers				
Standard	1103	887	916	928

Table 4 New EE Appliance Annual Energy Consumption
Source: National Energy Use Database, NRCan

lighting or regulation of minimum appliance efficiency standards) or by way of technological shifts (e.g. LED/LCD vs CRT TVs). As can be seen in Tables 4 and 5, purchases of efficient appliances have a major effect on the intensity of energy consumption in the home.

Table 5 Power Consumption Comparison between LED, LCD, CRT & Plasma:

Screen Size	LED	LCD	CRT	Plasma
15 inches	15	18	65	---
17 inches	18	20	75	---
19 inches	20	22	80	---
20 inches	24	26	90	---
21 inches	26	30	100	---
22 inches	30	40	110	---
24 inches	40	50	120	---
30 inches	50	60	---	150
32 inches	55	70	---	160
37 inches	60	80	---	180
42 inches	80	120	---	220
50 inches	100	150	---	300

*** Results may vary significantly; results assume displays are calibrated for energy saving performance.**

The technological developments in digital electronics and video displays enabled a shift from CRT televisions to LED/LCD televisions and this has created significant energy saving improvements for these video entertainment devices. However, cost improvements have meant that increased numbers of such devices in the home.

In its report Energy Efficiency Tends in Canada, 1990 to 2009 (http://oee.rncan.gc.ca/publications/statistics/trends11/chapter3.cfm), NR Canada stated "*in contrast to trends for major appliances, energy use for smaller appliances such as televisions, VCRs, DVDs, stereo systems and personal computers more than doubled (+158 percent). This increase more than outweighed the energy use reduction from major appliances. One example of the rapid growth in minor appliances is the increased penetration of personal computers. In 1990, computers were present in less than one out of six households but by 2009 they were present in more than four out of five households in Canada. Furthermore, the rapid penetration of digital TVs, DVDs and digital cable boxes also contributed to the increase.*" That report, however, indicated that in 2009 appliance energy use constituted 14% of household energy use. By 2013, though, appliance useage had decreased to 12% of overall energy useage. This reduction was likely due to a decrease in the level of new home construction, saturation of the market for minor appliances and continued replacement of older, lower efficiency appliances with newer even more energy efficient models.

ENS Claimed and Forecast DSM Savings for Dartmouth - System Coincident Peak Demand

YEAR	Cumulative MW
2011	3.01
2012	5.86
2013	9.88
2014	12.38
2015	15.32
2016	17.52
2017	19.72
2018	21.92
2019	24.12
2020	26.33
2021	28.53
2022	30.73
2023	29.92
2024	32.12
2025	31.47
2026	29.65
2027	29.35
2028	28.62
2029	30.82
2030	33.02

Table 6 Dartmouth Area Forecast Cumulative DSM Saving MW

Figure 17 Distribution of Residential Energy Use
Source: Distribution of residential energy use in Canada 2013, Natural Resources Canada.

In 2009, under the Efficiency Nova Scotia Corporation Act, the provincial government established the crown corporation Efficiency Nova Scotia Corporation to manage electricity Demand Side Management or DSM initiatives within Nova Scotia. These initiatives were funded by a DSM charge on electricity bills. In 2014, legislative changes under the Electricity Efficiency and Conservation Restructuring Act required DSM initiatives to be provided by a franchise holder. The franchise holder, now known as EfficiencyOne, has the exclusive right to supply Nova Scotia Power with reasonably available, cost-effective efficiency and conservation activities for a ten-year term. The business called "Efficiency Nova Scotia (ENS)" is the actual franchise operation that was created by the province and which is held by EfficiencyOne. ENS continues all the business

obligations formerly carried on by Efficiency Nova Scotia Corporation. It is a public utility regulated by the NSUARB.

The Board approves agreements between Nova Scotia Power and the franchisee EfficiencyOne on the level of DSM activity. The cost of these activities is included in electricity rates. The 2014 Electricity Efficiency act requires that energy and demand savings of the ENS programs be estimated through an audit process which in 2015 was undertaken by Econoler for ENS. The evaluations were conducted for the full cross section of ENS programs, which include:

- Appliance retirement incentive program
- Instant savings rebate programs
- LED holiday light exchange
- Home energy assessments plus rebate and financing
- Green heat – heat pump rebate and financing program for all-electric homes
- Residential direct install of energy efficient devices
- Rental properties and condos direct install of energy efficient devices
- New home construction incentives to exceed efficiency standards
- Home energy audits aimed at energy use behavioral modification
- Business energy efficient product rebate program
- Custom technical support, rebate and financing assistance program to assist business, non-profit and institutional customers with saving energy
- Energy management information system rebate and no cost financing program for medium and large industrial customers
- Small business energy saving measure cost rebate program

These estimates by Econoler form the basis for the ENS forecasts of savings from these programs. In addition to the ENS programs, Econoler estimated the amount of additional energy efficiency savings from new building codes and standards recently implemented in Nova Scotia.

Due to the difficulty in measuring with any great certainty by way of an audit process the specific savings achieved, there remains uncertainty around the actual impact of DSM programs already implemented. This continues to be a challenge for developing greater confidence in the forecasted impact of future DSM programs. The achievements of DSM in various areas will be commented on throughout the analysis of load data in Section 3 of this report.

2.5 Building Standards

The National building Code is periodically updated. The most recent update was issued in 2010 and was adopted by the province in 2011 (http://www.halifax.ca/building-renovating/BuildingCodeandRegulatoryInformation.php). The standard contains, in section 9, new prescriptive requirements for energy efficiency that applies to the building envelope, heating, ventilating and air conditioning equipment and to service water heating. Estimates of the impact of these new requirements suggest a 5% overall energy consumption reduction for housing built to the new standard.

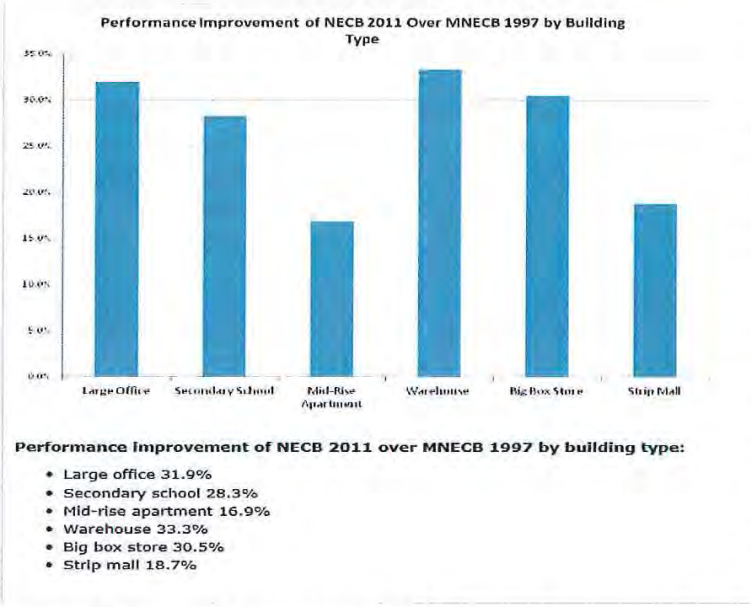


Figure 18 Performance Improvements of New National Energy Code

In 2011 Natural Resources Canada (NRC) published the New National Energy Code of Canada for Buildings and this was fully adopted by the province Jan 1, 2015. The code is aimed at offices, stores, warehouses, hotels, arenas, hospitals and schools and replaces the Model National Energy Code for Buildings 1997 (MNECB). The new National Energy Code is estimated to improve the energy efficiency of buildings by 25% over the MNEBC. The 2015 National Building Code has yet to be adopted by the Province; however, that is expected to take place effective April 1, 2017.

While not yet incorporated into Standards, NRC has recognized the growing interest in and demand for solar installations. In response to this growth in interest NRC has produced a Solar Ready Guideline for the installation of solar domestic hot water and photovoltaic systems in residential buildings: (https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/canmetenergy/files/pubs/SolarReadyGuidelines_en.pdf) . These guidelines are being promoted on HRM's Solar City Halifax webpage: https://halifax.ca/solarcity/Residents/Public.php .

In addition to requirements of the National Building Code (2010) and the National Energy code (2011), some building developers have adopted the Leadership in Energy and Environmental Design (LEED) building certification program. LEED is one of the most popular green building certification programs used worldwide. LEED certification – available for both housing and commercial buildings – provides independent, third-party verification that a building, home or community was designed and built using strategies aimed at achieving high performance in key areas of human and environmental health: **sustainable site development, water savings, energy efficiency, materials selection and indoor environmental quality**. A number of buildings in the local area were either built or renovated according to this certification program, including NS Power's head office in the renovated Water St generating station.

New housing and commercial buildings will use less energy than their predecessors due to the adoption of these new codes and measures. Forecasting future distribution system

load using past housing consumption levels as a gauge of future levels will produce overestimates of consumption.

2.6 Natural Gas

Natural gas distribution rights in Nova Scotia are held by Heritage Gas, a subsidiary of AltaGas. The company has been gradually expanding its distribution network in the area with the first priority being to service larger customers and then to expand into higher density neighborhoods with high penetrations of oil heating. An area of new construction in which Heritage Gas has achieved significant market penetration is Russell lake West. In that area many homes have ducted heat pump systems that employ natural gas as the backup heat source. These systems minimize contributions to the system peak when outside temperatures fall below the minimum temperature at which the heat pump can operate.

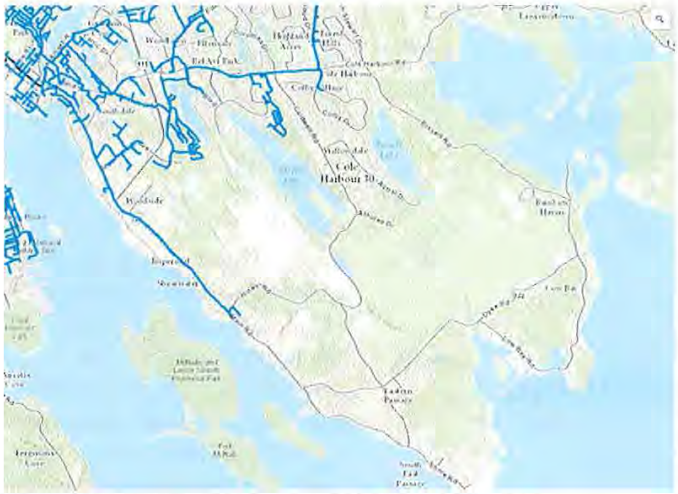


Figure 19 Heritage Gas Existing Distribution Network

Because natural gas is displacing primarily oil heating in its service areas the expansion of the system poses little change on existing electrical loads. Customers who already heat electrically are more inclined to install heat pumps to save on heating costs than they are to install a gas furnace as the conversion costs are far lower and heat pumps offer the added benefit of summer air conditioning.

It is for these reasons that natural gas system expansion is not expected to impact the load forecast for the Cole Harbour or Eastern Passage areas.

2.7 Solar – Thermal and Electric

Halifax is located at a latitude just south of the 45th parallel, in between the latitudes of Germany (with a latitude extending from around the south coast of Newfoundland to 200 km north of Happy Valley/ Goose Bay) and Spain (with a latitude extending from South Carolina to the southern tip of Nova Scotia). Both Germany and Spain are countries that have extensive solar installations. While the efficiency of solar to electric conversion has been improving it is the cost effectiveness of the technology that has made the largest gains.

China has become the world's largest producer of solar modules which they ship to panel manufacturers worldwide. Their market insight was that by focusing on the most cost effective solar module production rather than modules with the highest efficiency they

could have the lowest cost per kW product. Interestingly, the third largest manufacturer in the world of solar modules and panels is Canadian Solar, with production facilities in Canada, China and Vietnam.

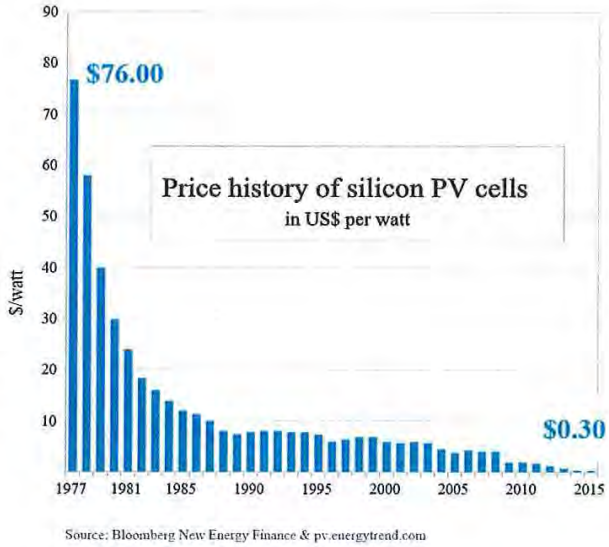


Figure 20 Price History of Silicon Photovoltaic Cells

The cost of photovoltaic solar cells, modules and panels has been declining and has reached a point where large installations are competitive with conventional generation sources or utility retail costs. With a rate of decline in cost around 10% per year, economics continue to improve as shown in Figure 20 (from Rfassbind - based on Hanjin's 2013-version (in Spanish), amended with average sales prices for 2014 and 2015. Original source data 1977–2013: Bloomberg, New Energy Finance). Solar module cost in 2015 is approximately US$0.16/W higher. Panel prices to solar companies in early 2016 were as low as US$0.75 per watt and homeowners could purchase individual panels at prices in the range of US$0.85 to $1.25. Typical 5 kW solar systems installed in US residential homes in 2016 averaged US$3.57, including a Federal income tax credit that reduces costs by about 30%. The added costs above the base panel cost are for inverters, solar batteries, additional equipment and permits etc. plus design and installation labor to implement a complete solar system.

Green Power Labs of Dartmouth, in responding to a request from Emera to estimate future solar power costs, has indicated that solar power in Nova Scotia will reach grid parity around 2019. The meaning of that statement is a consumer making a choice between either purchasing their electrical power for the subsequent 25 years from NS power, or installing a solar power system in their home would be faced with an equal cost choice. After 2019 solar would become the less expensive choice. An excellent assessment of breakeven costs for solar in the US is available at http://www.nrel.gov/docs/fy10osti/46909.pdf

Reaching breakeven does not foretell that customers will immediately abandon NS Power in favor of solar electric power installations as there are many other considerations: the ability to finance a solar installation; suitability of the customer's site; the customer's interest in being, or their ability to be, an operator of their facility; support infrastructure for installation and service; reliability of supply; etc. Aside from early adopters the transition is likely to take many years, but it is certain to happen. Today there are increasing amounts of solar photovoltaic installations both in specialized applications like highway signalling lights, remote telecommunications sites and off-grid recreational

properties where solar supplies all the requirements and in more conventional applications such as residential homes and commercial buildings where solar supplements their consumption from NS Power.

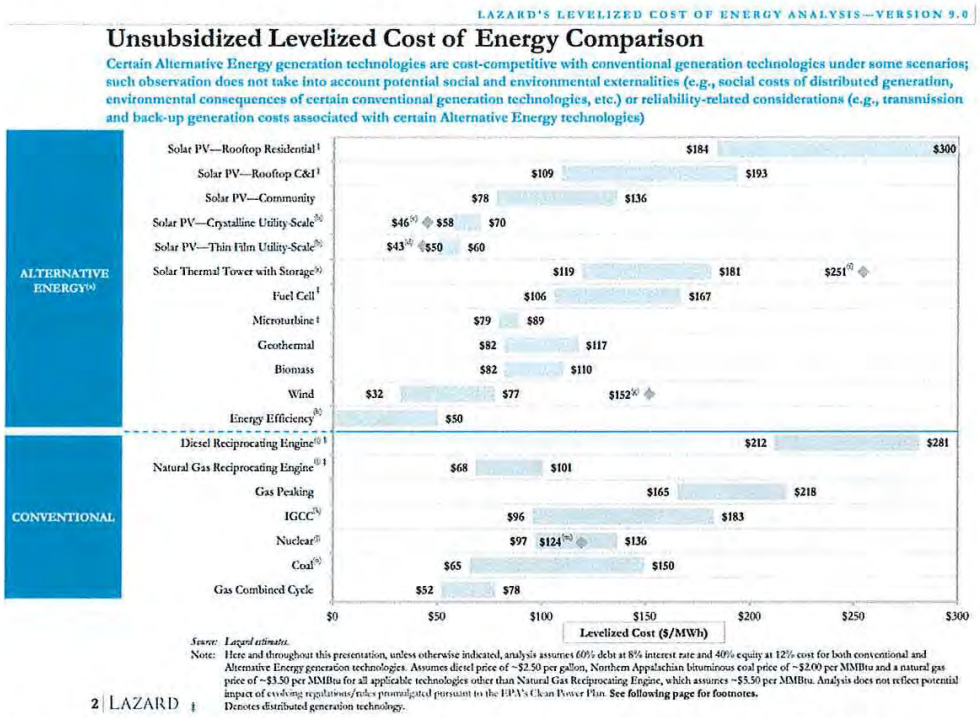


Figure 21 Comparison of Levelized Cost of Energy: Conventional and Alternative Energy

Ikea's new retail store under construction in the Dartmouth Crossing business park will have one of the largest solar installations in Nova Scotia. According to Ikea, the building will have 600 kW of solar panels on the roof, LED lighting throughout the store and a ground source heat pump for heating/cooling requirements. Although special concessions were made to Ikea to enable a PV installation larger than 100 kW, it might be expected

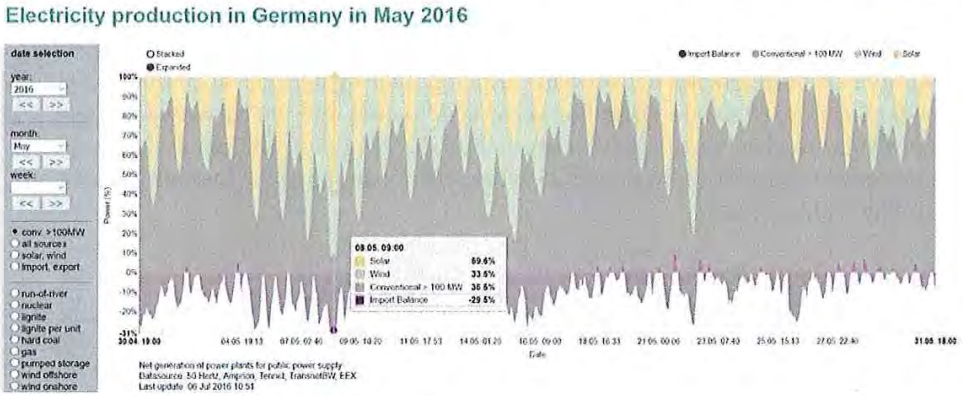


Figure 22 Solar Generation in Germany
https://www.energy-charts.de/power.htm

that as other commercial and industrial developers consider how they will represent themselves as being environmentally conscientious, there will be other developments that will follow this lead.

The interest in solar installations is growing around the world (and in HRM). In Germany, solar generation is already feeding into the grid and occasionally supplies over 60% of the conventional generation on the grid. Beginning five years ago HRM initiated a Solar City pilot program under which they completed 388 solar thermal installations. Monitoring on 200 of those systems provided data that enabled the city to calculate annual returns on investment of approximately 5% from the energy cost savings. Following the success of the pilot program, in 2015 HRM approved a full three year program under which they anticipate installing 400 systems per year. The program was expanded to include solar photovoltaic systems in addition to the solar thermal hot water and hot air systems that were included in the pilot. Interest in the program has been high.

Figure 23 Locations of Distributed Generation in Dartmouth Area (Black Crosses)

Solar photovoltaic installations approved under the HRM program require that the applicant arrange for an interconnection agreement with NS Power. A number of such sites are already in operation in the Dartmouth area ahead of the HRM program. They are coded in the CIS with a Rate Code 09. For those customers, electrical meters registering both energy consumption and delivery are installed. During periods when the customer's solar generation exceeds their need the excess is delivered into the NS Power system. The number of solar electric installations connected to the NS Power system at this time remains small as can be seen in Figure 23 where the locations in the Dartmouth area are marked with a black cross.

The 2015 Electricity Review Report (http://energy.novascotia.ca/sites/default/files/Electricity%20System%20Review_Report.pdf Pg. 33) prepared in response to the 2013 Electricity Reform Act contained a report from Solar Nova Scotia that stated "*installed solar photovoltaic capacity grew at an annual average rate of 80% in the previous 5 years. Future growth of a modest 30% annually could result in 32 MW of installed capacity by 2030*". It is anticipated that within the 10 year horizon of this plan, solar will begin to have a small impact on the

customer total energy consumption. However, due to the timing of the solar electrical generation – both daily and seasonal – there will probably be little to no impact on system peak electrical demand.

The ability to impact peak demand can be accomplished if electrical energy storage is added to the system in conjunction with solar or wind generation. Until such time as on-site battery storage costs become more economic (see 2.12 Battery Energy Storage), utility-scale battery storage would be a more cost effective and a real option in the right circumstances to reduce demand on circuits and equipment that is approaching capacity limits.

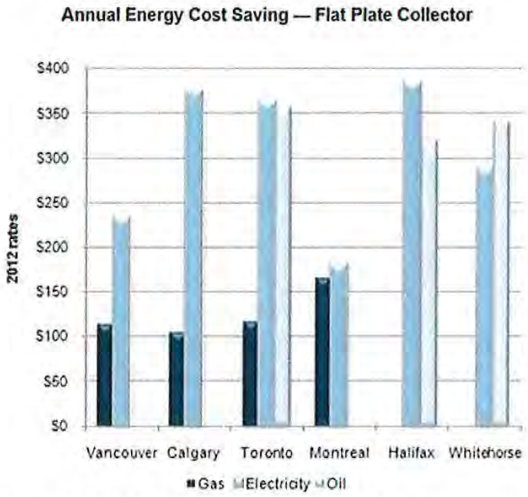


Figure 24 Solar Thermal Energy Cost Saving

Solar thermal presents opportunities that are different from solar photovoltaic. Thermal energy can be stored less expensively than electric energy making it possible to move water heating load off the system peak as water can be heated during the day and be available through the peak period. The option to this form of storage, however, is time-of-use electricity rate incentives that motivate customers to install relatively inexpensive relay switches that can move electric water heating load off the system peak.

Solar thermal should probably be viewed as an opportunity to reduce generated electric energy with accompanying reductions in environmental emissions rather than an opportunity to reduce load peaks.

2.8 Heat Pumps

Heat pumps provide space heating and cooling by employing a refrigerant, compressor and heat exchangers to move heat from one side of the building envelope to the other. For most temperature conditions this is a much more efficient method of providing space heating than creating the needed heat from the combustion of a fuel or via electrical resistance heating elements.

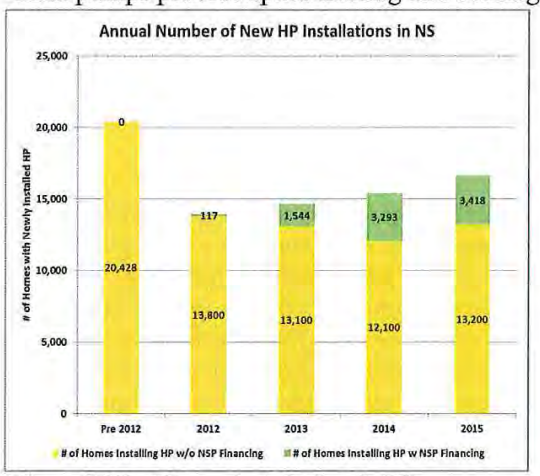


Figure 25 Heat Pump Installations in NS

Due to an interest by NS Power in managing its system load and limiting environmental impact from its generation, the company is offering its customers the opportunity to finance heat pump installations. Together, with the

customers who have installed heat pumps without NS Power financing, it is believed that at the end of 2015 there are approximately 81,000 heat pump installations throughout the province. This results in approximately 11% of Nova Scotia homes indicating a heat pump as their primary heating source. It was also estimated at the end of 2015 that heat pumps were installed in approximately 18% of Nova Scotia premises, providing some or all heating requirements. It is further estimated that the penetration into the home heating market will reach 35% by 2022.

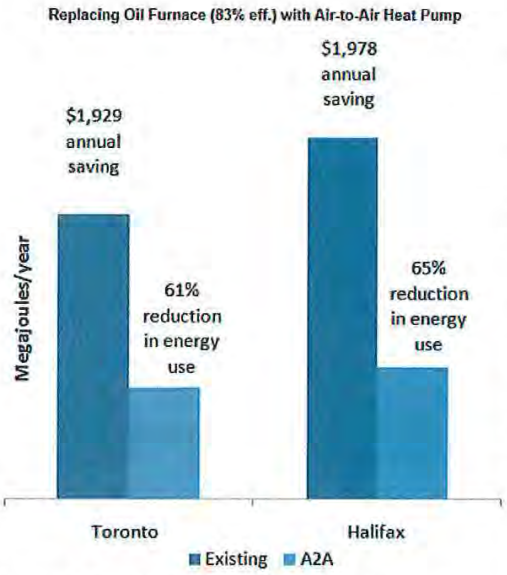


Figure 26 Cost Saving Oil to Heat Pump Conversion

The impact of heat pump installation on system peak load varies according to the type of heat pump and the original heating source. Non-all-electric customers who install an air-source heat pump and who retain a non-electric system for backup will have little impact at all on peak load. The experience of the NS Power heat pump financing program is that 37% of customers are converting from oil to heat pumps and 42% are converting from electric heat to heat pumps. This is probably reflective of the somewhat better economics of conversion from electric heat than from oil heat in Nova Scotia. It could be proposed that many conversions from oil heat result in the old heating system being retired and removed. Little information exists on customers' practices for backup heating needs during very cold weather. Anecdotal evidence suggests that there is a tendency for customers to tolerate cooler home temperatures during such temperature dips rather than activate backup heating systems, provided this does not extend over a prolonged period.

If customers depend on electric heating as a backup they will add substantially to the system peak as such peaks occur during the coldest weather when most types of heat pumps switch over to a backup system. From a peaking standpoint, the coincident peak load of all-electric customers who install a heat pump for their primary heating needs changes little during system peaks. However the nature of the load levels they create over time does change.

Heat pumps produce more heat energy output than the amount of electrical energy input; however, the output performance declines as temperature decreases. Two effects come into play: a) there is a greater coincidence rate that heat pumps will be operating simultaneously to supply the needed energy. This is similar to electric heat albeit at a lower overall electrical demand because of their efficiency; and b) at some outside temperature at which the heat pump is still providing more energy output than input (typically in the -10 C to -25 C range, depending on the manufacturer's model) the unit switches over to the backup heating system. From the supply standpoint this switchover

creates a step increase in load for that customer if that backup is electrical and the customer continues to demand the same indoor temperature.

These two considerations taken together create a relatively smooth transition in the rate of load increase as temperature falls. While the heating load diversity for heat pumps is lost with falling temperatures, the variation of the low temperature cut-out among models together with the variation in time at which the switchover temperature is reached at each installation site creates a smooth transition in the load increase as seen by the system.

Economics will continue to favor conversions from both oil and electric heating to heat pumps (https://www.cmhc-schl.gc.ca/en/inpr/su/sufepr/sufepr_001.cfm) driving higher penetration levels over time.

In the Eastern Passage area approximately 49% of customers heat electrically and 43% heat with oil as indicated by CIS Rate codes. Of the approximately 5,600 customers in the area there are, as of August 2016, only 85 who have accessed the NS Power heat pump program to install a system at their location. Using ratios of financed HP systems to estimated HP penetration levels across the province it could be estimated that there are about 1,000 HP installations in Eastern Passage, leaving substantial room to increase the installation numbers. As a result, it could be expected that heat pump conversions in the area may increase peak demand during cold weather events, particularly if natural gas is not extended into the area. This is a matter that invites ongoing monitoring of the load growth and peak load characteristics.

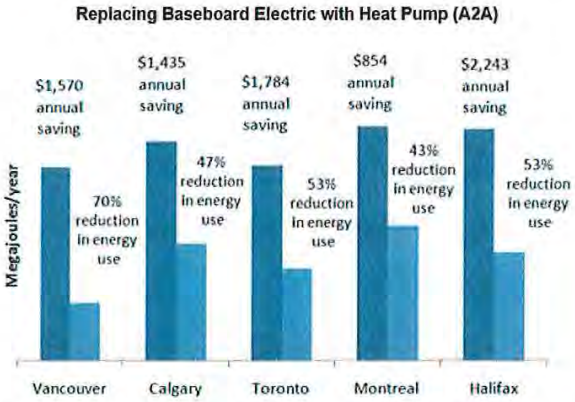


Figure 27 Cost Saving Electric Baseboard to Heat Pump

2.9 Electro-Thermal Storage and Time-of-Use

The incentive for NS Power to promote electro thermal energy storage derives primarily from the cost differentials that exist between peak and off-peak energy generation costs but also in part from the avoidance of the need to acquire new generating capacity. These factors can be costed and time-of-use rates developed to incent adoption of technologies that shift electrical useage to more advantageous time periods.

Approximately 1,000 of 43,000 homes and businesses in the Dartmouth area are on time-of-use billing – just over 2.3% penetration. There remain over 12,000 electric heat customers in the area to whom ETS and TOU can be marketed. The market interest in ETS has not reached the same levels as for heat pumps so it remains a marketing challenge to further increase penetration levels. The barriers that exist for growing ETS and TOU penetration will need to be well understood and overcome to make this a useful tool for shifting peak load.

2.10 Energy Retrofits

The largest energy consumption in any household is for space heating. The Canadian average is 63% of home energy consumption devoted to space heating. For many home owners an energy retrofit is the most cost effective way to reduce their home heating costs. In doing so they reduce electrical consumption related to electric heat and the operation of other heating equipment. Because the coincidence factor for the system load peak is near 100% it will have a corresponding beneficial impact on generation and system capacity needs.

Efficiency Nova Scotia operates a Home Energy Assessment program that provides help with rebates or financing. Econoler in its audit report found relatively small savings across the province from this program and a relatively high free ridership level of 31% for the program, which is an indication of the challenges involved in motivating households to undertake retrofits.

For these reasons it is anticipated that energy retrofits, while they have the potential to reduce electrical consumption, are unlikely to have a noticeable impact on load in the east Dartmouth or Eastern Passage areas.

2.11 Electric Vehicles

Total Canadian EV Fleet

As of September 30, 2016

Row Labels	Alberta	British Columbia	Manitoba	New Brunswick	Newfoundland & Labrador	Northwest Territories	Nova Scotia	Ontario	Prince Edward Island	Quebec	Saskatchewan	Yukon	Grand Total
BEV	318	3220	71	16	5	3	61	4420	9	5329	28	1	13482
BMW i3	1	182						82		40	1		255
CHEVROLET SPARK		4		1				14	1	96		1	117
FORD FOCUS	7	70					1	95		167	2		342
KIA SOUL	1	216						169		478			866
MITSUBISHI I-MIEV	12	123	5	3			4	122	1	418	1		688
NISSAN LEAF	44	1142	36	6	3	1	24	941	6	2432	9	1	4635
SMART FORTWO	10	219	2					548		337			1111
TESLA MODEL S	203	1091	23	6	1	1	32	2191	1	1223	13		4784
TESLA MODEL X	32	213	4		1	1		334		141	1		627
TESLA ROADSTER	8	9	1					27		7	1		53
TOYOTA RAV4		1						2			1		4
PHEV	340	1478	77	46	16	1	34	3852	3	6580	41	0	12747
AUDI A3	6	67		1	1			128		73			276
BMW 330e	1	6						6		2			15
BMW i3 REX		195		1	1			211		144			552
BMW i8	9	130	1	1				165		54			360
BMW X5	16	66	4	1	1			97		17	3		205
CADILLAC ELR	2	12	2					26		40			82
CHEVROLET VOLT	123	586	44	31	9	1	15	2156	2	5328	22		8317
FISKER KARMA	3	34						40		27			100
FORD C-MAX	65	110	10	5	2	0	2	848	0	848	5		1066
FORD FUSION	18	57	5	2	1	0	1	180	0	284	5		553
HYUNDAI SONATA	2	6	1	0	0	0	0	19	0	10	0		58
MCLAREN P1	3	2						3		1			9
MERCEDES S550E	2	2						3					7
PORSCHE 918	4	8	1					9		3	1		24
PORSCHE CAYENNE	37	92	8	2			5	181		77	5		404
PORSCHE PANAMERA	3	18	1				6	11		3	0		42
TOYOTA PRIUS PHV	10	50	3	1	1	0	1	94	0	149	1	0	289
VOLVO XC90	60	69					4	154		99	1		387
FCV	0	0	0	0	0	0	0	1	0	0	0	0	1
HYUNDAI TUCSON FCV								1					1
Grand Total	658	4698	148	62	21	4	95	8273	12	11909	69	1	26350

Figure 28 Total Canadian EV Fleet (http://www.fleetcarma.com/ev-sales-canada-2016-half-year/)

Electric vehicles continue to make inroads into the new vehicle market. While most electric vehicles on Nova Scotia roads are hybrid vehicles, there are increasing numbers of models of plug-in hybrid and battery electric vehicles being brought to the market by manufacturers and being purchased in Nova Scotia. NS Power has begun to promote electric vehicles on its website http://www.nspower.ca/en/home/community/electric-vehicles/default.aspx . For a period of time NNS Power had operated a program called ShareReady from which it had learned a great deal about the operation of EVs. The availability of EV recharging stations was found to be one of the most significant factors holding back their more general adoption. Although the AC charging network with Level 2 chargers now spans from Yarmouth to Sydney and there were plans to have as many as 50 stations installed in Nova Scotia by the end of 2015 charging stations are still not widely available for public use. As of this date there are only two high capacity Level 3 DC charging stations

Figure 29 Location of EV Charging Stations - PlugShare

in the province – one near downtown Halifax and another at the Truro Power Centre. There are no publicly accessible EV charging stations in the Eastern passage area.

A quick check of the information given for the charging stations shown on the PlugShare website (http://www.plugshare.com/) reveals that many of the stations are unavailable for use by the general public, continuing to limit opportunities for deploying electric vehicles.

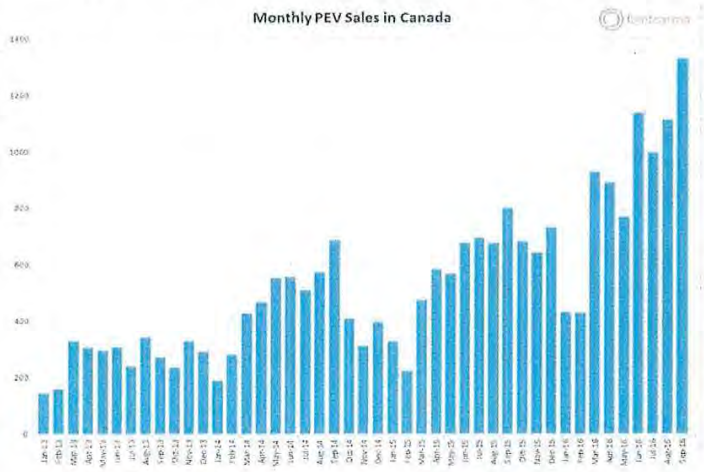


Figure 30 Monthly EV Sales in Canada (http://www.fleetcarma.com/ev-sales-canada-2016-half-year/)

There are strong and growing economic incentives to attract vehicle purchasers to consider EVs. While the initial purchase cost of an EV is higher than that of an equivalent gasoline vehicle, their operating cost over the vehicle life is up to 30% lower. Trends in EV battery costs are showing a 10% annual decline which is expected to put EV purchase prices on par with gasoline vehicles by the mid to late 2020s adding further to the vehicle economics.

Figure 31 Ten Year Cost of EV Ownership (http://www.nspower.ca/site/media/Parent/ShareReady%20v4.pdf)

With improving performance and cost EV sales are certain to increase, although it is difficult to predict by how much. Owners of EVs will almost certainly install charging stations for their vehicles at their residences and look to utilize charging infrastructure as it develops

High penetrations of vehicle charging stations could increase system peak loading; however, there are opportunities to manage much of the load through time-of-use incentives. There may be less opportunity with DC Fast Charge stations as they will most likely be in use during the day. The largest amount of charging, though, is likely to take place overnight at home making the load more compatible with the system capability.

Electric vehicle energy useage ranges from approximately 16 kWh/100 km to 25 kWh/100 km depending on the car model, which equates to fuel economy levels of approximately 1.7 to 2.8 L/100 km. Given typical annual driving distances of 20-30,000 km/year would put most cars in the energy consumption range of 4,000 to 6,000 kWh per year. This amount of electrical energy is in the range of half the annual consumption of a typical non-all-electric residential customer.

Table 7 EV Charging Time and Power (https://en.wikipedia.org/wiki/Charging_station)

Charging time for 100 km of BEV range	Power supply	Power	Voltage	Max. current
6–8 hours	Single phase	3.3 kW	230 V AC	16 A
3–4 hours	Single phase	7.4 kW	230 V AC	32 A
2–3 hours	Three phase	10 kW	400 V AC	16 A
1–2 hours	Three phase	22 kW	400 V AC	32 A
20–30 minutes	Three phase	43 kW	400 V AC	63 A
20–30 minutes	Direct current	50 kW	400–500 V DC	100–125 A
10 minutes	Direct current	120 kW	300–500 V DC	300–350 A

Given the current low level of penetration of electric vehicles in Nova Scotia it is not expected that their electricity consumption will contribute significantly to load on the Dartmouth and Eastern Passage areas within the 10 year time horizon of this study but could grow substantially beyond that timeframe should EV adoption increase as per some forecasts.

2.12 Battery Energy Storage

Battery energy storage used in a peak shaving mode has great potential for deferring capacity additions at substations. When installed on a feeder that is also at its capacity limit it has the potential to resolve both of the overload conditions at once. Costs of battery storage continue to decline.

The battery capturing the greatest amount of notice in the residential marketplace is the Tesla PowerWall battery. In the utility and business market Tesla PowerPack batteries are being installed or considered for such applications as backup, peak shaving, renewable energy storage, etc. With the completion of their new battery production facility in Nevada, Tesla will be scaling production upward to meet a growing market. While their product is relatively expensive for many applications, it is one of the most competitively priced battery energy storage systems in the marketplace.

Battery electricity storage opens up opportunities to develop distributed dispatchable power and energy on the distribution system. Many challenges need to be overcome before this becomes a reality. Those challenges are not anticipated to be overcome at the customer level within the ten year timeframe of this study. Utility scale installations could be considered under the right circumstances, but appear to not be required for the Eastern Passage area at this time. This recommendation should be revisited should the increasing penetration of heat pumps affect load peaks under cold weather conditions.

2.13 Distributed Generation

The installation of distributed generation (DG) affects the peak load on a feeder as measured at the substation. A challenge in computing the actual feeder loading is obtaining data on the instantaneous quantity of generation on the feeder. The effect of this is illustrated well at the 137H Hammonds Plains substation where 10 MW of wind generation at Pockwock on feeder 137H-413 is connected. In this instance load data from the wind generation is available, which enables the feeder load to be calculated.

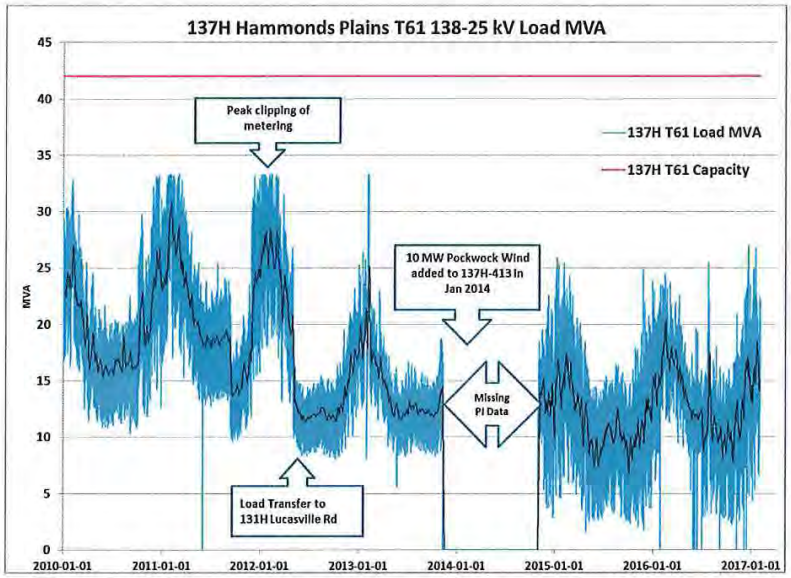


Figure 32 Impact of Distributed Generation on Metered Substation Load

However, many distributed generation installations today do not provide their data to the NS Power Control Centre. Under such conditions it is possible for peak load conditions that exceed the feeder or even the substation transformer capacity to exist without being evident to operators and planners. As NS Power is accountable for maintaining the reliability of supply to customers on the feeder and as DG output may only randomly offset load levels, and it is not able to be dispatched to address overloads, the potential exists for unexpected overloading to occur. While this shortcoming is gradually being addressed through increased communication requirements for larger sites it remains a challenge for small distributed installations.

As is the similar case with distributed battery storage, a smart grid communication system is an enabling technology that would facilitate the transmitting of distributed generation data to the control centre. The same communication system could also be used for monitoring the voltage profiles on the feeder under all loading and generating conditions.

The ultimate solution for ensuring that peak load reductions are able to be achieved is the availability of dispatchable capacity on the feeder. Dispatchability is not a normal feature of wind or solar generation. Matching wind and solar with energy storage can achieve that objective. The opportunity exists to incent the DG developer to install storage capacity. Delivering dispatchable power from storage offers an additional revenue stream for the developer and perhaps a cost-effective means for the utility to address overloading conditions without needing to expand equipment capacities.

Past concerns existed in regards to not exceeding the amount of distributed generation capacity allowable on the system – that is distributed generation capacity that does not have an inertia component for assisting with stability. Those concerns are now subsiding with the emergence of new types of power inverters. The Virtual Oscillator Control (VOC) inverter makes it possible to control grid stability under a broad range of operating conditions. The greater level of DG that with such controls would then be allowable on the system opens up possibilities for a micro grid concept for distribution system operation. This provides a strategic opportunity for building distribution system resiliency and reliability.

HRM has provided in its zoning plans for both Eastern Passage and Cole Harbour, zoned areas that could accommodate wind generation. However, there are no active applications for approval of any generator installations. An earlier proposal for generation near the Lake Major water treatment plant has been abandoned by the developer. The COMFIT program is now closed and NS Power has not issued any calls for generation capacity so there is little incentive for a developer to install any significant capacity in the area. As a result of regulations proclaimed by government in December 2015, individual interconnected generation installations are limited to the lessor of a capacity matched to the customer load or 100 kW. Of course, both of these restrictive conditions are subject to change at the will of government. However, should policy changes occur, the lead times to build any new generation developments that might impact the area should leave sufficient time to develop any needed supply capacity for the area.

2.14 Conservation Voltage Reduction

Conservation voltage reduction (CVR) is the deliberate reduction of voltage at the substation or down line regulation points aimed at reducing the downstream electrical demand. At one time this was more loosely referred to as a brown-out, so named in respect to the reduced light output from incandescent bulbs as their supply voltage was reduced. Load reductions in this way are only possible if load decreases with voltage. Growing numbers of home devices with internally regulated voltage supplies results in a load characteristic that may show little change with changes in the service voltage. As such, this will make a CVR approach to load reduction less viable over time.

NS Power is obligated to supply service voltages within standards that are set by the Canadian Standards Association CAN3-C235-83 (C2010). Fully avoiding supply voltage levels that extend below CSA standards at all customer locations would require that real time voltage measurements from across the feeder be available to the Control Centre. That voltage data can be used to establish the minimum voltage that needs to be sustained at the points of feeder voltage regulation. It is anticipated that this communication capacity will not exist until such time as Smart Grid is deployed on a widespread basis. That is not expected to occur in the Eastern Passage area within the timeframe being studied so CVR is not seen to be a viable option at this time to reduce peak loading on feeders supplying the area.

2.15 Environment – Carbon Pricing

Government policy on carbon reduction creates some uncertainty in regard to its impact on electrical useage. Should carbon tax rates be imposed on home heating fuel, it could

potentially drive homeowners and businesses to consider conversion away from oil heat. Likely alternative choices include heat pumps, possibly with electric back-up, and natural gas if it is available. This would accelerate some of the trends already existing in the market.

Nova Scotia has reached an agreement-in-principle with the Federal Government in respect to carbon pricing that will see the province implement a cap and trade system within the province by 2018. The agreement will also enable NS Power to continue to operate its coal generation plants to beyond 2030 as it transitions over to lower carbon options. The specifics of what type of cap and trade system will be implemented outside the electricity sector – for instance, whether it will apply to home heating fuel – are not yet known. Until the design of the government regulations are more clearly known it is impossible to predict the effects on customer electrical load. This is an area that will need further investigation for its long term effect on load.

2.15 Environment – Global Warming

The specific impacts of global warming on NS Power's electrical system load remain uncertain. Recent climate observations continue to support predictions of warmer average temperatures and also of more severe weather events. However, the matter of human caused global warming remains a controversial subject as there are many factors that are yet fully understood and it is not yet widely agreed that this is a real issue.

Should average temperatures continue to increase as they have been this will further increase the interest in and economics of heat pump installations. It may have other as yet unknown impacts on the electrical system – for example on the environmental conditions under which device capacities are established – so this should continue to be an area of study and review as knowledge in this area develops. An associated concern is that along with warming global temperatures comes more severe weather. The nature of the effects that this might have on the local distribution system remains uncertain.

3.0 Analysis of Electrical Load Data

Extracts from CIS of 10 years of consumption history for all customers in the Dartmouth, Cole Harbour and Eastern Passage area were analyzed for insights into electrical useage. This involved analyzing and aggregating close to 4 million records of data. Some highlights from that analysis are presented below.

3.1 Details of Analysis – Non-All-Electric

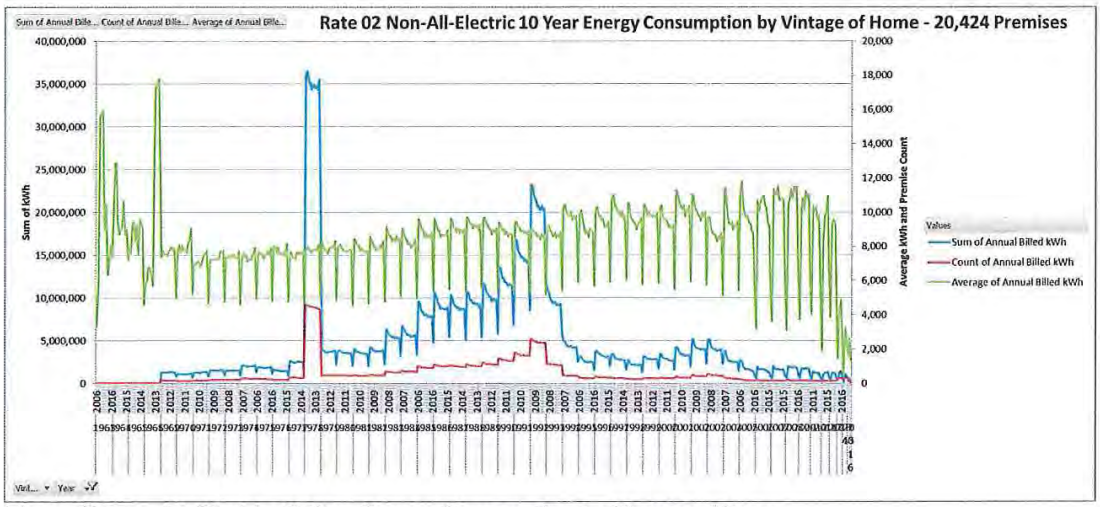


Figure 33 Non-All-Electric 10 Year Energy Consumption by Vintage of Home

Figure 33 above illustrates a summary of consumption records for over 20,000 Rate 02 Non-All-Electric customers in the Dartmouth, Cole Harbour and Eastern Passage area. The graphs show a 10 year consumption history, organized by the vintage of the premise (which is inferred from the CIS data employing the lessor of the Initial Service Date and the Connected at Premise Date). Premise vintage dates extend over the timeframe from the early 1960s to the current year.

The limited capability of Excel to format the horizontal axis of the graph prompts some explanation to facilitate interpretation. The upper set of numbers attempts to show the individual years 2006 to 2016 for each vintage of premise. The lower set of numbers attempts to show the vintage year for each group of premises of that vintage. The vintages extend from 1963 to 2016. The periodic appearance of the graph is showing a repetitive pattern of 10 year periods of data – one 10 year period for each vintage of premises.

The periodic deep inflections in the consumption curves are due to partial year consumption figures for the 2016 year, as the data was extracted from the CIS in July 2016. Within the last 10 years of premise vintages from 2006 to 2016, the first year of the consumption history for each premise is a partial year of consumption, an indeterminable amount that is dependent on when during the year service was first connected to the premise and the first readings of metered consumption taken.

It is observed that the pattern of the count of premises by vintage varies over time with a cresting peak in 1992 (ignoring the anomalous peak in 1978 which is said to be due to a change-over in the billing system). It is to be expected that there will be some variation in non-all-electric premise count over time, particularly considering the population demographics and more so in regard to a transition to the construction of a higher proportion of all-electric homes that began in the 1980s. Those changes, however, do not seem to fully explain the peak in the count which occurs in 1992. This suggests some discrepancy in the meanings and interpretations of Initial Service Date and Connected at Premise Date that occurs as part of CIS data entry procedures. Regardless of the precision of the vintage year inferred from the CIS data, the annual average consumption figures on the whole are still reasonably reflective of the patterns of use over time.

Within each vintage year there is seen, over the 10 year consumption period, a slight decline in the premise count. This can entirely be explained by conversions over to all-electric homes, perhaps because of ageing fuel-fired heating system replacement or perhaps choices related to environment, convenience, controllability or cost. Some rate category conversions, however, are driven by an NS Power stipulation that the premise be re-designated to an all-electric home if the non-all-electric homeowner finances a heat pump installation through NS Power.

A number of useful insights into electrical energy use can be interpreted from this data. First, it can be seen that there has been a general increase in overall electrical energy useage in newer vintage premises versus older vintage premises. The average annual use of a premise has risen from around the 7,500 kWh/Yr level in 1970s premises to the 11,000 kWh/Yr level in 1990s premises. A number of explanations could be posited for this increase; however it is typically the case that newer homes are larger and, in recent years, builders and owners have added more electricity-consuming features such as heat recovery ventilation, more electricity consuming devices (e.g. televisions, computers, electric fireplaces, space heaters, etc.) and perhaps a hot tub or pool. As well, newer homes tend to be occupied by younger families that would be more likely to have children at home – a significant factor in higher electricity useage.

The 10 year consumption trend for electricity useage in premises older than the 1980 vintage has remained relatively flat or perhaps has increased slightly over the period. A possible explanation is that older homes are more likely to be occupied by older residents who perhaps would be less inclined to upgrade to more efficient appliances over time. Possibly as well they would be increasingly inclined to be at home due to retirement; and as the residents get older, there might be an increased amount of heating loads such as supplemental electric heaters. Options such as increased attic insulation and higher efficiency windows are opportunities in older, non-all-electric houses to save home heating energy cost. But, because most of the saving is in fuel consumption, this would have only a small effect on electricity use.

Premises newer than 1980 vintage were generally built to higher insulation standards (e.g. 6" studs vs 4" studs, sealed vapour barriers, and better attic insulation standards). The electrical energy consumption pattern for newer premises shows a slight annual

decline in electricity energy use over the past 10 years across almost all vintages of premises up till about 2012. There are many factors that could explain this decline.

Premises of these vintages would more likely to be occupied by a demographic that has an interest in achieving energy savings, together with the financial means to do so. The premises are also of a vintage where it would be expected that older appliances (which have lifespans of 11-15 years) are being replaced with newer more energy efficient appliances. Families who would have had children at home would, over that time period, see some or all of those children moving out. This results in less cooking, dish washing, laundry, hot water use and lighting. Additionally, there has been a large scale replacement of older CRT televisions with newer LED and LCD flat screen televisions that have lower electricity use.

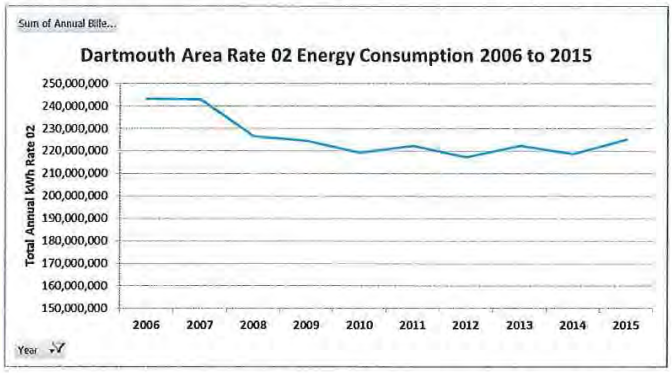


Figure 34 Dartmouth Rate 02 Energy Consumption kWh 2006 to 2015

Looking at how this data might be used for forecasting it is seen that the greatest part of the overall consumption increase occurred for homes of vintages up to 1997, after which there has been very little increased useage in newer homes. Beginning with homes of vintage 2013 and newer there has been a dramatic drop-off in average annual energy useage. The reason for this observed pattern in the data is not well understood and can only be speculated. A small portion is likely due to new homes being built to the new higher energy efficiency standards. Also, when home owners first move into their new home they may not immediately have all the electricity consuming appliances that they will acquire later. Another factor is that many new homeowners are couples who start families in the first few years after moving into their home, something that increases energy useage for such things as laundry, bathing, cooking, etc.

Without a full coverage of revenue meters that provide 15 minute interval readings, the demand for electricity in individual rate categories cannot be accurately measured and reported. However, to the degree that consumption patterns have remained relatively constant, the change in annual peak demand can be inferred from the change in annual energy consumption. Examining the past 10 years of energy consumption it is seen that there was a general decline over that period, paralleling what is seen for most vintages of homes. In years 2006 to 2010 energy consumption declined 2.64% annually followed by a period from 2011 to 2015 over which consumption increased 0.32% annually. This latter period is the same period over which Efficiency NS operated its DSM programs. Those programs, however, focused largely on energy saving in all-electric homes.

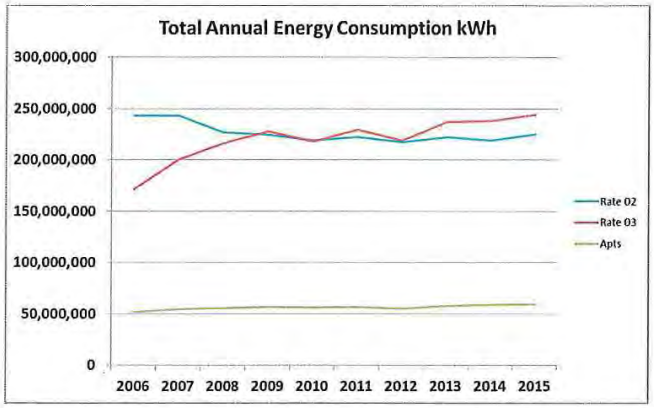


Figure 35 Consumption by Housing Type Dartmouth Area

The increase in total Rate 02 energy consumption also corresponds with an increase in the number of non-all-electric homes being constructed in areas where natural gas is available. In Dartmouth this includes areas such as Russell Lake West and Portland Hills. It is also known that many customers in these areas installed ducted heat pumps with natural gas backup which results in electrical energy consumption levels higher than typical non-all-electric but negligible impact on system peak loads as backup heating is being provided by natural gas.

3.2 Details of Analysis – All-Electric

Similar patterns are seen in electrical useage for Rate 03 All-Electric customers. In the following figure a similar pattern of premise counts can be seen with an anomalous peak in 1978 and a cresting peak in 1992, as was the case for non-all-electric promises.

It can also be seen that the average annual electrical energy consumption across almost all vintages of homes from the early 1970s till 2010 (except for the mid-1990s) has been relatively uniform at a level of approximately 18,000 kWh/Yr. After 2010 the annual consumption of newer vintage homes drops off dramatically. As with Rate 02 homes, the reason for this is not well understood but similar speculation for why this pattern exists can be made. What is also not known is the degree to which the annual energy consumption of these new homes may recover over time to what is the historical pattern of use in older vintage homes.

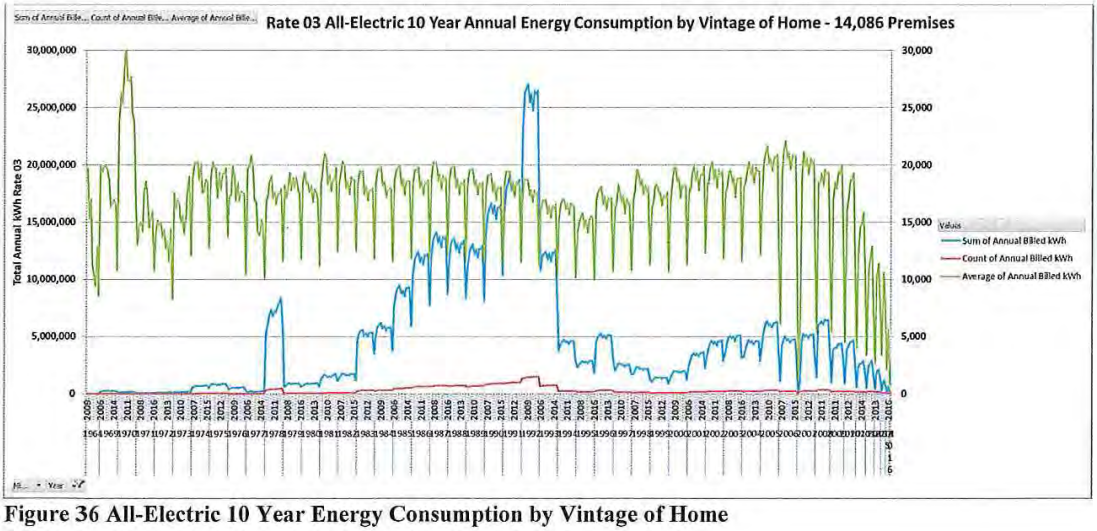


Figure 36 All-Electric 10 Year Energy Consumption by Vintage of Home

Figure 38 Residential All Dartmouth Area Non-Apartment/Condo Consumption by Premise Vintage

The periodic inflections in the consumption curves are due to the inclusion of the 2016 partial year consumption data, which was done intentionally to highlight the breaks between vintage year data and is not reflective of a sudden overall decrease in consumption. It was investigated and found that the count of all-electric premises increases in most vintage years is almost entirely reflective of conversions to all-electric from non-all-electric.

Within each home vintage year from the early 1970s to 2007 there is a trend of declining average energy useage over the 10 year period 2006 to 2015. The amount of decline is a lower percentage of annual consumption than is seen in the pattern observed for non-all-electric premises – about 0.9 % versus 1.2%, but the absolute amount of reduction is greater – about 1,550 kWh versus 1,100. The reasons for this decline over the ten year period include factors like the increasing penetration of heat pumps across all vintages of homes which, in comparison with non-all-electric homes, decrease electrical use.

Other factors within the home, like replacement of older appliances with more efficient new appliances, do not have the same consumption-reducing effect. This is due to their energy losses contributing to satisfying the heating requirement within the building envelope, thereby offsetting space heating consumption. An exception to this would be electric water heating energy reduction resulting from new, higher efficiency dishwashers and clothes washers.

There would also be the same demographic effects in all-electric homes as non-all-electric, including an ageing home-owner and children moving out to their own premises.

Again, there is no ability to directly measure the demand of this group of customers; however, using the assumption of a relatively constant relation between demand and energy use it can be seen that there has been growth in the total annual energy consumption of this class of customers over the past ten years. The amount of that growth has declined after 2009 and this corresponds with a trend towards the construction of apartments versus detached and semi-detached homes.

Because of the movement of customers from Rate 02 to Rate 03 a clearer picture of residential energy consumption for detached and semi-detached homes can be gained by combining their consumption data. When that is done new patterns in the data can be observed.

The transition over from the predominance of non-all-electric homes to all-electric homes that occurred in the early 1980s is more evident. A possible explanation for the sudden increase in average energy consumption, beginning in 2005 vintage homes up to 2009 vintage homes has yet to be proposed.

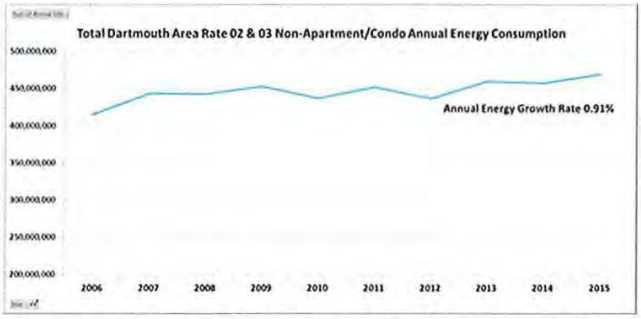


Figure 39 Dartmouth All Rate 02 and Rate 03 Non-Apt. kWh

The combined growth rate of the two rate categories remained relatively constant throughout the 2006 to 2015 period (at 0.9% annually). This reflects that there remains an ongoing level of new, detached and semi-detached home construction; the results of which causes energy consumption increases that outpace all energy efficiency and Demand Side Management savings.

3.3 Details of Analysis – Apartments & Condos

Energy use of customers in apartments and condominiums was analyzed separately from detached and semi-detached housing. As there is no marker in the CIS data that distinguishes a residence as being in an apartment or condominium building this breakout of the data was accomplished by looking for Rate 02 and 03 customers that contained "Apt" or "Unit" in the service address.

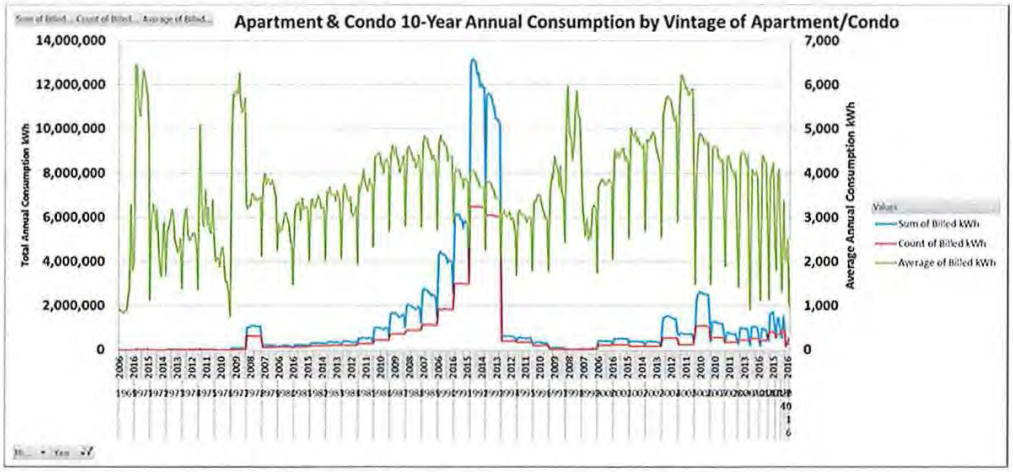


Figure 40 Dartmouth Apartments & Condos Annual kWh by Vintage

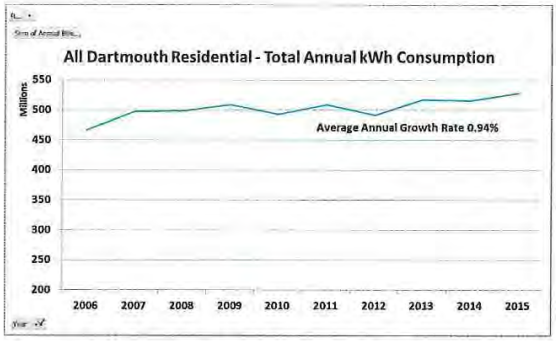


Figure 41 Dartmouth Area Residential Consumption kWh

There is a great deal of variation across the vintages of apartments in the average annual use, probably reflective of the design of individual apartment or condominium developments. However, what is significant to note is that the average annual consumption of an apartment or condo is approximately 4,000 kWh per year. This is less than half the consumption of a non-all-electric home and about a quarter of that of an all-electric home. It is this fact that is of significance in regard to the shift from detached home construction to apartment construction. As a consequence, there will be incrementally lower load increases with growing customer count.

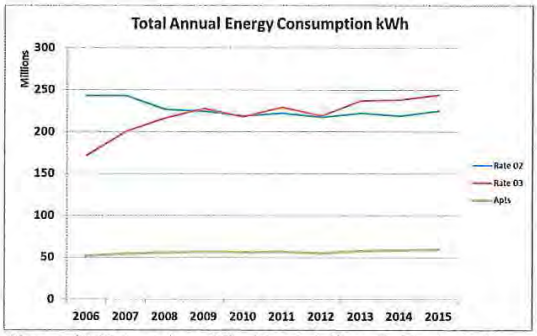


Figure 42 Categories of Residential Growth Dartmouth

When examined in total there remains a small amount of growth in residential load in the Dartmouth area of approximately 0.94% per year. As has been covered above, the largest portion of the energy consumption is in the all-electric home category. This has out-paced the consumption of non-all-electric homes and now dominates in terms of the total annual amount of electrical energy consumption and the number of new homes being constructed. The attraction of heat pumps for heating will almost certainly keep this trend going till it may be overtaken by growth in apartments.

3.4 Details of Analysis – Commercial

In the Large General Rate 12 category there are only two customers in the Dartmouth area: the Bedford Institute of Oceanography (BIO) and the Dartmouth General Hospital. BIO experienced growth from 2006 during a building expansion program but has remained relatively constant since then. The Dartmouth General Hospital has shown a reduction in consumption of approximately 15% from 2006 to 2015; however, an expansion announced in 2016 that will double the number of operating rooms and increase beds by 48, will result in some electricity consumption increases over the next couple of years.

The remainder of the Commercial load growth was analyzed in two categories: Rates 10 General and Rate 11 General Demand were analyzed together due to the movement of customers back and forth between the two categories. Energy growth patterns by vintage over the past ten years show less regularity than in the residential class due to the non-uniformity of the individual types of customers in these Rate classes. An attempt to understand trends within the Commercial group by analyzing the various types of load employing the Standard Industrial Classification (SIC) code was foiled by the fact that

the SIC coding of customers within the CIS has not been maintained for many years now. Due to the problem with accuracy and the fact that many customers lack any SIC coding information at all, no useful breakout was believed to be possible. Both the US and Canadian governments had in 1987 moved from SIC coding to the North American Industry Classification System (NAICS) coding system for businesses to report the nature

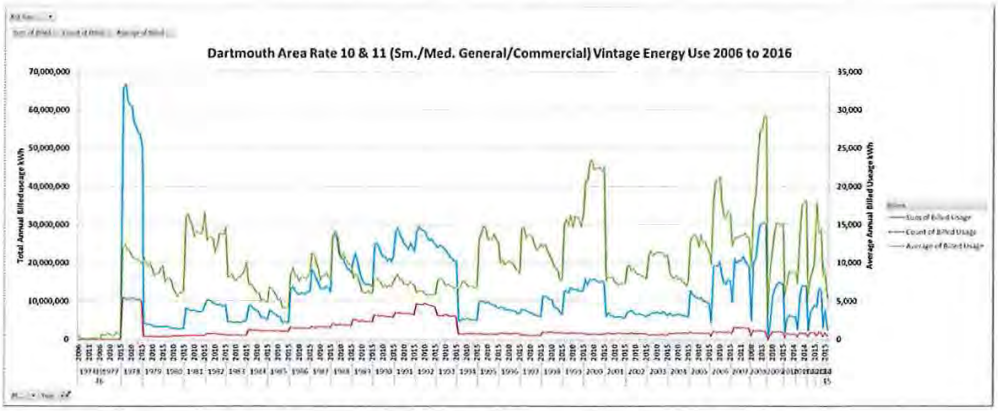


Figure 43 Dartmouth Area Rate 10 and 11 kWh Consumption by Vintage of Premise

of their business operations to government. The value of this information to the NS Power for such purposes as marketing, load forecasting and analysis should be explored and the information in CIS updated accordingly.

Examining the vintaged data for the Rate 10 and 11 aggregated group, only small discernable consumption patterns are apparent. The average consumption varies greatly from one vintage year to another and this would be expected considering the irregular nature of commercial businesses and developments. For many of the vintage years there is a significant tail-off of total energy consumption, which corresponds to a small decline in customer counts for each vintage of customer. Besides the overall decline, there is for each vintage an overall small drop in average consumption over the past ten years. This could be due to some amount of reduced business activity, but could also be due to active efforts by the customer to reduce electricity consumption through efficiency improvements or demand side management programs.

In the monthly consumption history for the past 10 years (Figure 44 below) there is a saw-toothed appearance that results from a mix of monthly and bi-monthly billing cycles within the two rate classes. The consumption trends over the 10 year period, however, indicate that there has been an annual decline of 0.63% in average annual energy consumption. In contrast, the number of commercial customers in the Dartmouth area has been continuing to grow at a steady rate that has averaged 1.39% annually from 2006 to 2015, which results in an overall energy growth averaging 0.67% annually for the rate 10 and 11 aggregated group of customers.

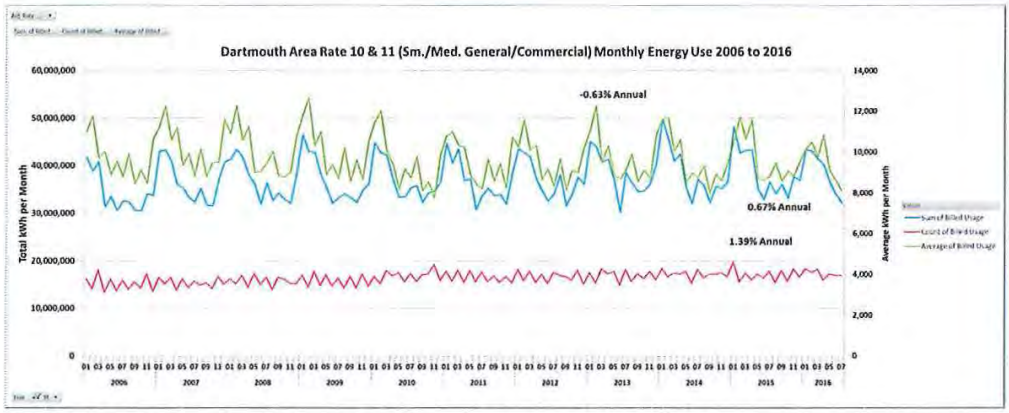


Figure 44 Combined Rate 10 and 11 Annual kWh Growth 2006 to 2016

Going forward, the new building efficiency standards (adopted in 2015) for commercial buildings, in combination with "green" initiatives such as solar power or LEED certification, will lead to lowered energy intensity and lower growth from new customers in these rate categories. With efficiency improvements from implementing the new standard estimated to be in the 15 to 30% range, the effect could be very significant. This is a matter worthy of further investigation, once construction projects that incorporate the standards have been in service for sufficient time to analyze their consumption.

In regard to the Eastern Passage area there have been no significant commercial developments announced and the low growth in residential development will likely mean a low probability of such development. Hence, commercial growth in the area is not anticipated to be a driver of electrical load increases.

3.5 Details of Analysis – Industrial

The industrial loads in the Dartmouth Area are all within Rate categories 21 - Small Industrial and 22 - Medium Industrial. The number of customers in the Dartmouth area in

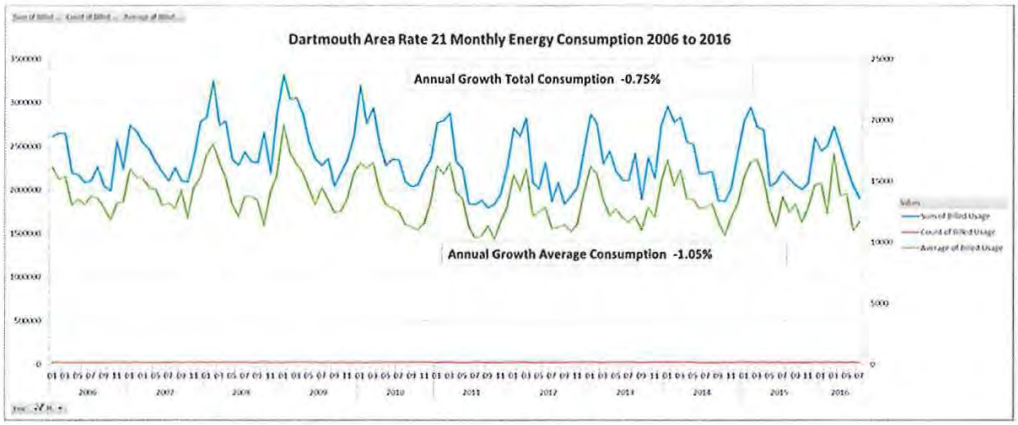


Figure 45 Dartmouth Area Rate 21 Consumption 2006 to 2016

the Rate 21 category has remained relatively constant over the past 10 year period.

Energy consumption by the total group has declined 0.75% annually and the average consumption by customers in the group has declined 1.05% annually. This could be the resulting effect of a small amount of energy conservation or it could be due to a decline in industrial activity over the period.

Similar patterns are seen in the Rate 22 Medium Industrial category. There has been a decline in customer count in this category over the 10 year period and a corresponding decline in electrical energy consumption 2.45 % annually.

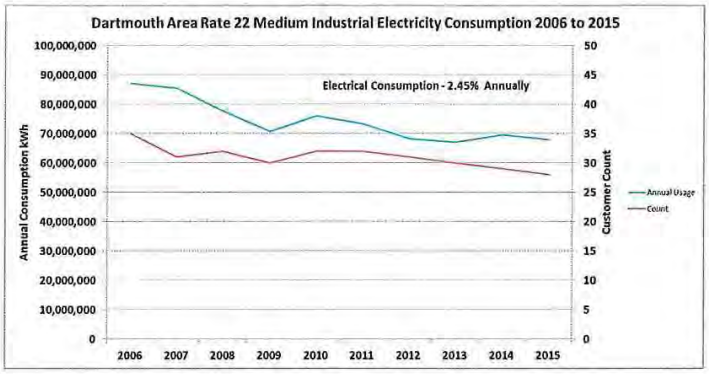


Figure 46 Dartmouth Area Rate 22 kWh Consumption

There have been no announcements of industrial expansions in the near future so industrial load growth is not anticipated to play a role in future load growth in the area over the forecast period.

3.6 Demand Load on Substations and Feeders

As certain assumptions about coincident demand load have been made from energy consumption trends over the past ten years it is worthwhile examining measured demand in relation to energy at locations where that information is available. Most substations in the area have metering for transmission lines, substation transformers` and feeder reclosers that provide some mix of Watt, Volt-Ampere and feeder Ampere measurements. The historical readings are recorded in a PI database at the Ragged Lake Energy Control Centre where they are available for electronic access.

Some challenges are presented in using the PI data. At some locations there is no metering. At others there have been failures in the metering that have created gaps in the historical data record. At others still there are departures from conventional signage for in and out flows. There are also examples of saturation of readings that give a false indication of a lower than actual peak. On some substation feeders there is distributed generation for which no metering exists making it impossible to distinguish the actual level of distribution load. Under some circumstances spurious readings were generated and are recorded in the PI data. There are instances of load transfers between substations or feeders and of cold load pick-up that can easily be mistaken for normal load peaks. Most but not all of these issues are present within the Dartmouth area. What is an issue everywhere is a gap in the PI data that results from the loss of a PI data storage drive that had not been backed up. Therefore, no PI data records exist from November 9 2013 at 17:00 to October 31, 2014 at 22:00.

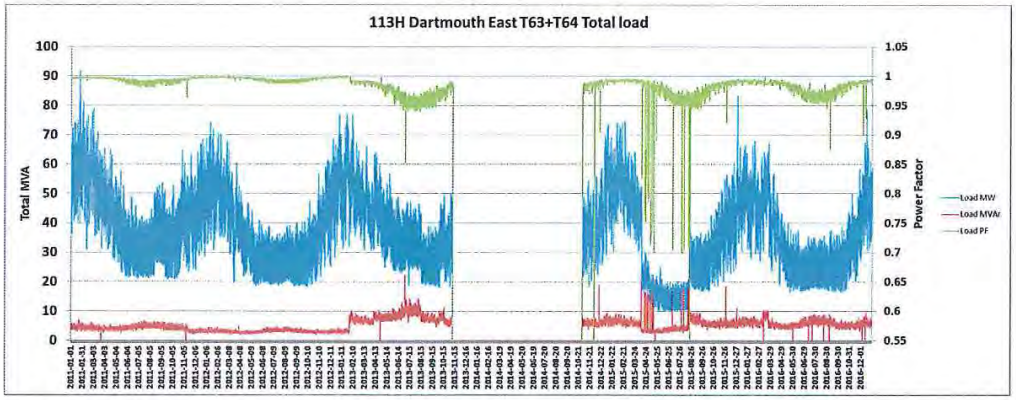


Figure 48 113H Dartmouth East Total Substation Load

The peak load at 113H Dartmouth East substation has declined in the period from Jan 2011 to Jan 2017 and it remains within the contingency capacity for the substation. What is instructive to examine in addition to the peak load is the summer minimum load. The minimum load level is a general indicator of the underlying base of connected load on the distribution system. As its useage pattern is minimally affected by temperature variations, trends in the connected load are more readily apparent. A small decline in the minimum load of 113H throughout the 6 year period can be observed, although some variations in that minimum due to temporary load transfers is also present. The overall decline may be due to energy efficiency, as it is known that the customer count continued to grow throughout the period. However, there may also be some effect as well from the conversion of load such as electric water heating to natural gas.

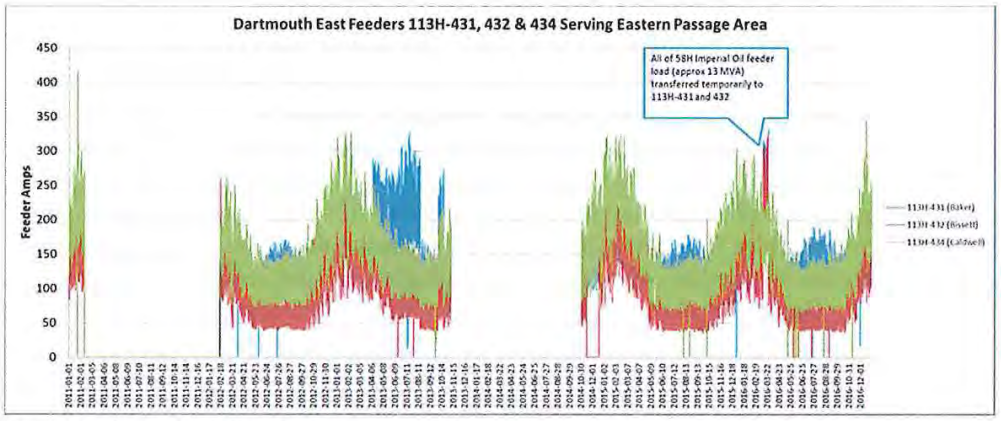


Figure 47 Dartmouth East Feeders Serving Eastern Passage

The three Dartmouth East feeders that supply load in the Eastern Passage area are 113H-431 via Baker Drive, 113H-432 via the Bissett Road and 113H-434 via Caldwell Road. Load data for these feeders (Figure 47) shows that they occasionally exceed their 325 Amp planning limit. Another feature seen in the data is the growing summer peak which is most noticeable on the Baker Drive feeder. A possible explanation for this is the growing number of heat pumps in the Russell Lake West area that have natural gas

backup. While they do not add to winter peak, their use during the summer is affecting the annual load shape by creating a growing summer peak load.

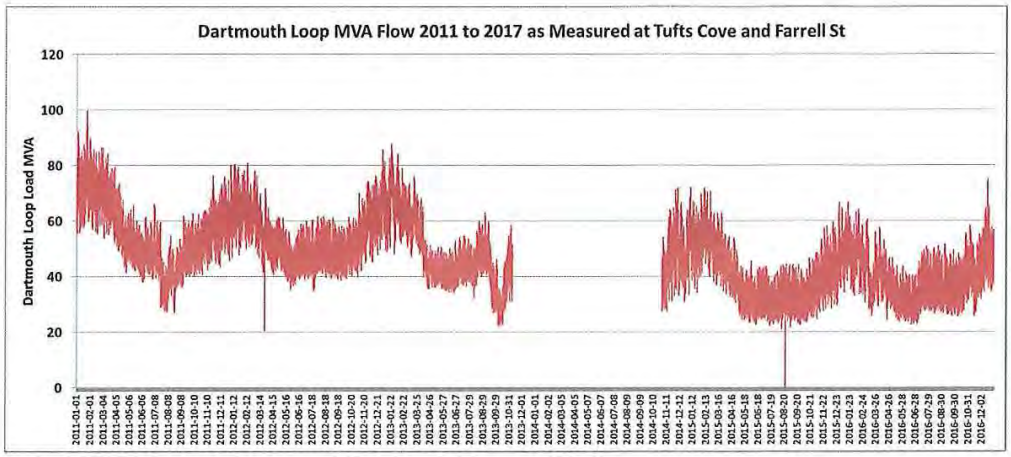


Figure 50 MVA Load Supplied on the Dartmouth 69 kV Loop

Loading on the Dartmouth Loop is no longer a concern from a capacity standpoint. The winter capacity of the loop is 115 MVA and with the closing of the Imperial Oil Refinery the peak load in December 2016 was only 75 MVA, leaving 40 MVA of room for load growth in substations fed off the loop – 40H Woodlawn, 48H Penhorn, 54H Maple St and 58H Imperial Oil. This also presents an opportunity to connect additional transformation capacity to the loop to deal with feeder loading at Dartmouth East.

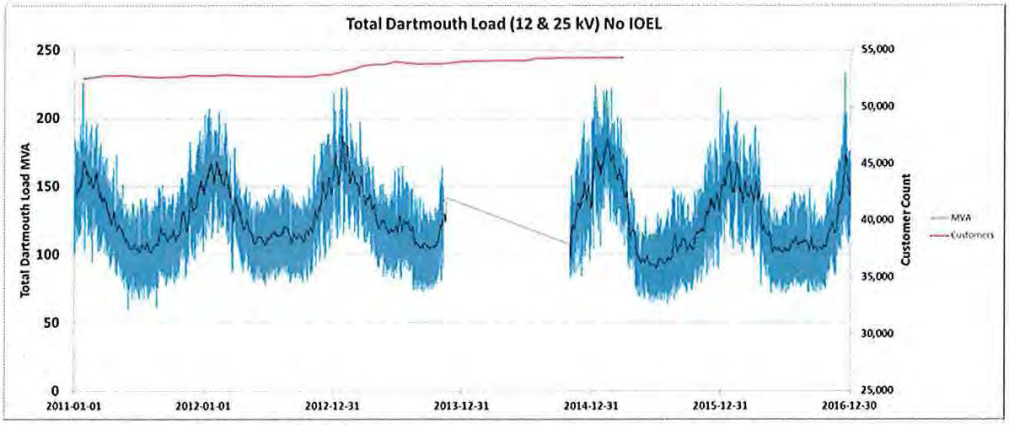


Figure 49 Total Dartmouth Distribution Load Without Imperial Oil Enterprises Ltd.

Total Dartmouth load, even when the effect of the loss of the Imperial Oil Refinery is taken into account, has shown only minimal growth from 2011 to 2017. There is a noticeable increase in summer load and this shift can be anticipated to continue as the penetration of heat pumps in the market grows.

This trend towards increased summertime peaks, while of only minimal concern to field operations in Dartmouth today, will begin to have an impact as the trend continues. The degree of impact is perhaps illustrated most dramatically by the load of the Halifax

peninsula. The summer peak of 2015 was only 8 MVA lower than the winter peak of 2015-16. In the peninsula load, over the longer term, can be seen the slight decline in summer minimum load. This is reflective of some loss of base distribution load. Again, this could be due in part to energy efficiency, but could also be due to conversions to natural gas.

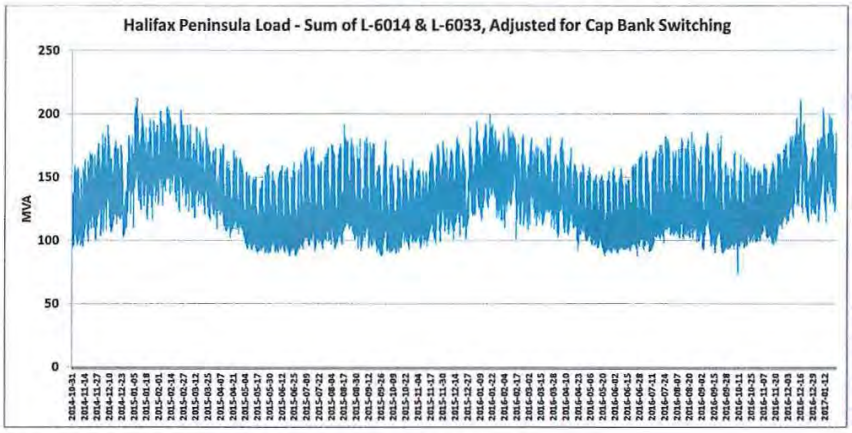


Figure 51 Halifax Peninsula Distribution Load

4.0 Conclusions and Recommendations

4.1 Summary of Analysis

In summary, the analysis of customer load and the driving factors behind it reveals that there has recently been very little load growth in the Dartmouth and Eastern passage areas and little reason to expect any significant degree of growth in the near future. Factors such as population demographics, trends in housing, shifting technology for space heating (heat pumps), and potential future offsets from solar electric generation appear to largely override factors that might otherwise grow load. Without any announcements of major developments in the area and with municipal land use bylaws pushing for limited development in Eastern Passage so as to maintain its largely rural character, it appears that the load growth factors that drove the decision for a Harbour East substation are no longer factors that continue to support that decision.

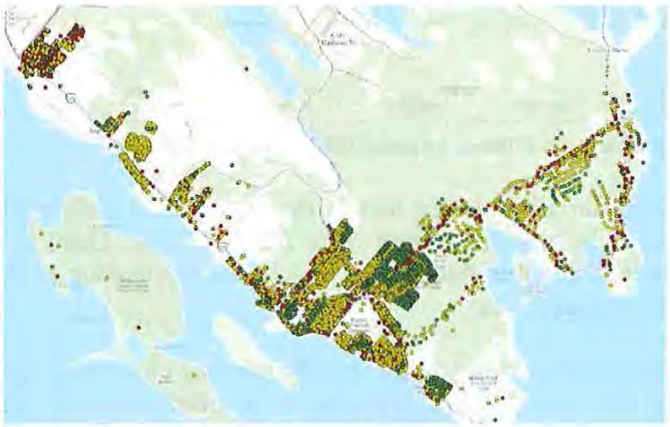


Figure 52 Housing Vintages Eastern Passage

Looking at the potential factors that could shift energy use within the existing customer base and affect the above conclusion it is useful to consider the housing mix in the area.

The adjacent Figure 52 shows housing older than 1980 (pre-dates building standards with 6" studs) in red symbols, from 1990 to

2000 (many homes built to R2000 standards) in yellow symbols and housing from 2000 to present (showing the most recent new subdivision developments) in green symbols. This highlights the areas of older housing in the Eastern Passage area which tend to be aligned along the main routes through the area.

Areas of non-all-electric housing shown in red in Figure 53 below) align with older housing in the area. Those homes would be candidates for conversion to natural gas as the gas distribution network extends further into the area. Conversions from oil to gas would not add to the system load peak. Areas of all-electric housing (shown in green below) are candidates for heat pump installations. They will reduce overall energy consumption without increasing peak loads beyond what they are today.

Figure 53 All-Electric and Non-All-Electric Premises in Eastern Passage

As pointed out earlier, the existing load on some Dartmouth East feeders already exceeds the normal operating limit of 325A under winter loading conditions. In the circumstances of the peak on Friday December 16, 2016, being a period of -15 to -17 C temperatures and windchills below -30 C, the over limit lasted 4 hours from 5 pm to 9 pm. Heavy loading on these feeders places Dartmouth East substation at risk of exceeding its contingency limit for failure of one of the two transformers as it restricts the ability to transfer load to adjoining substations.

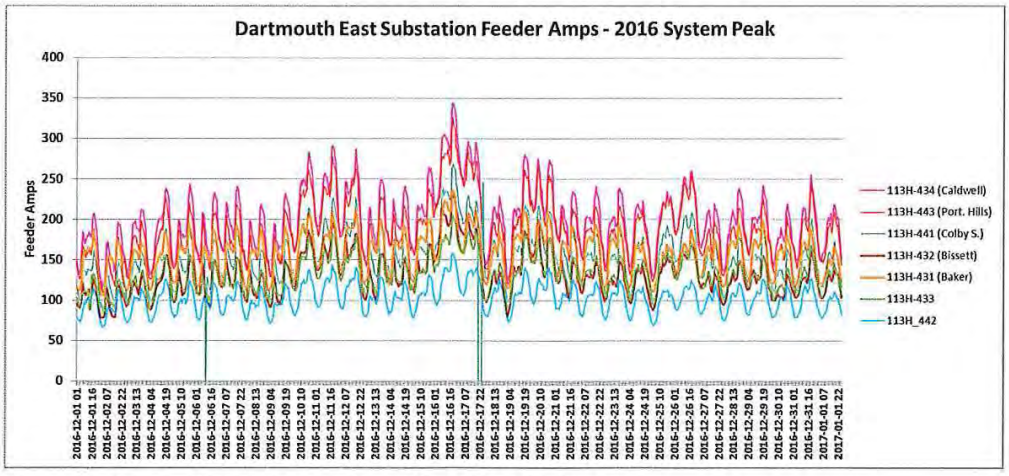


Figure 54 Dartmouth East Feeder Amps December 2016

The feeder configurations for the area place the four most heavily loaded Dartmouth East feeders adjacent to each other in the Portland Hills and Caldwell Road area. A new supply point that offloads 113H-443 by picking up load in the Portland Hills area will free up capacity that then enables feeder reconfigurations that, in turn, allow off-loading of load from 113H-434 to 113H-443.

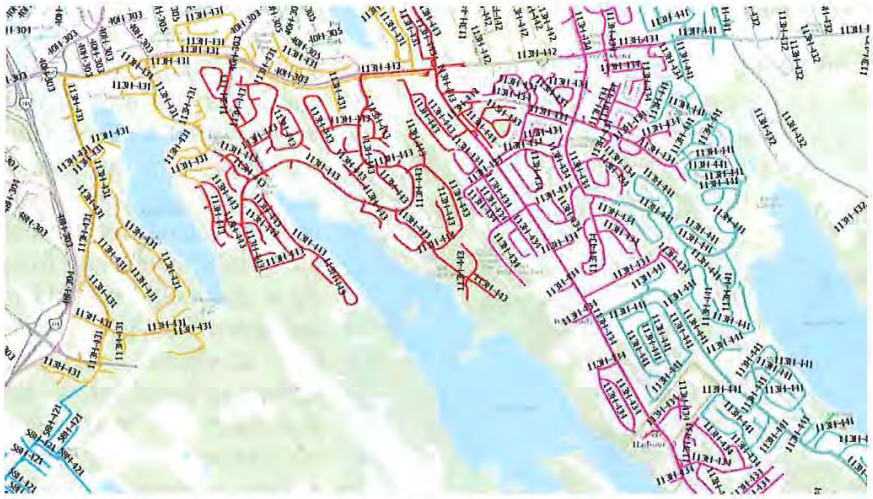


Figure 55 Dartmouth East Feeders in Portland Hills/Caldwell Rd. Area

The substation at Imperial Oil is built on a very restricted site making the addition of a second transformer or any additional feeders there problematic. The area in Mount Hope to the south side of the Russell Lake West development is a location where transmission lines L-5011 and L-5012 merge on to a single right-of-way. There appears to be sufficient undeveloped land at that location to construct a padmount power transformer substation.

This type of substation would be new to NS Power; however, it offers a number of advantages suited to the site. First it can be installed on a smaller footprint than a traditional design – approximately half the space. Second, it is visually less obtrusive as it does not require a fenced compound. This can facilitate the process of gaining approval for a site. Further, it can be constructed quickly – in under a year after the site has been acquired. Finally, it can be put in service at a cost that is approximately half that of a traditional substation.

It would normally be that case that a spare padmount power transformer would need to be acquired at the same time as the first padmount transformer is acquired. However, this location is ideal from the standpoint that there is sufficient feeder interconnectivity with sufficient contingency capacity in the early years to enable load to be transferred to adjacent substations. This can defer purchase of a spare till after other substations of this type are built and the spare can then be justified on providing support for multiple in-service units.

4.2 Recommendations

It is recommended to not proceed with construction of the Harbour East substation at this time. Following a detailed investigation of factors affecting customer load, there is no indication that the capacity is needed to supply load in the area within the ten year planning horizon of this study. There are long term factors that may ultimately set up the opportunity for growth in the area so it is recommended that the investment that NS Power has made in obtaining right-of-way and substation siting be protected for that eventuality.

In the shorter term only such factors as the announcement of a major new development in the Eastern Passage area, or the completion of the Mount Hope to Caldwell Road connector in conjunction with amore development-friendly land zoning regime coupled with additional water and sewer servicing could substantially affect this recommendation. If such were to occur then this recommendation will need to be revisited.

Besides serving Eastern Passage load growth, part of the previous justification for Harbour East substation was the capacity and flexibility to deal with overloading of Dartmouth East substation feeders adjacent to and serving area. With that option being removed, there remain two Dartmouth East feeders that currently exceed their operating limits. Much of the load responsible for that is in the Portland Hills and Colby Village area and a solution local to that area was explored in support of deferring Harbour East.

An option is presented that will relieve existing design criteria loading violations on the two Dartmouth East feeders that supply load in the Portland Hills and Colby village to Eastern Passage areas. The solution will provide additional operational load transfer capability between Dartmouth East and the Imperial Oil Substation. The recommendation is for the construction of a new substation to be installed in the Mount Hope area near the conjunction of 69 kV lines L-5011 and L-5012.

The recommended substation would be a 69-25 kV padmount power transformer substation with a capacity of 10 to 12 MVA with a single 25 kV feeder. The in-service date should be targeted in advance of the 2018 winter peak so as to limit the further amount of time that loading violations are sustained on the Dartmouth East feeders. Estimated cost for the substation is in the range of $2.3 Million.

The padmount style of substation is recommended due to its lower development cost (about half that of a regular substation), smaller footprint, compatibility of its appearance in the midst of local residential and commercial developments and fast implementation time (under one year following site acquisition). Further advantages, due to the low site development cost, are that a padmount power transformer station could easily be expanded, or removed and relocated at a later date should future load growth require it.

After this new supply is in place, reconfiguration of feeders 113H-443 and 113H-434, the two most heavily loaded Dartmouth East feeders, would be required to relieve load on 113H -443 and reduce the level of parasitic load on the Caldwell Road feeder 113H-434 that passes through the area to serve load in Eastern Passage. This would allow feeder 113H-434 to pick up additional Eastern passage load if necessary and provides needed load transfer flexibility with 58H Imperial Oil feeders.

It is recommended that a distribution feeder planning study be undertaken to facilitate the needed feeder reconfigurations associated with the development of a new Mount Hope substation. Besides relieving overload on two East Dartmouth feeders, additional benefits arise from the reduction of losses on those feeders. The estimated amount of those loss savings can only be determined from feeder load flow simulations that would be conducted as part of such a study. The scope of the study should also include an economic analysis of a padmount power transformer substation versus a conventional substation, considering such factors as the amount of initial loading and load growth that would weigh in favour of one alternative versus the other.

Appendix A: Transmission Line Ratings Summary

Last Updated: 2016-10-06

LINE NUMBER				SUMMER	WINTER	
L-5003a	90H Sackville	to	124H Akerley Blvd.	55	82	MVA
L-5003b	124H Akerley Blvd.	to	99H Farrell St.	55	72[1]	MVA
L-5004a	90H Sackville	to	23H Rockingham	55	72[1]	MVA
L-5004b	23H Rockingham	to	34H - Geizer Hill	55	72[1]	MVA
L-5010	58H Imperial Oil	to	111H Imperial Oil	20	28	MVA
L-5011a	99H Farrell St.	to	40H Woodlawn	106	115[2]	MVA
L-5011b	40H Woodlawn	to	58H Imperial Oil	115[2]	115[3]	MVA
L-5012a	91H Tufts Cove	to	54H Maple St.	96[4]	96[5]	MVA
L-5012b	54H Maple St.	to	48H Penhorn	96[4]	96[5]	MVA
L-5012c	48H Penhorn	to	58H Imperial Oil	55	82	MVA

[1] Limited by full scale metering. Conductor rating is 82 MVA.
[2] Limited by full scale metering. Conductor rating is 120 MVA.
[3] Limited by full scale metering. Conductor rating is 140 MVA.
[4] Limited by line switch. Conductor rating is 106MVA.
[5] Limited by line switch. Conductor rating is 120MVA.

CI Number: 52314

Title: 1C-GT1 and 1C-UT1 Transformer Replacement

Start Date: 2018/01
In-Service Date: 2019/12
Final Cost Date: 2020/06
Function: Transmission
Forecast Amount: $2,032,393

DESCRIPTION:

The scope of this project is to install a new station service transformer to replace two transformers (1C-GT1 and 1C-UT1) that are presently being used as backup station service transformers at 1C Point Tupper. The 1C station service transformer (1C-ST1) failed several years ago and at that time 1C-GT1 and 1C-UT1 were re-purposed for station service as a temporary measure for backup station service supply to transformer 1C-ST2. This project also includes the removal and retirement of three transformers (GT1, UT1 and the failed ST1).

Summary of Related CIs +/- 2 years:
No other projects in 2016, 2017, 2018, 2019 and 2020

Depreciation Class: Transmission System - Transformer

Estimated Life of the Asset: 45 Years

JUSTIFICATION:

Justification Criteria: Transmission Plant- Station Equipment
Transmission Plant- Underground Conductors and Devices
Transmission Plant- Poles and Fixtures

Sub Criteria: Equipment Replacement

Why do this project?

The station service transformer 1C-ST1 failed several years ago and 1C-GT1 and 1C-UT1 (originally installed in 1968) were re-purposed at that time to be used for temporary station service until 1C-ST1 could be replaced. 1C-GT1 and 1C-UT1 are now experiencing oil weeps and are in need of radiator and bushing replacement. If the transformers are not replaced, there is a risk of failure which will result in no back up station service for transformer 1C-ST2. If 1C-ST2 were to fail without back up station service, generation at the Pt. Tupper plant would be lost.

In addition, in order to get the 4.16kV station service voltage, GT1 first steps 138kV down to 13.2kV, and then UT1 steps 13.2kV down to 4.16kV, resulting in the operation of two transformers. This can be eliminated with the installation of a single station service transformer that is 138kV:4.16kV.

Why do this project now?

Due to the oil weeps and need for radiator and bushing replacement in 1C-UT1 and 1C-GT1, the risk of a failure continues to increase. Completing this project at this time will mitigate the risk of Point Tupper Generating Station going offline in the event that station service transformer 1C-ST2 fails.

Why do this project this way?

Replacement of 1C-GT1 and 1C-UT1 with a proper station service transformer similar to 1C-ST2 is the only option for permanent back-up station service.

CI Number : 52314 - 1C-GT1 and 1C-UT1 Transformer Replacement

Project Number 52314

Parent CI Number : -

Asset Location : 1455 - 1455 Transmission Plant General

Budget Version 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0300 - TP - Bldg.,Struct.Grnd.	56,597
Additions	0700 - TP - Environmental	264,222
Additions	2200 - TP - Elec Contr.Equip.	18,185
Additions	3500 - TP - Wood Poles	6,984
Additions	4300 - TP - Substn Dev.	5,332
Additions	4400 - TP - Substn.Transf.	1,047,869
Additions	4600 - TP - U/G Conductor	12,781
Retirements	3900 - TP - O/H Cond.	12,360
Retirements	4400 - TP - Substn.Transf.	608,064
	Total Cost:	2,032,393
	Original Cost:	554,685

Capital Project Detailed Estimate

Location: Transmission
CI# : 52314
Title: 1C-GT1 and 1C-UT1 Transformer Replacement
Execution Year: 2018-2019

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
Engineering	PD	41	$ 386	$ 15,914		
Labor Technologist	PD	5	$ 284	$ 1,420		
CADD Group	PD	17	$ 284	$ 4,909		
Electricians	PD	109	$ 366	$ 39,799		
Procurement/Financial Support	Lot	1	$ 17,826	$ 17,826		
			Sub-Total	$ 79,868		
OT Labor						
OT Labor	PD	8	$ 731	$ 5,850		
				$ -		
			Sub-Total	$ 5,850		
Travel Expense						
Travel Expense	Lot	1	$ 2,244	$ 2,244		
				$ -		
			Sub-Total	$ 2,244		
Materials						
Transformer (138-25kV)	ea.	1	$ 700,000	$ 700,000		
Deluge System	ea.	1	$ 150,000	$ 150,000		
New HV Bushings	ea.	1	$ 10,000	$ 10,000		
Oil / Water Separator Tank	ea.	1	$ 5,000	$ 5,000		
Motorized Ball Valve	ea.	1	$ 3,500	$ 3,500		
Other materials	Lot	1	$ 22,820	$ 22,820		
				$ -		
			Sub-Total	$ 891,320		
Contracts						
Concrete Foundations	Lot	1	$ 16,000	$ 16,000		
Oil / Water Separator Tank Installation	Lot	1	$ 10,000	$ 10,000		
Transformer Transport, Off Loading & Placement	Lot	1	$ 45,000	$ 45,000		
Civil Demolition	Lot	1	$ 350,000	$ 350,000		
Site Remediation	Lot	1	$ 50,000	$ 50,000		
Other contracts	Lot	1	$ 106,858	$ 106,858		
			Sub-Total	$ 577,858		
Consulting						
Transformer Inspections and Witnessing of Tests	Lot	1	$ 12,000	$ 12,000		
Ground Resistance Measurement	Lot	1	$ 2,000	$ 2,000		
				$ -		
			Sub-Total	$ 14,000		
Meals						
Meals	Lot	1	$ 2,060	$ 2,060		
				$ -		
			Sub-Total	$ 2,060		
Other Goods & Services						
Contingency	%	10%	$ 1,554,896	$ 155,490		
				$ -		
			Sub-Total	$ 155,490		
Vehicle Overhead						
Vehicle AO				$ 33,834		
			Sub-Total	$ 33,834		
Interest Capitalized						
AFUDC				$ 86,703		
				$ -		
			Sub-Total	$ 86,703		
Administrative Overhead						
Labor AO				73,523		
Contract AO				109,643		
			Sub-Total	$ 183,165		
			SUB-TOTAL (no AO, AFUDC)	$ 1,728,690		
			TOTAL (AO, AFUDC included)	$ 2,032,393		
536800 Original Cost				$ 554,685		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting

CI Number: 51398

Title: 2018/2019 Steel Tower Refurbishment

Start Date: 2018/01
In-Service Date: 2018/02
Final Cost Date: 2020/06
Function Class: Transmission
Amount: $1,992,692

DESCRIPTION:

This project is required to replace deteriorated steel tower components. NS Power has approximately 2,000 steel towers installed on the transmission system. These deteriorated steel tower components are identified through the NS Power transmission inspection program. Components that will be replaced include hardware, guy wires, tower legs and grillages, footings and steel members. The age profile of the steel tower fleet is illustrated in the table below.

Age Range	Kilometers of Steel Structures	% of Steel Structures
0-10	0	0%
11-20	5	1%
21-30	339	47%
31-40	122	17%
41-50	125	17%
51-55	6	1%
55+	120	17%

Summary of Related CIs +/- 2 years:
2016 CI 48113 2016 Steel Tower Refurbishment $1,699,991
2017 CI 49815 2017/2018 Steel Tower Refurbishment $2,003,317
2019 CI TBD 2019/2020 Steel Tower Refurbishment $TBD
2020 CI TBD 2020/2021 Steel Tower Refurbishment $TBD

Depreciation Class: Transmission Plant - Towers and Fixtures

Estimated Useful Life: 50-55 Years

JUSTIFICATION:

Justification Criteria: Transmission

Sub-Criteria: Equipment Replacement / Refurbishment

Why do this project?

NS Power's transmission inspection program has identified deteriorated assets on steel towers that require replacement. These lines are critical to the reliable operation of the transmission system. Work on these deficiencies will be prioritized based on inspection results and engineering assessments, consistent with how work has been completed under this program in the past. The exact towers that will be refurbished will be determined throughout the prioritization process.

Why do this project now?

This work will be prioritized based on transmission inspection results. Many of these steel tower components have reached the end of their expected service lives and if replacements are not completed, the reliability of the lines will be compromised.

This project is forecasted to be in-service when the refurbishment of the first tower is completed (February 2018). Therefore, the Final Cost Date (June 2020) is listed as six months after the last tower is forecasted to be completed (December 2019).

Why do this project this way?

Replacing the existing deteriorated steel tower components is more cost effective than replacement of the entire steel towers.

The contracts portion of this project will be sourced through NS Power's existing Power Line Technician (PLT) Service Agreement with Emera Utility Services. This is aligned with NS Power's workforce planning model which is designed to optimize the allocation and execution of PLT resources among work requirements.

CI Number : 51398 - 2018 / 2019 Steel Tower Refurbishment

Project Number 51398

Parent CI Number : -

Asset Location : 1455 - 1455 Transmission Plant General

Budget Version 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	3700 - TP - Steel Towers	1,922,806
Retirements	3700 - TP - Steel Towers	69,885
	Total Cost:	1,992,692
	Original Cost:	220,505

Capital Project Detailed Estimate

Location: **Transmission**
CI# / FP#: 51398
Title: 2018/2019 Steel Tower Refurbishment
Execution Year: 2018-2019

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
T&D Labor - Site Supervision	PD	127	$ 385	$ 48 891		
Procurement / Financial Support	Lot	1	$ 2 400	$ 2 400		
				$ -		
			Sub-Total	$ 51,291		
Materials						
Steel Tower Components	Lot	1	$ 120 000	$ 120 000		
				$ -		
			Sub-Total	$ 120,000		
Contracts						
Contract Line Work	Hrs.	[redacted]		$ 1,174,800		
External Supervision	Lot	1	$ 75,000	$ 75,000		
External Civil Design	Lot	1	$ 100,000	$ 100,000		
			Sub-Total	$ 1,349,800		
Meals & Entertainment						
Meals	Lot	1	$ 2,000	$ 2,000		
			Sub-Total	$ 2,000		
Other Goods & Services						
Contingency	%	10%	$ 1,469,800	$ 146,980		
			Sub-Total	$ 146,980		
Vehicle Overhead						
Vehicle AO				$ 20,961		
			Sub-Total	$ 20,961		
Administrative Overhead						
Labor AO				$ 45,548		
Contract AO				$ 256 111		
			Sub-Total	$ 301,659		
			SUB-TOTAL (no AO, AFUDC)	$ 1,670,071		
			TOTAL (AO, AFUDC included)	$ 1,992,692		
Original Cost				$ 220,505		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 52320

Title: L6549 Replacements and Upgrades

Start Date: 2018/09
In-Service Date: 2018/10
Final Cost Date: 2019/10
Function Class: Transmission
Forecast Amount: $1,406,535

DESCRIPTION:

L6549 is a 45 kilometer (205 Structures) 138kV transmission line, built in 1977, that connects the 5S Glen Tosh and 85S Wreck Cove substations. This project is required to replace deteriorated assets that have been identified through NS Power's transmission inspection program. This project includes the replacement of deteriorated assets on approximately 197 structures.

The project scope includes:

- Structure Replacements: 24 Structures
- Pole and Insulator Replacements: 5 Structures
- Timber and Insulator Replacements: 110 Structures
- Insulator Replacements: 57 Structures
- Other Deteriorated Assets: 1 Structure

Summary of Related CIs +/- 2 years:
No other projects in 2016, 2017, 2018, 2019 or 2020

Depreciation Class: Transmission Plant- Poles and Fixtures
Transmission Plant- Overhead Conductors and Devices
Transmission Plant- Station Equipment

Estimated Life of the Asset: 45 years

JUSTIFICATION:

Justification Criteria: Transmission Plant

Sub Criteria: Equipment Replacement

Why do this project?

The transmission inspection program identified deteriorated assets that require replacement to avoid transmission interruptions. Failure to complete this project would compromise the reliable operation of this line.

Why do this project now?

This work has been prioritized based on transmission inspection results. This project is required to support the reliable operation of the transmission line.

Why do this project this way?

Replacing the existing deteriorated assets is more cost effective than rebuilding the entire line.

The contracts portion of this project will be sourced through NS Power's existing Power Line Technician (PLT) Service Agreement with Emera Utility Services. This is aligned with NS Power's workforce planning model which is designed to optimize the allocation and execution of PLT resources among work requirements.

CI Number : 52320 - L6549 Replacements & Upgrades

Project Number 52320

Parent CI Number : -

Asset Location : 1455 - 1455 L6549 Municipality of the County of Victoria

Budget Version 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0700 - TP - Environmental	69,686
Additions	3500 - TP - Wood Poles	614,593
Additions	3800 - TP - Insulators	256,991
Additions	3900 - TP - O/H Cond.	334,853
Retirements	3500 - TP - Wood Poles	65,588
Retirements	3800 - TP - Insulators	64,824
	Total Cost:	1,406,535
	Original Cost:	346,737

Capital Project Detailed Estimate

Location: **Transmission**
CI# / FP#: 52320
Title: L6549 - Replacements and Upgrades
Execution Year: 2018-2019

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
T&D Labor - Electrician/Technician	PD	4	$ 366	$ 1,307		
T&D Labor - Site Supervision	PD	73	$ 389	$ 28,314		
Procurement / Financial Support	Lot	1	$ 3,219	$ 3,219		
			Sub-Total	$ 32,840		
Materials						
Poles	Lot	1	$ 112 920	$ 112 920		
Insulators	Lot	1	$ 42 964	$ 42 964		
Conductors	Lot	1	$ 80	$ 80		
			Sub-Total	$ 155,963		
Contracts						
Contract Line Work	Hrs.	[redacted]		$ 738 658		
Flagging	Lot	1	$ 5 000	$ 5 000		
Rock Breaking	Lot	1	$ 14,000	$ 14,000		
Pole Haulage	Lot	1	$ 6,400	$ 6,400		
Waste Disposal	Lot	1	$ 5,000	$ 5,000		
Helicopter services	Lot	1	$ 85,000	$ 85,000		
Lidar survey	Lot	1	$ 5,000	$ 5,000		
Environmental services	Lot	1	$ 52,093	$ 52,093		
			Sub-Total	$ 911,152		
Other Goods & Services						
Contingency	%	10%	$ 911,152	$ 91,115		
			Sub-Total	$ 91,115		
Vehicle Overhead						
Vehicle AO				$ 13 420		
			Sub-Total	$ 13,420		
Administrative Overhead						
Labor AO				$ 29,163		
Contracts AO				$ 172,882		
			Sub-Total	$ 202,045		
			SUB-TOTAL (no AO, AFUDC)	$ 1,191,070		
			TOTAL (AO, AFUDC included)	$ 1,406,535		
Original Cost				$ 346,737		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 51406

Title: 2018/2019 Transmission Switch & Breaker Replacement

Start Date: 2018/03
In-Service Date: 2018/03
Final Cost Date: 2019/06
Function Class: Transmission
Amount: $1,405,891

DESCRIPTION:

This project provides for the replacement of deteriorated substation circuit breakers and transmission switches on the NS Power transmission system. The project estimate includes the retirement and replacement of three 69kV breakers, one 138 kV breaker, four 69kV switches and four 138kV switches. The breakers being replaced are prioritized based on the maintenance history, age, number of operations, electrical test results, design or manufacturing issues, inspection results, customers supplied, system redundancy, and safety and environmental issues.

NS Power anticipates that a portion of the capital costs associated with this capital item will contribute toward settling the Company's Asset Retirement Obligation for PCB contaminated oil.

Summary of Related CIs +/- 2 years:
CI 48059 - 2016/2017 Transmission Switch & Breaker Replacement - $980,999
CI 49818 - 2017/2018 Transmission Switch & Breaker Replacement - $1,074,472
CI TBD - 2019/2020 Transmission Switch & Breaker Replacement - $TBD
CI TBD - 2020/2021 Transmission Switch & Breaker Replacement - $TBD

JUSTIFICATION:

Justification Criteria: Transmission Plant

Sub Criteria: Equipment Replacement

Depreciation Class: Transmission Plant – Station Equipment
Transmission Plant – Overhead Conductors and Devices

Estimated Useful Life: 40 Years

Why do this project?

This project will replace deteriorated substation circuit breakers and transmission switches. Completing this project will mitigate transmission supply interruptions and maintain reliable operation of the transmission system for customers.

This project is being done primarily to replace end-of-life assets, and secondly to reduce environmental risks by removing oil filled equipment.

Why do this project now?

The circuit breakers being replaced are, on average, 56 years old. The expected useful life of a circuit breaker is 40 years. Switches have an expected useful life of 40 years and the switches being evaluated for replacement are approaching or past this expected useful life.

This project is deemed in-service when the first switch or breaker is replaced (March 2018), therefore the Final Cost Date (December 2019) is listed as six months after the switch or breaker is completed (June 2019).

Why do this project this way?

Due to the age of the devices, spare parts are no longer available for the majority of the circuit breakers that are being replaced. The breakers being replaced are often oil filled so this project also serves to remove oil filled equipment from the fleet, reducing the environmental liability.

CI Number : 51406 - 2018/2019 Transmission Switch & Breaker Replacement **Project Number** 51406

Parent CI Number : -

Asset Location : 1455 - 1455 Transmission Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0300 - TP - Bldg.,Struct.Grnd.	108,403
Additions	2200 - TP - Elec Contr.Equip.	92,570
Additions	4000 - TP - O/H Cond.Devices	1,142,328
Retirements	4300 - TP - Substn Dev.	62,590
	Total Cost:	1,405,891
	Original Cost:	153,089

Capital Project Detailed Estimate

Location: **Transmission**
CI# / FP#: 51406
Title: 2018/2019 Transmission Switch and Breaker Replacement
Execution Year: 2018-2019

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
T&D Labor - Electrician/Technician	PD	155	$ 366	$ 56,627		
T&D Labor - Site Supervision	PD	5	$ 389	$ 1,949		
Project Support - Engineering Design	PD	499	$ 386	$ 192,793		
			Sub-Total	$ 251,369		CI 49818
Materials						
Control Cable	m	2000	$ 10	$ 20,000		
Misc. J-Boxes	each	2	$ 1,000	$ 2,000		
Misc. Conduit and Connectors	Lot	1	$ 500	$ 500		
138kV Switch	each	4	$ 12,850	$ 51,400		
138kV Vacuum Bottles	each	6	$ 3,000	$ 18,000		
138kV High Velocity Whips	each	4	$ 1,500	$ 6,000		
138kV Motor Operator	each	2	$ 5,000	$ 10,000		
138kV Insulators	each	36	$ 450	$ 16,200		
138kV Surge Arrestors	each	1	$ 9,000	$ 9,000		
138kV Connectors, Jumpers, etc.	Lot	1	$ 1,260	$ 1,260		
69kV Switch	each	4	$ 10,000	$ 40,000		
69kV High Velocity Whips	each	4	$ 1,500	$ 6,000		
69kV Vacuum Bottles	each	6	$ 3,000	$ 18,000		
69kV Surge Arrestors	each	6	$ 1,200	$ 7,200		
69kV Connectors, Jumpers, Etc.	Lot	1	$ 3,840	$ 3,840		
138kV Circuit Breaker	each	1	$ 71,518	$ 71,518		
69kV Circuit Breaker	each	3	$ 52,770	$ 158,310		
Grounding Attachments, Mats, Assemblies, etc.	Lot	1	$ 4,000	$ 4,000		
138kV A&B Steel Switch Support	each	2	$ 15,000	$ 30,000		
			Sub-Total	$ 473,228		CI 49818
Contracts						
Concrete Foundations, Conduit, and Civil works	Lot	1	$ 12,660	$ 12,660		
Labor for install/remove Circuit Breakers	Lot	1	$ 206,036	$ 206,036		
Boom Truck Rental	Lot	1	$ 640	$ 640		
			Sub-Total	$ 219,336		CI 49818
Other Goods & Services						
Contingency	%	10%	$ 943,933	$ 94,393		
			Sub-Total	$ 94,393		
Vehicle Overhead						
Vehicle AO				$ 102,724		
			Sub-Total	$ 102,724		
Administrative Overheads						
Labor AO				$ 223,223		
Contract AO				$ 41,617		
			Sub-Total	$ 264,840		
			SUB-TOTAL (no AO, AFUDC)	$ 1,038,326		
			TOTAL (AO, AFUDC included)	$ 1,405,891		
Original Cost				$ 153,089		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.

CI Number: 51405

Title: 2018/2019 Wood Pole Retreatment Program

Start Date:	2018/05
In-Service Date:	2018/05
Final Cost Date:	2020/02
Function Class:	Transmission
Amount:	$1,361,076

DESCRIPTION:

This project provides for the retreatment of approximately 4,874 transmission poles in both 2018 and 2019. This project is the second CI of a multi-year program that will continue beyond 2019.

NS Power carries out a pole retreatment program on transmission class poles. Wood poles originally treated with pentachlorophenol and creosote preservatives are retreated with wood preservatives to reinforce the preservative retention levels in the ground line area to maintain protection against fungal and insect damage.

Summary of Related CIs +/- 2 years:
2017 CI 2017 Wood Pole Retreatment Program $841,821
2020 CI TBD 2020 Wood Pole Retreatment Program $TBD

Depreciation Class: Transmission Plant- Poles and Fixtures

Estimated Useful Life: 55 years

JUSTIFICATION:

Justification Criteria: Pole Retreatment

Why do this project?

This project is being completed in order to extend the expected life of 9,748 transmission poles from 35 years to 55 years, delaying the replacement of these poles by approximately 20 years.

Why do this project now?

This project should be completed now to contribute to the reliable operation of the transmission system.

This project is forecasted to be in-service when the first pole is forecasted to be completed (May 2018), therefore the Final Cost Date (February 2020) is listed as six months after the last pole is forecasted to be completed (August 2019).

Why do this project this way?

Pole retreatment is a proven and accepted cost effective approach to extend the life of the pole. The average cost of a pole installation is $4,500 and a retreatment costs approximately $175. Four retreatments (at 15, 25, 35 and 45 years of service) extend the expected life of the pole from 35 years to 55 years at a total cost of $700 (4 treatments at $175 each). The average cost per year of service for a pole without retreatment is $129 ($4,500 / 35 years); with a retreatment program the average cost per year for the 20 additional years of service is $35 ($700 / 20 years). Completing pole retreatment in this manner is a cost effective way to extend the life of treated wood poles and to defer the replacement of the pole by approximately 20 years.

CI Number : 51405 - 2018/2019 Wood Pole Retreatment Program **Project Number** 51405

Parent CI Number : -

Asset Location : 1455 - 1455 Transmission Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	3500 - TP - Wood Poles	1,361,076
	Total Cost:	1,361,076
	Original Cost:	

Capital Project Detailed Estimate

Location: Transmission
CI# / FP#: 51405
Title: 2018/2019 Wood Pole Retreatment Program
Execution Year: 2018-2019

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
T&D Labour - Site Supervision	PD	90	$ 385	$ 34,650		
Procurement / Financial Support	Lot	1	$ 5,000	$ 5,000		
Engineering Design	PD	10	$ 382	$ 3,820		
			Sub-Total	$ 43,470		
Travel Expense						
Travel - Site Supervisor	Lot	1	$ 2,000	$ 2,000		
			Sub-Total	$ 2,000		
Contracts						
Pole Retreatment	EA	9748	$ 100	$ 974,800		
			Sub-Total	$ 974,800		
Meals & Entertainment						
Meals - Site Supervisor	Lot	1	$ 2,000	$ 2,000		
			Sub-Total	$ 2,000		
Other Goods & Services						
Contingency	%	10%	$ 974,800	$ 97,480		
			Sub-Total	$ 97,480		
Vehicle Overhead						
Vehicle AO				$ 17,764		
			Sub-Total	$ 17,764		
Administrative Overhead						
Labour AO				$ 38,603		
Contract AO				$ 184,959		
				$ -		
			Sub-Total	$ 223,561		
			SUB-TOTAL (no AO, AFUDC)	$ 1,119,750		
			TOTAL (AO, AFUDC included)	$ 1,361,076		
Original Cost				$ -		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 48131

Title: 48H-T1 Transformer Replacement

Start Date:	2017/10
In-Service Date:	2018/12
Final Cost Date:	2019/06
Function Class:	Transmission
Amount:	$1,281,449

DESCRIPTION:

The scope of this project is to replace the existing transformer at 48H Penhorn substation with a functionally equivalent new model. This transformer, 48H-T1 provides electric service to approximately 4,400 customers in the Dartmouth area. The replacement transformer will be placed in the same position and connected to the existing high voltage wiring. A loading study will be done prior to purchasing the replacement transformer, in order to determine the appropriate size transformer, accounting for existing loading and potential load growth. Also, the replacement transformer will have a new tap changer that will mitigate the risk of oil leakage.

Summary of Related CIs +/- 2 Years:
No other projects in 2016, 2017, 2018, 2019 and 2020

Depreciation Class: Transmission Plant- Station Equipment

Estimated Useful Life: 45 Years

JUSTIFICATION:

Justification Criteria: Transmission Plant

Sub Criteria: Equipment Replacement

Why do this project?

The existing transformer at the 48H substation is 45 years old and is a Ferranti Packard model with a known defect that causes the internal varnish to dissolve in the oil. This has been known to cause premature and sudden failure of transformers. Also, the existing tap changer has caused bolts to loosen upon operation, resulting in various oil leaks. If the existing transformer were to fail, a lengthy customer outage would be experienced until a mobile transformer and/or distribution switching could be completed to re-energize the 48H feeders.

Why do this project now?

The 48H-T1 transformer is at the end of its expected service life, there is a known defect with this transformer model, and the tap changer has experienced oil leaks. Therefore, the best course of action is to replace the transformer prior to a failure to avoid a large customer outage.

Why do this project this way?

Refurbishment of this transformer is not recommended due to its age and known defects, therefore replacement is the only alternative in order to minimize unplanned customer outages and mitigate oil leaks.

CI Number : 48131 - 48H-T1 Transformer Replacement **Project Number** 48131

Parent CI Number : -

Asset Location : 1455 - 1455 Transmission Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0300 - TP - Bldg.,Struct.Grnd.	17,499
Additions	0700 - TP - Environmental	43,524
Additions	2200 - TP - Elec Contr.Equip.	3,091
Additions	4300 - TP - Substn Dev.	32,217
Additions	4400 - TP - Substn.Transf.	1,131,686
Retirements	4400 - TP - Substn.Transf.	53,432
	Total Cost:	1,281,449
	Original Cost:	208,412

Capital Project Detailed Estimate

Location: Transmission
CI# : 48131
Title: 48H-T1 Transformer Replacement
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
Engineering	PD	50	$ 386	$ 19,300		
Labour Technologist	PD	9	$ 284	$ 2,434		
CADD Group	PD	18	$ 284	$ 5,031		
Electricians	PD	122	$ 366	$ 44,698		
Procurement/Financial Support	Lot	1	$ 14,498	$ 14,498		
			Sub-Total	$ 85,961		
OT Labour						
OT Labour	PD	20	$ 731	$ 14,625		
			Sub-Total	$ 14,625		
Travel Expense						
Travel Expense	Lot	1	$ 956	$ 956		
			Sub-Total	$ 956		
Materials						
Transformer	ea	1	$ 700,000	$ 700,000		
Other materials	Lot	1	$ 24,885	$ 24,885		
			Sub-Total	$ 724,885		
Contracts						
Concrete Foundations	Lot	1	$ 12,640	$ 12,640		
Oil Containment Foundation & Oil/Water Separator Tank Installation	Lot	1	$ 18,000	$ 18,000		
Transformer Transport, Offload, Assembly & Oil Transport	Lot	1	$ 120,360	$ 120,360		
Boom Truck Rental	Lot	1	$ 1,280	$ 1,280		
			Sub-Total	$ 152,280		
Consulting						
Transformer Inspections and Witnessing of Tests	Lot	1	$ 20,000	$ 20,000		
				$ -		
			Sub-Total	$ 20,000		
Meals & Entertainment						
Meals	Lot	1	$ 400	$ 400		
				$ -		
			Sub-Total	$ 400		
Other Goods & Services						
Contingency	%	10%	$ 977,751	$ 97,775		
				$ -		
			Sub-Total	$ 97,775		
Vehicle Overhead						
Vehicle AO				$ 38,982		
			Sub-Total	$ 38,982		
Interest Capitalized						
AFUDC				$ 34,661		
			Sub-Total	$ 34,661		
Administrative Overhead						
Labour AO				$ 81,841		
Contract AO				$ 29,083		
			Sub-Total	$ 110,925		
			SUB-TOTAL (no AO, AFUDC)	$ 1,096,882		
			TOTAL (AO, AFUDC included)	$ 1,281,449		
536800 Original Cost				$ 208,412		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 52328

Title: 56N-T1 Transformer Upgrade

Start Date: 2018/01
In-Service Date: 2019/03
Final Cost Date: 2019/09
Function: Transmission
Forecast Amount: $1,279,271

DESCRIPTION:

This project is for the capacity upgrade of the 56N-T1 transformer to 25MVA at the 56N Haliburton substation. Distribution Planning Study 367-0216-E31 (please refer to Attachment 1) was conducted for the Pictou area and identified the Haliburton substation (56N) for a transformer capacity increase to meet customer needs. The substation load will increase when the existing 4.16kV supplies, within the Town of Pictou, have been changed to the 25kV system.

Summary of Related CIs +/- 2 years:
No other projects in 2016, 2017, 2018, 2019 and 2020

Depreciation Class: Transmission Plant – Station Equipment
Transmission Plant – Underground Conduit
Transmission Plant – Overhead Conductors and Devices

Estimated Life of the Asset: 45 Years

JUSTIFICATION:

Justification Criteria: Transmission Plant

Why do this project?

The upgrade from 56N-T1 to 25MVA must be completed as outlined in the attached Distribution Study to address the pending increase in substation load when the distribution voltage conversion and new 25kV feeder addition is completed in 2019.

Why do this project now?

Conversion of the 4.16kV supply, in the town of Pictou, to 25kV will increase the load on the existing 11.2MVA transformer beyond its nameplate rating. The load on 56N-T1 peaked at over 14MVA in 2015. Failure to upgrade the capacity of 56N-T1 prior to the voltage conversion will push the transformer above its 133 percent overload rating during periods of peak demand.

Why do this project this way?

Two alternatives were evaluated as part of the planning study (please refer to Attachment 1) to determine the most economical solution. Alternative 1 consisted of the replacement of the existing 11.2MVA transformer with a 25MVA unit. Alternative 2 explored the installation of a second 14MVA transformer. The economic analysis provided in Appendix C of the planning study shows that Alternative 1 is the best solution.

CI Number : 52328 - 56N-T1 Transformer Upgrade **Project Number** 52328

Parent CI Number : -

Asset Location : 1455 - 1455 Transmission Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0300 - TP - Bldg.,Struct.Grnd.	20,940
Additions	0700 - TP - Environmental	34,932
Additions	2200 - TP - Elec Contr.Equip.	1,068
Additions	2300 - TP - Power Equip.-Station S	2,497
Additions	3900 - TP - O/H Cond.	257
Additions	4300 - TP - Substn Dev.	7,632
Additions	4400 - TP - Substn.Transf.	1,180,833
Additions	4500 - TP - U/G Conduit	5,663
Retirements	4400 - TP - Substn.Transf.	25,448
	Total Cost:	1,279,271
	Original Cost:	217,975

Capital Project Detailed Estimate

Location: **Transmission**
CI# / FP#: 52328
Title: 56N-T1 Transformer Upgrade
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
T&D Labor - Electrician/Technician	PD	35	$ 366	$ 12,875		
T&D Labor - Site Supervision	PD	12	$ 389	$ 4,813		
T&D Labor - Design	PD	40.6	$ 386	$ 15,654		
Procurement / Financial Support	Lot	1	$ 16,399	$ 16,399		
			Sub-Total	$ 49,741		
OT Labor						
T&D Labor - Electrician/Technician	PD	8	$ 731	$ 5,762		
			Sub-Total	$ 5,762		
Travel Expense						
Travel	Lot	1	$ 3,422	$ 3,422		
			Sub-Total	$ 3,422		
Materials						
Environmental	Lot	1	$ 11,700	$ 11,700		
Control & Grounding	Lot	1	$ 800	$ 800		
Power	Lot	1	$ 2,000	$ 2,000		
Substation Devices	Lot	1	$ 5,440	$ 5,440		
Transformer	Lot	1	$ 800,000	$ 800,000		
			Sub-Total	$ 819,940		
Contracts						
Civil	Lot	1	$ 38,000	$ 38,000		
Transformer (Transport/Offload/Assembly)	Lot	1	$ 86,780	$ 86,780		
Retired Transformer (Transport & Offload)	Lot	1	$ 20,720	$ 20,720		
			Sub-Total	$ 145,500		
Consulting						
Transformer FAT	Lot	1	$ 20,000	$ 20,000		
			Sub-Total	$ 20,000		
Meals						
Site Visits & Meal Chits	Lot	1	$ 750	$ 750		
			Sub-Total	$ 750		
Overtime Meals						
Site Visits & Meal Chits	Lot	1	$ 750	$ 750		
			Sub-Total	$ 750		
Other Goods & Services						
Contingency	$	10%	$ 1,020,943	$ 102,094		
			Sub-Total	$ 102,094		
Vehicle Overhead						
Vehicle Allocated Costs				$ 21,504		
			Sub-Total	$ 21,504		
Administrative Overhead						
Labor AO				$ 46,730		
Contract AO				$ 27,607		
			Sub-Total	$ 74,337		
Interest Capitalized						
AFUDC				$ 35,470		
			Sub-Total	$ 35,470		
			SUB-TOTAL (no AO, AFUDC)	$ 1,147,959		
			TOTAL (AO, AFUDC included)	$ 1,279,271		
Original Cost				$217,975		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

Pictou/Haliburton Rd Substation Service Areas
DISTRIBUTION PLANNING STUDY

Report #**367-0216-E31**

Revision		Date	Drafted By	Reviewed by	Approved By
0	Completed Study	09-May-2016	AB	ED	DEK

EXECUTIVE SUMMARY

This study was initiated by the Eastern Territory to determine solutions for the overloaded substation transformer 56N-T1 (7.5/10//11.2 MVA, 69-25kV) at Haliburton Substation (See Figure 1), to plan for the future of substation 55N (5/6.7//7.5 MVA, 69-4.16kV) at Pictou Town (See Figure 2) as well as identify and propose solutions to the distribution system supplied from these substations over a 15 year planning horizon.

Figure 1-Haliburton Substation (56N)

Figure 2-Pictou Town Substation (55N)

The service area of these substations is north of the Abercrombie Point causeway on Hwy #106 including Pictou and surrounding communities of Caribou, Braeshore; west along the Sunrise trail including Three Brooks, Caribou River, Waterside, Caribou Island, Toney River, Seafoam; west along Hwy#256 including Lyons Brook, Hardwood Hill, Scotsburn, Heathbell as far as river John; along Hwy #376 to Durham, Sylvester; and south along the Alma Road to interconnect with feeder

62N-414 from Stellarton Substation. (See Figure 3) Customers to the west of this area are supplied from Tatamagouche substation 4N in Central Territory

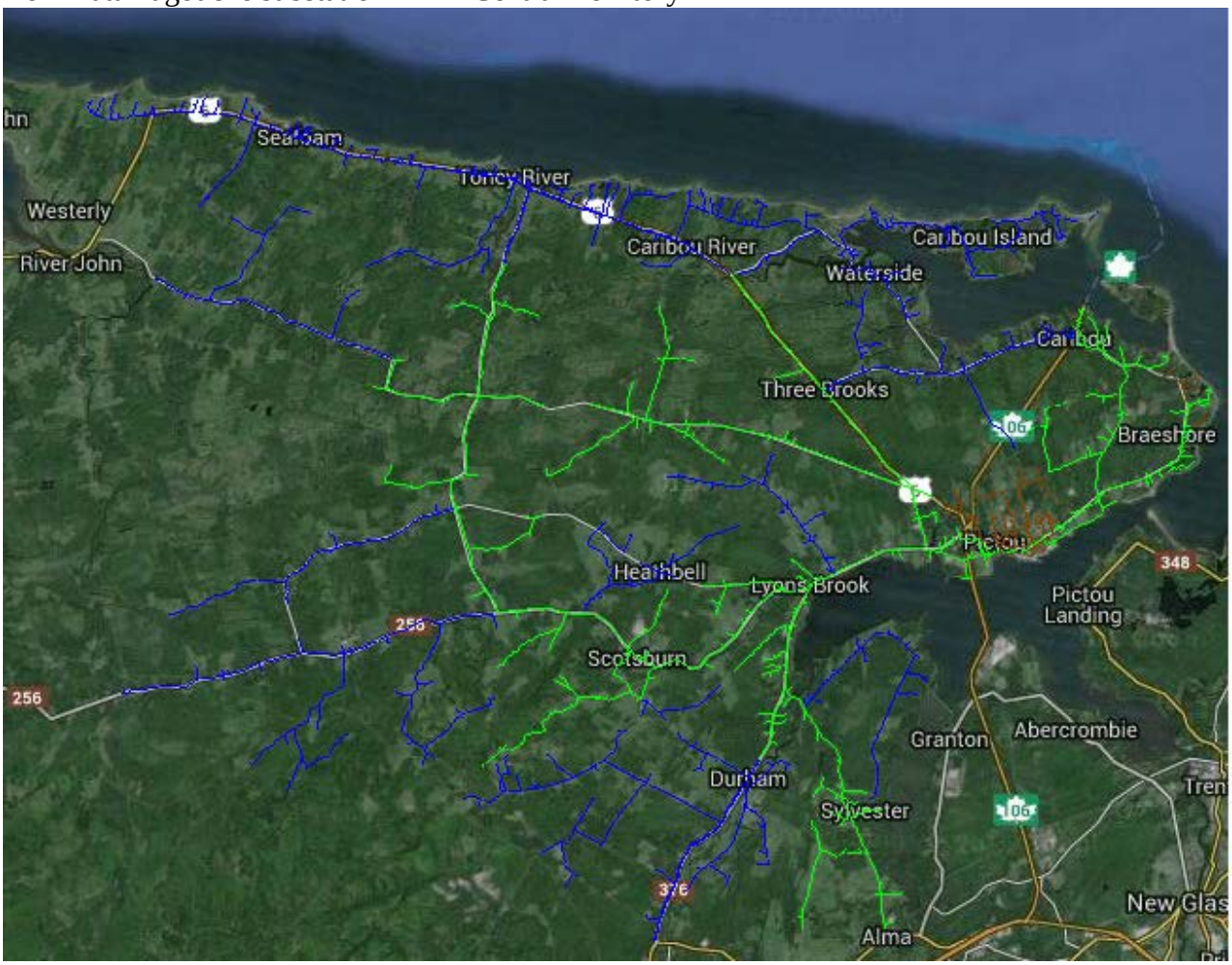


Figure 3-Study Area supplied by Substations 55N & 56N

The distribution system supplied from these two substations was modelled on CYME software (Version 7.2r01) from an equipment extract from OneGIS in Jan 2016 and load information from monthly load checks, PI data, annual clip on load measurements, CIS billing demands, dump from electronic controls of substation reclosers and wind turbine generation data. An adjacent feeder from Bridge Avenue substation 62N-414 was also modelled to examine the possibility of load relief for the service area under study. By curve fitting previous years load values a growth rate was determined which was applied to the CYME model to predict future problems on the system. (See Appendix B) By applying this growth rate to the CYME model it was possible to predict overloaded equipment as well as voltage levels to customers outside CSA limits. Each of these problems was solved by identifying solutions and selecting the solution with the least present worth cost without compromising customer service reliability. The economic analysis includes not only the capital costs but the operating costs resulting from line losses obtained from the CYME model. This study provides least cost solutions for the distribution system supply to the customers in this service area for the next 15 years (horizon year 2031). The timing of the load related capital items recommended by this report should be reviewed annually after peak load checks have been taken.

Recommendations from this study have been assessed based on these three basic questions for capital expenditures:
(1) Why Do This at All? Section 4.0 JUSTIFICATION FOR EXPENDITURE (CEJC)
(2) Why Do This Now? Section 4.0 JUSTIFICATION FOR EXPENDITURE (Violation Year)
(3) Why Do It This Way? Section 5.0 EVALUATION AND SOLUTIONS (Economic Analysis)

The recommendations are as follows:

1. 2016-The activation or replacement of the present communications system at Haliburton Road Substation to enable the hourly time stamped values from PI for the three distribution feeders is critical to determine the actual loading on this station due to the interconnection of Wind Turbine generators on feeder 56N-414 at Fitzpatrick's Mountain. This should be done as soon as possible. Either the current communication system and RTU should be reactivated or a new system installed via radio link to provide PI data as well as remote indication and control of 25kV reclosers. (Note from Brad Fiander in 2016 about the communication system) - *This is a DART RTU and the recloser currents are wired directly to RTU inputs. Long before we replaced the reclosers, we added a third recloser and even at that time we could not get the metering for the third recloser to work correctly. This also 'broke' the SCADA transformer metering since the transformer metering is the sum of the three feeders. We couldn't see why it wouldn't work and decided to live without it. When the reclosers were replaced, things went from bad to worse. I think the CTs are wired into the DART, but none of the feeders is metered correctly (at least before we had two feeders showing correct amps). By this time we had even less expertise to solve the problem, so we let it go, hoping for a new RTU.* This work needs to be designed and constructed by the Communications Group at Ragged Lake. Power Transformer 56N-T1 rated 7.5//11.2 MVA, 69-25kV at Haliburton Substation is forecast to be overloaded at the 2016/17 peak.
2. 2016-Temporarily reduce load on Haliburton Road power transformer 56N-T1 before the 2016-17 peak by transferring approximately 1MVA of load to Bridge Avenue feeder 62N-414 by repairing/replacing and closing switch L451-063 on Alma Road near Highway#4 and opening switch D451-062 on Riverview Drive. (See Figures 4 & 5 below.)

Figure 4-Defective N.O. switch L451-063 on Alma Road near Highway #4

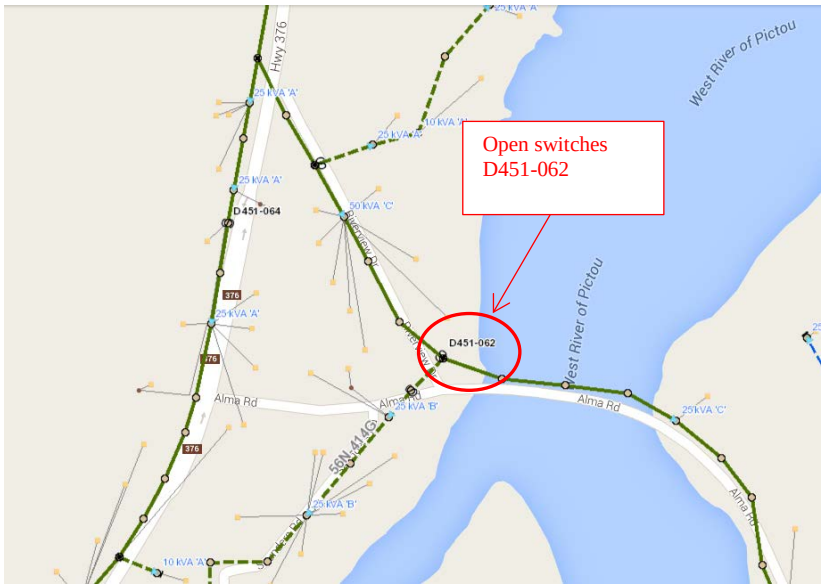


Figure 5-N.C. switches D451-062 at Alma Road & Riverview Dr.

3. 2017-Replace overloaded and deteriorated (weeping oil) 333kVA stepdown transformer 512N-T1 at Toney River substation built in 1956 with a 500KVA, 14.4-7.2 unit with HV tap set on 100%. Because the existing transformer bank is connected delta to wye this will necessitate the other two step-downs 512N-T2, T3 also be replaced with new 500KVA units and connected wye-wye. Since they are all the same age 60 years old and all weeping oil around tap changer they need to be replaced anyway before they suffer oil leaks and or failure. Since these units have been operating at a fixed 3.9% boost and to maintain customer voltage levels within the CSA criteria range in the area at light and peak load periods, replacement of these transformers should be accompanied with addition of three 100 amp 7.2kV regulators. If the existing substation is retained a new substation design is required to accommodate the transformers, regulators and reclosers including replacing the existing creosote timbers with concrete pads. An alternative arrangement may be to install the new step downs on a platform structure and pole-mount the regulators. (See Figure 6.)

Figure 6-Toney River Stepdowns 512N-T1, T2, T3

4. 2017-Install single phase 100 amp 7.2kV regulator on feeder 62N-414 just past West River recloser 639N-321 to solve low voltage issues. (See figure 7)

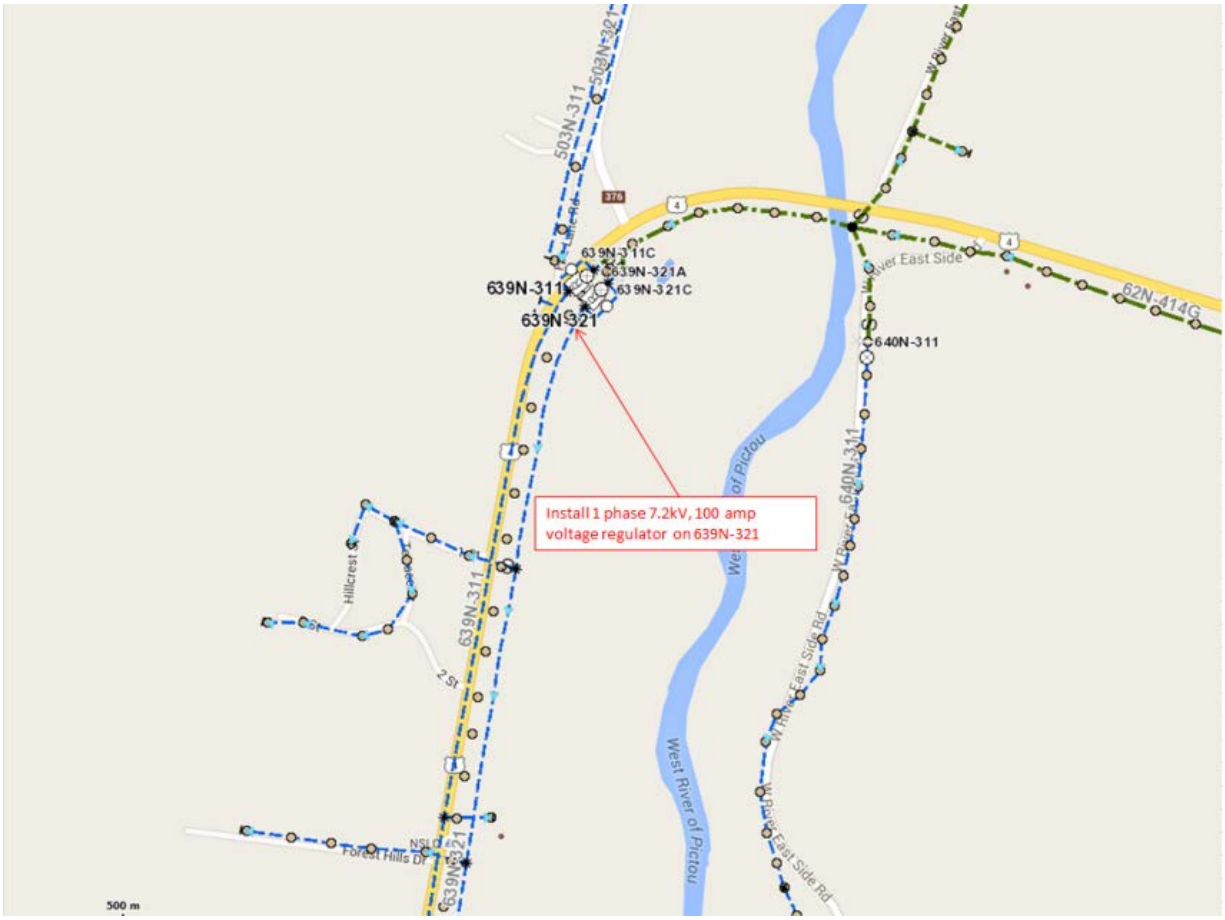


Figure 7-Addition of 1 phase regulator at West River

5. 2017-Reconductor 0.92 km of feeder 56N-414 from #4 Cu to 336ASC on the Scotsburn Road (Hwy#256) from Durham Rd to Condon Road. (See figure 8)

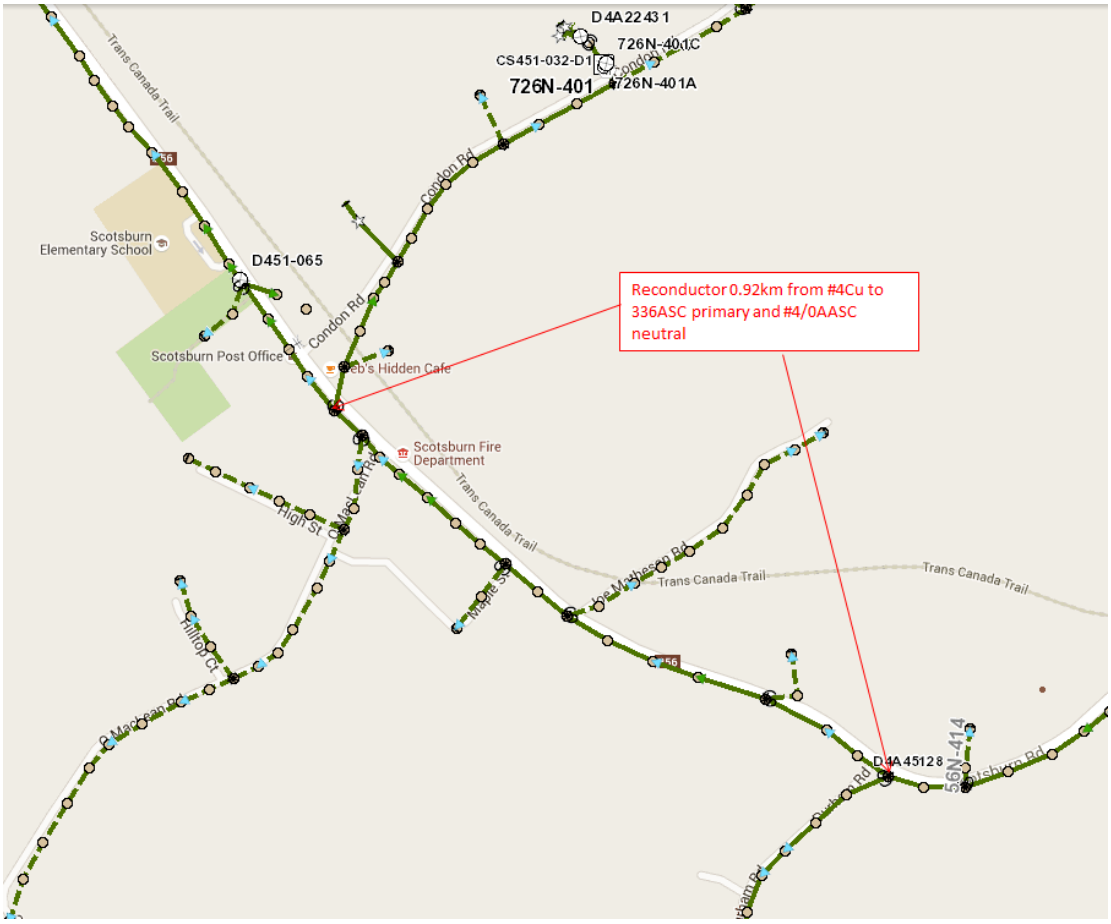


Figure 8-Reconductor 0.92 km of #4 Cu with 336ASC Scotsburn

6. 2018-Replace overloaded Haliburton Road power transformer 56N-T1with a unit rated 69-26.4kV, 15/20/25MVA and add a 25kV circuit to offload: (1) 56N-414, (2) stepdowns at 512N Toney River and (3) 4kV load converted from Pictou 4kV. The existing 7.5/10/11.2 MVA, 69-25kV transformer is needed as a system spare since the spare was utilized at 20V-T1 in Hantsport in 2016 to replace a failed transformer.
7. 2018- In conjunction with the 56N-T1 transformer replacement construct a new three phase 25kV feeder using 336ASC primary from Haliburton Substation on opposite side of the road from 56N-414 along the Haliburton Road (or double circuit) to Hwy #376 and west along Hwy #376 to Harris Road. Convert the single phase line on the Harris Road to three phase 336ASC conductor. Convert the single phase line on Highway #6 (Sunrise Trail) to Caribou River from single phase to three phase 336ASC. Construct a 3 phase 336 ASC tap on Hwy #376 eastward to Pine Tree Road and behind Pictou town along Division Road to interconnect with 56N-401 and pick up 4kV load. Add three stepdown transformers to off load 512N Toney River by supplying customers as far as Meadowville Station Road. (See figures 9&10)
8. 2019-2025-Manage the 4kV load on the Pictou Substation transformer 55N-T1 to the mobile transformer 3P rating of 6MVA by connecting new customers where possible to Haliburton 25kV substation feeder 56N-401 and the proposed new feeder from 56N. Due to the age of the substation a gradual conversion of the voltage from 4kV to 25kV should be undertaken in Pictou town approximately 625 KVA demand or 1250 KVA connected per year to allow for removal and retirement of 55N substation and the section of 69kV transmission line L5506 between 56N and 55N.

Figure 9-Proposed New 25kV Feeder from 56N Haliburton Rd Substation

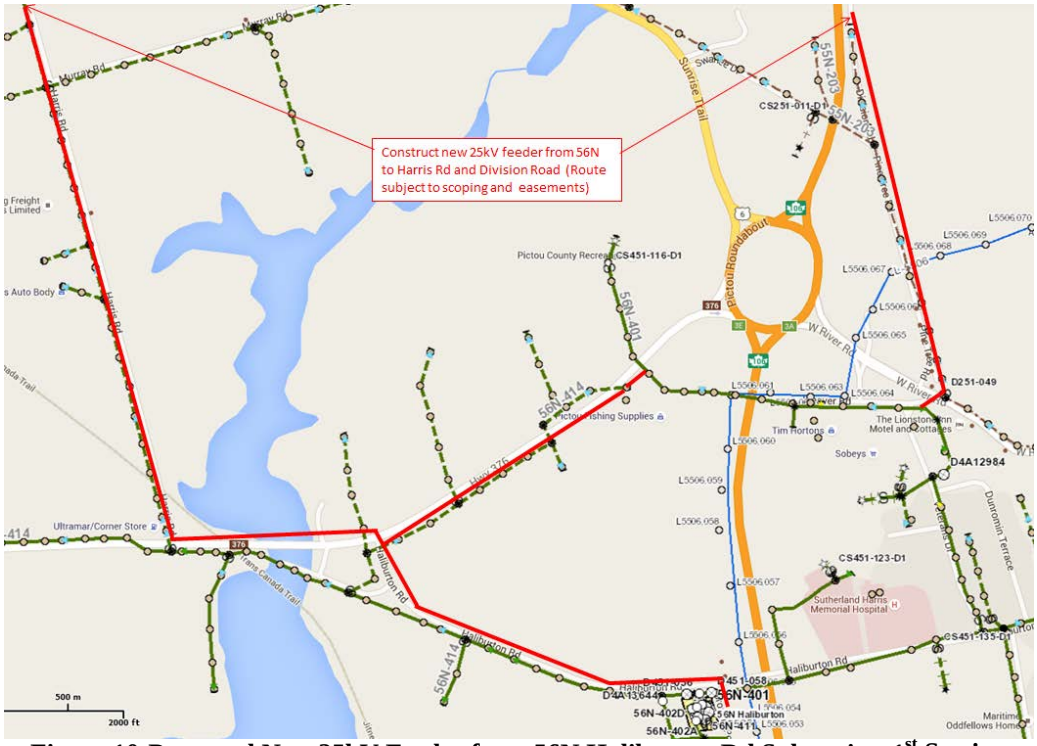


Figure 10-Proposed New 25kV Feeder from 56N Haliburton Rd Substation-1st Section

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1.0 SCOPE

This study was initiated by the Eastern Territory to determine solutions for the overloaded power transformer 56N-T1 (7.5/10//11.2 MVA, 69-25kV) at Haliburton Substation and to plan for the future of substation 55N (5/6.7//7.5 MVA, 69-4.16kV) in Pictou Town as well as the distribution system supplied from these substations. A coordinated plan to supply existing and future customers is required for this service area north of the Abercrombie Point causeway on Hwy #106 including Pictou and surrounding communities of Caribou, Braeshore; west along the Sunrise trail including Three Brooks, Caribou River, Waterside, Caribou Island, Toney River, Seafoam; west along Hwy#256 including Lyons Brook, Hardwood Hill, Scotsburn, Heathbell as far as river John; along Hwy #376 to Durham, Sylvester; and south along the Alma Road to interconnect with feeder 62N-414 from Bridge Avenue Substation. Customers to the west of this area are supplied from Tatamagouche substation 4N in Central Region. The scope of this study provides least cost solutions for the distribution system supply to the customers in this service area for the next 15 years (horizon year 2031).

2.0 EXISTING SYSTEMS

2.1 Transmission (See Figure 11)

The 50N-Trenton substation serves as the connection point for Trenton Thermal Generating Station and is along the route of a major transmission corridor spanning from Cape Breton to the hub in Onslow. The 230kV transmission lines L7003 and L7004 pass by this station whereas the 138kV system supplies sub-transmission in the area via lines: L-6503, L-6507, L-6508 and L-6511. The transmission system is outside the scope of this study.

2.2 Sub-Transmission (See Figure 11)

The sub-transmission system operates at 69kV. It is supplied by two 138-69kV, auto-transformers 50N-T8 and T12 each with a top rating of 93.3 MVA located at 50N Trenton substation. From there, a 69kV N.O. loop is made with 62N Bridge Ave (L-5500 and L-5501) as well as a radial feed (L-5502) to 54N Abercrombie supplying Northern Pulp (53N) and on radially via L5506 across the Abercrombie causeway to our service area substations 55N Pictou, 56N Haliburton. From 62N Bridge Ave another radial 69kV line (L5510) goes to 89H Trafalgar, Upper Musquodoboit 88H and to Sheet Harbour 95H, 96H, 97H. The sub-transmission system is not within the scope of this study however it should be pointed out that the 69kV load supplied from Trenton Substation is such that **for the contingency of the loss of one of the autotransformers 50N-T8 or 50N-T12 the remaining transformer would exceed its rating of 93.3MVA** depending on the generation at Northern Pulp, distribution wind turbines and the hydro generation on the Sheet Harbour system. (This issue was identified to Dave Stanford via an Email on Jan 28, 2016 and investigated further by John Charlton, Email to Dave Stanford on Jan 29, 2016).

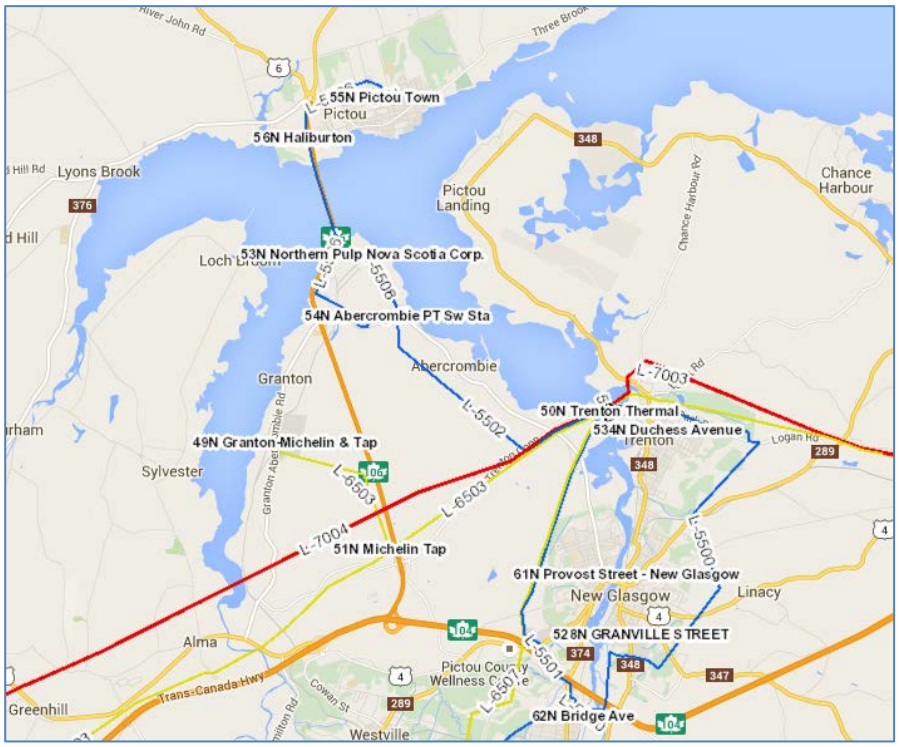


Figure 11-Trenton, Stellarton, and Pictou Area Transmission and Sub-transmission

2.3 56N-Haliburton Distribution (25kV)

The 56N-Haliburton substation has one Westinghouse 69-25kV, 7.5/10//11.2MVA power transformer T1 with a low side on-load tap changer (OLTC) with a ±15% range, built in 1973 and a Beckwith M2067B control. Transformer T1 supplies three feeders 56N-401, 402, 414 with new G&W Viper electronic reclosers which cover a large area including north of the Abercrombie Point causeway on Hwy#106 part of Pictou and surrounding communities of Caribou, Braeshore; west along the Sunrise trail including Three Brooks, Caribou River, Waterside, Caribou Island, Toney River, Seafoam; west along Hwy#256 including Lyons Brook, Hardwood Hill, Scotsburn, Heathbell as far as river John; along Hwy #376 to Durham, Sylvester; and south along the Alma Road to interconnect with feeder 62N-414 from Stellarton Substation. The system operating diagram is shown in Appendix A.

The largest single customer supplied by this substation is Scotsburn Lumber connected to 56N-414, CS451-032, premise #'s 291642, 389294, 468693 on Condon Rd (billing demand of **2920 KVA**) which accounts for nearly 1/2 of the load on feeder 56N-414. The second largest customer is the Pictou Advocate Newspaper plant connected to 56N-402, CS451-115, premise #431448 on Brown's Point Road (billing demand of **935KVA**) which accounts for most of the load on this feeder. Regional staff indicated that the Pictou Advocate paid for extension of circuit 56N-402 from Haliburton Substation to their site to improve their reliability and thus it is not available to be extended to off load feeder 56N-414 in the future. The feeder exit for 56N-402 is shown below in figure 12 behind the substation fence.

Figure 12-56N-402 Feeder exit to Pictou Advocate

2.4 55N-Pictou Distribution (4kV)

The 55N-Pictou substation in Pictou has one Westinghouse 69kV-4.16kV, 5//5.6MVA power transformer T1 with a low side OLTC with a ±15% range built in 1968. Transformer T1 supplies four feeders 56N-201, 202, 203, 204 from metal clad switchgear in a small geographical area limited to the Town of Pictou. The metal clad switchgear was built by Canadian Allis-Chalmers Ltd. of LaChine, Quebec. It consists of 4-1200 amp, 250MVA, horizontal draw out, Type MA 250B air circuit breakers. The 4kV distribution system is the original system supplying the down town core. Some equipment is deteriorating with the regional staff indicating that the wooden cross-arm pins and arms have rotted. Since the system is a relatively low voltage and the feeder lengths are short the reliability has been good but line losses and older distribution transformer losses are high. The system operating diagram is shown in Appendix A.

2.5 Distributed Generation

There are currently three distributed generation sites in service interconnected to the Haliburton Substation, all on 25kV distribution circuit 56N-414.

Table 1 Haliburton Distributed Generation

IR#	Site#	Name	Feeder	Size	In Service Date
IR#76	85N	Fitzpatrick's Mountain	56N-414	0.8MW	May 2006
IR#77	85N	Fitzpatrick's Mountain	56N-414	0.8MW	May 2006
IR#334	720N	Fitzpatrick's Mountain	56N-414	1.4MW	September 2015

The coincident distributed generation output has not been accounted for in this study as the PI points from the reclosers are inactive and therefore there is no time stamped data

available for the transformer to be compared with the generation at peak. Stellarton system maintenance were able to dump the load data for Jan and Feb 2016 from the 3 recloser controls in Feb 2016 but unfortunately the warmer temperatures in 2016 didn't result in a peak and the peak 2015-01 data was overwritten due to limited storage in recloser controls. The generation data isn't readily available from PI data but it can be extracted from the billing data, obtained from the Interconnection customer or approximated by applying the percentage of hourly output to full output from the adjacent Dalhousie Mountain wind farm (91N) which has PI data. Since the new Wind Turbine Generator 720N at Fitzpatrick's Mountain wasn't in service for the 2015-01 peak it has no impact on the load. The actual load on 56N-T1 at the 2015-01 peak may be greater than load check monthly demand readings by up to 1.6MW due to the wind generation at 85N Fitzpatrick's Mountain.

3.0 LOAD HISTORY AND FORECAST

The 25kV distribution is comprised of long rural feeders and small towns and a large number of summer cottages along the north shore bordering the Gulf of St Lawrence. The Gulf waters in the late summer are warm as compared to the Atlantic and Bay of Fundy coasts of Nova Scotia and thus make it a popular swimming and cottage area. Most of the coastal area is supplied at a distribution voltage of 12.47kV via stepdown transformers off the 25kV circuits. The reason for leaving the distribution voltage level at 12.47kV rather than supplying the area at 25kV is to prevent insulation tracking and subsequent customer outages caused by salt contamination from the Gulf by prevailing northwest winds. Since NSPI purchases standard insulators and other primary equipment with leakage distances suitable for the 25kV system, this provides an extra margin for salt contamination when operated at 12.47kV.

The 4kV distribution under study is mostly residential with a number of commercial customers in downtown Pictou. As illustrated in the load history for these feeders, Appendix B, the feeders being studied have had a larger winter peak than summer peak except for the step-down transformers at Toney River that supply cottage country along the north shore whose summer peak and winter peaks are very similar. Historical load data for the feeders and transformers being studied was collected from monthly load checks, PI data, annual clip on load measurements, CIS billing demands and wind turbine generation data. 15 years of historical data was used to determine a load growth rate and used to forecast future peak loads. Peak loads were compared to rated loads to determine when remedial action is required according to the Capital Expenditure Justification Criteria (CEJC).

3.1 Load Forecast 55N Pictou Town

Customer load growth has been slightly negative (-0.12%) in downtown Pictou on the 4kV system, probably because the load has been contained by 25kV feeder, 56N-401. The growth rates indicated in table 2 below were determined through examination of the peak load check data over the past 15 years. The forecasted load growth was then calculated using the 90th percentile of a linear fit. In Table 2 below **bold** are actual recorded values, future values have been estimated from extrapolation of historical data.

Table 2 90th Percentile Load Forecast 55N

Year / Peak MVA / Amps	55N-T1	55N-201	55N-202	55N-203	55N-204
Rating/CEJC	**6.67/6 MVA**	**325**	**325**	**325**	**325**
Current Customers					
Load Growth	**-0.12%**	**-0.48%**	**0.59%**	**0.63%**	**-0.26%**
2015	**4.22**	**116**	**146**	**176**	**195**
2016	4.97	137	171	204	237
2017	4.97	136	172	206	237
2018	4.96	135	173	207	236
2019	4.96	134	174	209	236
2020	4.95	133	175	211	235
2021	4.94	133	176	212	234
2022	4.94	132	177	214	234
2023	4.93	131	178	216	233
2024	4.93	130	179	217	233
2025	4.92	129	180	219	232
2026	4.92	128	181	221	231
2027	4.91	127	182	222	231
2028	4.90	127	184	224	230
2029	4.90	126	185	226	230
2030	4.89	125	186	227	229
2031	4.89	124	187	229	228

55N-T1 rated for 6.67 MVA (6MVA is its maximum capacity since its failure contingency is customer supply from the 6MVA, 3P mobile transformer) was loaded to 4.22 MVA at 2015 peak. The 2016 maximum temperature was less than 2015 so no new peak was reached. As long as the 4kV load is contained no transformer or feeder overloads will occur within the study period.

3.2 Load Forecast 56N Haliburton

Customer load growth has been modest (2.07%) on the Haliburton Sub 25kV system. The growth rates indicated in table 3 below were determined through examination of the peak load check data over the past 15 years. This growth probably includes the growth in the Pictou Town area as well. The forecasted load growth was calculated using the 90th percentile of a linear fit. In Table 3 below **bold** are actual recorded values, other values have been estimated from historical data.

Table 3 90th Percentile Load Forecast 56N

Year / Peak MVA / Amps	56N-T1	56N-401	56N-402	56N-414
Rating/CEJC	**11.2/14.93 MVA**	**325**	**325**	**325**
Current Customers				
Load Growth	**2.07%**	**1.91%**	**2.94%**	**1.34%**
2015	**14.40**	**97**	**26**	**211**
2016	15.73*	101	27	239
2017	16.11	103	28	243
2018	16.49	106	29	246
2019	16.86	108	30	250
2020	17.24	110	31	253
2021	17.61	112	32	257
2022	17.99	114	33	260
2023	18.37	117	34	264
2024	18.74	119	35	268
2025	19.12	121	36	271**
2026	19.50	123	37	275
2027	19.87	126	38	278
2028	20.25	128	39	282
2029	20.62	130	40	285
2030	21.00	132	41	289
2031	21.38	134	42	292

* Exceeds Overload Criteria-2016

** Exceeds #2/0 ACSR Feeder Conductor Rating (270amps)-2025

56N-T1 rated for 14.93 MVA was measured at a load of 14.4 MVA at the January 2015 peak. There is also between 0 and 1.6MW of wind generation from 85N-G1, G2 which was interconnected in 2006, which means that the real load may be higher. The PI data points on 56N are disabled so there is no time stamped data available to compare with time stamped data from the wind turbines billing interval meter to determine how much load at peak was being supplied by the two wind turbines at 85N Fitzpatrick's Mountain. The new 1.4 MW wind turbine at Fitzpatrick's Mountain 720N-G1 was put in service in September 2015 after the peak load of January 2015 was measured. The maximum temperature for 2016 was less than 2015 so no new peak was reached this year. Based on the load forecast this transformer could reach a peak load of 15.73MVA at the **2016/17 peak** with a 90th percentile probability.

The activation of the communications system to enable the hourly time stamped values from PI for at least the three distribution feeders and preferably the transformer itself is critical to determine the future loading on this station.

4.0 JUSTIFICATION FOR EXPENDITURE

The following section identifies issues that warrant correction based on NSPI's *Capital Expenditure Justification Criteria* (CEJC). Violation of the criteria provides the answer to the question: Why do this at all? The year that the criteria violation occurs provides the answer to the question: Why do it now?

4.1 Overloads

1. Power Transformer 56N-T1 rated 7.5//11.2 MVA, 69-25kV at Haliburton Substation is forecast to be overloaded at the 2016/17 peak reaching 15.73MVA. CEJC for winter overload is 133% of top nameplate rating or 133% x 11.2MVA=14.93MVA.
2. Stepdown transformer 512N-T1 rated 333KVA, 24-7.2 kV at Toney River Substation was overloaded as determined by field measurements on Aug 29, 2015 at 5:30PM of 59 amps (59 x 7.2kV=425KVA) resulting in overheating and oil weeping. CEJC for summer overload is top name plate rating of 333kVA.
3. Stepdown transformer 509N-T1 rated 167KVA, 14.4-7.2 kV at Carson's Corner was overloaded as determined by field measurements on Jan 13, 2015 at 4:00PM of 38 amps (38 amps x 7.2kV=273KVA). CEJC for winter overload is 133% x 167KVA=223KVA.
4. Stepdown transformer 512N-T2 rated 333KVA, 24-7.2 kV at Toney River Substation is forecast to be overloaded in 8 years at the 2024/25 peak. Field measurement on Oct 3, 2015 at 7:00PM of 32.7 amps (32.7 amps x 7.2kV=235KVA). CEJC for summer overload is top name plate rating of 333kVA.
5. Feeder 56N-414, #2/0ACSR primary conductor on Haliburton Road for three spans one on either side of switch D451-057 in front of the substation will be overloaded in 9 years by 2025. Load forecast is 271 amps whereas conductor rating is 270 amps.

4.2 Low Voltage (See Figure 13)

1. All customers supplied from stepdown transformer 509N-T1 (301) Carson's Corner (Hwy #256) have voltage below CSA Standard CAN3-C235-83 (C2010) limits at peak feeder load in 2016 per CYME computer model.
2. All customers supplied from stepdown transformer 512N-T1(311) Toney River (Seafoam) have voltage below CSA Standard CAN3-C235-83 (C2010) limits at peak feeder load in 2016 per CYME computer model.
3. Customers from Shore Road to Caribou Island supplied from stepdown transformer 500N-T1(301) Caribou Island have voltage below CSA Standard CAN3-C235-83 (C2010) limits at peak feeder load in 2016 per CYME computer model.
4. Customers supplied from 55N-203 Pictou 4kV on Hwy #6 north of Hwy#106 at the Traffic Circle have voltage below CSA Standard CAN3-C235-83 (C2010) limits at peak feeder load in 2016 per CYME computer model.

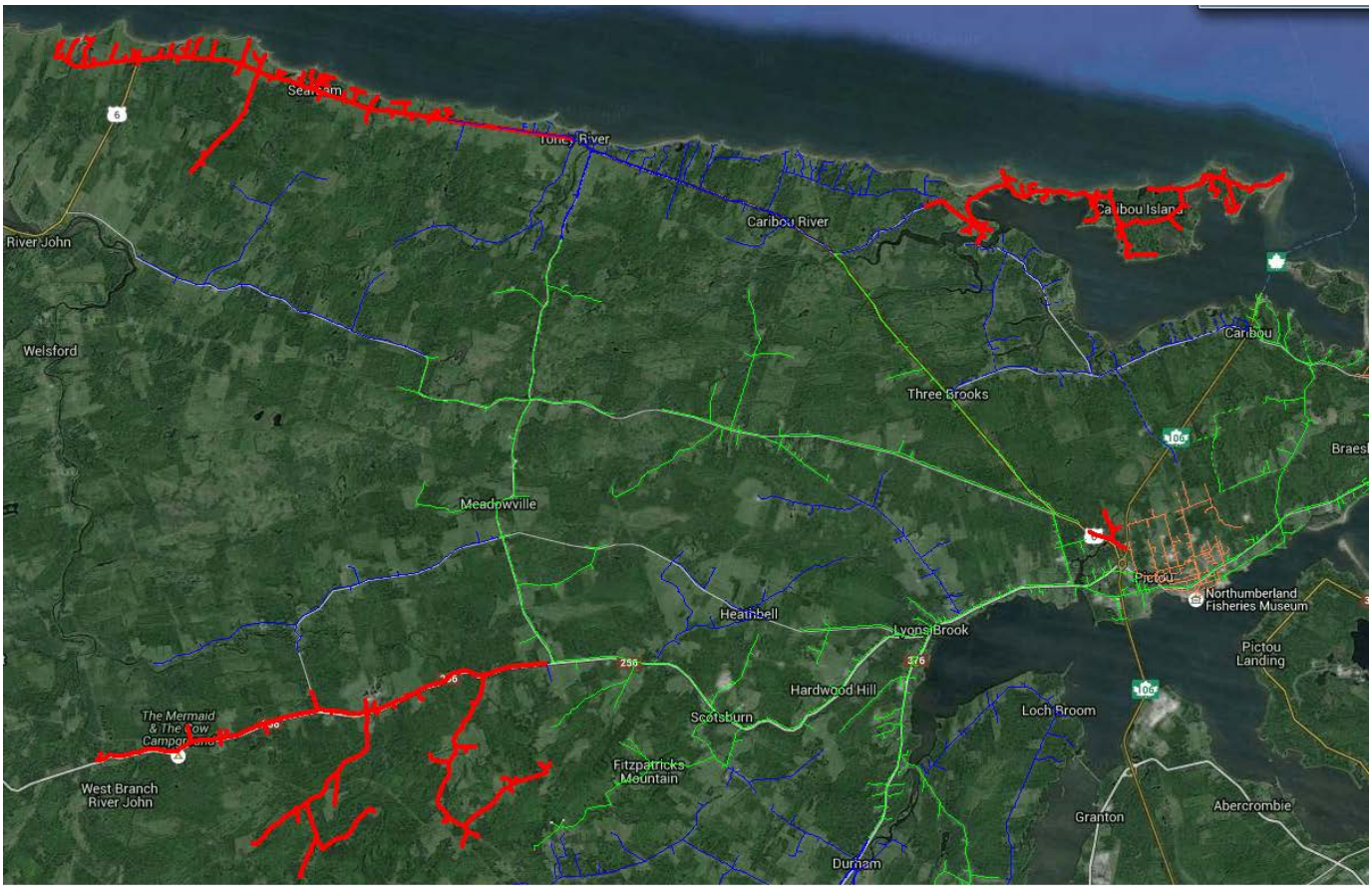


Figure 13-Low Voltage in Study Area 2016 (red)

4.3 Deteriorated Plant

1. The 333KVA stepdown transformers at Toney River built in 1956, 512N-T1, T2, T3 are deteriorated (weeping oil) and are now 60 years old. The probable life based on Iowa state survivor curve right modal R2 average life of 38 years is 165.95% x 38=63 years. Statistical probable remaining life is 3 years.
2. The low voltage metal clad switch gear at 55N is 48 years old and again based on the probable life from Iowa state survivor curve right modal R2 average life of 38.5 years is 142.53% x 38.5=55 years. Statistical probable remaining life is 7 years. A catastrophic failure within this enclosed switchgear could render it all out of service and result in a long outage while temporary reclosers are installed. (A failure of an incoming cable to metal

clad switch gear at Penhorn Substation (48H) in Dartmouth in 1998 caused a long outage, fortunately in that case there was transfer capability available from adjacent substations dissimilar to Pictou.)

3. The majority of 4kV distribution plant in Pictou Town is greater than 50 years old. Regional staff indicated that wood cross-arms and insulator pins are deteriorated and beginning to fail. (See figure 14). The 69kV bus pipe on the center phase at 55N is separated. (See figure 15). The 4kV voltage level is no longer one of the standard voltages for distribution at NSPI – in service and spare equipment will be phased out when possible.

Figure 14-Rotten arm and broken wooden pins 55N-201 St Andrews St. Pictou

Figure 15-69kV Copper Bus Center Phase Separated 55N-Pictou Town Sub.

4.4 Reliability

The outage statistics for the feeders supplied by Haliburton Substation and Pictou Town Substation averaged over the past 5 years are as follows:

Table 4 Reliability Statistics 55N, 56N

Circuit	Year	Customers	CI	CHI	SAIFI	SAIDI	CAIDI	SAIFI X SAIDI
55N-201	2010-2015	300	1322	3799	4.40	12.65	2.87	55.68
55N-202	2010-2015	318	88	2827	0.28	8.90	32.13	2.46
55N-203	2010-2015	363	50	934	0.14	2.58	18.55	0.36
55N-204	2010-2015	539	595	823	1.10	1.53	1.38	1.68
56N-401	2010-2015	852	2701	15180	3.17	17.81	5.62	56.45
56N-402	2010-2015	7	N/A	N/A	N/A	N/A	N/A	N/A
56N-414	2010-2015	2867	12213	49952	4.26	17.42	4.09	74.22

The reliability of the 4kV system is inherently better than the 25kV system because of the short length of the radial feeders and thus line exposure. The insulation level required is also much less and consequently tree contacts are less likely to cause an outage. This is offset somewhat by the age of the 4kV system as it was the initial voltage introduced into the urban areas when initial electrification of NS was undertaken.

The outage statistics above show that feeder 56N-414 has the poorest reliability (SAIFI x SAIDI=74.22) in the study area which is not surprising given the length of the feeder

is 416 km including branch lines and step-downs. This feeder also supplies 2867 customers, more than the other 6 feeders combined 2379. The reliability of feeder 56N-401(SAIFI x SAIDI=56.45) and 55N-201(SAIFI x SAIDI=55.68) are surprisingly high given the shorter length of the feeders; 56N-401 is 75 km including branch lines and step-downs and 55N-201 is only 3.4 km including branch lines.
Methods of improving the reliability to feeder 56N-414 will be explored.

5.0 EVALUATION AND SOLUTIONS

Solutions to the problems identified in Section 4 will be evaluated in this section and will answer the third CEJC question: Why do it this way?

5.1 Overloads

1. The activation or replacement of the present communications system at Haliburton Road Substation to enable the hourly time stamped values from PI for the three distribution feeders is critical to determine the actual loading on this station due to the interconnection of Wind Turbine generators on feeder 56N-414 at Fitzpatrick's Mountain. This should be done as soon as possible. Either the current communication system and RTU should be reactivated or a new system installed via radio link to provide PI data as well as remote indication and control of 25kV reclosers. (Note from Brad Fiander in 2016 about the communication system) - *This is a DART RTU and the recloser currents are wired directly to RTU inputs. Long before we replaced the reclosers, we added a third recloser and even at that time we could not get the metering for the third recloser to work correctly. This also 'broke' the SCADA transformer metering since the transformer metering is the sum of the three feeders. We couldn't see why it wouldn't work and decided to live without it. When the reclosers were replaced, things went from bad to worse. I think the CTs are wired into the DART, but none of the feeders is metered correctly (at least before we had two feeders showing correct amps). By this time we had even less expertise to solve the problem, so we let it go, hoping for a new RTU.* This work needs to be designed and constructed by the Communications Group at Ragged Lake. Power Transformer 56N-T1 rated 7.5//11.2 MVA, 69-25kV at Haliburton Substation is forecast to be overloaded at the 2016/17 peak.
2. Power Transformer 56N-T1 rated 7.5//11.2 MVA, 69-25kV at Haliburton Substation is forecast to be overloaded at the 2016/17 peak. To provide immediate temporary relief it is possible to transfer approximately 1MVA of load to Bridge Avenue Substation in Stellarton via feeder 62N-414 on the Alma Road. This can be accomplished by replacing and closing switch L451-063 on Alma Road near Highway#4 and opening switch D451-062 on Riverview Drive. See figures 4&5. This will allow time for the permanent solution of increased transformer capacity to be planned and scheduled before the 2017/18 peak load occurs. Two alternatives were evaluated economically Alt A-Replace 56N-T1 with a 15/20/25MVA unit or Alt B Add an additional 7.5/10/12.5 unit at 56N. The economic analysis of these two alternatives favors Alt A-Replace 56N-T1 with a 15/20/25MVA transformer with a present value of revenue requirement of $1,141,363 as compared to Alt B-Add a 7.5/10/12.5 transformer at 56N which has a present value of revenue requirement of $1,242,658. Alt A is favourable by $101,295 over Alt B. See Appendix C for Economic Analysis.
3. Stepdown transformer 512N-T1 rated 333KVA, 24-7.2 kV at Toney River Substation was overloaded at the 2015 summer peak. Since this step-down substation contains three stepdown transformers 512N-T1, T2, T3 and is connected delta wye with non-standard 24kV high voltage windings it is not possible to replace only transformer T1 with a larger unit. The transformer tanks

are rusting and oil is weeping, they were built in 1956 so are now 60 years old. All three transformers will have to be replaced with 500KVA, 14.4kV-7.2KV units and connected wye-wye which will also solve both the overload and deteriorated plant problem. Since the existing transformers have a fixed 3.9% boost due to the 24kV windings the new stepdown transformers will require voltage regulators be installed on the 12.47kV system. Rather than a fixed boost this will allow the voltage to be controlled as the load cycles from light to peak load and solve the voltage problems identified on 512N-311. The alternatives to this solution are to convert the system voltage beyond the step-downs from 7.2kV to 14.4kV which is not desirable from a reliability point of view due to the exposure to salt contamination from the Strait. A solution to the voltage issues would be to extend the three phase portion of the 12.47 circuit towards Seafoam which would still require the Toney River step-downs to be replaced and voltage regulators added which would obviously be more expensive since it includes all the costs from the recommended alternative and more.

4. Stepdown transformer 509N-T1 rated 167KVA, 14.4-7.2 kV at Carson's Corner was overloaded at the 2015 winter peak. This transformer is scheduled to be replaced with a 500KVA unit in the Eastern Capital plan in 2016.
5. Stepdown transformer 512N-T2 rated 333KVA, 24-7.2 kV at Toney River Substation is forecast to be overloaded at the 2024/25 peak. This transformer will be replaced in 2017 when T1 is replaced see Solution in section 3 above.
6. Feeder 56N-414, #2/0ACSR primary conductor on Haliburton Road for three spans in front of the substation will be overloaded by 2025. By adding an additional circuit, in addition to offloading feeder 56N-414, will serve to improve the reliability to customers supplied by 56N-414, improve low voltage to customers on Caribou Island, and allow for planned voltage conversion of Pictou 4kV system with minimal customer outages.

5.2 Low Voltage

1. All customers supplied from stepdown transformer 509N-T1 Carson's Corner (Hwy #276) have voltage below CSA standards at peak load. This transformer is scheduled to be replaced with a 500KVA unit in the Eastern Capital plan in 2016 and in conjunction with the reconductoring in Scotsburn from Durham Road to Condon Road (See Overloads Section 5.1,#4 and Deteriorated Plant Section 5.3, #4) will improve the voltage on this single phase branch line.
2. All customers supplied from stepdown transformer 512N-T1 (311) Toney River (Seafoam) have voltage below CSA standards at peak load. This transformer will be replaced in 2017 due to overload along with the other two transformers T2, T3. At this time the new transformers should be placed on 100% tap requiring three single phase 100 amp, 7.2kV regulators be purchased and installed as well which will also solve the low voltage issue.(See Overloads Section 5.1, #3)
3. Some customers supplied from stepdown transformer 500N-T1 Harris Road (Caribou Island) have voltage below CSA standards at peak load. Install a 100 amp, 7.2kV voltage regulator just after the Caribou Island stepdown 500N-T1 to solve the voltage problems. This in addition to adding a new feeder from 56N (See Overloads Section 5.1, #will improve voltage levels.

4. Customers supplied from 55N-203 Pictou 4kV on Hwy #6 north of Hwy#106 at the Traffic Circle have voltage below CSA standards at peak load. Fill in the gap and convert from 2.4kV to14.4kV the section of line on Hwy #6 to the traffic circle. This will be required anyway as part of adding the new feeder from 56N to Pine Tree Road and Division Road.

5.3 Deteriorated Plant

1. The 333KVA stepdown transformers at Toney River built in 1956, 512N-T1, T2, T3 are deteriorated (weeping oil) and are now 60 years old. The probable life based on Iowa state survivor curve right modal R2 average life of 38 years is 165.94590% x 38=63 years leaving 3 years remaining. These will be replaced for overload and voltage criteria violations as noted above.
2. Low voltage metal clad switch gear at 55N is 48 years old and again based on the probable life from Iowa state survivor curve right modal R2 average life of 38.5 years is 142.53% x 38.5=55 years leaving 7 years remaining. Since 4kV is no longer a standard voltage level for NSPI replacement of the switchgear is not an option. A plan for the 4kV system will be discussed in section 3.
3. The majority of 4kV distribution plant in Pictou Town is greater than 50 years old. Regional staff indicated that wood cross-arms and insulator pins are deteriorated and beginning to fail. (See figure 14). The 4kV voltage level is no longer one of the standard voltages for distribution at NSPI – in service and spare equipment will be phased out when possible. With the increase in capacity proposed for 56N substation, the 4kV system in Pictou Town can be gradually converted to 25kV and supplied from 56N. Any large new loads in the service area should be supplied from the 25kV system to avoid conversion costs later. Although there is no immediate cause other than some low voltage and deteriorated plant to convert the voltage I would propose that a new circuit from Haliburton Substation to the north of the town on Division Road be constructed as well as existing circuit 56N-401 be used to allow conversion of the side streets to occur towards 55N with minimum customer outages. This new feeder would also allow off-loading of feeder 56N-414. With this plan for the future, voltage conversions and conductor replacements can be undertaken in a more coordinated manner. If the 4kV load is reduced from 4 to 1.5MVA then a major failure of switchgear could be resolved by installation of 3x500kVA step down transformers. Map for proposed new feeder is shown as Figure 13&14 and I would recommend any conductor additions or replacements on this route use 336ASC primary conductor. The exact routing from 56N to Division Road should be explored in more detail by scoper. A route from Harris Road across Murray Road and Mill Dam Road would have heavy expensive tree trimming and require permits to cross Hwy #106. The route outlined in Figure 9 and 10 would require crossing under 69kV line L5506 on Pine Tree Road
4. The #4Cu conductor on Scotsburn Road from Durham Road to Campbell Hill Road was constructed in the mid 1950's and is reaching the end of its useful life. In addition the load on this conductor is high particularly due to the Scotsburn Lumber Mill on the Condon Road. Based on Iowa State survivor curves for distribution system overhead conductor using curve S-2 with average life of 35 years from NSPI depreciation study the probable remaining life of this conductor

is 3 years. An economic analysis was undertaken to see if the savings in line losses by reconductoring would offset the interest savings on borrowing for the capital project early. The results were that since the Scotsburn Saw Mill on the Condon Road accounted for most of the load and thus losses that is was only economical to replace the #4Cu conductor from the Durham Road to the Condon Road early, a distance of 0.92km in 2017. Two alternatives were evaluated economically Alt A-Replace 0.92km of #4Cu with 336ASC in 2017 or Alt B-Replace 0.92km of #4Cu with 336ASC in 2019 at end of life. The economic analysis of these two alternatives favors Alt A-Replace 0.92km of #4Cu with 336ASC in 2017 with a present value of revenue requirement of $86,752 as compared to Alt B- Replace 0.92km of #4Cu with 336ASC in 2019 at end of life which has a present value of revenue requirement of $97,803. Alt A is favourable by $11,051 over Alt B. See Appendix C for Economic Analysis.

5.4 Reliability

An analysis of the reliability data for this area reveals that the main causes of outages have been tree contacts so that capital expenditures to improve reliability are not warranted.

6.0 RECOMMENDATIONS

The recommendations are as follows:

1. 2016-The activation or replacement of the present communications system at Haliburton Road Substation to enable the hourly time stamped values from PI for the three distribution feeders is critical to determine the actual loading on this station due to the interconnection of Wind Turbine generators on feeder 56N-414 at Fitzpatrick's Mountain. This should be done as soon as possible. Either the current communication system and RTU should be reactivated or a new system installed via radio link to provide PI data as well as remote indication and control of 25kV reclosers. (Note from Brad Fiander in 2016 about the communication system) - *This is a DART RTU and the recloser currents are wired directly to RTU inputs. Long before we replaced the reclosers, we added a third recloser and even at that time we could not get the metering for the third recloser to work correctly. This also 'broke' the SCADA transformer metering since the transformer metering is the sum of the three feeders. We couldn't see why it wouldn't work and decided to live without it. When the reclosers were replaced, things went from bad to worse. I think the CTs are wired into the DART, but none of the feeders is metered correctly (at least before we had two feeders showing correct amps). By this time we had even less expertise to solve the problem, so we let it go, hoping for a new RTU.* This work needs to be designed and constructed by the Communications Group at Ragged Lake. Power Transformer 56N-T1 rated 7.5//11.2 MVA, 69-25kV at Haliburton Substation is forecast to be overloaded at the 2016/17 peak.
2. 2016-Temporarily reduce load on Haliburton Road power transformer 56N-T1 before the 2016-17 peak by transferring approximately 1MVA of load to Bridge Avenue feeder 62N-414 by repairing/replacing and closing switch L451-063 on Alma Road near Highway#4 and opening switch D451-062 on Riverview Drive. (See Figures 4 & 5)
3. 2017-Replace overloaded and deteriorated (weeping oil) 333kVA stepdown transformer 512N-T1 at Toney River substation built in 1956 with a 500KVA, 14.4-7.2 unit with HV tap set on 100%. Because the existing transformer bank is connected delta to wye this will necessitate the other two step-downs 512N-T2, T3 also be replaced with new 500KVA units and connected wye-wye. Since they are all the same age 60 years old and all weeping oil around tap changer they need to be replaced anyway before they suffer oil leaks and or failure. Since these units have been operating at a fixed 3.9% boost and to maintain customer voltage levels within the CSA criteria range in the area at light and peak load periods, replacement of these transformers should be accompanied with addition of three 100 amp 7.2kV regulators. If the existing substation is retained a new substation design is required to accommodate the transformers, regulators and reclosers including replacing the existing creosote timbers with concrete pads. An alternative arrangement may be to install the new step downs on a platform structure and pole-mount the regulators. (See Figure 6.)
4. 2017-Install single phase 100 amp 7.2kV regulator on feeder 62N-414 just past West River recloser 639N-321 to solve low voltage issues. (See figure 7)
5. 2017-Reconductor 0.9 km of feeder 56N-414 from #4 Cu to 336ASC on the Scotsburn Road (Hwy#256) from Durham Rd to Condon Road. (See figure 8)

6. 2018-Replace overloaded Haliburton Road power transformer 56N-T1with a unit rated 69-26.4kV, 15/20/25MVA and add a 25kV circuit to offload: (1) 56N-414, (2) stepdowns at 512N Toney River and (3) 4kV load converted from Pictou 4kV. The existing 7.5/10/11.2 MVA, 69-25kV transformer is needed as a system spare since the spare was utilized at 20V-T1 in Hantsport in 2016 to replace a failed transformer.
7. 2018- In conjunction with the 56N-T1 transformer replacement construct a new three phase 25kV feeder using 336ASC primary from Haliburton Substation on opposite side of the road from 56N-414 along the Haliburton Road (or double circuit) to Hwy #376 and west along Hwy #376 to Harris Road. Convert the single phase line on the Harris Road to three phase 336ASC conductor. Convert the single phase line on Highway #6 (Sunrise Trail) to Caribou River from single phase to three phase 336ASC. Construct a 3 phase 336 ASC tap on Hwy #376 eastward to Pine Tree Road and behind Pictou town along Division Road to interconnect with 56N-401 and pick up 4kV load. Add three stepdown transformers to off load 512N Toney River by supplying customers as far as Meadowville Station Road. (See figures 9&10)
8. 2019-2025-Manage the 4kV load on the Pictou Substation transformer 55N-T1 to the mobile transformer 3P rating of 6MVA by connecting new customers where possible to Haliburton 25kV substation feeder 56N-401 and the proposed new feeder from 56N. Due to the age of the substation a gradual conversion of the voltage from 4kV to 25kV should be undertaken in Pictou town approximately 625 KVA demand or 1250 KVA connected per year to allow for removal and retirement of 55N substation and the section of 69kV transmission line L5506 between 56N and 55N.

APPENDIX A

System Operating Diagrams

Pages 31-32 (Attachment 1) have been removed due to confidentiality.

APPENDIX B

Load History and Forecast

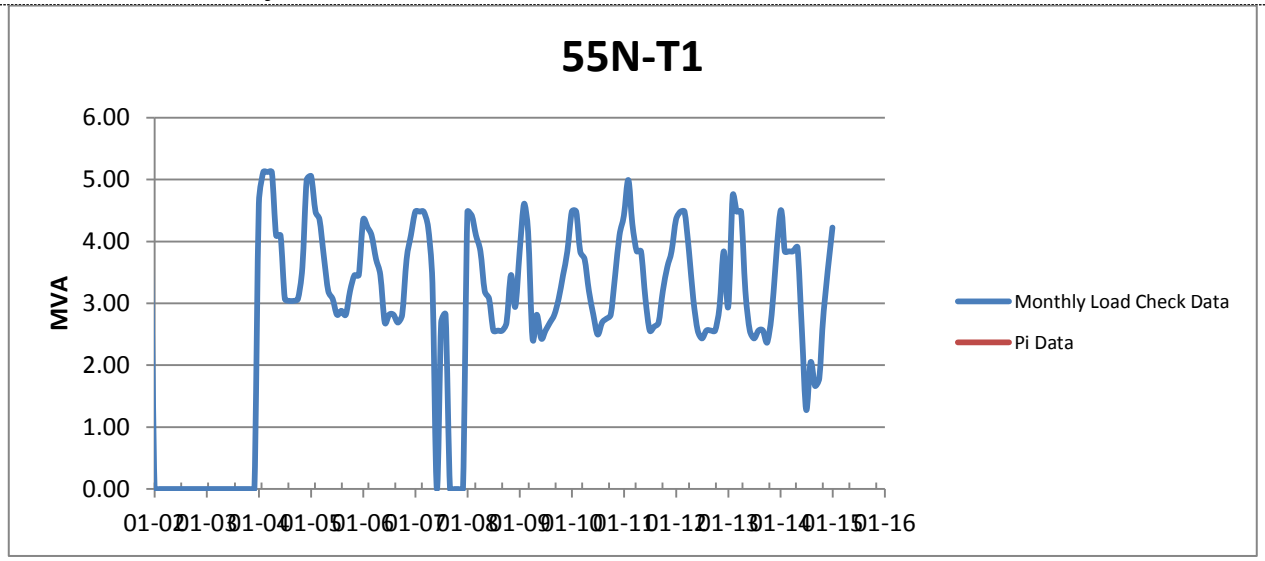


Figure 16-55N-T1 Load History

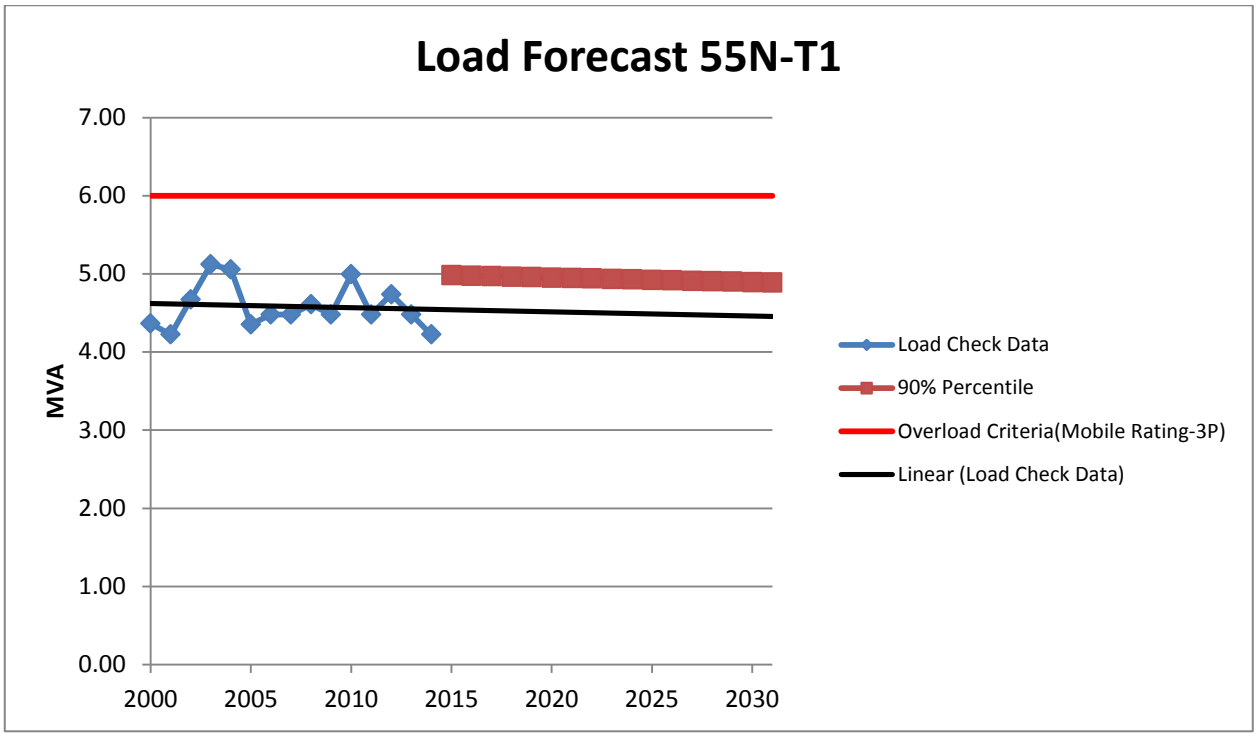


Figure 17-55N-201 Load Forecast

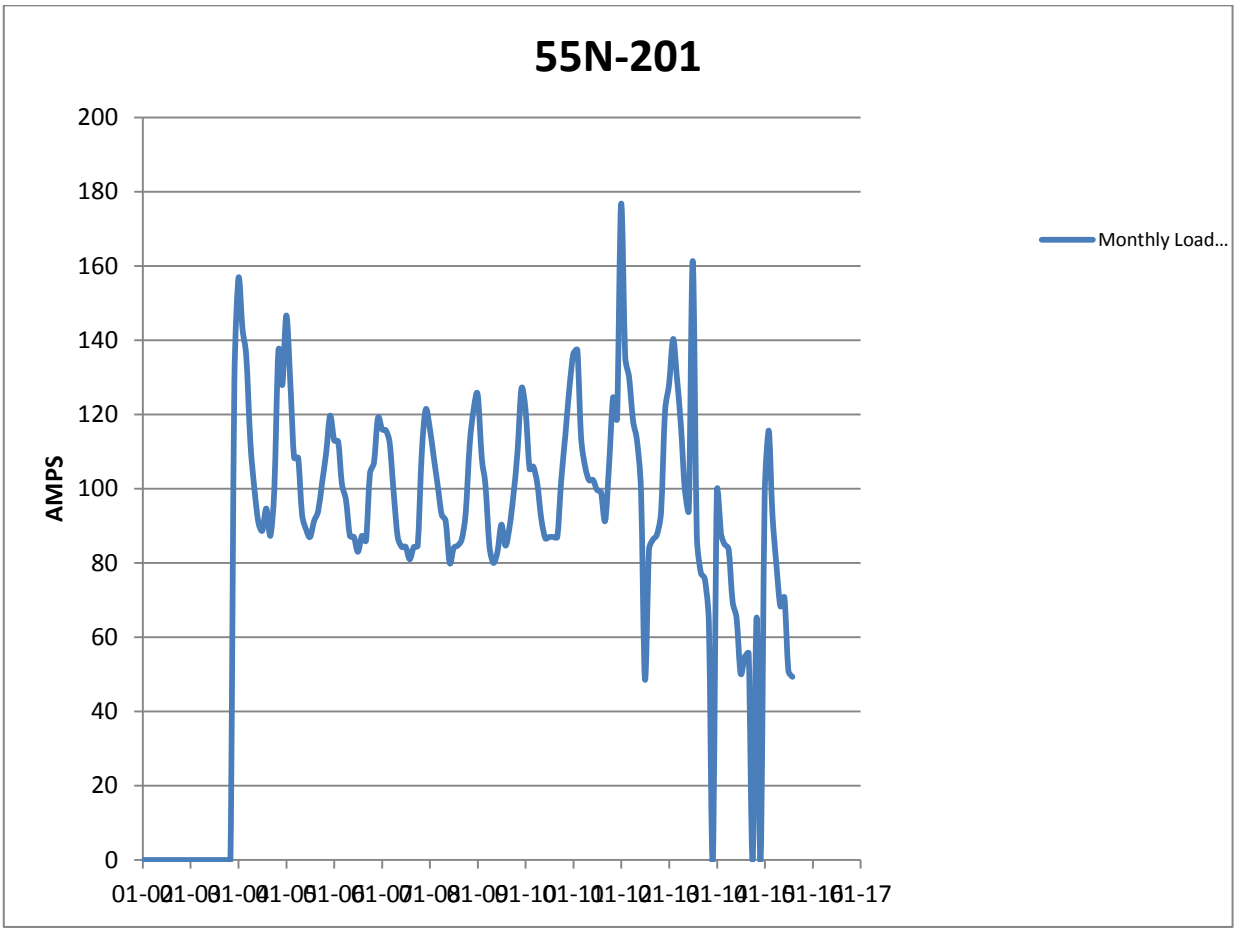


Figure 18-55N-201 Load History

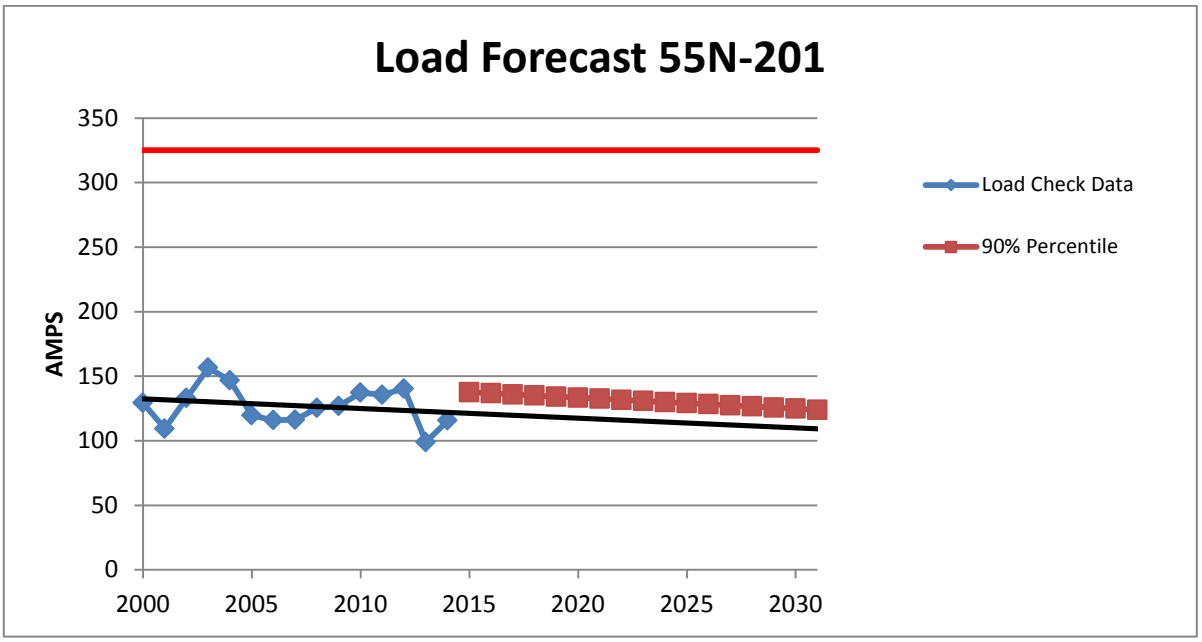


Figure 19-55N-201 Load Forecast

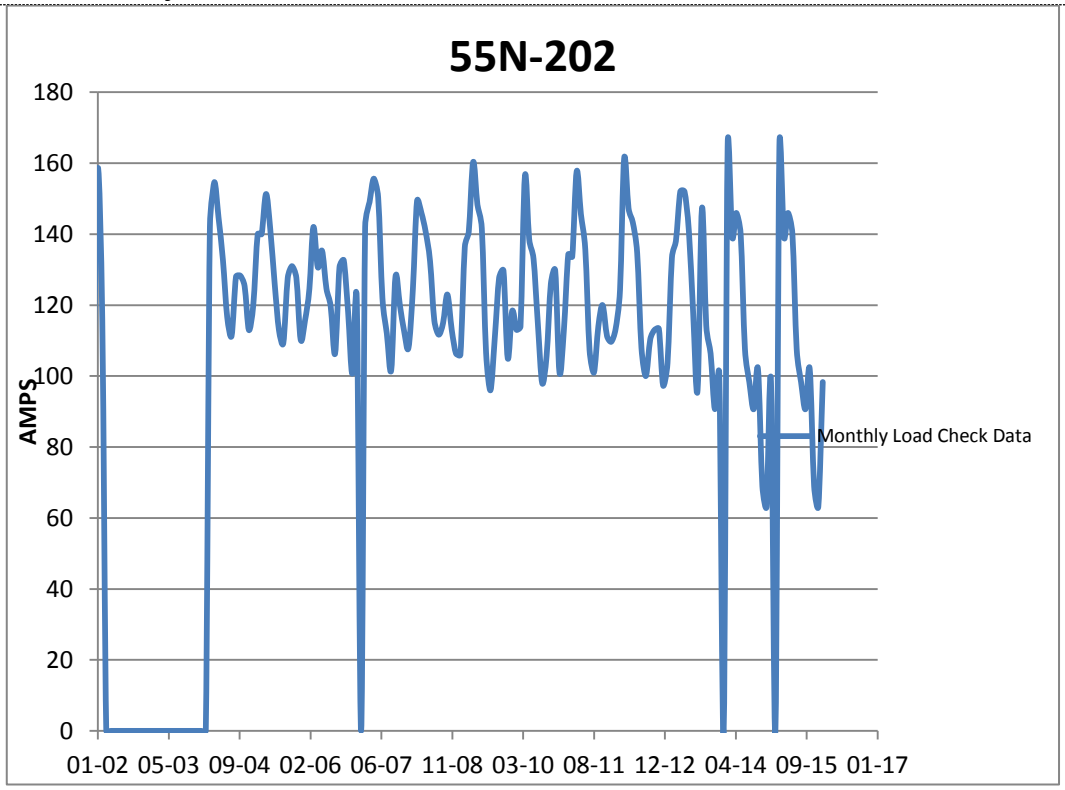


Figure 20-55N-202 Load History

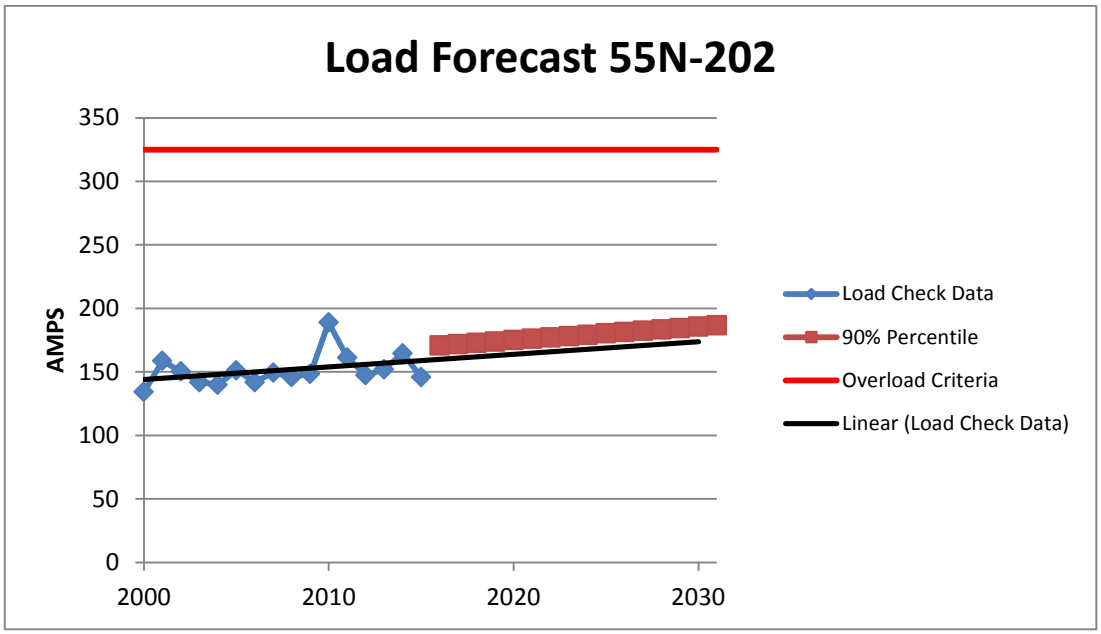


Figure 21-55N-202 Load Forecast

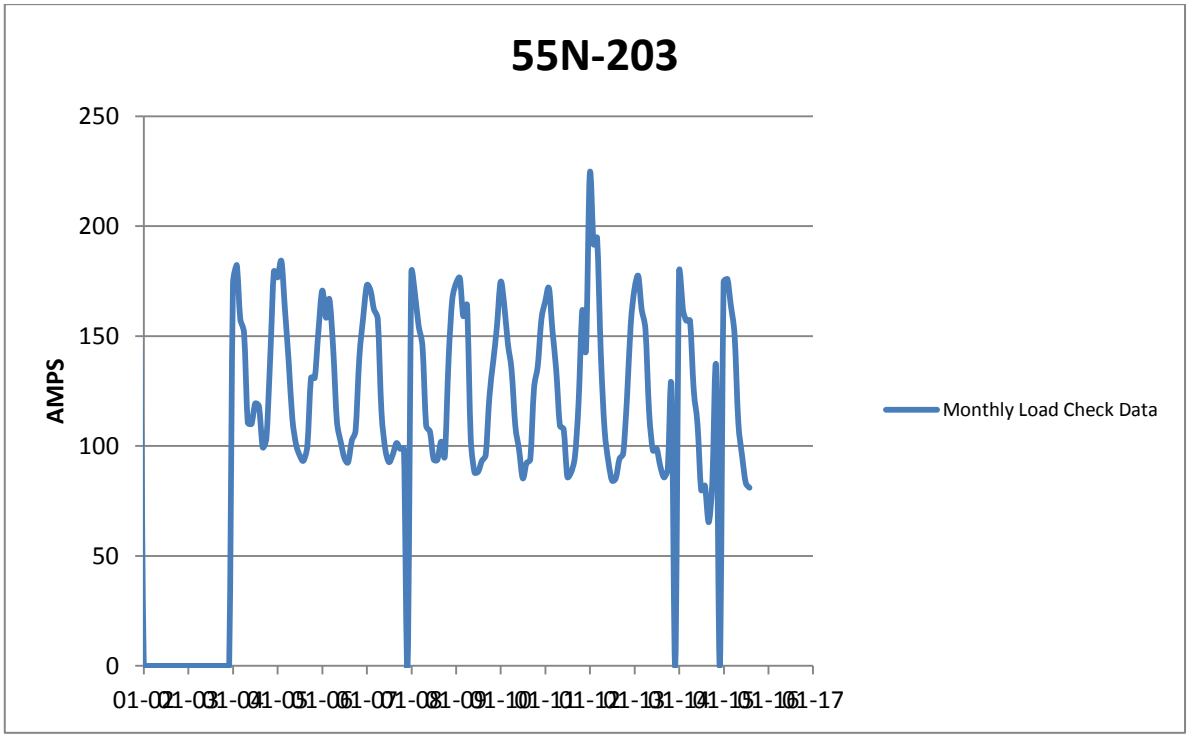


Figure 22-55N-203 Load History

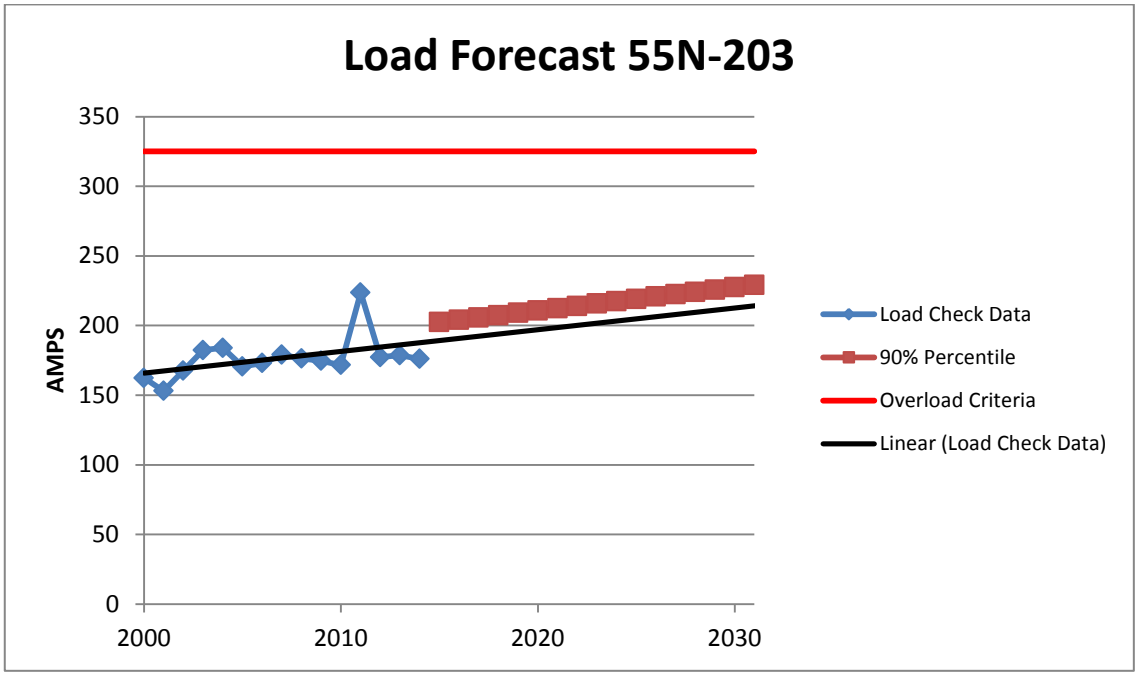


Figure 23-55N-203 Load Forecast

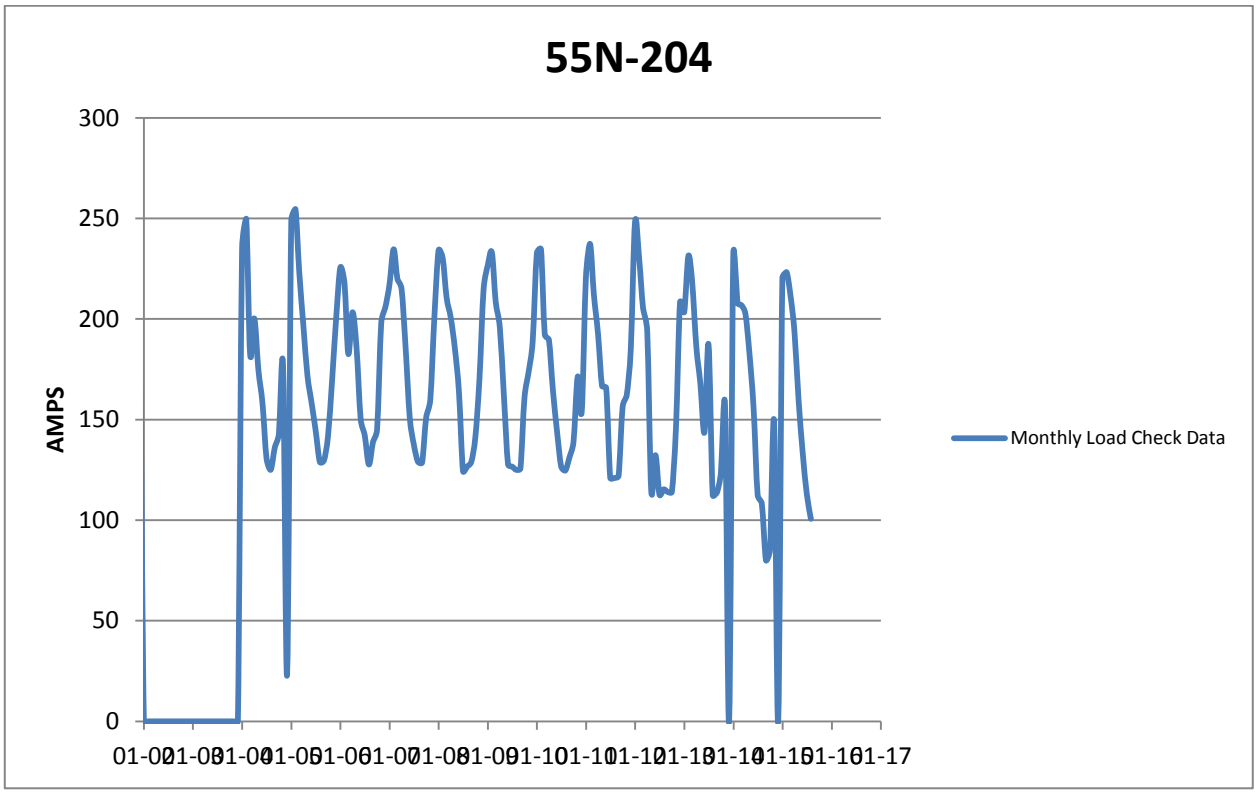


Figure 24-55N-204 Load History

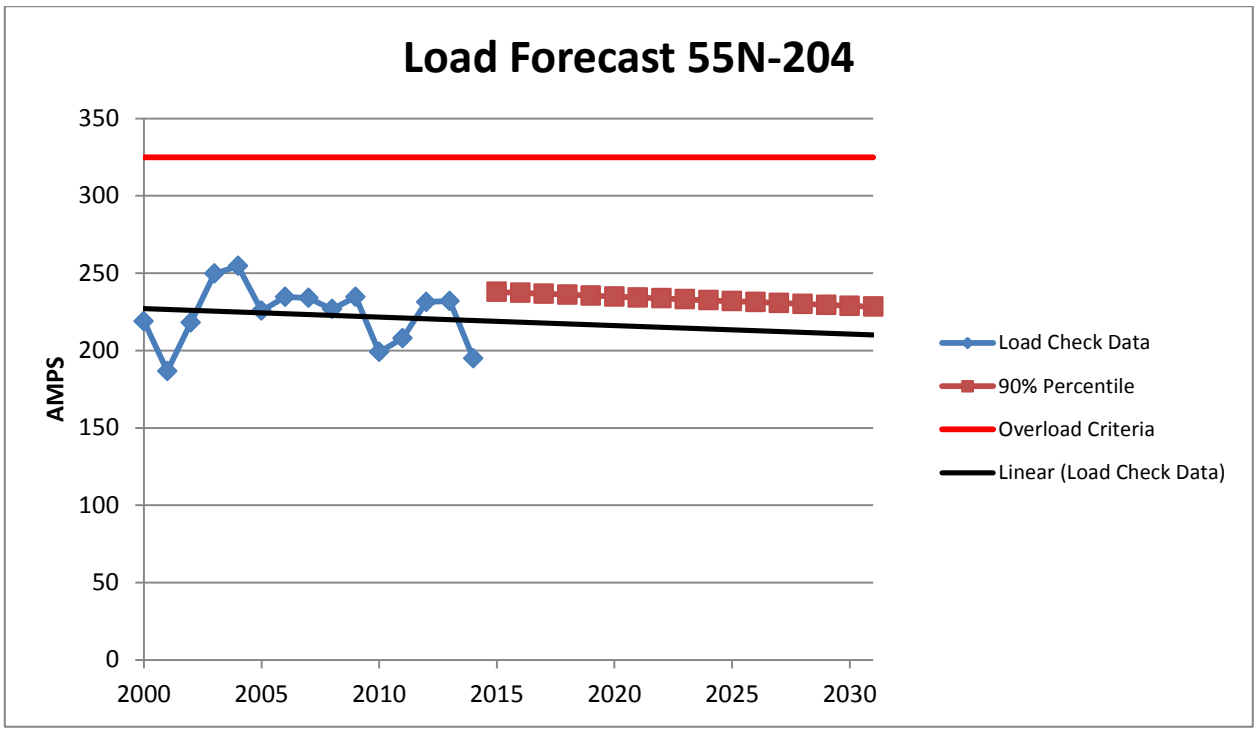


Figure 25-55N-204 Load Forecast

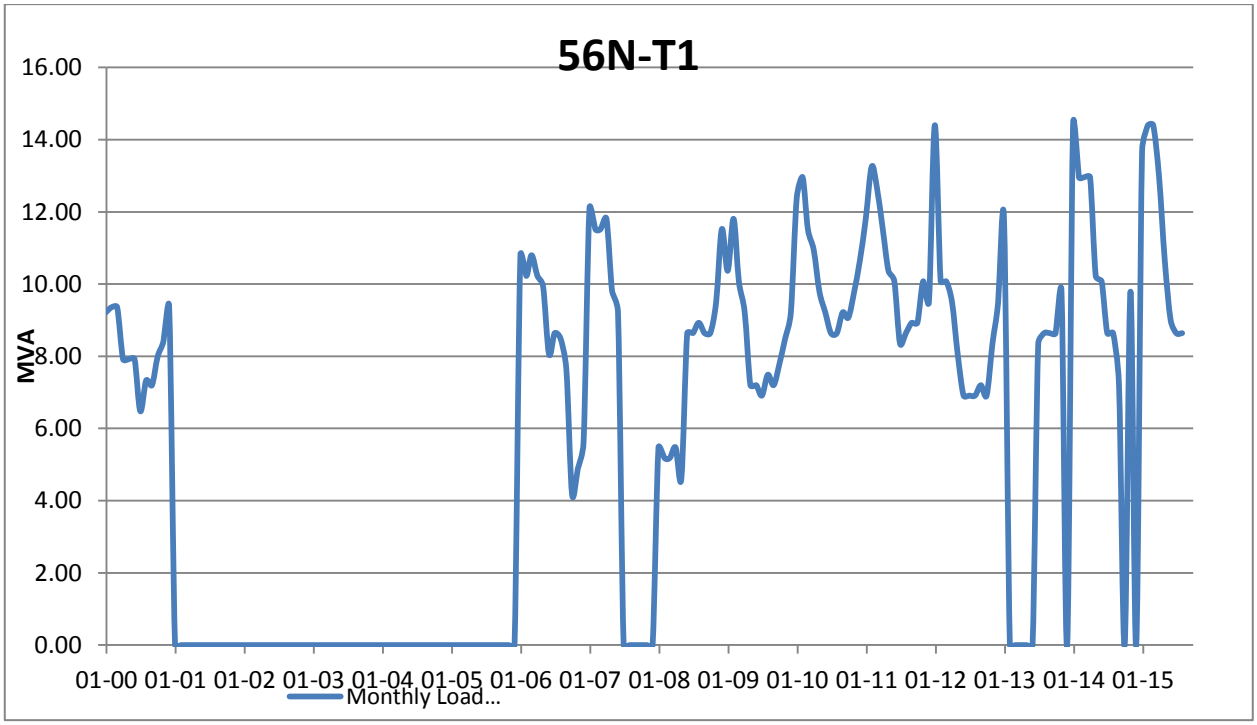


Figure 26-56N-T1 Load History

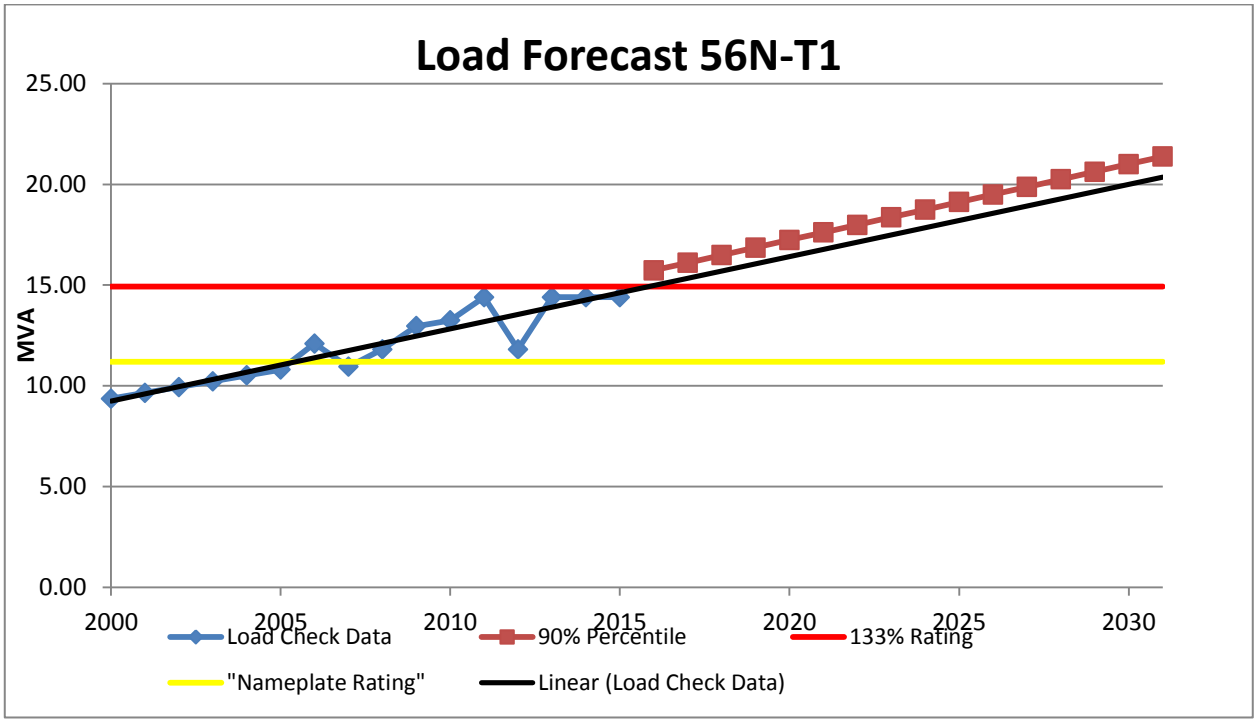


Figure 27-56N-T1 Load Forecast

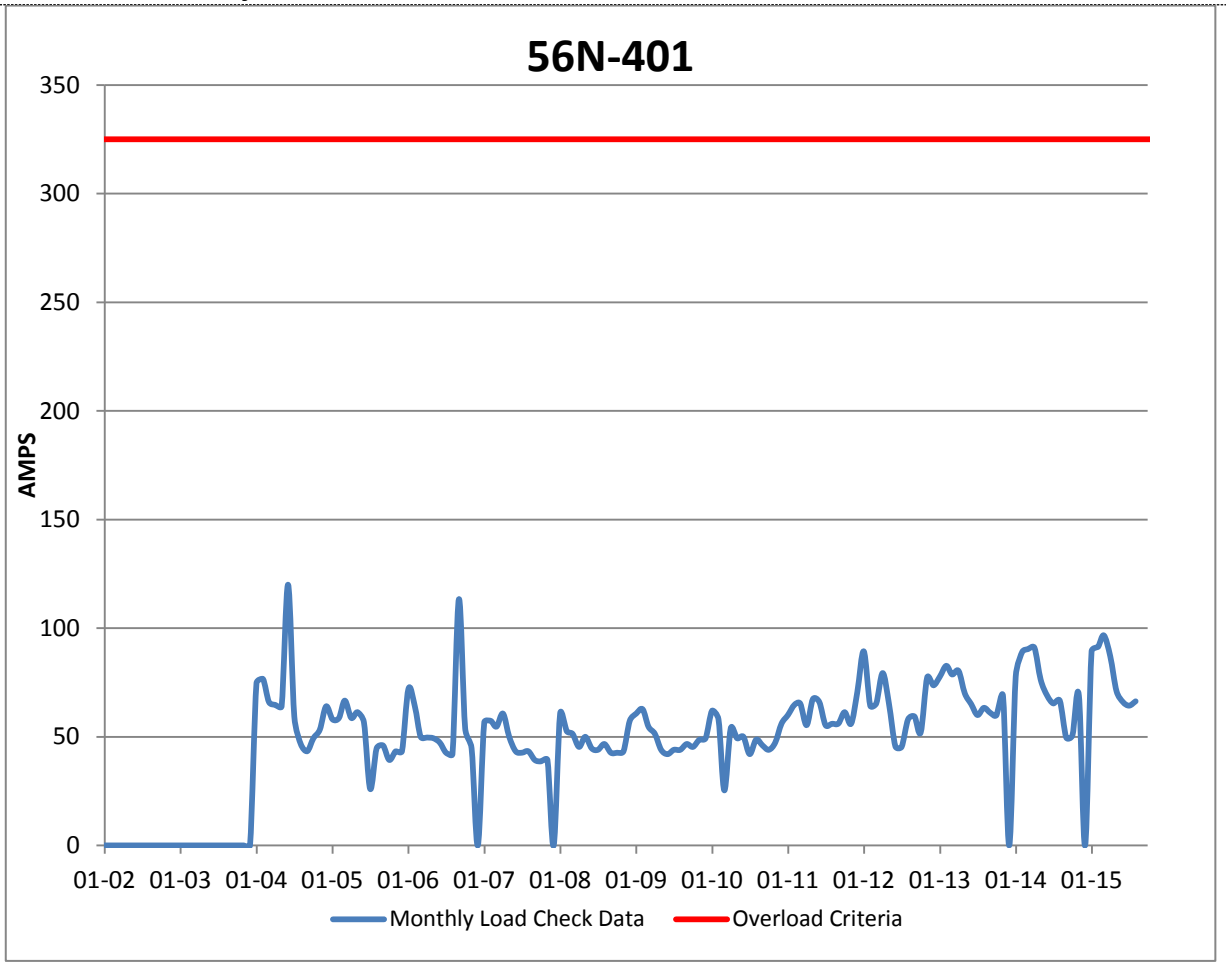


Figure 28-56N-401 Load History

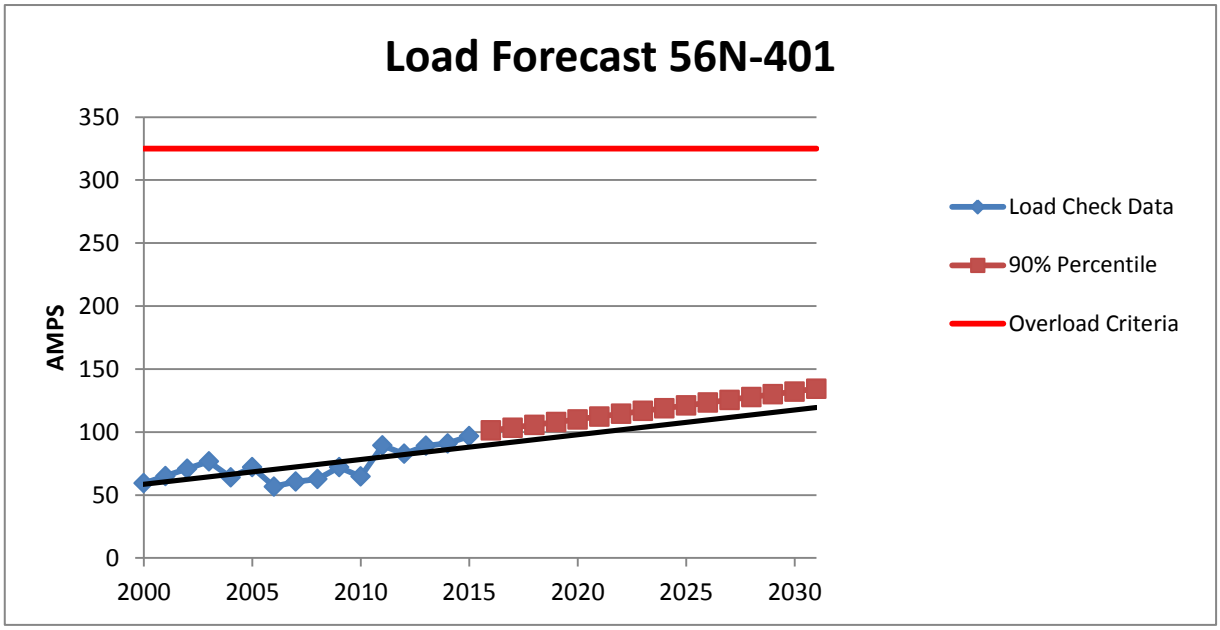


Figure 29-56N-401 Load Forecast

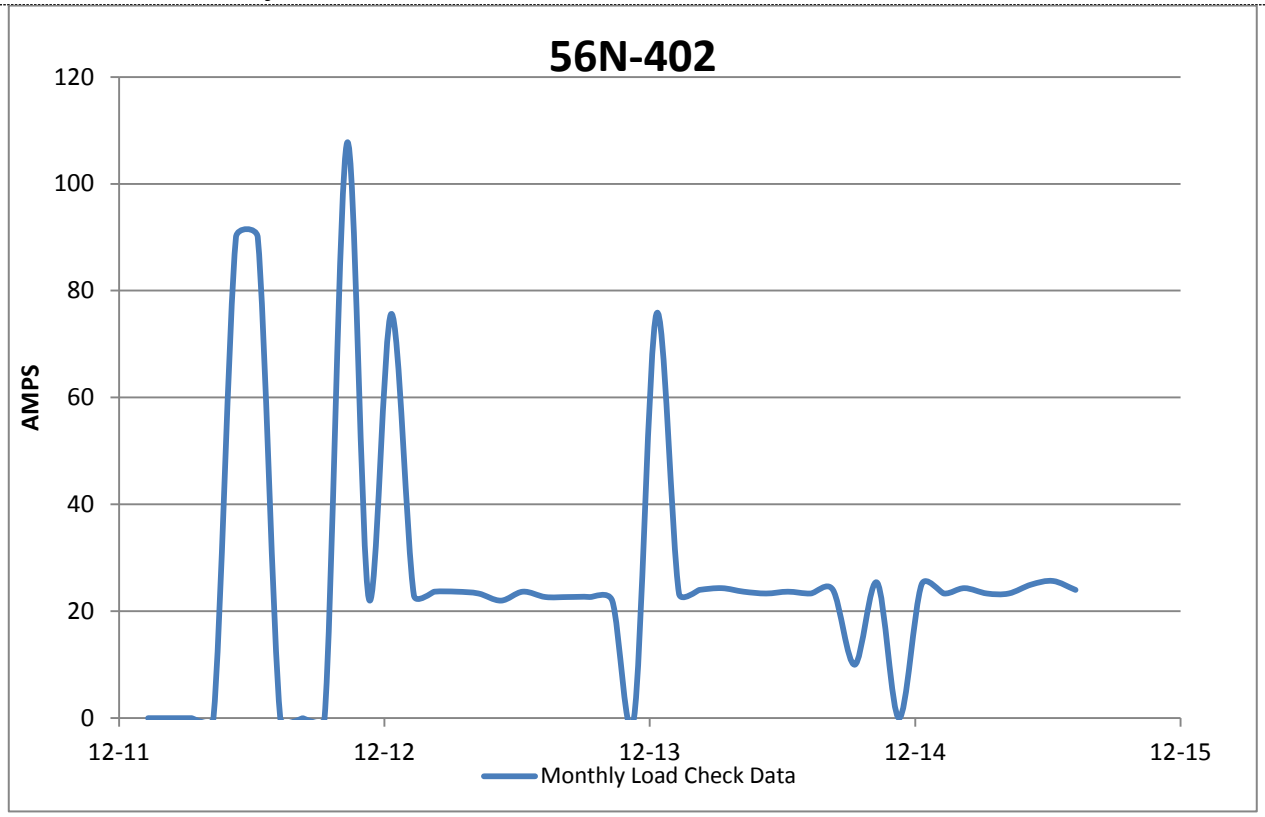


Figure 30-56N-402 Load History

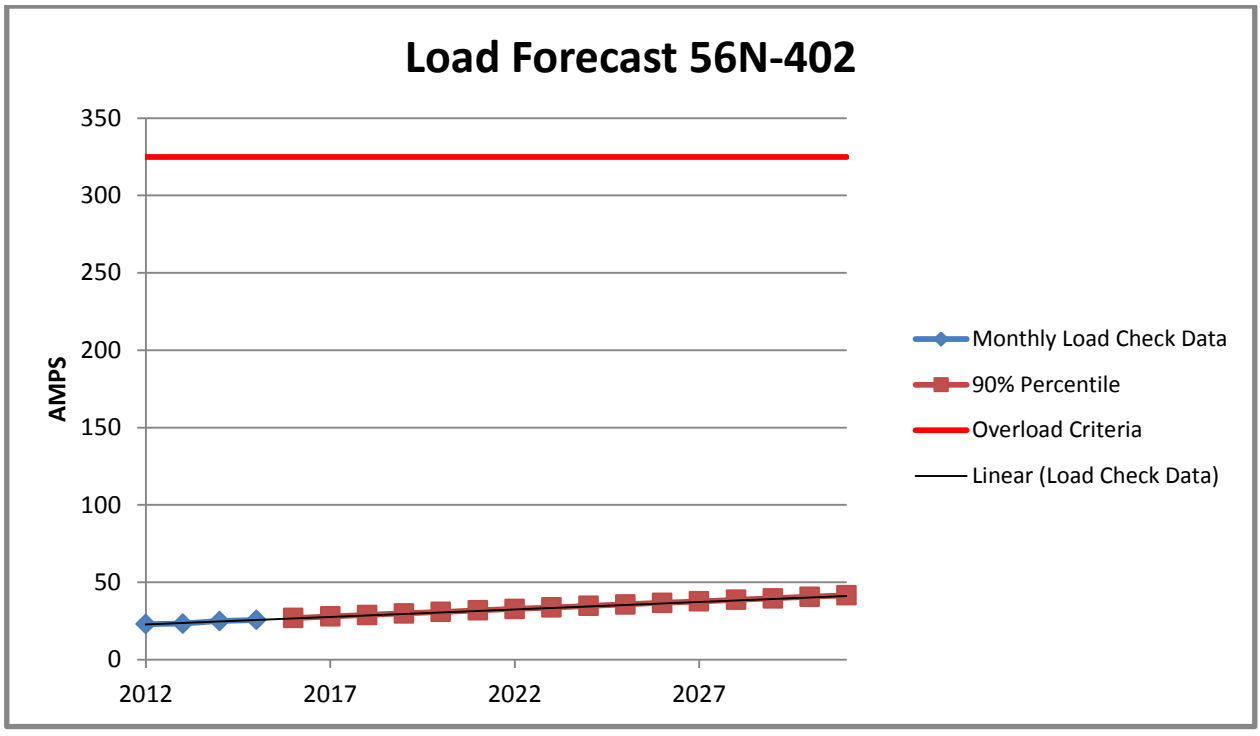


Figure 31-56N-402 Load Forecast

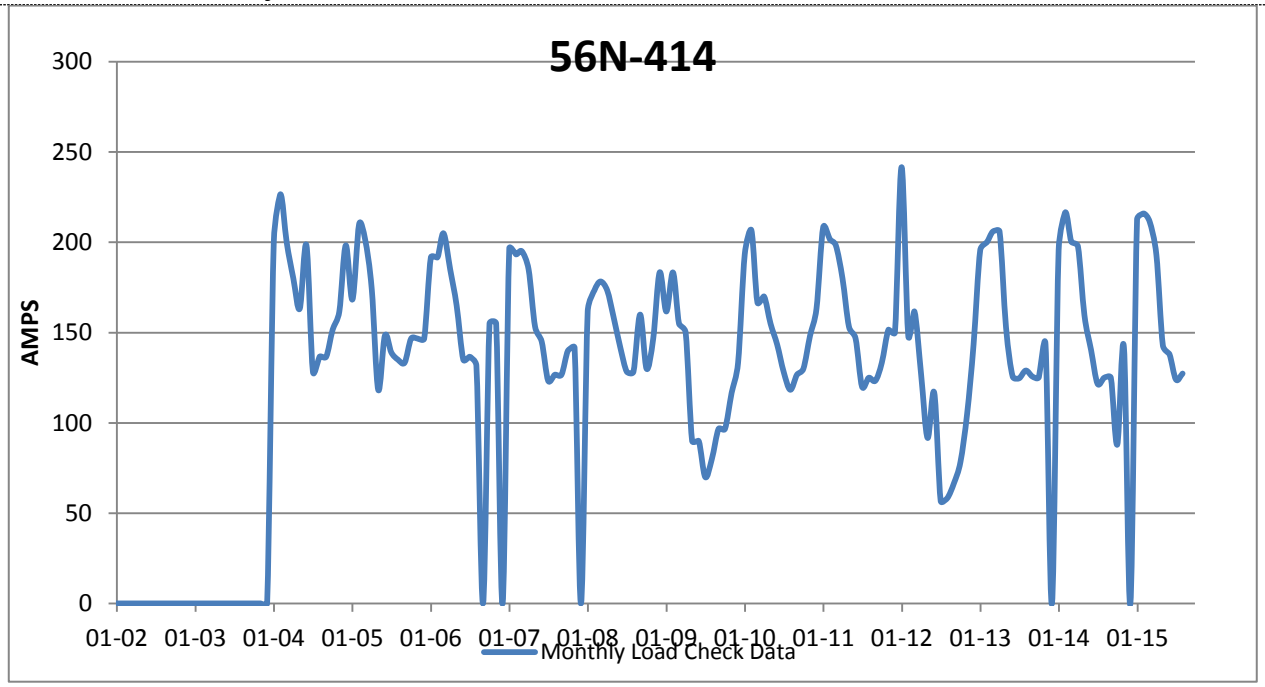


Figure 32-56N-414 Load History

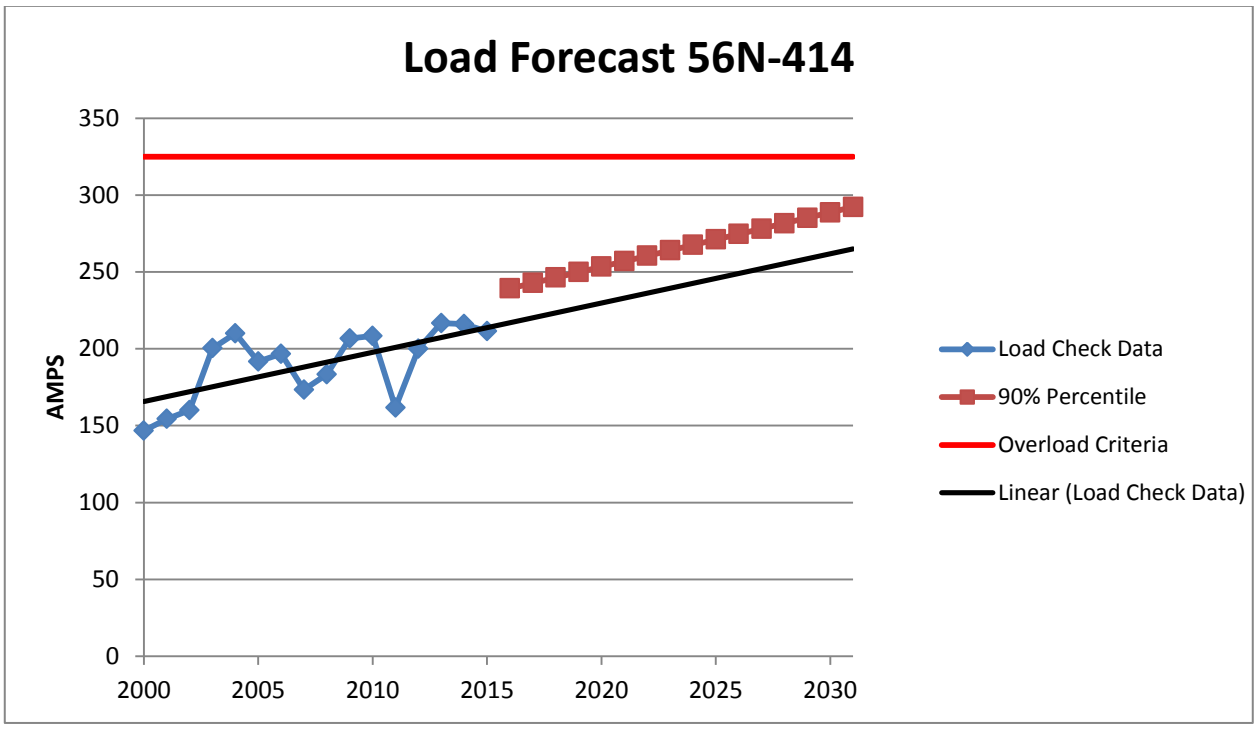


Figure 33-56N-414 Load Forecast

APPENDIX C

Economic Analysis

Economic Analysis of Alternatives for Replacing Overloaded Transformer 56N-T1

Substation Design Overviews Darryl Babin, Dave Downey

Haliburton Substation (56N) Transformer Capacity Increase

Introduction

The Haliburton Substation resides in Pictou County with a 7.5/10//11.2 MVA, 69kV (Delta) – 25kV (Wye) transformer (56N-T1). The transformer secondary has a ±15% tap changer in 32 steps and an impedance of %Z = 6.75. The 69kV source was tapped from line L-5506 with an overhead span entering the substation yard. Fused cut-outs (SMD-1A 100E Slow) provide the main protection for 56N-T1. Three 25 kV feeders originate from this substation: 56N-401, 56N-402 and 56N-414. Each 25kV feeder has a recloser for protection and a connection to the dead bus for recloser maintenance.

Purpose

Distribution planning has been conducting a study for the Pictou area and identified the Haliburton Substation (56N) for a transformer capacity increase to meet customer needs. The substation load will increase when the existing 4.16kV supplies, within the town of Pictou, have been changed to the 25kV system. Additionally, the load on feeder 56N-414 approaches the maximum capacity.

To assist distribution planning, the following estimate has been prepared to demonstrate the cost associate with increasing the transformer capacity in the Haliburton Substation (56N).

Options

Distribution planning proposed the following alternatives:

Alternative 1:

Replace the existing transformer with a 15/20/25 MVA, 69 (Delta) – 26.4kV ±10% (Wye) transformer and add a 25kV feeder.

Alternative 2:

Install a second transformer rated 8.4/11.2//14 MVA, 69kV (Delta) – 26.4kV ±10% (Wye) and add a 25kV feeder.

Design Basis

The following provides a high-level scope of work for each alternative.

Alternative 1:

Removal

- Transformer 7.5/10//11.2, 69 – 25kV
- Concrete Pad
- Existing ground grid (around transformer)
- Existing RTU SCADA communication system

Replace

- Concrete pad
- Relocate communication pole
- Extension of ground grid (transformer and additional 25kV structures)
- 69kV, 200E Fuses (replace fuse link within cut-outs)
    - May need to change fuse cut-outs to a SMD-2B as 200E would be the maximum fuse size for an SMD-1A

New

- Transformer with 15/20/25 MVA, 69 – 26.4kV ±10%
- Oil containment (Polyurethane or Concrete)
- 25kV Busbar and wooden structure
- 25kV Recloser and isolation switches (3)
- RTU SCADA communication system

Alternative 2:

New

- 69kV Switch
- 69kV Fuse Cut-outs
- 69kV Busbar, insulators and supports
- Transformer with 8.4/11.2//14 MVA, 69 – 26.4kV ±10%
- Concrete pad
- Oil containment (Polyurethane or Concrete)
- New ground grid (transformer and additional 25kV structures) and connection to existing grid
- 25kV Busbar and wooden structure
- 25kV Transformer Secondary disconnect switch and wooden structure
- 25kV Recloser and isolation switches (3)
- 25kV Switch between main 25kV buses

Replace/Relocate

- Relocate communication pole

Not Included in either Alternative

Fencing modifications or grounding associate with fencing.

Increase Transformer Capacity Haliburton Substation 56N
Summary of Alternatives

Nova Scotia POWER An Emera Company

Division :	Transmission & Distribution	Date :	4-May-16
Department :	T7D System Planning & Optimization	CI Number:	
Originator :	Art Burrill	Project No. :	

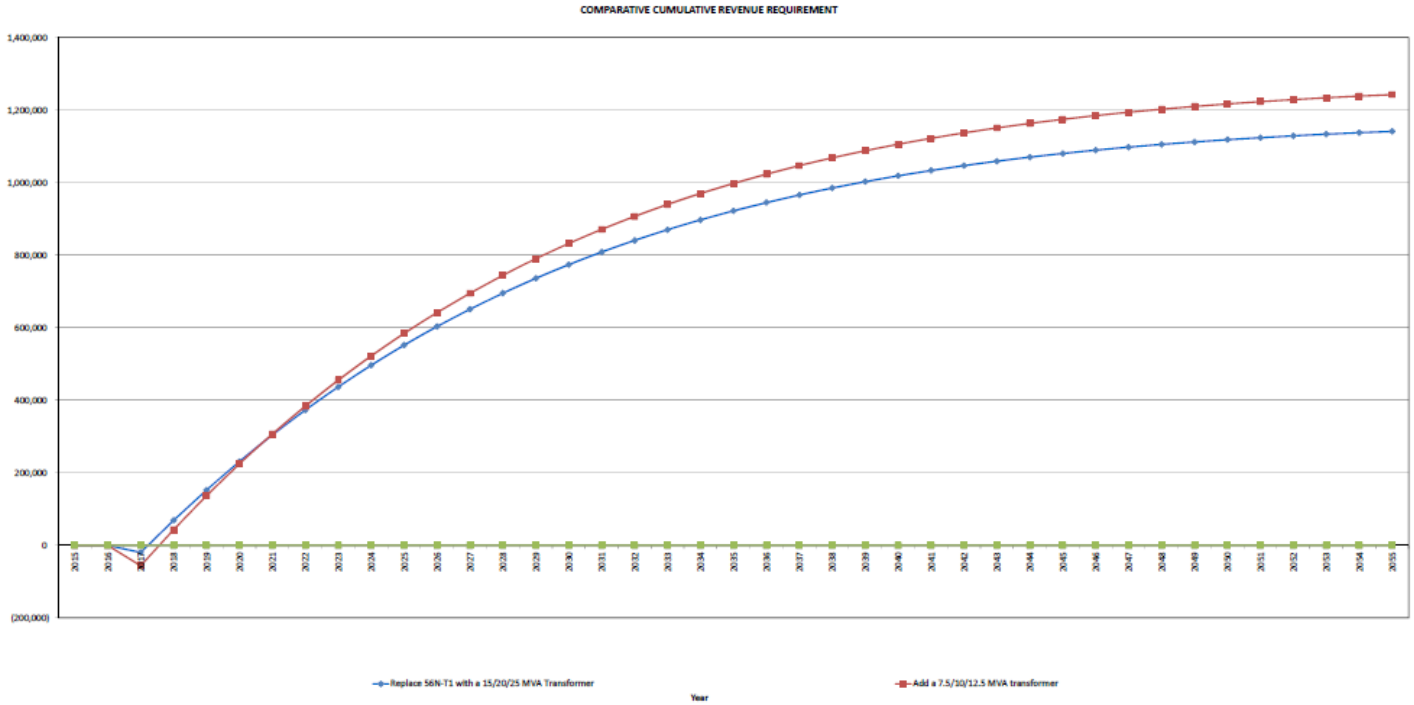
	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank (based on PV of RR)	IRR	Disc Pay
A	Replace 56N-T1 with a 15/20/25 MVA T	6.11%	1,141,363	-910,304	1	-8.04%	0.0 years
B	Add a 7.5/10/12.5 MVA transformer	6.11%	1,242,658	-992,615	2	-8.04%	0.0 years
	0	NA	NA	NA	NA	#NUM!	0.0 years
	0	NA	NA	NA	NA	#NUM!	0.0 years

Recommendation :

Notes/Comments :

Replace 56N-T1 with a 15/20/25 MVA Transformer

Add a 7.5/10/12.5 MVA transformer



Increase Transformer Capa Go to: Working Capital

Replace 56N-T1 with a 15/20/25 MVA Transf Capital

Expenses

Revenue

Add Operating Item

Project Description

		2015	2016	2017	2018	2019
Capital Invested						
1.	Replace 56N-T1 with 15/20/25 MVA			1,245,259		
2.						
3.						
4.						
5.						
6.						
7.						
8.						
9.						
10.						
11.						
12.						
13.						
14.						
15.						
16.						
17.						
18.						
19.						
20.						
	Total Direct Capital Invested by Year			1,245,259		
	AFUDC (entered as a positive value)			4,310		
	AO (entered as a positive value)			48,593		
	Total Indirect Capital Invested by Year			52,903		
	Total Capital Invested by Year			**1,298,162**		

Increase Transformer Capa

Add a 7.5/10/12.5 MVA transformer

Nova Scotia POWER An Emera Company

Go to: Working Capital | Capital | Expenses | Revenue

Add Operating Item

Project Description

		2015	2016	2017
Capital Invested				
1.	Add 7.5/10/12.5 Transformer			1,358,332
2.				
3.				
4.				
5.				
6.				
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11.				
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15.				
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17.				
18.				
19.				
20.				
	Total Direct Capital Invested by Year			1,358,332
	AFUDC (entered as a positive value)			4,310
	AO (entered as a positive value)			84,996
	Total Indirect Capital Invested by Year			89,306
	Total Capital Invested by Year			**1,447,638**

Economic Analysis of Alternatives for Replacing 0.92km of #4Cu Conductor Scotsburn

Reconductoring 0.9km #4Cu in Scotsburn 56N-414
Summary of Alternatives

Division :	T&D	Date :	4-May-16
Department :	T&D System Planning & Optimization	CI Number:	
Originator :		Project No. :	

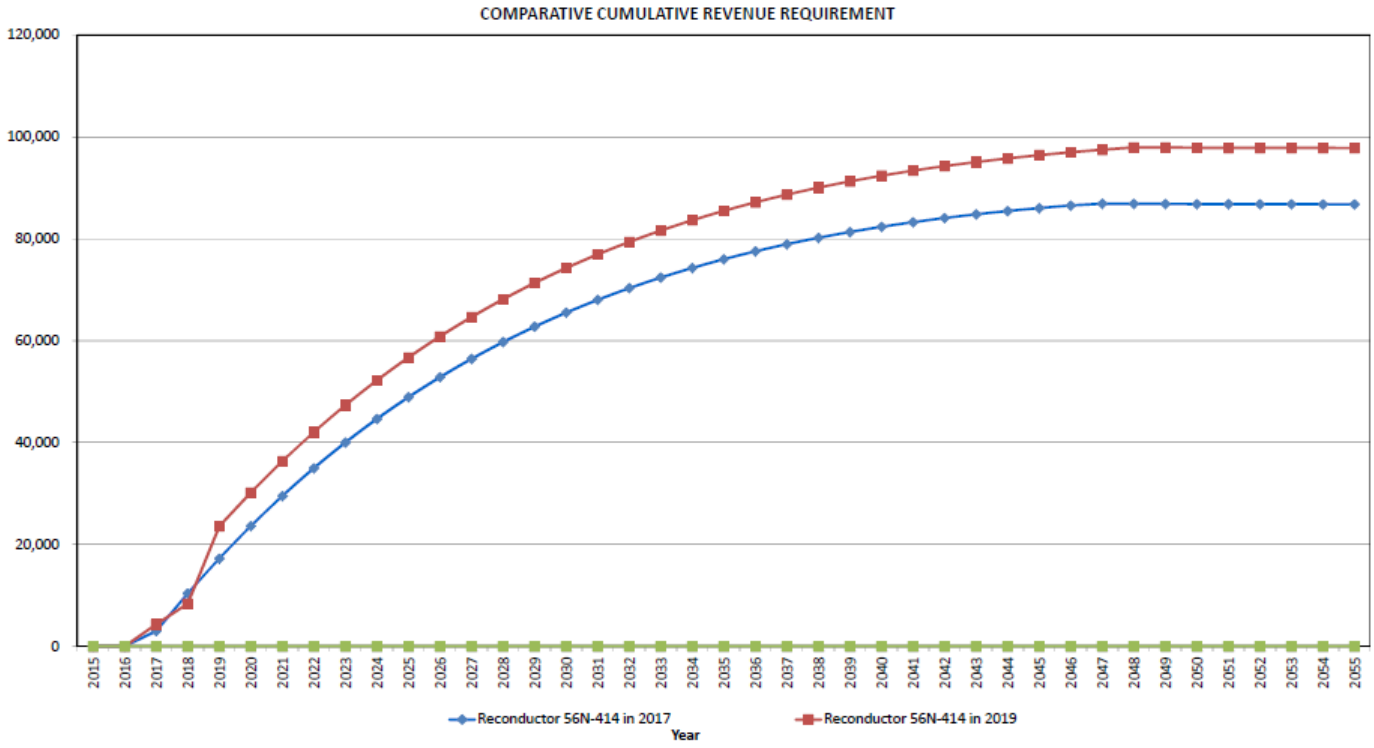
	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank (based on PV of RR)	IRR	Disc Pay
A	Reconductor 56N-414 in 2017	6.11%	86,752	-66,192	1	-8.02%	0.0 years
B	Reconductor 56N-414 in 2019	6.11%	97,803	-74,798	2	-9.19%	0.0 years
	0	NA	NA	NA	NA	#NUM!	0.0 years
	0	NA	NA	NA	NA	#NUM!	0.0 years

Recommendation :

Notes/Comments :

Reconductor 56N-414 in 2017

Reconductor 56N-414 in 2019


COMPARATIVE CUMULATIVE REVENUE REQUIREMENT
120,000
100,000
80,000
60,000
40,000
20,000
0
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
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2054
2055
Reconductor 56N-414 in 2017
Reconductor 56N-414 in 2019
Year

Reconductoring 0.9km #4C

Reconductor 56N-414 in 2017

Nova Scotia POWER An Emera Company

Go to: Working Capital | Capital | Expenses | Revenue

Add Operating Item

Project Description

		2015	2016	2017	20
Capital Invested					
1.	Reconductor 0.9km #4Cu to 336ASC			90,931	
2.					
3.					
4.					
5.					
6.					
7.					
8.					
9.					
10.					
11.					
12.					
13.					
14.					
15.					
16.					
17.					
18.					
19.					
20.					
	Total Direct Capital Invested by Year			90,931	
	AFUDC (entered as a positive value)				
	AO (entered as a positive value)				
	Total Indirect Capital Invested by Year				
	Total Capital Invested by Year			**90,931**	

Reconductoring 0.9km #4C

Reconductor 56N-414 in 2019

Nova Scotia POWER An Emera Company

Go to: Working Capital | Capital | Expenses | Revenue

Add Operating Item

Project Description

Capital Invested

		2015	2016	2017	2018	2019
1.	Reconductor 0.9km #4cu to 336ASC					94,605
2.						
3.						
4.						
5.						
6.						
7.						
8.						
9.						
10.						
11.						
12.						
13.						
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16.						
17.						
18.						
19.						
20.						

Total Direct Capital Invested by Year 94,605

Expense

	Description		1	2	3	4	5
1.	Cost of delta line losses #4Cu vs 336ASC	Cost			4,967		
		$/Unit			1		
		Expense-Subtotal			4,967		
2.	Cost of delta line losses #4Cu to 336ASC	Cost				4,968	
		$/Unit				1	
		Expense-Subtotal				4,968	
3.	Cost of delta line losses #4Cu vs 336ASC	Cost					14,894
		$/Unit					1
		Expense-Subtotal					14,894

APPENDIX D

Cost of Losses 4kv to 25kV Pictou Town Conversion

D1. Distribution Transformer Losses

The difference in losses between existing 4kV and new 25kV distribution transformers was determined. This information was obtained from the document 'Historical Losses of Standard Design' and '2015 NSPI CARTE Transformers Data', both available on the Distribution Planning SharePoint site under COST ESTIMATES. In the tables below, 'New' refers to the CARTE 25kV transformers we would buy today and 'Old' refers to 4kV transformers bought circa 1960.

Table 5 Distribution Transformer Loss Data

Dist. Transformer Test Data			
	Size (kVA)	LL (W)	NLL (W)
New	25	368	56
	50	569	94.5
Old	25	505	130
	50	819	187

D2. The Cost of Losses

Alternative A was used as the baseline for losses in the EAM. The additional losses that would result from selecting Alternative B were determined in kilowatts. These values were converted to dollars using the tables found in '2015 Cost of Losses', available on the Distribution Planning SharePoint site under COST ESTIMATES. The future cost of losses at 31% loss factor was used for primary conductor losses. For background information, see report '254-0807-A48 Cost of NSPI Distribution System Losses'.

Table 6 Future Cost of Distribution Losses – 31% Loss Factor

	Future Cost of Distribution Losses - 31%					
YEAR	Load Losses			No Load Losses		
	Demand $/kW	Energy $/kW	Total	Demand $/kW	Energy $/kW	Total
2015	$32.09	$173.80	$205.88	$38.37	$560.64	$599.01
2016	$32.73	$162.94	$195.66	$39.14	$525.60	$564.74
2017	$33.38	$160.22	$193.60	$39.92	$516.84	$556.76
2018	$34.05	$152.07	$186.12	$40.72	$490.56	$531.28
2019	$384.25	$152.07	$536.32	$459.54	$490.56	$950.10
2020	$199.31	$162.94	$362.25	$238.37	$525.60	$763.97
2021	$185.81	$165.65	$351.46	$222.21	$534.36	$756.57
2022	$195.73	$247.12	$442.85	$234.08	$797.16	$1,031.24
2023	$210.68	$244.40	$455.08	$251.96	$788.40	$1,040.36
2024	$206.42	$247.12	$453.54	$246.86	$797.16	$1,044.02
2025	$218.89	$252.55	$471.44	$261.78	$814.68	$1,076.46
2026	$208.80	$257.98	$466.78	$249.71	$832.20	$1,081.91
2027	$206.25	$268.84	$475.10	$246.67	$867.24	$1,113.91
2028	$204.56	$282.42	$486.98	$244.64	$911.04	$1,155.68
2029	$205.39	$287.85	$493.24	$245.63	$928.56	$1,174.19
2030	$204.56	$301.43	$506.00	$244.64	$972.36	$1,217.00
2031	$202.08	$317.73	$519.81	$241.68	$1,024.92	$1,266.60
2032	$186.24	$342.17	$528.41	$222.73	$1,103.76	$1,326.49
2033	$195.50	$312.29	$507.79	$233.81	$1,007.40	$1,241.21
2034	$196.42	$372.04	$568.45	$234.90	$1,200.12	$1,435.02
2035	$196.52	$412.77	$609.29	$235.02	$1,331.52	$1,566.54
2036	$198.31	$434.50	$632.80	$237.16	$1,401.60	$1,638.76
2037	$203.46	$450.79	$654.25	$243.32	$1,454.16	$1,697.48
2038	$207.53	$459.81	$667.33	$248.19	$1,483.24	$1,731.43
2039	$211.68	$469.00	$680.68	$253.15	$1,512.91	$1,766.06
2040	$215.91	$478.38	$694.29	$258.22	$1,543.17	$1,801.38
2041	$220.23	$487.95	$708.18	$263.38	$1,574.03	$1,837.41
2042	$224.64	$497.71	$722.34	$268.65	$1,605.51	$1,874.16
2043	$229.13	$507.66	$736.79	$274.02	$1,637.62	$1,911.64
2044	$233.71	$517.82	$751.53	$279.50	$1,670.37	$1,949.87
2045	$238.39	$528.17	$766.56	$285.09	$1,703.78	$1,988.87
2046	$243.15	$538.74	$781.89	$290.79	$1,737.86	$2,028.65
2047	$248.02	$549.51	$797.53	$296.61	$1,772.61	$2,069.22
2048	$252.98	$560.50	$813.48	$302.54	$1,808.07	$2,110.61
2049	$258.04	$571.71	$829.75	$308.59	$1,844.23	$2,152.82
2050	$263.20	$583.14	$846.34	$314.76	$1,881.11	$2,195.88
2051	$268.46	$594.81	$863.27	$321.06	$1,918.73	$2,239.79

Table 7 Reliability Statistics

55N-201:STE						
Year	**Customers**	**CI**	**CHI**	**SAIFI**	**SAIDI**	**CAIDI**
2010	326	80	2,343	0.25	7.19	29.29
2011	340	1,566	3,403	4.61	10.01	2.17
2012	341	1,549	16,471	4.54	48.30	10.63
2013	308	4,697	482	15.25	1.57	0.10
2014	244	39	91	0.16	0.37	2.33
2015	243	1	2	0.00	0.01	2.00

55N-202:STE						
Year	**Customers**	**CI**	**CHI**	**SAIFI**	**SAIDI**	**CAIDI**
2010	322	449	16,831	1.39	52.27	37.49
2011	310	4	9	0.01	0.03	2.29
2012	307	46	47	0.15	0.15	1.02
2013	321	23	44	0.07	0.14	1.92
2014	323	3	18	0.01	0.06	6.09
2015	324	3	14	0.01	0.04	4.56

55N-203:STE							S x S
Year	**Customers**	**CI**	**CHI**	**SAIFI**	**SAIDI**	**CAIDI**	
2010	363	13	146	0.04	0.40	11.20	
2011	359	32	231	0.09	0.64	7.22	
2012	358	34	51	0.09	0.14	1.50	
2013	368	90	200	0.24	0.54	2.22	
2014	364	131	4,973	0.36	13.66	37.96	
2015	364	2	3	0.01	0.01	1.44	

55N-204:STE						
Year	**Customers**	**CI**	**CHI**	**SAIFI**	**SAIDI**	**CAIDI**
2010	544	169	1,562	0.31	2.87	9.24
2011	546	32	84	0.06	0.15	2.62
2012	542	1,109	1,117	2.05	2.06	1.01
2013	535	542	386	1.01	0.72	0.71
2014	534	45	393	0.08	0.74	8.73
2015	534	1,670	1,395	3.13	2.61	0.84

56N-401:STE						
Year	Customers	CI	CHI	SAIFI	SAIDI	CAIDI
2010	807	2,302	8,345	2.85	10.34	3.63
2011	826	5,712	12,541	6.92	15.18	2.20
2012	837	4,244	39,328	5.07	46.99	9.27
2013	838	642	2,790	0.77	3.33	4.35
2014	904	2,197	26,241	2.43	29.03	11.94
2015	901	1,106	1,836	1.23	2.04	1.66

56N-402:STE						
Year	Customers	CI	CHI	SAIFI	SAIDI	CAIDI
2010	8	0	0	0.00	0.00	#DIV/0!
2011	7	0	0	0.00	0.00	#DIV/0!
2012	6	5,714	9,339	952.33	1556.56	1.63
2013	7	1	2	0.14	0.26	1.83
2014	7	4	146	0.57	20.79	36.39
2015	7	0	0	0.00	0.00	#DIV/0!

56N-414:STE						
Year	Customers	CI	CHI	SAIFI	SAIDI	CAIDI
2010	2811	19,195	103,165	6.83	36.70	5.37
2011	2798	8,314	9,103	2.97	3.25	1.09
2012	2841	6,842	17,853	2.41	6.28	2.61
2013	2904	11,363	18,801	3.91	6.47	1.65
2014	2920	16,747	115,464	5.74	39.54	6.89
2015	2927	10,814	35,324	3.69	12.07	3.27

CI Number: 49779

Title: L6537 Replacements and Upgrades Phase 2

Start Date: 2018/09
In-Service Date: 2018/10
Final Cost Date: 2019/10
Function Class: Transmission
Forecast Amount: $1,255,220

DESCRIPTION:

L-6537 is a 91 kilometer (431 structures) 138kV transmission line that connects 2C Port Hastings and 5S Glentosh substations. This line was built in 1971. This work is on the section of line between 9C Aberdeen Tap and 5S Glen Tosh (37 kilometer section). Phase 1 was the replacement of deteriorated assets on the 54km section from 2C Port Hastings to 9C Aberdeen Tap (CI 47914). This project is required to replace deteriorated assets and address ground clearance violations (as per CSA Standard 22.3) on 106 structures that have been identified through Nova Scotia Power's inspection program.

The estimated project scope includes:

- Structure Replacements: 11 Structures
- Timber Arm Replacements: 1 Structure
- Timber Arm and Insulator Replacements: 23 Structures
- Pole Replacements: 5 Structures
- Pole and Insulator Replacements: 7 Structures
- Insulator Replacements: 45 Structures
- Other Deteriorated Assets: 14 Structures

Summary of Related CIs +/- 2 years:
2016 CI 47914 L6537 Replacements and Upgrades $1,382,705

JUSTIFICATION:

Justification Criteria: Transmission Plant- Poles and Fixtures
Transmission Plant- Station Equipment
Transmission Plant- Overhead Conductors and Devices

Sub Criteria: Equipment Replacement

Depreciation Class: Transmission Plant

Estimated Life of the Asset: 45 years

Why do this project?

The transmission inspection program identified deteriorated assets that require replacement to avoid transmission interruptions. Not completing this project would compromise the reliable operation of this line.

Why do this project now?

This work has been prioritized based on transmission inspection results. This project is required to support the reliable operation of the transmission line.

This project is considered in-service when the first phase of component replacement / upgrades are complete (October 2018), therefore the forecasted final cost date (October 2019) is six months after the last replacement / upgrade is completed (April 2019).

Why do this project this way?

Replacing the existing deteriorated assets is more cost effective than rebuilding the entire line.

The contracts portion of this project will be sourced through NS Power's existing Power Line Technician (PLT) Service Agreement with Emera Utility Services. This is aligned with NS Power's workforce planning model which is designed to optimize the allocation and execution of PLT resources among work requirements.

CI Number : 49779 - L-6537 Replacements and Upgrades Phase 2 **Project Number** 49779

Parent CI Number : -

Asset Location : 1455 - 1455 Transmission Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0700 - TP - Environmental	227,148
Additions	3500 - TP - Wood Poles	433,672
Additions	3800 - TP - Insulators	193,715
Additions	3900 - TP - O/H Cond.	305,192
Retirements	3500 - TP - Wood Poles	47,151
Retirements	3800 - TP - Insulators	48,210
Retirements	3900 - TP - O/H Cond.	132
	Total Cost:	1,255,220
	Original Cost:	151,268

Capital Project Detailed Estimate

Location: Transmission
CI# / FP#: 49779
Title: L6537 Replacements and Upgrades Phase 2
Execution Year: 2018-2019

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
T&D Labour - Electrician/Technician	PD	3	$ 360	$ 1,017		
T&D Labour - Site Supervision	PD	75	$ 385	$ 28,937		
Procurement / Financial Support	Lot	1	$ 2,677	$ 2,677		
				$ -		
			Sub-Total	$ 32,631		
Materials						
Poles, Anchors, and Guys	Lot	1	$ 99,593	$ 99,593		
Insulators	Lot	1	$ 34,085	$ 34,085		
Conductor	Lot	1	$ 148	$ 148		
			Sub-Total	$ 133,826		
Contracts						
Contract Line Work	Hrs	[redacted]		$ 591,555		
Environmental Bridges and Mats	Lot	1	$ 169,411	$ 169,411		
Flagging	Lot	1	$ 5,000	$ 5,000		
Pole-Haulage	Lot	1	$ 7,400	$ 7,400		
Rockbreaking	Lot	1	$ 30,000	$ 30,000		
Waste Disposal	Lot	1	$ 7,000	$ 7,000		
Survey	Lot	1	$ 1,000	$ 1,000		
			Sub-Total	$ 811,366		
Other Goods & Services						
Contingency	%	10%	$ 811,366	$ 81,137		
				$ -		
			Sub-Total	$ 81,137		
Vehicle Overhead						
Vehicle Admin. Overhead				$ 13,335		
			Sub-Total	$ 13,335		
Administrative Overhead						
Labour AO				$ 28,977		
Contract AO				$ 153,948		
				$ -		
			Sub-Total	$ 182,926		
			SUB-TOTAL (no AO, AFUDC)	$ 1,058,959		
			TOTAL (AO, AFUDC included)	$ 1,255,220		
Original Cost				$ 151,268		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 49777

Title: L7002 Replacements and Upgrades

Start Date:	2018/04
In-Service Date:	2018/06
Final Cost Date:	2019/09
Function Class:	Transmission
Forecast Amount:	$926,777

DESCRIPTION:

L-7002 is a 75 kilometer (338 structures) 230kV transmission line that connects 67N Onslow to 120H Brushy Hill substations. This line was built in 1970. This project is required to replace deteriorated assets and address ground clearance violations (as per CSA Standard 22.3) on approximately 39 structures that have been identified through Nova Scotia Power's transmission inspection program.

The project scope includes:

- Structure Replacements: 19 Structures
- Timber Arm Replacements: 10 Structures
- Pole Replacements: 4 Structures
- Pole and Insulator Replacements: 1 Structure
- Other Deteriorated Assets: 5 Structures

Summary of Related CIs +/- 2 years
No other projects in 2016, 2017, 2019 and 2020

JUSTIFICATION:

Justification Criteria: Transmission Plant

Sub Criteria: Equipment Replacement

Why do this project?

The transmission inspection program identified ground clearance issues and deteriorated assets that require replacement to avoid transmission interruptions. Not completing this project would compromise the reliable operation and thermal rating of this line.

Why do this project now?

This work has been prioritized based on transmission inspection results. This project is required to support the reliable operation of the transmission line.

This project is considered in-service when the first phase of component replacement / upgrades are complete (June 2018), therefore the forecasted final cost date (September 2019) is six months after the last replacement / upgrade is completed (March 2019).

Why do this project this way?

Replacing the existing deteriorated assets is more cost effective than rebuilding the entire line.

The contracts portion of this project will be sourced through NS Power's existing Power Line Technician (PLT) Service Agreement with Emera Utility Services. This is aligned with NS Power's workforce planning model which is designed to optimize the allocation and execution of PLT resources among work requirements.

CI Number : 49777 - L7002 Replacements and Upgrades **Project Number** 49777

Parent CI Number : -

Asset Location : 1455 - 1455 Transmission Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0700 - TP - Environmental	106,642
Additions	3500 - TP - Wood Poles	547,316
Additions	3800 - TP - Insulators	54,121
Additions	3900 - TP - O/H Cond.	111,728
Retirements	3500 - TP - Wood Poles	104,324
Retirements	3800 - TP - Insulators	2,507
Retirements	3900 - TP - O/H Cond.	139
	Total Cost:	926,777
	Original Cost:	112,483

Capital Project Detailed Estimate

Location: Transmission
CI# / FP#: 49777
Title: L7002 Replacements and Upgrades
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
T&D Labour - Electrician/Technician	PD	2	$ 360	$ 643		
T&D Labour - Site Supervision	PD	57	$ 385	$ 22,137		
Procurement / Financial Support	Lot	1	$ 2,956	$ 2,956		
			Sub-Total	$ 25,735		
Materials						
Poles, Anchors, and Guys	Lot	1	$ 145,166	$ 145,166		
Insulators	Lot	1	$ 2,410	$ 2,410		
Conductor	Lot	1	$ 213	$ 213		
			Sub-Total	$ 147,789		
Contracts						
Contract Line Work	Hrs	[redacted]		$ 452,531		
Environmental Bridges and Mats	Lot	1	$ 79,260	$ 79,260		
Flagging	Lot	1	$ 5,000	$ 5,000		
Pole-Haulage	Lot	1	$ 6,600	$ 6,600		
Waste Disposal	Lot	1	$ 7,400	$ 7,400		
Survey	Lot	1	$ 5,000	$ 5,000		
			Sub-Total	$ 555,791		
Other Goods & Services						
Contingency	%	10%	$ 555,791	$ 55,579		
			Sub-Total	$ 55,579		
Interest Capitalized						
AFUDC				$ 3,058		
			Sub-Total	$ 3,058		
Vehicle Overhead						
Vehicle AO				$ 10,516		
			Sub-Total	$ 10,516		
Administrative Overhead						
Labour AO				$ 22,853		
Contracts AO				$ 105,456		
				$ -		
			Sub-Total	$ 128,309		
			SUB-TOTAL (no AO, AFUDC)	$ 784,895		
			TOTAL (AO, AFUDC included)	$ 926,777		
Original Cost				$ 112,483		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 52241

Title: 16V-T2 Weymouth Hydro Transformer Replacement

Start Date: 2018/01
In-Service Date: 2018/12
Final Cost Date: 2019/06
Function: Transmission
Forecast Amount: $889,253

DESCRIPTION:

The scope of this project includes the replacement of the existing 16V-T2 generator step-up transformer (GSU) at the 16V Weymouth substation as it is at the end of its useful life.

Summary of Related CIs (+/- 2 years):
No other projects in 2016, 2017, 2018, 2019 or 2020

JUSTIFICATION:

Justification Criteria: Transmission Plant

Sub Criteria: Equipment Replacement

Why do this project?

The existing transformer is 59 years old and fluid analysis test results show a high concentration of furan, which is an indicator that the transformer is nearing end of life. Therefore, the replacement of the transformer is required to mitigate the risk of the failure of the T2 transformer. In the case of a failure of 16V-T2, generation at the Weymouth Hydro Plant would have to be curtailed because 16V-T3 is not rated to support the full load operation of both generators. Both 16V-T2 and 16V-T3 must be operational to allow full hydro generation output.

Why do this project now?

The 16V-T2 transformer is 59 years old (estimated useful life is 45 years) and is exhibiting high levels of furan in insulating oil, indicating degradation of paper insulation and signifying that the transformer is nearing end of life. This indicates potential reliability issues with the 16V-T2 generator step up transformer. Proactive replacement will avoid the loss of generation in the event of an equipment failure.

Why do this project this way?

Due to the age of the transformer, full replacement is the best option. 16V-T2 is one of two generator transformers at the Weymouth HydroStation. The only way to transfer energy from the generator to the system is through a generator step up transformer.

CI Number : 52241 - 16V-T2 Weymouth Hydro Transformer Replacement

Project Number 52241

Parent CI Number : -

Asset Location : 1455 - 1455 Transmission Plant General

Budget Version 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0300 - TP - Bldg.,Struct.Grnd.	20,256
Additions	0700 - TP - Environmental	37,253
Additions	2200 - TP - Elec Contr.Equip.	6,077
Additions	4300 - TP - Substn Dev.	38,507
Additions	4400 - TP - Substn.Transf.	772,022
Retirements	4400 - TP - Substn.Transf.	15,138
	Total Cost:	889,253
	Original Cost:	89,309

Capital Project Detailed Estimate

Location: Transmission

CI# : 52241
Title: 16V-T2 Weymouth Hydro Transformer Replacement
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
T&D Labor - Electrician/Technician	PD	45	$ 360	$ 16,372		
Procurement / Financial Support	Lot	1	$ 10,018	$ 10,018		
Engineering	PD	29	$ 386	$ 11,194		
Drafting	PD	14	$ 284	$ 3,976		
			Sub-Total	$ 41,560		
Travel Expense						
Travel	Lot	1	$ 185	$ 185		
			Sub-Total	$ 185		
Materials						
Substation Transformers	Lot	1	$ 460,000	$ 460,000		
Substation Devices	Lot	1	$ 26,250	$ 26,250		
Environmental Equipment	Lot	1	$ 11,700	$ 11,700		
Other Materials	Lot	1	$ 2,970	$ 2,970		
			Sub-Total	$ 500,920		
Contracts						
Transformer Transport, Placement & Assembly	Lot	1	$ 100,000	$ 100,000		
Concrete Foundations	Lot	1	$ 12,000	$ 12,000		
Oil / Water Separator Tank Installation	Lot	1	$ 10,000	$ 10,000		
Other Contracts	Lot	1	$ 12,460	$ 12,460		
			Sub-Total	$ 134,460		
Consulting						
Transformer Inspections and Witnessing of Tests	Lot	1	$ 40,000	$ 40,000		
			Sub-Total	$ 40,000		
Other Goods & Services						
Contingency	%	10%	$ 676,940	$ 67,694		
			Sub-Total	$ 67,694		
Vehicle Overhead						
Vehicle AO				$ 16,984		
			Sub-Total	$ 16,984		
Interest Capitalized						
AFUDC				$ 25,033		
				$ -		
			Sub-Total	$ 25,033		
Administrative Overhead						
Labor AO				$ 36,906		
Contract AO				$ 25,512		
			Sub-Total	$ 62,418		
			SUB-TOTAL (no AO, AFUDC)	$ 784,819		
			TOTAL (AO, AFUDC included)	$ 889,253		
Original Cost- 536800				$ 89,309		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 52102

Title: L5014 Replacements and Upgrades

Start Date:	2018/08
In-Service Date:	2018/10
Final Cost Date:	2019/04
Function Class:	Transmission
Forecast Amount:	$849,700

DESCRIPTION:

This project will replace deteriorated assets on 97 structures on L5014, a 10.6 kilometer (138 structures) 69 kV transmission line, built in 1951, that connects the 17V St. Croix and 18V Upper Burlington substations. This project is required to replace deteriorated assets that have been identified through NS Power's transmission inspection program.

The project scope includes:

- Timber Replacement: 1 Structure
- Insulator Replacement: 96 Structures

Summary of Related CIs +/- 2 years:
No other projects in 2016, 2017, 2018, 2019 or 2020

JUSTIFICATION:

Justification Criteria: Transmission Plant

Sub Criteria: Equipment Replacement

Why do this project?

The transmission inspection program identified deteriorated assets that require replacement to avoid transmission interruptions. Failure to complete this project would compromise the reliable operation of the line, which is a radial transmission supply to the 18V Upper Burlington substation which serves 3,000 customers. Asset failures on a radial transmission supply such as this line would result in extended power outages as there are no other sources of energy available while repairs are made.

Why do this project now?

This work has been prioritized based on transmission inspection results. This project is required to support the reliable operation of the transmission line.

Why do this project this way?

Replacing the existing deteriorated assets is more cost effective than rebuilding the entire line.

The contracts portion of this project will be sourced through NS Power's existing Power Line Technician (PLT) Service Agreement with Emera Utility Services. This is aligned with NS Power's workforce planning model which is designed to optimize the allocation and execution of PLT resources among work requirements.

CI Number	: 52102	- L5014 Replacements and Upgrades	**Project Number**	52102
Parent CI Number	:	-		
Asset Location	: 1455	- 1455 L5014 Municipality of the District of West Hants	**Budget Version**	2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account		Forecast Amount
Additions	0700 - TP - Environmental		20,458
Additions	3500 - TP - Wood Poles		12,890
Additions	3800 - TP - Insulators		252,980
Additions	3900 - TP - O/H Cond.		521,210
Retirements	3500 - TP - Wood Poles		678
Retirements	3800 - TP - Insulators		41,484
		Total Cost:	849,700
		Original Cost:	84,439

Capital Project Detailed Estimate

Location: Transmission
CI# / FP#: 52102
Title: L5014 Replacements and Upgrades
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
T&D Labor - Electrician/Technician	PD	4	$ 360	$ 1,526		
T&D Labor - Site Supervision	PD	50	$ 385	$ 19,347		
Procurement / Financial Support	Lot	1	$ 1,366	$ 1,366		
			Sub-Total	$ 22,239		
Materials						
Poles	Lot	1	$ 707	$ 707		
Insulators	Lot	1	$ 64,766	$ 64,766		
Conductor	Lot	1	$ 2,828	$ 2,828		
			Sub-Total	$ 68,301		
Contracts						
Contract Line Work	Hrs.	[redacted]		$ 540,518		
Environmental Bridges and Mats	Lot	1	$ 31 008	$ 15 126		
Flagging	Lot	1	$ 10 000	$ 5 000		
Waste Disposal	Lot	1	$ 2,000	$ 2,000		
			Sub-Total	$ 562,644		
Other Goods & Services						
Contingency	%	10%	$ 562,644	$ 56,264		
			Sub-Total	$ 56,264		
Interest Capitalized						
AFUDC				$ 4,659		
				$ -		
			Sub-Total	$ 4,659		
Vehicle Overhead						
Vehicle AO				$ 9 088		
			Sub-Total	$ 9,088		
Administrative Overhead						
Labor AO				$ 19,749		
Contract AO				$ 106,756		
			Sub-Total	$ 126,505		
			SUB-TOTAL (no AO, AFUDC)	$ 709,448		
			TOTAL (AO, AFUDC included)	$ 849,700		
Original Cost				$ 84,439		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 49788

Title: L5564 Replacements and Upgrades

Start Date:	2018/10
In-Service Date:	2018/12
Final Cost Date:	2019/06
Function Class:	Transmission
Forecast Amount:	$738,853

DESCRIPTION:

L-5564 is an 18 kilometer (89 structures) 69kV transmission line built in 1966, that connects 2S Victoria Junction to 11S Keltic Drive substations. This project is required to replace deteriorated assets and address ground clearance violations (as per CSA Standard 22.3) on approximately 75 structures that have been identified through Nova Scotia Power's transmission inspection program.

The project scope includes:

- Structure Replacements: 12 Structures
- Timber Arm Replacements: 1 Structure
- Timber Arm and Insulator Replacements: 34 Structures
- Pole and Insulator Replacements: 2 Structures
- Insulator Replacements: 24 Structures
- Other Deteriorated Assets: 2 Structures

Summary of Related CIs +/- 2 years**:**
No other projects in 2016, 2017, 2018, 2019 and 2020

JUSTIFICATION:

Justification Criteria: Transmission Plant

Sub Criteria: Equipment Replacement

Why do this project?

The transmission inspection program identified deteriorated assets that require replacement to avoid transmission interruptions. Not completing this project would compromise the reliable operation of this line.

Why do this project now?

This work has been prioritized based on transmission inspection results. This project is required to support the reliable operation and thermal rating of the transmission line.

Why do this project this way?

Replacing the existing deteriorated assets is more cost effective than rebuilding the entire line.

The contracts portion of this project will be sourced through NS Power's existing Power Line Technician (PLT) Service Agreement with Emera Utility Services. This is aligned with NS Power's workforce planning model which is designed to optimize the allocation and execution of PLT resources among work requirements.

CI Number : 49788 - L5564 Replacements and Upgrades **Project Number** 49788

Parent CI Number : -

Asset Location : 1455 - 1455 Transmission Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0700 - TP - Environmental	58,584
Additions	3500 - TP - Wood Poles	270,222
Additions	3800 - TP - Insulators	127,442
Additions	3900 - TP - O/H Cond.	207,480
Retirements	3500 - TP - Wood Poles	42,192
Retirements	3800 - TP - Insulators	32,933
	Total Cost:	738,853
	Original Cost:	83,422

Capital Project Detailed Estimate

Location: Transmission
CI# / FP#: 49788
Title: L5564 Replacements and Upgrades
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
T&D Labour - Electrician/Technician	PD	3	$ 360	$ 1,030		
T&D Labour - Site Supervision	PD	53	$ 385	$ 20,330		
Procurement / Financial Support	Lot	1	$ 1,392	$ 1,392		
				$ -		
			Sub-Total	$ 22,752		
Materials						
Poles, Anchors and Guys	Lot	1	$ 53,667	$ 53,667		
Insulators	Lot	1	$ 15,927	$ 15,927		
				$ -		
			Sub-Total	$ 69,594		
Contracts						
Contract Line Work	Hrs			$ 415,607		
Environmental Bridges and Mats	Lot	1	$ 42,353	$ 42,353		
Flagging	Lot	1	$ 5,000	$ 5,000		
Pole-Haulage	Lot	1	$ 5,400	$ 5,400		
Waste Disposal	Lot	1	$ 4,000	$ 4,000		
Survey	Lot	1	$ 2,000	$ 2,000		
				$ -		
			Sub-Total	$ 474,360		
Other Goods & Services						
Contingency	%	10%	$ 474,360	$ 47,436		
				$ -		
			Sub-Total	$ 47,436		
Interest Capitalized						
AFUDC				$ 5,204		
				$ -		
			Sub-Total	$ 5,204		
Vehicle Overhead						
Vehicle AO				$ 9,298		
			Sub-Total	$ 9,298		
Administrative Overhead						
Labour AO				$ 20,205		
Contract AO				$ 90,005		
			Sub-Total	$ 110,210		
			SUB-TOTAL (no AO, AFUDC)	$ 614,142		
			TOTAL (AO, AFUDC included)	$ 738,853		
Original Cost				$ 83,422		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 52059

Title: L5039 2018 Replacements and Upgrades

Start Date:	2018/03
In-Service Date:	2018/05
Final Cost Date:	2019/06
Function Class:	Transmission
Forecast Amount:	$719,825

DESCRIPTION:

This project will replace deteriorated assets on approximately 30 structures on L5039, a 9.5 kilometer (77 Structure) 69 kV transmission line, built in 1972, that connects the 103H Lakeside and 20H Spryfield substations. These deteriorated assets that have been identified for replacement through NS Power's transmission inspection program.

The project scope includes:

- Structure Replacements: 7 Structures
- Timber and Insulator Replacements: 6 Structures
- Insulator Replacement: 16 Structures
- Other Deteriorated Assets: 1 Structure

Summary of Related CIs +/- 2 years:
No other projects in 2016, 2017, 2018, 2019 or 2020

JUSTIFICATION:

Justification Criteria: Transmission Plant

Sub Criteria: Equipment Replacement

Why do this project?

The transmission inspection program identified deteriorated assets that require replacement to avoid transmission interruptions. Not completing this project would compromise the reliable operation of this line. Asset failures on this transmission line, a radial feed to 13,000 customers, could result in extended power outages.

Why do this project now?

This work has been prioritized based on transmission inspection results and is required to support the reliable operation of the transmission line.

This project is deemed in-service when the first portion of the work is complete (May 2018), therefore the Final Cost Date (June 2019) is listed as six months after the final work is completed (December 2018).

Why do this project this way?

Replacing the existing deteriorated assets is more cost effective than rebuilding the entire line.

The contracts portion of this project will be sourced through NS Power's existing Power Line Technician (PLT) Service Agreement with Emera Utility Services. This is aligned with NS Power's workforce planning model which is designed to optimize the allocation and execution of PLT resources among work requirements.

CI Number : 52059 - L5039 - 2018 Replacements and Upgrades **Project Number** 52059

Parent CI Number : -

Asset Location : 1455 - 1455 L5039 Halifax Regional Municipality **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0700 - TP - Environmental	41,853
Additions	3500 - TP - Wood Poles	213,199
Additions	3800 - TP - Insulators	88,068
Additions	3900 - TP - O/H Cond.	297,040
Retirements	3500 - TP - Wood Poles	19,773
Retirements	3800 - TP - Insulators	24,199
Retirements	3900 - TP - O/H Cond.	35,692
	Total Cost:	719,825
	Original Cost:	105,784

Capital Project Detailed Estimate

Location: Transmission
CI# / FP#: 52059
Title: L5039 2018 Replacements and Upgrades
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
T&D Labor - Electrician/Technician	PD	3	$ 360	$ 1,071		
T&D Labor - Site Supervision	PD	35	$ 385	$ 13,362		
Procurement / Financial Support	Lot	1	$ 910	$ 910		
			Sub-Total	$ 15,343		
Materials						
Poles	Lot	1	$ 32,443	$ 32,443		
Insulators	Lot	1	$ 13,048	$ 13,048		
			Sub-Total	$ 45,491		
Contracts						
Contract Line Work	Hrs.	[redacted]		$ 399,671		
Environmental Bridges and Mats	Lot	1	$ 31,008	$ 31,008		
Flagging	Lot	1	$ 10,000	$ 10,000		
Pole-Haulage	Lot	1	$ 6,000	$ 6,000		
Rock break	Lot	1	$ 4,000	$ 4,000		
Waste Disposal	Lot	1	$ 8,000	$ 8,000		
Misc.	Lot	1	$ 36,000	$ 36,000		
			Sub-Total	$ 494,679		
Other Goods & Services						
Contingency	%	10%	$ 494,679	$ 49,468		
				$ -		
			Sub-Total	$ 49,468		
Interest Capitalized						
AFUDC				$ 1,089		
			Sub-Total	$ 1,089		
Vehicle Overhead						
Vehicle AO				$ 6,270		
			Sub-Total	$ 6,270		
Administrative Overhead						
Labor AO				$ 13,625		
Contract AO				$ 93,860		
			Sub-Total	$ 107,485		
			SUB-TOTAL (no AO, AFUDC)	$ 604,981		
			TOTAL (AO, AFUDC included)	$ 719,825		
Original Cost				$ 105,784		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 49783

Title: L5027A Replacements and Upgrades

Start Date: 2018/01
In-Service Date: 2018/03
Final Cost Date: 2018/09
Function Class: Transmission
Forecast Amount: $648,292

DESCRIPTION:

L-5027A is a 50 kilometer section of L-5027 (a 69 kV transmission line), built in 1980. It runs from 9W Tusket to 21W Lower Woods Harbour substations. This project is required to replace deteriorated assets on approximately 55 structures, as identified through Nova Scotia Power's transmission inspection program.

The project scope includes:

- Structure Replacements: 9 Structures
- Timber Arm Replacements: 22 Structures
- Timber Arm and Insulator Replacements: 1 Structure
- Pole Replacement: 1 Structure
- Pole and Timber Arm Replacements: 12 Structures
- Insulator Replacements: 1 Structure
- Other Deteriorated Assets: 9 Structures

Summary of Related CIs +/- 2 years:
2017 CI 49782 L5027B Replacements and Upgrades $1,093,542
2017 CI 49922 Western Switching Upgrades $378,843

JUSTIFICATION:

Justification Criteria: Transmission Plant

Sub Criteria: Equipment Replacement

Why do this project?

The transmission inspection program identified deteriorated assets that require replacement to avoid transmission interruptions. Not completing this project would compromise the reliable operation of this line.

Why do this project now?

This work has been prioritized based on transmission inspection results. This project is required to support the reliable operation of the transmission line.

Why do this project this way?

Replacing the existing deteriorated assets is more cost effective than rebuilding the entire line.

The contracts portion of this project will be sourced through NS Power's existing Power Line Technician (PLT) Service Agreement with Emera Utility Services. This is aligned with NS Power's workforce planning model which is designed to optimize the allocation and execution of PLT resources among work requirements.

CI Number : 49783 - L5027A Replacements and Upgrades **Project Number** 49783

Parent CI Number : -

Asset Location : 1455 - 1455 Transmission Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0700 - TP - Environmental	125,182
Additions	3500 - TP - Wood Poles	283,510
Additions	3800 - TP - Insulators	50,489
Additions	3900 - TP - O/H Cond.	140,569
Retirements	3500 - TP - Wood Poles	48,054
Retirements	3800 - TP - Insulators	209
Retirements	3900 - TP - O/H Cond.	279
	Total Cost:	648,292
	Original Cost:	161,443

Capital Project Detailed Estimate

Location: Transmission
CI# / FP#: 49783
Title: L5027A Replacements and Upgrades
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
T&D Labour - Electrician/Technician	PD	2	$ 360	$ 857		
T&D Labour - Site Supervision	PD	36	$ 385	$ 13,836		
Procurement / Financial Support	Lot	1	$ 1,966	$ 1,966		
				$ -		
			Sub-Total	$ 16,659		
Materials						
Poles, Anchors and Guys	Lot	1	$ 98,126	$ 98,126		
Insulators	Lot	1	$ 195	$ 195		
				$ -		
			Sub-Total	$ 98,322		
Contracts						
Contract Line Work	Hrs	[redacted]		$ 282,841		
Environmental Bridges and Mats	Lot	1	$ 94,386	$ 94,386		
Flagging	Lot	1	$ 5,000	$ 5,000		
Pole-Haulage	Lot	1	$ 6,600	$ 6,600		
Waste Disposal	Lot	1	$ 5,000	$ 5,000		
				$ -		
			Sub-Total	$ 393,827		
Other Goods & Services						
Contingency	%	10%	$ 393,827	$ 39,383		
				$ -		
			Sub-Total	$ 39,383		
Interest Capitalized						
AFUDC				$ 3,774		
			Sub-Total	$ 3,774		
Vehicle Overhead						
Vehicle AO				$ 6,808		
			Sub-Total	$ 6,808		
Administrative Overhead						
Labour AO				$ 14,794		
Contract AO				$ 74,725		
				$ -		
			Sub-Total	$ 89,519		
			SUB-TOTAL (no AO, AFUDC)	$ 548,191		
			TOTAL (AO, AFUDC included)	$ 648,292		
Original Cost				$ 161,443		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 52119

Title: L5054 2018 Replacements and Upgrades

Start Date:	2018/10
In-Service Date:	2018/11
Final Cost Date:	2019/05
Function Class:	Transmission
Forecast Amount:	$560,143

DESCRIPTION:

L5054 is a 23 kilometer (86 Structure) 69kV transmission line, built in 1982, that connects the 16V Weymouth and 93V Saulnierville substations. This project is required to replace deteriorated assets that have been identified through NS Power's transmission inspection program. This will include the replacement of deteriorated assets on approximately 29 structures.

The project scope includes:

- Structure Replacements: 9 Structures
- Pole and Insulator Replacements: 2 Structures
- Timber and Insulator Replacements: 10 Structures
- Other Deteriorated Assets: 8 Structures

Summary of Related CIs +/- 2 years:
No other projects in 2016, 2017, 2018, 2019 or 2020

JUSTIFICATION:

Justification Criteria: Transmission Plant

Sub Criteria: Equipment Replacement

Why do this project?

The transmission inspection program identified deteriorated assets that require replacement to avoid transmission interruptions. Not completing this project would compromise the reliable operation of this line. This transmission line is a radial feed to 4,300 customers. Asset failures on this line would result in extended power outages.

Why do this project now?

This work has been prioritized based on transmission inspection results. This project is required to support the reliable operation of the transmission line.

Why do this project this way?

Replacing the existing deteriorated assets is more cost effective than rebuilding the entire line.

The contracts portion of this project will be sourced through NS Power's existing Power Line Technician (PLT) Service Agreement with Emera Utility Services. This is aligned with NS Power's workforce planning model which is designed to optimize the allocation and execution of PLT resources among work requirements.

CI Number : 52119 - L5054 2018 Replacements and Upgrades

Project Number 52119

Parent CI Number : -

Asset Location : 1455 - 1455 Transmission Plant General

Budget Version 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0700 - TP - Environmental	22,647
Additions	3500 - TP - Wood Poles	193,177
Additions	3800 - TP - Insulators	52,874
Additions	3900 - TP - O/H Cond.	256,031
Retirements	3500 - TP - Wood Poles	22,243
Retirements	3800 - TP - Insulators	13,170
	Total Cost:	560,143
	Original Cost:	160,515

Capital Project Detailed Estimate

Location: **Transmission**
CI# / FP#: 52119
Title: L5054 2018 Replacements and Upgrades
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
T&D Labor - Electrician/Technician	PD	2	$ 366	$ 817		
T&D Labor - Site Supervision	PD	30	$ 389	$ 11,785		
Procurement / Financial Support	Lot	1	$ 1,017	$ 1,017		
			Sub-Total	$ 13,619		
Materials						
Poles	Lot	1	$ 43 027	$ 43 027		
Insulator	Lot	1	$ 7 819	$ 7 819		
			Sub-Total	$ 50 846		
Contracts						
Contract Line Work	Hrs.	[redacted]		$ 345 539		
Flagging	Lot	1	$ 2 250	$ 2 250		
Pole Haulage	Lot	1	$ 4 400	$ 4 400		
Waste Disposal	Lot	1	$ 1,500	$ 1,500		
Environmental Services	Lot	1	$ 16,941	$ 16,941		
			Sub-Total	$ 370,631		
Other Goods & Services						
Contingency	%	10%	$ 370,631	$ 37,063		
			Sub-Total	$ 37,063		
Vehicle Overhead						
Vehicle Allocated Costs				$ 5,566		
			Sub-Total	$ 5,566		
Administrative Overhead						
Labor AO				$ 12,094		
Contract AO				$ 70,323		
			Sub-Total	$ 82,418		
			SUB-TOTAL (no AO, AFUDC)	$ 472 159		
			TOTAL (AO, AFUDC included)	$ 560,143		
Original Cost				$ 160 515		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 52238

Title: 2018/2019 Capacitor Bank Breaker Replacements

Start Date: 2018/01
In-Service Date: 2019/01
Final Cost Date: 2019/10
Function Class: Transmission
Amount: $433,719

DESCRIPTION:

This project will retire and replace three capacitor bank breakers:

• 103H-439 Lakeside: 37 years old
• 104H-419 Kempt Road: 37 years old
• 101H-461 Cobequid Rd.: 46 years old

Capacitor bank breakers are used by system operators to control voltage on the transmission system. Breaker replacements are prioritized based on age, number of operations, maintenance history and criticality to the transmission system. Engineering, design and procurement will occur throughout 2018, with replacement scheduled for 2019.

Summary of Related CIs +/- 2 years:
2016 CI 48063 2016/2017 Capacitor Bank Breaker Replacements $385,850
2017 CI 49798 2017/2018 Capacitor Bank Breaker Replacements $ 378,150
2019 CI TBD 2019/2020 Capacitor Bank Breaker Replacements $ TBD
2020 CI TBD 2020/2021 Capacitor Bank Breaker Replacements $ TBD

JUSTIFICATION:

Justification Criteria: Transmission Plant

Why do this project?

There are currently 28 capacitor bank breakers on the transmission system. These breakers are critical to the operation of the transmission system as they are used to control the system voltage. These breakers are operated frequently and, as a result, see higher duty cycles compared to line breakers. This higher duty cycle increases the probability of failure in these devices. Issues on capacitor bank breakers in the Halifax area were discovered as a result of NS Power's preventative maintenance inspection program. This project decreases the probability of failure by replacing those most at risk.

Why do this project now?

To ensure the reliable operation of the transmission system, a capacitor bank breaker replacement program is required.

In 2014, issues on capacitor bank breakers in the Halifax area were discovered as a result of NS Power's preventative maintenance inspection program. In these instances, high contact resistance was identified and subsequent thermal imaging showed elevated temperatures on the affected poles. As these breakers can be operated multiple times per day, replacing three breakers at this time is the prudent decision to reduce the risk of failure. Failure of these devices could result in voltage issues on the transmission system.

This project is deemed in-service when the first breaker is replaced (January 2019), therefore the Final Cost Date (October 2019) is listed as six months after the last pole top transformer is installed under this project (April 2018).

Why do this project this way?

Due to the age of the breakers refurbishment is not an option. Accordingly, replacement is the recommended option.

CI Number : 52238 - 2018/2019 Capacitor Bank Breaker Replacements **Project Number** 52238

Parent CI Number : -

Asset Location : 1455 - 1455 Transmission Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0300 - TP - Bldg.,Struct.Grnd.	47,543
Additions	2200 - TP - Elec Contr.Equip.	61,642
Additions	3900 - TP - O/H Cond.	9,921
Additions	4300 - TP - Substn Dev.	299,975
Retirements	4300 - TP - Substn Dev.	14,638
	Total Cost:	433,719
	Original Cost:	123,379

Capital Project Detailed Estimate

Location: Transmission
CI# / FP#: 52238
Title: 2018/2019 Capacitor Bank Breaker Replacements
Execution Year: 2018-2019

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
T&D Labor - Electrician/Technician	PD	70	$ 366	$ 25,594		
Procurement / Financial Support	Lot	1	$ 3,056	$ 3,056		
Engineering Design	PD	110	$ 386	$ 42,267		
Field Supervision Civil Contracts	Lot	1	$ 2,027	$ 2,027		
			Sub-Total	$ 72,944		
Travel						
Travel	Lot	1	$ 185	$ 185		
			Sub-Total	$ 185		
Materials						
Ground Connectors	Lot	2	$ 210	$ 420		
Control Cables	Meter	800	$ 10	$ 8,000		
Misc. Conduit/ Connectors	Lot	1	$ 90	$ 90		
Control Panel Mod's	Lot	1	$ 10,000	$ 10,000		
JBOX	ea.	2	$ 1,000	$ 2,000		
Conductor and misc. Connectors	Lot	1	$ 5,080	$ 5,080		
Circuit Breaker and Breaker Trip Coils	ea.	3	$ 41,350	$ 124,050		
Surge Arrestors	ea.	6	$ 2,000	$ 12,000		
	ea.					
			Sub-Total	$ 161,640		
Contracts						
Concrete Foundations	ea.	3	$ 5,000	$ 15,000		
Installation of Breaker	Hour	230	$ 100	$ 23,000		
Civil Conduit, Grounding, Backfill	Lot	1	$ 10,650	$ 10,650		
EUS Conductor Labor	Lot	1	$ 3,600	$ 3,600		
Boom Truck Services	Lot	1	$ 3,475	$ 3,475		
			Sub-Total	$ 55,725		
Contingency						
Contingency	%	10%	$ 290,494	$ 29,049		
			Sub-Total	$ 29,049		
Vehicle Overhead						
Vehicle AO				$ 29,809		
			Sub-Total	$ 29,809		
Interest Capitalized						
AFUFC				$ 9,016		
			Sub-Total	$ 9,016		
Administrative Overhead						
Labor AO				$ 64,777		
Contract AO				$ 10,573		
			Sub-Total	$ 75,350		
			SUB-TOTAL (no AO, AFUDC)	$ 319,544		
			TOTAL (AO, AFUDC included)	$ 433,719		
Original Cost				$ 123,379		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 43268

Title: 9W-B53 Tusket Support Structure Replacement

Start Date: 2018/02
In-Service Date: 2018/11
Final Cost Date: 2019/05
Function: Transmission
Forecast Amount: $375,523

DESCRIPTION:

The scope of this project is to replace the six wood poles and associated wooden cross arms which make up the support structure for the 9W-B53 69kV bus at the 9W Tusket substation.

Summary of Related CIs (+ / - 2 years):
No other projects in 2016, 2017, 2018, 2019 or 2020

JUSTIFICATION:

Justification Criteria: Transmission Plant

Sub Criteria: Pole Strength

Why do this project?

This project is necessary because the existing wood support structure for 9W-B53 is in a deteriorated state. The 9W-B53 structure is constructed of wood poles and cross arms that support switches and take-offs for transmission lines L5534, L5535 and L5027 located in the western part of the province. Also connected to this structure is the 69kV supply to bus B53 from transformer 9W-T63 and capacitor bank 9W-C52. These wood poles and cross arms were originally installed in 1966 and are now over 50 years old. Failure of this structure would impact the reliability of the transmission system by limiting switching capability.

Why do this project now?

The wooden support structure has reached the end of its useful life and further delay in replacement may jeopardize the ability of the structure to support the associated buswork. This project is required to support the reliable operation of the transmission system.

Why do this project this way?

Replacement of the support structure with ‘like for like’ wooden material is more cost effective than replacement with steel structures.

CI Number : 43268 - 9W-B53 Tusket Support Structure Replacement **Project Number** 43268

Parent CI Number : -

Asset Location : 1455 - 1455 Transmission Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	3500 - TP - Wood Poles	253,323
Additions	4300 - TP - Substn Dev.	52,881
Retirements	3500 - TP - Wood Poles	69,318
	Total Cost:	375,523
	Original Cost:	41,245

Capital Project Detailed Estimate

Location: Transmission
CI# / FP#: 43268
Title: 9W-B53 Tusket Support Structure Replacement
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
T&D Labour - PLT	PD	210	$ 372	$ 78,166		
T&D Labour - Electrician/Technician	PD	36	$ 366	$ 13,163		
T&D Labour - Design	PD	26	$ 386	$ 9,843		
Procurement / Financial Support	Lot	1	$ 1,246	$ 1,246		
				$ -		
			Sub-Total	$ 102,418		
OT Labour						
T&D Labour - PLT	PD	42	$ 744	$ 31,269		
			Sub-Total	$ 31,269		
Travel Expense						
Travel	Lot	1	$ 222	$ 222		
			Sub-Total	$ 222		
Materials						
Poles	Lot	1	$ 46,800	$ 46,800		
Substation Devices	Lot	1	$ 14,265	$ 14,265		
			Sub-Total	$ 61,065		
Contracts						
Poles	Lot	1	$ 6,240	$ 6,240		
			Sub-Total	$ 6,240		
Other Goods & Services						
Contingency	%	10%	$ 169,723	$ 16,972		
			Sub-Total	$ 16,972		
Vehicle Overhead						
Vehicle Allocated Costs				$ 48,243		
			Sub-Total	$ 48,243		
Administrative Overhead						
Labour AO				$ 104,834		
Contracts AO				$ 1,184		
			Sub-Total	$ 106,018		
Interest Capitalized						
Interest				$ 3,075		
			Sub-Total	$ 3,075		
			SUB-TOTAL (no AO, AFUDC)	$ 218,186		
			TOTAL (AO, AFUDC included)	$ 375,523		
Original Cost				$41,245		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 51797

Title: 2018 Oil Containment Program

Start Date: 2018/05
In-Service Date: 2018/12
Final Cost Date: 2019/06
Function: Transmission
Forecast Amount: $331,507

DESCRIPTION:

The Oil Containment Program began in 2016 to mitigate the risk of oil from substation transformers being released to the local environment. NS Power completed a survey of the main power transformers without an oil containment system. The sites were also reviewed to determine their proximity to sensitive environmental sites, such as watercourses and wetlands, along with the presence of pathways for contaminants to reach the receptors. From these environmental risk assessments, a prioritized list of substation sites has been developed for retrofitting oil containment systems, thereby reducing the environmental risk. The 2018 project includes the installation of six oil containment systems at four substation main power transformer sites. The overall program is planned for completion in 2021.

In 2013, Nova Scotia Environment released the Contaminated Sites Regulations which outlines new cleanup criteria for spills, increasing cleanup and assessment costs. Cleanups and ongoing assessment costs for oil releases from substation transformers can account for a significant cost to NS Power. These regulations can be found at the following link:https://www.novascotia.ca/just/regulations/regs/envcontsite.htm.

Summary of Related CIs +/- 2 years:
2016 CI 48067 2016 Oil Containment Program $468,963
2017 CI 49833 2017 Oil Containment Program $432,518
2019 CI TBD 2019 Oil Containment Program $TBD
2020 CI TBD 2020 Oil Containment Program $TBD

JUSTIFICATION:

Justification Criteria: Environment

Why do this project?

NS Power has identified that there is risk of oil from substation transformers being released to nearby sensitive environmental areas at locations that currently do not have oil containment systems. Installation of oil containment systems will reduce the risk to the environment and public safety surrounding these substations.

This project is primarily justified under environment, and secondarily justified under safety.

Why do this project now?

Proactively adding oil containment systems to the highest environmental risk sites will mitigate the risk of costs associated with oil spill cleanups and will protect these adjacent areas from possible contamination.

Why do this project this way?

A total of 303 sites were evaluated for this project. Approximately 76 of these have known environmentally sensitive areas in the immediate vicinity that are at risk for possible contamination should an oil release occur. NS Power then identified the 30 sites which had the highest risk of pathways to be created between the potential contamination and the receptors. These are the sites to be addressed in this program.

Installation of oil containment was completed at five sites in the 2016 Oil Containment Program (CI #48067) and will be completed at four sites in the 2017 Oil Containment Program (CI #49833). The 2018 project includes the installation of six oil containment systems at four substation main power transformer sites. The overall program is planned for completion in 2021. Installing oil containment in these highest risk sites, using a prioritized approach, will reduce the risk of oil being released from NS Power's substations to nearby sensitive areas.

CI Number : 51797 - 2018 Oil Containment Program **Project Number** 51797

Parent CI Number : -

Asset Location : 1455 - 1455 Transmission Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0700 - TP - Environmental	331,507
	Total Cost:	331,507
	Original Cost:	

Capital Project Detailed Estimate

Location: **Transmission**
CI# / FP#: 51797
Title: 2018 Oil Containment Program
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
T&D Labor - Design	PD	44	$ 382	$ 16,863		
Procurement / Financial Support	Lot	1	$ 1,937	$ 1,937		
			Sub-Total	$ 18,800		
Materials						
Polyvinyl Oil Containment Materials	Lot	1	$ 96,841	$ 96,841		
			Sub-Total	$ 96,841		
Contracts						
Polyvinyl Oil Containment Installation	Lot	1	$ 96,841	$ 96,841		
Field Supervision (Civil)	hr.	480	$ 82	$ 39,360		
			Sub-Total	$ 136,201		
Other Goods & Services						
Contingency	%	10%	$ 233,042	$ 23,304		
			Sub-Total	$ 23,304		
Interest Capitalized						
AFUDC				$ 6,141		
			Sub-Total	$ 6,141		
Vehicle Overhead						
Vehicle AO				$ 7,683		
				$ -		
			Sub-Total	$ 7,683		
Administrative Overhead						
Labor AO				$ 16,695		
Contract AO				$ 25,843		
				$ -		
			Sub-Total	$ 42,538		
			SUB-TOTAL (no AO, AFUDC)	$ 275,146		
			TOTAL (AO, AFUDC included)	$ 331,507		
Original Cost				$ -		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 52305

Title: 2018 Substation Insulator Replacement Program

Start Date:	2018/02
In-Service Date:	2018/02
Final Cost Date:	2019/05
Function:	Transmission
Forecast Amount:	$316,348

DESCRIPTION:

The aim of this project is to identify the remaining installations of Canadian Porcelain and Canadian Ohio Brass insulators at substations, and remove them from service, replacing them with new insulators. This budget is based on replacing 603 substation insulators, identified through scoping activities completed to date.

Summary of Related CIs +/- 2 years:
2016 CI 48151 2016 Substation Insulator Replacement Program $244,828
2017 CI 49878 2017 Substation Insulator Replacement Program $508,893
2019 CI TBD 2019 Substation Insulator Replacement Program $TBD
2020 CI TBD 2020 Substation Insulator Replacement Program $TBD

JUSTIFICATION:

Justification Criteria: Transmission Plant

Why do this project?

In past years, NS Power has experienced reliability issues with strain insulators manufactured by Canadian Porcelain and Canadian Ohio Brass. These insulators are vulnerable to cement growth, an issue in which the cement used to seal the insulator begins to absorb moisture and swell, eventually leading to electrical and mechanical failure. These insulators can be found inside substations and on transmission lines, where failure can lead to lines being dropped to the ground, or on energized equipment, potentially leading to extensive outages and/or damage to equipment. These insulators are well known in the industry for being prone to failure. Replacing them proactively will prevent unnecessary outages and damage to equipment.

Why do this project now?

These insulators have been known to be an issue within the utility industry for several years. Installations of this type of insulator at substations have been identified and they should be replaced as soon as possible to avoid unnecessary outages.

This project is forecast to be in-service once the first insulator is replaced (February 2018), therefore the forecast Final Cost date (May 2019) is six months after the last structure is forecast to be replaced (November 2018).

Why do this project this way?

Replacing the existing defective insulators with the new insulators is the only option.

The contracts portion of this project will be sourced through NS Power's existing Power Line Technician (PLT) Service Agreement with Emera Utility Services. This is aligned with NS Power's workforce planning model which is designed to optimize the allocation and execution of PLT resources among work requirements.

CI Number	: 52305	- 2018 Substation Insulator Replacement Program	**Project Number**	52305
Parent CI Number	:	-		
Asset Location	: 1455	- 1455 Transmission Plant General	**Budget Version**	2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	3800 - TP - Insulators	246,629
Retirements	3800 - TP - Insulators	69,718
	Total Cost:	316,348
	Original Cost:	31,919

Capital Project Detailed Estimate

Location: Transmission
CI# : 52305
Title: 2018 Substation Insulator Replacement Program
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
T&D Labor - Electrician/Technician	PD	127	$ 360	$ 45,720		
Procurement / Financial Support	Lot	1	$ 3,515	$ 3,515		
			Sub-Total	$ 49,235		
OT Labor						
T&D Labor - Electrician/Technician	PD	24	$ 720	$ 17,280		
			Sub-Total	$ 17,280		
Travel Expense						
Travel	Lot	1	$ 4,717	$ 4,717		
				$ -		
			Sub-Total	$ 4,717		
Materials						
Insulators	Lot	1	$ 50,603	$ 50,603		
Contractors	Lot	1	$ 42,353	$ 42,353		
Jumper Wire	Lot	1	$ 15,415	$ 15,415		
			Sub-Total	$ 108,371		
Contracts						
Contract Line Labor	HR	[redacted]		$ 20 488		
Boom Truck	Lot	1	$ 13,812	$ 13,812		
				$ -		
			Sub-Total	$ 34,300		
Meals & Entertainment						
Meals	Lot	1	$ 1,700	$ 1,700		
				$ -		
			Sub-Total	$ 1,700		
Other Goods & Services						
Contingency	%	10%	$ 191,906	$ 19,191		
				$ -		
			Sub-Total	$ 19,191		
Vehicle Overhead						
Vehicle AO				$ 23,651		
			Sub-Total	$ 23,651		
Administrative Overhead						
Labor AO				$ 51,395		
Contract AO				$ 6,508		
			Sub-Total	$ 57,903		
			SUB-TOTAL (no AO, AFUDC)	$ 234,794		
			TOTAL (AO, AFUDC included)	$ 316,348		
Original Cost				$ 31,919		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 51863

Title: 2018 Tap Changer Replacements/Refurbishments

Start Date: 2018/05
In-Service Date: 2018/06
Final Cost Date: 2018/12
Function: Transmission
Forecast Amount: $306,102

DESCRIPTION:

This project is the second year of a multiple year program to refurbish aging tap changers at substations throughout the province. The scope of the 2018 project is to refurbish the tap changers on the following six transformers: 113H-T63 (Dartmouth East), 43V-T61 (Canaan Road), 91H-T62 (Tufts Cove), 131H-T62 (Lucasville), 79N-T81 (Hopewell) and 120H-T72 (Brushy Hill). The transformers completed under this project may vary due to changing priorities. This program is expected to be complete in 2020.

Summary of Related CIs +/- 2 years:
2017 CI 49929 2017 Tap Changer Replacements $318,236

JUSTIFICATION:

Justification Criteria: Transmission Plant

Sub Criteria: Equipment Replacement

Why do this project?

Tap changers are critical pieces of equipment to the NS Power transmission system. Tap changers are required to match transformer voltages to the system voltage and refurbishment of these devices is required to support the reliable operation of the transmission system. A tap changer failure could lead to outages or power quality issues for customers.

NS Power, in consultation with the tap changer manufacturer, developed a plan for tap changer refurbishment based on the number of operations (i.e. the number of times the tap changer has operated to match the transformer voltage to the system voltage), age of unit, available outage windows, type of tap changer, and long term replacement plans for transformers. Details on the tap changers planned for 2018 are given below (data as of May 2017):

Asset	Description	Location	Manu. Year	Ops Count	Serial #
101064	TAPCHANGER, 138, M	113H-T63	1989	89,177	184874
104452	TAPCHANGER, 69, 400, D1-400	43V-T61	1969	Manual	46128
109178	TAPCHANGER, 138, 500, M111D500-11OC	91H-T62	1981	5,699	86951
101630	TAPCHANGER, 138, 350, M111D350	131H-T62	1989	47,812	184875
107488	TAPCHANGER, 345, , M1-802-150/B	79N-T81	1991	13,034	184755
101411	TAPCHANGER, 230, , MI1200	120H-T72	1978	41,164	83868

Why do this project now?

The six targeted tap changers are due for refurbishment based on the number of operations (i.e. the number of times the tap changer has operated to match the transformer voltage to the system voltage), age of unit, maintenance schedules, available outage windows, type of tap changer, and long term replacement plan for transformers.

Why do this project this way?

The refurbishment of the tap changers under this project are being completed per the OEM's recommendation. Technicians from the tap changer manufacturer will complete the refurbishment of several components with the assistance of NS Power technicians/electricians. The project requires experience and knowledge of rebuilding these complex assets and therefore it is most efficient to engage the manufacturer to complete the work.

CI Number : 51863 - 2018 Tap Changer Replacements/Refurbishments **Project Number** 51863

Parent CI Number : -

Asset Location : 1455 - 1455 Transmission Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	4400 - TP - Substn.Transf.	306,102
	Total Cost:	306,102
	Original Cost:	132,148

Capital Project Detailed Estimate

Location: Transmission
CI# : 51863
Title: 2018 Tap Changer Replacements/Refurbishments
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
T&D Labor - Electrician / Technician	PD	155	$ 358	$ 55,534		
			Sub-Total	$ 55,534		
Materials						
Tap Changers	ea.	6	$ 5,036	$ 30,216		
Oil & Shop Supplies	Lot	1	$ 12,000	$ 12,000		
			Sub-Total	$ 42,216		
Contracts						
Boom Rental	Lot	1	$ 6,000	$ 6,000		
Tap Changer Overhaul (Manufacturer)	ea.	6	$ 16,073	$ 96,439		
			Sub-Total	$ 102,439		
Other Goods & Services						
Contingency	%	10%	$ 144,655	$ 14,466		
			Sub-Total	$ 14,466		
Vehicle Overhead						
Vehicle AO				$ 22,695		
			Sub-Total	$ 22,695		
Administrative Overhead						
Labor AO				$ 49,316		
Contract AO				$ 19,437		
			Sub-Total	$ 68,753		
			SUB-TOTAL (no AO, AFUDC)	$ 214,655		
			TOTAL (AO, AFUDC included)	$ 306,102		
Original Cost				$ 132,148		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: C0001950

Title: New Distribution Rights-of-Way Phase 3

Start Date: 2018/03
In-Service Date: 2018/03
Final Cost Date: 2019/12
Function Class: Distribution
Amount: $9,822,493

DESCRIPTION

This project is to establish new rights-of-way for distribution feeders where none have previously existed on targeted circuits, and where current vegetation management maintenance practices have limited impact on preventing off right-of-way tree contacts. The new rights-of-way will primarily be established adjacent to the road right-of-way edge, where the majority of distribution feeders are currently located and bordered by vegetation.

The total New Distribution Rights-of-Way program is estimated to be between $80 million and $97 million. NS Power anticipates the 10 year program will cost approximately $8 million to $10 million annually to complete.

The targeted circuits expected to be included in this project, subject to change based on factors such as feeder performance, permissions, and easements, are:

11S-301 - Barrachois/Balls Creek	1N-405 - Valley	4C-424 - Antigonish/North Grant
30N-412 - River Herbert	12V-304 - Lequille	62N-413 - Brookville/Thorburn
50N-410 - Stellerton	15N-403 - Hilden	62N-414 - Alma/Greenhill
56N-401 - Pictou/Bayview	1N-402 - Pleasant Valley/Urbania	62N-416 - Union Center
57C-422 - Giants Lake	23W-302 - Clyde River	96H-411 - Sheet Harbour
57S-401 - Albert Bridge/Catalone	25W-301 - Ohio	78C-311 - Guysborough Intervale
59C-402 - St Peters	4C-430 - Salt Springs/West River	88H-401 - Musquodboit
67C-411 -Mabou/Miramichi	4N-311 - Malagash	88H-402 - Moose River
7N-301 - Pugwash	4N-312 - Tatamagouche	92W-302 - Kemptville
85S-402 - Tarbot	62N-415 - Eureka/Stellerton	

Summary of Related CIs +/- 2 years:
2016 CI 49611 New Distribution Rights-of-Way Phase 1 $2,215,397
2017 CI 50796 New Distribution Rights-of-Way Phase 2 $3,353,445
2019 CI TBD New Distribution Rights-of-Way Phase 4 $TBD
2010 CI TBD New Distribution Rights-of-Way Phase 5 $TBD

Depreciation Class: –Distribution Plant- Land Rights- Easements, Surveys and Clearing

JUSTIFICATION:

Justification Criteria: Distribution System

Sub Criteria: Outage Performance

Why do this project?

Tree contacts are the leading cause of outages, both during non-storm and storm events. Over the last five years, tree contacts have caused over 15,300 outage events, 1.54 million customer interruptions and 8.45 million customer hours of interruption, which represents 27 percent, 23 percent and 38 percent of their totals, respectively. Approximately 80 percent of these tree contacts are caused by fallen trees from outside the right-of-way. The vegetation management practices performed under NS Power's maintenance program target vegetation within the rights-of-way and maintain existing, sustainable rights-of-way. These activities prevent tree growth from causing outages, but do not address edge or off right-of-way trees. Establishing new rights-of-way will reduce the occurrence of edge and off right-of-way tree contacts by increasing the separation between trees and distribution feeders.

Why do this project now?

During the Post-Tropical Storm Arthur Review (M06321), the Board's consultant, Liberty Consulting Group (Liberty) recommended NS Power accelerate the Distribution Right-of-Way sustainability efforts in order to achieve additional reliability benefits during major storm events. As set out in NS Power's February 13, 2015 Stakeholder Consultation Report, there was general stakeholder support for accelerating the sustainability program.

A focus on removing trees within and along the edge of the NSTIR rights-of-way will result in more immediate improvements in reliability and require less reactive maintenance going forward. Proactive establishment of new distribution rights-of-way will further improve customer reliability during major and extreme weather events.

This project is forecast to be in-service when the first right of way is widened (March 2018), therefore the Final Cost date (December 2019) is six months after the last new right of way is forecast to be established (June 2019).

Although CI 50796 - New Distribution Rights-of-Way Phase 2 – P&A was advanced due to the effective date of the Performance Standards of January 1, 2017, this project, and the broader capital program going forward, are not driven primarily by a need to achieve the reliability metrics under the Performance Standards, they are primarily driven by the findings of the Post-Tropical Storm Arthur Review as noted above, and general continuous improvements to customer reliability.

Why do this project this way?

Liberty's report on its review of NS Power's response to Post-Tropical Storm Arthur included the recommendation that, for distribution rights-of-way, NS Power should "develop a comprehensive plan for reclaiming and/or widening the overgrown ROW corridors". [1]

The distribution vegetation management program will be carried-out under three broad initiatives:

(1) Operating activities for distribution vegetation management
(2) Capital Routine D010 - Distribution Right-of-Way Widening
(3) New Distribution Right-of-Ways individual capital projects (i.e. CI 49611, CI 50796, and CI C0001950)

Taken together, these initiatives will address the findings of the Post-Tropical Storm Arthur proceeding. The scope of work to be completed under this CI and subsequent phases is to establish new rights-of-way where none have previously existed. The new rights-of-way will primarily be established adjacent to the road right-of-way edge, where the majority of distribution feeders are currently located and bordered by vegetation.

[1] Review of Nova Scotia Power Inc.'s (NSPI) state of preparedness and response to Post-Tropical Storm Arthur, M06321, Liberty Consulting Group, Comments on Review of NS Power's Storm Response, Exhibit A-4, September 9, 2014, page 7.

CI Number : C0001950 - New Distribution Rights-of-Way Phase 3 **Project Number** C0001950

Parent CI Number : -

Asset Location : 1456 - 1456 Distribution Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0200 - DP - Land Rights	9,822,493
	Total Cost:	9,822,493
	Original Cost:	

Capital Project Detailed Estimate

Location: **Distribution**
CI# / FP#: C0001950
Title: New Distribution Rights-of-Way Phase 3
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Contracts						
11S-301	km	15	$ 20,142	$ 302,130		
30N-412	km	5	$ 20,142	$ 100,710		
50N-410	km	5	$ 20,142	$ 100,710		
56N-401	km	25	$ 20,142	$ 503,550		
57C-422	km	30	$ 20,142	$ 604,260		
57S-401	km	15	$ 20,142	$ 302,130		
59C-402	km	5	$ 20,142	$ 100,710		
67C-411	km	10	$ 20,142	$ 201,420		
7N-301	km	10	$ 20,142	$ 201,420		
85S-402	km	4	$ 20,142	$ 80,568		
1N-405	km	5	$ 20,142	$ 100,710		
12V-304	km	10	$ 20,142	$ 201,420		
15N-403	km	10	$ 20,142	$ 201,420		
1N-402	km	20	$ 20,142	$ 402,840		
23W-302	km	15	$ 20,142	$ 302,130		
25W-301	km	25	$ 20,142	$ 503,550		
4C-430	km	25	$ 20,142	$ 503,550		
4N-311	km	15	$ 20,142	$ 302,130		
4N-312	km	20	$ 20,142	$ 402,840		
62N-415	km	10	$ 20,142	$ 201,420		
4C-424	km	10	$ 20,142	$ 201,420		
62N-413	km	15	$ 20,142	$ 302,130		
62N-414	km	5	$ 20,142	$ 100,710		
62N-416	km	20	$ 20,142	$ 402,840		
96H-411	km	10	$ 20,142	$ 201,420		
78C-311	km	10	$ 20,142	$ 201,420		
88H-401	km	11	$ 20,142	$ 219,342		
88H-402	km	10	$ 20,142	$ 201,420		
92W-302	km	40	$ 20,142	$ 805,680		
			Sub-Total	$ 8,256,000		
Administrative Overhead						
Contract AO				$ 1,566,493		
				$ -		
			Sub-Total	$ 1,566,493		
			SUB-TOTAL (no AO, AFUDC)	$ 8,256,000		
			TOTAL (AO, AFUDC included)	$ 9,822,493		
Original Cost				$ -		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 52271

Title: 2018 Padmount Replacement

Start Date: 2018/01
In-Service Date: 2018/01
Final Cost Date: 2019/06
Function Class: Distribution
Forecast Amount: $1,657,205

DESCRIPTION:

This project will replace 80 padmount transformers identified through the padmount inspection program as at or near end of expected useful life. NS Power has 4,205 padmount transformers across its fleet which are inspected annually. The expected useful life of these assets is between 35-45 years. This will be an ongoing program as part of lifecycle and condition management of the in-service distribution padmount transformer inventory.

NS Power anticipates that a portion of the costs associated with this capital item will contribute toward settling the Company's Asset Retirement Obligation for Polychlorinated Biphenyls (PCB) contaminated oil.

Summary of Related CIs +/- 2 years:
2016 CI 48093 2016 Padmount Replacement Program $1,911,470
2017 CI 49806 2017 Padmount Replacement Program $1,703,774
2019 CI TBD 2019 Padmount Replacement Program $TBD
2020 CI TBD 2020 Padmount Replacement Program $TBD

Depreciation Class: Distribution Plant- Line Transformers

Estimated Useful Life: 40 years

JUSTIFICATION:

Justification Criteria: Distribution System

Why do this project?

Padmount transformer inspections have identified transformers that need to be replaced due to deterioration. Proactive, planned replacement of end of expected useful life padmount transformers mitigates the potential for prolonged, unplanned customer outages from transformer failure.

This project will also aide in the prevention of environmental incidents, as padmount transformer failures can result in significant oil release, which is prohibited by environmental regulations and would result in remediation costs.

Why do this project now?

At or near end of expected useful life padmount transformers were identified through the padmount inspection process, and prioritized for replacement. They will be replaced in a planned manner as part of NS Power's environmental due diligence.

This project is deemed in-service when the first transformer is completed (January 2018), therefore the Final Cost Date (June 2019) is listed as six months after the last transformer is completed (December 2018).

Why do this project this way?

Padmount transformers are typically associated with commercial customers. Planned replacement of end of expected useful life padmount transformers is conducted during an outage coordinated at the convenience of the customer. The replacement of these transformers will minimize unplanned customer outages and mitigate potential environmental impact.

CI Number : 52271 - 2018 Padmount Replacement **Project Number** 52271

Parent CI Number : -

Asset Location : 1456 - 1456 Distribution Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	4800 - DP - U/G Line Transf.	1,592,115
Retirements	4800 - DP - U/G Line Transf.	65,090
	Total Cost:	1,657,205
	Original Cost:	865,763

Capital Project Detailed Estimate

Location: **Distribution**
CI# / FP#: 52271
Title: 2018 Padmount Replacement
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
T&D Labor - Electrician/Technician	PD	310	$ 366	$ 113,363		
Procurement / Financial Support	Lot	1	$ 4,199	$ 4,199		
			Sub-Total	$ 117,562		
Materials						
Padmount Transformers	Lot	80	$ 14,300	$ 1,144,000		
				$ -		
				$ -		
			Sub-Total	$ 1,144,000		
Contracts						
Transformer deliveries	Lot	1	$ 80,000	$ 80,000		
Flaggers	Lot	1	$ 10,752	$ 10,752		
				$ -		
			Sub-Total	$ 90,752		
Other Goods & Services						
Contingency	%	10%	$ 1,352,314	$ 135,231		
				$ -		
			Sub-Total	$ 135,231		
Vehicle Overhead						
Vehicle Allocated Costs				$ 48,043		
			Sub-Total	$ 48,043		
Administrative Overhead						
Labor AO				$ 104,398		
Contract AO				$ 17,219		
			Sub-Total	$ 121,617		
			SUB-TOTAL (no AO, AFUDC)	$ 1,487,545		
			TOTAL (AO, AFUDC included)	$ 1,657,205		
Original Cost				$ 865,763		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 51493

Title: 2018 PCB Pole Top Transformer Replacements

Start Date: 2017/06
In-Service Date: 2018/02
Final Cost Date: 2019/06
Function Class: Distribution
Amount: $1,360,354

DESCRIPTION:

This project provides for the systematic removal of equipment containing polychlorinated biphenyl (PCB) materials in accordance with federal guidelines. Regulations state that all pole top equipment containing PCBs in a concentration greater than 50 mg/kg must be removed from service by December 31, 2025. In 2018, NS Power will replace approximately 250 of the known road-side transformers that exceed these limits. This project includes the destruction of materials, as required.

A portion of the capital costs associated with this capital item will contribute toward settling the Company's Asset Retirement Obligation for PCB contaminated oil.

Summary of Related CIs +/- 2 years:
2016 CI 47721 – 2016 PCB Phase-out for Pole Top Transformers $4,409,579
2017 CI 49919 – 2017 PCB Pole Top Transformer Replacement $2,446,051
2019 CI TBD – 2019 PCB Pole Top Transformer Replacements $TBD
2020 CI TBD – 2020 PCB Pole Top Transformer Replacements $TBD
TBD CI TBD – Off-road/Rear-lot PCB Pole Top Transformer Replacements $TBD

JUSTIFICATION:

Justification Criteria: Environment

Depreciation Class: Distribution Plant – Poles, Towers and Fixtures
Distribution Plant – Line Transformers

Estimated Useful Life: 25-30 years

Why do this project?

The Canadian Council of Ministers of the Environment (CCME) has committed to a policy of phasing out the use of all PCBs in Canada. In support of this policy, NS Power will be focusing on eliminating all pole top electrical transformers and related pole top auxiliary electrical equipment containing PCBs in a concentration of 50 mg/kg or more before December 31, 2025.

Why do this project now?

Proceeding with this work over a multi-year timeframe will allow the work to be incorporated into NS Power's existing work plan and resources.

This project is deemed in-service when the first pole top transformer is replaced (February 2018), therefore the Final Cost Date (June 2019) is listed as six months after the last pole top transformer is installed under this project (December 2018).

Why do this project this way?

An inventory of pole top assets was completed to identify the location and number of potentially contaminated transformers. All units that test greater than the 50 mg/kg limit will be replaced. Based on pole top transformer disposal data from 2004 to 2013, approximately 5 percent of the pole-top transformers replaced contained PCB concentration equal to or above 50 mg/kg. Based on that percentage, NS Power anticipates 3,825 transformers of the 45,000 in-service will be replaced throughout the multiple annual projects. The 2018 project is focused on continuing to replace known PCB transformers.

CI Number : 51493-D861 - 2018 PCB Pole Top Transformer Replacements **Project Number** 51493-D861

Parent CI Number : -

Asset Location : 1456 - 1456 Distribution Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	3500 - DP - Wood Poles	83,966
Additions	4100 - DP - O/H Line Transf.	1,108,983
Retirements	4100 - DP - O/H Line Transf.	167,405
	Total Cost:	1,360,354
	Original Cost:	288,388

Capital Project Detailed Estimate

Location: **Distribution**
CI# / FP#: 51493
Title: 2018 PCB Pole Top Transformer Replacement
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
T&D Labor - PLT	PD	398	$ 372	$ 148,144		
T&D Labor - Design	PD	96	$ 386	$ 36,975		
			Sub-Total	$ 185,118		
OT Labor						
T&D Labor - PLT	PD	13	$ 744	$ 9,339		
			Sub-Total	$ 9,339		
Travel Expense						
Travel	Lot	2	$ 991	$ 991		
			Sub-Total	$ 991		
Materials						
Pole Top Transformers	ea.	379	$ 1,900	$ 720,220		
Miscellaneous overhead materials	Lot	1	$ 25,000	$ 25,000		
			Sub-Total	$ 745,220		
Contracts						
Flaggers	Lot	1	$ 61,887	$ 61,887		
				$ -		
			Sub-Total	$ 61,887		
OT Meals						
Meals	Lot	1	$ 571	$ 571		
				$ -		
			Sub-Total	$ 571		
Other Goods & Services						
Contingency	%	10%	$ 1,003,127	$ 100,313		
				$ -		
			Sub-Total	$ 100,313		
Vehicle Overhead						
Vehicle AO				$ 84,163		
				$ -		
			Sub-Total	$ 84,163		
Administrative Overhead						
COPS T&D Labor AO				$ 161,483		
COPS Contracts AO				$ 11,269		
			Sub-Total	$ 172,752		
			SUB-TOTAL (no AO, AFUDC)	$ 1,103,440		
			TOTAL (AO, AFUDC included)	$ 1,360,354		
Original Cost				$ 288,388		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 52184

Title: 37N-412 Glooscap Trail Rebuild Phase 2

Start Date: 2018/01
In-Service Date: 2018/04
Final Cost Date: 2018/10
Function Class: Distribution
Forecast Amount: $858,046

DESCRIPTION:

This project provides for the replacement of deteriorated poles, conductor and insulators on the 607N-301G step-down feeder section from 37N-412 along the Glooscap Trail near Spencer's Island. Approximately 96 poles will be replaced and upgraded as per current NS Power standards. In addition, 5.5 kilometres of the existing #4 three-phase primary and #6 and #4 neutral conductor will be replaced with 2/0 AASC primary conductor and neutral. Additional replacements include approximately 250 insulators and 3 transformers.

This project also provides for rebuilding of a 1.2 kilometre three-phase section of the off-road line on 37N-412 along Parrsboro Shore Road to the roadside. The new line construction will require installation of 1.3 kilometres of 2/0 AASC primary and neutral, approximately 90 insulators and 5 transformers. The new line will primarily be constructed on Bell Aliant poles, however approximately 12 new NS Power poles will be installed. The new line will be built along the road side and the existing line will be removed.

Summary of Related CIs +/- 2 years:
2017 CI 50772- 37N-412 Glooscap Trail Rebuild Phase 1 $771,476
2019 CI TBD 37N-412 Glooscap Trail Phase 3 $TBD

JUSTIFICATION:

Justification Criteria: Distribution System

Sub Criteria: Pole Strength

Why do this project?

The existing conductor and poles in both targeted areas are deteriorated and at risk of failure due to their age and condition, and the existing conductor cannot be worked on under live conditions. In addition, the targeted section of line along Parrsboro Shore Road is currently located off-road. Rebuilding the new line to roadside will improve accessibility for maintenance and outage restoration, and improve reliability for customers by reducing exposure to tree contacts.

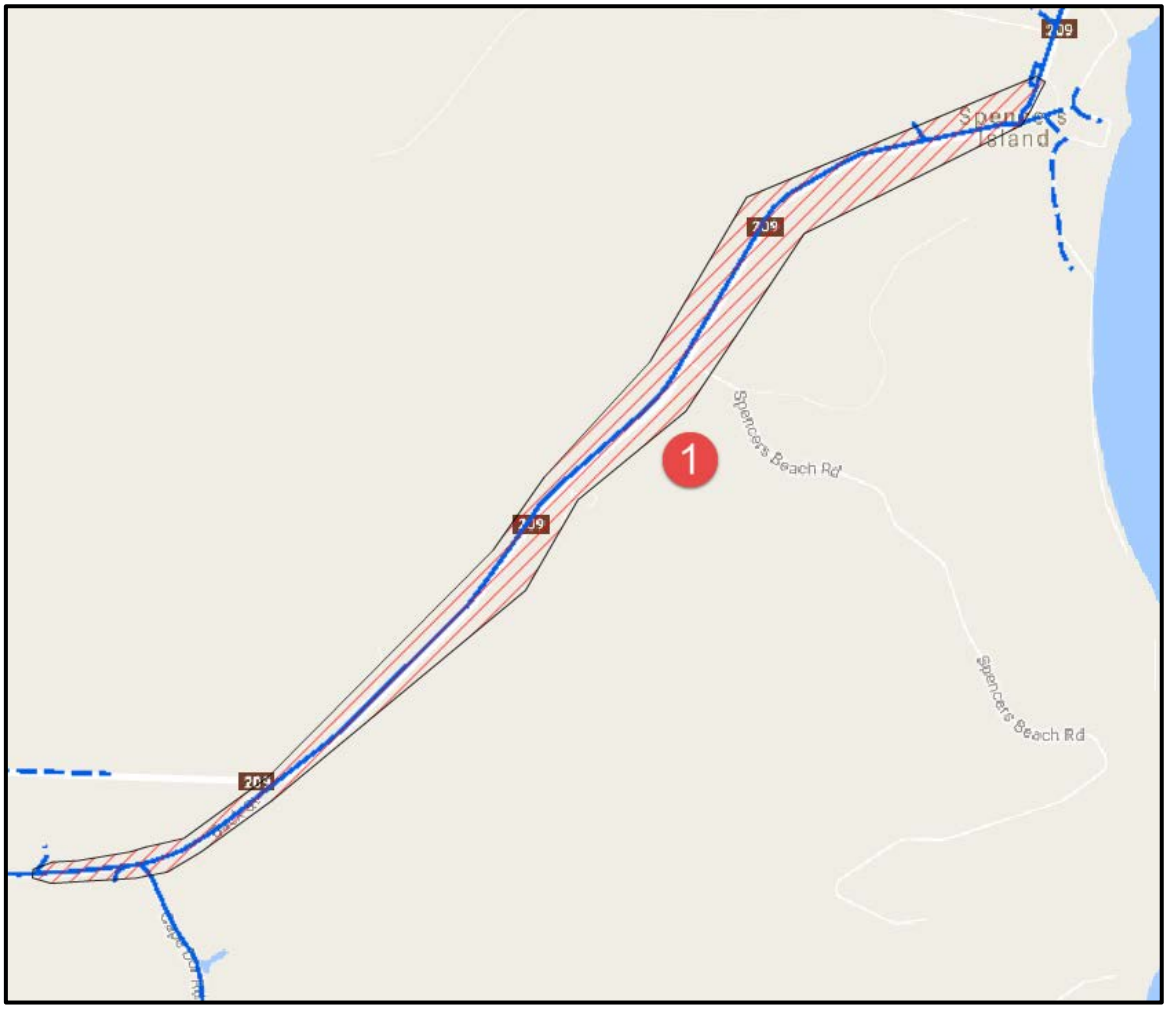
Why do this project now?

The existing poles and conductor are over 55 years old and have reached the end of their expected service life. Inspections of the targeted devices and assessment based on age, condition and risk of failure have determined that replacements are required.

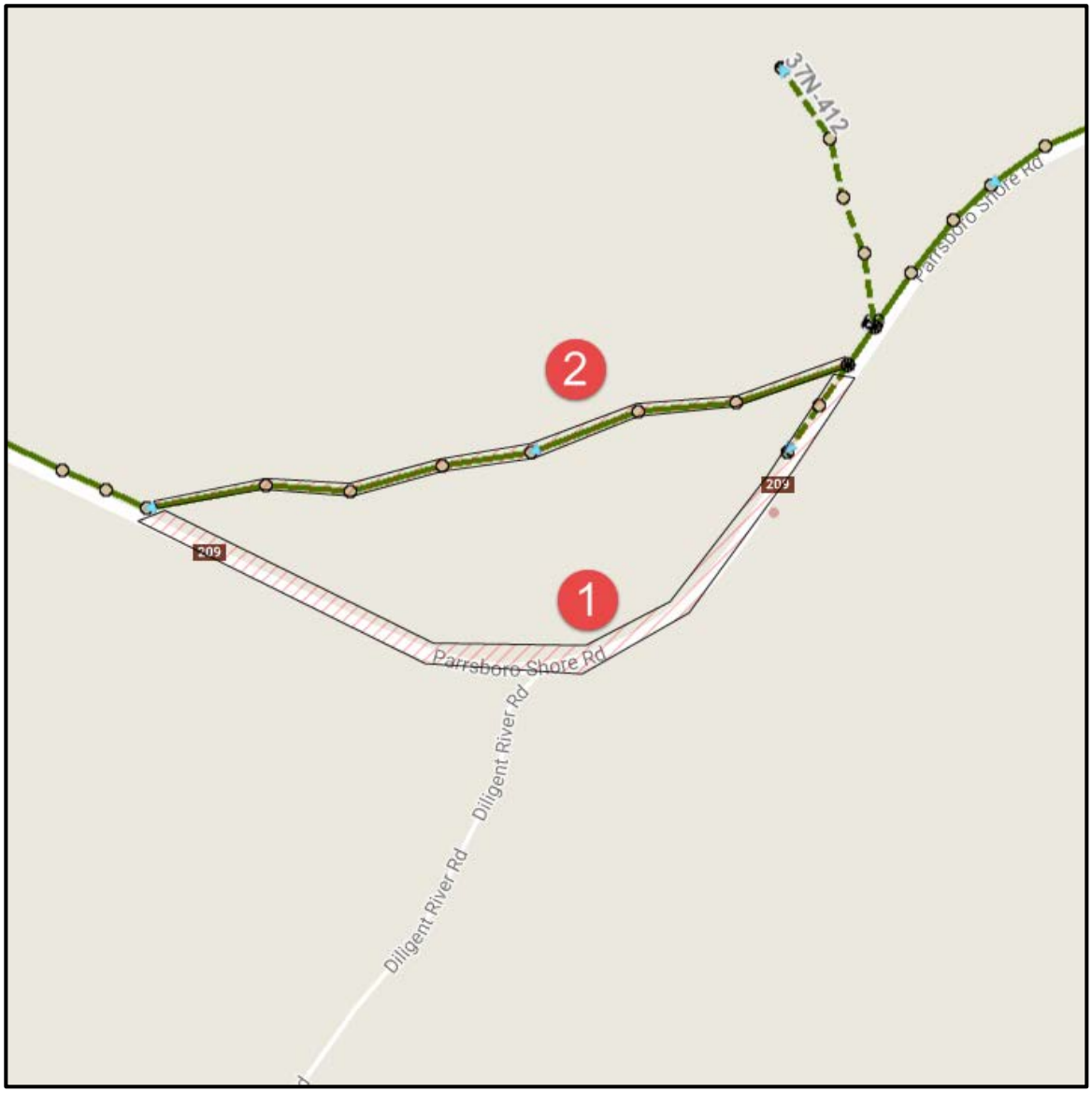
Why do this project this way?

There is no alternative source of supply for the customers in the targeted areas. Building the new line along the road side will improve accessibility for outage response. Poles will be upgraded in accordance with current NS Power standards.

The contracts portion of this project will be sourced through NS Power's existing Power Line Technician (PLT) Service Agreement with Emera Utility Services. This is aligned with NS Power's workforce planning model which is designed to optimize the allocation and execution of PLT resources among work requirements.



1. Rebuild approximately 5.5 kilometers of line along 607N-301G



1. Build new 1.3 kilometer 3-phase line along Parrsboro Shore Rd on 37N-412
2. Remove existing off-road line

CI Number : 52184 - 37N-412 Glooscap Trail Rebuild Phase 2 **Project Number** 52184

Parent CI Number : -

Asset Location : 1456 - 1456 Distribution Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	3500 - DP - Wood Poles	381,491
Additions	3900 - DP - O/H Cond.	274,560
Additions	4100 - DP - O/H Line Transf.	88,031
Additions	5200 - DP - Services	12,541
Retirements	3500 - DP - Wood Poles	33,249
Retirements	3900 - DP - O/H Cond.	24,711
Retirements	4000 - DP - O/H Cond.Devices	9,942
Retirements	4100 - DP - O/H Line Transf.	12,711
Retirements	5000 - DP - Street Lights	9,942
Retirements	5200 - DP - Services	10,865
	Total Cost:	858,046
	Original Cost:	67,917

Capital Project Detailed Estimate

Location: Distribution
CI# / FP#: 52184
Title: 37N-412 Glooscap Trail Rebuild Phase 2
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
T&D Labor - PLT	PD	354	$ 367	$ 129,981		
Procurement / Financial Support	Lot	1	$ 18,089	$ 18,089		
				-		
			Sub-Total	$ 148,070		
Materials						
Poles	Lot	1	$ 63,354	$ 63,354		
Overhead Conductor	Lot	1	$ 46,792	$ 46,792		
Cutouts	Lot	1	$ 141	$ 141		
Overhead Line Transformers	Lot	1	$ 13,424	$ 13,424		
LED Streetlights	Lot	1	$ 2,436	$ 2,436		
Services	Lot	1	$ 369	$ 369		
				$ -		
			Sub-Total	$ 126,514		
Contracts						
Contract Line Work	Hrs.	[redacted]		$ 81,669		
Flagging	Lot	1	$ 105,609	$ 105,609		
Backhoe	Lot	1	$ 100,801	$ 100,801		
			Sub-Total	$ 288,078		
Other Goods and Services						
Contingency	%	10%	$ 414,592	$ 41,459		
			Sub-Total	$ 41,459		
Vehicle Allocated Costs						
Vehicle Allocated Costs				$ 60,511		
			Sub-Total	$ 60,511		
Admin Overheads						
Labor AO				$ 131,492		
Contract AO				$ 54,660		
				$ 186,151		
AFUDC Interest Capitalized						
AFUDC				$ 7,263		
			Sub-Total	$ 7,263		
			SUB-TOTAL (no AO, AFUDC)	$ 604,122		
			TOTAL (AO, AFUDC included)	$ 858,046		
Original Cost				$ 67,917		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 52224

Title: 532N Elm Street Conversion Phase 2 & 3

Start Date:	2018/04
In-Service Date:	2019/03
Final Cost Date:	2019/09
Function Class:	Distribution
Amount:	$722,113

DESCRIPTION:

This project will implement recommendations 6.2.1 and 6.2.2 of the New Glasgow/Stellarton 4kV Distribution Planning Study 362-0615-E30 (please refer to Attachment 1). Sections 6.2.1 and 6.2.2 recommend converting the remainder of the existing 4kV line that is being supplied from 532N Elm Street substation to 25kV. In order to complete this conversion, the existing double circuit line along Mitchell Street, north of Elm Street, will be reconstructed, due to deterioration, to hold a single 25kV circuit. Additional replacements include upgrading 1.5 kilometers of existing primary conductor with a mixture of 336 AASC and 2/0 AASC, replacement of approximately 37 deteriorated poles, framing and insulators and the replacement of all existing single-tap transformers with dual-tap transformers.

Summary of Related CIs +/- 2 Years:
2017 CI 49799 - 532N Elm Street Conversion Phase 1 - $548,688
2019 CI TBD - 64N Lourdes Phase 1 - $TBD
2019 CI TBD - 64N Lourdes Phase 2 - $TBD

JUSTIFICATION:

Justification Criteria: Distribution System

Why do this project?

The existing 532N-Elm Street step-down substation equipment, infrastructure and associated 4kV distribution system are deteriorated. The condition of the targeted assets is further described in section 2.4.3 of planning study 362-0615-E30 (please refer to Attachment 1). If the 532N-T1 transformer failed, there would be an extended outage to approximately 500 customers as outlined in the contingency analysis in section 4.2.1.

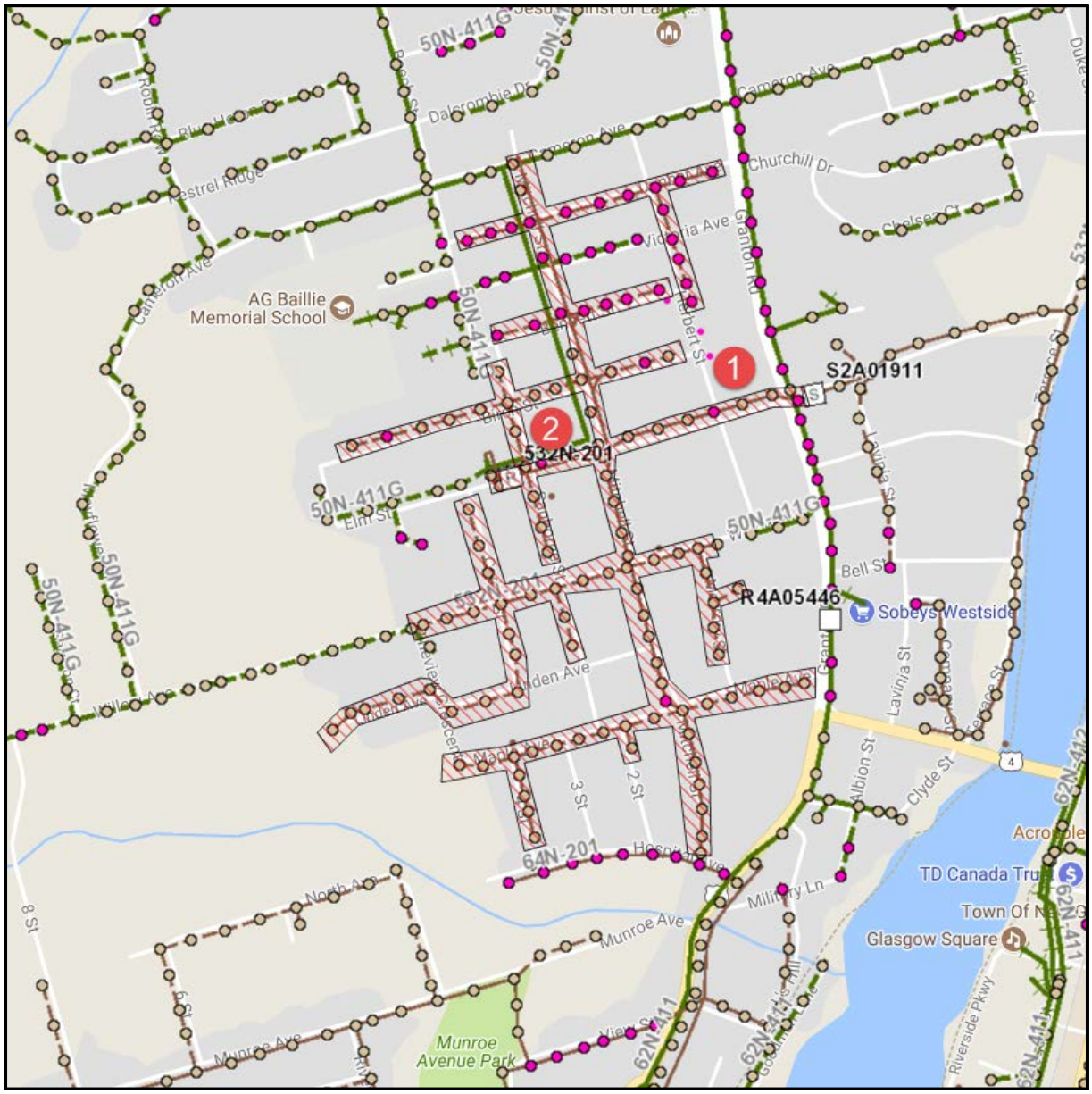
Why do this project now?

The 532N step-down substation equipment and 4kV distribution plant are up to 60 years old and have reached the end of their expected useful lives, as outlined in section 4.3. Two additional phases of conversion and load transfer must be completed before 532N can be retired, as outlined in Section 6.2 of the planning study. These projects were recommended for 2017 in Section 6.2, however were not initiated in 2017 due to the ongoing, and detailed assessment of all of the 4kV systems included in the study area. The recommendation to complete all 4kV conversions in the study by 2023 will be achieved by retiming the plans for conversions in future years.

Why do this project this way?

Alternatives are outlined in section 5.1 of the planning study, including voltage conversion to decommission the 532N substation, replacement of the substation with step-down transformers, and replacement of the substation with padmount transformers. The voltage conversion alternative was determined to be the most economical solution, as outlined in section 5.1.4.

The contracts portion of this project will be sourced through NS Power's existing Power Line Technician (PLT) Service Agreement with Emera Utility Services. This is aligned with NS Power's workforce planning model which is designed to optimize the allocation and execution of PLT resources among work requirements.



1. Upgrade existing conductor to 2/0 AASC and 336 AASC, replace targeted deteriorated poles, framing, insulators and the replacement of all existing single-tap transformers with dual-tap transformers to convert existing 4kV line to 25kV.
2. Retire 532N step-down substation.

CI Number : 52224 - 532N Elm Street Conversion Phase 2 & 3 **Project Number** 52224

Parent CI Number : -

Asset Location : 1456 - 1456 Distribution Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0200 - DP - Land Rights	51,487
Additions	3500 - DP - Wood Poles	245,569
Additions	3800 - DP - Insulators	22,014
Additions	3900 - DP - O/H Cond.	104,736
Additions	4000 - DP - O/H Cond.Devices	2,238
Additions	4100 - DP - O/H Line Transf.	36,866
Additions	4800 - DP - U/G Line Transf.	155,340
Retirements	3500 - DP - Wood Poles	26,012
Retirements	3900 - DP - O/H Cond.	19,580
Retirements	4000 - DP - O/H Cond.Devices	1,074
Retirements	4100 - DP - O/H Line Transf.	5,250
Retirements	4800 - DP - U/G Line Transf.	51,947
	Total Cost:	722,113
	Original Cost:	44,639

Capital Project Detailed Estimate

Location: **Distribution**
CI# / FP#: 52224
Title: 532N Elm Street Conversion Phase 2 & 3
Execution Year: 2018/2019

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
Procurement / Financial Support	Lot	1	$ 10,143	$ 10,143		
			Sub-Total	$ 10,143		
Materials						
Poles	Lot	1	$ 38,622	$ 38,622		
Insulators	Lot	1	$ 856	$ 856		
Conductor	Lot	1	$ 15 221	$ 15 221		
Cutouts	Lot	1	$ 535	$ 535		
Overhead Line Transformer	Lot	1	$ 24 228	$ 24 228		
Underground Line Transformer	Lot	1	$ 91 800	$ 91 800		
			Sub-Total	$ 171,262		
Contracts						
Contract Line Work	Hrs.	[redacted]		$ 255 366		
Tree Trimming	Lot	1	$ 25 000	$ 25 000		
Flagging	Lot	1	$ 54,190	$ 54,190		
Backhoe	Lot	1	$ 46,800	$ 46,800		
			Sub-Total	$ 381,356		
Royalty, Easement, Appraisal						
Easements	Lot	1	$ 15,000 00	$ 15,000		
			Sub-Total	$ 15,000		
Other Goods & Services						
Contingency	%	10%	$ 562,761	$ 56,276		
			Sub-Total	$ 56,276		
Administrative Overhead						
Contract AO				$ 72,358		
			Sub-Total	$ 72,358		
Interest Capitalized						
AFUDC				$ 15,718		
			Sub-Total	$ 15,718		
			SUB-TOTAL (no AO, AFUDC)	$ 634,037		
			TOTAL (AO, AFUDC included)	$ 722,113		
Original Cost				$ 44,639		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

New Glasgow/Stellarton 4kV
DISTRIBUTION PLANNING STUDY

Report number 362-0615-E30

Revision		Date	Drafted By	Reviewed by	Approved By
0	Issued for Study	25-June-2015	BH		
1	Issued for Release	5-Jan-2016	BH	AB	

EXECUTIVE SUMMARY

This study was initiated by the Eastern Territory, to determine solutions for aging/defective 4kV stepdown transformers in New Glasgow. The scope of this study encompasses the solutions to correct high priority issues in New Glasgow and the future of the 4kV system.

It was determined that conversion to 25kV is the best solution for all 4kV distribution remaining in the Stellarton area. Priority of conversions was determined through discussion with representatives from distribution planning, regional engineering, capital engineering, system maintenance and environmental services. Some temporary measures were identified, and assuming their completion, the following priority was agreed upon:

1. 532N-Elm St
2. 64N-Lourdes
3. 61N-Provost St
4. 528N-Granville St

This study makes recommendations by capital year for the phased conversion of these 4kV systems. There are currently no recommendations for capital work on the 25kV systems in this area; however, they should be studied again by 2020. To enable this study, communication work needs to be completed to enable the collection of interval data at 50N-Trenton and all interconnected distribution generation sites in the Stellarton area. This will allow for peak feeder loads to be determined annually.

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1.0 SCOPE

This study was initiated by the Eastern Territory, to determine solutions for aging/defective 4kV stepdown transformers in New Glasgow. The scope of this study includes the solutions to correct high priority issues in New Glasgow as well as a longer term plan for the remaining 4kV distribution.

The 4kV step-downs under study are fed from 50N-Trenton and 62N-Bridge Ave. The state of these substations will be considered within this study, although there are no imminent issues with either of these 25kV distribution networks. Timing for a future study will be recommended.

The focus of this study will be on the 4kV step-down sites in New Glasgow: 61N-Provost, 528N-Granville, 532N-Elm and 64N-Lourdes. There have been a variety of issues identified at these sites which pose risks to the environment as well as the reliability of the 4kV distribution in this area.

2.0 EXISTING SYSTEMS

2.1 Transmission

The 50N-Trenton substation serves as the connection point for Trenton Thermal Generating Station and is along the route of a major transmission corridor spanning from Cape Breton to the hub in Truro. The 230kV transmission passes by this station as the 138kV system supplies sub-transmission in the area via lines: L-6503, L-6507, L-6508 and L-6511. The transmission system will not be affected within the scope of this study.

2.2 Sub-Transmission

The sub-transmission system within the Stellarton area operates at 69kV. It is supplied by two 138-69kV auto-transformers located at 50N-Trenton. From there, a 69kV N.O. loop is made with 62N-Bridge Ave (L-5500 and L-5501) as well as a radial feed to 54N-Abercrombie (L-5502). From 62N-Bridge Ave another radial feed (L5510) goes to 89H-Trafalgar. The sub-transmission system will not be affected within the scope of this study.

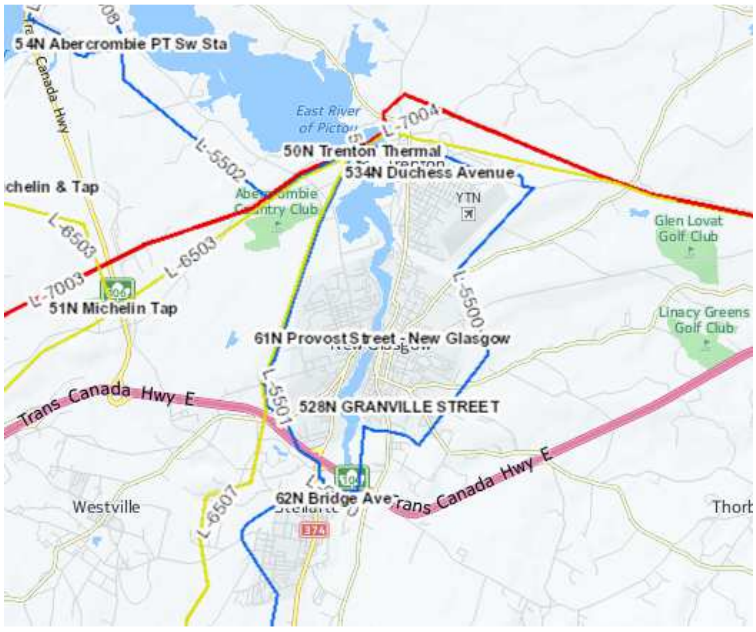


Figure 1 Stellarton Area Transmission

2.3 Distribution (25kV)

The 25kV distribution is not the area of focus for this planning study; however 25kV circuits from 50N-Trenton and 62N-Bridge Ave feed the 4kV distribution that is under study. There are no current or imminent issues with the 25kV distribution system that would justify capital expenditure, however the timing for a future study will be recommended.

2.3.1 50N-Trenton

The 50N-Trenton substation has two power transformers, T51 and T13. Transformer T51 has one 13.8kV feeder which supplies industrial customers along the East River of Pictou in Trenton. Transformer T13 has four feeders which cover a large area including: Trenton, Abercrombie, Pictou Landing, the north half of New Glasgow and the eastern extents of the Stellarton depot.

2.3.2 62N-Bridge Ave

The 62N-Bridge Ave substation in Stellarton has a unique configuration that is not standard for NS Power. There are two power transformers (T1/T2) which are connected in parallel to service six feeders. These feeders cover a large area including: Stellarton, Westville, the south half of New Glasgow and the southern extents of the Stellarton depot.

2.4 Distribution (4kV)

The 4kV distribution, stepped-down from 25kV circuits of 50N-Trenton and 62N-Bridge Ave, will be the focus of this study.

Error! Reference source not found.1 provides the transformer data for the 4kV step-downs that are directly impacted by the scope of this study. The stepdown substations will be looked at in greater detail. The phasing out of 4kV single phase pole or platform mounted transformers will be recommended as part of this study, but studied in less detail.

Table 1 Stellarton 4kV Step-down Transformers

Substation	25kV Source	Transformer Data				
		ID	MAN	kV	Rating kVA	Year
61N-Provost	50N-412	T1	Pioneer Electric	24-4.16	5000/6667	1968
528N-Granville	62N-412	T1	General Electric	22-4	5000/5600	1967
532N-Elm St	50N-411G	T41	Brown Boveri	23.9-4.16	2000	1956
64N-Lourdes	62N-411	T1	Packard Electric	22.55-4	1000	1956
534N-Duchess	50N-412	T1	General Electric	24.94-4.16	1000	1958
519N-Drummond	62N-416	T1	N/A	24.94-4.16	1500	1970
658N-Pictou Landing (platform)	50N-415	T41	N/A	14.4-2.4	333x1ph	N/A
536N-Woodburn (platform)	50N-410	T1	N/A	14.4-2.4	500x1ph	N/A
664N-Claremont (platform)	62N-415	T1	N/A	14.4-2.4	167x2ph	N/A
530N-Thorburn (pole)	62N-413	T1	N/A	14.4-2.4	100x1ph	N/A

2.4.1 61N-Provost Street

The 24-4.16kV 5MVA power transformer T1 at 61N-Provost Street was commissioned in 1968. It is fed from 50N-Trenton Thermal feeder 412. The feeders from 61N-Provost supply most of downtown New Glasgow, east of the river, as shown in Figure 2. There are approximately 1600 customers fed from this stepdown, mostly residential with some commercial.

This stepdown transformer has 4 feeders: 61N-201, 202, 203 and 204. Two of these 4kV feeders are tied to feeders from a nearby stepdown transformer at 528N-Granville Street:

- 61N-201 ties to 528N-201 on Stewart Street
- 61N-202 ties to 528N-202 on Marsh Street

This transformer is not overloaded and growth has been relatively flat in the area. The main area of concern in this location is the risk of environmental contamination. There are visible signs oil leakages and the oil level is intentionally left low to prevent excessive leakage.

Running this transformer below recommended oil levels also puts it at greater risk of failure. In the event of failure, this substation has the space and cable runs required to accommodate a mobile transformer.

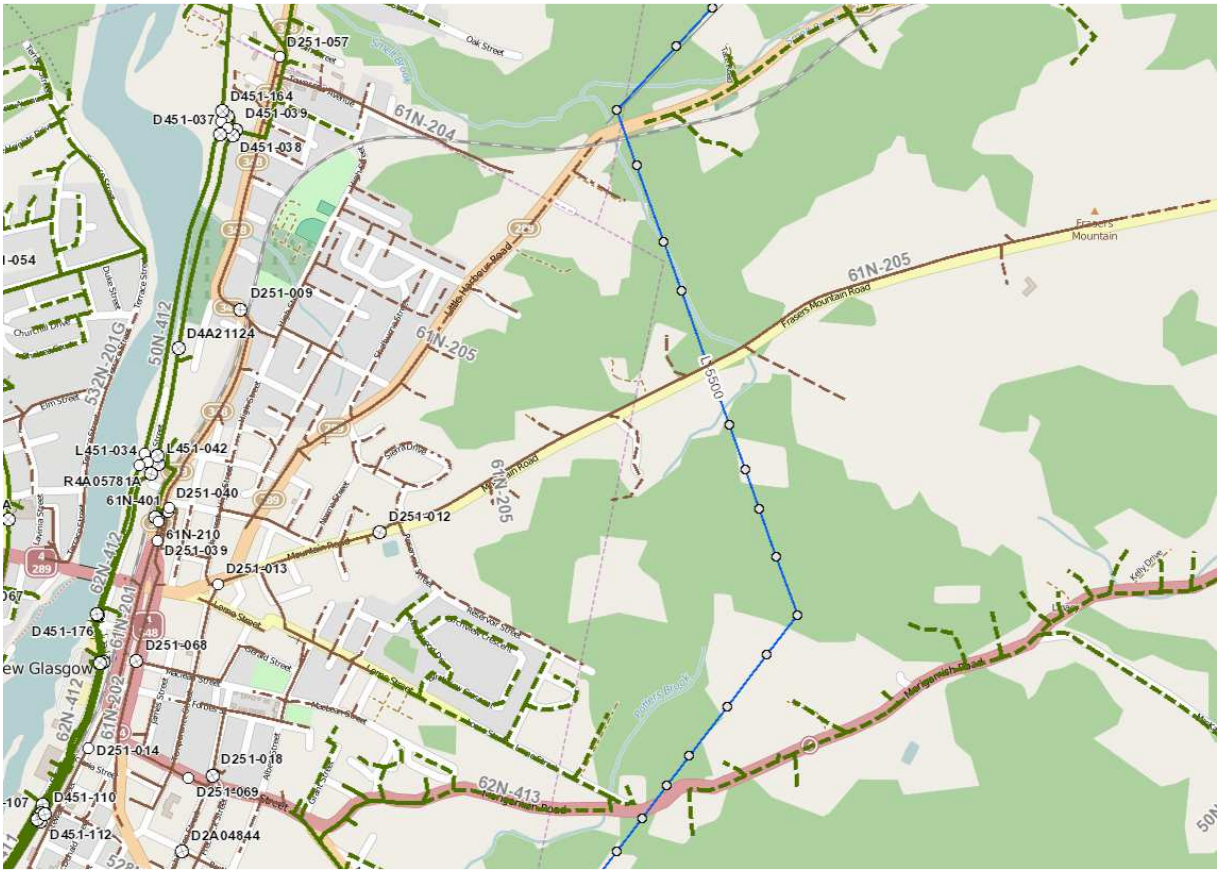


Figure 2 61N-Provost Street Extents

Figure 3 Photos of 61N-Provost St

2.4.2 528N-Granville Street

The 22-4kV 5MVA power transformer T1 at 528N-Granville Street was commissioned in 1967. A voltage regulator was installed to buck the voltage on the high side and allow this transformer to operate as a 25-4kV stepdown. This substation supplies load to southeast New Glasgow as shown in Figure 4.

The original voltage regulator is out of service but was not removed because it sits on the same set of support rails as the transformer and acts as a counter-weight. Engineering of a solution to allow for its removal is underway. This voltage regulator introduces environmental risk to the site as it is an oil filled container and its failure could go unnoticed for some time since it is out of service. There are also visible signs of oil leakages and the oil level is intentionally left low to prevent excessive leakage.

The stepdown transformer has 2 feeder exits: 528N-201 and 202. They are tied to 61N-201 and 202 as mentioned above. There is no space for a mobile transformer at this location.

This transformer is lightly loaded in an area with little growth.

Figure 4 **528N-Granville St Extents**

Figure 5 **Photos of 528N-Granville St**

2.4.3 532N-Elm Street

The 23.9-4.16kV 2MVA power transformer T41 at 532N-Elm Street was commissioned in 1956. To operate as a 25-4kV stepdown, three pole top transformers were installed in reverse polarity to buck the voltage to 2400V. The cases of the pole top transformers are painted red and are considered to be live as they are mounted on insulators. These transformers are suspected to be PCB contaminated, since they are of a pre-1982 vintage.

There are visible signs of oil leakages on this power transformer and the oil level is intentionally left low to prevent excessive leakage. There would be risk in maintaining this unit, as there are no spare parts available for it.

The 25kV underground cables appear weathered and the potheads are at about 7 feet above the ground. Due to this, any work on this transformer would likely be within the limits of approach specified in our safety standards.

This stepdown transformer has 1 feeder exit, 532N-201. It is tied to adjacent 4kV feeder 64N-201. There is no space for a mobile transformer at this location.

Overall, this is an unsightly substation in an established residential neighbourhood without readily available contingency. The load growth is flat in this area and has not reached the nameplate capacity of this transformer.

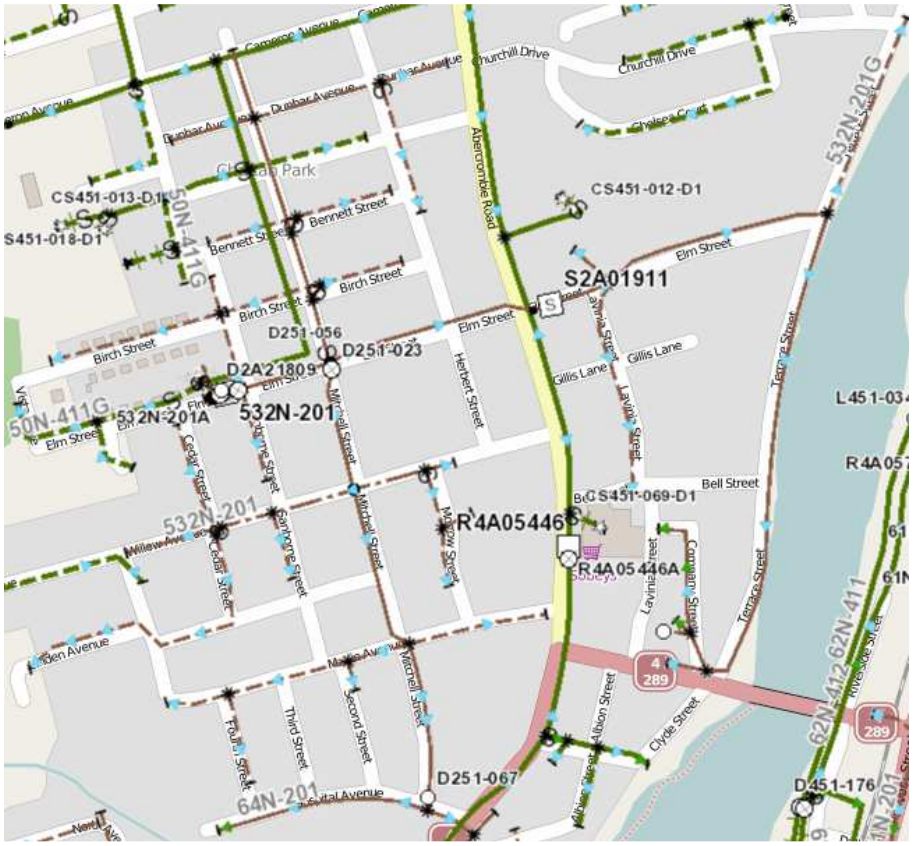


Figure 4 532N-Elm St Extents

Figure 6 Photos of 532N-Elm St

2.4.4 64N-Lourdes

The 22.55-4kV 5MVA power transformer T1 at 64N-Lourdes was commissioned in 1956. It is the most visually appealing of the four stepdown substations in New Glasgow, but also the most heavily loaded.

There are visible signs of oil leakages on this power transformer and the oil level is intentionally left low to prevent excessive leakage.

This stepdown transformer has 1 feeder exit, 64N-201. It is tied to adjacent 4kV feeder 532N-201. There is space on this site for a mobile transformer, although there are no existing provisions for one to be installed.

Figure 7 64N-Lourdes Extents

Figure 8 Photos of 64N-Lourdes

2.4.5 534N-Duchess Avenue

The 24.94-4.16kV 1MVA power transformer at 534N-Duchess was commissioned in 1958.

Due to heavy overload of this transformer, a large section of its load was converted to 25kV in 2014 (see Figure 10). Based on the reduction from 2990 to 2135kVA (connected) and 60 to 327 customers, it is estimated that the load on this transformer was reduced by 30%.

There are visible signs of oil leakages on this power transformer and the oil level is intentionally left low to prevent excessive leakage.

This stepdown transformer has one feeder exit, 534N-201, which is isolated from other 4kV feeders. In the event of failure, there is space for a mobile transformer.

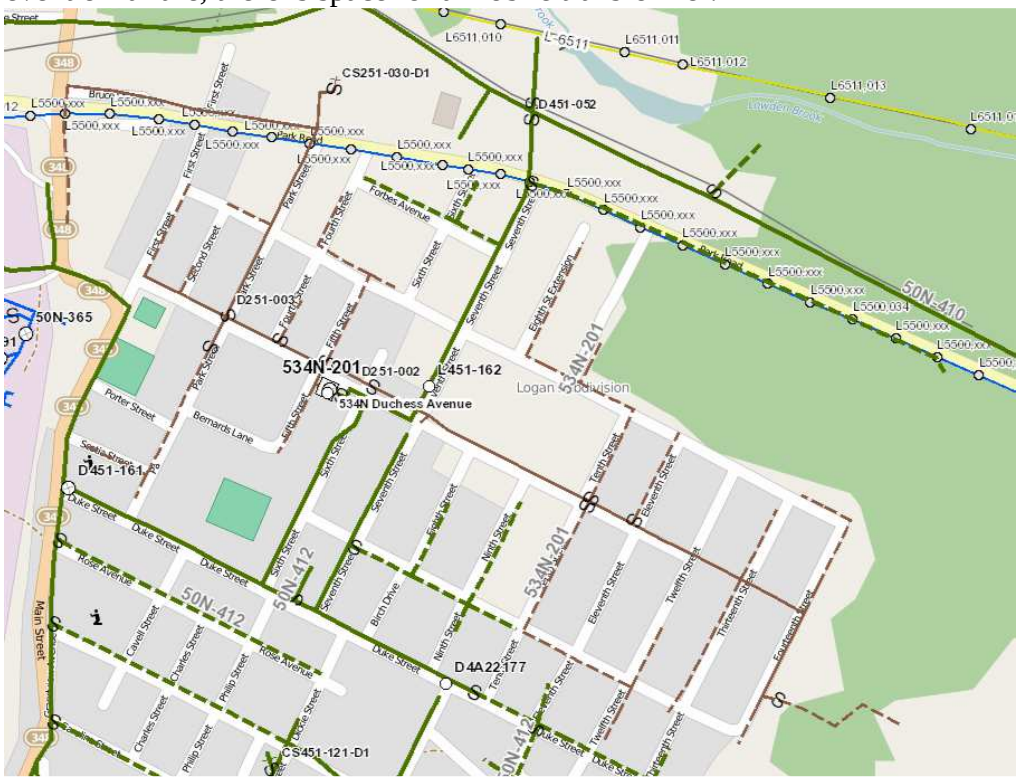


Figure 9 534N-Duchess Extents (2015)

Figure 10 **534N-Duchess Conversion (2014)**

Figure 11 **Photo of 534N-Duchess Ave**

2.4.6 519N-Drummond Road

The 24.94-4.16kV 1.5MVA power transformer at 519N-Drummond was commissioned in 1970.

In 2012, a partial conversion to 25kV was completed in this area (See Figure 13). Based on the reduction from 674 to 484 customers, it is estimated that the load on this transformer was reduced by 30%.

This stepdown transformer has one feeder exit, 519N-201, which is isolated from other 4kV feeders. In the event of failure, there is minimal to no space for a mobile transformer.

Figure 12 519N-Drummond Extents

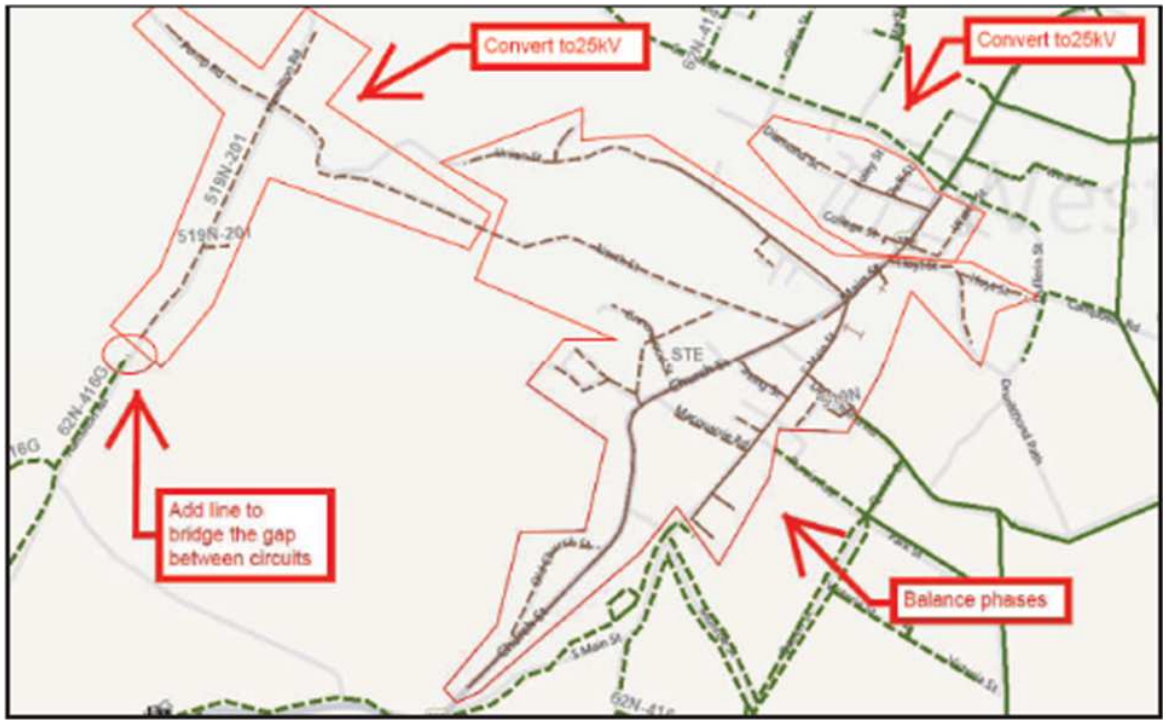


Figure 13 519N-Drummond Conversion (2012)

Figure 14 Photo of 519N-Drummond

2.5 Distributed Generation

There are currently three distributed generation sites in service and two more planned for the Stellarton area on 25kV distribution from 50N and 62N.

Table 2 Stellarton Distributed Generation

IR#	Site#	Name	Feeder	Size	In Service Date
IR312	717N	Auld's Mountain	50N-410	4.6MW	April 2015
IR257	82N	Irish Mountain	62N-413	1.99MW	November 2013
IR388/464	718N	Forbes Lake	62N-413	6.4MW	April 2015
IR308	724N	Avondale	50N-410	1.6MW	Future (Oct 2015)
IR333	722N	Limerock	62N-414	4.8MW	Future (Aug 2015)

The distributed generation does not affect the peak data or recommendations for the 4kV distribution. For the 25kV distribution, 82N Irish Mountain may have distorted peak feeder readings for 62N-413 for 2014 and 2015 peaks. Unfortunately there is no interval (PI) data available for this feeder during these peaks, however there is interval (MV90) data available for 82N itself.

3.0 LOAD HISTORY AND FORECAST

The 25kV distribution is comprised of long rural feeders and small towns. The 4kV distribution under study is mostly residential with a small number for commercial customers. As illustrated in the load history for these feeders, Appendix B, the feeders being studied have had a larger winter peak than summer. Historical load data for the feeders and transformers being studied was collected from the Distribution Load Check Database and PI data where available. Historical data was used to determine load growth rate and forecast future peak loads. Peak loads should be compared against the rated load and the Capital Expenditure Justification Criteria (CEJC).

3.1 Load Forecast

Customer load has grown at a modest pace in the Stellarton area. There is insufficient data for a load history/forecast for 534N, 519N, 658N, 536N, 664N and 530N. Clip data recorded in the Eastern Region Load Protection Report was used to determine if overloads exist on these stepdown transformers.

Table 3 Load Protection Report Clip Data

Transformer	Customers (#)	Rating (kVA)	2014 Clip (kVA)	2015 Clip (kVA)	% Loading (max)
519N-T1	484	1500	1236	1145	82%
534N-T1	327	1000	1308	NA	131%
530N-T1	41	100	130	89	130%
536N-T1	108	500	283	NA	57%
658N-T41	186	333	300	NA	90%
664N-T1 Ph A	101	167	220	218	132%
664N-T1 Ph C	108	167	182	200	120%

The growth rates indicated in following tables were determined through examination of the peak load check data over the past 15 years. The forecasted load growth was then calculated using the 90th percentile of a linear fit, to determine potential peak load growth in the area. In **bold** are actual recorded values, other values have been estimated from historical data. The 25kV feeders have not been included in these tables, but plots can be found in Appendix B.

Table 4 90th Percentile Load Forecast 25kV

Year / Peak MVA	50N-T13	62N-T1/T2
Rating/CEJC	**28/37.2 MVA**	**40/53.2 MVA**
Current Customers	**5015**	**9735**
Load Growth	**1.13%**	**1.10%**
2014	**24**	**44.1**
2015	**28.5**	46.5
2016	29.0	47.0
2017	29.3	47.6
2018	29.7	48.1
2019	30.0	48.7
2020	30.4	49.2
2021	30.7	49.8
2022	31.1	50.3
2023	31.4	50.9
2024	31.8	51.4
2025	32.1	52.0
2026	32.5	52.5
2027	32.8	53.1
2028	33.2	53.6
2029	33.5	54.2
2030	33.9	54.7

Table 5 90th Percentile Load Forecast 61N-Provost

Year / Peak MVA	61N-T1	61N-201	61N-202	61N-204	61N-205
Rating/CEJC	**6.67/8.87 MVA**	**300/325 A**	**300/325 A**	**300/325 A**	**300/325 A**
Current Customers	**1604**	**132**	**332**	**559**	**581**
Load Growth	**0.55%**	**0.32%**	**-1.16%**	**0.70%**	**1.92%**
2014	**5.0**	**72**	**234**	**222**	**290**
2015	**5.1**	**70**	**212**	**236**	**306**
2016	5.4	73	222	238	313
2017	5.4	73	220	239	320
2018	5.4	73	218	241	326
2019	5.5	73	215	243	333
2020	5.5	74	213	245	340
2021	5.5	74	210	246	347
2022	5.6	74	208	248	353
2023	5.6	74	206	250	360
2024	5.6	75	203	251	367
2025	5.7	75	201	253	374
2026	5.7	75	199	255	380
2027	5.7	75	196	257	387
2028	5.7	76	194	258	394
2029	5.8	76	192	260	401
2030	5.8	76	189	262	407

Table 6 90th Percentile Load Forecast 528N-Granville, 532N-Elm, 64N-Lourdes

Year / Peak MVA	528N-T1	528N-201	528N-202	532N-T41	64N-T1	532N/64N
Rating/CEJC	**5.6/7.45 MVA**	**300/325 A**	**300/325 A**	**2/2.66 MVA**	**1/1.33 MVA**	**Coincidence**
Current Customers	**802**	**395**	**407**	**494**	**374**	**Factor**
Load Growth	**0.62%**	**-0.76%**	**0.77%**	**-1.16%**	**1.24%**	**90%**
2014	1.91*	**170**	115*	**1.44**	**1.22**	**2.39**
2015	2.02*	**142.0**	148*	**1.44**	**1.21**	**2.39**
2016	2.13	166.7	150.5	1.58	1.40	2.68
2017	2.15	165.4	151.7	1.56	1.42	2.69
2018	2.16	164.2	152.9	1.54	1.44	2.69
2019	2.18	163.0	154.1	1.53	1.46	2.69
2020	2.19	161.8	155.3	1.51	1.48	2.69
2021	2.20	160.6	156.5	1.49	1.50	2.69
2022	2.22	159.4	157.7	1.48	1.52	2.69
2023	2.23	158.2	158.9	1.46	1.53	2.69
2024	2.24	157.0	160.1	1.44	1.55	2.70
2025	2.26	155.7	161.3	1.42	1.57	2.70
2026	2.27	154.5	162.5	1.41	1.59	2.70
2027	2.29	153.3	163.8	1.39	1.61	2.70
2028	2.30	152.1	165.0	1.37	1.63	2.70
2029	2.31	150.9	166.2	1.36	1.65	2.70
2030	2.33	149.7	167.4	1.34	1.67	2.70

***Data not available, values approximated using scaled clip measurements.**

4.0 JUSTIFICATION FOR EXPENDITURE

The following section identifies issues that warrant correction based on NSPI's *Capital Expenditure Justification Criteria*.

4.1 Overloads

There is only one overload condition that is expected within the study period for 25kV distribution: 62N-T1/T2 transformer is expected to peak above 133% of rating in 2028, based on load history

There are two overload conditions expected within the study period for 4kV distribution:

- 61N-205 feeder is expected to peak above 325A in 2018, unless load is transferred
- 64N-T1 transformer peaked above 133% of rating in 2012 and 2013 and is expected to reach similar peak values in the coming years.

An overload condition was present on 534N-T1 in 2013 and 2014 above 133% of rating. Data is not available for 2015 winter peak. In 2014, approximately 30% of the connected kVA was removed from this stepdown through conversion to 25kV. Based on this, the 2015 winter peak is estimated at 100% of rating. The peak winter load is not expected to exceed 133% of rating within the study period.

There are single phase stepdown transformers that are at or approaching overload. Based on 2014 clip data in the Eastern Region Load Protection Report, it is very likely that 530N-Thorburn and 664N-Claremont have exceeded 133% of rating during winter peak.

4.2 Contingency Loss of Supply

The 4kV distribution in New Glasgow is divided by the East River of Pictou. There are two stepdown substations on each side, but they are unable to provide full contingency on either side. The conclusions within this section were determined through modeling single contingency situations during 2015 winter peak loading. Other 4kV in the Stellarton area is completely isolated from alternate supplies.

4.2.1 532N-Elm St and 64N-Lourdes

These two substations supply similar loads. They are tied by a long run of #2 bare copper conductor, which causes voltage drop well below acceptable limits in a situation where 64N provides contingency for 532N. Peak load would greatly exceed 133% of the rating of 64N-T1. There is no room for a mobile transformer near the 532N-Elm St substation. There would be an extended outage to approximately 500 customers if 532N-T41 were to fail.

In the event of 64N-T1 failure, it is possible that Elm St could pick up the load, however voltage drop would be a concern in some areas during peak load. The 2015 peak load for 532N and 64N is just under 133% of 532N-T41 rating, however based on forecasted load, this would be exceeded in 2016. There is space for a mobile transformer at the 64N-Lourdes site, however there is nothing currently in place to facilitate installation. The outage duration would be the length of time required to transfer load in most cases, and the time required to install a mobile transformer during peak load. There are approximately 375 customers supplied by 64N.

4.2.2 61N-Provost and 528N-Granville

There are feeder ties between 61N-201/528N-201 as well as 61N-202/528N-202. These feeder ties cannot be used for contingency during winter peak conditions due to voltage drop below acceptable limits. In an off-peak situation, load could be transferred between these feeders for contingency. For feeders 61N-204 and 205 the load cannot be picked up by 528N-Granville, even off-peak.

In the event of 61N-T1 failure during peak load, customers would experience outages until the mobile transformer could be installed at the 61N-Provost site. The site has been built to accommodate a mobile transformer. There are approximately 1600 customers supplied from this substation.

In the event of 528N-T1 failure during peak load, outage duration would be dependent on the installation of an available replacement transformer. There is no space for a mobile unit at the 528N-Granville site. There are approximately 800 customers supplied from this substation.

4.2.3 534N-Duchess

There are no other 4kV feeders near 534N-Duchess. In the event of 534N-T1 failure, outage duration would be dependent on the installation of an available replacement transformer or mobile transformer. The site has not been built to accommodate a mobile transformer, but there is some space available. There are approximately 330 customers supplied from this substation.

4.2.4 519N-Drummond

There are no other 4kV feeders near 519N-Drummond. In the event of 519N-T1 failure, outage duration would be dependent on the installation of an available replacement transformer. There is no space for a mobile unit at the 519N-Drummond site. There are approximately 485 customers supplied from this substation.

4.2.5 Single Phase Stepdowns

The four other small pockets of 4kV in the Stellarton area: 658N-Pictou Landing, 536N-Woodburn, 664N-Claremont and 530N-Thorburn have similar deteriorated plant.

There are no other 4kV feeders near any of these platform or pole mounted stepdowns. In the event of failure, the outage duration would be dependent on the installation of an available replacement transformer. For 530N-Thorburn, replacement from stores should be very straight forward as it is only a 100kVA pole mounted transformer. Spares should also be available for the platform mounted transformers, however outage impact would be greater.

4.3 Deteriorated Plant

The majority of 4kV distribution plant in Stellarton is greater than 50 years old. There are many safety, environmental and reliability concerns due to the age of this equipment:

- Deteriorated #4 copper conductor has decreased tensile strength and presents a greater hazard for live line work.
- Chronically weeping transformers are left running on low oil to prevent excessive leakage. Lids can be tightened, however tightening of leaking gaskets could cause more harm than good. There are signs of oil leakage around the base of transformers. This condition is present at all 4kV substations in the Stellarton area: 532N, 64N, 61N, 528N, 534N and 519N.
- Historically, equipment failure has caused 4kV conversion to 25kV to proceed unplanned. This results in a much higher cost and customer impact than a planned approach.
- The 4kV voltage level is no longer one of the standard voltages for distribution at NSPI – in service and spare equipment will be phased out when possible.

Unique conditions exist at certain substations as explained in the Existing Systems section. These conditions provide additional justification for expenditure:

- 532N-Elm St
    - Using pole top transformers with possible PCBs to buck voltage and allow a 23.9-4.16kV transformer to be used to step down 25kV.
    - Unsightly equipment and graffiti, in an established residential neighbourhood.
    - 25kV potheads are only 7 feet above ground, so it is easy to be within the limits of approach
    - Center phase pothead has been replaced; failure of other two phases may be imminent.
- 528N-Granville St
    - Out-of-service, oil-filled regulator is sitting on the same rails as power transformer, acting as a counter weight. This presents an unnecessary environmental risk.
    - Sagging timbers support switches (A, B, C)

5.0 SOLUTIONS AND EVALUATION

There is significant justification to correct the deficiencies present in the 4kV distribution in Stellarton. The alternative to "Do Nothing" has not been considered as this would certainly result in environmental incidents, extended customer outages and economic loss for NSPI.

Deteriorated plant conditions and loss of supply contingency requirements have been used to prioritize the areas to correct. Top priorities were agreed upon by key stakeholders from System Maintenance, Regional Engineering, Capital Engineering, Environmental Services and Distribution Planning:

1. 532N-Elm Street
2. 528N-Granville Street
3. 61N-Provost Street
4. 64N-Lourdes

System Maintenance and Environmental Services will be performing work to alleviate certain issues in the short term:

- Install mobile transformer at 61N-Provost to allow: site clean-up and soil testing, transformer maintenance to potentially slow leaking of oil
- Engage a Civil Engineer to design a solution for the removal of the out of service regulator at 528N-Granville

This study recommends the phased conversion of 532N-Elm St and 64N-Lourdes proceeds immediately, followed by the phased conversion of 61N-Provost and 528N-Granville. All other conversions should follow based on observed conditions.

Within the scope of conversion to 25kV is the replacement of all distribution transformers, along with a percentage of conductor, poles, insulators and anchoring. The estimates are based on the scoping of one section of the 4kV distribution from 532N-Elm St. The rest of the 4kV distribution in New Glasgow is of approximately the same age and condition.

5.1 532N-Elm and 64N-Lourdes (New Glasgow East)

To resolve the issues at 532N-Elm Street and 64N-Lourdes, three options were considered:

- Convert the area to 25kV and decommission both substations
- Install 3 platform mounted stepdown locations and decommission both substations
- Replace both transformers with new padmounts and maintain 4kV distribution

Each alternative is proposed in phases and completed in 2017.

5.1.1 Alternative NG East-A, Convert to 25kV

This alternative is a phased approach to converting all of 532N and 64N load to 25kV. The conversion of this area would be completed in three phases for 532N-Elm St and two phases for 64N-Lourdes. The conversions should overlap, with both substations being decommissioned in 2017.

This conversion strategy allows both existing substations to remain in service and provide contingency for each other during conversion. Once the first phase of each conversion is complete, either substation could handle the remaining 4kV winter peak. Once conversion is complete, contingency is handled within the 25kV system. Recommendations for specific conversion steps by capital year can be found in Section 6.

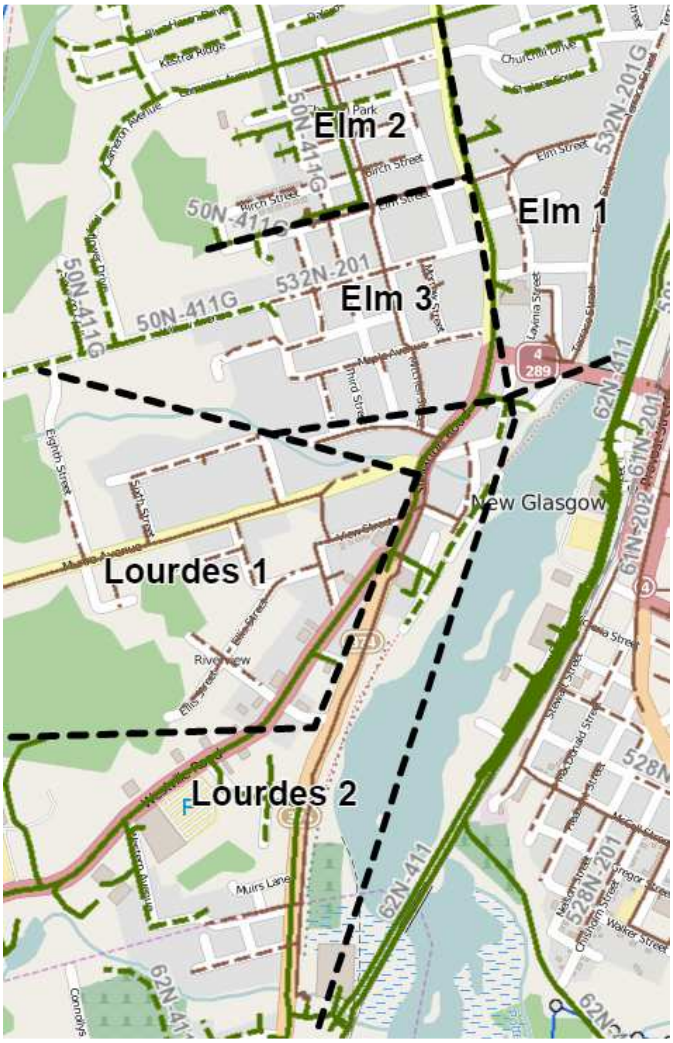


Figure 15 Geographic Overview of NG East-A Phases

5.1.2 Alternative NG East-B, Three Stepdown Locations

This alternative replaces the existing 4kV substations at 532N-Elm and 64N-Lourdes with three new 500kVA/phase stepdown transformers. There are very few appropriate locations for these platform-mounted transformers and there could be push back from the town of New Glasgow if this alternative were to go ahead. For the purpose of this study, suggested stepdown locations were assumed to be allowable:

1. Terrace Street near 25kV source 50N-411G
2. Elm St at or near existing substation location
3. N Foord Street at existing 64N substation location

This approach allows for the 4kV load in East New Glasgow to be shared by three stepdown locations and provides contingency for the loss of one stepdown. It also facilitates a phased conversion in the future, as its intent is to defer the eventual conversion to 25kV (complete by 2030). Within the scope of this alternative is the installation of one stepdown location per year, including any required conductor replacement – most notably, a long section of #2 Copper on Stellarton Avenue.

Figure 16 Geographic Overview of NG East-B Stepdowns

5.1.3 Alternative NG East-C, Replace Substations with Padmounts

This alternative replaces the existing transformers at 532N-Elm St and 64N-Lourdes with new 3MVA padmount transformers. Unlike alternative B, these substation locations are established and cleaning the sites up with new padmounts would be well received. These padmounts would provide contingency for each other. Unfortunately, this alternative does not facilitate the eventual conversion to 25kV (complete by 2030).

Within the scope of this alternative is the installation of new padmounts, site work, protection equipment, temporary transformers during removal of existing units and reconductoring of #2 Copper on Stellarton Avenue.

5.1.4 532N-Elm and 64N-Lourdes Recommendation

Based on the Economic Analysis Model (EAM) in Appendix C, Alternative NG East-A, Convert to 25kV is the most economical solution. Conversion to 25kV is also the preferred method to correct issues with deteriorated 4kV plant for a variety of reasons. Below is a summary of advantages/disadvantages for each alternative. This will give context for why these solutions were explored.

Alternative NG East-A, Convert to 25kV

- Most economical solution, based on alternatives deferring this eventuality by 15 years
- Results in the most old conductor and equipment being replaced – reliability improvements not considered in EAM
- Most visually appealing alternative
- Reduced cost of losses due to conversion (Appendix D) – considered in EAM as operating expense
- Historically, conversion to 25kV has been performed whenever possible throughout NSPI
- 25kV feeders are very accessible, which facilitates the conversion

Alternative NG East-B, Three Stepdown Locations

- Much less demanding on capital resources
- Configuration facilitates future conversion
- Unsightly platforms in residential neighbourhoods may have strong opposition
- NSPI has committed to phase out 4kV as a standard voltage level for distribution
- Spare units are available in stores

Alternative NG East-C, Replace Substations with Padmounts

- Less demanding on capital resources
- Does not facilitate future conversion
- Clean up of existing substation sites would be well received
- NSPI has committed to phase out 4kV as a standard voltage level for distribution
- A spare padmount would need to be purchased for stores

5.2 61N-Provost and 528N-Granville (New Glasgow West)

The 4kV distribution in the west of New Glasgow is very similar to the east. With the results of the previous economic analysis, it is apparent that alternatives to conversion would not provide economic benefit for the west side of New Glasgow. Further benefits of conversion over other alternatives:

- 61N-Provost St is a large substation with 4 feeder exits, a padmount replacement would not be practical in this situation
- There is four times more load in west New Glasgow compared to the east. To replace the substations with platform-mounted stepdowns, more units would be required and locations for them would be very difficult to find

A strategy for conversion to 25kV can be found in the Recommendations section. Timing is based on the priority discussed previously and predicted resource availability.

5.3 534N-Duchess and 519N-Drummond

The first phase of conversion to 25kV has been completed for each of these islands of 4kV. Based on this precedence and the analysis in Section 5.1, conversion is the preferred alternative for these locations. Phased conversions should proceed as resources are available.

5.4 Single Phase Stepdowns

Conversion is the preferred alternative for the other four small pockets of 4kV in the Stellarton area: 658N-Pictou Landing, 536N-Woodburn, 664N-Claremont and 530N-Thorburn. Phased conversions should proceed as resources are available. These locations should be addressed when overloaded, but not given priority over the 4kV substations.

6.0 RECOMMENDATIONS

This section will outline recommendations for the conversion to 25kV of 532N-Elm, 64N-Lourdes, 61N-Provost and 528N-Granville. These 4kV substations were identified as the highest priority and some strategy is required to complete conversion, based on priority of work, maintaining contingency and minimizing customer outages. Deteriorated 4kV plant should be replaced as required during conversion. Open points should be created as required to maintain the load between 50N and 62N.

Other pockets of 4kV should be converted to 25kV whenever possible. These include: 534N-Duchess, 519N-Drummond, 658N-Pictou Landing, 536N-Woodburn, 664N-Claremont and 530N-Thorburn. These conversions are quite linear, so different strategies for conversion have not been considered. These stations are lower priority in the big picture; in the event of imminent failure, measures should be taken to correct, but also to avoid deferral of recommended timeline below.

There are currently no capital recommendations for the 25kV substations, 50N-Trenton Thermal and 62N-Bridge Avenue. Based on projected load growth, these 25kV systems should be studied again by 2020. To enable this study, communication work needs to be completed to enable the collection of feeder load data in PI for 50N, which is currently not functional. Also, interval data at all distribution generation sites needs to be made available so that the peak feeder load can be determined annually. This study will be advanced or deferred based on new developments and requests from regional engineering.

6.1 2016 Capital Year

It is recommended that conversions to 25kV begin immediately, given the large scope of work required to relieve the issues identified. Since resources will not be available for 2015, the first phases of conversion should proceed in 2016. With the first phase of each conversion completed, the two 4kV substations will be able to provide contingency for each other. At this point, it would be possible to decommission one of these substations if required.

6.1.1 Terrace Street Conversion (532N-Elm Phase 1)

The first phase of conversion for 532N-Elm St covers Terrace St and Elm St east of Abercrombie. Extend a new 25kV branch onto George St from Abercrombie Rd to be used as a source for converting the 4kV in sections back to Elm St through Terrace St.

Figure 17 Terrace Street Conversion (532N-Elm Phase 1)

6.1.2 View Street Conversion (64N-Lourdes Phase 1)

The first phase of conversion for 64N-Lourdes covers the 4kV branch from Stellarton Rd on View St.

- Extend a new 25kV branch onto North St from Westville Rd
- Convert North St up to and including the Ellis St branch
- Rebuild Athletic St and Riverview Dr to 3 phase to Monroe Ave and convert
- Convert Monroe Ave east of Riverview Dr and 8th St
- Convert 6th St and North Ave
- Convert the rest of Monroe Ave and remove off-road section
- Finish conversion on View St

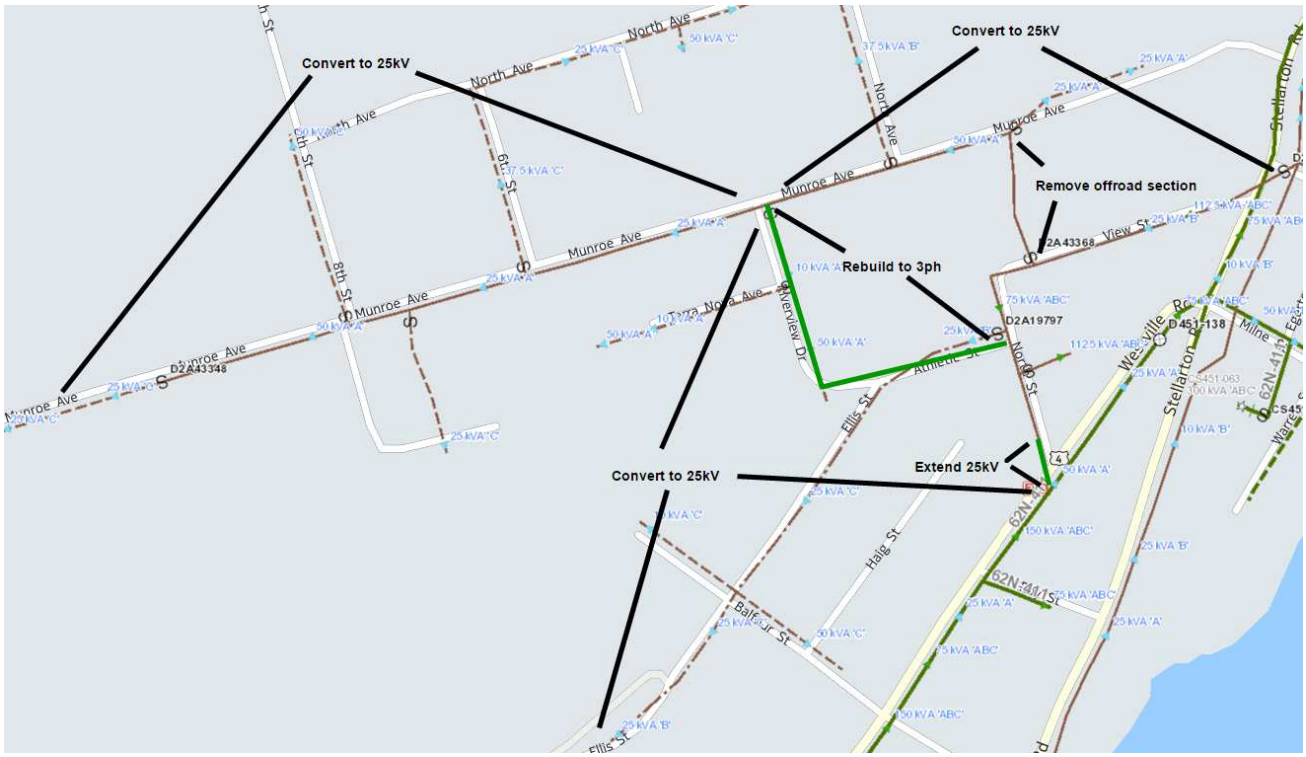


Figure 18 View Street Conversion (64N-Lourdes Phase 1)

6.2 2017 Capital Year

In 2016, the phased conversion of 532N should be completed.

6.2.1 North Mitchell Street Conversion (532N-Elm Phase 2)

The second phase of conversion for 532N-Elm St covers Mitchell Street north of Elm Street. There is an existing 25kV supply on north Mitchell St. so each branch can be converted independently.

Figure 19 North Mitchell Street Conversion (532N-Elm Phase 2)

6.2.2 South Mitchell Street Conversion (532N-Elm Phase 3)

The final phase of conversion for 532N-Elm St covers Mitchell Street south of Elm Street.

- Extend a new 25kV branch from Stellarton Ave onto Hospital Ave and convert
- Convert sections of Mitchell St and branches until Elm St
- Convert the remaining 4kV on Elm St and decommission the 532N site

Figure 20 South Mitchell Street Conversion (532N-Elm Phase 3)

6.3 2018 Capital Year

The final phase of 64N-Lourdes conversion should be completed in 2017. Once this is complete, both 532N-Elm and 64N-Lourdes sites can be retired. With the top priority 4kV plant dealt with, the phased conversion of 61N-Provost should begin. The conversion strategy for Provost will start with 204 and 205 feeders which are not tied to adjacent 4kV substation 528N-Granville.

6.3.1 Stellarton Road Conversion (64N-Lourdes Phase 2)

The final phase of conversion for 64N-Lourdes covers the remaining 4kV along Stellarton Rd from Hospital Ave to the 64N-Lourdes site.

- Convert sections of Stellarton Rd back to the intersection of Westville Rd
- Extend 25kV on Stellarton Rd from Westville Rd to Duff St
- Convert the remaining 4kV and decommission the 64N site

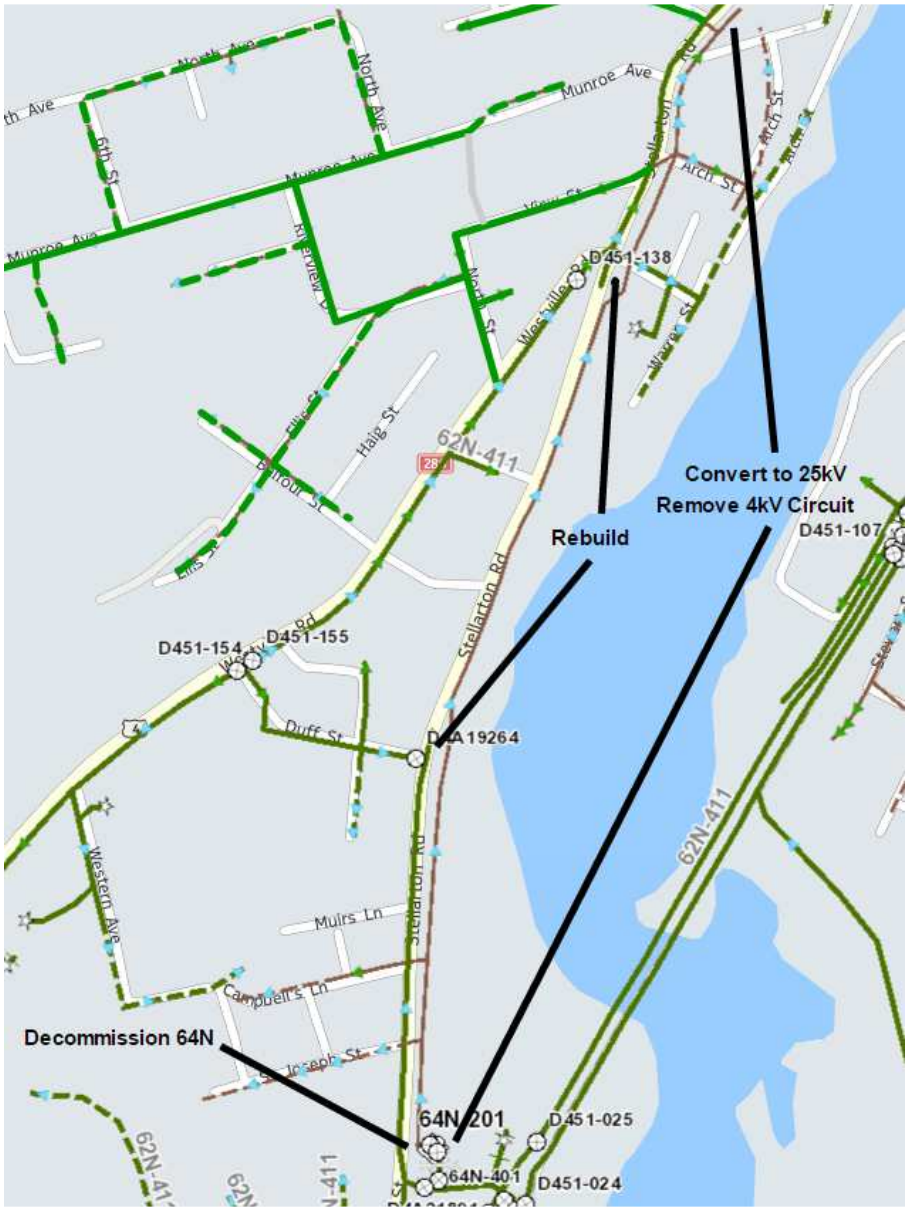


Figure 21 Stellarton Road Conversion (64N-Lourdes Phase 2)

6.3.2 Townsend Avenue Conversion (61N-Provost Phase 1)

The first phase of conversion for 61N-Provost covers Townsend Avenue and back to D251-009 on Trenton Road.

Figure 22 Townsend Avenue Conversion (61N-Provost Phase 1)

6.3.3 664N-Claremont Avenue Conversion

The two 167kVA single phase transformers (664N-T1) on Claremont Avenue are suspected to be at or near capacity. This small pocket of 4kV should be converted when resources are available. The conversion has no sequential effect on other conversions, so it can be advanced or deferred as required or broken down into small phases.

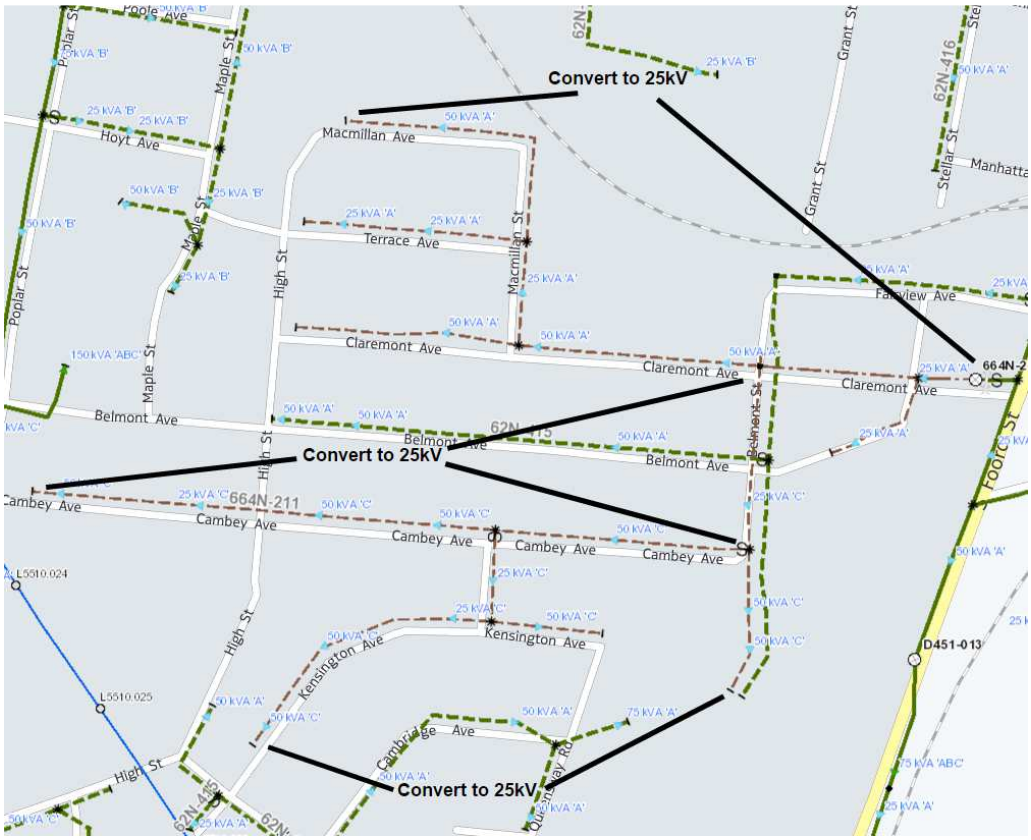


Figure 23 664N-Claremont Avenue Conversion

6.4 2019 Capital Year

In 2019, the phased conversion of 61N-Provost should continue.

6.4.1 High Street Conversion (61N-Provost Phase 2)

The second phase of conversion for 61N-Provost covers High Street and completes the conversion of 61N-204.

- Rebuild to 3 phase and extend 25kV from Townsend Street (rail crossing will need to be obtained in advance)
- Convert High Street and branches back to D251-010
- Create new open point at D251-010
- Convert Trenton Road back to 61N to retire 61N-204

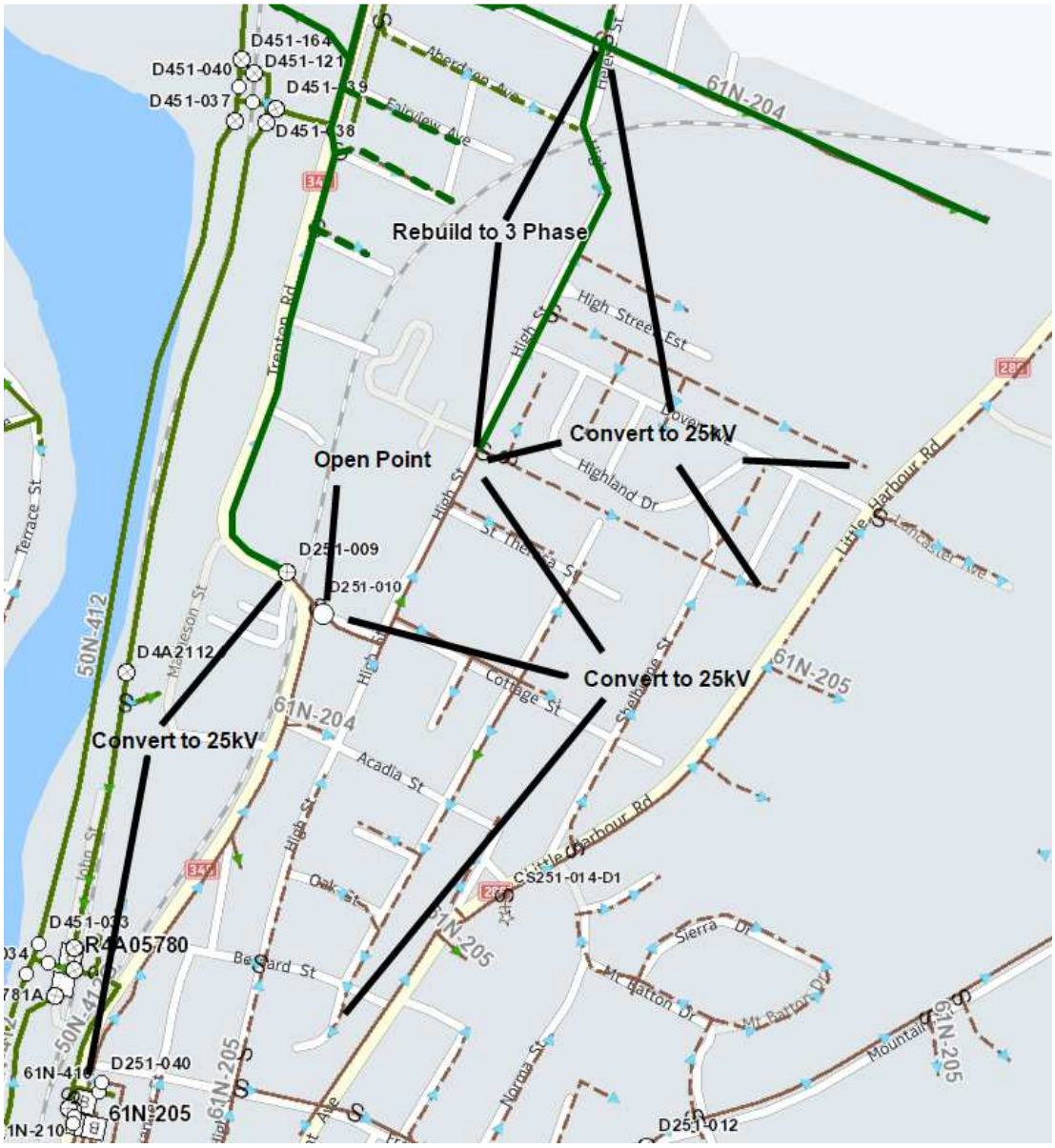


Figure 24 High Street Conversion (61N-Provost Phase 2)

6.4.2 Little Harbour Road Conversion (61N-Provost Phase 3)

The third phase of conversion for 61N-Provost begins to remove load from 61N-205 on Little Harbour Road.

- Rebuild Dover Avenue to 3 phase and move roadside
- Rebuild Little Harbour Road to 3 phase back to existing 3 phase
- Convert sections of Little Harbour Road, Almont Avenue and Fraser Street back to High Street
- Finish conversion of High Street

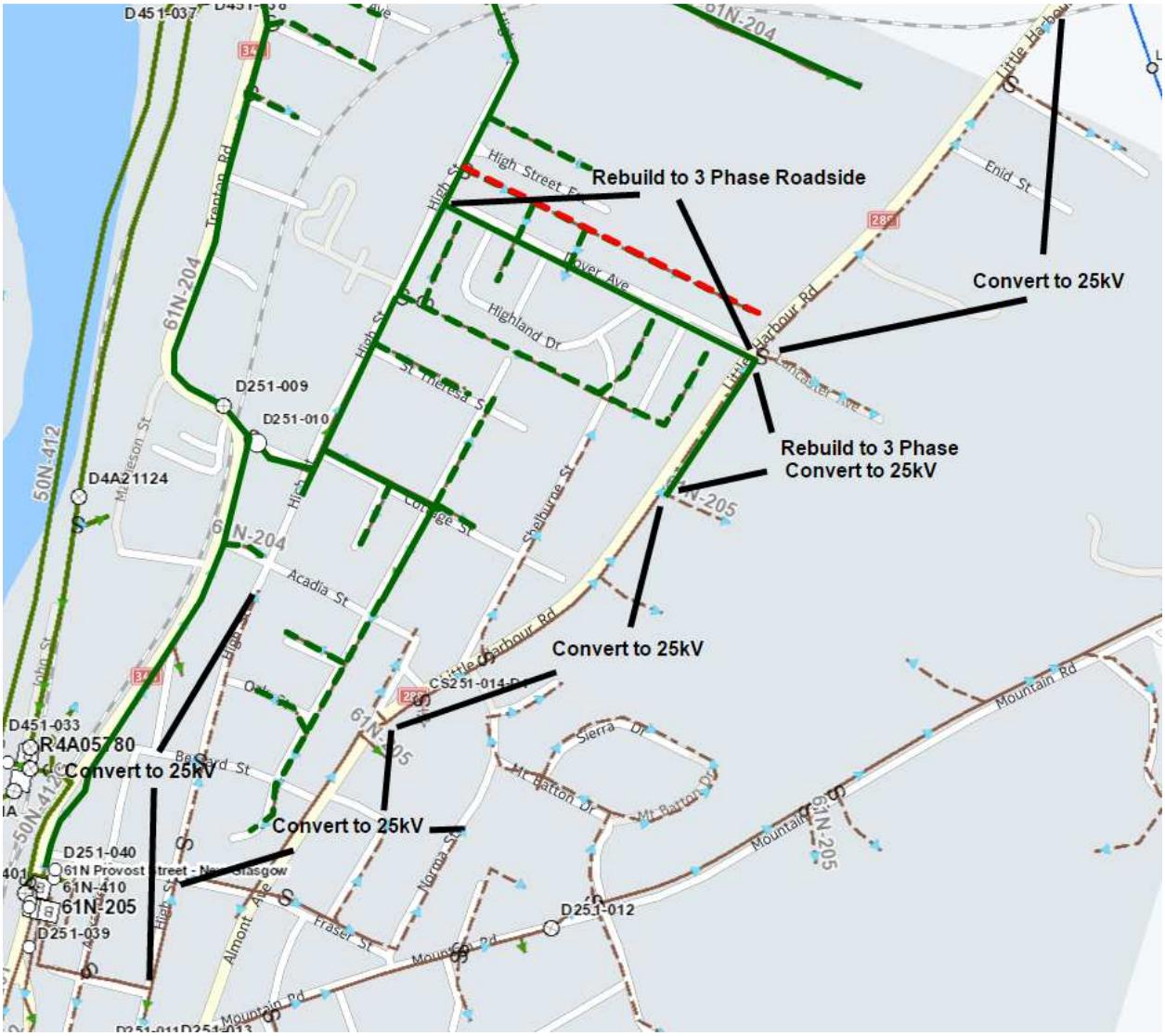


Figure 25 Little Harbour Road Conversion (61N-Provost Phase 3)

6.4.3 530N-MacLellan Mountain Road Conversion (Thorburn)

The 100kVA single phase transformer (530N-T1) on MacLellan Mountain Road is suspected to be at or near capacity. This small pocket of 4kV should be converted when resources are available. The conversion has no sequential effect on other conversions, so it can be advanced or deferred as required.

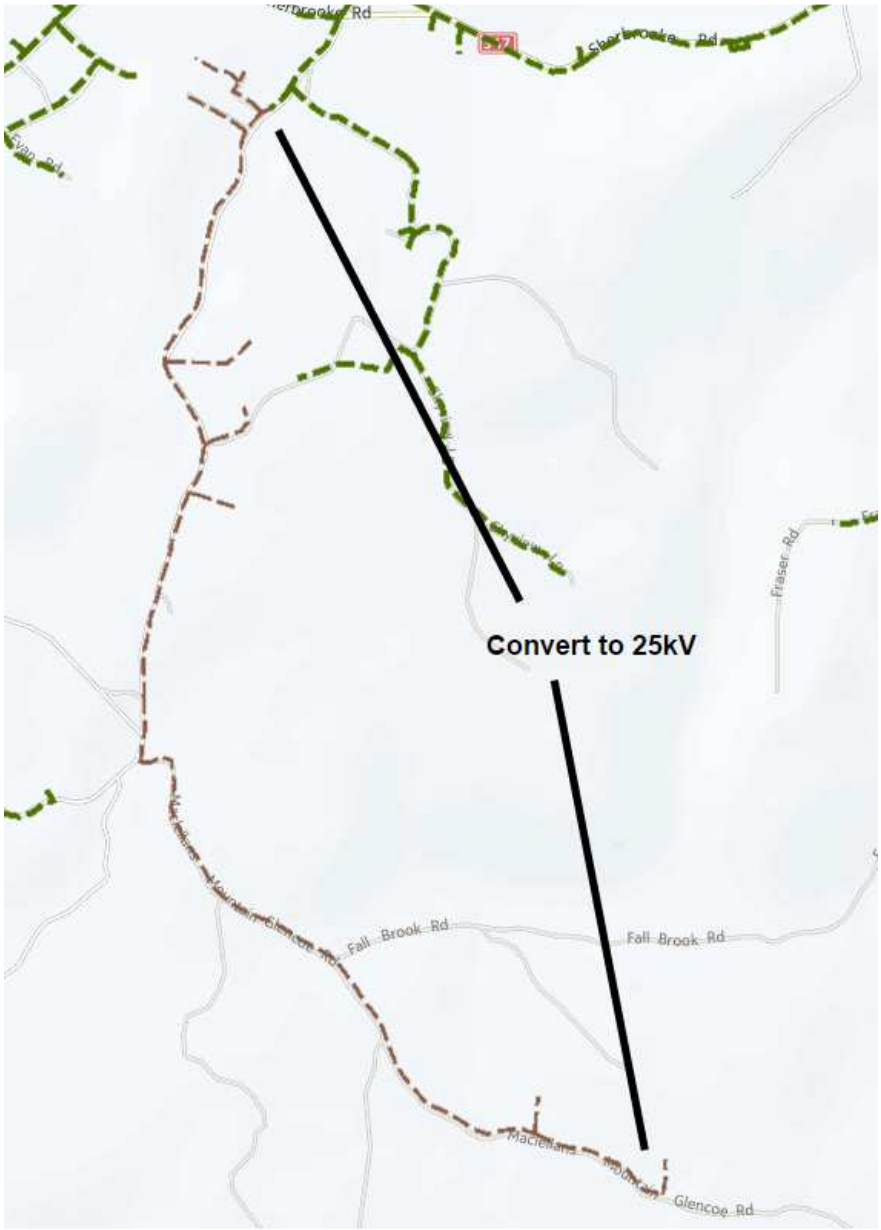


Figure 26 530N-MacLellan Mountain Road Conversion (Thorburn)

6.5 2020 Capital Year

In 2020, the conversion of 61N-205 should be mostly completed and the phased conversion of 528N should begin.

6.5.1 Frasers Mountain Road Conversion (61N-Provost Phase 4)

The fourth phase of conversion for 61N-Provost will cover Fraser Mountain Road.

- Rebuild and convert three phase from Little Harbour Road to Fraser Mountain Road
- Convert the long rural northwest extent of Fraser Mountain Road, dual voltage transformers could be used to limit outage time
- Convert Mountain Road in sections back to D251-013

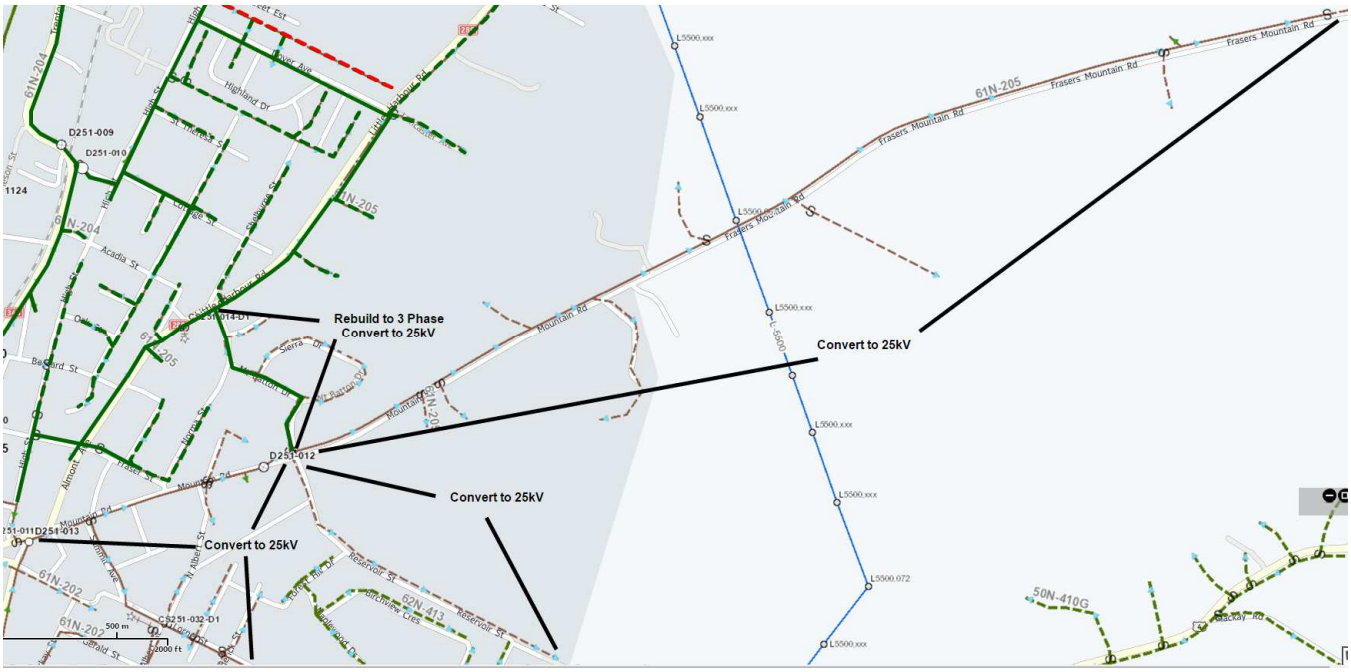


Figure 27 Frasers Mountain Road Conversion (61N-Provost Phase 4)

6.5.2 Albert Street Conversion (528N-Granville Phase 1)

The first phase of conversion for 528N-Granville extends 25kV from Lorne Street onto Albert St and back to D251-018 on Washington Street.

Figure 28 Albert Street Conversion (528N-Granville Phase 1)

6.6 2021 Capital Year

In 2021, the conversion of 61N-205 and 528N-202 should be completed.

6.6.1 528N-202 Conversion (528N-Granville Phase 2)

The second phase of conversion for 528N-Granville completes the conversion of 528N-202. This conversion will break the tie between 528N-202 and 61N-202.

- Extend 25kV three phase on Marsh Street
- Convert feeder 528N-202 in sections back from

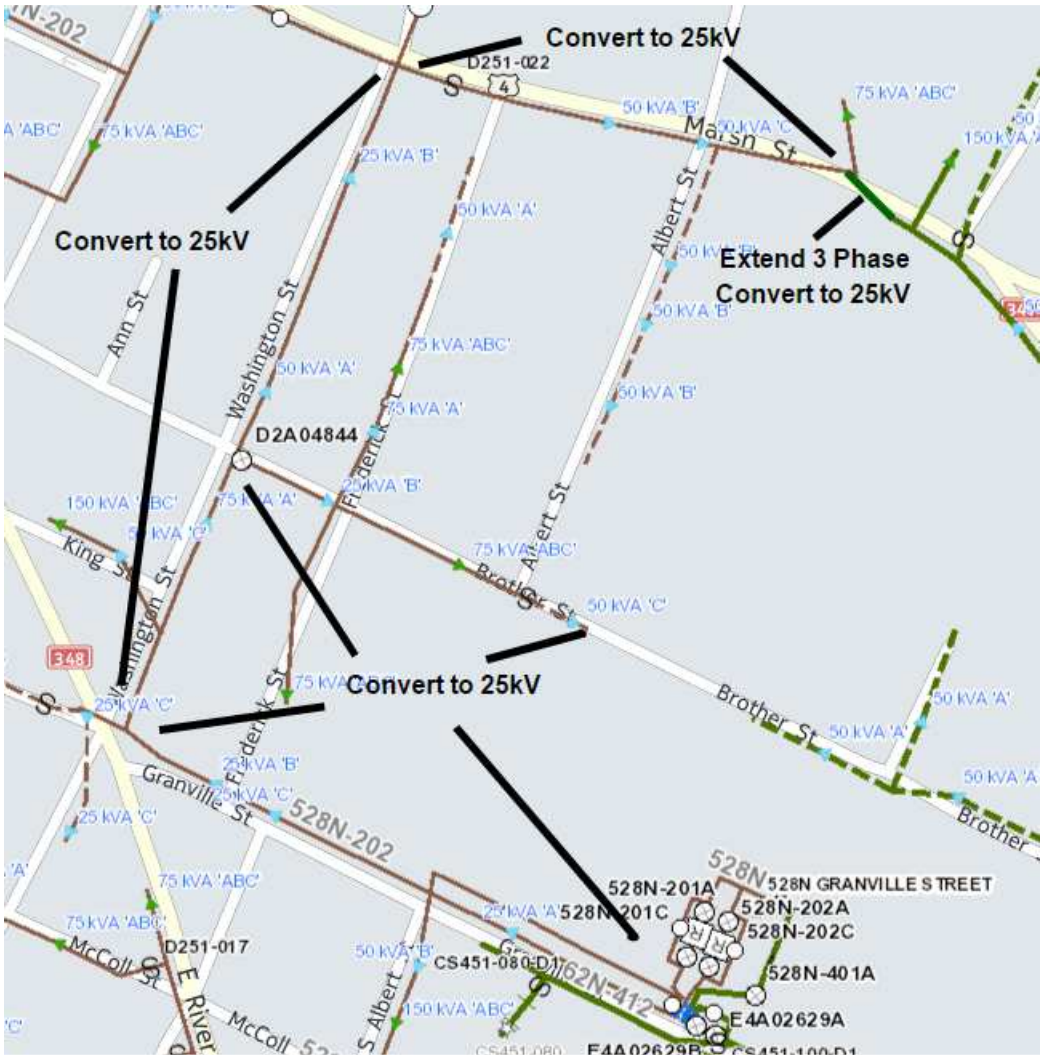


Figure 29 528N-202 Conversion (528N-Granville Phase 2)

6.6.2 Temperance Conversion (528N-Granville Phase 3)

The third phase of conversion for 528N-Granville (and 61N-Provost) covers Temperance Street, from Marsh Street back to 61N-Provost Street substation.

Figure 30 Temperance Conversion (528N-Granville Phase 3)

6.7 2022 Capital Year

In 2022, the conversion of 61N and 528N should be completed.

6.7.1 Archimedes Street Conversion (61N-Provost Phase 5)

The fifth phase of conversion for 61N-Provost covers Archimedes Street back to 61N substation.

- Extend 25kV three phase from Donald Street to Archimedes
- Convert Archimedes to 25kV in sections from Donald Street to 61N substation

Figure 31 Archimedes Street Conversion (61N-Provost Phase 5)

6.7.2 61N-201/528N-201 Conversions (528N-Granville Phase 4)

This final phase will complete the conversion of 61N and 528N to 25kV. Use the 61N-201 feeder to provide a 4kV source while the conversion is completed in sections back from 528N-Granville.

Figure 32 61N-201/528N-201 Conversions (528N-Granville Phase 4)

6.8 2023 Capital Year

The remainder of the 4kV conversions have been included in the 2023 capital year to maintain visibility. These areas are pockets of 4kV and have no impact on other conversions. They should be advanced or deferred as required.

6.8.1 534N-Duchess Avenue Conversion

This will complete the conversion of Duchess Avenue which began in 2014. It is unlikely this transformer will be overloaded, but deterioration issues will be present. This conversion could be divided into two phases.

Figure 33 534N-Duchess Avenue Conversion

6.8.2 519N-Drummond Road Conversion

This will complete the conversion of Drummond Road which began in 2012. It is unlikely this transformer will be overloaded, but deterioration issues will be present. This conversion could be divided into two phases.

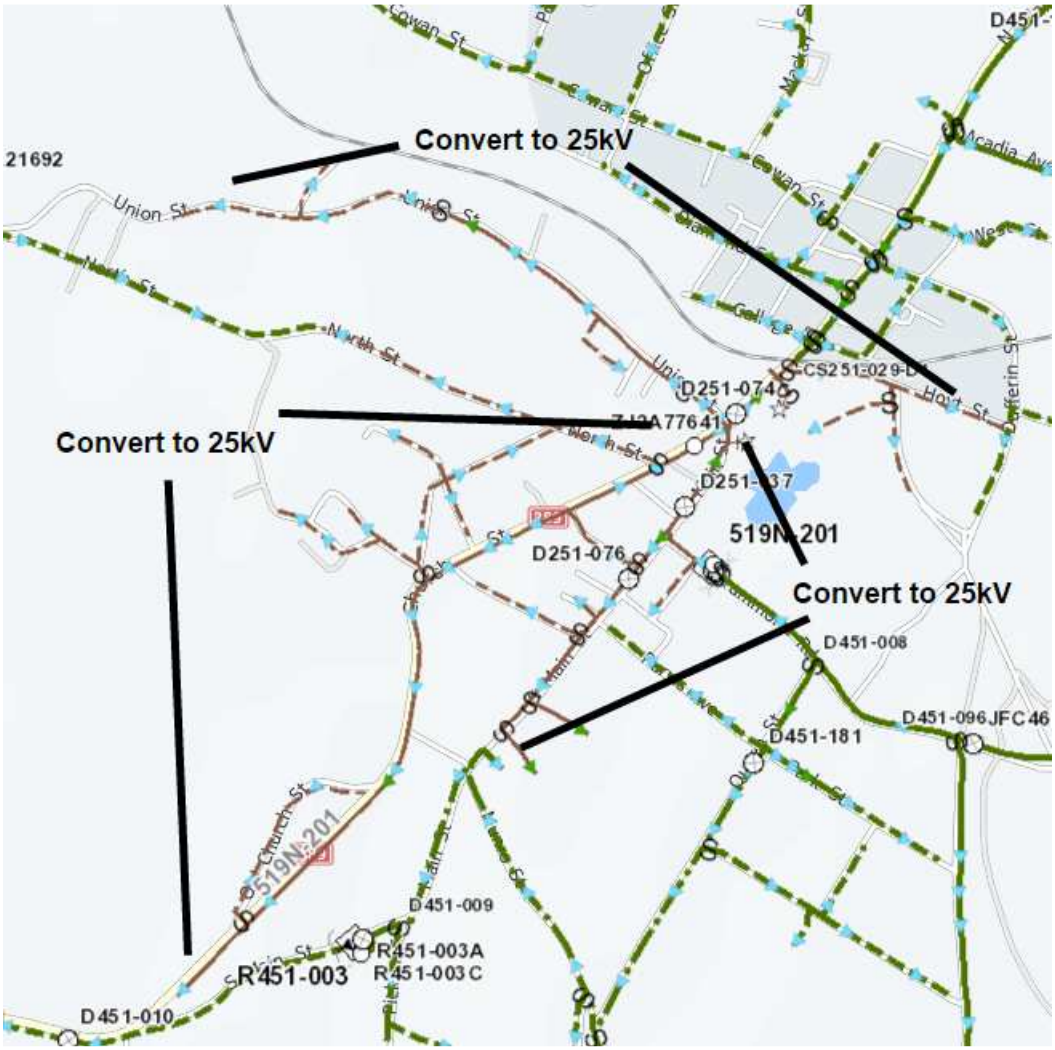


Figure 34 519N-Drummond Road Conversion

6.8.3 658N-Pictou Landing Conversion

This will complete the conversion of Pictou Landing 4kV. It is unlikely this transformer will be overloaded, but deterioration issues will be present.

Figure 35 658N-Pictou Landing Conversion

6.8.4 536N-Woodburn Conversion

This will complete the conversion of Pictou Landing 4kV. It is unlikely this transformer will be overloaded, but deterioration issues will be present. With this conversion, the voltage regulator E2A01301 and step up transformer 547N-T1 can be removed.

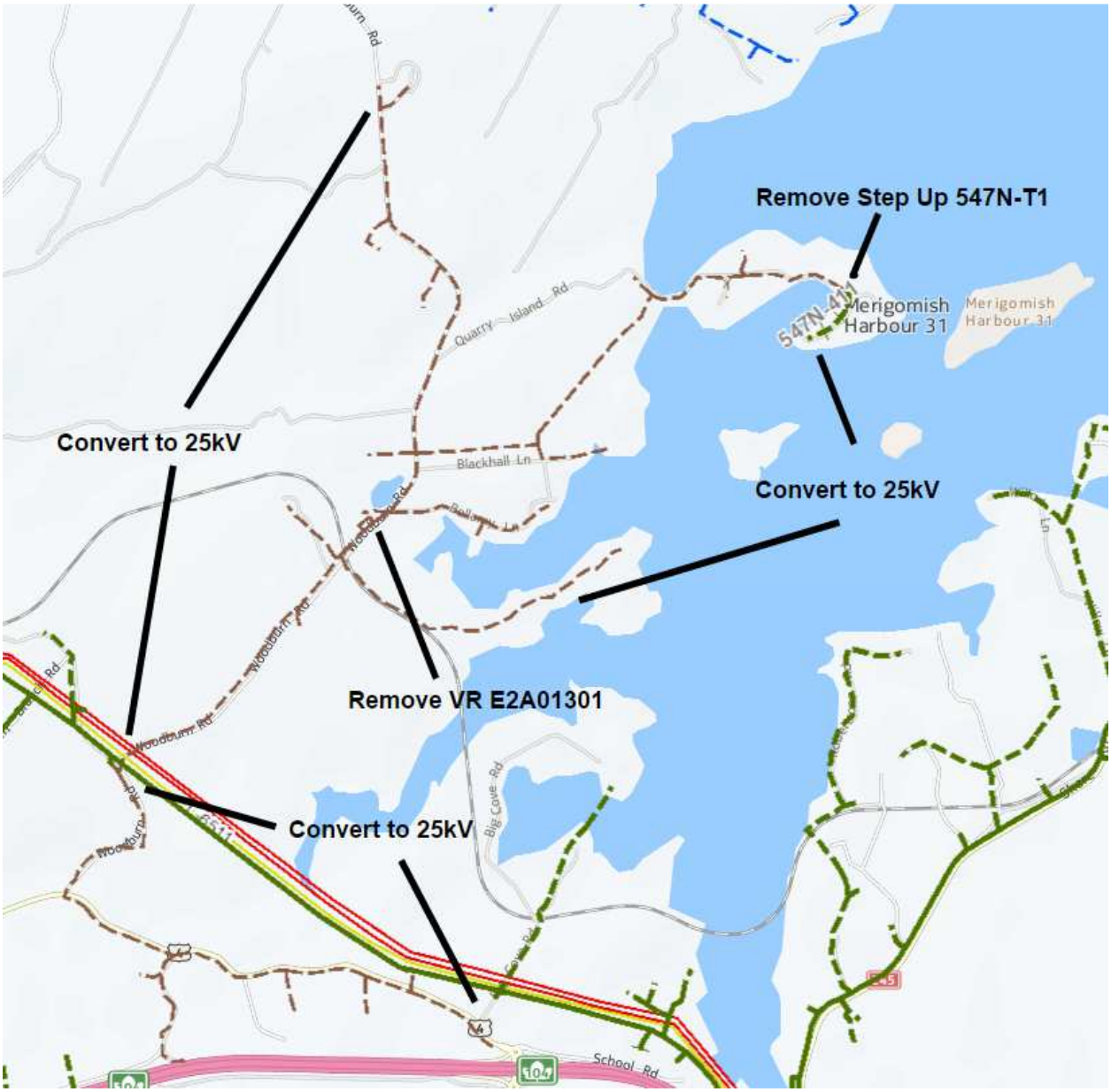


Figure 36 536N-Woodburn Conversion

APPENDIX A

System Operating Diagrams

Pages 53-54 (Attachment 1) have been removed due to confidentiality.

APPENDIX B

Load History and Forecast

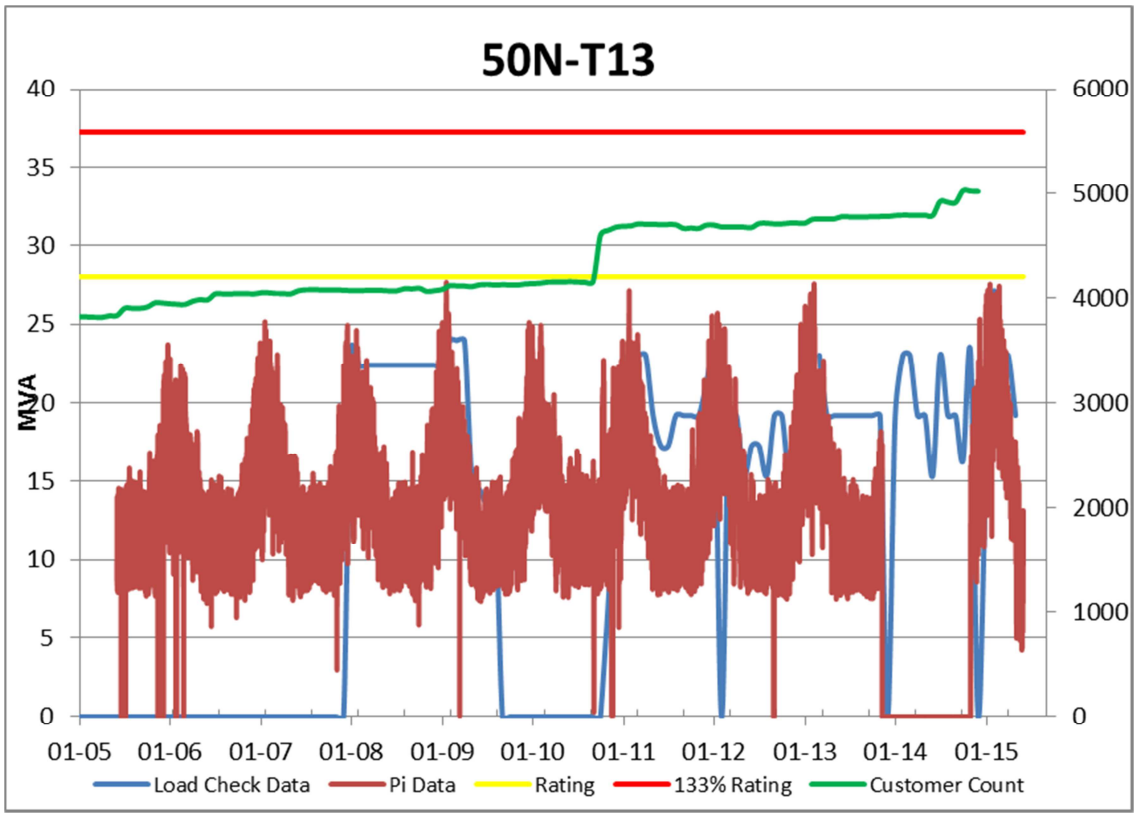


Figure 39 **50N-T13 Load History**

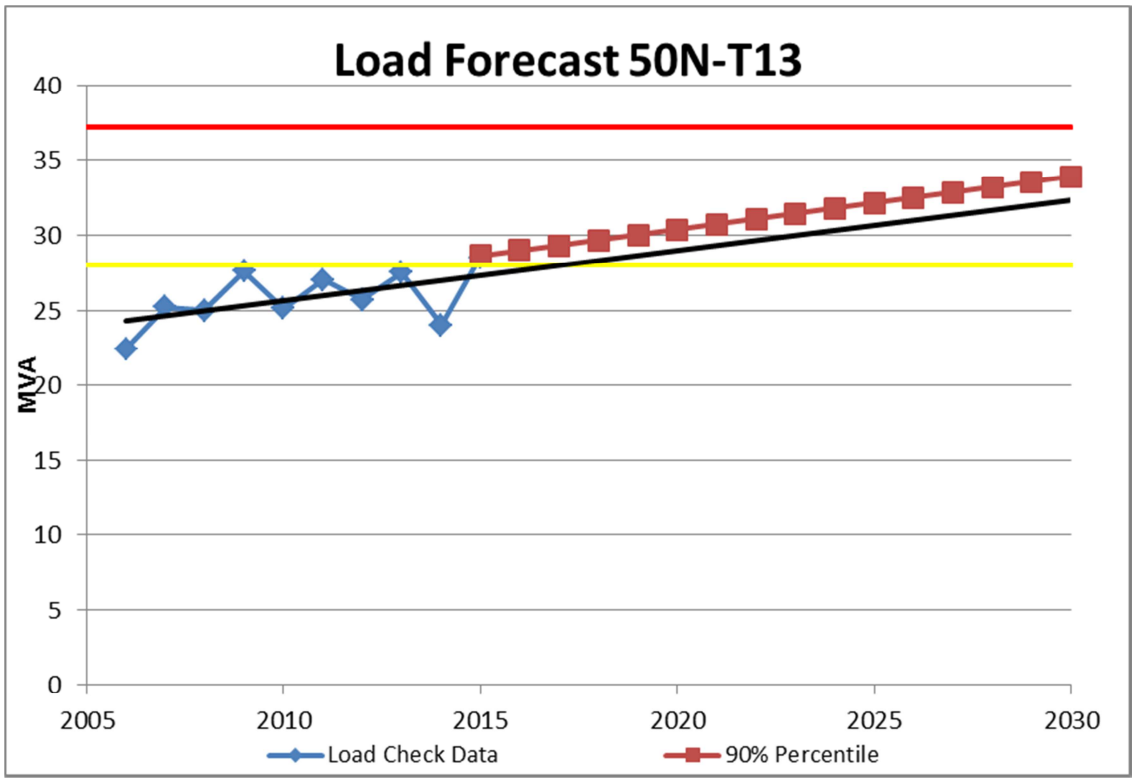


Figure 40 **50N-T13 Load Forecast**

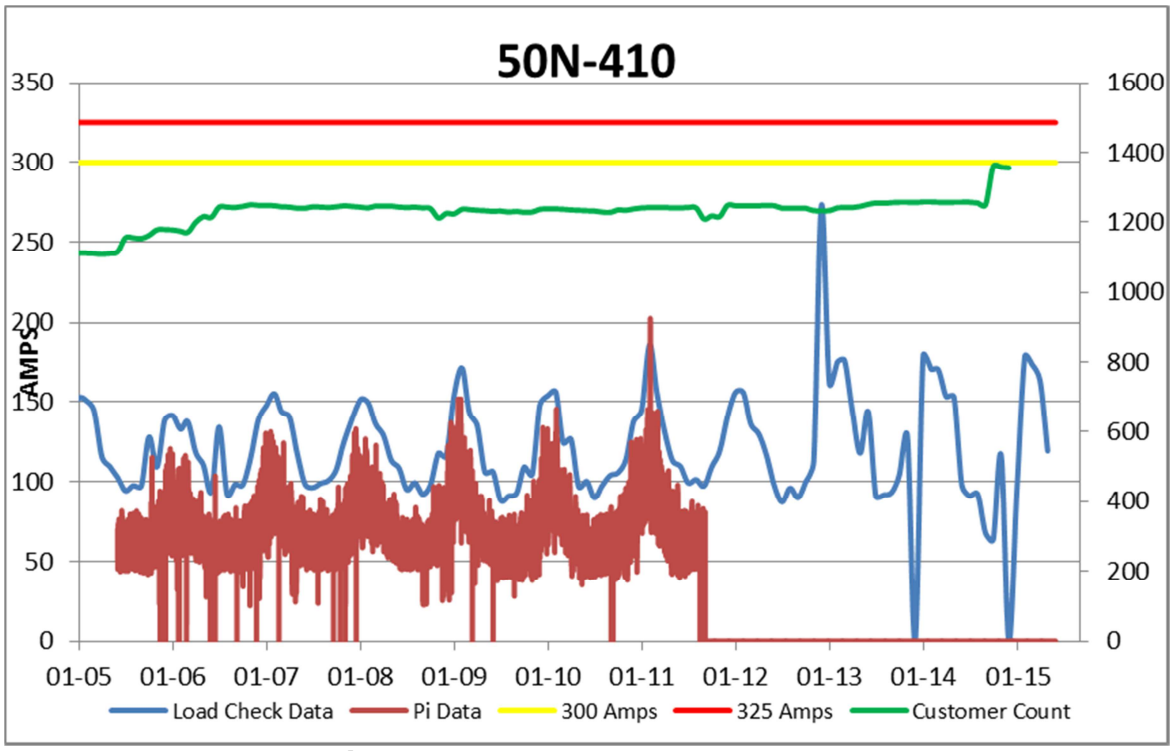


Figure 41 50N-410 Load History

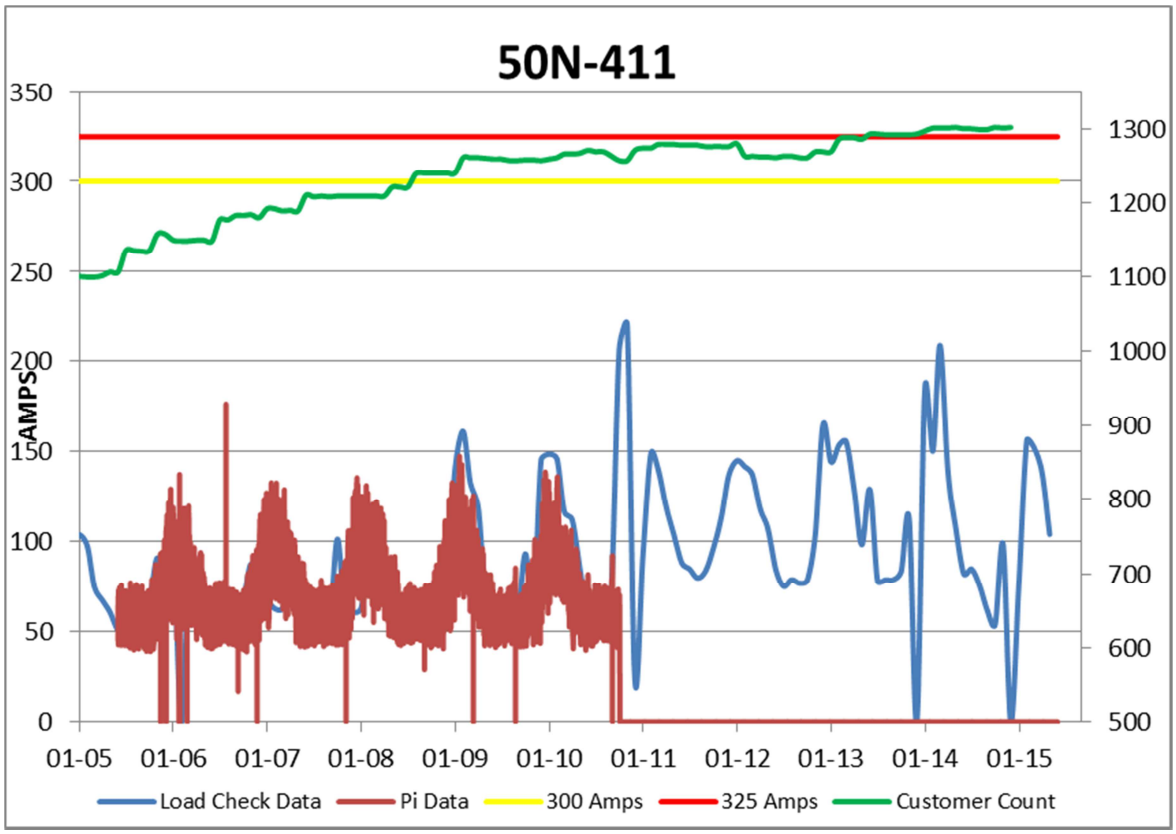


Figure 42 50N-411 Load History

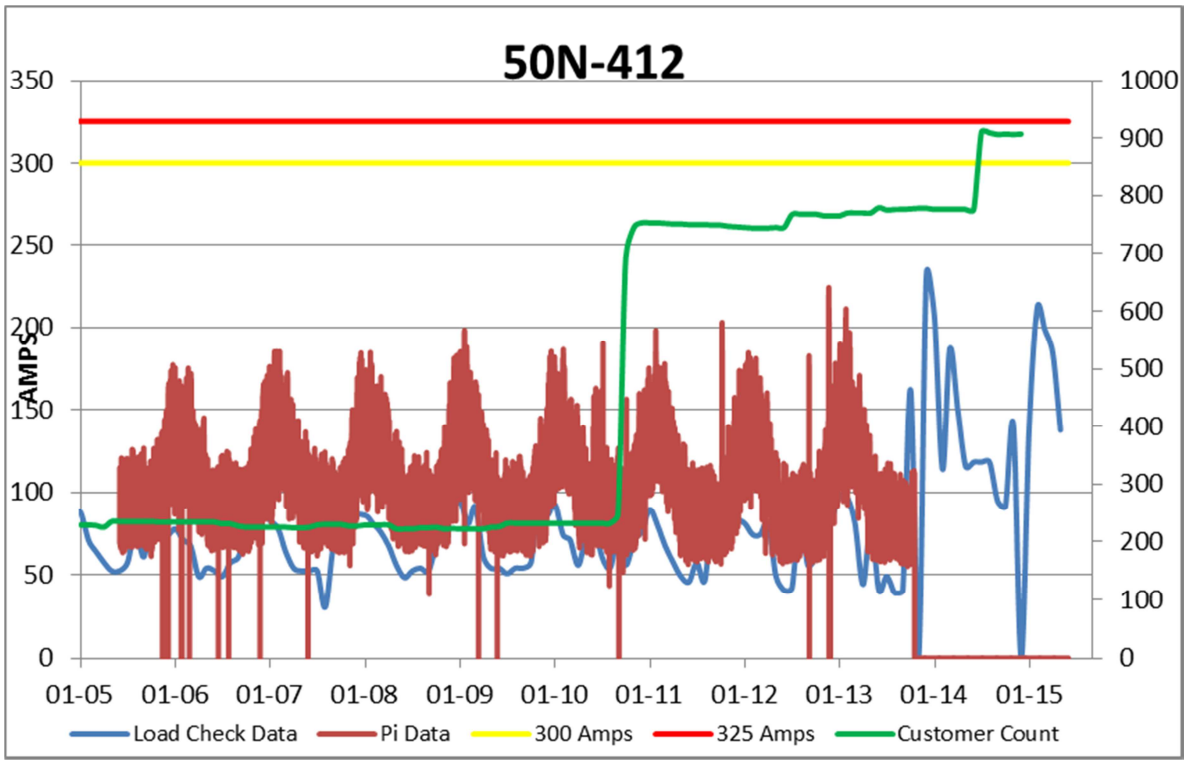


Figure 43 50N-412 Load History

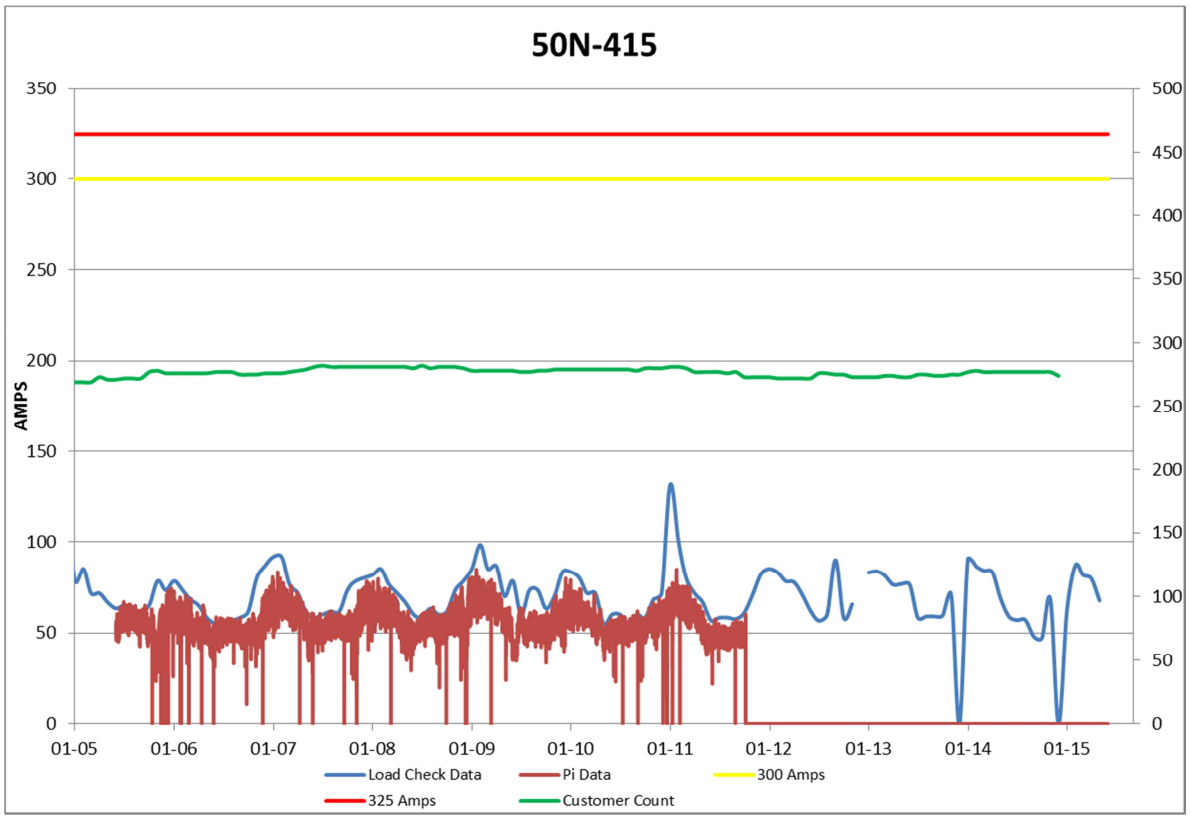


Figure 44 50N-415 Load History

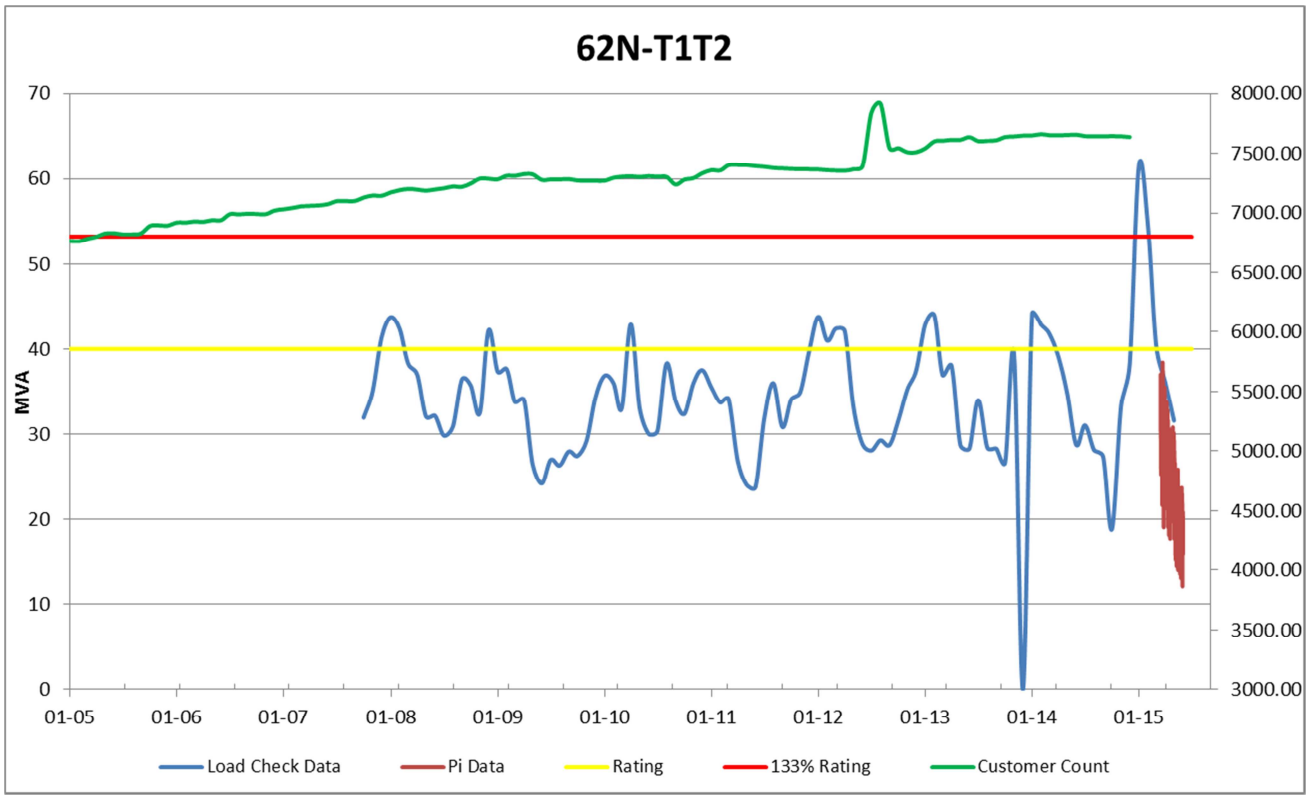


Figure 45 62N-T1T2 Load History

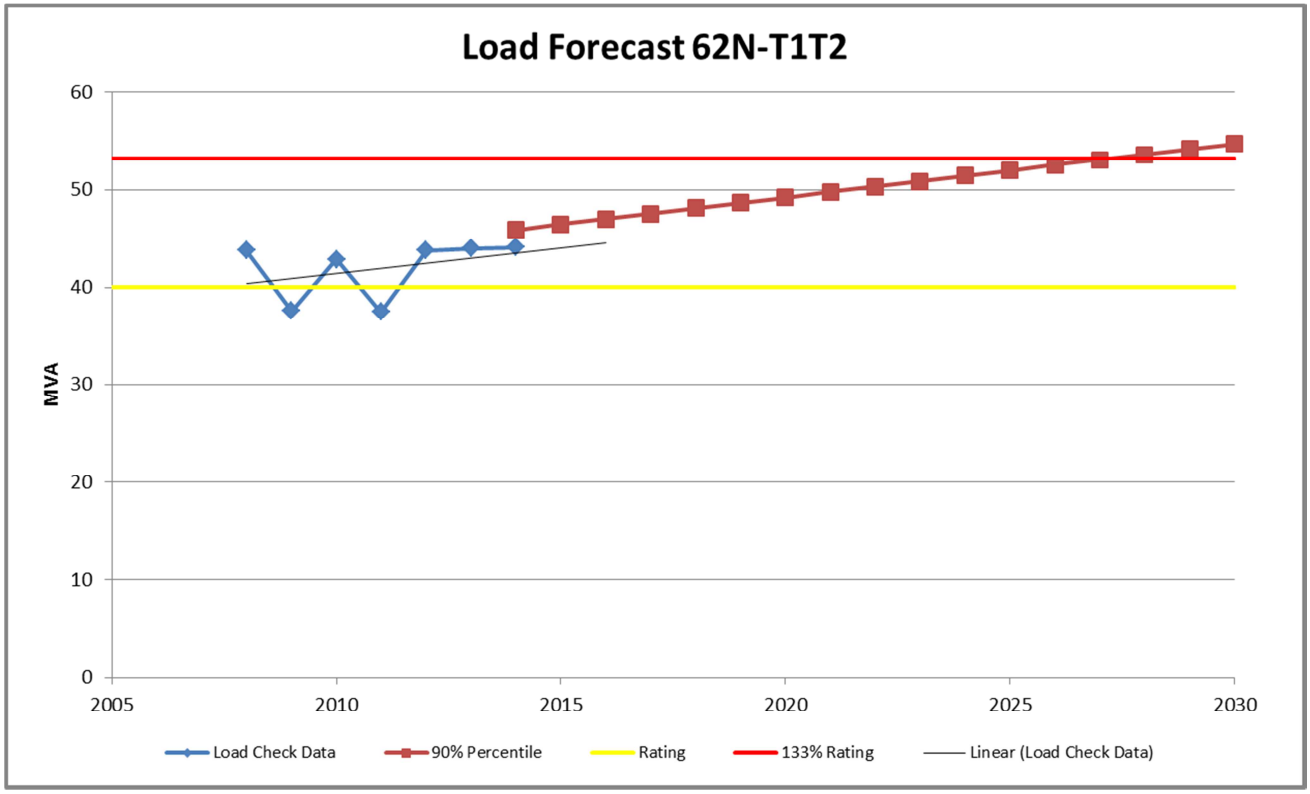


Figure 46 62N-T1T2 Load Forecast

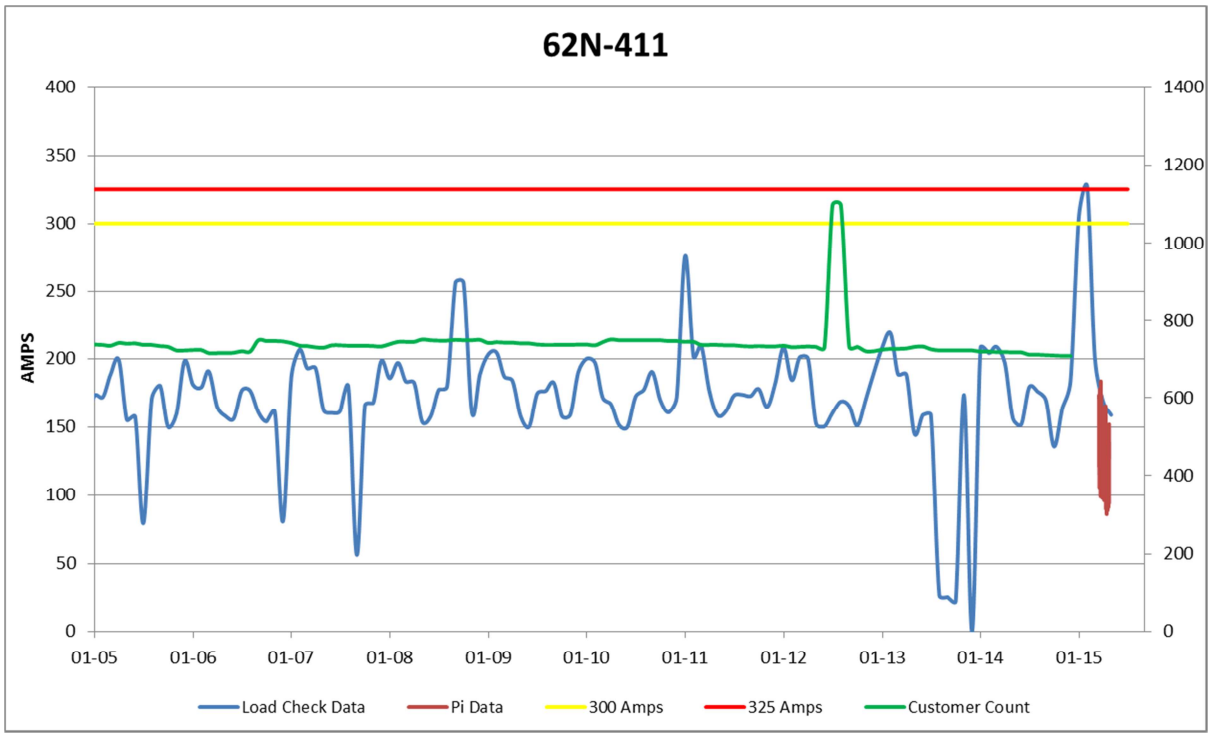


Figure 47 62N-411 Load History

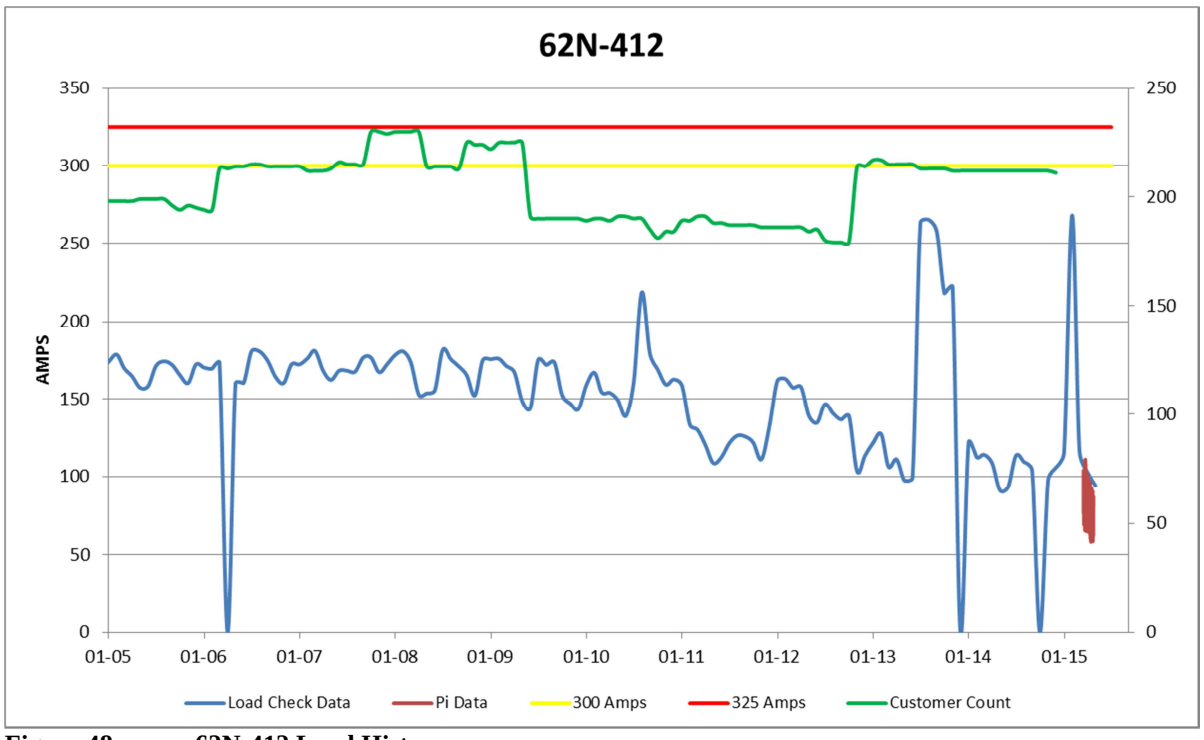


Figure 48 62N-412 Load History

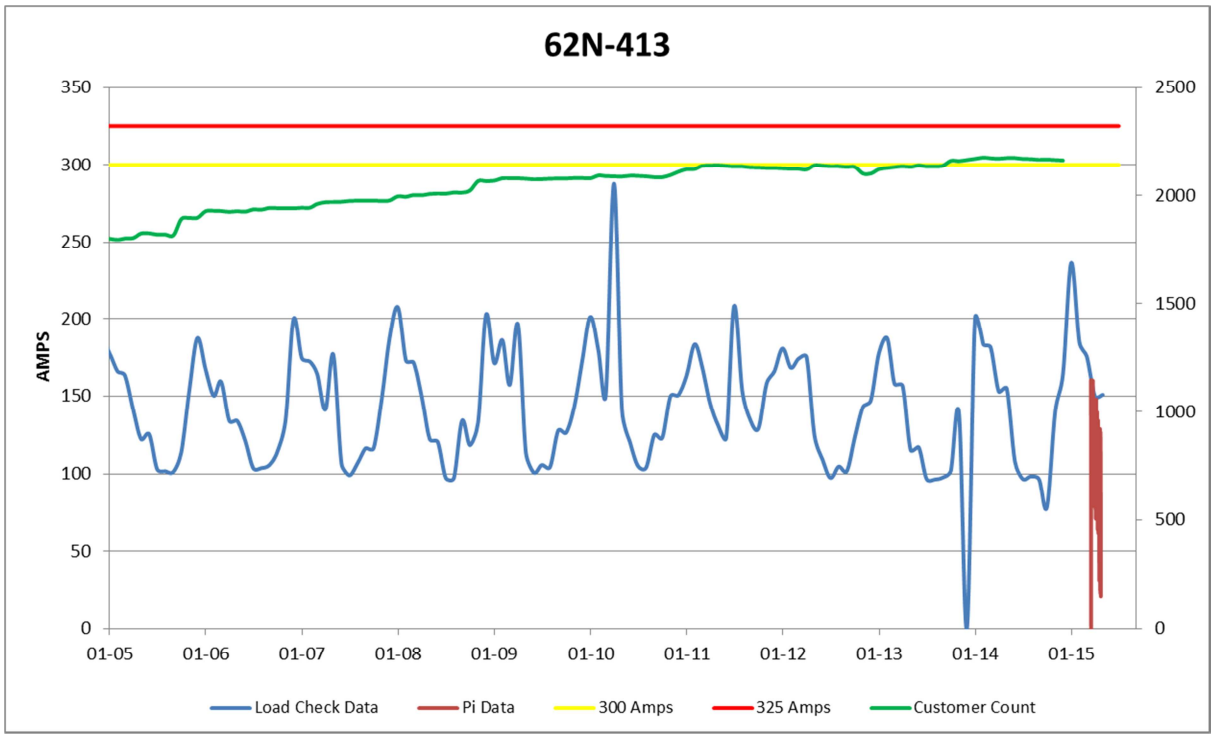


Figure 49 62N-411 Load History

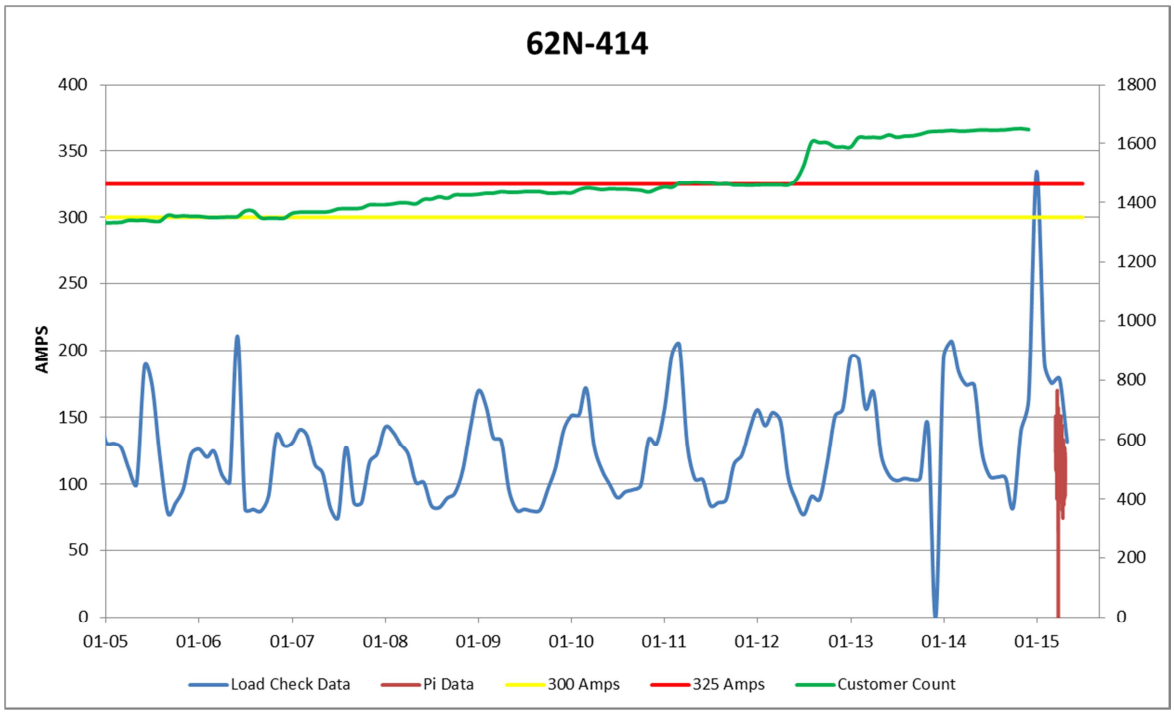


Figure 50 62N-411 Load History

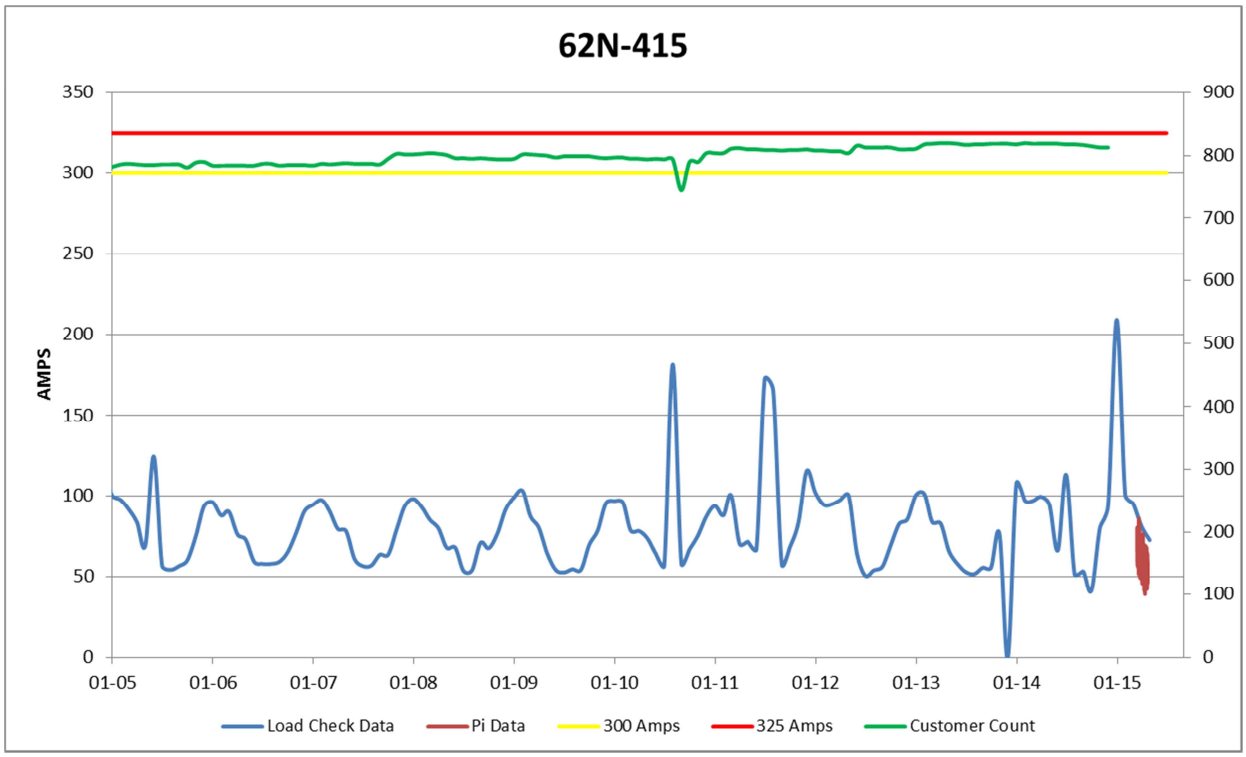


Figure 51 62N-411 Load History

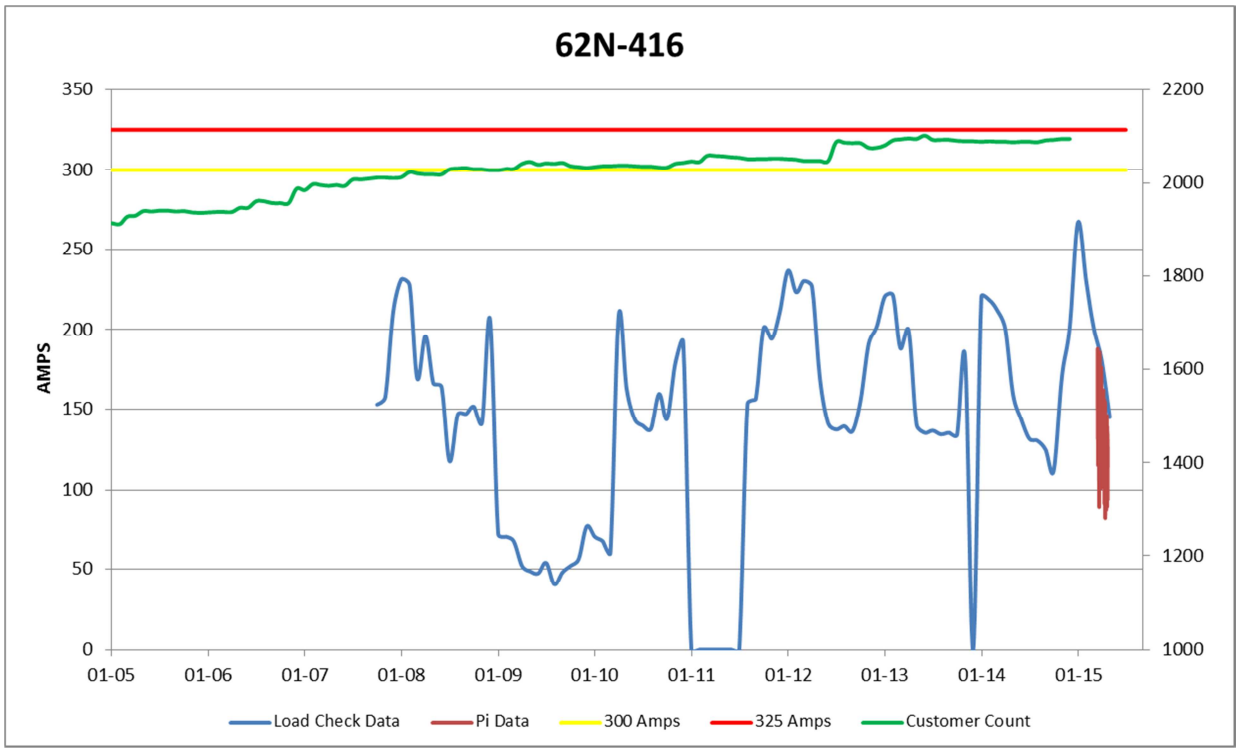


Figure 52 62N-411 Load History

APPENDIX C

Economic Analysis

532N-Elm St and 64N-Lourdes Alternatives

Summary of Alternatives

Stellarton 4kV
Summary of Alternatives

Division :		**Date :**	**13-Aug-15**
Department :	Distribution Planning	**CI Number:**	
Originator :	Brendon Henderson	**Project No. :**	

	Alternative	After Tax WACC	PV of Revenue Requirement	PV of EVA / NPV	Rank (based on PV of RR)	IRR	Disc Pay
A	Convert to 25kV	6.07%	1,672,608	-1,275,336	1	-8.03%	0.0 years
B	Three Stepdown Locations	6.07%	1,768,459	-1,465,093	2	-11.17%	0.0 years
C	Two Padmounts	6.07%	1,924,374	-1,823,638	3	#NUM!	0.0 years
	0	NA	NA	NA	NA	#NUM!	0.0 years

Recommendation :

The conversion to 25kV has a greater up front cost, but is the most economical choice in the long term. Further intangible benefits for converting are explained in full planning study. This analysis is valid for all 4kV pockets in Stellarton area, given their similarities.

Notes/Comments :

Convert to 25kV

Complete a phased conversion of all 4kV plant to 25kV. Retire 532N-Elm and 64N-Lourdes in 2018.

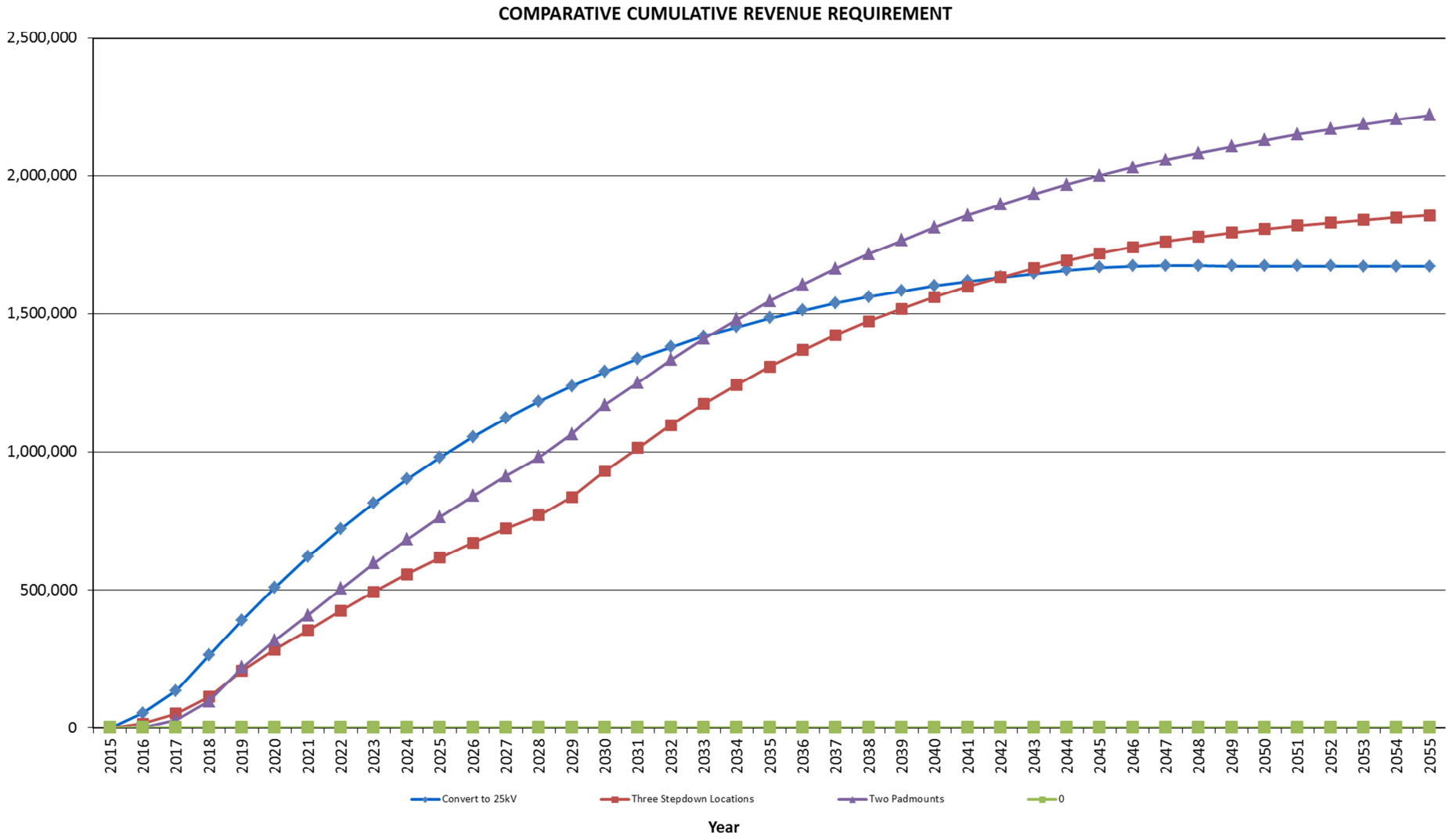
Three Stepdown Locations

Install new platform mounted stepdown transformers to remove load from 4kV substations to allow retirement of 532N-Elm and 64N-Lourdes in 2018. This delays the conversion to 25kV by 15 years.

Two Padmounts

Replace existing 4kV substations with padmount transformers. Both 532N-Elm and 64N-Lourdes replaced by 2018. This delays the conversion to 25kV by 15 years.

NPV Comparison



Alternative A- Convert to 25kV

Stellarton 4kV
Convert to 25kV

Nova Scotia POWER An Emera Company

Go to: Working Capital | Capital | Expenses | Revenue

Add Operating Item | Add Capital | Project Description | Delete Item

Select:
In-Service Month: January
In-Service Year: 2016

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital Invested																	
1. Elm St - Terrace		293,760															
2. Elm St - North Mitchell			262,181														
3. Elm St - South Mitchell			374,544														
4. Lourdes - View St		512,448															
5. Lourdes - Stellarton Rd				299,897													
6.																	
7.																	
8.																	
9.																	
10.																	
11.																	
12.																	
13.																	
14.																	
15.																	
16.																	
17.																	
18.																	
19.																	
20.																	
Total Direct Capital Invested by Year		806,208	636,725	299,897													
AFUDC (entered as a positive value)																	
AO (entered as a positive value)																	
Total Indirect Capital Invested by Year																	
Total Capital Invested by Year		**806,208**	**636,725**	**299,897**													

*This alternative was used as the baseline for operating costs, additional cost is shown for other alternatives.

Alternative B- Three Stepdown Locations

Stellarton 4kV
Three Stepdown Locations

Nova Scotia POWER An Emera Company

Go to: Working Capital | Capital | Expenses | Revenue

Add Operating Item | Add Capital | Project Description | Delete Item

Select:
In-Service Month: January
In-Service Year: 2016

Capital Invested

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1.	Terrace St Stepdown		163,200															
2.	Elm St Stepdown			166,464														
3.	Lourdes Stepdown				275,914													
4.	Terrace Conversion															380,010		
5.	North Mitchell Conversion																339,159	
6.	South Mitchell Conversion																484,513	
7.	View St Conversion															662,906		
8.	Stellarton Rd Coversion																	387,950
9.																		
10.																		
11.																		
12.																		
13.																		
14.																		
15.																		
16.																		
17.																		
18.																		
19.																		
20.																		
	Total Direct Capital Invested by Year		163,200	166,464	275,914											1,042,916	823,672	387,950
	AFUDC (entered as a positive value)																	
	AO (entered as a positive value)																	
	Total Indirect Capital Invested by Year																	
	Total Capital Invested by Year		**163,200**	**166,464**	**275,914**											**1,042,916**	**823,672**	**387,950**

Expense

	Description		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
1.	Stepdown Transformation Losses	Cost	1,310	1,241	1,226	1,174	2,827	2,027	1,981	2,571	2,623	2,621	2,716	2,705	2,765	2,848	2,888	2,975	3,072
		$/Unit		3	6	9	9	9	9	9	9	9	9	9	9	9	9	9	
		Expense-Subtotal		3,722	7,354	10,570	25,441	18,240	17,829	23,139	23,611	23,592	24,448	24,345	24,889	25,632	25,993	26,773	
2.	532N 4kV Distribution Tx Losses (less 25kV	Cost	5,244	4,985	4,933	4,743	9,949	7,487	7,364	9,589	9,750	9,764	10,095	10,092	10,339	10,668	10,827	11,169	11,556
		$/Unit		0.33	0.66	1	1	1	1	1	1	1	1	1	1	1	1	1	
		Expense-Subtotal		1,645	3,256	4,743	9,949	7,487	7,364	9,589	9,750	9,764	10,095	10,092	10,339	10,668	10,827	11,169	
3.	64N 4kV Distribution Tx Losses (less 25kV Distribution losses)	Cost	4,899	4,654	4,605	4,425	9,162	6,930	6,820	8,908	9,052	9,067	9,373	9,374	9,607	9,916	10,065	10,387	10,751
		$/Unit			0.5	1	1	1	1	1	1	1	1	1	1	1	1	1	
		Expense-Subtotal			2,302	4,425	9,162	6,930	6,820	8,908	9,052	9,067	9,373	9,374	9,607	9,916	10,065	10,387	
4.	532N 4kV Conductor Losses	Cost	1,624	1,544	1,528	1,469	4,232	2,858	2,773	3,494	3,591	3,578	3,720	3,683	3,749	3,842	3,892	3,992	4,101
		$/Unit		0.33	0.66	1	1	1	1	1	1	1	1	1	1	1	1	1	
		Expense-Subtotal		509	1,008	1,469	4,232	2,858	2,773	3,494	3,591	3,578	3,720	3,683	3,749	3,842	3,892	3,992	
5.	64N 4kV Conductor Losses	Cost	6,829	6,490	6,422	6,174	17,790	12,016	11,658	14,689	15,095	15,044	15,638	15,483	15,759	16,153	16,361	16,784	17,242
		$/Unit			0.5	1	1	1	1	1	1	1	1	1	1	1	1	1	
		Expense-Subtotal			3,211	6,174	17,790	12,016	11,658	14,689	15,095	15,044	15,638	15,483	15,759	16,153	16,361	16,784	

Alternative C- Two Padmounts

Stellarton 4kV
Two Padmounts

Nova Scotia POWER An Emera Company

Go to: Working Capital | Capital | Expenses | Revenue

Add Operating Item | Add Capital | Project Description | Delete Item

Select:
In-Service Month: January
In-Service Year: 2016

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital Invested																		
1.	Elm St Padmount			436,968														
2.	Lourdes Stepdown				445,707													
3.	Terrace Conversion															380,010		
4.	North Mitchell Conversion																339,159	
5.	South Mitchell Conversion																484,513	
6.	View St Conversion															662,906		
7.	Stellarton Rd Coversion																	387,950
8.																		
9.																		
10.																		
11.																		
12.																		
13.																		
14.																		
15.																		
16.																		
17.																		
18.																		
19.																		
20.																		
Total Direct Capital Invested by Year				436,968	445,707											1,042,916	823,672	387,950
AFUDC (entered as a positive value)																		
AO (entered as a positive value)																		
Total Indirect Capital Invested by Year																		
Total Capital Invested by Year				**436,968**	**445,707**											**1,042,916**	**823,672**	**387,950**

Appendix C: Economic Analysis

Expense

	Description		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
1.	Stepdown Transformation Losses	Cost	10,456	9,904	9,784	9,377	22,770	16,274	15,902	20,607	21,035	21,016	21,781	21,684	22,164	22,820	23,140	23,829	24,600
		$/Unit			1.0	2	2	2	2	2	2	2	2	2	2	2	2	2	
		Expense-Subtotal			9,784	18,755	45,540	32,549	31,804	41,215	42,070	42,032	43,563	43,368	44,327	45,639	46,280	47,659	
2.	532N 4kV Distribution Tx Losses (less 25kV Distribution Losses)	Cost	5,244	4,985	4,933	4,743	9,949	7,487	7,364	9,589	9,750	9,764	10,095	10,092	10,339	10,668	10,827	11,169	11,556
		$/Unit		0.33	0.66	1	1	1	1	1	1	1	1	1	1	1	1	1	
		Expense-Subtotal		1,645	3,256	4,743	9,949	7,487	7,364	9,589	9,750	9,764	10,095	10,092	10,339	10,668	10,827	11,169	
3.	64N 4kV Distribution Tx Losses (less 25kV Distribution losses)	Cost	4,899	4,654	4,605	4,425	9,162	6,930	6,820	8,908	9,052	9,067	9,373	9,374	9,607	9,916	10,065	10,387	10,751
		$/Unit			0.5	1	1	1	1	1	1	1	1	1	1	1	1	1	
		Expense-Subtotal			2,302	4,425	9,162	6,930	6,820	8,908	9,052	9,067	9,373	9,374	9,607	9,916	10,065	10,387	
4.	532N 4kV Conductor Losses	Cost	1,624	1,544	1,528	1,469	4,232	2,858	2,773	3,494	3,591	3,578	3,720	3,683	3,749	3,842	3,892	3,992	4,101
		$/Unit		0.33	0.66	1	1	1	1	1	1	1	1	1	1	1	1	1	
		Expense-Subtotal		509	1,008	1,469	4,232	2,858	2,773	3,494	3,591	3,578	3,720	3,683	3,749	3,842	3,892	3,992	
5.	64N 4kV Conductor Losses	Cost	6,829	6,490	6,422	$6,173.71	$17,789.85	$12,015.86	$11,657.93	$14,689.29	$15,095.17	$15,043.77	$15,637.66	$15,483.20	$15,759.03	$16,153.20	$16,360.88	$16,783.88	$17,242.04
		$/Unit			0.5	1	1	1	1	1	1	1	1	1	1	1	1	1	
		Expense-Subtotal			3,211	6,174	17,790	12,016	11,658	14,689	15,095	15,044	15,638	15,483	15,759	16,153	16,361	16,784	
6.	Monthly Subchecks	Cost				1,146	1,169	1,192	1,216	1,241	1,265	1,291	1,317	1,343	1,370	1,397	1,425	1,454	
		$/Unit				1	2	2	2	2	2	2	2	2	2	2	2	2	
		Expense-Subtotal				1,146	2,338	2,384	2,432	2,482	2,530	2,582	2,634	2,686	2,740	2,794	2,850	2,908	
7.	B Maintenance	Cost				637	649	662	676	689	703	717	731	746	761	776	792	808	
		$/Unit				1	2	2	2	2	2	2	2	2	2	2	2	2	
		Expense-Subtotal				637	1,298	1,324	1,352	1,378	1,406	1,434	1,462	1,492	1,522	1,552	1,584	1,616	
8.	C Maintenance (annualized)	Cost				1,327	1,353	1,380	1,408	1,436	1,465	1,494	1,524	1,554	1,585	1,617	1,649	1,682	
		$/Unit				1	2	2	2	2	2	2	2	2	2	2	2	2	
		Expense-Subtotal				1,327	2,706	2,760	2,816	2,872	2,930	2,988	3,048	3,108	3,170	3,234	3,298	3,364	
9.	Grounds upkeep	Cost				2,653	2,706	2,760	2,815	2,872	2,929	2,988	3,047	3,108	3,171	3,234	3,299	3,365	
		$/Unit				1	2	2	2	2	2	2	2	2	2	2	2	2	
		Expense-Subtotal				2,653	5,412	5,520	5,630	5,744	5,858	5,976	6,094	6,216	6,342	6,468	6,598	6,730	

APPENDIX D

Cost of Losses

D1. Station Transformer Losses

The losses of existing substation stepdown transformers were estimated using similar transformer test data as shown below. Note that the loss values of these transformers were not used in the EAM, since they do not remain in service for any of the alternatives.

Table 7 4kV Substation Transformer Loss Approximation

Station Transformers					
Station	**Man**	**Size (MVA)**	**Load (MVA)**	**LL (kW)**	**NLL (kW)**
61N-T1	Pioneer	5	4.16	30.45	10.715
528N-T1	GE	5	1.62	30.45	10.715
532N-T41	Brown Boveri	1	0.99	6.83	3.4
64N-T1	Packard	1	0.98	6.83	3.4

Table 8 Comparable 4kV Transformer Loss Data

Similar Transformers Test Data							
Location	**Station**	**Man**	**MVA**	**HV (kV)**	**LV (kV)**	**LL (kW)**	**NLL (kW)**
Tufts	36D-T1	Ferranti	0.9	22	4	6.83	3.4
HRM	1H-T51	Moloney	2	22.8	4	9.46	7.14
HRM	1H-T13/14	Brown Boveri	5	23	4	36.6	7.93
HRM	1H-T71	Bonar Long	5	22.8	4	24.3	13.5

D2. Stepdown Transformer Losses

The losses of the platform mounted stepdown transformers proposed in Alternative B were estimated using the document 'Old Transformer Losses' which is available on the Distribution Planning SharePoint under COST ESTIMATES.

Table 9 500kVA Stepdown Transformer Loss Approximation

Stepdown Transformers (500kVA)		
Station	**LL (kW)**	**NLL (kW)**
500kVA S.D.	3.57	0.96

D3. Padmount Transformer Losses

The losses of the padmount transformers proposed in Alternative C was estimated using the datasheet from a similar transformer installed on NSPI's system, 700S-T31.

Table 10 700S-T31 Padmount Loss Data

Padmount Transformers				
Station	**Man**	**Size (MVA)**	**LL (kW)**	**NLL (kW)**
700S	CARTE	5	29.488	7.32

D4. Distribution Transformer Losses

The difference in losses between existing 4kV and new 25kV distribution transformers was determined. This information was obtained from the document 'Historical Losses of Standard Design' and '2015 NSPI CARTE Transformers Data', both available on the Distribution Planning SharePoint site under COST ESTIMATES. In the tables below, 'New' refers to the CARTE 25kV transformers we would buy today and 'Old' refers to 4kV transformers bought circa 1960. The number of distribution transformers currently fed from 532N-Elm and 64N-Lourdes was used to estimate the loss savings resulting from conversion.

Table 11 Distribution Transformer Loss Data

Dist. Transformer Test Data			
	Size (kVA)	LL (W)	NLL (W)
New	25	368	56
	50	569	94.5
Old	25	505	130
	50	819	187

Table 12 Distribution Transformer Loss Savings from Conversion

Distribution Transformers									
			Old 4kV Tx		New 25kV Tx		Load Loss Savings		
Station	# of 50kVA	# of 25kVA	LL (W)	NLL (W)	LL (W)	NLL (W)	LL (kW)	NLL (kW)	Total (kW)
532N	51	18	50859	11877	35643	5827.5	15.22	6.05	21.27
64N	28	44	45152	10956	32124	5110	13.03	5.85	18.87

D5. Conductor Losses

The difference in conductor losses, before and after conversion to 25kV, was determined using CYME software. The existing system configurations for 532N-Elm and 64N-Lourdes were modelled at 4kV as well as 25kV. The built-in tool was used to calculate conductor losses. The following table summarizes the results.

Table 13 Line Losses Before and After Conversion

Line Losses from CYME after Conversions				
		Before (kW)	After (kW)	Savings (kW)
64N-Lourdes	201	34	0.83	33.17
532N-Elm	201	8.1	0.21	7.89

D6. The Cost of Losses

Alternative A was used as the baseline for losses in the EAM. The additional losses that would result from selecting Alternative B and Alternative C were determined in kilowatts. These values were converted to dollars using the tables found in '2015 Cost of Losses', available on the Distribution Planning SharePoint site under COST ESTIMATES. The future cost of losses at 31% loss factor was used for stepdown transformation and conductor losses. The future cost of losses at 12% loss factor was used for distribution transformers servicing customers. For background information, see report '254-0807-A48 Cost of NSPI Distribution System Losses'.

Table 14 Future Cost of Distribution Losses – 12% Loss Factor

	Future Cost of Distribution Losses - 12%					
YEAR	Load Losses			No Load Losses		
	Demand $/kW	Energy $/kW	Total	Demand $/kW	Energy $/kW	Total
2015	$33.54	$67.28	$100.81	$52.72	$560.64	$613.36
2016	$34.21	$63.07	$97.28	$53.78	$525.60	$579.38
2017	$34.89	$62.02	$96.91	$54.85	$516.84	$571.69
2018	$35.59	$58.87	$94.46	$55.95	$490.56	$546.51
2019	$211.06	$58.87	$269.93	$475.07	$490.56	$965.63
2020	$118.97	$63.07	$182.04	$254.21	$525.60	$779.81
2021	$112.60	$64.12	$176.73	$238.37	$534.36	$772.73
2022	$117.96	$95.66	$213.62	$250.56	$797.16	$1,047.72
2023	$125.84	$94.61	$220.44	$268.77	$788.40	$1,057.17
2024	$124.11	$95.66	$219.77	$264.01	$797.16	$1,061.17
2025	$130.77	$97.76	$228.53	$279.27	$814.68	$1,093.95
2026	$126.15	$99.86	$226.01	$267.55	$832.20	$1,099.75
2027	$125.31	$104.07	$229.38	$264.86	$867.24	$1,132.10
2028	$124.91	$109.32	$234.23	$263.20	$911.04	$1,174.24
2029	$125.78	$111.43	$237.20	$264.57	$928.56	$1,193.13
2030	$125.83	$116.68	$242.51	$263.96	$972.36	$1,236.32
2031	$125.06	$122.99	$248.05	$261.38	$1,024.92	$1,286.30
2032	$117.61	$132.45	$250.07	$242.82	$1,103.76	$1,346.58
2033	$122.73	$120.89	$243.62	$254.30	$1,007.40	$1,261.70
2034	$123.69	$144.01	$267.71	$255.81	$1,200.12	$1,455.93
2035	$124.25	$159.78	$284.03	$256.34	$1,331.52	$1,587.86
2036	$125.67	$168.19	$293.86	$258.91	$1,401.60	$1,660.51
2037	$128.77	$174.50	$303.27	$265.51	$1,454.16	$1,719.67
2038	$131.35	$177.99	$309.34	$270.82	$1,483.24	$1,754.06
2039	$133.98	$181.55	$315.52	$276.23	$1,512.91	$1,789.14
2040	$136.66	$185.18	$321.84	$281.76	$1,543.17	$1,824.92
2041	$139.39	$188.88	$328.27	$287.39	$1,574.03	$1,861.42
2042	$142.18	$192.66	$334.84	$293.14	$1,605.51	$1,898.65
2043	$145.02	$196.51	$341.53	$299.00	$1,637.62	$1,936.62
2044	$147.92	$200.44	$348.36	$304.98	$1,670.37	$1,975.36
2045	$150.88	$204.45	$355.33	$311.08	$1,703.78	$2,014.86
2046	$153.90	$208.54	$362.44	$317.31	$1,737.86	$2,055.16
2047	$156.97	$212.71	$369.69	$323.65	$1,772.61	$2,096.26
2048	$160.11	$216.97	$377.08	$330.12	$1,808.07	$2,138.19
2049	$163.32	$221.31	$384.62	$336.73	$1,844.23	$2,180.95
2050	$166.58	$225.73	$392.32	$343.46	$1,881.11	$2,224.57
2051	$169.91	$230.25	$400.16	$350.33	$1,918.73	$2,269.06

Table 15 Future Cost of Distribution Losses – 31% Loss Factor

YEAR	Future Cost of Distribution Losses - 31%					
	Load Losses			No Load Losses		
	Demand $/kW	Energy $/kW	Total	Demand $/kW	Energy $/kW	Total
2015	$32.09	$173.80	$205.88	$38.37	$560.64	$599.01
2016	$32.73	$162.94	$195.66	$39.14	$525.60	$564.74
2017	$33.38	$160.22	$193.60	$39.92	$516.84	$556.76
2018	$34.05	$152.07	$186.12	$40.72	$490.56	$531.28
2019	$384.25	$152.07	$536.32	$459.54	$490.56	$950.10
2020	$199.31	$162.94	$362.25	$238.37	$525.60	$763.97
2021	$185.81	$165.65	$351.46	$222.21	$534.36	$756.57
2022	$195.73	$247.12	$442.85	$234.08	$797.16	$1,031.24
2023	$210.68	$244.40	$455.08	$251.96	$788.40	$1,040.36
2024	$206.42	$247.12	$453.54	$246.86	$797.16	$1,044.02
2025	$218.89	$252.55	$471.44	$261.78	$814.68	$1,076.46
2026	$208.80	$257.98	$466.78	$249.71	$832.20	$1,081.91
2027	$206.25	$268.84	$475.10	$246.67	$867.24	$1,113.91
2028	$204.56	$282.42	$486.98	$244.64	$911.04	$1,155.68
2029	$205.39	$287.85	$493.24	$245.63	$928.56	$1,174.19
2030	$204.56	$301.43	$506.00	$244.64	$972.36	$1,217.00
2031	$202.08	$317.73	$519.81	$241.68	$1,024.92	$1,266.60
2032	$186.24	$342.17	$528.41	$222.73	$1,103.76	$1,326.49
2033	$195.50	$312.29	$507.79	$233.81	$1,007.40	$1,241.21
2034	$196.42	$372.04	$568.45	$234.90	$1,200.12	$1,435.02
2035	$196.52	$412.77	$609.29	$235.02	$1,331.52	$1,566.54
2036	$198.31	$434.50	$632.80	$237.16	$1,401.60	$1,638.76
2037	$203.46	$450.79	$654.25	$243.32	$1,454.16	$1,697.48
2038	$207.53	$459.81	$667.33	$248.19	$1,483.24	$1,731.43
2039	$211.68	$469.00	$680.68	$253.15	$1,512.91	$1,766.06
2040	$215.91	$478.38	$694.29	$258.22	$1,543.17	$1,801.38
2041	$220.23	$487.95	$708.18	$263.38	$1,574.03	$1,837.41
2042	$224.64	$497.71	$722.34	$268.65	$1,605.51	$1,874.16
2043	$229.13	$507.66	$736.79	$274.02	$1,637.62	$1,911.64
2044	$233.71	$517.82	$751.53	$279.50	$1,670.37	$1,949.87
2045	$238.39	$528.17	$766.56	$285.09	$1,703.78	$1,988.87
2046	$243.15	$538.74	$781.89	$290.79	$1,737.86	$2,028.65
2047	$248.02	$549.51	$797.53	$296.61	$1,772.61	$2,069.22
2048	$252.98	$560.50	$813.48	$302.54	$1,808.07	$2,110.61
2049	$258.04	$571.71	$829.75	$308.59	$1,844.23	$2,152.82
2050	$263.20	$583.14	$846.34	$314.76	$1,881.11	$2,195.88
2051	$268.46	$594.81	$863.27	$321.06	$1,918.73	$2,239.79

CI Number: C0001802

Title: 54C-211 Queen Street Conversion

Start Date: 2018/01
In-Service Date: 2018/04
Final Cost Date: 2018/10
Function Class: Distribution
Amount: $705,316

DESCRIPTION:

This project will partially convert the non-standard, deteriorated 4kV primary distribution feeder 54C-211 along Queen Street, and its side streets, in Port Hawkesbury. In order to complete this conversion, the existing 4kV source along Reeves Street will be completely removed, and two new 25kV extensions from feeder 1C-411 will be constructed along Sydney Road and Pitt Street. This conversion will require the upgrade of approximately 2 kilometres of existing 3-phase conductor to 336 AASC, the replacement of approximately 63 poles and associated framing and insulators, and the replacement of all existing single-tap transformers with dual-tap transformers.

Summary of Related CIs +/- 2 years:
2017 CI 50800 - 1C-411 Reinsulate and Pole Replacements Phase 1 - $442,732
2019 CI TBD - 1C-411 Reinsulate and Pole Replacements Phase 2 - $TBD

JUSTIFICATION:

Justification Criteria: Distribution System

Why do this project?

The targeted devices on 54C-211 are deteriorated and at risk of failure. The existing conductor can no longer be worked on under live conditions. In addition, this work is required to enable the conversion of non-standard, islanded 4kV equipment.

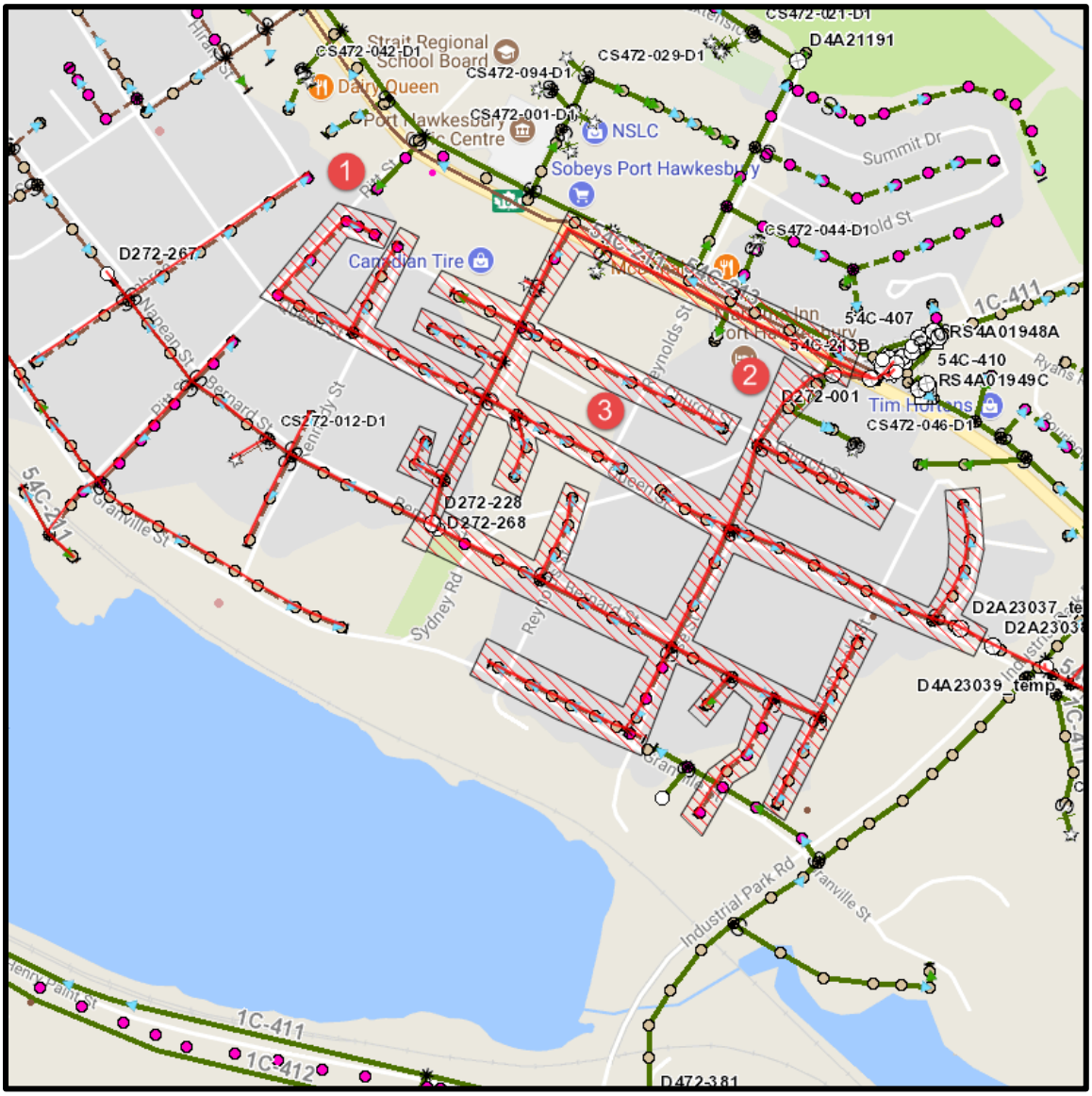
Why do this project now?

The targeted devices on 54C-211 are approximately 43 years old, and have reached the end of their expected service lives. Inspections of the targeted devices and assessments of age, condition and risk of failure have determined that replacements are required.

Why do this project this way?

There is no alternative source of supply for customers in the targeted area. Replacing the targeted assets is a more cost effective solution than rebuilding the entire line. Conductor and poles will be upgraded in accordance with current NS Power standards. In addition, voltage conversion is required as 4kV is no longer a NS Power standard. The remaining section of 54C-211 will be transferred to 54C-213 for future conversion.

The contracts portion of this project will be sourced through NS Power's existing Power Line Technician (PLT) Service Agreement with Emera Utility Services. This is aligned with NS Power's workforce planning model which is designed to optimize the allocation and execution of PLT resources among work requirements.



1. Extend feeder 1C-411, 25kV source along Pitt Street.
2. Extend feeder 1C-411, 25kV source along Sydney Road.
3. Upgrade existing conductor to 2/0 AASC, replace targeted poles, framing, insulators and replace all existing single-tap transformers with dual-tap transformers.

CI Number	: C0001802	- 54C-211 Queen Street Conversion	**Project Number**	C0001802
Parent CI Number	:	-		
Asset Location	: 1456	- 1456 Distribution General	**Budget Version**	2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	3500 - DP - Wood Poles	283,496
Additions	3800 - DP - Insulators	12,308
Additions	3900 - DP - O/H Cond.	144,344
Additions	4100 - DP - O/H Line Transf.	87,708
Additions	4800 - DP - U/G Line Transf.	96,323
Retirements	3500 - DP - Wood Poles	26,489
Retirements	3900 - DP - O/H Cond.	21,477
Retirements	4100 - DP - O/H Line Transf.	18,375
Retirements	4800 - DP - U/G Line Transf.	14,796
	Total Cost:	705,316
	Original Cost:	61,395

Capital Project Detailed Estimate

Location: Distribution
CI# / FP#: C0001802
Title: 54C-211 Queen Street Conversion
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
T&D Labour - Design	PD	10	$ 386	$ 3,695		
Procurement / Financial Support	Lot	1	$ 10,771	$ 10,771		
			Sub-Total	$ 14,466		
Materials						
Poles	Lot	1	$ 36,395	$ 36,395		
Insulators	Lot	1	$ 548	$ 548		
Conductor	Lot	1	$ 13,534	$ 13,534		
Cutouts	Lot	1	$ 50,540	$ 50,540		
Underground Line Transformer	Lot	1	$ 54,925	$ 54,925		
			Sub-Total	$ 155,942		
Contracts						
Contract Line Work	Hrs	[redacted]		$ 265,819		
Flagging	Lot	1	$ 60,037	$ 60,037		
Backhoe	Lot	1	$ 56,700	$ 56,700		
			Sub-Total	$ 382,555		
Other Goods & Services						
Contingency	%	10%	$ 552,964	$ 55,296		
			Sub-Total	$ 55,296		
Vehicle Overhead						
Vehicle Allocated Costs				$ 5,912		
			Sub-Total	$ 5,912		
Administrative Overhead						
Labour AO				$ 12,847		
Contract AO				$ 72,586		
			Sub-Total	$ 85,433		
Interest Capitalized						
AFUDC				$ 5,710		
			Sub-Total	$ 5,710		
			SUB-TOTAL (no AO, AFUDC)	$ 608,261		
			TOTAL (AO, AFUDC included)	$ 705,316		
Original Cost				$ 61,395		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 52185

Title: 50N-410 Rebuild Phase 2

Start Date:	2018/05
In-Service Date:	2018/07
Final Cost Date:	2019/01
Function Class:	Distribution
Amount:	$695,098

DESCRIPTION:

This project will upgrade approximately 3.4 kilometres of existing single-phase line on primary distribution feeder 50N-410 to three-phase along Little Harbor Road and John Campbell Road in Frasers Mountain in Pictou County. This work will facilitate the removal of approximately 3.1 kilometres of off-road, deteriorated line on feeder 50N-410G that is currently located within a transmission corridor from the intersection of Logan Road/Little Harbor Road to Frasers Mountain Branch Road. This project will see the addition of approximately 10 kilometers of 336 AASC primary conductor and associated framing and insulators, and the replacement of 43 poles and 10 anchors. In addition, approximately 20 transformers will require transfer to new poles and new phases.

Summary of Related CIs +/- 2 years:
2017 CI 49862 - 50N-410 Rebuild Trenton Phase 1 - $440,329
2019 CI TBD - 50N-410 Rebuild Phase 3 - $TBD

JUSTIFICATION:

Justification Criteria: Distribution System

Sub Criteria: Pole Strength

Why do this project?

The existing poles are deteriorated and at risk of failure due to their age and condition. In addition, the targeted section is currently located off-road. Rebuilding the new line to roadside will improve accessibility for maintenance and outage restoration, and improve reliability by reducing exposure to tree contacts.

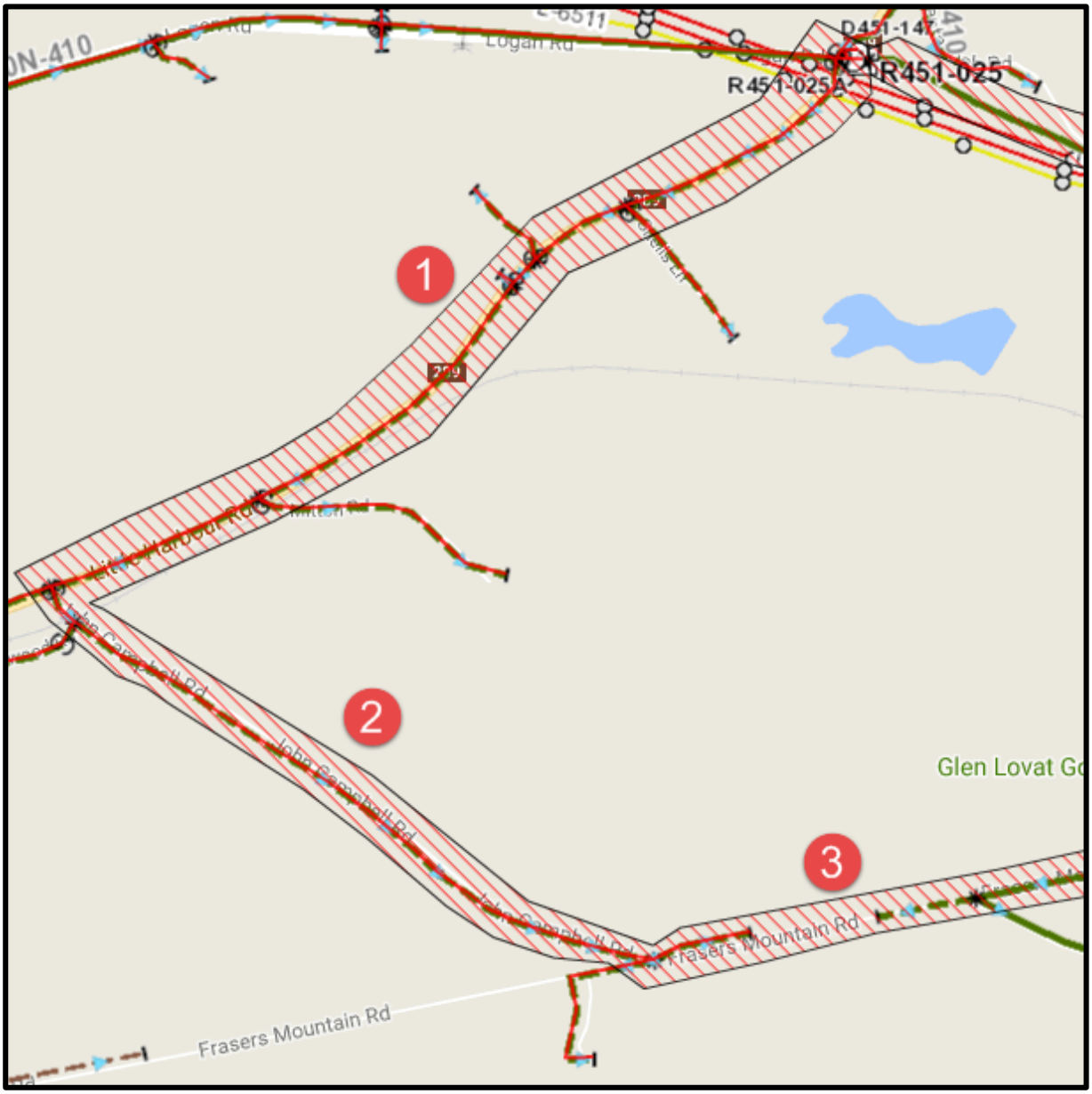
Why do this project now?

The existing line along the transmission corridor is approximately 52 years old and has reached the end of its expected service life. Inspection of the targeted devices and assessment based on age, condition and risk of failure has determined that replacement is required. In addition, bringing this line to roadside in phases will eliminate the need for off-road equipment during outage events.

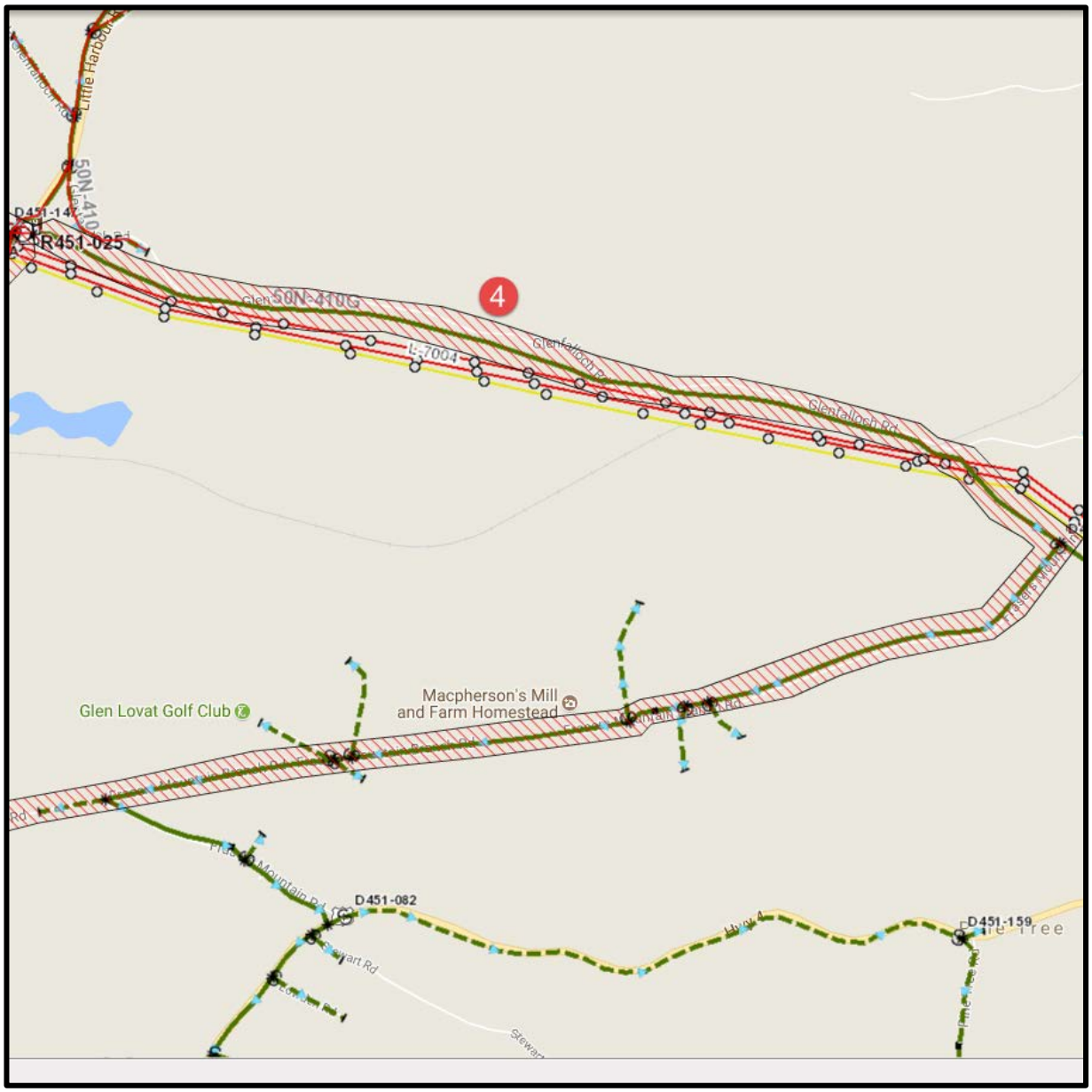
Why do this project this way?

There is no alternative source of supply for the customers in the targeted area. Rebuilding the existing line to roadside is a more cost effective solution than rebuilding the line in its current location due to the increased cost for off-road equipment.

The contracts portion of this project will be sourced through NS Power's existing Power Line Technician (PLT) Service Agreement with Emera Utility Services. This is aligned with NS Power's workforce planning model which is designed to optimize the allocation and execution of PLT resources among work requirements.



1. Upgrade approximately 1.8 kms of existing single-phase line to three-phase along Little Harbor Road.
2. Upgrade approximately 1.5 kms of existing single-phase line to three-phase along John Campbell Road.
3. Construct a new 0.2 kms, three-phase line along Frasers Mountain Road to connect the two sections.



Retire approximately 3.1 kms of three-phase, off-road line between recloser R451-025 and Frasers Mountain Branch Road

CI Number : 52185 - 50N-410 -Rebuild Phase 2 **Project Number** 52185

Parent CI Number : -

Asset Location : 1456 - 1456 Distribution Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0200 - DP - Land Rights	26,651
Additions	3500 - DP - Wood Poles	230,177
Additions	3800 - DP - Insulators	16,067
Additions	3900 - DP - O/H Cond.	365,091
Additions	4100 - DP - O/H Line Transf.	19,526
Retirements	3500 - DP - Wood Poles	16,884
Retirements	3900 - DP - O/H Cond.	20,225
Retirements	4100 - DP - O/H Line Transf.	477
	Total Cost:	695,098
	Original Cost:	85,791

Capital Project Detailed Estimate

Location: Distribution
CI# : 52185
Title: 50N-410 Rebuild Phase 2
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
Procurement/Financial Support	Lot	1	$ 1,432	$ 1,432		
Engineering	PD	5	$ 386	$ 1,930		
			Sub-Total	$ 3,362		
Materials						
Materials	Lot	1	$ 71,599	$ 71,599		
			Sub-Total	$ 71,599		
Contracts						
Flagging	Lot	1	$ 59,247	$ 59,247		
Backhoe	Lot	1	$ 38,700	$ 38,700		
Tree Trimming	Lot	1	$ 20,000	$ 20,000		
Removal of existing off-road line	Lot	1	$ 40,000	$ 40,000		
Contract Line Work	Lot	1	$ 295,472	$ 295,472		
			Sub-Total	$ 453,419		
Consulting						
Grade1 Rail crossing Design	Lot	1	$ 20,000	$ 20,000		
			Sub-Total	$ 20,000		
Other Goods & Services						
Contingency	%	10%	$ 528,380	$ 52,838		
			Sub-Total	$ 52,838		
Vehicle Overhead						
Vehicle AO				$ 1,374		
			Sub-Total	$ 1,374		
Interest Capitalized						
AFUDC				$ 3,489		
			Sub-Total	$ 3,489		
Administrative Overhead						
Labor AO				$ 2,986		
Contract AO				$ 86,032		
			Sub-Total	$ 89,017		
			SUB-TOTAL (no AO, AFUDC)	$ 601,218		
			TOTAL (AO, AFUDC included)	$ 695,098		
536800 Original Cost				$ 85,791		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 43218

Title: 88W-323A - Tusket Islands Phase 3

Start Date:	2016/07
In-Service Date:	2019/02
Final Cost Date:	2019/08
Function Class:	Distribution
Forecast Amount:	$654,721

DESCRIPTION:

This project will rebuild the 0.4 kilometer line on Deep Cove Island and the 1.6 kilometer line on Calf Island. The existing 1/0 ACSR conductor and neutral will be replaced with 2/0 AASC conductor and neutral. Total replacements include approximately 39 poles, 2.0 kilometers of conductor, 39 insulators, 2 transformers, and 7 cutouts. In addition, the new line will be constructed on Calf Island further inland from its current location. Phase1 of this project involved work on 0.6 kilometers of line on Harris Island in 2010 and phase 2 involved work on 1.9 kilometers of line on Big Tusket Island in 2011.

Summary of Related CIs +/- 2 years:
No other projects in 2016, 2017, 2018, 2019 and 2020

JUSTIFICATION:

Justification Criteria: Distribution System

Sub Criteria: Pole Strength

Why do this project?

The existing poles and conductor are deteriorated and are at risk of failure due to their age and condition. The conductor can no longer be worked on under live conditions. In addition, the targeted sections of line are located on islands which are only accessible by boat. Because the targeted sections provide supply to all other Tusket Islands, outages can affect multiple islands for extended durations.

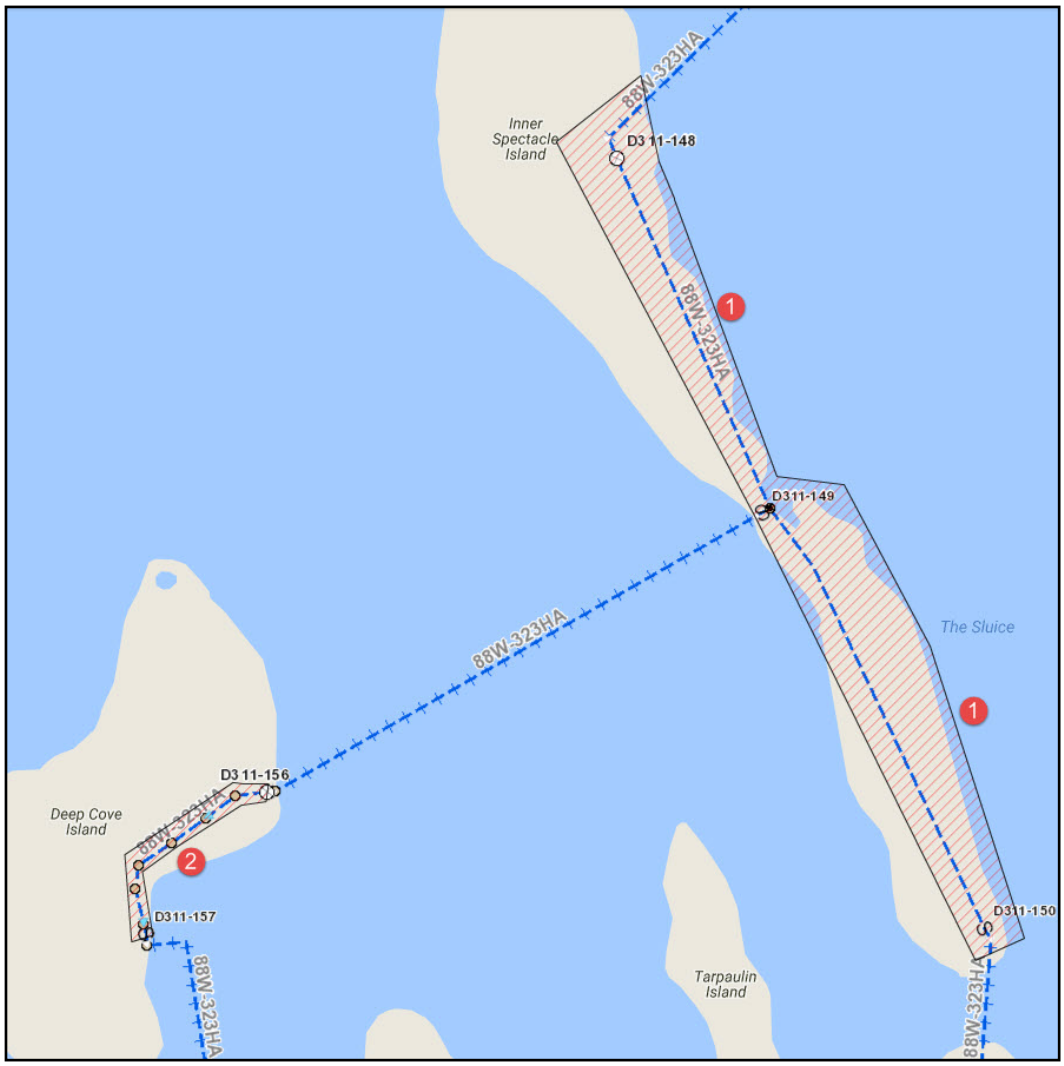
Why do this project now?

The targeted poles and conductor are more than 50 years old and have reached the end of their expected service lives. Inspections of the targeted devices and assessments based on age, condition and risk of failure have determined that replacements are required.

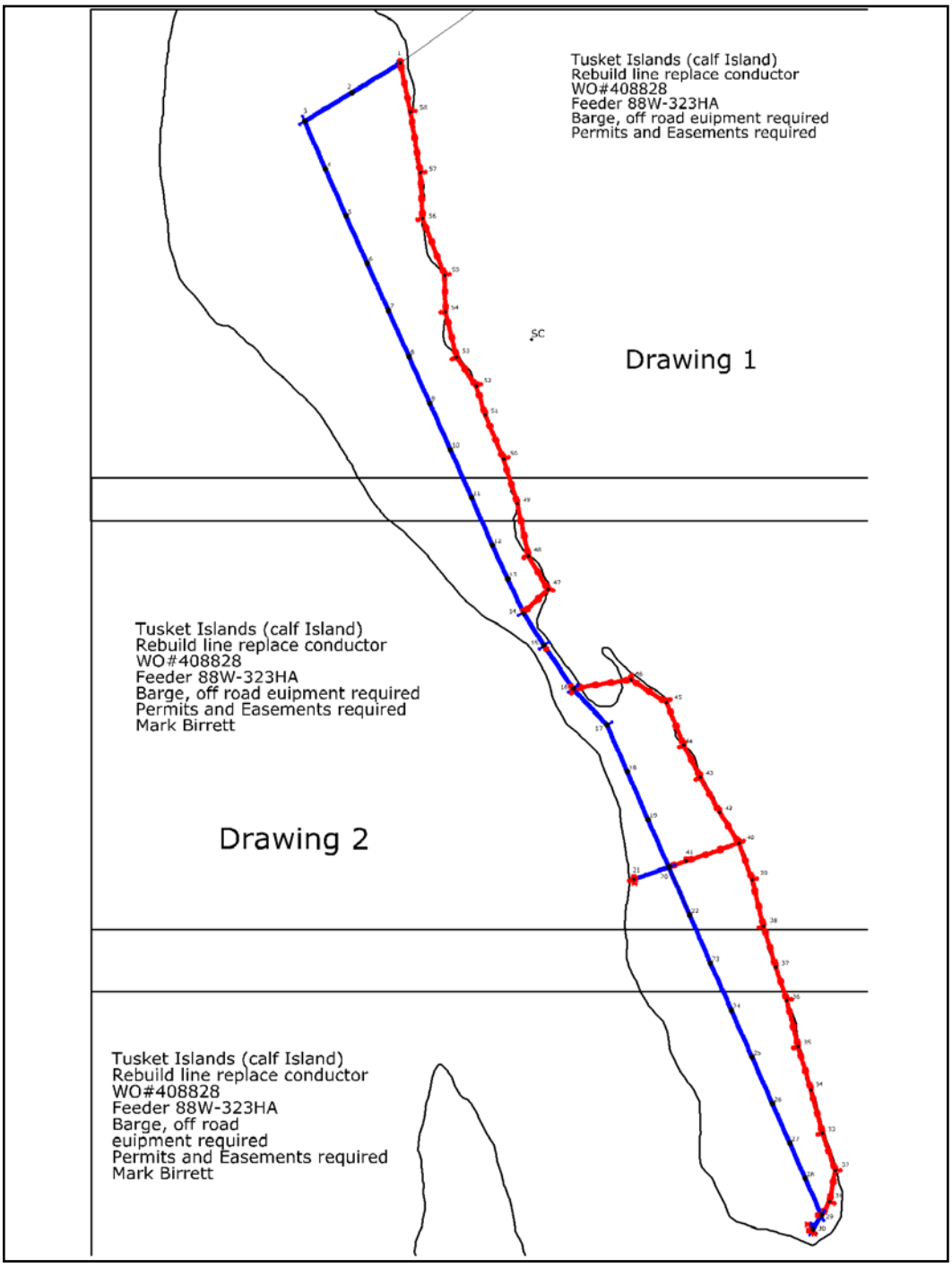
Why do this project this way?

There is no alternative source of supply for the 57 customers currently supplied by the targeted sections of line. Conductor and poles will be upgraded in accordance with current NS Power standards. On Calf Island, relocating the line further inland provides improved accessibility for maintenance and repair.

The contracts portion of this project will be sourced through NS Power's existing Power Line Technician (PLT) Service Agreement with Emera Utility Services. This is aligned with NS Power's workforce planning model which is designed to optimize the allocation and execution of PLT resources among work requirements.



1. Targeted section of line on Calf/ Inner Spectacle Island to be rebuilt further inland. See detailed design drawing below for more accurate line locations.
2. Targeted section of line on Deep Cove Island to be rebuilt in place.



Blue: New construction
Red: Existing line to be removed

CI Number : 43218-D757 - 88W-323A Tusket Islands Phase 3 **Project Number** 43218-D757

Parent CI Number : -

Asset Location : 1456 - 1456 Distribution Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0200 - DP - Land Rights	106,155
Additions	3500 - DP - Wood Poles	407,870
Additions	3900 - DP - O/H Cond.	71,379
Additions	4000 - DP - O/H Cond.Devices	3,002
Additions	4100 - DP - O/H Line Transf.	6,796
Additions	4600 - DP - U/G Conductor	14,886
Additions	5000 - DP - Street Lights	227
Additions	5200 - DP - Services	3,893
Retirements	3500 - DP - Wood Poles	27,184
Retirements	3900 - DP - O/H Cond.	9,298
Retirements	4000 - DP - O/H Cond.Devices	712
Retirements	4100 - DP - O/H Line Transf.	1,708
Retirements	4600 - DP - U/G Conductor	1,613
	Total Cost:	654,721
	Original Cost:	59,585

Capital Project Detailed Estimate

Location: Distribution
CI# / FP#: 43218-D757
Title: 88W-323A Tusket Islands Phase 3
Execution Year: 2016-2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
T&D Labour - Design	PD	9	$ 386	$ 3,548		
Procurement / Financial Support	Lot	1	$ 6,337	$ 6,337		
			Sub-Total	$ 9,885		
Materials						
Poles	Lot	1	$ 18,595	$ 18,595		
Conductors	Lot	1	$ 5,461	$ 5,461		
Cutouts	Lot	1	$ 620	$ 620		
Overhead Line Transformer	Lot	1	$ 3,099	$ 3,099		
Underground Conductor	Lot	1	$ 2,687	$ 2,687		
			Sub-Total	$ 30,461		
Contracts						
Contract Line Work	Hrs	[redacted]		$ 198,958		
Tree Trimming	Lot	1	$ 48,000	$ 48,000		
Flagging	Lot	1	$ 46,405	$ 46,405		
Backhoe	Lot	1	$ 44,400	$ 44,400		
Contractor services for barge and boat to travel to and from the islands	Lot	1	$ 88,606	$ 88,606		
			Sub-Total	$ 426,368		
Consulting						
Consulting	Lo	1	$ 3,308	$ 3,308		
			Sub-Total	$ 3,308		
Royalty, Easement, Appraisal						
Easements	Lot	1	$ 27,000	$ 27,000		
			Sub-Total	$ 27,000		
Other Goods & Services						
Contingency	%	10%	$ 466,714	$ 46,671.38	46612.578	$ 59
			Sub-Total	$ 46,671		
Vehicle Overhead						
Vehicle Allocated Costs				$ 3,799		
			Sub-Total	$ 3,799		
Administrative Overhead						
Labour AO				$ 8,613		
Contract AO				$ 80,899		
			Sub-Total	$ 89,512		
Interest Capitalized						
AFUDC				$ 17,717	18267.37	$ (550)
			Sub-Total	$ 17,717		
			SUB-TOTAL (no AO, AFUDC)	$ 543,692		
			TOTAL (AO, AFUDC included)	$ 654,721		$ (491)
Original Cost				$ 59,585		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 51400

Title: 2018 Substation Recloser Replacement

Start Date: 2018/04
In-Service Date: 2018/04
Final Cost Date: 2019/05
Function Class: Distribution
Amount: $644,710

DESCRIPTION:

This project will retire and replace 12 substation reclosers on the NS Power system. NS Power has an in-service inventory of over 440 substation reclosers, with an estimated useful life of 30-35 years. Oil filled reclosers have been targeted for replacement due to recent failures.

The solid dielectric reclosers with microprocessor controls being installed through this program have benefits that the existing models being replaced do not, including an increased number of protection curves, which facilitate coordination of feeder protection. Integrated instrument transformers provide data collection capabilities for planning studies and operations. It is also easier to integrate these into existing protection schemes due to the availability of programmable input/output.

The substation recloser replacement program was initiated in 2010 and approximately 217 of 440 substation reclosers have been replaced to date.

NS Power anticipates that a portion of the costs associated with this capital item will contribute toward settling the Company's Asset Retirement Obligation for PCB contaminated oil.

Summary of Related CIs +/- 2 years:
CI 48092 - 2016 Substation Recloser Replacements - $529,270
CI 50341 - 2017 Substation Recloser Replacements - $577,388
CI TBD - 2019 Substation Recloser Replacements - $TBD
CI TBD - 2020 Substation Recloser Replacements - $TBD

JUSTIFICATION:

Justification Criteria: Distribution System

Why do this project?

The targeted reclosers are deteriorated and are at risk of failure due to their age and condition. Failure of substation reclosers results in significant outages to the entire feeder, and often to the entire substation, and can cause significant customer outages. Recloser failures have recently occurred at the following substations: 92H-Tidewater, 113H - Dartmouth East, 126H -Porters Lake, 131H - Lucasville, 129H - Kearney Lake Road, 4S - Townsend Street and 101H - Cobequid Road. Recloser life expectancy is approximately 30-35 years, as designed by the manufacturer, with sufficient maintenance.

Why do this project now?

The targeted assets are over 30 years old and have reached the end of their expected service life. Inspection of the targeted assets and assessments of age, condition and risk of failure have determined that replacements are required. In addition, some recloser failures have occurred. This project targets the replacement of oil filled reclosers that have reached the end of their useful lives. To mitigate the risk of an in-service failure, replacement is necessary.

This project is deemed in-service when the first recloser is replaced (April 2018), therefore the Final Cost Date (May 2019) is listed as six months after the last recloser is replaced (November 2018).

Why do this project this way?

Substation reclosers are required in order to provide protection from faults for safety and reliability. Spare parts are becoming increasingly hard to come by for the installed fleet of oil filled reclosers. This necessitates replacing them with a modern solid dielectric equivalent. This also serves to remove oil filled equipment from the fleet, reducing the potential for environmental harm through leakage.

CI Number : 51400 - 2018 Substation Recloser Replacements **Project Number** 51400

Parent CI Number : -

Asset Location : 1456 - 1456 Distribution Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0300 - DP - Bldg.,Struct.Grnd.	154,455
Additions	3800 - DP - Insulators	1,958
Additions	4300 - DP - Substn Dev.	453,449
Retirements	4300 - DP - Substn Dev.	34,848
	Total Cost:	644,710
	Original Cost:	192,895

Capital Project Detailed Estimate

Location: Distribution
CI# / FP#: 51400
Title: 2018 Substation Recloser Replacements
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labour						
T&D Labour - Electrician/Technician	PD	5	$ 366	$ 1,645		
T&D Labour - Site Supervision	PD	16	$ 389	$ 6,216		
T&D Labour - Project Support	PD	26	$ 366	$ 9,415		
T&D Labour - Commissioning	PD	14	$ 366	$ 5,119		
Procurement / Financial Support	Lot	1	$ 6,197	$ 6,197		
Engineering Design	PD	42	$ 440	$ 18,480		
Project CADD Drafting	PD	39	$ 320.00	$ 12,480		
SCADA RTU Configuration Labour	PD	12	$ 360.00	$ 4,140		
			Sub-Total	$ 63,692		
Materials						
Ground Connections	ea	16	$ 35	$ 560		
Electrical Control Equipment	Lot	1	$ 36,300	$ 36,300		
Substation Devices - 25kV Recloser	ea	6	$ 21,585	$ 129,510		
Substation Devices - 15kV Recloser	ea	6	$ 21,389	$ 128,334		
Substation Devices - Misc Materials	Lot	1	$ 14,180	$ 14,180		
				$ -		
			Sub-Total	$ 308,884		
Contracts						
Conduit / Foundation Installation	Lot	1	$ 117,600	$ 117,600		
			Sub-Total	$ 117,600		
Other Goods & Services						
Contingency	%	10%	$ 490,176	$ 49,632		
				$ -		
			Sub-Total	$ 49,632		
Vehicle Overhead						
Vehicle T&D Labour Regular AO				$ 26,028		
			Sub-Total	$ 26,028		
Administrative Overhead						
Labour AO				$ 56,560		
Contracts AO				$ 22,313		
			Sub-Total	$ 78,874		
			SUB-TOTAL (no AO, AFUDC)	$ 539,808		
			TOTAL (AO, AFUDC included)	$ 644,710		
Original Cost				$ 192,895		

Note 1: The labour figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 52194

Title: 6S-223 Harold Street Conversion

Start Date: 2018/04
In-Service Date: 2018/08
Final Cost Date: 2019/02
Function Class: Distribution
Amount: $642,368

DESCRIPTION:

This project will implement recommendation 6.1.5.1 of the Sydney 4kV Conversion and Membertou Load Growth Planning Study 283-0212-E27 (please refer to Attachment 1). Section 6.1.5.1 recommends extending the existing 12kV feeder on George Street onto Harold Street, to allow for the existing 4kV circuit along Harold Street and its surrounding streets to be converted to 12kV, which will facilitate the retirement of the 6S substation.

In addition, the existing off-road line between Harold Street and Holly Street will be removed. This conversion will require the upgrade of approximately 4 kilometres of existing primary conductor to 336 AASC, replacement of approximately 40 deteriorated poles, framing, insulators, cut-outs, and replacement of all existing single-tap transformers with dual-tap transformers.

Summary of Related CIs +/- 2 years:
2016 CI 45306 - 111S Prime Brook Substation - $3,442,582
2016 CI 47776 - 111S Prime Brook Feeders - $1,504,630
2016 CI 47752 - 4S-333 Bentinck Street Rebuild - $575,357
2017 CI 50073 - 4S-332 Bernard Lind Drive Conversion - $302,893
2019 CI TBD - 6S-224 Birch Hill Drive Conversion - $TBD
2019 CI TBD - 6S-225 Townsend Street Conversion - $TBD

JUSTIFICATION:

Justification Criteria: Distribution System

Why do this project?

The existing 6S-Terrace Street substation equipment, infrastructure, and associated 4kV distribution plant are deteriorated due to age. The condition of the targeted assets is further described in Sections 2.3.2 and 4.3 of planning study 283-0212-E27 (please refer to Attachment 1). The customer load on 6S-Terrace Street needs to be converted from 4kV to 12kV and transferred in order to accommodate for the planned retirement of the 6S substation.

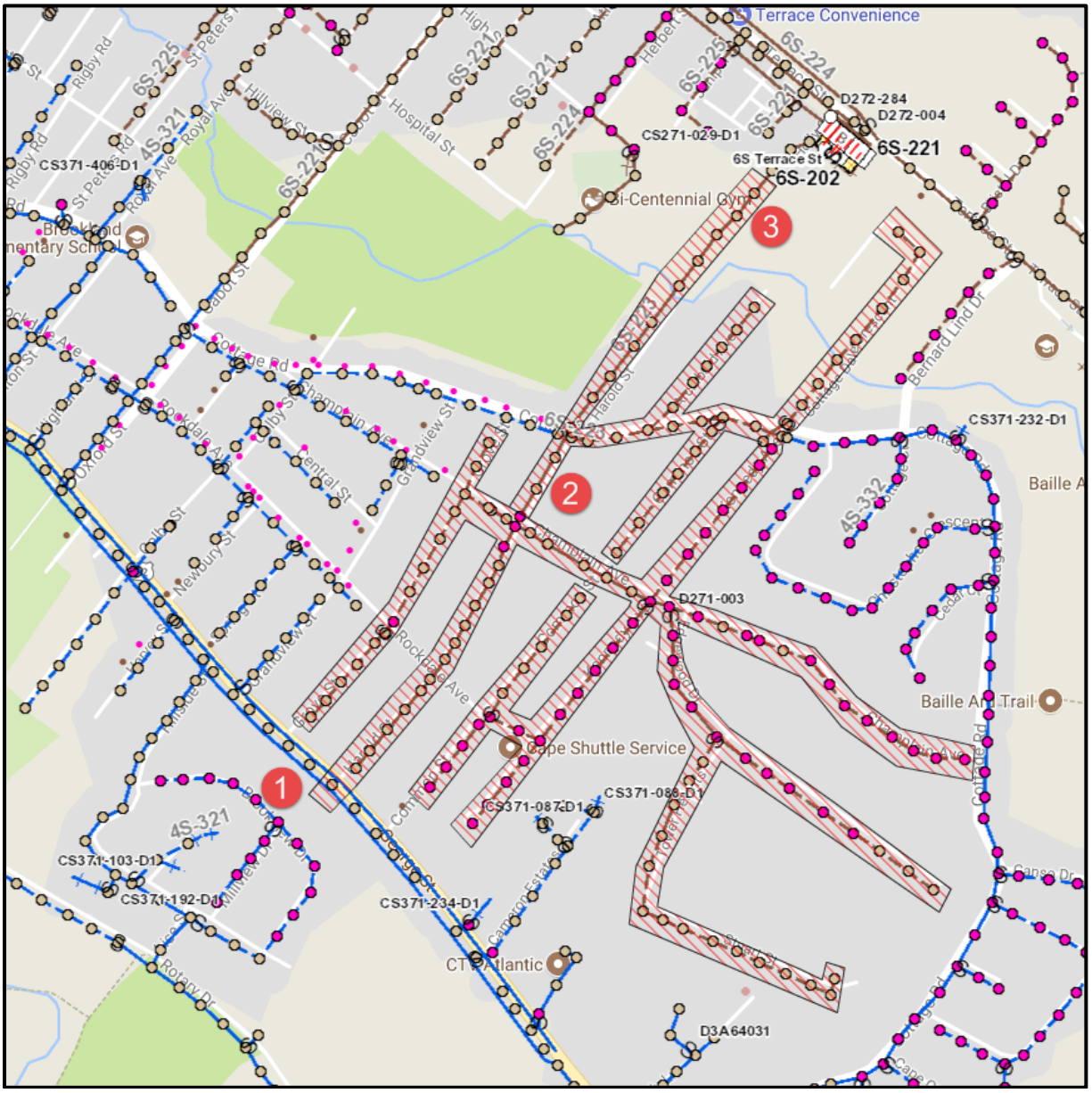
Why do this project now?

The 6S substation equipment and 4kV distribution plant are over 40 years old and are at or nearing the end of their expected service lives, as outlined in section 4.3. Multiple phases of conversion and load transfer must be completed over multiple years before 6S can be retired, as outlined in section 6.0 and sequentially under section 6.1, with 6S retirement recommended in 2021.

Why do this project this way?

Alternatives are outlined in Section 5.2, including three variations on timing of conversions and one on rebuilding the 6S substation. 4kV distribution systems are no longer an NS Power standard and are being phased out. Conversion of the existing 4kV feeders from 6S-Terrace Street is therefore the only feasible solution to accommodate the retirement of the 6S substation.

The contracts portion of this project will be sourced through NS Power's existing Power Line Technician (PLT) Service Agreement with Emera Utility Services. This is aligned with NS Power's workforce planning model which is designed to optimize the allocation and execution of PLT resources among work requirements.



(1) Extend the 12kV feeder from George Street onto Harold Street.
(2) Upgrade the existing conductor to 336 AASC, replace targeted deteriorated poles, framing, insulators, and the replacement of all existing single-tap transformers with dual-tap transformers to convert from 4kV to 12kV.
(3) Remove existing off-road section between Harold Street and Holly Street.

CI Number : 52194 - 6S-223-Harold Street Conversion **Project Number** 52194

Parent CI Number : -

Asset Location : 1456 - 1456 Distribution Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0200 - DP - Land Rights	19,382
Additions	3500 - DP - Wood Poles	188,859
Additions	3800 - DP - Insulators	22,552
Additions	3900 - DP - O/H Cond.	165,350
Additions	4100 - DP - O/H Line Transf.	150,058
Retirements	3500 - DP - Wood Poles	22,698
Retirements	3900 - DP - O/H Cond.	28,644
Retirements	4100 - DP - O/H Line Transf.	44,824
	Total Cost:	642,368
	Original Cost:	26,562

Capital Project Detailed Estimate

Location: Distribution
CI# : 52194
Title: 6S-223 Harold Street Conversion
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
Procurement/Financial Support	Lot	1	$ 2,455	$ 2,455		
Engineering	PD	5	$ 386	$ 1,930		
			Sub-Total	$ 4,385		
Materials						
Materials	Lot	1	$ 122,747	$ 122,747		
			Sub-Total	$ 122,747		
Contracts						
Flagging	Lot	1	$ 57,525	$ 57,525		
Backhoe	Lot	1	$ 18,000	$ 18,000		
Tree Trimming	Lot	1	$ 15,000	$ 15,000		
EUS Contracts	Lot	1	$ 290,275	$ 290,275		
			Sub-Total	$ 380,800		
Other Goods & Services						
Contingency	%	10%	$ 507,932	$ 50,793		
				$ -		
			Sub-Total	$ 50,793		
Vehicle Overhead						
Vehicle AO				$ 1,792		
			Sub-Total	$ 1,792		
Interest Capitalized						
AFUDC				$ 5,703		
				$ -		
			Sub-Total	$ 5,703		
Administrative Overhead						
Labor AO				$ 3,894		
Contract AO				$ 72,253		
			Sub-Total	$ 76,147		
			SUB-TOTAL (no AO, AFUDC)	$ 558,726		
			TOTAL (AO, AFUDC included)	$ 642,368		
536800 Original Cost				$ 26,562		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

Sydney 4kV Conversion and Membertou Load Growth
DISTRIBUTION PLANNING STUDY

Report number 283-0212-E27

Revision		Date	Drafted By	Reviewed by	Approved By
0	Issued for Study	16-Feb-2012	JMQ		
1	Issued for Release	16-Aug-2013	JMQ	MGS PZ	
2	Issued for Release	7-Apr-2014	JMQ	JC	JC
3	Issued for Release	5-June-2015	BH	YL/MD	

EXECUTIVE SUMMARY

This study was initiated by the Eastern Territory, in order to determine solutions to the anticipated large load growth in the Membertou area, of Sydney. Solutions were studied and recommendations made to address near and long term load growth in previous revisions. This revision was initiated to address two changes since the last revision:

- Additional reduction of 69kV load required as per transmission planning study, 049-2013-TSMG
- Unable to procure land for proposed substation location

Sydney 4kV to 12kV conversions are underway: Mason St, Cabot St and Rockdale Ave conversions are complete. Further conversion projects will continue until the eventual retirement of 6S-Terrace Street. The advancement or deferral of the 6S-Terrace Street conversion projects will be influenced by factors including residential/commercial development, feeder reconfigurations and/or ranking of capital projects within the ACE plan.

Creation of another supply into Membertou is partially completed. This will enable the transfer of load from the existing feeders, to a feeder that is more lightly loaded. The long term solution for the growth in Membertou is a new substation, which will now be located on Gabarus Hwy in Prime Brook, rather than on George St. This substation will be NSPI standard construction with a capacity of 15/20/25MVA rather than the initially recommended 15MVA pad-mounted option.

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1.0 SCOPE

This study was initiated by the Eastern Territory and undertaken by the Distribution Planning Department to identify solutions to meet the anticipated load growth in the Membertou area. Membertou is currently one of the fastest growing areas in the province. With the amount of development that has been announced for the area, there is a need to ensure enough capacity is available to meet this anticipated growth. This study outlined near and long term solutions to meet the growth in the Membertou area. This current revision (Rev 3), will address changes since the last revision:

- Additional reduction of 69kV load required as per transmission planning study, 049-2013-TSMG
- Unable to procure land for proposed substation location on George Street

Capital work for the recommended short term solution is underway. This solution eliminated an island of 4kV distribution and retired the 533S-Mason Street step-down. Reconfiguration of the feeders on Kings Road will allow the removal of a deteriorated off-road section of feeder 4S-333. A new feeder tie on Alexandra Street will create an additional 12kV supply into Membertou, which will allow balancing between existing feeders. These recommendations are unchanged in revision 3.

This study outlines the conversion of load from 6S-T1, in preparation for retirement of this substation. The first phases of conversions have been completed. The current 4kV breakers are being replaced with reclosers in 2015 to allow the substation to operate until its retirement. These recommendations are unchanged in revision 3.

The construction of a new 15/20/25MVA substation at the intersection of the transmission corridor and Gabarus Hwy will provide the long term solution for Membertou. This replaces the original recommendation for a 15MVA 138-12kV pad-mounted substation, as it does not meet the required capacity. Transmission planning study, 049-2013-TSMG, specified a 20MVA reduction of the 69kV load forecast in 2018, contingent on a new 138-12kV substation near Membertou. The release of this transmission study was the driver for revision 3 of this study.

A Distribution Automation study will be completed to outline future development of automatic transfer schemes in the Sydney area.

2.0 EXISTING SYSTEMS

2.1 Transmission

Presently, a transmission corridor exists from 2S-Victoria Junction to 101S-Woodbine. Prior to the corridor crossing the Louisburg Highway (Highway 22), one of the 138kV transmission lines, L-6539, separates from this corridor to join L-5564, which extends to 3S-Gannon Road. The System Operating Diagrams are attached, in Appendix A.

Table 1 Transmission Line Ratings

Transmission Line	Substation		MVA Rating	
	From	To	Summer	Winter
L-7011	88S-Lingan	3C-Port Hastings	298	383
L-7012	88S-Lingan	3C-Port Hastings	398	398
L-7014	88S-Lingan	101S-Woodbine	404	462
L-6516	2S-Victoria Junction	2C-Port Hastings	110	115
L-6539	2S-Victoria Junction	3S-Gannon Road	115	115
L-5564	2S-Victoria Junction	3S-Gannon Road	55	72
L-5563	2S-Victoria Junction	4S-Townsend Street	31	45
L-5560	2S-Victoria Junction	4S-Townsend Street	29	42
L-5569	4S-Townsend Street	6S-Terrace Street	43	43

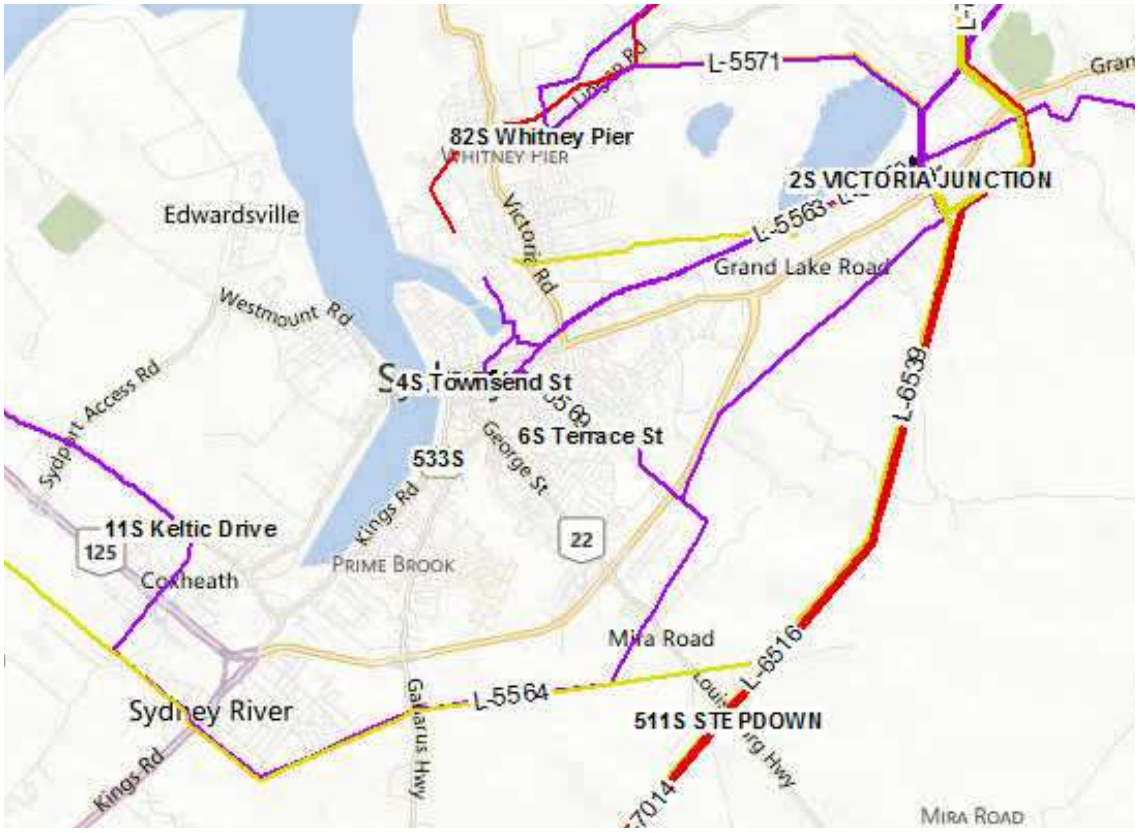


Figure 1 Industrial Cape Breton Transmission

2.2 Sub-Transmission

The sub-transmission system within the Sydney area operates at 69kV. It is supplied by three 138-72kV auto-transformers, two located at 2S-Victoria Junction and one located at 3S-Gannon Road. The System Operating Diagrams are attached, in Appendix A.

Table 2 Sydney Area Sub-Transmission

Substation	Auto-Transformer Data				
	ID	MAN	kV	Rating	Age
2S-Victoria Junction	T1	CGE.	138-72	60/80/100//112	1973
2S-Victoria Junction	T2	CGE.	138-72	60/80/100//112	1972
3S-Gannon Road	T1	CGE	138-72	30/40/50//56	1972

2.3 Distribution

The distribution system being studied in this report includes the 12kV feeders supplied from 4S-Townsend Street and 11S-Keltic Drive substation. The 4kV feeders supplied by the 6S-Terrace Street substation are also considered. The 25kV feeders from 11S-Keltic Dive have not been considered in this study.

Table 3 provides the transformer data for the substations that are directly impacted by the scope of this study.

Table 3 Sydney Area Distribution Transformers

Substation	Transformer Data				
	ID	MAN	kV	Rating	Age
4S-Townsend Street	T52	Federal Pioneer	69-12.47	15/20//24.6	1972
4S-Townsend Street	T53	Federal Pioneer	69-12.47	15/20//22.4	1973
6S-Terrace Street	T1	Moloney Electric	69-4.16	7.5/10	1969
11S-Keltic Drive	T51	Federal Pioneer	69-12.47	10/13.3//14.9	1972
11S-Keltic Drive	T52	Federal Pioneer	69-12.47	10/13//14.8	1972
11S-Keltic Drive	T53	Virginia Transformer	69-26.4	15/20/25	1999

2.3.1 533S-Mason Street

This area has been converted to 12kV as recommended in revision 2 of this study.

2.3.2 6S-Terrace Street

The lone transformer at the 6S-Terrace Street substation (6S-T1) was placed into service in 1969. This 69-4kV transformer is rated at 7.5/10MVA. The transformer annually peaks above 6MVA, with a recent maximum winter peak of 6.7MVA, recorded in the winter 2010 / 2011.The only suitable mobile transformer, in the NSPI fleet, is 3P-MS, which is rated at 6MVA, at 4kV. Given this, the mobile transformer is unable to assume the peak load on 6S-T1 without transferring a portion of customer load to 534S; the lone neighbouring 4kV stepdown transformer (near 4S-Townsend Street). While this response to a loss of 6S-T1 is feasible, it would extend the duration of the outage experienced by customers due to the failure of 6S-T1. The 4kV area covered by Terrace Street, as of 2014, can be found below in Figure 2. As per revision 2 of this study, this area has been partially converted as a short term solution. This reduces the load at 6S and allow mobile to be used in contingency situations. The remainder of the 4kV conversions will be planned for the future. See further details in the recommendations section.

The average age of the distribution plant in the area is greater than 40 years. At the present time, there is difficulty with maintaining the substation breakers due to the age and condition of the building structure. There is also an inability to source replacement components for the breakers themselves, representing a significant reliability concern. Replacement of these breakers is underway and will be completed in 2015. See further details in the recommendations section.

Figure 2 **6S-Terrace Street extents as of 2014**

3.0 LOAD HISTORY AND FORECAST

The loading for those feeders being studied is largely residential, with a small number of commercial customers. As illustrated in the load history for these feeders, Appendix B, the feeders being studied have had a larger winter peak than summer. Historical load data for the feeders and transformers studied in revision 2 was collected from the Distribution Load Check Database and presented in the tables below.

3.1 Load Forecast

Customer load has been generally consistent in the Sydney area, demonstrating a slight overall growth in recent years. That being stated, the community of Membertou has seen the largest growth in Sydney in recent years. This load growth is anticipated to continue for the next several years, due to the proposed developments outlined in subsequent sections of this study.

The growth rates indicated in following tables were determined through examination of the peak load check data over the past 15 years. The forecasted load growth was then calculated using the 90th percentile, to determine potential peak load growth in the area. The forecasted loading of the substation transformers are indicated in Table 7.

Table 4 90th Percentile Load Forecast for 4S-Townsend Street, in Amps (2014)

Year / Load Growth	4S-321	4S-322	4S-323	4S-324	4S-331	4S-332	4S-333	4S-334
Load Growth	2.64%	-0.97%	1.48%	0.03%	2.76%	-0.05%	1.53%	2.72%
2014 Peak	**234**	**188**	**256**	**290**	**118**	**279**	**244**	**67**
2014 / 2015	236	226	269	289	190	297	283	129
2015 / 2016	244	223	274	289	197	297	288	134
2016 / 2017	252	221	278	289	204	297	294	139
2017 / 2018	261	219	283	289	211	297	299	144
2018 / 2019	269	217	288	289	218	296	304	148
2019 / 2020	277	215	293	289	226	296	310	153
2020 / 2021	285	213	298	289	233	296	315	158
2021 / 2022	294	210	303	289	240	296	320	163
2022 / 2023	302	208	307	289	247	296	325	167
2023 / 2024	310	206	312	290	254	296	331	172
2024 / 2025	319	204	317	290	261	296	336	177
2025 / 2026	327	202	322	290	268	295	341	182
2026 / 2027	335	199	327	290	275	295	346	186
2027 / 2028	344	197	332	290	283	295	352	191
2028 / 2029	352	195	336	290	290	295	357	196
2029 / 2030	360	193	341	290	297	295	362	201

Note:

- 4S-331 supplies the 534S-Stepdown transformer, near 4S-Townsend Street.
- 4S-333 current supply to Membertou area and 533S-Mason Street.

Table 5 90th Percentile Load Forecast for 6S-Terrace Street, in Amps (2014)

Year / Load Growth	6S-221	6S-223	6S-224	6S-225
2014 Load Clip	**54**	**163**	**153**	**263**

Note:

- Load Clip measurements are presented for the 6S-Terrace Street feeders, as there isn't enough data to accurately forecast the load.
- These clip measurements were taken on a day with ambient temperature of -12°C.

Table 6 90th Percentile Load Forecast for 11S-Keltic Drive, in Amps (2014)

Year / Load Growth	11S-301	11S-302	11S-303	11S-304	11S-305	11S-306
Load Growth	0.83%	0.52%	0.57%	-0.53%	0.21%	0.61%
2014 Peak	**190**	**240**	**240**	**210**	**300**	**244**
2013 / 2014	197	237	307	151	307	246
2014 / 2015	199	238	309	150	307	248
2015 / 2016	201	239	311	149	308	250
2016 / 2017	202	241	313	148	309	251
2017 / 2018	204	242	315	147	309	253
2018 / 2019	206	243	317	146	310	255
2019 / 2020	208	245	319	146	311	256
2020 / 2021	210	246	321	145	311	258
2021 / 2022	212	248	323	144	312	260
2022 / 2023	214	249	325	143	313	261
2023 / 2024	215	250	327	142	313	263
2024 / 2025	217	252	329	142	314	265
2025 / 2026	219	253	331	141	314	266
2026 / 2027	221	255	333	140	315	268
2027 / 2028	223	256	334	139	316	270
2028 / 2029	225	257	336	138	316	271

Note:

- 11S-305 is the alternate supply to the Membertou area.

Table 7 90th Percentile Load Forecast for Sydney Transformers, in MVA (2014)

Year / Load Growth	4S-T52	4S-T53	6S-T1	11S-T51	11S-T52
Load Growth	0.42%	1.77%	-0.02%	0.51%	0.49%
2014 Peak	**20.9**	**14.4**	**4.6***	**13.4**	**13.4**
2013 / 2014	20.8	19.3	6.5	15.4	15.2
2014 / 2015	20.9	19.7	6.5	15.5	15.2
2015 / 2016	21.0	20.2	6.5	15.6	15.3
2016 / 2017	21.0	20.6	6.5	15.7	15.4
2017 / 2018	21.1	21.0	6.5	15.8	15.5
2018 / 2019	21.2	21.4	6.5	15.9	15.6
2019 / 2020	21.3	21.9	6.5	16.0	15.6
2020 / 2021	21.4	22.3	6.5	16.1	15.7
2021 / 2022	21.5	22.7	6.5	16.1	15.8
2022 / 2023	21.6	23.1	6.5	16.2	15.9
2023 / 2024	21.7	23.6	6.5	16.3	16.0
2024 / 2025	21.8	24.0	6.5	16.4	16.1
2025 / 2026	21.9	24.4	6.5	16.5	16.1
2026 / 2027	22.0	24.8	6.5	16.6	16.2
2027 / 2028	22.1	25.3	6.5	16.7	16.3
2028 / 2029	22.2	25.7	6.5	16.8	16.4

Note:

- No Peak load data for 2014 available for 6S-T1, 2014 peak values have been indicated (*****).

4.0 OVERLOADS AND OTHER CONSIDERATIONS

The following section identifies issues that warrant correction based on NSPI's *Capital Expenditure Justification Criteria*.

4.1 Feeder Overloads

There are several feeders whose peak loading is approaching 325A. These peak values can be seen in the feeder histories, located in Appendix B. These feeders include

- 6S-224 consistently peaked above 300A,with a peak above 325A in 2010
- 6S-225 peaked above 300A, in 2003 and 2004
- 4S-321 peaked above 325A, in 2007

4.2 Contingency Loss of Supply

4.2.1 6S-T1

The lone transformer at 6S-Terrace Street, 6S-T1, has not exceeded its nameplate rating, in recent years; however the peak winter loading was exceeding the capacity of the mobile substation, 3P-MS, as of 2014. Conversions have been completed which should allow the mobile transformer to be used under peak loading conditions.

4.2.2 533S-Mason Street

This area was converted to 12kV and 533S transformer retired as per revision 2 of this study.

4.3 Age of Plant

The average age of poles and equipment in the Hardwood Hill area of Sydney is greater than 40 years old. Inspections have confirmed this equipment is at or is nearing full service life.

The current breakers at 6S-Terrace Street are obsolete. The breaker manufacturer is no longer in business. The sourcing of replacement components is nearly impossible. Added to this is the deteriorated condition of the breaker house. In the event of a breaker failure, the duration of an outage would be significant in length.

Replacement of deteriorated plant is underway, including the replacement of 6S breakers which will be completed in 2015. The remainder will be budgeted and completed in phases.

4.4 Proposed Load Growth

There are several areas of load growth in the Sydney area impacting this study. The two largest developments are detailed below.

4.4.1 Membertou Load Growth

The community of Membertou is in the midst of large growth, through commercial and residential developments within the community. The anticipated increase in load has been considered throughout this study. Future development plans in the community include:

- Multi-surface ice rink (construction commencing summer 2013)
- New School
- New overpass across Highway 125 related to a new multi-unit Business Park,
- Expanding residential housing areas

Currently there are three supplies into the area, via Churchill Drive and Membertou Street, as seen in Figure 3 and Figure 4. The two feeders capable of supplying the area from the Kings Road side of the development, 11S-305 and 4S-333, do not have excess capacity to serve this proposed growth. The third feeder, 4S-332, has less capacity than those feeders capable supplying from the other side of the development. From the 2011/2012 winter load checks these feeders were measured at 249amps, 269amps, and 292amps respectively. Accordingly, a prolonged outage of one of these feeders could result in an extended customer outage, as the remaining feeders cannot support the peak winter load.

Figure 3 Feeders Currently Serving Membertou from Kings Road area

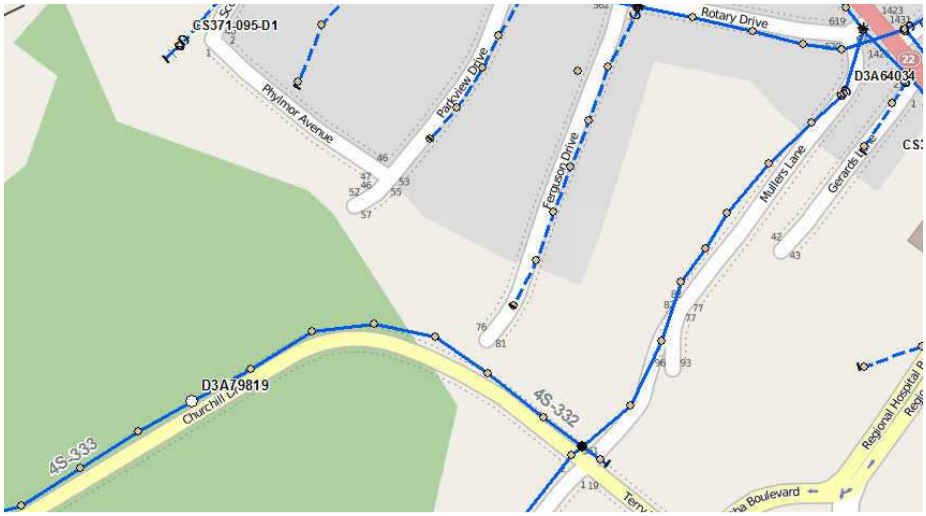


Figure 4 Feeder Currently Serving Membertou from George Street area

4.4.2 Cossitt Heights New Housing Development

A new housing development is planned for the Cossitt Heights area. This new subdivision is approximately 114 Acres and is slated to have both detached homes and multi-unit dwellings. This load will be added to one of the following feeders; 4S-324 or 4S-331. The area of this proposed development is shown below, in Figure 5.

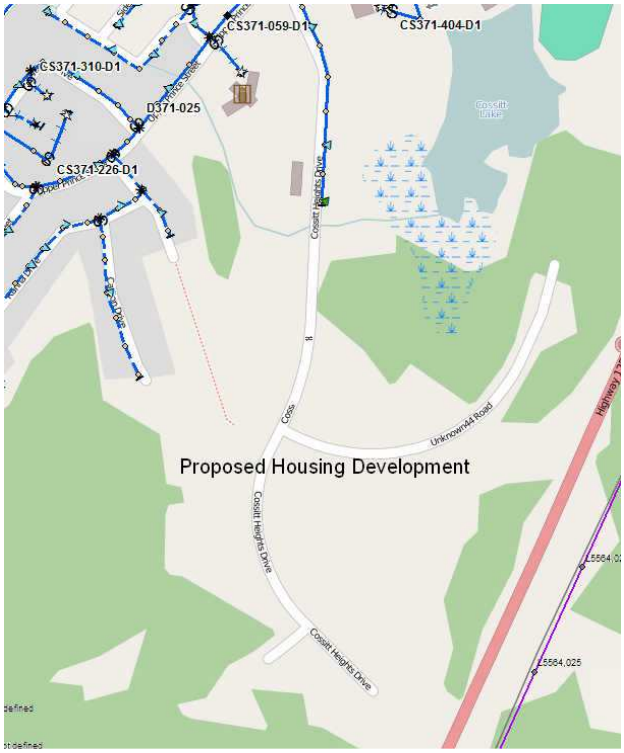


Figure 5 Cossitt Heights Residential Development

5.0 SOLUTIONS AND EVALUATION

Membertou is in the midst of large growth, in both residential and commercial developments. Due to the proposed and developing construction, the amount of expected load will exceed the existing capacity available. NSPI is obligated to accommodate this increased load growth, both in the short and long term.

The short term solution to meet this load growth is to create an additional supply into Membertou via existing distribution feeders. This is underway and the additional feeder, 4S-334, will pick up load from Membertou in 2015. Remainder of work will be completed in 2016, which will remove deteriorated off-road sections of 4S-333.

The longer term solution is to construct a new substation to supply this growing load and provide additional contingency to the distribution system in Sydney.

5.1 Mason Street

Currently, there are three feeders capable of supplying the Membertou area: 11S-305, 4S-333 and 4S-332. Two of these feeders, 11S-305 and 4S-333 supply Membertou from the Alexandra Street. 4S-332 enters from the George Street side of the community, but does not supply load in Membertou. Presently, these three feeders are heavily loaded, with 4S-332 serving as the primary supply for the Cape Breton Regional Hospital. Reducing the load on the existing feeder supplying Membertou or the extension of another feeder into Membertou is required to meet the forthcoming load, currently in the early project stages.

There were four alternatives outlined in revision 2 of this study. Alternative 533S-B was selected and capital work is in progress. The Mason Street area has been converted to 12kV and the step-down transformer (533S) has been retired. An additional feeder, 4S-334, will pick up Membertou load in 2015. Work will be completed in 2016 which will allow remaining deteriorated off-road sections of feeder 4S-333 to be removed. Full details of Alternative 533S-B are outlined below. Other alternatives have been removed in this revision.

5.1.1 Alternative 533S-B Convert 533S-Mason Street, via Bentinck Street

Alternative 533S-B would see the supply on Kings Road between School Street and Churchill Drive change from 4S-333 to 4S-334. This alternative would also see the conversion to 12kV of the islanded 4kV supplied by 533S-Mason Street to 12kV. Also included in this alternative would be the creation of another supply into Membertou via Towerview Place. Refer to Figure 6 for an overview of this proposed work.

Currently, Kings Road is supplied by 4S-333 which has a large off-road section, between Townsend Street and Kings Road. This off-road section is along the existing railway tracks, limiting access and prolonging response time to faults on this section of line. This off-road section is deteriorated and approaching its end of service life. Feeder 4S-334 currently supplies a portion of Kings Road from Falmouth Street to just prior to School Street; extending 4S-334 along Kings Road would be accomplished through the reconfiguration of the distribution at the Kings Road and School Street intersection. This reconfiguration would enable the use of a lightly loaded feeder, 4S-334, to supply Kings Road and Membertou.

In addition to resupplying a portion of Kings Road, the removal of the islanded 4kV supplied by 533S-Mason Street would also be addressed. The conversion, as outlined in Alternative 533S-A would entail the conversion of the lone 4kV feeder, 533S-211, to 12kV. Supplying this new section of 12kV would be accomplished through the rebuilding of Bentinck Street and supplying Argyle Street via 4S-333.

With the newly converted section of 4S-333 along Alexandra Street, the opportunity exists to create an additional supply into Membertou, as outlined in Alternative 533S-A, through the extension and rebuilding of Alexandra Street from Xavier Drive to Castle Drive. Extending the 3 phase circuit along Towerview Place to the Millard Street intersection would bring a second lightly loaded feeder into Membertou, 4S-333.

The detailed outline of this conversion and feeder tie creation is outlined in the recommendations section of this study.

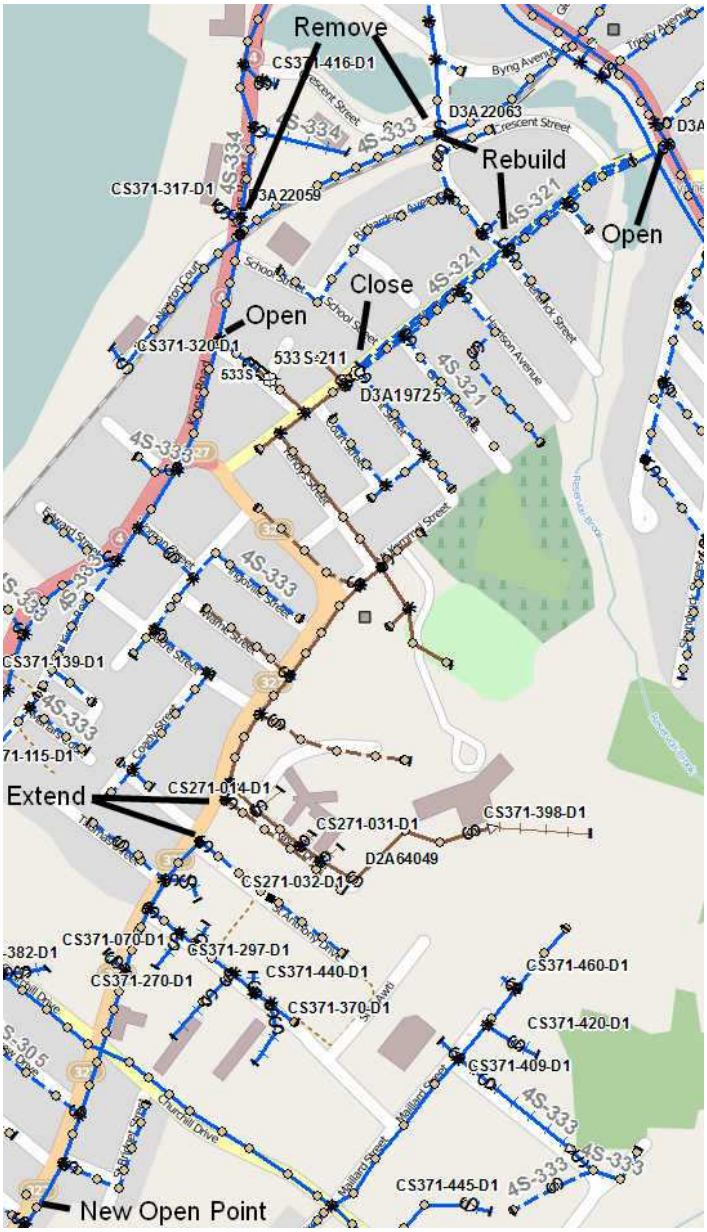


Figure 6 Alternative 533S-B Reconfigure Shipyard Supply

5.2 6S-Terrace Street

The substation infrastructure at the 6S-Terrace Street substation is approaching its end of service life. In order to extend the service life of the substation, the replacement of the existing breakers with reclosers is

required. In order to facilitate the replacement of these breakers, an overall reduction of load on 6S-T1 is necessary. Additionally, the 4kV distribution plant supplied by 6S-Terrace Street is approaching end of service life. This eventually leads to the planned retirement of 6S-T1 upon completion of the 4kV conversion.

There were three alternatives outlined in revision 2 of this study. These alternatives explored the timing conversions and retirement date for 6S. The fourth alternative to rebuild 6S with a new 69-4kV transformer was not considered since the 4kV voltage level is being phase out in Nova Scotia. The sections on each alternative have been removed in this revision as they only spoke to the timing of the recommended work.

The recommended solution would see retirement of 6S-Terrace Street by 2021. Capital work is in progress: initial 4kV to 12kV conversions are complete, which allow the mobile transformer to be installed under peak conditions, without the need to transfer a portion of the load to 534S. Upgrades to 6S will be completed in 2015, as outlined in recommendations section. The retirement of 6S-Terrace Street is planned for 2021, but this will depend on completion of remaining conversions which are dependent on the progress of other capital work outlined in this study.

5.3 Sydney Transformation

To meet the anticipated load growth in the Membertou area, a new source in Sydney will be required. Given the layouts at both 4S-Townsend Street and 11S-Keltic Drive, the ability to install additional feeders to supply developing load would be quite difficult. It makes sense to have a new source close to developing load.

Revision 2 of this study recommended Alternative Sub-D, the installation of a 15MVA 138-12kV pad-mounted substation at the intersection of existing 138kV transmission corridor and George Street. This recommendation has been re-evaluated since the release of transmission study, 049-2013-TSMG, which indicated a 20MVA reduction on the 69kV load forecast in 2018. The location of this substation was also revised due to issues with the purchase of land at this location. The new proposed location for alternatives Sub-A and Sub-D will be at intersection of Gabarus Hwy and existing 138kV transmission corridor – in Prime Brook. The construction year for all options was also revised to 2016.

The details of the four alternative solutions are outlined in further detail below.

5.3.1 Alternative Sub-A New Substation in Prime Brook

This alternative would address growth in Membertou with construction of a new 15/20/25MVA substation near the transmission right-of-way. This new 138-12kV substation would need to be in service prior to the end of 2016 to meet the developing load in the area. This substation would allow for the offloading of the the 69kV system. The location of this new substation would be near the intersection of existing transmission corridor and Gabarus Hwy. In constructing this substation, an additional 12kV supply would be added to the Sydney area for additional contingency to meet the load growth in the Membertou area. Creating a tap off of L-6539 would remove load from the existing 69kV loop that feeds 4S-Townsend Street, 6S-Terrace Street and 11S-Keltic Drive via 2S-Victoria Junction or 3S-Ganon Road.

Initially 4 new 12kV feeders would be able to provide new feeds to the Membertou community, as well as George Street and Alexandra Street. Additional feeders could be used to reduce loading or for contingency purposes for both 4S-Townsend Street and 11S-Keltic Drive feeders, further reducing loading on the 69kV.

In order for this alternative to proceed, land would need to be acquired and a new tap off of L-6539 would need to be engineered. In addition to this preliminary work, further investigation into the substation design would need to be considered. Refer to Figure 7 below for a proposed location.

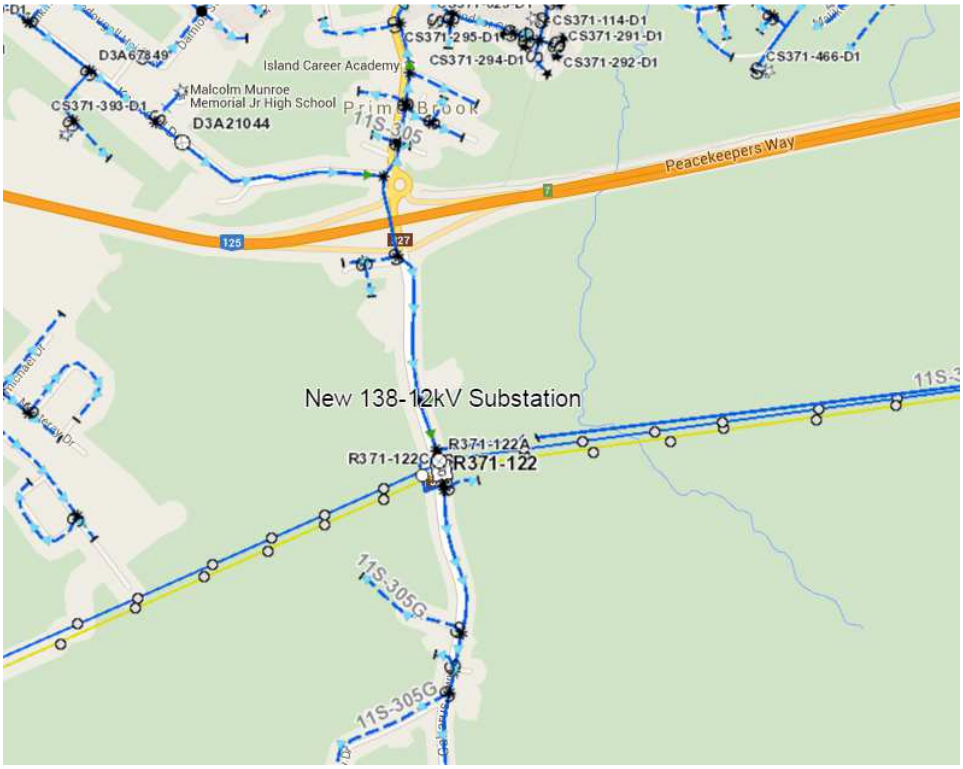


Figure 7Alternative Sub-A Construct New Substation in Prime Brook

5.3.2 Alternative Sub-B New 138-25kV Substation in Prime Brook

Similarly to Alternative Sub-A, the construction of a new substation near the transmission right-of-way would be capable of supplying the newly developing load in the Membertou area. Construction of the new 15/20/25MVA 138-25kV substation would be off of the Highway 327, near the transmission corridor and within close proximity to the existing 25kV distribution feeders in Sydney River. In constructing this substation, an additional 15/20/25MVA 25kV supply would be added to the Sydney area for additional contingency of 11S-Keltic Drive and to meet the load growth in the Membertou area. Creating a tap off of L-6539 would transfer existing load from the 69kV loop that supplies 4S-Townsend Street, 6S-Terrace Street and 11S-Keltic Drive, via 2S-Victoria Junction or 3S-Ganon Road. The loading on the 69kV loop would be further reduced with future customer conversions from 12kV to 25kV, in Sydney River and on Alexandra Street.

These new 25kV feeders would be able to provide feeders directly to the new growth in Membertou. Conversion of portions of Sydney River would enable the creation of new feeder ties between the new feeders and 11S-Keltic Drive 25kV feeders.

In order for this alternative to proceed land would need to be acquired and a new tap off of L-6539 would need to be engineered. In addition to this preliminary work, further investigation into the substation design would need to be considered. Refer to below Figure 8 for a proposed location.

Figure 8Alternative Sub-B Construct New Substation on Alexandra Street

5.3.3 Alternative Sub-C New 69-12kV transformer at 6S-Terrace Street

To meet the planned growth in Membertou, a new 69-12kV 7.5/10/12.5MVA power transformer would be installed, at the 6S-Terrace Street property, in 2015. This new transformer would initially be limited to loading, as the existing 4kV load is reduced. The new transformer would assume the load of the current 4kV transformer, upon load conversions to 12kV.This new transformer would also provide an alternate supply to the George Street area.

Another substation, possibly a padmount design would be required to further supply the Membertou load as it continues to materialize. The padmount substation would require a smaller footprint and be able to supply an additional two feeders to the developing load. It is estimated that this substation would be required in 2017, as the load growth continues, in Membertou. Annual monitoring of the load growth in the Sydney area would be required to ensure that the installation of additional transformation in the area coincides with the continued load growth in the area.
Refer to Figure 9 for an overview of the area.

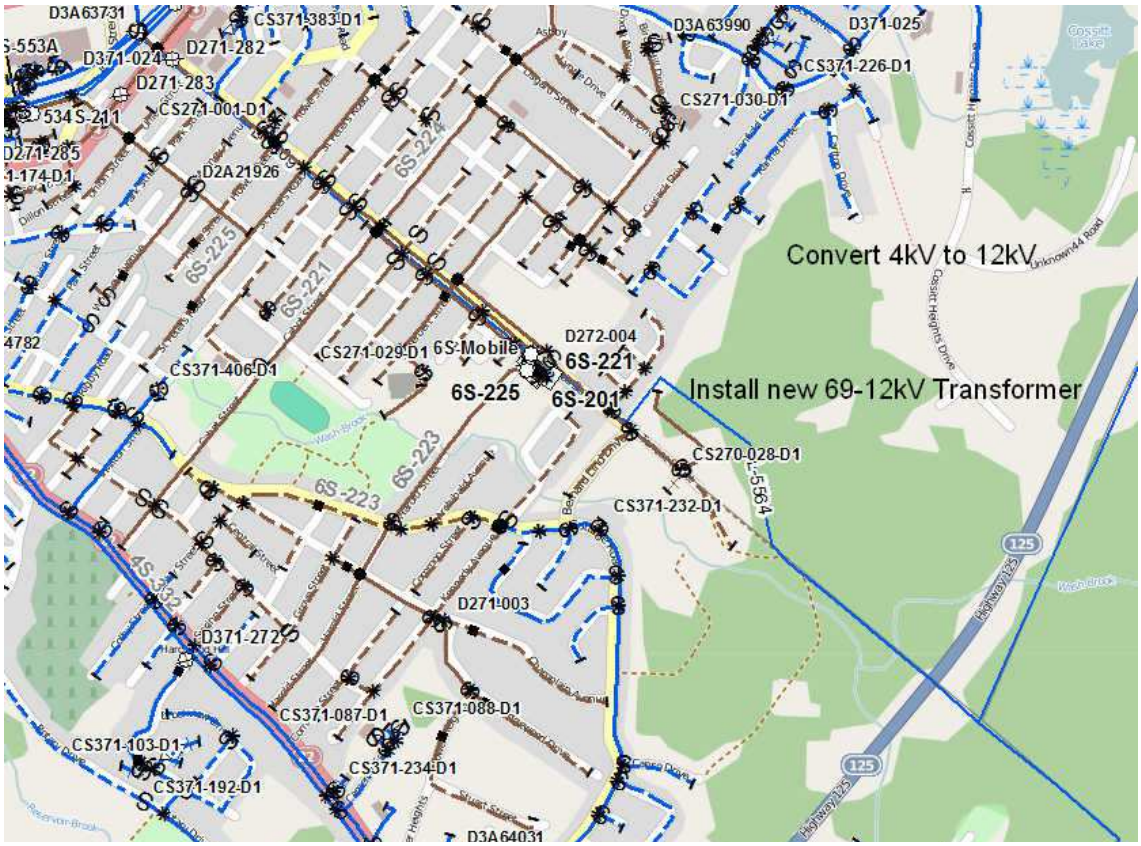


Figure 9 Alternative Sub-C Install New 69-12kV Transformer

5.3.4 Alternative Sub-D New 138-12kV Pad-Mounted Substation

This alternative is similar to Alternative Sub-A, in that a new 15MVA 12kV source would be constructed near the 138kV transmission corridor and George Street. Refer to Figure 10 below. The alternatives differ, in that this substation will have less capacity and be pad-mounted in design. The new 15MVA transformer would be supplied via a new tap off of L-6539, one of the 138kV transmission lines in the area. This substation would require less space than a traditional substation and does not require a substation fence, as all of the equipment is dead-front.

Unlike Alternative Sub-A, only three feeders would be supplied via this substation. One of these feeders would supply Membertou via a new highway crossing. This feeder will reduce the loading on the existing Membertou supply (4S-333). The second feeder will continue along the transmission Right of Way (ROW) to Alexandra Street. Load from 11S-305 will be transferred to this new feeder, allowing for a load reduction on 11S-305. The third feeder will extend to George Street and assume a portion of the loading along George Street.

As the load continues to grow, in both the Sydney and Membertou area, continual monitoring will indicate the need for any future additional transformation in the area. Given the modularity of the pad-mounted substation, future installations could occur near the 138kV transmission line, closer to the developing load center, when required. Initially, it was thought that expansion would not be required until 2027, but due to transmission planning requirements, an additional transformer would be required in 2018.

As with the introduction of any new equipment, spare components will be required with the initial purchase, but not necessarily for subsequent applications.

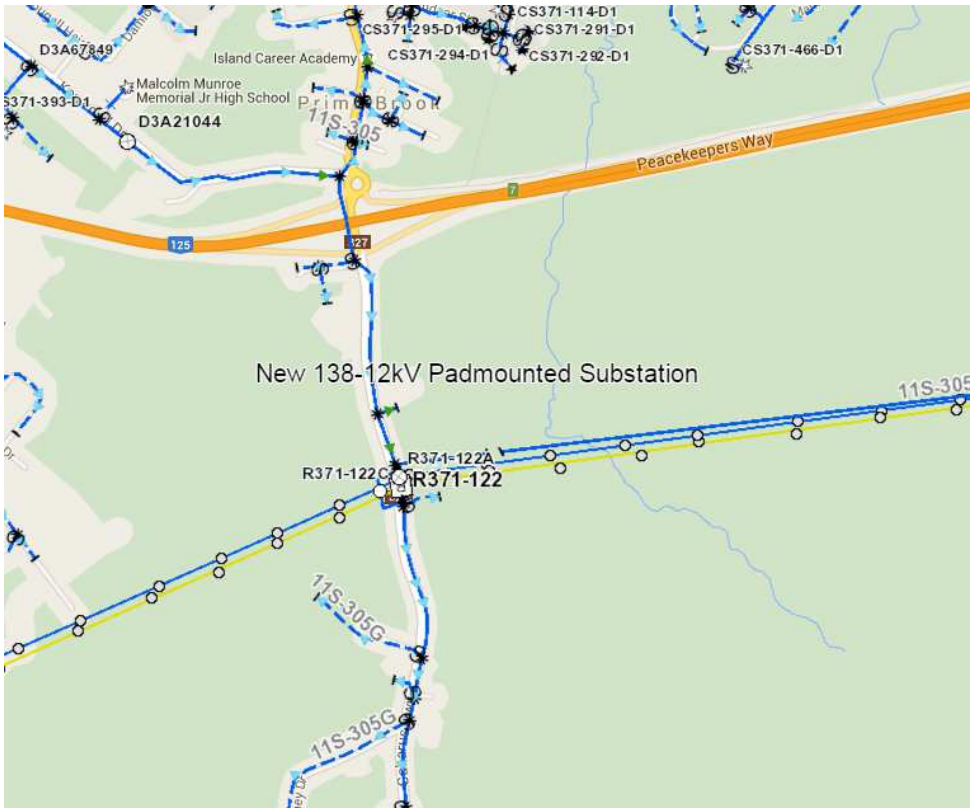


Figure 10 Alternative Sub-D New 138-12kV Pad-Mounted Substation

5.3.5 Sydney Transformation Recommendation

Alternative Sub-D was the least cost option when the Economic Assessment was completed in revision 2 (see Appendix C). With the requirement to remove 20MVA from the 69kV forecast by 2018, an additional pad-mounted transformer must be planned in the short term, rather than 2027. By moving the second pad-mount expansion to 2018, the cost of alternative Sub-D does not offer economic advantage over alternative Sub-A. The additional advantages to alternative Sub-A make it the best choice:

- Less risk due to standard substation construction
- No new spare equipment required
- Standard substation can accommodate mobile transformer, whereas pad-mounted option cannot

A detailed outline of conversions and substation construction is outlined in the recommendations section of this study.

6.0 RECOMMENDATIONS

In summary, the following provide the impetus for the recommendations contained herein:

- The existing feeders supplying the Membertou area are at or near their criteria limits and cannot be utilized to supply the long term capacity needs of Membertou.
- Membertou load growth is forecasted to continue as there are plans for a retail centre adjacent to Hwy125 at the site of the new highway interchange presently under construction
- The 4kV distribution facilities at 6S-Terrace Street are nearing their end of life and key components are obsolete, exposing customers to prolonged outages.
- The 4kV distribution facilities at 533S-Mason Street and 6S-Terrace Street are islanded 4kV that are susceptible to prolonged outages as load cannot be transferred to an adjacent feeder.
- Transmission study has indicated the need to remove 20MVA from 69kV system peak

This study revision does not recommend any change to the capital work underway for the conversion of 533S-Mason Street, as outlined in Alternative 533-B, section 5.1.1.

The recommendation for 4kV conversion and retirement of 6S-Terrace Street is unchanged in this revision. The Economic Assessment Model, refer to Appendix C, recommends the conversions of the 4kV distribution supplied by 6S-Terrace Street be converted to 12kV by 2020, as outlined in Alternative 6S-C, in section 5.2.3. Upon completion of these conversions, the 6S-Terrace Street substation will be retired. The advancement or deferment of these projects may be influenced by factors including: residential/commercial development, feeder reconfigurations and/or ranking of capital projects within the ACE plan.

The second Economic Assessment Model, refer to Appendix D, recommends the installation of a pad-mounted substation, with three feeders prior to the 2015/2016 winter peak. This has been re-evaluated in revision 3 of this study, as outlined in section 5.3. The new recommendation will be for a standard 15/20/25MVA substation constructed in 2016. This added transformation in the Sydney area will meet the area load growth for the next several years and allow for 20MVA reduction of forecasted peak load on 69kV system.

A detailed outline of the components of each of these alternatives is outlined below, organized by capital year completion. The originally recommended capital years were left intact for items that were not modified within this revision of the study. Comments were added to indicate the progress of each recommendation.

6.1 Recommendations by Capital Year

6.1.1 2013 Capital Year

The capital items to be completed in 2013 include the work associated with the conversion of 533S-Mason Street, as well as the work associated with the reduction of 4kV load at 6S-Terrace Street, to enable the retirement of the existing breakers at the substation.

The Shipyard Area Reconfigure and Mason Street Conversion were grouped as one capital item that is well underway. Full completion expected in summer 2015.

The Cabot Street and Rockdale Avenue conversions are complete and the 6S-Terrace Street substation upgrades are in their final stages.

6.1.1.1 Shipyard Area Reconfigure

This portion of the project outlines the change of supply within the Shipyard area, of Sydney. The supply for Kings Road will be changed from 4S-333 to 4S-334.The supply for Argyle Street will also be changed from 4S-321 to 4S-333. Refer to Figure 11 below. The details of this work are as follows:

- Dead-end 4S-333 adjacent to railway tracks, at Bentinck Street and open.
- Jumper 4S-334, to the existing 4S-333, on Kings Road.
- Remove the de-energized section of 4S-333, adjacent to the railway tracks, from Kings Road to Bentinck Street.
- Rebuild Bentinck Street, from Crescent Street to Argyle Street, to 3 phases.
- Open Argyle Street at George Street.

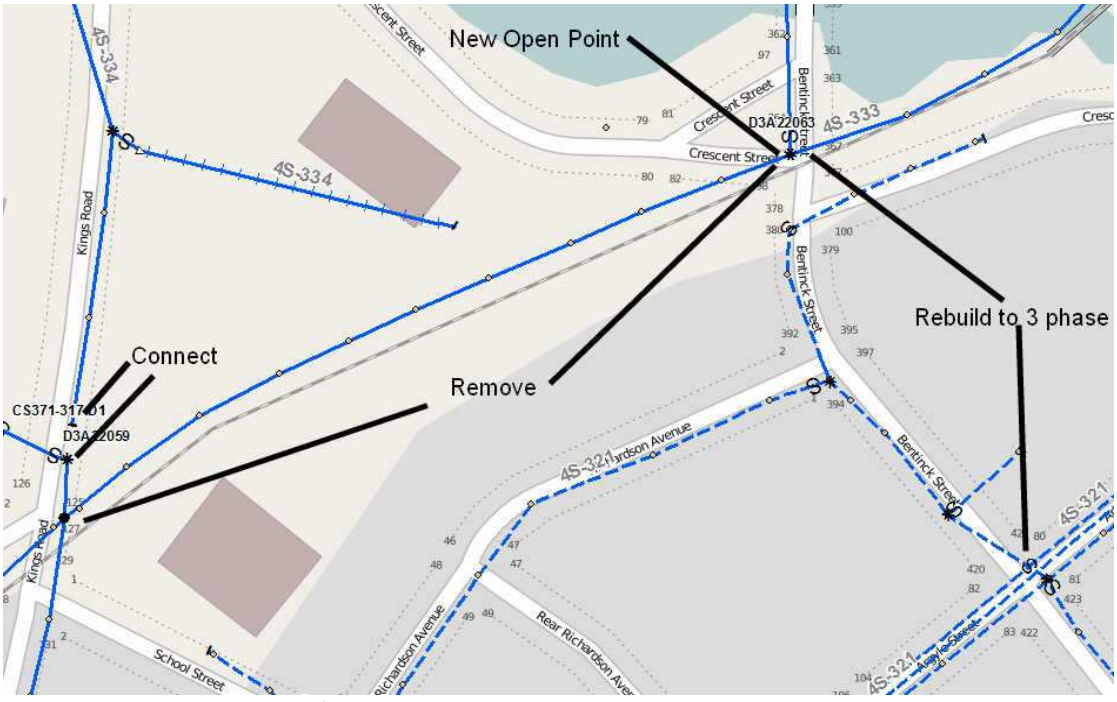


Figure 11 2013 Reconfigure Supply to Shipyard Area

6.1.1.2 533S- Mason Street Conversion

This portion of the project will convert 533S-Mason Street changing the supply to the area from Kings Road to Argyle Street. This portion of the project will also see the removal of the 533S-Mason Street stepdown, upon completion of the conversion to 12kV. Upon completion of this portion of the project, Alexandra Street will be supplied by 4S-333 from Yendys Street to Harbourview Drive. Refer to Figure 12 below. The details are as follows;

- Reconductor Mason Street to 336.
- Open Mason Street, at Kings Road
- Close D3A19725 on Argyle Street, at Kent Street
- Replace neutral on Argyle Street and Yendys Streets to 4/0.
- Reconductor primary and neutral on Xavier Drive to 2/0ACSR.
- Remove single phase primary on Xavier Drive.
- Convert area from 4kV to 12kV.

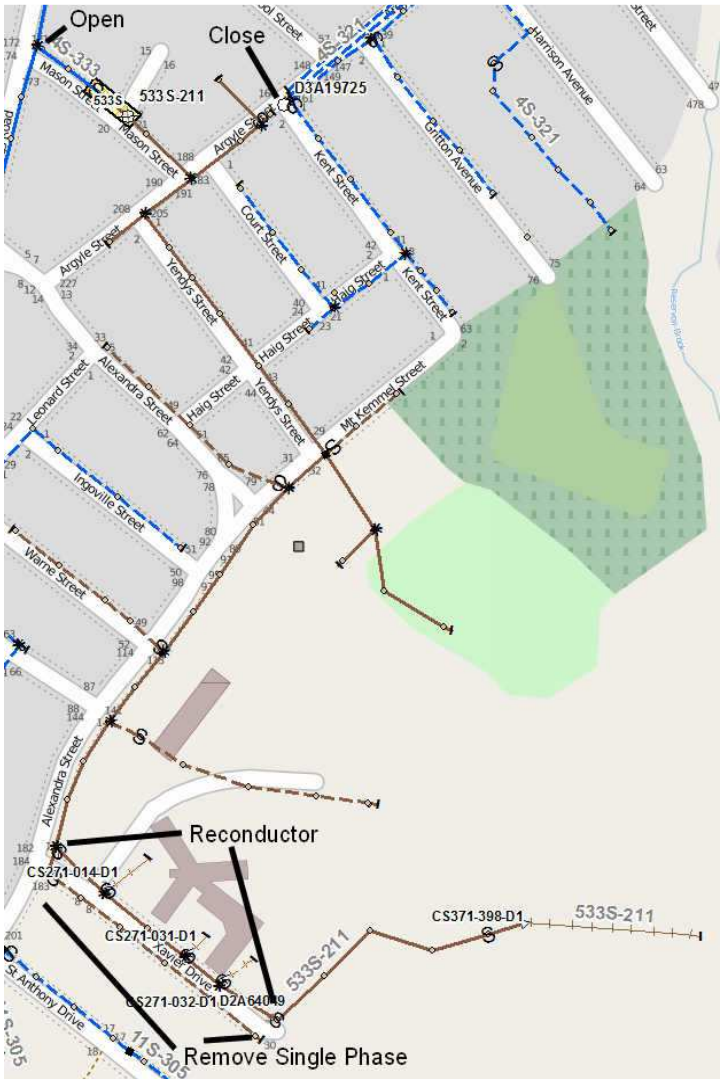


Figure 12 2013 533S-Mason Street Conversion

6.1.1.3 Cabot Street Conversion

This portion of the project will convert Cabot Street, north of Terrace Street. This conversion, along with the Rockdale Avenue conversion, will reduce the load on 6S-T1, to enable the installation of the mobile substation, minimizing the requirement to transfer load to 534S. Refer to Figure 13 below. This will be accomplished by:

- Fill in the gap on Cabot Street and Upper Prince Street
- Create open point at Cabot and Terrace.
- Install open point on Cornwallis Street at McConnell Drive.
- Convert shaded areas, including side streets.

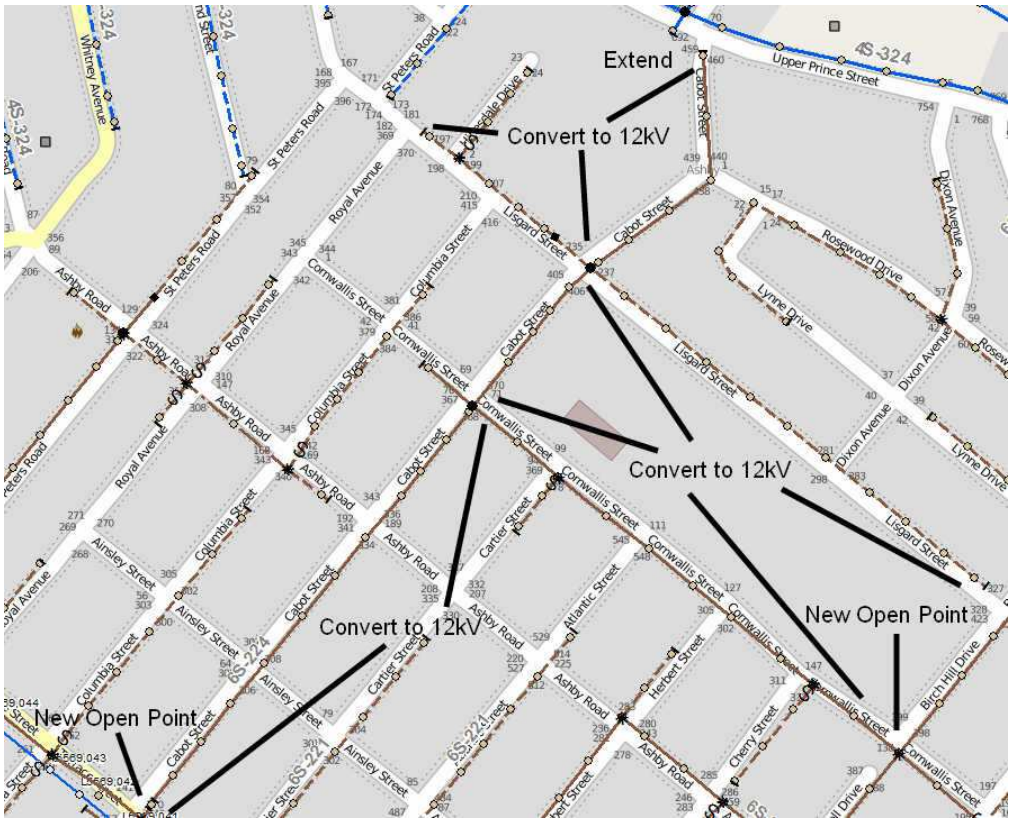


Figure 13 2013 Cabot Street Conversion

6.1.1.4 Rockdale Avenue Conversion

This portion of the project will convert Rockdale Avenue and Cottage Road to Harold Street. This phase of the project will further reduce the overall load on 6S-T1, reducing the need to transfer customer load to 534S, when the mobile substation is installed. Refer to Figure 14 below. This will be accomplished by:

- Close switch at Oxford Street onto George Street.
- Install cutout, on single phase along Cottage Road, at the intersection with Oxford Street.
- Open Harold and Cottage Road.
- Convert Oxford Street, to open point on Cottage Road, from 4kV to 12kV.
- Convert Rockdale Avenue, Champlain Avenue and Cottage Road, to Harold Street, including all side streets and branch lines, as indicated in Figure 14.

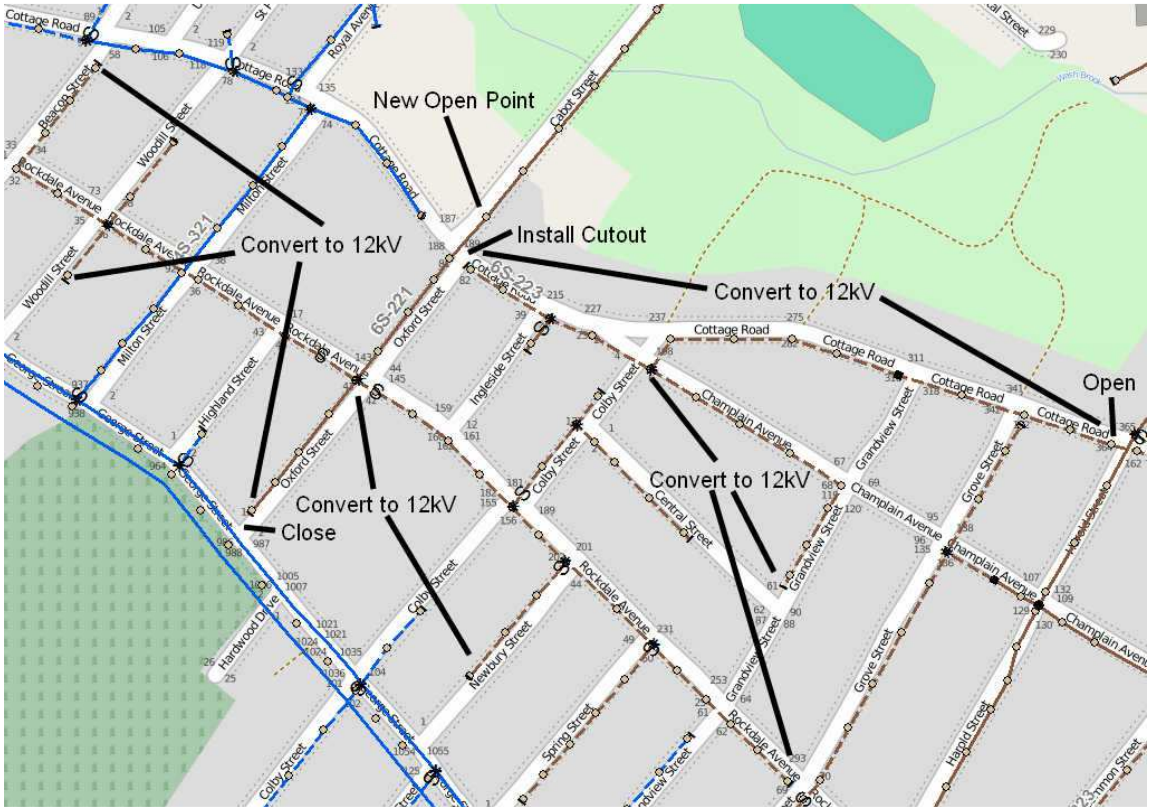


Figure 14 2013 Rockdale Conversion

6.1.1.5 6S-Terrace Street Substation Upgrades

This portion of the project will see the removal of the existing switchgear building, as well as the installation of pole mounted reclosers. This will be accomplished by:

- Installation of three dedicated power cables and buried ducts.
- The installation of three temporary pole mounted reclosers, to be supplied from new power cables.
- Removal of existing 4kV switchgear and building.

6.1.2 2014 Capital Year

The 2014 capital year includes completion of the reconfiguration of the Shipyard area supply, as well as the construction of a new feeder tie into Membertou. This continuation of work will increase the reliability and contingency within the Shipyard and Membertou areas.

The Membertou feeder tie has been completed and the new open point on Kings Road will be done in the summer of 2015. The Bentinck Street upgrades have been deferred until 2016.

New George Street pad-mounted substation preliminary engineering work has been removed.

6.1.2.1 Bentinck Street Upgrades

This portion of the project will upgrade the remaining conductor on Bentinck Street, to enable the removal of the remaining off-road section of feeder, along the railway tracks. This feeder 4S-333, is deteriorated and approaching its end of life. Rebuilding Bentinck Street and reconductoring the previously retired 4kV conductor on Townsend Street will enable 4S-333 to be adjacent to the road, from the substation to the majority of the load it supplies. Refer to Figure 15 below. The details are as follows:

- Reconductor Bentinck Street, from Crescent Street to Townsend Street.
- Reconductor lower circuit on Townsend Street, from 4S-Townsend Street to Bentinck Street, with 336.
- Remove 4S-333, adjacent to the railway tracks, from Bentinck Street to Townsend Street, except for the first two spans from George Street towards Townsend Street.
- Install new 3 phase tap from the remaining portion of 4S-333 to the top circuit along George Street, to supply the customers at the start of Glenwood Street.

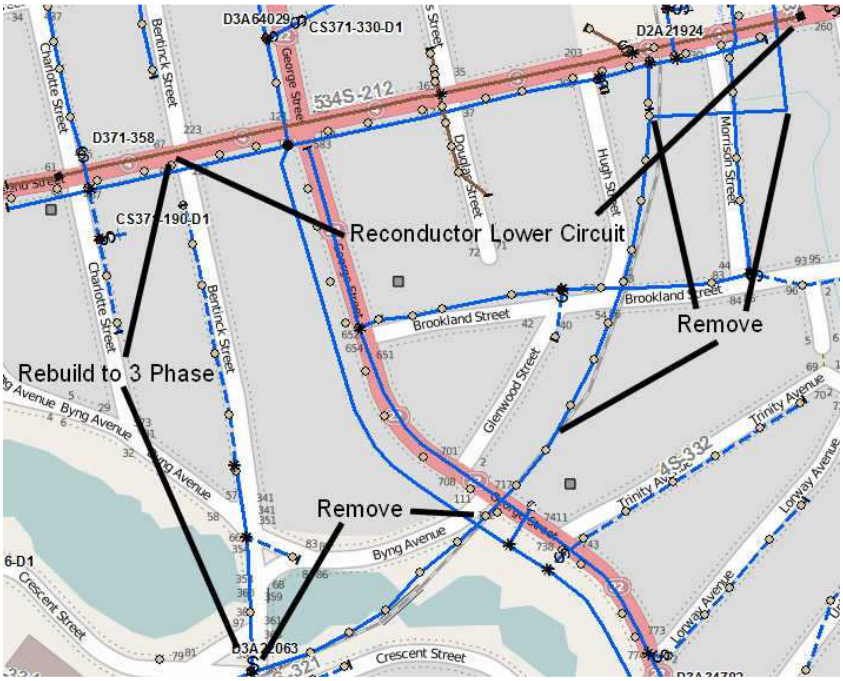


Figure 15 2014 Bentinck Street Upgrades

6.1.2.2 Membertou Feeder Tie

This portion of the project will see the creation of a feeder tie between the recently converted portion of Alexandra Street and the existing feeder on Alexandra Street. Also included in this portion of work is the construction of an additional feeder tie with the primary Membertou supply, on Maillard Street. Refer to Figure 16 below. The details are as follows:

- Extend newly converted 12kV (4S-333) along Alexandra Street to St. Anthony Drive, reconductoring from St Anthony Drive to the new open point with 336.
- Create new, normally closed, solid blade, sectionalizing point on Alexandra Street, at Xavier Drive.
- Create new open point on Alexandra Street, between Castle Drive and Harbourview Drive.
- Reconductor Towerview Place and extend to Maillard Street.
- Create new open point, on Maillard Street, on the north side of the intersection of Churchill Drive and Maillard Street.

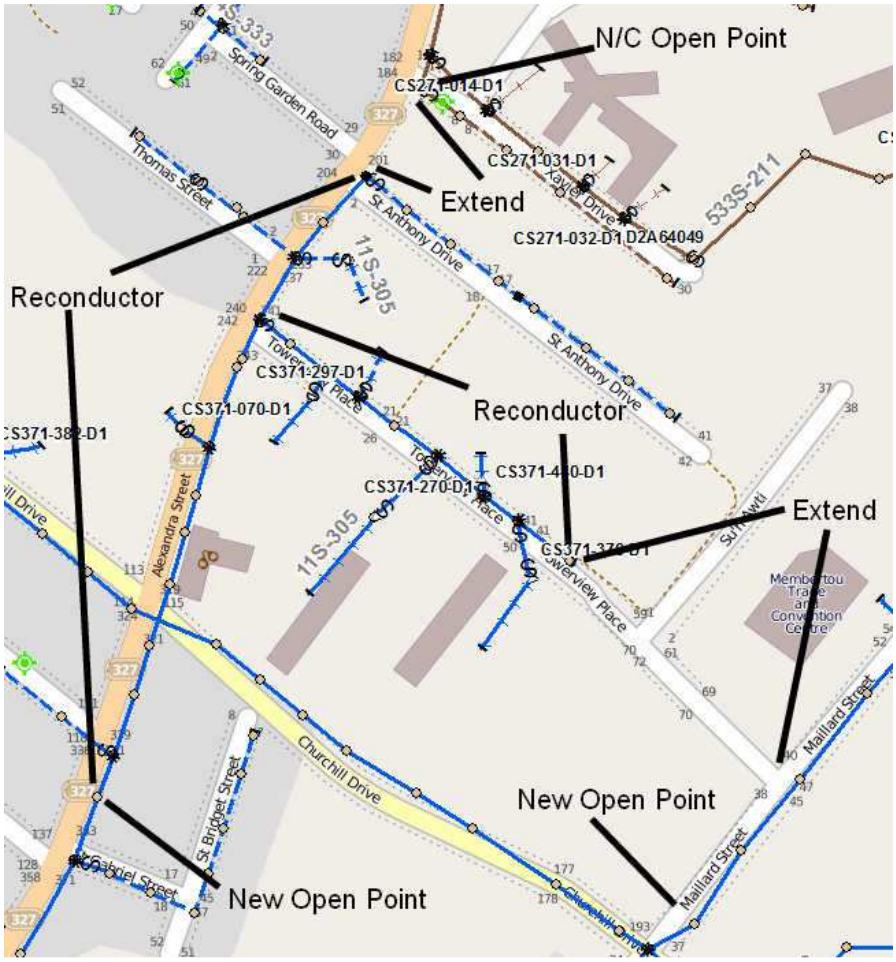


Figure 16 2014 Membertou Feeder Tie

6.1.2.3 New Kings Road Open Point

This portion of the project will enable the transfer of a portion of load from 4S-Townsend Street to 11S-Keltic Drive. This load transfer will reduce the overall loading on 4S-334 that will be supplying Membertou via Churchill Drive. Refer to Figure 17 below. The details are as follows:

- Install new open point on Kings Road, between Harbourview Drive and Churchill Drive.

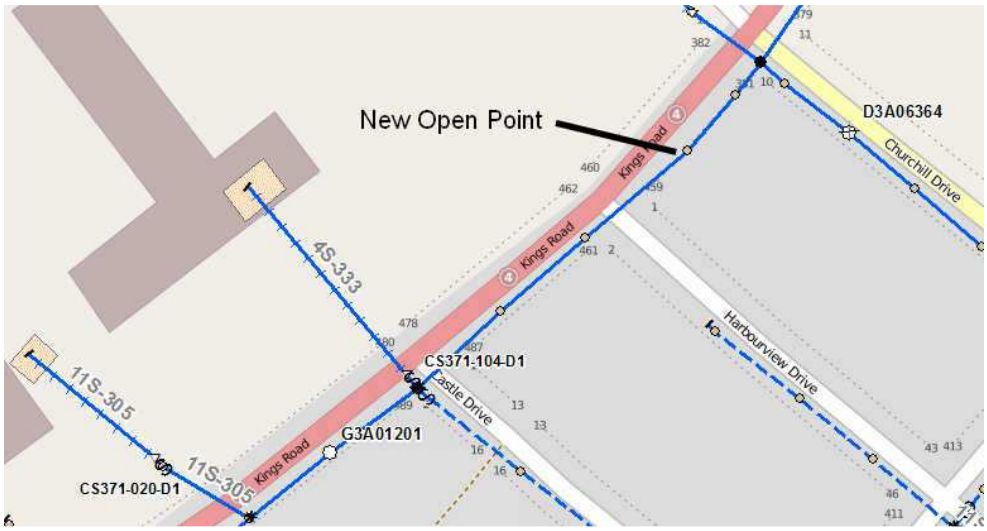


Figure 17 2014 Kings Road Open Point

6.1.3 2015 Capital Year

The capital 2015 work includes the completion of items noted above in 2013 and 2014 Capital Year sections, as well as the preliminary engineering of the new Prime Brook substation. Further 4kV to 12kV conversions at 6S-Terrace Street will be deferred until after substation construction.

6.1.3.1 New Prime Brook Substation Preliminary Work

This portion of the project will detail the preliminary work required with the construction of the new 15/20/25MVA 138-12kV substation on Gabarus Hwy, near the intersection of the 138kV and 69kV transmission lines, L-6539 and L-5564. Refer to Figure 18 below. This will be accomplished by:

- Secure land rights to new substation location.
- Completion of the substation engineering and sourcing of long lead items.

6.1.4 2016 Capital Year

6.1.4.1 New Prime Brook Substation Construction

This portion of the project will detail the construction of the new 15/20/25MVA 138-12kV substation in Prime Brook. Refer to Figure 18 below. This will be accomplished by:

- Construction of a new tap off of L-6539 and the installation of associated equipment.
- Construction of 15/20/25MVA 138-12kV substation and associated equipment.

6.1.4.2 New Prime Brook Substation Feeders

This portion of the project will construct the new feeders, from the new Prime Brook substation. Refer to Figure 18 below. This will be accomplished by:

- Four new feeder exits will be created.
- The first feeder will connect to existing 11S-305 feeder on Gabarus Hwy.
- Existing 11S-305 feeder along transmission ROW will be rebuilt to double circuit which will extend from the substation to George Street and toward Highway 125 up to existing highway crossing. One feeder will tie to existing 4S-321 feeder at highway crossing. The other feeder will extend beyond existing highway crossing and tie to existing 4S-332 feeder. The location of R371-103 will be determined in a subsequent distribution protection study.
- The fourth feeder will extend north of the substation and use existing ducting to cross Highway 125 and tie to existing 4S-333 feeder on Tupsi Drive.

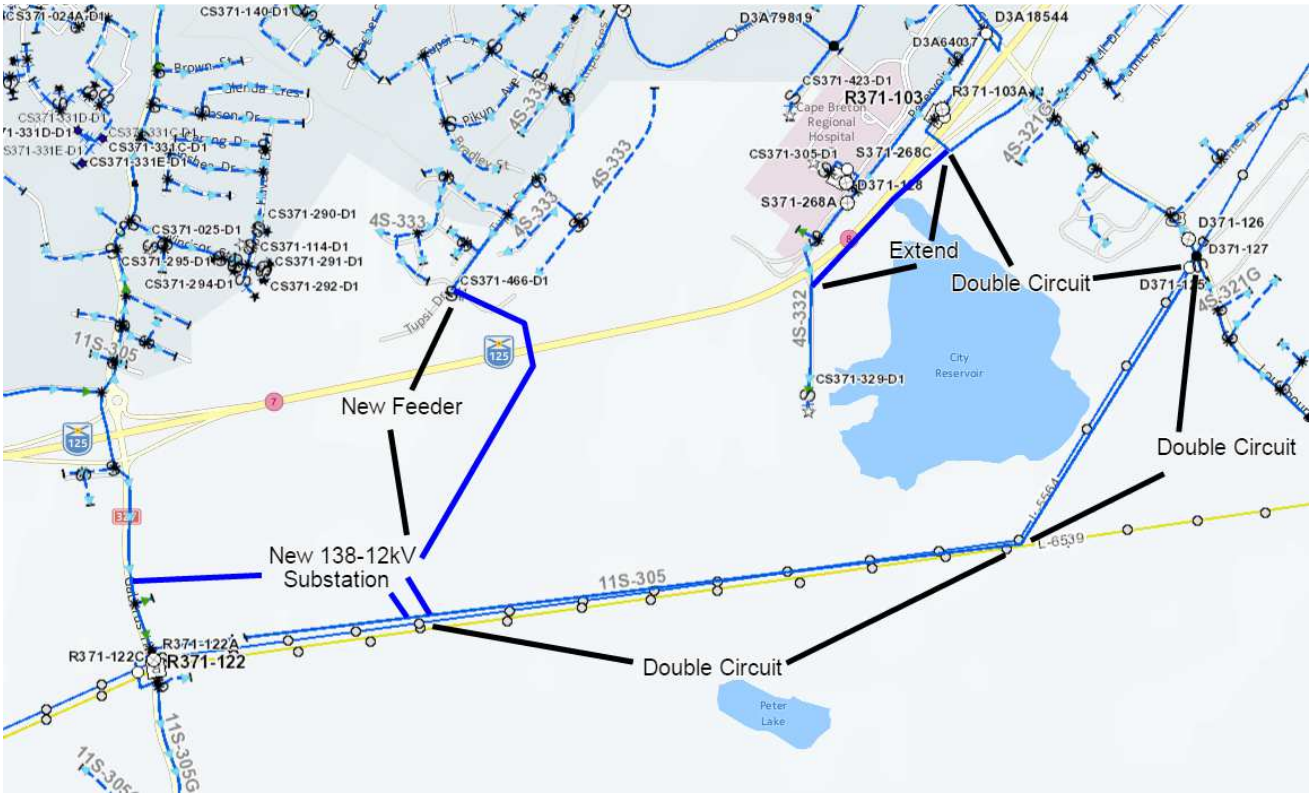


Figure 18 2016 New Prime Brook Substation

6.1.5 2017 Capital Year

Remaining 4kV to 12kV conversions will be dependent on the completion of Prime Brook substation. These conversions have been redistributed based on the new timeline for substation construction. The 2021 retirement of 6S-Terrace Street substation has been maintained.

6.1.5.1 Harold Street Conversion

This portion of the project will see the conversion of the Harold Street area, south of the 6S-Terrace Street substation. This will also include the conversion of the remaining sections of Champlain Avenue, Cottage Road and adjacent streets. This new conversion will be supplied via one of the 12kV feeders, on George Street. The off-road section of the existing 4kV feeder will be removed, between Harold Street and Holly Street. Holly Street will remain at 4kV. Refer to Figure 19below. This will be accomplished through the following:

- Create new N/C open point on Harold Street at George Street.
- Rebuild Cottage Road to Bernard Lind Drive with 3phase, 336ACSR.
- Create a new open point on Cottage Road, at Bernard Lind.
- Convert east of Harold Street to 12kV, as well as Grove Street.
- Remove off-road portion of feeder between Harold Street and Holy Street.
- Extend one phase on Holly Street to Terrace Street and remove the remaining two phases.
- Remove 2 phases from Harold Street, from Cottage Road towards Holly Street.

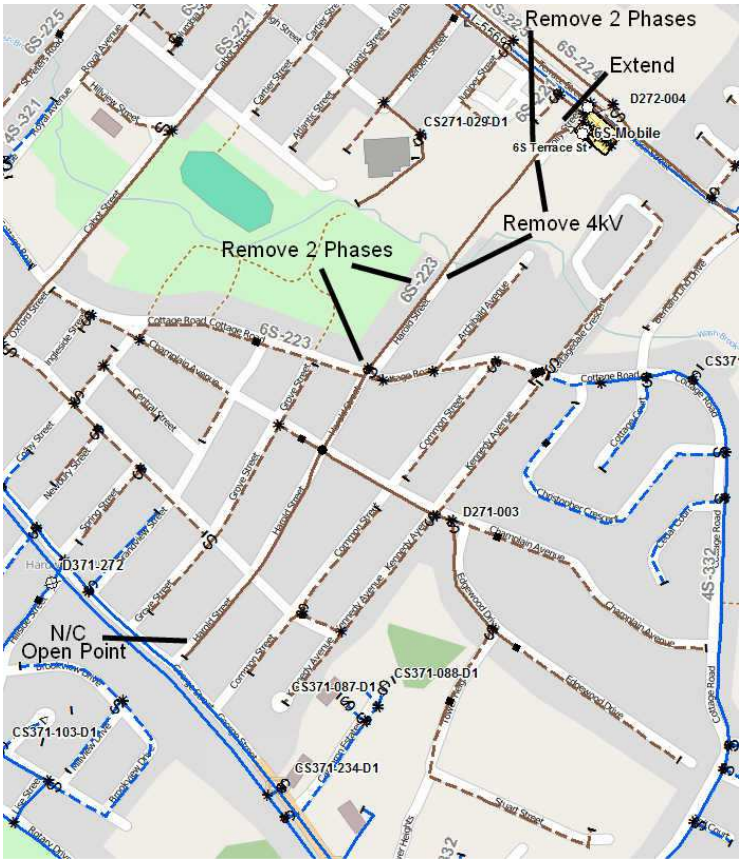


Figure 19 2015 Harold Street Conversion

6.1.5.2 Bernard Lind Drive Rebuild

This portion of the project will convert Terrace Street, east of the 6S-Terrace Street substation. This portion of the project will also see the addition of two phases along Bernard Lind Drive, supplying the area via Cottage Road. Refer to Figure 20 below. This will be accomplished by:

- Rebuild Bernard Lind Drive with three phase 4/0 primary and 4/0 neutral, from Cottage Road to Terrace Street.
- Install a new open point east of the 6S-Terrace Street substation.
- Convert Terrace Street east of the 6S-Terrace Street substation.
- Create new Open Point at the end of Bernard Lind Drive and Cottage Road.

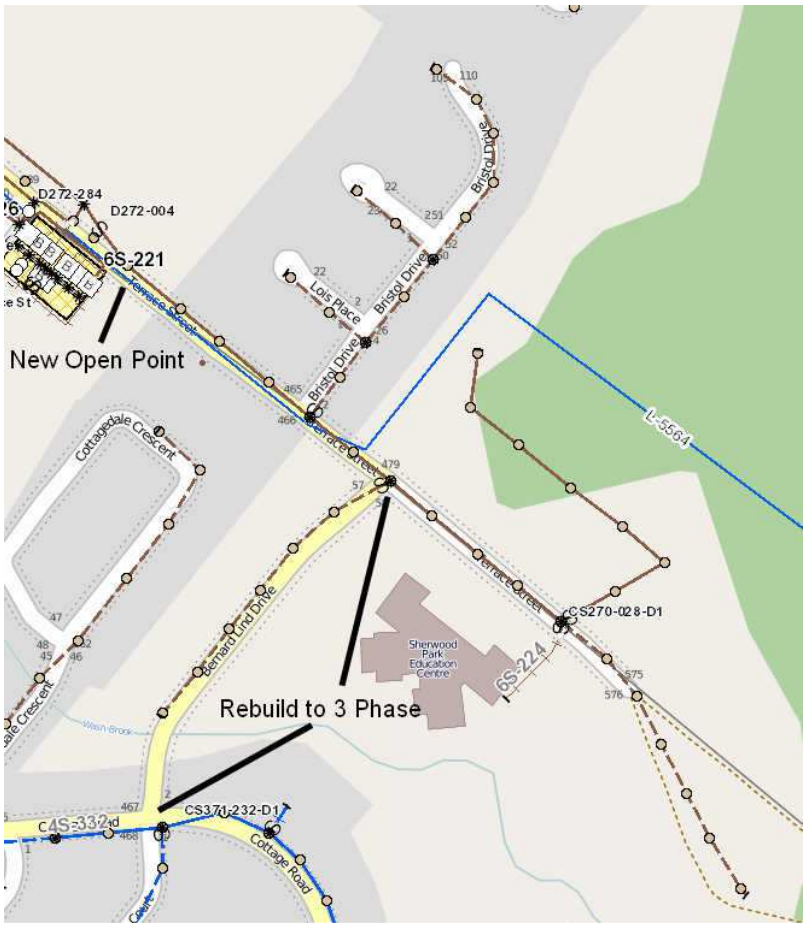


Figure 20 2016 Bernard Lind Rebuild

6.1.6 2018 Capital Year

6.1.6.1 Birch Hill Drive Conversion

This portion of the project will convert Birch Hill Drive and its side streets from 4kV to 12kV. This newly converted section will be supplied via 4S-324. Refer to Figure 21 below. The details are as follows;

- Extend 3phase on Birch Hill Drive to Upper Prince Street.
- Create new N/C open point at the intersection of Birch Hill Drive and Upper Prince Street.
- Convert Birch Hill Drive, McConnell Drive, Ashby Road and Herbert Street to Terrace Street, including side streets, from 4kV to 12kV.
- Change supply of Herbert Street, south of Terrace Street, to 6S-221. This portion of the street will be converted in a following portion of work.

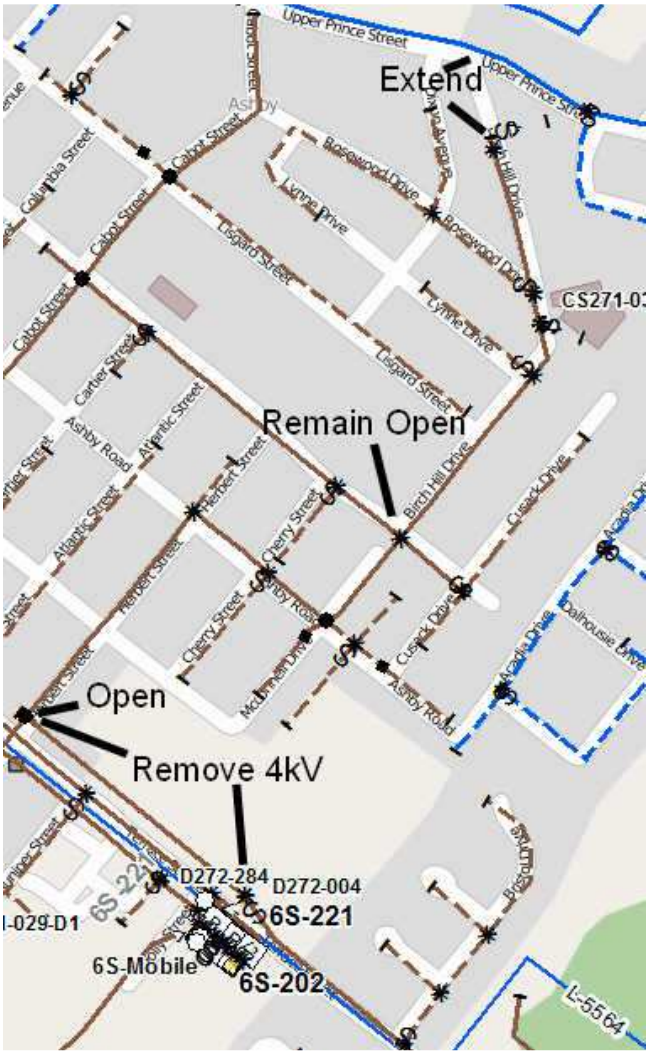


Figure 21 2017 Birch Hill Drive Conversion

6.1.6.2 Townsend Street Conversion

This portion of the project will convert the 4kV customer load on Terrace Street, from St. Peters Road to Townsend Street. The load will be supplied via 4S-324, until the remaining section of Terrace Street is converted. High Street, from St. Peters Road to Townsend Street will continue to be supplied via 6S-225. Refer to Figure 22 below. The details are as follows;

- Install open point on Terrace Street, between Howe Street and St. Peters Road.
- Open Howe Street, between High Street and Terrace Street.
- Install new open point on the north side of the Howe Street and High Street intersection.
- Install new tap on south Howe Street, to High Street.
- Open D271-283.
- Extend High Street to St Peters Road.
- Install new open point on Park Street, at Terrace Street.
- Convert Terrace Street, from St. Peters Road to Townsend Street, as well as the side streets indicated in Figure 22.

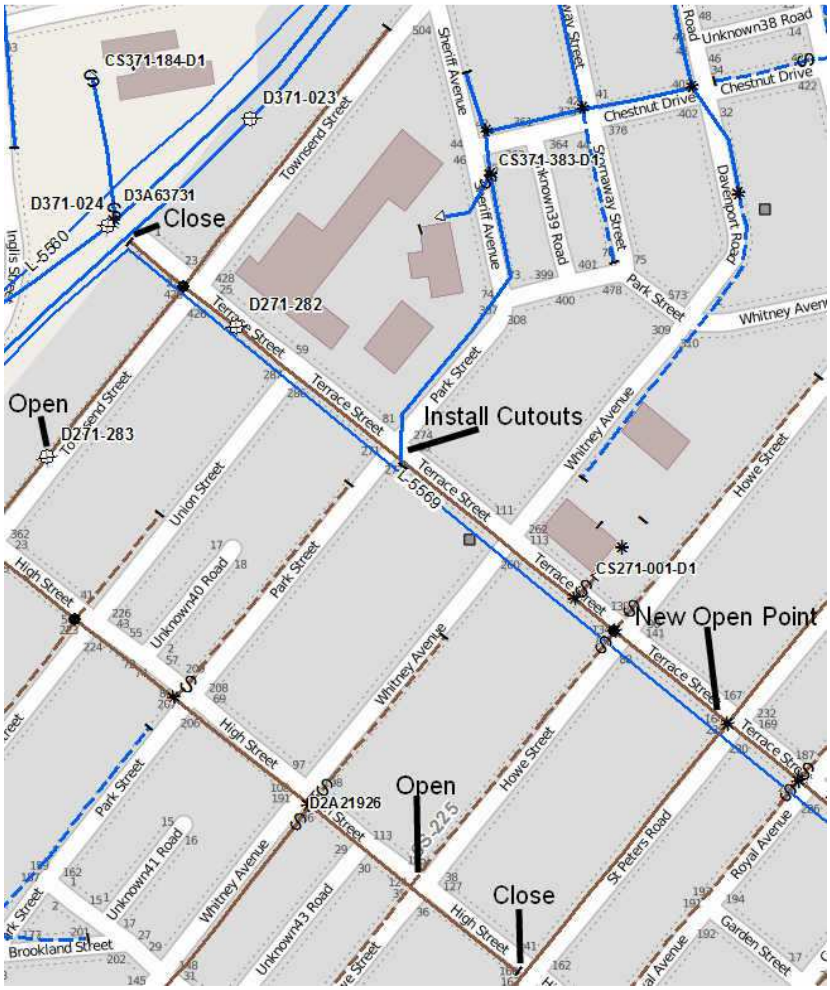


Figure 22 2018 Townsend Street Conversion

6.1.7 2019 Capital Year

6.1.7.1 High Street Conversion

This portion of the project will convert the High Street area, from 4kV to 12kV. The load will be supplied by 4S-324, via the open point on Townsend Street. Upon completion of this portion of work, the 534S stepdown will be removed from service, as there will be no load able to be transferred to it. Refer to Figure 23 below. The details are as follows;

- Close D271-283, on Townsend Street.
- Install new Open Point on Terrace Street, between St. Peters Road and Royal Avenue.
- Convert High Street, from Styles Lane (534S stepdown) to St. Peters Road, including all side streets.
- Convert St. Peters Road, including all side streets.
- Remove 534S stepdown.

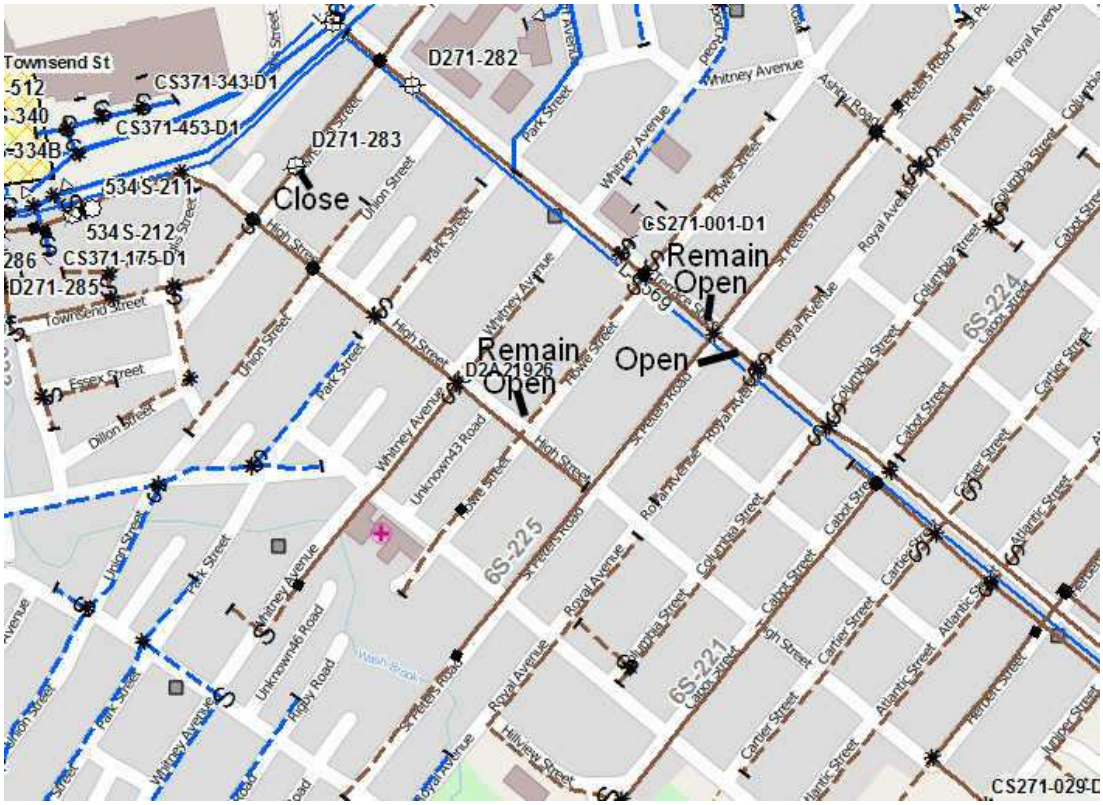


Figure 23 2019 High Street Conversion

6.1.8 2020 Capital Year

6.1.8.1 Terrace Street

This portion of the project will see the conversion of the remaining 4kV, east of the 6S-Terrace Street substation. This conversion will include rebuild of a section of Terrace Street, from the substation to Cabot Street. This rebuild will reduce the feeders along Terrace Street from a maximum of three to one. Refer to Figure 24 below. The details are as follows;

- Convert Terrace Street, from the 6S-Terrace Street substation to St. Peters Road, from 4kV to 12kV, including all side streets that have not been previously converted.
- Rebuild Terrace Street, from the 6S-Terrace Street substation, to St. Peters Road with one, 3-phase 336, circuit.

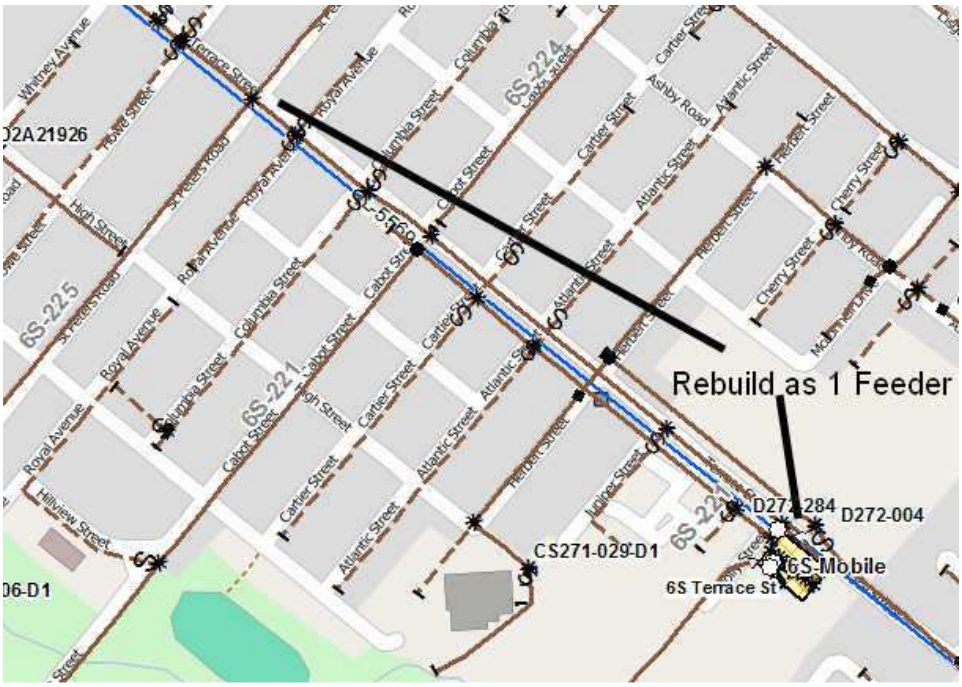


Figure 24 2020 Terrace Street

6.1.9 2021 Capital Year

6.1.9.1 6S-Terrace Street Retirement

This portion of the project will see the retirement of the 6S-Terrace Street substation. This will include the decommissioning of 6S-T1, as well as the removal of most substation equipment. A requirement to modify the 69kV transmission will be necessary, to facilitate the removal of the substation buswork. Refer to Figure 25 below. This will be accomplished by:

- Decommission 6S-T1.
- Reconfigure L-5564, in front of the 6S-Terrace Street substation, to bypass the substation.
- Remove buswork and all NSPI owned equipment.

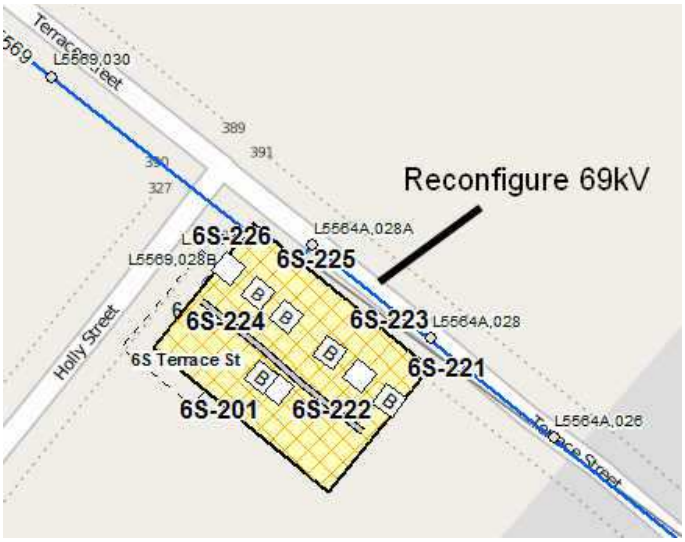


Figure 25 2021 6S-Terrace Street Retirement

APPENDIX A

System Operating Diagrams

Pages 41-46 (Attachment 1) have been removed due to confidentiality.

APPENDIX B

Load History and Forecast

Please refer to section 3.2 Load Forecast for the 90th Percentile Data values

Appendix B: Load History and Forecast

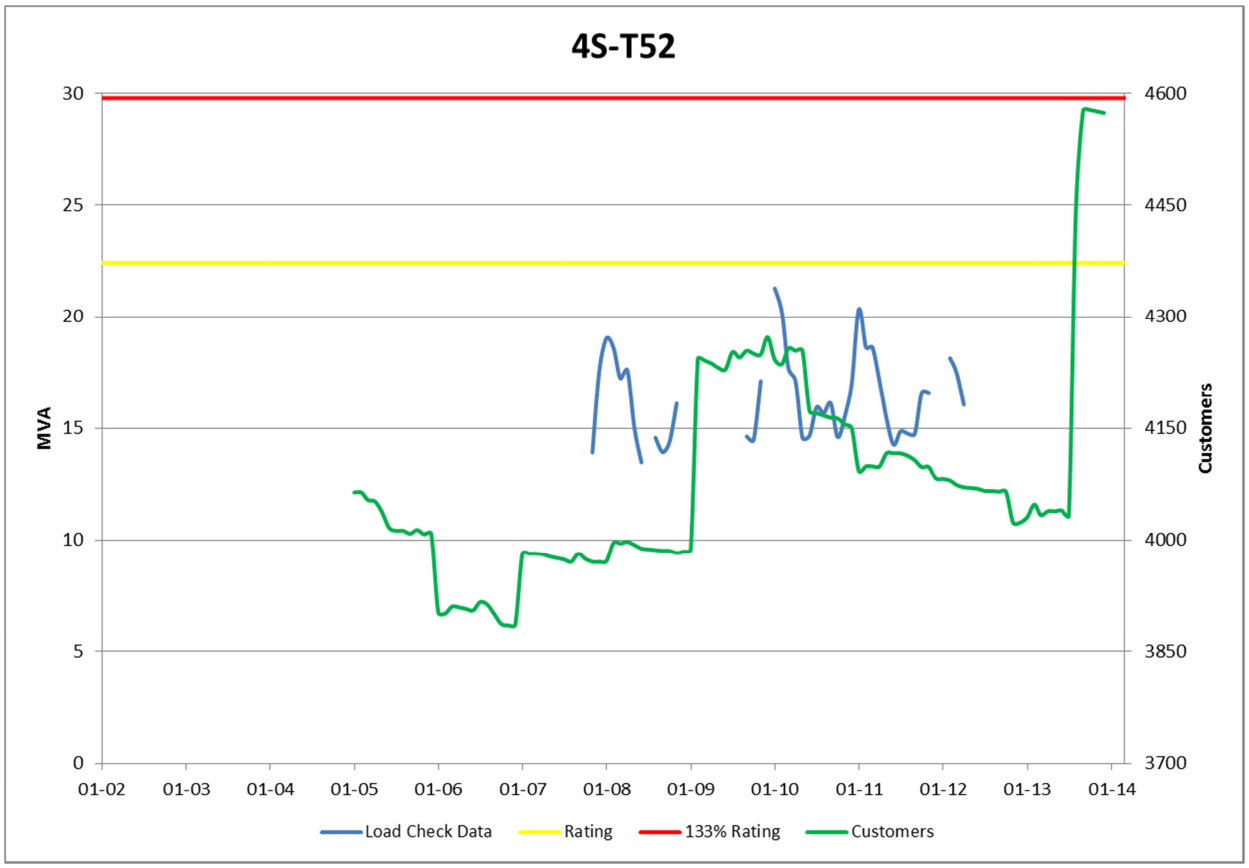


Figure 32 4S-T52 Load History

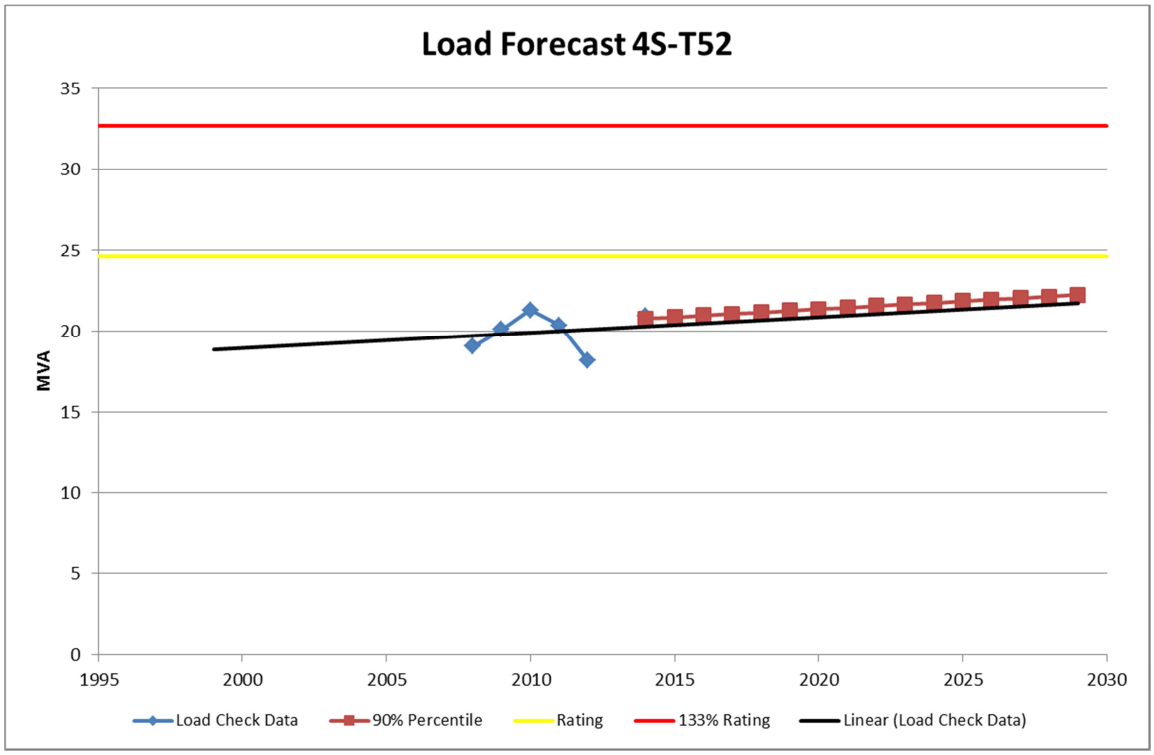


Figure 33 4S-T52 Load Forecast

Load Growth 0.42%**

Appendix B: Load History and Forecast

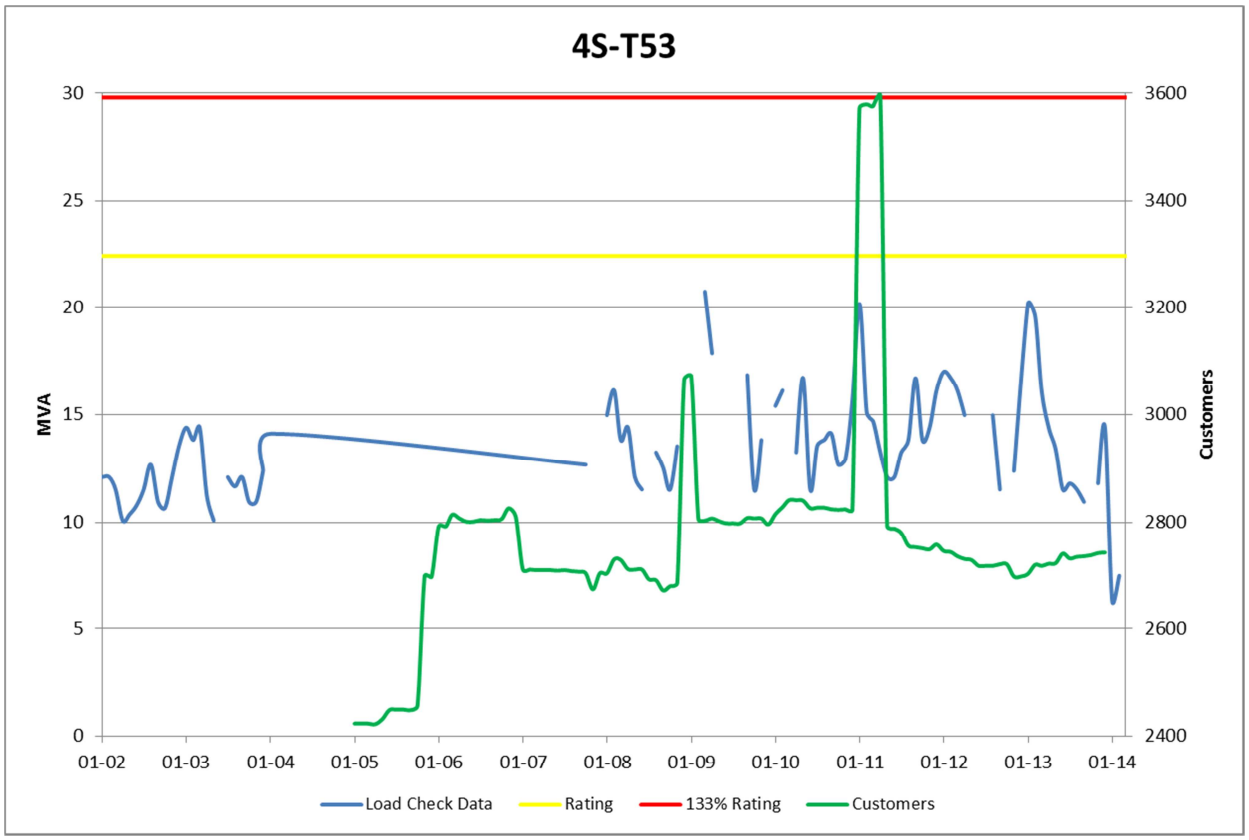


Figure 34 **4S-T53 Load History**

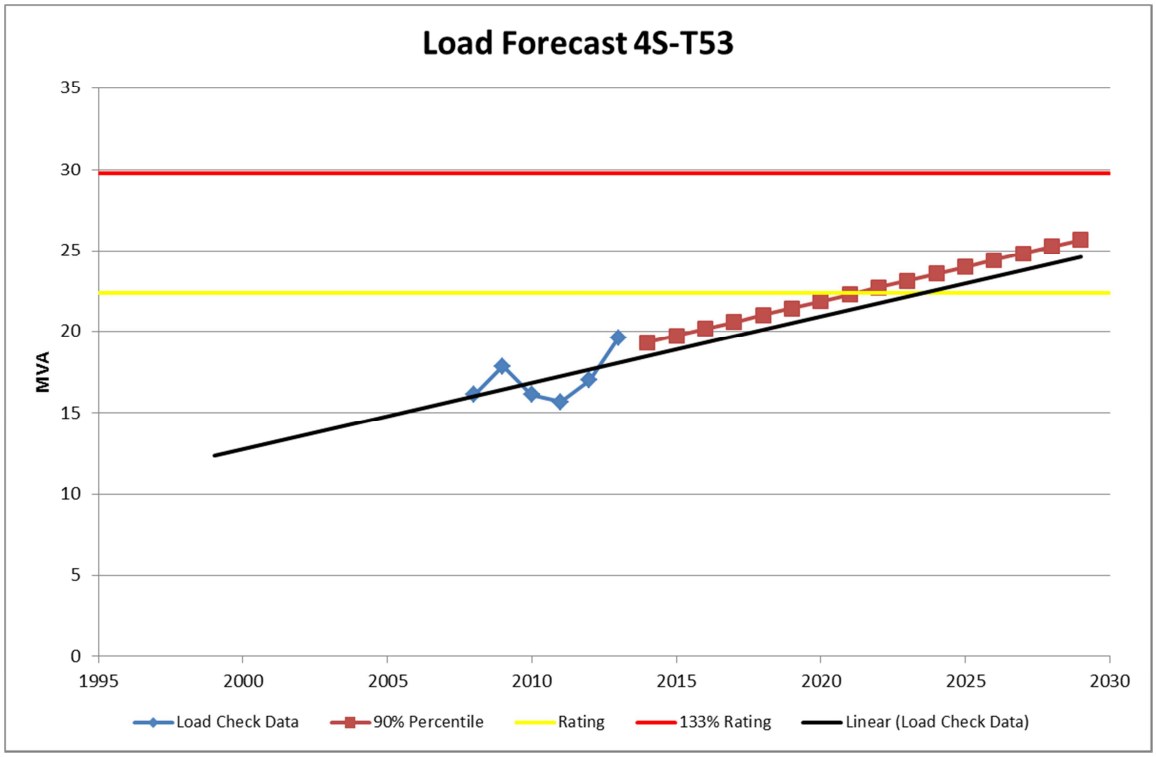


Figure 35 **4S-T53 Load Forecast**

Load Growth **1.77%**

Appendix B: Load History and Forecast

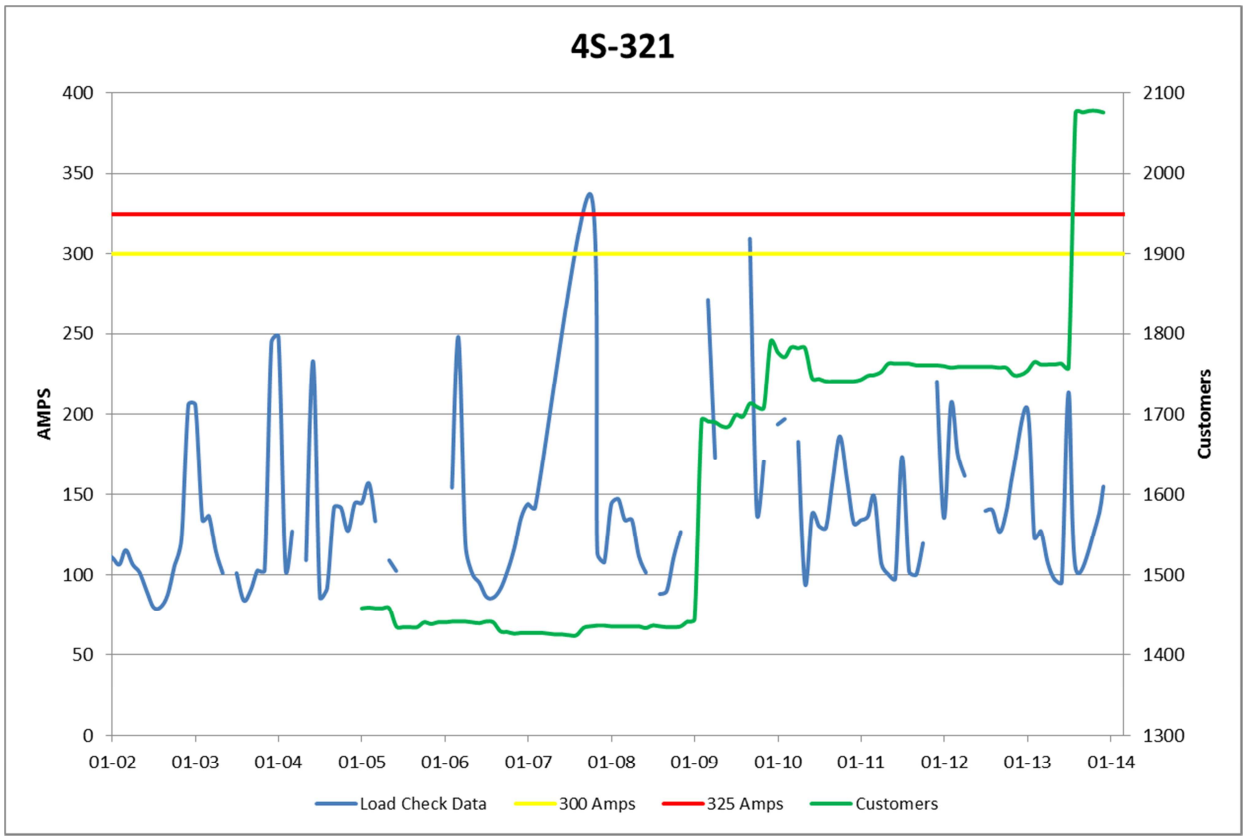


Figure 36 **4S-321 Load History**

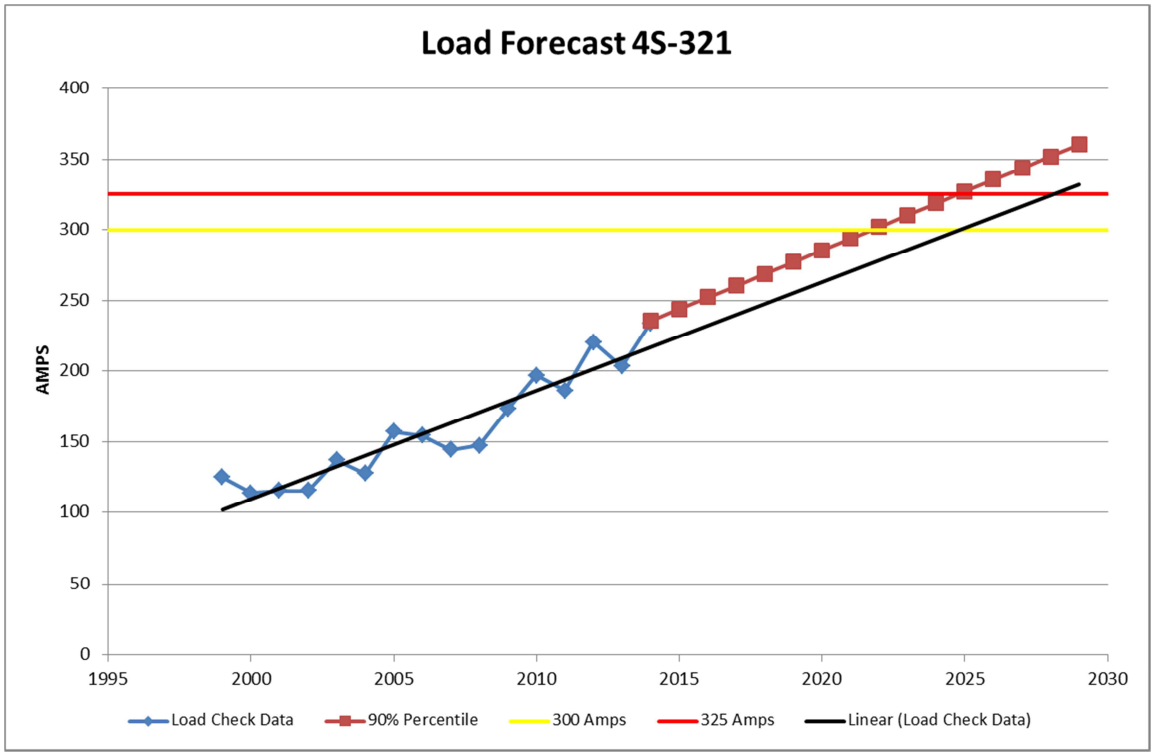


Figure 37 **4S-321 Load Forecast**

Load Growth **2.64%**

Appendix B: Load History and Forecast

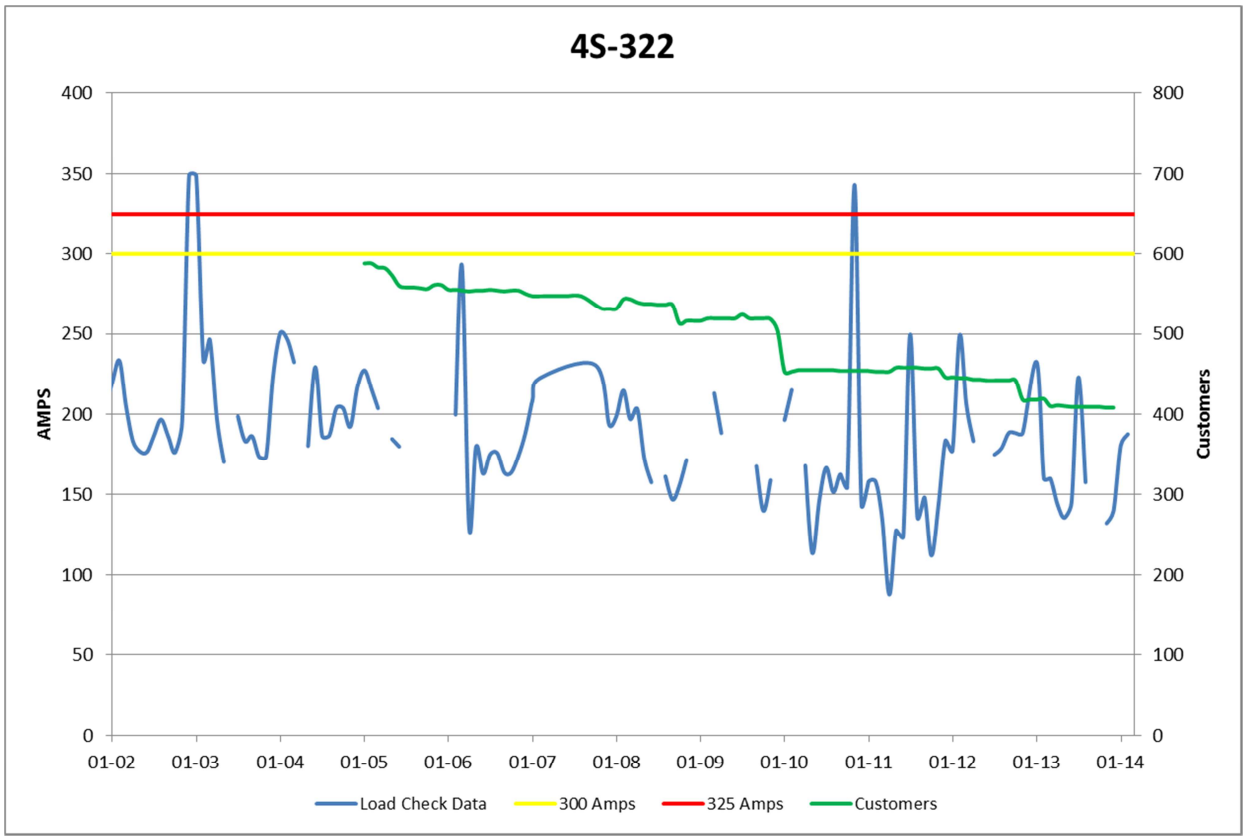


Figure 38 **4S-322 Load History**

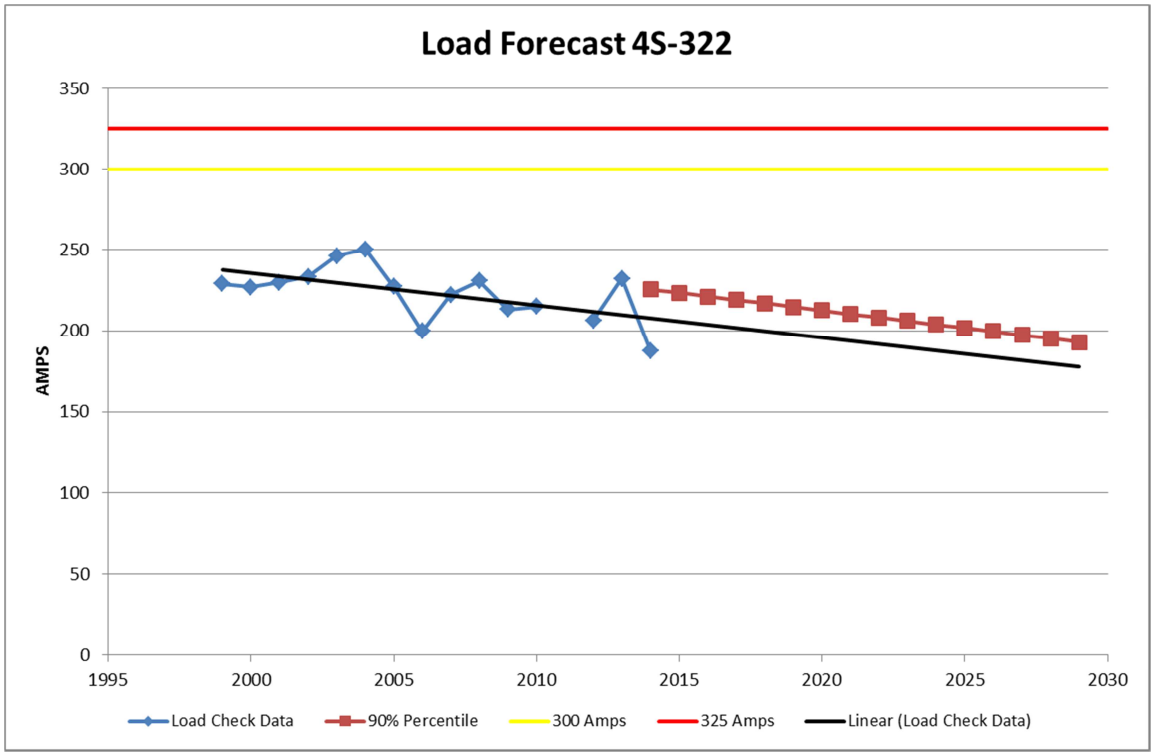


Figure 39 **4S-322 Load Forecast**

Load Growth **-0.97%**

Appendix B: Load History and Forecast

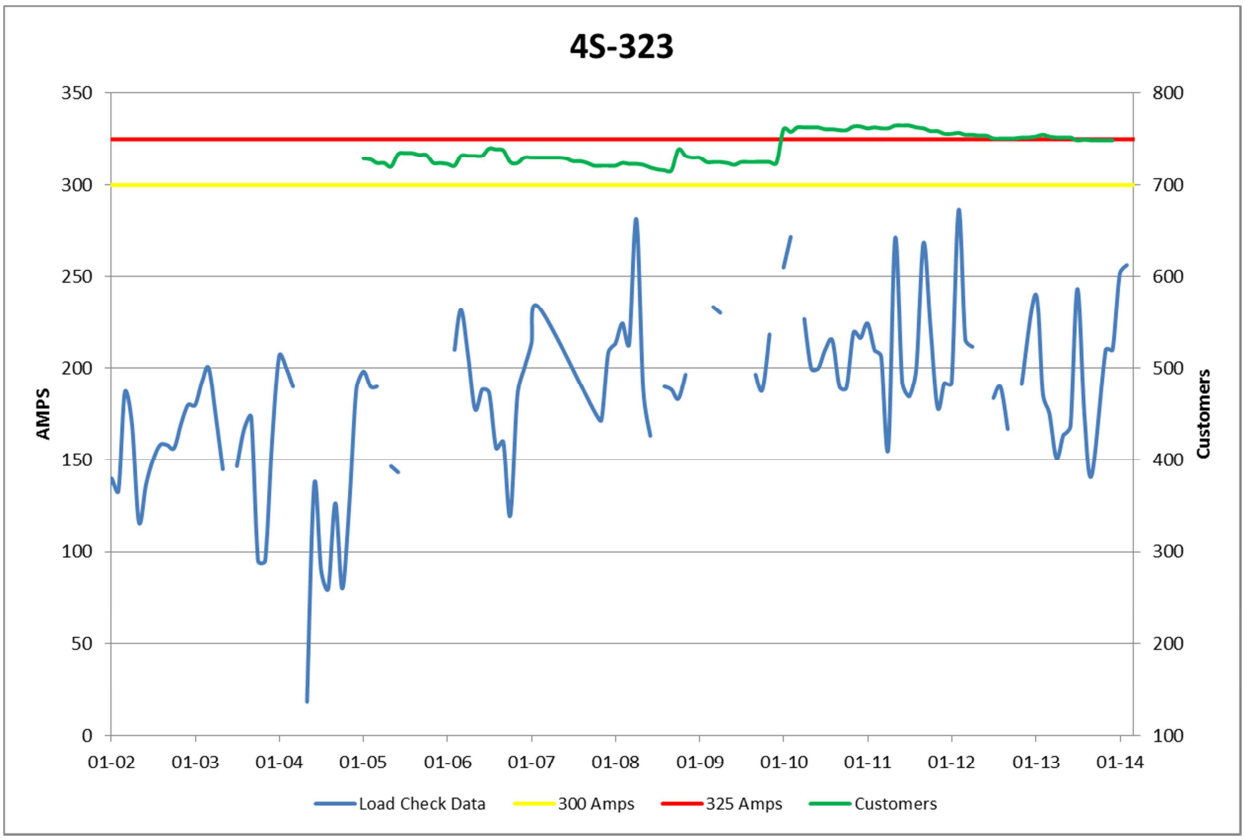


Figure 40 **4S-323 Load History**

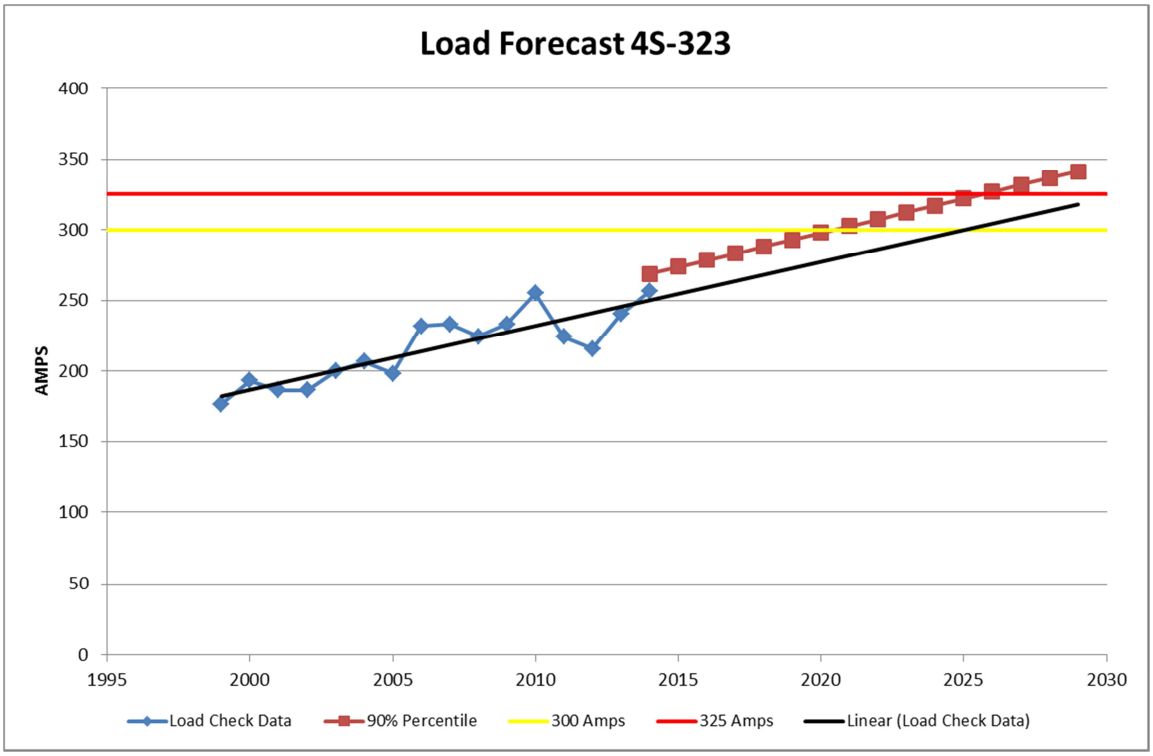


Figure 41 **4S-323 Load Forecast**

Load Growth **1.48%**

Appendix B: Load History and Forecast

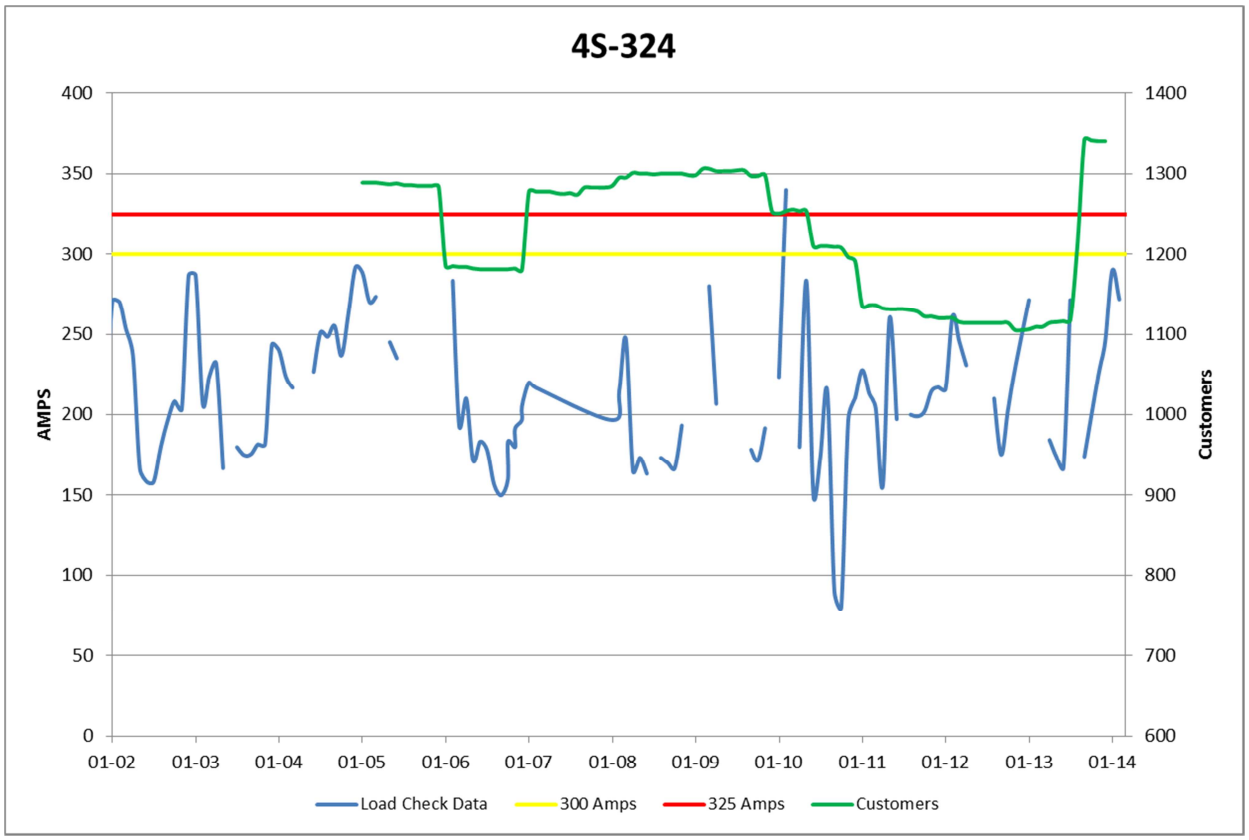


Figure 42 **4S-324 Load History**

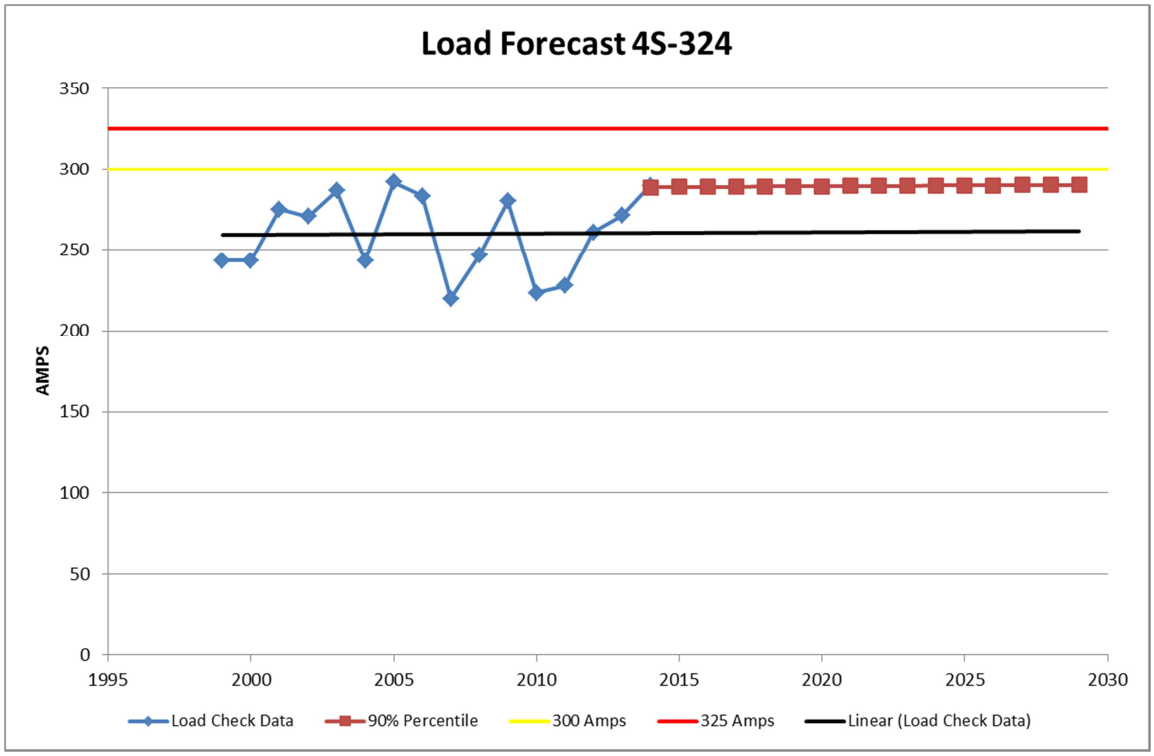


Figure 43 **4S-324 Load Forecast**

Load Growth **0.03%**

Appendix B: Load History and Forecast

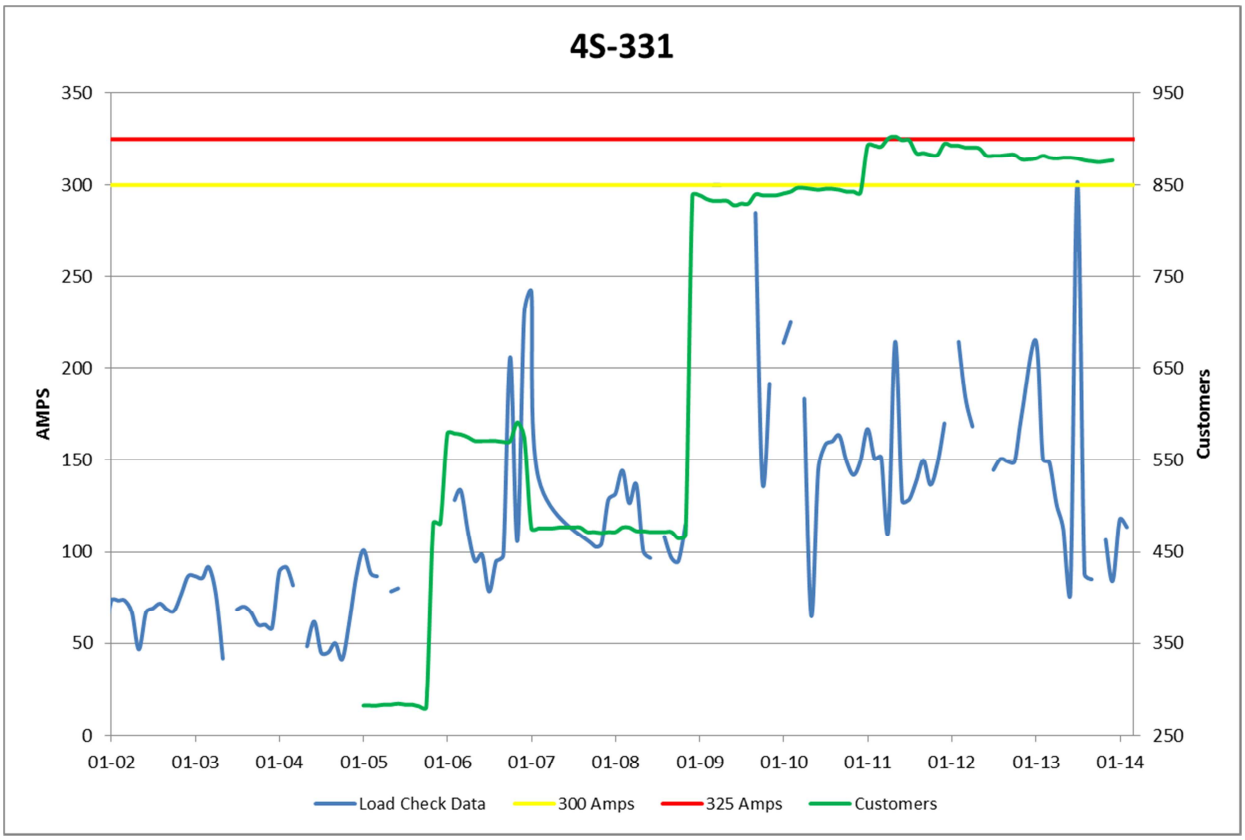


Figure 44 4S-331 Load History

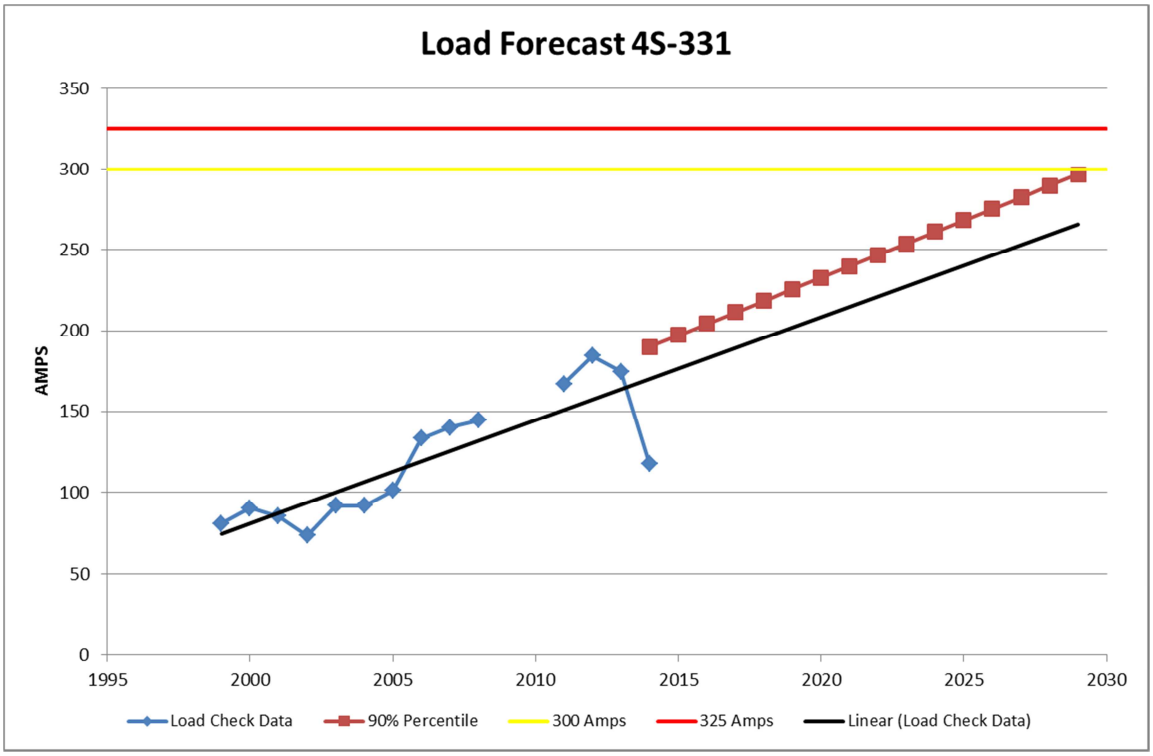


Figure 45 4S-331 Load Forecast

Load Growth 2.76%

Appendix B: Load History and Forecast

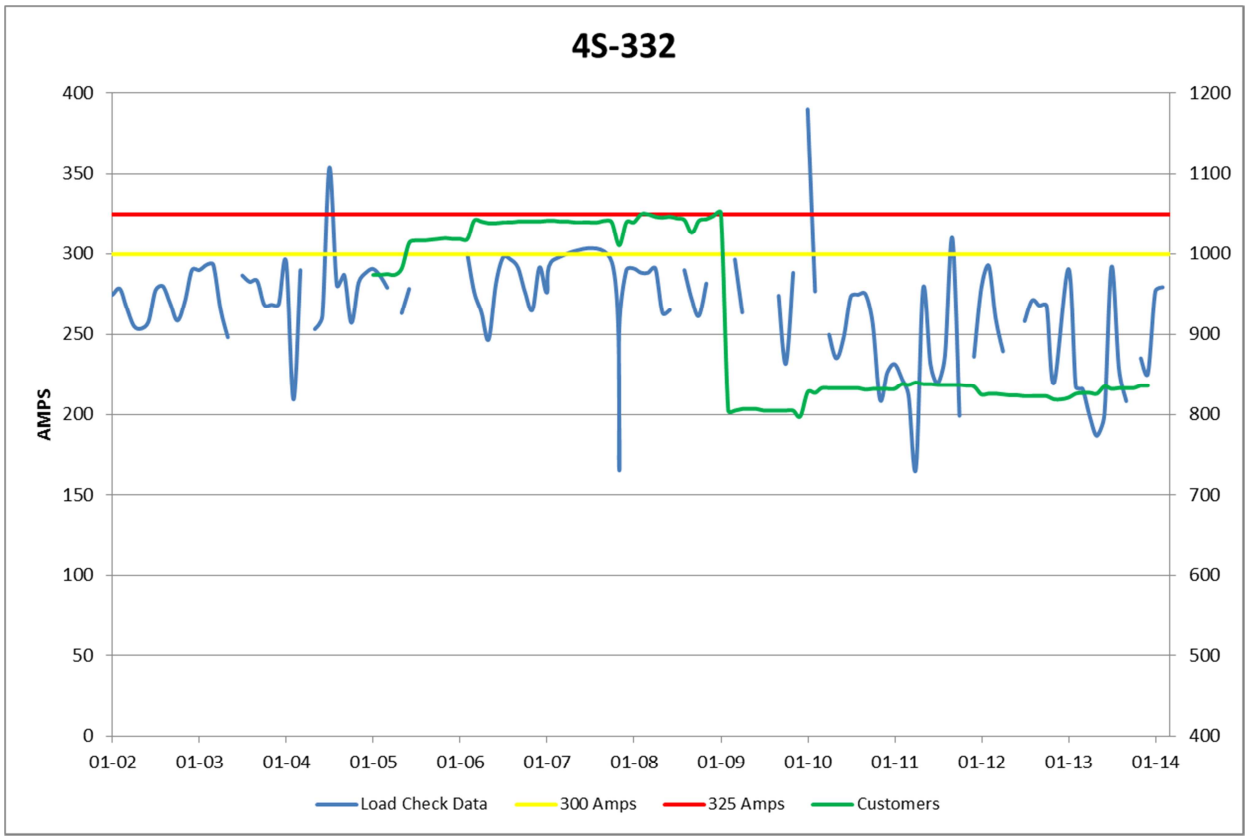


Figure 46 **4S-332 Load History**

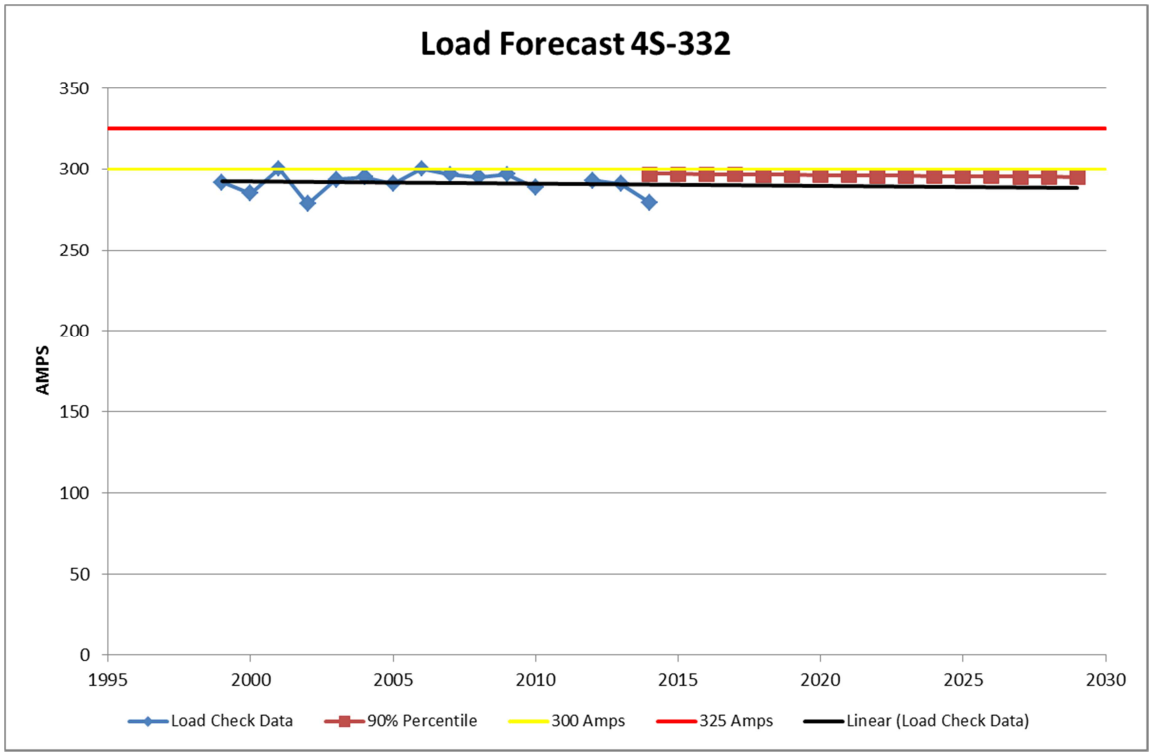


Figure 47 **4S-332 Load Forecast**

Load Growth **-0.05%**

Appendix B: Load History and Forecast

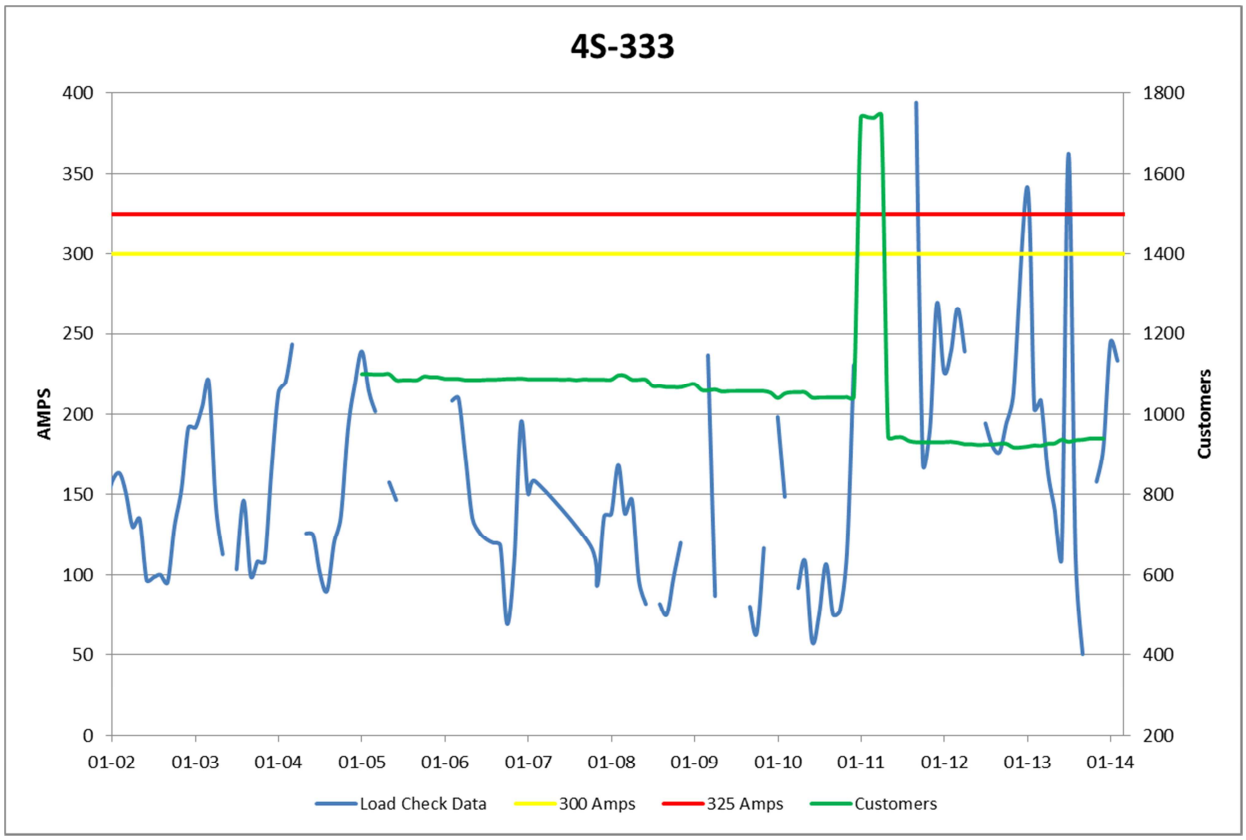


Figure 48 **4S-333 Load History**

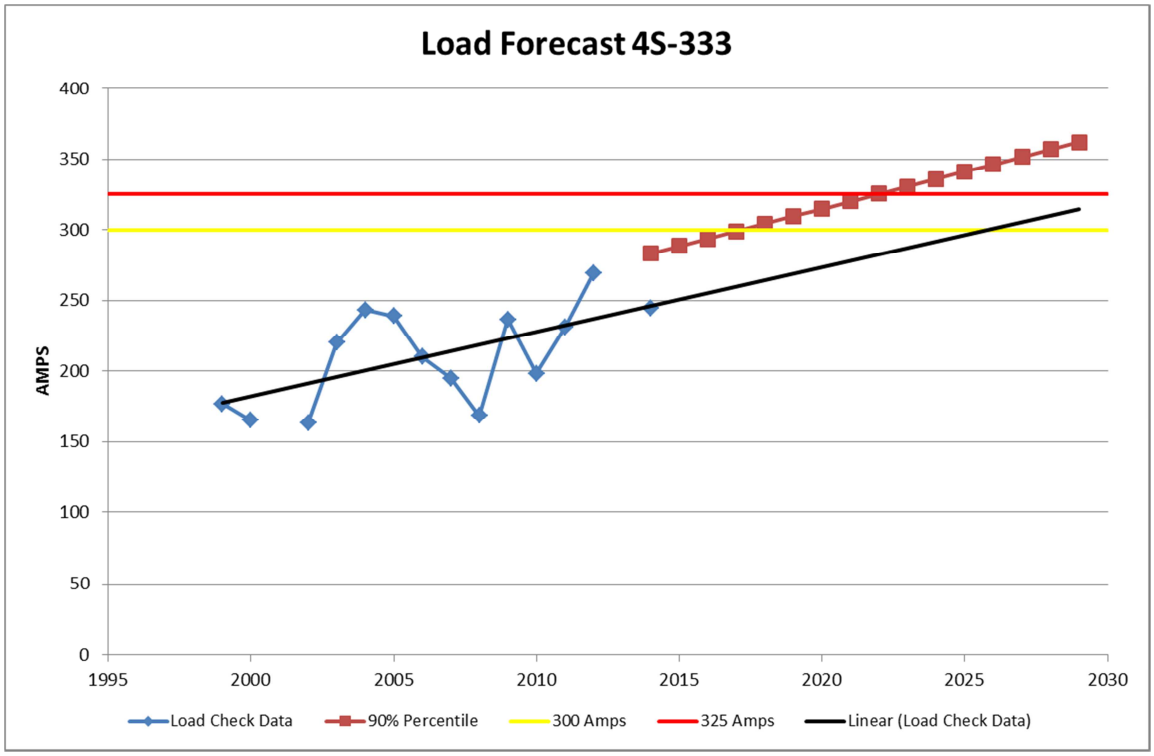


Figure 49 **4S-333 Load Forecast**

Load Growth **1.53%**

Appendix B: Load History and Forecast

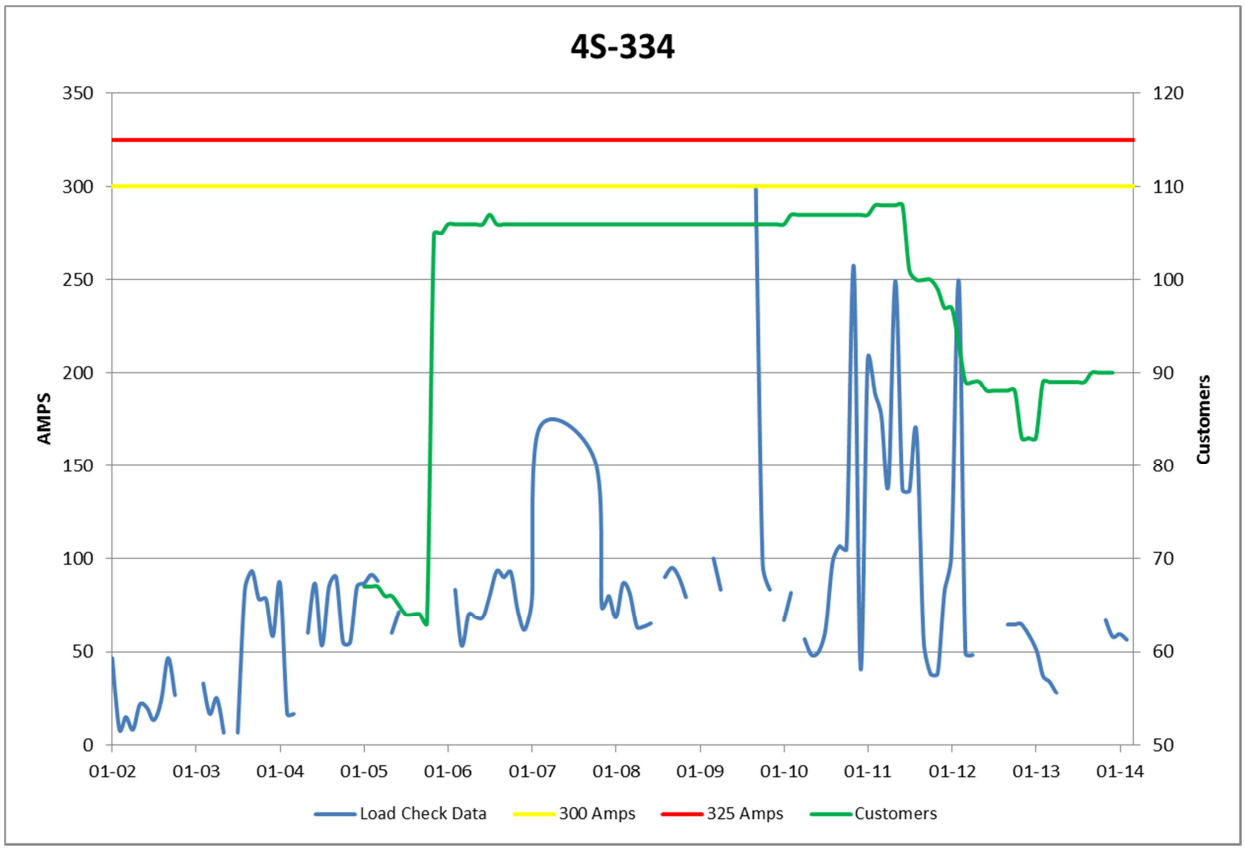


Figure 50 **4S-334 Load History**

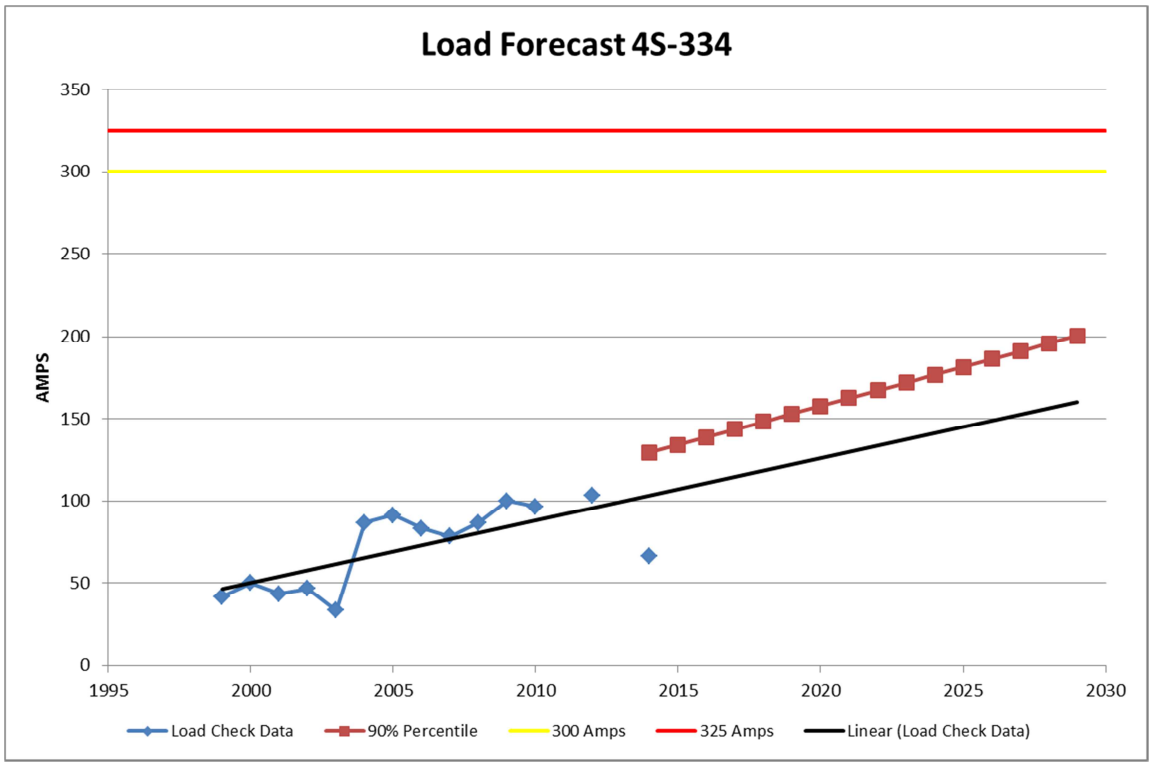


Figure 51 **4S-334 Load Forecast**

Load Growth **2.72%**

Appendix B: Load History and Forecast

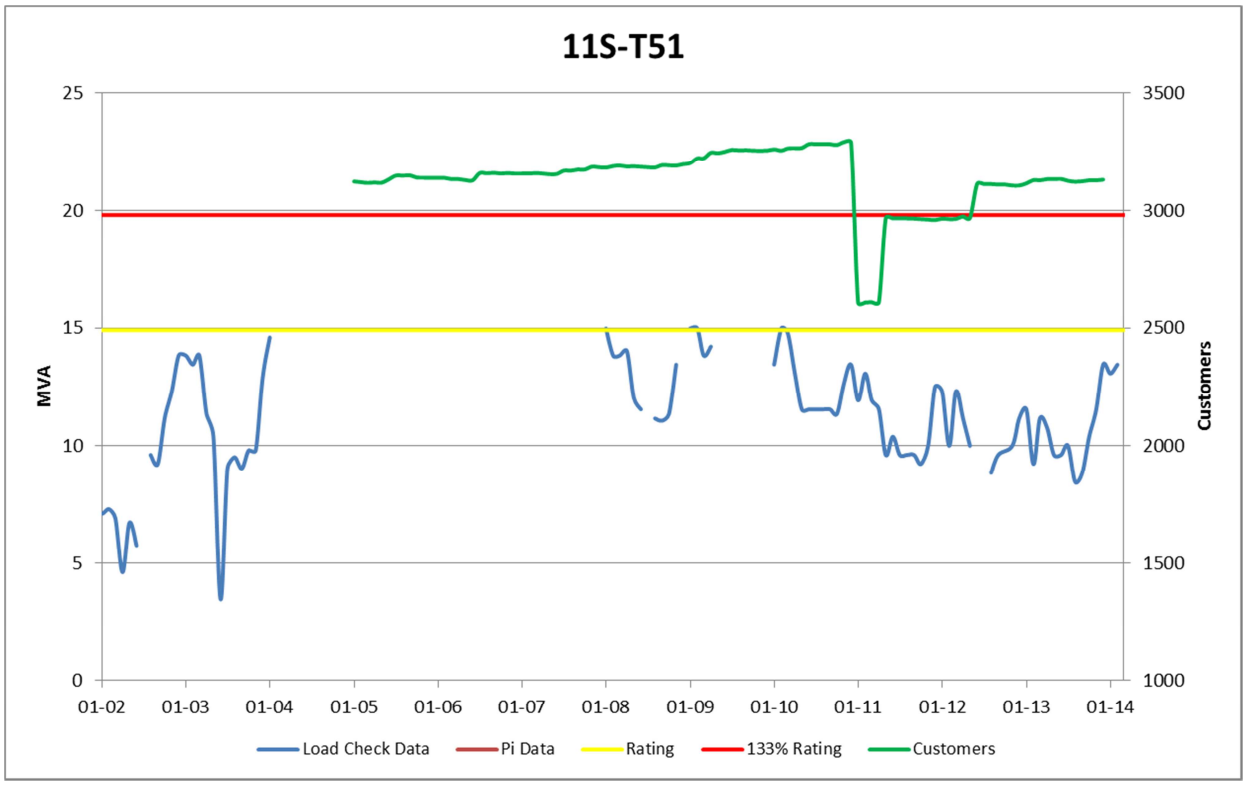


Figure 52 11S-T51 Load History

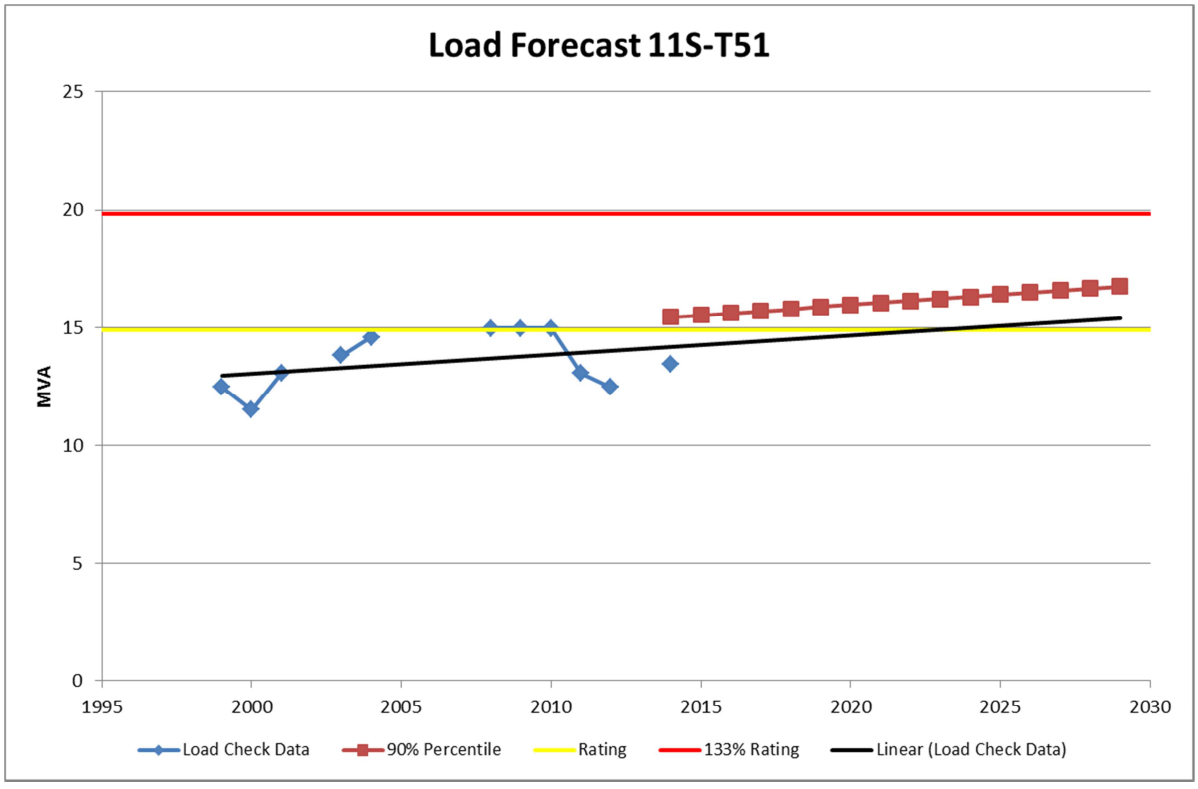


Figure 53 11S-T51 Load History

Load Growth 0.51%

Appendix B: Load History and Forecast

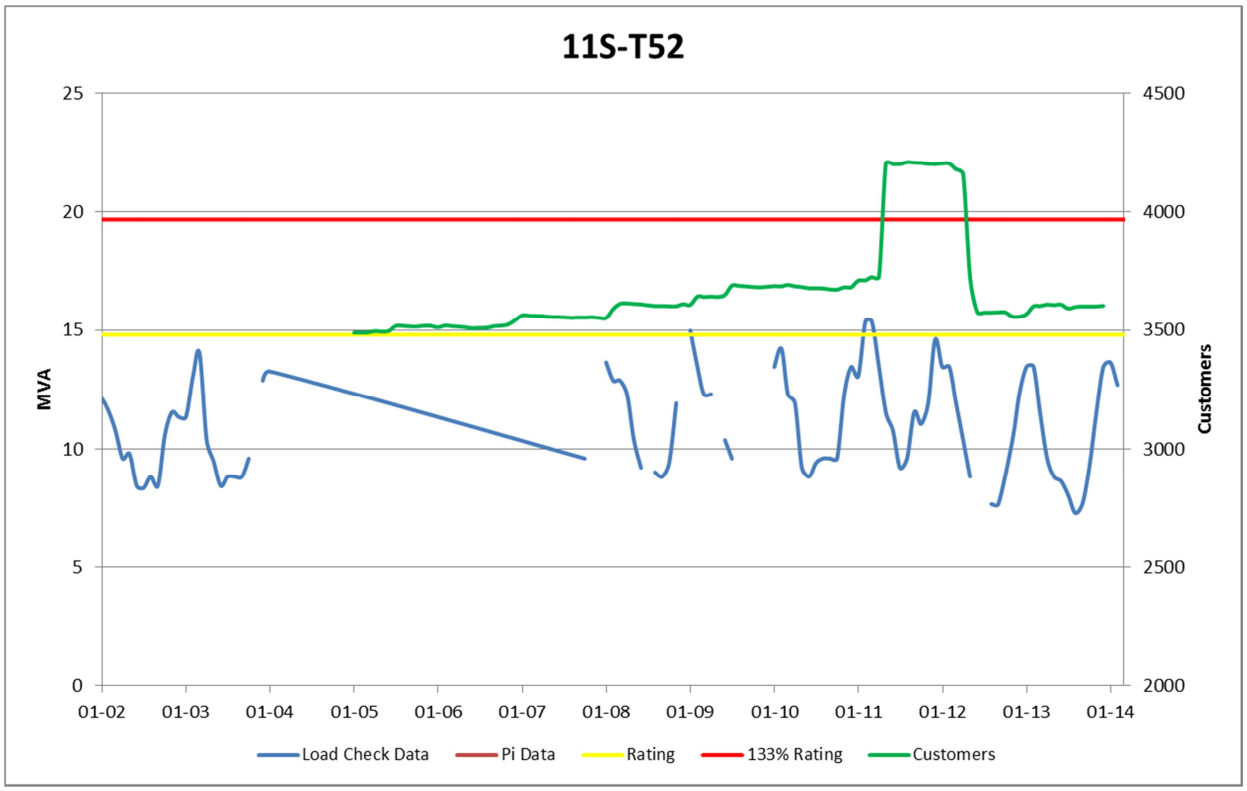


Figure 54 11S-T52 Load History

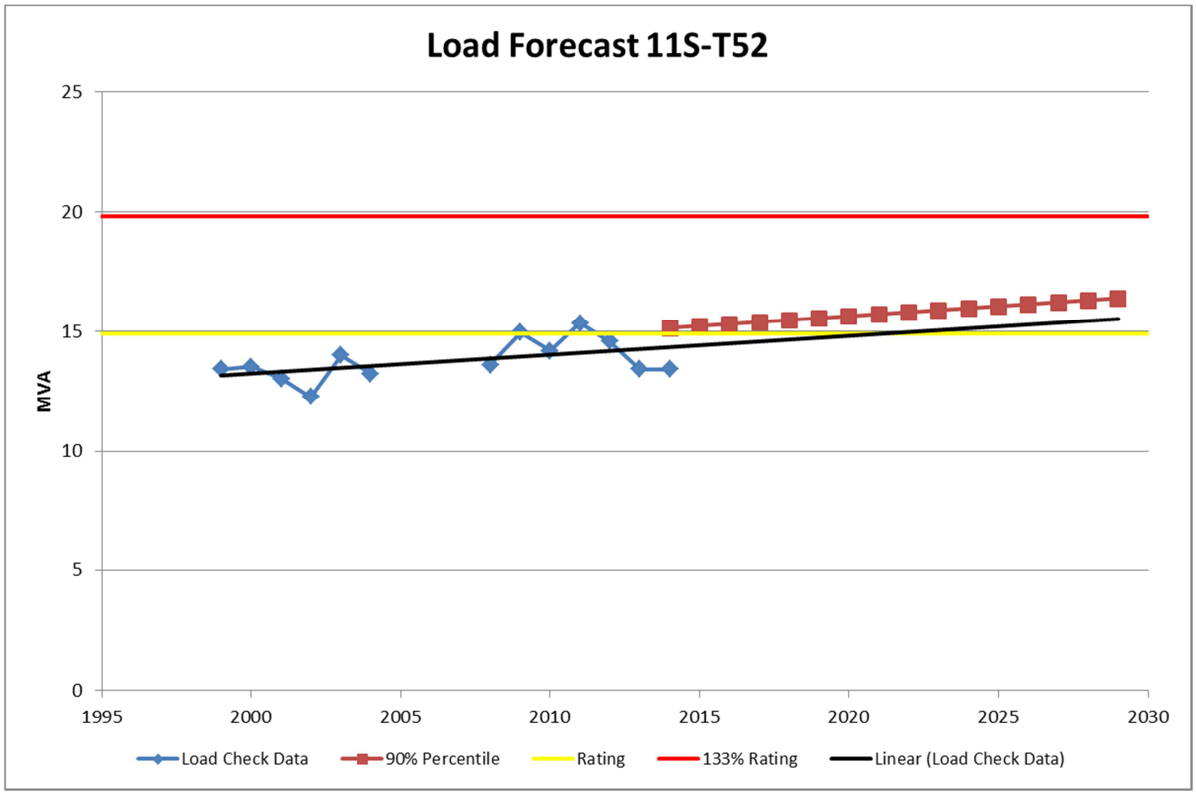


Figure 55 11S-T52 Load Forecast

Load Growth 0.49%

Appendix B: Load History and Forecast

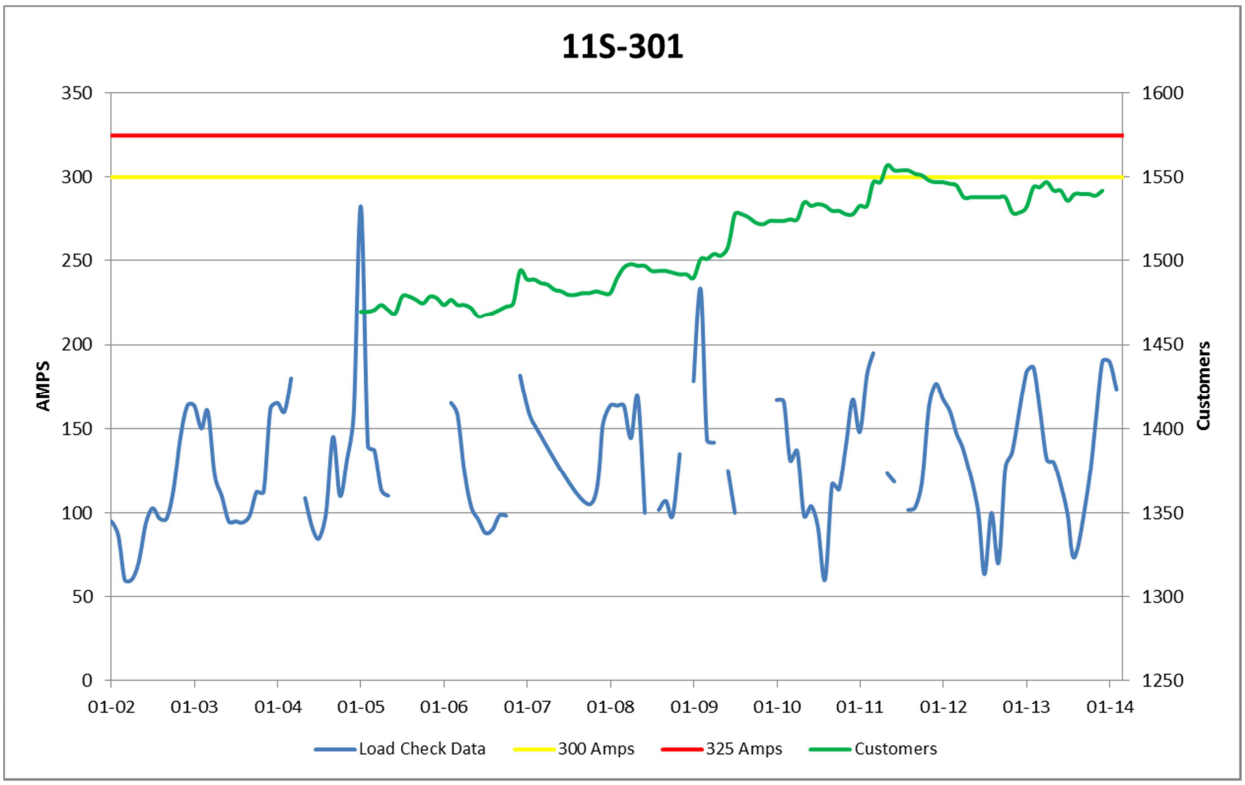


Figure 56 11S-301 Load History

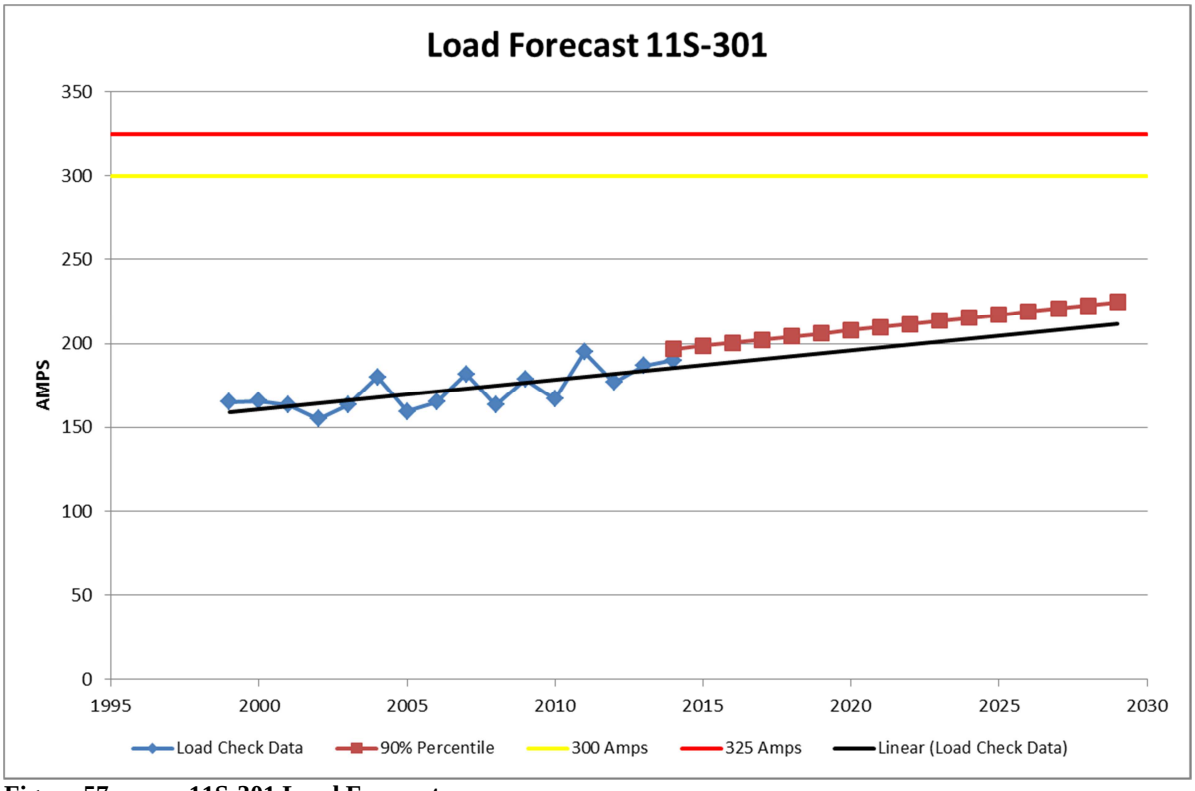


Figure 57 11S-301 Load Forecast

Load Growth 0.83%

Appendix B: Load History and Forecast

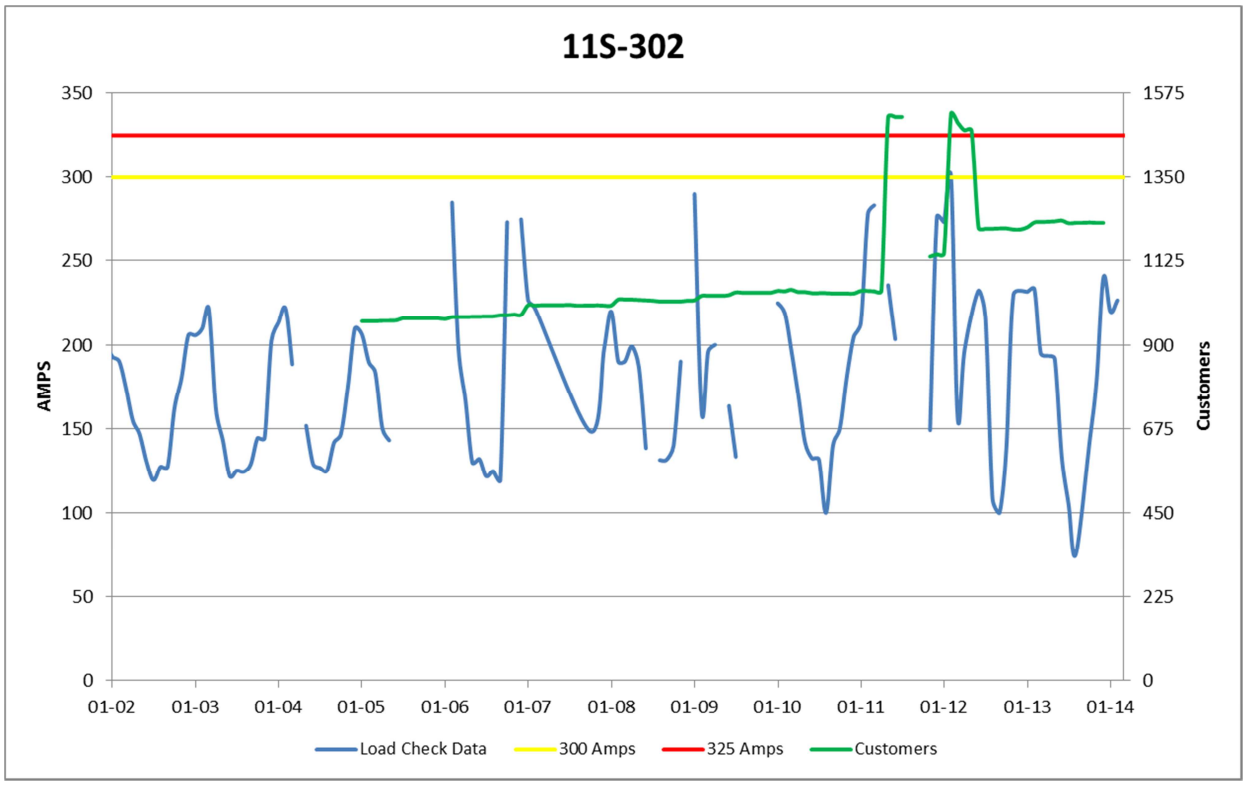


Figure 58 11S-302 Load History

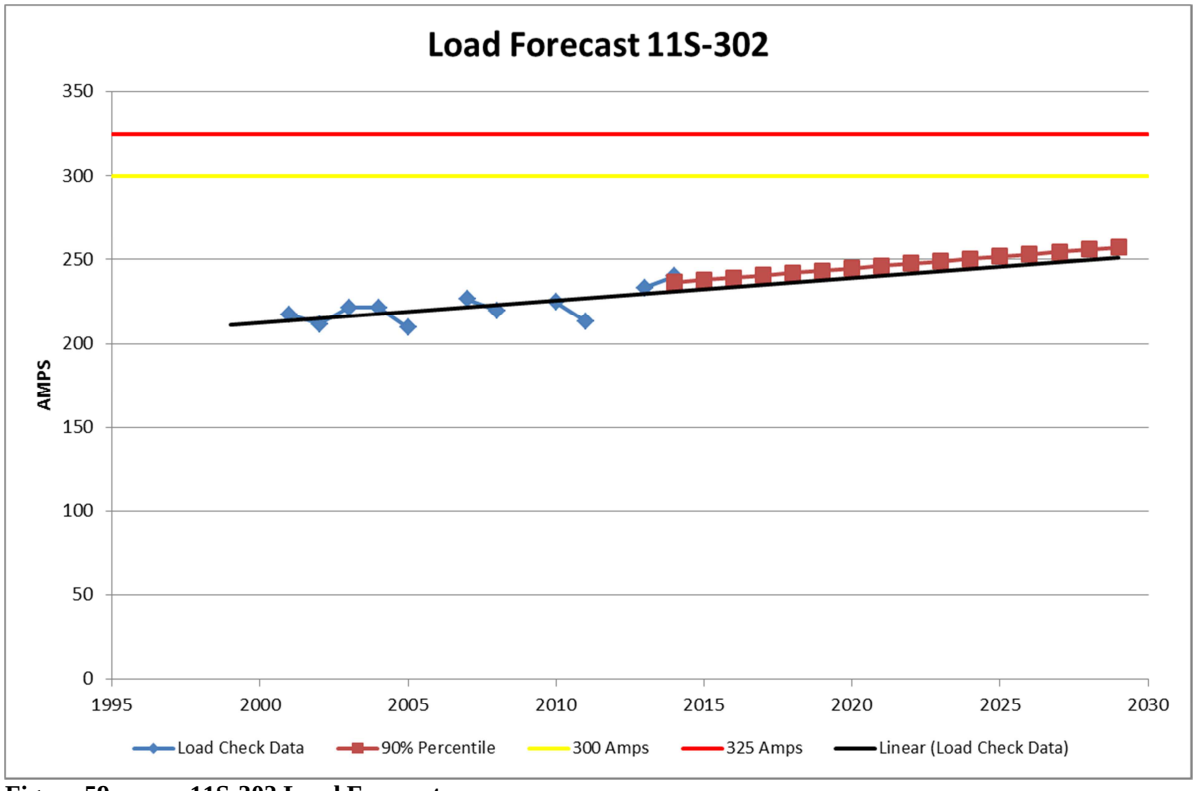


Figure 59 11S-302 Load Forecast

Load Growth 0.52%

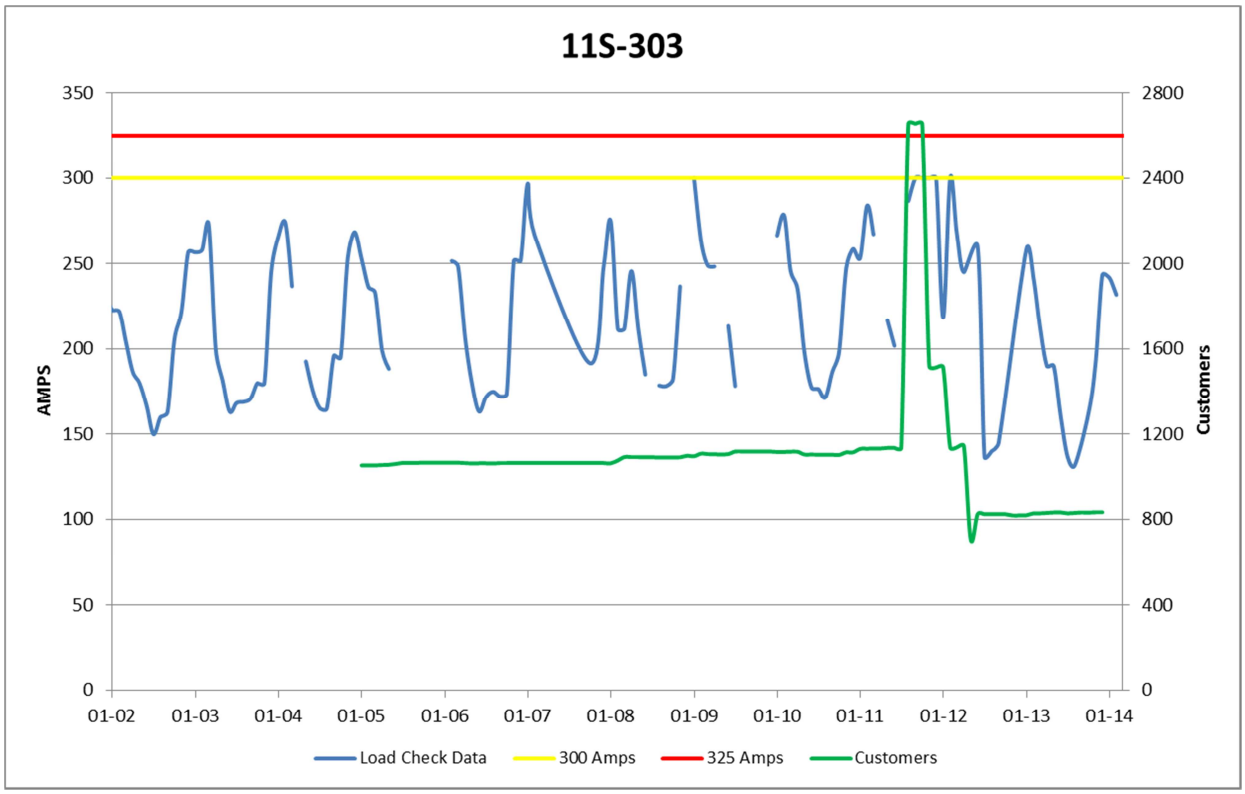


Figure 60 **11S-303 Load History**

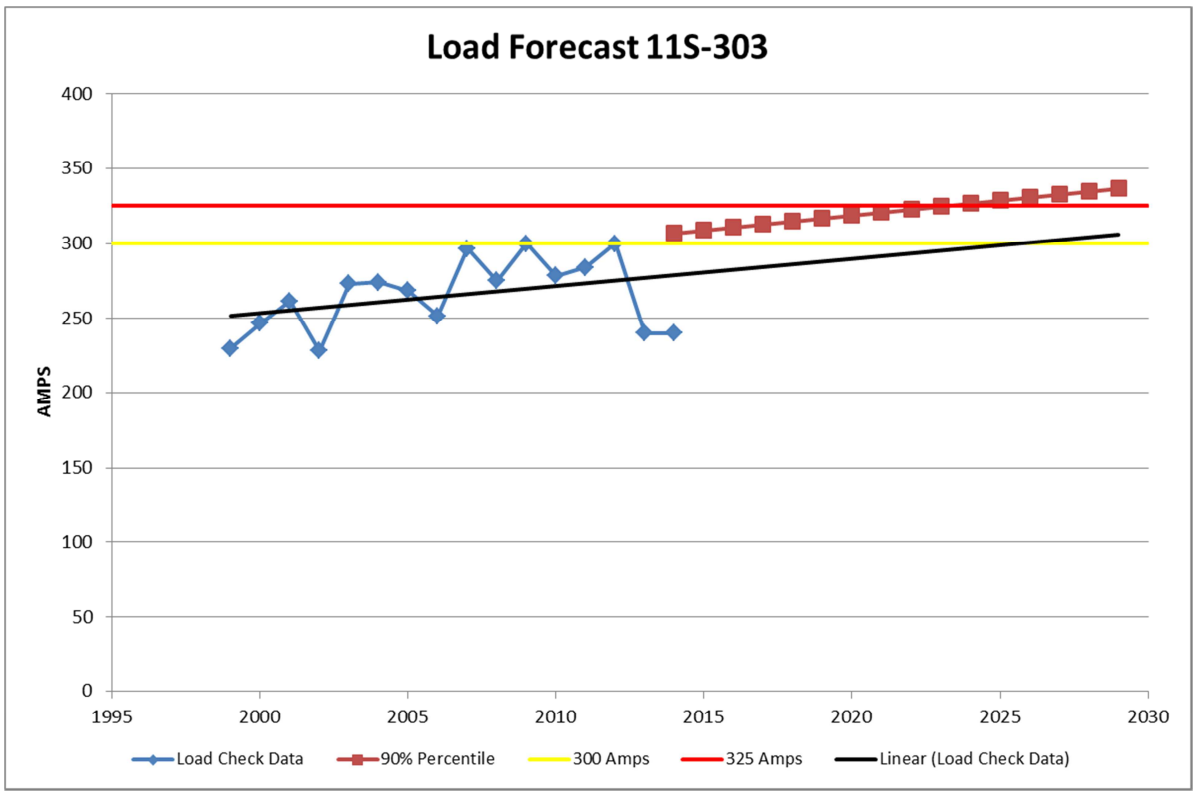


Figure 61 **11S-303 Load Forecast**

Load Growth **0.57%**

Appendix B: Load History and Forecast

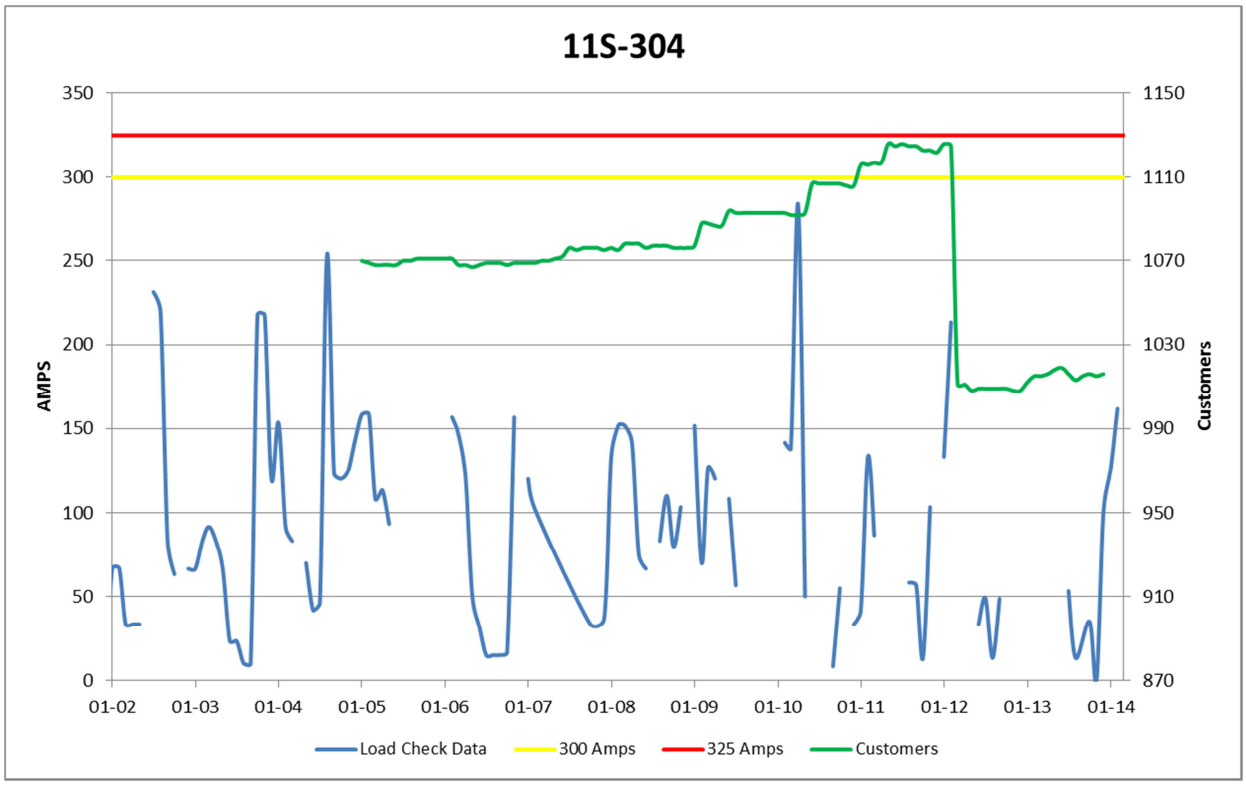


Figure 62 11S-304 Load History

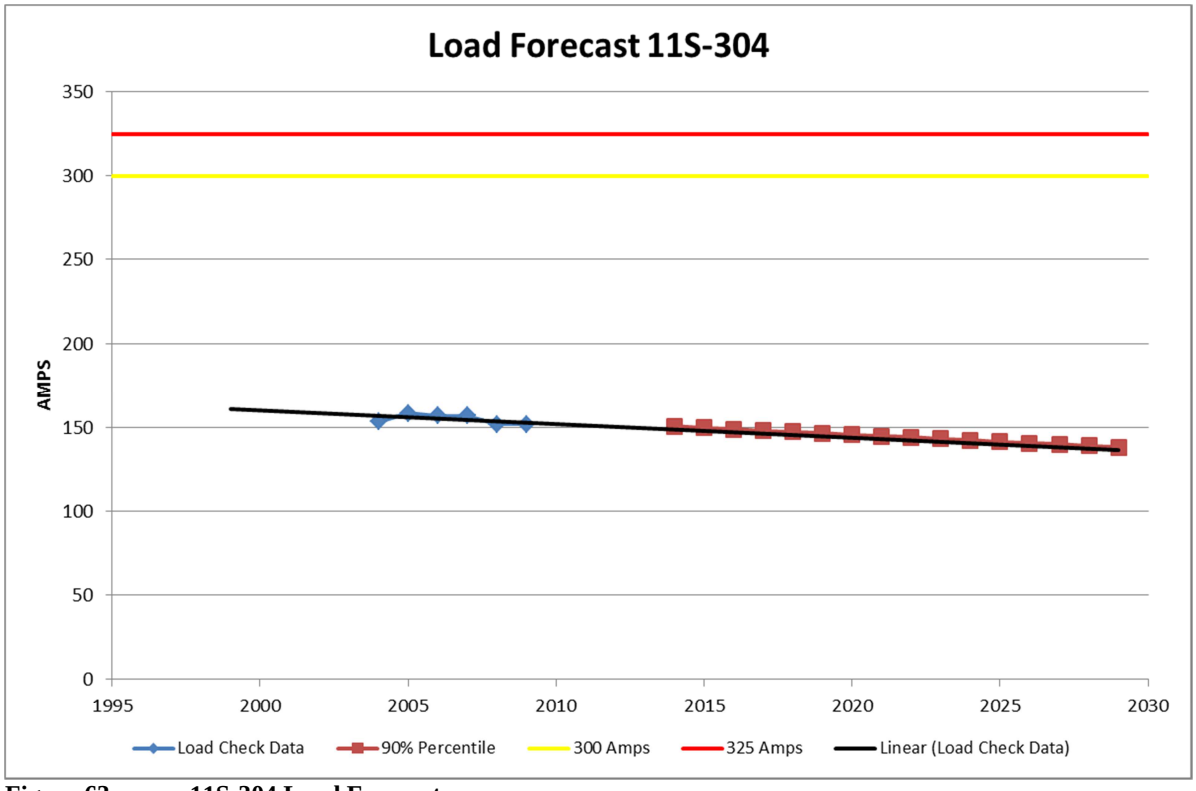


Figure 63 11S-304 Load Forecast

Load Growth -0.53%

Appendix B: Load History and Forecast

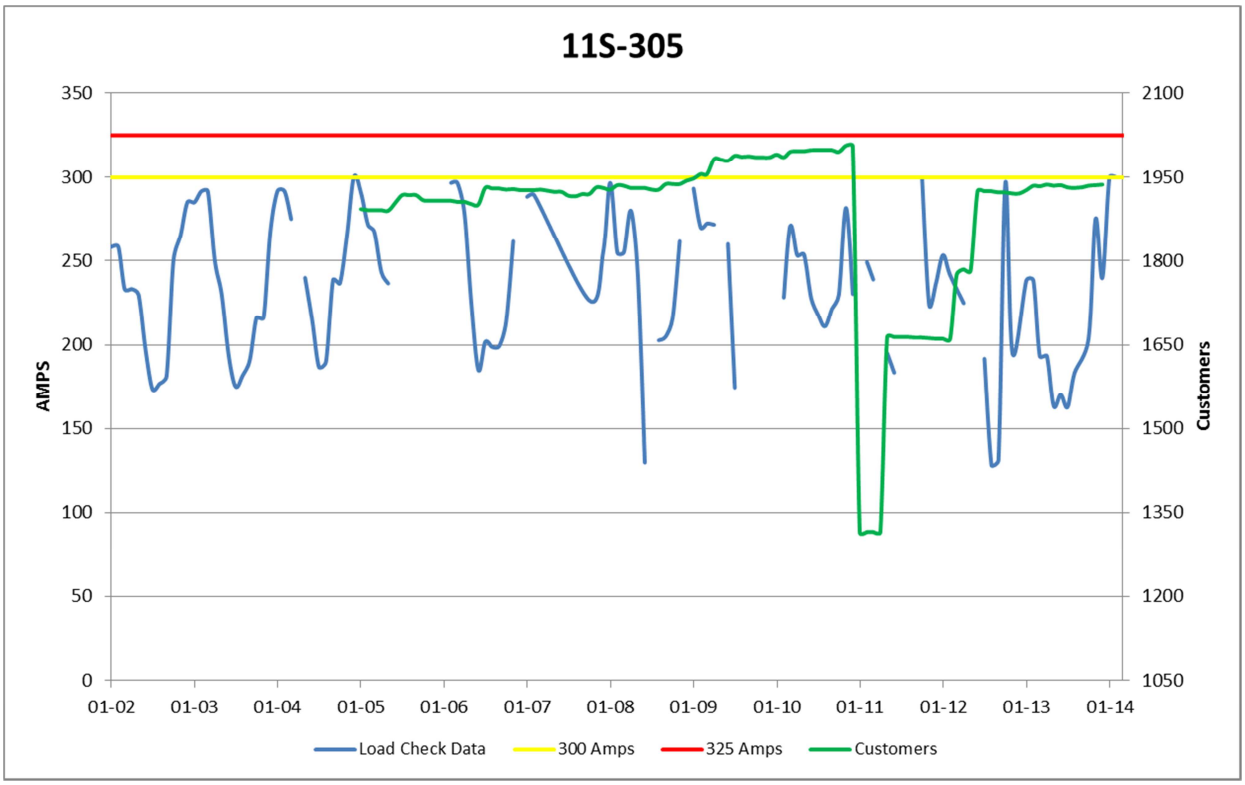


Figure 64 11S-305 Load History

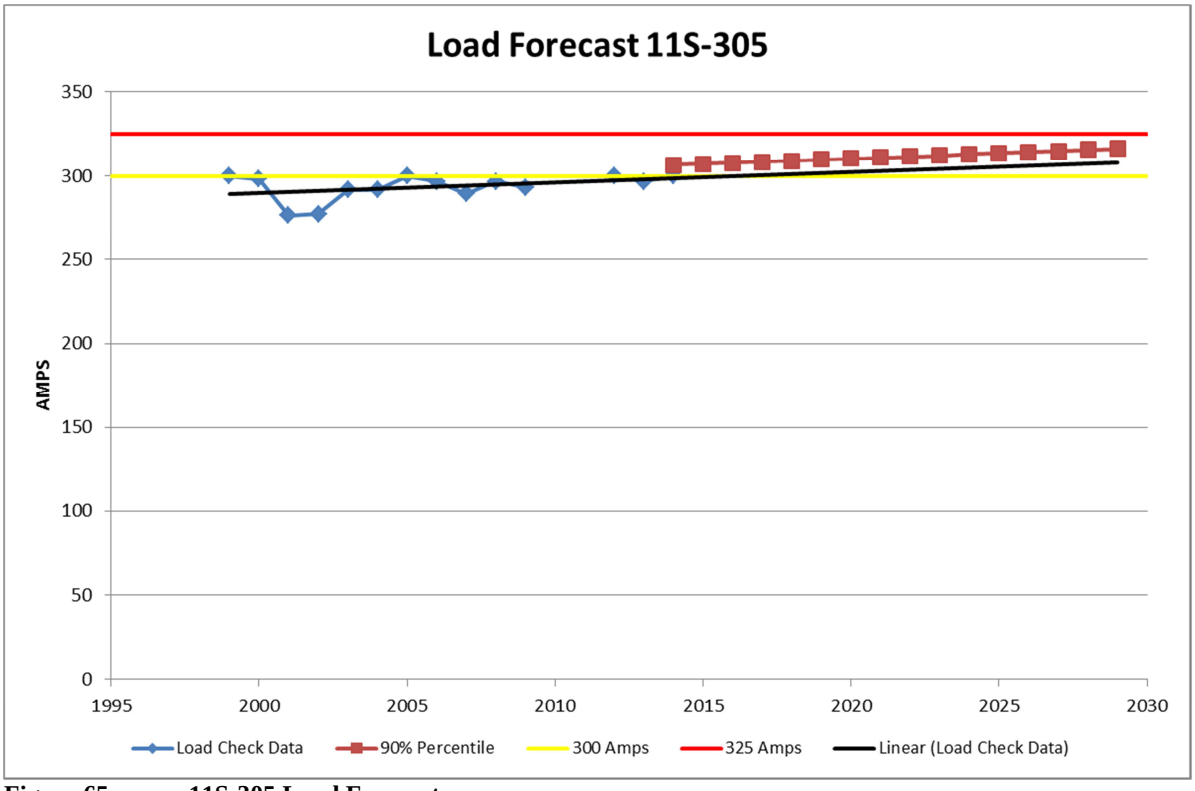


Figure 65 11S-305 Load Forecast

Load Growth 0.21%

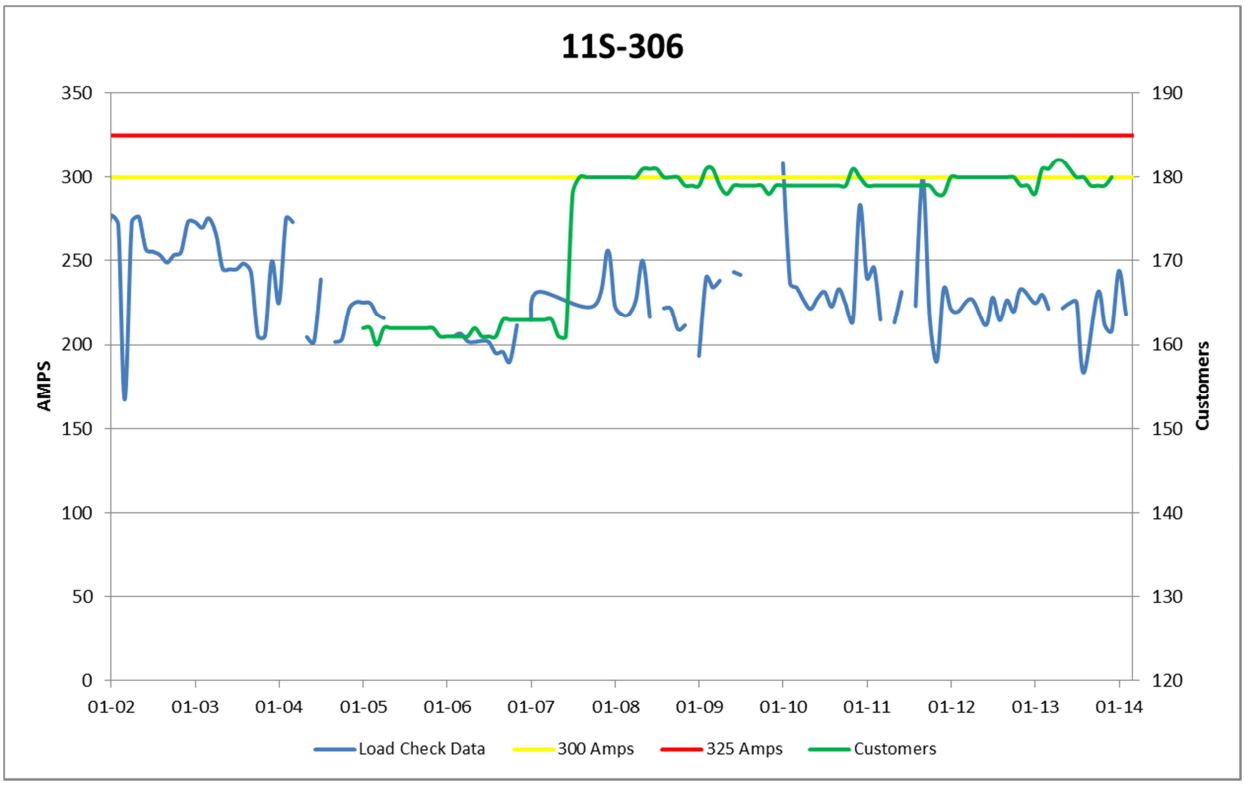


Figure 66 11S-306 Load History

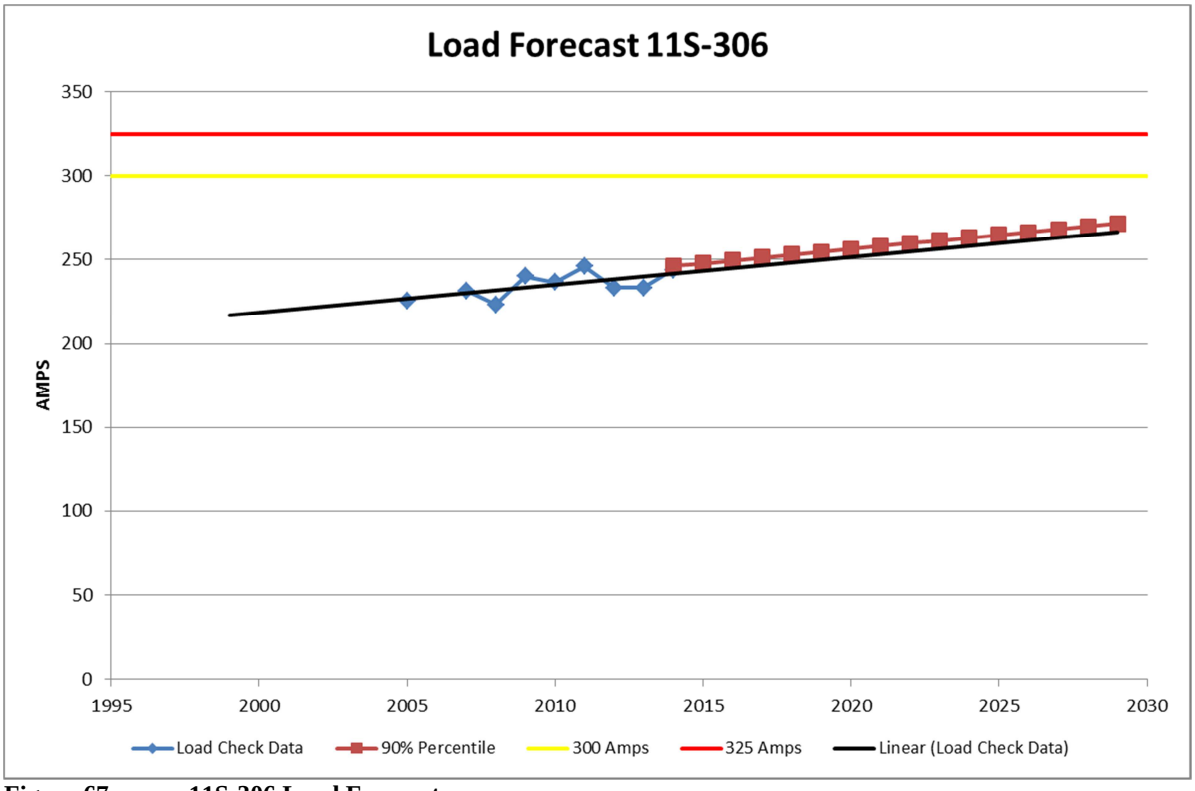


Figure 67 11S-306 Load Forecast

Load Growth 0.61%

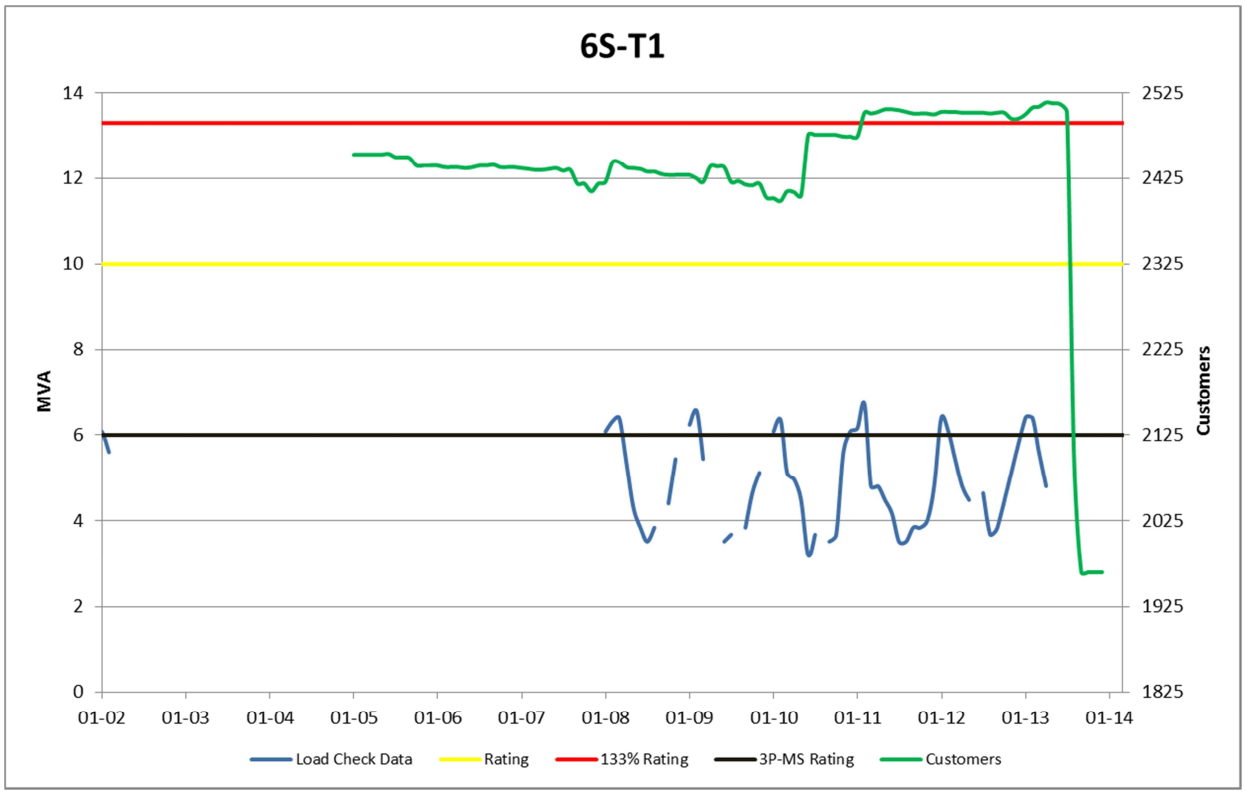


Figure 68 6S-T1 Load History

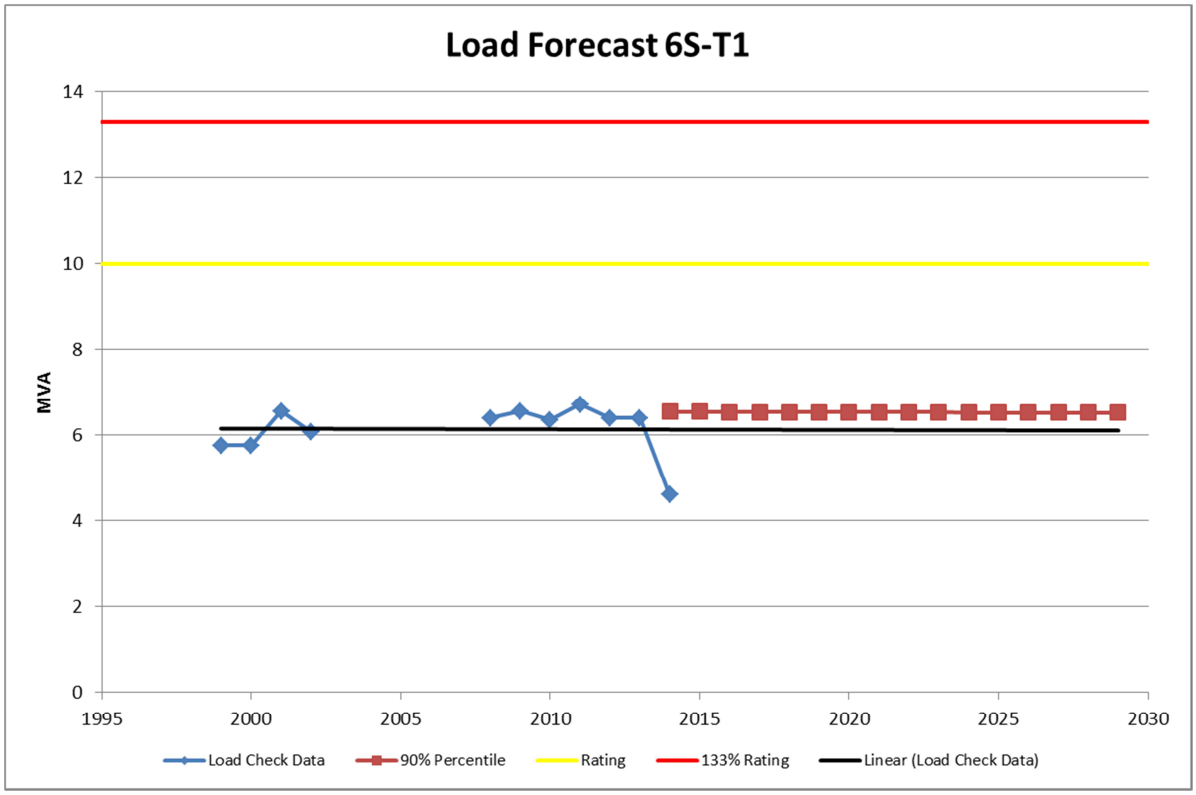


Figure 69 6S-T1 Load Forecast

Load Growth 0.02%

Appendix B: Load History and Forecast

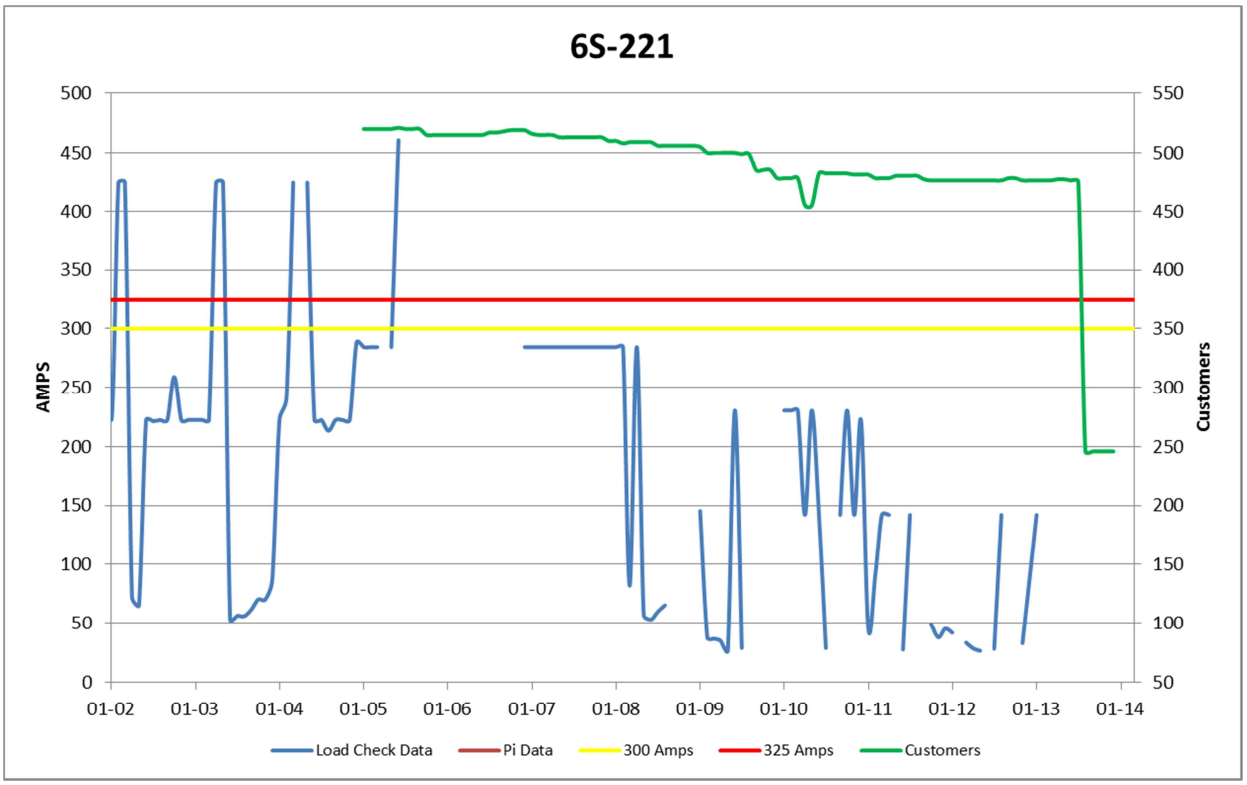


Figure 70 6S-221 Load History

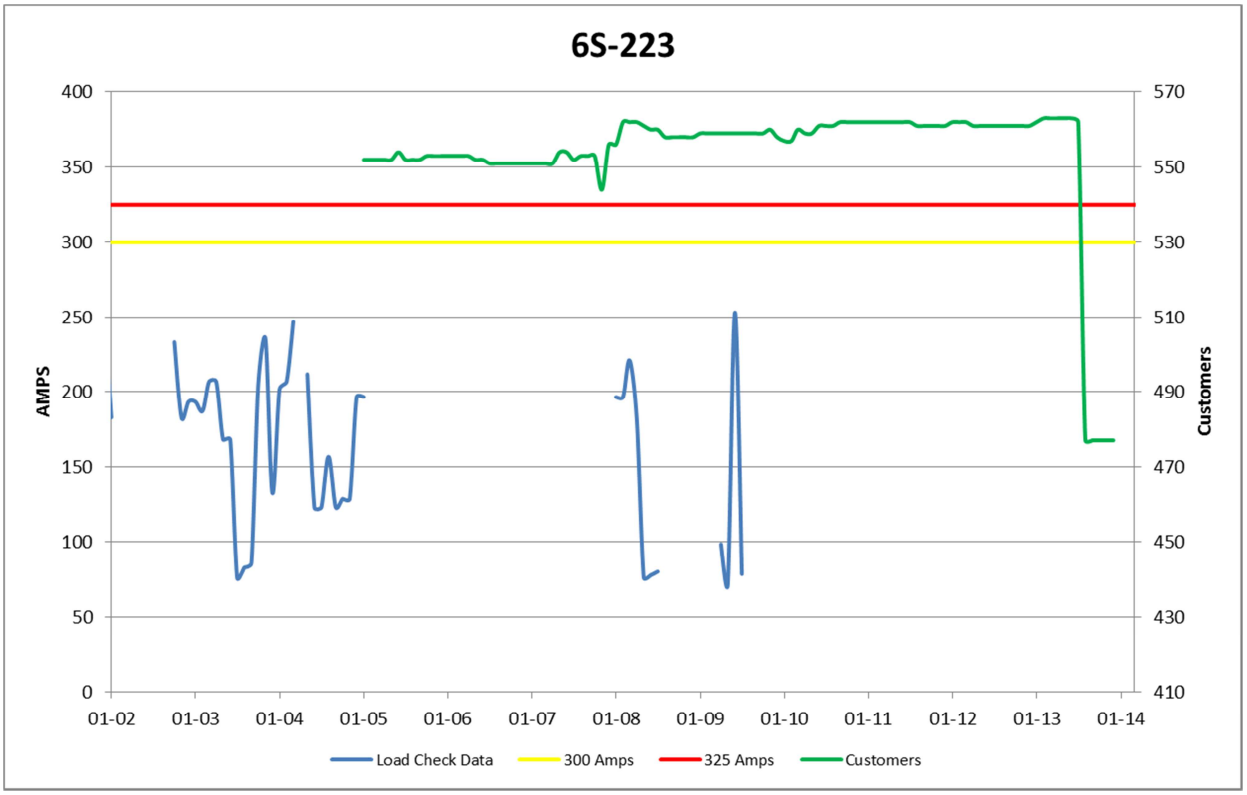


Figure 71 6S-223 Load History

Due to the ability to transfer 4kV load at 6S-Terrace Street, only the transformer forecast (6S-T1) will be presented.

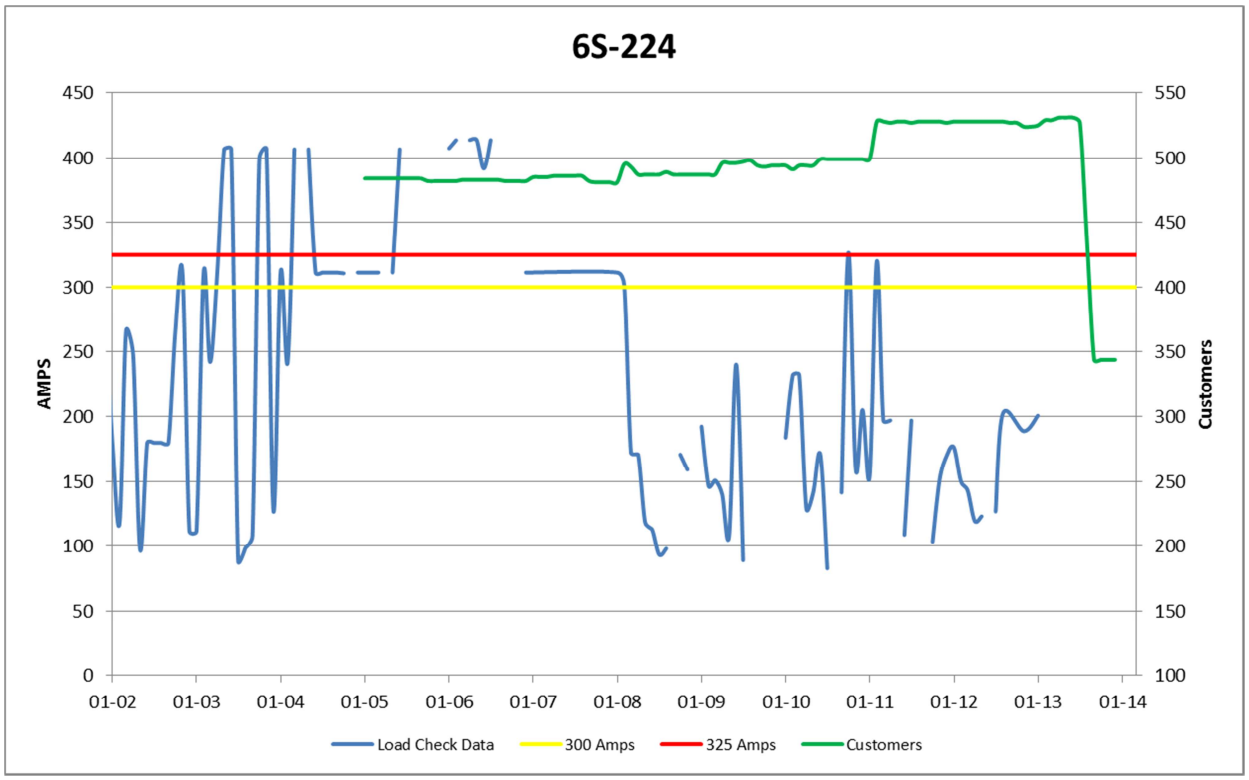


Figure 72 6S-224 Load History

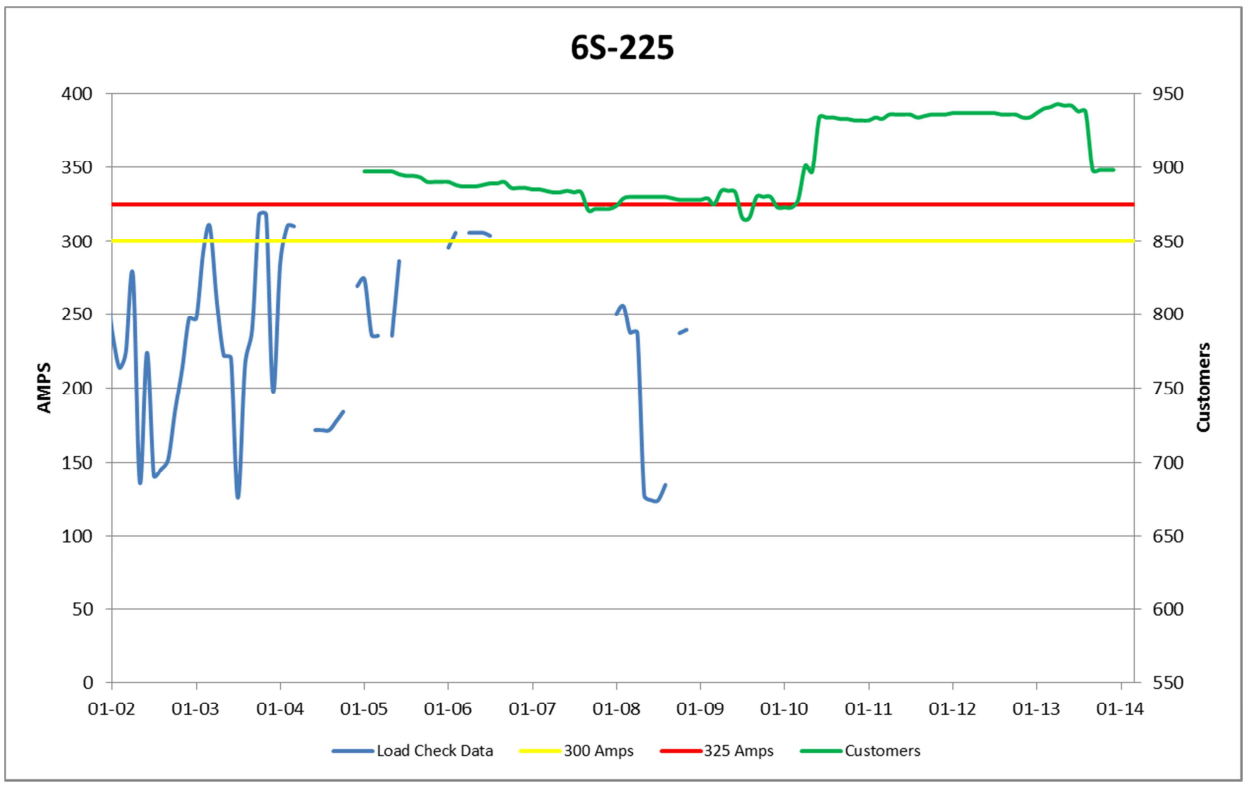


Figure 73 6S-225 Load History

APPENDIX C

Economic Analysis

533S-Mason Street Conversion and 6S-Terrace Street Retirement

Summary of Alternatives

Sydney 4kV Conversions
Summary of Alternatives

Division :		Date :	23-Jul-13
Department :	Distribution Planning	CI Number:	
Originator :	James MacQueen	Project No. :	

	Alternative	After Tax WACC	PV of EVA / NPV	Rank	IRR	Disc Pay
A	533S-B 6S-A; Convert and Retire 6S-Terrace Street by 2016	6.48%	-2,074,838	3	-7.86%	0.0 years
B	533S-B 6S-B; Convert and Retire 6S-Terrace Street by 2018	6.48%	-2,029,860	2	-7.97%	0.0 years
C	533S-B 6S-C; Convert and Retire 6S-Terrace Streert by 2021	6.48%	-2,010,029	1	-8.28%	0.0 years
	0	NA	NA	NA	#NUM!	0.0 years

Recommendation :

This Economic Assessment recommends the following:
1. Conversion of 533S-Mason Street, from 4 to 12kV, supplied via Bentinck Street
2. Conversion of 4kV load supplied by 6S-Terrace Street to 12kV, over an 8 year period
3. Retirement of 6S-Terrace Street substation in 2021

Notes/Comments :

533S-B 6S-A; Convert and Retire 6S-Terrace Street by 2016

2013: Conversion of 533S-Mason Street stepdown
Conversion at 6S-Terrace Street to reduce overall loading for the installation of mobile substation
Replacement of 4kV breakers and related equipment at 6S-Terrace Street
2014-2015: Continued conversion of 6S-Terrace Street load to 12kV
2016: Retirement of 6S-Terrace Street substation

533S-B 6S-B; Convert and Retire 6S-Terrace Street by 2018

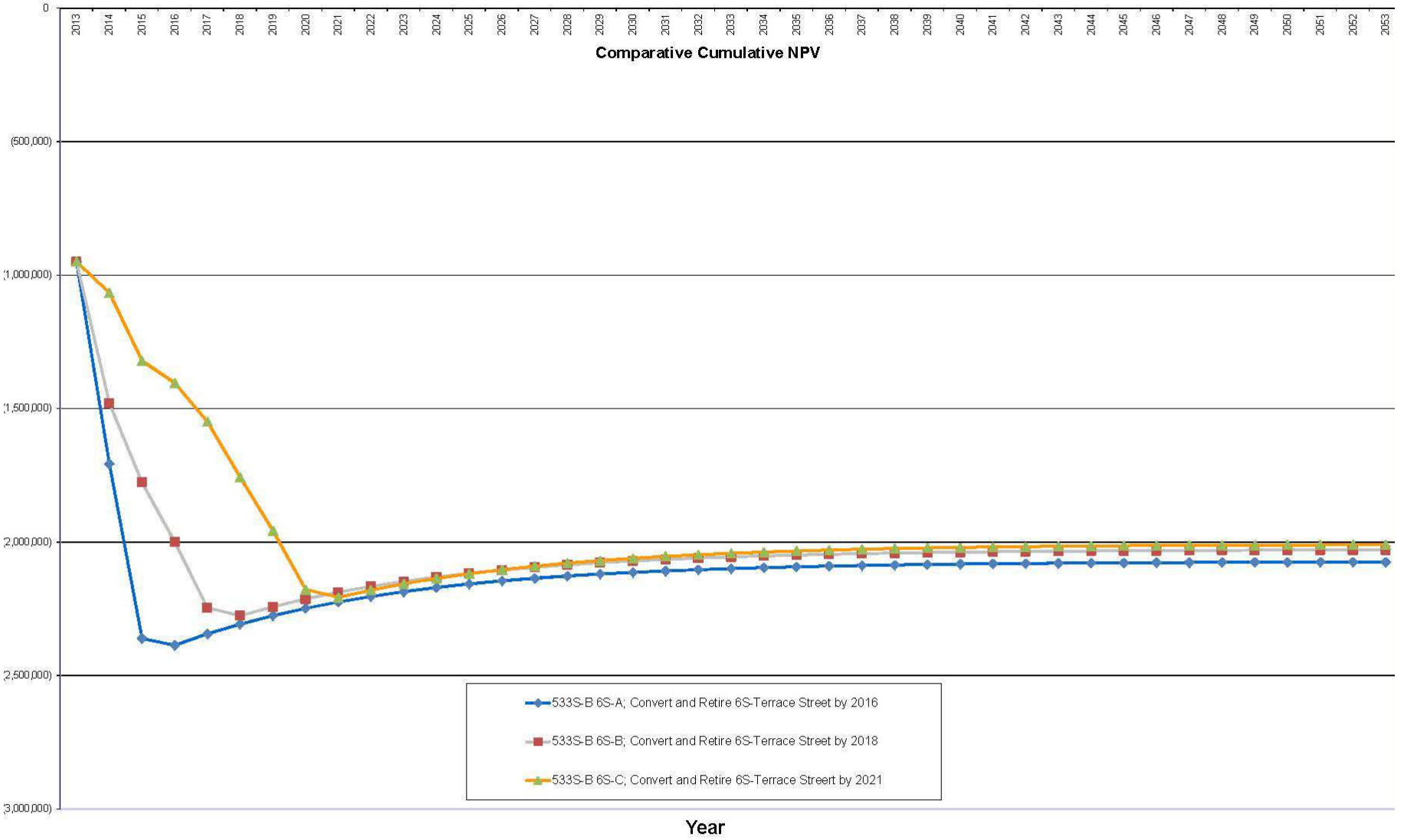
2013: Conversion of 533S-Mason Street stepdown
Conversion at 6S-Terrace Street to reduce overall loading for the installation of mobile substation
Replacement of 4kV breakers and related equipment at 6S-Terrace Street
2014-2017: Continued conversion of 6S-Terrace Street load to 12kV
2018: Retirement of 6S-Terrace Street substation

533S-B 6S-C; Convert and Retire 6S-Terrace Streert by 2021

2013: Conversion of 533S-Mason Street stepdown
Conversion at 6S-Terrace Street to reduce overall loading for the installation of mobile substation
Replacement of 4kV breakers and related equipment at 6S-Terrace Street
2014-2020: Continued conversion of 6S-Terrace Street load to 12kV
2018: Maintain 6S-T1, as part of maintenance cycle
2021: Retirement of 6S-Terrace Street substation

0

NPV Comparison



Alternative A- 533S-B and 6S-A: Convert and Retire 6S-Terrace Street by 2016

Sydney 4kV Conversions
533S-B 6S-A; Convert and Retire 6S-Terrace Street by

Go to: Working Capital | Capital Expenses | Revenue

Add Operating Item

Project Description

Select:
In-Service Month: January
In-Service Year: 2014

Capital Invested

	Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
1.	Shipyard Reconfigure	35,042									
2.	533S-Msaon Street Conversion	274,188									
3.	Bentinck Street Reconfigure		102,510								
4.	Membertou Feeder Tie		35,228								
5.	Cabot Street Conversion	104,080									
6.	Rockdale Avenue Conversion	134,835									
7.	6S-Terrace Street Upgrade	401,500									
8.	Birch Hill Drive Conversion		211,271								
9.	Harold Street Conversion		315,355								
10.	Townsend Street Conversion		164,201								
11.	High Street Conversion			313,381							
12.	Terrace Street Conversion			358,471							
13.	Bernard Lind Conversion			132,214							
14.	6S-Terrace Street Retirement				90,203						
15.											
16.											
17.											
18.											
19.											
20.											
	Total Direct Capital Invested by Year	949,645	828,564	804,066	90,203						
	AFUDC (entered as a positive value)										
	AO (entered as a positive value)										
	Total Indirect Capital Invested by Year										
	Total Capital Invested by Year	**949,645**	**828,564**	**804,066**	**90,203**						

Alternative B- 533S-B and 6S-B: Convert and Retire 6S-Terrace Street by 2018

Sydney 4kV Conversions
533S-B 6S-B; Convert and Retire 6S-Terrace Street by

Nova Scotia POWER An Emera Company

Go to: Working Capital
Capital
Expenses
Revenue

Add Operating Item
Project Description

Select:
In-Service Month: January
In-Service Year: 2014

Capital Invested

	Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
1.	Shipyard Reconfigure	35,042									
2.	533S-Mason Street Conversion	274,188									
3.	Bentinck Street Reconfigure		102,510								
4.	Membertou Feeder Tie		35,228								
5.	Caobt Street Conversion	104,080									
6.	Rockdale Avenue Conversion	134,835									
7.	6S-Terrace Street Upgrades	401,500									
8.	Birch Hill Drive Conversion			215,496							
9.	Harold Street Conversion		315,355								
10.	Townsend Street Conversion			167,485							
11.	High Street Conversion				319,649						
12.	Terrace Street Conversion					372,953					
13.	Bernard Lind Conversion		129,622								
14.	6S-Terrace Street Retirement						93,847				
15.											
16.											
17.											
18.											
19.											
20.											
	Total Direct Capital Invested by Year	949,645	582,715	382,981	319,649	372,953	93,847				
	AFUDC (entered as a positive value)										
	AO (entered as a positive value)										
	Total Indirect Capital Invested by Year										
	Total Capital Invested by Year	**949,645**	**582,715**	**382,981**	**319,649**	**372,953**	**93,847**				

Alternative C- 533S-B and 6S-C: Convert and Retire 6S-Terrace Street, by 2021

Sydney 4kV Conversions
533S-B 6S-C; Convert and Retire 6S-Terrace Streert t

Nova Scotia POWER An Emera Company

Go to: Working Capital | Capital | Expenses | Revenue

Add Operating Item

Project Description

Select:
In-Service Month: January
In-Service Year: 2014

Capital Invested

	Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
1.	Shipyard Reconfigure	35,042									
2.	533S-Mason Street Conversion	274,188									
3.	Bentinck Street Reconfigure		102,510								
4.	Membertou Feeder Tie		35,228								
5.	Cabot Street Conversion	104,080									
6.	Rockdale Avenue Conversion	134,835									
7.	6S-Terrace Street Upgrades	401,500									
8.	Birch Hill Drive Conversion					224,202					
9.	Harold Street Conversion			321,663							
10.	Townsend Street Conversion						177,736				
11.	High Street Conversion							339,214			
12.	Terrace Street Conversion								395,781		
13.	Bernard Lind Conversion				134,858						
14.	Maintain 6S-T1						150,000				
15.	6S-Terrace Street Retirement									99,591	
16.											
17.											
18.											
19.											
20.											
	Total Direct Capital Invested by Year	949,645	137,738	321,663	134,858	224,202	327,736	339,214	395,781	99,591	
	AFUDC (entered as a positive value)										
	AO (entered as a positive value)										
	Total Indirect Capital Invested by Year										
	Total Capital Invested by Year	**949,645**	**137,738**	**321,663**	**134,858**	**224,202**	**327,736**	**339,214**	**395,781**	**99,591**	

APPENDIX D

Economic Analysis

Membertou Load Growth

Summary of Alternatives

Membertou Load Growth
Summary of Alternatives

Division :		**Date :**	25-Mar-14
Department :	Distribution Planning	**CI Number:**	
Originator :	James MacQueen	**Project No. :**	

	Alternative	After Tax WACC	PV of EVA / NPV	Rank	IRR	Disc Pay
A	New George Street Substation, 138kV-12kV	6.48%	-3,585,299	2	-8.15%	0.0 years
B	New Alexandra Street Substation, 138kV-25kV	6.48%	-4,175,037	4	-8.17%	0.0 years
C	6S-Terrace Street Replacement, 69kV - 12kV	6.48%	-3,920,697	3	-8.25%	0.0 years
D	George Street Pad-Mounted Substation 138kV - 12kV	6.48%	-3,098,378	1	-9.04%	0.0 years

Recommendation :

This economic assessment recommends the construction of a pad-mounted substation, near George Street, as outlined in the Distribution Planning Study.

An expansion of the pad-mounted substation will be required, as load materializes and has been accounted for in this EAM.

Notes/Comments :

New George Street Substation, 138kV-12kV

2014-2015: Construction of new 138-12kV sustation off of George Street

New Alexandra Street Substation, 138kV-25kV

2014-2015: Construction of new 138-25kV sustation off of Alexandra Street, with 15/20/25MVA initial transformation
2015: Conversion of 11S-305G from 12 to 25kV
2015: Conversion of Membertou from 12 to 25kV
2016: Conversion of remaining 12kV in Sydney River to 25kV

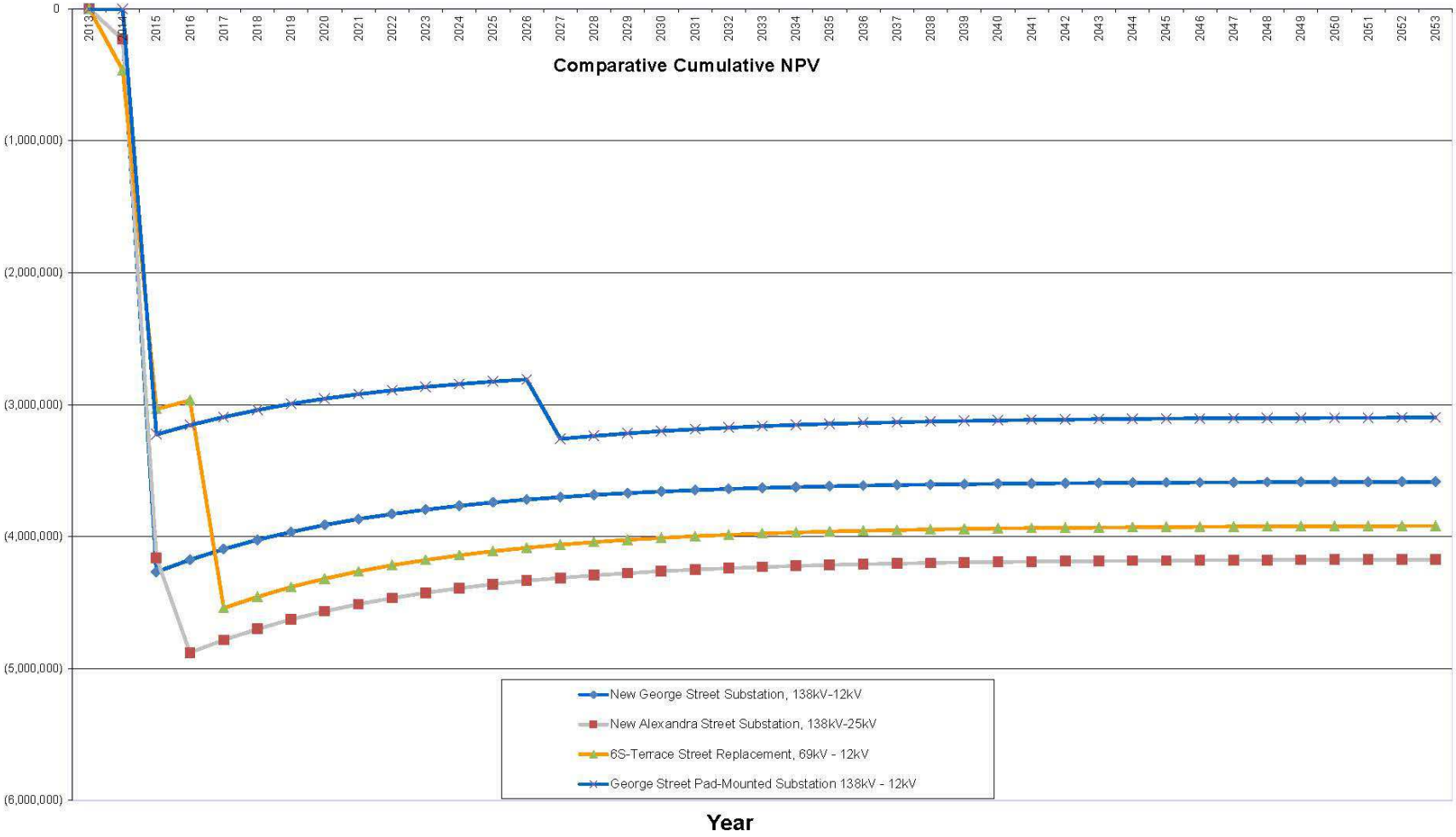
6S-Terrace Street Replacement, 69kV - 12kV

2014-2015: Installation of new 10/12/15MVA 69-12kV transformer at 6S-Terrace Street
2017: Installation of new pad-mounted substation to supply Membertou area

George Street Pad-Mounted Substation 138kV - 12kV

2015: Installation of new 15MVA 138-12kV pad-mounted substation near George Street
2027: Expansion of pad-mounted substation

NPV Comparison



Appendix C: Economic Analysis

Alternative Sub-A- New George Street Substation

Membertou Load Growth
New George Street Substation, 138kV-12kV

Go to: Working Capital | Capital Expenses | Revenue

Add Operating Item

Project Description

Select:
In-Service Month: January
In-Service Year: 2014

Capital Invested

	Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1.	New George Street Substation, Part 1		250,000													
2.	New George Street Substation, Part 2			3,500,000												
3.	New George Street Substation Distribution Upgardes			1,200,000												
4.																
5.																
6.																
7.																
8.																
9.																
10.																
11.																
12.																
13.																
14.																
15.																
16.																
17.																
18.																
19.																
20.																
	Total Direct Capital Invested by Year		250,000	4,700,000												
	AFUDC (entered as a positive value)															
	AO (entered as a positive value)															
	Total Indirect Capital Invested by Year															
	Total Capital Invested by Year		**250,000**	**4,700,000**												

Appendix C: Economic Analysis

Alternative Sub-B- New Alexandra Street Substation

Membertou Load Growth
New Alexandra Street Substation, 138kV-25kV

Go to: Working Capital | Capital | Expenses | Revenue

Add Operating Item
Project Description

Select:
In-Service Month: January
In-Service Year: 2014

Capital Invested

	Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1.	New Alexandra Street Substation, Part 1		250,000													
2.	New Alexandra Substation, Part 2			3,500,000												
3.	11S-305G Conversion from 12-25kV			425,000												
4.	Membertou Conversion from 12 to 25kV			650,250												
5.	Sydney River Conversion from 12-25kV				1,002,842											
6.																
7.																
8.																
9.																
10.																
11.																
12.																
13.																
14.																
15.																
16.																
17.																
18.																
19.																
20.																
	Total Direct Capital Invested by Year		250,000	4,575,250	1,002,842											
	AFUDC (entered as a positive value)															
	AO (entered as a positive value)															
	Total Indirect Capital Invested by Year															
	Total Capital Invested by Year		250,000	4,575,250	1,002,842											

Appendix C: Economic Analysis

Alternative Sub-C- 6S-Terrace Street Replacement, 69kV-12kV

Membertou Load Growth
6S-Terrace Street Replacement, 69kV - 12kV

Go to: Working Capital | Capital | Expenses | Revenue

Add Operating Item
Project Description

Select:
In-Service Month: January
In-Service Year: 2014

Capital Invested

	Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1.	6S-Terrace Street 69-12kV Preparation		500,000													
2.	6S-Terrace Street 69-12kV Completion			3,000,000												
3.	Pad-Mounted Substation, George Street					1,900,000										
4.	Pad-Mounted Substation Distribution Upgrades					250,000										
5.																
6.																
7.																
8.																
9.																
10.																
11.																
12.																
13.																
14.																
15.																
16.																
17.																
18.																
19.																
20.																
	Total Direct Capital Invested by Year		500,000	3,000,000		2,150,000										
	AFUDC (entered as a positive value)															
	AO (entered as a positive value)															
	Total Indirect Capital Invested by Year															
	Total Capital Invested by Year		500,000	3,000,000		2,150,000										

Appendix C: Economic Analysis

Alternative D- Sub-D George Street Pad-Mounted Substation, 138kV-12kV

Membertou Load Growth
George Street Pad-Mounted Substation 138kV - 12kV

Go to: Working Capital | Capital | Expenses | Revenue

Add Operating Item
Project Description

Select:
In-Service Month: January
In-Service Year: 2014

Capital Invested

	Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1.	Pad-Mounted Substation, George Street			1,900,000												
2.	Pad-Mounted Substation Expansion															900,000
3.	New George Street Substation Distribution Upgrades			1,000,000												
4.	Spare Pad-Mounted substation equipment			850,000												
5.	Distribution Upgrades for Substation Expansion															250,000
6.																
7.																
8.																
9.																
10.																
11.																
12.																
13.																
14.																
15.																
16.																
17.																
18.																
19.																
20.																
	Total Direct Capital Invested by Year			3,750,000												1,150,000
	AFUDC (entered as a positive value)															
	AO (entered as a positive value)															
	Total Indirect Capital Invested by Year															
	Total Capital Invested by Year			3,750,000												1,150,000

CI Number: 52200

Title: 65V-301 Brickton Reconductor

Start Date:	2018/01
In-Service Date:	2019/04
Final Cost Date:	2019/10
Function Class:	Distribution
Amount:	$594,362

DESCRIPTION:

This project includes reconductoring approximately 5.1 kilometers of existing three-phase line on primary distribution feeder 65V-301 along Mount Hanley Rd and Brooklyn Rd in Brickton. This section of line requires the replacement of three phase #2 AASC primary and neutral conductor with 4.2 kilometers of three phase and 0.9 kilometers of single phase 2/0 AASC primary and neutral, along with associated framing and insulators. Approximately 34 poles, 6 transformers and 12 cutouts will be replaced, and approximately 2 stub poles and overhead guys will be added to increase anchoring.

Summary of Related CIs +/- 2 years:
No other projects in 2016, 2017, 2018, 2019 and 2020

JUSTIFICATION:

Justification Criteria: Distribution System

Sub Criteria: Deteriorated Conductor

Why do this project?

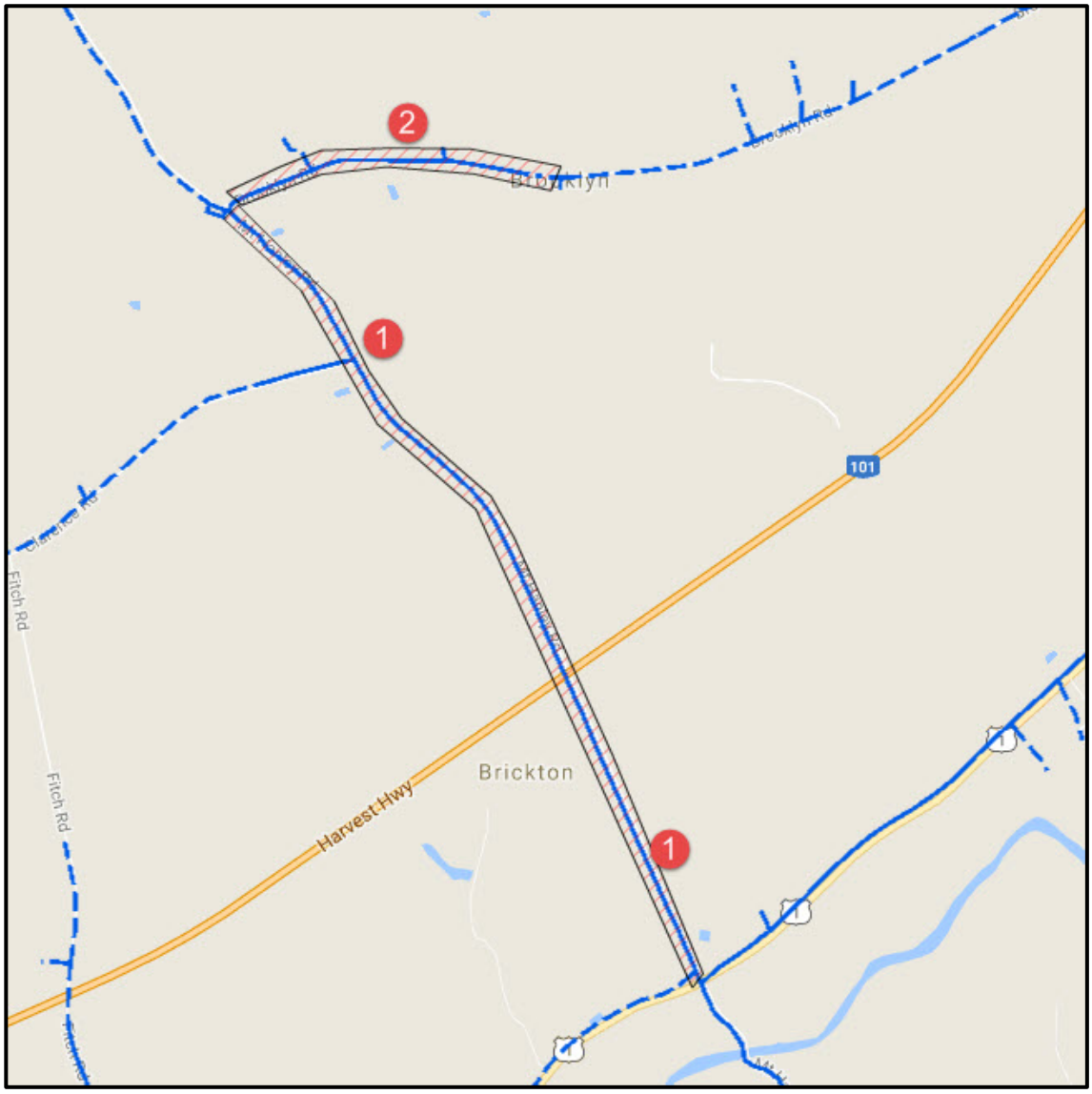
The existing conductor and targeted poles are deteriorated and at risk of failure due to their age and condition. In addition, a number of sections of the conductor can no longer be worked on under live conditions.

Why do this project now?

The existing poles and conductor are over 40 years old and have reached the end of their expected useful lives. Inspections of the targeted devices and assessment based on age, condition and risk of failure have determined that replacements are required. In addition, primary conductor failures have occurred on this section of line in both 2016 and 2017, and there are approximately 82 splices in the targeted section of line. Splices are a weak point in the line. Splice counts this high are indicative of a history of conductor failures over time.

Why do this project this way?

There is no alternative source of supply for the customers in the targeted area. Conductor and anchoring is the only alternative to mitigating the risk of failure.



1. Reconductor approximately 4.2 kilometers of three phase conductor to three phase 2/0 AASC
2. Remove two phases and reconductor approximately 0.9 kilometers of single phase to 2/0 AASC

CI Number : 52200 - 65V-301-Brickton Reconductor **Project Number** 52200

Parent CI Number : -

Asset Location : 1456 - 1456 Distribution Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	3500 - DP - Wood Poles	210,850
Additions	3800 - DP - Insulators	12,720
Additions	3900 - DP - O/H Cond.	271,882
Additions	4000 - DP - O/H Cond.Devices	1,820
Additions	4100 - DP - O/H Line Transf.	23,217
Additions	5200 - DP - Services	6,409
Retirements	3500 - DP - Wood Poles	26,101
Retirements	3900 - DP - O/H Cond.	36,492
Retirements	4000 - DP - O/H Cond.Devices	597
Retirements	4100 - DP - O/H Line Transf.	4,176
Retirements	5200 - DP - Services	99
	Total Cost:	594,362
	Original Cost:	133,722

Capital Project Detailed Estimate

Location: Distribution
CI# : 52200
Title: 65V-301 Brickton Reconductor
Execution Year: 2018-2019

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
Engineering	PD	3	$ 386	$ 1,144		
			Sub-Total	$ 1,144		
Materials						
Materials	Lot	1	$ 57,221	$ 57,221		
			Sub-Total	$ 57,221		
Contracts						
Flagging	Lot	1	$ 58,907	$ 58,907		
Backhoe	Lot	1	$ 32,250	$ 32,250		
EUS Contracts	Lot	1	$ 293,114	$ 293,114		
			Sub-Total	$ 384,271		
Consulting						
Consulting	Lot	1	$ 12,000	$ 12,000		
			Sub-Total	$ 12,000		
Other Goods & Services						
Contingency	%	10%	$ 442,636	$ 44,264		
			Sub-Total	$ 44,264		
Vehicle Overhead						
Vehicle AO				$ 468		
			Sub-Total	$ 468		
Interest Capitalized						
AFUDC				$ 21,067		
			Sub-Total	$ 21,067		
Administrative Overhead						
Labor AO				$ 1,016		
Contracts AO				$ 72,912		
			Sub-Total	$ 73,928		
			SUB-TOTAL (no AO, AFUDC)	$ 498,900		
			TOTAL (AO, AFUDC included)	$ 594,362		
Original Cost				$ 133,722		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 52205

Title: 30N-412 Hwy 242 Fundy Shore Rebuild

Start Date: 2018/02
In-Service Date: 2018/06
Final Cost Date: 2018/12
Function Class: Distribution
Forecast Amount: $536,670

DESCRIPTION:

This project will rebuild deteriorated conductor and poles on primary distribution feeder 30N-412 near Hwy 242 Fundy Shore Ecotour in River Hebert. Approximately 4.2 kilometers of existing off road line, including 103 poles and a mixture of #6, #4, and #2 conductors will be removed. The existing off-road line will be replaced, and moved to roadside, by a three-phase upgrade along Hwy 242 and a three-phase extension along Pit Road. On Hwy 242, the upgrade will require the replacement of 14 poles and 14 insulators, and the addition of approximately 4 kilometers of 2/0 primary conductor, 89 crossarms, and 178 insulators. On Pit Road, a 1.5 kilometer, three-phase, 2/0 primary and neutral extension is required. This line will be built on a combination of NS Power and Bell Aliant poles. Approximately 13 NS Power poles will be replaced, and approximately 26 crossarms and 78 insulators will be installed. Additional replacements include three transformers and two cutouts.

Summary of Related CIs +/- 2 years:
No other projects in 2016, 2017, 2018, 2019 and 2020

JUSTIFICATION:

Justification Criteria: Distribution System

Sub Criteria: Deteriorated Conductor

Why do this project?

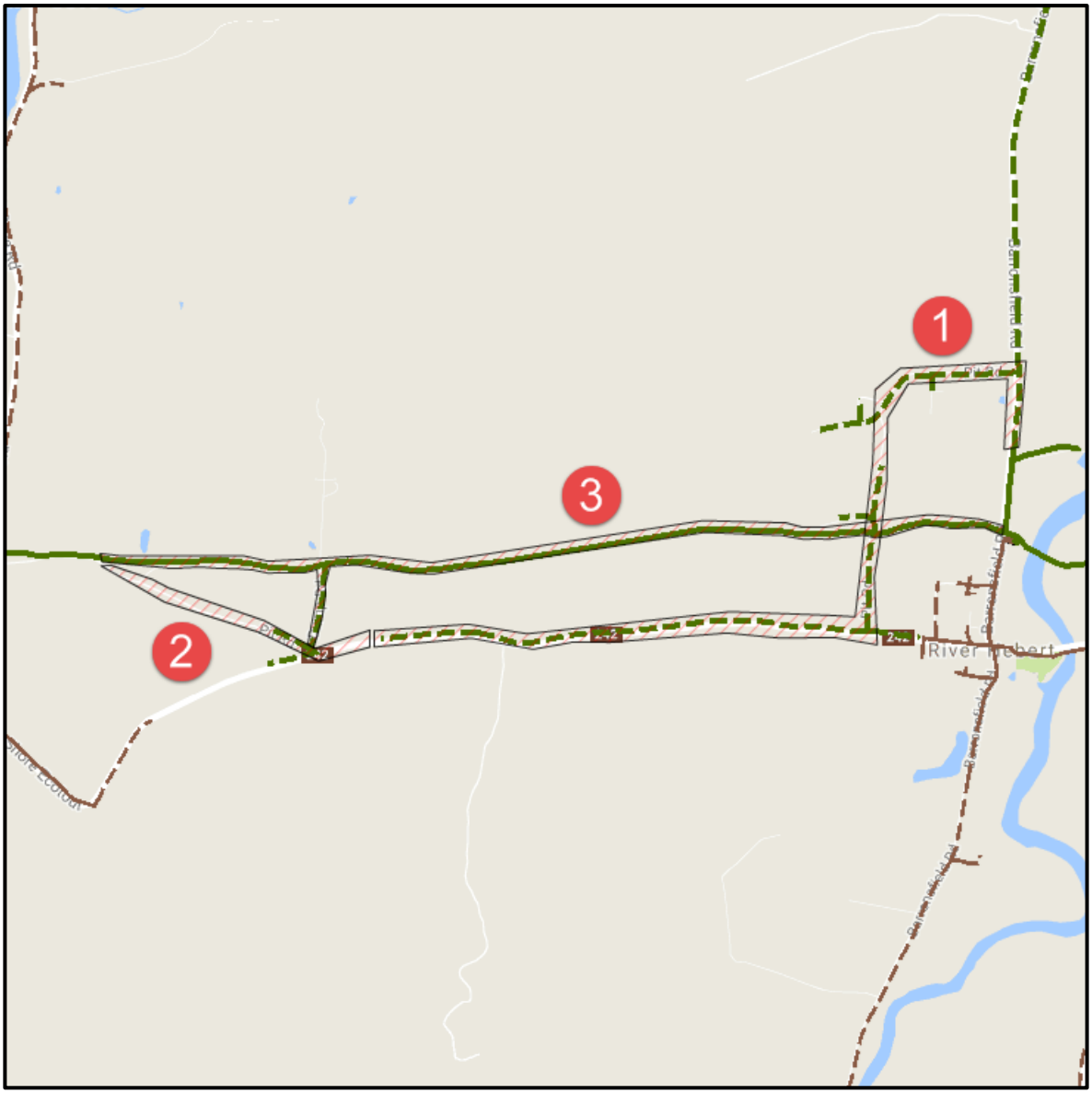
The existing conductor and poles are deteriorated and at risk of failure due to their age and condition. The existing conductor cannot be worked on under live conditions. In addition, the targeted section of line is located off-road with reduced accessibility, which limits NS Power's ability to maintain it and respond to outages.

Why do this project now?

The existing poles and conductor are over 40 years old and have reached the end of their expected service lives. Inspections of the targeted devices and assessments based on age, condition and risk of failure have determined that replacements are required.

Why do this project this way?

There is no alternative source of supply for the customers in the targeted area. Building the new line along the roadside will improve accessibility for outage response, and is also a lower cost solution, reducing the need for off-road equipment.



1. Upgrade single-phase line to three-phase along Hwy 242
2. Continue the three-phase line extension along Pit Road
3. Remove existing off-road line

CI Number : 52205 - 30N-412 Hwy 242 Fundy Shore Rebuild **Project Number** 52205

Parent CI Number : -

Asset Location : 1456 - 1456 Distribution Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	3500 - DP - Wood Poles	211,215
Additions	3900 - DP - O/H Cond.	215,789
Additions	4000 - DP - O/H Cond.Devices	1,639
Additions	4100 - DP - O/H Line Transf.	22,408
Additions	5000 - DP - Street Lights	718
Additions	5200 - DP - Services	5,503
Additions	9000 - DP - LED Street Lights	7,821
Retirements	3500 - DP - Wood Poles	42,196
Retirements	3900 - DP - O/H Cond.	27,922
Retirements	4000 - DP - O/H Cond.Devices	625
Retirements	4100 - DP - O/H Line Transf.	417
Retirements	5000 - DP - Street Lights	278
Retirements	5200 - DP - Services	139
	Total Cost:	536,670
	Original Cost:	121,037

Capital Project Detailed Estimate

Location: Distribution
CI# : 52205
Title: 30N-412 Hwy 242 Fundy Shore Rebuild
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
T&D Labor - PLT	PD	240	$ 372	$ 89,383		
T&D Labor - Design	PD	24	$ 386	$ 9,244		
Procurement/Financial Support		1	$ 1,083	$ 1,083		
			Sub-Total	$ 99,710		
Materials						
Poles, Conductor	Lot	1	$ 59,354	$ 59,354		
			Sub-Total	$ 59,354		
Contracts						
Flagging	Lot	1	$ 71,448	$ 71,448		
Backhoe	Lot	1	$ 57,150	$ 57,150		
Tree Trimming	Lot	1	$ 40,000	$ 40,000		
			Sub-Total	$ 168,598		
Royalty, Easement, Appraisal						
Easement	Lot	1	$ 10,000	$ 10,000		
				$ -		
			Sub-Total	$ 10,000		
Other Goods & Services						
Contingency	%	10%	$ 327,661	$ 32,766		
				$ -		
			Sub-Total	$ 32,766		
Vehicle Overhead						
Vehicle AO				$ 40,747		
				$ -		
			Sub-Total	$ 40,747		
Interest Capitalized						
AFUDC				$ 4,960		
				$ -		
			Sub-Total	$ 4,960		
Administrative Overhead						
Labor AO				$ 88,545		
Contract AO				$ 31,990		
			Sub-Total	$ 120,535		
			SUB-TOTAL (no AO, AFUDC)	$ 370,427		
			TOTAL (AO, AFUDC included)	$ 536,670		
Original Cost				$ 121,037		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 51744

Title: 30N-411 Maccan River Crossing Rebuild

Start Date: 2018/07
In-Service Date: 2018/10
Final Cost Date: 2019/04
Function Class: Distribution
Forecast Amount: $473,044

DESCRIPTION:

This project includes the reconfiguration of the section of primary feeder 30N-411 currently crossing the Maccan River. An existing 2 kilometer single-phase section of 30N-411 will be upgraded to three-phase. The existing 1 kilometer three-phase section of 30N-411 currently crossing the Maccan River will be removed once the reconfiguration and load transfer is completed.

Summary of Related CI's +/- 2 years
No other projects in 2016, 2017, 2018, 2019 and 2020

JUSTIFICATION:

Justification Criteria: Distribution System

Why do this project?

The existing river crossing is deteriorated and at risk of failure due to its age and condition. In addition, the targeted section of line is located off-road with reduced accessibility, which limits NS Power's ability to conduct maintenance and respond to outages.

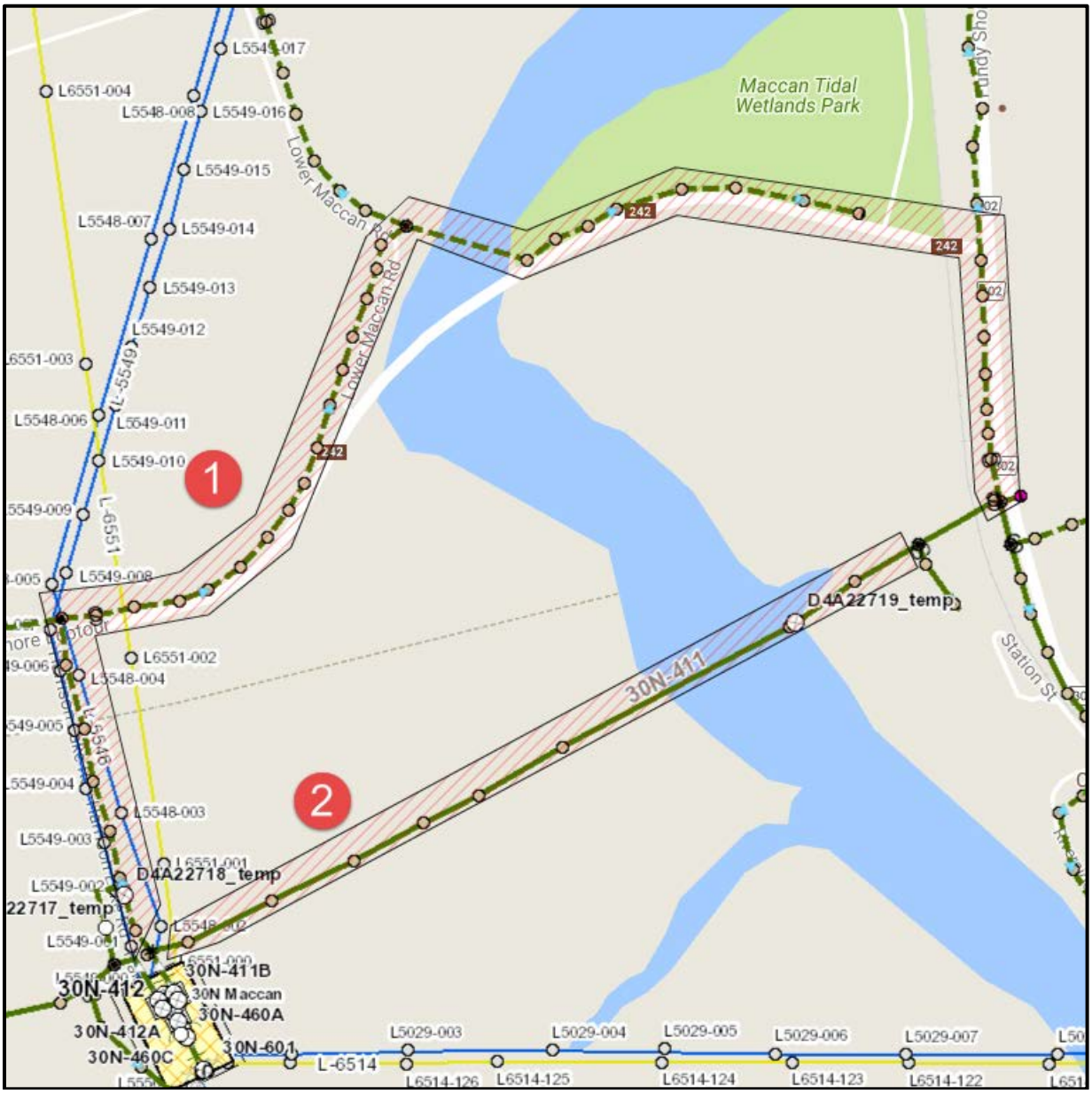
Why do this project now?

The existing conductor and poles are approximately 65 years old and have reached the end of their expected service lives. Inspection of the targeted section of 30N-411 and assessment based on age, condition and risk of failure has determined that replacement is required. In addition, inspection of the current crossing has identified that the existing structures are sinking due to the condition of the soil.

Why do this project this way?

An alternative considered was rebuilding the existing off-road section in its current location. This alternative would be more expensive due to the requirement of off-road construction equipment. In addition, the existing crossing is in a marsh environment, whereas the reconfiguration will bring the line to roadside.

The contracts portion of this project will be sourced through NS Power's existing Power Line Technician (PLT) Service Agreement with Emera Utility Services. This is aligned with NS Power's workforce planning model which is designed to optimize the allocation and execution of PLT resources among work requirements.



1. Construct new three phase line.
2. Remove existing feed across Macccan river

CI Number : 51744 - 30N-411 Maccan River Crossing Rebuild **Project Number** 51744

Parent CI Number : -

Asset Location : 1456 - 1456 Distribution Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0200 - DP - Land Rights	27,774
Additions	3500 - DP - Wood Poles	191,165
Additions	3800 - DP - Insulators	426
Additions	3900 - DP - O/H Cond.	200,350
Additions	4100 - DP - O/H Line Transf.	3,317
Additions	5000 - DP - Street Lights	2,857
Additions	5200 - DP - Services	3,723
Retirements	3500 - DP - Wood Poles	25,274
Retirements	3900 - DP - O/H Cond.	17,536
Retirements	4100 - DP - O/H Line Transf.	622
	Total Cost:	473,044
	Original Cost:	36,975

Capital Project Detailed Estimate

Location: Distribution
CI# / FP#: 51744
Title: 30N-411 Maccan River Crossing Rebuild
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
Procurement / Financial Support	Lot	1	$ 6,886	$ 6,886		
			Sub-Total	$ 6,886		
Materials						
Poles	Lot	1	$ 29,125	$ 29,125		
Insulators	Lot	1	$ 37	$ 37		
Conductor	Lot	1	$ 25,374	$ 25,374		
Overhead Line Transformer	Lot	1	$ 238	$ 238		
			Sub-Total	$ 54,773		
Contracts						
Contract Line Work	Hrs.	[redacted]		$ 201,127		
Tree Trimming	Lot	1	$ 7,500	$ 7,500		
Flagging	Lot	1	$ 40,539	$ 40,539		
Backhoe	Lot	1	$ 22,200	$ 22,200		
			Sub-Total	$ 271,366		
Consulting						
Consulting	Lot	1	$ 30,610	$ 30,610		
			Sub-Total	$ 30,610		
Royalty, Easement, Appraisal						
Permits	Lot	1	$ 12,000	$ 12,000		
			Sub-Total	$ 12,000		
Other Goods & Services						
Contingency	%	10%	$ 333,025	$ 33,302		
			Sub-Total	$ 33,302		
Vehicle Overhead						
Vehicle Allocated Costs				$ 2,814		
			Sub-Total	$ 2,814		
Administrative Overhead						
Labor AO				$ 6,115		
Contract AO				$ 51,489		
			Sub-Total	$ 57,604		
Interest Capitalized						
AFUDC				$ 3,689		
			Sub-Total	$ 3,689		
			SUB-TOTAL (no AO, AFUDC)	$ 408,937		
			TOTAL (AO, AFUDC included)	$ 473,044		
Original Cost				$ 36,975		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 52204

Title: 87W-312G Big Tancook Island Replacements

Start Date:	2018/05
In-Service Date:	2019/06
Final Cost Date:	2019/12
Function Class:	Distribution
Forecast Amount:	$454,096

DESCRIPTION:

This project will replace deteriorated equipment on Big Tancook Island. Approximately 25 deteriorated poles, 13 pin insulators, and 24 transformers will be replaced.

Summary of Related CIs +/- 2 years:
No other projects in 2016, 2017, 2018, 2019 and 2020

JUSTIFICATION:

Justification Criteria: Distribution System

Why do this project?

The existing poles, insulators and transformers are deteriorated and at risk of failure due to their age and condition. In addition, the targeted section of line is located on an island, with limited accessibility, which can lead to extended duration outages due to the restricted access.

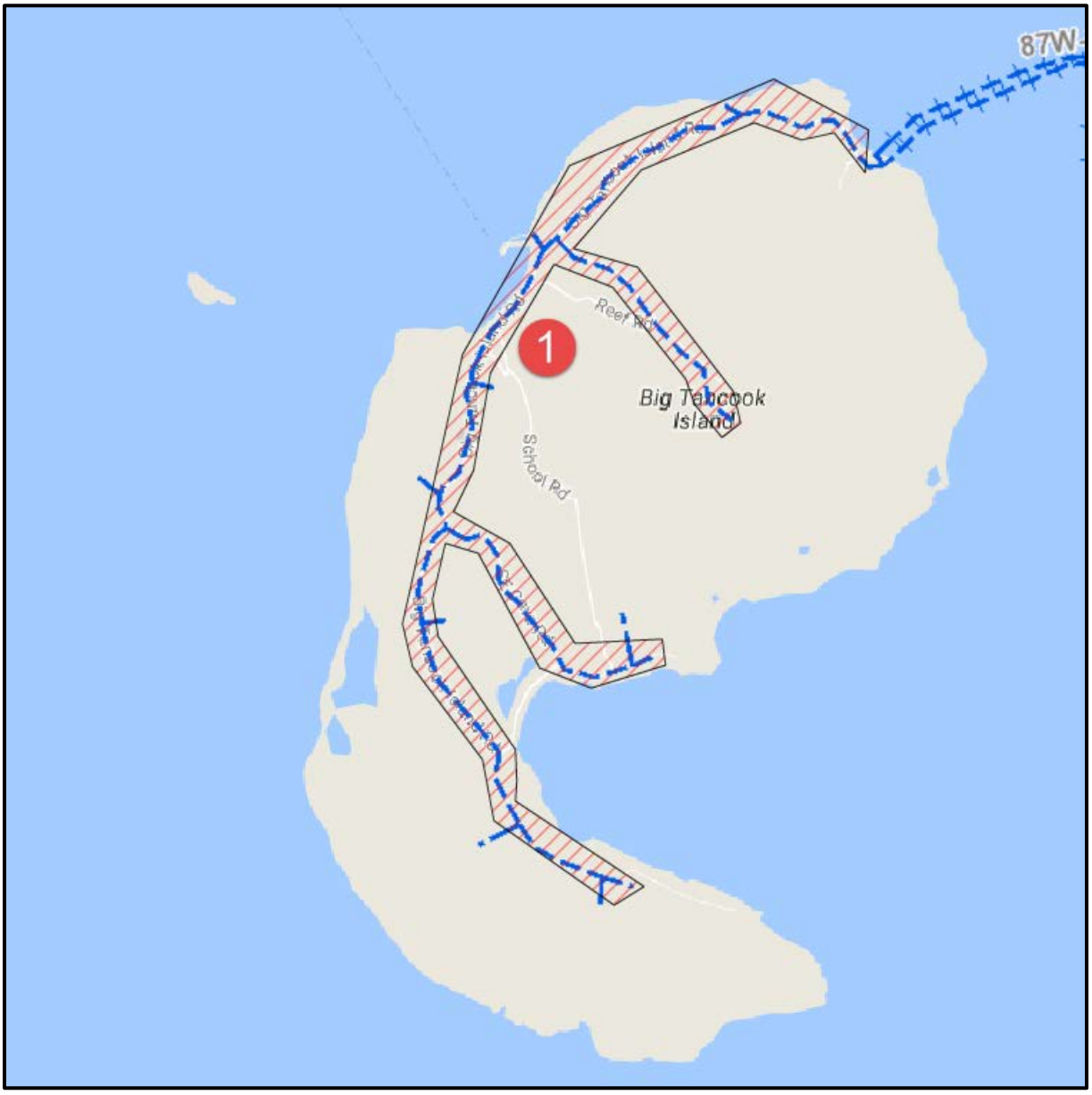
Why do this project now?

The existing poles are over 50 years old and have reached the end of their expected service lives. Inspections of the targeted devices and assessment based on age, condition and risk of failure have determined that replacements are required. Proactive replacement is required to prevent high-cost, extended duration outages due to the restricted access to the island.

Why do this project this way?

There is no alternative source of supply for the customers in the targeted area. Replacing the targeted assets is a more cost effective solution than rebuilding the entire line.

The contracts portion of this project will be sourced through NS Power's existing Power Line Technician (PLT) Service Agreement with Emera Utility Services. This is aligned with NS Power's workforce planning model which is designed to optimize the allocation and execution of PLT resources among work requirements.



1. Replace targeted poles, insulators and transformers.

CI Number : 52204 - 87W-312G Big Tancook Island Replacements

Project Number 52204

Parent CI Number : -

Asset Location : 1456 - 1456 Distribution Plant General

Budget Version 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0200 - DP - Land Rights	40,323
Additions	3500 - DP - Wood Poles	234,276
Additions	3900 - DP - O/H Cond.	51,248
Additions	4000 - DP - O/H Cond.Devices	5,734
Additions	4100 - DP - O/H Line Transf.	84,946
Retirements	3500 - DP - Wood Poles	19,012
Retirements	4000 - DP - O/H Cond.Devices	2,738
Retirements	4100 - DP - O/H Line Transf.	15,818
	Total Cost:	454,096
	Original Cost:	42,463

Capital Project Detailed Estimate

Location: Distribution
CI# / FP#: 52204
Title: 87W-312G Big Tancook Island Replacements
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
T&D Labor - Design	PD	5.6	$ 386	$ 2,160		
Procurement / Financial Support	Lot	1	$ 4 697	$ 4 697		
			Sub-Total	$ 6,857		
Materials						
Poles	Lot	1	$ 8,277	$ 8,277		
Conductor	Lot	1	$ 99	$ 99		
Cutouts	Lot	1	$ 1,126	$ 1,126		
Overhead Line Transformer	Lot	1	$ 43,737	$ 43,737		
			Sub-Total	$ 53,239		
Contracts						
Contract Line Work	Hrs.	[redacted]		$ 126,178		
Tree Trimming	Lot	1	$ 29,500	$ 29,500		
Backhoe	Lot	1	34,500	34,500		
Ferry Services for Equipment and Crews	Lot	1	56,885	56,885		
Off-Road Equipment	Lot	1	36,000	36,000		
			Sub-Total	$ 283,063		
Other Goods & Services						
Contingency	%	10%	$ 343 159	$ 34 316		
			Sub-Total	$ 34,316		
Vehicle Overhead						
Vehicle Allocated Costs				$ 2,802		
			Sub-Total	$ 2,802		
Administrative Overhead						
Labor AO				$ 6,089		
Contract AO				$ 53,708		
			Sub-Total	$ 59,797		
Interest Capitalized						
AFUDC				$ 14,022		
			Sub-Total	$ 14,022		
			SUB-TOTAL (no AO, AFUDC)	$ 377,474		
			TOTAL (AO, AFUDC included)	$ 454,096		
Original Cost				$ 42,463		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 52267

Title: 16W-302H Brenton Rd Rebuild

Start Date:	2018/04
In-Service Date:	2019/04
Final Cost Date:	2019/10
Function Class:	Distribution
Amount:	$387,767

DESCRIPTION:

This project will replace approximately 3.1 kilometers of existing single-phase line on primary distribution feeder 16W-302H along Brenton Road in Brenton. This will require the replacement of approximately 3.1 kilometers of #4 ACSR primary and neutral conductor with 2/0 AASC, and associated framing and insulators. Additional replacements include approximately 19 poles, 6 transformers and 10 cutouts. In addition, approximately 8 poles will be added to reduce span lengths to current standards.

Summary of Related CIs +/- 2 years:
No other projects in 2016, 2017, 2018, 2019 and 2020

JUSTIFICATION:

Justification Criteria: Distribution System

Sub Criteria: Deteriorated Conductor

Why do this project?

The existing conductor and poles are deteriorated and at risk of failure due to their age and condition. In addition, the conductor can no longer be worked on under live conditions.

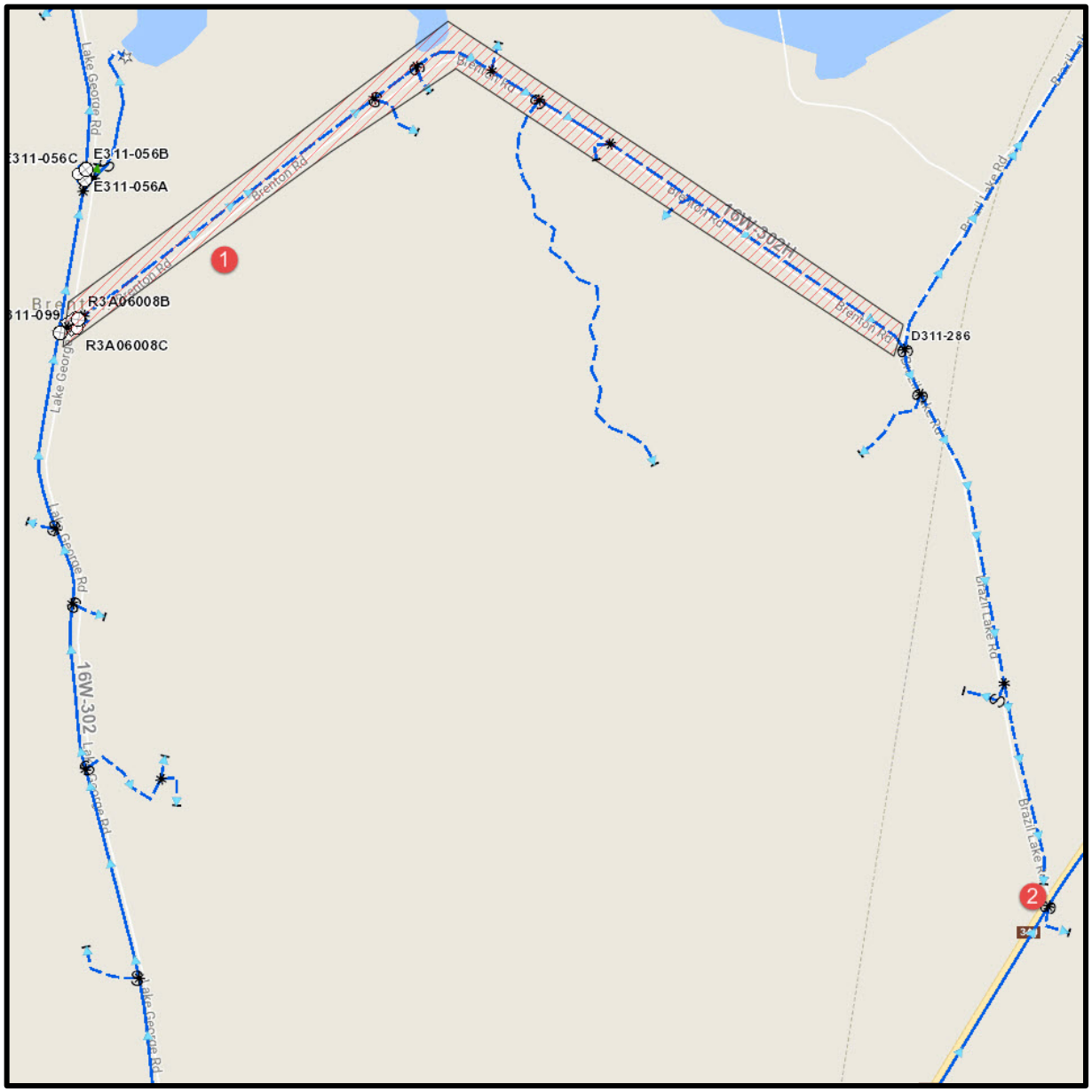
Why do this project now?

The existing conductor and poles are over 35 years old and have reached the end of their expected service lives. Inspections of the targeted devices and assessment based on age, condition and risk of failure has determined that replacements are required. In addition, the existing conductor is unable to support cold load pick up during an outage on, or upstream, of 16W-302H due to its condition. This results in additional delays and travel time in restoring customers to avoid conductor failure.

Why do this project this way?

There is no alternative source of supply for the customers in the targeted area. In order to minimize customer outages during construction, customers near Brazil Lake will be transferred to another line section fed from Brazil Lake Rd. Alternatively, NS Power considered upgrading this alternate feed to permanently transfer the load from Brenton Rd to Brazil Lake Rd; however this requires an additional 1.7 kilometers of conductor upgrades on Brazil Lake Rd in addition to the 3.1 kilometers required on Brenton Rd.

The contracts portion of this project will be sourced through NS Power's existing Power Line Technician (PLT) Service Agreement with Emera Utility Services. This is aligned with NS Power's workforce planning model which is designed to optimize the allocation and execution of PLT resources among work requirements.



1. Rebuild approximately 3.1 km of existing single-phase line.
2. Source of temporary feed for Brazil Lake.

CI Number : 52267 - 16W-302H-Brenton Rd Rebuild

Project Number 52267

Parent CI Number : -

Asset Location : 1456 - 1456 Distribution Plant General

Budget Version 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0200 - DP - Land Rights	10,190
Additions	3500 - DP - Wood Poles	216,099
Additions	3900 - DP - O/H Cond.	100,436
Additions	4000 - DP - O/H Cond.Devices	4,558
Additions	4100 - DP - O/H Line Transf.	17,222
Additions	5000 - DP - Street Lights	1,817
Additions	5200 - DP - Services	2,057
Retirements	3500 - DP - Wood Poles	15,860
Retirements	3800 - DP - Insulators	99
Retirements	3900 - DP - O/H Cond.	13,921
Retirements	4000 - DP - O/H Cond.Devices	1,193
Retirements	4100 - DP - O/H Line Transf.	3,778
Retirements	5200 - DP - Services	537
	Total Cost:	387,767
	Original Cost:	106,746

Capital Project Detailed Estimate

Location: **Distribution**
CI# / FP#: 52267
Title: 16W-302H Brenton Rd Rebuild
Execution Year: 2018/2019

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
Procurement / Financial Support	Lot	1	$ 4,827	$ 4,827		
			Sub-Total	$ 4,827		
Materials						
Poles	Lot	1	$ 13,953	$ 13,953		
Conductor	Lot	1	$ 9 752	$ 9 752		
Cutouts	Lot	1	$ 1 265	$ 1 265		
Overhead Line Transformer	Lot	1	$ 9 666	$ 9 666		
Services	Lot	1	$ 9	$ 9		
			Sub-Total	$ 34,645		
Contracts						
Contract Line Work	Hrs.	[redacted]		143 104		
Tree Trimming	Lot	1	$ 30 000	30 000		
Flagging	Lot	1	$ 33,091	33,091		
Backhoe	Lot	1	$ 30,750	30,750		
Rock Breaking	Lot	1	$ 10,000	10,000		
			Sub-Total	$ 246,945		
Royalty, Easement, Appraisal						
Easements	Lot	1	$ 7,500	$ 7,500		
			Sub-Total	$ 7,500		
Other Goods & Services						
Contingency	%	10%	$ 286,417	$ 28,642		
				$ -		
			Sub-Total	$ 28,642		
Vehicle Overhead						
Vehicle Allocated Costs				$ 1,972		
			Sub-Total	$ 1,972		
Administrative Overhead						
Labor AO				$ 4 286		
Contract AO				$ 46,855		
			Sub-Total	$ 51,142		
Interest Capitalized						
AFUDC				$ 12,093		
			Sub-Total	$ 12,093		
			SUB-TOTAL (no AO, AFUDC)	$ 322,559		
			TOTAL (AO, AFUDC included)	$ 387,767		
Original Cost				$ 106,746		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 52207

Title: 678H-211 McNab's Island Replacements

Start Date: 2018/07
In-Service Date: 2019/03
Final Cost Date: 2019/09
Function Class: Distribution
Forecast Amount: 350,176

DESCRIPTION:

This project will replace deteriorated equipment on McNab's Island in Halifax. Approximately 24 deteriorated poles, 21 pin insulators, and 3 transformers will be replaced.

Summary of Related CIs +/- 2 years:
No other projects in 2016, 2017, 2018, 2019 and 2020

JUSTIFICATION:

Justification Criteria: Distribution System

Sub Criteria: Pole Strength

Why do this project?

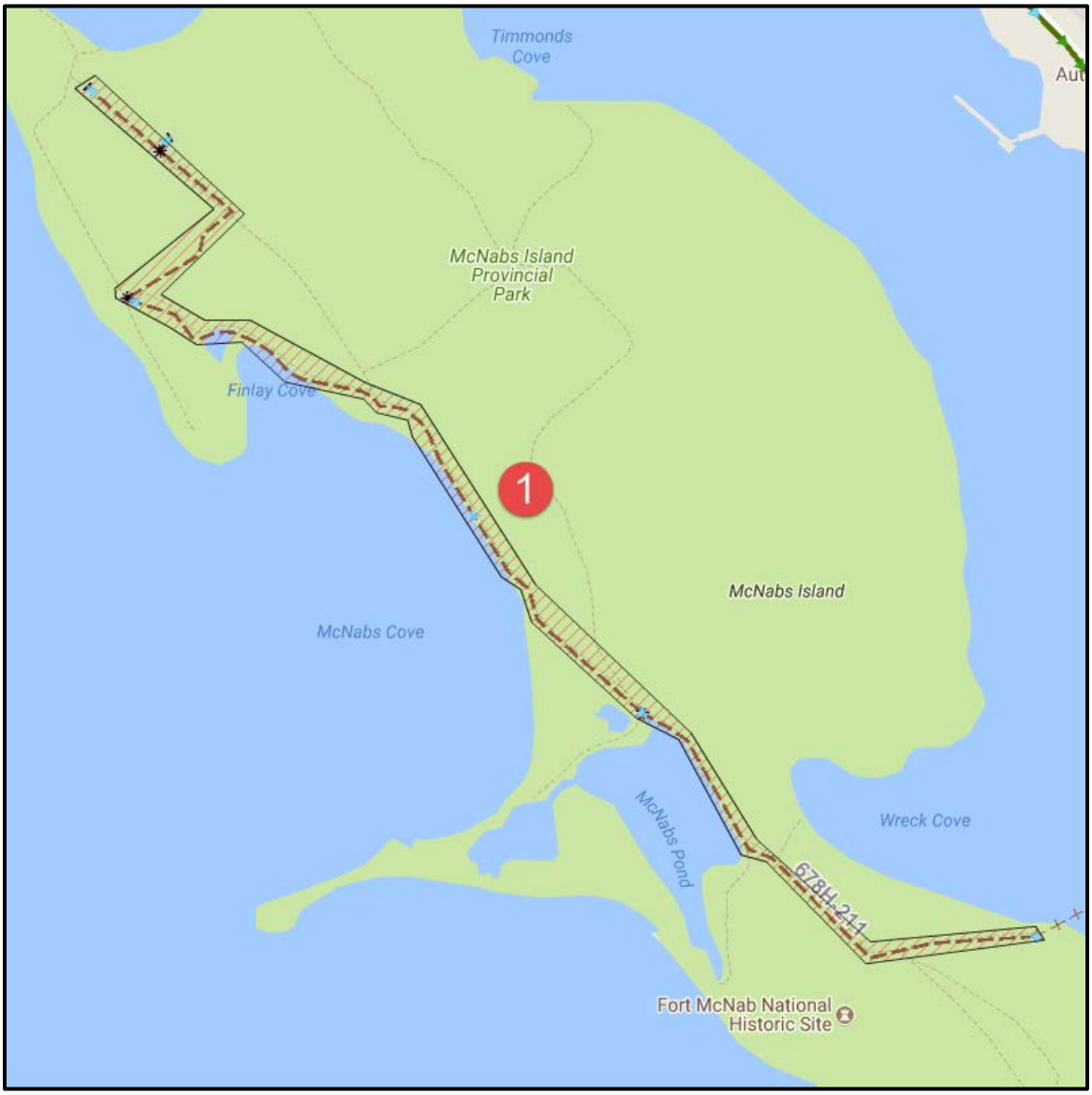
The existing poles and transformers are deteriorated and at risk of failure due to their age and condition. In addition, the targeted section is located on an island, with limited accessibility, which can lead to extended duration outages due to the restricted access.

Why do this project now?

The existing poles are over 65 years old and have reached the end of their expected service lives. Inspections of the targeted devices and assessments based on age, condition and risk of failure have determined that replacements are required. Proactive replacement is required to prevent high-cost, extended duration outages due to the restricted access to the island.

Why do this project this way?

There is no alternative source of supply for the customers in the targeted area. Poles will be upgraded in accordance with current NS Power standards.



1. Replace targeted poles, insulators and transformers on the island.

CI Number : 52207 - 678H-211 McNab's Island Replacements **Project Number** 52207

Parent CI Number : -

Asset Location : 1456 - 1456 Distribution Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0200 - DP - Land Rights	79,354
Additions	3500 - DP - Wood Poles	237,776
Additions	3900 - DP - O/H Cond.	18,789
Additions	5000 - DP - Street Lights	862
Additions	5200 - DP - Services	221
Retirements	3500 - DP - Wood Poles	12,578
Retirements	4100 - DP - O/H Line Transf.	398
Retirements	5000 - DP - Street Lights	199
	Total Cost:	350,176
	Original Cost:	27,287

Capital Project Detailed Estimate

Location: Distribution
CI# : 52207
Title: 678H-211 McNab's Island Replacements
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
Procurement / Financial Support	Lot	1	$ 361	$ 361		
			Sub-Total	$ 361		
Materials						
Materials	Lot	1	$ 18,045	$ 18,045		
			Sub-Total	$ 18,045		
Contracts						
EUS Contracts	Lot	1	$ 84,904	$ 84,904		
Flagging	Lot	1	$ 19,684	$ 19,684		
Backhoe	Lot	1	$ 24,900	$ 24,900		
Tree Trimming	Lot	1	$ 60,000	$ 60,000		
Barging Equipment	Lot	1	$ 20,000	$ 20,000		
Track Machine	Lot	1	$ 27,000	$ 27,000		
Archaeologist	Lot	1	$ 11,350	$ 11,350		
			Sub-Total	$ 247,838		
Royalty, Easement, Appraisal						
Easement	Lot	1	$ 5,000	$ 5,000		
			Sub-Total	$ 5,000		
Other Goods & Services						
Contingency	%	10%	$ 266,243	$ 26,624		
			Sub-Total	$ 26,624		
Interest Capitalized						
AFUDC				$ 5,284		
			Sub-Total	$ 5,284		
Administrative Overhead						
Contract AO				$ 47,025		
			Sub-Total	$ 47,025		
			SUB-TOTAL (no AO, AFUDC)	$ 297,868		
			TOTAL (AO, AFUDC included)	$ 350,176		
Original Cost				27,287		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 51500

Title: 2018 Pin Insulator Replacements

Start Date: 2018/01
In-Service Date: 2018/01
Final Cost Date: 2019/06
Function Class: Distribution
Amount: $350,100

DESCRIPTION:

This project includes the replacement of distribution pin insulators on various targeted feeder sections. Approximately 750 pin insulators will be replaced. In cases where insulators require replacement and the cross arm, porcelain cut out or pole is also deteriorated, those components will be replaced as part of this project as well.

Summary of Related CIs +/- 2 years:
2019 CI TBD 2019 Pin Insulator Replacements $TBD
2020 CI TBD 2020 Pin Insulator Replacements $TBD

JUSTIFICATION:

Justification Criteria: Distribution System

Why do this project?

The existing pin insulators are deteriorated and at risk of failure. Failed pin insulators are the leading cause of deteriorated equipment customer interruptions (CI) and customer hours of interruption (CHI).

Why do this project now?

The targeted pin insulators are over 35 years old and have reached the end of their service life. Pin insulator failures have resulted in over 300,000 CI and over 475,000 CHI over the last five years. In addition, pin insulator failures also have the potential to cause pole fires resulting in premature pole replacements.

This project is deemed in-service when the first pin insulator is installed (January 2018), therefore the Final Cost Date (June 2019) is listed as six months after the last pin insulator is installed (December 2018).

Why do this project this way?

Replacing the targeted assets is a more cost effective solution than rebuilding the entire line. Proactive replacement of targeted pin insulators improves reliability and reduces the risk of pole damage.

CI Number : 51500 - 2018 Pin Insulator Replacements

Project Number 51500

Parent CI Number : -

Asset Location : 1456 - 1456 Distribution Plant General

Budget Version 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0200 - DP - Land Rights	45,479
Additions	3500 - DP - Wood Poles	183,175
Additions	3800 - DP - Insulators	25,374
Additions	3900 - DP - O/H Cond.	66,300
Additions	4000 - DP - O/H Cond.Devices	12,083
Retirements	3500 - DP - Wood Poles	12,951
Retirements	3900 - DP - O/H Cond.	1,579
Retirements	4000 - DP - O/H Cond.Devices	3,159
	Total Cost:	350,100
	Original Cost:	29,014

Capital Project Detailed Estimate

Location: **Distribution**
CI# / FP#: 51500
Title: 2018 Pin Insulator Replacements
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
T&D Labor - PLT	PD	199	$ 367	$ 73,086		
T&D Labor - Design	PD	9	$ 382	$ 3,343		
Procurement / Financial Support	Lot	1	$ 7,788	$ 7,788		
			Sub-Total	$ 84,217		
Materials						
Poles	Lot	1	$ 11,371	$ 11,371		
Insulators	Lot	1	$ 1,915	$ 1,915		
Cutouts	Lot	1	$ 2,975	$ 2,975		
			Sub-Total	$ 16,260		
Contracts						
Tree Trimming	Lot	1	$ 25,000	$ 25,000		
Flagging	Lot	1	$ 65,285	$ 65,285		
Backhoe	Lot	1	$ 10,800	$ 10,800		
			Sub-Total	$ 101,085		
Other Goods & Services						
Contingency	%	10%	$ 201,561	$ 20,156		
			Sub-Total	$ 20,156		
Vehicle Overhead						
Vehicle AO				$ 34,416		
			Sub-Total	$ 34,416		
Administrative Overhead						
Labor AO				$ 74,787		
Contract AO				$ 19,180		
			Sub-Total	$ 93,967		
			SUB-TOTAL (no AO, AFUDC)	$ 221,717		
			TOTAL (AO, AFUDC included)	$ 350,100		
Original Cost				$ 29,014		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 52192

Title: 54H-303 Underground Device Replacements Phase 2

Start Date: 2018/05
In-Service Date: 2018/12
Final Cost Date: 2019/06
Function Class: Distribution
Forecast Amount: $309,230

DESCRIPTION:

This is the second phase of the 54H-303 Underground Device Replacement project. This project will replace approximately 0.8 kilometers of deteriorated underground cables and various underground devices on primary distribution feeder 54H-303. The targeted equipment is part of the Dartmouth underground system, and is located in four vaults in the downtown area. Replacements include underground cables, submersible transformers, submersible switchgear, switching cubicles, fault indicators and related hardware.

Summary of Related CIs +/- 2 years:
2017 CI 49918 54H-303 Underground Device Replacements Phase 1 $469,605

JUSTIFICATION:

Justification Criteria: Distribution System

Sub Criteria: Deteriorated Conductor

Why do this project?

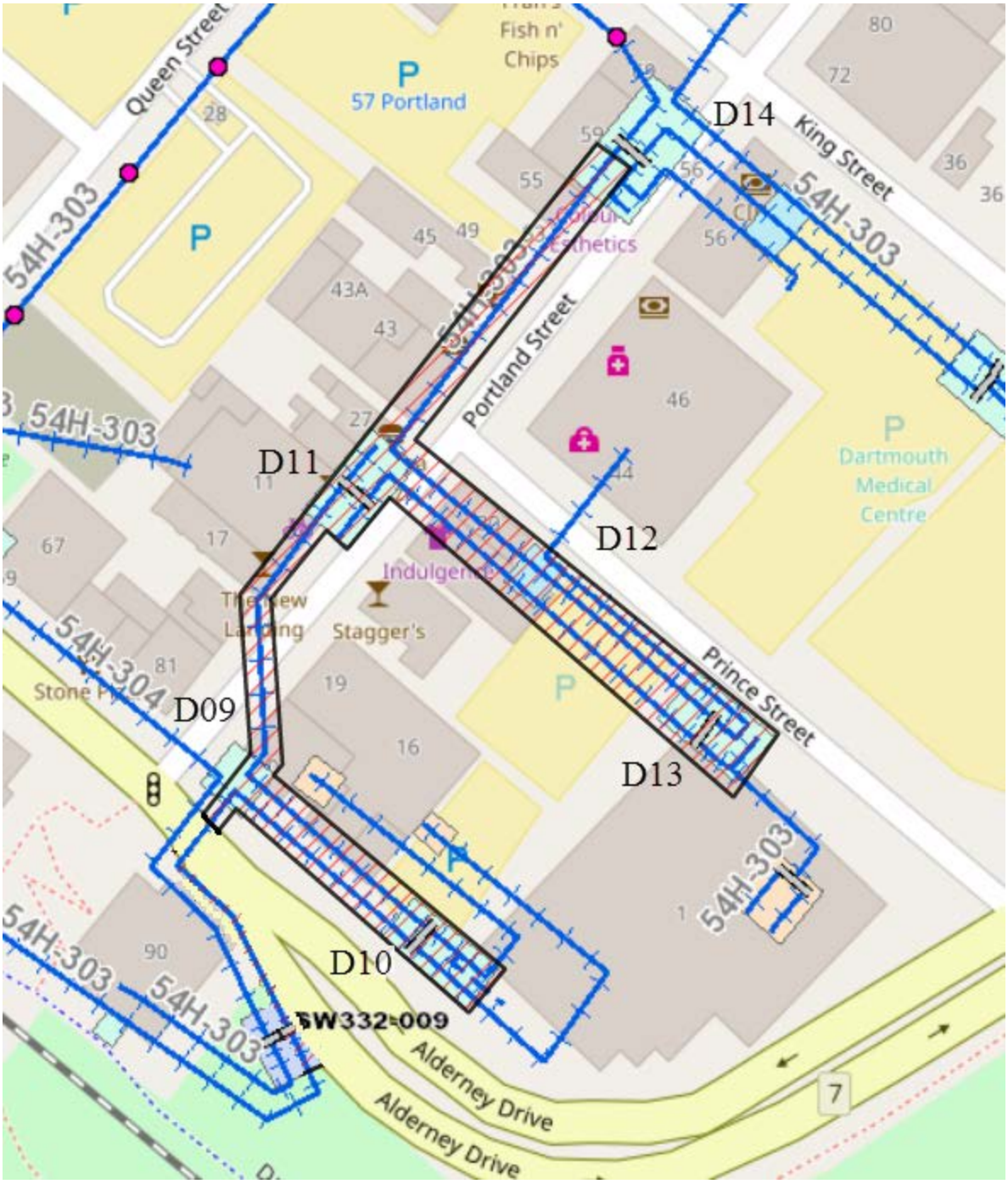
The existing cables and related equipment are deteriorated and at risk of failure due to their age and condition. Failure of this equipment would result in outages to Downtown Dartmouth (approximately 1260 customers), including multiple commercial customers.

Why do this project now?

The targeted cables, transformers, switchgear and related equipment are approximately 35 years old, and have reached the end of their expected useful lives. Inspections of the targeted devices and assessments based on age, condition, and risk of failure have determined that replacements are required. There have been eight failures in the last three years on the targeted underground feeder due to the age and condition of the assets. These events resulted in lengthy outages to customers due to the time required to isolate the faulted section and make repairs.

Why do this project this way?

There is no alternate source of supply for customers served by the targeted underground equipment. Replacing the targeted assets is a more cost effective solution than rebuilding the entire underground line, or building new overhead lines. Planned cable replacements can be performed with little to no customer interruptions, as switching can be performed between vaults to supply customers.



Replacement includes cable and equipment between D14 and D10

- Replace approximately 0.8kms of underground distribution line between D14 and D10.
- Replace operators.
- Replace submersible transformers.
- Install/replace fault indicators in vaults. Replace cables trays and cable brackets.

CI Number : 52192 - 54H-303 Underground Device Replacements Phase 2 **Project Number** 52192

Parent CI Number : -

Asset Location : 1456 - 1456 Distribution Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account		Forecast Amount
Additions	3900 - DP - O/H Cond.		4,278
Additions	4600 - DP - U/G Conductor		260,635
Additions	4700 - DP - U/G Conductor Devices		8,165
Additions	4800 - DP - U/G Line Transf.		13,337
Retirements	4000 - DP - O/H Cond.Devices		414
Retirements	4600 - DP - U/G Conductor		22,401
		Total Cost:	309,230
		Original Cost:	110,530

Capital Project Detailed Estimate

Location: Distribution
CI# : 52192
Title: 54H-303 Underground Device Replacements Phase 2
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
Engineering	PD	33	$ 386	$ 12,654		
Electricians	PD	130	$ 372	$ 48,561		
Procurement/Financial Support	Lot	1	$ 1,484	$ 1,484		
			Sub-Total	$ 62,699		
Materials						
Materials	Lot	1	$ 74,181	$ 74,181		
				$ -		
			Sub-Total	$ 74,181		
Contracts						
Flagging	Lot	1	$ 38,854	$ 38,854		
Crane operator charges	Lot	1	$ 10,000	$ 10,000		
Hydro vac charges	Lot	1	$ 6,000	$ 6,000		
Vacpac Stand _ Stainless steel	Lot	1	$ 1,000	$ 1,000		
			Sub-Total	$ 55,854		
Other Goods & Services						
Contingency	%	10%	$ 192,734	$ 19,273		
			Sub-Total	$ 19,273		
Vehicle Overhead						
Vehicle AO				$ 25,622		
			Sub-Total	$ 25,622		
Interest Capitalized						
AFUDC				$ 5,324		
			Sub-Total	$ 5,324		
Administrative Overhead						
Labor AO				$ 55,678		
Contract AO				$ 10,598		
			Sub-Total	$ 66,276		
			SUB-TOTAL (no AO, AFUDC)	$ 212,008		
			TOTAL (AO, AFUDC included)	$ 309,230		
Original Cost				$ 110,530		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 52206

Title: 20V-311 Bishop Ville Rd Reconductor

Start Date): 2018/05
In-Service Date: 2018/08
Final Cost Date: 2019/02
Function Class: Distribution
Amount: $303,533

DESCRIPTION:

This project includes targeted conductor replacement on primary distribution feeder 20V-311 along Bishopville Rd near Hantsport. Approximately 3.8 kilometers of #4 ACSR primary and neutral conductor will be upgraded to 2/0 AASC primary and neutral. Additionally, 58 insulators, 2 cutouts, and 5 transformers will be replaced.

Summary of Related CIs +/- 2 years:
No other projects in 2016, 2017, 2018, 2019 and 2020

JUSTIFICATION:

Justification Criteria: Distribution System

Sub Criteria: Deteriorated Conductor

Why do this project?

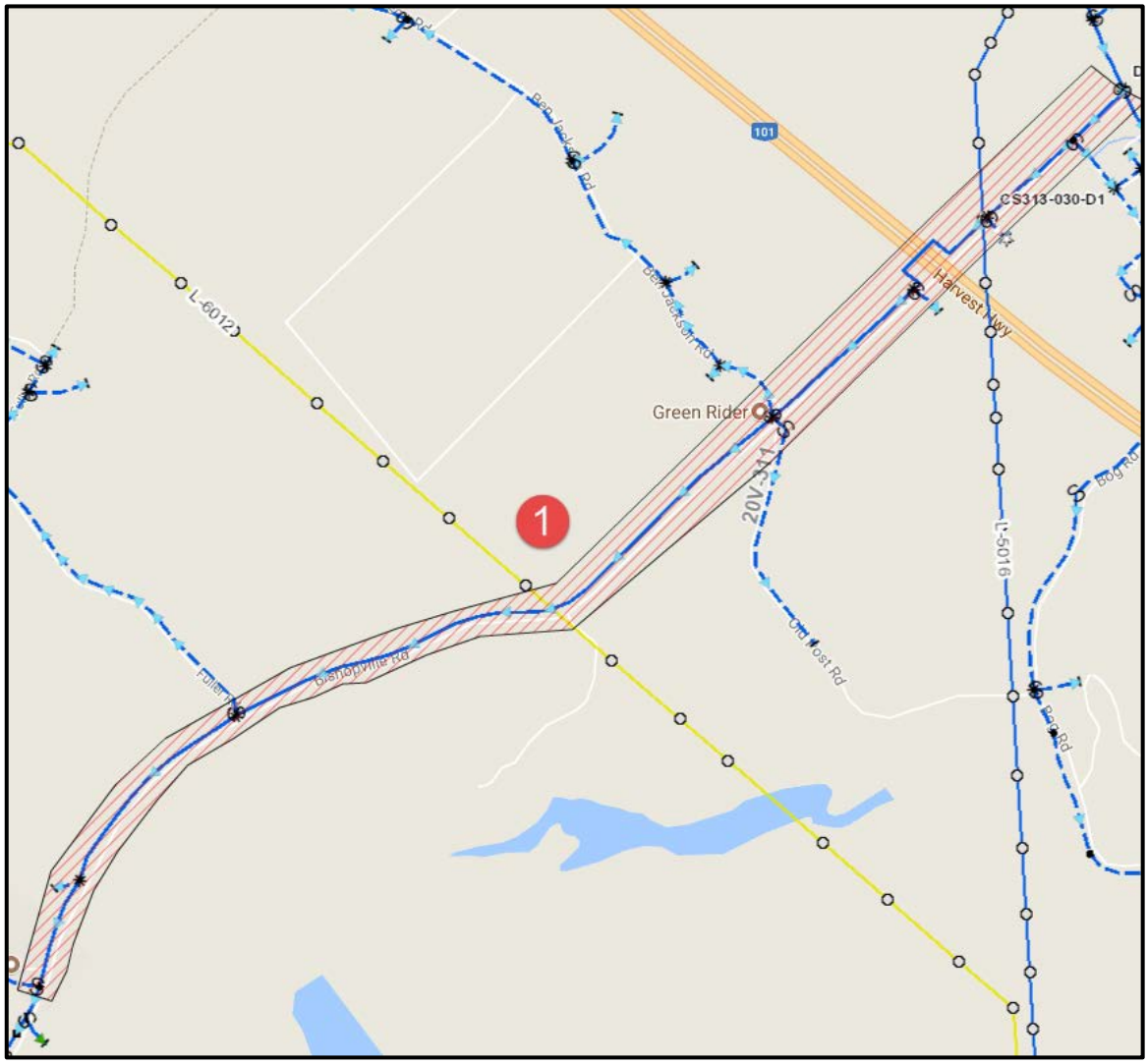
The existing conductor is deteriorated and at risk of failure due to its age and condition. In addition, the existing conductor cannot be worked on under live conditions.

Why do this project now?

The existing conductor is over 55 years old and has reached the end of its expected useful life. Inspections of the targeted devices and assessment based on age, condition and risk of failure has determined that replacements are required.

Why do this project this way?

There is no alternative source of supply for the customers in the targeted area. Replacing the targeted assets is a more cost effective solution than rebuilding the entire line. The conductor will be upgraded in accordance with current NS Power standards.



1. Upgrade approximately 3.8 kilometers of conductor and replace targeted devices along Bishop Ville Rd.

CI Number : 52206 - 20V-311 Bishop Ville Rd Reconductor

Project Number 52206

Parent CI Number : -

Asset Location : 1456 - 1456 Distribution Plant General

Budget Version 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0200 - DP - Land Rights	81,610
Additions	3500 - DP - Wood Poles	90,886
Additions	3900 - DP - O/H Cond.	82,400
Additions	4000 - DP - O/H Cond.Devices	622
Additions	4100 - DP - O/H Line Transf.	20,517
Additions	5000 - DP - Street Lights	693
Additions	5200 - DP - Services	6,466
Retirements	3500 - DP - Wood Poles	6,807
Retirements	3900 - DP - O/H Cond.	10,827
Retirements	4000 - DP - O/H Cond.Devices	239
Retirements	4100 - DP - O/H Line Transf.	2,229
Retirements	5200 - DP - Services	239
	Total Cost:	303,533
	Original Cost:	28,577

Capital Project Detailed Estimate

Location: **Distribution**
CI# / FP#: 52206
Title: 20V-311 Bishop Ville Rd Reconductor
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
T&D Labor - PLT	PD	157	$ 372	$ 58,407		
Procurement / Financial Support	Lot	1	$ 6,778	$ 6,778		
			Sub-Total	$ 65,185		
Materials						
Poles	Lot	1	$ 15,634	$ 15,634		
Conductor	Lot	1	$ 11,258	$ 11,258		
Cutouts	Lot	1	$ 235	$ 235		
Overhead Line Transformer	Lot	1	$ 9,753	$ 9,753		
			Sub-Total	$ 36,880		
Contracts						
Tree Trimming	Lot	1	$ 37,000	$ 37,000		
Flagging	Lot	1	$ 34,603	$ 34,603		
			Sub-Total	$ 71,603		
Royalty, Easement, Appraisal						
Grade 1 Highway Crossing	Lot	1	$ 12,000	$ 12,000		
			Sub-Total	$ 12,000		
Other Goods & Services						
Contingency	%	10%	$ 173,668	$ 17,367		
				$ -		
			Sub-Total	$ 17,367		
Vehicle Overhead						
Vehicle Allocated Costs				$ 26,639		
			Sub-Total	$ 26,639		
Administrative Overhead						
Labor AO				$ 57,887		
Contract AO				$ 13,586		
			Sub-Total	$ 71,472		
Interest Capitalized						
AFUDC				$ 2,387		
			Sub-Total	$ 2,387		
			SUB-TOTAL (no AO, AFUDC)	$ 203,035		
			TOTAL (AO, AFUDC included)	$ 303,533		
Original Cost				$ 28,577		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 52186

Title: 4S Feeder Exit Cable Replacement Phase 1

Start Date:	2018/04
In-Service Date:	2018/12
Final Cost Date:	2019/06
Function:	Distribution
Amount:	$293,509

DESCRIPTION:

This project will replace four sets of deteriorated primary distribution feeder exit cables at the 4S Townsend Street substation in Sydney. The feeder exit cables at this substation are deteriorated and have reached end of expected useful life. Feeder exit cables prevent overhead congestion in the area of a substation by routing feeders underground from the reclosers located in the substation to adjacent poles at roadside.

Summary of Related CIs +/- 2 years:
2019 CI TBD - 4S Feeder Exit Cable Replacement Phase 2 - $TBD

JUSTIFICATION:

Justification Criteria: Distribution System

Sub Criteria: Deteriorated Conductor

Why do this project?

The feeder exit cables at Towsend Street substation are deteriorated, and have reached end of expected useful life. Cable failures at 4S will result in lengthy customer outages, affecting up to 2,000 customers. In addition, the underground cables at 4S Townsend St substation have shown signs of water migration into the cable insulation, which can cause cable failure.

Why do this project now?

The 4S feeder exit cables are approximately 38 years old and have reached the end of their expected useful lives. Cables are showing signs of water migration into the insulation. Water migration can cause cable failure, which affects the ability to maintain a reliable supply to customers.

Why do this project this way?

Planned replacements of the feeder exit cables can be done without customer interruptions by transferring load to other feeders. The new cables will be installed in the existing duct system, taking advantage of the existing structure and minimizing additional costs.

CI Number : 52186 - 4S Feeder Exit Cable Replacement Phase 1 **Project Number** 52186

Parent CI Number : -

Asset Location : 1456 - 1456 Distribution Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0200 - DP - Land Rights	13,408
Additions	3500 - DP - Wood Poles	157,038
Additions	3900 - DP - O/H Cond.	6,030
Additions	4000 - DP - O/H Cond.Devices	6,809
Additions	4600 - DP - U/G Conductor	86,851
Additions	4700 - DP - U/G Conductor Devices	1,716
Additions	4800 - DP - U/G Line Transf.	3,860
Retirements	3500 - DP - Wood Poles	2,468
Retirements	3900 - DP - O/H Cond.	235
Retirements	4000 - DP - O/H Cond.Devices	15,093
	Total Cost:	293,509
	Original Cost:	22,328

Capital Project Detailed Estimate

Location: Distribution
CI# : 52186
Title: 4S Feeder Exit Cable Replacement Phase 1
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
Electrician	PD	84	$ 372	$ 31,353		
Engineering	PD	15	$ 386	$ 5,657		
Project Supervision	PD	7	$ 389	$ 2,850		
Procurement/Financial Support	Lot	1	$ 1,032	$ 1,032		
			Sub-Total	$ 40,891		
Materials						
Materials	Lot	1	$ 51,605	$ 51,605		
			Sub-Total	$ 51,605		
Contracts						
Flagging	Lot	1	$ 39,297	$ 39,297		
Backhoe	Lot	1	$ 9,000	$ 9,000		
Civil	Lot	1	$ 13,000	$ 13,000		
Railway Traffic Control	Lot	1	$ 20,000	$ 20,000		
			Sub-Total	$ 81,297		
Consulting						
Engineering Design Consultant	Lot	1	$ 20,000	$ 20,000		
			Sub-Total	$ 20,000		
Royalty, Easement, Appraisal						
Permitting	Lot	1	$ 8,000	$ 8,000		
			Sub-Total	$ 8,000		
Other Goods & Services						
Contingency	%	10%	$ 173,793	$ 17,379		
			Sub-Total	$ 17,379		
Vehicle Overhead						
Vehicle AO				$ 16,711		
			Sub-Total	$ 16,711		
Interest Capitalized						
AFUDC				$ 5,888		
			Sub-Total	$ 5,888		
Administrative Overhead						
Labor AO				$ 36,313		
Contract AO				$ 15,425		
			Sub-Total	$ 51,738		
			SUB-TOTAL (no AO, AFUDC)	$ 219,172		
			TOTAL (AO, AFUDC included)	$ 293,509		
Original Cost				$ 22,328		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 52208

Title: 3S Feeder Exit Cable Replacement Phase 2

Start Date:	2018/04
In-Service Date:	2018/12
Final Cost Date:	2019/06
Function:	Distribution
Amount:	$293,228

DESCRIPTION:

This project will replace the four remaining sets of deteriorated feeder exit cables at the 3S Gannon Road substation. The existing feeder exit cables are direct buried, and will be replaced with feeder exit cables in a duct system. The feeder exit cables at the 3S Gannon Road Substation are deteriorated and have reached end of life. Feeder exit cables prevent overhead congestion in the area of a substation by routing feeders underground from the breakers located in the substation to the adjacent roadside poles. Feeder exit cable failures result in lengthy customer outages, particularly where the cables are direct buried and not installed in a duct system.

Summary of Related CIs +/- 2 years:
2017 CI 49591 - 3S Feeder Exit Cable Replacement - $335,842

JUSTIFICATION:

Justification Criteria: Distribution System

Sub Criteria: Deteriorated Conductor

Why do this project?

The feeder exit cables at the 3S Gannon Road substation are deteriorated, and have reached end of their expected life. Cable failures at 3S will result in lengthy customer outages, affecting up to 2,000 customers. In addition, the existing underground cables at the 3S Gannon Road substation are direct buried installations, which cannot be easily accessed, replaced or repaired.

Why do this project now?

The 3S substation feeder exit cables are approximately 45 years old and have reached the end of their expected useful lives. Cables have previously failed at 3S in 2014 and 2015. Assessment of the 2015 failure indicated that replacement is required to maintain a reliable supply to customers.

Why do this project this way?

Planned replacements of the feeder exit cables can be done without customer interruptions by transferring load to other feeders. The new cables will be installed in a duct system, as per current NS Power standards, to allow for improved access, maintainability and reliability.

CI Number : 52208 - 3S Feeder Exit Cable Replacement Phase 2 **Project Number** 52208

Parent CI Number : -

Asset Location : 1456 - 1456 Distribution Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	3500 - DP - Wood Poles	37,992
Additions	3900 - DP - O/H Cond.	7,923
Additions	4000 - DP - O/H Cond.Devices	14,006
Additions	4600 - DP - U/G Conductor	216,443
Retirements	3500 - DP - Wood Poles	1,469
Retirements	3900 - DP - O/H Cond.	20
Retirements	4000 - DP - O/H Cond.Devices	2,404
Retirements	4600 - DP - U/G Conductor	12,970
	Total Cost:	293,228
	Original Cost:	46,694

Capital Project Detailed Estimate

Location: Distribution
CI# : 52208
Title: 3S Feeder Exit Cable Replacement Phase 2
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
Engineering	PD	24	$ 386.00	$ 9,082		
Electrician	PD	80	$ 372.22	$ 29,948		
Procurement/Financial Support	Lot	1	$ 1,430	$ 1,430		
			Sub-Total	$ 40,460		
Materials						
Materials	Lot	1	$ 71,494	$ 71,494		
				$ -		
			Sub-Total	$ 71,494		
Contracts						
Flagging	Lot	1	$ 11,059	$ 11,059		
Backhoe	Lot	1	$ 5,600	$ 5,600		
Civil work	Lot	1	$ 70,000	$ 70,000		
			Sub-Total	$ 86,659		
Other Goods & Services						
Contingency	%	10%	$ 198,614	$ 19,861		
			Sub-Total	$ 19,861		
Vehicle Overhead						
Vehicle AO				$ 16,534		
			Sub-Total	$ 16,534		
Interest Capitalized						
AFUDC				$ 5,846		
				$ -		
			Sub-Total	$ 5,846		
Administrative Overhead						
Labor AO				$ 35,930		
Contract AO				$ 16,443		
			Sub-Total	$ 52,372		
			SUB-TOTAL (no AO, AFUDC)	$ 218,475		
			TOTAL (AO, AFUDC included)	$ 293,228		
536800 Original Cost				$ 46,694		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 52201

Title: 55V-314GA Welsford Reconductor

Start Date	2018/06
In-Service Date:	2018/09
Final Cost Date:	2019/03
Function Class:	Distribution
Amount:	$275,161

DESCRIPTION:

This project includes reconductoring approximately 3.2 kilometers of existing three-phase line on primary distribution feeder 55V-314GA along Highway 221 between Highway 360 and Long Point Rd in Welsford. This section of line requires the replacement of three phase #4 AASC primary and ACSR neutral conductor with 2/0 AASC primary and neutral, and associated framing and insulators. Approximately 9 poles, 2 transformers and 12 cutouts will be replaced and approximately 4 stub poles with overhead guys will be added to upgrade pole anchoring.

Summary of Related CIs +/- 2 years:
No other projects in 2016, 2017, 2018, 2019 or 2020

JUSTIFICATION:

Justification Criteria: Distribution System

Sub Criteria: Deteriorated Conductor

Why do this project?

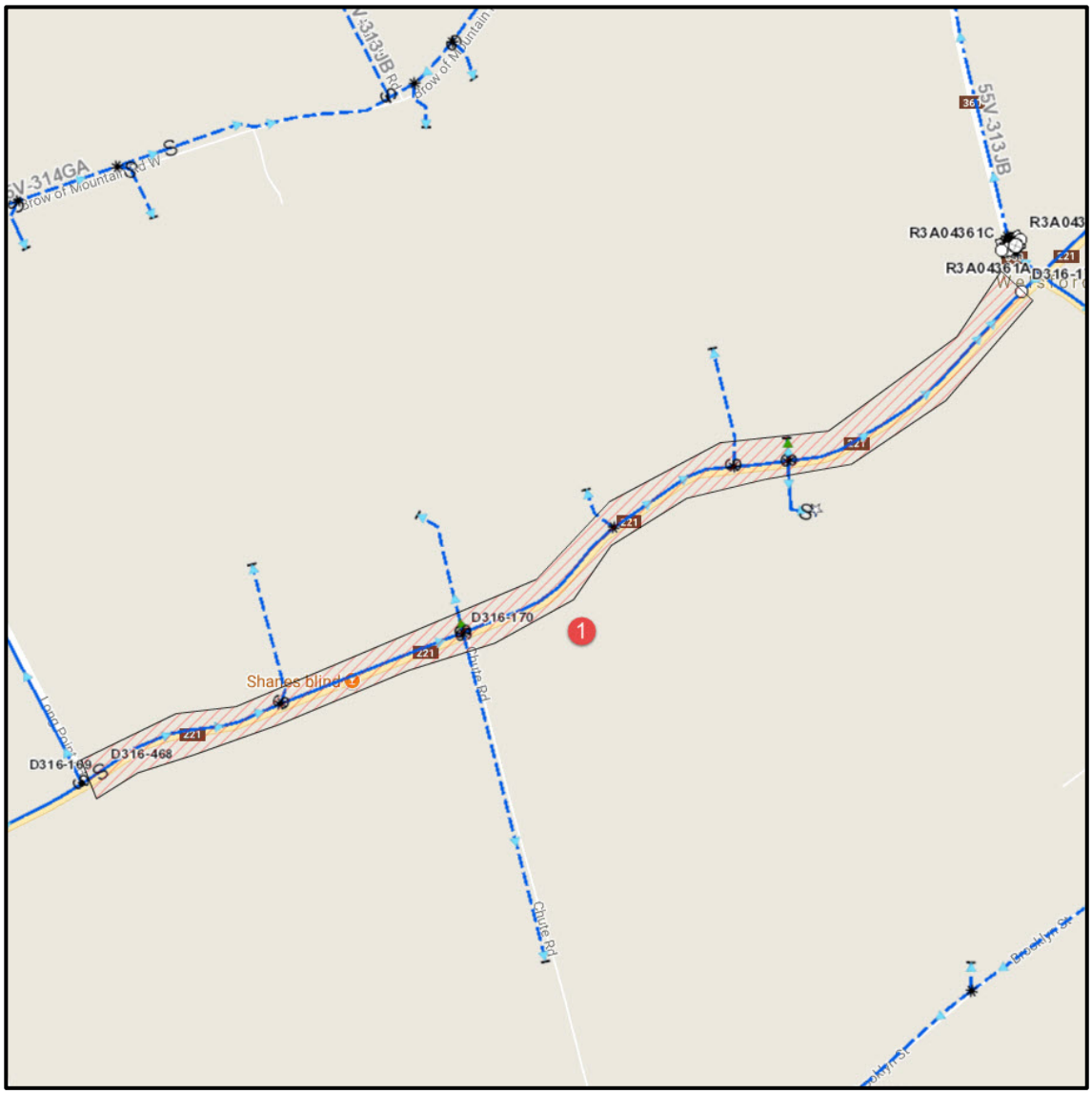
The existing conductor and targeted poles are deteriorated and at risk of failure due to their age and condition. In addition, the conductor can no longer be worked on under live conditions.

Why do this project now?

The existing poles and conductor are over 40 years old and have reached the end of their expected service life. Inspections of the targeted devices and assessment based on age, condition and risk of failure has determined that replacements are required. In addition, the existing conductor has approximately 150 splices on the targeted section of line. Splices are a weak point in the line. Splice counts this high are indicative of a history of conductor failures over time as each time the conductor breaks it is repaired with the splice.

Why do this project this way?

There is no alternative source of supply for the customers in the targeted area. Conductor and anchoring is the only alternative to mitigating the risk of failure. The line will be upgraded in accordance with current NS Power standards.



1. Reconductor approximately 3.2 kilometers of conductor along Highway 221 to 2/0 AASC.

CI Number : 52201 - 55V-314GA-Welsford Reconductor

Project Number 52201

Parent CI Number : -

Asset Location : 1456 - 1456 Distribution Plant General

Budget Version 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0200 - DP - Land Rights	23,929
Additions	3500 - DP - Wood Poles	87,999
Additions	3800 - DP - Insulators	4,353
Additions	3900 - DP - O/H Cond.	109,123
Additions	4000 - DP - O/H Cond.Devices	3,796
Additions	4100 - DP - O/H Line Transf.	9,140
Additions	5000 - DP - Street Lights	2,567
Retirements	3500 - DP - Wood Poles	9,844
Retirements	3900 - DP - O/H Cond.	20,583
Retirements	4000 - DP - O/H Cond.Devices	1,641
Retirements	4100 - DP - O/H Line Transf.	2,188
	Total Cost:	275,161
	Original Cost:	32,234

Capital Project Detailed Estimate

Location: Distribution
CI# : 52201
Title: 55V-314GA Welsford Reconductor
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
Procurement/Financial Support	PD	2	$ 386	$ 636		
			Sub-Total	$ 636		
Materials						
Materials	Lot	1	$ 31,792	$ 31,792		
			Sub-Total	$ 31,792		
Contracts						
Flagging	Lot	1	$ 24,679	$ 24,679		
Backhoe	Lot	1	$ 14,550	$ 14,550		
Tree Trimming	Lot	1	$ 11,200	$ 11,200		
EUS Contracts	Lot	1	$ 127,332	$ 127,332		
			Sub-Total	$ 177,760		
Royalty, Easement, Appraisal						
Easement	Lot	1	$ 7,500	$ 7,500		
			Sub-Total	$ 7,500		
Other Goods & Services						
Contingency	%	10%	$ 210,188	$ 21,019		
			Sub-Total	$ 21,019		
Vehicle Overhead						
Vehicle AO				$ 260		
			Sub-Total	$ 260		
Interest Capitalized						
AFUDC				$ 1,901		
				$ -		
			Sub-Total	$ 1,901		
Administrative Overhead						
Labor AO				$ 565		
COPS Contract AO				$ 33,728		
			Sub-Total	$ 34,293		
			SUB-TOTAL (no AO, AFUDC)	$ 238,707		
			TOTAL (AO, AFUDC included)	$ 275,161		
Original Cost				$ 32,234		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CI Number: 52308

Title: 2018/2019 RTU Replacements Program

Start Date:	2018/04
In-Service Date:	2019/01
Final Cost Date:	2020/06
Function:	General Plant
Forecast Amount:	$988,056

DESCRIPTION:

Remote Terminal Units (RTUs) are deployed in substations and generating stations to allow for communications of data and control signals to enable the operation of NS Power's SCADA system. This project provides for the replacement of four RTUs, over two years (2018 and 2019), associated telecommunications equipment and the connection of Intelligent Electronic Devices (IEDs), such as recloser controllers, transformer meters and relays. The RTU equipment removed will enable NS Power to redeploy the equipment as spare parts for other similar RTUs in service that are not yet being replaced. The work under this project will be completed over two years.

Summary of Related CIs +/- 2 years:
2017 CI 46572 2017 RTU Replacement Program $693,354
2019 CI TBD 2019 RTU Replacement Program $TBD
2020 CI TBD 2020 RTU Replacement Program $TBD

JUSTIFICATION:

Justification Criteria: Work Support Facilities

Sub Criteria: Telecontrol & Telecommunications

Why do this project?

Due to evolving industry standards, technology and product lifespans, approximately 83 of the RTUs that are currently in service have been deemed as obsolete by their manufacturers (please refer to Attachment 1). The commercial availability of spare parts is becoming difficult to manage effectively. Equipment removed from service under this project can be harvested for spare parts which will support other existing RTUs until such time that they are also replaced.

Why do this project now?

The inventory of RTU spare parts has become sparse. The RTUs being replaced by this project have been deemed obsolete, as discussed above. RTU installations require extensive time and effort (approximately 12 weeks) to complete and having an effective RTU management plan is critical for the orderly replacement of units that are experiencing reliability issues and for the gradual modernization of the fleet.

This project is deemed in-service when the first RTU is installed (January 2019), therefore the Final Cost Date (June 2020) is listed as six months after the last RTU is installed (December 2019).

Why do this project this way?

RTU replacement is the only alternative, as these RTUs are now considered to be obsolete. The technology, both hardware and software, is familiar to field and engineering personnel through regular training and exposure. Additionally, standardization of equipment will lead to a more sustainable spare parts inventory.

CI Number : 52308 - 2018/2019 RTU Replacements Program **Project Number** 52308

Parent CI Number : -

Asset Location : 1500 - 1500 General Plant General **Budget Version** 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	6400 - GP - Sup. Control and DA	924,298
Retirements	6400 - GP - Sup. Control and DA	63,758
	Total Cost:	988,056
	Original Cost:	520,935

Capital Project Detailed Estimate

Location: General Plant
CI# : 52308
Title: 2018/2019 RTU Replacements Program
Execution Year: 2018-2019

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
Engineering	PD	202	$ 386	$ 77,835		
Maintenance Trades	PD	249	$ 366	$ 91,003		
CADD Operators	PD	24	$ 294	$ 7,058		
			Sub-Total	$ 175,896		
OT Labor						
Maintenance Trades	PD	12	$ 731	$ 8,775		
			Sub-Total	$ 8,775		
Travel Expense						
Engineering / Telecom Technicians	lot	1	$ 15,300	$ 15,300		
				$ -		
			Sub-Total	$ 15,300		
Materials						
RTU	ea.	4	$ 54,725	$ 218,900		
RTU Accessories	lot	1	$ 14,110	$ 14,110		
Fibre	ea.	4	$ 2,000	$ 8,000		
Power Meter	ea.	5	$ 8,200	$ 41,000		
Radio	ea.	4	$ 1,500	$ 6,000		
Feedline	m	175	$ 14	$ 2,450		
Antenna	lot	5	$ 900	$ 4,500		
Radio Accessories	lot	3	$ 6,000	$ 18,000		
Antenna Pole	ea.	3	$ 3,000	$ 9,000		
			Sub-Total	$ 321,960		
Contracts						
Civil Construction	days	15	$ 4,000	$ 60,000		
Antenna Rigging	ea.	5	$ 5,000	$ 25,000		
			Sub-Total	$ 85,000		
Consulting						
RTU Integration Design	hr.	308	$ 110	$ 33,880		
Tower Upgrades	ea.	3	$ 5,000	$ 15,000		
Structural Analysis	ea.	3	$ 3,000	$ 9,000		
			Sub-Total	$ 57,880		
Meals & Entertainment						
Engineering / Telecom Technicians	Lot	1	$ 5,975	$ 5,975		
				$ -		
			Sub-Total	$ 5,975		
Other Goods & Services						
Contingency	%	10%	$ 606,931	$ 60,693		
			Sub-Total	$ 60,693		
Vehicle Overhead						
Vehicle AO				$ 73,675		
			Sub-Total	$ 73,675		
Interest Capitalized						
AFUDC				$ 6,678		
				$ -		
			Sub-Total	$ 6,678		
Administrative Overhead						
Labor AO				$ 160,097		
Contract AO				$ 16,128		
			Sub-Total	$ 176,225		
			SUB-TOTAL (no AO, AFUDC)	$ 731,479		
			TOTAL (AO, AFUDC included)	$ 988,056		
Original Cost				$ 520,935		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

GE Energy Services

Product Bulletin

Bulletin Number		**Rev**		**Date**	Jan 30, 2003
Product	D20M++ / D20ME			**Distribution**	General
Part Number				**Classification**	Information
Summary	D20M++ Discontinuance				
Originator	Daryl Cowie			**Title**	

GE SAS will be discontinuing all models of D20M++ Main Board by the end of calendar year 2003. These models will be replaced with our D20ME Main Board models 526-2004 (non-VME) and 526-2005 (VME). The D20ME Main Boards will become the only models of D20 Main Board available. The D20ME Main Board is a mature product, and is expected to be available for more than 5 years.

The following tables outline product comparison, compatibility issues, and time line of events.

D20M++ v.s. D20ME Comparison

	D20M++	D20ME
Processing Power	100% (Benchmark)	250% compared to D20M++
Serial Communications	Single Port Max: 38.4bps Aggregate Max: 38.4kbps	Single Port Max: 110kbps Aggregate Max: 500kbps
Memory Models	Multiple Models. Largest Mem Model: • 1MB EPROM • 2MB SRAM • 512kB NVRAM • 128kB BootROM	One Memory Model for improved inventory mgmt • 2MB FLASH • 1.5MB SRAM • 512kB NVRAM • 1MB BootROM
TCXO	Optional	Standard
Firmware Storage	EPROM	FLASH

D20ME Compatibility

	D20ME Compatibility
D20/D200 Chassis	Compatible with all chassis. When adding Ethernet to D20, the MX Chassis is required for proper cable routing. The Ethernet MIC interconnect cable can physically be routed out the back of an older chassis, but this invalidates emissions compliance statements.
D20/D200 Backplane	D20 minimum backplane revision requirements apply (included in upgrade kit) D200 Backplanes are all compatible with the D20ME
D20 Peripherals	Compatible with old and new style peripherals (same as D20M++)
D20M++ Compatibility	Limited compatibility with D20M++ in a D200 multi-node environment. Only systems with 3 nodes or less may mix D20M++ and D20ME boards.
Base System	CCU Base Single Node System: 1.88 & greater CCU Base Multi Node System: 2.03 & greater D20 Base: 3.51 & greater Note: D20 Base only sees 1Mb of code space
Configuration System	ConfigPro 4.00 or greater required (previous versions do not list D20ME)
Application Software	All D20 software applications are compatible with the D20ME

D20M++ Discontinuance Time Line

Stage	Description	Actions Required	Duration / Milestones
PRODUCT MATURITY	Product is mature and quality is very high.	• Orders and shipments permitted.	5 years (since 1994)
PRODUCT DECLINE	Product no longer meets industry expectations for new projects.	• Orders and shipments permitted. • Decision to discontinue the product must be made • Product alternative must be identified and recommended for new designs.	3 years Product Decline Stage ends with Discontinuance Notice: Aug 2002
PRODUCT PHASE OUT	Product alternative identified. Product alternative is field proven.	• Limitations on shipments can occur. • Product should no longer be considered for new designs. • Formal discontinuance notice must be given. • Formal upgrade plan and incentives must be established. • Product last buy date must be established.	17 months Phase Out Stage ends with Last Buy: Dec 2003
PRODUCT NOT AVAILABLE	Product is no longer available. Inventory is removed.	• New orders are limited to existing or residual inventory. • Repairs / replacements may be done with refurbished parts. • Product support from Customer Service continues. • Product support cut-off date must be established	24 months Not Available Stage ends when Product Support ends: Dec 2005
PRODUCT NOT SUPPORTED	Product is no longer supported.	• No new orders, no shipments, and no inventory exist. • Customer Service stops supporting the product. • All internal supporting hardware, software, and documentation are removed from active systems.	

The following supporting documents are available to guide you through the upgrade process:

- TSFM-010 D20M++ to D20ME Upgrade Checklist
  This checklist guides the customer through gathering all information required by GE SAS to identify potential issues with the standard upgrade. The process is designed to identify problems during the quotation stage.

- TSPD-003 Guide to Upgrading D20M++ to D20ME
  This comprehensive, step-by-step guide illustrates how to perform a D20M++ to D20ME upgrade.

TINGLEY, SARA

From: Van Wyk, Johann <Johann.vanWyk@landisgyr.com>
Sent: November 3, 2013 5:48 PM
To: PENNEY, ERIC
Cc: OAKLEY, BILL; VICTOR, CHUCK
Subject: RE: Product Life Cycle Inquiry

Dear sir, thank you for contacting us.

Unfortunately all the equipment mentioned below are:

End-of-Service (EOS) products are not being manufactured or supported any longer.

Freundliche Grüsse / Kind regards / Beste Wense / Asante Sana / Viele Grüße / التحيـــات اطيـب مع

Johann van Wyk
Smart\Credit Meter Support

Landis+Gyr
manage energy better

From: PENNEY, ERIC [mailto:Eric.Penney@nspower.ca]
Sent: 29 October 2013 21:51
To: ZA JNB Support
Cc: OAKLEY, BILL; VICTOR, CHUCK
Subject: Product Life Cycle Inquiry
Importance: High

Good day,

My name is Eric Penney and I work at Nova Scotia Power. We have several Landis & Gyr RTUs, installed between 1988 and 1995, in our substations and we need to know their Life Cycle status. The table below may help you answer my inquiry.

Current products would be those that are still being manufactured and are fully supported (technical & repair).
Retiring products are approaching or are currently in their last year of manufacturing but are still fully supported.
End-of-Build (EOB) products are not being manufactured but full support is available.
End-of-Service (EOS) products are not being manufactured or supported any longer.

Indicate the column that applies for each model.

	Current Products	Retiring Products	End-of-Build	End-of-Service
MPS-9000S				
Telegyr 0500				
Telegyr 5200				
Telegyr 5300				
Telegyr 5320				

Telegyr 5500				
Telegyr 5520				
Telegyr 8500				

Any additional information you have about these models would be appreciated as well.

--

Eric Penney | TeleControl Engineer | **Nova Scotia Power**

T: 902-428-7706 | C: 902-221-5855 | F: 902-428-7715

E: eric.penney@nspower.ca

www.nspower.ca

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CI Number: 52233

Title: 2018 Telecom Building Replacement - Onslow

Start Date: 2018/04
In-Service Date: 2018/11
Final Cost Date: 2019/05
Function: General Plant
Forecast Amount: $314,929

DESCRIPTION:

This project will replace the Onslow radio building with a new telecommunications building. Installation of electrical wiring, heating, ventilation and air conditioning (HVAC) system controls in the new building, as well as a generator and automatic transfer switch to provide emergency backup for this radio site are included in the scope of this project.

This is the fifth project of a multi-year program to replace and upgrade NS Power's radio site buildings and the associated backup generators. These buildings, installed in the late 1970s, are approximately 40 years old and contain asbestos wallboard. Replacements are prioritized based on degree of building deterioration, and the presence of asbestos.

Summary of Related CIs +/- 2 years:
2017 CI 49902 2017 Telecom Building Replacement – Wittenburg $294,000
2019 CI TBD 2019 Telecom Building Replacement $TBD
2020 CI TBD 2020 Telecom Building Replacement $TBD

JUSTIFICATION:

Justification Criteria: Work Support Facilities

Why do this project?

This project will replace the Onslow telecommunications building which was installed in 1978. The building has deteriorated to the point that replacement of the building is required. Additionally, asbestos wallboard is present and is hazardous if disturbed in any way, therefore full replacement is required to mitigate that risk.

The Onslow radio site is an important site for the existing and future mobile radio system. It provides access to several Very High Frequency (VHF) repeaters which provide radio coverage for Power Line Technicians, System Maintenance personnel and other field crews in the area. This site also provides a critical radio link to 408N Nuttby Mountain which is connected to NS Power telecommunications backbone infrastructure, and supports critical SCADA, teleprotection and other operational traffic.

This project is primarily justified on ensuring the buildings functionality, and secondarily justified on safety (asbestos) concerns.

Why do this project now?

The Onslow telecommunication building must be replaced, due to its deteriorated condition and the presence of asbestos, to provide proper shelter and backup power for the critical equipment at this site. The backup generator equipment within the building must also be replaced as it is over thirty years old and difficult to maintain due to a lack of availability of spare parts.

Why do this project this way?

Replacing the existing telecom building and backup generator at Onslow is the most practical and safe option to provide proper shelter and backup power for the critical equipment at this site. Further maintenance and/or modifications to the building risk the disturbance of the asbestos wallboard, which would be a significant safety concern.

CI Number : 52233 - 2018 Telecom Building Replacement - Onslow

Project Number 52233

Parent CI Number : -

Asset Location : 1500 - 1500 General Plant General

Budget Version 2018 Ace Plan

Capital Item Accounts

Exp. Type	Utility Account	Forecast Amount
Additions	0300 - GP - Bldg.,Struct.Grnd.	308,444
Retirements	0300 - GP - Bldg.,Struct.Grnd.	6,485
	Total Cost:	314,929
	Original Cost:	87,821

Capital Project Detailed Estimate

Location: General Plant
CI# / FP#: 52233
Title: 2018 Telecom Building Replacement - Onslow
Execution Year: 2018

Description	Unit	Quantity	Unit Estimate	Total Estimate	Cost Support Reference	Completed Similar Projects (FP#'s)
Regular Labor						
T&D Labor - Electrician/Technician	PD	20	$ 366	$ 7,313		
T&D Labor - Site Supervision	PD	10	$ 389	$ 3,890		
Procurement / Financial Support	Lot	1	$ 2,760	$ 2,760		
Engineering Design	PD	42	$ 386	$ 16,212		
			Sub-Total	$ 30,175		
OT Labor						
T&D Labor - Electrician/Technician	PD	4	$ 731	$ 2,925		
			Sub-Total	$ 2,925		
Travel Expense						
Engineering	Lot	1	$ 1,200	$ 1,200		
Site Supervisor	Lot	1	$ 1,500	$ 1,500		
				$ -		
			Sub-Total	$ 2,700		
Materials						
New Building materials	Lot	1	$ 110,000	$ 110,000		
Backup Generator	Lot	1	$ 28,000	$ 28,000		
			Sub-Total	$ 138,000		
Contracts						
Install New building and site upgrades	Lot	1	$ 40,000	$ 40,000		
Install new generator	Lot	1	$ 7,500	$ 7,500		
				$ -		
				$ -		
			Sub-Total	$ 47,500		
Consulting						
Electrical and Mechanical drawings	Lot	1	$ 15,000	$ 15,000		
			Sub-Total	$ 15,000		
Meals & Entertainment						
Meals	Lot	1	$ 1,000	$ 1,000		
			Sub-Total	$ 1,000		
Other Goods & Services						
Contingency	%	10%	$ 218,600	$ 21,860.00		
			Sub-Total	$ 21,860		
Interest Capitalized						
AFUDC				$ 5,732		
			Sub-Total	$ 5,732		
Vehicle Overhead						
Vehicle AO				$ 12,929		
			Sub-Total	$ 12,929		
Administrative Overhead						
Labor AO				$ 28,095		
COPS Contract AO				$ 9,013		
			Sub-Total	$ 37,108		
			SUB-TOTAL (no AO, AFUDC)	$ 259,160		
			TOTAL (AO, AFUDC included)	$ 314,929		
Original Cost				$ 87,821		

Note 1: The labor figures noted above are an average of salaries across a variety of jobs within similar classifications including fringe, and are used solely for budgeting purposes.
Note 2: Small differences in totals are attributable to rounding.

CONFIDENTIALITY MATRIX

LEGEND	
Confidential in Entirety (shaded)	TS = Technical Support
Partially Confidential (Italicized)	CS = Cost Support
(1) = Commercial/Cost Information	
(2) = Third Party Proprietary Information	*Includes Description, PowerPlant (PP), Detailed Cost Estimate (DCE), and Economic Analysis Model (EAM).
(3) = System Security	

Function/Tab#	Capital Work Order	Work Order Main Body*	Attachment 1	Attachment2	Attachment 3	Attachment 4
Generation						
	Hydro Projects					
G01	51236 - HYD - WRC Tailrace Rock Bolting Phase 1	*DCE(1)*	*CS:Vendor Cost Estimate(1)*	*CS: Vendor Pricing(1)*	TS: Inspection and Survey Report	
G02	48533 - HYD - Lequille Headpond Refurbishment	*DCE(1)*	*CS: Construction Cost Estimate(1)*	TS: Dam Safety Report (2)	TS: Dam Safety Report Addendum (2)	TS: Flood Routing Analysis
G03	49033 - HYD - WRC Tunnel T-2 Intake Gate and Hoist Replacement	*DCE(1)*	*CS:Vendor Cost Estimate(1)*	TS: Condition Assessment	TS: Intake Gate Assessment	
G04	51235 - HYD - WRC Main Access Road Refurbishment	*DCE(1)*	*CS: Vendor Cost Estimate(1)*	*TS: Vendor Technical Support (1)*		
G05	51234 - HYD - WRC HVAC Upgrade		TS: Temperature and Relative Humidity Readings Report			
G06	49943 - HYD - Ruth Falls Facility Refurbishment	*DCE(1)*	*CS: Vendor Cost Estimate(1)*			
G07	49942 - HYD - Tidewater Facility Refurbishment	*DCE(1)*	*CS: Vendor Cost Estimate(1)*	TS: Condition Surveys		
G08	49946 - HYD - Fourth Lake Overhaul	*DCE(1), EAM(1)*	*CS: Vendor Proposal(1)*			
G09	49945 - HYD - Malay Falls Switchgear Replacement					
G10	52262 - HYD - Hells Gate #1 Overhaul	*EAM(1)*				
G11	51972 - HYD - Nictaux Canal Embankment Upgrade	*DCE(1)*	TS: Canal Study (2)			
G12	51866 - HYD - Fourth Lake Penstock Refurbishment	*EAM(1)*				
G13	47655 - HYD - Paradise Controls Upgrade					
G14	49944 - HYD - Dickie Brook Penstock Refurbishment	*EAM(1)*	TS: Assessment Summary			
G15	48712 - HYD - Dam Instrumentation Upgrade	*DCE(1)*	*CS: Internal Cost Estimate(1)*	*CS: Vendor Cost Estimate(1)*		
G16	52018 - HYD - Renewable Energy Generation Meter Upgrade					
	Steam Projects					
	Boiler					
G17	51802 - TRE5 - Boiler Refurbishment 2018	*EAM(1)*				
G18	51805 - LIN4 - Boiler Refurbishment 2018	*EAM(1)*				
G19	47684 - LIN3 - Boiler Refurbishment 2018	*EAM(1)*				
G20	51825 - POT - Boiler Refurbishment 2018	*EAM(1)*				
G21	52252 - LIN1 - SH5 Tube Replacement	*EAM(1)*				
G22	52253 - LIN3 - Economizer Header Refurbishment	*EAM(1)*				
G23	51821 - TRE5 - Air Heater Drive Assembly and Seal Refurbishment	*DCE(1), EAM(1)*	*CS: Vendor Cost Estimate(1)*			
G24	51824 - LIN3 - ID Fan Damper and VIV Refurbishment	*EAM(1)*				
G25	51818 - PHB - Boiler Refurbishment 2018					
G26	51807 - TUC2 - Boiler Lower Vestibule Refurbishment	*DCE(1)*	*CS: Vendor Cost Estimate(1)*			
G27	51849 - LIN3 - RH Tube Replacement					
G28	51850 - LIN4 - RH Tube Replacement					
G29	49547 - TRE5 - 5-1 BFP Refurbishment	*EAM(1)*				
G30	51857 - TRE5 - Burner Refurbishments 2018					
	Turbine					
G31	49534 - TRE6 - Turbine Controls Upgrade	*DCE(1)*	*CS: Vendor Quote(1)*	TS: Offer Specification		
G32	51820 - TRE5 - Turbine Reheat Valve Refurbishment					
G33	51862 - TRE6 - Lube Oil Cooler Refurbishment					
G34	43429 - TRE5 - Turbine Lube Oil Cooler Refurbishment	*DCE(1)*	*CS:Vendor Quote(1)*			
G35	51853 - LIN3 - Turbine Valve Refurbishment 2018					
	Generator					
G36	51803 - TUC2 - Generator Flux Probe Installation	*DCE(1)*	*CS:Vendor Quote(1)*	*CS:Generator Inspection(1)*		
	Environmental					
G37	50577 - TRE6 - CEMS Replacement	*DCE(1)*	*CS:Vendor Quote(1)*			
G38	49676 - TUC2 - CEMS Replacement	*DCE(1)*	*CS:Vendor Quote(1)*			
	Balance of Plant					
G39	51806 - LIN - Mill Refurbishment 2018	*EAM(1)*				
G40	52093 - ICP - Rail System Refurbishment Program 2018		TS: Inspection Report			
G41	51811 - LIN - Reclaim Feeder Refurbishment Phase 2					
G42	51815 - LIN - CW Pump Refurbishment 2018	*EAM(1)*				
G43	51861 - TRE6 - CW Screen Replacement 2018	*DCE(1),EAM(1)*	*CS:Vendor Quote(1)*			
G44	51816 - TRE - Asbestos Abatement 2018					
G45	51835 - TUC2 - Hydrogen Panel Replacement	*DCE(1)*	*CS:Vendor Quote(1)*			
G46	51836 - TRE5 - Mill Refurbishments 2018	*EAM(1)*				
G47	47871 - LIN - Stack Re-Coating	*DCE(1)*	*CS:Vendor Proposal(1)*	TS: Inspection Report		
G48	51839 - LIN - Coal Plant Structural Refurbishment Phase 4					
G49	51851 - LIN - CW Screen Refurbishment 2018	*EAM(1)*				
G50	C0001419 - TRE (Bunker C) - HFO Refurbishment Project Phase 1					
G51	51804 - LIN - ACW Duplex Strainer Replacement	*EAM(1)*				
G52	51852 - POT - Coal Mill Refurbishment 2018	*EAM(1)*				
G53	52156 - LIN 3&4 - Condenser Vacuum Pump Replacement	*DCE(1), EAM(1)*	TS: Inspection Report			
G54	51860 - TRE5 - Pulverizer Fuel Line Refurbishment					
Gas Turbine Generation						
G55	52143 - LM6000 - 191-332 Hot Section Engine Refurbishment	*Description(1), DCE(1)*	CS: Commercial Offering(1)	*CS:Vendor Proposal*		
Transmission						
T01	51969 - 2018 Transmission Right-of-Way Widening 69kV					
T02	51975 - 5P Mobile Substation Replacement					
T03	52258 - 2018/2019 Isolated Transmission Structure Replacements	*DCE(1)*				
T04	51403 - 2018/2019 Substation Polychlorinated Biphenyl (PCB) Equipment Remova					
T05	51402 - 2018/2019 Sacrificial Anode Installation Program					
T06	C001900 - Mount Hope 69-25kV Substation		TS:Planning Study			
T07	52314 - 1C-GT1 and 1C-UT1 Transformer Replacement					
T08	51398 - 2018/2019 Steel Tower Refurbishment	*DCE(1)*				
T09	52320 - L6549 Replacements and Upgrades	*DCE(1)*				
T10	51406 - 2018/2019 Transmission Switch & Breaker Replacement					

CONFIDENTIALITY MATRIX

LEGEND	
Confidential in Entirety (shaded)	TS = Technical Support
Partially Confidential (Italicized)	CS = Cost Support
(1) = Commercial/Cost Information	
(2) = Third Party Proprietary Information	*Includes Description, PowerPlant (PP), Detailed Cost Estimate (DCE), and Economic Analysis Model (EAM).
(3) = System Security	

Function/Tab#	Capital Work Order	Work Order Main Body*	Attachment 1	Attachment2	Attachment 3	Attachment 4
T11	51405 - 2018/2019 Wood Pole Retreatment Program					
T12	48131 - 48H-T1 Transformer Replacement					
T13	52328 - 56N-T1 Transformer Upgrade		*TS: Planning Study(3)*			
T14	49779 - L6537 Replacements and Upgrades Phase 2	*DCE(1)*				
T15	49777 - L7002 Replacements and Upgrades	*DCE(1)*				
T16	52241 - 16V-T2 Weymouth Hydro Transformer Replacement					
T17	52102 - L5014 Replacements and Upgrades	*DCE(1)*				
T18	49788 - L5564 Replacements and Upgrades	*DCE(1)*				
T19	52059 - L5039 2018 Replacements and Upgrades	*DCE(1)*				
T20	49783 - L5027A Replacements and Upgrades	*DCE(1)*				
T21	52119 - L5054 2018 Replacements and Upgrades	*DCE(1)*				
T22	52238 - 2018/2019 Capacitor Bank Breaker Replacements					
T23	43268 - 9W-B53 Tusket Support Structure Replacement					
T24	51797 - 2018 Oil Containment Program					
T25	52305 - 2018 Substation Insulator Replacement Program	*DCE(1)*				
T26	51863 - 2018 Tap Changer Replacements/Refurbishments					
Distribution						
D01	C0001950 - New Distribution Rights-of-Way Phase 3					
D02	52271 - 2018 Padmount Replacement					
D03	51493 - 2018 PCB Pole Top Transformer Replacement					
D04	52184 - 37N-412-Glooscap Trail Rebuild Phase 2	*DCE(1)*				
D05	52224 - 532N Elm Street Conversion Phase 2 & 3	*DCE(1)*	*TS: Planning Study (3)*			
D06	C0001802 - 54C-211 Queen Street Conversion	*DCE(1)*				
D07	52185 - 50N-410 Rebuild Phase 2					
D08	43218 - 88W-323A Tusket Islands Phase 3	*DCE(1)*				
D09	51400 - 2018 Substation Recloser Replacement					
D10	52194 - 6S-223 Harold Street Conversion		*TS: Planning Study (3)*			
D11	52200 - 65V-301 Brickton Reconductor					
D12	52205 - 30N-412 Hwy 242 Fundy Shore Rebuild					
D13	51744 - 30N-411 Maccan River Crossing Rebuild	*DCE(1)*				
D14	52204 - 87W-312G Big Tancook Island Replacements	*DCE(1)*				
D15	52267 - 16W-302H Brenton Road Rebuild	*DCE(1)*				
D16	52207 - 678H-211 McNab's Island Replacements					
D17	51500 - 2018 Pin Insulator Replacements					
D18	52192 - 54H-303 Underground Device Replacements Phase 2					
D19	52206 - 20V-311 Bishop Ville Road Reconductor					
D20	52186- 4S Feeder Exit Cable Replacement Phase 1					
D21	52208 - 3S Feeder Exit Cable Replacement Phase 2					
D22	52201 - 55V-314GA Welsford Reconductor					
General Plant						
GP01	52308 - 2018/2019 RTU Replacements Program		TS: Product Bulletin			
GP02	52233 - 2018 Telecom Building Replacement - Onslow					

1 - Commercial Information
To protect value for customers and mitigate the risk of prospective proponents having access to the information itemized in the confidentiality matrix, and maintain good business relations with vendors, this information is confidential.

The more a supplier is aware of NS Power's specific requirements and a competing vendor's costs, the better the supplier's ability to obtain the highest price, reduce competition and ultimately increase the cost for NS Power and its customers. The cost of such transparency is not always immediately evident. Information from regulatory proceedings can provide competitive advantages over other suppliers, and that could be advantageous in bidding or negotiation. Higher prices, or avoidable contractual constraints, will result in unnecessary higher costs to customers.

NS Power seeks to keep the terms and conditions of suppliers pricing and arrangements confidential from their other customers or potential competitors. This prevents competitors from using the information to gain a competitive advantage. This is equally true for NS Power, which desires to protect its ability to acquire services and equipment on the most competitive terms. Those "best" terms may not be available if there is a risk that they will be disclosed to the customers or competitors of the supplier.

Since NS Power customer rates are cost-based, the maintenance of confidentiality for this item is to the direct benefit of customers.

2 - Third Party Proprietary Information
This is information belonging to third parties for which those third parties have asserted confidentiality over proprietary cost and technical information.

3 - System Security
One-Line diagrams frequently included in system planning studies are confidential due to system security concerns. Protection of the power system preserves reliability and reduces the risks associated with external threats.

2018 ACE Appendix B has been filed electronically only.

2017 3rd Quarter Overview - as of September 30, 2017

	Generation	Distribution	Transmission	General Property	Total NS Power
2017 Submitted ACE Total	**$ 105,967,434**	**$ 83,927,878**	**$ 91,181,192**	**$ 116,923,450**	**$ 397,999,955**
Total YTD Spend	82,493,026	55,822,170	48,864,284	69,956,645	257,136,125
Variance YTD/ACE Spend	(23,474,408)	(28,105,708)	(42,316,908)	(46,966,805)	(140,863,830)
Percentage of ACE Spent as of September 30, 2017	78%	67%	54%	60%	65%
Add:					
ATOs	12,734,377	-	-	-	12,734,377
U&Us/P&As	12,370,389	3,310,111	1,282,424	-	16,962,925
Changes to ACE Items for Subsequent Approval	4,401,831	1,711,344	371,132	(329,681)	6,154,626
Total Increase	**29,506,597**	**5,021,455**	**1,653,557**	**(329,681)**	**35,851,928**
Less:					
Projects cancelled	(1,839,015)	(118,563)	(300,000)	(1,314,868)	(3,572,447)
Projects deferred	(7,024,152)	-	(321,656)	(19,031,361)	(26,377,169)
Total Decrease	**(8,863,167)**	**(118,563)**	**(621,656)**	**(20,346,229)**	**(29,949,616)**
2017 Potential Capital Spend	**$ 126,610,864**	**$ 88,830,770**	**$ 92,213,093**	**$ 96,247,540**	**$ 403,902,266**

* Amounts do not reflect the reforecast of capital projects since ACE 2017, or reforecasting of subsequent items filed.

2017 3rd Quarter Overview - Updated for Ace 2018

Status		CI Number	Title	ACE Plan Reference (or U&U and P&A)	Submission/Date	ACE Amount	Submission or Approved Amount	Actual Spend	ATO or FIN Submission Date	FIN or ATO/FIN Amount	Variance
Approved	Generation	20758	HYD - Nictaux Pipeline Replacement & Intake Refurbishment	2014 ACE Plan (Deferred/Cancelled)	2013 ACE Plan/OTQ - March 4, 2014	$ 4,379,301	$ 4,472,431	$ 3,522,500			
Approved	Generation	30163	POT - Control room and permit room		Q3 2016 - November 18, 2016	$ 201,956	$ 387,997	$ 113,274			
Awaiting Approval	Generation	33142	CT- Burnside #4 Unit Restoration	2015 ACE Plan (for Subsequent Approval)	Q3 2015 - October 31, 2015	$ 3,469,160	$ 8,320,984	$ 6,149,606	OTQ - September 15, 2017	$ 9,552,963	$ 1,231,979
Approved w/ Directives	Distribution	40320	LED Street Light Conversion	2015 ACE Plan (for Subsequent Approval)	OTQ - July 3, 2015	$ 40,609,354	$ 36,041,594	$ 23,174,807			
Approved - FIN'd Internally	Generation	40363	LIN3 High Voltage Bushing Refurbishment	2015 ACE Plan	2015 ACE Plan	$ 628,531	$ 628,531	$ 821,038			
Approved	Generation	40785	Sable Wind Project	2014 ACE Plan (2013 Capital Items Pending Submission)	May 1, 2014	$ 13,198,950	$ 12,936,847	$ 12,366,192			
Approved	Generation	41130	HYD - Avon #2 Generator Stator Rewind	2015 ACE Plan (for Subsequent Approval)	Q4 2014 - January 30, 2015	$ 694,096	$ 633,484	$ 652,128			
Approved	Generation	41139	HYD - Annapolis Sluiceway Superstructure Refurbishment	2015 ACE Plan	2015 ACE Plan	$ 3,410,322	$ 3,410,322	$ 3,066,386			
Approved - FIN'd Internally	Generation	41227	LIN3 Condenser Large Bore Pipe and Valve Refurbishment	2015 ACE Plan	2015 ACE Plan	$ 1,299,329	$ 1,299,329	$ 1,521,588			
Approved	Distribution	41350	16W-301 Hebron Rebuild Phase 2	2013 ACE Plan	2017 ACE Plan	$ 904,732	$ 904,732	$ 35,404			
Approved	General Plant	41425	IT - Cognos Upgrade	2016 ACE Plan (for Subsequent Approval)	OTQ - December 17, 2015	$ 1,431,257	$ 1,527,747	$ 1,589,573			
Withdrawn	Transmission	41438	8SS Cable Termination Replacement Wreck Cove	2015 ACE Plan (for Subsequent Approval)	Q2 2015 - July 31, 2015	$ 616,959		$ 427,630			
Approved - FIN'd Internally	Generation	41505	TRE5 - 5F Conveyor Structural Refurbishment	2016 ACE Plan	2016 ACE Plan	$ 484,801	$ 484,801	$ 443,482			
Approved	Generation	41511	TRE6 - Condenser Waterbox and Cooling Water Piping Refurbishment	2013 ACE Plan	2017 ACE Plan	$ 700,809	$ 700,809	$ 95,881			
Deferred	Transmission	41519	Harbour East 138 kV Transmission Line	2016 ACE Plan (for Subsequent Approval)		$ 11,672,021		$ 1,133,554			
Approved - FIN'd Internally	Generation	41645	TRE6 Bottom Ash Seal Replacement	2015 ACE Plan	2015 ACE Plan	$ 307,499	$ 307,499	$ 406,181			
Approved	General Plant	41705	Milton Hydro Office Renovation and Upgrade	2014 ACE Plan (2013 CIs Pending)	Q1 2014 - April 30, 2014	$ 716,836	$ 733,611	$ 739,021			
Approved - FIN'd Internally	Generation	42806	LIN3 L-0 Turbine Blade Replacements	2015 ACE Plan	2015 ACE Plan	$ 4,157,741	$ 4,157,741	$ 4,280,589			
Approved	Generation	42939	TUC2 - South Circulating Water Pump Refurbishment	2014 ACE Plan	2014 ACE Plan	$ 431,536	$ 431,536	$ 307,749			
Approved	Generation	42943	TUC2 - T-G Areas Fire Protection	2014 ACE Plan	2014 ACE Plan	$ 292,621	$ 292,621	$ 370,512			
Approved	Generation	43066	HYD - Little Indian Dam / Mill Lake Upgrade	2015 ACE Plan	2015 ACE Plan	$ 1,409,587	$ 1,409,587	$ 1,355,011			
Approved - FIN'd Internally	Generation	43067	HYD - Cheticamp Dam D-1 Refurbishment	2014 ACE Plan (for Subsequent Approval)	OTQ - March 4, 2014	$ 4,313,991	$ 5,778,847	$ 5,899,122			
Approved	Generation	43136	HYD - Weymouth Headcover Replacement	2013 ACE Plan	2013 ACE Plan	$ 438,158	$ 751,989	$ 982,575			
Deferred	Generation	43155	CT - BGT2 Air Intake Structure Refurbishment	2014 ACE Plan (for Subsequent Approval)		$ 306,586		$ -			
Approved - FIN'd Internally	Generation	43170	LIN4 AVR Replacement	2013 ACE Plan	2016 ACE Plan	$ 842,207	$ 842,207	$ 774,938			
Approved	Distribution	43177	103W-311 Gold River Reconductor Phase 3	2014 ACE Plan	2014 ACE Plan	$ 377,721	$ 377,721	$ 338,490			
Approved	Transmission	43200	2017 Wood Pole Retreatment Program	2013 ACE Plan	2017 ACE Plan	$ 841,821	$ 841,821	$ 6,117			
Approved	Distribution	43203	58C-405 / 11C Belle Cote Phase 1	2015 ACE Plan	2015 ACE Plan	$ 339,419	$ 339,419	$ 307,313			
Approved	Distribution	43217	24C-442G Hwy 16 Rebuild Phase 1	2014 ACE Plan	2014 ACE Plan	$ 800,769	$ 800,769	$ 830,186			
Approved	General Plant	43227	2014 RTU Replacements	2014 ACE Plan	2014 ACE Plan	$ 687,839	$ 687,839	$ 853,593			
Approved	Distribution	43234	104S-313 Baddeck Rebuild	2015 ACE Plan	2015 ACE Plan	$ 778,470	$ 778,470	$ 957,095			
Approved	Transmission	43261	6V-GT1 Hollow Bridge Hydro Transformer Replacement	2015 ACE Plan	2015 ACE Plan	$ 550,938	$ 550,938	$ 533,273			
Approved	Transmission	43267	13V Gulch Hydro Replace 13V-GT1 and 13V-VR1	2015 ACE Plan	2015 ACE Plan	$ 1,061,902	$ 1,061,902	$ 456,564			
Not Approved	Transmission	43324	L6513 Rebuild/upgrade line terminals	2015 ACE Plan (for Subsequent Approval)	OTQ - January 13, 2015	$ 23,429,902		$ 6,762,060			
Approved - FIN'd Internally	Generation	43424	TRE5 Analytical Panel	2014 ACE Plan	2014 ACE Plan	$ 393,825	$ 393,825	$ 487,979			
Approved	Transmission	43490	2015 Steel Tower Life Extension	2015 ACE Plan	2015 ACE Plan	$ 1,441,709	$ 1,441,709	$ 830,745			
Approved	Generation	43607	HYD - Malay Falls #5 Unit Overhaul	2015 ACE Plan	2015 ACE Plan	$ 1,077,255	$ 1,077,255	$ 1,102,889			
Pending Submission	Transmission	43678	Separate L8004/L7005 on Canso Crossing Double Circuit Tower(DCT)	2017 ACE Plan (for Subsequent Approval)		$ 16,183,691		$ 15,202,998			
Approved	Transmission	43681	South Canoe Wind Project Network Upgrades	2014 ACE Plan (2013 CIs Pending)	OTQ - Dec 23, 2013	$ 3,761,382	$ 4,650,955	$ 4,262,374			
Approved	Transmission	43683	South Canoe Wind Project Transmission Line	2014 ACE Plan (2013 CIs Pending)	OTQ - Dec 23, 2013	$ 5,193,391	$ 5,831,002	$ 5,161,039			
Approved	Transmission	43684	Interconnection Substation South Canoe Wind Project	2014 ACE Plan (2013 CIs Pending)	OTQ - Dec 23, 2013	$ 6,688,062	$ 7,760,891	$ 7,975,834			
Approved	Generation	44191	POT Coal Nozzle and Bucket Replacement	2015 ACE Plan	2015 ACE Plan	$ 570,309	$ 570,309	$ 761,780			
Approved	Generation	44248	HYD - MacMillan Dam D-7 Refurbishment	2014 ACE Plan (for Subsequent Approval)	OTQ - March 4, 2014	$ 5,279,936	$ 3,273,174	$ 3,389,214			
Approved	Generation	44667	HYD Upper Lake Falls Unit #1 Overhaul	2015 ACE Plan	2015 ACE Plan	$ 477,533	$ 477,533	$ 641,840			
Approved	General Plant	44671	IT-Oracle Financials Upgrade	2016 ACE Plan (for Subsequent Approval)	OTQ - November 10, 2016	$ 9,891,170	$ 89,664,000	$ 72,188,061			
Approved	Generation	44717	TUC2 - Condenser Vacuum Pump Replacement	2014 ACE Plan	2014 ACE Plan	$ 428,783	$ 428,783	$ 578,073			
Approved	Generation	44729	TUC - Station & Unit Transformer Connection Cable Replacement	2014 ACE Plan	2014 ACE Plan	$ 313,042	$ 313,042	$ 556,257			
Approved - FIN'd Internally	Generation	44731	TRE5 Coal System Upgrades	2014 ACE Plan	2014 ACE Plan	$ 413,416	$ 413,416	$ 588,578			
Awaiting Approval	Distribution	44749	Tiverton Tower Refurbishment	2017 ACE Plan (for Subsequent Approval)	Q3 2017 - October 30, 2017	$ 1,058,200	$ 1,465,132	$ 488,166			
Deferred	Generation	44752	BGT1 - Generator Rotor Retaining Ring Replacement	2015 ACE Plan (for Subsequent Approval)		$ 357,869		$ -			
Approved	Generation	44775	TUC#4 LM6000 Generator Stator Refur	2016 ACE Plan (for Subsequent Approval)	OTQ - August 31, 2016	$ 1,722,180	$ 1,177,954	$ 1,196,641			
Deferred	Generation	44788	BGT1 Vibration Monitoring & Protection System Upgrade	2016 ACE Plan (for Subsequent Approval)		$ 252,674		$ -			
Approved	Distribution	44826	2014 Build-to-Roadside	2014 ACE Plan	2014 ACE Plan	$ 791,268	$ 791,268	$ 667,359			
Approved - FIN'd Internally	Distribution	44833	99V-312 - Highbury New Feeder	2014 ACE Plan	2014 ACE Plan	$ 256,828	$ 256,828	$ 397,976			
Approved	Distribution	44836	Halifax 4kV Conversion Part 2	2015 ACE Plan (for Subsequent Approval)	OTQ - December 17, 2015	$ 842,670	$ 678,393	$ 771,984			
Approved	General Plant	44966	2014 Microwave System Capacity Upgrade	2014 ACE Plan	2014 ACE Plan	$ 397,729	$ 397,729	$ 401,907			
Approved	General Plant	44967	2014 Multiplexer Network Upgrades	2014 ACE Plan	2014 ACE Plan	$ 435,618	$ 435,618	$ 452,193			
Approved	Generation	44968	HYD - Wreck Cove Unit 2 Excitation System	2014 ACE Plan	2014 ACE Plan	$ 601,088	$ 601,088	$ 506,901			
Approved	Transmission	44976	10H 25kV Breaker Replacement	2015 ACE Plan	2015 ACE Plan	$ 953,521	$ 953,521	$ 1,156,921			
Approved	Transmission	44977	3W Breaker, Switch & Cable Replacements	2014 ACE Plan	2014 ACE Plan	$ 401,463	$ 401,463	$ 645,740			
Approved	Generation	44978	HYD-Wreck Cove Automation	2015 ACE Plan (for Subsequent Approval)	Q2 2015 - July 31, 2015	$ 2,379,999	$ 3,802,446	$ 2,712,916			
Approved	Transmission	44979	L5527 Structure Replacements	2015 ACE Plan	2015 ACE Plan	$ 721,068	$ 721,068	$ 655,227			
Approved	Transmission	44981	2C Port Hastings Add 138-25kV Transformer	2016 ACE Plan	2016 ACE Plan	$ 2,053,799	$ 2,053,799	$ 1,662,504			
Approved - FIN'd Internally	Transmission	44983	Reactor Bank Breaker Replacements	2014 ACE Plan	2014 ACE Plan	$ 385,032	$ 385,032	$ 415,814			
Approved	Transmission	44984	9C Debert Transmission Line Installation	2014 ACE Plan (for Subsequent Approval)	Q3 2014 - October 31, 2014	$ 846,755	$ 834,595	$ 831,032			
Approved	Transmission	44985	Replace 230kV Kearney Disconnect Switch Assemblies	2014 ACE Plan	2014 ACE Plan	$ 319,246	$ 319,246	$ 242,773			
Approved	Transmission	44987	L7003 Lidar Upgrades	2015 ACE Plan (for Subsequent Approval)	OTQ - August 31, 2015	$ 6,885,817	$ 11,032,275	$ 9,057,084			
Approved	Distribution	45003	2015 Hydraulic Recloser Replacements	2015 ACE Plan	2015 ACE Plan	$ 260,524	$ 260,524	$ 236,173			
Approved	Distribution	45031	3N Oxford Conversion Phase 1	2015 ACE Plan	2015 ACE Plan	$ 716,167	$ 716,167	$ 791,281			
Approved	Transmission	45033	L7001 Replacements	2014 ACE Plan	2014 ACE Plan	$ 813,226	$ 813,226	$ 699,379			
Deferred	General Plant	45036	ArcMap Design Software	2014 ACE Plan (for Subsequent Approval)		$ 344,459		$ 28,689			
Approved - FIN'd Internally	Distribution	45046	2014 PCB Phase-out for Pole Top Transformers	2014 ACE Plan	2014 ACE Plan	$ 779,620	$ 779,620	$ 644,155			
Deferred	Transmission	45053	69Kv Structure Replacements West	2017 ACE Plan (for Subsequent Approval)		$ 4,818,017		$ 187,073			
Not Approved	Transmission	45066	Upgrade L6511 and L7019 Thermal Rating	2015 ACE Plan (for Subsequent Approval)	OTQ - April 20, 2015	$ 3,693,033		$ 2,648,181			
Board does not object	Transmission	45067	67N Onslow 345 KV Node Swap	2014 ACE Plan (for Subsequent Approval)	OTQ - November 14, 2014	$ 3,006,487		$ 2,932,531			
Approved	Generation	45116	CT - BGT1 GG4C-1D Engine Refurbishment	2015 ACE Plan (for Subsequent Approval)		$ 1,168,167	$ 1,168,167	$ -			
Deferred	Generation	45117	BGT1 - PLC and Field Device Control Upgrade	2015 ACE Plan (for Subsequent Approval)		$ 253,768		$ -			
Approved - FIN'd Internally	Generation	45126	TRE5 Continuous Emissions Monitor for Mercury Measurement	2014 ACE Plan	2014 ACE Plan	$ 515,698	$ 515,698	$ 705,800			
Approved	Generation	45171	HYD-Avon 1 Pipeline Replacement	2015 ACE Plan (for Subsequent Approval)	OTQ - March 31, 2015	$ 547,780	$ 1,012,419	$ 1,129,354			
Approved	Generation	45189	HYD - Upper Lake Falls #2 Overhaul	2014 ACE Plan	2014 ACE Plan	$ 441,716	$ 441,716	$ (2,163)			
Approved	Transmission	45306	George Street Substation Addition	2015 ACE Plan (for Subsequent Approval)	Q2 2015 - July 31, 2015	$ 4,300,627	$ 3,442,582	$ 3,289,444			
Approved	Generation	45330	HYD - WRC C3 Culvert Replacement	2014 ACE Plan (less than $250K)	OTQ - March 18, 2016	$ 116,396	$ 660,123	$ 677,048			
Approved	Generation	45370	HYD - WRC Unit 1 Excitation System	2015 ACE Plan	2015 ACE Plan	$ 578,113	$ 578,113	$ 627,787			
Approved	Generation	45592	TUC3 – U & U Turbine-IP Row 2 Blading Phase 1	U&U - 2014	OTQ - March 4, 2014		$ 509,816	$ 372,616			
Approved - FIN'd Internally	Generation	45611	LIN U&U Heavy Oil Recirculation Line Refurbishment	U&U - 2014	Q2 2014 - July 31, 2014		$ 1,304,395	$ 1,404,444			
Approved	Generation	45733	CT Burnside Unit #3 Generator Refurb	U&U - 2014	OTQ - December 2, 2014		$ 2,567,808	$ 2,595,189			
Approved	Transmission	45795	L6503 Upgrade	2015 ACE Plan (for Subsequent Approval)	OTQ - August 31, 2015	$ 780,641	$ 870,870	$ 803,352			
Approved	Generation	45816	TUC3 U&U Turbine IP Row 21 Blading Phase 2	U&U - 2014	Q1 2014 - April 30, 2014		$ 1,150,115	$ 856,230			
Approved - FIN'd Internally	Generation	45851	POT - Stack Repairs	2015 ACE Plan	2015 ACE Plan	$ 381,316	$ 381,316	$ 438,401			
Approved	Generation	45876	TUC3 U&U Generator Refurbishment	U&U - 2014	Q1 2014 - April 30, 2014		$ 1,500,239	$ 1,232,581			
Approved	Transmission	45882	103H-T63 Transformer	U&U - 2015	Q2 2015 - July 31, 2015		$ 1,706,615	$ 1,402,349			
Approved	Generation	45958	HYD - Nictaux Rotor Rewind U&U	U&U - 2014	Q3 2014 - October 29, 2014		$ 413,143	$ 450,522			
Approved	General Plant	46050	Operator Training Simulator	2015 ACE Plan	2015 ACE Plan	$ 531,119	$ 531,119	$ 663,690			
Approved	Generation	46055	LIN - Coal Mill Refurbishment 2015	2015 ACE Plan	2015 ACE Plan	$ 736,546	$ 736,546	$ 777,173			
Approved	Generation	46057	LIN - CW Screen Refurbishment 2015	2015 ACE Plan	2015 ACE Plan	$ 292,634	$ 292,634	$ 374,520			
Approved	Generation	46065	HYD- Tom's Lake Spillway Refurbishment	U&U - 2014	OTQ - December 2, 2014		$ 612,312	$ 597,934			
Approved	Generation	46068	LIN CW Debris Removal System	2015 ACE Plan (for Subsequent Approval)	Q2 2015 - July 31, 2015	$ 1,575,866	$ 1,746,988	$ 176			
Approved	General Plant	46073	IT - Lotus Notes Applications Replacement	2016 ACE Plan (for Subsequent Approval)	Q4 2015 - January 29, 2016	$ 744,698	$ 776,331	$ 531,744			
Deferred	General Plant	46075	IT - Work & Asset Management	2017 ACE Plan (for Subsequent Approval)		$ 28,027,680		$ 1,783,245			

2017 3rd Quarter Overview - Updated for Ace 2018

Status		CI Number	Title	ACE Plan Reference (or U&U and P&A)	Submission/Date	ACE Amount	Submission or Approved Amount	Actual Spend	ATO or FIN Submission Date	FIN or ATO/FIN Amount	Variance
Approved	Generation	46171	HYD Paradise Bearing Replacement U&U	U&U - 2014	Q3 2014 - October 29, 2014		$ 349,957	$ 425,409			
Approved	Generation	46191	Tusket Fuel System Upgrade	2016 ACE Plan (for Subsequent Approval)	OTQ - May 31, 2016	$ 892,178	$ 1,952,408	$ 1,721,575			
Approved	Generation	46232	HYD - WHR Pipeline Replacement	2015 ACE Plan (for Subsequent Approval)	OTQ - March 31, 2015	$ 538,454	$ 685,805	$ 649,686			
Approved	Distribution	46251	36V-303 Saxon Double Circuit	2015 ACE Plan	2015 ACE Plan	$ 425,838	$ 425,838	$ 515,500			
Deferred	Generation	46254	HYD - Mill Lake Surge Tank Refurbishment	2016 ACE Plan (for Subsequent Approval)		$ 1,421,366		$ 81,570			
Approved - FIN'd Internally	Distribution	46292	2015 Padmount Transformer Replacement Program	2015 ACE Plan	2015 ACE Plan	$ 1,536,110	$ 1,536,110	$ 1,461,143			
Approved	Generation	46294	HYD U&U WRC Unit 1 Stator Repair	U&U - 2014	Q2 2014 - July 31, 2014		$ 366,027	$ 171,588			
Approved	Generation	46298	HYD Five Mile Lake Dam Refurbishment	2016 ACE Plan	2016 ACE Plan	$ 2,209,018	$ 2,209,018	$ 2,390,663			
Approved - FIN'd Internally	Generation	46301	TRE6 6A 6B Mills Refurbishment	2015 ACE Plan	2015 ACE Plan	$ 665,045	$ 665,045	$ 796,757			
Approved	Distribution	46304	20W-311 Argyle Sound Reconductor	2015 ACE Plan	2015 ACE Plan	$ 430,435	$ 430,435	$ 632,921			
Approved	General Plant	46306	2015 Telecom Building Replacement	2015 ACE Plan	2015 ACE Plan	$ 251,727	$ 251,727	$ 173,170			
Approved	General Plant	46307	2015 Multiplexer Network Upgrades	2015 ACE Plan	2015 ACE Plan	$ 446,538	$ 446,538	$ 421,475			
Approved	General Plant	46308	2015 Microwave System Capacity Upgrade	2015 ACE Plan	2015 ACE Plan	$ 316,142	$ 316,142	$ 291,845			
Approved	Transmission	46331	L7001 Replacements - Phase 2	2015 ACE Plan	2015 ACE Plan	$ 888,192	$ 888,192	$ 822,291			
Approved - FIN'd Internally	Transmission	46332	L6539 Replacements	2015 ACE Plan (for Subsequent Approval)	OTQ - August 31, 2015	$ 736,393	$ 723,796	$ 705,260			
Approved	Transmission	46333	L6538 Replacements	2015 ACE Plan (for Subsequent Approval)	OTQ - August 31, 2015	$ 1,019,443	$ 1,008,356	$ 893,876			
Approved - FIN'd Internally	Transmission	46335	L5511 Replacements	2015 ACE Plan	2015 ACE Plan	$ 722,934	$ 722,934	$ 569,222			
Approved - FIN'd Internally	Transmission	46337	L6535/L6551 Insulator Replacements	2015 ACE Plan	2015 ACE Plan	$ 459,422	$ 459,422	$ 377,199			
Approved	Transmission	46339	120H Brushy Hill - SVC Controls Replacement	2015 ACE Plan	2015 ACE Plan	$ 9,959,330	$ 9,959,330	$ 10,526,014			
Approved	Transmission	46340	2015 Transmission Switch & Breaker Replacements	2015 ACE Plan	2015 ACE Plan	$ 1,581,599	$ 1,581,599	$ 1,503,449			
Approved	Transmission	46353	2015 Substation Recloser Replacements	2015 ACE Plan	2015 ACE Plan	$ 596,893	$ 596,893	$ 386,145			
Approved	Transmission	46354	2015 Reactor Breaker Replacements	2015 ACE Plan	2015 ACE Plan	$ 460,691	$ 460,691	$ 516,432			
Approved	Transmission	46360	L5545B Reconductor	2016 ACE Plan (Less than $250K)	OTQ - March 18, 2016	$ 202,492	$ 820,437	$ 535,800			
Approved	Transmission	46362	L5560 Transmission Line Reconductor	2015 ACE Plan	2015 ACE Plan	$ 626,895	$ 626,895	$ 799,127			
Approved	General Plant	46364	Maximo Enhancements for Telecom & Relays	2015 ACE Plan	2015 ACE Plan	$ 272,539	$ 272,539	$ 280,593			
Approved	General Plant	46365	Maximo Enhancements for Substation Field Mobility	2015 ACE Plan	2015 ACE Plan	$ 315,242	$ 315,242	$ 217,211			
Approved	Distribution	46398	20H Spryfield Voltage Conversion	2015 ACE Plan (for Subsequent Approval)	Q1 2015 - April 30, 2015	$ 444,970	$ 480,510	$ 607,212			
Approved	General Plant	46411	AMO Hydro Asset Management PE	2015 ACE Plan (for Subsequent Approval)	OTQ - March 31, 2015	$ 376,637	$ 590,884	$ 559,231			
Approved	Generation	46422	POT Automatic Trash Rack Cleaning System	2015 ACE Plan (Items less than $250K)	OTQ - June 30, 2015	$ 233,741	$ 329,721	$ 464,704			
Approved - FIN'd Internally	Distribution	46456	11W Yarmouth 4kV Conversion	2015 ACE Plan	2015 ACE Plan	$ 545,514	$ 545,514	$ 791,983			
Approved - FIN'd Internally	Distribution	46457	79V-401 Cameron Lake Voltage Conversion	2015 ACE Plan	2015 ACE Plan	$ 637,939	$ 637,939	$ 575,571			
Approved	Distribution	46458	16N-302 Stewiacke Reconductor	2015 ACE Plan	2015 ACE Plan	$ 965,830	$ 965,830	$ 791,877			
Approved	Generation	46464	TUC1 - Turbine Valve Refurbishment	2015 ACE Plan	2015 ACE Plan	$ 541,162	$ 541,162	$ 527,454			
Approved	Generation	46465	TUC2 Turbine Valve Refurbishment	2016 ACE Plan	2016 ACE Plan	$ 651,362	$ 651,362	$ 498,287			
Approved - FIN'd Internally	Generation	46470	LIN1 - Boiler Refurbishment 2015	2015 ACE Plan	2015 ACE Plan	$ 496,369	$ 496,369	$ 716,170			
Approved	Generation	46473	TUC3 - Turbine Valve Refurbishment	2015 ACE Plan	2015 ACE Plan	$ 609,870	$ 609,870	$ 780,580			
Deferred	Generation	46483	CT - Tusket Control System Upgrade	2015 ACE Plan (for Subsequent Approval)		$ 441,816		$ -			
Approved	Generation	46484	TUC - Unit 1&2 Analytical Panel Replacement	2015 ACE Plan	2015 ACE Plan	$ 386,607	$ 386,607	$ 519,816			
Approved - FIN'd Internally	Generation	46496	LIN3 Analytical Panel Replacement	2015 ACE Plan	2015 ACE Plan	$ 276,756	$ 276,756	$ 346,110			
Approved	Generation	46505	TUC2 UU LP Row6 Blade Replace	U&U - 2015	Q4 2015 - January 29, 2016		$ 570,207	$ 698,912			
Approved	Transmission	46513	3C Port Hastings BPS Upgrade	2015 ACE Plan	2015 ACE Plan	$ 3,684,823	$ 3,684,823	$ 3,322,349			
Approved	General Plant	46552	Backbone Communications System Upgrade	2015 ACE Plan (for Subsequent Approval)	OTQ - September 30, 2015	$ 12,525,792	$ 8,913,092	$ 7,608,529			
Approved	General Plant	46572	2017 RTU Replacement Program	2017 ACE Plan	2017 ACE Plan	$ 693,354	$ 693,354	$ 45,602			
Approved - FIN'd Internally	Distribution	46576	2015 PCB Phase-out for Pole Top Transformers	2015 ACE Plan	2015 ACE Plan	$ 733,503	$ 733,503	$ 756,617			
Approved	Transmission	46582	L5569 Upgrade	2015 ACE Plan	2015 ACE Plan	$ 369,032	$ 369,032	$ 149,514			
Approved - FIN'd Internally	Transmission	46583	L6511 Replacements	2015 ACE Plan	2015 ACE Plan	$ 905,745	$ 905,745	$ 783,892			
Approved	Transmission	46586	2015 PCB Removal - Substation	2015 ACE Plan (for Subsequent Approval)	Q1 2015 - April 30, 2015	$ 1,262,087	$ 1,236,351	$ 1,473,218			
Approved	Transmission	46587	Metro Voltage Support Add Capacitor	2015 ACE Plan (for Subsequent Approval)	2016 ACE Plan	$ 3,373,511	$ 3,373,511	$ 3,051,476			
Approved	Transmission	46591	88S Lingan Replace 230kV GIS	2015 ACE Plan (for Subsequent Approval)	2016 ACE Plan	$ 14,249,882	$ 14,249,882	$ 2,280,297			
Approved	Generation	46594	HYD Sissiboo Falls Overhaul	2015 ACE Plan	2015 ACE Plan	$ 817,153	$ 817,153	$ 1,052,713			
Approved	Distribution	46651	23H-303G Rockingham Conversion Part 1	2015 ACE Plan (for Subsequent Approval)	Q3 2015 - October 30, 2015	$ 572,750	$ 566,694	$ 675,402			
Deferred	Generation	46655	ICP Mile 10.1 Bridge Repairs	2015 ACE Plan (for Subsequent Approval)		$ 377,279		$ -			
Approved	General Plant	46657	Wire Inspection Services - Analyzer Replacement	2015 ACE Plan	2015 ACE Plan	$ 448,300	$ 448,300	$ 322,217			
Approved	General Plant	46671	NERC CIP Version 5 Implementation	2016 ACE Plan (for Subsequent Approval)	Q4 2015 - January 29, 2016	$ 1,528,492	$ 2,433,239	$ 2,563,772			
Approved	Generation	46713	TUC5 LM6000 – Engine 191-332 Refurbishment P&A	P&A - 2014	Q4 2014 - January 30, 2015		$ 7,768,463	$ 8,066,077			
Approved	General Plant	46739	IT - Outage Map Technology Upgrades	2015 ACE Plan (for Subsequent Approval)	OTQ - September 30, 2015	$ 1,023,269	$ 2,895,963	$ 2,450,544			
Approved	Transmission	46757	88S Lingan 230kV BPS Upgrades	2016 ACE Plan	2016 ACE Plan	$ 3,218,221	$ 3,218,221	$ 2,502,940			
Approved	Generation	46791	HYD - Annapolis Runner Refurbishment U&U	U&U - 2015	OTQ - March 31, 2015		$ 526,329	$ 663,996			
Approved	Transmission	46811	2H Armdale Transformer Addition	2016 ACE Plan (For Subsequent Approval)	OTQ - June 30, 2016	$ 2,545,596	$ 2,566,861	$ 709,732			
Awaiting Approval	Distribution	47124	Advanced Metering Infrastructure - Pilot Project	2017 ACE Plan (for Subsequent Approval)	OTQ - November 18, 2016	$ 8,274,738	$ 8,274,738	$ 4,238,354			
Approved	Transmission	47131	L8001 Steel Tower Replacements U&U	U&U - 2015	OTQ - June 30, 2015		$ 928,377	$ 666,603			
Approved	Generation	47163	HYD - Tusket Controls Upgrade	2016 ACE Plan (for Subsequent Approval)	Q4 2015 - January 29, 2016	$ 880,570	$ 906,688	$ 146,603			
Approved	Generation	47167	HYD - Sandy Lake Surge Tank Ref. PE	2016 ACE Plan (for Subsequent Approval)	OTQ - March 18, 2016	$ 1,358,796	$ 2,955,458	$ 3,121,159			
Approved	Generation	47396	HYD Nictaux Powerhouse Dam Refurbishment	2016 ACE Plan	2016 ACE Plan	$ 1,792,968	$ 1,792,968	$ 1,226,108			
Approved	Generation	47397	HYD - Gisborne Dam D4 and Spillway S4 Refurbishment PE	2016 ACE Plan	2016 ACE Plan	$ 2,050,519	$ 2,050,519	$ 2,003,368			
Approved	General Plant	47403	Load Research Sample Update	2016 ACE Plan (for Subsequent Approval)	OTQ - August 31, 2016	$ 322,387	$ 440,453	$ 386,431			
Approved	Generation	47432	HYD - Ridge Overhaul	2016 ACE Plan	2016 ACE Plan	$ 869,304	$ 869,304	$ 1,037,167			
Approved	Distribution	47471	131H-422G-East Uniacke Road Load Growth P&A	P&A - 2015	OTQ - August 31, 2015		$ 904,331	$ 731,035			
Approved	Generation	47476	HYD – Wreck Cove Tailrace Rockfall U&U	U&U - 2015	OTQ - August 31, 2015		$ 2,422,964	$ 2,608,434			
Approved	General Plant	47477	IT - Next Generation Firewall	2016 ACE Plan (for Subsequent Approval)	OTQ - May 31, 2016	$ 2,536,182	$ 3,927,576	$ 3,383,264			
Approved	Generation	47505	LIN Coal Mill Refurbishment 2016	2016 ACE Plan	2016 ACE Plan	$ 749,183	$ 749,183	$ 853,644			
Approved - FIN'd Internally	Generation	47507	LIN CW Pump Rebuild 2016	2016 ACE Plan	2016 ACE Plan	$ 441,560	$ 441,560	$ 655,544			
Approved - FIN'd Internally	Generation	47510	LIN Coal Plant Structural Refurbishment Phase 2	2016 ACE Plan	2016 ACE Plan	$ 359,425	$ 359,425	$ 445,560			
Approved	Generation	47551	HYD - SHH Controls Upgrade	2016 ACE Plan (for Subsequent Approval)	Q4 2015 - January 29, 2016	$ 1,092,851	$ 1,749,212	$ 255,405			
Approved	Generation	47554	TRE5 5-1 FD Fan Refurbishment	2016 ACE Plan	2016 ACE Plan	$ 494,802	$ 494,802	$ 569,532			
Approved	Generation	47597	TRE6 Bottom Ash Chain Replacement	2017 ACE Plan	2017 ACE Plan	$ 793,792	$ 793,792	$ 783,239			
Approved	Generation	47611	POT - Demolish Unit 1 Stack	2016 ACE Plan	2016 ACE Plan	$ 1,732,346	$ 1,732,346	$ 34,928			
Approved	Generation	47617	TRE6 Elevator Controls Upgrade	2016 ACE Plan	2016 ACE Plan	$ 320,704	$ 320,704	$ 335,755			
Approved	Transmission	47631	U&U Capacitor Bank Breaker Replacement	U&U - 2015	Q2 2015 - July 31, 2015		$ 411,871	$ 272,954			
Approved	Generation	47657	LIN4 High Voltage Bushing Refurbishment	2016 ACE Plan	2016 ACE Plan	$ 822,570	$ 822,570	$ 897,926			
Approved - FIN'd Internally	Generation	47658	LIN4 L-0 Blade Replacement	2016 ACE Plan	2016 ACE Plan	$ 4,597,152	$ 4,597,152	$ 4,497,121			
Approved	Generation	47662	POT Coal Mill Overhauls 2016	2016 ACE Plan	2016 ACE Plan	$ 324,874	$ 324,874	$ 225,216			
Approved - FIN'd Internally	Generation	47663	LIN4 - SH5 Boiler Tube Replacement	2016 ACE Plan	2016 ACE Plan	$ 538,776	$ 538,776	$ 615,511			
Approved - FIN'd Internally	Generation	47664	LIN4 Division Wall Replacement	2016 ACE Plan	2016 ACE Plan	$ 619,243	$ 619,243	$ 684,404			
Approved - FIN'd Internally	Generation	47666	LIN4 Boiler Refurbishment 2016	2016 ACE Plan	2016 ACE Plan	$ 571,859	$ 571,859	$ 650,949			
Approved	Generation	47668	POT - Plant Siding 2016	2016 ACE Plan	2016 ACE Plan	$ 287,926	$ 287,926	$ 324,888			
Approved	Generation	47673	LIN4 Generator Rotor Rewind	2016 ACE Plan	2016 ACE Plan	$ 2,602,159	$ 2,602,159	$ 2,521,027			
Approved	Generation	47689	LIN4 - Air Heater Refurbishment	2016 ACE Plan	2016 ACE Plan	$ 521,951	$ 521,951	$ 550,720			
Approved	Generation	47690	LIN4 Burner Front Refurbishment	2016 ACE Plan	2016 ACE Plan	$ 480,349	$ 480,349	$ 561,308			
Approved - FIN'd Internally	Distribution	47693	63V-313G-Evangeline Trail Reconductor	P&A - 2015	Q3 2015 - October 30, 2015		$ 426,363	$ 413,941			
Approved - FIN'd Internally	Generation	47704	POT - Replace Polisher Chemical Skid	2016 ACE Plan	2016 ACE Plan	$ 321,950	$ 321,950	$ 274,723			
Approved	Distribution	47721	2016 PCB Phase-out for Pole Top Transformers	2016 ACE Plan	2016 ACE Plan	$ 4,409,579	$ 4,409,579	$ 4,183,438			
Approved	Distribution	47732	131H-424/137H-412 Hammonds Plains Feeder Tie	2016 ACE Plan	2016 ACE Plan	$ 337,133	$ 337,133	$ 287,524			
Approved	Distribution	47734	1C-411 Highway 4 Reconductor	2016 ACE Plan	2016 ACE Plan	$ 437,410	$ 437,410	$ 559,541			
Deferred	General Plant	47751	Dynamic Transmission Limits	2017 ACE Plan (for Subsequent Approval)		$ 537,466		$ 48,647			
Approved	Distribution	47752	4S-333 Bentinck St. Rebuild	2016 ACE Plan	2016 ACE Plan	$ 575,357	$ 575,357	$ 816,088			
Approved	Distribution	47753	24C-442GB Highway 16 Reconductor Phase 2	2016 ACE Plan (for Subsequent Approval)	OTQ - December 17, 2015	$ 1,154,302	$ 1,425,322	$ 1,335,742			
Approved	Distribution	47754	63V-313 Ward Rd Reconductor	2016 ACE Plan	2016 ACE Plan	$ 308,994	$ 308,994	$ 203,211			
Approved	Generation	47755	LIN4 Turbine High Temperature Fasteners Replacement	2016 ACE Plan	2016 ACE Plan	$ 1,073,877	$ 1,073,877	$ 1,099,663			

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Status		CI Number	Title	ACE Plan Reference (or U&U and P&A)	Submission/Date	ACE Amount	Submission or Approved Amount	Actual Spend	ATO or FIN Submission Date	FIN or ATO/FIN Amount	Variance
Deferred	Generation	47761	LIN1 Boiler Refurbishment	2016 ACE Plan	2016 ACE Plan	$ 506,845	$ 506,845	$ 481,604			
Approved	Generation	47762	LIN4 Analytical Panel Replacement	2016 ACE Plan	2016 ACE Plan	$ 401,658	$ 401,658	$ 509,827			
Approved	Distribution	47765	58C-405 Belle Cote Phase 2	2016 ACE Plan	2016 ACE Plan	$ 477,154	$ 477,154	$ 258,709			
Approved	Distribution	47766	70V-302 Centerlea Rebuild	2016 ACE Plan	2016 ACE Plan	$ 456,314	$ 456,314	$ 382,072			
Approved	Distribution	47769	509V-301 Overcove Rd Replacements	2017 ACE Plan	2017 ACE Plan	$ 402,493	$ 402,493	$ 22,948			
Approved	Distribution	47773	3N - Oxford Conversion Phase 2 P&A	P&A - 2015	Q3 2015 - October 30, 2015		$ 631,686	$ 720,286			
Approved	Distribution	47776	111S Prime Brook Feeder Exits & Feeders	2017 ACE Plan (for Subsequent Approval)	Q3 2016 - November 18, 2016	$ 1,503,986	$ 1,504,630	$ 1,567,024			
Deferred	Distribution	47792	Distribution Automation Remote Communications	2016 ACE Plan (for Subsequent Approval)		$ 415,762		$ -			
Approved	Generation	47814	HYD - WRC Evacuation Tunnel Upgrade	U&U - 2015	Q4 2015 - January 29, 2016		$ 503,962	$ 523,877			
Approved - FIN'd Internally	Generation	47869	LIN4 Bottom Ash	2016 ACE Plan	2016 ACE Plan	$ 616,599	$ 616,599	$ 711,030			
Approved	Generation	47872	LIN E Gallery Structural Steel Protective Coating	2016 ACE Plan	2016 ACE Plan	$ 481,492	$ 481,492	$ 543,047			
Approved	Generation	47893	TUC3 PE Generator Hydrogen Panel Replacement	2016 ACE Plan (for Subsequent Approval)	2017 ACE Plan	$ 423,798	$ 423,798	$ 11,506			
Approved	Generation	47911	TUC1 High Temperature Fastener Replacement	2016 ACE Plan	2016 ACE Plan	$ 828,968	$ 828,968	$ 837,458			
Approved	Transmission	47912	L-6552 Replacements and Upgrades	2016 ACE Plan	2016 ACE Plan	$ 1,054,326	$ 1,054,326	$ 947,930			
Approved	Transmission	47914	L-6537 Replacements and Upgrades	2016 ACE Plan	2016 ACE Plan	$ 1,382,705	$ 1,382,705	$ 663,927			
Approved	Transmission	47915	L5053 Replacements and Upgrades	2017 ACE Plan	2017 ACE Plan	$ 692,706	$ 692,706	$ 19,305			
Approved	Generation	47934	TUC3 CW Piping Refurbishment	U&U - 2015	Q4 2015 - January 29, 2016		$ 584,991	$ 585,372			
Approved	Transmission	47935	L5040 Replacements	2016 ACE Plan	2016 ACE Plan	$ 1,241,298	$ 1,241,298	$ 1,097,568			
Approved	Generation	47945	TUC Electrode-ionization (EDI) Unit Replacement	2016 ACE Plan	2016 ACE Plan	$ 275,154	$ 275,154	$ 330,779			
Approved	Transmission	47949	L-5028 Replacements and Upgrades	2016 ACE Plan	2016 ACE Plan	$ 1,144,355	$ 1,144,355	$ 747,491			
Approved	Transmission	47950	L5017 Replacements & Upgrades	2016 ACE Plan	2016 ACE Plan	$ 2,182,142	$ 2,182,142	$ 1,086,772			
Approved	Transmission	47952	L-7001 Replacements (Phase 3 & 4)	2016 ACE Plan	2016 ACE Plan	$ 1,725,284	$ 1,725,284	$ 1,509,307			
Approved	Generation	47953	LIN Railcar Positioner Upgrade	2016 ACE Plan (for Subsequent Approval)	2017 ACE Plan	$ 566,619	$ 566,619	$ 76,584			
Approved	Transmission	47954	L7012 Replacements and Upgrades	2017 ACE Plan	2017 ACE Plan	$ 4,428,520	$ 4,428,520	$ 2,873,922			
Approved	Transmission	47956	L7004 Replacements and Upgrades	2017 ACE Plan	2017 ACE Plan	$ 672,131	$ 672,131	$ 444,947			
Deferred	Generation	47961	LIN1 Condenser Tube Coating	2016 ACE Plan	2016 ACE Plan	$ 333,944	$ 333,944	$ -			
Approved	Generation	48018	TUC1 IP Blading Refurbishments	2016 ACE Plan	2016 ACE Plan	$ 1,137,208	$ 1,137,208	$ 1,076,908			
Approved	Generation	48020	HYD - RUT3 Generator Refurbishment	2016 ACE Plan (for Subsequent Approval)	Q4 2015 - January 29, 2016	$ 1,030,940	$ 992,418	$ 1,225,249			
Approved	Transmission	48022	Spider Lake Substation Addition	2016 ACE Plan (for Subsequent Approval)	OTQ - July 15, 2016	$ 6,348,981	$ 6,839,528	$ 884,915			
Approved	Transmission	48057	Replace 69kV cables between 2S and 83S	2017 ACE Plan	2017 ACE Plan	$ 459,931	$ 459,931	$ 581			
Approved	Generation	48058	PTMT - Railcar Access Ramp U&U	U&U - 2015	Q3 2015 - October 30, 2015		$ 309,180	$ 485,036			
Approved	Transmission	48059	2016/2017 Transmission Switch & Breaker Replacements	2016 ACE Plan	2016 ACE Plan	$ 980,999	$ 980,999	$ 1,169,355			
Approved	Transmission	48061	New Mobile Substation 7.5MVA	2016 ACE Plan (for Subsequent Approval)	OTQ - June 30, 2016	$ 1,728,234	$ 2,390,744	$ 812,661			
Approved	Transmission	48062	2016/2017 Reactor Breaker Replacements	2016 ACE Plan	2016 ACE Plan	$ 384,974	$ 384,974	$ 370,725			
Approved	Transmission	48063	2016/2017 Capacitor Bank Breaker Replacements	2016 ACE Plan	2016 ACE Plan	$ 385,850	$ 385,850	$ 211,159			
Approved	Transmission	48066	2016/2017 Substation Polychlorinated Biphenyl (PCB) Equipment Removal Program	2016 ACE Plan	2016 ACE Plan	$ 3,500,427	$ 3,500,427	$ 3,423,646			
Approved	Transmission	48067	2016 Oil Containment Program	2016 ACE Plan	2016 ACE Plan	$ 468,963	$ 468,963	$ 342,143			
Cancelled	General Plant	48072	2016 ADMS Switch Order Management	2016 ACE Plan	2016 ACE Plan	$ 305,469	$ 305,469	$ -			
Approved	Distribution	48092	2016 Substation Recloser Replacements	2016 ACE Plan	2016 ACE Plan	$ 529,270	$ 529,270	$ 490,913			
Approved	Distribution	48093	2016 Padmount Replacement Program	2016 ACE Plan	2016 ACE Plan	$ 1,911,470	$ 1,911,470	$ 1,506,947			
Approved	Transmission	48116	2016 Sacrificial Anode Installation Program	2016 ACE Plan	2016 ACE Plan	$ 970,909	$ 970,909	$ 1,198,820			
Approved	Distribution	48152	20H-Spryfield Voltage Conversion Ph	2016 ACE Plan (for Subsequent Approval)	OTQ - June 30, 2016	$ 375,848	$ 460,246	$ 402,860			
Approved	Generation	48157	TUC Main Auxiliary Boiler Install	2016 ACE Plan (for Subsequent Approval)	OTQ - March 18, 2016	$ 2,822,565	$ 3,478,421	$ 3,713,030			
Approved	Distribution	48195	Halifax 4kV Conversion Ph 3	2016 ACE Plan (for Subsequent Approval)	OTQ - August 31, 2016	$ 250,336	$ 429,235	$ 353,029			
Approved	General Plant	48236	Self Serve Dev Phase 1	2016 ACE Plan (for Subsequent Approval)	Q3 2016 - November 18, 2016	$ 1,802,719	$ 811,203	$ 1,105,359			
Approved	General Plant	48254	IT - Outage Comm Tech Cap Improvement	2016 ACE Plan (for Subsequent Approval)	OTQ - May 31, 2016	$ 1,500,000	$ 2,146,079	$ 2,006,658			
Approved - FIN'd Internally	Generation	48438	LIN4 PE ID Fan Damper & VIV Refurb.	U&U	OTQ - July 15, 2016		$ 524,658	$ 449,342			
Approved	Generation	48471	TUC3 UU HEP FAC Upgrades	U&U	OTQ - March 18, 2016		$ 313,287	$ 323,491			
Approved	Generation	48535	HYD Scragg Lake Dam and Spillway Refurbishment	2017 ACE Plan	2017 ACE Plan	$ 1,956,298	$ 1,956,298	$ 1,342,618			
Approved	Distribution	48610	16N-301 Stewiacke - Load Trans Ph1	P&A	Q3 2016 - November 18, 2016		$ 852,654	$ 816,701			
Approved	Generation	48631	HYD - Gulch Spillway Refurbishment	2017 ACE Plan	2017 ACE Plan	$ 617,034	$ 617,034	$ 63,328			
Approved	General Plant	48633	IT - Java Security	2016 ACE Plan (for Subsequent Approval) - 47477	OTQ - June 30, 2016	$ 2,536,182	$ 548,032	$ 731,277			
Approved	General Plant	48635	IT - Endpoint Data Encr & Malwre Pr	2016 ACE Plan (for Subsequent Approval) - 47477	OTQ - August 31, 2016	$ 2,536,182	$ 813,587	$ 816,959			
Approved	General Plant	48774	HYD - Milton Shop HVAC Upgrade	2017 ACE Plan	2017 ACE Plan	$ 564,347	$ 564,347	$ 79,802			
Approved	Generation	48951	LIN4 UU 72" CW Condenser Pipe Repl.	U&U	OTQ - August 31, 2016	$ -	$ 414,715	$ 414,801			
Approved	General Plant	49043	IT-Contact Centre Infrastructure	U&U	OTQ - November 1, 2016		$ 2,504,109	$ 2,817,384			
Approved	Generation	49057	TRE6 Excitation System Replacement	2017 ACE Plan	2017 ACE Plan	$ 904,011	$ 904,011	$ 595,475			
Approved	General Plant	49212	IT - My Account Single Sign-On	U&U	OTQ - May 31, 2016		$ 465,079	$ 600,141			
Approved	Transmission	49253	U&U 20V-T1 Transformer Replacement	U&U	OTQ - May 31, 2016		$ 1,305,748	$ 903,391			
Approved	Distribution	49311	93V-312 Lower Saulnierville Conduct	P&A	OTQ - July 15, 2016		$ 549,642	$ 144,542			
Approved	Generation	49351	LIN4 UU LTSH1 Tube Replacement	U&U	OTQ - August 31, 2016	$ -	$ 352,205	$ 320,815			
Approved	Generation	49415	LIN4 UU HP IP Seal Replacement	U&U	OTQ - August 31, 2016	$ -	$ 531,485	$ 549,956			
Approved - FIN'd Internally	Generation	49416	LIN4 UU Generator Stator Rewedge	U&U	OTQ - August 31, 2016	$ -	$ 596,766	$ 539,354			
Approved	Generation	49419	POT Boiler Refurbishment 2017	2017 ACE Plan	2017 ACE Plan	$ 969,292	$ 969,292	$ 1,197,701			
Approved	Generation	49427	LIN Coal Plant Structural Refurbishment Phase 3	2017 ACE Plan	2017 ACE Plan	$ 365,003	$ 365,003	$ 395,352			
Approved	Generation	49429	LIN Coal Pile Run Off Pond Expansion	2017 ACE Plan	2017 ACE Plan	$ 311,793	$ 311,793	$ -			
Approved	Generation	49430	LIN CW Pump Refurbishment 2017	2017 ACE Plan	2017 ACE Plan	$ 516,270	$ 516,270	$ 429,737			
Approved	Generation	49431	LIN Mill Refurbishment 2017	2017 ACE Plan	2017 ACE Plan	$ 665,839	$ 665,839	$ 669,323			
Approved	Generation	49434	LIN CW Screen Refurbishment 2017	2017 ACE Plan	2017 ACE Plan	$ 347,062	$ 347,062	$ 324,455			
Approved	Generation	49437	LIN Vacuum Pump Cooler Refurbishment	2017 ACE Plan	2017 ACE Plan	$ 282,034	$ 282,034	$ 31,071			
Approved	Generation	49463	POT Coal Mill Overhauls 2017	2017 ACE Plan	2017 ACE Plan	$ 328,410	$ 328,410	$ 64,722			
Awaiting Approval	Generation	49466	PTMT - Dock and Inhaul Conveyor Replacement	2017 ACE Plan	2017 ACE Plan	$ 467,607	$ 467,607	$ 2,808	OTQ - September 15, 2017	$ 920,823	$ 453,216
Approved - FIN'd Internally	Generation	49497	LIN4 UU Snout Ring Replacement	U&U	OTQ - August 31, 2016	$ -	$ 282,601	$ 294,011			
Approved	Generation	49532	TRE6 Air Heater Refurbishment	2017 ACE Plan	2017 ACE Plan	$ 1,428,236	$ 1,428,236	$ 1,189,918			
Approved	Generation	49533	TRE6 Boiler Refurbishment	2017 ACE Plan	2017 ACE Plan	$ 1,259,454	$ 1,259,454	$ 648,418			
Approved	Generation	49535	TRE6 Mills Refurbishment 2017	2017 ACE Plan	2017 ACE Plan	$ 822,141	$ 822,141	$ 288,065			
Approved	Generation	49536	TRE5 Boiler Refurbishments 2017	2017 ACE Plan	2017 ACE Plan	$ 717,589	$ 717,589	$ 926,271			
Approved	Generation	49537	TRE6 Analytical Panel Upgrade	2017 ACE Plan	2017 ACE Plan	$ 438,216	$ 438,216	$ -			
Approved	Distribution	49591	3S Feeder Exit Cable Replacement	2017 ACE Plan	2017 ACE Plan	$ 335,842	$ 335,842	$ 64,542			
Approved	Distribution	49611	New Distribution Rights-of-Way Phase 1	2016 ACE Plan - Routines	OTQ - November 1, 2016	$ 2,400,000	$ 2,215,397	$ 1,845,410			
Approved	Generation	49675	TUC2 Cooling Water Piping Refurbishment	2017 ACE Plan	2017 ACE Plan	$ 568,673	$ 568,673	$ 813,044			
Approved	Generation	49707	TUC2 High Voltage Bushing	2017 ACE Plan	2017 ACE Plan	$ 440,082	$ 440,082	$ 6,556			
Approved	Generation	49751	TUC1 PE LP Blading Refurbishment	U&U	OTQ - September 30, 2016	$ -	$ 709,189	$ 948,184			
Approved	Transmission	49774	L5527 Replacements and Upgrades	2017 ACE Plan	2017 ACE Plan	$ 1,537,852	$ 1,537,852	$ 88,473			
Approved	Transmission	49775	L5004 Replacements and Upgrades	2017 ACE Plan	2017 ACE Plan	$ 995,712	$ 995,712	$ 605,893			
Approved	Transmission	49776	L7008 Replacements and Upgrades	2017 ACE Plan	2017 ACE Plan	$ 876,277	$ 876,277	$ 349,207			
Approved	Transmission	49778	L5535 Replacements and Upgrades	2017 ACE Plan	2017 ACE Plan	$ 1,261,920	$ 1,261,920	$ 77,105			
Approved	Transmission	49782	L5027B Replacements and Upgrades	2017 ACE Plan	2017 ACE Plan	$ 1,093,542	$ 1,093,542	$ 35,635			
Approved	Transmission	49789	L6515 Replacements and Upgrades	2017 ACE Plan	2017 ACE Plan	$ 2,340,989	$ 2,340,989	$ 2,544,816			
Approved	Transmission	49790	L5505 Replacements and Upgrades	2017 ACE Plan	2017 ACE Plan	$ 1,223,571	$ 1,223,571	$ 403			
Approved	Distribution	49791	3N Oxford Conversion Phase 3	2017 ACE Plan	2017 ACE Plan	$ 358,369	$ 358,369	$ 187,094			
Approved	Transmission	49792	2017 Transmission Line Retirement Program	2017 ACE Plan	2017 ACE Plan	$ 526,064	$ 526,064	$ 391,856			
Approved	Transmission	49793	L7011 Replacements and Upgrades	2017 ACE Plan	2017 ACE Plan	$ 3,343,484	$ 3,343,484	$ 938,022			
Approved	Transmission	49798	2017 / 2018 Capacitor Bank Breaker Replacements	2017 ACE Plan	2017 ACE Plan	$ 378,150	$ 378,150	$ 147,207			
Approved	Distribution	49799	532N Elm Street Conversion Phase 1	2017 ACE Plan	2017 ACE Plan	$ 548,688	$ 548,688	$ 881			
Approved	Generation	49804	HYD - Fall River Pipeline Repair	U&U	OTQ - August 31, 2016	$ -	$ 275,841	$ 282,288			
Approved	Distribution	49806	2017 Padmount Replacement Program	2017 ACE Plan	2017 ACE Plan	$ 1,703,774	$ 1,703,774	$ 1,054,546			
Approved	Transmission	49813	2017 Sacrificial Anode Installation Program	2017 ACE Plan	2017 ACE Plan	$ 1,532,340	$ 1,532,340	$ 1,633,043			
Approved	Transmission	49814	2017 / 2018 Steel Tower Life Extension	2017 ACE Plan	2017 ACE Plan	$ 1,462,100	$ 1,462,100	$ 1,529,293			

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Status		CI Number	Title	ACE Plan Reference (or U&U and P&A)	Submission/Date	ACE Amount	Submission or Approved Amount	Actual Spend	ATO or FIN Submission Date	FIN or ATO/FIN Amount	Variance
Approved	Transmission	49815	2017 / 2018 Steel Tower Refurbishment	2017 ACE Plan	2017 ACE Plan	$ 2,003,317	$ 2,003,317	$ 422,274			
Approved	Transmission	49818	2017/2018 Transmission Switch & Breaker Replacement	2017 ACE Plan	2017 ACE Plan	$ 1,074,472	$ 1,074,472	$ 608,643			
Approved	Transmission	49821	Mersey River Hydro Spare Transformer	2017 ACE Plan	2017 ACE Plan	$ 519,994	$ 519,994	$ 2,299			
Approved	Transmission	49833	2017 Oil Containment Program	2017 ACE Plan	2017 ACE Plan	$ 432,518	$ 432,518	$ 136,062			
Approved	Distribution	49836	11S-302 11S-401 Rebuild Coxheath Phase 2	2017 ACE Plan	2017 ACE Plan	$ 807,456	$ 807,456	$ 404,342			
Approved	Transmission	49838	2017/2018 Substation Polychlorinated Biphenyl (PCB) Equipment Removal Program	2017 ACE Plan	2017 ACE Plan	$ 4,127,023	$ 4,127,023	$ 2,227,682			
Approved	Distribution	49841	23H-Rockingham Voltage Conversion-Phase 2	2017 ACE Plan	2017 ACE Plan	$ 743,213	$ 743,213	$ 392,852			
Approved	General Plant	49861	IT - PI System Upgrade	2017 ACE Plan	2017 ACE Plan	$ 801,253	$ 801,253	$ 71,236			
Approved	Distribution	49866	512N-Toney River Upgrade	2017 ACE Plan	2017 ACE Plan	$ 285,219	$ 285,219	$ 320,099			
Approved	Distribution	49867	55V-313-Berwick North Replacements	2017 ACE Plan	2017 ACE Plan	$ 345,565	$ 345,565	$ 269,121			
Approved	Transmission	49878	2017 Substation Insulator Replacement Program	2017 ACE Plan	2017 ACE Plan	$ 508,893	$ 508,893	$ 324,668			
Approved	General Plant	49880	Meter Shop Test Console Replacement	2017 ACE Plan	2017 ACE Plan	$ 410,457	$ 410,457	$ -			
Approved	Distribution	49891	509V Recloser and Voltage Regulator Replacement	2017 ACE Plan	2017 ACE Plan	$ 319,649	$ 319,649	$ 81,218			
Approved	Generation	49897	POT - Fire System Upgrades 2017	2017 ACE Plan	2017 ACE Plan	$ 538,437	$ 538,437	$ 4,554			
Approved	General Plant	49902	2017 Telecom Building Replacement - Wittenburg	2017 ACE Plan	2017 ACE Plan	$ 294,000	$ 294,000	$ 436			
Approved	Distribution	49918	54H-303 Underground Device Replacements Phase I	2017 ACE Plan	2017 ACE Plan	$ 469,604	$ 469,604	$ 500,283			
Approved	Distribution	49919	2017 PCB Pole Top Transformer Replacement	2017 ACE Plan	2017 ACE Plan	$ 2,446,051	$ 2,446,051	$ 1,230,232			
Approved	Transmission	49948	2017/2018 Isolated Structure Replacements	2017 ACE Plan	2017 ACE Plan	$ 3,822,487	$ 3,822,487	$ 220,410			
Approved	Transmission	49992	2017 Transmission Right of Way Widening	2017 ACE Plan	2017 ACE Plan	$ 5,400,855	$ 5,400,855	$ 5,358,223			
Approved	General Plant	50071	T&D Inspection Application Upgrade Phase 1	2017 ACE Plan	2017 ACE Plan	$ 411,191	$ 411,191	$ 343,850			
Approved	Distribution	50073	4S-332 Bernard Lind Drive Rebuild	2017 ACE Plan	2017 ACE Plan	$ 302,893	$ 302,893	$ 127,842			
Awaiting Approval	Generation	47687	POT Boiler Chem Clean ATO	2017 ACE Plan	2017 ACE Plan	$ 974,604	$ 974,604	$ 1,592,128	OTQ - September 15, 2017	$ 1,603,103	
Approved	Generation	50151	HYD - WRC Main Access Entr Bridge	U&U	Q3 2016 - November 18, 2016	$ -	$ 716,508	$ 789,188			
Deferred	Generation	39472	HYD Mersey Hydro System Re-Development	2017 ACE Plan (for Subsequent Approval)		$ 84,000,000		$ 2,841,037			
Awaiting Approval	Generation	48913	HYD - Tusket Facility Refurbishment	2017 ACE Plan (for Subsequent Approval)	Q3 2017 - October 30, 2017	$ 657,956	$ 1,183,470	$ 26,320			
Cancelled	Generation	49835	HYD - Dive Site Risk Mitigation	2017 ACE Plan (for Subsequent Approval)		$ 650,533		$ -			
Deferred	Generation	47166	HYD - McAskill Brook Decommissioning	2017 ACE Plan (for Subsequent Approval)		$ 562,684		$ 84,229			
Awaiting Approval	Generation	48914	HYD - Malay Falls Facility Repair	2017 ACE Plan (for Subsequent Approval)	Q3 2017 - October 30, 2017	$ 446,237	$ 1,034,045	$ 30,371			
Awaiting Approval	Generation	48396	HYD - Bridge Remediation	2017 ACE Plan (for Subsequent Approval)	Q3 2017 - October 30, 2017	$ 404,616	$ 677,591	$ 159,751			
Pending Submission	Generation	49940	LM6000 TUC5 Control System Upgrade	2017 ACE Plan (for Subsequent Approval)		$ 1,018,769		$ -			
Deferred	Generation	49594	LM6000 TUC5 Airhouse Upgrade	2017 ACE Plan (for Subsequent Approval)		$ 833,200		$ 106,403			
Pending Submission	Generation	49926	LM6000 TUC4 Airhouse Upgrade	2017 ACE Plan (for Subsequent Approval)		$ 815,633		$ 148,480			
Deferred	Generation	49949	LM6000 TUC4 Control System Replacement	2017 ACE Plan (for Subsequent Approval)		$ 710,815		$ 23,322			
Approved	Generation	47531	TRE6 Turbine Refurbishments	2017 ACE Plan (for Subsequent Approval)	Q1 2017 - May 1, 2017	$ 2,322,487	$ 1,704,784	$ 1,476,901			
Pending Submission	Generation	49060	POT - Condenser Dog Bone Expansion Joint Replacement	2017 ACE Plan (for Subsequent Approval)		$ 298,253		$ 150,097			
Cancelled	Generation	48868	AMO Fleet TWIP Upgrades	2017 ACE Plan (for Subsequent Approval)		$ 280,608		$ 32,417			
Cancelled	Transmission	50342	Western Transmission System Voltage Support	2017 ACE Plan (for Subsequent Approval)		$ 4,000,000		$ -			
Now less than $250k.	Transmission	50021	91H Tufts Cove Bus and Line Upgrades	2017 ACE Plan (for Subsequent Approval)		$ 417,178		$ -			
Pending Submission	Distribution	50343	Advanced Metering Infrastructure	2017 ACE Plan (for Subsequent Approval)		$ 111,707,380		$ -			
Now less than $250k.	Distribution	49899	10H Halifax 4kV Conversion Year 4	2017 ACE Plan (for Subsequent Approval)		$ 254,608		$ 189,513			
Awaiting Approval	General Plant	49857	IT - Storage Infrastructure Upgrade	2017 ACE Plan (for Subsequent Approval)	OTQ - November 17, 2017	$ 5,045,955	$ 1,901,189	$ 13,158			
Awaiting Approval	General Plant	49860	IT - Sharepoint Upgrade	2017 ACE Plan (for Subsequent Approval)	Q3 2017 - October 30, 2017	$ 4,021,915	$ 3,903,594	$ 535,769			
Deferred	General Plant	49093	IT - Security Operations Center (SOC) and Security Information Event Monitoring (SIEM)	2017 ACE Plan (for Subsequent Approval)		$ 2,476,976		$ 365,521			
Deferred	General Plant	49859	IT - Windows Server 2008 Upgrade	2017 ACE Plan (for Subsequent Approval)		$ 2,069,258		$ -			
Awaiting Approval	General Plant	49855	IT - Desktop Software Modernization	2017 ACE Plan (for Subsequent Approval)	Q3 2017 - October 30, 2017	$ 2,013,034	$ 4,620,516	$ 2,630,852			
Awaiting Approval	General Plant	50153	Self Serve Development Phase 2	2017 ACE Plan (for Subsequent Approval)	OTQ - September 15, 2017	$ 1,827,720	$ 1,160,528	$ 40,133			
Deferred	General Plant	49094	IT - Identity Access Management Infrastructure	2017 ACE Plan (for Subsequent Approval)		$ 1,711,147		$ 115,369			
Deferred	General Plant	49858	IT - Microsoft Exchange Upgrade	2017 ACE Plan (for Subsequent Approval)		$ 1,500,000		$ -			
Awaiting Approval	General Plant	48773	IT - VOIP Expansion to NSPI sites	2017 ACE Plan (for Subsequent Approval)	Q3 2017 - October 30, 2017	$ 1,499,731	$ 1,708,923	$ 123,286			
Deferred	General Plant	49480	IT - Disaster Recovery	2017 ACE Plan (for Subsequent Approval)		$ 1,483,365		$ 209,690			
Deferred	General Plant	49601	IT - Data loss Prevention	2017 ACE Plan (for Subsequent Approval)		$ 1,199,013		$ -			
Deferred	General Plant	49600	IT - Network Architecture Redesign	2017 ACE Plan (for Subsequent Approval)		$ 1,183,826		$ -			
Pending Submission	General Plant	49876	Real Time Economic Dispatch	2017 ACE Plan (for Subsequent Approval)		$ 1,161,618		$ 245,751			
Deferred	General Plant	50112	Consolidated Customer Web Portal	2017 ACE Plan (for Subsequent Approval)		$ 770,977		$ -			
Awaiting Approval	General Plant	50113	Customer Experience - Streetlight improvements	2017 ACE Plan (for Subsequent Approval)	Q3 2017 - October 30, 2017	$ 679,394	$ 875,836	$ 58,368			
Cancelled	General Plant	49603	IT - Patch Management	2017 ACE Plan (for Subsequent Approval)		$ 536,350		$ -			
Deferred	General Plant	48044	Bentley Nevada Upgrade and Integration to Fleet Monitoring	2017 ACE Plan (for Subsequent Approval)		$ 401,459		$ 17,201			
Awaiting Approval	General Plant	50295	Electric Vehicle Infrastructure Deployment	2017 ACE Plan (for Subsequent Approval)	OTQ - August 2, 2017	$ 400,000	$ 419,908	$ 18,422			
Deferred	General Plant	50132	Joint Regulation	2017 ACE Plan (for Subsequent Approval)		$ 387,704		$ -			
Awaiting Approval	General Plant	49953	IT - CIS High Availability	2017 ACE Plan (for Subsequent Approval)	OTQ - November 17, 2017	$ 354,578	$ 519,023	$ -			
Awaiting Approval	General Plant	50292	FAC - Kempt Road Depot Truck Bay	2017 ACE Plan (for Subsequent Approval)	Q3 2017 - October 30, 2017	$ 340,655	$ 1,095,720	$ 36,275			
Pending Submission	Generation	47678	HYD Prince Mine Dam Decommissioning	2017 ACE Plan (for Subsequent Approval)		$ 819,451		$ 538,718			
Cancelled	General Plant	50115	Customer Support System Enhancement	2017 ACE Plan (for Subsequent Approval)		$ 332,847		$ -			
Pending Submission	General Plant	48837	AMO Fleet Environmental Data Management	2017 ACE Plan (for Subsequent Approval)		$ 317,215		$ 38,471			
Cancelled	General Plant	49856	IT - ITSM Replacement	2017 ACE Plan (for Subsequent Approval)		$ 300,000		$ -			
Approved	Generation	49605	CTs- BGT 3 Engine Refurbishment	U&U	OTQ - December 16, 2016		$ 2,032,866	$ 2,126,377			
Approved	Generation	49869	ICP UU Armour Stone Replacement	U&U	OTQ - December 16, 2016		$ 2,793,935	$ 1,332,141			
Approved	General Plant	48155	2016 SCADA Application Upgrade	2017 ACE Plan (for Subsequent Approval)	OTQ - December 16, 2016	$ 400,688	$ 400,688	$ 346,866			
Approved	Transmission	49879	77V-T52 Replacement	2017 ACE Plan (for Subsequent Approval)	OTQ - December 16, 2016	$ 775,082	$ 772,208	$ 4,019			
Approved	General Plant	48238	Customer Billing Experience Improve	2017 ACE Plan (for Subsequent Approval)	OTQ - December 16, 2016	$ 490,878	$ 405,324	$ 386,317			
Approved	Generation	49061	LM6000 191-443 Engine Repair	U&U	OTQ - December 16, 2016		$ 1,077,840	$ 1,077,840			
Approved	General Plant	43202	Replace Mobile Radio System	2017 ACE Plan (for Subsequent Approval)	Q4 2016 - January 31, 2017	$ 6,537,700	$ 6,296,878	$ 488,992			
Approved	Transmission	49922	Western Switching Upgrades	2017 ACE Plan (for Subsequent Approval)	Q4 2016 - January 31, 2017	$ 353,906	$ 378,843	$ 6,067			
Approved	Generation	44595	HYD - Hollow Bridge Canal & Intake	2016 ACE Plan (for Subsequent Approval)	Q4 2016 - January 31, 2017	$ 3,137,002	$ 4,600,336	$ 4,683,012			
Approved	Generation	47600	TRE Asbestos Abatement (2016)	2016 ACE Plan (Items less than $250K)	Q4 2016 - January 31, 2017	$ 154,303	$ 2,096,391	$ 2,088,671			
Approved - FIN'd Internally	Generation	47933	LIN4 Turbine Vibr. Monit. Upgrade	2016 ACE Plan (Items less than $250K)	Q4 2016 - January 31, 2017	$ 238,216	$ 280,095	$ 291,238			
Approved	Generation	46499	Stator Rewind Kit Capital Spare	2017 ACE Plan (for Subsequent Approval)	OTQ - March 8, 2017	$ 5,219,939	$ 2,871,003	$ 880,884			
Approved	Generation	47553	TRE6 Turbine Valve Refurbishment	2017 ACE Plan (for Subsequent Approval)	OTQ - March 8, 2017	$ 392,887	$ 570,600	$ 415,049			
Approved	Generation	47648	HYO Lequille Pipeline Replacement	2017 ACE Plan (for Subsequent Approval)	OTQ - March 8, 2017	$ 1,384,448	$ 1,121,253	$ 322,891			
Approved	Generation	47876	HYD Lequille Overhaul	2017 ACE Plan (for Subsequent Approval)	OTQ - March 8, 2017	$ 1,155,418	$ 1,395,229	$ 845,642			
Approved	Generation	48052	HYD Annapolis HVAC Upgrade	2017 ACE Plan (for Subsequent Approval)	OTQ - March 8, 2017	$ 1,498,367	$ 1,573,596	$ 128,985			
Approved	Generation	49596	HYD – Hells Gate 2 Overhaul	2017 ACE Plan (for Subsequent Approval)	OTQ - March 8, 2017	$ 970,827	$ 1,204,263	$ 359,757			
Approved	Generation	49674	TUC2 - Boiler Selective Waterwall Tube Replacements	2017 ACE Plan (for Subsequent Approval)	OTQ - March 8, 2017	$ 390,898	$ 421,518	$ 698,270			
Approved	Generation	47947	TUC6 Condenser Waterbox Coating Replacement	2016 ACE Plan (Items less than $250K)	OTQ - March 8, 2017	$ 225,210	$ 366,978	$ 368,637			
Approved	Generation	49632	HYD White Rock Canal Refurbishment	U&U	OTQ - March 8, 2017		$ 590,670	$ 65,416			
Approved	Generation	49633	HYD Trout River Lake Canal Refurbishment	U&U	OTQ - March 8, 2017		$ 519,531	$ 49,872			
Approved - FIN'd Internally	Generation	50192	TRE5 U&U Turbine Valve Refurbishment	U&U	OTQ - March 8, 2017		$ 391,152	$ 392,297			
Approved	Distribution	47760	85S-402 Re-Insulate	2017 ACE Plan (for Subsequent Approval)	OTQ - March 31, 2017	$ 1,259,666	$ 1,551,859	$ 1,101,691			
Approved	Transmission	49928	3S Gannon Road – Bus Reconfiguration	2017 ACE Plan (for Subsequent Approval)	OTQ - March 31, 2017	$ 364,777	$ 371,395	$ 422,727			
Approved	Transmission	49929	Tap Changer Replacements	2017 ACE Plan (for Subsequent Approval)	OTQ - March 31, 2017	$ 262,526	$ 318,236	$ 535,602			
Approved	Generation	47654	HYD - Gulch Penstock & Surge Tank Replacement	2017 ACE Plan (for Subsequent Approval)	OTQ - March 31, 2017	$ 3,629,655	$ 4,970,542	$ 3,159,308			
Approved	Generation	47682	HYD Lequille Switchgear Replacement	2017 ACE Plan (for Subsequent Approval)	OTQ - March 31, 2017	$ 698,659	$ 776,391	$ 627,709			
Approved	Generation	48893	TUC3 IP Turbine Refurbishment	2017 ACE Plan (for Subsequent Approval)	OTQ - March 31, 2017	$ 4,798,475	$ 4,871,454	$ 2,045,954			
Approved	Generation	49039	HYD Lequille Controls Upgrades	2017 ACE Plan (for Subsequent Approval)	OTQ - March 31, 2017	$ 304,121	$ 762,912	$ 164,741			
Approved	Generation	49111	POT Air Heater Refurbishment	2017 ACE Plan (for Subsequent Approval)	OTQ - March 31, 2017	$ 471,204	$ 272,538	$ 384,355			
Approved	Generation	49538	TRE6 Generator Rotor Flux Probe Installation	2017 ACE Plan (for Subsequent Approval)	OTQ - March 31, 2017	$ 411,766	$ 784,610	$ 354,172			
Approved	Generation	49598	HYD Gisborne Switchgear Replacement	2017 ACE Plan (for Subsequent Approval)	OTQ - March 31, 2017	$ 623,814	$ 747,450	$ 13,435			
Approved	Generation	51052	TRE6 Generator High Voltage Bushings Critical Spare	2017 ACE Plan (for Subsequent Approval)	OTQ - March 31, 2017	$ 411,766	$ 264,250	$ -			
Approved	Distribution	49787	Intelligent Feeder Project	2017 ACE Plan (for Subsequent Approval)	OTQ - March 31, 2017	$ 2,399,368	$ 2,782,384	$ 1,136,580			

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Status		CI Number	Title	ACE Plan Reference (or U&U and P&A)	Submission/Date	ACE Amount	Submission or Approved Amount	Actual Spend	ATO or FIN Submission Date	FIN or ATO/FIN Amount	Variance
Approved	Distribution	47756	36V-303 Reconductor Middle Dyke Rd	2016 ACE Plan (Items less than $250K)	OTQ - March 31, 2017	$ 226,303	$ 287,779	$ 285,805			
Approved	Transmission	48111	East Switch Upgrades 15S	2016 ACE Plan (Items less than $250K)	OTQ - March 31, 2017	$ 122,220	$ 304,379	$ 14,630			
Approved	Generation	47606	TRE5 Sootblower Controls Upgrade	2016 ACE Plan (<$250K)	OTQ - March 31, 2017	$ 158,399	$ 285,301	$ 286,649			
Approved	Generation	43128	HYD Gisborne Gearbox and Bearing Replacement	2013 ACE Plan	OTQ - March 31, 2017	$ 360,731	$ 829,447	$ 993,685			
Approved	Generation	46352	TRE5 Air Heater Refurbishment	2015 ACE Plan	OTQ - March 31, 2017	$ 530,139	$ 1,088,844	$ 1,079,177			
Approved	Generation	47552	TRE5 – Boiler Refurbishment 2016	2016 ACE Plan	OTQ - March 31, 2017	$ 1,204,387	$ 2,429,444	$ 2,390,614			
Approved - FIN'd Internally	Generation	47506	LIN CW Screen Refurbishment	2016 ACE Plan	2016 ACE Plan	$ 349,743	$ 349,743	$ 666,534	OTQ - March 31, 2017	$ 666,401	$ 316,658
Approved - FIN'd Internally	Generation	47661	POT – Asbestos Management 2016	2016 ACE Plan	2016 ACE Plan	$ 721,551	$ 721,551	$ 347,326	OTQ - March 31, 2017	$ 347,326	$ (374,225)
Approved	Generation	48811	LIN4 Feedwater Heater Level Control Upgrade	U&U	OTQ - March 31, 2017		$ 296,832	$ 287,149			
Approved	Distribution	50796	New Distribution Rights-of-Way Phase II	P&A	OTQ - April 4th, 2017		$ 3,353,445	$ 1,462,199			
Approved	Distribution	50800	1C-411 Reinsulate and Pole Replacements Phase 1	P&A	OTQ - April 4th, 2017		$ 442,732	$ 123,977			
Approved	Distribution	50772	37N-412 Glooscap Trail Rebuild Phase 1	P&A	OTQ - April 4th, 2017		$ 771,476	$ 380,541			
Approved	Distribution	49862	50N-410 Rebuild Trenton Phase 1	2017 ACE Plan (Items less than $250K)	OTQ - April 4th, 2017	$ 247,773	$ 440,329	$ 436,076			
Approved	Transmission	48114	2016 Steel Tower Life Extension	2016 ACE Plan	Q1 2017 - May 2, 2017	$ 1,477,739	$ 1,465,712	$ 1,307,045			
Approved	Distribution	50341	2017 Substation Recloser Replacements	2017 ACE Plan (for Subsequent Approval)	Q1 2017 - May 2, 2017	$ 577,388	$ 604,888	$ 268,789			
Approved	Generation	17581	HYD Weymouth Electrical Replacement	2013 ACE Plan	Q1 2017 - May 2, 2017	$ 1,641,359	$ 2,366,025	$ 2,327,646			
Approved	Generation	44716	TUC2 North Boiler Feedwater Pump Refurbishment	2015 ACE Plan (Items less than 250K)	Q1 2017 - May 2, 2017	$ 191,007	$ 274,951	$ 349,468			
Approved	Generation	51053	TRE6 HIP Turbine Diaphragm Partition Refurbishment	2017 ACE Plan (for Subsequent Approval) - 47531	Q1 2017 - May 2, 2017	$ 2,322,487	$ 1,185,445	$ 997,440			
Approved	Generation	20511	CT – Victoria Junction Replace Halon Fire Protection System	2015 ACE Plan	OTQ - May 31, 2017	$ 268,467	$ 619,750	$ 30,904			
Approved - FIN'd Internally	Transmission	43205	L5510 Insulator Replacements	2014 ACE Plan	2014 ACE Plan	$ 3,191,398	$ 3,191,398	$ 2,908,944	OTQ - May 31, 2017	$ 2,908,944	$ (282,454)
Approved	Generation	44776	TUC#5 LM6000 Generator Stator Re-wedge	2017 ACE Plan (for Subsequent Approval)	OTQ - May 31, 2017	$ 1,073,280	$ 1,361,301	$ 957,829			
Approved	Generation	47874	LIN Ash Scale Replacement	2016 ACE Plan (<$250K)	OTQ - May 31, 2017	$ 237,241	$ 481,252	$ 224,120			
Approved	Generation	48514	LIN U&U Coal Truck Scale	U&U	OTQ - May 31, 2017	$ -	$ 308,468	$ 329,281			
Approved	Generation	49438	LIN A Gallery Floor Replacement	2017 ACE Plan (for Subsequent Approval)	OTQ - May 31, 2017	$ 593,814	$ 591,761	$ 390,730			
Approved	Generation	50017	TUC4 CEMS Installation U&U	U&U	OTQ - May 31, 2017	$ -	$ 410,817	$ 376,704			
Approved	Generation	50018	TUC5 CEMS Installation U&U	U&U	OTQ - May 31, 2017	$ -	$ 450,496	$ 385,824			
Approved	Generation	51409	LIN Track Dozer Replacement U&U	U&U	OTQ - May 31, 2017	$ -	$ 985,497	$ 948,020			
Awaiting Approval	Generation	51526	CT Tusket Generator Replacement	P&A	OTQ - May 31, 2017	$ -	$ 3,190,415	$ 515,585			
Not approved	Generation	47331	LM6000 191-253 Engine Refurbishment	U&U	OTQ - June 30, 2017	$ -	$ 1,023,342	$ 1,023,343			
Approved	Distribution	47787	2H Armdale New Feeders	2017 ACE Plan (for Subsequent Approval)	OTQ - July 7, 2017	$ 1,285,679	$ 988,498	$ 2,208			
Awaiting Approval	Generation	49273	BGT2 Engine Refurbishment	2017 ACE Plan (for Subsequent Approval)	OTQ - July 7, 2017	$ 1,019,832	$ 2,170,157	$ 1,607,010			
Approved	Generation	49499	PHB Boiler Refurbishment 2017	2017 ACE Plan (for Subsequent Approval)	OTQ - July 7, 2017	$ 484,730	$ 593,740	$ 436,848			
Approved	Generation	49553	TRE Asbestos Abatement 2017	2017 ACE Plan (<$250K)	OTQ - July 7, 2017	$ 226,451	$ 728,886	$ 597,779			
Awaiting Approval	Generation	44267	TRE Ash Lagoon Site Closure	2015 ACE Plan	OTQ - July 7, 2017	$ 7,994,849	$ 9,568,879	$ 7,108,609			
Awaiting Approval	Generation	51711	CT Burnside #2 Generator Replacement	P&A	OTQ - July 7, 2017	$ -	$ 2,876,865	$ 527,260			
Approved	Generation	51317	TRE5 CW Inlet System Refurbishment	U&U	OTQ - July 7, 2017	$ -	$ 390,035	$ 390,258			
Approved - Fin'd externally	Generation	44188	TRE Ash Site Phase 1 Capping	2015 ACE Plan	2015 ACE Plan	$ 4,538,289	$ 5,022,051	$ 5,021,932	Q1 - May 2, 2017 (amounts subsequently revised in IRs)	$ 5,022,051	$ 483,762
Awaiting Approval	Generation	29807	HYD - Tusket Falls Main Dam	2017 ACE Plan (for Subsequent Approval)	OTQ - July 5, 2017	$ 9,940,664	$ 18,157,609	$ 1,971,840			
Approved	Generation	49132	PTMT Dock Winching & Access Refurb	U&U	Q2 - July 31, 2017	$ -	$ 416,998	$ 29,170			
Approved	Generation	49433	LIN1 SH5 Boiler Tube Replacement	2017 ACE Plan	Q2 - July 31, 2017	$ 493,396	$ 848,377	$ 795,846			
Approved	Generation	49551	TRE5 CEMS Replacement	2017 ACE Plan (<$250K)	Q2 - July 31, 2017	$ 162,647	$ 671,295	$ 164,472			
Approved	Generation	51593	HYD WRC WG Thrust Assembly Refurb U&U	U&U	Q2 - July 31, 2017	$ -	$ 667,024	$ 569,921			
Approved	Generation	49316	TUC3 UU CEMS Installation	U&U	OTQ - September 15, 2017	$ -	$ 461,704	$ 495			
Approved	Generation	49693	TUC HFO Tank Dyke Piping Refurbishments	2017 ACE Plan (<$250K)	OTQ - September 15, 2017	$ 219,022	$ 664,753	$ 98,310			
Awaiting Approval	Transmission	51404	2018/2019 Steel Tower PA	P&A	OTQ - September 15, 2017	$ -	$ 2,981,318	$ 750,414			
Awaiting Approval	Distribution	47786	129H Kearney Lake Load Transfer	2016 ACE Plan (for Subsequent Approval)	Q3 2017 - October 30, 2017	$ 311,817	$ 286,280	$ 276,951			
Awaiting Approval	Transmission	51956	6P Mobile Substation Rewind U&U	U&U	Q3 2017 - October 30, 2017	$ -	$ 1,516,121	$ -			
Awaiting Approval	Generation	38931	HYD Harmony Site Stabilization	2017 ACE Plan (for Subsequent Approval)	Q3 2017 - October 30, 2017	$ 1,106,122	$ 931,942	$ 574,583			
Awaiting Approval	Generation	50020	LIN CEMS Replacement	2017 ACE Plan (<$250K)	OTQ - November 17, 2017	$ 170,281	$ 633,355	$ -			
Awaiting Approval	General Plant	51485	IT Threat Management	P&A	OTQ - November 17, 2017	$ -	$ 813,449	$ 61,095			
Awaiting Approval	General Plant	51484	IT SCADA Network Firewall	U&U	OTQ - November 17, 2017	$ -	$ 365,737	$ 81,378			
Awaiting Approval	Distribution	43218	88W-323A Tusket Islands Phase 3		2018 ACE Plan	$ 654,721	$ 654,721	$ 6,802			
Awaiting Approval	Transmission	43268	9W-B53 Tusket Replace Structure		2018 ACE Plan	$ 375,523	$ 375,523	$ -			
Awaiting Approval	Generation	43429	TRE5 Lube Oil Cooler Retube		2018 ACE Plan	$ 338,398	$ 338,398	$ -			
Awaiting Approval	Generation	47655	HYD - Paradise Controls Upgrade		2018 ACE Plan	$ 639,991	$ 639,991	$ 22,906			
Awaiting Approval	Generation	47684	LIN3 Boiler Refurbishment 2018		2018 ACE Plan	$ 739,657	$ 739,657	$ -			
Awaiting Approval	Generation	47871	LIN Stack Re-Coating		2018 ACE Plan	$ 381,034	$ 381,034	$ -			
Awaiting Approval	Transmission	48131	48H-T1 Replacement		2018 ACE Plan	$ 1,281,449	$ 1,281,449	$ -			
Awaiting Approval	Generation	48533	HYD Lequille Headpond Refurbishment		2018 ACE Plan	$ 4,472,369	$ 4,472,369	$ 119,088			
Awaiting Approval	Generation	48712	HYD - Dam Instrumentation Upgrade		2018 ACE Plan	$ 476,207	$ 476,207	$ 63,227			
Awaiting Approval	Generation	49033	HYD WRC Tunnel T-2 Intake Replacement		2018 ACE Plan	$ 2,851,582	$ 2,851,582	$ 257,757			
Awaiting Approval	Generation	49534	TRE6 EHG/Turbine Controls Upgrade		2018 ACE Plan	$ 2,725,344	$ 2,725,344	$ 6,448			
Awaiting Approval	Generation	49547	TRE5 5-1 BFP Refurbishment		2018 ACE Plan	$ 345,523	$ 345,523	$ -			
Awaiting Approval	Generation	49676	TUC2 CEMS Replacement		2018 ACE Plan	$ 380,140	$ 380,140	$ -			
Awaiting Approval	Transmission	49777	L7002 Replacements and Upgrades		2018 ACE Plan	$ 926,777	$ 926,777	$ -			
Awaiting Approval	Transmission	49779	L6537 Replacements and Upgrades		2018 ACE Plan	$ 1,255,220	$ 1,255,220	$ -			
Awaiting Approval	Transmission	49783	L5027A Replacements and Upgrades		2018 ACE Plan	$ 648,292	$ 648,292	$ -			
Awaiting Approval	Transmission	49788	L5564 Replacements and Upgrades		2018 ACE Plan	$ 738,853	$ 738,853	$ -			
Awaiting Approval	Generation	49942	HYD - Tidewater Facility Refurbishment		2018 ACE Plan	$ 1,234,178	$ 1,234,178	$ -			
Awaiting Approval	Generation	49943	HYD - Ruth Falls Facility Refurbishment		2018 ACE Plan	$ 1,234,931	$ 1,234,931	$ 15,236			
Awaiting Approval	Generation	49944	HYD - Dickie Brook Penstock Refurbishment		2018 ACE Plan	$ 478,820	$ 478,820	$ -			
Awaiting Approval	Generation	49945	HYD - Malay Falls Switchgear Replacement		2018 ACE Plan	$ 958,631	$ 958,631	$ -			
Awaiting Approval	Generation	49946	HYD - Fourth Lake Overhaul		2018 ACE Plan	$ 1,025,769	$ 1,025,769	$ -			
Awaiting Approval	Generation	50577	TRE6 CEMS Replacement		2018 ACE Plan	$ 715,562	$ 715,562	$ 668			
Awaiting Approval	Generation	51234	HYD - WRC HVAC Upgrade		2018 ACE Plan	$ 1,876,537	$ 1,876,537	$ 130,291			
Awaiting Approval	Generation	51235	HYD - WRC Main Access Rd Refurbishment		2018 ACE Plan	$ 2,686,075	$ 2,686,075	$ 83,480			
Awaiting Approval	Generation	51236	HYD - WRC Tailrace Rock Bolting		2018 ACE Plan	$ 8,861,996	$ 8,861,996	$ 160,694			
Awaiting Approval	Transmission	51398	2018/2019 Steel Tower Refurbishment		2018 ACE Plan	$ 1,992,692	$ 1,992,692	$ -			
Awaiting Approval	Distribution	51400	2018 Sub Recloser Replacements		2018 ACE Plan	$ 644,710	$ 644,710	$ -			
Awaiting Approval	Transmission	51402	2018/2019 Sacrificial Anode Installation		2018 ACE Plan	$ 3,023,668	$ 3,023,668	$ -			
Awaiting Approval	Transmission	51403	2018 PCB Removal Program		2018 ACE Plan	$ 4,402,342	$ 4,402,342	$ -			
Awaiting Approval	Transmission	51405	2018 Wood Pole Retreatment Program		2018 ACE Plan	$ 1,361,076	$ 1,361,076	$ -			
Awaiting Approval	Transmission	51406	2018/2019 Transmission Switch & Breaker Replacement		2018 ACE Plan	$ 1,405,891	$ 1,405,891	$ -			
Awaiting Approval	Distribution	51493	2018 PCB Pole Top Transformer Replacement		2018 ACE Plan	$ 1,360,354	$ 1,360,354	$ 154,022			
Awaiting Approval	Distribution	51500	2018 Pin Insulator Replacements		2018 ACE Plan	$ 350,100	$ 350,100	$ -			
Awaiting Approval	Distribution	51744	30N-411 Maccan River Rebuild		2018 ACE Plan	$ 473,044	$ 473,044	$ -			
Awaiting Approval	Transmission	51797	2018 Oil Containment Program		2018 ACE Plan	$ 331,507	$ 331,507	$ -			
Awaiting Approval	Generation	51802	TRE5 Boiler Refurbishment 2018		2018 ACE Plan	$ 1,212,228	$ 1,212,228	$ -			
Awaiting Approval	Generation	51803	TUC2 Generator Flux Probe Installation		2018 ACE Plan	$ 840,158	$ 840,158	$ -			
Awaiting Approval	Generation	51804	LIN3&4 ACW Duplex Strainer Replacement		2018 ACE Plan	$ 333,808	$ 333,808	$ -			
Awaiting Approval	Generation	51805	LIN4 Boiler Refurbishment 2018		2018 ACE Plan	$ 739,657	$ 739,657	$ -			
Awaiting Approval	Generation	51806	LIN Mill Refurbishment 2018		2018 ACE Plan	$ 673,153	$ 673,153	$ -			
Awaiting Approval	Generation	51807	TUC2 Boiler Lower Vestibule Refurbishment		2018 ACE Plan	$ 412,872	$ 412,872	$ -			
Awaiting Approval	Generation	51811	LIN Reclaim Refurbishment Phase 2		2018 ACE Plan	$ 534,666	$ 534,666	$ -			
Awaiting Approval	Generation	51815	LIN CW Pump Refurbishment 2018		2018 ACE Plan	$ 520,436	$ 520,436	$ -			
Awaiting Approval	Generation	51816	TRE Asbestos Abatement 2018		2018 ACE Plan	$ 509,035	$ 509,035	$ -			
Awaiting Approval	Generation	51818	PHB Boiler Refurbishment 2018		2018 ACE Plan	$ 440,315	$ 440,315	$ -			
Awaiting Approval	Generation	51820	TRE5 Reheat Turbine Valves		2018 ACE Plan	$ 450,408	$ 450,408	$ -			
Awaiting Approval	Generation	51821	TRE5 Air Heater Refurbishment		2018 ACE Plan	$ 487,376	$ 487,376	$ -			

2017 3rd Quarter Overview - Updated for Ace 2018

Status		CI Number	Title	ACE Plan Reference (or U&U and P&A)	Submission/Date	ACE Amount	Submission or Approved Amount	Actual Spend	ATO or FIN Submission Date	FIN or ATO/FIN Amount	Variance
Awaiting Approval	Generation	51824	LIN3 ID Fan Damper and VIV Refurbishment		2018 ACE Plan	$ 443,311	$ 443,311	$ -			
Awaiting Approval	Generation	51825	POT Boiler Refurbishment 2018		2018 ACE Plan	$ 568,740	$ 568,740	$ -			
Awaiting Approval	Generation	51835	TUC2 H2 Panel Upgrades		2018 ACE Plan	$ 454,886	$ 454,886	$ -			
Awaiting Approval	Generation	51836	TRE5 Mill Refurbishments 2018		2018 ACE Plan	$ 409,458	$ 409,458	$ -			
Awaiting Approval	Generation	51839	LIN Coal Plant Structural Refurbishment		2018 ACE Plan	$ 354,067	$ 354,067	$ -			
Awaiting Approval	Generation	51849	LIN3 RH Tube Replacement		2018 ACE Plan	$ 399,546	$ 399,546	$ -			
Awaiting Approval	Generation	51850	LIN4 RH Tube Replacement		2018 ACE Plan	$ 399,546	$ 399,546	$ -			
Awaiting Approval	Generation	51851	LIN CW Screen Refurbishment 2018		2018 ACE Plan	$ 350,534	$ 350,534	$ -			
Awaiting Approval	Generation	51852	POT Mill Refurbishment 2018		2018 ACE Plan	$ 327,267	$ 327,267	$ -			
Awaiting Approval	Generation	51853	LIN3 Turbine Valve Refurb 2018		2018 ACE Plan	$ 295,709	$ 295,709	$ -			
Awaiting Approval	Generation	51857	TRE5 Burner Refurbishments 2018		2018 ACE Plan	$ 332,497	$ 332,497	$ -			
Awaiting Approval	Generation	51860	TRE5 PF Mill Line Replacement		2018 ACE Plan	$ 258,761	$ 258,761	$ -			
Awaiting Approval	Generation	51861	TRE6 CW Screen Replacement 2018		2018 ACE Plan	$ 513,192	$ 513,192	$ -			
Awaiting Approval	Generation	51862	TRE6 Lube Oil Cooler Refurbishment		2018 ACE Plan	$ 341,769	$ 341,769	$ -			
Awaiting Approval	Transmission	51863	2018 Tap Changer Replacements		2018 ACE Plan	$ 306,102	$ 306,102	$ -			
Awaiting Approval	Generation	51866	HYD - 4th Lake Penstock Refurbishment		2018 ACE Plan	$ 696,963	$ 696,963	$ -			
Awaiting Approval	Transmission	51969	2018 Transmission ROW Widening 69kV		2018 ACE Plan	$ 5,487,686	$ 5,487,686	$ -			
Awaiting Approval	Generation	51972	HYD Nictaux Canal Embank Refurbishment		2018 ACE Plan	$ 789,918	$ 789,918	$ 170			
Awaiting Approval	Transmission	51975	5P Mobile Substation Replacement		2018 ACE Plan	$ 4,829,458	$ 4,829,458	$ -			
Awaiting Approval	Generation	52018	HYD - RES Revenue Meter Replacement		2018 ACE Plan	$ 378,248	$ 378,248	$ -			
Awaiting Approval	Transmission	52059	L5039 - 2018 Replacements and Upgrades		2018 ACE Plan	$ 719,825	$ 719,825	$ -			
Awaiting Approval	Generation	52093	ICP Rail Crossing Refurbishment		2018 ACE Plan	$ 592,402	$ 592,402	$ -			
Awaiting Approval	Transmission	52102	L5014-2018 Replacements and Upgrades		2018 ACE Plan	$ 849,700	$ 849,700	$ -			
Awaiting Approval	Transmission	52119	L5054 2018 Replacements and Upgrades		2018 ACE Plan	$ 560,143	$ 560,143	$ -			
Awaiting Approval	Generation	52143	LM6000 Engine 191-332 Hot Section		2018 ACE Plan	$ 1,776,275	$ 1,776,275	$ -			
Awaiting Approval	Generation	52156	LIN Vacuum Pump Upgrades		2018 ACE Plan	$ 302,714	$ 302,714	$ -			
Awaiting Approval	Distribution	52184	37N-412-Glooscap Trail Rebuild Phase 2		2018 ACE Plan	$ 858,046	$ 858,046	$ 225			
Awaiting Approval	Distribution	52185	5DN-410 Rebuild Phase 2		2018 ACE Plan	$ 695,098	$ 695,098	$ -			
Awaiting Approval	Distribution	52186	4S Feeder Exit Cable Replacement Phase 1		2018 ACE Plan	$ 293,509	$ 293,509	$ -			
Awaiting Approval	Distribution	52192	54H-303 Underground Device Replacement		2018 ACE Plan	$ 309,230	$ 309,230	$ -			
Awaiting Approval	Distribution	52194	6S-223 Harold Street Conversion		2018 ACE Plan	$ 642,368	$ 642,368	$ -			
Awaiting Approval	Distribution	52200	65V-301 Brickton Reconductor		2018 ACE Plan	$ 594,362	$ 594,362	$ -			
Awaiting Approval	Distribution	52201	55V-314GA-Welsford Reconductor		2018 ACE Plan	$ 275,161	$ 275,161	$ -			
Awaiting Approval	Distribution	52204	87W-312G-Tancook Island Replacement		2018 ACE Plan	$ 454,096	$ 454,096	$ -			
Awaiting Approval	Distribution	52205	30N-412 Hwy 242 Fundy Shore Rebuild		2018 ACE Plan	$ 536,670	$ 536,670	$ -			
Awaiting Approval	Distribution	52206	20V-311-Bishop Ville Rd		2018 ACE Plan	$ 303,533	$ 303,533	$ -			
Awaiting Approval	Distribution	52207	678H-211 McNab's Island Replacement		2018 ACE Plan	$ 350,176	$ 350,176	$ -			
Awaiting Approval	Distribution	52208	3S Feeder Exit Cable Replacement Phase 2		2018 ACE Plan	$ 293,228	$ 293,228	$ -			
Awaiting Approval	Distribution	52224	532N-Elm Street Conversion Phase 2		2018 ACE Plan	$ 722,113	$ 722,113	$ -			
Awaiting Approval	General Plant	52233	2018 Telecom Building Replacement		2018 ACE Plan	$ 314,929	$ 314,929	$ -			
Awaiting Approval	Transmission	52238	2018/2019 Capacitor Bank Breaker Replacement		2018 ACE Plan	$ 433,719	$ 433,719	$ -			
Awaiting Approval	Transmission	52241	16V-T2 Weymouth Hydro Transformer Replacement		2018 ACE Plan	$ 889,253	$ 889,253	$ -			
Awaiting Approval	Generation	52252	LIN1 5H5 Tube Replacement		2018 ACE Plan	$ 521,259	$ 521,259	$ -			
Awaiting Approval	Generation	52253	LIN3 Economizer Header Refurbishment		2018 ACE Plan	$ 499,951	$ 499,951	$ -			
Awaiting Approval	Transmission	52258	2018/2019 Isolated Structure Replacement		2018 ACE Plan	$ 4,818,521	$ 4,818,521	$ -			
Awaiting Approval	Generation	52262	HYD - Hells Gate 1 Overhaul		2018 ACE Plan	$ 854,993	$ 854,993	$ -			
Awaiting Approval	Distribution	52267	16W-302H-Brenton Rd Rebuild		2018 ACE Plan	$ 387,767	$ 387,767	$ -			
Awaiting Approval	Distribution	52271	2018 Padmount Replacement		2018 ACE Plan	$ 1,657,205	$ 1,657,205	$ -			
Awaiting Approval	Transmission	52305	2018 Substation Insulator Replacement		2018 ACE Plan	$ 316,348	$ 316,348	$ -			
Awaiting Approval	General Plant	52308	2018 RTU Replacement Program		2018 ACE Plan	$ 988,056	$ 988,056	$ -			
Awaiting Approval	Transmission	52314	1C-GT1/UT1 Replacement		2018 ACE Plan	$ 2,032,393	$ 2,032,393	$ -			
Awaiting Approval	Transmission	52320	L6549 2018 Replacements & Upgrades		2018 ACE Plan	$ 1,406,535	$ 1,406,535	$ -			
Awaiting Approval	Transmission	52328	56N-T1 Transformer Upgrades		2018 ACE Plan	$ 1,279,271	$ 1,279,271	$ -			
Awaiting Approval	Generation	C0001419	TRE HFO Refurbishment Phase 1		2018 ACE Plan	$ 340,618	$ 340,618	$ -			
Awaiting Approval	Distribution	C0001802	54C-211 Queen Street Conversion		2018 ACE Plan	$ 705,316	$ 705,316	$ -			
Awaiting Approval	Transmission	C0001900	Mount Hope 69-25kV Substation		2018 ACE Plan	$ 2,982,338	$ 2,982,338	$ -			
Awaiting Approval	Distribution	C0001950	New Distribution Rights-of-Way Ph 3		2018 ACE Plan	$ 9,822,493	$ 9,822,493	$ -			
Pending Submission	Generation	39472	HYD Mersey System Re-Development	2018 ACE Plan (for Subsequent Approval)		83,595,607		$ 2,841,037			
Pending Submission	General Plant	46075	IT - Work and Asset Management	2018 ACE Plan (for Subsequent Approval)		45,509,963		$ 1,783,245			
Pending Submission	Generation	47659	HYD - Fall River Controls Upgrade	2018 ACE Plan (for Subsequent Approval)		$ 302,867	$ 302,867	$ -			
Pending Submission	Generation	47660	HYD - Dickie Brook Controls Upgrade	2018 ACE Plan (for Subsequent Approval)		$ 885,586	$ 885,586	$ -			
Pending Submission	Distribution	47794	Heckman Island Underwater Cable Replacement	2018 ACE Plan (for Subsequent Approval)		1,524,923		$ -			
Pending Submission	Generation	48791	HYD - WRC Safety Standards Upgrades	2018 ACE Plan (for Subsequent Approval)		1,019,928		$ 432,530			
Pending Submission	General Plant	49094	IT - Identity Access Mgmt. Infrastructure	2018 ACE Plan (for Subsequent Approval)		977,498		$ 115,369			
Pending Submission	General Plant	49480	IT - Disaster Recovery	2018 ACE Plan (for Subsequent Approval)		6,312,277		$ 209,690			
Pending Submission	Generation	49594	LM6000 TUC5 Airhouse Upgrade	2018 ACE Plan (for Subsequent Approval)		916,391		$ 106,403			
Pending Submission	General Plant	49858	IT - MS Exchange Upgrade	2018 ACE Plan (for Subsequent Approval)		1,555,597		$ -			
Pending Submission	General Plant	50112	Customer Experience Consolidated Customer Web Portal	2018 ACE Plan (for Subsequent Approval)		1,190,588		$ -			
Pending Submission	Generation	51772	HYD Arc Flash Mitigation	2018 ACE Plan (for Subsequent Approval)		403,175		$ 745			
Pending Submission	Generation	51775	HYD Fixed Ladder & Machine Guard	2018 ACE Plan (for Subsequent Approval)		999,149		$ 2,006			
Pending Submission	Generation	51808	TUC HFO Piping Refurbishment	2018 ACE Plan (for Subsequent Approval)		1,291,933		$ -			
Pending Submission	Generation	52017	HYD ANN Exciter Replacement	2018 ACE Plan (for Subsequent Approval)		473,350		$ -			
Pending Submission	Generation	52107	TUC6 CW Screen Replacement	2018 ACE Plan (for Subsequent Approval)		1,029,787		$ -			
Pending Submission	Generation	52321	TUC3 Air Heater Refurbishment	2018 ACE Plan (for Subsequent Approval)		570,623		$ -			
Pending Submission	General Plant	52335	IT-Automate Manual Billing	2018 ACE Plan (for Subsequent Approval)		506,403		$ -			
Pending Submission	General Plant	52337	IT-Group Billing Experience	2018 ACE Plan (for Subsequent Approval)		505,823		$ -			
Pending Submission	General Plant	C0002106	Vegetation Inventory System Upgrade	2018 ACE Plan (for Subsequent Approval)		260,172		$ -			
Pending Submission	General Plant	C0002130	ADMS Distribution Fault Location	2018 ACE Plan (for Subsequent Approval)		473,660		$ -			
Pending Submission	General Plant	C0002241	IT-Generation Operation Upgrade	2018 ACE Plan (for Subsequent Approval)		511,673		$ -			
Pending Submission	General Plant	C0002254	IT- MV90 Upgrade	2018 ACE Plan (for Subsequent Approval)		254,062		$ -			
Pending Submission	Generation	C0002978	CTs Motor Control Centre Upgrades	2018 ACE Plan (for Subsequent Approval)		1,199,221		$ -			

CI	Project Title	2017 ACE Amount	2017 ACE Project Total	Cancelled/ Deferred	Deferred To	Prior Approval	2017 ACE Plan Reference	Commentary
Generation								
47118	CT Tusket Hydraulic Starter	317,015	317,015	Cancelled			Subsequent Submittal	*A new valve technology has led to the replacement of the air start system no longer being required.*
49874	CT-BGT Replace Halon Fire Protection	226,366	226,366	Deferred	2019		Less than $250k	*Fire protection at Tusket and Victoria Junction are being completed in 2017, which has reduced vendor availability to complete this work.*
49932	CT - TUC 4 LM6000 Roof Skid Access	33,161	33,161	Deferred	2018		Less than $250k	*Further analysis determined additional requirements were required to the roof skid. Additional planning and a longer outage are required. Due to this change in project scope, the project is deferred to 2018.*
49933	CT - TUC 5 LM6000 Roof Skid Access	33,161	33,161	Deferred	2018		Less than $250k	*Further analysis determined additional requirements were required to the roof skid. Additional planning and a longer outage are required. Due to this change in project scope, the project is deferred to 2018.*
48533	HYD - Lequille Headpond Water Retaining Structures Refurbishment	1,809,228	1,919,166	Deferred	2018		Subsequent Submittal	*Further analysis of the most recent flood study completed on Lequille is required to validate the dam classification.*
49622	HYD - Fourth Lake PLC Upgrades	116,767	116,767	Cancelled			Less than $250k	*This project will now be completed as part of a larger Sissiboo River Controls Upgrade, currently planned for 2020.*
49912	ICP - Armour Stone Refurbishment Phase 2	242,644	242,644	Cancelled			Less than $250k	*This work is being completed under CI 49869 ICP Armour Stone Replacement U&U, approved on March 10, 2017.*
47834	ICP Ranger Motor Upgrade	242,512	242,512	Deferred	2018		Less than $250k	*This project is deferred to 2018 as conveyor modifications were found to be required prior to a motor upgrade*
49452	LIN3 Heater Level Controls Upgrade	235,135	235,135	Deferred	2018		Less than $250k	*NS Power has deferred the planned outage on Lingan 3 in 2017; therefore this project will be completed in 2018.*
49666	TUC1 South Boiler Feedpump Refurbishment	226,025	226,025	Deferred	2019		Less than $250k	*This project is deferred while NS Power addresses an issue on the north boiler feed pump which needs to be in operation to allow for the south boiler feed pump to come offline to complete this project.*
49546	TRE6 FW Heater Level Control	187,434	187,434	Deferred	2018		Less than $250k	*Based on the daily monitoring of feedwater heater drain temperatures, the temperatures and level controls are stable. Therefore, this upgrade can be safely deferred to 2018.*
49547	TRE5 5-1 BFP Refurbishment	185,294	185,294	Deferred	2018		Less than $250k	*Condition assessments completed in 2017 determined the condition of the Boiler Feed Pumps allowed for this project to be safely deferred to 2018. Now included in ACE 2018 for approval.*
49667	TUC1 Oil Purifier I&C Heater Replacement	160,593	160,593	Deferred	2019		Less than $250k	*This project is deferred while NS Power confirms that the technology installed on TUC3 works as expected. Once this is confirmed, this project will proceed.*
49991	TUC1 CEMS Replacement	159,167	159,167	Deferred	2019		Less than $250k	*Temporary repairs on TUC1 CEM allowed this project to be deferred to 2019 to allow for CEMS replacements on TUC3, 4 and 5 which were found to be higher priority,*
49676	TUC2 CEMS Replacement	150,374	150,374	Deferred	2018		Less than $250k	*This project is being deferred to 2018 to allow for CEMS replacements on TUC3, 4 and 5 which were found to be higher priority, Now included in ACE 2018 for approval.*
45832	TUC6 Boiler Purge Credit	138,577	138,864	Deferred	2019		Less than $250k	*This project is dependent on similar work being implemented on TUC4 & 5, and those projects are still being developed.*
49670	TUC1 4kv/600V Breaker Replacement	104,851	104,851	Deferred	2018		Less than $250k	*Further analysis indicated the breakers scheduled for replacement can be safely deferred to 2018.*
49515	POT - Replacement of Graver valves and solenoids	59,496	59,496	Cancelled			Less than $250k	*Repairs completed on the existing valves and equipment mitigated the need for capital investment.*
49688	TUC3 Analytical Panel Upgrades	55,050	55,050	Deferred	2018		Less than $250k	*Further analysis of the Analytical Panel determined this project could be deferred until 2018*
49700	TUC6 Vacuum Cooler	54,610	54,610	Deferred	2019		Less than $250k	*The condition of the vacuum cooler has allowed for a deferral to 2019. An inspection of the coating solution on the vacuum cooler completed in 2017 will further determine the required timing of the project.*
47909	TUC Nat Gas Valves Refurbishment	54,153	54,153	Deferred	2019		Less than $250k	*Further analysis of the natural gas valves indicated that this project could be safely deferred.*
49653	TUC Dehumidifier Air Unit	51,073	51,073	Deferred	2019		Less than $250k	*Due to the higher utilization of the TUC Units in 2017 than anticipated, the need for an additional dehumidifier is not required.*
49701	TUC6 Turbine Control Valves	50,584	50,584	Deferred	2019		Less than $250k	*As this turbine is of similar vintage to the Port Hawkesbury Biomass generating station, a determination of what is required on this turbine will be made based on the condition of the PHB turbine which will be assessed as part of the 2017 planned outage. This will determine the requirements of this project for 2019.*
49673	TUC1 Extraction Pump Rotork Valve Actuator	48,479	48,479	Deferred	2019		Less than $250k	*Further analysis indicated the Rotork Valve Actuator can be safely deferred to 2019.*
47907	TUC6 Vacuum Pumps' Seal Water Cooler Upgrade	40,501	40,501	Cancelled			Less than $250k	*The scope of this project will be completed as part of CI 49700 TUC6 Vacuum Cooler Upgrade.*
39472	HYD Mersey Hydro System Re-Development	300,000	84,000,000	Deferred	2018		Subsequent Submittal	*Further consultation with First Nations was required in 2017 in order to proceed with this project, pushing the start of this project to late 2018*
49594	LM6000 TUC5 Airhouse Upgrade	833,200	833,200	Deferred	2018		Subsequent Submittal	*Vendor fabrication of components could not be completed to align with the planned TUC5 annual outage.*
49949	LM6000 TUC4 Control System Replacement	710,815	710,815	Deferred	2019		Subsequent Submittal	*Internal review of control systems is ongoing. NS Power expects to complete controls upgrade on TUC5 in 2018, and TUC4 in 2019.*
49835	HYD - Dive Site Risk Mitigation	315,851	650,533	Cancelled			Subsequent Submittal	*Changes in procedure and dive requirements have mitigated the risk and negated the requirement for project.*
47166	HYD - McAskill Brook Decommissioning	459,736	562,684	Deferred	2019		Subsequent Submittal	*Project delayed as engagement with First Nations is undertaken*
47660	HYD - Dickie Brook Controls Upgrade	94,032	307,251	Deferred	2018		Subsequent Submittal	*Project originally scheduled for a late 2017 start, has been pushed to a 2018 start as other control projects are being completed.*
48868	AMO Fleet TWIP Upgrades	257,442	280,608	Cancelled			Subsequent Submittal	*This project was for a fleet wide upgrade. However, this is being split amongst the individual steam plants to better align with timing.*
47659	HYD - Fall River Controls Upgrade	95,201	226,054	Deferred	2018		Less than $250k	*Project originally scheduled for a late 2017 start, has been pushed to a 2018 start as other control projects are being completed.*
47655	HYD - Paradise Controls Upgrade	87,796	207,802	Deferred	2018		Less than $250k	*Project originally scheduled for a late 2017 start, has been pushed to a 2018 start as other control projects are being completed. Now included in ACE 2018 for approval.*
49654	TUC Refurbishment Gas Compressor 6A/6B	133,870	133,870	Cancelled			Less than $250k	*This project was initiated as a Steam project, however these compressors are better considered Gas Turbine projects related to the Tufts Cove 4 / 5 units, therefore two CIs (51731 and 51798) replaced this work. No change to the actual work completed.*
49711	TUC Low Load Oil Operation, Flue Gas monitoring	130,429	130,429	Cancelled			Less than $250k	*This project is cancelled as efforts are now focused on TUC3 low load operation*
49456	LIN1 Electric Motor Refurbishment	113,171	113,171	Cancelled			Less than $250k	*Further analysis has shown the condition of the motors is such that investment is not required.*
49457	LIN3 Electric Motor Refurbishment	111,829	111,829	Cancelled			Less than $250k	*Further analysis has shown the condition of the motors is such that investment is not required.*
49715	TUC Upgrade PLC Control Panel	99,875	99,875	Deferred	2019		Less than $250k	*Other DCS / PLC priorities are required to be completed prior to this project. Project can be safely deferred to 2019.*
49699	TUC6 Access Doors	64,304	64,304	Deferred	2019		Less than $250k	*It has been determined that these areas do not require investment at this time. Current expectation is that it will be needed in 2019 as operating hours accumulate.*
49945	HYD - Malay Falls Switchgear Replacement	43,459	54,729	Deferred	2018		Less than $250k	*The amount included in the 2017 ACE Plan was for preliminary engineering which has been underway, with full construction scheduled for 2018. Now included in ACE 2018 for approval.*
49959	CT - VJ Varec Gauges Upgrade/Refurbishment	29,904	29,904	Deferred	2019		Less than $250k	*Temporary repairs have been made to restore level indication which has allowed the deferral of this project to 2019.*
Transmission								
50342	Western Transmission System Voltage Support	300,000	4,000,000	Cancelled			Subsequent Submittal	*Further analysis completed in 2017 has shown this project is no longer required.*

CI	Project Title	2017 ACE Amount	2017 ACE Project Total	Cancelled/ Deferred	Deferred To	Prior Approval	2017 ACE Plan Reference	Commentary
45053	69Kv Structure Replacements West	321,656	4,818,017	Deferred	2019		Subsequent Submittal	*The planning study for this project is still underway and will be completed throughout 2018, leading to project construction in 2019.*
50021	91H Tufts Cove Bus and Line Upgrades	417,178	417,178	Deferred	2019		Subsequent Submittal	*Further analysis of the engineering solutions was completed in 2017 and has shown this project can be safely deferred to 2019, and is also now under $250,000.*
Distribution								
46305	103W-311G Gold River Reconductor - Phase 3	118,563	118,563	Cancelled			Less than $250k	*This project was a duplicate of CI 43177, approved as part of ACE 2014, and completed in 2017*
General Plant								
49094	IT - Identity Access Management Infrastructure	1,500,000	1,711,147	Deferred	2018		Subsequent Submittal	*Subsequent to the 2017 ACE Plan, NS Power re-examined the resource availability / requirements with the implementation of the ERP project in 2017 and determined that these projects would carry less risk during implementation if completed in 2018.*
49601	IT - Data loss Prevention	1,158,633	1,199,013	Deferred	2019		Subsequent Submittal	*Subsequent to the 2017 ACE Plan, NS Power re-examined this project and determined that this project could be safely deferred to 2019.*
49600	IT - Network Architecture Redesign	1,033,597	1,183,826	Deferred	2019		Subsequent Submittal	*Subsequent to the 2017 ACE Plan, NS Power re-examined the resource availability / requirements with the implementation of the ERP project in 2017 and determined that these projects would carry less risk during implementation if completed in 2018*
49856	IT - ITSM Replacement	300,000	300,000	Cancelled			Subsequent Submittal	*Subsequent to the 2017 ACE Plan, NS Power re-examined the options to address this need and determined that a capital project is not necessary.*
49825	Radio Site Grounding Review & Upgrade	228,414	228,414	Deferred	2018		Less than $250k	*This project is deferred as internal resources are focusing on other, higher priority, telecommunication projects.*
49832	Victoria Junction Substations Fiber Links	65,972	65,972	Deferred	2018		Less than $250k	*This project is deferred as internal resources are focusing on other, higher priority, telecommunication projects.*
46075	IT - Work & Asset Management	8,008,495	28,027,680	Deferred	2018		Subsequent Submittal	*Project has been deferred to better align with availability of resources required to complete the work, and to finish the project scoping / detailed design. Project will be filed in 2018.*
49093	IT - Security Operations Center (SOC) and Security Information Event Monitoring (SIEM	2,191,284	2,476,976	Deferred	2019		Subsequent Submittal	*Implementation of ERP resulted in constrained resources and NS Power chose to minimize the disruption to the business. Further evaluation revealed that this work could be deferred to 2019.*
49859	IT - Windows Server 2008 Upgrade	158,886	2,069,258	Deferred	2019		Subsequent Submittal	*Implementation of ERP resulted in constrained resources and NS Power wanted to minimize disruption to the business. Further evaluation revealed that this work could be deferred to 2019.*
49858	IT - Microsoft Exchange Upgrade	1,500,000	1,500,000	Deferred	2018		Subsequent Submittal	*The assessment on whether this project will include an on-premises or a cloud solution is currently being completed which led the project to be deferred to 2018.*
49480	IT - Disaster Recovery	1,270,691	1,483,365	Deferred	2018		Subsequent Submittal	*Project scoping had revealed that further work is required to determine the project requirements.*
50112	Consolidated Customer Web Portal	770,977	770,977	Deferred	2018		Subsequent Submittal	*Project has been deferred to allow for further scoping and customer engagement.*
47751	Dynamic Transmission Limits	524,616	537,466	Deferred	2019		Subsequent Submittal	*Further analysis is required before this project is pursued.*
49603	IT - Patch Management	500,970	536,350	Cancelled			Subsequent Submittal	*Project scoping has determined the solution for this project is not capital investment.*
48044	Bentley Nevada Upgrade and Integration to Fleet Monitoring	383,621	401,459	Deferred	2019		Subsequent Submittal	*Operational Technology Infrastructure required for implementation delayed this project due to identified Cyber Security concerns. Once the infrastructure is deployed to ensure a secure gateway into the Plant environment, this project will be executed.*
50132	Joint Regulation	236,175	387,704	Deferred	2019		Subsequent Submittal	*Further analysis is required before this project is pursued.*
50115	Customer Support System Enhancement	310,647	332,847	Cancelled			Subsequent Submittal	*Project has been cancelled as the scope has been consolidated into other customer experience capital projects.*
49602	IT - Internal Vulnerability Assessment	203,251	238,543	Cancelled			Less than $250k	*Project scoping has determined the solution for this project is not capital investment.*
49876	Real Time Economic Dispatch	816,638	1,161,618	Deferred	2019		Subsequent Submittal	Continued project planning is required in 2018 to understand the full scope of the RTED implementation, in particular, how to deal with transmission constraints
Previously listed as deferred, now active in 2017.								
49940	LM6000 TUC5 Control System Upgrade	1,018,769	1,018,769	Deferred	2018		Subsequent Submittal	*Commercial negotiations have completed in a timelier manner than originally expected, project planned for filing in late 2017.*
41229	LIN - Cable Spreading Rooms Fire Protection	161,946	200,252	Deferred	2018		Less than $250k	*Further analysis to determine the most appropriate solution was completed with the insurer earlier than anticipated, therefore this project has been activated in 2017.*
49877	23H-302 Clayton Park Rebuild Phase II	215,859	215,859	Deferred	2018		Less than $250k	*Easements were obtained earlier than expected, therefore this project can proceed starting in 2017.*

CI	Project	Ops Date	UARB Approval	Spend to September 30, 2017	Comment
45876	TUC3 U&U Generator Refurbishment	7/31/2014	1,500,239	1,232,581	Commercial negotiations on this project are still on-going. Expected to be finalized and Final Costed in late 2017 / early 2018.
45816	TUC3 U&U Turbine Blade Replace Phase 2	7/31/2014	1,150,115	856,230	Commercial negotiations on this project are still on-going. Expected to be finalized and Final Costed in late 2017 / early 2018.
45882	103H-T63 Transformer Replacement	11/30/2015	1,706,615	1,402,349	Transformer is in-service, but remaining bushing work on the replaced transformer (being converted to a spare) is being completed throughout 2017.
35083	LIN 2011 Ash Site Sealing and Capping	11/30/2015	1,112,451	821,411	Project continues into 2017, however as portions of the ash site are sealed and capped, the project is made operational. Project will be completed in 2017 and filed in late 2017 / early 2018.
46513	3C Port Hastings BPS Upgrade	9/12/2016	3,684,823	3,322,349	Final project activity occurring in Spring 2017. Will be FIN'd in late 2017 / early 2018
43681	South Canoe Subs. Network Upgrades	10/17/2014	4,650,955	4,262,374	Final Costing efforts will be completed concurrently on all South Canoe projects once all project related costs are considered final. Expected to be complete in 2017 and filed in late 2017 / early 2018
46739	IT - Outage Map Technology Upgrades	12/31/2015	2,895,963	2,450,544	Project is operational, with some final licenses to be purchased in Q2 2017. Project expected to be Final Costed in late 2017 / early 2018.
43490	Steel Tower Life Ext - Halifax Harbour	8/31/2016	1,441,709	830,745	Final costs still hitting the project, will be Final Costed in late 2017 / early 2018.
48093	2016 Padmount Replacement Program	7/31/2016	1,911,470	1,506,947	Project being completed in Q1 2017. Final costing will occur in Summer 2017. This project goes in-service when the first padmount is replaced, therefore filing a FIN within six months of the in-service date is not feasible.
43683	South Canoe Wind Project Tx Line	10/31/2014	5,831,002	5,161,039	Final Costing efforts will be completed concurrently on all South Canoe projects once all project related costs are considered final. Will be filed in late 2017.
40103	U&U Load Control Demo	12/31/2010	4,293,793	3,610,924	NS Power withheld the Final Cost application for this project while the smart grid strategy for NS Power was being developed. This was necessary to determine the direction of the work related to this CI. This project is now expected to be Final Costed in late 2017 / early 2018.
20758	HYD - Nictaux Pipeline and Intake	11/30/2015	4,472,431	3,522,500	Deficiencies were identified when putting the gate in-service in late 2015. As the required parts were not available until January 2016, the first available time to complete the work (which involved isolation) was in Summer 2016. Project is now complete with as-built drawings being finalized. Project will be final costed in late 2017 / early 2018.
29009	Right of Way Purchase Northern NS	1/31/2012	4,462,493	3,323,209	Project remains ongoing. Land related projects go in-service when first parcel of land is purchased, therefore filing a FIN within six months of the in-service date is not feasible.
33562	FAC Land Registration Act	1/1/2012	1,899,162	664,726	Project remains ongoing. Land related projects go in-service when first parcel of land is purchased, therefore filing a FIN within six months of the in-service date is not feasible.
40648	IT - Field Mobility System	9/30/2015	3,332,514	1,986,532	This project has completed a portion of the intended scope, which is operational. The remaining work is tied to the future T&D Work & Asset Management project. NS Power has delayed this project to ensure proper alignment between the two efforts.
42230	UU Harbour East Land Purchase & ROW	1/1/2012	2,567,623	1,039,993	Project remains ongoing. Land related projects go in-service when first parcel of land is purchased, therefore filing a FIN within six months of the in-service date is not feasible.
47396	HYD - Nictaux Powerhouse Dam Refurb	10/17/2016	1,792,968	1,226,108	Final project drawings are in the process of being completed. Project will be final costed in late 2017.
41139	HYD - ANN Sluiceway Superstructure	11/28/2016	3,410,322	3,066,386	Project requires rip-rap work to be completed in August 2017. Once complete, a Final Cost application will be submitted in late 2017 / early 2018.
47949	L5028 Replacements and Upgrades	8/31/2016	1,144,355	747,491	The final structures are being completed on this project in Q3 2017. The project will be final costed in early 2018. Whereas this project was placed in-service when the first structures were replaced, the 6-month timeframe from in-service date does not apply.
Projects that have been in-service for 6 months, but have a project forecast within the allowed tolerance (Greater of 5% or $250,000) are not included on this list.					

2018 ACE Appendix D has been filed electronically only.