Nova Scotia Utility and Review Board

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

2014 Integrated Resource Plan

NS Power DRAFT Report

September 30, 2014

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1.0 EXECUTIVE SUMMARY

The 2014 Integrated Resource Plan (IRP) process represents a continuation of Nova Scotia Power's (NS Power, the Company) previous 2007 and 2009 IRP work. The process has built on learnings and actions from the previous IRPs to further shape the future of the Nova Scotia electrical system in a collaborative, consultative and planned manner. The IRP Terms of Reference (TOR) highlight this objective:

> To develop a long-term Preferred Resource Plan that establishes the direction for NS Power to meet customer demand and energy requirements, and environmental obligations in a cost-effective, safe and reliable manner across a reasonable range of foreseeable futures; and to develop an Action Plan describing the major tasks required to implement a no regrets strategy that aligns with the Preferred Resource Plan during the first five years of the planning horizon.

Since the initiation of the 2014 IRP through the Nova Scotia Utility and Review Board's (NSUARB, UARB, the Board) letter of December 18, 2013, the Company has worked in collaboration with Synapse Energy Economics, Multeese Consulting, and The Liberty Consulting Group (the UARB's Consultants), UARB Staff, and in consultation with stakeholders. The process was similar to previous IRPs in that a Terms of Reference was jointly developed and submitted to stakeholders, assumptions were submitted for comment and an Analysis Plan was sent out for consideration. This collaborative and consultative process allowed NS Power to use its long term and detailed modeling tools (Strategist and Plexos) to consider a broad range of potential Candidate Resource Plans (CRPs) with a focus on four key variables:

- Plant retirement dates
- Level of Demand Side Management
- Level of Renewable Generation
- Potential for a large PPA

These variables were considered under a Reference World that assumed base load, current and currently proposed environmental regulations, and energy generated at Muskrat Falls and delivered to NS Power through the Maritime Link including economic market purchase opportunities. Worlds where load was flat or growing, or where DSM did not achieve its potential, were also contemplated.

NS Power then tested the sensitivity of the plans to potential changes in market dynamics including the following:

- More stringent air emissions regulations
- No further reductions in air emissions regulations
- High natural gas, high import power pricing
- Low natural gas, low import power price
- No Demand Response Programs
- Low international price for high sulphur coal
- High international price for high sulphur coal
- Low cost, high output wind

A number of key conclusions can be derived from the data and ensuing analysis performed by the Company and the feedback garnered from both collaboration with UARB Staff and consultants and consultation with the stakeholder group:

- Investment in renewables and DSM has allowed NS Power to meet its current environmental obligations and well-positioned the Company to meet pending environmental requirements.

- There is now a near-term window where limited incremental capital spending is required. This window provides an opportunity to ensure we optimize our near-term demand and supply-side resources in order to minimize near-term rate pressures without compromising longer term environmental and economic objectives.

- An Action Plan focused on developing the optimal balance between near-term electricity service affordability and ensuring the long-term benefits of DSM and capital spending are maintained is required. This includes:
  - determining the optimal near-term DSM spending profile;
  - assessing the appropriate near and medium term sustaining capital spend on NS Power generation assets;
  - exploring opportunities for enhanced regional integration and cooperation;
  - examining additional opportunities to enhance renewable energy integration and performance;
  - calculating the avoided cost of DSM and reporting to stakeholders and ENSC;
  - studying the potential cost and benefit of a flue gas desulphurization unit at Lingan; and,
  - refurbishing the Mersey Hydro System and studying the cost and benefit of increasing the capacity of that system.

The IRP has confirmed that with DSM programing within the range tested, adequate demand and supply resources are available to NS Power to economically meet its planning constraints to 2020, without significant capacity additions. Capacity additions are required across a number of CRPs to meet either Renewable Electricity Standard

(RES) requirements or system requirements over the planning period, specifically in the 2030s, for the most economic plans (please note that there will be additional IRPs before decision points are reached for the 2030s). The current IRP process has served to identify a number of resource plans which provide comparable costs and benefits to customers over the long term, but differ significantly in the near term with respect to upward pressure on power rates.

Nova Scotia Power believes that reducing rate pressure in the near term is in the interest of our customers. In parallel to the technical IRP, Nova Scotia Power has conducted – and continues to conduct – direct consultation with residential, business, and institutional customers, as well as elected officials. More than 300 customers have attended NS Power's consultation sessions as of the writing of this report. The overwhelming feedback from customers has been that price is their top priority on electricity: customers want power rates that are affordable, predictable and stable.

Evaluating on a five-year net present value (NPV) basis, the IRP has shown that the near-term spending level for demand side management is the primary driver of increased customer costs among the most economic plans. Some IRP participants object to evaluating on a five-year NPV basis, but NS Power maintains that such evaluation is essential to assessing near-term rate impacts on customers, and thus is critical to the planning process. NS Power's position is further supported by the Terms of Reference, which recommend "a no regrets strategy that aligns with the Preferred Resource Plan during the first five years of the planning horizon."

NS Power acknowledges that some parties would prefer that this report include a choice of a specific Preferred Resource Plan and accompanying level of notional DSM spending for planning purposes. However, pre-determining a level of DSM, even if only for planning purposes, would limit the ability of Nova Scotia Power, Efficiency Nova Scotia, and ultimately the UARB to finalize an operational level of cost-effective, affordable DSM to be procured by the utility from the DSM provider, in accordance with the

Electricity Efficiency and Conservation Restructuring (2014) Act. In the interest of customers, the process established by the Act must take precedence.

The results of this Integrated Resource Plan have demonstrated that there is a common, no regrets path forward for the Action Plan period and several years thereafter. This path requires minimal incremental capital spending for capacity, while maximizing the lifespan of existing generation assets and selecting an optimal level of DSM. While the detailed Action Plan will resolve some key areas requiring additional study, this collaborative and consultative IRP process has provided clear direction for the future of the power system that will benefit Nova Scotia Power customers.

2.0 INTRODUCTION

An Integrated Resource Plan (IRP) is a comprehensive and public utility planning exercise that integrates supply and demand-side options to develop a long-term resource plan for the utility. NS Power filed an Integrated Resource Plan in 2007 and an Integrated Resource Plan Update in 2009 with the Nova Scotia Utility and Review Board. In its letter of December 18, 2013 the Board directed NS Power to undertake development of the full-scale analysis and preparation of a 2014 Integrated Resource Plan.

The 2014 IRP Terms of Reference, as approved by the Board, contains the following objective:

> To develop a long-term Preferred Resource Plan that establishes the direction for NS Power to meet customer demand and energy requirements, and environmental obligations in a cost-effective, safe and reliable manner across a reasonable range of foreseeable futures; and to develop an Action Plan describing the major tasks required to implement a no regrets strategy that aligns with the Preferred Resource Plan during the first five years of the planning horizon.[1]

The policy judgments and decisions concerning the IRP are made by NS Power in light of its obligations to its customers and regulator. The resultant Action Plan is a road-map to guide the utility’s strategy for meeting its resource needs over the planning horizon. It is directional, not prescriptive, in nature, and is meant to provide the utility with sufficient flexibility to effectively accommodate a range of future uncertainties.

This IRP fulfills the Company’s obligation to develop a long-term resource plan that establishes the direction for NS Power which considers customer demand and energy requirements as well as environmental obligations, cost-effectiveness, safety and reliability. NS Power has applied the IRP process described in Section 4 of this report in

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[1] Nova Scotia Power Integrated Resource Plan – 2014 Terms of Reference, Appendix A, page 1.

collaboration with UARB staff and its consultants, and in consultation with customer representatives and interested parties.

This chapter outlines the primary steps of the IRP process, summarizes advancements in the Company's Integrated Resource Planning approach, and provides an overview of the public process.

2.1 2014 Integrated Resource Plan Process

The primary steps of the Integrated Resource Planning process, and where they are addressed in this report, are outlined below:

- Develop the Terms of Reference and timeline for the IRP – Section 4.1

- Establish the criteria for evaluation of various plans and selection of the Preferred Resource Plan(s) – Section 4.2, 4.3, 4.5

- Develop input assumptions reflecting projections of the most likely values for variables representing the planning environment and resource options – Section 4.2

- Evaluate potential resource plans using screening methods, modeling, and sensitivity analysis – Section 5

- Select the Preferred Resource Plan based on analysis results – Section 5.7

- Develop an Action Plan describing major tasks required to implement a no-regrets strategy that aligns with the Preferred Resource Plan during the first five years of the planning horizon – Section 6

- Engage with Stakeholders throughout the IRP process – Section 2.4

Section 4 of the TOR requires the IRP report to address 11 specific areas. Those 11 areas, and the section where NS Power addresses them in this document, are as follows:

1. Background/Process Overview – Sections 2 and 4
2. Stakeholder engagement process – Section 2.4
3. Criteria for evaluation of the various plans – Section 4
4. Load forecast of future supply requirements – Appendix B (Final Assumptions), slides 77-94
5. Sets of alternative supply-side and DSM alternatives to meet future system requirements – Appendix B (Final Assumptions), slides 35-38 and slides 94-111, respectively
6. Screening analysis used to determine which alternatives were evaluated – Section 4
7. Evaluation of alternative plans in order to determine the least cost plans and rates impact – Section 5
8. Sensitivity analysis on the least cost plans and other selected plans to determine the robustness of the plans to variations in input assumptions – Section 5
9. Preferred Resource Plan – Section 5
10. Avoided cost of DSM methodology method utilized and results – Section 6
11. Action Plan. Actions required over the next 5 years to meet load projections and other regulatory and environmental requirements through implementation of a no regrets strategy that follows the Preferred Resource Plan – Section 6

2.2 Advancements in the IRP Approach

This IRP builds on NS Power’s prior resource planning efforts and reflects continued advancements in resource plan modeling and methodology. These advancements are described in Sections 2.2.1 – 2.2.3.

2.2.1 Candidate Resource Plan (CRP) Approach

In previous IRPs, the resource plans were produced by the output of Strategist. The Base World assumptions were run through the model and from the numerous output resource plans developed, candidate plans to be considered for the Preferred Plan were selected. For the 2014 IRP, UARB staff and consultants recommended the Candidate Resource Plan approach and the Company agreed to employ this methodology. Advantages of the Candidate Resource Plan approach (a full description of the CRP approach is included in Section 4.2 of this report) are the ability to test a wide range of possible outcomes while minimizing the required computing time. While providing advantages within the relatively short timeframe allotted for the execution of the IRP, one of the challenges with the Candidate Resource Plan approach was the development of a fully optimized resource plan. Major components of resource plans, such as level of DSM, steam unit retirements and wind generation additions, are pre-determined rather than optimized,[2] so the optimal path forward may prove to be a combination of the most favorable aspects of the top performing Candidate Resource Plans. While it is possible to select the best of the Candidate Resource Plans, it is clear that many of the plans could be further optimized.

A table describing the CRPs can be found in Section 4.3, page 39 of this report.

2.2.2 Evaluation with Plexos

Operational viability of a select set of Candidate Resource Plans was tested in chronological hourly dispatch optimization software examining CRP performance within unit commitment, system security and other system dispatch constraints.

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[2] While Strategist can optimize various levels of DSM year to year, due to the problem size, this process is time consuming and it could not have been completed in the IRP time frame.

NS Power described the basis for using Plexos in its July 30 Memo to stakeholders:

> The Company proposes to use Plexos to examine certain CRPs (i.e. high wind, high DSM, Scenario "C" emissions) to evaluate key system operational attributes that Strategist does not evaluate, such as dispatch within generating unit commitment constraints, transmission system constraints, dynamic reactive reserve requirements, wind generation curtailment, and other chronological system constraints. The analysis may show that the system needs reinforcement or that, although Strategist has indicated that a given CRP meets the system's annual capacity, generation and emissions needs, the CRP does not satisfy the system's hourly operational needs. NS Power will use its engineering judgment, in collaboration with Synapse, to determine which CRPs require Plexos analysis. NS Power will document its rationale for choosing to apply Plexos to specific CRPs. It will also identify any CRP that it excludes from further consideration based upon the Plexos assessment and the reasons for that exclusion.[3]

Chronological dispatch analysis offers several indicators of system stress under certain CRPs' system configurations and these are wind energy curtailment, uneconomic exports, system constraint violations, steam unit start-stops, heat rate impact, barriers to purchasing otherwise economic Maritime Link surplus energy, etc. The use of Plexos in conjunction with Strategist is an adaptation of the NS Power IRP process reflecting the complexity of the power system as it transitions away from base loaded coal generation.

2.2.3 Sustaining Capital Investments

Sustaining capital investments for existing and new thermal units were included in the cost comparison among Candidate Resource Plans. Sustaining Capital investments are investments to maintain NS Power's generation fleet. This is the first IRP where sustaining capital was added to the modeling exercise due to the variety of retirement options. Sustaining capital costs for the early, base and max retirement assumptions are calculated outside of Strategist and added as an input to the model. Steam unit retirements have not been a feature of previous NS Power IRPs. NS Power modeled a

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[3] Appendix J – NS Power July 30, 2014 memo to stakeholders.

60-year life for steam resources, and this assumption was modified following stakeholder consultation to reflect two additions (shorter life) steam resource retirement strategies. To allow for the side-by-side comparison of CRPs with differing retirement strategies in the planning period, it became necessary to include sustaining capital investments for these assets.

2.3 Role of Board Staff and Consultants

NS Power’s 2014 Integrated Resource Plan has been developed as a joint effort between the Company and Board staff and consultants. This collaboration has included: establishing the Terms of Reference and key evaluation criteria; identifying key input assumptions; designing the analysis framework; screening, selecting and assessing resource plans and analyzing model results. In addition, Board consultants provided comments on draft versions of this report.

The knowledge brought to this project by Board staff and consultants, Synapse Energy Economics, Inc., Multeese Consulting Inc., and The Liberty Consulting Group, along with NS Power technical and analytical expertise, has produced a comprehensive IRP. The key outcomes confirm the direction indicated by the 2009 IRP Update and have resulted in an Action Plan which the Company believes will enable it to meet future customer needs as well as environmental, safety, and reliability obligations.

2.4 Stakeholder Consultation & Public Process

2.4.1 Stakeholder Consultation

Stakeholder input is an integral part of the IRP process**.** In accordance with the 2014 IRP Terms of Reference, NS Power consulted with stakeholders throughout the planning process.

Technical Conferences were conducted with regulatory stakeholders on March 7, June 25, and September 12, 2014. Stakeholder update memos were also distributed on April 11, June 5 and July 30. Comments were accepted and considered by the Company from stakeholders throughout the 2014 IRP process, including comments on the Company's analysis results presented on September 12. Appendix N contains all comments and written feedback received by the Company from stakeholders throughout the 2014 IRP process. NS Power has responded to feedback it received from stakeholders and offers the following for consideration based on the September 12 feedback.

Generally speaking, the Company has identified 4 main areas that are of concern to the stakeholder group. These are listed below followed by NS Power's response to each.

- The Role of a Preferred Resource Plan
- The Role of the Action Plan
- DSM
- IRP Timelines and Content

The Role of a Preferred Resource Plan:

Often in advance of initiation of an IRP, the need for specific capacity additions or potential changes to the planning environment are identified in the near-term and these additions or changes are the basis for initiating the planning exercise. This was the case in 2007 and 2009 for NS Power's previous IRPs. Changes to emissions and renewable regulations required the Company and stakeholders to examine what was the most cost-effective means to manage existing capacity as new capacity came online. The 2014 IRP, however, is quite different. Through the course of this process, the analysis has shown that with the addition of the Maritime Link, maximized life of current assets and a level of DSM to be determined by a subsequent regulatory process, the Company can meet its near-term[4] capacity and energy needs.

Several plans have emerged that produce similar, “no regrets” paths for the first 5 years of the Action Plan. In CRPs 1, 2 and 5, there is minimal incremental capital investment required to meet emissions and renewable energy requirements out to 2020. The main variable between these plans is the level of DSM investment required. There are other plans that are less economic over various time horizons that the Company can implement if there are significant changes to load or environmental regulations.

NS Power has planning flexibility over the next 5 years because the least cost alternatives emerging from the IRP do not call for new capacity additions in that window. The Company proposes to take advantage of this flexibility by implementing the items identified in the Action Plan.

The Role of the Action Plan

NS Power has developed a robust Action Plan to address its findings from the IRP analysis. The Company proposes to examine further elements raised by stakeholders as items for further study and areas where the Company has firm deliverables. This type of detailed Action Plan, with input from the Board’s consultants and in consultation with stakeholders, requires the Company to perform the work per the established timelines. The resulting required information will be available to inform the next long-term planning exercise.

The Action Plan contains a number of items that emerged from the IRP and are critical elements for planning the future of the power system. The Action Plan will significantly bolster the content of the 10 Year System Outlook report, filed annually. The 10 Year System Outlook is a report to the UARB which describes NS Power’s system for the next

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[4] “near-term” is out to 2020.

10 years, from a system operations perspective. The report will inform stakeholders of key items raised in the IRP, for example: plant retirement schedules, regional integration and the requirement for flexible generation assets. There are also significant standalone studies that will be completed as part of the Action Plan raised by the stakeholder group, including: an Energy Resource Interconnection Resource/Network Energy Resource Interconnection Request (ERIS/NRIS) capacity value study, a study to determine the viability and potential economic benefit of adding a flue gas desulphurizer and a detailed examination of the Company's sustaining capital spend for its generation fleet.

The Action Plan provides the means to conduct further analyses of areas that were not fully examined during the IRP or emerged from the analysis of this IRP.

DSM

Stakeholders have varying views on DSM; some advocate for higher or lower DSM levels, while recognizing that there should be a separate process to determine the level of DSM that will be implemented. Feedback from the Industrial Group, the Consumer Advocate and the Small Business Advocate, representatives for the vast majority of NS Power's customers, acknowledges that DSM has its own regulatory process outside of the IRP. Efficiency NS also acknowledges this in their submission following the September 12 Technical Conference. This is aligned with NS Power's position in its Action Plan. The Company proposes to engage ENS to bring a filing to the UARB for approval. This aligns with what is called for under the provisions of the recently amended Public Utilities Act for electricity efficiency and conservation activities.

Given the direction provided within the new Act, NS Power believes that the IRP is not the appropriate forum to derive an optimal level of DSM. Instead NS Power believes the new Act requires the formal process to approve the level of DSM to be a separate regulatory proceeding to determine the cost-effective, affordable level of DSM.

The IRP process has informed NS Power and stakeholders that different levels of DSM investment will produce different cost profiles over time. In conjunction with stakeholders, NS Power will also produce an avoided cost analysis of DSM as part of the Action Plan. The Company can also use the IRP modeling tools to determine how best to balance cost effectiveness and affordability during the establishment of an application with ENSC to be made to the UARB to approve the 2016-2018 DSM investment profile.

As part of its Action Plan the Company will produce the additional modeling requested by the Industrial Group:

> The Industrial Group requests that NSPI model an optimum DSM spending profile on a variable basis, having regard to any operational constraints (on the part of NSPI and ENS). It is understood that NSPI and ENS will be negotiating an agreement for the delivery of efficiency programs on three year terms so the ultimate level of DSM will be determined in that process and approved by the Board; nonetheless, for planning purposes, it would be helpful to understand the implications of an optimum variable DSM spend…
>
> The Industrial Group requests that NSPI run a sensitivity of both higher and lower costs of DSM per MWh and also higher and lower achievable energy and demand savings for the same DSM dollar investment (Base, Half Low).

IRP Timelines and Content

The IRP timeline has been challenging. The Company endeavoured to provide stakeholders with a meaningful opportunity to comment on the process at critical stages. NS Power sees the Action Plan period as an important vehicle for resolving key resource matters and to shape the next IRP. The Company does not consider the end of the analysis phase to be the conclusion of the IRP. There is significant work ahead and NS Power would like to continue to engage the stakeholder group as part of that process. Having a robust Action Plan and several low-cost resource plans with similar no-regrets paths will allow the Company to maintain a broad perspective on near to longer-term resource options and ensure stakeholders have the opportunity to remain fully engaged in resource planning matters leading to the next IRP.

2.4.2 Public Consultation Process

Nova Scotians have a great deal of interest in electricity issues. The Company continually engages customers through tools like the NS Power website, TomorrowsPower.ca, and regional meetings to have a dialogue on the different aspects of the electrical system. The 2014 Integrated Resource Planning process presented a significant opportunity for NS Power to engage customers in a dialogue about long term electricity planning and to discuss the various challenges and opportunities with customers.

Customer Engagement Sessions

The Company held thirteen customer engagement sessions in regions across Nova Scotia. Invitations to the events were extended by NS Power to a broad representation of stakeholders. Stakeholders were encouraged to forward the invites to their own networks. An electricity primer with information on key aspects of Nova Scotia’s electricity system and issues related to the IRP process was shared with participants to help them prepare.

The sessions included an overview by NS Power’s Vice President, Generation and Delivery, of the key IRP issues and how customer input will guide long term plans. For the purposes of the discussion, the content for the sessions was crafted based on four themes that align closely with the various aspects of the overall IRP process: cost, innovation, energy sources and reliability. Each session was broken into four groups based on the above four topic areas. For each of the topic areas, participants were asked the following questions:

1) What are your thoughts on this topic?
2) What outcomes do you care most about?

Information boards about the four topics were used to trigger conversations. Facilitators recorded responses, which were later used towards reports shared with the participants and posted on our TomorrowsPower.ca website. The Company finished the session with an open question and answer period.

In November, NS Power intends to hold a second round of sessions throughout the province to report back to the stakeholders on the outcome of the IRP.

NS Power met with approximately 300 customers about the IRP through these sessions. The Company provided an exit survey to each participant to collect their feedback on the sessions as well as their overall perspective on NS Power. Customers who attended the engagement sessions provided a positive rating of the session (94 percent). In addition, a large majority of participants found the sessions to be informative (82 percent) and useful (87 percent). Overall, a vast majority of the participants found the events to be an effective platform to share feedback and learn about electricity planning.

Online Engagement and Other Activities

NS Power also provided an online customer engagement platform called TomorrowsPower.ca. On this website, we encouraged customers to "ask us anything", read information on the IRP (based on the four topic areas mentioned above) and answer poll questions developed on key themes that arose during the deliberative polling stakeholder sessions. The Company created awareness about the process through some paid advertising, NS Power's customer newsletter "Connections" and social media.

NS Power provided a dedicated email address for customers to get in touch directly with the IRP Team, electricityplanning@tomorrowspower.ca, and responded to follow-up phone calls. At various public events, NS Power used a board, and an opportunity for customers to provide input on their priorities and thoughts for our electricity future.

From April 2014 to the present, nearly 300 questions were submitted through TomorrowsPower.ca for which we have provided answers with the help of NS Power's technical experts, with close to 21,000 unique visits to the website during the same period. This includes collecting brief written comments on the future of electricity.

Conclusions

As stated above, the objective of using a variety of tools was to ensure the process would be relevant for as many customers as possible. Here are the key insights we heard in order of priority:

- Affordability[5] is a key concern for residential and business customers and the importance of striking a reasonable balance between cost and moving to a greener grid.

- In almost all cases, the outcomes identified as most important to customers had strong financial and/or environmental considerations.

- Customers would like to see Nova Scotia Power provide more information about the business, and education on existing programs that will help them manage usage and reduce their costs.

- On the topic of reliability, customers emphasized the importance of improved outage and restoration communications as well as continuous investment in preventative maintenance.

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[5] Affordability was defined as having the minimum revenue requirement increase possible over the near term.

- On the topic of energy sources, the majority of participants validated NS Power's focus on a diversified portfolio, with an emphasis on the best utilization of local sources.

- On the topic of innovation, we heard customers' overwhelming desire for more awareness on innovation programs that we already offer, such as the heat pump program and Time-of-day rates. There was a strong interest in technologies that allow customers to see real time information on and control over their electrical use.

The Company will be reporting back detailed results to stakeholders both online as well as through a second round of sessions throughout the province in November. NS Power will also take the opportunity to inform customers about the technical IRP submission with the Board.

NS Power has been encouraged by the positive response and the level of engagement the process has generated. The Company intends to continue the dialogue with customers going forward.

3.0 PLANNING ENVIRONMENT

3.1 NS Power System Overview

NS Power is a vertically integrated electric utility, regulated by the Nova Scotia Utility and Review Board. The Company serves approximately 501,000 residential, commercial, industrial and municipal customers across Nova Scotia. In 2013 system peak load was 2,033 megawatts; net system requirement was 11,193 gigawatt hours.

Nova Scotia's generation portfolio is comprised of a mix of fuel types that includes coal, petroleum coke, diesel and heavy fuel oil, natural gas, biomass, wind and hydro. In addition, NS Power purchases renewable energy from Independent Power Producers located in the Province resulting in total firm capacity of 2,341 MW. The table below summarizes the resource mix of the Company's generation fleet.

Generation Type	Capacity (Firm MW)
Coal/Petcoke	1,247
Natural Gas/Heavy Fuel Oil	321
Natural Gas Combined Cycle	147
Diesel Combustion Turbine	194
Hydro	376
NS Power Wind (firm)	5
Independent Power Producers Renewable (firm)	51
Total Existing Firm Capacity	**2,341**

3.2 Air Emissions Legislation and Regulation

Nova Scotia Greenhouse Gas Emission Regulations outline hard caps for 2010 to 2030.[6] Nova Scotia was the first jurisdiction in North America to place a “hard cap” on greenhouse gas (GHG) emissions from the electricity sector.

In September 2012, the Federal Government released its regulations for coal-fired electricity generators to come into force in 2015. The regulations would require coal-fired units to meet a GHG emissions standard of 420 t CO_2/GWh or to be retired at the end of their useful life, approximately 50 years from commissioning.[7] In September 2012, the Federal and Provincial governments released a draft equivalency agreement.[8] In June 2014, Environment Canada posted the draft Order authorizing the GHG Equivalency in the federal Gazette Part 1. Once finalized, likely in early 2015, the agreement will ensure provincial regulations will apply in Nova Scotia and electricity customers will receive the full value of the coal-fired generating facilities.

Nova Scotia Air Quality Regulations outline hard targets for SO_2, NO_x, and Hg until 2020. In June 2013, Nova Scotia Environment released a discussion paper[9] outlining emission limits for SO_2, NO_x, and Hg until 2030. The general intent for emissions reductions targets described in the discussion paper is consistent with the Department’s goal of long term reductions.

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[6] An Agreement on the Equivalency of Federal and Nova Scotia Regulations for the Control of Greenhouse Gas Emissions from Electricity Producers in Nova Scotia (September 2012).

[7] Canadian Environmental Protection Act, 1999, Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations.

[8] An Agreement on the Equivalency of Federal and Nova Scotia Regulations for the Control of Greenhouse Gas Emissions from Electricity Producers in Nova Scotia (September 2012).

[9] Amendments to Greenhouse Gas & Air Quality Emissions Regulations Discussion Paper (NSE, June 2013).

3.3 Renewable Electricity Standards

Nova Scotia Renewable Electricity Regulations outline the Renewable Electricity Standards. The Renewable Electricity Standards are summarized below:

- As of 2014, at least 10 percent of net sales must be generated by renewable electricity, of which 5 percent can be owned by NS Power (not including NS Power owned renewables built prior to 2001).

- As of 2015, at least 25 percent of net sales must be generated by renewable electricity, of which at least 5 percent plus an additional 300 GWh must be supplied by IPPs. The additional generation may be supplied by the feed-in-tariff program, facilities owned by NS Power, or other sources of renewables. NS Power can only supply 150 GWh or less from co-firing biomass.

- As of 2020, at least 40 percent of net sales must be generated by renewable electricity, of which at least 5 percent plus an additional 300 GWh must be supplied by IPPs. The additional generation may be supplied by the feed-in-tariff program, distribution connected generators, up to 150 GWh of biomass co-firing, other NS Power-owned facilities, or other sources of renewables, as well as 20 percent of the generation produced at the Muskrat Falls facility currently under construction.

- In addition, there is also a requirement to procure or generate 260 GWh of firm renewable electricity in 2013 and 350 GWh of firm renewables in 2014 and subsequent years. The regulatory definition of firm indicates this generation must be from sources commissioned after December 31, 2001, of which the Port Hawkesbury Biomass facility would apply.

3.4 The Maritime Link

On July 22, 2013, the UARB concluded that the Maritime Link was the lowest long term cost alternative for electricity supply for Nova Scotia in accordance with section 5.1 of the Maritime Link Regulations. However, the UARB concluded that this was only the case if customers had access to market-priced energy.[10] Subsequently, NSP Maritime Link (NSPML) negotiated an Energy Access Agreement with Nalcor to ensure that Nova Scotians have access to market priced energy flowing through the province from the Maritime Link. NSPML then submitted a Compliance Filing to the UARB and final approval was given to the Maritime Link on November 29, 2013.

The Maritime Link is a 500 MW high voltage direct current (HVDC) cable that will bring energy from the Muskrat Falls Hydro project in Newfoundland and Labrador through Nova Scotia. There are several different components to the energy available from the Link. First is the Nova Scotia Block of approximately 0.9 TWh annually (153MW firm capacity 16 hours/day), which is essentially 20 percent of the Muskrat Falls output adjusted for line losses over a 35 year period. NS Power also receives a Supplemental Energy Block of approximately 0.24 TWh annually for the first five years of operation delivered in the overnight hours of November through March. Nova Scotians will also have access to an average of 1.2 TWh of market priced energy annually under this agreement and Nalcor has agreed to bid its forecast of up to 1.8 TWh of energy annually, meaning that Nova Scotians will have the opportunity to bid on the full forecast.

When combined with the Nova Scotia Block, the Maritime Link has the potential to provide 2.6 TWh of Nova Scotia's annual energy requirement for beyond the length of the IRP Planning Period. The Link is currently scheduled to come online in late 2017 and is a crucial tool for NS Power to meet its 2020 environmental obligations. In

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[10] Market priced energy is energy priced off of the New England Market at Mass Hub plus applicable transmission, if any, as outlined in slides 60-62 of the Final Assumptions – Appendix B.

addition to providing energy, the Maritime Link also provides enhanced interconnection and opportunities for better regional system cooperation.

3.5 Demand Side Management

Changes to electricity efficiency legislation in Nova Scotia have impacted the analysis of DSM in the 2014 IRP. In order to better integrate DSM within the Candidate Resource Plan model NS Power used various pre-determined levels of DSM which will inform the process of contracting with the DSM franchisee contemplated in the revised regulations. Efficiency Nova Scotia Corp (ENSC) provided the DSM profiles utilized in this planning exercise through a Potential Study undertaken on their behalf by Navigant Consulting, Inc. The Company communicated this approach in its April 11 memo to stakeholders that accompanied the final assumptions:

> On April 7, 2014, the Province of Nova Scotia introduced Bill No. 41, Electricity Efficiency and Conservation Restructuring (2014) Act.[11] The Act, when passed, and the Regulations to be made thereunder, represent a significant shift in the approach to DSM in the Province. Just as the IRP is not a regulatory process that determines NS Power’s capital spend or revenue requirements, the IRP is not a regulatory process to determine a DSM supplier’s level, programs or evaluation tests. The proposed legislation requires NS Power to undertake cost-effective electricity efficiency and conservation activities that are reasonably available in an effort to reduce costs for its customers.[12] It provides that in order to meet this obligation NS Power must contract with the government’s approved franchise holder for the supply of efficiency and conservation programs, and that such agreement must be approved by the UARB.[13] The Board shall approve NS Power’s agreement with the franchise holder if it is satisfied that the conservation and efficiency activities that are the subject of the agreement are in the best interests of customers.[14] The Board's assessment of the proposed electricity efficiency and conservation activities for the purpose of the approval must take into account their

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[11] Bill 41, *Electricity Efficiency and Conservation Restructuring (2014) Act*, 1st Sess., 62nd General Assembly, Nova Scotia, 2014 (First Reading: April 7, 2014).
[12] Ibid, s. 79(I)(1).
[13] Ibid, s. 79(I)(2)(a).
[14] Ibid, s. 79(L)(8).

> affordability to Nova Scotia Power Incorporated's customers, along with any other matters considered appropriate by the Board or as may be prescribed.[15]

Given the above, NS Power anticipates that the assessment of cost effective DSM potential will require evaluation as part of a regulatory process as part of or in anticipation of the proceedings to approve NS Power’s agreements with the efficiency and conservation franchise holder in the future.

3.6 Wind Energy

Wind energy variability is reflected in the Strategist model by one representative week per month compression of observed wind generation shapes. Two other assumptions regarding wind generation which need to be specified in the model are:

1. Capacity Value of wind
2. Integration costs of wind

With significant quantity of wind generation on the system, capacity value or Effective Load Carrying Capacity (ELCC) of wind generation is a crucial assumption. If ELCC is assumed to be too high, it can erode system reliability by too high contribution of wind generation to planning reserve margin. If ELCC is assumed to be too low, the assumption may drive unnecessary investment in firm capacity in order to meet planning reserve margin.

ELCC of wind was calculated by GE Energy in Renewable Energy Integration study commissioned by NS Power and published in June 2013. GE Energy used the Loss of Load Expectation (LOLE) methodology to calculate capacity value of wind, based on a 2006 year wind-load data set which was developed by AWS Truepower from location specific wind speed measurements. GE Energy calculated ELCC of wind to be 27

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[15] Ibid, s. 79(L)(9).

percent at approximately 585 MW of wind generation on the system, representing the presently built and committed wind generation in Nova Scotia.

Subsequent to publishing NS Renewable Energy Integration study, GE Energy identified shortcomings with the LOLE methodology based on a single year's wind-load data pair. When used on a single year load-wind data set, the LOLE methodology can yield unreliable conclusions due to widely varying ELCC figures from year to year.

GE Energy's subsequent, March 2014, analysis of PJM ELCC of wind calculation based on three years of data, showed widely ranging results of between 8 percent and 44 percent. Please refer to Appendix O (PJM Renewable Integration Study), page 22, figure 1-11.

Another example of the same concern with LOLE methodology is MISO 2014 Wind Capacity Credit Report which shows ELCC of wind based on 9 years of wind-load data, ranging from 3 percent to 18 percent. Please refer to Appendix P (MISO 2014 Wind Capacity Credit Report), page 8, figure 2-3.

The graph from MISO report, containing 8 years of wind-load data, was also used by Synapse in Technical Training document Session 2: Best and Worst Practices in IRP and CPCN, in August 2013. Please refer to Appendix Q, page 40.

As the industry continues to address the planning questions raised by the integration of variable generation, some approaches like the single wind-load data set ELCC calculation employed by GE Energy in the NS Renewable Energy Integration Study are refined to improve the information provided to system planners and operators.

Due to time constraints, the Company was unable to complete a multi-year LOLE study in order to assess the reliability of LOLE methodology and inform a conclusive selection of ELCC of wind based on LOLE methodology.

NS Power conducted a single year LOLE study in order to validate GE Energy results and a Cumulative Frequency Analysis study which showed ELCC of wind generation ranging from four to sixteen percent, depending on the level of confidence.[16] Based on the referenced studies, NS Power chose ELCC of wind generation to be 12 percent. In subsequent discussions with Synapse, the Company and Synapse agreed to use 17 percent ELCC of wind for the purpose of this IRP exercise.

3.6.1 NRIS vs. ERIS Interconnected Wind Generation Resources

For the 2014 IRP study simulations, wind generators connected under Network Resource Interconnection Service (NRIS) were assumed to have firm capacity value of 17 percent, while the wind generators connected under Energy Resource Interconnection Service (ERIS): Nuttby Mountain, Dalhousie Mountain and Glen Dhu, were assumed to have no firm capacity, until further studies can be conducted by the System Operator. All future wind generation additions up to the contracted 582 MW were assumed to be connected under NRIS and thus have firm capacity value of 17 percent. The decision to treat wind generating resources connected under ERIS as having no firm capacity was consistent with NS Power’s planning approach.

In order to avoid undue influence of capacity value of wind selection on the IRP results, optimistic capacity value of wind was studied under:

- Separate CRP dedicated to optimistic capacity value of wind CRP-9 WIND CAP
- Optimistic Wind Cost/Output sensitivity across all CRPs

The subject of capacity value of ERIS resources is further discussed in Section 6.4.6.

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[16] Please refer to Appendix C.

3.6.2 Medium and High Wind ELCC Assumptions

Capacity Value of incremental wind additions were taken from 2013 GE Energy Renewable Energy Integration Study report and were also tested with the Optimistic Wind Cost/Output sensitivity.

3.6.3 Wind Integration Costs

Integration costs of a significant quantity of wind generation show up in four major system assumptions:

1. **Effect on generating fleet efficiency**

   The costs of wind energy integration reflected in suboptimal hydro fleet dispatch and deterioration of thermal system heat rates were modeled implicitly in Strategist. Additional generating unit start and stops and associated wear and tear were not reflected in the model.

2. **Wind generation curtailment and uneconomic exports**

   Strategist does not model wind curtailment. Rather than expressing the costs associated with wind curtailment explicitly and providing it to the Strategist model as an assumption, wind curtailment costs were not modeled, due to the possibility of unduly penalizing wind generation.

3. **Additional system reserve requirement**

   Additional reserve requirement associated with incremental additions of wind generation is not yet known to a sufficient degree for the assumption to be included in the IRP. No additional reserve was assumed for incremental wind additions.

4. Additional system upgrades to maintain system stability and security

Wind integration costs of incremental wind additions beyond the presently-installed and committed wind generation associated with system upgrades required to securely integrate further quantities of wind were modeled as an explicit cost associated with each incremental 150 MW wind generation block. Please refer to Appendix D for details.

4.0 ASSUMPTIONS & ANALYSIS PLAN DEVELOPMENT

4.1 Introduction

In its Terms of Reference, the Company put forward a timeline for the IRP to meet the directive of the UARB to submit a draft final report for September 30, 2014. That timeline included the following steps for the development of assumptions and the Analysis Plan:

1. Develop criteria for evaluation of various plans and selection of a Preferred Resource Plan.

2. Identify the major input assumptions which will drive evaluation and selection of the Preferred Resource Plan.

3. Evaluation of potential resource plans

4. Select Preferred Resource plan and Develop Action Plan

5. Prepare final report and Action Plan. File with UARB

On March 7, 2014, NS Power hosted a Technical Conference for participants at which it reviewed initial draft assumptions and discussed its preliminary thoughts on the Analysis Plan for the 2014 Integrated Resource Plan (IRP) to obtain feedback from participants. Final assumptions were developed based on stakeholder feedback and circulated on April 11, with additional final assumptions for wind capacity value and variable generation integration costs circulated on April 23 and May 1 respectively. Please refer to Appendices B, C and D for the detailed slide decks of final assumptions.

4.2 Assumptions & Analysis Plan

On March 14, 2014, NS Power circulated draft basic assumptions for feedback. The Company also circulated additional assumptions details in response to requests from Larry Hughes, PhD., the Industrial Group and the Nova Scotia Department of Energy. The March 14 material included a memo[17] describing the 5 steps listed above that NS Power suggested for the Analysis Plan. That memo contained the following description of the Analysis Plan:

> The Analysis Plan strives to;
>
> i. identify candidate resource plans, including the least cost plan under the Reference World
> ii. identify a reasonable range of foreseeable futures,
> iii. evaluate the candidate plans including least cost plans across that range of futures and
> iv. select the Preferred Resource Plan.
>
> NS Power has developed the following analysis plan in line with IRP best practices and will continue to refine its plan based on feedback from Synapse and Stakeholders. The Company suggests the 5 following steps:
>
> 1. **Candidate Resource Plans**
>   a. Develop a set of candidate resource plans under the Reference World. Begin with a broad range of draft resource plans, each developed based on existing resources and high-level screening of possible resource options.
>   b. Optimize each draft resource plan under the Reference World using Strategist. The optimizations would include the resource options that pass the high level screening. The results from Strategist will be candidate resource plans. The results will indicate the relative cost of each resource plan.
>
> 2. **Candidate Resource Plan Evaluation**
>   a. Run sensitivity tests under the Reference World on each candidate resource plan from step 1. Strategist may need to re-optimize certain of the resource plans under certain of

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[17] Please refer to Appendix E – NS Power memo to stakeholders re: Analysis Plan.

the sensitivity tests in order for those plans to meet all reliability and regulatory constraints.

3. **Scenario Testing ("Worlds" Development)**
   - a. Develop additional "Worlds" and sensitivities for further evaluation of the candidate resource plans (a World is a combination of key assumptions and constraints). This step includes Worlds of interest to NSPI, Synapse and Stakeholders.

4. **Evaluation and Optimization**
   - a. Evaluate the candidate resource plans from step 1 under the different Worlds and sensitivities. Strategist may need to re-optimize certain of the resource plans under certain of the different Worlds in order for those plans to meet all reliability and regulatory constraints.
   - b. The results will indicate the expected relative cost of each resource plan.

5. **Preferred Resource Plan Development**
   - a. Evaluate performance of resource plans across Worlds and select Preferred Resource Plan.

> At this point NS Power will have tested and optimized a number of candidate resource plans across a range of foreseeable futures, i.e. "Worlds" based on stakeholder feedback and consultation with Synapse. NS Power would select its Preferred Resource Plan from among those candidate plans. The Preferred Resource Plan should have the flexibility to enable NS Power to meet customer demand and energy requirements, and environmental obligations in a cost-effective, safe and reliable manner across a reasonable range of foreseeable futures. This should enable development of an Action plan for the next 5 years that reflects the type of "course corrections" that may be required depending on how the world (e.g., net load, emissions targets, RES requirements) unfolds.[18]

On April 11, 2014, based on stakeholder feedback on the draft assumptions, NS Power supplied Intervenors with the final assumptions for the 2014 IRP developed in collaboration with UARB Staff and their consultants.[19] In addition, the Company provided detailed feedback on Intervenor comments on the assumptions with its April 11

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[18] Appendix E - NS Power Memo to Stakeholders, March 14, 2014.

[19] Please refer to Appendix B.

submission. Please refer to Appendices F and G for NS Power's response to stakeholder feedback. Intervenors were also given the opportunity to comment on final assumptions not provided with the April 11 package (capacity value of wind and variable generation integration costs). The April 11 memo[20] included a brief discussion of NS Power's proposed approach to completing the Analysis Plan, specifically to model a limited number of Candidate Resource Plans, sensitivities and Worlds that bound the wide range of possible permutations and combinations that have been suggested. The Company committed to meeting to discuss the Analysis Plan with stakeholders throughout the modeling phase of the IRP. NS Power held a meeting for customer representatives at its offices on June 4, 2014 and ENSC on June 20, 2014 to discuss progress on the Analysis Plan in advance of the scheduled June 25 Technical Conference. The Company provided an Analysis Plan status update in its memo of June 5, 2014.[21] The Company also made all IRP information publically available on its website at the following address:

http://www.nspower.ca/en/home/about-us/electricity-rates-and-regulations/regulatory-initiatives/IRP.aspx

On June 25, 2014 the Company hosted its second Technical Conference[22] with stakeholders. The goal of the consultation was to discuss the Analysis Plan as well as preliminary results.

4.3 Candidate Resource Plans

The Candidate Resource Plan component of the 2014 IRP was a change from previous IRP practices. NS Power discussed how CRPs were selected in its update memo to stakeholders on July 30, 2014.[23] Candidate Resource Plans are potential IRP plans for further examination through Strategist modeling and sensitivity analysis. Key

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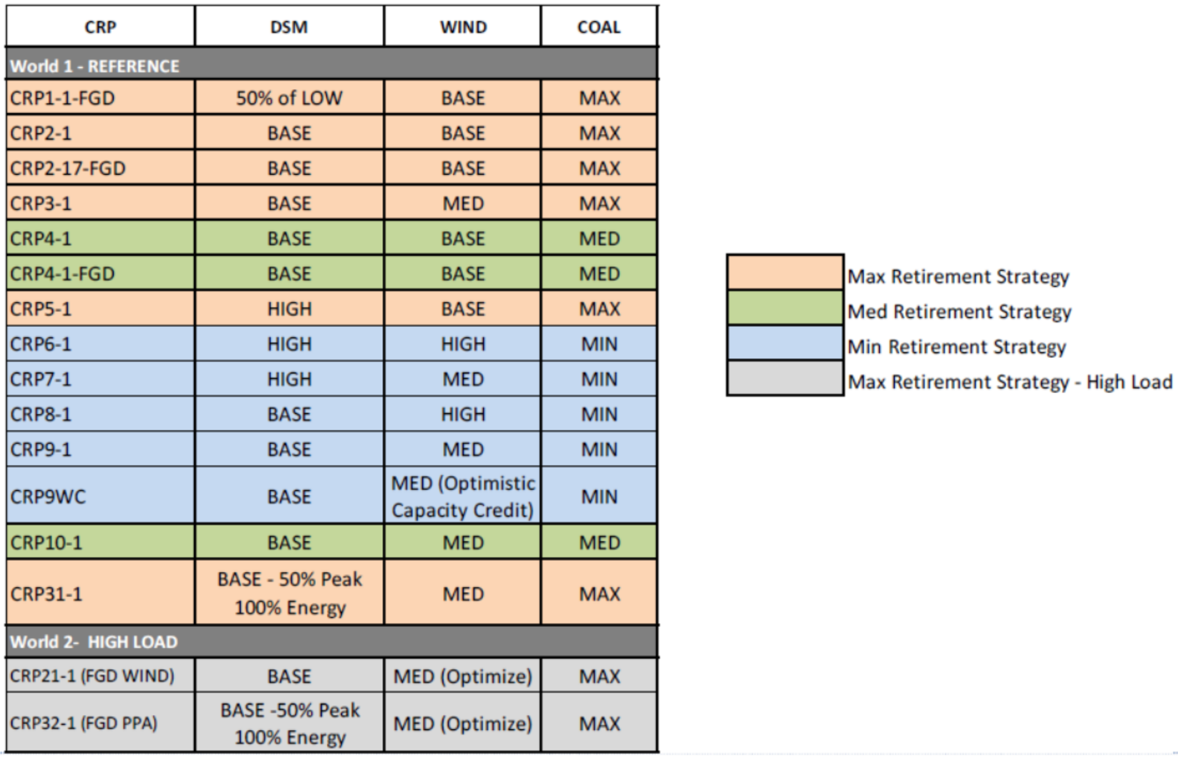
[20] Please refer to Appendix F.
[21] Please refer to Appendix H.
[22] Please refer to Appendix I for the presentation materials from the Technical Conference.
[23] Please refer to Appendix J.

assumptions are modified to establish different Candidate Resource Plans modifications. The following excerpt from the July 30, 2014 memo elaborates on how CRPs were selected:

> ***Basis for selection of initial Candidate Resource Plans (CRPs) from 30 draft resource plans***
>
> The initial Candidate Resource Plans were selected from the 30 draft resource plans based on the goal of developing a set of CRPs that span a reasonable range of plausible resource choices (the IRP Terms of Reference at page 3 specify that NS Power is to assess "a reasonable, but not unlimited, number of alternative plans"). The sequence in which NS Power made this selection, and the criteria it considered at each stage of the sequence, is summarized below:
>
> - NS Power, in collaboration with UARB staff and consultants, began by identifying 30 draft resource plans (see Attachment 1 to June 5, 2014 memo to stakeholders). Each draft resource plan began with the existing resources and resource commitments in effect as of 2015. Those draft resource plans differed in terms of four major input variables/components that were expected to have the potential to significantly change the results of the plan (e.g. revenue requirements, robustness). Those four key input variables/components were: DSM level, variable generation level (e.g. wind), fossil unit retirement dates (coal, Tufts Cove) and potential for a large Power Purchase Agreement (PPA) – please refer to the June 5th memo to stakeholders and its Attachment 2, slide 12.
>
> - NS Power then identified five of the 30 draft resource plans to model in Strategist as initial CRPs under the Reference World. The initial CRPs were selected to begin developing a set of CRPs that spanned a reasonable range of plausible, and materially different, resource choices. They were selected to reflect three different levels of DSM, two levels of variable generation (e.g. wind), and two levels of coal retirements. NS Power expected that the results from modelling these five initial CRPs would help it determine which of the remaining draft resource plans it would need to model in order to evaluate a reasonable range of plausible, and materially different, CRPs and which it would not need to model because they would not produce materially different results.

- Based upon the results of modelling the initial five CRPs and upon further examination of the components that can most affect the results of CRPs, NS Power has identified an additional 11 initial CRPs to model under the Reference World. These 11 additional CRPS are included in the list of CRPs described earlier in this memo. These additional initial CRPs were again selected as part of the process to develop a set of CRPs that span a reasonable range of plausible, and materially different, resource choices. The additional 11 CRPs reflect higher levels of wind, earlier coal plant retirement and different DSM levels. They complement the initial five CRPs by representing a further range of differences in levels of DSM, variable generation, levels of coal retirements, Demand response levels, Tufts Cove unit retirements and repowering and PPAs. The Company has also identified two additional CRPs to be modelled under the High Load World.[24]

In total the Company used Strategist to optimize the following 16 resource plans:



CRP	DSM	WIND	COAL
World 1 - REFERENCE			
CRP1-1-FGD	50% of LOW	BASE	MAX
CRP2-1	BASE	BASE	MAX
CRP2-17-FGD	BASE	BASE	MAX
CRP3-1	BASE	MED	MAX
CRP4-1	BASE	BASE	MED
CRP4-1-FGD	BASE	BASE	MED
CRP5-1	HIGH	BASE	MAX
CRP6-1	HIGH	HIGH	MIN
CRP7-1	HIGH	MED	MIN
CRP8-1	BASE	HIGH	MIN
CRP9-1	BASE	MED	MIN
CRP9WC	BASE	MED (Optimistic Capacity Credit)	MIN
CRP10-1	BASE	MED	MED
CRP31-1	BASE - 50% Peak 100% Energy	MED	MAX
World 2- HIGH LOAD			
CRP21-1 (FGD WIND)	BASE	MED (Optimize)	MAX
CRP32-1 (FGD PPA)	BASE -50% Peak 100% Energy	MED (Optimize)	MAX

🟧 Max Retirement Strategy
🟩 Med Retirement Strategy
🟦 Min Retirement Strategy
⬜ Max Retirement Strategy - High Load

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[24] Appendix J - NS Power Memo to IRP Stakeholders, July 30, 2014.

Note: Max retirement strategy indicates the Company plans to maximize utilization of the units to a 60 year life span. Medium is between 50 and 55 years and minimum is around a 40 year life before retirement.

4.4 Sensitivity Analysis

In addition to a broad range of initial resource plans NS Power ran a significant number of sensitivity analyses leading to 76 re-dispatch simulations of the various CRPs:

- Scenario B emissions – hold emissions at currently legislated levels
- Scenario C emissions – Reduce CO2 emissions to 2.25 MT by 2040 and associated co-benefits
- High Natural Gas and High Import Power pricing
- Low Natural Gas and Low Import Power pricing
- Low International Price of High Sulphur Coal
- High International Price of High Sulphur Coal
- Optimistic Wind – low cost, high output wind

4.5 Plan Evaluation

Based on the output from the Strategist modeling, NS Power in collaboration with Synapse and consultation with stakeholders analyzed the results against the following criterion:

- *NPV*: Cross-section of near and long term NPVs including end effects NPVs
- *Rate Effects*: Relative time-series revenue requirements
- *Future Regulatory emissions outlook*: Results of sensitivity tests
- *Risk*: Relative complexity and risks inherent in CRPs
- *Flexibility*: Diversity of technological solutions
- *Robustness*: Results of sensitivity tests

These metrics include both qualitative and quantitative measures.

- *NPV and Rate Effects* – For the NPV and Rate Effects metrics, NS Power evaluated the NPV of the partial revenue requirements for the planning period (2015 - 2039) and the shorter term NPV (2015 - 2020) from the Strategist modeling results. This provides an indication of the performance of the plans based on the ability to deliver long-term value while giving consideration to near-term affordability.

- *Future Regulatory Emissions Outlook* – For the Future Regulatory Emissions Outlook metric, the Company looked at a range of emissions constraints. For its base case NS Power selected the currently proposed emissions level over the planning period; sensitivities were run comparing the impact of changing emissions to lower or higher levels and the impact on the NPVs was analyzed. As discussed in Section 5, the plan reordering based on emissions scenarios was not significant.

In terms of its assessment of the qualitative metrics listed above – Risk, Flexibility and Robustness – the Company took a higher level approach. NS Power sought to analyze the plans to ensure that, while effective from a quantitative perspective, no plan introduced imbalance from a qualitative perspective. Generally speaking, the plans performed well qualitatively; this can be seen through the sensitivity analysis discussed in the next section. The fact that there are no major outliers across the range of sensitivities speaks to the relative low-risk, robust and flexible nature of the plans.

- *Risk* – Risk takes on two dimensions in utility planning; financial risk and operational risk. Financial risks could be considered the risk that utility spending to serve forecasted customer needs proves with time to be off target, leaving the utility and its customers exposed to greater-than-anticipated costs. In the window of the Action Plan, most CRPs have no need for investments in new capital expansion. DSM programing levels are the largest discretionary consideration faced in most of the CRPs. One perspective is that choosing not to maximize DSM spending leaves an opportunity for load reduction unattained. Conversely, DSM programming has some level of scalability, allowing for a balancing of near term cost pressure with longer-term efficiency objectives. NS Power proposes that seeking to find this balance through upcoming contracting discussions with ENSC mitigates some of the near-term financial risks. Operational risk reflects the need for the utility to have the proper mix of reliable assets to meet customer needs for capacity and energy. The NS Power system is in the midst of a major transformation away from base loaded coal to a broader mix of generation including renewables. All CRPs share much of the same operational risks in the near years. Plexos modeling indicates greater operational challenges are faced by CRPs with higher wind and lighter system load. Certain CRPs presented more complex (higher risk) solutions than others. Risk across the plans was measured relative to the plans that had the simplest and most proven solutions implemented in the near-term period. The Company considered risk over the planning period to a lesser extent, as future technology changes over the longer period create less certainty. As a result, plans demonstrating minimal incremental investment over the short term and a reliance on established technology in the longer term pass the bar.

- *Flexibility* – Nova Scotia Power’s generation assets are very diverse with a capacity mix that includes; coal, petcoke, natural gas, HFO, LFO, hydro and wind. This diversity will be enhanced by the Maritime Link which brings augmented market connection. As the system evolves, modeling from this study suggests that a key focus should be to ensure that it does not become too reliant on any one supply side or demand side resource to meet its energy and capacity needs. So, plans that maintained a more diversified portfolio across the planning period were judged favorably to plans that had a heavier reliance on one or two specific technologies. Plexos modeling indicates the interplay between some of the resource options. For example in times of heavy wind generation, system load can be a valuable tool held by a system operator to integrate variable generation. When wind becomes a large proportion of the instantaneous online generation, system operators must give consideration to power system inertia, frequency response and general stability. The ratio of wind generation to load increases through the development of new wind generation resources, but it also increases with the reduction of system load through DSM or customer load loss. Put another way, a barrier to system flexibility could be the reduction of power system load. Other flexibility considerations come from fuel options. Retiring coal generation reduces the opportunity to take advantage of possible lower coal pricing relative to natural gas in this region. Equally true are the inherent challenges in utilizing conventional steam units in variable generation integration efforts. The industry is facing the need to repurpose these units on power systems seeking to integrate greater amounts of non-dispatchable assets. Flue Gas Desulphurization opens opportunities for higher sulphur domestic fuels with security of supply, price and economic development advantages, but aggressive and early DSM spending could be seen as a flexibility measure opening up opportunities for lower load futures. However, overspending in DSM might constrain system flexibility by compounding bulk power system operational challenges that could be introduced by customer self-generation or other load loss in the future.

- *Robustness* – NS Power tested a range of sensitivities including pricing and modified emissions constraints. The results of the sensitivity runs are reflected in Section 5.5, they show that the plans move relatively uniformly across the sensitivities. For example the lower cost plans in the base case remain the lower cost plans across sensitivities and the higher cost plans in the base case remain the higher cost plans in the sensitivities. Had there been significant swings in the plans across sensitivities, the Company would have had to further examine plan robustness.

Further discussion with stakeholders on evaluation criteria and metrics for choosing a Preferred Plan took place at the September 12 Technical Conference. The Company concluded that there are a number of plans with common attributes in the Action Plan period that should be considered as the Preferred Plan. CPR 2-1 and CRP 5-1 share a similar resource addition profile out to 2030. The level of DSM spend is the significant difference in the two plans, but modeling forecasts that neither of the CRPs have capacity additions during the proposed Action Plan period. These CRPs are robust and flexible as well as cost effective over both the planning and study periods. NS Power is proposing that the resource addition profiles from these CRPs represent the most reasonable planning path until the next IRP. DSM programming levels are to be determined in a separate regulatory process as per the legislation.

5.0 MODELING RESULTS & PREFERRED RESOURCE PLAN SELECTION

5.1 Introduction

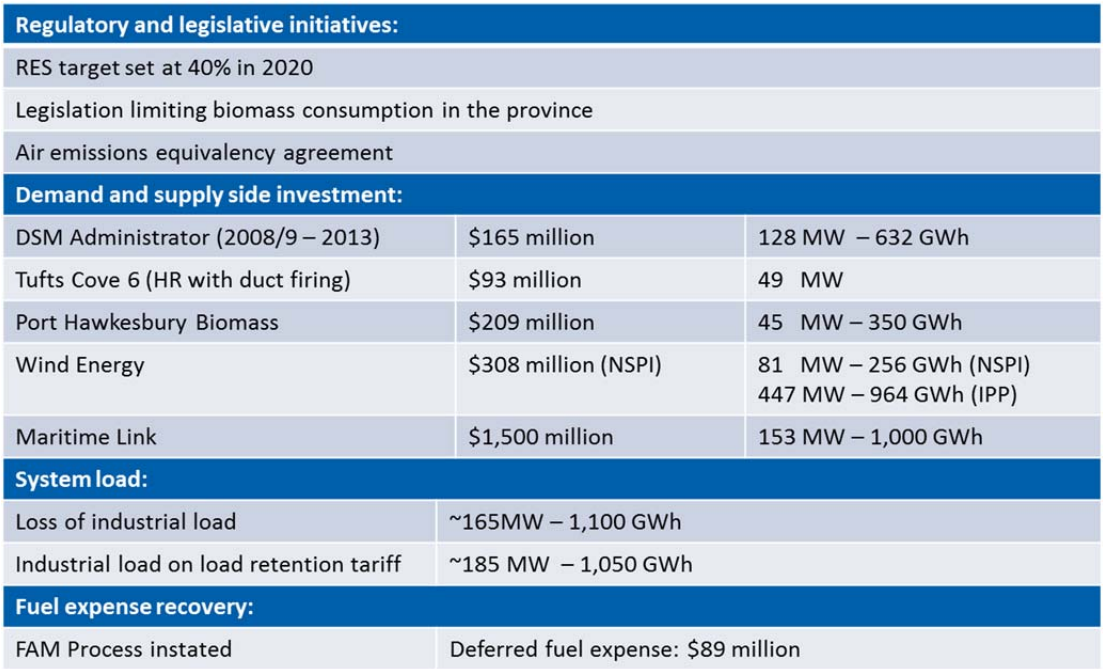
NS Power started the Candidate Resource Plan screening process with over 30 plans under consideration. In collaboration with Synapse those plans were screened down to 16 CRPs. The selected plans represent a broad array of considerations and can reasonably be expected to represent the range of futures that should be considered to plan for the future electricity system. The main variables in planning the power system for the next 25 years were considered in the IRP; they include:

- Load
- DSM
- Unit retirements
- Fuel prices
- Wind levels

By changing these assumptions through the various CRPs and sensitivities, the Company has produced resource plans that can withstand a variety of futures at various costs. For example, if there are additional renewable requirements, the Company could choose a high wind CRP; if more DSM is needed, the Company could pick a plan with a higher DSM investment level.

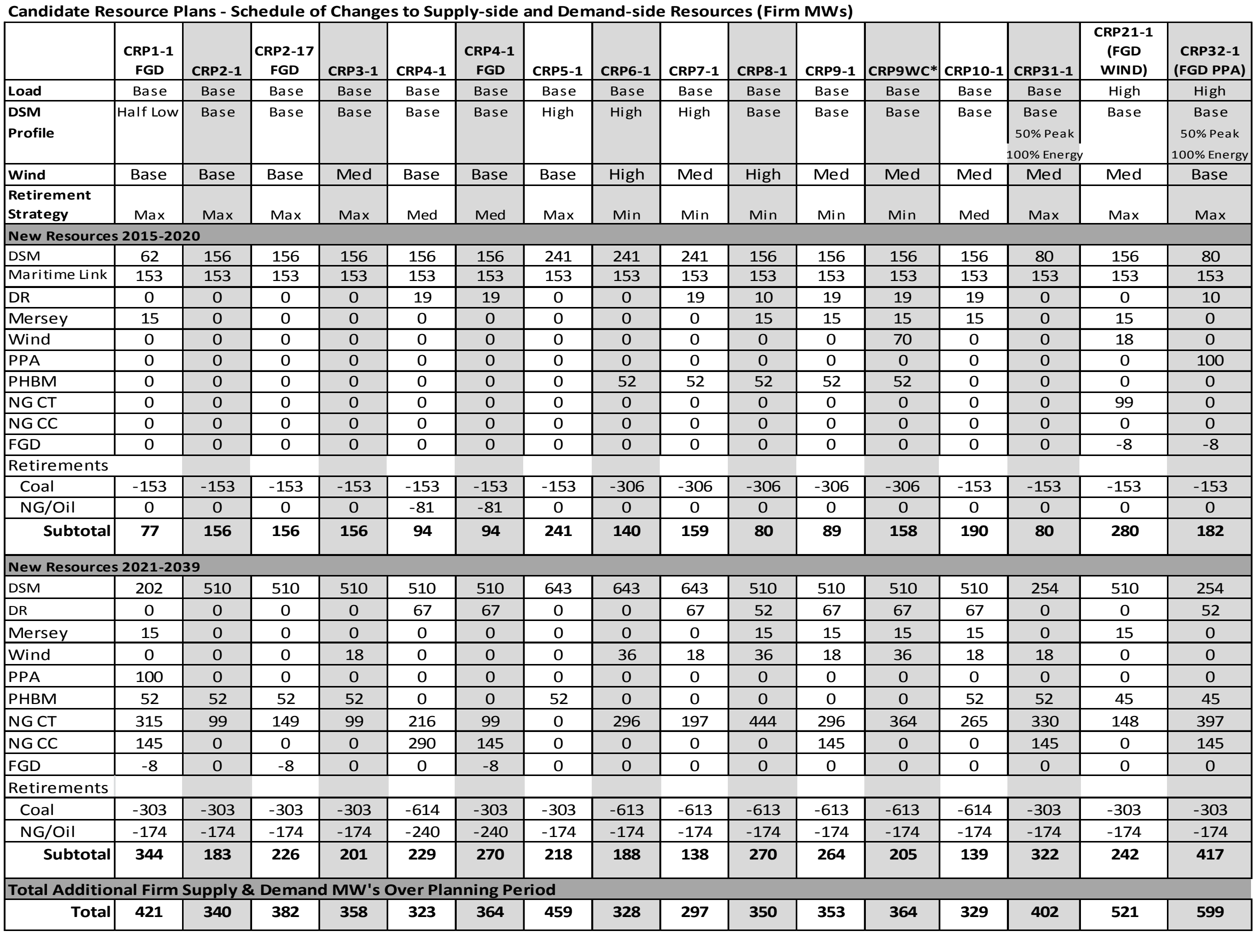
Please refer to Appendix K for a summary of the CRP analysis results. The detailed modeling results are available in Appendix L. The CRP results generally shared a couple of common themes; major capacity additions before 2020 were not necessary in the most economic plans and most plans were similar in NPV over the planning period – most were within 5 percent of the lowest NPV plan. The Company examined various levels of wind additions, DSM and coal retirement dates as well as several sensitivities and High Load World CRPs. The Company’s analysis of the similarity in the planning period NPV across a number of plans is that previous resource planning has proven robust and should allow the electricity system in Nova Scotia to meet its environmental and service requirements in a cost effective manner.

Since the 2007 and 2009 IRPs, renewable integration and DSM have been successful tools to manage load and green the power system. The following table shows the significant changes to the system since the last IRP Update:



Regulatory and legislative initiatives:		
RES target set at 40% in 2020		
Legislation limiting biomass consumption in the province		
Air emissions equivalency agreement		
Demand and supply side investment:		
DSM Administrator (2008/9 – 2013)	$165 million	128 MW – 632 GWh
Tufts Cove 6 (HR with duct firing)	$93 million	49 MW
Port Hawkesbury Biomass	$209 million	45 MW – 350 GWh
Wind Energy	$308 million (NSPI)	81 MW – 256 GWh (NSPI) 447 MW – 964 GWh (IPP)
Maritime Link	$1,500 million	153 MW – 1,000 GWh
System load:		
Loss of industrial load	~165MW – 1,100 GWh	
Industrial load on load retention tariff	~185 MW – 1,050 GWh	
Fuel expense recovery:		
FAM Process instated	Deferred fuel expense: $89 million	

The modeling results from this IRP reflect the major changes to the power system since 2009. With the addition of the Maritime Link, slated to be online in late 2017, the Company is well positioned to meet its environmental targets. Results from Strategist showed compliance with RES and emissions requirements across all CRPs for the 2020 period and beyond. The plans with the lowest NPVs over the planning and study periods, CRP 2 and CRP 5, did not require capacity additions beyond the Maritime Link pre-2020 to meet emissions and RES requirements. The following table shows resource additions for all plans in the pre-2020 and post-2020 periods.



Candidate Resource Plans - Schedule of Changes to Supply-side and Demand-side Resources (Firm MWs)

	CRP1-1 FGD	CRP2-1	CRP2-17 FGD	CRP3-1	CRP4-1	CRP4-1 FGD	CRP5-1	CRP6-1	CRP7-1	CRP8-1	CRP9-1	CRP9WC*	CRP10-1	CRP31-1	CRP21-1 (FGD WIND)	CRP32-1 (FGD PPA)
Load	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	High	High
DSM Profile	Half Low	Base	Base	Base	Base	Base	High	High	High	Base	Base	Base	Base	Base 50% Peak 100% Energy	Base	Base 50% Peak 100% Energy
Wind	Base	Base	Base	Med	Base	Base	Base	High	Med	High	Med	Med	Med	Med	Med	Base
Retirement Strategy	Max	Max	Max	Max	Med	Med	Max	Min	Min	Min	Min	Min	Med	Max	Max	Max
New Resources 2015-2020																
DSM	62	156	156	156	156	156	241	241	241	156	156	156	156	80	156	80
Maritime Link	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153
DR	0	0	0	0	19	19	0	0	19	10	19	19	19	0	0	10
Mersey	15	0	0	0	0	0	0	0	0	15	15	15	15	0	15	0
Wind	0	0	0	0	0	0	0	0	0	0	0	70	0	0	18	0
PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100
PHBM	0	0	0	0	0	0	0	52	52	52	52	52	0	0	0	0
NG CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	99	0
NG CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FGD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-8	-8
Retirements																
Coal	-153	-153	-153	-153	-153	-153	-153	-306	-306	-306	-306	-306	-153	-153	-153	-153
NG/Oil	0	0	0	0	-81	-81	0	0	0	0	0	0	0	0	0	0
Subtotal	**77**	**156**	**156**	**156**	**94**	**94**	**241**	**140**	**159**	**80**	**89**	**158**	**190**	**80**	**280**	**182**
New Resources 2021-2039																
DSM	202	510	510	510	510	510	643	643	643	510	510	510	510	254	510	254
DR	0	0	0	0	67	67	0	0	67	52	67	67	67	0	0	52
Mersey	15	0	0	0	0	0	0	0	0	15	15	15	15	0	15	0
Wind	0	0	0	18	0	0	0	36	18	36	18	36	18	18	0	0
PPA	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PHBM	52	52	52	52	0	0	52	0	0	0	0	0	52	52	45	45
NG CT	315	99	149	99	216	99	0	296	197	444	296	364	265	330	148	397
NG CC	145	0	0	0	290	145	0	0	0	0	145	0	0	145	0	145
FGD	-8	0	-8	0	0	-8	0	0	0	0	0	0	0	0	0	0
Retirements																
Coal	-303	-303	-303	-303	-614	-303	-303	-613	-613	-613	-613	-613	-614	-303	-303	-303
NG/Oil	-174	-174	-174	-174	-240	-240	-174	-174	-174	-174	-174	-174	-174	-174	-174	-174
Subtotal	**344**	**183**	**226**	**201**	**229**	**270**	**218**	**188**	**138**	**270**	**264**	**205**	**139**	**322**	**242**	**417**
Total Additional Firm Supply & Demand MW's Over Planning Period																
Total	**421**	**340**	**382**	**358**	**323**	**364**	**459**	**328**	**297**	**350**	**353**	**364**	**329**	**402**	**521**	**599**

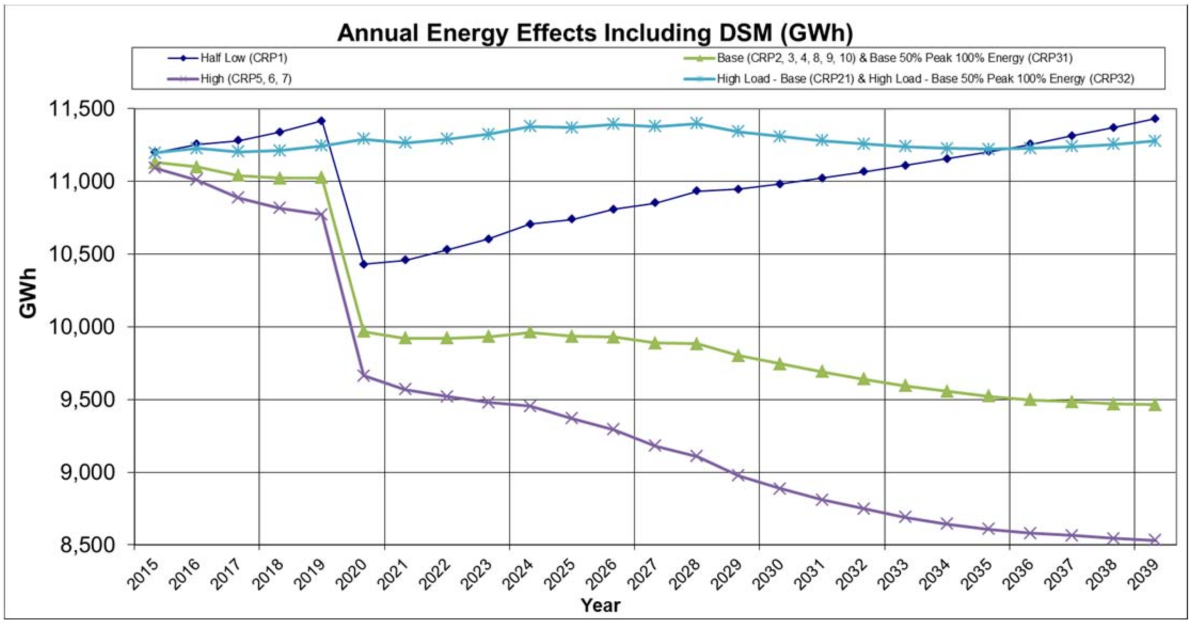
Notes for Schedule of Changes to Supply-side and Demand-side Resources (Firm MWs):

- DSM - capacity refers to reduction in firm demand (net of interruptible industrial portion)
- DR (Demand Response) - capacity refers to reduction in firm demand
- Mersey - incremental capacity upgrade
- Wind - firm contribution of incremental wind above planned and committed wind of 582 MW
  - * for CRP 9 WC the firm contribution of planned /committed wind and incremental wind was increased to 24.1 percent.
- PPA - Large non-emitting, RES compliant Purchased Power Agreement
- PHBM - PH Biomass unit is assumed to transition to a firm capacity resource upon the retirement of a second Lingan unit
- NG CT - Natural Gas Combustion Turbine
- NG CC - Natural Gas Combined Cycle
- FGD - coal retrofit with an FGD (scrubber) results in reduced capacity due to parasitic power

As indicated in the table above, apart from investment in Demand Response, incremental Mersey capacity and a change to the Port Hawkesbury biomass facility from Energy Resource Interconnection Service to Network Resource Interconnection Service, there is no call for new capacity in the next 5 years under any of the 14 CRPs for the Reference World. The resources the system needs to serve load over the near term period are in place and available. The key variable, from a planning perspective, for the Reference World over the near term period is the level of DSM.

5.2 DSM

The range of DSM levels modeled was derived from the most recent Efficiency Nova Scotia Corporation DSM Potential Study and was intended to reflect a wide range of potential DSM outcomes. The graph below shows the various DSM impacts assumed across the CRPs. Base DSM is the base amount from the ENSC potential study, High is the amount assumed in the high case of that same study and Half Low is 50 percent of the low range of the study. Current energy savings and investment in DSM was set at $35 million for 2015, producing an energy savings of 121 GWh. This level was established by the government of Nova Scotia in the Electricity Efficiency and Conservation Restructuring (2014) Act. The investment levels for the High, Base and Half Low cases are roughly $100 million, $50 million and $25 million respectively and are reflected in the graph labelled “DSM Program Administrator Costs” on page 56.



5.3 Thermal Fleet

The CRPs with the lowest Planning Period NPVs (CRP 2 and CRP 2-17 FGD) both had coal retirements occurring at 60 years, demonstrating that delaying retirement of existing coal assets is the lowest cost option for customers. This is the case across all sensitivities, as can be seen from the table below, CRP 2 and CRP 2-17 consistently rank 1 and 2 in planning period NPV across the scenarios considered. 60 year retirements represent the optimal economic life of the units from the analysis of the Company's asset management team. Apart from Lingan 2 which retires when the Maritime Link comes in service, there are no scheduled coal plant retirements in the lowest NPV plans until post 2020. Such a strategy will require ongoing asset management efforts to mitigate the risks associated with the transition away from base loaded operation to more of a load-following dispatch.

These results include the NPV adders for Sustaining Capital
Study period NPV's can only be compared within the same unit retirement strategies (e.g. all maximum coal)

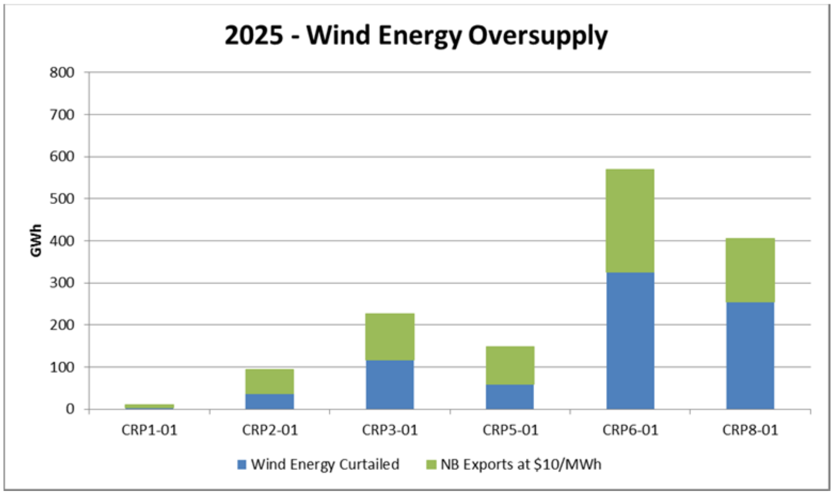
🟩 50% Low DSM 🟧 High DSM ⬜ Base DSM 🟦 Base DSM- 50% PEAK, 100% ENERGY 🟨 Cost unchanged from Original Case

All Values in $M	Original Data		S1 - Emissions B		S2 - Emissions C		S3 - High NG & IMPORT Prices		S4 - Low NG & IMPORT Prices		S6 -Low Price High S Coal		S7- High Price High S Coal		S9- Optimistic Wind - cost -output	
CRP	Planning Period Cost	Study Period Cost	Planning Period Cost	Study Period Cost	Planning Period Cost	Study Period Cost	Planning Period Cost	Study Period Cost	Planning Period Cost	Study Period Cost	Planning Period Cost	Study Period Cost	Planning Period Cost	Study Period Cost	Planning Period Cost	Study Period Cost
World 1 - REFERENCE																
CRP1-1-FGD	$12,449	$19,774	$12,370	$19,617			$13,166	$21,288	$11,899	$18,331	$12,372	$19,600	$12,619	$20,203	$12,449	$19,774
CRP2-1	$11,544	$17,103	$11,405	$16,802	$11,551	$17,192	$12,097	$18,216	$11,090	$15,993	$11,544	$17,103	$11,544	$17,103	$11,544	$17,103
CRP2-17-FGD	$11,530	$17,200	$11,489	$17,102	$11,580	$17,391	$11,996	$18,280	$11,157	$16,259	$11,460	$17,093	$11,704	$17,484	$11,530	$17,200
CRP3-1	$11,825	$17,419	$11,704	$17,150			$12,308	$18,392	$11,406	$16,412	$11,825	$17,419	$11,825	$17,419	$11,742	$17,199
CRP4-1	$11,736	$17,643	$11,609	$17,436	$11,743	$17,686	$12,309	$18,807	$11,253	$16,258	$11,736	$17,643	$11,736	$17,643	$11,736	$17,643
CRP4-1-FGD	$11,692	$17,469	$11,654	$17,343	$11,734	$17,594	$12,156	$18,563	$11,305	$16,401	$11,622	$17,326	$11,863	$17,713	$11,692	$17,469
CRP5-1	$12,125	$17,076	$12,027	$16,849			$12,548	$17,900	$11,746	$16,185	$12,125	$17,076	$12,125	$17,076	$12,125	$17,076
CRP6-1	$12,638	$17,829	$12,617	$17,808	$12,638	$17,829	$13,110	$18,735	$12,264	$16,965	$12,638	$17,829	$12,638	$17,829	$12,478	$17,405
CRP7-1	$12,512	$17,666	$12,479	$17,633			$13,016	$18,653	$12,108	$16,727	$12,512	$17,666	$12,512	$17,666	$12,430	$17,452
CRP8-1	$12,240	$18,095	$12,205	$18,059	$12,240	$18,095	$12,811	$19,263	$11,784	$16,991	$12,240	$18,095	$12,240	$18,095	$12,075	$17,651
CRP9-1	$12,200	$18,091	$12,158	$18,049	$12,200	$18,091	$12,824	$19,396	$11,680	$16,770	$12,200	$18,091	$12,200	$18,091	$12,117	$17,870
CRP9WC	$12,101	$17,968	$12,059	$17,926	$12,101	$17,968	$12,718	$19,281	$11,600	$16,736	$12,101	$17,968	$12,101	$17,968	$12,017	$17,742
CRP10-1	$12,000	$17,731	$11,904	$17,566			$12,490	$18,733	$11,576	$16,694	$12,000	$17,731	$12,000	$17,731	$11,919	$17,515
CRP31-1	$11,934	$17,831	$11,815	$17,563			$12,424	$18,822	$11,505	$16,690	$11,934	$17,831	$11,934	$17,831	$11,856	$17,620
World 2- HIGH LOAD																
CRP21-1 (FGD	$13,071	$19,852	$12,990	$19,712	$13,157	$20,289	$13,706	$21,267	$12,593	$18,690	$12,962	$19,685	$13,322	$20,246	$12,979	$19,624
CRP32-1 (FGD PPA)	$13,256	$20,585	$13,166	$20,389			$14,056	$22,161	$12,697	$19,067	$13,143	$20,371	$13,508	$21,084	$13,256	$20,585

What can also be seen from the table above is that in several cases, and in the High Load World, flue gas desulphurization (FGD) technology appears to be an economic investment. FGD is an emission control technology fitted to the coal fired generating units to remove most of the sulphur dioxide from boiler flue gases prior to release to the atmosphere. Utilization of FGD technology allows for the combustion of generally high sulphur, lower cost fuels (coal and petcoke). This could introduce the opportunity of domestic high sulphur coals, provided that the source presented a cost effective option. The Company is proposing to study this further in the context of solid fuel pricing as part of its Action Plan. As can be seen in the schedule of changes to supply, there are capacity additions in the high load scenarios before 2020 and the Company anticipates that if energy demand or peak demand exceed the base levels forecast or DSM does not perform then capacity additions either via a PPA or natural gas combustion turbines may be necessary.

5.4 Renewables

Several different levels of renewable generation were assumed in the IRP: existing and committed wind generation of 582 MW (Base), and two incremental levels of wind addition bring the installed total to 750 MW (Medium) and 900 MW (High). Assumptions included incremental capital investments for system reliability to manage wind cases of 750 MW and 900 MW. Plexos modeling was used to evaluate dispatch and operating challenges associated with some of the selected CRPs. This work revealed that wind generation above base levels[25] when combined with significant DSM programing could result in significant uneconomic exports and wind curtailments.



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[25] Base levels are the 582 MW currently planned or under development and included in slide 34 of the presentation given at the June 25, 2014 Technical Conference.

The Company continues to gain firsthand experience with the integration of wind generation on the power system. Accordingly, the Company proposes to report on the ongoing integration experience of variable renewable generation as part of its Action Plan.

The basic assumptions also called for the Mersey system redevelopment as a feature that was included across all plans. Strategist was then given the option to select 2 blocks of 15 MW capacity additions associated with the Mersey system upgrades, as when the refurbishment occurs it has been estimated that there could be a capacity increase of 30 MW.

The Maritime Link is scheduled to come online in the first 5 years of the IRP. The Company has a number of transmission projects related to the Maritime Link that will be implemented prior to the completion of the Link. NS Power also expects that the Link will bring opportunities for enhanced regional coordination and integration. This enhanced interconnection will also enable better access to markets for imports and exports.

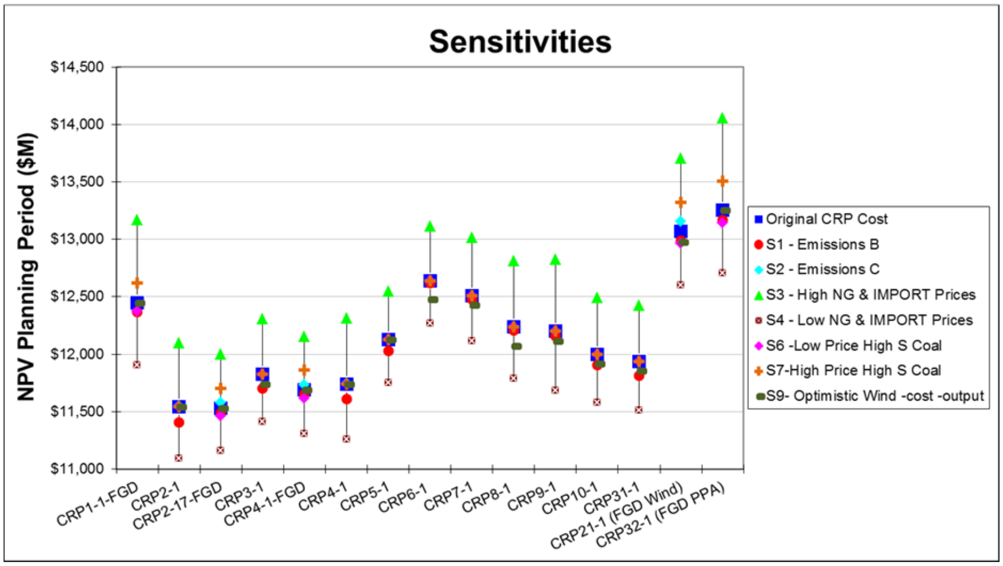
5.5 Sensitivities and Worlds

Nova Scotia Power ran the following sensitivities:

- Deeper emissions cuts
- Less emissions cuts
- High natural gas, high import power pricing
- Low natural gas, low import power price
- No Demand Response Programs
- Low international price for high sulphur coal
- High international price for high sulphur coal

- Low cost, high output wind

The whisker graph below shows that CRPs performed similarly across the various sensitivities. This shows that the resource mix for supplying the Nova Scotia system is robust. The diversified portfolio of options includes; coal, natural gas, oil, biomass, hydro, wind, Maritime Link and DSM. Having such a diversified system provides a natural hedge so if one commodity spikes there isn't necessarily a system wide impact.



5.6 Evaluation of Alternative CRPs

NS Power evaluated the suite of CRPs using planning period NPV and rate impact as the primary criteria to judge the various plans. However the Company also considered Risk, Flexibility, Robustness and Future Regulatory Emissions Outlook as qualitative screens to ensure that the chosen path could maintain the characteristics of previous IRPs and be a "no regrets" solution.

The various DSM profiles result in a range of nearly 3,000 GWh by the end of the study period, roughly 25 percent of the annual energy in the high load case. There is also a significant difference in the NPVs, and therefore potentially the revenue requirements, of the various DSM profiles over the short, medium and long terms respectively. The following table shows the NPVs of all plans across 4 periods:

- to 2020 (5 years)
- to 2030 (15 years)
- to 2039 (Planning Period)
- beyond 2039 (Study Period)

	CRP1-1 FGD	CRP2-1	CRP2-17 FGD	CRP3-1	CRP4-1	CRP4-1 FGD	CRP5-1	CRP6-1	CRP7-1	CRP8-1	CRP9-1	CRP9WC	CRP10-1	CRP31-1	* CRP21-1 (FGD WIND)	* CRP32-1 (FGD PPA)
Load	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	High	High
DSM Profile	Half Low	Base	Base	Base	Base	Base	High	High	High	Base	Base	Base	Base	Base 50% Peak 100% Energy	Base	Base 50% Peak 100% Energy
Wind	Base	Base	Base	Med	Base	Base	Base	High	Med	High	Med	Med	Med	Med	Med	Base
Retirement Strategy	Max	Max	Max	Max	Med	Med	Max	Min	Min	Min	Min	Min	Med	Max	Max	Max
TRC $ M																
NPV 2020	$3,907	$4,049	$4,049	$4,049	$4,065	$4,065	$4,491	$4,489	$4,507	$4,062	$4,072	$4,072	$4,075	$4,050	$4,194	$4,195
NPV 2030	$9,025	$8,777	$8,780	$8,959	$8,836	$8,838	$9,547	$9,864	$9,790	$9,203	$9,182	$9,113	$9,063	$8,963	$9,764	$9,761
Planning Period	$12,449	$11,544	$11,530	$11,825	$11,737	$11,693	$12,125	$12,638	$12,512	$12,240	$12,200	$12,101	$12,000	$11,933	$13,070	$13,256
**** Study Period**	$19,775	$17,103	$17,201	$17,419	$17,643	$17,469	$17,076	$17,829	$17,666	$18,095	$18,091	$17,968	$17,731	$17,831	$19,851	$20,585
TRC Rank																
NPV 2020	1	3	2	3	7	7	13	12	14	6	9	9	11	5	1	2
NPV 2030	7	1	2	5	3	4	12	14	13	11	10	9	8	6	2	1
Planning Period	12	2	1	5	4	3	9	14	13	11	10	8	7	6	1	2
Avg. Rank	*6.7*	*2.0*	*1.7*	*4.3*	*4.7*	*4.7*	*11.3*	*13.3*	*13.3*	*9.3*	*9.7*	*8.7*	*8.7*	*5.7*	*1.25*	*1.75*
**** Study Period**	6	2	3	4	2	1	1	2	1	5	4	3	3	5	1	2
Utility Cost $ M																
NPV 2020	$3,784	$3,858	$3,857	$3,858	$3,874	$3,874	$4,054	$4,051	$4,069	$3,871	$3,880	$3,880	$3,883	$3,859	$4,002	$4,003
NPV 2030	$8,762	$8,416	$8,420	$8,599	$8,475	$8,478	$8,672	$8,989	$8,915	$8,843	$8,822	$8,753	$8,703	$8,603	$9,403	$9,401
Planning Period	$12,086	$11,069	$11,055	$11,350	$11,262	$11,218	$11,087	$11,601	$11,475	$11,765	$11,725	$11,626	$11,525	$11,458	$12,595	$12,781
**** Study Period**	$19,270	$16,471	$16,568	$16,786	$17,010	$16,836	$15,846	$16,599	$16,436	$17,462	$17,458	$17,336	$17,098	$17,198	$19,219	$19,953
Utility Cost Rank																
NPV 2020	1	3	2	3	7	7	13	12	14	6	9	9	11	5	1	2
NPV 2030	10	1	2	5	3	4	7	14	13	12	11	9	8	6	2	1
Planning Period	14	2	1	6	5	4	3	10	8	13	12	11	9	7	1	2
Avg. Rank	*8.3*	*2.0*	*1.7*	*4.7*	*5.0*	*5.0*	*7.7*	*12.0*	*11.7*	*10.3*	*10.7*	*9.7*	*9.3*	*6.0*	*1.25*	*1.75*
**** Study Period**	6	2	3	4	2	1	1	2	1	5	4	3	3	5	1	2

🟧 Max Retirement Strategy 🟩 Med Retirement Strategy 🟦 Min Retirement Strategy

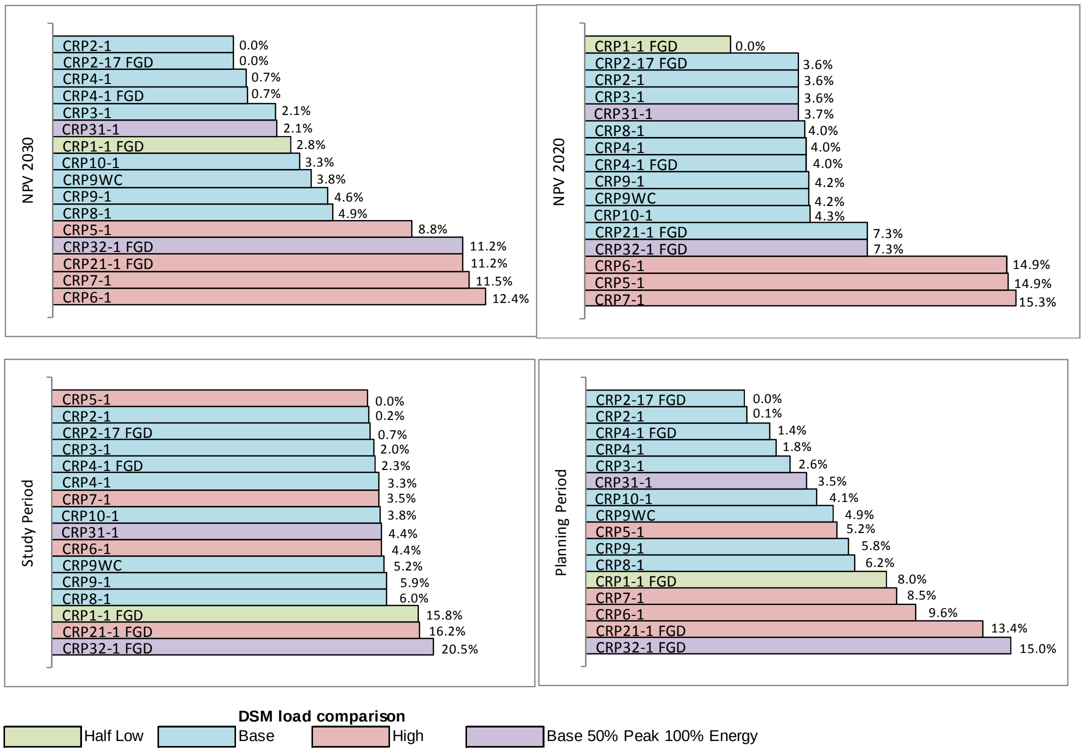
This table shows that from an NPV perspective, 4 plans with 3 different DSM profiles emerge as the low-cost plan depending on the timeframe;

- to 2020 (5 years) – CRP 1-1 FGD
- to 2030 (15 years) – CRP 2-1
- to 2039 (Planning Period) – CRP 2-17 FGD
- beyond 2039 (Study Period) – CRP 5-1

These plans share common assumptions for wind levels and retirement strategies – base wind levels and maximizing the life of NS Power's coal fleet. However, these plans vary in their DSM investment:

- CRP 1-1 FGD – 50% of low
- CRP 2-1 – Base
- CRP 2-17 FGD – Base
- CRP 5-1 – High

The following graphs show the variation in NPVs based on DSM profiles across the periods:



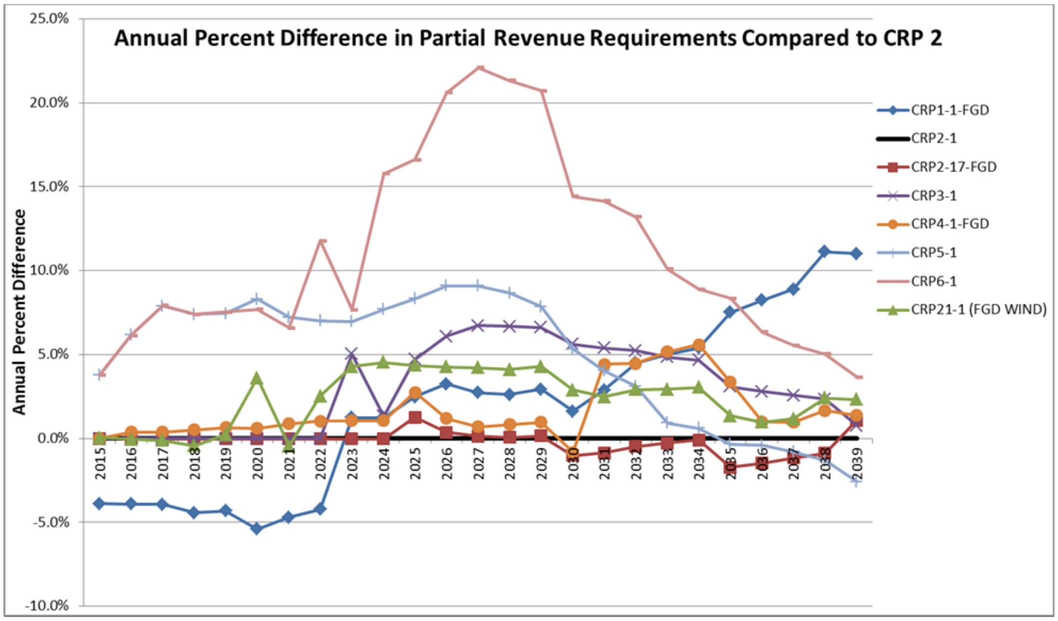
The percentages on the charts represent what percentage the plans' respective NPV is higher than the plan with the lowest NPV in that period. While the IRP is a long-term planning exercise, it can provide an indication of potential rate pressures for the near term through partial revenue requirements produced by the modeling. Partial revenue requirements include the following:

- fuel and purchased power
- thermal and hydro unit O&M
- capital costs for new resources added in the CRP
- DSM program administrator costs
- sustaining capital costs for existing and new generation added in the CRP

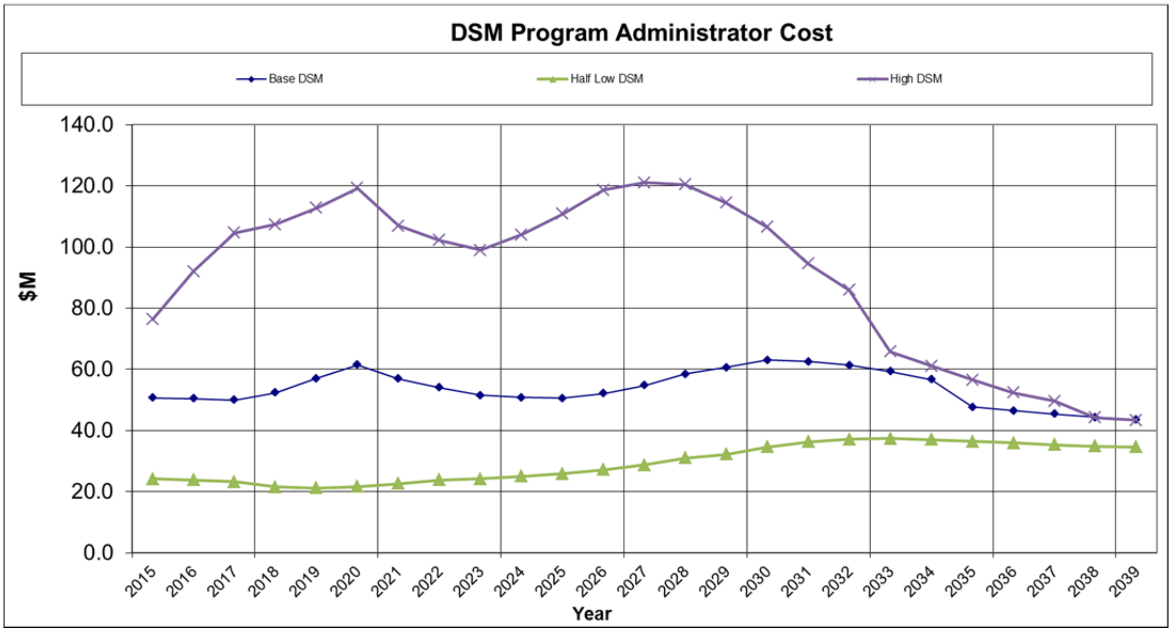
Strategist revenue requirements do not include the following:

- remaining O&M
- regulatory adjustments/amortizations,
- depreciation, interest and tax impacts for existing assets
- T&D sustaining capital cost

The following graph illustrates the revenue requirements compared against CRP 2, the lowest cost plan over the planning period;



In the near-term, low DSM investment produces the lowest revenue requirement and potentially the least rate pressure. Alternatively, High DSM produces the highest revenue requirement in the near-term but the lowest in the final years of the planning period. This should be expected as the graph below shows the difference in investment in DSM between the various cases, close to $100 million in revenue requirement in some years.



As part of its Action Plan, NS Power will work with ENSC and stakeholders to determine the optimal level of DSM spend that balances short term affordability[26] with long term performance.

DSM levels in the Planning Period also have a significant impact on planning reserve margin. The graph below demonstrates that some CRPs have much higher levels of planning reserve margin than the 20 percent reserve margin requirement.

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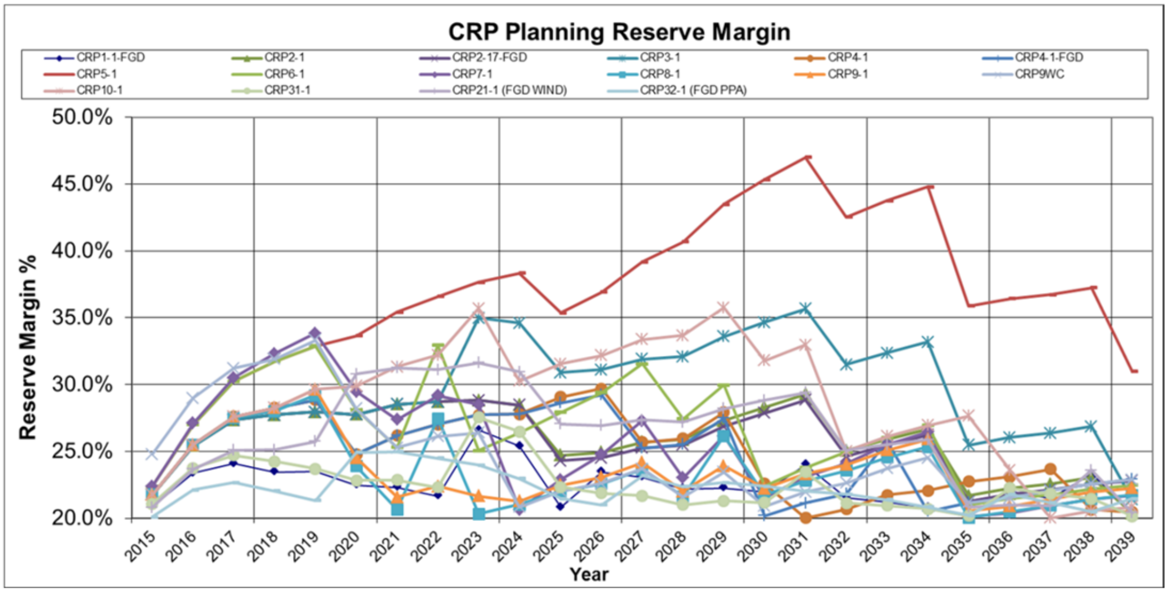
[26] Affordability as referenced in Bill 41, Electricity Efficiency and Conservation Restructuring (2014) Act, 1st Sess., 62nd General Assembly, Nova Scotia, 2014 (First Reading: April 7, 2014).



The Company has committed to studying levels of sustaining capital that could, if necessary, reduce the level of surplus planning reserve margin in the event of lower firm peak load. NS Power will also produce a report on industry best practices regarding sustaining capital. Sustaining capital as discussed in the IRP is the investment the Company makes on an annual basis to maintain over 1500 MW of firm thermal generating capacity. The estimates of sustaining capital required for the planning period were derived for the different fleet utilization strategies and expressed as a net present value of approximately $300 million dollars. Having excess planning reserve margin could mean that capacity could be retired therefore reducing the amount of sustaining capital required. But like DSM investment, discrete retirement strategies were selected for modeling and were not optimized in the CRP process. Further work will be undertaken within the Action Plan to refine and report on unit retirement forecasts.

5.7 Preferred Plan

As indicated, the IRP is a 25 year planning exercise but the various plans perform differently at different time intervals within and beyond that period. The top performing plans from a planning period NPV perspective have similar attributes – they utilize existing coal units to their maximum lifespans, there is no incremental variable generation added and new thermal generation, if any, is natural gas combustion turbines.

The Company believes that maximizing coal plant life, not adding incremental variable generation, and a focus on affordability to be a no regrets path and has tried to reflect that in the Action Plan. So while in past IRPs the Company would have selected a certain plan to base its Action Plan on, the range of reasonable futures and therefore plans seems to have converged significantly around a strategy of minimal incremental capital expenditure, especially in the near term.

The notable exception to this trend of convergence and minimal investment is DSM. The low DSM plan has the best NPV in the near term, the base DSM plan has the best NPV in the 25 years of the planning period, and high levels of spending on DSM show the best NPV in the long term period, while exerting the highest rate pressure in the near term. The Company feels that the IRP process has identified the appropriate range of DSM to acquire over the planning period from a planning perspective. Given the Electricity Efficiency and Conservation Restructuring Act, which received Royal Assent on May 1, 2014, NS Power expects to establish the specific level of DSM to acquire during the Action Plan period in a separate proceeding. The Act calls for NS Power to contract with the electricity efficiency and conservation franchise holder over the next ten years in 3 year terms, the first term beginning in 2016. This will enable NS Power to work with ENSC and stakeholders to establish a proposal for the level of DSM that considers the long term benefits of DSM in conjunction with affordability considerations as outlined in its Action Plan.

6.0 ACTION PLAN

6.1 Action Plan Introduction

The intent of the Action Plan is to provide the UARB, NS Power and stakeholders with a guideline for system planning over the next 5 years. The Action Plan also serves to inform the next IRP by studying key findings from the analysis phase of this IRP. There are action items pertaining to DSM, renewables, regional integration, sustaining capital, transmission and capacity reserve margin.

6.2 2014 IRP Action Items

The 2014 IRP Action Plan identifies specific actions the Company will take over the next five years. Action items are based on the type and timing of resources identified in the least cost plans from analysis completed over the course of the IRP modeling, and feedback received from stakeholders throughout the IRP process. The directed actions also recognize the limitations of the modeling processes used, and reflect NS Power's understanding of additional analytical efforts required to sufficiently address certain areas of inquiry.

6.2.1 Demand Side Management

Changes to electricity efficiency legislation in Nova Scotia have impacted the analysis of DSM in the 2014 IRP. In order to evaluate DSM programming within the Candidate Resource Plan model, various pre-determined levels of DSM were used. These levels will inform the process of contracting with the DSM franchisee contemplated in the revised legislation. NS Power therefore proposes to work with ENSC and stakeholders to obtain a cost-effective and affordable level of DSM consistent with the IRP findings, to be submitted to the UARB for approval in accordance with the revised DSM legislation.

Demand Side Management Actions:

- Engage with ENSC and stakeholders to develop a 3 year plan and file for UARB approval: first half of 2015.

- Obtain DSM resource commitments (annual system energy and peak period capacity reductions) for the 2016-2018 period that are consistent with the IRP analysis.

- Engage with stakeholders and ENSC to monitor DSM performance and options: Q4, 2014, Q1, 2015.

- During 2015, determine whether evaluation, monitoring and verification will be sufficient to establish the savings impacts of DSM resources going forward, including commitments for the period 2016-2018.

- Pursue cost-effective Demand Response opportunities: ongoing.

6.2.2 Renewable Resources

Several different levels of renewable generation were assumed in the IRP: 582 MW (base), 750 MW (medium), and 900 MW (high). Wind levels above currently planned capacity additions when combined with medium and early coal retirement dates could result in uneconomic exports and additional wind curtailments. However, the IRP studies do not explicitly account for the potential of mitigating factors (such as infrastructure investment, and increased regional cooperation) to manage such concerns. Action Plan items will address this.

The Maritime Link is scheduled to come online in the first five years of the IRP. The Company has a number of transmission projects related to the Maritime Link that will be implemented prior to the completion of the Link. NS Power also expects that the Link will bring opportunities for enhanced regional coordination and integration. This enhanced interconnection will also enable better access to markets for imports and potentially exports.

The basic assumptions also called for the Mersey system redevelopment as a feature that was included across all plans. Strategist was then given the option to select 2 blocks of 15 MW capacity additions associated with the Mersey system upgrades as when the refurbishment occurs, it has been estimated that there could be a capacity increase of 30MW. A s noted elsewhere, since the Strategist modeling process did not economically optimize capacity contributions from different resources, the extent to which the Mersey system increment could be a cost-effective capacity contribution to NS Power's system is still to be determined through a UARB process if the Company makes application for the upgrades.

NS Power recognizes there are challenges and opportunities over the course of the Action Plan period concerning the integration of renewable energy and proposes the following action items.

Renewable Resource Actions:

- During 2015-2016, continue to evaluate the coincidence of wind generation with peak load to better understand the Capacity Value of wind assets on the NS Power system.

- Monitor ongoing developments of tidal energy and report to the UARB as part of the 10 Year System Outlook filed annually in June.

- Complete the integration of the Maritime Link.

- Evaluate the options for Mersey Hydro System redevelopment and file an Application with the UARB, inclusive of both existing capacity and potential capacity expansions. Conduct further analysis to understand the value of incremental capacity associated with the Mersey redevelopment, accounting for the value of small-scale capacity additions, possible different thermal plant retirement paths (thus affecting the need for a Mersey increment), the flexibly dispatchable nature of a Mersey hydro increment, and the lack of emissions associated with any increase in hydro development.

- Continue to develop an understanding of the operational challenges associated with increasing levels of variable generation integration and report to the UARB as part of the 10-Year System Outlook Report.

- File Renewable to Retail Tariff Application by September 1, 2015.

- Report to the UARB on the status of the need for flexible resources to integrate additional variable generation in the 10-Year System Outlook Report.

6.2.3 Regional Opportunities

The Maritime Link is scheduled to come online in 2017 and is a crucial tool for NS Power to meet its 2020 environmental obligations. In addition to providing energy, the Maritime Link also provides enhanced interconnection and opportunities for better regional system cooperation. There is also greater interconnection and cooperation possibilities with New Brunswick, the Company would like to further consider these opportunities through the Action Plan period.

The IRP modeling process did not include explicit modeling of the potential benefits of greater levels of regional cooperation, as the work focused primarily on in-province actions.

Regional Opportunities Actions:

- Monitor cost-effective market opportunities (imports and exports) as well as enhancements in regional balancing and interconnection and report on developments in the 10-Year System Outlook Report.

- During 2015, continue discussions with Newfoundland (NALCOR) and New Brunswick (New Brunswick Power) on greater regional electric system coordination.

    - Provide an annual update to the UARB.

    - Discuss need, impacts, and cost allocation associated with a second 345 kV line to New Brunswick.

    - Explore mechanisms to advance efficient regional unit commitment, dispatch, and operating reserve sharing policies.

    - Examine the effects of the operation of the Maritime Link on these issues.

6.2.4 Existing Thermal Resources

CRPs with lower planning period NPVs generally reflect “maximum coal” utilization inputs to Strategist, indicating the potential value of extending coal plant asset life in order to meet planning reserve requirements. However, since Strategist does not optimize plant retirement, the modeling results do not provide absolute clarity on the most economic retirement or plant life extension path for the thermal units.

In several cases, and in the High Load World CRPs, flue gas desulphurization appears to be an economic investment. The Company is proposing to study this further in the context of solid fuel pricing.

Over the study period CRP 5-1 had the lowest NPV; it was also competitive over the planning period. CRP 5-1 and other CRPs had excess capacity margin, as a result of the modeling technique, indicating that there may be opportunity to optimize asset management over the planning period to reduce spare capacity reserve. NS Power proposes to further study its asset management practices and sustaining capital spend within the context of the Action Plan.

Existing Thermal Resources Actions:

- Continue the thermal generation asset analysis work from the IRP process. By the end of June 2015, file an initial thermal asset management plan striving to optimize the level of sustaining capital expenditures required for the fleet of coal/oil/gas plant. Update this plan each year in the 10-Year System Outlook Report filing. The plan will include the following:

    - Recognition of uncertainty of many elements involved in this form of analysis.

    - Recognition of/adherence to planning reserve margin requirement and level of planning reserve surplus associated with different net firm peak load trajectories based on then-anticipated DSM peak reductions and associated net firm peak load forecast.

    - Projections of possible retirement paths for the thermal fleet.

    - Prioritization of units or plans for retention given system constraints.

    - Consideration of locational value of Tufts Cove plant, and flexible operating characteristics of gas and oil-fired steam units compared to coal-fired units. There may be locational or system considerations that could give preference to sustaining capital or life extension expenditures at the Tufts Cove location compared to other plants.

    - Consideration of location of other system resources, either NS Power-owned or IPP-owned, and their capacity value.

    - Consideration of unit utilization forecasts and the significant driver that operating hours is for maintenance investment.

  Ultimately, this Action Plan item will result in an analysis of investment plans for the existing thermal fleet given forecasted system peak and unit utilization. Based on the modeling results, high DSM plans can lead to excess planning reserve margin if no changes are made to the coal utilization path modeled; this may also be the case with base-level DSM resource commitments.

- Provide an outlook of sustaining capital expenditures for thermal assets for a five year period in the Annual Capital Expenditure Plan.

- Study the economic potential of an FGD in combination with opportunities to optimize solid fuel use.

6.2.5 Transmission and System Studies

NS Power expects regional transmission opportunities to result from the integration of the Maritime Link and subsequent improvements to the Nova Scotia transmission system. The Company will monitor and report on these opportunities during the Action Plan period. Additional system level studies will continue to be required to assess how NS Power’s changing generation asset mix, and potential regional coordination actions, will affect the need for new transmission system resources.

Transmission and System Studies Actions:

- Execute the Maritime Link transmission investments.

- During 2015 - 2020, conduct additional system studies to evaluate operations with increased levels of renewable resources that are expected over the next few years. Include investigation of system requirements with fewer steam units providing real power operations.

  - Report on the status of such efforts each year in the 10-Year System Outlook report.

  - Use Plexos to continue to assess hourly patterns of system need and resources with respect to operation under higher levels of wind resources expected over the next few years.

  - Conduct system studies to estimate requirements to ensure reliability with levels of wind similar to those seen in CRP 7 (medium wind, ~750 MW installed capacity) and CRP 6 (high wind, ~900 MW of installed capacity).

  - Consider the effect of the presence of the Maritime Link on system operations with higher levels of wind, and/or lower levels of connected coal-fired capacity.

- Conduct system studies that evaluate the economics, stability and reliability of the system with accelerated coal unit retirements.

- Assess the type, level, cost, sequencing, and integration of transmission system reinforcement requirements that could accompany various coal plant retirement schedules. This includes the presence of additional transmission line assets or reinforcement of existing assets; the presence of dynamic and static reactive power devices including synchronous condensers (new, or conversions of existing power generators to operate in this mode); regional coordination opportunities; improved forecasting techniques; greater use of advanced wind turbine technologies with new wind; demand response resources; and any other technical innovations that would affect operations.

6.2.6 Ongoing Analysis of Value of Capacity Contribution towards Resource Adequacy Requirements

Strategist used coal plant retirement schedules as an input assumption to the modeling; it did not determine an economic optimum retirement path as this was not contemplated in the Candidate Resource Plan process. Sustaining capital needs were also evaluated outside of the Strategist environment; therefore, additional efforts are required to determine whether or not certain non-thermal capacity additions can be considered cost-effective for customers as a contribution towards resource adequacy requirements. The Candidate Resource Plan method tests characteristics but leaves some optimizations as actions. This Action Plan element summarizes the actions required to address this issue.

Capacity Contribution Actions:

- ERIS connected wind resources will be evaluated for firm capacity contribution. During 2015, NS Power will determine the extent to which ERIS resources can count as capacity towards resource adequacy during winter peak.

- As part of DSM programming, evaluate the DR resource contributions to capacity. During 2015-2020, NS Power will continue to assess the availability and potential for cost-effective Demand Response.

6.2.7 Planning Reserve Margin

NS Power maintains a planning reserve margin for system reliability purposes. NS Power's current planning reserve margin, in compliance with Northeast Power Coordinating Council (NPCC) criteria, is equal to 20 percent of firm system peak demand. Enhanced regional cooperation and variable generation integration may impact planning reserve margin over the Action Plan period. NS Power proposes to keep the Board and stakeholders advised of any such changes.

Planning Reserve Margin Actions:

- Report on the ongoing evaluation of the planning reserve margin for the power system in the 10-Year System Outlook Report.

6.2.8 Regulatory

Since the last IRP, there have been numerous regulatory and environmental changes. The Company does not expect significant additional regulatory changes; however, this remains a possibility and NS Power wants to ensure the UARB and stakeholders are informed of the impact of such changes to the IRP planning process.

Regulatory Actions:

- Monitor renewable and emissions related legislative/regulatory developments.

- Report to the UARB on legislative/regulatory changes that may have a material impact on the Action Plan – one update to be sent in Q3 2016.

6.2.9 IRP Planning and Modeling Process Improvement

IRP and Planning Process Actions:

- During 2015, create a plan for an update to the IRP process during the 2016-2018 ENSC performance period to reflect then-current performance and then-current net load forecasts for firm peak and annual energy. Report to the UARB by the end of 2015 on this.

- Review model use for the next IRP. Consider how Strategist, Plexos, and power flow modeling tools can be best utilized for the next round of integrated resource planning.

    - Strategist – analyze strengths and weaknesses.

    - Plexos – analyze strengths and weaknesses.

    - Power flow modeling tools – analyze their role in assessing capital requirements for system stability and related transmission reinforcement.

6.3 Strategic Resource Plan Decision Paths

As with all long-term planning exercises or forecasts in general, there are considerable uncertainties within the planning period. One of the goals of the IRP is to produce a path that maintains enough flexibility to allow for such uncertainty. As part of its Analysis Plan, the Company considered a number of possible deviations from the basic assumptions to enable it optionality in the event of a different planning horizon. The table below references potential triggers that could cause the Company to alter its planning path and identifies the CRPs which it would consider under such circumstances.

Trigger	2014 IRP World	Resource Plan to Consider
Higher sustained load growth	High Load World	CRP 21
High DSM performance	Reference World	CRP 5
Low DSM performance	Reference World	CRP 1
More stringent environmental requirements introduced	Reference World High Load World	CRP 2 CRP 21
Additional RES requirement	Reference World	CRP 3 (medium wind) CRP 8 (high wind)

6.4 Risk and Opportunity Analysis

The following sections outline the potential risks and opportunities that the Company envisions over the planning horizon. These are items that NS Power will continue to evaluate over the Action Plan Period and consider as part of subsequent IRPs.

6.4.1 Retirements

Early steam fleet retirement did not show significant benefit when compared to maximum steam fleet utilization. The risk associated with early steam fleet retirement is the reduced system flexibility while attempting to integrate approximately 600 MW of variable generation and significant quantity of DSM. If DSM programs do not deliver energy and peak reductions as forecasted, early steam fleet retirement scenarios will call for new capacity to be built in order to maintain system reliability.

We acknowledge that the load-following service envisioned for many of NS Power's conventional steam units will introduce new maintenance risks that will be addressed through asset management strategies.

6.4.2 DSM

High investment in DSM in the early years poses a risk of increasing pressure on power rates in the near term, while the risk of underperformance associated with unprecedented levels of DSM may require additional investment in firm capacity, exerting further pressure on power rates.

Low investment in DSM in the early years carries the risk of missed opportunity to reduce demand and provide immediate fuel cost savings in the near term, while providing extended benefits for the life of the program.

Suboptimal investment in DSM coupled with the potential loss of industrial load poses a challenge with taking advantage of Maritime Link surplus energy and is showing higher amounts of wind energy curtailment and uneconomic exports.

6.4.3 Environmental regulations

There are no legislated environmental regulations past year 2030. In the IRP simulations, the Company extrapolated the most likely set of emissions limits based on the existing regulations, and tested two sensitivities around the base line. The risk associated with uncertain environmental regulations in the long term stresses the importance of maintaining the flexibility of the existing diverse generation fleet and planning additional supply and demand side resources as required.

While different emission sensitivities were tested this analysis was conducted with only base case fuel and energy prices and the impact of variable fuel and energy pricing on emission compliance costs was not evaluated in this IRP.

6.4.4 Flu Gas Desulphurization

More so than in the previous IRPs, FGD emerged as optimal even with the assumed relatively high price of high sulfur coal. With decreasing SO_2 emissions caps, an FGD could provide an opportunity to take advantage of low priced high sulfur coal which can help stabilize power rates and provide an attractive incentive for retention of present industrial load and even attracting new industrial customers. Due the single stack shared by two generating units configuration, Lingan power station is an ideal site for an FGD providing most value for a single installation.

The risk associated with building of an FGD lies partly in the availability of sufficient quantity of relatively inexpensive high sulfur coal product, and partly in the uncertainty with CO_2 air emissions regulations in the future.

6.4.5 Resource Incompatibility and Unintended Competition

Nova Scotia climate causes the phenomenon of low overnight system demand, followed by relatively high morning demand, with significant seasonal variations. Due to system stability and security issues, minimum amount of high inertia steam generation is required to be online, which in low load periods causes wind curtailment and sub optimal utilization of Maritime Link off-peak surplus energy. Chronological hourly system simulations have shown high levels of wind curtailment and uneconomic energy exports, coupled with low utilization of Maritime Link available off-peak surplus energy, in resource plans containing additional wind generation and high levels of DSM. Investment in wind resources and DSM programs will have to be designed not to exert further downward pressure on low load periods and not to compete with Maritime Link surplus energy utilization and with each other. DSM programs may have to include demand response in order to be optimal.

6.4.6 Firm Capacity and ERIS Wind Generation

Arising from the Cost of Service proceedings was an action for NS Power to evaluate the contribution to firm capacity which is available from Energy Resource Interconnection Service (ERIS) wind projects. The concept around ERIS is that the generation interconnection customer can operate up to its full rated output only if transmission capacity is available. Under peak conditions, many transmission corridors are operating at rated transfer capacity, leaving no transmission capability available for ERIS generator and requiring a down dispatch or curtailment of that generator. Network Resource Interconnection Service generation projects are considered firm assets as transmission capacity is available at all times for the facility to deliver its full rated capacity to the power system.

On the NS Power electric power system, at the present level of wind integration, curtailment of ERIS wind projects is not frequently observed leaving the impression that there is adequate transmission capacity to accommodate both NRIS and ERIS projects even during peak operating conditions. As most ERIS projects on the NS Power system are recently added renewable electricity generators they receive priority environmental dispatch to assist NS Power in meeting the requirements of the Nova Scotia Renewable Electricity Regulations. What often goes unnoticed is the down dispatch or the bottling of NRIS generating capacity to allow the renewable projects to operate and meet production targets. In other words, firm generation is being dispatched down in order to allow ERIS wind generation on the system, at times when all firm generation capacity is not required. On most occasions the down dispatch of firm resources has no bearing on the power system, but this does become a consideration in the planning of the contribution of these ERIS projects to firm system capacity. If ERIS projects operate on peak system conditions only when NRIS generation is restricted to accommodate the renewables, then the full capacity of the NRIS resources and the ERIS resources cannot be counted towards the systems firm capacity.

ERIS generation is considered non-firm energy under the Open Access Transmission Tariff (OATT) and an ERIS generation unit cannot be assigned as a Network Resource by a Network Service Customer as per Section III of the Tariff. Despite this, the NS Power was requested to evaluate the possible contribution to firm capacity that could be counted from ERIS wind projects.

The Nova Scotia Power System Operator (NSPSO) examined the following wind powered generation facilities which are designated ERIS on the NS Power transmission System:

- 89N-Nuttby Mountain 49.5 MW
- 91N-Dalhousie Mountain 50.0 MW
- 93N-Glen Dhu 62.0 MW

Any such evaluation is subject to power system configuration and the NSPSO examined conditions anticipated after the integration of the Maritime Link. The particulars of these system modeling assumptions are summarized in Appendix M. All design contingencies as described by NPCC and the North American Electricity Reliability Corporation (NERC) criteria were tested for the assumed system configuration. No violations of voltage, stability, or thermal overloads were found under these tested conditions for the wind projects noted above.

Accordingly it can be concluded that, given the study assumptions**,** the transmission connected ERIS wind projects considered in this study would not likely be curtailed if they are operating at 17 percent of their nameplate capacity. It is important to note that this is not a derivation of the Capacity Value of the wind which is a consideration discussed in Section 3.6 of this report. It should also be noted that this evaluation is limited to the projects studied and is not applicable to all future ERIS projects. It is also possible that if system development deviates from the conditions assumed in Appendix M that these study outcomes could change.

This analysis does not constitute the System Impact Study necessary to change the designation of any wind project from ERIS to NRIS. For these installations to be designated as Network Resource Interconnection Service (NRIS), and therefore be eligible to be counted as Network Resources, an application for NRIS would be required via the Generator Interconnection Procedures (GIP) and the appropriate procedures would be followed. This work suggests that a portion of the installed projects could be counted towards the firm system generating capacity, but it isn't clear how this could be handled within the provisions of the Tariff. NS Power is proposing an Action Plan item to determine how to work through these Tariff and GIP related issues.

7.0 GLOSSARY OF TERMS

ACI	Activated Carbon Injection
BSD	Burnside
CAES	Compressed Air Energy Storage
CC	Combined Cycle
CCS	Carbon Capture and Storage
CO_2	Carbon Dioxide
COMFIT	Community Feed-In Tariff
CRP	Candidate Resource Plan
CT	Combustion Turbine
CV	Capacity Value
DR	Demand Response
DSM	Demand Side Management
ERIS	Energy Resource Interconnection Service
FGD	Flue Gas Desulfurization
GHG	Greenhouse Gas
HFO	Heavy Fuel Oil
Hg	Mercury
HRSG	Heat Recovery Steam Generator
HS	High Sulfur
IGCC	Integrated Gasification Combined Cycle
IPP	Independent Power Producer
IRP	Integrated Resource Plan
LFO	Light Fuel Oil
LIN	Lingan
LS	Low Sulfur
ML	Maritime Link
MS	Medium Sulfur
NB	New Brunswick
NG	Natural Gas
NO_x	Oxides of Nitrogen (NO and NO_2)

NPV	Net Present Value
NRIS	Network Resource Interconnection Service
NS	Nova Scotia
NSPI	Nova Scotia Power Incorporated
PAC	Powder Activated Carbon
PC	Pulverized Coal
PHP	Port Hawkesbury Paper
POA	Point Aconi
POT	Point Tupper
PPA	Power Purchase Agreement
RES	Renewable Electricity Standard
RM	Reserve Margin
SO_2	Sulfur Dioxide
TRE	Trenton
TRL	Technology Readiness Level
TUC	Tuft’s Cove
WRC	Wreck Cove

Nova Scotia Power Integrated Resource Plan - 2014
Terms of Reference

Objective

To develop a long-term Preferred Resource Plan that establishes the direction for NS Power to meet customer demand and energy requirements, and environmental obligations in a cost-effective, safe and reliable manner across a reasonable range of foreseeable futures; and to develop an Action Plan describing the major tasks required to implement a no regrets strategy[1] that aligns with the Preferred Resource Plan during the first five years of the planning horizon.

Preamble

In its letter of December 18, 2013 the Nova Scotia Utility and Review Board (UARB, Board) directed NS Power to undertake Integrated Resource Plan (IRP) development. The Board provided that the IRP development process should follow a similar collaborative approach to that employed in the 2007 and 2009 IRP processes, with one significant change. The Board has directed NS Power to provide the Board's consultant, Synapse Energy Economics, with the input data Synapse will require to conduct modeling analyses using Strategist and Plexos in order to supplement the modeling prepared by NS Power. The Board also stated that stakeholder consultation is to be an integral component of the process. The Board anticipates that a final IRP report will be filed by Nova Scotia Power by October 15, 2014.

Approach

In developing the Integrated Resource Plan, NS Power will:

- Apply the IRP framework as described below in collaboration with UARB staff and its consultants, and in consultation with customer representatives; and
- Engage interested parties in the development of assumptions, future scenarios and review of modeling results.

Scope

The IRP will consider a 25-year Planning Horizon (2015-2039).

The primary steps of the Integrated Resource Planning process will be: establish evaluation criteria; develop input assumptions; evaluate potential resource plans; select the Preferred Resource Plan and Action plan; and File the IRP Report. Some degree of iteration may be required between steps. The steps are:

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[1] A 'no regrets' strategy is one in which future decisions are unlikely to be negatively affected by earlier decisions made.

1. Develop criteria for evaluation of various plans and selection of a Preferred Resource Plan.
2. Identify the major input assumptions which will drive evaluation and selection of the Preferred Resource Plan. Develop projections of the most likely values for each of those major input assumptions over the planning horizon, as well as projections of plausible high and low values of those assumptions over that horizon. These major input assumptions include, but are not necessarily limited to:
    a. Load forecasts for a range of possible future supply requirements.
    b. Ranges of operating, capital and financial assumptions for the planning horizon.
    c. Technical and economic characteristics of realistic supply-side and demand-side alternatives to meet future load, emissions and other requirements.
    d. Environmental regulations.
    e. Renewable Electricity Standard requirements.
    f. Develop planning "worlds" (i.e. sets of related assumptions to reflect reasonable potential planning scenarios).
    g. Treatment of "end effects" for evaluation and Preferred Resource Plan selection.
3. Evaluation of potential resource plans:
    a. Perform a screening analysis to determine which alternatives are to be evaluated further in the IRP process and which can be removed from further consideration. Resource options may exhibit synergistic effects on overall system costs or benefits that are difficult to discern at the screening stage, or that may be difficult to quantify. Thus, this step will aim for inclusivity, to avoid premature rejection of options.
    b. Evaluate alternative plans in order to determine the Preferred Resource Plan.
    c. Perform sensitivity analysis to determine the effect of realistic variations in input assumptions to test plan robustness. The results of these sensitivity analyses may lead to a more detailed analysis of certain of the assumption values developed in step two.
    d. Assess preferred capacity plan to evaluate the proposed assets.
4. Select Preferred Resource plan and Develop Action Plan describing major tasks required to implement a no regrets strategy that aligns with the Preferred Resource Plan during the first five years of the planning horizon.
5. Prepare final report and Action Plan. File with UARB.

IRP Framework

Purpose

The IRP is a comprehensive and public utility planning exercise that integrates supply and demand-side options to develop a long-term Preferred Resource Plan for the utility. The resultant Preferred Resource Plan is a road-map to guide the utility's strategy for meeting its resource needs over the planning horizon. It is directional, not prescriptive in nature. The Preferred Resource Plan does not commit the utility to certain courses of action or foreclose options determined to be in the interests of our customers subsequent to completion of the IRP process. Instead, the Preferred Resource Plan is meant to provide the utility with sufficient flexibility to effectively accommodate a range of future uncertainties. As a result, the utility is expected to adhere to the strategy expressed through the Action Plan.

Process

The objective function is the minimization of the cumulative present worth of the annual revenue requirements over the planning horizon adjusted for end-effects and subject to a number of considerations, including:

- System reliability requirements;
- Plan robustness - the ability of a plan to withstand realistic potential changes to key assumptions;
- Flexibility - the absence of constraints on future decisions arising from the selection of a particular plan;
- Future regulatory emissions outlook; and
- Timing and rates effects - the timing and magnitude of benefits relative to the timing and magnitude of required expenditures and/or rates impacts.

Modeling assumptions will include financial analysis assumptions, emissions constraints, renewable requirements, load forecast, supply-side options and demand-side options, fuel and purchased power cost forecasts. Where appropriate, NS Power will address contrasting views about reasonable assumptions through sensitivity analyses.

NS Power will consider technically and economically viable supply-side technologies by evaluating operating characteristics, capital and operating costs and operational assumptions.

The potential role and range of options of demand-side management in a resource plan will be assessed. Estimated DSM costs and related demand and energy effects will be included in the IRP analysis.

NS Power’s planning models will be employed to evaluate a reasonable, but not unlimited, number of alternative plans as part of an Analysis Plan. The Analysis Plan will describe how Strategist (and when appropriate, Plexos) will be used to determine the relative value of different resource plans. The long-term resource planning tool Strategist will be employed to derive optimized resource plans for the planning horizon. Once specific, realistic plans are identified, they will be assessed against the objective and the final criteria. Additionally, the preferred plans will be evaluated for operational feasibility using Plexos where appropriate.

IRP Deliverables

1. Criteria for evaluation of various plans and selection of Preferred Resource Plan.

The primary criterion will be cumulative present worth of the annual revenue requirements of the resource plan over the planning horizon. Additional criteria will include System reliability requirements, Plan robustness, Flexibility, Future regulatory emissions outlook, Timing and rates effects, and consideration of "end effects" that extend beyond the planning horizon.

2. Major input assumptions

- **Load Forecast**

  NS Power has traditionally employed an econometric load forecast to provide annual energy consumption by customer sector and annual peak system demand. The Company has developed an End-Use Model forecast tool and will examine how best to utilize the models during the IRP process.

- **Supply-side Options**

  NS Power will provide a summary of viable supply-side options, including emissions abatement technologies. The summary will identify the cost and operating characteristics of the various technologies and discuss the opportunity and limitations of these within the power system.

  A screening of the technologies will be completed using publicly available information and focusing on the following parameters:

  - Cost;
  - Flexibility;
  - Available, commercialized technology;
  - System stability;
  - Fuel considerations; and
  - Emissions outlook.

  Included in the supply-side assessment will be:

  - Optimization of existing generation;
  - Renewables;
  - Solid fuel generation;
  - Gas-fired generation;
  - Storage;
  - Storage enhancements to existing hydroelectric facilities
  - Market opening effects including distributed generation
  - Emissions management options including abatement technologies, fuel choice and other options;
  - Emerging technologies, particularly those expected to be commercially available by 2025; and
  - Enhanced interconnection, Nova Scotia transmission expansion and power purchasing.

- **Demand-side Options**

  This process will examine the role and approach to demand-side management initiatives in Nova Scotia in the coming years to develop assumptions regarding the quantity of reductions, the ability of DSM to contribute to load shaping and the optimal levels of DSM for different system conditions. NS Power will consider ENSC's input from its DSM potential assessment and other reports and studies when forecasting energy savings over the planning horizon. Nova Scotia Power will also consider input from stakeholders regarding the utilization of load as a resource.

  Stakeholders will be engaged in the calculation methodology of the avoided costs of DSM. The avoided costs will be calculated based on the reference plan(s).

- **Basic Assumptions**

  Nova Scotia Power will file a Basic Modeling Assumptions document containing a consolidation of all modeling assumptions. This will include the planning "worlds" (i.e. sets of related assumptions to reflect reasonable potential planning scenarios).

3. Evaluation of potential resource plans

- **Plan Integration**

  Plan scenarios will be developed based on combinations of supply-side and demand-side options as described above. The alternative plans will be assessed using the Company's planning software. Plans will be ranked according to cumulative net present worth of the revenue requirements with commentary on the rates impacts of the plans.

- **Sensitivity Analysis**

  The IRP process involves adoption of a variety of assumptions, some of which may involve significant uncertainty. Views on these assumptions may vary significantly.

  Reflecting this, sensitivities will be identified against which to assess the various competing resource plans. Ultimately the test of the soundness of the Preferred Resource Plan is its ability to enable NS Power to provide reliable service at reasonable cost/rates impact across a range of worlds/scenarios and assumption values.

4. Prepare Final Report and Action Plan. File with UARB.

The IRP will culminate in a report to the UARB which will address the following areas:

1. Background/Process Overview.
2. Stakeholder engagement process.
3. Criteria for evaluation of the various plans.
4. Load forecast of future supply requirements.
5. Sets of alternative supply-side and DSM alternatives to meet future system requirements.
6. Screening analysis used to determine which alternatives were evaluated.
7. Evaluation of alternative plans in order to determine the least cost plans and rates impact.
8. Sensitivity analysis on the least cost plans and other selected plans to determine the robustness of the plans to variations in input assumptions.
9. Preferred Resource Plan.
10. Avoided cost of DSM methodology method utilized and results.
11. Action Plan. Actions required over the next 5 years to meet load projections and other regulatory and environmental requirements through implementation of a no regrets strategy that follows the Preferred Resource Plan.

Stakeholder Engagement

The IRP framework and the resultant plan will form the foundation for demand-side and supply-side investments. Stakeholder input is an integral part of the process. The Company will promote transparency with stakeholders in assumption development and plan evaluation through the distribution of draft assumptions for stakeholder review and Technical conferences on assumptions and modeling results.

While the IRP process will provide structure and enable direct stakeholder input to NS Power’s planning process, it is important to acknowledge that uncertainty will continue to exist in key areas. Despite this uncertainty, decisions will need to be made.

NS Power will consult with stakeholders at appropriate points in the planning process and in a manner which delivers value to all involved.

Confidential Information

NS Power will make reasonable efforts to use publicly available information in the development of this IRP. With respect to transmission confidential information, NS Power will comply with the OATT Standards of Conduct.

IRP Process Timeline Summary	**No later than**
1. Terms of Reference submitted to UARB for approval	January 22
2. Comments by interested parties	January 29
3. UARB approval of Terms of Reference	February 7
4. Public advertising	February 15 and 19
5. Notice of Intention to Participate by Interested Parties	February 28
6. Introduction to IRP Technical Conference and IRP Assumptions Session with Stakeholders	March 7
7. Draft assumptions including load forecast, supply and demand side options compiled and issued to stakeholders along with discussion of approach to modeling analysis (i.e. Analysis Plan) (IRP Process Step 2)	March 14
8. Stakeholder comments on assumptions and Analysis Plan (IRP Process Step 2)	March 26
9. Final consolidated modeling assumptions and Analysis Plan issued (IRP Process Step 2)	April 11
10. Interim Analysis Progress Report Technical Conference	June 25
11. Base scenarios for alternative Plans established and sensitivities identified (IRP Process Step 3)	July 24
12. Develop analysis results and issue to stakeholders (IRP Process Steps 3 and 4)	September 5
13. Stakeholder Technical Conference on Analysis Results (IRP Process Steps 3 and 4)	September 12
14. Draft report filed with stakeholders	September 30
15. Comments from stakeholders	October 7
16. Final report filed with UARB (IRP Process Step 5)	October 15

Nova Scotia POWER
An Emera Company

APRIL 11, 2014

2014 IRP – Finalized Assumptions

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Nova Scotia POWER
An Emera Company

APRIL 11, 2014

Environmental & Emissions Assumptions (Revised)

CO_2/Greenhouse Gases Regulatory Context

- In September 2012, the Government of Canada released its regulations for coal-fired electricity generators to come into force in 2015.
- Regulations would require coal-fired units to meet GHG emission standard of 420 t CO_2/GWh or shut down at the end of their useful life, approximately 50 years from commissioning.
- It was determined that Nova Scotia's regulatory approach can meet or exceed the federal GHG reductions in a less costly manner.

CO_2/Greenhouse Gases Regulatory Context

- In September 2012, the Federal and Provincial governments released a draft equivalency agreement which, once finalized, will ensure the provincial regulations will apply in NS.
- Nova Scotia *Greenhouse Gas Emission Regulations* outline hard caps for 2010 to 2030.

CO_2/Greenhouse Gases Assumptions

Scenario A

- Emissions limits as per *An Agreement on the Equivalency of Federal and Nova Scotia Regulations for the Control of Greenhouse Gas Emissions from Electricity Producers in Nova Scotia* (Sept. 2012)
- Limit declines to 3.4 Mt in 2040
- The downward path of the GHG constraint in Scenario A is consistent with the long range goals of the Federal Government for 2050

Scenario B

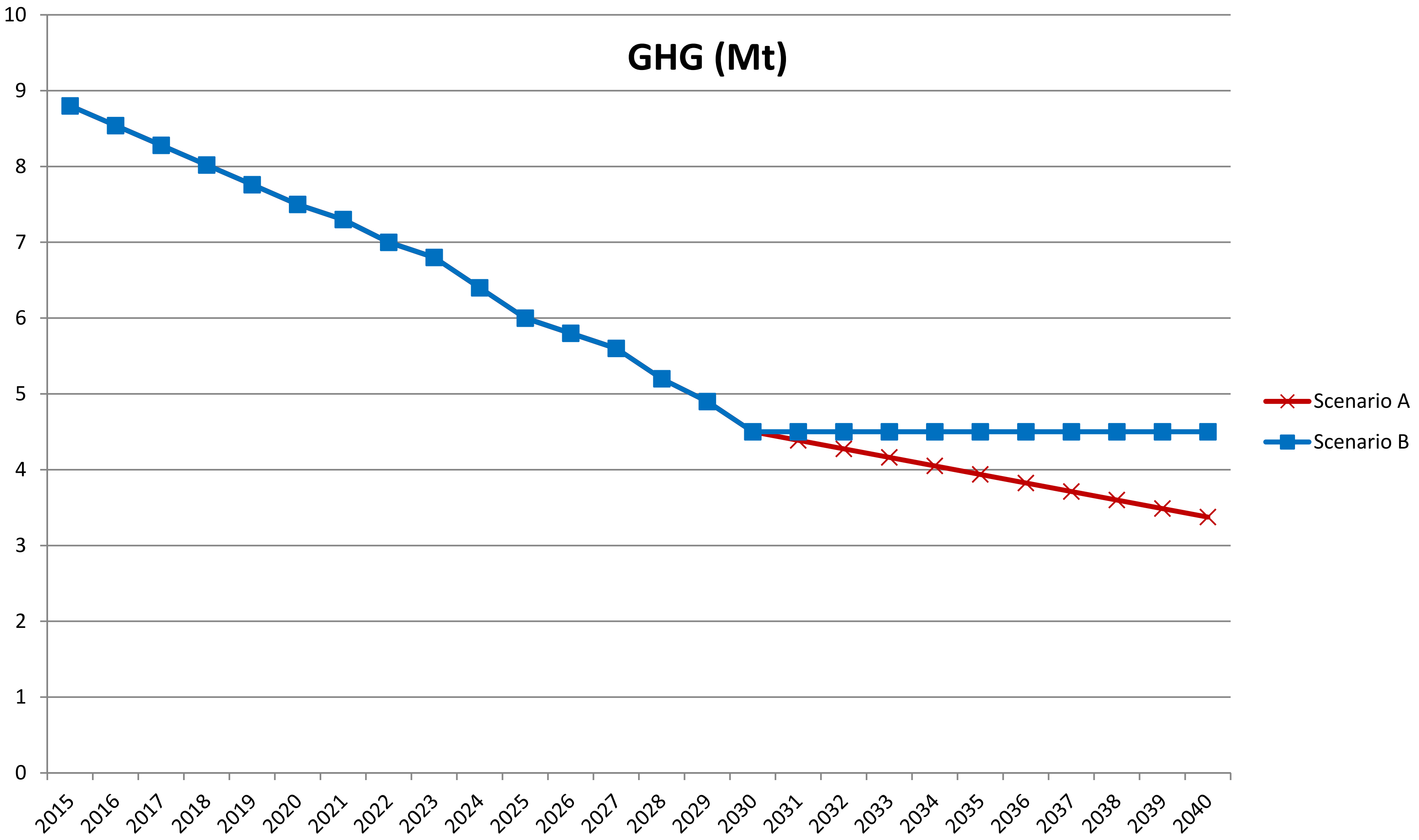
- Emissions limits as per *An Agreement on the Equivalency of Federal and Nova Scotia Regulations for the Control of Greenhouse Gas Emissions from Electricity Producers in Nova Scotia* (Sept. 2012)
- No decline in limit post 2030

CO_2/Greenhouse Gases Assumptions

SCENARIO C

- The Company will model GHG emission cuts to 2.25MT in 2040 as a Scenario C (and associated co-benefits for other air emissions and RES targets)

GHG Emission Targets



Air Pollutants Regulatory Context

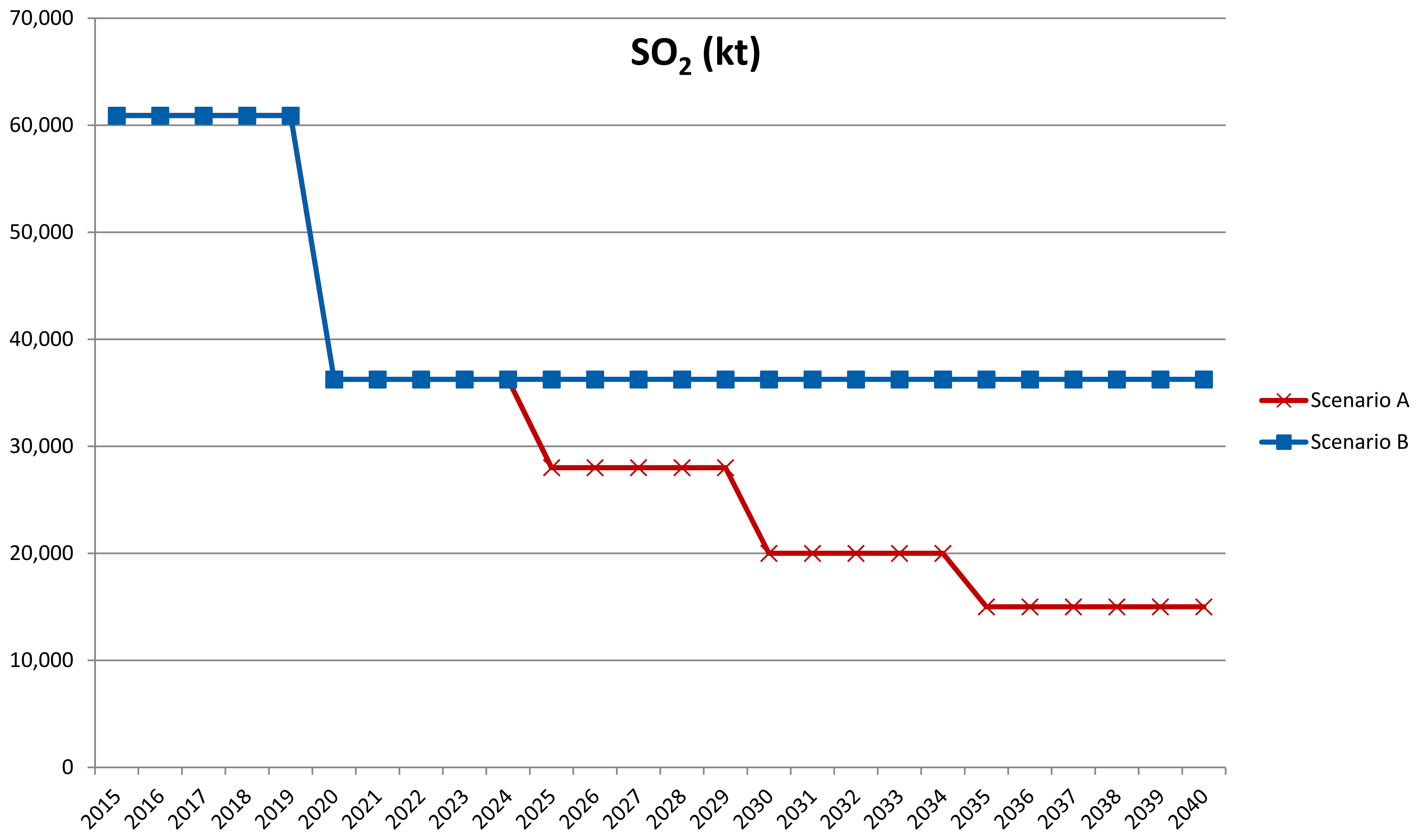
- Nova Scotia *Air Quality Regulations* outline hard targets for SO_2, NOx, and Hg until 2020.
- In June 2013, Nova Scotia Environment released a discussion paper outlining emission limits for SO_2, NOx, and Hg until 2030.

SO_2 Assumptions

- Scenario A
- Emissions limits as per *NS Air Quality Regulations* to 2020
- Post 2020 limits guided by *Amendments to Greenhouse Gas & Air Quality Emissions Regulations Discussion Paper* (NSE, June 2013).

- Scenario B
- Emissions limits as per *NS Air Quality Regulations*
- 2020 Emission limit holds through 2040.

SO_2 Emission Targets

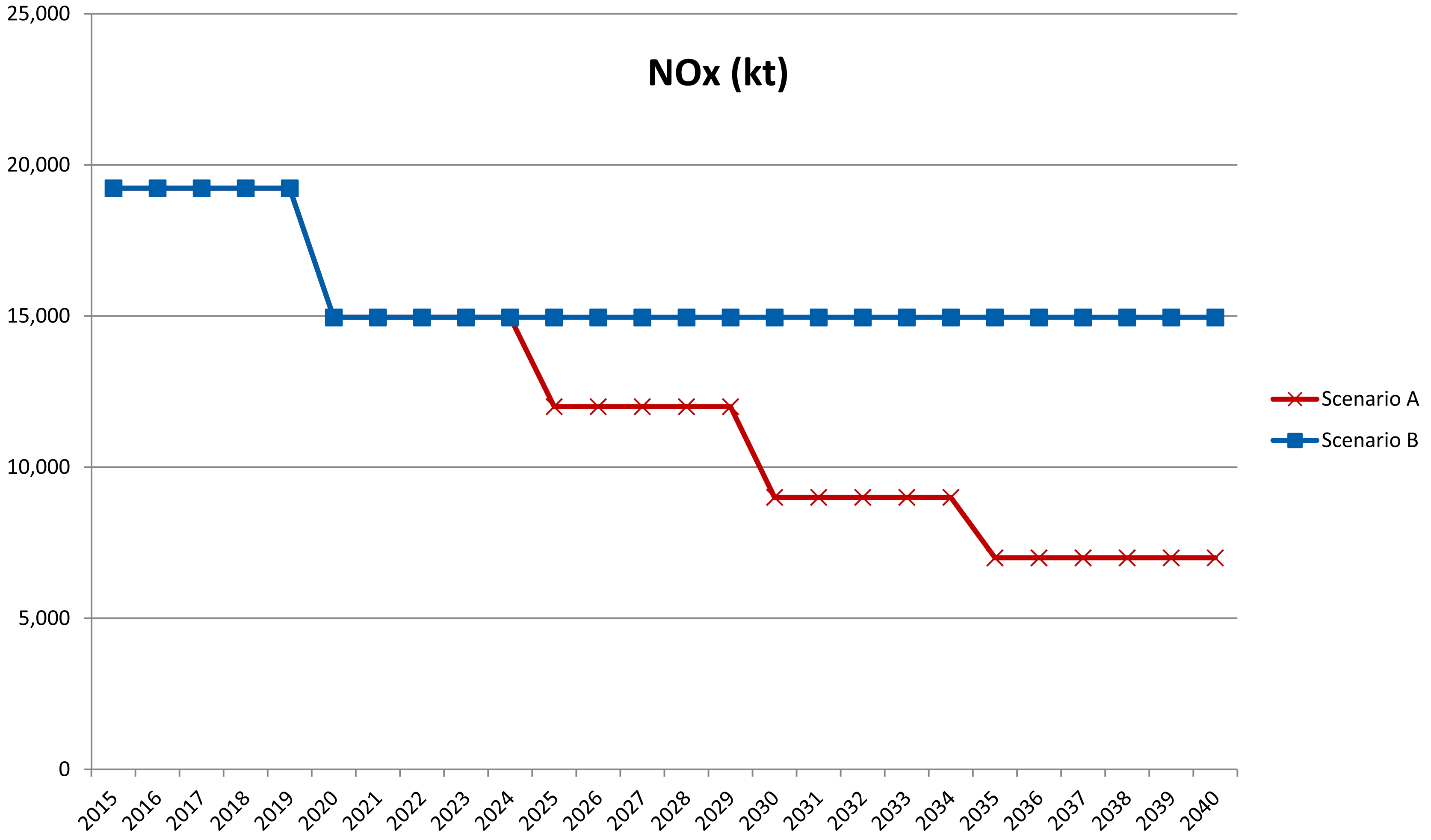


NOx Assumptions

- Scenario A
- Emissions limits as per *NS Air Quality Regulations* to 2020
- Post 2020 limits guided by *Amendments to Greenhouse Gas & Air Quality Emissions Regulations Discussion Paper* (NSE, June 2013).

- Scenario B
- Emissions limits as per *NS Air Quality Regulations*
- 2020 Emission limit holds through 2040.

NOx Emission Targets

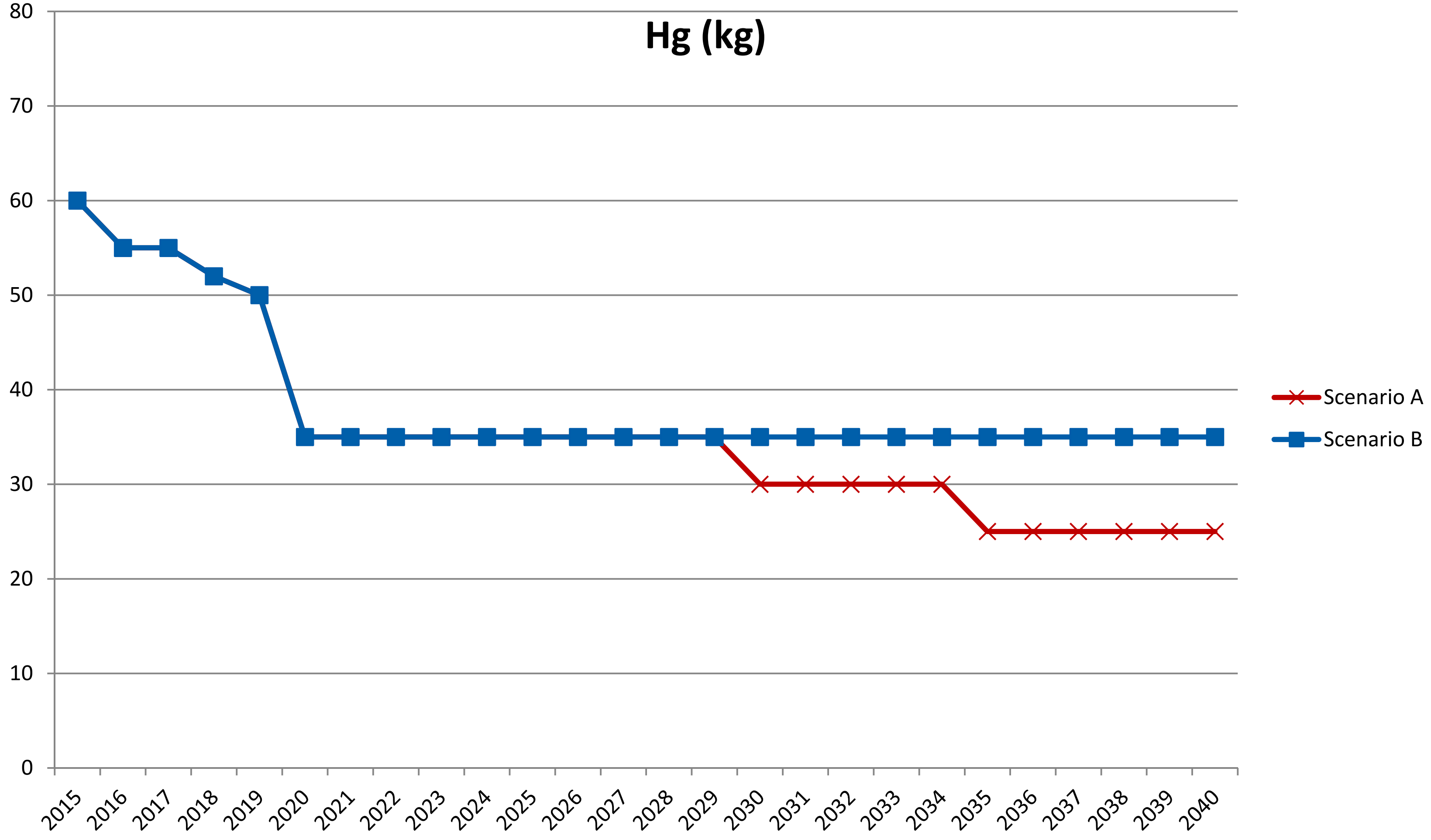


Hg Assumptions

- Scenario A
- Emissions limits as per *NS Air Quality Regulations*
- 2015-2019 limits based on 65 kg limit minus supplemental emissions from 2010 through 2014.
- Post 2020 limits guided by *Amendments to Greenhouse Gas & Air Quality Emissions Regulations Discussion Paper* (NSE, June 2013).

- Scenario B
- Emissions limits as per *NS Air Quality Regulations*
- 2015-2019 limits based on 65 kg limit minus supplemental emissions from 2010 through 2014.
- Post 2020 limit is 35kg - limit holds through 2040.

Hg Emission Targets



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RES Requirements

- The Renewable Electricity Standards for Nova Scotia are defined in the *Renewable Electricity Regulations* under the *Electricity Act*.
- http://www.novascotia.ca/just/regulations/regs/elecrenew.htm
- The RES requirements are outlined in the following slide with timelines.

RES Requirements

- The following RES measures must be met by NSPI
    - As of 2014, at least 10% of net sales must be generated by renewable electricity, of which 5% can be NSPI owned.
    - As of 2015, at least 25% of net sales must be generated by renewable electricity, of which at least 5% plus an additional 300 GWh must be supplied by IPPs. The additional generation may be supplied by the feed-in-tariff program, NSPI owned facilities, or other sources of renewables. NSPI can only supply 150 GWh or less from co-firing biomass.
    - As of 2020, at least 40% of net sales must be generated by renewable electricity, of which at least 5% plus an additional 300 GWh must be supplied by IPPs. The additional generation may be supplied by the feed-in-tariff program, distribution connected generators, up to 150 GWh of biomass co-firing, other NSPI owned facilities, or other sources of renewables as well as 20% of the generation of Muskrat Falls.
    - In addition there is also a requirement to procure or generate 260 GWh of firm renewable electricity in 2013 and 350 GWh of firm renewables in 2014 and subsequent years. The regulatory definition of firm indicates this generation must be from sources commissioned after December 31, 2001, of which the Port Hawkesbury Biomass facility would apply.

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Future Supply Side Options Assumptions (Revised)

Background

- New supply side options reviewed and upgrades to existing assets provided
- Fuel options considered for flexibility
- Future environmental constraints considered
- Cost structure of traditional builds based on Nova Scotia Power recent activities
- Costs based on building in Nova Scotia
- Conscious effort to recognize transformation of generation technologies

Supply-Side Options

	Capacity (MW)	Heat Rate (btu/kWh)	Capital Cost (2013$) ($/kW)	Lead Time (years)	Readiness
Coal					
Single Unit Advanced PC	300	9,600	$3,600	4-8	TRL-9
Single Unit Advanced PC with CCS	360	12,800	$6,700	5-10	TRL-7
Underground Coal Gasification	300	9,600	$4,800	10-15	TRL-6
Single Unit Integrated Gasification Combined Cycle (IGCC)	360	8,700	$4,100	4-7	TRL-8
Single Unit IGCC with CCS	520	10,700	$6,600	5-10	TRL-6
Natural Gas					
Phased-in Conversion CC (Add HRSG)	150	8,000	$1,600	4-7	TRL-9
Conventional CC (2 x 1)	145	7,200	$1,500	3-5	TRL-9
Combustion turbine	100	8,700	$1,600	3	TRL-9
Combustion turbine	49	9,600	$1,100	2-4	TRL-9
Combustion turbine	34	9,700	$1,500	2-4	TRL-9
Conventional CC (1 X 1)	253	7,200	$1,400	3-5	TRL-9
Fuel Cells	10	9,500	$7,100	10-15	TRL-5
Uranium	not considered due to legislation				

Supply-Side Options

	Capacity (MW)	Heat Rate (btu/kWh)	Capital Cost (2013$) ($/kW)	Lead Time (years)	Readiness
Biomass					
Biomass Grate	60	13,500	$3,500	3-5	TRL-9
Wind					
Onshore Wind *	100		$2100-$2500 [1]	2	TRL-9
Solar					
Solar Thermal *	>10		$9,000	3-5	TRL-7
Photovoltaic *	>10		$3,500	3-5	TRL-7
Geothermal	Not considered although small sources available				
Municipal Solid Waste					
Municipal Solid Waste	50	18,000	$8,300	3-5	TRL-8
Hydroelectric					
Pumped Storage	100	85%	$2,700	5-10	TRL-9
Mersey Incremental Upgrade	30		$3,500	5-10	TRL-9
CAES	100	55%	$1,400	5-10	TRL-7
Tidal	10		$10,000	10-15	TRL-5
* Plus intermittent integration costs					

1) Demonstrates range of costs from utility-built to COMFIT projects.

Future Environmental Control Technologies

Plant/Unit	Technology	Capital Cost			Emission Impact %Removal			
		Low	Base	High				
		(2013M$)			NOx	SO_2	Hg[1]	CO_2
Lingan								
	Wet Limestone FGD (300MW) (parasitic power 4 MW/ unit)		220 (300MW)		n/a	95	85[2]	n/a
	2.5%S Dry Lime FGD (300MW)		210		n/a	95	85[2]	n/a
	Carbon Capture 25% Power Penalty (in addition to scrubber)		790		n/a	95	85	70
	Baghouse (adapt ACI) (150 MW)		43					
	Baghouse (adapt ACI) (300MW)		85		n/a	n/a	85	n/a
Pt. Tupper	Natural Gas Co-fire[3]	-25%	12	+30%	n/a	n/a	n/a	n/a
Trenton 5	Co-firing Biomass	-25%	23	+40%	n/a	n/a	n/a	n/a
Trenton 6	Selective Catalytic Reduction		48		50	n/a	n/a	n/a

1) Hg removal depends on coal specification
2) Hg removal with FGD assumes unit has ACI
3) Tupper NG co-fire - estimated max 53% co-fire due to other customers using gas on the pipeline. To get 100% co-fire there would be another $20-30M in NG pipeline upgrades.

Future Supply-side Thermal Options

Alternative	Technology	Capital Cost Low	Capital Cost Base	Capital Cost High	Net Capacity	Fuel Type
			(2013M$)		MW	
BSD Gas	Gas Conversion (4 units)		6.2		4 x 33	Gas
TUC1 +20	Increase Capacity		9.2		101	HFO/Gas
TUC2 +8	Increase Capacity		3.37		101	HFO/Gas

COMFIT Assumption

- Approximately 200MW of COMFIT projects assumed by NS Energy.
- Based on projections of advanced projects assuming 90MW of COMFIT in operation by 2015.
- Based on number of projects approved by the provincial government, assume another 60 MW phased in over the next 2 years (2015-2016).
- Total 150MW of COMFIT wind generation by the end of 2016.

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Capacity Value of Wind & Intermittent Generation Integration Costs

Intermittent Generation/Wind Assumptions

NS Power will release draft assumptions on the capacity value and integration cost of intermittent generation **on April 22, 2015.**

Stakeholders will be asked to provide comments **by April 28, 2015.**

Final wind capacity value and intermittent generation integration cost assumptions will be released **May 1, 2015**.

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Hydro Generation Assumptions

Hydro Assumptions

- Company estimates there are over $500M in sustaining capital costs required to maintain the operating capability of existing hydro systems.
- Sustaining hydro investments are included across all plans.
- Incremental hydro capacity investments will be tested as discrete options. Refer to Future Supply Assumptions for Mersey River Hydro incremental development option.

Hydro Assumptions

- Assume the sustaining capital is common to all plans on the basis that hydro is a valuable generating resource providing dispatchable firm capacity, operating reserves, and qualifies as renewable electricity for 2015 per the NS Renewable Electricity Regulations.
- Much of the power system’s flexibility to integrate existing variable sources of generation is provided by legacy hydro facilities.

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Import Options Assumptions

PPAs/Import Options

- NB IMPORT OPTIONS[1]:
    - Mass Hub Forecast plus NB Transmission Tariff
    - Option NB1: 100MW nonfirm – no transmission investments
    - Option NB2: 100MW firm – necessary transmission investments
    - Option NB3: 300MW firm – necessary transmission investments (some limits could apply with simultaneous imports from ML)
- ML SURPLUS ENERGY[1]:
    - Mass Hub Forecast
    - Option ML1: 300MW less Base Block – nonfirm

[1] NS Power will work with Liberty and Synapse (Board Consultants) to establish price-quantity pairs for modeling imports.

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Transmission Assumptions

Transmission Options

				Transmission Cost		
Generation Alternative	**Capacity (MW)**	**Location**	**Retired Units**	**High ($M)**	**Base ($M)**	**Comment**
LM6000	50	HRM	TC1 or TC2	2	0	High: no TC retirement
LMS2500	34	HRM	TC1 or TC2	2	0	High: no TC retirement
LMS100	100	HRM	TC1 or TC2	2	0	High: no TC retirement
CC 150	150	HRM	TC1 or TC2	12	0	High: no TC retirement+2nd Harbour Crossing 138 kV line
CC250	250	HRM	TC1 & TC2	12	0	High: no TC retirement+2nd Harbour Crossing 138 kV line
CC250	250	HRM		20	3	Base: Brushy Hill gas lateral. High: Burnside+Spider Lake sub.
PC 360	360	Point Tupper	LG2	425	285	Base: 345kV Hastings-Spider Lake. High:Base+2nd 345 kV tie line NS-NB
PC 450	450	Point Tupper	LG2 & LG3	425	285	Base: 345kV Hastings-Spider Lake. High:Base+2nd 345 kV tie line NS-NB
Firm Import	100	From NB			45	SVC and upgrade 138 kV lines in NB & NS
Firm Import	300	From NB		440	230	Base:SVC+345kV NS-NB. High: Base+345kV Salisbury-Coleson Cove
CAES	100	Debert			20	230kV Debert-Onslow
Wind	200	Mainland			30	230kV and 138kV connections for Wind Farms
CAES+Wind	300	Deb+Main			50	230kV and 138kV connections for CAES and Wind Farms
PSH	177	Wreck Cove	LG2	265	130	Base:230kV WC-Hastings. High:345kV WC-Hastings-Onslow-Brushy Hill

Transmission Options

- System upgrades associated with the Maritime Link are in service. The Maritime Link retires one Lingan unit.
- Transmission Facility estimates were completed as if resource options were independent of each other and the cost cannot be used to sum up any combination of options.
- Any new generation in Cape Breton will supply load growth east of Onslow. This will require an increase in CBX (Cape Breton Export), ONI (Onslow Import) and ONS (Onslow South).
- Any net generation unit larger than Point Aconi net will require additional operating reserve (cost not included here).
- Transmission cost does not include generator transformer and station service cost which can be in the range of $4M - $12M.
- Back-up and Load Following for non-dispatchable renewables is assumed to be provided within NS and not included in Network Upgrades cost estimates. If back-up source is external to NS then a second NS-NB tie is required.
- Transmission cost for generation options east of Onslow includes corresponding ONS upgrades.
- The cost estimate is preliminary and in the range of -10% to +30%. In some cases, unforeseen system requirements may increase the cost significantly as complete system impact studies are not performed.

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Existing Supply Assumptions Overview (Revised)

Existing Supply

Thermal Unit	Net Demonstrated Capacity (MW)	In Service	Fuel
Pt Aconi	171	1994	Coal/Petcoke & limestone sorbent (CFB)
Lingan 1	153	1979	Coal/Petcoke/HFO
Lingan 2	153	1980	Coal/Petcoke/HFO
Lingan 3	158	1983	Coal/Petcoke/HFO
Lingan 4	153	1984	Coal/Petcoke/HFO
Tupper 2	152	1973, coal conversion 1987	Coal/Petcoke/HFO
Trenton 5	150	1969	Coal/Petcoke/HFO
Trenton 6	157	1991	Coal/Petcoke/HFO
Tufts Cove 1	81	1965	NG
Tufts Cove 2	93	1972	NG / HFO
Tufts Cove 3	147	1976	NG / HFO
Total	**1568**		
Combustion Turbines			
Burnside 1 - 4	4@33	1976	LFO
Victoria Junction 1 - 2	2@33	1975	LFO
Tusket 1	29	1971	LFO
Total	**227**		
Combined Cycle			
Tufts Cove 6	147	2011	NG
Import			
Maritime Link Base Block	153	Oct 2017	

Existing Supply

Hydro System	Net Demonstrated Capacity (MW)
Wreck Cove	210.0
Annapolis Tidal	3.5
Avon	6.8
Black River	22.5
Nictaux	8.3
Lequille	13.2
Paradise	4.7
Mersey	42.5
Sissiboo	27.0
Bear River	11.2
Tusket	2.4
Roseway/Harmony	1.8
St Margaret's Bay	10.8
Sheet Harbour	10.8
Dickie Brook	2.2
Fall River	0.5
Total	**378.1**
Biomass	
PH Biomass (mill load present/ not present)	45/52
Small Biomass IPP (2016)	10
Other	**Installed Capacity (MW)**
NSPI Owned Wind	80.8
Renewable IPP (Pre 2001)	25.8
Renewable IPP (Post 2001)	250.9
Renewable Electricity Administrator Projects	115.8
COMFIT (expected in-service by end of 2014)	91
Total	**564.3**

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Power Plant Life Assumptions

Overview

POWER PLANTS CAN LIVE LONG LIVES

- With suitable asset investment (refurbishment and replacements)
- Major investments would be associated with STGs and Boilers, Environmental and Cooling Systems.
- Other areas of investments include: Rotating Equipment, Static Equipment, I&C and Building Structures and Grounds.

DETERMINING USEFUL LIFE INCLUDES CONSIDERATION FOR:

- Asset investments required to sustain operation
- Regulatory requirements
- Performance (Efficiency and Reliability)
- Replacement cost (i.e. new generation)

Industry Experience

NOT UNCOMMON FOR POWER PLANTS TO SEE SIGNIFICANT GENERATION FOR 50 YEARS

- Health assessments and prognostics, related to key assets, are crucial
- Many components will see midlife replacements and regular refurbishments
- Major component replacement may be required (Generators, Turbine Spindles, Boiler Components)
- Operating history is significant

AS ASSETS CONTINUE TO AGE (I.E. PAST 50 YEARS):

- Increasing uncertainty for Balance of Plant including static equipment and infrastructure
- Increasing likelihood of major component replacement

50+ YEAR LIFE IS ALSO ATTAINABLE HOWEVER:

- increased consideration for end of life and end of life planning
- likely a more modest operating regime

Long Term Planning Approach

BEYOND 50 YEARS - ADDITIONAL 10 YEARS OF SERVICE IS REASONABLE BUT:

- Asset Management programs are necessary for reliability and investment planning
- a more modest utilization (lower annual capacity factor)
- Includes planning for retirement

EXAMPLE:

- TUC1 fits within this philosophical treatment
- Present Utilization and Investment planning fits this model.

Generating Unit Retirement Assumption for IRP

Thermal Unit	Net Demonstrated Capacity (MW)	In Service	60 Year Life	Assumed Retirement Year for Modeling Puposes
Pt Aconi	171	1994	2054	Beyond planning horizon *
Lingan 1	153	1979	2039	2039
Lingan 2	153	1980	2040	2018 (Coincident with Maritime Link)
Lingan 3	158	1983	2043	Beyond planning horizon *
Lingan 4	153	1984	2044	Beyond planning horizon *
Tupper 2	152	1973, coal conversion 1987	2047	Beyond planning horizon *
Trenton 5	150	1969	2029	2035
Trenton 6	157	1991	2051	Beyond planning horizon *
Tufts Cove 1	81	1965	2025	2025
Tufts Cove 2	93	1972	2032	2032
Tufts Cove 3	147	1976	2036	2036

Tupper 2 assumes 60 years from date of coal conversion.
Trenton 5 expect to extend life beyond 60 years due to recent significant capital investment.
*25 year planning horizon 2015-2039.

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Financial Assumptions

Rates

Weighted Average Cost of Capital (WACC):

Before-tax = 7.78%

After-tax = 6.49%

Source: 2014 rate as approved in most recent GRA

Inflation rate:

25 year average rate = 2.0%

Based on Conference Board of Canada CPI growth forecast for NS.

Rates

US Foreign Exchange:

2015 = 1.10

2016 = 1.06

2017 = 1.07

2018-2040 = 1.08

Source: Treasury. 2015-2016 average of 6 banks.
2017-2040 average of 2 banks.

Revenue Requirement Profiles

Supply-side options that represent a capital investment require a revenue requirement profile.

Revenue requirement profiles for input into Strategist will be developed outside of the model.

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Fuel Price Forecast Assumptions (Revised)

Forecasting Approach

NS POWER FUELS, ENERGY & RISK MANAGEMENT (FE&RM) UTILISED COMMERCIALLY AVAILABLE LONG TERM PRICE FORECASTS FOR *SOLID FUELS*, *NATURAL GAS*, *OIL* AND *POWER* WHICH IT SUBSEQUENTLY ADJUSTED FOR DELIVERY TO NS BASED ON:

- Current and Expected Transportation (Transmission) Costs and Tolls
- Market Insight and Proprietary Views on Long Term Market Development, including High, Low and Expected Scenarios (by third parties and NSPI)
- Proprietary Forecasts on Macroeconomic Inputs (by NSPI)

Third Party Service Providers

PIRA ENERGY GROUP (NAT GAS, OIL & POWER)

- Long time service provider to NSPI
- World-wide perspective and insight
- Forecasts utilised in Maritime Link, 2009 IRP

ENERGY VENTURES ANALYSIS (COAL)

- Used in the Maritime Link hearing
- Comprehensive suite of forecasts for varying coal grades, other solid fuels and supply regions

Service Providers[1]

“PIRA Energy Group, founded in 1976, is a preeminent energy information provider specializing in global energy markets research, analysis, and intelligence. PIRA offers primarily Retainer Client Services, but also can perform customized consulting, on a broad range of subjects in the international crude oil (and NGLs), refined products, natural gas (and LNG), electricity, coal, biofuels, shipping and emissions markets. The full range of PIRA services provides exceptional coverage and evaluation of key U.S. and international (country by country, region by region) energy fundamentals and issues that impact the behavior and performance of the energy industry and its various markets and sectors.” PIRA Energy Group; 2014

“Energy Ventures Analysis, Inc. has been a key player in the energy industry since 1981. Our unmatched success in guiding clients to sound investment and operational decisions stems from the outstanding capabilities of our expert consultants, coupled with the unique hands-on approach of our firm. Because EVA is a smaller company than most energy consulting conglomerates, we provide a much more personalized, focused, interactive, and responsive experience for our clients and customers. EVA maintains a wide range of proprietary models and databases that have evolved from over 30-years of experience in the energy industry. These proprietary models and databases are critical to the successful completion of many of EVA’s consulting projects, its’ suit of periodic multi-client reports, and the population of its electricity dispatch model. Detailed discussions of these models and databases are included in the pages covering each of the energy areas.” Energy Ventures Analysis; 2014

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[1] From their respective websites as accessed on March 06, 2014

Fundamental Price Forecasts

Commodity	Pricing Point	Provider	Updated
Nat. Gas	(N.A.) Henry Hub	PIRA Energy Group	FEB 2014
	(LNG) UK Nat’l Balancing Pt.		
	New England Basis		FEB 2014
Int’l Coal	FOB Colombia	Energy Ventures Analysis	MAR 2014
US Coal	FOB Baltimore		
Pet Coke	FOB US Gulf		
Imported Power	MASS HUB	PIRA Energy Group	FEB 2014
Fuel Oil	NY Harbour	PIRA Energy Group	FEB 2014

FUNDAMENTAL NAT GAS SCENARIOS (PIRA ENERGY GROUP)

	Likelihood (PIRA)	Highlights
Base Case (Expected)	45%	• North American nat gas demand grows at 2.4% p.a. (2.2% in the US) (Revised upwards) • Power generation leads the way and some penetration into transportation • Modest carbon cost introduced to power generation in 2020 rising through to 2030 • Supply continues to rise in Canada and the US but Canada begins exporting to Asia pre-2020 and exports to the US fall • Growth in the short term met by “low cost” Marcellus but higher cost un-conventional supplies are introduced by 2020
High Case	25%	• High oil prices pull natural gas into higher value markets overseas • Much tougher environmental constraints reduce N.A. shale gas supply or significantly raise prices
Low Case	30%	• Supply keeps up with increasing demand • Productivity improvements offset the cost of lower quality resources • Supplier competition keeps prices in check

NATURAL GAS PRICE ASSUMPTIONS

- Case development
- Pricing methodology
- Long Term Prices

NS Case Development (Nat Gas)

	Highlights
Base Case (Expected)	• Based on PIRA Expected Case for North American Gas at Henry Hub • New pipeline capacity comes on line in 2018 (TGP) and sets the marginal gas price into New England
High Case	• Based on PIRA High Case for North American Gas at Henry Hub and UK Nat’l Balancing Point (High) • New pipeline capacity comes on line in 2019 but is fully contracted by LNG exporters. As a result, gas has to be “bid-away” from European markets • Prices until the January 2019 pipeline expansion are volatile (similar to what was experienced in 2013/14) and the market premium for gas is very high
Low Case	• Based on PIRA Low Case for North American Gas at Henry Hub • New pipeline capacity comes on line in 2017 (PNGTS) and sets the marginal gas price into New England in the winter • Summer pricing is set by Atlantic Bridge expansion

Natural Gas – Base Case (Expected)

Delivered Price	=	Commodity	+	Basis	+	Transportation	+	Market Premium
2015 - 2018	=	**Henry Hub** Source: PIRA Annual Guidebook 2014 Reference Case	+	**Algonquin** Source: PIRA Long Term Price Forecast (2014FEB20) (Basis) & PIRA Short Term Price Forecast (2014FEB25) (Monthly Profile)	+	**nil**	+	**Premium** Source: NSPI
2018 - 2030	=	**Henry Hub** Source: Same	+	**Transco Zone 6** Source: Same	+	**Fuel & Tolls: Wright to Tufts Cove** Source: Current Tolls (escalated)	+	**nil**
2030 - 2040	=	**Henry Hub** Source: Same (escalated)	+	**Transco Zone 6** Source: Same (escalated)	+	**Fuel & Tolls: Wright to Tufts Cove** Source: Same (escalated)	+	**nil**

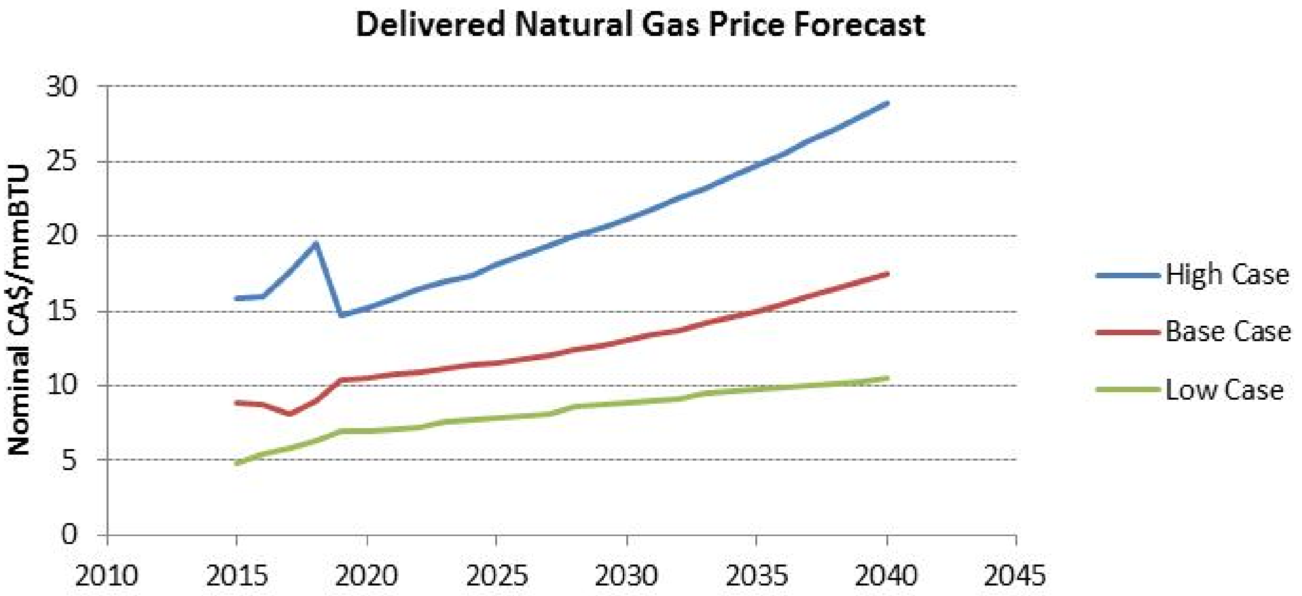
Natural Gas – Low Case

Delivered Price	=	Commodity	+	Basis	+	Transportation	+	Market Premium
2015 – 2017	=	**Henry Hub** Source: PIRA Annual Guidebook 2014 Low Case	+	**Algonquin** Source: Historical (2011/12) & PIRA Long Term Price Forecast (2014FEB20) (Basis) & PIRA Short Term Price Forecast (2014FEB25) (Monthly Profile)	+	**nil**		**Premium** Source: NSPI
2017 – 2040 Winter	=	**Henry Hub** Source: Same; escalated 2030+	+	**Dawn** Source: Same; escalated 2030+	+	**Fuel & Tolls: Dawn to Tufts Cove** Source: Current Tolls (escalated)		**nil**
2017-2040 Summer	=	**Henry Hub** Source: Same	+	**Algonquin** Source: Same	+	**Fuel & Tolls: Algonquin to Tufts Cove** Source: Same		**nil**

Natural Gas – High Case

Delivered Price	=	Commodity	+/-	Basis	+	Transportation	+	Market Premium
2015 – 2018	=	**Henry Hub** Source: PIRA Annual Guidebook 2014 High Case	+	**Algonquin** Source: Platts Inside FERC FOM; ICE (2013/14)	+	**nil**	+	**Premium** Source: NSPI
2019 – 2040	=	**UK Nat'l Balancing Point** Source: PIRA Annual Guidebook 2014 High Case (escalated 2030+)	-	**● % of Liquefaction & Transportation Cost** Source: NSPI	+	**nil**	+	**nil**

Natural Gas Price Assumptions



Delivered Natural Gas Price Forecast

NS Natural Gas Delivered Price Forecast (Nominal CAD$/mmBTU)

	2015	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2030*	*2035*	*2040*
High Case	15.8	16.0	17.7	19.5	14.7	15.2	15.8	16.4	16.9	17.4	18.1	21.2	24.7	28.9
Base Case	8.9	8.7	8.2	9.0	10.4	10.5	10.7	10.9	11.2	11.4	11.6	13.1	15.0	17.5
Low Case	4.8	5.4	5.8	6.3	6.9	7.0	7.1	7.2	7.6	7.8	7.9	8.8	9.8	10.4

NS Natural Gas Delivered Price Forecast (2014$/mmBTU)

	2015	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2030*	*2035*	*2040*
High Case	15.6	15.5	16.8	18.1	13.4	13.6	13.9	14.1	14.2	14.3	14.6	15.4	16.3	17.2
Base Case	8.8	8.4	7.7	8.4	9.5	9.4	9.4	9.4	9.4	9.4	9.3	9.5	9.9	10.4
Low Case	4.7	5.3	5.5	5.9	6.3	6.3	6.2	6.2	6.4	6.4	6.4	6.4	6.4	6.2

IMPORT POWER PRICE ASSUMPTIONS

- Case development
- Pricing methodology
- Forecast prices

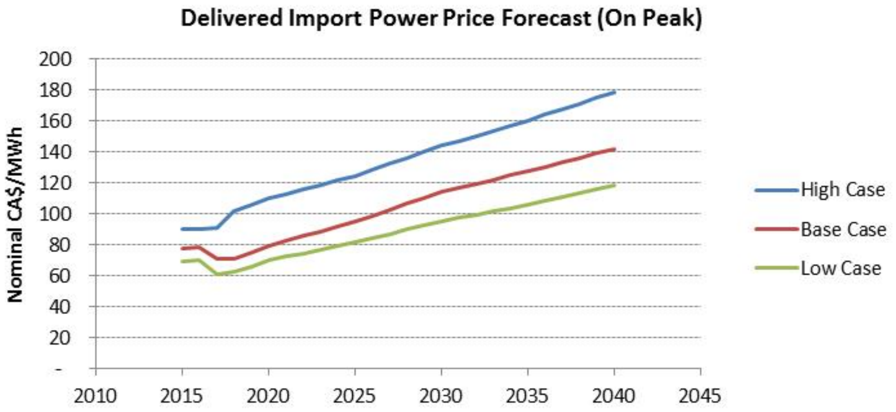
Case Development (Power)

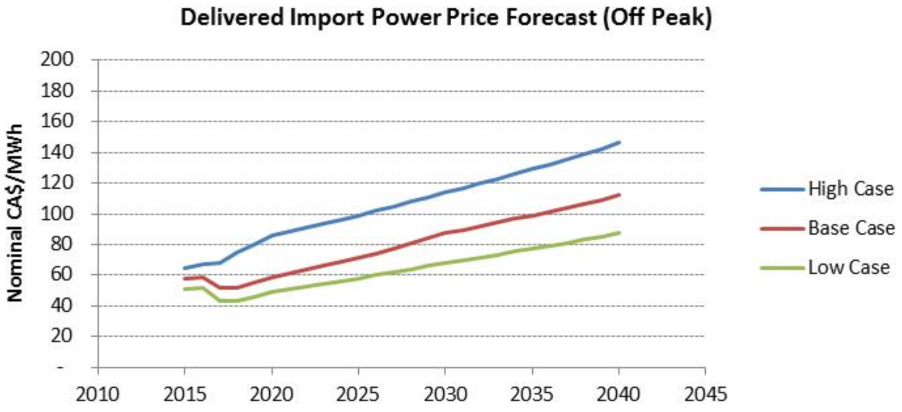
	Highlights
Base Case (Expected)	• Driven by PIRA Annual Guidebook Natural Gas Scenario (Expected) and economics of Natural Gas Combined Cycle (NGCC) generation • Carbon cost of US$15 in 2020 escalating to US$37/Ton CO_2 in 2030
High Case	• Driven by PIRA Annual Guidebook Natural Gas Scenario (High) and economics of Natural Gas Combined Cycle (NGCC) generation
Low Case	• Driven by PIRA Annual Guidebook Natural Gas Scenario (Low) and economics of Natural Gas Combined Cycle (NGCC) generation

Power Forecast (Base, High & Low)

Delivered Price	=	Commodity	+	NB Transmission
2015 – 2040	=	**Mass Hub** Source: PIRA on PIRA Annual Guidebook 2014 Reference, High and Low North American Natural Gas Cases	+	**Transmission Tariffs** Source: Current Tariffs

Long Term Price Assumptions


Delivered Import Power Price Forecast (On Peak)


Delivered Import Power Price Forecast (Off Peak)

NS Delivered Power Forecast - On Peak (Nominal CA$/MWh)

	2015	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2030*	*2035*	*2040*
High Case	90	90	91	102	106	110	113	116	119	122	125	144	161	179
Base Case	78	79	71	71	75	80	83	86	89	92	95	114	128	142
Low Case	69	70	61	62	66	70	72	75	77	79	81	95	106	118

NS Delivered Power Forecast - Off Peak (Nominal CA$/MWh)

	2015	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2030*	*2035*	*2040*
High Case	64	67	68	75	80	86	88	91	94	96	99	114	129	146
Base Case	58	59	52	52	55	59	61	64	66	69	71	88	99	112
Low Case	51	52	43	43	46	49	51	53	54	56	58	68	77	87

SOLID FUEL PRICE ASSUMPTIONS

- Case development
- Pricing methodology
- Long term prices

Case Development (Solid Fuels)

	Highlights
Base Case (Expected)	• Current (bearish) market continues
High Case	• High electricity demand growth, high natural gas prices, no carbon controls and the construction of Pacific Northwest coal terminals drive demand growth in seaborne coal trade • Higher prices go unchecked while supply cannot keep up with demand
Low Case	• Stringent carbon policies, low natural gas prices, higher renewable generation, lower GDP growth and evergreen renewals of nuclear power plants keep demand for coal low

Solid Fuel

Delivered Price	=	Commodity	+	Marine Freight	+	Land Transportation
Low Sulphur Coal	=	**Low Sulphur Colombian** Source: EVA Long Term Forecast (Mar '14) FOB Vessel	+	**Marine Freight** Source: NSPI Current Contracts (Bolivar) escalated (2016+)	+	**Terminaling** Source: NSPI 2014 Contract Prices escalated 2015+
Mid Sulphur Coal	=	**NAPP Pittsburgh Seam** Source: EVA Long Term Forecast (Mar '14) Northern Appalachia Pittsburgh Seam FOB Vessel	+	**Marine Freight** Source: same	+	**Terminaling** Source: same
Pet Coke (for POA)	=	**US Gulf Coast Pet Coke** Source: EVA Long Term Forecast (Mar '14) Pet Coke U.S. Gulf Coast FOB Vessel	+	**Marine Freight** Source: NSPI Current Contracts (escalated 2016+)	+	**Terminaling** Source: same
Domestic (for TR6)	=	**Domestic Coal** Source: NSPI Current Contracts	+	**nil**	+	**nil**

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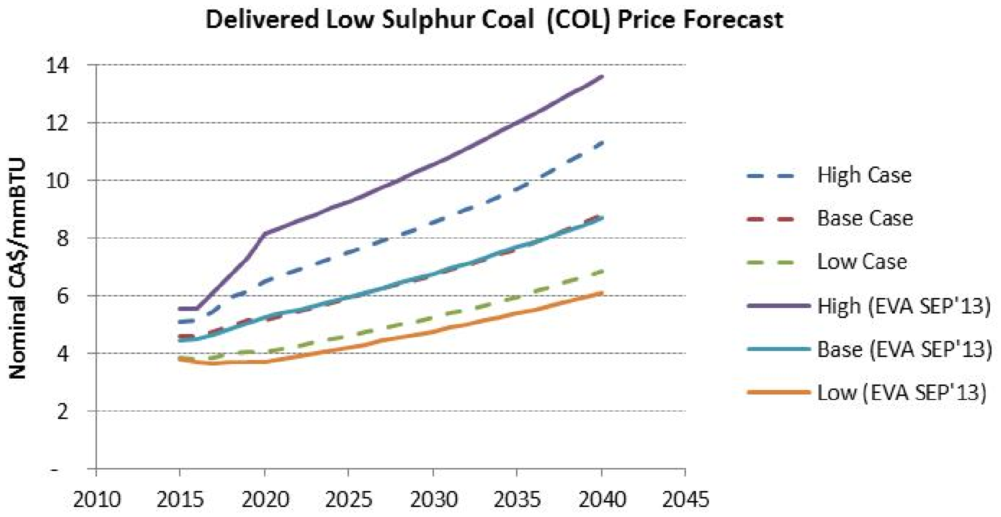
2014 IRP – Updated Long Term Solid Fuel Price Assumptions

SIGNIFICANT CHANGES

- Updated market outlook (March 2014)
  - Previous forecast performed by EVA in September 2013
- Adjustments for more aggressive assumptions in the high and low cases in the previous forecast

LOW-SULPHUR COAL (COL)


Delivered Low Sulphur Coal (COL) Price Forecast

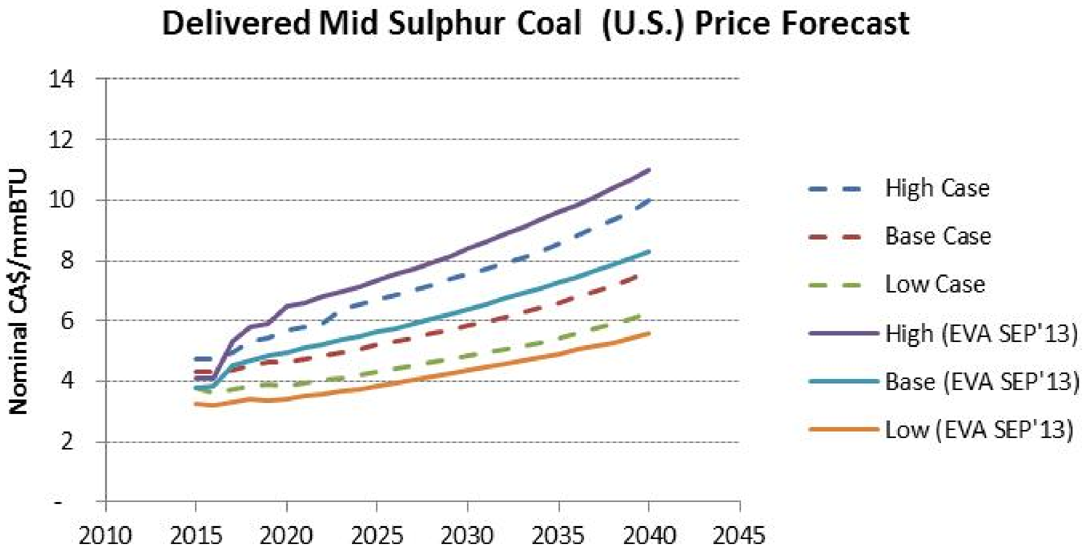
NS Delivered Low Sulphur (COL) Coal Price Forecast (Nominal CA$/mmBTU) (Plant Weighted)

	2015	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2030*	*2035*	*2040*
High Case	5.1	5.2	5.5	6.0	6.2	6.5	6.7	6.9	7.1	7.3	7.5	8.6	9.7	11.3
Base Case	4.6	4.6	4.8	5.0	5.2	5.2	5.3	5.5	5.6	5.8	5.9	6.7	7.6	8.8
Low Case	3.9	3.8	3.9	4.0	4.1	4.0	4.2	4.3	4.4	4.5	4.6	5.3	6.0	6.9

NS Delivered Low Sulphur (COL) Coal Price Forecast (2014 CA$/mmBTU) (Plant Weighted)

	2015	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2030*	*2035*	*2040*
High Case	5.0	5.0	5.2	5.5	5.6	5.8	5.8	5.9	5.9	6.0	6.0	6.2	6.4	6.8
Base Case	4.5	4.4	4.5	4.6	4.7	4.6	4.6	4.7	4.7	4.7	4.8	4.9	5.0	5.3
Low Case	3.8	3.7	3.6	3.7	3.7	3.6	3.6	3.7	3.7	3.7	3.7	3.8	3.9	4.1

MID-SULPHUR COAL (US)



Delivered Mid Sulphur Coal (U.S.) Price Forecast

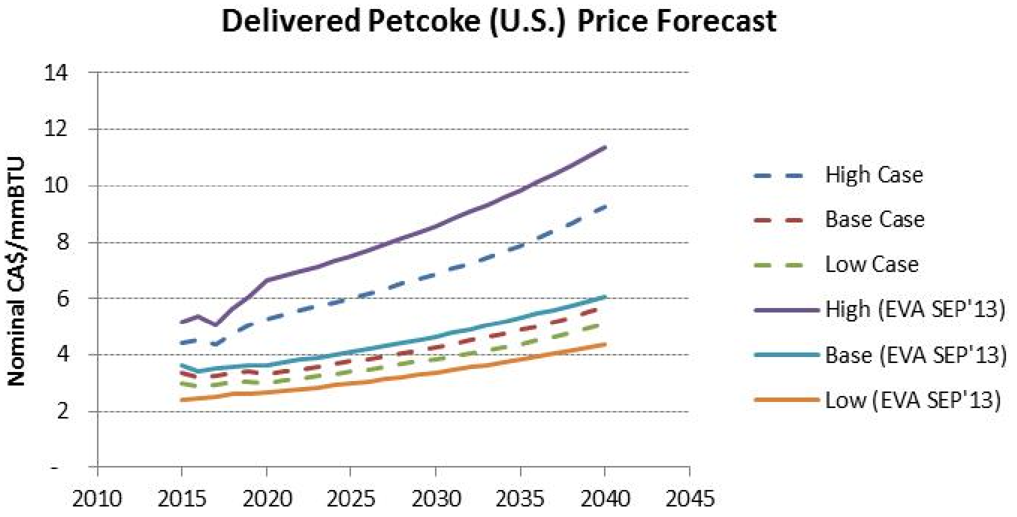
NS Delivered Mid Sulphur (U.S.) Coal Price Forecast (Nominal CA$/mmBTU) (Plant Weighted)

	2015	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2030*	*2035*	*2040*
High Case	4.8	4.7	5.0	5.3	5.5	5.7	5.8	5.9	6.4	6.5	6.7	7.6	8.6	10.0
Base Case	4.3	4.3	4.4	4.5	4.6	4.6	4.7	4.9	5.0	5.1	5.2	5.9	6.6	7.7
Low Case	3.8	3.6	3.8	3.9	3.9	3.9	3.9	4.0	4.1	4.2	4.3	4.8	5.4	6.3

NS Delivered Mid Sulphur (U.S.) Coal Price Forecast (2014 CA$/mmBTU) (Plant Weighted)

	2015	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2030*	*2035*	*2040*
High Case	4.7	4.5	4.7	4.9	4.9	5.0	5.1	5.1	5.4	5.4	5.4	5.5	5.6	6.0
Base Case	4.2	4.1	4.1	4.2	4.2	4.1	4.1	4.1	4.2	4.2	4.2	4.3	4.4	4.6
Low Case	3.7	3.5	3.5	3.6	3.5	3.4	3.4	3.4	3.4	3.5	3.5	3.5	3.6	3.8

PETCOKE (US)



NS Delivered Pet Coke Forecast (Nominal CA$/mmBTU)

	2015	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2030*	*2035*	*2040*
High Case	4.4	4.5	4.4	4.7	5.1	5.3	5.4	5.6	5.7	5.9	6.0	6.9	7.9	9.3
Base Case	3.4	3.2	3.3	3.4	3.4	3.3	3.4	3.5	3.6	3.7	3.8	4.3	4.9	5.7
Low Case	3.0	2.9	2.9	3.0	3.1	3.0	3.1	3.2	3.2	3.3	3.4	3.9	4.4	5.1

NS Delivered Pet Coke Forecast (2014 CA$/mmBTU)

	2015	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2030*	*2035*	*2040*
High Case	4.4	4.3	4.1	4.4	4.6	4.7	4.7	4.8	4.8	4.8	4.8	5.0	5.2	5.5
Base Case	3.3	3.1	3.1	3.1	3.1	2.9	3.0	3.0	3.0	3.0	3.0	3.1	3.2	3.4
Low Case	2.9	2.8	2.8	2.8	2.8	2.7	2.7	2.7	2.7	2.7	2.7	2.8	2.9	3.0

FUEL OIL PRICE ASSUMPTIONS

- Case development
- Pricing methodology
- Long term prices

Case Development (Fuel Oil)

	Highlights
Base Case (Expected)	• Driven by PIRA Annual Guidebook 2014 Global Oil Price Scenarios
High Case	
Low Case	

HFO Price Assumptions

Delivered Price	=	Commodity	x	NY Harbour Basis	+	Supplier Delivery Premium
2.2% Sulphur	=	**Brent** Source: PIRA Annual Guidebook 2014; High, Low and Expected Cases	x	**● %** Source: NSPI	+	**Premium** Source: NSPI
1% Sulphur	=	**Brent** Source: Same	x	**● %** Source: NSPI	+	**Premium** Source: NSPI

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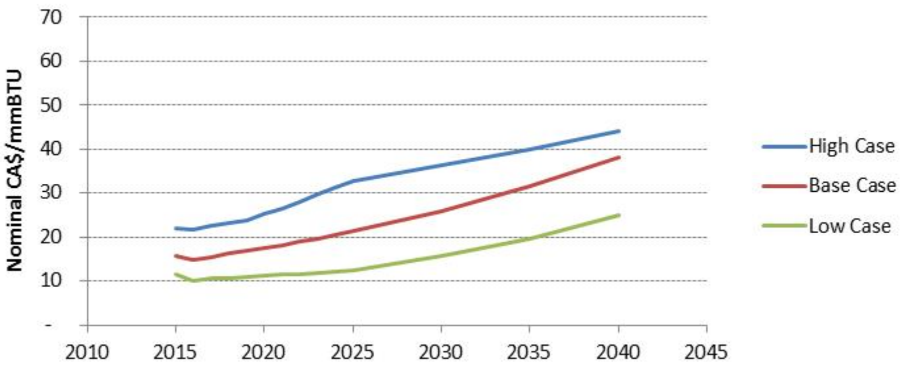
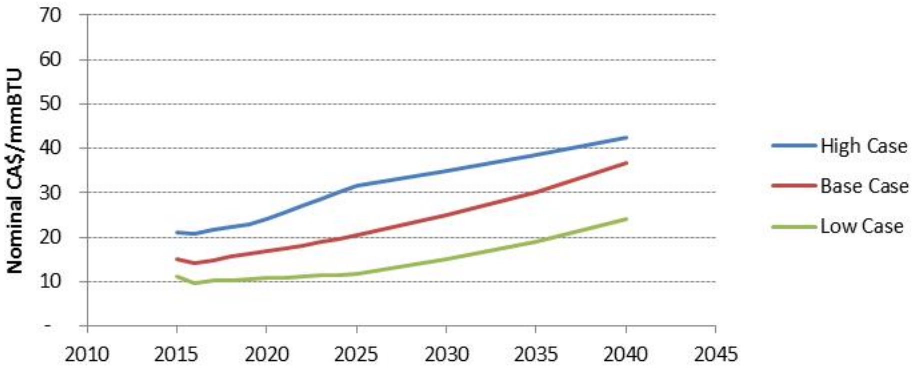
LFO Price Assumptions

Delivered Price	=	Commodity	x	ULSD Basis Adjustment	+	NS Delivery Premium
Ultra Low Sulphur Diesel	=	**Ultra Low Sulphur Diesel** Source: PIRA Annual Guidebook 2014; High, Low and Expected Cases	x	**N/A**	+	**Premium** + $0.06/litre per NS Government pricing regulation Source: NS Department of Energy
Heating Oil	=	**Ultra Low Sulphur Diesel** Source: Same	x	**Historic Annual Discount, Profiled by month** Source: NSPI	+	**Premium** + $0.06/litre per NS Government pricing regulation Source: NS Department of Energy

HEAVY FUEL OIL PRICE ASSUMPTIONS


Delivered 1% Sulphur HFO Price Forecast


Delivered 2.2% Sulphur HFO Price Forecast

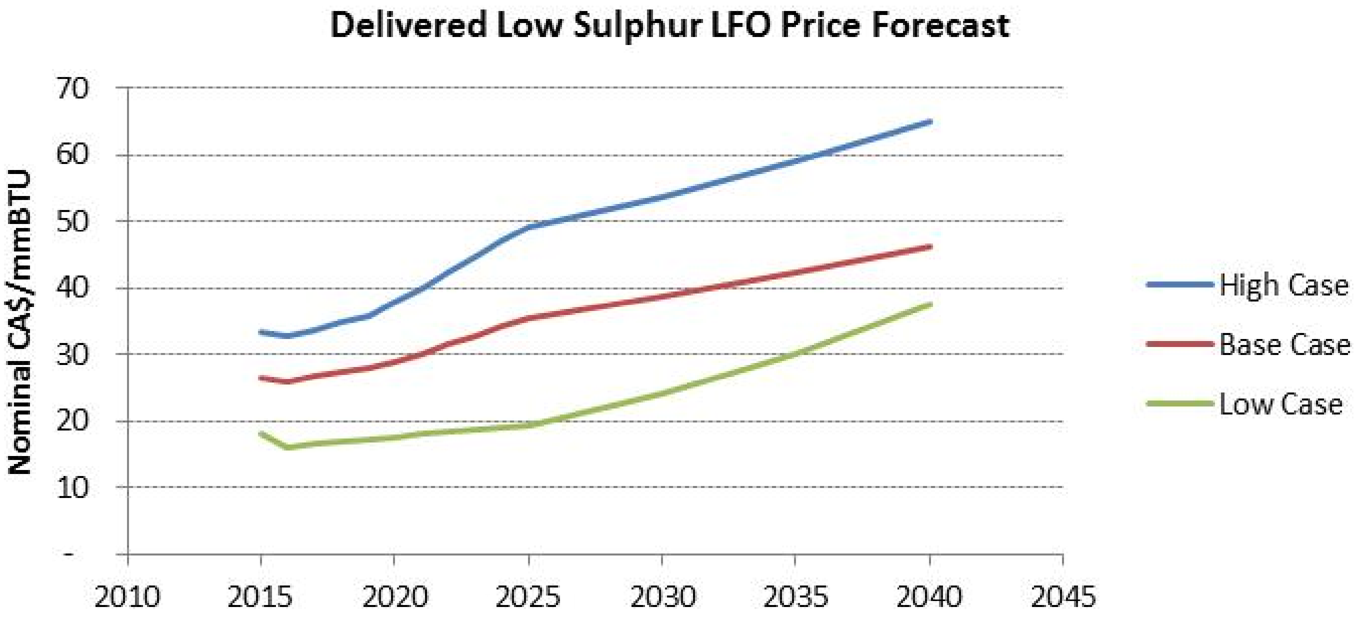
NS Delivered 1% HFO Forecast (Nominal CA$/mmBTU)

	2015	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2030*	*2035*	*2040*
High Case	21.9	21.8	22.5	23.2	23.8	25.2	26.6	28.1	29.6	31.2	32.9	36.3	40.0	44.2
Base Case	15.8	14.7	15.4	16.2	16.8	17.5	18.2	18.9	19.7	20.5	21.3	25.8	31.4	38.2
Low Case	11.5	10.0	10.5	10.7	10.9	11.2	11.4	11.6	11.8	12.1	12.3	15.6	19.7	25.0

NS Delivered 2.2% HFO Forecast (Nominal CA$/mmBTU)

	2015	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2030*	*2035*	*2040*
High Case	21.0	20.9	21.6	22.3	22.8	24.2	25.6	27.0	28.5	30.0	31.6	34.9	38.5	42.5
Base Case	15.2	14.2	14.9	15.6	16.2	16.8	17.5	18.2	18.9	19.7	20.5	24.8	30.2	36.7
Low Case	11.1	9.7	10.1	10.3	10.5	10.7	10.9	11.2	11.4	11.6	11.8	15.0	19.0	24.0

LIGHT FUEL OIL PRICE ASSUMPTIONS



NS Delivered Low S LFO Forecast (Nominal CA$/mmBTU) (Fleet Average)

	2015	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2030*	*2035*	*2040*
High Case	33.2	32.8	33.7	34.8	35.6	37.7	39.9	42.3	44.7	47.0	49.2	53.8	59.2	65.2
Base Case	26.6	26.0	26.6	27.4	28.1	28.8	30.0	31.5	32.9	34.2	35.5	38.8	42.4	46.3
Low Case	18.2	15.9	16.6	16.8	17.2	17.6	18.0	18.4	18.8	19.1	19.4	24.0	30.0	37.6

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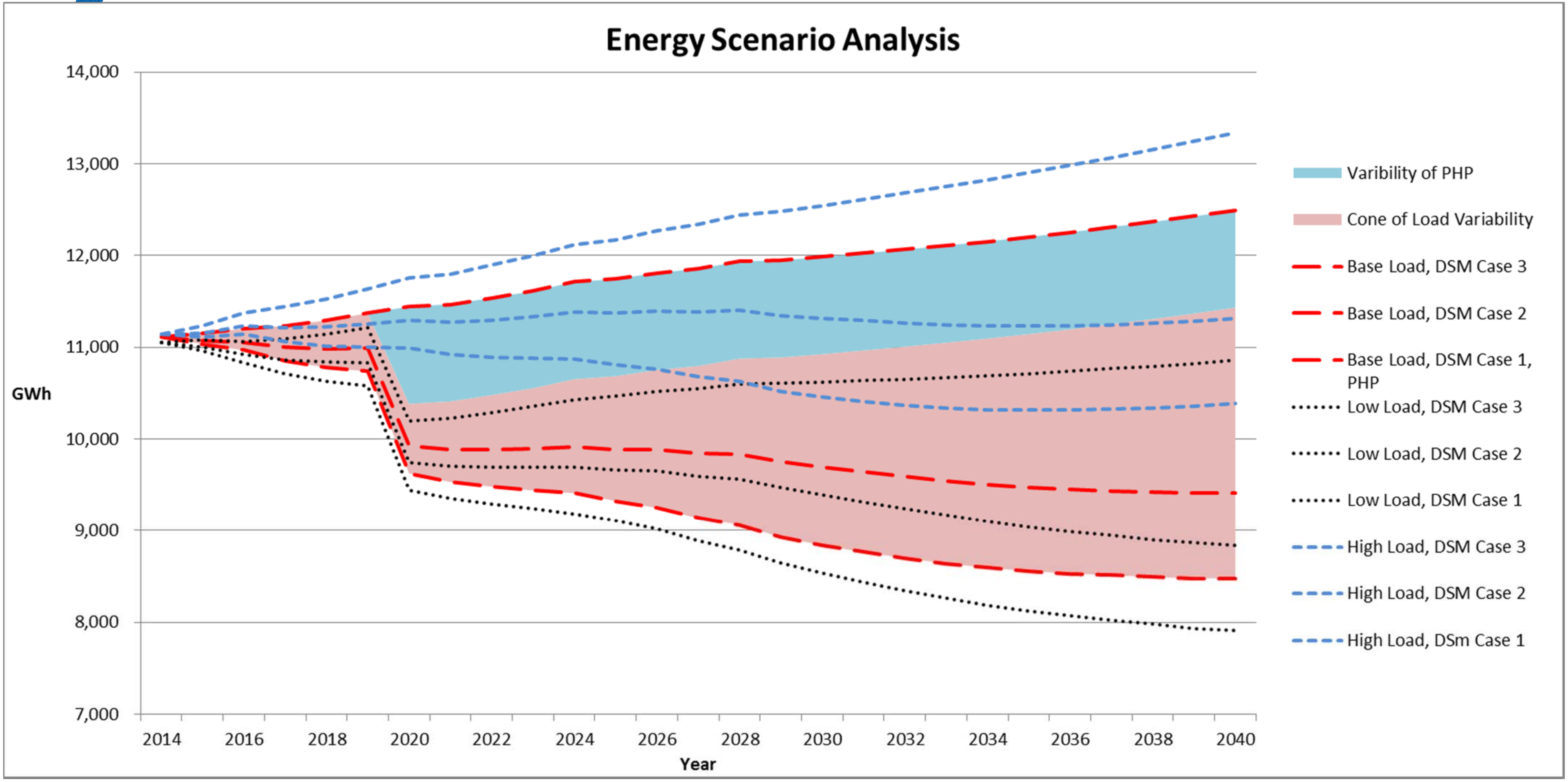
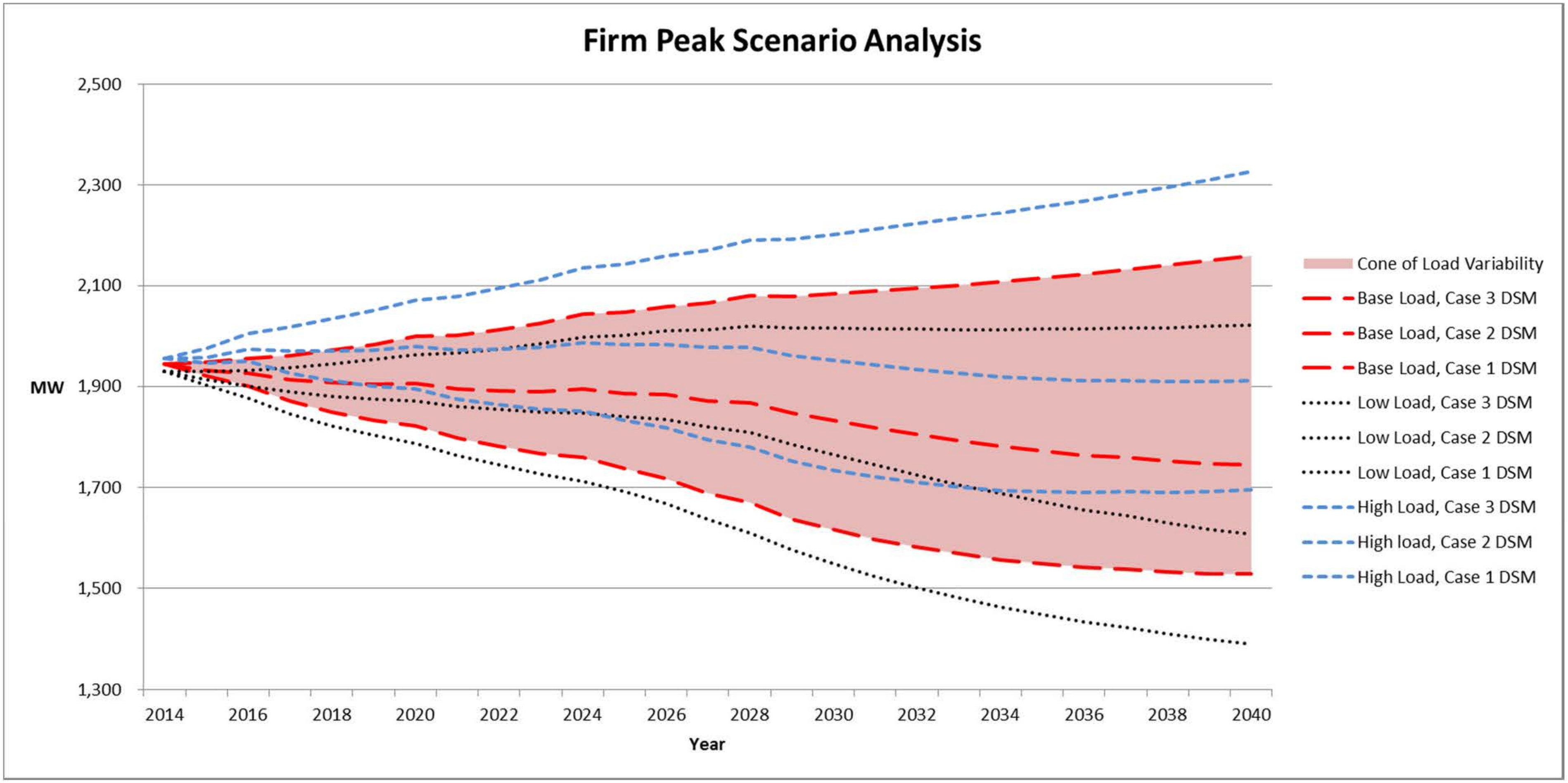
IRP Load Assumptions (Revised)

Load Scenarios

- The combination of 3 load forecasts and 3 DSM scenarios creates 9 possible load scenarios to test
- Many of these load scenarios are similar
- By choosing just a few scenarios for modeling it is possible to cover a range of loads which encompasses the majority of the scenarios



- DSM Case 1 - 1.3 TWh of DSM savings from 2015 to 2040
- DSM Case 2 - 3.3 TWh of DSM savings from 2015 to 2040
- DSM Case 3 - 4.2 TWh of DSM savings from 2015 to 2040


Firm Peak Scenario Analysis
MW
2,500
2,300
2,100
1,900
1,700
1,500
1,300
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Year
Cone of Load Variability
Base Load, Case 3 DSM
Base Load, Case 2 DSM
Base Load, Case 1 DSM
Low Load, Case 3 DSM
Low Load, Case 2 DSM
Low Load, Case 1 DSM
High Load, Case 3 DSM
High load, Case 2 DSM
High Load, Case 1 DSM

Variance to Base Load, Case 2 DSM

	Energy		Demand	
Year	Base Load, Case 3 DSM	Base Load, PHP, Case 1 DSM	Base Load, Case 3 DSM	Base Load, PHP, Case 1 DSM
2025	-6%	+19%	-8%	+9%
2040	-10%	+33%	-12%	+24%

Recommendation

- Model three worlds:
    - Base load forecast with PHP beyond 2019 and DSM Case 3
    - Base load forecast with DSM Case 2
    - Base load forecast with DSM Case 1
- This recommendation creates a range which encompass all of the 9 scenarios but 2
- The two scenarios outside this cone are unlikely combinations because they are the high load, DSM Case 1 and low load, DSM Case 3.

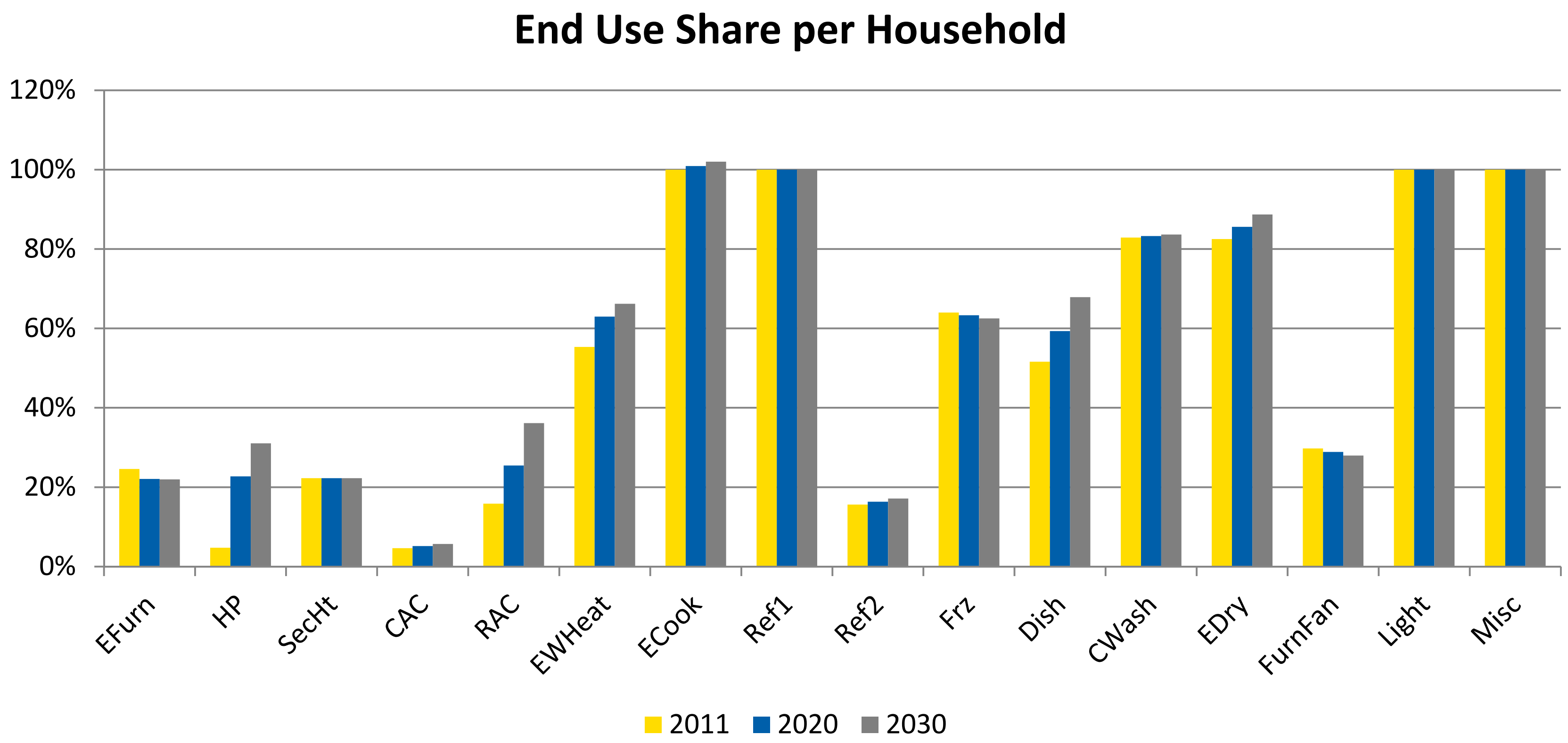
Updates to the Load Forecast

Updates to the Base Case Load Forecast

1. Updated Michelin Granton load to reflect best available information
2. Extended Small and Medium Industrial load forecast to 2030. Load is projected from 2030 to 2040.
3. Updated PHP losses from 3% to 2.04%
4. Updated demand calculations. Interruptible load in 2020 now deceases by 66.3 MW (65 MW + 2.04% losses) if PHP is offline
5. Worked with ENSC to align end use assumptions with information in DSM potential study
6. Updated year over year change in heat pump stock efficiency

Additional End Use Information

Residential End Use Shares



- A share is the percentage of homes with a particular end use.
- TVs are another end use that is tracked, with shares increasing from 216% (more than 2 per house) in 2011 to 253% in 2030.

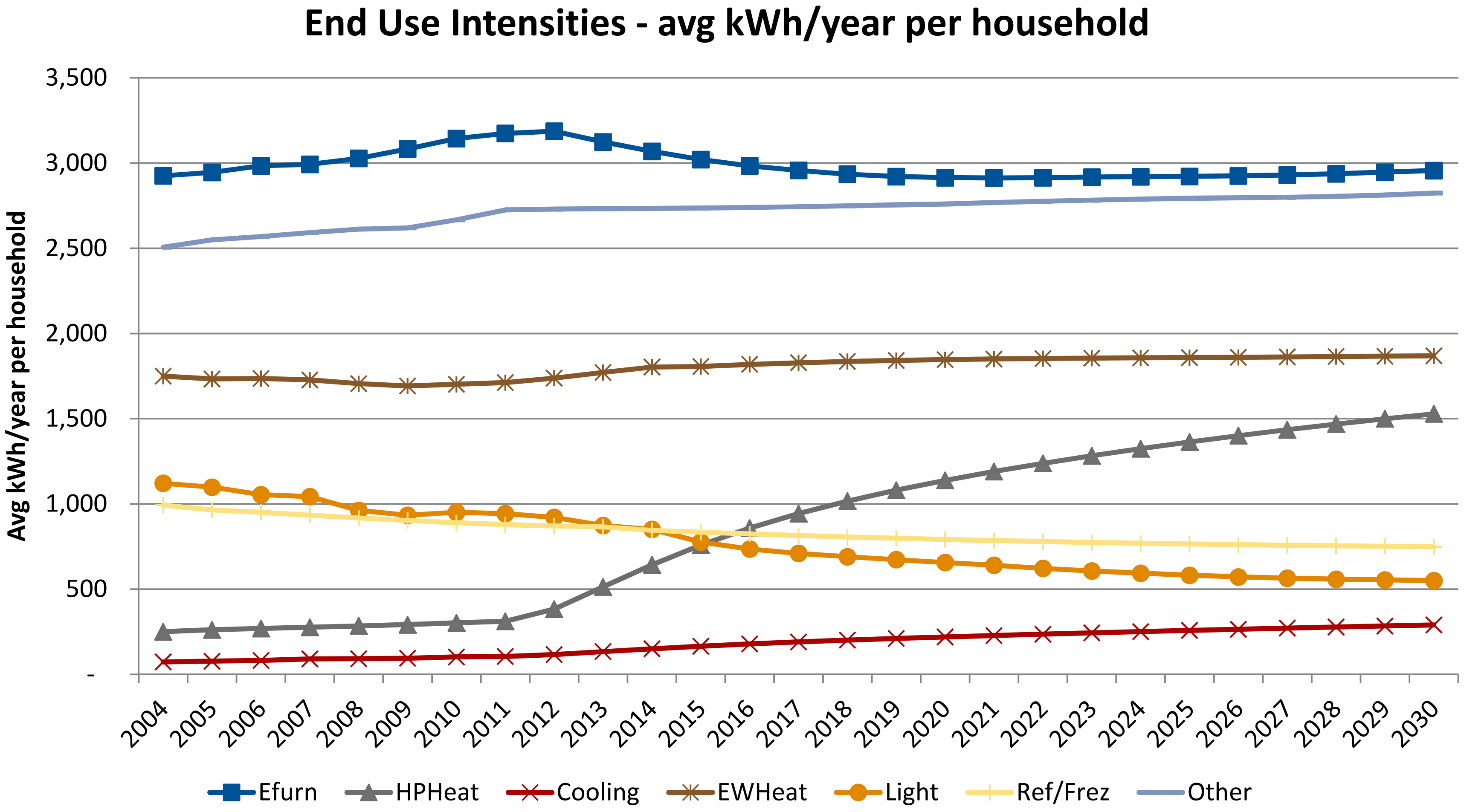
Legend - Residential End Use Shares

- Electric furnace (EFurn) – base board and forced air
- Heat pump (HP)
- Secondary heating (SecHt)
- Air conditioning - Central AC (CAC), Room AC (RAC)
- Electric water heat (EWHeat)
- Stoves (ECook)
- Refrigerators and freezers (Ref1/Ref2/Frz)
- Dishwashers (Dish)
- Clothes washers (CWash) and dryers (EDry)
- Furnace fans (Furn Fan)
- Lights
- Plug loads (Misc)

Residential End Use Intensities

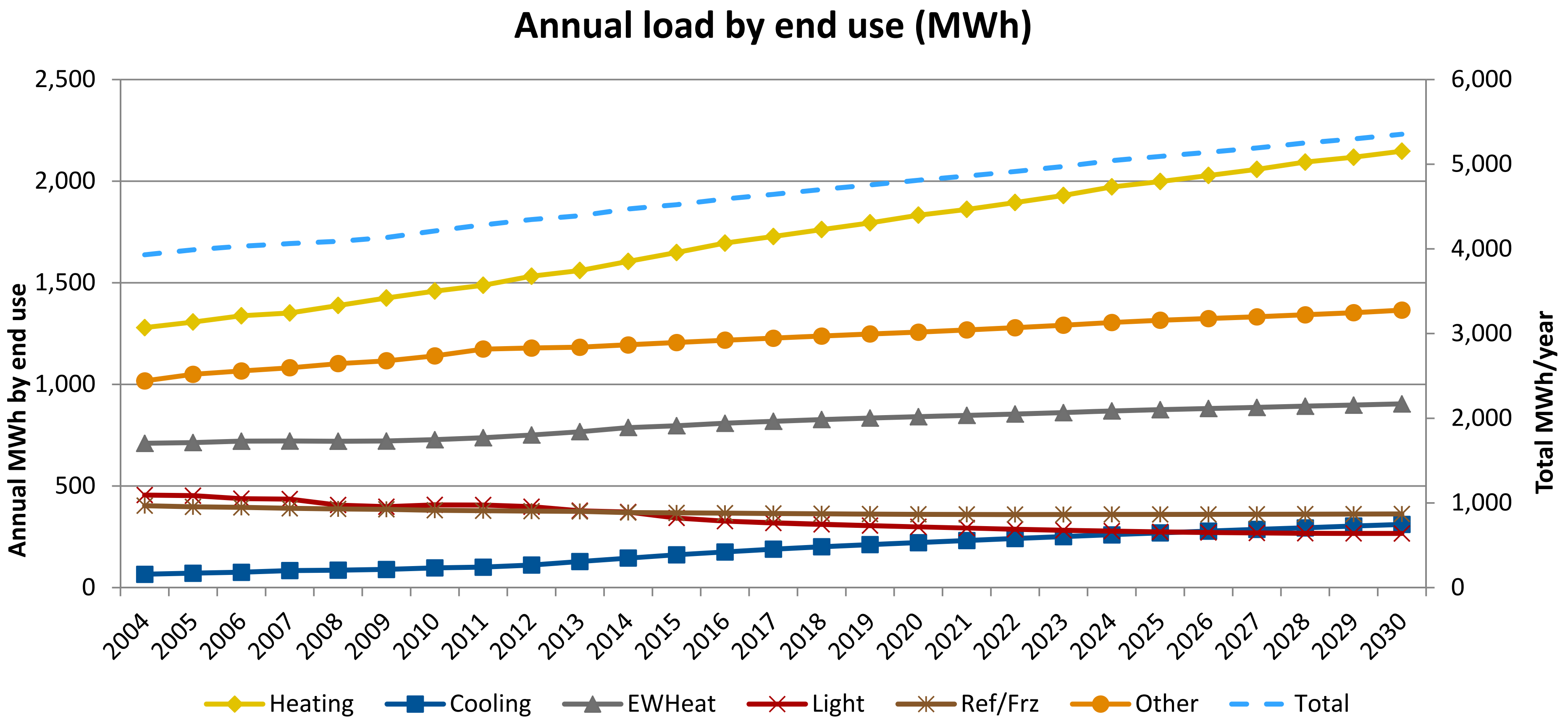
- Intensities represent the average use for each end use for all households in the province.
- End use intensities are based on NRCan end use data for Nova Scotia and are calibrated to sales in a base year (2005).
- Intensity projections are based on year over year change in shares, efficiencies, and in some cases (like heating and cooling) building characteristics.
- Efurn includes secondary heat and furnace fans
- Cooling includes central, room and heat pump cooling
- Other includes all end uses not listed specifically

Residential End Use Intensities



Residential End Use Contribution

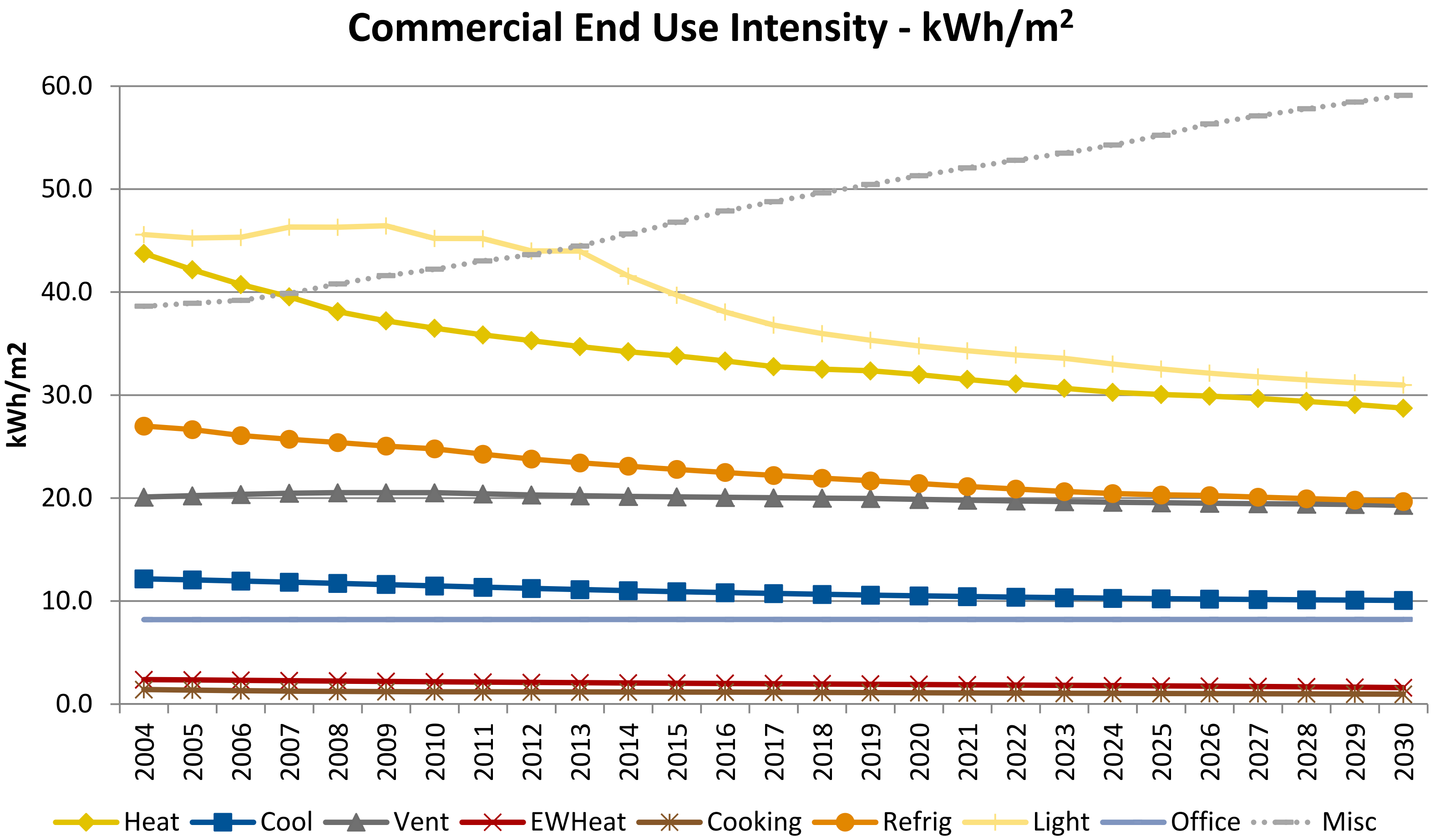
- Combining intensities with the economic variables provides the annual contribution.



Commercial End Use Intensities

- Commercial intensities are calculated on a per square meter basis, as opposed to a per customer basis as with residential.
- End use intensities are based on NRCan end use data for Atlantic Canada and are calibrated to sales in a base year (2004).
- Intensity projections are based on year over year change in shares and efficiencies.
- End uses provided by NRCan include heating, cooling, water heating, auxiliary equipment, auxiliary motors, and lighting. EIA provides additional data for ventilation, cooking, refrigeration, office equipment (PCs, copiers) and miscellaneous. These are assumed to fall within the auxiliary equipment and motors categories.
- The miscellaneous category is the most significant contributor to growth over the forecast, and is made up by loads such as data servers, elevators, displays/televisions, medical equipment, etc.

Commercial End Use Intensities



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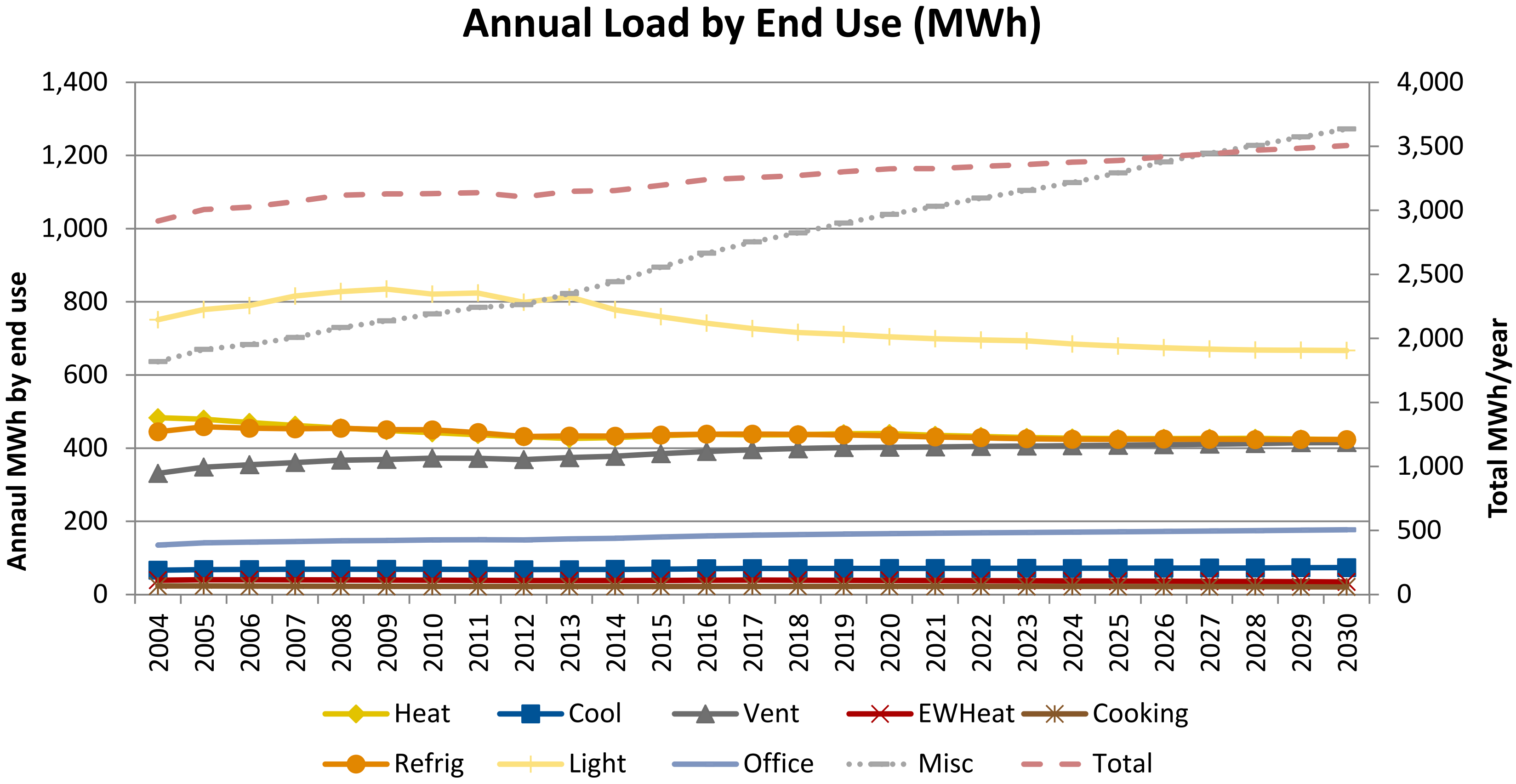
Commercial End Use Contribution

- Combining intensities with the economic variables provides the annual contribution.



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DSM Assumptions (Revised)

DSM and DR Levels

NS Power proposes to model candidate resource plans that include various levels of DSM and Demand Response (DR).

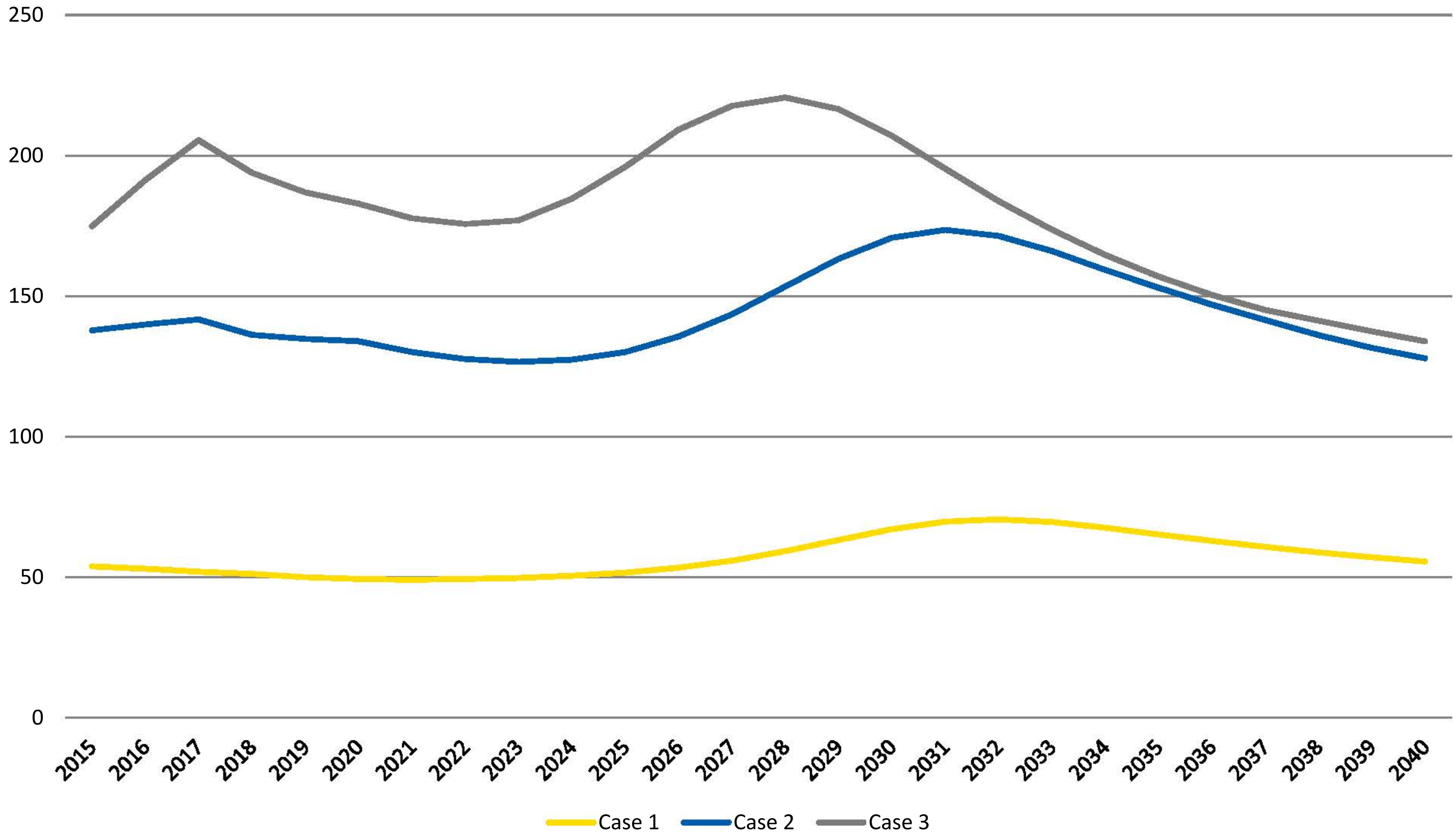
DSM levels. NS Power proposes to model a range of different candidate resource plans that have one of three different levels of DSM:

Case 1: 50% of Low Case from ENSC/Navigant January 2014 DSM Potential Study
Case 2: Base Case from ENSC/Navigant January 2014 DSM Potential Study
Case 3: High Case from ENSC/Navigant January 2014 DSM Potential Study

NS Power believes that the ENSC/Navigant January 2014 DSM Potential Study warrants review and vetting by stakeholders in a separate regulatory process at a future date. NS Power considers this data to be sufficient for IRP purposes.

DR levels. In addition to the reductions in peak demand associated with each of the DSM levels, NS Power proposes to model several direct load control solutions to mitigate peak demand and provide some ancillary services. These DR assumptions do not preclude the utilization of other customer solutions as a resource in the future.

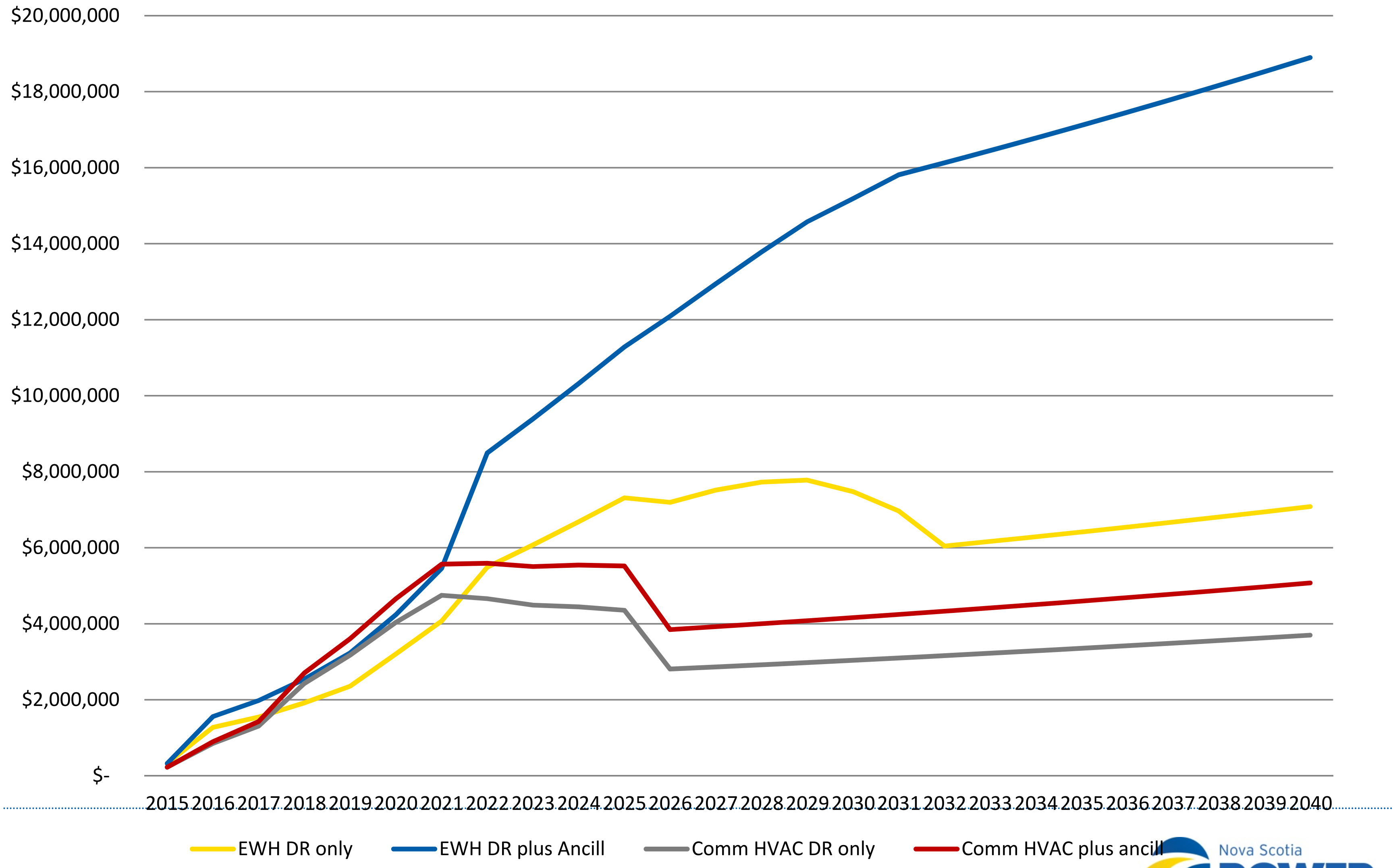
DSM Scenarios: Incremental Energy Reductions GWh



DSM and DR Costs

- NS Power proposes to calculate the revenue requirements of candidate resource plans that include DSM using the total cost of that DSM. These costs, referred to as Total Resource Costs (TRC), consist of the DSM program administrator costs plus the customer costs, i.e., costs paid by participants in those programs.
- NS Power is proposing this approach consistent with the TRC, previous IRPs and with the IRP treatment of DSM in other jurisdictions that use TRC as a primary test. The TRC is the predominant cost effectiveness test used for screening in North America. The TRC is the test currently accepted by the UARB.
- For information purposes, NS Power will also calculate the revenue requirements of candidate resource plans that include DSM without customer costs.
- Consistent with the treatment of supply side options, NS Power will apply its after-tax WACC as the discount rate for DSM.
- Stakeholders will have the opportunity to address these issues as the subject of future regulatory filings allowing for stakeholder input and Board Decision

Forecast DR Program Costs
$ (nominal)



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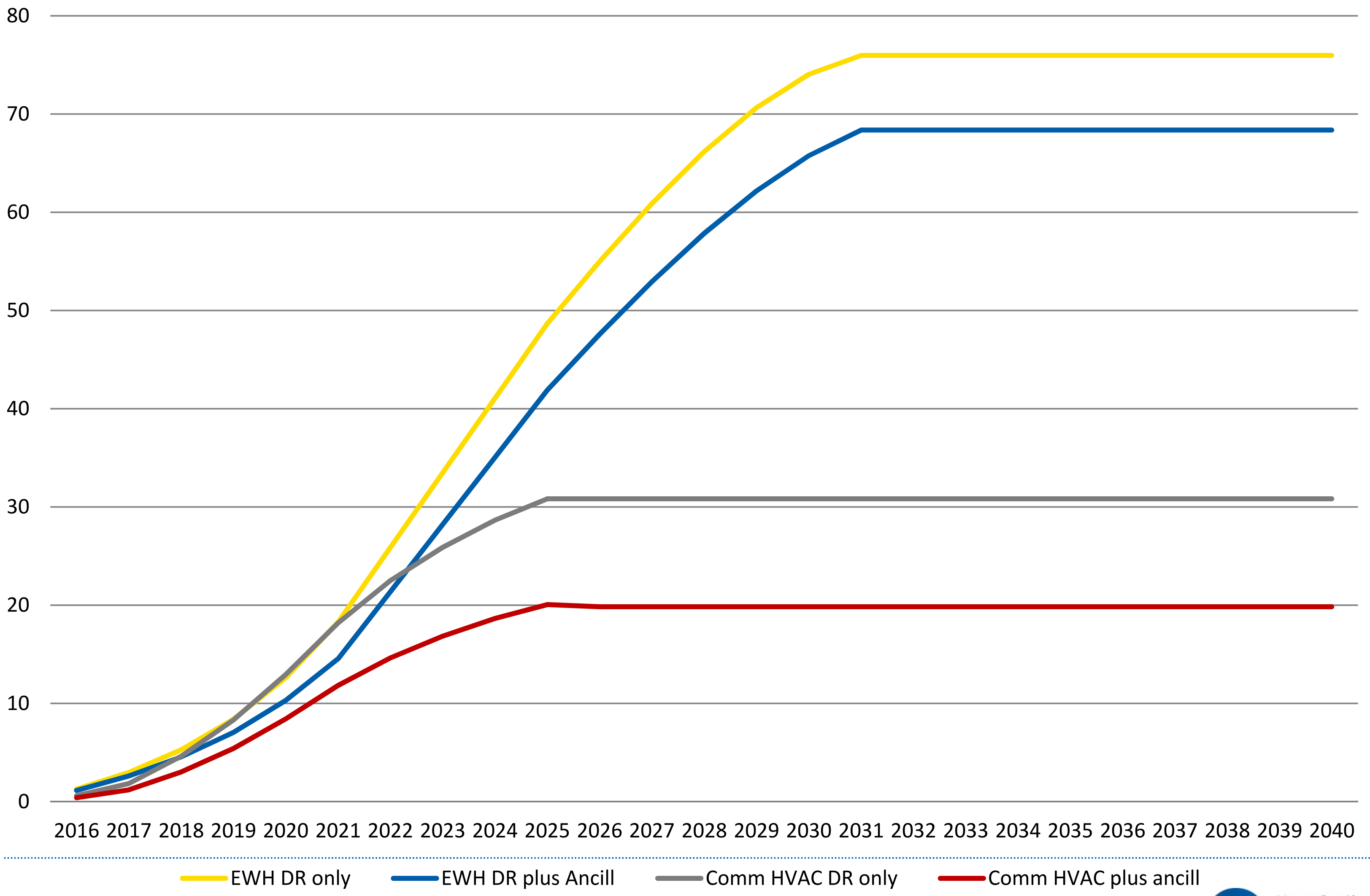
Forecast DR Program Impacts MW



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Avoided Cost Methodology

- Historically NS Power has relied upon a difference in total plan costs (no DSM vs DSM plans) as the basis for the avoided costs
- The avoided cost methodology will be discussed in more detail at the June technical conference

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Demand Response

Water Heater DR Development Costs

- Servers
  - $20,000 (based on PSA server purchase cost)
- Software & systems interface development
  - 1st year: $175,000 (based on development costs of PSA aggregation systems from PSA vendors)
  - 2nd year: $23,000 (continued support and refinement)
  - 3rd year: $15,000 (continued support and refinement)
- Training
  - 2 years: $15,000

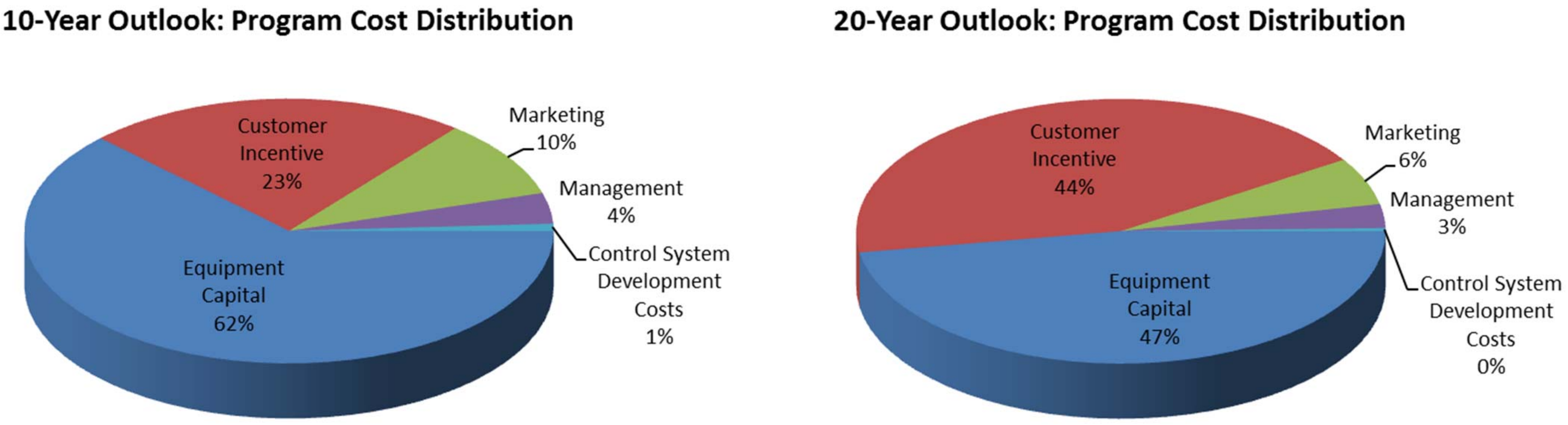
Water Heater DR Annual Costs

- New customer installation capital costs
  - 275 $/install (based on PSA info and Navigant feedback)
- Customer incentive
  - 25 $/year (matches WH incentive of FP&L and PE Florida)
- Aggregation fees
  - No aggregator required for simple DR operations
- Marketing
  - 1.5 FTE + $300,000/yr budget declining to 1 FTE + $100,000/yr budget over 10 years
- Management
  - 1.5 FTE

Water Heater DR Uptake Assumptions

- Installations occur in replacement market only
- 10-year average tank life
  - 422,000 WHs in NS (NRCAN)
    - 42,200 replacements annually
- 1st year: 5% of replacement market (2110 installations)
- Increasing 30% annually thereafter (eg. 6.5% of replacement market in 2nd year; 2849 installations)
- Market saturation of 30% of replacements reached after 7 years

Water Heater Cost Distribution



Levelized cost $128/kW (nominal dollars)

Water Heater Ancillary Services

- Packaged water heater
  - Incremental purchase cost incentive of $400 (based on vendor feedback for packaged controllable water heater solutions)
  - Replaced every 10 years – recurring incentive
- Aggregation fees
  - 24 $/device/year (based on PowerShift vendor feedback)
- All other assumptions remain the same
- Levelized cost: 248 $/kW

Commercial DR Development Costs

- Servers
  - $20,000 (based on PSA server purchase cost)
- Software & systems interface development
  - 1st year: $75,000 (based on development costs of PSA aggregation systems from PSA vendors)
  - 2nd year: $15,000 (continued support and refinement)
  - 3rd year: $10,000 (continued support and refinement)
- Training
  - 2 years: $15,000

Commercial DR Annual Costs

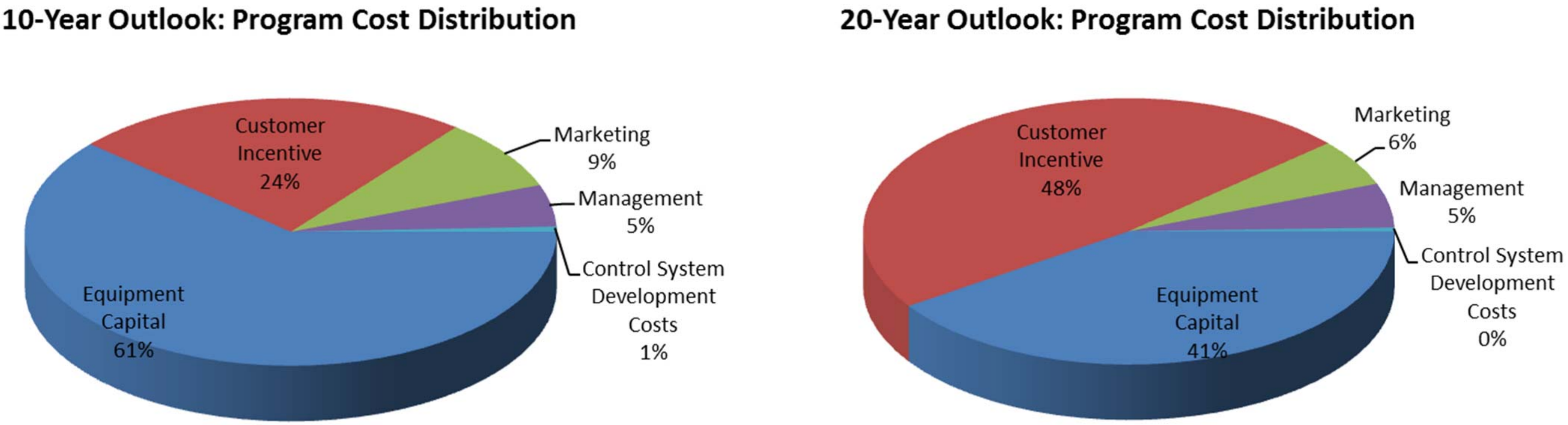
- New customer installation capital costs
  - 35,000 $/install (based on PSA info and Navigant feedback)
    - 4% reduction annually due to maturing markets (5 year maturity)
- Customer incentive
  - 40 $/kW/year
- Aggregation fee
  - 1700 $/site/year (based on projection from PSA)
- Marketing
  - 1.5 FTE + $150,000/yr budget declining to 1 FTE + $80,000/yr budget over 10 years
- Management
  - 1.5 FTE

Commercial DR Uptake Assumptions

- Market saturation of 30% reached after 10 years
- 25% of customer demand used as capacity estimate
- 60 kW/site average based on:

	Count	Avg size	kW/cust.	Uptake	Range MW	Sites (max)
Large comm > 2000 kVa	18	3200	400	30%	2.2	5
500kW < customer < 2000kW	130	800	200	30%	7.8	39
300kW < customer < 500kW	195	400	100	30%	5.9	59
200kW < customer < 300kW	218	250	62.5	30%	4.1	65
100kW < customer < 200kW	704	150	37.5	30%	7.9	211
50kW < customer < 100kW	1602	75	18.75	10%	3.0	160
1kW < customer < 50kW	8479					
Total	**11328**				**33**	**553**

Commercial DR Cost Distribution



Levelized cost 156 $/kW (nominal dollars)

Commercial Ancillary Services

- Site integration cost
  - Increase to 37,000 $/site
- Aggregation cost
  - Increase to 3000 $/site
- All other assumptions remain the same
- Resulting levelized cost of 189 $/kW

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APRIL 11, 2014

Analysis Plan Overview

Analysis Plan Overview

- Begin with a broad range of draft resource plans
- Evaluate them under a Reference World (using base, most likely assumptions)
- Narrow those resource plans down to a set of candidate resource plans
- Evaluate the candidate plans under different “views of the world” or different sets of assumptions for key inputs.

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APRIL 23, 2014

Capacity Value of Wind Assumptions and Planning Reserve Margin

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Executive Summary

Effective Load Carrying Capacity (ELCC), or capacity value, of variable generation and required planning reserve margin are two important input assumptions for the 2014 Integrated Resource Plan (IRP). NS Power has re-examined these input assumptions with the present and future system configurations.

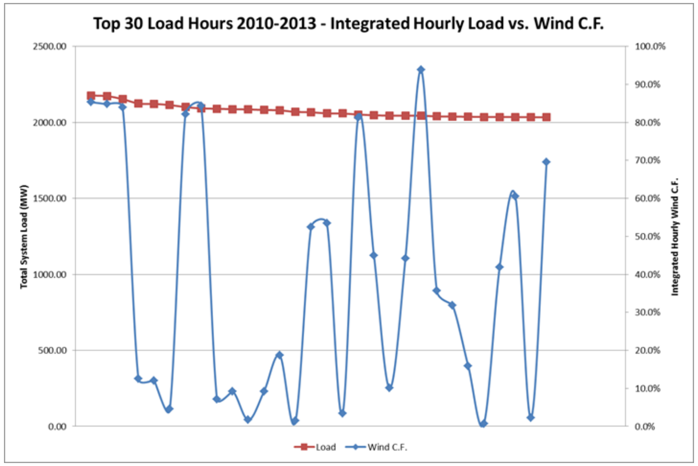
Loss of Load Expectation (LOLE) methodology is an accepted method for the calculation of required planning reserve margin and, in some jurisdictions, ELCC of variable generation. NSPI conducted an LOLE study to confirm the variable energy generation ELCC results in the recent GE Energy integration study.

A cumulative frequency analysis is another accepted method for capacity valuation and this analysis was also conducted using actual historical NSPI data to compare with the results of the LOLE study.

NS Power will test resource plans using wind with capacity values of 12% (from the cumulative distribution analysis) and 27% (from the GE Energy integration study).

LOLE Study Results

- The required planning reserve margin was confirmed to be 20 percent.
- GE Energy LOLE study concluded that the ELCC of present and committed wind generation on NSPI system could be as high as 27 percent. ELCC estimates in other jurisdictions have typically been between 5 and 20 percent.
- NSPI's LOLE study has largely matched the GE Energy study's calculations.



- However, the LOLE methodology may not be a suitable method to calculate wind generation capacity value on NSPI's system. This is due to the averaging nature of the LOLE methodology and the observed bimodal distribution of wind generation output during peak demand on NSPI's system.
- This figure shows how wind generation falls short during many of the highest system demand hours. Over valuation of wind generation capacity effectively diminishes the planning reserve leaving the system challenged to reliably serve firm peak under high demand conditions.

Cumulative Distribution Analysis Study Results

A cumulative distribution analysis of actual NSPI wind generation data, consistent with the methodology used in other jurisdictions, i.e. CAISO, BPA, & SPP, shows a significantly lower capacity value for wind generation.

Confidence level	ELCC of Wind Generation
95%	4%
90%	8%
85%	12%
80%	16%

The empirical analysis expresses numerically the actual historical wind generation behaviour described on the previous page.

Accepting a confidence level of 85%, this study indicates that a capacity value of wind should not exceed 12% for planning purposes.

Effective Load Carrying Capacity of Variable Generation

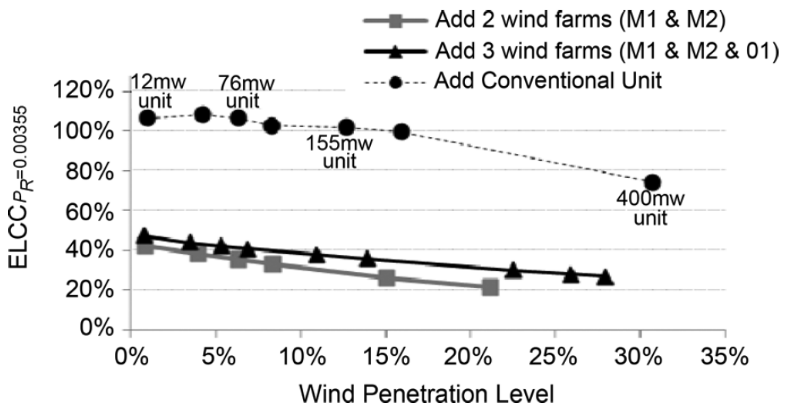
(LOLE Method)

Capacity Value of Wind – LOLE method

Effective Load Carrying Capacity (ELCC) of wind calculation was conducted in PLEXOS software using equivalent LOLE with firm energy substitution methodology, which is consistent with the methodology prescribed by the IEEE Task Force on the Capacity Value of Wind Power.

ELCC of wind generation is expected to decrease with increased wind penetration, as in the accrual ELCC example below.

IEEE TRANSACTIONS ON POWER SYSTEMS, VOL. 27, NO. 4, NOVEMBER 2012



GE Energy LOLE study

GE Energy found that the capacity value of 336 MW of wind generation was 31% or 103 MW, while the capacity value of an incremental 335MW, on top of installed and contracted ~540 MW of wind was 12%, or 40 MW.
Reference: Pages 261-272 of Nova Scotia Renewable Energy Integration Study.

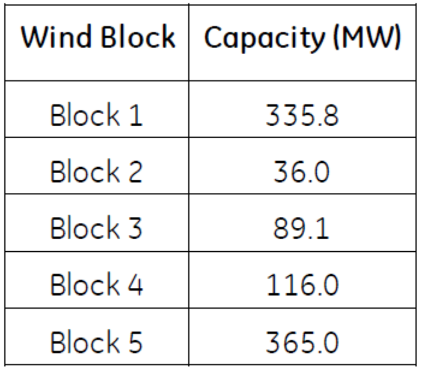
GE reports capacity value of 540 MW of wind to be 27%, or 146 MW, on pg. 266 of the study, fig. 220, which is slightly higher but consistent with NSPI LOLE study findings.
On the same page GE Energy states: *"This is an indication that wind regime in Nova Scotia is well suited to the provincial power needs. Values in the range of 5-20% are more common in the northeast US. "*

It is expected that the discrepancy between the two analyses is the result of the observed bi-modal behaviour of the Nova Scotia wind regime as it relates to power system peak and averaging nature of the LOLE methodology.

GE Energy LOLE study - Excerpts

The figures below are excerpts from GE Energy's calculation of ELCC of wind generation. The GE Energy ELCC calculation has a notable excursion from the expected curve slope at about 550 MW of wind which is explained by increasing diversity. *GE Energy Renewable Energy Integration Study, Page 266.*

Table 51: Wind Blocks for Capacity Valuation



Wind Block	Capacity (MW)
Block 1	335.8
Block 2	36.0
Block 3	89.1
Block 4	116.0
Block 5	365.0

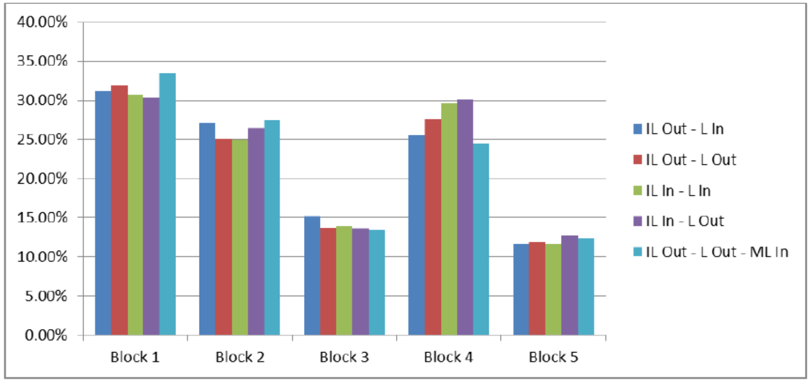


Figure 220: Incremental Capacity Value (%) for all blocks

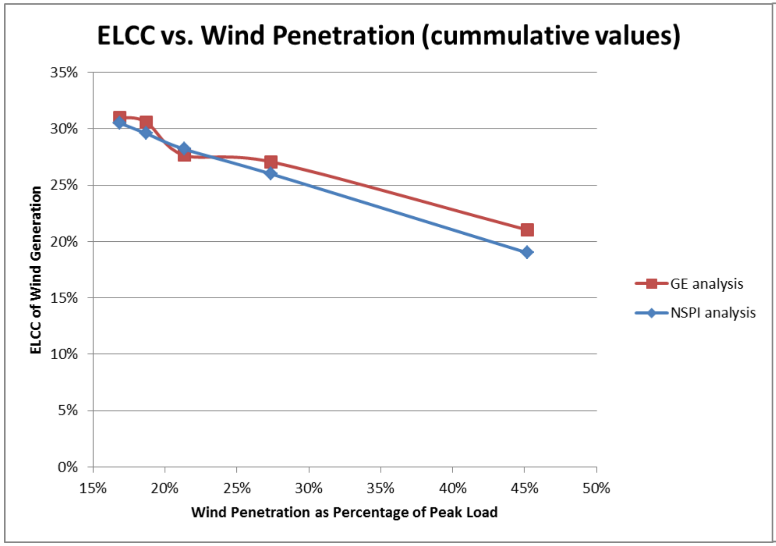
Capacity Value of Wind – ELCC

Wind penetration level	GE Energy calculated ELCC (Incremental)	NSPI calculated ELCC (Incremental)	GE Energy calculated ELCC (cumulative)	NSPI calculated ELCC (cumulative)
336 MW	31%	30.5%	31.0%	30.5%
372 MW	27%	21.2%	30.6%	29.6%
425 MW	15%	19.5%	27.6%	28.2%
~545 MW	25%	19.9%	27.1%	26%
Need to estimate incremental and cumulative effects for wind penetration between ~545 - ~900 MW				
~900 MW	12%	8.5%	21.0%	19%

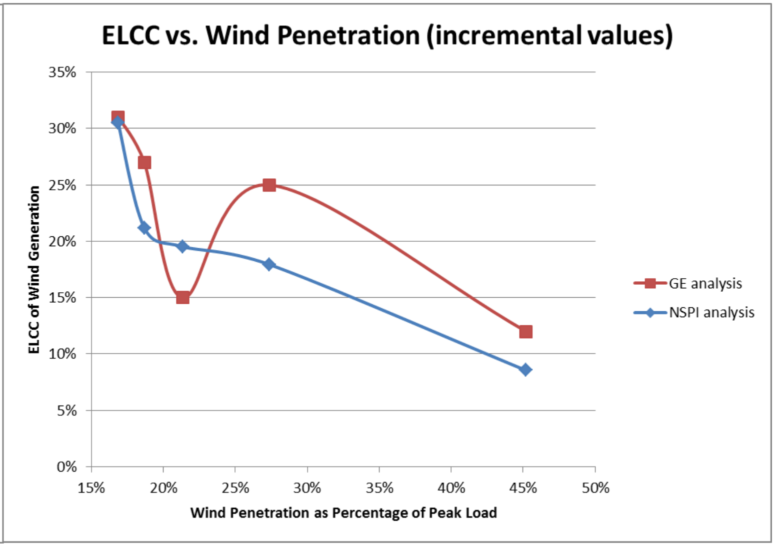
Cumulative values of GE Energy incremental ELCC values were calculated using a weighted average with respect to penetration levels.

Capacity Value of Wind – ELCC

Graphical representation of cumulative and incremental ELCC values for wind generation as calculated by GE Energy and NSPI.



ELCC vs. Wind Penetration (cummulative values)



ELCC vs. Wind Penetration (incremental values)

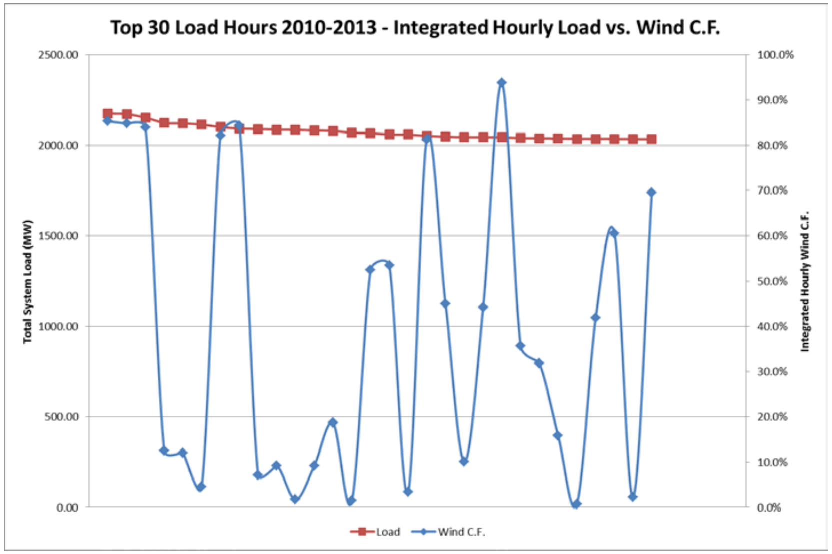
GE Energy ELCC vs. Wind Penetration curve is similar to the one derived by NSPI using similar LOLE methodology.

NOTE: The incremental values plot is equivalent to the plot in GE Energy study Figure 220.

Challenges applying LOLE methodology to NSPI's system

The graph below shows the 30 highest load hours over the past 4 years and the coincident available wind capacity during those hours.

In this plot it can be seen that while wind generation may be present at near nameplate capacity during some high load hours, it may not be there at all in other high load hours. While the hourly capacities shown here may average to a large figure, that ELCC would not adequately represent the true system operating requirements. In fact, in 1/3 of the peak load hours shown here wind generation is at 10% or less.



This bi-modal wind generation behavior makes the inherent averaging LOLE method of calculating capacity value of wind, with matched load –wind shapes, rather optimistic.

The risk of overstating capacity value of wind is designing a system with inadequate firm capacity to serve load in all peak hours.

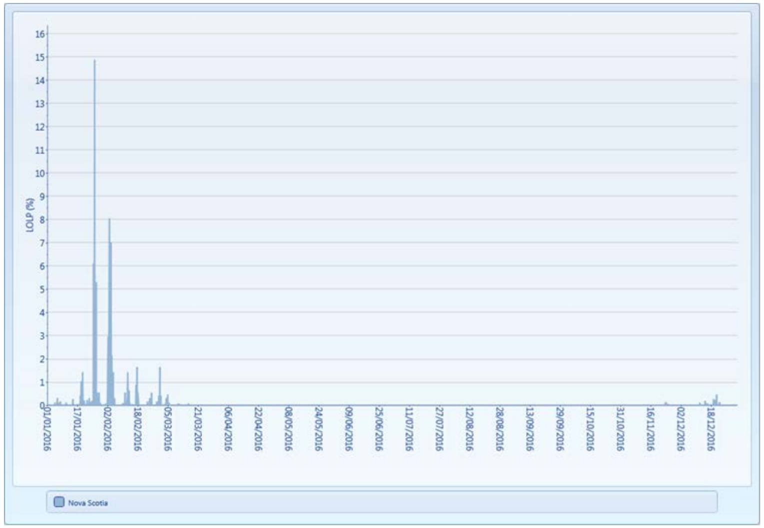
Challenges applying LOLE methodology to NSPI's system

LOLE is inherently an averaging quantity:

LOLE = Average (LOLP)/100*8784/24

Where LOLP = Loss of Load Probability

As such LOLE quantity does not adequately preserve the high LOLP values impact on the system. The plot below is an example of the LOLP distribution throughout a year and it illustrates why averaging of LOLP quantities into an annual LOLE quantity may not be the best method for calculating NSPI's capacity value of wind.



Effective Load Carrying Capacity of Variable Generation

Cumulative Frequency Analysis

Capacity Value of Wind – Empirical Analysis

- Objective: To determine what minimum capacity factor of wind we can predict to be available to the NS Power system, in peak hours, with *x*% certainty

- Methodology: **Cumulative Frequency Analysis** is the technique of analyzing a set of historical data points to see how often a particular value is exceeded
  - Other systems including CAISO, BPA, & SPP use variations on this approach

Cumulative Frequency Analysis - Procedure

1. Collect as much logged data on wind generation as possible
   - Using data in terms of hourly Capacity Factor allows us to consider a longer history, over which installed wind capacity has grown
2. Assign that data into bin(s) we are interested in
   - Single bin containing the top 10% of load hours
3. Fit a probability distribution to the data
4. Calculate the inverse cumulative probability for the confidence level *x*; this is the value we have (1-x)% chance of being less than according to the fitted distribution (and therefore x% chance of exceeding)

Cumulative Frequency Analysis - Data Sources

- Integrated hourly generation (MWh) for the following wind farms (299.6 MW):
  - Covers 94.6% of installed capacity at end of 2013
    - Pubnico
    - Gulliver (Digby)
    - Nuttby
    - Dalhousie
    - Maryvale
    - Glen Dhu
    - Bearhead
    - Lingan
    - Amherst
- Study period was 4 full years 2010-2013
- Data was cleaned to remove commissioning periods
- Any hourly value reported above max station capacity was reduced to that of max capacity

Cumulative Frequency Analysis – Key Assumptions

- Data within each bin are from a single population
    - No significant differences caused by increased diversity in later years of study period as additional wind farms come online
- Historical performance is representative of our future expectations for wind generation

Cumulative Frequency Analysis - Results

- Within the top 10% of load hours, 2010-2013:

Confidence level	ELCC of Wind Generation
95%	4%
90%	8%
85%	12%
80%	16%

Required Planning Reserve Margin

Required Planning Reserve

Methodology:

1. Wind energy is substituted with firm equivalent generation

2. If LOLE is < 0.1 days per year, firm system demand will be added until LOLE is = 0.1; Total installed capacity minus added load is the required capacity for LOLE of 0.1

3. If LOLE is >0.1 days per year, firm capacity will be added until LOLE = 0.1; Total installed capacity plus added firm capacity is the required capacity for LOLE of 0.1

Planning Reserve Margin = (Required Generation Capacity – Peak Load) / Peak Load

NOTE: If actual wind generation, rather than firm equivalent, was included in the calculation of the planning reserve margin, a decision would have to be made on the capacity value of wind, in order to calculate the required planning reserve for 0.1 LOLE.

As such, the calculation provides the firm planning reserve margin requirement, part of which can be served by wind generation, depending on the calculated capacity value of wind.

Required Planning Reserve

Planning reserve requirement calculation is based on the NPCC accepted criterion of loss of firm load no more that 1 day in ten years or 0.1 days per year. This means that the system planning reserve is such that it allows the system to fail to meet peak system demand on the average for 2.4 hours every year, on average.

Methodology: Adjust capacity on the system to produce LOLE of 0.1 days per year.

MW	2016	2020	2025
Firm Peak Load Forecast [MW]	2011.2	1991.2	1966.9
Required capacity for 0.1 days LOLE [MW]	2390	2372	2362
Total Planning Reserve Requirement	(2390-2011.2)/2011.2 =378.8/2011.2 =18.8%	(2372-1991.2)/1991.2 =380.8/1991.2 =19.1%	(2362-1966.9)/1966.9 =395.1/1966.9 =20.1%

2016 – no Maritime Link (ML) – no thermal retirements
2020 – with ML both base & supplemental blocks – One Lingan unit retired
2025 – with ML base and no supplemental block – no additional steam retirements

Study Discussion, Conclusions and Recommendations

Planning Reserve Margin Risks with Wind Capacity Factor

The cost of under- or over-estimating the capacity value of wind is asymmetrical. Over-estimating the capacity value of wind and then operating the system accordingly could result in inadequate resources to meet peak system demand. That situation has much more severe consequences than under-estimating wind resources capacity and having more than adequate resources to meet peak demands, particularly as NSPI is a winter peaking utility.

There are uncertainties associated with load growth. For example, we have seen the highest system peak firm load in history in January 2014, which adds to the importance of carrying adequate planning reserve margin .

The planning reserve margin can be compromised by assigning a high capacity value to wind generation in the planning process. For example, a 27% capacity value for committed wind generation of 550-600 MW means that ~150-160 MW, or 40% of the required planning reserve, may or may not be available depending on the wind generation output.

Furthermore, there is uncertainty associated with the integration of ~550-600 MW of committed wind capacity on the system from 2016 onward.

Study Conclusion and Recommendation

The required planning reserve margin was confirmed to be 20%, consistent with the assumption used in previous long term studies.

Due to the nature of wind generation in Nova Scotia, the LOLE averaging methodology may overstate ELCC of wind generation, if a careful examination of risk is not allowed for.

Cumulative frequency analysis of existing wind generation data shows the capacity value of wind generation within specified risk levels and can be used as a qualifier of the LOLE results.

In order to be able to design the system with adequate resources to maintain system reliability, the study indicates an appropriate capacity value for wind resources is 12%, taking into account the empirical data analysis results and a reasonable level of risk.

Even though the LOLE methodology had to be qualified by the empirical analysis in order to determine the absolute ELCC of wind generation, the relative slope of the ELCC vs. Wind Penetration curve can be used to calculate the ELCC of future wind generation additions.

IRP Wind Capacity Value Assumptions

- For this long term-planning exercise, two different wind capacity value constructs will be used to test Candidate Resource Plans:
    - Existing and incremental values per the GE Study (page 266), 27% cumulative capacity value up to ~545 MW, and lower incremental values beyond 545 MW;
    - 12% capacity value as determined by the cumulative frequency analysis study.

Appendix 1

Study Assumptions

System Assumptions

REQUIRED SYSTEM ASSUMPTIONS FOR THE LOLE STUDY

- WIND FORECAST / HOURLY WIND SHAPE
- LOAD FORECAST / HOURLY LOAD SHAPE
- UNAVAILABILITY OF VARIABLE GENERATION
- DAFOR (DERATION ADJUSTED FORCED OUTAGE RATE) FORECAST
- CAPACITY ADDITIONS/ RETIREMENTS
- MARITIME LINK AND NB IMPORTS CAPABILITY
- FLEET MAINTENANCE SCHEDULE

System Assumptions – WIND

Wind shape:
Use AWS Truepower wind shape, based on 2006 wind speed measurements as provided by GE Energy.

Wind Forecast:
IRP wind forecast including COMFIT.

Unavailability of Variable Generation:
Unavailability due to transmission congestion, icing, forced outages, wind over speed, etc… will be represented by a 5% forced outage rate applied to all variable generators. This value is consistent with literature and with common practice among other jurisdictions.

System Assumptions – SYSTEM DEMAND

System demand without PHP will be used in this study. In order to calculate capacity value of wind and required planning reserve margin, it is irrelevant whether PHP demand is on the system or not. PHP demand is only relevant when calculating absolute system LOLE.

The LOLE study was conducted with 2006 load shape in order to match load to the AWST wind shape which is based on 2006 measurements.

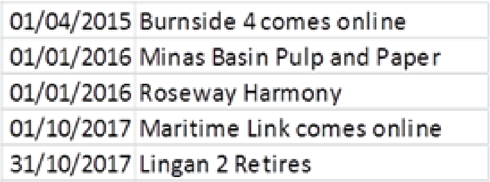
System Assumptions – CAPACITY

Deration Adjusted Forced Outage Rate

Use DAFOR based on historical plant performance values for thermal plants.
Use 5% DAFOR for wind and hydro generation.

Methodology:
Plexos uses convolution method, as opposed to Monte Carlo Stochastic method, to calculate ELCC of generating units as a part of the LOLP/LOLE indices computation.

Capacity Additions and Retirements:



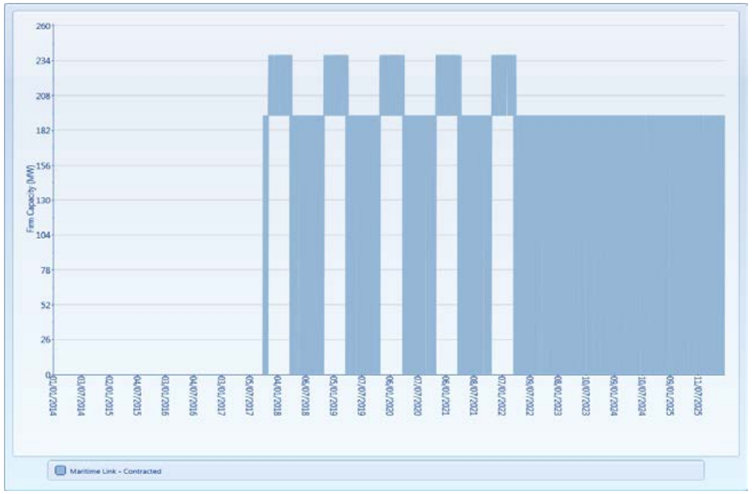
01/04/2015	Burnside 4 comes online
01/01/2016	Minas Basin Pulp and Paper
01/01/2016	Roseway Harmony
01/10/2017	Maritime Link comes online
31/10/2017	Lingan 2 Retires

Maintenance

Generating fleet maintenance schedule will be the same maintenance schedule used in the IRP simulations.

System Assumptions – MARITIME LINK

Maritime Link is assumed to be able to provide maximum contracted firm capacity of 153 MW for the Nova Scotia Block, and 198 MW for the Supplemental Block. The Surplus ML energy will be considered as non firm and thus having no capacity for the purpose of this study.



NB Imports

NB imports will be modeled with no firm capacity for the purpose of LOLE study.

Appendix 2

Examples of ELCC Calculation Methodologies and Results in Other Jurisdictions

ELCC Calculation Methods Used in Different Jurisdictions

Jurisdiction	Methodology Category	Calculation Details	Values
SPP	Peak Period - Percentile	Monthly Capacity Value: 85th Percentile of Wind Generation on Top 10% of Load Hours (up to 10 Years of Data)	
CAISO	Peak Period - Percentile	Monthly Capacity Values: 3-Year Average of Wind Output Equal or Exceeding the 70th percentile, 1pm - 6pm: Apr– Oct / 4pm - 9pm: Jan - Mar and Nov – Dec.	
Bonneville Power Administration	Peak Period – Percentile	Monthly capacity factor during summers 2003 to 2008, only considering 85th and 95th percentile values.	0%
ISO-NE	Peak Period - Median	Summer: 5-Year Average of Median Wind Output, 2pm - 6pm, Jun - Sep Winter: 5-Year Average of Median Wind Output, 5pm - 7pm, Oct – May	Summer Peaking Winter period values high twenties (%).
Ontario IESO	Peak Period - Median	Probability Distribution of Median Wind Output for Modeled (10 Years) and Actual (7 Years) Wind Output Data [Smallest of the 2 Data Points Used each Time]. One Distribution for Summer, One for Winter, Monthly for Shoulder Months. Wind Output for Top 5 Contiguous Daily Peak Demand Hours.	On Summer Peak: 13.6% Winter period (Dec-Feb) values: ~33.4%
NYISO	Peak Period - Average	Summer: Previous Year's Wind Capacity Factor, 2pm - 6pm, Jun - Aug Winter: Previous Year's Wind Capacity Factor, 4pm - 8pm, Dec – Feb	Default Summer: 10%(onshore), 38%(offshore) Default Winter: 30%(onshore), 38%(offshore)
PJM	Peak Period - Average	3-Year Average Wind Capacity Factor, 2pm - 6pm, Jun – Aug	Default: 13% (summer)
BC Hydro	ELCC	Based on synthesized hourly wind data.	24% (onshore & offshore wind)
ERCOT	ELCC	Based on random wind data, not synchronized with load.	8.7% (summer)
Midwest ISO	ELCC	Average ELCC over 7 previous years considered.	14.1% (2014 planning yr), 13.3% (2013 planning yr), 14.7% (2012 planning yr), 12.9% (2011 planning yr)
Quebec Balancing Authority	ELCC	Wind power time series obtained from meteorological data supplemented by analysis of extreme cold weather events.	Winter: 30%

Sources:
NERC. *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning,* March 2011. http://www.nerc.com/files/ivgtf1-2.pdf
NREL. *Summary of Time Period-Based and Other Approximation Methods for Determining the Capacity Value of Wind and Solar in the United States September 2010–February 2012.* NREL/SR-5500-54338, March 2012. http://www.nrel.gov/docs/fy12osti/54338.pdf

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Variable Generation Integration Costs

Executive Summary

The addition of variable generation (wind and solar) to the electrical system introduces additional costs associated with unit dispatch and commitment, system reserves and capital investments. These additional costs the utility incurred due to addition of variable energy sources are called: Variable Energy Integration costs.

Modelling of NSPI's 2020 system (current system plus committed wind plus Maritime Link, but excluding other new infrastructure) indicates that operational dispatch costs associated with integration of variable energy on the NSPI system would increase sharply after 550-600 MW of wind generation reflecting dispatch challenges, absent new capital infrastructure.

Experience with the characteristics of wind generation on the system and wind forecasting suggests that the existing and committed 550-600 MW of wind generation, and any further increases, will increase operational reserve requirements. The extent of such increases will depend on many factors, including wind forecast error. The system must have adequate reserves to ensure reliable operation, and the planning exercise must include an estimate of such reserve requirements.

In order to maintain system reliability, new capital investments will be necessary to integrate more variable generation on the system past 600 MW. The capital investments will address needed requirements for fast acting firm capacity, system inertia, reactive power support, primary and secondary frequency response and other system reliability requirements. In addition, they mitigate some of the operating cost increases.

Executive Summary

Quantifying Variable Generation Integration Costs

Integration costs vary depending on the level of variable generation penetration and system characteristics, and thus it is not possible to provide a single integration cost figure to cover all scenarios.

Variable generation integration costs will be included in the analysis of resource plan costs by considering the following:

1. Operational Dispatch Costs
2. Capital Investment Costs
3. Additional Reserve Requirement Costs

Operational dispatch costs reflect costs associated with generating unit operation at lower heat rates, unit starts and stops, and unit commitment optimization. Estimates for these costs absent incremental infrastructure have been derived using simulation software.

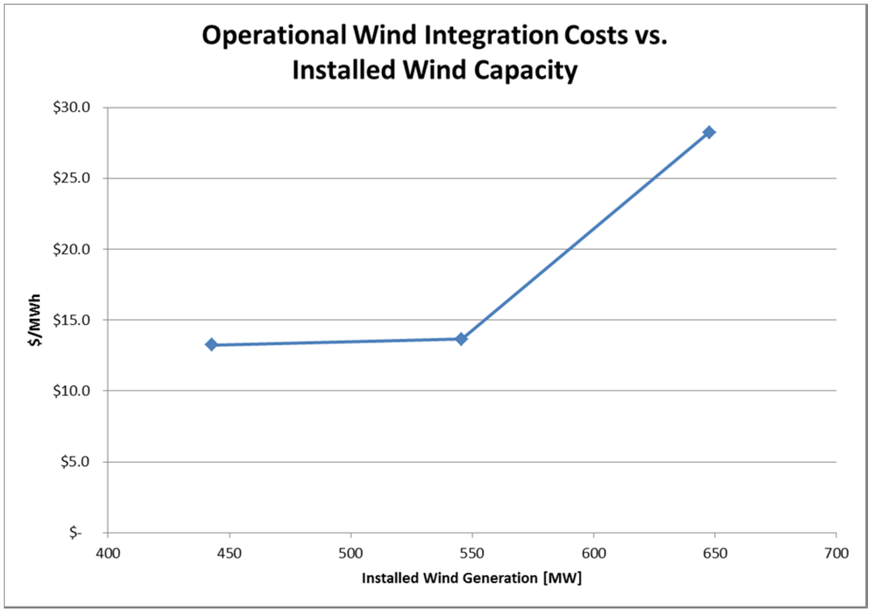
Capital investments for system upgrades are necessary to support reliable system operation for additional variable generation above the existing and committed 600 MW. A profile for the capital investments required for incremental variable generation will be derived to complete the template table that follows.

The cost of additional, non-contingency reserves will not be directly factored into this analysis, but is reflected to some extent in the capital investments discussed above.

These cost elements have interrelationships that should be considered. For example system upgrades required to integrate additional renewable generation could be expected to lower the operating portion of integration costs. To account for this NS Power proposes to redevelop operational dispatch cost estimates based on the capital investments that are assumed for incremental additions of variable generation.

Executive Summary

Operational Dispatch Costs



The sharp increase in the operating portions of variable generation integration costs indicates stress on the current power system. Graph shows costs in 2020 dollars per MWh.

Simulations conducted in this study, supported by conclusions in the GE Energy Renewable Energy Integration Study, suggest that the maximum quantity of wind generation that can be reliably integrated on the presently forecasted 2020 system configuration is 550-600 MW.

The operating portion of wind integration cost presented here does not include the effects of capital investments made for system reliability, which are expected to lower this cost and will be calculated on a case by case basis.

Executive Summary

Capital Investments to Support Variable Generation Integration

600 MW + Required Technology - roughly in order of lower to higher cost	50 MW (650 MW)	100 MW (700 MW)	150 MW (750 MW)	200 MW (800 MW)	250 MW (850 MW)	300 MW (900 MW)	Estimated Cost Range / Notes
Minimum requirements for wind turbine characteristics							TBD?
Reactive power support (SVC, Synch Cond, Cap Bank)							$15 - $35 million
NS Transmission other than Link reinforcements							TBD?
Incremental existing hydro storage/capability (eg Wreck Cove, Mersey system)	Some of the costs associated with this incremental investment may be included in all resource plans.						TBD?
Firm fast acting capacity – CTs or CCs							$50 million per 45MW, 45-135 MW need
Additional Reliability Tie to NB							$170 million
Other Energy Storage							$135 million per 50 MW, 50-100 MW need

The table above is a template of capital projects which will enable integration of further variable intermittent generation. The table will inform candidate resource plan development as the necessary system upgrades will be included in the model representation for each plan involving variable generation additions to the system. Additionally, these same capital investments will be used to redevelop the operational dispatch costs on a plan by plan basis. In this manner, NS Power expects to properly reflect the costs and the benefits of any system upgrades on variable generation integration costs.

Additional Study Information

Study Methodology

Variable energy integration costs consist of:

1. Operational Dispatch Costs
2. Capital Investment Costs
3. Additional Reserve Requirement Costs

All three aspects of the variable energy integration cost will be addressed individually.

Once candidate resource plans which contain incremental additions of variable generation are developed with respect to resource location and timing, the scenario specific operating portion of integration costs can be calculated by including the capital investments to support variable generation integration in the simulation.

Study Methodology –

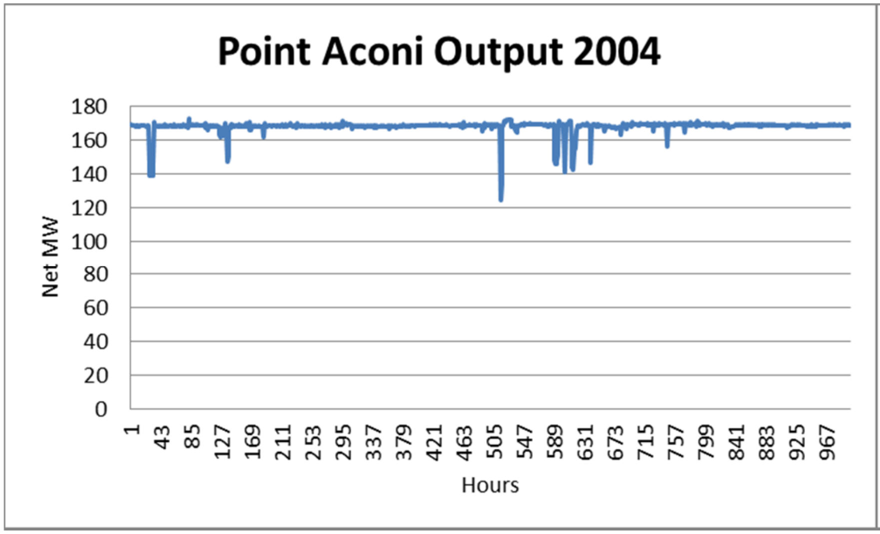
Operational Dispatch Costs

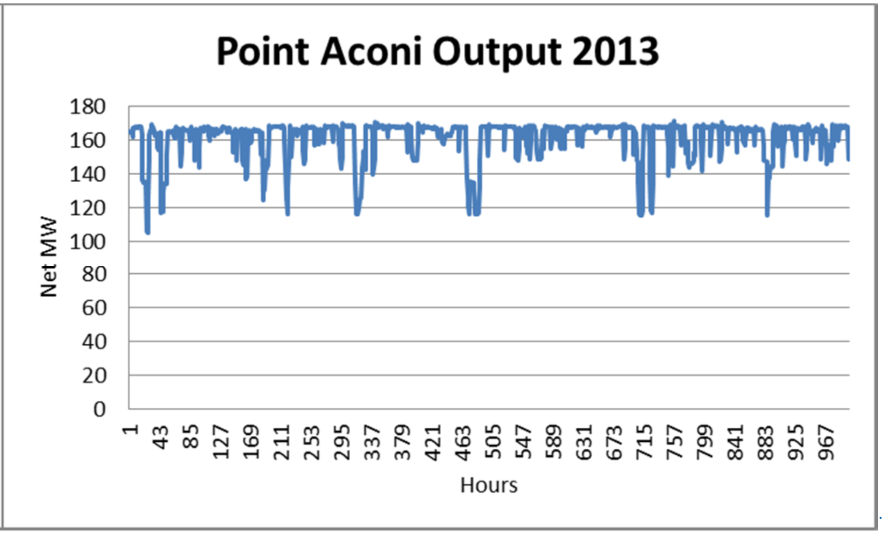
- In order to profile operational integration costs of variable generation increases a series of comparison simulations was conducted (for 2020, assuming the existing system plus Maritime Link) in which variable non-dispatchable generation was replaced with equivalent dispatchable generation (i.e. generation of the same capacity but whose limited monthly energy could be dispatched most cost effectively). This simulates how variable, non-dispatchable generation affects the overall system operating costs associated with unit operation at lower heat rates, unit starts and stops, and unit commitment optimization.

- These operating cost simulations did not consider:
  - additional non-contingency reserve requirements
  - additional reliability mitigating resources additions
  - additional maintenance costs associated with unit ramping and 2-shifts

Introduction – Examples of Variable Generation Impact on System

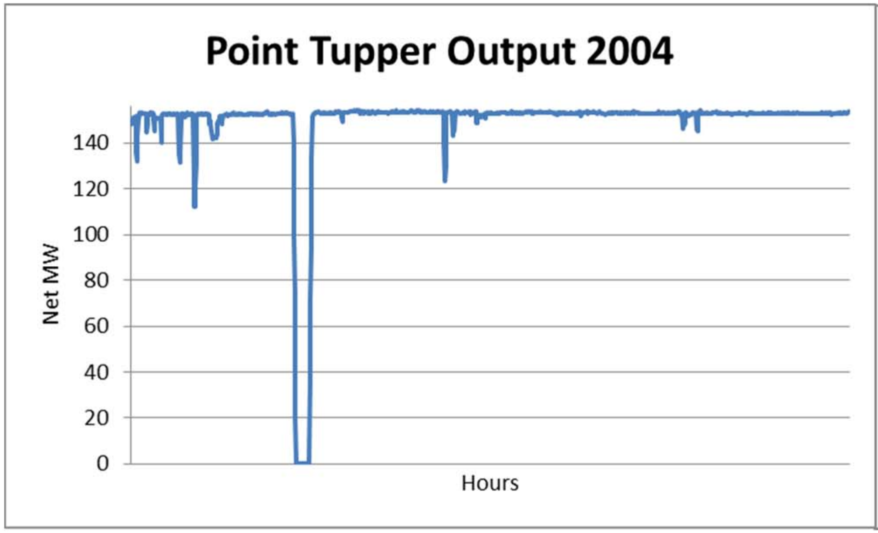
- The example below shows Point Aconi hourly generation for the first 1000 hours in two different years; 2004, with little wind generation on the system, and 2013 with approximately 300 MW of wind generation.
- In the 2013 Point Aconi is frequently seen to be operating in sub-optimal regions largely to accommodate the variability generation.
- Operating in sub-optimal regions will incur costs in the form of higher realized heat rate and resulting higher fuel consumption as well as wear and tear of the unit components.
- Similar pattern has been observed on other generating units, but Point Aconi was picked as an example of a unit which by design (related to sulphur capture technology) is not well suited to such mode of operation.

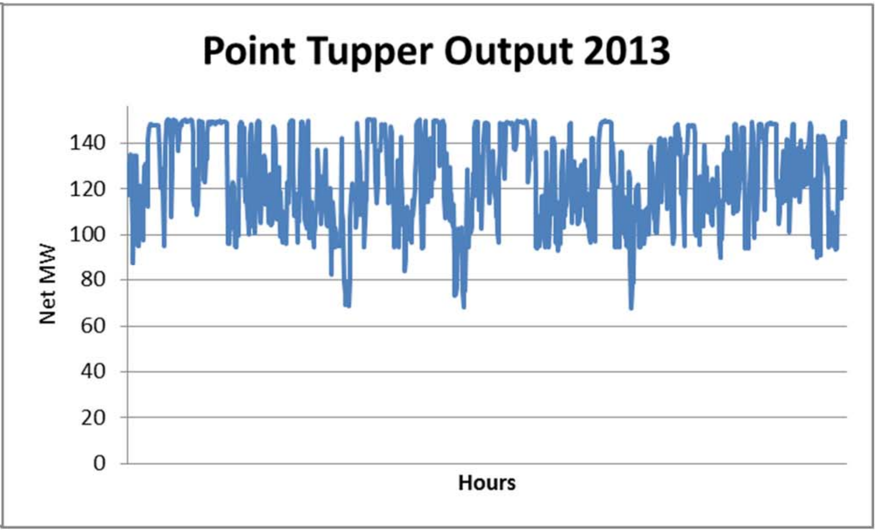




Introduction –
Examples of Variable Generation Impact on System

- A more pronounced contrast in the way steam units on the NSPI system are being dispatched to follow variable generation can be seen at Point Tupper. As in the previous example, we see that the unit seldom operates steadily at full output, which has an effect on average realized heat rate as well as wear and tear of the unit components.

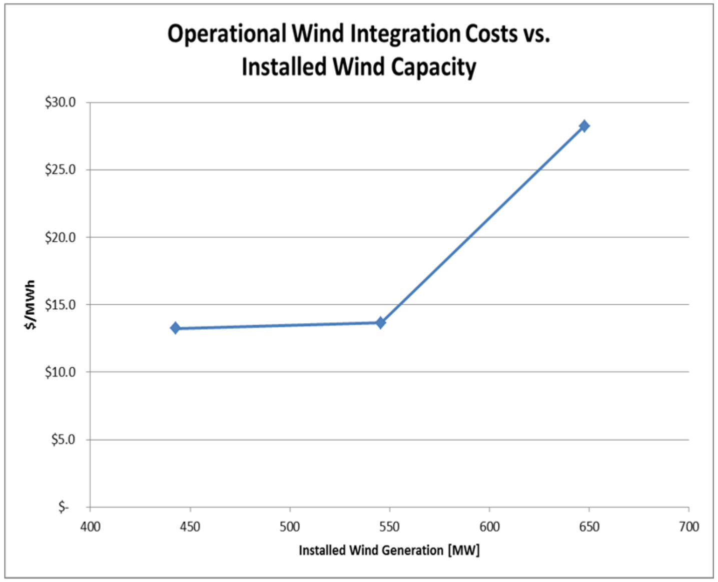

Point Tupper Output 2004


Point Tupper Output 2013

Operational Dispatch

System Costs

Wind Penetration Level [MW]	Incremental Operating Integration Cost [$/ MWh]
650	28.2
550	13.7
450	13.2



Operational costs of integration wind energy on the system result from steam generating unit heat rate degradation - as described on the previous slides, increased number of starts and stops, wind and hydro energy curtailment, etc.

The modeling work shows that the cost of integrating wind generation up to 550 MW is in the range of $10-$15/MWh, which is consistent with the assumptions used in the studies leading up the integration of 550 MW of wind generation .

The cost of wind generation integration past 550 MW increases, with the simulation showing dispatch challenges associated with integrating this quantity of wind, indicating that additional system reliability mitigating measures will be required as we integrate more than 550 MW of wind generation.

NOTE: The integration cost figure for 650 MW of wind generation is only an indication of sharply increasing integration costs at present system configuration plus Maritime Link. The simulation producing this figures did not include any system reliability mitigating measures, such as additional ties or firm capacity. Integration costs used in simulations will be re-calculated for specific candidate resource plans reflecting the operational benefits of any capital investments made to support further variable generation additions.

Operating Reserve Requirement

- Additional operating reserve requirements were not considered in the modeling of operational dispatch integration costs.

- GE Renewable Energy Integration Study shows that additional 10-minute reserve will be required to integrate large quantities of wind generation: *"The wind variability adds to the short-term variability of net load (load minus wind), which requires following with synchronized reserve. This additional synchronous reserve requirement is above and beyond the synchronized contingency reserves or Regulation Up and Regulation Down since most variations should not impinge on the contingency reserves. The grid operator needs guidance, in advance, to set and hold these incremental reserves."*

  (Page 64 GE Renewable Energy Integration Study)

- The discrete cost of 10-minute reserve additions is difficult to estimate since it may result in the requirement to add additional capacity. GE Energy estimates that NSPI will have to carry additional 32 MW of non synchronous 10-minute reserve in order to integrate ~600 MW of wind generation, and additional reserve for further variable generation. A estimate for this cost was not prepared for this integration assumption set.

Capital Investments to Support Variable Generation Integration

- Since much of the flexibility in the existing power system plus Maritime Link has been consumed by the variable generation existing and committed, some combination of resources indicated on slide 5 – including possibly new fast acting generation - will be needed in order to integrate additional wind generation past the already committed 550-600 MW. Additional flexibility obtained with the addition of the Maritime Link will be included in resource scenario modeling.

- The new capacity is needed to address challenges in:
  - additional replacement reserve
  - wind forecast error reserve
  - wind following capability
  - system stability

Capital Investments to Support Variable Generation Integration

- It is difficult to estimate the exact level of wind penetration at which the system starts to experience instabilities. System modelling indicates that operating cost rises past 550-600 MW of wind generation. This coupled with violations of system constraints within the Plexos modeling conducted to date suggests that the system is experiencing difficulty integrating larger quantities of variable generation with the existing balancing resources.
- Furthermore, system dispatch simulations show system constraints violations with incremental 200 MW past 550 MW of installed wind generation, which indicates that there is a problem with system stability at this level of wind penetration, even with hourly simulation granularity which assumes average hourly wind generation and system demand, without considering sub hourly fluctuations.
- For the purpose of this study, we may assume (based on Plexos analysis to be performed) that additional fast acting firm capacity will be required to reliably integrate wind generation past the presently committed 600 MW. We will first analyze the system with anticipated incremental flexibility available from the Maritime Link, possible incremental hydro improvements, demand response resources, and internal transmission improvements.

Capital Investments to Support Variable Generation Integration

At a wind penetration level somewhere above 600MW, an additional 345kV line to New Brunswick may be required to ensure NS system stability, depending on the extent of infrastructure investment (e.g. (but not limited to) increased amounts of fast-start generation). The threshold wind penetration level will be difficult to determine with certainty, but the modeling exercise will aim to create increased wind penetration scenarios up to, and then above this level, including the costs of a 2nd tie for the highest level of wind penetration to be studied.

If the single tie to NB trips, and NS is separated from NB with a high percentage of wind generation, reliability standards require the re-dispatch of the system to survive the next contingency within 30 minutes. System studies have shown the NS system would collapse under such conditions. A properly configured second tie would minimize the probability of this configuration. It should be noted, however, that transmission configuration inside NB may require further upgrades to meet this goal.

At a certain (currently unknown) level of higher wind penetration, it is possible that additional energy storage will also be needed to effectively use the energy from incremental wind additions. Whether or not this is required will depend on the overall level of system “flexibility” which is based in part on the set of resources in place in the modeled resource scenario. We will determine whether or not a storage resource (incremental to other infrastructure improvements) will be required as part of the modeling of higher wind penetration scenarios.

Internal Transmission Reinforcements

Displacement of conventional generation with wind generation will require augmentation of the characteristics of the displaced generation to maintain system reliability. Wind generation is, in theory, capable of providing some of these features, but they are not "off the shelf" and are not available from all wind generation suppliers.

Unit inertial response, high speed reactive power control, system frequency control, synchronized operating reserve, system black-start capability, under-frequency load shedding programs, and short-circuit ratio are all considerations that will raise the cost of future generations of wind turbine technologies. These necessary "ancillary services" currently provided by conventional generation can be augmented by external devices such as Static VAr Compensators, Statcom, synchronous condensers, and other Flexible AC Transmission Systems (FACTS) devices.

It may not be possible or feasible to retro-fit existing wind farms with such controls. Depending on which additional infrastructure investments are considered in place in different resource scenarios, future wind farms may need to be specified with some combination of these types of auxiliary equipment to permit higher wind generation penetration levels.

It is anticipated that SVC and/or synchronous condensers will be needed at Tupper, Onslow, and in HRM. The proposed reactive power support solutions are chosen for being more cost effective than building new generation and /or transmission while still enabling higher energy transfer.

Nova Scotia POWER
An Emera Company

Memorandum

Date: **March 14, 2014**
To: **IRP Intervenors**
From: **NS Power**
Subject: **2014 IRP Analysis Plan**

The Analysis Plan was briefly discussed during the technical conference and it is important for stakeholders to consider since it describes the IRP modelling process. Specifically, it describes how the resource plans and future scenarios (worlds) to which the input assumptions will be used in modeling. The Analysis Plan strives to;

i. identify candidate resource plans, including the least cost plan under the Reference World
ii. identify a reasonable range of foreseeable futures,
iii. evaluate the candidate plans including least cost plans across that range of futures and
iv. select the Preferred Resource Plan.

NS Power has developed the following analysis plan in line with IRP best practices and will continue to refine its plan based on feedback from Synapse and Stakeholders. The Company suggests the 5 following steps:

1. **Candidate Resource Plans**
   a. Develop a set of candidate resource plans under the Reference World. Begin with a broad range of draft resource plans, each developed based on existing resources and high-level screening of possible resource options.
   b. Optimize each draft resource plan under the Reference World using Strategist. The optimizations would include the resource options that pass the high level screening. The results from Strategist will be candidate resource plans. The results will indicate the relative cost of each resource plan.

2. **Candidate Resource Plan Evaluation**
   a. Run sensitivity tests under the Reference World on each candidate resource plan from step 1. Strategist may need to re-optimize certain of the resource plans under certain of the sensitivity tests in order for those plans to meet all reliability and regulatory constraints..

3. **Scenario Testing ("Worlds" Development)**
    1. Develop additional "Worlds" and sensitivities for further evaluation of the candidate resource plans (a World is a combination of key assumptions and constraints). This step includes Worlds of interest to NSPI, Synapse and Stakeholders.

4. **Evaluation and Optimization**
    1. Evaluate the candidate resource plans from step 1 under the different Worlds and sensitivities. Strategist may need to re-optimize certain of the resource plans under certain of the different Worlds in order for those plans to meet all reliability and regulatory constraints.
    2. The results will indicate the expected relative cost of each resource plan.

5. **Preferred Resource Plan Development**
    1. Evaluate performance of resource plans across Worlds and select Preferred Resource Plan.

At this point NS Power will have tested and optimized a number of candidate resource plans across a range of foreseeable futures, i.e. "Worlds" based on stakeholder feedback and consultation with Synapse. NS Power would select its Preferred Resource Plan from among those candidate plans. The Preferred Resource Plan should have the flexibility to enable NS Power to meet customer demand and energy requirements, and environmental obligations in a cost-effective, safe and reliable manner across a reasonable range of foreseeable futures. This should enable development of an Action plan for the next 5 years that reflects the type of "course corrections" that may be required depending on how the world (e.g., net load, emissions targets, RES requirements) unfolds.

Memorandum

Date: **April 11, 2014**
To: **IRP Intervenors**
From: **NS Power**
Subject: **2014 Responses to Stakeholder Input on Basic Assumptions**

Introduction

On March 7, 2014, NS Power hosted a Technical Conference for participants at which it reviewed initial draft assumptions and discussed its preliminary thoughts on the analysis plan for the 2014 Integrated Resource Plan (IRP) to obtain feedback from participants.

On March 14, 2014, NS Power circulated draft basic assumptions for feedback. The Company also circulated additional assumptions details in response to requests from Larry Hughes, PhD., the Industrial Group and the Nova Scotia Department of Energy. A record of these communications can be found at the following link:

http://www.nspower.ca/en/home/about-us/electricity-rates-and-regulations/regulatory-

Participants provided written comments on the assumptions and analysis plan on March 26. Comments were received from:

1. Small Business Advocate
2. Consumer Advocate
3. The Industrial Group
4. Port Hawkesbury Paper
5. Ecology Action Centre
6. Efficiency Nova Scotia Corporation
7. Environment Northeast
8. Natural Forces
9. Scotian Windfields
10. NS Department of Environment
11. NS Department of Energy

NS Power and the Board staff and Board staff consultants reviewed the input received. In consideration of comments received, NS Power has made changes to the assumptions which will be modeled in the IRP. The Final Assumptions are provided at Appendix A. For responses to comments, questions and recommendations, please refer to the attached table provided at Appendix B.

Context for Responses

There were several issues raised across the stakeholder group. In some cases opposing views were presented. To provide context for some of the responses below, NS Power provides the following comments respecting integrated resource planning including references to the Terms of Reference approved by the NSUARB.

An IRP is a long-term (25 year) planning exercise that integrates supply and demand-side options to develop a long-term Preferred Resource Plan for the utility. The IRP is not an attempt to identify a Preferred Resource Plan that will meet those goals under a single particular future (e.g. a "world" with tight emission constraints, high gas prices, high load, low financing etc.) Instead, the purpose of the IRP is to identify the Preferred Resource Plan which will provide NS Power with sufficient flexibility to effectively accommodate a range of future uncertainties. As such, the Preferred Resource Plan and the Action Plan chosen to implement it must be robust, flexible, economic and sustainable. In the "Analysis Plan" stage of the IRP, NS Power will identify a Preferred Resource Plan that meets those goals in a balanced manner by evaluating a range of candidate resource plans across a range of worlds/scenarios and assumption values. NS Power will accomplish this by using its planning models to evaluate a reasonable, but not unlimited, number of candidate resource plans under a reasonable, but not unlimited, range of sensitivity analyses (i.e. resource assumption values) and worlds/scenarios (i.e., requirement / constraint assumption values).

Analysis Plan

As part of the Analysis Plan NS Power, in collaboration with Board Staff and Board Staff consultants, will identify the candidate resource plans, sensitivity analyses and worlds/scenarios for modelling and optimization. In order to complete its evaluations within the timeline approved by the NSUARB, NS Power expects that it will have to model a limited number of sensitivities and worlds that "bound" or "bookend" the wide range of possible permutations and combinations that have been suggested, including those suggested by intervenors. NS Power would be happy to meet with interested parties during the IRP process to discuss the Analysis Plan and modelling phase. In addition, NS Power will provide periodic reports to all stakeholders during the Analysis Plan stage.

Demand Side Management and Demand Response

As part of its development and evaluation of candidate resource plans NS Power will consider the High, Base and 50% of the Low levels of DSM in the Potential Study dated January 7, 2014 that ENSC filed with the UARB on January 14, 2014. NS Power will use the UARB-approved Total Resource Cost Test for input to these figures. NS Power also has committed to providing revenue requirement information without the customer cost component of DSM for stakeholder information. This will provide the information needed for discussion of the selection of the Preferred Resource Plan.

On April 7, 2014, the Province of Nova Scotia introduced Bill No. 41, Electricity Efficiency and Conservation Restructuring (2014) Act.[1] The Act, when passed, and the Regulations to be made thereunder, represent a significant shift in the approach to DSM in the Province. Just as the IRP is not a regulatory process that determines NS Power's capital spend or revenue requirements, the IRP is not a regulatory process to determine a DSM supplier's level, programs or evaluation tests. The proposed legislation requires NS Power to undertake cost-effective electricity efficiency and conservation activities that are reasonably available in an effort to reduce costs for its customers.[2] It provides that in order to meet this obligation NS Power must contract with the government's approved franchise holder for the supply of efficiency and conservation programs, and that such agreement must be approved by the UARB.[3] The Board shall approve NS Power's agreement with the franchise holder if it is satisfied that the conservation and efficiency activities that are the subject of the agreement are in the best interests of customers.[4] The Board's assessment of the proposed electricity efficiency and conservation activities for the purpose of the approval must take into account their

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[1] Bill 41, *Electricity Efficiency and Conservation Restructuring (2014) Act*, 1st Sess., 62nd General Assembly, Nova Scotia, 2014 (First Reading: April 7, 2014).

[2] Ibid, s. 79(I)(1).

[3] Ibid, s. 79(I)(2)(a)

[4] Ibid, 79(L)(8).

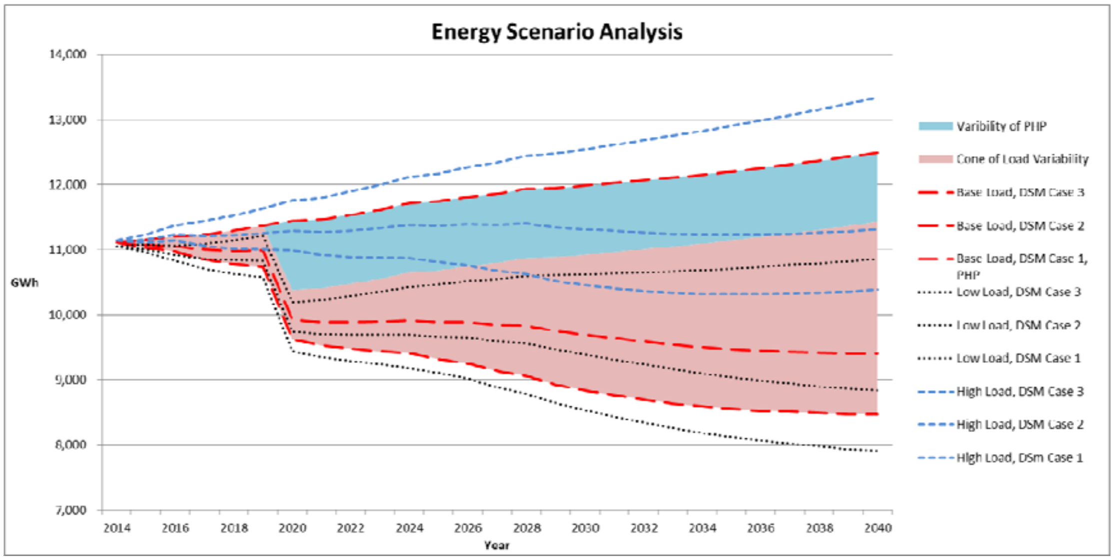
affordability to Nova Scotia Power Incorporated's customers, along with any other matters considered appropriate by the Board or as may be prescribed.[5]

Given the above, NS Power anticipates that the assessment of cost effective DSM potential will require evaluation as part of a regulatory process as part of or in anticipation of the proceedings to approve NS Power’s agreements with the efficiency and conservation franchise holder in the future.

Load Forecast

Load variability has been relatively constant in Nova Scotia for a number of years. The past five years have seen industrial load decline and partial renewal as well as residential load growth. There is significant economic opportunity and challenge on the horizon for Nova Scotia that will have implications on the load that NS Power has to serve. The graph below shows the load forecast range that NS Power will model to consider this uncertainty within the IRP. Of note is that of the possible combinations and permutations of potential load and DSM, all but two outliers are considered within the range of load assumed for IRP purposes.

Please refer to page 77 to 93 in Appendix A (the Final Assumptions Deck).



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[5] Ibid, 79(L)(9).

Emissions and RES targets

Scenario A of the IRP analysis represents emissions reductions that are aligned with the Province’s white paper on future emissions scenarios. The emissions caps proposed in the assumptions are slightly more stringent. The Company recognizes that we are in a declining emissions scenario, however customer representatives have requested that the IRP test the cost of these policy decisions. Scenario B will accomplish this.

There is also the potential that as sectors turn to electricity for their energy needs (e.g. automotive, home heating, industrial) credits may become available as total emissions decline. The Company has also added a Scenario C which will contemplate GHG reductions to 2.25 MT by 2040 as well as the associated reductions in other emissions from co-benefits.

For Renewable Electricity Standard (RES) requirements the Company is testing supply side options (wind, solar, imports etc.) that may result in greater renewable penetration and will model a world where greater than 40 percent RES is contemplated.

As noted above, NS Power’s Final Assumptions are attached as Appendix A. NS Power’s detailed response to all stakeholder comments is provided in Appendix B.

The Company would like to thank the working group and participants for their feedback.

#	Comment/Question	Party	Draft Response
Fuels Forecast			
General Comments/Questions			
1	Slide 52 shows percentages of likelihood (PIRA) for the Base, High, and Low case natural gas scenarios of 45%, 25%, and 30%, respectively. The further slides do not refer to these percentages and PHP assumes that there is no specific weighting given to the probability of occurrence of the three separate cases in the proposed analysis. PHP would appreciate confirmation, or an explanation of why and how these percentage figures are to be utilized in the analysis.	PHP	Correct. The percentage likelihood figures by PIRA are quoted by NS Power for information purposes only.
2	Slide 55 shows that for the natural gas Base Case (Expected), there is no premium for the periods 2018-2030 or 2030-2040. This appears to assume as a Base Case that the U.S. Northeast and Atlantic Canadian gas market structural issues are fully mitigated by 2018 for the entire Planning Horizon. What level of confidence does NSPI place on this assumption to the extent that it can utilize it as the Base Case, considering the occurrence of the current unexpected natural gas pricing conditions, the capital works required to address this issue, and the increasing upward pressure on natural gas demand in New England?	PHP	NS Power relies on PIRA who expect pipeline capacity additions in the NE US in the 2017 timeframe. By extending this timeframe to 2018 (in the Base Case) and employing two additional cases for fuel price development (High and Low), the Company is comfortable that market uncertainty with regard to pipeline capacity additions in the NE US is captured.
3	Slide 65 states that for domestic coal, the price source is NSPI current contracts. For the analysis, what constraints, if any, are placed on the amount/volume of domestic coal and its source (i.e. will the modeling be able to choose Donkin coal, for example, or only coal from the coal fields currently supplying NSPI)? If the model is constrained in this regard, PHP believes it will be important to do sensitivities around the utilization of other indigenous resources to the greatest extent possible.	PHP	With respect to domestic coal, NS Power assumptions reflect current supply contracts only (for the duration of the current contracts). NS Power will evaluate alternative scenarios by performing sensitivities.
4	Please provide the updated Slide 66 (Solid Fuel Pricing Assumptions) as soon as possible on the basis of the revised underlying fuel forecast. Please note any significant assumption changes in the revision.	PHP	Please refer to slides 66 to 70 in the final assumptions.

5	In order to better understand the impact of different fuel forecast assumptions, it would be helpful if NSPI would provide a graph comparing historic and forecast fuel costs over the planning horizon (in $/mmbtu) on a single graph. Where there are relative price differentials that diverge from historic differentials, it would be appropriate for NSPI to comment on the market (or other) assumptions that influence the change.	Industrial	Please refer to Figure D.
6	NSPI should consider using other fuel forecasts.	Industrial	NS Power considered the use of the EIA price forecasts but elected to rely on existing commercial relationships (such as PIRA and EVA) considering ready access to professional insight, support and visibility to underlying assumptions. NS Power's preferred third party providers' forecasts are in-line with EIA's expectations according to Annual Energy Outlook 2014 Early Release, Reference Case. Please refer to Figures B and C.
6a	In the 2014 US Energy Information Administration (EIA) forecast, the low oil price case projects flat oil prices to 2040 (flat in real terms – adjusted for inflation). Has NSPI considered a low coal forecast that holds coal prices flat, apart from inflation adjustment, for a significant portion of the IRP period?	Industrial	NS Power relies on EVA who have provided a range of potential outcomes for world coal prices (including a case of low (in real terms relatively "flat") prices). Further consideration will be given to lower coal prices during sensitivity analysis
6b	What coal market trends has NSPI observed recently that support coal forecasts included in the IRP assumptions?	Industrial	EVA's projections for a general "softening" of the market are consistent with NSPI's own observations or recent market trends.
7	Has NSPI considered the IRP impact if the assumptions regarding the installation of new natural gas pipelines are not met? What are the costs and risks associated with delay?	Industrial	NS Power is proposing to consider three distinct cases for natural gas price development in the NE US and is reasonably comfortable that market uncertainty will be adequately captured across scenarios. The high gas price case considers later implementation of additional pipeline capacity and the low earlier implementation. Please refer to item 2 for discussion on risk.
8	For the Solid Fuel Price Assumptions, can NSPI provide prices in real and nominal terms?	Industrial	Please refer to slides 66 to 70 in the final assumptions deck.

9	NSPI should examine whether capacity exists on the TCPL system to get gas from Wright to Maritimes & Northeast at firm tariff rates.	CA	The Company has examined this and understands that firm transport capacity is not currently available on the TCPL system from Wright to M&NP. TCPL has suggested that an expansion is possible, at Tariff Rates comparable to the current open season rates for Spectra and Tennessee Gas.
10	NSPI should provide more detail on the conversion of pipeline tariff rates into $/MMBtu used at Tufts Cove, given the fixed tariff charges and scheduling requirements.	CA	NS Power has used indicative $/MMBtu rates as quoted by pipeline project sponsors for new pipeline projects and historical costs (escalated where appropriate) for existing pipelines assuming similar volumes and scheduling requirements continuing in the future.
11	Scotian WindFields has the below comments regarding the Draft Assumptions for Fuel Price Forecast Assumptions, particularly for the long-term price forecasting for Natural Gas, Petroleum-based fuels and solid fuels. a. The Average Annual Increase of fuel pricing for Natural Gas between years 2015 and 2040, as presented in the Draft Assumptions (Slide 58) is between 2.4% and 3.1%. This is exceedingly optimistic consider that the Average Annual Increase of Natural Gas pricing between years 1991 and 2013/2014 was calculated at 5.5%.[5] b. The Average Annual Increase of fuel pricing for HFO and LFO between years 2015 and 2040, as presented in the Draft Assumptions (Slide 72) is between 2.3% and 3.59%. This seems exceedingly conservative as the Average Annual Increase of WTI crude pricing between years 1990 and 2013/2014 was calculated at 6.1%[6] and the Average Annual Increase of Heating Oil was calculated at 6.3%.[7] c. Based on the above presented historical data, we recommend that NS Power consider more appropriate energy inflation figures in the IRP Model.	Scotian WindFields	Further consideration will be given to lower and higher prices during sensitivity analysis. For its basic starting point, NS Power relies on the opinion of PIRA and EVA for the development of long term fundamental price forecasts including assumptions about price growth rates across a range of potential outcomes.
12	There appears to be an inconsistency among the natural gas forecasts, emissions costs and import price assumptions over the study period.	SBA	NSPI is not aware of any significant inconsistencies across fuel price assumptions.

13	The fuel cost assumptions should take into account the possibility of gas storage in the Province. There should be a scenario where we can avoid the winter spikes as we will have storage in the area to fill up during the summer months and withdraw in the winter months. Heritage Gas is already considering such an investment.	Natural Forces	The pricing impact of natural gas storage is expected to evolve within the range of the IRP fuel price assumptions and sensitivities. Storage is not currently available in NS but projects have been announced or are being pursued. These projects are uncertain and NSPI may procure natural gas storage subject to availability and extensive review by the Company and others, based in part on the results of the IRP study and NSPI's long term fuel source mix expectations.
	Carbon Pricing in Fuel/Import Prices		
14	Carbon costs should be counted and not only for U.S. imports so as to quantify the potential carbon price risk associated with the candidate resource plans.	ENE	All fuel price forecasts embed a cost of carbon as assumed by PIRA and EVA. These assumptions appear reasonable and within generally accepted market expectations. Nova Scotia carbon pricing is assumed to be incorporated as the costs required for the Company to meet the GHG cap.
15	High carbon pricing cases should explore prices well above 50$ a tonne by the end of the IRP timeframe and should be consistent with similar planning activities across North America.	EAC	NS Power relies on PIRA and EVA with respect to assumptions about the price of carbon, which appear reasonable and within generally accepted market expectations including those published by Synapse Energy Economics Inc. Please refer to Figure A.
16	Why is the assumption made that there is CO2 emissions limits or costs established for the reference natural gas forecast and not in either of the high and low forecasts?	SBA	The assumption regarding the cost of carbon (by PIRA) is common to the three cases for natural gas prices.
17	Scotian WindFields has the below comments regarding the Draft Assumptions for Carbon Pricing. Under the Case Development (Power) on Slide 60, it is stated that the assumed cost of Carbon is US$15/Ton CO2 in 2020, escalating to US$37/Ton CO2 in 2030. The values for cost of carbon provided in the Draft Assumptions are associated with imported power. If and how carbon pricing is applied within Nova Scotia is a very significant variable as well. a. The IRP model should consider the potential for NS Power to be required to pay a price on carbon emissions. Regarding the cost of carbon emissions specifically, we have drawn our analysis from a report commissioned by Synapse Energy Economics Inc. on November 1, 2013 - "2013 Carbon Dioxide Price Forecast". This study considered the carbon price information from the most recent IRP efforts of 28 utilities. With the Canadian	Scotian WindFields	Please refer to items 47 and 52.

	federal government's stated intention to harmonize carbon policy with the US and our economic interdependence, we feel it is reasonable to use US projections for Canadian pricing scenarios. We would request that the costs from this study for long-term carbon pricing be considered. The three key scenarios are itemized below: b. The Low Case forecasts a cost of Carbon at US$10/Ton CO2 in 2020, escalating to US$40/Ton CO2 in 2030.2 c. The Mid Case forecasts a cost of Carbon at US$15/Ton CO2 in 2020, escalating to US$60/Ton CO2 in 2030.3 d. The High Case forecasts a cost of Carbon at US$25/Ton CO2 in 2020, escalating to US$90/Ton CO2 in 2030.4		
Load Forecast			
18	The Department appreciates the need for an accurate model to define the base case load forecast, however the Department respectfully suggests that the proposed scenarios do not show the levels of variance required to ensure that all reasonable futures will be included in the modeling. The proposed residential forecast in particular is extremely narrow in scope and the department believes that a much wider range should be considered; ideally at least +/- 15% of the base case for each customer class.	Dept. of Energy	The proposed scenarios are based on assumptions similar to those used historically to create a range of possible load requirements for the province. When DSM is added to the various load scenarios a cone of load variability emerges with enough scope to sufficiently cover a broad range of reasonable future load scenarios, please refer to the final Load Forecast assumptions.
19	The low forecast should assume flat or declining industrial load.	SBA	The large industrial class is where most of the loss of industrial load has come from in recent history. The forecast for this class is decreased by 40 GWh in 2016 and held flat throughout the rest of the forecast. Additionally the requirement to serve some of the municipalities' industrial load is decreased by the integration of the Ellerhouse wind farm into the forecast. The industrial load growth is being driven by the small and medium industrial classes. These are derived from the Conference Board of Canada's forecasts for provincial GDP and Manufacturing related GDP, both of which show an increasing trend.

20	It would be helpful if further details were provided on the assumptions that go into developing the end use model base case load forecast.	Dept. of Energy	Further details on the end use model are included on slides 85 to 93 in the Final Assumptions slide deck.
21	Can NSPI explain how the total industrial forecast is so closely aligned to the medium and small industrial forecast? Wouldn't the flat large industrial forecast impact the overall industrial load projections?	Industrial	Because the large industrial forecast is held flat the only year over year change to the industrial sector load is from the small and medium industrial classes. Currently approximately 50% of industrial load comes from the small and medium industrial classes and 50% is from the large industrial class. Since small and medium industrial load is forecasted to grow, while load is forecasted flat for the large industrial class, small and medium industrial load as a percentage of total industrial load will grow for the duration of the forecast. As a result, year over year change in the industrial load forecast is closely aligned with the small and medium load forecast.
22	Can NSPI speak to what changes had occurred in the past year such that the ML base load case is included in the IRP assumptions as the High Scenario?	Industrial	There has not been any change in the past year to cause the Company to significantly alter its load assumptions. The naming of the load scenarios was a point of debate during the Maritime Link hearing and NS Power has adjusted the naming of its load assumptions to reflect the positions taken by stakeholders in the Maritime Link hearing. This change is not philosophical in nature but rather meant to provide clarity.
23	Will NSPI provide a scenario in which PHP is not on the Load Retention Tariff for the duration of the IRP period?	Industrial	In the base and high load scenarios where PHP remains in operation beyond 2019 it is assumed that PHP will transition from the load retention rate to an industrial rate in 2020. The Company assumes that PHP load will remain interruptible and that the load considered in the high case could be PHP or other interruptible load(s).
24	In terms of load growth, the possibility of the LNG plant should be viewed in this study. This would represent a step up in load growth which should be considered for electricity demand.	Natural Forces	Recent announcements have indicated the development of a LNG plant in Goldboro will include up to 180 MW of natural gas fired generation. Based on this information it appears the LNG plant will meet most or all of their load requirements with their own generation.
25	Sensitivity on load growth due to electric cars would be of interest to see	Natural Forces	The potential uptake of electric cars is considered in the high load scenario.

DSM			
	Amount of DSM to be Modelled		
26	ENE supports modeling the High and Low scenarios from the Navigant potential study. ENE strongly recommends that the Mid scenario be included as the third DSM scenario.	ENE	NS Power understands from ENSC that the High DSM scenario represents the DSM Administrator's view of the highest amounts achievable in Nova Scotia. The Company will also model the Base scenario.
27	DSM and supply-side resources should be assessed on an even playing field. Only those costs and benefits incurred by the utility should be included in the IRP. DSM should not be assessed from a total resource cost perspective, but rather from a utility cost perspective. April 7, 2014: ENE again strongly recommends that NSPI consider DSM resources from a utility cost perspective.	ENE	The TRC test has been used for DSM screening in Nova Scotia since 2007 and remains the predominant primary-screening test used in North America. Based on the EERAM model, use of the TRC does not appear to significantly alter the DSM achievable potential. Consideration of the DSM potential assuming a PAC test would therefore not produce materially different results and would not have an effect on this IRP. NS Power has also indicated that it will provide revenue requirement information with and without the customer cost component of DSM for stakeholder information. This will provide the information needed for discussion of the selection of the Preferred Resource Plan.

28	The IRP should include cost effectives DSM programming from any available source, including the utility's own incentive and infrastructure plans such as intelligent metering, conservation voltage reduction and other smart-grid based technologies.	Dept. of Energy	With respect to NS Power's infrastructure, the company continuously investigates and evaluates projects which could assist in improving the energy efficiency of its overall operations. These projects are either OM&G investments or are approved by the UARB as part of the capital program, assuming they have a strong business case. The DSM energy efficiency assumptions to be used in the IRP are substantial enough to encompass a range of future programs, regardless of source. NS Power has proposed Demand Response assumptions for modelling. Demand Response using direct load control has been shown to provide effective and reliable peak mitigation in other jurisdictions. The IRP will also consider whether using this approach can also provide ancillary services of benefit to the system. If this option forms part of the IRP action plan, the utility would have a role in developing it into a program for future consideration by the UARB and other stakeholders.
	Avoided Costs		
29	In terms of avoided costs, NSP should provide stakeholders with justification for using a value other than $135/MWh	ENE	The IRP will provide new avoided cost information. Discussion about which components and methods to be used for calculating the avoided costs of DSM will be part of the IRP process.
30	The IRP offers an opportunity for NSP to engage stakeholders in the development of the avoided cost. The process should be transparent, and generate a breakdown of the avoided cost value by its components.	ENE	Please refer to item 29.
	General DSM Questions/Comments		
31	If NSP runs a sensitivity analysis on the results of Navigant's DSM potential study, then it is necessary for stakeholders to have access to this methodology and assumptions prior to commenting on proposed DSM scenarios.	ENE	Please refer to item 26. Since the IRP is intended to provide direction rather than an explicit and detailed plan, NS Power has accepted ENSC's recommendation to base IRP DSM input assumptions on their DSM Potential scenarios. There is no need to review or revise EERAM in detail at this time.

32	NSP should explain and support its contention that DSM potential is affected by the electric rate.	CA	In reviewing ENSC's EERAM model, it was discovered that the model includes electricity prices as input and it seemed appropriate to ensure these were up to date. NS Power recommended that EERAM's forecast of electricity prices be adjusted to reflect a historical average rather than a single year's increase. Please refer to DR-10 (Industrial Group). While it is unclear to NSPI how EERAM specifically utilizes the electricity price forecast, electric prices are generally a consideration in determining the expected bill savings and payback period of proposed DSM measures and could affect the uptake of certain programs.
33	ENE recommends using a discount rate that is equal to a recent average of the historic yields from a ten-year government bond.	ENE	NS Power's WACC has been used for DSM screening in Nova Scotia since 2007. Use of utility WACC is a common approach to setting the DSM discount rate in North America. Based on the EERAM model, use of the WACC does not appear to significantly alter the DSM achievable potential. Consideration of the DSM potential using a different rate would therefore not produce materially different results and would not have an effect on this IRP. Discussion regarding which discount rate should be used for DSM calculations is best conducted in a future ENSC DSM proceeding before the UARB. In the IRP, DSM is a capital or operating cost as are all other NS Power costs and should be subject to the same discount rate as all other expenses.
34	While Demand Response is mentioned it is not clear if it will be modeled as a separate process or only as an effect of Energy Efficiency DSM. The Department would suggest that as emerging technologies (such as smart-grid) will make Demand Response increasingly effective and relevant, it would be useful for the IRP to model these specific effects on peak load system demand.	Dept. of Energy	Yes, NSPI will be including four demand response programs in its IRP analysis. Please refer to the DR assumptions.
35	ENSC requests clarification on whether the IRP will include costs associated with increased spinning and planning reserve associated with new supply alternatives. Additionally ENSC requests clarification on whether the IRP will credit DSM activities (Demand Response and Energy Efficiency) commensurate with the associated reductions in reserve requirements.	ENSC	The model will include any reductions in firm peak associated with DSM effects and the corresponding reductions in planning reserve requirements. The contribution of any new supply option to the planning reserve requirements will be included in the Strategist modeling. Operating reserve requirements will be considered in Plexos.

36	ENSC requests that NSPI share all relevant assumptions and supporting research for demand response alternatives included in this IRP.	ENSC	NS Power provided IRP Demand Response assumptions to all stakeholders on March 28th. Additional information can be found in the Demand Response Section of the Final Assumptions deck (slides 101 to 111).
	Treatment of DSM		
37	DSM should be evaluated as a resource option alongside supply-side resources.	ENE	The ENSC DSM quantities to be used in the IRP have passed the TRC test based on ENSC's assumptions and at the cost levels presented by ENSC are generally anticipated to be competitive with supply side options. As a result, NS Power believes that the use of the scenarios as load modifiers is a reasonable and appropriate method for DSM analysis in this IRP.
38	Treat DSM as a resource alongside generation options.	EAC	Please refer to item 37.
39	Program Administrator Costs for incremental levels of DSM should be optimized along with supply side options so that the level of utility cost effective DSM is an output of the process, not an input.	EAC	Please refer to item 37.
40	Clarify what is meant by "layers" of DSM in the IRP process description. Indicate how the model will settle on the amount of DSM programming.	Dept. of Energy	Please refer to slides 78 to 82 and 94 to 100 in the Final Assumptions deck.
41	ENSC requests that the IRP Assumptions state that demand-side resources will be considered as an alternative to both existing and future supply resources as the IRP seeks to minimize the cumulative present worth of the annual revenue requirements over the planning period. For existing thermal plants, the IRP should consider reduced operations and earlier retirement.	ENSC	NS Power will consider the amounts of DSM proposed in ENSC's potential study. Please refer to item 26.

Financial			
42	The cost of capital stated by NSPI should not be a single number; there should be a sensitivity to see what could be possible if the cost of capital for NSPI was 100 basis points lower.	Natural Forces	Please refer to item 43.
43	Request clarification on whether or not the IRP will include the costs of financing associated with candidate IRP alternatives. ENSC also requests clarification on whether sensitivities in future borrowing rates will be explored.	Scotian WindFields	Only one WACC is possible in the modelling and as the same WACC is used across all assumptions there is no benefit in using a range for WACC.
44	With respect to the Financial Assumptions, can NSPI confirm whether the revenue requirement profiles are appropriate for the IRP? Has NSPI considered levelized cost profiles? Have risk adjusted discount rates been considered?	Industrial	Revenue Requirement profiles closely match the actual annual spend of the Company and allow for other analysis. Levelized cost profiles were not considered because of the advantages of the revenue requirement profiles. Risk adjusted discount rates were not considered because there is only one rate allowed in the modelling.
45	It is suggested that the Canadian vs US currency values track closely to global oil prices. As global oil prices (and hence other commodity prices) increase in a sustained way, the value of the Canadian dollar rises. A high oil price case would be aligned with a strong Canadian dollar, while a low oil price case would see a weaker Canadian dollar. Does the exchange rate in the IRP reflect this trend and if not, why not?	Industrial	The forecasted exchange rates in the IRP are averages of the forecasted exchange rates provided by the economic departments of a number of major banks. It is believed that one of their many considerations in developing these rate forecasts would be commodity prices.

Environmental & Emissions			
Emissions Scenarios			
46	ENE recommends assessing a GHG emissions reduction scenario with a trajectory that achieves science-based targets in 2050 as a high environmental constraint. This would translate into an emissions level of approximately 5.14 Mt in 2020 and 2.60 Mt in 2040.	ENE	NS Power is aware of The Climate Change Accountability Act Bill C-311. Since Bill C-311 was defeated in 2010, the Government of Canada has released regulations for coal fired generators to come into force in 2015. Currently, the Nova Scotia Greenhouse Gas Emission Regulations outline hard caps for 2010 to 2030. In September 2012, the Provincial and Federal governments released a draft equivalency agreement which, once finalized, will ensure the provincial regulations will apply in Nova Scotia. It has been determined that the Nova Scotia regulatory regime will meet or exceed the Federal GHG reductions in a less costly manner. NS Power must follow future regulations implemented by the Provincial and Federal Government, which at this time, are most likely those standards set out in the draft equivalency agreement and reflected as Scenario A. The Company will consider deeper emissions cuts than Scenario A, please refer to item 47.
47	EAC proposes that a third GHG scenario that approaches zero electricity GHG emissions to be added: Scenario C: Emission limits as per An Agreement on the Equivalency of Federal and Nova Scotia Regulations for the Control of Greenhouse Gas Emissions from Electricity Producers in Nova Scotia (Sept. 2012) Limit declines to 2.25 in 2040, 0 in 2050. The downward path of the GHG constraint in Scenario C is consistent with the established medium term goals and long-term commitments consistent with the Federal government's signature to the Copenhagen Accord.	EAC	The Company will model GHG emission cuts to 2.25MT in 2040 as a Scenario C (and associated co-benefits for other air emissions and RES targets); however, the Company will not extend the modelling exercise past the 2040 window during this IRP.
48	This would suggest that the current assumption set only includes one probable scenario, making it prudent for the IRP to include a third, more aggressive, scenario for these pollutants as well as for CO2 to illustrate the relative costs of achieving such reductions.	ENSC	Please refer to item 47.

49	Should IRP study emissions reduction targets that go beyond compliance in order to establish the impact of policy changes that might ratchet down emissions? What would these targets be? Would it be valuable to test targets desired by individual stakeholder groups?	SBA	Please refer to item 47.
50	Given scenario B is outside the reasonable range of possible air pollution trajectories, NSE suggests replacing it with a more realistic scenario similar to the approach taken with the GHG emission assumptions. NSE recommends that Scenario B reflects the air pollution reduction trajectory as depicted in “the Paper” (Scenario A) until 2030, then assumes no continual reduction after 2030.	NSE	Scenario B for SO2, NOx and Hg, was included to demonstrate the cost of achieving emissions reductions beyond what is currently in legislation (to 2020). Not all emissions reductions for these air pollutants are achieved through co-benefits of GHG reductions, so it is important to demonstrate the costs associated with the proposed post-2020 emissions reductions.
51	A sensitivity of more and less stringent emissions reductions strategies than Scenario A for the GHG and various Air Pollutants assumptions in order to fully assess the impact of policy changes in the Federal and Provincial governments should be carried out.	Industrial	NS Power agrees that assessing the cost of policy change is important. Scenario B provides the emission targets currently legislated. Scenario A is meant to provide more stringent targets, and is based on direction from Nova Scotia Environment through their Discussion Paper (June 2013) and their long term goal of continuous emissions reductions. NS Power agrees that a less stringent scenario should also be examined to assess the relative costs of current and proposed future policy.
52	The IRP model should consider the potential for NS Power to be required to pay a price on carbon emissions.	Scotian WindFields	NS regulations have hard caps which impose an implied price on carbon emissions.
53	Are there different scenarios of constraints? How will NSPI incorporate the A&B scenarios for emissions constraints? Is it the best use of limited time/resources to study both? Why not plan for the more stringent resources since there will be many IRPs prior to reaching the point where the Scenarios A & B diverge?	SBA	See items 47, 50 and 51.

54	The stated GHG emission targets for the period between 2015 & 2035 have been drafted on the basis of the existing Federal legislation. With global developments as described above we believe that more discussion and thought is required as to what the appropriate GHG ‘book-end’ cases would look like. A suggestion would be to look at the British and German 2050 targets and perhaps applying standards similar to these to Nova Scotia as a ‘book-end’. NSPI’s Case A and B show what a base case (current government standards) is and a lower standard (less reduction) of reducing GHGs, NOX, SOX and Hg. We believe it would be important to also show an increased standard (more reduction) than what the current government policies mandate.	Natural Forces	Please refer to items 46, 47, and 49.
55	In many jurisdictions carrying out resource planning, it is now common to include scenarios which seek to understand what the cost to the rate payer would be with varying costs allocated to carbon and other GHG emissions. Perhaps allocating a payment for non compliance in terms of GHG emissions or a saving by selling over compliance to another jurisdiction.	Natural Forces	Please refer to items 47 and 52.
	RES Requirements		
56	The Province of Nova Scotia has no current plans to change the requirements of the Renewable Electricity Standards (RES), as defined under the Renewable Electricity Regulations. However, the government continues to support the development of renewables and expects that the percentage of renewable electricity supply is likely to increase beyond levels currently mandated by the RES Regulations.	Dept. of Energy	Increased renewables will be considered during the development of candidate resource plans. In addition, the company may need to examine renewables above 40% in order to meet Scenario C emissions scenarios.

57	Include within the RES assumptions an additional scenario where: Electricity Supply consists of 100% Renewable Energy Sources by 2040 Electricity Supply consists of 80% Renewable Energy Sources by 2030	EAC	Please refer to Item 47, NS Power will model increased RES requirement associated with achieving GHG reductions to 2.25 MT by 2040.
58	Are the existing RES requirements the only future to be analyzed? Should the IRP evaluate renewable energy strategy targets beyond RES compliance?	SBA	Please refer to items 56 and 57.
59	While NSPI believes this is taken care of by the differing level of environmental standards, it would be of interest to us to see what an increased renewable energy standard would cost or save.	Natural Forces	Refer to items 56 and 57.
Analysis Plan			
60	The Industrial Group requests that NSPI provide a clearer articulation of the basis for evaluation and selection of the Preferred Plan and a means for resolving competing objectives.	Industrial	NS Power is working with Synapse to establish the preferred resource plan selection criteria - they are along the lines of previous IRPs and IRP best practices. They include robustness across a range of futures, relative revenue requirements, technology, fuel availability etc. NS Power will provide periodic reports to all stakeholders during the Analysis Plan stage. Please also refer to item 64.
61	The Industrial Group requests that NSPI circulate the proposed evaluation criteria for the high-level screening and to select the Preferred Resource Plan with commentary on how the other IRP objectives identified in the TOR have been defined, measured, and weighted in establishing the criteria.	Industrial	Please refer to item 60.
62	The SBA believes that it is important for stakeholders to come to agreements first and foremost on the objectives of the IRP. This includes establishing metrics NS Power intends to look at to determine the best resource plan or even the good resource plans.	SBA	Please refer to item 60.

63	The objectives should be made up of three areas, goals, metrics, and key questions that should be answered.	SBA	These concerns will be addressed during the evaluation of the Candidate Resource Plans – please refer to item 60.
64	The Terms of Reference provide specifically for a Stakeholder Engagement Process. "Stakeholder input is an integral part of the process". With this in mind the SBA is concerned that the process is not more interactive.	SBA	The Company is committed to meeting with stakeholders throughout the IRP process to ensure engagement and information sharing to the level required. NS Power is committed to meet the timelines established with the UARB for the completion of the IRP.
65	What are the plans that will be tested? What are the metrics? Will stakeholders get to comment on the plans before the analysis? What is the process to choose or design these "Worlds"? Will these be established using primarily a consultant or forecasting organization's scenarios? How will the optimization process work? Will Plans be allowed to recognize the alternative scenario at some point in time? Risk Analysis – how is this going to be evaluated? What risks?	SBA	Please refer to item 60.
66	It would be helpful if the Analysis Plan included a schedule (or perhaps an outline of the sequencing and work flow) for several tasks required for near-term planning.	CA	NS Power is working on an analysis schedule with Synapse and will make it available when it is finalized.
67	If NSP will be assessing and potentially reporting rate impacts, then the company should also assess and report bill impacts.	ENE	Consistent with past IRPs, NS Power only plans to compare the relative revenue requirements of the various plans as the test of cost effectiveness, not the rate impacts.
68	Will each supply option provided be separate options in the IRP analysis or will NSP establish certain generation options to each represent a group of similar supply options?	SBA	Candidate resource plans will consist of a variety of resource options

69	Resource Plans for consideration provided on pg. 5 of submission	SBA	NS Power and Synapse are working to establish candidate resource plans that encompass a broad range of futures that will screen out or encompass those suggested. Please refer to item 60.
70	Candidate Resource Plans suggested on pg. 5 of submission	Scotian WindFields	Please refer to item 69.
Future Supply Options			
Wind & Solar			
71	Since wind costs, both in Nova Scotia and globally, have tended to trend downward (from $2,600 for Nuttby and Digby and over $2,300/kW for Point Tupper), future wind costs should be even less than the South Canoe cost.	CA	South Canoe is favorably priced taking advantage of market conditions and technology development. In the future, inflation effects on construction and less favorable sites could offset reductions if any on machine costs. Please refer to item 77.
72	NSPI's estimate of the cost of photovoltaic solar ($5,600/kW) is also overstated. Taking into account currency exchange rates, the NSPI estimate is at the high end of US costs for 2012, and probably even more overstated for the future. Considering the amount of PV solar installed in North America and Europe, the readiness level of PV seems as high as wind.	CA	The Company has modified solar cost estimates down to $3500 / kW.
73	The CAES option requires greater detail on the operating cost of the plant (especially the cost of gas necessary to warm the compressed air as it is expanded).	CA	The operating cost in reference to natural gas is reflected in the round trip efficiency of 55% shown in the heat rate column.
74	This method [the capacity value of wind calculated based on statistical probabilities of wind generation being available at peak load] should be modified to estimate the contribution of wind at times of NSPI's tightest capacity conditions; that may be higher or lower than the contribution at peak load.	CA	The capacity value of wind is a parameter which determines the contribution of nameplate wind capacity to help meet the firm system peak. The Company will model a capacity value range of 12% low case to 27% high case.

75	No support is cited for the presumption that "additional firm capacity will have to be built in order to securely integrate more intermittent generation in the future," and "The study may show that integration costs are in line with the estimates used in Regulatory proceedings." Available support should be identified.	CA	More information will follow on this matter in the release of the full integration cost assumptions. Additional time will be provided to stakeholders to comment on these assumptions.
76	In light of the agile transmission link available to Newfoundland and Labrador in the near term and the potential for near equal cost interconnection through New Brunswick to Quebec, the IRP should thoroughly examine the capacity for inter-regional power pooling to maximize the value of zero emission wind resources across the Atlantic region.	EAC	This type of study is outside of the scope of the IRP.
77	a. Wind energy supply in excess of an additional 100MW should be considered as a Supply-Side Option b. Additional distribution-connected wind energy should be considered as a Supply-Side Option, with specific capital costs and integration costs considered. c. We would recommend that COMFIT-scale development and along with future distribution connected wind energy has a capital range of $2500-$2800/kW.	Scotian WindFields	The Company has adjusted the capital cost of distribution connected wind to $2500.
78	a. We recommend that large amounts (>10MW) of distribution-connected, individual and commercial-scale (1-100kW) solar photovoltaic energy be considered as a Supply-Side Option. b. We recommend that large amounts (>10MW) of individual and commercial-scale (1-100kW) solar thermal energy be considered as a Supply-Side offset. c. We recommend that the capital costs for solar photovoltaic and individual-scale development be considered with a capital range as low as $3,500/kW. d. We recommend that the capital costs for solar photovoltaic and utility-scale development be considered with a capital range as low as $3,000/kW. e. We recommend that the costs for solar thermal for individual and commercial-scale development at $2,000/kW.	Scotian WindFields	Please refer to item 72.

79	Welcome further discussion on the capacity factors of the various types of solar energy.	Scotian WindFields	More details will accompany the assumptions on variable integration costs. Stakeholders will be given the opportunity to comment on these assumptions.
80	The SBA wants to get specific assumptions on how NSPI intends to evaluate any potential strategic and cost advantages to wind procurement through PPAs versus NSPI ownership	SBA	NS Power would expect the most cost competitive option of a given resource alternative to be employed. That is currently assumed to be NS Power owned wind based on the South Canoe regulatory application.
	COMFIT		
81	The Department suggests that a range of approximately 110 - 120 MW of COMFIT projects will be in-service by 2016.	Dept. of Energy	The Company will consider this recommendation as part of the candidate resource plan phase of analysis.
82	EAC strongly urges that the RES assumptions bring COMFIT projects to the full 200MW level by 2016 and include an extension of the program ongoing at 20 - 30 MW per year.	EAC	Please refer to item 81.
	Hydro		
83	The value of the Mersey Incremental Upgrade option depends on the energy production and the dependable capacity, as well as the installed cost per kW. Additional information on this option will be necessary.	CA	The Mersey incremental upgrade assumes a 30MW increase in firm capacity and an incremental 40 GWh of energy production. The additional energy results from re-engineering and restructuring of power houses.
84	NSPI should provide a breakdown of the $500M in sustaining capital by facility, to test whether the investments are small compared to the value of the hydro plants. NSPI should examine the cost-effectiveness in greater detail.	CA	The majority of the sustaining capital is for the Mersey, Wreck Cove and Annapolis systems. For the purposes of the IRP, it will be assumed that these legacy assets will continue to run providing value as flexible system assets. Any capital expenditures required to sustain the hydro systems will be studied on an individual basis outside the IRP and will require UARB approval.

85	The Industrial Group queries the underlying assumptions for sustaining capital projects for existing hydro systems. Is this an economic option given the generation capacity of existing hydro systems?	Industrial	The assumption is common across all plans and will not impact the relative economics across plans. Project economics will be determined on a case by case basis as projects are reviewed by the UARB
86	Why is the 500M$ hydro assumption made?	SBA	The $500M figure is immaterial in the IRP analysis as the assumption is that the preservation of the valuable hydro assets is common across all of the cases to be considered. Incremental hydro developments will be added to the resource option list of the IRP.
87	Cost associated with the incremental capacity increased in hydro should be the total cost of the refurbishment not just the difference between maintenance and total capital cost, unless the maintenance is due that year.	Natural Forces	Please refer to item 84.
	Import Options		
88	What are the risks, costs, and benefits of the firm and non-firm options proposed?	Industrial	Costs, risks and benefits will be considered in the IRP candidate resource plan development process.
89	Can NSPI confirm that the Mass Hub Forecast that will be used to price import power is consistent with the natural gas assumptions?	Industrial	Confirmed.
	Supply Alternatives		
90	Burnside 4 is included with 33 MW of net demonstrated capacity. That capacity is not currently available and NSPI should review the cost and appropriate timing of reactivation of that unit.	CA	Burnside 4 provides capacity at the load centre and other services such as operating reserve, VAR support in Metro Halifax and black start capability. For these reasons the IRP will assume the unit is available. Any capital expenditure to return the unit to service will require UARB approval. This is currently the most economic option.
91	NSPI's assumptions about the feasibility of continued operations of steam plants, especially the gas-fire units, should be tested. Tufts Cove (especially the more flexible units 2 and 3) should be compared to replacement peakers.	CA	NS Power anticipates steam unit retirement alternatives will be explored.

92	For the steam plants, NSPI should consider whether costs would be minimized by retiring Lingan 2 (and possibly 1) or by converting multiple coal units to cycling operation, as suggested by a recent NREL study…	CA	Coal unit cycling will be considered in the integrated resource plan modeling.
93	As all parties are aware, the IRP terms of reference were explicitly revised to consider the potential utilization of load as a resource. The current version of the Draft Assumptions does not specifically refer to consideration of this possibility.	PHP	NS Power is meeting with PHP to assess the options for demand response.
94	It is unclear to PHP if the modeling will have a constraint on the amount of non-dispatchable renewables that can be backed-up by Nova Scotia resources. If there is such a constraint, how will the modeling deal with the non-dispatchable renewables excess to this constraint?	PHP	This information will be provided with the wind integration assumptions.
95	NSE believes the environmental control technology assumptions as outlined on page 21 of the Assumptions are limited in scope. NSE suggests that a broader look at a diversity of options for various types of abatement equipment would make for a more robust analysis.	NSE	The IRP will identify the need for environmental control technologies. Further study following the IRP will determine the detailed specifications and location for each control technology identified in the IRP.
96	NSE would also like to have additional context around "municipal solid waste" supply scenario. It should be noted that any such projects are subject to environmental regulations and the appropriate environmental approvals.	NSE	The configuration used includes a dry flue gas scrubber with a baghouse with NOx control and activated carbon injection. This should meet compliance with environmental regulations including dioxin /furans and particulate emission limits that have been a concern for these facilities.
97	The Supply Side Options (19) list several options for coal-fired plants; these are presented as if each are equally established and viable options. The Industrial Group questions whether NSPI has evaluated the technical risk and associated costs that are linked to these generation options. An evaluation of the costs and risks should be part of the modeling exercise.	Industrial	These aspects have been addressed in the associated costs of each coal option as well as the lead times and readiness levels.
98	It is noted that fluidized bed combustion (FBC) units have not been included in the supply-side options for coal-fired plants. An FBC plant equipped to burn petcoke may be an economically attractive generation option and should be evaluated.	Industrial	Although an FBC solution is not identified, the single unit advanced PC holds this placeholder for modelling purposes, as does the advanced PC with CCS. The current front runner would be an oxy fired CFB but it is assumed it would have to be price competitive with an advanced PC Unit. Any premium price to accommodate Pet coke would need to offset by a long term fuel contract. This would require detailed engineering beyond the scope of the IRP and would be

			studied at the time of project conception to make the correct decision.
99	The Industrial Group urges NSPI to explore storage options more closely, particularly given the need to integrate significant amounts of intermittent renewable into the system.	Industrial	Various storage options have been considered including batteries, fly wheel storage, etc. In order to meet the IRP requirements at utility level we have chosen both pumped storage and CAES. Other solutions need to become cost competitive with these technologies and we continue to monitor their development.
100	What are the costs to maintain each existing generating resource?	SBA	Capital investment profiles reflect unit utilization intensity. O&M costs are included in the unit profiles within the model.
101	How much will certain generating units operate under various ML energy delivery scenarios?	SBA	The model will determine the ML surplus energy purchases and the generation from the existing units based on the input assumptions such as fuel costs and power costs.
102	The cost/MW for the various technologies is stated but there is no comment on the cost per MWh	Natural Forces	In order to provide the capital cost on a $/MWh basis a capacity factor would have to be assumed. Depending on the technology this could vary with location of resource, unit dispatch, etc. Rather make an assumption for capacity factor, costs have been provided on a $/kW basis.
103	There are a variety of battery storage options on the market now which should also be considered.	Natural Forces	Please refer to item 99.
DSM Comments Received on March 28, 2014 DSM Assumptions Deck			
104	DSM is screened solely on economics versus avoided costs, when in fact, ‘avoided costs’ is an output parameter of the new resource plan.	SBA	Please refer to ENSC’s IRP submission on March 24 in which ENSC explains its rationale for the Achievable Potential presented in its potential study. NSPI provides the following excerpt: “Achievable potential is an amount of DSM that, given such constraints as the existing capacity of the administrator, the willingness and awareness of Nova Scotians to engage in DSM activities, the incentive levels provided, the amount of free-ridership that is measured, and other factors, can reasonably be expected to be obtained in Nova Scotia over the period. The Achievable potential presented in the study has been calculated to include a calibration to these factors and prior years’ DSM achievements. Achievable potential does not need to be economic, and not all economic potential is achievable. To be conservative, ENSC presented Achievable DSM that was determined to be economic; however, even if the economic potential was determined to be lower, the achievable potential, particularly in the near term, would not materially change.”

105	The IRP process should use substantial information from the DSM potential study.	SBA	NS Power's proposal is based on the DSM potential study.
106	A DSM supply curve should be created as an output of the DSM potential study.	SBA	NS Power anticipates that its modelling approach will illustrate the levels of DSM beneficial for customers over the planning horizon.
107	Requests confirmation that NS Power will consider potential opportunities for industrial-type DR programs that may be different than what is proposed to be modelled.	PHP	The DR programs being investigated for peak reduction in the IRP are to mitigate Firm Peak, not NS Power's Total System Peak. Most of NS Power's large industrial load is on an interruptible tariff, meaning that it is not counted in the Firm Peak. There is no further peak reduction benefit to be derived from customers under these tariffs, though it is possible that large industrial load may be capable of providing ancillary services. Consideration will also be given in the IRP (outside the specific modeling) to identifying potential opportunities where a different DR option (including ones that can provide ancillary services) may be of interest.
108	Recommend that ENSC's Base Case DSM should be included in IRP analysis.	NSDoE, Industrial Group, ENSC	NS Power accepts this recommendation and will replace Case 2 (ENSC's Low DSM Case) with ENSC's Base DSM Case.
109	Recommends that revenue requirements be prepared from IRP analysis showing both a) total DSM costs and b) program administrator costs only. ENSC and ENE state that only Program Administrator Costs should be considered.	NSDoE, ENE, ENSC	NS Power will provide information for both DSM costing approaches.
110	Request more detailed information on the DR options NS Power has outlined. Industrial Group requested that NS Power outline all demand reduction options in use or that might be used in NS.	Industrial Group, CA, ENSC	As requested, NS Power has released the details underlying the Demand Response assumptions to be modelled in the IRP. NS Power is at this time proposing to model direct load control options rather than pricing options due to the predictable responsiveness associated with direct load control. Please refer to NS Power's response to PHP re: DSM for further information. It is important to remember that for IRP purposes, both EE and DR DSM levels are intended to represent possibilities for the purpose of determining direction.
111	Disagree with the use of an NSPI-constructed DSM case (Case 1, which is 50% of ENSC's Low Case and costed at the same $/MWh as ENSC's Low Case).	ENSC, ENE, EAC	The IRP is intended to provide direction rather than explicit plans. Assumptions should represent a range of possible scenarios. ENSC indicated that it believes its Base Case is most appropriate for use and its High Case represented the highest practically achievable level. NS Power has agreed to use both these cases. NS

			Power considered it appropriate to also include a lower (total) cost DSM scenario in its range of possible DSM options and chose to base this on a portion of ENSC's Low DSM case.
112	Reiterating desire to be involved in discussions regarding the method to be used to calculate avoided costs for DSM evaluation purposes.	ENSC, CA	NS Power has committed to involving stakeholders in these discussions during the IRP process and has indicated that this will be a subject of discussion at the June technical conference.
113	A Long Term Government Bond rate should be used as the DSM discount rate.	ENE	The selection of a DSM discount rate is best addressed in a future DSM proceeding. This view is also shared by ENSC as stated in their April 7 comments. Please refer to item 33.
114	We share the concerns expressed by the Small Business Advocate that the assumptions do not minimize the cumulative present worth of the annual revenue requirement, the central objective of the IRP.	EAC	Please refer to item 104.
115	Here again, the proposed assumptions are in conflict with the terms of reference by including non-utility costs for DSM and thereby masking potential DSM benefits.	EAC	Please refer to item 27.
116	The DSM study provides sufficient information to model DSM as a resource, with a variable cost curve, or at least multiple discrete levels. Only by integrating DSM within the resource selection process will the IRP fully inform the Preferred Resource Plan.	EAC	Please refer to item 37.
117	Use of NSPI's WACC as the discount rate for DSM exaggerates the risk associated with DSM. Compared to the long life associated with capital assets (for generation assets see slide 41 – 50 plus years), DSM programs on a 1 to 3 year planning cycle are far more nimble and able to respond to variations in their performance. As such their risks are lower as should be their discount rates.	EAC	Please refer to items 33 and 113.

Figure A

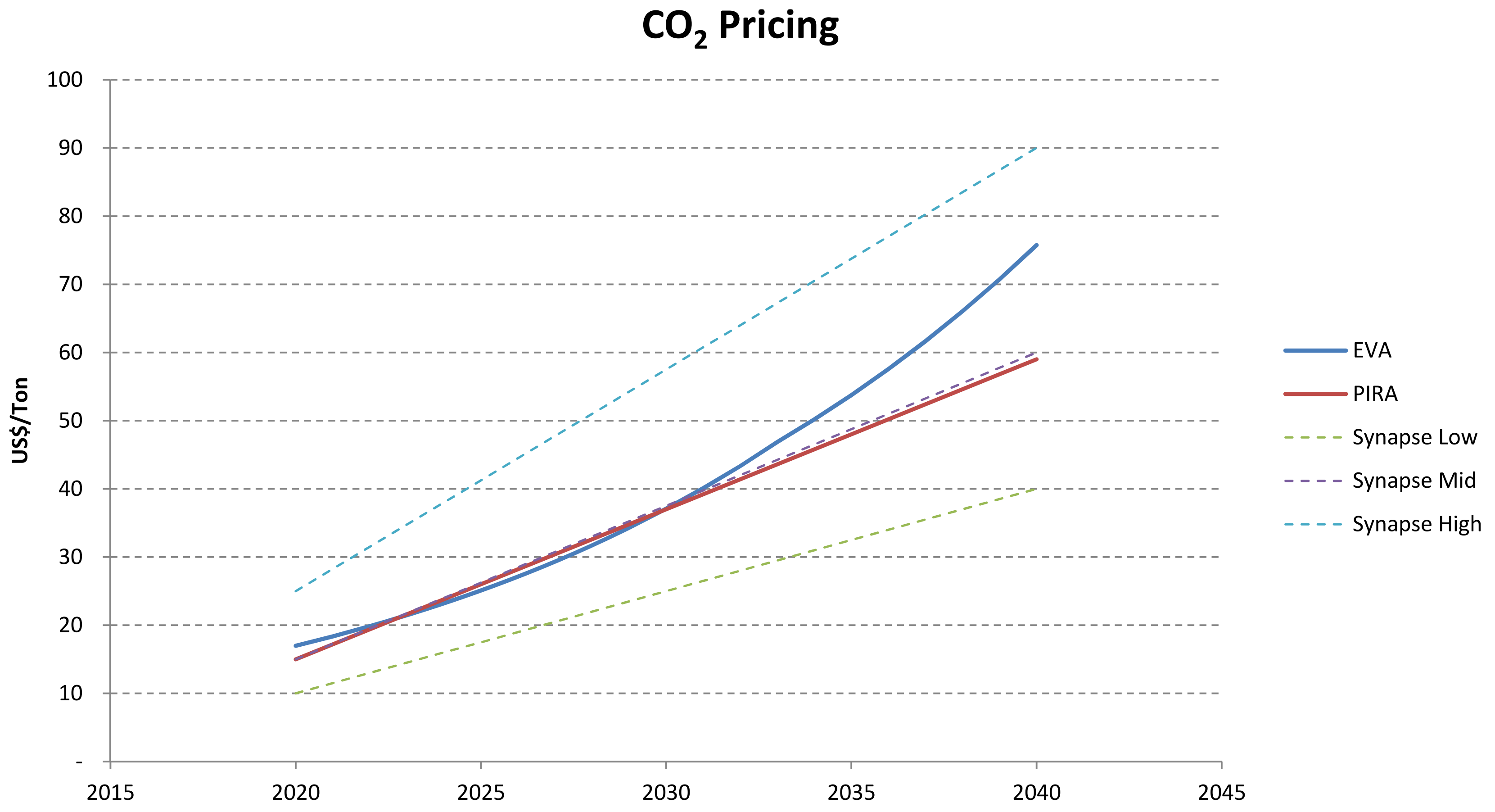

CO2 Pricing
US$/Ton
100
90
80
70
60
50
40
30
20
10
-
2015
2020
2025
2030
2035
2040
2045
EVA
PIRA
Synapse Low
Synapse Mid
Synapse High

Figure B

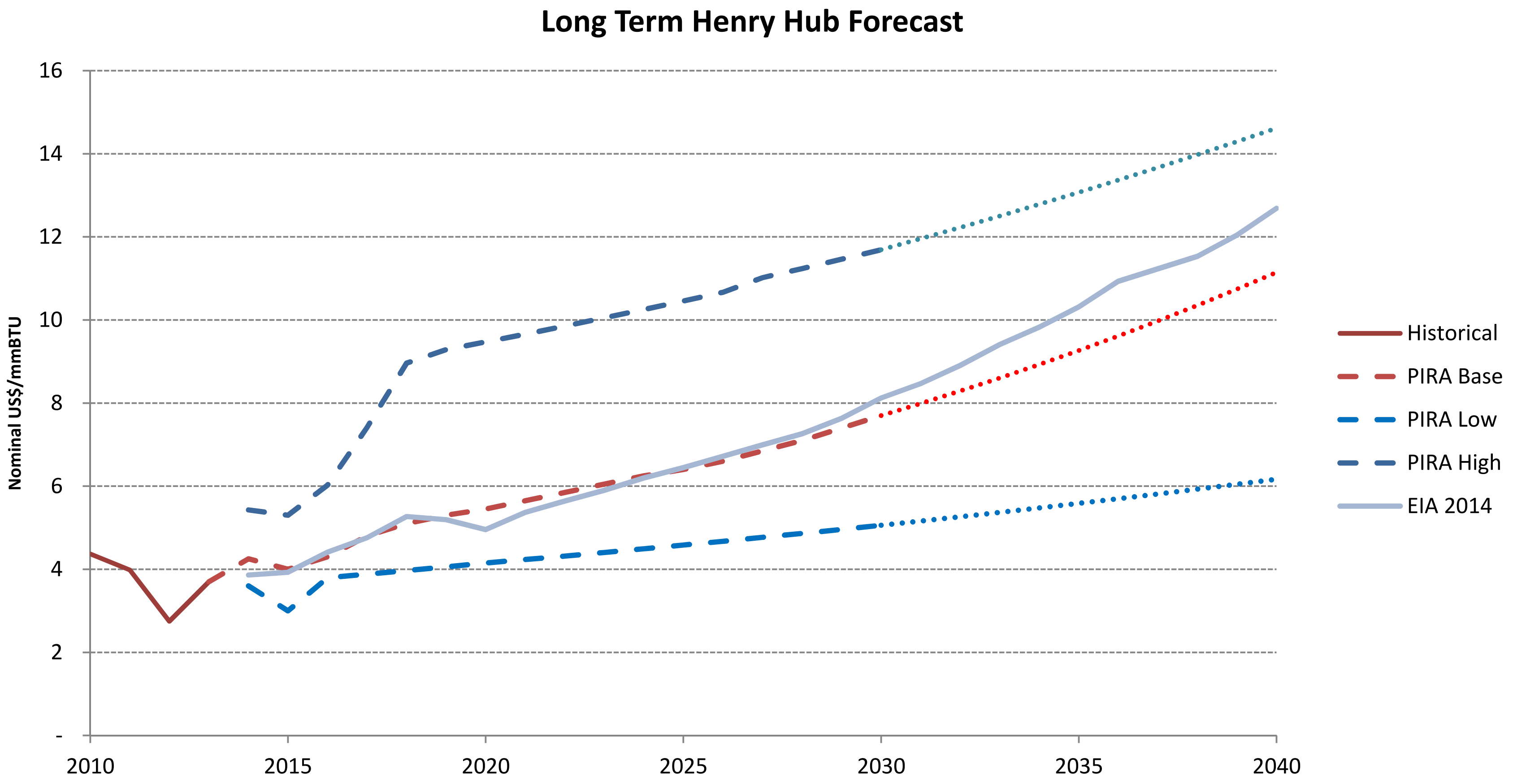

Long Term Henry Hub Forecast
Nominal US$/mmBTU
16
14
12
10
8
6
4
2
-
2010
2015
2020
2025
2030
2035
2040
Historical
PIRA Base
PIRA Low
PIRA High
EIA 2014

Figure C

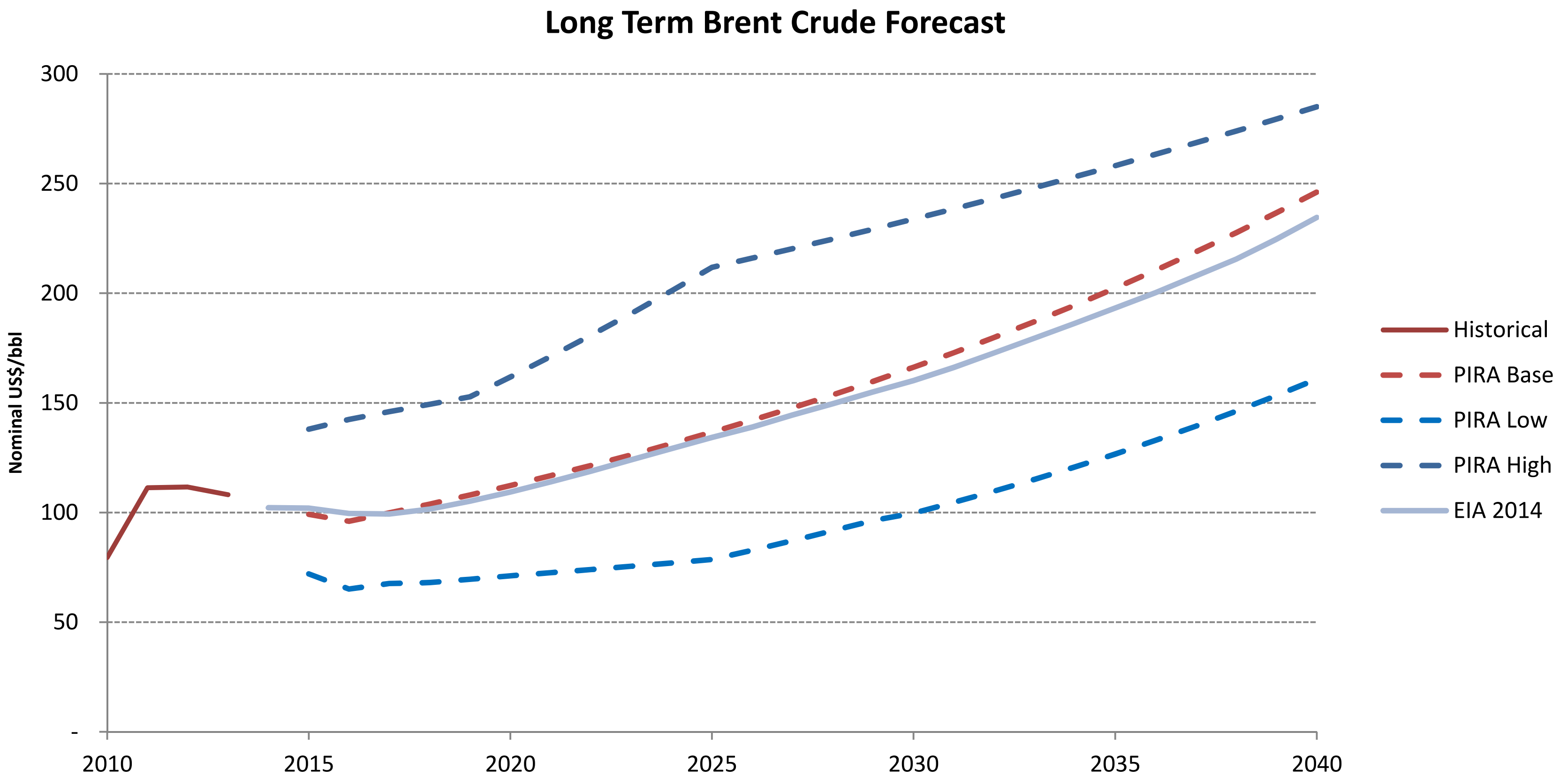
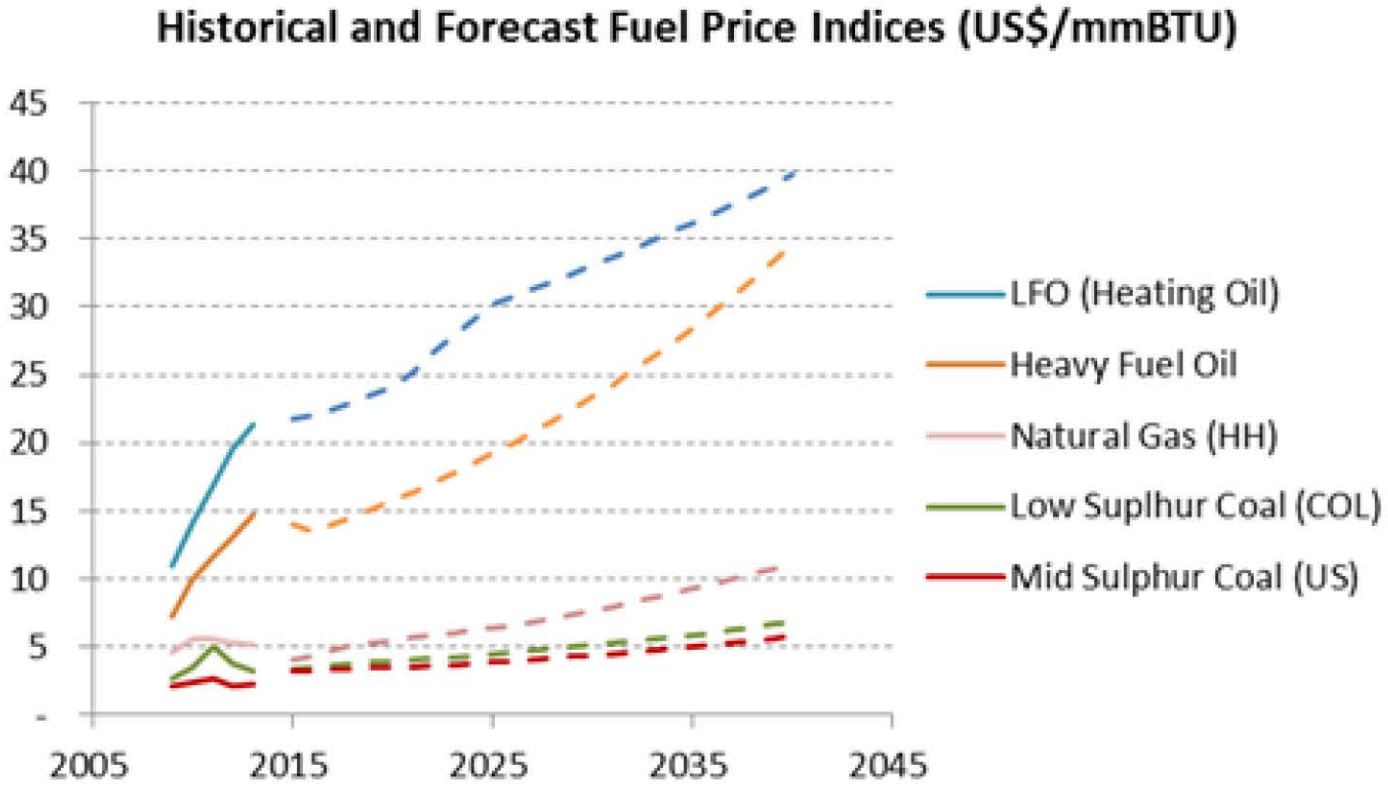

Long Term Brent Crude Forecast
Nominal US$/bbl
300
250
200
150
100
50
-
2010
2015
2020
2025
2030
2035
2040
Historical
PIRA Base
PIRA Low
PIRA High
EIA 2014

Figure D


Historical and Forecast Fuel Price Indices (US$/mmBTU)
45
40
35
30
25
20
15
10
5
-
2005
2015
2025
2035
2045
LFO (Heating Oil)
Heavy Fuel Oil
Natural Gas (HH)
Low Suplhur Coal (COL)
Mid Sulphur Coal (US)

Memorandum

Date: **June 5, 2014**
To: **IRP Intervenors**
From: **NS Power**
Subject: **2014 IRP – Analysis Plan Update and June 25 Technical Conference**

In the spirit of the IRP's consultative goals, the Company would like to take the opportunity to provide a status update on the work that has taken place since the last correspondence, provide a draft agenda for the upcoming Technical Conference on June 25 and discuss progress on items raised in Intervenor submissions.

Introduction

On March 7, 2014, NS Power hosted a Technical Conference for participants at which it reviewed initial draft assumptions and discussed its preliminary thoughts on the analysis plan for the 2014 Integrated Resource Plan (IRP) to obtain feedback from participants.

On March 14, 2014, NS Power circulated draft basic assumptions for feedback. The Company also circulated additional assumptions details in response to requests from Larry Hughes, PhD., the Industrial Group and the Nova Scotia Department of Energy. The March 14 material included a memo describing the 5 steps NS Power suggested for the Analysis Plan.

On April 11, 2014, NS Power supplied Intervenors with the final assumptions for the 2014 IRP developed in collaboration with UARB Staff and their consultants. In addition, the Company provided detailed feedback on Intervenor comments on the assumptions with its April 11th submission. Intervenors were also given the opportunity to comment on final assumptions not provided with the April 11th package (capacity value of wind and variable generation integration costs). The April 11 memo included a brief discussion of NS Power's proposed approach to completing the Analysis Plan, specifically to model a limited number of candidate resource plans, sensitivities and worlds that bound the wide range of possible permutations and combinations that have been suggested.

A record of IRP communications to date can be found at the following link:
http://www.nspower.ca/en/home/about-us/electricity-rates-and-regulations/regulatory-

Analysis Plan Update

In the March 14 memo NS Power proposed completing the Analysis Plan in 5 steps – Candidate Resource Plans, Candidate Resource Plan Evaluation, Scenario Testing (“Worlds” development), Evaluation and Optimization and Preferred Resource Plan Development.

Analysis Plan step 1 - Candidate Resource Plans

Slide 113 of the Final Assumptions dated April 11 gave an outline of the 3 major tasks required to complete Step 1 of the analysis plan. Those three tasks and their status as of May 30 are as follows:

i. identify a broad range of draft resource plans – completed,
ii. evaluate draft resource plans under a Reference World – in progress,
iii. narrow draft resource plans down to a set of candidate resource plans - in progress .

Task i, draft resource plans - completed

In collaboration with UARB Staff and consultants, NS Power identified 30 draft resource plans. NS Power developed each draft resource plan based upon a general “theme” and on the existing resources and resource commitments in effect at the start of that plan.

The draft resource plans reflect different input assumptions for four key components

- DSM levels
- Coal plant retirement dates
- Target levels of wind generation assets
- Potential for a large Power Purchase Agreement (PPA)

Attachment 1 illustrates the 30 draft resource plans.

Tasks ii and iii - evaluate draft resource plans under a Reference World and narrow draft resource plans down to a set of candidate resource plans – in progress

In collaboration with UARB Staff and consultants, NS Power identified 5 of the 30 draft resource plans as candidate resource plans for initial modeling in Strategist under a

Reference World. The inputs to the Strategist modeling of a specific candidate resource plan include the existing resources and resource commitments in effect at the start of that candidate resource plan. Strategist then identifies the optimal resource additions and retirements under that candidate resource plan (i.e. types, quantities, timing of resource additions and retirements).

The 5 candidate resource plans, indicated in Attachment 1, are as follows:

Candiate Resource plan 1.	Low DSM, coal retirements over 60 years, base wind
Candiate Resource plan 2.	Base DSM, coal retirements over 60 years, base wind
Candiate Resource plan 3.	Base DSM, coal retirements over 60 years, high wind (up to 900 MW)
Candiate Resource plan 4.	Base DSM, coal retirements over 50 years, base wind
Candiate Resource plan 5.	High DSM, coal retirements over 60 years, base wind

The Reference World is characterized by the following key assumptions from the April 11 set - base load forecast, Scenario A emission constraints, 40% RES requirement in 2020 and Maritime Link+ economy energy purchases.

It is expected that the examination of Candidate Resource Plans will be an iterative process and that additional candidate resource plans will be examined based on the results of the 5 initial candidate resource plans. The results from modeling those 5 initial candidate resource plans under the Reference World will help NS Power determine what additional candidate resource plans need to be analyzed to ensure a broad breadth of candidate resource plans and a robust modelling process. The Company expects to discuss preliminary results with Stakeholders at the June 25th technical conference. NS Power will circulate draft materials in advance of the conference for consideration by the group.

Analysis Plan steps 2 to 4.

Once a broad set of Candidate Resource Plans have been selected, NS Power and the UARB's consultants will proceed with steps 2 to 4 of the Analysis Plan, i.e., Candidate Resource Plan Evaluation, Scenario Testing ("Worlds" development), Evaluation and Optimization. In these steps NS Power will test the candidate resource plans against a variety of different "worlds" and sensitivities such as (list not exhaustive):

- Variable loads (high or low)

- Different environmental constraints
- Various fuel prices

Through this process the Candidate Resource Plans will be examined and, as appropriate, additional Candidate Resource Plans will be identified for further screening to ensure that the IRP has examined the Candidate Resource Plans under the full breadth of potential scenarios (Worlds) that may unfold in the future in Nova Scotia.

June 25 Technical Conference

NS Power will be releasing preliminary draft results of a subset of the Candidate Resource Plans prior to June 25 for stakeholder review and for discussion at the Technical Conference.

On June 25, 2014 the Company will host a technical conference. The draft agenda is:

- Discussion of 5 candidate resource plans being tested in Strategist, and results to date
- Discussion of other candidate resource plans of potential interest
- Discussion of sensitivity analysis to be conducted
- Discussion of other “Worlds” to be developed
- Discussion of framework of Action Plan

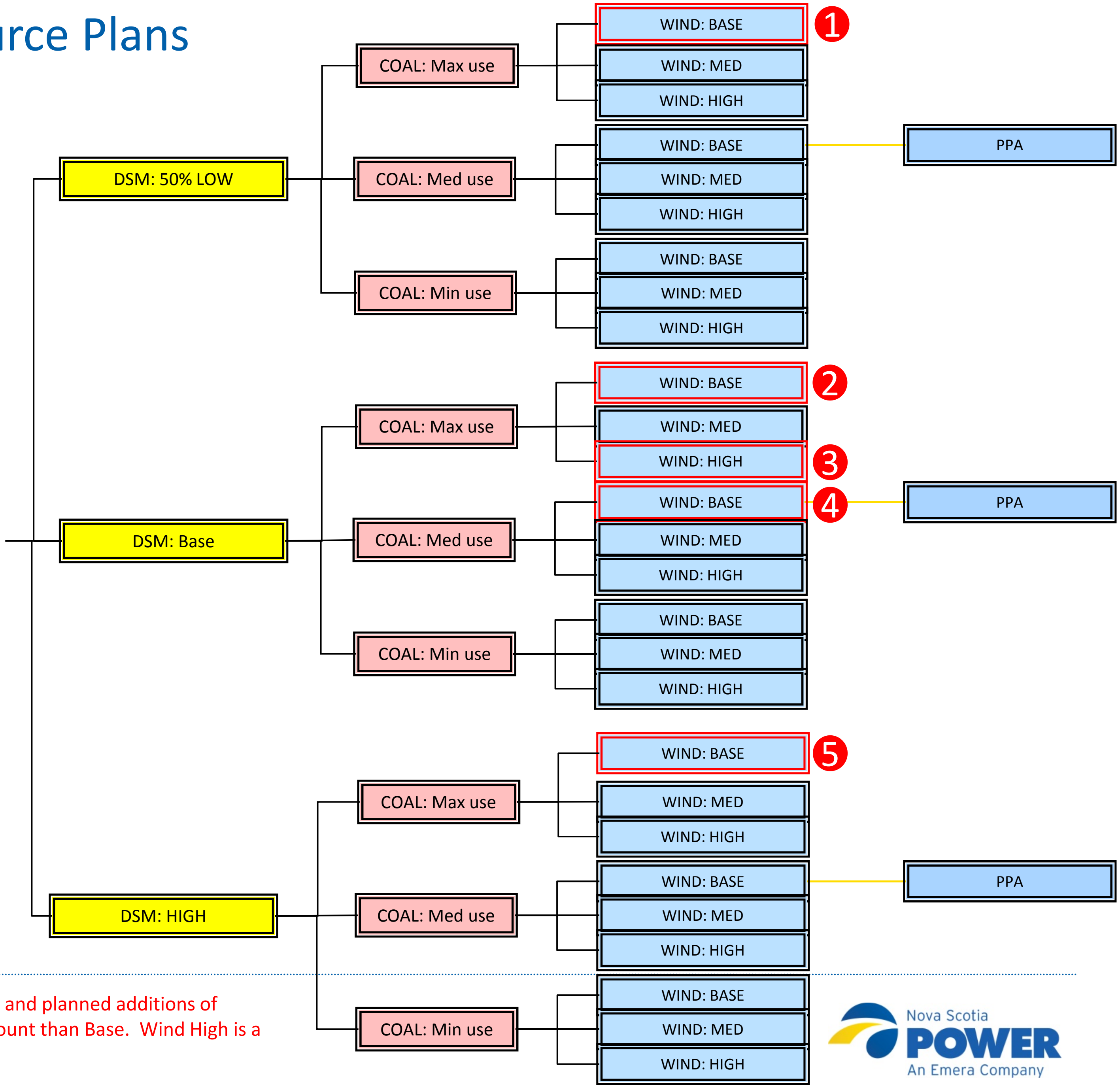
The Company will respond to stakeholder comments and questions at the Technical Conference.

Progress on items raised in Intervenor submissions

Please refer to Attachment 2.

NS Power would like to thank the working group and participants for their feedback.

Draft Resource Plans



NOTE: Base Wind refers to existing and planned additions of 582MW. Wind Med is a higher amount than Base. Wind High is a higher amount than Med.

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JUNE 4, 2014

IRP Process Update & Intervenor Feedback

Agenda

1. Project schedule
2. Intervenor Submissions & NS Power Responses
3. Candidate resource plan development
4. Early modeling results

Project Schedule – Completed Milestones

- TOR finalized - February 7
- Stakeholder Technical Conference - March 7
- Draft Assumptions issued - March 14
- Stakeholder Comments on Draft Assumptions - March 28
- Assumptions finalized - April 11
- Wind Capacity Value & Integration Cost Assumptions Released – April 23 & May 1
- Regulatory Stakeholder questions - Ongoing

Project Schedule – Upcoming Milestones

- Model Database & Candidate Resource Plan Development – underway
- Regulatory Stakeholder Technical Conf. – June 25
- Base scenarios for alternative plans established and sensitivities identified – July 24
- Release Draft Results – September 5
- Regulatory Stakeholder Technical Conf. – Sept 12
- Draft Report & Action Plan Filed – September 30
- Regulatory Stakeholder Comments – October 7
- Final Report & Action Plan Filed – October 15

Intervenor Submissions Recap

INTERVENOR SUBMISSIONS & MAIN THEMES:

- Submissions received from most intervenors (SBA, CA, PHP, Industrial Group, EAC, Environment Northeast, Scotian Windfields, Natural Forces Wind, NSE and NS DoE)
- Most common thread across submissions: Process timeline and "Analysis Plan" – desire for more intervenor involvement and feedback
- Diverse positions on the other main issues (DSM, Environment, Renewables, Retirements)

Intervenor Feedback – Analysis Plan

- Analysis Plan
  - Desire for greater stakeholder input
  - Desire for more detail respecting the "candidate resource plans" and evaluation criteria for the process to get to a reference plan
  - Request for the schedule for the Analysis Plan process
  - Several "candidate resource plans" have been recommended by intervenors for evaluation
- NS Power Response
  - Implementing additional "information sessions" for intervenors
  - Reaching out to key intervenors on a regular basis through the modelling period
  - Establishing detailed schedule with Synapse to share with stakeholders
  - Screening preferred resource plans so that they take into account stakeholder feedback
  - Will consider additional strategist runs based on time

Intervenor Feedback - DSM

- DSM Stakeholder Submissions
  - Request to consider an accelerated DSM implementation profile (above ENSC high potential)
  - Request for more detail on how DSM will be modelled
  - Consider Demand Response for peak reduction including DR from customers
- NS Power Response
  - The assumptions submitted are a reasonable range of DSM to be considered
  - More detail provided on DSM modeling in written response

Intervenor Feedback - Emissions

- Emissions Stakeholder Submissions
  - Consider more stringent emissions scenarios
  - The Scenario B – holding emissions at current legislated limits is not reasonable – govt targets will be lower
  - Higher and lower emissions scenarios should be run as sensitivities to assess the cost impact of constraints
- NS Power Response
  - There are a range of intervenor views on emissions levels, it is good IRP practice for NS Power to run a range of scenarios

Intervenor Feedback – Fuel forecast

- Fuel Stakeholder Submissions
  - Company should use other fuel forecasts
  - Compare historic actuals to the forecast
  - How is forecast accuracy considered
- NS Power Response
  - More information provided in written responses
  - Fuel forecast accuracy will be addressed in sensitivity analysis and World development

Intervenor Feedback - Renewables

- Renewables Stakeholder Submissions
  - More COMFIT should be considered
  - COMFIT should be assumed at 110 – 120 in 2016
  - Renewables beyond 40% should be considered
  - Capacity value of wind needs to consider availability of wind during peak periods
  - Supply side cost estimates for wind and solar are over stated

- NS Power Response
  - Renewables beyond 40% may be considered due to Emissions constrains
  - Wind and solar cost estimates adjusted in assumptions
  - NS Power produced a detailed study demonstrating that when examined using cumulative frequency analysis the CV for renewables was much lower than the Renewable Energy Integration Study value based on a loss of load expectation methodology (12% vs 27%)
  - Agreed with Synapse prior to use 17% for base assumption and will use both values as high and low bands for candidate resource plans

Intervenor Feedback - Load

- Load Stakeholder Submissions
  - The Company should fix load at 15% above and below the base case for the high and low scenarios
  - Industrial load should be assumed to be flat or declining

- NS Power Response
  - Proposed load “cone” using load and DSM case combinations

Candidate Resource Plan Development

NS POWER & SYNAPSE CONSIDERED STAKEHOLDER FEEDBACK TO DEVELOP CANDIDATE RESOURCE PLANS

- Key variables were identified as significantly capable of changing CRP outcomes
    - DSM, Variable generation levels, plant retirement dates and potential for a large PPA
- Using these variables over 30 CRPs were screened
- 6 initial CRPs will be optimized in strategist with others under consideration for the additional modelling

Candidate Resource Plan Development

THE FOLLOWING RESOURCE PLANS HAVE BEEN CHOSEN FOR INITIAL OPTIMIZATION RUNS

- Plan 1 (Base Run*): Case 1 (Low) DSM, 60 year coal plant retirements and base (currently planned) wind
- Plan 2: Case 2 (Base) DSM, 60 year coal plant retirements and base wind
- Plan 3: Case 2 (Base) DSM, 60 year coal plant retirements and high wind (up to 900 MW)
- Plan 4: Case 2 (Base) DSM, 50 year coal retirements and base wind
- Plan 5: Case 3 (High) DSM, 60 year coal retirements and base wind
- All plans to run under the Reference World, with assumed Scenario A emissions, 40% RES requirement by 2020 and Maritime Link + Economy energy purchases

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* formerly known as the "least cost" run

Candidate Resource Plan Development

ONCE CANDIDATE RESOURCE PLANS HAVE BEEN OPTIMIZED SOME WILL BE SELECTED FOR ROBUSTNESS TESTING

- Plans will be evaluated under conditions where changes to load, fuel prices and environmental constraints (list non- exhaustive) are made to the assumptions
- The plan performance will be evaluated based on cost-effectiveness, system stability, environmental benefits, operational flexibility, etc.
- Developing resource plans this way allows for the broadest consideration of changes to assumptions and potential shifts in policy

Initial modelling results

THE COMPANY HAS COMPLETED ONE STRATEGIST RUN USING THE BASE ASSUMPTIONS (I.E. THE MOST LIKELY ASSUMPTIONS)

- Plan results in no new capacity additions until mid to late 2030's
- RES targets are met
- Plan is highly DSM dependent to meet reserve and environmental requirements (700 MW of peak reduction for the period)
- No robustness testing has been carried out on this plan

Run 1 (Preliminary)-Results

	Plan 1 (Base Run)
2015	
2016	
2017	ML Oct 2017 Lin 2 retire
2018	
2019	
2020	
2021	
2022	
2023	
2024	
2025	TUC 1 Retire
2026	
2027	
2028	
2029	
2030	
2031	
2032	TUC 2 Retire
2033	
2034	
2035	CT 50MW Tre 5 Retire
2036	CT100 MW & CT50 MW TUC 3 Retire
2037	
2038	
2039	CT 100 MW Lin 1 Retire
Planning PV $M	11,274
Study PV $M	17,002

Run 1 (Preliminary)-Load and Resources

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Firm Peak	1,989	2,012	2,026	2,046	2,067	2,092	2,103	2,123	2,144	2,172	2,185	2,204	2,222	2,247	2,258	2,277	2,296	2,314	2,333	2,352	2,371	2,390	2,409	2,428	2,448
DSM	49	80	110	136	160	182	204	228	250	273	293	316	345	373	405	438	471	502	533	563	591	619	642	668	692
Firm Peak Less DSM	1,940	1,932	1,916	1,910	1,907	1,910	1,899	1,896	1,894	1,899	1,892	1,888	1,877	1,874	1,853	1,839	1,825	1,812	1,800	1,789	1,780	1,771	1,767	1,760	1,756
RM Required	388	386	383	382	381	382	380	379	379	380	378	378	375	375	371	368	365	362	360	358	356	354	353	352	351
Required MWs	2,328	2,319	2,299	2,293	2,288	2,292	2,278	2,275	2,273	2,279	2,270	2,266	2,252	2,249	2,224	2,206	2,190	2,174	2,160	2,147	2,136	2,126	2,120	2,112	2,107
Existing MWs	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341
Resource Additions (MW):																									
Burnside #4		33																							
COMFIT - Biomass	4.2	6																							
COMFIT - Wind	14.14	4.56	5.1																						
REA Wind	2.35	17.34																							
Maritime Link				153.25																					
Small Biomass PPA			10																						
Hydro			1.8																						
FGD parasitic power																									
Additional Wind																									
Assumed Unit Retirement				-153							-81							-93			-150	-147			-153
Natural Gas Unit																					49.4	149.4			100
Total Annual Additions	20.7	60.9	16.9	0.3	0.0	0.0	0.0	0.0	0.0	0.0	-81.0	0.0	0.0	0.0	0.0	0.0	0.0	-93.0	0.0	0.0	-100.6	2.4	0.0	0.0	-53.0
Total Cumulative Additions	20.7	81.6	98.5	98.7	98.7	98.7	98.7	98.7	98.7	98.7	17.7	17.7	17.7	17.7	17.7	17.7	17.7	-75.3	-75.3	-75.3	-175.9	-173.5	-173.5	-173.5	-226.5
Total Firm Capacity	2362.1	2423.0	2439.9	2440.1	2440.1	2440.1	2440.1	2440.1	2440.1	2440.1	2359.1	2359.1	2359.1	2359.1	2359.1	2359.1	2359.1	2266.1	2266.1	2266.1	2165.5	2167.9	2167.9	2167.9	2114.9
Surplus (Deficit) MWs above RM	34	104	141	148	152	148	162	165	167	161	89	93	107	110	135	153	169	92	106	119	30	42	48	56	8
Reserve Margin %	21.8%	25.4%	27.3%	27.7%	28.0%	27.8%	28.5%	28.7%	28.8%	28.5%	24.7%	24.9%	25.7%	25.9%	27.3%	28.3%	29.3%	25.1%	25.9%	26.7%	21.7%	22.4%	22.7%	23.2%	20.4%

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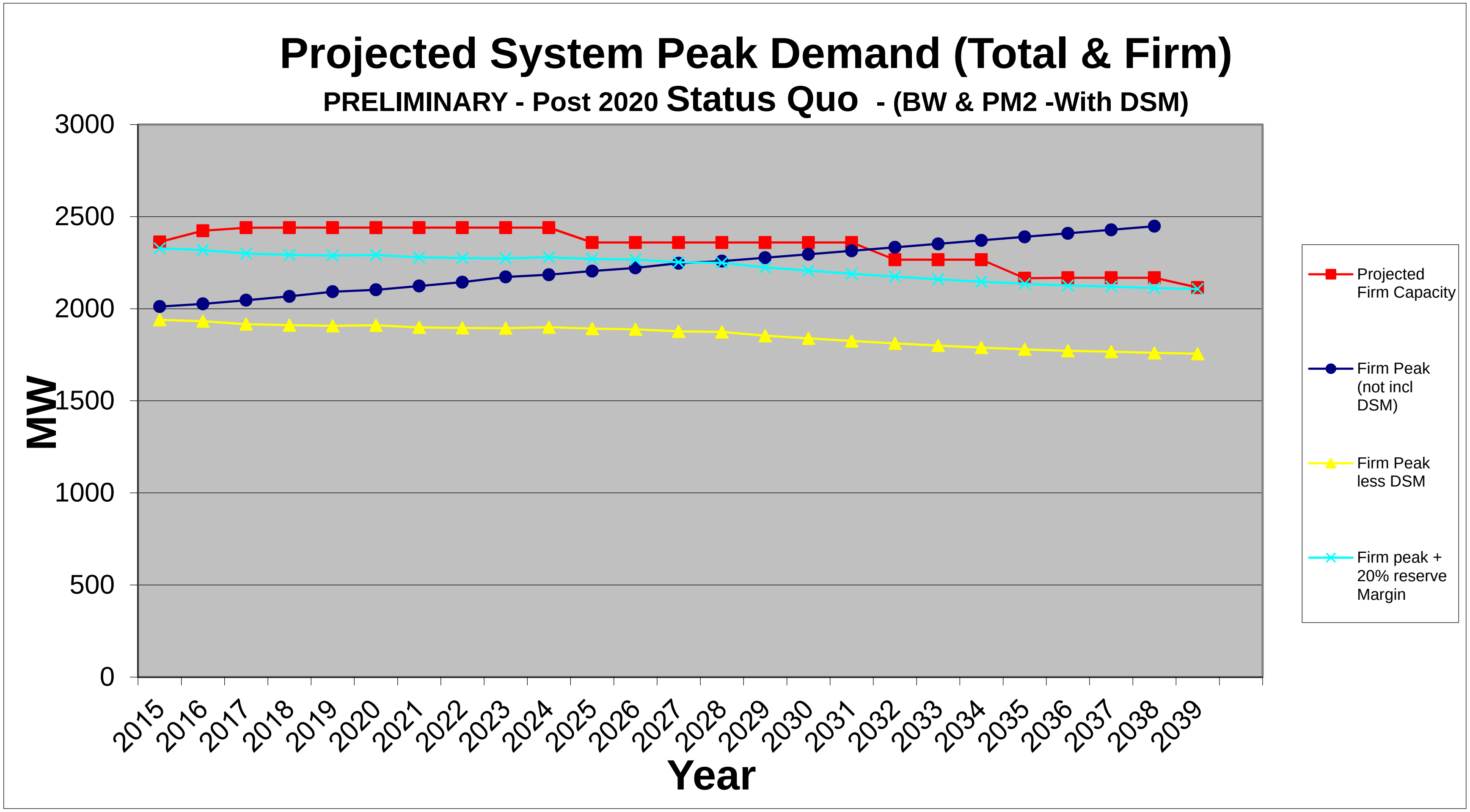
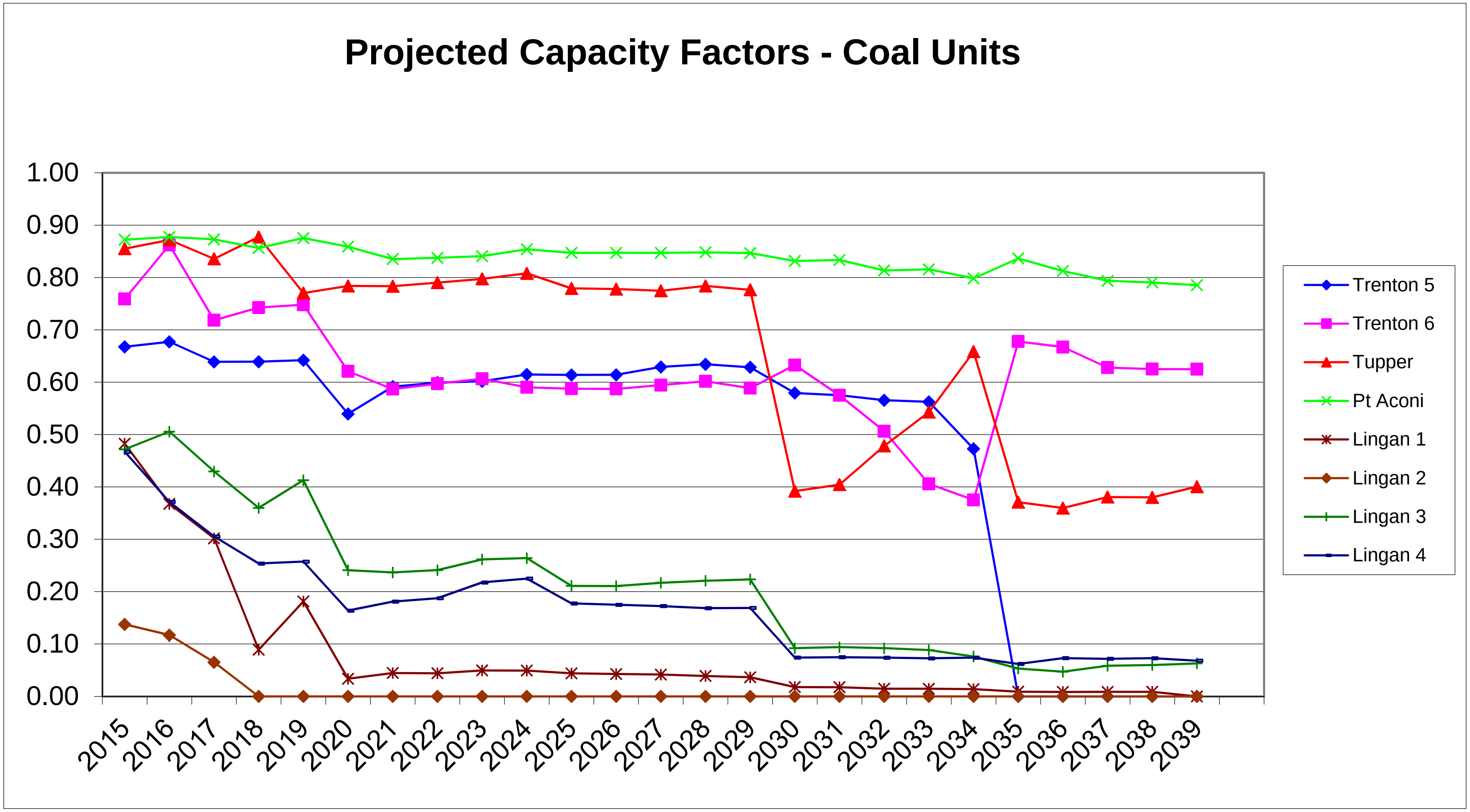
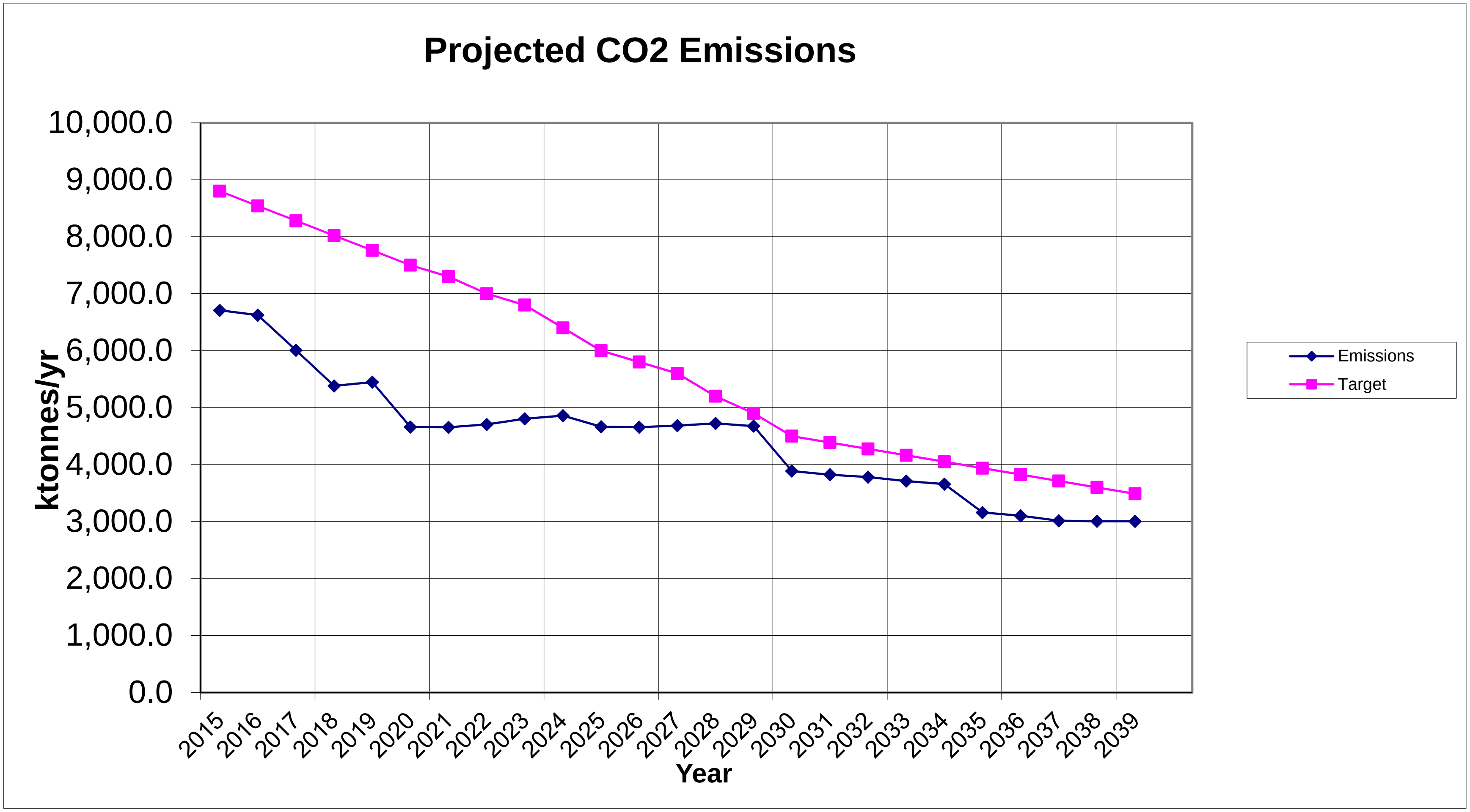
Run 1 (Preliminary)-Demand and DSM



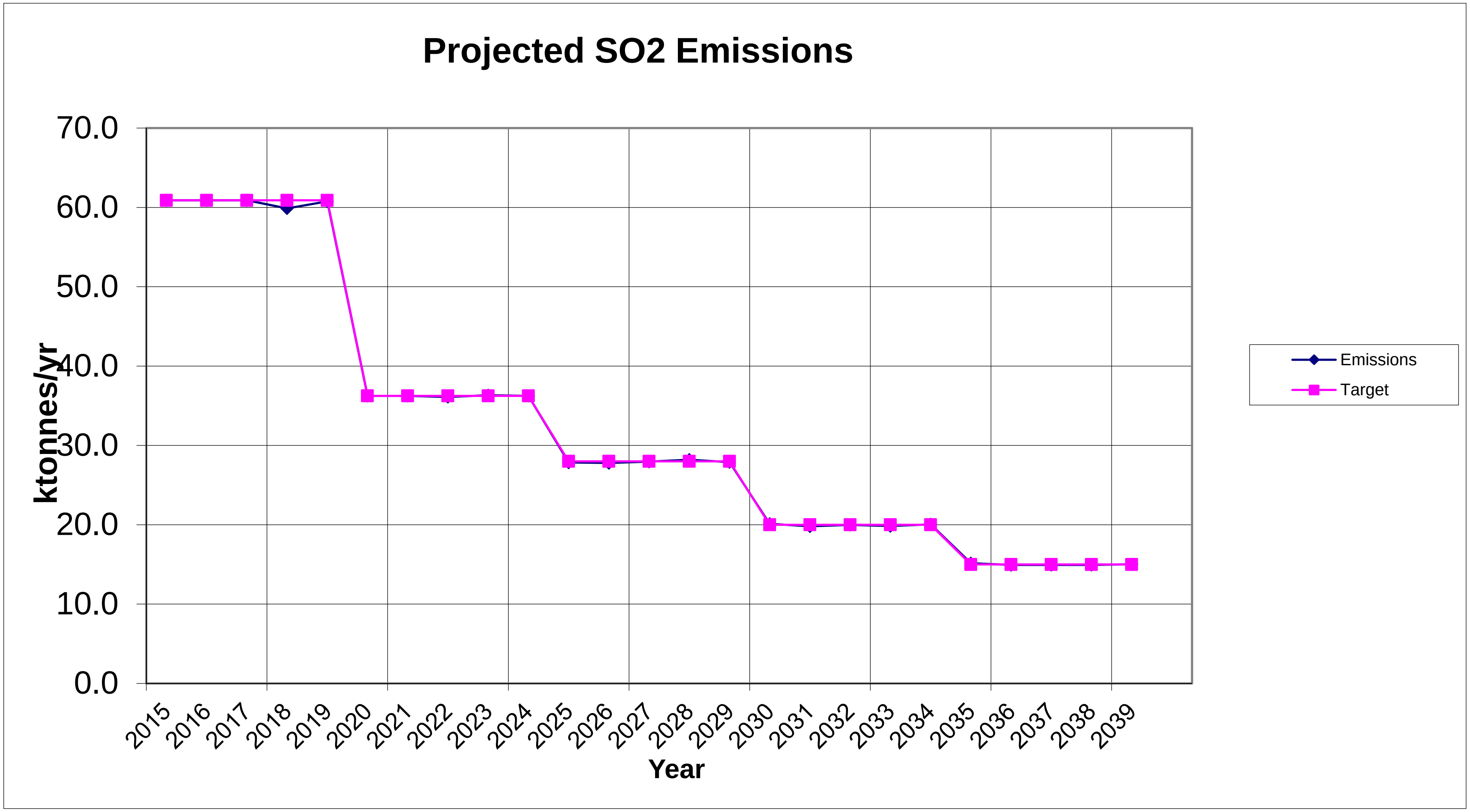
Run 1 (Preliminary)-Coal Capacity Factors



Run 1(Preliminary)-CO_2 Emissions



Run 1(Preliminary) – SO_2 Emissions



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JUNE 25, 2014

IRP Technical Conference – Progress Update

Agenda

- Key assumptions overview
- Candidate Resource Plans
    - What is a CRP
    - Plans screened and selected for modelling
    - How plans are modelled in Strategist
- Strategist® – Output and limitations
- Assumption variations in Candidate Resource plans
- Sustaining Capital requirements – 40 vs. 50 vs 60 yr. retirements
- Strategist run results to date
- Plexos use to enhance Candidate Resource Plan Analysis
- Next Steps in Analysis phase
    - Action Plan Development
    - Finalize CRP process and modelling
    - Determine sensitivities and worlds
    - Evaluate results and update stakeholders

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2014 IRP – Finalized Assumptions

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Final Environmental & Emissions Assumptions

CO_2/Greenhouse Gases Assumptions

Scenario A

- Emissions limits as per *An Agreement on the Equivalency of Federal and Nova Scotia Regulations for the Control of Greenhouse Gas Emissions from Electricity Producers in Nova Scotia* (Sept. 2012).
- Limit declines to 3.4 Mt in 2040.
- The downward path of the GHG constraint in Scenario A is consistent with the long range goals of the Federal Government for 2050.

Scenario B

- Emissions limits as per *An Agreement on the Equivalency of Federal and Nova Scotia Regulations for the Control of Greenhouse Gas Emissions from Electricity Producers in Nova Scotia* (Sept. 2012).
- No decline in limit post 2030.

CO_2/Greenhouse Gases Assumptions

Scenario C

- The Company will model GHG emission cuts to 2.25MT in 2040 as a Scenario C (and associated co-benefits for other air emissions and RES targets).

Air Pollutants Regulatory Context

- Nova Scotia *Air Quality Regulations* outline hard targets for SO_2, NOx, and Hg until 2020.
- In June 2013, Nova Scotia Environment released a discussion paper outlining emission limits for SO_2, NOx, and Hg until 2030.

SO_2 Assumptions

Scenario A

- Emissions limits as per *NS Air Quality Regulations* to 2020.
- Post 2020 limits guided by *Amendments to Greenhouse Gas & Air Quality Emissions Regulations Discussion Paper* (NSE, June 2013).

Scenario B

- Emissions limits as per *NS Air Quality Regulations.*
- 2020 Emission limit holds through 2040.

NOx Assumptions

Scenario A

- Emissions limits as per *NS Air Quality Regulations* to 2020.
- Post 2020 limits guided by *Amendments to Greenhouse Gas & Air Quality Emissions Regulations Discussion Paper* (NSE, June 2013).

Scenario B

- Emissions limits as per *NS Air Quality Regulations.*
- 2020 Emission limit holds through 2040.

Hg Assumptions

Scenario A

- Emissions limits as per *NS Air Quality Regulations.*
- 2015-2019 limits based on 65 kg limit minus supplemental emissions from 2010 through 2014.
- Post 2020 limits guided by *Amendments to Greenhouse Gas & Air Quality Emissions Regulations Discussion Paper* (NSE, June 2013).

Scenario B

- Emissions limits as per *NS Air Quality Regulations.*
- 2015-2019 limits based on 65 kg limit minus supplemental emissions from 2010 through 2014.
- Post 2020 limit is 35kg - limit holds through 2040.

RES Requirements

The following RES measures must be met by NSPI:

- As of 2014, at least 10% of net sales must be generated by renewable electricity, of which 5% can be NSPI owned.
- As of 2015, at least 25% of net sales must be generated by renewable electricity, of which at least 5% plus an additional 300 GWh must be supplied by IPPs. The additional generation may be supplied by the feed-in-tariff program, NSPI-owned facilities, or other sources of renewables. NSPI can only supply 150 GWh or less from co-firing biomass.
- As of 2020, at least 40% of net sales must be generated by renewable electricity, of which at least 5% plus an additional 300 GWh must be supplied by IPPs. The additional generation may be supplied by the feed-in-tariff program, distribution connected generators, up to 150 GWh of biomass co-firing, other NSPI-owned facilities, or other sources of renewables as well as 20% of the generation of Muskrat Falls.
- In addition, there is also a requirement to procure or generate 260 GWh of firm renewable electricity in 2013 and 350 GWh of firm renewables in 2014 and subsequent years. The regulatory definition of firm indicates this generation must be from sources commissioned after December 31, 2001, of which the Port Hawkesbury Biomass facility would apply.

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Final Future Supply Side Options Assumptions

Supply-Side Options

	Capacity (MW)	Heat Rate (btu/kWh)	Capital Cost (2013$) ($/kW)	Lead Time (years)	Readiness
Coal					
Single Unit Advanced PC	300	9,600	$3,600	4-8	TRL-9
Single Unit Advanced PC with CCS	360	12,800	$6,700	5-10	TRL-7
Underground Coal Gasification	300	9,600	$4,800	10-15	TRL-6
Single Unit Integrated Gasification Combined Cycle (IGCC)	360	8,700	$4,100	4-7	TRL-8
Single Unit IGCC with CCS	520	10,700	$6,600	5-10	TRL-6
Natural Gas					
Phased-in Conversion CC (Add HRSG)	150	8,000	$1,600	4-7	TRL-9
Conventional CC (2 x 1)	145	7,200	$1,500	3-5	TRL-9
Combustion turbine	100	8,700	$1,600	3	TRL-9
Combustion turbine	49	9,600	$1,100	2-4	TRL-9
Combustion turbine	34	9,700	$1,500	2-4	TRL-9
Conventional CC (1 X 1)	253	7,200	$1,400	3-5	TRL-9
Fuel Cells	10	9,500	$7,100	10-15	TRL-5
Uranium	not considered due to legislation				

Supply-Side Options

	Capacity (MW)	Heat Rate (btu/kWh)	Capital Cost (2013$) ($/kW)	Lead Time (years)	Readiness
Biomass					
Biomass Grate	60	13,500	$3,500	3-5	TRL-9
Wind					
Onshore Wind *	100		$2100-$2500 [1]	2	TRL-9
Solar					
Solar Thermal *	>10		$9,000	3-5	TRL-7
Photovoltaic *	>10		$3,500	3-5	TRL-7
Geothermal	Not considered although small sources available				
Municipal Solid Waste					
Municipal Solid Waste	50	18,000	$8,300	3-5	TRL-8
Hydroelectric					
Pumped Storage	100	85%	$2,700	5-10	TRL-9
Mersey Incremental Upgrade	30		$3,500	5-10	TRL-9
CAES	100	55%	$1,400	5-10	TRL-7
Tidal	10		$10,000	10-15	TRL-5
* Plus intermittent integration costs					

[1] Demonstrates range of costs from utility-built to COMFIT projects.

Future Environmental Control Technologies

Plant/Unit	Technology	Capital Cost			Emission Impact %Removal			
		Low	Base	High				
		(2013M$)			NOx	SO_2	Hg[1]	CO_2
Lingan								
	Wet Limestone FGD (300MW) (parasitic power 4 MW/ unit)		220 (300MW)		n/a	95	85[2]	n/a
	2.5%S Dry Lime FGD (300MW)		210		n/a	95	85[2]	n/a
	Carbon Capture 25% Power Penalty (in addition to scrubber)		790		n/a	95	85	70
	Baghouse (adapt ACI) (150 MW)		43					
	Baghouse (adapt ACI) (300MW)		85		n/a	n/a	85	n/a
Pt. Tupper	Natural Gas Co-fire[3]	-25%	12	+30%	n/a	n/a	n/a	n/a
Trenton 5	Co-firing Biomass	-25%	23	+40%	n/a	n/a	n/a	n/a
Trenton 6	Selective Catalytic Reduction		48		50	n/a	n/a	n/a

[1] Hg removal depends on coal specification

[2] Hg removal with FGD assumes unit has ACI

[3] Tupper NG co-fire - estimated max 53% co-fire due to other customers using gas on the pipeline. To get 100% co-fire there would be another $20-30M in NG pipeline upgrades.

Future Supply-side Thermal Options

Alternative	Technology	Capital Cost Low	Capital Cost Base	Capital Cost High	Net Capacity	Fuel Type
			(2013M$)		MW	
BSD Gas	Gas Conversion (4 units)		6.2		4 x 33	Gas
TUC1 +20	Increase Capacity		9.2		101	HFO/Gas
TUC2 +8	Increase Capacity		3.37		101	HFO/Gas

COMFIT Assumption

- Approximately 200MW of COMFIT projects approved by NS Energy.
- Based on projections of advanced projects assuming 90MW of COMFIT in operation by 2015.
- Based on number of projects approved by the provincial government, assume another 60 MW phased in over the next 2 years (2015-2016).
- Total 150MW of COMFIT wind generation by the end of 2016.

PPAs/Import Options

- NB IMPORT OPTIONS[1]:
  - Mass Hub Forecast plus NB Transmission Tariff
  - Option NB1: 100MW nonfirm – no transmission investments
  - Option NB2: 100MW firm – necessary transmission investments
  - Option NB3: 300MW firm – necessary transmission investments (some limits could apply with simultaneous imports from ML)

- ML SURPLUS ENERGY[1]:
  - Mass Hub Forecast
  - Option ML1: 300MW less Base Block – nonfirm

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[1] NS Power will work with Liberty and Synapse (Board Consultants) to establish price-quantity pairs for modeling imports.

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Final Existing Supply Assumptions Overview

Existing Supply

Thermal Unit	Net Demonstrated Capacity (MW)	In Service	Fuel
Pt Aconi	171	1994	Coal/Petcoke & limestone sorbent (CFB)
Lingan 1	153	1979	Coal/Petcoke/HFO
Lingan 2	153	1980	Coal/Petcoke/HFO
Lingan 3	158	1983	Coal/Petcoke/HFO
Lingan 4	153	1984	Coal/Petcoke/HFO
Tupper 2	152	1973, coal conversion 1987	Coal/Petcoke/HFO
Trenton 5	150	1969	Coal/Petcoke/HFO
Trenton 6	157	1991	Coal/Petcoke/HFO
Tufts Cove 1	81	1965	NG
Tufts Cove 2	93	1972	NG / HFO
Tufts Cove 3	147	1976	NG / HFO
Total	**1568**		
Combustion Turbines			
Burnside 1 - 4	4@33	1976	LFO
Victoria Junction 1 - 2	2@33	1975	LFO
Tusket 1	29	1971	LFO
Total	**227**		
Combined Cycle			
Tufts Cove 6	147	2011	NG
Import			
Maritime Link Base Block	153	Oct 2017	

Existing Supply

Hydro System	Net Demonstrated Capacity (MW)
Wreck Cove	210.0
Annapolis Tidal	3.5
Avon	6.8
Black River	22.5
Nictaux	8.3
Lequille	13.2
Paradise	4.7
Mersey	42.5
Sissiboo	27.0
Bear River	11.2
Tusket	2.4
Roseway/Harmony	1.8
St Margaret's Bay	10.8
Sheet Harbour	10.8
Dickie Brook	2.2
Fall River	0.5
Total	**378.1**
Biomass	
PH Biomass (mill load present/ not present)	45/52
Small Biomass IPP (2016)	10
Other	**Installed Capacity (MW)**
NSPI Owned Wind	80.8
Renewable IPP (Pre 2001)	25.8
Renewable IPP (Post 2001)	250.9
Renewable Electricity Administrator Projects	115.8
COMFIT (expected in-service by end of 2014)	91
Total	**564.3**

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Final Power Plant Life Assumptions

Generating Unit Retirement Assumption for IRP (Maximum Coal Cases)

Thermal Unit	Net Demonstrated Capacity (MW)	In Service	60 Year Life	Assumed Retirement Year for Modeling Puposes
Pt Aconi	171	1994	2054	Beyond planning horizon *
Lingan 1	153	1979	2039	2039
Lingan 2	153	1980	2040	2018 (Coincident with Maritime Link)
Lingan 3	158	1983	2043	Beyond planning horizon *
Lingan 4	153	1984	2044	Beyond planning horizon *
Tupper 2	152	1973, coal conversion 1987	2047	Beyond planning horizon *
Trenton 5	150	1969	2029	2035
Trenton 6	157	1991	2051	Beyond planning horizon *
Tufts Cove 1	81	1965	2025	2025
Tufts Cove 2	93	1972	2032	2032
Tufts Cove 3	147	1976	2036	2036

Tupper 2 assumes 60 years from date of coal conversion.
Trenton 5 expect to extend life beyond 60 years due to recent significant capital investment.
*25 year planning horizon 2015-2039.

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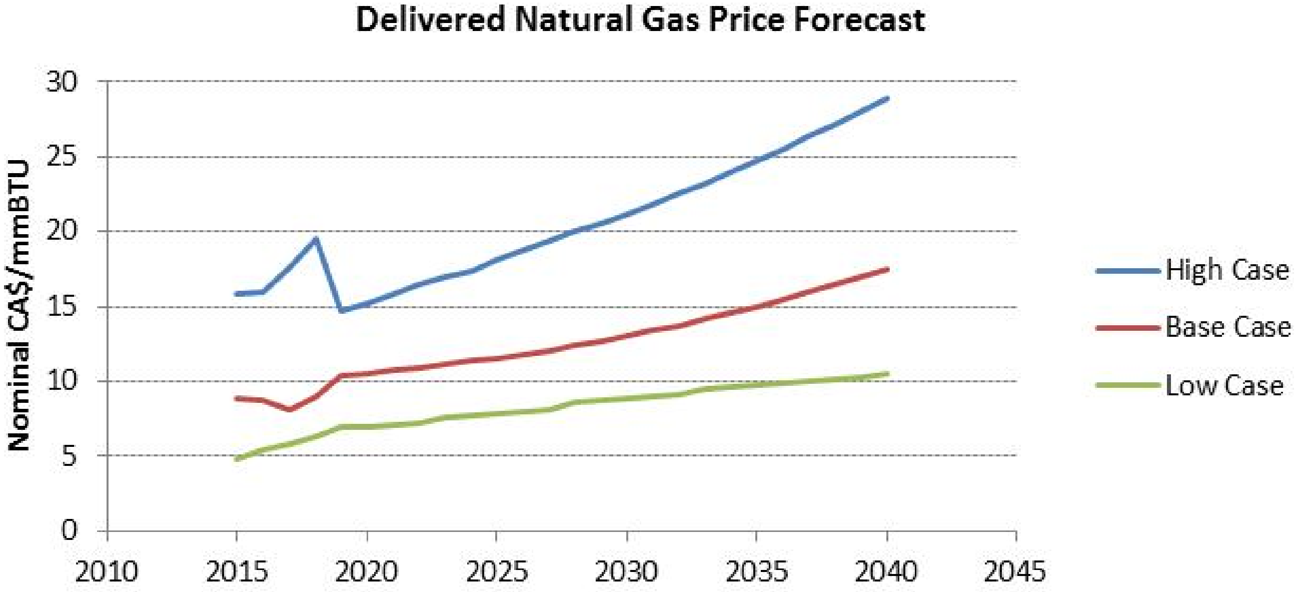
Final Fuel Price Forecast Assumptions

Natural Gas Price Assumptions



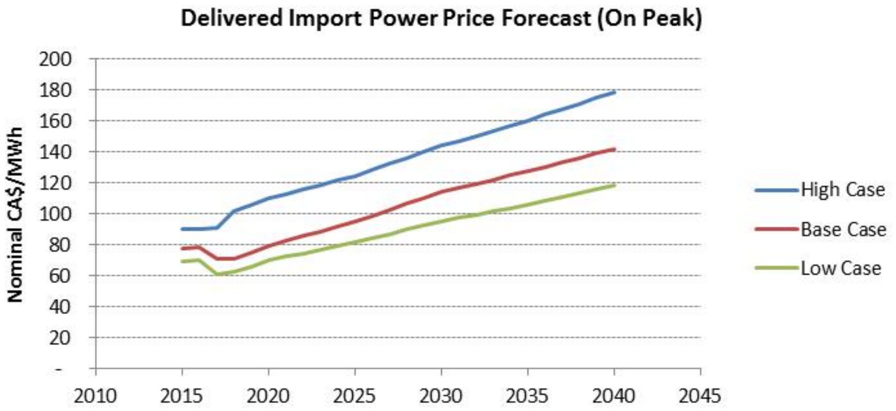
NS Natural Gas Delivered Price Forecast (Nominal CAD$/mmBTU)

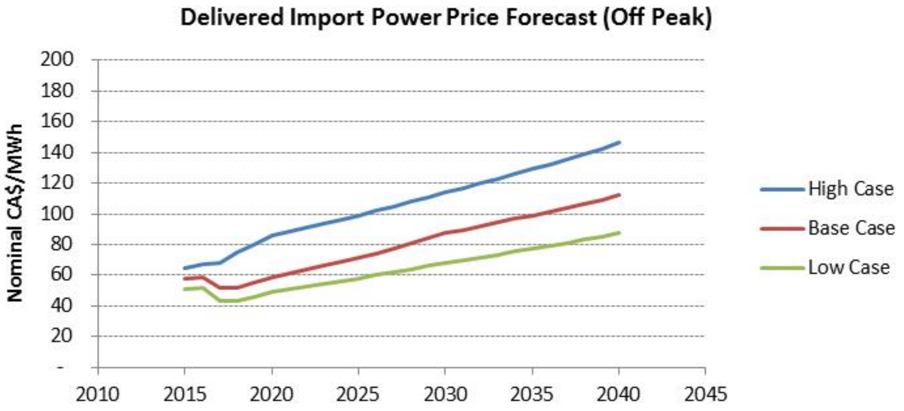
	2015	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2030*	*2035*	*2040*
High Case	15.8	16.0	17.7	19.5	14.7	15.2	15.8	16.4	16.9	17.4	18.1	21.2	24.7	28.9
Base Case	8.9	8.7	8.2	9.0	10.4	10.5	10.7	10.9	11.2	11.4	11.6	13.1	15.0	17.5
Low Case	4.8	5.4	5.8	6.3	6.9	7.0	7.1	7.2	7.6	7.8	7.9	8.8	9.8	10.4

NS Natural Gas Delivered Price Forecast (2014$/mmBTU)

	2015	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2030*	*2035*	*2040*
High Case	15.6	15.5	16.8	18.1	13.4	13.6	13.9	14.1	14.2	14.3	14.6	15.4	16.3	17.2
Base Case	8.8	8.4	7.7	8.4	9.5	9.4	9.4	9.4	9.4	9.4	9.3	9.5	9.9	10.4
Low Case	4.7	5.3	5.5	5.9	6.3	6.3	6.2	6.2	6.4	6.4	6.4	6.4	6.4	6.2

Long Term Price Assumptions


Delivered Import Power Price Forecast (On Peak)


Delivered Import Power Price Forecast (Off Peak)

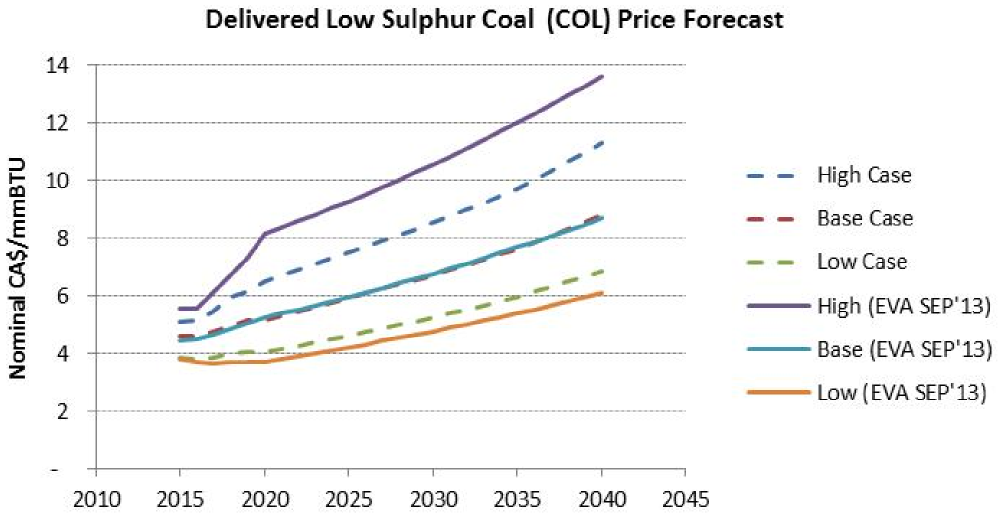
NS Delivered Power Forecast - On Peak (Nominal CA$/MWh)

	2015	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2030*	*2035*	*2040*
High Case	90	90	91	102	106	110	113	116	119	122	125	144	161	179
Base Case	78	79	71	71	75	80	83	86	89	92	95	114	128	142
Low Case	69	70	61	62	66	70	72	75	77	79	81	95	106	118

NS Delivered Power Forecast - Off Peak (Nominal CA$/MWh)

	2015	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2030*	*2035*	*2040*
High Case	64	67	68	75	80	86	88	91	94	96	99	114	129	146
Base Case	58	59	52	52	55	59	61	64	66	69	71	88	99	112
Low Case	51	52	43	43	46	49	51	53	54	56	58	68	77	87

LOW-SULPHUR COAL (COL)



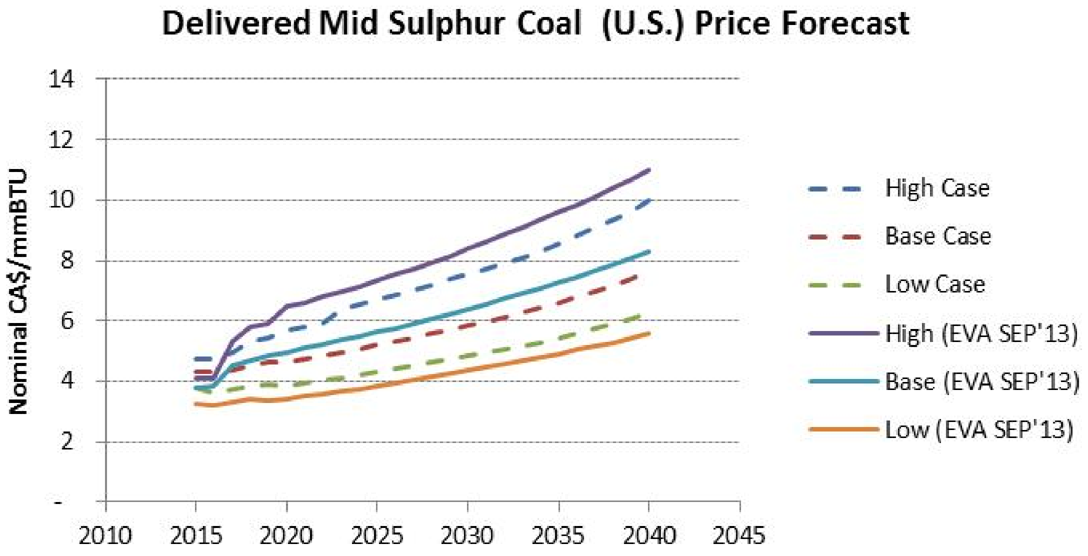
NS Delivered Low Sulphur (COL) Coal Price Forecast (Nominal CA$/mmBTU) (Plant Weighted)

	2015	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2030*	*2035*	*2040*
High Case	5.1	5.2	5.5	6.0	6.2	6.5	6.7	6.9	7.1	7.3	7.5	8.6	9.7	11.3
Base Case	4.6	4.6	4.8	5.0	5.2	5.2	5.3	5.5	5.6	5.8	5.9	6.7	7.6	8.8
Low Case	3.9	3.8	3.9	4.0	4.1	4.0	4.2	4.3	4.4	4.5	4.6	5.3	6.0	6.9

NS Delivered Low Sulphur (COL) Coal Price Forecast (2014 CA$/mmBTU) (Plant Weighted)

	2015	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2030*	*2035*	*2040*
High Case	5.0	5.0	5.2	5.5	5.6	5.8	5.8	5.9	5.9	6.0	6.0	6.2	6.4	6.8
Base Case	4.5	4.4	4.5	4.6	4.7	4.6	4.6	4.7	4.7	4.7	4.8	4.9	5.0	5.3
Low Case	3.8	3.7	3.6	3.7	3.7	3.6	3.6	3.7	3.7	3.7	3.7	3.8	3.9	4.1

MID-SULPHUR COAL (US)



NS Delivered Mid Sulphur (U.S.) Coal Price Forecast (Nominal CA$/mmBTU) (Plant Weighted)

	2015	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2030*	*2035*	*2040*
High Case	4.8	4.7	5.0	5.3	5.5	5.7	5.8	5.9	6.4	6.5	6.7	7.6	8.6	10.0
Base Case	4.3	4.3	4.4	4.5	4.6	4.6	4.7	4.9	5.0	5.1	5.2	5.9	6.6	7.7
Low Case	3.8	3.6	3.8	3.9	3.9	3.9	3.9	4.0	4.1	4.2	4.3	4.8	5.4	6.3

NS Delivered Mid Sulphur (U.S.) Coal Price Forecast (2014 CA$/mmBTU) (Plant Weighted)

	2015	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2030*	*2035*	*2040*
High Case	4.7	4.5	4.7	4.9	4.9	5.0	5.1	5.1	5.4	5.4	5.4	5.5	5.6	6.0
Base Case	4.2	4.1	4.1	4.2	4.2	4.1	4.1	4.1	4.2	4.2	4.2	4.3	4.4	4.6
Low Case	3.7	3.5	3.5	3.6	3.5	3.4	3.4	3.4	3.4	3.5	3.5	3.5	3.6	3.8

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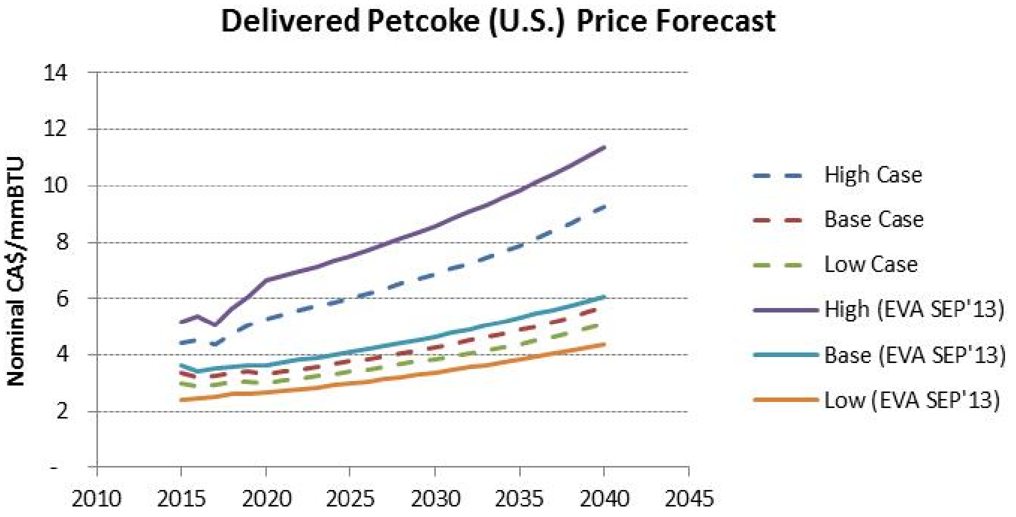
PETCOKE (US)



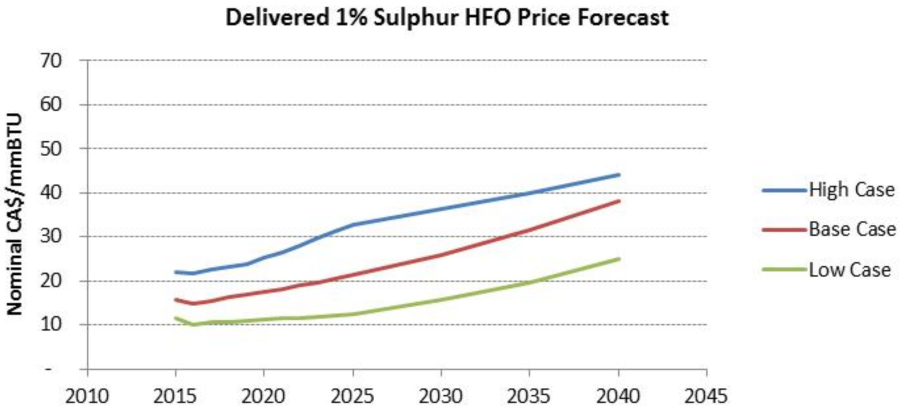
NS Delivered Pet Coke Forecast (Nominal CA$/mmBTU)

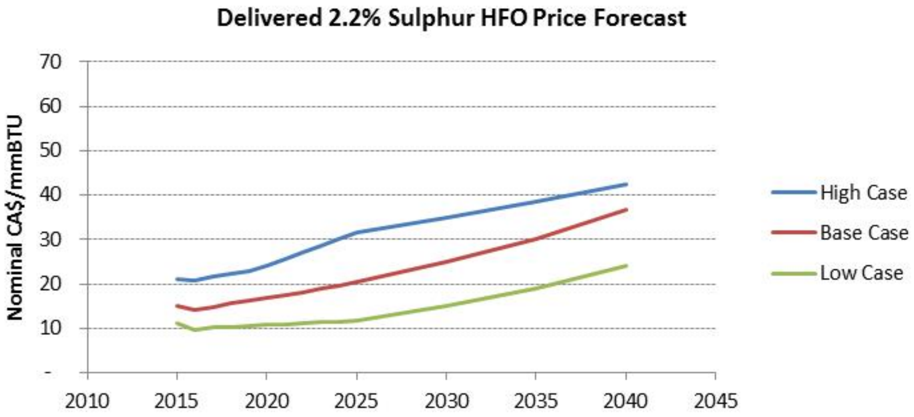
	2015	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2030*	*2035*	*2040*
High Case	4.4	4.5	4.4	4.7	5.1	5.3	5.4	5.6	5.7	5.9	6.0	6.9	7.9	9.3
Base Case	3.4	3.2	3.3	3.4	3.4	3.3	3.4	3.5	3.6	3.7	3.8	4.3	4.9	5.7
Low Case	3.0	2.9	2.9	3.0	3.1	3.0	3.1	3.2	3.2	3.3	3.4	3.9	4.4	5.1

NS Delivered Pet Coke Forecast (2014 CA$/mmBTU)

	2015	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2030*	*2035*	*2040*
High Case	4.4	4.3	4.1	4.4	4.6	4.7	4.7	4.8	4.8	4.8	4.8	5.0	5.2	5.5
Base Case	3.3	3.1	3.1	3.1	3.1	2.9	3.0	3.0	3.0	3.0	3.0	3.1	3.2	3.4
Low Case	2.9	2.8	2.8	2.8	2.8	2.7	2.7	2.7	2.7	2.7	2.7	2.8	2.9	3.0

HEAVY FUEL OIL PRICE ASSUMPTIONS


Delivered 1% Sulphur HFO Price Forecast


Delivered 2.2% Sulphur HFO Price Forecast

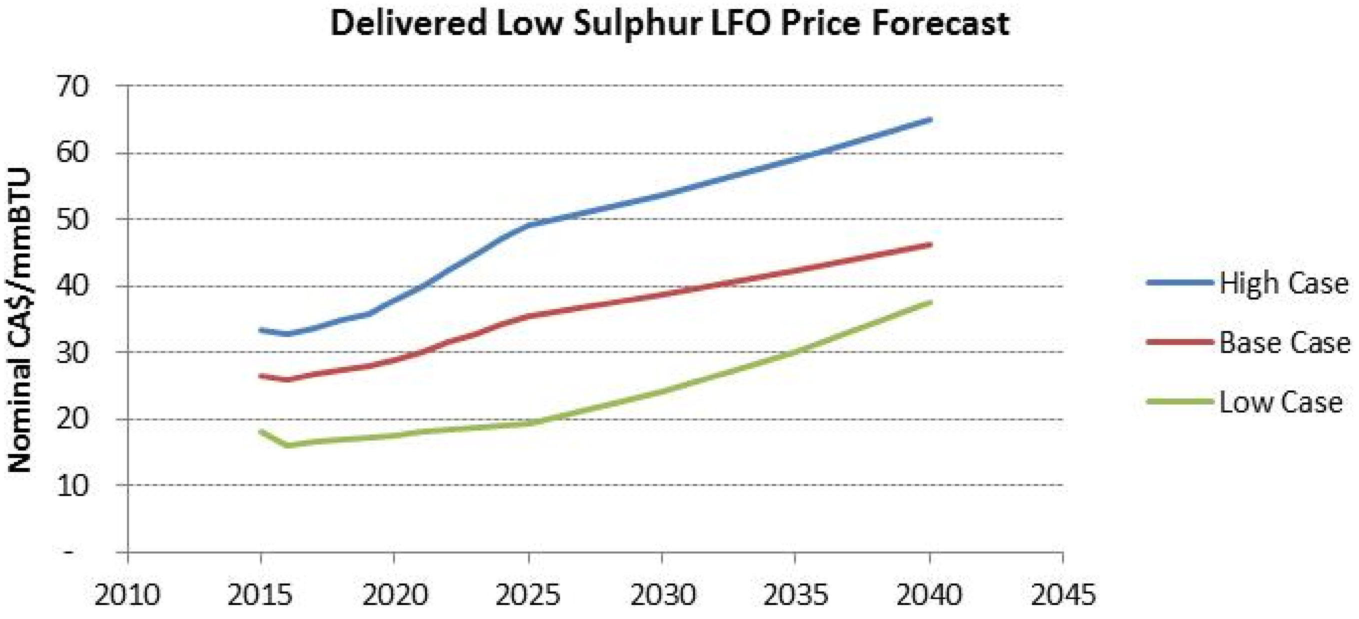
NS Delivered 1% HFO Forecast (Nominal CA$/mmBTU)

	2015	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2030*	*2035*	*2040*
High Case	21.9	21.8	22.5	23.2	23.8	25.2	26.6	28.1	29.6	31.2	32.9	36.3	40.0	44.2
Base Case	15.8	14.7	15.4	16.2	16.8	17.5	18.2	18.9	19.7	20.5	21.3	25.8	31.4	38.2
Low Case	11.5	10.0	10.5	10.7	10.9	11.2	11.4	11.6	11.8	12.1	12.3	15.6	19.7	25.0

NS Delivered 2.2% HFO Forecast (Nominal CA$/mmBTU)

	2015	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2030*	*2035*	*2040*
High Case	21.0	20.9	21.6	22.3	22.8	24.2	25.6	27.0	28.5	30.0	31.6	34.9	38.5	42.5
Base Case	15.2	14.2	14.9	15.6	16.2	16.8	17.5	18.2	18.9	19.7	20.5	24.8	30.2	36.7
Low Case	11.1	9.7	10.1	10.3	10.5	10.7	10.9	11.2	11.4	11.6	11.8	15.0	19.0	24.0

LIGHT FUEL OIL PRICE ASSUMPTIONS



NS Delivered Low S LFO Forecast (Nominal CA$/mmBTU) (Fleet Average)

	2015	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2030*	*2035*	*2040*
High Case	33.2	32.8	33.7	34.8	35.6	37.7	39.9	42.3	44.7	47.0	49.2	53.8	59.2	65.2
Base Case	26.6	26.0	26.6	27.4	28.1	28.8	30.0	31.5	32.9	34.2	35.5	38.8	42.4	46.3
Low Case	18.2	15.9	16.6	16.8	17.2	17.6	18.0	18.4	18.8	19.1	19.4	24.0	30.0	37.6

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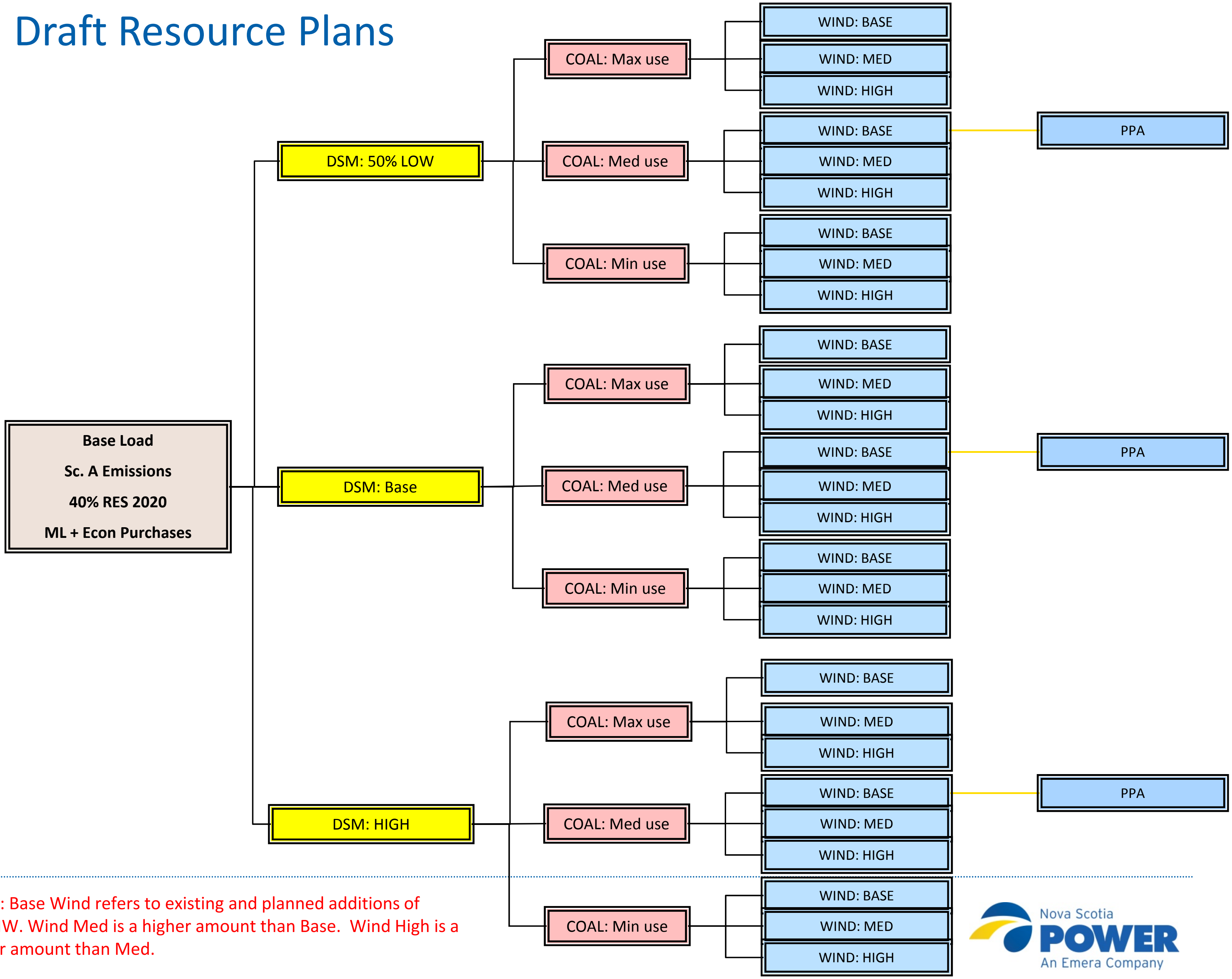
Candidate Resource Plans

Candidate Resource Plan Development

NS POWER & SYNAPSE CONSIDERED STAKEHOLDER FEEDBACK TO DEVELOP CANDIDATE RESOURCE PLANS (CRP)

- Key variables were identified as capable of significantly changing CRP outcomes
  - DSM, Variable generation levels, plant retirement dates and potential for a large PPA
- Using these variables, over 30 Draft CRPs were screened

Draft Resource Plans



- **Base Load**
Sc. A Emissions
40% RES 2020
ML + Econ Purchases
  - DSM: 50% LOW
    - COAL: Max use
      - WIND: BASE
      - WIND: MED
      - WIND: HIGH
    - COAL: Med use
      - WIND: BASE
        - PPA
      - WIND: MED
      - WIND: HIGH
    - COAL: Min use
      - WIND: BASE
      - WIND: MED
      - WIND: HIGH
  - DSM: Base
    - COAL: Max use
      - WIND: BASE
      - WIND: MED
      - WIND: HIGH
    - COAL: Med use
      - WIND: BASE
        - PPA
      - WIND: MED
      - WIND: HIGH
    - COAL: Min use
      - WIND: BASE
      - WIND: MED
      - WIND: HIGH
  - DSM: HIGH
    - COAL: Max use
      - WIND: BASE
      - WIND: MED
      - WIND: HIGH
    - COAL: Med use
      - WIND: BASE
        - PPA
      - WIND: MED
      - WIND: HIGH
    - COAL: Min use
      - WIND: BASE
      - WIND: MED
      - WIND: HIGH

NOTE: Base Wind refers to existing and planned additions of 582MW. Wind Med is a higher amount than Base. Wind High is a higher amount than Med.

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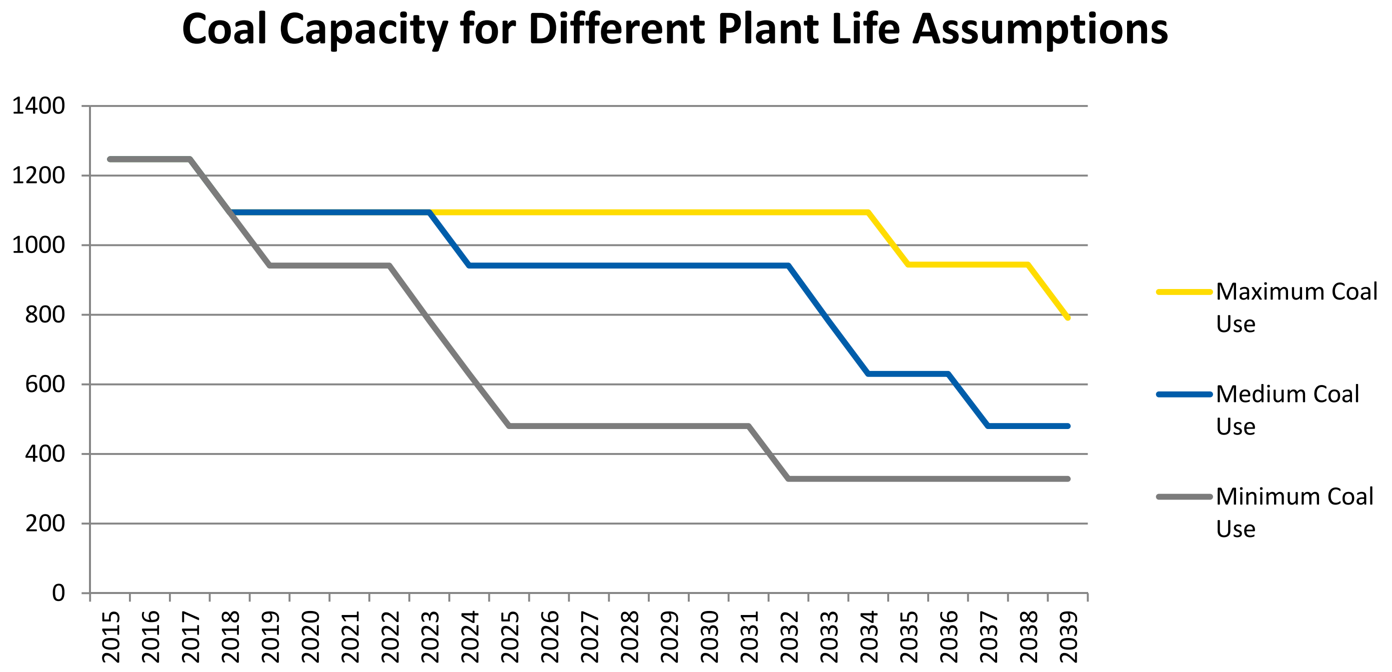
Plant Life Assumptions for Coal



Candidate Resource Plan Development

THE FOLLOWING RESOURCE PLANS HAVE BEEN CHOSEN FOR INITIAL OPTIMIZATION RUNS IN STRATEGIST®:

- Plan 1 (Base Run*): Case 1 (Low) DSM, 60 year coal plant retirements and base (currently planned – 582 MW) wind with PPA
- Plan 2: Case 2 (Base) DSM, 60 year coal plant retirements and base wind
- Plan 3: Case 2 (Base) DSM, 60 year coal plant retirements and high wind (up to 900 MW)
- Plan 4: Case 2 (Base) DSM, 50 year coal retirements and base wind
- Plan 5: Case 3 (High) DSM, 60 year coal retirements and base wind
- All plans to run under the Reference World, with assumed Scenario A emissions, 40% RES requirement by 2020 and Maritime Link + Economy energy purchases

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* formerly known as the "least cost" run

Candidate Resource Plan Development

THESE 5 INITIAL CRPs WERE SELECTED BASED ON:

- Representing each of the three levels of DSM
- Exploring the range of intermittent generation
- Changing only one variable relative to Base Load, Base DSM, Base Wind to see how individual variables affect the results

Candidate Resource Plan Development

MODELLING IN STRATEGIST®

- Enter the input assumptions for the particular CRP into the model
- Include the existing resources and additional resources committed in the CRP which are fixed in the model
- Strategist® then identifies optimal resource additions under that CRP as to type, timing, and quantity of resource
- Strategist® ensures that system requirements are met (e.g. planning reserve margin, emission limits, renewable energy)

CRP - Sustaining Capital

- Output from Strategist® provides a profile of unit capacity factors over the planning period for each CRP. This includes existing units as well as new units that are added in each CRP.
- Based on the capacity factors and the timing of unit retirements assumed for each CRP, a profile of sustaining capital costs can be developed for each unit
- These sustaining capital costs will be used to account for CRPs with differing retirement schedules.

CRP Plan Numbering

STRATEGIST® PRODUCES UP TO 4000 SEQUENTIAL OPTIONS FOR EACH CANDIDATE RESOURCE PLAN. THEY ARE RANKED FROM 1 TO 4000 BASED ON NET PRESENT VALUE

- NS Power has developed a naming convention for referencing these plans
- CRP 2 – is CRP 2
- CRP 2.1 - is the first plan (Lowest NPV) derived by Strategist® for CRP 2 assumptions
- CRP 2.8 – is the eighth most cost effective plan under CRP 2 assumptions....

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Strategist® Resource Optimization Model

Strategist® Detail

STRATEGIST® IS COMPOSED OF MODULES LINKED BY A GRAPHICAL USER INTERFACE. IT INCORPORATES ALL ASPECTS OF UTILITY PLANNING AND OPERATIONS INCLUDING:

- Modeling of forecasted load
- Production cost calculations including the dispatch of energy resources
- Optimization of future supply and demand side resources

Strategist® Detail

PRODUCTION COSTING AND ENERGY DISPATCH

- Provides production costs, unit generation, fuel usage, and emissions output through dispatch of resources.
- Strategist® is a planning tool and does not capture all the operational aspects of dispatch particularly those related to high levels of intermittent resources

Strategist® Detail

STRATEGIST® EVALUATES THE ECONOMICS OF ADDING NEW SUPPLY SIDE AND DEMAND SIDE ALTERNATIVES:

- Natural Gas CCs and CTs
- New Coal Options
- Demand Response programs
- Hydro option (Mersey upgrade)
- Renewable Options
- Control Technologies

An alternative can either be fixed in the plan as may be the case for a particular CRP and/or provided as an option for the model to pick from in the run.

Strategist® Detail

STRATEGIST® OPTIMIZATIONS:

- Strategist® optimizes the various alternatives while targeting an objective function, minimization of cost.
- The model create all possible combinations of new alternatives, subject to input constraints (reserve margin, emissions, min RES %, etc), to develop multiple resource plans.
- Several optimizations are required to get to a final set of plans because Strategist® can only solve for one hard emission cap at the time. Also, alternatives have to be introduced in a staged approach to manage problem size.
- Plans are ranked based on net present value cost.

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Candidate Resource Plan Input Variables

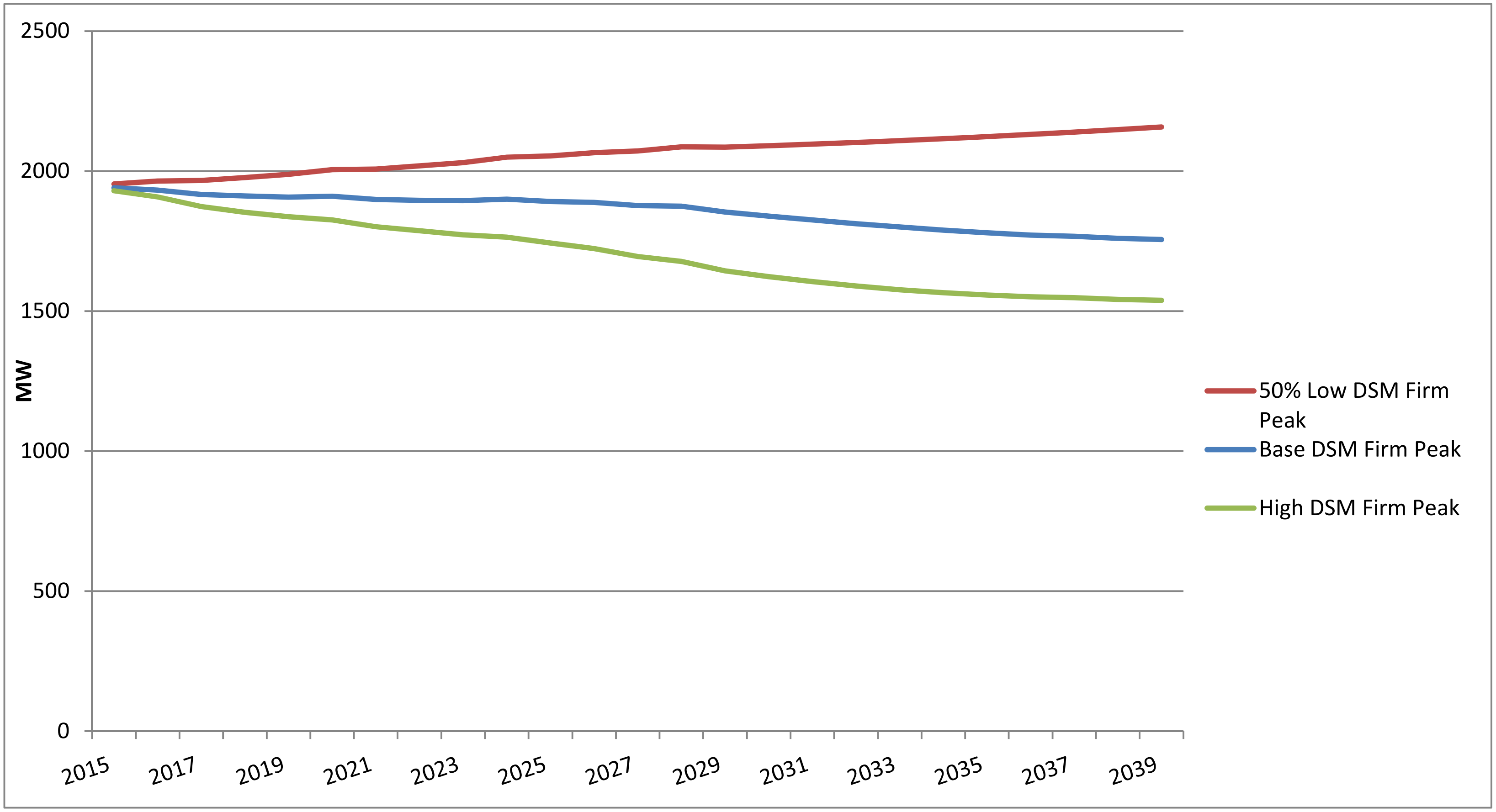
DSM Firm Demand Reduction

All Values in MWs

	No DSM Firm Peak	Base DSM Firm Peak Reduction	Base DSM Firm Peak		50% Low DSM Firm Peak Reduction	50% Low DSM Firm Peak		High DSM Firm Peak Reduction	High DSM Firm Peak
2015	1963	23	1940		9	1954		33	1930
2016	1986	54	1932		22	1964		78	1908
2017	2000	84	1916		34	1967		127	1874
2018	2020	110	1910		44	1977		168	1852
2019	2041	134	1907		53	1988		205	1836
2020	2066	156	1910		62	2005		241	1826
2021	2077	178	1899		70	2007		275	1802
2022	2097	202	1896		79	2018		311	1786
2023	2118	224	1894		88	2030		345	1773
2024	2147	247	1899		97	2050		383	1764
2025	2159	267	1892		105	2054		416	1743
2026	2178	290	1888		113	2065		455	1723
2027	2196	319	1877		125	2071		501	1695
2028	2221	347	1874		135	2086		544	1677
2029	2232	379	1853		147	2085		588	1644
2030	2251	412	1839		161	2090		628	1623
2031	2270	445	1825		174	2096		665	1605
2032	2288	476	1812		187	2102		698	1590
2033	2307	507	1800		199	2108		731	1576
2034	2326	537	1789		211	2115		761	1565
2035	2345	566	1780		223	2123		788	1557
2036	2364	593	1771		234	2130		813	1551
2037	2383	616	1767		244	2140		836	1548
2038	2403	643	1760		255	2148		861	1542
2039	2422	666	1756		264	2157		884	1538

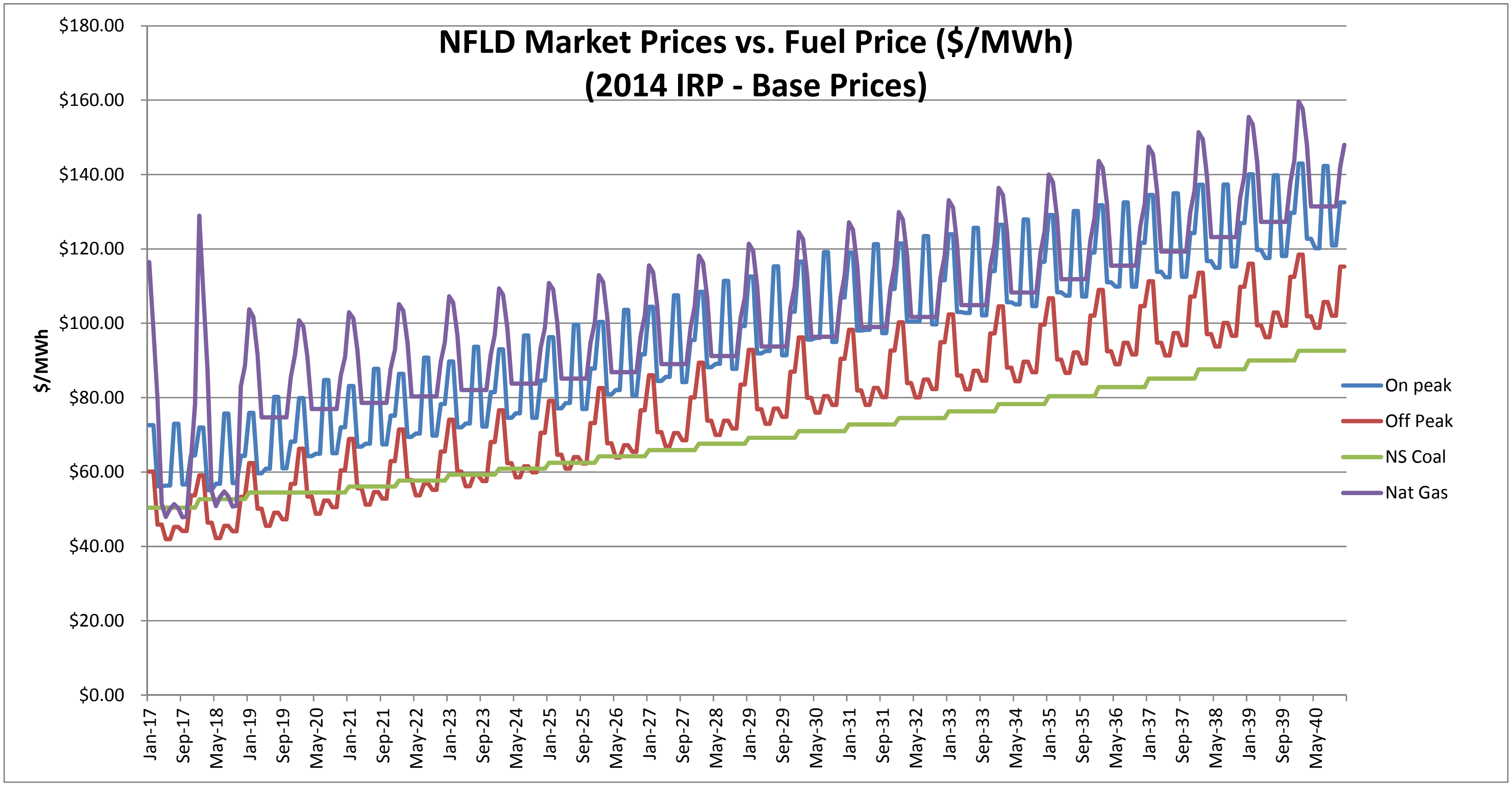
DSM Firm Demand Reduction

20% Planning Reserve Margin requirement based on Firm Peak demand



Relative Fuel and Power Costs

Base Values for Coal, Natural Gas and Power Prices



NFLD Market Prices are based on the Mass Hub forecast assuming no tariffs or netback (see Power Price forecast in April 11th Assumptions). Purchase price for Maritime Link surplus energy.

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Strategist® Preliminary Results

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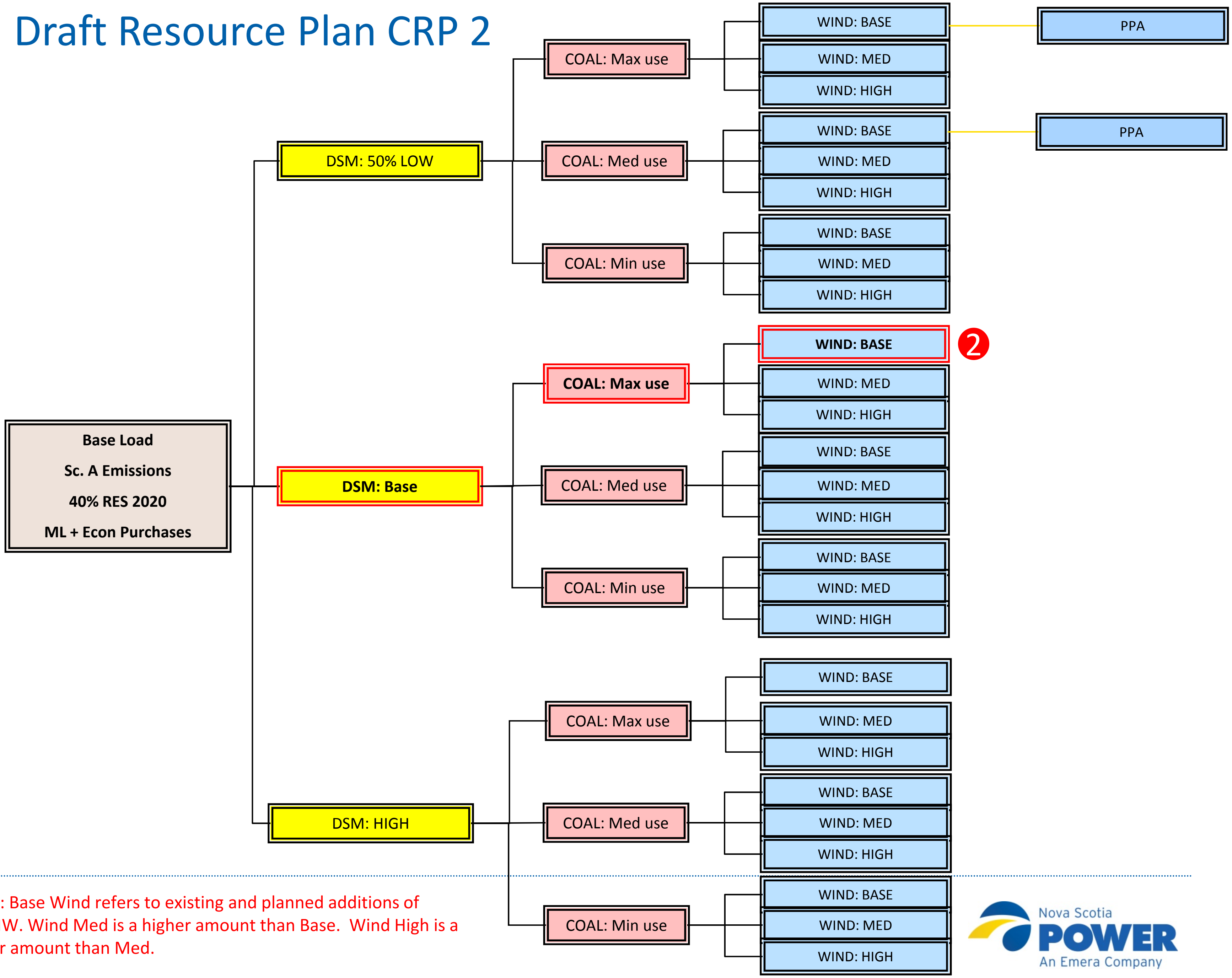
CRP 2 Preliminary Results

Draft Resource Plan CRP 2



- **Base Load**
  Sc. A Emissions
  40% RES 2020
  ML + Econ Purchases
  - DSM: 50% LOW
    - COAL: Max use
      - WIND: BASE
        - PPA
      - WIND: MED
      - WIND: HIGH
    - COAL: Med use
      - WIND: BASE
        - PPA
      - WIND: MED
      - WIND: HIGH
    - COAL: Min use
      - WIND: BASE
      - WIND: MED
      - WIND: HIGH
  - **DSM: Base**
    - **COAL: Max use**
      - **WIND: BASE** ②
      - WIND: MED
      - WIND: HIGH
    - COAL: Med use
      - WIND: BASE
      - WIND: MED
      - WIND: HIGH
    - COAL: Min use
      - WIND: BASE
      - WIND: MED
      - WIND: HIGH
  - DSM: HIGH
    - COAL: Max use
      - WIND: BASE
      - WIND: MED
      - WIND: HIGH
    - COAL: Med use
      - WIND: BASE
      - WIND: MED
      - WIND: HIGH
    - COAL: Min use
      - WIND: BASE
      - WIND: MED
      - WIND: HIGH

NOTE: Base Wind refers to existing and planned additions of 582MW. Wind Med is a higher amount than Base. Wind High is a higher amount than Med.

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CRP 2 Input Assumptions

- Base Load Forecast
- Base DSM
- Emissions - Scenario A
- Planned and committed resources are fixed in the plan (REA wind, COMFIT, Maritime Link/ Retire Lin #2)
- Maximum Coal Use
- Constraints
  - Planning reserve margin min = 20%
  - RES: 2015-2019 = 25%; 2020-2039 = 40%

CRP 2 Preliminary Results

	CRP2-1-R01	**CRP2-8-R01**	**CRP2-50-R01**
	Least cost study period	**Plan of interest**	**Least cost Planning period**
2015			
2016		DR - Water Heaters	
2017	ML Oct 2017	ML Oct 2017	ML Oct 2017
	Lin 2 retire	Lin 2 retire	Lin 2 retire
2018			
2019		Mersey Phase 1	
2020			
2021			
2022			
2023		Mersey Phase 2	
2024			
2025	TUC 1 Retire	TUC 1 Retire	TUC 1 Retire
			FGD (Lin 3/4 300 MW)
2026			
2027			
2028			
2029			
2030			
2031			
2032	TUC 2 Retire	TUC 2 Retire	TUC 2 Retire
2033			
2034			
2035	CT 50MW	CT 50MW	CT 50MW
	Tre 5 Retire	Tre 5 Retire	Tre 5 Retire
2036	CT100 MW & CT50 MW	CT50 MW	CT100 MW & CT50 MW
	TUC 3 Retire	TUC 3 Retire	TUC 3 Retire
2037			
2038			
2039	CT 100 MW	CT 100 MW	CC 145 MW
	Lin 1 Retire	Lin 1 Retire	Lin 1 Retire
Planning PV $M	11,274	11,365	11,247
Study PV $M	17,002	17,033	17,113

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CRP 2.1 Preliminary Results

CRP 2.1 Preliminary Results

	CRP 2.1 (Base Run)
2015	
2016	
2017	ML Oct 2017 Lin 2 retire
2018	
2019	
2020	
2021	
2022	
2023	
2024	
2025	TUC 1 Retire
2026	
2027	
2028	
2029	

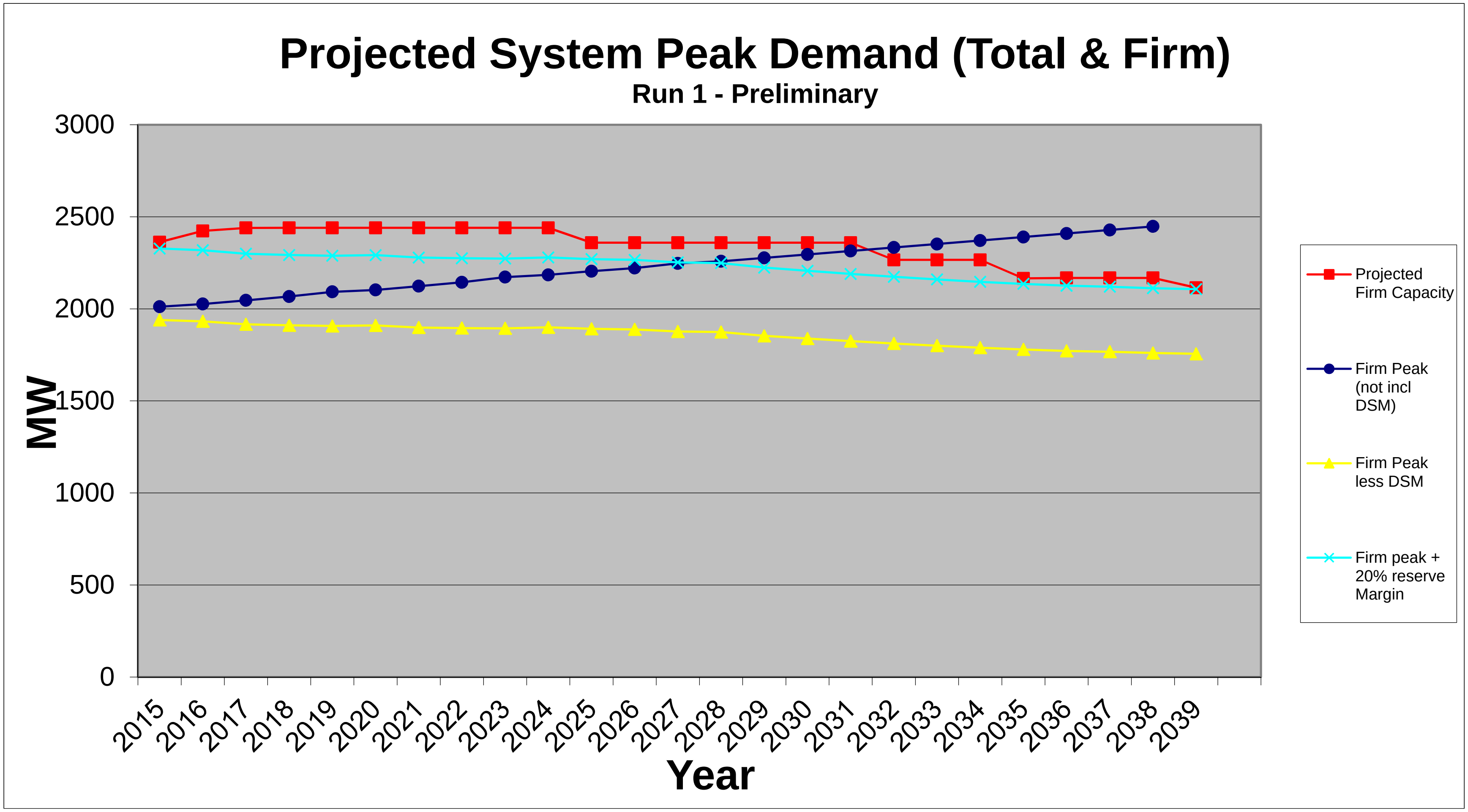
2030	
2031	
2032	TUC 2 Retire
2033	
2034	
2035	CT 50MW Tre 5 Retire
2036	CT100 MW & CT50 MW TUC 3 Retire
2037	
2038	
2039	CT 100 MW Lin 1 Retire
Planning PV $M	11,274
Study PV $M	17,002

CRP 2.1 Preliminary - Load and Resources

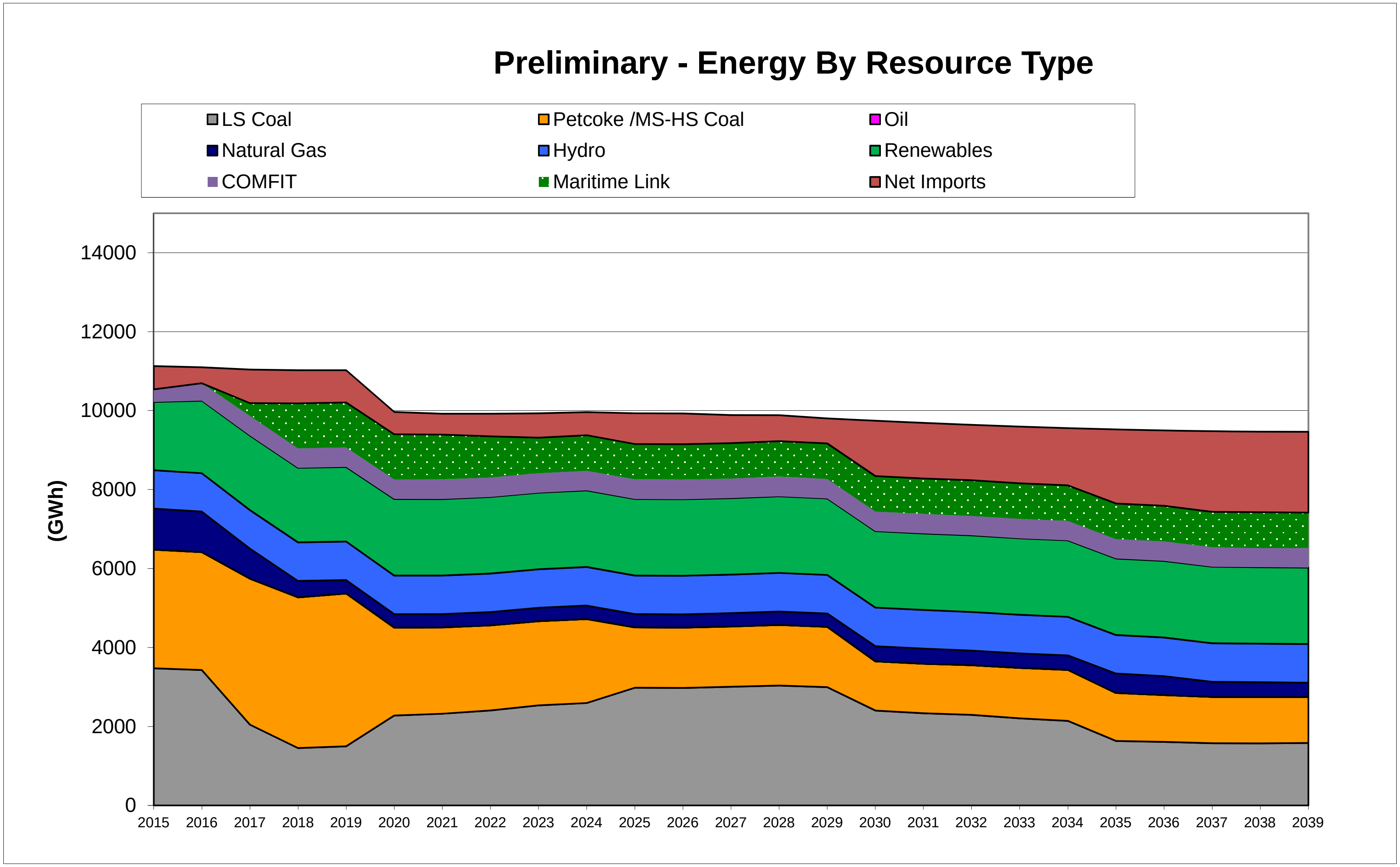
	2015	2016	2017	2018	2019	2020	2025	2030	2035	2036	2037	2038	2039
Firm Peak	1,963	1,986	2,000	2,020	2,041	2,066	2,159	2,251	2,345	2,364	2,383	2,403	2,422
DSM	23	54	84	110	134	156	267	412	566	593	616	643	666
Firm Peak Less DSM	1,940	1,932	1,916	1,910	1,907	1,910	1,892	1,839	1,780	1,771	1,767	1,760	1,756
RM Required	388	386	383	382	381	382	378	368	356	354	353	352	351
Required MWs	2,328	2,319	2,299	2,293	2,288	2,292	2,270	2,206	2,136	2,126	2,120	2,112	2,107
Existing MWs	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341
Resource Additions (MW):													
Burnside #4		33											
COMFIT - Biomass	4.2	6											
COMFIT - Wind	14.14	4.56	5.1										
REA Wind	2.35	17.34											
Maritime Link				153.25									
Small Biomass PPA			10										
Hydro			1.8										
Additional Wind													
Assumed Unit Retirement				-153			-81		-150	-147			-153
Natural Gas Unit									49.4	149.4			100
Total Annual Additions	20.7	60.9	16.9	0.3	0.0	0.0	-81.0	0.0	-100.6	2.4	0.0	0.0	-53.0
Total Cumulative Additions	20.7	81.6	98.5	98.7	98.7	98.7	17.7	17.7	-175.9	-173.5	-173.5	-173.5	-226.5
Total Firm Capacity	2362	2423	2440	2440	2440	2440	2359	2359	2166	2168	2168	2168	2115
Surplus (Deficit) MWs above RM	34	104	141	148	152	148	89	153	30	42	48	56	8
Reserve Margin %	21.8%	25.4%	27.3%	27.7%	28.0%	27.8%	24.7%	28.3%	21.7%	22.4%	22.7%	23.2%	20.4%

Resource Type	Firm MW
Thermal	1568
Diesel CTs	194
Combined Cycle	147
Hydro	376
Firm Contribution of Renewables	56
Total Existing	**2341**

CRP 2.1 Preliminary - Demand and DSM



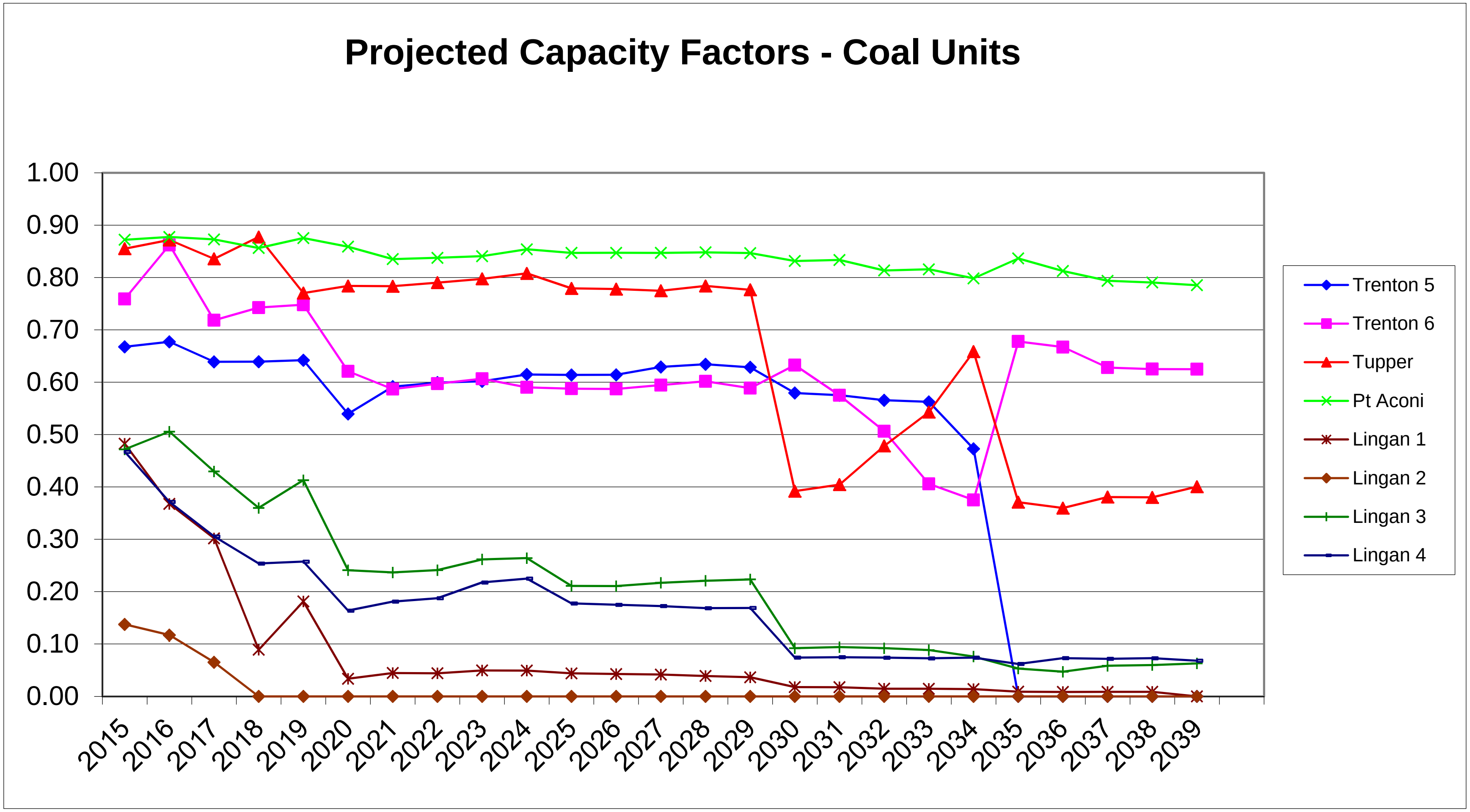
CRP 2.1 Preliminary Energy by Resource Type



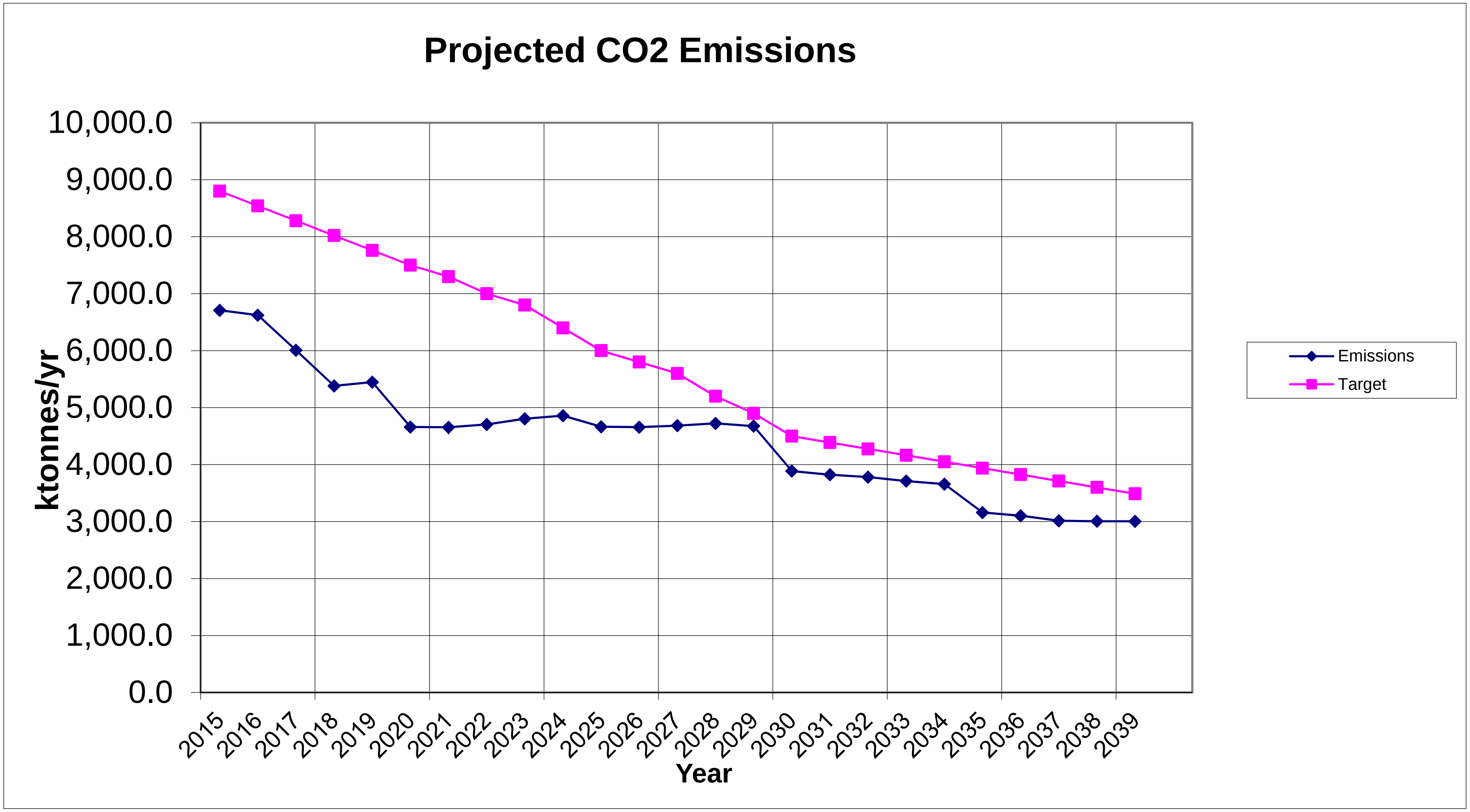
Step change in load starting in 2020 - assumes a large industrial customer (PHP) is in-service until 2019 and off-line starting in 2020.

Net Imports include economy energy imports from NB and Maritime Link surplus energy.

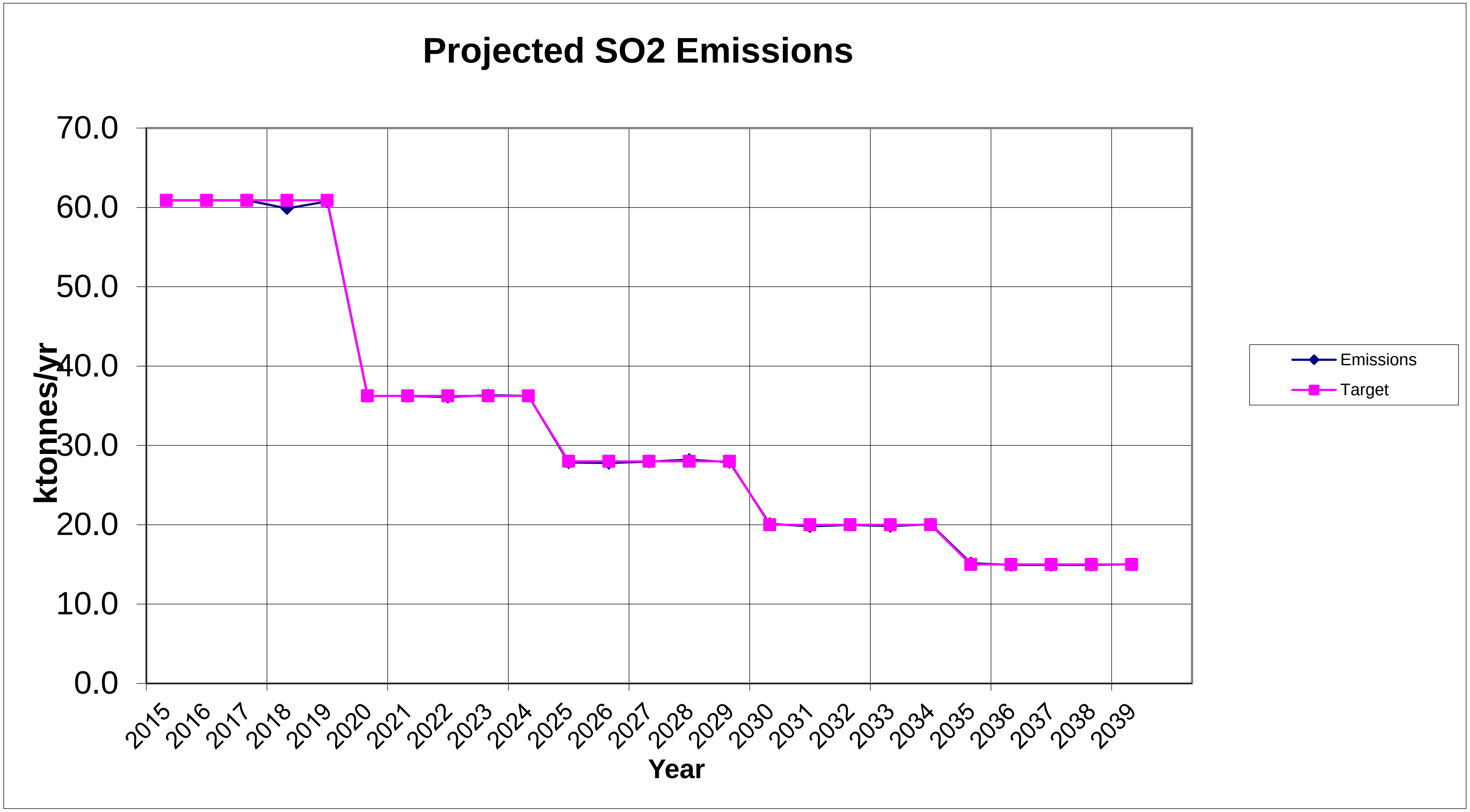
CRP 2.1 Preliminary - Coal Capacity Factors



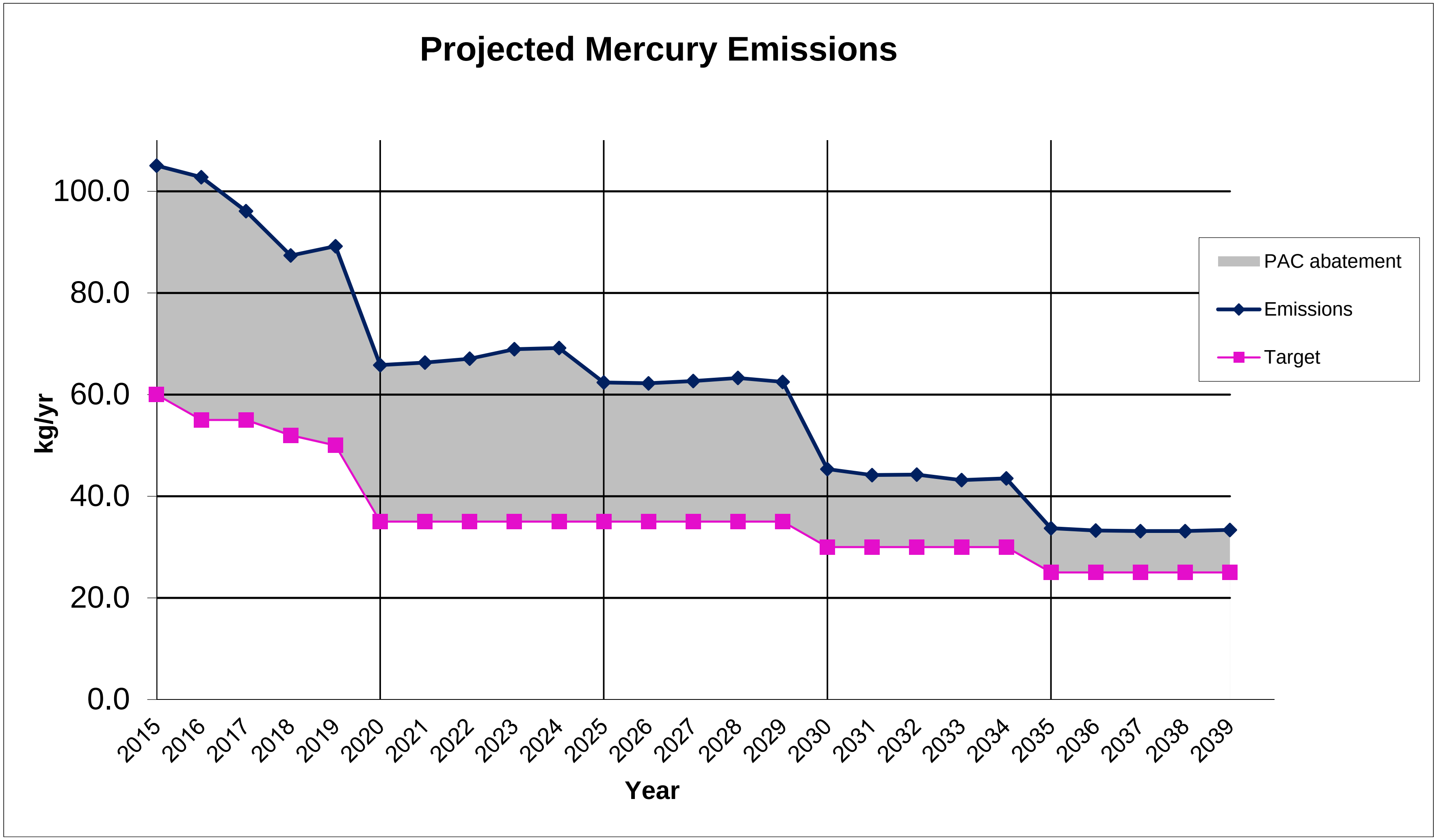
CRP 2.1 Preliminary - CO_2 Emissions



CRP 2.1 Preliminary - SO_2 Emissions



CRP 2-1 Preliminary Hg Emissions



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CRP 2-8 Preliminary Results

CRP 2-8 Preliminary Load and Resources

	2015	2016	2017	2018	2019	2020	2025	2030	2035	2036	2037	2038	2039
Firm Peak	1,963	1,986	2,000	2,020	2,041	2,066	2,159	2,251	2,345	2,364	2,383	2,403	2,422
DSM	23	54	84	110	134	156	267	412	566	593	616	643	666
Firm Peak Less DSM	1,940	1,932	1,916	1,910	1,907	1,910	1,892	1,839	1,780	1,771	1,767	1,760	1,756
DRWH Reduction	0	1	2	4	7	10	39	60	62	60	62	62	62
Firm Peak Less DR	1,940	1,931	1,914	1,906	1,900	1,900	1,852	1,779	1,718	1,712	1,705	1,698	1,694
RM Required	388	386	383	381	380	380	370	356	344	342	341	340	339
Required MWs	2,328	2,317	2,296	2,287	2,280	2,280	2,223	2,134	2,062	2,054	2,046	2,038	2,033
Existing MWs	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341
Resource Additions (MW):													
Burnside #4		33											
COMFIT - Biomass	4.2	6											
COMFIT - Wind	14.1	4.6	5.1										
REA Wind	2.4	17.3											
Maritime Link				153									
Small Biomass PPA			10										
Hydro			1.8		15								
FGD parasitic power													
Additional Wind													
Assumed Unit Retirement				-153			-81		-150	-147			-153
Natural Gas Unit									49.4	49.4			100
Total Annual Additions	20.7	60.9	16.9	0.3	15.0	0.0	-81.0	0.0	-100.6	-97.6	0.0	0.0	-53.0
Total Cumulative Additions	20.7	81.6	98.5	98.7	113.7	113.7	47.7	47.7	-145.9	-243.5	-243.5	-243.5	-296.5
Total Firm Capacity	2362	2423	2440	2440	2455	2455	2389	2389	2196	2098	2098	2098	2045
Surplus (Deficit) MWs above RM	34	106	143	153	175	175	167	255	134	44	52	60	12
Reserve Margin %	21.8%	25.5%	27.5%	28.0%	29.2%	29.2%	29.0%	34.3%	27.8%	22.6%	23.0%	23.5%	20.7%

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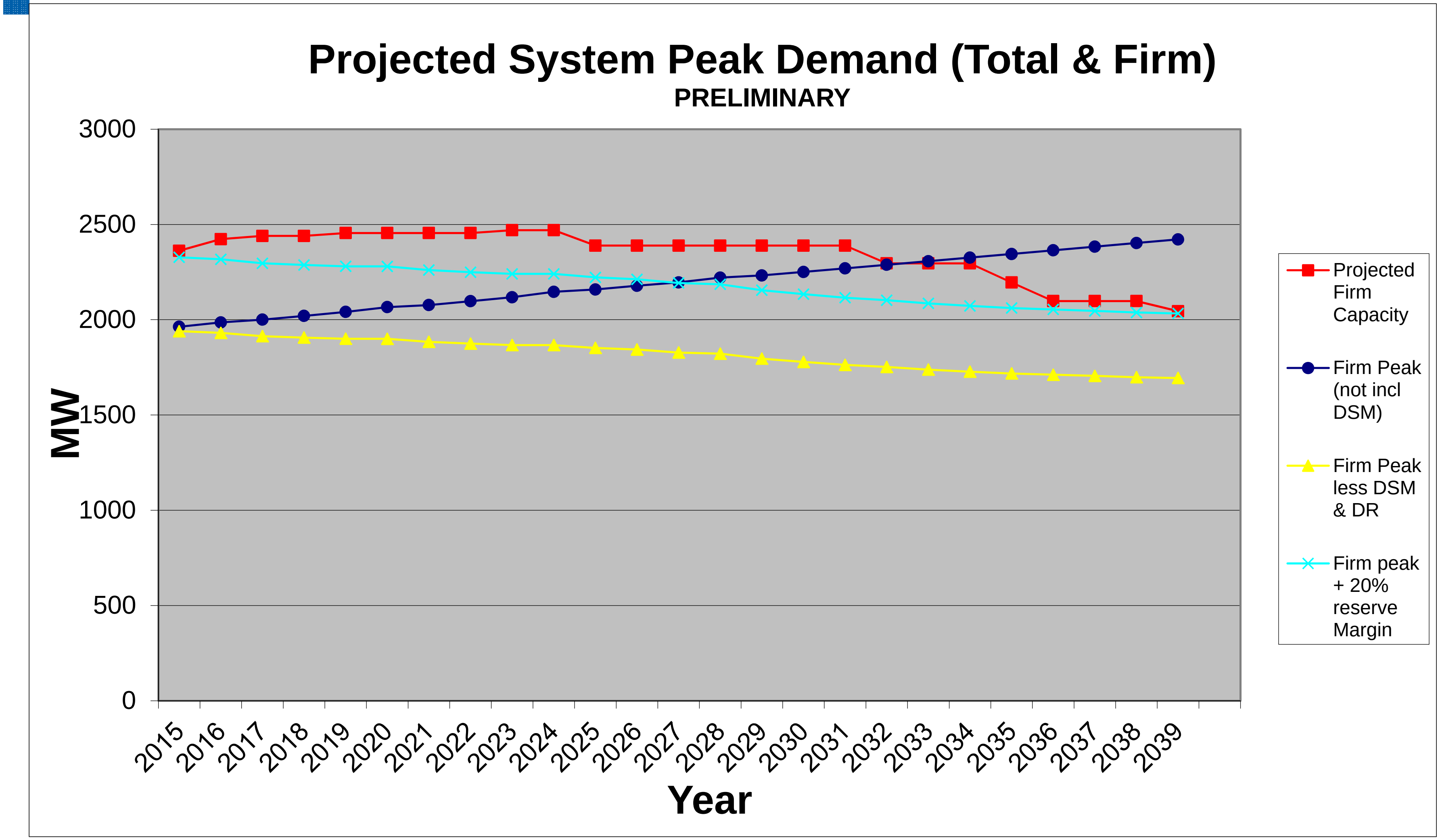
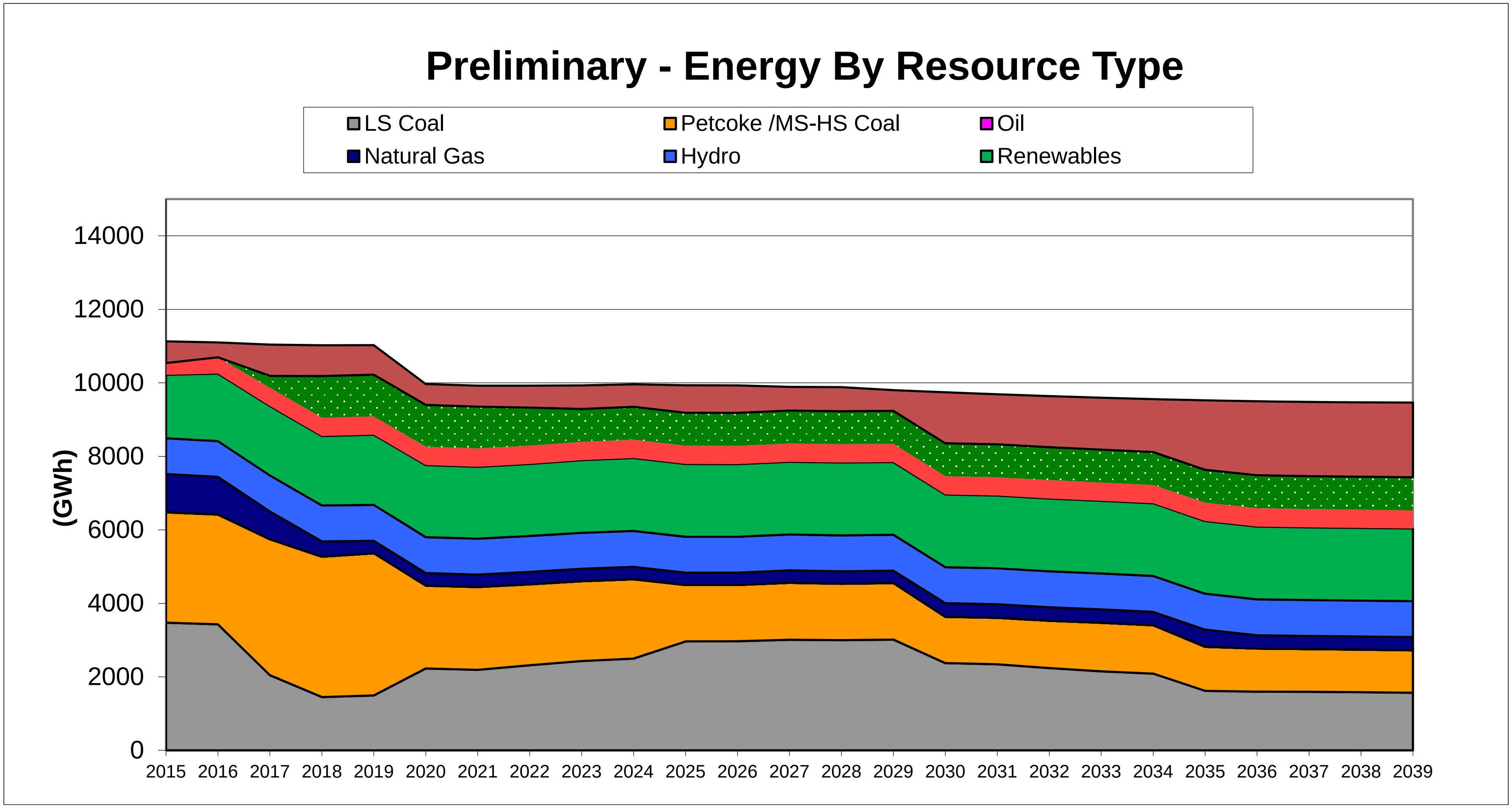
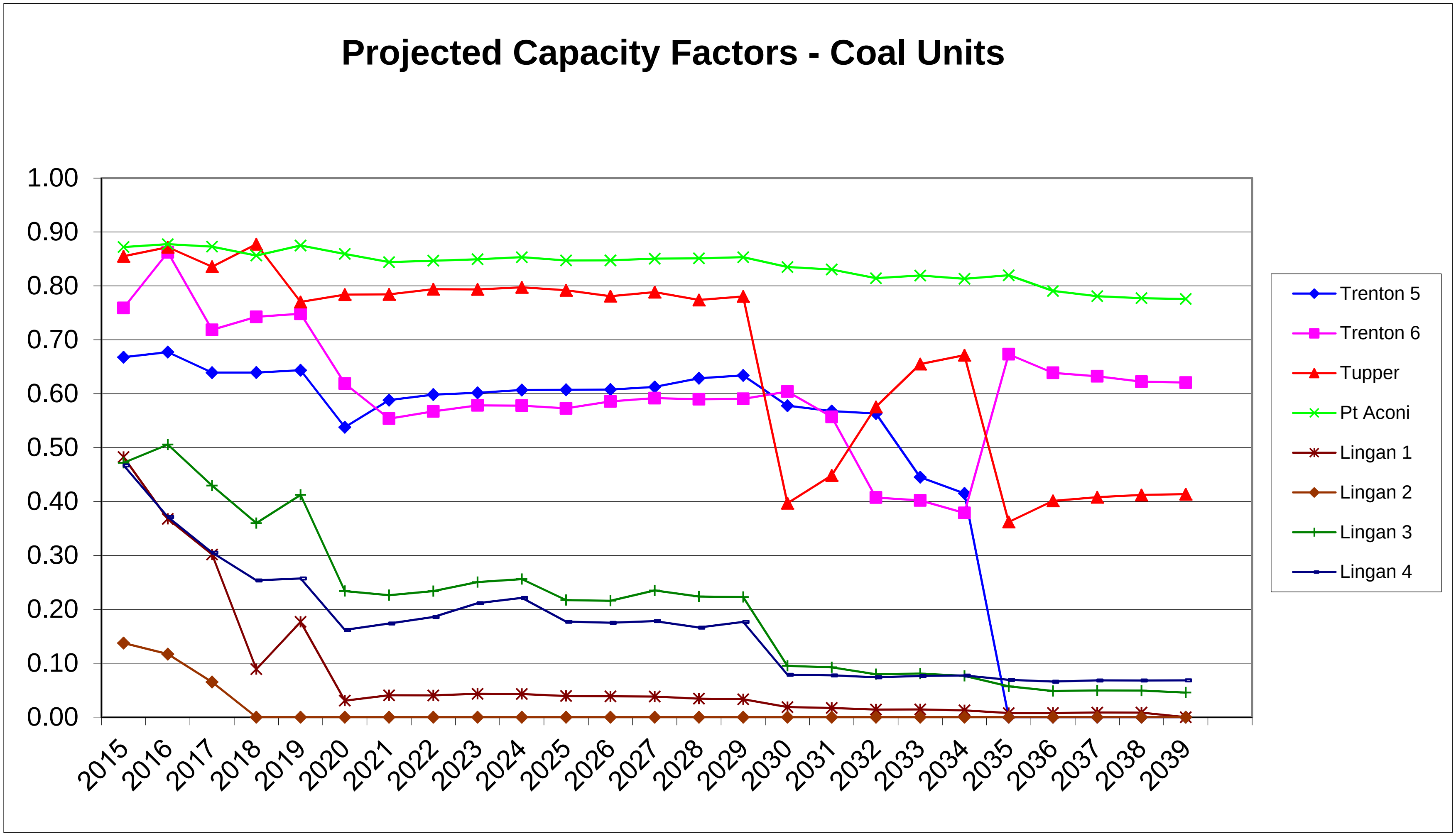
CRP 2-8 Preliminary Demand and DSM



CRP 2-8 Preliminary Energy by Resource Type



CRP 2-8 Preliminary Coal Capacity Factors



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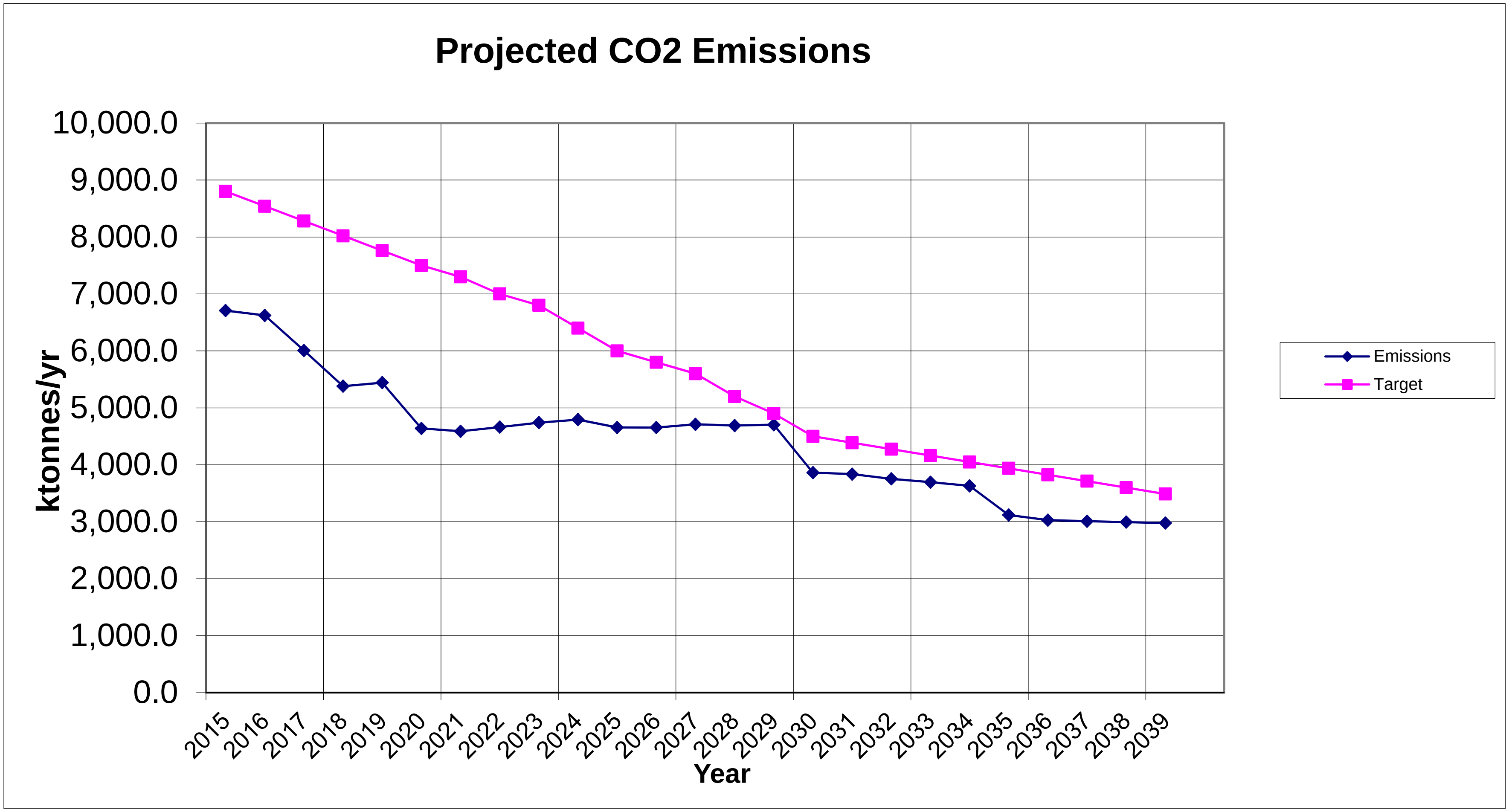
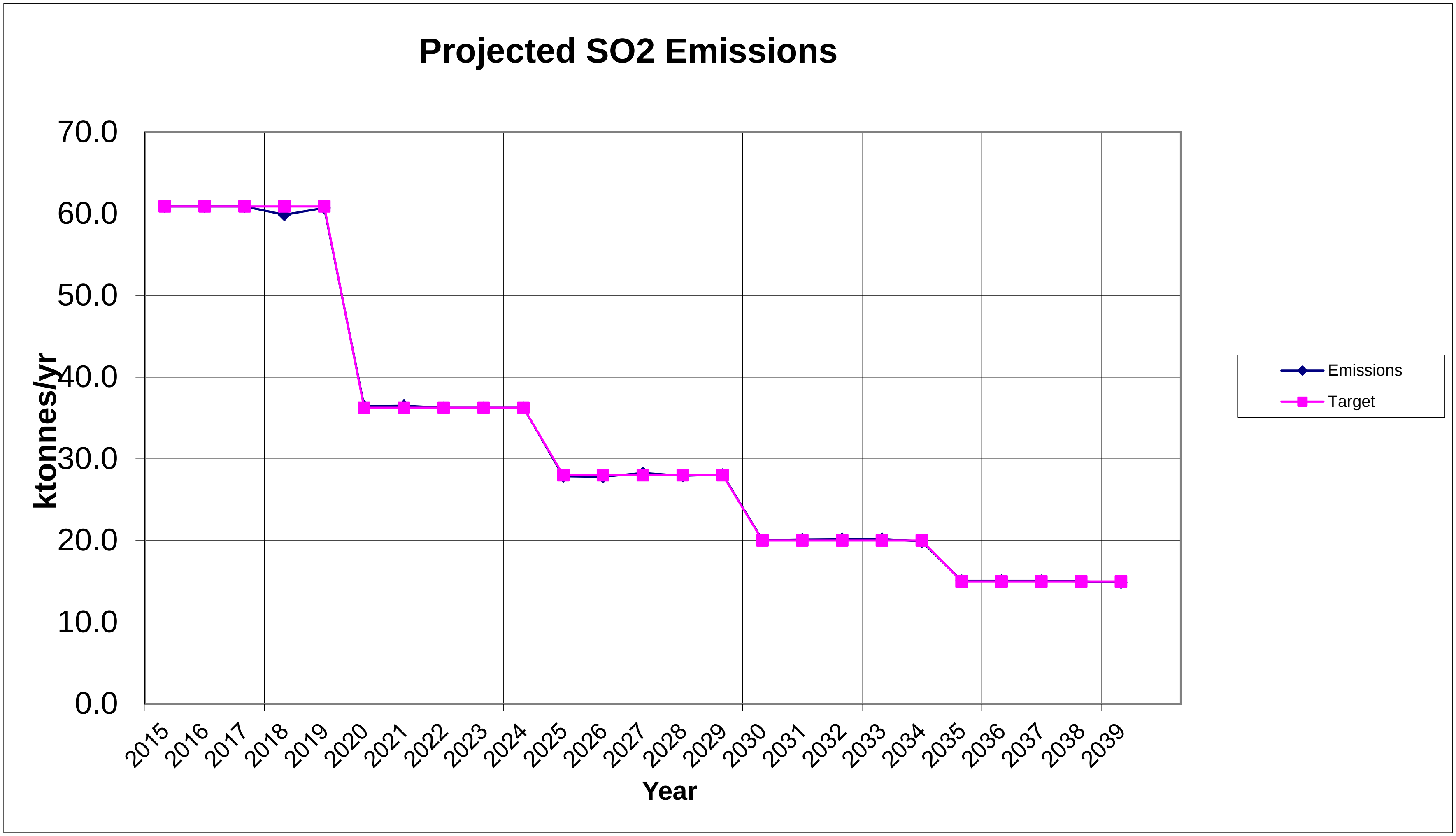
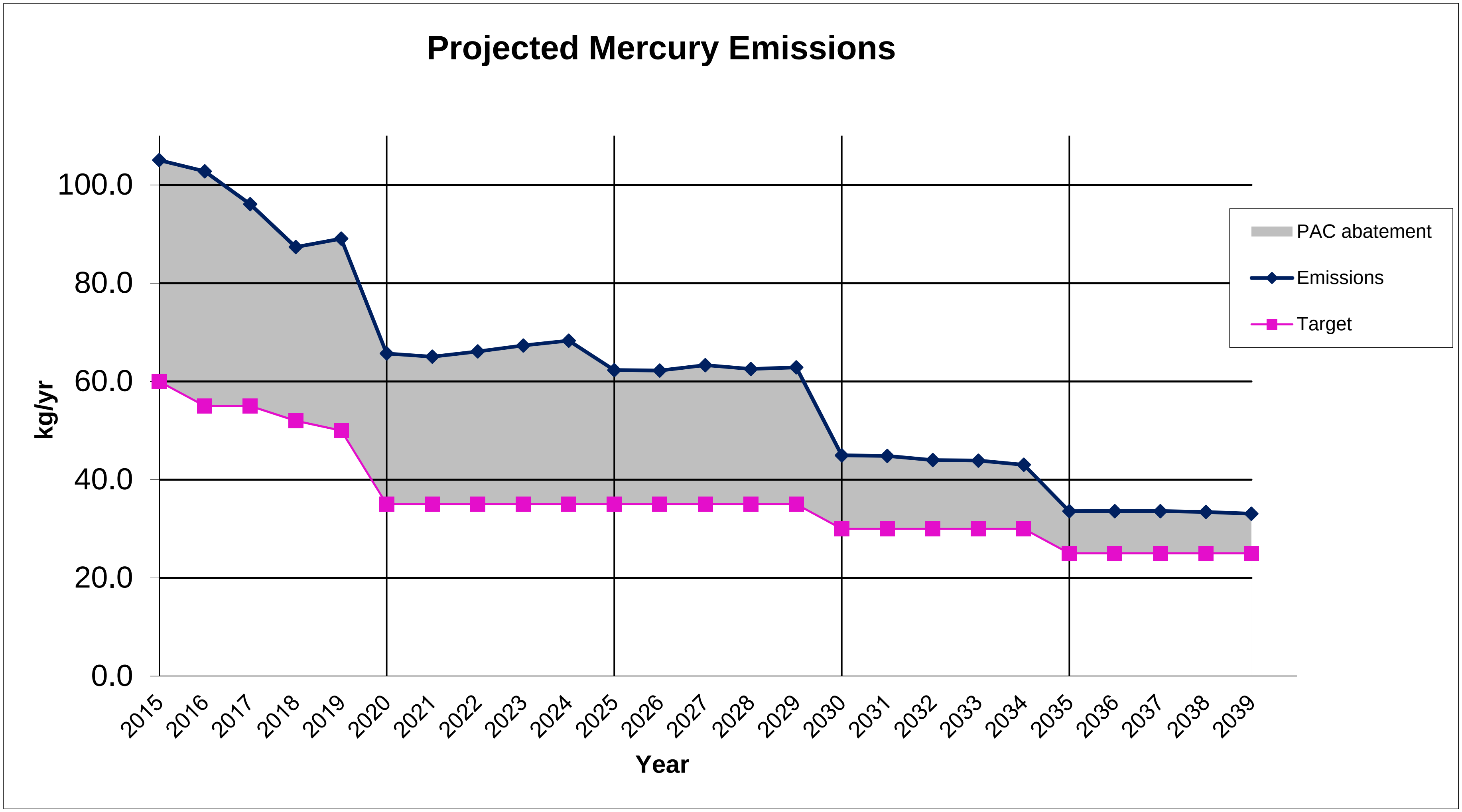
CRP 2-8 Preliminary CO_2 Emissions



CRP 2-8 Preliminary SO_2 Emissions



CRP 2-8 Preliminary Hg Emissions



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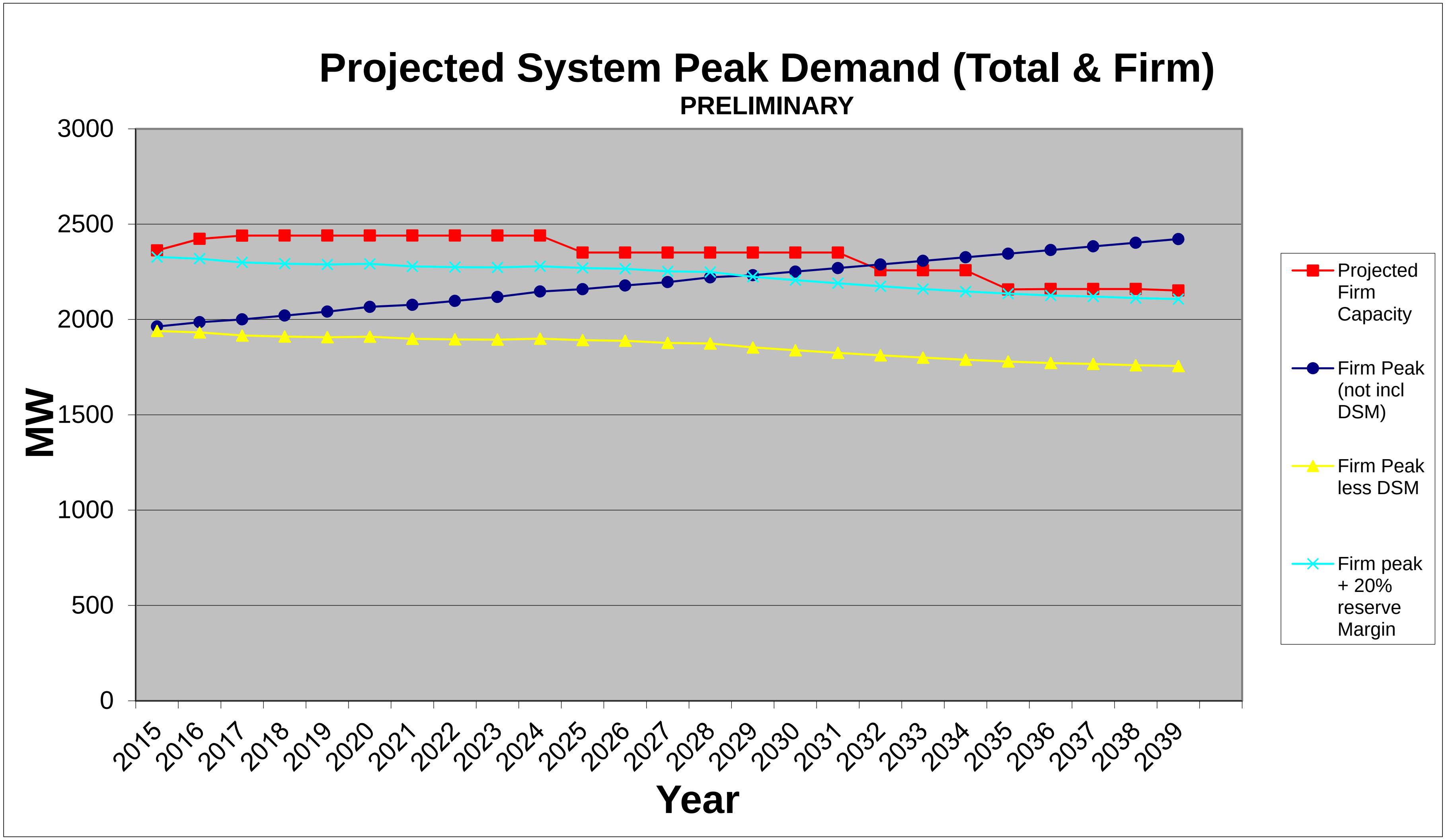
CRP 2-50 Preliminary Results

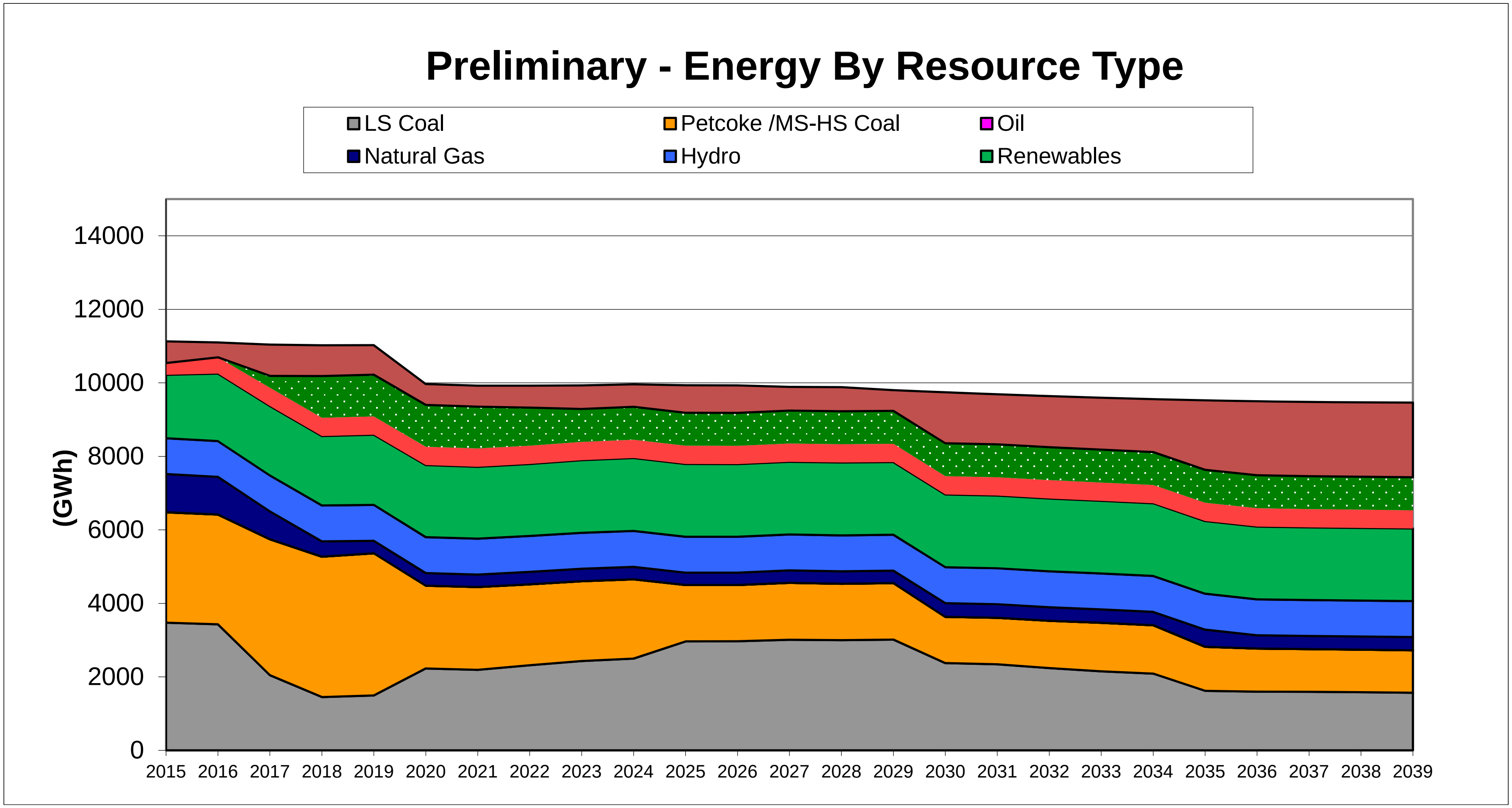
CRP 2-50 Preliminary Load and Resources

	2015	2016	2017	2018	2019	2020	2025	2030	2035	2036	2037	2038	2039
Firm Peak	1,963	1,986	2,000	2,020	2,041	2,066	2,159	2,251	2,345	2,364	2,383	2,403	2,422
DSM	23	54	84	110	134	156	267	412	566	593	616	643	666
Firm Peak Less DSM	1,940	1,932	1,916	1,910	1,907	1,910	1,892	1,839	1,780	1,771	1,767	1,760	1,756
RM Required	388	386	383	382	381	382	378	368	356	354	353	352	351
Required MWs	2,328	2,319	2,299	2,293	2,288	2,292	2,270	2,206	2,136	2,126	2,120	2,112	2,107
Existing MWs	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341
Resource Additions (MW):													
Burnside #4		33											
COMFIT - Biomass	4.2	6											
COMFIT - Wind	14.14	4.56	5.1										
REA Wind	2.35	17.34											
Maritime Link				153									
Small Biomass PPA			10										
Hydro			1.8										
FGD parasitic power							-8.0						
Additional Wind													
Assumed Unit Retirement				-153			-81		-150	-147			-153
Natural Gas Unit									49.4	149.4			145
Total Annual Additions	20.7	60.9	16.9	0.3	0.0	0.0	-89.0	0.0	-100.6	2.4	0.0	0.0	-8.0
Total Cumulative Additions	20.7	81.6	98.5	98.7	98.7	98.7	9.7	9.7	-183.9	-181.5	-181.5	-181.5	-189.5
Total Firm Capacity	2362	2423	2440	2440	2440	2440	2351	2351	2158	2160	2160	2160	2152
Surplus (Deficit) MWs above RM	34	104	141	148	152	148	81	145	22	34	40	48	45
Reserve Margin %	21.8%	25.4%	27.3%	27.7%	28.0%	27.8%	24.3%	27.9%	21.2%	21.9%	22.2%	22.7%	22.6%

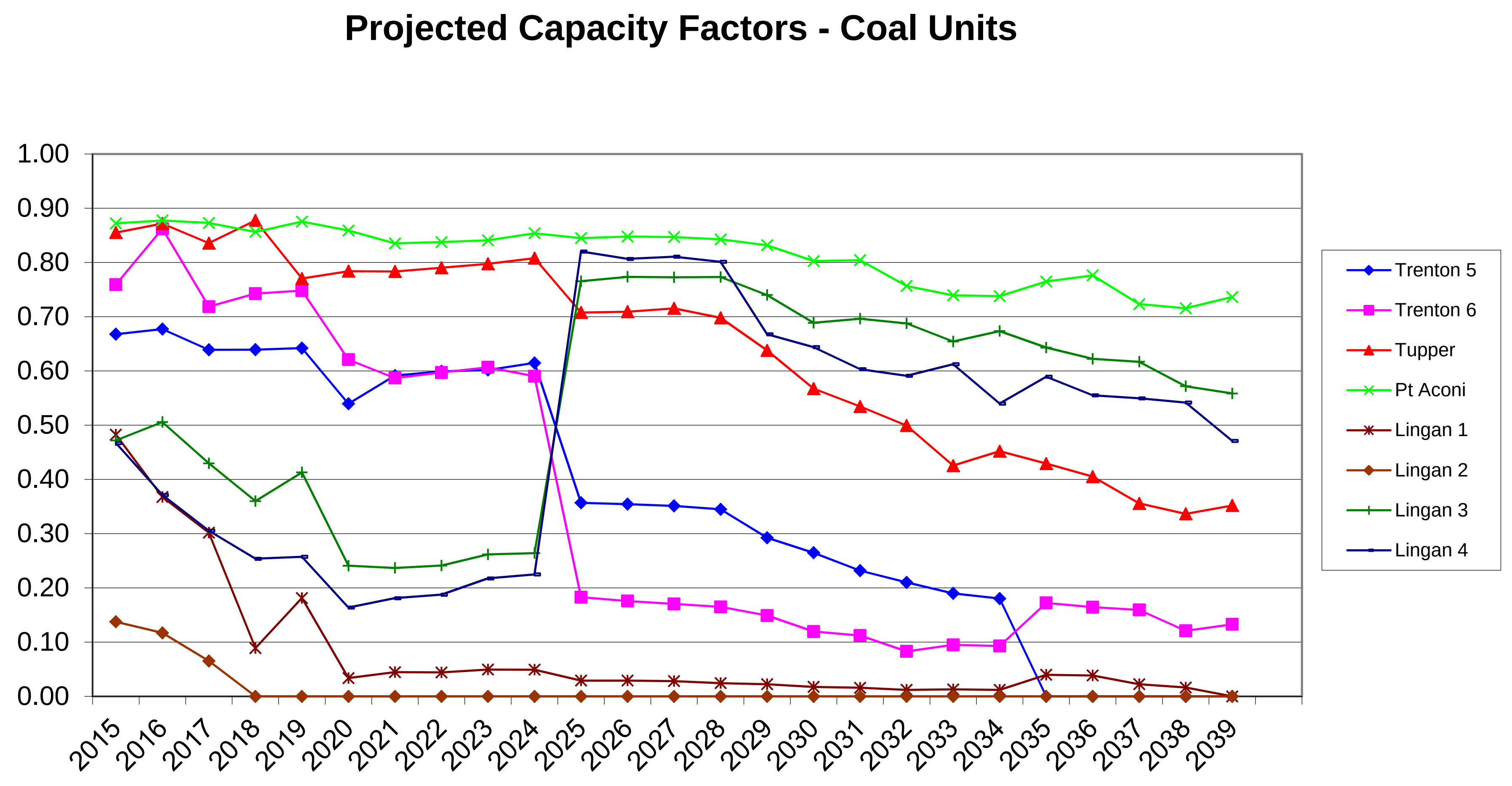
CRP 2-50 Preliminary Demand and DSM



CRP 2-50 Preliminary Energy by Resource Type



CRP 2-50 Preliminary Coal Capacity Factors



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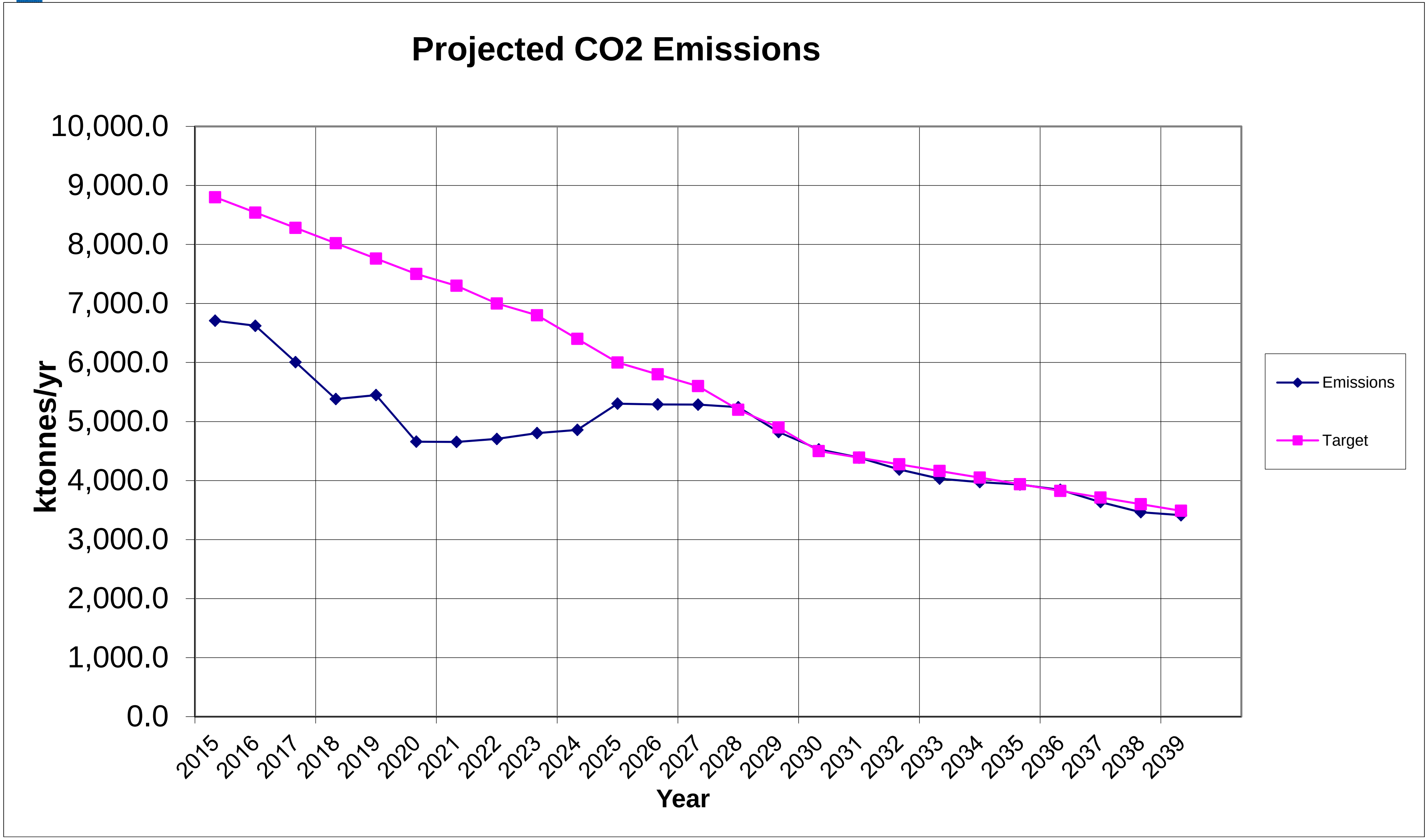
CRP 2-50 Preliminary CO_2 Emissions



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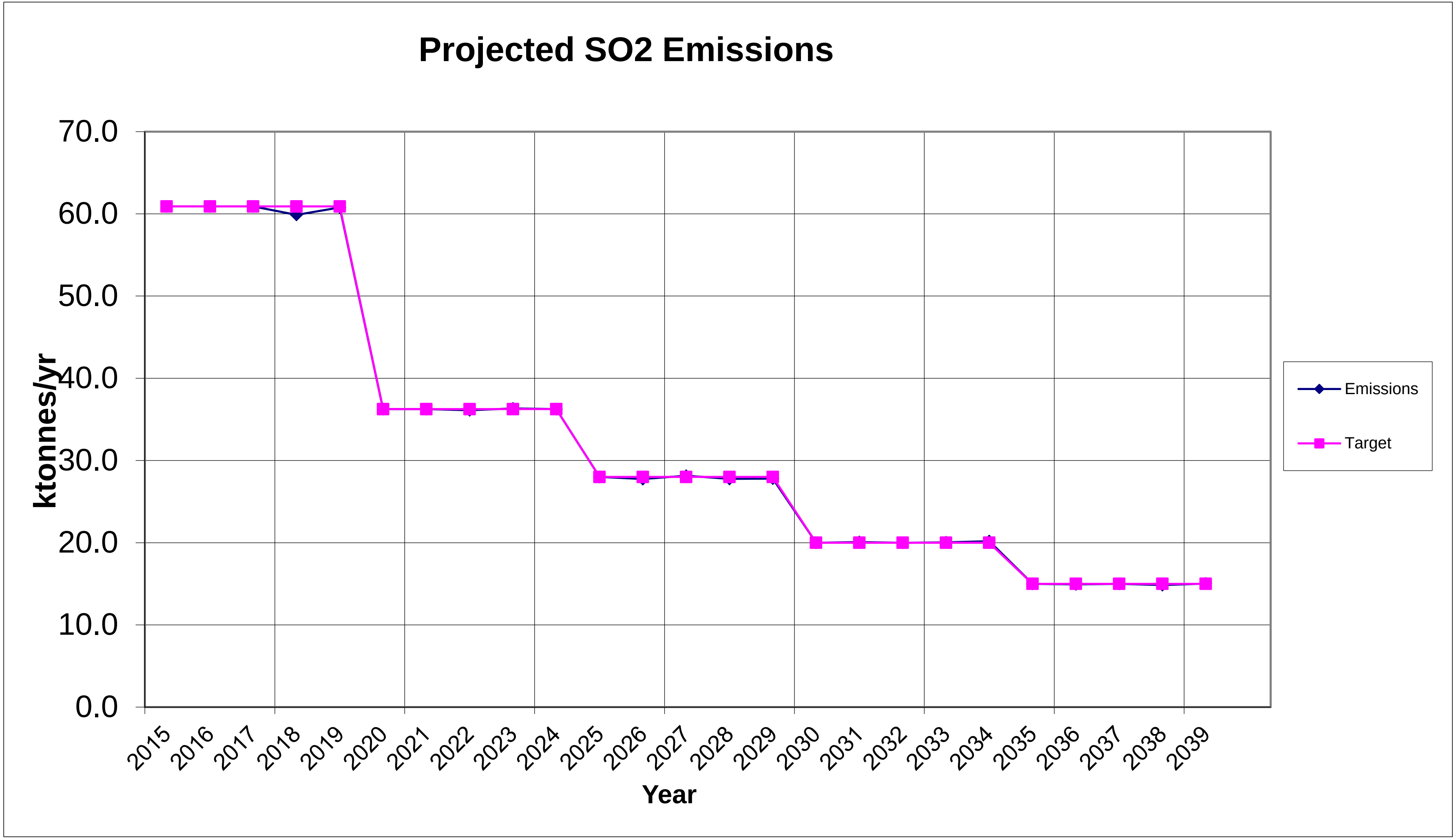
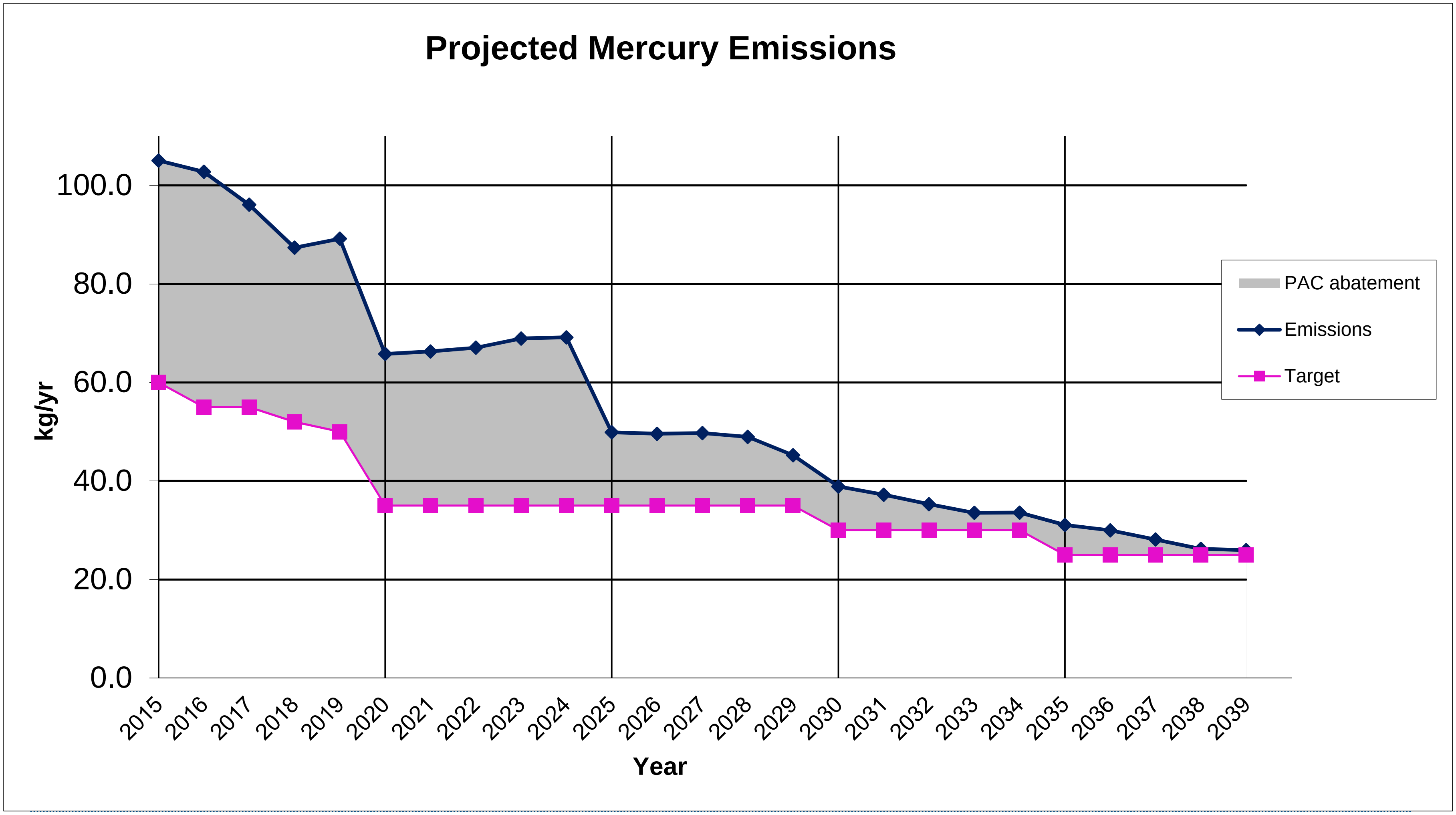
CRP 2-50 Preliminary SO_2 Emissions



CRP 2-50 Preliminary Hg Emissions



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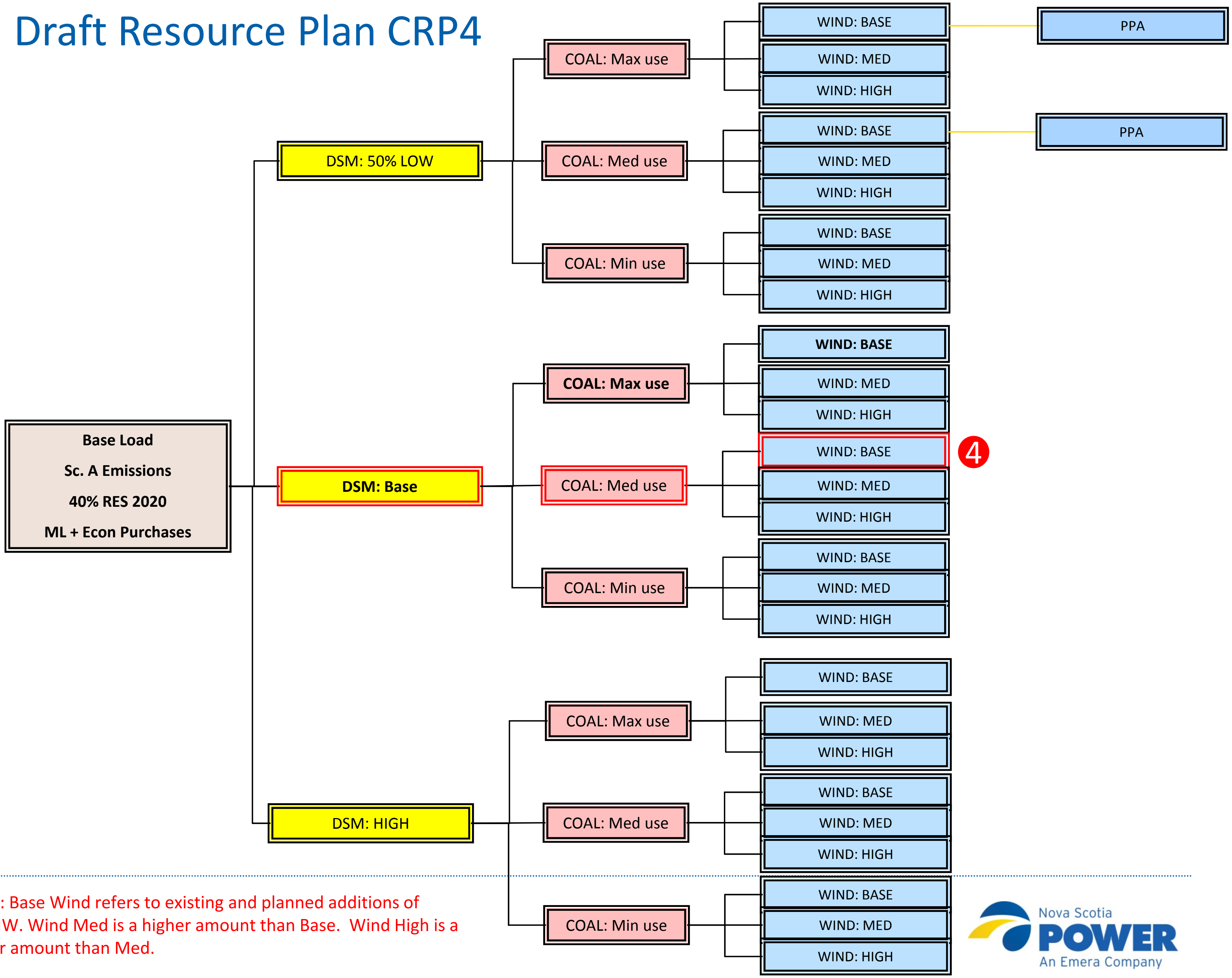
CRP 4 Preliminary Results

Draft Resource Plan CRP4



- **Base Load**
Sc. A Emissions
40% RES 2020
ML + Econ Purchases
  - DSM: 50% LOW
    - COAL: Max use
      - WIND: BASE — PPA
      - WIND: MED
      - WIND: HIGH
    - COAL: Med use
      - WIND: BASE — PPA
      - WIND: MED
      - WIND: HIGH
    - COAL: Min use
      - WIND: BASE
      - WIND: MED
      - WIND: HIGH
  - **DSM: Base**
    - **COAL: Max use**
      - **WIND: BASE**
      - WIND: MED
      - WIND: HIGH
    - COAL: Med use
      - WIND: BASE ❹
      - WIND: MED
      - WIND: HIGH
    - COAL: Min use
      - WIND: BASE
      - WIND: MED
      - WIND: HIGH
  - DSM: HIGH
    - COAL: Max use
      - WIND: BASE
      - WIND: MED
      - WIND: HIGH
    - COAL: Med use
      - WIND: BASE
      - WIND: MED
      - WIND: HIGH
    - COAL: Min use
      - WIND: BASE
      - WIND: MED
      - WIND: HIGH

NOTE: Base Wind refers to existing and planned additions of 582MW. Wind Med is a higher amount than Base. Wind High is a higher amount than Med.

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CRP 4 Input Assumptions

- Base Load Forecast
- Base DSM
- Emissions - Scenario A
- Planned and committed resources are fixed in the plan (REA wind, COMFIT, Maritime Link/ Retire Lin #2)
- Medium Coal Use
- Constraints
    - Planning reserve margin min = 20%
    - RES: 2015-2019 = 25%; 2020-2039 = 40%

CRP 4 Preliminary Results

	CRP4-1-R01	CRP4-8-R01	CRP4-34-R01	CRP4-1-FGD-R01
	Least cost study period	**Plan of Interest**	**Least cost planning period**	**Least cost study period (w FGD)**
2015				
2016	DR Water H & DR Comm	DR Water H & DR Comm		DR Water H & DR Comm
2017	ML Oct 2017	ML Oct 2017	ML Oct 2017	ML Oct 2017
	Lin 2 retire	Lin 2 retire	Lin 2 retire	Lin 2 retire
2018				
2019		Mersey Phase 1		
2020	TUC 1 Retire	TUC 1 Retire	TUC 1 Retire	TUC 1 Retire
2021				
2022				
2023		Mersey Phase 2		
2024				
2025				FGD (Lin3/4 300 MW)
2026				
2027	TUC 2 Retire	TUC 2 Retire	TUC 2 Retire	TUC 2 Retire
2028				
2029				
2030	CT 34MW		2 x CT 50MW	
	Tre 5 Retire	Tre 5 Retire	Tre 5 Retire	Tre 5 Retire
2031	CT 50MW & CT 34MW	2 x CT 50MW	CT 100MW & CT 34MW	CC 145MW
	TUC 3 Retire	TUC 3 Retire	TUC 3 Retire	TUC 3 Retire
2032				
2033				CT 50MW
2034	CC 145MW	CC 145MW	CT 100MW	CT 50MW
	Lin 1 Retire	Lin 1 Retire	Lin 1 Retire	Lin 1 Retire
2035				
2036				
2037				
2038	2 x CT 50MW	CT 50MW & CT 34MW	CC 145 MW	
	Lin 3 Retire	Lin 3 Retire	Lin 3 Retire	
2039	CC 145MW	CC 145MW	CC 145 MW	
	Lin 4 Retire	Lin 4 Retire	Lin 4 Retire	
Planning PV $M	11,419	11,461	11,388	11,372
Study PV $M	17,326	17,349	17,380	17,149 *

* Study PV needs to be adjusted for retirements

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JUNE 25, 2014

Plexos in the IRP

Use of Plexos in 2014 IRP

Plexos software is a security constrained commitment based chronological system dispatch simulator.

Plexos system dispatch simulator is capable of evaluating system operability with respect to constraints having to do with: capacity adequacy, dispatch, transmission, reserve, reactive power, voltage support, emissions and other system constraints simultaneously.

Plexos will be used to evaluate:

1. operability of a selection of Candidate Resource Plans developed by Strategist®.

2. operability of Medium and High wind penetration cases and with various levels of DSM and to calculate operating portion of wind integration costs.

3. collateral benefit of system upgrades required to integrate further wind energy on the system

NOTE: Due to nature of select CRPs, system complexity, and the work involved in developing and analyzing system simulations in Plexos, a limited number of Plexos runs will be conducted in the time allotted for the completion of the IRP.

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JUNE 25, 2014

Next steps in Analysis Phase

Finalize CRPs Process and Sensitivities

ONCE CANDIDATE RESOURCE PLANS HAVE BEEN OPTIMIZED SOME WILL BE SELECTED FOR ROBUSTNESS TESTING IN ORDER TO IDENTIFY THE PREFERRED PLAN:

- Sensitivity Analysis and Alternative Worlds: Plans will be evaluated under conditions where changes to load, fuel prices and environmental constraints (list non- exhaustive) are made to the assumptions
- Ranking: The plan performance will be evaluated based on cost-effectiveness, system stability, environmental benefits, operational flexibility, etc.

DEVELOPING RESOURCE PLANS THIS WAY ALLOWS FOR THE BROADEST CONSIDERATION OF CHANGES TO ASSUMPTIONS AND POTENTIAL SHIFTS IN POLICY

Sensitivity Analysis & Alternative Worlds

- Potential sensitivities for CRP evaluation:
  - Gas prices
  - Coal prices
  - Import pricing
  - Wind performance
  - Wind contribution to capacity
- Potential changes for Alternative Worlds testing:
  - Varying load forecast
  - Scenario B and C emissions constraints

Customer Engagement Sessions

OBJECTIVES:

- To provide interested customers an opportunity to increase awareness of the IRP process.
- To collect qualitative feedback from customers to identify opportunities to make business improvements .
- Validate themes that are important to customers for long-term electricity planning.

APPROACH:

- Provide different ways for customers to become engaged.
- Generate open and transparent dialogue.
- Ensure engagement is anchored in as broad a context as possible to help foster a big picture focus.

Customer Engagement Activities & Feedback

- 8 sessions held across the province in April and May. Approximately 200 customers participated in person.
- Additional sessions continuing in June and July.
- Website set up for customers who prefer web content and engagement (tomorrowspower.ca/IRP).
- Another round of sessions being planned in the fall to create awareness of the final IRP outcomes.
- An email address created for customers with direct queries.
- An electricity primer for customers interested in fundamental NS electricity facts and issues. Shared with all session participants, plus many more.
- Positive feedback from customers, particularly around awareness and NSP's openness to engage them. Clear appetite for additional activity.
- A report to be created in the near future, summarizing customer feedback.

Action Plan Development

- NS Power will develop a detailed action plan based on the reference world:
  - The plan will identify specific actions to take place over the next 5 to 7 years.
  - Plan action items will be based on the type and timing of resource in the preferred resource plan, findings from analysis completed over the course of the IRP modeling, and feedback received from stakeholders.
  - Identify driving factors the Company will monitor to identify if the future is unfolding differently than the reference world. The Action Plan will determine actions NS Power should take a result of these changes.

Action Plan Development

- The following areas will have specific actions:
  - *Renewable Resource*
  - *Distributed Generation*
  - *Firm Market Purchases*
  - *Flexible Resources*
  - *Demand Side Management*
  - *Demand Response*
  - *Coal Resources*
  - *Transmission Actions*
  - *Planning Reserve Margin*
  - *IRP Planning and Modeling Process Improvement*

Memorandum

Date: **July 30, 2014**
To: **IRP Intervenors**
From: **NS Power**
Subject: **2014 IRP – Analysis Plan Update and June 25 Technical Conference**

This memorandum provides a status update on the work that has taken place since the June 25 Technical Conference and NS Power's response to feedback from interested parties.

1. Introduction

On March 7, 2014, NS Power hosted a Technical Conference at which it reviewed initial draft assumptions and discussed its preliminary thoughts on the analysis plan for the 2014 Integrated Resource Plan (IRP) to obtain feedback from participants.

On March 14, 2014, NS Power circulated draft basic assumptions for feedback. The Company also circulated additional assumptions details in response to requests from Larry Hughes, PhD., the Industrial Group and the Nova Scotia Department of Energy. The March 14th material included a memo describing the five steps NS Power proposed for the Analysis Plan.

On April 11, 2014, NS Power circulated final assumptions which were developed in collaboration with UARB staff and their consultants. The April 11 memo included a brief discussion of NS Power's proposed approach to completing the Analysis Plan, specifically to model a limited number of Candidate Resource Plans, sensitivities and worlds that bound the wide range of possible permutations and combinations that have been suggested. The Company released draft assumptions for Wind Capacity Value and Variable Generation Integration on April 23 and May 1, 2014, respectively, for stakeholder feedback.

On June 5, 2014, NS Power circulated an Analysis Plan update that proposed assumptions/attributes for the Reference World drawn from the April 11 set. They are: the base load forecast, Scenario A emission constraints, 40% RES requirement in 2020 and Maritime Link+ economy energy purchases. The June 5th memo explained that NS Power, in collaboration with UARB staff and consultants, identified 30 draft resource plans. NS Power developed each draft resource plan based upon a general "theme" and on the existing resources and resource commitments in effect at the start of that plan.

The draft resource plans reflect different input assumptions for four key components:

- DSM levels
- Coal plant retirement dates
- Target levels of wind generation assets
- Potential for a large Power Purchase Agreement (PPA)

NS Power identified five of the 30 draft resource plans as Candidate Resource Plans for initial modelling in Strategist under the Reference World.

On June 25, 2014, NS Power hosted a Technical Conference to discuss the analysis plan and preliminary IRP results. The Company also solicited comments from interested parties with respect to Candidate Resource Plans, sensitivity testing and worlds to be modelled.

A record of IRP communications to date can be found at the following link:
http://www.nspower.ca/en/home/about-us/electricity-rates-and-regulations/regulatory-

2. Progress since June 25 Technical Conference

Following discussions with interested parties and submissions from the June 25th Technical Conference, the Company has added several Candidate Resource Plans and proposed sensitivities. It is also proposing an additional alternative world. The details of the current set of CRPs, sensitivities and worlds are provided in Attachment 1 and discussed below.

Candidate Resource Plans

In collaboration with Synapse and based on feedback from interested parties, NS Power has selected 16 Candidate Resource Plans (from among an initial set of ~30) that it may ultimately evaluate under the Reference World and 2 CRPs under the High Load World. NS Power has identified these based upon:

- DSM levels
- Coal plant retirement dates
- Target levels of wind generation assets
- Mersey hydro incremental capacity capability
- DR levels
- Potential for a large Power Purchase Agreement (PPA)
- Tufts Cove unit retirements & repowering

As noted in the June 5th memo, and at the June 25th Technical Conference, the evaluation of this universe of Candidate Resource Plans is an iterative process. As of July 29, NS Power has modelled seven of the 18 CRPs. The results from modelling those initial CRPs, and the next several CRPs, will help NS Power determine which of the remaining CRPs it should model.

CRP 1	Low DSM, Maximum Coal Use, Base Wind
CRP 2-1	Base DSM, Maximum Coal Use, Base Wind
CRP 2-No-DR	Base DSM, Maximum Coal Use, Base Wind, no DR
CRP 2-50 (FGD)	Base DSM, Maximum Coal Use, Base Wind, with FGD
CRP 3	Base DSM, Maximum Coal Use, Medium Wind
CRP 3-Wind_cap	Base DSM, Maximum Coal Use, Medium Wind with optimized wind capacity credit
CRP 4-1 (FGD)	Base DSM, Medium Coal Use, Base Wind, with FGD
CRP 4-1	Base DSM, Medium Coal Use, Base Wind
CRP 5	High DSM, Maximum Coal Use, Base Wind
CRP 5-No-DR	High DSM, Maximum Coal Use, Base Wind, no DR
CRP 6	High DSM, Minimum Coal Use, High Wind
CRP 7	High DSM, Minimum Coal Use, Medium Wind
CRP 8	Base DSM, Minimum Coal Use, High Wind
CRP 9	Base DSM, Minimum Coal Use, Medium Wind
CRP 10	Base DSM, Medium Coal Use, Medium Wind
CRP 21	Base DSM, Maximum Coal Use, Medium Wind, PPA *(High Load World)*
CRP 31	Base DSM (performance limited to 50% peak reduction, 100% energy), Maximum Coal Use, Medium Wind
CRP 32	Base DSM (performance limited to 50% peak reduction, 100% energy), Maximum Coal Use, Medium Wind, PPA *(High Load World)*

For the above plans, “Base Wind” refers to the currently planned 582MW of wind, “Medium Wind” is a total of 732MW, and “High Wind” is a total of 882MW of wind. Please refer to Attachment 3 for assumed retirement dates for each of the coal retirement levels in the various CRPs.

Sensitivity Analysis

The purpose of a sensitivity analysis is to test plan robustness; it does this by computing the change in revenue requirements for a given set of CRPs given a change to key input assumptions. In these sensitivity analyses, NS Power holds all capital investments and build-outs constant, and thus effectively limits the evaluation to a re-dispatch of the resources available under the given CRP.

S1: Scenario B emissions *Run across all CRPs*

S1 sensitivity analysis will be performed using the Scenario “B” emissions constraints assumptions.

S2: Scenario C emissions *CRP 2-1, CRP 2-No_DR, CRP 2-50(FGD), CRP 4-1, CRP 4-1(FGD), CRP 6, CRP 8, CRP 9, CRP 21*

S2 sensitivity analysis will be performed using the Scenario “C” emissions constraints assumptions.

S3: High natural gas price, High import price *Run across all CRPs*

S3 sensitivity analysis will be performed using the “high” forecast assumptions for natural gas and import prices.

S4: Low natural gas price, Low import price *Run across all CRP*s

S4 sensitivity analysis will be performed using the “low” forecast assumptions for natural gas and import prices.

S5: Regional Coordination Approach *CRP 3, CRP 3-Wind_cap, CRP 6, CRP 7, CRP 8, CRP 9, CRP 10, CRP 21, CRP 31, CRP 32*

S5 sensitivity analysis will reflect a “regional coordination” approach, lowering only the New Brunswick import prices, representing a situation where there is more coordination between NB and NS to allow better wind integration.

S6: Low cost, high sulphur coal *CRP 2-50(FGD), CRP 4-1(FGD)*

S6 sensitivity analysis will be performed by making high sulphur coal available at a low cost.

S7: High cost, high sulphur coal *CRP 2-50(FGD), CRP 4-1(FGD)*

S7 sensitivity analysis will be performed by making high sulphur coal available at a high cost.

S8: Higher DSM cost	*Run across all CRPs*

S8 sensitivity analysis will be performed by increasing the cost of the DSM program.

S9: Optimistic wind	*CRP 3, CRP 3-Wind_cap, CRP 6, CRP 7, CRP 8, CRP 9, CRP 10, CRP 21, CRP 31, CRP 32*

S9 sensitivity analysis will be performed by modelling wind with a lower cost and higher output.

S10: Optimistic natural gas CTs	*CRP 1, CRP 2-1, CRP 2-No_DR, CRP 2-50(FGD), CRP 5, CRP 5-No_DR, CRP 6, CRP 8, CRP 21*

S10 sensitivity analysis will be performed by modelling natural gas CTs with a lower cost and lower heat rate.

Worlds

The selection of worlds is intended to reflect what could happen if load in the future is significantly higher than the load assumed in the Reference World. The Company wants to analyze what may happen if the Reference World does not materialize. The worlds are not intended to be an exhaustive analysis of all potential futures. Rather, they are meant to “bracket” the range of possible futures.

In these analyses, NS Power runs Strategist and allows it to change the build-out. NS Power expects to identify a CRP or CRPs different from the 16 identified under the Reference World because of the higher load requirements.

High Load World (World 2)

CRP 21	Base DSM, Maximum Coal Use, Medium Wind, PPA
CRP 32	Base DSM (performance limited to 50% peak reduction, 100% energy), Maximum Coal Use, Medium Wind, PPA

The CRP, sensitivity and worlds selection represent an effort to reflect the broad views of the stakeholder group. Certain sensitivities and CRPs are intended to test the bounds of the planning exercise and are outliers in the analysis process.

3. Responses to feedback on June 25 Technical Conference materials

The Company would like to thank interested parties for their feedback.

Attachment 2 provides a detailed response to the feedback received on the Company's analysis plan. Following is a synopsis of the Company's responses on several common comments:

Basis for selection of initial Candidate Resource Plans (CRPs) from 30 draft resource plans

The initial Candidate Resource Plans were selected from the 30 draft resource plans based on the goal of developing a set of CRPs that span a reasonable range of plausible resource choices (the IRP Terms of Reference at page 3 specify that NS Power is to assess "a reasonable, but not unlimited, number of alternative plans"). The sequence in which NS Power made this selection, and the criteria it considered at each stage of the sequence, is summarized below:

- NS Power, in collaboration with UARB staff and consultants, began by identifying 30 draft resource plans (see Attachment 1 to June 5, 2014 memo to stakeholders). Each draft resource plan began with the existing resources and resource commitments in effect as of 2015. Those draft resource plans differed in terms of four major input variables/components that were expected to have the potential to significantly change the results of the plan (e.g. revenue requirements, robustness). Those four key input variables/components were: DSM level, variable generation level (e.g. wind), fossil unit retirement dates (coal, Tufts Cove) and potential for a large Power Purchase Agreement (PPA) – please refer to the June 5th memo to stakeholders and its Attachment 2, slide 12.

- NS Power then identified five of the 30 draft resource plans to model in Strategist as initial CRPs under the Reference World. The initial CRPs were selected to begin developing a set of CRPs that spanned a reasonable range of plausible, and materially different, resource choices. They were selected to reflect three different levels of DSM, two levels of variable generation (e.g. wind), and two levels of coal retirements. NS Power expected that the results from modelling these five initial CRPs would help it determine which of the remaining draft resource plans it would need to model in order to evaluate a reasonable range of plausible, and materially different, CRPs and which it would not need to model because they would not produce materially different results.

- Based upon the results of modelling the initial five CRPs and upon further examination of the components that can most affect the results of CRPs, NS Power has identified an additional 11 initial CRPs to model under the Reference World. These 11 additional CRPS are included in the list of CRPs described earlier in this memo. These additional initial CRPs were again selected as part of the process to develop a set of CRPs that span a reasonable range of plausible, and materially different, resource choices. The additional 11 CRPs reflect higher levels of wind, earlier coal plant retirement and different DSM levels. They complement the initial five CRPs by representing a further range of differences in levels of DSM, variable generation, levels of coal retirements, Demand response levels, Tufts Cove unit retirements and repowering and PPAs. The Company has also identified two additional CRPs to be modelled under the High Load World.

Basis for choosing to use Plexos to perform more granular analyses of certain CRPs

NS Power uses Strategist to identify the optimal resource additions for a given CRP and to model the operation of its system over the 25 year planning period for that CRP (see June 25, 2014 slide deck, slides 38 to 45). Strategist models "typical week" profiles for loads and non-dispatchable resources, but it does not conduct an hourly dispatch simulation of thermal resources.

Modelling the NS Power system at this level of detail in Strategist is typically a sufficiently accurate representation for CRPs composed primarily of DSM resources and dispatchable supply resources. However, modelling the NS Power system at this level of detail may not be a sufficiently accurate representation for CRPs with high levels of non-dispatchable or intermittent resources such as wind and solar. As a result, NS Power expects to use Plexos to model the operation of its system in selected years for certain CRPs (see June 25, 2014 slide deck, slide 85).

Plexos is a system simulation model designed to analyze a full spectrum of system attributes in each of the 8,760 hours that make up a given year. The Company proposes to use Plexos to examine certain CRPs (i.e. high wind, high DSM, Scenario "C" emissions) to evaluate key system operational attributes that Strategist does not evaluate, such as dispatch within generating unit commitment constraints, transmission system constraints, dynamic reactive reserve requirements, wind generation curtailment, and other chronological system constraints. The analysis may show that the system needs reinforcement or that, although Strategist has indicated that a given CRP meets the system's annual capacity, generation and emissions needs, the CRP does not satisfy the system's hourly operational needs. NS Power will use its engineering judgment, in collaboration with Synapse, to determine which CRPs require Plexos analysis. NS Power will document its rationale for choosing to apply Plexos to specific CRPs. It will also identify any CRP that it excludes from further consideration based upon the Plexos assessment and the reasons for that exclusion.

Basis for Selection of the Preferred Resource Plan

NS Power will present stakeholders with the results of its analyses of the CRPs on or before the Technical Conference scheduled for September 12, 2014. In those materials, NS Power will present for discussion the Preferred Resource Plan it is proposing to select from those CRPs and the basis for that selection.

The primary criterion for selection of the Preferred Resource Plan will be cumulative present worth of the annual revenue requirements of the resource plan over the planning horizon, as specified on page 3 of the IRP Terms of Reference approved by the UARB. When applying that criterion, NS Power will consider the robustness of the CRPs under consideration by assessing their results under the sensitivity analyses and the other worlds.

NS Power will also consider additional criteria, including system reliability requirements, flexibility, future regulatory emissions outlook, timing and rate effects and end effects beyond the planning horizon. NS Power will attempt to quantify each of these additional criteria for each of the CRPs it considers in the selection of the Preferred Resource Plan in monetary terms where possible, but otherwise in physical terms. One of the issues for discussion at the September 12 Technical Conference will be the relative weights to give each of these additional criteria.

NS Power invites stakeholders to submit suggestions for developing physical and/or monetary values for the additional criteria, as well as the weights to be given to each additional criterion. NS Power will discuss these suggestions in the September Technical Conference.

ATTACHMENT 1 – Matrix of CRPS, WORLDS and SENSITIVITIES

											SENSITIVITIES									
World 1 - REFERENCE											S1	S2	S3	S4	S5	S6	S7	S8	S9	S10
CRP	DSM	WIND	COAL	Mersey	DR	PPA	Tufts Cove Repowering CT/CC				Emissions B	Emissions C	High NG High IMPORT	Low NG Low IMPORT	Regional Coord. High Wind Low NB price	Low Cost High S Coal	High Cost High S Coal	Higher DSM cost	Optimistic Wind -cost -output	Optimistic NG CT -cost -heat rate
							TUC 1	**TUC 2**	**TUC 3**	**NEW CT/CC**										
CRP 2-1	BASE	BASE	MAX	OPTIMIZE	OPTIMIZE	-	2025	2032	2036	OPTIMIZE	x	x	x	x				x		x
CRP 2-No_DR	BASE	BASE	MAX	OPTIMIZE	No DR	-	2025	2032	2036	OPTIMIZE	x	x	x	x				x		x
CRP2-50 (FGD)	BASE	BASE	MAX	OPTIMIZE	OPTIMIZE	-	2020	2027	2031	OPTIMIZE	x	x	x	x		x	x	x		x
CRP 4-1	BASE	BASE	MED	OPTIMIZE	OPTIMIZE	-	2020	2027	2031	OPTIMIZE	x	x	x	x				x		
CRP 4-1 (FGD)	BASE	BASE	MED	OPTIMIZE	OPTIMIZE	-	2020	2027	2031	OPTIMIZE	x	x	x	x		x	x	x		
CRP 3	BASE	MED	MAX	OPTIMIZE	OPTIMIZE	-	2025	2032	-	OPTIMIZE	x		x	x	x			x	x	
CRP 3-Wind_cap	BASE	MED optimist cap cred	MAX	OPTIMIZE	OPTIMIZE	-	2025	2032	-	OPTIMIZE	x		x	x	x			x	x	
CRP 31	BASE 50% PEAK 100% ENERGY	MED	MAX	OPTIMIZE	OPTIMIZE	-	2025	2032	-	OPTIMIZE	x		x	x	x			x	x	
CRP 1	50% LOW	BASE	MAX	OPTIMIZE	OPTIMIZE	PPA	2025	2032	-	OPTIMIZE	x		x	x				x		x
CRP 5	HIGH	BASE	MAX	OPTIMIZE	OPTIMIZE	-	2025	2032	-	OPTIMIZE	x		x	x				x		x
CRP 5-No_DR	HIGH	BASE	MAX	OPTIMIZE	No DR	-	2025	2032	-	OPTIMIZE	x		x	x				x		x
CRP 9	BASE	MED	MIN	FIX	FIX	-	2021	2028	-	OPTIMIZE	x	x	x	x	x			x	x	
CRP 10	BASE	MED	MED	FIX	FIX	-	2023	2030	-	OPTIMIZE	x		x	x	x			x	x	
CRP 7	HIGH	MED	MIN	OPTIMIZE	OPTIMIZE	-	2021	2028	-	OPTIMIZE	x		x	x	x			x	x	
CRP 6	HIGH	HIGH	MIN	OPTIMIZE	OPTIMIZE	-	2021	2030	-	OPTIMIZE	x	x	x	x	x			x	x	x
CRP 8	BASE	HIGH	MIN	OPTIMIZE	OPTIMIZE	-	2021	2030	-	OPTIMIZE	x	x	x	x	x			x	x	x
World 2 - HIGH LOAD																				
CRP 21	BASE	MED	MAX	FIX	FIX	PPA	2025	2032	-	OPTIMIZE	x	x	x	x	x			x	x	x
CRP 32	BASE 50% PEAK 100% ENERGY	MED	MAX	OPTIMIZE	OPTIMIZE	PPA	2025	2032	-	OPTIMIZE	x		x	x	x			x	x	

Item	Stakeholder Comment	Intervenor	Draft Response	Category
1	At the Technical Conference, NSPI had indicated that it would provide the detailed assumptions that were used to develop the natural gas price assumptions (slide 25). Please provide these assumptions.	Industrial Group	Please refer to slides 52 to 58 of the April 11, 2014 Finalized Assumptions deck.	Assumptions
2	Also, if NSPI intends to revise or update coal, natural gas or other fuel prices prior to completing the IRP modelling, please provide relevant information as to when and how NSPI will update the assumptions.	Industrial Group	The Company does not plan to update the fuel assumptions any further for this IRP.	Assumptions
3	With respect to purchased power assumptions, the Industrial Group requests that NSPI include, in the plan modelling, (a) scenarios where the Maritime Link is delayed in completion and (b) scenarios where supply from the Link is curtailed such that there is no "market price" power available (only the "basic block")	Industrial Group	NS Power will test pricing sensitivities for imported electricity. The Company expects the Maritime Link will be completed in the timeframe discussed during the regulatory process that approved the project. Regular updates are sent to the UARB on project timelines.	Alternative Worlds
4	…there appears to be some inconsistencies with the life-spans specified. … This suggests a 5 year difference in coal plant retirements between max and med coal, i.e. 55 year lives, which is inconsistent with the 60 and 50 year life spans specified in slide 36.	Industrial Group	Please refer to Attachment 3 for the retirement assumptions for the CRP coal use levels.	CRPs
5	The Industrial Group suggests that NSPI apply its knowledge to vary and extend the plant lives individually as a limiting factor and then allow Strategist to choose the most cost-effective time for retirement within individual plant life constraints.	Industrial Group	Please refer to item 4.	CRPs
6	The Industrial Group requests that NSPI provide more information with respect to the treatment of costs for retired generating plants.	Industrial Group	The Company will consider the retirement cost on a case by case basis for the retirement schedule of the Candidate Resource Plans. Decommissioning costs are considered through depreciation rates.	Assumptions
7	What heat rates were used to translate natural gas and coal prices to equivalent power prices for this graph? Heat rates of NSPI's existing units (for coal) or potential new units (gas)?	Industrial Group	Coal power prices were based on NS Power's existing coal units. Gas power prices were based on a unit similar to Tufts Cove 6 combined cycle.	Assumptions
8	Does NSPI expect winter peak power prices to consistently reflect a heat rate lower than they can generate at (as implied by the graph)? If so, will Strategist not always (under the Base Price scenarios) select winter peak purchases prior to running or building gas units? What is the likelihood of this happening year after year, as implied in the fuel price input data?	Industrial Group	Correct. Strategist will select import power (up to available amounts) if imports are cheaper than domestic generation. NEPOOL market prices are the result of a combination of evolving generation fleet composition (which drives the heat rate) and evolving natural gas prices (both by PIRA). NS Power's cost of natural gas fired generation shown in this graph is driven by natural gas prices and the heat rate of existing NS Power facilities, and shown for information purposes only. Model outputs will consider all relevant quantities, including (among others): import transmission constraints, NEPOOL power prices, NS delivered natural gas prices and existing and new facility (if any) heat rates. NS Power cannot comment on the specific likelihood of any scenario under consideration but is instead providing high, low and base scenarios to capture many potential outcomes.	Assumptions
9	In the early years coal is lower cost than off-peak purchases only in the winter. Has this been the case in the recent past or is this a new paradigm?	Industrial Group	Import prices are set by prices in New England, which are set by gas and oil in the winter, both on and off peak. As a result, import prices are higher than NS Power's own coal facilities. In the summer, NS coal is typically more competitive.	Assumptions

Item	Stakeholder Comment	Intervenor	Draft Response	Category
10	Given that Plexos will reveal useful information about the CRPs, but that it must be used in a limited fashion, the Industrial Group requests that NSPI develop and circulate a protocol that outlines when and how Plexos will be used. We suggest that this should include a "control" scenario - one where NSPI expects that modelling in Plexos would not produce significantly different results from the Strategist model - to confirm that modelling in Plexos is only useful in the situations established by the protocol.	Industrial Group	Plexos is not used for resource optimization and it cannot produce different results from Strategist, but rather expose operational issues with CRPs which are expected to stretch the system operating limits. Plexos and Strategist outputs were benchmarked with control scenarios as a part of the FAM Plan of Administration revision in 2013. Differences in dispatch optimization as well as their causes are well understood. Prior to commencement of the IRP CRP analysis, Plexos and Strategist system assumptions and output will be aligned using the Candidate Resource Plan 2 results. Plexos chronological dispatch will be used at the discretion of NS Power modellers and the Board's consultant to simulate critical years on a selection of CRPs containing resources whose viability and effects on the system are better explored in a chronological dispatch model. Please also refer to the accompanying memo.	Modelling
11	The Industrial Group requests that NSPI develop and circulate criteria for assessing these "other qualities" and provide further information on how these qualities will be weighted or otherwise used to rank CRPs that have been, initially, ranked by NPV of the plan.	Industrial Group	NS Power has provided a non-exhaustive list of qualities that are used to evaluate Candidate Resource Plans, including: robustness, flexibility, and cost effectiveness. The Company would encourage the stakeholder group to provide additional elements or specific metrics that should be considered. The process and criteria for selecting the Preferred Resource Plan will be examined in detail in the Technical Conference on September 12. Please also refer to the accompanying memo.	Modelling
12	Where judgment is used, particularly in significant steps in the process such as establishing the foundational or core CRPs, the Industrial Group requests that NSPI document how judgment was applied. This could include further information such as what factors were considered, why some were selected and others were rejected and what constraints shaped NSPI's decision-making. This information will increase transparency and will facilitate a shared understanding of the overall process that leads to the selection of a preferred plan.	Industrial Group	The June 25, 2014 Technical Conference presentation describes where judgment has been applied by NS Power and Synapse in the selection of CRPs. The Company and Synapse used a matrix where load, DSM, renewable energy, plant retirement dates and a potential large PPA were considered. Based on changes to these variables and feedback from the stakeholder group, NS Power and Synapse developed the Candidate Resource Plans in this submission. Please also refer to the accompanying memo and item 21.	Modelling
13	NSE believes that NSPI and the UARB should focus resources, sensitivity cases and analyses on the realistic scenario that reflects "Scenario A". … Moreover, NSE reiterates that compliance periods should be incorporated into the modeling, as indicated in NSE's April 2014 letter, since this is the realistic future.	NSE	NS Power will be focusing its resources on Scenario "A" emissions (modelled in the Reference World) and will also be testing higher and lower emissions scenarios as requested by the Intervenors - please refer to sensitivity analysis cases S1 and S2.	Alternative Worlds
14	The following market scenarios and technologies are suggested for consideration in relation to the IRP world's analyses: Future opportunities for imports and exports (i.e. a regional approach to energy markets). Additional hydro resources from either Quebec or Newfoundland	Dept of Energy	The Company has included a PPA in its Candidate Resource Plans 1, 21, and 32.	CRPs
15	Grid optimization/Smart grid/Demand response development	Dept of Energy	The Company is considering demand response in the IRP and improvements in grid technology, while not explicitly modelled, could be reflected by declining load in various Candidate Resource Plans and sensitivities considered. The CRPs will identify the value of various levels of energy reduction via DSM and demand response, regardless of the measures through which they are achieved.	CRPs
16	We would suggest that a range of +/- 15%-20% should be modelled for load, imported electricity pricing, import economy energy availability and coal and natural gas prices.	Dept of Energy	Sensitivities for import pricing, coal and natural gas prices are defined by the "Low" and "High" cases from the IRP Assumptions. Please refer to sensitivities S3 to S7. In addition, testing will be done using the High Load World (World 2).	Sensitivity Analysis

Item	Stakeholder Comment	Intervenor	Draft Response	Category
17	The SBA recommends that a workshop be held with stakeholders to take input on a decision framework.	SBA	The Company welcomes feedback from the stakeholder group on specific metrics and a decision framework. Please also refer to item 11.	Modelling
18	The supply side option information does not show how the costs of future options vary. For example, are certain technologies such as PV Solar or Wind, declining on a real dollar basis while others are not?	SBA	Varying the costs of future options will be examined in the sensitivities for some technologies - please refer to sensitivity analysis cases S9 and S10.	Assumptions
19	The assumptions for technology improvement over time are not apparent, such as heat rate of combined cycles.	SBA	Technology improvement over time was not modelled in the base assumptions. This will be examined in the sensitivities for some technologies - please refer to sensitivity analysis cases S9 and S10.	Assumptions
20	It is critical that variation in the amount of energy delivered through the PPAs from New Brunswick and the Maritime Link be evaluated to determine the value of existing resource, and the timing of additional resource requirements.	SBA	Various amounts of energy imports will vary through the testing of import price sensitivity. Please refer to sensitivity analysis cases S3, S4 and S5 and item 3.	Assumptions
21	The SBA requests that NSPI… provide information and specific examples as to how some plans did not make operational or economic sense in its development of the Candidate Resource Plans. This screening logic is critical to stakeholders developing confidence in the NSPI process.	SBA	The Company and Synapse, with feedback from intervenors, has screened plans using the process described in the June 25th presentation. Specifically plans that were similar to other plans being explored were not considered for optimization, i.e. variations in load and DSM combinations (medium DSM with high load, low DSM with base load). Plans that weren't operationally viable were not considered for optimization. Please also refer to the accompanying memo.	CRPs
22	The use of Strategist and Plexos needs to be presented with more concrete examples to gain support of the stakeholders. While a formal protocol may not be possible to establish up front, a 'de facto' protocol should be explained…	SBA	Please refer to item 10.	Modelling
23	Customer Engagement Sessions - Did these include Small Business Customers? If so, how many?	SBA	Small Business customers were in attendance at the IRP customer engagement sessions. For Regional Sessions organized and hosted by NS Power (April and May), the following estimated number of Small Business Customers were in attendance: Yarmouth 7 Port Hawkesbury 6 Bridgewater 2 Wolfville 2 Halifax 13 Sydney 7 Truro 4 Stellarton 2 For the sessions hosted in partnership between NS Power and chambers of commerce (July): Amherst 16 New Glasgow 10 Sydney 11 Port Hawkesbury 5	Customer Engagement
24	NSPI should clarify the scope of its supply cost estimates, specifying whether they include such factors as transmission network upgrades.	CA	Transmission network upgrades were not included in the supply cost estimate. They are provided separately in the April 11 Finalized Assumptions under Transmission Options on slide 33.	Assumptions
25	…should clarify the energy storage in MWh for each alternative, and for the CAES, the amount of natural gas required for reheating the compressed air during generation conditions.	CA	The example the Company used was adiabatic CAES. This is new generation CAES and uses turbo expanders, not natural gas.	Assumptions
26	NSPI should clarify its expectation for the incremental energy output from the Mersey upgrade.	CA	An incremental 40 GWh is assumed from the Mersey Upgrade.	Assumptions
27	The presentation of the Lingan "Carbon Capture 25% Power Penalty (in addition to scrubber)" option is confusing. How many units would this apply to? Does the $790 M include the $210 - $220 M for the scrubber, or is that additional?	CA	The carbon capture option is assumed for two units at Lingan (300MW). The scrubber costs are additional.	Assumptions
29	NSPI should evaluate the option of keeping Lingan 1 - 4 running as load following units, accepting accelerated wear, until one unit wears out, justifying retirement.	CA	Please refer to Attachment 3 for the retirement assumptions for the CRP coal use levels.	CRPs

Item	Stakeholder Comment	Intervenor	Draft Response	Category
30	The assumption that Trenton 5 would be retired before Lingan 1, 3 and 4 is odd, given the much higher usage of Trenton 5.	CA	Please refer to item 29. In addition to age and operating cost, other factors such as location of a unit drive retirement decisions.	Assumptions
31	For IRP modeling, NSPI should ensure that assuming the retirement of Tufts Cove units is not biasing any near-term decisions.	CA	Please refer to item 29.	Assumptions
32	It is not clear why the low-DSM case is designated as Plan 1 (Base Run). This terminology appears to reflect a judgment that ENSC's DSM projection is too high. NSPI should articulate the basis for this judgment.	CA	The Candidate Resource Plan numbering is random and is not intended to indicate a ranking. The numbering is used to keep track of which plans are being modelled and their results. As agreed during the Technical Conference, NS Power will remove the phrase "Base Case" (and the footnote regarding "least cost run") from this list.	CRPs
33	The CRP descriptions do not specify the treatment of Tufts Cove Requirements.	CA	Please refer to Attachment 1 and 3.	CRPs
34	NSPI should clarify whether "Maximum Coal Use" is synonymous with the retirement schedule on Slide 23, or whether other inputs force higher levels of coal use. Similarly, NSPI should clarify the meaning of "Medium" and "Minimum" coal use.	CA	Please refer to Attachment 3.	CRPs
35	NSPI's numbering system for the CRP plans, naming the plans in order of their NPVs, is apt to be clumsy for presentation and discussion of results.	CA	Please refer to item 32. The CRPs are not numbered by their NPVs, the numbering is random and not intended to imply a ranking.	CRPs
36	Similarly, CRP 2.3 and CRP 4.3 may be completely different; the portion of the CRP number after the decimal point has no consistent meaning.	CA	The number after the decimal point indicates the ranking of the plan in the resource optimization for that CRP. It is simply a way to identify an individual plan.	CRPs
37	PHP believes it is very important that… Alternative Worlds testing include Worlds based on each of the Scenario B and C emissions constraints.	PHP	The Company is testing both Scenario "B" and "C" emissions at the request of stakeholders in sensitivity analysis cases S1 and S2.	Alternative Worlds
38	Sensitivities for the CRPs be tested against the high price scenario for natural gas, solid fuel and imports	PHP	The Company will conduct fuel price sensitivities; please refer to sensitivity analysis cases S3, S4, S6 and S7.	Sensitivity Analysis
39	Alternative Worlds noted… above also be tested with the high fuel price sensitivity…	PHP	The Company will conduct fuel price sensitivities. Please refer to item 38 and Attachment 1.	Sensitivity Analysis
40	World 1, Business as Usual: This is the world established within the existing assumptions.	EAC	This is the Reference World, the first world NS Power is modelling CRPs in.	Alternative Worlds
41	World 2, Zero GHG World: This is a world where carbon emissions from stationary sources like power generation are no longer permitted. Emission sequestration options would become mandatory. GHG emissions would be limited to transportation, forestry and agricultural activities.	EAC	NS Power is testing Scenario "C" emissions - 2.25 MT by the end of the planning period - please refer to sensitivity analysis case S2.	Alternative Worlds
42	World 3, Renewable World: This a world where carbon emissions from stationary sources like power generation are no longer permitted and sequestration of C02 is either not permitted or locally impractical. GHG emissions would be limited to transportation, forestry and agricultural activities.	EAC	Please refer to item 41.	Alternative Worlds
43	Understanding that Strategist as a planning tool may not fairly examine resource plans with high variable generation and low load, EAC strongly recommends that Plexos be used to examine a high wind and high/medium DSM case.	EAC	Please refer to item 10.	Modelling
44	Likewise, Strategist may not fully reveal the value of Demand Response or Storage options. EAC strongly recommends that Plexos be used to examine a high wind and high/medium DSM case so that both the potential benefit and cost implications of these options are clear.	EAC	Please refer to item 10.	Modelling
45	EAC recommends that the COMFIT be extended indefinitely. This IRP will aid in identifying the amount and type of COMFIT generation that should be included in the future.	EAC	The Company will consider increased renewables in the CRPs modelled. As well, the Company may need to examine increased renewables in order to meet Scenario "C" emission scenarios. Please refer to CRPs 6 and 8 and sensitivity analysis case S2.	CRPs
46	A CRP that reflects improved regional interconnection and balancing and also reflects the potential cost sharing of these improvements should be investigated. Balancing in particular may offer the chance to narrow the duration of low wind periods.	EAC	The IRP is a planning exercise that only models the resources required on the Nova Scotia system; however, better regional integration will be examined in sensitivity analysis case S5 (please refer to the accompanying memo and Attachment 1).	CRPs

Item	Stakeholder Comment	Intervenor	Draft Response	Category
47	EAC recommends that sensitivities explored for all options be non-linear. That is, that the negative cost sensitivity be less than the opposing positive cost sensitivity. EAC recommends that sensitivities examined take the form of -25%/+50%. Plans that respond in proportion to these sensitivities are clearly robust. Plans that do not are clearly riskier.	EAC	The Company will use various sensitivities depending on the plan being examined and the impact. There are no pre-defined maximum or minimum thresholds; rather, the Company uses the Assumptions which were designed based on expert judgment and research to define ranges for examination. Please refer to the accompanying memo.	Sensitivity Analysis
48	A Candidate Resource Plan that includes a transition to an electricity supply that consists of 100% Renewable Energy Sources by the year 2040.	Scotian WindFields	Due to the operational issues and uncertainties of this CRP this has not been selected as a Candidate Resource Plan. However, CRPs 6 and 8 and Scenario "C" emissions sensitivity analysis (S2) may provide relevant information regarding this proposal.	CRPs
49	A Candidate Resource Plan that includes a transition to an electricity supply that consists of 80% Renewable Energy Sources by the year 2040.	Scotian WindFields	Due to the operational issues and uncertainties of this CRP this has not been selected as a Candidate Resource Plan. However, CRPs 6 and 8 and Scenario "C" emissions sensitivity analysis (S2) may provide relevant information regarding this proposal.	CRPs
50	A Candidate Resource Plan that includes a transition to an electricity supply that consists of 60% Renewable Energy Sources by the year 2040.	Scotian WindFields	This has not been selected as a Candidate Resource Plan; however, CRPs 6 and 8 and Scenario "C" emissions sensitivity analysis (S2) may provide relevant information regarding this proposal.	CRPs
51	A Candidate Resource Plan that includes the following criteria: High DSM Case, Min Use Coal Case, High Wind Case.	Scotian WindFields	This proposal is being modelled as CRP 6.	CRPs
52	A Candidate Resource Plan that includes Scenario C GHG Emissions cust to 2.25 MT in 2040.	Scotian WindFields	Scenario C emissions will be tested as sensitivity analysis case S2.	Alternative Worlds
53	A Candidate Resource Plan that includes Scenario C GHG Emissions cust to 0 MT in 2040.	Scotian WindFields	Please refer to items 41 and 42.	Alternative Worlds
54	Scotian Windfields Inc. requests that utilization of CAES, and other energy storage technologies be considered in high-RES Candidate Resource Plans.	Scotian WindFields	The Company will examine the need for storage technologies in CRPs with increased intermittent renewable generation.	CRPs

Attachment 3 Page 1 of 2

	Max Use of Coal	Max Use of Coal	Med Use of Coal	Med Use of Coal	Min Use of Coal
	Based on 60 Years - CRP2 only	**Based on 60 Years with Flexibility - All Max Coal CRPs except CRP2**	**Based on 55 Years - CRP4 only**	**Based on 55 Years with Flexibility - All Med Coal CRPs except CRP4**	**All Min Coal CRPs**
2015					
2016					
2017					
2018	Lingan 2 (Oct 2017)	Lingan 2 (Oct 2017)	Lingan 2 (Oct 2017)	Lingan 2 (Oct 2017)	Lingan 2 (Oct 2017)
2019					
2020			TUC 1		Lingan 1
2021					TUC 1
2022					
2023				TUC 1	Lingan 3
2024				Lingan 1	Lingan 4
2025	TUC 1	TUC 1			
2026					
2027			TUC 2		
2028					TUC 2
2029					
2030			Trenton 5	TUC 2	Trenton 5
2031			TUC 3		
2032	TUC 2	TUC 2		Trenton 5	
2033					
2034			Lingan 1		
2035	Trenton 5	Trenton 5			Tupper 2
2036	TUC 3			Lingan 3	
2037				Lingan 4	
2038			Lingan 3		
2039	Lingan 1	Lingan 1	Lingan 4		
	3 Coal 3 Oil/Gas Total 6	3 Coal 2 Oil/Gas Total 5	5 Coal 3 Oil/Gas Total 8	5 Coal 2 Oil/Gas Total 7	6 Coal 2 Oil/Gas Total 8

	60 Years	55 Years	50 Years	40 Years
Thermal Unit	**Assumed Retirement Year for Modeling Purposes**	**Assumed Retirement Year for Modeling Purposes**	**Assumed Retirement Year for Modeling Purposes**	**Assumed Retirement Year for Modeling Purposes**
Pt Aconi	Beyond planning horizon *	Beyond planning horizon *	Beyond planning horizon *	Not expected to retire within planning period
Lingan 1	2039	2034	2029	2019
Lingan 2	2018 (Coincident with Maritime Link)	2018 (Coincident with Maritime Link)	2018 (Coincident with Maritime Link)	2018 (Coincident with Maritime Link)
Lingan 3	Beyond planning horizon *	2038	2033	2023
Lingan 4	Beyond planning horizon *	2039	2034	2024
Tupper 2	Beyond planning horizon *	Beyond planning horizon *	2037	2027
Trenton 5	2035	2030	2025	2020
Trenton 6	Beyond planning horizon *	Beyond planning horizon *	Beyond planning horizon *	Not expected to retire within planning period
Tufts Cove 1	2025	2020	2017	2015
Tufts Cove 2	2032	2027	2022	2015
Tufts Cove 3	2036	2031	2026	2016

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SEPTEMBER 12, 2014

2014 IRP Technical Conference Analysis Results

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Schedule for Remainder of IRP Process

Sep 12: Technical Conference
Sep 19: Feedback from Intervenors/Stakeholders (for incorporation in final report)
Sep 30: Issue Draft Final Report and Action Plan to Intervenors/Stakeholders
Oct 7: Comments on Draft Final Report received from Intervenors/Stakeholders
Oct 15: Final Report and Action Plan to UARB

Development Since Previous IRPs

Regulatory and legislative initiatives:		
RES target set at 40% in 2020		
Legislation limiting biomass consumption in the province		
Air emissions equivalency agreement		
Demand and supply side investment:		
DSM Administrator (2008/9 – 2013)	$165 million	128 MW – 632 GWh
Tufts Cove 6 (HR with duct firing)	$93 million	49 MW
Port Hawkesbury Biomass	$209 million	45 MW – 350 GWh
Wind Energy	$308 million (NSPI)	81 MW – 256 GWh (NSPI) 447 MW – 964 GWh (IPP)
Maritime Link	$1,500 million	153 MW – 1,000 GWh
System load:		
Loss of industrial load	~165MW – 1,100 GWh	
Industrial load on load retention tariff	~185 MW – 1,050 GWh	
Fuel expense recovery:		
FAM Process instated	Deferred fuel expense: $89 million	

Objective of the 2014 IRP

From Terms of Reference: *"To develop a long-term Preferred Resource Plan that establishes the direction for NS Power to meet customer demand and energy requirements, and environmental obligations in a cost-effective, safe and reliable manner across a reasonable range of foreseeable futures; and to develop an Action Plan describing the major tasks required to implement a no regrets strategy that aligns with the Preferred Resource Plan during the first five years of the planning horizon."*

The IRP study was designed to examine a broad spectrum of outcomes considering major existing and future resource drivers:

- Demand growth
- Demand side management
- Asset management of existing resources
- Addition of new conventional and renewable resources

The major decision drivers were combined into Candidate Resource Plans (CRPs), which were examined under a number of sensitivities including: possible future emissions regulations, fuel costs and possible technology advancements.

Executive Summary

We have been successful in building renewables and investing in DSM to meet environmental obligations since the last IRP. The results from this IRP show there is a near-term window* where limited incremental investment is required.

It appears there are opportunities to minimize short term rate impacts without compromising longer term environmental and economic benefits.

Environmental compliance and capacity planning is heavily reliant on DSM performing as forecasted.

For the next 4-5 years a flexible action plan which minimizes capacity additions is appropriate.

There is a range of potential preferred resource plans based on the NPVs and other metrics; however, the company believes that alleviating rate pressure in the near term is in the interest of the customers.

* Near term refers to the period before 2020.

Candidate Resource Plan Descriptions

CRP	DSM	WIND	COAL
World 1 - REFERENCE			
CRP1-1-FGD	50% of LOW	BASE	MAX
CRP2-1	BASE	BASE	MAX
CRP2-17-FGD	BASE	BASE	MAX
CRP3-1	BASE	MED	MAX
CRP4-1	BASE	BASE	MED
CRP4-1-FGD	BASE	BASE	MED
CRP5-1	HIGH	BASE	MAX
CRP6-1	HIGH	HIGH	MIN
CRP7-1	HIGH	MED	MIN
CRP8-1	BASE	HIGH	MIN
CRP9-1	BASE	MED	MIN
CRP9WC	BASE	MED (Optimistic Capacity Credit)	MIN
CRP10-1	BASE	MED	MED
CRP31-1	BASE - 50% Peak 100% Energy	MED	MAX
World 2- HIGH LOAD			
CRP21-1 (FGD WIND)	BASE	MED (Optimize)	MAX
CRP32-1 (FGD PPA)	BASE -50% Peak 100% Energy	MED (Optimize)	MAX

🟧	Max Retirement Strategy
🟩	Med Retirement Strategy
🟦	Min Retirement Strategy
⬜	Max Retirement Strategy - High Load

Preliminary Results
Schedule of Firm Supply

Candidate Resource Plans - Schedule of Changes to Supply-side and Demand-side Resources (Firm MWs)

	CRP1-1 FGD	CRP2-1	CRP2-17 FGD	CRP3-1	CRP4-1	CRP4-1 FGD	CRP5-1	CRP6-1	CRP7-1	CRP8-1	CRP9-1	CRP9WC*	CRP10-1	CRP31-1	CRP21-1 (FGD WIND)	CRP32-1 (FGD PPA)
Load	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	High	High
DSM Profile	Half Low	Base	Base	Base	Base	Base	High	High	High	Base	Base	Base	Base	Base 50% Peak 100% Energy	Base	Base 50% Peak 100% Energy
Wind	Base	Base	Base	Med	Base	Base	Base	High	Med	High	Med	Med	Med	Med	Med	Base
Retirement Strategy	Max	Max	Max	Max	Med	Med	Max	Min	Min	Min	Min	Min	Med	Max	Max	Max
New Resources 2015-2020																
DSM	62	156	156	156	156	156	241	241	241	156	156	156	156	80	156	80
Maritime Link	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153
DR	0	0	0	0	19	19	0	0	19	10	19	19	19	0	0	10
Mersey	15	0	0	0	0	0	0	0	0	15	15	15	15	0	15	0
Wind	0	0	0	0	0	0	0	0	0	0	0	70	0	0	18	0
PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100
PHBM	0	0	0	0	0	0	0	52	52	52	52	52	0	0	0	0
NG CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	99	0
NG CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FGD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-8	-8
Retirements																
Coal	-153	-153	-153	-153	-153	-153	-153	-306	-306	-306	-306	-306	-153	-153	-153	-153
NG/Oil	0	0	0	0	-81	-81	0	0	0	0	0	0	0	0	0	0
Subtotal	**77**	**156**	**156**	**156**	**94**	**94**	**241**	**140**	**159**	**80**	**89**	**158**	**190**	**80**	**280**	**182**
New Resources 2021-2039																
DSM	202	510	510	510	510	510	643	643	643	510	510	510	510	254	510	254
DR	0	0	0	0	67	67	0	0	67	52	67	67	67	0	0	52
Mersey	15	0	0	0	0	0	0	0	0	15	15	15	15	0	15	0
Wind	0	0	0	18	0	0	0	36	18	36	18	36	18	18	0	0
PPA	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PHBM	52	52	52	52	0	0	52	0	0	0	0	0	52	52	45	45
NG CT	315	99	149	99	216	99	0	296	197	444	296	364	265	330	148	397
NG CC	145	0	0	0	290	145	0	0	0	0	145	0	0	145	0	145
FGD	-8	0	-8	0	0	-8	0	0	0	0	0	0	0	0	0	0
Retirements																
Coal	-303	-303	-303	-303	-614	-303	-303	-613	-613	-613	-613	-613	-614	-303	-303	-303
NG/Oil	-174	-174	-174	-174	-240	-240	-174	-174	-174	-174	-174	-174	-174	-174	-174	-174
Subtotal	**344**	**183**	**226**	**201**	**229**	**270**	**218**	**188**	**138**	**270**	**264**	**205**	**139**	**322**	**242**	**417**
Total Additional Firm Supply & Demand MW's Over Planning Period																
Total	**421**	**340**	**382**	**358**	**323**	**364**	**459**	**328**	**297**	**350**	**353**	**364**	**329**	**402**	**521**	**599**

See Notes on next slide

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Preliminary Results
Schedule of Firm Supply

Notes for Schedule of Changes to Supply-side and Demand-side Resources (Firm MWs)

- DSM - capacity refers to reduction in firm demand (net of interruptible industrial portion)
- DR (Demand Response) - capacity refers to reduction in firm demand
- Mersey - incremental capacity upgrade
- Wind - firm contribution of incremental wind above planned and committed wind of 582 MW
  - * for CRP9WC the firm contribution of planned /committed wind and incremental wind was increased to 24.1%
- PPA - Large non-emitting, RES compliant Purchased Power Agreement
- PHBM - PH Biomass unit is assumed to transition to a firm capacity resource upon the retirement of a second Lingan unit
- NG CT - Natural Gas Combustion Turbine
- NG CC - Natural Gas Combined Cycle
- FGD - coal retrofit with an FGD (scrubber) results in reduced capacity due to parasitic power

Key Observations

1. The planning done through the 2007 IRP and refined in the 2009 IRP Update has proven robust. Combined with the Maritime Link, continued operation of NS Power's existing assets and investment in renewables and DSM continue as key elements of the 2014 IRP low-cost plans.

2. CRP 2 reflects the Base IRP assumptions and has emerged as the lowest NPV plan over the 25 year period.

3. For CRP 2 and other lower cost plans, it appears there is limited incremental spending required up to 2020 to meet environmental requirements. The spending that is required in this period is largely limited to investment in DSM.

4. Base DSM, as forecasted, would offset Base Load Growth. If DSM delivery beyond 2020 does not meet the DSM forecast then the system will experience reliability and environmental/emissions challenges.

Key Observations

5. A variable DSM[1] spending profile has the potential to lower near term (~5 year) rate pressure while being competitive on a planning period NPV basis. The amount of DSM economically justified over this period and across the planning period remains a matter to be addressed through negotiations between NS Power and ENSC and the subsequent regulatory proceeding.

6. Uncertainty in the outer years may make it more beneficial to concentrate on nearer term IRP metrics.

7. FGD at Lingan 3 and 4 appears economic in several Base Load CRPs and in all High Load Word (flat net load) CRPs based on the international price of HS coal.

8. Capacity additions are required for High Load World CRPs in the early 2020s.

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[1] A variable DSM spending profile refers to DSM programming that could be modified from year to year to have lower spending in the near term and higher spending post 2020.

Key Observations

9. Environmental regulations can be most economically met over the 25 year planning period by maintaining wind penetration at current levels.

10. High DSM plans present the greatest near-term rate pressure.

11. All plans respond similarly over the range of sensitivities, which is a reflection of resource flexibility of the NSPI system.

12. All other things being equal, a 60-year life retirement schedule for the coal fleet (Max Coal) is the most economic over the planning period.

13. Tested against the Base Assumptions, Emissions scenarios do not show major movement in NPVs.

Criteria for Evaluating the Path Forward

The indicators available from Strategist and other sources:

- **NPV:** Cross-section of near and long term NPVs including end effects NPVs
- **Rate Effects:** Relative time-series revenue requirements
- **Risk:** Relative complexity and risks inherent in CRPs
- **Flexibility:** Diversity of technological solutions
- **Robustness:** Results of sensitivity tests
- **Future Regulatory emissions outlook**

The best performing aspects of several CRPs may be combined to inform development of a robust resource plan that is adaptable to future regulatory, supply, and demand side requirements, while being sensitive to accuracy of system assumptions in the outer years.

Metrics for Evaluating the Path Forward (NPV)

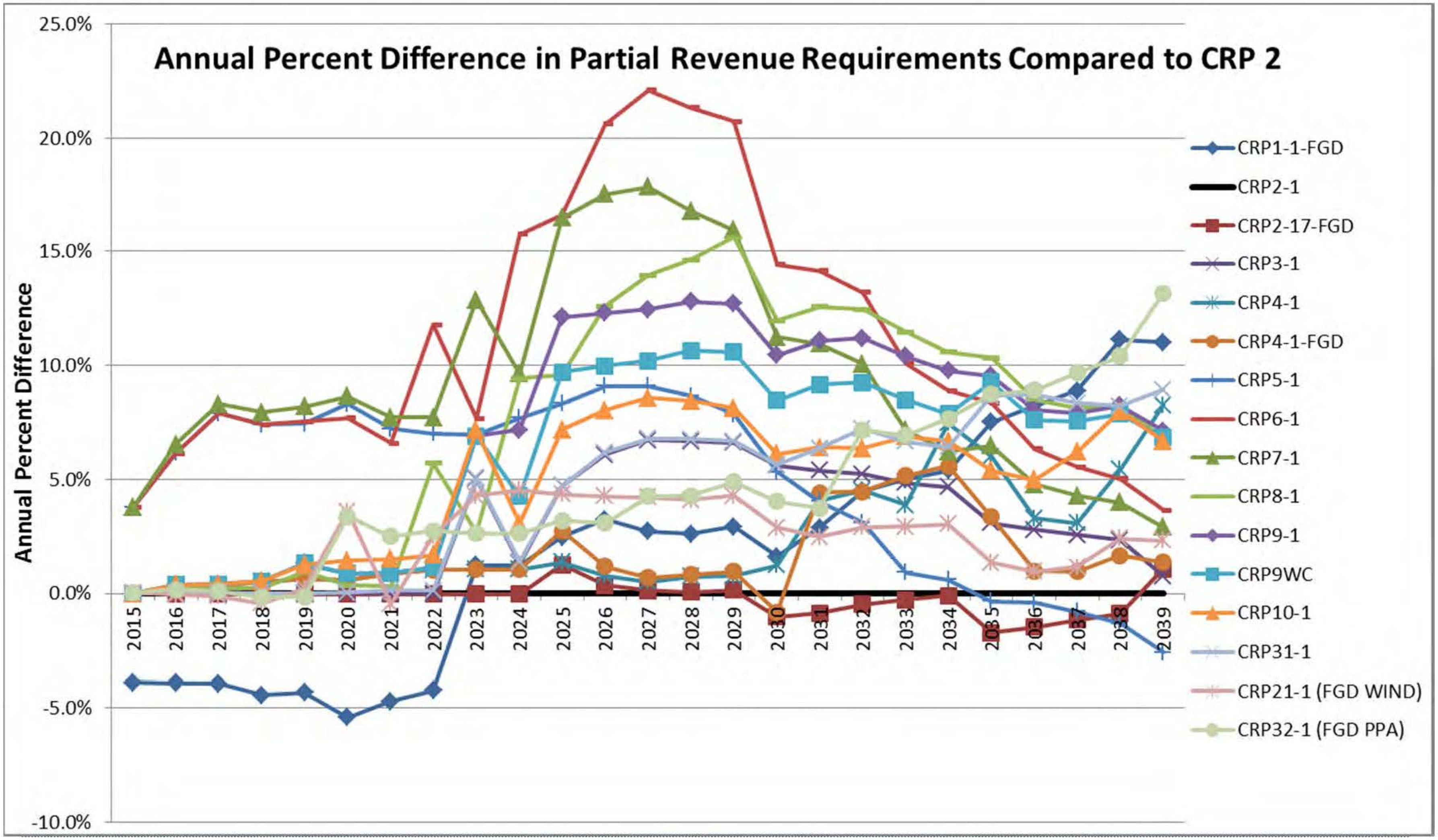
Net Present Value of Candidate Resource Plans are presented for four periods, Derived form the significant milestones horizons in the regulatory/legislative framework as well as standard modeling horizons.

NPV Horizon	Description
Short term period leading to 40% RES requirement (2020)	NPV considering short term rate impact concentrating on evaluating CRPs with near term system assumptions.
Legislated Emissions Regulations Period (2030)	NPV considering only presently active emissions regulations without speculating on future legislative direction.
Planning Period (2039)	Planning Period NPV will include sustaining capital overlays in order to provide equalized comparison base for plans with early and late asset retirement schedules.
Study Period (Infinity)	This NPV takes in account costs beyond 2039 in the end effects. The model determines the end effects costs internally as a single net present value calculation and adds it to the planning period costs to give the study period costs. Study period NPVs are not comparable across retirement horizons.

Comparison of Partial Revenue Requirements Graphs

- NS Power believes customers are concerned with affordability particularly in the short term.
- The following two graphs present a CRP comparison based on the partial revenue requirements.
- The partial revenue requirements are those costs which have been included in the Strategist modeling as well as the adjustment for sustaining capital costs completed outside of the model.
- These costs do not encompass NS Power's total revenue requirement. They include only a portion of the costs such as fuel and purchased power, thermal and hydro unit O&M, capital costs for new resources added in the CRP and DSM program administrator costs.
- The graphs do not include other cost items that would be common among all CRPs such as remaining O&M, regulatory adjustments/amortizations, interest and tax impacts.
- These partial revenue requirements were adjusted by load to put the CRPs on an equal basis for comparison. The graphs show the annual percent difference compared to CRP 2.
- Since the total revenue requirement is not reflected in these partial costs, the graphs provide an indication of relative cost pressures among CRPs rather than an increase in rates.
- These graphs present a relative comparison among CRPs. They do not provide a comparison relative to NS Power's currently approved revenue requirement.

Preliminary Results Annual Percent Difference



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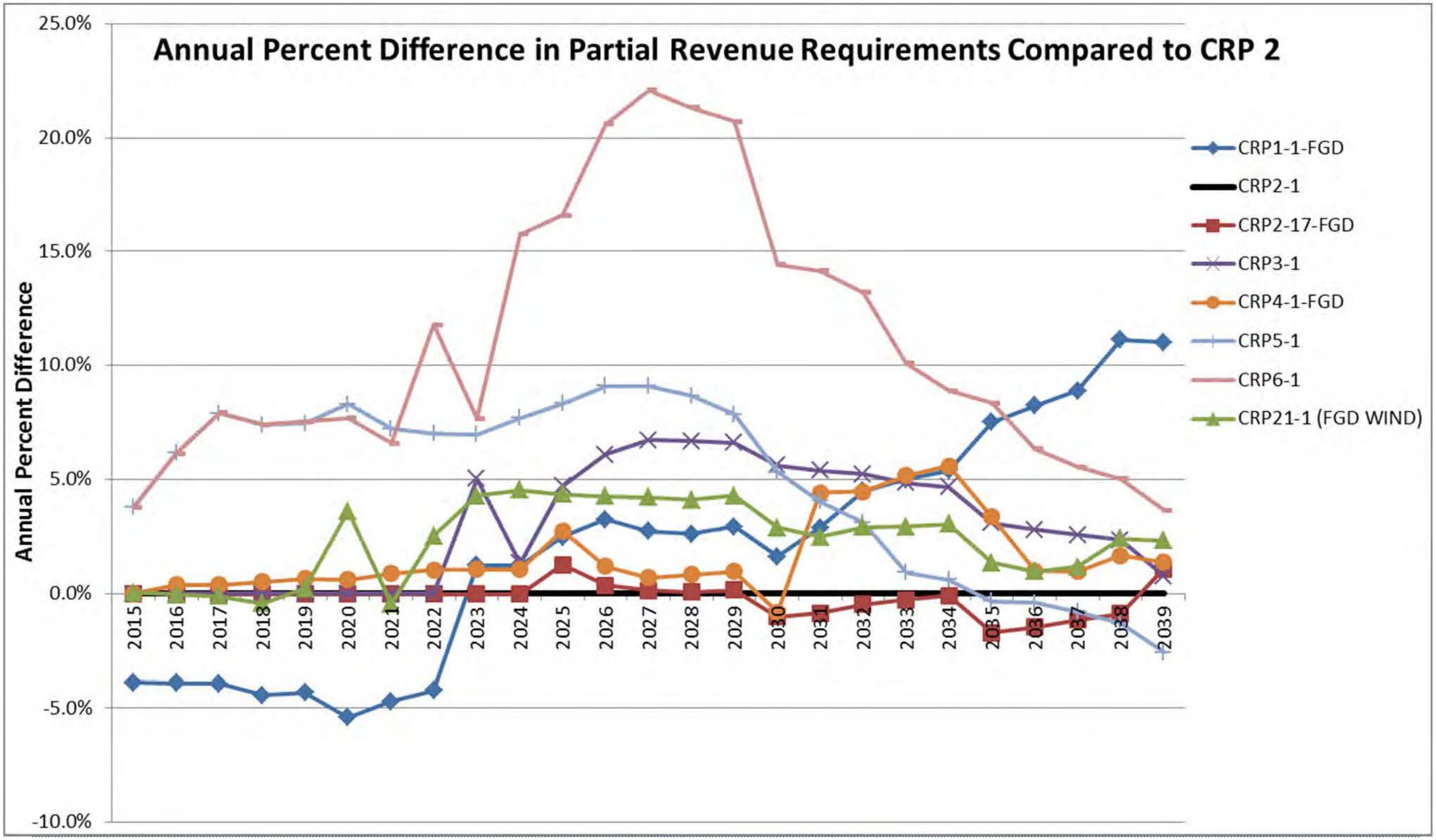
Preliminary Results Annual Percent Difference (Select Group of CRP's)



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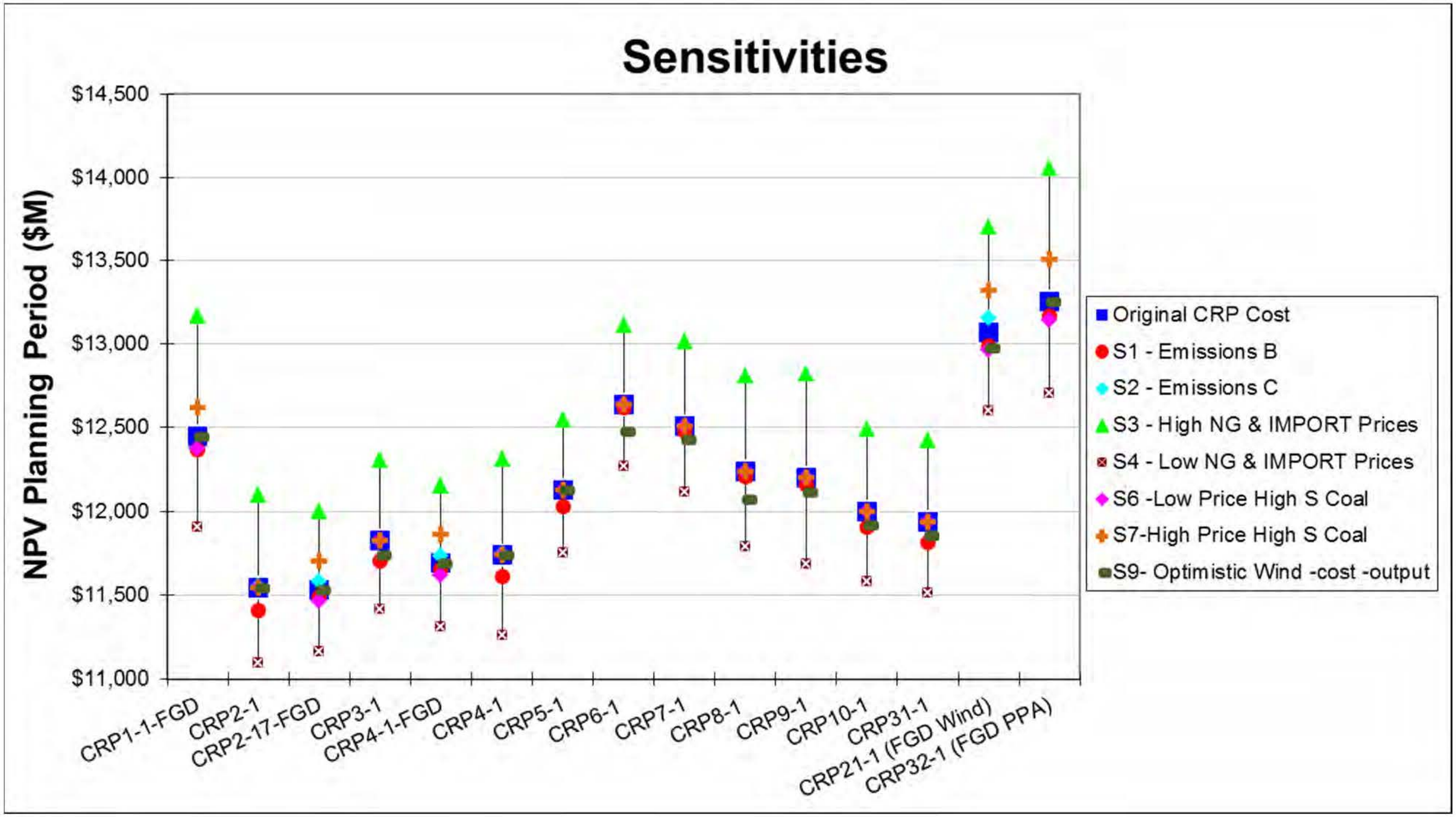
Preliminary Results
CRP Comparison of Sensitivities



Draft Action Plan Items

- Demand Side Management
  - Engage with ENSC and stakeholders to develop 3 year plan and file for UARB approval
  - Engage with stakeholders and ENSC to monitor DSM performance and options
  - Pursue cost-effective Demand Response opportunities

- Renewable Resources
  - Pursue the study of further intermittent generation to determine appropriate capacity value and Network Resource Interconnection Service (NRIS) and Energy Resource Interconnection Service (ERIS) capacity by Q4 2016
  - Monitor ongoing developments of tidal energy and report to the UARB as part of the 10 Year System Outlook
  - Complete the integration of the Maritime Link
  - Undertake Mersey (base) Redevelopment Capital Application for filing with the UARB
  - Continue to develop an understanding of the operational challenges associated with variable generation and report to the UARB as part of the 10 Year System Outlook
  - File Renewable to Retail Tariff Application
  - Report to the UARB on the status of the need for flexible resources to integrate additional variable generation in the 10 Year System Outlook Report

Draft Action Plan Items (cont'd)

- Regional Opportunities
    - Monitor cost-effective market opportunities (imports and exports) as well as enhancements in regional balancing and interconnection and report on developments in the 10 Year System Outlook Report
- Existing Thermal Resources
    - Within 24 months of the IRP, produce a report on industry best practices regarding sustaining capital
    - Report on the status of sustaining capital expenditures for 5 year periods in the Annual Capital Expenditure Plan
    - Present current retirement forecast in 10 Year System Outlook Report
    - Study the economic potential of an FGD in combination with opportunities to optimize solid fuel use
    - Analyze potential optimal capital spending plans for the existing thermal fleet given peak load and annual energy paths that would align with "high" levels of DSM spending and associated high levels of firm peak reduction. This includes devising capital investment plans that reduce the level of "surplus" planning reserve margin that would exist with, e.g., CRP 5-1.

Draft Action Plan Items (cont'd)

- Transmission
  - Execute the Maritime Link transmission investments
  - Monitor and report on regional transmission integration opportunities by the end of Q2 2016

- Planning Reserve Margin
  - Report on the ongoing evaluation of the appropriate planning reserve margin for the power system in the 10 Year System Outlook Report

- Regulatory
  - Monitor renewable and emissions related legislative/regulatory developments
  - Report to the UARB on legislative/regulatory changes that may have a material impact on the Action Plan - one update to be sent in Q3 2016

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SEPTEMBER 12, 2014

Supporting Materials

Preliminary Results
CRP Sensitivity Matrix

These results include the NPV adders for Sustaining Capital
Study period NPV's can only be compared within the same unit retirement strategies (e.g. all maximum coal)

🟩 50% Low DSM 🟧 High DSM ☐ Base DSM 🟦 Base DSM- 50% PEAK, 100% ENERGY 🟨 Cost unchanged from Original Case

All Values in $M	Original Data		S1 - Emissions B		S2 - Emissions C		S3 - High NG & IMPORT Prices		S4 - Low NG & IMPORT Prices		S6 -Low Price High S Coal		S7- High Price High S Coal		S9- Optimistic Wind - cost -output	
CRP	Planning Period Cost	Study Period Cost	Planning Period Cost	Study Period Cost	Planning Period Cost	Study Period Cost	Planning Period Cost	Study Period Cost	Planning Period Cost	Study Period Cost	Planning Period Cost	Study Period Cost	Planning Period Cost	Study Period Cost	Planning Period Cost	Study Period Cost
World 1 - REFERENCE																
CRP1-1-FGD	$12,449	$19,774	$12,370	$19,617			$13,166	$21,288	$11,899	$18,331	$12,372	$19,600	$12,619	$20,203	$12,449	$19,774
CRP2-1	$11,544	$17,103	$11,405	$16,802	$11,551	$17,192	$12,097	$18,216	$11,090	$15,993	$11,544	$17,103	$11,544	$17,103	$11,544	$17,103
CRP2-17-FGD	$11,530	$17,200	$11,489	$17,102	$11,580	$17,391	$11,996	$18,280	$11,157	$16,259	$11,460	$17,093	$11,704	$17,484	$11,530	$17,200
CRP3-1	$11,825	$17,419	$11,704	$17,150			$12,308	$18,392	$11,406	$16,412	$11,825	$17,419	$11,825	$17,419	$11,742	$17,199
CRP4-1	$11,736	$17,643	$11,609	$17,436	$11,743	$17,686	$12,309	$18,807	$11,253	$16,258	$11,736	$17,643	$11,736	$17,643	$11,736	$17,643
CRP4-1-FGD	$11,692	$17,469	$11,654	$17,343	$11,734	$17,594	$12,156	$18,563	$11,305	$16,401	$11,622	$17,326	$11,863	$17,713	$11,692	$17,469
CRP5-1	$12,125	$17,076	$12,027	$16,849			$12,548	$17,900	$11,746	$16,185	$12,125	$17,076	$12,125	$17,076	$12,125	$17,076
CRP6-1	$12,638	$17,829	$12,617	$17,808	$12,638	$17,829	$13,110	$18,735	$12,264	$16,965	$12,638	$17,829	$12,638	$17,829	$12,478	$17,405
CRP7-1	$12,512	$17,666	$12,479	$17,633			$13,016	$18,653	$12,108	$16,727	$12,512	$17,666	$12,512	$17,666	$12,430	$17,452
CRP8-1	$12,240	$18,095	$12,205	$18,059	$12,240	$18,095	$12,811	$19,263	$11,784	$16,991	$12,240	$18,095	$12,240	$18,095	$12,075	$17,651
CRP9-1	$12,200	$18,091	$12,158	$18,049	$12,200	$18,091	$12,824	$19,396	$11,680	$16,770	$12,200	$18,091	$12,200	$18,091	$12,117	$17,870
CRP9WC	$12,101	$17,968	$12,059	$17,926	$12,101	$17,968	$12,718	$19,281	$11,600	$16,736	$12,101	$17,968	$12,101	$17,968	$12,017	$17,742
CRP10-1	$12,000	$17,731	$11,904	$17,566			$12,490	$18,733	$11,576	$16,694	$12,000	$17,731	$12,000	$17,731	$11,919	$17,515
CRP31-1	$11,934	$17,831	$11,815	$17,563			$12,424	$18,822	$11,505	$16,690	$11,934	$17,831	$11,934	$17,831	$11,856	$17,620
World 2- HIGH LOAD																
CRP21-1 (FGD	$13,071	$19,852	$12,990	$19,712	$13,157	$20,289	$13,706	$21,267	$12,593	$18,690	$12,962	$19,685	$13,322	$20,246	$12,979	$19,624
CRP32-1 (FGD PPA)	$13,256	$20,585	$13,166	$20,389			$14,056	$22,161	$12,697	$19,067	$13,143	$20,371	$13,508	$21,084	$13,256	$20,585

Preliminary Results
Ranking for Sensitivities

🟧 Max Retirement Strategy 🟩 Med Retirement Strategy 🟦 Min Retirement Strategy

	Original Data		S1 - Emissions B		S2 - Emissions C		S3 - High NG & IMPORT Prices		S4 - Low NG & IMPORT Prices		S6 -Low Price High S Coal		S7- High Price High S Coal		S9- Optimistic Wind -cost -output	
CRP	Planning Period Rank	** Study Period Rank	Planning Period Rank	** Study Period Rank	Planning Period Rank	** Study Period Rank	Planning Period Rank	** Study Period Rank	Planning Period Rank	** Study Period Rank	Planning Period Rank	** Study Period Rank	Planning Period Rank	** Study Period Rank	Planning Period Rank	** Study Period Rank
World 1 - REFERENCE																
CRP1-1-FGD	12	6	12	6			14	6	12	6	12	6	13	6	13	6
CRP2-1	2	2	1	1	1	1	2	2	1	1	2	3	1	2	2	2
CRP2-17-FGD	1	3	2	3	2	2	1	3	2	3	1	2	2	4	1	4
CRP3-1	5	4	5	4			4	4	5	4	5	4	4	3	5	3
CRP4-1	4	2	3	2	4	2	5	3	3	1	4	2	3	1	4	3
CRP4-1-FGD	3	1	4	1	3	1	3	1	4	2	3	1	5	2	3	1
CRP5-1	9	1	8	2			8	1	10	2	9	1	9	1	11	1
CRP6-1	14	2	14	2	8	1	13	2	14	4	14	2	14	2	14	1
CRP7-1	13	1	13	1			12	1	13	1	13	1	12	1	12	2
CRP8-1	11	5	11	5	7	4	10	3	11	5	11	5	11	5	9	3
CRP9-1	10	4	10	4	6	3	11	5	9	3	10	4	10	4	10	5
CRP9WC	8	3	9	3	5	2	9	4	8	2	8	3	8	3	8	4
CRP10-1	7	3	7	3			7	2	7	3	7	3	7	3	7	2
CRP31-1	6	5	6	5			6	5	6	5	6	5	6	5	6	5
World 2- HIGH LOAD																
*CRP21-1 (FGD	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
*CRP32-1 (FGD PPA)	2	2	2	2			2	2	2	2	2	2	2	2	2	2

* High Load plans (CRP 21 & 32) are ranked separately from Base Load plans.

** CRPs have been grouped by retirement strategy for rankings on Study Period costs. For example, all five CRPs with Min Coal retirement strategy are shaded in blue and have been ranked from 1 to 5.

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Preliminary Results
% Difference for Sensitivities

🟧 Max Retirement Strategy 🟩 Med Retirement Strategy 🟦 Min Retirement Strategy

	Original Data		S1 - Emissions B		S2 - Emissions C		S3 - High NG & IMPORT Prices		S4 - Low NG & IMPORT Prices		S6 -Low Price High S Coal		S7- High Price High S Coal		S9- Optimistic Wind -cost -output	
CRP	Planning Period Rank	** Study Period Rank	Planning Period Rank	** Study Period Rank	Planning Period Rank	** Study Period Rank	Planning Period Rank	** Study Period Rank	Planning Period Rank	** Study Period Rank	Planning Period Rank	** Study Period Rank	Planning Period Rank	** Study Period Rank	Planning Period Rank	** Study Period Rank
World 1 - REFERENCE																
CRP1-1-FGD	8.0%	15.8%	8.5%	16.8%			9.8%	18.9%	7.3%	14.6%	8.0%	14.8%	9.3%	18.3%	8.0%	15.8%
CRP2-1	0.1%	0.2%	0.0%	0.0%	0.0%	0.0%	0.8%	1.8%	0.0%	0.0%	0.7%	0.2%	0.0%	0.2%	0.1%	0.2%
CRP2-17-FGD	0.0%	0.7%	0.7%	1.8%	0.3%	1.2%	0.0%	2.1%	0.6%	1.7%	0.0%	0.1%	1.4%	2.4%	0.0%	0.7%
CRP3-1	2.6%	2.0%	2.6%	2.1%			2.6%	2.7%	2.8%	2.6%	3.2%	2.0%	2.4%	2.0%	1.8%	0.7%
CRP4-1	1.8%	1.0%	1.8%	0.5%	1.7%	0.5%	2.6%	1.3%	1.5%	0.0%	2.4%	1.8%	1.7%	0.0%	1.8%	1.0%
CRP4-1-FGD	1.4%	0.0%	2.2%	0.0%	1.6%	0.0%	1.3%	0.0%	1.9%	0.9%	1.4%	0.0%	2.8%	0.4%	1.4%	0.0%
CRP5-1	5.2%	0.0%	5.5%	0.3%			4.6%	0.0%	5.9%	1.2%	5.8%	0.0%	5.0%	0.0%	5.2%	0.0%
CRP6-1	9.6%	0.9%	10.6%	1.0%	9.4%	0.0%	9.3%	0.4%	10.6%	1.4%	10.3%	0.9%	9.5%	0.9%	8.2%	0.0%
CRP7-1	8.5%	0.0%	9.4%	0.0%			8.5%	0.0%	9.2%	0.0%	9.2%	0.0%	8.4%	0.0%	7.8%	0.3%
CRP8-1	6.2%	2.4%	7.0%	2.4%	6.0%	1.5%	6.8%	3.3%	6.3%	1.6%	6.8%	2.4%	6.0%	2.4%	4.7%	1.4%
CRP9-1	5.8%	2.4%	6.6%	2.4%	5.6%	1.5%	6.9%	4.0%	5.3%	0.3%	6.5%	2.4%	5.7%	2.4%	5.1%	2.7%
CRP9WC	4.9%	1.7%	5.7%	1.7%	4.8%	0.8%	6.0%	3.4%	4.6%	0.1%	5.6%	1.7%	4.8%	1.7%	4.2%	1.9%
CRP10-1	4.1%	1.5%	4.4%	1.3%			4.1%	0.9%	4.4%	2.7%	4.7%	2.3%	3.9%	0.1%	3.4%	0.3%
CRP31-1	3.5%	4.4%	3.6%	4.5%			3.6%	5.2%	3.7%	4.4%	4.1%	4.4%	3.4%	4.4%	2.8%	3.2%
World 2- HIGH LOAD																
*CRP21-1 (FGD	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
*CRP32-1 (FGD PPA)	1.4%	3.7%	1.4%	3.4%			2.6%	4.2%	0.8%	2.0%	1.4%	3.5%	1.4%	4.1%	2.1%	4.9%

* High Load plans (CRP 21 & 32) are ranked separately from Base Load plans.

** CRPs have been grouped by retirement strategy for rankings on Study Period costs. For example, all five CRPs with Min Coal retirement strategy are shaded in blue and have been ranked from 1 to 5.

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Preliminary Results (with Sustaining Capital)
TRC and Ranking / Utility Cost and Ranking

	CRP1-1 FGD	CRP2-1	CRP2-17 FGD	CRP3-1	CRP4-1	CRP4-1 FGD	CRP5-1	CRP6-1	CRP7-1	CRP8-1	CRP9-1	CRP9WC	CRP10-1	CRP31-1	* CRP21-1 (FGD WIND)	* CRP32-1 (FGD PPA)
Load	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	High	High
DSM Profile	Half Low	Base	Base	Base	Base	Base	High	High	High	Base	Base	Base	Base	Base 50% Peak 100% Energy	Base	Base 50% Peak 100% Energy
Wind	Base	Base	Base	Med	Base	Base	Base	High	Med	High	Med	Med	Med	Med	Med	Base
Retirement Strategy	Max	Max	Max	Max	Med	Med	Max	Min	Min	Min	Min	Min	Med	Max	Max	Max
TRC $ M																
NPV 2020	$3,907	$4,049	$4,049	$4,049	$4,065	$4,065	$4,491	$4,489	$4,507	$4,062	$4,072	$4,072	$4,075	$4,050	$4,194	$4,195
NPV 2030	$9,025	$8,777	$8,780	$8,959	$8,836	$8,838	$9,547	$9,864	$9,790	$9,203	$9,182	$9,113	$9,063	$8,963	$9,764	$9,761
Planning Period	$12,449	$11,544	$11,530	$11,825	$11,737	$11,693	$12,125	$12,638	$12,512	$12,240	$12,200	$12,101	$12,000	$11,933	$13,070	$13,256
**** Study Period**	$19,775	$17,103	$17,201	$17,419	$17,643	$17,469	$17,076	$17,829	$17,666	$18,095	$18,091	$17,968	$17,731	$17,831	$19,851	$20,585
TRC Rank																
NPV 2020	1	3	2	3	7	7	13	12	14	6	9	9	11	5	1	2
NPV 2030	7	1	2	5	3	4	12	14	13	11	10	9	8	6	2	1
Planning Period	12	2	1	5	4	3	9	14	13	11	10	8	7	6	1	2
Avg. Rank	*6.7*	*2.0*	*1.7*	*4.3*	*4.7*	*4.7*	*11.3*	*13.3*	*13.3*	*9.3*	*9.7*	*8.7*	*8.7*	*5.7*	*1.25*	*1.75*
**** Study Period**	6	2	3	4	2	1	1	2	1	5	4	3	3	5	1	2
Utility Cost $ M																
NPV 2020	$3,784	$3,858	$3,857	$3,858	$3,874	$3,874	$4,054	$4,051	$4,069	$3,871	$3,880	$3,880	$3,883	$3,859	$4,002	$4,003
NPV 2030	$8,762	$8,416	$8,420	$8,599	$8,475	$8,478	$8,672	$8,989	$8,915	$8,843	$8,822	$8,753	$8,703	$8,603	$9,403	$9,401
Planning Period	$12,086	$11,069	$11,055	$11,350	$11,262	$11,218	$11,087	$11,601	$11,475	$11,765	$11,725	$11,626	$11,525	$11,458	$12,595	$12,781
**** Study Period**	$19,270	$16,471	$16,568	$16,786	$17,010	$16,836	$15,846	$16,599	$16,436	$17,462	$17,458	$17,336	$17,098	$17,198	$19,219	$19,953
Utility Cost Rank																
NPV 2020	1	3	2	3	7	7	13	12	14	6	9	9	11	5	1	2
NPV 2030	10	1	2	5	3	4	7	14	13	12	11	9	8	6	2	1
Planning Period	14	2	1	6	5	4	3	10	8	13	12	11	9	7	1	2
Avg. Rank	*8.3*	*2.0*	*1.7*	*4.7*	*5.0*	*5.0*	*7.7*	*12.0*	*11.7*	*10.3*	*10.7*	*9.7*	*9.3*	*6.0*	*1.25*	*1.75*
**** Study Period**	6	2	3	4	2	1	1	2	1	5	4	3	3	5	1	2

🟧 Max Retirement Strategy 🟩 Med Retirement Strategy 🟦 Min Retirement Strategy

* High Load plans (CRP 21 & 32) are ranked separately from Base Load plans.

** CRPs have been grouped by retirement strategy for rankings on Study Period costs. For example, all five CRPs with Min Coal retirement strategy are shaded in blue and have been ranked from 1 to 5.

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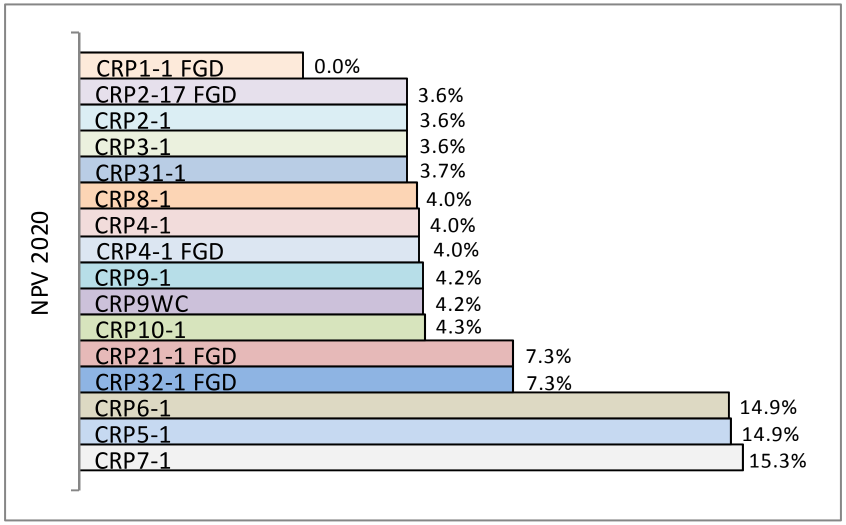
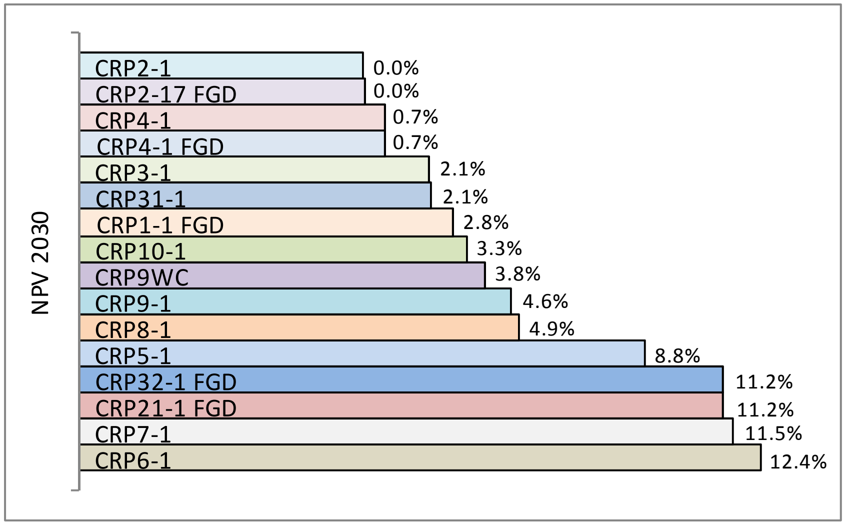
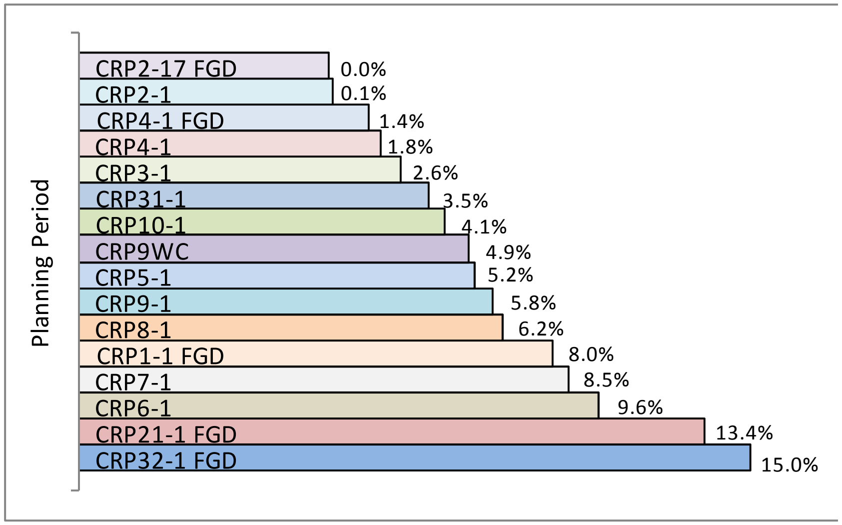
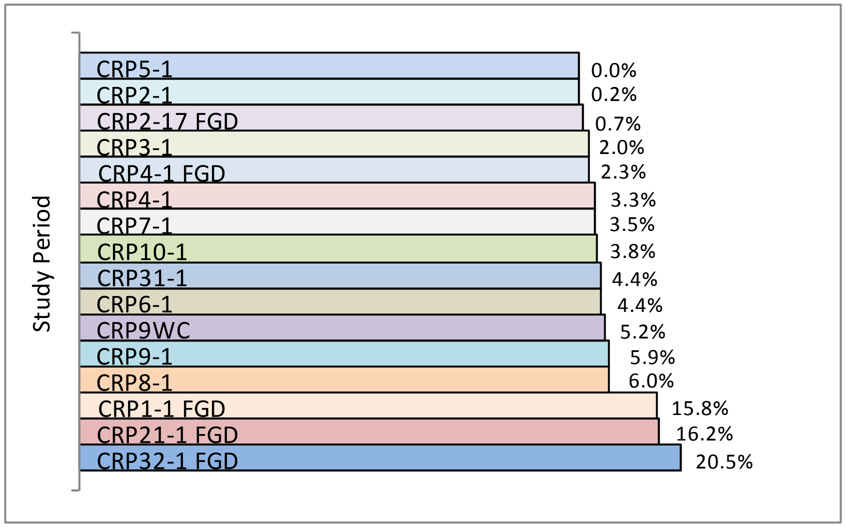
Preliminary Results
TRC – NPV 2020, NPV 2030, Planning and Study Period Costs









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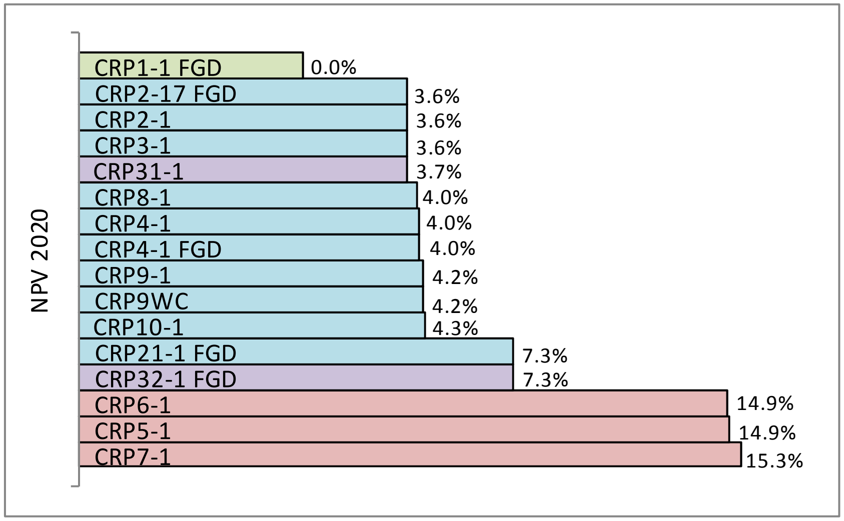
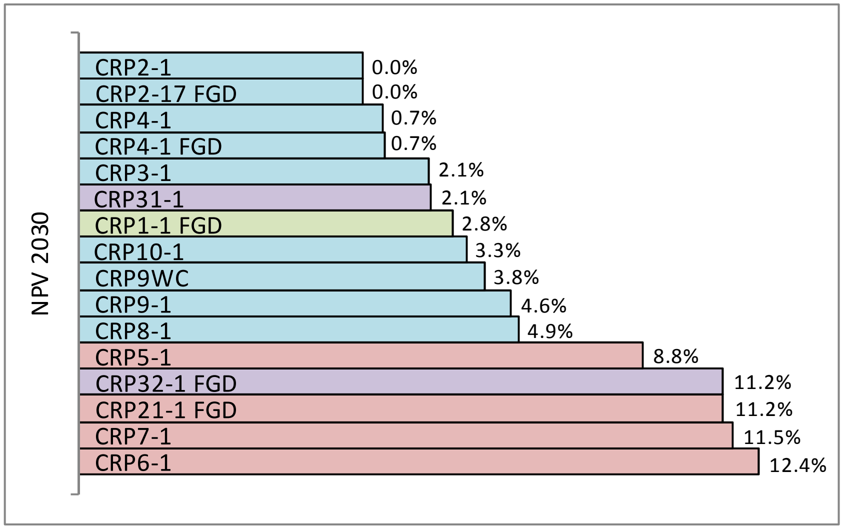
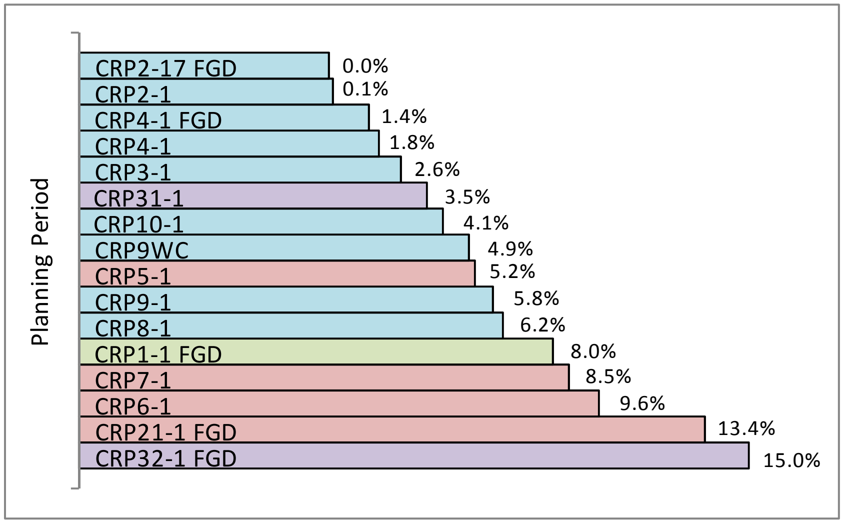
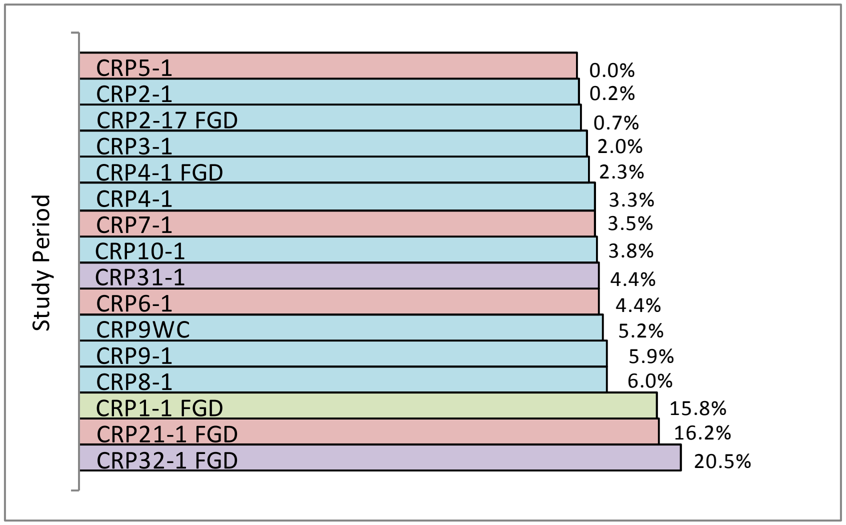
Preliminary Results
TRC – NPV 2020, NPV 2030, Planning and Study Period Costs (DSM Load Comparison)









DSM load comparison

🟩 Half Low 🟦 Base 🟥 High 🟪 Base 50% Peak 100% Energy

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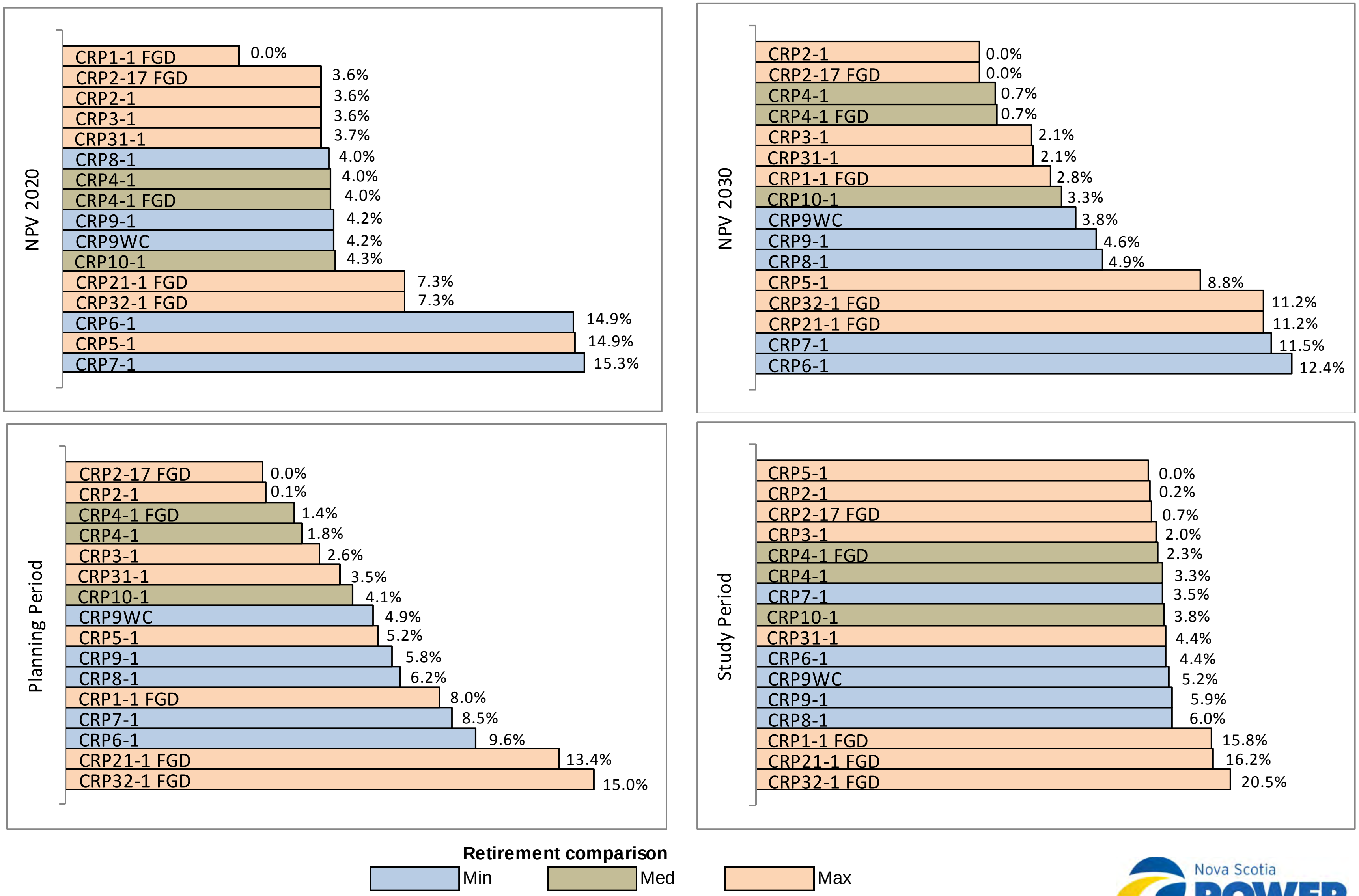
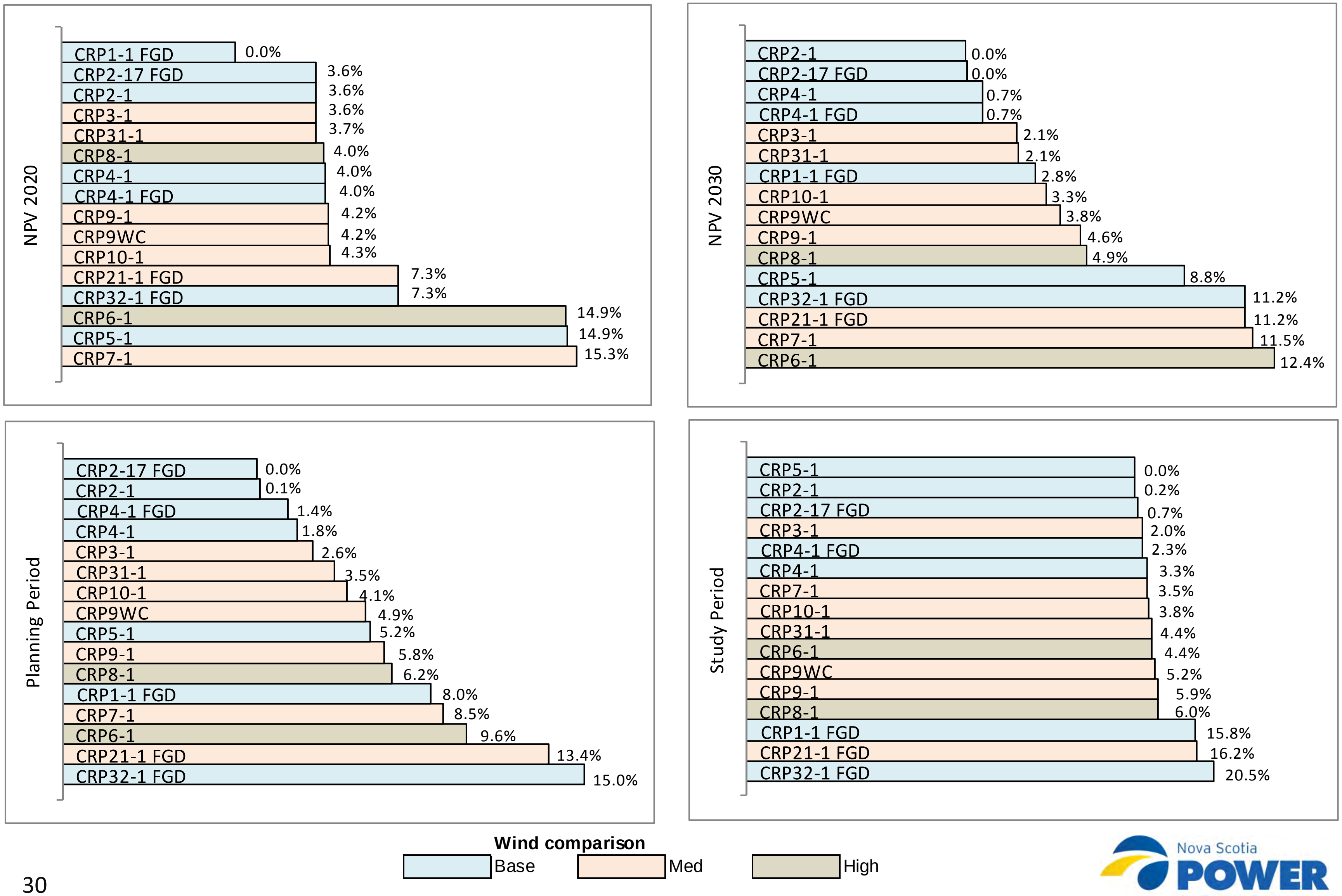
Preliminary Results
TRC – NPV 2020, NPV 2030, Planning and Study Period Costs (Retirement Comparison)



Preliminary Results
TRC – NPV 2020, NPV 2030, Planning and Study Period Costs (Wind Comparison)



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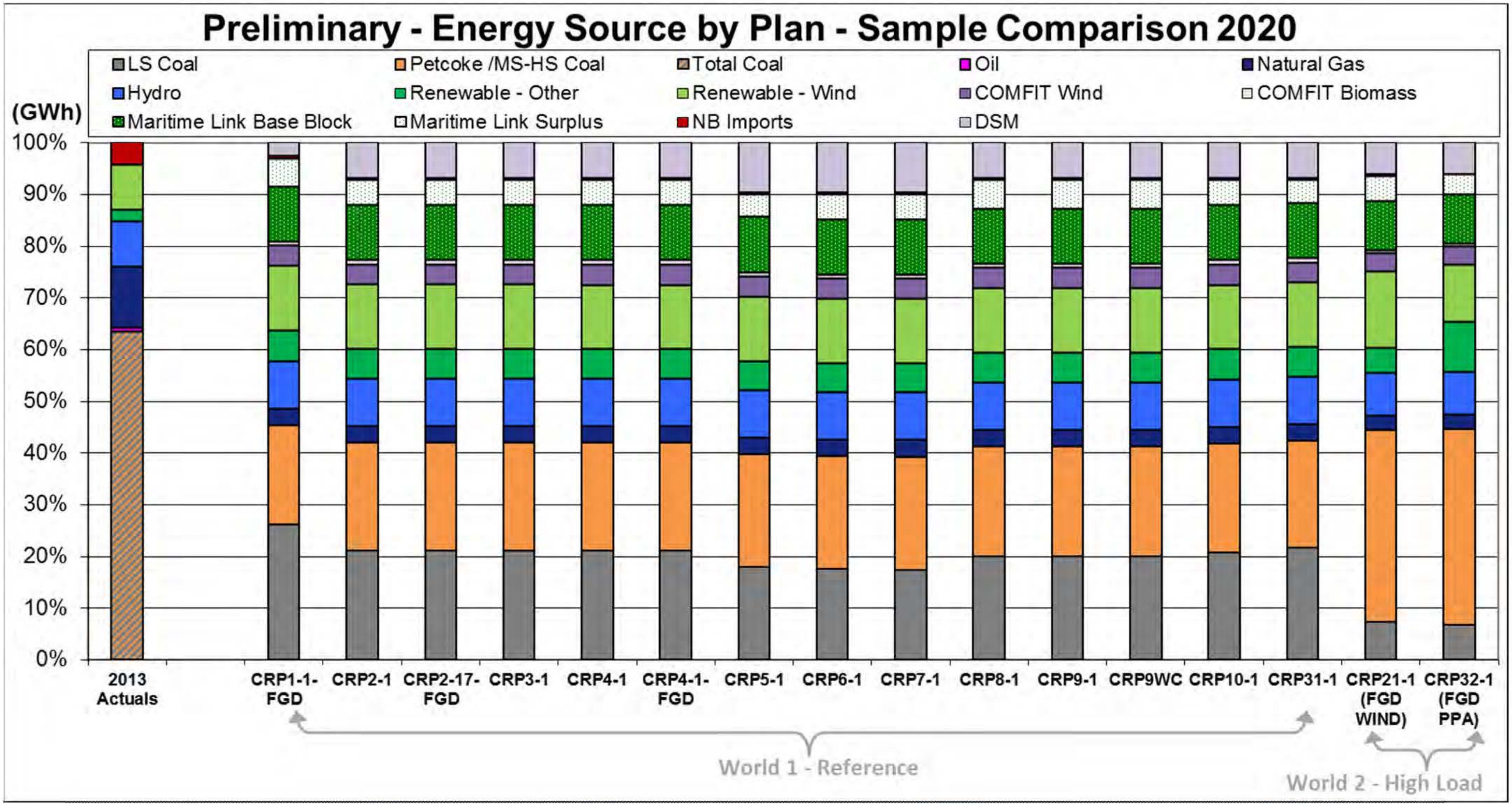
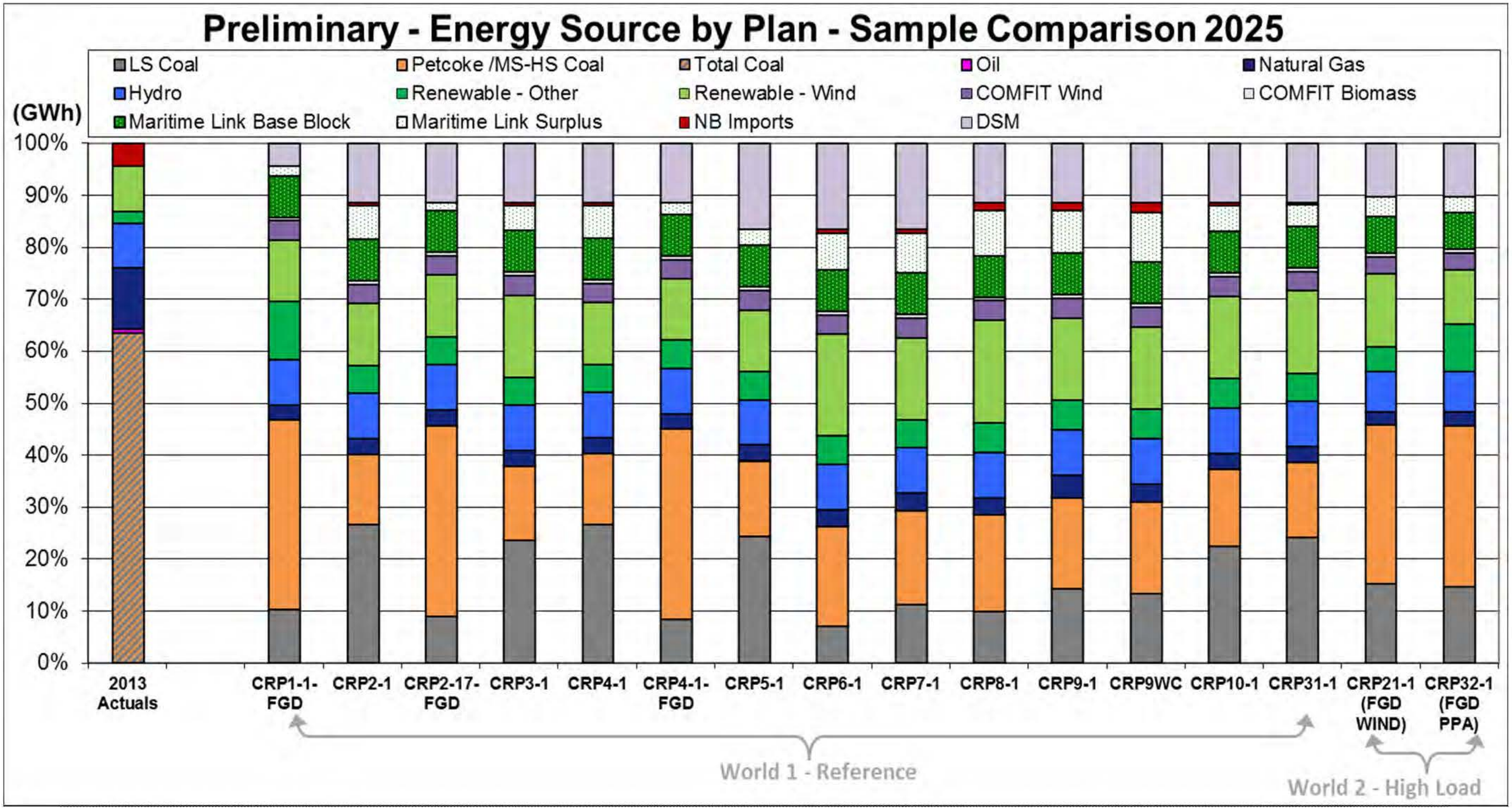
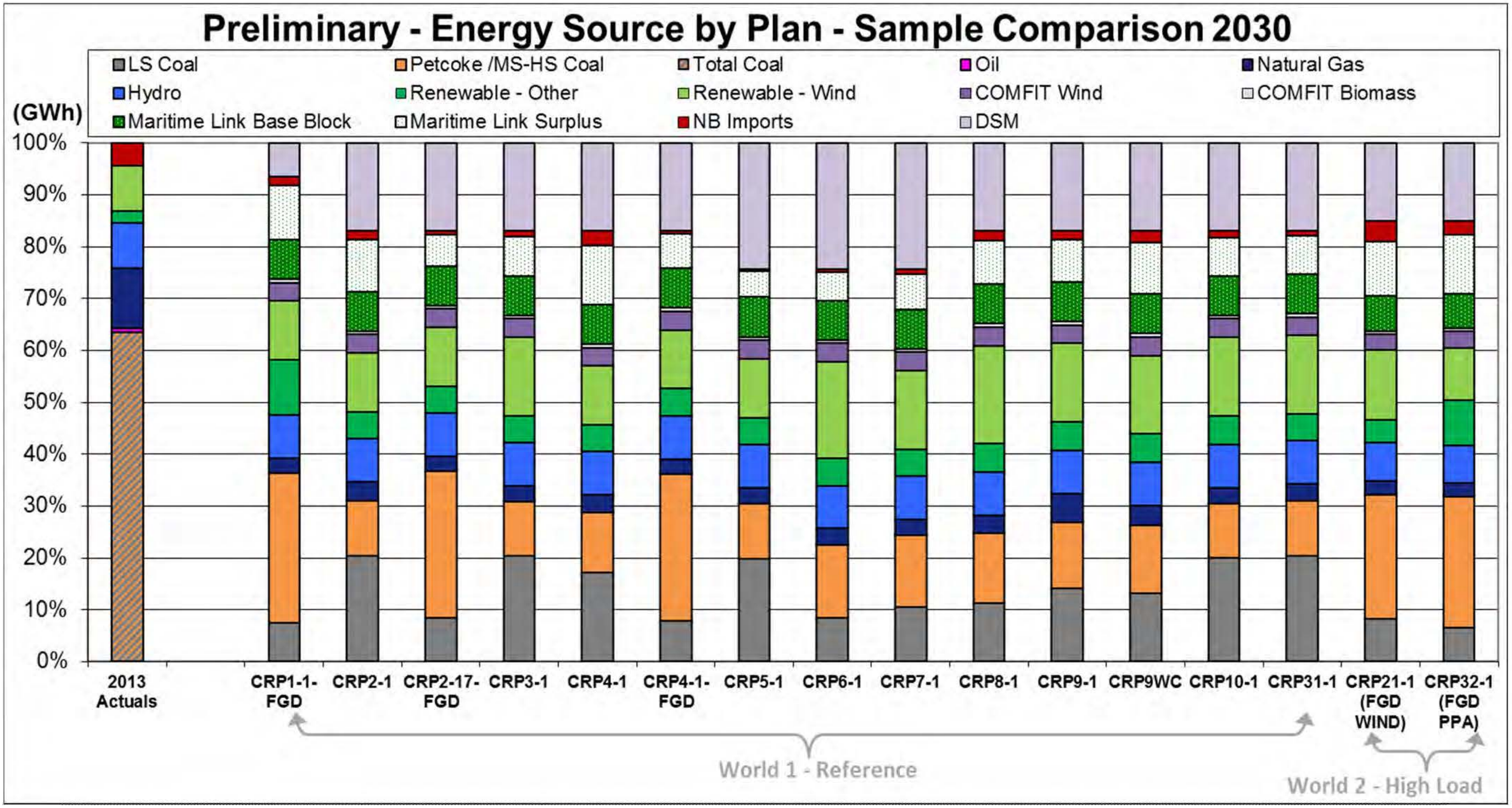
Preliminary Energy Source by Plan – Sample Comparison 2020



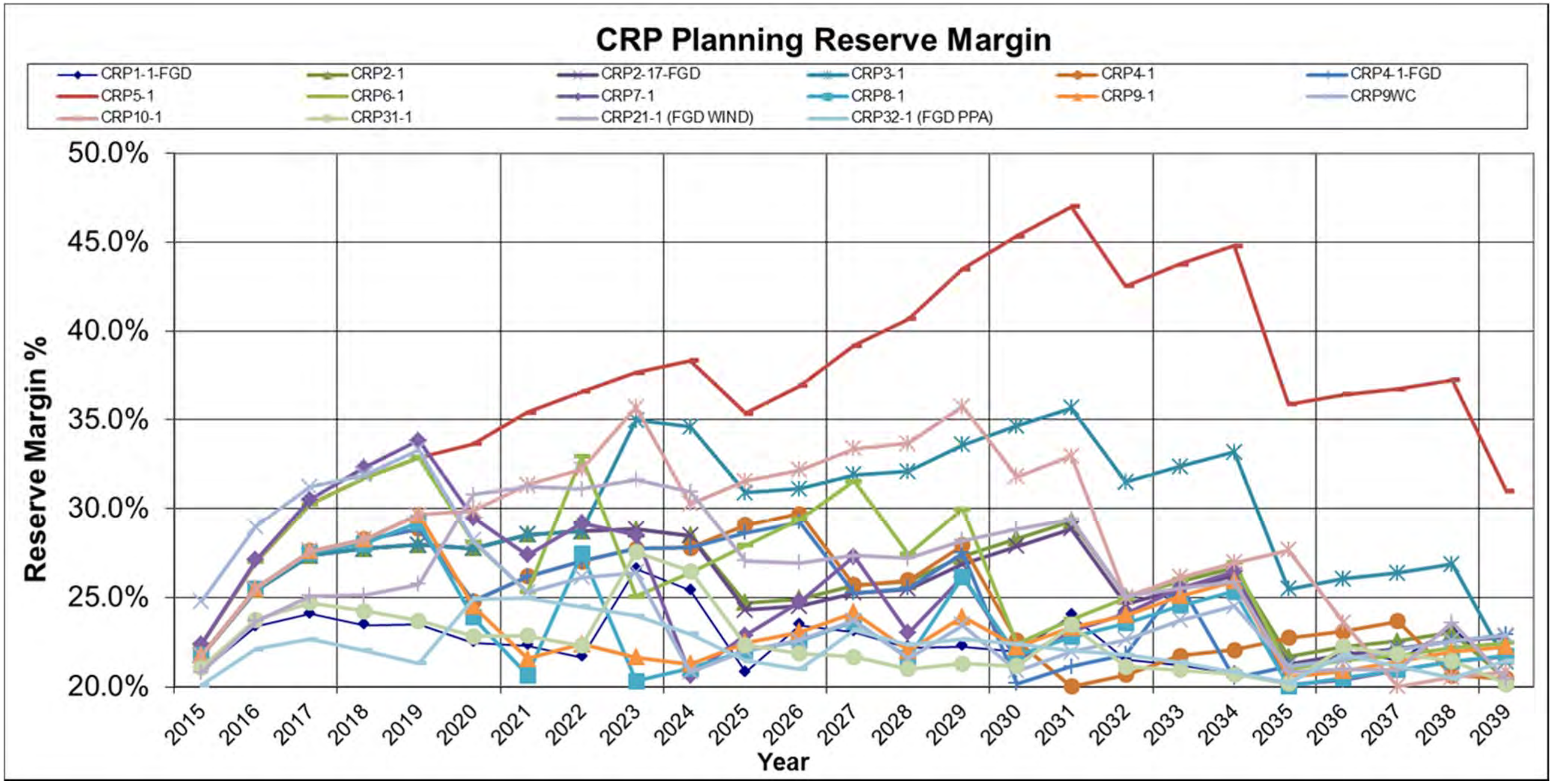
Preliminary Energy Source by Plan – Sample Comparison 2025



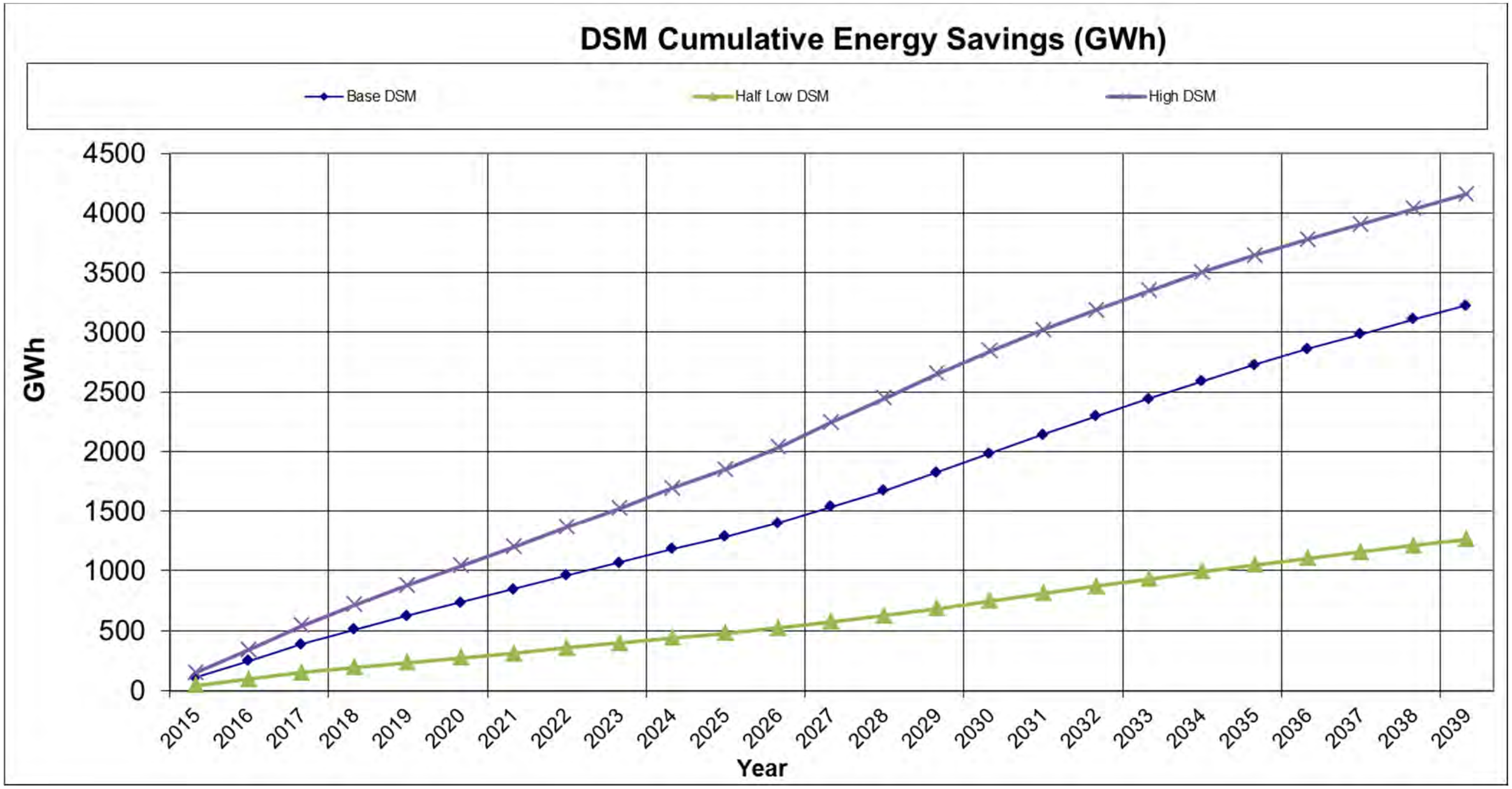
Preliminary Energy Source by Plan – Sample Comparison 2030



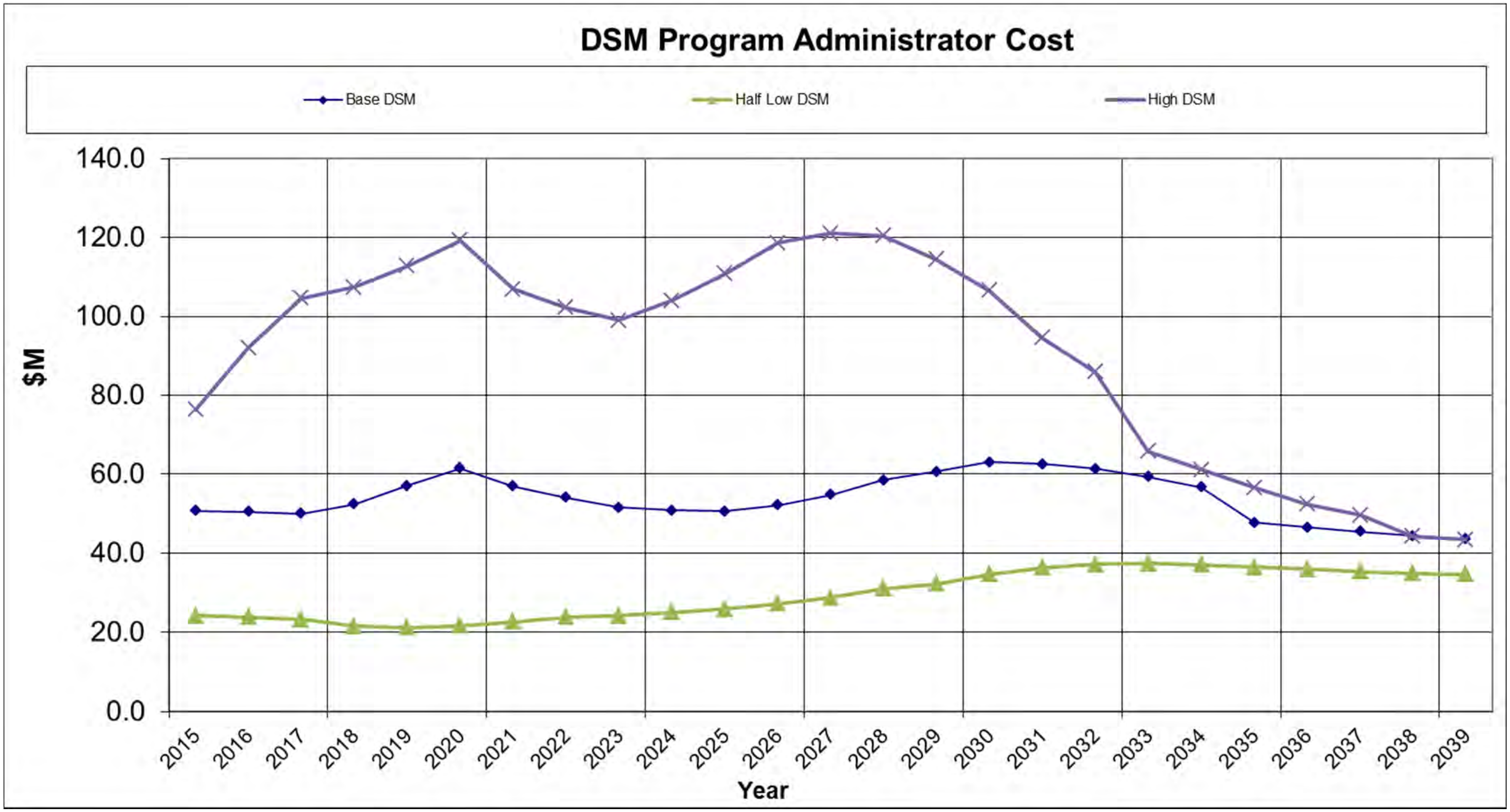
Preliminary Results
CRP Planning Reserve



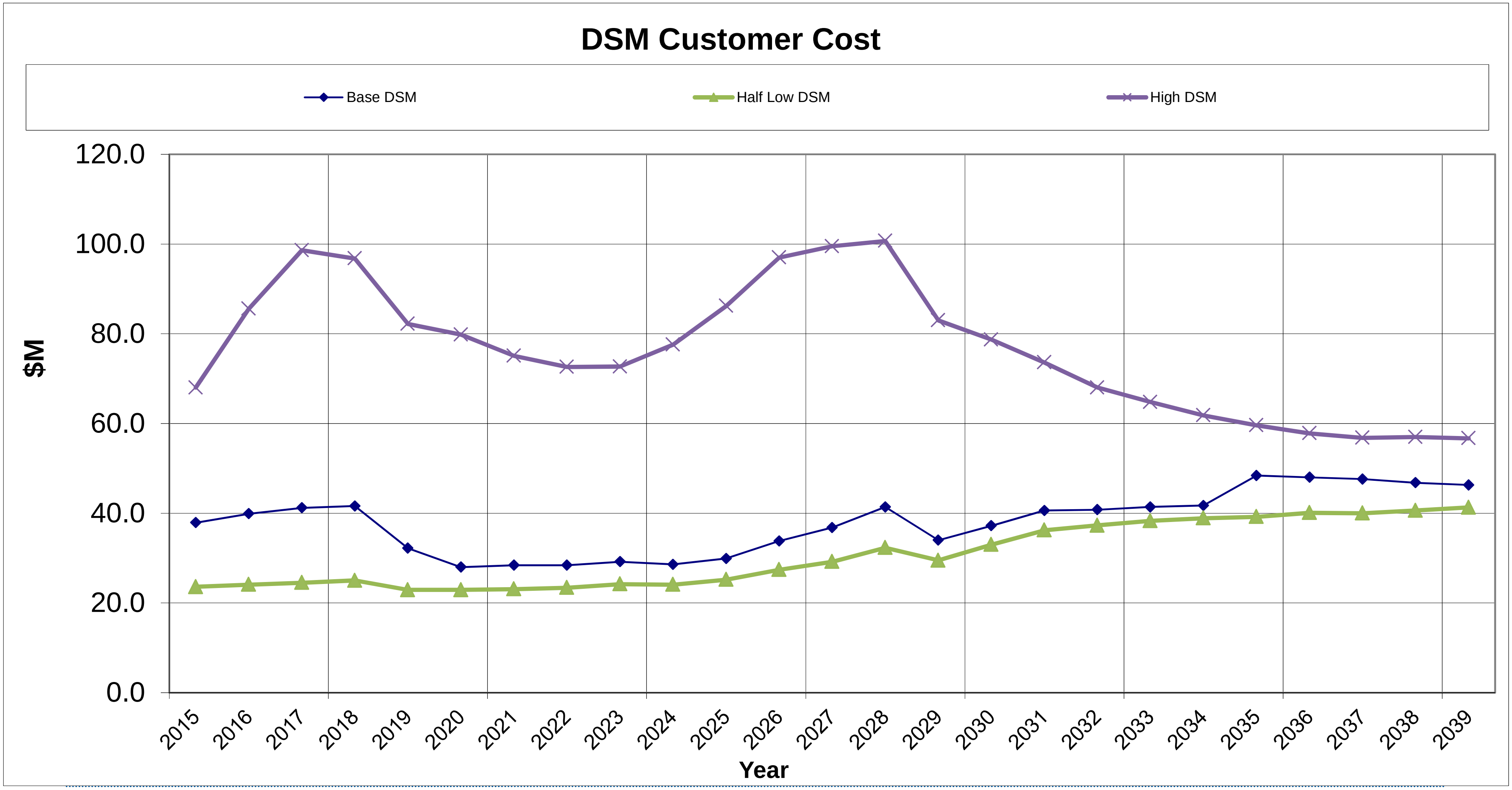
Preliminary Results
DSM Cumulative GWh



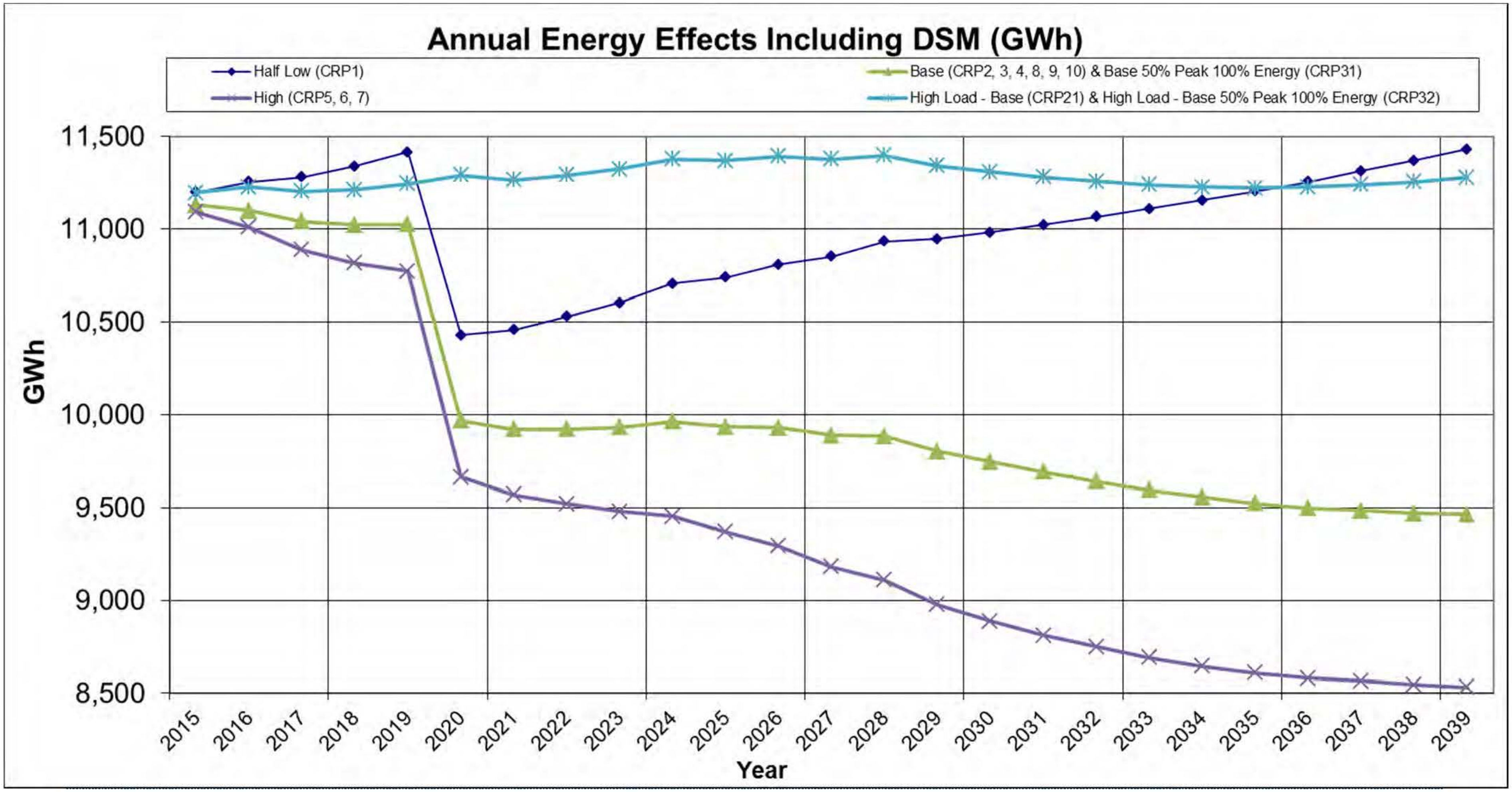
Preliminary Results
DSM Program Administrator Cost



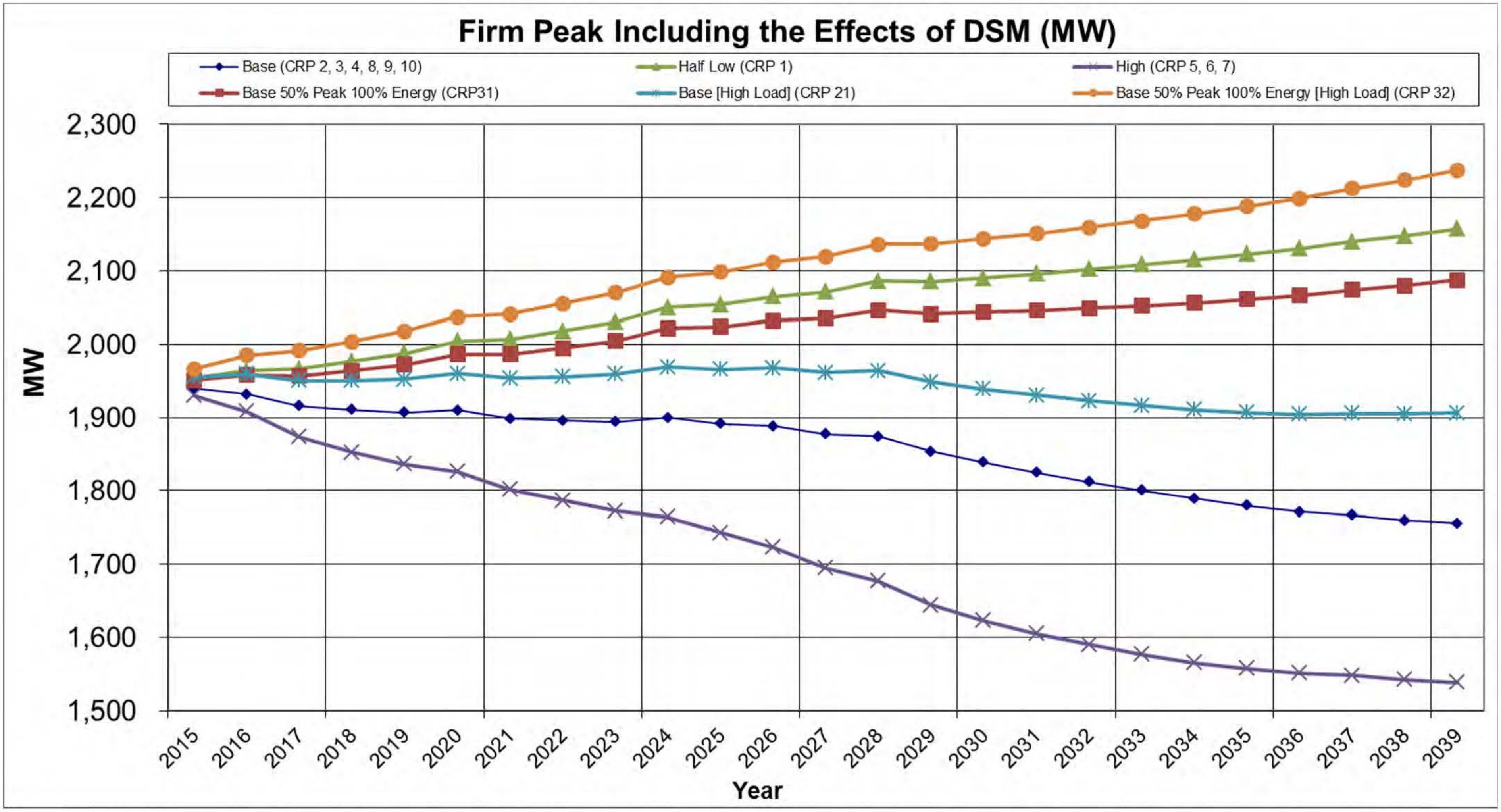
Preliminary Results
DSM Customer Cost



Preliminary Results
Annual Energy Including the Effects of DSM (GWh)



Preliminary Results
Firm Peak Including the Effects of DSM (MW)



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Sustaining Capital Adjustment

- Sustaining capital adjustment is necessary in order for CRPs with different coal fleet retirement timelines to be comparable by NPV up to the planning period horizon.

- Sustaining capital adjustment is calculated for certain CRPs to represent the different retirement strategies (Max, Med & Min) and the different load levels (Base and High load).

- Assume that CRPs with the same retirement strategy and same load level have the same sustaining capital adjustment.

Representative CRP	Load	Retirement Strategy	CRPs with the same Sustaining Capital Adjustment
CRP2-01	Base	Max	CRP 3, 5, 31
CRP2-01-FGD	Base	Max	CRP 1
CRP4-01	Base	Med	
CRP4-1-FGD	Base	Med	
CRP 10	Base	Med	this Med retirement strategy is different that CRP 4
CRP 9	Base	Min	CRP 6, 7, 8, 9WC
CRP21	High	Max	CRP 32

Annual Sustaining Capital Costs

Approach:

- Historical analysis is used to establish an investment rate for each asset class.
- Asset Health (based on latest assessments) is used to establish when large (special) investments are to be made. Major outages for example.
- Each scenario specifies the capacity factors and retirements (cycling assumption are also applied) which:
  - refines the prediction of maintenance intervals.
  - determines the degree to which regular (non-major) investments should be prorated.

Annual Sustaining Capital Costs

- Using the Economic Analysis Model (EAM), the revenue requirement profile was determined for each annual sustaining capital investment for 2015 to 2039
- This was done for each thermal unit (existing and new units added in the plan).
- For units that are retiring, any revenue requirements for undepreciated sustaining capital are assumed to be recovered over the 5 years after retirement.
- NPV of this stream of values was taken back to 2015.
- The resulting values is now the adder to the planning period costs (2015-2039) for all CRPs with that retirement strategy.
- This analysis does not adjust the costs in the end effects portion of the study period (post 2039).
- These calculations were completed outside of Strategist.

Plexos Operational Test of Select CRPs

The following CRPs were tested in hourly system dispatch model, on sample years 2020, 2025 and 2030, in order to identify any potential operational issues:

- CRP 1 – DSM 50% low – Wind Base – Maximum Coal retirement strategy
- CRP 2 – DSM BASE – Wind Base – Maximum Coal retirement strategy
- CRP 3 – DSM BASE – Wind Medium – Maximum Coal retirement strategy
- CRP 5 – DSM HIGH – Wind Base – Maximum Coal retirement strategy
- CRP 6 – DSM HIGH – Wind High – Minimum Coal retirement strategy
- CRP 8 – DSM BASE – Wind High – Minimum Coal retirement strategy

These CRPs are selected in order to examine broad range of system configuration possibilities.
CRP 2 is most similar to the present day system configuration and as such it was used to benchmark and validate Plexos model against Strategist output and provide a base for comparison.
CRP 1 was selected to explore the effects of higher system demand and the benefit of the scrubber which was picked as optimal by Strategist.
CRPs 3 and 5 were selected as relatively close relatives to CRP 2, in order to examine operational fleet behavior with high DSM and additional wind generation coupled with maximum coal utilization in both plans.
CRPs 6 and 8 are the two more far reaching CRPs both containing the highest studied wind penetration, with high and base DSM coupled with early coal fleet retirement (min coal).

Plexos Output Analysis

Plexos model output results were summarized across variables which were not handled by Strategist resource optimization modules:

1. **Wind energy Curtailed**
   Wind energy is curtailed only due to system security violations and as such is a good indicator of system stability.

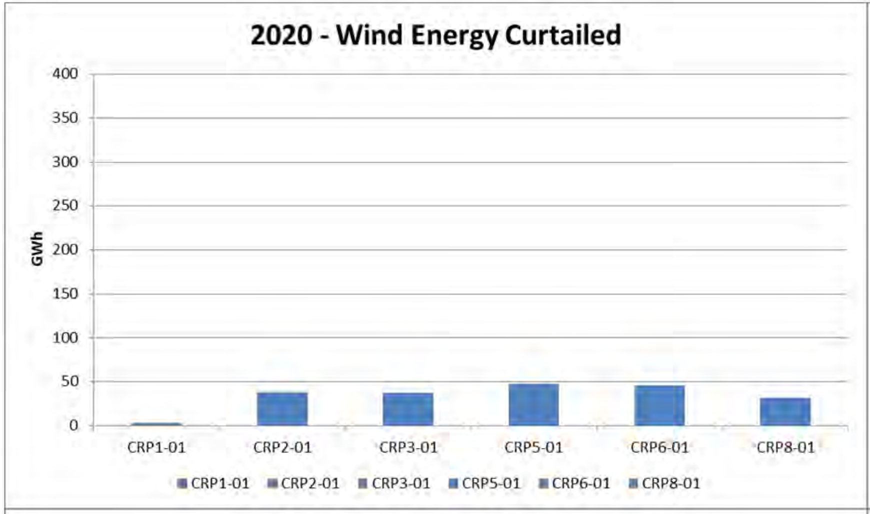
2. **Uneconomic exports to NB**
   Export energy to New Brunswick was modeled to always be priced at $10 per MWh. This low export price simulation technique allows system flexibility to aid model convergence, while assuring that export decisions were based not on economics but only on excess energy basis.

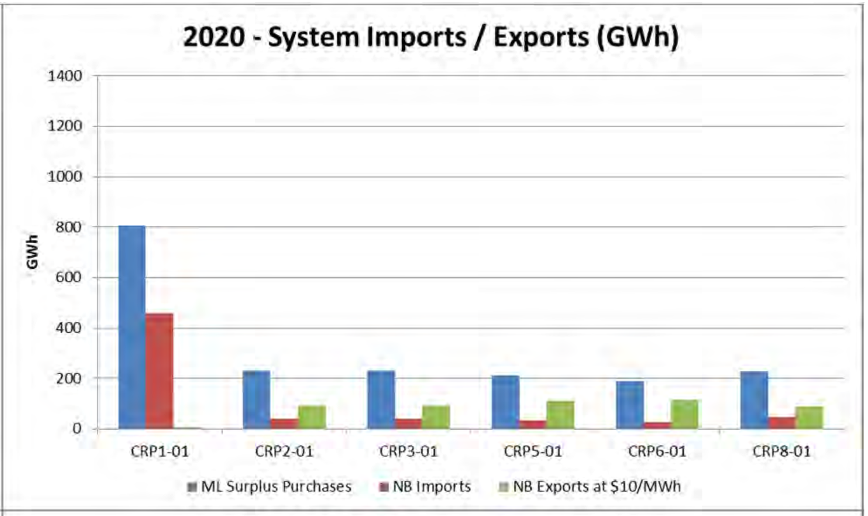
3. **Imports form NB**
   Import of economic energy from New Brunswick is an important indicator of system behavior as it can be used to indicate inadequate generating capacity or type of generating capacity in the province.

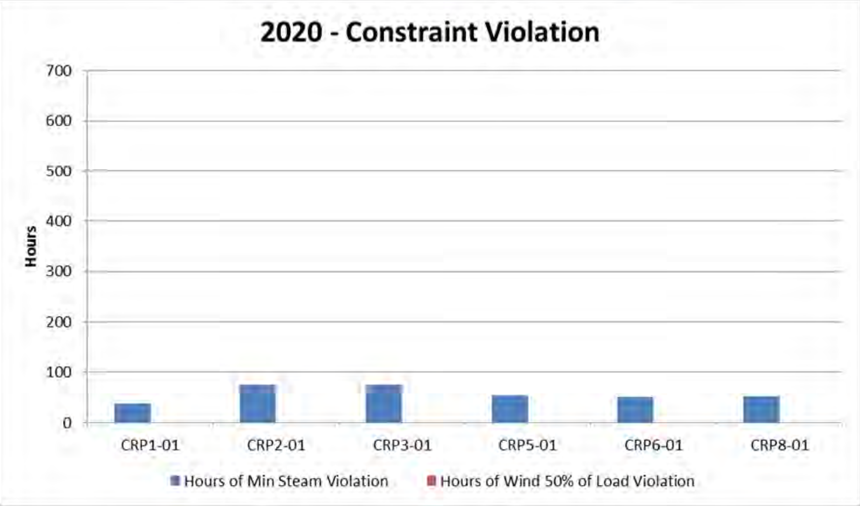
4. **Surplus energy purchases form Maritime Link**
   Being able to purchase additional energy from Maritime Link is crucial to taking the full advantage of the Maritime Link investment. This measure is selected to indicate whether the resource composition of certain CRPs is presenting a barrier to being able to fully utilize this resource.

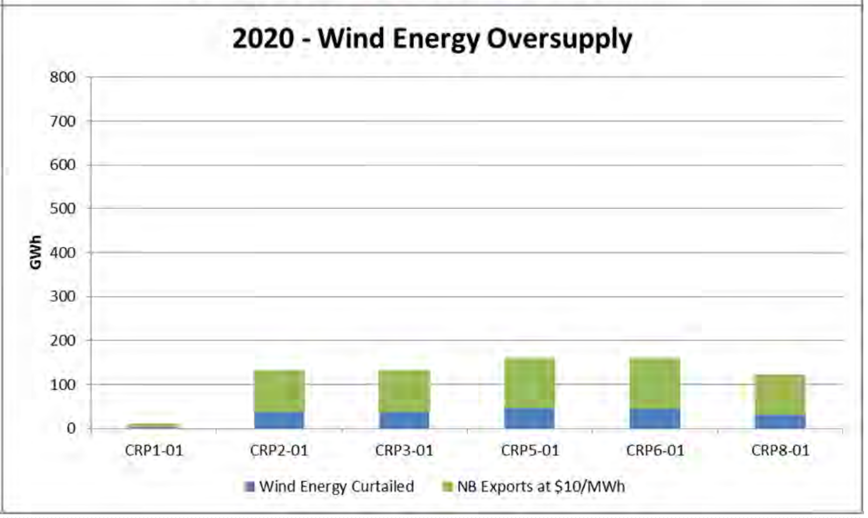
5. **Model Constraints Violation**
   Plexos allows for modeling of “soft” constraints, which can be violated under a notional penalty, in order to aid model convergence and indicate operational difficulties. Minimum steam commitment and wind generation as a percentage of total system demand are two system security constraints sensitive to demand and variable generation hourly excursions.

Plexos system performance indices for 2020

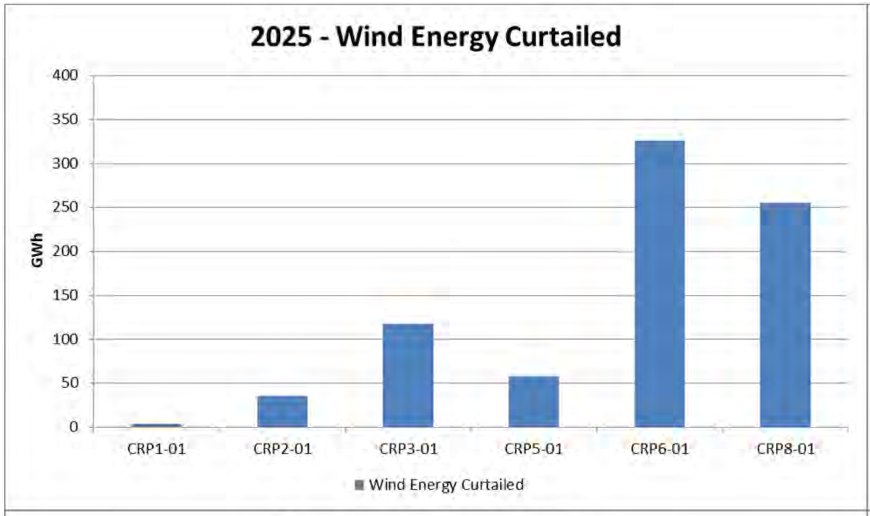

2020 - Wind Energy Curtailed

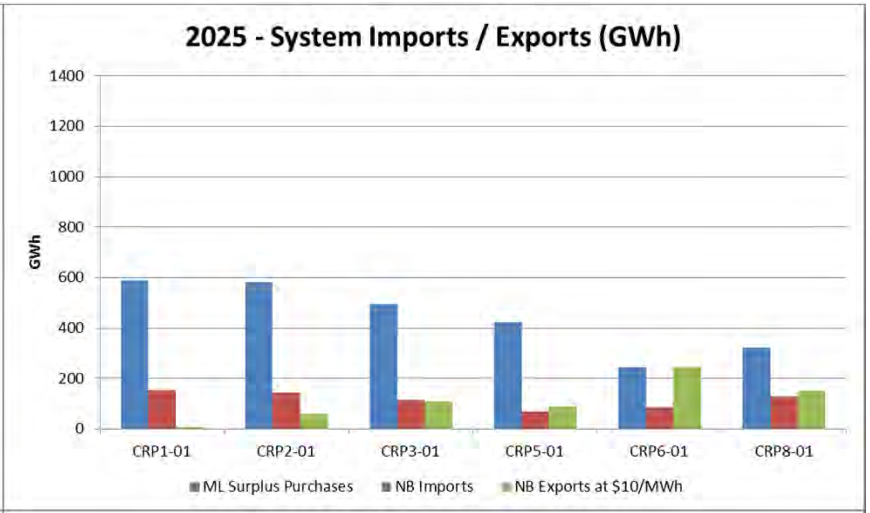

2020 - System Imports / Exports (GWh)

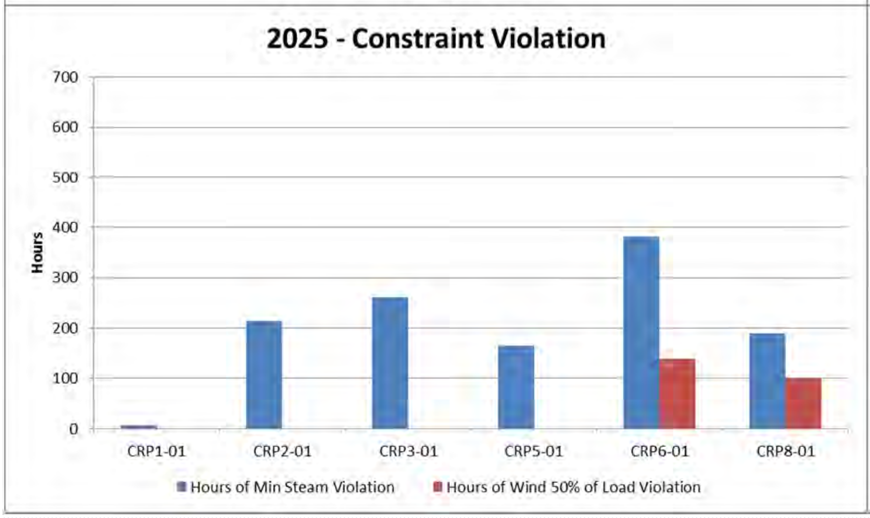

2020 - Constraint Violation

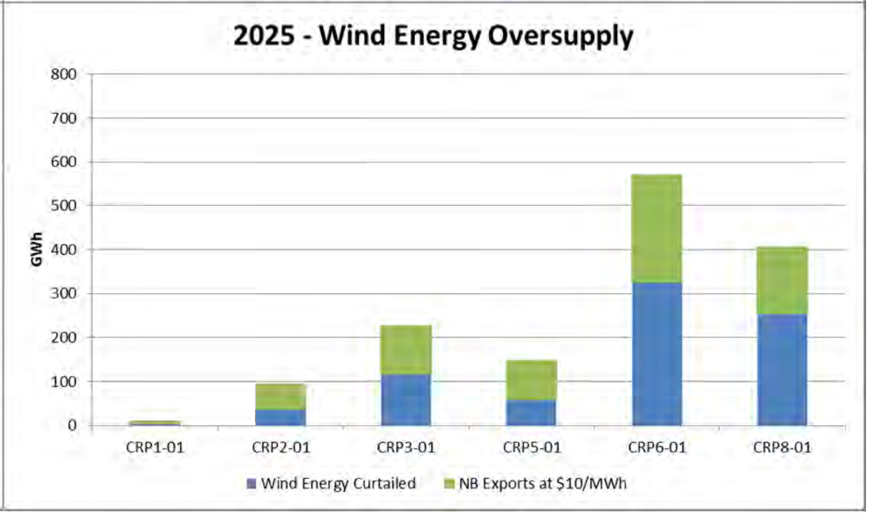

2020 - Wind Energy Oversupply

Plexos system performance indices for 2025

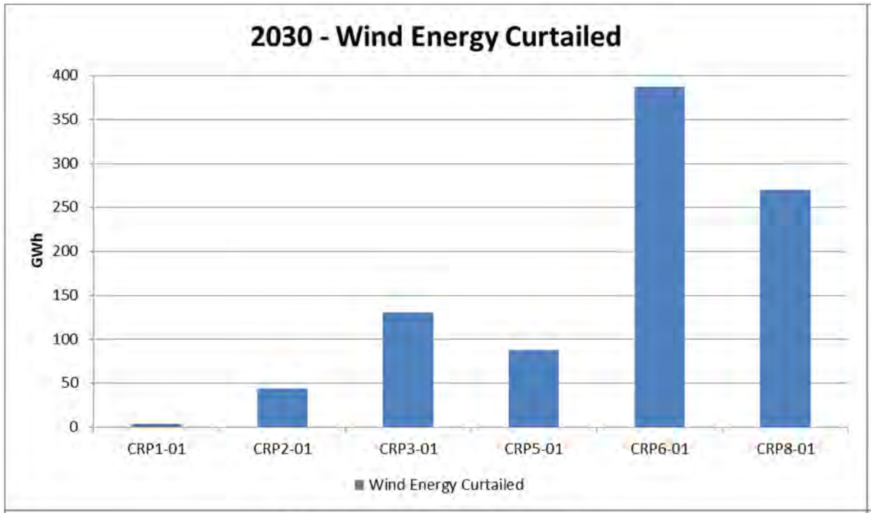

2025 - Wind Energy Curtailed

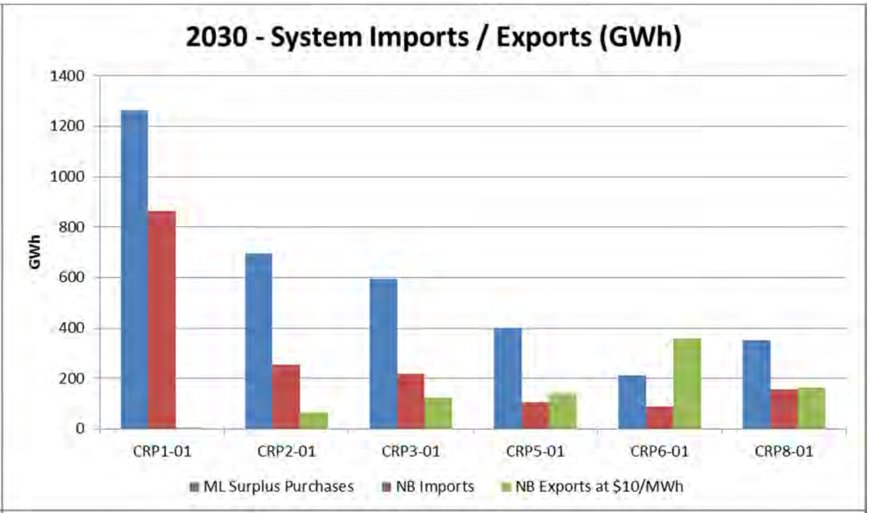

2025 - System Imports / Exports (GWh)

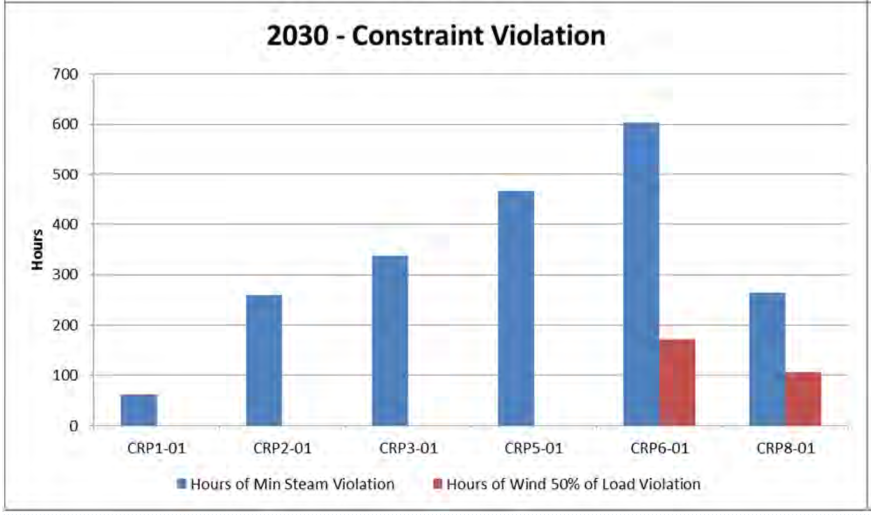

2025 - Constraint Violation

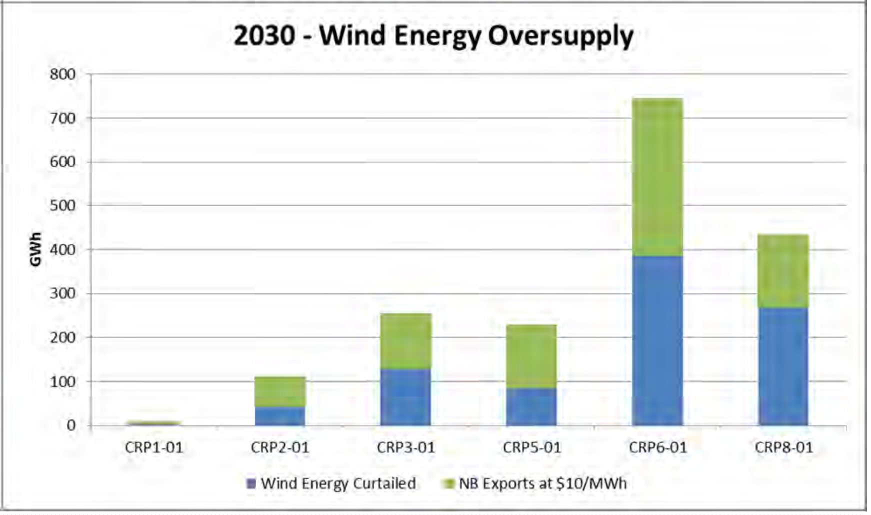

2025 - Wind Energy Oversupply

Plexos system performance indices for 2030









Plexos Output Analysis – discussion:

CRP-1
Plexos system simulation shows that higher energy requirement is beneficial to integration of base quantity of wind generation with minimum curtailment and uneconomic exports of excess energy. It also allows the system to take advantage of economic Maritime Link and New Brunswick energy purchases.

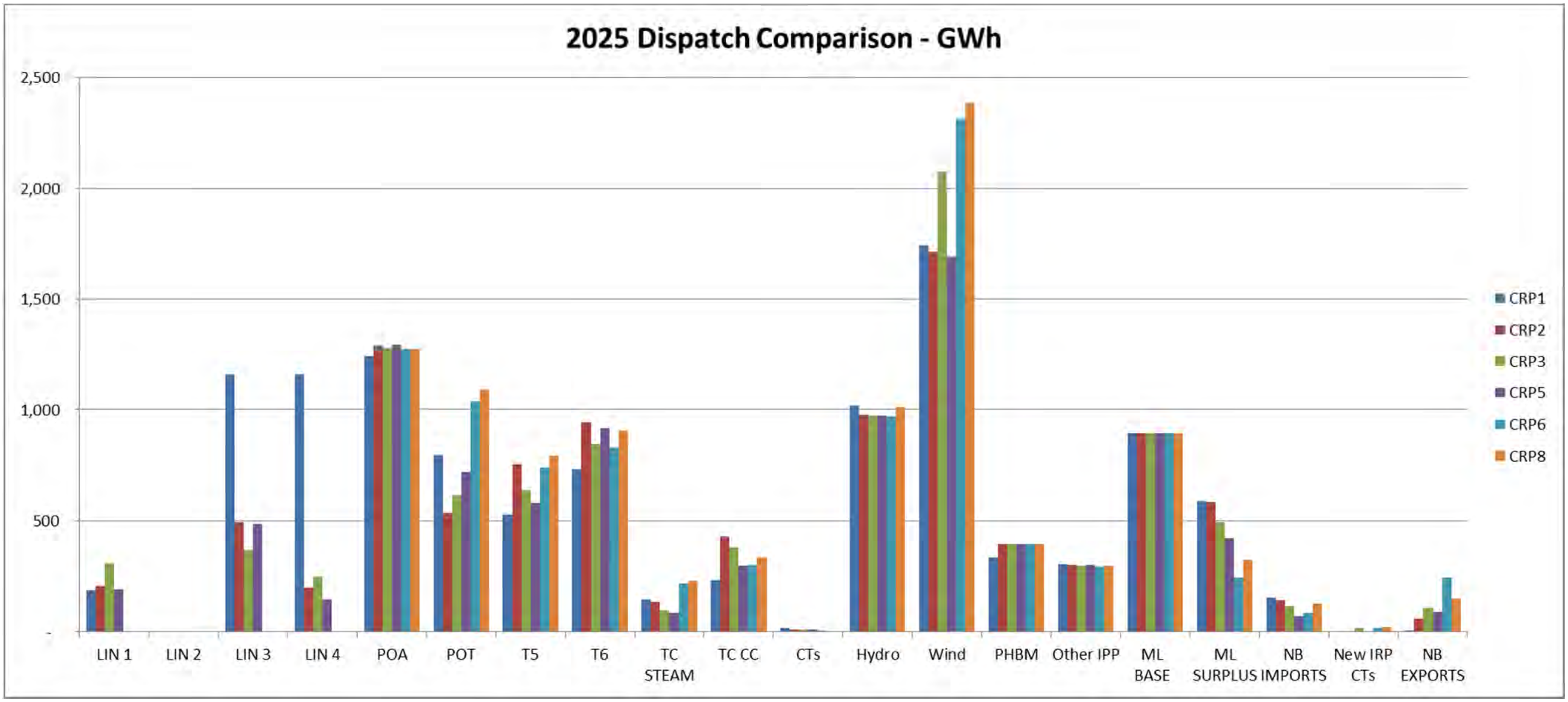
CRP-2
Due to lower system energy requirement, CRP-2 shows higher wind curtailment and uneconomic exports than CRP-1, while it shows lower uptake of Maritime Link surplus energy in later years. Increase in system constraint violations indicate the need for mitigation of operational difficulties by system reinforcements, in later years.

CRP-3
Similar to CRP-2 but with additional block of 150 MW of wind, this CRP shows that nearly half of the new wind energy would be either curtailed or sold across the border as uneconomic exports. The effect of additional variable generation is also seen in increased system constraint violations in later years and lower Maritime Link and New Brunswick economic purchases.

CRP-5
This high DSM CRP is similar to CRP-2, except for high DSM penetration assumption. The reduced system energy requirement results in additional wind energy curtailment and uneconomic sales, as well as lower capability to take in Maritime Link economic energy.

CRP-6 and CRP-8 containing High DSM, early coal fleet retirement, and high and medium additional wind generation additions show that significant system reconfiguration and expansions would be required in order to maintain system stability. Large quantities of curtailed or uneconomically exported energy indicate that energy storage may be required in order to make these CRPs viable.

Plexos generation fleet output 2025



Comprehensive overview of generating fleet output across the 6 CRPs tested in Plexos showing resource utilization, while considering operational constraints.

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SEPTEMBER 2014

2014 IRP Draft Analysis Results* Detailed Candidate Resource Plan Results

* These are indicative results from a high level planning perspective. Can only be used to provide guidance and direction. This is not a prescriptive solution.

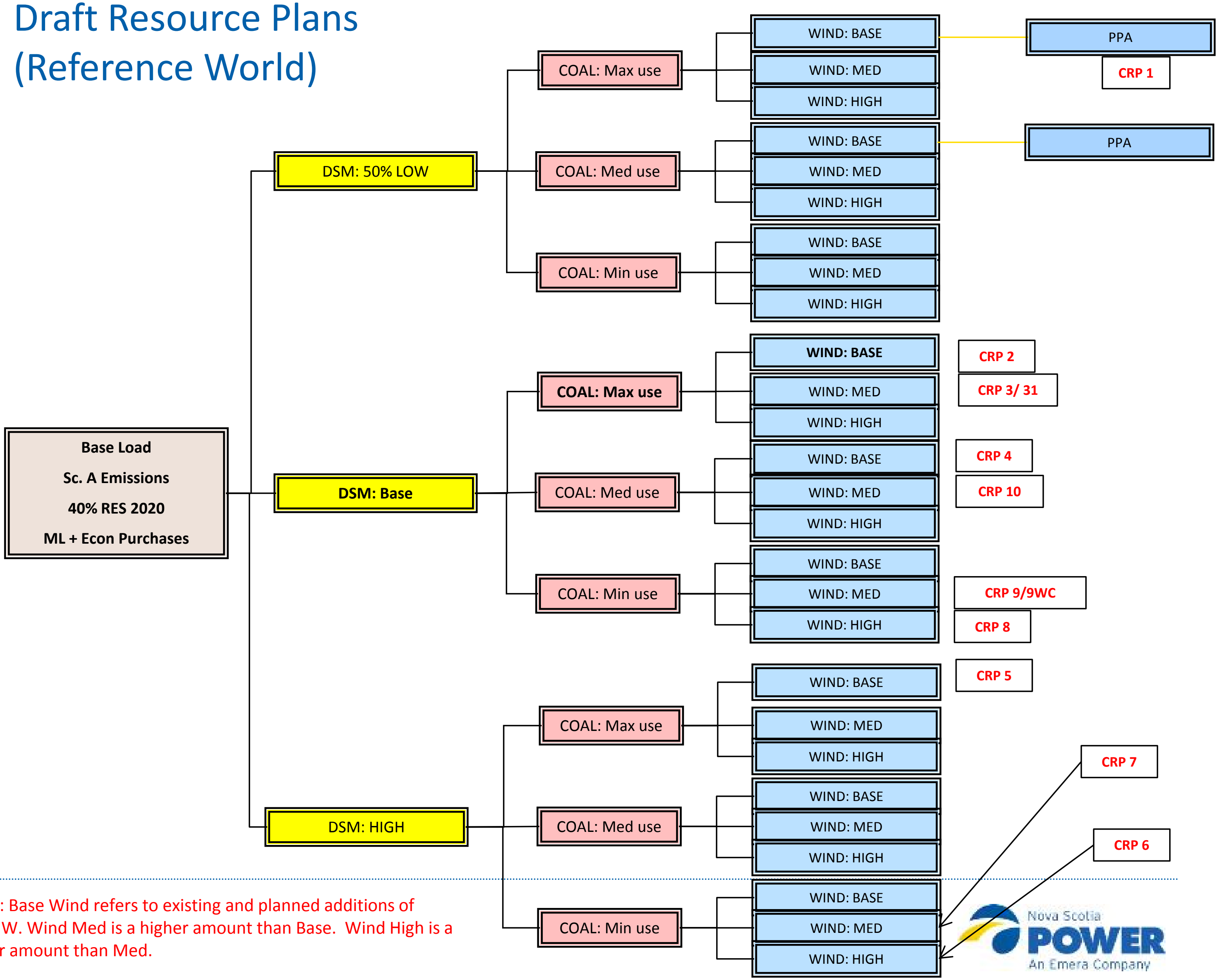
Table of Contents

Note to Reviewers

Please note the following in the review of this draft deck:

- The NPV cost results are the from the Strategist modeling.
- The adders to represent sustaining capital investments have not been included in the NPV costs for the CRPs.
- Study period NPV’s can only be compared within the same unit retirement strategies (e.g. all maximum coal).
    - For existing units that are not retired in the planning period and are assumed to run indefinitely, the cost to keep those units running have not been included in the study period costs. For CRPs with the same retirement strategy these costs are common across all plans and do not affect the ranking of the plans in the study period. For CRPs with different retirement strategies the costs vary and could affect ranking in the study period.
- The costs for Hg abatement shown in the Hg emissions graphs have been included in the candidate resource plan NPVs.

Draft Resource Plans (Reference World)



Base Load
Sc. A Emissions
40% RES 2020
ML + Econ Purchases

- DSM: 50% LOW
  - COAL: Max use
    - WIND: BASE — PPA
    - WIND: MED — CRP 1
    - WIND: HIGH
  - COAL: Med use
    - WIND: BASE — PPA
    - WIND: MED
    - WIND: HIGH
  - COAL: Min use
    - WIND: BASE
    - WIND: MED
    - WIND: HIGH
- **DSM: Base**
  - **COAL: Max use**
    - **WIND: BASE** — **CRP 2**
    - WIND: MED — **CRP 3/ 31**
    - WIND: HIGH
  - COAL: Med use
    - WIND: BASE — **CRP 4**
    - WIND: MED — **CRP 10**
    - WIND: HIGH
  - COAL: Min use
    - WIND: BASE
    - WIND: MED — **CRP 9/9WC**
    - WIND: HIGH — **CRP 8**
- DSM: HIGH
  - COAL: Max use
    - WIND: BASE — **CRP 5**
    - WIND: MED
    - WIND: HIGH
  - COAL: Med use
    - WIND: BASE
    - WIND: MED
    - WIND: HIGH
  - COAL: Min use
    - WIND: BASE
    - WIND: MED — **CRP 7**
    - WIND: HIGH — **CRP 6**

NOTE: Base Wind refers to existing and planned additions of 582MW. Wind Med is a higher amount than Base. Wind High is a higher amount than Med.

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Candidate Resource Plans – Description Table

CRP	DSM	WIND	COAL
World 1 - REFERENCE			
CRP 1	50% of LOW	BASE	MAX
CRP 2	BASE	BASE	MAX
CRP 3	BASE	MED	MAX
CRP 4	BASE	BASE	MED
CRP 5	HIGH	BASE	MAX
CRP 6	HIGH	HIGH	MIN
CRP 7	HIGH	MED	MIN
CRP 8	BASE	HIGH	MIN
CRP 9	BASE	MED	MIN
CRP 9WC	BASE	MED (Optimistic Capacity Credit)	MIN
CRP 10	BASE	MED	MED
CRP 31	BASE - 50% Peak 100% Energy	MED	MAX
World 2- HIGH LOAD			
CRP 21	BASE	MED (Optimize)	MAX
CRP 32	BASE -50% Peak 100% Energy	MED (Optimize)	MAX

🟧	Max Retirement Strategy
🟩	Med Retirement Strategy
🟦	Min Retirement Strategy
⬜	Max Retirement Strategy - High Load

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CRP1 Preliminary Results

CRP1 Input Assumptions

Candidate Resource Plan 1 (CRP1):

- Base Load Forecast
- Half Low DSM
- Emissions - Scenario A
- Planned and committed resources are fixed in the plan (REA wind, COMFIT, Maritime Link/ Retire Lin #2)
- Maximum Coal Use
- PPA fixed in the plan in 2023 for RES
- Constraints
  - Planning reserve margin min = 20%
  - RES: 2015-2019 = 25%; 2020-2039 = 40%

CRP1 Preliminary Results

	CRP01-01-FGD-R01	CRP01-01-R01
	Least cost study period	**Least cost study period (without FGD)**
2015		
2016		DR Water Heaters
2017	ML Oct 2017	ML Oct 2017
	Lin 2 retire	Lin 2 retire
2018		
2019	Mersey Phase 1	Mersey Phase 1
2020		
2021		
2022		
2023	Mersey Phase 2	Mersey Phase 2
	PPA 100MW Firm	PPA 100MW Firm
2024		
2025	TUC 1 Retire	TUC 1 Retire
	FGD (Lin 3/4 300 MW)	
2026	2 x CT 34MW	
2027		
2028		
2029		
2030		
2031	CT 50MW	
2032	TUC 2 Retire	TUC 2 Retire
	CT 50MW	CT 50MW & CT 34MW
2033		
2034		
2035	Tre 5 Retire	Tre 5 Retire
	CC 145MW	CC 145MW
2036	CT 50MW	CT 50MW
2037		
2038	CT 50 MW	CT 50 MW
2039	PHBM 51.7 MW Firm	PHBM 51.7 MW Firm
	CT 50 MW	CT 50 MW
	Lin 1 Retire	Lin 1 Retire
Planning PV $M	12,125	12,143
Study PV $M	19,450	19,647

	Half LowDSM	Half LowDSM
	Program Adm Cost	Customer Cost
	$M	$M
2015	24.2	23.6
2016	23.8	24.1
2017	23.2	24.5
2018	21.6	25.0
2019	21.2	22.9
2020	21.7	22.9
2021	22.6	23.1
2022	23.8	23.4
2023	24.2	24.2
2024	25.1	24.1
2025	25.9	25.2
2026	27.2	27.4
2027	28.8	29.2
2028	31.0	32.3
2029	32.3	29.5
2030	34.7	33.0
2031	36.3	36.2
2032	37.2	37.3
2033	37.4	38.3
2034	37.1	38.9
2035	36.5	39.2
2036	36.0	40.1
2037	35.4	40.0
2038	34.9	40.6
2039	34.6	41.3
NPV	**352.5**	**363.2**

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CRP1-1 (FGD) Preliminary Results

CRP1-1 (FGD)
Preliminary Load and Resources

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	2036	2037	2038	2039
Firm Peak	1,963	1,986	2,000	2,020	2,041	2,066	2,077	2,097	2,118	2,147	2,159	2,251	2,345	2,364	2,383	2,403	2,422
DSM	9	22	34	44	53	62	70	79	88	97	105	161	223	234	244	255	264
Firm Peak Less DSM	1,954	1,964	1,967	1,977	1,988	2,005	2,007	2,018	2,030	2,050	2,054	2,090	2,123	2,130	2,140	2,148	2,157
DRWH Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DRCM Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Less DR	1,954	1,964	1,967	1,977	1,988	2,005	2,007	2,018	2,030	2,050	2054	2090	2123	2,130	2,140	2,148	2,157
RM Required	391	393	393	395	398	401	401	404	406	410	411	418	424.5	426	428	430	431
Required MWs	2,345	2,357	2,360	2,372	2,386	2,406	2,409	2,422	2,436	2,460	2464	2508	2547	2,556	2,568	2,578	2,589
Existing MWs	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341
Resource Additions (MW):																	
Burnside #4		33															
COMFIT - Biomass	4.2	6															
COMFIT - Wind	14.14	4.56	5.1														
REA Wind	2.35	17.34															
Maritime Link				153.3													
Small Biomass PPA			10														
Hydro			1.8		15				15								
PH Biomass																	51.7
PPA									100								
Assumed Unit Retirement				-153							-89		-150				-153
Natural Gas Unit													145.0	49.4		49.4	49.4
Total Annual Additions	20.7	60.9	16.9	0.3	15.0	0.0	0.0	0.0	115.0	0.0	-89.0	0.0	-5.0	49.4	0.0	49.4	-51.9
Total Cumulative Additions	20.7	81.6	98.5	98.7	113.7	113.7	113.7	113.7	228.7	228.7	139.7	207.7	208.5	257.9	257.9	307.3	255.4
Total Firm Capacity	2362	2423	2440	2440	2455	2455	2455	2455	2570	2570	2481	2549	2550	2599	2599	2649	2597
Surplus (Deficit) MWs above RM	17	66	80	68	70	50	46	33	134	110	17	41	3	43	31	71	8
Reserve Margin %	20.9%	23.4%	24.1%	23.4%	23.5%	22.5%	22.3%	21.6%	26.6%	25.4%	20.8%	22.0%	20.1%	22.0%	21.5%	23.3%	20.4%

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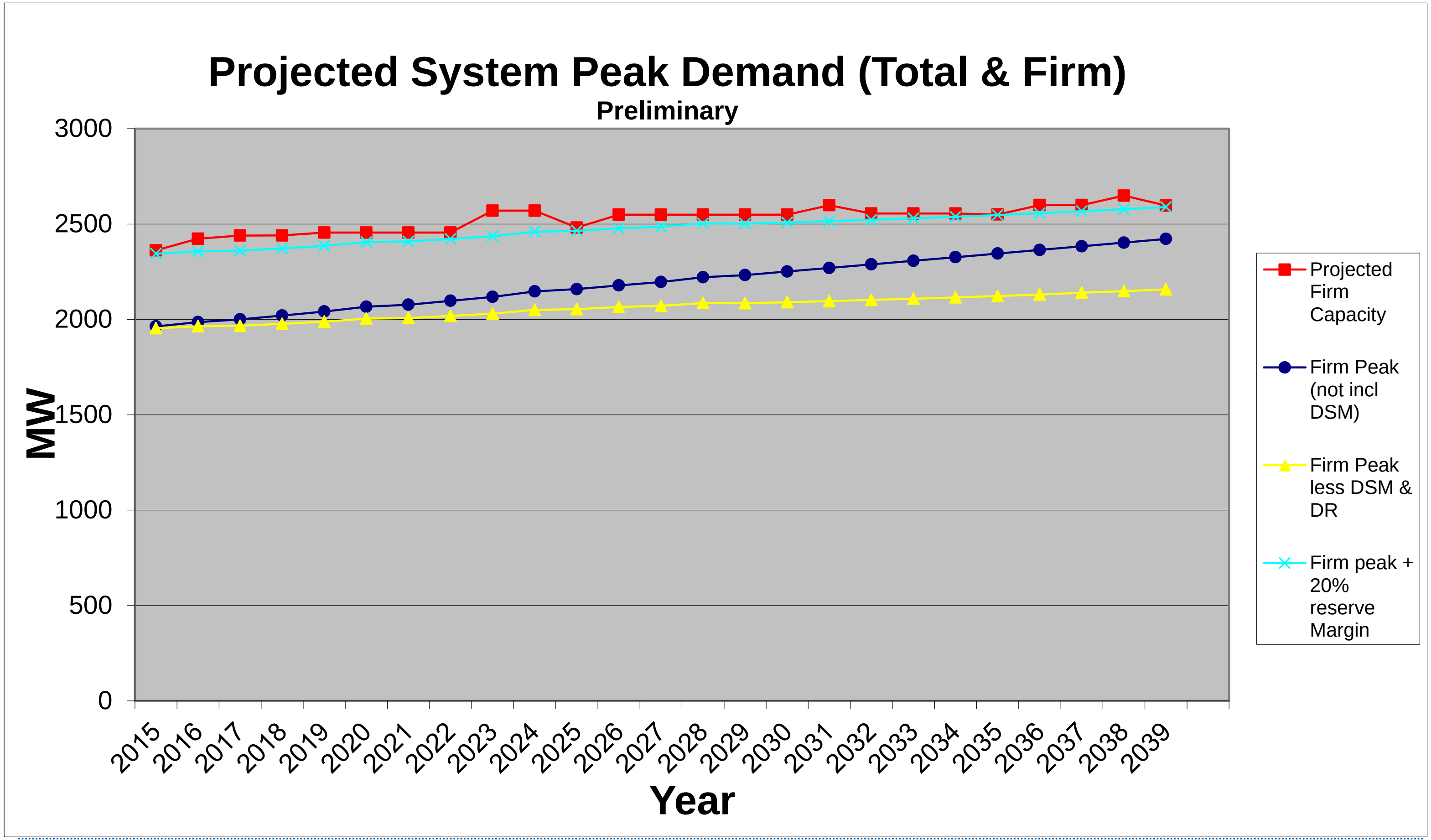
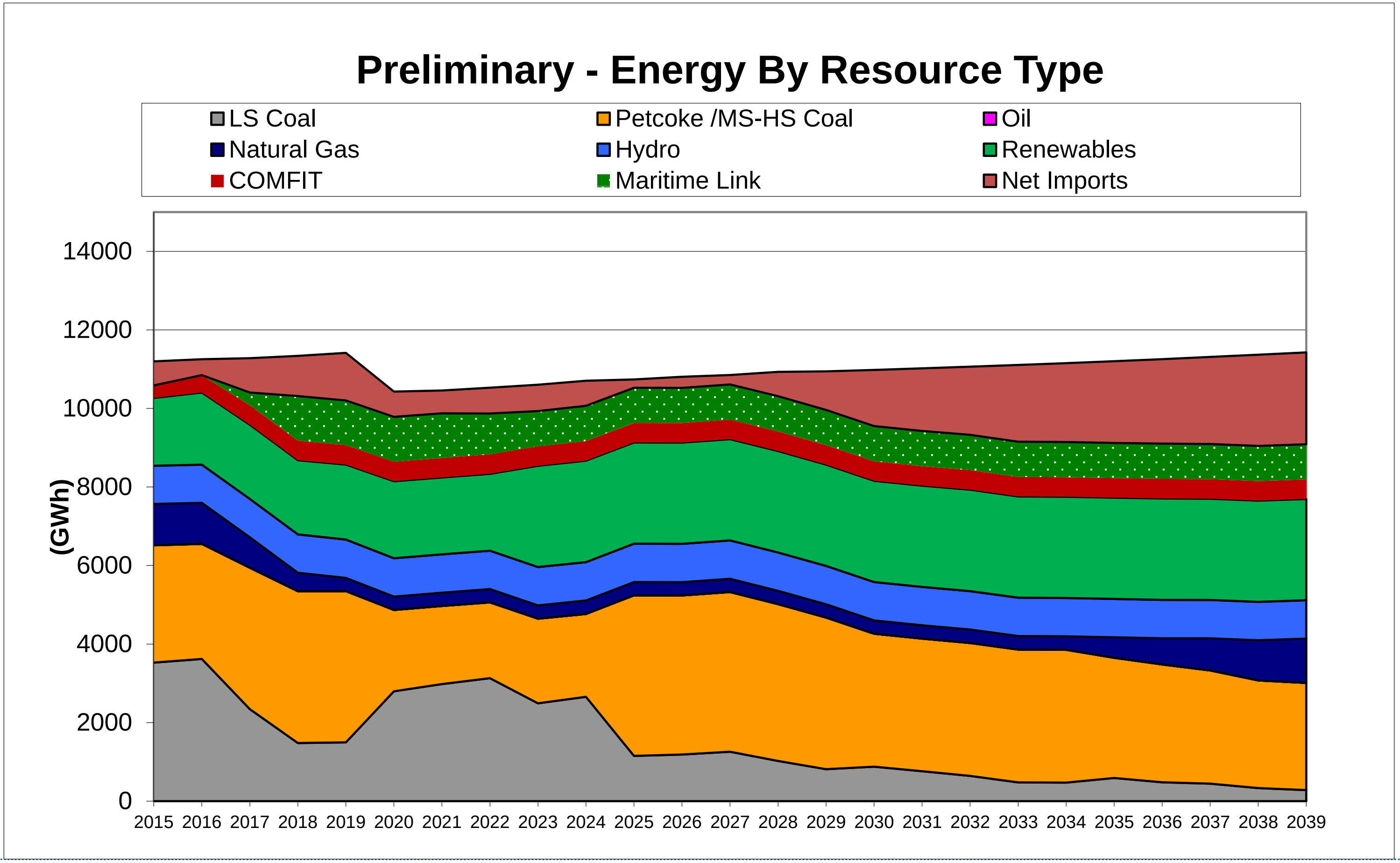
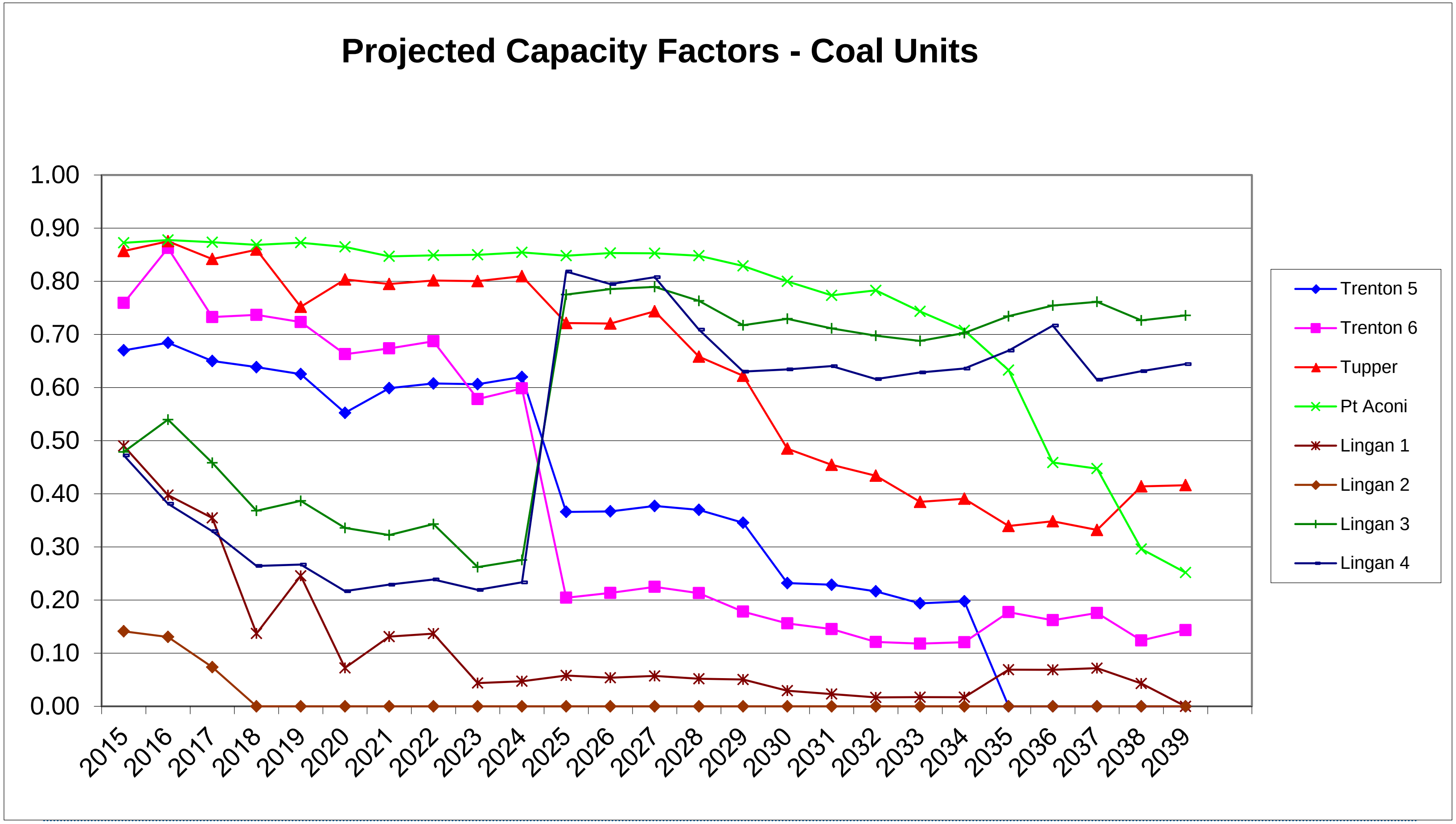
CRP1-1 (FGD)
Preliminary Demand and DSM



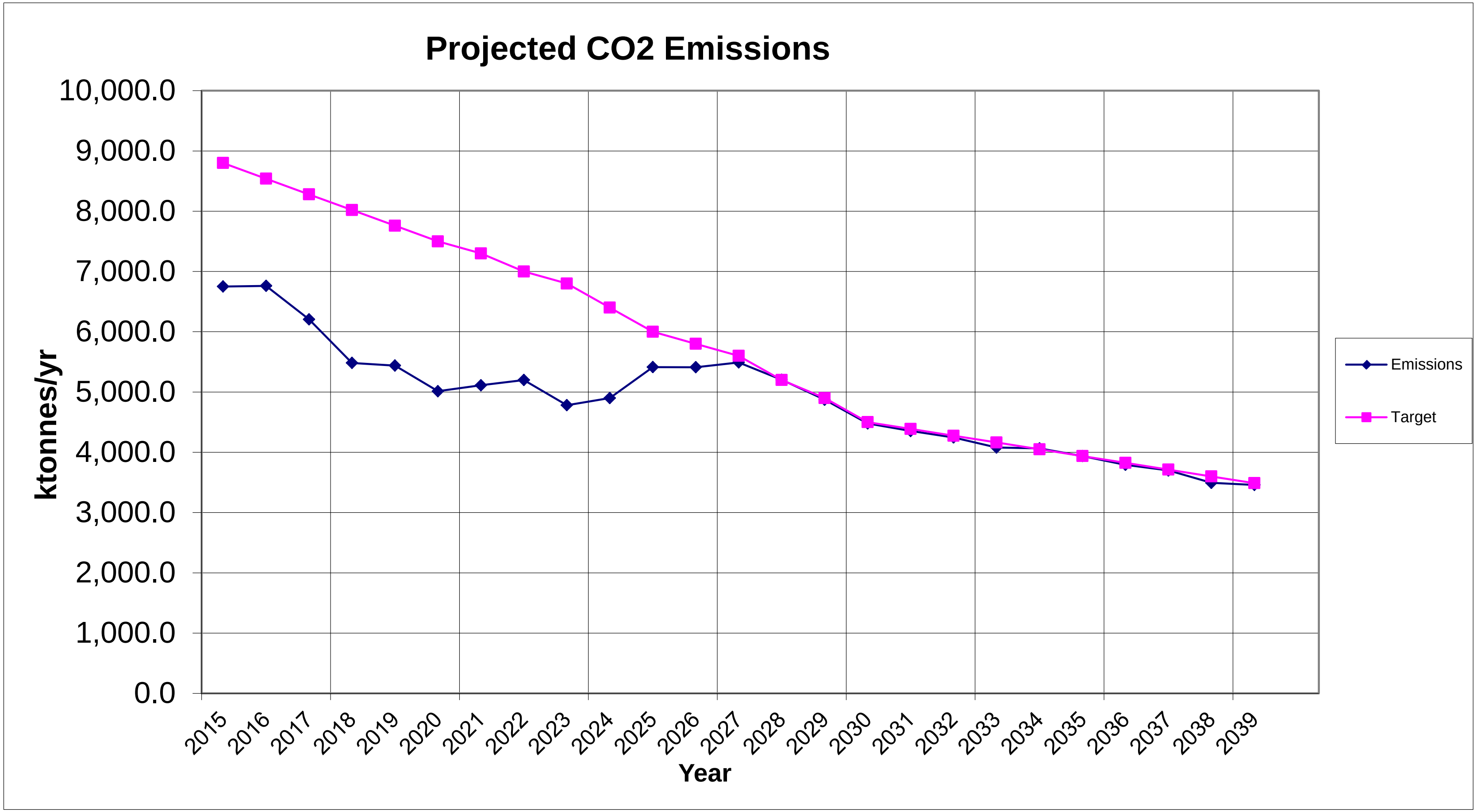
CRP1-1 (FGD)
Preliminary Energy by Resource Type



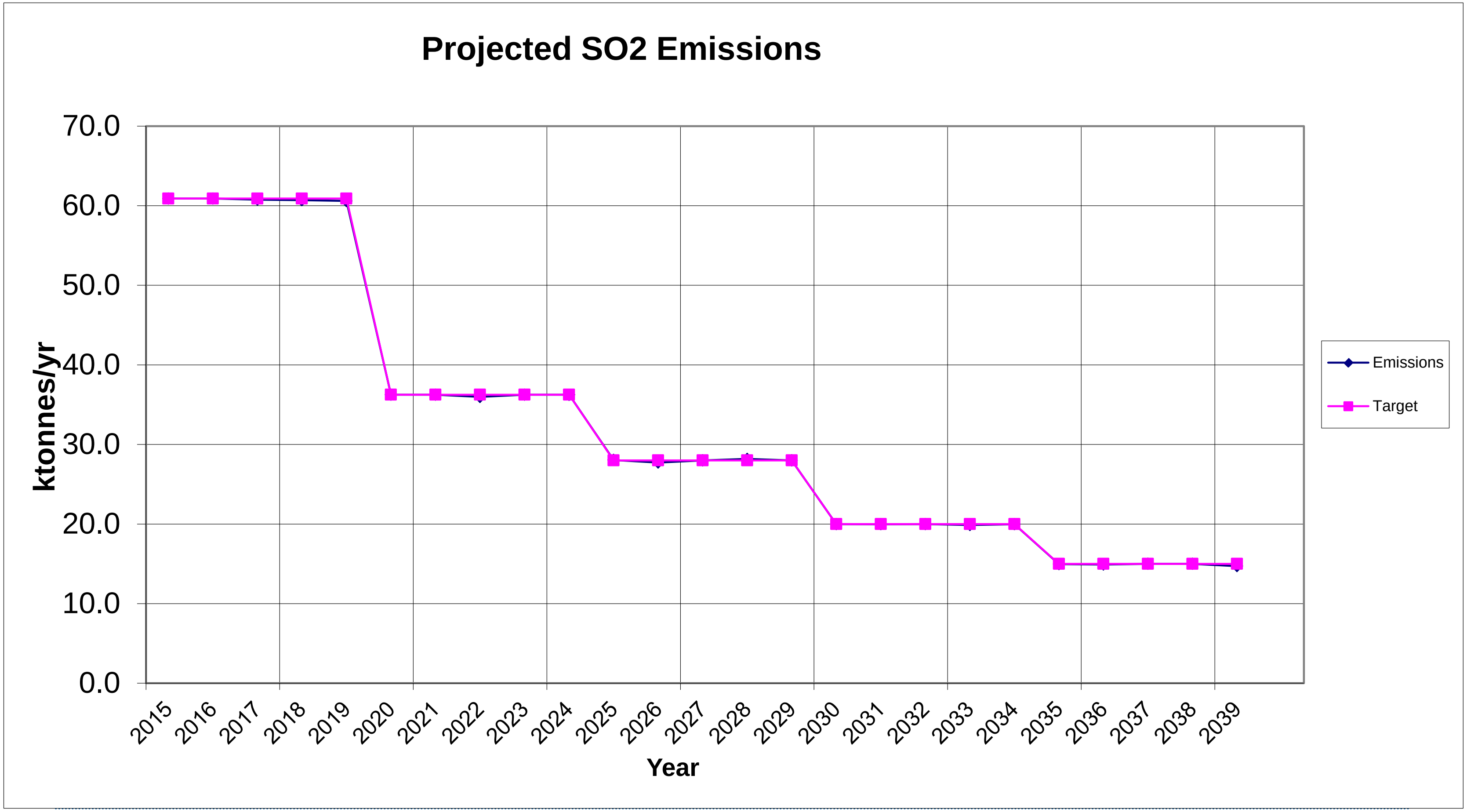
CRP1-1 (FGD)
Preliminary Coal Capacity Factors



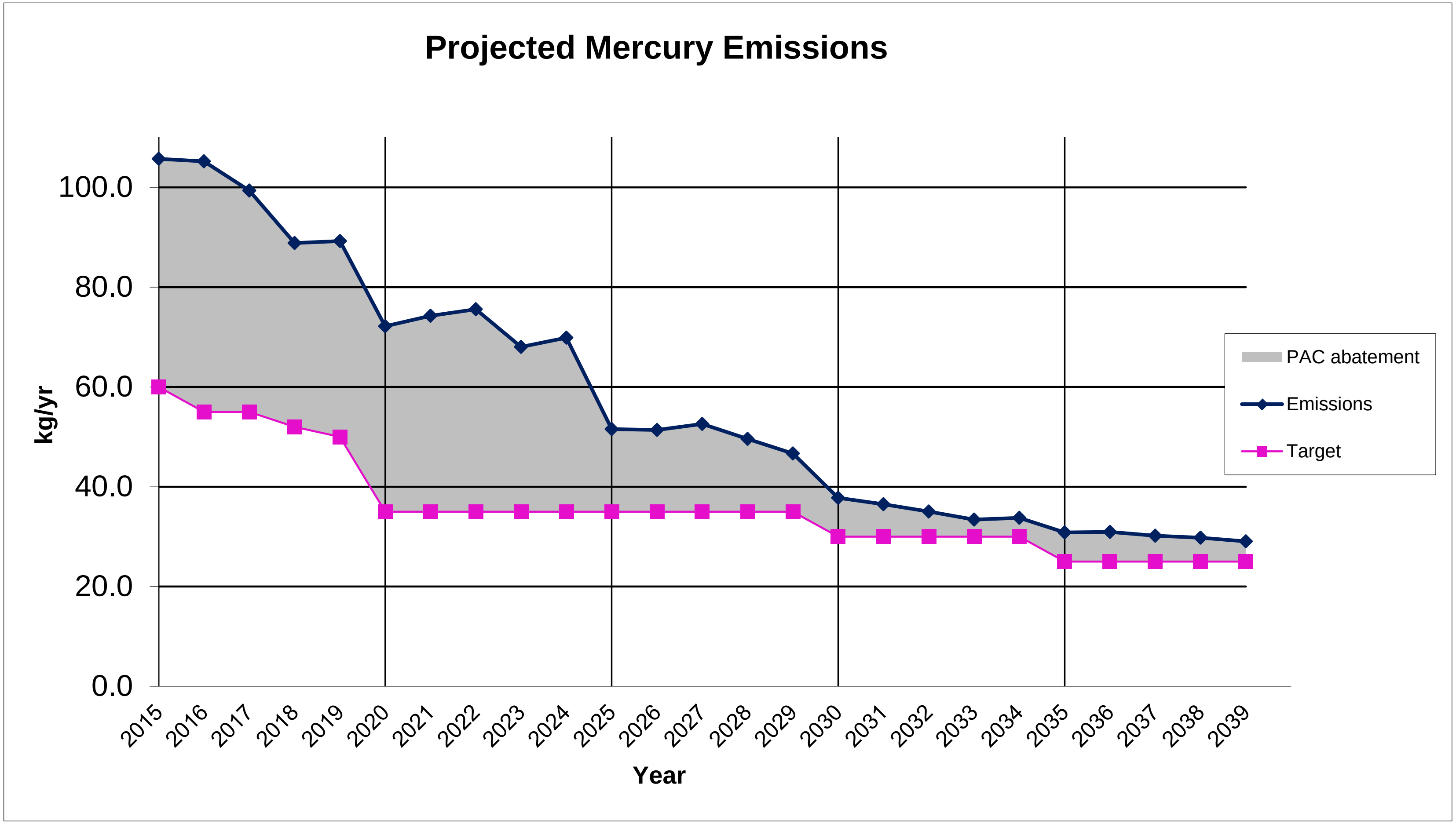
CRP1-1 (FGD) Preliminary CO_2 Emissions



CRP1-1 (FGD) Preliminary SO_2 Emissions



CRP1-1 (FGD) Preliminary Hg Emissions



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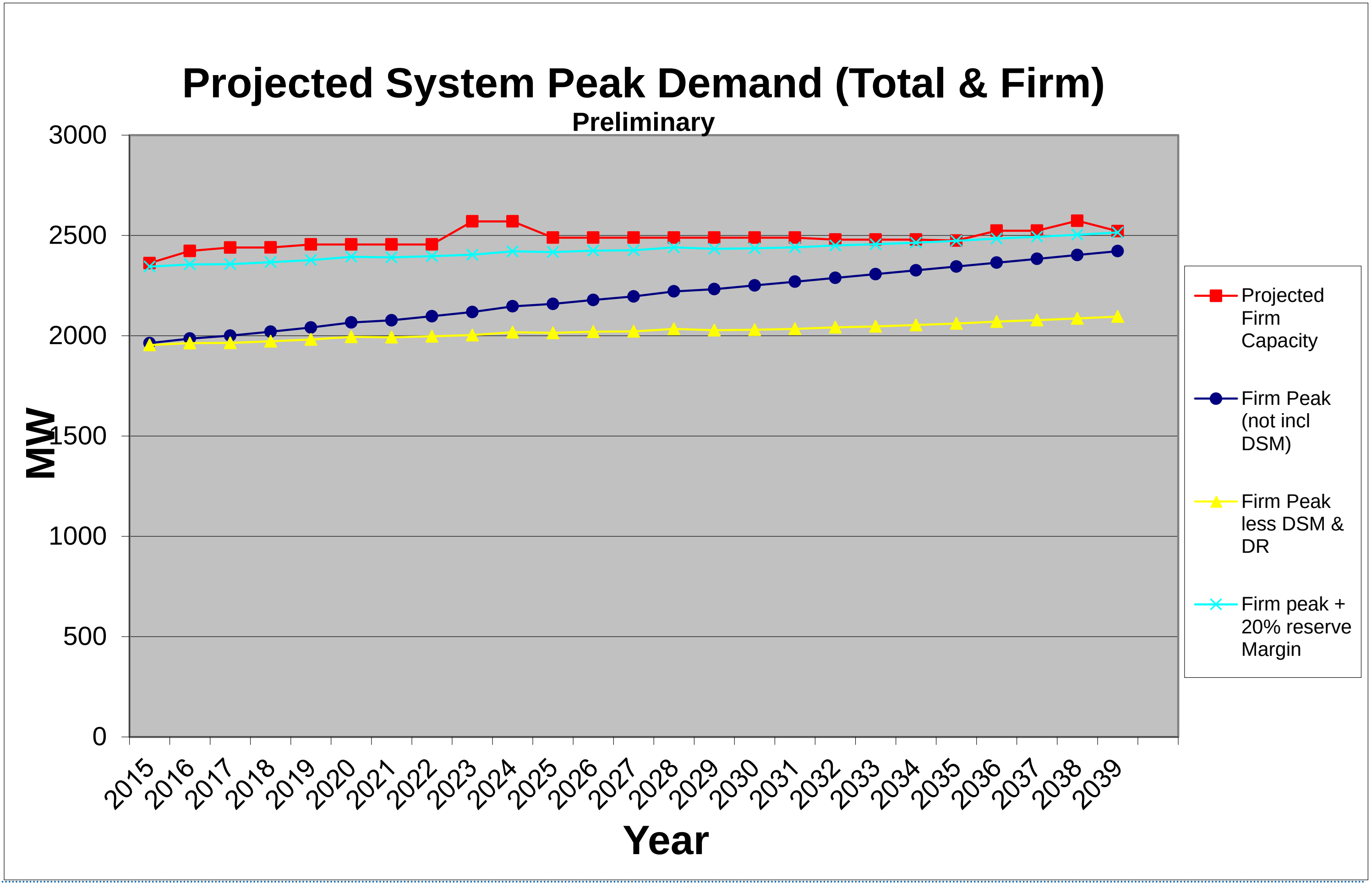
CRP1-1 Preliminary Results

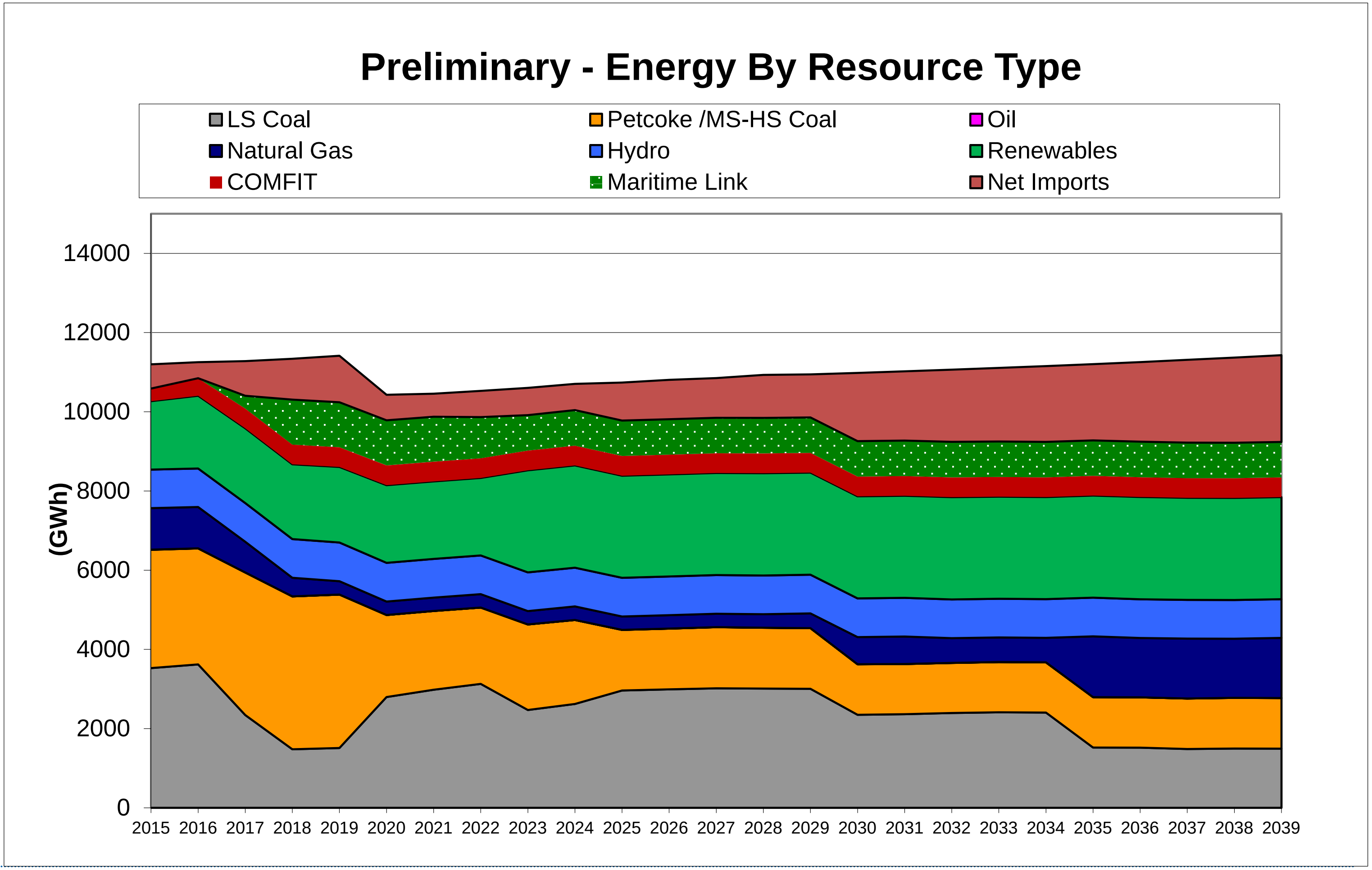
CRP1-1 Preliminary Load and Resources

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	2036	2037	2038	2039
Firm Peak	1,963	1,986	2,000	2,020	2,041	2,066	2,077	2,097	2,118	2,147	2,159	2,251	2,345	2,364	2,383	2,403	2,422
DSM	9	22	34	44	53	62	70	79	88	97	105	161	223	234	244	255	264
Firm Peak Less DSM	1,954	1,964	1,967	1,977	1,988	2,005	2,007	2,018	2,030	2,050	2,054	2,090	2,123	2,130	2,140	2,148	2,157
DRWH Reduction	0	1	2	4	7	10	15	21	27	32	39	60	62	60	62	62	62
DRCM Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Less DR	1,954	1,963	1,964	1,972	1,981	1,995	1,992	1,997	2,003	2,017	2014	2030	2061	2,070	2,078	2,086	2,096
RM Required	391	393	393	394	396	399	398	399	401	403	403	406	412.2	414	416	417	419
Required MWs	2,345	2,356	2,357	2,367	2,377	2,394	2,391	2,397	2,404	2,421	2417	2436	2473	2,485	2,494	2,504	2,515
Existing MWs	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341
Resource Additions (MW):																	
Burnside #4		33															
COMFIT - Biomass	4.2	6															
COMFIT - Wind	14.14	4.56	5.1														
REA Wind	2.35	17.34															
Maritime Link				153.3													
Small Biomass PPA			10														
Hydro			1.8		15				15								
PH Biomass																	51.7
PPA									100								
Assumed Unit Retirement				-153							-81		-150				-153
Natural Gas Unit													145.0	49.4		49.4	49.4
Total Annual Additions	20.7	60.9	16.9	0.3	15.0	0.0	0.0	0.0	115.0	0.0	-81.0	0.0	-5.0	49.4	0.0	49.4	-51.9
Total Cumulative Additions	20.7	81.6	98.5	98.7	113.7	113.7	113.7	113.7	228.7	228.7	147.7	147.7	133.1	182.5	182.5	231.9	180.0
Total Firm Capacity	2362	2423	2440	2440	2455	2455	2455	2455	2570	2570	2489	2489	2475	2524	2524	2573	2521
Surplus (Deficit) MWs above RM	17	67	83	73	78	61	64	58	166	149	72	53	1	39	30	70	7
Reserve Margin %	20.9%	23.4%	24.2%	23.7%	23.9%	23.1%	23.2%	22.9%	28.3%	27.4%	23.6%	22.6%	20.1%	21.9%	21.4%	23.3%	20.3%

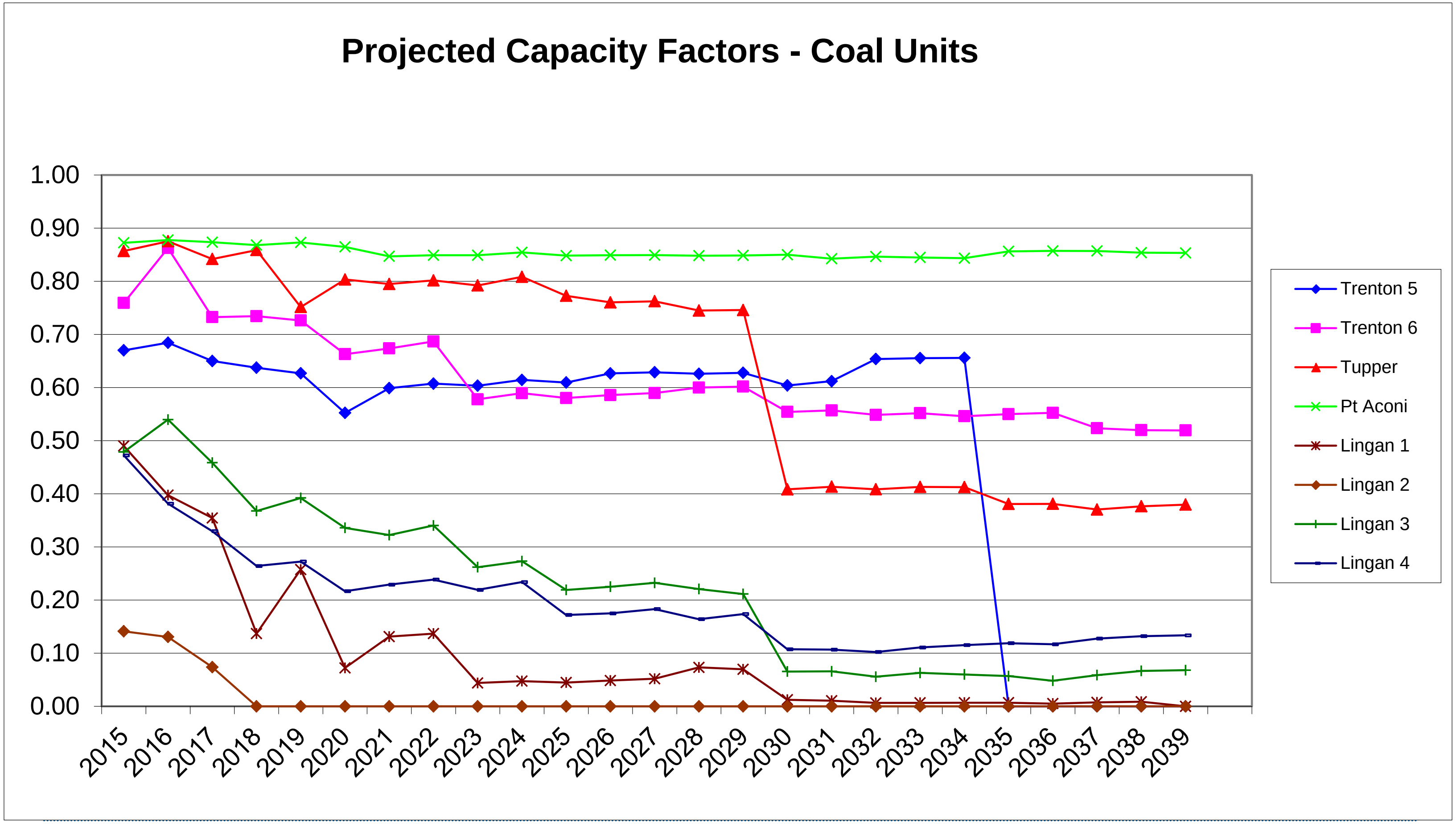
CRP1-1 Preliminary Demand and DSM



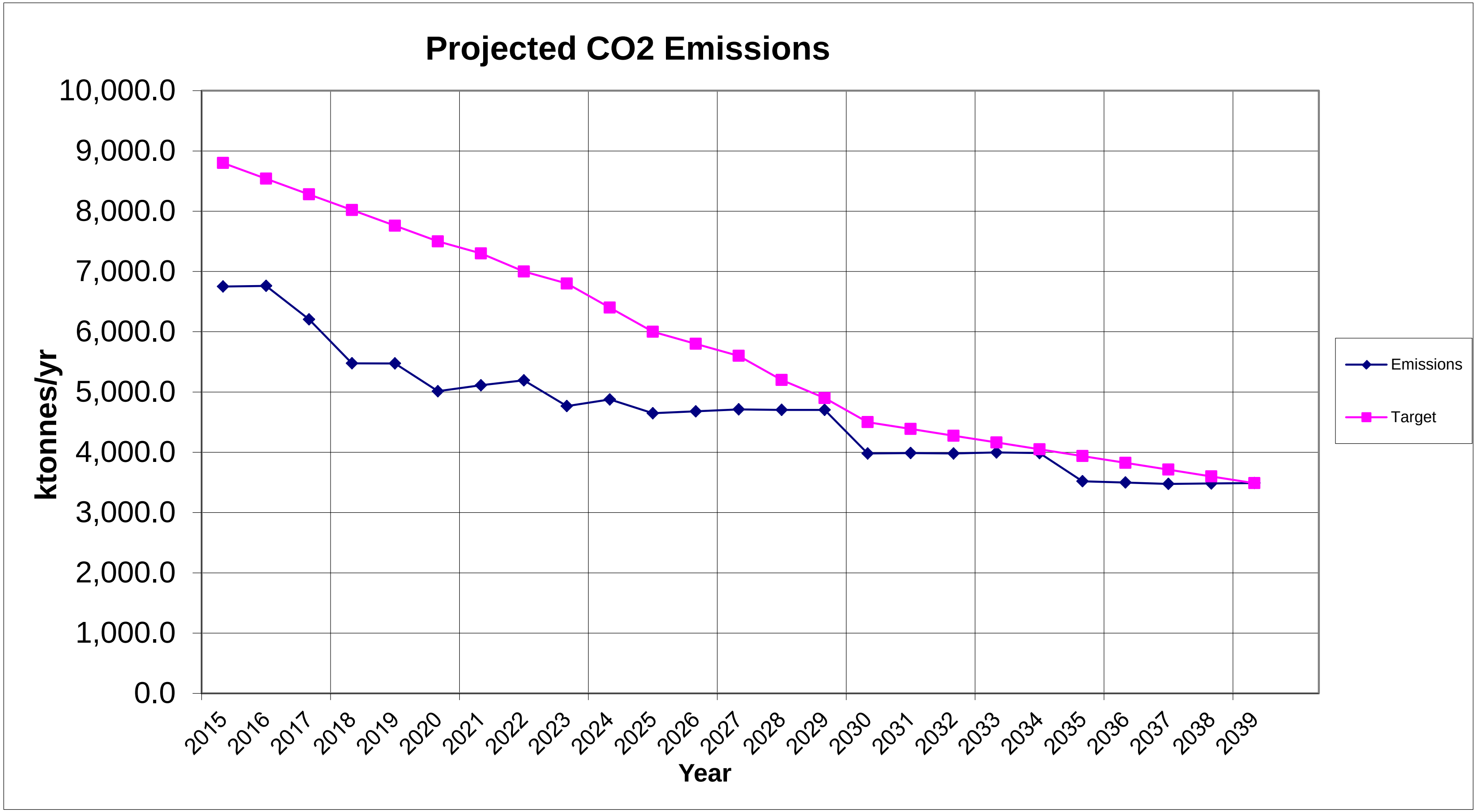
CRP1-1 Preliminary Energy by Resource Type



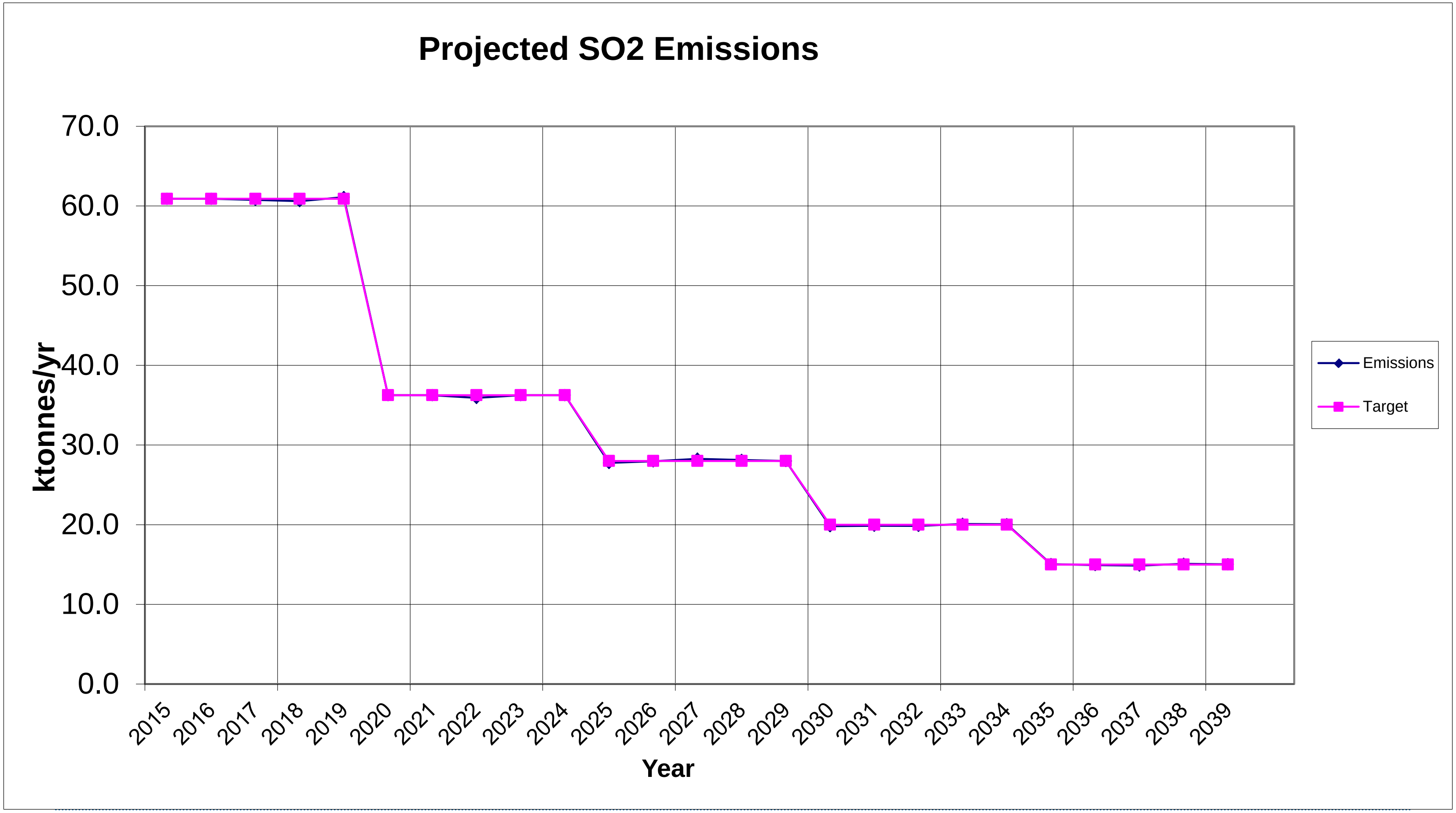
CRP1-1 Preliminary Coal Capacity Factors



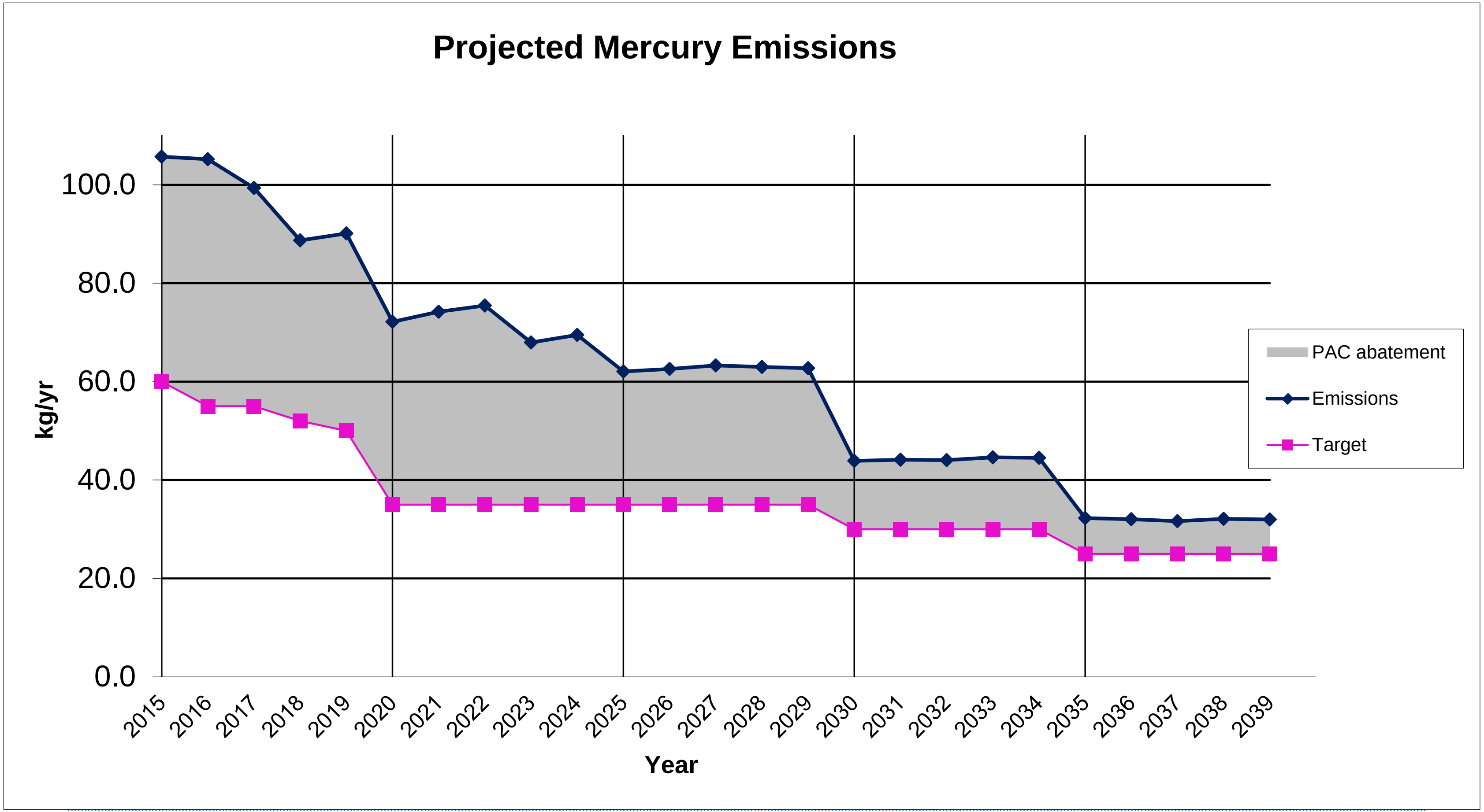
CRP1-1 Preliminary CO_2 Emissions



CRP1-1 Preliminary SO_2 Emissions



CRP1-1 Preliminary Hg Emissions



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CRP2 Preliminary Results

CRP2 Input Assumptions

Candidate Resource Plan 2 (CRP2):

- Base Load Forecast
- Base DSM
- Emissions - Scenario A
- Planned and committed resources are fixed in the plan (REA wind, COMFIT, Maritime Link/ Retire Lin #2)
- Maximum Coal Use
- Constraints
  - Planning reserve margin min = 20%
  - RES: 2015-2019 = 25%; 2020-2039 = 40%

CRP2 Preliminary Results

	CRP02-01-R03	**CRP02-17-R03 (FGD)**
	Least cost study period	**Least cost Planning period**
2015		
2016		
2017	ML Oct 2017	ML Oct 2017
	Lin 2 retire	Lin 2 retire
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025	TUC 1 Retire	TUC 1 Retire
		FGD (Lin 3/4 300 MW)
2026		
2027		
2028		
2029		
2030		
2031		
2032	TUC 2 Retire	TUC 2 Retire
2033		
2034		
2035	CT 50MW	CT 50MW
	Tre 5 Retire	Tre 5 Retire
2036		
2037		
2038		
2039	CT 50 MW	CT 100MW
	PHBM 51.7MW firm	PHBM 51.7MW firm
	Lin 1 Retire	Lin 1 Retire
Planning PV $M	11,235	11,206
Study PV $M	16,794	16,876

	Base DSM	Base DSM
	Program Adm Cost	Customer Cost
	$M	$M
2015	50.7	37.9
2016	50.5	39.9
2017	50.0	41.2
2018	52.4	41.6
2019	57.0	32.2
2020	61.5	28.0
2021	56.9	28.4
2022	54.1	28.4
2023	51.5	29.2
2024	50.8	28.6
2025	50.6	29.9
2026	52.1	33.8
2027	54.8	36.8
2028	58.5	41.4
2029	60.7	34.0
2030	63.1	37.2
2031	62.6	40.6
2032	61.4	40.8
2033	59.3	41.4
2034	56.7	41.7
2035	47.7	48.4
2036	46.5	48.0
2037	45.4	47.6
2038	44.4	46.8
2039	43.5	46.3
NPV	**700.8**	**474.9**

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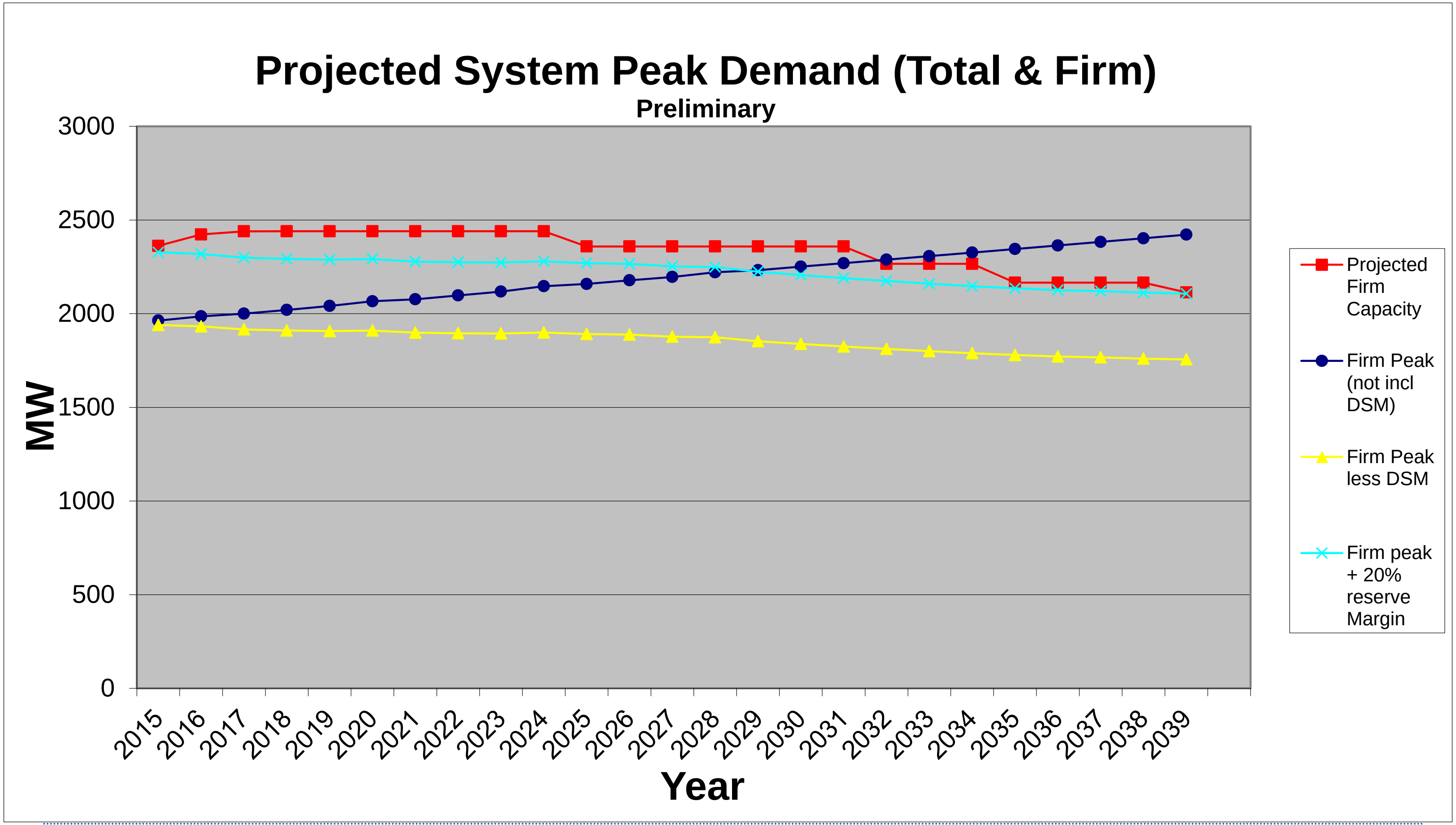
CRP2-1 Preliminary Results

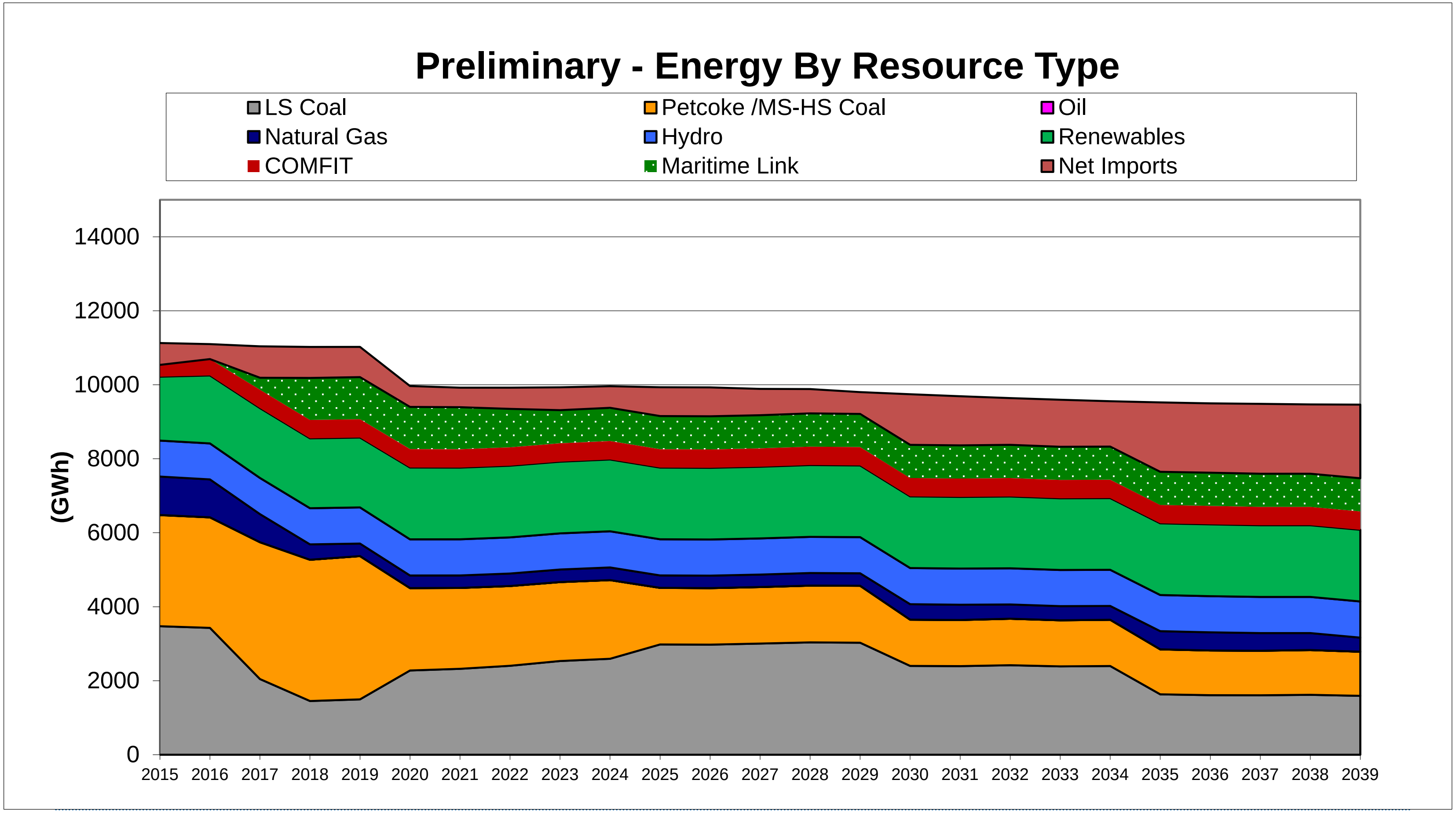
CRP2-1 Preliminary Load and Resources

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	2036	2037	2038	2039
Firm Peak	1,963	1,986	2,000	2,020	2,041	2,066	2,077	2,097	2,118	2,147	2,159	2,251	2,345	2,364	2,383	2,403	2,422
DSM	23	54	84	110	134	156	178	202	224	247	267	412	566	593	616	643	666
Firm Peak Less DSM	1,940	1,932	1,916	1,910	1,907	1,910	1,899	1,896	1,894	1,899	1,892	1,839	1,780	1,771	1,767	1,760	1,756
RM Required	388	386	383	382	381	382	380	379	379	380	378	368	356	354	353	352	351
Required MWs	2,328	2,319	2,299	2,293	2,288	2,292	2,278	2,275	2,273	2,279	2,270	2,206	2,136	2,126	2,120	2,112	2,107
Existing MWs	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341
Resource Additions (MW):																	
Burnside #4		33															
COMFIT - Biomass	4.2	6															
COMFIT - Wind	14.14	4.56	5.1														
REA Wind	2.35	17.34															
Maritime Link				153.3													
Small Biomass PPA			10														
Hydro			1.8														
PH Biomass																	51.7
Additional Wind																	
Assumed Unit Retirement				-153							-81		-150				-153
Natural Gas Unit													49.4				49.4
Total Annual Additions	20.7	60.9	16.9	0.3	0.0	0.0	0.0	0.0	0.0	0.0	-81.0	0.0	-100.6	0.0	0.0	0.0	-51.9
Total Cumulative Additions	20.7	81.6	98.5	98.7	98.7	98.7	98.7	98.7	98.7	98.7	17.7	17.7	-175.9	-175.9	-175.9	-175.9	-227.8
Total Firm Capacity	2362	2423	2440	2440	2440	2440	2440	2440	2440	2440	2359	2359	2166	2166	2166	2166	2114
Surplus (Deficit) MWs above RM	34	104	141	148	152	148	162	165	167	161	89	153	30	40	45	53	7
Reserve Margin %	21.8%	25.4%	27.3%	27.7%	28.0%	27.8%	28.5%	28.7%	28.8%	28.5%	24.7%	28.3%	21.7%	22.2%	22.6%	23.0%	20.4%

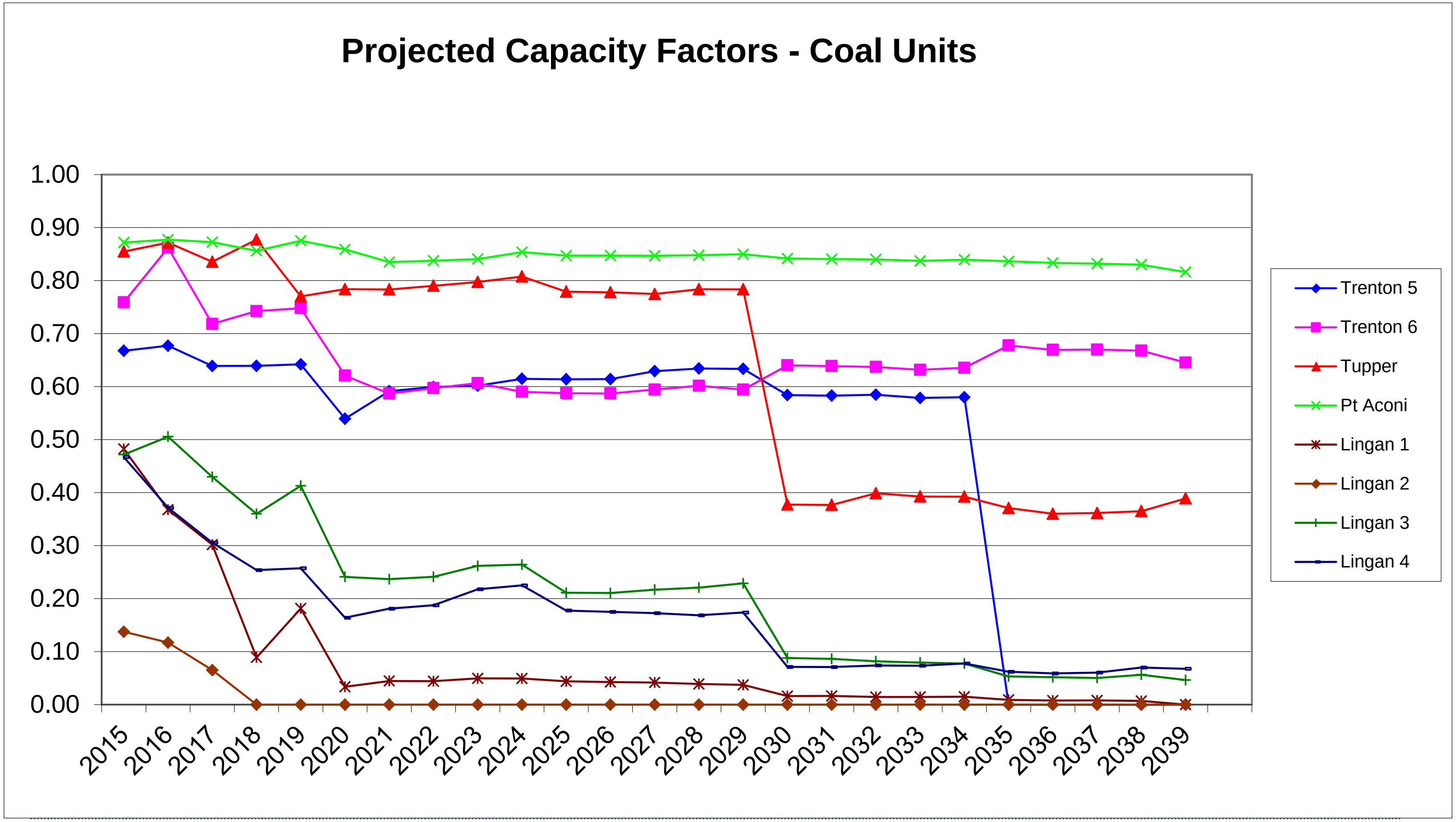
CRP2-1 Preliminary Demand and DSM



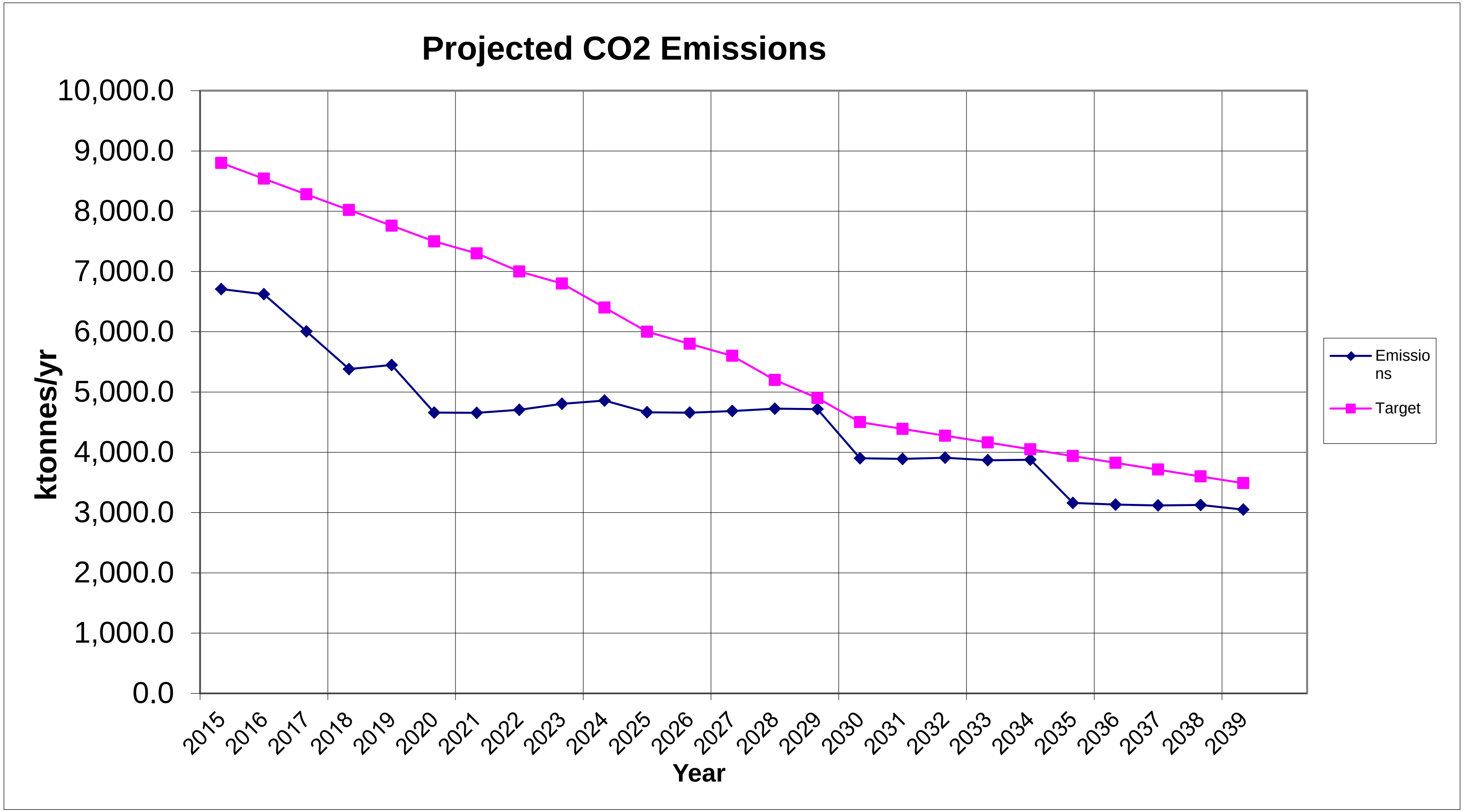
CRP2-1 Preliminary Energy by Resource Type



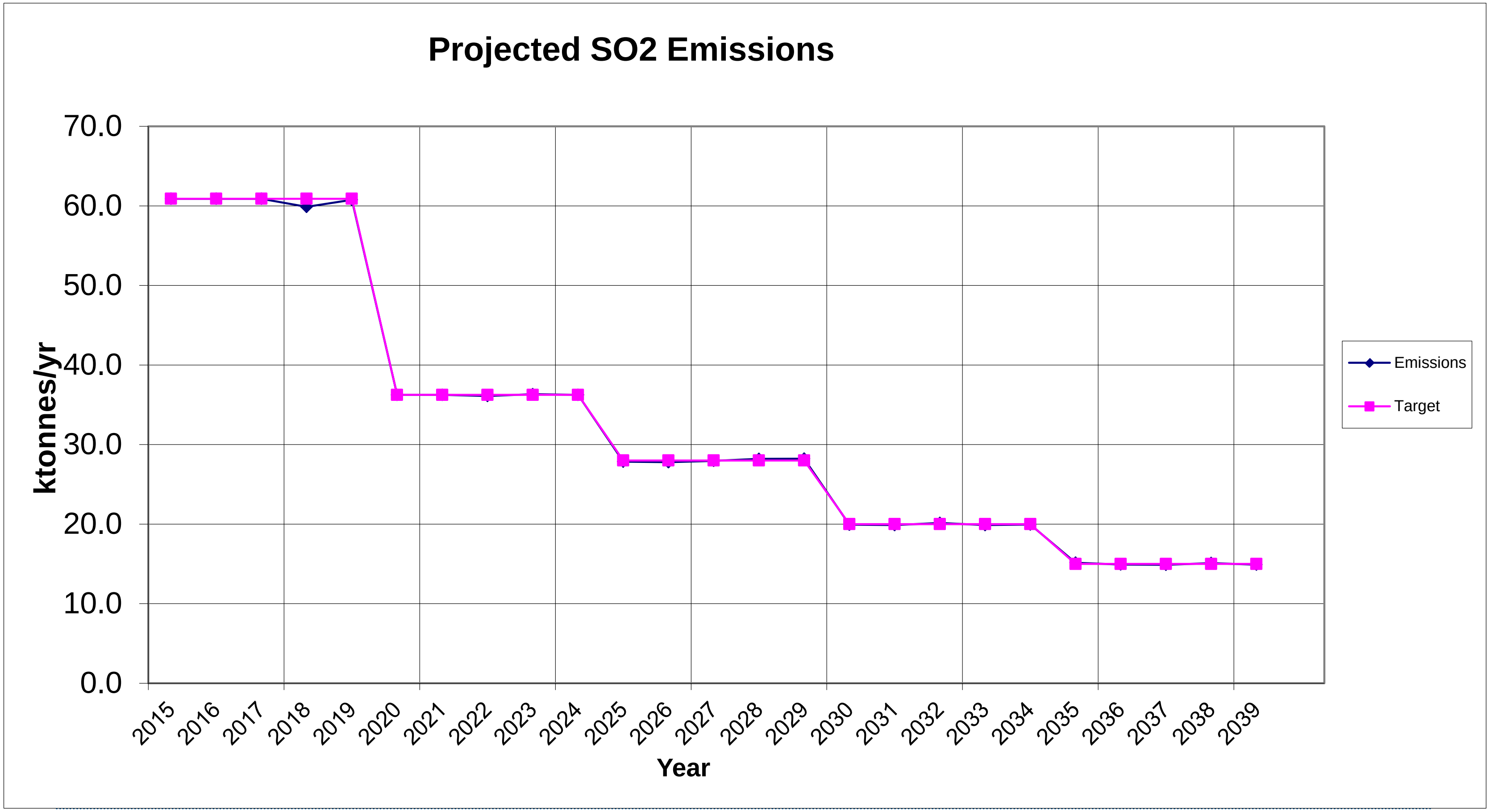
CRP2-1 Preliminary Coal Capacity Factors



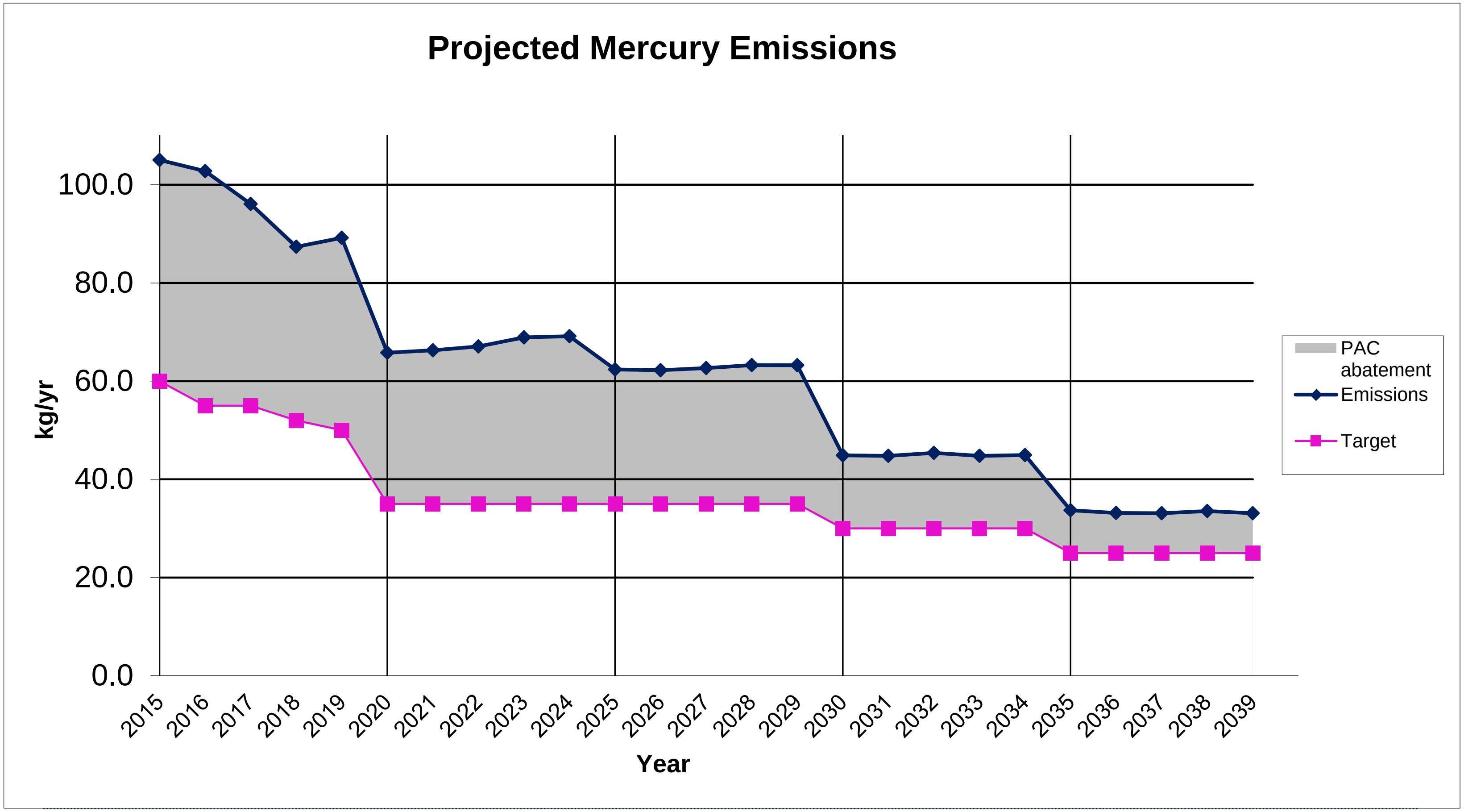
CRP2-1 Preliminary CO_2 Emissions



CRP2-1 Preliminary SO_2 Emissions



CRP2-1 Preliminary Hg Emissions



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CRP2-17 Preliminary Results

CRP2-17 Preliminary Load and Resources

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	2036	2037	2038	2039
Firm Peak	1,963	1,986	2,000	2,020	2,041	2,066	2,077	2,097	2,118	2,147	2,159	2,251	2,345	2,364	2,383	2,403	2,422
DSM	23	54	84	110	134	156	178	202	224	247	267	412	566	593	616	643	666
Firm Peak Less DSM	1,940	1,932	1,916	1,910	1,907	1,910	1,899	1,896	1,894	1,899	1,892	1,839	1,780	1,771	1,767	1,760	1,756
RM Required	388	386	383	382	381	382	380	379	379	380	378	368	356	354	353	352	351
Required MWs	2,328	2,319	2,299	2,293	2,288	2,292	2,278	2,275	2,273	2,279	2,270	2,206	2,136	2,126	2,120	2,112	2,107
Existing MWs	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341
Resource Additions (MW):																	
Burnside #4		33															
COMFIT - Biomass	4.2	6															
COMFIT - Wind	14.14	4.56	5.1														
REA Wind	2.35	17.34															
Maritime Link				153													
Small Biomass PPA			10														
Hydro			1.8														
FGD parasitic power											-8.0						
PH Biomass																	51.7
Assumed Unit Retirement				-153							-81		-150				-153
Natural Gas Unit													49.4				100
Total Annual Additions	20.7	60.9	16.9	0.3	0.0	0.0	0.0	0.0	0.0	0.0	-89.0	0.0	-100.6	0.0	0.0	0.0	-1.3
Total Cumulative Additions	20.7	81.6	98.5	98.7	98.7	98.7	98.7	98.7	98.7	98.7	9.7	9.7	-183.9	-183.9	-183.9	-183.9	-185.2
Total Firm Capacity	2362	2423	2440	2440	2440	2440	2440	2440	2440	2440	2351	2351	2158	2158	2158	2158	2156
Surplus (Deficit) MWs above RM	34	104	141	148	152	148	162	165	167	161	81	145	22	32	37	45	49
Reserve Margin %	21.8%	25.4%	27.3%	27.7%	28.0%	27.8%	28.5%	28.7%	28.8%	28.5%	24.3%	27.9%	21.2%	21.8%	22.1%	22.6%	22.8%

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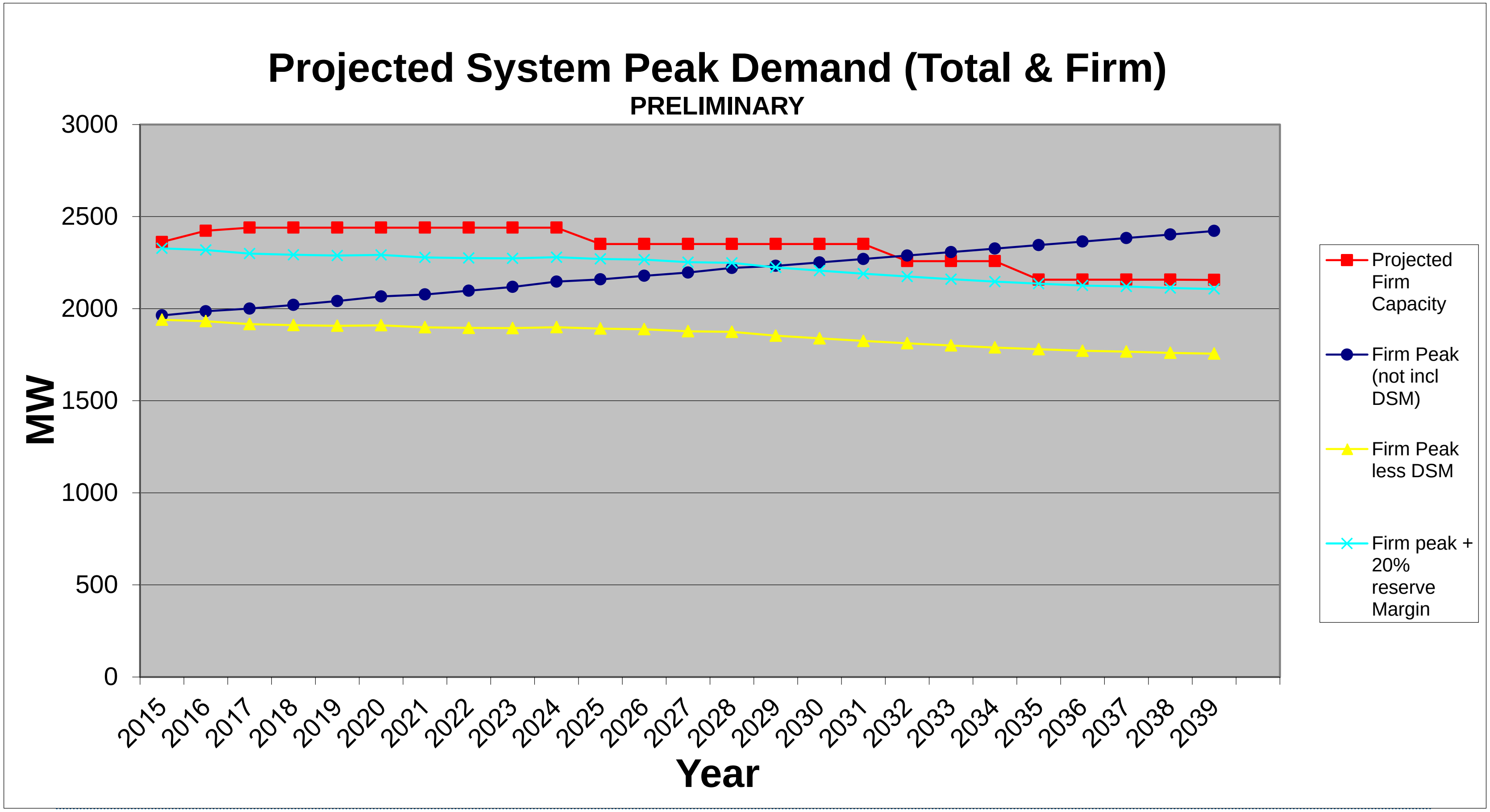
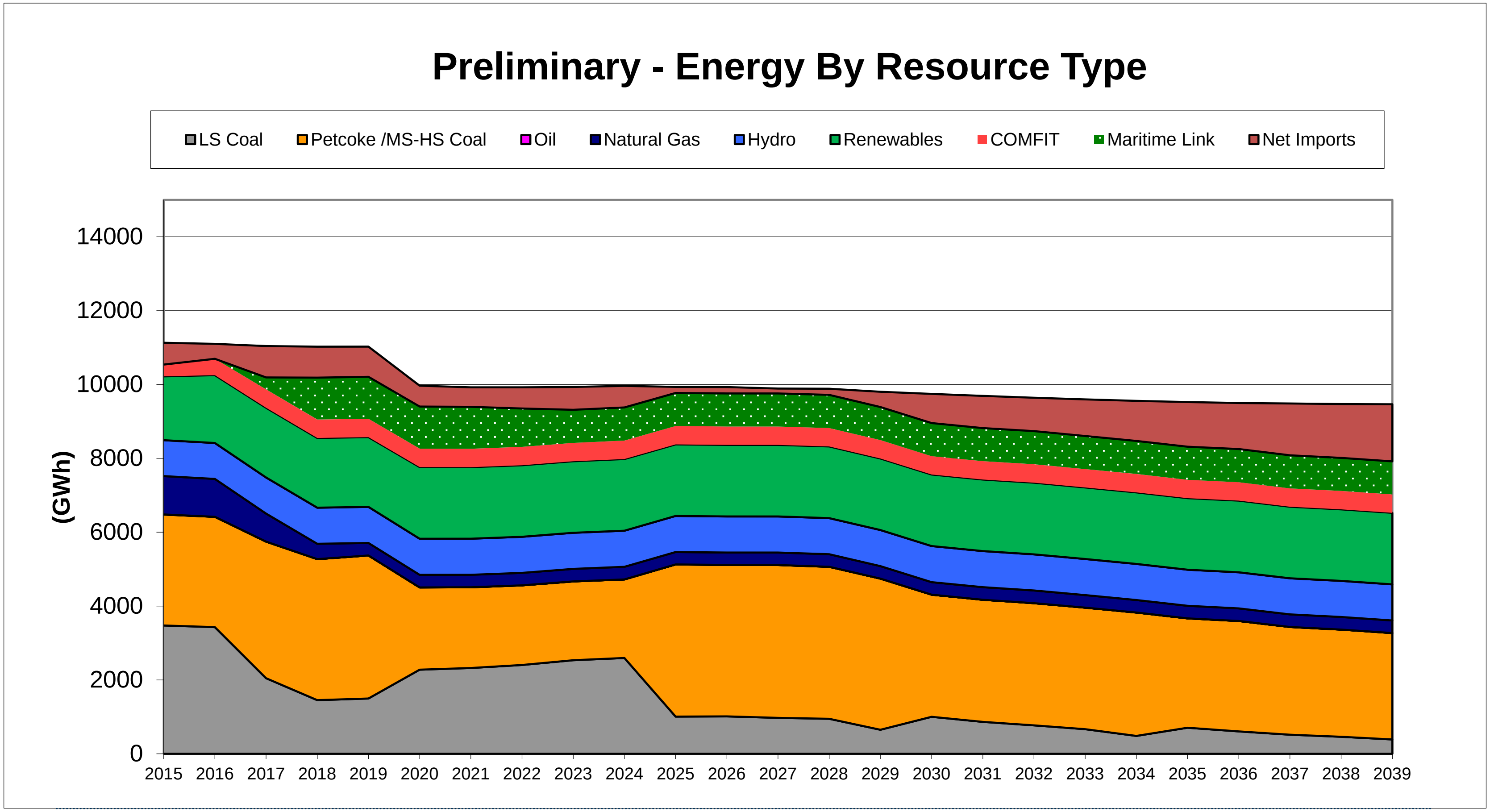
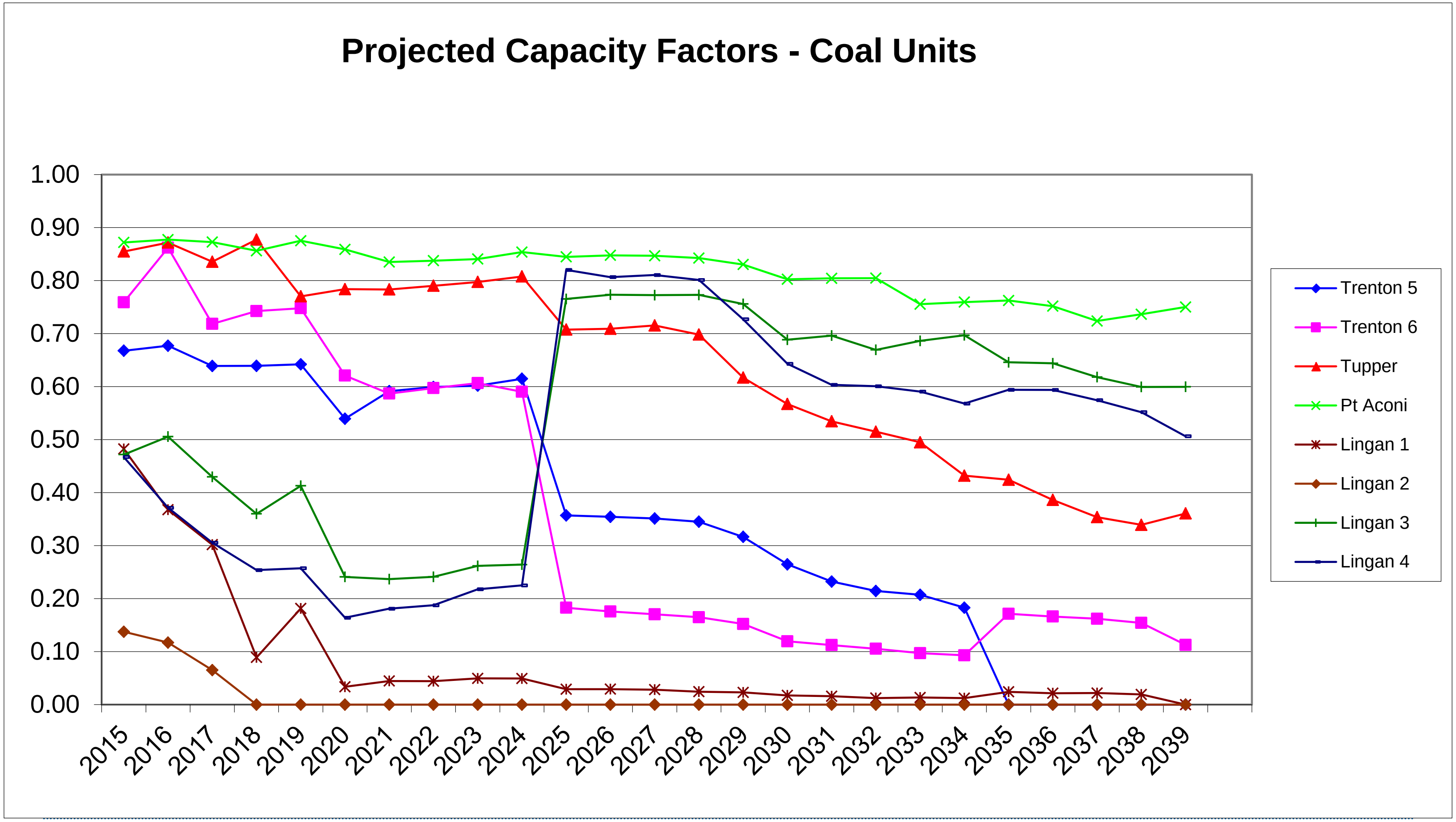
CRP2-17 Preliminary Demand and DSM



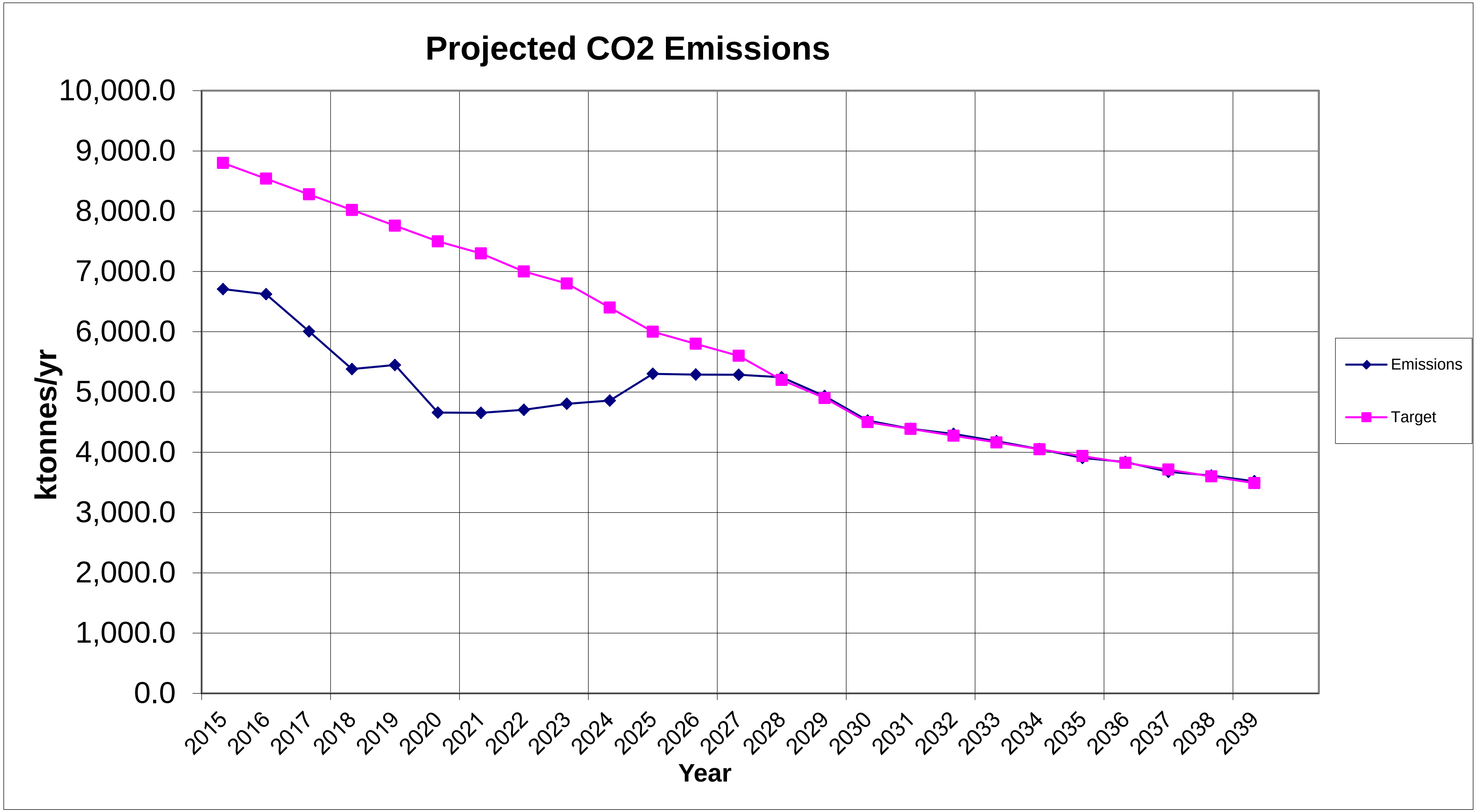
CRP2-17 Preliminary Energy by Resource Type



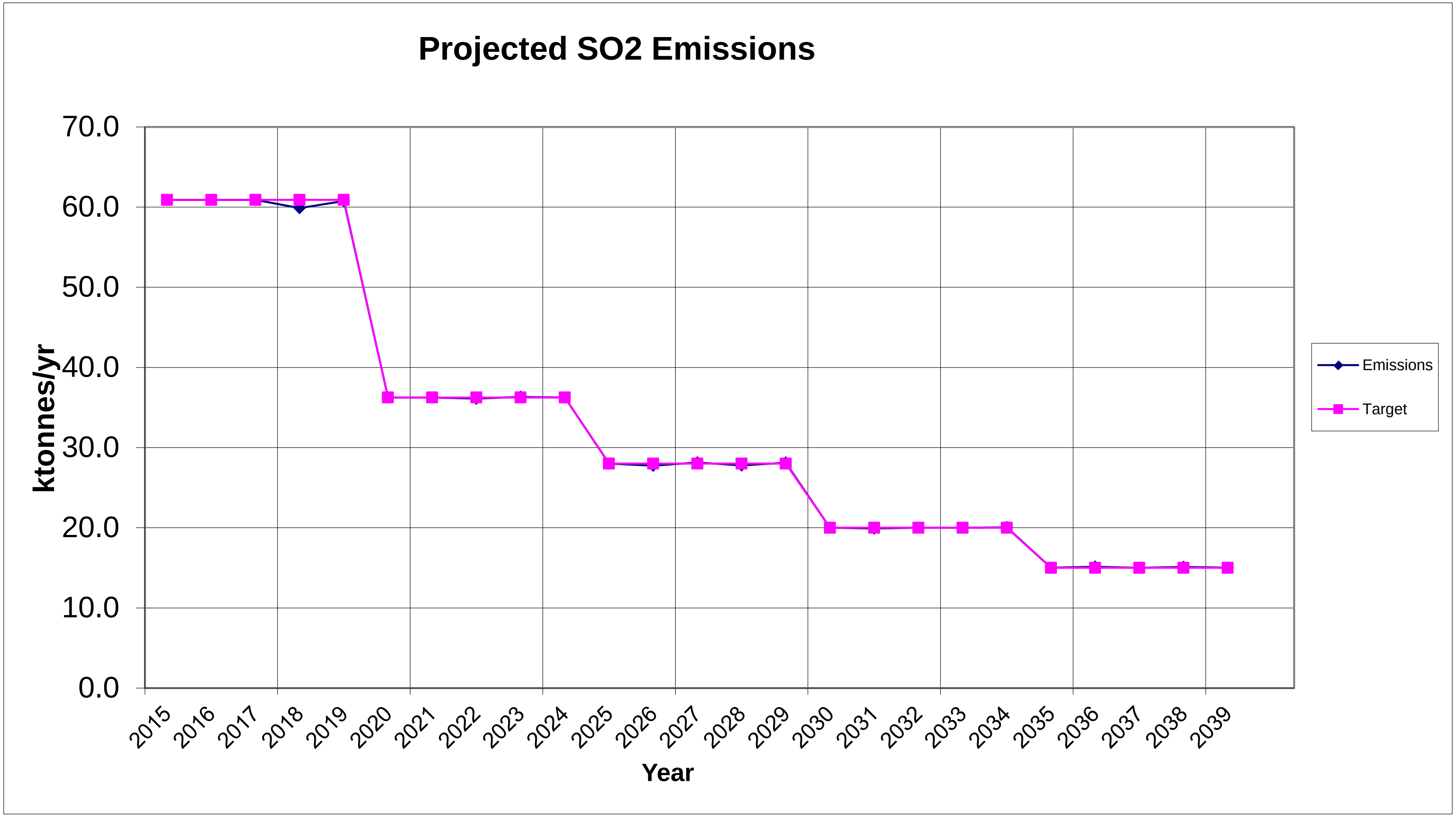
CRP2-17 Preliminary Coal Capacity Factors



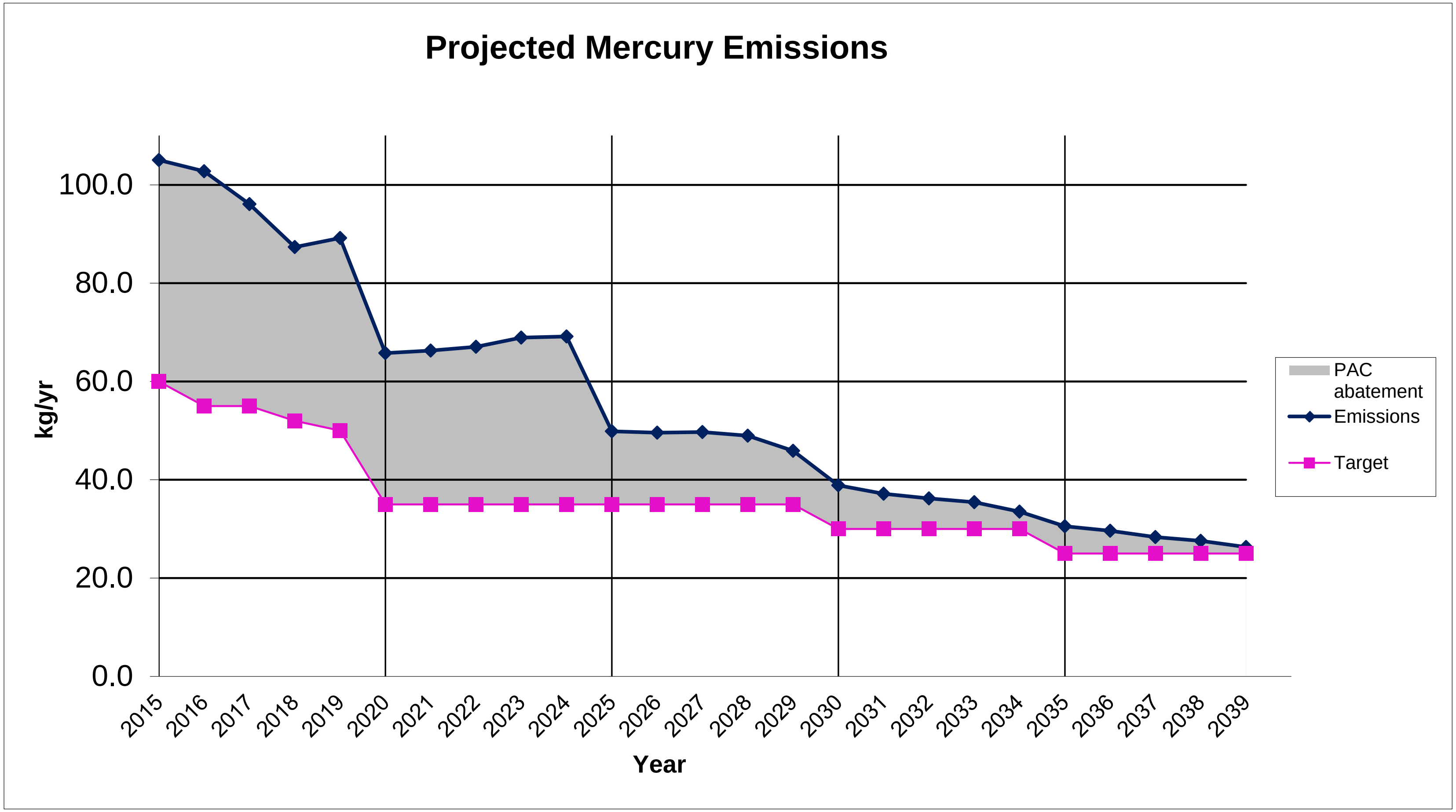
CRP2-17 Preliminary CO_2 Emissions



CRP2-17 Preliminary SO_2 Emissions



CRP2-17 Preliminary Hg Emissions



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CRP3 Preliminary Results

CRP3 Input Assumptions

Candidate Resource Plan 3 (CRP3):

- Base Load Forecast
- Base DSM
- Emissions - Scenario A
- Planned and committed resources are fixed in the plan (REA wind, COMFIT, Maritime Link/ Retire Lin #2)
- Maximum Coal Use
- Medium Wind (Wind integration: 2 x CT 50 MW and $200M for reliability tie and transmission upgrades)
- Constraints
  - Planning reserve margin min = 20%
  - RES: 2015-2019 = 25%; 2020-2039 = 40%

CRP3 Preliminary Results

	CRP3-01-R01	**CRP3-05-R01**
	Least cost study period	**Least cost planning period**
2015		
2016		
2017	ML Oct 2017	ML Oct 2017
	Lin 2 retire	Lin 2 retire
2018		
2019		
2020		
2021		
2022		
2023	Wind Block 150MW 2 x CT 50 MW (for wind integration)	Wind Block 150MW 2 x CT 50 MW (for wind integration)
2024		
2025	TUC 1 Retire	TUC 1 Retire
		FGD (Lin 3/4 300MW)
2026		
2027		
2028		
2029		
2030		
2031		
2032	TUC 2 Retire	TUC 2 Retire
2033		
2034		
2035	Tre 5 Retire	Tre 5 Retire
2036		
2037		
2038		
2039	PHBM 51.7 MW Firm	PHBM 51.7 MW Firm
	Lin 1 Retire	Lin 1 Retire
Planning PV $M	11,516	11,493
Study PV $M	17,110	17,181

	Base DSM	Base DSM
	Program Adm Cost	Customer Cost
	$M	$M
2015	50.7	37.9
2016	50.5	39.9
2017	50.0	41.2
2018	52.4	41.6
2019	57.0	32.2
2020	61.5	28.0
2021	56.9	28.4
2022	54.1	28.4
2023	51.5	29.2
2024	50.8	28.6
2025	50.6	29.9
2026	52.1	33.8
2027	54.8	36.8
2028	58.5	41.4
2029	60.7	34.0
2030	63.1	37.2
2031	62.6	40.6
2032	61.4	40.8
2033	59.3	41.4
2034	56.7	41.7
2035	47.7	48.4
2036	46.5	48.0
2037	45.4	47.6
2038	44.4	46.8
2039	43.5	46.3
NPV	**700.8**	**474.9**

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CRP3-1 Preliminary Results

CRP3-1 Preliminary Load and Resources

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	2036	2037	2038	2039
Firm Peak	1,963	1,986	2,000	2,020	2,041	2,066	2,077	2,097	2,118	2,147	2,159	2,251	2,345	2,364	2,383	2,403	2,422
DSM	23	54	84	110	134	156	178	202	224	247	267	412	566	593	616	643	666
Firm Peak Less DSM	1,940	1,932	1,916	1,910	1,907	1,910	1,899	1,896	1,894	1,899	1,892	1,839	1,780	1,771	1,767	1,760	1,756
RM Required	388	386	383	382	381	382	380	379	379	380	378	368	356	354	353	352	351
Required MWs	2,328	2,319	2,299	2,293	2,288	2,292	2,278	2,275	2,273	2,279	2,270	2,206	2,136	2,126	2,120	2,112	2,107
Existing MWs	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341
Resource Additions (MW):																	
Burnside #4		33															
COMFIT - Biomass	4.2	6															
COMFIT - Wind	14.14	4.56	5.1														
REA Wind	2.35	17.34															
Maritime Link				153.3													
Small Biomass PPA			10														
Hydro			1.8														
PH Biomass																	51.7
Additional Wind									18								
Assumed Unit Retirement				-153							-81		-150				-153
Natural Gas Unit									98.6								
Total Annual Additions	20.7	60.9	16.9	0.3	0.0	0.0	0.0	0.0	116.6	0.0	-81.0	0.0	-150.0	0.0	0.0	0.0	-101.3
Total Cumulative Additions	20.7	81.6	98.5	98.7	98.7	98.7	98.7	98.7	215.3	215.3	134.3	134.3	-108.7	-108.7	-108.7	-108.7	-210.0
Total Firm Capacity	2362	2423	2440	2440	2440	2440	2440	2440	2557	2557	2476	2476	2233	2233	2233	2233	2131
Surplus (Deficit) MWs above RM	34	104	141	148	152	148	162	165	284	277	206	269	97	107	112	121	24
Reserve Margin %	21.8%	25.4%	27.3%	27.7%	28.0%	27.8%	28.5%	28.7%	35.0%	34.6%	30.9%	34.6%	25.5%	26.0%	26.4%	26.9%	21.4%

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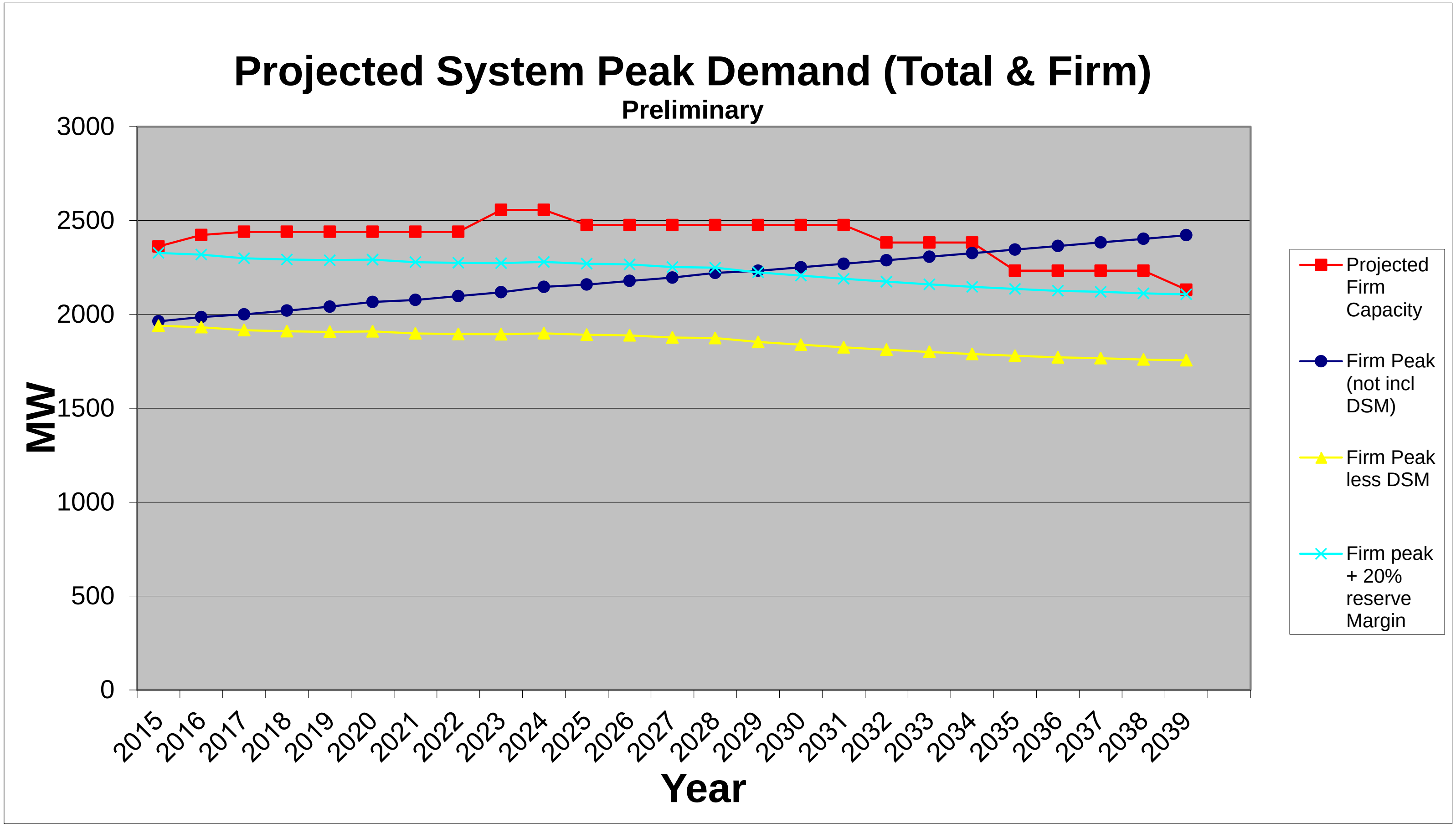
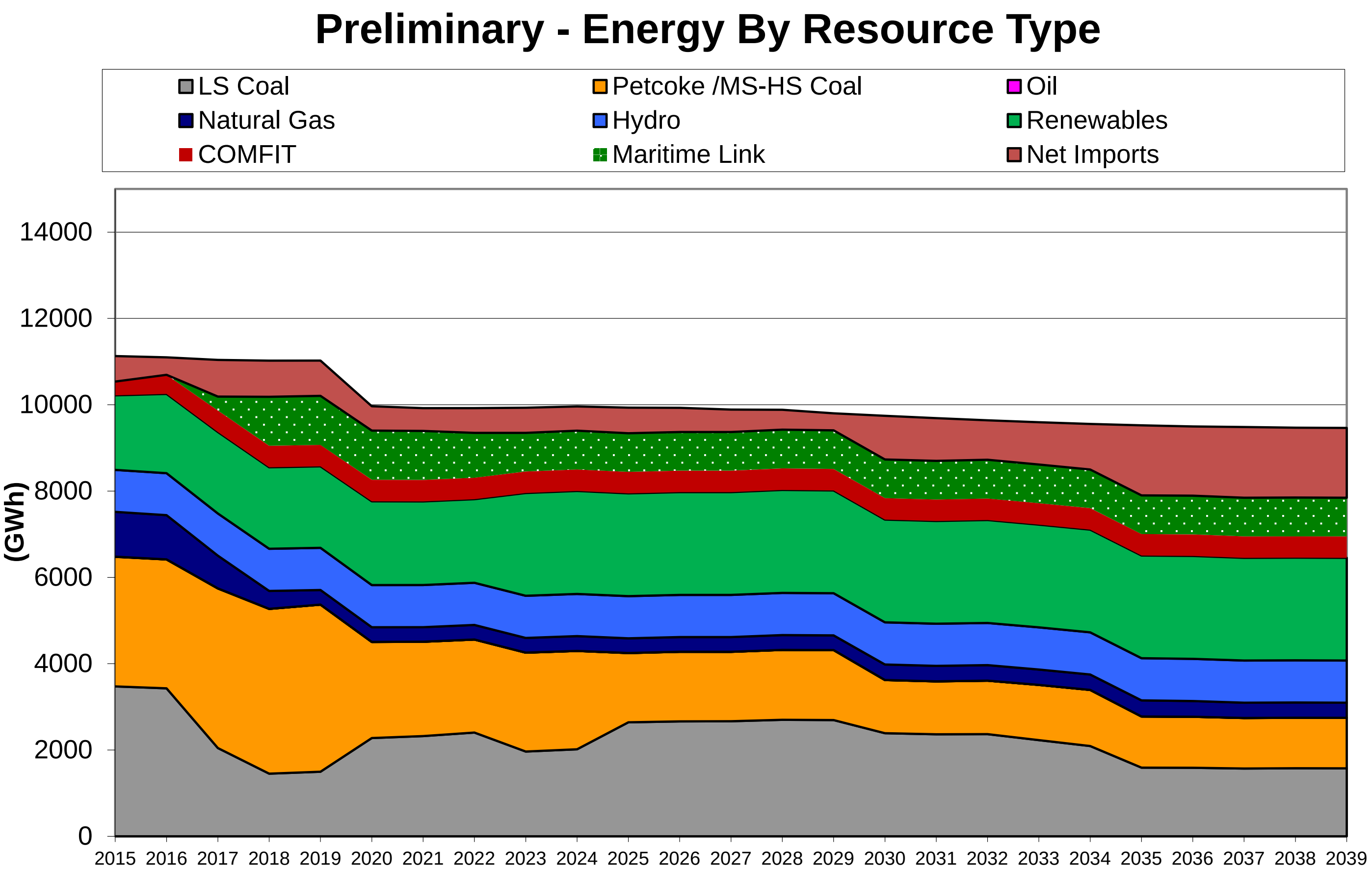
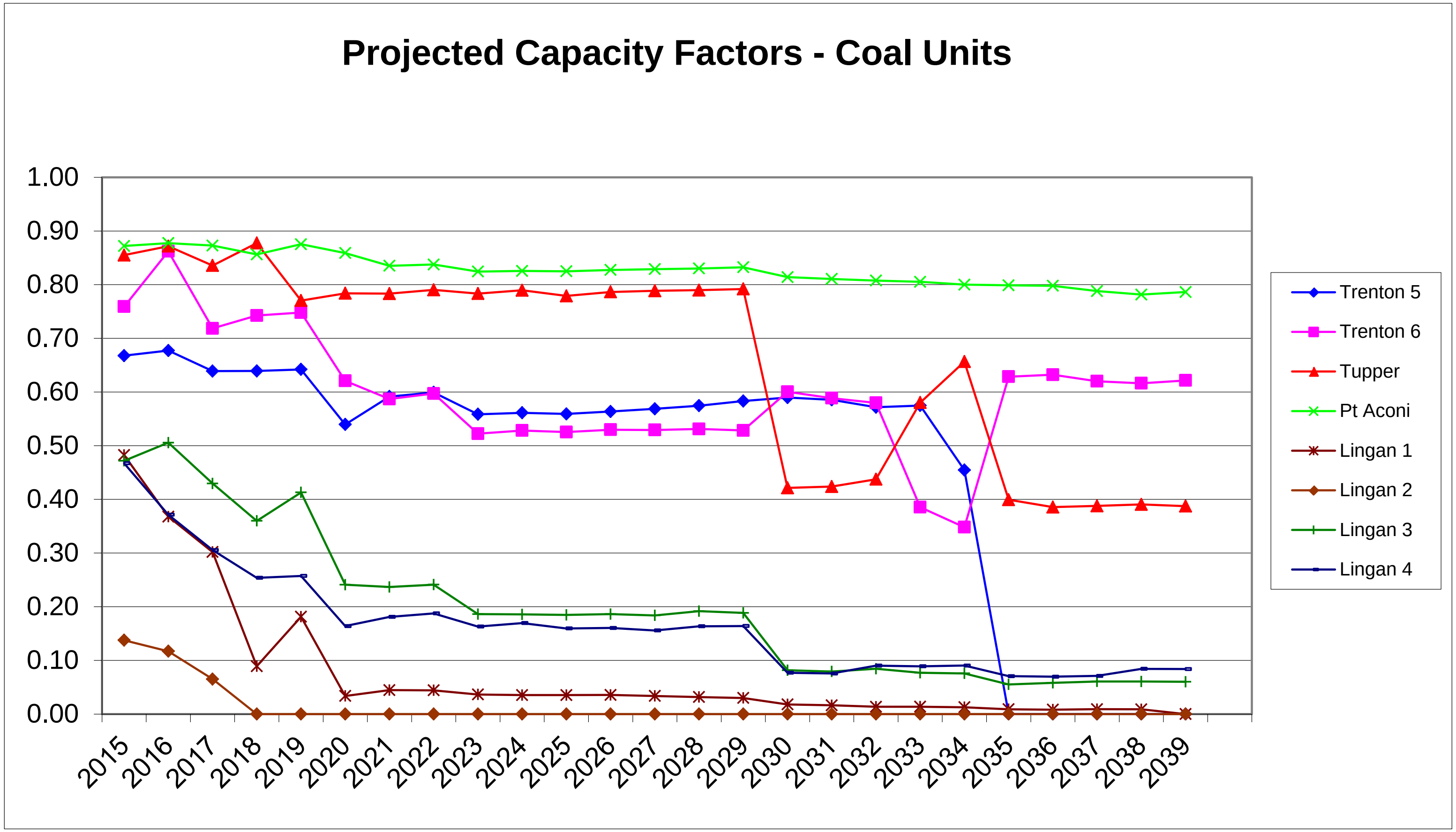
CRP3-1 Preliminary Demand and DSM



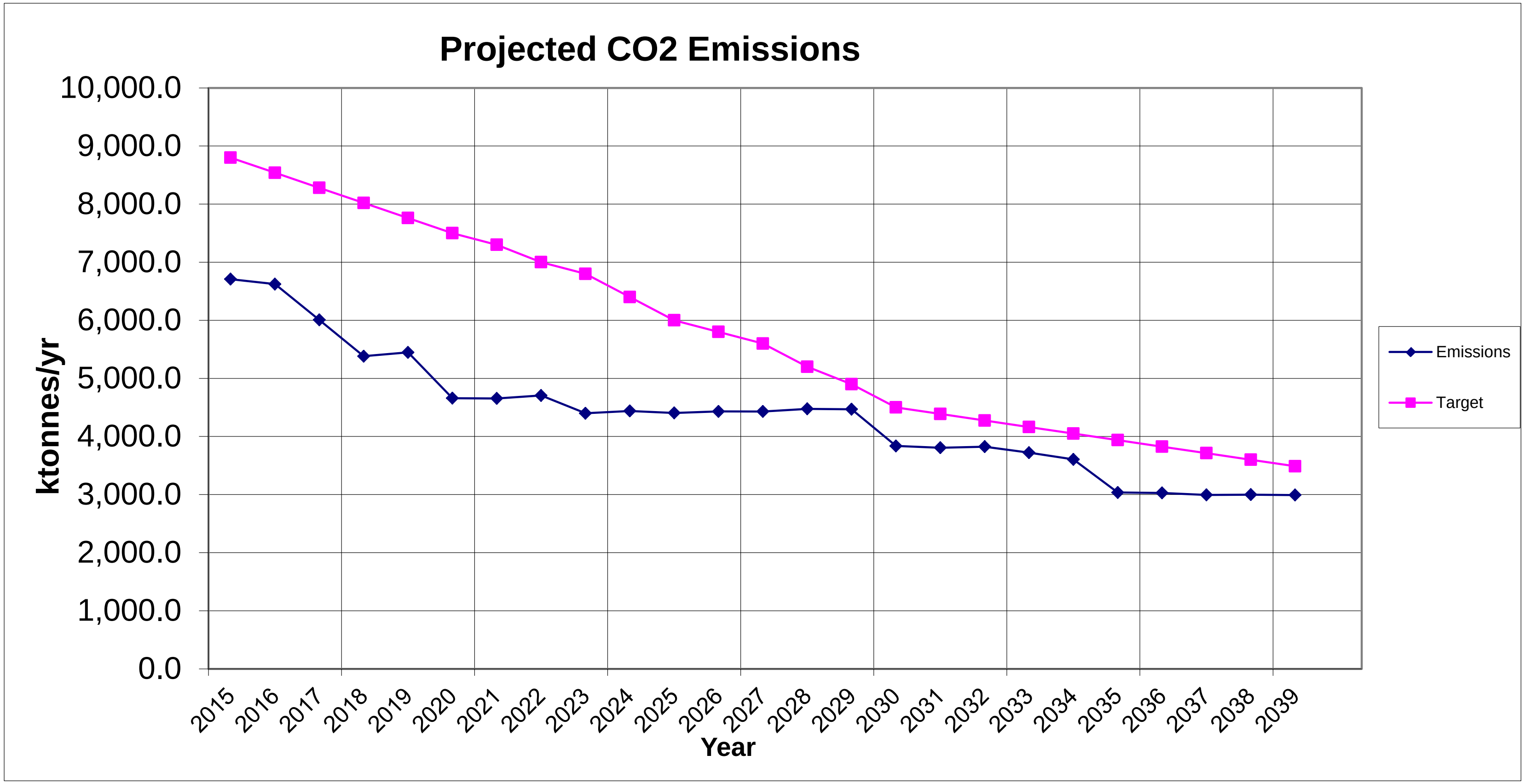
CRP3-1 Preliminary Energy by Resource Type



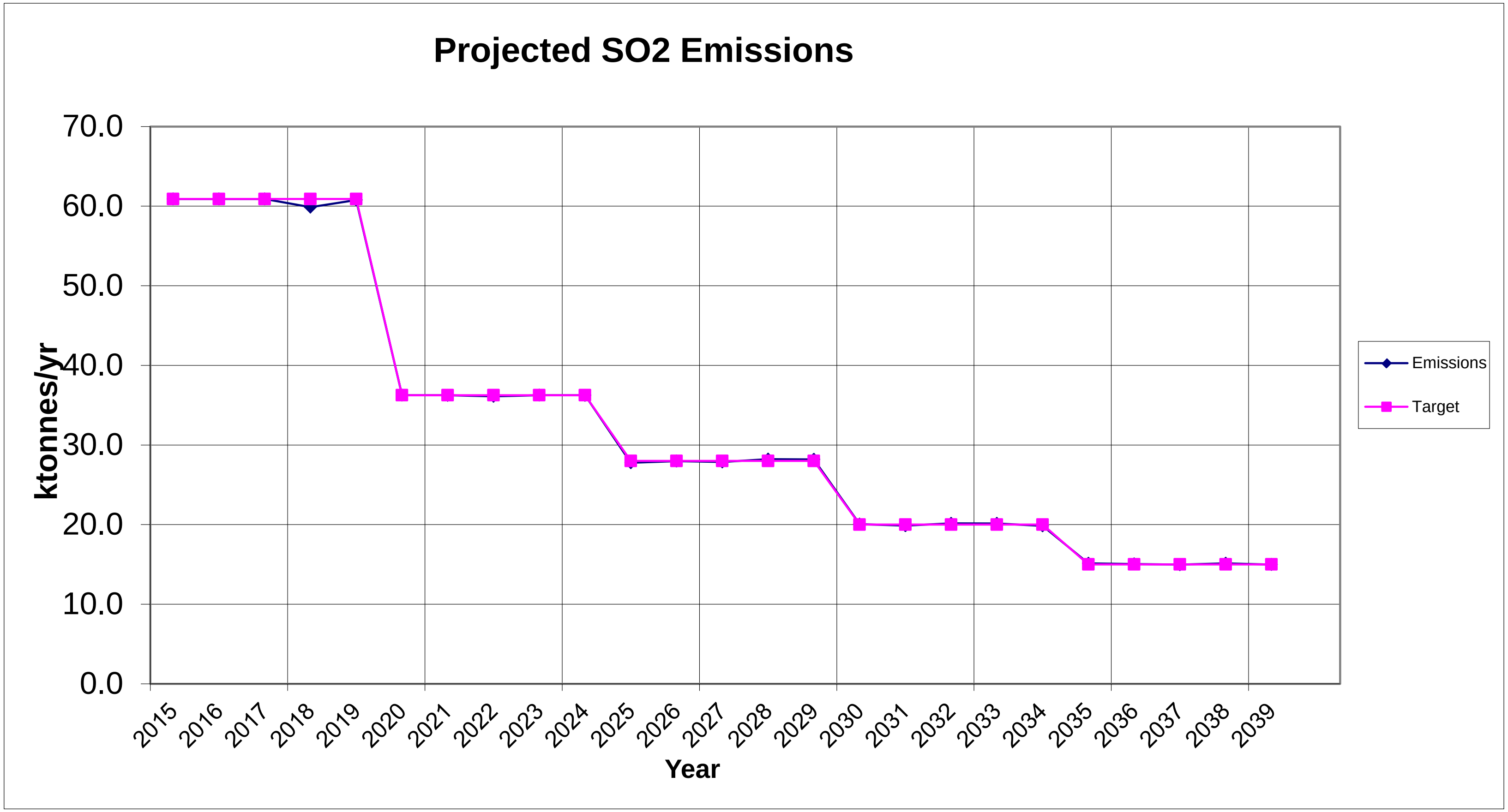
CRP3-1 Preliminary Coal Capacity Factors



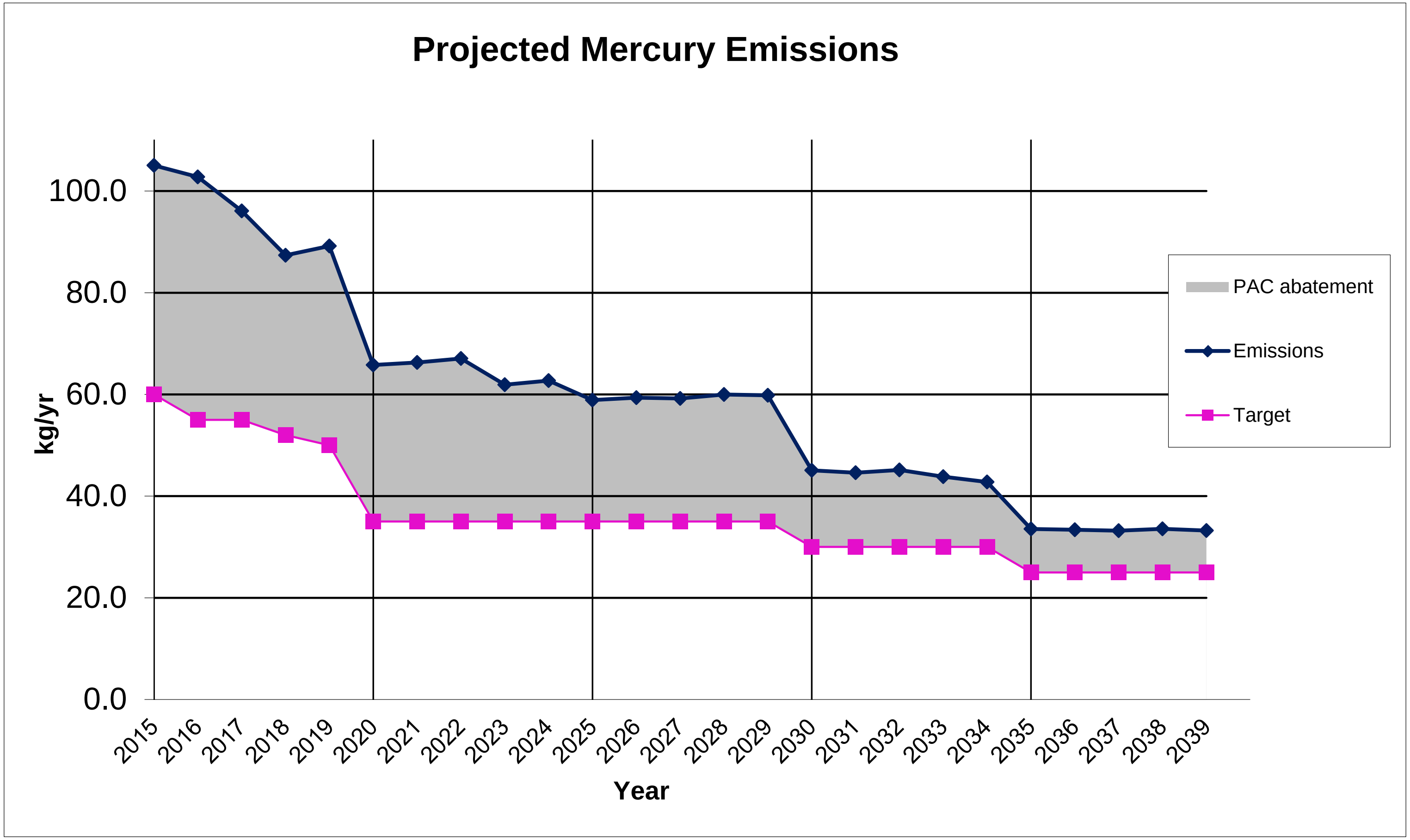
CRP3-1 Preliminary CO_2 Emissions



CRP3-1 Preliminary SO_2 Emissions



CRP3-1 Preliminary Mercury Emissions



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CRP3-5 Preliminary Results

CRP3-5 Preliminary Load and Resources

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	2036	2037	2038	2039
Firm Peak	1,963	1,986	2,000	2,020	2,041	2,066	2,077	2,097	2,118	2,147	2,159	2,251	2,345	2,364	2,383	2,403	2,422
DSM	23	54	84	110	134	156	178	202	224	247	267	412	566	593	616	643	666
Firm Peak Less DSM	1,940	1,932	1,916	1,910	1,907	1,910	1,899	1,896	1,894	1,899	1,892	1,839	1,780	1,771	1,767	1,760	1,756
RM Required	388	386	383	382	381	382	380	379	379	380	378	368	356	354	353	352	351
Required MWs	2,328	2,319	2,299	2,293	2,288	2,292	2,278	2,275	2,273	2,279	2,270	2,206	2,136	2,126	2,120	2,112	2,107
Existing MWs	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341
Resource Additions (MW):																	
Burnside #4		33															
COMFIT - Biomass	4.2	6															
COMFIT - Wind	14.14	4.56	5.1														
REA Wind	2.35	17.34															
Maritime Link				153.3													
Small Biomass PPA			10														
Hydro			1.8														
PH Biomass																	51.7
FGD Parasitic power											-8.0						
Additional Wind									18								
Assumed Unit Retirement				-153							-81		-150				-153
Natural Gas Unit									98.6								
Total Annual Additions	20.7	60.9	16.9	0.3	0.0	0.0	0.0	0.0	116.6	0.0	-89.0	0.0	-150.0	0.0	0.0	0.0	-101.3
Total Cumulative Additions	20.7	81.6	98.5	98.7	98.7	98.7	98.7	98.7	215.3	215.3	126.3	126.3	-116.7	-116.7	-116.7	-116.7	-218.0
Total Firm Capacity	2362	2423	2440	2440	2440	2440	2440	2440	2557	2557	2468	2468	2225	2225	2225	2225	2123
Surplus (Deficit) MWs above RM	34	104	141	148	152	148	162	165	284	277	198	261	89	99	104	113	16
Reserve Margin %	21.8%	25.4%	27.3%	27.7%	28.0%	27.8%	28.5%	28.7%	35.0%	34.6%	30.5%	34.2%	25.0%	25.6%	25.9%	26.4%	20.9%

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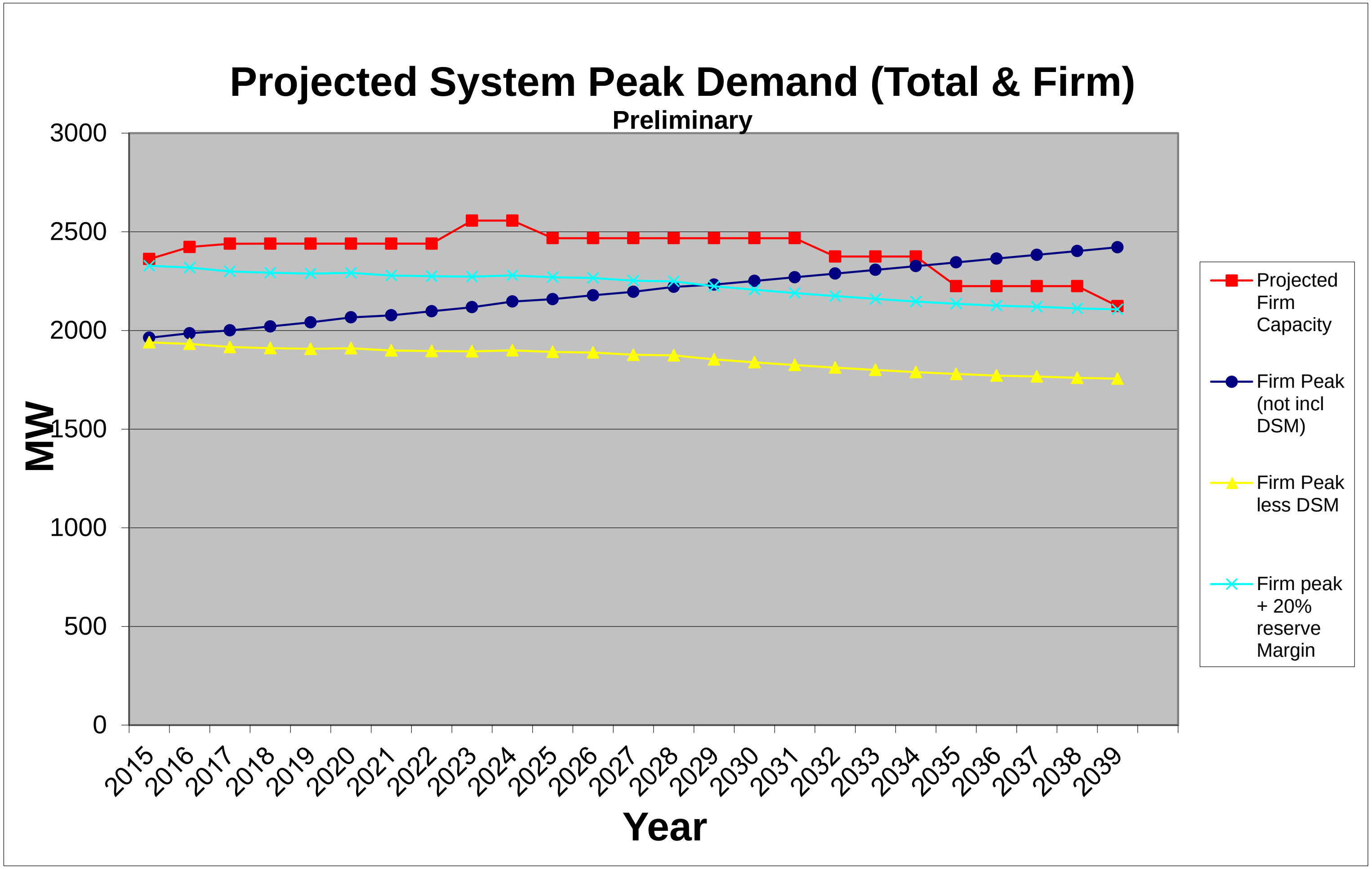
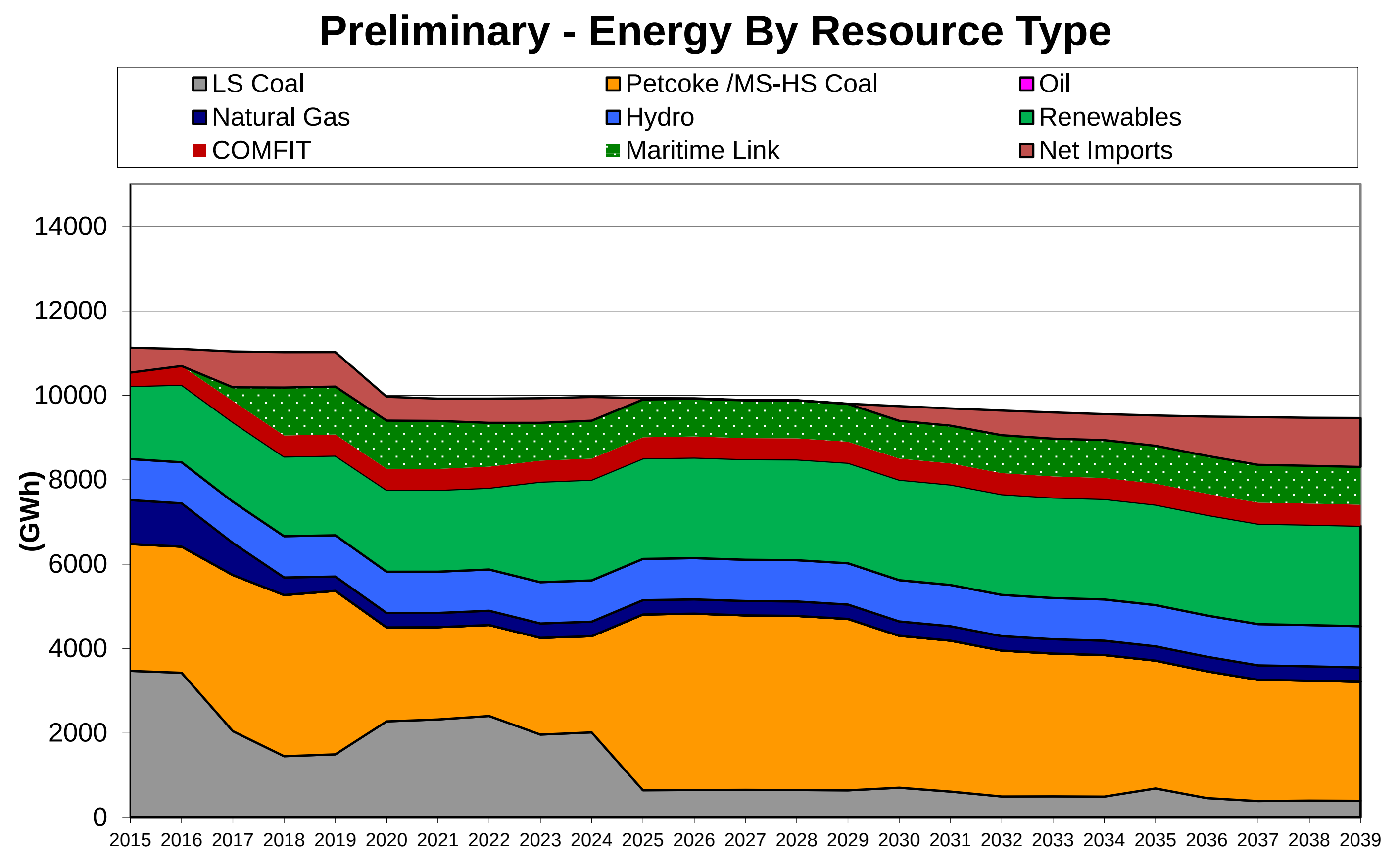
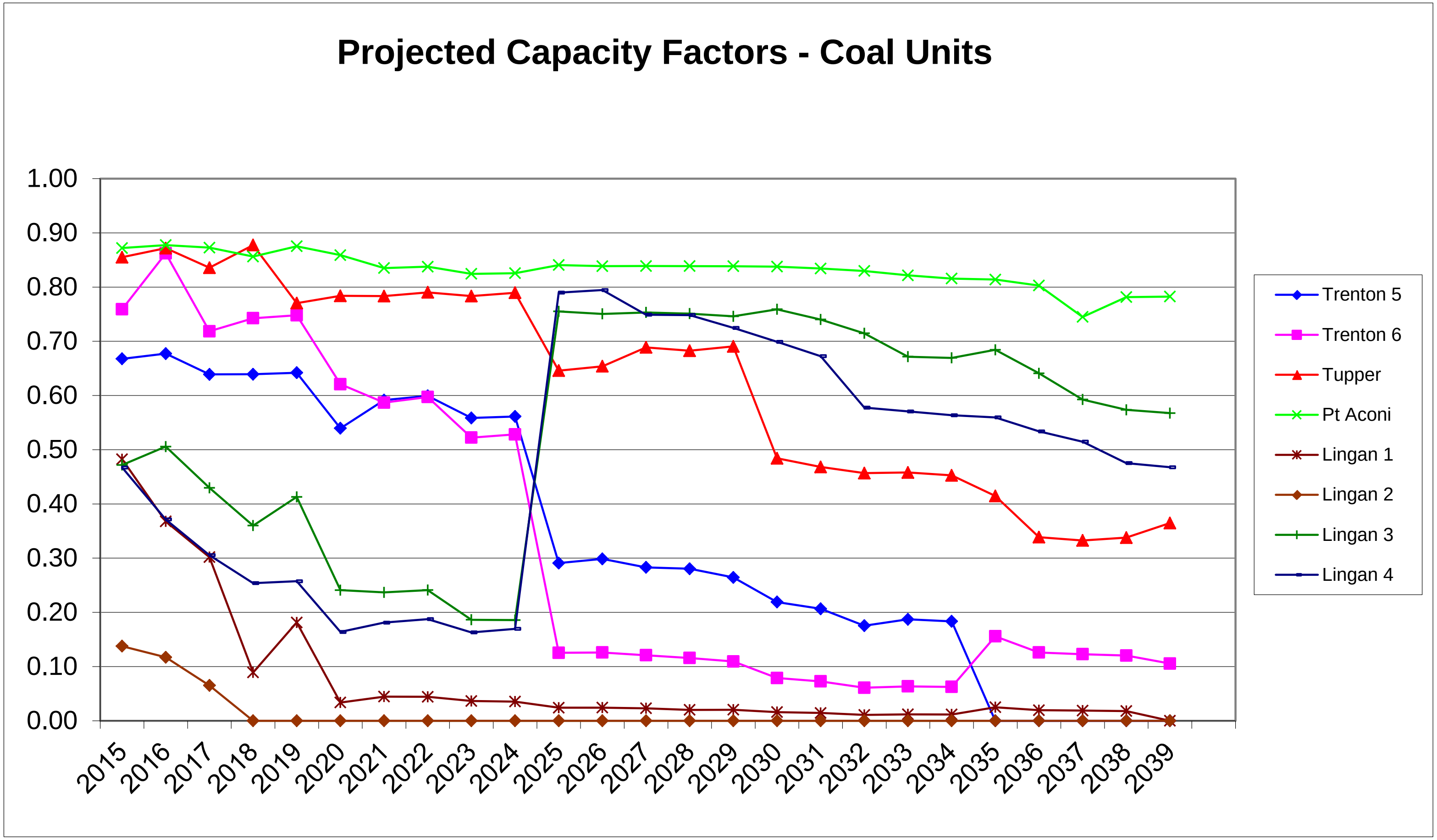
CRP3-5 Preliminary Demand and DSM



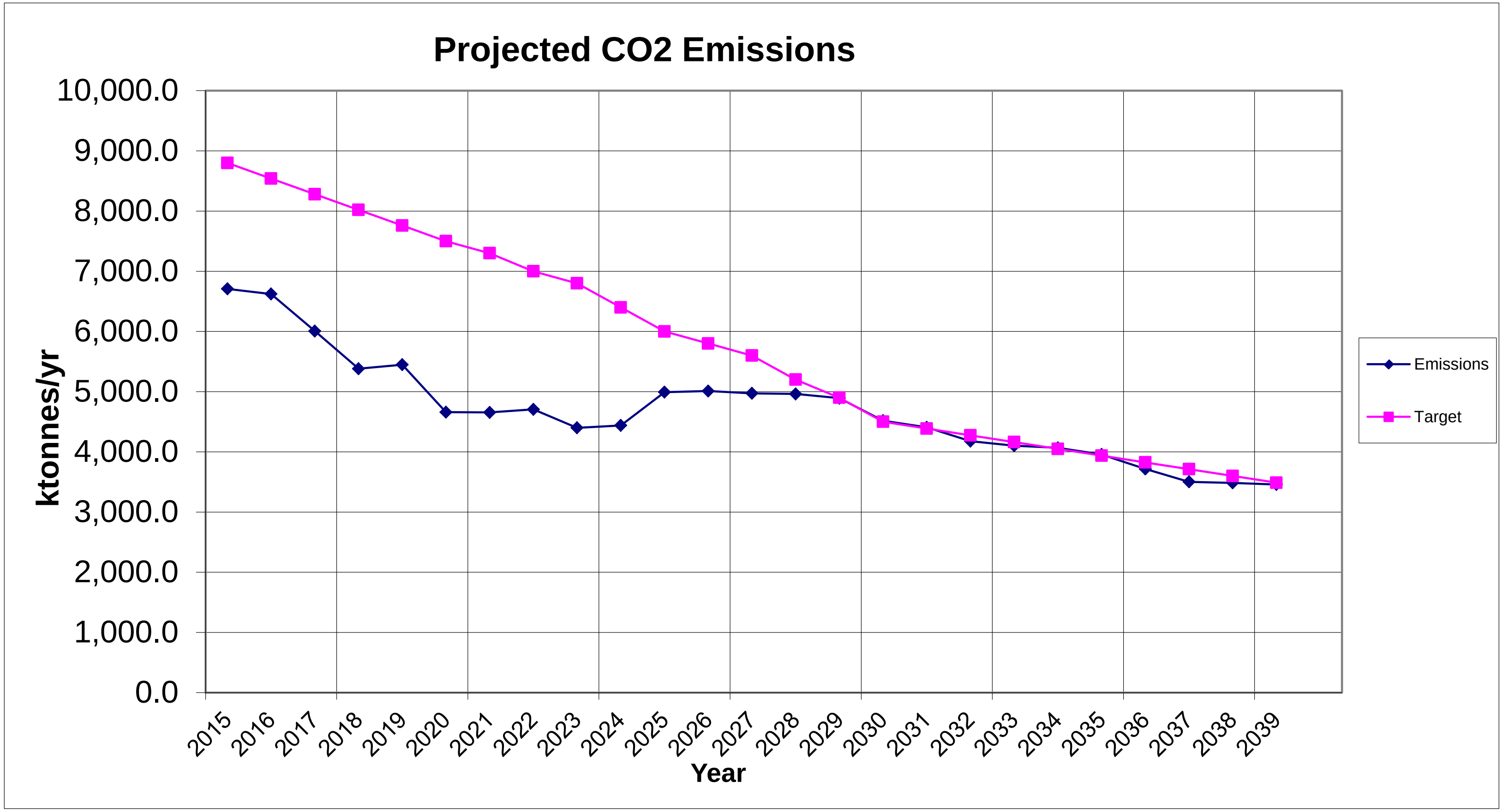
CRP3-5 Preliminary Energy by Resource Type



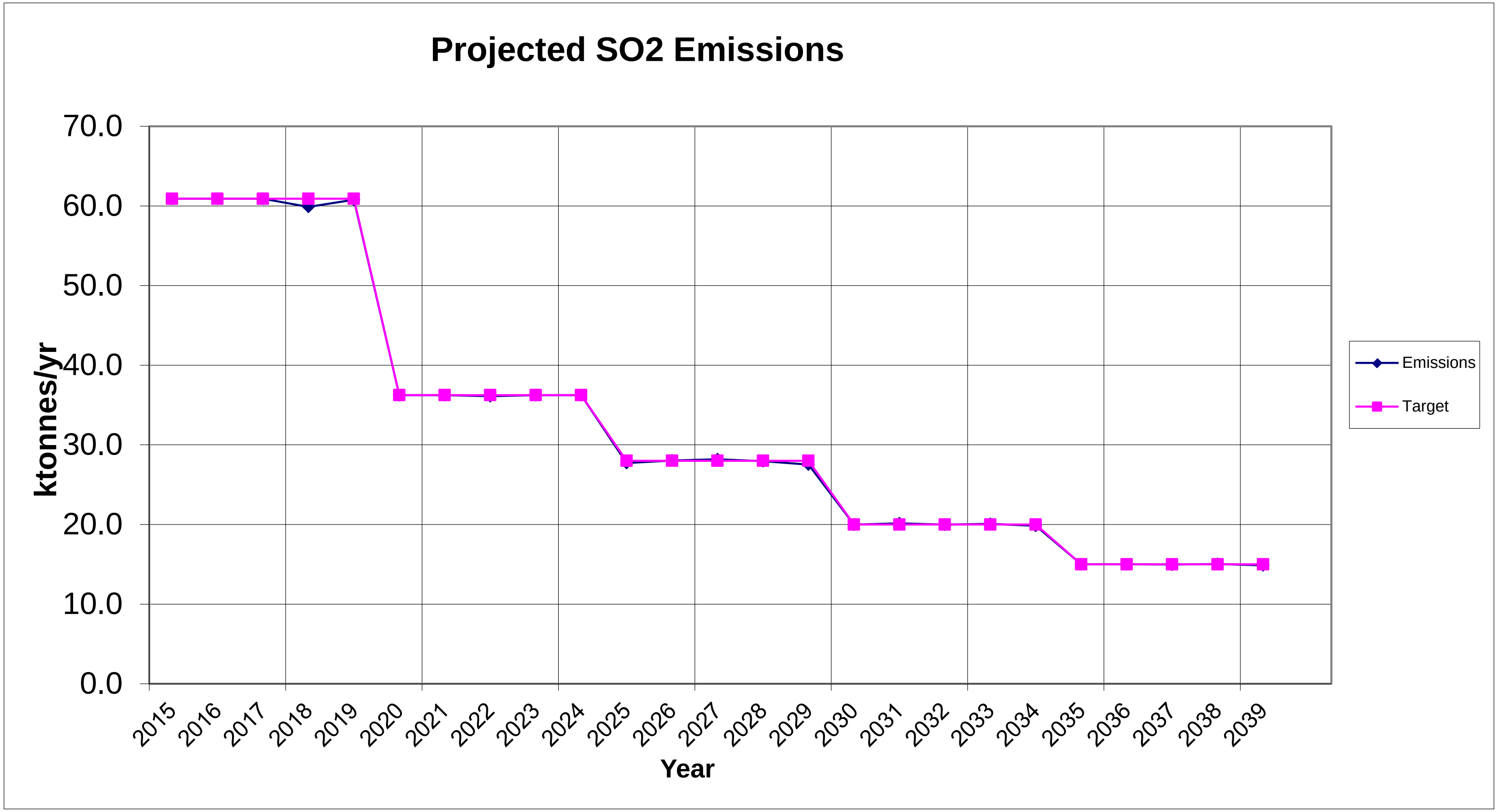
CRP3-5 Preliminary Coal Capacity Factors



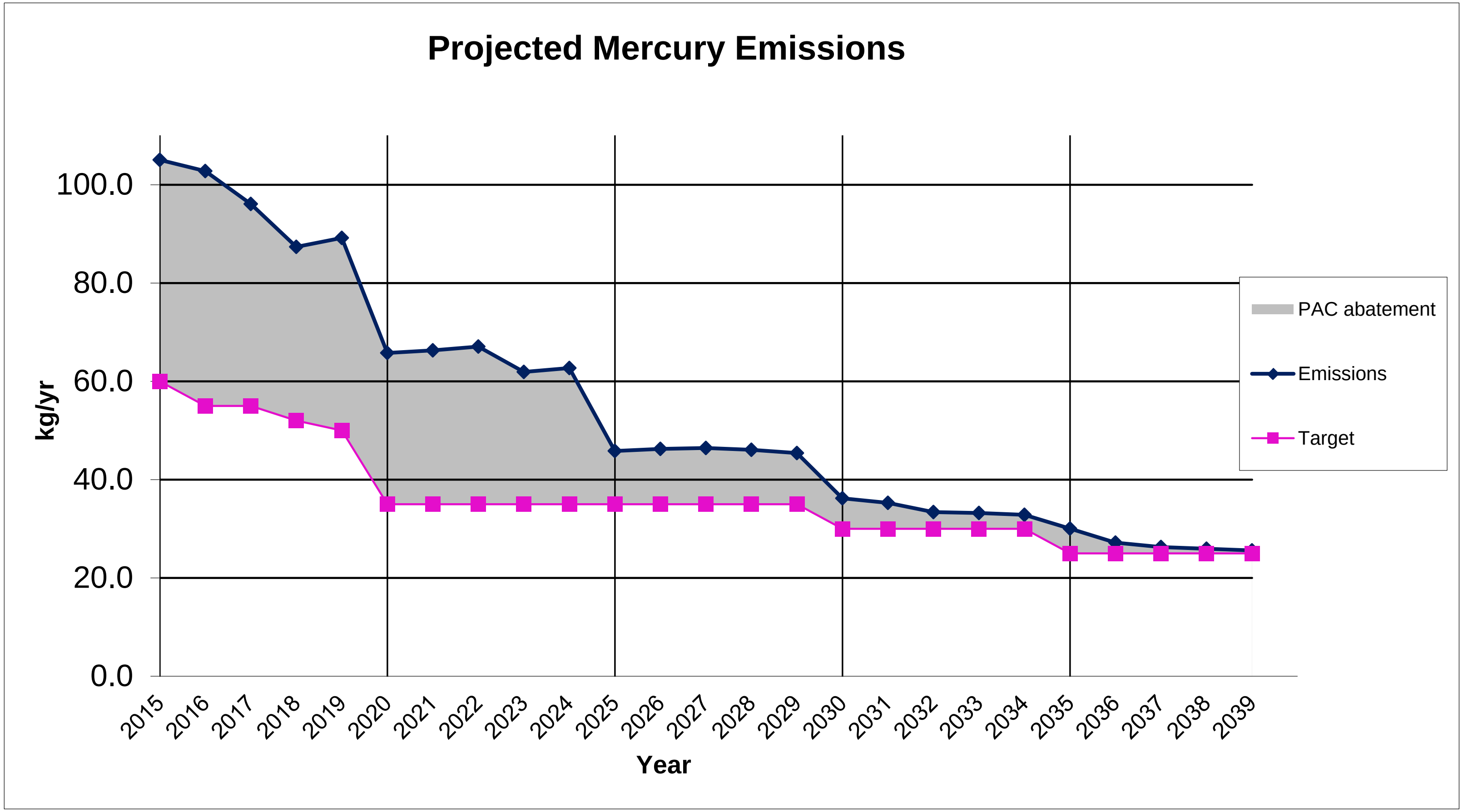
CRP3-5 Preliminary CO_2 Emissions



CRP3-5 Preliminary SO_2 Emissions



CRP3-5 Preliminary Mercury Emissions



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CRP4 Preliminary Results

CRP4 Input Assumptions

Candidate Resource Plan 4 (CRP4):

- Base Load Forecast
- Base DSM
- Emissions - Scenario A
- Planned and committed resources are fixed in the plan (REA wind, COMFIT, Maritime Link/ Retire Lin #2)
- Medium Coal Use
- Constraints
  - Planning reserve margin min = 20%
  - RES: 2015-2019 = 25%; 2020-2039 = 40%

CRP4 Preliminary Results

	CRP4-1-R01	**CRP4-1-FGD-R01**
	Least cost study period	**Least cost study period (w FGD)**
2015		
2016	DR Water H & DR Comm	DR Water H & DR Comm
2017	ML Oct 2017	ML Oct 2017
	Lin 2 retire	Lin 2 retire
2018		
2019		
2020	TUC 1 Retire	TUC 1 Retire
2021		
2022		
2023		
2024		
2025		FGD (Lin3/4 300 MW)
2026		
2027	TUC 2 Retire	TUC 2 Retire
2028		
2029		
2030	CT 34MW	
	Tre 5 Retire	Tre 5 Retire
2031	CT 50MW & CT 34MW	CC 145MW
	TUC 3 Retire	TUC 3 Retire
2032		
2033		CT 50MW
2034	CC 145MW	CT 50MW
	Lin 1 Retire	Lin 1 Retire
2035		
2036		
2037		
2038	2 x CT 50MW	
	Lin 3 Retire	
2039	CC 145MW	
	Lin 4 Retire	
Planning PV $M	11,419	11,372
Study PV $M	17,326	17,149 *
		* Study PV needs to be adjusted for retirements

	Base DSM Program Adm Cost $M	Base DSM Customer Cost $M
2015	50.7	37.9
2016	50.5	39.9
2017	50.0	41.2
2018	52.4	41.6
2019	57.0	32.2
2020	61.5	28.0
2021	56.9	28.4
2022	54.1	28.4
2023	51.5	29.2
2024	50.8	28.6
2025	50.6	29.9
2026	52.1	33.8
2027	54.8	36.8
2028	58.5	41.4
2029	60.7	34.0
2030	63.1	37.2
2031	62.6	40.6
2032	61.4	40.8
2033	59.3	41.4
2034	56.7	41.7
2035	47.7	48.4
2036	46.5	48.0
2037	45.4	47.6
2038	44.4	46.8
2039	43.5	46.3
NPV	**700.8**	**474.9**

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CRP4-1 Preliminary Results

CRP4-1 Preliminary Load and Resources

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	2036	2037	2038	2039
Firm Peak	1,963	1,986	2,000	2,020	2,041	2,066	2,077	2,097	2,118	2,147	2,159	2,251	2,345	2,364	2,383	2,403	2,422
DSM	23	54	84	110	134	156	178	202	224	247	267	412	566	593	616	643	666
Firm Peak Less DSM	1,940	1,932	1,916	1,910	1,907	1,910	1,899	1,896	1,894	1,899	1,892	1,839	1,780	1,771	1,767	1,760	1,756
DRWH Reduction	0	1	2	4	7	10	15	21	27	32	39	60	62	60	62	62	62
DRCM Reduction	0	0	1	4	7	10	14	18	20	21	24	24	24	23	24	24	24
Firm Peak Less DR	1,940	1,931	1,912	1,903	1,894	1,890	1,870	1,857	1,847	1,846	1,828	1,754	1,693	1,689	1,681	1,674	1,670
RM Required	388	386	382	381	379	378	374	371	369	369	366	351	339	338	336	335	334
Required MWs	2,328	2,317	2,295	2,283	2,272	2,269	2,244	2,229	2,216	2,215	2,194	2,105	2,032	2,026	2,017	2,009	2,004
Existing MWs	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341
Resource Additions (MW):																	
Burnside #4		33															
COMFIT - Biomass	4.2	6															
COMFIT - Wind	14.14	4.56	5.1														
REA Wind	2.35	17.34															
Maritime Link				153.25													
Small Biomass PPA			10														
Hydro			1.8														
FGD parasitic power																	
Additional Wind																	
Assumed Unit Retirement				-153		-81						-150				-158	-153
Natural Gas Unit												34				98.8	145
Total Annual Additions	20.7	60.9	16.9	0.3	0.0	-81.0	0.0	0.0	0.0	0.0	0.0	-116.0	0.0	0.0	0.0	-59.2	-8.0
Total Cumulative Additions	20.7	81.6	98.5	98.7	98.7	17.7	17.7	17.7	17.7	17.7	17.7	-191.3	-262.9	-262.9	-262.9	-322.1	-330.1
Total Firm Capacity	2362	2423	2440	2440	2440	2359	2359	2359	2359	2359	2359	2150	2079	2079	2079	2019	2011
Surplus (Deficit) MWs above RM	34	106	145	157	168	91	116	131	143	144	166	45	46	52	62	11	8
Reserve Margin %	21.8%	25.5%	27.6%	28.3%	28.9%	24.8%	26.2%	27.0%	27.7%	27.8%	29.1%	22.6%	22.7%	23.1%	23.7%	20.6%	20.5%

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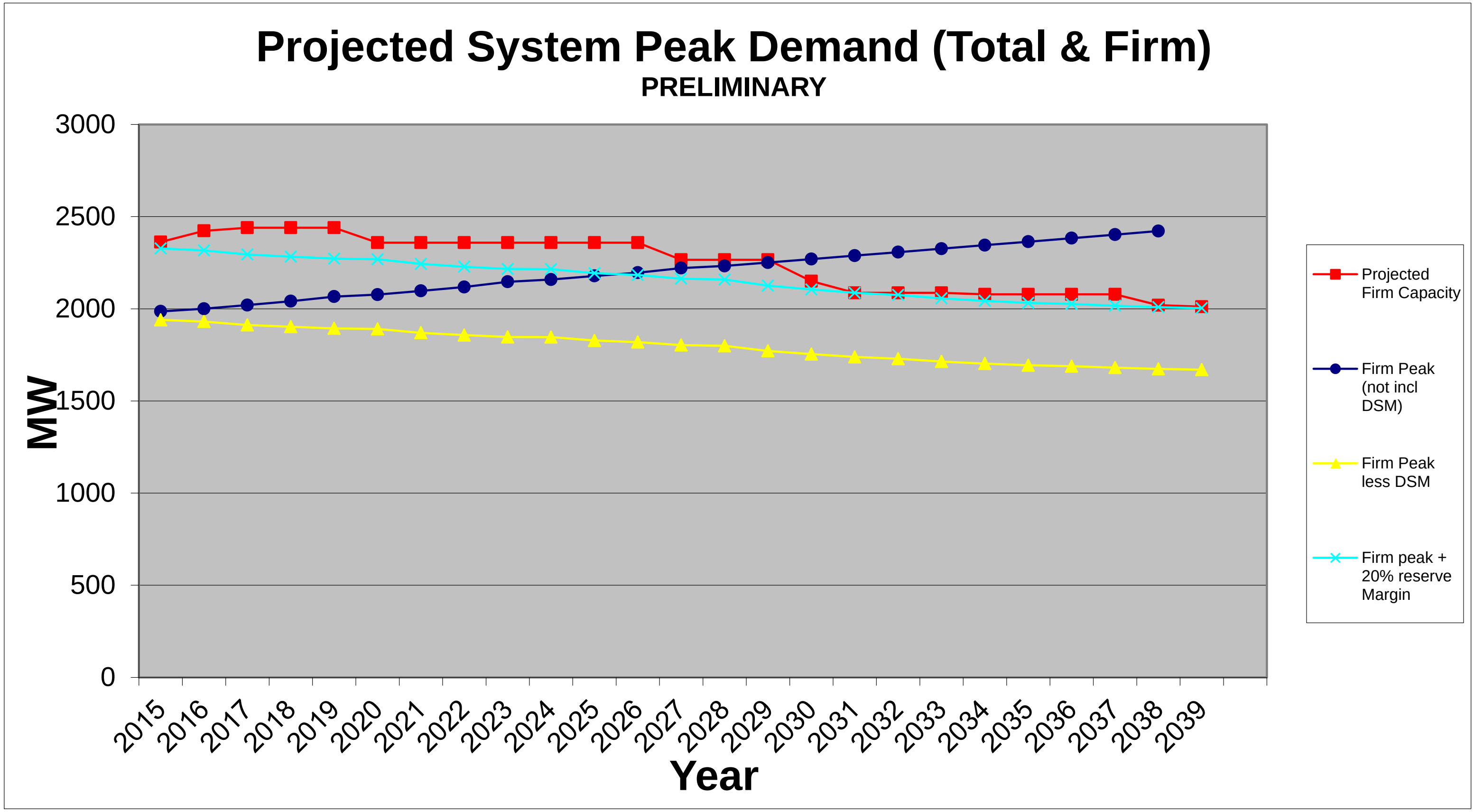
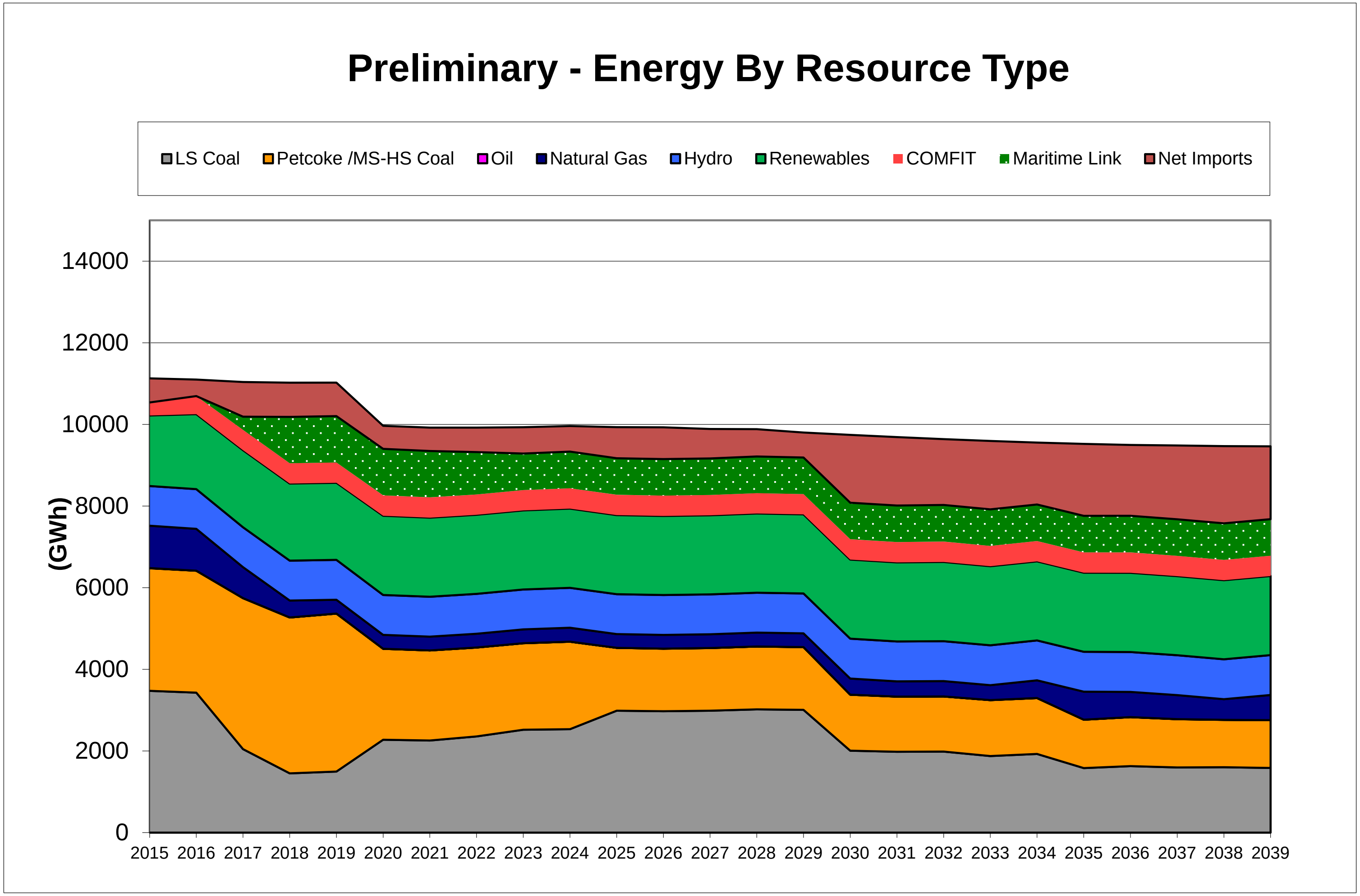
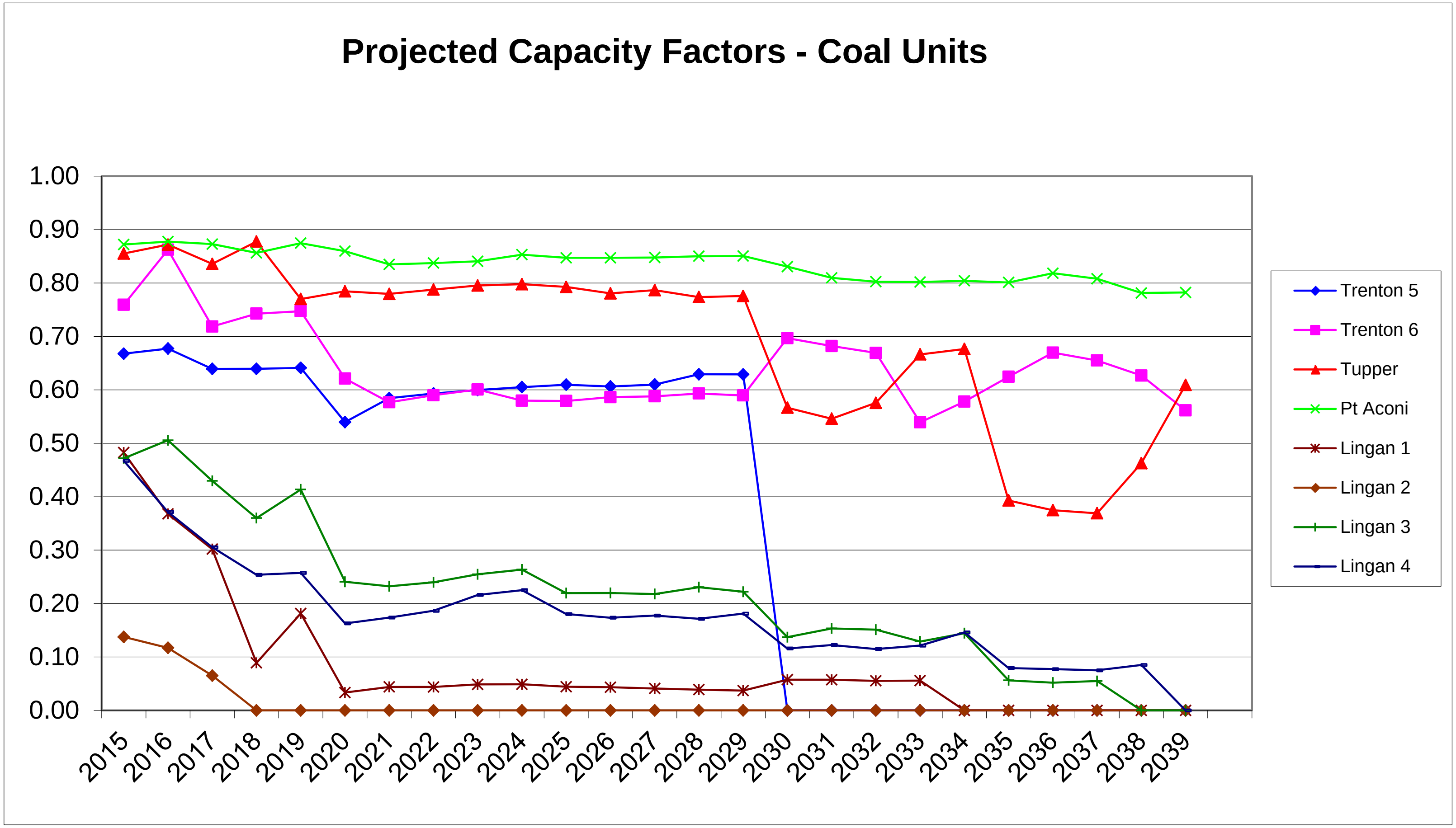
CRP4-1 Preliminary Demand and DSM



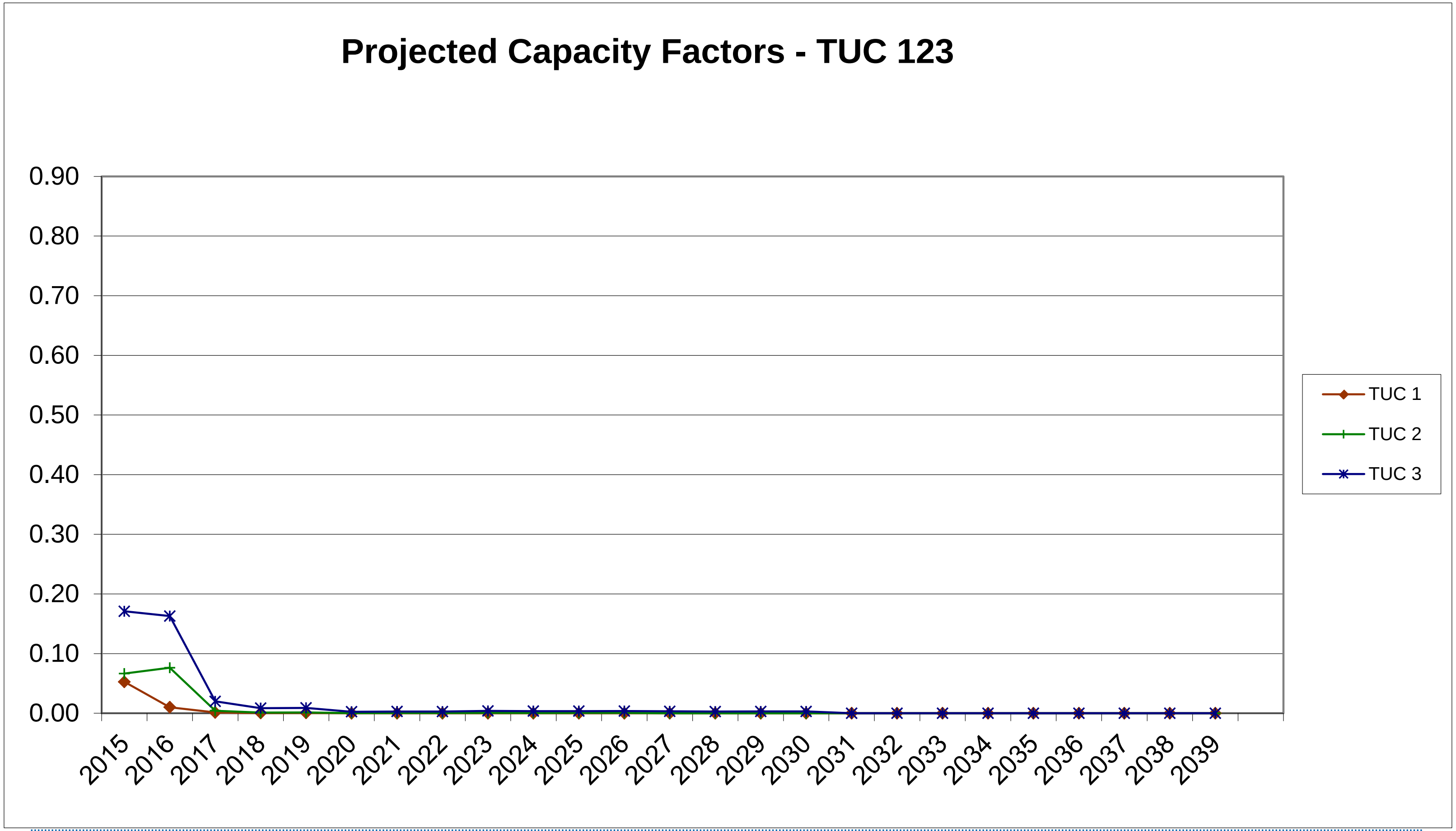
CRP4-1 Preliminary Energy by Resource Type



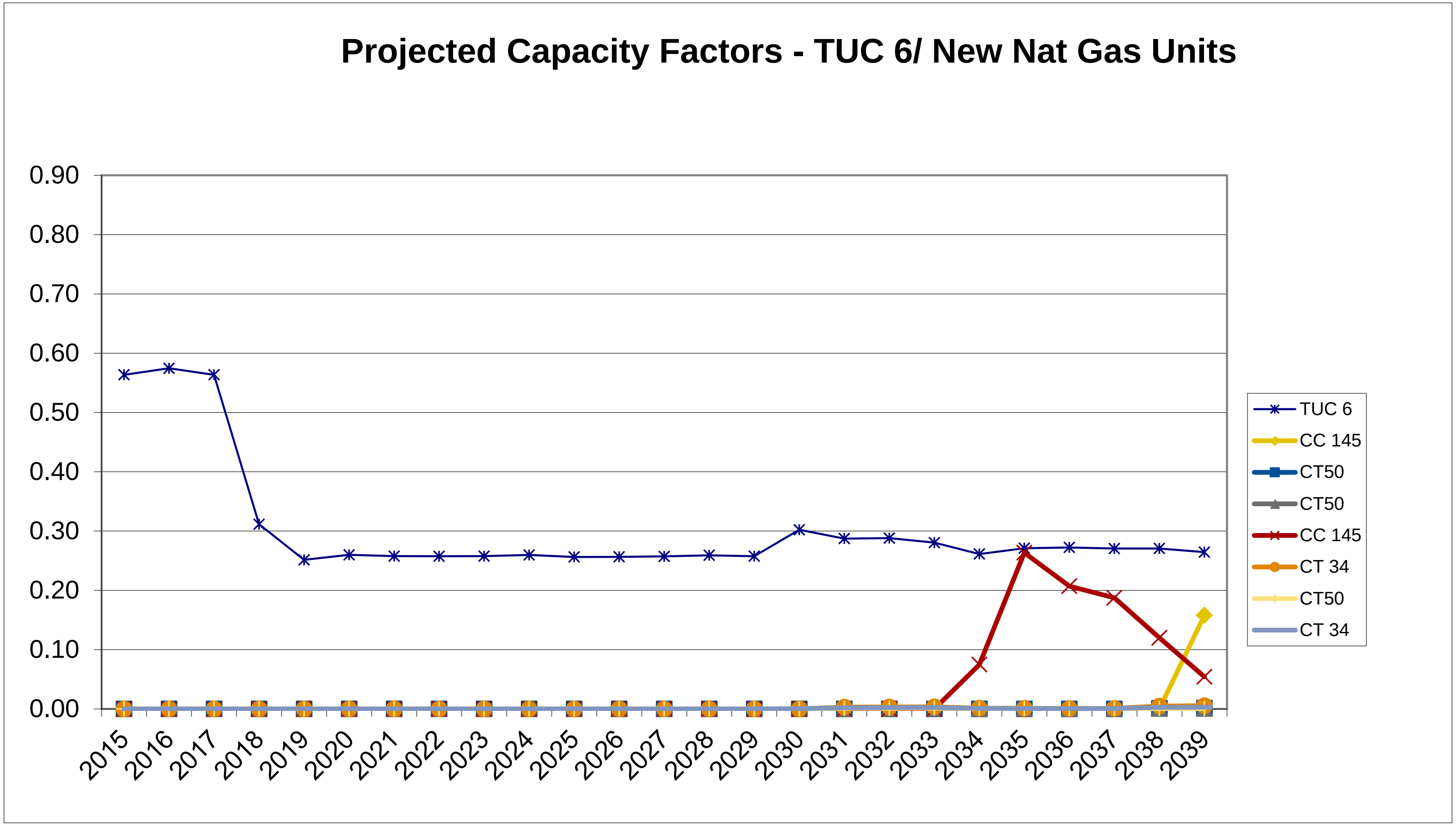
CRP4-1 Preliminary Coal Capacity Factors



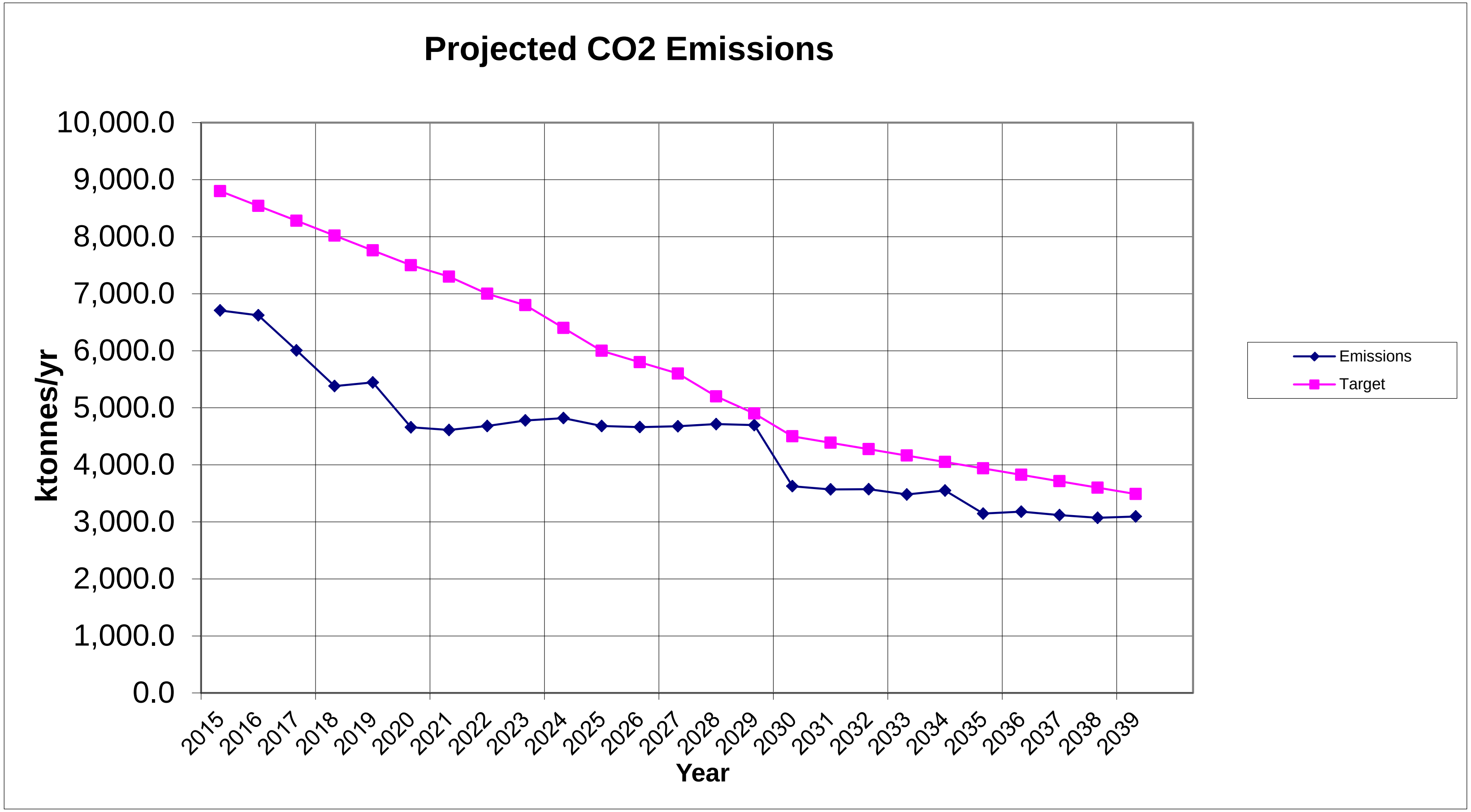
CRP4-1 Preliminary TUC Capacity Factors



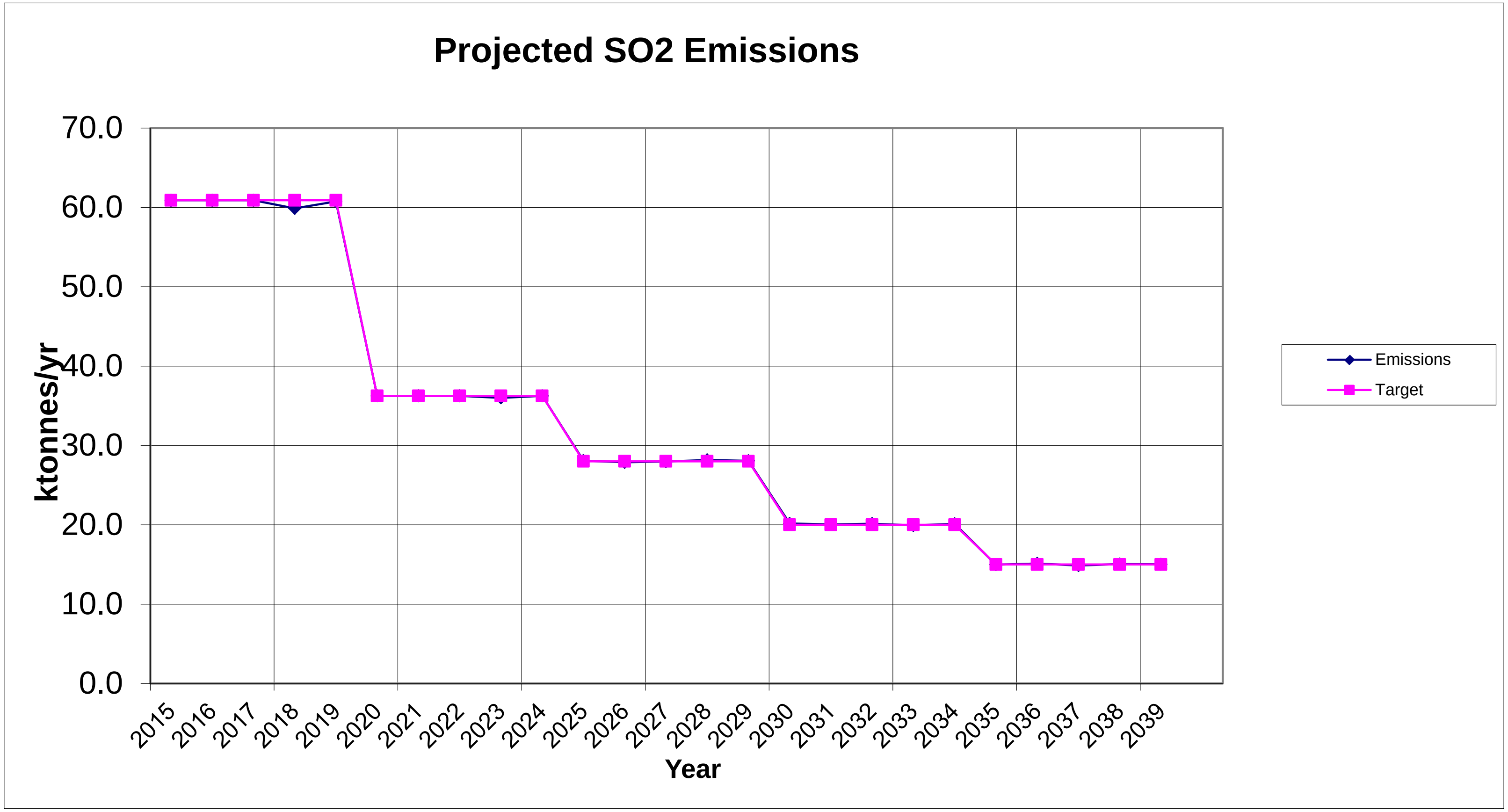
CRP4-1 Preliminary CT/CC Capacity Factors



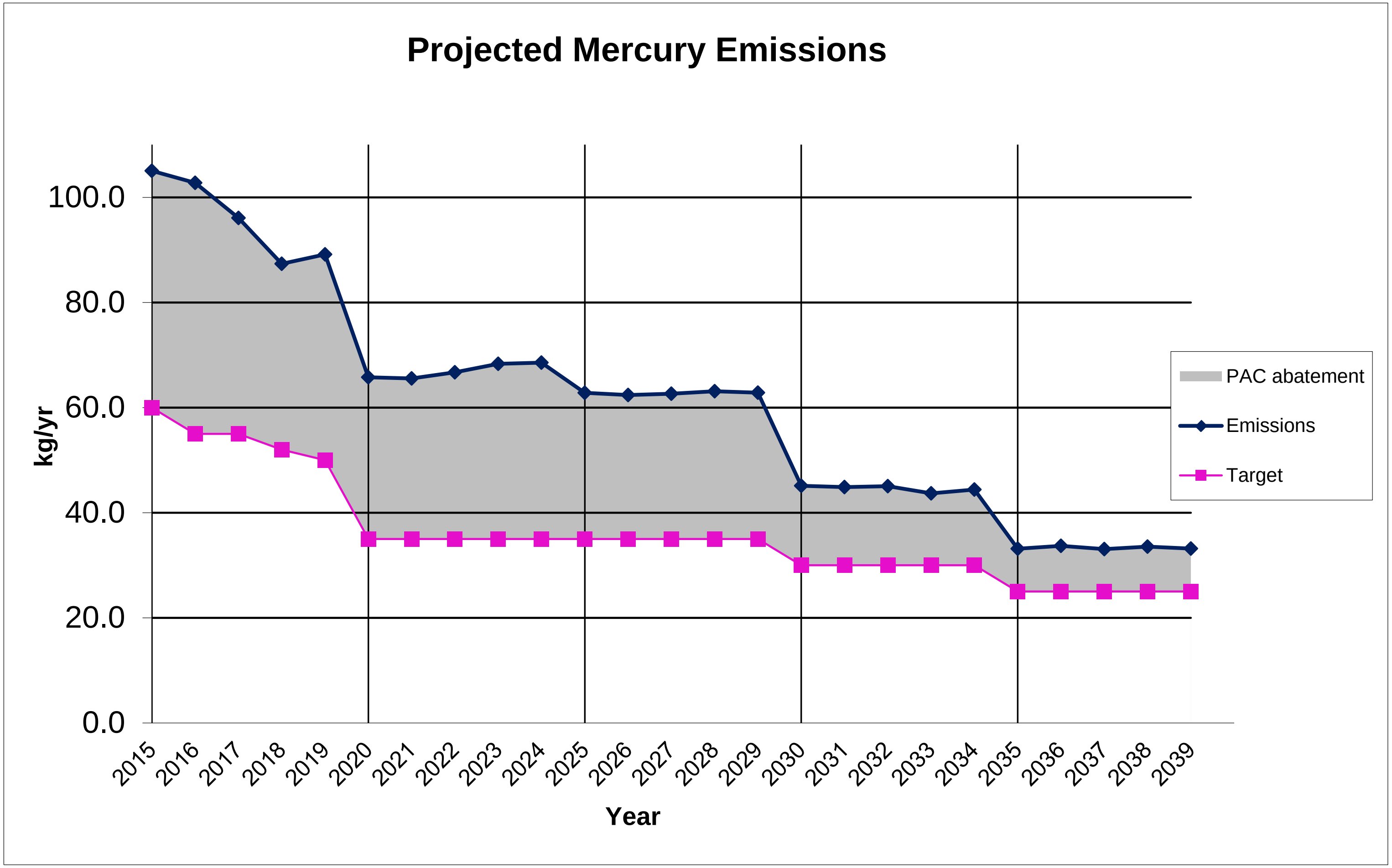
CRP4-1 Preliminary CO_2 Emissions



CRP4-1 Preliminary SO_2 Emissions



CRP4-1 Preliminary Mercury Emissions



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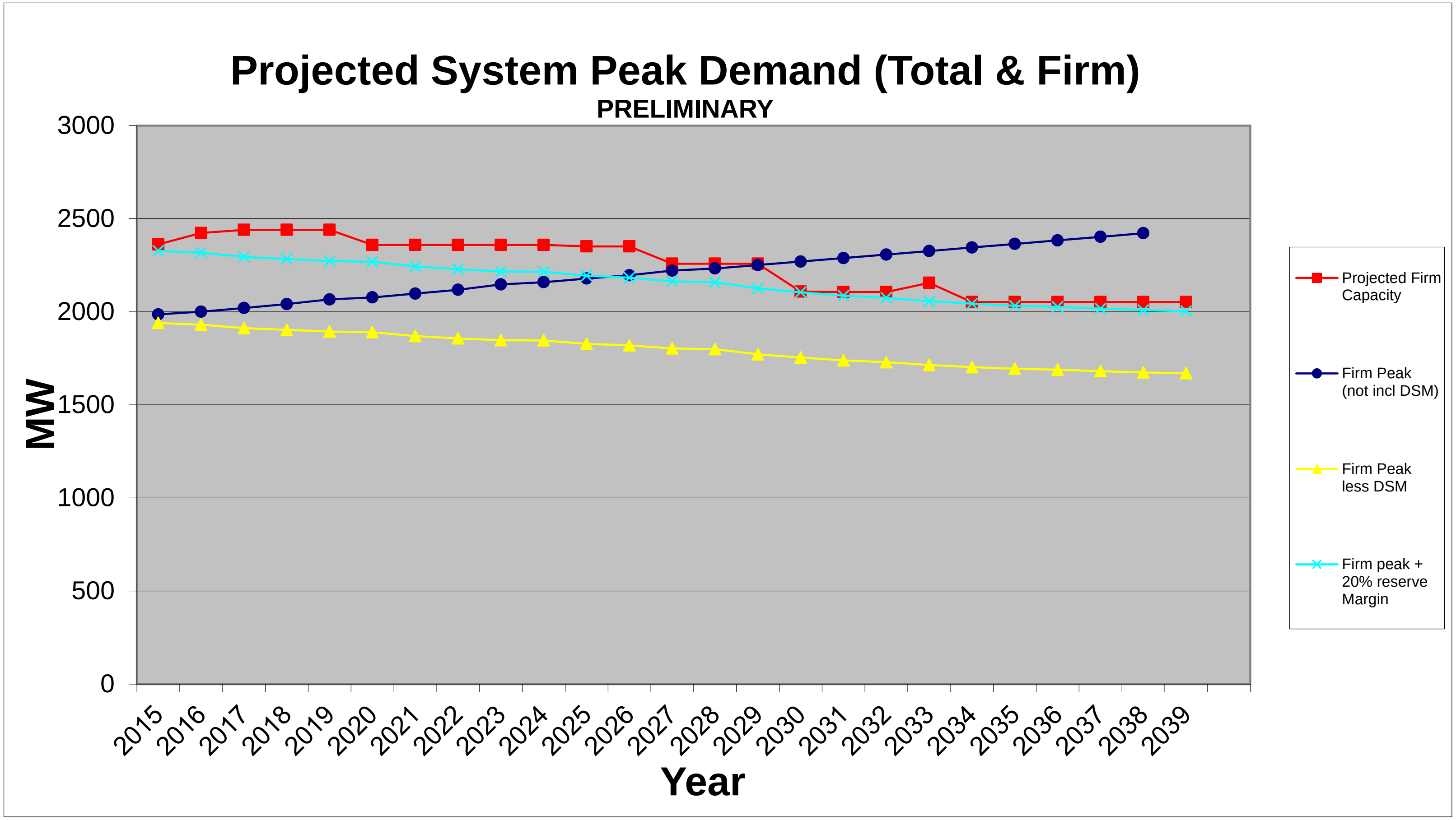
CRP4-1-FGD Preliminary Results

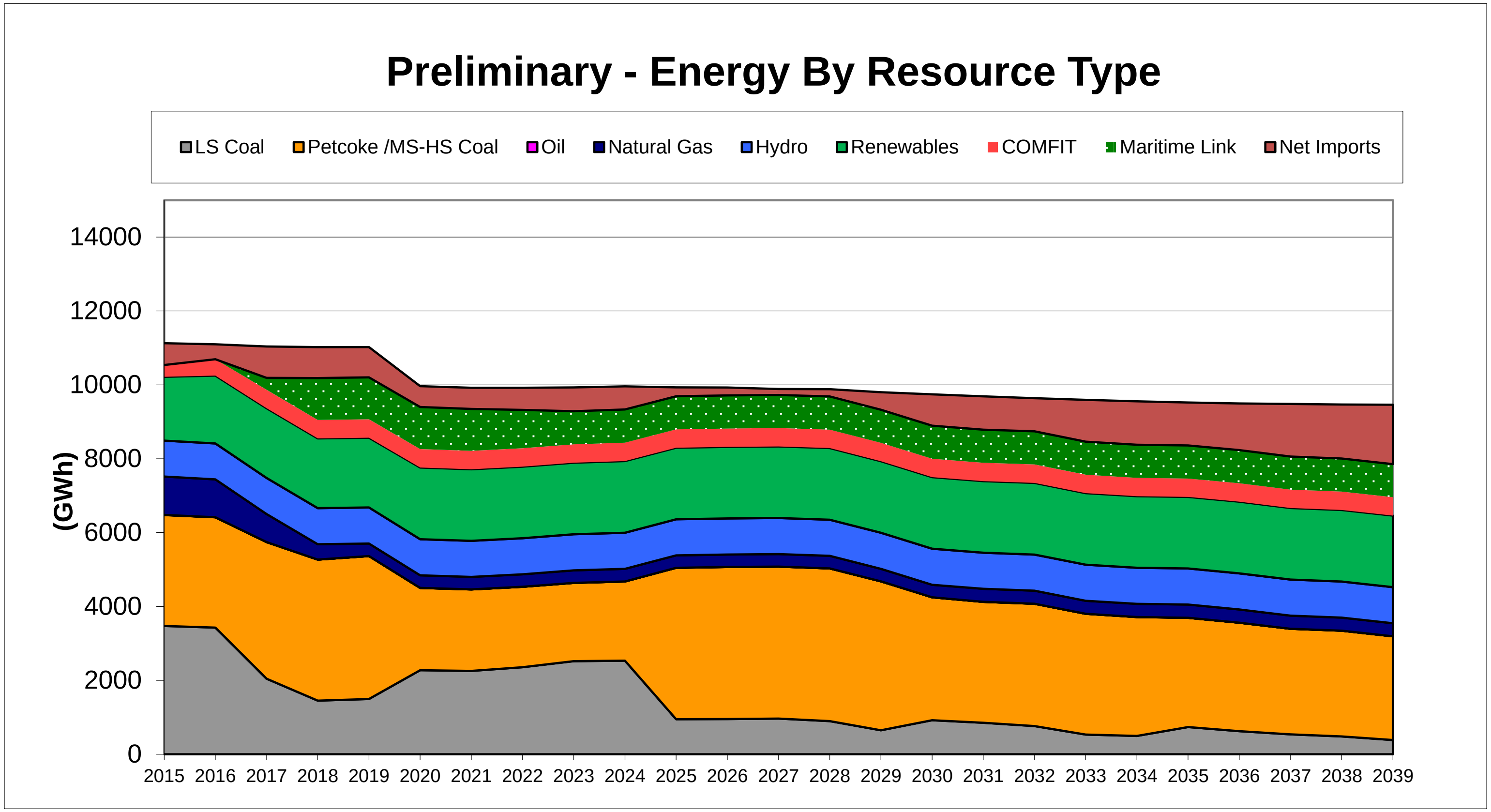
CRP4-1-FGD Preliminary Load and Resources

	2015	2016	2017	2018	2019	2020	2025	2030	2035	2036	2037	2038	2039
Firm Peak	1,963	1,986	2,000	2,020	2,041	2,066	2,159	2,251	2,345	2,364	2,383	2,403	2,422
DSM	23	54	84	110	134	156	267	412	566	593	616	643	666
Firm Peak Less DSM	1,940	1,932	1,916	1,910	1,907	1,910	1,892	1,839	1,780	1,771	1,767	1,760	1,756
DRWH Reduction	0	1	2	4	7	10	39	60	62	60	62	62	62
DRCM Reduction	0	0	1	4	7	10	24	24	24	23	24	24	24
Firm Peak Less DR	1,940	1,931	1,912	1,903	1,894	1,890	1,828	1,754	1,693	1,689	1,681	1,674	1,670
RM Required	388	386	382	381	379	378	366	351	339	338	336	335	334
Required MWs	2,328	2,317	2,295	2,283	2,272	2,269	2,194	2,105	2,032	2,026	2,017	2,009	2,004
Existing MWs	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341
Resource Additions (MW):													
Burnside #4		33											
COMFIT - Biomass	4.2	6											
COMFIT - Wind	14.14	4.56	5.1										
REA Wind	2.35	17.34											
Maritime Link				153									
Small Biomass PPA			10										
Hydro			1.8										
FGD parasitic power							-8.0						
Additional Wind													
Assumed Unit Retirement				-153		-81		-150					
Natural Gas Unit													
Total Annual Additions	20.7	60.9	16.9	0.3	0.0	-81.0	-8.0	-150.0	0.0	0.0	0.0	0.0	0.0
Total Cumulative Additions	20.7	81.6	98.5	98.7	98.7	17.7	9.7	-233.3	-289.5	-289.5	-289.5	-289.5	-289.5
Total Firm Capacity	2362	2423	2440	2440	2440	2359	2351	2108	2052	2052	2052	2052	2052
Surplus (Deficit) MWs above RM	34	106	145	157	168	91	158	3	20	26	35	43	48
Reserve Margin %	21.8%	25.5%	27.6%	28.3%	28.9%	24.8%	28.6%	20.2%	21.2%	21.5%	22.1%	22.6%	22.9%

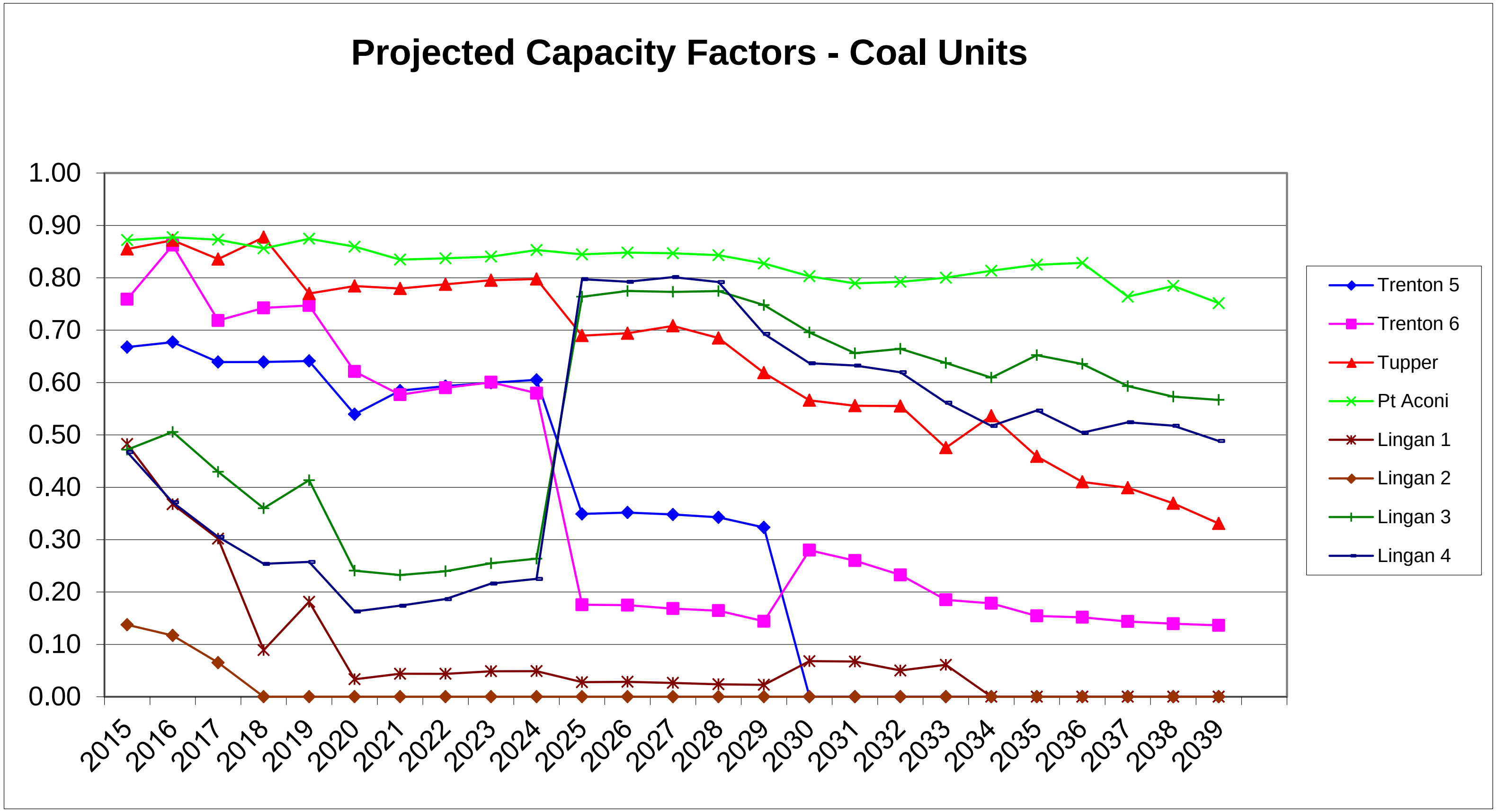
CRP4-1-FGD Preliminary Demand and DSM



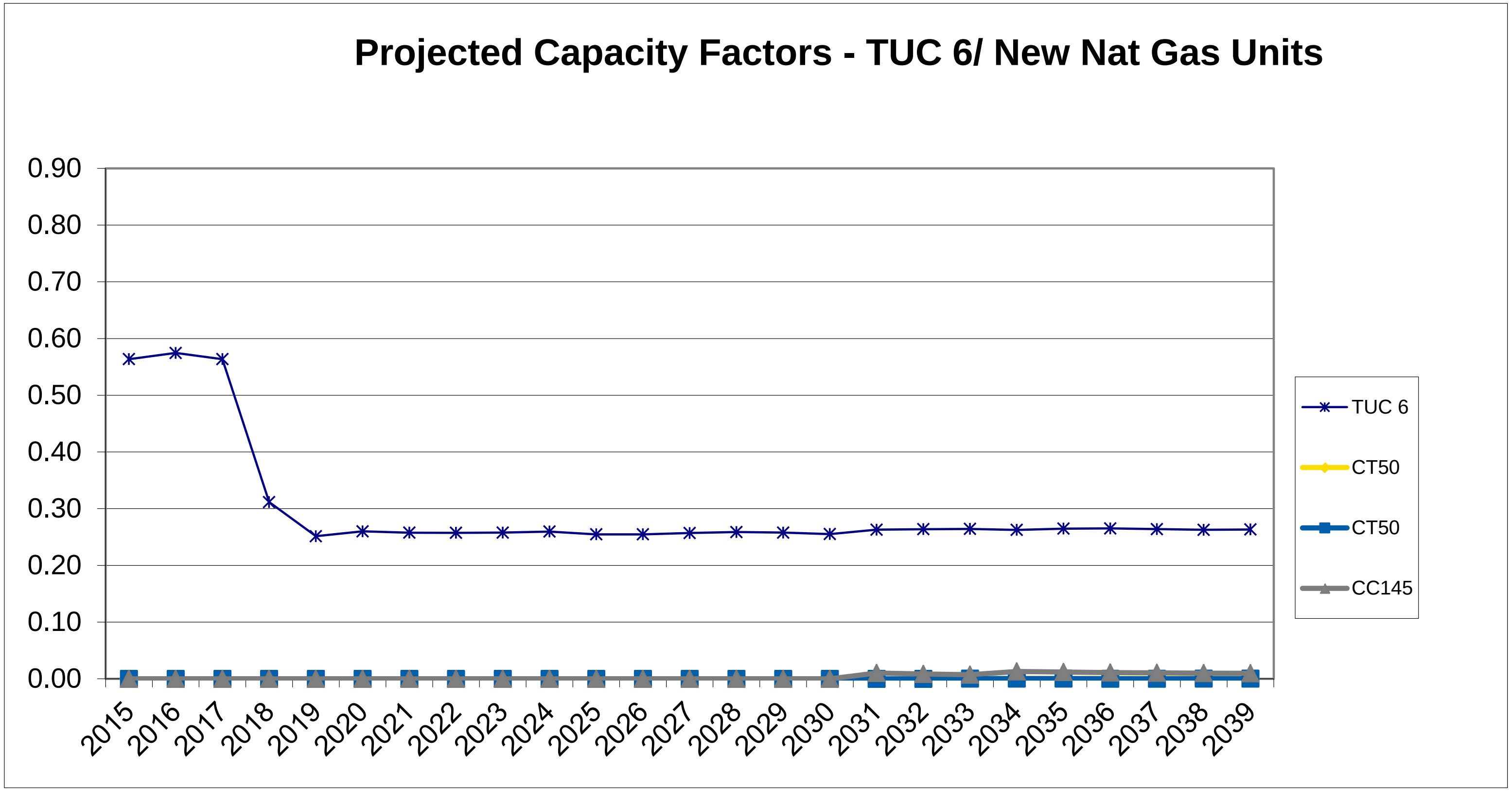
CRP4-1-FGD Preliminary Energy by Resource Type



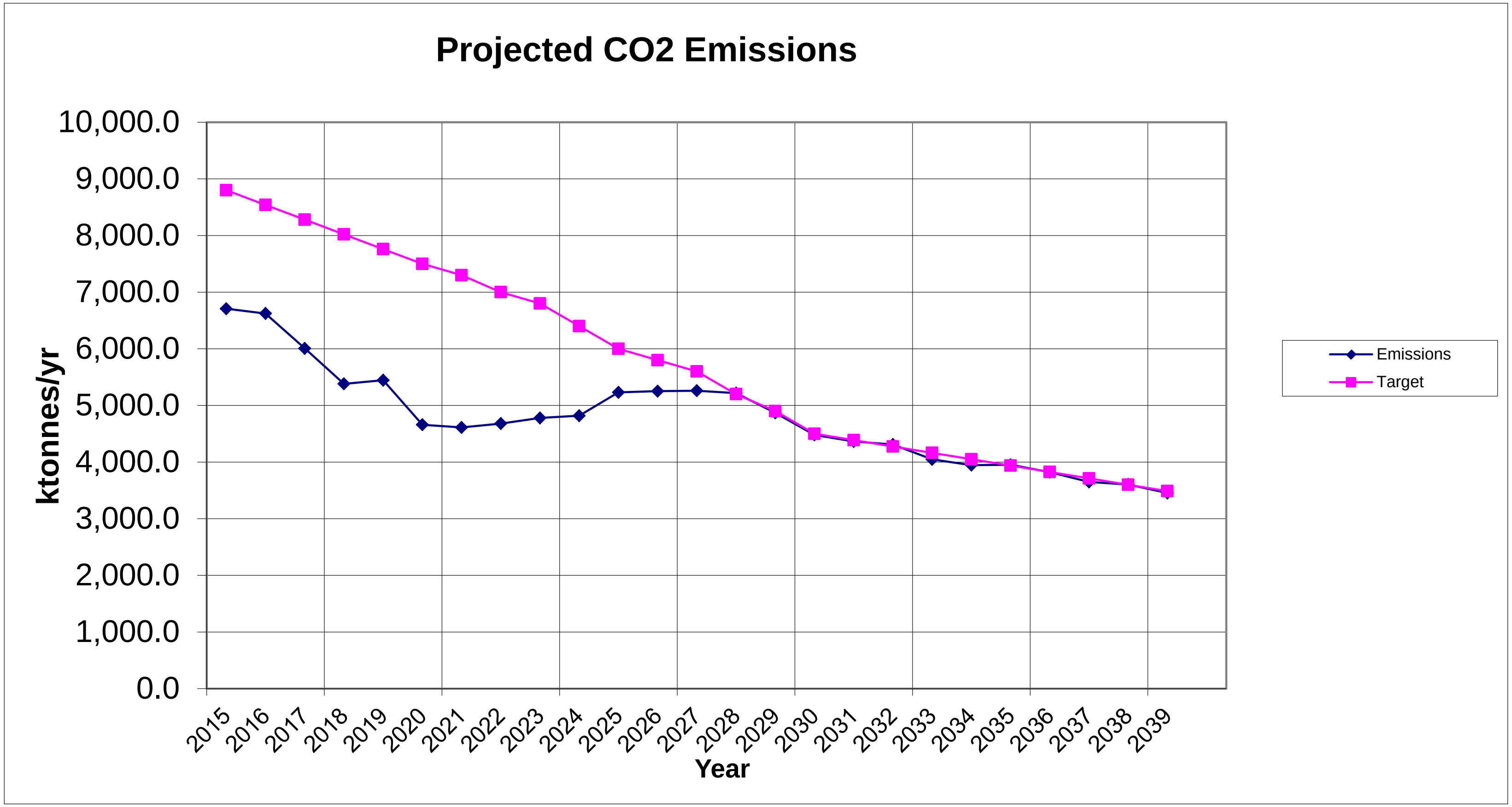
CRP4-1-FGD Preliminary Coal Capacity Factors



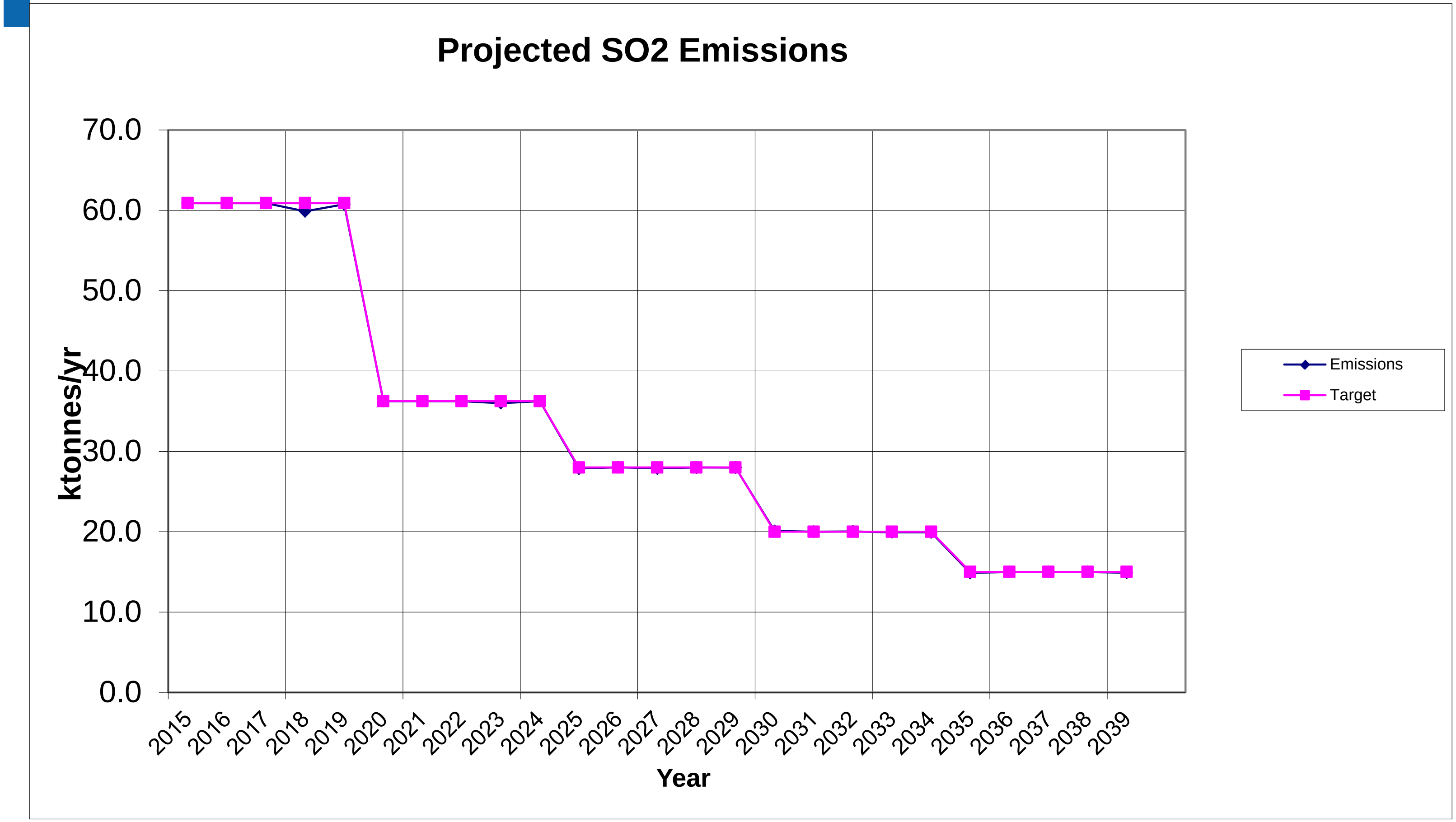
CRP4-1-FGD Preliminary CT/CC Capacity Factors



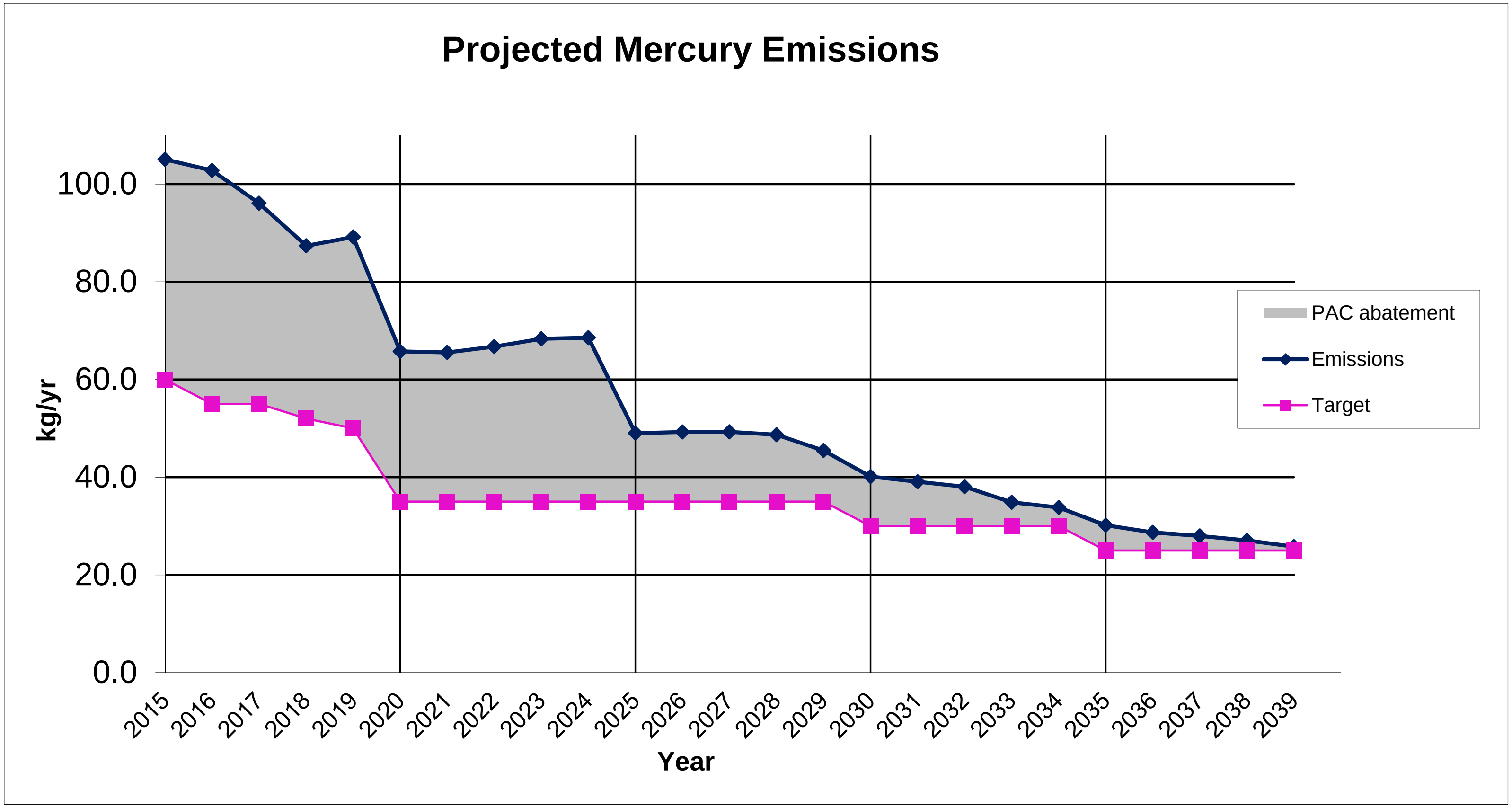
CRP4-1-FGD Preliminary CO_2 Emissions



CRP4-1-FGD Preliminary SO_2 Emissions



CRP4-1-FGD Preliminary Mercury Emissions



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CRP5 Preliminary Results

CRP5 Input Assumptions

Candidate Resource Plan 5 (CRP5):

- Base Load Forecast
- High DSM
- Emissions - Scenario A
- Planned and committed resources are fixed in the plan (REA wind, COMFIT, Maritime Link/ Retire Lin #2)
- Maximum Coal Use
- Constraints
  - Planning reserve margin min = 20%
  - RES: 2015-2019 = 25%; 2020-2039 = 40%

CRP5 Preliminary Results

	CRP5-01-R01	CRP5-08-R01
	Least cost study period	**Least cost Planning period**
2015		
2016		
2017	ML Oct 2017	ML Oct 2017
	Lin 2 retire	Lin 2 retire
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025	TUC 1 Retire	TUC 1 Retire
2026		
2027		
2028		
2029		
2030		FGD (LIN 3/4 300MW)
2031		
2032	TUC 2 Retire	TUC 2 Retire
2033		
2034		
2035		
	Tre 5 Retire	Tre 5 Retire
2036		
2037		
2038		
2039	PHBM 51.7 MW Firm	PHBM 51.7 MW Firm
	Lin 1 Retire	Lin 1 Retire
Planning PV $M	11,816	11,810
Study PV $M	16,767	16,855

	High DSM	High DSM
	Program Adm Cost	Customer Cost
	$M	$M
2015	76.3	68.0
2016	92.0	85.6
2017	104.6	98.6
2018	107.4	96.8
2019	112.8	82.2
2020	119.3	79.8
2021	106.9	75.1
2022	102.2	72.6
2023	99.0	72.7
2024	104.0	77.6
2025	110.9	86.2
2026	118.6	97.0
2027	121.1	99.5
2028	120.4	100.7
2029	114.5	83.0
2030	106.5	78.7
2031	94.6	73.6
2032	85.9	68.0
2033	65.8	64.8
2034	61.1	61.8
2035	56.6	59.6
2036	52.4	57.8
2037	49.6	56.8
2038	44.2	57.0
2039	43.4	56.7
NPV	**1,260.6**	**1,037.2**

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CRP5-1 Preliminary Results

CRP5-1 Preliminary Load and Resources

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	2036	2037	2038	2039
Firm Peak	1,963	1,986	2,000	2,020	2,041	2,066	2,077	2,097	2,118	2,147	2,159	2,251	2,345	2,364	2,383	2,403	2,422
DSM	33	78	127	168	205	241	275	311	345	383	416	628	788	813	836	861	884
Firm Peak Less DSM	1,930	1,908	1,874	1,852	1,836	1,826	1,802	1,786	1,773	1,764	1,743	1,623	1,557	1,551	1,548	1,542	1,538
RM Required	386	382	375	370	367	365	360	357	355	353	349	325	311	310	310	308	308
Required MWs	2,316	2,289	2,248	2,223	2,204	2,191	2,162	2,144	2,127	2,117	2,091	1,948	1,869	1,861	1,857	1,850	1,846
Existing MWs	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341
Resource Additions (MW):																	
Burnside #4		33															
COMFIT - Biomass	4.2	6															
COMFIT - Wind	14.14	4.56	5.1														
REA Wind	2.35	17.34															
Maritime Link				153.3													
Small Biomass PPA			10														51.7
Hydro			1.8														
Additional Wind																	
Assumed Unit Retirement				-153							-81		-150				-153
Natural Gas Unit																	
Total Annual Additions	20.7	60.9	16.9	0.3	0.0	0.0	0.0	0.0	0.0	0.0	-81.0	0.0	-150.0	0.0	0.0	0.0	-101.3
Total Cumulative Additions	20.7	81.6	98.5	98.7	98.7	98.7	98.7	98.7	98.7	98.7	17.7	17.7	-225.3	-225.3	-225.3	-225.3	-326.6
Total Firm Capacity	2362	2423	2440	2440	2440	2440	2440	2440	2440	2440	2359	2359	2116	2116	2116	2116	2015
Surplus (Deficit) MWs above RM	46	134	192	217	236	249	278	296	313	323	268	411	247	255	259	266	169
Reserve Margin %	22.4%	27.0%	30.2%	31.7%	32.9%	33.6%	35.4%	36.6%	37.7%	38.3%	35.4%	45.3%	35.9%	36.4%	36.7%	37.2%	31.0%

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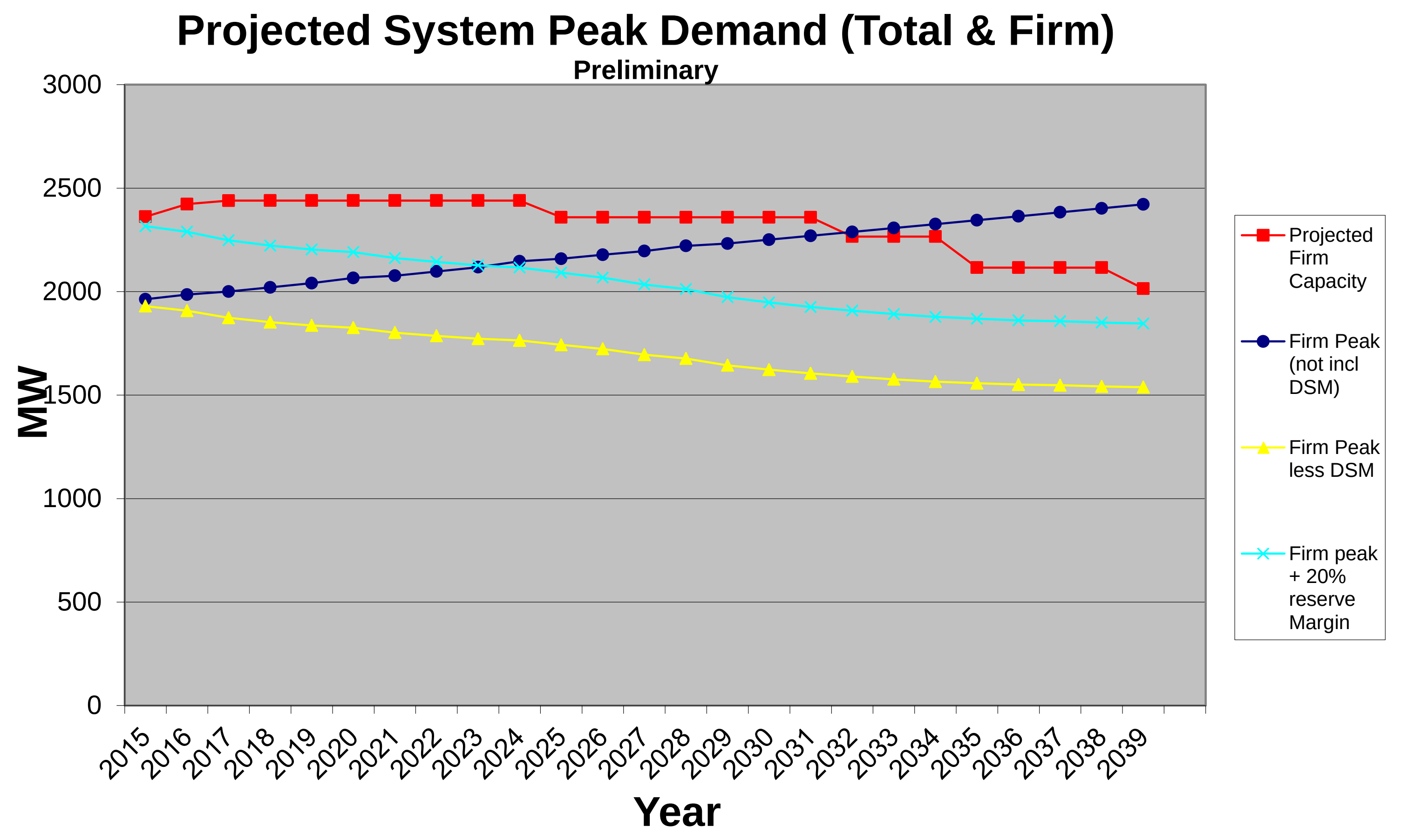
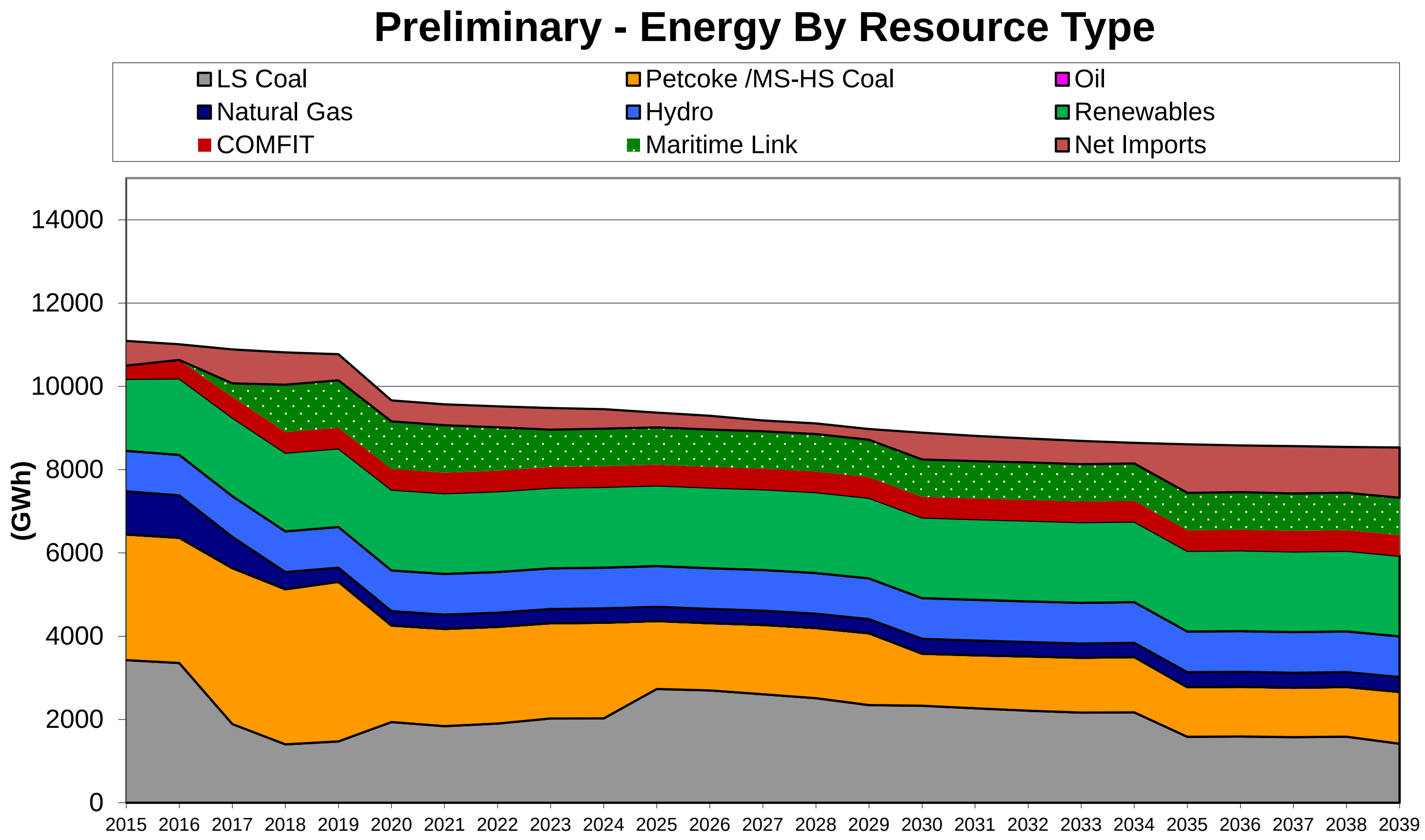
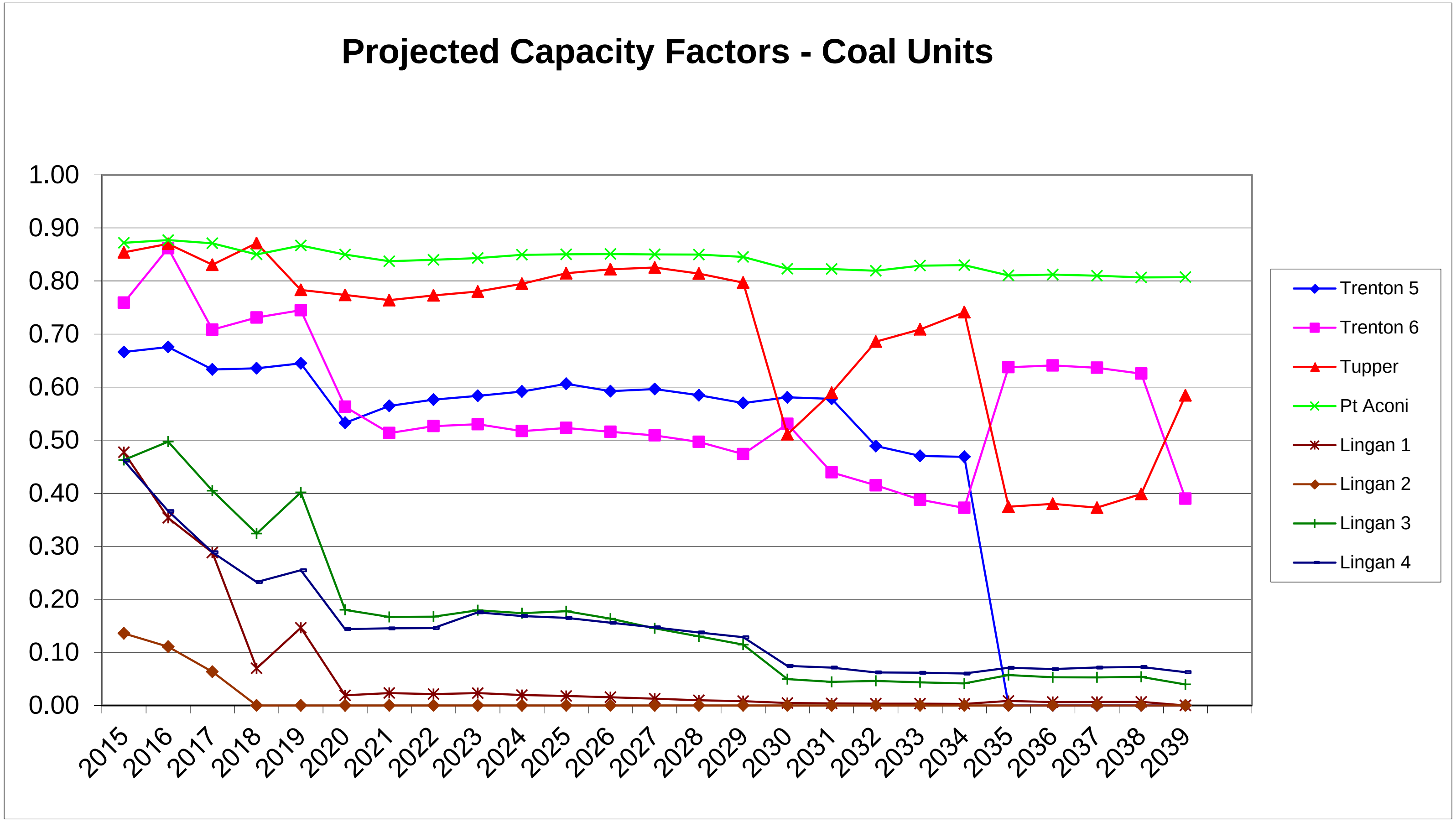
CRP5-1 Preliminary Demand and DSM



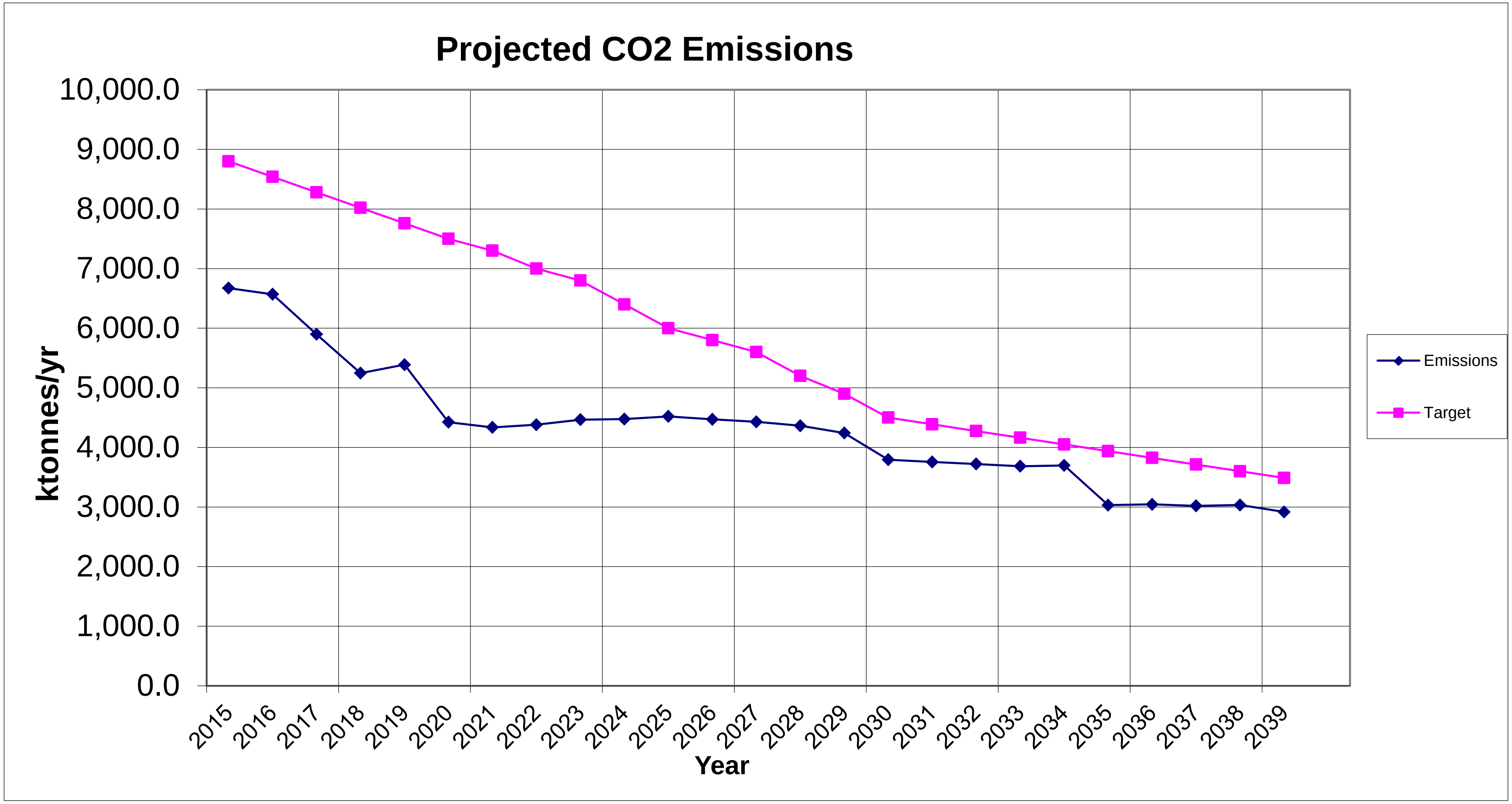
CRP5-1 Preliminary Energy by Resource Type



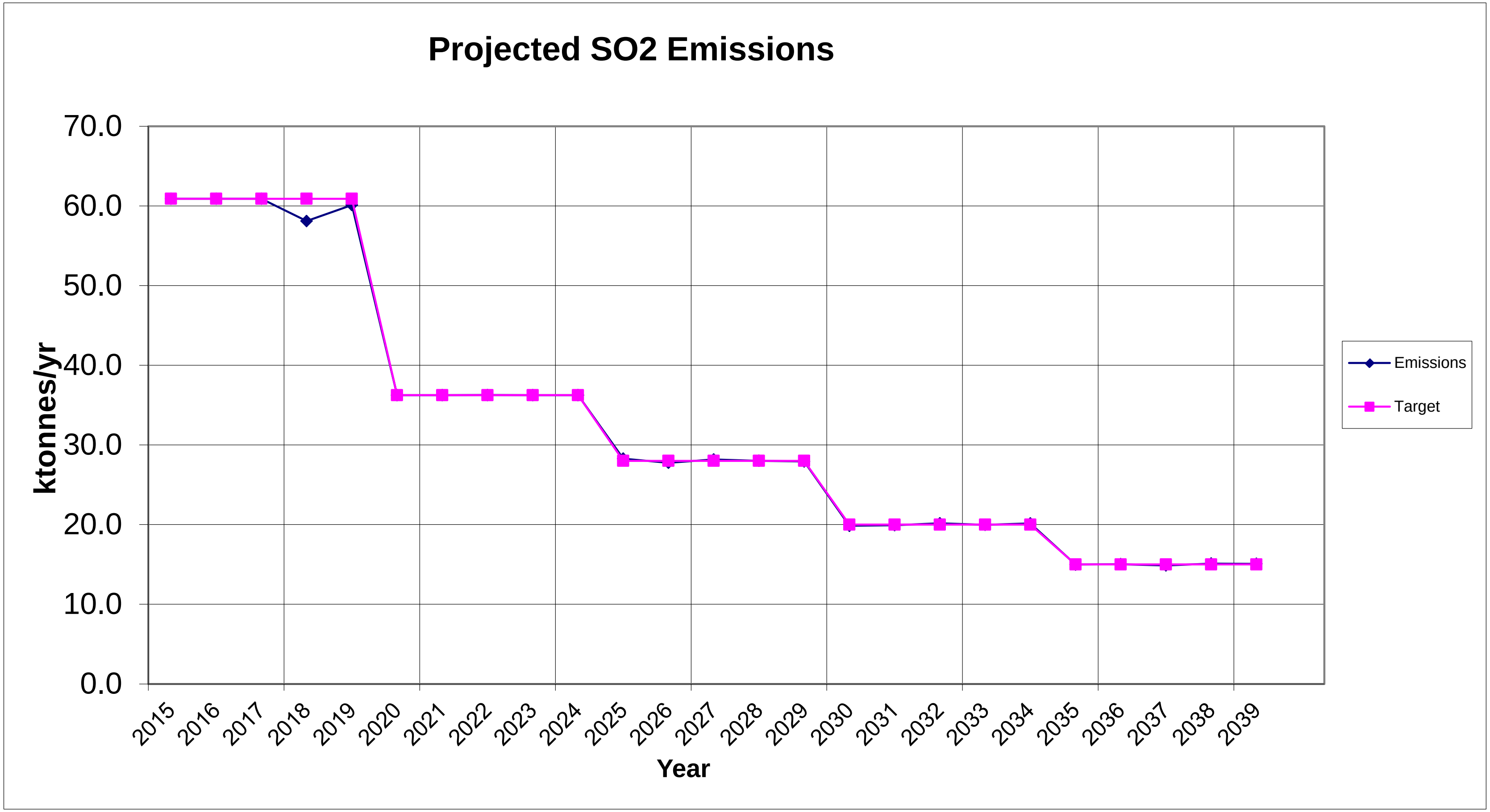
CRP5-1 Preliminary Coal Capacity Factors



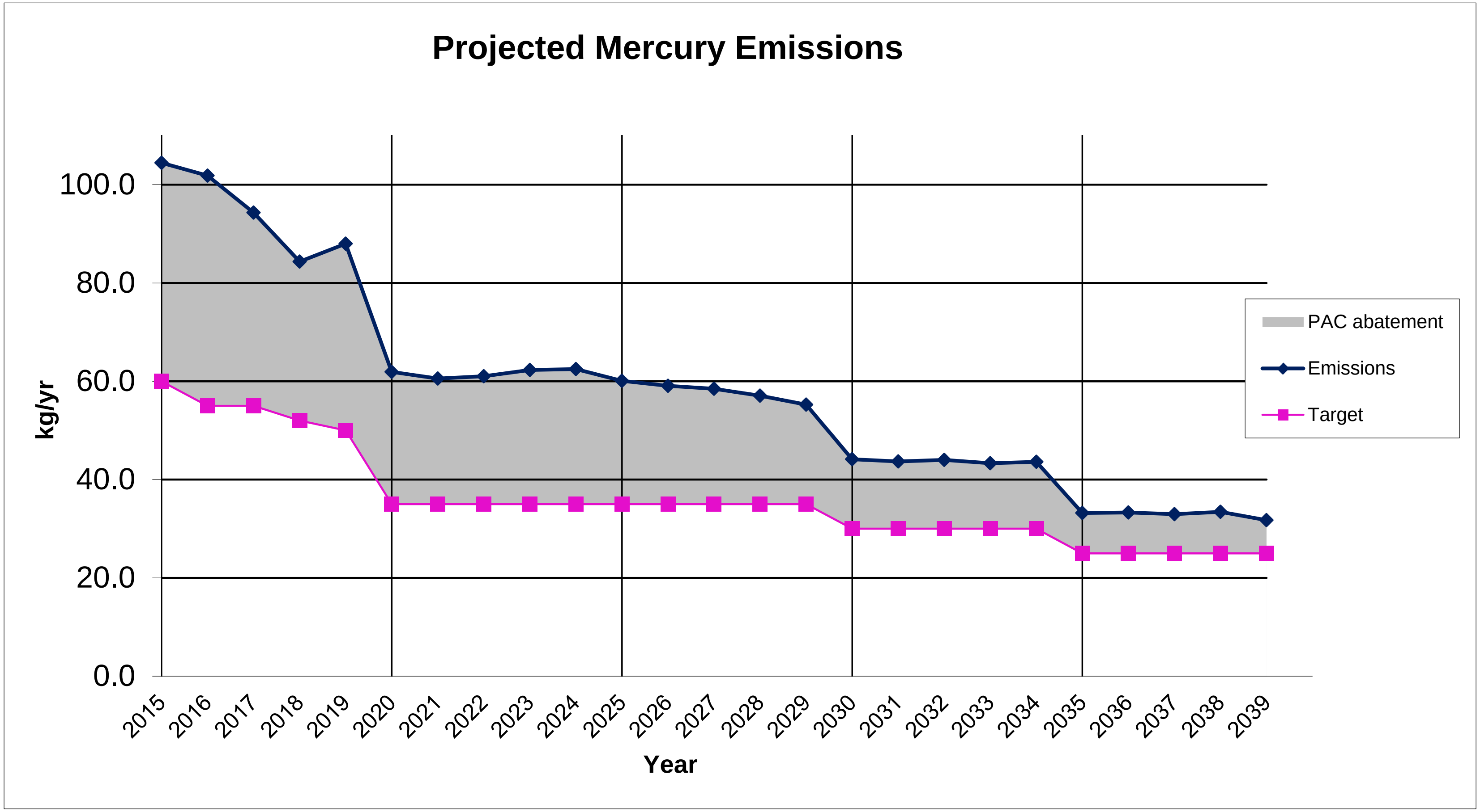
CRP5-1 Preliminary CO_2 Emissions



CRP5-1 Preliminary SO_2 Emissions



CRP5-1 Preliminary Mercury Emissions



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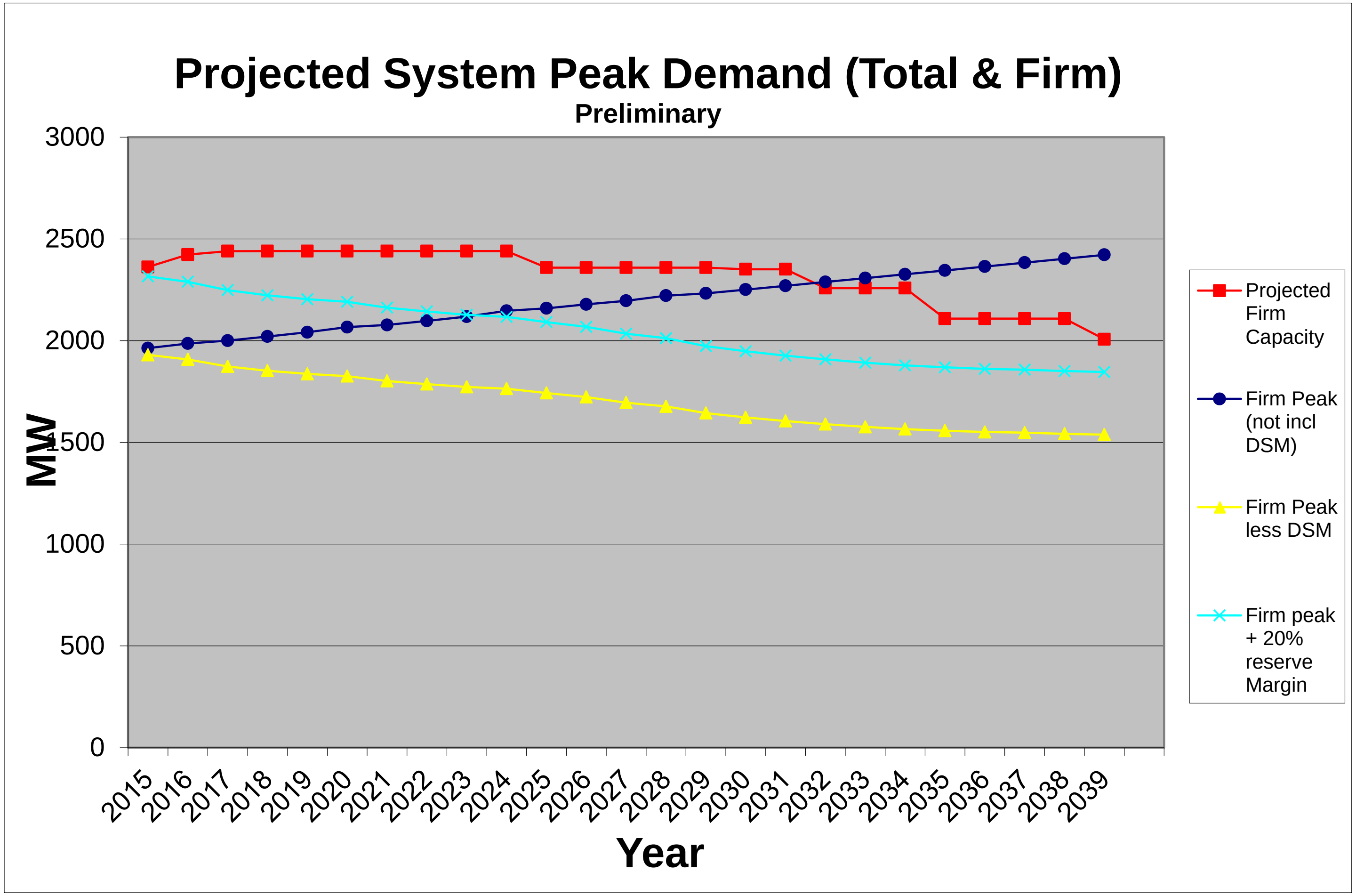
CRP5-8 Preliminary Results

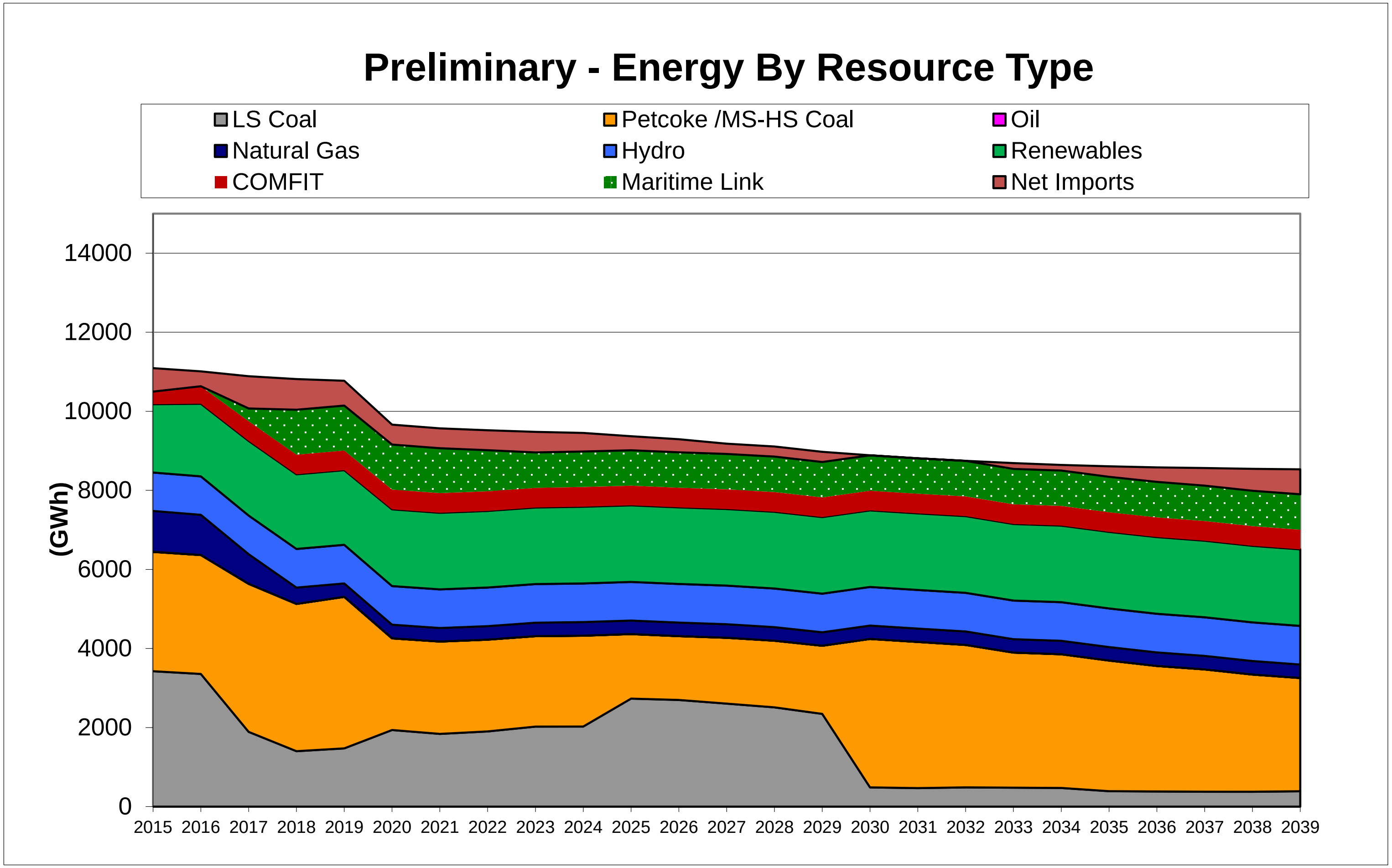
CRP5-8 Preliminary Load and Resources

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	2036	2037	2038	2039
Firm Peak	1,963	1,986	2,000	2,020	2,041	2,066	2,077	2,097	2,118	2,147	2,159	2,251	2,345	2,364	2,383	2,403	2,422
DSM	33	78	127	168	205	241	275	311	345	383	416	628	788	813	836	861	884
Firm Peak Less DSM	1,930	1,908	1,874	1,852	1,836	1,826	1,802	1,786	1,773	1,764	1,743	1,623	1,557	1,551	1,548	1,542	1,538
RM Required	386	382	375	370	367	365	360	357	355	353	349	325	311	310	310	308	308
Required MWs	2,316	2,289	2,248	2,223	2,204	2,191	2,162	2,144	2,127	2,117	2,091	1,948	1,869	1,861	1,857	1,850	1,846
Existing MWs	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341
Resource Additions (MW):																	
Burnside #4		33															
COMFIT - Biomass	4.2	6															
COMFIT - Wind	14.14	4.56	5.1														
REA Wind	2.35	17.34															
Maritime Link				153.3													
Small Biomass PPA			10														51.7
Hydro			1.8														
FGD Parasitic Power												-8					
Additional Wind																	
Assumed Unit Retirement				-153							-81		-150				-153
Natural Gas Unit																	
Total Annual Additions	20.7	60.9	16.9	0.3	0.0	0.0	0.0	0.0	0.0	0.0	-81.0	-8.0	-150.0	0.0	0.0	0.0	-101.3
Total Cumulative Additions	20.7	81.6	98.5	98.7	98.7	98.7	98.7	98.7	98.7	98.7	17.7	9.7	-233.3	-233.3	-233.3	-233.3	-334.6
Total Firm Capacity	2362	2423	2440	2440	2440	2440	2440	2440	2440	2440	2359	2351	2108	2108	2108	2108	2007
Surplus (Deficit) MWs above RM	46	134	192	217	236	249	278	296	313	323	268	403	239	247	251	258	161
Reserve Margin %	22.4%	27.0%	30.2%	31.7%	32.9%	33.6%	35.4%	36.6%	37.7%	38.3%	35.4%	44.9%	35.4%	35.9%	36.2%	36.7%	30.5%

CRP5-8 Preliminary Demand and DSM



CRP5-8 Preliminary Energy by Resource Type



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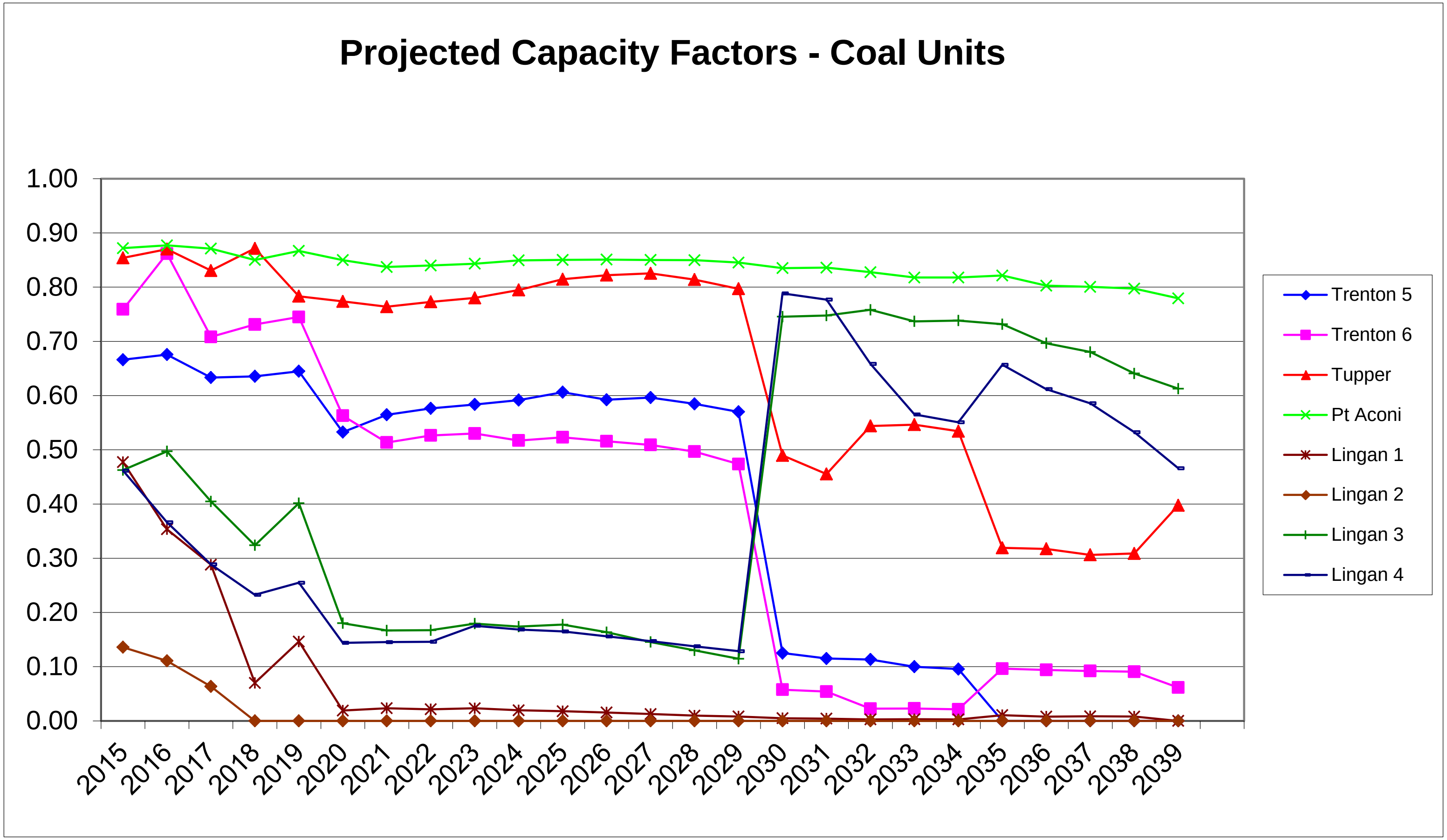
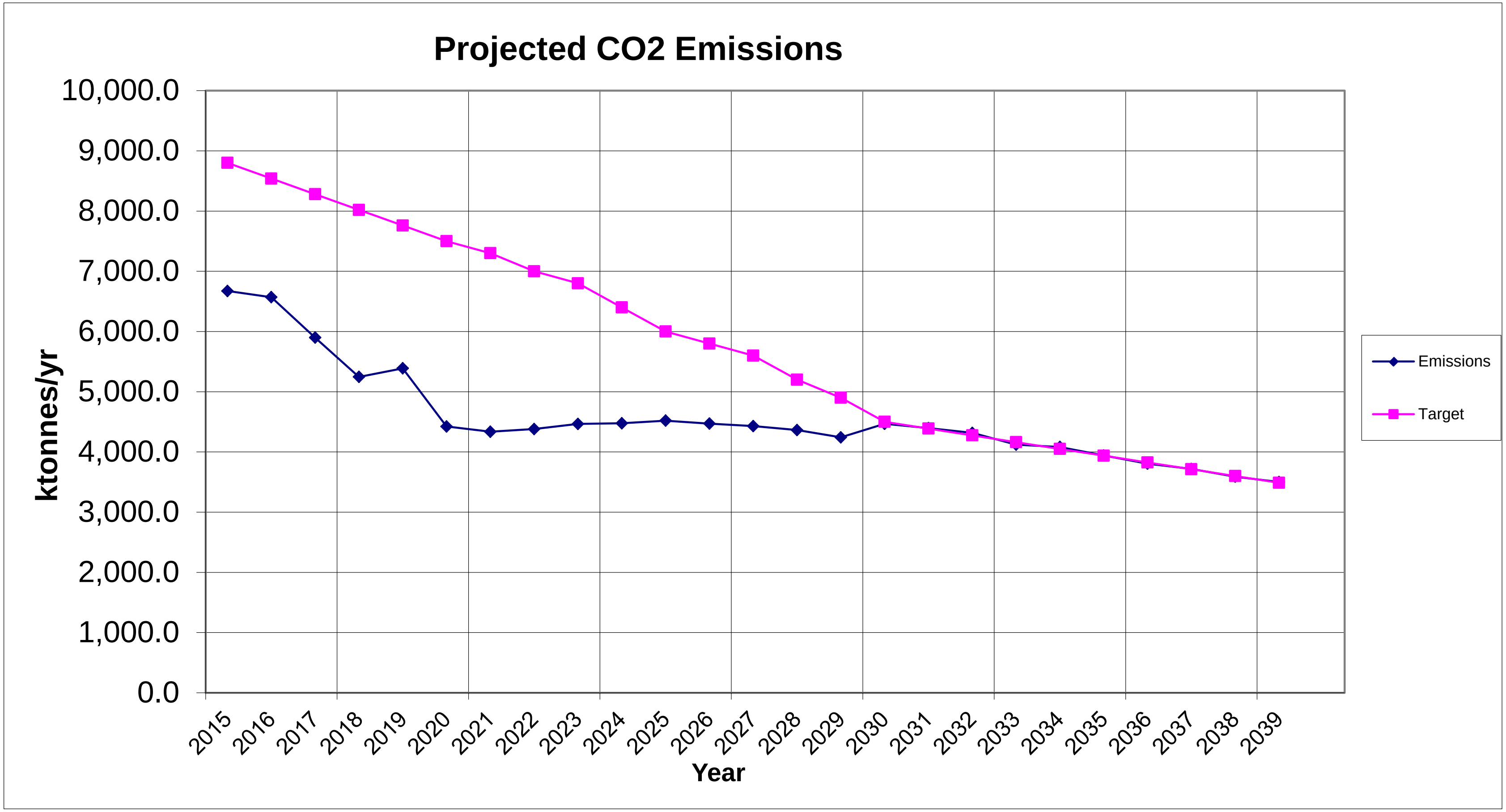
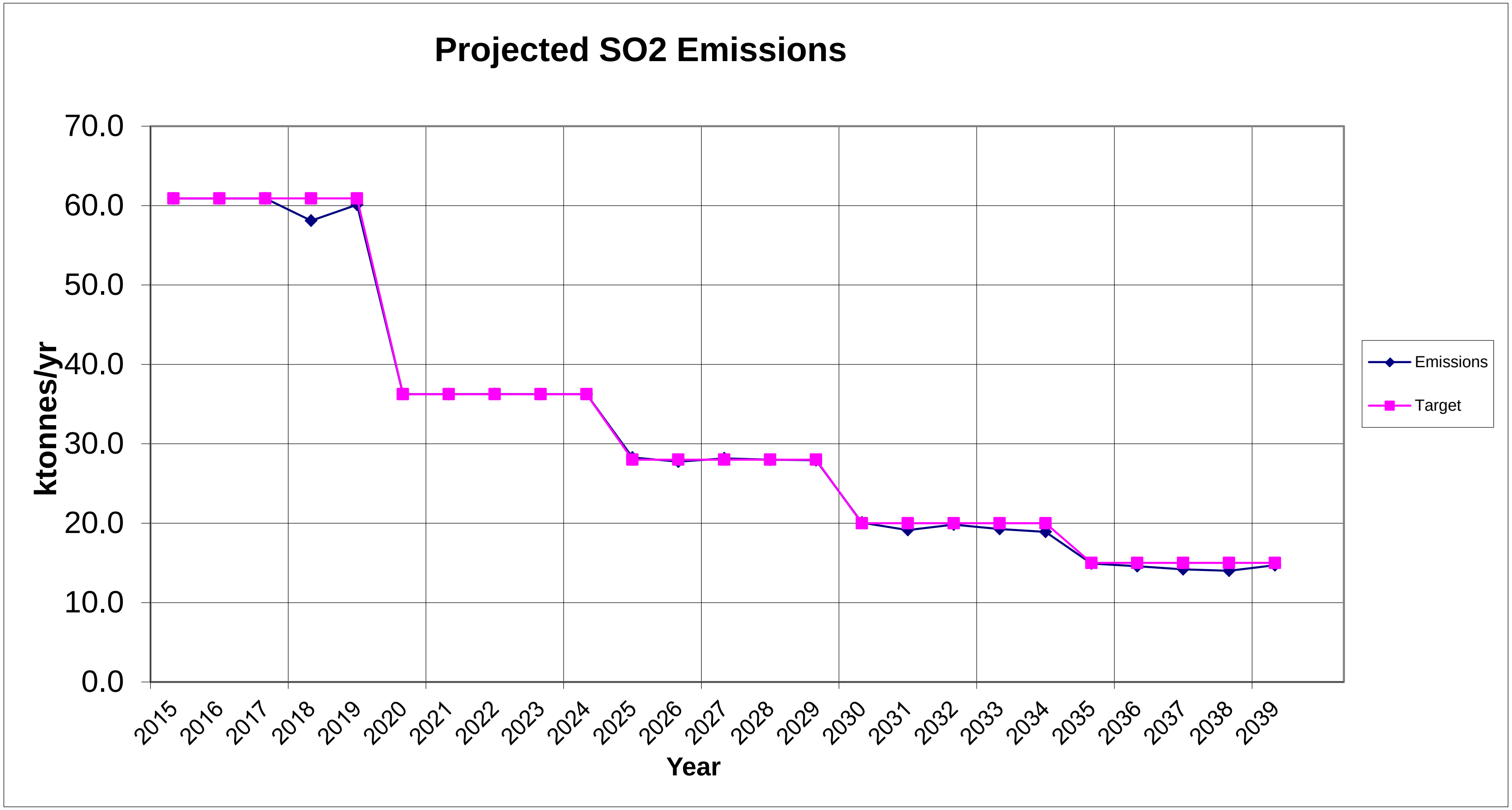
CRP5-8 Preliminary Coal Capacity Factors



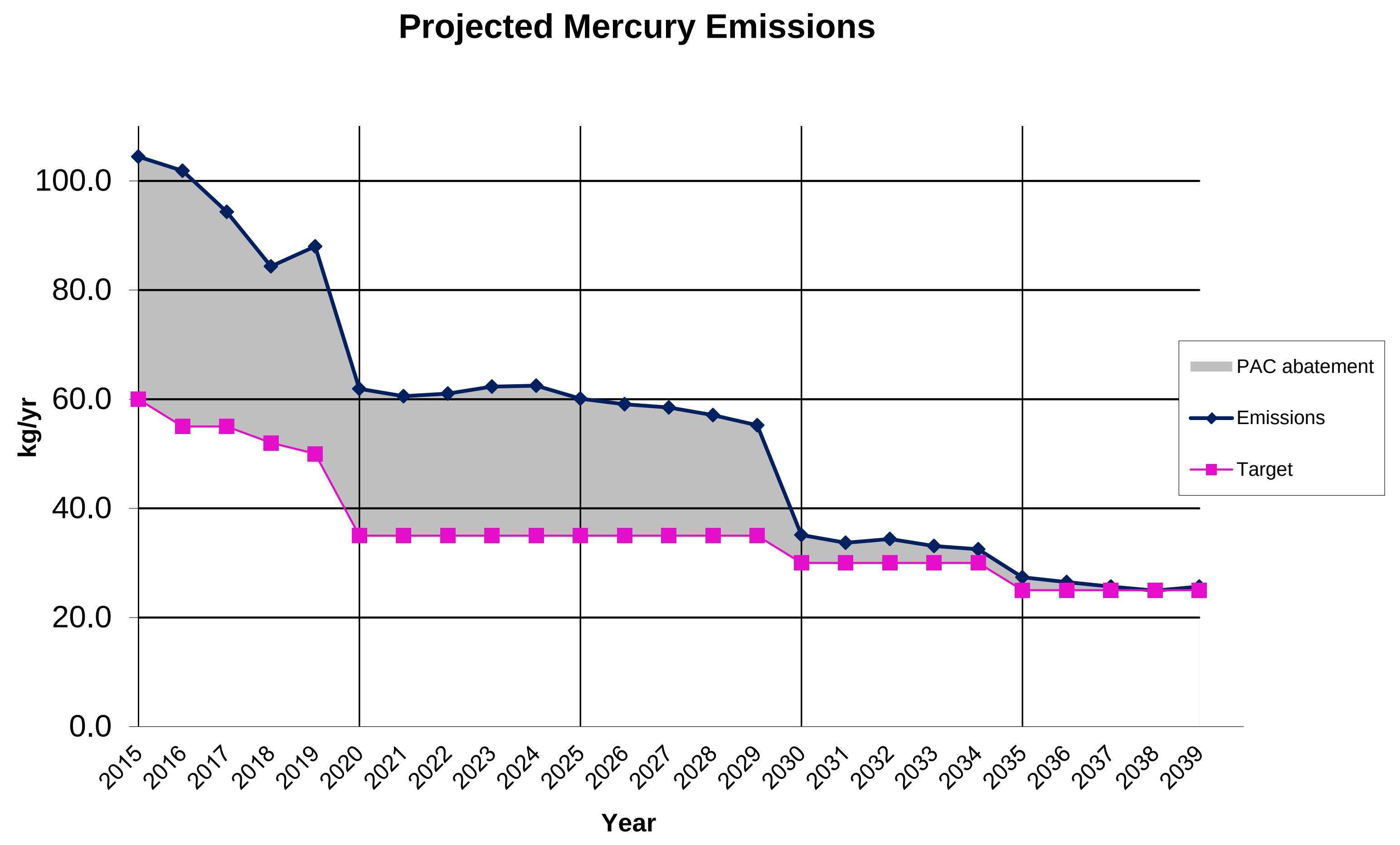
CRP5-8 Preliminary CO_2 Emissions



CRP5-8 Preliminary SO_2 Emissions



CRP5-8 Preliminary Mercury Emissions



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CRP6 Preliminary Results

CRP6 Input Assumptions

Candidate Resource Plan 6 (CRP6):

- Base Load Forecast
- High DSM
- Emissions - Scenario A
- Planned and committed resources are fixed in the plan (REA wind, COMFIT, Maritime Link/ Retire Lin #2)
- Minimum Coal Use
- High Wind (Wind integration: 5 x CT 50 MW and $238M for reliability tie and transmission upgrades.
- Constraints
    - Planning reserve margin min = 20%
    - RES: 2015-2019 = 25%; 2020-2039 = 40%

CRP6 Preliminary Results

	CRP6-01-R01
	Least cost planning & study period
2015	
2016	
2017	ML Oct 2017
	Lingan 2 Retire
2018	
2019	
2020	Lingan 1 Retire
	PHBM 51.7 MW Firm
2021	TUC 1 Retire
2022	Wind Block 150 MW
	2 x 50 MW CT (wind integration)
2023	Lingan 3 Retire
2024	Lingan 4 Retire
	Wind Block 150 MW
	3 x 50 MW CT (wind integration)
2025	
2026	
2027	
2028	TUC 2 Retire
2029	
2030	Trenton 5 Retire
2031	
2032	
2033	
2034	
2035	Tupper 2 Retire
	CT 50MW
2036	
2037	
2038	
2039	
Planning PV $M	12,334
Study PV $M	17,525

	High DSM	High DSM
	Program Adm Cost	Customer Cost
	$M	$M
2015	76.3	68.0
2016	92.0	85.6
2017	104.6	98.6
2018	107.4	96.8
2019	112.8	82.2
2020	119.3	79.8
2021	106.9	75.1
2022	102.2	72.6
2023	99.0	72.7
2024	104.0	77.6
2025	110.9	86.2
2026	118.6	97.0
2027	121.1	99.5
2028	120.4	100.7
2029	114.5	83.0
2030	106.5	78.7
2031	94.6	73.6
2032	85.9	68.0
2033	65.8	64.8
2034	61.1	61.8
2035	56.6	59.6
2036	52.4	57.8
2037	49.6	56.8
2038	44.2	57.0
2039	43.4	56.7
NPV	**1,260.6**	**1,037.2**

CRP6-1 Preliminary Results

CRP6-1 Preliminary Load and Resources

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	2036	2037	2038	2039
Firm Peak	1,963	1,986	2,000	2,020	2,041	2,066	2,077	2,097	2,118	2,147	2,159	2,251	2,345	2,364	2,383	2,403	2,422
DSM	33	78	127	168	205	241	275	311	345	383	416	628	788	813	836	861	884
Firm Peak Less DSM	1,930	1,908	1,874	1,852	1,836	1,826	1,802	1,786	1,773	1,764	1,743	1,623	1,557	1,551	1,548	1,542	1,538
DRWH Reduction																	
DRCM Reduction																	
Firm Peak Less DR	1,930	1,908	1,874	1,852	1,836	1,826	1,802	1,786	1,773	1,764	1743	1623	1557	1,551	1,548	1,542	1,538
RM Required	386	382	375	370	367	365	360	357	355	353	349	324.6	311.5	310	310	308	308
Required MWs	2,316	2,289	2,248	2,223	2,204	2,191	2,162	2,144	2,127	2,117	2091	1948	1869	1,861	1,857	1,850	1,846
Existing MWs	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341
Resource Additions (MW):																	
Burnside #4		33															
COMFIT - Biomass	4.2	6															
COMFIT - Wind	14.14	4.56	5.1														
REA Wind	2.35	17.34															
Maritime Link				153.3													
Small Biomass PPA			10														
Hydro			1.8														
PH Biomass						51.7											
Additional Wind								18		18							
Assumed Unit Retirement				-153		-153	-81		-158	-153		-150	-152				
Natural Gas Unit								98.8		148.1			49.4				
Total Annual Additions	20.7	60.9	16.9	0.3	0.0	-101.3	-81.0	116.8	-158.0	13.1	0.0	-150.0	-102.6	0.0	0.0	0.0	0.0
Total Cumulative Additions	20.7	81.6	98.5	98.7	98.7	-2.6	-83.6	33.2	-124.8	-111.7	-111.7	-354.7	-457.3	-457.3	-457.3	-457.3	-457.3
Total Firm Capacity	2362	2423	2440	2440	2440	2339	2258	2375	2217	2230	2230	1987	1884	1884	1884	1884	1884
Surplus (Deficit) MWs above RM	46	134	192	217	236	148	96	231	89	113	138	39	15	23	27	34	38
Reserve Margin %	22.4%	27.0%	30.2%	31.7%	32.9%	28.1%	25.3%	32.9%	25.0%	26.4%	27.9%	22.4%	21.0%	21.5%	21.7%	22.2%	22.5%

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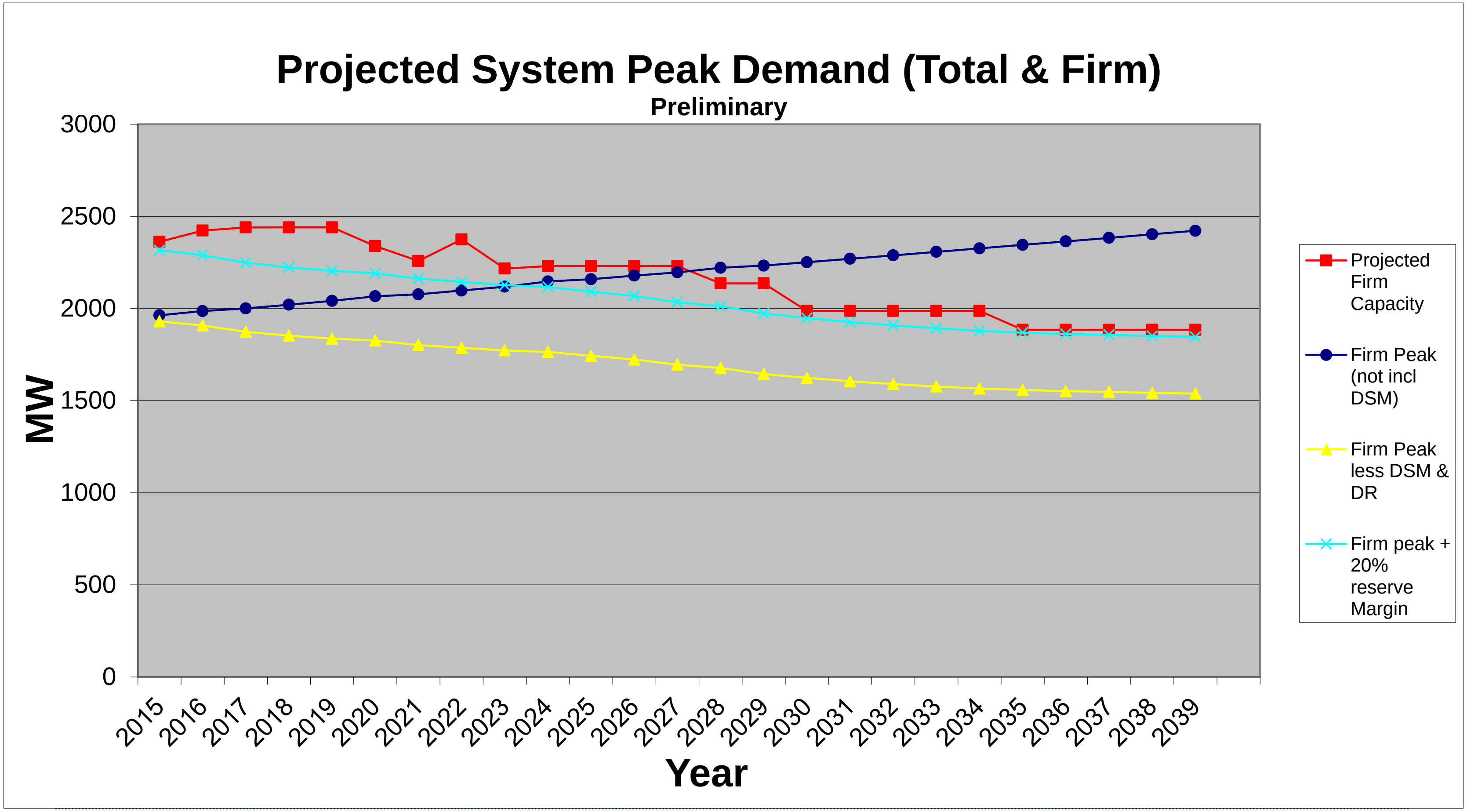
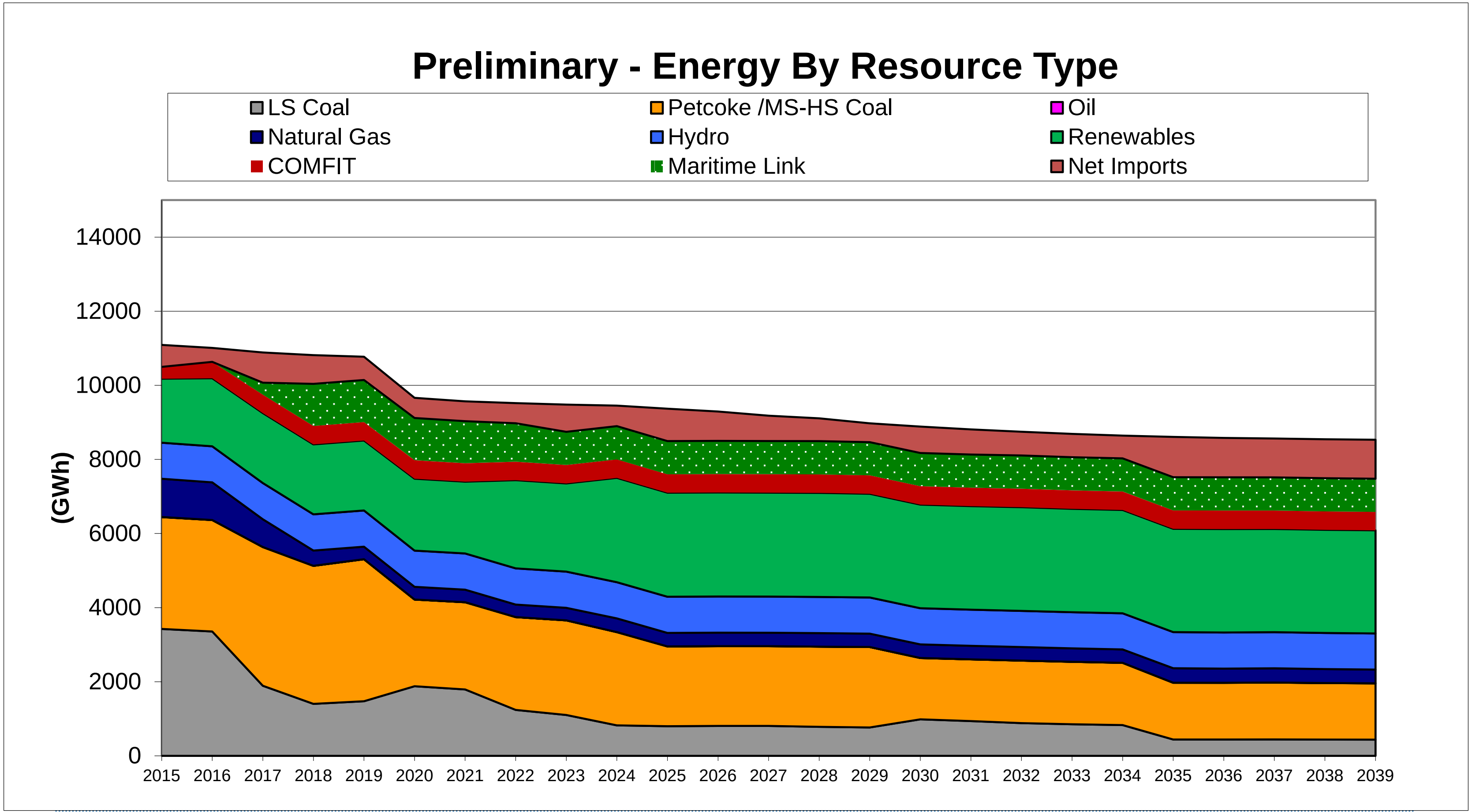
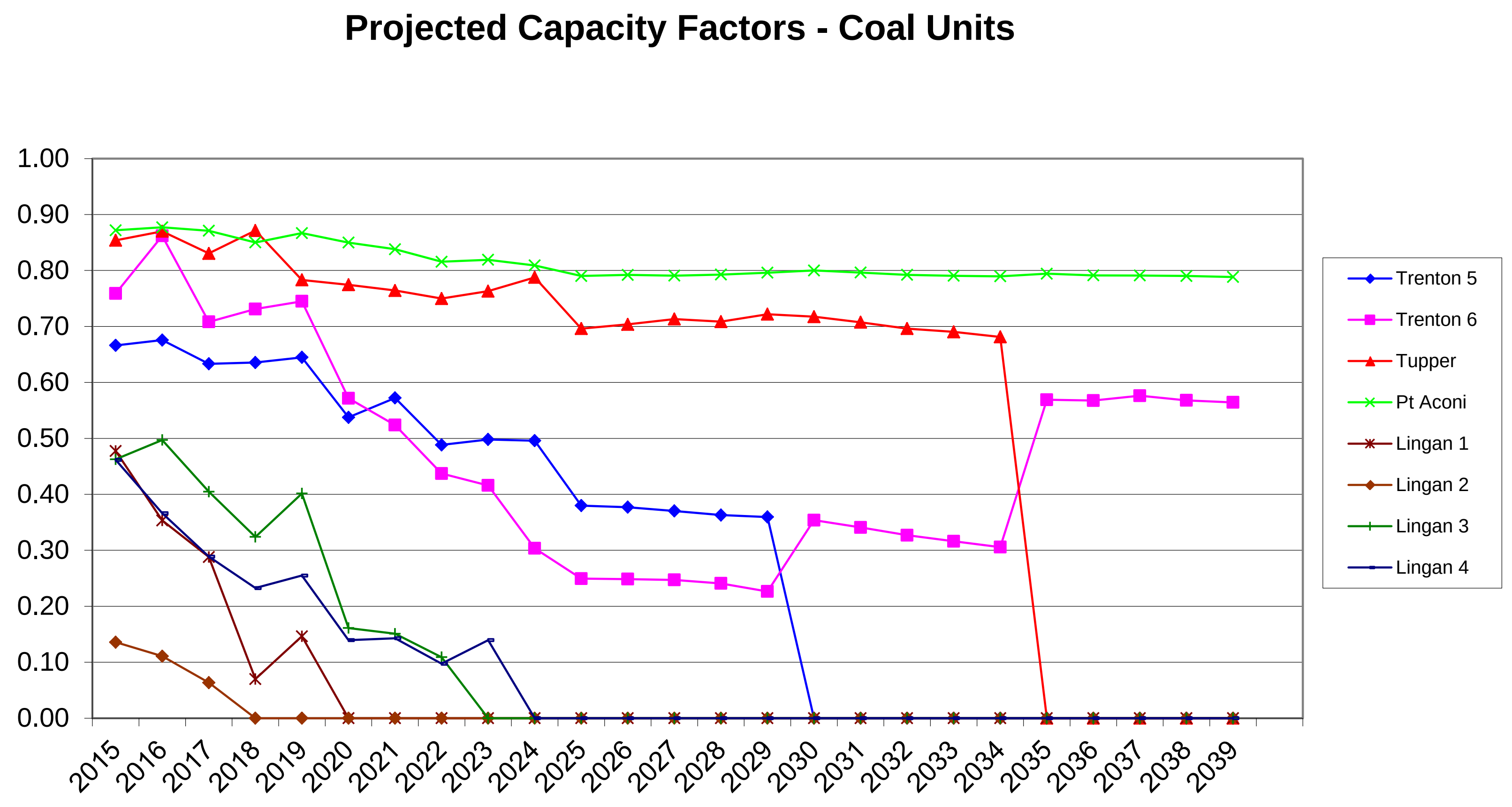
CRP6-1 Preliminary Demand and DSM



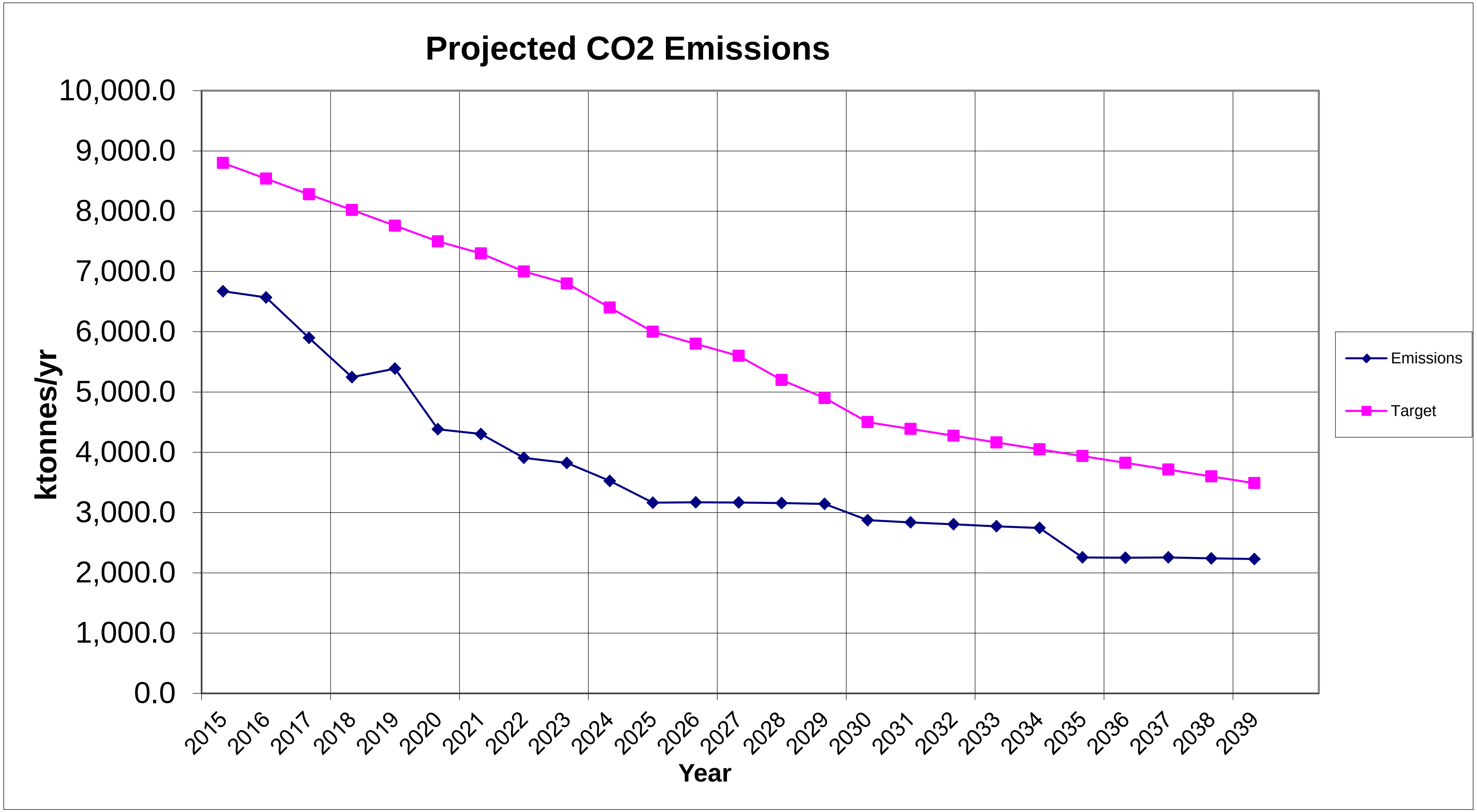
CRP6-1 Preliminary Energy by Resource Type



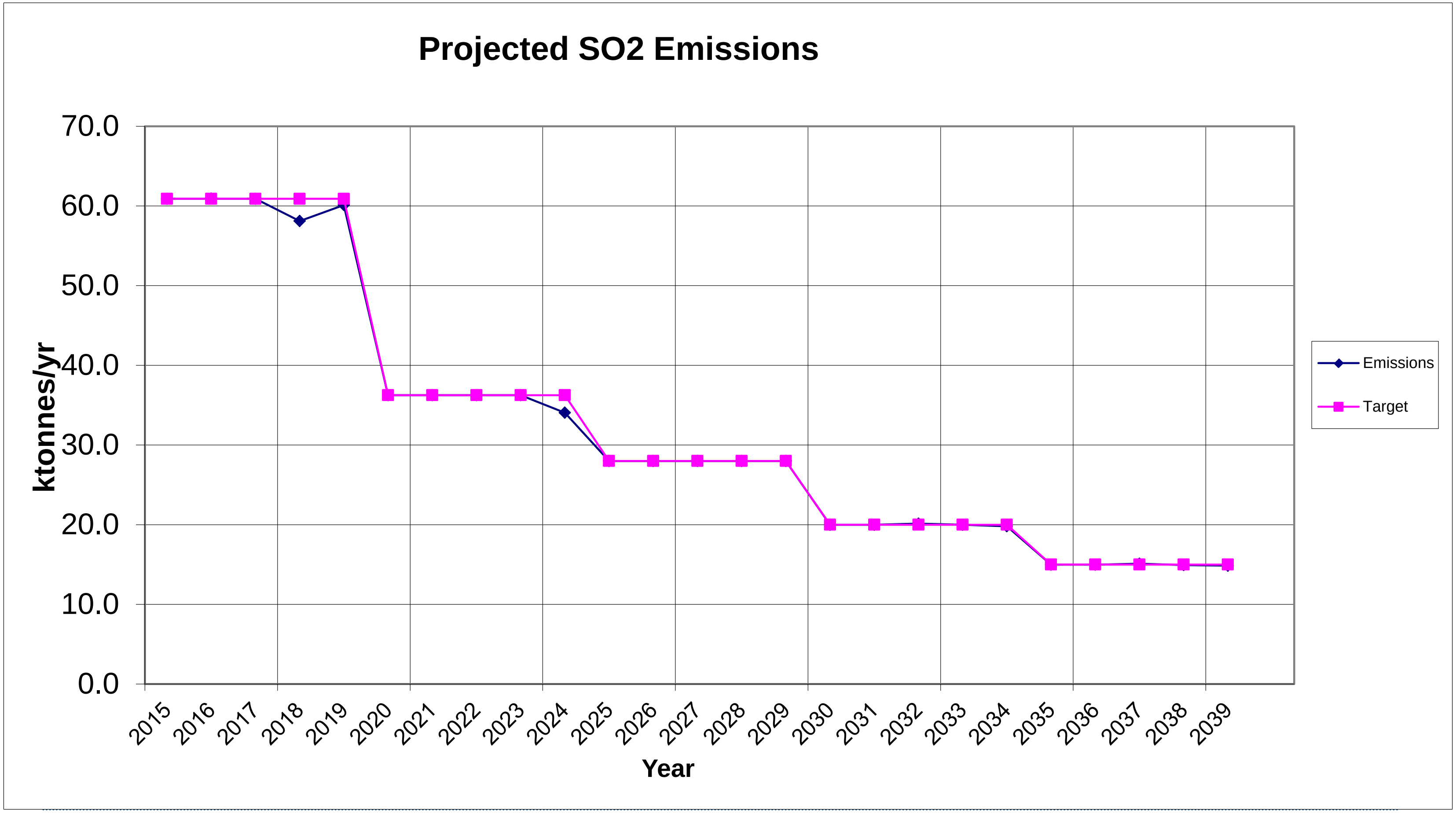
CRP6-1 Preliminary Coal Capacity Factors



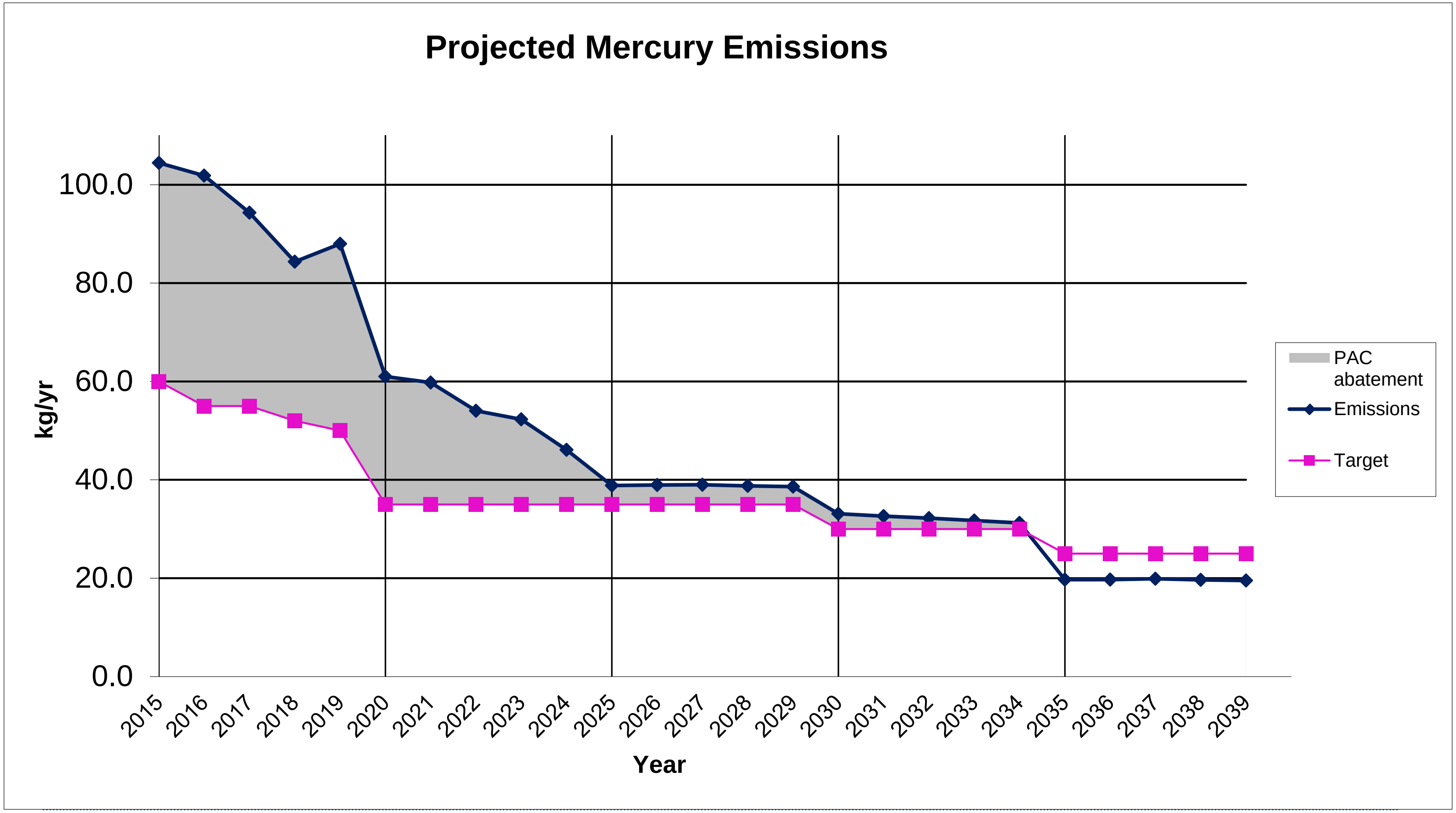
CRP6-1 Preliminary CO_2 Emissions



CRP6-1 Preliminary SO_2 Emissions



CRP6-1 Preliminary Mercury Emissions



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CRP7 Preliminary Results

CRP7 Input Assumptions

Candidate Resource Plan 7 (CRP7):

- Base Load Forecast
- High DSM
- Emissions - Scenario A
- Planned and committed resources are fixed in the plan (REA wind, COMFIT, Maritime Link/ Retire Lin #2)
- Minimum Coal Use
- Medium Wind (Wind integration: 2 x CT 50 MW and $200M for reliability tie and transmission upgrades)
- Constraints
  - Planning reserve margin min = 20%
  - RES: 2015-2019 = 25%; 2020-2039 = 40%

CRP7 Preliminary Results

	CRP7-01-R01	CRP7-05-R01
	Least cost study period	Least cost Planning period
2015		
2016	Demand Response - Water Heater and Comm	Demand Response - Commercial
2017	ML Oct 2017	ML Oct 2017
	Lingan 2 Retire	Lingan 2 Retire
2018		
2019		
2020	Lingan 1 Retire	Lingan 1 Retire
	PHBM 51.7 MW Firm	PHBM 51.7 MW Firm
2021	TUC 1 Retire	TUC 1 Retire
2022		
2023	Lingan 3 Retire	Lingan 3 Retire
	Wind Block 150 MW	Wind Block 150 MW
	2 x 50 MW CT (wind integration)	2 x 50 MW CT (wind integration)
2024	Lingan 4 Retire	Lingan 4 Retire
		CT 50MW
2025		
2026		
2027		
2028	TUC 2 Retire	TUC 2 Retire
2029		
2030	Trenton 5 Retire	Trenton 5 Retire
	CT 50MW	CT 50MW
2031		
2032		
2033		
2034		
2035	Tupper 2 Retire	Tupper 2 Retire
	CT 50MW	CT 50MW & CT 34 MW
2036		
2037		
2038		
2039		
Planning PV $M	12,208	12,202
Study PV $M	17,362	17,388

	High DSM	High DSM
	Program Adm Cost	Customer Cost
	$M	$M
2015	76.3	68.0
2016	92.0	85.6
2017	104.6	98.6
2018	107.4	96.8
2019	112.8	82.2
2020	119.3	79.8
2021	106.9	75.1
2022	102.2	72.6
2023	99.0	72.7
2024	104.0	77.6
2025	110.9	86.2
2026	118.6	97.0
2027	121.1	99.5
2028	120.4	100.7
2029	114.5	83.0
2030	106.5	78.7
2031	94.6	73.6
2032	85.9	68.0
2033	65.8	64.8
2034	61.1	61.8
2035	56.6	59.6
2036	52.4	57.8
2037	49.6	56.8
2038	44.2	57.0
2039	43.4	56.7
NPV	**1,260.6**	**1,037.2**

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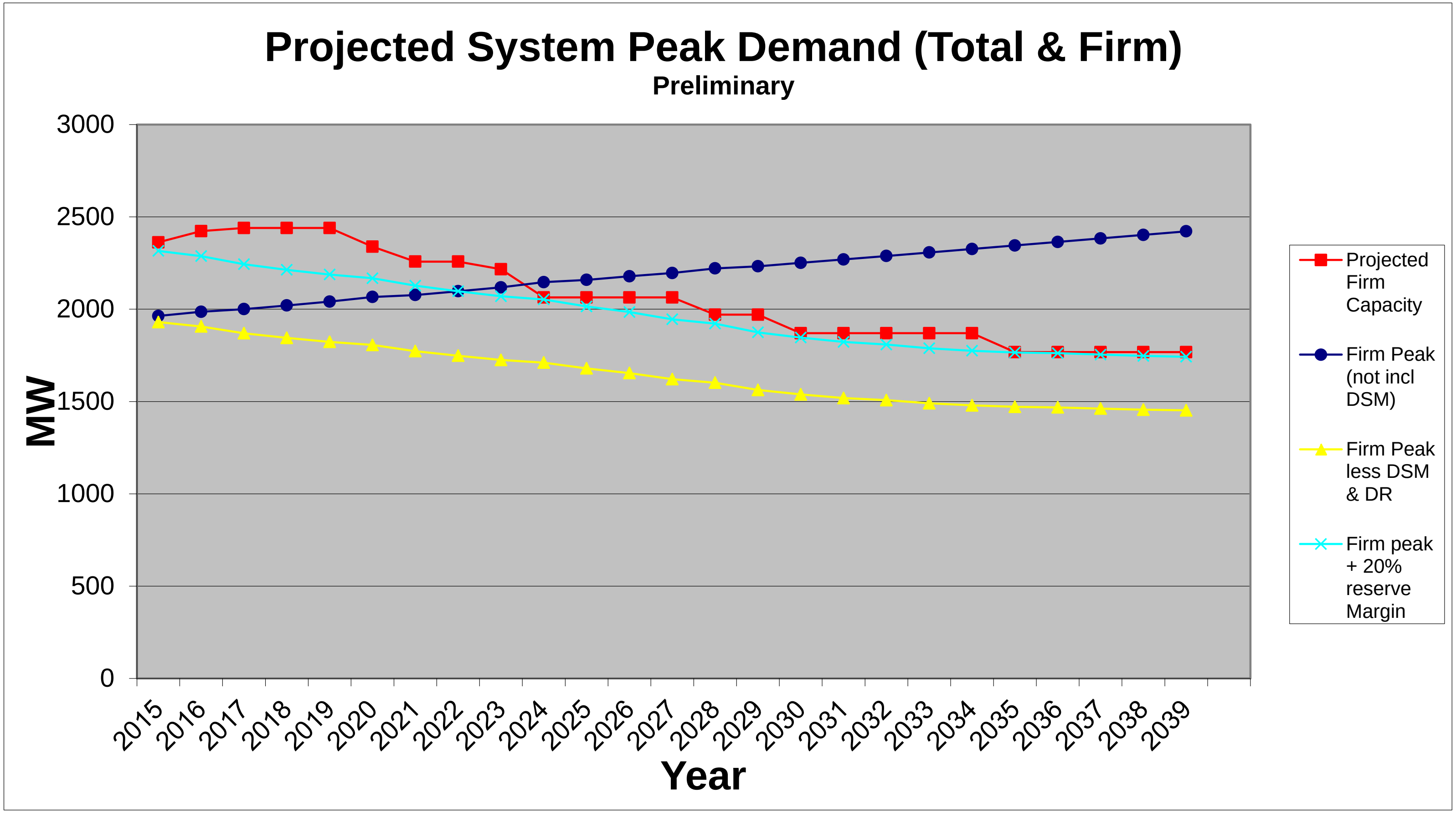
CRP7-1 Preliminary Results

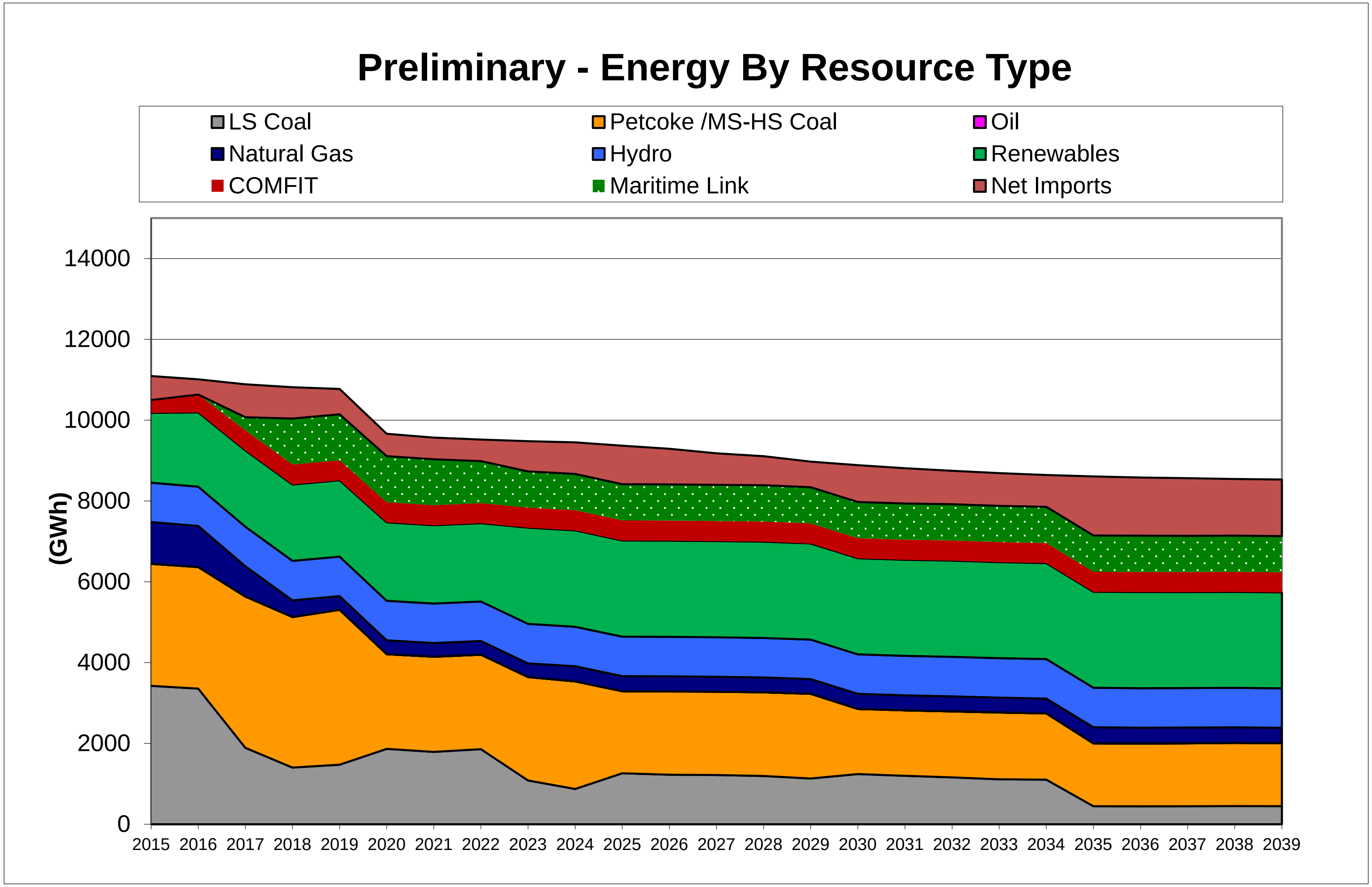
CRP7-1 Preliminary Load and Resources

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	2036	2037	2038	2039
Firm Peak	1,963	1,986	2,000	2,020	2,041	2,066	2,077	2,097	2,118	2,147	2,159	2,251	2,345	2,364	2,383	2,403	2,422
DSM	33	78	127	168	205	241	275	311	345	383	416	628	788	813	836	861	884
Firm Peak Less DSM	1,930	1,908	1,874	1,852	1,836	1,826	1,802	1,786	1,773	1,764	1,743	1,623	1,557	1,551	1,548	1,542	1,538
DRWH Reduction	0	1	2	4	7	10	15	21	27	32	39	60	62	60	62	62	62
DRCM Reduction	0	0	1	4	7	10	14	18	20	21	24	24	24	23	24	24	24
Firm Peak Less DR	1,930	1,906	1,870	1,844	1,823	1,806	1,773	1,748	1,725	1,711	1679	1538	1471	1,468	1,462	1,456	1,452
RM Required	386	381	374	369	365	361	355	350	345	342	336	307.7	294.3	294	292	291	290
Required MWs	2,316	2,288	2,244	2,213	2,188	2,168	2,127	2,097	2,070	2,053	2015	1846	1766	1,762	1,754	1,747	1,743
Existing MWs	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341
Resource Additions (MW):																	
Burnside #4		33															
COMFIT - Biomass	4.2	6															
COMFIT - Wind	14.14	4.56	5.1														
REA Wind	2.35	17.34															
Maritime Link				153.3													
Small Biomass PPA			10														
Hydro			1.8														
PH Biomass						51.7											
Additional Wind									18								
Assumed Unit Retirement				-153		-153	-81		-158	-153		-150	-152				
Natural Gas Unit									98.8			49.4	49.4				
Total Annual Additions	20.7	60.9	16.9	0.3	0.0	-101.3	-81.0	0.0	-41.2	-153.0	0.0	-100.6	-102.6	0.0	0.0	0.0	0.0
Total Cumulative Additions	20.7	81.6	98.5	98.7	98.7	-2.6	-83.6	-83.6	-124.8	-277.8	-277.8	-471.4	-574.0	-574.0	-574.0	-574.0	-574.0
Total Firm Capacity	2362	2423	2440	2440	2440	2339	2258	2258	2217	2064	2064	1870	1767	1767	1767	1767	1767
Surplus (Deficit) MWs above RM	46	135	196	227	252	171	131	160	146	11	48	24	2	6	13	20	25
Reserve Margin %	22.4%	27.1%	30.5%	32.3%	33.8%	29.5%	27.4%	29.2%	28.5%	20.6%	22.9%	21.5%	20.1%	20.4%	20.9%	21.4%	21.7%

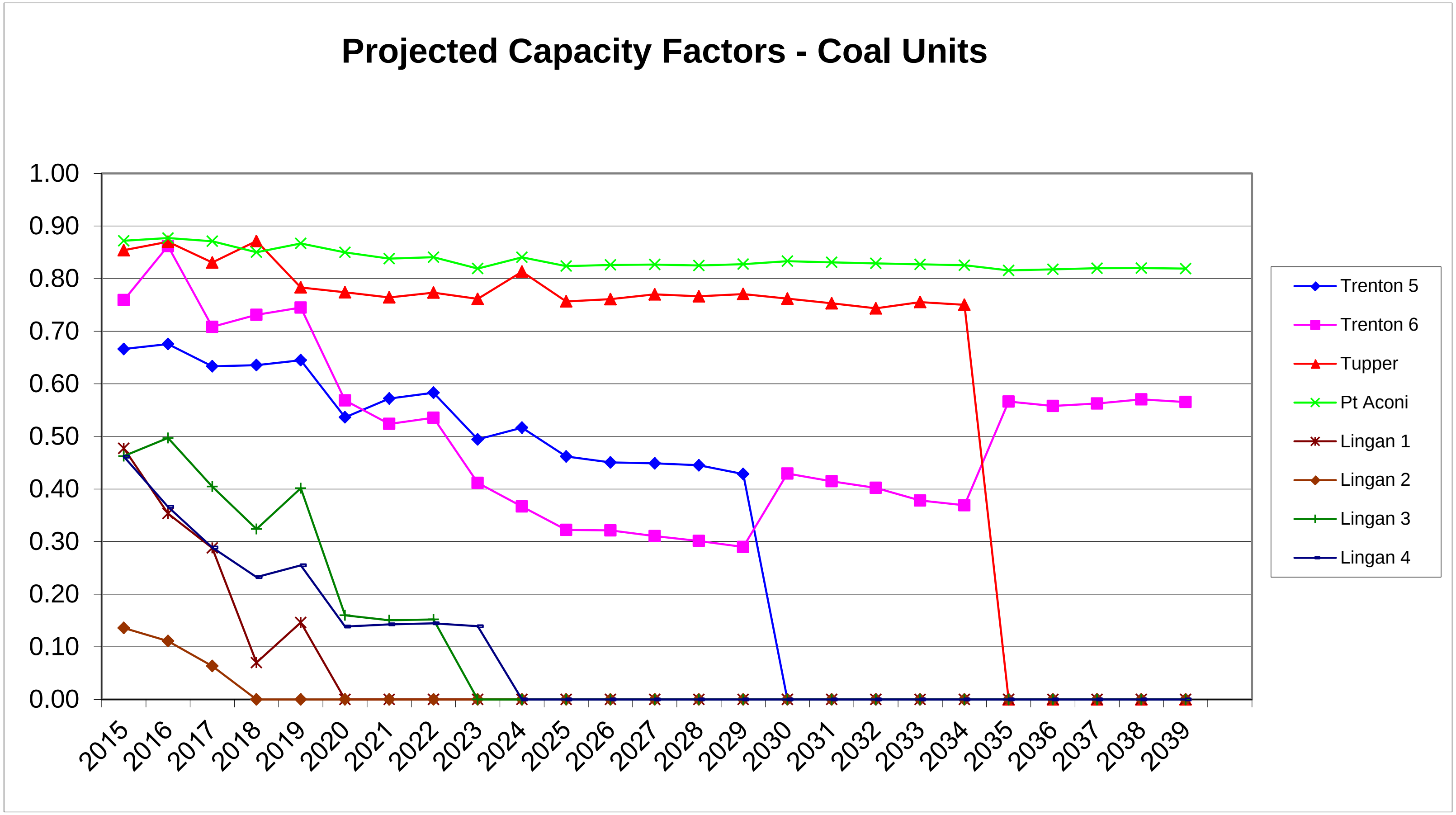
CRP7-1 Preliminary Demand and DSM



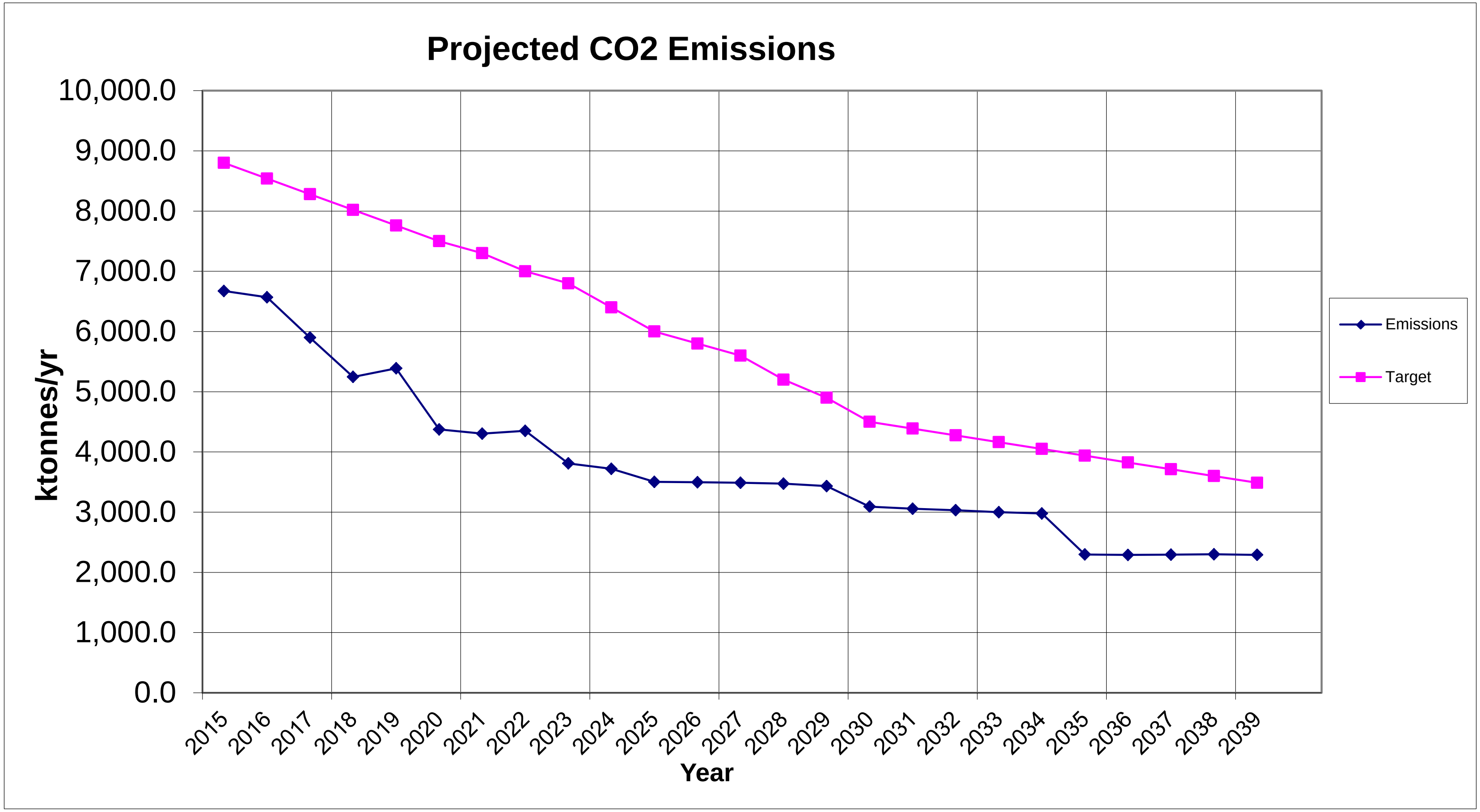
CRP7-1 Preliminary Energy by Resource Type



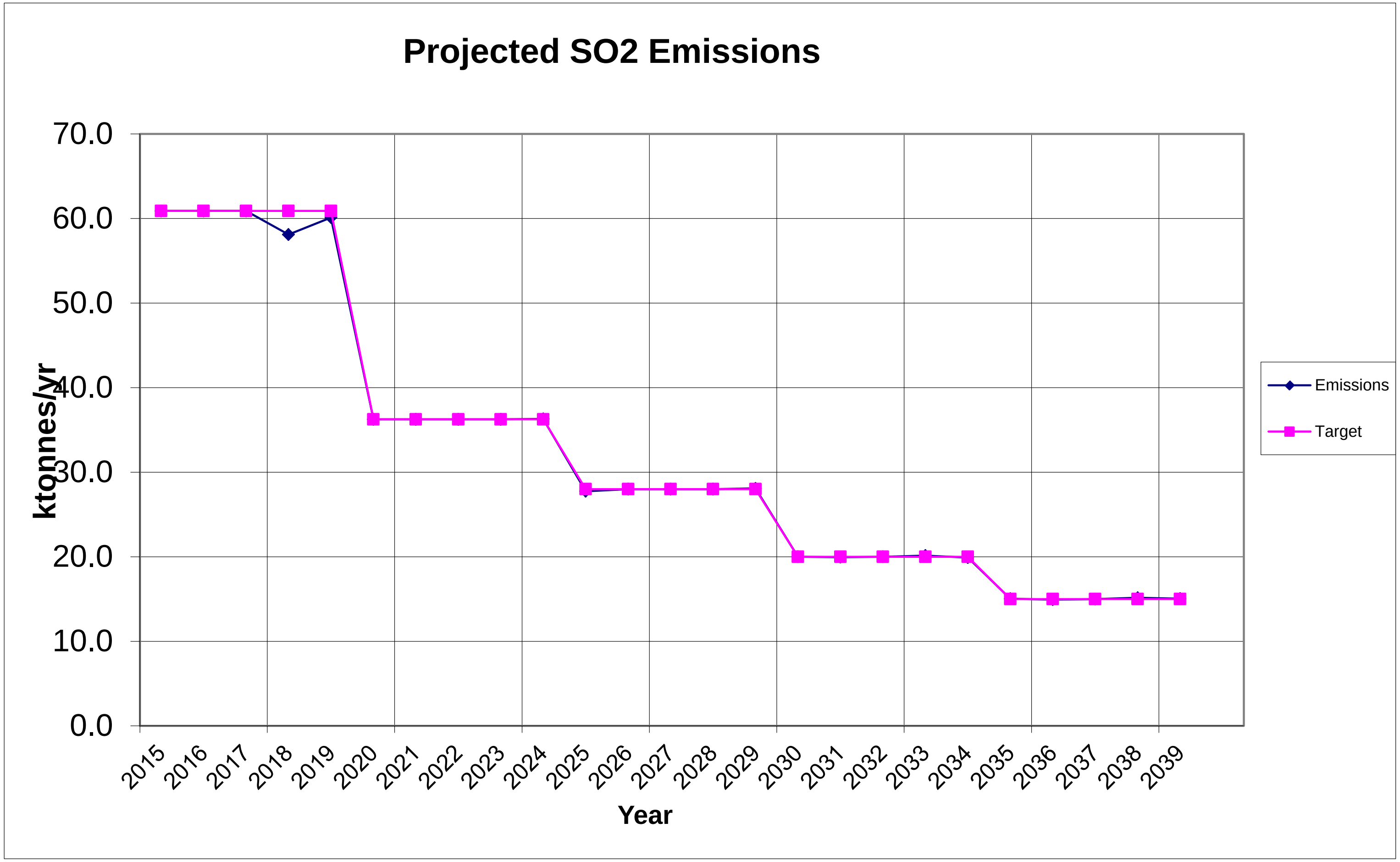
CRP7-1 Preliminary Coal Capacity Factors



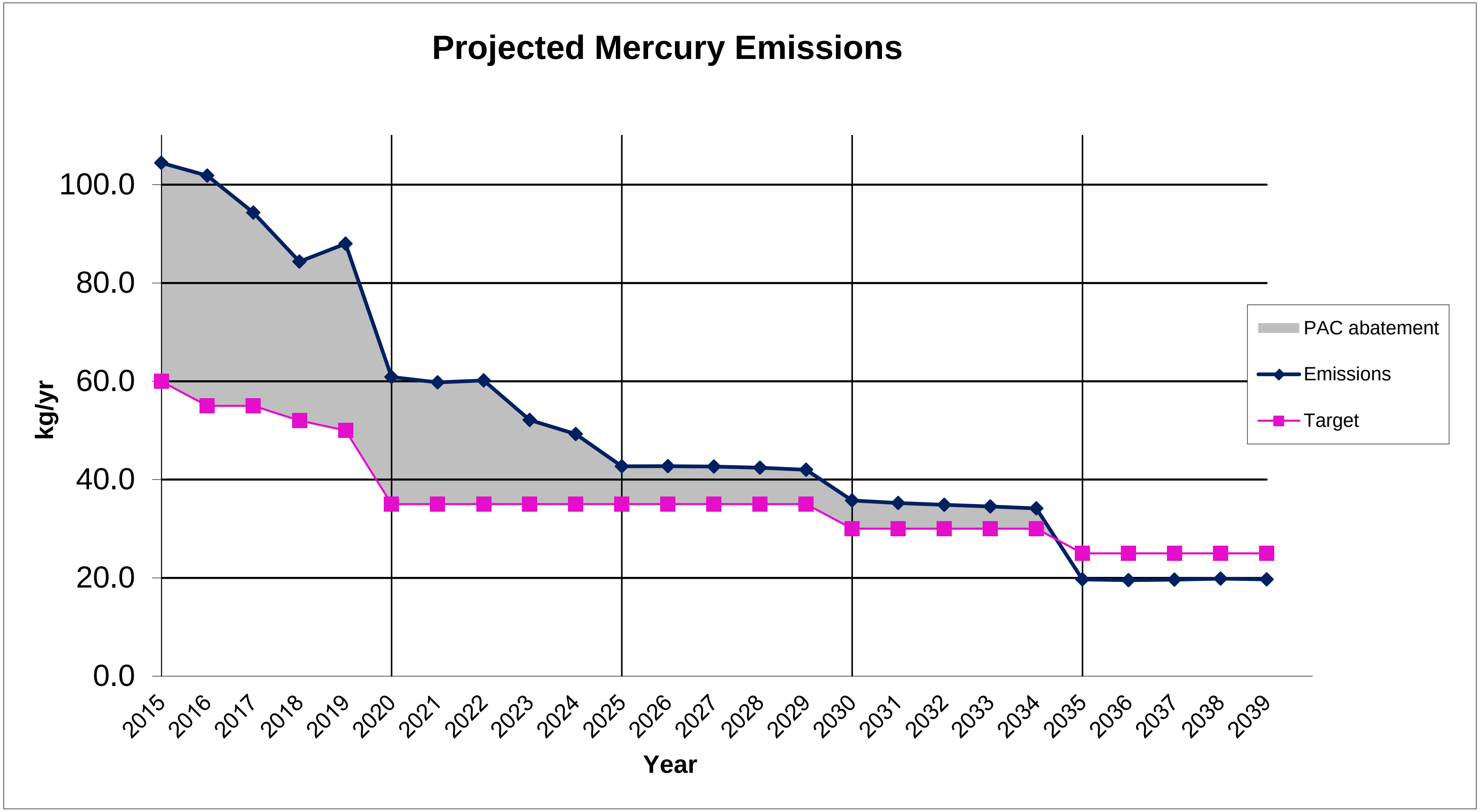
CRP7-1 Preliminary CO_2 Emissions



CRP7-1 Preliminary SO_2 Emissions



CRP7-1 Preliminary Mercury Emissions



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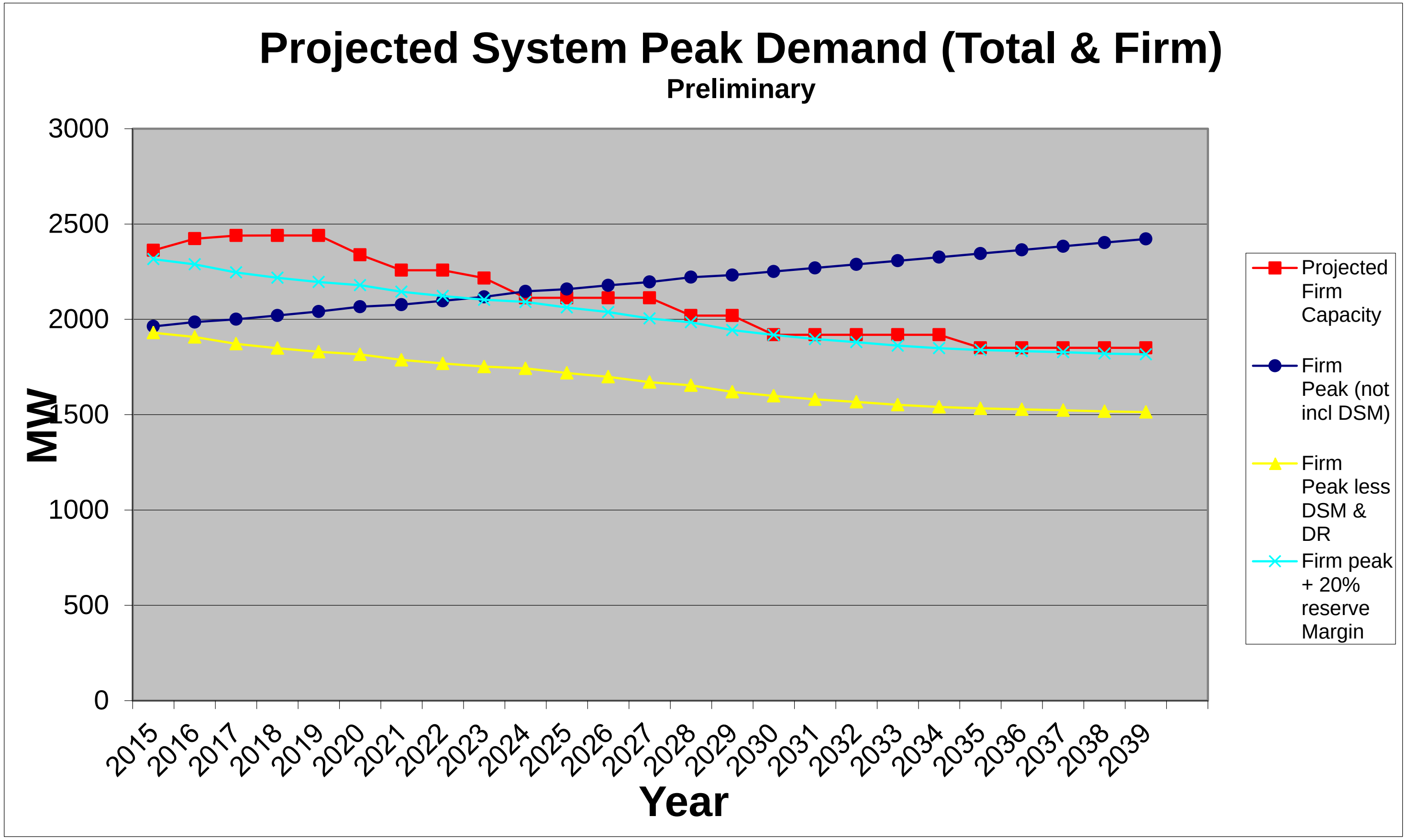
CRP7-5 Preliminary Results

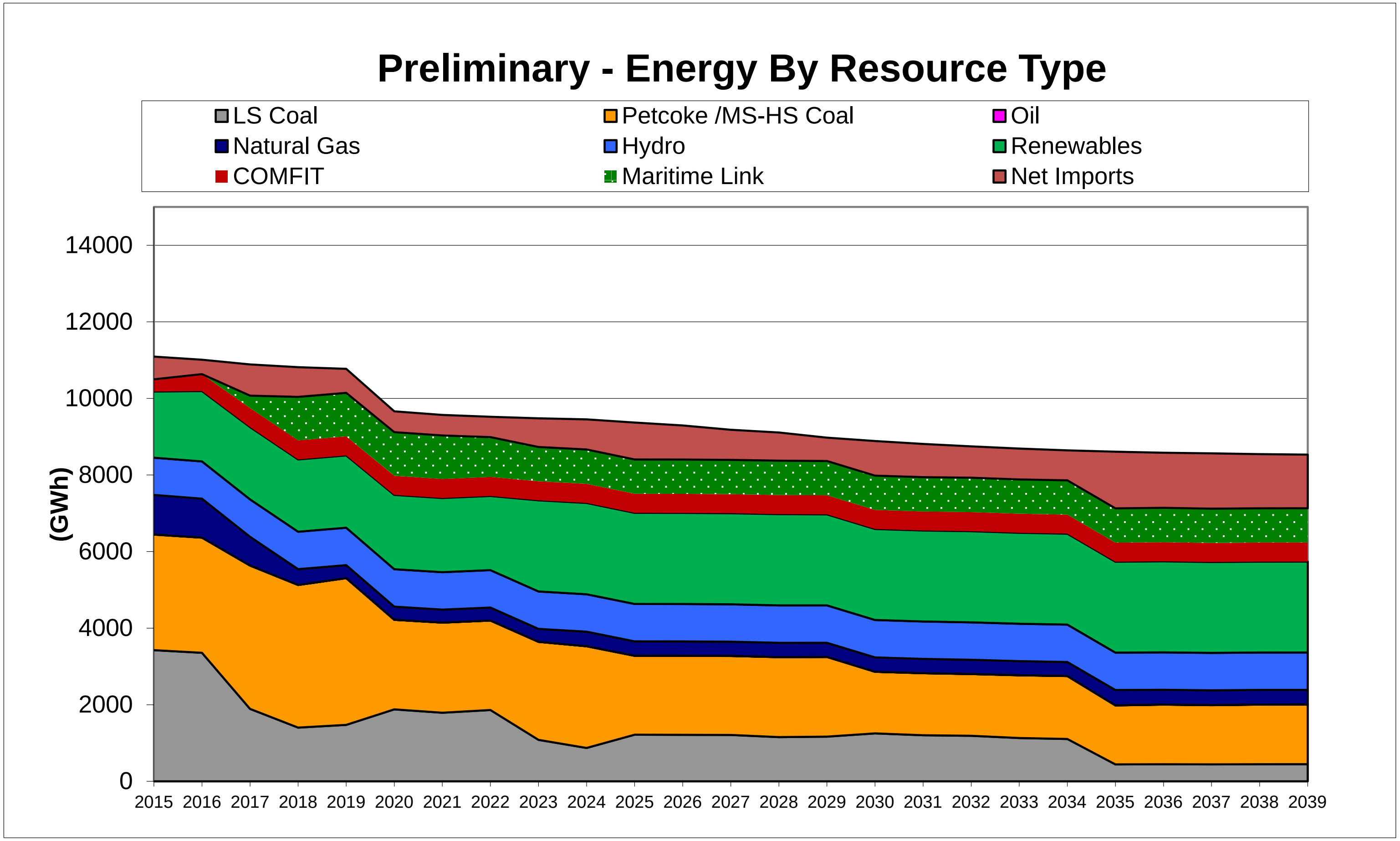
CRP7-5 Preliminary Load and Resources

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	2036	2037	2038	2039
Firm Peak	1,963	1,986	2,000	2,020	2,041	2,066	2,077	2,097	2,118	2,147	2,159	2,251	2,345	2,364	2,383	2,403	2,422
DSM	33	78	127	168	205	241	275	311	345	383	416	628	788	813	836	861	884
Firm Peak Less DSM	1,930	1,908	1,874	1,852	1,836	1,826	1,802	1,786	1,773	1,764	1,743	1,623	1,557	1,551	1,548	1,542	1,538
DRWH Reduction																	
DRCM Reduction	0	0	1	4	7	10	14	18	20	21	24	24	24	23	24	24	24
Firm Peak Less DR	1,930	1,907	1,872	1,849	1,830	1,816	1,788	1,769	1,752	1,743	1719	1599	1533	1,528	1,523	1,518	1,514
RM Required	386	381	374	370	366	363	358	354	350	349	344	319.7	306.6	306	305	304	303
Required MWs	2,316	2,289	2,246	2,218	2,196	2,180	2,145	2,123	2,103	2,092	2062	1918	1840	1,834	1,828	1,821	1,817
Existing MWs	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341
Resource Additions (MW):																	
Burnside #4		33															
COMFIT - Biomass	4.2	6															
COMFIT - Wind	14.14	4.56	5.1														
REA Wind	2.35	17.34															
Maritime Link				153.3													
Small Biomass PPA			10														
Hydro			1.8														
PH Biomass						51.7											
Additional Wind									18								
Assumed Unit Retirement				-153		-153	-81		-158	-153		-150	-152				
Natural Gas Unit									98.8	49.4		49.4	83.4				
Total Annual Additions	20.7	60.9	16.9	0.3	0.0	-101.3	-81.0	0.0	-41.2	-103.6	0.0	-100.6	-68.6	0.0	0.0	0.0	0.0
Total Cumulative Additions	20.7	81.6	98.5	98.7	98.7	-2.6	-83.6	-83.6	-124.8	-228.4	-228.4	-422.0	-490.6	-490.6	-490.6	-490.6	-490.6
Total Firm Capacity	2362	2423	2440	2440	2440	2339	2258	2258	2217	2113	2113	1919	1851	1851	1851	1851	1851
Surplus (Deficit) MWs above RM	46	134	193	222	244	159	113	135	114	21	51	1	11	17	23	30	34
Reserve Margin %	22.4%	27.0%	30.3%	32.0%	33.3%	28.8%	26.3%	27.6%	26.5%	21.2%	22.9%	20.1%	20.7%	21.1%	21.5%	22.0%	22.3%

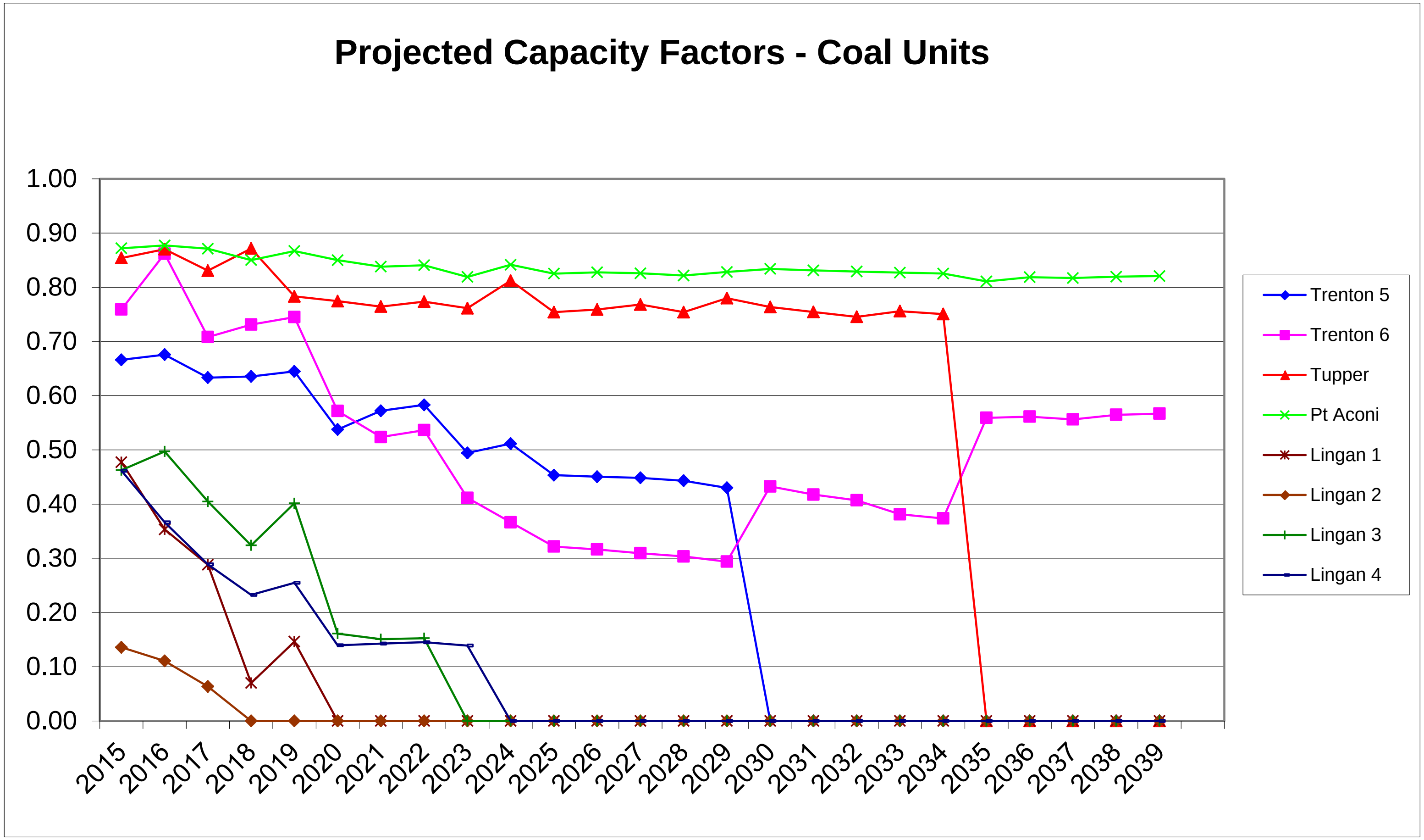
CRP7-5 Preliminary Demand and DSM



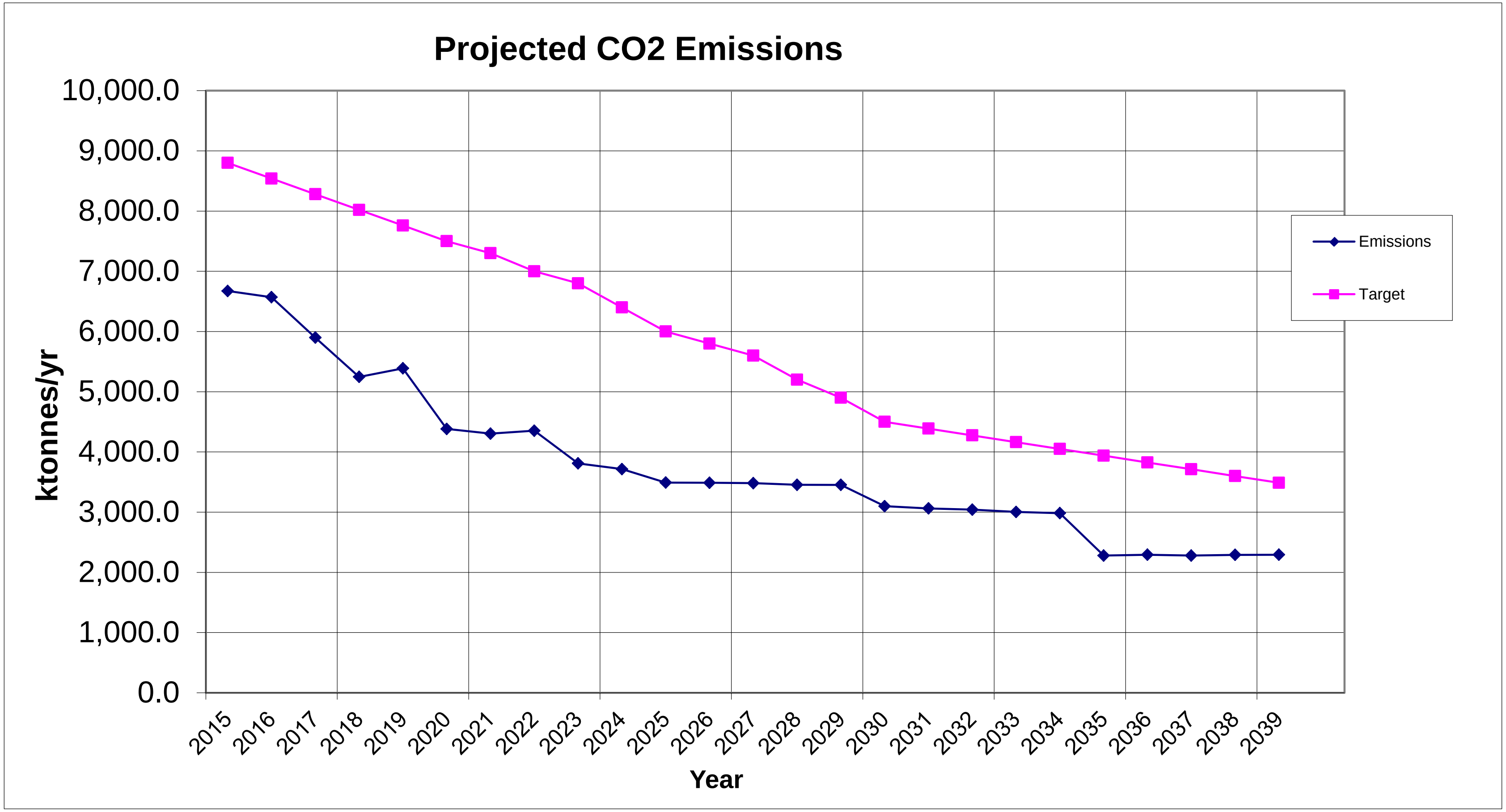
CRP7-5 Preliminary Energy by Resource Type



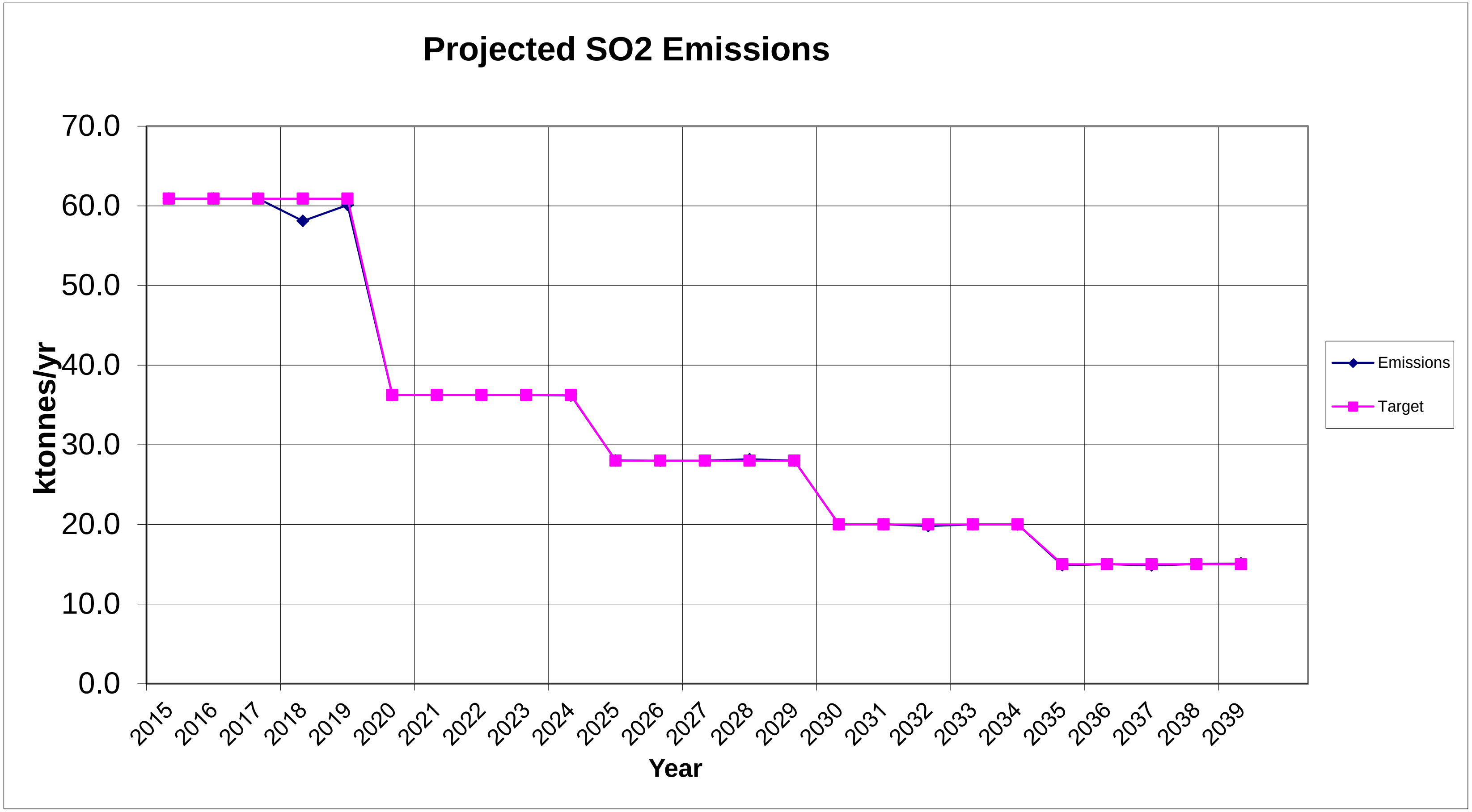
CRP7-5 Preliminary Coal Capacity Factors



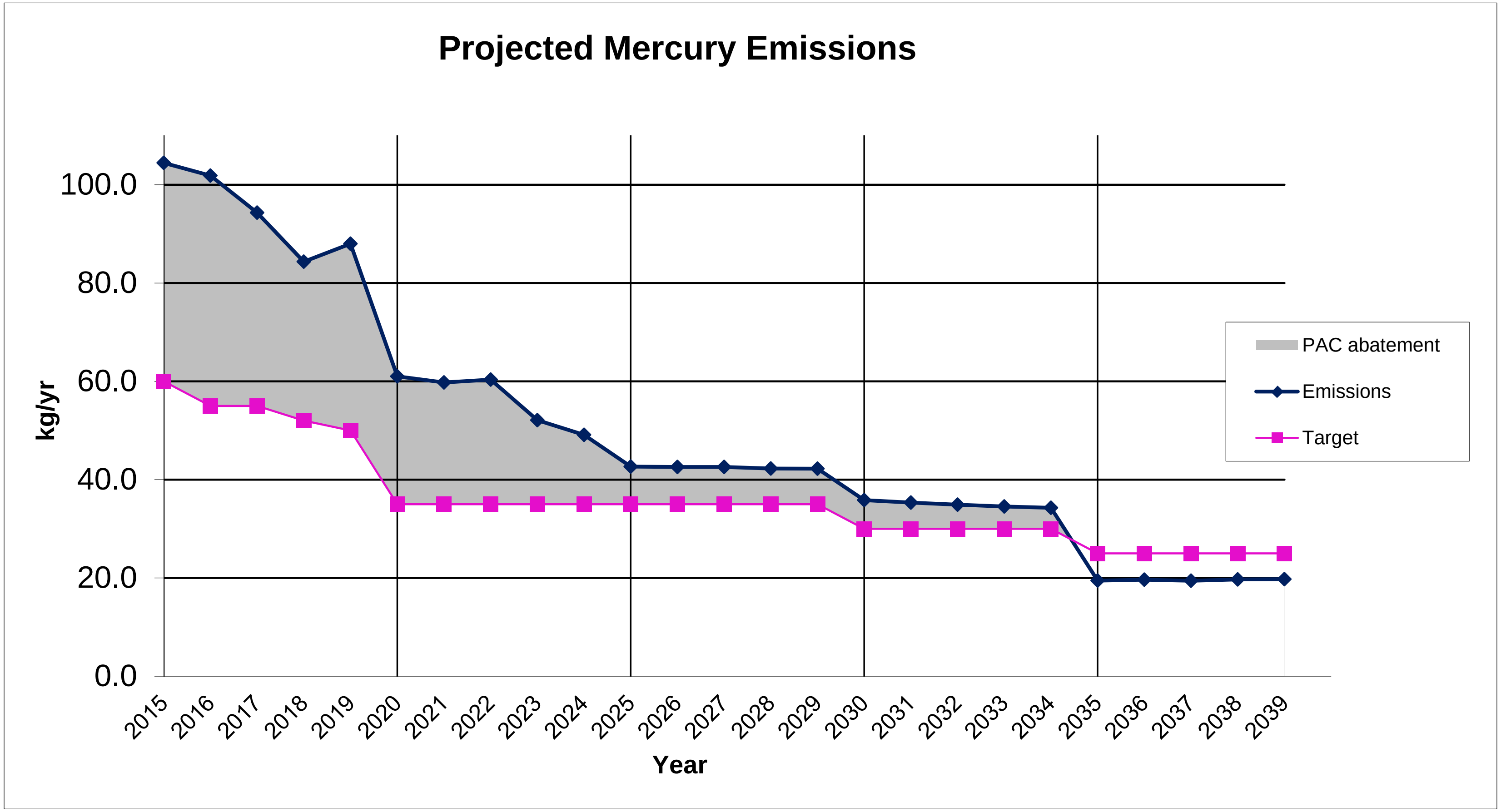
CRP7-5 Preliminary CO$_2$ Emissions



CRP7-5 Preliminary SO_2 Emissions



CRP7-5 Preliminary Mercury Emissions



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CRP8 Preliminary Results

CRP8 Input Assumptions

Candidate Resource Plan 8 (CRP8):

- Base Load Forecast
- Base DSM
- Emissions - Scenario A
- Planned and committed resources are fixed in the plan (REA wind, COMFIT, Maritime Link/ Retire Lin #2)
- Minimum Coal Use
- High Wind (Wind integration: 5 x CT 50 MW and $238M for reliability tie and transmission upgrades)
- Constraints
  - Planning reserve margin min = 20%
  - RES: 2015-2019 = 25%; 2020-2039 = 40%

CRP8 Preliminary Results

	CRP8-01-R01
	Least cost study period
2015	
2016	Demand Response - Water Heater
2017	ML Oct 2017
	Lingan 2 Retire
2018	
2019	Mersey Phase 1
2020	Lingan 1 Retire
	PHBM 51.7 MW Firm
2021	TUC 1 Retire
2022	Wind Block 150 MW
	2 x 50 MW CT (wind integration)
2023	Lingan 3 Retire
	Mersey Phase 2
2024	Lingan 4 Retire
	Wind Block 150 MW
	3 x 50 MW CT (wind integration)
2025	
2026	
2027	
2028	TUC 2 Retire
	CT 50MW
2029	CT 50MW
2030	Trenton 5 Retire
	CT 50MW
2031	
2032	
2033	
2034	
2035	Tupper 2 Retire
	CT 50MW
2036	
2037	
2038	
2039	
Planning PV $M	11,936
Study PV $M	17,791

	Base DSM Program Adm Cost $M	Base DSM Customer Cost $M
2015	50.7	37.9
2016	50.5	39.9
2017	50.0	41.2
2018	52.4	41.6
2019	57.0	32.2
2020	61.5	28.0
2021	56.9	28.4
2022	54.1	28.4
2023	51.5	29.2
2024	50.8	28.6
2025	50.6	29.9
2026	52.1	33.8
2027	54.8	36.8
2028	58.5	41.4
2029	60.7	34.0
2030	63.1	37.2
2031	62.6	40.6
2032	61.4	40.8
2033	59.3	41.4
2034	56.7	41.7
2035	47.7	48.4
2036	46.5	48.0
2037	45.4	47.6
2038	44.4	46.8
2039	43.5	46.3
NPV	**700.8**	**474.9**

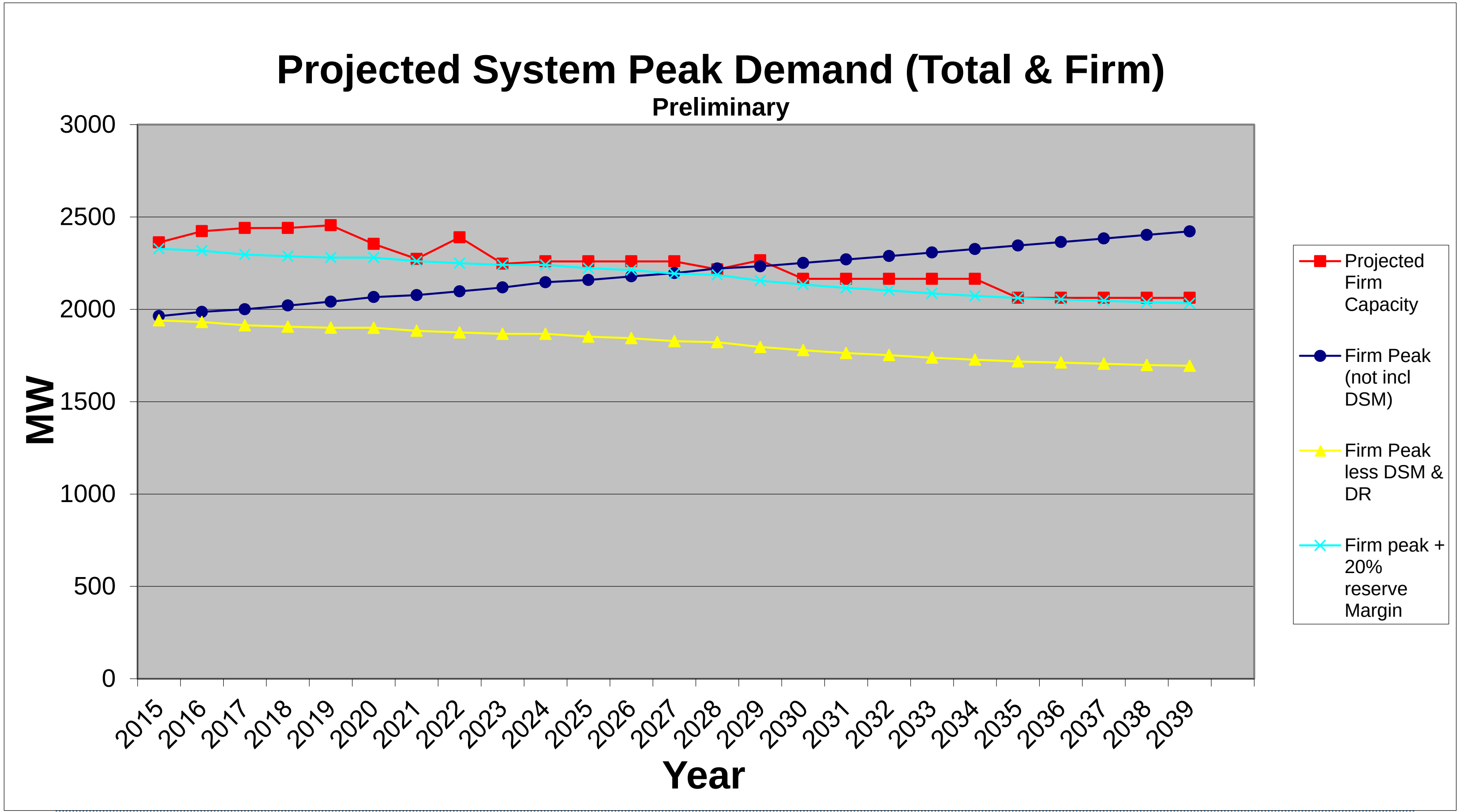
Nova Scotia POWER An Emera Company

CRP8-1 Preliminary Results

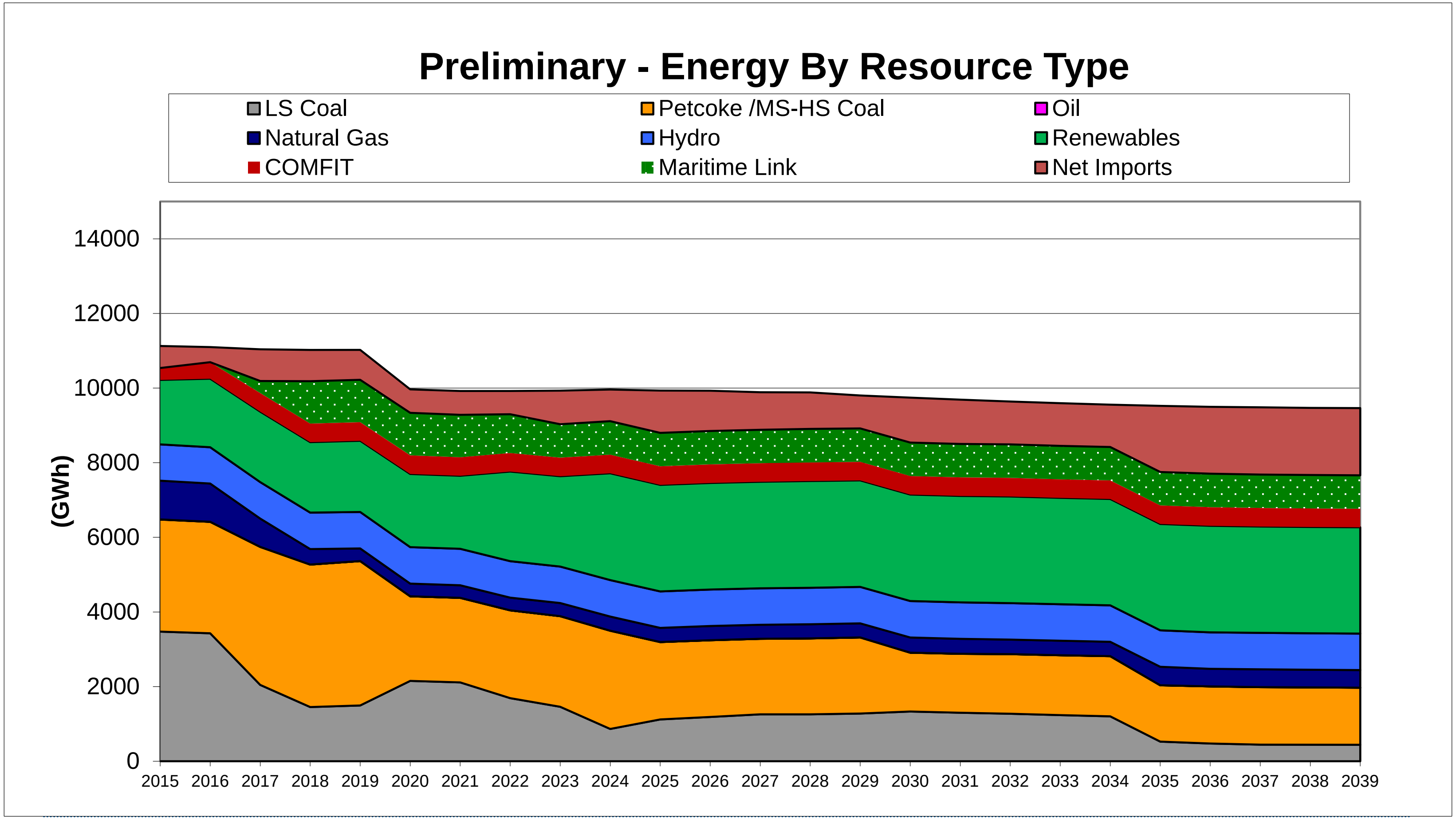
CRP8-1 Preliminary Load and Resources

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	2036	2037	2038	2039
Firm Peak	1,963	1,986	2,000	2,020	2,041	2,066	2,077	2,097	2,118	2,147	2,159	2,251	2,345	2,364	2,383	2,403	2,422
DSM	23	54	84	110	134	156	178	202	224	247	267	412	566	593	616	643	666
Firm Peak Less DSM	1,940	1,932	1,916	1,910	1,907	1,910	1,899	1,896	1,894	1,899	1,892	1,839	1,780	1,771	1,767	1,760	1,756
DRWH Reduction	0	1	2	4	7	10	15	21	27	32	39	60	62	60	62	62	62
DRCM Reduction																	
Firm Peak Less DR	1,940	1,931	1,914	1,906	1,900	1,900	1,884	1,875	1,867	1,867	1852	1779	1718	1,712	1,705	1,698	1,694
RM Required	388	386	383	381	380	380	377	375	373	373	370	355.7	343.6	342	341	340	339
Required MWs	2,328	2,317	2,296	2,287	2,280	2,280	2,261	2,250	2,241	2,241	2223	2134	2062	2,054	2,046	2,038	2,033
Existing MWs	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341
Resource Additions (MW):																	
Burnside #4		33															
COMFIT - Biomass	4.2	6															
COMFIT - Wind	14.14	4.56	5.1														
REA Wind	2.35	17.34															
Maritime Link				153.3													
Small Biomass PPA			10														
Hydro			1.8		15				15								
PH Biomass						51.7											
Additional Wind								18		18							
Assumed Unit Retirement				-153		-153	-81		-158	-153		-150	-152				
Natural Gas Unit								98.8		148.1		49.4	49.4				
Total Annual Additions	20.7	60.9	16.9	0.3	15.0	-101.3	-81.0	116.8	-143.0	13.1	0.0	-100.6	-102.6	0.0	0.0	0.0	0.0
Total Cumulative Additions	20.7	81.6	98.5	98.7	113.7	12.4	-68.6	48.2	-94.8	-81.7	-81.7	-176.5	-279.1	-279.1	-279.1	-279.1	-279.1
Total Firm Capacity	2362	2423	2440	2440	2455	2354	2273	2390	2247	2260	2260	2165	2062	2062	2062	2062	2062
Surplus (Deficit) MWs above RM	34	106	143	153	175	74	12	140	6	19	37	31	1	8	16	24	29
Reserve Margin %	21.8%	25.5%	27.5%	28.0%	29.2%	23.9%	20.6%	27.5%	20.3%	21.0%	22.0%	21.7%	20.0%	20.5%	20.9%	21.4%	21.7%

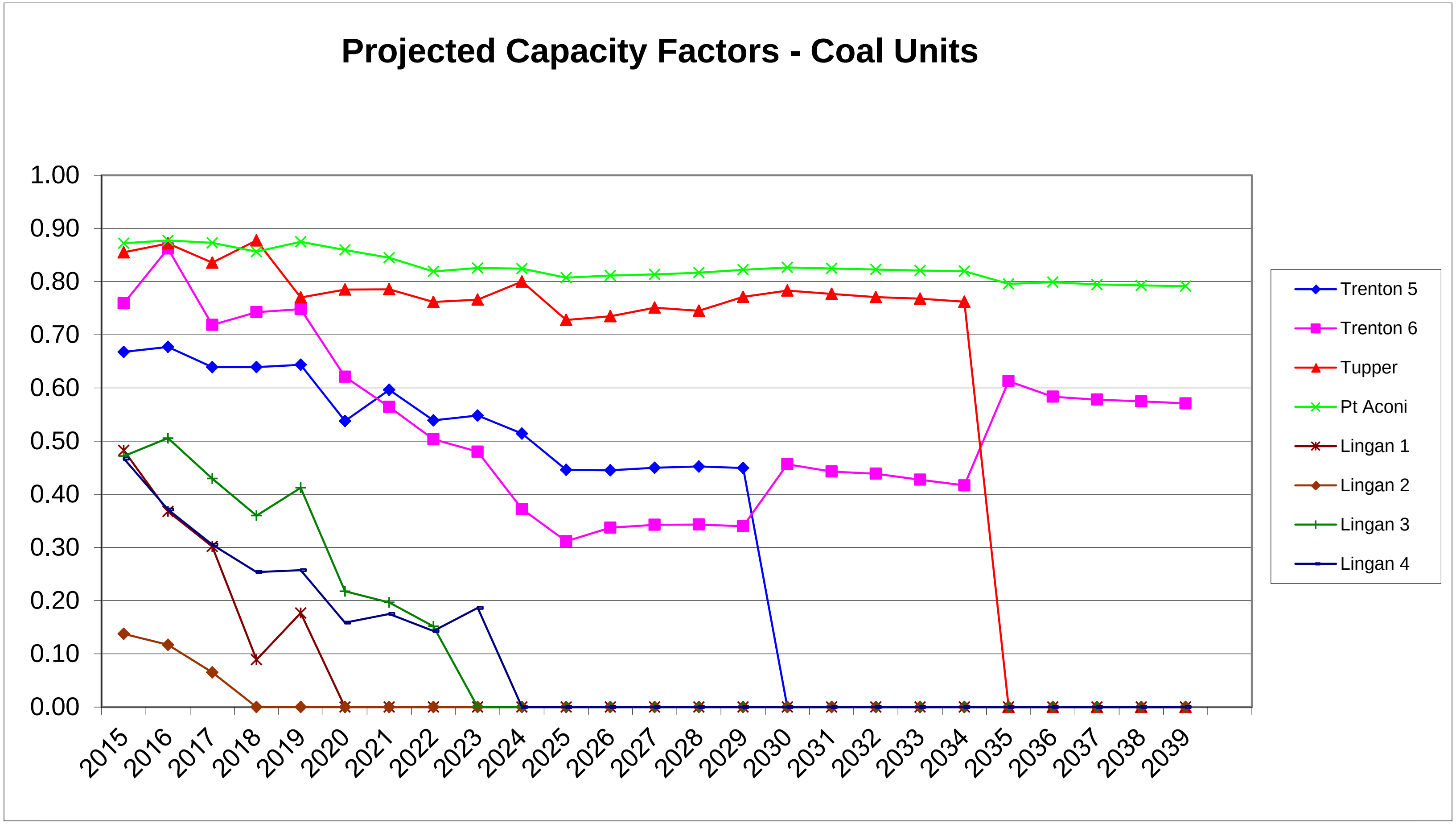
CRP8-1 Preliminary Demand and DSM



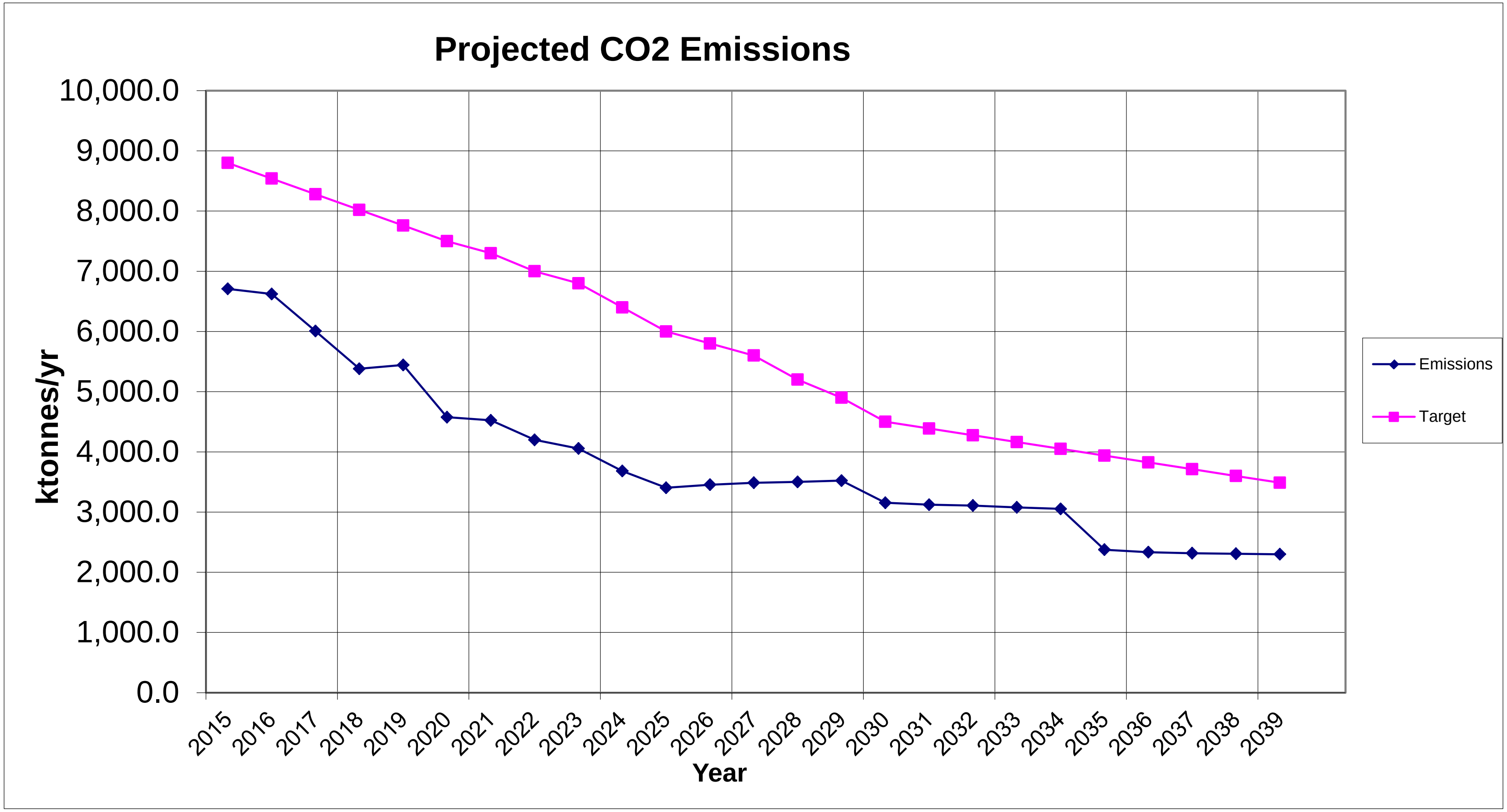
CRP8-1 Preliminary Energy by Resource Type



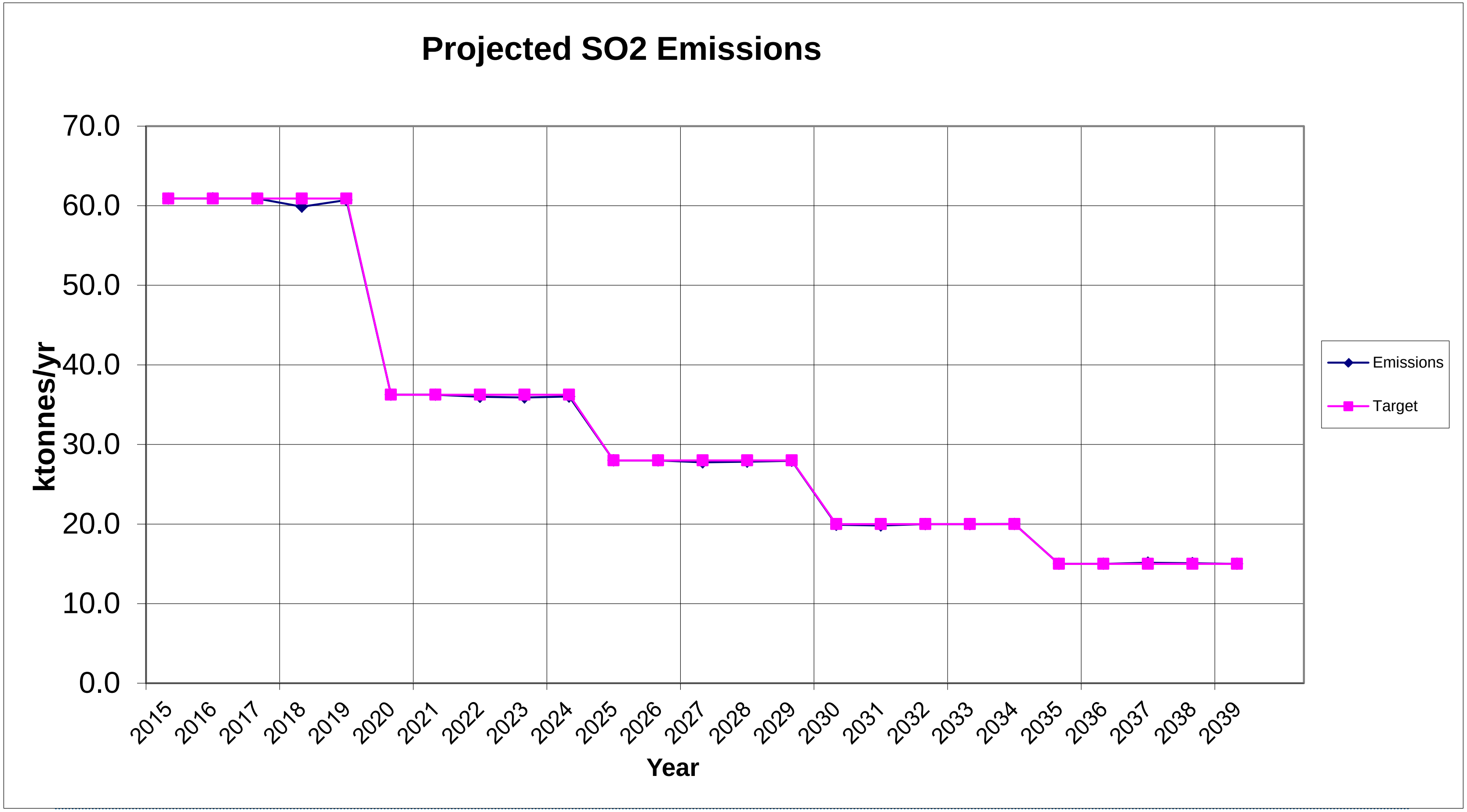
CRP8-1 Preliminary Coal Capacity Factors



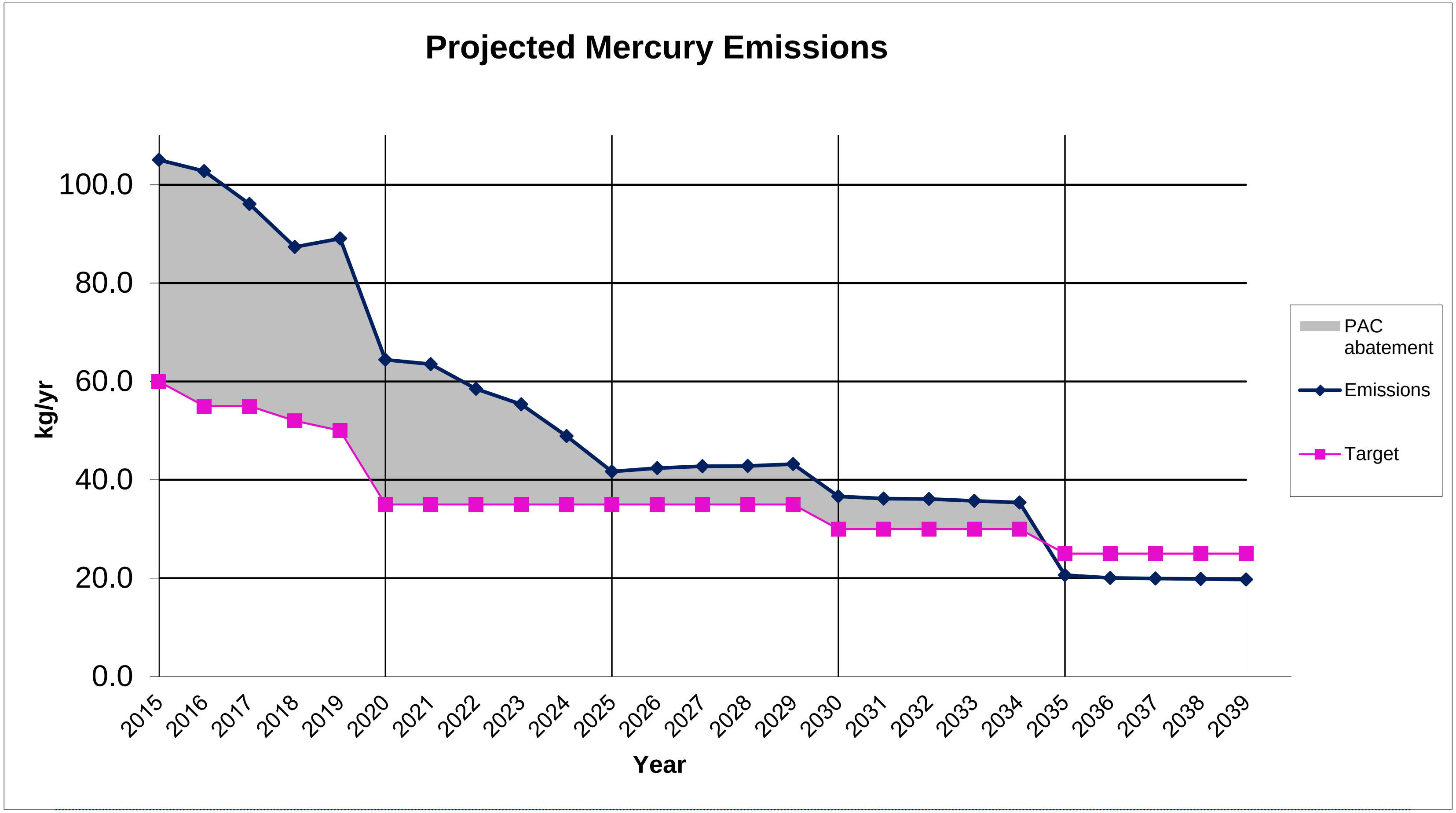
CRP8-1 Preliminary CO_2 Emissions



CRP8-1 Preliminary SO_2 Emissions



CRP8-1 Preliminary Mercury Emissions



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CRP9 Preliminary Results

CRP9 Input Assumptions

Candidate Resource Plan 9 (CRP9):

- Base Load Forecast
- Base DSM
- Emissions - Scenario A
- Planned and committed resources are fixed in the plan (REA wind, COMFIT, Maritime Link/ Retire Lin #2)
- Minimum Coal Use
- Medium Wind (Wind integration: 2 x CT 50 MW and $200M for reliability tie and transmission upgrades)
- Constraints
  - Planning reserve margin min = 20%
  - RES: 2015-2019 = 25%; 2020-2039 = 40%

CRP9 Preliminary Results

	CRP9-01-R01	**CRP9-03-R01**
	Least cost study period	**Least cost in planning period**
2015		
2016	DR Water H & DR Comm	DR Water H & DR Comm
2017	ML Oct 2017	ML Oct 2017
	Lin 2 retire	Lin 2 retire
2018		
2019	Mersey Phase 1	Mersey Phase 1
2020	Lingan 1 Retire	Lingan 1 Retire
	PHBM 51.7 MW Firm	PHBM 51.7 MW Firm
2021	TUC 1 Retire	TUC 1 Retire
2022		
2023	Lingan 3 Retire	Lingan 3 Retire
	Mersey Phase 2	Mersey Phase 2
	Wind Block 150 MW	Wind Block 150 MW
	2 x 50 MW CT (wind integration)	2 x 50 MW CT (wind integration)
2024	Lingan 4 Retire	Lingan 4 Retire
	CC 145 MW	CT 34 MW & 2 x CT 50 MW
2025		
2026		
2027		
2028	TUC 2 Retire	TUC 2 Retire
	CT 50MW	CT 34 MW
2029		
2030	Trenton 5 Retire	Trenton 5 Retire
	2 x CT 50MW	2 x CT 50MW
2031		
2032		
2033		
2034		
2035	Tupper 2 Retire	Tupper 2 Retire
	CT 50MW	CT 34 MW & CT 50 MW
2036		
2037		
2038		
2039		
Planning PV $M	11,896	11,878
Study PV $M	17,787	17,796

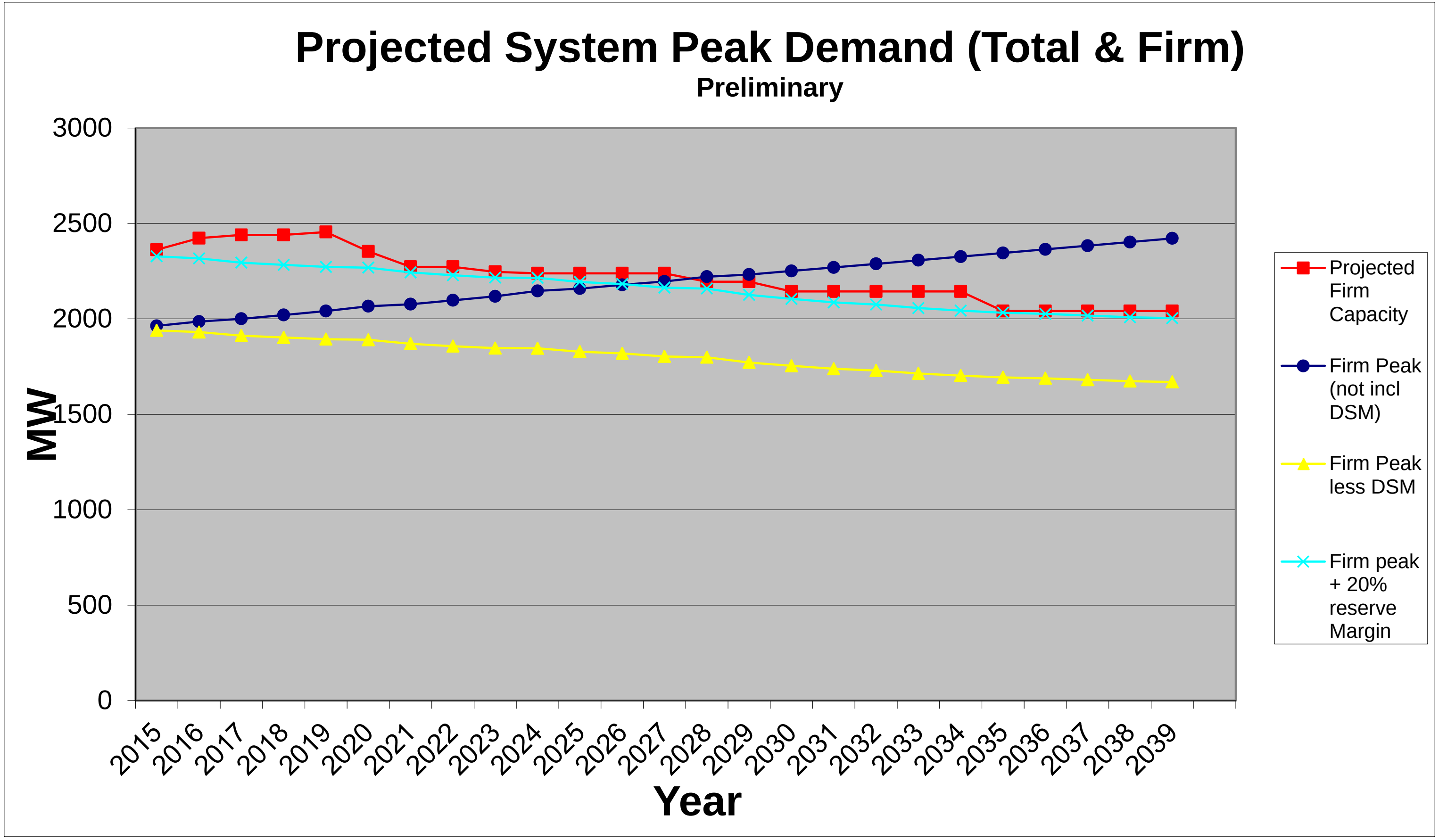
	Base DSM	Base DSM
	Program Adm Cost	Customer Cost
	$M	$M
2015	50.7	37.9
2016	50.5	39.9
2017	50.0	41.2
2018	52.4	41.6
2019	57.0	32.2
2020	61.5	28.0
2021	56.9	28.4
2022	54.1	28.4
2023	51.5	29.2
2024	50.8	28.6
2025	50.6	29.9
2026	52.1	33.8
2027	54.8	36.8
2028	58.5	41.4
2029	60.7	34.0
2030	63.1	37.2
2031	62.6	40.6
2032	61.4	40.8
2033	59.3	41.4
2034	56.7	41.7
2035	47.7	48.4
2036	46.5	48.0
2037	45.4	47.6
2038	44.4	46.8
2039	43.5	46.3
NPV	**700.8**	**474.9**

CRP9-1 Preliminary Results

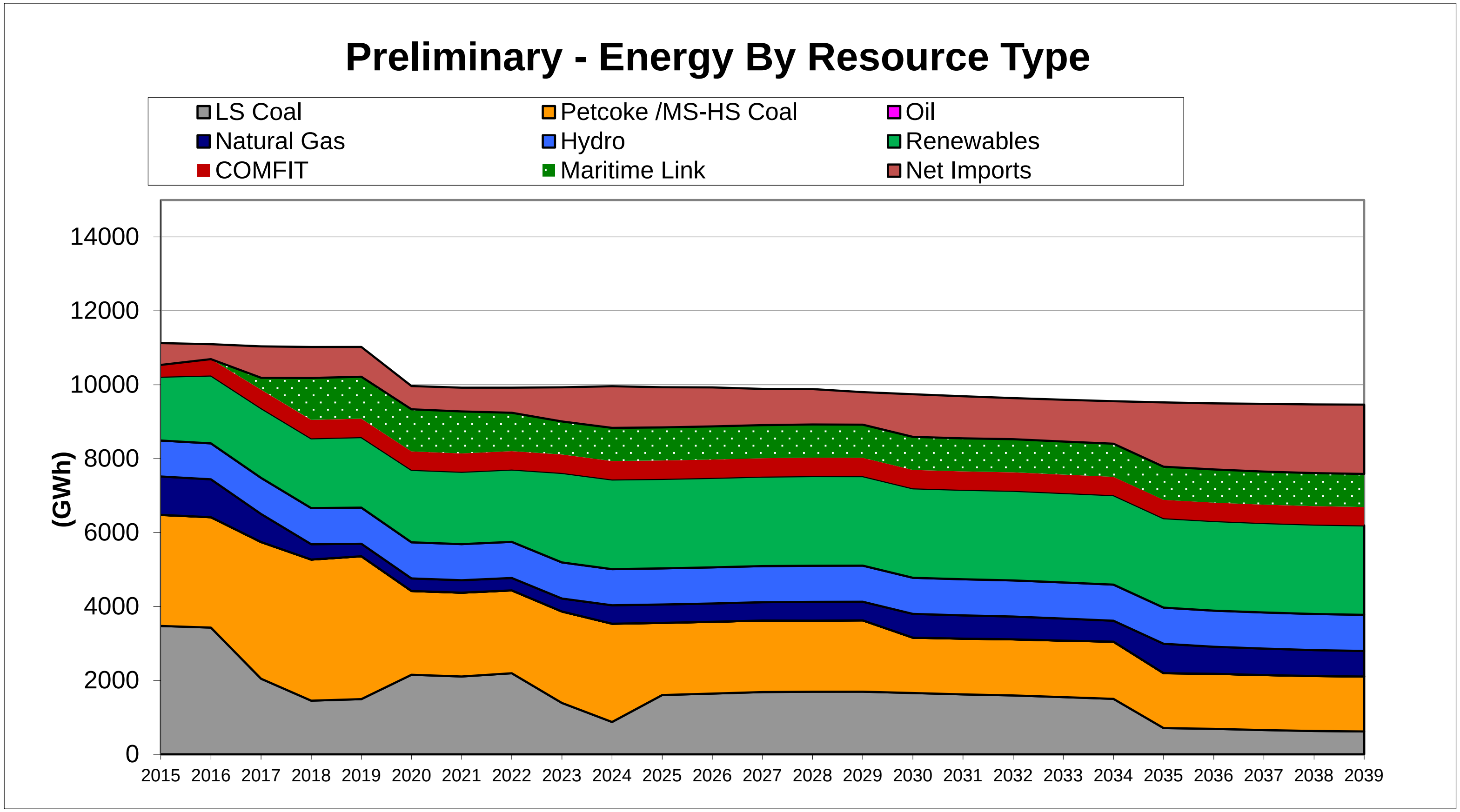
CRP9-1 Preliminary Load and Resources

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	2036	2037	2038	2039
Firm Peak	1,963	1,986	2,000	2,020	2,041	2,066	2,077	2,097	2,118	2,147	2,159	2,251	2,345	2,364	2,383	2,403	2,422
DSM	23	54	84	110	134	156	178	202	224	247	267	412	566	593	616	643	666
Firm Peak Less DSM	1,940	1,932	1,916	1,910	1,907	1,910	1,899	1,896	1,894	1,899	1,892	1,839	1,780	1,771	1,767	1,760	1,756
DRWH Reduction	0	1	2	4	7	10	15	21	27	32	39	60	62	60	62	62	62
DRCM Reduction	0	0	1	4	7	10	14	18	20	21	24	24	24	23	24	24	24
Firm Peak Less DR	1,940	1,931	1,912	1,903	1,894	1,890	1,870	1,857	1,847	1,846	1828	1754	1693	1,689	1,681	1,674	1,670
RM Required	388	386	382	381	379	378	374	371	369	369	366	350.8	338.7	338	336	335	334
Required MWs	2,328	2,317	2,295	2,283	2,272	2,269	2,244	2,229	2,216	2,215	2194	2105	2032	2,026	2,017	2,009	2,004
Existing MWs	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341
Resource Additions (MW):																	
Burnside #4		33															
COMFIT - Biomass	4.2	6															
COMFIT - Wind	14.14	4.56	5.1														
REA Wind	2.35	17.34															
Maritime Link				153.3													
Small Biomass PPA			10														
Hydro			1.8		15				15								
PH Biomass						51.7											
Additional Wind									18								
Assumed Unit Retirement				-153		-153	-81		-158	-153		-150	-152				
Natural Gas Unit									98.8	145		98.8	49.4				
Total Annual Additions	20.7	60.9	16.9	0.3	15.0	-101.3	-81.0	0.0	-26.2	-8.0	0.0	-51.2	-102.6	0.0	0.0	0.0	0.0
Total Cumulative Additions	20.7	81.6	98.5	98.7	113.7	12.4	-68.6	-68.6	-94.8	-102.8	-102.8	-197.6	-300.2	-300.2	-300.2	-300.2	-300.2
Total Firm Capacity	2362	2423	2440	2440	2455	2354	2273	2273	2247	2239	2239	2144	2041	2041	2041	2041	2041
Surplus (Deficit) MWs above RM	34	106	145	157	183	85	29	44	30	23	45	39	9	15	24	33	38
Reserve Margin %	21.8%	25.5%	27.6%	28.3%	29.6%	24.5%	21.6%	22.4%	21.6%	21.3%	22.5%	22.2%	20.5%	20.9%	21.4%	21.9%	22.3%

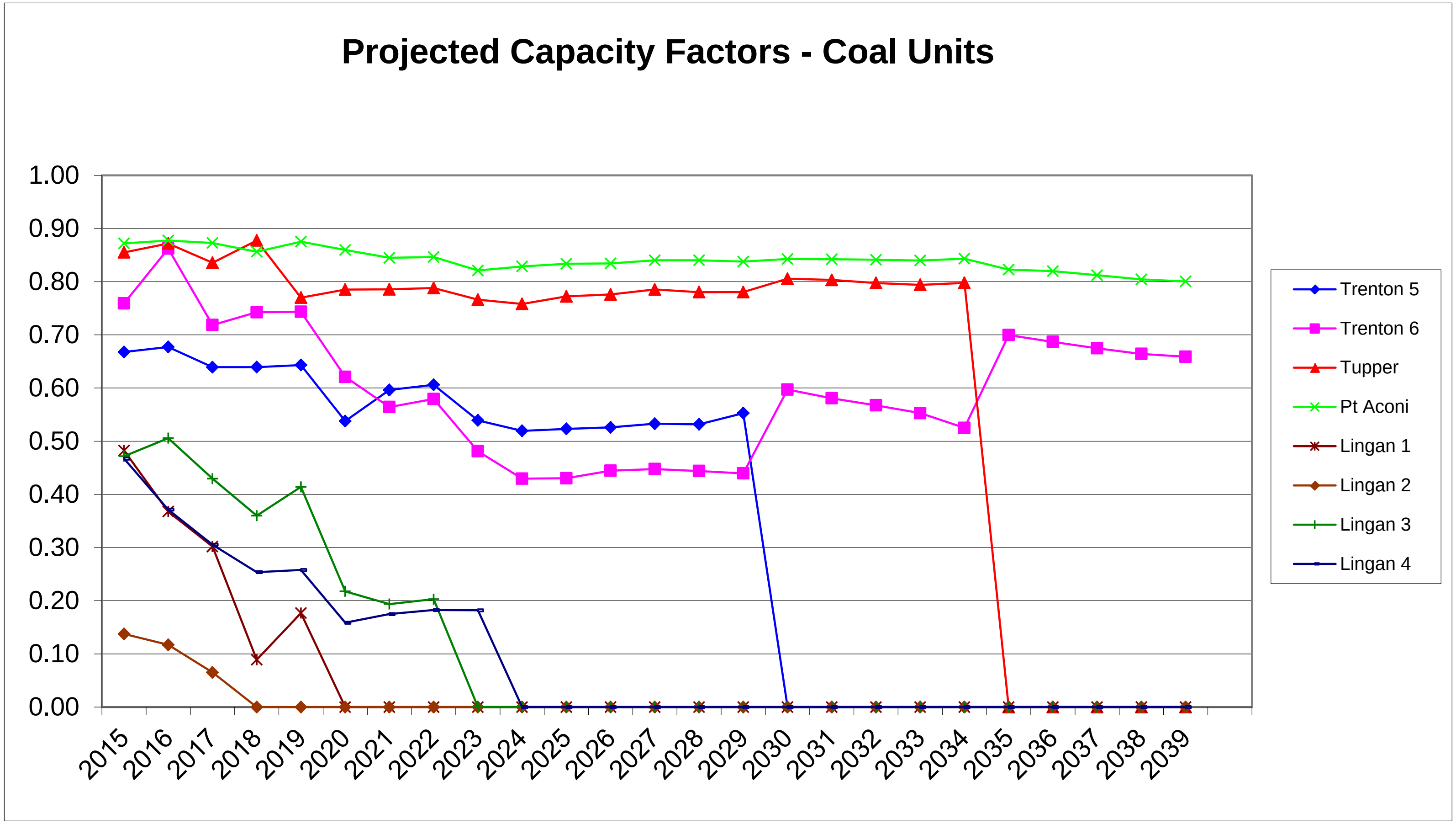
CRP9-1 Preliminary Demand and DSM



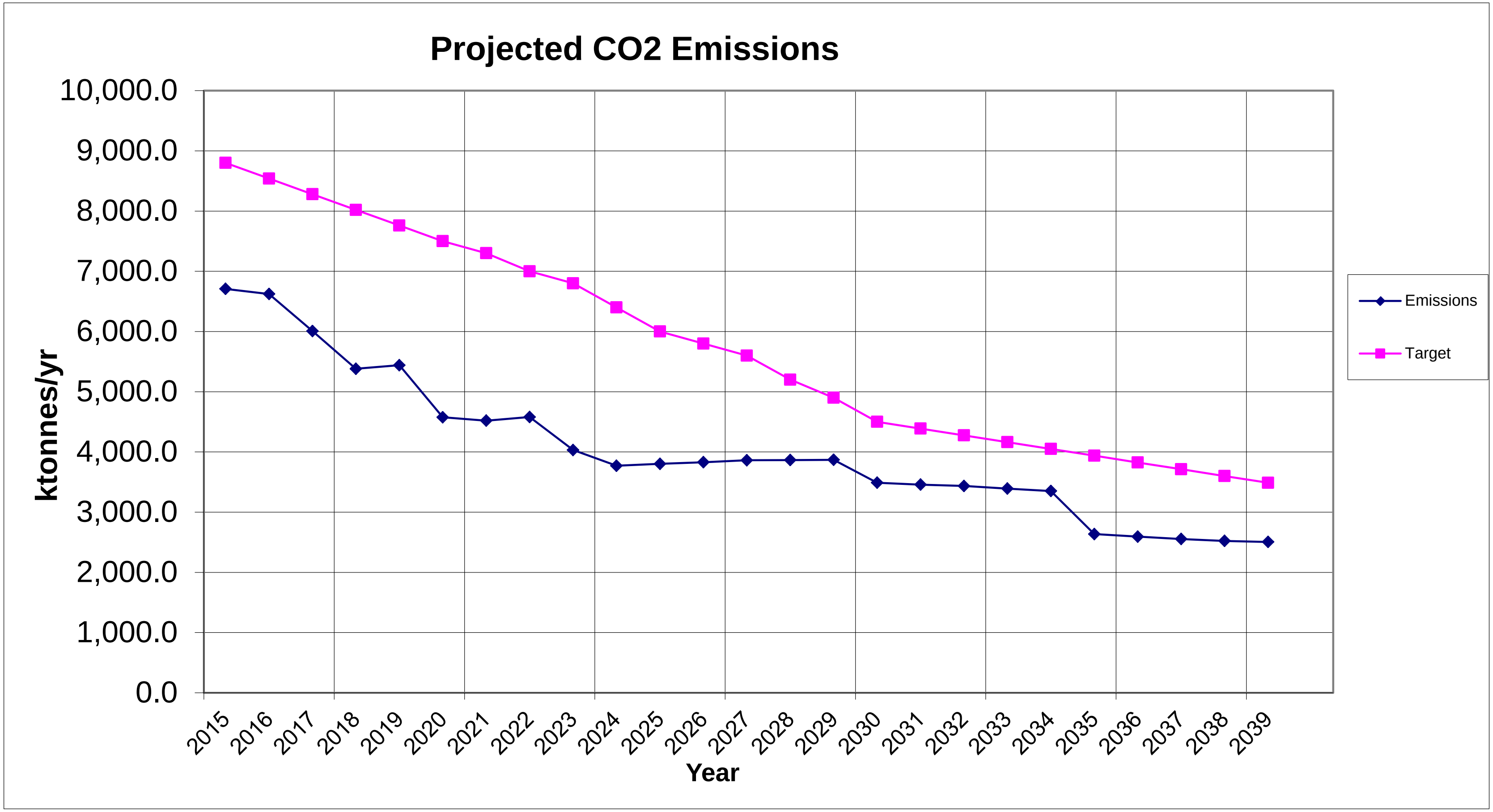
CRP9-1 Preliminary Energy by Resource Type



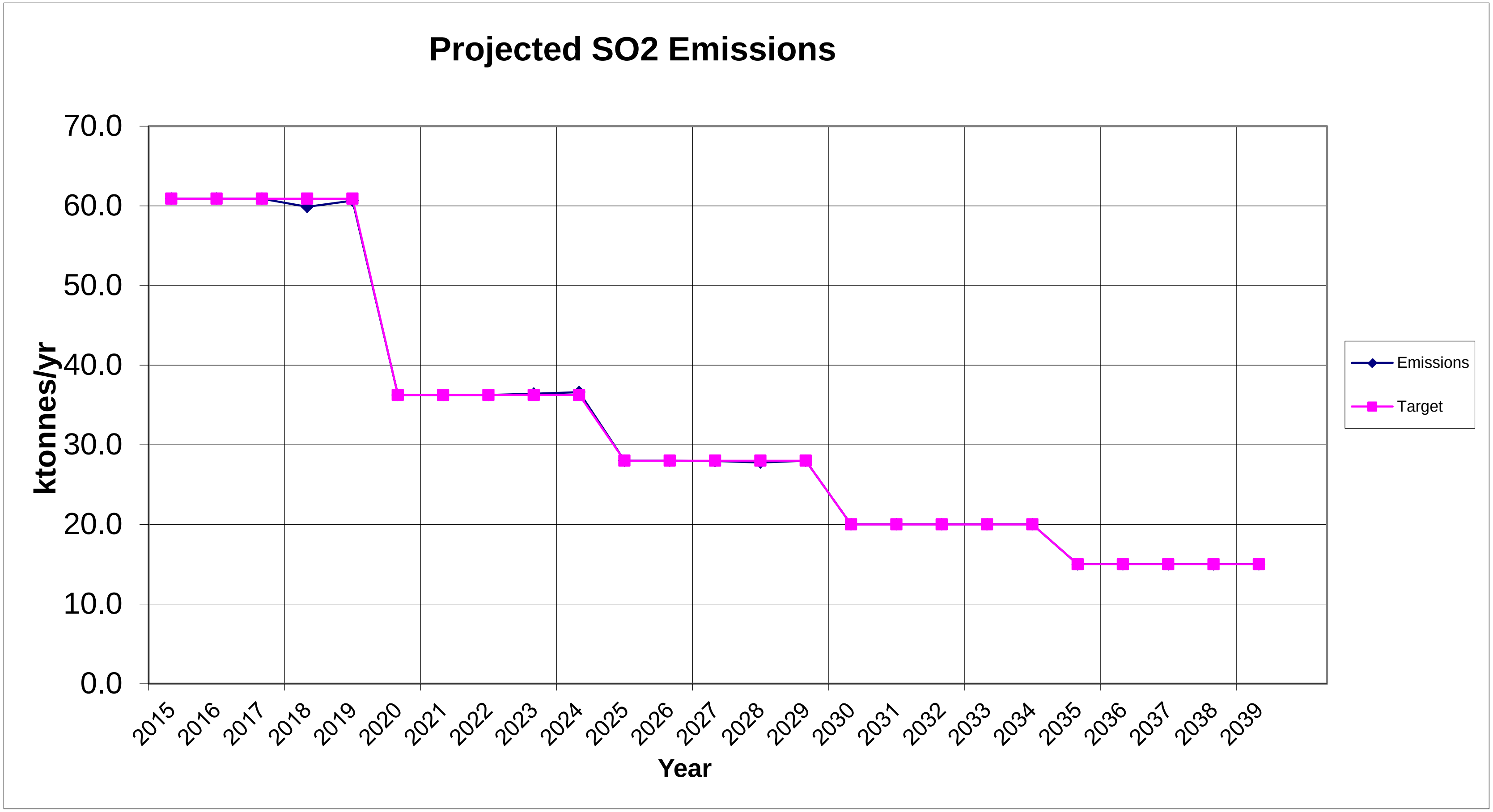
CRP9-1 Preliminary Coal Capacity Factors



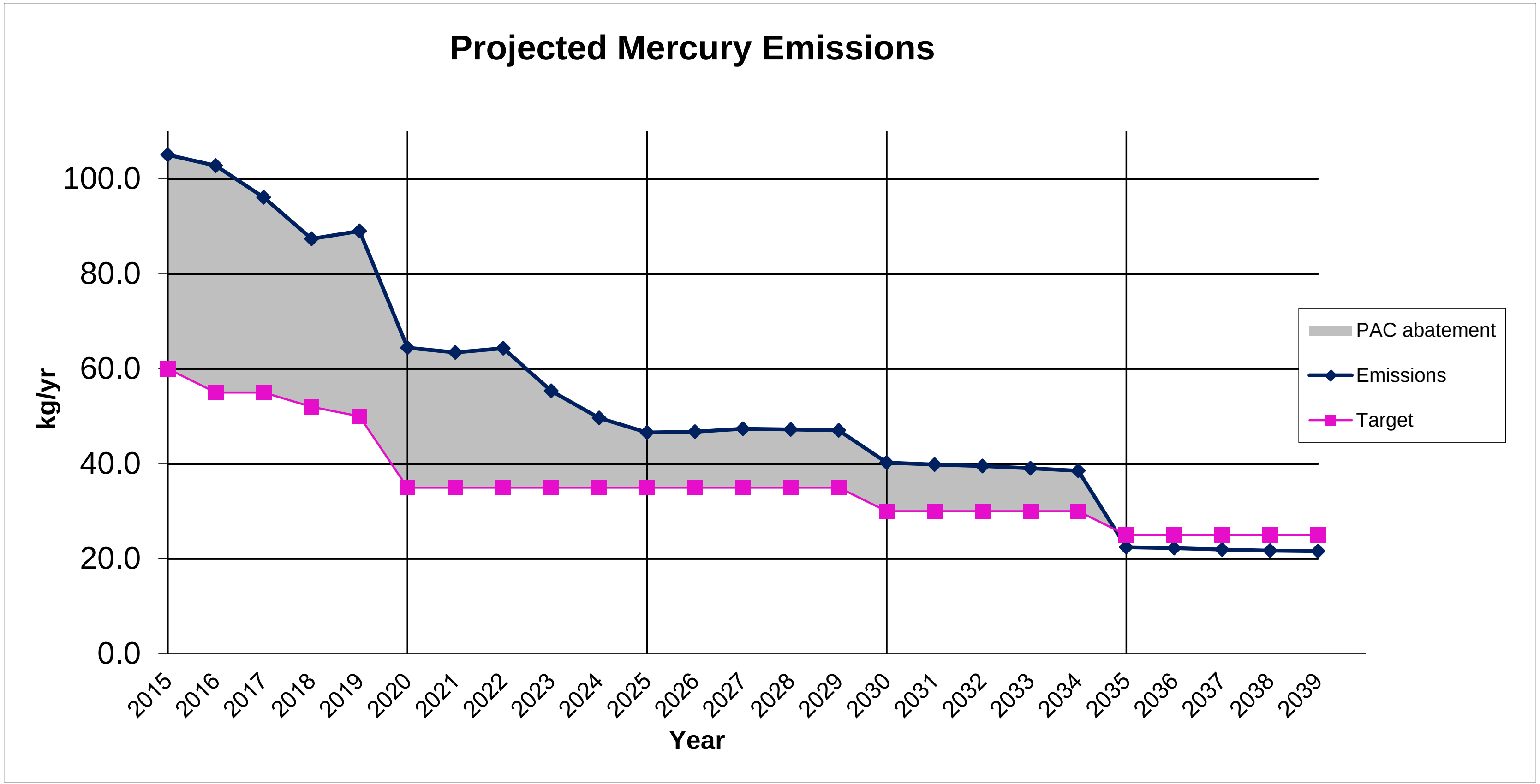
CRP9-1 Preliminary CO$_2$ Emissions



CRP9-1 Preliminary SO_2 Emissions



CRP9-1 Preliminary Mercury Emissions



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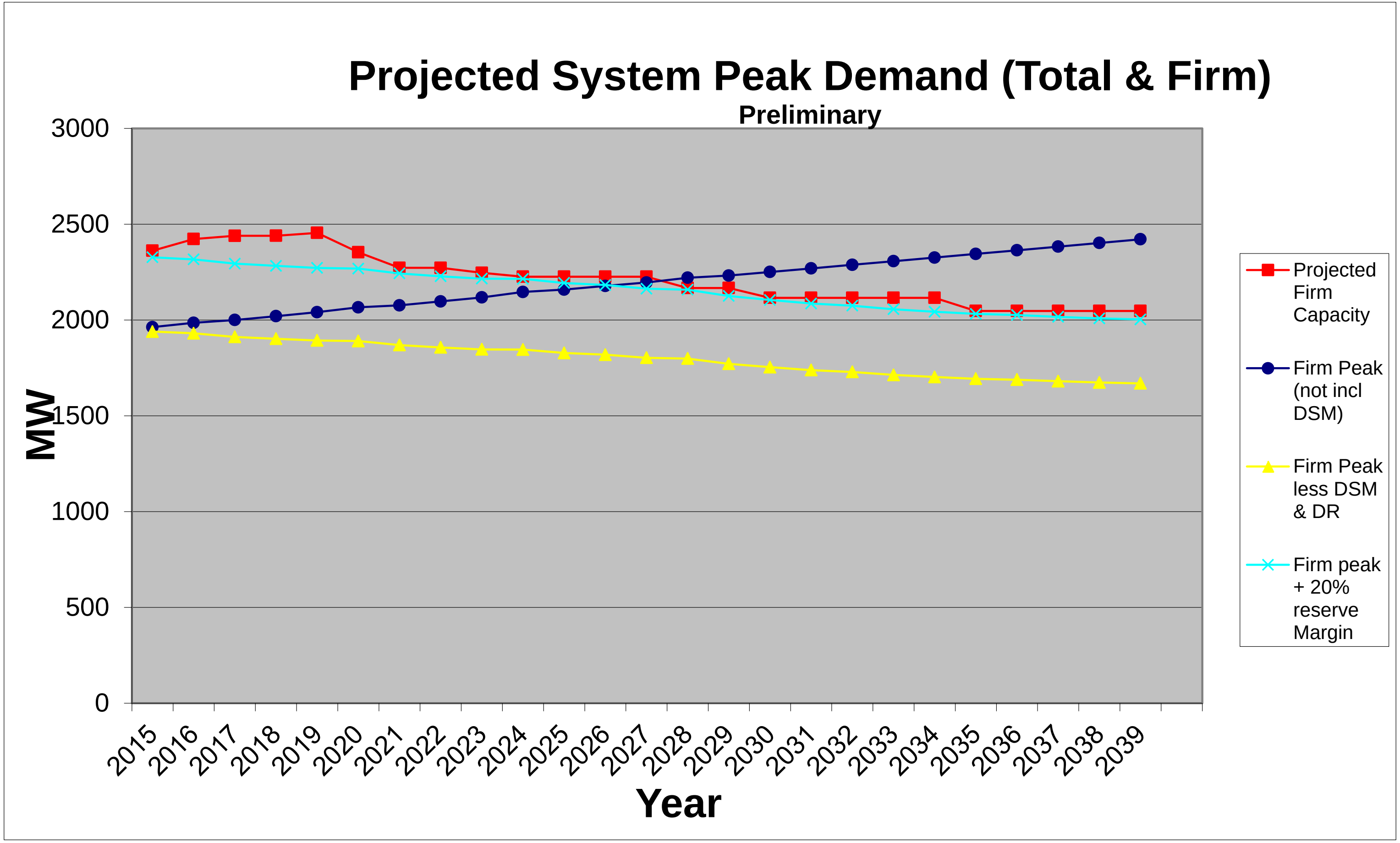
CRP9-3 Preliminary Results

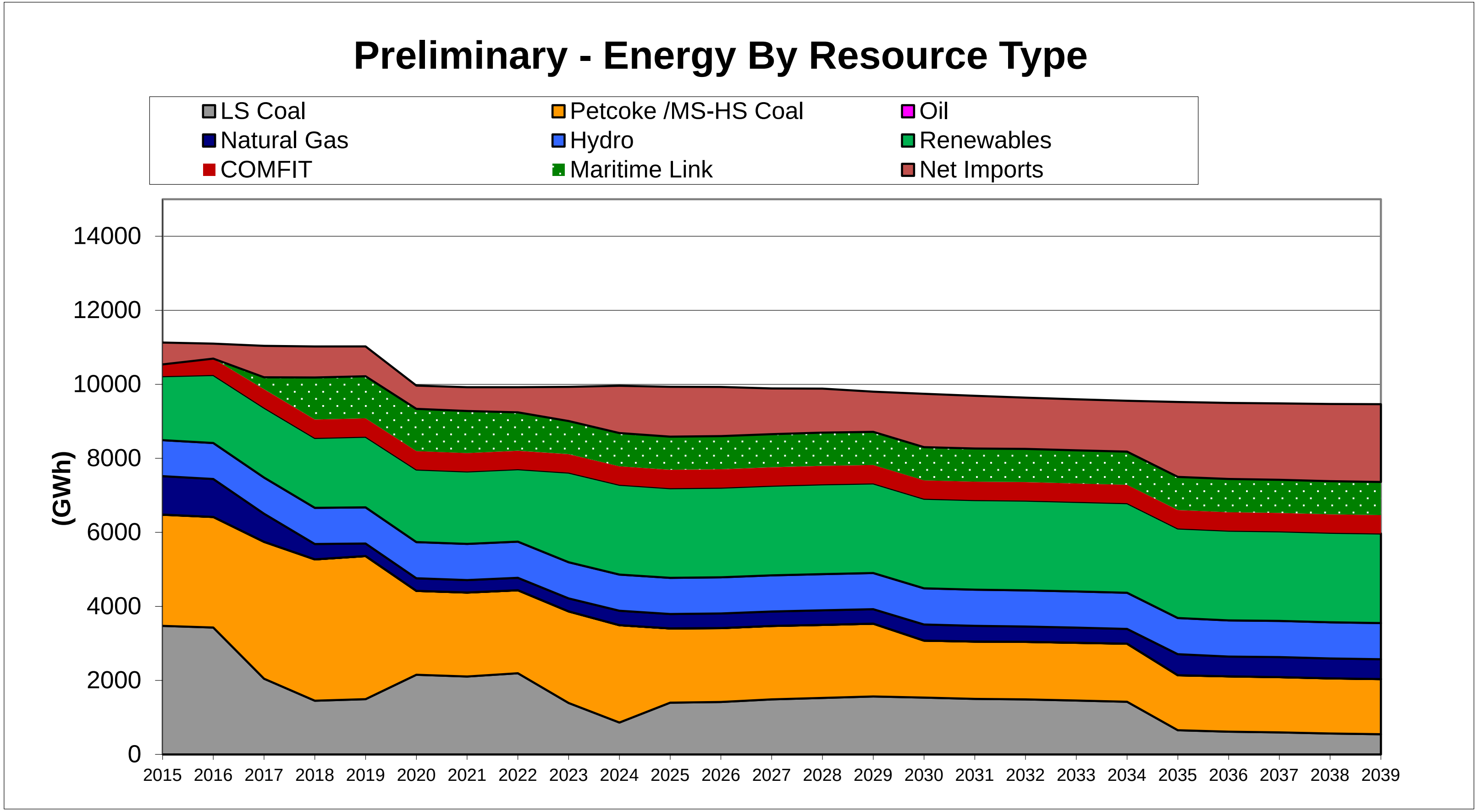
CRP9-3 Preliminary Load and Resources

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	2036	2037	2038	2039
Firm Peak	1,963	1,986	2,000	2,020	2,041	2,066	2,077	2,097	2,118	2,147	2,159	2,251	2,345	2,364	2,383	2,403	2,422
DSM	23	54	84	110	134	156	178	202	224	247	267	412	566	593	616	643	666
Firm Peak Less DSM	1,940	1,932	1,916	1,910	1,907	1,910	1,899	1,896	1,894	1,899	1,892	1,839	1,780	1,771	1,767	1,760	1,756
DRWH Reduction	0	1	2	4	7	10	15	21	27	32	39	60	62	60	62	62	62
DRCM Reduction	0	0	1	4	7	10	14	18	20	21	24	24	24	23	24	24	24
Firm Peak Less DR	1,940	1,931	1,912	1,903	1,894	1,890	1,870	1,857	1,847	1,846	1828	1754	1693	1,689	1,681	1,674	1,670
RM Required	388	386	382	381	379	378	374	371	369	369	366	350.8	338.7	338	336	335	334
Required MWs	2,328	2,317	2,295	2,283	2,272	2,269	2,244	2,229	2,216	2,215	2194	2105	2032	2,026	2,017	2,009	2,004
Existing MWs	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341
Resource Additions (MW):																	
Burnside #4		33															
COMFIT - Biomass	4.2	6															
COMFIT - Wind	14.14	4.56	5.1														
REA Wind	2.35	17.34															
Maritime Link				153.3													
Small Biomass PPA			10														
Hydro			1.8		15				15								
PH Biomass						51.7											
Additional Wind									18								
Assumed Unit Retirement				-153		-153	-81		-158	-153		-150	-152				
Natural Gas Unit									98.8	132.8		98.8	83.4				
Total Annual Additions	20.7	60.9	16.9	0.3	15.0	-101.3	-81.0	0.0	-26.2	-20.2	0.0	-51.2	-68.6	0.0	0.0	0.0	0.0
Total Cumulative Additions	20.7	81.6	98.5	98.7	113.7	12.4	-68.6	-68.6	-94.8	-115.0	-115.0	-225.2	-293.8	-293.8	-293.8	-293.8	-293.8
Total Firm Capacity	2362	2423	2440	2440	2455	2354	2273	2273	2247	2226	2226	2116	2048	2048	2048	2048	2048
Surplus (Deficit) MWs above RM	34	106	145	157	183	85	29	44	30	11	33	11	15	21	31	39	44
Reserve Margin %	21.8%	25.5%	27.6%	28.3%	29.6%	24.5%	21.6%	22.4%	21.6%	20.6%	21.8%	20.6%	20.9%	21.3%	21.8%	22.3%	22.6%

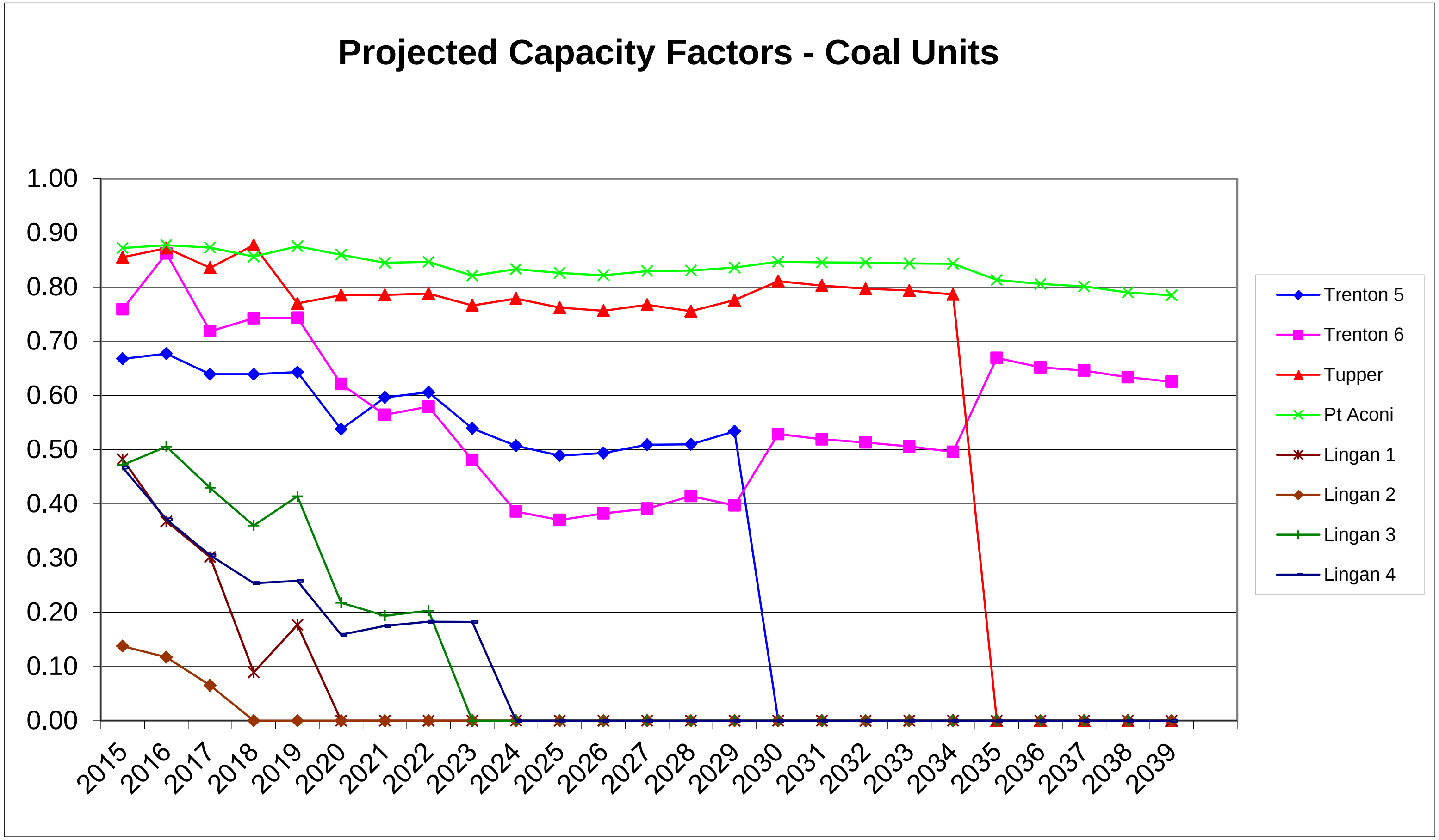
CRP9-3 Preliminary Demand and DSM



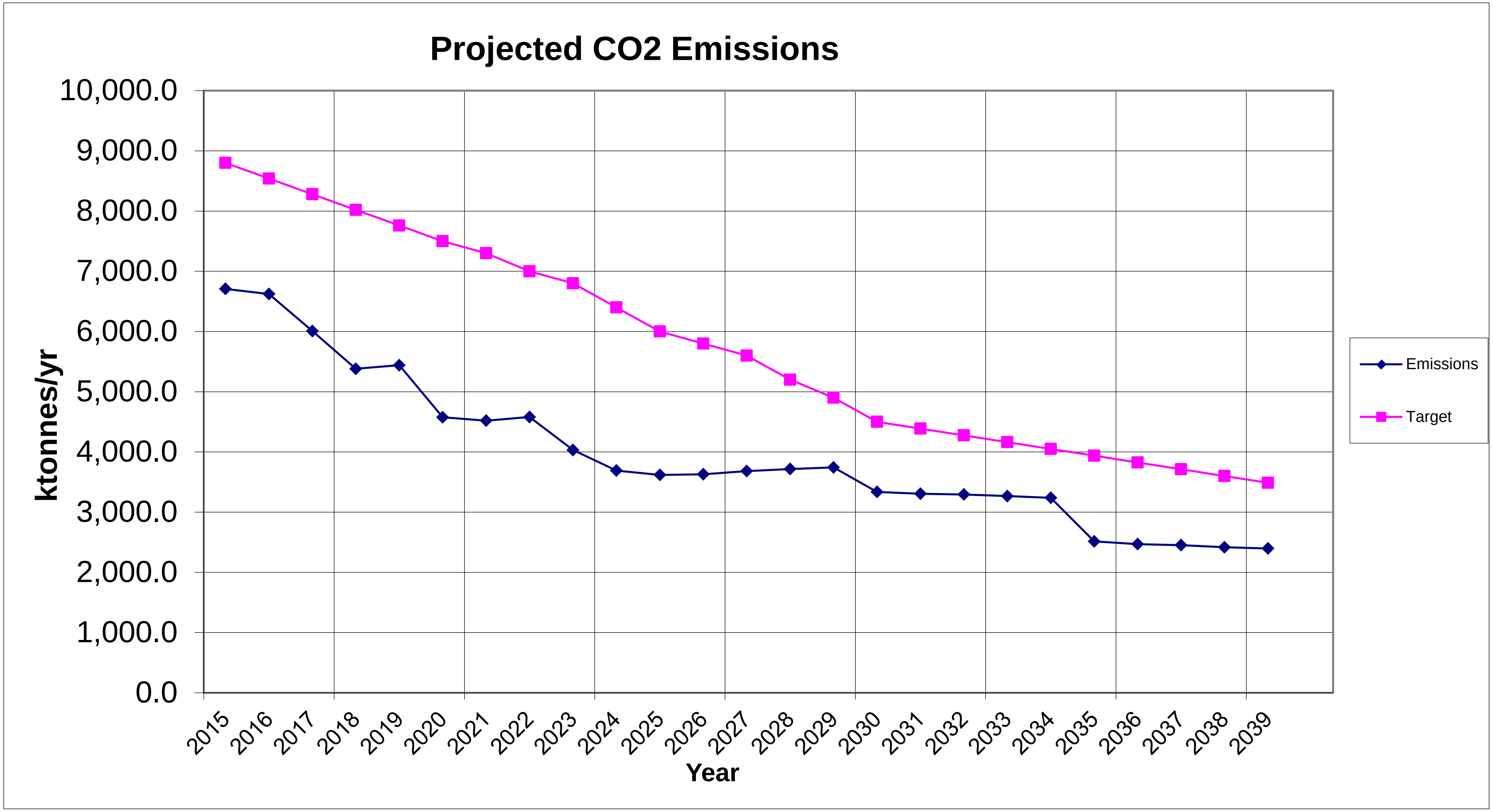
CRP9-3 Preliminary Energy by Resource Type



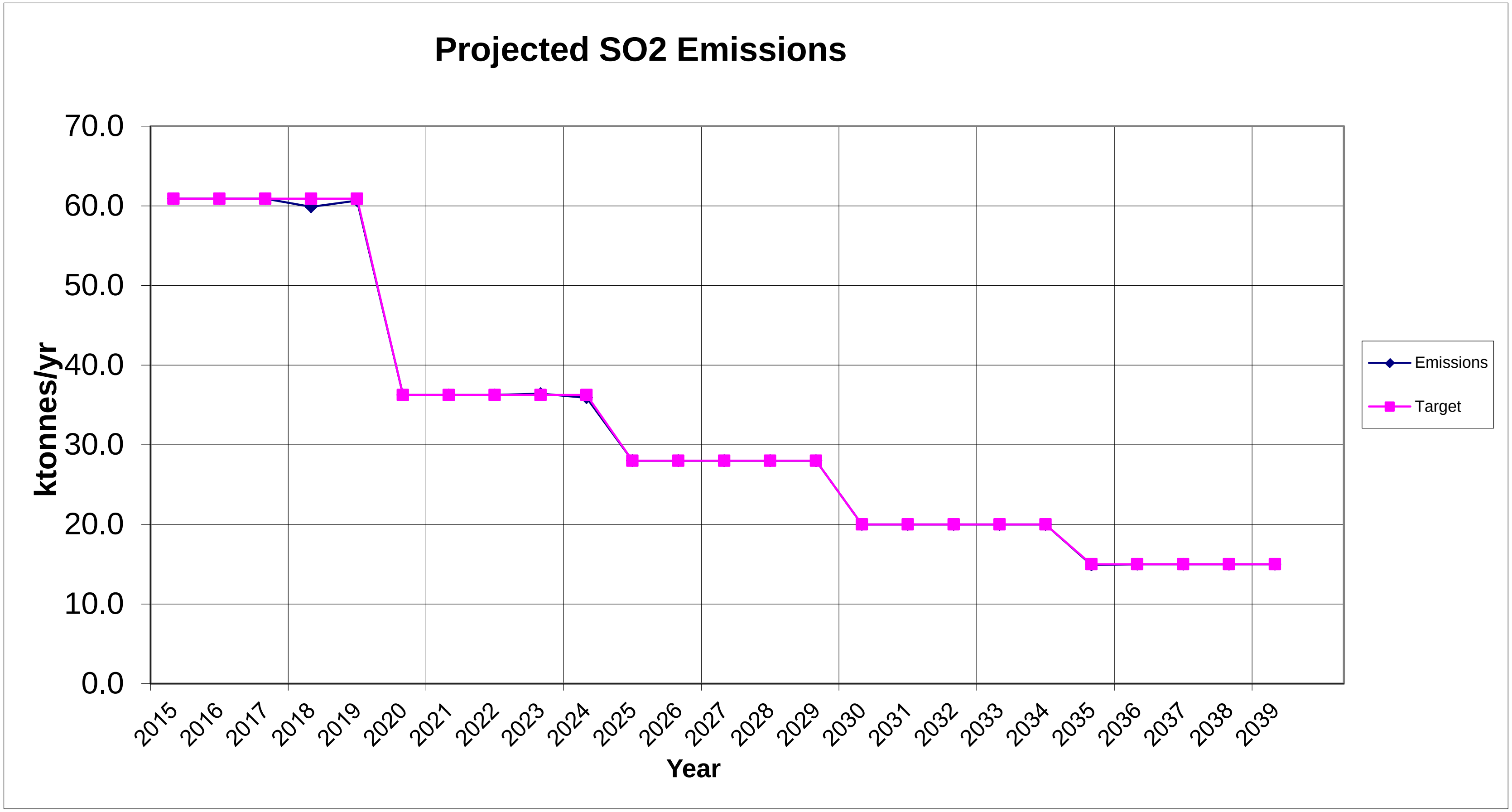
CRP9-3 Preliminary Coal Capacity Factors



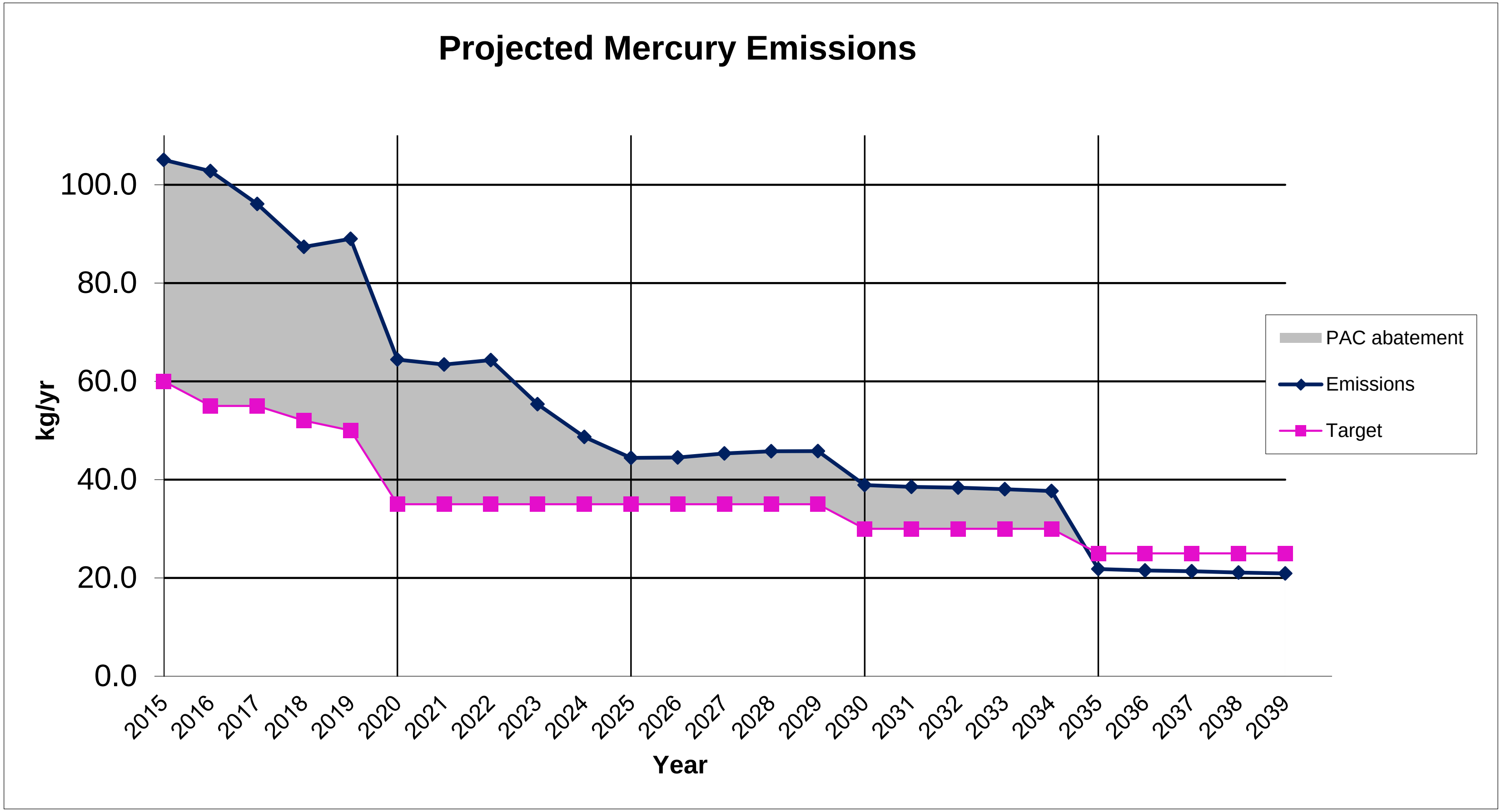
CRP9-3 Preliminary CO_2 Emissions



CRP9-3 Preliminary SO_2 Emissions



CRP9-3 Preliminary Mercury Emissions



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CRP9WC Preliminary Results

CRP9WC Input Assumptions

Candidate Resource Plan 9 Wind Firm Capacity (CRP9WC):

- Base Load Forecast
- Base DSM
- Emissions - Scenario A
- Planned and committed resources are fixed in the plan (REA wind, COMFIT, Maritime Link/ Retire Lin #2)
- Minimum Coal Use
- Medium Wind (Wind integration: 2 x CT 50 MW and $200M for reliability tie and transmission upgrades)
- Firm capacity credit for all wind assumed to be 24.1%
- Constraints
  - Planning reserve margin min = 20%
  - RES: 2015-2019 = 25%; 2020-2039 = 40%

CRP9WC Preliminary Results

	CRP9WC-02-R01
	Least cost planning period
2015	(All Wind 24.1% Firm Capacity Credit)
2016	DR Water H & DR Comm
2017	ML Oct 2017
	Lin 2 retire
2018	
2019	Mersey Phase 1
2020	Lingan 1 Retire
	PHBM 51.7 MW Firm
2021	TUC 1 Retire
2022	
2023	Lingan 3 Retire
	Mersey Phase 2
	Wind Block 150 MW
	2 x 50 MW CT (wind integration)
2024	Lingan 4 Retire
	CT 50MW
2025	
2026	
2027	
2028	TUC 2 Retire
	CT 50MW
2029	
2030	Trenton 5 Retire
	CT 50MW & CT 34MW
2031	
2032	
2033	
2034	
2035	Tupper 2 Retire
	CT 50MW & CT 34MW
2036	
2037	
2038	
2039	
Planning PV $M	11,797
Study PV $M	17,664

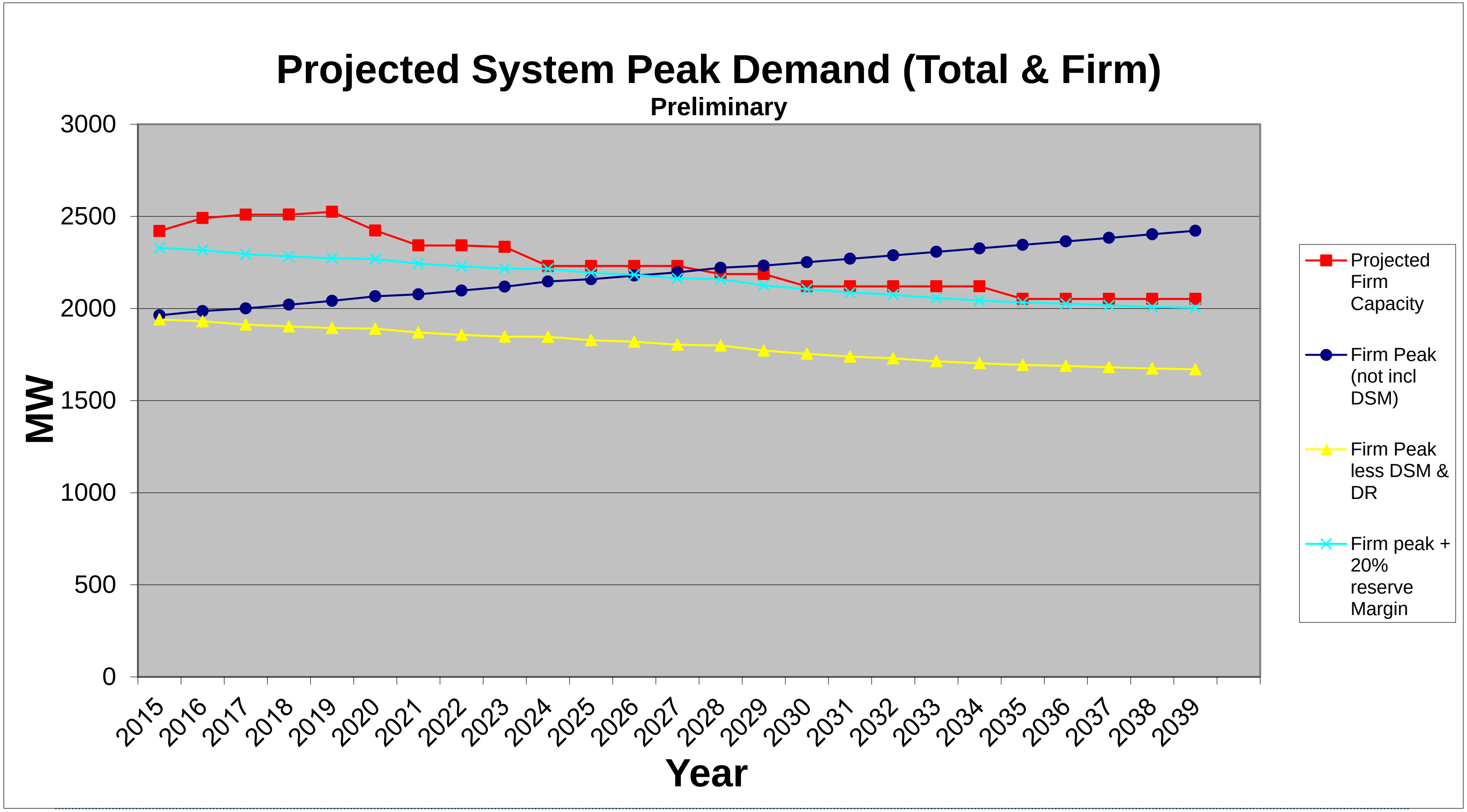
	Base DSM	Base DSM
	Program Adm Cost	Customer Cost
	$M	$M
2015	50.7	37.9
2016	50.5	39.9
2017	50.0	41.2
2018	52.4	41.6
2019	57.0	32.2
2020	61.5	28.0
2021	56.9	28.4
2022	54.1	28.4
2023	51.5	29.2
2024	50.8	28.6
2025	50.6	29.9
2026	52.1	33.8
2027	54.8	36.8
2028	58.5	41.4
2029	60.7	34.0
2030	63.1	37.2
2031	62.6	40.6
2032	61.4	40.8
2033	59.3	41.4
2034	56.7	41.7
2035	47.7	48.4
2036	46.5	48.0
2037	45.4	47.6
2038	44.4	46.8
2039	43.5	46.3
NPV	**700.8**	**474.9**

CRP9WC-2 Preliminary Results

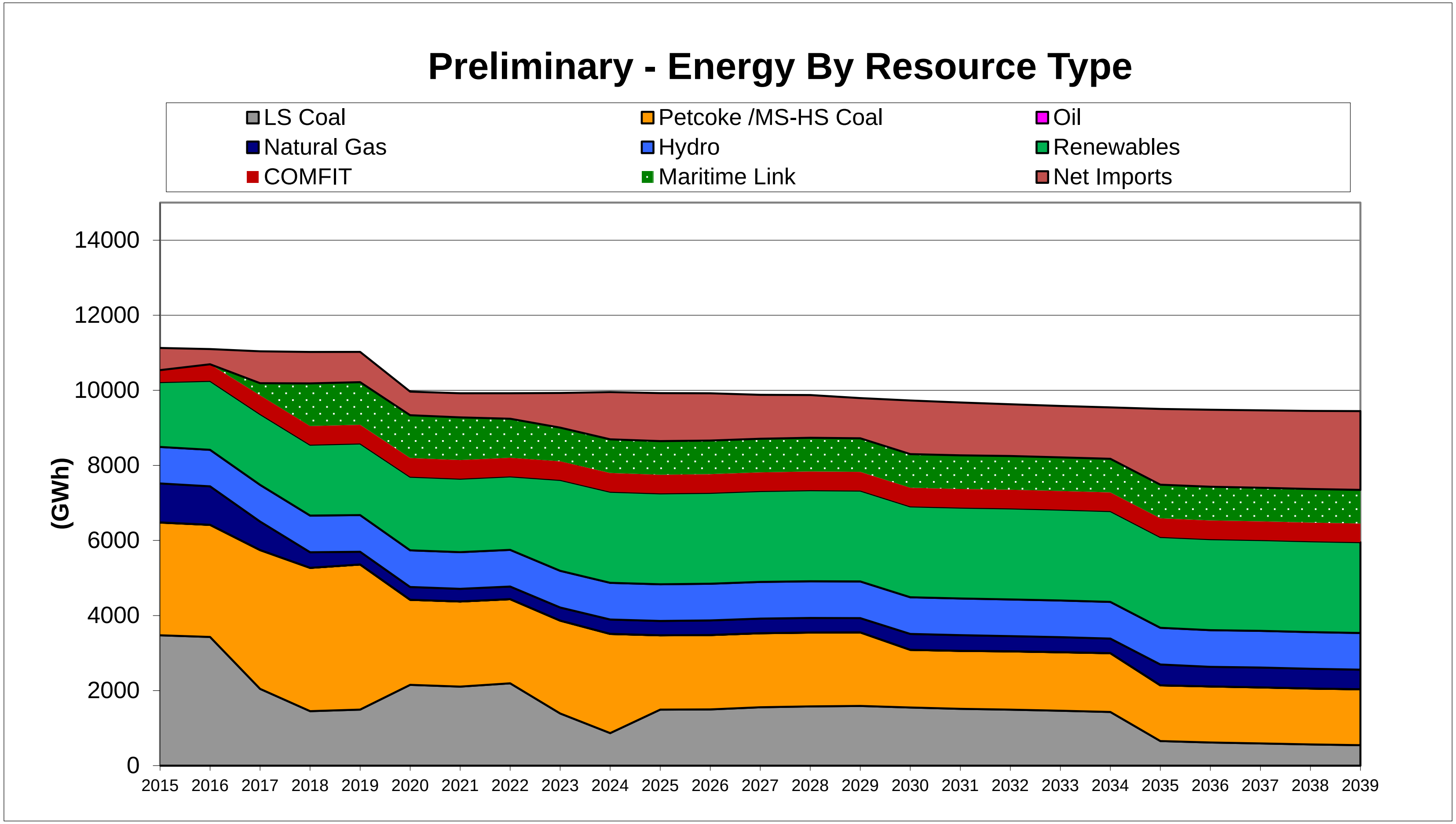
CRP9WC-2 Preliminary Load and Resources

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	2036	2037	2038	2039
Firm Peak	1,963	1,986	2,000	2,020	2,041	2,066	2,077	2,097	2,118	2,147	2,159	2,251	2,345	2,364	2,383	2,403	2,422
DSM	23	54	84	110	134	156	178	202	224	247	267	412	566	593	616	643	666
Firm Peak Less DSM	1,940	1,932	1,916	1,910	1,907	1,910	1,899	1,896	1,894	1,899	1,892	1,839	1,780	1,771	1,767	1,760	1,756
DRWH Reduction	0	1	2	4	7	10	15	21	27	32	39	60	62	60	62	62	62
DRCM Reduction	0	0	1	4	7	10	14	18	20	21	24	24	24	23	24	24	24
Firm Peak Less DR	1,940	1,931	1,912	1,903	1,894	1,890	1,870	1,857	1,847	1,846	1828	1754	1693	1,689	1,681	1,674	1,670
RM Required	388	386	382	381	379	378	374	371	369	369	366	350.8	338.7	338	336	335	334
Required MWs	2,328	2,317	2,295	2,283	2,272	2,269	2,244	2,229	2,216	2,215	2194	2105	2032	2,026	2,017	2,009	2,004
Existing MWs	2393	2393	2393	2393	2393	2393	2393	2393	2393	2393	2393	2393	2393	2393	2393	2393	2393
Resource Additions (MW):																	
Burnside #4		33															
COMFIT - Biomass	4.2	6															
COMFIT - Wind	20.04	6.47	7.2														
REA Wind	3.33	24.58															
Maritime Link				153.3													
Small Biomass PPA			10														
Hydro			1.8		15				15								
PH Biomass						51.7											
Additional Wind									36.15								
Assumed Unit Retirement				-153		-153	-81		-158	-153		-150	-152				
Natural Gas Unit									98.7	49.4		83.4	83.4				
Total Annual Additions	27.6	70.1	19.0	0.3	15.0	-101.3	-81.0	0.0	-8.1	-103.6	0.0	-66.6	-68.6	0.0	0.0	0.0	0.0
Total Cumulative Additions	27.6	97.6	116.6	116.8	131.8	30.5	-50.5	-50.5	-58.6	-162.2	-162.2	-272.4	-341.0	-341.0	-341.0	-341.0	-341.0
Total Firm Capacity	2420	2490	2509	2510	2525	2423	2342	2342	2334	2231	2231	2120	2052	2052	2052	2052	2052
Surplus (Deficit) MWs above RM	93	174	215	227	252	155	99	114	118	15	37	15	20	25	35	43	48
Reserve Margin %	24.8%	29.0%	31.2%	31.9%	33.3%	28.2%	25.3%	26.1%	26.4%	20.8%	22.0%	20.9%	21.2%	21.5%	22.1%	22.6%	22.9%

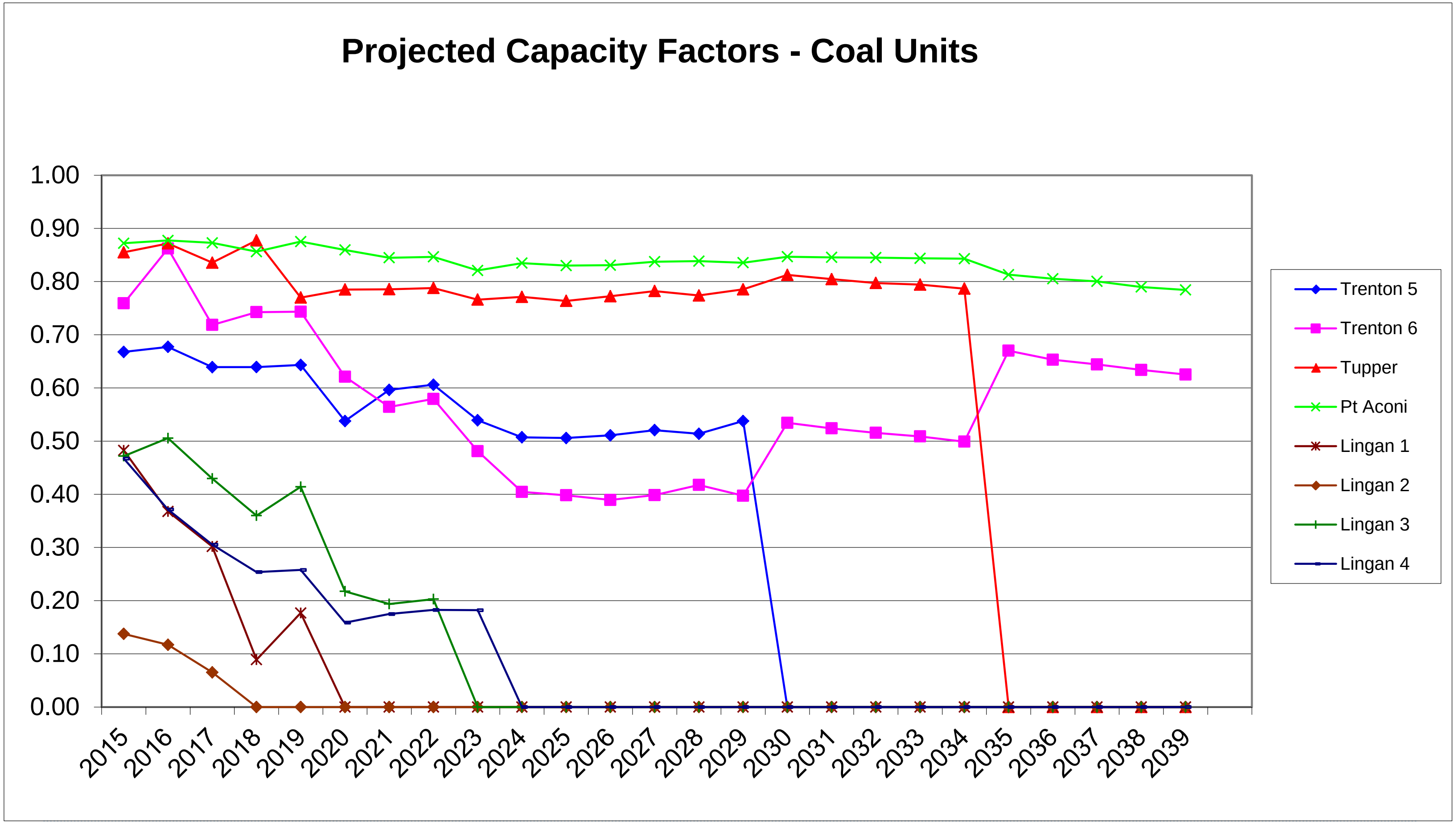
CRP9WC-2 Preliminary Demand and DSM



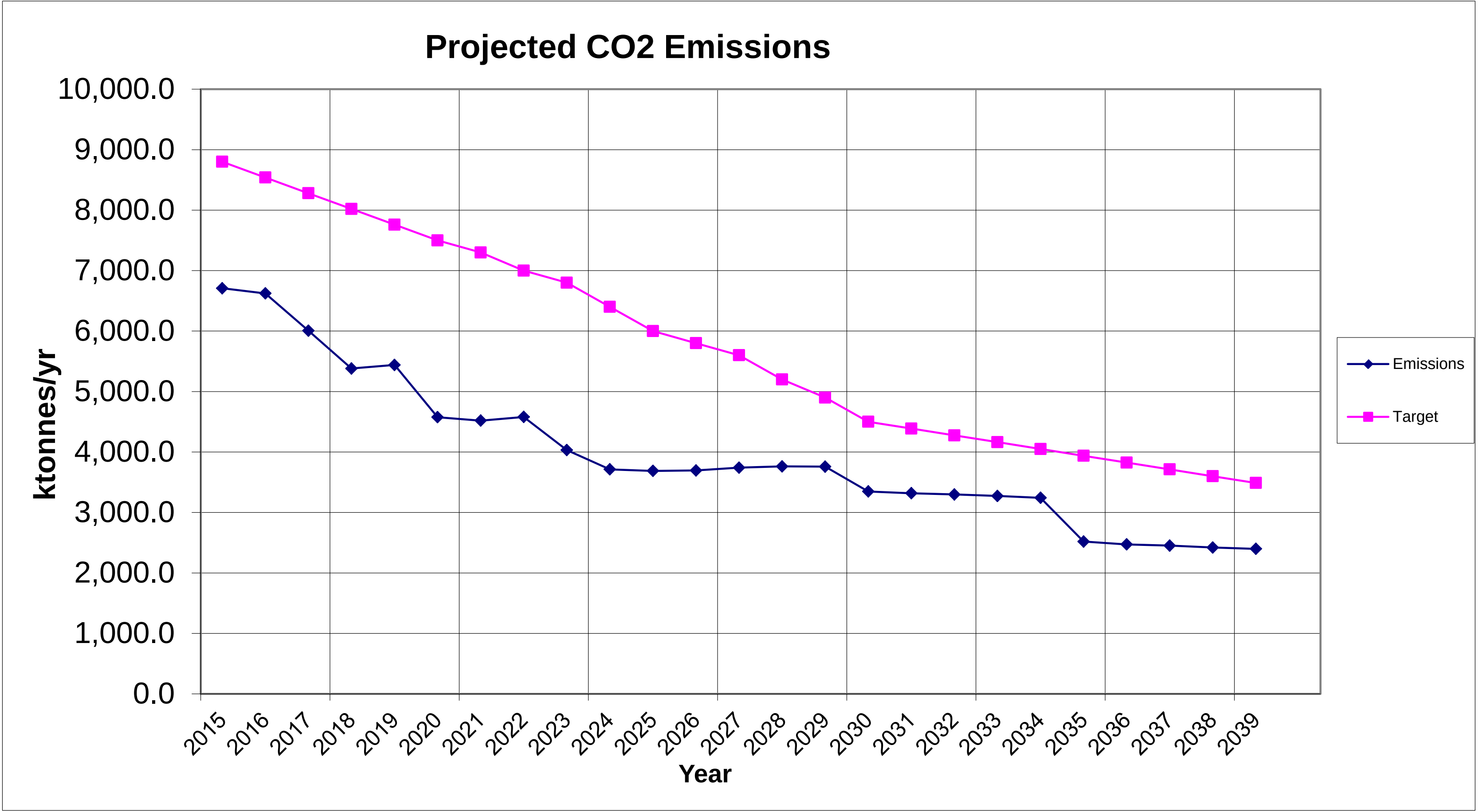
CRP9WC-2 Preliminary Energy by Resource Type



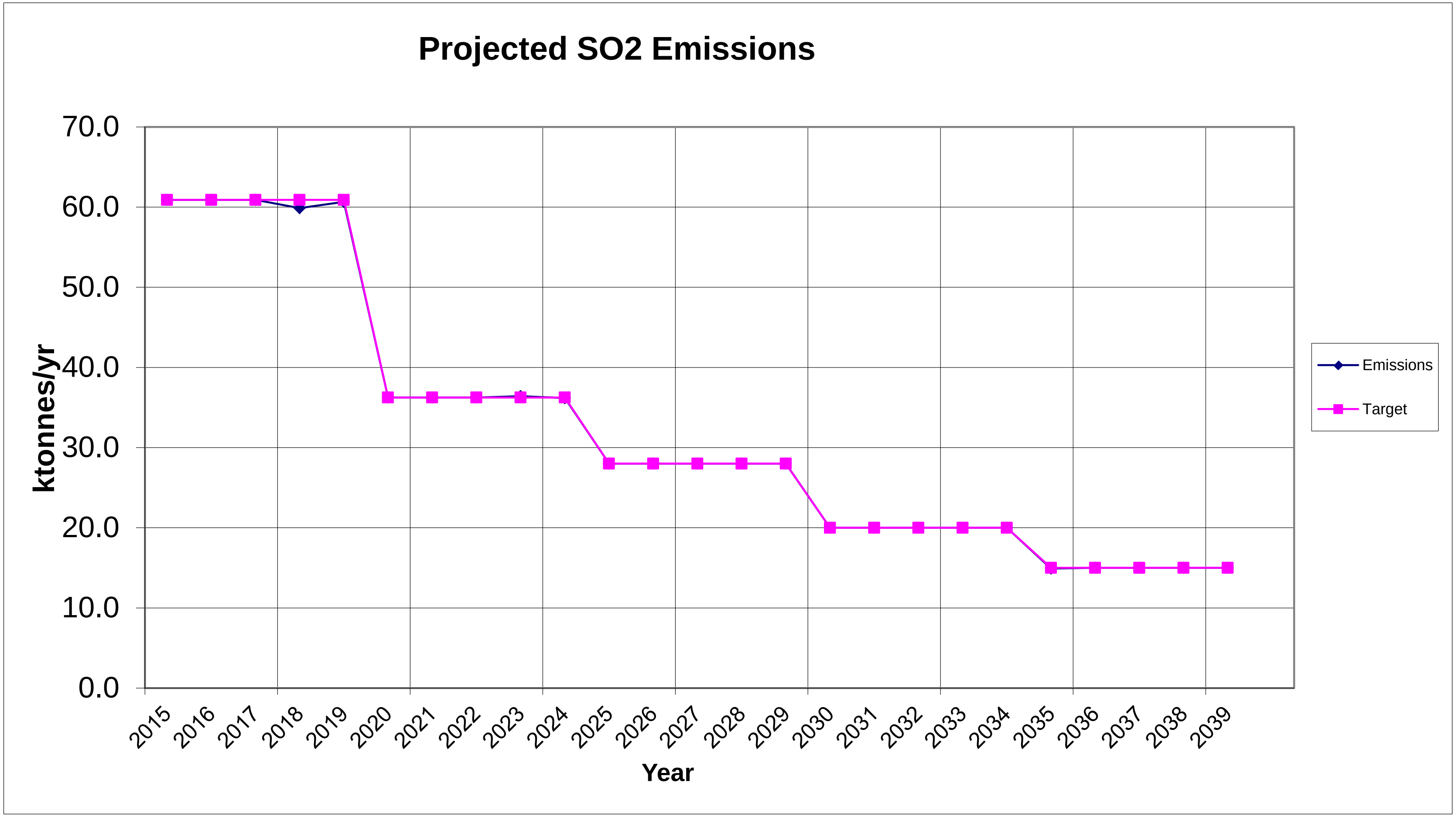
CRP9WC-2 Preliminary Coal Capacity Factors



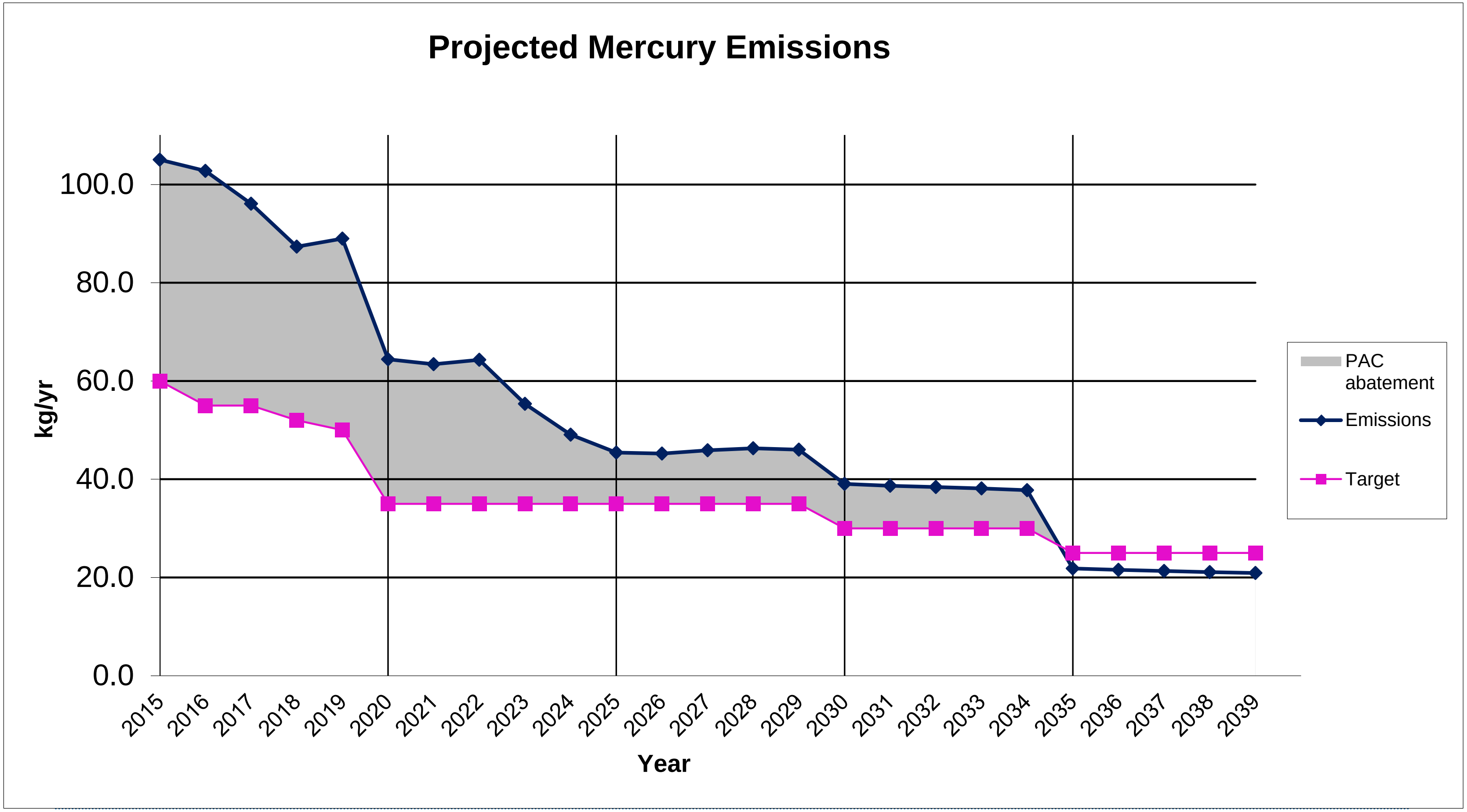
CRP9WC-2 Preliminary CO_2 Emissions



CRP9WC-2 Preliminary SO_2 Emissions



CRP9WC-2 Preliminary Mercury Emissions



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CRP10 Preliminary Results

CRP10 Input Assumptions

Candidate Resource Plan 10 (CRP10):

- Base Load Forecast
- Base DSM
- Emissions - Scenario A
- Planned and committed resources are fixed in the plan (REA wind, COMFIT, Maritime Link/ Retire Lin #2)
- Medium Coal Use
- Medium Wind (Wind integration: 2 x CT 50 MW and $200M for reliability tie and transmission upgrades)
- Constraints
  - Planning reserve margin min = 20%
  - RES: 2015-2019 = 25%; 2020-2039 = 40%

CRP10 Preliminary Results

	CRP10-01-R01
	Least cost planning & study period
2015	
2016	DR Water H & DR Comm
2017	ML Oct 2017
	Lin 2 retire
2018	
2019	Mersey Phase 1
2020	
2021	
2022	
2023	TUC 1 Retire
	Mersey Phase 2
	Wind Block 150 MW
	2 x 50 MW CT (wind integration)
2024	Lingan 1 Retire
	PHBM 51.7 MW Firm
2025	
2026	
2027	
2028	
2029	
2030	TUC 2 Retire
2031	
2032	Trenton 5 Retire
2033	
2034	
2035	
2036	Lingan 3 Retire
	CT 50MW & CT 34MW
2037	Lingan 4 Retire
	CT 50MW & CT 34MW
2038	
2039	
Planning PV $M	11,665
Study PV $M	17,396

	Base DSM Program Adm Cost $M	Base DSM Customer Cost $M
2015	50.7	37.9
2016	50.5	39.9
2017	50.0	41.2
2018	52.4	41.6
2019	57.0	32.2
2020	61.5	28.0
2021	56.9	28.4
2022	54.1	28.4
2023	51.5	29.2
2024	50.8	28.6
2025	50.6	29.9
2026	52.1	33.8
2027	54.8	36.8
2028	58.5	41.4
2029	60.7	34.0
2030	63.1	37.2
2031	62.6	40.6
2032	61.4	40.8
2033	59.3	41.4
2034	56.7	41.7
2035	47.7	48.4
2036	46.5	48.0
2037	45.4	47.6
2038	44.4	46.8
2039	43.5	46.3
NPV	**700.8**	**474.9**

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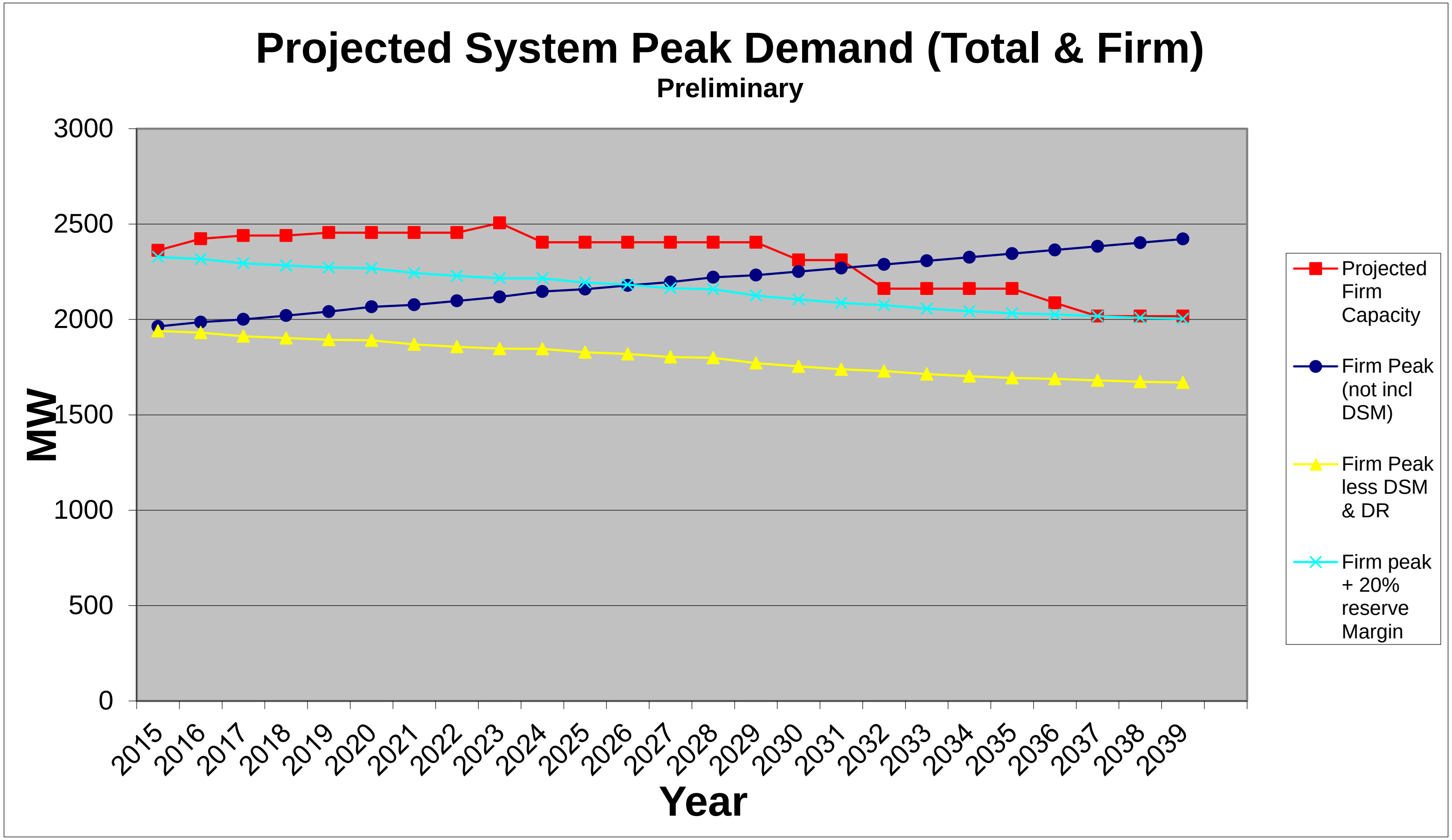
CRP10-1 Preliminary Results

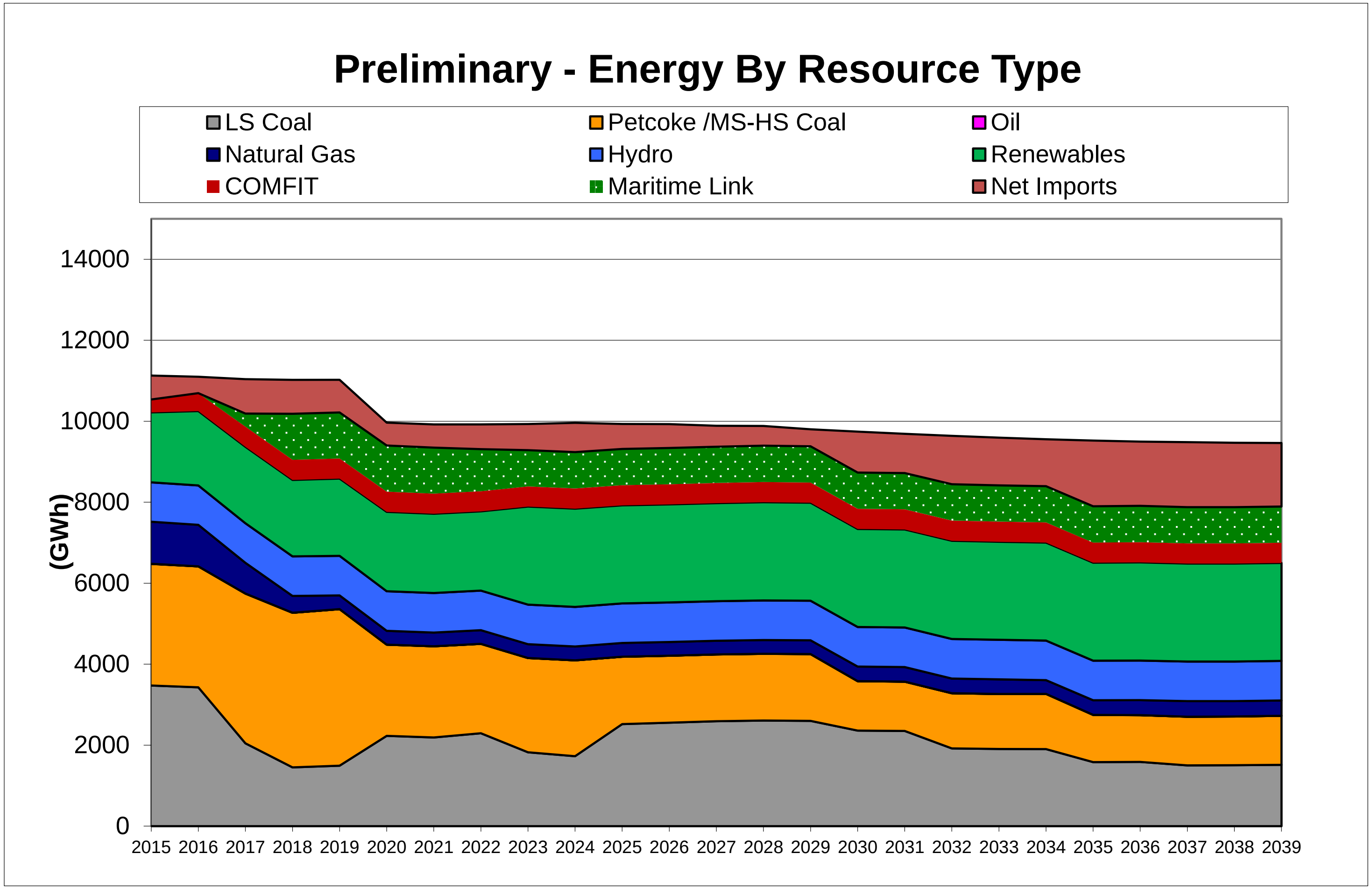
CRP10-1 Preliminary Load and Resources

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	2036	2037	2038	2039
Firm Peak	1,963	1,986	2,000	2,020	2,041	2,066	2,077	2,097	2,118	2,147	2,159	2,251	2,345	2,364	2,383	2,403	2,422
DSM	23	54	84	110	134	156	178	202	224	247	267	412	566	593	616	643	666
Firm Peak Less DSM	1,940	1,932	1,916	1,910	1,907	1,910	1,899	1,896	1,894	1,899	1,892	1,839	1,780	1,771	1,767	1,760	1,756
DRWH Reduction	0	1	2	4	7	10	15	21	27	32	39	60	62	60	62	62	62
DRCM Reduction	0	0	1	4	7	10	14	18	20	21	24	24	24	23	24	24	24
Firm Peak Less DR	1,940	1,931	1,912	1,903	1,894	1,890	1,870	1,857	1,847	1,846	1828	1754	1693	1,689	1,681	1,674	1,670
RM Required	388	386	382	381	379	378	374	371	369	369	366	350.8	338.7	338	336	335	334
Required MWs	2,328	2,317	2,295	2,283	2,272	2,269	2,244	2,229	2,216	2,215	2194	2105	2032	2,026	2,017	2,009	2,004
Existing MWs	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341
Resource Additions (MW):																	
Burnside #4		33															
COMFIT - Biomass	4.2	6															
COMFIT - Wind	14.14	4.56	5.1														
REA Wind	2.35	17.34															
Maritime Link				153.3													
Small Biomass PPA			10														
Hydro			1.8		15				15								
PH Biomass										51.7							
Additional Wind									18								
Assumed Unit Retirement				-153					-81	-153		-93		-158	-153		
Natural Gas Unit									98.8					83.4	83.4		
Total Annual Additions	20.7	60.9	16.9	0.3	15.0	0.0	0.0	0.0	50.8	-101.3	0.0	-93.0	0.0	-74.6	-69.6	0.0	0.0
Total Cumulative Additions	20.7	81.6	98.5	98.7	113.7	113.7	113.7	113.7	164.5	63.2	63.2	-29.8	-179.8	-254.4	-324.0	-324.0	-324.0
Total Firm Capacity	2362	2423	2440	2440	2455	2455	2455	2455	2506	2405	2405	2312	2162	2087	2017	2017	2017
Surplus (Deficit) MWs above RM	34	106	145	157	183	187	212	227	290	189	211	207	129	61	0	9	14
Reserve Margin %	21.8%	25.5%	27.6%	28.3%	29.6%	29.9%	31.3%	32.2%	35.7%	30.3%	31.5%	31.8%	27.6%	23.6%	20.0%	20.5%	20.8%

CRP10-1 Preliminary Demand and DSM



CRP10-1 Preliminary Energy by Resource Type



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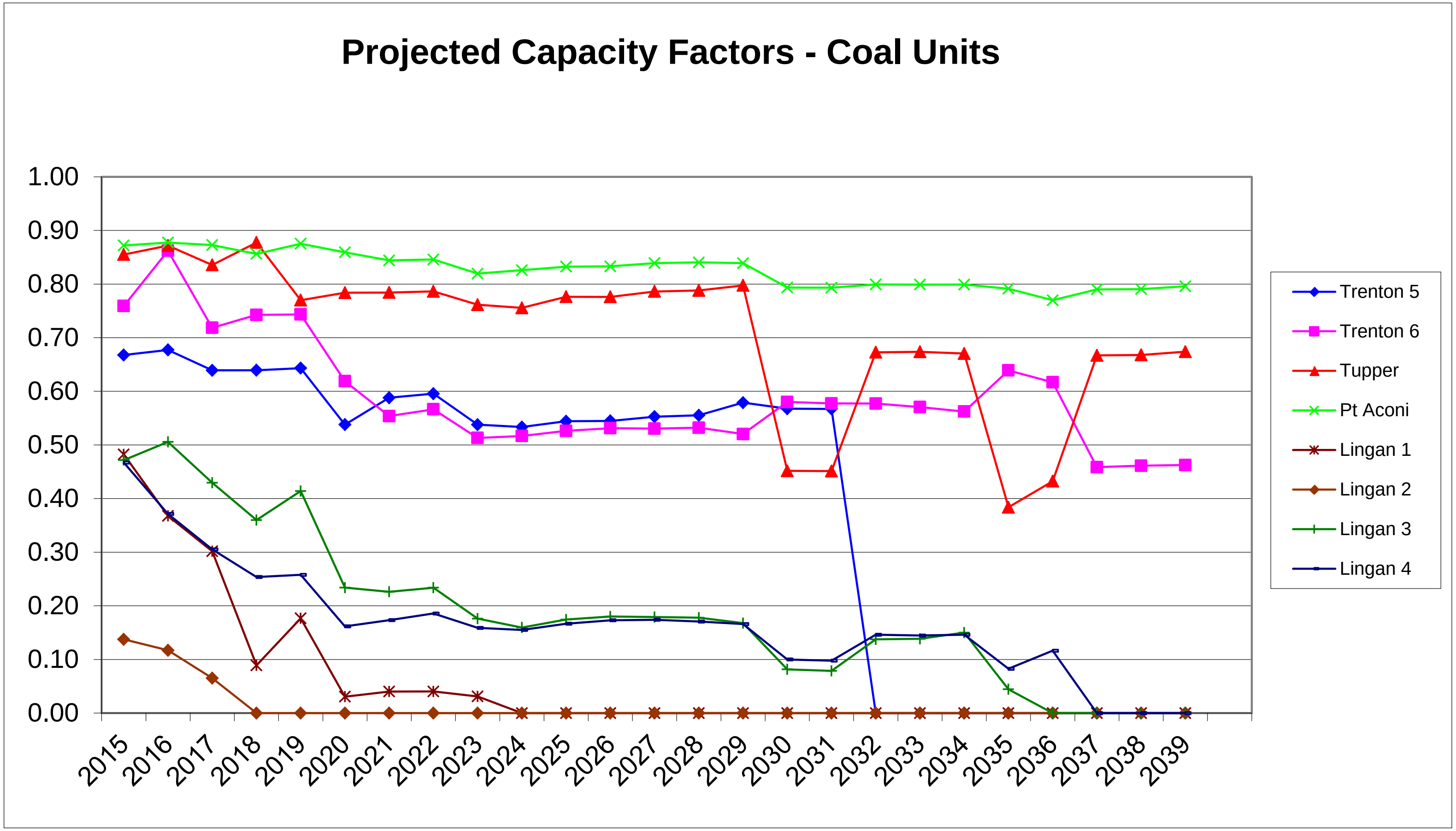
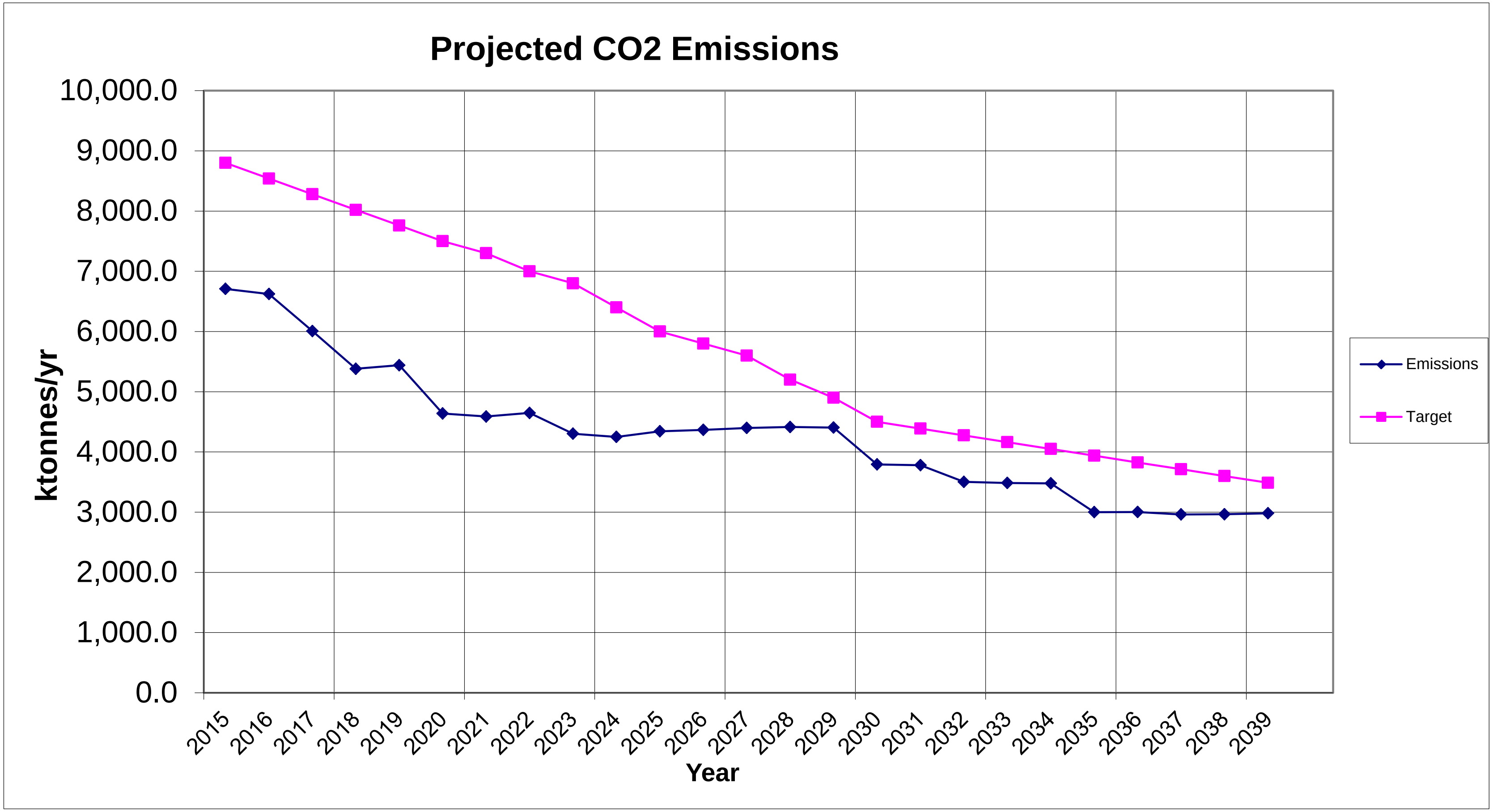
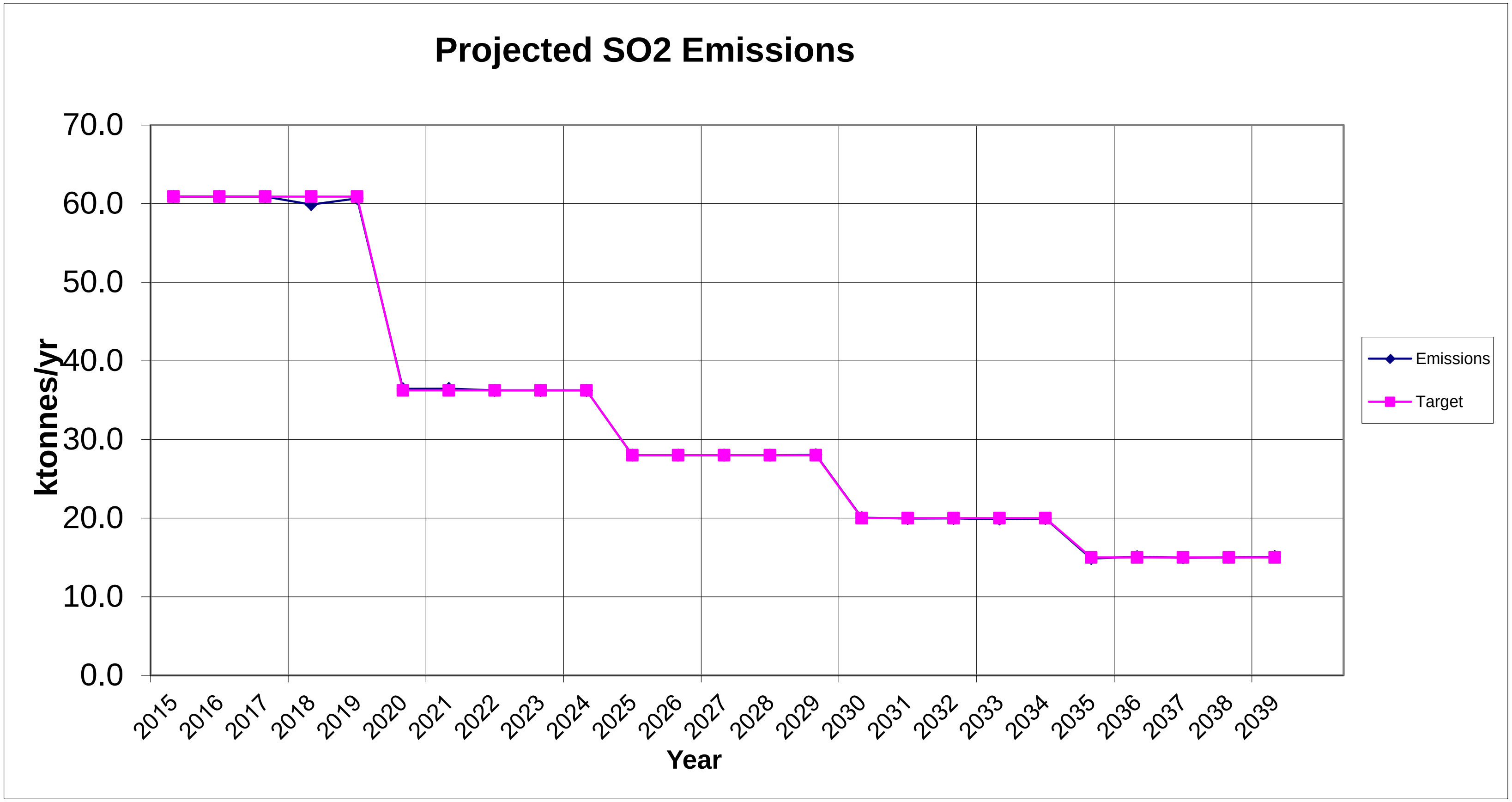
CRP10-1 Preliminary Coal Capacity Factors



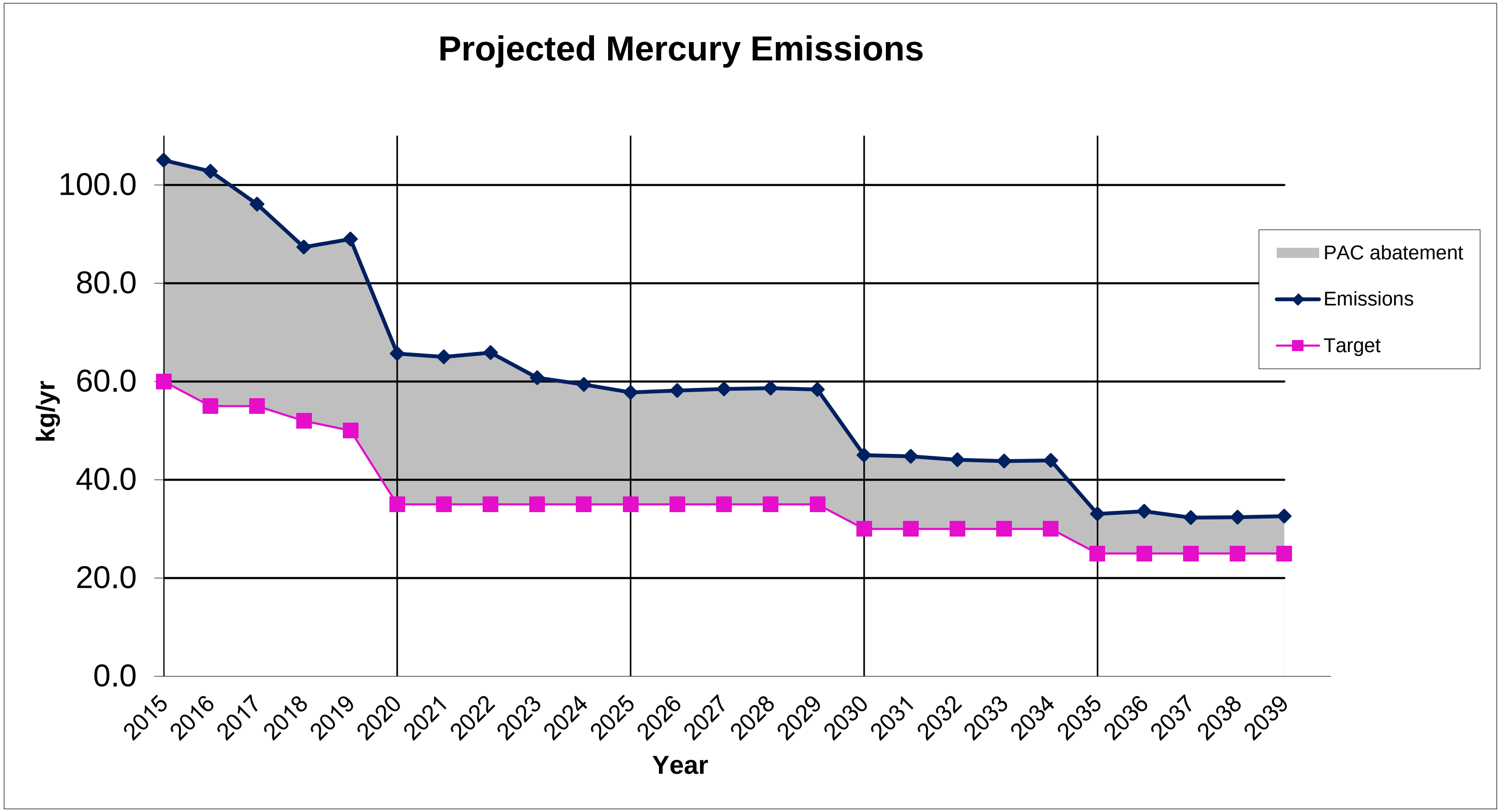
CRP10-1 Preliminary CO_2 Emissions



CRP10-1 Preliminary SO_2 Emissions



CRP10-1 Preliminary Mercury Emissions



CRP31 Preliminary Results

CRP31 Input Assumptions

Candidate Resource Plan 31 (CRP31):

- Base Load Forecast
- Base DSM (50% of Peak savings, 100% of energy savings)
- Emissions - Scenario A
- Planned and committed resources are fixed in the plan (REA wind, COMFIT, Maritime Link/ Retire Lin #2)
- Maximum Coal Use
- Medium Wind (Wind integration: 2 x CT 50 MW and $200M for reliability tie and transmission upgrades)
- Constraints
    - Planning reserve margin min = 20%
    - RES: 2015-2019 = 25%; 2020-2039 = 40%

CRP31 Preliminary Results

	CRP31-01-R01
	Least cost study period
2015	
2016	
2017	ML Oct 2017
	Lin 2 retire
2018	
2019	
2020	
2021	
2022	
2023	Wind Block 150MW 2 x CT 50 MW (for wind integration)
2024	
2025	TUC 1 Retire
2026	
2027	
2028	
2029	
2030	
2031	CT 50MW
2032	CT 50MW
	TUC 2 Retire
2033	
2034	
2035	CC 145MW
	Tre 5 Retire
2036	CT 50MW
2037	
2038	
2039	PHBM 51.7 MW Firm
	CT 50MW & CT 34MW
	Lin 1 Retire
Planning PV $M	11,625
Study PV $M	17,522

	Base DSM	Base DSM
	Program Adm Cost	Customer Cost
	$M	$M
2015	50.7	37.9
2016	50.5	39.9
2017	50.0	41.2
2018	52.4	41.6
2019	57.0	32.2
2020	61.5	28.0
2021	56.9	28.4
2022	54.1	28.4
2023	51.5	29.2
2024	50.8	28.6
2025	50.6	29.9
2026	52.1	33.8
2027	54.8	36.8
2028	58.5	41.4
2029	60.7	34.0
2030	63.1	37.2
2031	62.6	40.6
2032	61.4	40.8
2033	59.3	41.4
2034	56.7	41.7
2035	47.7	48.4
2036	46.5	48.0
2037	45.4	47.6
2038	44.4	46.8
2039	43.5	46.3
NPV	**700.8**	**474.9**

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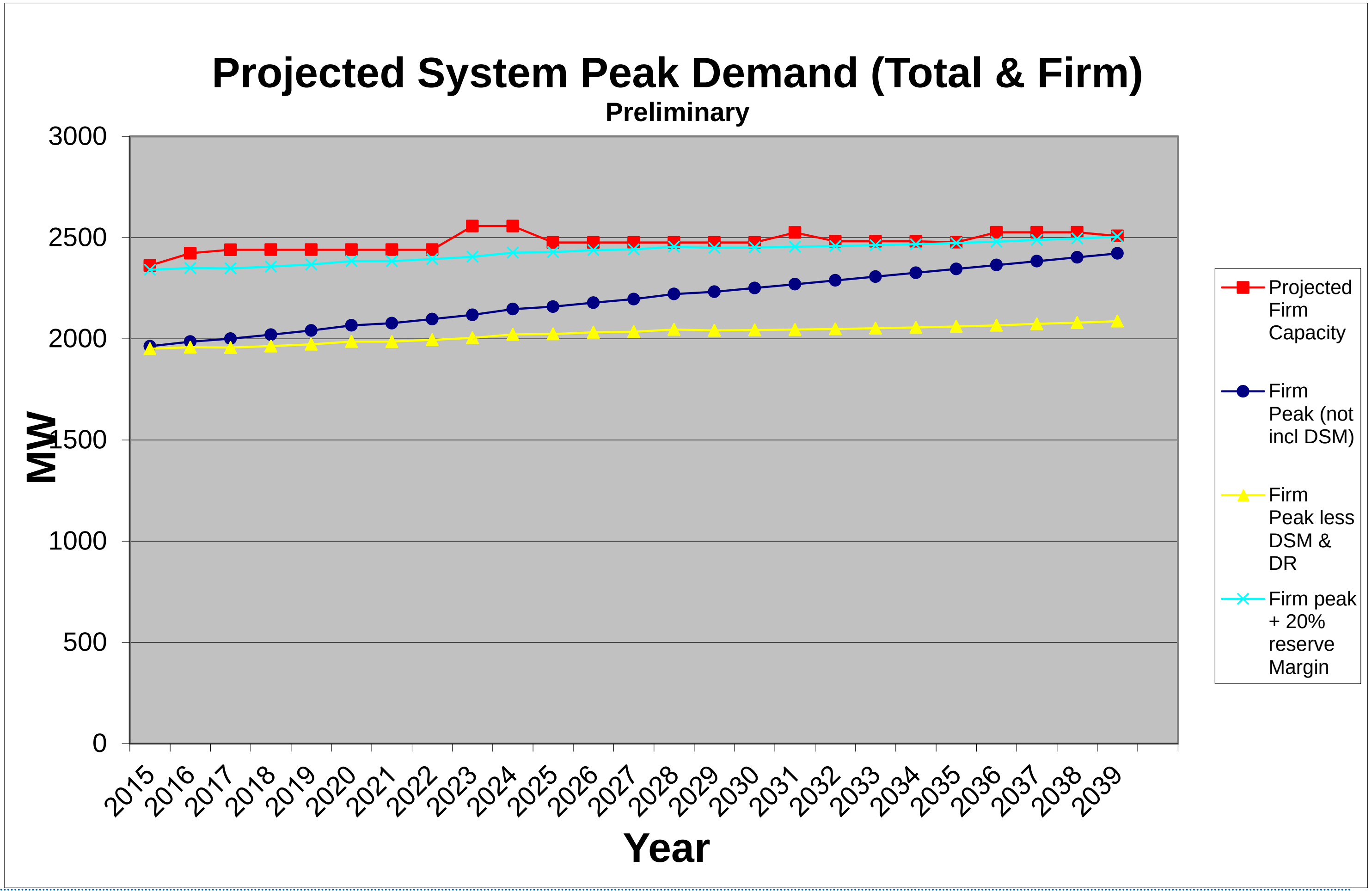
CRP31-1 Preliminary Results

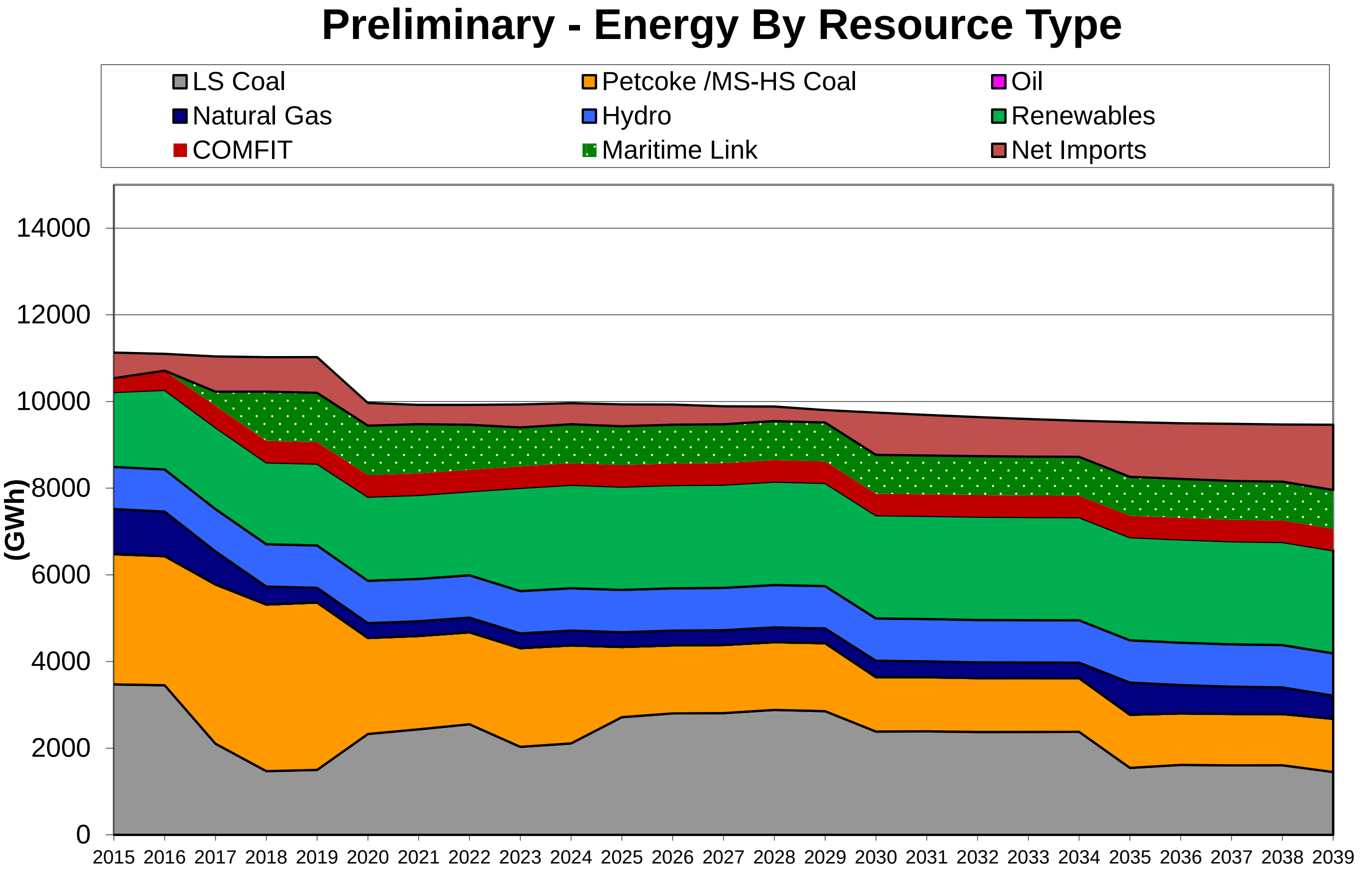
CRP31-1 Preliminary Load and Resources

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	2036	2037	2038	2039
Firm Peak	1,963	1,986	2,000	2,020	2,041	2,066	2,077	2,097	2,118	2,147	2,159	2,251	2,345	2,364	2,383	2,403	2,422
DSM	12	28	44	56	69	80	91	102	113	125	135	208	284	298	310	323	334
Firm Peak Less DSM	1,951	1,958	1,957	1,964	1,973	1,987	1,986	1,995	2,005	2,022	2,024	2,043	2,061	2,066	2,074	2,080	2,087
DRWH Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DRCM Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Less DR	1,951	1,958	1,957	1,964	1,973	1,987	1,986	1,995	2,005	2,022	2024	2043	2061	2,066	2,074	2,080	2,087
RM Required	390	392	391	393	395	397	397	399	401	404	405	408.7	412.2	413	415	416	417
Required MWs	2,341	2,350	2,348	2,357	2,367	2,384	2,384	2,394	2,406	2,426	2428	2452	2473	2,480	2,488	2,496	2,505
Existing MWs	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341
Resource Additions (MW):																	
Burnside #4		33															
COMFIT - Biomass	4.2	6															
COMFIT - Wind	14.14	4.56	5.1														
REA Wind	2.35	17.34															
Maritime Link				153.3													
Small Biomass PPA			10														
Hydro			1.8														
PH Biomass																	51.7
Additional Wind									18								
Assumed Unit Retirement				-153							-81		-150				-153
Natural Gas Unit									98.8				145.0	49.4			83.4
Total Annual Additions	20.7	60.9	16.9	0.3	0.0	0.0	0.0	0.0	116.8	0.0	-81.0	0.0	-5.0	49.4	0.0	0.0	-17.9
Total Cumulative Additions	20.7	81.6	98.5	98.7	98.7	98.7	98.7	98.7	215.5	215.5	134.5	134.5	135.3	184.7	184.7	184.7	166.8
Total Firm Capacity	2362	2423	2440	2440	2440	2440	2440	2440	2557	2557	2476	2476	2477	2526	2526	2526	2508
Surplus (Deficit) MWs above RM	21	73	92	83	73	56	57	46	151	131	47	24	4	46	38	30	3
Reserve Margin %	21.1%	23.7%	24.7%	24.2%	23.7%	22.8%	22.8%	22.3%	27.5%	26.5%	22.3%	21.2%	20.2%	22.3%	21.8%	21.5%	20.2%

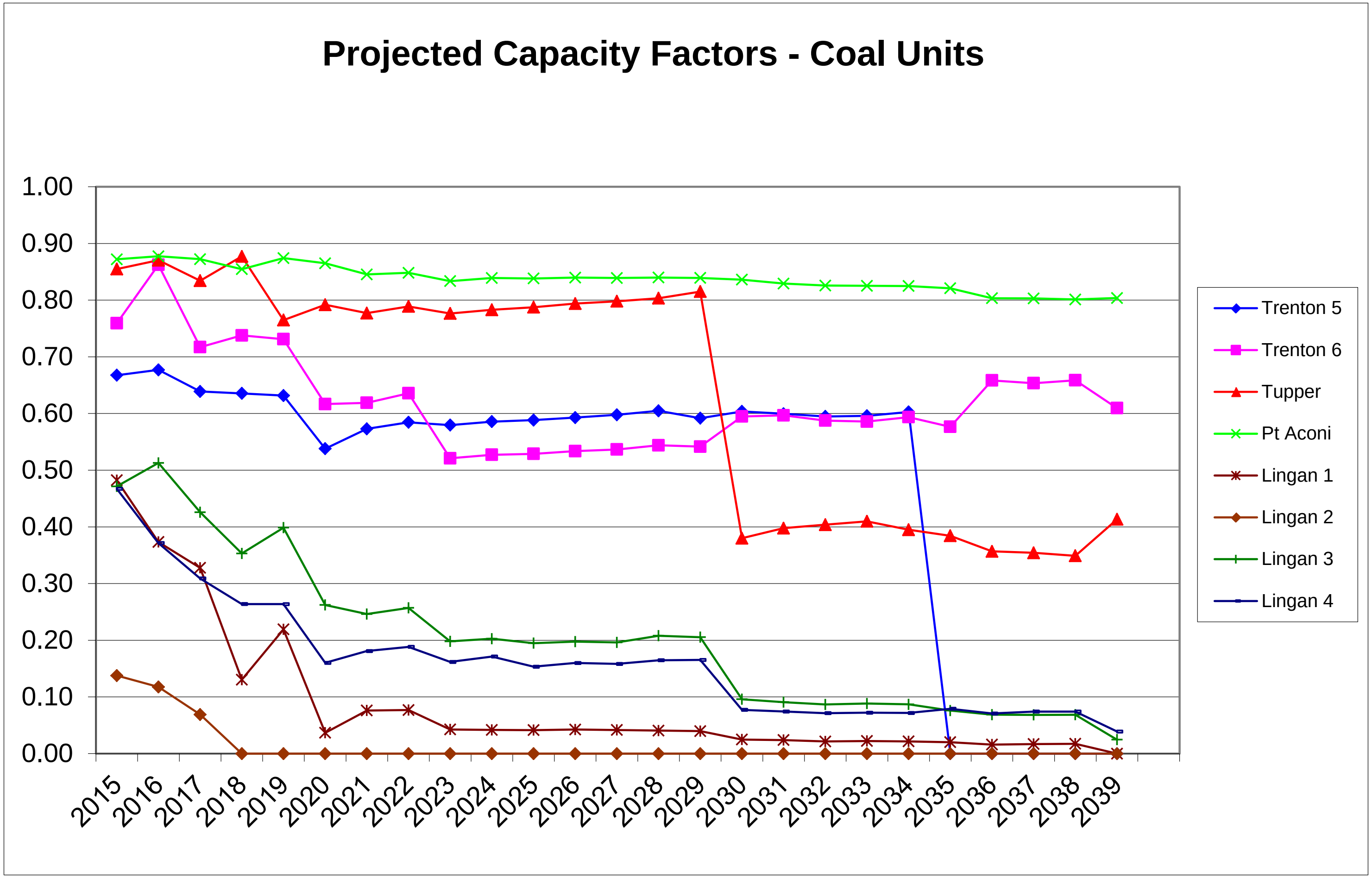
CRP31-1 Preliminary Demand and DSM



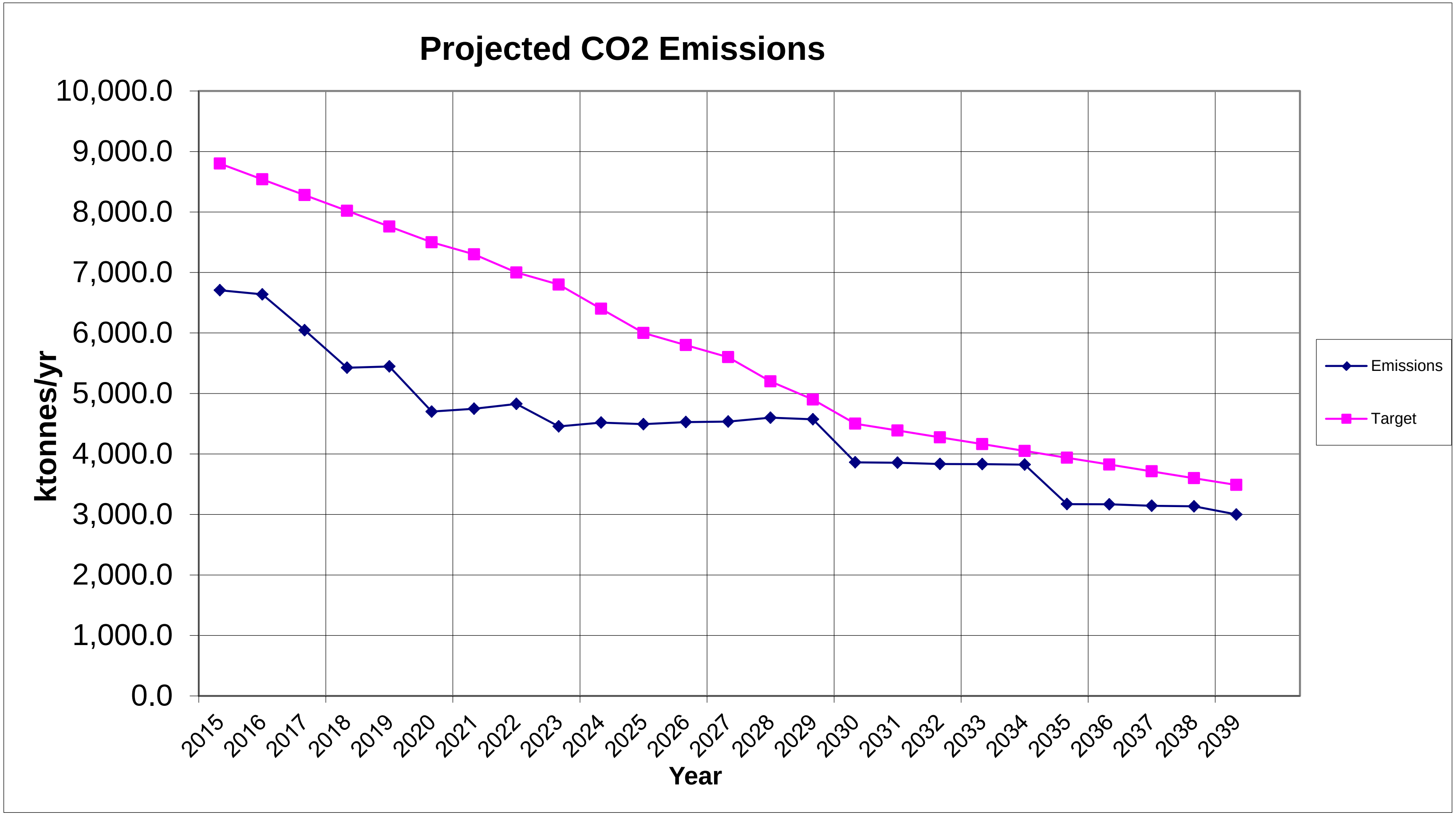
CRP31-1 Preliminary Energy by Resource Type



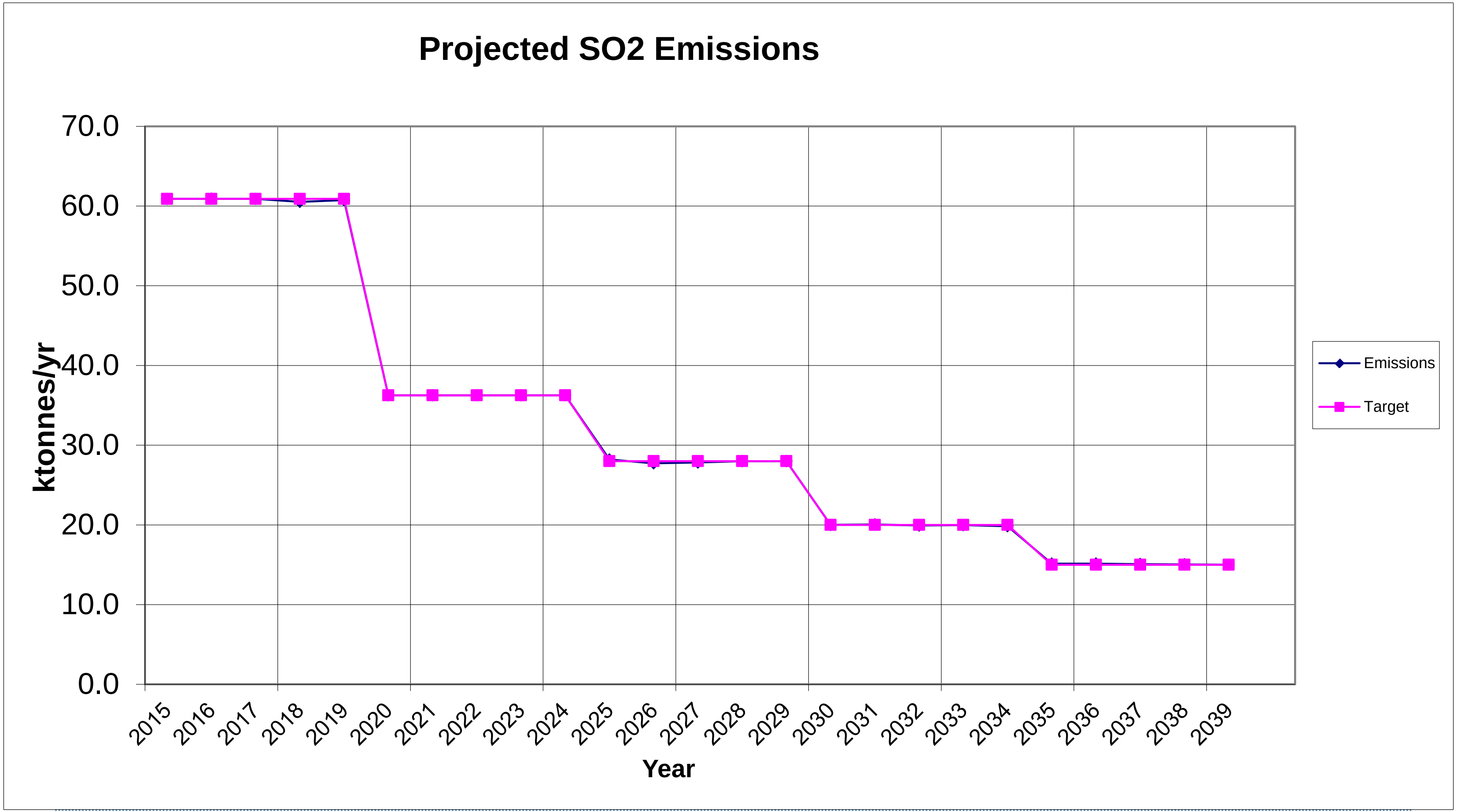
CRP31-1 Preliminary Coal Capacity Factors



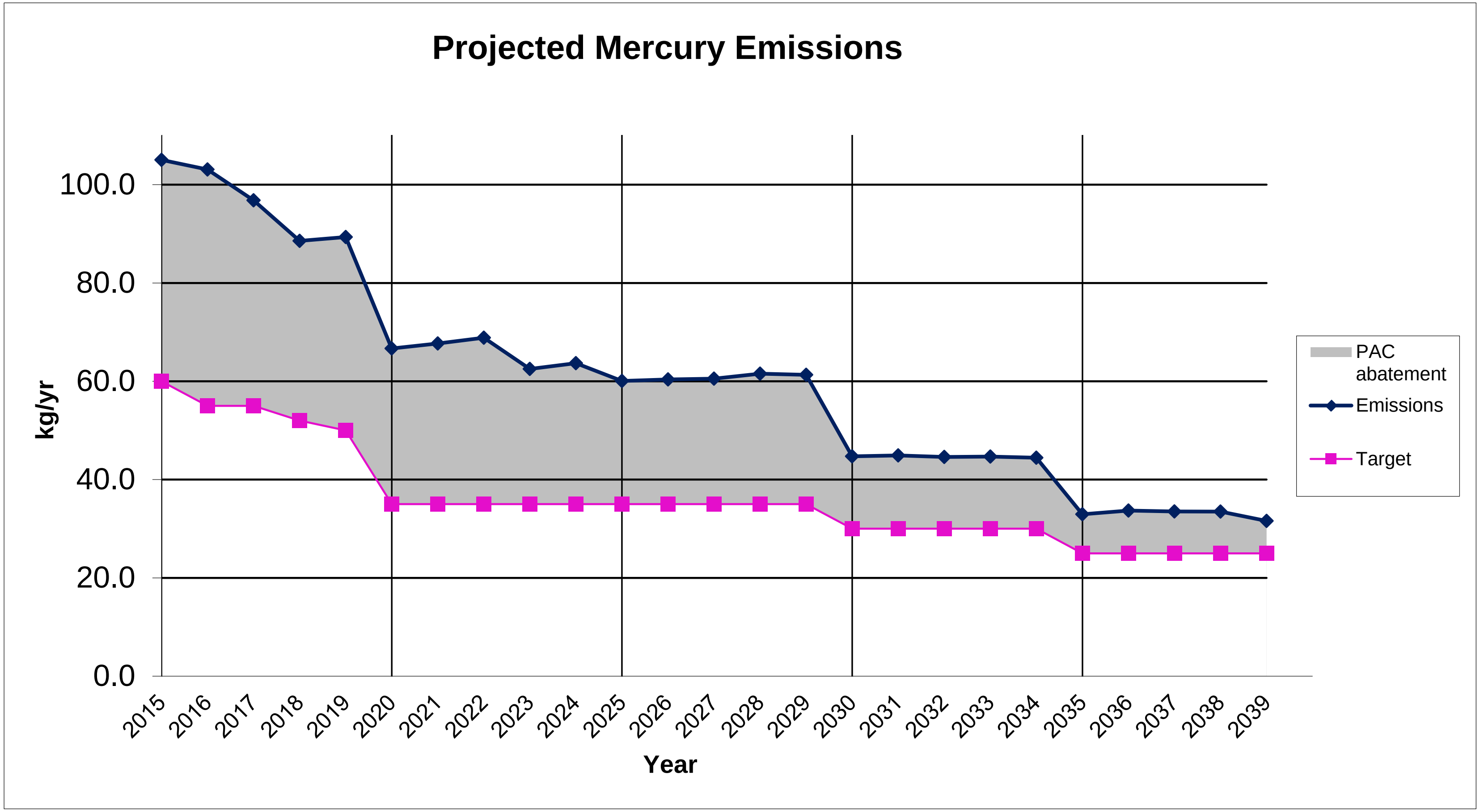
CRP31-1 Preliminary CO_2 Emissions



CRP31-1 Preliminary SO_2 Emissions



CRP31-1 Preliminary Hg Emissions



Nova Scotia POWER
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CRP21 Preliminary Results

CRP21 Input Assumptions

Candidate Resource Plan 21 (CRP21):

- High Load Forecast
- Base DSM
- Emissions - Scenario A
- Planned and committed resources are fixed in the plan (REA wind, COMFIT, Maritime Link/ Retire Lin #2)
- Maximum Coal Use
- Constraints
  - Planning reserve margin min = 20%
  - RES: 2015-2019 = 25%; 2020-2039 = 40%

CRP21 Preliminary Results

	CRP21-01-WND-R01	CRP21-03-PPA-R01
	Least cost study period	**Least cost planning period**
2015		
2016		
2017	ML Oct 2017	ML Oct 2017
	Lin 2 retire	Lin 2 retire
2018		
2019	Mersey Phase 1	
2020	FGD (Lin 3/4 300 MW)	FGD (Lin 3/4 300 MW)
	Wind Block 150 MW	PPA 100MW Firm
	2 x 50 MW CT (wind integration)	
2021		
2022		
2023	Mersey Phase 2	
2024		
2025	TUC 1 Retire	TUC 1 Retire
2026		
2027		
2028		
2029		
2030		
2031		
2032	TUC 2 Retire	TUC 2 Retire
2033		
2034		CT 50MW
2035	Tre 5 Retire	Tre 5 Retire
	CT 50MW	CT 50MW
2036		
2037		
2038	CT 50MW	CT 50MW
2039	PHBM 45.4 MW Firm	PHBM 45.4 MW Firm
	CT 50MW	CT 50MW
	Lin 1 Retire	Lin 1 Retire
Planning PV $M	12,722	12,680
Study PV $M	19,503	19,830

	Base DSM	Base DSM
	Program Adm Cost	Customer Cost
	$M	$M
2015	50.7	37.9
2016	50.5	39.9
2017	50.0	41.2
2018	52.4	41.6
2019	57.0	32.2
2020	61.5	28.0
2021	56.9	28.4
2022	54.1	28.4
2023	51.5	29.2
2024	50.8	28.6
2025	50.6	29.9
2026	52.1	33.8
2027	54.8	36.8
2028	58.5	41.4
2029	60.7	34.0
2030	63.1	37.2
2031	62.6	40.6
2032	61.4	40.8
2033	59.3	41.4
2034	56.7	41.7
2035	47.7	48.4
2036	46.5	48.0
2037	45.4	47.6
2038	44.4	46.8
2039	43.5	46.3
NPV	**700.8**	**474.9**

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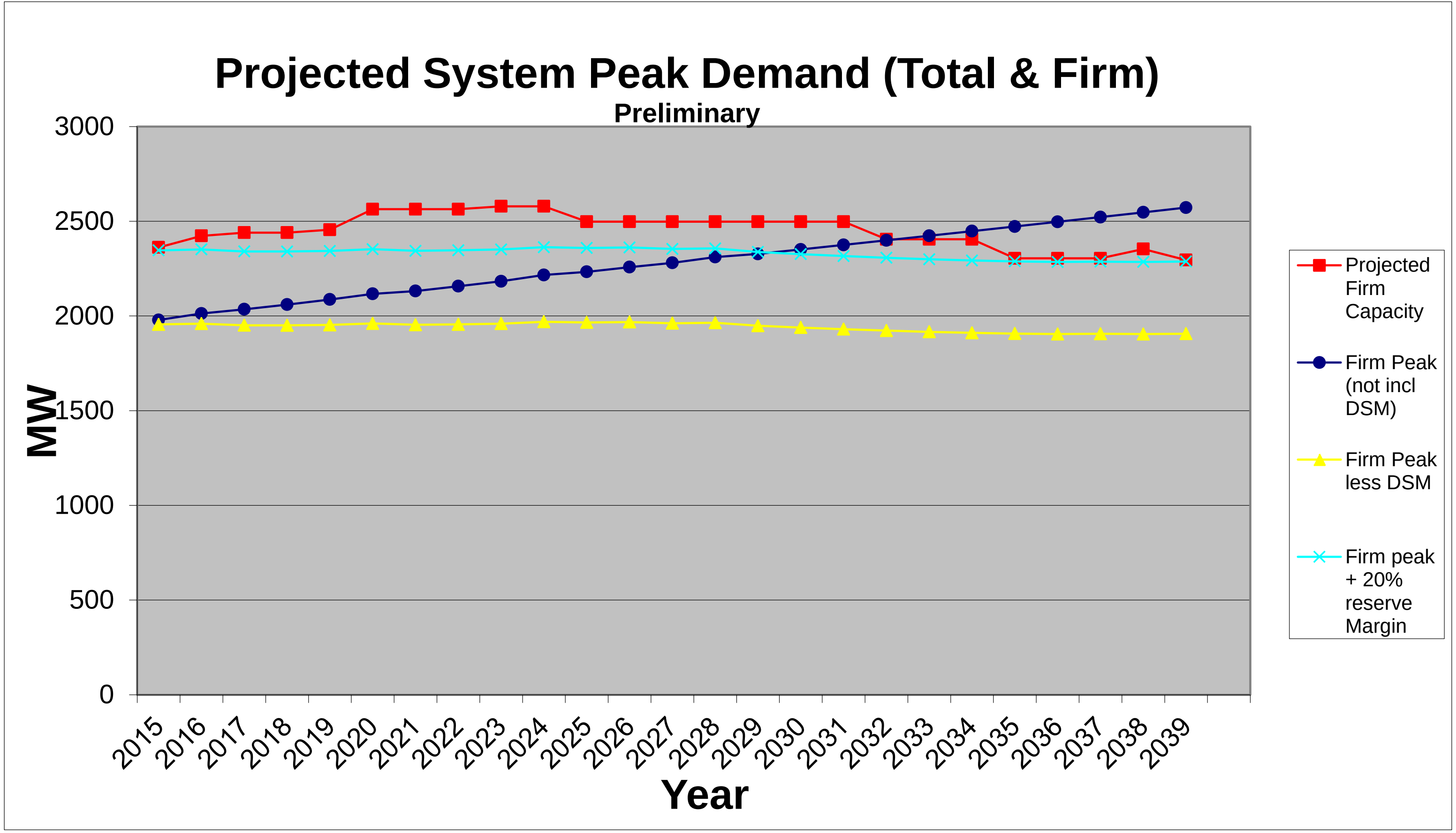
CRP21-1 Preliminary Results

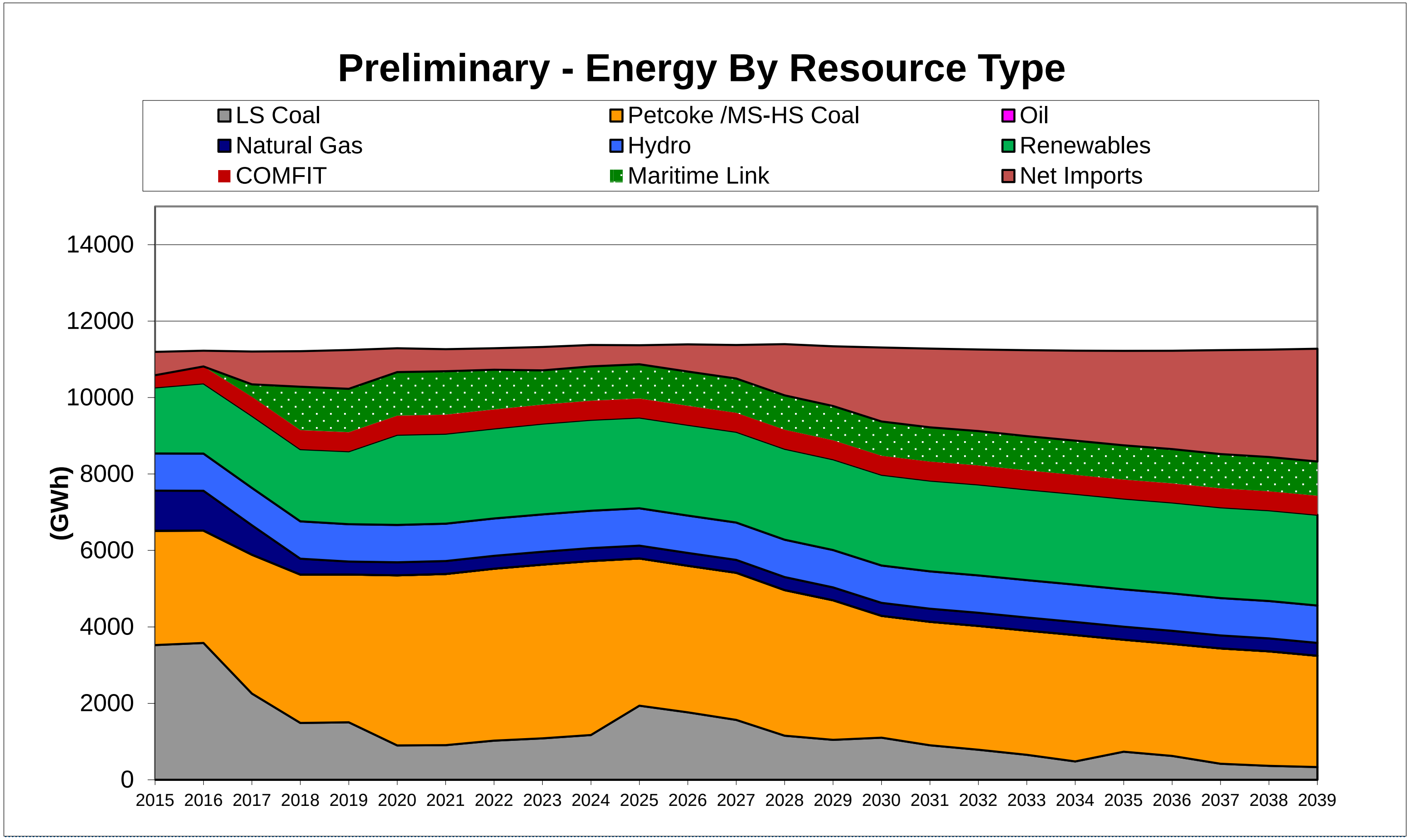
CRP21-1 Preliminary Load and Resources

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	2036	2037	2038	2039
Firm Peak	1,979	2,013	2,035	2,060	2,087	2,117	2,132	2,157	2,183	2,216	2,233	2,351	2,472	2,497	2,522	2,547	2,572
DSM	23	54	84	110	134	156	178	202	224	247	267	412	566	593	616	643	666
Firm Peak Less DSM	1,955	1,959	1,951	1,950	1,953	1,960	1,953	1,956	1,959	1,969	1,966	1,939	1,907	1,904	1,906	1,905	1,906
RM Required	391	392	390	390	391	392	391	391	392	394	393	388	381	381	381	381	381
Required MWs	2,346	2,351	2,341	2,340	2,343	2,352	2,344	2,347	2,351	2,363	2,359	2,327	2,288	2,285	2,287	2,286	2,288
Existing MWs	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341
Resource Additions (MW):																	
Burnside #4		33															
COMFIT - Biomass	4.2	6															
COMFIT - Wind	14.14	4.56	5.1														
REA Wind	2.35	17.34															
Maritime Link				153.3													
Small Biomass PPA			10														
Hydro			1.8		15				15								
PH Biomass																	45.4
Additional Wind						18											
Assumed Unit Retirement				-153		-8					-81		-150				-153
Natural Gas Unit						98.7							49.4			49.4	49.4
Total Annual Additions	20.7	60.9	16.9	0.3	15.0	108.7	0.0	0.0	15.0	0.0	-81.0	0.0	-100.6	0.0	0.0	49.4	-58.2
Total Cumulative Additions	20.7	81.6	98.5	98.7	113.7	222.4	222.4	222.4	237.4	237.4	156.4	156.4	-37.2	-37.2	-37.2	12.2	-46.0
Total Firm Capacity	2362	2423	2440	2440	2455	2564	2564	2564	2579	2579	2498	2498	2304	2304	2304	2354	2295
Surplus (Deficit) MWs above RM	16	72	99	100	112	211	220	217	228	216	139	171	16	19	17	68	8
Reserve Margin %	20.8%	23.7%	25.1%	25.1%	25.7%	30.8%	31.2%	31.1%	31.6%	31.0%	27.1%	28.8%	20.8%	21.0%	20.9%	23.6%	20.4%

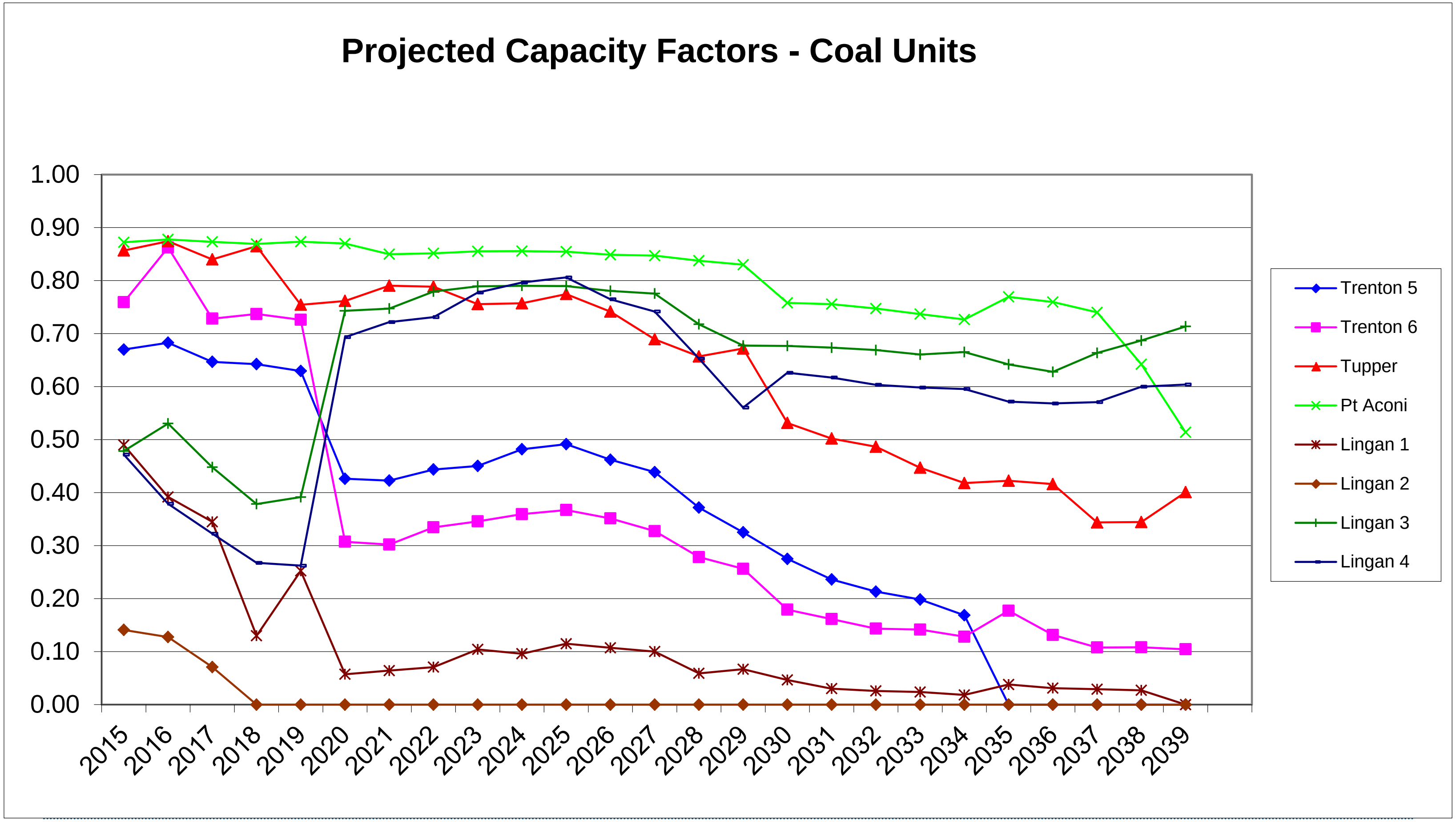
CRP21-1 Preliminary Demand and DSM



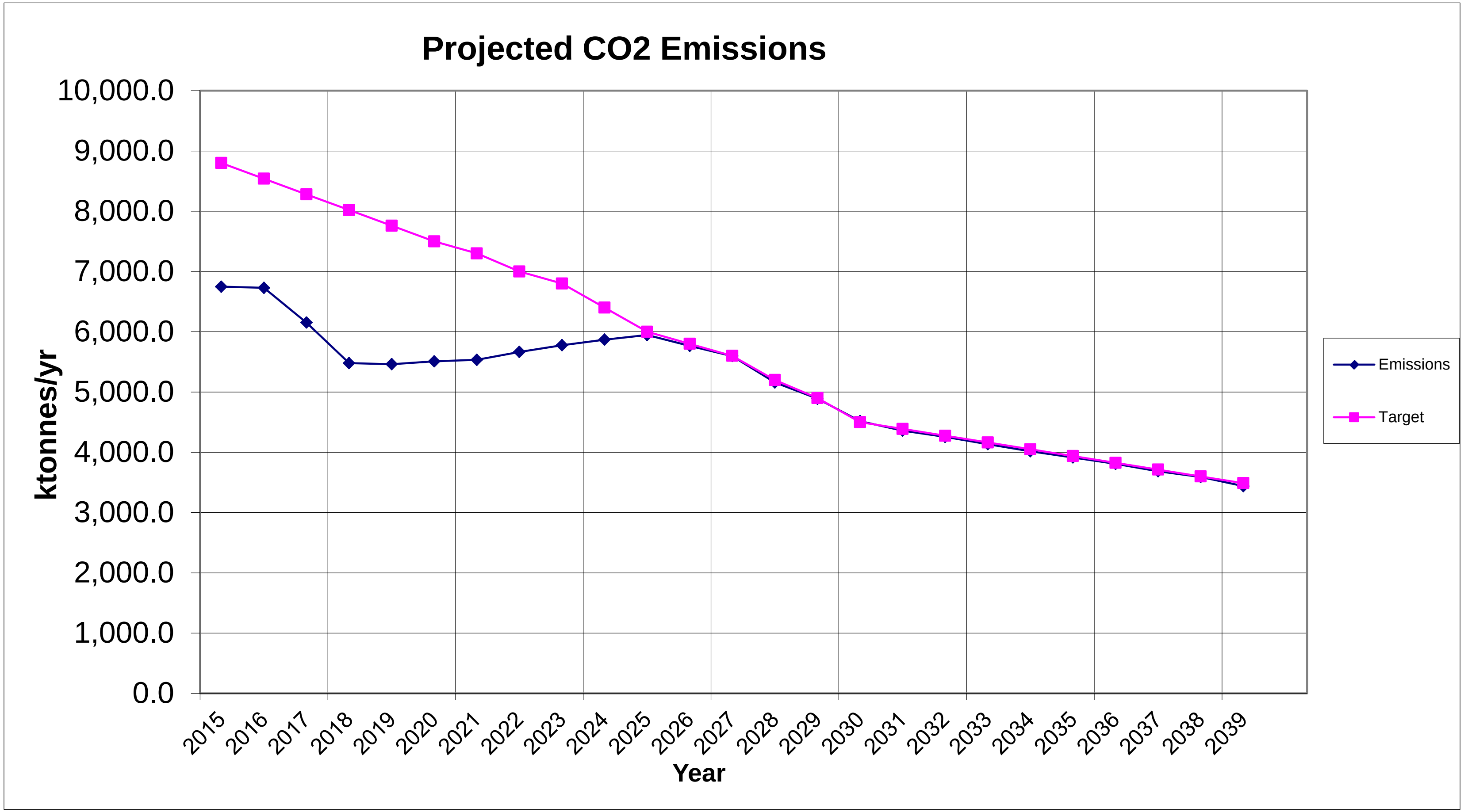
CRP21-1
Preliminary Energy by Resource Type



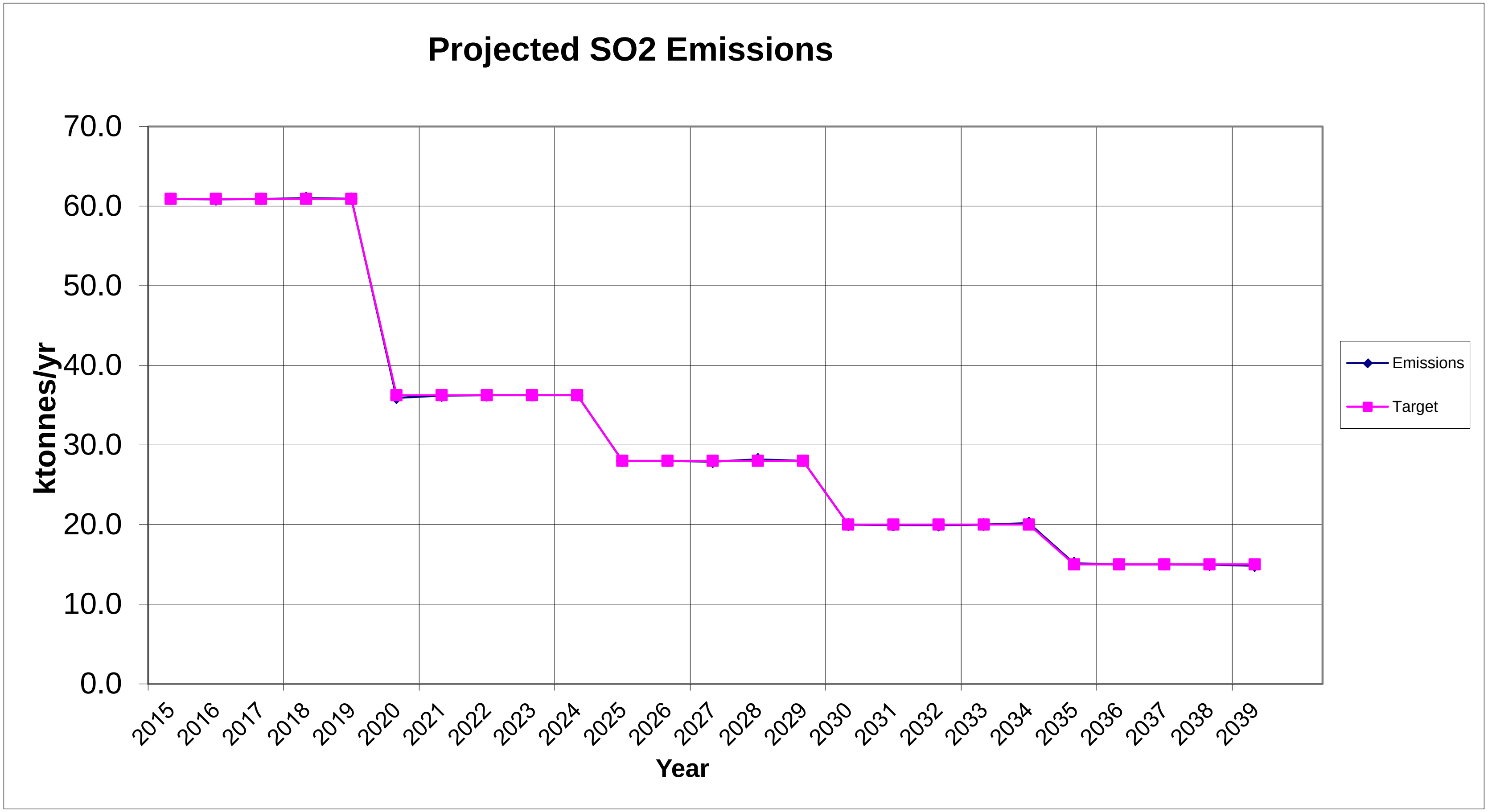
CRP21-1 Preliminary Coal Capacity Factors



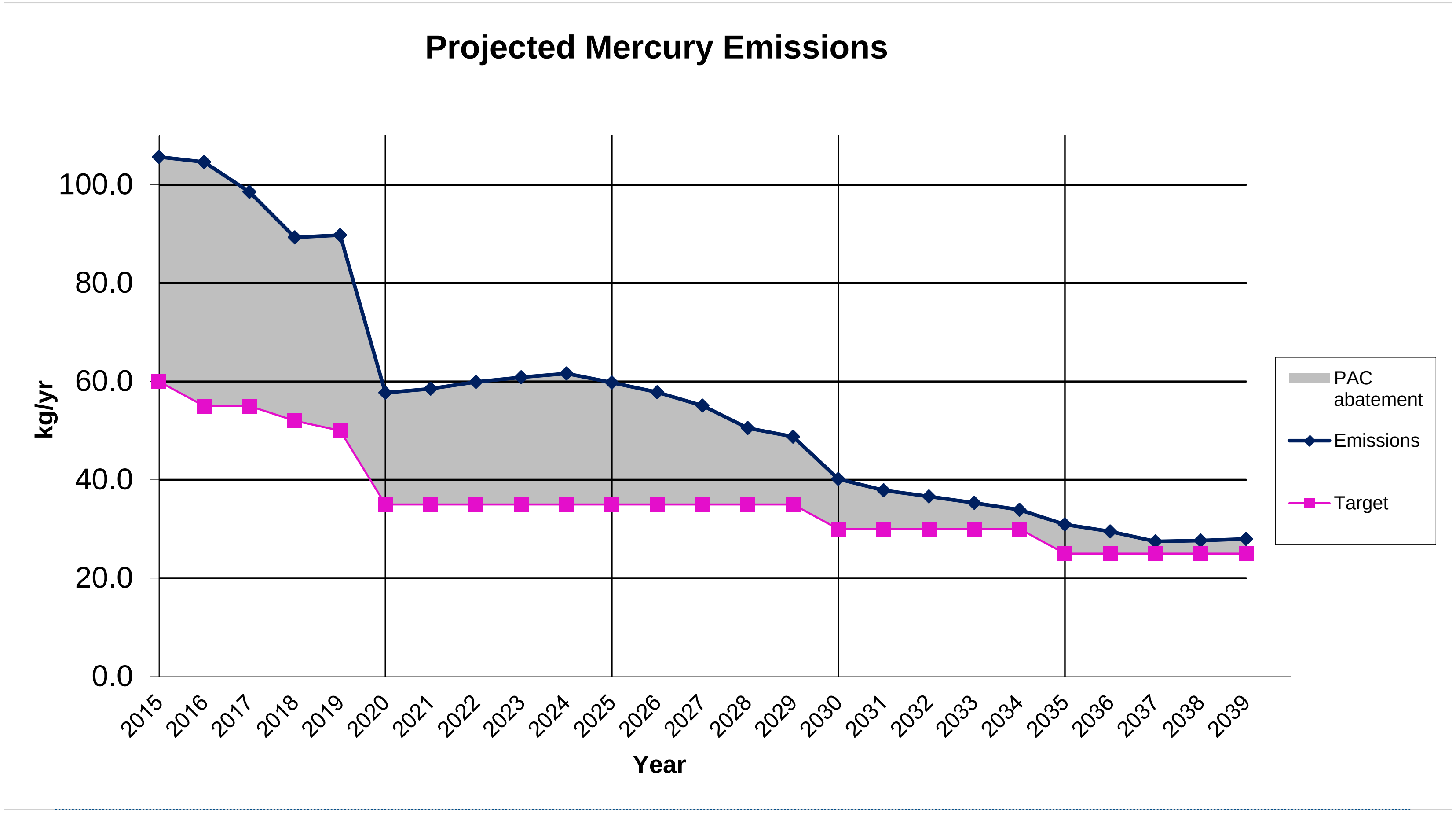
CRP21-1 Preliminary CO_2 Emissions



CRP21-1 Preliminary SO_2 Emissions



CRP21-1 Preliminary Hg Emissions



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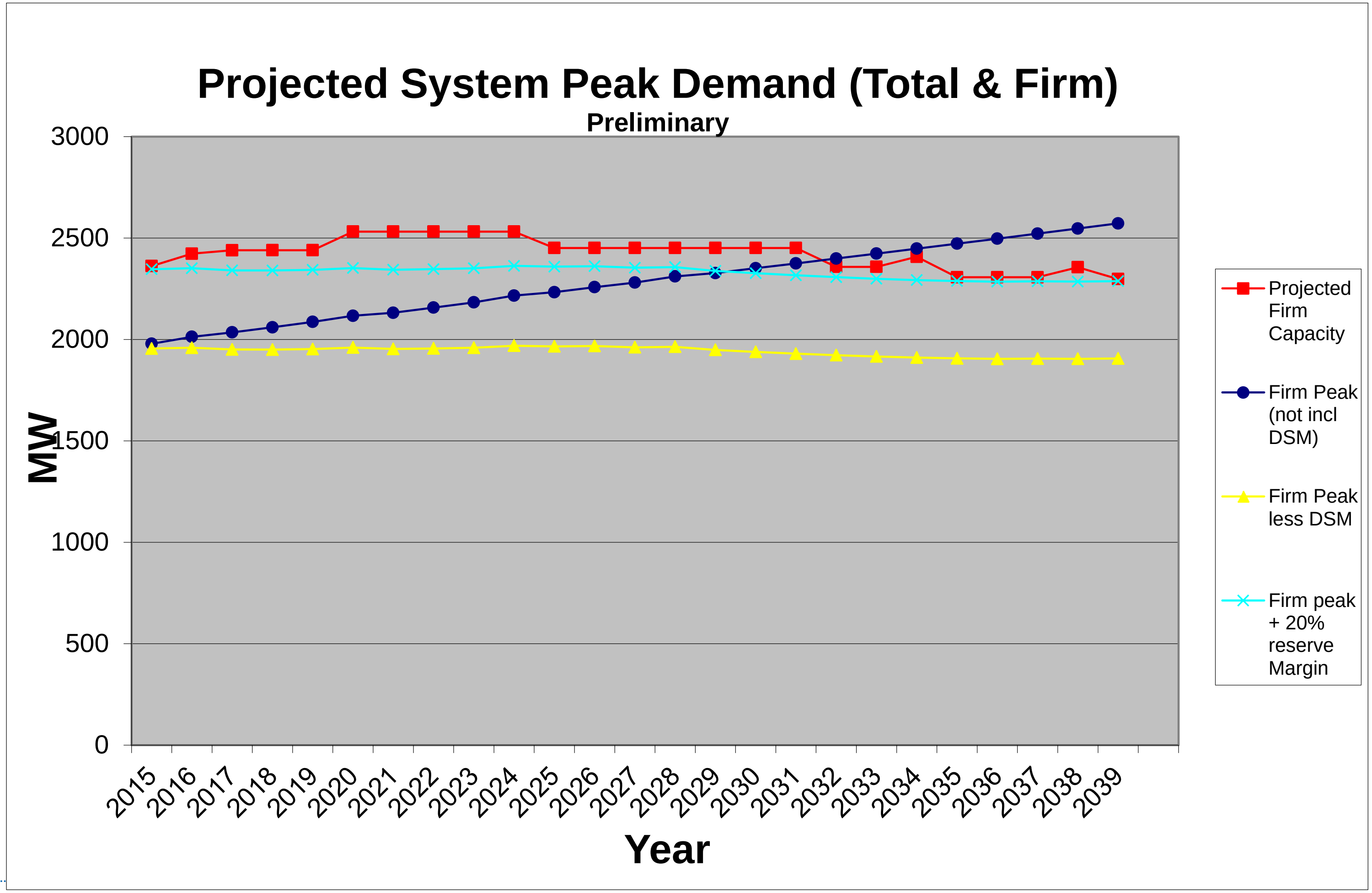
CRP21-3 Preliminary Results

CRP21-3 Preliminary Load and Resources

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	2036	2037	2038	2039
Firm Peak	1,979	2,013	2,035	2,060	2,087	2,117	2,132	2,157	2,183	2,216	2,233	2,351	2,472	2,497	2,522	2,547	2,572
DSM	23	54	84	110	134	156	178	202	224	247	267	412	566	593	616	643	666
Firm Peak Less DSM	1,955	1,959	1,951	1,950	1,953	1,960	1,953	1,956	1,959	1,969	1,966	1,939	1,907	1,904	1,906	1,905	1,906
RM Required	391	392	390	390	391	392	391	391	392	394	393	388	381	381	381	381	381
Required MWs	2,346	2,351	2,341	2,340	2,343	2,352	2,344	2,347	2,351	2,363	2,359	2,327	2,288	2,285	2,287	2,286	2,288
Existing MWs	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341
Resource Additions (MW):																	
Burnside #4		33															
COMFIT - Biomass	4.2	6															
COMFIT - Wind	14.14	4.56	5.1														
REA Wind	2.35	17.34															
Maritime Link				153.3													
Small Biomass PPA			10														
Hydro			1.8														
PH Biomass																	45.4
PPA						100											
Assumed Unit Retirement				-153		-8					-81		-150				-153
Natural Gas Unit													49.4			49.4	49.4
Total Annual Additions	20.7	60.9	16.9	0.3	0.0	92.0	0.0	0.0	0.0	0.0	-81.0	0.0	-100.6	0.0	0.0	49.4	-58.2
Total Cumulative Additions	20.7	81.6	98.5	98.7	98.7	190.7	190.7	190.7	190.7	190.7	109.7	109.7	-34.5	-34.5	-34.5	14.9	-43.3
Total Firm Capacity	2362	2423	2440	2440	2440	2532	2532	2532	2532	2532	2451	2451	2307	2307	2307	2356	2298
Surplus (Deficit) MWs above RM	16	72	99	100	97	180	188	185	181	169	92	124	19	22	20	71	10
Reserve Margin %	20.8%	23.7%	25.1%	25.1%	25.0%	29.2%	29.6%	29.5%	29.2%	28.6%	24.7%	26.4%	21.0%	21.1%	21.1%	23.7%	20.6%

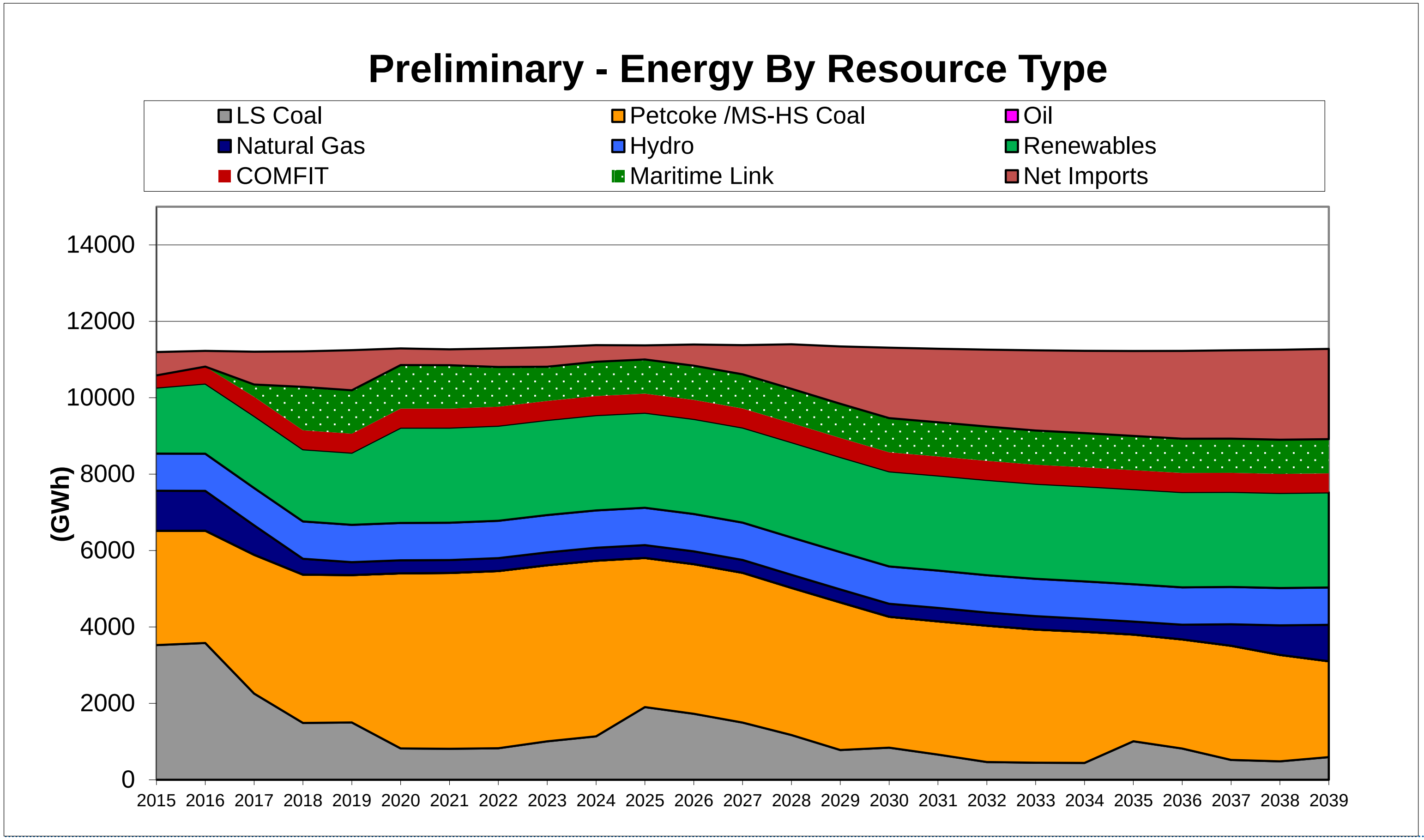
CRP21-3 Preliminary Demand and DSM



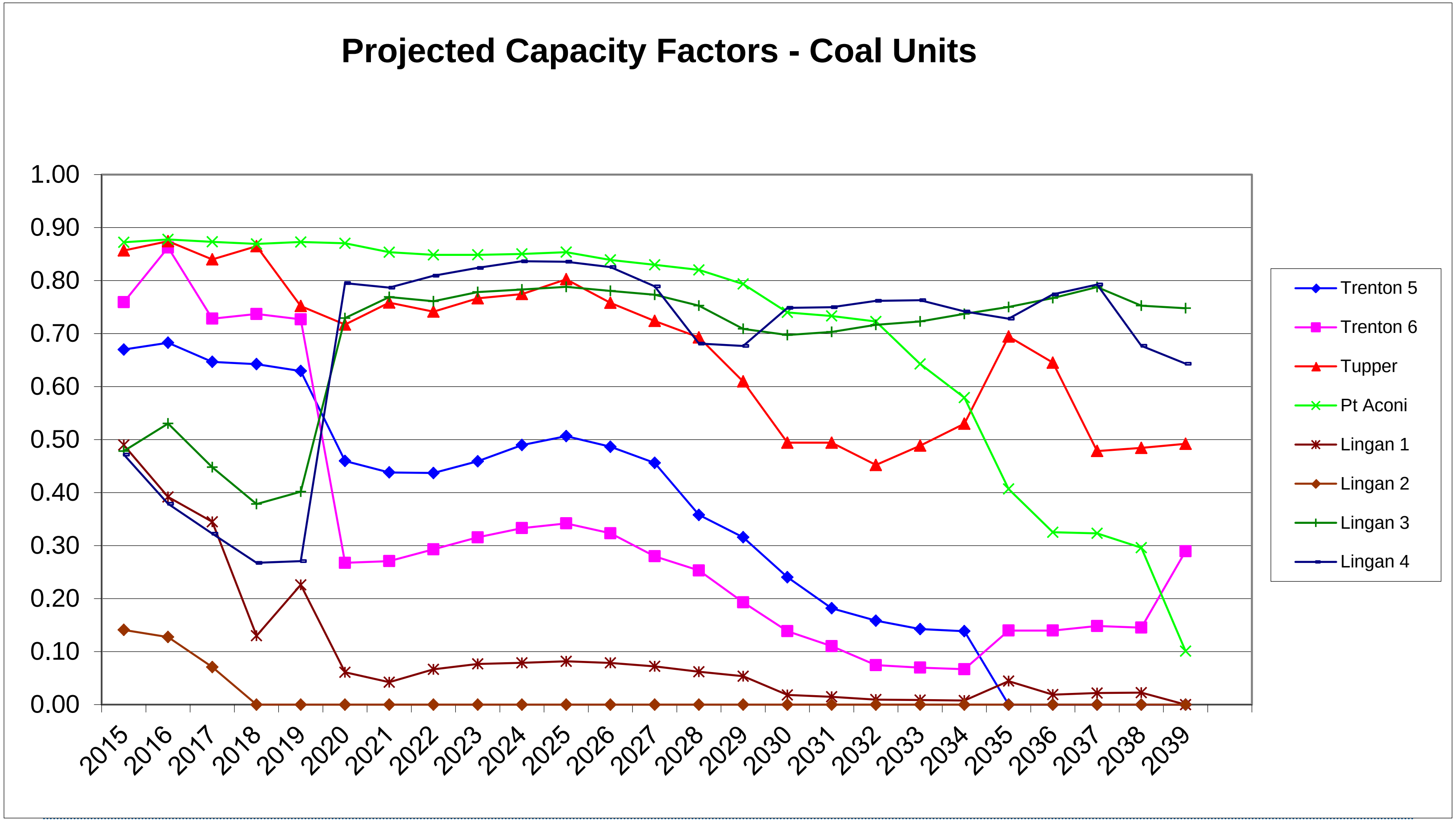
Projected System Peak Demand (Total & Firm)

Preliminary

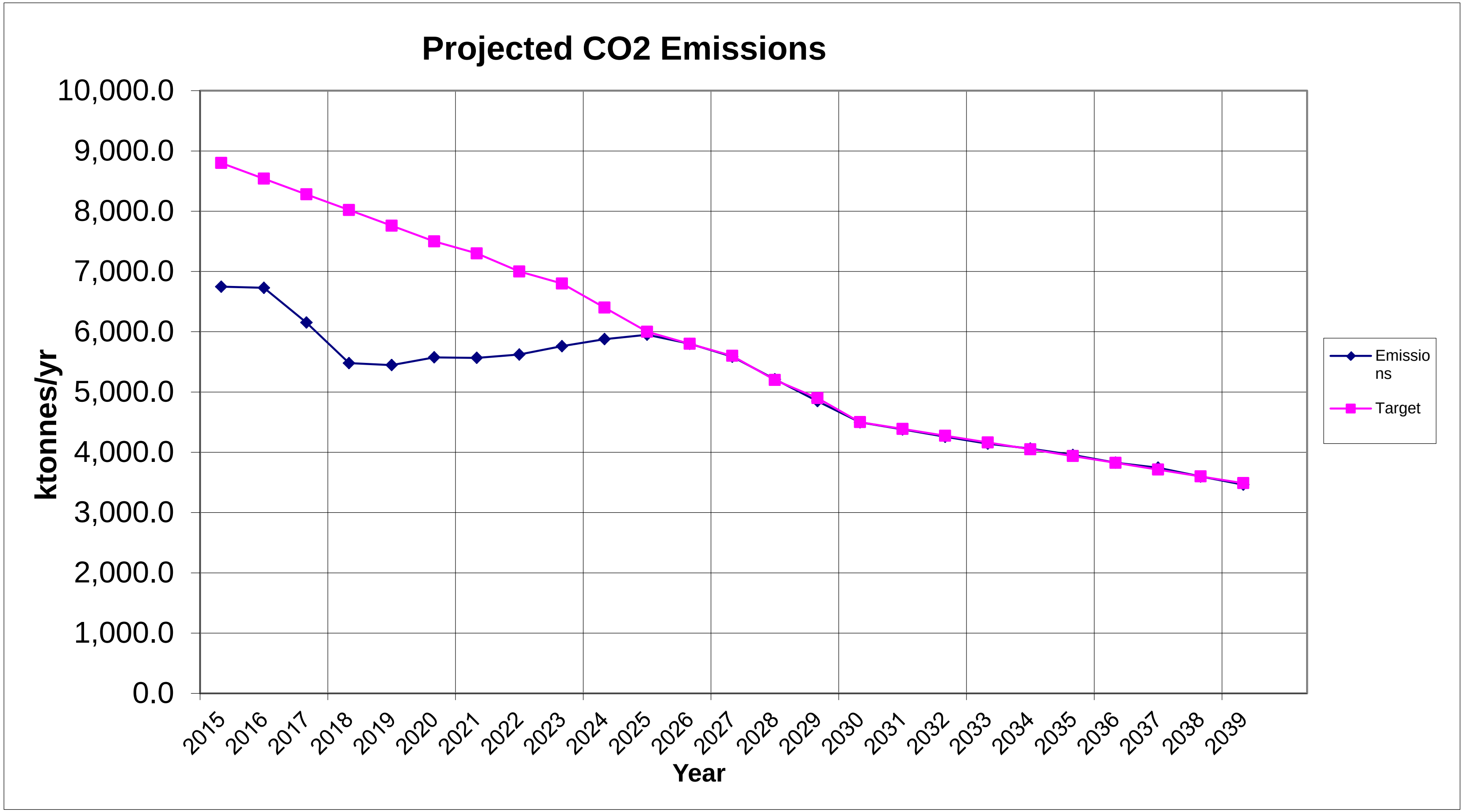
CRP21-3
Preliminary Energy by Resource Type



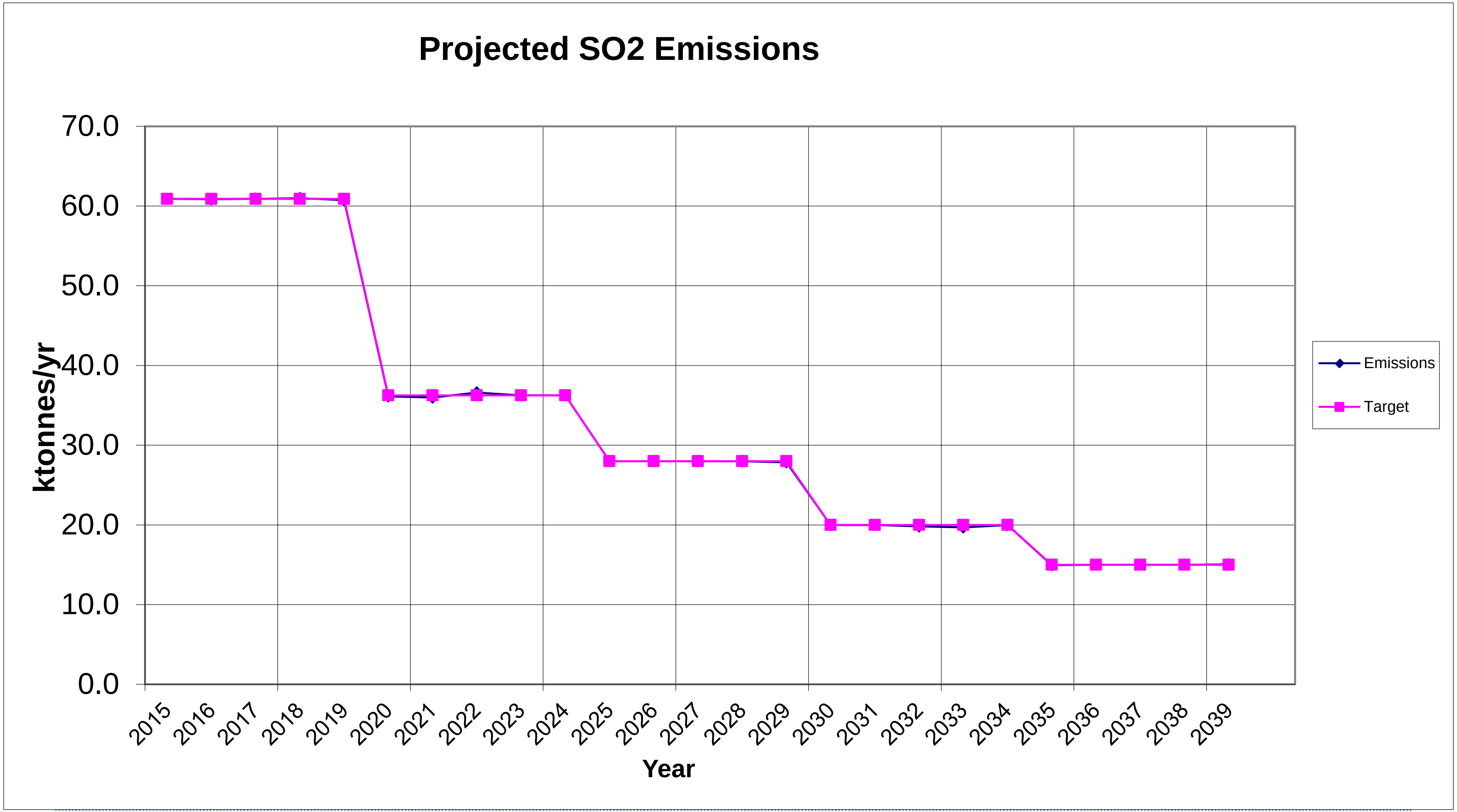
CRP21-3 Preliminary Coal Capacity Factors



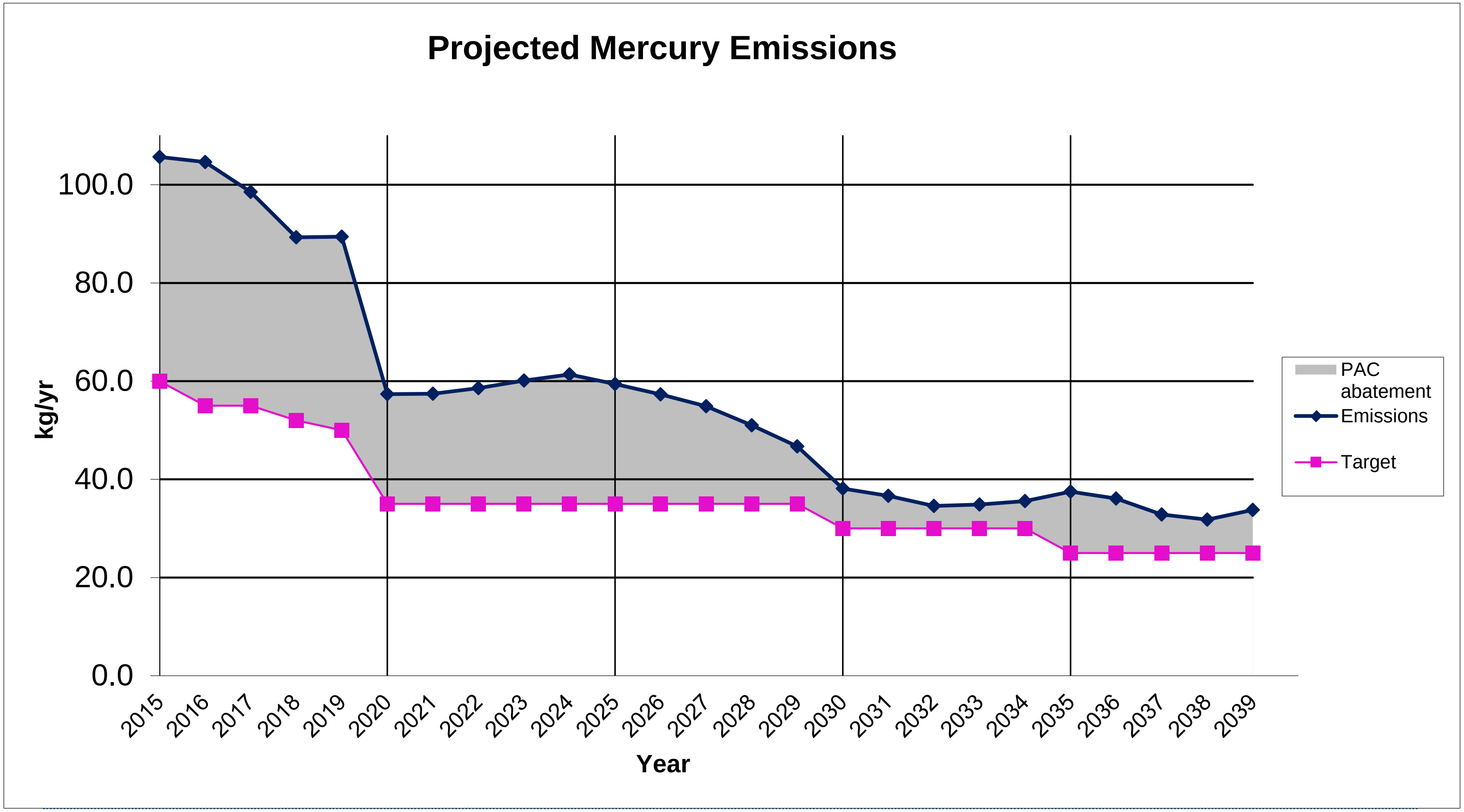
CRP21-3 Preliminary CO_2 Emissions



CRP21-3 Preliminary SO_2 Emissions



CRP21-3 Preliminary Hg Emissions



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CRP32 Preliminary Results

CRP32 Input Assumptions

Candidate Resource Plan 32 (CRP32):

- High Load Forecast
- Base DSM (50% of peak savings, 100% of energy)
- Emissions - Scenario A
- Planned and committed resources are fixed in the plan (REA wind, COMFIT, Maritime Link/ Retire Lin #2)
- Maximum Coal Use
- Constraints
    - Planning reserve margin min = 20%
    - RES: 2015-2019 = 25%; 2020-2039 = 40%

CRP32 Preliminary Results

	CRP32-01-WND-R01	CRP32-01-PPA-R01
	Least cost study period	**Least cost planning period**
2015		
2016	DR Water Heaters	DR Water Heaters
2017	ML Oct 2017	ML Oct 2017
	Lin 2 retire	Lin 2 retire
2018		
2019	Mersey Phase 1	
2020	FGD (Lin 3/4 300 MW)	FGD (Lin 3/4 300 MW)
	Wind Block 150 MW	PPA 100MW Firm
	2 x 50 MW CT (wind integration)	
2021		
2022		
2023	Mersey Phase 2	
2024		
2025	TUC 1 Retire	TUC 1 Retire
	CT 50MW	CT 50MW
2026		
2027		CT 50MW
2028	CT 50MW	
2029		
2030		
2031		
2032	TUC 2 Retire	TUC 2 Retire
	CT 50MW	CT 100MW
2033		
2034		
2035	Tre 5 Retire	Tre 5 Retire
	CT 50MW & CT 100MW	CT 50MW & CT 100MW
2036	CT 34MW	CT 50MW
2037		
2038	CC 145 MW	
2039	PHBM 51.7 MW Firm	PHBM 51.7 MW Firm
		CC 145 MW
	Lin 1 Retire	Lin 1 Retire
Planning PV $M	12,925	12,907
Study PV $M	20,008	20,236

	Base DSM	Base DSM
	Program Adm Cost	Customer Cost
	$M	$M
2015	50.7	37.9
2016	50.5	39.9
2017	50.0	41.2
2018	52.4	41.6
2019	57.0	32.2
2020	61.5	28.0
2021	56.9	28.4
2022	54.1	28.4
2023	51.5	29.2
2024	50.8	28.6
2025	50.6	29.9
2026	52.1	33.8
2027	54.8	36.8
2028	58.5	41.4
2029	60.7	34.0
2030	63.1	37.2
2031	62.6	40.6
2032	61.4	40.8
2033	59.3	41.4
2034	56.7	41.7
2035	47.7	48.4
2036	46.5	48.0
2037	45.4	47.6
2038	44.4	46.8
2039	43.5	46.3
NPV	**700.8**	**474.9**

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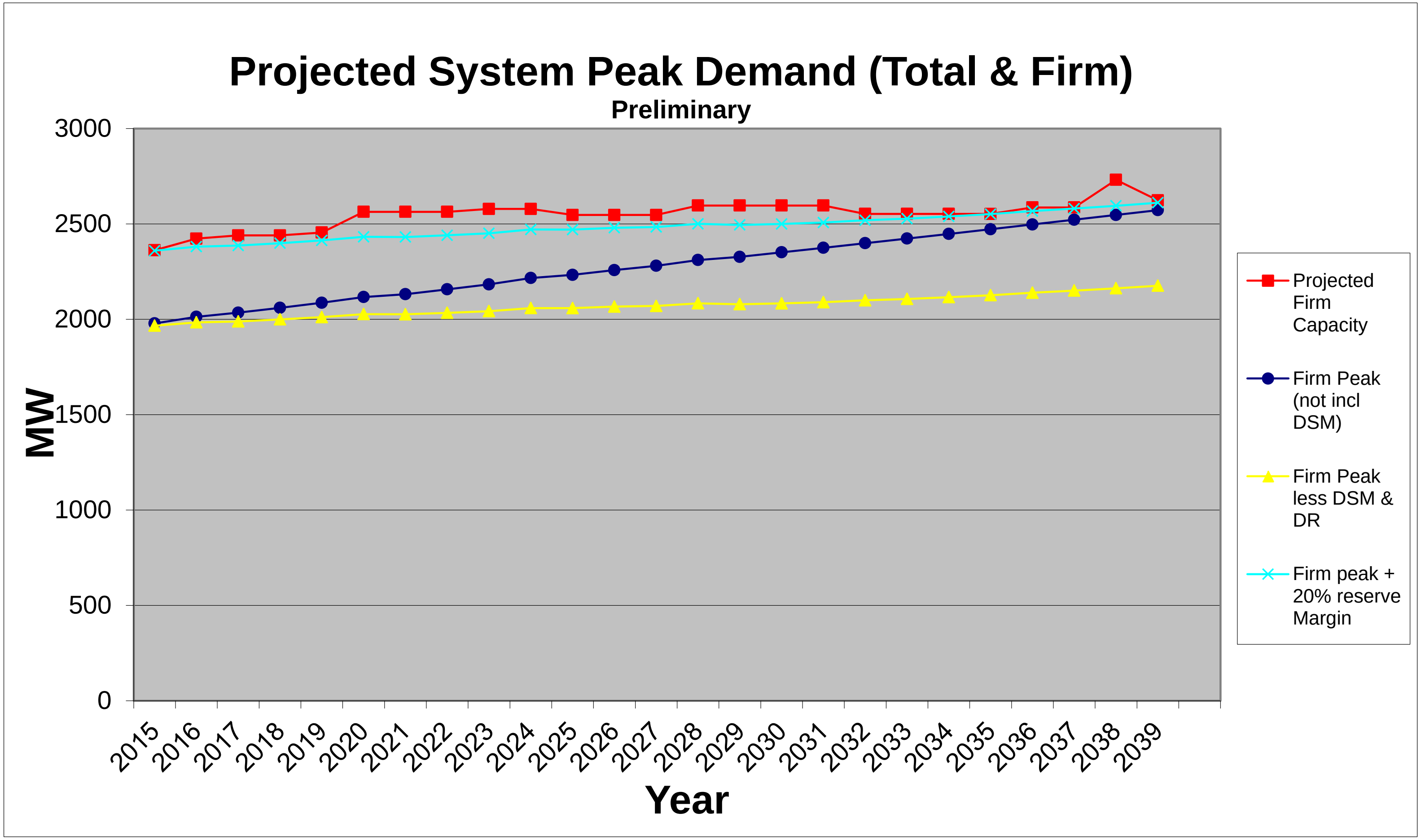
CRP32-1 (WIND) Preliminary Results

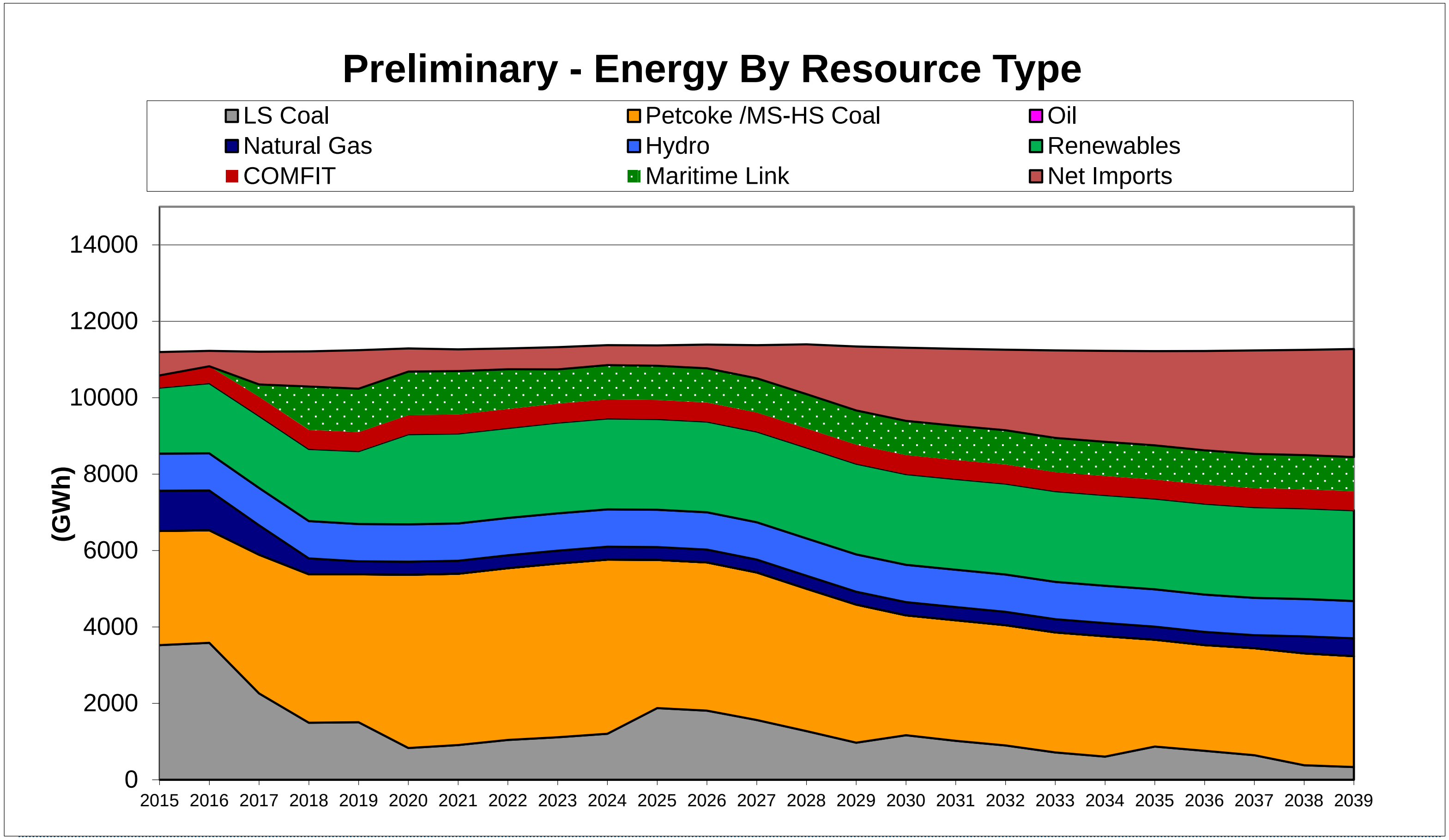
CRP32-1 (WIND)
Preliminary Load and Resources

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	2036	2037	2038	2039
Firm Peak	1,979	2,013	2,035	2,060	2,087	2,117	2,132	2,157	2,183	2,216	2,233	2,351	2,472	2,497	2,522	2,547	2,572
DSM	12	28	44	56	69	80	91	102	113	125	135	208	284	298	310	323	334
Firm Peak Less DSM	1,967	1,985	1,991	2,004	2,018	2,037	2,041	2,055	2,070	2,091	2,098	2,144	2,188	2,199	2,212	2,224	2,238
DRWH Reduction	0	1	2	4	7	10	15	21	27	32	39	60	62	60	62	62	62
DRCM Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Less DR	1,967	1,984	1,989	1,999	2,011	2,027	2,026	2,034	2,043	2,059	2059	2083	2126	2,139	2,151	2,163	2,176
RM Required	393	397	398	400	402	405	405	407	409	412	412	416.7	425.3	428	430	433	435
Required MWs	2,360	2,381	2,387	2,399	2,414	2,433	2,432	2,441	2,451	2,471	2470	2500	2552	2,567	2,581	2,595	2,611
Existing MWs	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341
Resource Additions (MW):																	
Burnside #4		33															
COMFIT - Biomass	4.2	6															
COMFIT - Wind	14.14	4.56	5.1														
REA Wind	2.35	17.34															
Maritime Link				153.3													
Small Biomass PPA			10														
Hydro			1.8		15				15								
PH Biomass																	45.4
Additional Wind						18											
Assumed Unit Retirement				-153		-8					-81		-150				-153
Natural Gas Unit						98.7					49.4		149.4	34		145	
Total Annual Additions	20.7	60.9	16.9	0.3	15.0	108.7	0.0	0.0	15.0	0.0	-31.6	0.0	-0.6	34.0	0.0	145.0	-107.6
Total Cumulative Additions	20.7	81.6	98.5	98.7	113.7	222.4	222.4	222.4	237.4	237.4	205.8	255.2	211.0	245.0	245.0	390.0	282.4
Total Firm Capacity	2362	2423	2440	2440	2455	2564	2564	2564	2579	2579	2547	2597	2552	2586	2586	2731	2624
Surplus (Deficit) MWs above RM	2	42	53	41	41	131	132	123	128	108	77	96	1	19	6	136	12
Reserve Margin %	20.1%	22.1%	22.7%	22.0%	22.1%	26.5%	26.5%	26.0%	26.2%	25.2%	23.7%	24.6%	20.0%	20.9%	20.3%	26.3%	20.6%

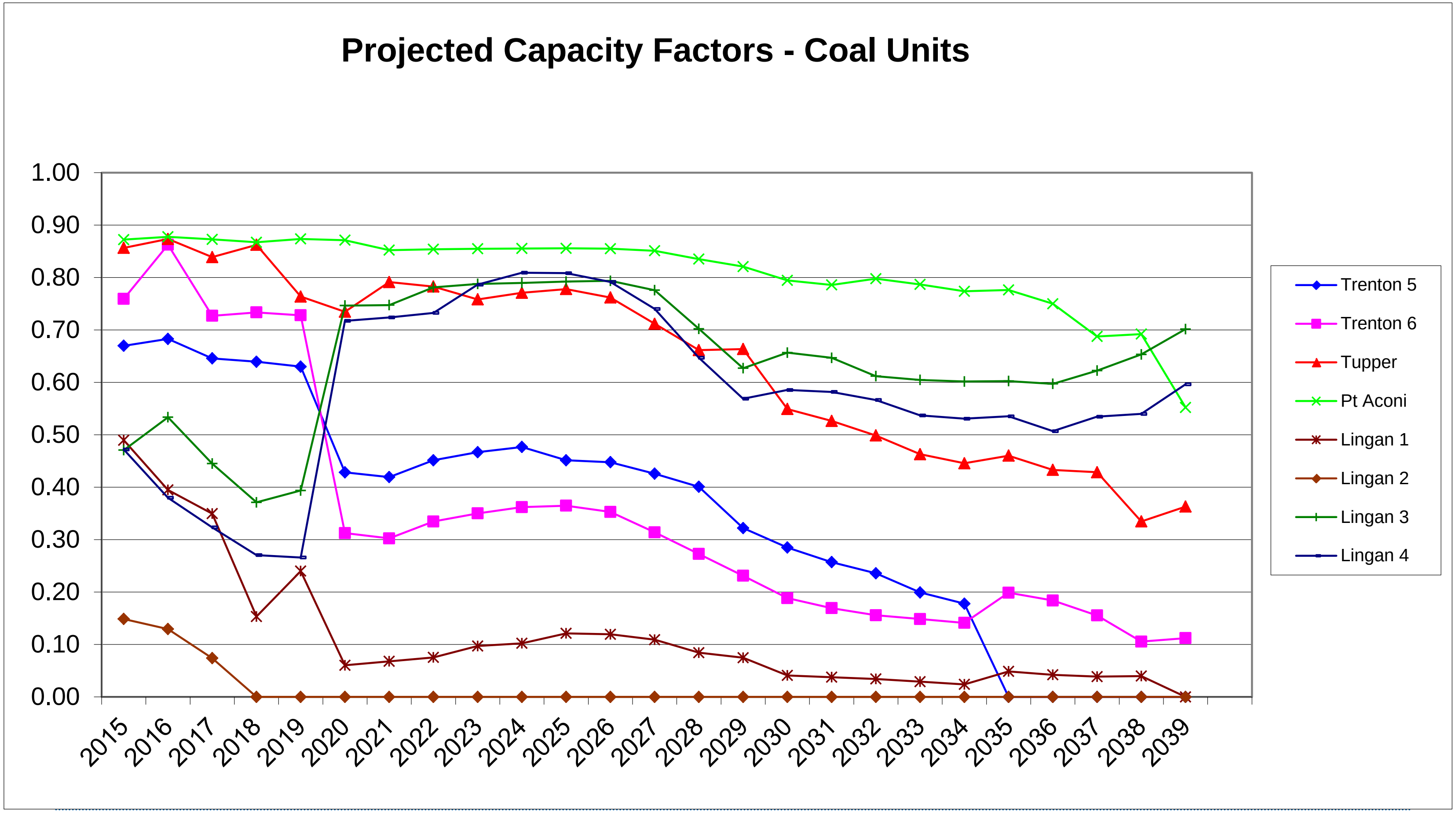
CRP32-1 (WIND)
Preliminary Demand and DSM



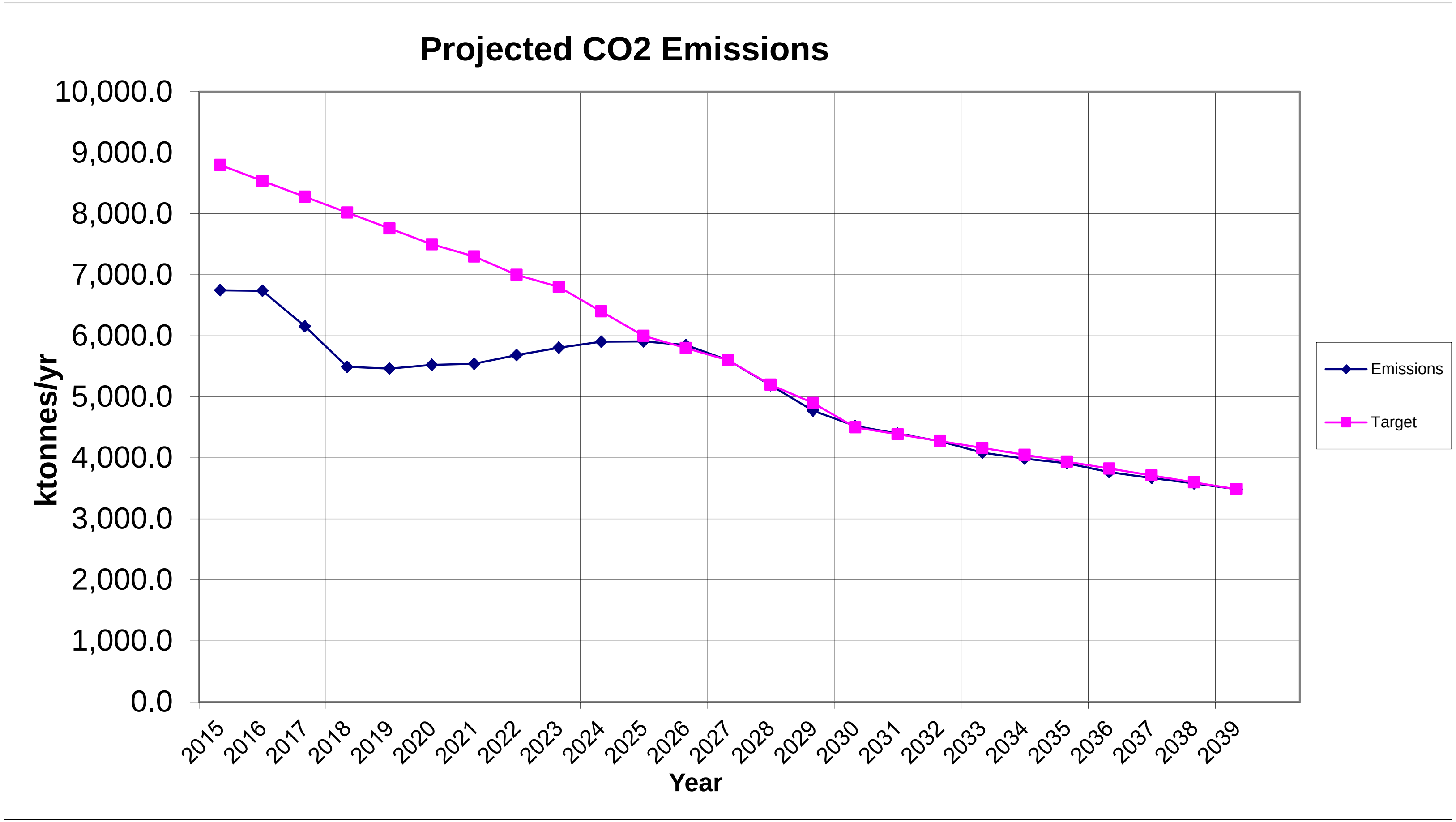
CRP32-1 (WIND)
Preliminary Energy by Resource Type



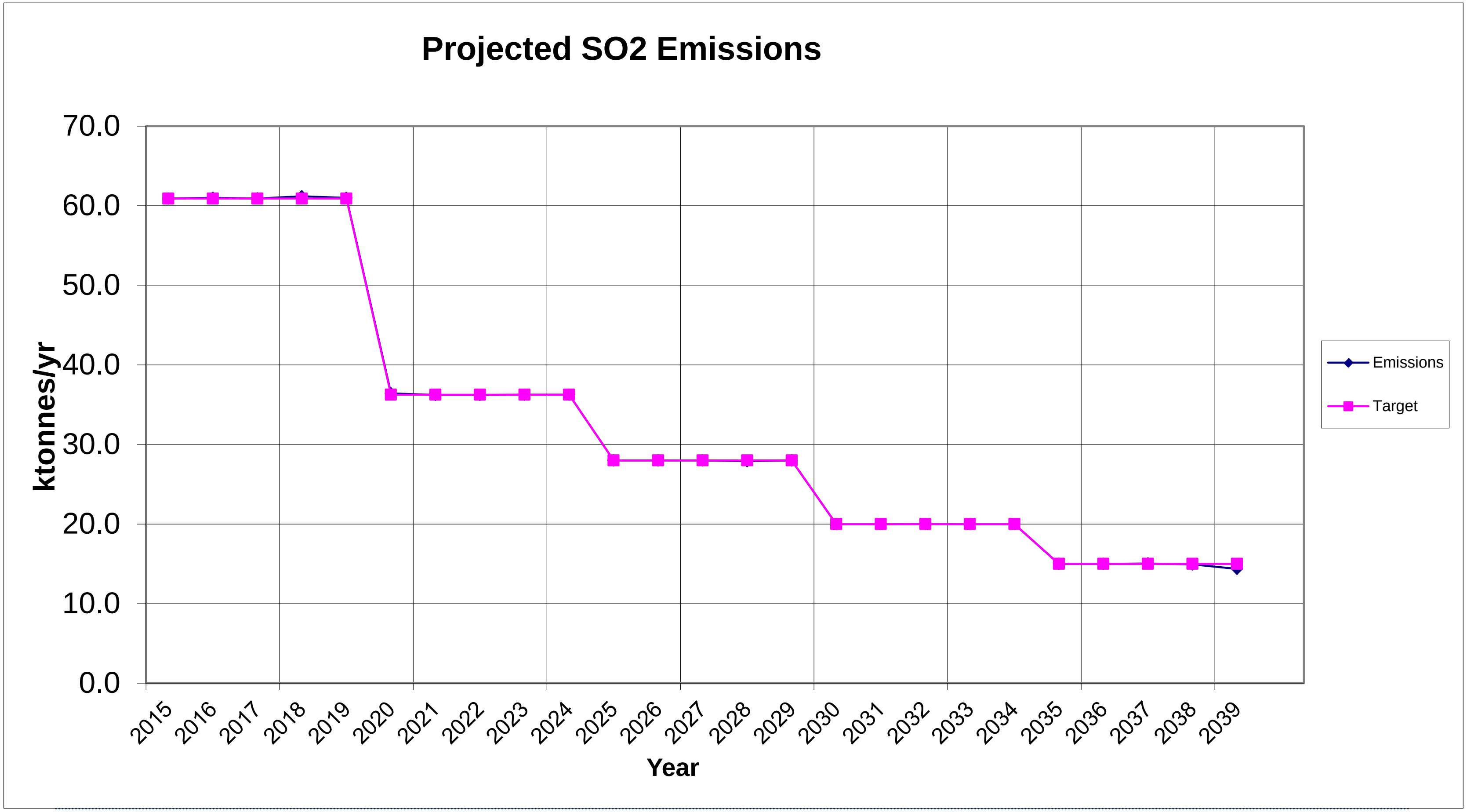
CRP32-1 (WIND)
Preliminary Coal Capacity Factors



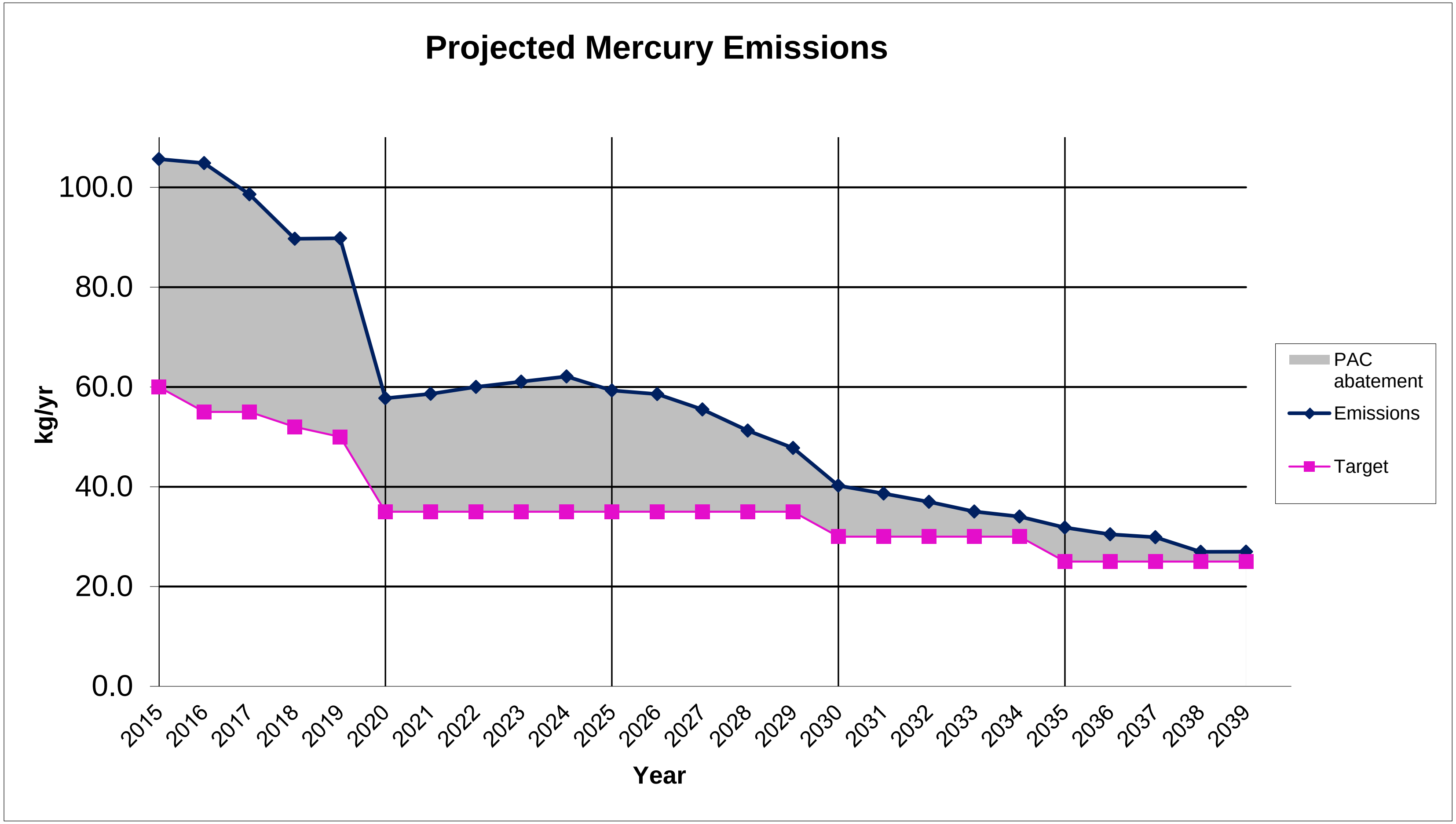
CRP32-1 (WIND)
Preliminary CO_2 Emissions



CRP32-1 (WIND)
Preliminary SO_2 Emissions



CRP32-1 (WIND) Preliminary Hg Emissions



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CRP32-1 (PPA) Preliminary Results

CRP32-1 (PPA)
Preliminary Load and Resources

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	2036	2037	2038	2039
Firm Peak	1,979	2,013	2,035	2,060	2,087	2,117	2,132	2,157	2,183	2,216	2,233	2,351	2,472	2,497	2,522	2,547	2,572
DSM	12	28	44	56	69	80	91	102	113	125	135	208	284	298	310	323	334
Firm Peak Less DSM	1,967	1,985	1,991	2,004	2,018	2,037	2,041	2,055	2,070	2,091	2,098	2,144	2,188	2,199	2,212	2,224	2,238
DRWH Reduction	0	1	2	4	7	10	15	21	27	32	39	60	62	60	62	62	62
DRCM Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Less DR	1,967	1,984	1,989	1,999	2,011	2,027	2,026	2,034	2,043	2,059	2059	2083	2126	2,139	2,151	2,163	2,176
RM Required	393	397	398	400	402	405	405	407	409	412	412	416.7	425.3	428	430	433	435
Required MWs	2,360	2,381	2,387	2,399	2,414	2,433	2,432	2,441	2,451	2,471	2470	2500	2552	2,567	2,581	2,595	2,611
Existing MWs	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341	2341
Resource Additions (MW):																	
Burnside #4		33															
COMFIT - Biomass	4.2	6															
COMFIT - Wind	14.14	4.56	5.1														
REA Wind	2.35	17.34															
Maritime Link				153.3													
Small Biomass PPA			10														
Hydro			1.8														
PH Biomass																	45.4
PPA						100											
Assumed Unit Retirement				-153		-8					-81		-150				-153
Natural Gas Unit											49.4		149.4	49.4			145
Total Annual Additions	20.7	60.9	16.9	0.3	0.0	92.0	0.0	0.0	0.0	0.0	-31.6	0.0	-0.6	49.4	0.0	0.0	37.4
Total Cumulative Additions	20.7	81.6	98.5	98.7	98.7	190.7	190.7	190.7	190.7	190.7	159.1	208.5	214.9	264.3	264.3	264.3	301.7
Total Firm Capacity	2362	2423	2440	2440	2440	2532	2532	2532	2532	2532	2501	2550	2556	2606	2606	2606	2643
Surplus (Deficit) MWs above RM	2	42	53	41	26	99	101	91	81	61	30	50	5	38	25	11	32
Reserve Margin %	20.1%	22.1%	22.7%	22.0%	21.3%	24.9%	25.0%	24.5%	24.0%	23.0%	21.5%	22.4%	20.2%	21.8%	21.2%	20.5%	21.5%

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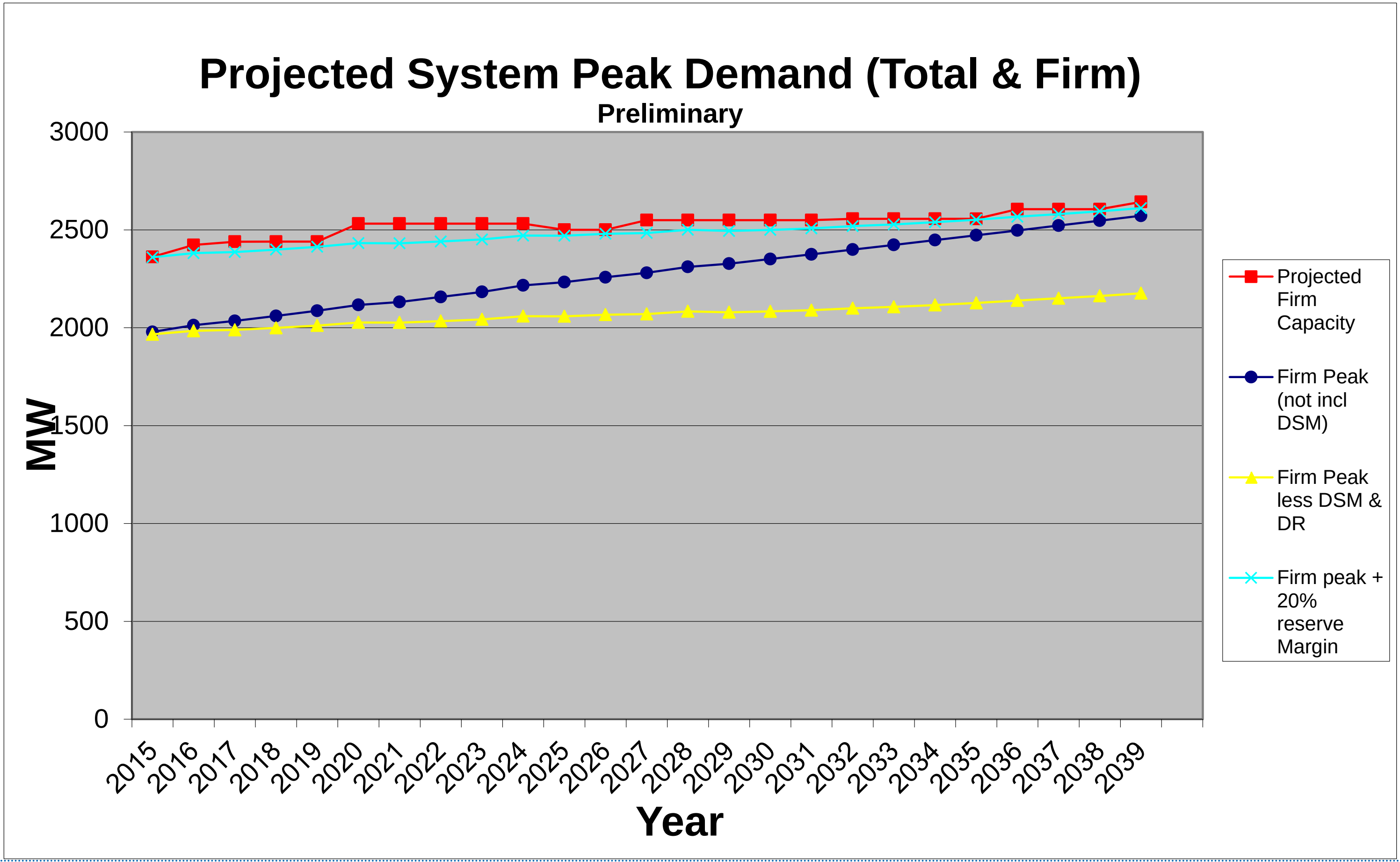
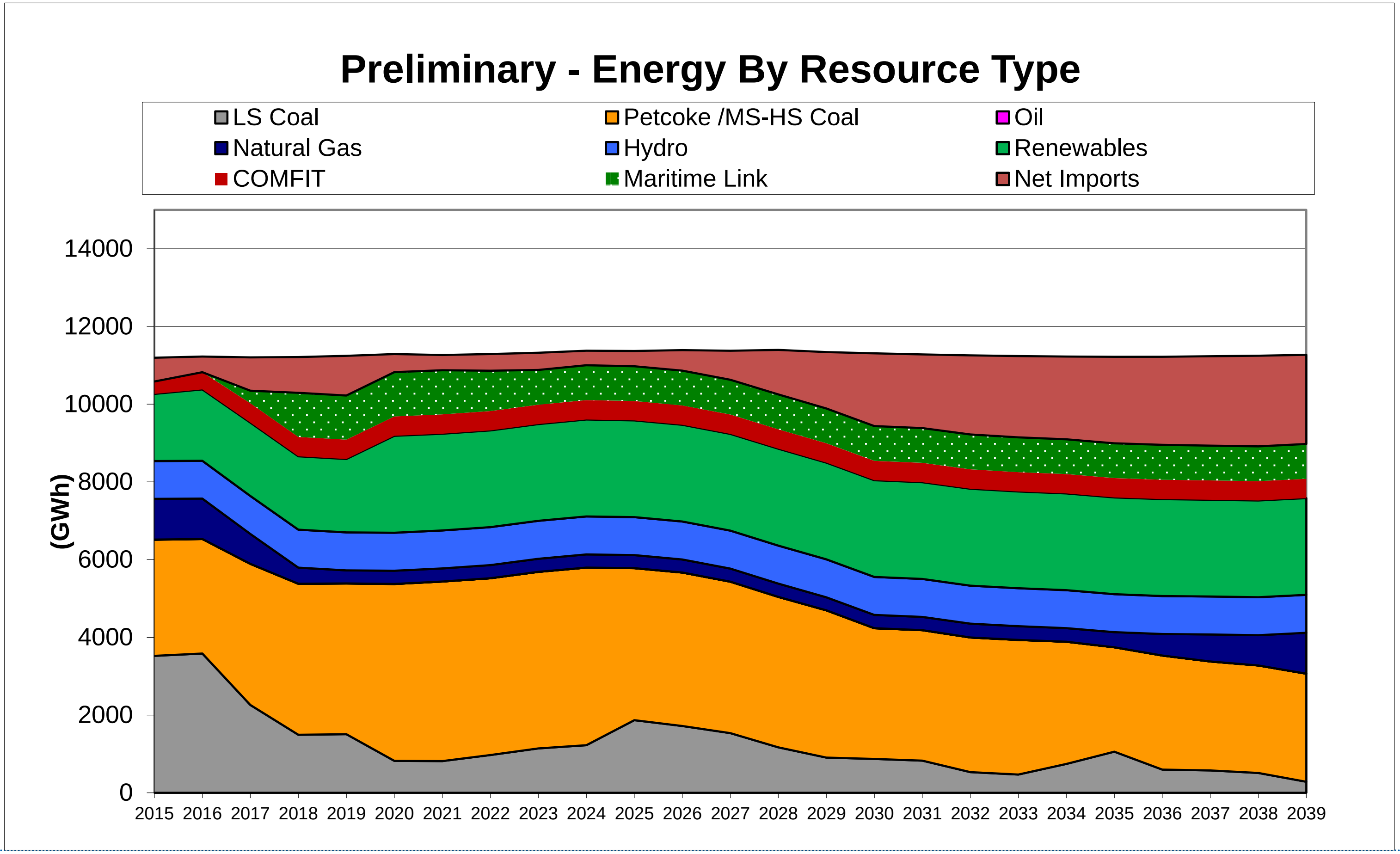
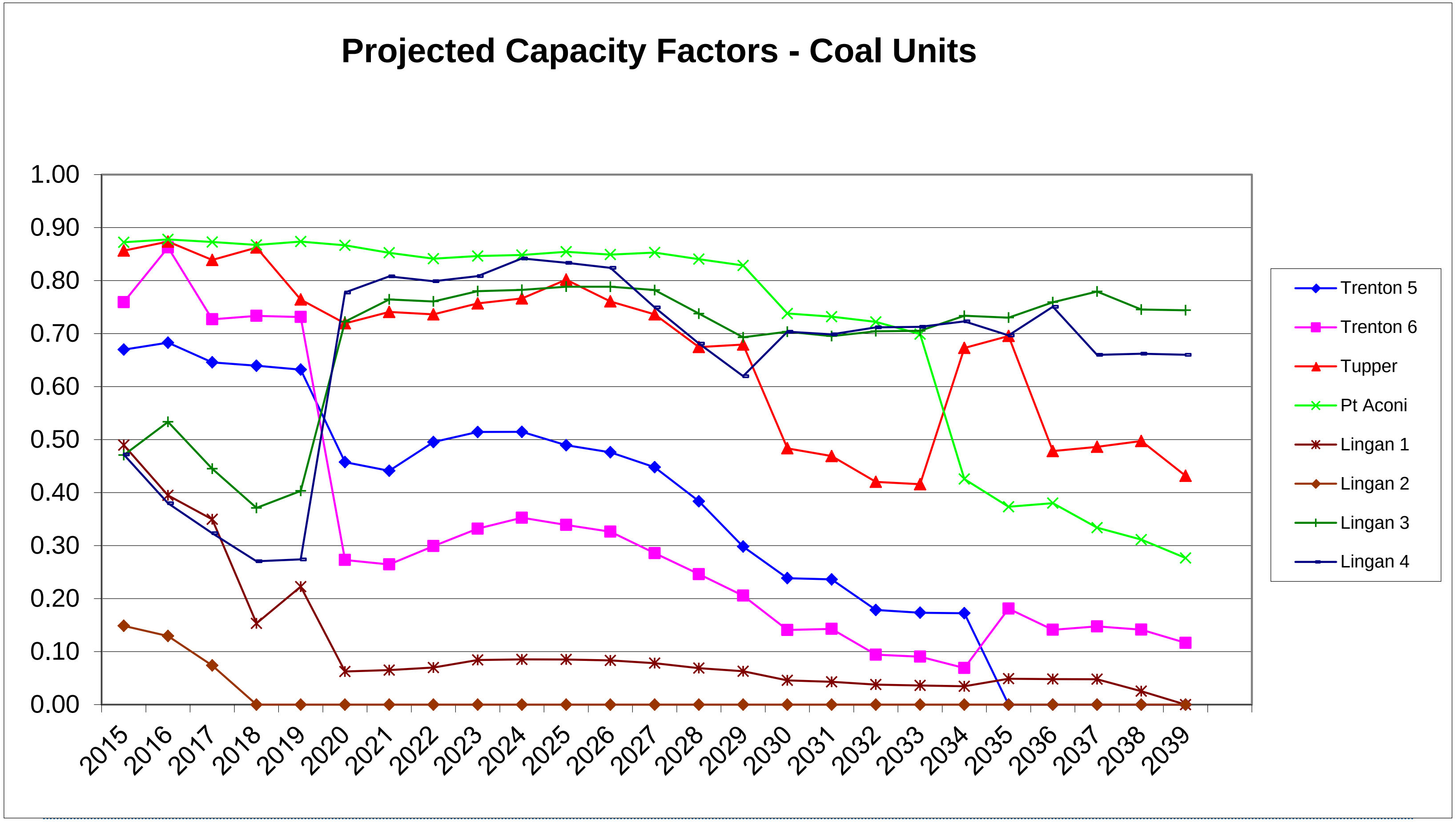
CRP32-1 (PPA) Preliminary Demand and DSM



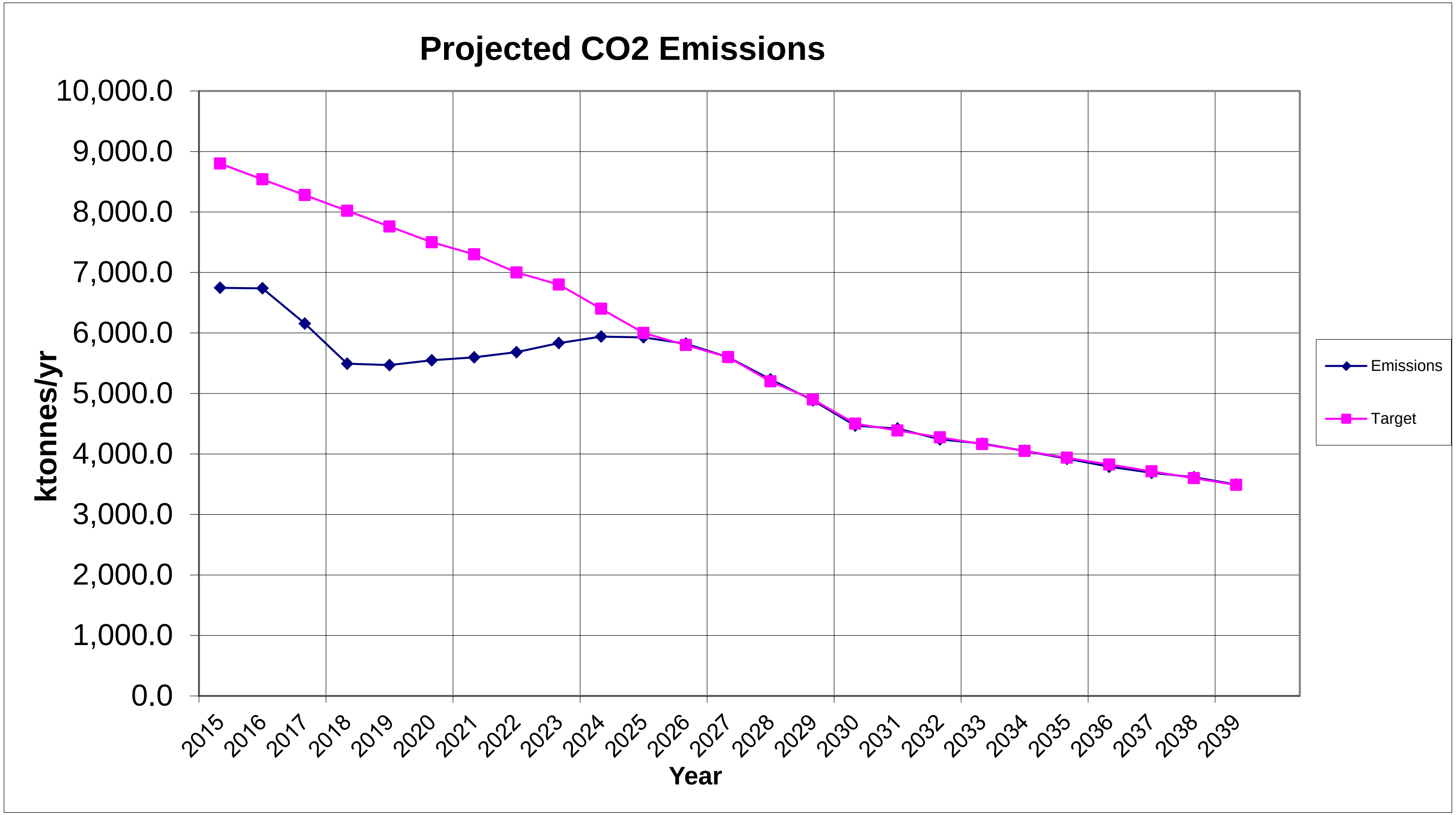
CRP32-1 (PPA)
Preliminary Energy by Resource Type



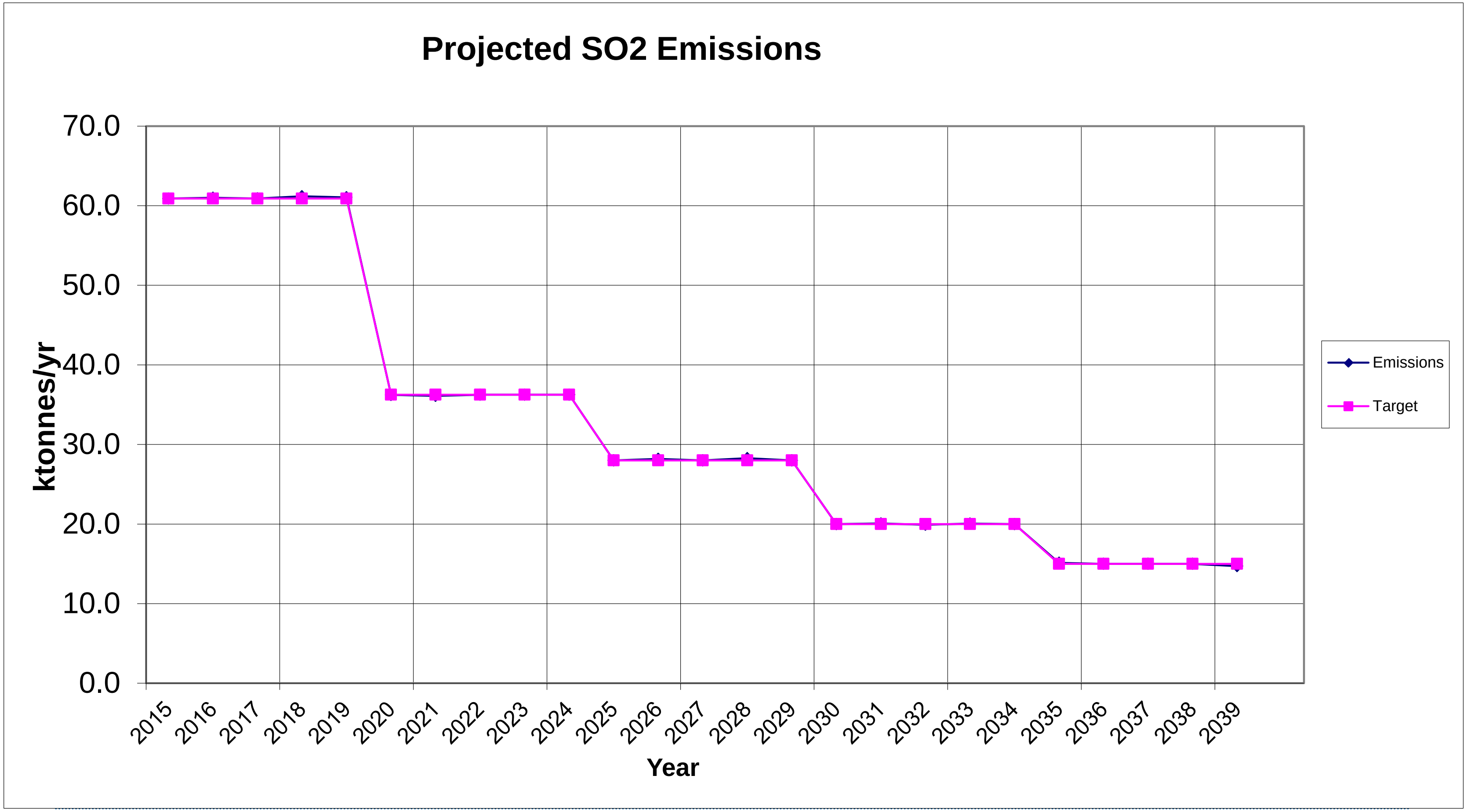
CRP32-1 (PPA)
Preliminary Coal Capacity Factors



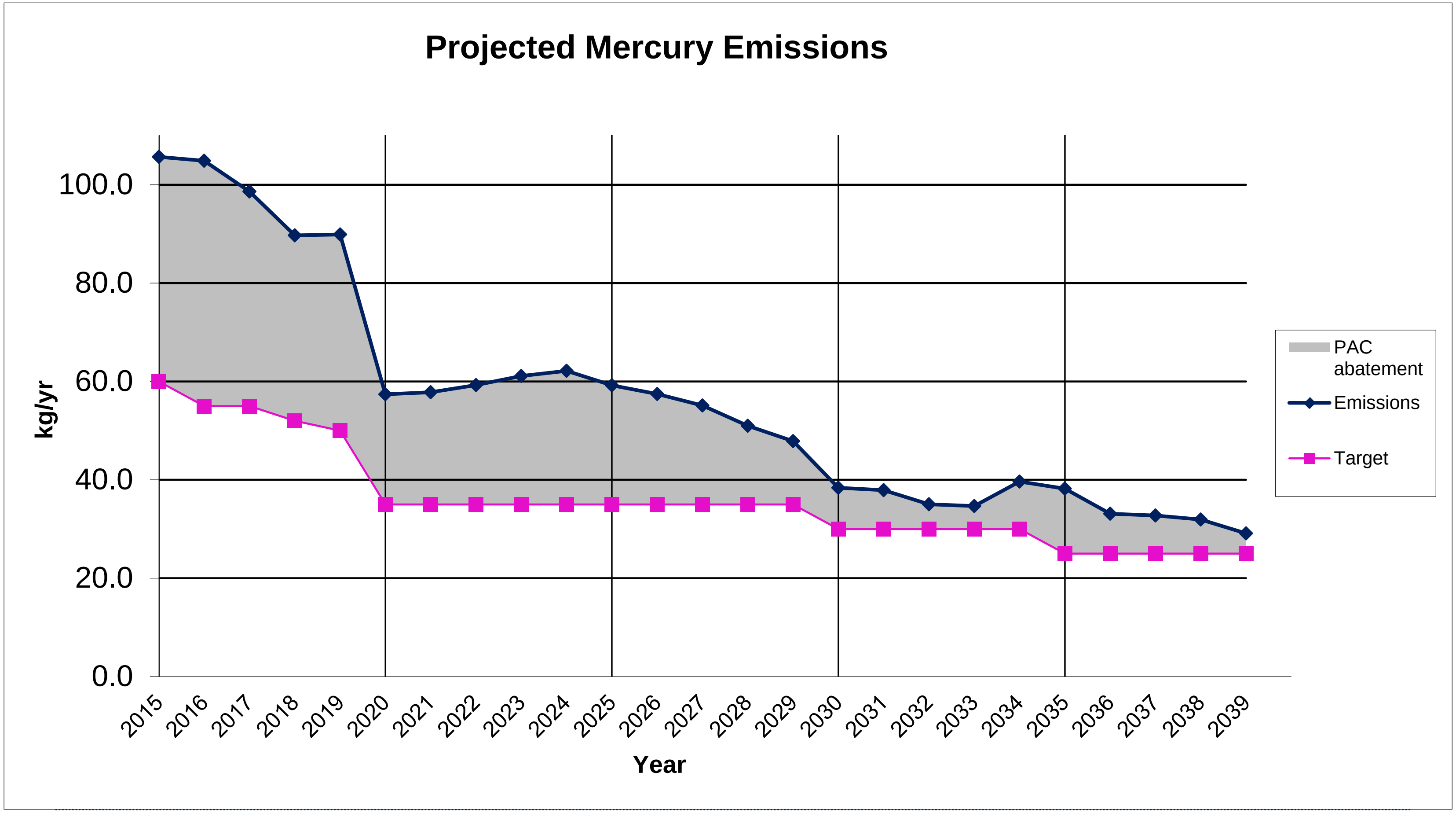
CRP32-1 (PPA) Preliminary CO_2 Emissions



CRP32-1 (PPA) Preliminary SO_2 Emissions



CRP32-1 (PPA) Preliminary Hg Emissions



APPENDIX M

Firm Capacity Contribution from ERIS Wind

The following summarizes the system assumptions used to evaluate the possible contribution to firm capacity that could be counted from ERIS wind projects. System conditions anticipated after the integration of the Maritime Link in late 2017 were considered in the study.

The following assumptions are critical to the analysis:

1. System load levels at winter peak are as per the load demand forecast.
2. Maritime Link is in-service and operating at 300 MW. 150 MW is exported to NB as per Transmission Service Request TSR-400.
3. One Lingan Unit has been retired and displaced by Maritime Link.
4. All generation east of Onslow is on-line operating at its accredited capacity, with the exception of 60 MW held as Operating Reserve.
5. All transmission elements are in-service, including capacitor banks and the Static Var Compensator.
6. All transmission upgrades associated with Maritime Link have been completed:
    a. Woodbine bus developed
    b. L-7011 and L-7012 turned into Woodbine
    c. L-7005 and L-8004 no longer share a common tower
    d. L-7019, L-6511, L-6515 and L-6513 have been uprated
    e. Onslow bus has been re-configured to eliminate L-8002 + L-8003 common breaker
7. All wind generation is operating at less than 20% of nameplate capacity.
8. Special Protection Systems are armed to reject or run-back up to 330 MW for contingencies.
9. COMFIT generation is not modeled**.**

natural forces

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Ms. Doreen Friis
Regulatory Affairs Officer/Clerk of the Board
Nova Scotia Utility and Review Board
3rd Floor, 1601 Lower Water Street
PO Box 1692, Unit "M"
Halifax, NS, B3J 3S3

14th March 2014

RE: NSPI 2014 Integrated Resource Plan

Dear Ms. Friis,

We welcome the opportunity to comment on Nova Scotia Power's draft assumptions for the IRP as presented to interested parties on Friday the 7th March. We have only been given one week to prepare a response, which in the context of such an important process to our industry, does not represent sufficient time to prepare a more fulsome analysis of the presented information.

To frame out response we believe it is important to set the global context in which we are living.

- In 2012, the World Bank published in their report 'Turning down the Heat' in which they outlined some of the catastrophic consequences of failing to tackle climate change will have on the developing world.
- Last year, the Intergovernmental Panel on Climate Change published in September 2013 the latest updated entitled 'Climate Change – the Physical Science Basis'. This report states with 95 percent confidence that humans are the main cause of the current global warming and goes on to set out some quite frightening prospects in a 'business as usual scenario'.
- In a Canadian context the National Round Table on the Environment and the Economy have published a series of climate change reports, including 'Paying the Price: The Economic Impacts for Climate Change in Canada' which sets out that climate change costs for Canada could escalate from roughly $5 billion per year in 2020 — less than 10 years away — and to between $21 billion and $43 billion per year by the 2050s.

Governments around the world are taking these developments very seriously. The German government legislated for its 'Energiewende' policy (energy transformation) in 2011 an 85% reduction in GHG emissions by 2050. In a similar vein the British Government legislated by way of its Climate Change Act an 80% reduction in GHG emissions by 2050. The Federal Government's only response to date has been by way of the regulations for coal-fired electricity generators that are due to come into force in 2015. However, it is clear, given the latest science and the leadership being taken by various governments around the world that over the next decade there will be considerable pressure on Canada to follow suit and legislate for much more ambitious GHG reduction targets.

It is in this context that we now turn to the draft assumptions in the IRP. In our opinion, the IRP is a key instrument to inform government policy about the development of the electricity system here in Nova Scotia but equally as important the opportunity to inform government about the consequences of the dramatic changes that are likely to occur in the way we generate and use electricity over the next twenty years. It is well recognized that the electricity sector presents some of the 'low-hanging fruit' when it comes to offsetting GHG emissions and in this context we contend that the draft assumptions fall short in terms of the projected GHG reduction targets and increased renewable energy deployment. Given the short timeframe for responses we are not in a position to set out alternative assumptions but rather we focus on proposing why further thought and discussion is merited:

1. Environmental/Emissions Constraints

- The stated GHG emission targets for the period between 2015 & 2035 have been drafted on the basis of the existing Federal legislation. With global developments as described above we believe that more discussion and thought is required as to what the appropriate GHG 'book-end' cases would look like. A suggestion would be to look at the British and German 2050 targets and perhaps applying standards similar to these to Nova Scotia as a 'book-end'.
- NSPI's Case A and B show what a base case (current government standards) is and a lower standard (less reduction) of reducing GHGs, NOX, SOX and Hg. We believe it would be important to also show an increased standard (more reduction) than what the current government policies mandate.
- There is no increase in mandated renewable energy penetration proposed beyond 2020. Given the global context we do not believe that this adequately represents a likely scenario and believe that two 'book-end' scenarios are merited and require more discussion. While NSPI believes that this is taken care of by the differing levels of environmental standards, it would be of interest to us to see what an increased renewable energy standard would cost or save.
- In many jurisdictions carrying out resource planning, it is now common to include scenarios which seek to understand what the cost to the rate payer would be with varying costs allocated to carbon and other GHG emissions. Perhaps allocating a payment for non compliance in terms of GHG emissions or a saving by selling over compliance to another jurisdiction.

2. Wind Capacity Factor & Integration Cost

- The new studies that are being completed by NSPI should not be included in the IRP until they have been reviewed by the many stakeholders in wind energy in the Province. While all people realize there is a cost to Wind integration as there is with any form of energy, it is important the IRP is not biased by studies that still have not been review appropriately.
- The GE Wind integration study identified many areas of further study that were required in order to understand the operational impacts of higher levels of wind penetration. The impact of a more stringent grid code requiring wind facilities to provide frequency response, curtailment, ramp rate restrictions and other performance enhancements would dramatically increase the ability to integrate larger quantities of wind. As stated above, without understanding how these would affect the system, it is important to not be too conservative on the approach to renewable energy and specifically wind.
- The capacity value of wind is difficult to quantify. As the study by NSPI has not come out, it is premature to include that information in the IRP without first reviewing it with stakeholders.

3. Load Forecast

- In terms of load growth, the possibility of the LNG plant should be viewed in this study. This would represent a step up in load growth which should be considered for electricity demand.

- Sensitivity on load growth due to electric cars would be of interest to see.

4. Future Supply Options

- In the draft assumptions, the cost/MW for the various technologies is stated but there is no comment on the cost per MWh.
- The assumption that integration costs should be added to wind energy is premature and is not something that can be added as a step factor. Once again this is difficult to comment on as no numbers have been given.
- It is noted that only pumped hydro storage has been considered for the assumed storage options. There are a variety of battery storage options on the market now which should also considered.

5. Hydro Generation

- The costs associated with incremental capacity increased in hydro should be the total cost of the refurbishment not just the difference between maintenance and total capital cost, unless the maintenance is due that year. In other words if the maintenance is not due until 2030 and it is only 2020, the maintenance cost should not be removed. If however it is the same year, than it seems acceptable to delete off the maintenance cost.

6. Fuels Forecast

- The fuel cost assumptions should take into account the possibility of gas storage in the Province. There should be a scenario where we can avoid the winter spikes as we will have storage in the area to fill up during the summer months and withdraw in the winter months. Heritage Gas is already considering such an investment.

7. Financials

- The cost of capital stated by NSPI should not be a single number; there should be a sensitivity to see what could be possible if the cost of capital for NSPI was 100 basis points lower.

Natural Forces is happy to comment on this process, but once again must state that the short timeframe given to stakeholders to comment makes it difficult to comment on all portions of the IRP assumptions. Thank you for inviting us to work on the IRP process and we look forward to continuing to work on this study.

Yours Truly,

John Brereton
President, Natural Forces Wind Inc.

wickwire holm
BARRISTERS SOLICITORS

March 24, 2014

By Electronic Delivery

#55246-SF

Ms. Doreen Friis
Regulatory Affairs Officer/Clerk
Nova Scotia Utility and Review Board
3rd Floor, Summit Place
1601 Lower Water Street
Halifax, Nova Scotia B3J 3P6

Dear Ms. Friis:

Re: [M05522] P-884.14 – 2014 Integrated Resource Plan (IRP)

Efficiency Nova Scotia Corporation (ENSC) has reviewed the proposed IRP Assumptions filed by Nova Scotia Power Inc. (NSPI) on March 14, 2014. We appreciate the opportunity to respond and provide these written comments for incorporation into the final IRP Assumptions to be completed by NSPI.

Treatment of DSM in the IRP

ENSC notes that NSPI's filed assumptions do not include details regarding how DSM will be treated in the IRP; the assumptions filed relate to the inputs to ENSC's DSM Potential Study.

While ENSC agrees it is important for NSPI and stakeholders to understand the inputs into the DSM Potential Study, ENSC asserts that it is critical that the DSM assumptions regarding the IRP be provided and that stakeholders be given enough time to review and comment on them in supplementary submissions.

ENSC has not seen NSPI's DSM-related assumptions. However, ENSC is concerned that DSM costs will not be treated by NSPI in a comparable manner to supply costs within the IRP.

In its comments on the IRP Terms of Reference, filed with the UARB on January 29, 2014, ENSC noted its agreement with NSPI's proposed Terms of Reference, based on the new description of the purpose and objective function of the IRP provided by NSPI.

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ENSC was satisfied with the new description of the purpose and objective function of the IRP, as outlined on page 3 of 7 of the Terms of Reference, because previous reference to DSM Total Resource Cost had been deleted.

As emphasized, this change helps put both supply and demand-side options on an equal footing and is critical to ensure a fair and consistent treatment of supply and demand-side options within an Integrated Resource Planning exercise, which is primarily concerned with minimizing the cumulative present worth of the utility's annual revenue requirements over the planning period.

ENSC's submission also included a report by its expert DSM consultant, Dunsky Energy Consulting, providing a review of industry best-practice in support of this equal treatment of demand and supply options within the context of IRP development. ENSC's position of January 29, 2014, that inclusion of utility costs only is necessary to ensure a fair and consistent treatment of supply and demand-side options within the IRP, did not elicit any comment or objection from NSPI.

In subsequent discussions with NSPI, however, ENSC has been asked to provide customer costs for the four DSM scenarios included in the DSM Potential Study. ENSC confirms that it has provided these customer costs to NSPI for informational purposes only, with the clear statement that including customer costs on the demand side violates the objective function in the approved Terms of Reference, and if used will not result in a fair and consistent treatment of demand and supply-side options to determine the utility's "least cost" options for purposes of the IRP.

Other questions also exist. For example, ENSC does not have an indication as to how NSPI intends to "layer" the DSM options or incorporate demand response programs within the IRP. This lack of clarity illustrates the importance of NSPI filing its assumptions regarding the treatment of demand-side options within the IRP, with enough time for stakeholders to file supplementary submissions on them.

As with the Industrial Group's letter to NSPI dated March 21, 2014, ENSC submits that this will help to ensure that the IRP that emerges from this process is robust and reliable, and can be supported by ENSC and other stakeholders.

DSM Potential Study Assumptions

Specifically on ENSC's DSM Potential Study Report ("the Report"), ENSC maintains that the Report as filed provides an appropriate range of DSM potential for incorporation into the IRP.

NSPI's assumptions include a recommendation to change the Avoided Costs and electricity rate increases used in the Report. Throughout preparation of the Report, ENSC worked closely with Navigant to ensure the inputs and outputs were reasonable estimates of the achievable DSM potential in Nova Scotia. ENSC provided Navigant with the most recent Avoided Costs of DSM that had been vetted through a UARB regulatory process, and the electricity rate increases were based on files given to ENSC by NSPI.

ENSC understands, however, that there may be a lack of awareness for Parties of the extent to which NSPI's recommendations impact the outputs of the DSM Potential Study. The following comments are designed to ensure that NSPI, the Board, its consultants, and stakeholders are aware of how the achievable potential filed by ENSC was developed.

As is highlighted in the DSM Potential Study, Navigant analyzed three types of DSM potential:

- **Technical**: The total amount of DSM potential in Nova Scotia (based on existing DSM measures) that may or may not be economic to administer.
- **Economic**: The total amount of DSM potential that passes a cost-effectiveness screening test (for the purposes of the study, the Total Resource Cost test was used).
- **Achievable**: The total amount of DSM that can be achieved in Nova Scotia over time.

It should be noted that while the amount of Achievable potential calculated in the DSM Potential study is a subset of the total Economic potential, the two are not directly linked.

Achievable potential is an amount of DSM that, given such constraints as the existing capacity of the administrator, the willingness and awareness of Nova Scotians to engage in DSM activities, the incentive levels provided, the amount of free-ridership that is measured, and other factors, can reasonably be expected to be obtained in Nova Scotia over the period.

The Achievable potential presented in the study has been calculated to include a calibration to these factors and prior years' DSM achievements. Achievable potential does not need to be economic, and not all economic potential is achievable. To be conservative, ENSC presented Achievable DSM that was determined to be economic; however, even if the economic potential was determined to be lower, the achievable potential, particularly in the near term, would not materially change.

ENSC could have presented a scenario for incorporation into the IRP that did not pass the TRC test. If the IRP analysis determined that that amount of DSM was lower cost than supply, then even non-economic DSM would minimize the revenue requirement to the utility.

This explanation is intended to demonstrate that whether or not specific inputs to the DSM Potential Study, including Avoided Costs and electricity rates, were changed, the amount of achievable DSM in Nova Scotia, particularly in the short term, when the calibration is most relevant, would still be achievable.

ENSC, like other stakeholders and NSPI, wants to ensure the IRP contains appropriate assumptions and inputs. It is ENSC's position that the base, low, mid, and high scenarios of DSM achievable potential put forward in the DSM Potential Study are appropriate for incorporation into the IRP.

Supply Side Assumptions

Regarding assumptions on the supply side of the IRP, ENSC is concerned that several of the current assumptions may underestimate supply-side costs.

The assumptions in question are as follows:

Emissions Requirements

NSPI has included two sets of assumptions regarding the future emissions limits of CO_2, SO_2, NO_x and Hg throughout the IRP analysis period. At the March 7th IRP Technical Conference, the Nova Scotia Department of Environment expressed its concern that the low reduction scenarios presented for SO_2 and NO_x are unlikely. This would suggest that the current assumption set only includes one probable scenario, making it prudent for the IRP to include a third, more aggressive, scenario for these pollutants as well as for CO_2 to illustrate the relative costs of achieving such reductions.

Inclusion of Financing Costs for IRP Alternatives

ENSC requests clarification on whether or not the IRP will include the costs of financing associated with candidate IRP alternatives. ENSC also requests clarification on whether sensitivities in future borrowing rates will be explored.

Reserve Requirements

ENSC requests clarification on whether the IRP will include costs associated with increased spinning and planning reserve associated with new supply alternatives. Additionally ENSC requests clarification on whether the IRP will credit DSM activities (Demand Response and Energy Efficiency) commensurate with the associated reductions in reserve requirements.

Early Plant Retirement

In addition to a comparison with new generation, demand-side resources may be a less costly alternative when compared to existing supply. ENSC requests that the IRP Assumptions state that demand-side resources will be considered as an alternative to both existing and future supply-side resources as the IRP seeks to minimize the cumulative present worth of the annual revenue requirements over the planning period. For existing thermal plants, the IRP should consider reduced operations and earlier retirement.

Demand Response

NSPI has suggested to stakeholders that demand response programs will be included for consideration within IRP scenario development. Such programs must receive equitable treatment in terms of utility costs and benefits when compared with supply-side options and Energy Efficiency. ENSC requests that NSPI share all relevant assumptions and supporting research for demand response alternatives included in this IRP.

Conclusion

We appreciate the opportunity to provide these formal written comments on the proposed IRP Assumptions filed by NSPI. We reiterate our position that it is critical that both supply and demand-side options are assessed on an equal footing throughout this IRP process.

We look forward to continuing to work closely with NSPI and all stakeholders throughout completion of the IRP process.

Yours very truly,

WICKWIRE HOLM

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In reply please quote our file number:

Lana Myatt
Nova Scotia Power Incorporated
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Dear Ms. Myatt:

The Province of Nova Scotia is committed to maintaining a healthy environment for the benefit to our citizens. Nova Scotia's approach to reducing air pollutant and greenhouse gas emissions is not in isolation but part of a larger comprehensive plan to move away from coal-based electricity generation to cleaner energy sources. This path forward helps to shield us from volatile fuel markets while protecting the environment and the health of our citizens. Nova Scotia's commitment to continual progress on emission reductions is evident when you consider the recent amendments to the Greenhouse Gas Emission (GHG) Regulations and the negotiation of a pending equivalency agreement with the federal government relating to GHG reductions from coal-fired electricity.

Nova Scotia Environment (NSE) is committed to continual reductions in air pollution to preserve the environment and protect the health of all Nova Scotians. Environmental impacts from air pollution, such as acid rain can damage vegetation, watercourses and fish habitat, as has happened in south western Nova Scotia. Health impacts from air pollution range widely from cardiac and respiratory illness to cancers and even premature death. Air pollution can make it harder to breathe, and can trigger preexisting respiratory illness such as asthma and chronic obstructive pulmonary disease. Moreover, air pollution can incite episodes of angina, irregular heart patterns and even heart attacks. The detrimental health impacts of air pollution are of significant concern to individuals of higher risk such as our children, the elderly, and individuals with pre-existing health concerns such as diabetes. According to a 2008 Canadian Medical Association Study[1], economical and health care costs are significant impacts from air pollution, for example, Nova Scotia is projected to have millions of dollars in costs attributed to air pollution over the next few decades including over a hundred premature deaths.

Through the Minister of Environment, NSE has the mandate to preserve and protect the environment, including protected areas; and to deliver on the goals outlined in the Environmental Goals and Sustainable Prosperity Act (EGSPA). The Minister of Environment is also the Executive Council lead on matters relating to climate change. As such, NSE welcomes the opportunity to provide feedback on the draft environmental assumptions as filed on March 14, 2014 as part of the 2014 IRP Assumptions and Analysis Plan.

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[1] Illness Cost Of Air Pollution, 2008, Canadian Medical Association. Submitted by DSS Management Consultants

NSE believes that the scenarios related to GHG emissions are reasonable for both trajectories. Both scenarios accurately reflect emission reductions required out to 2030, consistent with the *Greenhouse Gas Emission Regulations* as amended in 2013 and the intended successful negotiation of an equivalency agreement with the federal government. The assumed reductions envisioned after 2030 are consistent with Government's long term goal for continual reductions. It is useful to be aware that the intended successful negotiation of an equivalency agreement would allow for Provincial regulations to govern to 2030. NSE would like to highlight that a 50 year end of life scenario of unit closures to mimic the federal GHG coal regulations would be within the realm of reasonable possibilities. NSE would also like to highlight the upcoming federal natural gas regulations for GHG reductions and encourages NSPI to adequately account for that within the analysis.

Nova Scotia is committed to additional regulated reductions in air pollutants from the electricity sector. Moreover, NSE is committed to amending the *Air Quality Regulations* to include new reduction requirements after 2020, for SOx, NOx and mercury.

"Scenario A" is a realistic assumption that depicts reductions that encompass both the current *Air Quality Regulations* and the reductions envisioned within the Amendment to Greenhouse Gas and Air Quality Emission Regulations Discussion Paper (" the Paper") (NSE June 2013) then continues the trend of reductions out to 2040. "Scenario B", however, which depicts no further reductions in air pollutants after 2020, is not within the reasonable trajectory range of future environmental constraints and requirements.

According to the approved Terms of Reference for the IRP, the objective of the IRP is, "To develop a long-term Preferred Resource Plan that establishes the direction for NS Power to meet customer demand and energy requirements, and environmental obligations in a cost effective, safe and reliable manner across a reasonable range of foreseeable futures…". "Scenario B" is not a reasonably foreseeable future, and would not result in NS Power meeting its environmental obligations.

"The Paper" (NSE 2013) was a forum for all individuals, businesses and stakeholders to be able to voice their views and provide feedback on the policy direction of air quality reductions within the electricity sector. NSE values all feedback provided from that public-wide opportunity. NSE is committed to continual air pollution reductions and re-iterates the commitment to additional air pollution reductions after 2020 for NOx, SOx and mercury as described.

Moreover, under the Air Quality Management System, the Government of Canada intends to introduce regulatory standards to reduce air pollution from coal-fired electricity generation. Such standards are envisioned to be benchmarked against leading jurisdictions and provide good baseline reductions. Thus, both levels of Government are committed to continual reductions after 2020.

Given scenario B is outside the reasonable range of possible air pollution trajectories, NSE suggests replacing it with a more realistic scenario similar to the approach taken with the GHG emission assumptions. NSE recommends that Scenario B reflects the air pollution reduction trajectory as depicted in "the Paper" (Scenario A) until 2030, then assumes no continual reduction after 2030.

NSE appreciates NSPI's goal to reflect realistic options and constraints with the IRP analysis plan. NSE also acknowledges that certain plants and units face technical and space barriers for certain control technologies. However, NSE believes the environmental control technology assumptions as outlined on page 21 of the Assumptions are limited in scope. Certain plants or units are restricted to a single technology option; for example, only a Selective Catalytic Reduction is highlighted for Trenton 6 where sulphur control technology may also be an option. Co-firing may not be the only choice at Trenton 5 where SOx or NOx controls may be considered. NSE suggests that a broader look at a diversity of options for various types of abatement equipment would make for a more robust analysis.

NSE would also like to have additional context around "municipal solid waste" supply scenario. It should be noted that any such projects are subject to environmental regulations and the appropriate environmental approvals.

NSE appreciates the opportunity to provide feedback, input and comments on the environmental aspects within the Draft Assumptions and Analysis Plan for the 2014 IRP Analysis.

Yours truly,

Elizabeth A. Cody
Deputy Minister

c: Murray Cooligan, Deputy Minister of Energy

BLACKBURN ENGLISH

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OUR FILE:

March 25, 2014

Ms. Nicole Godbout
Nova Scotia Power Inc.
1223 Lower Water Street
Halifax, NS B3J 2W5

Dear Ms. Godbout:

RE: M05522 - Nova Scotia Power Inc. (NSPI) 2014 Integrated Resource Plan (IRP) - P-884.14

I. Introduction

The Office of the Small Business Advocate ("SBA") intends to be an active stakeholder in the NSPI 2014 IRP. The SBA welcomes this opportunity on behalf of our constituents, small businesses, who we all hope will operate, grow and prosper over the horizon of this important planning which will shape electric costs over the next 25 years and beyond. This is the first IRP since the SBA was established. The SBA will participate it stakeholder workshops, initiate direct dialogue with NSPI and among the other stakeholders, and provide written comments such as these provided here. The SBA and its consultant have thoroughly reviewed the draft Assumptions Presentation Materials provided by NSPI.

The SBA believes that the 'Objectives and Metrics / Stakeholder' step should be first before the nuts and bolts review of assumptions. The SBA believes NSPI should review exact objectives and even solicit additional objectives from the stakeholder group to assure a comprehensive actionable IRP is developed. The SBA offers these comments as its first step in participation throughout the 2014 IRP.

II. Overview of Comments

The SBA believes that it is important for the stakeholders to come to agreements first and foremost on the objectives of the IRP. This includes establishing metrics NS Power intends to look at to determine the best resource plan or even the good resource plans. This would also include discussion of policy objectives that are implicitly and explicitly going to factor into the analysis and the ultimate decisions and report.

A good IRP analyzes plans in a way that develops metrics relevant to all stakeholder objectives and then at the end will be able to articulate the proper weight or priority given to some objectives over others given the results.

As an example, the slide package refers to testing through Strategist the packages of DSM programs that pass the Total Resource Test. There is nothing wrong with that if the only metric to be used to choose a Resource Plan is economics. Will there be other attributes, along with their metrics, that will be compared between plans to develop a preference. If a minimize Capital Expenditure Objective is applied, and DSM is screened out based upon TRC we would not know if more DSM could help fulfill a minimize Capital Expenditure Objective. This would also be true of a minimize emissions or meet emissions targets such as CO2, NOx, Sox, Mercury etc., strategies. DSM could contribute to those goals and be left behind due to screening only on TRC economics. Other objectives could be minimizing prices over the next 10 years or revenue requirements over the next 10 years all to promote economic development. These are just examples.

III. Analysis Plan Comments

The SBA has included comments on the limited information on the Analysis Plan. The comments below also include discussion of aspect missing from the IRP process. We have broken out our analysis plan comments on a discussion of objectives, our view on the stakeholder process as constructed by NSPI, methodology, and particular resource plan strategies that the SBA would like to see evaluated in the 2014 IRP.

A. Objectives

The objectives should be made up of three areas, goals, metrics and key questions that should be answered. The Terms of Reference under Deliverables Item 1 defines the primary objective of minimizing electric costs, but clearing states that the criteria should include other aspects similar to what we have listed below. The SBA, through its consultant, is familiar with the Strategist model which will be used by NSPI. While this model is widely used and among the more popular models for IRP, the SBA cautions that it is often used by utilities who give heavy weighting to revenue requirement minimization rather than fully develop the trade-offs among the metrics that establish the accomplishments toward the goals that best serve Nova Scotia. While there has been some discussion on the other objectives, goals and metrics have not been established. The process does not seem to include the briefing of and receiving input from the stakeholders in this all important area. The SBA has a strong desire to be involved at the level of establishing metrics and goals.

In addition, in its March 14, 2014 memo to IRP Intervenors, NSPI is vague on its analysis plan, merely stating items established in the terms of reference. Even the name intervenors connotes a less inclusive position than recognizing the SBA and others as stakeholders who will pay for the brilliance or errors that result from the planning process. According to the Terms of Reference the presentation workshop and comments are the final 'input' opportunities before NSPI issues its assumptions and analysis plan, without discussing the NSPI analysis plan so that comments could be made. Even without an indication of the 'meat' of NSPI analysis the SBA offers five key questions , the answers of which will help drive costs to small business and other customers to the lowest reasonable levels.

i. **Goals & Metrics**
   1. Revenue Requirement Minimization - Primary
   2. Acceptable Price of Electricity paths has been discussed somewhat
   3. Plan Robustness and Flexibility needs definition
   4. Environmental / Emissions Outlook need specific metrics
   5. Reliability & Energy Security – the levels of which alternative resource plans provide for Nova Scotia.

ii. **Key Resource Planning Questions to Address**
   1. How does the Maritime Link affect resource planning choices?
   2. What are the economic benefits of the continued operation of existing thermal and hydroelectric generation?
   3. What is the least cost way to meet environmental constraints?
   4. What is the cost to meet various levels of emissions?
   5. What is the role of DSM, energy efficiency and price responsive demand, in the resource portfolio? Does more DSM spending have a measurable impact on rates now or over the 25 year planning horizon?

B. Stakeholder Process

The Terms of Reference provide specifically for a Stakeholder Engagement Process. "Stakeholder Input an integral part of the process". With this in mind the SBA is concerned that the process is not more interactive. Providing a pre-look at assumptions is hardly input. Providing the specifications of the analysis required in the Terms of Reference is hardly input into analysis. We appreciate the early efforts of NSPI, but the SBA notes we have a lot more to do before the IRP truly has input and transparency

i. **Thoroughness of information sharing with stakeholders –** Stakeholders will not see which plans are analyzed and which metrics are developed prior to the Interim Analysis Progress Report Technical Conference on June 25th when the scope of the analytics has been long established and is now partly complete.

ii. **Timeliness and frequency of stakeholder comment and input –** On September 5th analysis results will be 'issued' to stakeholders, with a Stakeholder Technical Conference on Analysis Results on September 30th. There are not any provisions in the 'Timeline' for additional analysis based upon stakeholder input prior to the Draft Report is issued to stakeholders on September 30th.

iii. **Degree of Impact of the stakeholders –** There is not a process for Stakeholder comments at the progress report, or after the 'results' conference. Stakeholders have a week to comment after the draft report. The final report will be filed with the UARB 8 days later. How can anyone expect the stakeholders to have significant influence and impact on the 2014 IRP? NSPI has followed the exact letter of the Terms of Reference, not its intent. The SBA hopes that the opportunities for the stakeholders to provide actual input, influence and impact is properly represented as properly represented.

C. Methodology

The SBA has developed some thoughts on the methodologies being utilized by NSPI in the 2014 IRP. The SBA recognizes that its comments on the "Evaluation and Optimization" process are relatively minor as a result of the lack of information on what exactly NSPI intends to do in this process. However, the SBA believes that there is a flaw in the DSM integration process as the IRP analysis has been presented.

i. **Evaluation of DSM** - In the process described DSM economics are developed prior to the Evaluation and Optimization steps. While it is appropriate to establish specific energy efficiency program designs and funding through analysis using the Total Resource Cost (TRC) Test, it is not appropriate to use this criteria prior to DSM's value is studied in resource plans that are judged by more than just the TRC economics. Supply options are not screened as compared to avoided costs prior to IRP, but DSM options are. Supply options are more prominent in resource plans depending upon their fuel, their size, their impact on system operation and their capital cost. DSM is screened solely on economics versus avoided costs. In fact, 'avoided costs' is an output parameter of the new resource plan that is selected as the Preferred Plan. DSM economics established in the DSM potential study or in a screening evaluation in IRP both use with vintage information.

The IRP process should use substantial information from the DSM potential study. A DSM 'supply curve' should be created as output of the DSM potential study. Incremental blocks of increasing cost DSM can be used within the IRP analysis, just as additional supply options are deployed within a resource plan or resource strategy. Blocks are not cumulative DSM levels they are incremental DSM that can be harvested for a price.

For example, under the process roughly described by NSPI, if a static amount of DSM passes the Strategist Test and included in all plans as the full economic achievable program DSM potential, and a plan needs to lower its emissions to meet constraints or goals, the next supply option may be the non-emitting or low-emitting resource, likely renewable. The cost of that resource is very likely to be above the avoided costs used to establish the amount of 'economic' DSM. Thus we do not know if more DSM could have been a better substitute into the resource plan to meet an emissions objective or goal.

ii. Evaluation and Optimization

The SBA agrees that a process that analyzes many plans under Reference conditions, a subset through Scenario Testing and a few plans through Risk Analysis, is very useful. Our comments below describe information we would like to know about the NSPI process. We would like the opportunity to comments on the evaluation process, unfortunately we do not know specifics of what NSPI intends.

1. ***Reference Scenario Analysis*** – What are the plans that will be tested? What are the metrics? Or is there only one metric? Will stakeholders get to comment on the plans before the analysis?
2. ***Scenario Testing ("Worlds" Development)*** – What is the process to choose or design these "Worlds". Will these be established using primarily a consultant or forecasting organization's scenarios? How will the optimization process work? Will Plans be allowed to recognize the alternative scenario at some point in time? These are key areas for the stakeholders to understand prior to the analysis; allowing the stakeholders to provide input.
3. ***Risk analysis*** - How is this going to be evaluated? What risks?

D. Thoughts on Resource Plans for Consideration

The SBA provides these four plans or strategies that we would like to see evaluated. The SBA participates diligently in rate cases, major project approvals and the ACE Review Process, all to fulfill our responsibility to small businesses that the costs are necessary and prudent. The approval of the ACE Plan and certainly the proceeding to approve the Maritime Link provided the SBA with more input and details to review than the IRP. The IRP sets in motion the plans that form a major element of NSPI's cost to serve customers. Failure to test stakeholder strategies to lower cost or to provide information on the impact of certain resources and policies would prove to be a lost opportunity for the 2014 IRP.

- **i. Lowest Capital Investment Plan**
- **ii. Lowest Emissions Plan contrasted with Compliance levels of emissions**
- **iii. Maximum retirement / replacement of existing resources**
- **iv. Optimized continued operation of existing generation**

IV. Assumptions Comments

The SBA does have some specific comments or questions regarding specific draft assumptions proposed by NSPI.

A. Environmental/Emissions

i. **Constraints –** Are there different scenarios of constraints? How will NSPI incorporate the A & B Scenarios for emissions constraints? Is it the best use of limited time and analytical resources to study both scenarios? Why not plan for the more stringent resources since there will be many IRPs prior to reaching the points where the Scenarios A & B diverge? Are the existing RES requirements the only future to be analyzed?

ii. **Targets-** Should IRP study emissions reduction targets that go beyond compliance in order to establish the impact of policy changes that might ratchet down emissions? What would these targets be? Would it be valuable to test targets desired by individual stakeholder groups? Should the IRP evaluate renewable energy strategy targets beyond RES compliance?

B. Existing Supply Side Options

What are the costs to maintain each existing generating resource? Capital and O&M. How much will certain generating units operate under various Maritime Link energy delivery scenarios? The ability to keep thermal generation operating well beyond 50 years as noted on Slide 41makes some units exempt from evaluating the generation for economic obsolescence? What better place to test the strategic value of existing assets?

In Slides 28 and 29 NSPI discusses its rationale for assuming it is a given that ***$500 million dollars should be spent on existing hydroelectric facilities***? This is a substantial cost that must vary across the NSPI hydro facilities. Why is this assumption made?

C. DSM Options

See discussion above

D. Load Forecast

The low forecast should assume flat or declining industrial load. The SBA hopes that growth from its industrial constituents helps drive economic recovery in Nova Scotia. The SBA also recognizes that the risks that small commercial customers will shoulder an unnecessary burden if a plan is developed that is not flexible or robust.

E. Wind Capacity Factor & Integration Costs

The SBA wants to get specific assumptions on how NSPI intends to evaluate any potential strategic and cost advantages to wind procurement through purchase power agreements versus NSPI ownership.

F. Import Options

There appears to be an inconsistency among the natural gas forecasts, emissions costs and import price assumptions over the study period.

G. Future Supply Options

Will each supply option provided on slides 19 to 22 be separate options in the IRP analysis or will NSPI establish certain generation options to each represent a group of similar supply options?

H. Natural Gas Price Forecasts

Why is the assumption made that there is CO2 emissions limits or costs established for the reference natural gas forecast and not in either of the high and low forecasts?

V. Conclusion

The SBA is appreciative of the opportunity to participate in the on-going stakeholder process for IRP. The SBA would like more involvement in the process. The SBA cautions that the current degree of stakeholder input is unlikely to result in preferred resource plan with broad stakeholder support.

Yours truly,

E.A. NELSON BLACKBURN, Q.C.

SMALL BUSINESS ADVOCATE

Memorandum

TO: NSPI (c. Interested Parties)

FROM: Consumer Advocate

DATE: March 26, 2014

RE: Comments on Analysis Plan and Draft IRP Assumptions

These are the comments of the CA regarding NSPI's assumptions and Analysis Plan. These comments are based on NSPI's memo 2014 IRP Analysis Plan, and the 2014 IRP – Draft Assumptions.

Analysis Plan

The Analysis Plan represents a reasonable structure for considering long-term futures for NSPI. Due consideration should also be given to ways the 2014 IRP might be useful in guiding resource acquisition. The results of previous IRPs have not been particularly useful in guiding resource acquisition decisions. To some extent, that outcome resulted from repeated changes in regulations and market conditions, which complicate the application of long-run plans to short-term decisions. To the extent that the Analysis Plan assists NSPI in identifying the appropriate responses to changes in conditions, the 2014 IRP may be more helpful in the planning and evaluation of short-term decisions.

It would be helpful if the Analysis Plan included a schedule (or perhaps an outline of the sequencing and work flow) for several tasks required for near-term planning, including:

- Determining the reliability contribution of wind generation.
- Determining the reliability contribution of generation (wind and Port Hawkesbury biomass) connected through ERIS transmission.
- Examining whether the capacity value for wind would allow NSPI to retire Lingan 2 in 2015 and Lingan 1 in 2018, as projected in the Maritime Link proceeding, rather than Lingan 2 in 2018 and Lingan 1 in 2039.
- Determining whether it is economic to convert Burnside to gas and/or reactivate Burnside 4.
- Comparing Tufts Cove capacity increases and life extension to construction of replacement peakers and CCs, especially as those plans will drive decisions about maintenance of the Tufts Cove units, as well as planning for transmission and replacement generation in the Halifax area.
- Analyzing the potential for profitable sales of renewable energy to New England and identification of any barriers to those sales.

- Developing updated avoided costs for ENSC, consistent with the IRP assumptions.
- Determining the characteristics of power purchases and wind-firming services that NSPI should be seeking starting 2017/18, with the addition of Maritime Link and the flow of power through Nova Scotia to New Brunswick and beyond.

Many of these issues are discussed in the "2014 IRP – Draft Assumptions" slides, but are not identified in the Analysis Plan.

Comments on IRP Assumptions Document

General

NSPI indicates that issues such as the capacity value of wind and wind integration costs are "currently being discussed with Board Staff and Consultants". Rather than discussing these issues exclusively with Board Staff and Consultants, and presenting other stakeholders with a finalized analysis, the Consumer Advocate would urge NSPI to solicit input from other stakeholders, particularly those who raised these issues in the Maritime Link and COS proceedings (e.g., the CA, SBA and the Industrials).

Page 20

The low end of the range of wind capital costs ($2,100/kW) appears to be higher than the cost of recent wind-plant costs, especially South Canoe at less than $2,000/kW. Since wind costs, both in Nova Scotia and globally, have tended to trend downward (from $2,600 for Nuttby and Digby and over $2,300/kW for Point Tupper), future wind costs should be even less than the South Canoe cost.

NSPI's estimate of the cost of photovoltaic solar ($5,600/kW) is also overstated. "Among the roughly 50,000 residential and commercial PV systems in the sample installed in 2012, the median installed price was $5.3/W for systems ≤10 kW, $4.9/W for systems 10-100 kW in size, and $4.6/W for systems >100 kW." (Lawrence Berkeley National Laboratory, *Tracking the Sun VI*, p. 13) US-wide costs have fallen by about 50% since 2002 (ibid.). Photovoltaic costs have been higher in California (as are most costs), but for those size ranges, costs fell another $0.5–$0.8/W from 2012 to the first half of 2013 (ibid., p. 14) Taking into account currency exchange rates, the NSPI estimate is at the high end of US costs for 2012, and probably even more overstated for the future. Considering the amount of PV solar installed in North America and Europe, the readiness level of PV seems as high as wind.

The value of the Mersey Incremental Upgrade option depends on the energy production and the dependable capacity, as well as the installed cost per kW. Additional information on this option will be necessary.

The CAES option requires greater detail on the operating cost of the plant (especially the cost of gas necessary to warm the compressed air as it is expanded). Reliable values for CAES and pumped storage may be important in negotiating and evaluating storage contracts with Nalcor and HQ.

Page 25

"Capacity value of wind calculated based on statistical probabilities of wind generation being available at peak load" does not reflect the actual reliability contribution of the wind plant. Some capacity shortages occur at other times, due to generation outages. This pattern is confirmed by the seasonal pattern of the operation of the oil CTs and of NSPI's interruption of interruptible loads. This method should be modified to estimate the contribution of wind at times of NSPI's tightest capacity conditions; that may be higher or lower than the contribution at peak load.

Page 26

No support is cited for the presumption that "additional firm capacity will have to be built in order to securely integrate more intermittent generation in the future," and "The study may show that integration costs are in line with the estimates used in Regulatory proceedings,". Available support should be identified.

Page 29

"Hydro Assumptions: Assume the sustaining capital is common to all plans." NSPI should provide a breakdown of the $500M in sustaining capital by facility, to test whether the investments are small compared to the value of the hydro plants. If, for example, $30 million is required to maintain Fall River's 0.5 MW of capacity (or a similar small part of a multi-unit river system), NSPI should examine the cost-effectiveness in greater detail.

Page 36

Burnside 4 is included with 33 MW of net demonstrated capacity. That capacity is not currently available and NSPI should review the cost and appropriate timing of reactivation of that unit.

Page 40

NSPI's assumptions about the feasibility of continued operation of steam plants, especially the gas-fired units, should be tested. Retirement is an economic decision, driven by the relative cost of investment and fixed O&M of maintaining the unit, compared to the costs of replacement capacity, taking into account heat rate, variable O&M, and ramping constrains. Tufts Cove (especially the more flexible units 2 and 3) should be compared to replacement peakers.

For the steam plants, NSPI should consider whether costs would be minimized by retiring Lingan 2 (and possibly 1) or by converting multiple coal units to cycling operation, as suggested by a recent NREL study (Flexible Coal: Evolution from Baseload to Peaking Plant, www.nrel.gov/docs/fy14osti/60575.pdf) The NSPI system is currently limited in ramping ability, which will become more important as wind output grows. Cycling the coal units will eventually result in higher forced outage rates and maintenance costs, at which point NSPI could retire some units. The higher forced-outage rates could be offset by the continued operation of one or two additional units. The most appropriate operational approach will depend on the estimated costs of the alternatives.

Pages 54–55

NSPI should examine whether capacity exists on the TCPL system to get gas from Wright to Maritimes & Northeast at firm tariff rates.

NSPI should provide more detail on the conversion of pipeline tariff rates into $/MMBtu used at Tufts Cove, given the fixed tariff charges and scheduling requirements.

Page 95

NSPI should explain (and support) its contention that DSM potential is affected by the electric rate.

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Nicole Godbout
Regulatory Counsel
Nova Scotia Power Incorporated
P.O. Box 910
Halifax NS B3J 2W5

March 26th, 2014

Dear Ms. Godbout,

RE: M05522 – 2014 Integrated Resource Plan
Ecology Action Centre Comments on Draft IRP Assumptions

Ecology Action Centre (EAC) has reviewed the proposed IRP Assumptions provided by Nova Scotia Power Incorporated (NSPI) on March 14th, 2014. We appreciated the spirit of transparency and collaboration shown in the March 7th technical conference concerning the Draft Assumptions. We look forward to ongoing participation in an open and informative dialogue as the IRP develops.

Please find our comments and recommendations on the Draft Assumptions below.

CO2/Greenhouse Gas (GHG) Emissions

As acknowledged during the March 7th technical conference, Nova Scotia is a national leader in setting targets for and achieving GHG emissions reductions from the electricity sector. EAC applauds Nova Scotia's initiative and impressive progress to date.

A critical concept also discussed during the technical conference is the unique opportunity the IRP process presents to identify possible worlds and explore their potential implications for Nova Scotia's and NSPI's future.

The EAC submits that while the two CO2/GHG scenarios suggested by NSPI incorporate existing federal and provincial regulations, they do not sufficiently recognize the underlying commitment from which those regulations were derived, specifically Canada's signature to the Copenhagen Accord. The differing approaches federal parties have to fulfilling Canada's commitment to the Copenhagen Accord mean the regulatory world within which NSPI must operate through the 2039 IRP timeframe could change substantially with a change in government.

It is incumbent upon the IRP process to provide a full and realistic assessment of NSPI's carbon liability. To do this, an assessment of the impacts of global warming and complimentary assessments of both international conventions and future national political realities are critical.

International Conventions

The Copenhagen Accord, signed by world government representatives including Canada, at the COPP 16 UNFCC conference states:

> "We agree that deep cuts in global emissions are required according to science, and as documented by the IPCC Fourth Assessment Report with a view to

> reduce global emissions so as to hold the increase in global temperature below 2 degrees Celsius, and take action to meet this objective consistent with science and on the basis of equity." i

The accord further commits developed nations, including Canada, to establish GHG emissions goals for 2020 that, in Canada, resulted in existing regulations.

National and international agencies across all sectors recognize that the costs of climate change are upon us and that action is required to avert both the physical and economic consequences.

The Canadian Council of Chief Executives state:

> "The Copenhagen Accord is an important building block since it brings in all major emitting countries in a way that meets their needs and aspirations […] Meaningful progress will not be possible without an overall framework that encourages and enables the ongoing creation and dissemination of new generations of low-carbon technology across the globe."ii

The Organization on Economic Cooperation and Development (OECD) of which Canada is a member, writes:

> "Acting now is not only environmentally rational, it is also economically rational. For example, (this) outlook suggests that if countries act now, there is still a chance – although a receding one – of global GHG emissions peaking before 2020 and limiting the world's average temperature increase to 2 degrees C. To do so would make the costs of adaptation and mitigation much more affordable. But unless more ambitious decisions are taken soon, the window of opportunity will close. ***Investment decisions that are being made today will lock in infrastructure for years or decades to come. The environmental consequences of emissions-intensive investments today will be long-lasting*.**"iii [emphasis added]

Limiting GHGs to Prevent Greater Than 2^0 Celsius of Warming

The Copenhagen Accord's core goal is to prevent greater than 2^0 Celsius of warming. Scientific understanding of this goal implies global reductions in GHG emissions to 80% below 1990 levels by 2050.

As the graph below from the Stern Review on Climate Change indicates, some of the most severe impacts begin to occur at a level of warming that is 2^{0}C above the pre-industrial mean. At this level, extensive damage to coral reefs will have occurred, significant decreases in crop yields and water availability will occur, and the risk of dangerous feedbacks, leading to abrupt shifts in the climate system, could occur. After 2^{0}C the climatic system is expected to enter the realm of "abrupt and major

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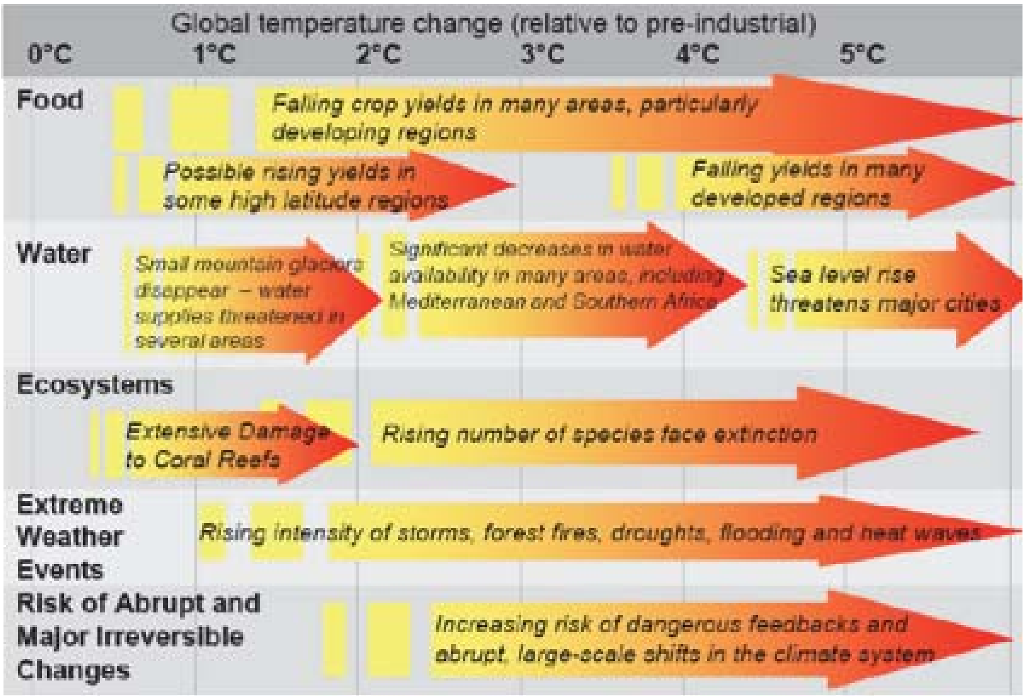
i UN Framework Convention on Climate Change. 2009. *Copenhagen Accord*. United Nations.

ii Canadian Council of Chief Executives. 2010. *Clean Growth 2.0: How Canada Can Be A Leader In Energy And Environmental Innovation*. Policy Paper Task Force On Energy, The Environment And Climate Change

iii OECD. 2012. OECD Environmental Outlook to 2050. OECD Publishing. http://dx.doi.org/10.1787/9789264122246-en irreversible changes". These abrupt changes can create a point of no return, where climate change becomes irreversible.

Projected Impacts of Climate Change iv
Stern Review on the Economics of Climate Change (2006)



The United Nations Framework on Climate Change notes that:

> "[…] the largest share of the historical and current global emissions of greenhouse gases has originated in developed countries, that per capita emissions in developing countries are still relatively low and that the share of global emissions originating in developing countries will grow to meet their social and development needs."v

International conventions such as the Copenhagen Accord therefor accept the principle that industrialized countries have both an historic responsibility and a capacity to act. Thus, emissions reduction targets to prevent greater than 2°C will ideally be greater for industrialized countries like Canada. These principles must be kept in mind when NSPI is considering any estimates of its future carbon liabilities.

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iv Stern, N. 2006. *Stern Review: The Economics of Climate Change*. London School of Economics. http://mudancasclimaticas.cptec.inpe.br/~rmclima/pdfs/destaques/sternreview_report_complete.pdf

v United Nations. 1992. *United Nations Framework on Climate Change.*

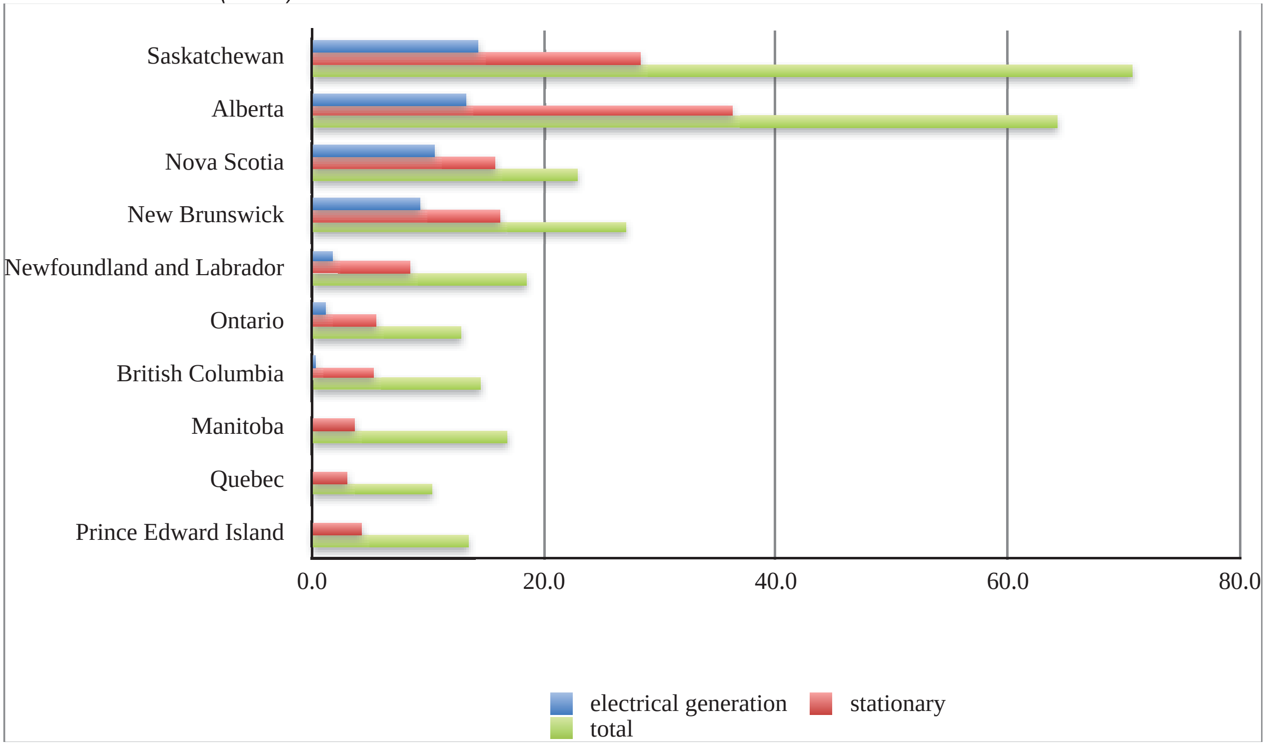
Potential Future National Political Realities

On a global per capita basis, a Canadian target consistent with the goal of preventing greater than 2°C would set national GHG emissions reductions by 2050 at 95% below 2010 levels. In the 2039 IRP timeframe, national targets would limit GHGs to approximately 1/3 to 1/4 of present-day emissions.

These reduction targets lie within the range of policies under consideration by Canadian federal parties. The Climate Change Accountability Act Bill C-311 (2010) proposed similar limits and passed third reading in the House of Commons in 2010. Originally sponsored by Member of Parliament Bruce Hyer (then an NDP MP and now a Green Party MP), Bill C-311 achieved broad support including, among others, current leaders of both opposition parties. Bill C-311 was only defeated on second reading in the Senate in 2010. The current official opposition has resubmitted this bill for consideration and policies similar to it are likely to remain under active consideration for the foreseeable future.

Stationary emissions, especially electrical power generation facilities, present the largest opportunity for easy reductions today, particularly when compared to the difficulty associated with reducing emissions from transportation or oil and gas extraction. For this reason, under potential future federal emissions reductions regulations, electricity generation will be looked to virtually eliminate GHG emissions as soon as possible.

2009 Per Capita CO2 equivalent Emissions [vi]
Statistics Canada (2012)



[vi] Statistics Canada. 2012. *Reality Check: The State of Climate Progress in Canada*. National Round Table on the Environment and the Economy

To ignore the reality of global warming and its devastating impacts and the effect NSPI's future carbon liability could have on the ratepayers of this province will not allow the IRP to make a realistic assessment of the future. The IRP, therefore, should reflect the stark reality that deeper GHG emission limits will be imposed. To ignore this probable future is to risk potentially inappropriate investment in infrastructure that may need to be abandoned or subject to costly alteration.

Recommendations

1) The EAC proposes that a third GHG scenario that approaches zero electricity GHG emissions be added:

> **Scenario C: Emission limits as per An Agreement on the Equivalency of Federal and Nova Scotia Regulations for the Control of Greenhouse Gas Emissions from Electricity Producers in Nova Scotia (Sept. 2012)**
>
> **Limit declines to 2.25 in 2040, 0 in 2050.**
>
> **The downward path of the GHG constraint in Scenario C is consistent with the established medium term goals and long-term commitments consistent with the Federal government's signature to the Copenhagen Accord.**

2) Scenario A, as an intermediate path, should be retained as it represents the path where regulatory response lags behind science-based recommendations.

3) Scenario B, although inconsistent with a science-based mitigation path, should be retained as it represents the current regulatory regime.

Renewable Electricity Standards (RES) Requirements

Given the above discussion of the likelihood that Canada's electricity sector will represent the 'low-hanging fruit' of GHG emissions reductions under potential future regulatory regimes, it would be wise for the IRP to consider a scenario where fossil fuel -dependent electricity generation is entirely phased out and replaced by renewable generation.

Recommendation

4) Include within the RES assumptions an **additional scenario** where:

> **Electricity Supply consists of 100% Renewable Energy Sources by 2040**
>
> **Electricity Supply consists of 80% Renewable Energy Sources by 2030**

Future Supply-Side Options

COMFIT

Community and distribution -scale generation is recognized to be an important element in an electricity system moving towards zero GHG emissions. In particular they build public acceptance and trust for both renewable energy and the public utility. In this sense they offer intrinsic value that reaches beyond the usual parsing of the regulatory process. Their presence encourages participation in the electricity system that builds a sense of ownership and undermines the cynicism that often conflates the ratemaking process. Continued modest expansion of the Community Feed-In Tariff (COMFIT) program should therefor be a basic assumption in the IRP.

Recommendation

5) The draft assumptions identify a government commitment of 200MW but propose only 150 MW by 2016. **The Ecology Action Centre strongly urges that the RES assumptions bring COMFIT projects to the full 200 MW level by 2016 and include an extension of the program ongoing at 20 - 30 MW per year.**

Capacity Value of Wind and Intermittent Generation Integration Costs AND
Hydro Generation AND
Import Options AND
Transmission

EAC concurs that wind and hydro resources are complimentary as indicated in the draft assumptions: “much of the power system’s flexibility to integrate existing variable sources of generation is provided by legacy hydro facilities.” (Slide 29 – draft assumptions). These benefits grow as the regional footprint for both wind and hydro operations grow.

The approved Maritime Link will significantly alter the regional interplay of electricity generated from wind and hydro energy. The low cost of wind and hydro generation coupled with the inherent reliability of a more robust transmission system should be compared over the region to ensure that the recognized benefits are realized to their greatest extent.

Recommendation

6) In light of the agile transmission link available to Newfoundland and Labrador in the near term and the potential for near equal cost interconnection through New Brunswick to Quebec, **the IRP should thoroughly examine the capacity for inter-regional power pooling to maximize the value of zero emission wind resources across the Atlantic region.**

Fuel Price Forecast

Carbon Pricing

The carbon prices in the assumptions are low. As with assumed GHG limits, it would be prudent for the IRP to examine a stricter future carbon pricing regime.

Recommendation

7) High carbon pricing cases should explore prices well above $50 a tonne by the end of the IRP timeframe and should be consistent with similar planning activities across North America.

Demand Side Management (DSM)

As highlighted by the 2007 IRP process, DSM is a cost-effective resource that can be rapidly deployed to reduce waste in the electricity system.

The assumptions for DSM in the IRP process are not entirely clear and should be presented in greater detail. Fair assessment of the full potential for DSM to reduce utility costs is critical to this IRP.

Economic benefit, energy security, and business energy productivity are all agreed to be critical to the success of Nova Scotia in the future. To disadvantage the full potential for DSM within the IRP will diminish the full impact of DSM and result in a sub-optimal plan that may be biased towards capital-intensive infrastructure of lesser benefit.

As such, the assumptions around DSM should not modify input load curves but should be included in the IRP analysis as a resource alongside generation options and traded off based on their cost to the utility. The analysis should be unconstrained regarding the level of DSM and be free to trade increasing levels of DSM at their estimated costs against other estimated supply side cost options. For the purposes of this work, the costs as estimated in the DSM Potential Study provide an adequate cost comparison. They will have accuracy on the same order as other supply side estimates while presenting considerably lower risk. Specific costs of DSM programs can be more carefully defined as the board reviews future detailed DSM plans.

Recommendations

8) **Treat DSM as a resource alongside generation options.**

9) It is essential that DSM programs be treated on equal economic footing to supply side options. **Program Administration Costs for incremental levels of DSM should be optimized along with supply side options so that the level of utility cost effective DSM is an output of the process, not an input.**

10) The Ecology Action Centre fully endorses Efficiency Nova Scotia's letter of comment (March 24, 2014) on this issue and urges NSPI to model DSM as ENSC suggests as it is the fairest method to ensure cost effective reliable service.

Another World: The Deep Green Scenario and Demand Response

Declining GHG emission levels may well be the fundamental driving requirement in the IRP but the ability to explore the full potential of a transformed electricity system may not emerge without explicit study.

A potential scenario exists where there may be considerably higher load due to heating fuel switching and transport electrification. Technology transformation is rarely linear and unforeseen price or political shocks can induce technology cascades that can leave a transformed landscape. The revolution in communications technology is a very recent example, but many others exist.

The IRP should therefore include analysis of a 100% renewables scenario that encompasses an increased level of load from heating demand and vehicle charging.

Within this world, aggressive assumptions around distributed demand response should be included to investigate the ability of vehicle battery and residential and commercial heat storage to cost effectively align electrical demand with the availability of renewable energy.

For example, a home built to the Passive House standard, the Naugler House in New Brunswick (www.nauglerhouse.com), had a peak heating demand this past winter of 730 kWhr/month, or less than 25 kWhr per day. Thermal storage systems, such as those currently being evaluated through the PowerShift Atlantic program would be capable of multi-day storage under loads of this magnitude offering both the ability to shift peak demand and minimize wind energy curtailment in high wind generation configurations. Promised retail renewable sales, in this environment, would begin to look more like fuel delivery and offer dramatically simpler dispatch arrangements than are currently envisioned for demand response.

Likewise electric car charging offers similar load shifting benefits and challenges. A model investigating significant penetration of these or similar loads with a 100% renewable supply should be examined.

Conclusion

The Ecology Action Centre appreciates the opportunity to present the above ten recommendations for amendments to the Draft Assumptions and an additional recommendation for the inclusion of another 'Deep Green' scenario.

Sincerely,

Catherine Abreu

Energy Coordinator
Ecology Action Centre

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SENT BY EMAIL ON MARCH 26, 2014

March 26, 2014

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ENE Comments related to the Draft Assumptions for Nova Scotia Power Incorporated's 2014 Integrated Resource Plan
Matter No. M05522

Dear Ms. Godbout:

ENE appreciates the opportunity to comment on Nova Scotia Power's *2014 IRP – Draft Assumptions* of March 14, 2014. ENE's submission is attached below.

Do not hesitate to contact me with questions.

Respectfully submitted,

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Cc. David Landrigan, NSPI
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ENE Comments related to Nova Scotia Power's *2014 IRP – Draft Assumptions*

1. Demand Side Management Potential Study

The levels of achievable potential presented in the Navigant study fall within a reasonable range, but are considered low relative to other jurisdictions.

The total level of achievable savings potential in Navigant's *Nova Scotia 2015-2040 Demand Side Management (DSM) Potential Study* ranges from approximately 19-31%.[1] Based on Nova Scotia Power's proposed 2014 IRP load scenario energy forecasts (Base, High, and Low), ENE estimates that these levels of savings – in addition to existing DSM program savings – translate into a reduction in load ranging from 17-33% in 2040 (see Table 1).[2]

Table 1: Estimated Levels of Total Achievable Potential (% reduction in 2040) based on the NS 2015-2040 Potential Study and NSP's 2014 IRP Load Scenario Energy Forecasts

	2014 IRP Load Forecasts		
Achievable Potential	**Base**	**High**	**Low**
BASE	-25%	-22%	-26%
HIGH	-32%	-29%	-33%
MID	-31%	-27%	-31%
LOW	-20%	-17%	-20%

Recent potential studies from other jurisdictions show achievable potential levels of: 23% (Connecticut); 25.5% (Massachusetts); 16% (Maine); 13.5% (New York); 27% Rhode Island; and, 26.1% (Vermont).[3] However, it is important to note that the savings potential is assessed over a 10-year period in five out of six of the studies, whereas the Nova Scotia potential study is based on a 26-year period. ENE estimates that over a comparable 10-year period (2014-2023), the levels of achievable potential captured in Nova Scotia – in addition to existing program savings – are 11-19% of forecasted load in 2023 (see Table 2), which is low compared to the above results in the U.S. Northeast states.

Table 2: Estimated Levels of Total Achievable Potential Captured (% reduction in 2023) based on the NS 2015-2040 Potential Study and NSP's 2014 IRP Load Scenario Energy Forecasts

	2014 IRP Load Forecasts		
Achievable Potential	**Base**	**High**	**Low**
BASE	-15%	-13%	-15%
HIGH	-19%	-17%	-19%
MID	-18%	-16%	-18%
LOW	-13%	-11%	-13%

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[1] Based on an estimated load of 13,800 GWh in 2040 derived from the potential study.

[2] Existing savings (2008-2013) are estimates from Efficiency Nova Scotia's Annual Reports and 2013-2015 DSM Plan. Nova Scotia Power's 10-year System Outlook (2013) was also used as a reference. An average measure life of 13 years was used to generate lifetime energy savings.

[3] See Massachusetts Energy Efficiency Advisory Council Consultant Team's *Preliminary Assessment of Potential* (http://www.ma-eeac.org/Docs/3.1_Council%20Meeting%20Minutes/2012%20Minutes/3.13.12/Potential%20Assessment%20Final.pdf), and The Cadmus Group's *Assessment of Energy Efficiency and Distributed Generation Baseline and Opportunities* (http://www.efficiencymaine.com/docs/Cadmus-Baseline-Opps.pdf)

Figure 1 compares the estimates of achievable potential under the various scenarios in Nova Scotia to the results from the 2011 study in Vermont based on average annual percent savings. The period for the Vermont study was 20 years, and therefore the average annual percent savings from 2014-2040 (Table 1) are used for Nova Scotia.

Figure 1: Achievable Potential Results in Vermont Compared to Estimates for Nova Scotia based on the NS 2015-2040 Potential Study and NSP's 2014 IRP Load Forecasts (average annual % savings over 20 years (VT) and 26 years (NS))

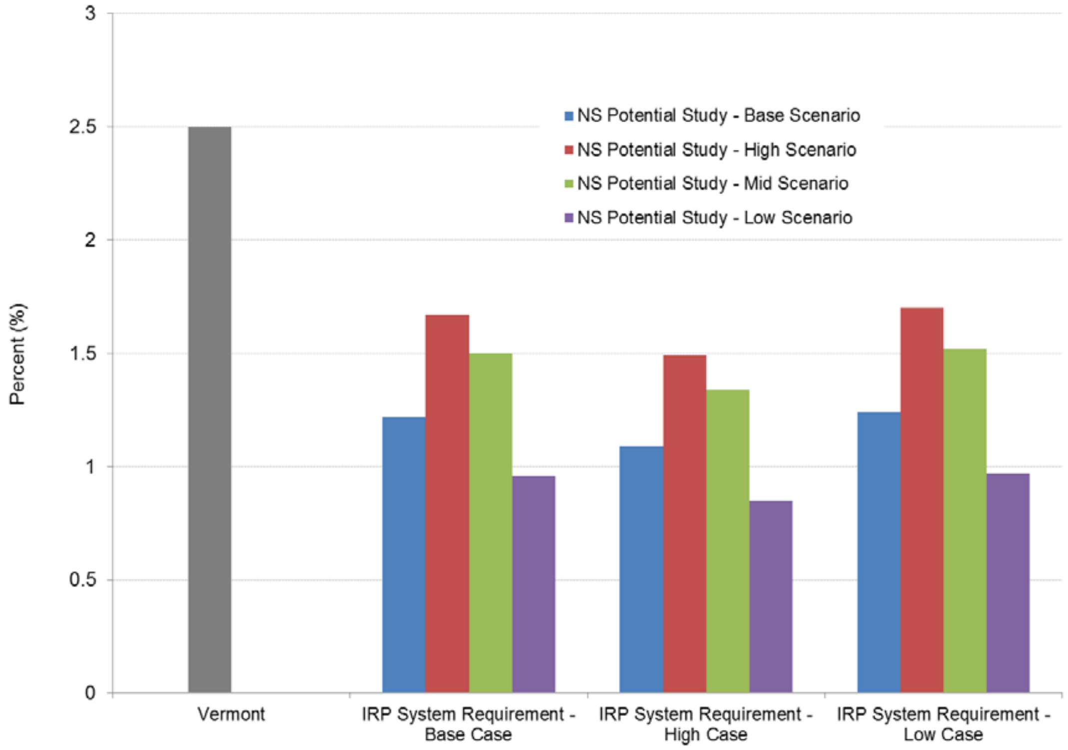

Figure 2 compares the estimates of achievable potential under the various scenarios in Nova Scotia to the results from studies in Connecticut, Massachusetts, Maine, and Rhode Island based on the average annual percent savings. The period for the U.S. studies is 10 years, and therefore the average annual percent savings from 2014-2023 (Table 2) are used for the Nova Scotia estimates.

To note, the Massachusetts Energy Efficiency Advisory Committee Consulting Team report – which summarizes most of the above studies – states that the potential estimates for Vermont in the first 10 years are actually higher than the 20 year study average; however, a figure was not provided.[4]

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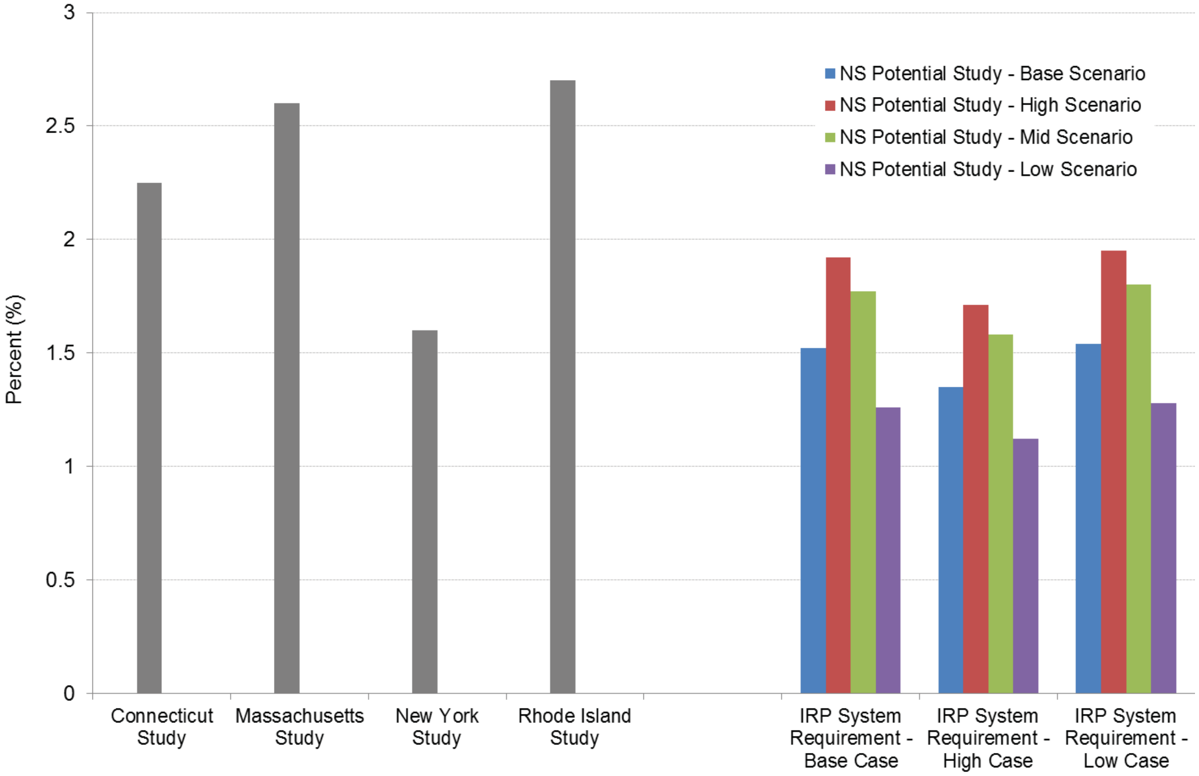
[4] Massachusetts Energy Efficiency Advisory Council Consultant Team (2012, April 13). *Preliminary Assessment of Potential.* Prepared for Mass EEAC. Available on-line at: http://www.ma-eeac.org/Docs/3.1_Council%20Meeting%20Minutes/2012%20Minutes/3.13.12/Potential%20Assessment%20Final.pdf

Figure 2: Level of Energy Efficiency/DSM Captured per year in Four U.S. Studies Compared to Estimates for Nova Scotia based on the NS 2015-2040 Potential Study and NSP's 2014 IRP Load Forecasts (average annual % savings over 10 years)



A number of factors will have contributed to the relatively low levels of cost-effective achievable potential presented for Nova Scotia. One key factor is that the discount rate used was NSP's Weighted Avoided Cost of Capital (WACC) of approximately 6.81%. An emerging best practice for energy efficiency is to use a discount rate that is equal to a recent average of the historic yields from a ten-year government bond.[5] Another key factor is the conservative application of the cost-effectiveness screening test. The TRC was the only test used to determine economic potential, and no utility system, participant, or societal non-energy benefits were included. As such, these levels of achievable potential should be the minimum considered for the IRP.

2. Potential Study Sensitivity Analysis

All assumptions used in the sensitivity analysis should be presented to stakeholders along with the modeling results before soliciting comments on proposed DSM scenarios. The assumptions used should reflect best practices in energy efficiency assessment.

If NSP runs a sensitivity analysis on the results of Navigant's DSM potential study, then it is necessary for stakeholders to have access to the methodology and assumptions prior to commenting on proposed DSM scenarios.

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[5] Synapse Energy Economics, Inc. (2013, October 2). *Energy Efficiency Cost-Effectiveness Screening in the Northeast and Mid-Atlantic States*. Available on-line at: http://www.neep.org/Assets/uploads/files/emv/emv-rfp/emv-products/EMV_Forum_C-E-Testing_Report_Synapse_2013%2010%2002%20Final.pdf

The screening tests used should fully account for the long-run benefits and costs of energy efficiency programs, and allow for achievement of all cost-effective energy efficiency. The underlying methodology and assumptions should be transparent. The screening test should include appropriate non-energy benefits and avoided environmental compliance cost (i.e. CO_2 emissions and other).

ENE recommends using a discount rate that is equal to a recent average of the historic yields from a ten-year government bond. The utility weighted avoided cost of capital is too high relative to the low risk of efficiency programs. As stated above, an alternate discount rate that reflects the lower risk associated with energy efficiency programs is considered a best practice.

In terms of avoided costs, NSP should provide stakeholders with justification for using a value other than $135/MWh. The 2014 IRP process will establish an updated avoided cost value, and therefore NSP's rationale for using a value other than what is public and approved in a regulatory proceeding is required.

3. Preliminary DSM Scenario Recommendations

ENE recommends assessing three DSM scenarios: the Mid and High achievable potential levels from the 2015-2040 potential study, and a third that achieves deeper savings (e.g. 25%) within a shorter timeframe. NSP's proposed DSM scenarios should be presented to stakeholders for comment prior to inclusion in the model.

ENE may revise its recommendations when information regarding the proposed DSM scenarios is available for comment; however, based on the assessment presented in the first section of this submission, at this time it is recommended that NSP assess three DSM scenarios:

i) Low DSM
    a. Based on the Mid scenario in the potential study
ii) High DSM
    a. Based on the High scenario in the potential study
iii) Accelerated DSM
    a. Based on the High scenario but with an accelerated ramp-up to achieve a deeper level of savings earlier (annual savings levels would taper off to capture any remaining achievable savings once the near-term target (e.g. 25% reduction by 2025) is reached).

DSM should be evaluated as a resource option alongside supply-side resources (i.e. not removed from the load forecast prior to assessing the candidate resource plans) as it will be important to understand system costs with and without DSM resources.

DSM and supply-side resources should be assessed on an "even playing field." Only those costs and benefits incurred by the utility should be included in the IRP. DSM should not be assessed from a total resource cost perspective, but rather from a utility cost perspective. The purpose of the IRP is to minimize the utility's revenue requirement. It is not appropriate to include participant costs (or benefits) when assessing DSM in the context of an IRP as they are not utility costs that are recovered in rates.

Further, as stated above, ENE recommends using a discount rate that is equal to a recent average of the historic yields from a ten-year government bond. The utility weighted avoided cost of capital is too high relative to the low risk of energy efficiency programs.

4. Greenhouse Gas Emissions Reduction Scenarios

ENE recommends assessing a greenhouse gas (GHG) emissions reduction scenario with a trajectory that achieves science-based targets in 2050.

ENE recommends using Scenario A as the low environmental constrain as the 2040 emissions level is in-line with the New England Governors and Eastern Canadian Premiers commitment of to reduce GHG emissions by 75-85% below 2001 levels by 2050.[6]

ENE also recommends modeling a science-based scenario as the high environmental constraint. The federal Climate Change Accountability Act, which requires a reduction of 25% below 1990 levels by 2020 and 80% below 1990 levels by 2050, could be used as a reference. This would translate into an emissions level of approximately 5.14 Mt in 2020 and 2.60 Mt in 2040.

5. Carbon Costs

Carbon costs should be counted and not only for U.S. imports so as to quantify the potential carbon price risk associated with the candidate resource plans.

It is important to understand the impact and risk associated with a potential future wherein a price on carbon is established in Canada and/or jurisdictions with which Nova Scotia engages in energy trade and/or has other economic ties. A range of carbon prices should be considered. The Low, Mid, and High cases in Synapse's *2013 Carbon Dioxide Price Forecast* may be used as a reference to develop an appropriate range, or NSP may peg it to, for example, the current carbon tax rate in British Columbia.[7]

6. Avoided Costs

The IRP offers an opportunity for NSP to engage stakeholders in the development of the avoided cost. The process should be transparent, and generate a breakdown of the avoided cost value by its components.

NSP's "all in" or "fully loaded" avoided cost value is not sufficient as it only provides avoided energy and capacity costs, and does not break out avoided transmission and distribution costs. The IRP process offers an opportunity for an open process that incorporates stakeholder input. An outcome of this process should be a detailed and transparent summary of NSP's methodology, along with a final avoided cost value that can be broken out by avoided energy, capacity, and transmission and distribution costs.

7. Rate and Bill Impacts

If NSP will be assessing and potentially reporting rate impacts, then the company should also assess and report bill impacts.

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[6] A linear line from NSP's emissions in 2030 (approximately 4.5 Mt) to the NEG-ECP 2050 commitment results in approximately the following levels for 2040: 3.36 Mt (75% reduction); 3.14 Mt (80% reduction); and 2.91 Mt (85% reduction).

[7] Synapse Energy Economics, Inc. (2013, November 1). 2013 Carbon Dioxide Price Forecast. Available on-line at: http://www.synapse-energy.com/Downloads/SynapseReport.2013-11.0.2013-Carbon-Forecast.13-098.pdf

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March 26, 2014

Nicole Godbout
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Dear Ms. Godbout:

Re: 2014 Integrated Resource Plan (IRP) – M05522

The Large Industrial Group welcomes this opportunity to participate in the 2014 Integrated Resource Plan ("IRP") process. As we have stated in earlier submissions on the IRP Analysis Plan and Terms of Reference and in the first Technical Conference, we are interested in meaningful and informed participation that results in an IRP that accurately reflects the input of stakeholders. We expect that Nova Scotia Power Inc. ("NSPI") will take this opportunity to carefully consider the submissions from all IRP participants and to revise and update the IRP assumptions where it is appropriate to do so.

IRP ANALYSIS PLAN

NSPI circulated a short memorandum on March 14, 2014 to outline the objectives and components of the IRP Analysis Plan. The Industrial Group is concerned that the Analysis Plan does not provide sufficient information as to how NSPI intends to accomplish the final objective of the IRP Analysis Plan: "*select the Preferred Resource Plan.*"

The first Deliverable under the Terms of Reference is "*Criterion for evaluation of various plans and selection of Preferred Resource Plan*." Within this Deliverable, the primary criterion is monetary: cumulative present "worth" of the annual revenue requirements of the resource plan over the planning horizon. Other criteria are also listed, including reliability requirements, robustness, flexibility, end effects and regulatory emissions outlook. It is apparent that the IRP is intended to reflect multiple, possibly competing, objectives. It is unclear from whose perspective "worth" is evaluated – is this customer cost? the value to NSPI in growing its rate base? Further, NSPI has not proposed definitions of these secondary criteria, the metrics by which they will be assessed nor the weight that they will be given in studying and selecting the Preferred Plan. The Industrial Group requests that NSPI provide a clearer articulation of the basis for evaluation and selection of the Preferred Plan and a means for resolving competing objectives.

The third Deliverable of the Terms of Reference, "*Evaluation of potential resource plans*" does not provide guidance on this issue, as it states only that plans will be ranked by the cumulative net present worth of the revenue requirement that "*ultimately the test of soundness of the Preferred Resource Plan is its ability to enable NS Power to provide reliable service at reasonable cost/rates impact across a range of worlds/scenarios and assumption values.*"

A discussion on the overall objectives of the IRP and how these will be factored into the analysis and selection of the Preferred Resource Plan has been largely absent from the stakeholder process. It appears from the submissions of the SBA that these concerns regarding development of the proposed IRP Analysis Plan are shared and we endorse the comments of the SBA in this regard.

If NSPI intends to report to the Utility and Review Board on the criteria for evaluation of various plans, as required by the fourth Deliverable in the Terms of Reference, it is appropriate to articulate and advance the specific evaluation criteria for stakeholder review and commentary prior to embarking on the first step of the IRP Analysis – developing candidate resource plans and high-level screening of resource options.

The Industrial Group requests that NSPI circulate the proposed evaluation criteria for the high-level screening (Analysis Plan Step #1) and to select the Preferred Resource Plan (Analysis Plan Step #5) with commentary on how the other IRP objectives identified in the Terms of Reference have been defined, measured and weighted in establishing the criteria.

IRP ASSUMPTIONS

The Industrial Group's comments on the IRP Assumptions will follow the organization of the materials circulated by NSPI. Specific slides are referenced in brackets.

Environmental and Emissions Constraints

1. The Industrial Group agrees that there is some utility in modelling both Scenario A and B for the CO2 and Greenhouse Gas (GHG) emissions (6) and Air Pollutants (SO2, NOx and Hg) (9) as this will provide an analysis of the cost of further increasing emissions controls after current regulations end. A sensitivity of both more and less stringent emission reduction strategies than are provided in Scenario A for the GHG and various Air Pollutants assumptions in order to fully assess the impact of policy changes in the Federal and Provincial governments should be carried out.

2. In the IRP process, when emissions targets are graphed, it would be helpful to show the current, actual emissions levels in order to understand whether operations are above, below or on target.

Supply Side Options

Generation Options

1. The Supply Side Options (19) list several options for coal-fired plants; these are presented as if each are equally established and viable options. The Industrial Group questions whether NSPI has evaluated the technical risk and associated costs that are linked to these generation options. An evaluation of the costs and risks should be part of the modeling exercise.

2. It is noted that fluidized bed combustion (FBC) units (like Point Aconi) have not been included in the supply side options for coal-fired plants. These units are known to be effective at removing high levels of sulphur and mercury and can handle lower grades of coal, such as domestic coal and high sulphur imports, and petcoke, which is a by-product of oil sands processing and which is being used as generation fuel source in the

US Gulf Coast and Midwest. An FBC plant equipped to burn petcoke may be an economically attractive generation option and should be evaluated.

3. The input assumptions for intermittent integration costs are not stated (p.20). P.26 states that a study is being discussed among NSPI, Board staff and consultants. The Industrial Group states that IRP participants should be afforded equal opportunity to participate in the process.

4. Apart from pumped storage, there are no other storage technologies considered in the Supply Side Options (20). Has NSPI considered whether other forms of electricity storage, such as compressed air, flywheels and battery storage, will be viable in the planning horizon? The Industrial Group urges NSPI to explore storage options more closely, particularly given the need to integrate significant amounts of intermittent renewable into the system.

5. The capacity value of wind, NRIS and ERIS, was an issue for determination in the IRP as agreed to by participants in the COSS Hearing. P.25 states that studies are currently being discussed among NSPI, Board staff and consultants. Again, IRP participants must meaningfully participate in the process and not simply be advised regarding studies "once finalized".

6. The Industrial Group queries the underlying assumptions for sustaining capital projects for existing hydro systems (28). Is this an economic option given the generation capacity of existing hydro systems?

Import Assumptions

7. Import Assumptions (31) do not provide much consideration of the implications of non-firm imports (such as Maritime Link surplus energy) vs. firm imports from New Brunswick. What are the risks, costs, and benefits of the firm and non-firm options proposed?

8. Can NSPI confirm that the Mass Hub Forecast that will be used to price import power (31) is consistent with the natural gas assumptions (54)? As Mass Hub prices tend to move with the gas, it is expected that the import power and natural gas prices used in the IRP model are aligned.

Financial Assumptions

9. With respect to the Financial Assumptions (44-45), can NSPI confirm whether the revenue requirement profiles are appropriate for the IRP? Has NSPI considered levelized cost profiles? Have risk adjusted discount rates been considered?

10. It is suggested that the Canadian vs. US currency values track closely to global oil prices. As global oil prices (and hence other commodity prices) increase in a sustained way, the value of the Canadian dollar rises. A high oil price case would be aligned with a strong Canadian dollar, while a low oil price case would see a weaker Canadian dollar. Does the exchange rate in the IRP reflect this trend and if not, why not?

Fuel Price Forecast Assumptions

11. In order to better understand the impact of different fuel forecast assumptions, it would be helpful if NSPI would provide a graph comparing historic and forecast fuel costs over the planning horizon (in $/mmbtu) on a single graph. Where there are relative price differentials that diverge from historic differentials, it would be appropriate for NSPI to comment on the market (or other) assumptions that influence the change.

12. NSPI should consider using other fuel forecasts (49).

    a. In the 2014 US Energy Information Administration (EIA) forecast, the low oil price case projects flat oil prices to 2040 (flat in real terms – adjusted for inflation).

    b. Has NSPI considered a low coal forecast that holds coal prices flat, apart from inflation adjustment, for a significant portion of the IRP period? What coal market trends has NSPI observed recently that support the coal forecasts included in the IRM assumptions?

13. The Industrial Group previously requested additional information about the industry assumptions that underlie the PIRA Forecasts; we intend to make further submissions on this area when we have had the opportunity to review these assumptions.

14. Has NSPI considered the IRP impact if the assumptions regarding the installation of new natural gas pipelines are not met? What are the costs and risks associated with delay? (54).

15. For the Solid Fuel Price Assumptions (66), can NSPI provide prices in real and nominal terms?

Demand-side Assumptions

Load Assumptions

16. In relation to this, it would be helpful to have more insight from NSPI on the basis of the forecast load increases for the small and medium industrial classes. Further, given that “other industrial” (large industrial) is projected to be flat for the IRP period, can NSPI explain how the total industrial forecast is so closely aligned to the medium and small industrial forecast? Wouldn’t the flat large industrial forecast impact the overall industrial load projections? (87-88)

17. Can NSPI speak to what changes had occurred in the past year such that the Maritime Link base load case is included in the IRP assumptions as the High Scenario? (79)

18. Will NSPI provide a scenario in which PHP is not on the Load Retention Tariff for the duration of the IRP period?

We look forward to receiving the additional information requested in our March 21, 2014 correspondence and to providing supplementary submissions on the IRP Assumptions.

Regards,

Nancy G. Rubiin

MAS/ NGR

c. IRP Participants

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File No.:

Via Email

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Dear Ms. Godbout:

Re: NSPI IRP Stakeholder Comments on Assumptions and Analysis Plan

The Department of Energy (herein referred to as "the Department") is generally supportive of the IRP Assumptions and Analysis Plan. After reviewing the reference files provided by NSPI, the Department would like to offer some comments in relation to the Analysis Plan and the following four (4) assumptions:

1 Renewable Electricity Standards

The Province of Nova Scotia has no current plans to change the requirements of the Renewable Electricity Standards (RES), as defined under the Renewable Electricity Regulations. However, the government continues to support the development of renewables and expects that the percentage of renewable electricity supply is likely to increase beyond levels currently mandated by the RES Regulations. Through the initiation of a thorough review of Nova Scotia's electricity system (the Electricity Review), the recently passed Electricity Reform Act represents an opportunity to clarify the future opportunities for the use of renewable energy in the province.

2 COMFIT

To date approximately 89 COMFIT projects have been approved. The Department is no longer accepting applications over 500kw. Historically there have been high attrition rates for distribution projects within the province, and the Department has set aggressive in-service timelines that must be adhered to.

The Department suggests that a range of approximately 110-120 MW of COMFIT projects will be in-service by 2016.

3 Load Forecasts

The Department appreciates the need for an accurate model to define the base case load forecast, however the Department respectfully suggests that the proposed scenarios do not show the levels of variance required to ensure that all reasonable futures will be included in the modeling. The proposed residential forecast in particular is extremely narrow in scope and the department believes that a much wider range should be considered; ideally at least +/- 15% of the base case for each customer class. Previous load forecasts for other regulatory submissions have been similar to this broader range.

It would be helpful if further details were provided on the assumptions that go into developing the end use model base case load forecast. This is a key input to the IRP therefore the Department feels that additional information is needed to better understand how the forecast is developed.

4 Demand Side Management

Through the aforementioned Electricity Review the Province will be examining the continued role for Demand Side Management (DSM) in the Nova Scotia electricity system, and expects new technology will continue to be cost effective for reduction of both energy and capacity demand. The Department does not find there is sufficient information presented in the assumptions to explain how DSM will be handled by the model and requests that NSPI provide more information related to the following points (at minimum):

- DSM programming includes more than just the end-user portfolio included in the DSM potential study. The IRP should include cost effective DSM programming from any available source, including the utility's own incentive and infrastructure plans such as intelligent metering, conservation voltage reduction and other smart-grid based technologies.

- Clarify what is meant by "layers" of DSM in the IRP process description. Indicate how the model will settle on the amount of DSM programming.

- While Demand Response is mentioned it is not clear if it will be modeled as a separate process or only as an effect of Energy Efficiency DSM. The Department would suggest that as emerging technologies (such as smart-grid) will make Demand Response increasingly effective and relevant, it would be useful for the IRP to model these specific effects on peak load system demand.

Respectfully,

Stephen T. McGrath

cc: 2014 IRP Participants

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Our File: 100384
March 26, 2014

Ms. Nicole Godbout
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Dear Ms. Godbout:

Re: Integrated Resource Plan (IRP) 2014 – Matter M05522/P-884.14

In accordance with the current Board schedule with respect to the above-noted matter, please accept this letter as the initial comments of Port Hawkesbury Paper LP ("PHP") regarding the Draft Assumptions circulated by Nova Scotia Power Inc. ("NSPI") on March 14, 2014.

1. Environmental & Emissions Assumptions

As discussed at the Technical Conference, NSPI is proposing to model two scenarios with respect to future emission restrictions, including a "Scenario B" in which the post-2020 emission limits for SO2, NOX, and Hg are maintained at the 2020 levels to 2040, and there is no decline in the C02 limit post 2030. For modeling purposes, PHP supports the use of the scenarios as proposed. The modeling of these two scenarios will provide a useful indication of the relative costs associated with reductions of the type suggested in Scenario A, if reductions of that magnitude were considered at some point in the future.

2. Demand-Side Management ("DSM") Assumptions and the Use of Load as a Resource

On Slide 97 of the Draft Assumptions, NSPI indicates that it "continues to work with ENSC and Synapse to develop DSM levels" and that it "will consider intervenor feedback on DSM levels to be modelled and propose 'layers' as soon as available for comment before April 11."

PHP looks forward to receiving the additional information on the proposed DSM levels as soon as possible. PHP assumes that the views of Efficiency Nova Scotia with respect to the treatment of DSM will inform the assumptions to be used with respect to DSM in the IRP.

As all parties are aware, the IRP terms of reference were explicitly revised to consider the potential utilization of load as a resource. The current version of the Draft Assumptions does not specifically refer to consideration of this possibility. PHP would be pleased to meet with NSPI and Synapse in the near term and prior to the finalization of the assumptions on April 11 to provide direct input on the specific potential opportunities associated with its load to ensure that this will be appropriately examined as part of the modeling for the IRP.

3. Fuel Price Forecast Assumptions

In its latest version of the Draft Assumptions, NSPI has provided additional detail regarding its proposed Fuel Price forecasts. As the Technical Conference did not deal with this additional information, PHP has the following questions based on its review of these slides (48-73), responses to which would assist PHP in determining whether it has any specific comments on the Fuel Price assumptions:

> (a) Slide 52 shows percentages of likelihood (PIRA) for the Base, High, and Low case natural gas scenarios of 45%, 25%, and 30%, respectively. The further slides do not refer to these percentages and PHP assumes that there is no specific weighting given to the probability of occurrence of the three separate cases in the proposed analysis. PHP would appreciate confirmation, or an explanation of why and how these percentage figures are to be utilized in the analysis.
>
> (b) Slide 55 shows that for the natural gas Base Case (Expected), there is no premium for the periods 2018-2030 or 2030-2040. This appears to assume as a Base Case that the U.S. Northeast and Atlantic Canadian gas market structural issues are fully mitigated by 2018 for the entire Planning Horizon. What level of confidence does NSPI place on this assumption to the extent that it can utilize it as the Base Case, considering the occurrence of the current unexpected natural gas pricing conditions, the capital works required to address this issue, and the increasing upward pressure on natural gas demand in New England?
>
> (c) Slide 65 states that for domestic coal, the price source is NSPI current contracts. For the analysis, what constraints, if any, are placed on the amount/volume of domestic coal and its source (i.e. will the modeling be able to choose Donkin coal, for example, or only coal from the coal fields currently supplying NSPI)? If the model is constrained in this regard, PHP believes it will be important to do sensitivities around the utilization of other indigenous resources to the greatest extent possible.
>
> (d) Slide 51 refers to a "pending update with revised fundamental forecast (expected in March 2014)" for coal pricing. Please provide the updated Slide 66 (Solid Fuel Pricing Assumptions) as soon as possible on the basis of the revised underlying fuel forecast. Please note any significant assumption changes in the revision.

PHP looks forward to receiving the information noted above as soon as possible so that it can provide further comments, if any, prior to the finalization of the assumptions on April 11.

4. Transmission Assumptions

On slide 34, NSPI indicates that: "Back-up and Load Following for non-dispatchable renewables is assumed to be provided within NS and not included in Network Upgrade cost estimates. If back-up source is external to NS, then a second NS-NB tie is required." It is unclear to PHP if the modeling will have a constraint on the amount of non-dispatchable renewables that can be backed-up by Nova Scotia resources. If there is such a constraint, how will the modeling deal with the non-dispatchable renewables excess to this constraint? PHP may have further comments on this issue depending on the response.

PHP appreciates the opportunity to provide this input.

Yours truly,

David S. MacDougall

cc: Interested Parties

Scotian
WindFields
Community Owned. Naturally.

March 26, 2014

Ms. Nicole Godbout
Nova Scotia Power Inc.
1223 Lower Water St.
Halifax, Nova Scotia
B3J 2 W5

RE: Submission of Comments on March 14, 2014 Draft Assumptions.

Hello,

Scotian WindFields would like to submit the below comments and suggestions based on the 2014 IRP - Draft Assumptions documentation that was provided on March 14, 2014.

Should you require any clarification or further details on and of the points included in this response, please do not hesitate to contact Scotian Windfields directly. Thank you for your consideration of these comments and we look forward to further discussion and analysis.

Sincerely,

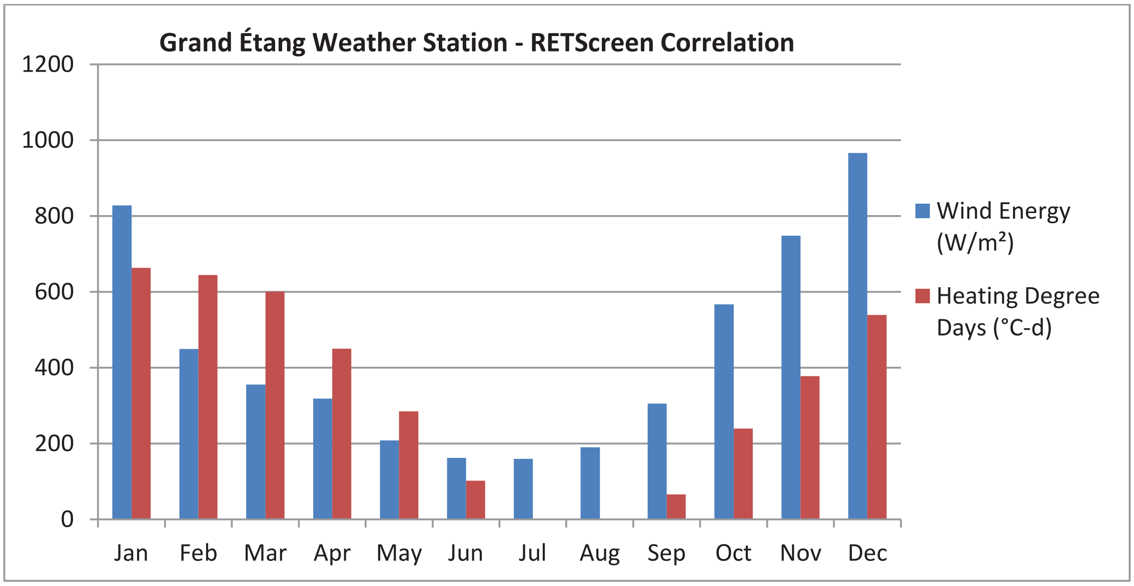
Daniel Roscoe, P.Eng.
Chief Operating Officer
Scotian WindFields Inc.

Scotian WindFields
Community Owned. Naturally.

1) Wind Integration Study

During the technical conference March 7th, 2014, and in the Draft Assumptions provided on March 14th, 2014, it was stated that additional information would be provided on the operation and integration costs of wind energy, in the form of a Wind Integration Study. This information is essential to considering Candidate Resource Plans that include distribution-connected and transmission-connected wind energy. This is a complex issue that will require review and potential revision once provided.

a. When will the Wind Integration Study be provided?
b. When will the Capacity Value of Wind studies be provided?
c. Will the Wind Integration Study differentiate between Transmission-connected and Distribution-connected wind energy as possible Supply-Side Options?
d. Will Integration Studies be provided or considered for other forms of variable generation (Solar PV, Tidal, etc.)
e. Will a diurnal analysis be provided to show the correlation of heating degree-days versus wind energy production?
f. Will the use of electric thermal storage or buffering, with respect to wind integration, be considered?
g. The residential heating load, under the provided Draft Assumptions, is shown to be expanding. Is this increased demand considered in the analysis along with the correlation between heating requirements and wind energy availability? For greater context, please see the below graph which correlates wind power density with heating degree days at the Grand Étang Weather Station[1]:



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[1] These data have been correlated with the Environment Canada historical weather data available through RETScreen and from the Environment Canada website historical weather database: http://climate.weather.gc.ca/climateData/hourlydata_e.html?StationID=10792

2) Wind Assumptions

Scotian WindFields has a number of comments regarding the Draft Assumptions provided for costs and scale of wind energy. The Draft Supply-Side Options (Slide 20) only consider 100MW of transmission-connected wind energy. The Range of Capital Costs on the Draft Supply-Side Options gives a range of $2100-$3500/kW, while attributing the high end of this range to COMFIT-developed wind energy projects.

a. Wind energy supply in excess of an additional 100MW should be considered as a Supply-Side Option
b. Additional distribution-connected wind energy should be considered as a Supply-Side Option, with specific capital costs and integration costs considered.
c. We would recommend that COMFIT-scale development and along with future distribution connected wind energy has a capital range of **$2500-$2800/kW.**

3) Solar Assumptions

Scotian WindFields has a number of comments regarding the Draft Assumptions provided for costs and scale of Solar Thermal and Solar Photovoltaic resources. The Draft Supply-Side Options (Slide 20) only considers “>10MW” each of transmission-connected solar thermal and solar photovoltaic supply options. The Draft Assumptions for Supply-Side Options gives a Capital cost of solar thermal at $9,000/kW and of solar photovoltaic at $5,600/kW.

a. We recommend that large amounts (>10MW) of distribution-connected, individual and commercial-scale (1-100kW) solar photovoltaic energy be considered as a Supply-Side Option.
b. We recommend that large amounts (>10MW) of individual and commercial-scale (1-100kW) solar thermal energy be considered as a Supply-Side offset.
c. We recommend that the capital costs for solar photovoltaic and individual-scale development be considered with a capital range as low as **$3,500/kW.**
d. We recommend that the capital costs for solar photovoltaic and utility-scale development be considered with a capital range as low as **$3,000/kW.**
e. We recommend that the costs for solar thermal for individual and commercial-scale development at **$2,000/kW.**
f. We welcome further discussion on the capacity factors of the various types of solar energy which were not discussed in the Draft Assumptions provided

4) Forecast Cost of Carbon

Scotian WindFields has the below comments regarding the Draft Assumptions for Carbon Pricing. Under the Case Development (Power) on Slide 60, it is stated that the assumed cost of Carbon is US$15/Ton CO_2 in 2020, escalating to US$37/Ton CO_2 in 2030.

The values for cost of carbon provided in the Draft Assumptions are associated with imported power. If and how carbon pricing is applied within Nova Scotia is vary significant variable as well.

a. The IRP model should consider the potential for NS Power to be required to pay a price on carbon emissions.

Regarding the cost of carbon emissions specifically, we have drawn our analysis from a report commissioned by Synapse Energy Economics Inc. on November 1, 2013 - "2013 Carbon Dioxide Price Forecast". This study considered the carbon price information from the most recent IRP efforts of 28 utilities. With the Canadian federal government's stated intention to harmonize carbon policy with the US and our economic interdependence, we feel it is reasonable to use US projections for Canadian pricing scenarios. We would request that the costs from this study for long-term carbon pricing be considered. The three key scenarios are itemized below:

b. The **Low Case** forecasts a cost of Carbon at US$10/Ton CO_2 in 2020, escalating to US$40/Ton CO_2 in 2030.[2]
c. The **Mid Case** forecasts a cost of Carbon at US$15/Ton CO_2 in 2020, escalating to US$60/Ton CO_2 in 2030.[3]
d. The **High Case** forecasts a cost of Carbon at US$25/Ton CO_2 in 2020, escalating to US$90/Ton CO_2 in 2030.[4]

[2,2,3,] Synapse Energy Economics Inc., 2013 Carbon Dioxide Price Forecast, (Massachusetts, 2013)

5) Fuel Price Forecast Assumptions

Scotian WindFields has the below comments regarding the Draft Assumptions for Fuel Price Forecast Assumptions, particularly for the long-term price forecasting for Natural Gas, Petroleum-based fuels and solid fuels.

a. The Average Annual Increase of fuel pricing for Natural Gas between years 2015 and 2040, as presented in the Draft Assumptions (Slide 58) is between 2.4% and 3.1%. This is exceedingly optimistic consider that the Average Annual Increase of Natural Gas pricing between years 1991 and 2013/2014 was calculated at **5.5%**.[5]
b. The Average Annual Increase of fuel pricing for HFO and LFO between years 2015 and 2040, as presented in the Draft Assumptions (Slide 72) is between 2.3% and 3.59%. This seems exceedingly conservative as the Average Annual Increase of WTI crude pricing between years 1990 and 2013/2014 was calculated at **6.1%**[6] and the Average Annual Increase of Heating Oil was calculated at **6.3%.**[7]
c. Based on the above presented historical data, we recommend that NS Power consider more appropriate energy inflation figures in the IRP Model.

6) Candidate Resource Plans

Scotian WindFields would to suggest a number of Candidate Resource Plan criteria to be included in the evaluation modelling with Strategist.

a. A Candidate Resource Plan that includes a transition to an electricity supply that consists of **100% Renewable Energy Sources by the year 2040** – Including Wind, Solar PV, Solar Thermal, Tidal, Legacy Hydro, Maritime Link/Muskrat Falls, and other sources.
b. A Candidate Resource Plan that includes a transition to an electricity supply that consists of **80% Renewable Energy Sources by the year 2030** – Including Wind, Solar PV, Solar Thermal, Tidal, Legacy Hydro, Maritime Link/Muskrat Falls, and other sources.
c. A Candidate Resource Plan that includes a transition to an electricity supply that results in GHG emissions **of 80% below 1990 levels by the year 2040**.

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[5] As calculated from data provided by IndexMundi regarding $US/mmBTU monthly price of Natural Gas: http://www.indexmundi.com/commodities/?commodity=natural-gas&months=300

[6] As calculated from data provided by IndexMundi regarding $US/barrel WTI monthly price of Crude Oil: http://www.indexmundi.com/commodities/?commodity=crude-oil-west-texas-intermediate&months=300

[7] As calculated from data provided by IndexMundi regarding $US/gallon monthly price of heating oil: http://www.indexmundi.com/commodities/?commodity=heating-oil&months=300

2013 Carbon Dioxide Price Forecast

November 1, 2013

(Minor corrections February 2014)

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CONTENTS

1. EXECUTIVE SUMMARY

Prudent planning requires electric utilities and other stakeholders in carbon-intensive industries to use a reasonable estimate of the future price of carbon dioxide (CO_2) emissions when evaluating resource investment decisions with multi-decade lifetimes. However, forecasting a CO_2 price can be difficult. While several bills have been introduced in Congress, the federal government has yet to legislate a policy to reduce greenhouse gas emissions in the United States.

Although this lack of a defined policy that sets a price on carbon poses a challenge in CO_2 price forecasting, an assumption that there will be no CO_2 price in the long run is not, in our view, reasonable. The scientific basis for attributing climatic changes to human-driven greenhouse gas emissions is irrefutable, as are the type and scale of damages expected to both infrastructure and ecosystems. The need for a comprehensive U.S. effort to reduce greenhouse gas emissions is clear. Any policy requiring or leading to greenhouse gas emission reductions will result in higher costs to the electricity resources that emit CO_2.

The Synapse 2013 CO_2 price forecast is designed to provide a reasonable range of price estimates for use in utility Integrated Resource Planning (IRP) and other electricity resource planning analyses. The current forecast updates Synapse's 2012 CO_2 price forecast, published in October 2012.[1] Our 2013 forecast incorporates new data that have become available since 2012, in order to provide useful CO_2 price estimates for utility resource planning purposes.

1.1. Key Assumptions

Synapse's 2013 CO_2 price forecast reflects our expert judgment that near-term regulatory measures to reduce greenhouse gas emissions, coupled with longer-term cap-and-trade or carbon tax legislation passed by Congress, will result in significant pressure to decarbonize the electric power sector. The key assumptions of our forecast include:

- A federal program establishing a price for greenhouse gases is the probable eventual outcome, as it allows for a least-cost path to emissions reduction.
- Initial climate-focused policy actions are more likely to take a regulatory approach, e.g. Section 111(d) of the Clean Air Act. In the longer-term, federal legislation setting a price on emissions through a cap-and-trade policy or a carbon tax will likely be prompted by one or more of the following factors:
    - New technological opportunities that lower the cost of carbon mitigation;

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[1] Wilson et al., "2012 Carbon Dioxide Price Forecast," October 2012. http://www.synapse-energy.com/Downloads/SynapseReport.2012-10.0.2012-CO2-Forecast.A0035.pdf.

  - A patchwork of state policies that achieve state emission targets for 2020, spurring industry demands for federal action;
  - A series of executive actions taken by the President that spur demand for Congressional action;
  - A Supreme Court decision that permits nuisance lawsuits, making it possible for states to sue companies within their boundaries that own high-carbon-emitting resources, and creating a financial incentive for energy companies to act; and
  - Mounting public outcry in response to increasingly compelling evidence of human-driven climate change.

Given the growing interest in reducing greenhouse gas emissions by states and municipalities throughout the nation, a lack of timely, substantive federal action will result in the enactment of diverse state and local policies. Heterogeneous—and potentially incompatible—sub-national climate policies would present a challenge to any company seeking to invest in CO_2 emitting power plants, both existing and new. Historically, there has been a pattern of states and regions leading with energy and environmental initiatives that have in time been superseded at the national level. It seems likely that this will be the dynamic going forward: a combination of state and regional actions, together with federal regulations, that are eventually eclipsed by a comprehensive federal carbon price.

We expect that federal regulatory measures together with regional and state policies will lead to the existence of a cost associated with greenhouse gas reductions in the near term. Prudent utility planning requires that utilities take this cost into account when engaging in resource planning, even before a federal carbon price is enacted.

1.2. Study Approach

To develop the 2013 CO_2 price forecast, Synapse reviewed several key developments that have occurred over the past year. These include:

- Proposed federal regulatory measures to limit CO_2 emissions from new power plants and administrative initiatives to advance regulation for existing units;
- Updates to the U.S. carbon price used to assess the climate benefit of federal rulemakings;
- Revisions to the Northeast's Regional Greenhouse Gas Initiative (RGGI) CO_2 policy and the first allowance auctions under California's AB 32 Cap-and-Trade program;
- The results of a multi-year Energy Modeling Forum (EMF) research effort on the costs of U.S. emissions abatement from nine integrated assessment modeling teams; and
- Carbon price forecasts from the most recent IRP efforts of 28 utilities.

1.3. Synapse's 2013 CO_2 Price Forecast

Based on analyses of the sources described in sections 3 through 9, and relying on our own expert judgment, Synapse developed Low, Mid, and High case forecasts for CO_2 prices from 2013 to 2040. Figure ES-1 (below) shows the range covered by the Synapse forecasts. These projections assume that state and regional policies will combine with federal regulatory measures to put economic pressure on carbon-emitting resources in the next several years such that the costs of operating a high-carbon-emitting plant increase—followed later by a broader federal, market-based policy. In states other than the RGGI region[2] and California, we assume a zero carbon price for the next several years; by 2020, we expect that federal regulatory measures will begin to put economic pressure on carbon-emitting power plants throughout the United States. All annual carbon prices are reported in 2012 dollars per short ton of CO_2.[3]

Each of the forecasts shown in Figure ES-1 represents a different level of political will for reducing carbon emissions, as described below.

- The **Low case** forecasts a carbon price that begins in 2020 at $10 per ton, and increases to $40 per ton in 2040, representing a $22 per ton levelized price over the period 2020-2040. This forecast represents a scenario in which federal policies—either regulatory or legislative—exist but are not very stringent.
- The **Mid case** forecasts a carbon price that begins in 2020 at $15 per ton, and increases to $60 per ton in 2040, representing a $34 per ton levelized price over the period 2020-2040. This forecast represents a scenario in which federal policies are implemented with significant but reasonably achievable goals.
- The **High case** forecasts a carbon price that begins in 2020 at $25 per ton, and increases to approximately $90 per ton in 2040, representing a $52 per ton levelized price over the period 2020-2040. This forecast is consistent with the occurrence of one or more factors that have the effect of raising carbon prices. These factors include somewhat more aggressive emissions reduction targets; greater restrictions on the use of offsets; restricted availability or high cost of technological alternatives such as nuclear, biomass, and carbon capture and sequestration; more aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters); or higher baseline emissions.

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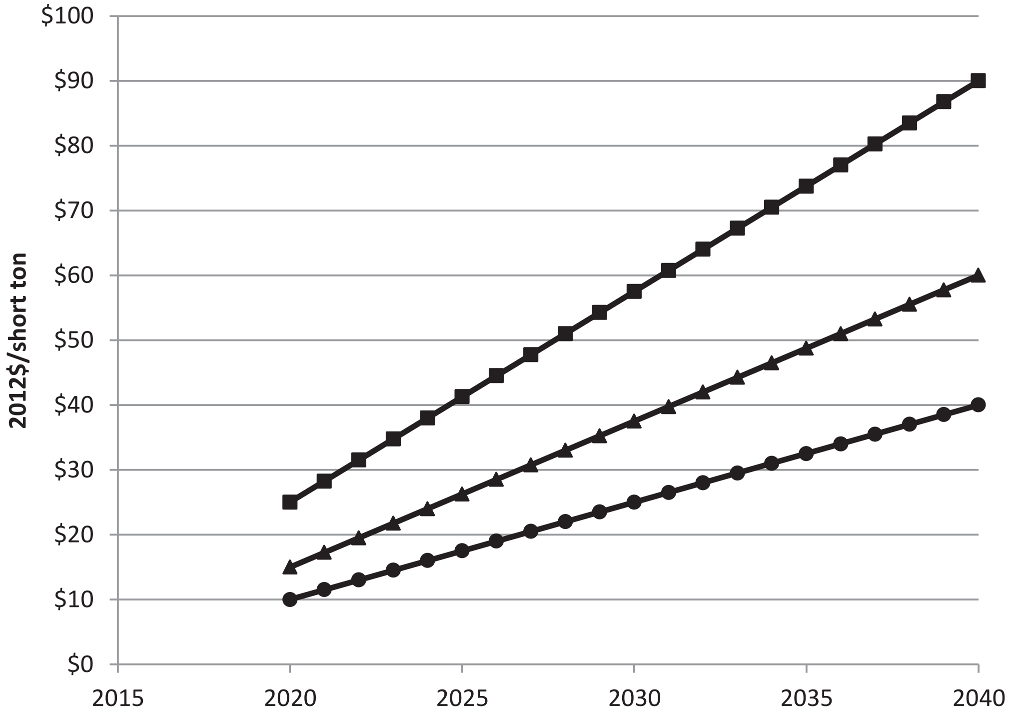
[2] Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont.

[3] Results from public modeling analyses were converted to 2012 dollars using price deflators taken from the U.S. Bureau of Economic Analysis, and are available at: http://www.bea.gov/national/nipaweb/SelectTable.asp. Consistent with U.S. Energy Information Administration and U.S. Environmental Protection Agency modeling analyses, a 5 percent real discount rate was used in all levelization calculations.

ES-1: Synapse 2013 CO_2 Price Trajectories



2. STRUCTURE OF THIS REPORT

This report presents Synapse's 2013 Low, Mid and High CO_2 price forecasts, along with the evidence assembled to inform these forecasts:

- Section 3 discusses broader concepts of CO_2 pricing.
- Sections 4 through 8 discuss existing state and federal legislation, potential future legislation, recent cap-and-trade results from the research community, and a range of current CO_2 price forecasts from utilities.
- Section 9 presents Synapse's 2013 Low, Mid, and High CO_2 price forecast, along with a comparison to recent utility forecasts.

Unless otherwise indicated, all prices are in 2012 dollars and CO_2 emissions are given in short tons.

3. WHAT IS A CARBON PRICE?

There are several co-existing meanings for the term “carbon price” or “CO_2 price”: each of these meanings is appropriate in its own context. Here we give a brief introduction to five common types of carbon prices, along with a quick guide to which of the carbon price estimates reviewed in this report are based on which of these meanings. (Note that the definition of an additional term—the “price of carbon”—is ambiguous because it can at times mean several of the following.)

Carbon allowances (sometimes called credits or certificates, and best known for their use in policies called “cap and trade”): Allowances are certificates that give their holder the right to emit a unit of a particular pollutant. A fixed number of carbon allowances are issued by a government, some sold and, perhaps, some given away.[4] Subsequent trade of allowances in a secondary market is common to this policy design. The price that firms must pay to obtain allowances increases their cost of doing business, thereby giving an advantage to firms with cleaner, greener operations, and creating an incentive to lower emissions whenever it can be done for less than the price of allowances. The number of allowances—the “cap” in the cap-and-trade system—reflects the required society-wide emission reduction target. A greater reduction target results in a lower cap and a higher price for allowances. In the field of economics, pricing emissions is called “internalizing an externality”: The external (not borne by the polluting enterprise) cost of pollution damages is assigned a market price (thus making it internal to the enterprise).

In this report: The Northeast’s RGGI and California’s Cap-and-Trade Program are both carbon allowance trading systems. In addition, the Kerry-Lieberman, Waxman-Markey, and Cantwell-Collins bills all proposed policy measures that included carbon allowance trading.

Carbon tax: A carbon tax also internalizes the externality of carbon pollution, but instead of selling or giving away rights to pollute (the allowance approach), a carbon tax creates an obligation for firms to pay a fee for each unit of carbon that they emit. In theory, if the value of damages were known with certainty, a tax could internalize the damages more accurately, by setting the tax rate equal to the damages; in practice, the valuation of damages is typically uncertain. In contrast to the government issuance of allowances, with a carbon tax there is no fixed amount of possible emissions (no “cap”). A cap-and-trade system specifies the amount of emission reduction, allowing variation in the price; a tax specifies the price on emissions, allowing variation in the resulting reductions. In both cases there is an incentive to reduce emissions whenever it can be done for less than the prevailing price. In both cases there is the option to continue emitting pollution, at the cost of either buying allowances or paying the tax. While some advocates have claimed that a tax is administratively simpler and reduces bureaucratic, regulatory, and compliance costs, a general aversion to new taxes has meant that no carbon tax proposals have received substantial support in recent policy debate.

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[4] Whether or not allowances are initially given away for free or sold, they represent an opportunity cost of emissions to the holder.

Effective price of carbon (sometimes called the notional, hypothetical, or voluntary price): Carbon allowances and carbon taxes internalize the climate change externality by making polluters pay. However, many other types of climate policies work not by making polluting more expensive per se, but instead by requiring firms to use one technology instead of another, or to maintain particular emission limitations in order to avoid legal repercussions. Non-market-based emission control regulatory policies are called "command and control." For any such non-market policy there is an "effective" price: a market price that—if instituted as an allowance or tax—would result in the identical emission reduction as the non-market policy. An effective price may be used internally within a firm, government agency, or other entity to represent the effects of command and control policies for the purpose of improved decision making. Renewable Portfolio Standards, energy efficiency measures, and other policies designed to mitigate CO_2 emissions impose an effective price on carbon.

In this report: Utility carbon price forecasts are effective prices used for state-required IRPs and internal planning purposes. The U.S. Environmental Protection Agency's (EPA's) proposed carbon pollution standard for new sources of electric generation is a non-market-based policy that would represent an effective price.

Marginal abatement cost of carbon: An abatement cost refers to an estimate of the expected cost of reducing emissions of a particular pollutant. Estimation of a marginal abatement cost requires the construction of a "supply curve": all of the possible solutions to controlling emissions (these may be technologies or policies) are lined up in order of their cost per unit of pollution reduction. Then, starting from the least expensive option, one tallies up the pollution reduction from various solutions until the desired total reduction is almost achieved, and then asks: what would it cost to reduce emissions by one more unit to achieve the target? The answer is the "marginal" cost of that level of pollution reduction; a greater reduction target would have a higher marginal cost. The marginal abatement cost of carbon is not a market price used to internalize an externality. Rather, it is a method for estimating the price that, if it were applied as a market price, would have the effect of achieving a given emission reduction target. In a well-functioning cap-and-trade system, the allowance price would tend towards the marginal abatement cost of carbon.

In this report: We do not analyze any marginal abatement costs in this report—see the *2012 Synapse Carbon Dioxide Price Forecast* for further information. McKinsey & Company has been a consistent producer of this type of analysis, an example being their 2010 report *Impact of the Financial Crisis on Carbon Economics: Version 2.1 of the Global Greenhouse Gas Abatement Cost Curve*.

Social cost of carbon: Whereas the marginal abatement cost estimates the price of stopping pollution, the social cost of carbon estimates the cost, per unit of emissions, of allowing pollution to continue. The social cost of carbon is the societal cost of current and future damages related to climate change from the emission of one additional unit of pollutant. Estimating the uncertain costs of uncertain future damages from uncertain future climatic events is, of course, a tricky business. If enough information were available, a marginal abatement cost for each level of future emissions (the supply of emission reductions) could be compared to a social cost of carbon for each level of future emissions (the demand for emission reductions) to determine an "optimal" level of pollution (such that the next higher unit of emission reduction would cost more to achieve than its value in reduced damages). More commonly, the social cost of carbon is used as part of the calculation of benefits of emission-reducing measures.

In this report: The U.S. federal government's internal carbon price for use in policy making is estimated as the social cost of carbon.

4. FEDERAL CLIMATE ACTION IS INCREASINGLY LIKELY

In the near term, comprehensive federal climate legislation appears unlikely to come out of a divided Congress. The Executive Branch, however, is moving forward with regulatory actions to limit greenhouse gas emissions. Following a directive issued by President Obama, EPA released revised CO_2 performance standards for new power plants on September 20, 2013.[5] In June 2013, President Obama also instructed EPA to use its Clean Air Act authority to propose CO_2 standards for existing power plants by June 2014 and to finalize these standards by June 2015.[6] While this report is focused on electric sector CO_2 policies, similar regulatory measures have been proposed for the transportation, buildings, and industrial sectors; policies enacted in other sectors include vehicle efficiency standards set to rise to 54.5 miles per gallon by 2025 for new cars and light-duty trucks, and new energy efficiency standards for federal buildings set to reduce energy consumption by nearly 20 percent.[7,8]

We continue to expect that a federal cap-and-trade program for greenhouse gases is the most likely policy outcome in the long term, because it permits reductions to come from sources that can mitigate emissions at the lower cost. While state and regional policies combined with federal regulatory actions appear to be more likely than a federal cap-and-trade policy in the near term, according to a WRI analysis these local measures are unlikely to be able to meet long-term goals of reducing total greenhouse gas emissions to 83 percent below 2005 levels by 2050, even in the most aggressive of scenarios.[9]

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[5] EPA. "2013 Proposed Carbon Pollution Standard for New Power Plants." Available at: http://www2.epa.gov/carbon-pollution-standards/2013-proposed-carbon-pollution-standard-new-power-plants.

[6] Memorandum from President Obama to Administrator of the Environmental Protection Agency, Power Sector Carbon Pollution Standards (June 25, 2013). Available at: http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.

[7] Vlasic, Bill. "US Sets Higher Fuel Efficiency Standards." *The New York Times*. August 28th, 2012. Available at: http://www.nytimes.com/2012/08/29/business/energy-environment/obama-unveils-tighter-fuel-efficiency-standards.html.

[8] "Energy Efficiency Design Standards for New Federal Commercial and Multi-Family High-Rise Residential Buildings." A Rule by the Department of Energy. July 9th, 2013. Available at: https://www.federalregister.gov/articles/2013/07/09/2013-16297/energy-efficiency-design-standards-for-new-federal-commercial-and-multi-family-high-rise-residential#h-9.

[9] See WRI's analysis of these scenarios in the 2013 report "Can the U.S. Get There From Here?: Using Existing Federal Laws and State Action to Reduce Greenhouse Gas Emissions." Available at: http://www.wri.org/publication/can-us-get-there-from-here.

4.1. Regulatory Measures for Reducing Greenhouse Gas Emissions

Clean Air Act

As a result of the 2007 Supreme Court finding in *Massachusetts v. EPA*, greenhouse gas emissions were determined to be subject to the Clean Air Act and (in a later ruling) to contribute to air pollution anticipated to endanger public health and welfare. In 2009, EPA issued an "endangerment finding," obligating the agency to regulate emissions of greenhouse gases from stationary sources such as power plants.[10] EPA released draft New Source Performance Standards (NSPS) in April 2012 and revised NSPS standards on September 20, 2013. The revised standards limit CO_2 emissions from new fossil-fuel power plants to 1,000-1,100 pounds of CO_2 per MWh (lbs/MWh)—a level achievable by a new natural gas combined-cycle plant. The exact limit of CO_2 emissions within that range depend on the type of plant and period over which the emission rate would be averaged.[11]

Under Section 111(d) of the Clean Air Act, the EPA is required to propose standards for existing power plants by June 2014, but there remains substantial uncertainty over what form these regulations will take. Unit-specific emission rates standards, such as the NSPS for greenhouse gases, are only one of several plausible options. Unit-specific standards could apply to power plants based on categories by fuel type and technology type, each with its own maximum emission rate. Units that are not in compliance could undertake upgrades to improve efficiency; however, these kinds of upgrades can be expensive, can only achieve small, one-time changes to emission rates, and could trigger New Source Review/Prevention of Significant Deterioration (NSR/PSD) provisions, increasing the cost further.[12,13]

Other regulatory design options for existing plants under 111(d) include maintaining a state-wide average maximum emission rate, and market-based (e.g. cap-and-trade) approaches. More flexible mechanisms like these could lower the cost of compliance, but could also result in additional legal challenges as compared to a simpler but more rigid system of unit-specific regulation.[14] An Edison Electric Institute white paper on potential regulation of existing sources notes that "because of concerns about legal challenges to the guidelines, EPA may be reluctant to incorporate a wide range of

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[10] EPA. "Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act." Available at: http://www.epa.gov/climatechange/endangerment/.

[11] EPA. "Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units." Available at: http://www2.epa.gov/sites/production/files/2013-09/documents/20130920proposal.pdf.

[12] EEI. "Existing Source GHGH NSPS White Paper," Page 5. Available at: http://online.wsj.com/public/resources/documents/carbon04232013.pdf.

[13] Tarr J., Monast J., Profeta T. "Regulating Carbon Dioxide under Section 111(d) of the Clean Air Act." The Nicholas Institute. January 2013. Available at: http://nicholasinstitute.duke.edu/sites/default/files/publications/ni_r_13-01.pdf.

[14] Fine, Steven and MacCracken, Chris. "President Obama's Climate Action Plan: What It Could Mean to the Power Sector." ICF International. August 2013. Available at: http://www.icfi.com/insights/white-papers/2013/president-obama-climate-action-plan.

compliance flexibility mechanisms in the guidelines, but may be more receptive to such mechanisms if proposed by the states in compliance plans."[15]

End-use energy efficiency may be an important part of a comprehensive compliance strategy in a regulation that averages emission rates across states. States may be able to achieve emissions reductions at a lower cost through the structures of their existing energy efficiency resource standards.

Methods for demonstrating compliance with 111(d) may be similar to existing regulations: in a process similar to Section 110 of the Clean Air Act, under which EPA sets National Ambient Air Quality Standards (NAAQS), states will be required to submit State Implementation Plans (SIPs) that specify how they intend to comply with 111(d). EPA can then decide whether a proposed SIP meets the terms of the regulation; in the absence of an acceptable SIP, EPA can impose a Federal Implementation Plan (FIP). Under the schedule outlined by President Obama in his Climate Action Plan, regulations for existing sources under 111(d) will be finalized by June 2015, and states would be required to submit SIPs to the EPA by June 2016.

Performance standards for new and existing sources will affect decisions made by utilities regarding operation, expansion, and retirements. Enforcement of the Clean Air Act creates an opportunity cost of greenhouse gas abatement: prudent utilities will take Clean Air Act compliance into consideration in their planning, either explicitly as a maximum allowable emissions rate, or implicitly as an effective carbon price. An NRDC analysis of the impacts of 111(d) implementation estimated compliance costs under this policy at \$7.53 per ton of CO_2 avoided.[16]

Other regulatory measures put economic pressure on carbon-intensive power plants

A suite of current and proposed EPA regulations require pollution-intensive power plants to install environmental controls for compliance. The cost of complying with environmental regulations reduces the profitability of the worst polluters, sometime rendering them uneconomic. These policies demonstrate momentum towards appropriately regulating or pricing environmentally harmful activities in the electric sector. To the extent that plants with high emissions of other pollutants also have high carbon emissions, these policies would tend to *lower* the future CO_2 price necessary to achieve a given reduction; as more pollution-intensive plants retire in response to other EPA regulations, the necessary carbon price is reduced. Specific regulatory measures include:

- *National Ambient Air Quality Standards (NAAQS)* set maximum air quality limitations that must be met at all locations across the nation. EPA has established NAAQS for six pollutants: sulfur dioxide (SO_2), nitrogen dioxides (NO_2), carbon monoxide (CO), ozone, particulate matter—measured as particulate matter less than or equal to 10

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[15] Edison Electric Institute. "Existing Source GHG NSPS White Paper," Page 2. Available at: http://online.wsj.com/public/resources/documents/carbon04232013.pdf.

[16] Natural Resources Defense Council. "Closing the Power Plant Carbon Pollution Loophole: Smart Ways the Clean Air Act Can Clean Up America's Biggest Climate Polluters," March 2013. Available at: http://www.nrdc.org/air/pollution-standards/files/pollution-standards-report.pdf.

micrometers in diameter (PM10) and particulate matter less than or equal to 2.5 micrometers in diameter (PM2.5)—and lead.

- *The Cross State Air Pollution Rule (CSAPR)*, finalized in 2011, establishes the obligations of each affected state to reduce emissions of NO_x and SO_2 that significantly contribute to another state's PM2.5 and ozone non-attainment problems. CSAPR was vacated by the U.S. Court of Appeals for the District of Columbia on August 21, 2012. In June 2013, the U.S. Supreme Court announced that it would review CSAPR. Even if EPA fails to salvage CSAPR through the courts, the Agency must still promulgate a replacement rule to implement Clean Air Act requirements to address the transport of air pollution across state boundaries. In the meantime, the court left the requirements of the 2005 Clean Air Interstate Rule in place.
- *Mercury and Air Toxics Standards (MATS)*: The final MATS rule, approved in December 2011, sets stack emissions limits for mercury, other metal toxins, organic and inorganic hazardous air pollutants, and acid gasses. Compliance with MATS is required by 2015, with a potential extension to 2016. Many utilities have already committed to capital improvements at their coal plants to comply with the standard.
- *Coal Combustion Residuals (CCR) Disposal Rule:* On June 21, 2010, EPA proposed to regulate CCR for the first time either as a Subtitle C hazardous waste or Subtitle D solid waste under the Resource Conservation and Recovery Act. Under a Subtitle C designation, the EPA would regulate siting, liners, run-on and run-off controls, groundwater monitoring, fugitive dust controls, and any corrective actions required. In addition, the EPA would implement minimum requirements for dam safety at impoundments. Under a solid waste Subtitle D designation, the EPA would require minimum siting and construction standards for new coal ash ponds, compel existing unlined impoundments to install liners, and require standards for long-term stability and closure care.
- *Steam Electric Effluent Limitation Guidelines (ELGs):* On June 7, 2013, EPA released eight regulatory options for new, proposed steam-electric ELGs to reduce or eliminate the release of toxins into U.S. waterways. A final rule is required by May 22, 2014.[17] New requirements will be implemented in 2014 to 2019 through the five-year National Pollutant Discharge Elimination System permit cycle.[18]

Other regulations which may raise costs for carbon-intensive resources include Regional Haze rules and cooling water rules under the Clean Water Act.

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[17] See U.S. Environmental Protection Agency website. Accessed February 21, 2013. Available at: http://water.epa.gov/scitech/wastetech/guide/steam-electric/amendment.cfm.

[18] See U.S. Environmental Protection Agency. Steam Electric ELG Rulemaking. UMRA and Federalism Implications: Consultation Meeting. October 11, 2011. http://water.epa.gov/scitech/wastetech/guide/upload/Steam-Electric-ELG-Rulemaking-UMRA-and-Federalism-Implications-Consultation-Meeting-Presentation.pdf.

4.2. Proposed Cap-and-Trade Legislation

Over the past decade, there have been several Congressional proposals to legislate cap-and-trade programs, with the goal of reducing greenhouse gas emissions by up to 83 percent below recent levels by 2050 through a federal cap. Such programs would allow trading of allowances to promote least-cost reductions in greenhouse gas emissions.

Comprehensive climate legislation was passed by the House in the 111th Congress: the American Clean Energy and Security Act of 2009, also known as Waxman-Markey or H.R. 2454. However, the Senate did not vote on either of the two climate bills before it in that session (Kerry-Lieberman APA 2010 and Cantwell-Collins S. 2877). Waxman-Markey was a cap-and-trade program that would have required a 17 percent reduction in emissions from 2005 levels by 2020, and an 83 percent reduction by 2050.[19] Further analysis of these proposals is provided in Synapse's 2012 Carbon Dioxide Price Forecast.

Congressional interest in climate policy has been ongoing. In March 2012, Senator Bingaman introduced the Clean Energy Standard Act of 2012 (S. 2146), which would have required larger utilities to meet a percentage of their sales with electric generation from sources that produce less greenhouse gas emissions than a conventional coal-fired power plant. Credits generated by these clean technologies would have been tradable with a market price. In February 2013, Senators Sanders and Boxer introduced new comprehensive climate change legislation, the Climate Protection Act of 2013. This bill proposed a carbon fee of $20 per ton of CO_2 or CO_2 equivalent content of methane, rising at 5.6 percent per year over a ten-year period. The bill has not yet been brought to a vote.

We expect that federal cap-and-trade legislation will eventually be enacted but that it is unlikely to happen in the near term. In contrast, federal carbon regulations are in effect or under development today, and the economic pressure—or opportunity cost—that they create may be represented as an effective price of greenhouse gas emissions. Regulatory measures may be successful in achieving near-term targets of 17 percent below 2005 levels by 2020, but according to a WRI analysis are unlikely to meet long-term goals of reducing total greenhouse gas emissions to approximately 80 percent below 2005 levels by 2050, even in the most aggressive of scenarios.[20] A broader approach will be increasingly attractive in order to meet these goals at lower costs, and our judgment indicates this is most likely to take the form of a federal cap-and-trade system.

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[19] U.S. Energy Information Administration (EIA); Energy Market and Economic Impacts of the American Power Act of 2010 (July 2010). Available at http://www.eia.gov/oiaf/servicerpt/kgl/index.html. EIA; Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009 (August 2009). Available at http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html.

[20] See WRI's analysis of these scenarios in their 2013 report "Can the U.S. Get There From Here?: Using Existing Federal Laws and State Action to Reduce Greenhouse Gas Emissions." Available at: http://www.wri.org/publication/can-us-get-there-from-here.

5. STATE AND REGIONAL CLIMATE POLICIES

Since the October 2012 release of our 2012 CO_2 price forecasts, there have been significant updates to the two existing regional and state cap-and-trade programs, the Northeast's RGGI and California's Cap-and-Trade Program under AB32. In addition, a total of 20 states plus the District of Columbia have set greenhouse gas emissions targets as low as 80 percent below 1990 levels by 2050.[21]

Recent Revisions to RGGI

RGGI is a cap-and-trade greenhouse gas program for power plants in the northeastern United States. Current participant states are Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. Pennsylvania, Québec, New Brunswick, and Ontario are official "observers" in the RGGI process. RGGI recently marked five years of successful CO_2 allowance auctions, with Auction 21 resulting in a clearing price of $2.67 per ton.[22] RGGI is designed to reduce electricity sector CO_2 emissions to at least 45 percent below 2005 levels by 2020.[23]

When RGGI was established in 2007, the expectation was that the CO_2 emissions allowance auction would generate revenues for consumer benefit programs such as energy efficiency, renewable energy, and clean energy technologies. While RGGI has provided significant revenues for consumer benefit, its allowance prices have generally remained near the statutory minimum price. External influences, including changes to fuel prices, caused a shift from coal and oil to lower-carbon natural gas generation. Compared to those external factors, the effect of the original RGGI cap requirements were relatively minor in meeting the goals of reducing CO_2 emissions in the power sector.[24]

In 2012 and 2013, the RGGI states evaluated a number of plans for tighter emissions caps with the goal of raising allowance prices. In February of 2013, participating states agreed to lower the CO_2 cap from 165 million to 91 million short tons in 2014, to be reduced by 2.5 percent each year from 2015 to 2020. RGGI analysis indicates that with these lower caps, allowance prices will rise to $4.16 per short ton in 2014, increasing to $10.40 per ton in 2020.[24]

California's Cap-and Trade-Program under AB32

With the goal of reducing the state's emissions to 1990 levels by 2020, California's Global Warming Solutions Act (AB32) has created the world's second largest carbon market, after the European Union's

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[21] "Greenhouse Gas Emissions Targets." Center for Climate and Energy Solutions. Accessed September 13, 2013. Available at: http://www.c2es.org/us-states-regions/policy-maps/emissions-targets.

[22] RGGI Auction 21 results available at: http://www.rggi.org/market/co2_auctions/results/Auction-21

[23] RGGI. "RGGI States Propose Lowering Regional CO_2 Emission Cap 45%, Implementing a More Flexible Cost-Control Mechanism." February 2013. Available at: http://www.rggi.org/docs/PressReleases/PR130207_ModelRule.pdf.

[24] Environment Northeast. "RGGI at One Year: An Evaluation of the Design and Implementation of the Regional Greenhouse Gas Initiative." February 2010. Available at: http://www.env-ne.org/public/resources/pdf/ENE_2009_RGGI_Evaluation_20100223_FINAL.pdf.

Emissions Trading System. The first compliance period for California's Cap-and-Trade Program began on January 1, 2013 and covers electricity generators, CO_2 suppliers, large industrial sources, and petroleum and natural gas facilities emitting at least 27,600 tons of CO_2e per year.[25,26] On August 16, 2013, the California Air Resources Board held its fourth quarterly allowance auction, resulting in a clearing price of $11.11 per ton.[27] This first phase of the program includes electricity generators and large industrials. Phase II, beginning in 2015, will also include transportation fuels and smaller industrial sources.

6. ASSESSMENT OF CARBON PRICE FOR FEDERAL RULEMAKING

In 2010, the U.S. federal government began including a carbon cost in regulatory rulemakings to account for the climate damages resulting from each additional ton of greenhouse gas emissions;[28] updated values were released in 2013.[29] The 2013 Economic Report of the President acknowledges that these values will continue to be updated as scientific understanding improves.[30]

An Interagency Working Group on the Social Cost of Carbon—composed of members of the Department of Agriculture, Department of Commerce, Department of Energy, Environmental Protection Agency, and Department of Transportation, among others—was tasked with the development of a consistent value for the social benefits of climate change abatement. Four values were developed (see Section 3 for more explanation of the "social cost of carbon" methodology). These values--$11, $36, $55, and $101 per ton of CO_2 in 2013, rising over time— represent average (most likely) damages at three discount rates, along with one estimate at the 95th percentile of the assumed distribution of climate impacts.[31,32,33,34] While

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[25] "CO_2e" refers to CO_2-equivalent, the combination of CO_2 and an equivalent value for other greenhouse gases.

[26] CARB 2013a. "California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms to Allow for the Use of Compliance Instruments by Linked Jurisdictions." July 2013. Available at: http://www.arb.ca.gov/cc/capandtrade/ctlinkqc.pdf. Legislated value is 25,000 metric tons, converted here to short tons.

[27] CARB 2013b. "CARB Quarterly Auction 4, August 2013: Summary Results Report." August 21, 2013. Available at: http://www.arb.ca.gov/cc/capandtrade/auction/august-2013/results.pdf.

[28] Interagency Working Group on the Social Cost of Carbon, U. S. G. (2010). Appendix 15a. Social cost of carbon for regulatory impact analysis under Executive Order 12866. In Final Rule Technical Support Document (TSD): Energy Efficiency Program for Commercial and Industrial Equipment: Small Electric Motors. U.S. Department of Energy. URL http://go.usa.gov/3fH.

[29] Interagency Working Group on the Social Cost of Carbon (2013) Technical Support Document – Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866. Available at: http://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf.

[30] 2013 Economic Report of the President (2013). Chapter 6. March 2013. Available at: http://www.whitehouse.gov/sites/default/files/docs/erp2013/ERP2013_Chapter_6.pdf.

[31] These values represent recently revised costs for the SCC. Originally, these values were $5, $21, $35, and $65 per metric tonne for the year 2010 in 2007 dollars.

[32] In a 2012 paper, Ackerman and Stanton modified the Interagency Working Group's assumptions regarding uncertainty in the sensitivity of temperature change to emissions, the expected level of damages at low and high greenhouse gas concentrations, and the assumed discount rate, and found values for the social cost of carbon ranging from the Working Group's level up to more than an order of magnitude greater. Similarly, Laurie Johnson and Chris Hope modified discount rates and methodologies and found results up to twelve times larger than the Working Group's central estimate.

subject to significant uncertainty, this multi-agency effort represents an initial attempt at incorporating the benefits associated with CO_2 abatement into federal policy.

As of May 2012, these estimates had been used in at least 20 federal government rulemakings, for policies including fuel economy standards, industrial equipment efficiency, lighting standards, and air quality rules.[35, 36] In the first rule in which the revised 2013 values were used—improving energy efficiency in microwave ovens—the net present value of benefits over a 30-year timeframe increased by $400 million as a result of the increase in effective carbon price.[37] While a carbon price for federal rulemaking assessments is a fundamentally different kind of cost metric than the others discussed in this report, it nonetheless represents a dollar value for greenhouse gas emissions currently in use by the U.S. federal government.

7. RECENT CO_2 PRICE FORECASTS FROM THE RESEARCH COMMUNITY

The Energy Modeling Forum (EMF), a working group of government and private modeling teams, has been convening to explore energy system issues since the late 1970s. The group recently completed its EMF 24 analysis with the objective of evaluating what CO_2 price trajectories are consistent with proposed emission reduction targets under different technology scenarios. This analysis also incorporated several complementary policies in a cap-and-trade proposal, including: transportation emissions reduction through vehicle gas mileage standards; renewable portfolio standards in the electric sector; and mandates that all new coal facilities employ carbon capture and storage (CCS) technology—a

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[33] Frank Ackerman and Elizabeth A. Stanton (2012). "Climate Risks and Carbon Prices: Revising the Social Cost of Carbon." *Economics: The Open-Access, Open-Assessment E-Journal*, Vol. 6, 2012-10. http://dx.doi.org/10.5018/economics-ejournal.ja.2012-10.

[34] Laurie T. Johnson, Chris Hope. "The social cost of carbon in U.S. regulatory impact analyses: an introduction and critique." *Journal of Environmental Studies and Sciences*, 2012; DOI: 10.1007/s13412-012-0087-7.

[35] Robert E. Kopp and Bryan K. Mignone (2012). "The U.S. Government's Social Cost of Carbon Estimates after Their First Two Years: Pathways for Improvement." Economics: The Open-Access, Open-Assessment E-Journal, Vol. 6, 2012-15. http://dx.doi.org/10.5018/economics-ejournal.ja.2012-15.

[36] See, for example, "Rulemaking for Microwave Ovens Energy Conservation Standard: Technical Support Document." May 2013. Available at: http://www1.eere.energy.gov/buildings/appliance_standards/rulemaking.aspx/ruleid/37

[37] Brad Blumer (2013). "The social cost of carbon is on the rise." The Washington Post, June 6th, 2013. Available at: http://articles.washingtonpost.com/2013-06-06/business/39789409_1_carbon-dioxide-emissions-obama-administration.

policy similar to EPA's proposed NSPS for coal plants. Nine modeling teams participated in this study.[38,39]

Results from the EMF 24 exercise show a range of CO_2 price trajectories depending on availability of new technologies, policy type, model baseline trajectories, and other more structural characteristics of the models. One question asked by this study that is of particular relevance to users of the Synapse CO_2 price forecast is: which economic sectors would emissions reductions come from in an economically efficient approach to emissions mitigation? Consistent with earlier EMF analyses, the electric sector was found to be the largest contributor to CO_2 emissions reductions across all models.

Under a cap-and-trade scenario designed to reduce energy system emissions 50 percent below 2005 levels by 2050, most of the EMF 24 models reduced electric sector emissions by 75 percent by 2050. Under an 80 percent emissions reduction scenario, most of the additional emissions reductions came from other sectors. Although CO_2 prices are higher under the 80 percent scenario, most electricity customers are not paying these prices, as the electricity sector is largely decarbonized before 2050.

CO_2 prices estimated by the EMF 24 models show substantial variation. While it is difficult to distinguish the roles of model structure and model assumptions in this variation, the results present a reasonable range across which prices may fall. Under the most optimistic technology assumptions, with low-cost renewables, high levels of energy efficiency, and availability of new nuclear and CCS, CO_2 prices in 2020 fell between \$10 per tCO_2 and \$40 per tCO_2. In contrast, prices fell between \$20 per tCO_2 to \$80 per tCO_2 under the most pessimistic assumptions. Complementary policies, such as renewable portfolio standards or fuel economy standards, reduce carbon prices, as indicated in Figure 1.

Universally, the models show that substantial emissions reductions are not achievable in the absence of a policy. Even in the most optimistic technology scenario, the most aggressive emissions reductions from any model in the absence of a policy was 0.19 percent per year, resulting in emissions 7 percent below 2005 levels in 2050.

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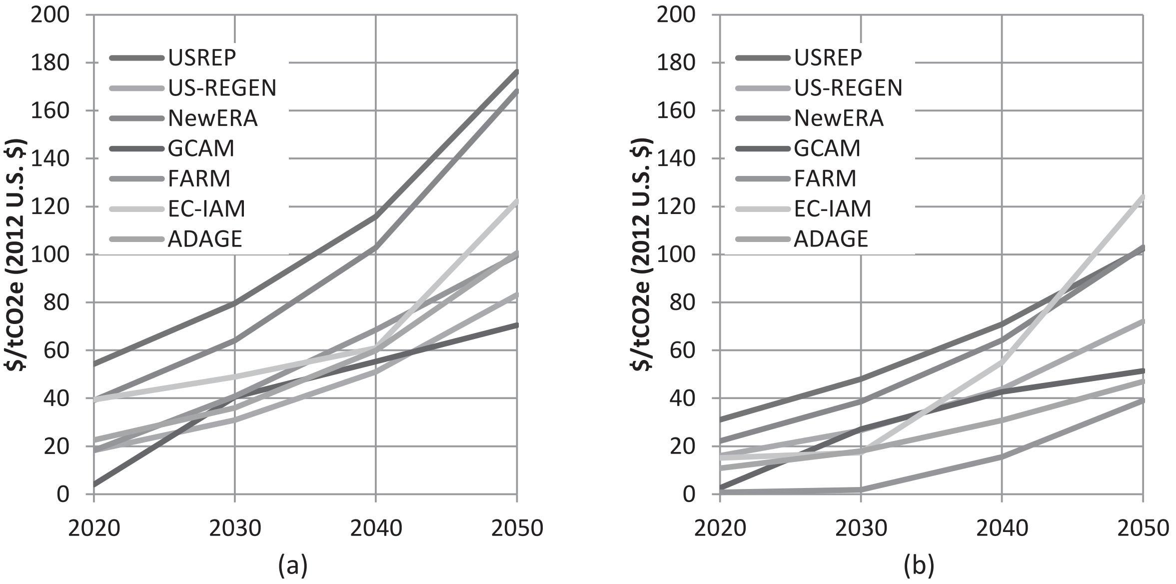
[38] Clarke, L.C., A.A. Fawcett, J.P. Weyant, V. Chaturvedi, J. MacFarland, Y. Zhou, "Technology and U.S. Emissions Reductions Goals: Results of the EMF 24 Modeling Exercise," (forthcoming). *The Energy Journal.*

[39] Fawcett, A.A., L.C. Clarke, S. Rausch, J.P. Weyant. "Overview of EMF 24 Policy Scenarios," (forthcoming). *The Energy Journal*.

Figure 1: Allowance prices from EMF study under (a) 50 percent cap-and-trade policy and with (b) the addition of several complementary policies (optimistic CCS/nuclear technology assumptions) [35,36]



(a) (b)

8. CO$_2$ PRICE FORECASTS IN UTILITY IRPS

A growing number of electric utilities include projections of the costs that will be associated with greenhouse gas emissions in their resource planning procedures. Figure 2 summarizes the reference case values (often described as their “mid” or “central” values) of publicly available forecasts used by utilities in resource planning over the past two years.[40]

Despite ongoing obstacles to a federally legislated CO$_2$ price and challenges in Congress to addressing climate or energy policy in a meaningful way, many utilities are including an effective price for carbon in their planning. The majority of utility reference case carbon price forecasts start in the 2015-2020 timeframe, and rise gradually (in real terms) throughout the study period.

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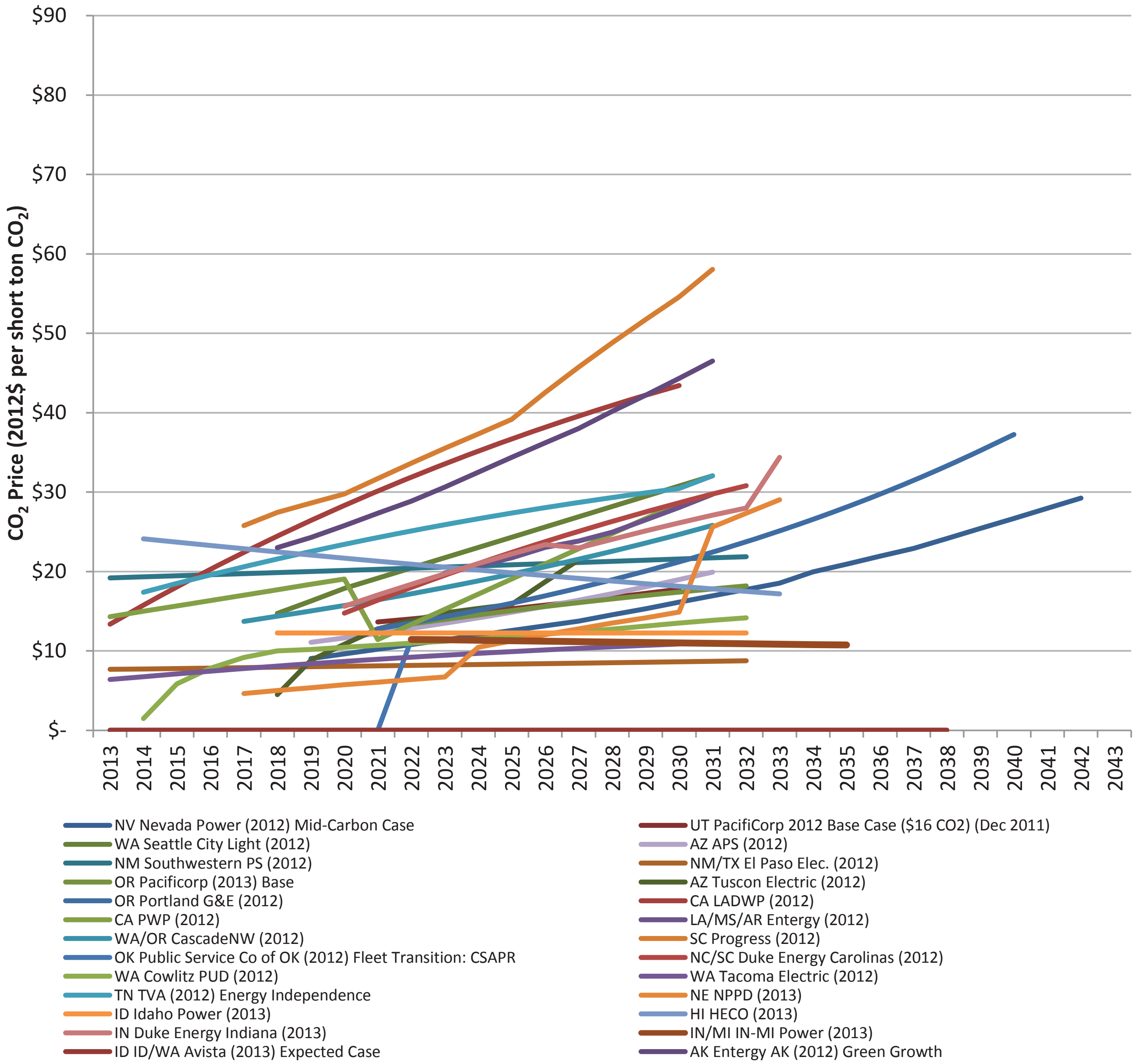
[40] Where a utility has released multiple IRP or IRP updates in the past two years, we have included only the most recent value. The IRPs shown here represent those publicly available by internet as of the October 2013.

Figure 2: Utility Reference Case Forecasts from 2012 and 2013



9. OVERVIEW OF THE EVIDENCE FOR A FUTURE CO_2 PRICE

Our CO_2 price forecasts are developed based on the data sources and information presented above and reflect a reasonable range of expectations regarding future efforts to limit greenhouse gas emissions. The following items have guided the development of the Synapse forecasts:

- **Regulatory measures limiting CO_2 emissions from power plants will be implemented in the near term**. The EPA is required to propose emissions standards for existing power plants under Section 111(d) of the Clean Air Act by June 2014. Standards for new power plants were proposed on September 20, 2013. These actions represent an effective price that will affect utility planning and operational decisions.

- **State and regional action limiting CO_2 is ongoing and growing more stringent**. In the Northeast, the RGGI CO_2 cap has been tightened, resulting in higher CO_2 prices for electric generators in the region. California's Cap-and-Trade Program, which represents an even larger carbon market than RGGI, has held many successful allowance auctions, and has been successfully defended against numerous legal challenges.

- **A price for CO_2 is already being factored into federal rulemakings.** The federal government has demonstrated a commitment to considering the benefits of CO_2 abatement in rulemakings such as fuel economy and appliance standards.

- **Ongoing analysis of emissions caps suggests a wide range of possible prices.** Important factors include the stringency of any future climate policy, the existence of complementary policies, technology availability, and how quickly old capital stock can be phased out in favor of new technologies.

- **Electric suppliers continue to account for the opportunity cost of CO_2 abatement in their resource planning.** Prudent planning requires utilities to consider adequately the potential for future policies. The range of carbon prices reported in section 8 indicates that many utilities believe that by 2020 there will likely be significant economic pressure towards low-carbon electric generation.

10. SYNAPSE 2013 CO_2 PRICE FORECAST

Based on analyses of the sources described in sections 3 through 8 (above), and relying on our own expert judgment, Synapse has developed Low, Mid, and High case forecasts for CO_2 prices from 2013 to 2040. Figure 3 and Table 1 show the Synapse forecasts over this period.

Figure 3: Synapse 2013 CO_2 Price Trajectories

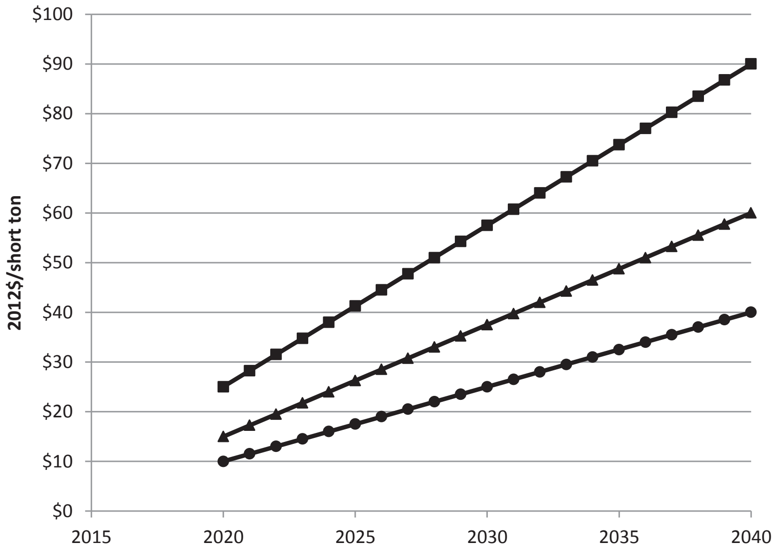


Table 1: Synapse 2013 CO_2 Allowance Price Projections (2012 dollars per ton CO_2)

Year	Low Case	Mid Case	High Case
2020	$10.00	$15.00	$25.00
2021	$11.50	$17.25	$28.25
2022	$13.00	$19.50	$31.50
2023	$14.50	$21.75	$34.75
2024	$16.00	$24.00	$38.00
2025	$17.50	$26.25	$41.25
2026	$19.00	$28.50	$44.50
2027	$20.50	$30.75	$47.75
2028	$22.00	$33.00	$51.00
2029	$23.50	$35.25	$54.25
2030	$25.00	$37.50	$57.50
2031	$26.50	$39.75	$60.75
2032	$28.00	$42.00	$64.00
2033	$29.50	$44.25	$67.25
2034	$31.00	$46.50	$70.50
2035	$32.50	$48.75	$73.75
2036	$34.00	$51.00	$77.00
2037	$35.50	$53.25	$80.25
2038	$37.00	$55.50	$83.50
2039	$38.50	$57.75	$86.75
2040	$40.00	$60.00	$90.00
Levelized 2020-2040	$22.36	$33.54	$51.79

In these forecasts, state and regional policies, together with federal regulatory measures, place economic pressure on CO_2 emitting resources in the next several years, such that it is relatively more expensive to operate a high-carbon-emitting power plant. These pressures are followed later by a broader federal policy, such as cap and trade. In any state other than the RGGI region and California, we assume a zero carbon price through 2019; beginning in 2020, we expect that federal regulatory measures will put economic pressure on carbon-emitting power plants throughout the United States. All annual allowance prices and levelized values are reported in 2012 dollars per short ton of carbon dioxide.

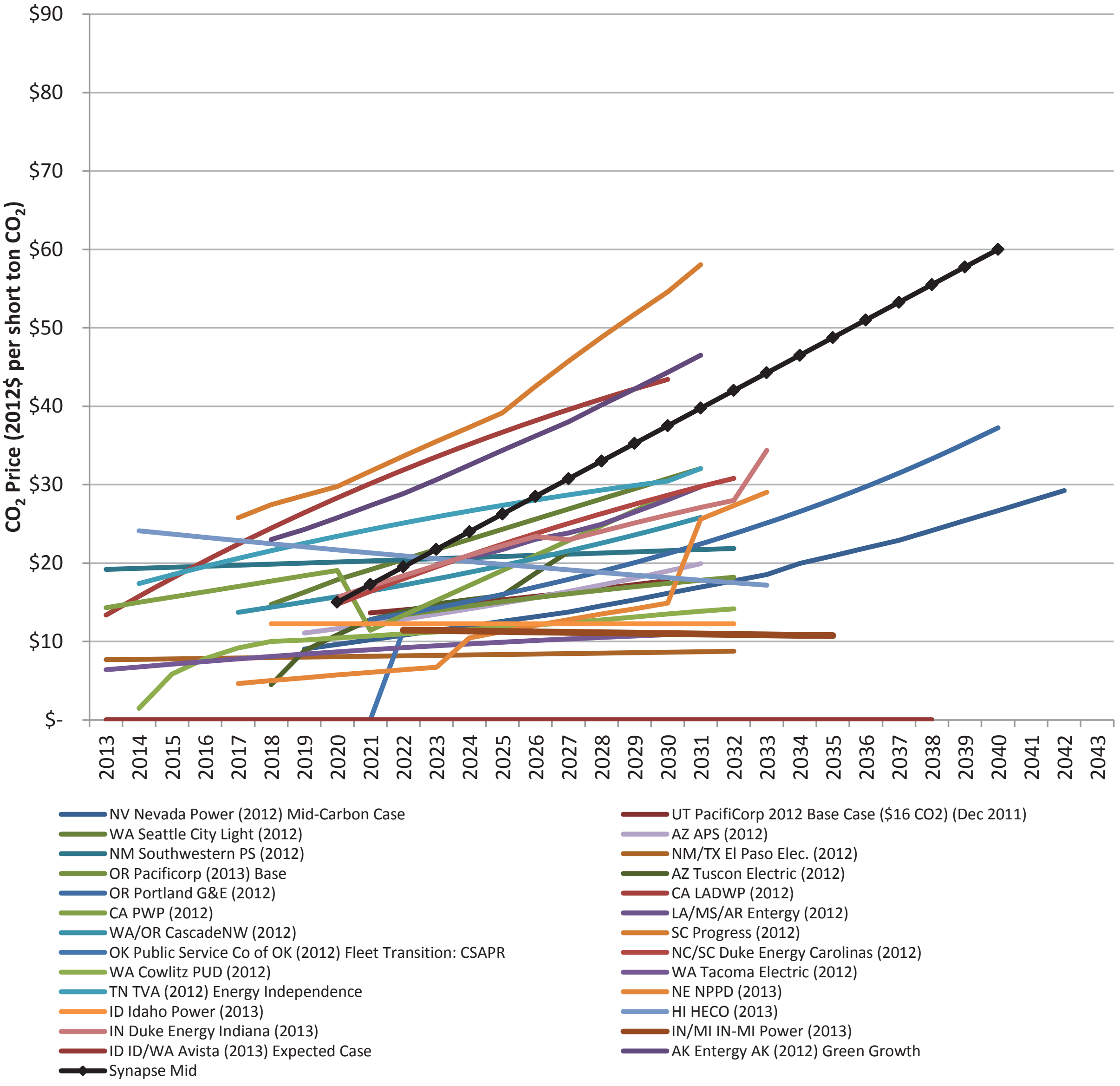
- The **Low case** forecasts a carbon price that begins in 2020 at $10 per ton, and increases to $40 per ton in 2040, representing a $22 per ton levelized price over the period 2020-2040. This forecast represents a scenario in which federal policies—either regulatory or legislative—exist but are not very stringent.
- The **Mid case** forecasts a carbon price that begins in 2020 at $15 per ton, and increases to $60 per ton in 2040, representing a $34 per ton levelized price over the period 2020-2040. This forecast represents a scenario in which federal policies are implemented with significant but reasonably achievable goals.
- The **High case** forecasts a carbon price that begins in 2020 at $25 per ton, and increases to approximately $90 per ton in 2040, representing a $52 per ton levelized price over the period 2020-2040. This forecast is consistent with the occurrence of one or more factors that have the effect of raising carbon prices. These factors include somewhat more aggressive emissions reduction targets; greater restrictions on the use of offsets; restricted availability or high cost of technology alternatives such as nuclear, biomass and carbon capture and sequestration; more

aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters); or higher baseline emissions.

These price trajectories are designed for planning purposes, so that a reasonable range of emissions costs can be used to investigate the likely costs of alternative resource plans. We expect an actual CO_2 price to fall somewhere between the low and high estimates throughout the forecast period.

In Figure 4, the Synapse Mid forecast is shown in comparison to the reference case utility forecasts presented earlier. See Appendix A for comparisons to utilities' Low and High case forecasts.

Figure 4: Synapse Mid Forecast Compared to Recent Utility Mid Case Forecasts



In Figure 5, the Synapse forecasts are compared to the carbon price used in federal rulemaking. While the federal price starts out higher in 2020, the Synapse Mid forecast approaches this value at the end of the projected period. In Figure 6, the Synapse forecasts for 2020 are compared to several of the sources identified in this report: the carbon price used in federal rulemakings, EMF 24 study results, and recent utility forecasts. The high and low ends of these sources span a wide range, but the central values show less variation.

Figure 5: Synapse Forecast Compared to Carbon Price Used in Federal Rulemakings

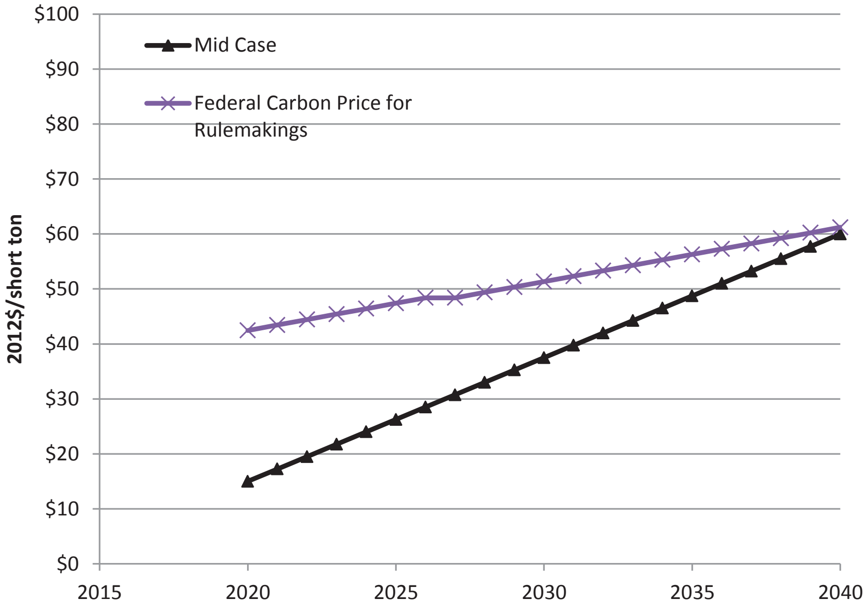
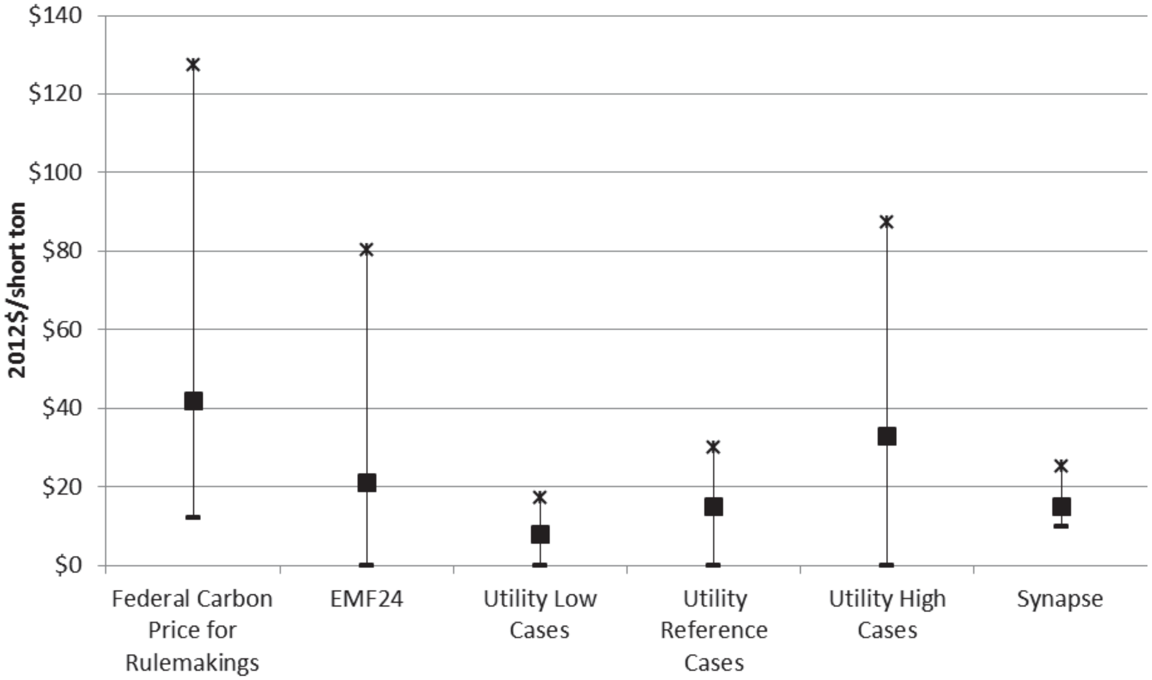


Figure 6: Synapse CO_2 Forecasts for 2020 Compared to Other Sources



APPENDIX A: SYNAPSE FORECAST COMPARED TO UTILITY FORECASTS

Figure 7: Synapse CO_2 Price Forecast Compared to Recent Utility Low-case Forecasts

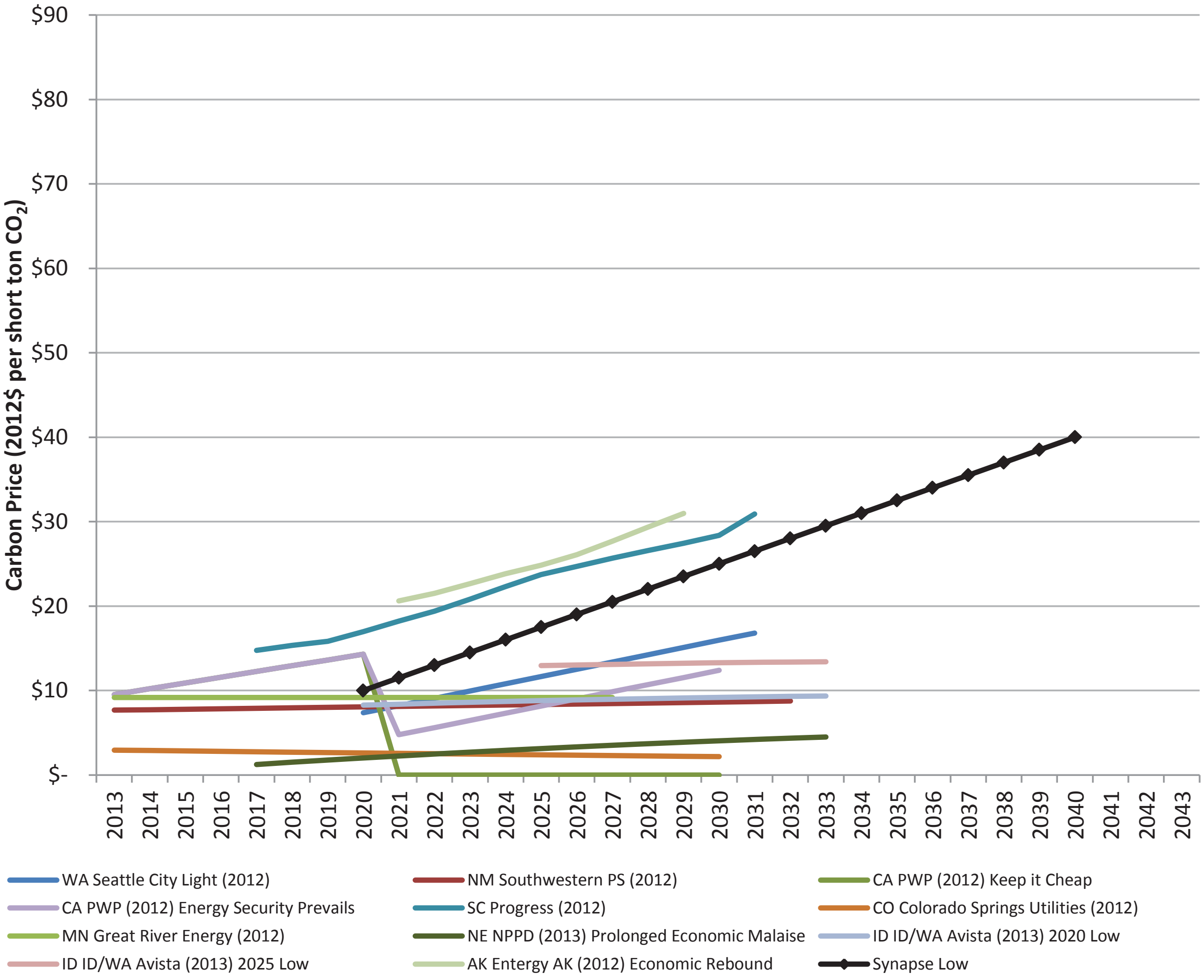
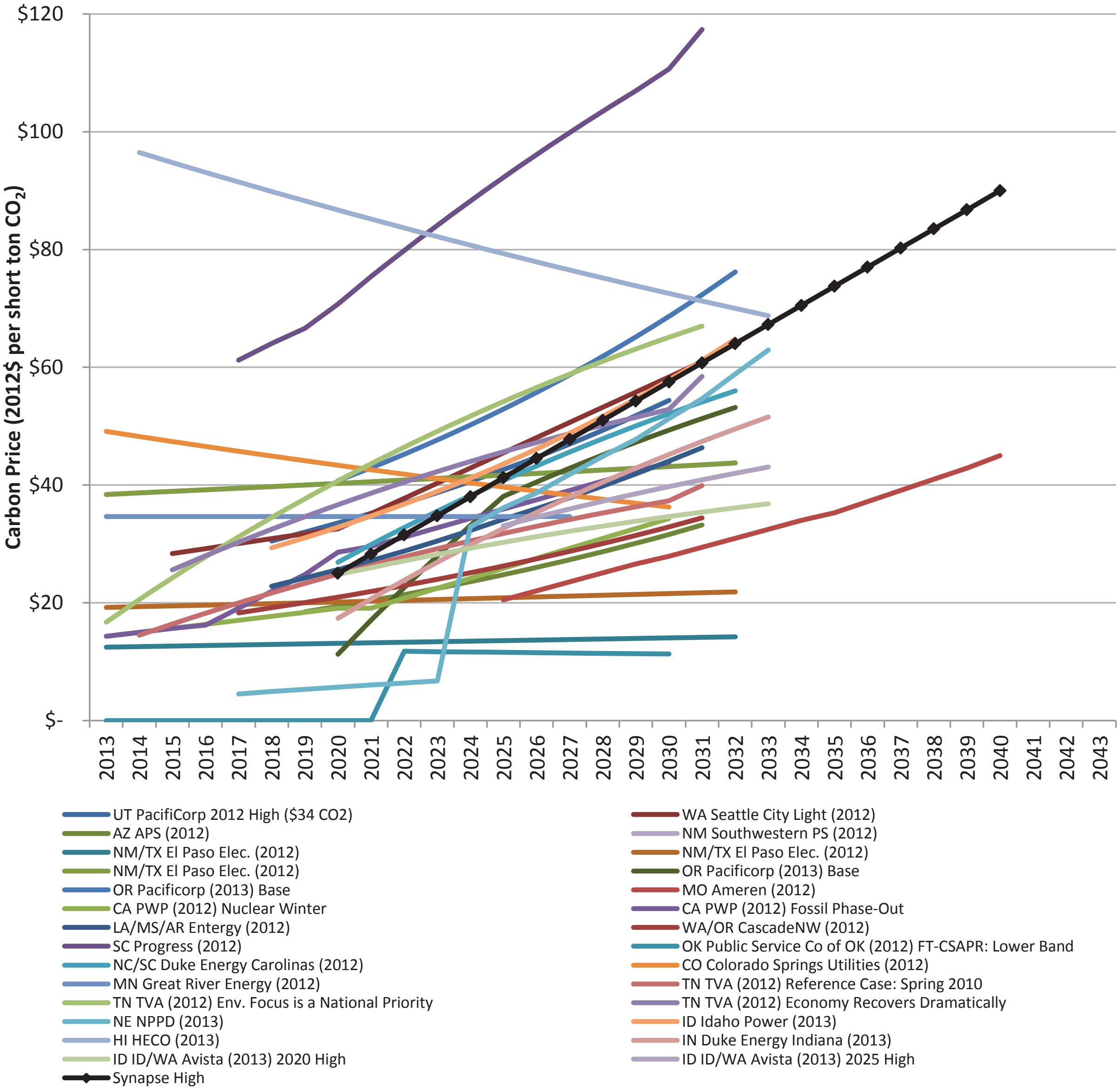


Figure 8: Synapse CO_2 Price Forecast Compared to Recent Utility High-case Forecasts



MERRICK
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TRUSTED COUNSEL. SKILLED ADVOCATES.

April 3, 2014

VIA E-MAIL – lana.myatt@nspower.ca

26872

Ms. Lana Myatt
Administrative Assistant IV – Regulatory Affairs
Nova Scotia Power
1223 Lower Water Street
Halifax, NS   B3J 3S8

Dear Ms. Myatt:

Re: M05522 – 2014 IRP Assumptions (DSM and Additional Details)

We write further to your e-mail of March 28, 2014 that enclosed Nova Scotia Power's draft Demand Side Management and Demand Response Assumptions.

The Consumer Advocate requests that NSPI provide a derivation of its estimates of the various DR option peak reductions and costs.

The Consumer Advocate also notes the significance of the discussions regarding avoided costs methodology to occur at the June technical conference.

Yours truly,

WL Mahody

William L. Mahody
Direct: (902) 429-3547
bill@mjswm.com

WLM/cw

c   All Interested Parties
205300

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April 4, 2014

Delivered by E-mail

Nicole Godbout
Regulatory Counsel
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PO Box 910
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Dear Ms. Godbout:

Re: Integrated Resource Plan (IRP) 2014 – M05522/P-884.14

We have had the opportunity to review the materials that were circulated by NSPI on March 28, 2014, which included further information on assumptions related to DSM and Demand Reduction (DR), as well as responses to questions raised by various parties, including the Industrial Group. We offer these comments now and, after Monday when the ENSC legislation is made public, will consider whether further comments are warranted.

DSM AND DR ASSUMPTIONS – LEVELS AND COST

DSM Potential

At page 2 of the materials, NSPI proposed to model a range of DSM Potential. The Industrial Group notes that the ENSC/Navigant DSM Potential Study (January 2014) provided for Technical Potential, Economic Potential and Achievable Potential results. We would expect that NSPI would use the Achievable Potential results for the IRP, but this is not clear within the materials that were provided.

NSPI intends to develop models with the High and Low cases from the DSM Potential Study and an option that is 50% of the Low case. It is noted that the DSM Potential Study High scenario is set at twice the Base incentive and that the Low scenario is set at half of the Base. The model using 50% of the Low case would be 25% of the Base year.

The Industrial Group is unclear why NSPI would not have included the Base year in the levels of DSM Potential to be modeled. Without the Base year NSPI would be modeling extreme ends of DSM potential without modeling the average or expected Potential. We would suggest that NSPI include the Base case from the ENSC/Navigent DSM Potential Study in the DSM levels to be modeled in the IRP.

DR Programs

While we appreciate the additional materials related to DR programs, the Industrial Group notes that the slides provided are not sufficiently detailed for stakeholders to understand and analyze the proposed Demand Reduction Projects and how these will be incorporated into the IRP. Although we understand that NSPI intends to provide more detail at the June technical conference, this will be too late for stakeholders provide feedback that will shape the IRP assumptions.

In order to be able to provide meaningful input, the Industrial Group requests that NSPI provide more detailed information about the DR programs, including the rationale for the programs, the methodology that the programs will follow and the ways by which the programs will be measured. Also, the Industrial Group requests that NSPI provide information with respect to the full range of Demand Reduction Programs that are or could be made available in this jurisdiction including programs for commercial, residential and industrial customers.

RESPONSES TO INDUSTRIAL GROUP REQUESTS

PIRA Forecasts

We note that the PIRA assumptions include assumptions related to pipeline completion dates. While we believe that these are reasonable, it is not uncommon for major projects such as these to exceed planned timelines. The Industrial Group feels that it would be prudent to model the effects of a three-year delay for each of these projects. We would ask NSPI to consider whether this would impact fuel choices in the IRP.

Also, as was noted in our submissions regarding the IRP assumptions, the EIA is now using a flat oil price forecast for modeling its low case. We understand that this is not the case in the PIRA forecasts. We would request that NSPI consider the impact of a flat oil price when developing IRP models.

Carbon Tax

The PIRA Key Assumptions for the reference case for natural gas include modest carbon prices to be imposed directly or indirectly by 2020. The Industrial Group asks that NSPI confirm that the carbon prices assumed by PIRA are consistent with the carbon prices that are assumed for imported power included elsewhere in the NSPI IRP assumptions. The Industrial Group believes that it would be appropriate for these to be consistent assumptions.

PHP Load

NSPI states that it forecasts PHP’s energy requirements using the same assumption that is applied to other large industrials: “*load is assumed unchanged year over year unless supplemental information is known about a customer’s expected operating conditions.”*

Given that NSPI and PHP are in contact on a daily (if not hourly) basis regarding PHP’s energy needs, it seems unwise to simply *assume* that the PHP load will be unchanged. The Industrial Group believes that NSPI should request information from PHP as to planned operating conditions and anticipated energy needs.

PHP Line Losses

The Industrial Group notes that in other NSPI filings (such as the 2011 GRA filing), transmission losses for the PHP plant (then under NewPage) have been estimated at 2.04%. The Industrial

Group expects that NSPI would use the most current transmission losses for the IRP; further, it is expected that the PHP transmission losses assumptions are consistent with the losses that are used for calculating the incremental cost of serving PHP.

PHP Contribution to Firm Peak

The Interruptible Base and Low load cases in the IRP assumptions drop by 56 MW after 2019. NSPI explains that this is due to the removal of PHP from the forecast after 2019 and that PHP is assumed to contribute 65 MW to firm peak. It is unclear whether the assumed PHP contribution to firm peak is 56 or 65 MW.

Yours truly,

signed by:

Nancy Rubin

Nancy G. Rubin

NGR/lmc

c. IRP Participants

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SENT BY EMAIL ON April 7, 2014

April 7, 2014

Ms. Nicole Godbout
Regulatory Counsel
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ENE Comments related to the Draft DSM Assumptions for Nova Scotia Power Incorporated's 2014 Integrated Resource Plan Matter No. M05522

Dear Ms. Godbout:

ENE appreciates the opportunity to comment on Nova Scotia Power's draft *DSM and DR Assumptions – Levels and Costs* of March 28, 2014. ENE's submission is attached below.

Do not hesitate to contact me with questions.

Respectfully submitted,

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IRP 2014 Stakeholders

ENE Comments related to Nova Scotia Power's 2014 IRP – DSM Assumptions

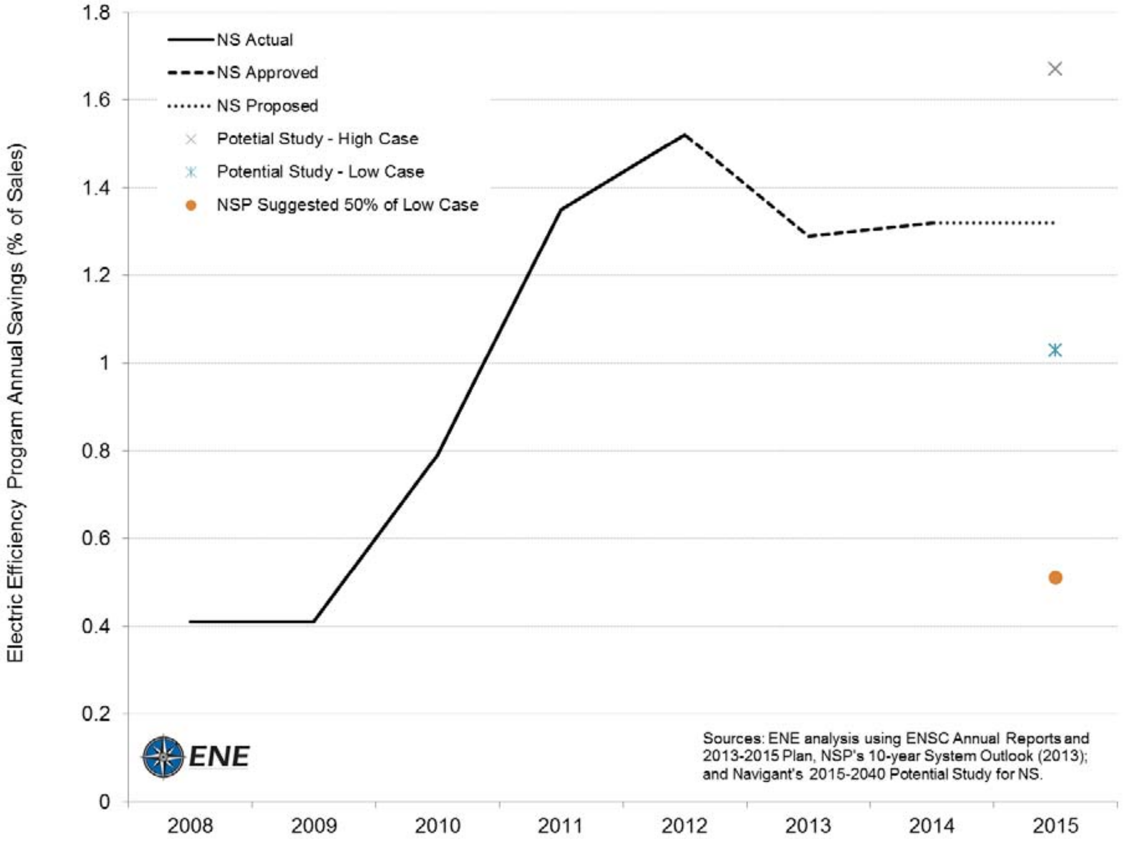
1. Proposed DSM Levels

ENE supports modeling the High and Low scenarios from the Navigant potential study. ENE strongly recommends that the Mid scenario be included as the third DSM scenario.

The 50% Low case would be a significant reduction compared to recent levels of effort, bringing the province back to approximately 2008/09 levels based on savings as a percent of 2012 sales (see Figure 1). Further, the program costs for the High, Mid, and Low scenarios were established through detailed measure characterizations and achievable potential based on different incentive levels. It is unclear how NSPI would develop first-year or levelized unit costs for the 50% Low scenario.

Typically, IRP processes seek to procure the least cost resources first to minimize utility revenue requirements and thus ratepayer costs. Savings levels in the High scenario have been deemed cost-effective by the Navigant study. While it is prudent to consider lower cost efficiency resources and levels, the 50% Low scenario sets an arbitrarily low cap on DSM that would preclude significant opportunities to bring low-cost efficiency resources into the NS system, thus reducing the efficacy of the planning process.

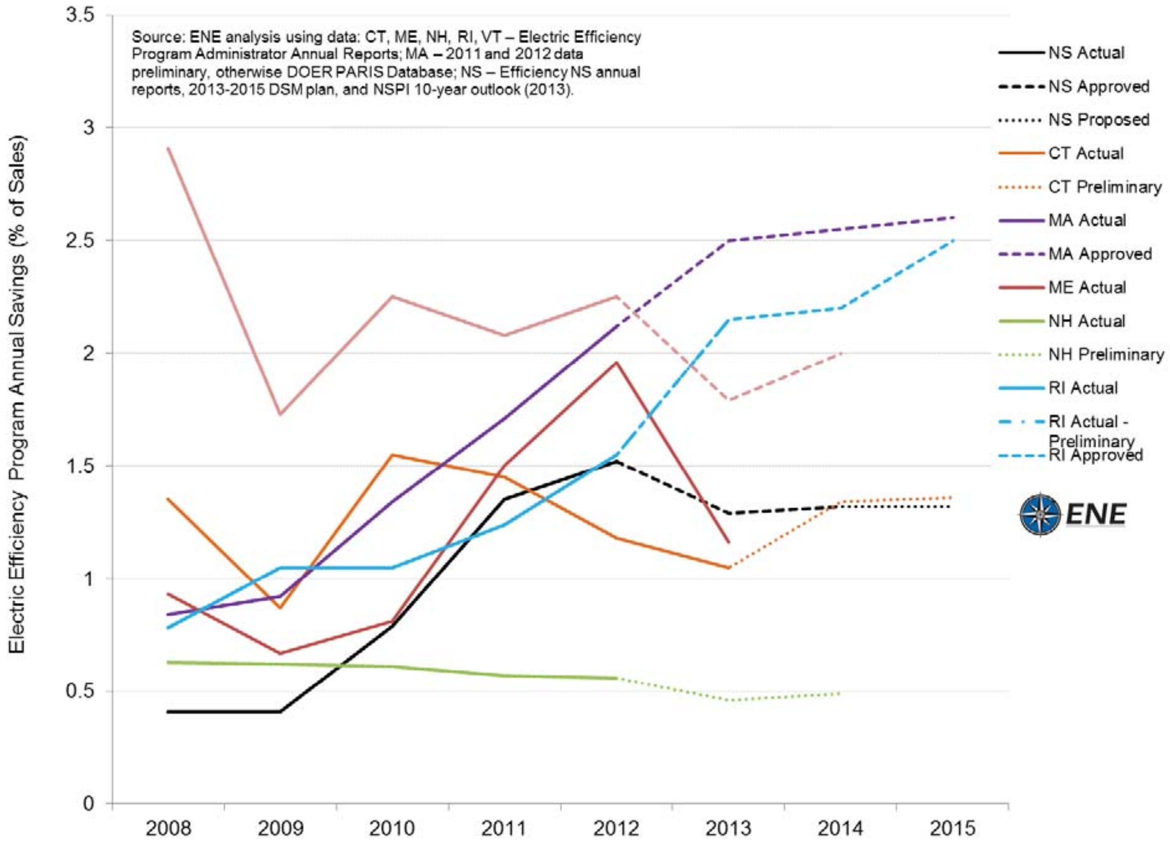
Figure 1: Nova Scotia Annual Electric Efficiency Program Savings (Actual, Approved, and Proposed) and NSPI's Suggested DSM Scenarios in 2015 – All Savings Levels as a % of 2012 Electricity Sales



Sources: ENE analysis using ENSC Annual Reports and 2013-2015 Plan, NSP's 10-year System Outlook (2013); and Navigant's 2015-2040 Potential Study for NS.

It is also worth noting that Nova Scotia was on track to be a North American leader in terms of procuring cost-effective energy efficiency (see Figure 2). In 2011 and 2012, Nova Scotia's savings levels (as a % of 2012 sales) were in-line with those of Rhode Island, which has just approved a three-year plan with annual savings targets of 2.6% by 2017 (equal to Massachusetts' 2015 target). Massachusetts is currently ranked #1 in ACEEE's 2013 assessment of energy efficiency efforts in the US. As shown by Figures 1 and 2, the 50% Low scenario would be a significant backslide compared to current efforts, and relative to leading jurisdictions.

Figure 2: Nova Scotia Annual Electric Efficiency Program Savings as a % of 2012 Sales Compared to Actual and Proposed Savings Levels in the New England States (2008-2015)



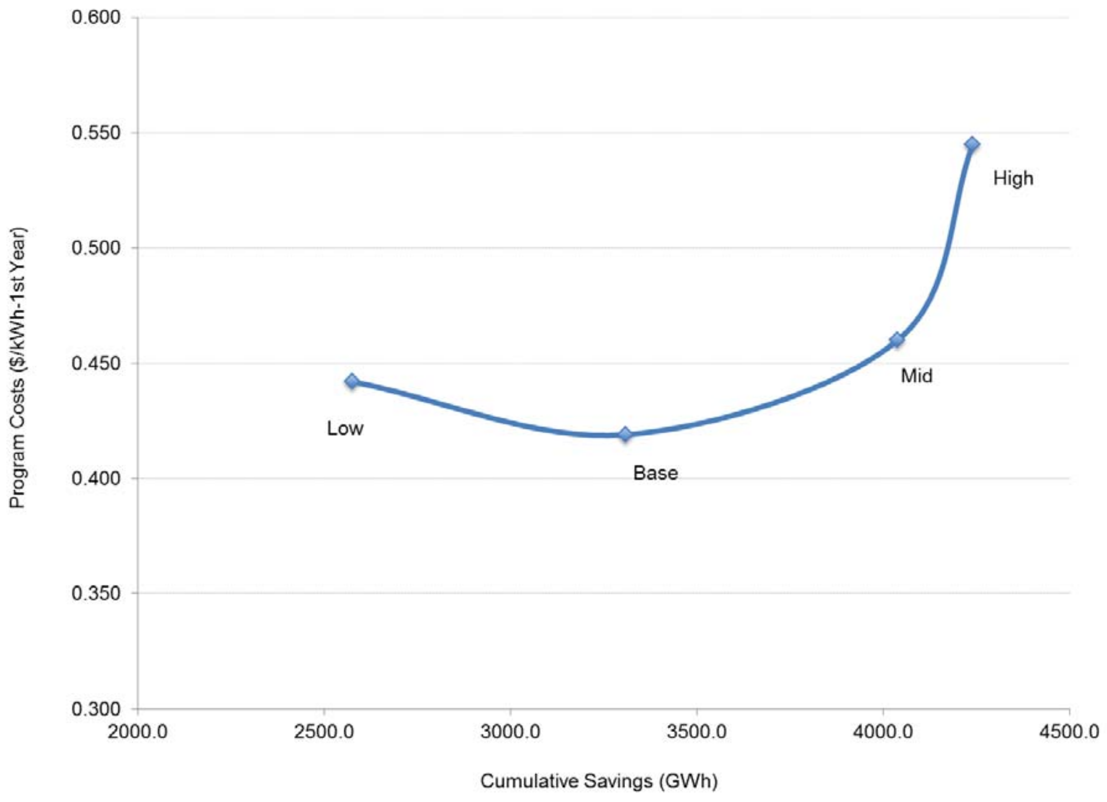
Source: ENE analysis using data: CT, ME, NH, RI, VT – Electric Efficiency Program Administrator Annual Reports; MA – 2011 and 2012 data preliminary, otherwise DOER PARIS Database; NS – Efficiency NS annual reports, 2013-2015 DSM plan, and NSPI 10-year outlook (2013).

The Mid scenario delivers almost as many cumulative savings as the High scenario at a first-year unit cost that is only slightly higher than that of the Low scenario (see Figure 3). The optimal amount of DSM in the IRP will be the highest block of energy savings that are lower than supply-side costs. Only including scenarios with low savings and higher costs than the base case (i.e. Low scenario), or high savings but significantly higher costs (i.e. High scenario) makes it less likely that the IRP will be able to find an optimal level of DSM.

The Mid scenario provides significant energy savings without running into significant diminishing returns with respect to savings per dollar invested. Not including this scenario will likely reduce the model's ability to find the most cost-effective level of DSM from a system perspective. ENE also fully supports continuing to include the High scenario since that level of

DSM could still be cheaper than the supply-side options, as has been the case in other jurisdictions.

Figure 3: Potential Study Scenarios First-year Unit Program Costs vs. Cumulative Savings Levels



2. Total Resource Cost Perspective

ENE again strongly recommends that NSPI consider DSM resources from a utility cost perspective.

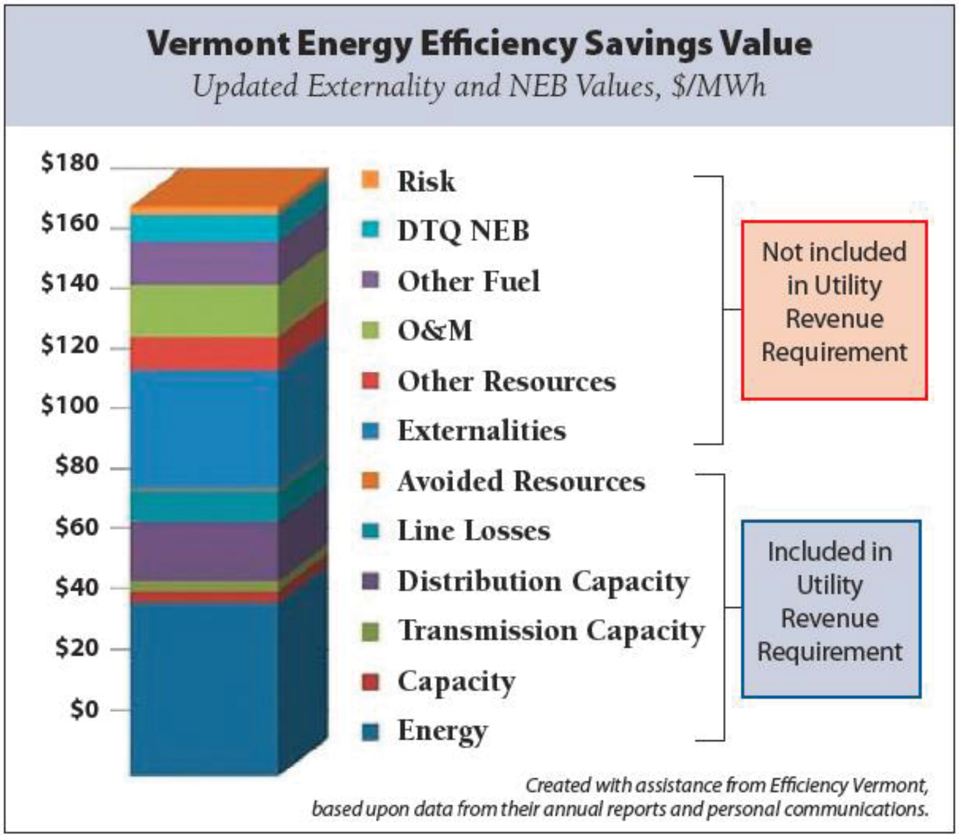
In a process that is intended to inform future investments based on utility system revenue requirements, it is not appropriate to factor in costs that will not be borne by the utility. Program administrative and incentive costs should be included; however, the dollars that would come directly out of the pockets of households and businesses should not be claimed by NSPI as a utility cost.

Assessing DSM from a total resource cost perspective in the IRP – i.e. including both program and participant costs – is biased against DSM and effectively places a premium on supply-side resources.

If NSPI uses the total resource cost approach based on the fact that the TRC test is its preferred screening test, then it is only fair and reasonable to also factor in Other Program Impacts (OPIs). The Board's consultant has released a report that states:

> "The TRC test includes the impacts to both the utility and the program participant, and therefore should account for all of the costs and all of the benefits that are experienced by the utility and the participants. This requires including all of the participant-perspective OPIs."
>
> And;
>
> "If a state chooses not to account for OPIs, then it should screen for cost-effectiveness using the PAC test." (Synapse, 2013)[1]

Appendix C of the Synapse study includes examples of OPIs – such as other fuel and water savings and improved comfort – and values for Non-Energy Benefits (NEBs) that have informed the NEB values incorporated into utility planning processes in Massachusetts and Rhode Island. Also, below is a visual taken from a Regulatory Assistance Project (RAP) report that shows the components of Efficiency Vermont's energy efficiency savings value.[2]



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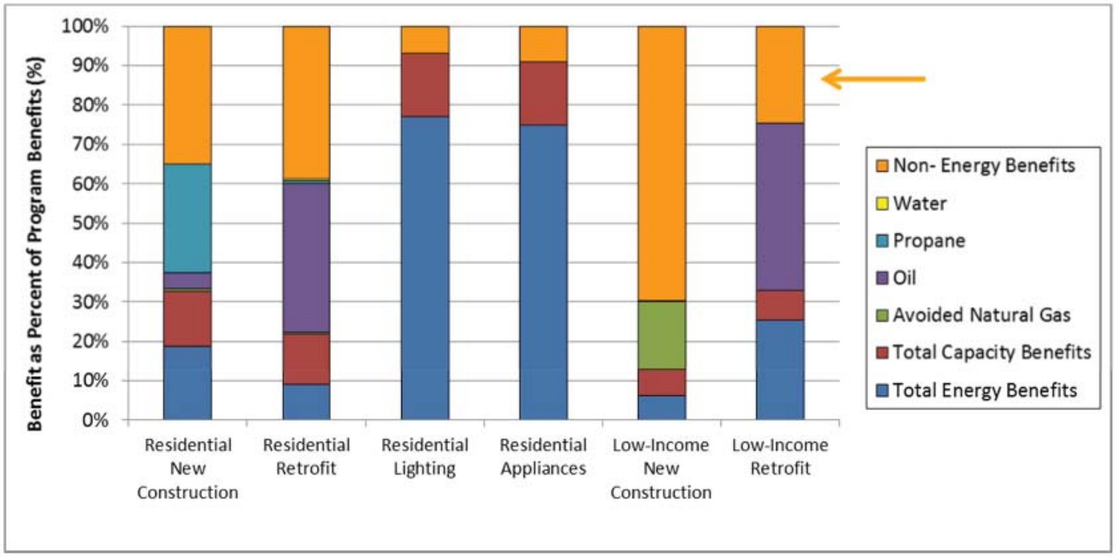
[1] Synapse Energy Economics, Inc. (2013, October 2). *Energy Efficiency Cost-Effectiveness Screening in the Northeast and Mid-Atlantic States*. Available at: http://www.neep.org/Assets/uploads/files/emv/emv-rfp/emv-products/EMV_Forum_C-E-Testing_Report_Synapse_2013%2010%2002%20Final.pdf

[2] Regulatory Assistance Project (2013, September). *A Layer Cake of Benefits: Recognizing the Full Value of Energy Efficiency*. Available at: http://www.raponline.org/document/download/id/6739

Including OPIs, which NSPI should if it wishes to use the TRC approach, will mean a significant increase over the utility's typical avoided cost value. The following visual – taken from a presentation by Tim Woolf of Synapse – shows that avoided energy and capacity costs are generally only a fraction of the total program benefits delivered by residential and low-income energy efficiency programs in Massachusetts.[3] The majority of the benefits come from other energy and water savings and NEBs.



If NSPI does not yet have research related to OPIs, an alternative to quantifying and including all the other fuel and water savings and NEBs in this IRP process would be to include only those components associated with the PAC test (i.e. assess DSM resources from a utility perspective). This approach could act as a proxy for a comprehensive TRC approach.

3. Discount Rate

ENE again recommends using a discount rate that is equal to a recent average of the historic yields from a ten-year government bond.

The utility weighted avoided cost of capital, even the after-tax WACC, is too high relative to the low risk of efficiency programs. A lower discount rate places energy efficiency on a level playing field with supply-side options.

A summary of the discount rates used in cost-effectiveness test in six US states is summarized by Synapse on page 9 of its report – *Energy Efficiency Cost-Effectiveness Screening in the Northeast and Mid-Atlantic States* (referenced above).

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[3] Presentation by Tim Woolf of Synapse to the NEEP EM&V Forum Annual Public Meeting (2013, December 12) – *Survey of Energy Efficiency Screening Practices in the Northeast and Mid-Atlantic.* Available at: http://www.neep.org/Assets/uploads/files/emv/Annual-Public-Meeting/Cost-Effectiveness_Synapse_EMV-Forum-APM_2013Dec12.pdf

wickwire holm
BARRISTERS SOLICITORS

April 7, 2014

VIA EMAIL

#55246-GAS

Nicole Godbout
Regulatory Counsel
Nova Scotia Power
1223 Lower Water Street
Halifax NS, B3J 3S8

Dear Ms. Godbout:

Re: M05522-2014 IRP Assumptions (DSM and Additional Details)

Efficiency Nova Scotia Corporation (ENSC) has reviewed the DSM and DR Assumptions – Levels and Costs, released by Nova Scotia Power Inc. (NSPI) on March 28, 2014. We appreciate the opportunity to respond and provide these written comments. For convenience, we set out below excerpts from your document, followed by our comments.

1. **NS Power proposes to model candidate resource plans that include various levels of DSM and Demand Response (DR).**

ENSC agrees with NSPI's approach.

2. **DSM levels. NS Power proposes to model a range of different candidate resource plans that have one of three different levels of DSM:**
   - **High Case from ENSC/Navigant January 2014 DSM Potential Study**
   - **Low Case from ENSC/Navigant January 2014 DSM Potential Study**
   - **50% Low Case from ENSC/Navigant January 2014 DSM Potential Study**

ENSC strongly objects to NSPI's selection of an inappropriate scenario to be modelled. ENSC was not consulted during the process of selecting which three scenarios would be proposed, despite the UARB's letter of January 9, 2014 to ENSC and copied to NSPI, stating that the Board "expects NSPI will consult with ENSC at various stages throughout the IRP development process to ensure that DSM input assumptions are appropriately included within the Strategist modelling scenarios."

The three DSM scenarios proposed by NSPI do not include ENSC's least-cost DSM scenario, and one of the scenarios was created by NSPI instead of coming from ENSC's DSM Potential Study.

The least-cost DSM scenario is ENSC's Base Case, which has a first-year unit cost of \$0.419/kWh; this translates into a conservative lifetime unit cost of \$0.032/kWh (using the portfolio average measure life of 12.96 years as calculated by Navigant's EERAM tool based on the DSM Potential Study). ENSC would make this Base Case the highest priority for inclusion in IRP scenario planning. The Low and High scenarios selected by NSPI have lifetime unit costs of \$0.034 and \$0.042, respectively, and should also be included.

If NSPI believes it is necessary to limit the number of levels of DSM included in the candidate resource plans, ENSC agrees with modeling the Low and the High Case, which would provide a broad range of options. However, ENSC strongly disagrees with the inclusion of a scenario (i.e., 50% of Low Case) that has not been researched, benchmarked, and modelled and as a result, is not part of the DSM Potential Study. For the third level of DSM, ENSC recommends the inclusion of the Base Case, as it contains a future consistent with ENSC's past performance and is viewed by ENSC to be the most robust, as well as cost-effective, case.

To minimize the utility's revenue requirements, the IRP analysis must be constructed to select all DSM that is more cost effective than the supply side alternatives, which could include capital expenditures to extend the life of thermal generating units. To ensure this requirement is met, ENSC recommends that the IRP analysis include scenarios for early retirement of generation assets, where sustaining those assets is not the most cost effective alternative for ratepayers.

3. **NS Power believes that the ENSC/Navigant January 2014 DSM Potential Study warrants review and vetting by stakeholders in a separate regulatory process at a future date. NS Power considers this data to be sufficient for IRP purposes.**

ENSC agrees that the data from the DSM Potential Study is sufficient for IRP purposes.

ENSC filed its DSM Potential Study in January with the primary purpose of providing relevant data for the IRP to fully consider Achievable Demand-Side Resources as an alternative to Supply-Side Resources. The study identifies four varying levels of Achievable DSM Potential and presents each of these scenarios in components of Residential, Commercial and Industrial, along with costs, peak demand savings and energy savings for each year of the IRP Planning Period.

The Base scenario presented in the Study is based on ENSC's proven track record of cost effectively achieving energy savings in Nova Scotia, and the alternate scenarios presented use the Base as a starting point, analyzing the impacts of varying incentive levels for DSM.

ENSC disagrees with the notion that its DSM Potential Study should be reviewed in a separate regulatory process at a future date. The purpose of its DSM Potential Study is to inform this current IRP process. ENSC will use the IRP to guide the direction of its future DSM Plans. These future Plans will involve separate processes that incorporate new inputs resulting from the 2014 IRP.

4. **DR levels. In addition to the reductions in peak demand associated with each of the DSM levels, NS Power proposes to model several direct load control solutions to mitigate peak demand and provide some ancillary services. These DR assumptions do not preclude the utilization of other customer solutions as a resource in the future.**

ENSC agrees with the general proposal to model DR within the IRP. However, we agree with the Consumer Advocate and the Industrial Group that NSPI should provide more detail on the various DR options for stakeholders to comment on, including detailed assumptions and sources, as ENSC provided in its DSM Potential Study.

ENSC also notes that NSPI's promotion of heat pumps to convert oil heat customers to electric heat is both increasing the system peak demand and increasing electrical energy consumption. With NSPI's new concern over Capacity and Demand Response Initiatives, ENSC expects that this would translate into upward pressure on avoided costs once the new Avoided Costs are developed through a stakeholder consultation process during this IRP. If the rationale for DR is to mitigate the effect that intermittent supply resources have on regulating system capacity, then the IRP should consider that the costs of such intermittent supply resources are directly linked to the associated DR costs.

5. **NS Power proposes to calculate the revenue requirements of candidate resource plans that include DSM using the total cost of that DSM. These costs, referred to as Total Resource Costs (TRC), consist of the DSM program administrator costs plus the customer costs, i.e., costs paid by participants in those programs.**

   NS Power is proposing this approach consistent with the TRC, previous IRPs and with the IRP treatment of DSM in other jurisdictions that use TRC as a primary test. The TRC is the predominant cost effectiveness test used for screening in North America. The TRC is the test currently accepted by the UARB.

> **For information purposes, NS Power will also calculate the revenue requirements of candidate resource plans that include DSM without customer costs.**

ENSC disagrees with NSPI's proposed approach of inflating the total utility costs of DSM by adding customer costs.

- Such an approach is in direct violation of the objective function of the approved Terms of Reference for the 2014 IRP. The Terms of Reference identifies the objective function as the minimization of the cumulative present worth of the annual revenue requirements over the planning period.

- Revenue requirements, by their very definition, are the amounts that must be recovered from customers to cover the utility's costs.

- For Demand Side Management resources, the DSM Program Administrator costs fully represent those amounts that must be recovered from the utility's customers and, as such, are the full utility revenue requirements associated with DSM.

- Participation in DSM programs is voluntary. Only the DSM Rate Rider is mandatory and this alone represents the utility's investment in Demand Side Management resources to offset the need for Supply Side Resources.

- When individuals or businesses volunteer to participate in DSM programs they are doing so for their own personal or business interests. The fundamental concept of DSM programming is to provide incentives to program participants that are just enough to cause them to decide to implement an energy efficiency measure. The clear distinction here is that the utility's portion of the cost (i.e. incentive amounts plus program administrator costs) is the amount invested by the utility to offset electricity system supply-side costs, and the participant's portion of the cost (above and beyond their rate rider cost) is the amount invested voluntarily by them for a wide variety of their own reasons; examples include increasing the insulation of their home for comfort, improving the quality of lighting in their commercial building, or improving the efficiency of their industrial processes. For certain, the individuals and businesses participating in DSM programs are not investing their own dollars (above and beyond their rate rider cost) for the purpose of offsetting the utility's cost of supply-side resources.

- It would be fundamentally and logically flawed, as well as mathematically incorrect, to proceed with the approach that NSPI has proposed to calculate its revenue requirements associated with DSM resources.

- Customers actually incur a net benefit as opposed to a net cost. Their costs of participating in DSM programs are significantly more than offset by their savings of lower power bills, as provided for in Attachment A. ENSC is providing these net customer benefits for illustration purposes only and asserts that it would also

> be incorrect for NSPI to deflate their total utility costs of providing DSM by subtracting customer net benefits.

NSPI is correct that its proposed approach is consistent with the approach taken in the 2007 and 2009 IRPs. However, these should not be taken as appropriate precedents because of the reasons the TRC approach was addressed by NSPI in 2009. In 2009, the Ecology Action Centre pointed out that "If the IRP only wishes to optimize with respect to the electric system, then the IRP should use a utility cost test rather than a TRC test which counts all resources." NSPI's response was that "since DSM is a cost-effective option compared to supply alternatives, the model will pick DSM over other alternatives. The suggestion to either enhance the benefits associated with DSM or to use the utility costs instead of total costs would increase the attractiveness of DSM versus supply options. The DSM as projected will be in the Reference plan and increasing the economic attractiveness of DSM will not change that outcome" (NSPI's 2009 Integrated Resource Plan Update Final Report. Appendix F, Attachment 1, p.6). In other words, NSPI's only argument was that including customer costs did not matter, not that it was correct. Including a calculation that is incorrect but doesn't matter is not one that ENSC believes should be incorporated within this IRP, and it is not one that should be used to set a precedent.

NSPI is correct that TRC is the predominant cost-effectiveness test used for screening DSM programming in North America. However, the traditional TRC test is not predominant among leading DSM jurisdictions in North America.[1] Over the past year, ENSC has engaged Dunsky Energy Consulting to help advise on best practices and has been working closely with the DSM Advisory Group in advancing our thinking on such concepts and methodologies. ENSC agrees that the TRC test is the one currently accepted by the UARB. ENSC also agrees that this is an item that warrants further review and full vetting by stakeholders in a UARB regulatory process at a future date rather than during the IRP. However, ENSC wishes to reiterate that there is a distinction between cost-effectiveness screening, which takes place within DSM modeling software, and least-cost analysis, which takes place within IRP modeling software.

It should be pointed out that all of the "Achievable DSM Potential" put forward in the Scenarios of ENSC's DSM Potential Study has already been screened for cost-effectiveness using the TRC test within the DSM modeling software. In addition, should NSPI include customer costs for DSM (despite the fact that doing so is in opposition to the IRP Terms of Reference and provides an inconsistent comparison between supply and demand-side options), the unit costs of the Low and High scenarios would be the two highest costs of ENSC's four scenarios: they are \$0.070/kWh and \$0.078/kWh, as compared to the Base scenario of \$0.056/kWh.

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[1] As provided in Dunsky Energy Consulting's report, "Appropriate Treatment of DSM in Integrated Resource Planning (IRP)", filed on January 29, 2014 as part of ENSC's comments on NSPI's 2014 IRP Terms of Reference.

In contrast, for Supply-Side resources, the notion of cost-effectiveness pre-screening does not exist. It does not exist because the IRP analysis is one that inherently determines the least- cost of viable resource alternatives for the utility.

6. **For information purposes, NS Power will also calculate the revenue requirements of candidate resource plans that include DSM without customer costs.**

ENSC requests confirmation that the calculation of revenue requirements of candidate resource plans will occur at a point in the process in which stakeholders can provide input that may influence which revenue requirement calculation (with or without customer costs) is included in the IRP outputs.

7. **Consistent with the treatment of supply side options, NS Power will apply its after-tax WACC as the discount rate for DSM.**

ENSC agrees with NSPI's approach for the purpose of this IRP. ENSC believes that this issue warrants review and full vetting by stakeholders in a DSM regulatory process at a future date.

8. **Slides 5 & 6**

ENSC requests that NSPI provide the detailed assumptions, including all source data, references, documents and spreadsheets that were used in preparing the graphs on Slides 5 and 6 and provide stakeholders with an opportunity to comment on them.

Summary of ENSC's Comments

1. ENSC recommends that NSPI use the DSM scenarios of ENSC's DSM Potential Study that have been researched, benchmarked and modelled by ENSC for input to the IRP analysis. ENSC's DSM Potential Study should not be deferred to a separate regulatory process. If NSPI needs to limit the number of scenarios to three, ENSC recommends the Base, Low and High Case DSM potential scenarios.

2. In order to minimize utility revenue requirements, ENSC recommends that the IRP analysis be constructed to select all DSM that is more beneficial to ratepayers than supply-side expenditures, including those expenditures intended to avoid retirement of NSPI assets, as well as an examination of the cost-effectiveness of early retirement of existing generation.

3. NSPI is requested to provide detailed assumptions and sources for the direct load control solutions intended to mitigate peak demand or to provide ancillary

services, and that stakeholders be given adequate opportunity to assess and direct the selection of these options.

4. The stakeholder consultation process on the development of Avoided Capacity Costs, to be conducted in accordance with the IRP Terms of Reference and ENSC's 2013-2014 DSM Plan Settlement Agreement, is expected to allow for appropriate reflection of NSPI's acknowledgement of the value provided by demand response and customer peak reduction initiatives.

5. NSPI should not inflate the total utility costs of DSM by adding customer costs.

6. ENSC requests confirmation that the calculation of revenue requirements of candidate resource plans will occur at a point in the process in which stakeholders can provide input that may influence which revenue requirement calculation (with or without customer costs) is included in the IRP outputs.

7. NSPI is requested to provide the detailed assumptions, including all source data, references, documents and spreadsheets that were used in preparing the graphs on Slides 5 and 6 and provide an opportunity for stakeholders to comment on them.

As always, we appreciate the opportunity to provide our comments and look forward to our continued involvement in the IRP process.

Yours very truly,

WICKWIRE HOLM

GSaunders

Geoffrey A. Saunders

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GAS/

c. Participant List

ATTACHMENT A

Total All Sectors Achievable Potential (Net-at-Generator) with Net Customer Costs[1]

	Base Scenario									
	Program Administrator Costs ($ millions)		Customer Costs ($ millions)		Energy Savings GWh		Customer Power Bill Savings ($ millions)		Net Customer Costs ($ millions)	
Year	Incremental	Cumulative	Incremental	Cumulative	Incremental	Cumulative	Incremental	Cumulative	Incremental	Cumulative
2015	$50.70	$50.70	$37.90	$37.90	137.8	137.8	$ (16.8)	$ (16.8)	$ 21.1	$ 21.1
2016	$50.50	$101.20	$39.90	$77.80	139.9	226.1	$ (27.6)	$ (44.4)	$ 12.3	$ 33.4
2017	$50.00	$151.20	$41.20	$119.00	141.7	360.8	$ (44.0)	$ (88.4)	$ (2.8)	$ 30.6
2018	$52.40	$203.60	$41.60	$160.60	136.2	480.3	$ (58.6)	$ (147.0)	$ (17.0)	$ 13.6
2019	$57.00	$260.60	$32.20	$192.80	134.8	597.4	$ (72.9)	$ (219.9)	$ (40.7)	$ (27.1)
2020	$61.50	$322.10	$28.00	$220.80	133.9	708.9	$ (86.5)	$ (306.4)	$ (58.5)	$ (85.6)
2021	$56.90	$379.00	$28.40	$249.20	130.1	817.1	$ (99.7)	$ (406.1)	$ (71.3)	$ (156.9)
2022	$54.10	$433.20	$28.40	$277.60	127.6	932.3	$ (113.7)	$ (519.8)	$ (85.3)	$ (242.2)
2023	$51.50	$484.70	$29.20	$306.80	126.6	1,040.9	$ (127.0)	$ (646.8)	$ (97.8)	$ (340.0)
2024	$50.80	$535.50	$28.60	$335.40	127.4	1,155.4	$ (141.0)	$ (787.8)	$ (112.4)	$ (452.4)
2025	$50.60	$586.10	$29.90	$365.30	130.1	1,257.1	$ (153.4)	$ (941.1)	$ (123.5)	$ (575.8)
2026	$52.10	$638.30	$33.80	$399.10	135.6	1,371.0	$ (167.3)	$ (1,108.4)	$ (133.5)	$ (709.3)
2027	$54.80	$693.00	$36.80	$435.90	143.5	1,509.5	$ (184.2)	$ (1,292.5)	$ (147.4)	$ (856.6)
2028	$58.50	$751.50	$41.40	$477.30	153.4	1,644.6	$ (200.6)	$ (1,493.2)	$ (159.2)	$ (1,015.9)
2029	$60.70	$812.20	$34.00	$511.30	163.3	1,797.6	$ (219.3)	$ (1,712.5)	$ (185.3)	$ (1,201.2)
2030	$63.10	$875.30	$37.20	$548.50	170.7	1,956.3	$ (238.7)	$ (1,951.2)	$ (201.5)	$ (1,402.7)
2031	$62.60	$937.90	$40.60	$589.10	173.5	2,112.9	$ (257.8)	$ (2,208.9)	$ (217.2)	$ (1,619.8)
2032	$61.40	$999.40	$40.80	$629.90	171.4	2,266.2	$ (276.5)	$ (2,485.4)	$ (235.7)	$ (1,855.5)
2033	$59.30	$1,058.70	$41.40	$671.30	166.0	2,415.4	$ (294.7)	$ (2,780.1)	$ (253.3)	$ (2,108.8)
2034	$56.70	$1,115.40	$41.70	$713.00	159.3	2,560.6	$ (312.4)	$ (3,092.5)	$ (270.7)	$ (2,379.5)
2035	$47.70	$1,163.10	$48.40	$761.40	153.0	2,699.4	$ (329.3)	$ (3,421.8)	$ (280.9)	$ (2,660.4)
2036	$46.50	$1,209.60	$48.00	$809.40	147.0	2,833.1	$ (345.6)	$ (3,767.4)	$ (297.6)	$ (2,958.0)
2037	$45.40	$1,254.90	$47.60	$856.90	141.5	2,955.0	$ (360.5)	$ (4,128.0)	$ (312.9)	$ (3,271.0)
2038	$44.40	$1,299.30	$46.80	$903.70	136.1	3,080.8	$ (375.9)	$ (4,503.8)	$ (329.1)	$ (3,600.0)
2039	$43.50	$1,342.80	$46.30	$950.00	131.6	3,197.5	$ (390.1)	$ (4,893.9)	$ (343.8)	$ (3,943.8)
2040	$42.30	$1,385.00	$46.30	$996.30	127.9	3,308.7	$ (403.7)	$ (5,297.6)	$ (357.4)	$ (4,301.2)

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[1] For illustrative purposes only, so no escalation has been applied to 2013 rates.

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Stephen T. McGrath
Senior Solicitor

April 7, 2014

Nicole Godbout, Regulatory Counsel
Nova Scotia Power Inc.
1223 Lower Water Street
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Dear Ms. Godbout:

Re: M05522-2014 IRP Assumptions (DSM and Additional Details)

After reviewing the "DSM and DR Assumptions – Levels and Costs" document, released by Nova Scotia Power Inc., the Department of Energy would like to submit the following comments for your consideration:

- The Department notes that the DSM scenarios selected for modelling do not include the "base" case defined in the DSM potential study. As the "base" case represents the most cost effective option presented in the study it would be in the interest of rate-payers for it to be included in the modelling. Please take note of the table on page 11 in Exhibit N-1 "DSM potential study".

- Anticipating that the use of one particular cost test over another may be a point of debate in future proceedings, it would be beneficial to have model runs completed to review the impact of the two main tests, the Total Resource Cost (TRC) and the Program Administrator Cost (PAC), through the IRP.

Respectfully,

Stephen T. McGrath
STM/vm

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Our File: 100384
April 7, 2014

Ms. Nicole Godbout
Regulatory Counsel
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Dear Ms. Godbout:

Re: Integrated Resource Plan (IRP) 2014 – Matter M05522/P-884.14

On March 28, 2014, Nova Scotia Power Inc. ("NSPI") circulated its Draft Demand Side Management and Demand Response Assumptions (the "DSM and DR Assumptions"). Please accept the following comment on behalf of Port Hawkesbury Paper LP ("PHP").

On slide 2 of the DSM and DR Assumptions, NSPI indicates that it "proposes to model several direct load control solutions to mitigate peak demand and provide some ancillary services. These DR assumptions do not preclude the utilization of other customer solutions as a resource in the future." NSPI's proposed Forecast DR Program Costs ($) and Forecast DR Program Impacts (MW) are provided in Slides 5 and 6 and relate to Electric Water Heaters ("EWH") and Commercial Heating, Ventilation, and Air Conditioning ("Comm HVAC").

On April 3, 2014, PHP met with NSPI to discuss the potential opportunities associated with its load to ensure that this can also be considered as part of the IRP, since an industrial-type DR program would differ in some respects from the specific residential and commercial programs identified by NSPI in the DSM and DR Assumptions. PHP understands from this meeting that Plexos as well as Strategist will be used to consider the potential benefits (including ancillary services) that can be offered by DR programs as part of the IRP modeling. PHP also understands that the iterative process that this will allow for will enable NSPI to consider potential opportunities for industrial-type DR programs that may have different program costs, timing and/or scale than the EWH and Comm HVAC programs.

We would appreciate confirmation of this understanding.

Yours truly,

David S. MacDougall
cc: Interested Parties

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OUR FILE:

April 7, 2014

Ms. Lana Myatt
Administrative Assistant IV – Regulatory Affairs
Nova Scotia Power
1223 Lower Water Street
Halifax, NS B3J 3S8

Dear Ms. Myatt:

RE: ***M05522 – 2014 IRP Assumptions (DSM and Additional Details)***

Further to your letter dated March 28, 2014 regarding Nova Scotia Power's (NS Power's) draft Demand Side Management (DSM) and Demand Response (DR) Assumptions, the Nova Scotia Small Business Advocate ("the SBA") wishes to submit its comments and observations as summarized below. Please consider this response as preliminary as the SBA has been informed that the provincial government is expected to table new legislation, possibly as early as today, regarding Efficiency Nova Scotia ("ENSC") that has the potential to affect DSM and the IRP assumptions already presented. Upon review of that legislation, the SBA may send a revised version of this letter at a later date.

The SBA wishes to submit the following comments and questions regarding the specific draft assumptions proposed by NSPI as well as comments on its overall approach to conducting the 2014 IRP process with stakeholder input.

Specific comments and questions about NSPI DSM and DR assumptions in the 2014 IRP:

1. **Environmental/Emissions**
    a. **Constraints** –How will NSPI incorporate the A & B Scenarios for emissions constraints? Why not plan for the more stringent resources since there will be many IRPs prior to reaching the points where the Scenarios A & B diverge?
    b. **Targets-** Should IRP study emissions reduction targets that go beyond compliance in order to establish the impact of policy changes that might ratchet down emissions? Should the IRP evaluate renewable energy strategy targets beyond RES compliance?

2. **Existing Supply Side Options**
    a. ***What are the costs to maintain each existing generating resource?*** How much will certain generating units operate under various Maritime Link energy delivery scenarios? Does the ability to keep thermal generation operating well beyond 50 years, as noted on Slide 41, make some units exempt from evaluating for economic obsolescence?
    b. In Slides 28 and 29 what is the basis for NSPI's rationale for assuming that ***$500 million dollars should be spent on existing hydroelectric facilities***? Does this total reflect variable costs among the NSPI hydro facilities?

3. **DSM Options:** ***See discussion in Section III.1., below.***

4. **Load Forecast**
The low forecast should assume flat or declining industrial load. The SBA hopes that growth from its industrial constituents helps drive economic recovery in Nova Scotia. However, the SBA also recognizes the risk that small commercial customers will shoulder an unnecessary burden if the plan is not flexible or robust.

5. **Wind Capacity Factor & Integration Costs**
The SBA requests specific assumptions on how NSPI intends to evaluate any potential strategic and cost advantages to wind procurement through purchase power agreements versus NSPI ownership.

6. **Import Options**
Please explain the apparent inconsistency among the natural gas forecasts, emissions costs and import price assumptions over the study period.

7. **Future Supply Options**
Will each supply option provided on slides 19 to 22 be separate options in the IRP analysis or will NSPI establish separate generation options to represent a group of similar supply options?

8. **Natural Gas Price Forecasts**
Why is the assumption made that there are CO2 emissions limits or costs established for the reference natural gas forecast and not in either of the high and low forecasts?

Comments on NSPI's approach to conducting the 2014 IRP stakeholder review process:

In addition to these specific questions and comments, the SBA would like to provide comments regarding NS Power's approach to conducting the IRP process to address resource planning objectives through the choice of metrics and methodology. The SBA also comments on the way NSPI has chosen to include stakeholders in that process. Finally, the SBA provides suggested resource plan themes for consideration in the Stakeholder process.

I. Goals & Metrics

First and foremost, the SBA believes, it is important for the stakeholders to come to agreement on the objectives of the IRP. This includes establishing the metrics that NS Power intends to look at to determine the best resource plan or even the good resource plans. This would also include discussion of policy goals and objectives that are implicitly and explicitly going to factor into the analysis and the ultimate decisions and report.

Example goals and metrics include:

1. Revenue Requirement Minimization
2. Acceptable Price of Electricity paths
3. Plan Robustness and Flexibility
4. Environmental / Emissions Outlook
5. Reliability & Energy Security for Nova Scotia.

Incorporating these metrics in the IRP process allows NS Power and stakeholders to answer key resource acquisition questions, including, for example:

Key Resource Planning Questions to Address:

1. How does the Maritime Link affect resource planning choices?
2. What are the economic benefits of the continued operation of existing thermal and hydroelectric generation?
3. What is the least cost way to meet environmental constraints?
4. What is the cost to meet various levels of emissions?
5. What is the role of DSM, energy efficiency and price responsive demand, in the resource portfolio?
6. Does more DSM spending have a measurable impact on rates now or over the 25 year planning horizon?

II. Stakeholder Process

The Terms of Reference provide specifically for a Stakeholder Engagement Process, however, the SBA is concerned that the process is not more interactive. While the early efforts of NSPI are appreciated, the SBA notes that more should be done to support IRP input and transparency:

1. **Timeline for stakeholder input** – Stakeholders will not see which plans and metrics are developed and analyzed prior to the Interim Analysis Progress Report Technical Conference on June 25th, nor with they be able to provide input to additional analysis to be done prior to the September 30th Draft Report issue date.

2. **Degree of Impact of the stakeholders** –Stakeholders have only one week to comment after the draft report, with the final report to be filed with the UARB a short eight days later.

III. Methodology

The SBA has the following preliminary comments on how NSPI evaluates DSM and selects plans through an optimization process for the 2014 IRP:

1. **Evaluation of DSM:**
   a. **DSM is not evaluated on an equal footing with Supply options:**
   NSPI's process description develops DSM economics prior to the Evaluation and Optimization steps. Supply options are not screened as compared to avoided costs prior to IRP, but DSM options are. DSM is screened solely on economics versus avoided costs, when in fact, 'avoided costs' is an output parameter of the new resource plan.

   b. **The IRP process should use substantial information from the DSM potential study:**
   A DSM 'supply curve' should be created as an output of the DSM potential study, where the blocks are incremental DSM that can be harvested for a price.

2. **Evaluation and Optimization:**

   The SBA agrees that a process that analyzes many plans under Reference conditions, from which a subset is selected for further analysis through Scenario Testing and Risk Analysis, is very useful. The SBA has the following questions about the NSPI scenario evaluation process:

   a. ***Reference Scenario Analysis*** – What are the plans that will be tested? What are the metrics? Will stakeholders get to comment on the plans before the analysis?
   b. ***Scenario Testing ("Worlds" Development)*** – What is the process to choose or design these "Worlds". Will Plans recognize the alternative scenario at some point in time?
   c. ***Risk analysis*** - How will risk be evaluated? Which risks?

IV. SBA's four Resource Plans or Strategies Proposed for Consideration:

i. **Lowest Capital Investment Plan**
ii. **Lowest Emissions Plan contrasted with Compliance levels of emissions**
iii. **Maximum retirement / replacement of existing resources**
iv. **Optimized continued operation of existing generation**

The SBA participates diligently in rate cases, major project approvals and the ACE Review Process, all to fulfill our responsibility to small businesses that the costs are necessary and prudent. The approval of the ACE Plan and certainly the proceeding to approve the Maritime Link provided the SBA with more input and details to review than the IRP. The IRP sets in motion the plans that form a major element of NSPI's cost to serve customers. Failure to test stakeholder strategies to lower cost or to provide information on the impact of certain resources and policies would prove to be a lost opportunity for the 2014 IRP.

The SBA appreciates the opportunity to submit these comments and questions and looks forward to the opportunity to participate fully in NSPI's stakeholder process for the 2014 IRP.

Sincerely,

Sandy Durling for

E.A. Nelson Blackburn, Q.C.
SMALL BUSINESS ADVOCATE

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Nicole Godbout
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Nova Scotia Power Incorporated
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Halifax NS B3J 2W5

April 10, 2014

Dear Ms. Godbout,

RE: M05522 – 2014 Integrated Resource Plan
Ecology Action Centre Comments on Draft IRP DSM Assumptions

While the official period for comments on Draft IRP DSM Assumptions has passed, the Ecology Action Centre (EAC) respectfully requests consideration of the following proposal and comments.

Having reviewed the Draft IRP DSM Assumptions and subsequent comments from various stakeholders, the EAC finds that it is unclear where the values associated with the draft DSM scenarios derive from. **EAC submits that the process for developing DSM Assumptions must be more closely guided by the Utility and Review Board and Board Consultants so as to ensure adequate and impartial consideration of Demand Side Management as a resource within the IRP.**

Proposal

EAC proposes that Board Consultants, Synapse, develop the DSM Assumptions to be used in modelling in collaboration with NSPI and ENSC. It is critical for this process to be lead by a third-party such as the Board Consultant in order to avoid conflicts of interest.

Comments on the Draft IRP Assumptions as presented follow.

Comments on Draft IRP DSM Assumptions

The Ecology Action centre has reviewed the proposed DSM assumptions and is deeply concerned that the proposed assumptions conflict with the terms of reference for the IRP and risk wasting this opportunity to fairly evaluate DSM in conjunction with other supply-side options over the study period. In particular, the no-regrets perspective, at least for the ratepayer and the environment, is at risk.

We share the concerns expressed by the Small Business Advocate that the assumptions do not minimize the cumulative present worth of the annual revenue requirement, the central objective of the IRP.

In addition, we are concerned that the proposed assumptions set aside the basic objective to meet energy requirements “in a cost-effective, safe and reliable manner across a reasonable range of foreseeable futures”. In particular the proposed assumptions disregard item 2 of the scope of the IRP which calls for the “most likely” values and “projections of plausible high and low values” to be considered. Our specific concerns are as follows:

DSM Levels

The proposed low DSM case of 50% of the DSM Study low case is simply implausible. DSM levels of 50% of 50% of the current base rate (equalling 25% of our present baseline level) as pointed out by ENE, is extremely unlikely to be a cost effective course of action given the demonstrated success of DSM to date and accepted assumptions around fuel and supply side generation costs, none of which are assumed to fall by 75%.

Considering that costs are “most likely” to continue to rise (see slide 58, Natural Gas Price Assumptions, slide 62, Long Term [Import] Price assumptions and slides 66 and 67, Solid Fuel Price Assumptions) achievable cost effective DSM options will continue to increase, the low case for the IRP should be no lower than 75% of present DSM levels.

Likewise, for a mid-range assumption, a conservative and no regrets level of DSM should simply be the present baseline level.

We agree that the High case from the DSM study is acceptable.

DSM Cost Assumptions

Here again, the proposed assumptions are in conflict with the terms of reference by including non-utility costs for DSM and thereby masking potential DSM benefits. Moreover, in light of the legislative changes to the relationship of efficiency programs in the public utility act announced Monday April 7, the IRP and the utility should concern themselves simply with the DSM costs borne by the utility. It will be the responsibility of ENSC, in consultation with the Board and stakeholders, the utility among them, to deliver energy demand reductions for the expected costs. Consistent with the stated intent of the IRP framework, resource needs should be directional and not prescriptive. Participant expenses are simply not relevant to comparing cost effective DSM options within the IRP.

Avoided Cost Methodology

Here again EAC supports the view of the SBA. The DSM study provides sufficient information to model DSM as a resource, with a variable cost curve, or at least multiple discrete levels. Only by integrating DSM within the resource selection process will the IRP fully inform the Preferred Resource Plan. The models may identify differing levels of DSM over the study period that are cost effective. Or the model may identify that full application of cost effective achievable DSM minimizes costs. Or not.

What is clear is that without comparing DSM as a resource fairly with others, by simply comparing potential resource plans with and without various fixed levels of DSM across the study period, the IRP will not reveal the benefits, costs or risks of DSM in comparison to other potential resources and we will be no further along than we were in 2007 and 2009.

Cost of Capital

Use of NSPI's WACC as the discount rate for DSM exaggerates the risk associated with DSM. Compared to the long life associated with capital assets (for generation assets see slide 41 - 50 plus years), DSM programs on a 1 to 3 year planning cycle are far more nimble and able to respond to variations in their performance. As such their risks are lower as should be their discount rates.

Sincerely,

Catherine Abreu

Energy Coordinator
Ecology Action Centre

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May 7, 2014

Delivered by E-mail

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Dear Ms. Godbout:

Re: NSPI Draft Variable Generation Integration Costs Assumptions
Integrated Resource Plan (IRP) 2014 – M05522/P-884.14

These comments are submitted regarding the above draft Integration Costs Assumptions circulated on May 1st. We note that we await responses to our questions on the wind capacity assumptions and look forward to receipt of those.

The graphs on pages 4 and 11 show operational wind integration costs versus installed wind capacity with the costs expressed in dollars/MWh. The graph shows a sharp increase in the average cost as wind capacity increases. If $14/MWh is the average cost at 550 MW and $28/MWh is the average cost at 650 MW, please confirm that the incremental cost of integration to go from 550 MW to 650 MW is $105/MWh, (derived as follows):

1. We assume that the $/MWh cost shown in the graph on page 4 is the average cost for the level of installed wind generation (not the incremental cost at each level of installed wind generation).
2. The total wind integration costs with 550 MW of installed wind generation appear to be about $24 million per year [550 MW x 8760 hours/year x 35% CF[1] x $14/MWh (from graph) = $23.6 million/year].
3. Total wind integration costs with 650 MW of installed wind generation appear to be about $56 million per year [650 MW x 8760 hours/year x 35% CF x $28/MWh (from graph) = $55.8 million/year].
4. The difference in total wind integration costs between 550 MW and 650 MW is therefore $105/MWh [($55.8 million - $23.6 million]/((650 MW – 550 MW) x 8760 hours/year x 35% CF) = $105/MWh].

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[1] The 35% capacity factor is an average for NSPI owned wind (and also for total renewable) as per the Maritime Link Application, Appendix 6.02, p.9 of 42, Table 2.1.

If this calculation and interpretation of the graph is incorrect, please explain. Alternatively, if the cost of accommodating additional wind above 550 MW is this high (higher than the cost of wind generation itself), why would it be considered as a resource in the IRP?

With respect to the study methodology – operational dispatch costs (page 8) the Industrial Group suggests that estimates or calculations of the incremental emissions associated with heat rate degradation and additional unit starts resulting from variable generation would be useful in assessing the actual (net) emissions reductions associated with mandatory RES or other policies and should be included.

At p.12 NSPI indicates "GE Energy estimates that NSPI will have to carry additional 32 MW of non-synchronous 10-minute reserve ...". Is this value reported in the Renewable Energy Integration Strategy? If so, where? If not and it was derived, please explain the derivation.

Please provide the back-up data and documentation on how the numbers in the tables on pages 4 and 11 were calculated.

There is little in the document to indicate what NSPI is doing to control operational dispatch costs and additional reserve requirements. In other areas where wind is being aggressively integrated, eg. ERCOT (Texas) and Alberta, wind is being made dispatchable (contracts limit this to about 10% of total hours per year in order to still make the wind project financeable.) Under existing 100% take-or-pay contracts, it would seem to make sense in light of the "incremental operating integration costs" to sometimes simply pay the wind farm operator. The Industrial Group suggests that appropriate consideration be given to this option in evaluating the plans.

Going forward, the Industrial Group submits there should be a requirement for all additional wind farms that they be dispatchable and provide certain system services such as reactive power.

In addition, with respect to new wind technology, the Industrial Group queries if the low production from wind during peak times as NSPI discussed in its Wind Capacity Value Assumptions, is due to the wind turbine blades being iced. It is understood that the existing farms have no de-icing capability, but new turbines do.

It is further noted that wind in Ontario and Quebec carries approximately 30% capacity values. The lower values indicated by NSPI appear to be elsewhere in North America where the system peaks in summer – a low production period for wind. We are different in Nova Scotia as our system peaks when wind production is highest, suggesting a higher value more comparable to Ontario and Quebec.

At page 16, NSPI expresses concern that such technical features for wind turbines are "not available from all wind generation suppliers". The advice we have received is that if one goes out for a tender for wind today, one would normally include many of these technical requirements. The cost of wind turbines over the past five years has fallen significantly and the additional system integration features listed by NSPI have offset some of the cost decline for the "plain vanilla" wind turbines. The Industrial Group recommends that these alternatives be modelled.

With respect to the 10-minute reserve additions discussed on p.12, the Industrial Group presumes that NSPI would tender for this before it incurs the high capital costs of building its own new generation and that alternatives to be considered in such a tender would include facilities on interconnected systems such as in New Brunswick.

Thank you for considering these points.

Yours truly,

Nancy G. Rubin

NGR/lmc

cc IRP Participants

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May 9, 2014

Delivered by E-mail

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Dear Ms. Friis:

Re: NSPI Draft Variable Generation Integration Costs Assumptions
Integrated Resource Plan (IRP) 2014 – M05522/P-884.14

Further to our May 7, 2014 comments on the draft Integration Costs Assumptions, we make these additional submissions.

In the Maritime Link hearing, NSPI / NSPML confirmed that energy from the link would support the integration of variable energy sources.[1] Do the simulations used to develop the Variable Generation Integration Costs assume that the Link facilitates the integration of variable renewables? If not, please explain.

Has NSPI determined that a specific amount of variable renewables can be added because of the Link? How much? If the simulations run to develop the draft Integration Costs Assumptions did not assume that the Link facilitates integration of variable renewals, please run a simulation that has this assumption and provide a report that discusses the impact of this change on variable generation integration costs.

Regarding the Point Aconi and Point Tupper outputs on pages 9 and 10, has NSPI considered the impact of non-wind variables that affect output, such as changes to load, the operation of the Port Hawkesbury Biomass, and the increased use of natural gas at Tufts Cove? Please explain.

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[1] NSPML Application (M-2), page 25 (M05419)

Finally, we note that the Port Hawkesbury Biomass generator continues, by legislated requirement, to be designated as "must run." Given that this IRP process intends to explore all generation requirements and options, we believe that it would be appropriate to consider the impact on dispatch, generation costs and the overall cost of achieving renewables targets of changing the Biomass designation so that it is not a "must run" unit. Please run a simulation that assumes that the Biomass is not "must run" and provide a report that discusses the impact of this change on variable generation integration costs.

Regards,

Maggie A. Stewart

MAS/

Cc Interested Parties

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Our File: 100384
May 9, 2014

Ms. Nicole Godbout
Regulatory Counsel
Nova Scotia Power
P.O. Box 910
Halifax, NS B3J 2W5

Dear Ms. Godbout:

Re: Integrated Resource Plan (IRP) 2014 – Matter M05522/P-884.14

On May 1, 2014, Nova Scotia Power Inc. ("NSPI") circulated its proposed assumptions with respect to its "Variable Generation Integration Costs", or costs that the utility is expected to incur due to the addition of variable energy sources to its electrical system. Please accept the following comments on behalf of Port Hawkesbury Paper LP ("PHP").

In its executive summary (slide 2), NSPI states that the addition of variable generation (wind and solar) introduces additional costs associated with unit dispatch and commitment, system reserves and capital investments. NSPI's analysis indicates that the existing and committed 550-600 MW of wind generation and any further increases will increase operational reserve requirements.

NSPI also assumes that in order to maintain system reliability, new capital investments will be necessary to integrate more variable generation on the system past 600 MW. NSPI states on slide 2 that such capital investments "...will address needed requirements for fast-acting firm capacity, system inertia, reactive power support, primary and secondary frequency response and other system reliability requirements."

As parties are aware, the IRP terms of reference were explicitly revised to consider the potential utilization of load as a resource. As referenced in NSPI's responses to Stakeholder Comments on the IRP Assumptions (Item 93), NSPI has been meeting with PHP to assess the options for demand response. PHP continues to believe that there are options available to use load as a resource (including the PHP load, industrial load, and other demand response initiatives) to address numerous system issues including system reliability issues in the context of increasing variable generation on the system. PHP believes that this use of load as a resource may be able to offset or defer the requirement for new capital investments.

On slide 14, NSPI states that "...it will first analyze the system with anticipated incremental flexibility available from the Maritime Link, possible incremental hydro improvements, **demand response resources**, and internal transmission improvements."

PHP submits that other wind balancing resources that could be available to defer the need for new capital projects need to be closely analyzed. PHP will continue to make itself and its consultants available as part of this process to assist in ensuring that use of load as a resource can be appropriately modeled as part of the overall process, including with respect to modelling variable generation integration costs.

In this regard, PHP agrees with the comments of the Industrial Group at page 3 of its May 7, submission, where it states that it presumes that NSPI would tender for 10-minute reserve additions before it incurs the high capital costs of building its own new generation and that alternatives would be considered.

Yours truly,

f: David S. MacDougall

cc: Interested Parties

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OUR FILE:

May 9, 2014

Ms. Nicole Godbout
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Dear Ms. Godbout,

RE: M05522 2014 IRP Assumptions re: Variable Generation Integration Costs

Further to your letter dated May 1, 2014 presenting Nova Scotia Power's (NS Power's) draft Variable Generation Integration Cost assumptions included in NS Power's 2014 IRP, the Nova Scotia Small Business Advocate ("the SBA") offers the following comments and observations as summarized below:

1. **Amount of variable generation**: The graphs on pages 4 and 11 denote the operational wind integration costs versus installed wind capacity. NSPI indicates throughout the document that 600 MW of variable generation are available and committed. Furthermore, the template on page 5 describes how NPSI will conduct the capital investment cost analysis for projects above 600 MW of variable generation. Please confirm that NSPI will evaluate in the 2014 IRP only additional to 600 MW of variable generation.

2. **NB additional tie**: If 600 MW of variable generation exist and are committed for the 2014 IRP, NSPI should evaluate a case where an additional tie to NB is constructed. This additional transmission line will provide mitigated measures for the wind integration and displace the potential need for capital investments of new fast start generators in Nova Scotia. The document describes the need for the additional tie but only at a level above 600 MW of variable generation. SBA believes that the benefits from an additional tie to NB may appear before the 600 MW level.

3. **Wind-Hydro Synergies**: The document does not provide information on potential synergies between hydro and wind in Nova Scotia. The large amount of hydro resources in Nova Scotia and its potential ability to quickly adjust its output to meet system demand can assist in reducing the wear and tear on the thermal units by utilizing hydro before thermal to follow system conditions. Therefore, SBA requests NSPI to consider in its modeling the enhanced ability of hydro resources to follow load in comparison with thermal units.

4. **Smart grid integration**: There are many new developments that can assist in the integration of variable generation. This may include the deployment of smart meters to facilitate more demand response programs, incentives to promote the installation of stationary and mobile storage facilities, and generation on the distribution system. This document does not provide any information on whether NSPI will consider the initiation of these programs in correlation with the integration costs of the variable generation.

5. **Better wind technology can reduce the wind forecast error**: The rapid growth of variable generation technology results in wind and solar actively participating in system reliability along with conventional generation. For example pitch controlled wind turbines can minimize the forecast error by adjusting to the system needs without the additional cost of non-contingency reserves. SBA requests NSPI to model different estimates of reserve requirements that will result in different integration costs. In addition the internal transmission reinforcements, which are described in page 16, will further reduce the impact of variable generation.

6. **Potential changes in unit dispatch in Nova Scotia:** The considerable increase of variable generation will increase the system uncertainty that NPSI must factor in its operating decisions. This will initiate enhancements to existing operating criteria, practices and procedures to account for the significant penetration of the new resources, and potentially result in changes in how dispatch is commenced. In practical terms, NSPI may decide to commit additional capacity for ramping capability and ancillary services to ensure the system can withstand significant contingencies (Similar to Must Run). Also

the company may initiate restrictions on the range of oscillations on thermal units, which are not designed to operate in such mode, to minimize their potential wear and tear.

7. **32 MW of additional non-spinning 10-minute reserve mentioned on page 12:** The document does not provide adequate information on how this number was derived. The 10 minute criterion is related to the procurement of enough 10 minute reserves for a balancing authority to meet is first contingency loss. NSPI must explain how the added variable generation will affect this procurement.

8. **Graphs on page 4 and 11 cost calculation:** There is no information or documentation on how the graphs on pages 4 and 11 were developed. In addition, it is not clear how NSPI will model these costs in the candidate resource plan process.

The SBA appreciates the comprehensive effort NS Power is making to review the assumptions to its 2014 IRP with the members of the IRP Participants group. In order for the SBA to reach a greater level of comfort with the proposed Variable Generation Integration Cost assumptions, however, we would appreciate obtaining more detailed information as summarized in the comments above.

The SBA appreciates the opportunity to submit these comments and information requests and looks forward NS Power's response, as well as to continuing to participate fully in NSPI's stakeholder process for the 2014 IRP.

Sincerely,

Sandy Dunling for
E.A. Nelson Blackburn, Q.C.

SMALL BUSINESS ADVOCATE

Scotian WindFields
Community Owned. Naturally.

May 9, 2014

Nova Scotia Power Inc.
1223 Lower Water St.
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B3J 2 W5

RE: Submission of Comments: May 1, 2014 Variable Generation Integration Cost Assumptions.

Hello,

Scotian WindFields would like to submit the below comments and suggestions based on the Variable Generation Integration Cost Assumptions provided on May 1, 2014.

i) Distribution-Connected Variable Generation

The cost assumptions provided indicate that the total projected model of NSPI's 2020 system (current system plus committed wind plus Maritime Link, but excluding other new infrastructure) gives a value of 550-600 MW of total wind general. However, there is no detailed distinction between distribution-connection and transmission-connected generation sources throughout the analysis provided.

In the provided 2014 IRP Draft Assumptions, NSPI models 150-200 MW of COMFIT wind generation in operation by 2020. All COMFIT wind generation is distribution-connected and is limited by the existing substation minimum load, greatly simplifying the considerations for excess generation and localized infrastructure.

Given that this distribution-connected generation accounts for nearly a third of all wind generation on NSPI's 2020 system model, Scotian WindFields requests a clear distinction be made for the integration costs of distribution-connected and transmission-connected wind generation.

ii) Details on Considered Energy Storage Technologies

The cost assumptions provided indicate, on page 5, that "Other Energy Storage" is considered, at a capital cost of $135M/50MW, with 50-100 MW needed. Scotian WindFields requests details of what technologies are considered, how the capital cost estimate were derived, what operational costs exist and in what configuration the resources are planned to tie into the NSPI system.

Should you require any clarification or further details on and of the points included in this response, please do not hesitate to contact Scotian Windfields directly. Thank you for your consideration of these comments and we look forward to further discussion and analysis.

Sincerely,

Stephen Thomas, EIT
p.p. Daniel Roscoe, P.Eng.
Chief Operating Officer
Scotian WindFields Inc.

Comments on June 23 IRP Update

Paul Chernick

Consultant to the Consumer Advocate

July 8, 2014

Environmental Constraints (slides 5–10)

Scenario B for GHG limits (no reduction after 2020) seems unlikely, and little or no analytical effort should be expended analyzing this option.

For SO_2, NOx and mercury, NSPI proposes to model the June 2013 proposal through 2030 from Nova Scotia Environment as Scenario A, and no post-2020 reductions as Scenario B. Unless NSPI has some information indicating that there is a significant probability that NSE will withdraw its proposal and not substitute some other reduction in allowed emissions, NSPI should not waste efforts on Scenario B. If NSPI believes that exploring sensitivities in emissions caps would be important, it might consider modeling scenarios (1) averaging Scenarios A and B and (2) requiring reductions greater than Scenario A, including additional reductions after 2030.

Supply-Side Options (Slides 13–14)

If the coal options are under serious considerations, NSPI should explain how it estimated the costs of these somewhat exotic technologies.

Among the gas-fired options, NSPI lists some combined-cycle options as being less expensive than some combustion turbines. This result may be correct, but it is contrary to most recent experience and warrants some explanation of the source of the cost estimates.

The installed wind costs appear high, especially since the next wind additions are likely to be several years into the future, benefiting from significant technical progress. The South Canoe wind farm is budgeted at about $1,800/kW in 2013$, plus about $150/kW for transmission facilities and upgrades. NSPI should document the source of its wind-plant cost estimates.

More broadly, NSPI should clarify the scope of its supply cost estimates, specifying whether they include such factors as transmission network upgrades.

If NSPI intends to seriously pursue the analysis of storage options, it should clarify the energy storage in MWh for each alternative, and for the CAES, the amount of natural gas required for reheating the compressed air during generation conditions.

NSPI should clarify its expectation for the incremental energy output from the Mersey upgrade.

Environmental Controls
(Slide 15)

The presentation of the Lingan “Carbon Capture 25% Power Penalty (in addition to scrubber)” option is confusing. How many units would this apply to? Does the $790 M include the $210–$220 M for the scrubber, or is that additional?

The emission reductions for the Pt. Tupper gas cofiring should be estimated. At 53% gas, the SO_2 and Hg reductions should probably also be 53%, with a lower reduction for NOx and about 25% CO_2 reduction.

The emission reductions for the Trenton 5 biomass cofiring should be estimated. NSPI should also indicate why Trenton 5 is the prime candidate for biomass cofiring, rather than Pt. Tupper or Lingan.

PPA Options
(Slide 18)

Cost estimates are needed for Options NB2 and NB3.

Generation Retirement Assumptions
(Slide 23)

NSPI should evaluate the option of keeping Lingan 1–4 running as load following units, accepting accelerated wear, until one unit wears out, justifying retirement. The paper “Flexible Coal: Evolution from Baseload to Peaking Plant,” from US DOE’s National Renewable Energy Laboratory, explains this approach to using baseload coal plants for load following.

The assumption that Trenton 5 would be retired before Lingan 1, 3 and 4 is odd, given the much higher usage of Trenton 5 (Slides 60, 68).

If the coal plants can operate for 60 years, the gas-fired steam plants (with less corrosive operating conditions) should be able to operate much longer. Considering the importance of Tufts Cove steam (especially Units 2 and 3) for load following, NSPI should continue investing in these units over the next few years as if they will operate indefinitely. For IRP modeling, NSPI should ensure that assuming the retirement of Tufts Cove units is not biasing any near-term decisions. For example, the analysis described in Slide 85 could lead to the conclusion that a CRP is infeasible, due to load-following limitations that would not have occurred without the retirement of Tufts Cove.

Final Fuel Price Forecast (Slides 25–26)

Slide 25 appears to be driven by forecasts of Henry Hub prices, with adjustments for basis to New England and tariff charges to Nova Scotia. It would be helpful for NSPI to share the forecasts and adjustments, so that these projections can be compared to other sources.

Similarly, Slide 26 appears to be driven by forecasts of Henry Hub prices, with adjustments for basis to New England and implied heat rates. It would be helpful for NSPI to share the forecasts and adjustments, including the selection of the peak and off-peak heat rates. NSPI should also explain how the carbon emission limits that EPA has proposed for 2020–2030 will affect import pricing.

In addition to the above, the gas and power prices should show strong seasonal variation. NSPI should provide its assumptions regarding monthly or seasonal prices and heat rates.

Candidate Resource Plans (Slides 33–40)

Slide 33 treats plant retirement as an assumption, rather than a cost-minimizing result of the resource plan and cost assumptions. At some point, NSPI should examine whether its retirement assumptions are appropriate, given the other components of the leading plans.

It is not clear why the low-DSM case is designated “Plan 1 (Base Run).” This terminology appears to reflect a judgment that ENSC’s DSM projection is too high. NSPI should articulate the basis for this judgment.

The CRP descriptions (slides 34–36) do not specify the treatment of Tufts Cove retirements.

NSPI should clarify whether “Maximum Coal Use” is synonymous with the retirement schedule on Slide 23, or whether other inputs force higher levels of coal use. Similarly, NSPI should clarify the meaning of “Medium” and “Minimum” coal use.

NSPI’s numbering system for the CRP plans, naming the plans in order of their NPVs (slide 40), is apt to be clumsy for presentation and discussion of results. If, during the analysis, NSPI changes any input assumptions, the plans may all be renamed. Similarly, CRP 2.3 and CRP 4.3 may be completely different; the portion of the CRP number after the decimal point has no consistent meaning.

MERRICK
JAMIESON
STERNS
WASHINGTON
& MAHODY
BARRISTERS

TRUSTED COUNSEL. SKILLED ADVOCATES.

July 8, 2014

VIA EMAIL

26872
Nicole Godbout
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Halifax, NS B3J 2W5

Dear Ms. Godbout:

Re: IRP – June 25 – Avoided Costs

These are the comments of the CA in relation to the presentation on avoided costs that occurred on June 25, 2014.

The CA agrees that the difference in revenue requirement (DRR) is the most appropriate approach for establishing avoided costs in Nova Scotia. NSPI will need to address the issue of avoided transmission and distribution costs, perhaps based on an historical relationship between load growth and load related additions.

The CA supports a periodic update of avoided costs, on a regular basis. The timing should be long enough to allow some predictability in DSM planning and minimize excess effort on the part of NSPI and stakeholders, but short enough that avoided costs do not fall out of date. Depending on the schedule established for DSM planning, an appropriate interval for avoided costs updates might be two or three years.

Yours truly,

WL Mahody

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July 8, 2014

Nicole Godbout, Regulatory Counsel
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1223 Lower Water Street,
Halifax, NS B3J 3S8

Dear Ms. Godbout:

RE: M05522 - 2014 IRP - Stakeholder Comments on IRP Focus and Resource Allocation

After reviewing the reference files provided by NSPI during the "IRP Conference – Progress Update", the Department of Energy ("the Department") offers the following comments:

- The following market scenarios and technologies are suggested for consideration in relation to the IRP world's analyses:
    - Future opportunities for imports and exports (i.e. a regional approach to energy markets). Additional hydro resources from either Quebec or Newfoundland,
    - Biomass co-firing (e.g. agricultural biomass),
    - Tidal power,
    - Grid optimization/Smart grid/Demand response development;

- The International Energy Agency (IEA) Technology Roadmap report, suggests smart grid deployment, could reduce peak demand increases by 13%-24% over the period spanning from 2010 to 2050. This reference may provide some directional information that is useful for parties to consider.

  Refer to: http://www.iea.org/publications/freepublications/publication/name,3972,en.html.

- For the tidal scenario, it should be similar to that modeled for the Atlantic Energy Gateway - 300 MW at prices competitive to other low impact renewables.

- In terms of sensitivities, we would suggest that a range of ± 15%-20% should be modelled for load, imported electricity pricing, import economy energy availability and coal and natural gas prices.

Respectfully,

Andrew Weatherbee

AW/vm

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Nicole Godbout
Regulatory Counsel
Nova Scotia Power Incorporated
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Halifax NS   B3J 2W5

July 9th, 2014

Dear Ms. Godbout,

RE: M05522 – 2014 Integrated Resource Plan
Ecology Action Centre Comments on June 25th Technical Conference

Thank you for the opportunity to comment further on the Integrated Resource Plan. The initial results for the selected candidate resource plans were informative and EAC looks forward to further results. Our specific comments and suggestions are as follows:

Demand Side Management

Particularly given new legislation on energy efficiency, it is essential that DSM programs be treated on equal economic footing to supply side options without constraining allowable investment in DSM so that viable DSM scenarios are not prematurely rejected.

While EAC does not at this time have specific comment on the Avoided Costs of DSM discussion introduced at the technical conference, we would like to reiterate our stance that the Program Administrator Cost test is a more appropriate test to use within the context of the IRP. Though the Total Resource Cost test has been used to date, it fails to adequately quantify the total benefit of a portfolio of energy efficiency programs.

Candidate Resource Plans

EAC is concerned that both the number of plans considered and the potentially large number of fair solutions for each CRP will be difficult to present and examine for potential Preferred Resource Plans. As stated in the Terms of Reference, 3a, the effort should be inclusive to avoid premature rejection of options.

We agree with comments made at the recent technical conference regarding cost accuracy. It is clear that because the analysis inputs are estimates and many assumptions are speculative, Strategist solutions with similar overall predicted costs are, within the accuracy of the analysis, equivalent cost solutions. Although they may be ranked above or below each other, EAC feels that solutions with NPV costs within 5% of each other should be examined thoroughly.

It would be good to see which Strategist supply side and demand side alternatives are selected for solutions that rank within 5% of each other for overall NPV. Understanding which of the commonly selected alternatives will help avoid premature rejection of options. These alternatives should include the options, or variations on them, listed in the final assumptions (Supply Side Options, Future Environmental Control Technologies, Future Supply-side Thermal Options and PPAs/Import Options). For example, EAC feels that it is of particular interest to Nova Scotians to know which, if any, regional transmission options (especially NB2 and NB3) offer cost effective solutions.

Please consider including in future CRP results a table, or something similar, with options/alternatives listed against considered CRP's that shows which CRP sub-solutions employ each listed option. It may be that listing specific sub-solutions for each option is too cumbersome in which case, simply showing the number of top 5% cost solutions that employed the option in each CRP would be instructive.

Worlds to Consider

The assumptions established to date are based on modest deviations from the current trends of increasing fuel prices, higher renewable content and more restrictive emissions constraints. Identifying resource plans optimized for these conditions makes sense. Notwithstanding, change has swept through the Nova Scotia electricity system in the past as we transitioned from fuel oil to coal generation and the potential for future shocks of this type is growing.

For this reason, ***EAC feels that three alternate worlds should be examined***.

> World 1, Business as Usual: This is the world established within the existing assumptions.

> World 2, Zero GHG World: This is a world where carbon emissions from stationary sources like power generation are no longer permitted. Emission sequestration options would become mandatory. GHG emissions would be limited to transportation, forestry and agricultural activities.

> World 3, Renewable World: This a world where carbon emissions from stationary sources like power generation are no longer permitted and sequestration of C02 is either not permitted or locally impractical. GHG emissions would be limited to transportation, forestry and agricultural activities.

While EAC recognizes that these are extreme perspectives, they do represent worst case change scenarios for our power generation system. Solutions that emerge from these worlds bound the range of low carbon transformation options for our power system and will help to focus selection of a 'no regrets' Preferred Resource Plan in World 1.

These options represent real conditions that may result from further Federal government regulation, either as a component of the current administration greening an overall resource intensive fossil fuel exporting economy, or as the result of policies choices within a future government formed by one of the opposition parties (see Appendix 1 for a discussion of potential future national political realities).

Demand Side Management and High Wind Resource Plans

Understanding that Strategist as a planning tool may not fairly examine resource plans with high variable generation and low load, EAC strongly recommends that Plexos be used to examine a high wind and high/medium DSM case. Understanding the capacity factor for existing thermal plants, the value of regional interconnection and the degree to which wind curtailment / export becomes necessary is important so that resource plans of this type are not prematurely rejected.

Demand Response and Storage Evaluation

Likewise, Strategist may not fully reveal the value of Demand Response or Storage options. ***EAC strongly recommends that Plexos be used to examine a high wind and high/medium DSM case so that both the potential benefit and cost implications of these options are clear.*** Understanding the potential value and costs of demand response and storage is important so that resource plans of this type are not prematurely rejected.

COMFIT Assumption

EAC recommends that the Full COMFIT allocation be applied to all CRP's. EAC recommends that the assumptions as stated be retained (Total 150MW of COMFIT wind generation by the end of 2016), but that an additional COMFIT generation capacity of 25 MW per year in 2017 and 2018 be assumed to bring full amount on line.

Not withstanding this assumption, ***EAC recomends that the COMFIT be extended indefinitely***. This IRP will aid in identifying the amount and type of COMFIT generation that should be included in the future.

Regional Balancing and Interconnection Options

In addition to ensuring that import options are considered, EAC feels that the assumptions and CRP's are not well configured to explore the potential benefits of improved regional interconnection and power balancing. ***A CRP that reflects improved regional interconnection and balancing and also reflects the potential cost sharing of these improvements should be investigated.*** Balancing in particular may offer the chance to narrow the duration of low wind periods.

Changes to meet our needs may well benefit the power system within other Atlantic region provinces. As an example, the Maritime Link has the potential to improve congestion within areas of the New Brunswick power system, a windfall to ratepayers there. Regional interconnection costs may well be something that can be shared.

Sensitivities

EAC recommends that the assumed price of carbon emissions be one of the sensitivities explored.

EAC recommends that sensitivities explored for all options be non-linear. That is, that the negative cost sensitivity be less than the opposing positive cost sensitivity. This reflects the unfortunate mathematical reality of cost differences. In our world, the probability that a cost may increase 10% is typically greater than the likelihood that it will decrease 10%. In the extreme, while there is a chance that a cost will double (+100%), the chance that the cost will go to zero, (-100%) is far smaller.

Likewise, the magnitude of the sensitivity considered should not be small. As discussed in the technical conference and echoed here, the accuracy of the Strategist solutions is dependent on the input assumptions. Within small sensitivities, the effects are not likely to be significant and will not show that the prospective resource plan is robust. EAC recommends that sensitivities examined take the form of -25%/+50%. Plans that respond in proportion to these sensitivities are clearly robust. Plans that do not are clearly riskier.

Sincerely,

Catherine Abreu

Energy Coordinator
Ecology Action Centre

Appendix 1: Potential Future National Political Realities

On a global per capita basis, a Canadian target consistent with the goal of preventing greater than 2^{0}C would set national GHG emissions reductions by 2050 at 95% below 2010 levels. In the 2039 IRP timeframe, national targets would limit GHGs to approximately 1/3 to 1/4 of present-day emissions.

These reduction targets lie within the range of policies under consideration by Canadian federal parties. The Climate Change Accountability Act Bill C-311 (2010) proposed similar limits and passed third reading in the House of Commons in 2010. Originally sponsored by Member of Parliament Bruce Hyer (then an NDP MP and now a Green Party MP), Bill C-311 achieved broad support including, among others, current leaders of both opposition parties. Bill C-311 was only defeated on second reading in the Senate in 2010. The current official opposition has resubmitted this bill for consideration and policies similar to it are likely to remain under active consideration for the foreseeable future.

Stationary emissions, especially electrical power generation facilities, present the largest opportunity for easy reductions today, particularly when compared to the difficulty associated with reducing emissions from transportation or oil and gas extraction. For this reason, under potential future federal emissions reductions regulations, electricity generation will be looked to virtually eliminate GHG emissions as soon as possible.

THE BRETON LAW GROUP

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July 9, 2014

File No. 41736-5

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Dear Ms. Godbout:

Re: June 25th IRP Technical Conference

Efficiency Nova Scotia (ENSC) has reviewed the materials provided by Nova Scotia Power Inc. (NSPI) in advance of its June 25th Technical Conference. We appreciate the opportunity to provide feedback on these materials and provide the following comments.

Candidate Resource Plans

In reference to the further development and analysis of Candidate Resource Plans, ENSC supports flexibility in the particular date of retirement for individual coal thermal generating stations within the 40, 50 and 60 year retirement scenarios. Since these retirement dates are not automatically optimized by modelling software, exploration of the most cost-effective retirement dates by NSPI on a per-unit basis is important for ensuring the selection of a resource plan that minimizes the utility's revenue requirement.

Avoided Costs

ENSC agrees with NSPI's suggested approach of further engagement with stakeholders to determine the most appropriate methodology. As a precursor to these consultations, it would be beneficial if NSPI provided sample calculations using the three potential methodologies put forward during the Technical Conference. These example calculations could show outputs of both the Peaker method and the Proxy Unit method as compared to the latest avoided costs produced using the Difference in Revenue Requirement method used in the 2009 IRP update.

ENSC supports the breakout of transmission and distribution avoided costs from the calculation of energy and capacity avoided costs.

During discussions on the “Future approach under new legislation warrant further discussion” item on slide 6, a reference was made to DSM being screened using avoided costs from, for example, a three-year period rather than the current approach of a longer period (20 years in the last DSM Plan). The calculation of “short-term” avoided costs of DSM may have unintended consequences, as the benefits of DSM activities are inherently long term, thus rendering a short-term analysis potentially problematic. ENSC suggests that a thorough discussion on this topic, among other potential changes to the calculation and incorporation of avoided costs, should be included in the stakeholder discussions on avoided cost methodology.

Conclusion

ENSC appreciates the opportunity to provide these comments on the candidate resource plans and the avoided costs presentation from the June 25th IRP Technical Conference. We look forward to continuing to work with NSPI and all stakeholders throughout the remainder of the IRP process.

Yours very truly,

THE BRETON LAW GROUP

James R. Gogan

cc. Allan Crandlemire
John Aguinaga
Julie-Ann Vincent
cc. M05522 Participants

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July 9, 2014

Delivered by E-mail

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Dear Ms. Godbout:

Re: Feedback on IRP Analysis Plan (Technical Conference No. 2)
Integrated Resource Plan (IRP) 2014 – M05522/P-884.14

Following the second IRP Technical Conference on June 25 and review of the "Progress Update" materials circulated by NSPI in advance of the conference, on behalf of the Industrial Group, we make the following submissions regarding the IRP Analysis Plan.

Environmental and Emissions Assumptions

1. NSPI has proposed to model Scenario "B" for emissions constraints which assumes no further reduction in CO2/ GHG and SO2, NOx and Hg past 2020 (slides 5 and 8). We have heard some participants express the view that these scenarios are unlikely and that additional reductions likely will be in place. However, we believe that there are valid reasons to include Scenario "B" in the modelling. The IRP is a long term planning exercise and successive governments may have different priorities. At the very least, modelling Scenario "B" would allow for a proper analysis of the costs associated with increasing emissions controls beyond the 2020 targets. Given that the objective of the IRP includes development of an Action Plan in a "cost-effective" manner, it is important to fully understand the costs surrounding certain courses of action. The Industrial Group supports the inclusion of Scenario "B".

Supply Assumptions

2. At slide 13, it is noted that the CC option is only roughly 50% heat rate efficiency (7200 Btu/KWh). We are advised that co-generation options in Alberta typically have heat rates that are approximately 5 GJ/MWh (closer to 70% efficiency). As there are currently viable natural gas options with better heat rates, the Industrial Group suggests these should be modelled.

3. At the Technical Conference, NSPI had indicated that it would provide the detailed assumptions that were used to develop the natural gas price assumptions (slide 25). Please provide these assumptions.

4. Also, if NSPI intends to revise or update coal, natural gas or other fuel prices prior to completing the IRP modelling, please provide relevant information as to when and how NSPI will update the assumptions.

5. With respect to purchased power assumptions, the Industrial Group requests that NSPI include, in the plan modelling, (a) scenarios where the Maritime Link is delayed in its completion and (b) scenarios where supply from the Link is curtailed such that there is no “market price” power available (only the “basic block”).

6. The Industrial Group would like NSPI to consider whether it is reasonable that the ratio of high case prices to low case prices in 2020 is lower for power (the one commodity that cannot be stored) (110/70), than for gas (15.2/7.0), coal (low sulphur 6.5/4.0) or HFO (25.2/11.2). One might reasonably expect that NSPI could better manage costs for fuel sources that can be hedged and/or stored, than costs for imported power which cannot be stored.

Plant Retirement

7. Based on the preliminary Strategist results provided in the Technical Conference materials, there appears to be a correlation between coal use and plant retirement. Specifically, that max coal use is based on 60 year retirements; medium coal use is based on 55 year retirements and minimum coal based on 50 year retirements. If this is correct, there appear to be some inconsistencies with the life-spans specified.

8. We have observed that:

- Slide 36 suggests Plan 1, 2 and 3 use 60 year coal plant retirements and Plan 4 uses 50 year retirements;
- Slide 52 CRP 2 is maximum coal use;
    - Slide 54 preliminary results for CRP 2 shows TUC 1 retirement in 2025 and TUC 2 retirement in 2032 (consistent with 60 year lives, from slide 23);
    - Slide 35 does not appear to reflect any retirements in 2025 and 2032 for maximum coal (although these units are small);
- Slide 81 CRP 4 is medium coal use;
    - Slide 83 Preliminary results for CRP 4 shows TUC 1 retirement in 2020 and TUC 2 retirement in 2027, 5 years earlier than CRP 2;
    - Slide 35 does not appear to reflect any retirements in 2020 and 2027 for med coal (although these units are small);
- This suggests a 5 year difference in coal plant retirements between max and med coal, i.e. 55 year lives, which is inconsistent with the 60 and 50 year life spans specified in slide 36.

9. Rather than controlling the plant retirement as an input across the fleet, the Industrial Group suspects that certain plants may be capable of extended lives. The Industrial Group suggests that NSPI apply its knowledge to vary and extend the plant lives individually as a limiting factor and then allow Strategist to choose the most cost-effective time for retirement within individual plant life constraints.

10. Further, at the Technical Conference, NSPI indicated it had not considered whether the expense of retiring a plant would be the cost of mothballing the plant or the cost of completely dismantling the plant (or some other option.) This choice will impact the overall cost of retiring a plant and so it is important to establish what assumptions will be used. The Industrial Group requests that NSPI provide more information with respect to the treatment of costs for retired generating plants.

Candidate Resource Plan Analysis and Preliminary Results

- Relative Fuel and Power Costs (slide 49)

11. These price differentials (imports vs. gas. vs. coal) are significant drivers for the Strategist model choices.

    (a) What heat rates were used to translate natural gas and coal prices to equivalent power prices for this graph? Heat rates of NSPI's existing units (for coal) or potential new units (gas)?

    (b) The on-peak power prices appear to exhibit two peaks per year, presumably summer and winter. Gas prices are shown with a consistent winter peak. Does NSPI expect winter peak power prices to consistently reflect a heat rate lower than they can generate at (as implied by the graph)? If so, will Strategist not always (under the Base Price scenarios) select winter peak purchases prior to running or building gas units? What is the likelihood of this happening year after year, as implied in the fuel price input data?

    (c) In the early years coal is lower cost than off-peak purchases only in the winter. Has this been the case in the recent past or is this a new paradigm?

- Use of Plexos in 2014 IRP

12. It is understood that there are certain benefits to evaluating a CRP through Plexos; unlike Strategist, it can control for multiple emissions constraints at the same time, can assess a Plan at a higher level of detail and can reveal understated benefits of some options. NSPI stated that Plexos cannot be used to evaluate all CRPs, but rather will be used strategically to take a closer look at those Plans that are "close to the line" for emissions controls and to better understand wind integration costs where there are Medium and High wind penetration cases (slide 85).

13. Given that Plexos will reveal useful information about the CRPs, but that it must be used in a limited fashion, the Industrial Group requests that NSPI develop and circulate a protocol that outlines when and how Plexos will be used.

14. We suggest that this should include a “control” scenario - one where NSPI expects that modelling in Plexos would not produce significantly different results from the Strategist model – to confirm that modelling in Plexos is only useful in the situations established by the protocol.

- Defining IRP Goals

15. Apart from evaluating the Net Present Value of different CRPs, NSPI has indicated that it will be looking at other qualities, such as the “robustness” of a plan, the impact on “system stability”, “cost effectiveness” and “flexibility.” It is important that stakeholders and NSPI have a common understanding of what these criteria are, how they will be used to assess individual CRPs and how they will impact the ranking of the CRPs once they have been ranked by NPV through Strategist.

16. The Industrial Group requests that NSPI develop and circulate criteria for assessing these “other qualities” and provide further information on how these qualities will be weighted or otherwise used to rank CRPs that have been, initially, ranked by NPV of the plan.

- Use of Judgment

17. It is understood that there are many instances where NSPI and Synapse apply judgment when developing the IRP plan analysis. For example, the steps that led to the creation of the five preliminary CRPs that were chosen for optimization runs in Strategist. These steps are outlined briefly in slides 33 to 37, but there is not a clear explanation of the process that led to the development of the five CRPs or why some inputs / options were selected over others.

18. Where judgment is used, particularly in significant steps in the process such as establishing the foundational or core CRPs, the Industrial Group requests that NSPI document how judgment was applied. This could include further information such as what factors were considered, why some were selected and others were rejected and what constraints shaped NSPI’s decision-making. This information will increase transparency and will facilitate a shared understanding of the overall process that leads to the selection of a preferred plan.

Thank you for the opportunity to provide these additional comments.

Yours truly,

Nancy Rubin

Nancy G. Rubin

NGR/lmc

cc IRP Participants

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In reply please quote our file number:

Lana Myatt
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Lana.Myatt@nspower.ca

Dear Ms. Myatt:

RE: M05522 - 2014 IRP - Intervenor Comments on IRP Focus and Resource Allocation

The Government of Nova Scotia is committed to maintaining a healthy environment for the benefit to our citizens. Through the *Environment Act*, *Environmental Goals and Sustainable Prosperity Act* (EGSPA) and their associated regulations NSE is mandated to protect and ensure the prudent use of Nova Scotia's environment. Nova Scotia has an approach for reducing air pollutant and greenhouse gas emissions that is part of a larger comprehensive plan to move away from coal-based electricity generation to cleaner energy sources. This approach helps to shield us from volatile fuel markets while protecting the environment and the health of our citizens.

Nova Scotia Power (NSPI) has requested feedback and direction from intervenors to help focus the analysis and sensitivities of the current Integrated Resource Planning process on realistic scenarios. NSE welcomes the opportunity to provide our valuable feedback and direction below to help focus this analysis.

As indicated in NSE's March 2014 letter, NSE believes that a scenario where no further air emission reduction occurs after 2020 is not realistic and would not result in NSPI meeting environmental regulations. As such, NSE believes that NSPI and the UARB should focus resources, sensitivity cases and analyses on the realistic scenario that reflects "Scenario A". This scenario encompasses both the current *Air Quality Regulations* and the reductions envisioned within the Amendment to Greenhouse Gas and

Air Quality Emission Regulations Discussion Paper ("the Paper") (NSE June 2013), which includes further reductions out to 2030. Moreover, NSE reiterates that compliance periods should be incorporated into the modeling, as indicated in NSE's April 2014 letter, since this is the realistic future.

Under its Air Quality Management System, the Government of Canada intends to introduce regulatory standards to reduce air pollution from coal-fired electricity generation. Such standards are envisioned to be benchmarked against leading jurisdictions and provide good baseline reductions. Nova Scotia approaches regulation of air pollutants from the electricity sector differently than most other jurisdictions that use a capital intensive approach. The approach of in-stack limits and/or requirements for abatement equipment provides immediate and near term reductions. In contrast, Nova Scotia's approach reflects a long term vision ("Scenario A"). This vision achieves good reductions through a flexible fleet requirement which does not dictate how NSPI complies with regulated emission limits. Rather, Nova Scotia's approach allows the freedom of choice as highlighted in recent IRPs. Both levels of government are committed to continual reductions after 2020. A strong but flexible approach in Nova Scotia ("Scenario A") may allow us to negotiate an equivalency agreement with the Government of Canada, as we did with GHGs, to the benefit of all ratepayers.

Finally, NSE suggests that NSPI take a broader look at a diversity of options for various types of air pollutant abatement equipment to reflect realistic options and constraints within the current IRP analysis plan. Limiting the type and location of equipment to only specific units hinders the ability to fully look at emission compliance, and limits the ability to assess all options to meet environmental constraints, including mercury control.

Thank you for this opportunity to provide NSE's valuable feedback into the IRP process to ensure NSPI's resources are adequately allotted to realistic and reasonable futures.

Yours truly,

EA Cody

Elizabeth A. Cody
Deputy Minister

c.c Murray Coolican, Deputy Minister of Energy

MacDougall, David

From:	MacDougall, David
Sent:	June 30, 2014 2:14 PM
To:	GODBOUT, NICOLE; WOOD, TIM
Cc:	MacDuff, James; Mahaney, Sara
Subject:	IRP input

Nicole and Tim,

Further to our comments at the recent TC and in response to your request for written input this is to confirm that PHP believes it is very important that:

1. as indicated on slide 88 of the TC presentation, Alternative Worlds testing include Worlds based on each of the Scenario B and C emissions constraints,
2. as also indicated on slide 88 of the TC presentation, sensitivities for the Candidate Resource Plans be tested against the high price scenario for natural gas, solid fuel and imports, and
3. to ensure a complete spectrum of economic analysis is available to both fully inform the robustness of the IRP and provide meaningful data for go forward policy development that the Alternative Worlds noted in 1 above also be tested with the high fuel price sensitivity noted in 2 above.

We look forward to seeing the results of the CRP runs and the Worlds/sensitivity analysis noted above.

Cheers
David

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July 9, 2014

OUR FILE:

Nicole Godbout
Regulatory Counsel
Nova Scotia Power Inc.
1223 Lower Water Street
Halifax, NS B3J 2W5

Dear Ms. Godbout:

RE: M005522 – IRP Comments

The following are the IRP comments of the Small Business Advocate.

I. Introduction

The Office of the Small Business Advocate ("SBA") is pleased with the opportunity to participate as an active stakeholder in the NSPI 2014 IRP. The SBA views this IRP as important planning exercise which will influence electric costs over the next 25 years and beyond. The SBA and its consultant have reviewed the draft Assumptions Presentation Materials provided by NSPI, met with NSPI staff and actively participated in the Technical Conferences.

The SBA stated in prior comments that we believe that an 'Objectives and Metrics / Stakeholder' step is missing. The SBA believes NSPI should review exact objectives and even solicit additional objectives from the stakeholder group to assure a comprehensive actionable IRP is developed. The SBA offers these comments as its next step in participation throughout the 2014 IRP.

II. Overview of SBA Comments

The SBA believes that NSPI is conducting a comprehensive and insightful IRP process in 2014. Our comments all focus on the decision framework employed by NSPI.

The SBA has concerns that too much time could be spent on analyzing extreme environmental scenarios as discussed by a stakeholder at the Technical Conference. The SBA recognizes the need to focus analysis on developing information to understand NSPI's strategy for resource development over the next five years. The longer term aspect of the Plan chosen provides context over the next few years for planning resources, but is certain to change as the energy world evolves.

III. General Comments – Decision Framework

The SBA stated in its prior comments that it is important for the stakeholders to come to agreements on the objectives of the IRP. The SBA does not see where this has occurred, nor is it apparent as to how this will happen during the IRP project prior to a draft report being issued in September, 2014. This would include establishing metrics NSPI intends to look at to determine the best resource plan or even the good resource plans. This would also include discussion of policy objectives that are implicitly and explicitly going to factor into the analysis and the ultimate decisions and report.

The objectives should be made up of goals and metrics. The Terms of Reference under Deliverables Item 1 defines the primary objective of minimizing electric costs, but clearing states that the criteria should include other aspects similar to what we have listed below. While there has been some discussion again throughout the June 25th Technical Conference on the other objectives, goals and metrics other than the Strategist cost output have not been established. The process still does not seem to include the briefing of and receiving input from the stakeholders in this all important area. The SBA has a strong desire to be involved at the level of establishing metrics and goals.

Goals & Metrics

1. Revenue Requirement Minimization - Primary
2. Acceptable Price of Electricity paths, specifically the average price of electricity in 2020, and 2025. The price of electricity in the relatively near term is perhaps the important result to the small businesses trying to survive in today's economic climate.
3. Plan Robustness and Flexibility still needs definition as others questioned during the Technical Conference
4. Environmental / Emissions Outlook need specific metrics. We must be able to show the true cost of a minimize emissions plan versus a meet emissions targets (such as CO2, NOx, Sox, Mercury etc.) plan.
5. Reliability & Energy Security – the levels of which alternative resource plans provide for Nova Scotia. The process has to provide metrics that allow decision makers to understand any differences in reliability of the plans and resource options.

A good IRP analyzes plans in a way that develops metrics relevant to all stakeholder objectives and then at the end will be able to articulate the proper weight or priority given to some objectives over others given the results. **The SBA recommends that a workshop be held with stakeholders to take input on a decision framework**.

IV. Finalized Assumptions

The following comments are specific topics of discussion from the June 25th Technical Conference. The comments below represent SBA and its consultants view on each topic.

A. Finalized Environmental & Emissions Assumptions

- There was considerable discussion as to whether NSPI should model scenarios that quickly lead the NSPI system to **zero carbon.** The SBA believes this is premature for the 2014 IRP. The SBA believes that a zero carbon or ultralow carbon future for Nova Scotia is a multi-sector question that needs analysis of the electric system, transportation system, industrialization and other fuel uses such as heating. Any analysis of the electric system at such a low or no carbon emissions level would not capture the interaction of the sectors and thus the results are not meaningful information for any strategic direction that would be set from the 2014 IRP.
- The NSPI scenarios of various RES requirements are adequate.

B. Final Future Supply Side Options Assumptions

- The supply side option information does not show how the costs of future options vary. For example, are certain technologies such as PV Solar or Wind, declining on a real dollar basis while others are not?
- The assumptions for technology improvement over time are not apparent, such as heat rate of combined cycles.

C. Final Existing Supply Assumptions

- It is critical that variation in the amount of energy delivered through the PPAs from New Brunswick and the Maritime Link be evaluated to determine the value of existing resource, and the timing of additional resource requirements.

D. Final Power Plant Life Assumptions

- The SBA believes that NSPI is making reasonable efforts to gain valuable information on the economics involving the existing coal fleet. One of the most important pieces of information that should result from this 2014 IRP is how should investments in the remaining life of the coal fleet be managed.
- The Sustaining Capital estimated from the ACE program data is a good starting point for IRP.

E. Final Fuel Price Forecast Assumptions

- No comments from the SBA at this time

F. Candidate Resource Plans

- The SBA requests that NSPI in it future technical conferences and in its report provide information and specific examples as to how some plans did not make operational or economic sense in its development of the Candidate Resource Plans. This screening logic is critical to stakeholders developing confidence in the NSPI process. (Slide 34)

- There must be discussion of the logic behind the DSM scenario choices, including helping the stakeholders understand the use of the DSM potential study.

- NSPI has stated that Strategist will provide lots of information including the cost and environmental data from the lowest cost version of a Candidate Resource Plan and other versions modeled. This data must be consolidated into visible metrics. Metrics such as emissions at future years and carbon emissions over the study period need to be developed from the data. Fuel mix metrics are also valuable. The amount of reliance on imported energy is also important. The total NSPI capital investments over the next 10 or 20 years is another metric that needs to be produced.

- There are many trade-offs to determine which Candidate Resource Plan is favored (better) than the other plans. The metrics used must be visible.

G. Strategist Resource Optimization Model & Preliminary Results

- The SBA hopes that NSPI analytical efforts are not deployed on differentiating between the types of resource deployed in 15 years when we will have many IRP efforts before that commitment needs to be made. It appeared that the discussion was driving to far too specific questions on model decisions that do not affect strategies developed today.

- The use of Strategist and Plexos needs to be presented with more concrete examples to gain support of the stakeholders. While a formal protocol may not be possible to establish up front, a 'de factor' protocol should be explained in the IRP report and future Technical Conferences.

H. Next Steps

a. Finalizing CRPs Process and Sensitivities

  - This process must recognize that a strategy is multi-faceted, requiring flexibility and decision signposts that determine the actual use of resources, including DSM, Renewables, existing Coal and Imports.

  - The IRP analysis should discuss the lead times on specific resources and how that contributes to flexibility.

b. Customer Engagement Sessions

- Did these include Small Business Customers? If so how many?

i. Avoided Costs of DSM

- The SBA wants avoided costs for DSM to be based on the differential of Revenue Requirements and not based on factors or costs external to the electric system.

V. Summary

The SBA has expressed comments above that center around the decision process, specifically the metrics that will be used. There are specific suggestions within some comments sections. The decision framework is what is most lacking in the NSPI process as it has been articulated within Technical Conferences. The SBA and its consultant are willing to work closely with NSPI and other stakeholders to develop a decision framework and specific metrics that will be produced as the results of each Plan evaluated.

Yours truly,

BLACKBURN ENGLISH

E.A. Nelson Blackburn, Q.C.
SMALL BUSINESS ADVOCATE

EANB/sld

Scotian WindFields
Community Owned. Naturally.

July 9, 2014

Nova Scotia Power Inc.
1223 Lower Water St.
Halifax, Nova Scotia
B3J 2W5

RE: Submission of Comments on IRP Analysis Plan

Scotian WindFields Inc. welcomes the opportunity to participate in the 2014 Integrated Resource Plan and submits the below comments and suggestions based on the IRP Process Update & Intervenor Feedback documentation that was provided on June 4, 2014, and information included in and leading up to the Technical Conference held June 25, 2014.

In general, we feel that the proposed IRP strategy has significant shortcomings with respect to the future cost of fossil fuels and carbon pricing. These shortcomings greatly reduce the effectiveness of this plan to adequately prepare our electrical system in the best interests of the environment and Nova Scotia's electrical stimulus. The following items that are detailed in the attached document will need to be addressed to alleviate these shortcomings:

- Fossil Fuel Price Forecast Assumptions
- Carbon Pricing Assumptions
- Limited Candidate Resource Plans

Should you require any clarification or further details on and of the points included in this response, please do not hesitate to contact Scotian WindFields Inc. directly.

Thank you for your consideration of these comments and we look forward to further discussion and analysis.

Sincerely,

Daniel Roscoe, P.Eng.
Chief Operating Officer
Scotian WindFields Inc.

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info@scotianwindfields.ca | www.scotianwindfields.ca

Scotian WindFields
Community Owned. Naturally.

1) Wind Assumptions

Scotian WindFields Inc. requests that the below points, regarding wind energy assumptions, be considered in upcoming analysis of Candidate Resource Plans.

a. Wind energy supply in excess of an additional 100MW (as currently shown as a Supply Side Option) should be considered.
b. Additional distribution-connected wind energy should be considered as a Supply-Side Option, with specific capital costs and integration costs considered.
c. Integration Costs and Demand Reduction should be considered in anticipation of **>200MW by 2030** of wind generation under the upcoming Renewable to Retail framework.

2) Solar Assumptions

The Draft Supply-Side Options only consider “>10MW” each of transmission-connected solar thermal and solar photovoltaic supply options. Scotian WindFields Inc. requests that the below points, regarding solar energy assumptions, be considered in upcoming analysis of Candidate Resource Plans.

a. We recommend that large amounts **(>10MW) of distribution-connected, individual and commercial-scale (1-100kW) solar photovoltaic energy** be considered as a Supply-Side Option.
b. We recommend that large amounts **(>10MW) of individual and commercial-scale (1-100kW) solar thermal energy** be considered as a Supply-Side offset.
c. Integration Costs and Demand Reduction should be considered in anticipation of **>100MW by 2030** of Solar Photovoltaic generation under the upcoming Renewable to Retail framework.
d. We welcome further discussion on the capacity factors of the various types of solar energy which were not discussed in the initial analysis provided.

3) Energy Storage Assumptions

Scotian Windfields Inc. requests that utilization of CAES, and other energy storage technologies be considered in high-RES Candidate Resource Plans.

The Capital Cost assumption for CAES is stated at **$1,400/kW** in the provided Supply-Side Options which is similar to the average capital cost of various Natural Gas-fired Combustion Turbines **($1,100 - $1,600)** that would also be considered in high-RES Candidate Resource Plans.

Scotian Windfields Inc. requests that energy storage technologies be considered in the transition to a high-RES world following the 2020 benchmark of 40% RES generation.

4) Fuel Price Forecast Assumptions

Scotian WindFields has the below comments regarding the initial Assumptions for Fuel Price Forecast Assumptions, particularly for the long-term price forecasting for Natural Gas, Petroleum-based fuels and solid fuels.

a. The Average Annual Increase of fuel pricing for Natural Gas between years 2015 and 2040, as presented in the Draft Assumptions (Slide 58) is between 2.4% and 3.1%. This is exceedingly optimistic consider that the Average Annual Increase of Natural Gas pricing between years 1991 and 2013/2014 was calculated at **5.5%**.[1]
b. The Average Annual Increase of fuel pricing for HFO and LFO between years 2015 and 2040, as presented in the Draft Assumptions (Slide 72) is between 2.3% and 3.59%. This seems exceedingly conservative as the Average Annual Increase of WTI crude pricing between years 1990 and 2013/2014 was calculated at **6.1%**[2] and the Average Annual Increase of Heating Oil was calculated at **6.3%.**[3]
c. Based on the above presented historical data, we **recommend that NS Power consider more representative energy inflation figures** in future IRP modelling.

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[1] As calculated from data provided by IndexMundi regarding $US/mmBTU monthly price of Natural Gas: http://www.indexmundi.com/commodities/?commodity=natural-gas&months=300

[2] As calculated from data provided by IndexMundi regarding $US/barrel WTI monthly price of Crude Oil: http://www.indexmundi.com/commodities/?commodity=crude-oil-west-texas-intermediate&months=300

[3] As calculated from data provided by IndexMundi regarding $US/gallon monthly price of heating oil: http://www.indexmundi.com/commodities/?commodity=heating-oil&months=300

5) Forecast Cost of Carbon

Scotian WindFields has the below comments regarding the Draft Assumptions for Carbon Pricing. Under the Case Development (Power) on Slide 60, it is stated that the assumed cost of Carbon is US$15/Ton CO_2 in 2020, escalating to US$37/Ton CO_2 in 2030.

The values for cost of carbon provided in the Draft Assumptions are associated with imported power. If and how carbon pricing is applied within Nova Scotia is vary significant variable as well.

- **a.** The IRP model should consider the potential for NS Power to be required to pay a price on carbon emissions.

Regarding the cost of carbon emissions specifically, we have drawn our analysis from a report commissioned by Synapse Energy Economics Inc. on November 1, 2013 - “2013 Carbon Dioxide Price Forecast”. This study considered the carbon price information from the most recent IRP efforts of 28 utilities. With the Canadian federal government's stated intention to harmonize carbon policy with the US and our economic interdependence, we feel it is reasonable to use US projections for Canadian pricing scenarios. We would request that the costs from this study for long-term carbon pricing be considered. The three key scenarios are itemized below:

- **b.** The **Low Case** forecasts a cost of Carbon at US$10/Ton CO_2 in 2020, escalating to US$40/Ton CO_2 in 2030.[4]
- **c.** The **Mid Case** forecasts a cost of Carbon at US$15/Ton CO_2 in 2020, escalating to US$60/Ton CO_2 in 2030.[5]
- **d.** The **High Case** forecasts a cost of Carbon at US$25/Ton CO_2 in 2020, escalating to US$90/Ton CO_2 in 2030.[6]

[4,2,3,] Synapse Energy Economics Inc., 2013 Carbon Dioxide Price Forecast, (Massachusetts, 2013)

6) Suggested Candidate Resource Plans

Scotian WindFields would to suggest a number of Candidate Resource Plan criteria to be included in the evaluation modelling. We understand that the five Draft Resource Plans, as presented in the June 25 Technical Conference, are preliminary in nature, however, we feel the range of plans considered in this initial analysis does not acceptably consider low-carbon or high-RES worlds.

None of the five Draft Resource Plans include the minimum coal use scenario, only one plan includes the medium coal use scenario and four plans include maximum coal use scenarios.

a. A Candidate Resource Plan that includes a transition to an electricity supply that consists of **100% Renewable Energy Sources by the year 2040** – Including Wind, Solar PV, Solar Thermal, Tidal, Legacy Hydro, Maritime Link/Muskrat Falls, Biomass and other sources for generation, with a phase-in approach to energy storage technologies.
b. A Candidate Resource Plan that includes a transition to an electricity supply that consists of **80% Renewable Energy Sources by the year 2040** – Including Wind, Solar PV, Solar Thermal, Tidal, Legacy Hydro, Maritime Link/Muskrat Falls, Biomass and other sources for generation, with a phase-in approach to energy storage technologies.
c. A Candidate Resource Plan that includes a transition to an electricity supply that consists of **60% Renewable Energy Sources by the year 2040** – Including Wind, Solar PV, Solar Thermal, Tidal, Legacy Hydro, Maritime Link/Muskrat Falls, Biomass and other sources for generation, with a phase-in approach to energy storage technologies.
d. A Candidate Resource Plan that includes the following criteria: **High DSM Case, Min Use Coal Case, High Wind Case.**
e. A Candidate Resource plan that includes Scenario C GHG Emission cuts to **2.25MT in 2040.**
f. A Candidate Resource plan that includes Scenario with GHG Emissions cut to **0MT in 2040.**

Comments on 2014 IRP Technical Conference Analysis Results

Paul Chernick
Resource Insight
19 September 2014

Many questions remain following the September 12, 2014 Technical Conference. These questions fall into three groups:

1. Information that NSPI must have developed in preparing the presentation but has not provided.
2. Important issues raised by the analysis, but not resolved.
3. Important issues that the IRP process does not appear to have addressed.

In the Technical Conference, NSPI indicated that not further analysis of plans or scenarios would be possible in this process. My impression is that the IRP analysis, as it currently stands, will not be particularly useful in providing guidance for future decisions. While NSPI plans to issue a Draft Final Report and Action Plan on September 30, it would be more appropriate that the work to date should be considered Phase I of the IRP, and the NSPI should be defining Phase II, to refine the inconclusive results of date.

In fairness, NSPI’s description of the Action Plan (slides 19–21) acknowledges that it has some major analysis and collaboration before it, including DSM planning and evaluation and further study of

- intermittent generation,
- “the operational challenges associated with variable generation,”
- “the need for flexible resources to integrate additional variable generation,”
- “cost-effective market opportunities,”
- “industry best practices regarding sustaining capital,”
- the generation retirement forecast,
- the economics of an FGD at Lingan 3 and 4,

- optimization of solid fuel use,
- potential for savings in fossil-plant O&M and sustaining capital in the high DSM case, and
- appropriate planning reserve margin.

Some of these items are flagged for results as late as fourth quarter 2016, which seems like an excessively long delay. Other items are slated for reports in some future 10 Year System Outlook; NSPI should be aiming to produce results by the next 10 Year System Outlook, in June 2015.

Considering all the outstanding issues, NSPI has not completed the 2014 IRP. The analyses listed above, and some discussed below, should be considered to be part of a second phase of the 2014 IRP, with NSPI running far behind schedule in addressing important issues.

Normally, an Action Plan would consist of specific activities to implement the results of the IRP. NSPI is generally far from that point. Even if NSPI insists on calling its ongoing efforts an Action Plan, rather than a second phase of the IRP, all parties must recognize that no usable 2014 IRP exists and NSPI faces multiple decisions without the background of a tested IRP.

Information Embedded in Results but Not Provided

Underlying Data

Some of the figures are difficult to read, due to the large number of overlapping CRPs. Most of the tables present derived data (differences from a reference case, percentage changes, present values). NSPI should provide the underlying data.

Revenue Requirements

The slides for the technical conference provided summaries of the relative revenue requirement per kWh for a subset of revenue requirements. The results are provided as percentage differences in \$/kWh across CRPs.[1] This information is of limited value, for three reasons:

- The percentage differences in partial revenue requirements per kWh can only be meaningfully interpreted if the reviewer knows what share of the revenue requirements are included in these results. The partial revenue requirements appear to exclude the return and depreciation on the existing generation system, all T&D costs (the treatment of the Maritime Link transmission is not clear); all retail costs administration, general and overhead costs; all taxes; and other costs listed on slide 15.[2] Hence, the significance of a 10% difference in this part of the rate is unclear: is it 8% of the average rate, or 4%, or 2%?
- The total revenue requirement is at least as important as the revenue requirement per kWh, but the presentation provides no information on the differences in total revenue requirement between plans.
- The percentage difference between the partial rates is less meaningful than the \$/MWh difference, which NSPI does not provide.

NSPI should report both the rates and revenue requirements for the various CRPs, and report those values for full revenue requirements. As part of that computation, NSPI should reflect the reduction in T&D costs and line losses for the high-DSM CRPs and increase for the low-DSM CRPs.

Treatment of Port Hawkesbury Biomass as Firm Capacity

In the past, NSPI has assumed that retirement of one 150-MW coal unit on Cape Breton (e.g., Lingan 2) would free up more than enough transmission capacity off the island to allow the Port Hawkesbury biomass plant to be counted as firm NRIS capacity. For some reason, NSPI now assumes (slide 8) that at least two Cape Breton coal units would have to retire before Port Hawkesbury would

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[1] Rather than admitting that it is comparing rates per kWh, NSPI refers vaguely to “adjusting the revenue requirements by load” (Slide 15) and refers to the rates as “revenue requirements.”

[2] Slide 15 mentions the exclusion of interest payments, but does not discuss the treatment of return on equity.

become firm capacity, and in CRP 4-1 Port Hawkesbury does not become firm capacity even after 600 MW of retirements.

Retirement Rationale

Slide 8 shows Tufts Cove 1 and 2 being retired in every CRP. It is not clear why NSPI has forced the retirement of these units in all plans, considering the relatively low cost of keeping these units on line, the high cost of transmission to serve the Halifax load centre with less local generation, and the operational flexibility of the gas-fueled steam units (less so for Tufts Cove 1 than Tufts Cove 2) for integrating wind and providing reserve.

Similarly, in CRP4-1 and CRP4-1FGD (and only those two cases), NSPI assumes retirement of Tufts Cove 3. It is not clear how NSPI decided that it could and should retire this flexible unit, and why this retirement would be justified in CRP4-1, but not the lower-load CRP6-1.

NSPI should reconcile these apparent inconsistencies.

Fuel-Price Forecasts

Gas prices and market electric prices appear to be forecast from Henry Hub prices, with adjustments for basis to New England, tariff charges to Nova Scotia and implied heat rates. It would be helpful for NSPI to share the forecasts and adjustments, so that these projections can be compared to other sources, including the effect of carbon emission limits pending in the US.

The IRP should also provide information on the seasonal variation in gas and power prices.

Areas in which Analysis is Incomplete

The Treatment of the PHP Energy Load

Once again, NSPI has included PHP’s economy energy under the load-retention tariff as it were firm energy for planning purposes, in violation of NSPI’s clear promises in the LRT proceeding, Matter No. 4862, including the oral testimony of Mark Sidebottom, NSPI’s Vice-President for Power Generation and Delivery, that NPSI would start with “a plan that has [the mill] not served, and then that we would provide them the incremental cost calculation that would then compare not serving them to serving them, and in that way we'll cover the incremental costs of them taking that decision to take that energy at the time" (Matter No. 4862, transcript at 400) and that "the obligation [to the mill] is limited to covering the incremental cost, not planning for the future" (ibid. at 459–460). NSPI followed up in writing with the following promises:

> To be clear, the agreement between NS Power and PWCC is that the mill will be served on a purely incremental basis only. As a result, NS Power will assume for all planning purposes, that the load required to be served is that excluding the mill's load. The Company will plan and optimize its fleet on this basis, independent of whether the mill operates. (Matter No. 4862, NS Power Reply Evidence at 9–10)
>
> Mill electricity consumption [is] treated as fully incremental throughout the term of the agreement. This means that the Company will not build generation capacity to serve this load, will not include this load in its planning work and will not manage its fuel portfolio to minimize cost associated with this load. (Matter No. 4862, NSPI closing submission at 14)

The Board accepted that representation as part of its approval of the LRT:

> NSPI will not include PWCC in its planning considerations, including future capacity additions or the restart of generation which has been seasonally shut down. (Matter No. 4862 Order of September 12, 2012, Appendix B)

This proceeding is exactly the type of "planning" from which the mill energy consumption must be excluded. Yet NSPI included the mill load, on the flimsy excuse that the load was needed "in order to calculate RES and emission compliance." (NSPI 2014 IRP – Draft Assumptions, March 14, 2014, slide 75). The RES is not binding in the CRPs during the LRT, so accounting for RES compliance is no excuse for this planning error. While the emission constraints must be accounted for, NSPI could have used a side computation to set aside enough emission allowances to meet the PHP load and optimize the system without PHP, rather than including the PHP load in computing energy costs.

As a result of this error, NSPI once again runs the risk of committing firm customers to pay for investments and other commitments to reduce the price charged PHP, even though PHP will not pay for those commitments.

The final IRP, or failing that, the Action Plan, must address this issue and determine whether any of the IRP results would change without the improper inclusion of PHP energy in NSPI's computation of plan costs.

Wind Capacity Value

In the Action Plan item list, NSPI proposes to "Pursue the study of further intermittent generation to determine appropriate capacity value…by Q4 2016." (slide 19). It is not clear why NSPI thinks it needs another two years to study the issue, or what further analysis is possible.

The difference between NSPI's current estimated value of wind capacity (12%) and the GE Consulting estimates (about 30%, excluding a case in which the COMFIT projects were assumed to be tightly clustered) is large enough to be the difference between the need to retain a fossil unit and being able to retire it. NSPI should provide a more complete explanation of why it believes that its 12% value is better than GE's estimates, or explain how it intends to improve its estimate.

Intermittent Generation Integration Costs

In March, NSPI reported that "A study to determine the costs to integrate additional intermittent generation is in progress." (2014 IRP – Draft Assumptions, p. 26)

In the June 25, 2014 Technical Conference, NSPI described the "use of Plexos in 2014 IRP… Plexos will be used to evaluate: 1. operability of a selection of Candidate Resource Plans developed by Strategist. 2. operability of Medium and High wind penetration cases and with various levels of DSM and to calculate operating portion of wind integration costs. 3. collateral benefit of system upgrades required to integrate further wind energy on the system." And "a limited number of Plexos runs will be conducted in the time allotted for the completion of the IRP." (Slide 85)

Six months after the draft assumptions, and three months after the June Technical Conference, the Analysis Results slides do not mention integration, but include the following in the Action Plan item list:

- Continue to develop an understanding of the operational challenges associated with variable generation and report to the UARB as part of the 10 Year System Outlook.

- Report to the UARB on the status of the need for flexible resources to integrate additional variable generation in the 10 Year System Outlook Report.

Assuming that NSPI means that it will report to the UARB in the June 2015 10 Year System Outlook Report (as opposed to some later report), NSPI is not promising any results for at least 15 months from the start of the study, and perhaps much longer. This delay is unacceptable. NSPI should have addressed renewable integration in this IRP; its failure to do so may increase costs to ratepayers. The final report on this phase of the IRP should describe NSPI's progress to date (including identifying the consultants who have been working on these issues), the plan for completing the analysis, and specific milestones leading to results that can be used to make resource decisions starting in 2015.

Effect of DSM on Total Costs and Revenue Requirements

In NSPI's revenue-requirements analysis for the CRPs with DSM differing from the base (CRPs 1, 5, 6, 7, 31 and 32), NSPI does not appear to have included the effect of avoided T&D investments, reduced losses, and increased steam plant layups and retirements. These DSM benefits should be explicitly included in the analyses conducted as part of the Action Plan and beyond.

Optimization of CRPs

Several of the CRPs, especially those with higher wind and/or DSM, have significant excess capacity, and will have even more, if and when NSPI recognizes the capacity value of ERIS resources. NSPI should be studying the feasibility and economics of additional retirements, to identify the least-cost plans for thermal generation in these CRPs.

Important Topics Not Yet Addressed

ERIS Capacity Value

Slide 19 proposes that NSPI should study the capacity value of Energy Resource Interconnection Service (ERIS) capacity until Q4 2016. That date is over two years in the future, and almost three years from NSPI's commitment (in the cost of service proceeding) to resolve this issue in the IRP. This issue appears to require only the examination of the nature of the constraints affecting each ERIS plant to determine whether it affects the deliverability of the plant's output at times of relatively high load and multiple outages of other capacity. This is a task for transmission engineers and does not conflict with the model runs for the IRP.

In addition to its role in the COSS, the capacity value of the ERIS capacity (wind and Port Hawkesbury biomass) may affect the ability of NSPI to retire or lay up additional generation, and should be resolved as quickly as possible.

The Value of Allowing Port Hawkesbury Biomass to Operate Economically

Following operation of the Maritime Link, NSPI will be able to meet its RES requirement while dispatching the Port Hawkesbury biomass plant only when it is economic. NSPI should be estimating the benefit of relaxing the current dispatch requirement, and seeking statutory and engineering solutions to allow that outcome.

Wind Plant Costs

NSPI's estimate of installed wind costs appears to be high, especially since the next wind additions are likely to be several years into the future, benefiting from significant technical progress. The South Canoe wind farm is budgeted at about $1,800/kW in 2013$, plus about $150/kW for transmission facilities and upgrades. NSPI should document the source of its wind-plant cost estimates.

Power Purchase Options

The IRP to date has not added anything to our information of the types and costs of power purchases that may be available in the future, including the cost and timing of required upgrades to the New Brunswick intertie.

Renewable Sales Options

NSPI has not addressed the long-standing issue of selling some of its excess renewable energy to New England at prices much higher than those available for fossil or large hydro. This option may have important effects in moderating the rate and bill increases from the Maritime Link.

Optimization of the Aging Fossil Fleet

In addition to determining the appropriate order of retirements, NSPI should consider whether it would be better to operate several units (Lingan 1–4, Trenton 5, Tufts Cove 1–3) in load-following service, accepting accelerated wear and retiring the units in the order that they wear out. This approach is explained at www.nrel.gov/docs/fy14osti/60575.pdf.

The IRP also does not address the local supply and reserve concerns that would arise with the retirement of one or more units at Tufts Cove (let alone all three, as assumed in some CRPs) and possibly at Trenton.

Inconsistencies and Questions

Additions and Retirements

The Preliminary Load and Resources tables in the Detailed CRP Results slides include additions that do not appear in slide 8 of the Analysis Results, including the 100 MW of small additions in 2015–2017.

The Preliminary Load and Resources tables, the addition and retirement in the "Preliminary Results" in the Detailed CRP Results slides, and slide 8 of the Analysis Results also show inconsistencies in later additions and retirements. For example,

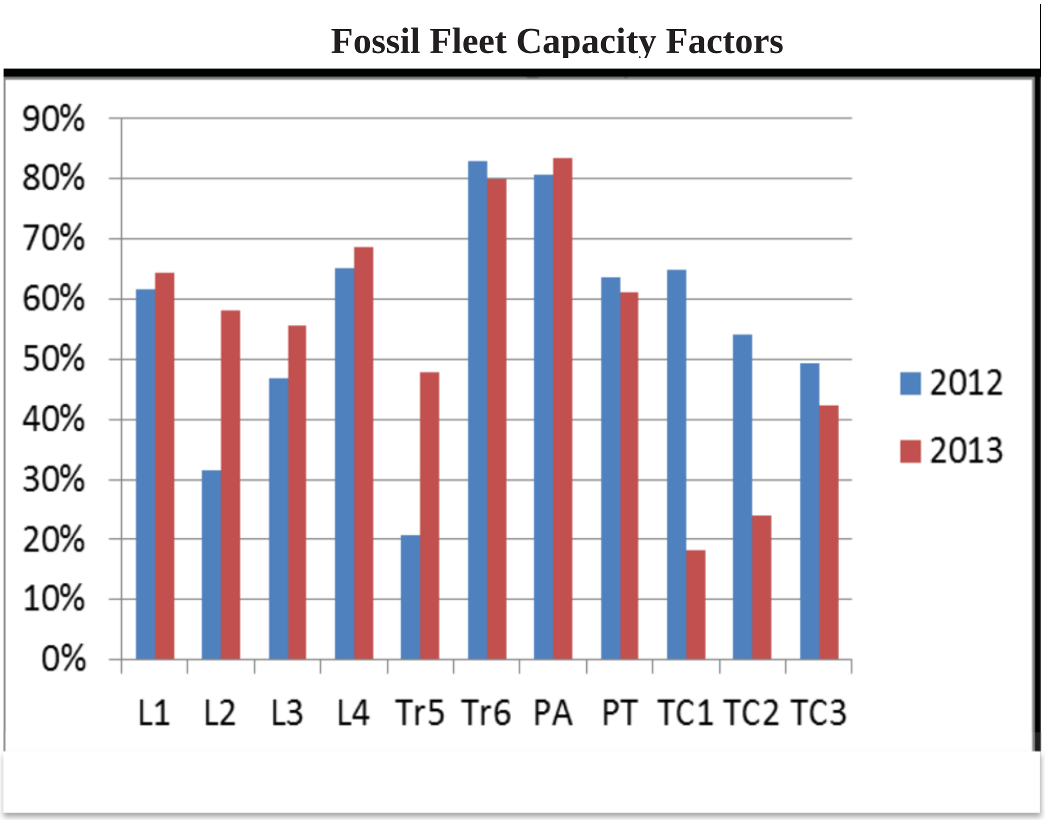
- For CRP 4-1, the Preliminary Results table shows the retirement of six 150-MW units, plus Tufts Cove 1 and 2; the Preliminary Load and Resources table shows 4 150-MW retirements and Tufts Cove 1; and Table 8 shows retirement of five coal units and Tufts Cove 1–3.
- For CRP 6-1, the Preliminary Load and Resources table shows the same coal retirements as slide 8, and Tufts Cove 1 and 3, but excludes the retirement of Tufts Cove 2 shown in slide 8.

Coal Plant Capacity Factors

For many of the CRPs (e.g., 1-1, 2-1, 3-1, 4-1, 5-1, 5-8, 10-1, 31-1), the Detailed CRP Results slides project that Trenton 5 will have capacity factors exceeding 65% in 2015–2019, and about 60% in 2020 through the unit's planned retirement in 2030 or 2035. With higher wind and/or DSM (CRPs 6-1, 7-1, 7-5, 8-

1, 21-1, 21-3, 32-1, and more modestly in 9-1, 9-3, and 9WC-2) , the Trenton 5 capacity factors gradually fall after 2020, to the 40% or 30% range. In all those cases, the Trenton 5 capacity factor is much higher than those of each of the Lingan units.[3]

Yet historically, Trenton 5 has run less than most or all of the Lingan units, as shown in this figure from the 2012–2013 FAM Audit. Since Trenton 5 was out of service for seven months in 2012 (March–September), its capacity factor was depressed. But since Trenton 5 operates primarily in the winter, it is not clear how much higher its capacity factor would have been without the outage.


Fossil Fleet Capacity Factors

The operating expense filings and the fuel updates from the last two GRAs and Figure 230 of the GE Nova Scotia Renewable Energy Integration Study support the conclusion that Trenton 5 generally runs less than the Lingan units.

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[3] In the cases that add an FGD to Lingan 3 and 4, those units' capacity factors rise and the Trenton 5 capacity factor declines dramatically. That situation is not comparable to the historical data.

The IRP should explain why NSPI is projecting that future dispatch order would be so different from historical dispatch.

In addition, considering the operating problems Trenton 5 has experienced, and the limited dispatch of the unit in the real world, NSPI should reconsider its assumption that "Trenton 5 [is] expected to extend life beyond 60 years due to recent significant capital investment" (June 25 slide 23). NSPI should explain why it has consistently assumed that Lingan 2 (installed 1980) would be retired 12 to 17 years earlier than Trenton 5 (installed 1969), and that in the cases with higher DSM and/or wind (CRPs 6-1, 7-1, 8-1, 9-1), all four Lingan units (installed as late as 1984) would retire as much as a decade before Trenton 5.

NSPI should be selecting to retire schedules to minimize total system costs, rather than to maximize its recovery of plant investment through depreciation prior to retirement. If NSPI has concerns about stranded prudently-incurred costs, it should approach consumer representatives to find a solution to that problem. Customers are better off paying the sunk costs of a retired plant that is uneconomic to operate than both the sunk costs and continuing O&M and sustaining capital.

As Liberty observes "the largest [fossil unit] investments came at Trenton. Considering the longstanding and continuing trend of poor performance at Unit 5, the value of this large investment should be questioned. One cannot observe a correlation between spending at Trenton and improvements in performance." (2012–2013 FAM Audit, p. VIII-27)

Assessment of 2007 and 2009 IRPs

Slide 10 asserts that "The planning done through the 2007 IRP and refined in the 2009 IRP Update has proven robust." Given the magnitude of changes in NSPI's load and supply not anticipated in 2007 or 2009 (e.g., addition of the Port Hawkesbury biomass plant, another 170 MW of contract wind, COMFIT, and the Maritime Link; loss of large amounts of industrial load), it is not clear what planning in the 2007 IRP and the 2009 IRP Update has proven robust. That raises questions about the realism of NSPI's view of its planning efforts. Rather than broadly congratulating itself for its past planning, NSPI should clarify what part of that planning has proven to be valuable, and what parts problematic, to inform future planning.

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Nicole Godbout
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September 19, 2014

Dear Ms. Godbout,

RE: M05522 – 2014 Integrated Resource Plan
Ecology Action Centre Feedback for Incorporation into IRP Action Plan

Ecology Action Centre welcomes the opportunity to offer these key observations and comments on the Integrated Resource Plan Analysis Results and other information presented in Technical Conference held September 12, 2014.

5 Year Action Plan

Integrated Resource Plan (IRP) Terms of Reference:

> "To develop a long-term Preferred Resource Plan that establishes the direction for NS Power to meet customer demand and energy requirements, and environmental obligations in a cost-effective, safe and reliable manner across a reasonable range of foreseeable futures; and to develop an Action Plan describing the major tasks required to implement a no regrets strategy that aligns with the Preferred Resource Plan during the first five years of the planning horizon."

The Ecology Action Centre emphasizes that the IRP process must focus on *long-term* priorities for NSPI, Nova Scotia's electricity system, and Nova Scotian electricity consumers. A 5 Year Action Plan should describe steps to be taken toward the fulfilment of a long-term plan over the next 5 years. A 5 Year Action Plan should not be used as a means of favouring resource plans that have desirable short-term implications while losing sight of long-term goals.

A 5 Year Action Plan that does the latter - favours resource plans with desirable short-term implications while losing sight of long-term goals - might, for instance, disadvantage demand side management (DSM), which requires upfront investment for long-term benefit. The International Energy Agency recently analyzed the long-term benefits of investments in energy efficiency and found "when the value of multiple benefits is calculated alongside traditional benefits of energy demand and greenhouse gas emissions reductions, investments in energy efficiency measures have delivered returns as high as four US dollars for every one US dollar invested" (*Capturing the Multiple Benefits of Energy Efficiency,* IEA, 2014).

Likewise, pieces of infrastructure deemed critical by NSPI, such as the Maritime Link, have relied heavily on longer planning periods and assessment of end effects to justify the high upfront investments they require.

The Ecology Action Centre believes a 5 Year Action Plan, informed by a resource plan which prioritizes long-term goals, should place more emphasis on the benefits of DSM, the risks due to anticipated emissions regulatory changes and the potential benefits of improved regional collaboration.

Integrated Resource Plan Emphasis

The Ecology Action Centre appreciates that NSPI felt some discomfort over rate hikes during recent public meetings but feels strongly that this is only one of many factors to be considered. For example, meetings today in western Nova Scotia would highlight other concerns such as reliability. Future rate increases will be no less comfortable when the time comes. It is the duty of the utility to undertake long-term planning so that near and long -term effects are understood and balanced actions undertaken. The IRP process is a central tool in the long term planning process and that longer view should remain it's primary concern.

We disagree with NSPI's assertion that "There is a range of potential preferred resource plans based on the NPVs and other metrics; however, the company believes that alleviating rate pressure in the near term is in the interest of the customers." Surely Nova Scotians will be in no better position 5 years from now to face incremental DSM costs than they are today.

Likewise, we disagree with the assertion that "Uncertainty in the outer years may make it more beneficial to concentrate on nearer term IRP metrics." Short term cost concerns will always be present and are best left to the rate application process and capital planning process, as guided by the insights from IRPs and 5 year action plans.

The fundamental benefit of the IRP process and Strategist analysis is to examine long term impacts. In a system that is considering extending asset life to 60 years, serious examination of effects 25 years out is critical. If the results are too closely clustered, it is just as likely that the scenarios and sensitivities considered have been overly conservative.

Rate Impacts vs. Bill Impacts

Rates are not bills. While the Ecology Action Centre acknowledges that it is unrealistic to ask NSPI to move away from highlighting rate impacts, we are uncomfortable with the unspoken suggestion that rate impacts are entirely coincident with bill impacts. Electricity rates can rise while electricity bills decrease. We ask that this distinction between rate impacts and bill impacts - impacts to the end costs to customers - be made explicit in the Final Report and Action Plan arising from the IRP.

The modelling undertaken in the IRP assumes many things, load and population effects among many others. If NSPI is truly concerned about customers, it would be helpful to present estimated per customer cost changes in some form. Extrapolating from the partial annual revenue requirement data presented based on current overall revenue requirements and accounting for population/customer growth would seem to be possible. It defies imagination that a per-customer based metric cannot in some way be extracted from this effort. Such a per customer cost metric would be much more productive in assessing the potential reaction to rate impacts in both the near and linger term.

Demand Side Management

The EAC objects to the statement presented in the executive summary that "Environmental compliance and capacity planning is heavily reliant on DSM performing as forecasted." The same is true for virtually every component of the power system and especially so for plans considering extended life operation of aging assets. We would ask that the statement be dropped or expanded to include other threats to system compliance and capacity. The established processes to negotiate, review, audit and authorize DSM plans in Nova Scotia are thorough. DSM planning is a widespread activity in progressive regulatory bodies across North America and planning reliance on their performance is of less concern than many other factors such as industrial load growth or loss, fuel price volatility and changing regulatory constraints.

In considering DSM levels, it is simply the nature of demand side management that program spending now results in savings later. So CRP's that show near term costs increasing with benefits accruing in the future are both predictable and unremarkable. What is of interest is how reduced overall load in the future impacts the cost of operating the utility. The preliminary results clearly indicate these benefits:

-CRP5-1 shows a lower annual partial revenue requirement by the end of the planning period
-CRP5-1 shows the most preferable overall NPV over the study period.
-CRP5-1 shows a 50% excess planning margin in every year beyond 2017 and shows twice the required planning margin between 2028 and 2034.

As noted in the technical conference, the excess planning margin indicates that optimization of high DSM scenarios would result in even lower calculated system NPVs. In the context of proposed maximum coal plant retirement, some excess planning margin may well be prudent as public discomfort with modest rate increases would pale when compared with widespread loss of service as was the case with aging plant management in Newfoundland this past winter.

To hold off on DSM program spending today is to plan to defer benefits from 2034 to beyond 2039. The 5 year action plan should be frank with ratepayers and plan for steadily increasing levels of DSM so that the Nova Scotia of 2034 will be more competitive and prosperous than it is today.

Considering the evaluation criteria suggested, high DSM offers:

> Improved long term rate effects;
> Reduced risk because of the high certainty associated with DSM measures;
> Increased flexibility and robustness because the existing assets can be managed to serve an overall lower load;
> Reduced future regulatory emissions risk due to lower load served by planned and existing renewable assets.

Regulatory Environment

During the technical conference, repeated references were made to more stringent emissions regulations being a significant trend since the last IRP, specifically increased renewable energy requirements, carbon emission caps, and equivalency to federally regulated plant retirements.

This trend is clear. It is reasonable to expect that further limits will be imposed. As such, the EAC welcomes the limited sensitivity results that show emissions regulations present a much lower cost threat than fuel price increases.

Not withstanding the Scenario C sensitivity examination, the Ecology Action Centre feels that this IRP has failed in not squarely addressing the reasonable potential that the regulatory environment - for stationary thermal generation - may fall to zero GHG emissions.

It is important to view this within the Canadian regulatory context. We are where we are today because the federal government imposed coal plant retirement regulations. Given that the current federal government is likely to be the most generous in permitting continued GHG emissions, it is reasonable to expect future federal governments to take a stronger and more restrictive stance.

Thermal generation is likely to be singled out for zero emission regulations for the following suite of reasons:

- Thermal generators represent the largest single point emissions sources and are the primary point sources amenable to carbon sequestration or replacement.
- Canada's highest emitting provinces, Saskatchewan and Alberta, are the largest thermal power generators. (Alberta = 65 T per capita, Saskatchewan = 70 T per capita, Nova Scotia = 22 T per capita) and it is reasonable to ask them to take this step.
- Canada's highest emitting provinces, due to their resource wealth and infrastructure, are the most able to undertake zero emission projects.
- Canada's continued difficulty meeting stated emission targets will mean that when a government acts, they will be looking for early, easy gains such as zero emissions from thermal fossil power generation.

Simply put, thermal generation emission regulations provide the most regulated GHG reduction bang for the buck. This fact will not go away. As the federal government continues to examine how it can meet GHG targets while minimizing impact on the resource sector, or addressing the far more complex problem of transportation emissions, it is reasonable to expect them to consider a ban on GHG emissions from thermal fossil power generation.

It may be that Nova Scotia will be able to dodge this bullet, but the gun is loaded and on the shelf. It is reasonable to expect that at some time near the end of the study period, a government of the day will decide to pull the trigger.

The tools to consider this scenario lie within Strategist (increased regional transmission, sequestration costs, storage systems and renewable energy) and response to a zero emission regulatory environment should be examined for leading candidate resource plans.

This is especially the case when considering maximum coal plant life. CRP2-1, for example continues to operate thermal plants at 4 locations. It may be that CRP's with plants at fewer locations are less expensive to react to this scenario. The EAC strongly recommends that zero emission Strategist runs for leading plans, 2-1 and 5-1, to name two, be undertaken and their results included in this IRP. This will provide data that will be essential in assessing potential CRP's against all of the presented criteria (NPV, Rate Effects, Risk, Flexibility, Robustness, Future Regulatory Emissions Outlook risk) and, as specified in the terms of reference, for a reasonably foreseeable future.

Enhanced Regional Power Sharing/Balancing/Pooling

Nova Scotia and its neighbours are already facing the limits of what provincial grids can do to integrate intermittent renewable energy. While investing in the research and development of storage and smart grid technologies is an important piece of addressing this problem, we cannot predict what technologies will advance when and how we might be able to make the best use of them in Nova Scotia.

What we do have available to us right now is the capacity to improve regional sharing, balancing, and pooling of power. The Final Report and Action Plan must make clear how absolutely necessary enhanced regionalization is to the strength and long-term viability of Nova Scotia's electricity system under current and emerging regulatory requirements. While we are a long way from determining whether a regional system operator is the right solution for Atlantic Canada, there are many steps along the way from current near-energy island operations to a regional SO.

The Atlantic Energy Gateway Initiative conducted extensive studies on the potential for enhanced regionalization of electricity systems and has shown us that there is much optimization and great cost savings to be gained. It is time for the governments and utilities of the Atlantic provinces to get down to brass tacks on establishing what model would work best for our region. The IRP is a critical opportunity for NSPI to highlight this necessity.

Other Observations

The EAC would ask that the partial revenue requirement information be presented with reference to the annual spending in dollars associated with each plan and not represented as a fraction of one particular plan. This will allow comparison with respect to absolute system costs as they are today rather than a percentage of partial costs of an unknown magnitude for one plan over the other.

The Ecology Action Center asks that the results for Sensitivity Set 2, Emissions Scenario C be extrapolated to all presented CRPs. If the results from another CRP serve as a proxy, simply indicate this or repeat the results. At present it is not clear which other results reflect the sensitivity result for each CRP. Likewise the associated graph should represent the sensitivity to Scenario C on all bars.

We recognize the utility of comparing plans amongst each other with a single plan as the baseline, such as is the case for the presentation of partial revenue requirements (slide 16). It would be useful if other results, in particular the excess planning margin results (slide 34) were presented in a similar fashion. A graph showing fraction of the required planning margin for each CRP over time would help to compare between plans and weigh any potential benefit that might be gained from further optimization.

Sincerely,

Catherine Abreu

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September 19, 2014

File No. 41736-5

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Dear Ms. Godbout:

Re: September 12th IRP Technical Conference

Efficiency Nova Scotia Corporation (ENSC) has reviewed the information provided by Nova Scotia Power Inc. (NSPI) at its September 12th IRP Technical Conference. We appreciate the opportunity to respond and provide the following four comments.

1. ENSC agrees with Synapse's comments from the Technical Conference that the IRP is a long-term planning exercise, not a rate-setting exercise.

    - It is ENSC's position that, in order for the integrity of the IRP process to remain intact, the output of the IRP must follow its own Terms of Reference by selecting a preferred resource plan that has the lowest cumulative present worth of annual revenue requirements over a 25-year horizon. The notion of introducing a 5-year NPV is not consistent with the long-term objective of an Integrated Resource Planning analysis and has the effect of masking the long-term optimal results that the IRP must deliver.

    - While ENSC understands that, with a majority of candidate resource plans (CRPs) falling within 5% of each other in terms of their NPVs, there may be added value given to the additional considerations included in the IRP Terms of Reference (i.e., system reliability, plan robustness, etc.), details on how these considerations may be interpreted have not been provided for stakeholder discussion in the results presented to date.

    - The IRP is a technical analysis. ENSC suggests that it is therefore not appropriate for stakeholders to be asked to vote on their preference for a preferred candidate resource plan.

2. ENSC agrees with NSPI that affordability is an important issue to be addressed. However, ENSC does not believe it should be addressed within an IRP. Consistent with NSPI's suggestion that Avoided Costs could be dealt with in a process subsequent to the IRP, so too could the issue of affordability.

   - Affordability can have different definitions. It should be given careful consideration and be included within a subsequent process or regulatory proceeding to allow full engagement of interested parties.

   - The consideration of affordability is clearly identified as a requirement in the *Electricity Efficiency and Conservation Restructuring (2014) Act, R.S.N.S. 2014, c. 5* (the "Act"), Section 79L (9):

     > *The Board's assessment of the proposed electricity efficiency and conservation activities for the purpose of the approval must take into account their affordability to Nova Scotia Power Incorporated's customers, along with any other matters considered appropriate by the Board or as may be prescribed.*

     Therefore, affordability must be included within the next DSM Resource Plan application, allowing for a fuller discussion of this important issue.

3. Some of NSPI's key observations appear to be untested or at odds:

   - With the completion of months of modeling work indicating that 13 of the 14 top-ranking candidate resource plans including either Base or High levels of DSM, ENSC suggests it is not appropriate to propose an action plan that includes an untested concept of a variable DSM spending profile. There is no modeling to indicate whether or not such a scenario would be competitive on a planning horizon basis, which is important from an IRP perspective. Again, a subsequent process can include discussion on factors such as affordability.

   - NSPI's Key Observation #8 suggests that capacity additions are required for High Load World CRPs in the early 2020s. ENSC respectfully notes that the High Load World CRPs were not tested with High DSM to offset load growth.

   - While it is appropriate to consider different amounts of DSM as part of the negotiated agreement, the notion of variable (lower near-term spending) DSM in the IRP process appears to be at odds with mitigating the concern raised in Key Observation #8 and may even exacerbate the situation. Moreover, a variable DSM spending profile with lower near-term spending greatly increases the risk-profile of such a resource plan, even beyond the years of lower DSM expenditures.

4. Regarding NSPI's draft action plan items relating to DSM, ENSC is happy to work with NSPI and stakeholders on developing a 3-year Plan and filing it for UARB approval as well as examining ways to place an increased focus on demand, as NSPI has indicated is important.

Conclusion

ENSC appreciates the opportunity to provide these comments.

Yours very truly,

THE BRETON LAW GROUP

James R. Gogan

cc.	Allan Crandlemire John Aguinaga Julie-Ann Vincent
cc.	M05522 Participants

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File Reference: SM002557-00003

September 19, 2014

Delivered by E-mail – tim.wood@nspower.ca

Tim Wood
Nova Scotia Power Inc.
P.O. Box 848
Halifax, NS B3J 2V5

Dear Mr. Wood:

Re: M05522 Integrated Resource Plan (IRP)

This letter and the attached comments from Drazen Consulting Group are submitted on behalf of the Industrial Group with respect to the draft Analysis Results. NSPI has requested input on the relative weighting to be assigned to the factors to select the "preferred plan" (or any additional factors) and comments on the proposed "Action Plan". In addition, NSPI indicated it would be receptive to requests for additional analyses or comparisons.

At the outset, we commend NSPI's efforts to compile the extensive information in an understandable graphic format which facilitates comparisons across the various CRPs. That said, distribution of the Analysis Results did not occur until two days before the Technical Conference and there has been insufficient time on our part to fully evaluate and understand the modeling and assumptions. Our impression is that both NSPI and stakeholders would benefit from additional time to have some questions addressed and for NSPI to carry out some of the studies identified as part of its Action Plan before selecting a course of conduct and preferred Plan.

"No Regrets"

It is noted that many of the CRPs look the same for a number of years before they diverge. It would be helpful for NSPI to produce an analysis and graphic to demonstrate the point of divergence i.e. the year and what decision needs to be made at that point. The Industrial Group supports NSPI's "no regrets" approach given that the only certainty is that there is no certainty in the long term.

It is expected that NSPI will be continuing to carry out regular (5-6 year) updates to the IRP, so the Industrial Group recommends a focus on the CRPs which yield the lowest costs out to 2020; these are characterized by maximum coal, currently committed levels of wind and Base Case or Low Case DSM (or some optimum combination discussed further below). Assuming there are no regrets, this would provide sufficient opportunity in future to re-evaluate and change course if some assumptions do not bear out or there is a significant change in the market.

The Industrial Group does not believe that there is sufficient certainty in the long term to place any weight on the NPV over the Study Period (to infinity). Examples of events that could alter the fuel outlook considerably would be the reopening of the Donkin mine in Sydney (potentially requiring the addition of a scrubber at Lingan), the potential for a significant offshore gas discovery by Shell/Chevron and expansion of the Tennessee pipeline with large volumes of Marcellus shale gas being made available.

Demand Side Management (DSM)

At slide 11 of the Analysis Results, NSPI has observed (#11) that a variable DSM spending profile has the potential to lower rate pressure in the near term (five years) while being competitive on a planning period NPV basis. In making observation #11, it is unclear whether NSPI has considered the scalability of DSM from the perspective of ENSC and its service delivery.

It appears from the results that there are near term cost benefits to a lower level of DSM but higher costs in the long term if this lower level is sustained (slide 26). There are, however, clear operational advantages to lower levels of DSM investment as identified in the Plexos work through to 2030 (slides 46-48) – minimum curtailment and uneconomic exports of excess energy and maximum economic Maritime Link and NB energy purchases.

The Industrial Group requests that NSPI model an optimum DSM spending profile on a variable basis, having regard to any operational constraints (on the part of NSPI and ENS). It is understood that NSPI and ENS will be negotiating an agreement for the delivery of efficiency programs on three year terms so the ultimate level of DSM will be determined in that process and approved by the Board; nonetheless, for planning purposes, it would be helpful to understand the implications of an optimum variable DSM spend.

Secondly, with respect to DSM, in NSPI's memo to IRP stakeholders of July 30, 2014, NSPI stated that it would be modeling a sensitivity in relation to higher DSM costs i.e. an S8 sensitivity analysis would be performed by increasing the cost of the DSM program and run across all CRPs. Nowhere in the Analysis Results of September 12, 2014, does it show this sensitivity.

The Industrial Group requests that NSPI run a sensitivity of both higher and lower costs of DSM per MWh and also higher and lower achievable energy and demand savings for the same DSM dollar investment (Base, Half Low).

Combining CRPs

NSPI noted at slide 13 that "the best performing aspects of several CRPs may be combined to inform development of a robust Resource Plan that is adaptable to future regulatory supply, and demand side requirements, while being sensitive to accuracy of system assumptions in the outer years." Please clarify how NSPI proposes to combine the CRPs, which have been identified as "best performing".

Action Plan

While the Industrial Group does not take issue with the items listed, insofar as we concur they should be completed and many are simply compliant with legislative requirements, the timelines for completion should be clarified.

With respect to "Renewable Resources" (slide 19), it notes that the Mersey redevelopment capital application will be undertaken for filing with the Board. This seems to presuppose that such an application will be filed but the Mersey upgrade is not a component of all CRPs. NSPI should clarify its operational necessity and the costs as part of its evaluation of the IRP.

A number of items are proposed to form part of the 10 Year System Outlook report (tidal energy; operational challenges regarding variable generation; need for flexible resources to integrate additional variable generation; regional market opportunities, balancing and interconnection; retirement forecast for existing thermal fleet; planning reserve margin). Historically, this has never involved a stakeholder component. The Industrial Group recommends that stakeholders be offered the opportunity to comment before finalization of the Report.

Thank you for the opportunity to submit these comments and we look forward to the additional analysis requested.

Yours truly,

Nancy G. Rubin

NGR/lmc

cc IRP Stakeholders

att. – Drazen Consulting Group Comments

NOVA SCOTIA POWER

Comments of the Industrial Group Comments on 2014 IRP

NSPI's presentation leaves some issues unclear or unanswered.

Slide 4: Developments Since Previous IRPs

This slide shows:

Loss of industrial load ~165 MW – 1,100 GWh
Industrial load on LR tariff: ~185 MW – 1,050 GWh

Comments:

Does lost load include NewPage, Bowater, Michelin and Imperial? Anything else?
Is LR all PHP? If so, why is it nearly equal to the loss of industrial load?

The treatment of LR load for planning and operating purposes was left unclear. The response to the question at the meeting was that the LR load is included during the LR contract period and zero thereafter. The CRPs should assume zero LR load throughout.

Slide 10: Key Observations

Point 4: *If DSM delivery beyond 2020 does not meet the DSM forecast then the system will experience reliability and environmental/emissions challenges.*

Comment:

What does "not meet the DSM forecast" mean? (1) That less-than-forecast DSM is installed? Or (2) That installed DSM does not reduce usage as much as expected? Or?

Slide 15: Comparison of Partial Revenue Requirements Graphs (graphs on Slide 16)

1st bullet: *NS Power believes customers are concerned with affordability particularly in the short term.*

4th bullet: *These costs do not encompass NS Power's total revenue requirement. They include only a portion of the costs such as fuel and purchased power, thermal and hydro unit O&M, capital costs for new resources added in the CRP and DSM program administrator costs.*

5th bullet: *The graphs do not include other cost items that would be common among all CRPs such as remaining O&M, regulatory adjustments/amortizations, interest and tax impacts.*

Comment:

What are the dollars in each case? Since NSPI recognizes that customers are concerned with affordability, it would make sense to get a feel for the potential levels of rates.

NOVA SCOTIA POWER

Comments of the Industrial Group Comments on 2014 IRP

Slide 21: Draft Action Plan Items (cont'd)

2nd major bullet: Planning Reserve Margin

> *Report on the ongoing evaluation of the appropriate planning reserve margin for the power system in the 10 Year System Outlook Report*

Comments:

What will NSPI evaluate? NSPI stated that it uses the "1 day in 10 years" criterion. (Presumably, it means that NPCC uses it.) We are aware that NPCC currently specifies a 20% reserve margin for the Maritimes. However, it is not clear whether NSPI (or any other Maritimes utility) has ever questioned this or raised the issue with NPCC. It appears that there has been no evaluation of whether this is the best criterion (there are others, such as EENS – Expected Energy Not Served or LOLH – Loss of Load Hours), nor whether it translates into a 20% reserve margin.

Has NSPI reviewed other utilities' analysis of the economically-appropriate reserve margin?

How would the CRPs be affected by different levels (e.g., 15%)?

Background:

Reliability is fundamentally an economic concept—the cost to customers of outages versus the cost of extra capacity--so it is logical to analyze the potential cost savings of a lower reserve margin.

A 2012 study by The Brattle Group for the Electric reliability Council of Texas (ERCOT) explained:

> Consistent with industry practice, ERCOT's reliability target for the bulk power system is based on LOLE, or the frequency of expected firm load shed events caused by supply shortages. For decades, the utility industry has used a 1-day-in-10-years bulk power standard for setting target reserve margins and capacity requirements. While the origin of the 1-in-10 metric is unclear, references to the standard appear as early as the 1940s. **Usually, utilities and system operators offer no justification for the reasonableness of 1-in-10 other than that it is the industry standard or that it is consistent with NERC guidelines.** Because customers rarely complain about bulk power reliability under the 1-in-10 standard and system operators and policymakers generally are not faulted if they adhere to long-term industry practices, few question 1-in-10 as an appropriate standard.
>
> It is also helpful to understand that the 1-in-10 standard is not applied uniformly throughout the industry. For example, ERCOT and many other system operators interpret the 1-day-in-10-years standard as "1 outage event in 10 years," while other

> system operators such as SPP interpret the 1-day-in-10-years standard as "24 outage hours in 10 years." While the two interpretations sound semantically similar, the level of reliability they impose differs significantly. As shown in a recent case study of a 40,000 MW power system, the former definition requires a 14.5% reserve margin, while the latter requires only 10%.
>
> ***
>
> Despite these considerations, **little empirical work has been done in the industry to quantify the economics of the 1-in-10 criterion** to confirm that it reasonably balances the tradeoffs between the economic value of reliability and the system capital costs imposed.

http://www.ercot.com/content/news/presentations/2012/Brattle%20ERCOT%20Resource%20Adequacy%20Review%20-%202012-06-01.pdf

Other utilities that have studied the issue have found that a reserve margin lower than 20% is appropriate. An example is Southern Company's 2010 IRP analysis:

> **1.10 RESERVE MARGINS**
>
> After an analysis of load forecast and weather uncertainty as well as the current and near-term projected generation reliability of the System, the Company has selected a target reserve margin of 15 percent in the long term, which is near the minimum total cost but carries less risk than the absolute minimum cost point. For the short-term horizon, the Company will maintain a 13.5 percent planning reserve margin guideline, but may periodically review the availability and cost of resources in the market and adjust short-term resource procurement decisions accordingly.

http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=125981

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Our File: 100384
September 19, 2014

Ms. Nicole Godbout
Regulatory Counsel
Nova Scotia Power
P.O. Box 910
Halifax, NS B3J 2W5

Dear Ms. Godbout:

Re: Integrated Resource Plan (IRP) 2014 – Matter M05522/P-884.14

On September 12, 2014, Nova Scotia Power Inc. ("NSPI") held a technical conference to present the Analysis Results for the 2014 IRP, which had been circulated to stakeholders on September 10, 2014.

The objective of the 2014 IRP (as noted on slide 5 of the Analysis Results presentation) includes developing "...an Action Plan describing the major tasks required to implement a no regrets strategy that aligns with the Preferred Resource Plan during the first five years of the planning horizon." The development of an appropriate near-term Action Plan is a critical part of the IRP process, and NSPI has outlined several proposed Draft Action Plan Items at slides 19 to 21 of the Analysis Results.

Please accept the following comments on behalf of Port Hawkesbury Paper LP ("PHP") with respect to the Analysis Results and, more specifically, the Action Plan that should be included in the final IRP report.

Demand Side Management

NSPI's Draft Action Plan references the 3 year plan that will be developed with Efficiency Nova Scotia Corporation ("ENSC") and stakeholders and submitted to the Board for approval for the 2016-2018 time period, but it does not provide any comments regarding the target level of DSM savings that should be pursued as part of this plan. In fact, in other sections of the Analysis Results, NSPI appears to suggest that the Analysis Results demonstrate that a level of DSM below the Base Case should be considered. For example, in Slide 11, NSPI observes that a "variable DSM spending profile [with lower spending in the near term] has the potential to lower near term rate pressure while being competitive on a planning period NPV basis."

PHP does not agree that the Analysis Results support any reduction in the pursuit of the demand and energy savings identified in the DSM Base Case. To the contrary, in PHP's view, the Analysis Results emphasize the importance of working to ensure that, at a minimum, the Base Case DSM demand and energy savings are achieved in the near-term. The Analysis

Results are clear regarding the potential negative cost implications associated with failing to achieve the Base Level DSM targets in the near-term. The following points are notable in this regard:

- On Slide 27, NSPI provides the Net Present Values ("NPVs") of the various scenarios. The Base Load Candidate Resource Plan with a DSM profile lower than the DSM Base Case (CRP 1-1 FGD) is significantly more expensive in the Planning and Study Periods than all of the DSM Base Case Plans in the Base Load scenario.

- On Slide 8, NSPI shows the incremental resources that are required in the various cases. The Base Case DSM Profile assumes that 156 MW of incremental DSM is acquired during the 2015-2020 time period, whereas CRP 1-1 FGD assumes only 62 MW of DSM would be added. This difference of 94 MW is significant, as any shortfall in DSM versus the Base Case may need to be met by more expensive capacity additions to supply the load on NSPI's system in future.

- If there is a shortfall in obtaining incremental DSM resources in the 2015-2020 period, this could impact NSPI's flexibility to meet its load, particularly in the High Load scenario, which already requires capacity additions prior to 2020 even assuming that the DSM Base Case is achieved (as shown in Slide 8). NSPI did not model a High Load / High DSM scenario to test whether higher levels of DSM than the Base Case would be economic, but PHP assumes that increased DSM spending could at least help alleviate the need for some of the capacity additions called for in the High Load / Base DSM scenario. Alternatively, lower DSM spending in the early years of the Planning Period would require even more capacity additions to be added in the near term in a High Load scenario.

- Since the Low DSM Case contemplates more significant capacity additions post-2020, it is likely to be the most sensitive to further load increases (as well as fuel price increases and environmental restrictions) above the Base forecast throughout the Planning Period. As a result, there appear to be increased risks associated with any plan that fails to achieve the Base DSM levels in the near term.

The IRP is a long-term planning exercise designed to help indicate which actions would be beneficial to pursue in the short-term over a broad range of reasonable future scenarios to ensure there are "no regrets". The Analysis Results indicate that pursuit of the Base Case DSM is beneficial across a range of scenarios and the action most consistent with a "no regrets" approach. The Action Plan should prioritize the importance of the achievement of this level of DSM demand and energy savings, starting with the upcoming 3 year plan to be negotiated with ENSC and submitted to the Board for approval.

Demand Response

Under the Demand Side Management heading, NSPI's Draft Action Plan also indicates that it will "pursue cost-effective Demand Response opportunities." As discussed further below in the context of NSPI's integration of its renewable resources, PHP believes that there are cost-effective opportunities to use its load as a resource as part of future Demand Response initiatives. The Draft Action Plan should specifically note that NSPI will continue to work with PHP to explore the opportunities that may be available to ensure that the potential value associated with the use of PHP's load is considered as part of its evaluation of Demand Response options.

Integration of Renewable Resources

At Slide 48, NSPI notes that the Plexos Output Analysis shows that a "higher energy requirement is beneficial to integration of base quantity of wind generation with minimal curtailment and uneconomic exports of excess energy." At Slide 19, NSPI's Draft Action Plan indicates that it will continue to develop an understanding of the operational challenges associated with variable generation and it will report to the UARB on these challenges and the status of the need for flexible resources to integrate additional variable generation in the 10 Year System Outlook Report.

At the technical conference, NSPI agreed that it saw the use of PHP's load and the potential development of further energy storage solutions as potential resources that will assist in dealing with the challenges associated with the incorporation of variable generation in its system. In addition to the reporting requirements referenced in NSPI's Draft Action Plan, PHP submits that the Action Plan included in the Final IRP Report should specifically reference the fact that NSPI will continue to engage in discussions with PHP to explore any possibilities that may be available in terms of the flexible use of its load and storage capabilities, particularly in the near term prior to the implementation of the Maritime Link and the development of other potential resources that may involve more extended lead time.

Existing Thermal Resources

On Slide 20, NSPI highlights various reports and studies that it plans to conduct with respect to its thermal resources. The proposed Draft Action Plan indicates that NSPI will produce a report on best industry practices regarding sustaining capital within 24 months of the Final IRP Report. It also notes that it will study the economic potential of an FGD and analyze potential optimal capital spending plans for the existing thermal fleet, but no timeline is provided for these studies.

As NSPI observes at Slide 12, the Analysis Results suggest that a 60-year life retirement schedule for the coal fleet is the most economic over the Planning Period. At the technical conference, Synapse noted that more analysis needs to be done to confirm this finding. The issue of the future availability and optimal use of NSPI's coal units is a critical issue. Since the preliminary indications in the Analysis Results are that these units will be economic over the long-term, PHP believes that NSPI should prioritize its analysis of the requirements for sustaining capital, rather than wait another two years for the results of a report on best industry practices.

In this regard, PHP notes that Liberty's Audit in the Fuel Adjustment Mechanism process recommends that NSPI complete an optimization study to address the optimal way of running (or not running) the coal units on a day to day basis (Chapter VIII, Recommendation 1). Liberty also recommends that NSPI develop and implement an aggressive program to improve Trenton 5's performance based on recent challenges associated with the operation of that unit (Chapter VIII, Recommendation 6). The Action Plan in the Final IRP Report should emphasize the importance of ensuring that the appropriate cost effective capital investments will be made to ensure the continued economic performance of NSPI's solid fuel plants, in both the near and long term. The analysis should also be closely linked with the analysis done by NSPI's fuels department regarding the ongoing operation of these plants.

10 Year System Outlook Report

PHP notes that NSPI's intention is to report to the Board on the issue of variable generation integration as part of its current 10 Year System Outlook. NSPI is also proposing to use this report to update the Board on other issues such as the status of cost-effective regional market opportunities, current coal retirement forecasts, regional transmission integration opportunities, and NSPI's ongoing evaluation of the appropriate planning margin for the power system. PHP agrees with this approach, and suggests that as part of this process, stakeholders should also be provided with the opportunity to provide any comments they may have on the 10 Year System Outlook to the Board each year following NSPI's filing of the report. PHP submits that the Action Plan should highlight the proposed use of the 10 Year System Outlook as a reporting document and also recommend that stakeholders be given an opportunity to provide their views to the Board as part of that process.

Ongoing Analysis and Future IRPs

As noted at the technical conference, the NPVs of many of the Candidate Resource Plans that were actually modeled are very similar for the Planning Period. As part of NSPI's ongoing long-term planning analysis and as part of future IRP processes, PHP believes it would be useful to study a wider variety of options with greater differentiation. This would allow NSPI and stakeholders to fully test the resilience of different plans in more detail. For example, high load scenarios matched with high demand side management, or high emissions reduction scenarios matched with high gas and coal prices would provide useful information regarding the most cost effective approaches across a range of reasonable scenarios.

We look forward to receiving the Draft Final IRP Report on September 30 so that we can provide further comments.

Yours truly,

James MacDuff

cc: Interested Parties

(16848002)

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September 19, 2014

OUR FILE:

Mr. Tim Wood
Nova Scotia Power
PO Box 848
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Dear Mr. Wood:

RE: M05522 – IRP Technical Conference Analysis Results September 12, 2014

Please accept the following as submission from the Small Business Advocate with respect to the above-noted matter.

I. Introduction

The Small Business Advocate ("SBA") is pleased with the opportunity to participate as an active stakeholder in the NSPI 2014 IRP. The SBA views this IRP as an important planning exercise which will influence electricity costs over the next 25 years and beyond. The SBA and its consultant participated in the September 12th technical conference. The SBA had limited time to review the PowerPoint Presentation Materials provided by NSPI prior to the technical conference. Given the short timeframe for review, the SBA's ability to provide insightful comment on NSPI's strategic direction is limited.

The SBA offers these comments as the next step in participation throughout the 2014 IRP.

II. Overview of SBA Comments

The SBA's comments touch on the following:

1. The difficulties that result from the SBA having a very short time prior to the IRP technical conference to analyze and consider significant amounts of analytical data and results;

2. The decision framework employed by NSPI;
3. The detail provided regarding options and resource plans analyzed by NSPI; and
4. The action plan items NSPI sponsored during the technical conference held on September 12, 2014.

The SBA has concerns that the overall process falls short of NSPI truly capturing the value of stakeholder engagement. The SBA is of the opinion that more detailed information is required from NSPI for stakeholders to truly offer meaningful input and discussion to NSPI in relation to filing of the final IRP report.

The SBA is concerned that regardless of stakeholder input, NSPI will not alter the strategy they intend to pursue in filing the final IRP report.

III. Stakeholder Process and NSPI's Decision Framework

The SBA was pleased that NSPI highlighted the need to ensure several considerations are canvassed when choosing a resource strategy. Prior discussions and analytical data appeared to focus on long-term Net Present Value (NPV) of costs associated with various resource strategies. It appears to the SBA that NSPI now recognizes the importance of affordability considerations as well as risk, flexibility and robustness of the 'candidate resource plans'. These considerations were reflected in the metrics listed on Slide 13 of the presentation materials used on September 12th by NSPI.

- NPV: Cross-section of near and long term
- Rate Effects: Relative time-series of revenue requirements
- Risk: Relative complexity of the plans
- Flexibility Diversity of technological solutions
- Robustness: Results of Sensitivity Analysis
- Future Regulatory emissions outlook

NSPI's analysis also included developing information on the varying operational impacts to the electricity system through its use of PLEXOS. Given the short timeframe available for review of materials provided by NSPI, as well as the limited information supplied, the SBA is unable to appropriately canvass how various results will ultimately affect NSPI's choice for a plan moving forward.

The SBA favors a process that considers the above noted metrics in determining an appropriate strategic direction. However, it is unfortunate that all metrics outlined were not sufficiently incorporated into the conference materials and decision framework as discussed at the technical conference. Particularly, the SBA would have appreciated further detail surrounding the metrics of risk and flexibility. Notwithstanding the limited analysis of the quantitative or qualitative results of these metrics, NSPI has suggested a draft action plan. NSPI also noted emissions as a listed metric for consideration. However, a review of the materials provided by NSPI suggests emissions were included as a sensitivity with compliance measured, rather than a strategic metric. It is the SBA's position that given NSPI's consideration of emissions as a sensitivity, emissions should not be listed as a "metric" at Slide 13.

The SBA requests that NSPI clearly articulate its decision criteria tradeoffs made within the draft report. The SBA understands and appreciates that NSPI is seeking comment from stakeholders on defining flexibility and risk metrics. Unfortunately, the SBA is not able to provide said comments as a result of time limitations for review of materials provided by NSPI.

IV. Resource Options and Candidate Resource Plans

The SBA is satisfied that NSPI has studied a reasonable amount of resource options that cover DSM, renewable energy, continued operation versus retirement of resources and conventional utility scale natural gas generation. The SBA notes, however, that value of customer sited generation has not been included in this analysis. NSPI needs to articulate how these options as the costs of technologies such as solar which continue to decline are included in its resource planning.

The SBA is somewhat satisfied with both the number and particulars of the Candidate Resource Plans outlined by NSPI, provided the analysis is a learning exercise. The actual strategic direction chosen by NSPI should not be limited to one particular Candidate Resource Plan, rather if warranted, NSPI should consider the possibility of a hybrid of two or more resource plans. There are likely changes in timing and availability of resources within the plan chosen by NSPI. The SBA anxiously awaits additional information from NSPI on its actual chosen strategy or path. The SBA expects an 'informing process' with a draft report that allows time for true stakeholder evaluation and comment.

V. Comments on Observations

NSPI discussed its Observations (slides 10-12) at the technical conference. The SBA provides the following regarding the specific SPI observations listed on those slides.

- Observation 4 – "If DSM delivery beyond 2020 does not meet the DSM forecast then the system will experience reliability and environmental/emissions challenges". The SBA does not understand how NSPI will allow reliability to suffer if DSM savings fall short of expectation. The SBA recognizes the challenge of creating actual DSM savings at the lowest possible cost and its benefits to small business if successful. The SBA is actively involved with the DSM process in order to minimize adverse ratepayer impacts. The SBA expects NSPI to be a full participant and assure that through its IRP and other planning processes that emissions and reliability standards will be met even if resources fall short in terms of their performance. This is true whether the resource is an existing coal unit, wind generation, imports via the Maritime Link or DSM.

- Observation 7 – the question was raised in the conference and the SBA agrees it needs to be answered in the IRP report whether the use of FGD on coal plants restores the ability to utilize domestic coal. The SBA notes that NSPI did not discuss the short term rate impacts of the FGD investments which basically only breakeven over long period NPV metrics.
- Observation 11 – the SBA does not see how this observation is made. The SBA has concerns about the definition of the NPV parameters used through the materials in that they are obscured by the inclusion of a significant amount of costs common to all resource plans evaluated.
- Observation 12 – This observation that Max Coal is the 'most' economic has not been made on a basis that incorporates risk.

VI. Comments on the Action Plan Items

As previously mentioned, the SBA believes discussion of an action plan at the technical conference and in the materials was premature. The Action Plan was presented without numbering or prioritizing on slides 19 through 21. The SBA is not endorsing the action plan but will offer these specific comments on elements of the action plan.

- Demand-Side Management – The SBA does not understand on what basis the proposed action of pursuing demand response is made. Also, the SBA is concerned with the performance of all resources not just DSM.
- Renewable Resources – Why will it take NSPI two years to complete its interconnection and capacity value study for renewables? When will NSPI report to the UARB its 10 Year System Outlook Report? Will there be a stakeholder process for discussion of that report which is now looking like an extension of IRP?
- Regional Opportunities – Why are these options part of the IRP Action Plan but ignored within the IRP analysis?
- Existing Thermal Resources – How much investment in existing resources is NSPI planning to make during the next 24 months while it studies 'Best Practices' of the industry? Why does this take 24 months?

- What is the current retirement plan that will be presented in the 10 Year Outlook? It is not obvious from NSPI materials.

VII. Summary

The SBA has expressed concerns above that center around the decision process, specifically the metrics that have yet to be incorporated by NSPI. While the SBA is grateful to participate as a stakeholder in the process, there was lack of proper time for review of information and comment. Thus, while the SBA has offered comments, the SBA cannot endorse the IRP analysis, results, decisions and action plan at this time.

Yours truly,

E.A. Nelson Blackburn, Q.C.

SMALL BUSINESS ADVOCATE

Scotian WindFields
Community Owned. Naturally.

Sept 17, 2014

Nova Scotia Power Inc.
1223 Lower Water St.
Halifax, Nova Scotia
B3J 2W5

RE: Feedback for Incorporation into IRP 2014 Final Report

Scotian WindFields Inc. welcomes the opportunity to participate in the 2014 Integrated Resource Plan and submits the below comments and suggestions based on the IRP Technical Conference Analysis Results and Appendix (Draft Analysis) information that were provided on September 10, 2014, leading up to the Technical Conference held September 12, 2014.

In general, we feel that the proposed IRP strategy has been well laid out, but has significant shortcomings with respect to the future cost of fossil fuels, carbon pricing, and opportunities for increased grid reliability and possible operation strategies. These shortcomings greatly reduce the effectiveness of this plan to adequately prepare our electrical system in the best interests of the environment and Nova Scotia's electrical system. The following items that are detailed in the attached document and are submitted as final comment from Scotian WindFields for consideration of the Action Plan being developed as part of the 2014 IRP process:

- Fossil Fuel Price Forecast Assumptions
- Carbon Pricing Assumptions
- Opportunity to plan for and address future RES Operational Strategies
- Limited Candidate Resource Plans

Should you require any clarification or further details on and of the points included in this response, please do not hesitate to contact Scotian WindFields Inc. directly.

Thank you for your consideration of these comments and we look forward to further discussion and the issuing of the Final Report for the 2014 IRP.

Sincerely,

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1) Wind Assumptions

With consideration of the documentation provided on Sept 10, 2014, Scotian WindFields Inc. requests that the below points, regarding wind energy assumptions, be considered in upcoming analysis of the Action Plan being developed as part of the 2014 IRP process.

a. Additional distribution-connected wind energy should be considered as a Supply-Side Option, with specific capital costs and integration costs considered.
b. Integration Costs and Demand Reduction should be considered in anticipation of **>200MW by 2030** of wind generation under the upcoming Renewable to Retail framework.
c. Flexibility with the Surplus Energy available through the Maritime Link should be considered to work as a possible operational strategy for load-following and the real-time considerations of wind energy generation. Scotian WindFields Inc. request that this be considered as a possible option *in place of* the purchasing and deployment of additional Combustion Turbines and other dispatchable generation.
d. Scotian WindFields feels that greater consideration can be given to the planning of future RES and variable generation Operational Strategies – as is further outlined in **Section 6** of this response.

2) Solar Assumptions

Scotian WindFields does not see that, in the documentation provided September 10, 2014, larger-scale generation from photovoltaics have been considered in the various models and sensitivities for the chosen Candidate Resource Plans. We would, then, restate our considerations for photovoltaics in Nova Scotia:

The Supply-Side Options only consider ">10MW" each of transmission-connected solar photovoltaic supply options. Scotian WindFields Inc. requests that the below points, regarding solar energy assumptions, be considered in upcoming Action Plan being developed as part of the 2014 IRP process.

a. We recommend that large amounts **(>10MW) of distribution-connected, individual and commercial-scale (1-100kW) solar photovoltaic energy** be considered as a Supply-Side Option.
b. Integration Costs and Demand Reduction should be considered in anticipation of **>100MW by 2030** of Solar Photovoltaic generation under the upcoming Renewable to Retail framework.
c. We welcome further discussion on the capacity factors of the various types of solar energy which were not discussed in the initial analysis provided.

4) Fuel Price Forecast Assumptions

The analysis shown in the documentation provided on September 10, 2014 still considers these values presented in earlier documentation and it is not clear that greater sensitivity has been taken into account. We feel that these price ranges affect the NPV criteria of the Candidate Resource Plan selection process. Scotian WindFields has the below comments regarding the initial Assumptions for Fuel Price Forecast Assumptions, particularly for the long-term price forecasting for Natural Gas, Petroleum-based fuels and solid fuels.

a. The Average Annual Increase of fuel pricing for Natural Gas between years 2015 and 2040, as presented in the Draft Assumptions (Slide 58) is between 2.4% and 3.1%. This is exceedingly optimistic consider that the Average Annual Increase of Natural Gas pricing between years 1991 and 2013/2014 was calculated at **5.5%**.[1]
b. The Average Annual Increase of fuel pricing for HFO and LFO between years 2015 and 2040, as presented in the Draft Assumptions (Slide 72) is between 2.3% and 3.59%. This seems exceedingly conservative as the Average Annual Increase of WTI crude pricing between years 1990 and 2013/2014 was calculated at **6.1%**[2] and the Average Annual Increase of Heating Oil was calculated at **6.3%.**[3]
c. Based on the above presented historical data, we **recommend that NS Power consider more representative energy inflation figures** in future IRP modelling.

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[1] As calculated from data provided by IndexMundi regarding $US/mmBTU monthly price of Natural Gas: http://www.indexmundi.com/commodities/?commodity=natural-gas&months=300

[2] As calculated from data provided by IndexMundi regarding $US/barrel WTI monthly price of Crude Oil: http://www.indexmundi.com/commodities/?commodity=crude-oil-west-texas-intermediate&months=300

[3] As calculated from data provided by IndexMundi regarding $US/gallon monthly price of heating oil: http://www.indexmundi.com/commodities/?commodity=heating-oil&months=300

5) Forecast Cost of Carbon

Scotian WindFields does not see that, in the documentation provided September 10, 2014, specific carbon pricing metrics have been considered in the various models and sensitivities for the chosen Candidate Resource Plans. We would, then, restate our considerations for carbon pricing in Canada – in preparation for the upcoming Action Plan being developed as part of the 2014 IRP process.

Scotian WindFields has the below comments regarding the Draft Assumptions for Carbon Pricing. Under the Case Development (Power) on Slide 60, it is stated that the assumed cost of Carbon is US$15/Ton CO_2 in 2020, escalating to US$37/Ton CO_2 in 2030.

The values for cost of carbon provided in the Draft Assumptions are associated with imported power. If and how carbon pricing is applied within Nova Scotia is vary significant variable as well.

a. The IRP model should consider the potential for NS Power to be required to pay a price on carbon emissions.

Regarding the cost of carbon emissions specifically, we have drawn our analysis from a report commissioned by Synapse Energy Economics Inc. on November 1, 2013 - "2013 Carbon Dioxide Price Forecast". This study considered the carbon price information from the most recent IRP efforts of 28 utilities. With the Canadian federal government's stated intention to harmonize carbon policy with the US and our economic interdependence, we feel it is reasonable to use US projections for Canadian pricing scenarios. We would request that the costs from this study for long-term carbon pricing be considered. The three key scenarios are itemized below:

b. The **Low Case** forecasts a cost of Carbon at US$10/Ton CO_2 in 2020, escalating to US$40/Ton CO_2 in 2030.[4]

c. The **Mid Case** forecasts a cost of Carbon at US$15/Ton CO_2 in 2020, escalating to US$60/Ton CO_2 in 2030.[5]

d. The **High Case** forecasts a cost of Carbon at US$25/Ton CO_2 in 2020, escalating to US$90/Ton CO_2 in 2030.[6]

[4,2,3,] Synapse Energy Economics Inc., 2013 Carbon Dioxide Price Forecast, (Massachusetts, 2013)

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6) Suggested Candidate Resource Plans

Scotian WindFields had suggested the consideration of the below six Candidate Resource Plans. Nova Scotia Power Inc. has responded to each of these requests in correspondence on July 30, 2014. Scotian WindFields would like to offer the comments that are given below as further consideration for the Action Plan being developed as part of the 2014 IRP process.

1) SWFI Requests [CRPs a, b, c respectively]: *"A Candidate Resource Plan that includes a transition to an electricity supply that consists of* ***100%, 80% or 60% (a, b, c respectively) Renewable Energy Sources by the year 2040*** *– Including Wind, Solar PV, Solar Thermal, Tidal, Legacy Hydro, Maritime Link/Muskrat Falls, Biomass and other sources for generation, with a phase-in approach to energy storage technologies."*

NSPI Response [48, 49, 50 Respectively]: *"Due to the operational issues and uncertainties of this CRP this has not been selected as a Candidate Resource Plan. However, CRPs 6 and 8 and Scenario "C" emissions sensitivity analysis (S2) may provide relevant information regarding this proposal."*

Scotian Windfields feels that the specific operation issues that have been identified as barriers to high-RES worlds within the IRP process present **an opportunity for further study**, within this IRP framework. We feel that the analysis and models used within this process could have been utilized to explore exactly what operational strategies, capital infrastructure and sustaining capital would need to be implemented to achieve this high-RES scenario.

2) SWFI Request: *A Candidate Resource Plan that includes the following criteria:* ***High DSM Case, Min Use Coal Case, High Wind Case.***
   NSPI Response: *This proposal is being modelled as CRP 6.*

3) SWFI Request: A Candidate Resource plan that includes Scenario C GHG Emission cuts to **2.25MT in 2040.**
   NSPI Response: "Scenario C emissions will be tested as sensitivity analysis case S2"

4) SWFI Request: *A Candidate Resource plan that includes Scenario with GHG Emissions cut to* ***0MT in 2040.***
   NSPI Response: "NS Power is testing Scenario "C" emissions - 2.25 MT by the end of the planning period - please refer to sensitivity analysis case S2."

   Scotian WindFields feels that Nova Scotia Power Inc. should consider future regulatory and emissions frameworks that would require net-zero GHG worlds.

GE
Energy Consulting

PJM Renewable Integration Study

Task 3A Part F

Capacity Valuation

Prepared for: PJM Interconnection, LLC.

Prepared by: General Electric International, Inc.

March 31, 2014

imagination at work

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Acronyms and Nomenclatures

2% BAU	2% Renewable Penetration – Business-As-Usual Scenario
14% RPS	14% Renewable Penetration – RPS Scenario
20% LOBO	20% Renewable Penetration – Low Offshore Best Onshore Scenario
20% LODO	20% Renewable Penetration – Low Offshore Dispersed Onshore Scenario
20% HOBO	20% Renewable Penetration – High Offshore Best Onshore Scenario
20% HSBO	20% Renewable Penetration – High Solar Best Onshore Scenario
30% LOBO	30% Renewable Penetration – Low Offshore Best Onshore Scenario
30% LODO	30% Renewable Penetration – Low Offshore Dispersed Onshore Scenario
30% HOBO	30% Renewable Penetration – High Offshore Best Onshore Scenario
30% HSBO	30% Renewable Penetration – High Solar Best Onshore Scenario
AEPS	Alternative Energy Portfolio Standard
AGC	Automatic Generation Control
AWS/AWST	AWS Truepower
Bbl.	Barrel
BAA	Balancing Area Authority
BAU	Business as Usual
BTU	British Thermal Unit
CA	Intertek AIM's Cycling⬍Advisor™ tool
CAISO	California Independent System Operator
CC/CCGT	Combined Cycle Gas Turbine
CEMS	Continuous Emissions Monitoring Systems
CF	Capacity Factor
CO2	Carbon Dioxide
CV	Capacity Value
DA	Day-Ahead
DR	Demand Response
DSM	Demand Side Management
EI	Eastern Interconnection

EIPC	Eastern Interconnection Planning Collaborative
ELCC	Effective Load Carrying Capability
ERCOT	Electricity Reliability Council of Texas
EST	Eastern Standard Time
EUE	Expected Un-served Energy
EWITS	Eastern Wind Integration and Transmission Study
FERC	Federal Energy Regulatory Commission
FLHR	Full Load Heat Rate
FSA	PJM Facilities Study Agreement
GE	General Electric International, Inc. / GE Energy Consulting
GE MAPS	GE's "Multi Area Production Simulation" model
GE MARS	GE's "Multi Area Reliability Simulation" model
GT	Gas Turbine
GW	Gigawatt
GWh	Gigawatt Hour
HA	Hour Ahead
HSBO	High Solar Best Onshore Scenarios
HOBO	High Offshore Best Onshore Scenarios
HR	Heat Rate
HVAC	Heating, Ventilation, and Air Conditioning
IPP	Independent Power Producers
IRP	Integrated Resource Planning
ISA	PJM Interconnection Service Agreement
ISO-NE	Independent System Operator of New England
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
lbs	Pounds (British Imperial Mass Unit)
LDC	Load Duration Curve

LM	Intertek AIM's Loads Model ™ tool
LMP	Locational Marginal Prices
LNR	Load Net of Renewable Energy
LOBO	Low Offshore Best Onshore Scenarios
LODO	Low Offshore Dispersed Onshore Scenarios
LOLE	Loss of Load Expectation
MAE	Mean-Absolute Error
MAPP	Mid-Atlantic Power Pathway
MMBtu	Millions of BTU
MVA	Megavolt Ampere
MW	Megawatts
MWh	Megawatt Hour
NERC	North American Electric Reliability Corporation
NOx	Nitrogen Oxides
NREL	National Renewable Energy Laboratory
NWP	"Numerical Weather Prediction" model
O&M	Operational & Maintenance
PATH	Potomac Appalachian Transmission Highline
PJM	PJM Interconnection, LLC.
PPA	Power Purchase Agreement
PRIS	PJM Renewable Integration Study
PRISM	Probabilistic Reliability Index Study Model
PROBE	"Portfolio Ownership & Bid Evaluation Model" of PowerGEM
PSH	Pumped Storage Hydro
PV	Photovoltaic
REC	Renewable Energy Credit
Rest of EI	Rest of Eastern Interconnection
RPS	Renewable Portfolio Standard
RT	Real Time

RTEP	Regional Transmission Expansion Plan
SC/SCGT	Simple Cycle Gas Turbine
SCUC/EC	Security Constrained Unit Commitment / Economic Dispatch
SOx	Sulfur Oxides
ST	Steam Turbine
TARA	“Transmission Adequacy and Reliability Assessment” software of PowerGEM
UCT	Coordinated Universal Time
VOC	Variable Operating Cost
WI	Western Interconnection

1 Capacity Valuation Analysis

1.1 Introduction to the Wind Capacity Valuation

The reliability of a power system is governed by having sufficient generation capacity to meet the load at all times. There are several type of randomly occurring events, such as generator forced outages, unexpected de-ratings, etc., which must be taken into consideration during the planning stage to ensure sufficient generation capacity is available. Since the rated MW of installed generation may not be available at all times, due to the factors described above, the effective capacity value of generation is normally lower than 100% of its rated capacity. This effect becomes more pronounced for variable and intermittent resources, such as wind and solar PV. As an example, a 100 MW gas turbine will typically have a capacity value of approximately 95 MW, while a 100 MW wind plant may only have a capacity value of approximately 15 MW. It is therefore important to characterize the capacity value of such resources so that grid planners can ensure sufficient reserve margin or generation capacity is available at all times under a projected load growth scenario.

This report presents the analysis on the capacity value of wind and solar resources in different scenarios considered in the study. The analysis is conducted using GE Multi-Area Reliability Simulation (GE MARS) Software, and the capacity value is measured in terms of "Effective Load Carrying Capability."

1.2 PJM Rules on Capacity Value of Intermittent Energy Resources

PJM Manual 21 defines the current procedures for estimating the capacity value of intermittent resources, such as wind and solar PV generators. The manual defines capacity value of the intermittent resource (in percentage terms) as the average capacity factor that the resources have exhibited in the last three years during the summer period. The summer period is between the hour beginning at 2 PM and the hour ending at 6 PM, local time, during the months of June, July, and August. The capacity value in MWs can be obtained by multiplying the average capacity factor with the installed MW capacity of the intermittent resource. PJM Manual 21 also indicates the currently effective class average capacity factors as 13% for Wind and 38% for Solar PV.

Table 1-1 presents the average capacity factor of central PV and onshore wind resources during the summer period in 2004-2006 in the 2% BAU scenario. It should be noted that this scenario consists of only central PV (installed capacity of 72 MW) and onshore wind (installed capacity of 5,122 MW). The capacity factor of central PV is between 59% and 60% and that of onshore wind is approximately between 22 and 25%. The table also shows the average of the capacity factor of these resources in these three years, which is 60% for central PV and 23% for onshore wind, based on the modeled data. The modeled data for wind is based on the power curve of a 2.5 MW turbine with a 100-meter tower height. These wind turbines perform much better at higher and lower wind speeds. The modeled data for Solar PV gives 93-95 % rated capacity output at the point of interconnection to the grid, while in reality the Solar PV output maybe limited to 50-80% accounting for cell, module and interconnection losses. These factors may account for the higher capacity value observed in the modeled data as compared to the PJM data.

Table 1-2 repeats the same exercise for the 14% RPS scenario. The average capacity factor in the years 2004 to 2006 shows that the central PV has a higher value than distributed PV. It also shows that offshore wind has a higher average capacity factor than onshore wind. Both of these are well-known facts and supported by the data in these tables. The comparison across the years indicates that the annual weather differences affect the capacity factors, which in turn affects the capacity value.

Table 1-1: Average Summer Capacity Factor of Onshore Wind and Central PV, 2004 to 2006 (2% BAU)

Column1	Residential PV	Commercial PV	Central PV	Onshore Wind	Offshore Wind
2004	-	-	59.0%	24.8%	-
2005	-	-	61.0%	21.8%	-
2006	-	-	59.7%	22.9%	-
Average	-	-	59.9%	23.2%	-

Table 1-2: Average Summer Capacity Factor of Onshore Wind and Central PV, 2004 to 2006 (14% RPS)

Column1	Residential PV	Commercial PV	Central PV	Onshore Wind	Offshore Wind
2004	46.8%	44.7%	61.7%	27.2%	32.4%
2005	49.4%	47.3%	63.8%	19.9%	27.5%
2006	47.5%	45.4%	62.0%	24.5%	36.9%
Average	47.9%	45.8%	62.5%	23.9%	32.3%

As depicted in Figure 1-1, Year 2005 experiences a lower summer capacity factor for onshore wind compared to Year 2006 or Year 2004. The box inside each chart encapsulates the summer-period and clearly shows that Year 2005 has a lower available energy during this period. Appendix A provides a summary of the average capacity factors for each of the resources in each scenario.

The average capacity factor of wind and solar resources during the peak summer hours is a reasonable proxy to estimate capacity values since most of the capacity adequacy-related reliability risk in PJM is concentrated in the afternoon hours of a summer day. However, including all the afternoon hours in the capacity factor computation, regardless of the actual reliability risk during that hour, may result in over/under estimation of the capacity value. The analyses in this report are based on the ELCC of wind/solar resources, a method that provides an estimation of the capacity value of a resource by focusing primarily on the resource output during the hours that carry more capacity adequacy-related reliability risk.

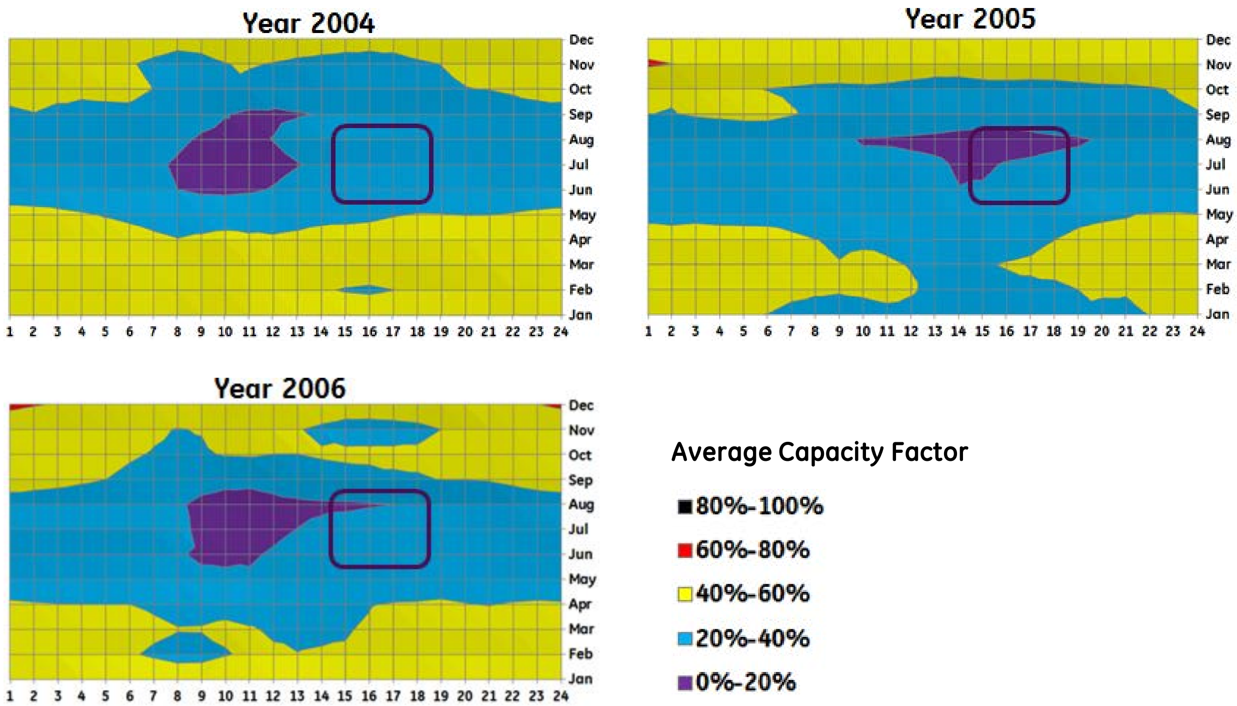


Figure 1-1: Average Capacity Factor of Onshore Wind Resources from 2004 to 2006

1.3 GE Multi-Area Reliability Simulation (GE MARS) Model

A Loss of Load Expectation (LOLE) reliability evaluation was performed for each of the cases. GE Concorda Suite's Multi-Area Reliability Simulation (GE MARS) software was used to calculate the daily LOLE, in days per year, for each scenario. In addition to the daily LOLE, GE MARS also calculated hourly LOLE, in hours per year, and Expected Unserved Energy (EUE), in MWh per year.

The LOLE is determined as the number of days on which loss of load is expected to occur. Since typical generation outages are equally likely at any time of the day, this index is historically calculated at the time of the system daily peak load. However, wind generation varies throughout the day. In recent study work, GE Energy Consulting has expanded the GE MARS program to determine the daily LOLE while looking at every hour of the day. In this way, any off-peak loss of load outages caused by significant drops in the wind generation will be fully accounted for.

The following reliability indices are available on both an isolated (zero ties between areas) and interconnected (using the input tie ratings between areas) basis:

- Daily LOLE (days/year)
- Hourly LOLE (hours/year)
- Loss of Energy Expectation (LOEE) (MWh/year)
- Frequency of loss of load events (events/year)
- Duration of outage (hours/event)
- Need for initiating emergency operating procedures (days/year)

1.3.1 Modeling Assumptions

The approach is based on a sequential Monte Carlo simulation, which provides for a detailed representation of the hourly loads, generating units, and interfaces between the interconnected areas. In the sequential Monte Carlo simulation, chronological system histories are developed by combining randomly generated operating histories of the generating units with the inter-area transfer limits and the hourly chronological loads. Consequently, the system can be modeled in great detail with accurate recognition of random events, such as equipment failures, as well as deterministic rules and policies, which govern system operation, without the simplifying or idealizing assumptions often required in analytical methods. GE MARS is based on a sequential Monte Carlo simulation, and it uses state transition rates rather than state probabilities, to describe the random forced outages of the thermal units. State probabilities give the probability of a unit being in a given capacity state at any particular time, and can be used if one assumes that the unit's capacity state for a given hour is independent of its state at any other hour. Sequential Monte Carlo simulation recognizes the fact that a unit's capacity state in a given hour is dependent on its state in previous hours and influences its state in future hours. It thus requires the additional information that is contained in the transition rate data.

For this analysis, the PJM system was isolated from the rest of the system, and no assistance from the outside was available to PJM. PJM area loads were scaled to obtain a starting risk of 0.1 days/year. With assistance from outside resources, the starting risk would decrease and a different load scaling factor would need to be used to obtain LOLE of 0.1 days/year. Nonetheless, the capacity value obtained under these two system conditions would be the same. It was agreed upon by the study team to model the PJM system with no outside assistance. Unit characteristics and maintenance schedules were copied from the GE MAPS input assumptions. Units were modeled as two state units, either fully available or unavailable, based on their state transition rates. Since state transition rates cannot be calculated from forced outage rates alone, the number of transitions between the two states was taken from the 2007-2011 class averages in the NERC Generating Availability Report, issued in September 2012.

The PJM demand response program was modeled as an operating procedure, since, as mentioned above, GE MARS can provide statistics on the use of operating procedures. The program was modeled with a benefit of approximately 15.7 GW.

The values used for load forecast uncertainty were taken from the data that PJM provides to the Northeast Power Coordinating Council for their reliability analysis.

1.3.2 Load Forecast Uncertainty

Figure 1-2 shows the probability distribution of the load forecast (weighted by area load) that was used by the Northeast Power Coordinating Council (NPCC) for the PJM region in the 2012 NERC reliability analysis. The forecast uncertainty is expressed as multipliers for the mean, as well as one, two, and three standard deviations above and below the mean. In Figure 1-2, the expected value (average value weighted by probability) is shown as approximately 94%, which is less than the intuitive value of 100%. This is consistent with the planning methodology used by PJM internally as part of their capacity analysis.

The data is shown only for the month of July, a peak load month for PJM. This distribution is symmetric around its mean, with an average (expected) value of 0.94 p.u. (per unit). This means, on the average, modeled peak load will be 6% lower than the nominal forecasted peak. Since the system peak load was adjusted to the PJM design criteria of 0.1 days/year LOLE, this will not significantly impact the capacity values determined.

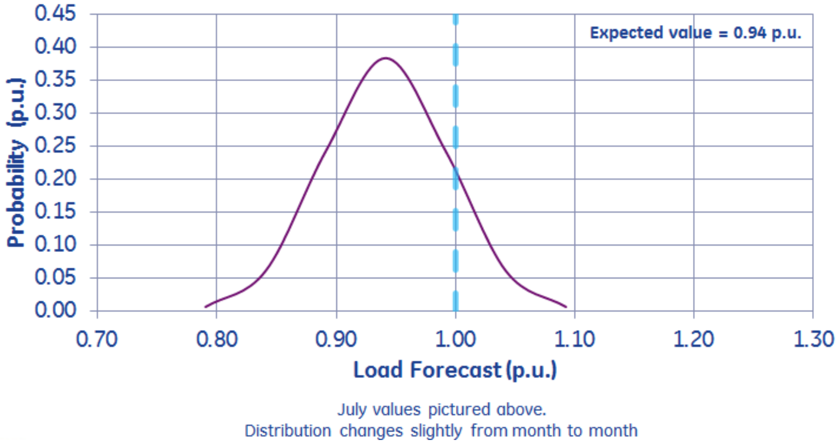


Figure 1-2: Probability Distribution of Load Forecast

1.3.3 Load Shape

In this draft report, the analysis is based on the load shapes from years 2004, 2005, and 2006. In order to get stable estimates on capacity value of a resource many years of load and synchronized resource data is required. A single year load shape and same year resource shape may give highly inflated or deflated values for capacity value (depending on the weather profile and other factors that influence the load profile).

The load shape for each of the years was scaled to meet the projected annual energy in the study year 2026. As an example, Figure 1-3 shows the peak load by month and hour of day for the year 2006. The adjusted 2006 shape has a peak load of 200,288 MW. This occurs on the 26th of July. For comparison, 2004 and 2005 load shapes are also shown in Figure 1-4. The peak days are noted for each of the shapes. The emphasis on peak load days, as will become evident in the later sections, is because the reserve margin or loss of load probability is determined to a large extent by the peak load days. The year 2006 load shape shows the highest peak load (200 GW), while the energy is the same in all three years.

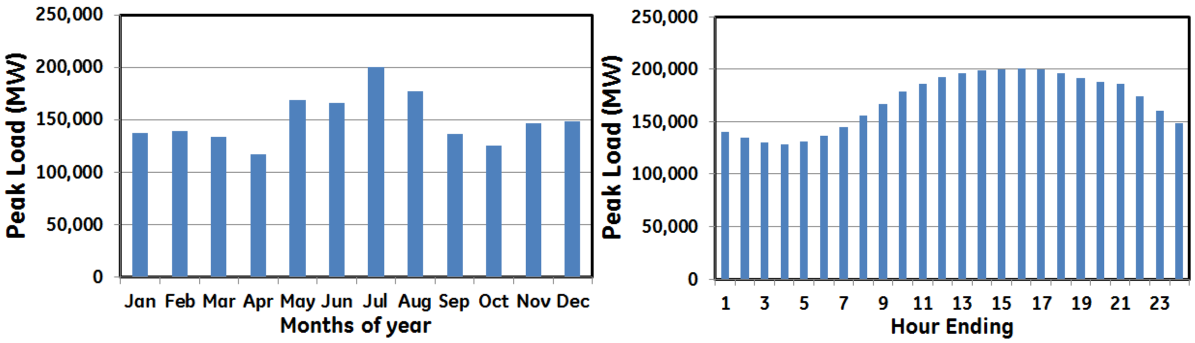


Figure 1-3: 2006 (Scaled to 2026 Energy) Peak Load Variation by Month and Hour of Day

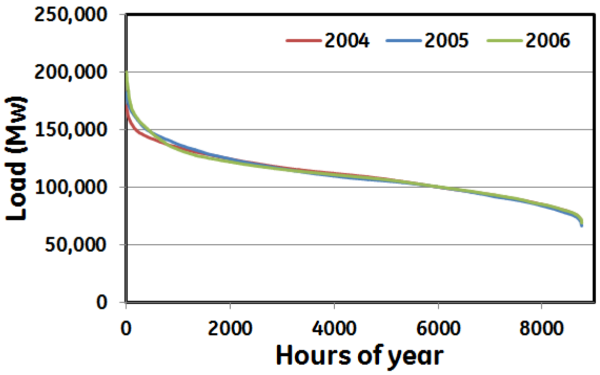


Figure 1-4: Load Duration Curves for 2004, 2005, and 2006

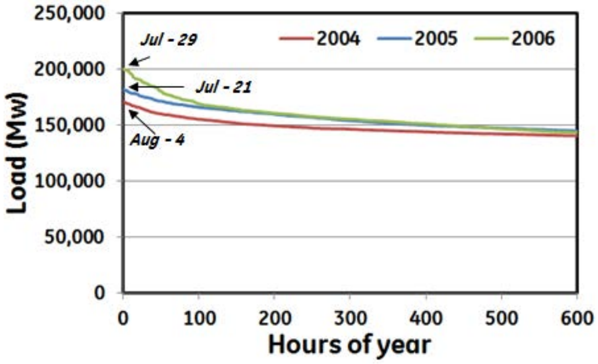


Figure 1-5: Zoomed-in View of the Load Duration Curves for 2004, 2005, and 2006

1.4 LOLE of Base System

As mentioned in Section 1.3, GE MARS can report information on Loss of Load Expectation (LOLE) in days/year, hours/year or MWh/year. LOLE (days/year) is the most frequently used metric by utilities, and PJM also uses this metric in their reliability analysis. Figure 1-6 shows LOLE of the base system (no wind/solar), using the 2006 load shape, on a logarithm axis. The base system has a high reliability of 0.012 days/year at the forecasted 2026 peak load (200,200 MW) and the projected thermal generation mix. The plot shows reliability levels at different system load peaks. The LOLE increases as the peak load is scaled up. LOLE increases to 0.15 days/year at 212,000 MW of peak load (6% higher than the current forecasted peak).

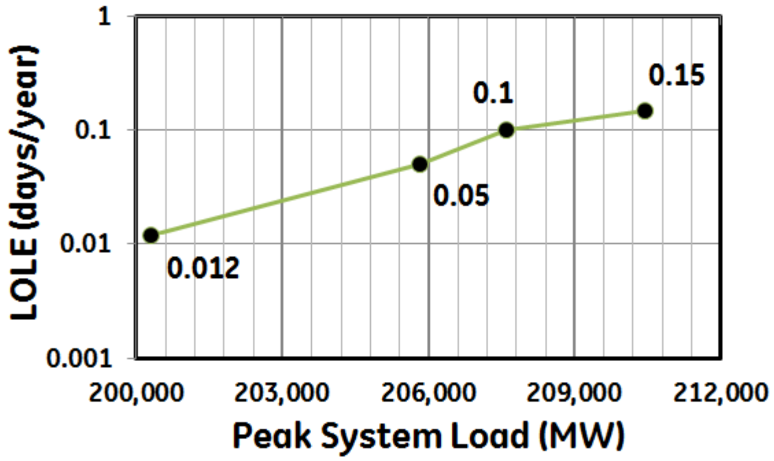
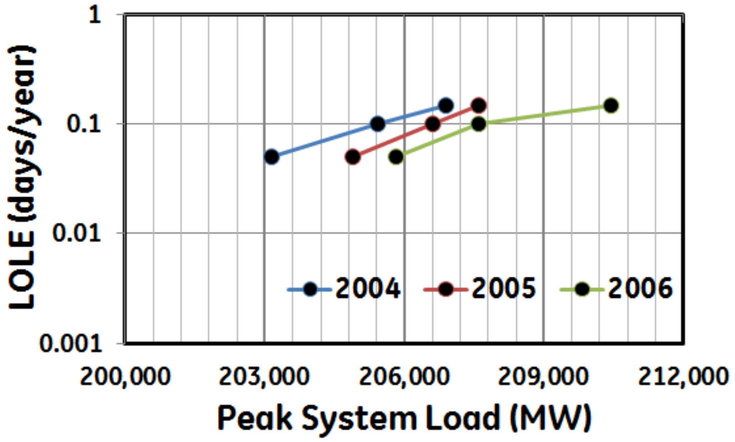


Figure 1-6: LOLE (days/year) for the Base System (2006 Load Shape)

Figure 1-7 shows the relation between LOLE (days/year) and the system peak load for the three years. This figure highlights the peak load in each of the three years that is required to meet PJM's design criteria of 0.1 LOLE days/year. For example, the 2005 load shape needs to be scaled-up such that the peak load increases from 182,086 MW to 206,879 MW in order to have a LOLE of 0.1 days/year. The load shapes in each of the three years is scaled-up to the corresponding values shown in the chart below in GE MARS analysis.



Year	2026 scaled Peak Load (MW)	Peak Load (MW) for LOLE of 0.1 days
2004	170,768	205,421
2005	182,086	206,879
2006	200,288	207,600

Figure 1-7: LOLE (days/year) for Different Load Shape Years

1.4.1 Capacity Value based on Effective Load Carrying Capability

Effective load carrying capability of a resource is defined as the increase in peak load that will give the same system reliability as the original system without the resource. This methodology of measuring capacity value is applicable even when the system is saturated (i.e. conditions when system LOLE with the new resource is extremely low). Figure 1-8 illustrates the process of determining ELCC of a resource. Assume that the base case LOLE is 0.1 days/year and it decreases to 0.001 days/year when a new resource (such as wind or solar PV) is added. The system peak load is then increased such that the system returns to the original LOLE of 0.1 days/year. In this case, the peak load needed to be increased by 30,000 MW. Thus, the ELCC of the resource is equal to serving 30,000 MW of additional load. Assuming the installed capacity of the resource was 50,000 MW, ELCC is simply equal to the ratio of these two quantities, 30,000 / 50,000 = 60%.

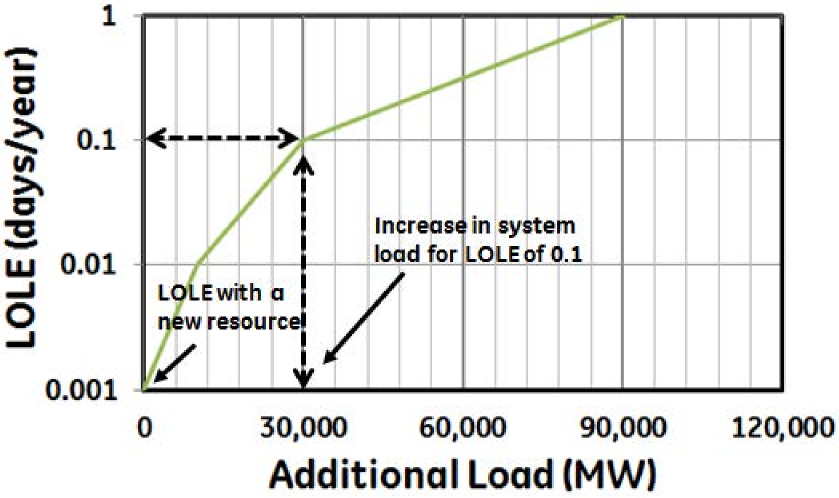


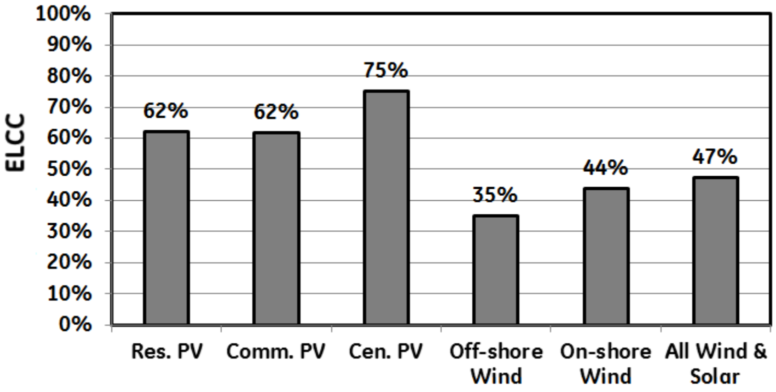
Figure 1-8: Addition of Onshore Wind in 14% RPS Scenario

ELCC methodology can establish the capacity value of a resource even when the installed capacity is extremely high, resulting in almost zero LOLE of the system. Conventional methods for estimating the capacity value of the resource under these conditions would fail. For this reason, all results in this study are based on the ELCC methodology.

1.5 Proposed Methodology to Estimate Capacity Value in Absence of Multiple Years of Load and Resource Data

This section highlights the requirement to have many years of load and resource data in order to obtain a stable capacity value of a resource. IEA Wind Task 25 recommends that at least eight years of synchronized load and wind data may be required to obtain stable capacity values [1]. In this study, we are limited to 3 years of load and resource data. The following sections explain the different methods that were tried in the study to calculate the capacity value of a resource under the constraint of having limited datasets. The final proposed methodology is able to produce stable capacity values by inducing artificial variability in the dataset. The 14% RPS scenario is used as a test system to report the results and findings in this section.

Figure 1-9 shows the installed capacity (in megawatts) and ELCC of the wind/solar resources in the 14% RPS scenario, based on the 2006 load and resource shape. Distributed PV (residential and commercial) shows an ELCC of 62%, lower than the ELCC of central PV (which is 75%). This result is expected because of the tracking system on central PV plants that results in a higher capacity factor and therefore higher capacity value (or ELCC). Offshore Wind shows a lower ELCC (35%) as compared to the onshore wind (44%). This result is counter-intuitive at first glance because offshore wind normally has a higher capacity factor than onshore wind and therefore should have a higher capacity value. This observation is explained in the next section.



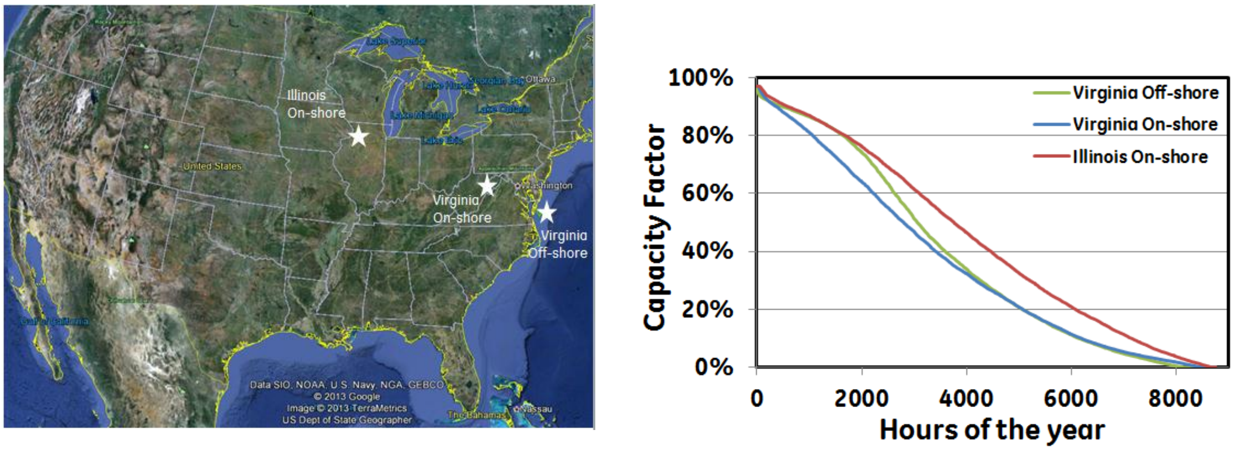
Resource	MW
Residential PV	851
Commercial PV	3,251
Central PV	3,253
Off-shore Wind	4,000
On-shore Wind	28,833

Figure 1-9: Wind and Solar ELCC and Installed Capacity in the 14% RPS Scenario Based On 2006 Load & Resource Shape

1.5.1 Higher ELCC of Onshore Wind than Off-shore Wind

Figure 1-10 shows three wind sites in the RPS-14% case: onshore wind plant in Illinois (150 MW), another onshore wind plant in Virginia (38 MW), and an offshore wind plant in Virginia (20 MW). The instantaneous capacity factor of these plants is plotted on an annual duration curve. The graph shows that the Virginia offshore plant has a higher capacity factor than the Virginia onshore plant for many hours of the year. The average capacity factor for the year (shown in the chart) is also higher for Virginia offshore plant. This is consistent with known facts that an offshore wind plant at a location has a higher capacity factor than the onshore wind facility in the same geographical location.

However, Illinois onshore wind plant has a higher capacity factor than the Virginia onshore as well as offshore for almost all hours of the year. This indicates that weather conditions in Illinois are more favorable for wind power than in Virginia to such an extent that an onshore wind plant in Illinois has a better capacity factor than an off-shore wind plant in Virginia. It is this effect that makes the ELCC of onshore wind higher than that of the offshore wind in this scenario.



Illinois On-shore (Site: 90052)	Virginia On-shore (Site: 90176)	Virginia Off-shore (Site: 68037)
44%	35%	38%

Figure 1-10: Onshore and Offshore Wind Capacity Factors in Illinois and Virginia

1.5.2 Year-to-year Variation in ELCC

Figure 1-11 shows the ELCC of different resources in 14% RPS scenario in different years. Each of the years was modeled with the provided load shape (scaled to 2026 energy) and a provided wind/solar profile. Year 2006 shows a higher ELCC for almost all resources. One observation that stands out is the large variation in ELCC for onshore wind. Year 2005 shows an abnormally lower ELCC for onshore wind; around five times lower than Year 2006. The reason behind this, as explained below, is the low capacity factor for onshore wind during high load periods in 2005.

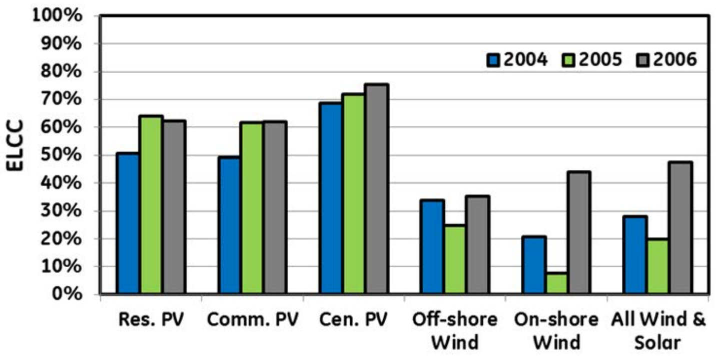


Figure 1-11: ELCC of Wind and Solar Resources across Different Years in 14% RPS Scenario

Figure 1-12 shows the average net load factor for a particular hour in a particular month. A higher net load factor implies that the wind resource was not strong enough to reduce the load and vice versa. In other words, a higher net load factor would imply lower capacity or ELCC for the wind resource. A comparison across the three plots shows that average net load factor is the highest in 2005 during the peak summer period (2-6 pm in the months of Jun-Aug), which explains the low ELCC for onshore wind in this year (Figure 1-11).

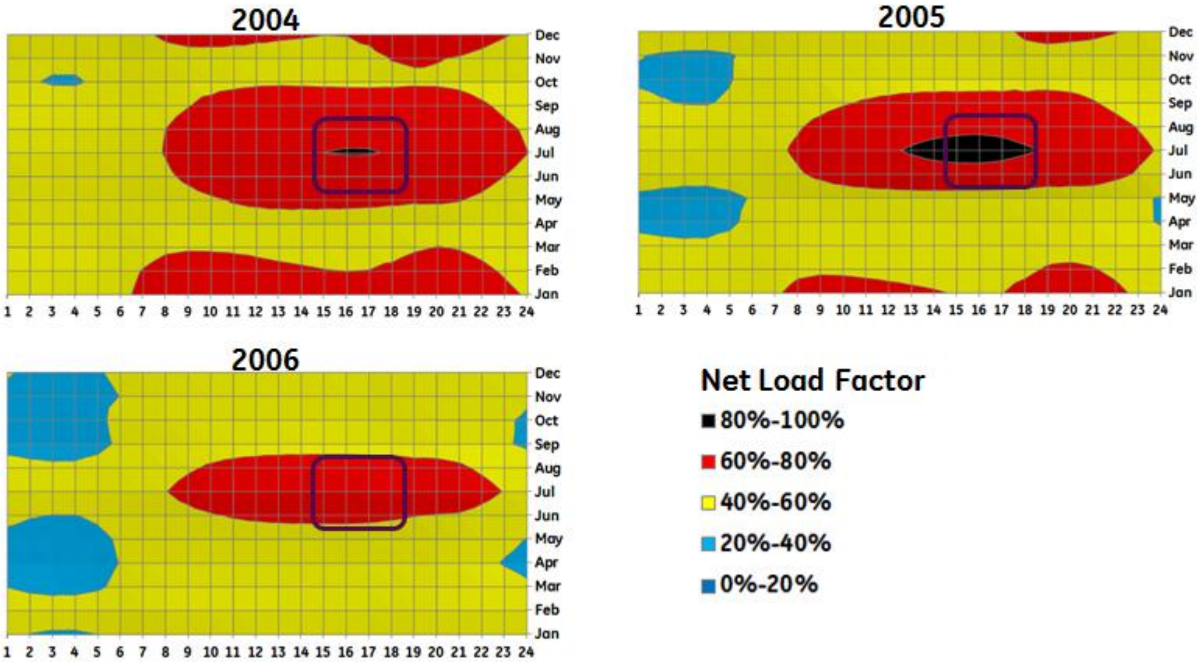


Figure 1-12: Net Load Factor with Onshore Wind in 14% RPS Scenario for Different Years

The results indicate that year-to-year differences in wind/solar shape, as well as differences in the load shapes can significantly alter the capacity value of the wind/solar resources. For this study, only three years of synchronized wind, solar, and load data are available. In order to account for these year-to-year differences and large variability, the following three methods are examined.

Method 1 *Average of the three-year ELCC values*: This methodology proposes to use the average of the ELCC values that a resource exhibits in the three years (2004 to 2006). Figure 1-13 shows the year-to-year variation in the ELCC of onshore wind: from 7.6% to 43.9%. The average of these three years approximates the ELCC at 24%. However, chances are that this can still be an inflated or deflated value due to the small sample size considered. The advantage of this method is that it preserves the synchronization between load and resource shape.

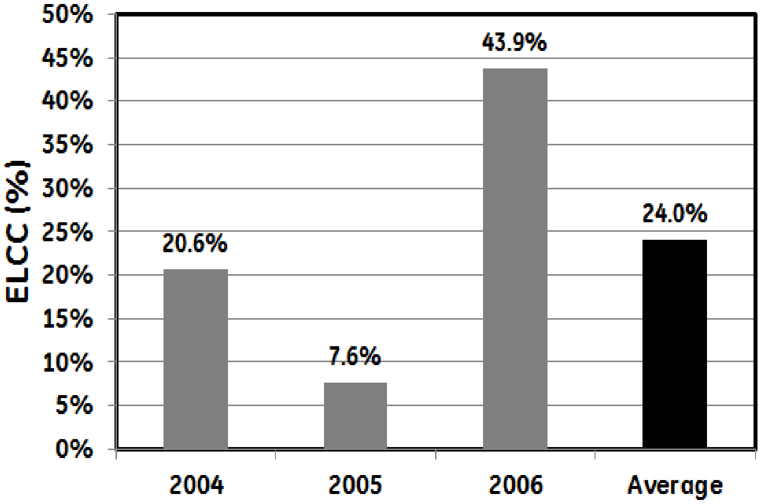


Figure 1-13: Variation of Onshore Wind ELCC in Different Years

Method 2 *Convolving a single year load shape with a resource shape from every year*: This methodology increases the number of combinations of load and resource shapes. Figure 1-14 shows the capacity value for each combination of convolving a single year load shape with onshore wind shape from each of the three years (2004, 2005, and 2006). Again, there is a big variation in the capacity value from one combination to another. The average of these nine combinations gives a capacity value of 16.7% for onshore wind. This methodology however tends to lose the synchronization between load and seasonal (year-to-year) weather characteristics.

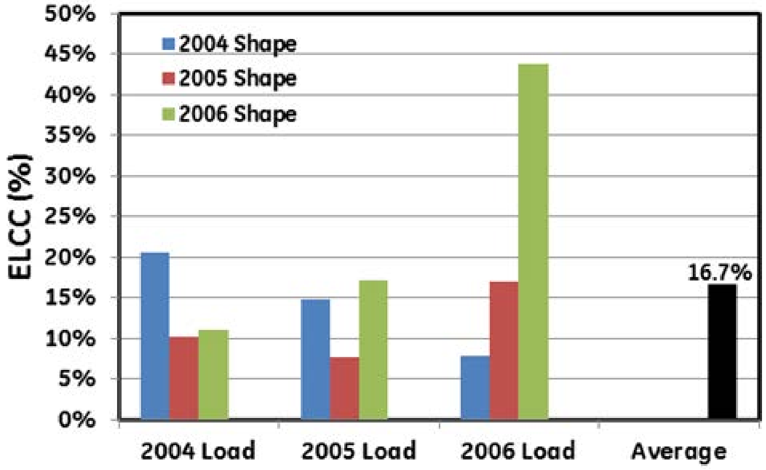


Figure 1-14: Variation of Onshore Wind Capacity Value with Different Combinations of Load & Shape Years

Method 3 *Introducing artificial variability in the resource shape*: This is simulated by using a random draw for the current day resource profile from a given number of days around the present day, such as ± 7 days, for a total of 15 days (7 days before the simulation day, 7 days after the simulation day, and the simulation day). Once the draw determines a particular day, the profile for all the hours of the current day is used from the chosen day. This methodology tends to preserve the synchronization between load and weather better than Method 2 since the weather occurring on days within that window is likely to be similar. The results are shown in Figure 1-15. For comparison purposes, sensitivities with ±14 days and ± 30 days are also shown. The observed year-to-year variation is smaller, and the average ELCC across the years (with any window length) is between 16.8% and 17.4%. In comparison, Method 1 (equivalent to have a 0 day window) gives a higher average ELCC of 24%.

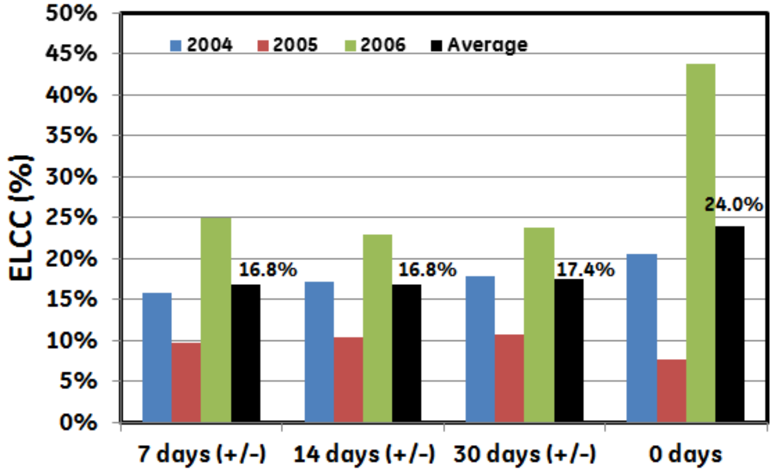


Figure 1-15: Onshore Wind ELCC after Introducing Artificial Variability in Wind Shape

Figure 1-16 compares the average ELCC across the different methods discussed in the above sections. Method 2 and Method 3 give similar average ELCC. Method 1 gives a higher ELCC due to the use of a smaller sample size. Method 2 convolves each year load against each year wind shape and hence tends to lose the year-to-year synchronization between load and wind. Method 3 introduces sufficient variability and smoothens out the year-to-year differences in weather patterns, while also preserving to a certain extent the relation between load and weather patterns. This methodology was only evaluated for the 14% on-shore wind resource. Based on these results, the project team decided to use Method 3 for estimating the average capacity value of every resource type in each scenario. All the analysis beyond this section and the final results for each of the scenarios are based on this methodology.

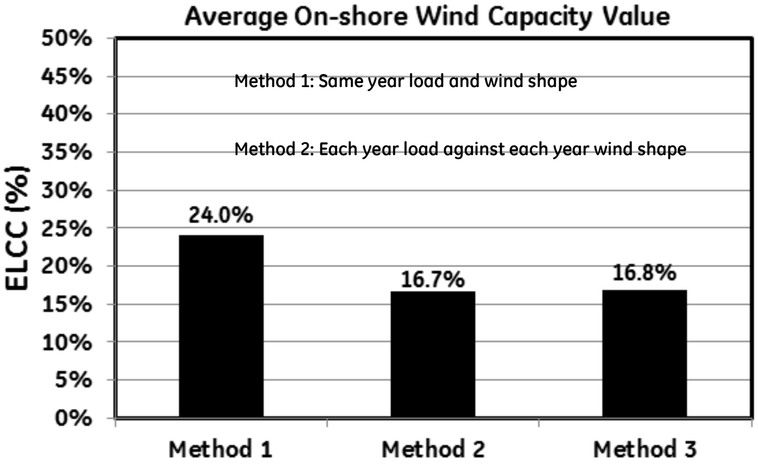
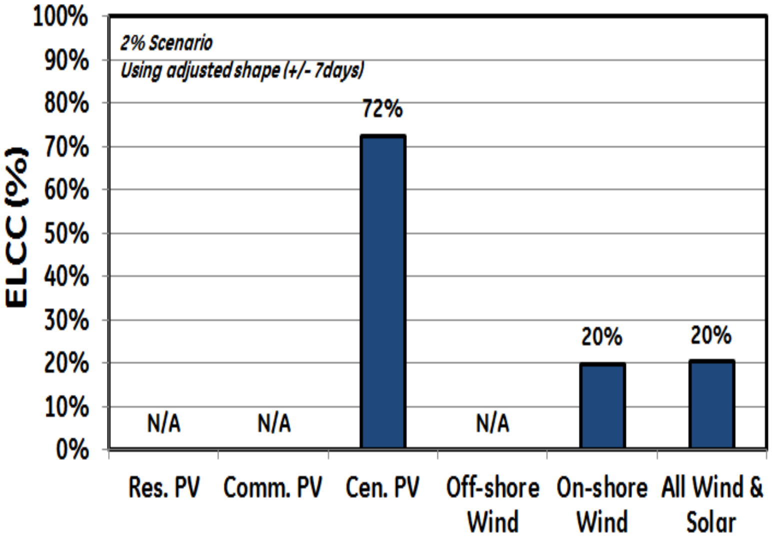


Figure 1-16: Comparison of Onshore Wind ELCC Value with the Three Methods

1.6 ELCC of 2% BAU Scenario

Figure 1-17 shows the ELCC and the installed capacity of the resources (central PV and onshore wind) in the 2% BAU scenario using Method 3. Central PV (72 MW installed capacity) has an ELCC of 72%. Similarly, 5,122 MW of onshore wind has an ELCC of 20%.



Resource	MW
Residential PV	-
Commercial PV	-
Central PV	72
Off-shore Wind	-
On-shore Wind	5,122

Figure 1-17: ELCC of Different Resources in 2% BAU Scenarios Using Method 3

1.7 ELCC of 14% RPS Scenario

Figure 1-18 shows the average ELCC of wind and solar resources in the RPS 14% scenario using Method 3. This method uses load shape of same year against the wind/solar shape of the same year with the adjustment that the current day wind/solar profile can be drawn from ± 7-day period. Compared to Figure 1-9, it can be observed that the average ELCC of all the resources decreases when artificial variability is introduced using Method 3. This is summarized in Table 1-3. The biggest decrease is seen in the value of onshore wind (from 44% to 17%). The reported capacity values are similar to the values observed in the Western Wind Integration Study [2].

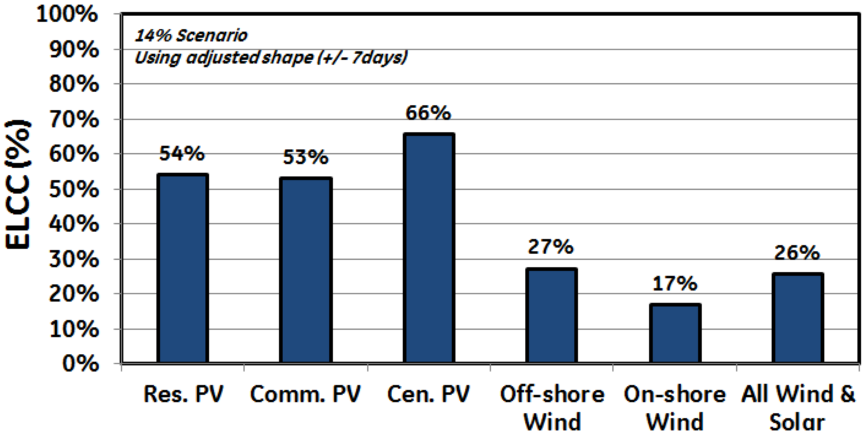


Figure 1-18: ELCC of Different Resources in 14% RPS Scenario Using Method 3

Table 1-3: Comparison of Results Using Method 3 and 2006 Load & 2006 Resource Shape (14% RPS)

	2006 Load/Resource Shape	Method 3
Residential PV	62%	54%
Commercial PV	62%	53%
Central PV	65%	66%
Off-shore Wind	35%	27%
Onshore Wind	44%	17%
All Wind and Solar	47%	26%

1.8 ELCC of 20% Scenarios

Table 1-4 shows the installed capacity of wind/solar resources in the 20% scenarios. The ELCC of the different resources is shown in Figure 1-19.

Table 1-4: Installed Capacity of Wind and Solar Resources in 20% Scenarios

Resource	High Off	Low Off (Best)	Low off (Disp)	High Solar
Residential PV	2,148	2,148	2,148	4,296
Commercial PV	8,265	8,265	8,265	16,530
Central PV	8,078	8,078	8,078	16,198
Off-shore Wind	22,581	4,851	4,851	4,026
On-shore Wind	22,699	40,255	41,745	32,228

The ELCC value of distributed PV is between 55% and 58%, while that of central PV is between 63 and 65% in each of the sub-scenarios. This is expected because of the higher capacity factor of a single-axis tracking system on central PV plants. The ELCC of central PV decreases in the "High Solar" sub-scenario because of saturation effects.

Offshore wind has an ELCC between 25% and 27%. The low ELCC in the "High Off-shore" sub-scenario is due to saturation effects. The ELCC of Onshore wind is between 16% and 18%.

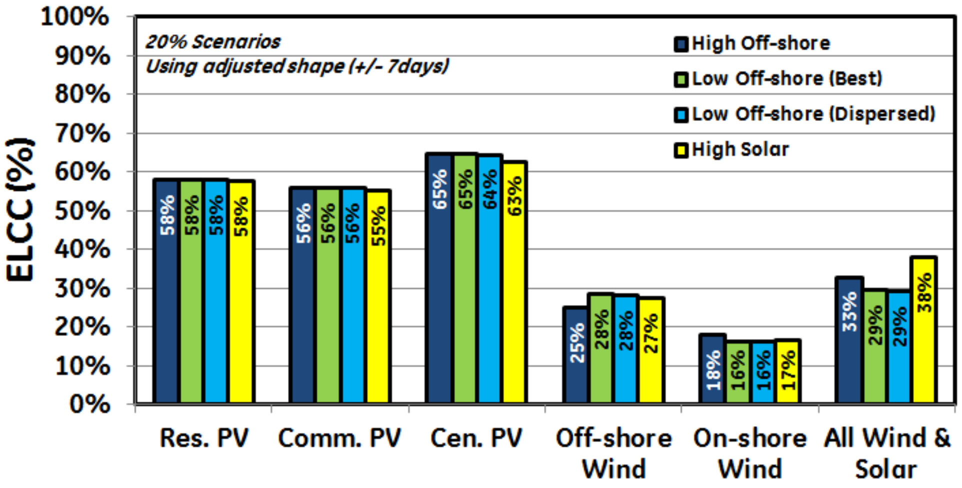


Figure 1-19: ELCC of Different Resources in 20% Scenarios

1.9 ELCC of 30% Scenarios

Table 1-5 shows the installed capacity of wind/solar resources in the 30% scenarios. The ELCC of the different resources is shown in Figure 1-20.

Table 1-5: Installed Capacity of Wind and Solar Resources in 30% Scenarios

Resource	High Off	Low Off (Best)	Low off (Disp)	High Solar
Residential PV	3,580	3,580	3,580	7,160
Commercial PV	13,775	13,775	13,775	27,550
Central PV	13,465	13,465	13,465	27,454
Off-shore Wind	34,489	6,846	6,846	5,430
On-shore Wind	33,806	60,669	64,125	47,126

The ELCC of the resources in the different sub-scenarios is similar to the 20% cases. The ELCC of some resources is lower because of saturation. As an example, the offshore wind ELCC drops from 25% to 21% in the "High Off-shore" sub-scenario, as the installed capacity is increased from 22,581 MW to 33,489 MW. Each additional MW of offshore wind has a lower load carrying capability, implying diminishing returns in the capacity value of the resource.

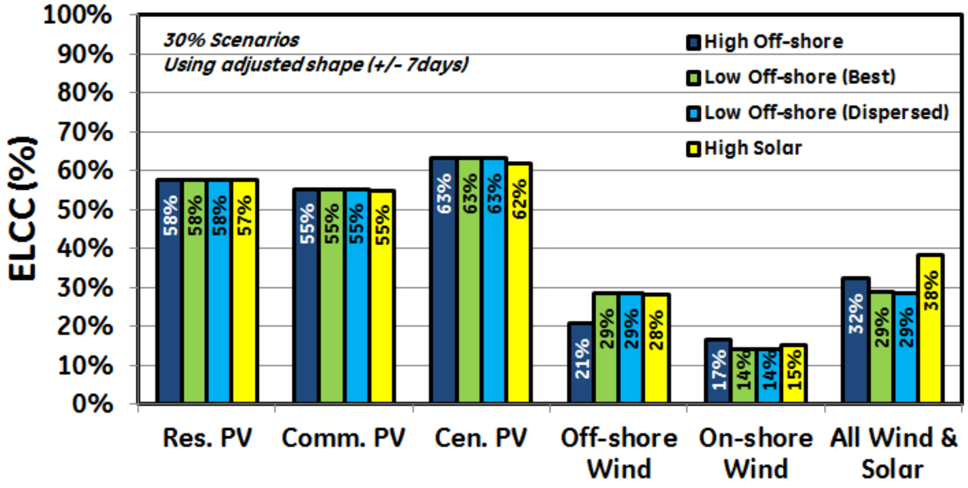
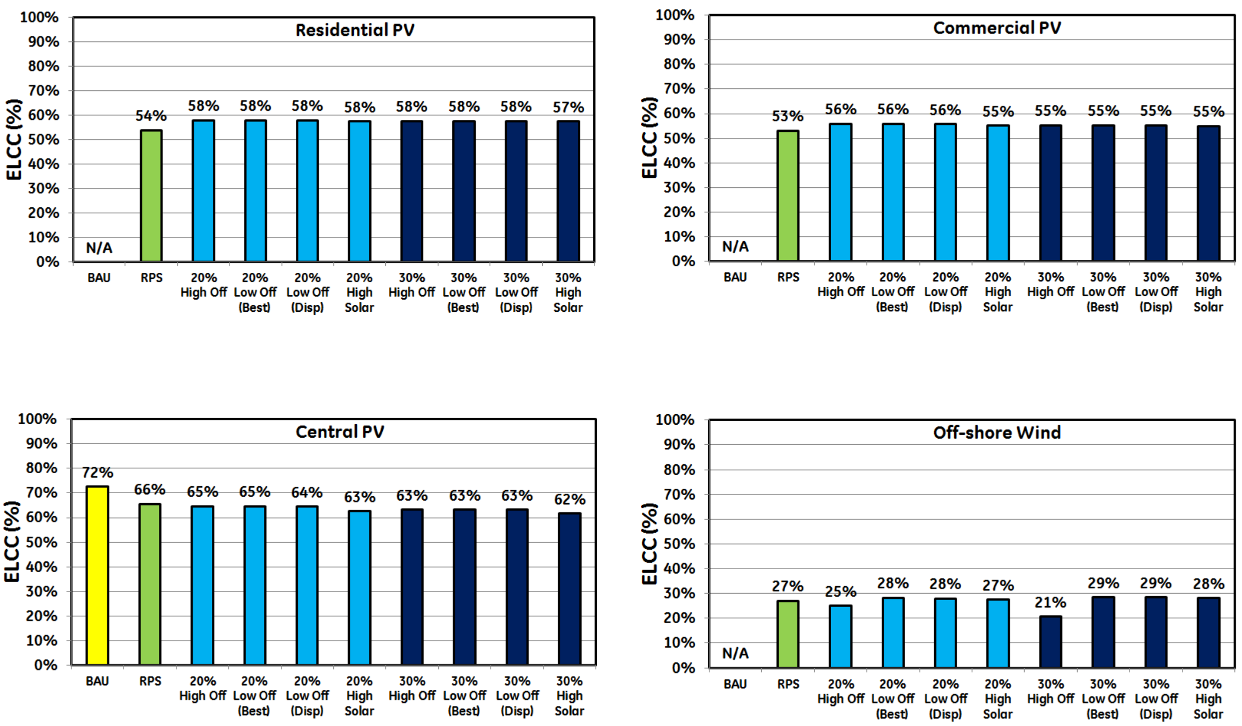


Figure 1-20: ELCC of Wind and Solar Resources in 30% Scenarios

1.10 Capacity Valuation Study Conclusions

This section summarizes the ELCC of the wind and solar resources in each of the scenarios. Figure 1-21 presents ELCC of different wind/solar resources in all scenarios.



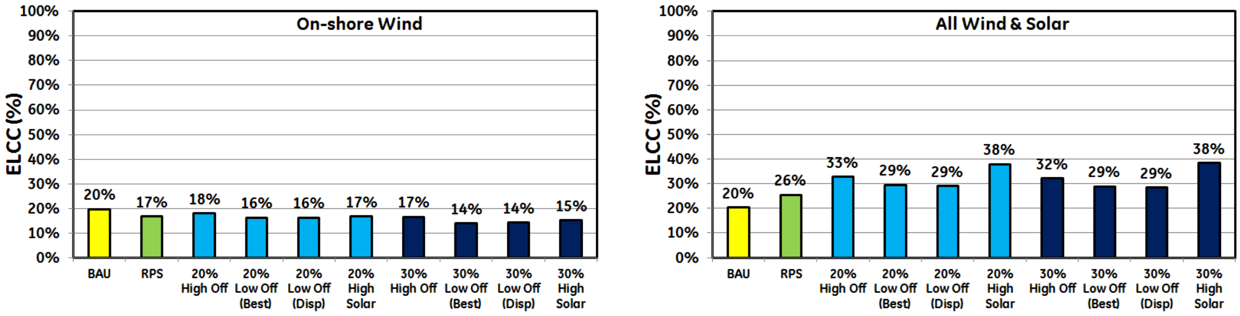


Figure 1-21: ELCC of Different Wind/Solar Resources in All Scenarios

Major findings and lessons learned are summarized below:

- ELCC overcomes the limitations of measuring the capacity value of a resource under saturation, i.e., under conditions when the installed capacity of a resource is high enough to drive the system LOLE close to zero days/year.
- Modified ELCC methodology (referred to as Method 3) is recommended in this study. This methodology helps estimate stable capacity values of a resource (and reduce the variation from one year to another) in absence of many years of load and resource data. The comparison is shown in Figure 1-16. This method should be used for some years until actual wind and solar data is available.
- The capacity factor of a resource under peak load conditions drives the ELCC value of the resource. The initial increase in ELCC from 2% BAU scenario to higher penetration scenarios is because of the inclusion of best sites, which have higher capacity factors.
- ELCC of some resources decreases as the installed capacity increases. As an example, the ELCC value of Central PV decreases from 75% in BAU to 62% in "High Solar" scenario. This occurs because at higher penetration levels the resource may saturate the system and hence the incremental value of serving an additional MW of load will decrease. ELCC of some resources, such as Off-shore Wind, increases in the high penetration scenario. This occurs due to inclusion of sites that have higher capacity value (or higher capacity factor during the peak load periods).

Table 1-6 compares the range of ELCC values to those determined using the PJM Manual 21 methodology. These values can be compared since they were based on the same hourly generation profiles. ELCC values vary as the resource penetration levels change and therefore a range is provided for each resource type. The ELCC values for each resource in other scenarios are shown in Figure 1-21. The comparison to PJM methodology can be made based on the results provided in Section 1.11. The modeling assumptions are listed in Section 1.3.1. As a reference, in the "New England Wind Integration Study," the average capacity value of on-shore wind in the "20% Best Sites Onshore Scenario" was 20%; while the average capacity value of off-shore wind in the "20% Best Sites Offshore Scenario" was 32%. Please note that "20% Best Sites Onshore Scenario" had 8% off-shore wind by installed capacity, and the "20% Best Sites Offshore Scenario" had 58% off-shore wind by installed capacity.

Table 1-6: Range of Effective Load Carrying Capability (ELCC) for Wind and Solar Resources in 20% and 30% Scenarios

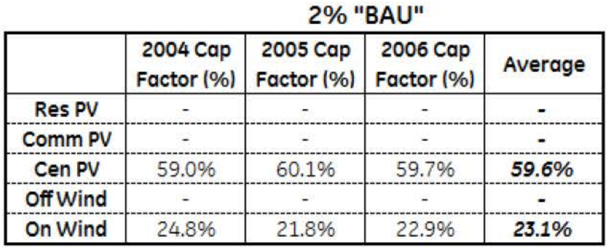
Resource	ELCC (%)	PJM Manual 21 (Summer Peak Hour Average Capacity Factor)
Residential PV	57% - 58%	51%
Commercial PV	55% - 56%	49%
Central PV	62% - 66%	62% - 63%
Off-shore Wind	21% - 29%	31% - 34%
Onshore Wind	14% - 18%	24% - 26%

These values are larger than the current class averages of 13% for wind and 38% for solar which were based on actual historical values. This is because the profiles were developed at optimum sites using the most current power conversion technologies. It was felt that these would provide a better estimate of the likely capacity values of the renewable plants in the future. Individual plants will continue to have their capacity values based on their actual performance and it is expected that the plants with newer technology will have higher values than existing ones.

1.11 Average Capacity Factors of Wind and Solar during Summer Peak Period

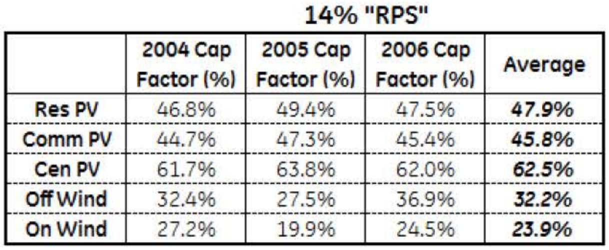
The following tables show the average capacity factor of wind and solar resources (as described in Section 10.3) in the peak summer period of 2004 to 2006. PJM Manual 21 uses the average capacity factors during the summer peak period of the last three years as the capacity credit value of that intermittent energy resource.

Table 1-7: Average Capacity Factor of Wind & Solar Resources in the Peak Summer Period of 2004 – 2006



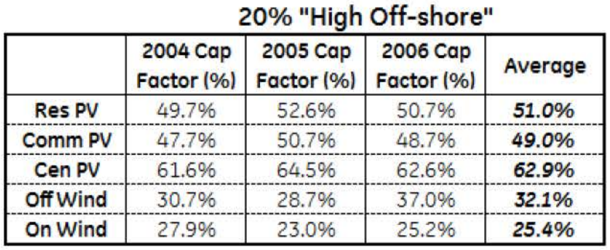
2% "BAU"

	2004 Cap Factor (%)	2005 Cap Factor (%)	2006 Cap Factor (%)	Average
Res PV	-	-	-	**-**
Comm PV	-	-	-	**-**
Cen PV	59.0%	60.1%	59.7%	***59.6%***
Off Wind	-	-	-	**-**
On Wind	24.8%	21.8%	22.9%	***23.1%***



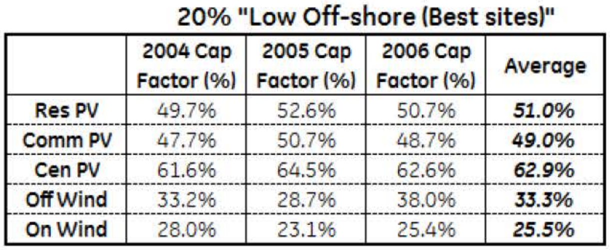
14% "RPS"

	2004 Cap Factor (%)	2005 Cap Factor (%)	2006 Cap Factor (%)	Average
Res PV	46.8%	49.4%	47.5%	***47.9%***
Comm PV	44.7%	47.3%	45.4%	***45.8%***
Cen PV	61.7%	63.8%	62.0%	***62.5%***
Off Wind	32.4%	27.5%	36.9%	***32.2%***
On Wind	27.2%	19.9%	24.5%	***23.9%***



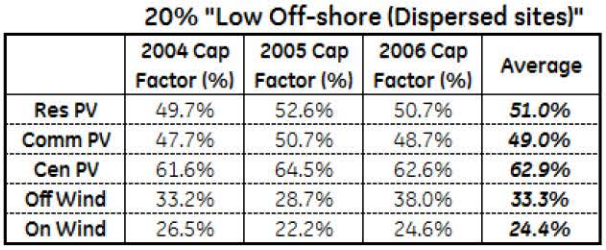
20% "High Off-shore"

	2004 Cap Factor (%)	2005 Cap Factor (%)	2006 Cap Factor (%)	Average
Res PV	49.7%	52.6%	50.7%	***51.0%***
Comm PV	47.7%	50.7%	48.7%	***49.0%***
Cen PV	61.6%	64.5%	62.6%	***62.9%***
Off Wind	30.7%	28.7%	37.0%	***32.1%***
On Wind	27.9%	23.0%	25.2%	***25.4%***



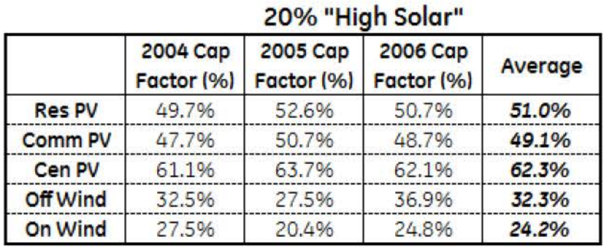
20% "Low Off-shore (Best sites)"

	2004 Cap Factor (%)	2005 Cap Factor (%)	2006 Cap Factor (%)	Average
Res PV	49.7%	52.6%	50.7%	***51.0%***
Comm PV	47.7%	50.7%	48.7%	***49.0%***
Cen PV	61.6%	64.5%	62.6%	***62.9%***
Off Wind	33.2%	28.7%	38.0%	***33.3%***
On Wind	28.0%	23.1%	25.4%	***25.5%***



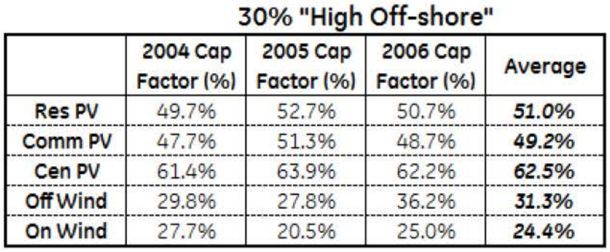
20% "Low Off-shore (Dispersed sites)"

	2004 Cap Factor (%)	2005 Cap Factor (%)	2006 Cap Factor (%)	Average
Res PV	49.7%	52.6%	50.7%	***51.0%***
Comm PV	47.7%	50.7%	48.7%	***49.0%***
Cen PV	61.6%	64.5%	62.6%	***62.9%***
Off Wind	33.2%	28.7%	38.0%	***33.3%***
On Wind	26.5%	22.2%	24.6%	***24.4%***



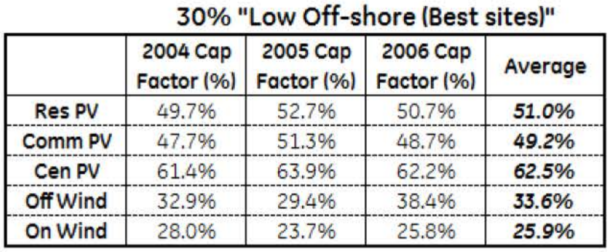
20% "High Solar"

	2004 Cap Factor (%)	2005 Cap Factor (%)	2006 Cap Factor (%)	Average
Res PV	49.7%	52.6%	50.7%	***51.0%***
Comm PV	47.7%	50.7%	48.7%	***49.1%***
Cen PV	61.1%	63.7%	62.1%	***62.3%***
Off Wind	32.5%	27.5%	36.9%	***32.3%***
On Wind	27.5%	20.4%	24.8%	***24.2%***



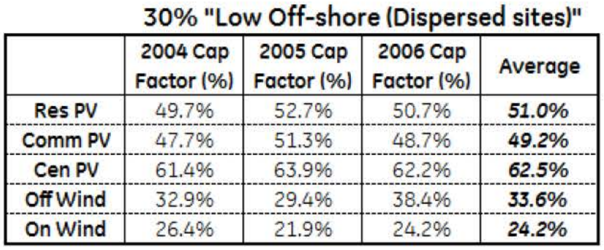
30% "High Off-shore"

	2004 Cap Factor (%)	2005 Cap Factor (%)	2006 Cap Factor (%)	Average
Res PV	49.7%	52.7%	50.7%	***51.0%***
Comm PV	47.7%	51.3%	48.7%	***49.2%***
Cen PV	61.4%	63.9%	62.2%	***62.5%***
Off Wind	29.8%	27.8%	36.2%	***31.3%***
On Wind	27.7%	20.5%	25.0%	***24.4%***



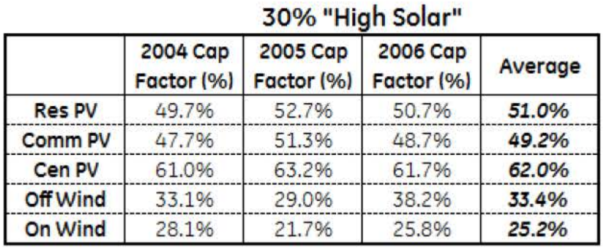
30% "Low Off-shore (Best sites)"

	2004 Cap Factor (%)	2005 Cap Factor (%)	2006 Cap Factor (%)	Average
Res PV	49.7%	52.7%	50.7%	***51.0%***
Comm PV	47.7%	51.3%	48.7%	***49.2%***
Cen PV	61.4%	63.9%	62.2%	***62.5%***
Off Wind	32.9%	29.4%	38.4%	***33.6%***
On Wind	28.0%	23.7%	25.8%	***25.9%***



30% "Low Off-shore (Dispersed sites)"

	2004 Cap Factor (%)	2005 Cap Factor (%)	2006 Cap Factor (%)	Average
Res PV	49.7%	52.7%	50.7%	***51.0%***
Comm PV	47.7%	51.3%	48.7%	***49.2%***
Cen PV	61.4%	63.9%	62.2%	***62.5%***
Off Wind	32.9%	29.4%	38.4%	***33.6%***
On Wind	26.4%	21.9%	24.2%	***24.2%***



30% "High Solar"

	2004 Cap Factor (%)	2005 Cap Factor (%)	2006 Cap Factor (%)	Average
Res PV	49.7%	52.7%	50.7%	***51.0%***
Comm PV	47.7%	51.3%	48.7%	***49.2%***
Cen PV	61.0%	63.2%	61.7%	***62.0%***
Off Wind	33.1%	29.0%	38.2%	***33.4%***
On Wind	28.1%	21.7%	25.8%	***25.2%***

It should be pointed out that the wind profiles used in this study assumed advanced turbine design expected to be available in the future, and therefore, the values reported here would be slightly higher than what has been historically observed in PJM.

1.12 Capacity Valuation References

[1] Michael Milligan, "IEA Wind Task 25 Recommended Practices for Wind Integration Studies: Recent Work on Capacity Value Estimation," UVIG Spring Workshop, Charleston SC, April 2013

[2] NREL, "Western Wind and Solar Integration Study":

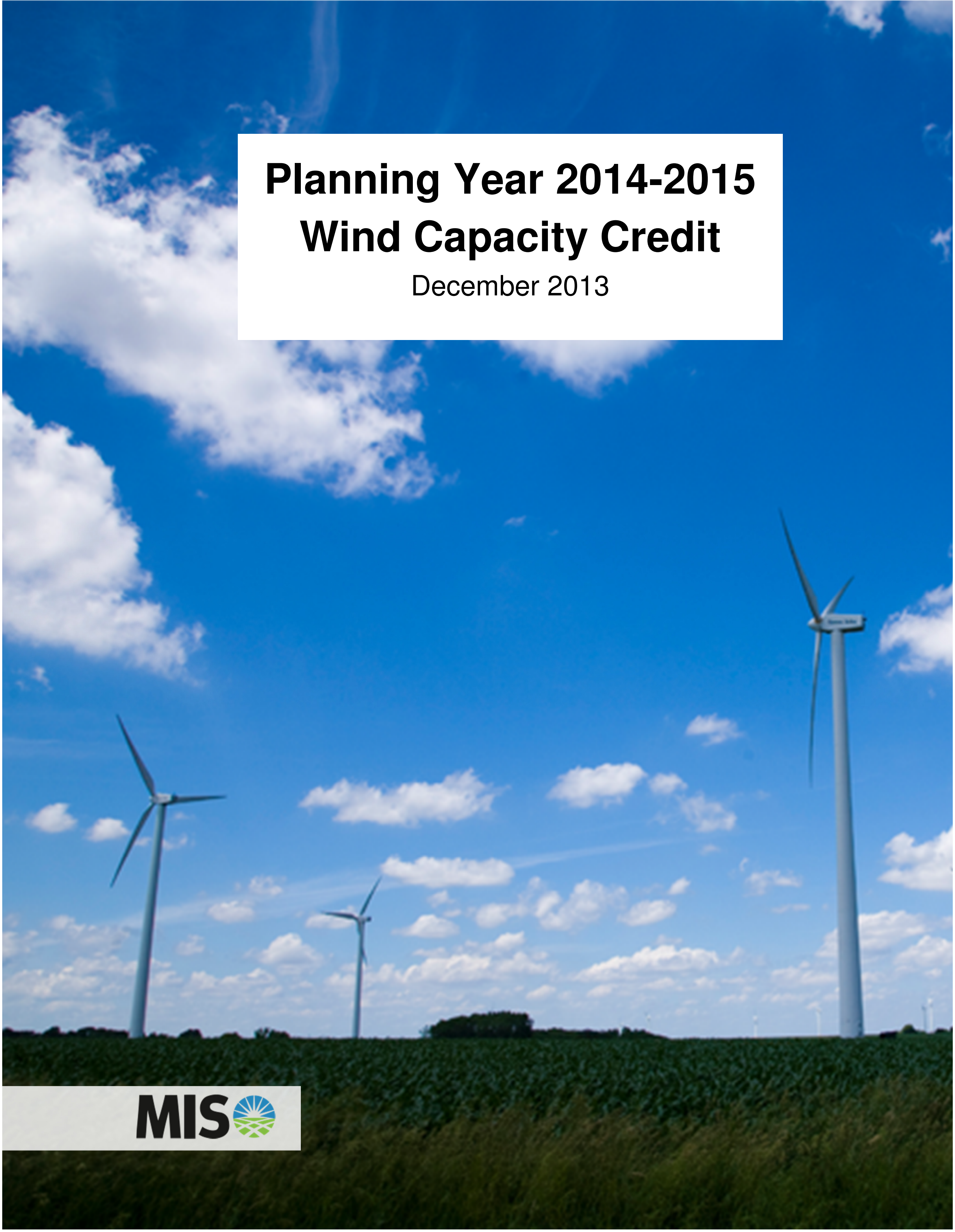
http://www.nrel.gov/wind/systemsintegration/pdfs/2010/wwsis_final_report.pdf

[3] GE Energy Consulting, EnerNEX Corporation, AWS Truepower, "New England Wind Integration Study": http://www.uwig.org/newis_es.pdf

imagination at work

Planning Year 2014-2015 Wind Capacity Credit

December 2013



MISO

Contents

Reason for Revision	Revised by:	Date:
Draft Posted	MISO Staff	11/25/2013
Final Posted	MISO Staff	12/17/2013

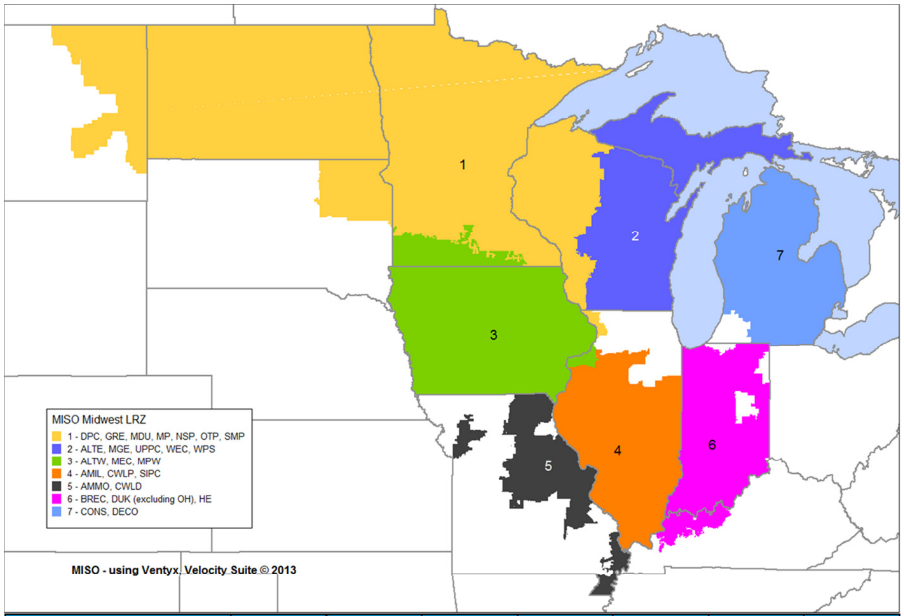
1 Executive Summary

The MISO system-wide wind capacity credit for the 2014-2015 planning year is 14.1 percent. Since 2009 MISO has embarked on a process to determine the capacity value for the increasing fleet of wind generation in the MISO system. The MISO process as developed and vetted through the MISO stakeholder community consists of a two-step method. The first-step utilizes a probabilistic approach to calculate the MISO system-wide Effective Load Carrying Capability (ELCC) value for all wind resources in the MISO footprint. The second-step employs a deterministic approach using the historical output of each wind resource, which considers each wind resource's location. The MISO system-wide ELCC value is then allocated across all wind Commercial Pricing Nodes (CPNodes) in the MISO system to determine a wind capacity credit for each wind CPNode.

As of June 30th, 2013, the MISO system had 12,239 MW (176 CPNodes) of registered wind capacity. This means 1,723 MW (12,239 MW x 14.1%) of unforced wind capacity potentially qualifies under Module E-1 of MISO's tariff. To the extent that the 1,723 MW of unforced wind capacity is deliverable at the individual wind CPNodes, the unforced capacity megawatts may be converted to Zonal Resource Credits (ZRC) to meet Resource Adequacy obligations. Based on the Network Resource Interconnection Service (NRIS) of each wind CPNode, approximately 75% of the 2013 unforced wind capacity would qualify to be converted to ZRC's in the 2014-2015 Planning Resource Auction.

The capacity credit at the 176 individual wind CPNodes is proprietary information, however, the percent credit across all wind CPNodes ranged from zero to 25.3 percent. Section 3 describes the details of allocating the total 1,723 MW to the 176 wind CPNodes. Upon request to MISO, the capacity credit details for individual wind CPNodes are available to the associated Market Participants. Figure 1-1 geographically illustrates the seven MISO Midwest Local Resource Zones (LRZ). The table in Figure 1-1 shows the most detailed results that MISO can share. All LRZs have multiple market participants with wind CPNodes with the exception of LRZ 5. Therefore, the values for LRZ 5 shown in Figure 1-1 were combined with LRZ 4 so that proprietary information would not be revealed.

One thing to consider about future planning year studies is that a lower penetration level of wind will be observed than the current 13 percent. This will be due to the addition of MISO South in December 2013 to the MISO system. MISO South will bring a substantial amount of load to the MISO footprint with very little to no wind capacity. This will decrease the wind penetration in MISO as compared to the 2014-2015 planning year.



Metric	MISO	Zone 1	Zone 2	Zone 3	Zone 4 and Zone 5	Zone 6	Zone 7
Registered Max (MW)	12,239	3,941	627	5,932	514	282	943
UCAP (MW)	1,723	622	76	811	48	22	145
ELCC %	14.1%	15.8%	12.1%	13.7%	9.3%	7.8%	15.4%
Wind CPnode Count	176	67	10	72	7	4	16

Figure 1-1: MISO Midwest Local Resource Zones (LRZ) And Distribution of Wind Capacity

2 MISO System-Wide Wind ELCC Study

2.1 Probabilistic Analytical Approach

The probabilistic measure of load not being served is known as Loss of Load Probability (LOLP) and when this probability is summed over a time frame, e.g. one year; it is known as Loss of Load Expectation (LOLE). The accepted industry standard for what has been considered a reliable system has been the “Less than 1 Day in 10 Years” criteria for LOLE. This measure is often expressed as 0.1 days/year, as that is often the time period (1 year) over which the LOLE index is calculated.

Effective Load Carrying Capability (ELCC) is defined as the amount of incremental load a resource, such as wind, can dependably and reliably serve, while considering the probabilistic nature of generation shortfalls and random forced outages as driving factors to load not being served. Using ELCC in the determination of capacity value for generation resources has been around for nearly half a century. In 1966, Garver demonstrated the use of loss-of-load probability mathematics in the calculation of ELCC[1]

To measure the ELCC of a particular resource, the reliability effects need to be isolated for the resource in question from those of all the other sources. This is accomplished by calculating the LOLE of two different

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[1] Garver, L.L.; , "Effective Load Carrying Capability of Generating Units," Power Apparatus and Systems, IEEE Transactions on , vol.PAS-85, no.8, pp.910-919, Aug. 1966

cases: one “With” and one “Without” the resource. Inherently, the case “with” the resource should be more reliable and consequently have fewer days per year of expected loss of load (smaller LOLE).

The new resource in the example shown in Figure 2-1 made the system 0.07 days/year more reliable, but there is another way to express the reliability contribution of the new resource besides the change in LOLE. This way requires establishing a common baseline reliability level and then adjusting the load in each case “With” and “Without” the new resource to this common LOLE level. A common baseline that is chosen is the industry accepted reliability standard of 1 Day in 10 Years (0.1 days/year) LOLE criteria.

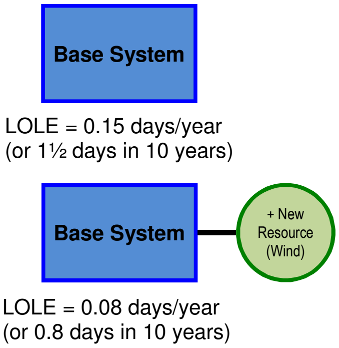

Figure 2-1: Example System “With” & “Without” New Resource

With each case being at the same reliability level, as shown in Figure 2-2, the only difference between the two cases is that the load was adjusted. The difference is the amount of ELCC expressed in load or megawatts, which is 300 MW (100 minus -200) for the new resource in this example. Sometimes this number is divided by the Registerd Maximum Capacity (RMax) of the new resource and then expressed in percentage (%) form. The new resource in the ELCC Example Figure 2-2 has an ELCC of 30 percent of the resource’s nameplate capacity.

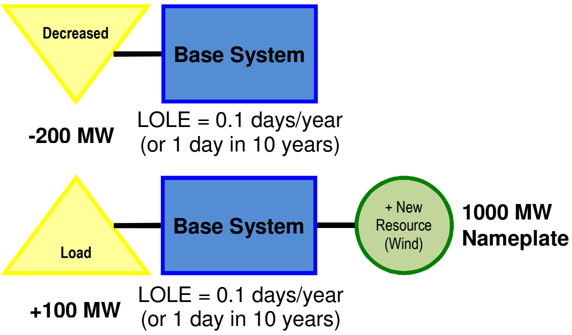

Figure 2-2: ELCC Example System at the same LOLE

The same methodology illustrated in the simple example of Figure 2-2 was utilized as the analytical approach for the determination of the 2014 MISO system-wide ELCC of the wind resources in the much more complex MISO system. Using ELCC is the preferred method of calculation for determining the capacity value of wind[2].

2.2 LOLE Model Inputs & Assumptions

MISO applies the ELCC calculation methodology by utilizing the Multi-Area Reliability Simulation (MARS) program by GE Energy to calculate LOLE values with and without wind resources modeled. This model consists of three major inputs:

1. Generator Forced Outage Rates (FOR)
2. Actual Historic Hourly Load Values
3. Actual Historic Hourly Wind Output Values

Forced outage rates are used for the conventional type of units in the LOLE model. These FOR are calculated from the Generator Availability Data System (GADS) that MISO uses to collect historic operation performance data for all conventional unit types in the MISO system.

For the 2014 ELCC Study, the actual 2013 historical hourly concurrent load and wind output at the wind CPNodes is used to calculate the ELCC values for the wind generation in MISO on a system-wide basis. The second to last column of Table 2-1 illustrates the ELCC results for the past 9 years.

2.3 MISO System Wide ELCC Results

MISO calculated ELCC percentage results for historical years 2005 through 2013 and at multiple scenarios of penetration levels, corresponding to 10 GW, 20 GW and 30 GW of installed wind capacity. This creates an ELCC penetration characteristic for each year, as illustrated by the different curves in Figure 2-3. The ELCC characteristic of each year can be represented by a trend line equation that has an R squared coefficient of no less than 0.999. This is the basis for achieving accuracy with sparse or few years of data. The initial left most data point for each curve is at the lowest penetration point and represents the actual annual ELCC for that year. These values are shown in the second to last column of Table 2-1. The values along each year's characteristic curve at the higher penetration levels reflect what that year's wind resources would have as an ELCC if more capacity had been installed over the same year and footprint. The high end 30 GW level of penetration (approximately 30 percent on x-axis of Figure 2-3) is an estimate of the amount of wind generation that could result in MISO, as the Load Serving Entities (LSE) collectively meet renewable resource mandates of the various MISO States. Figure 2-3 illustrates the ELCC versus penetration characteristic of each of the nine years, and how those characteristics from multiple years were merged to establish the current 14.1 percent wind capacity credit.

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[2] Keane, A.; Milligan, M.; Dent, C.J.; Hasche, B.; D'Annunzio, C.; Dragoon, K.; Holttinen, H.; Samaan, N.; Soder, L.; O'Malley, M.; , "Capacity Value of Wind Power," Power Systems, IEEE Transactions on , vol.26, no.2, pp.564-572, May 2011

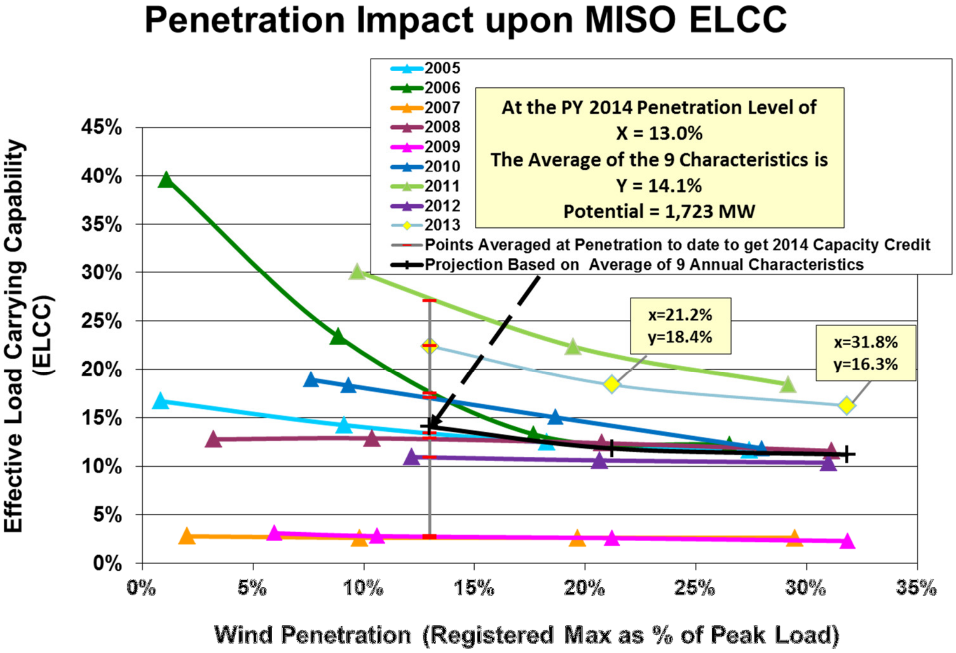

Figure 2-3: Nine Years of Historical ELCC Penetration Characteristics

The Planning Year (PY) 2014 wind capacity credit is determined by averaging the nine ELCC values found along each year's ELCC-and-penetration characteristic curve. The averaging is done at the penetration level that corresponds to the penetration level at the end of the 2nd Quarter 2013. The registered amount of capacity at the end of the 2nd Quarter is the convention used to set the capacity going into the summer season. The penetration level at the end of the 2nd Quarter 2013 was 13.0 percent. The historical 2013 penetration level is calculated by dividing the 2nd Quarter 12,239 MW (from column 4 of Table 2-1) by the 94,298 MW peak load (column 1 of Table 2-1). The peak load is defined as the highest average integrated hourly load for the year. The vertical line called out in the legend of Figure 2-3 as "Points Averaged at penetration to date to get 2014Capacity Credit" illustrates where each of the nine ELCC values from each year's characteristic curve intersect with the most recent 13.0 percent historical penetration level. The legend of Figure 2-3 also indicates that the average of the intersected values is the 14.1 percent system-wide ELCC for PY 2014. The black projection line in Figure 2-3 starts with the PY 2014 14.1 percent, and is more clearly observed as the current 14.1 percent point and forward projection in Figure 2-4.

The resulting wind capacity credit is expressed in Unforced Capacity (UCAP) megawatts. If the individual CPNodes were to have full deliverability via the Generator Interconnection process, the system-wide capacity rating could represent as much as 1,723 MW of UCAP in 2014. MISO calculates the associated UCAP at each wind CPNode and provides it to the appropriate Market Participant on a requested confidential basis. The capacity credit values can also be viewed in the Module E Capacity Tracking (MECT) tool. For the 2014-2015 planning year, a total UCAP of 1,723 MW is allocated among 176 wind CPNodes, up from 169 CPNodes in planning year 2013. Section 3 shows the details of the allocation method. The amount at each node that can qualify under Module E-1 is subject to the specific deliverability limit for each location.

Market-wide Operational Tracking

Peak Load (MW)	Planning Year (PY)	Metered Wind at Peak Load[1] (MW)	Registered Maximum Capacity[2] (MW)	Peak Day RMax[2] (%)	Historical Penetration (%)	Annual Historical ELCC (%)	MISO Capacity Credit (%)
109,473	2005	104	908	11.5%	0.8%	16.7%	N/A
113,095	2006	700	1,251	56.0%	1.1%	39.6%	N/A
101,800	2007	44	2,065	2.1%	2.0%	2.8%	N/A
96,321	2008	384	3,086	12.4%	3.2%	12.8%	N/A
94,185	2009	86	5,636	1.5%	6.0%	3.1%	20.0%
107,171	2010	1,770	8,179	21.6%	7.6%	18.9%	8.0%
102,804	2011	4,421	9,996	44.2%	9.7%	30.1%	12.9%
96,764	2012	1,152	11,774	9.8%	12.2%	11.0%	14.7%
94,298	2013	6,439	12,239	52.6%	13.0%	22.4%	13.3%
Pending	2014	Pending	Pending	Pending	Pending	Pending	14.1%

Notes: 1 Curtailed and Dispatchable Intermittent Resources (DIR) MW have bee added to settlement MW

2 Registered Maximum (Rmax)

Table 2-1: Historical Tracking of Wind Related Metrics

The current method to set the capacity credit was developed at the LOLE Working Group, and was first applied to planning year 2011. Table 2-2 shows the consistency of that method's results over five Planning Years, which includes the PY 2010 value if the current method had also been applied. Again, the black curve in Figure 2-4 is the projection going forward, where the influence of future annual ELCC characteristics are still pending. For related study work that require hourly wind and load patterns, such as required in PROMOD ® simulations, MISO has indicated that the historical 2005 wind and load shapes are typical patterns to use at MISO. The appropriateness of continuing to use 2005 as a typical year is confirmed in Figure 2-3 since the black trend line that reflects all history lies nearly on top of the blue line representing the single year 2005. The left portion of Figure 2-4 demonstrates the increasing volatility that would have resulted if the current calculating process had been applied to successively fewer sets of historical annual ELCC penetration characteristics. Figure 2-4 also repeats the 2014 point and the extension to future higher penetration levels from Figure 2-3.

Table 2-2: Consistent and Responsive System-Wide ELCC Method Demonstrated by Applying it Over Five Planning Years

Planning Year	Wind Penetration	ELCC
PY 2010	6.0%	12.4%
PY 2011	7.6%	12.9%
PY 2012	9.7%	14.7%
PY 2013	12.2%	13.3%
PY 2014	13.0%	14.1%

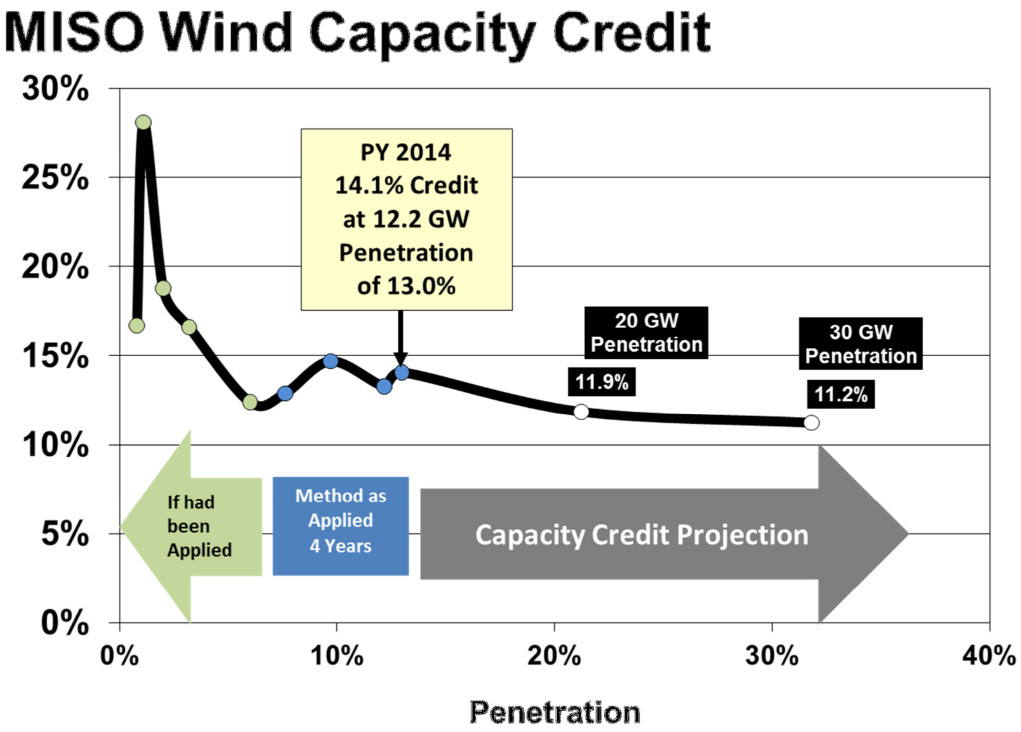

Figure 2-4: Demonstration of Applying Capacity Credit Method Starting with PY 2006

3 Details of Wind Capacity by CPNode

3.1 Deterministic Analytical Technique

Since there are many wind CPNodes throughout the MISO system (176 in 2013), a deterministic approach involving a historic-period metric is used to allocate the single system-wide ELCC value of wind to all the registered wind CPNodes. While evaluation of all CPNodes captures the benefit of the geographic diversity, it is also important to assign the capacity credit of wind at the individual CPNode locations, because in the MISO market the location relates to deliverability due to possible congestion on the transmission system. Also, in a market it is important to convey the correct incentive signal regarding where wind resources are relatively more effective. The location and relative performance is a valuable input in determining the tradeoffs between constructing wind facilities in high capacity factor locations that typically require more transmission investment versus locating wind generating facilities at less effective wind resource locations that may require less transmission build-out.

For the 2014-2015 planning year, the system-wide wind ELCC value of 14.1 percent times the 2013 registered maximum wind capacity (RMax) of 12,239 MW (2nd Quarter 2013) results in 1,723 MW of system-wide capacity. The 1,723 MW is then allocated to the 176 different CPNodes in the MISO system. The historic output has been tracked for each wind CPNode over the top 8 daily peak hours for each year 2005 through 2013. The average capacity factor for each CPNode during all 72 (8-hours x 9-years) historical daily peak hours is called the "$\text{PKmetric}_{\text{CPNode}}$" for that CPNode. The capacity factor over those 72 hours and the RMax at each CPNode are the basis for allocating the 1,723 MW of capacity to the 176 CPNodes. If the start date of the CPNode's name was after 2005, then the average capacity factor over fewer years is used. MISO has developed business practice rules for the handling of new wind CPNodes that do not have historical output data. Table 3-1 is a listing of the total system wind output at the time of 72 daily peak loads. These 72 peaks are the top nine daily peaks over the past nine summers.

Tracking the top 8 daily peak hours in a year is sufficient to capture the peak load times that contribute to the annual LOLE of 0.1 days/year. For example, in the LOLE run for year 2013, all of the 0.1 days/year LOLE occurred in the month of July, but only 5 of the top 8 daily peaks occurred in the months of July. Therefore, no more than 5 of the top daily peaks contributed to the LOLE. Other years have LOLE contributions due to more than 5 days, however 8 days was found sufficient to capture the correlation between wind output and peak load times in all cases. If many more years of historical data were available, one could simply utilize the single peak hour from each year as the basis for determining the $\text{PKmetric}_{\text{CPNode}}$ over multiple years. Using the top 8 daily peak days will be evaluated each year as more data is received.

Table 3-1 - Wind Output for 9 Years
At Time of 8 Top Daily Load Peaks each Year

END_TIME of Daily Peak (EST)	Wind Registered Max (MW)	Estimated Curtailment and DIR (MW)	Wind Output at Daily Peak Load[1] (MW)	Wind Output % of Registered Max at Daily Peak Load[1]	Daily Peak Load (MW)	Year	Planning Year Daily Peak Rank
6/27/05 15:00	908	0	291	32.1%	105,353	2005	6
7/21/05 16:00	908	0	92	10.2%	104,998	2005	7
7/25/05 15:00	908	0	89	9.8%	108,558	2005	3
8/1/05 17:00	908	0	58	6.4%	106,949	2005	5
8/2/05 16:00	908	0	211	23.2%	109,099	2005	2
8/3/05 16:00	908	0	104	11.5%	109,473	2005	1
8/8/05 17:00	908	0	396	43.6%	104,011	2005	8
8/9/05 16:00	908	0	282	31.1%	107,615	2005	4
7/17/06 16:00	1,251	0	430	34.4%	110,011	2006	4
7/18/06 16:00	1,251	0	63	5.1%	102,742	2006	5
7/19/06 16:00	1,251	0	378	30.2%	101,744	2006	7
7/25/06 17:00	1,251	0	53	4.3%	100,948	2006	8
7/28/06 16:00	1,251	0	471	37.6%	102,161	2006	6
7/31/06 16:00	1,251	0	700	56.0%	113,095	2006	1
8/1/06 16:00	1,251	0	139	11.1%	110,947	2006	2
8/2/06 16:00	1,251	0	36	2.9%	110,499	2006	3
6/26/07 15:00	2,065	0	363	17.6%	97,413	2007	8
7/9/07 15:00	2,065	0	45	2.2%	98,049	2007	6
7/31/07 17:00	2,065	0	352	17.0%	98,955	2007	5
8/1/07 16:00	2,065	0	64	3.1%	101,496	2007	2
8/2/07 16:00	2,065	0	45	2.2%	101,268	2007	4
8/6/07 17:00	2,065	0	76	3.7%	97,435	2007	7
8/7/07 17:00	2,065	0	59	2.9%	101,306	2007	3
8/8/07 16:00	2,065	0	44	2.1%	101,800	2007	1
7/16/08 16:00	3,086	0	455	14.8%	95,982	2008	2
7/17/08 16:00	3,086	0	423	13.7%	95,592	2008	3
7/18/08 16:00	3,086	0	97	3.1%	93,144	2008	5
7/29/08 16:00	3,086	0	384	12.5%	96,321	2008	1
7/31/08 17:00	3,086	0	402	13.0%	92,544	2008	7
8/1/08 16:00	3,086	0	405	13.1%	93,422	2008	4
8/4/08 17:00	3,086	0	178	5.8%	92,245	2008	8
8/5/08 16:00	3,086	0	212	6.9%	93,089	2008	6
6/22/09 16:00	5,636	0	527	9.4%	87,846	2009	5
6/23/09 15:00	5,636	0	720	12.8%	91,671	2009	3
6/24/09 17:00	5,636	0	300	5.3%	92,402	2009	2
6/25/09 14:00	5,636	0	86	1.5%	94,185	2009	1
6/26/09 16:00	5,636	0	1,082	19.2%	87,355	2009	6
8/10/09 14:00	5,636	0	167	3.0%	89,039	2009	4
8/14/09 16:00	5,636	0	2,126	37.7%	87,023	2009	7

8/17/09 15:00	5,636	0	1,132	20.1%	85,593	2009	8
7/23/10 16:00	8,179	0	692	8.5%	102,995	2010	8
8/3/10 16:00	8,179	0	365	4.5%	103,646	2010	4
8/4/10 16:00	8,179	0	948	11.6%	103,527	2010	6
8/9/10 16:00	8,179	0	383	4.7%	103,571	2010	5
8/10/10 16:00	8,179	30	1,770	21.6%	107,171	2010	1
8/11/10 16:00	8,179	0	129	1.6%	104,075	2010	3
8/12/10 16:00	8,179	25	1,788	21.9%	106,653	2010	2
8/13/10 16:00	8,179	0	2,072	25.3%	102,996	2010	7
6/7/11 17:00	9,996	57	5,624	56.3%	94,933	2011	7
7/18/11 15:00	9,996	0	991	9.9%	98,177	2011	4
7/19/11 16:00	9,996	0	1,880	18.8%	101,076	2011	2
7/20/11 17:00	9,996	197	4,421	44.2%	102,804	2011	1
7/21/11 16:00	9,996	158	961	9.6%	99,601	2011	3
7/22/11 16:00	9,996	71	1,192	11.9%	93,759	2011	8
8/1/11 15:00	9,996	0	2,427	24.3%	95,703	2011	5
8/2/11 16:00	9,996	64	2,613	26.1%	95,169	2011	6
6/28/12 17:00	11,774	8	1,387	11.8%	93,031	2012	6
7/2/12 16:00	11,774	80	3,668	31.1%	92,605	2012	7
7/5/12 16:00	11,774	0	659	5.6%	92,473	2012	8
7/6/12 16:00	11,774	75	2,397	20.4%	95,262	2012	3
7/16/12 17:00	11,774	2	4,336	36.8%	94,727	2012	4
7/17/12 15:00	11,774	8	1,159	9.8%	96,102	2012	2
7/23/12 16:00	11,774	0	1,152	9.8%	96,794	2012	1
7/25/12 17:00	11,774	63	4,276	36.3%	93,408	2012	5
7/15/13 16:00	12,239	14	1,734	14.2%	88,517	2013	8
7/16/13 17:00	12,239	23	1,798	14.7%	90,807	2013	4
7/17/13 17:00	12,239	17	1,478	12.1%	93,190	2013	2
7/18/13 16:00	12,239	212	6,439	52.6%	94,298	2013	1
7/19/13 16:00	12,239	51	3,606	29.5%	91,097	2013	3
8/26/13 17:00	12,239	124	4,515	36.9%	89,196	2013	7
8/27/13 17:00	12,239	93	2,776	22.7%	89,456	2013	6
8/29/13 16:00	12,239	16	1,849	15.1%	89,642	2013	5
System-Wide Average Peak Metric				**17.39%**			
Note [1] **Curtailed and DIR MW have been added to settlement MW**							

3.2 Wind CPNode Equations

Registered Maximum (RMax) is the MISO market term for the installed capacity of a resource. The relationship of the wind capacity rating to a CPNode's installed capacity value and Capacity Credit percent is expressed as:

$$(\text{Wind Capacity Rating})_{\text{CPNode n}} = \text{RMax}_{\text{CPNode n}} \times (\text{Capacity Credit }\%)_{\text{CPNode n}} \tag{1}$$

Where RMax$_{\text{CPNode n}}$ = Registered Maximum installed capacity of the wind facility at the CPNode n. The right most term in expression (1), the (Capacity Credit %)$_{\text{CPNode n}}$, can be replaced by the expression (2) :

$$\text{K} \times (\text{PKmetric}_{\text{CPNode n}}\,\%) \tag{2}$$

Where "K" for Year 2013 was found by obtaining the PKmetric at each CPNode over the 9 year period, and solving expression (3):

$$\text{K} = \frac{\text{ELCC}}{\sum_{1}^{176} \text{RMax}_{\text{CPNode n}} \times \text{PKmetric}_{\text{CPNode n}}} \tag{3}$$

This results in the sum of the MW ratings calculated for the CPNodes equal to the system wide ELCC 1,723 MW. The values in (3) are:

ELCC = 1,723 MW

$\sum$ RMax$_{\text{CPNode n}}$ x PKmetric$_{\text{CPNode n}}$ = 2,723 MW

Therefore: K = 0.6329 = 1,723 / 2,723

3.3 Wind CPNode Capacity Credit Results & Example

The individual PKmetric$_{\text{CPNode}}$ of the CPNodes ranged from zero to 40.0%. The individual Capacity Credit percent for CPNodes therefore ranged from zero to 25.3%, by applying expression (2).

Example: RMax = 100 MW

PKmetric = 25%

K = 0.6329

Capacity Credit (MW) = RMax * PKmetric * K

= 100 * 0.25 * 0.6329

= 15.82 MW

Capacity Credit (%) = Capacity Credit (MW)/RMax

= 15.82/100

= 15.82%

Figure 3-1 shows how the system-wide 14.1percent capacity credit percent compares with the individual capacity credit percents for the 176 active CPNodes as of 2nd quarter 2013. This reflects implementing the formulas referred to earlier in this section to allocate the total system 1,723 MW to the 176 CPNodes. The CPNodes have been sorted by their capacity credit percentages. Along with the specific identity of CPNodes, a given market participant is provided only the results, or selected bars on the chart that correspond to their CPNodes. The percentage is applied to the node's RMax and provides the CPNodes capacity credit in megawatts for the market participant. The CPNode's deliverability status determines the amount of the capacity credit MW that qualifies for LRZ credits in Module E-1.

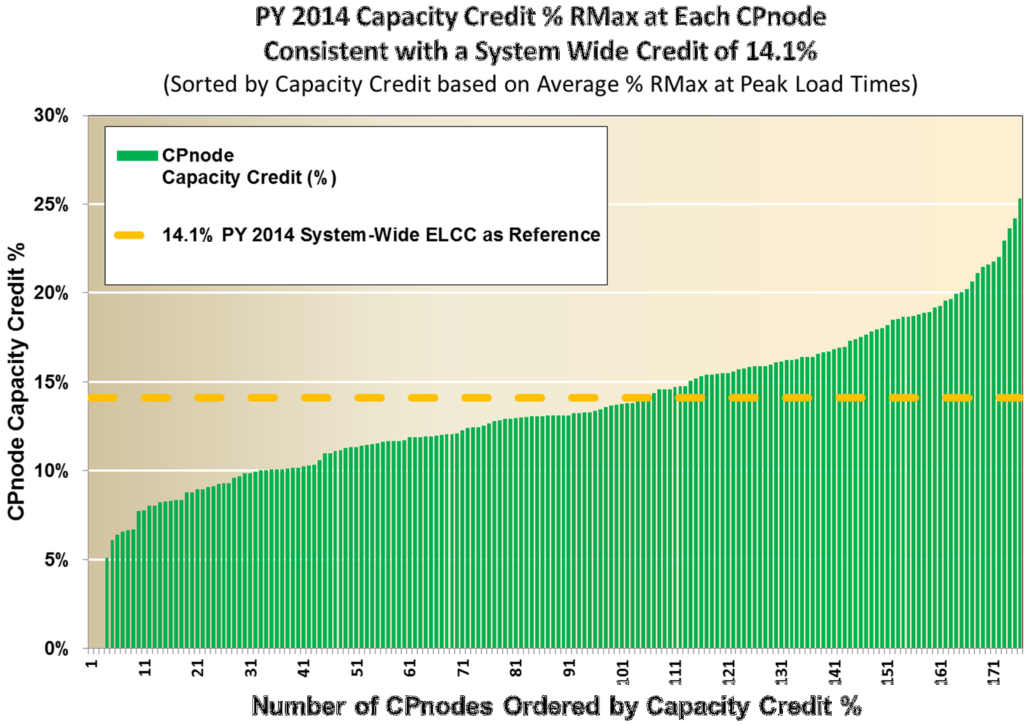

Figure 3-1 – Allocation of Capacity Credit % over 176 CPNodes Consistent with a System-Wide Credit of 14.1%

Synapse
Energy Economics, Inc.

Synapse 2013 Technical Training

Session 2: Best and Worst Practices in IRP and CPCN

Synapse Energy Economics

August 8, 2013

Overview of IRP/CPCN Structure

- Driver of IRP or CPCN
  - Filing requirement
  - Need for new supply
  - Environmental regulation
  - End of resource life
- Planning Environment
  - Wholesale markets
  - Environmental
  - RPS
  - Relicensure (hydro/nuclear)
- Requirement
  - Load forecast
  - Reserves and reliability
- Resources
  - Supply options
  - Demand side management
  - Existing resources
  - Transmission options
- Modeling
  - Commodity prices
  - Environmental constraints
  - Interaction with market
  - Model options
  - Uncertainty
- Evaluation of outcomes
  - Metrics
  - Risk
- Action plan

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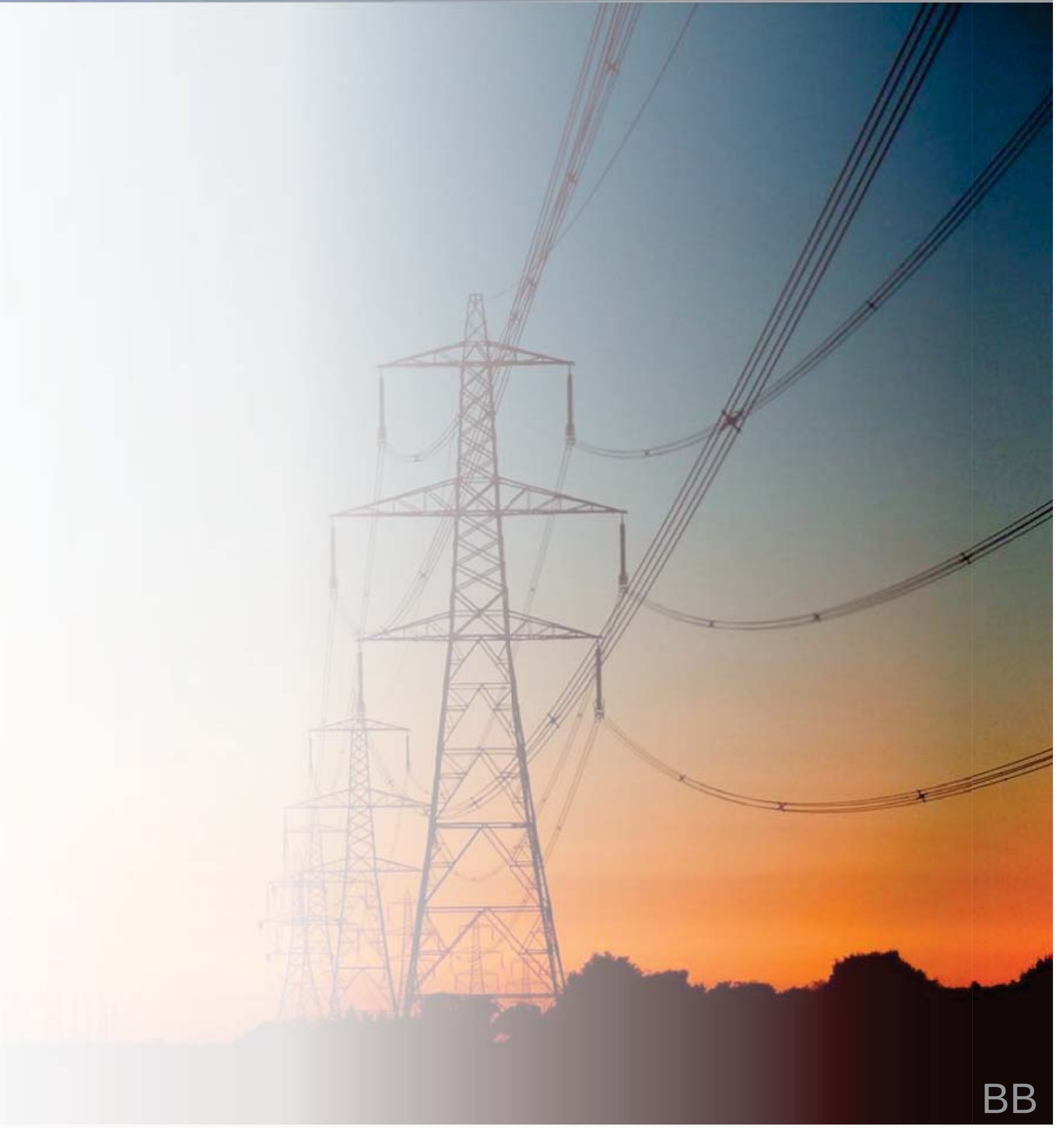
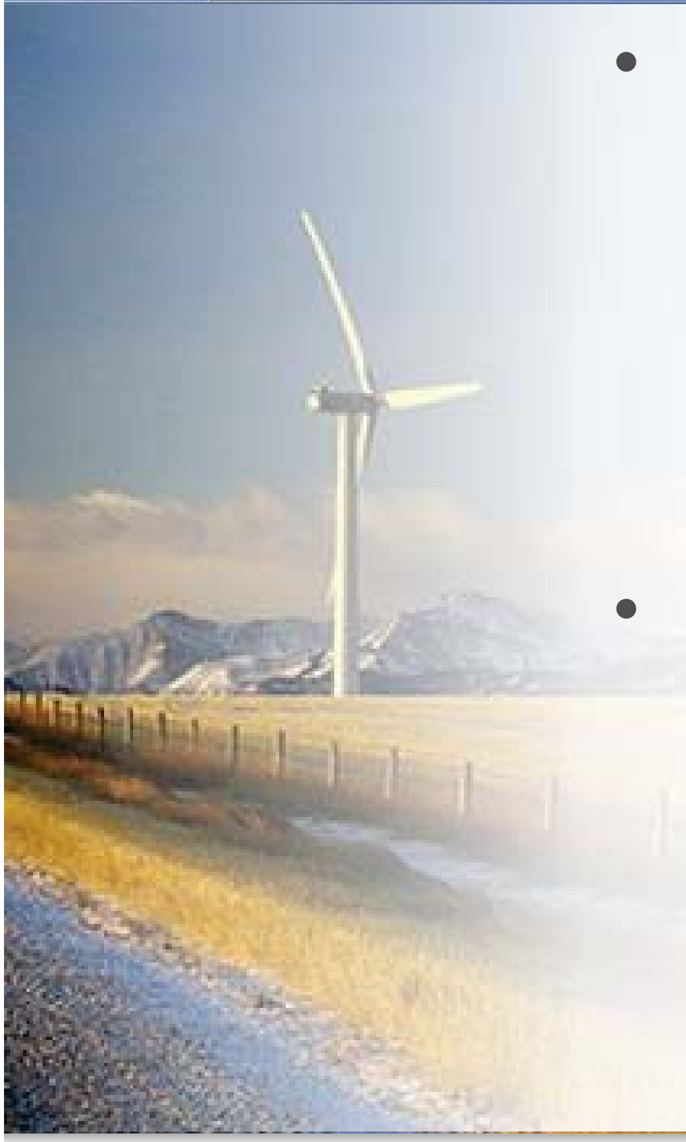
Elements for consideration in IRP/CPCN

- Avoided costs
- Fresh information
- Integrated analysis
- Timeframe
- Utility incentives
- Action plan
- Documentation
- Stakeholder participation



BB

Purpose of Electric System Planning



- IRP – Integrated Resource Plan
  - Planning context, information
  - Participation (regulators, interveners, the public)
  - Various types and levels of buy-in
  - Action plan
- CPCN – Certificate of Public Convenience and Necessity
  - Specific action(s)
  - Authority to construct
  - Authority to spend and recover capital from ratepayers

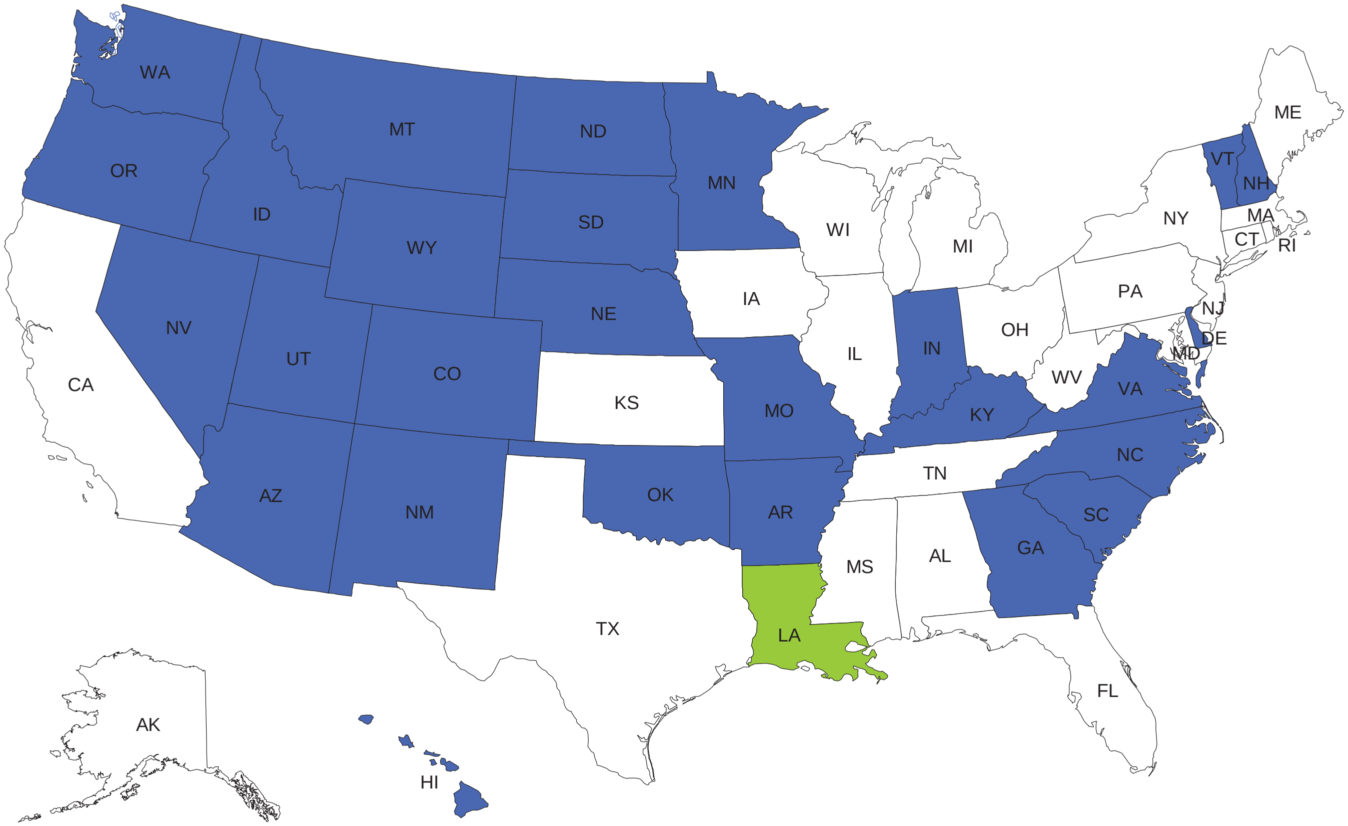
BB

Possible Commission activities on IRP

- Reject
- Ignore
- Acknowledge
- Accept
- Approve
- Approve specific resource decisions
- Other?

BB

Presence or absence of State IRP rules



🟦 State has an IRP rule and filing requirement

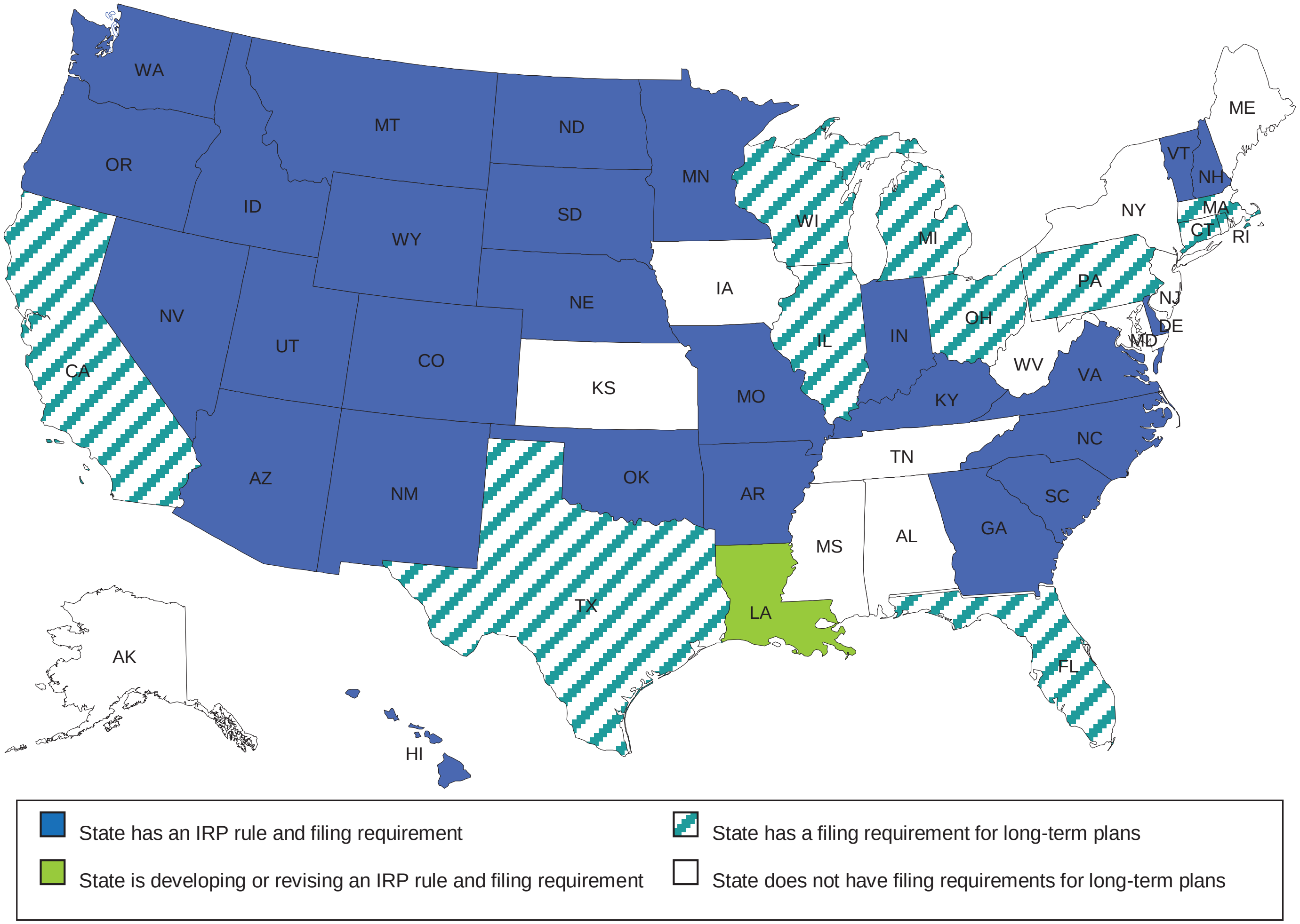
☐ State does not have an IRP rule

🟩 State is developing or revising an IRP rule and filing requirement

Source: Peterson & Wilson 2011

BB

Presence or absence of State IRP rules and procurement plan filing requirements



Source: Peterson & Wilson 2011

BB

Overview
Electric Industry Structure

Generation	Transmission	Distribution	Retail Electric Service
Merchant	ISO/RTO		Competitive
Public Power		Local Distribution Companies	Default Service
Investor-Owned Utility	Utilities are Planning Authorities and Grid Operators		Cost-Based Utility Supply

BB

Driver of IRP or CPCN

- IRP Drivers:
  - State regulations or commission orders
- CPCN Drivers:
  - Significant change in status or load (APCo)
  - Acquisition of a new resource or purchase of existing resource
  - Permission to spend capital on an existing resource to meet environmental regulations

BB

IRP Drivers

Filing Requirements

Frequency of IRP updates, as determined by State rules

Updates Required	States with Specified Update Requirement
Every 2 years	Arizona, Delaware, Idaho, Indiana, Minnesota, Montana, New Hampshire, North Carolina, North Dakota, Oregon, South Dakota, Utah, Virginia, Washington
Every 3 years	Arkansas, Georgia, Hawaii, Kentucky, Montana, Missouri, Nevada, New Mexico, Oklahoma, South Carolina, Vermont
Every 4 years	Colorado
Every 5 years	Nebraska
Not specified	Wyoming

Source: Peterson & Wilson 2011

BB

Planning Environment

- Exogenous elements that impact utility planning
  - Presence and strength of wholesale markets
  - Environmental compliance obligations
  - Renewable energy / efficiency portfolio standards or policies
  - Relicensure requirements for hydro or nuclear facilities
  - Politics (state pressure for particular outcomes)

BB

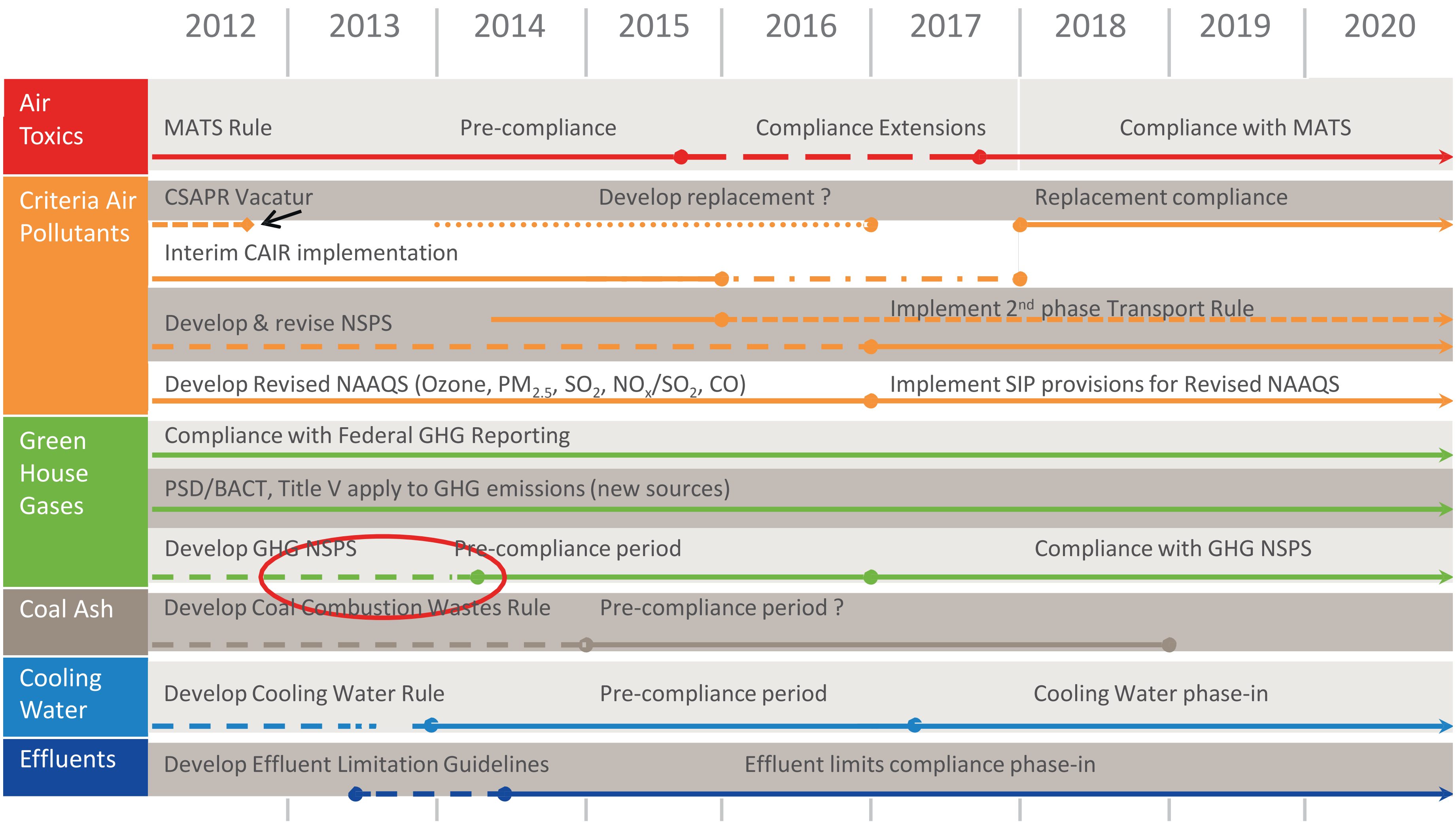
Planning Environment
Environmental Compliance Obligations

- Mercury and Air Toxics Standard
- National Ambient Air Quality Standards
- CSAPR 2.0
- Regional Haze
- Coal Combustion Residuals
- Cooling Water Intake Structures (316(b))
- Effluent Limitations Guidelines
- NSR/PSD and BACT for GHGs
- GHG Performance Standards for Existing Sources
- State Climate Regulations/Performance Standards

SJ

Planning Environment

Environmental Compliance Obligations



Requirement: Load Forecast

A reasonable, up-to-date, and fully documented forecast of system peak and energy requirements.

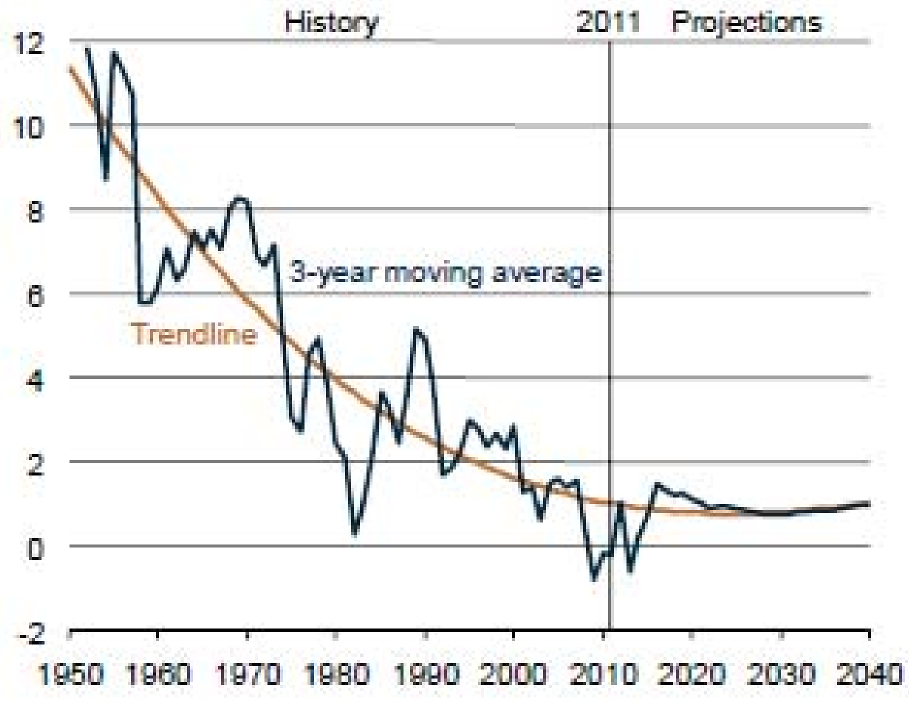
BB

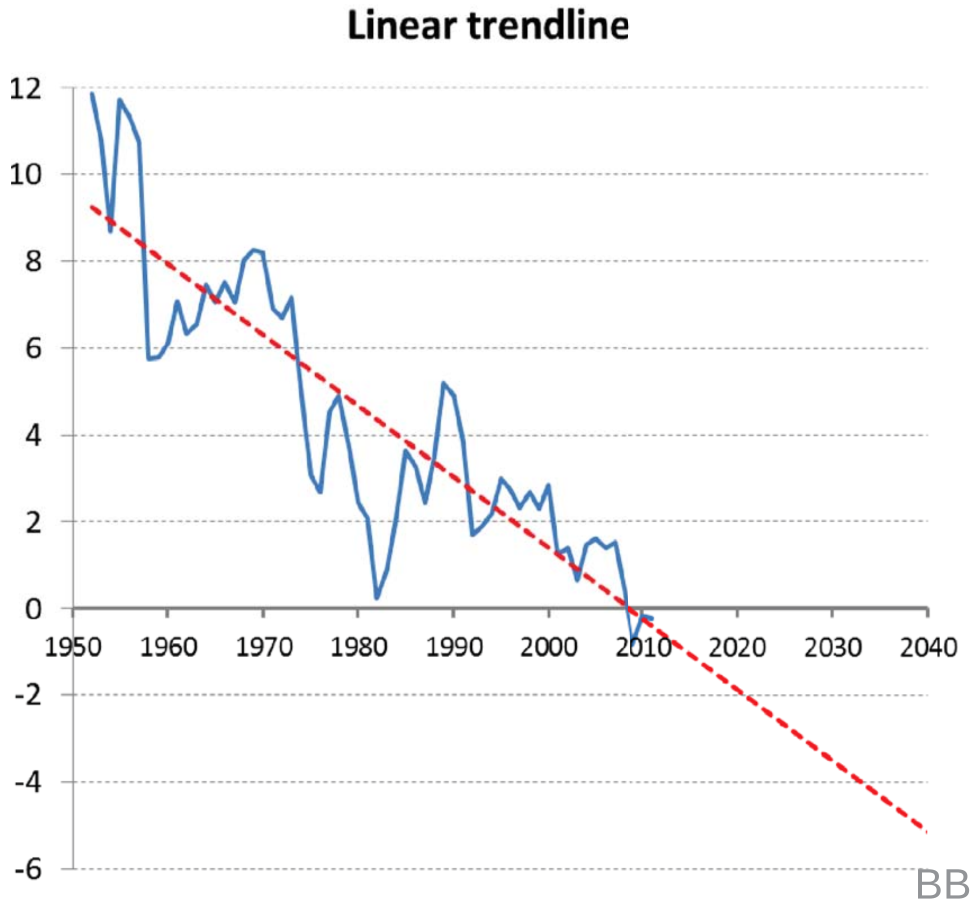
Load Forecast

Example: National Load Forecast

How will national electricity demand change in the future?

Figure 75. U.S. electricity demand growth, 1950-2040 (percent, 3-year moving average)

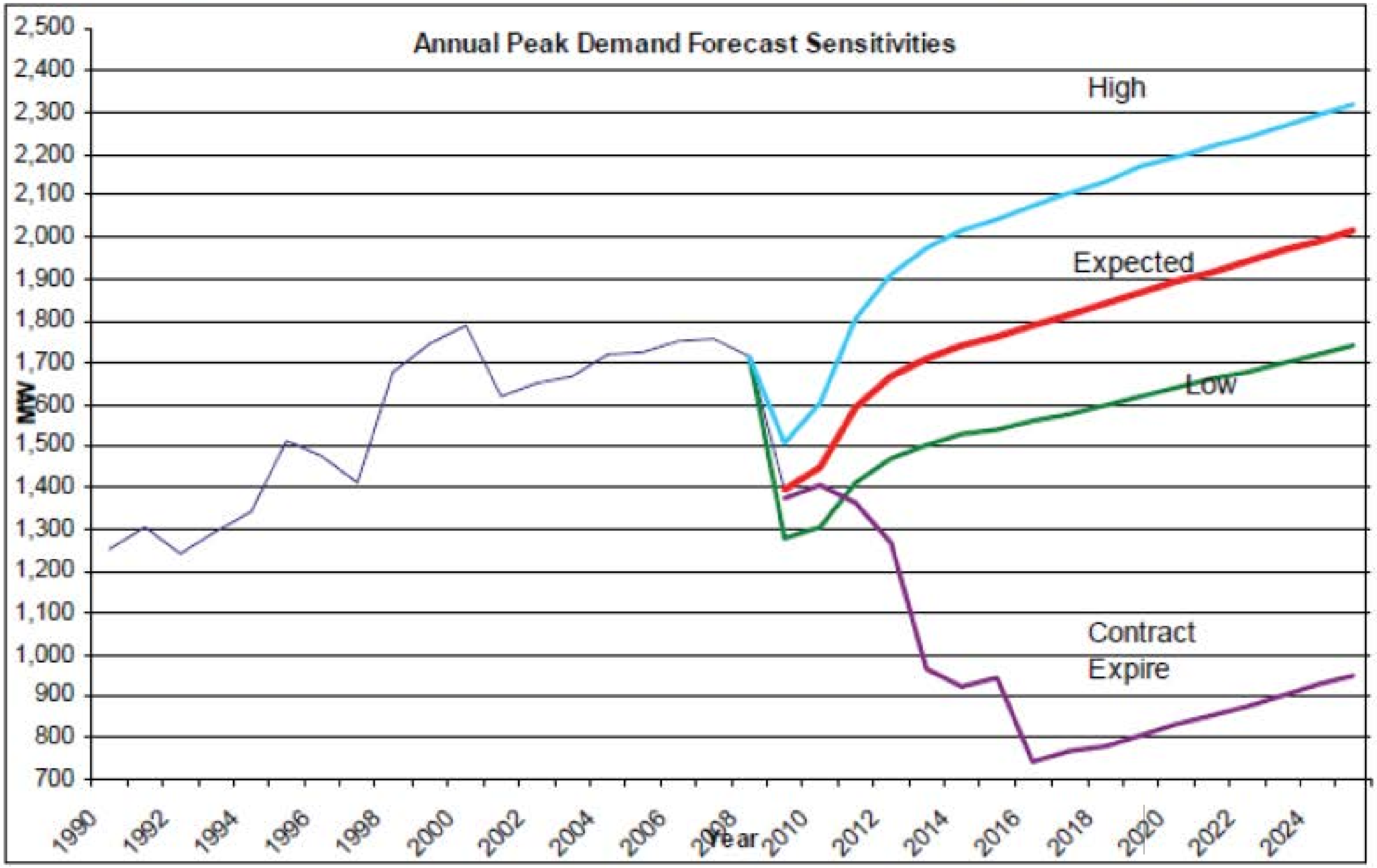



Linear trendline

BB

Load Forecast

Minnesota Power’s 2009 Electric Utility Forecast



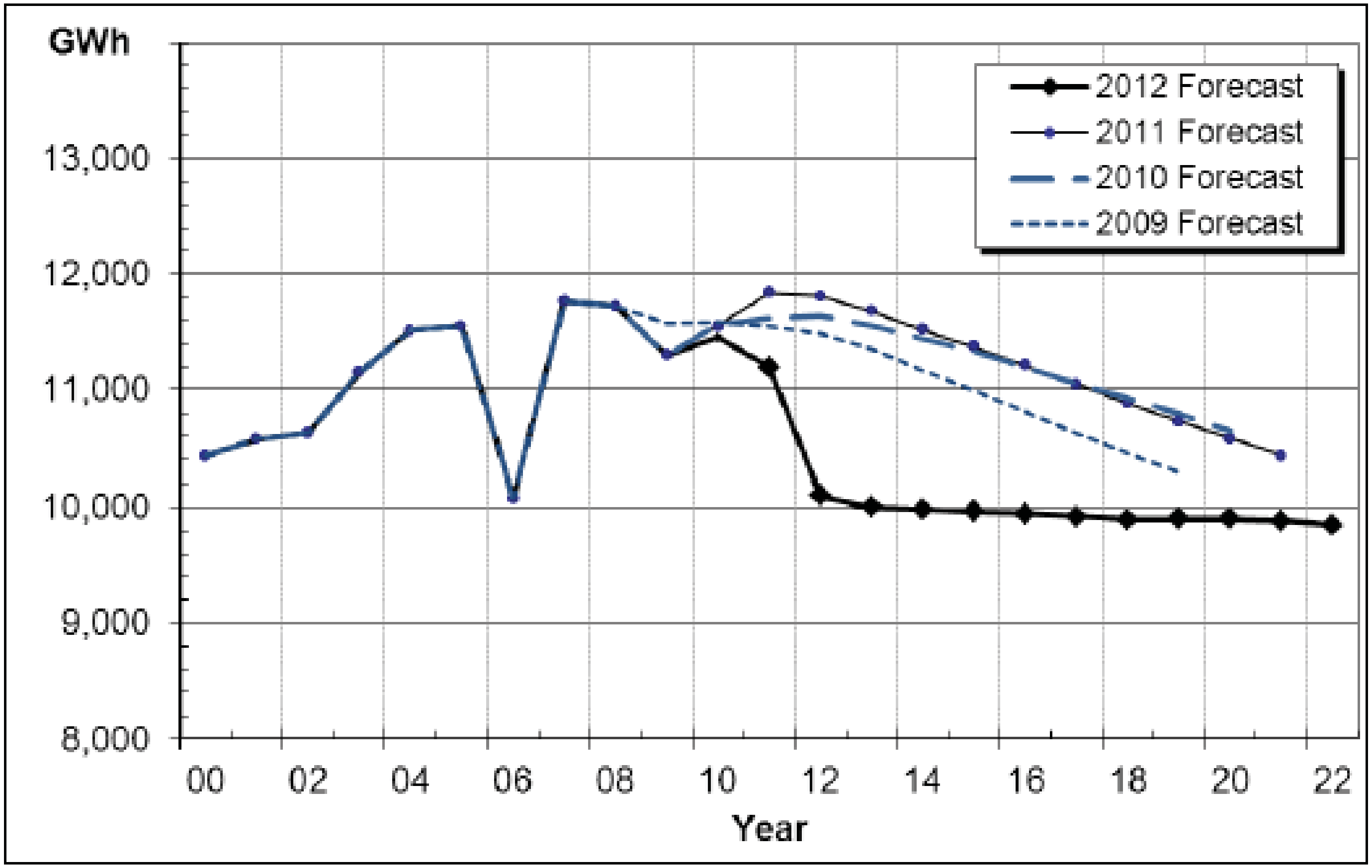
Source: Minnesota Power 2009

BB

Load Forecast

Nova Scotia IRP

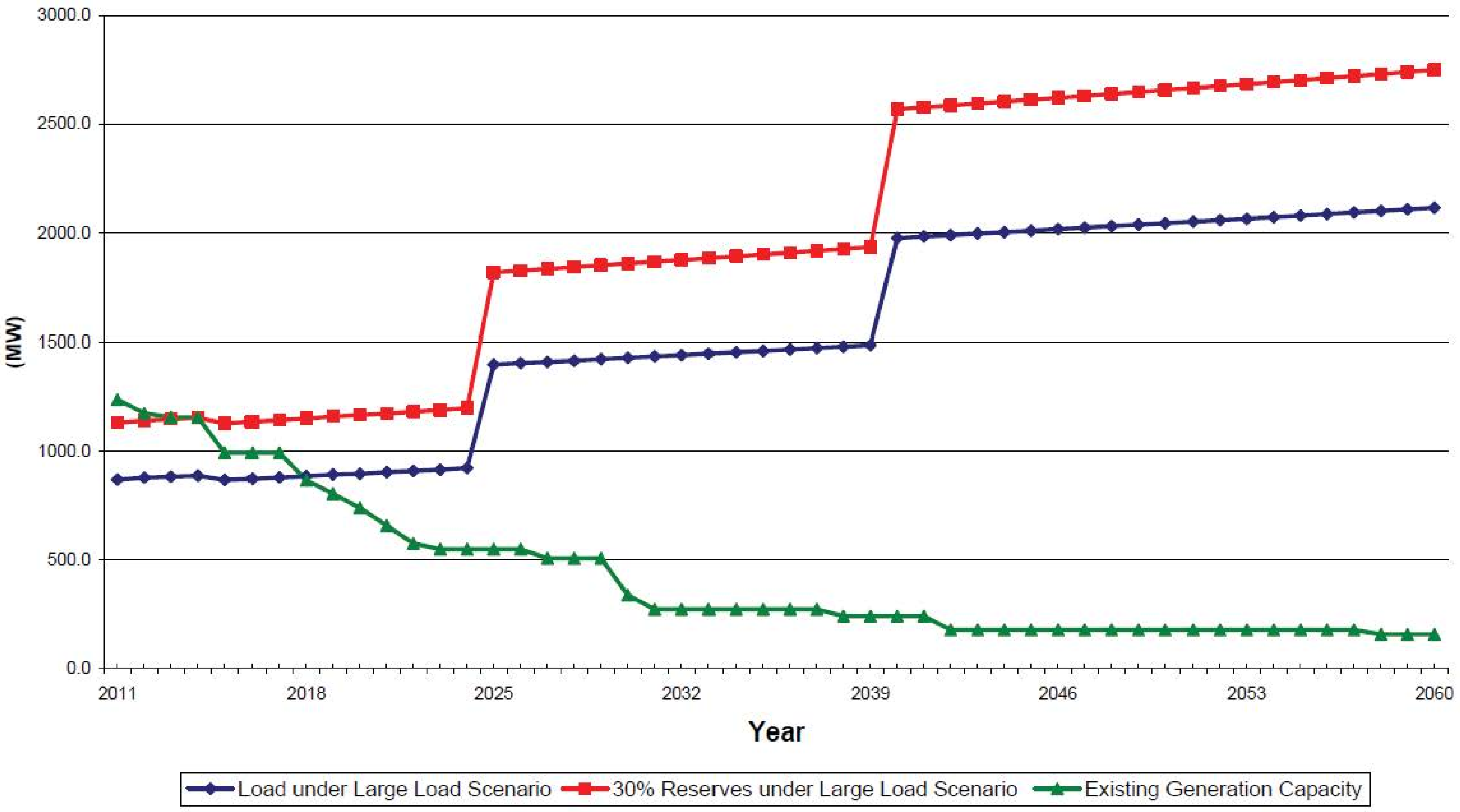
Is loss of a major customer a concern?
Nova Scotia Energy Sales Forecasts



BB

Load Forecast
Alaska Railbelt Regional IRP

Scenario 2A Capacity Requirements Without DSM/EE

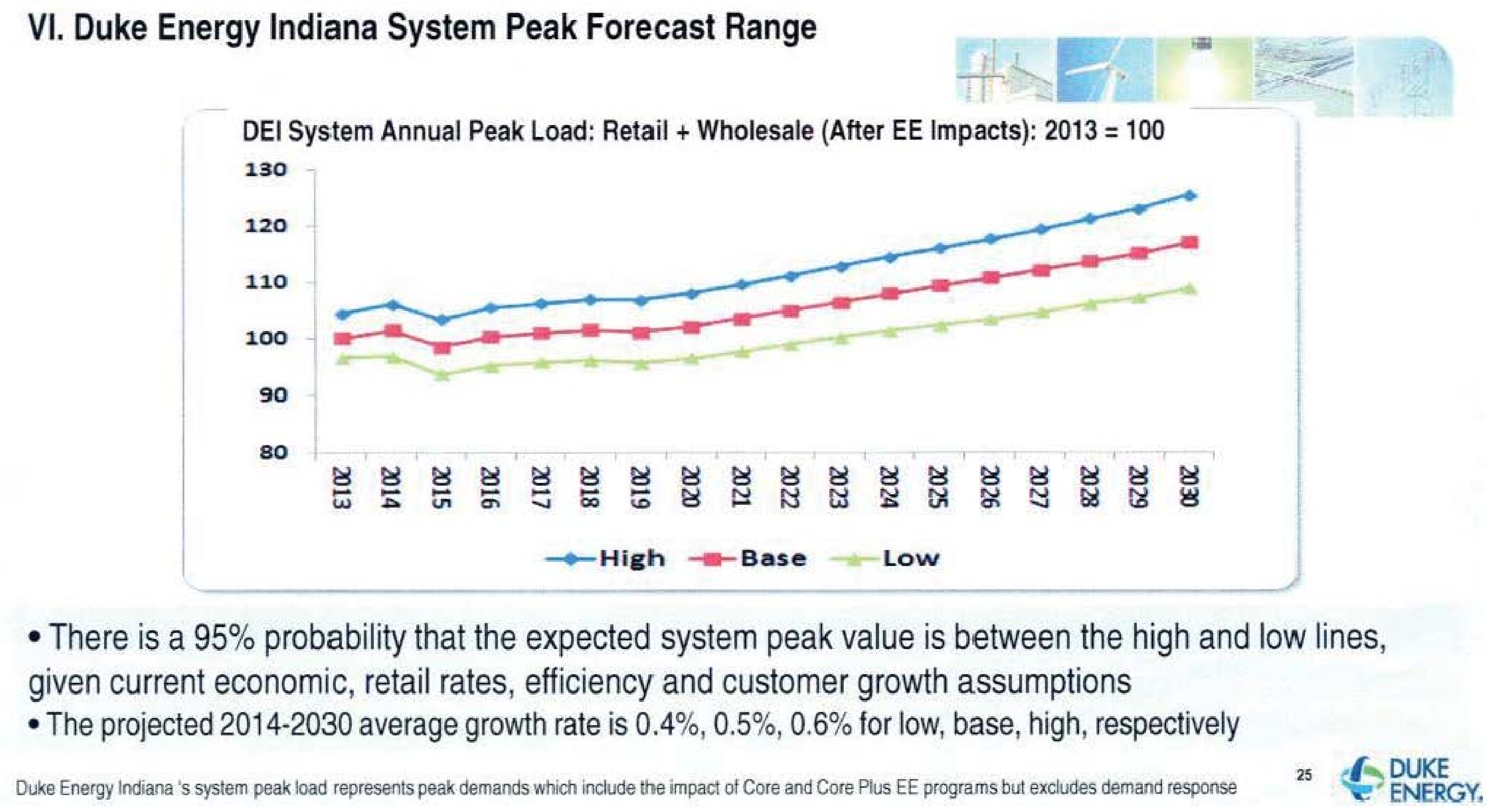


Source: Black & Veatch 2010

JF

Load Forecast

Duke Energy Indiana 2013 IRP



VI. Duke Energy Indiana System Peak Forecast Range

DEI System Annual Peak Load: Retail + Wholesale (After EE Impacts): 2013 = 100

- There is a 95% probability that the expected system peak value is between the high and low lines, given current economic, retail rates, efficiency and customer growth assumptions
- The projected 2014-2030 average growth rate is 0.4%, 0.5%, 0.6% for low, base, high, respectively

Duke Energy Indiana 's system peak load represents peak demands which include the impact of Core and Core Plus EE programs but excludes demand response

25

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Load Forecast
Large changes realized

- Big Rivers – loss of two smelters and 70% of load
- TVA – loss of uranium enrichment facility (8% of TVA load)
- APCo – acquisition (or not) of neighboring utility
- PacifiCorp – new accounting in load forecast methodology

JF

Requirement: Reserves and reliability

- **Planning Reserve:** Reserve requirements to provide capacity adequacy based on rigorous analysis of system characteristics and proper treatment of intermittent resources.
  - Planning reserve margin of ~12-18%

- **Operating Reserve:** Short term (day ahead, week ahead) requirements.
  - Spin, non-spin, and regulation (and load-following)
  - Covers contingency requirements and forecast uncertainties

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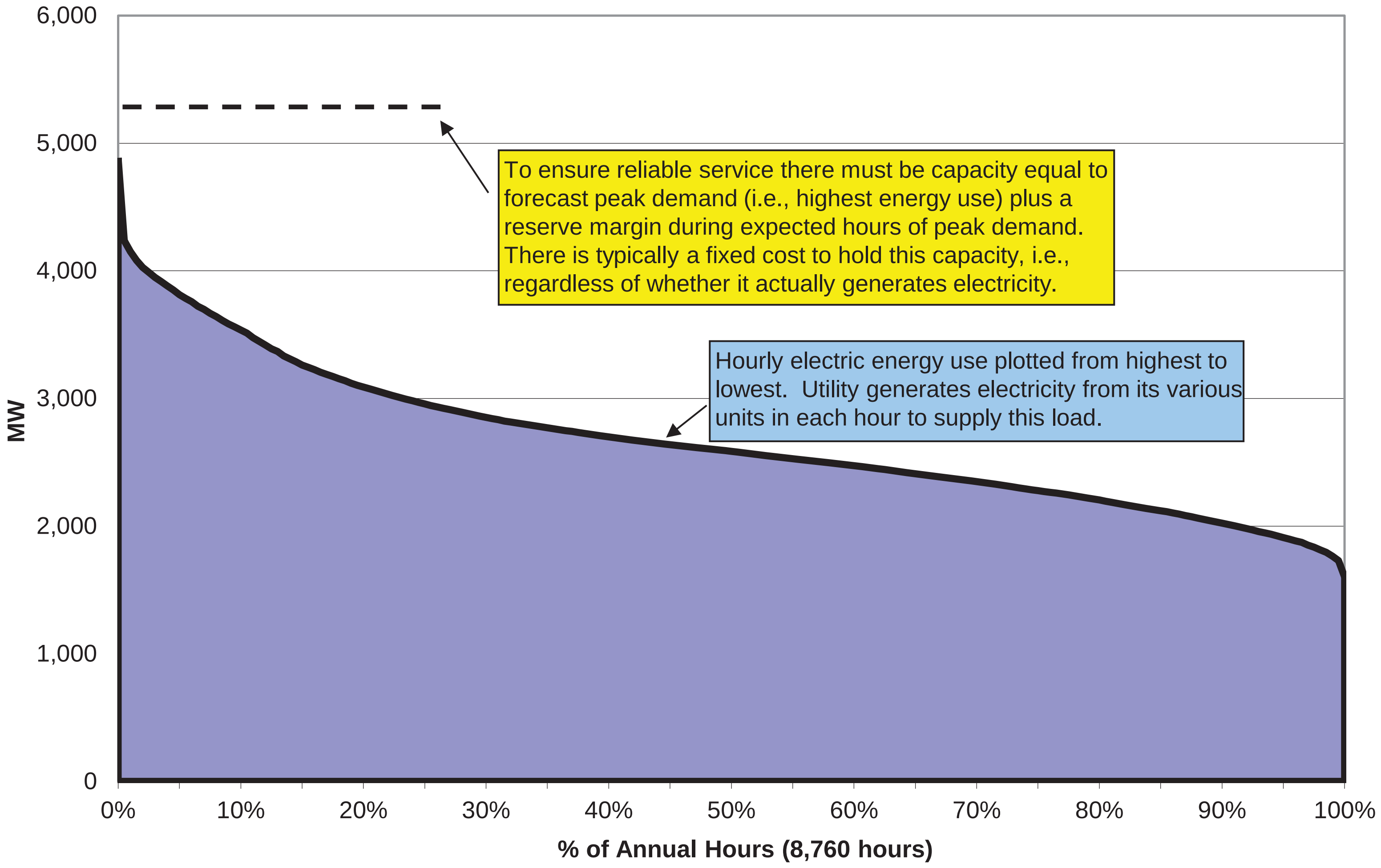
Reliability

Illustrative Load Duration Curve (8,760 hours)



To ensure reliable service there must be capacity equal to forecast peak demand (i.e., highest energy use) plus a reserve margin during expected hours of peak demand. There is typically a fixed cost to hold this capacity, i.e., regardless of whether it actually generates electricity.

Hourly electric energy use plotted from highest to lowest. Utility generates electricity from its various units in each hour to supply this load.

Source: Hornby, Hurley, & Knight 2011

BF

General Characteristics of Utility Systems that Affect Reliability and Reserves Requirements

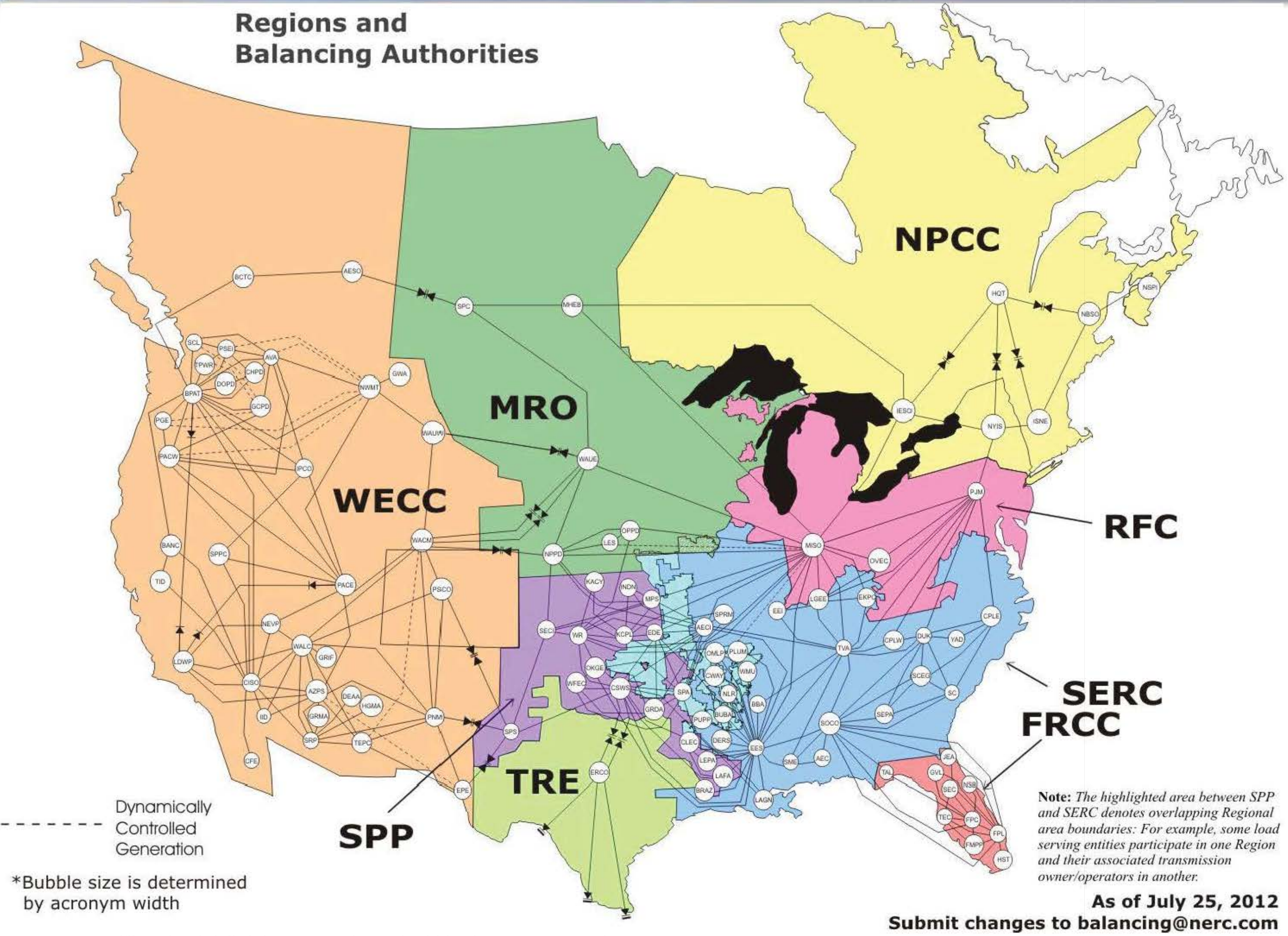
1. **Load shape**
2. **Forced outage** rates
3. **Maintenance outage** requirements
4. **Number and size** of generating units
5. **Transmission** interties with neighboring utilities
6. Availability and effectiveness of **intervention procedures**

Source: Biewald & Bernow 1988

BF

Reliability

NERC Regions and Balancing Authorities



Regions and Balancing Authorities

Dynamically Controlled Generation

*Bubble size is determined by acronym width

Note: *The highlighted area between SPP and SERC denotes overlapping Regional area boundaries: For example, some load serving entities participate in one Region and their associated transmission owner/operators in another.*

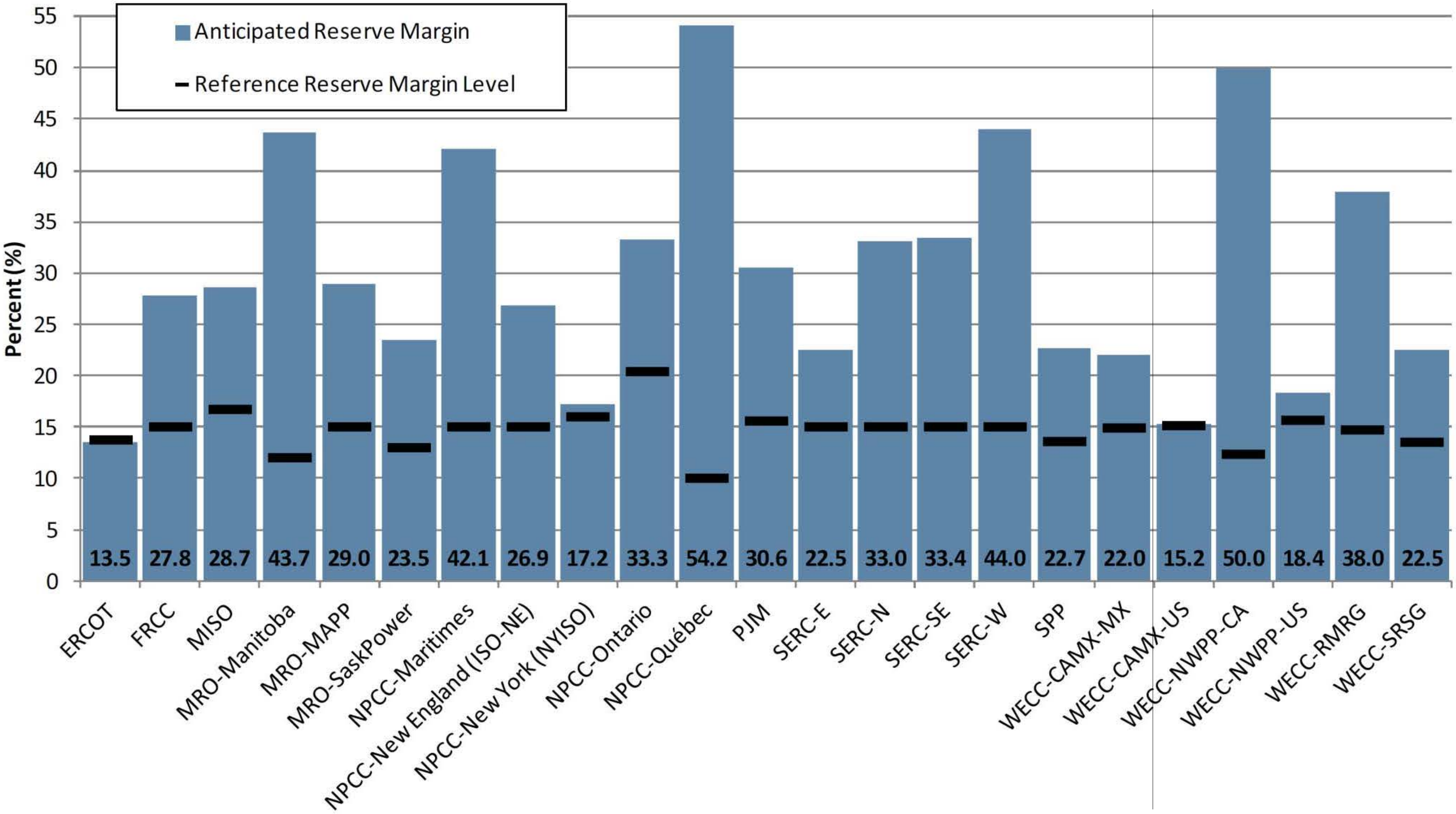
As of July 25, 2012
Submit changes to balancing@nerc.com

Available at: http://www.nerc.com/fileUploads/File/AboutNERC/maps/BubbleDiagram_072512.jpg

BF

Reliability

NERC Anticipated Reserve Margins for Summer 2012

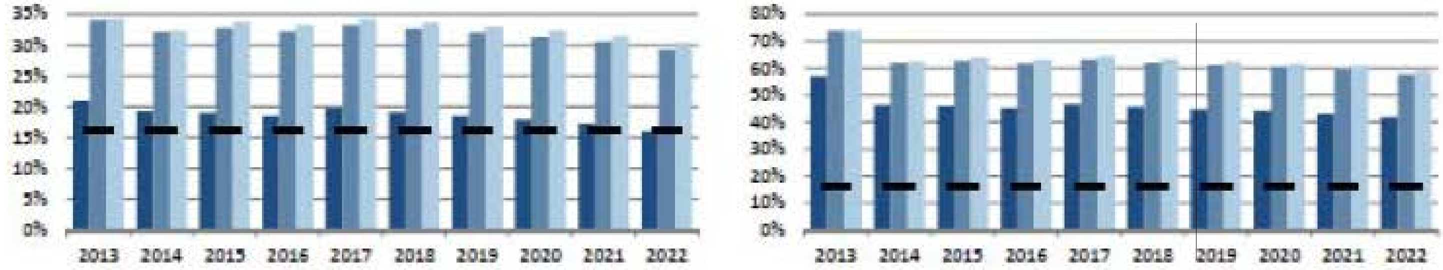


Source: NERC 2012

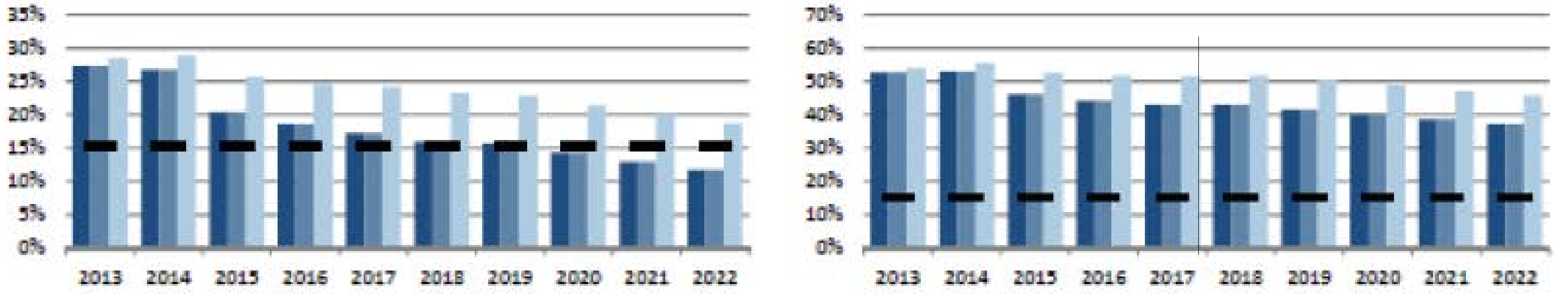
BF

Planning Reserve Margins Over Time

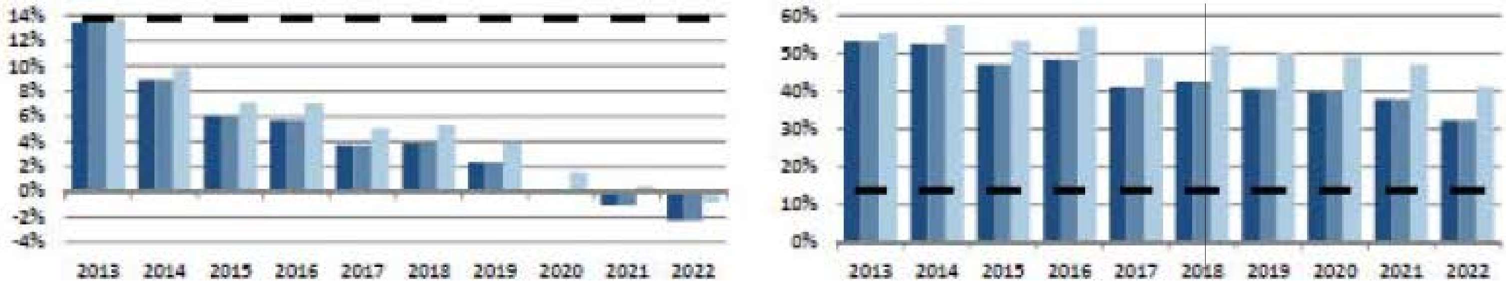
MISO-Figure 1: Summer (Left) and Winter[189] (Right) Planning Reserve Margins



PJM-Figure 1: Summer (Left) and Winter[240] (Right) Planning Reserve Margins



ERCOT-Figure 1: Summer (Left) and Winter[218] (Right) Planning Reserve Margins



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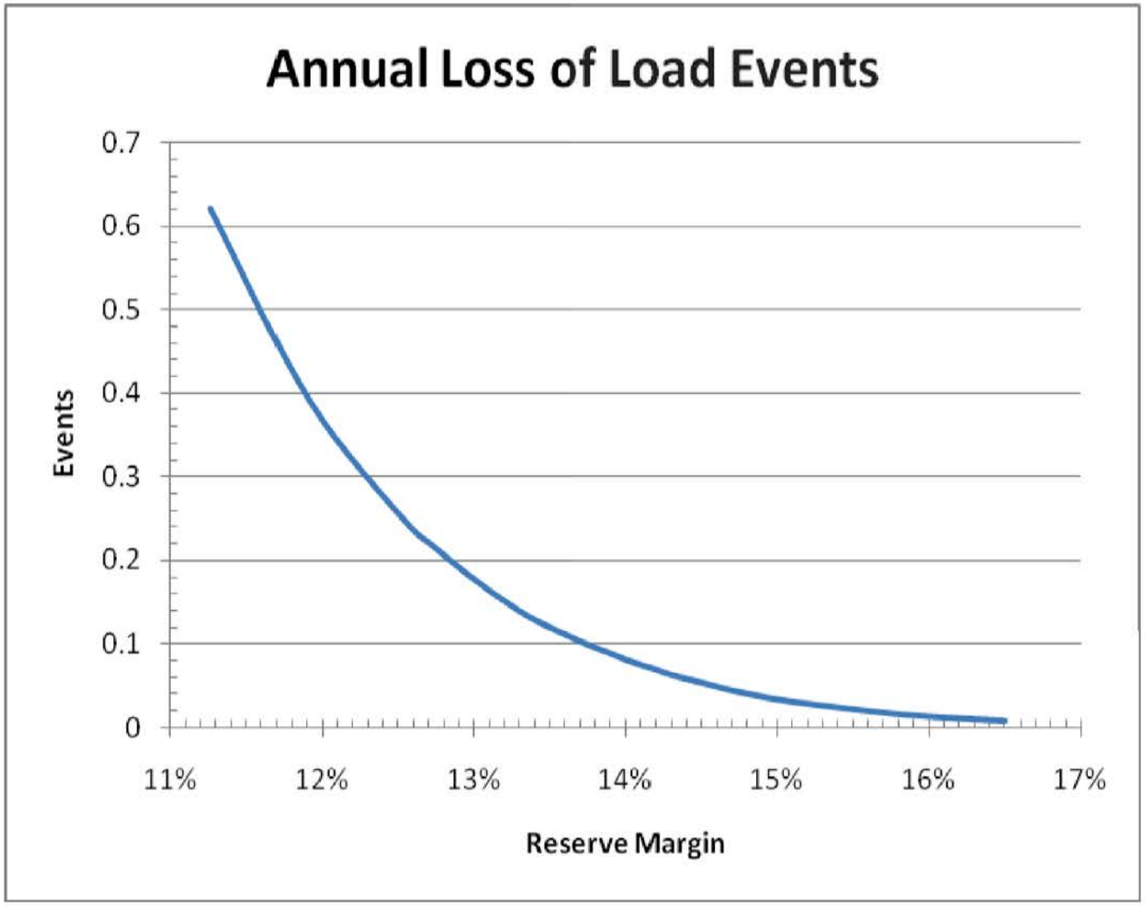
Reliability
LOLE and Reserve Margin



Source: ERCOT 2010

BB

|

Reliability

Where did “1 in 10” standard come from?

“The fraction of time… will be called the *loss of load duration*… expressed in terms of “so many days upon which loss of load may be expected to occur during a given number of years,” say 10 or 100.

This number of days provides a first index for measuring and comparing service reliabilities.”

- Giuseppe Calabrese, 1947

Source: NERC 1991

BB

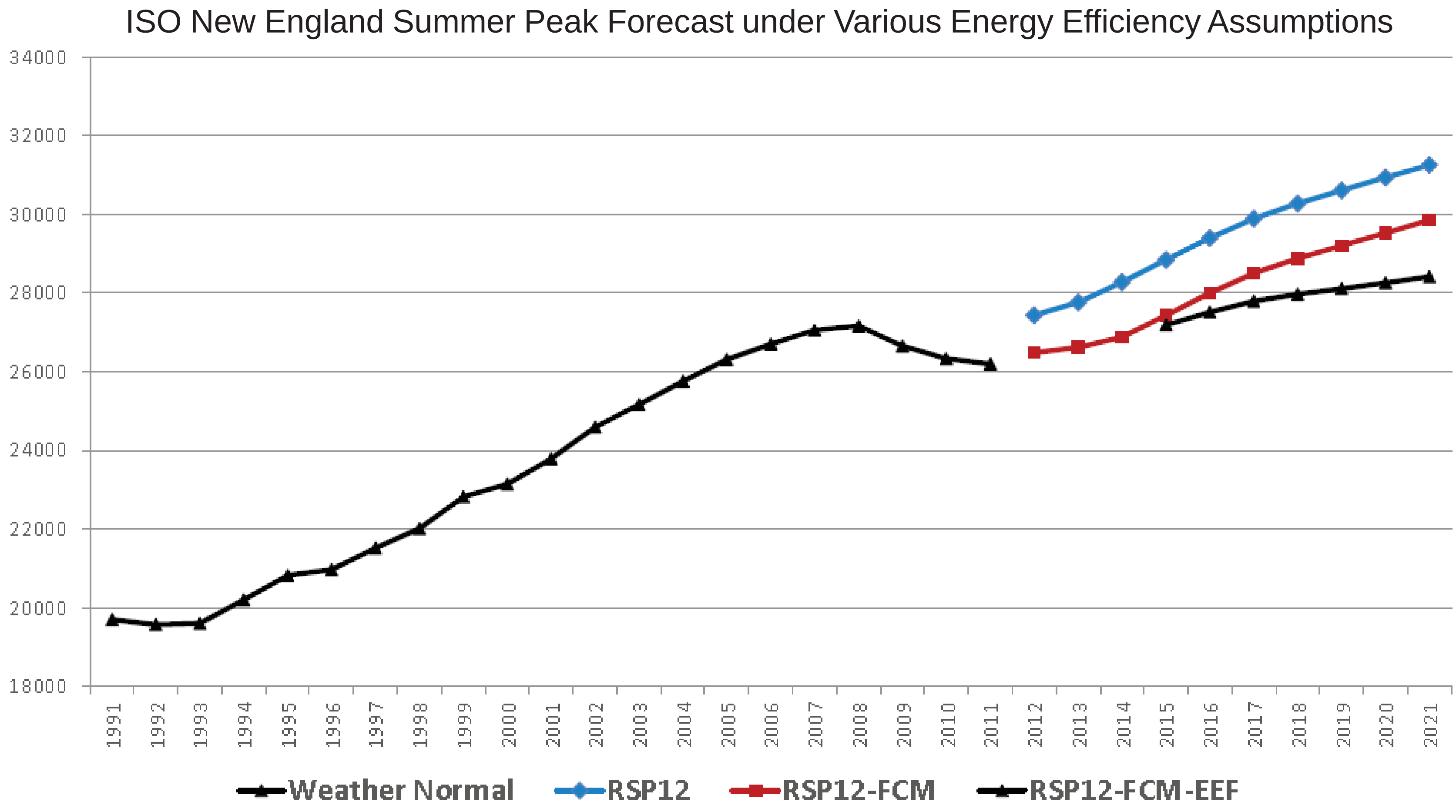
Resources: Demand Side Management

Consideration of various levels of DSM savings ranging from low to something beyond “all cost effective” DSM in order to provide confidence that “all cost effective DSM” has been included.

BB

DSM

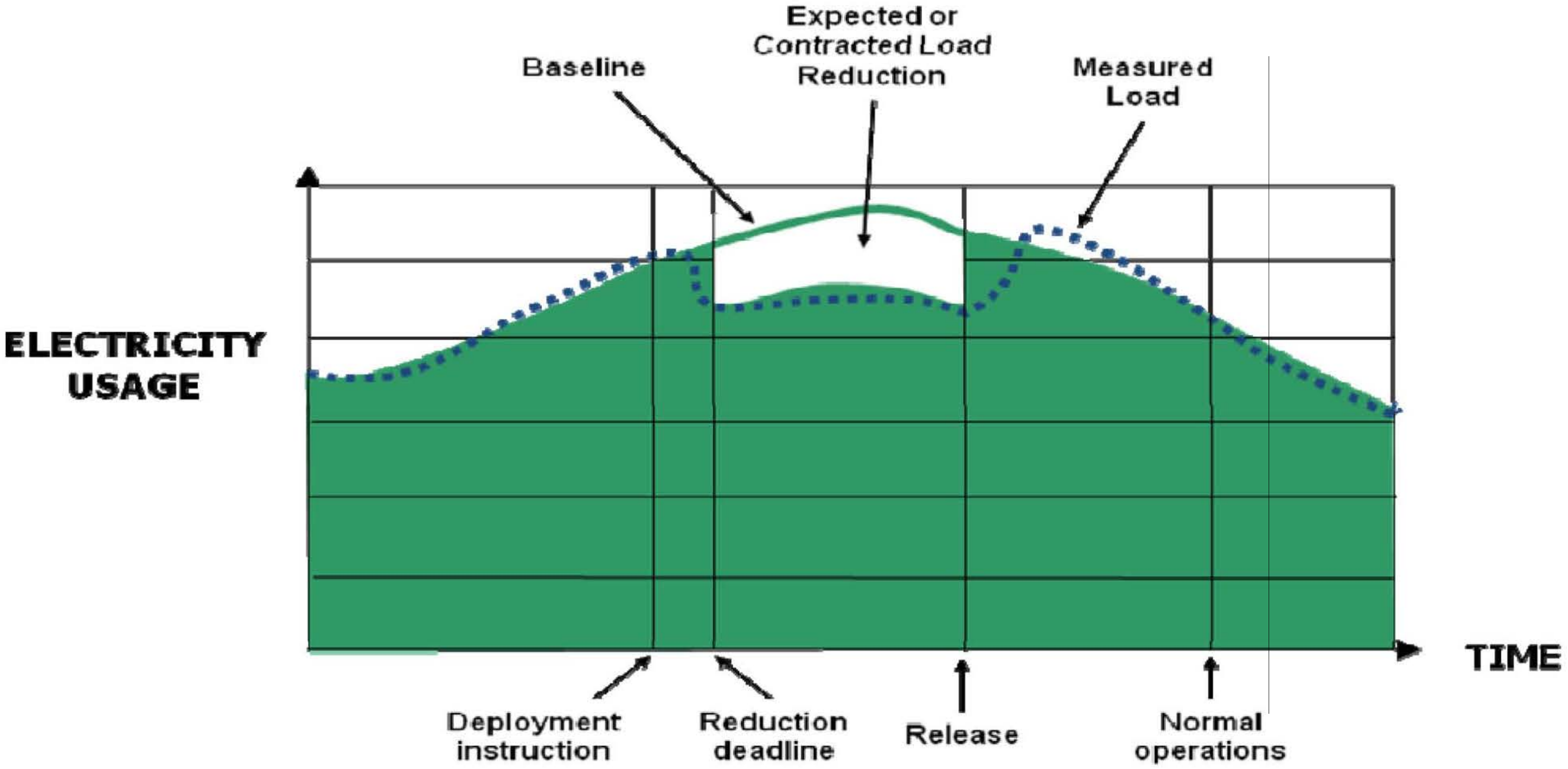
Energy Efficiency Forecasts


ISO New England Summer Peak Forecast under Various Energy Efficiency Assumptions

Source: Peterson, et al. 2012

BB

Baseline relative to a Demand Response Event



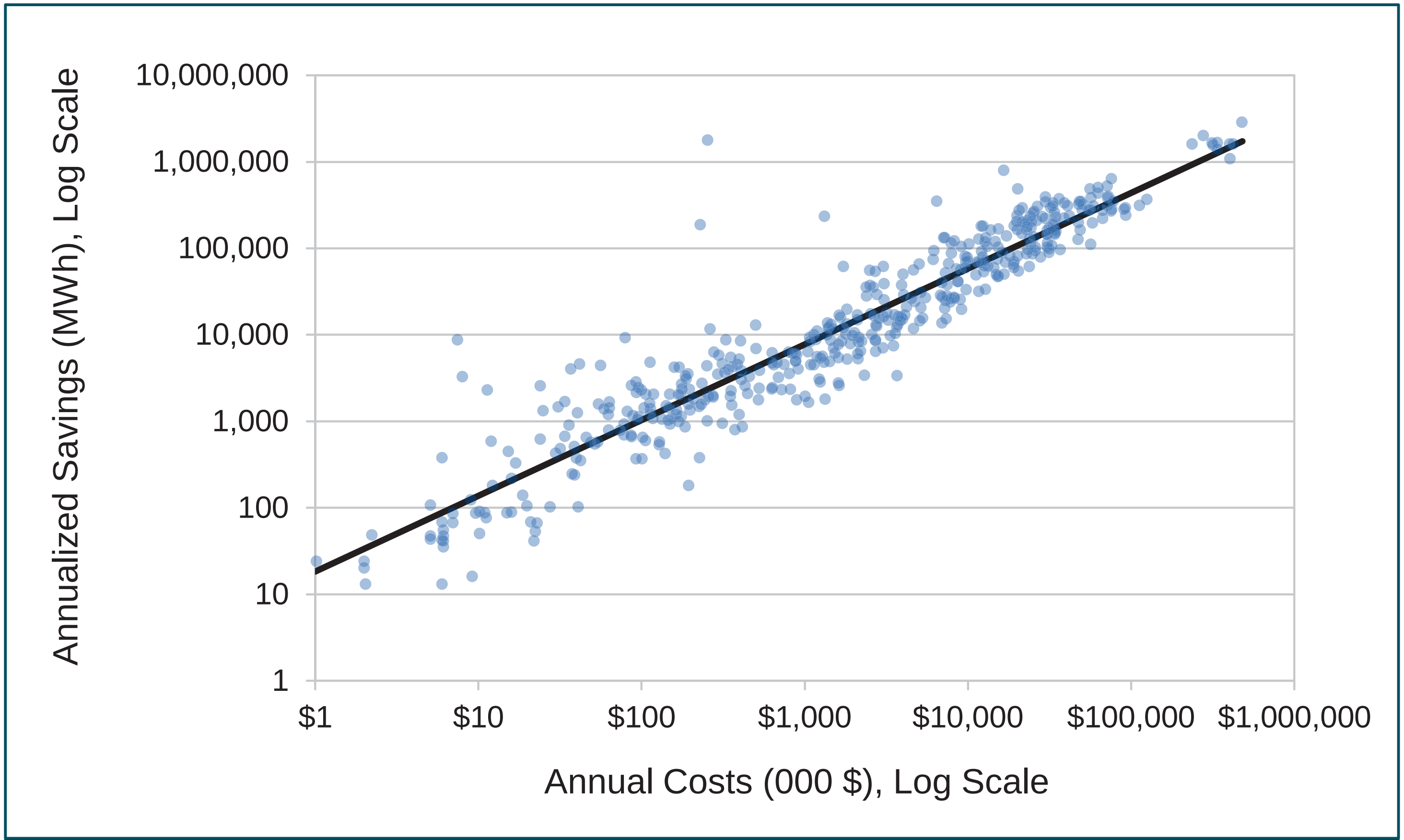
Source: NERC 2010

BB

DSM

EE Cost vs. Savings

Program years with savings as a percent of sales greater than 0.5% (n=468)



Best Estimate Regression: $y = 18.274x^{0.875}$, $r^2 = 0.889$

Source: Synapse Analysis of EIA 861 Dataset, 2007-2011

BB

DSM

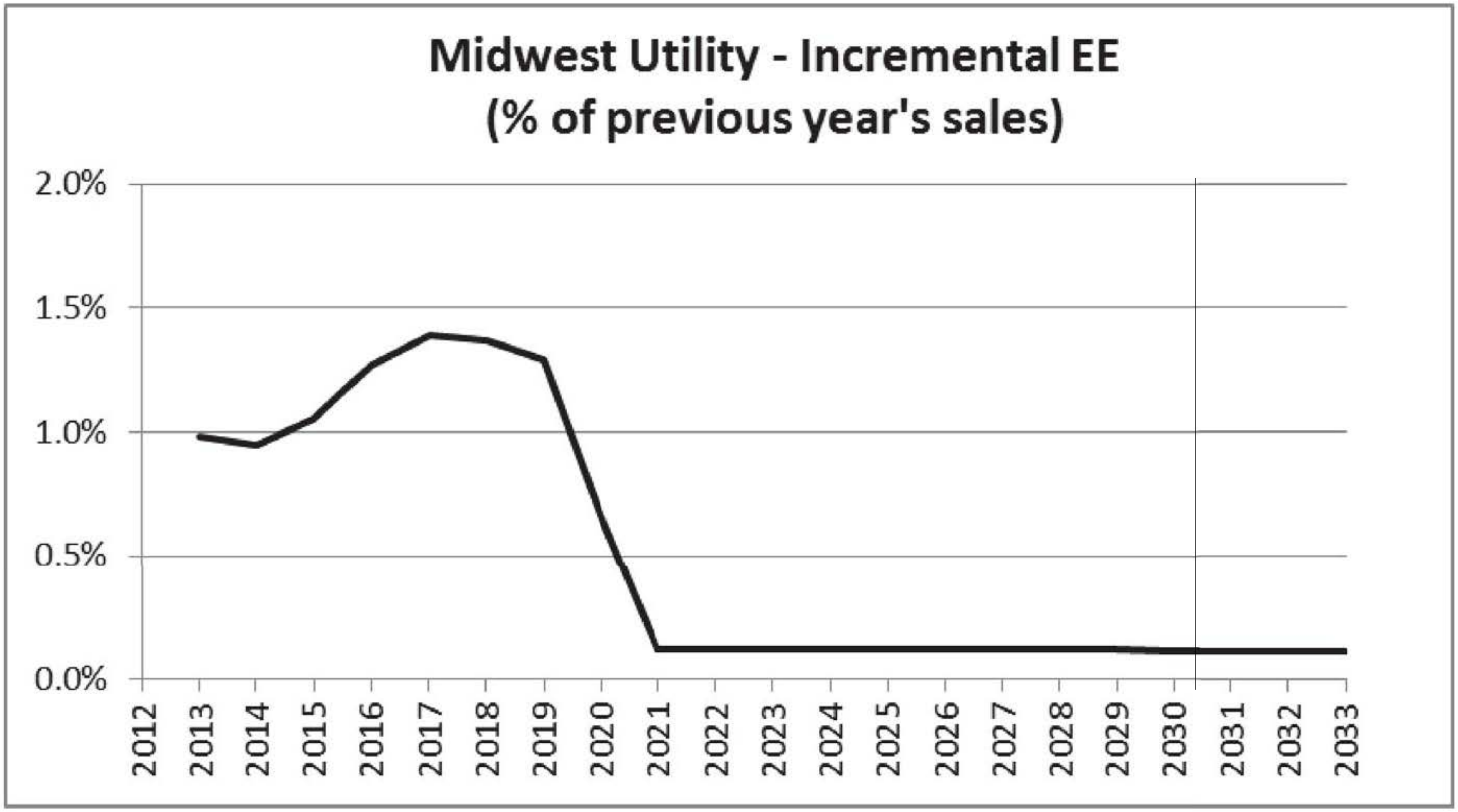
EE Cost vs. Savings

- Slope indicates cost per kWh of first year savings at 16.2c/kWh.
- Assuming 12 year measure life and 4.5 percent real discount rate this amounts to a levelized unit cost to the utility of 1.7 c/kWh by EE programs.

BB

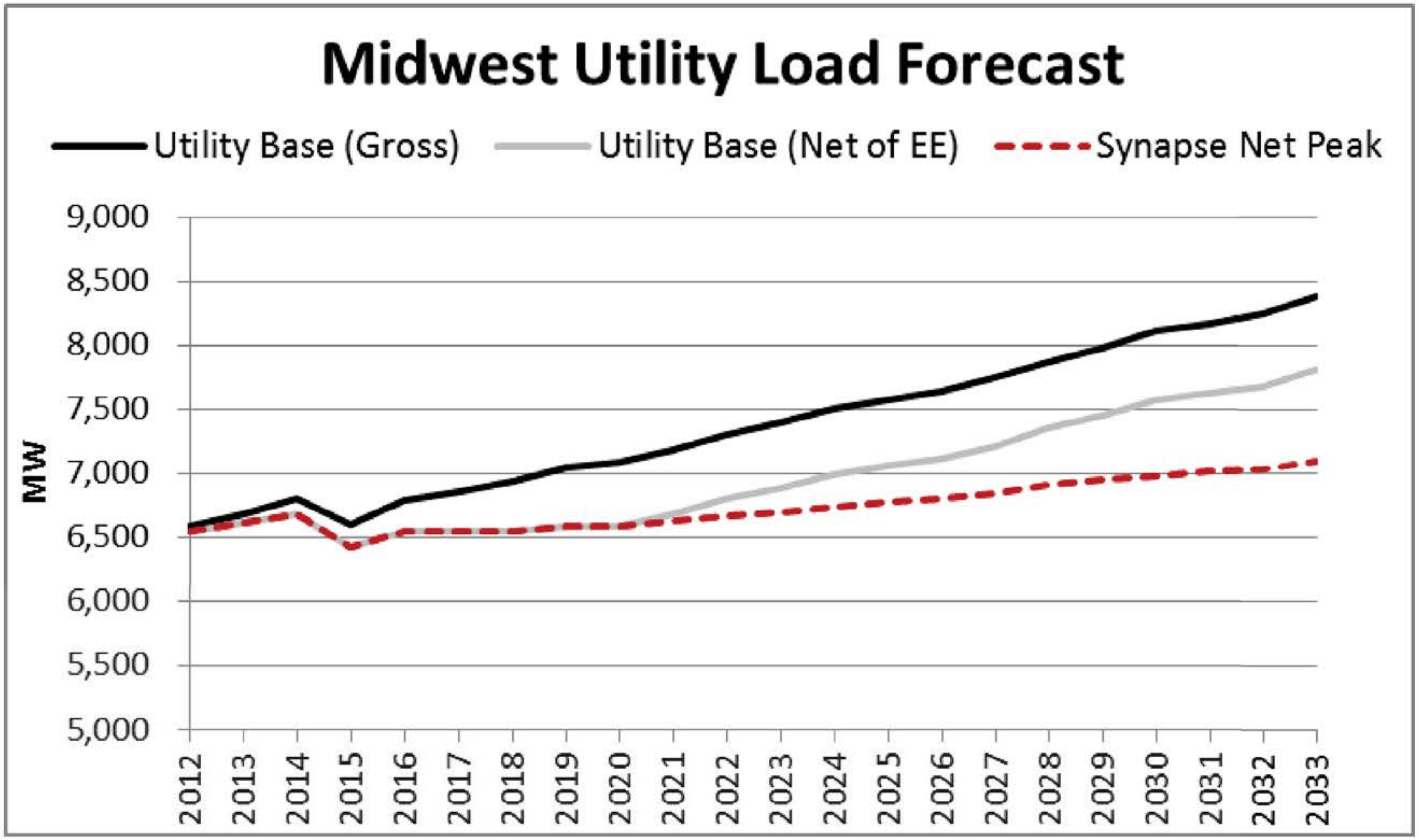
DSM

DSM Impacts on Load Forecast: Example



TC

DSM Impacts on Load Forecast: Example



TC

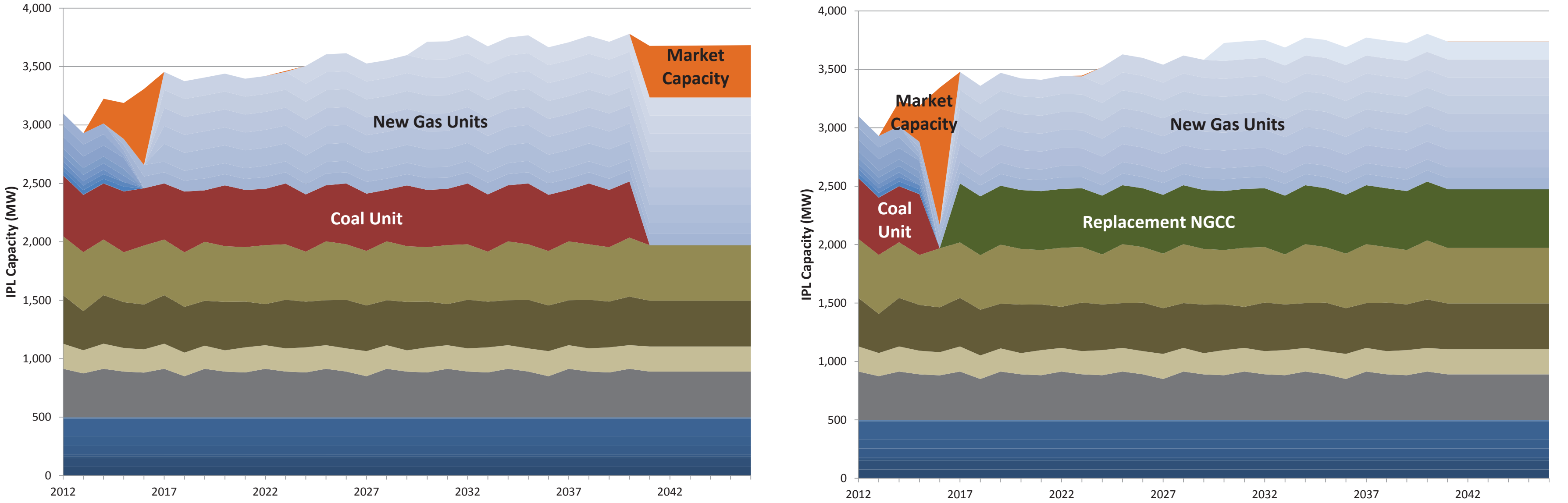
Resources: Supply options

Consideration of a **full range** of supply alternatives, with reasonable assumptions for their costs, performance, and availability.

JF

Supply Options

Example: Coal replacement with NGCC



No options considered except replacement NGCC 1:1

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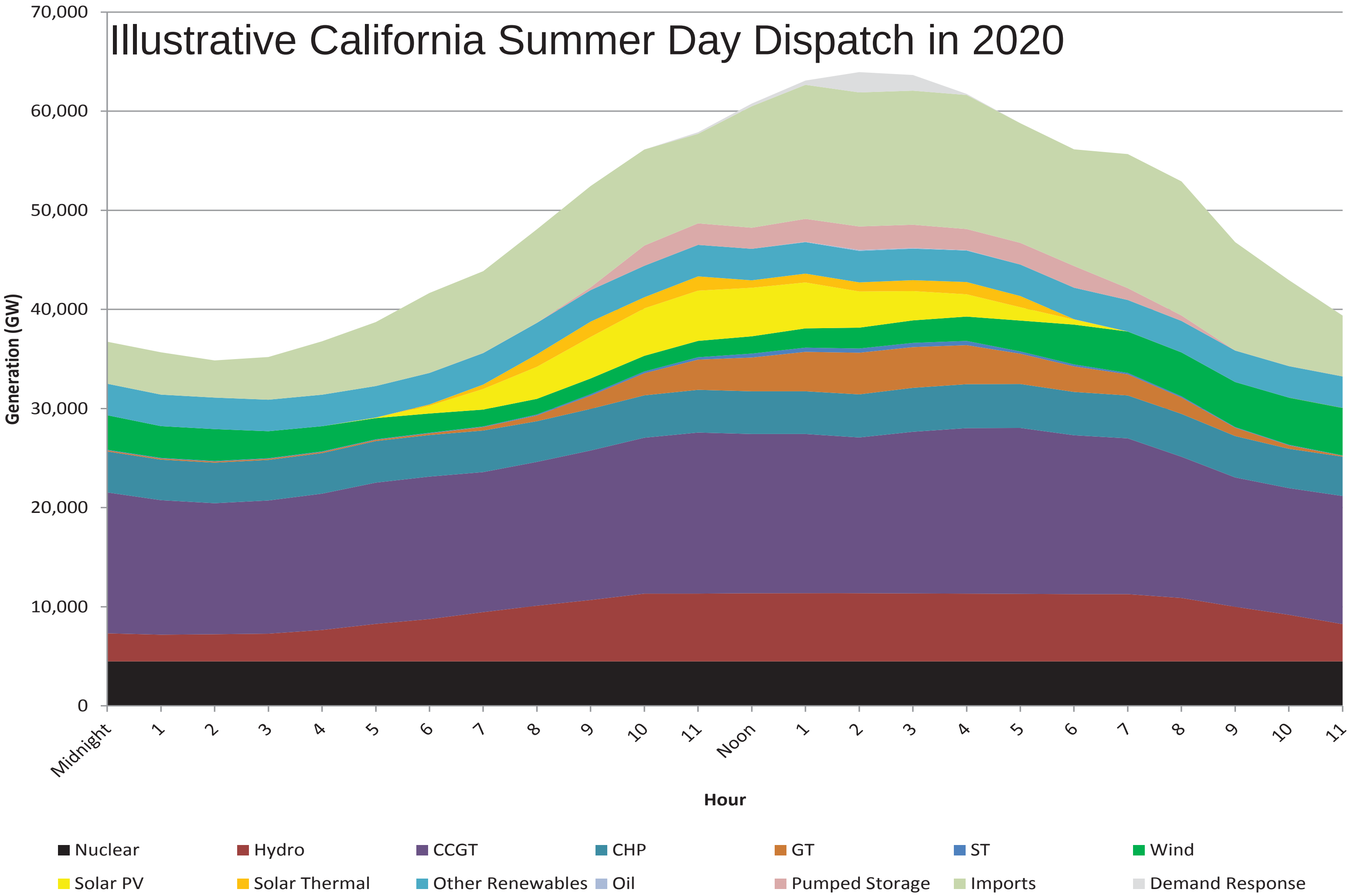
Supply Options

Understanding Supply Option Limitations

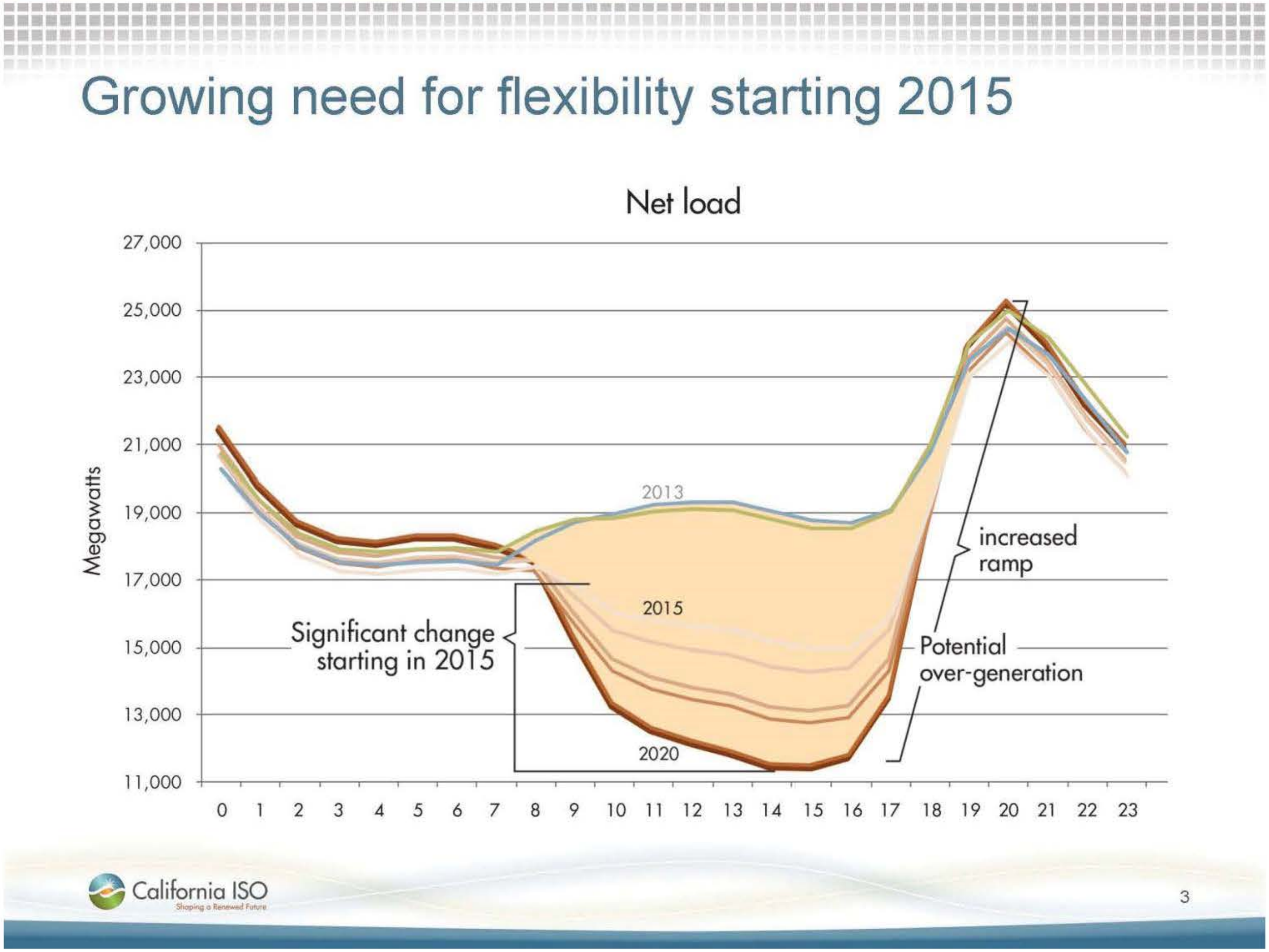


Source: Synapse Energy Economics' Plexos model results for California ISO base scenario with 33% RPS.

??

Supply Options

Understanding Supply Option Limitations

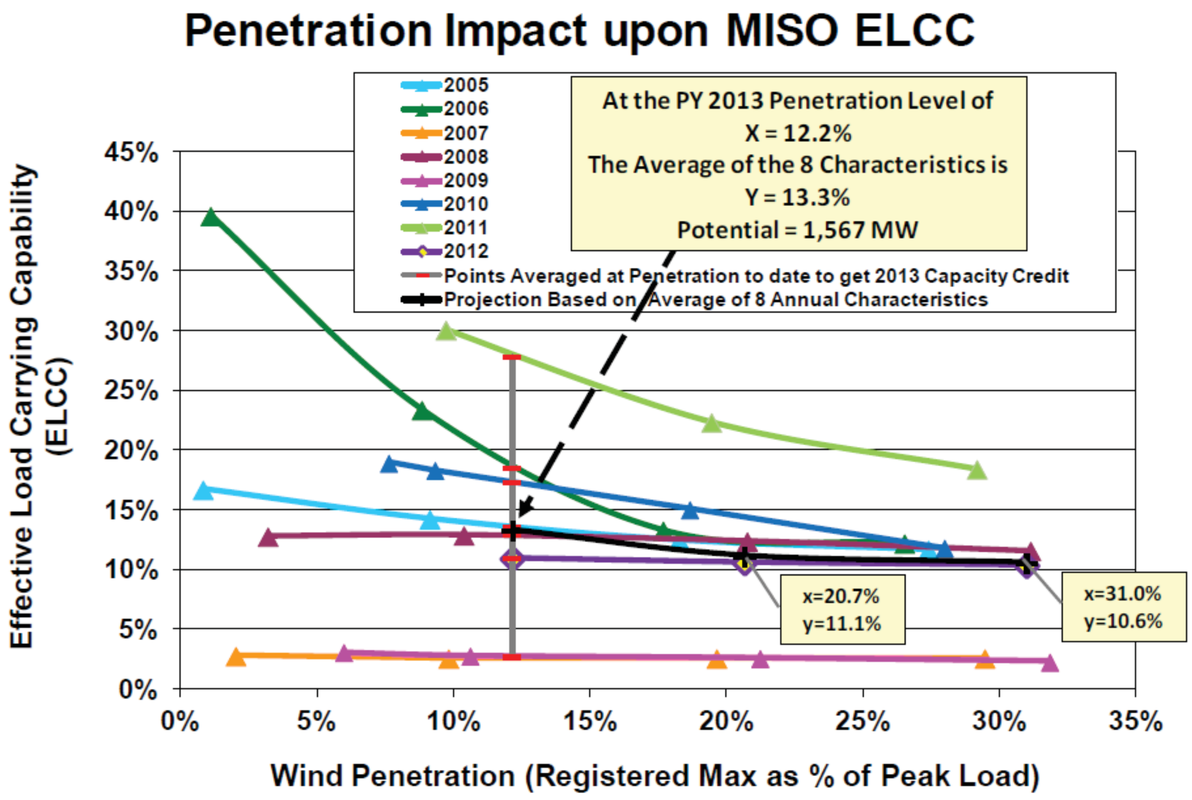


Growing need for flexibility starting 2015

Supply Options

Effective Load Carry Capability (ELCC)

Location-specific expectation of peak contribution for renewable energy resources. Varies by renewable energy penetration.



At the PY 2013 Penetration Level of
X = 12.2%
The Average of the 8 Characteristics is
Y = 13.3%
Potential = 1,567 MW

Figure 2-1: Eight Years of Historical ELCC Penetration Characteristics

Planning Year 2013-2014 Wind Capacity Credit Report, MISO. December 2012

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Resources: Existing Resources

Consideration of existing resource longevity, availability, and long-term performance.

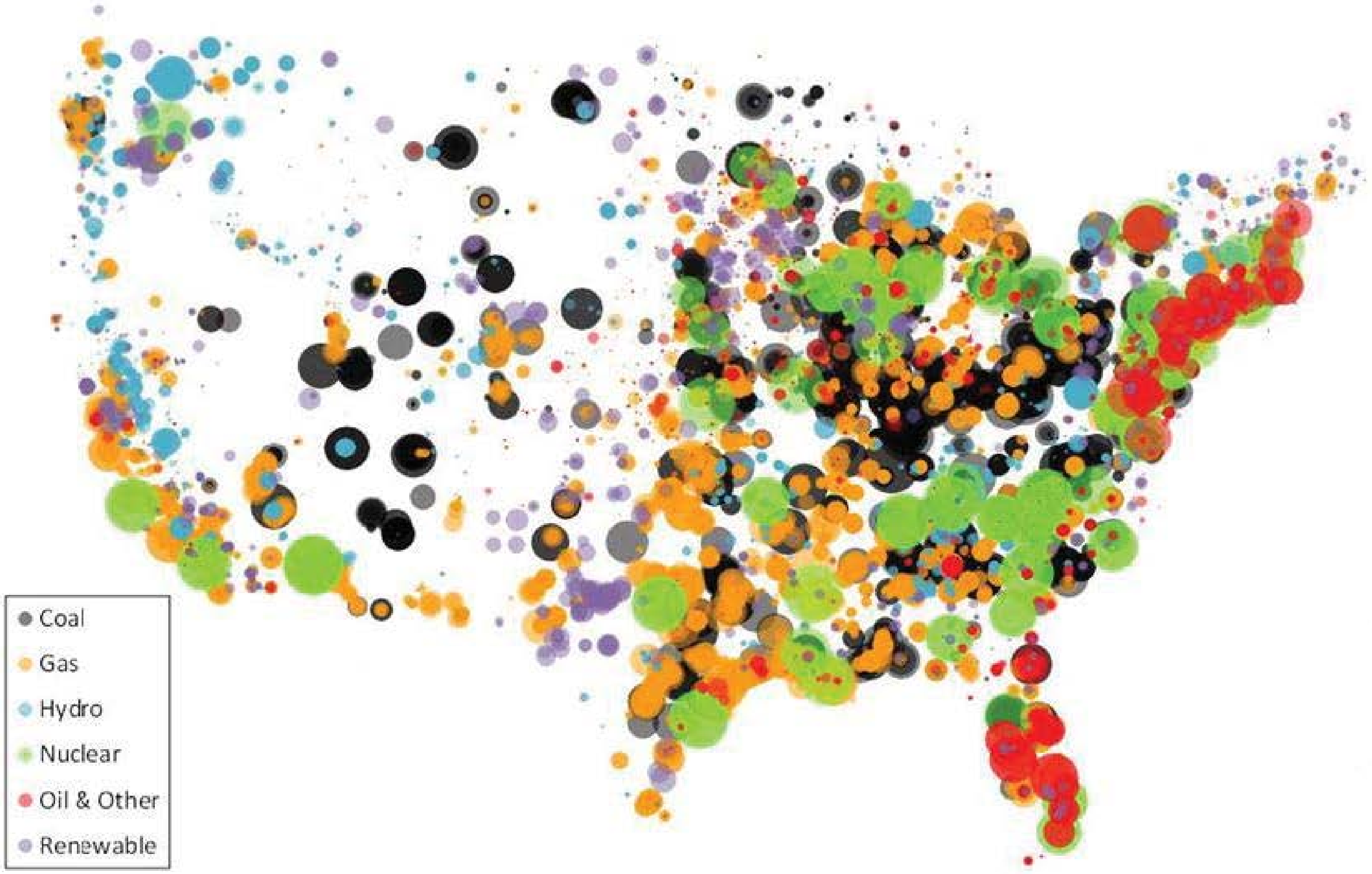
Detailed accounting for ongoing costs, risks, and liabilities.

Review of opportunities to avoid future investments, including retirement, should be included in analysis.

JF

Existing Resources

Existing EGU capacity by fuel type

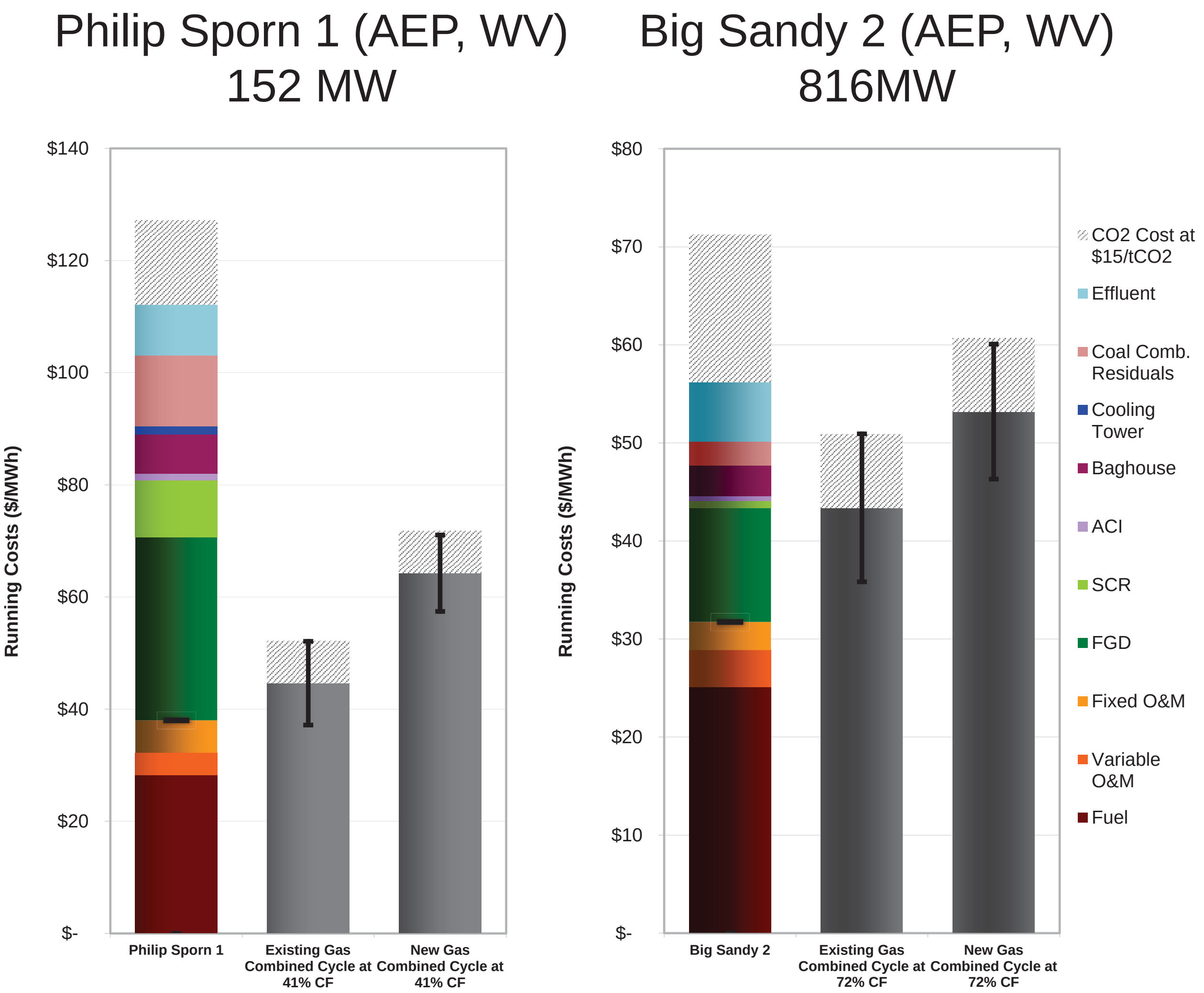


Source: EIA Form 860 2009

JF

Existing Resources

Coal Unit Forward Going Costs: Two Examples



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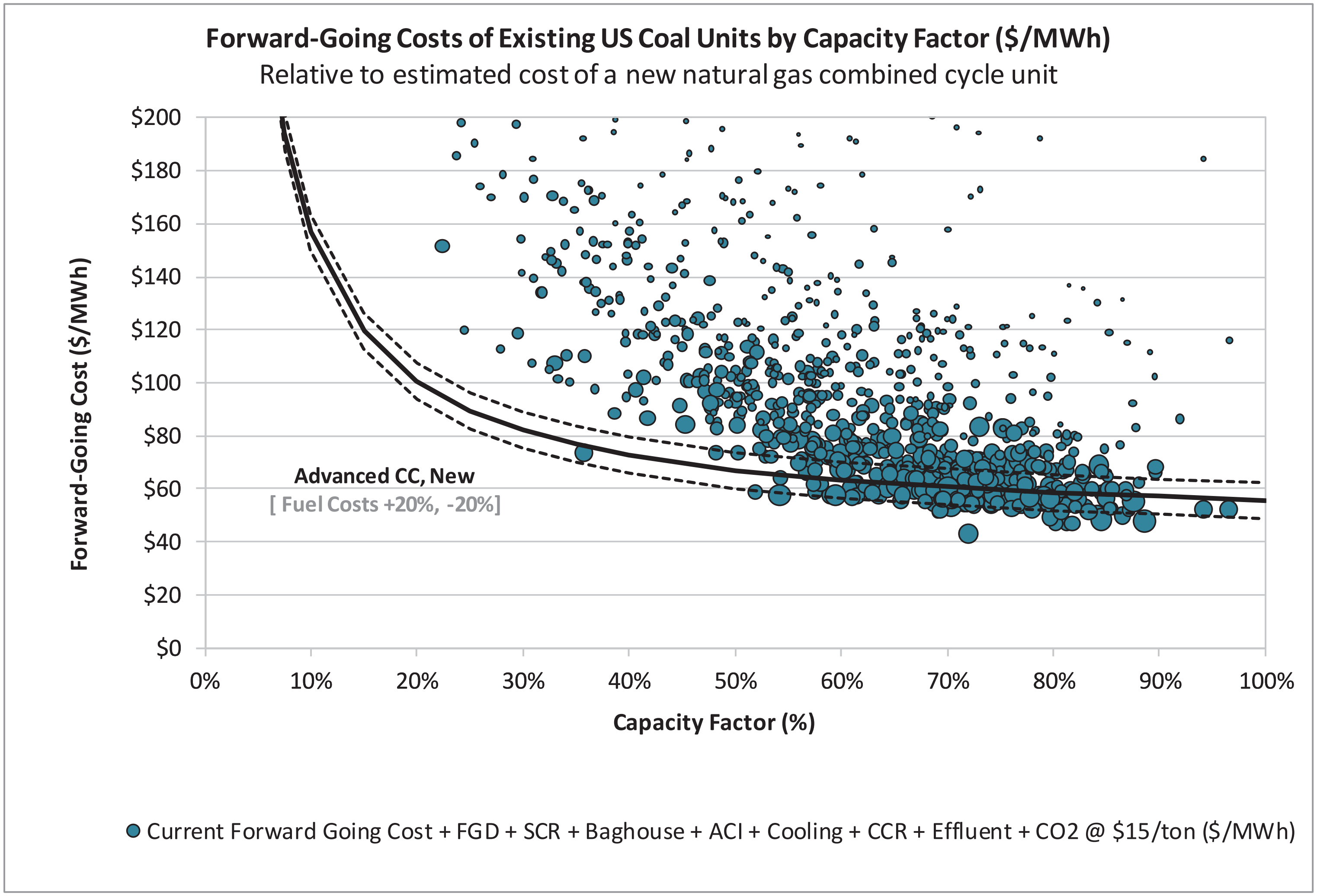
Existing Resources

Existing US Coal Fleet Forward-Going Costs


Forward-Going Costs of Existing US Coal Units by Capacity Factor ($/MWh)

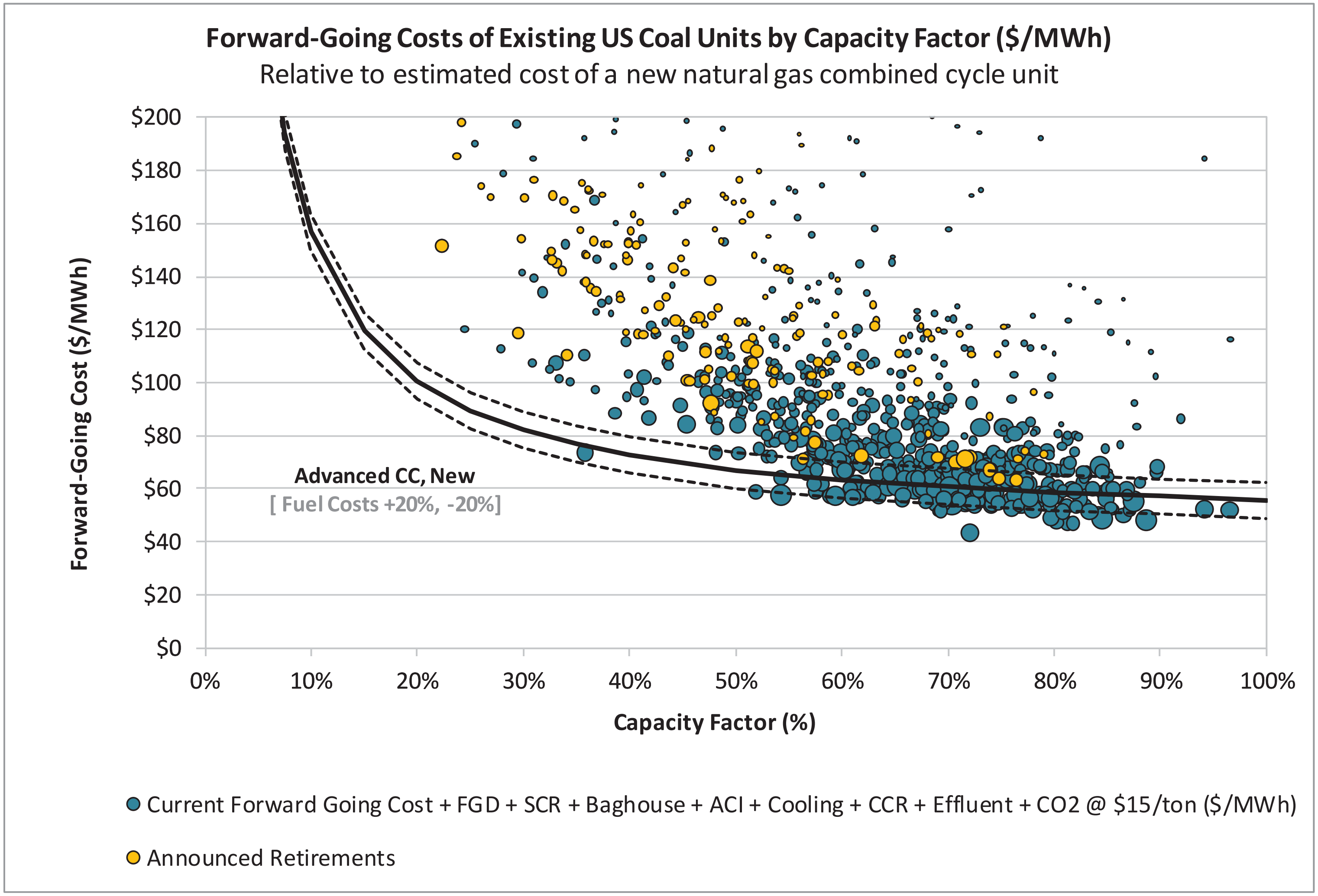
Relative to estimated cost of a new natural gas combined cycle unit

Note: Area of circles indicate MW capacity of units

JF

Existing Resources

Announced Retirements of US Coal Fleet



Note: Area of circles indicate MW capacity of units

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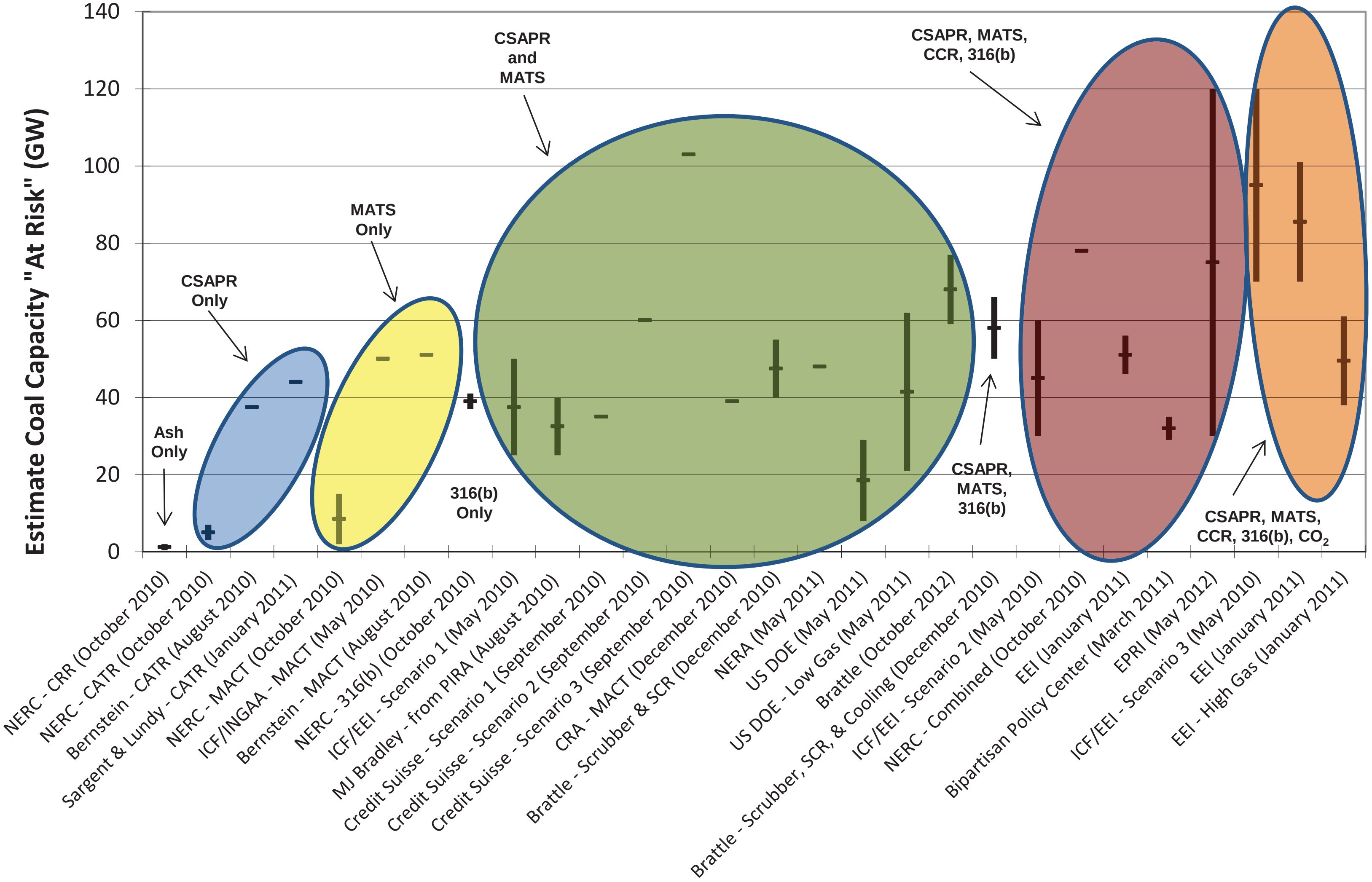
Existing Resources
Studies of Coal Capacity at Risk



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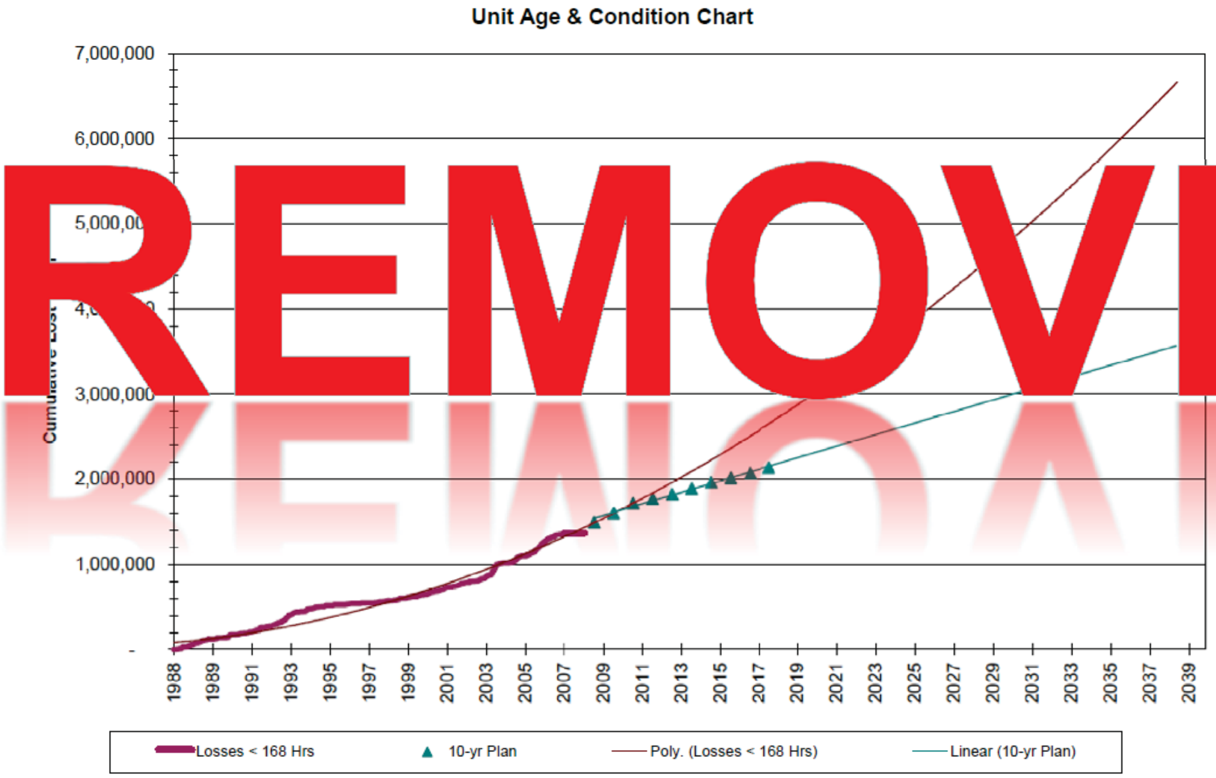
Existing Resources
Future forced outages

Expected future forced outages for example coal unit.



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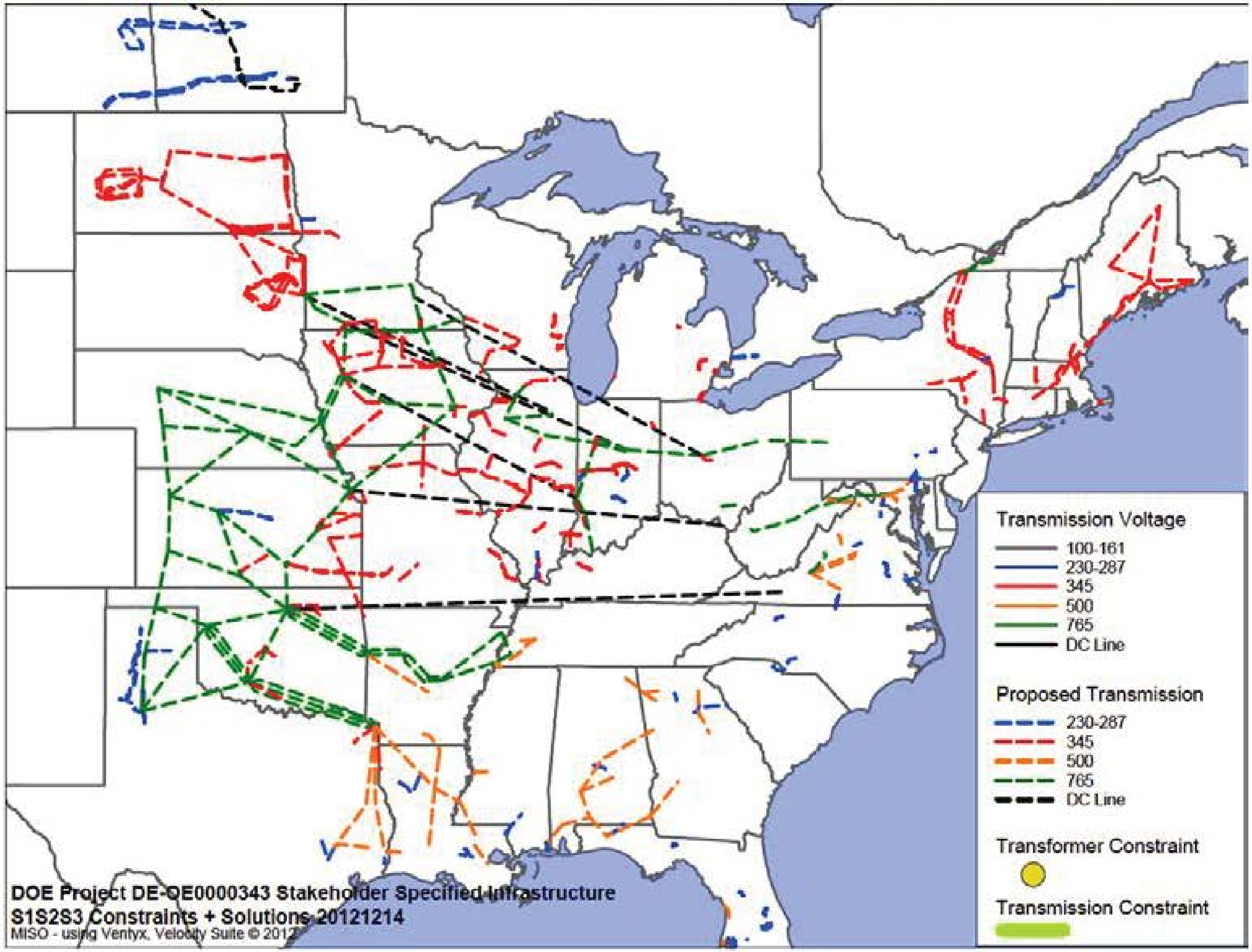
Resources: Transmission

- Thermal limits – captured in PC models, with limitations (zone, rough scale, paths)
- Voltage limits – not typically captured, important in reliability assessments

BF

Transmission

EIPC transmission buildout for wind – Sc. 1



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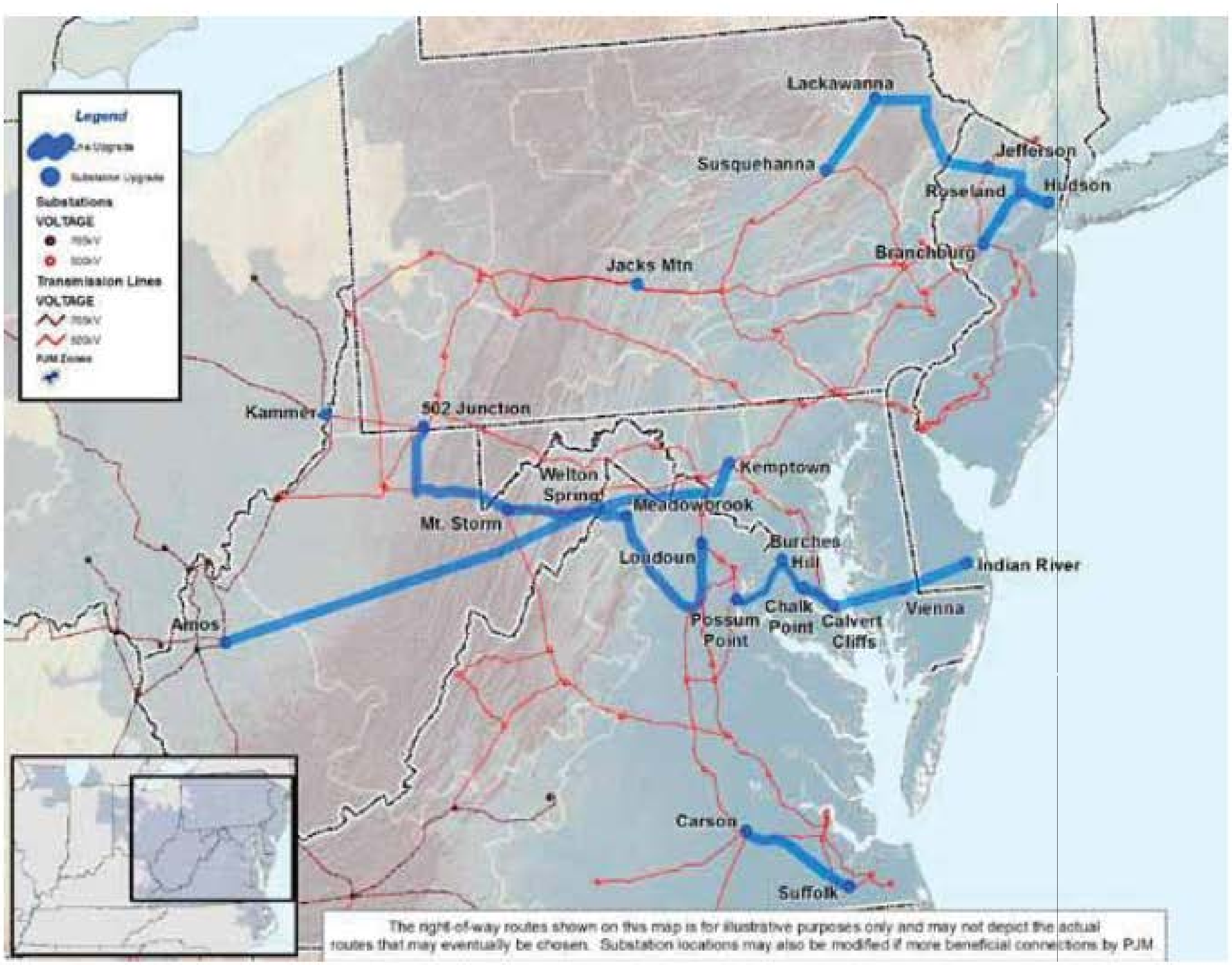
Transmission

Potomac Appalachian Transmission Highline (PATH)



The right-of-way routes shown on this map is for illustrative purposes only and may not depict the actual routes that may eventually be chosen. Substation locations may also be modified if more beneficial connections by PJM

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Potomac Appalachian Transmission Highline (PATH)

- PJM projected PATH need in ~2005 based on forecasted load absent significant EE/DR peak savings (that had not cleared RPM) and forecasted gross load.
- When EE/DR/recession and new generation added in, need for PATH was pushed out beyond planning period.

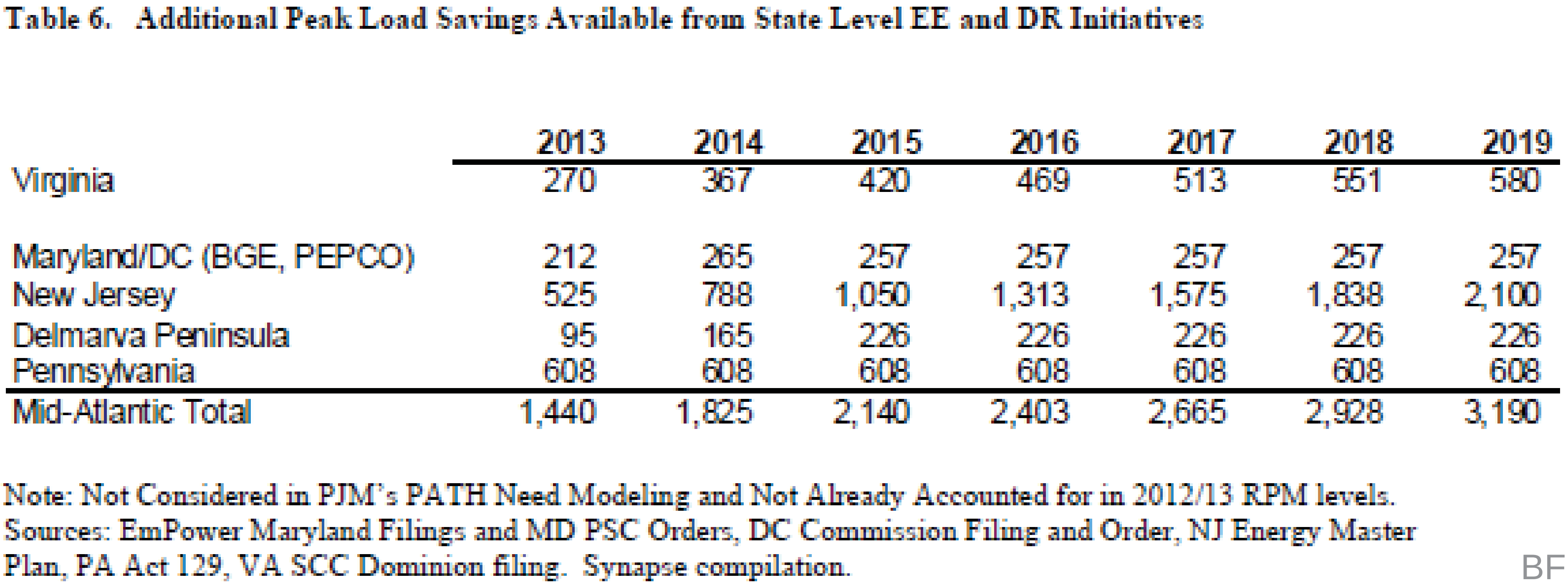

Table 6. Additional Peak Load Savings Available from State Level EE and DR Initiatives

	2013	2014	2015	2016	2017	2018	2019
Virginia	270	367	420	469	513	551	580
Maryland/DC (BGE, PEPCO)	212	265	257	257	257	257	257
New Jersey	525	788	1,050	1,313	1,575	1,838	2,100
Delmarva Peninsula	95	165	226	226	226	226	226
Pennsylvania	608	608	608	608	608	608	608
Mid-Atlantic Total	1,440	1,825	2,140	2,403	2,665	2,928	3,190

Note: Not Considered in PJM's PATH Need Modeling and Not Already Accounted for in 2012/13 RPM levels.
Sources: EmPower Maryland Filings and MD PSC Orders, DC Commission Filing and Order, NJ Energy Master Plan, PA Act 129, VA SCC Dominion filing. Synapse compilation.

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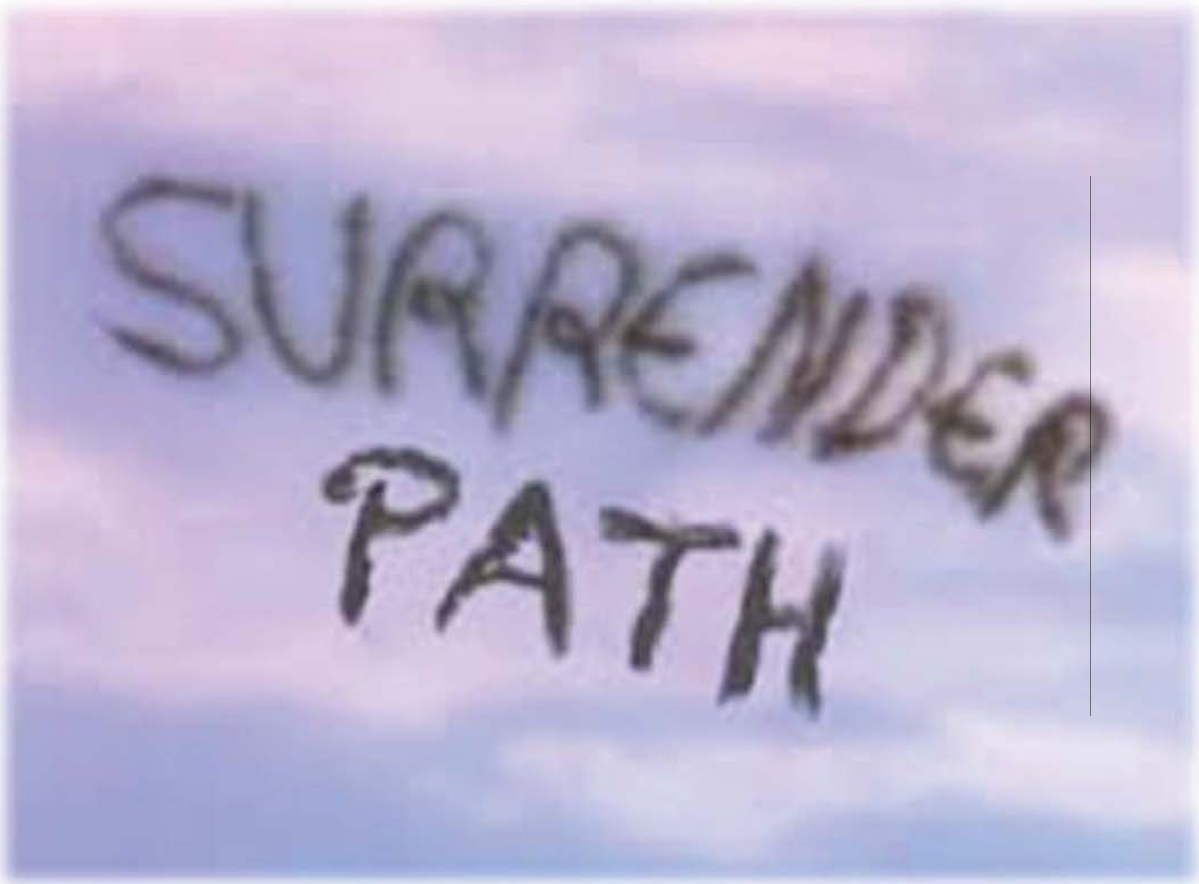
Transmission
End Result



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Modeling: Commodity Prices

Reasonable, recent, and consistent projections of fuel and electricity prices.

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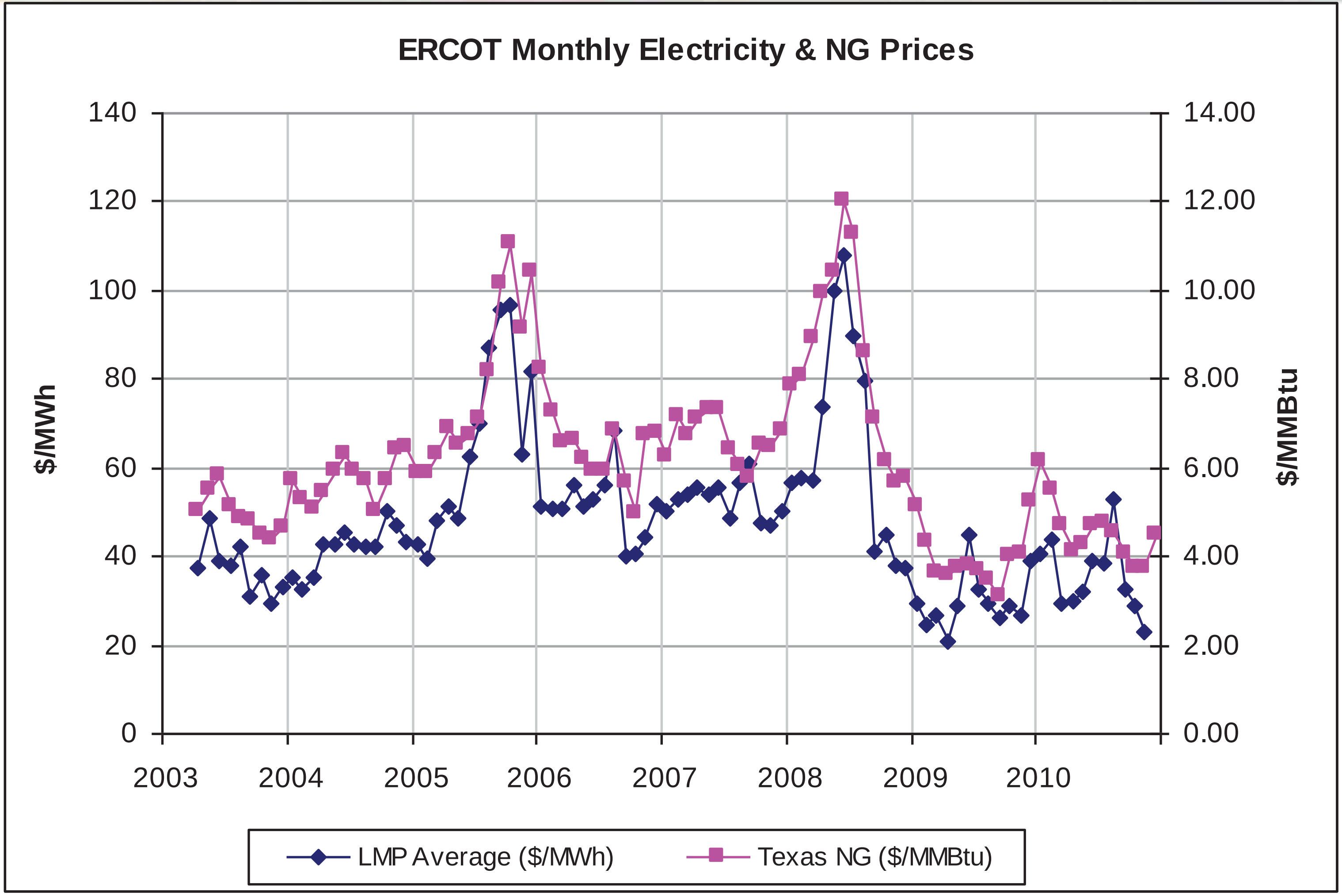
Fuel Price
Electricity prices related to gas prices

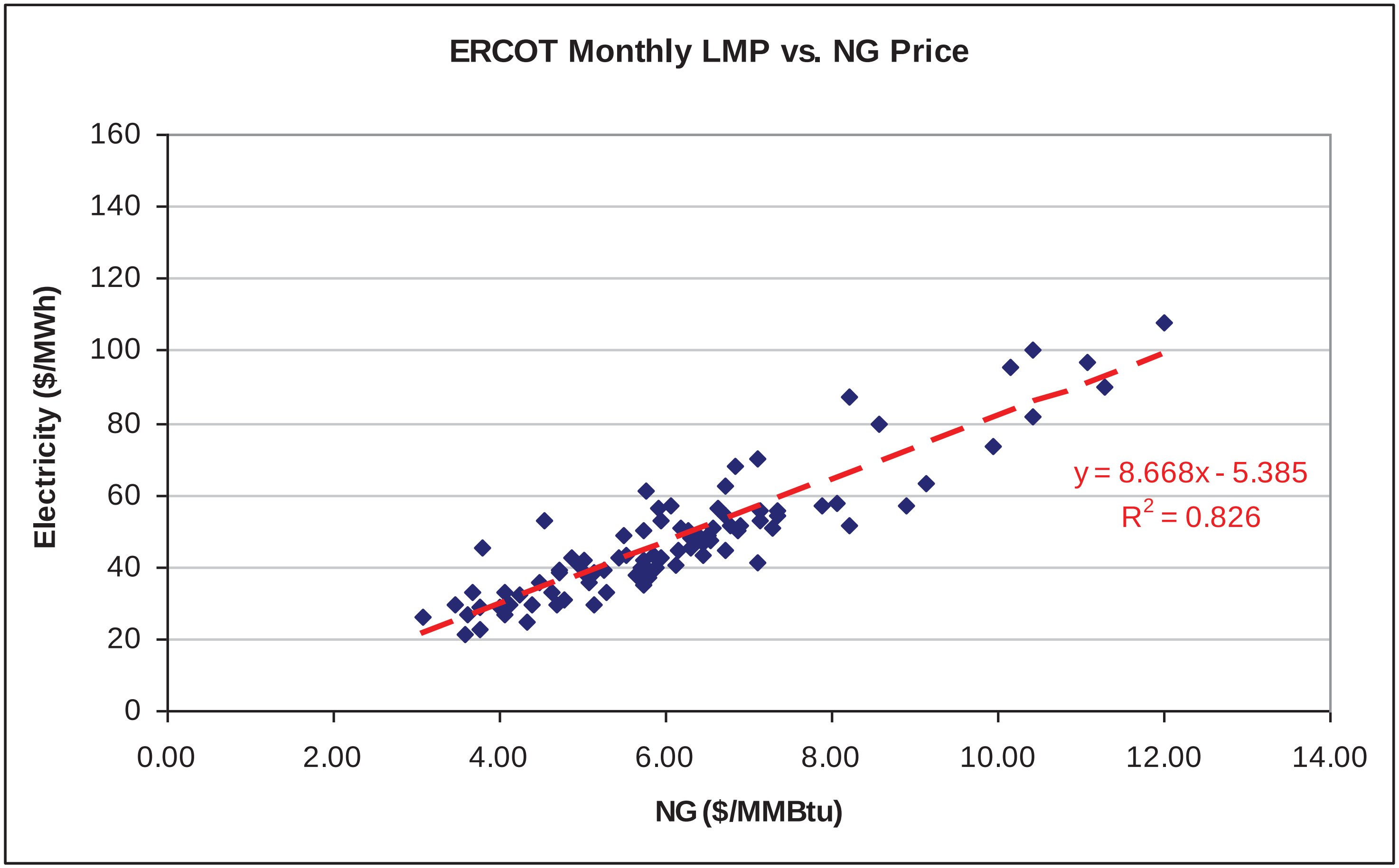


Source: ERCOT Archive

BB

Fuel Price

ERCOT monthly LMP vs. natural gas prices



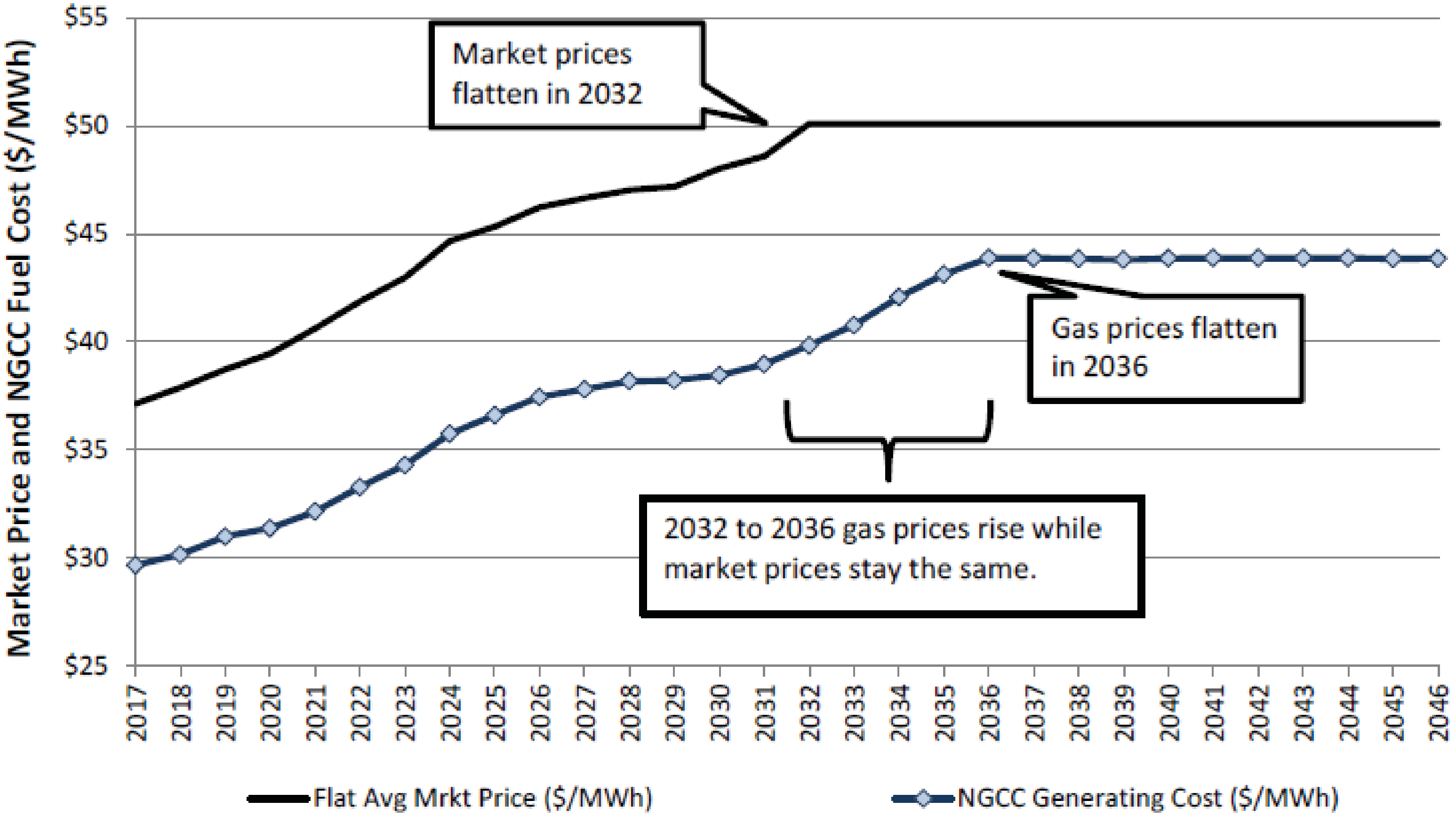
Source: ERCOT Archive

BB

Fuel Price

Mismatch between fuel and market prices

Recent case with extrapolation mismatch on gas/market prices…



Market prices flatten in 2032

Gas prices flatten in 2036

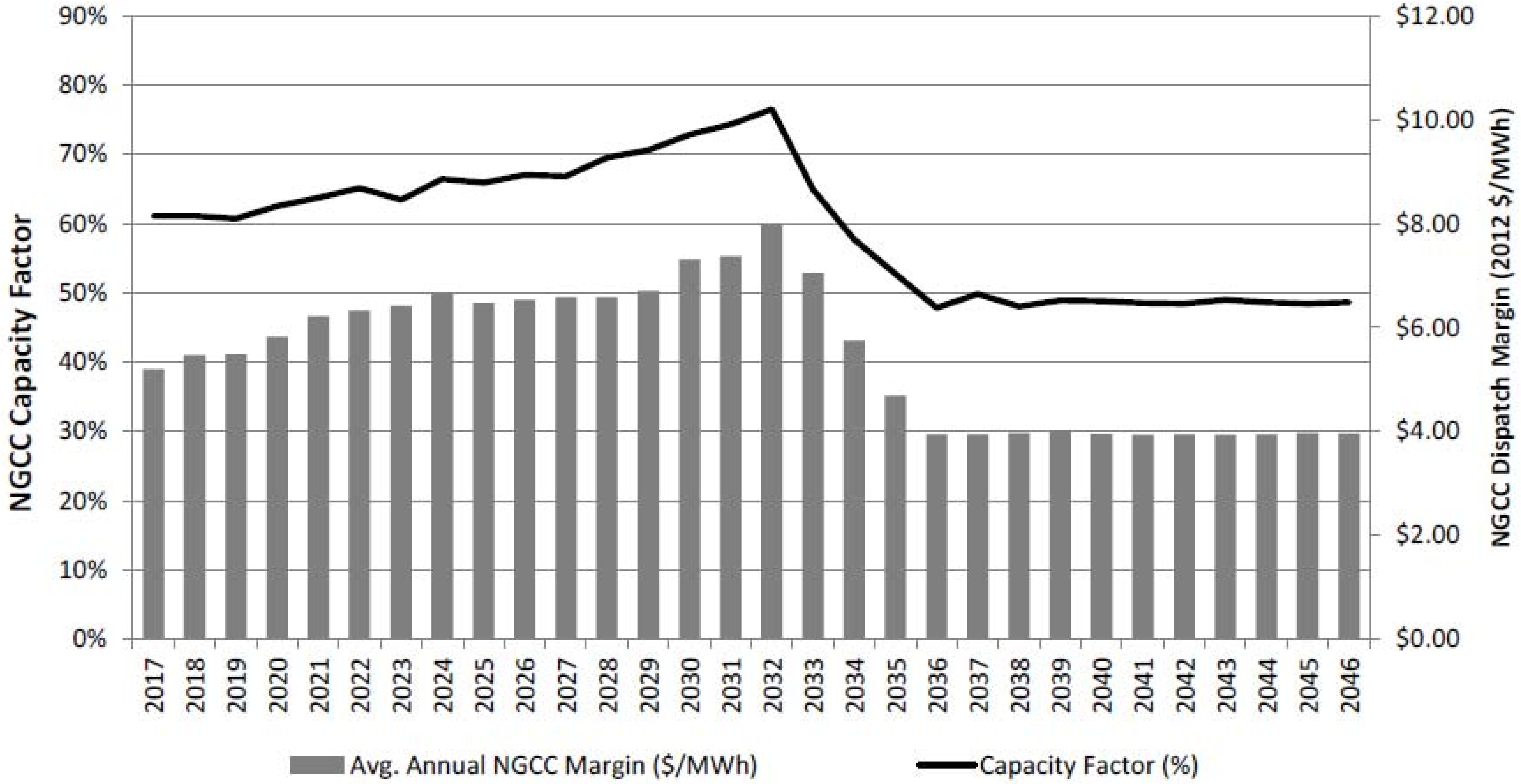
2032 to 2036 gas prices rise while market prices stay the same.

JF

Fuel Price

Mismatch between fuel and market prices

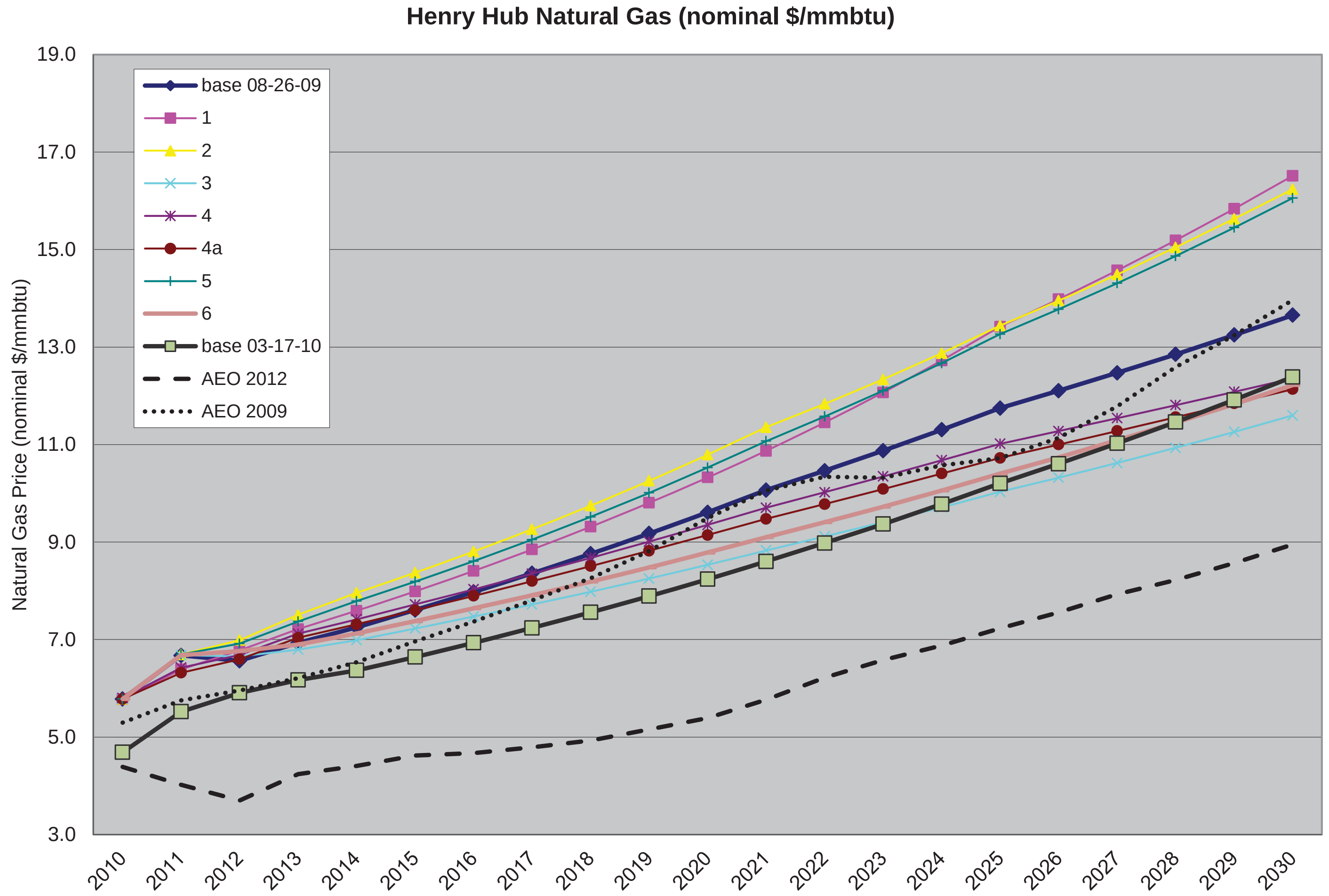
…results in surprising capacity factor drop in out-years.



JF

Fuel Price

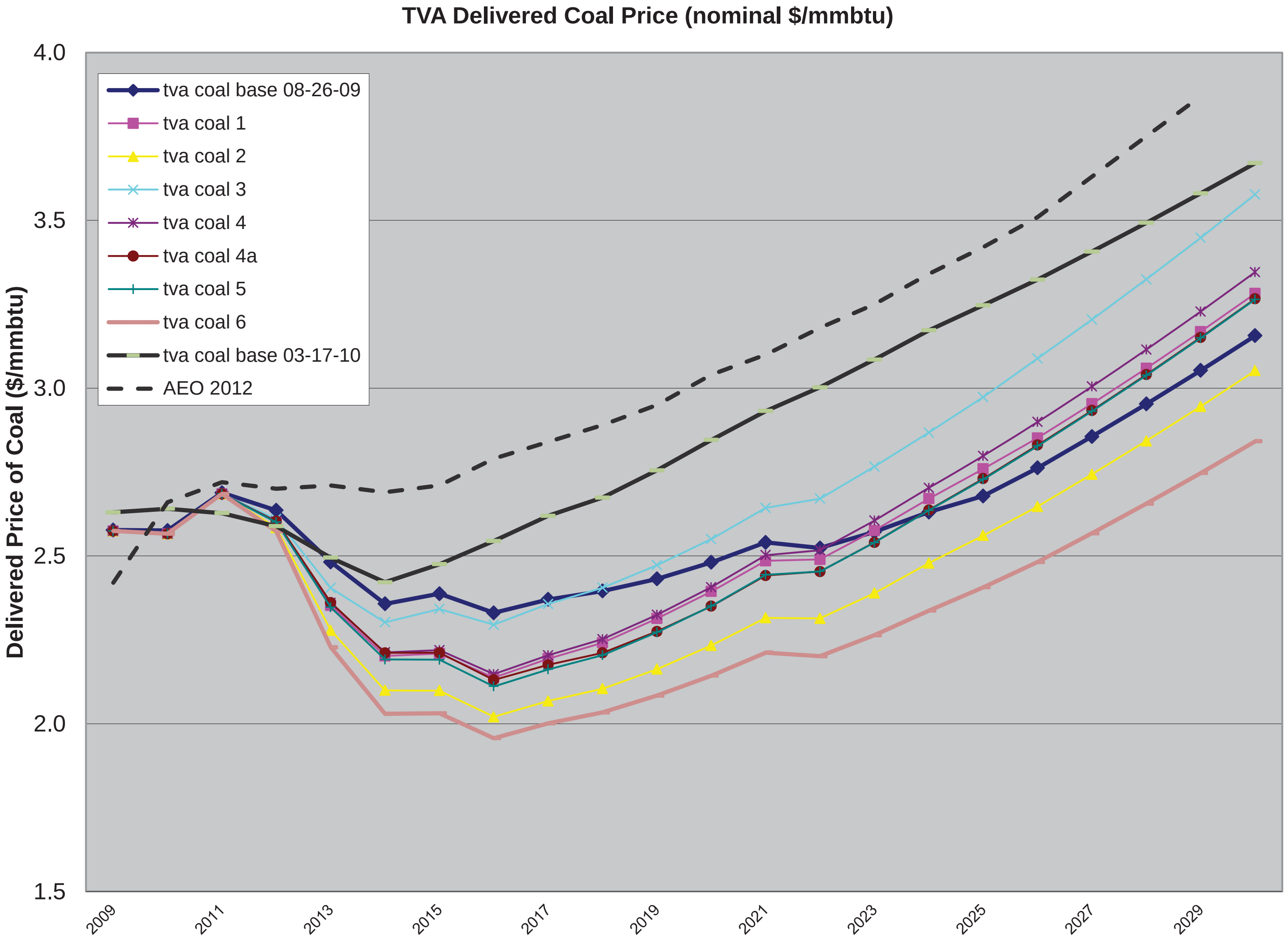
Natural Gas prices in TVA 2011 IRP



JF

Fuel Price

Coal prices in TVA 2011 IRP



JF

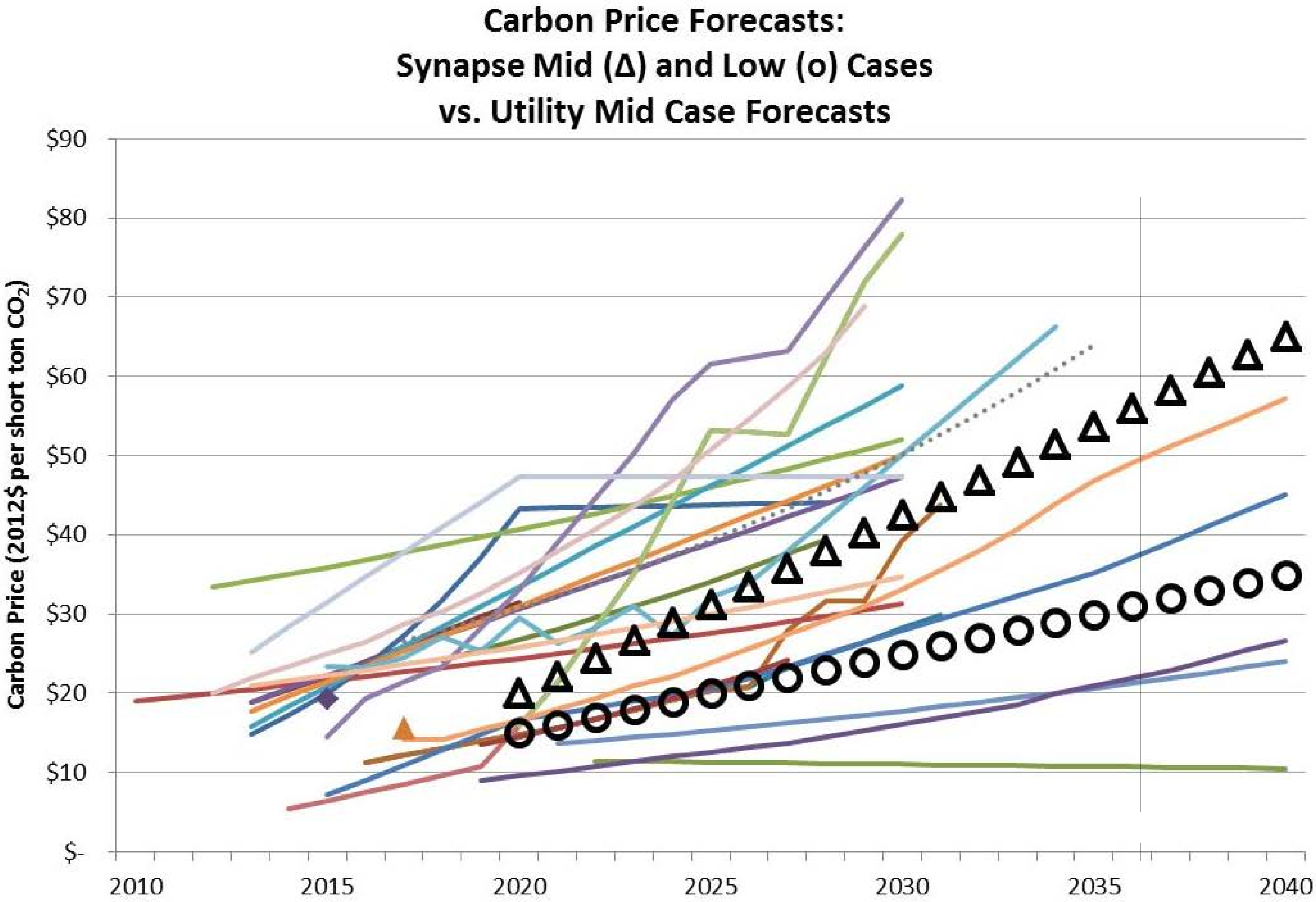
Modeling: CO_2 Pricing

Reasonable range of CO2 prices to reflect risks of federal legislation, rulemaking, or state/regional implementation.

FA

CO_2 Pricing

Synapse CO_2 Price Forecasts

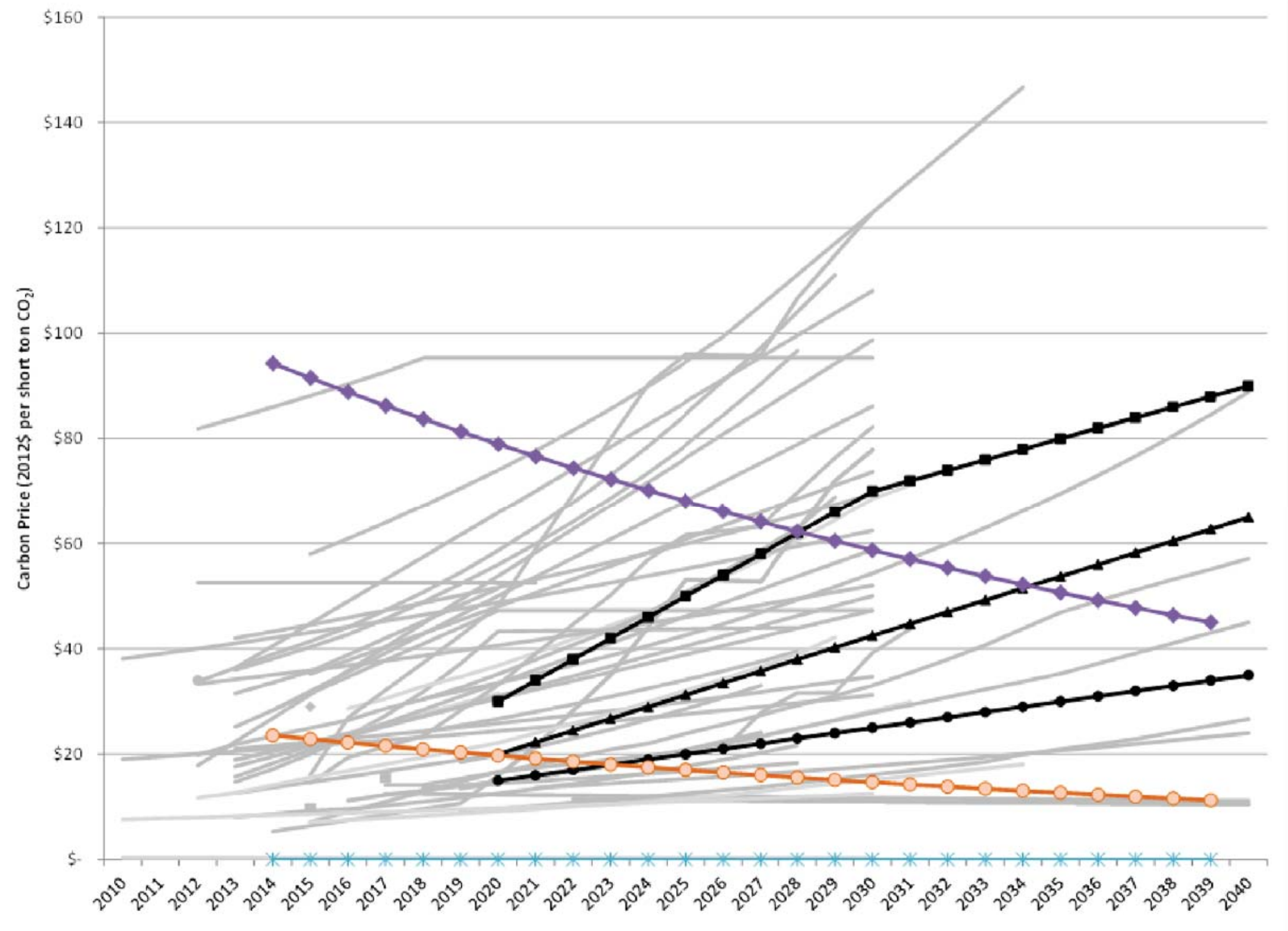


FA

CO_2 Pricing

Hawaii CO_2 Price Modeling

CO_2 prices assumed constant in nominal dollars



Lunch Break

Modeling: Environmental constraints

Projection of environmental compliance costs, including recognition of all reasonably expected future regulations.

Correct characterization of reasonably anticipated emissions/effluent limitations.

Environmental Constraints

Big Rivers CPCN: ignores internal recommendation

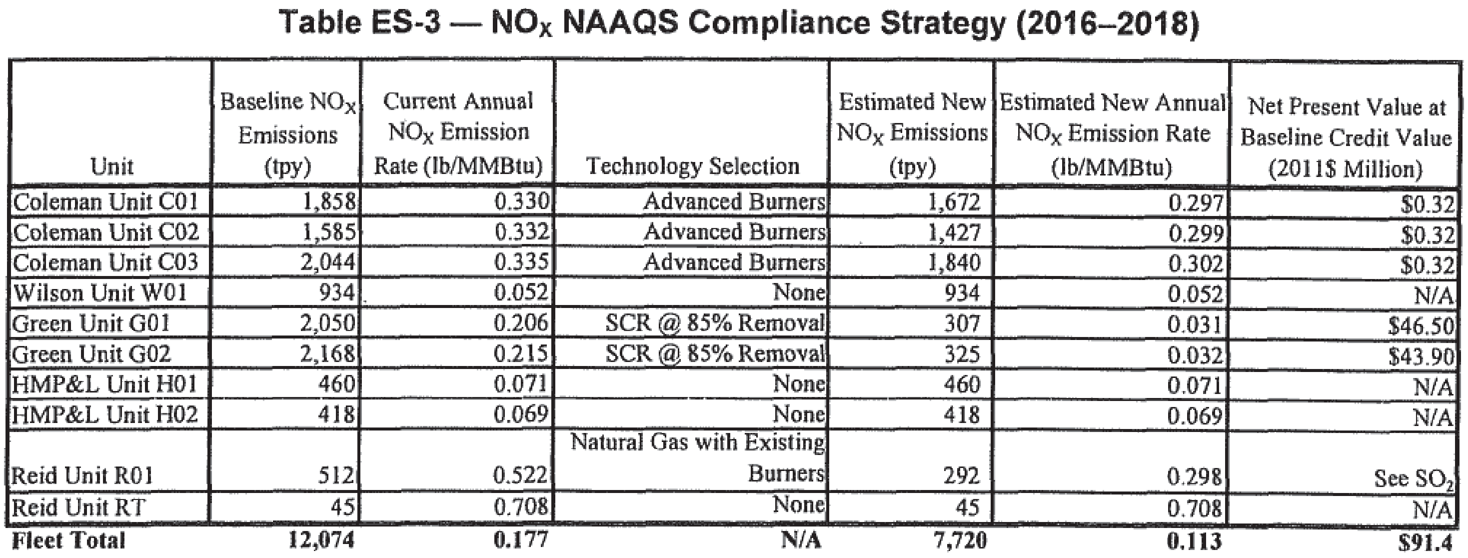


Table ES-3 — NO_X NAAQS Compliance Strategy (2016–2018)

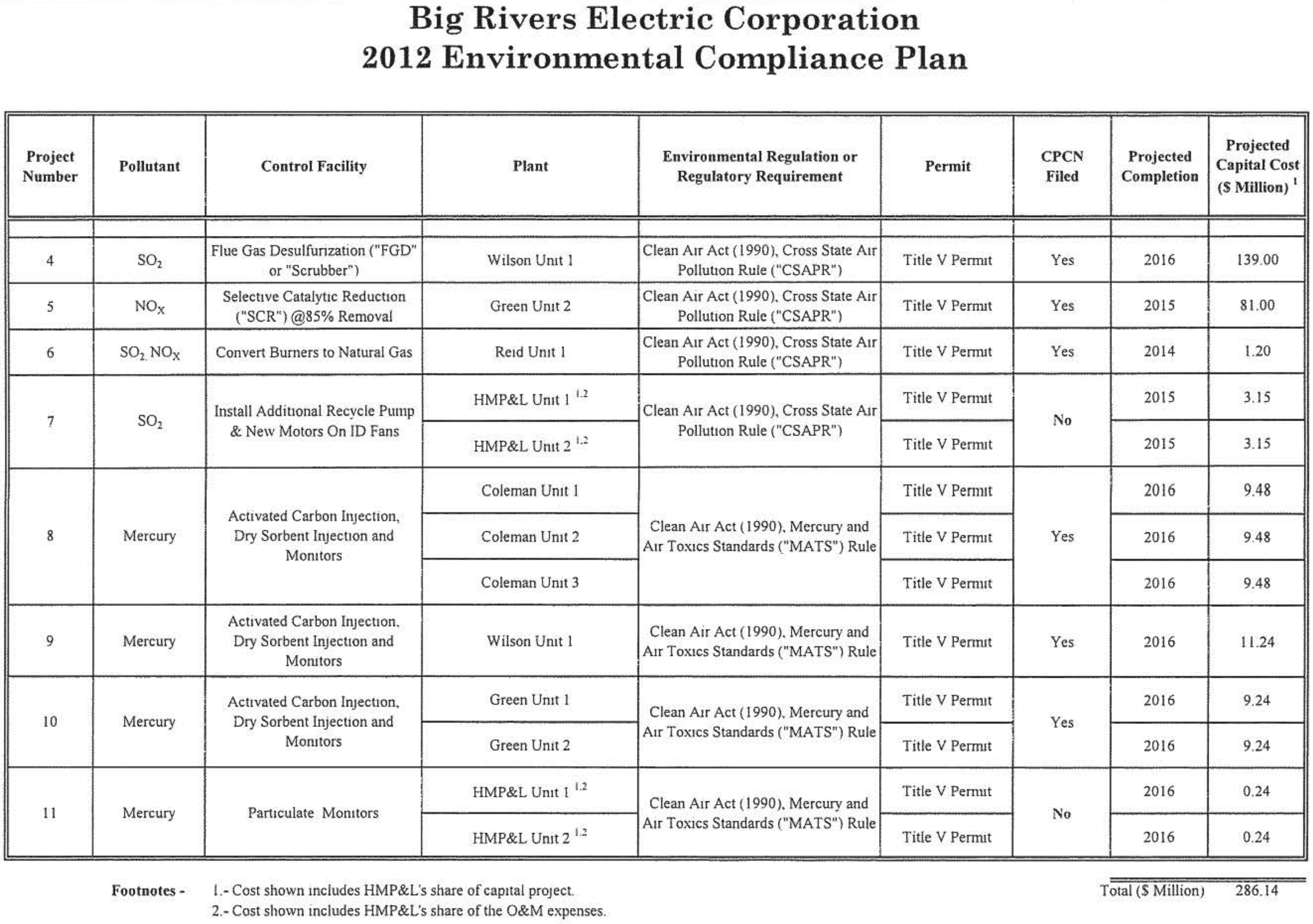
Unit	Baseline NO_X Emissions (tpy)	Current Annual NO_X Emission Rate (lb/MMBtu)	Technology Selection	Estimated New NO_X Emissions (tpy)	Estimated New Annual NO_X Emission Rate (lb/MMBtu)	Net Present Value at Baseline Credit Value (2011$ Million)
Coleman Unit C01	1,858	0.330	Advanced Burners	1,672	0.297	$0.32
Coleman Unit C02	1,585	0.332	Advanced Burners	1,427	0.299	$0.32
Coleman Unit C03	2,044	0.335	Advanced Burners	1,840	0.302	$0.32
Wilson Unit W01	934	0.052	None	934	0.052	N/A
Green Unit G01	2,050	0.206	SCR @ 85% Removal	307	0.031	$46.50
Green Unit G02	2,168	0.215	SCR @ 85% Removal	325	0.032	$43.90
HMP&L Unit H01	460	0.071	None	460	0.071	N/A
HMP&L Unit H02	418	0.069	None	418	0.069	N/A
Reid Unit R01	512	0.522	Natural Gas with Existing Burners	292	0.298	See SO_2
Reid Unit RT	45	0.708	None	45	0.708	N/A
Fleet Total	**12,074**	**0.177**	**N/A**	**7,720**	**0.113**	**$91.4**

BREC. April 2, 2012. DePreist, Exhibit 2. Case 2012-00063
Sargent and Lundy Report filed with BREC Case

JF

Environmental Constraints

Big Rivers CPCN: ignores internal recommendation



Big Rivers Electric Corporation
2012 Environmental Compliance Plan

Project Number	Pollutant	Control Facility	Plant	Environmental Regulation or Regulatory Requirement	Permit	CPCN Filed	Projected Completion	Projected Capital Cost ($ Million)[1]
4	SO_2	Flue Gas Desulfurization ("FGD" or "Scrubber")	Wilson Unit 1	Clean Air Act (1990), Cross State Air Pollution Rule ("CSAPR")	Title V Permit	Yes	2016	139.00
5	NO_X	Selective Catalytic Reduction ("SCR") @85% Removal	Green Unit 2	Clean Air Act (1990), Cross State Air Pollution Rule ("CSAPR")	Title V Permit	Yes	2015	81.00
6	SO_2, NO_X	Convert Burners to Natural Gas	Reid Unit 1	Clean Air Act (1990), Cross State Air Pollution Rule ("CSAPR")	Title V Permit	Yes	2014	1.20
7	SO_2	Install Additional Recycle Pump & New Motors On ID Fans	HMP&L Unit 1 [1,2]	Clean Air Act (1990), Cross State Air Pollution Rule ("CSAPR")	Title V Permit	No	2015	3.15
			HMP&L Unit 2 [1,2]		Title V Permit		2015	3.15
8	Mercury	Activated Carbon Injection, Dry Sorbent Injection and Monitors	Coleman Unit 1	Clean Air Act (1990), Mercury and Air Toxics Standards ("MATS") Rule	Title V Permit	Yes	2016	9.48
			Coleman Unit 2		Title V Permit		2016	9.48
			Coleman Unit 3		Title V Permit		2016	9.48
9	Mercury	Activated Carbon Injection, Dry Sorbent Injection and Monitors	Wilson Unit 1	Clean Air Act (1990), Mercury and Air Toxics Standards ("MATS") Rule	Title V Permit	Yes	2016	11.24
10	Mercury	Activated Carbon Injection, Dry Sorbent Injection and Monitors	Green Unit 1	Clean Air Act (1990), Mercury and Air Toxics Standards ("MATS") Rule	Title V Permit	Yes	2016	9.24
			Green Unit 2		Title V Permit		2016	9.24
11	Mercury	Particulate Monitors	HMP&L Unit 1 [1,2]	Clean Air Act (1990), Mercury and Air Toxics Standards ("MATS") Rule	Title V Permit	No	2016	0.24
			HMP&L Unit 2 [1,2]		Title V Permit		2016	0.24

Total ($ Million) 286.14

Footnotes - 1.- Cost shown includes HMP&L's share of capital project.
2.- Cost shown includes HMP&L's share of the O&M expenses.

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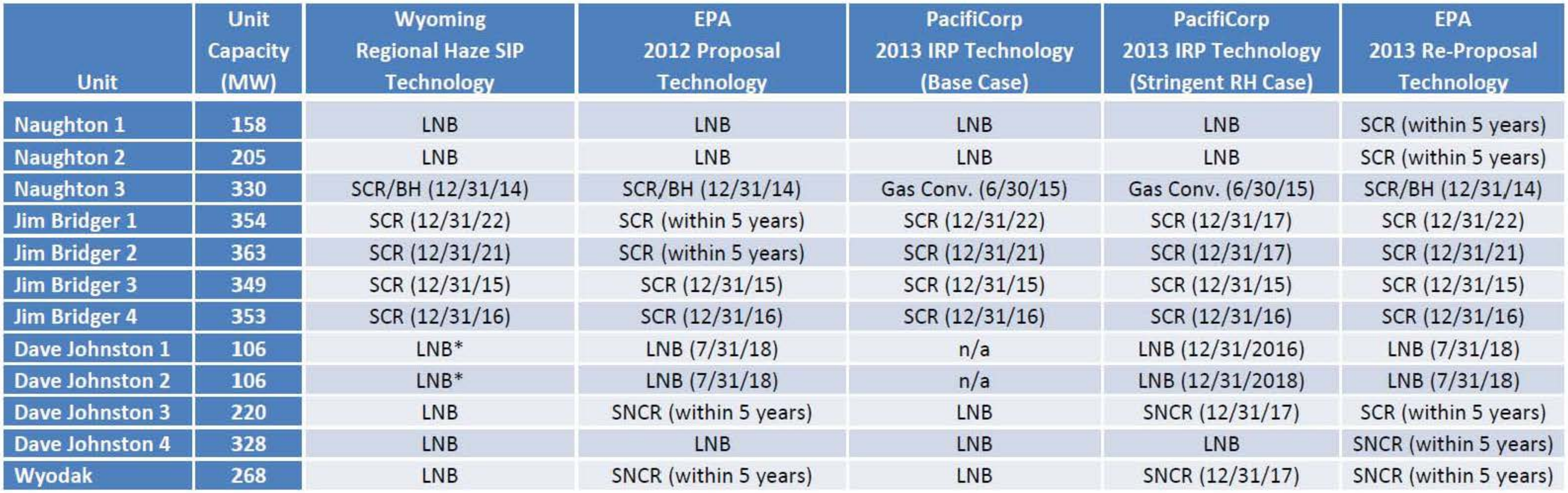
Environmental Constraints

PacifiCorp 2013 IRP does not reflect FIP

Comparison of Wyoming SIP, EPA FIP Proposals and PacifiCorp IRP Cases



Unit	Unit Capacity (MW)	Wyoming Regional Haze SIP Technology	EPA 2012 Proposal Technology	PacifiCorp 2013 IRP Technology (Base Case)	PacifiCorp 2013 IRP Technology (Stringent RH Case)	EPA 2013 Re-Proposal Technology
Naughton 1	158	LNB	LNB	LNB	LNB	SCR (within 5 years)
Naughton 2	205	LNB	LNB	LNB	LNB	SCR (within 5 years)
Naughton 3	330	SCR/BH (12/31/14)	SCR/BH (12/31/14)	Gas Conv. (6/30/15)	Gas Conv. (6/30/15)	SCR/BH (12/31/14)
Jim Bridger 1	354	SCR (12/31/22)	SCR (within 5 years)	SCR (12/31/22)	SCR (12/31/17)	SCR (12/31/22)
Jim Bridger 2	363	SCR (12/31/21)	SCR (within 5 years)	SCR (12/31/21)	SCR (12/31/17)	SCR (12/31/21)
Jim Bridger 3	349	SCR (12/31/15)	SCR (12/31/15)	SCR (12/31/15)	SCR (12/31/15)	SCR (12/31/15)
Jim Bridger 4	353	SCR (12/31/16)	SCR (12/31/16)	SCR (12/31/16)	SCR (12/31/16)	SCR (12/31/16)
Dave Johnston 1	106	LNB*	LNB (7/31/18)	n/a	LNB (12/31/2016)	LNB (7/31/18)
Dave Johnston 2	106	LNB*	LNB (7/31/18)	n/a	LNB (12/31/2018)	LNB (7/31/18)
Dave Johnston 3	220	LNB	SNCR (within 5 years)	LNB	SNCR (12/31/17)	SCR (within 5 years)
Dave Johnston 4	328	LNB	LNB	LNB	LNB	SNCR (within 5 years)
Wyodak	268	LNB	SNCR (within 5 years)	LNB	SNCR (12/31/17)	SNCR (within 5 years)

JF

Modeling: Market Interactions

- Utilities with connections to deregulated markets need to take into consideration the potential to buy energy and/or capacity from wholesale markets, as available.
- Utilities in fully regulated areas can still trade with neighboring utilities at an effective market price.

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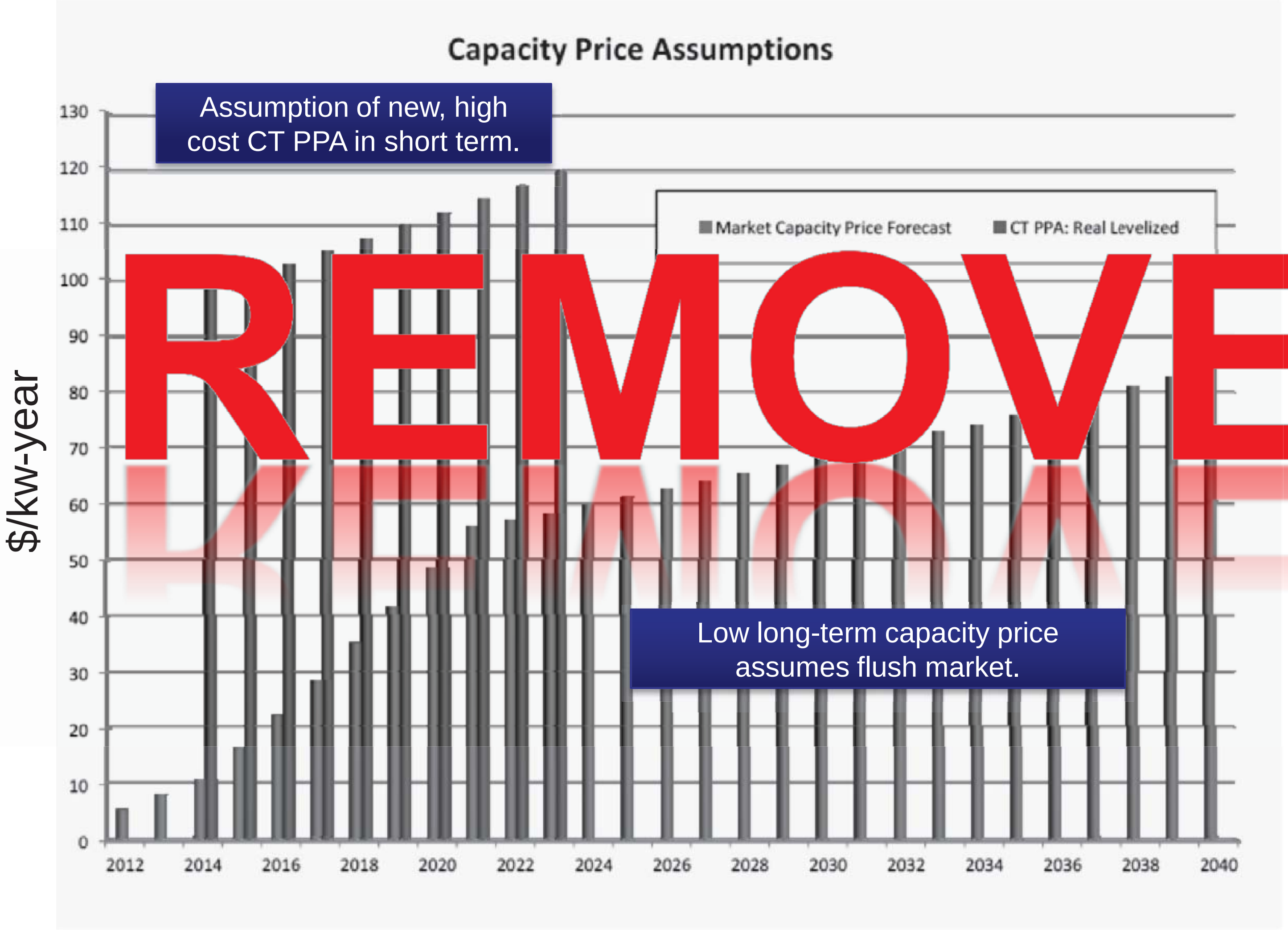
Market Interactions
Capacity Availability and Price



Assumption of new, high cost CT PPA in short term.

Low long-term capacity price assumes flush market.

REMOVE

JF

Modeling: Model Options

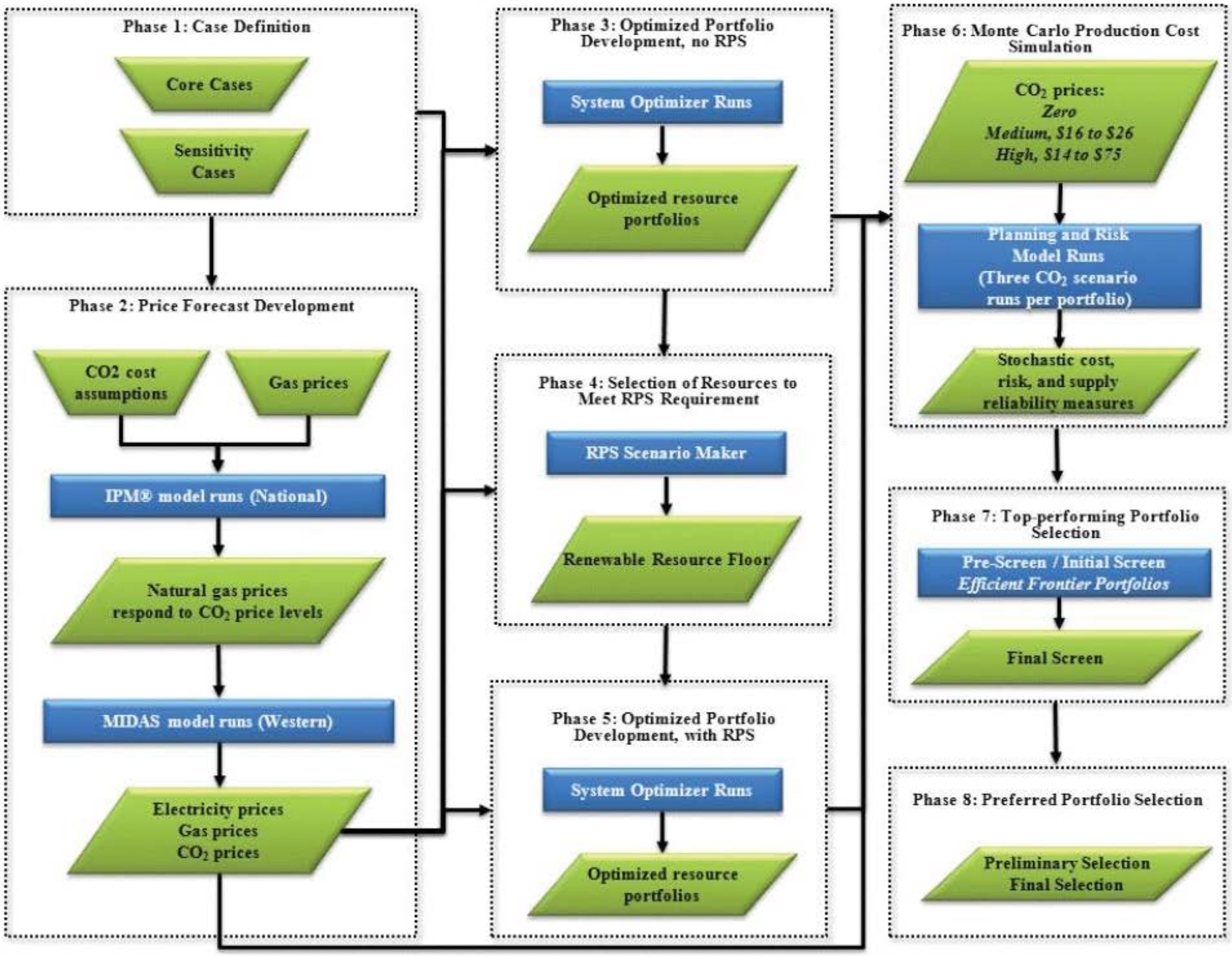
- An IRP typically requires multiple layers of models:
  - **Economy-wide models** for commodity-price (fuel) projections
  - **Electric-system models** for market price projections
  - **Optimization models** to determine new portfolio build-out (and retirement)
  - **Production cost models** to cost or stress-test portfolios

JF

Modeling

PacifiCorp 2013 Model Use

Figure 7.1 – Modeling and Risk Analysis Process



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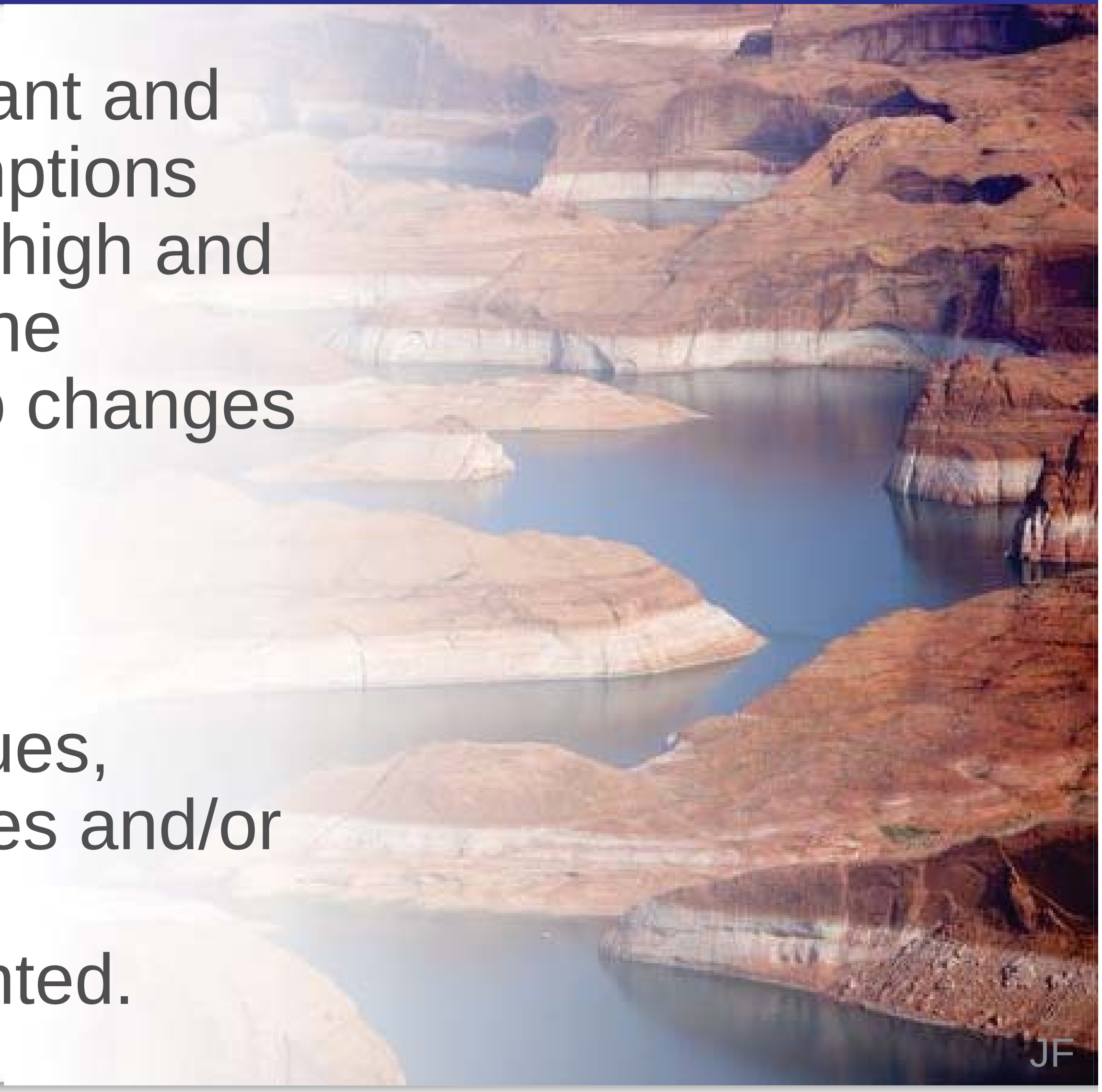
Modeling: Dealing with Uncertainty

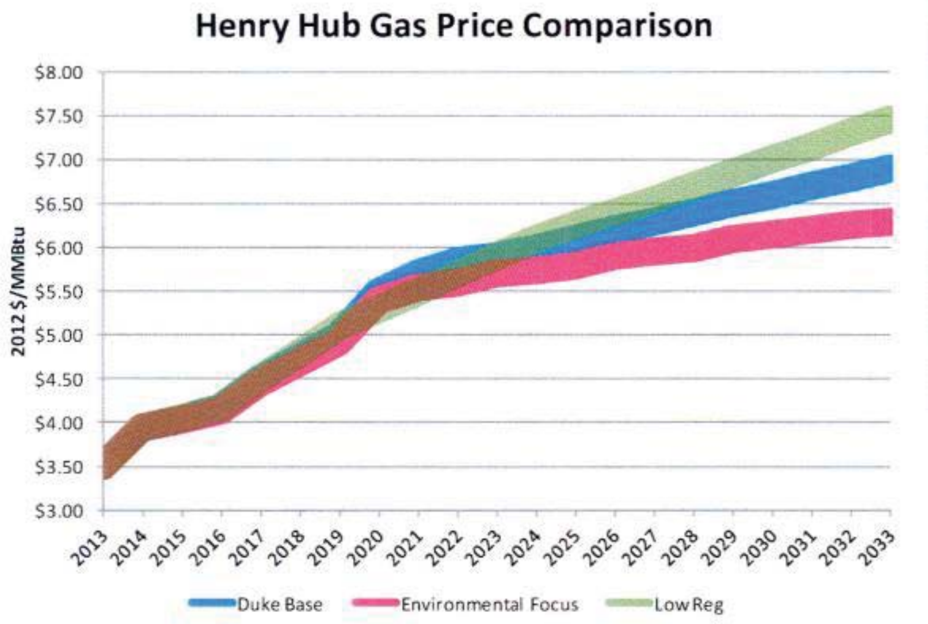


At a minimum, important and uncertain input assumptions should be tested with high and low cases to assess the sensitivity of results to changes in the input values.

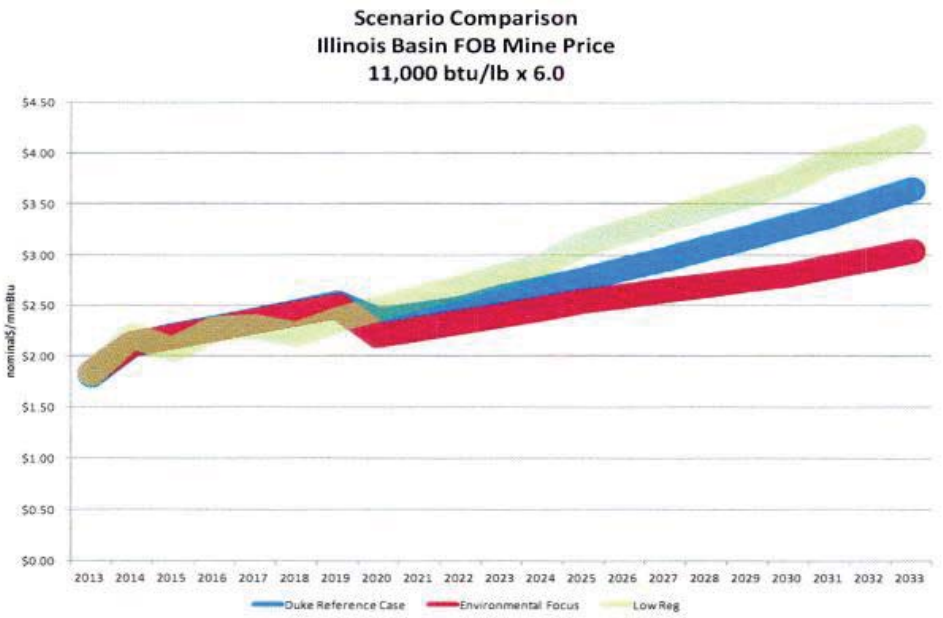
In many cases more sophisticated techniques, combining uncertainties and/or involving probabilistic techniques are warranted.

Dealing with Uncertainty

Duke 2013 IRP: the no-stress tests



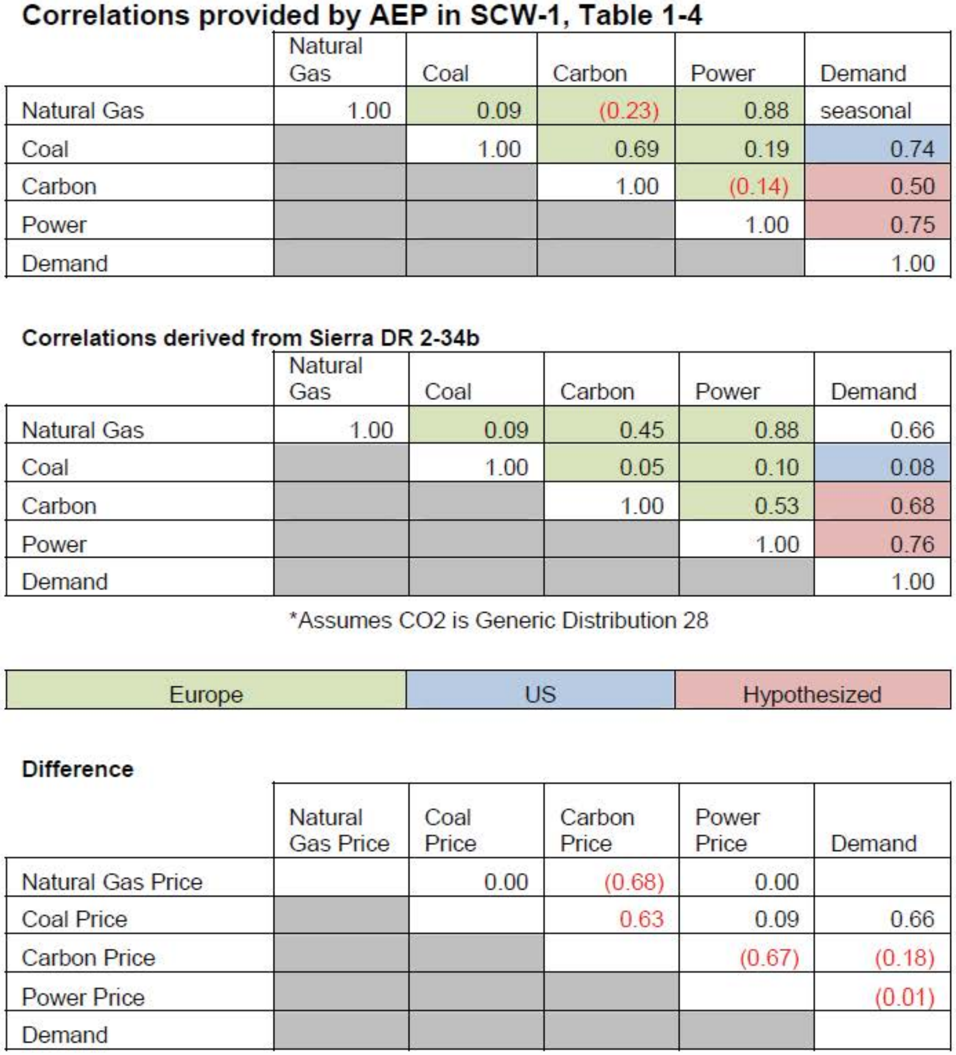
Base, environmental focus, and “LowReg” cases are highly correlated: i.e. no stress test for coal/gas switch.



JF

Dealing with Uncertainty

KPCo Big Sandy: Nonsense Correlations



Correlations provided by AEP in SCW-1, Table 1-4

	Natural Gas	Coal	Carbon	Power	Demand
Natural Gas	1.00	0.09	(0.23)	0.88	seasonal
Coal		1.00	0.69	0.19	0.74
Carbon			1.00	(0.14)	0.50
Power				1.00	0.75
Demand					1.00

Correlations derived from Sierra DR 2-34b

	Natural Gas	Coal	Carbon	Power	Demand
Natural Gas	1.00	0.09	0.45	0.88	0.66
Coal		1.00	0.05	0.10	0.08
Carbon			1.00	0.53	0.68
Power				1.00	0.76
Demand					1.00

*Assumes CO2 is Generic Distribution 28

Europe	US	Hypothesized

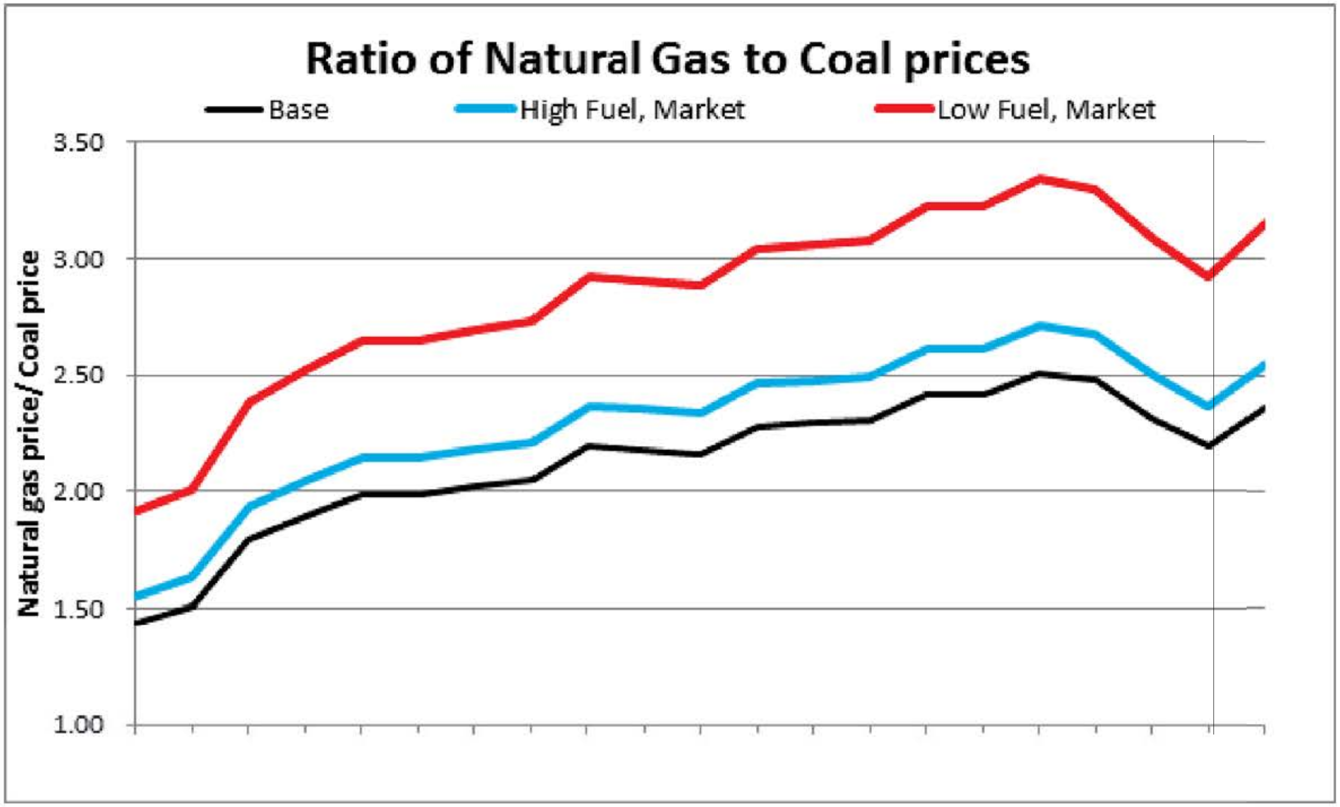
Difference

	Natural Gas Price	Coal Price	Carbon Price	Power Price	Demand
Natural Gas Price		0.00	(0.68)	0.00	
Coal Price			0.63	0.09	0.66
Carbon Price				(0.67)	(0.18)
Power Price					(0.01)
Demand					

JF

Dealing with Uncertainty

Price scenarios: High, higher, and highest



FA

Evaluation of Outcomes
Metrics, Valuation, and Risk

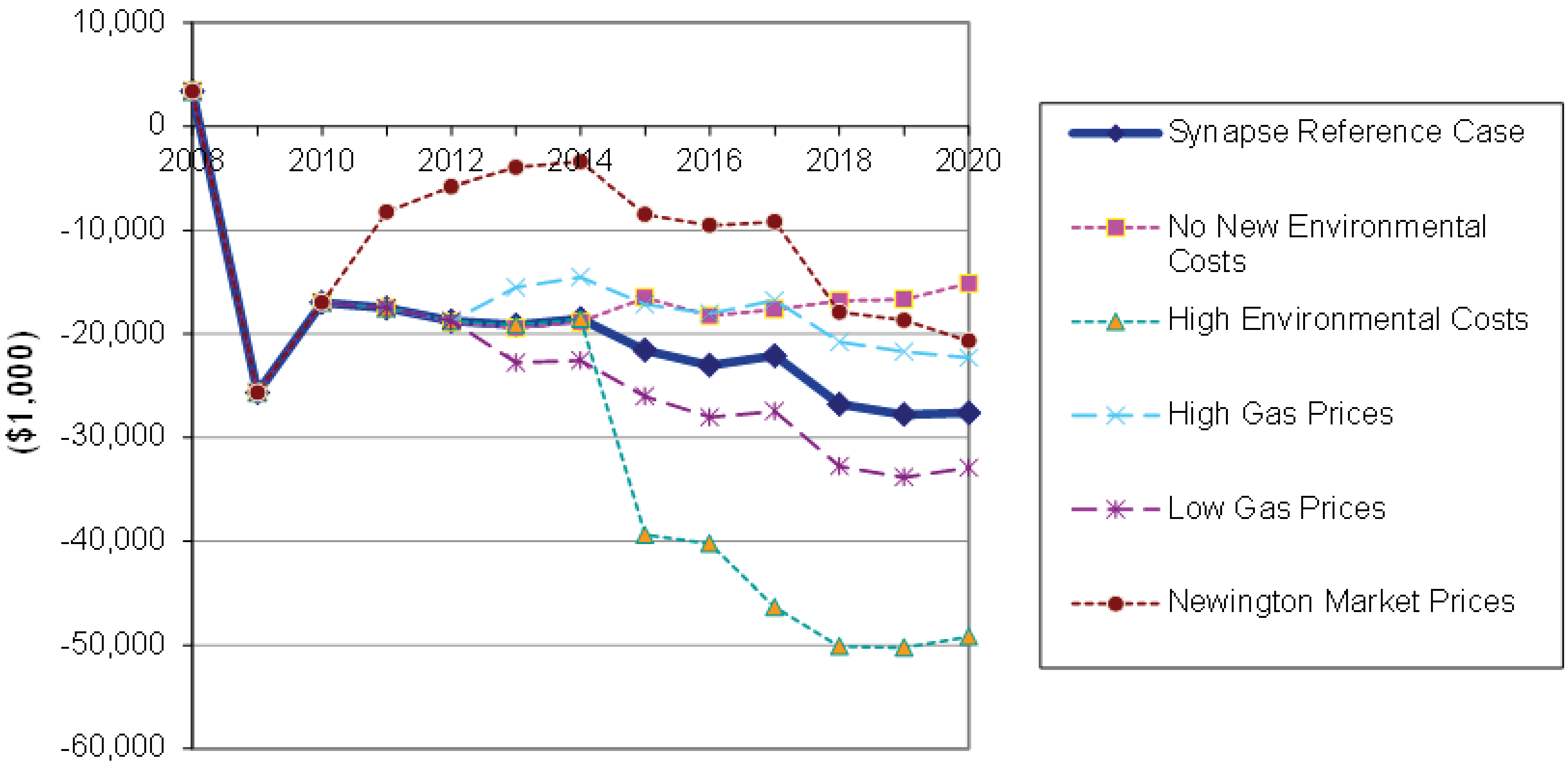
Generally the "present value of revenue requirements" is the primary metric to be minimized in an IRP process. Other important metrics can include minimizing risks, environmental costs, rate or bill increases, and so on.

BB

Evaluation of Outcomes

No Reasonable Outcome.

Schiller 4 and 6 Net Revenue

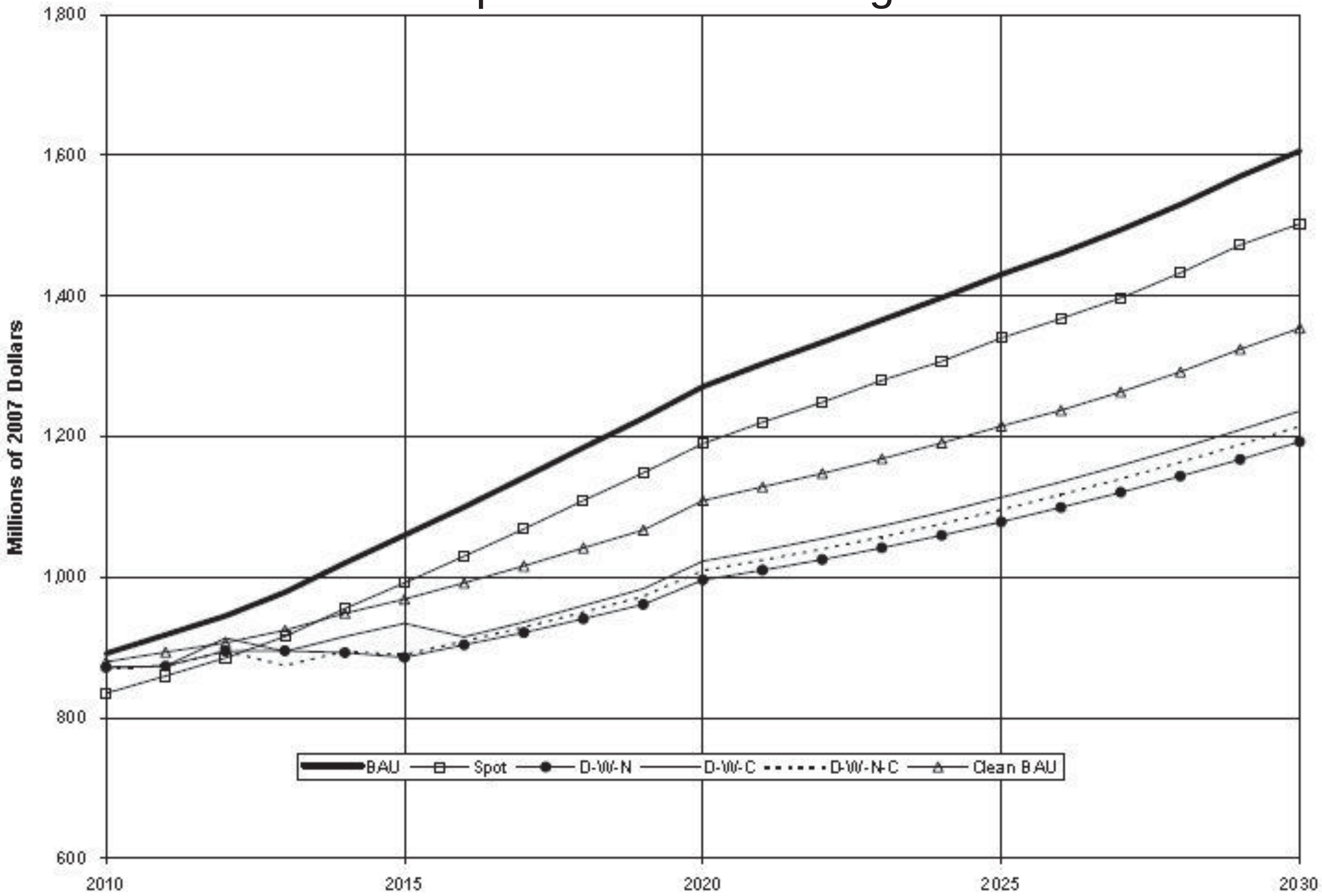


Source: White, et al. 2011

BB/DH

Evaluation of Outcomes
Case Example

Risk analysis for residential standard offer procurement strategies



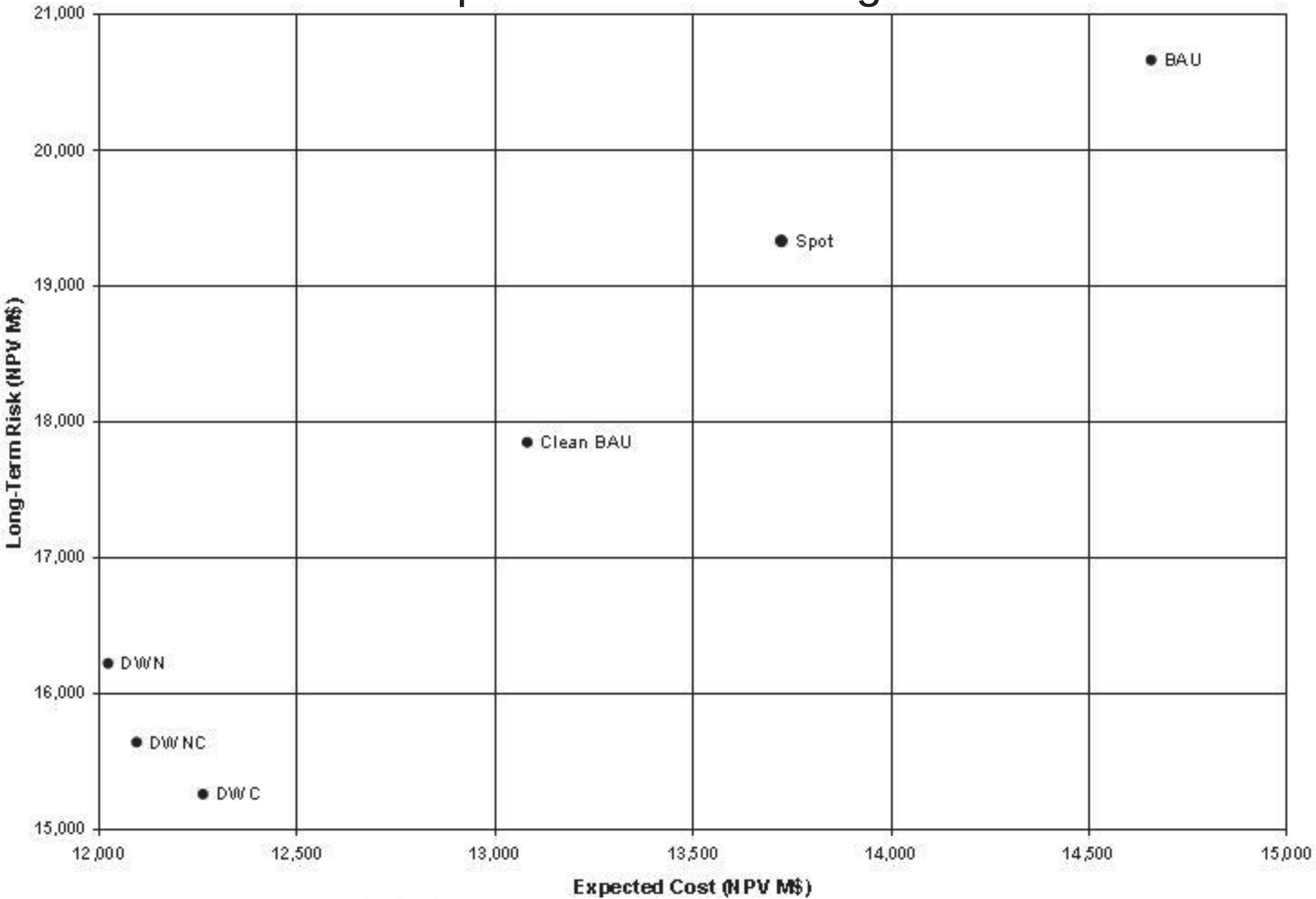
Expected Annual Portfolio Costs

Source: Chernick, et al. 2008

BB

Evaluation of Outcomes
Case Example

Risk analysis for residential standard offer procurement strategies



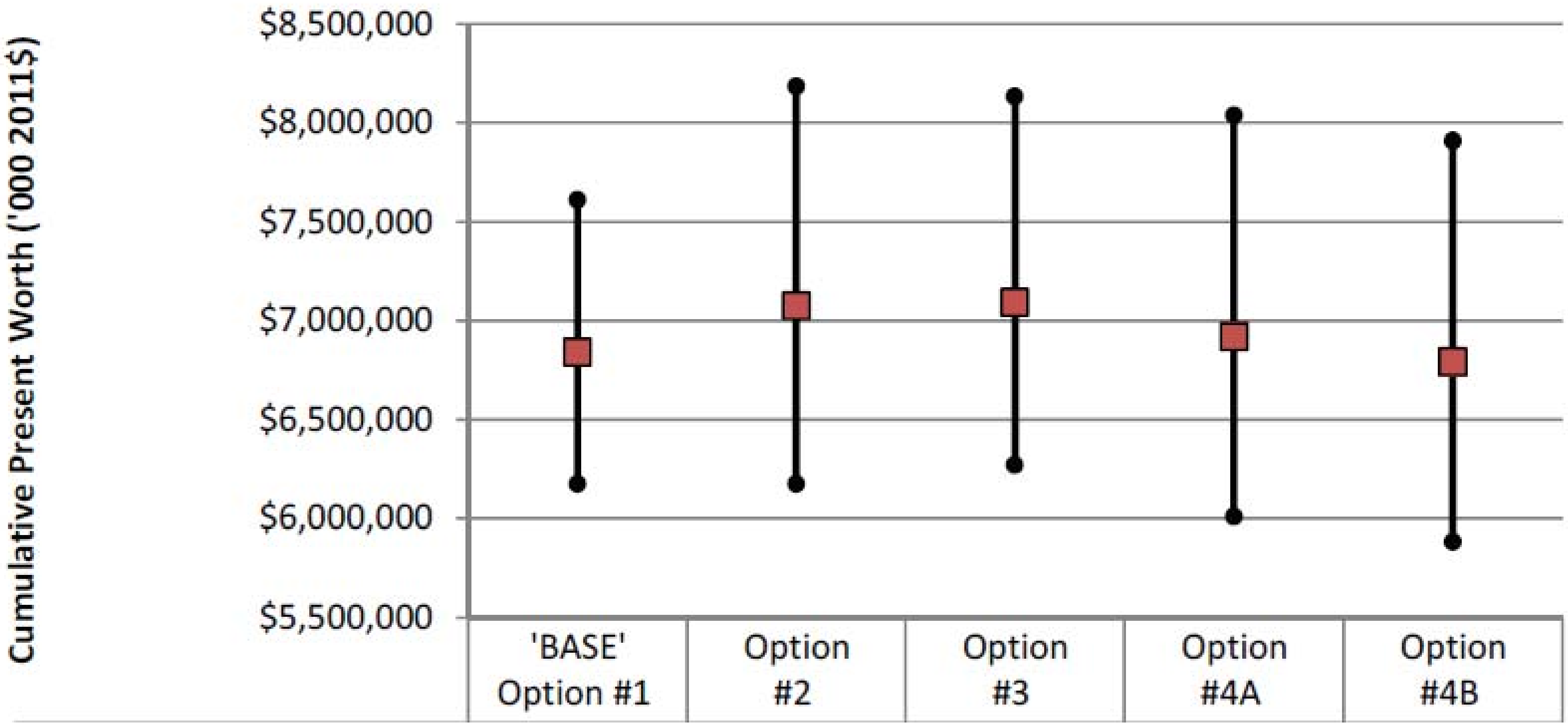
Long-Term Cost vs. Risk by Portfolio

Source: Chernick, et al. 2008

BB

Evaluation of Outcomes
Midwest Utility

Outcome of risk-based model for coal retrofit (Option #1) vs. alternatives. Wide error bars suggests uncertain outcome.



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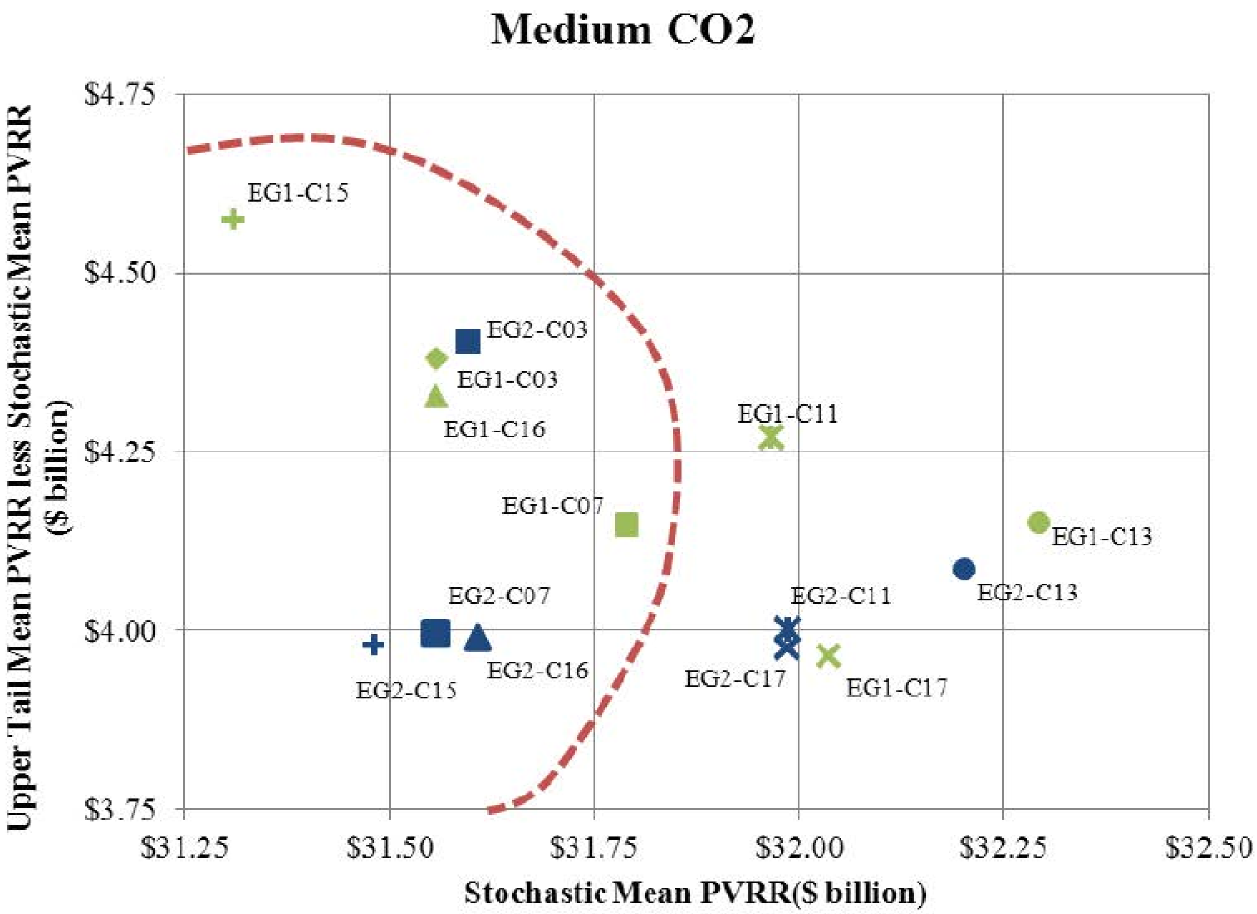
Evaluation of Outcomes
PacifiCorp 2013 IRP



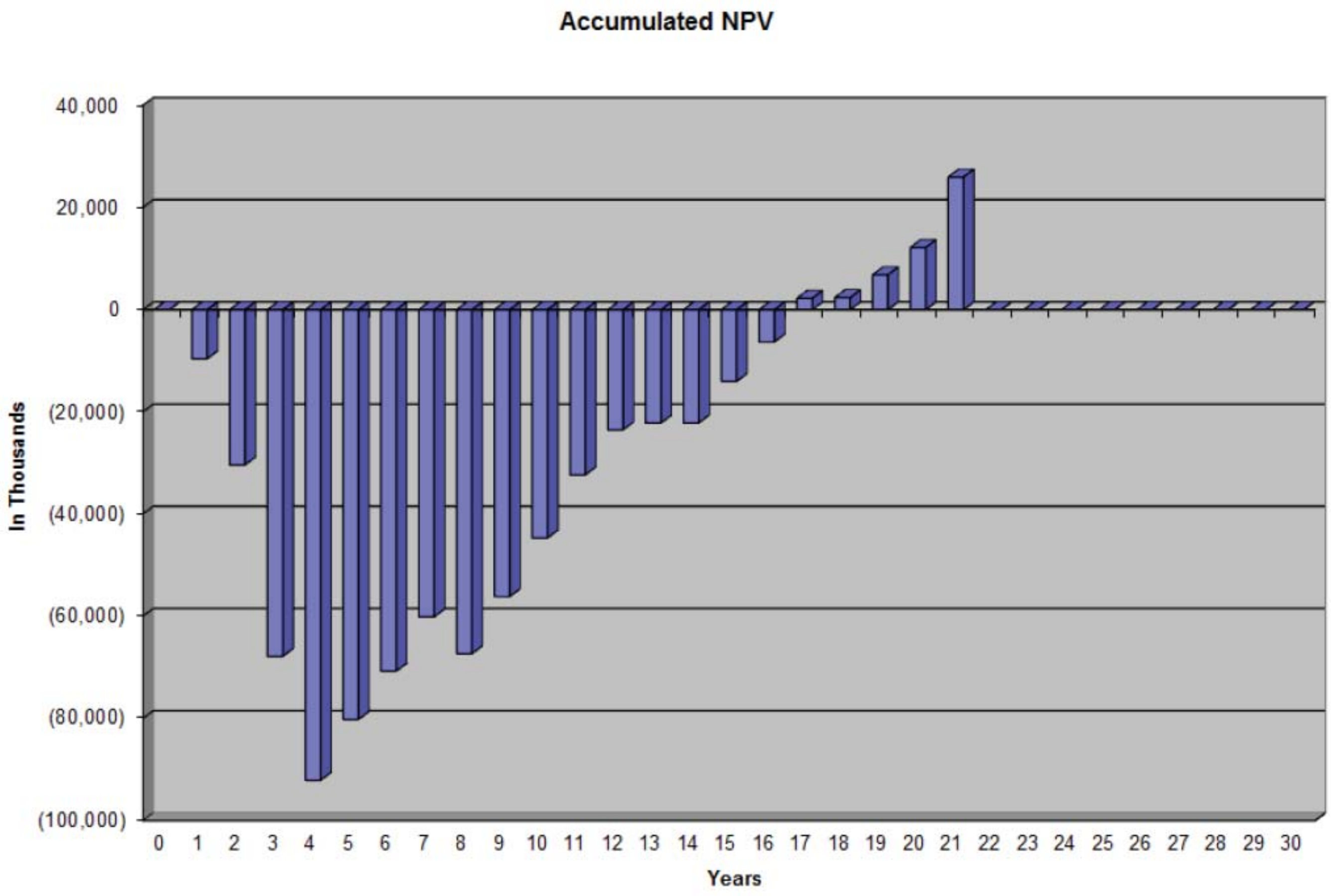
PacifiCorp 2013 IRP, Fig 7.28

JF

Evaluation of Outcomes

Coal Plant Cumulative Present Value

Accumulated net present value for coal retrofit. Only positive in last five years of expected life.



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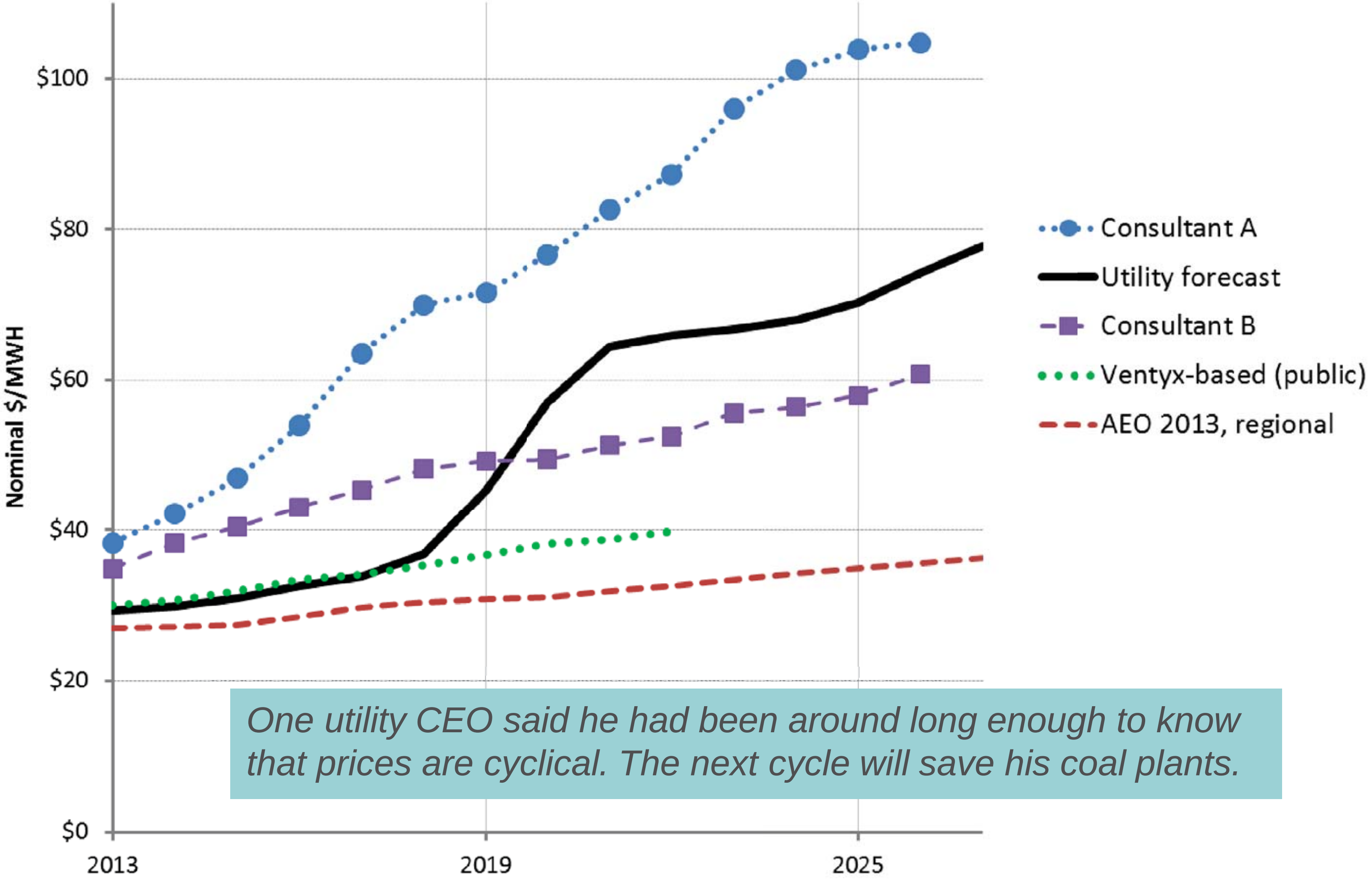
Evaluation of Outcomes

"What goes down must go up"

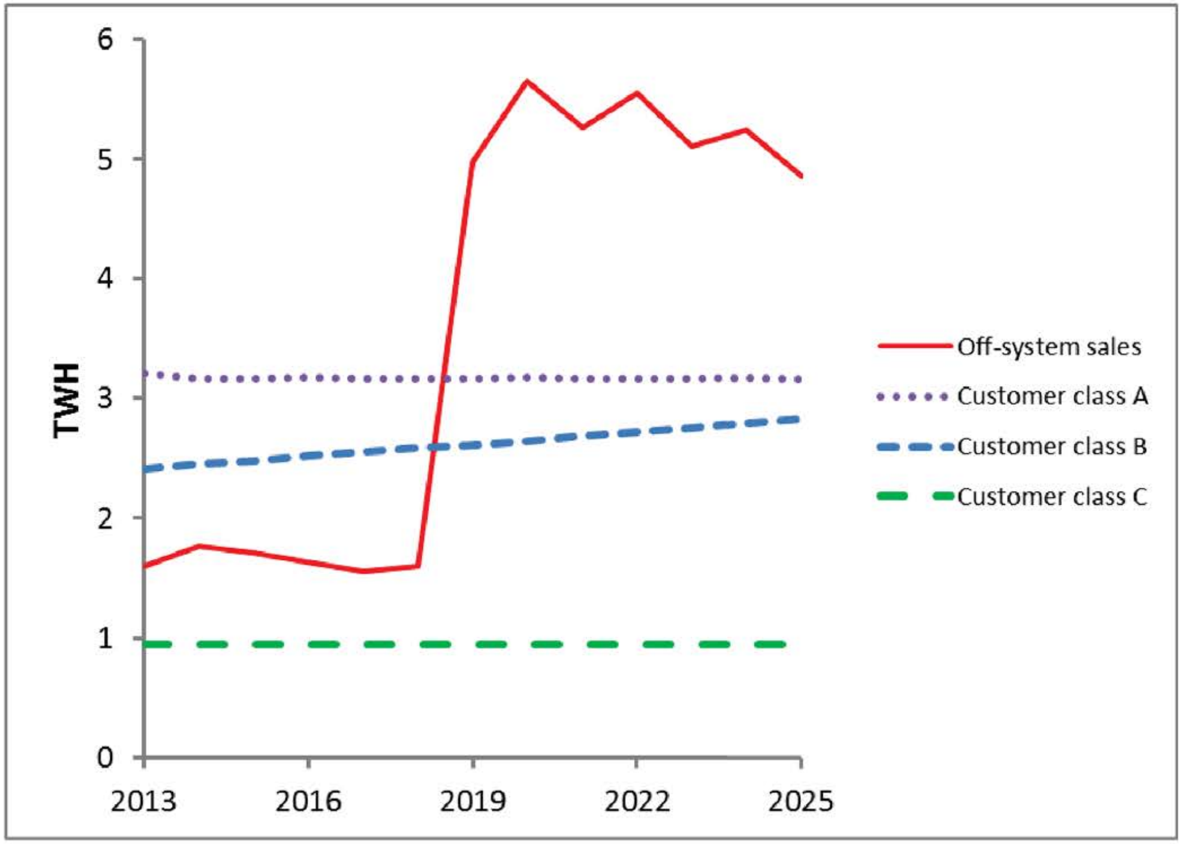


One utility CEO said he had been around long enough to know that prices are cyclical. The next cycle will save his coal plants.

FA

Evaluations of Outcomes

If you build it, they might come



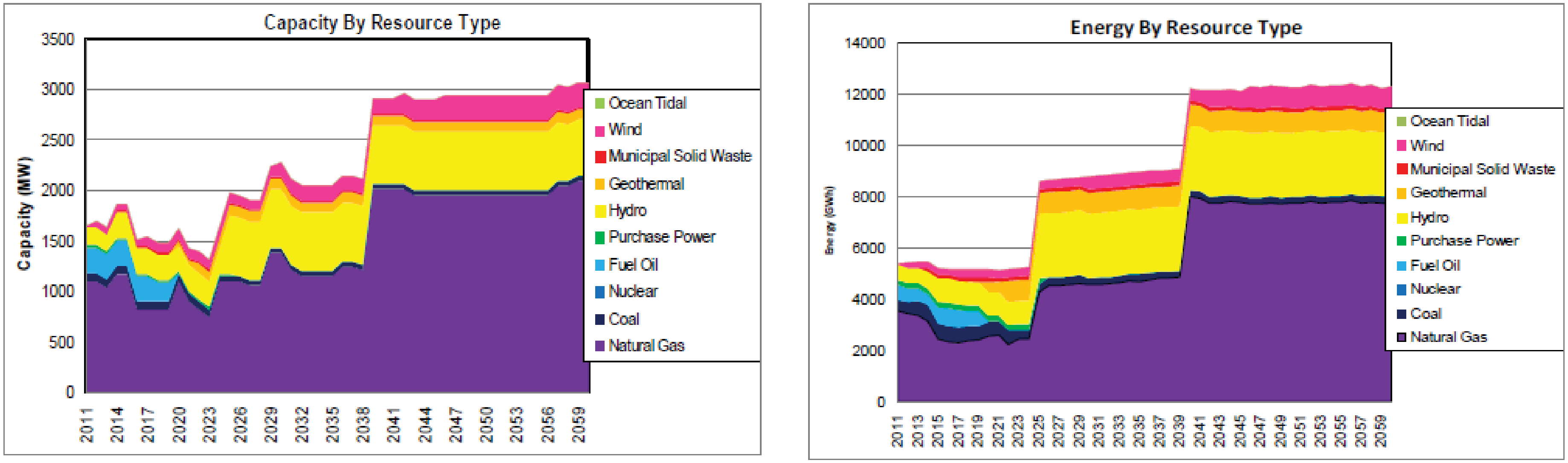
Sales forecasts, from the same utility. Just wait until 2019, and their plants will all be profitable.

FA

Evaluation of Outcomes
Passing a laugh test

Alaska Regional IRP
If you build it, they might come (II)

Results – Scenario 2A Reference Case



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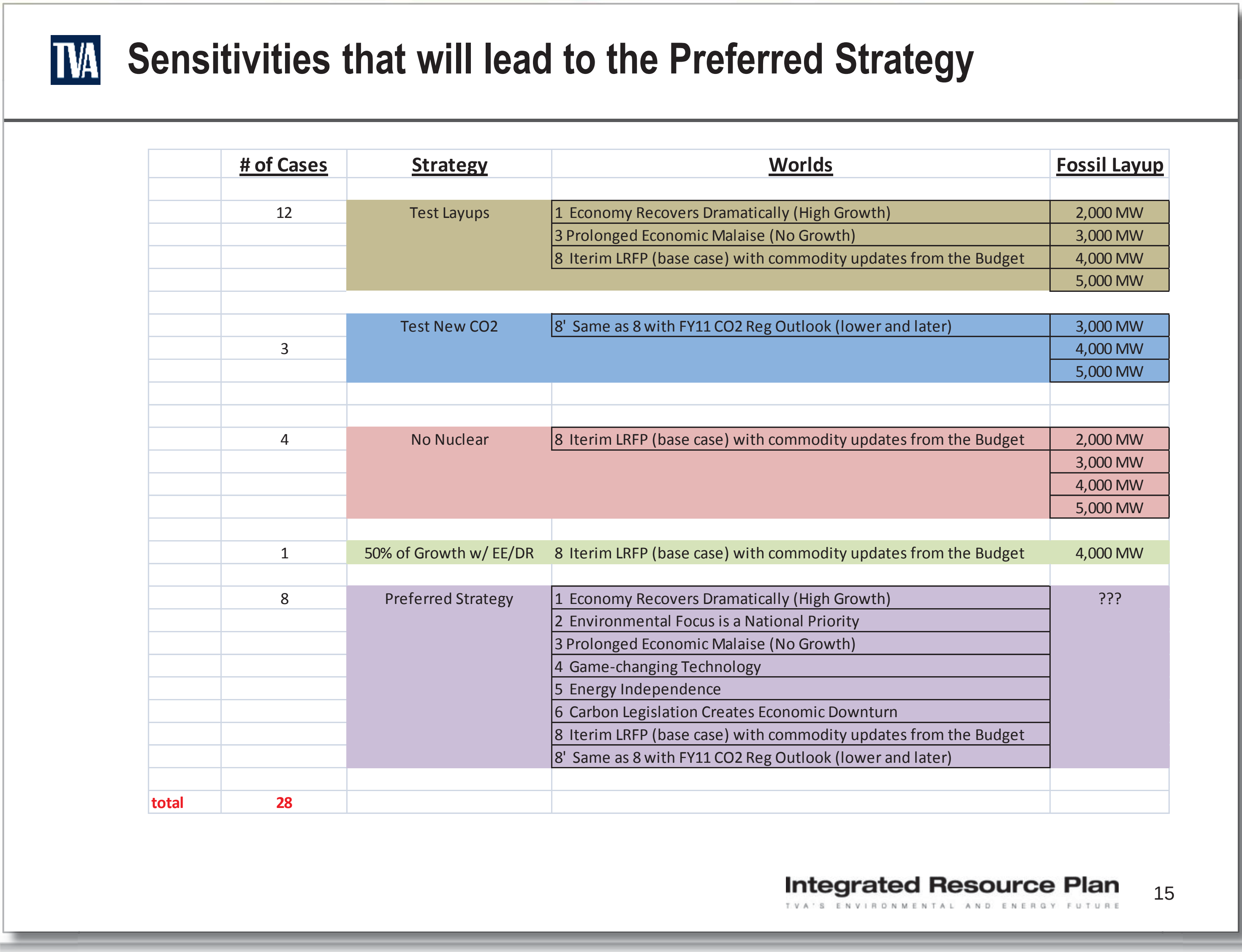
Evaluation of Outcomes

Select a preferred strategy and justify later



Sensitivities that will lead to the Preferred Strategy

	# of Cases	Strategy	Worlds	Fossil Layup
	12	Test Layups	1 Economy Recovers Dramatically (High Growth)	2,000 MW
			3 Prolonged Economic Malaise (No Growth)	3,000 MW
			8 Iterim LRFP (base case) with commodity updates from the Budget	4,000 MW
				5,000 MW
		Test New CO2	8' Same as 8 with FY11 CO2 Reg Outlook (lower and later)	3,000 MW
	3			4,000 MW
				5,000 MW
	4	No Nuclear	8 Iterim LRFP (base case) with commodity updates from the Budget	2,000 MW
				3,000 MW
				4,000 MW
				5,000 MW
	1	50% of Growth w/ EE/DR	8 Iterim LRFP (base case) with commodity updates from the Budget	4,000 MW
	8	Preferred Strategy	1 Economy Recovers Dramatically (High Growth)	???
			2 Environmental Focus is a National Priority	
			3 Prolonged Economic Malaise (No Growth)	
			4 Game-changing Technology	
			5 Energy Independence	
			6 Carbon Legislation Creates Economic Downturn	
			8 Iterim LRFP (base case) with commodity updates from the Budget	
			8' Same as 8 with FY11 CO2 Reg Outlook (lower and later)	
total	28			

JF

BREAK