Deep Decarbonization in Nova Scotia: Phase 1 Report

Nova Scotia Power Inc.

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Energy+Environmental Economics

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Corrections

- **Figure 22**: Updated x-axis labeling due to unit conversion issue in preparing graphic.
- **Tables 9 and 10:** Updated total final energy demand, electric load, and biofuels demand values due to univ conversion error in preparing tables. These errors were introduced during conversion from modeling software to report presentation and do not affect the underlying modeling of Nova Scotia system.

Table of Contents

Acronyms

AEO	Annual Energy Outlook
DR	Demand Response
EE	Energy Efficiency
GHG	Greenhouse Gas
MMT	Million Metric Tons
NEMS	National Energy Modeling System
NREL	National Renewable Energy Laboratory
NRCAN	Natural Resources Canada (Department of Natural Resources)
NSPI	Nova Scotia Power Inc.
SDGA	Sustainable Development Goals Act
UARB	Nova Scotia Utility and Review Board

Executive Summary

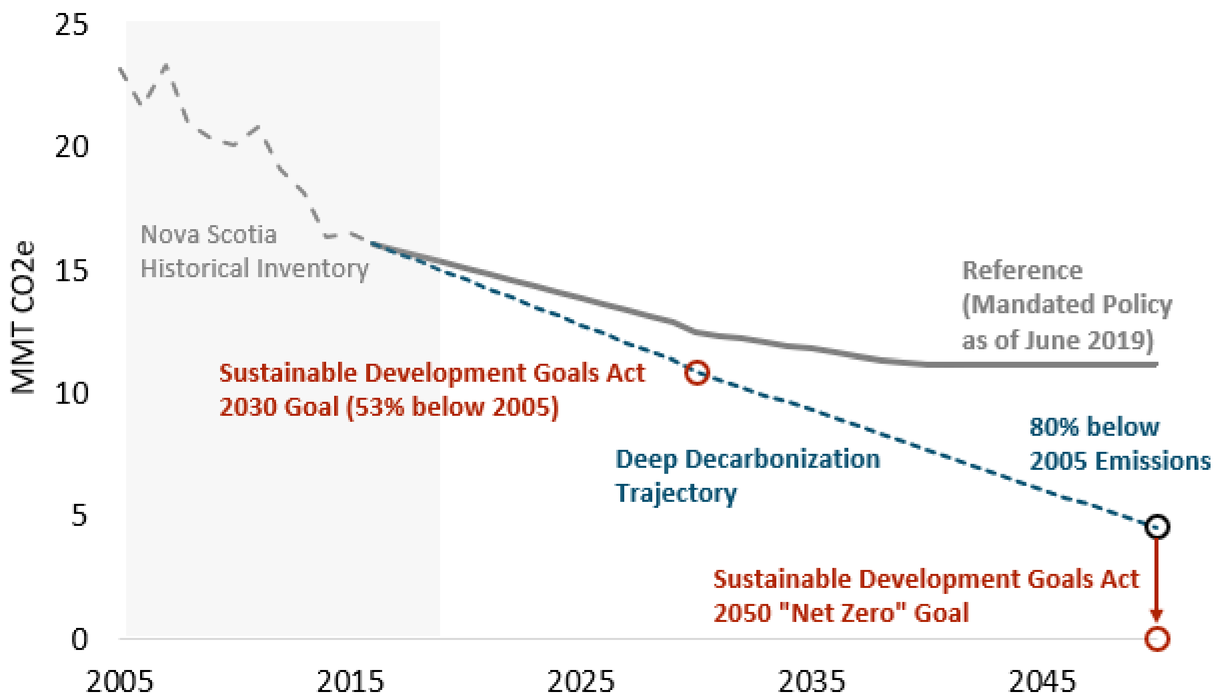
Study Background

The Province of Nova Scotia has been a leader in recognizing the threat of climate change and enacting policy to tackle the problem. On October 30, 2019, Nova Scotia's legislature passed the Sustainable Development Goals Act (SDGA), establishing provincial greenhouse gas (GHG) emission reduction goals of at least 10% below 1990 levels by 2020; at least 53% below 2005 levels by 2030; and "net zero" by 2050, which requires balancing all GHG emissions with removals or offsetting measures.

As the province's primary electricity provider, Nova Scotia Power Inc. (NSPI) recognizes that it must play a critical role in enabling the transition to a low-carbon economy, including decarbonizing its generation fleet, supporting energy efficiency and conservation, and enabling electrification. To better understand the scope and scale of emission reduction measures required to meet these climate goals, NSPI commissioned Energy and Environmental Economics, Inc. (E3) to perform an independent analysis of strategies to achieve long-term, province-wide GHG reductions, with a focus on electricity, buildings, and transportation sectors.

This study, commissioned prior to passage of the SDGA, identifies potentially viable pathways for reducing GHG emissions 80% below 2005 levels by 2050, a level of reduction often called "deep decarbonization". The detailed pathways provide NSP with an indication of the level of electricity sector emissions reductions that may be required as part of economy-wide decarbonization, and also demonstrate the potential impacts of electrification on load. Attainment of the 80% reduction goal would reduce economy-wide emissions to 4.6 million metric tons (MMT) in Nova Scotia in 2050 (Figure 1). Meeting the SDGA's "net zero" target would require additional abatement beyond what is considered in this study.

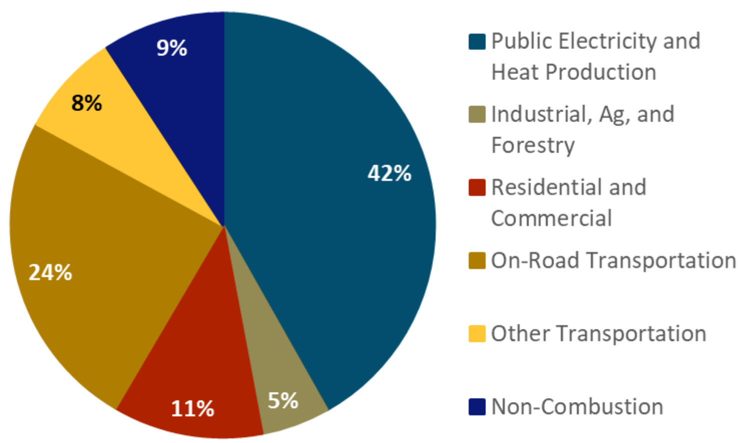
Figure 1. Nova Scotia Historical Greenhouse Gas Emissions and Greenhouse Gas Emission Targets



Nova Scotia's GHG emissions declined rapidly between 2005 and 2016. Many factors contributed to the decrease in GHG, including the electricity sector's transition to renewable and cleaner sources of energy, as well as investments in energy efficiency. Despite this trend, E3's modeling demonstrates that additional abatement measures will be required to meet the 80% by 2050 goal. As discussed in Section 2.4, the Reference scenario shows projected emissions levels under existing policy (prior to SDGA), such as Nova Scotia's hard caps on electricity sector GHGs. The "Mitigation" scenarios demonstrate the incremental effort required to achieve the 80% target.

Figure 2 presents Nova Scotia emissions by sector in 2016. Electricity generation, heat for buildings, and transportation represent most of the emissions in the economy. The emissions profile in Figure 2 represents the starting point for E3's pathways analysis. From here, E3 investigated pathways to achieving deep decarbonization of the Nova Scotia economy focusing on the sectors that are the largest emitters and the most relevant to an electric utility: electricity generation, transportation, and buildings. Emissions from other sectors (industrial, agriculture, forestry, and non-combustion) are included in the study but are not the primary focus of the policy analysis discussed in this report.

Figure 2. Nova Scotia Emissions by Sector in 2016



Source: E3 calculations based on greenhouse gas emissions inventory data and categories for Nova Scotia from Environmental and Climate Change Canada[1]

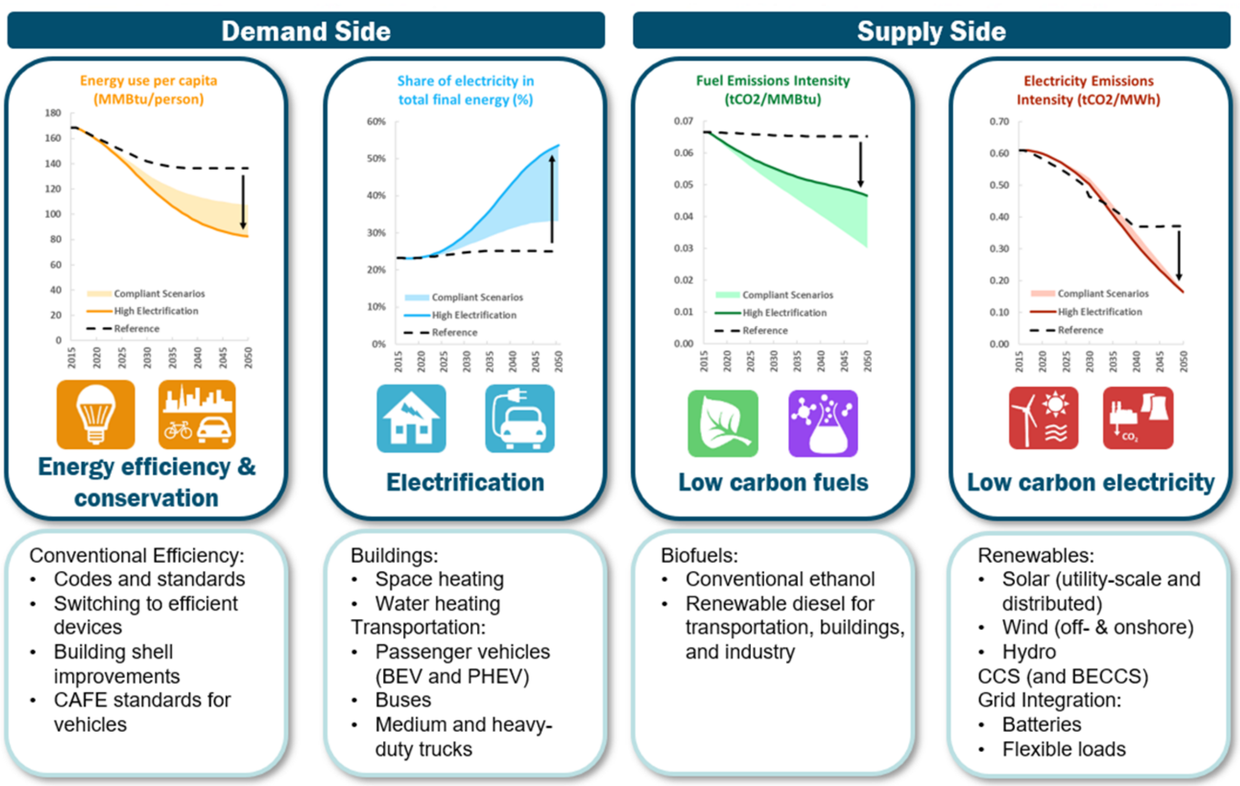
Approach

E3's modeling approach for this project relied on E3's deep decarbonization scenario tool, PATHWAYS. PATHWAYS is an economic, energy, and GHG emissions accounting tool; E3 has used PATHWAYS in

[1] Greenhouse Gas Inventory from Environmental and Climate Change Canada: https://open.canada.ca/data/en/dataset/779c7bcf-4982-47eb-af1b-a33618a05e5b

jurisdictions across North America, including Minnesota, California, Maryland, and Oregon to help utilities and government agencies develop economy-wide low carbon scenarios. E3 developed a PATHWAYS model customized to Nova Scotia, as described in detail in Section 2. Figure 3 shows the four "pillars" of decarbonization for Nova Scotia and other jurisdictions in North America: (1) energy efficiency and conservation; (2) electrification; (3) low-carbon fuels; and (4) low-carbon electricity. For each pillar, a range of values is depicted based on the main scenarios evaluated in the study.

Figure 3. Four "Pillars" for Decarbonizing the Nova Scotia Energy System



Because there is substantial uncertainty about the availability and relative cost of many of the technologies needed to achieve deep decarbonization, E3 utilizes a scenario-based approach to quantitative modeling. This report presents the results of several custom scenarios: a "Reference" (business-as-usual) scenario and three core "mitigation" scenarios (Building Electrification Only, Moderate Electrification, and High Electrification) which vary across a number of dimensions including reliance on electrification and utilization of advanced, carbon-neutral fuels for heating and transportation. Two additional "book end" sensitivity scenarios (High Biofuels, Very High Electrification) are discussed in the appendix. Details on scenario definition are presented in Section 2.4 and Appendix Section 5.2.

Key Findings and Implications for Nova Scotia Power

E3's PATHWAYS modeling generated several key findings related to deep decarbonization in Nova Scotia.

1. **Synergistic action is required across sectors.** Figure 5 below lays out a set of strategies and milestones that will enable the province to reach 80% reductions in greenhouse gases by 2050. This timeline demonstrates the need for broad and integrated effort across the power, transportation, and building sectors. Complementary efforts would also be required in industrial and non-combustion energy sectors, though these efforts were not modeled in detail in this study. The initial stages of transformation have begun but would need to be accelerated to achieve the 2050 target.

2. **Low-carbon electricity is essential to achieving decarbonization by enabling emissions reductions in the electricity sector, as well as by enabling complementary reductions in buildings and transportation from electrification.** Over the last decade, the electricity sector in Nova Scotia has reduced emissions by more than 30% relative to 2005 levels, thanks to a transition to cleaner and renewable energy sources. Maintaining this momentum would require continuing to integrate low-carbon resources like wind and hydro into its portfolio, while ensuring reliability and affordability. This transition would enable NSPI to meet energy demand from existing electric load

as well as new load growth from space and water heating and transportation, without emitting more carbon.

Figure 4. Nova Scotia Historical Emissions and Projected 2030 and 2050 Emissions by Mitigation Scenario

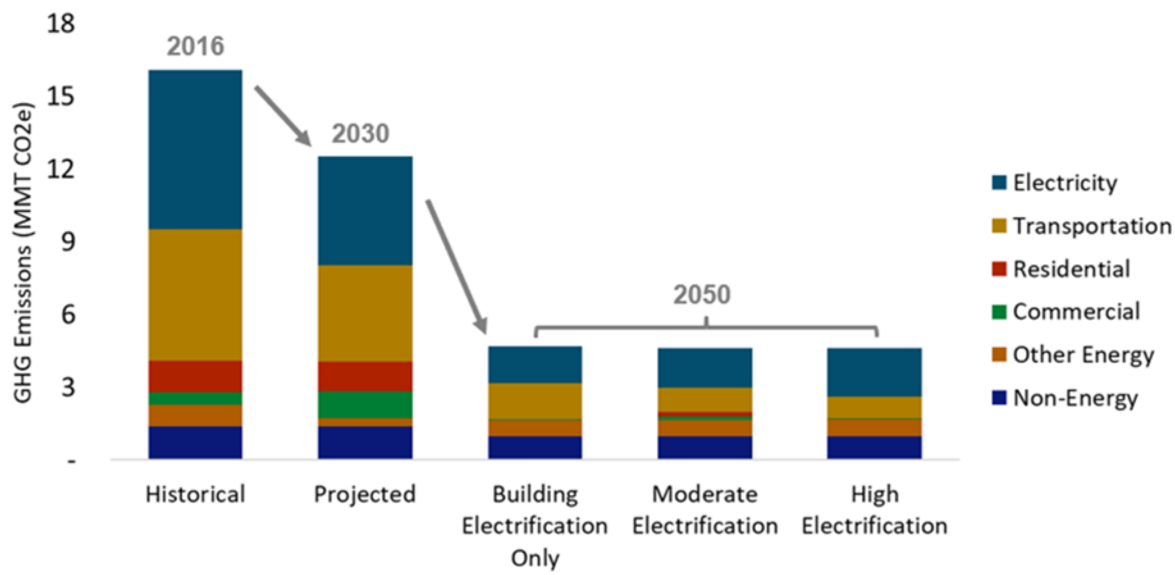
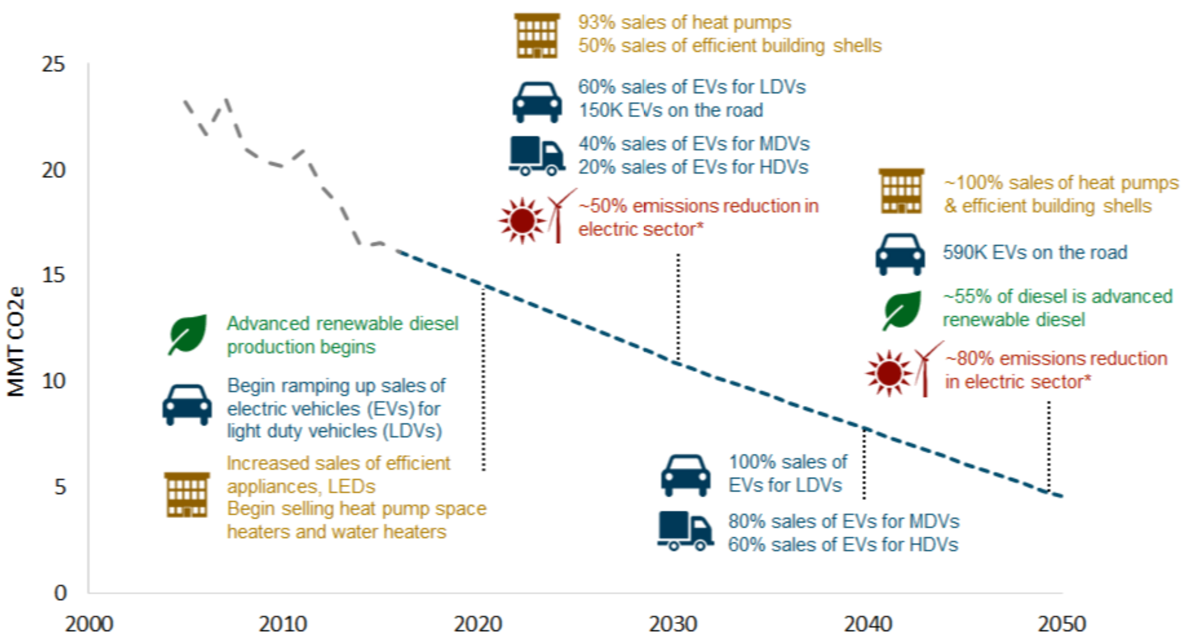


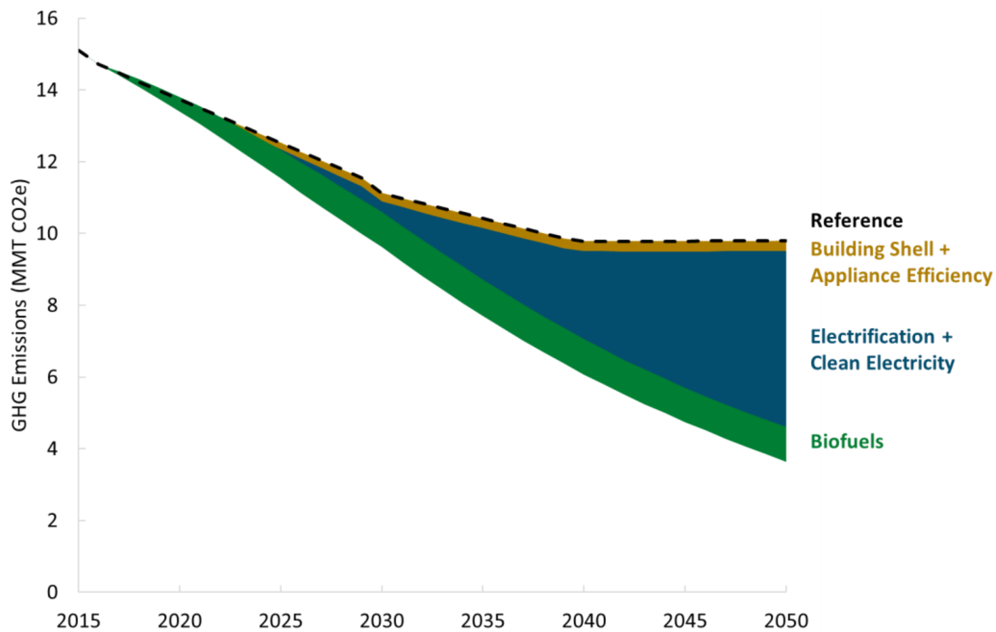
Figure 5. Nova Scotia GHG Emissions Reductions Milestones in High Electrification Scenario



**Electric sector emissions reductions relative to 2005 (10.7 MMT)*

3. **Low-carbon electricity alone is not enough to achieve 80% economy-wide reductions.** All mitigation scenarios, including E3's high electrification scenarios, require additional measures and actions beyond low-carbon electricity in order to achieve the 80% reduction target. Figure 6 below presents emissions reductions by measure for the high electrification scenario. Electrification is used to leverage low-carbon electricity to dramatically reduce emissions from transportation and buildings. Advanced biofuels were used as the main low-carbon fuel in this analysis to supplement the emissions savings needed to achieve the 2050 GHG goal, although other options like hydrogen produced with clean electricity could serve this need as well. However, these strategies will only be viable if the technologies can reach economies of scale in a global market. Nova Scotia should therefore monitor the development of these emerging energy sectors and perform more detailed assessments of their potential deployment in Nova Scotia.

Figure 6. Emissions Reduction by Strategy for the High Electrification Scenario



4. **Long lifetimes require early action.** Investments in infrastructure and equipment can last decades or more, thus having long-lasting effects on emissions. Because there are a limited number of investment opportunities to ensure low-carbon alternatives are selected over alternatives that lead to higher emissions, meeting 2050 goals may require measures to encourage early adoption of electric and/or low-emissions infrastructure and equipment where possible. Delayed action in early years may require more costly early retirements or buy-back programs closer to goal years in order to make up the difference and meet targets. In particular, E3's mitigation scenarios assume near-complete electrification of passenger vehicles by 2050, an aggressive target given there are only around 300 EVs registered in Nova Scotia today. While the costs of electric vehicles are declining quickly, complementary investments in public charging infrastructure may help enable widespread adoption. NSPI could start by defining adoption targets, determining the

infrastructure and initiatives needed to achieve those targets, and developing a strategy to support those markets.

5. **Building electrification is dependent on reducing costs and enhancing incentives, which may be facilitated by the utility and the province.** To achieve the levels of electrification modeled in the decarbonization scenarios, rapid increases in consumer adoption of more efficient and electrified equipment is required. Adoption is unlikely to meet these targets without lower capital costs and attractive rate structures. This study includes scenarios which rely on rapid and widespread adoption of cold climate heat pumps, which are a relatively new technology with significant emissions reduction potential. This technology is commercially available but not yet broadly adopted. The currently high up-front costs of this technology could be addressed with government or NSPI support. From a planning perspective, NSPI must also more thoroughly evaluate the peak electricity demand impacts associated with widespread electric space heating, which were not investigated in detail in this study. The Appendix also contains a scenario in which E3 modeled low-carbon biofuels as an alternative building decarbonization strategy.

6. **Getting to "net zero" will be an even greater challenge, requiring more direct reductions, and/or carbon removal technologies or carbon offsets.** Although this target was not modeled directly in this study, achieving "net zero" would likely require investments in negative emissions technologies such as direct air capture or carbon capture and sequestration. These technologies will be valuable in removing emissions from the hardest-to-decarbonize sectors such as industry. While not typically cost effective today, these technologies may become more feasible strategies with cost declines and performance improvements.

1 Background

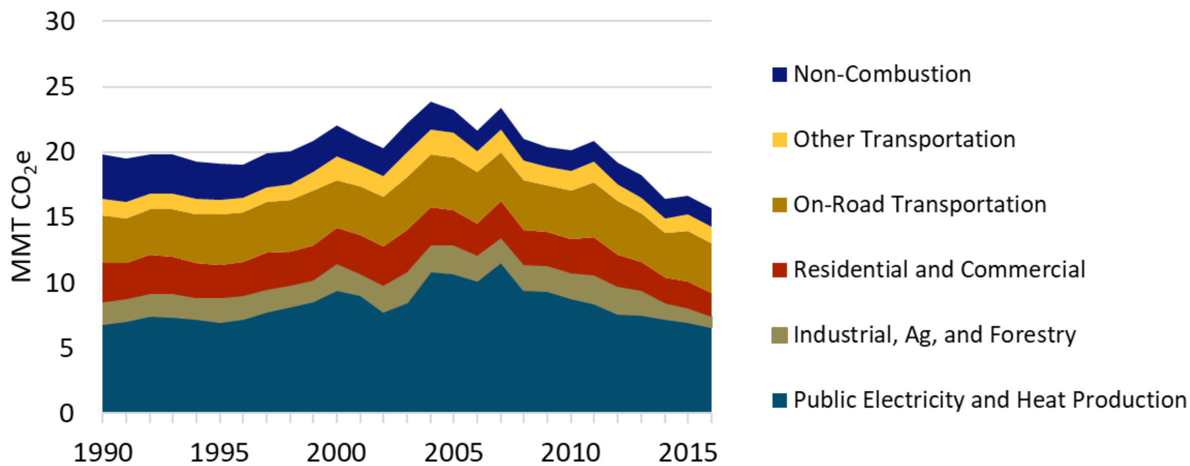
1.1 Nova Scotia Policy Landscape

Climate change threatens human health and livelihoods around the globe, including risks to Nova Scotians, particularly given the province's 7,600 km of coastline and position at the northern end of the Atlantic. In October 2019, the Nova Scotia legislature passed some of the most ambitious climate targets in North America, setting goals of reducing greenhouse gas (GHG) emissions by 53% below 2005 levels by 2030 and attaining "net zero" emissions by 2050. This legislation, the Sustainable Development Goals Act, supersedes the Environmental Goals and Sustainable Prosperity Act of 2007 (updated in 2012), which included a goal of 10 percent reductions relative to 1990 by 2020 and a goal of 40% electricity generation from renewables by 2020. This study, commissioned prior to the passage of the SDGA, evaluates pathways for Nova Scotia to achieve an 80% reduction in GHGs by 2050. This level of climate mitigation is often referred to as "deep decarbonization".

1.2 Nova Scotia Existing Greenhouse Gas Emissions

As of 2016, GHG emissions from electricity and heat production made up over 40% of Nova Scotia's GHG emissions. This portion of total emissions continues to decline given the province's transition to cleaner and renewable fuels; including the addition of Muskrat Falls energy in 2020, the share of NS Power's non-emitting sources will reach approximately 60% of the Company's electricity supply portfolio. The next largest source of emissions is on-road transportation, which makes up almost a quarter of emissions in Nova Scotia as of 2016.

Figure 7. Total GHG Emissions in Nova Scotia by Sector, 1990-2016



Source: E3 calculations based on greenhouse gas emissions inventory data and categories for Nova Scotia from Environmental and Climate Change Canada

2 Study Approach

2.1 Study Questions

This analysis investigates pathways to achieving deep decarbonization of the Nova Scotia economy, with a specific focus on electricity decarbonization and the impacts of economy-wide decarbonization on the electricity sector.

The key research questions include:

+ What are viable pathways to achieve deep decarbonization in Nova Scotia?
+ What level of electricity sector carbon reductions might be required as part of an economy-wide deep decarbonization strategy for Nova Scotia?
+ What role might be played by electrification of vehicles and appliances, and how might that impact electric load served by Nova Scotia Power?

2.2 PATHWAYS Model Framework

This study used E3's PATHWAYS model to develop emissions projections for a reference scenario and five mitigation scenarios. The PATHWAYS model is an economy-wide representation of infrastructure, energy use, and emissions within a specific jurisdiction. E3 developed the PATHWAYS framework in 2008 to help policymakers, businesses and other stakeholders understand and compare plausible decarbonization scenarios. The model has since been modified and improved over time in projects that analyze deep decarbonization in jurisdictions across North America; recent examples include working with the California Energy Commission and with Xcel Energy in Minnesota.

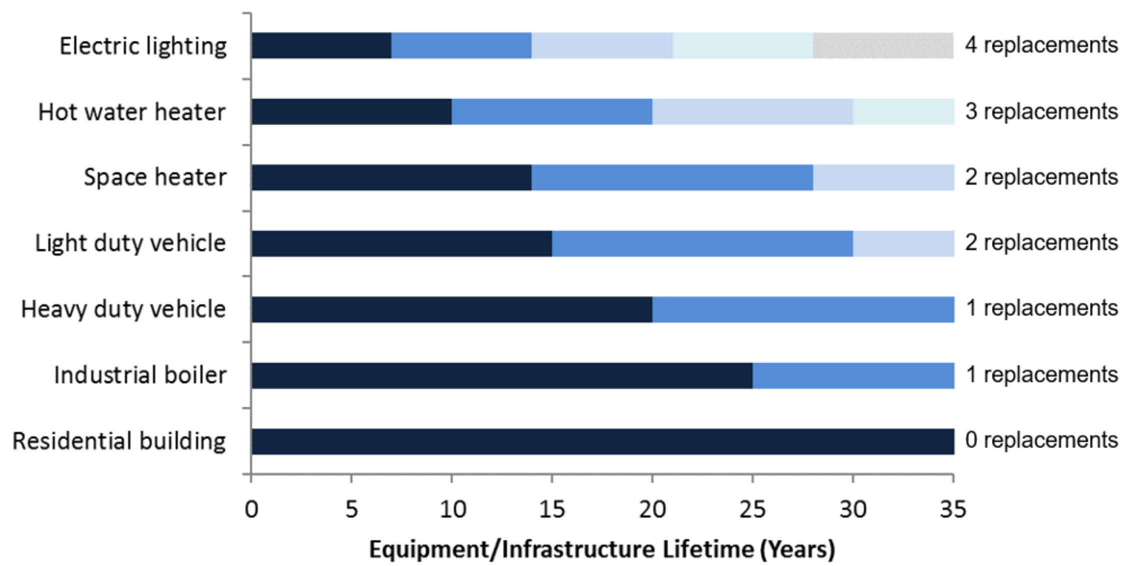
E3's PATHWAYS modeling includes detailed information regarding energy infrastructure including power plants, trucks, cars, buses and building appliances, industrial processes, and more. Each type of infrastructure consumes energy and produces emissions differently, but they collectively determine the region's emissions trajectory. Many of these technologies are long-lived. For instance, a home built today will likely still be in use by mid-century. Because investments made in the near-term shape the energy system of the future, the PATHWAYS model includes a detailed, "bottom-up" stock accounting of the region's energy infrastructure on a technology-specific level (Figure 8). With detailed accounting of residential, commercial, industrial, agricultural and transportation equipment lifetimes, PATHWAYS determines the pace of change necessary to deploy decarbonization strategies while avoiding costly early retirement and captures potential path dependencies of near-term decisions.

A second key feature of the PATHWAYS model is its ability to link sectors. This enables PATHWAYS to identify where aggressive action in one sector can enable emissions reductions elsewhere. For instance, the detailed treatment of the electricity sector is explicitly tied to the carbon savings associated with electric vehicles.

Demands for energy in PATHWAYS are driven by forecasts of population, building square footage, vehicle miles traveled, and other drivers of energy services. The rate and type of technology adoption and energy supply resources are all user-defined scenario inputs. PATHWAYS calculates energy demand, GHG emissions, the portfolio of technology stocks in selected sectors, as well as capital costs and fuel costs for each year between 2015 and 2050. E3 will use the PATHWAYS model to assess the costs of alternative feasible pathways to decarbonization in Phase 2 of this study.

PATHWAYS also features representation of biofuels availability. Based on an assessment of biofuel demands, the model optimizes a biofuels portfolio based on available sustainable feedstocks and selected conversion pathways. The biofuels portfolio meets pre-defined demand for renewable jet kerosene, renewable diesel, and renewable natural gas.

Figure 8. Infrastructure Lifetimes in PATHWAYS



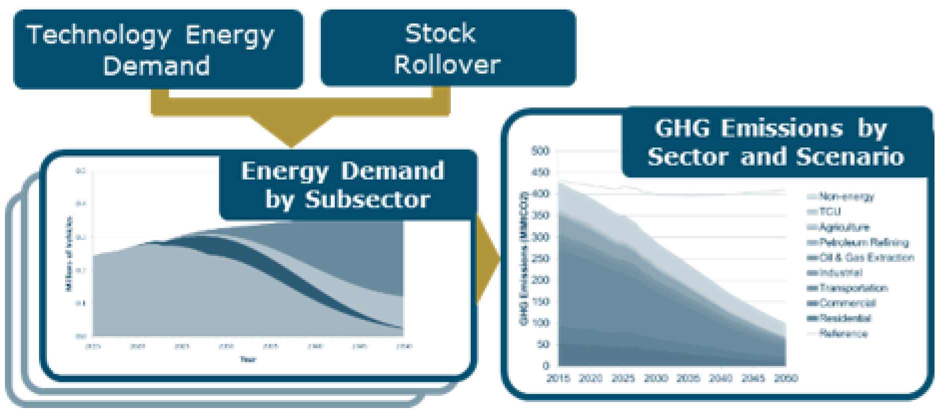
2.3 Nova Scotia PATHWAYS Model

E3 built a bottom-up PATHWAYS model of the Nova Scotia economy using the LEAP tool (Long-range Energy Alternatives Planning System)[2]. This modeling tool implements the framework described above and is customized to the desired region. In particular, the model quantifies the energy and emissions associated with the projected trends in consumption and production in all sectors of an economy, and also accounts for complementary policies targeting future emissions. E3 built a model of Nova Scotia's energy and non-energy emission sources, projecting them through 2050 using multiple scenarios to understand different pathways that can be reached through complementary actions across the province. E3 notes that this study does not perform detailed electricity sector modeling of the Nova Scotia system, given this modeling will

[2] LEAP is developed by the Stockholm Environment Institute. More information on the LEAP software can be found at www.energycommunity.org

occur during the 2020 IRP. Instead, E3 utilized a range of plausible carbon intensities typical of a more deeply decarbonized system, and assumed this range of emissions intensities would be associated with plausible future NPSI loads. As noted in the conclusion, more detailed electricity sector modeling should be performed within the context of the IRP or in future NSPI study

Figure 9. PATHWAYS Energy Modeling Framework Utilized for Nova Scotia Study



2.4 Scenarios

The study considers one reference scenario, which reflects the NS government's greenhouse gas reduction target in 2030 of a 45-50% GHG reduction below 2005 levels, as of the study initiation. At the time, this was more ambitious than the federal target of 30% below 2005 levels by 2030. In the Reference scenario, the 2030 target was held flat across the remaining period to serve as a baseline for comparing against the mitigation scenarios, all of which meet 80% emissions reductions by 2050. The study considers one reference and three primary mitigation scenarios.

- **Reference Scenario:** The current policy scenario includes the 2030 hard cap on emissions from the electricity sector as required by the 2009 Greenhouse Gas Emissions Regulations[3] and utility-driven energy efficiency. This scenario also assumes some improved appliance and vehicle efficiency standards and further electric sector emissions reductions in 2040-2050, beyond the 2030 hard cap as required by the 2009 Greenhouse Gas Emissions Regulation. This Reference scenario is based on current stock and sales of devices as represented by publicly available governmental data sources, and is not based on NS Power produced internal load forecasts.

- **High Electrification Scenario:** This mitigation scenario relies on significant energy efficiency, near-complete electrification of space and water heating demands by 2050, and complete electrification of light duty vehicles by 2050, with significant electrification of other transportation sectors. Some emissions reductions are achieved from advanced biofuels to displace fossil combustion, especially in freight transportation; industry; and other off-road transportation.

- **Moderate Electrification Scenario:** This mitigation scenario relies on significant energy efficiency and achieves about half of the building and transportation electrification achieved in the High Electrification Scenario. Additional emissions reductions come from use of advanced biofuels to displace fossil fuel combustion.

- **Building Electrification Only Scenario**: A mitigation scenario that relies on significant energy efficiency and achieves near-complete electrification of space and water heating demands by 2050. Because there is no transportation electrification, additional emissions reductions come from use of advanced biofuels to displace fossil fuel combustion.

[3] The Greenhouse Gas Emissions Regulations set hard cap on electricity emissions https://www.novascotia.ca/JUST/REGULATIONS/regs/envgreenhouse.htm

Two additional "bookend" scenarios –one focusing on more extreme reliance on biofuels and the other focusing on more extreme reliance on electrification – were also modeled. These scenario assumptions and results are available in the report appendix. Key assumptions are also reported in Table 1 below. E3 notes that it developed its assumptions using publicly available data sources, and that these explicitly do not reflect NSPI's assumptions.

Figure 10. Historical Greenhouse Gas Emissions and 2050 Greenhouse Gas Targets

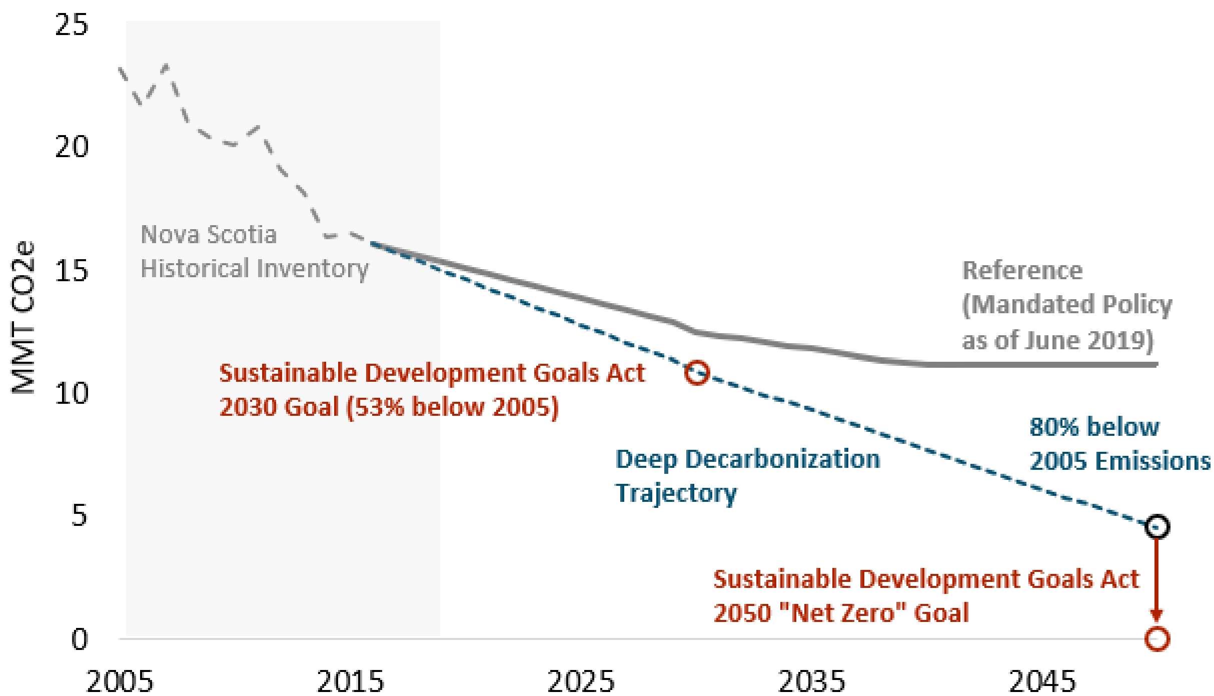


Table 1. Key Assumptions Across Scenarios

	Reference	High Electrification	Building Electrification Only	Moderate Electrification
2050 GHG emissions budget for electricity generation	3.5 MMT CO_2e	2.0 MMT CO_2e	1.5 MMT CO_2e	1.65 MMT CO_2e
Building energy efficiency	None	54% of homes are assumed to have significant weatherization upgrades by 2050, leading to a 7% reduction in space conditioning demands		
Sales of electric heat pump equipment / other appliances	25% sales of air source heat pumps for space heating by 2050	100% sales of heat pump space heaters and water heaters by 2030 in the residential sector 98% sales of heat pump space heaters and 93% sales of heat pump water heaters by 2040 in the commercial sector 100% sales of electric cookstoves by 2040		50% sales of heat pump space heaters and water heaters by 2040 in the residential and commercial sectors 50% sales of electric cookstoves by 2050
Zero-emission vehicles	LDVs: 2% Zero Emission Vehicles (ZEV*) sales by 2050 MDVs: 10% compressed natural gas sales, 2% EV sales and 1.5% H_2 fuel cell sales by 2050 HDVs: 10% compressed natural gas sales and 0.5% EV sales by 2050 Buses: 5% EV sales by 2030	LDVs: 100% ZEV sales by 2040 MDVs: 80% EV sales by 2040 and 9% diesel electric hybrid sales by 2050 HDVs: 60% EV sales and 40% diesel electric hybrid sales by 2040 Buses: 60% EV sales by 2040	Same as Reference	LDVs: 50% ZEV sales by 2040 MDVs: 90% diesel electric hybrid sales by 2050 HDVs: 100% diesel electric hybrid sales by 2050 Buses: 5% EV sales by 2030
Vehicle fuel economy	U.S. CAFE standards for LDVs through 2026			
Advanced Biofuels	None	Advanced biofuels using agricultural residues and forestry wastes assumed to be available, based on assumption of broader North American biomass feedstock market		
Non-energy	None	30% reductions relative to 2016		

*ZEV: Zero Emission Vehicles include battery electric (BEV) and plug-in hybrid electric (PHEV) vehicles.

2.5 Model Inputs

As described above, PATHWAYS is a stock rollover modeling framework which projects energy demands and the associated GHG emissions. Input data for PATHWAYS were constructed based on Canadian and United States government data. Data on device efficiencies and average lifetimes were sourced from the United States National Energy Modeling System (NEMS) as used in the Annual Energy Outlook (AEO) 2019.

2.5.1 FIRST YEAR EMISSIONS BENCHMARKING

In each sector of the economy, E3 created a representation of base year (2016) infrastructure and energy, and identified key variables that drive activity changes over the duration of each scenario (2017-2050). E3 benchmarked the Nova Scotia PATHWAYS model created for this analysis to Nova Scotia 2016 emissions from the Canadian Government 2016 GHG Inventory data for Nova Scotia.

2.5.2 KEY DRIVERS AND DEMOGRAPHICS

To project future energy use and corresponding emissions, E3 projected key macroeconomic variables that drive energy services demands. The most impactful inputs are population growth, household growth, and growth in vehicle miles traveled (VMT). For these key variables, E3 assumed flat growth from 2015-2050. This assumption is based on population trends as seen in the National Energy Board (NEB) Reference forecast, which projects slightly negative population growth through 2040. However, E3 conservatively forecasts flat population growth, indicating that fundamental demand for energy services does not change over time.

2.5.3 BUILDING SECTOR

2.5.3.1 Base Year

In 2016, Nova Scotia had a population of about 942,000 people residing in about 403,000 households.[4] The buildings sector includes energy usage for residential and commercial customers. In a stock rollover approach, total energy usage in buildings is decomposed into energy use per device multiplied by number of devices. In the residential subsectors, E3 performed a stock rollover of physical devices themselves (e.g. number of natural gas furnaces). Because of the more heterogenous nature of commercial buildings and the difficulty in comparing physical devices across commercial building types, in the commercial subsectors E3 abstracts stock rollover into modeling the unit of stock as a square footage of commercial building.

E3 sourced data on population and number of households from Natural Resources Canada (NRCAN) data when available, filling in gaps with the New England region of the NEMS database when NRCAN data are unavailable. To calculate the distribution of device types within a subsector (e.g., the percentage of residential space heaters which are natural gas versus electric resistance), E3 again relies on NRCAN data. Device efficiency data are sourced from the United States National Energy Modeling System (NEMS)[5]. For energy services demand per household or per commercial square foot, NEMS data are used as a default and modified to benchmark to NRCAN data. For residential subsectors, NRCAN data are available for the Nova Scotia province, and for commercial subsectors an emissions-weighted downscale of the Atlantic provinces region are used.

[4] National Energy Use Database by Natural Resources Canada: http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive_tables/list.cfm

[5] Updated Buildings Sector Appliance and Equipment Costs and Efficiencies. Report by Navigant Consulting, Inc. and Leidos (formerly SAIC) for the US Energy Information Administration. https://www.eia.gov/analysis/studies/buildings/equipcosts/pdf/full.pdf

Table 2. Representation of 2016 Building Energy Consumption by Subsector in Nova Scotia

Sector	Subsector	Modeling Approach	Energy Use in 2016 [TBtu]	Percent of 2016 Building Energy Use [%]
Residential	Central Air Conditioning	Stock Rollover	0.09	0%
	Room Air Conditioning	Stock Rollover	0.09	0%
	Building Shell+	Stock Rollover	-	0%
	Clothes Drying	Stock Rollover	0.83	1%
	Clothes Washing	Stock Rollover	0.07	0%
	Cooking	Stock Rollover	0.42	1%
	Dishwashing	Stock Rollover	0.25	0%
	Freezing	Stock Rollover	1.11	2%
	Reflector Lighting	Stock Rollover	0.24	0%
	General Service Lighting	Stock Rollover	1.05	2%
	Exterior Lighting	Stock Rollover	0.17	0%
	Linear Fluorescent Lighting	Stock Rollover	0.18	0%
	Single Family Space Heating	Stock Rollover	28.20	45%
	Refrigeration	Stock Rollover	3.22	5%
	Water Heating	Stock Rollover	6.39	10%
	Other*	Total Energy by Fuel	-	0%
Commercial	Air Conditioning	Stock Rollover	2.07	3%
	Cooking	Stock Rollover	0.35	1%
	General Service Lighting	Stock Rollover	1.38	2%
	High Intensity Discharge Lighting	Stock Rollover	0.20	0%
	Linear Fluorescent Lighting	Stock Rollover	1.44	2%
	Refrigeration	Stock Rollover	2.72	4%
	Space Heating	Stock Rollover	7.89	13%
	Ventilation	Stock Rollover	1.27	2%
	Water Heating	Stock Rollover	1.10	2%
	Other*	Total Energy by Fuel	1.88	3%
All Buildings Subsectors			**62.59**	**100%**

+Building Shell is modeled to represent potential deep home retrofits and other measures which significantly reduce space conditioning demands. By itself a Building Shell stock does not consume energy, but E3 models an Efficient building shell reducing space heating service demand by 20%.
*Residential Other includes furnace fans, plug loads (e.g. computers, phones, speakers, printers), secondary heating, fireplaces, and outdoor grills. Commercial Other includes plug loads, office equipment, fireplaces, and outdoor grills.

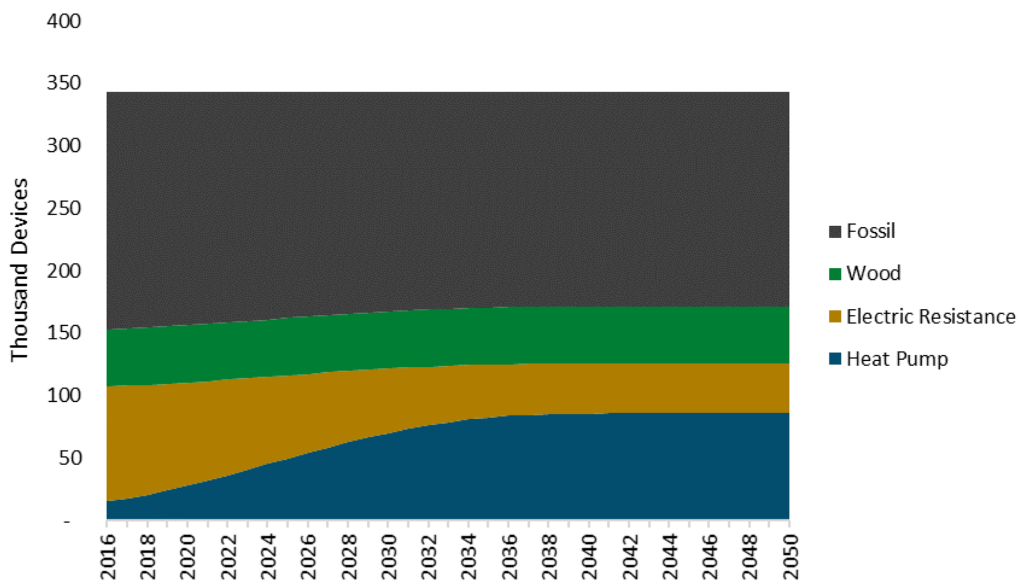
2.5.3.2 Reference Scenario

The primary measure represented in buildings for the Reference Scenario is the achievement of electric energy efficiency. Energy efficiency in buildings is implemented in the PATHWAYS model in the form of increased device efficiencies for new building devices. Specifically, E3 assumes a greater share of high efficiency appliances or lighting are purchased and therefore used in the residential and commercial sectors. New equipment is typically assumed to replace existing equipment "on burn-out", e.g., at the end of the useful lifetime of existing equipment. Efficiency improvements in new devices are included in the NEMS forecast of device efficiency improvements. In addition, a percentage of the current stock of electric resistance space heating is swapped to heat pump space heaters as heat pump space heaters provide large efficiency improvements. Table 3 documents key assumptions for the Reference Scenario, and Figure 11 provides an example of the stock rollover assumed in the Reference Scenario, showing residential space heating stock.

Table 3. Reference Scenario Assumptions for Building Energy Efficiency

Category of Building Measures	Reference Scenario Assumption
Device efficiencies	NEMS reference technology efficiency improvements
Building electrification	20% of space heater sales are heat pumps by 2020

Figure 11. Stock Rollover from the Reference Case: Residential Space Heating



Since the model is based on a bottom-up forecast of technology stock rollover in the residential and commercial sectors, the model does not use a single load forecast or energy efficiency savings forecast as a model input. It is important to note that the modeling assumptions used in this analysis may not reflect specific future energy efficiency programs or activities.

2.5.3.3 Mitigation Scenarios

The mitigation scenarios include varying levels of aggressive energy efficiency and building electrification measures. These mitigation scenarios are designed to test a range of future outcomes for building electrification, which in practice, will depend on the availability of incentives for building electrification as well as future technology trends and fuel cost trajectories. The scenarios are not attempting to predict future consumer adoption based on economics alone. Three major mitigation categories are modeled in the Buildings sector:

1. **Building retrofits for high efficiency building shells**: Deep home retrofits of existing buildings are performed when space conditioning appliances are replaced, in addition to mandating ultra-efficient building shells for new homes and commercial buildings. These efficient building shells reduce the demand for space conditioning by up to 20% over a Reference building shell.
2. **New appliance sales:** In addition to the efficiency of conventional devices improving over time, new appliance sales begin switching over to efficient alternatives, such as EnergyStar appliances.
3. **Building electrification:** As discussed in the Reference scenario, heat pump space heaters have significant GHG mitigation benefits since heat pumps are significantly more efficient than conventional fossil or electric alternatives over an annual energy basis.

Table 4 documents the key building mitigation measure utilized in the modeling, while Figure 12 and Figure 13 show a stock rollover of residential space heating in the Moderate and Building/High Electrification scenarios respectively.

Table 4. Building Mitigation Measures

Category of Building Measures	Building Electrification Only	Moderate Electrification Scenario	High Electrification Scenario
Building retrofits for high efficiency building shells	100% adoption of efficient building shell and weatherization measures by 2040		
New appliance sales	100% of new sales of all appliances are assumed to be efficient (e.g. EnergyStar) by 2030 (except space heaters, which are considered below).		
Building electrification	100% sales of electric heat pumps by 2030	50% sales of electric heat pumps by 2030	100% sales of electric heat pumps by 2030

Figure 12. Stock Rollover in the Moderate Electrification Scenarios: Residential Space Heating

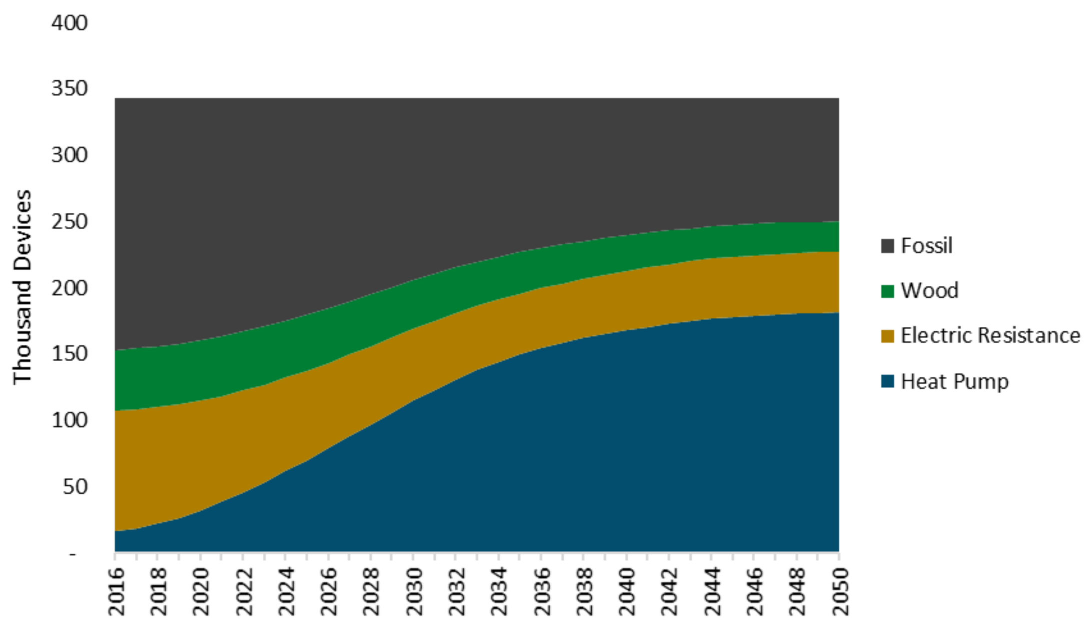
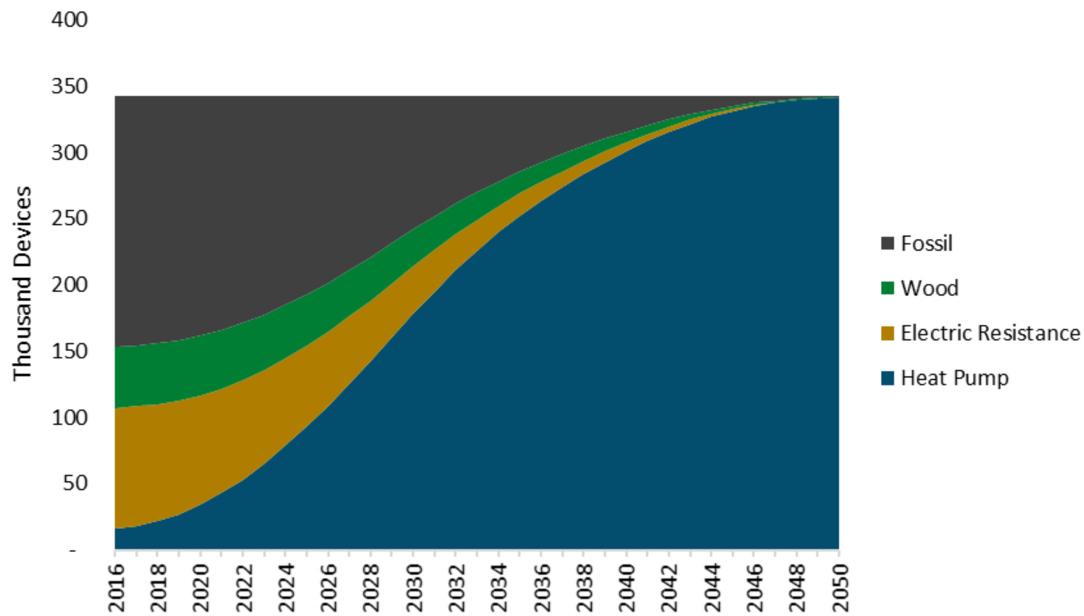


Figure 13. Stock Rollover in the Building Electrification and High Electrification Scenarios: Residential Space Heating



2.5.4 TRANSPORTATION SECTOR

2.5.4.1 Base Year

The Nova Scotia PATHWAYS model includes a stock-rollover representation of five transportation sectors and an energy representation of seven subsectors. Sectoral energy demand is benchmarked to energy consumption from the Nova Scotia GHG Inventory for 2016 and is disaggregated by subsector based on the EIA National Energy Modeling System (NEMS) technology characterization and additional data from Nova Scotia GHG Inventory and federal Canadian data on vehicle miles traveled (VMT) by vehicle class. All subsectors represented in the transportation sector are listed in Table 5.

Table 5. Representation of 2016 Transportation Energy Consumption by Subsector in Nova Scotia

Subsector	Modeling Approach	Energy Use in 2016 [TBtu]	Percent of 2016 Transportation Energy Use [%]
Long Wheelbase Light Duty Vehicle (Long LDV)	Stock Rollover	25.81	35%
Short Wheelbase Light Duty Vehicle (Short LDV)	Stock Rollover	17.13	23%
Heavy Duty Trucks	Stock Rollover	13.67	18%
Other (all other transportation energy to benchmark to the GHG Inventory, including shipping; rail; other non-road and off-road vehicles)	Total Energy by Fuel	11.67	16%
Aviation	Total Energy by Fuel	2.87	4%
Medium Duty Trucks	Stock Rollover	2.61	4%
Buses	Stock Rollover	0.73	1%
All Transportation Subsectors		**74.48**	**100%**

2.5.4.2 Reference Scenario

The main driver of energy reductions in the Reference scenario are continued federal Light Duty Vehicle (LDV) Corporate Average Fuel Economy (CAFE) Standards. While there is continued policy uncertainty in the US around CAFE standard implementation, E3 understanding is Canada has pledged to continue following CAFE standard improvements through model year 2026, and as such those improvements are modeled within this analysis. In addition, a nominal amount of electric passenger vehicles (codified as short and long wheelbase light duty vehicles in the table above), and a small amount of electric bus sales are modeled. Figure 15 presents the reference case stock rollover graph for light duty electric vehicles.

While freight trucks as a whole consume less energy and emit fewer emissions than passenger vehicles, the energy and emissions demands from freight trucking are not insignificant. There are currently a small amount of compressed natural gas (CNG) vehicle sales in Nova Scotia, and a small market for CNG trucks continues to be modeled in the Reference scenario.

Figure 14: Fuel Economy for New Light Duty Vehicles (LDVs)

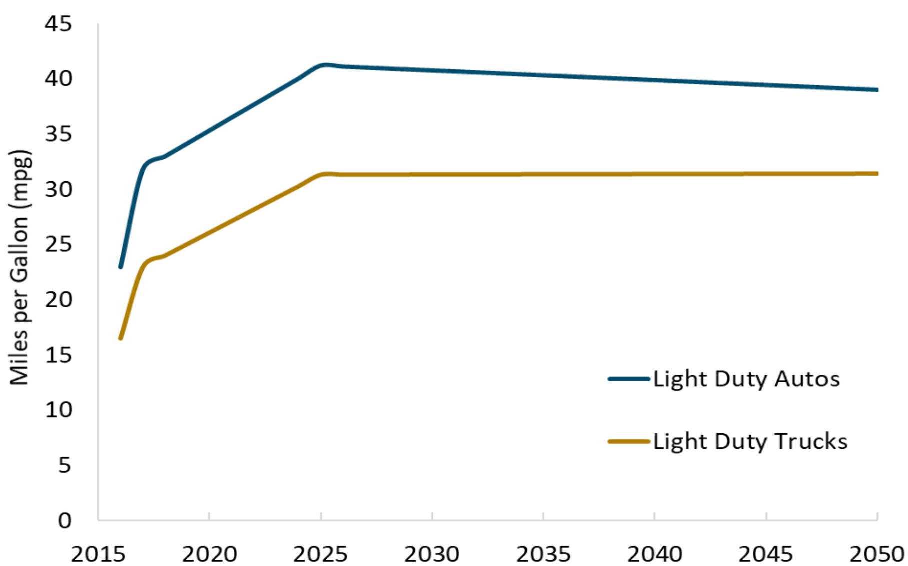
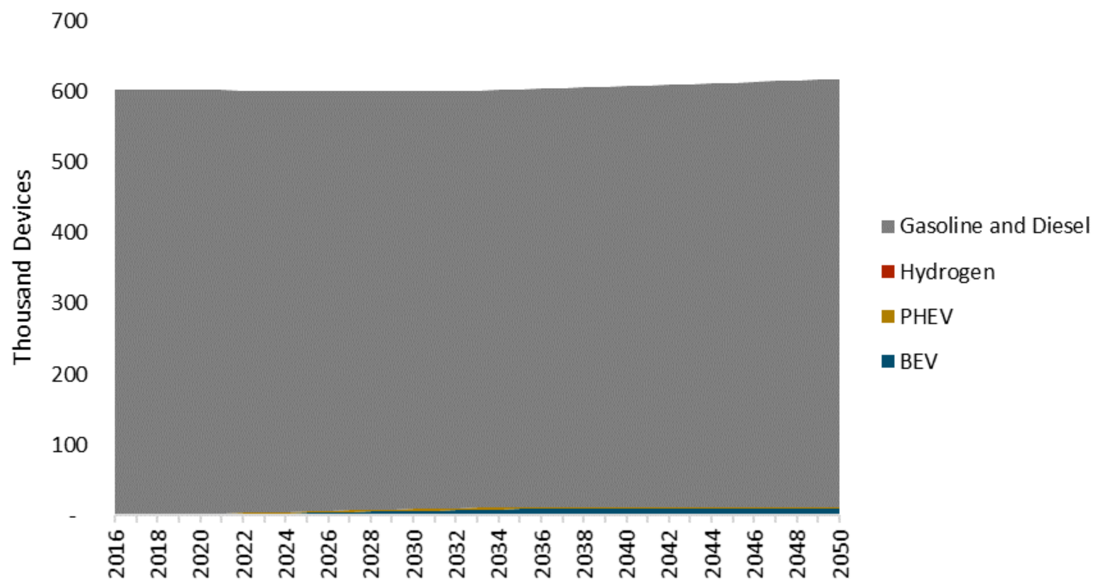


Figure 15. Stock Rollover from the Reference Scenario and Building Electrification Scenario: Light Duty Vehicles



2.5.4.3 Mitigation Scenarios

The main vehicle decarbonization measure in the mitigation scenarios is electrification of internal combustion engine vehicles to electrified alternatives; these alternatives range from hybrid-electric vehicles to zero emission vehicles (ZEV) such as battery electric (BEV) and plug-in hybrid electric (PHEV). Table 6 below documents the main mitigation measures used in constructing the three mitigation scenarios.

Table 6. Transportation Mitigation Measures

Category of Transportation Measures	Building Electrification	Moderate Electrification Scenario	High Electrification Scenario
Zero-emission Light Duty Vehicle (LDV) sales	Same as Reference (2% by 2020, flat at 2% after)	Reach 50% annual sales by 2040 (15% of the ZEV are PHEV)	100% annual sales by 2040 (20% of ZEV are PHEV by 2050)
Zero-emission Medium Duty Vehicle (MDV) sales	None	By 2050 achieve 90% sales of Diesel Hybrids	By 2040 assume 80% annual sales of ZEV MDVs
Zero-emission Heavy Duty Vehicle (HDV) sales	None	By 2050 achieve 100% sales of Diesel Hybrids	By 2040 assume 60% annual sales of ZEV HDVs
Zero-emission Bus sales	Same as Reference (5% by 2030, flat at 5% after)	Same as Reference (5% by 2030, flat at 5% after)	By 2040 assume 60% annual sales of ZEV Buses.

Note: The Very High Electrification Scenario (provided in the Appendix) includes some electrification of the Transportation Other subsector. That means 60% of all other transportation fuels which are uncategorized or unknown are electrified.

Figure 16. Stock Rollover from the Moderate Electrification Scenario: Light Duty Vehicles

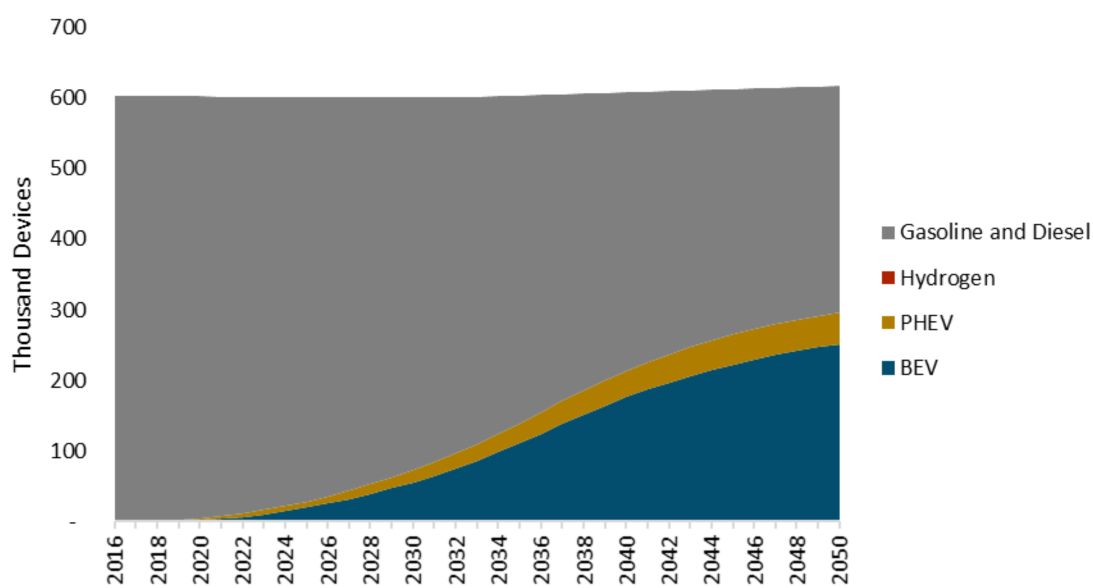
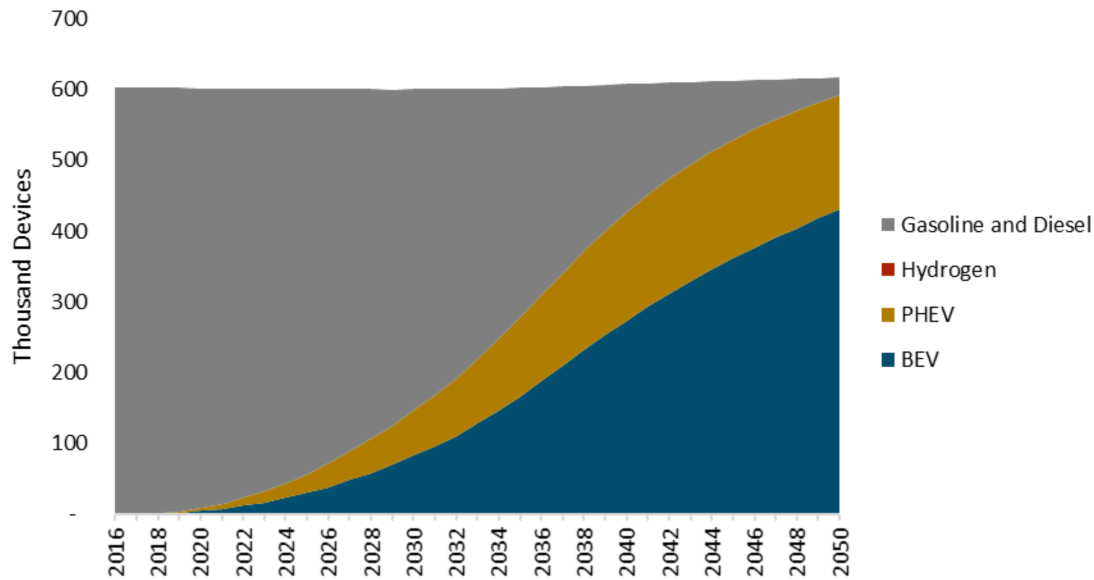


Figure 17. Stock Rollover from the High Electrification Scenario: Light Duty Vehicles



2.5.5 ELECTRICITY SECTOR

To assess potential decarbonization in the electricity sector, E3 identified a range of emissions intensities associated with deeply decarbonized electricity systems and developed a trajectory for NSP to attain an emissions intensity within this range. E3 did not perform detailed electricity dispatch modeling, recognizing that this would be performed in the upcoming IRP. In particular, E3 recognizes that a more detailed assessment of integrating renewables, primarily wind, will include evaluating the variability of wind output; grid strength and stability; seasonal energy requirements; and reduced capacity contribution of wind when replacing firm thermal units. This modeling assumes that NSPI can achieve a reduction in emissions intensity of at least 80% relative to 2005 levels. E3 recommends further study on the cost, reliability, and potential of electricity sector decarbonization under deep decarbonization and load growth scenarios.

2.5.6 OTHER ENERGY (INDUSTRIAL) SECTOR

The “other energy” category mainly consists of industrial energy activities. Because energy emissions from the industrial sector are relatively low compared to buildings and transportation, efficiency or electrification measures for industry are not modeled in the main mitigation scenarios. However, emissions do decline in industry in all three main mitigation scenarios due to biofuels replacing up to 72% of diesel consumption.

2.5.7 NON-ENERGY SECTOR

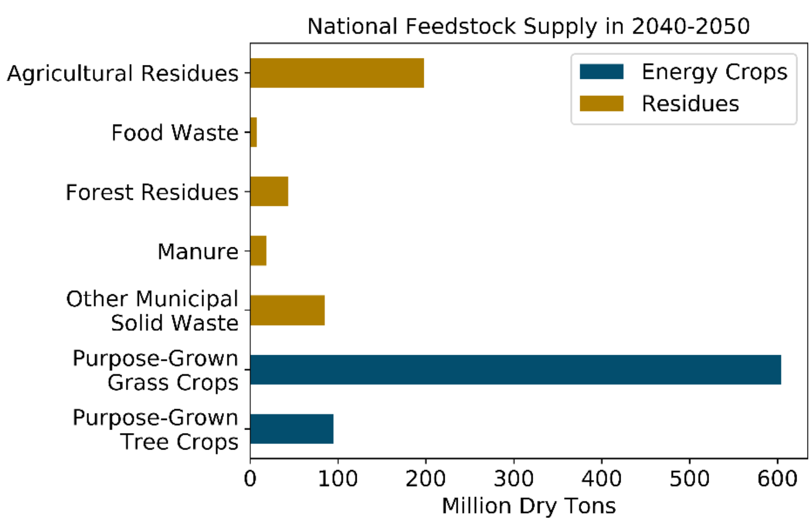
Non-energy greenhouse gas emissions include methane and other high global warming potential gases from agriculture, waste, and industrial processes. By 2050, all mitigation scenarios are assumed to achieve 30% reductions in non-energy emissions relative to 2006. These reductions could be achieved by changes in agricultural practices, increased methane control and treatment for municipal solid waste, and the phase down of (hydrofluorocarbons) HFCs. For HFCs in particular, Canada’s ratification of the Kigali Amendment in 2017 established a nationwide target of 85% reduction in HFC consumption by 2036, relative to 2016 levels.

2.5.8 BIOFUELS SECTOR

Advanced renewable biofuels, i.e., drop-in fuels which are chemically indistinguishable from the conventional fossil alternative, are a potentially important resource option when decarbonizing certain subsectors, particularly those which are difficult to electrify or otherwise convert to other low-carbon alternatives. These advanced renewable fuels are modeled as carbon neutral from a life cycle emissions perspective. There is a limited supply of appropriate biomass feedstock which can be used to produce biofuels, and the competing demands for biofuels are contingent on a regional biofuels market to incentivize the appropriate capital investments into biofuel conversion refineries.

Due to limited data regarding the biomass resource potential for biofuel production in Canada, E3 used the United States Department of Energy Billion Ton Study (BTS) dataset to calculate feedstock availability and costs for biofuels produced from US feedstocks, and then converted this amount to an estimate of the amount of available feedstocks expected to be available in Canada. The BTS dataset was updated in 2016, and its base assumptions include over one billion tons of biomass potential by 2040, incremental to resources currently utilized. However, most of this resource is new purpose-grown crops and forests, which E3 excludes from this analysis due to concerns about their sustainability. The advantage of using the BTS data is that it includes biomass supply curves that account for the costs of reserving, collecting, and transporting the raw biomass for central processing. Conversion efficiencies and costs and long-distance transport are layered on top of the raw feedstock costs. Detailed conversion assumptions for biofuels are available in Appendix Table 12.

Figure 18. US Billion Ton Study (BTS) National Feedstock Supply



Using population data and United Nations Food and Agriculture Organization (FAO) data on acreage of various agricultural resources within Canada, E3 estimated the Canadian biomass potential at 128 million dry tons by 2040 excluding purpose-grown crops. E3 considered modifying some of the crop and tree feedstock categories to be more representative of Canadian resources, such as by replacing corn with colder climate grains like barley and replacing hardwood (deciduous trees) with softwood (coniferous). However, the results are not especially sensitive to the particular feedstock and conversion assumptions, because Canada's supply is likely many times greater on a per capita basis than in the US. Although there is a potentially large supply of biofuels, if these resources were developed for commercial use, it may be feasible for Canada to export these biofuels into a global market as decarbonization proceeds elsewhere. While it is technically feasible for Nova Scotia to rely exclusively on Canadian biomass feedstocks and produce biofuels, such a strategy would be inconsistent with the global action necessary to achieve deep decarbonization and limit warming to below 2 degrees Celsius. Given this, these scenarios do not rely exclusively on domestic biomass feedstocks to produce biofuels, instead considering mitigation measures such as efficiency, electrification, and other types of fuel switching.

As noted above, E3 modeled a "bookend" scenario in which Nova Scotia pursues deep decarbonization using solely biofuels, which is presented in the appendix. Biomass is not used for electricity generation in this study. This might be a lower cost solution than using biomass for biofuel production and direct end-uses, but there may be other constraints limiting the ability to use biomass for electric generation.

Table 7. US 2040 Biomass Feedstock and potential Canadian equivalent with appropriate scaling factor

Feedstock	US Potential (Million Tons)	Scaling factor to convert US potential to estimated Canadian potential	Estimated Canadian Potential (Million Tons)
Ag Residues	198	Cropland	62
Purpose-Grown Grasses	604	Cropland	189
Food Waste	8	Population	1
Forest Residues	44	Forest	49
Manure	18	Cropland	6
Other MSW	85	Population	10
Purpose-Grown Trees	95	Forest	106
Total	1,051		423
Total Excl. Purpose-Grown	**352**		**128**

3 Results

The results in this section demonstrate the transformative change that must occur in order to achieve 80% GHG reductions (relative to 2005) by 2050. The Reference scenario reflects projected economic activity without an economy-wide emissions budget, while the three mitigation scenarios reflect a target economy-wide 2050 emissions budget of 4.6 MMT, utilizing the PATHWAYS model and assumptions outlined in Section 2.

3.1 Economy-wide GHG Emissions

While all three of the mitigation scenarios achieve 80% reductions by 2050, the scenarios diverge in their allocation of emissions across sectors. Figure 19 represents the total emissions allowed (and projected to be achieved) in each sector of the economy. In scenarios with greater electrification, E3 allocated additional emissions budget to the electricity sector in order to accommodate the greater portion of energy demand met by the electricity sector. E3 notes that detailed electricity sector modeling was not done for this PATHWAYS study. Rather, E3 determined electricity sector emissions budgets with implied emissions intensities that fell within a range of electricity sector emissions intensities that were consistent with a deeply decarbonized NSP system. This was done as a preliminary step in order to assess the feasibility of a given budget, and the utility's ability to reduce emissions to a given level while meeting growing demand, ensuring reliability, and maintaining reasonable costs.

Across the three mitigation scenarios, the High Electrification scenario assumes the highest level of building and transportation electrification. The Moderate Electrification scenario, alternately, assumes end-use electrification in the building and transportation sectors is slower and thus more emissions remain in those sectors. The Building Electrification Only scenario looks at a hypothetical future in which aggressive building electrification occurs, but no similar vehicle electrification; thus, most transportation sector emissions persist. This demonstrates that a range of electrification levels are possible while still meeting the 80% reduction, as shown in Figure 19 below.

E3 does not model the detailed changes that may occur in non-energy emissions, which include agriculture, waste, and some industrial processes. Rather, E3 assumes all mitigation scenarios achieve 30% reduction in non-energy emissions relative to 2016. The “other energy” category mainly consists of industry energy activities for which E3 do not model any efficiency or electrification measures, since emissions are relatively low compared to buildings and transportation. Across the sectors, remaining emissions include emissions from hard-to-electrify end-uses, such as long-haul trucks, aviation, shipping and industrial activities.

Figure 19. Nova Scotia 2050 Mitigation Scenario Sectoral Share of Carbon Emissions Budget (4.6 MMT)

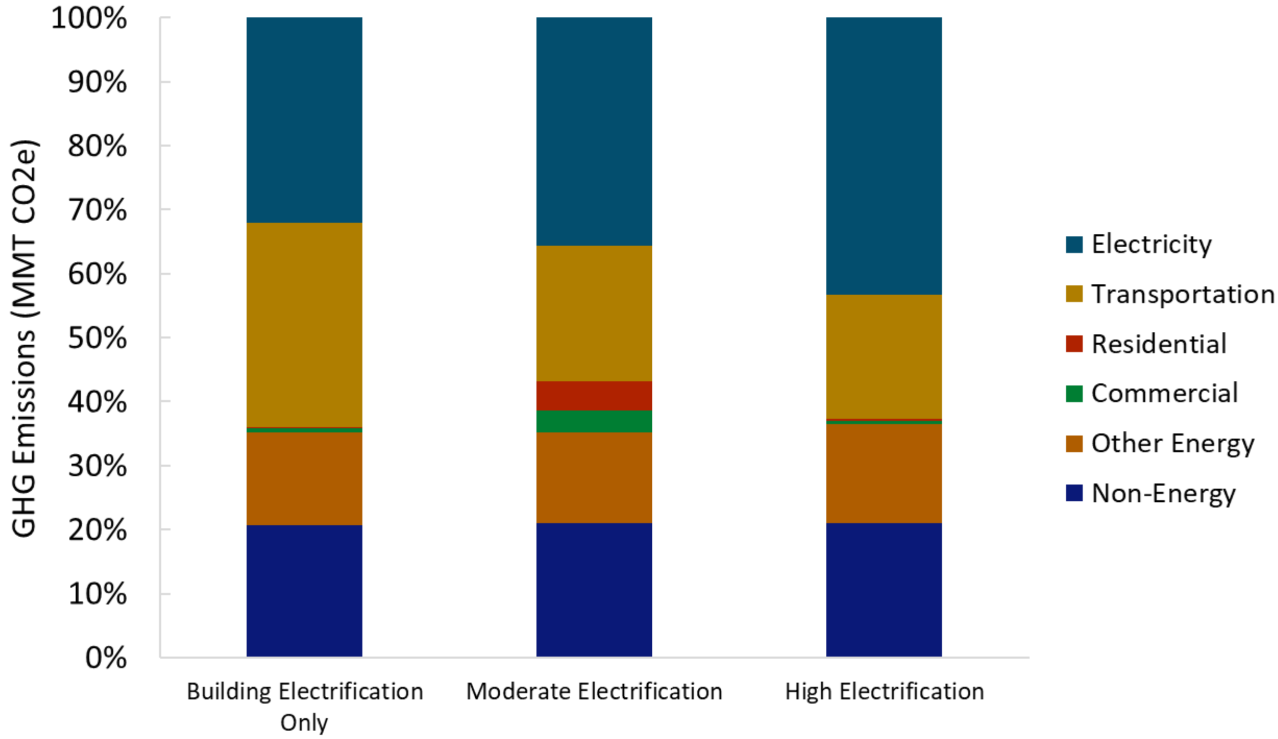
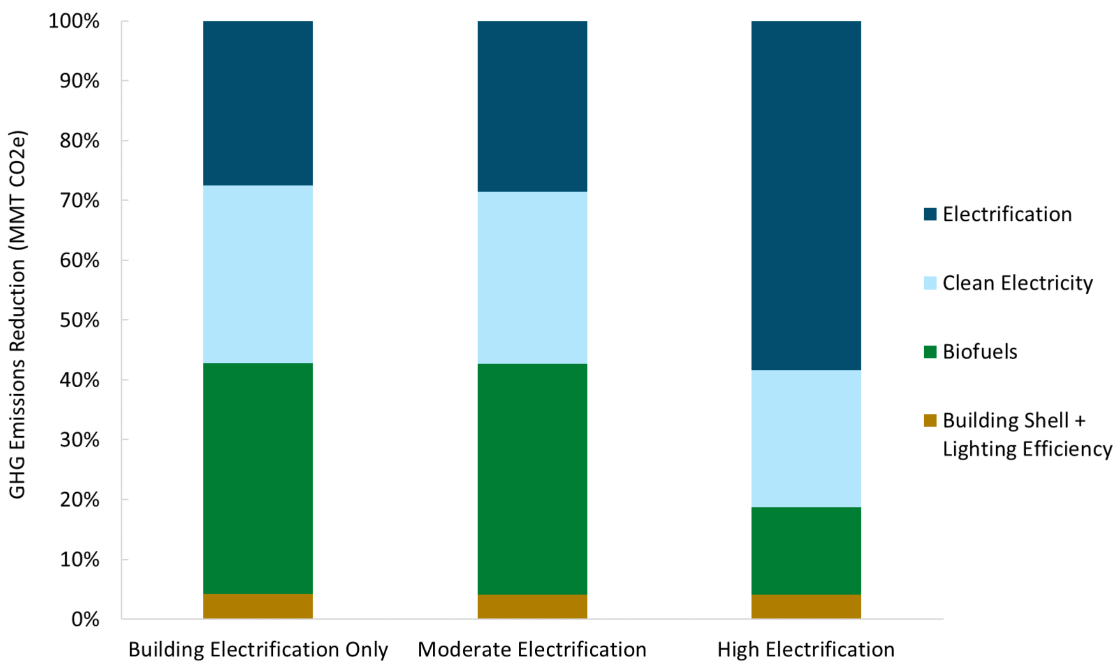


Figure 20. Share of Greenhouse Gas Reductions by Measure in 2050 (6.5 MMT, Relative to Reference)



Note: Emissions reductions from Electrification and Clean Electricity measures are interdependent and were not modeled separately in this analysis. Thus, allocations to these two categories are preliminary approximations.

3.2 Final Energy Demand

Final energy demand includes demand for energy of all forms across sectors. Final energy demand falls over time as a result of the combined impact of energy efficiency in all sectors (buildings, industry and transportation), as well as the efficiency savings associated with electrification. Improvement in new appliance efficiency, on-road vehicle efficiency, and building shells are among the energy efficiency measures that contribute to reductions in final energy demand. Electrification also contributes significant reductions in final energy demand. For example, heat pumps are assumed to have an average efficiency of 350% in delivering space heating, almost four times as efficient as even a high-efficiency furnace with 90% efficiency. In transportation, electrification lowers total energy demand given the relatively greater efficiency from switching from internal combustion engines in vehicles (~40 MPG) to electric motor drivetrains in the transportation sector (~150-180 MPGe).

Final energy demand in the High Electrification scenario is about 20% lower than in the other two mitigation scenarios, thanks to the efficiency gains from high levels of electrification. Building and transportation electrification, together with building shell improvements, reduce final energy demand by ~60 TBtu, ~40% below the Reference scenario.

Figure 21. Nova Scotia Final Energy Demand

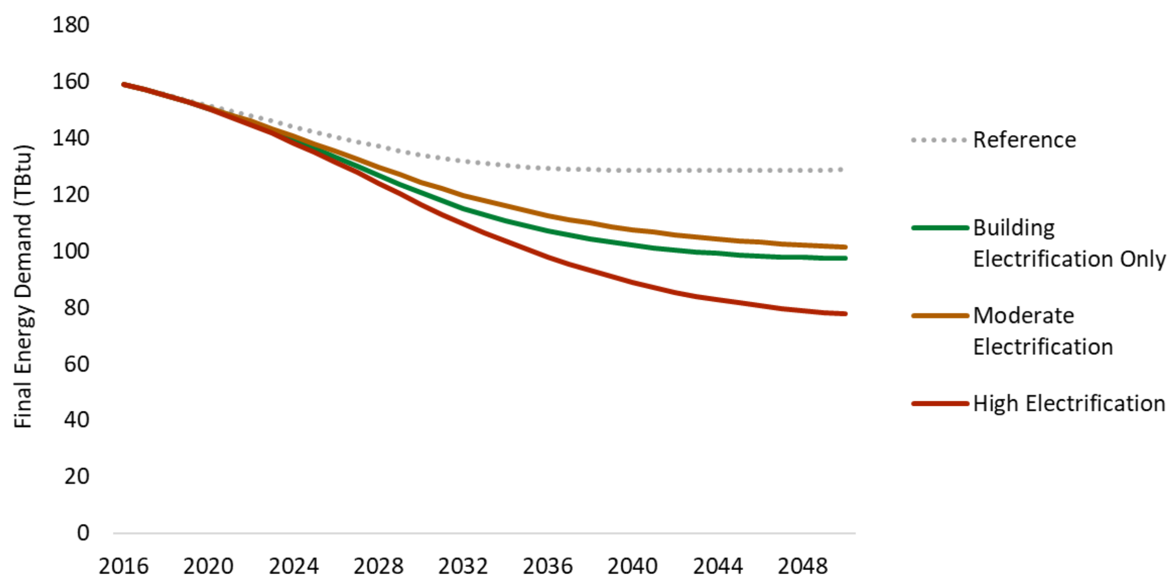
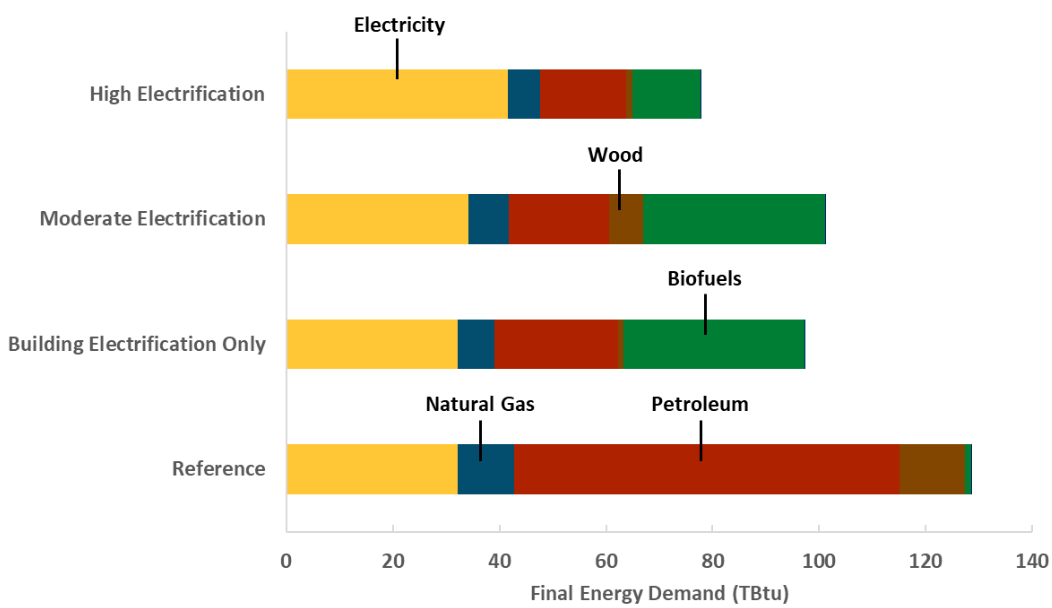


Figure 22. Final Energy Demand by Fuel Type and Scenario in 2050



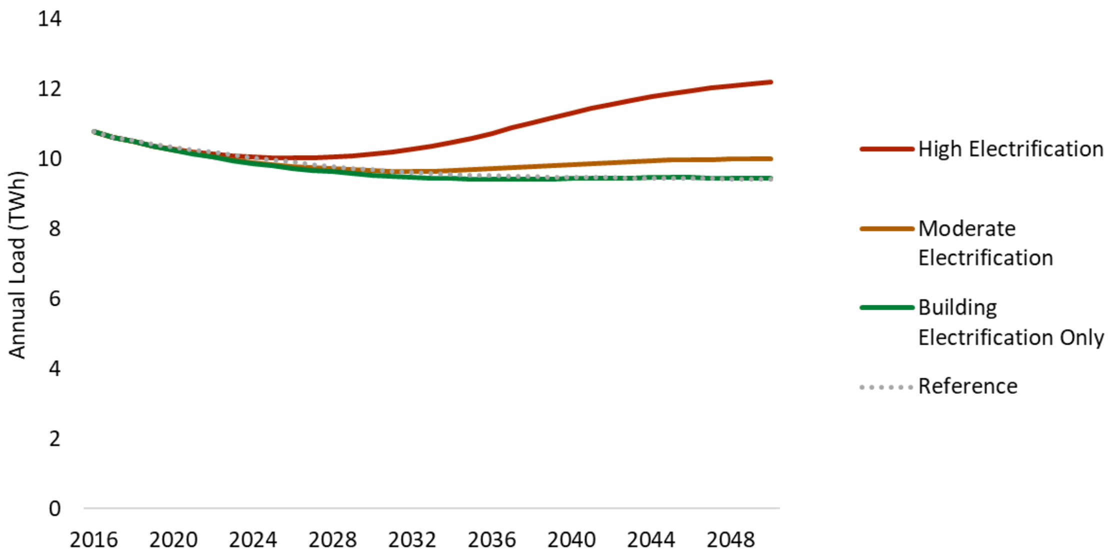
3.3 Electricity Sector

3.3.1 ELECTRIC LOAD

PATHWAYS generates electric load by aggregating the electricity demand of end-use appliances, devices and activities in all sectors (buildings, transportation and industry). The change in electric load is determined by the level of electrification and the magnitude of energy efficiency measures (such as device-level efficiency gain and behavioral conservation). Our analysis determines a budget for the electricity sector based on our estimates of feasible emissions intensities for a deeply decarbonized system, the emissions reductions in the other sectors, and the economy-wide emissions reduction goal.

This study's results show that the High Electrification Scenario projects electric load growth due to increasing level of transportation and building electrification. In contrast, the Moderate Electrification scenario projects moderate load growth because increased heat pump and EV load is offset by reduced load from conversion of resistance heaters to more efficient heat pumps, and from decreased space heat demands due to highly efficient building shell measures. The Building Electrification Only scenario has similar annual load as the Reference scenario due to a larger effect of heat pump load offset by building shell improvement.

Figure 23. Annual Electricity Demand (excluding losses) by Scenario, 2015-2050



As Table 8 shows below, in all mitigation cases the electric sector achieves over 80% emissions reductions relative to 2005 levels. Even in the High Electrification scenario in which E3 have significant vehicle and building electrification (and corresponding load growth), the electric sector must hit an 80% by 2050 decarbonization target. If transportation electrification is not included and only building electrification occurs, the burden is much greater on electricity as it must hit an 87% emissions reduction relative to 2005 levels. As noted in Section 2.5.5 above, this analysis relies on assessed bounds of feasible electric sector emissions intensities. More detailed electric sector simulation with increased loads is necessary to more completely evaluate costs and reliability, as well as considering the different resource constraints and peak load impacts of various electrification technologies.

Table 8. Electricity Sector Demand and Emissions

	2005	2016	Reference (2050)	Building Electrification Only (2050)	Moderate Electrification (2050)	High Electrification (2050)
Electricity Demand (TWh)	11.08	10.80	9.67	9.44	10.00	12.20
Emissions (MMT CO_2e)	10.77	6.58	3.5	1.5	1.65	2.0
Percent Reduction relative to 2005 emissions (%)	n/a	39%	68%	87%	85%	81%
Emissions Intensity (MMT/TWh)	0.972	0.609	0.362	0.158	0.165	0.163
Percent Reduction relative to 2005 intensity (%)	n/a	37%	63%	84%	83%	83%

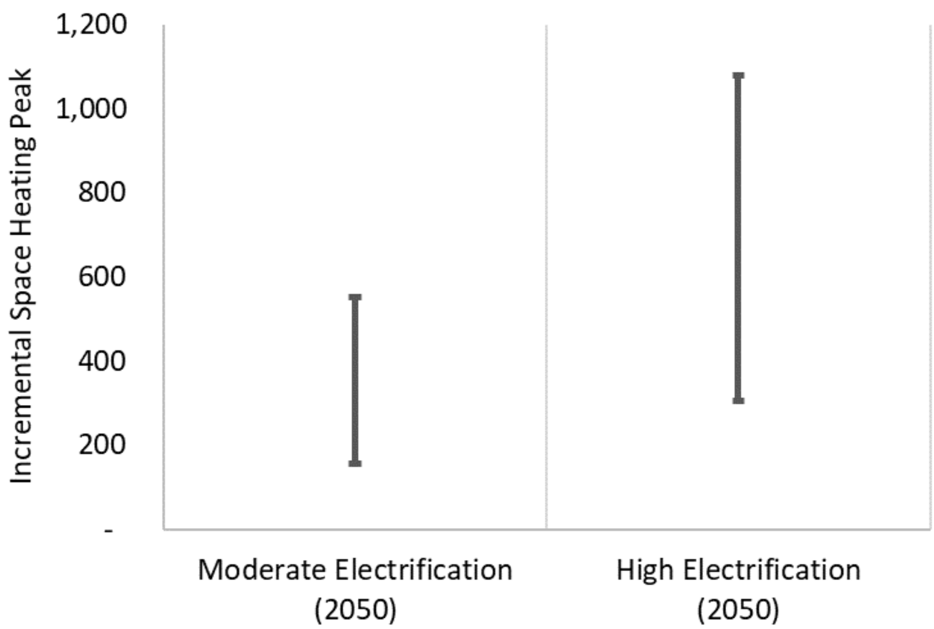
3.3.2 PEAK IMPACTS

Nova Scotia is a winter peaking electricity system, driven by electric resistance space heating. E3's modeling indicates that this winter peak may increase as a result of electrified space heating, driven by customers switching away from oil furnaces, the most prevalent heating appliances in Nova Scotia, to heat pumps. E3 notes, however, that as temperature drops, heat pump efficiencies decline until, in very cold conditions, heat pumps revert to electric resistance mode as back-up heat. Because heat pumps might operate in electric resistance mode during the coldest winter hours in Nova Scotia, there would be no reduction in peak load impact from switching from electric resistance units to heat pumps, even though switching from electric resistance units to heat pumps would provide efficiency gains for most of the year.

In this analysis, E3 estimated a range of heat pump impacts on peak demand by assuming a range of heat pump performance and weather conditions. Results show that the High Electrification scenario could have a peak impact between 304 MW and 1080 MW, depending on the temperature of the coldest day and the efficiency of the heat pump technology (Figure 24). The Moderate Electrification case could generate a smaller peak impact of between 155 MW and 552 MW.

This analysis shows the impact of heat pump electrification on peak loads could be a significant driver of peaking capacity requirements and reliability impacts on the electricity sector, and merits further investigation. However, note that that while a range of heat pump peak impacts were modeled, other measures can reduce this peak impact. These measures include, for example, using ground source heat pumps, which operate a thermal loop using underground pipes and are less affected by ambient temperature conditions. Another method to reduce electrified space heating peak effects is to pair a new heat pump space heater with an existing thermal backup (such as an oil furnace) for very cold hours. In this way the heat pump space heater allows for the majority of space heat demands to be met with decarbonized electricity throughout the year, but during peak cold hours the thermal furnace provides supplemental heat. Since a majority of Nova Scotian households currently have some type of oil furnace or wood stove, this might be a significantly more effective cost mitigation strategy than building electricity capacity to meet space heat peak impacts from electrified space heaters with no thermal backup source.

Figure 24. Estimated Space Heating Incremental Peak in 2050* (MW)

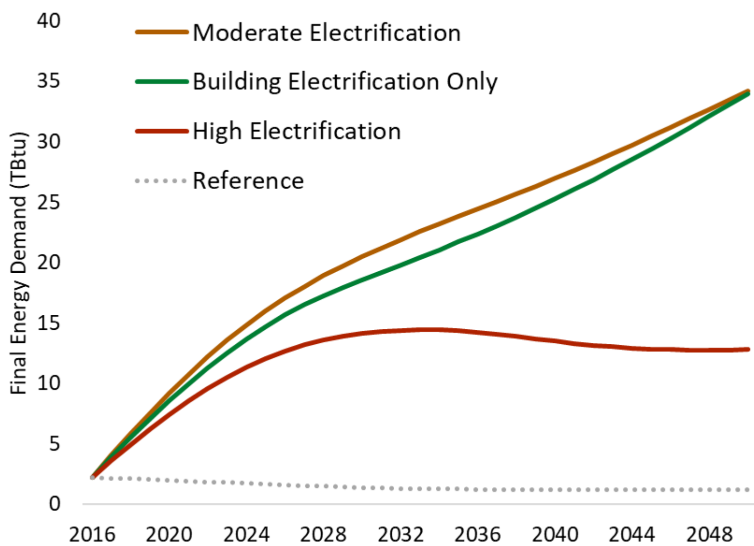


*Note: These ranges estimate the impact of electrifying fossil furnaces with air source heat pumps. The ranges estimate the impacts of different types of air source heat pump technologies, but do not account for other measures which might reduce peak impacts. As discussed in the text above, using a ground source heat pump, or using air source heat pumps with thermal backups, would cause smaller incremental peak impacts from space heat electrification.

3.4 Biofuel Demand

Biofuels are utilized as a carbon-neutral source of energy. Biofuel demand in the High Electrification Scenario peaks at 14 TBtu in 2030 and slightly decreases after 2030 due to highly electrified end-uses and cleaner electricity to meet the GHG reduction goals (Figure 25). Biofuel is used mainly in the hard-to-electrify sectors such as long-haul trucks, aviation, shipping and industry. The Moderate Electrification and the Building Electrification Only scenarios have increasing biofuel demand through 2050 using biofuels for all types of end-uses but primarily for vehicles to meet the increasingly stringent economy-wide GHG goals.

Figure 25. Final Energy Demand by Scenario



4 Conclusions

This climate pathways analysis illustrates that achieving deep decarbonization will require tremendous shifts within the energy sector in just over 30 years. Efficiency and conservation, electrification, low carbon electricity, and low carbon fuels are all "no regrets" strategies that can help Nova Scotia to achieve economy-wide deep decarbonization. The section below discusses these key findings, implications for NSPI, and areas for future research.

4.1 Key Findings and Implications for NSPI

This report illustrates several key findings related to how to make this transition in Nova Scotia, and the actions NSPI can take to support this transition.

1. **Synergistic action is required across sectors.** Figure 5 in the Executive Summary lays out a set of strategies and milestones that will enable the province to reach 80% reductions by 2050. This timeline demonstrates the need for broad and integrated effort across the power, transportation, and building sectors. Complementary efforts would also be required in industrial and non-combustion energy sectors, though these efforts were not modeled in detail in this study. The initial stages of transformation have begun but would need to be accelerated to achieve the 2050 target.

2. **Low-carbon electricity is essential to achieving decarbonization by enabling emissions reductions in the electricity sector as well as complementary reductions in buildings and transportation.** Over the last decade, the electricity sector in Nova Scotia has reduced emissions by more than 30% relative to 2005 levels, thanks to a transition to cleaner and renewable energy

sources. Maintaining this momentum would require continuing to integrate low-carbon resources like wind and hydro into its portfolio, while ensuring reliability and affordability. This transition would enable NSPI to meet energy demand from existing electric load as well as new load growth from space and water heating and transportation, without emitting more carbon.

3. **Low-carbon electricity alone is not enough to achieve 80% economy-wide reductions.** All mitigation scenarios, including E3's high electrification scenarios, require additional measures and actions beyond low-carbon electricity in order to achieve the 80% reduction target. Figure 6 in the Executive Summary presents emissions reductions by measure. Electrification can also leverage low-carbon electricity to dramatically reduce emissions from transportation and buildings. That said, in the scenarios modeled here, other low-carbon fuels are still needed to provide incremental carbon-neutral energy services after all economic clean energy and electrification measures are implemented. Advanced biofuels were used as the main low-carbon fuel in this analysis, although other options like hydrogen produced with clean electricity could serve this need as well. However, these strategies will only be viable if the technologies can reach economies of scale in a global market. Nova Scotia should therefore monitor the development of these emerging energy sectors and perform more detailed assessments of their potential deployment in Nova Scotia.

4. **Long lifetimes require early action.** Investments in infrastructure and equipment can last decades or more, thus having long-lasting effects on emissions. Because there are a limited number of investment opportunities to ensure low-carbon alternatives are selected over alternatives that lead to higher emissions, meeting 2050 goals may require measures to encourage early adoption of electric and/or low-emissions infrastructure and equipment where possible. Delayed action in early years may require more costly early retirements or buy-back programs closer to goal years in order to make up the difference and meet targets. In particular, E3's mitigation scenarios assume near-complete electrification of passenger vehicles by 2050, an aggressive target given there are only around 300 EVs registered in Nova Scotia today. While the costs of electric vehicles

are declining quickly, complementary investments in public charging infrastructure may help enable widespread adoption. NSPI could start by defining adoption targets, determining the infrastructure and initiatives needed to achieve those targets, and developing a strategy to support those markets.

5. **Building electrification is dependent on reducing costs and enhancing incentives, which may be facilitated by the utility and the province.** To achieve the levels of electrification modeled in the decarbonization scenarios, rapid increases in consumer adoption of more efficient and electrified equipment is required. Adoption is unlikely to meet these targets without lower capital costs and attractive rate structures. This study relies on rapid and widespread adoption of cold climate heat pumps, which are a relatively new technology with significant emissions reduction potential. This technology is commercially available but not yet broadly adopted. The currently high up-front costs of this technology should be addressed with government or NSPI support. From a planning perspective, NSPI must also more thoroughly evaluate the peak electricity demand impacts associated with widespread electric space heating, which were not investigated in detail in this study. The Appendix also contains a scenario in which E3 modeled low-carbon biofuels as an alternative building decarbonization strategy.

6. **Getting to "net zero" will be an even greater challenge, requiring more direct reductions, and/or carbon removal technologies or carbon offsets.** Although this target was not modeled directly in this study, achieving "net zero" would likely require investments in negative emissions technologies such as direct air capture or carbon capture and sequestration. These technologies will be valuable in removing emissions from the hardest-to-decarbonize sectors such as industry. While not typically cost effective today, these technologies may become more feasible strategies with cost declines and performance improvements.

4.2 Recommendations for Additional Analysis

The scenarios evaluated in this analysis represent an initial modeling assessment of strategies to decarbonize, focusing on emissions in electricity generation, buildings, and transportation. Additional modeling in the context of NSPI's IRP planning process will be necessary to better understand the potential for decarbonization in the electricity sector, and the implications of economy-wide decarbonization on electricity system operability and reliability. In addition, this report does not assess the costs of different decarbonization pathways, which will be important for prioritizing strategies for decarbonization. Finally, while these sectors will continue to be the most important sectors for achieving decarbonization goals in Nova Scotia, additional modeling may also be valuable to investigate the emissions reduction potential of industrial and non-energy sectors. This report is a first step to understand the pathways to economy-wide decarbonization; E3 recommends future research efforts consider:

+ **Cost Modeling:** This study does not report the economy-wide or sector-level costs associated with each of the mitigation scenarios. In order to fully assess trade-offs among different decarbonization pathways, it will be essential for NSPI to investigate the costs associated with the different potential pathways. At a minimum, this assessment would include the direct costs of energy infrastructure, the associated operations and maintenance costs, and fuel costs. E3 will undertake a more detailed review of costs in Phase 2 of this analysis.

+ **Electricity Sector Modeling:** This study did not perform detailed dispatch or capacity expansion modeling. Efforts to more completely characterize potential electricity system impacts, including operability and reliability, should be performed in future work. For example, as discussed above, cold climate heat pumps are anticipated to have significant impacts on peak load. More detailed evaluation of peak impacts and potential mitigation strategies (e.g., flexible load) will be particularly valuable to resource planning. Moreover, given Nova Scotia's exposure to extreme weather, electrifying more sectors of the economy will require utility planners to think more carefully about the resilience and reliability of the electric grid.

+ **Consumer Adoption Modeling:** As noted above, the PATHWAYS modeling assumes the ability for rapid adoption of several low/no carbon technologies, including but not limited to high-efficiency appliances, cold-temperature heat pumps, and electric vehicles. Valuable future work should evaluate the consumer economics and choices that may drive the adoption of more efficient, lower emitting technologies, such as cold climate heat pumps and electric vehicles.

+ **Technical Feasibility:** This study includes scenarios that rely significantly on adoption of cold climate heat pumps. Research to understand heat pump technology feasibility and costs specifically within Nova Scotia will be valuable, in particular to assess the potential for performance degradation in cold temperatures.

5 Appendix

5.1 Mitigation Scenario Results

Table 9. 2050 Results for Reference and Mitigation Scenarios

Category	Reference	Building Electrification Only	Moderate Electrification	High Electrification
Electric Sector Emissions (MMT CO2e)	3.5	1.6	1.6	2.0
Non-Electric Emissions (MMT CO2e)	7.7	3.2	3.0	2.6
Total Emissions (MMT CO2e)	11.2	4.8	4.6	4.6
Total Final Energy Demand (TBtu)	129	97	101	78
Electric Load (TWh)	9	9	10	12
Electricity Share of Final Energy Demand (%)	25%	33%	34%	54%
Biofuels Demand (TBtu)	1	34	34	13
Biofuels Share of Final Energy Demand (%)	1%	35%	34%	16%

5.2 Additional Scenarios

Table 10. 2050 Results for Reference Scenario and Additional Scenarios

Category	Reference	Very High Electrification	High Biofuels
Electric Sector Emissions (MMT CO2e)	3.5	2.0	1.1
Non-Electric Emissions (MMT CO2e)	7.7	2.8	3.9
Total Emissions (MMT CO2e)	11.2	4.8	5.0
Total Final Energy Demand (TBtu)	129	75	118
Electric Load (TWh)	9	14	8
Electricity Share of Final Energy Demand (%)	25%	64%	23%
Biofuels Demand (TBtu)	1	0	44
Biofuels Share of Final Energy Demand (%)	1%	0%	37%

Table 11. Key Assumptions for Reference Scenario and Additional Scenarios

	Reference	Very High Electrification	High Biofuels
GHG emissions budget for electricity generation	3.5 MMT CO2e	2.0 MMT CO2e	1.0 MMT CO2e
Building energy efficiency	None	50% of building shell sales are efficient by 2030 (20% reduction in space heating demand and 12% reduction in air conditioning demand), and 100% by 2040	None
Sales of electric heat pump equipment	25% sales of air source heat pumps for space heating	100% sales of heat pump space heaters and water heaters by 2040 in the residential sector and 90% by 2040 in the commercial sector; 80% sales of electric cookstoves and clothes dryers by 2050	Same as Reference
Zero-emission vehicles	LDVs: 2% EV sales by 2050 MDVs: 10% compressed natural gas sales, 2% EV sales and 1.5% H_2 fuel cell sales by 2050 HDVs: 10% compressed natural gas sales and 0.5% EV sales by 2050 Buses: 5% EV sales by 2030	LDVs: 100% EV sales by 2050 MDVs: 95% EV sales and 5% diesel electric hybrid sales by 2050 HDVs: 60% EV sales and 40% diesel electric hybrid sales by 2050 Buses: 95% EV sales by 2040	Same as Reference
Other transportation	None	60% of total energy is electrified by 2050 including rail, domestic navigation and off-road vehicles	None
Vehicle fuel economy	US CAFE standards for LDVs by 2026		
Advanced Biofuels	None	None	Advanced biofuels using agricultural residues and forestry wastes assuming there is a broader North American biomass feedstock market
Industry	None	20% liquid fuel consumption is electrified by 2050	None
Non-energy	None	30% reductions relative to 2016	30% reductions relative to 2016

5.3 Biofuels Tables

Table 12. 2050 Biomethane Conversion Inputs

Feedstock Type (Disaggregated)	Feedstock Category	Conversion Process	Efficiency (GJ/dry ton)	Process Costs (2012$/dry ton)
Barley straw	Ag Residues (Cellulose)	gasification	14.001	80.65
Biomass sorghum	Ag Residues (Cellulose)	gasification	13.864	79.28
CD waste	Other MSW (Wood)	gasification	13.985	80.59
Citrus residues	Ag Residues	gasification	13.744	79.21
Corn stover	Ag Residues	gasification	13.535	78.10
Cotton gin trash	Ag Residues	gasification	14.884	85.97
Cotton residue	Ag Residues	gasification	13.190	76.53
Energy cane	Purpose-Grown Grasses	gasification	13.623	78.26
Eucalyptus	Purpose-Grown Trees	gasification	15.141	87.15
Food waste	Other MSW	gasification	11.487	66.41
Hardwood, lowland, residue	Forest Residues	gasification	14.700	84.63
Hardwood, lowland, tree	Purpose-Grown Trees	gasification	14.700	84.63
Hardwood, upland, residue	Forest Residues	gasification	14.700	84.63
Hardwood, upland, tree	Purpose-Grown Trees	gasification	14.700	84.63
Hogs, 1000+ head	Manure	anaerobic digestion	7.415	79.81
MSW wood	Other MSW (Wood)	gasification	14.346	82.76
Milk cows, 500+ head	Manure	anaerobic digestion	8.096	87.13
Miscanthus	Purpose-Grown Grasses	gasification	14.346	82.41
Mixed wood, residue	Forest Residues	gasification	14.700	84.63
Mixed wood, tree	Purpose-Grown Trees	gasification	14.700	84.63
Non-citrus residues	Ag Residues	gasification	13.655	77.95
Oats straw	Ag Residues	gasification	13.663	78.25
Other	Other MSW	gasification	12.852	73.55
Other forest residue	Forest Residues	gasification	13.655	77.95
Other forest thinnings	Forest Residues	gasification	13.655	77.95

Feedstock Type (Disaggregated)	Feedstock Category	Conversion Process	Efficiency (GJ/dry ton)	Process Costs (2012$/dry ton)
Paper and paperboard	Other MSW (Cellulose)	gasification	15.824	91.34
Pine	Purpose-Grown Trees	gasification	15.021	86.29
Plastics*	Other MSW	gasification	28.460	163.12
Poplar	Purpose-Grown Trees	gasification	15.085	86.84
Primary mill residue	Other MSW (Wood)	gasification	15.342	88.15
Rice hulls	Ag Residues	gasification	12.210	69.84
Rice straw	Ag Residues	gasification	12.266	70.38
Rubber and leather*	Other MSW	gasification	21.367	122.27
Secondary mill residue	Other MSW (Wood)	gasification	15.342	88.15
Softwood, natural, residue	Forest Residues	gasification	14.860	85.41
Softwood, natural, tree	Purpose-Grown Trees	gasification	14.860	85.41
Softwood, planted, residue	Forest Residues	gasification	14.860	85.41
Softwood, planted, tree	Purpose-Grown Trees	gasification	14.860	85.41
Sorghum stubble	Ag Residues	gasification	11.808	66.87
Sugarcane bagasse	Ag Residues	gasification	13.623	78.26
Sugarcane trash	Ag Residues	gasification	13.382	77.04
Switchgrass	Purpose-Grown Grasses	gasification	13.471	77.75
Textiles*	Other MSW	gasification	14.095	80.52
Tree nut residues	Ag Residues	gasification	15.294	87.75
Wheat straw	Ag Residues	gasification	15.704	89.80
Willow	Purpose-Grown Trees	gasification	14.796	85.26
Yard trimmings	Other MSW (Cellulose)	gasification	13.688	78.61

Notes: Ag residues are classed as cellulosic for liquid biofuel conversions below. Food waste, manure, and other MSW not categorized as wood or cellulose is not considered to be convertible into liquid fuels.
*These feedstocks are included in BTS but typically contain petroleum-based content so are excluded from the renewable biomass potential.

Table 13. 2050 Conversion Inputs for Liquid Biofuels

Feedstock Type (Aggregated)	Fuel	Conversion Process	Efficiency (GJ/dry ton)	Process Costs (2012$/dry ton)
Cellulose	renewable gasoline	hydrolysis	10.101	175.74
Cellulose	renewable gasoline	pyrolysis	8.088	206.49
Cellulose	renewable ethanol	hydrolysis	6.328	86.71
Cellulose	renewable diesel	pyrolysis	8.949	228.48
Cellulose	renewable diesel	biomass to liquids*	10.705	126.43
Cellulose	renewable jet fuel	pyrolysis	8.682	221.65
Wood	renewable gasoline	pyrolysis	10.784	206.49
Wood	renewable ethanol	hydrolysis	7.838	92.57
Wood	renewable diesel	pyrolysis	11.933	228.48
Wood	renewable diesel	biomass to liquids*	10.705	126.43
Wood	renewable jet fuel	pyrolysis	11.576	221.65

*Biomass to liquids refers to thermochemical conversion using gasification plus Fisher-Tropsch synthesis of drop-in synthetic fuels.

6 References

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2020 INTEGRATED RESOURCE PLAN (IRP): FINAL ASSUMPTIONS SET

MARCH 11, 2020

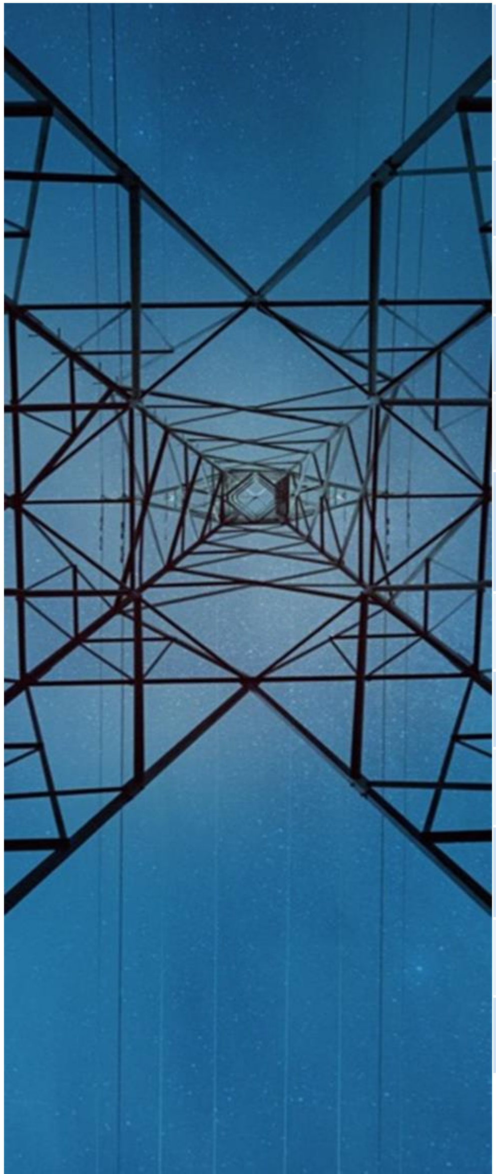
Nova Scotia POWER
An Emera Company

INTRODUCTION

- The following materials represent the final Input Assumptions to be used in the 2020 IRP Modeling.
- Since the release of the draft assumptions on January 20, NS Power has held two stakeholder workshops (via telephone on February 7 and in person on February 27) and has continued to work with interested parties in order to answer questions and make updates to assumptions where appropriate.
- NS Power would like to thank interested parties for their valued input and interest in developing this Assumption Set.

NS Power will now begin the modeling phase of the IRP process and will report to IRP participants with an interim modeling update in April 2020.

2020 IRP ASSUMPTIONS TABLE OF CONTENTS



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2020 IRP: FINANCIAL ASSUMPTIONS

MARCH 11, 2020

Nova Scotia POWER An Emera Company

FINANCIAL ASSUMPTIONS

Weighted Average Cost of Capital (WACC):*

Pre-tax = 6.62%

After-tax = 5.64%

Inflation Rate:

25-year Average = 2%

Based on Conference Board of Canada CPI growth forecast for NS

Revenue Requirement Profiles:

- Supply-side options that represent a capital investment require a revenue requirement profile
- Revenue requirement profiles for input into Plexos will be developed outside of the model using E3's Pro Forma financial model

*Utility and Review Board M09498 – Approval of pre-tax WACC/AFUDC rate for both capital and non-capital matters

EXCHANGE RATES

US Foreign Exchange Rate

Year	2021	2022	2023	2024
Forecasted USD/CAD	1.31	1.35	1.35	1.35

2020 is an average of 6 banks
2021 is an average of 5 banks
2022 and beyond is an average of 2 banks

2020 IRP:
LOAD ASSUMPTIONS

MARCH 11, 2020

Nova Scotia POWER An Emera Company

LOAD ASSUMPTIONS OVERVIEW

- The underlying data for the “Base Load Forecast” is based on NS Power’s annual Load Forecast Report, as filed with the UARB in 2019.
- Incremental load drivers based on the PATHWAYS report (e.g. electrification of building heating and transportation) are layered onto the Base Load Forecast according to the electrification scenario.
- The DSM scenarios from E1’s Potential Study are then applied to these modified loads; there is also a “No New DSM” scenario which is required for calculating the Avoided Cost of Demand Side Management.

BASE LOAD FORECAST

Base Load Forecast assumptions include:

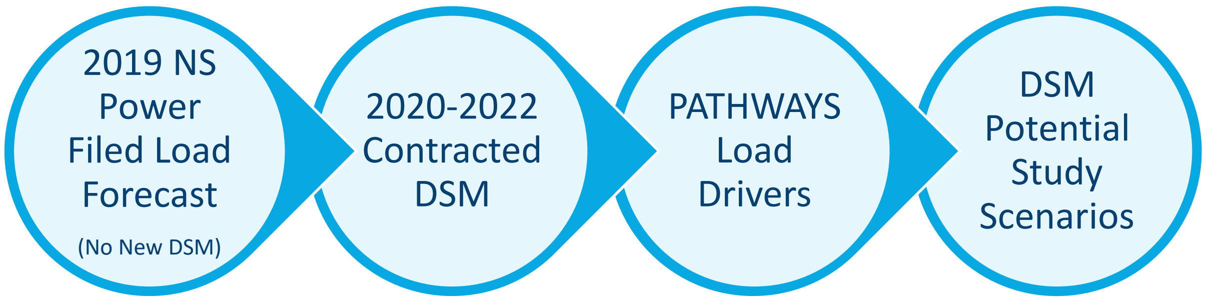
- Economic forecast from Conference Board of Canada
- Electric Vehicle (EV) penetration based on conservative estimate of Electric Mobility Canada's growth model
- EV includes estimate for peak mitigation
- 10-year average used for normal weather

DEMAND SIDE MANAGEMENT IN THE LOAD SCENARIOS

- The 4 DSM scenarios (Base, Low, Mid, Max Achievable) were subtracted from the "no new DSM" forecast.
- For 2021-2022, DSM amounts reflect the 2020-2022 DSM supply agreement - remaining years are held constant on an incremental basis.
- The scenarios are assumed to include all DSM, including:
    - Cost-effective electricity efficiency and conservation activities provided by the franchise holder
    - Initiatives that may be pursued by NS Power as permitted under the Public Utilities Act
    - Consumer behaviour and investments
    - Energy efficiency codes and standards
    - Initiatives undertaken by other agencies
    - Technological and market developments.

LOAD ASSUMPTIONS OVERVIEW

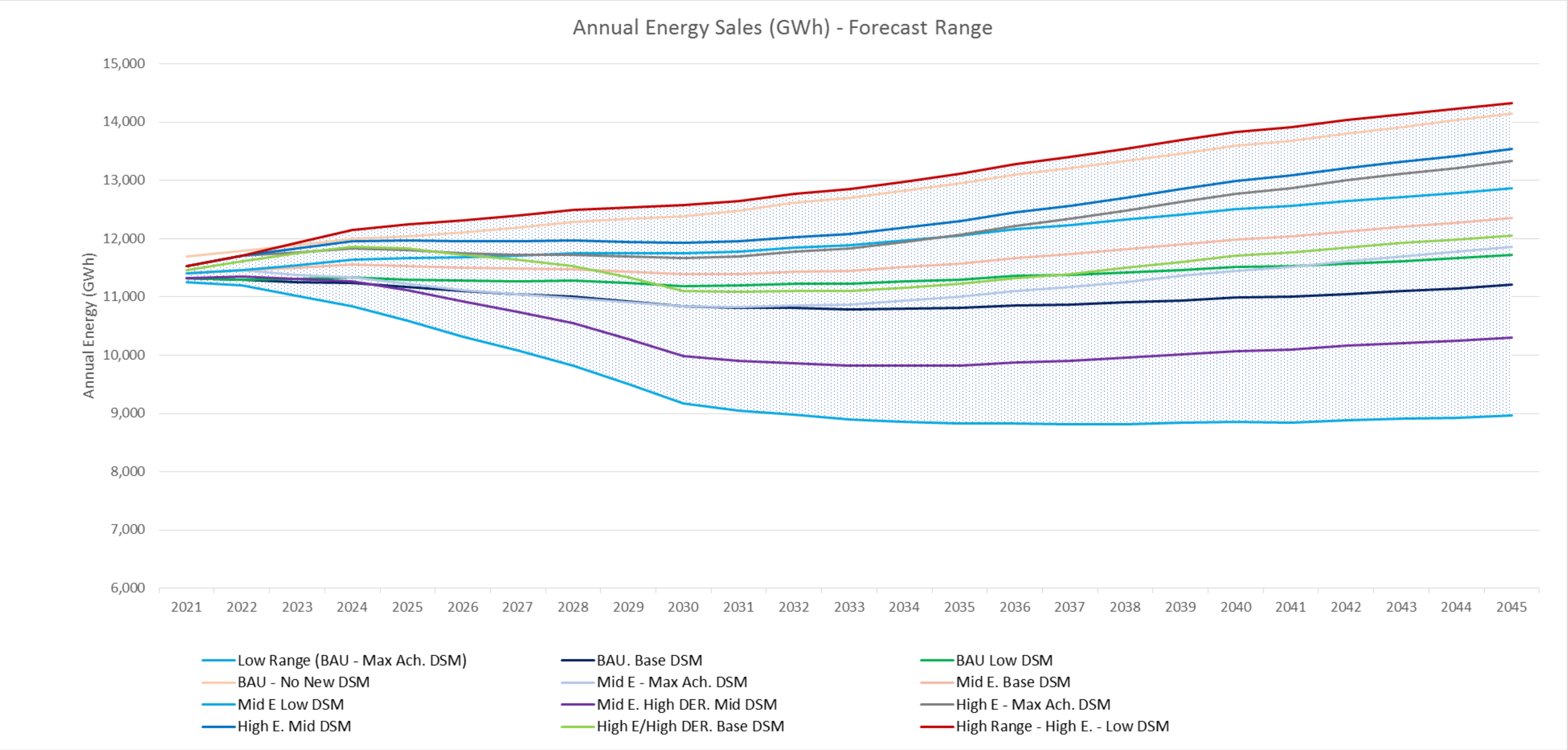
- NS Power has developed IRP load forecasts to integrate 4 sources of data:



- These load forecasts have been paired with the appropriate scenarios for the Initial Portfolio Study Phase (based on PATHWAYS Load Driver) – Final Scenarios and Modeling Plan
  - For resource portfolios of interest, multiple DSM Scenarios can be tested
- Intent of this approach is to provide a broad range of forecasts that also captures the provincial pathway to the Sustainable Development Goals Act (SDGA) targets.
- Load shape will be based on 2018 actuals; forecast shapes will need to be evaluated to ensure reasonableness and adjusted if necessary.

IRP LOAD FORECAST SCENARIOS ANNUAL ENERGY

- The following load scenarios (annual energy) have been developed for analysis in the IRP modeling phase, in order to test a meaningful range of potential future outcomes.



IRP LOAD FORECAST SCENARIOS ANNUAL ENERGY

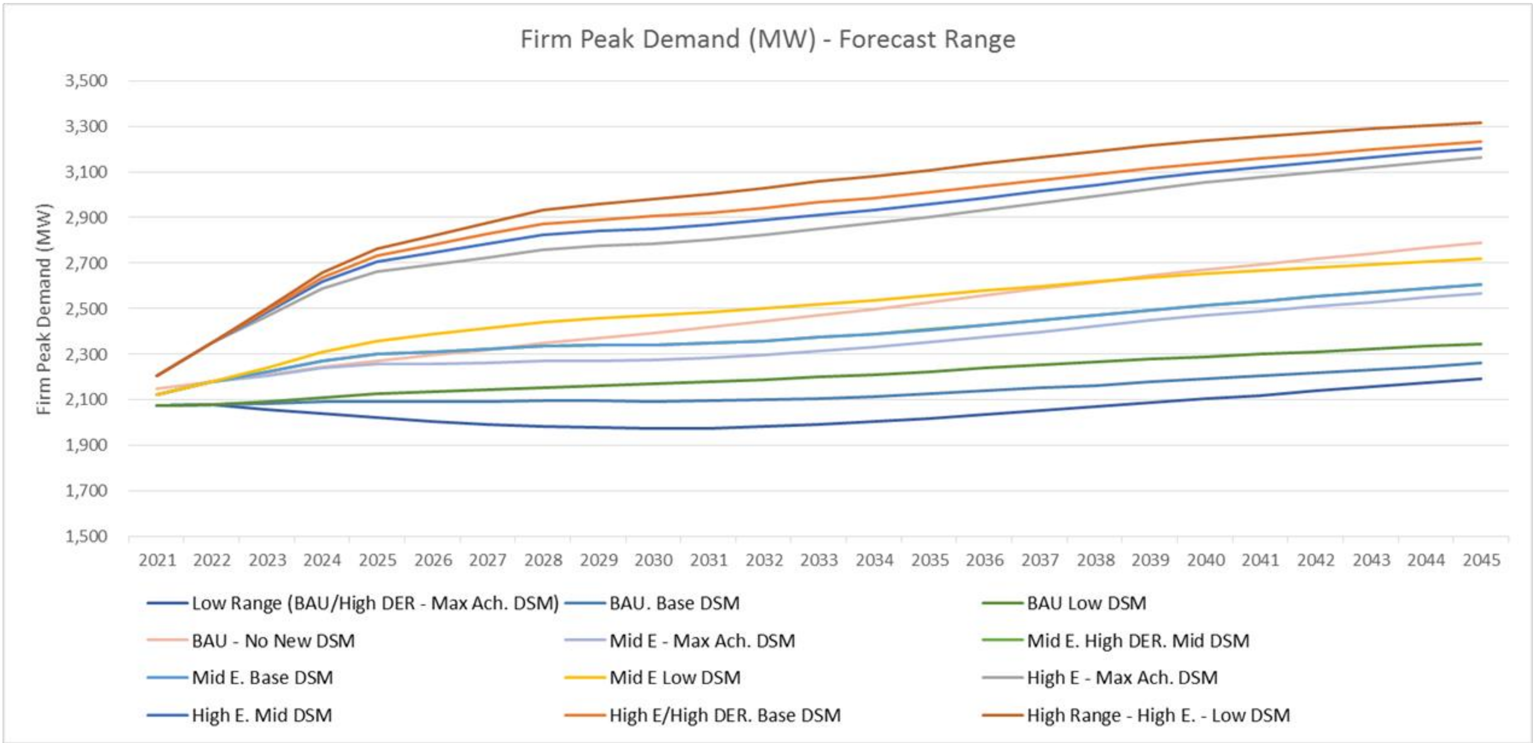
Year	Low Range (BAU/High DER - Max Ach. DSM)	BAU. Base DSM	BAU Low DSM	BAU - No New DSM	Mid E. Base DSM	Mid E Low DSM	Mid E. High DER. Mid DSM	Mid E - Max Ach. DSM	High E/High DER. Base DSM	High E. Mid DSM	High E - Max Ach. DSM	High Range - High E. - Low DSM
2021	11,252	11,327	11,327	11,695	11,403	11,403	11,329	11,403	11,457	11,531	11,531	11,531
2022	11,199	11,302	11,302	11,797	11,458	11,458	11,355	11,458	11,613	11,715	11,715	11,715
2023	11,015	11,260	11,306	11,886	11,449	11,541	11,315	11,384	11,748	11,835	11,770	11,927
2024	10,835	11,242	11,333	11,993	11,459	11,643	11,265	11,337	11,860	11,961	11,839	12,144
2025	10,588	11,165	11,300	12,038	11,391	11,662	11,113	11,228	11,829	11,972	11,809	12,243
2026	10,321	11,100	11,281	12,108	11,323	11,679	10,919	11,123	11,728	11,956	11,757	12,313
2027	10,079	11,044	11,270	12,187	11,269	11,708	10,744	11,042	11,643	11,955	11,728	12,394
2028	9,821	11,002	11,276	12,293	11,232	11,753	10,548	10,982	11,534	11,969	11,719	12,490
2029	9,504	10,924	11,236	12,342	11,165	11,751	10,276	10,908	11,334	11,949	11,692	12,535
2030	9,170	10,843	11,192	12,392	11,100	11,744	9,983	10,838	11,106	11,928	11,667	12,572
2031	9,054	10,809	11,192	12,483	11,086	11,781	9,902	10,827	11,085	11,958	11,699	12,653
2032	8,984	10,811	11,227	12,615	11,113	11,854	9,868	10,856	11,109	12,029	11,771	12,770
2033	8,898	10,786	11,226	12,699	11,122	11,893	9,815	10,873	11,107	12,084	11,834	12,855
2034	8,862	10,800	11,261	12,822	11,177	11,973	9,816	10,934	11,161	12,187	11,944	12,983
2035	8,829	10,816	11,297	12,947	11,240	12,055	9,825	11,003	11,221	12,302	12,064	13,117
2036	8,831	10,860	11,358	13,104	11,333	12,167	9,875	11,099	11,326	12,449	12,214	13,283
2037	8,811	10,873	11,380	13,207	11,401	12,239	9,898	11,173	11,399	12,570	12,342	13,408
2038	8,818	10,904	11,420	13,335	11,485	12,329	9,952	11,259	11,501	12,705	12,480	13,549
2039	8,841	10,944	11,464	13,462	11,578	12,419	10,014	11,359	11,606	12,848	12,629	13,689
2040	8,856	10,987	11,511	13,596	11,670	12,511	10,074	11,451	11,710	12,988	12,769	13,829
2041	8,848	11,003	11,525	13,681	11,730	12,563	10,102	11,513	11,770	13,086	12,870	13,920
2042	8,877	11,053	11,572	13,801	11,819	12,643	10,159	11,608	11,854	13,209	12,999	14,033
2043	8,905	11,104	11,619	13,919	11,905	12,718	10,211	11,698	11,928	13,324	13,117	14,137
2044	8,923	11,149	11,661	14,036	11,979	12,784	10,251	11,773	11,988	13,424	13,217	14,228
2045	8,963	11,216	11,721	14,151	12,072	12,862	10,310	11,868	12,060	13,537	13,333	14,327

High/Mid E = High or Mid Electrification impact from PATHWAYS
Max Ach. = Max Achievable DSM from E1's DSM Potential Study

1) Not all possible load cases
2) Units are Annual GWh

IRP LOAD FORECAST SCENARIOS FIRM PEAK

- The following load scenarios (firm peak demand) have been developed for analysis in the IRP modeling phase, in order to test a meaningful range of potential future outcomes.



IRP LOAD FORECAST SCENARIOS FIRM PEAK

Year	Low Range (BAU/High DER - Max Ach. DSM)	BAU. Base DSM	BAU Low DSM	BAU - No New DSM	Mid E - Max Ach. DSM	Mid E. Base DSM	Mid E. High DER. Mid DSM	Mid E Low DSM	High E. Mid DSM	High E/High DER. Base DSM	High E - Max Ach. DSM	High Range - High E. - Low DSM
2021	2,073	2,073	2,073	2,148	2,121	2,121	2,121	2,121	2,205	2,205	2,205	2,205
2022	2,078	2,078	2,078	2,180	2,176	2,176	2,176	2,176	2,347	2,347	2,347	2,347
2023	2,055	2,081	2,091	2,209	2,205	2,222	2,222	2,241	2,482	2,491	2,465	2,501
2024	2,040	2,089	2,110	2,242	2,240	2,271	2,271	2,309	2,617	2,635	2,586	2,656
2025	2,023	2,093	2,124	2,270	2,257	2,301	2,301	2,358	2,706	2,732	2,663	2,763
2026	2,004	2,092	2,133	2,294	2,257	2,310	2,310	2,385	2,746	2,780	2,692	2,821
2027	1,992	2,093	2,143	2,320	2,261	2,322	2,322	2,413	2,786	2,827	2,725	2,877
2028	1,982	2,094	2,154	2,346	2,268	2,333	2,333	2,440	2,824	2,870	2,759	2,930
2029	1,978	2,094	2,163	2,371	2,272	2,338	2,338	2,457	2,840	2,890	2,774	2,959
2030	1,973	2,093	2,169	2,393	2,274	2,340	2,341	2,469	2,851	2,904	2,784	2,980
2031	1,974	2,094	2,177	2,417	2,281	2,346	2,346	2,484	2,865	2,919	2,799	3,002
2032	1,980	2,099	2,187	2,443	2,295	2,358	2,358	2,501	2,887	2,942	2,824	3,030
2033	1,990	2,106	2,198	2,470	2,312	2,373	2,373	2,520	2,911	2,966	2,850	3,058
2034	2,003	2,115	2,211	2,499	2,330	2,388	2,388	2,538	2,933	2,986	2,874	3,082
2035	2,018	2,125	2,224	2,528	2,351	2,407	2,407	2,557	2,959	3,010	2,903	3,109
2036	2,034	2,137	2,237	2,557	2,374	2,428	2,428	2,577	2,986	3,036	2,933	3,136
2037	2,051	2,150	2,251	2,587	2,398	2,449	2,449	2,597	3,015	3,063	2,964	3,163
2038	2,068	2,163	2,264	2,616	2,421	2,471	2,471	2,616	3,043	3,088	2,994	3,189
2039	2,089	2,178	2,277	2,644	2,447	2,494	2,494	2,636	3,073	3,114	3,026	3,214
2040	2,105	2,191	2,289	2,670	2,468	2,515	2,515	2,653	3,099	3,138	3,053	3,237
2041	2,119	2,202	2,299	2,694	2,487	2,532	2,533	2,667	3,121	3,158	3,075	3,255
2042	2,137	2,216	2,310	2,718	2,508	2,552	2,552	2,681	3,143	3,178	3,099	3,272
2043	2,155	2,230	2,322	2,742	2,528	2,570	2,570	2,694	3,164	3,196	3,122	3,288
2044	2,173	2,245	2,334	2,765	2,548	2,589	2,589	2,708	3,185	3,214	3,143	3,303
2045	2,191	2,260	2,346	2,788	2,566	2,607	2,607	2,721	3,203	3,231	3,162	3,317

High/Mid E = High or Mid Electrification impact from PATHWAYS
Max Ach. = Max Achievable DSM from E1's DSM Potential Study

1) Not all possible load cases
2) Units are Firm Peak MW

2020 IRP: ENVIRONMENTAL ASSUMPTIONS (EXISTING & DEFINED POLICY)

MARCH 11, 2020

Nova Scotia POWER An Emera Company

APPLICABLE LEGISLATION

- Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations
- Regulations Limiting Carbon Dioxide Emissions from Natural Gas-Fired Generation of Electricity
- Greenhouse Gas Emissions Regulations
- Greenhouse Gas Pollution Pricing Act
- Cap and Trade Regulations
- Clean Fuel Standard

APPLICABLE LEGISLATION (CONT.)

- Air Quality Regulations
- Renewable Electricity Regulations

The following slides provide an overview of each of the regulations above as well as the current existing values of these policies.

REDUCTION OF CARBON EMISSIONS FROM COAL FIRED GENERATION

These Federal regulations require coal units to meet greenhouse gas (GHG) emissions intensity of 420t/GWh (via conversion to other fuel) or shut down at the end of "useful life", as defined by the regulations based on commissioning dates, and would cause conversion or retirement by the following years for the NS Power fleet:

- Nova Scotia's Equivalency Agreement with the Federal Government enables NS Power to continue to operate coal units after these dates.
- SCENARIO NOTE: Modeling scenarios will examine portfolios where all coal units are retired by Dec 31, 2029 in accordance with the 2018 Federal Coal Regulations.

GREENHOUSE GAS EMISSIONS REGULATIONS

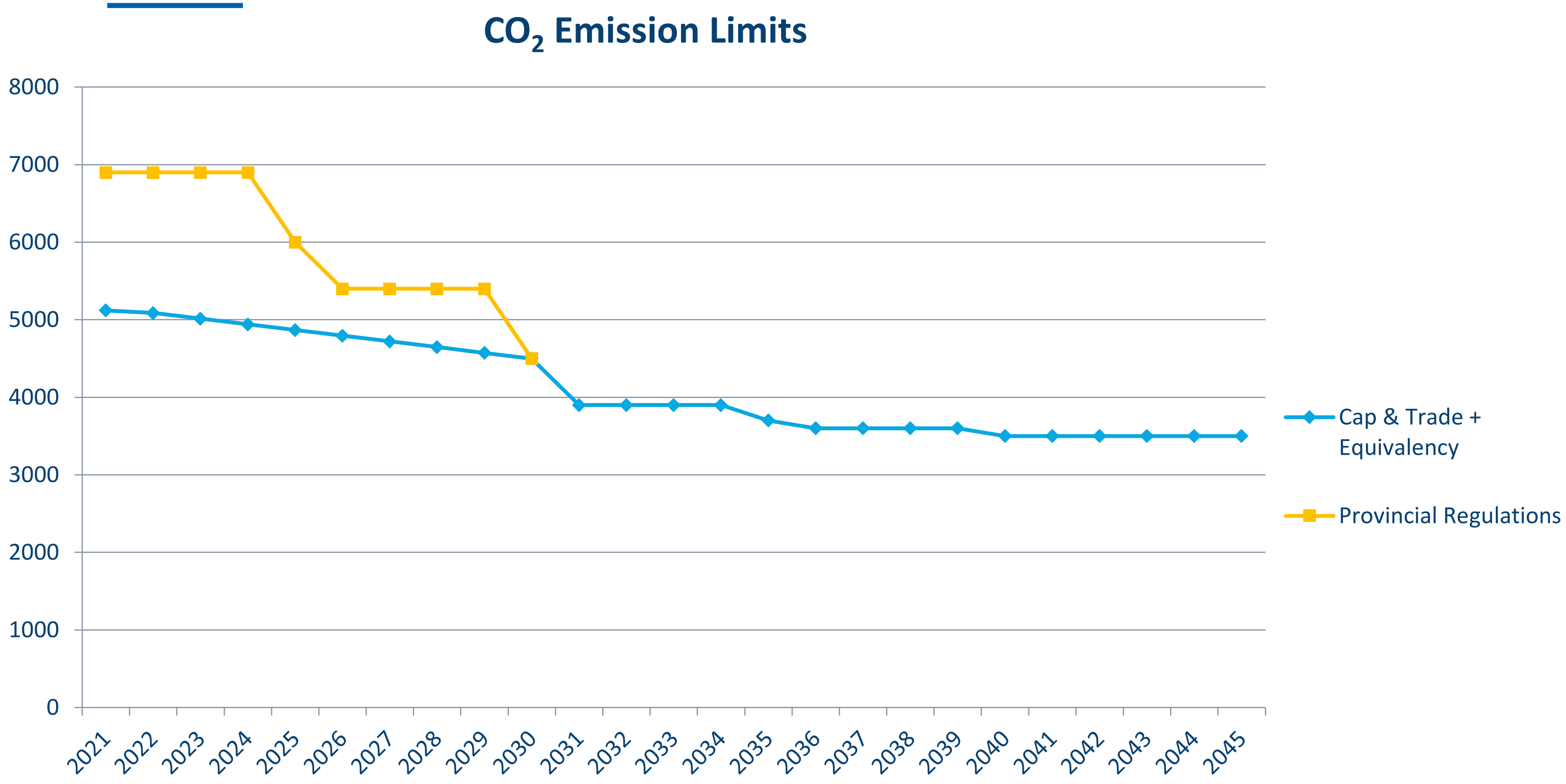
- These Provincial regulations stipulate GHG emission limits from 2010 to 2030 for all facilities in the province that emit greater than 10,000 tonnes GHG per year.

- Nova Scotia's equivalency agreement with the Federal government enables NS Power to meet the *Greenhouse Gas Emissions Regulations* as opposed to the requirements of the *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations*

- Nova Scotia's equivalency agreement has been renewed from 2020-2024 with agreement on future methodology from 2025-2040.

- Nova Scotia's equivalency agreements must meet evolving Federal requirements.

FORECAST CO_2 EMISSION HARD CAPS*



*Source: Greenhouse Gas Emission Regulations & Quantitative Analysis of 2019 NS Equivalency Agreement

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GREENHOUSE GAS POLLUTION PRICING ACT

- This act is the implementation of the Federal carbon pollution pricing system.
- Introduces an output-based pricing system (OBPS) for large industrial emitters.
- Provinces are free to choose an OBPS or cap and trade system if they meet the minimum Federal pricing and emissions reduction targets.
- Nova Scotia has opted for a cap-and-trade system, therefore, this act does not currently affect NS Power in the form of a carbon tax.

CAP AND TRADE PROGRAM REGULATIONS

- Provincial regulations that outline framework and requirements for cap and trade program.
- Stipulate free allocations for NS Power GHG emissions
- Meets the Federal *Greenhouse Gas Pollution Pricing Act* requirements

Greenhouse Gas Free Allowances 2021-2022

Year	GHG Free Allowances Million tonnes
2021	5.120
2022	5.087

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CAP & TRADE – MARKET PARTICIPATION

- The Nova Scotia cap and trade market is still developing with the first auction set for June of 2020.
- In the Resource Screening phase of the Modeling Plan, NS Power's IRP will screen the value of reductions in GHG emissions below the current allowances and selling those credits in the cap and trade market.
- NS Power's IRP model will not allow the company to purchase credits in order to over-emit current allowances.
- The sale price will be set at the market floor price of $20/tonne in 2020, escalating annually at 5% + inflation.

During Screening, Nova Scotia Power will:

- Examine whether the capacity expansion model generates different resource decisions based on the opportunity to sell credits, or if it simply monetizes available emission credits to offset fuel and production costs.
- Evaluate whether the quantities being sold are reasonable given the anticipated size of the Nova Scotia cap and trade market.
- Based on the screening results, NS Power will determine how cap and trade will be represented during the Portfolio Study phase of the modeling work.

CLEAN FUEL STANDARD

- Federal government published a regulatory framework for the Clean Fuel Standard which will apply to liquid, solid and gaseous fuels combusted for the purposed of creating energy.
- Coal combusted at facilities covered by *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations* will be exempt.
- Draft regulations have not yet been published.
- Expecting requirements for liquids to come into force by 2022 and for gaseous fuels by 2023.
- For IRP, NS Power expects "high" fuel price sensitivities to capture impact of this standard (e.g. no explicit assumption required for modeling).

AIR QUALITY REGULATIONS

- Provincial regulations that stipulate NS Power emission limits for Sulphur dioxide (SO2), nitrogen oxides (NOx) and mercury (Hg) from 2010 to 2030
- For mercury, Air Quality Regulations outline requirements for mercury diversion program and stipulates NS Power can use credits for compliance from 2020 to 2029.

Emissions Multi-Year Caps (SO2, NOx, Hg)

<table>
<tr><th>Multi-Year Caps
Period</th><th>SO_2 (t)</th><th>NO_X (t)</th><th>Hg (kg)</th></tr>
<tr><td>2020</td><td>60,900</td><td rowspan="2">14,955</td><td rowspan="2">35</td></tr>
<tr><td>2021-2022</td><td>90,000</td></tr>
<tr><td>2023-2024</td><td>68,000</td><td>56,000</td><td>35</td></tr>
<tr><td>2025</td><td>28,000</td><td>11,500</td><td>35</td></tr>
<tr><td>2026 – 2029</td><td>104,000</td><td>44,000</td><td>35</td></tr>
<tr><td>2030</td><td>20,000</td><td>8,800</td><td>30</td></tr>
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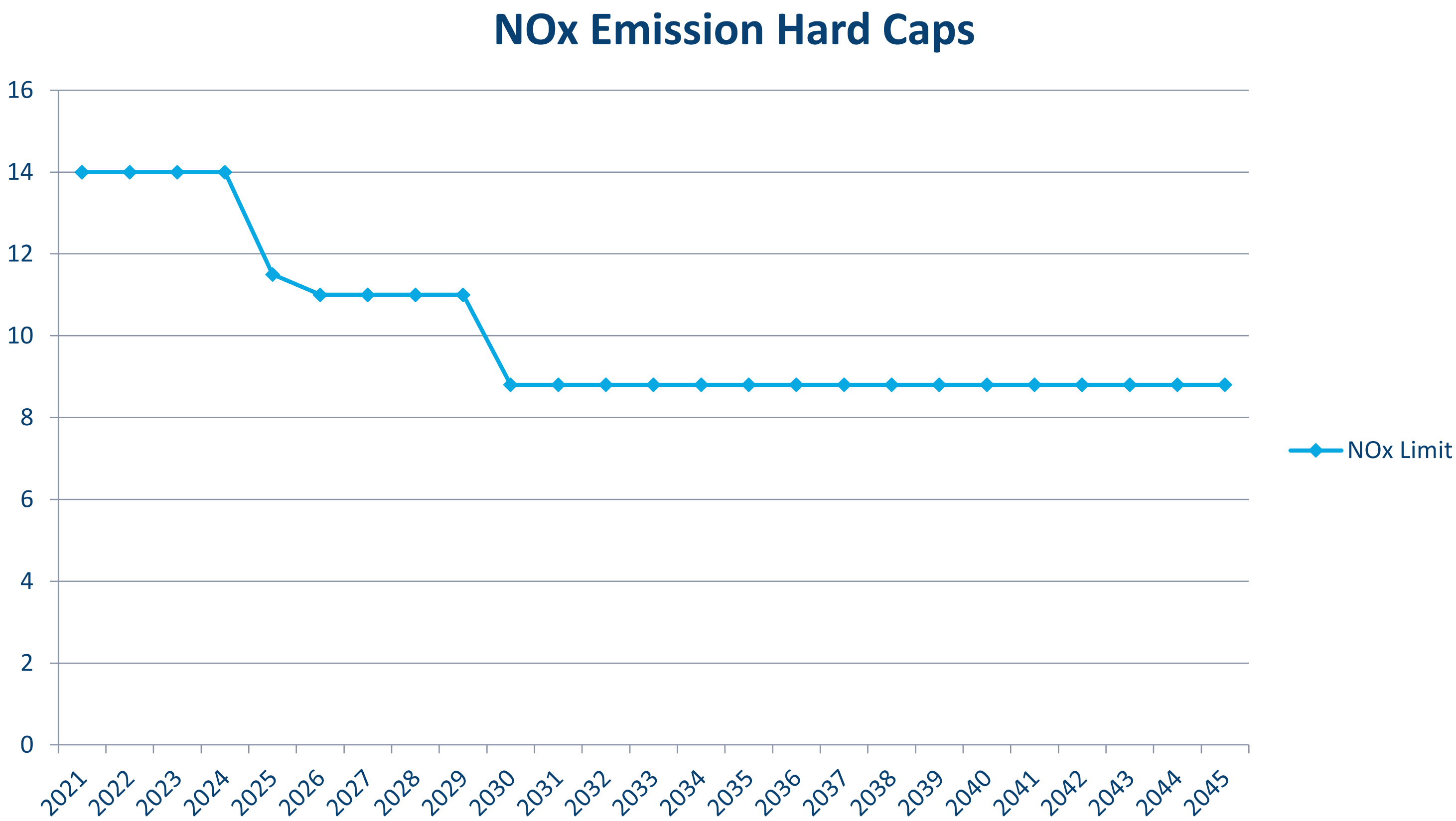
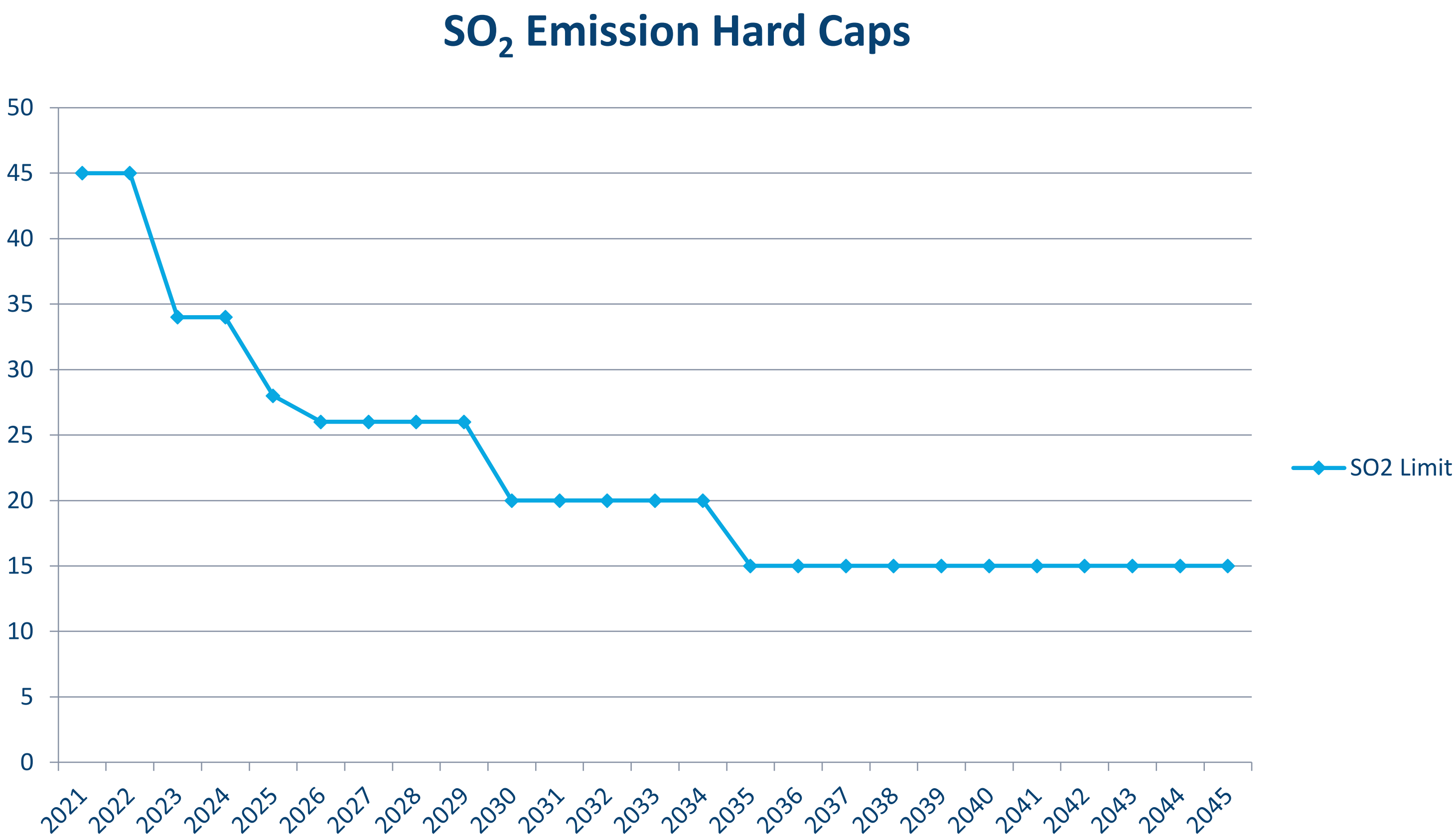
FORECAST NO_X EMISSION HARD CAPS

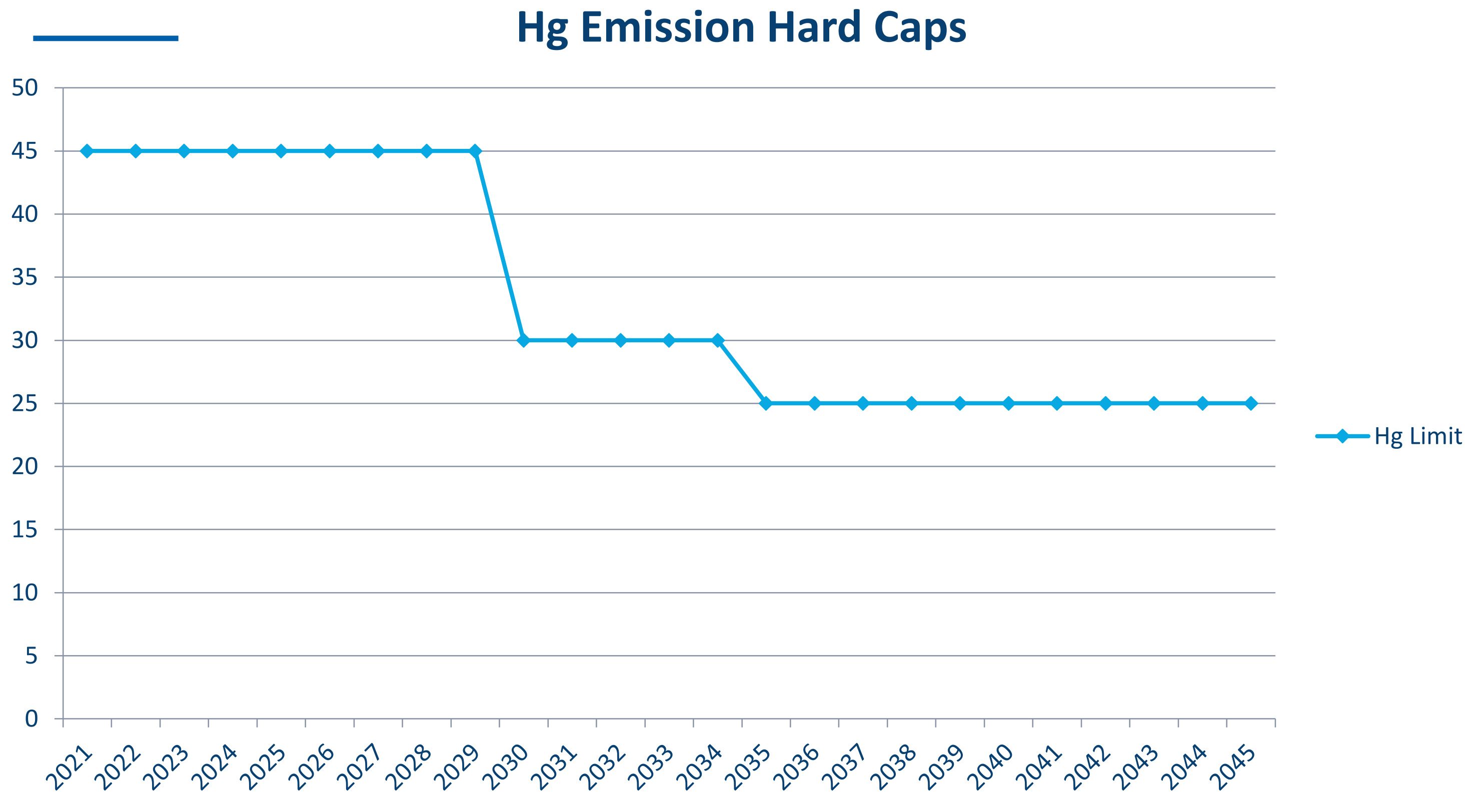


FORECAST SO_2 EMISSION HARD CAPS



*Based on the 2014 IRP which assumed further reductions beyond 2030 to reflect the declining path of emission caps. It is anticipated that more stringent CO_2 scenarios being tested in the 2020 IRP will result in a natural continued declining emissions trajectory.

FORECAST MERCURY EMISSION HARD CAPS*



*Air Quality Regulations outline requirements for mercury diversion program and stipulates NS Power can use credits for compliance from 2020 to 2029. The hard caps for 2020 to 2029 assume use of these credits.

*Based on the 2014 IRP which assumed further reductions beyond 2030 to reflect the declining path of emission caps. It is anticipated that more stringent CO_2 scenarios being tested in the 2020 IRP will result in a natural continued declining emissions trajectory.

RENEWABLE ELECTRICITY REGULATIONS

- Provincial regulations that require 40% renewable energy by 2020.
- NS Power has not assumed future specific renewable energy standards (RES) other than what will be required by the drive to net-zero carbon emissions from the *Sustainable Development Goals Act.*
- NS Power will evaluate renewable energy outcomes associated with effects of carbon caps/EGSPA (net zero) policy.

2020 IRP:
NEW SUPPLY SIDE OPTIONS

MARCH 11, 2020

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SUPPLY SIDE OPTIONS OVERVIEW

- The original draft assumptions for the costs of new bulk grid scale resources (capital costs and fixed and variable operating costs) were based on the E3 Resource Options Study from the Pre-IRP Deliverables.
- Since the Pre-IRP Work was completed, several of the public sources for pricing assumptions have released late 2019 datasets. The following slides reflect these updated data sources and subsequent pricing.
- For certain resource types NS Power will model a low capital cost as a sensitivity to assess the impact on resource additions in the capacity expansion model. This is designed to reflect lower than projected capital costs and/or serve as a proxy for lower cost of capital financing or alternative capital structures.

Energy+Environmental Economics

NS Power Resource Options Study
2020 Updates

Nova Scotia Power

March 11, 2020

Liz Mettetal, Sr. Consultant
Charles Li, Consultant
Aaron Burdick, Sr. Consultant
Sandy Hull, Sr. Consultant
Zach Ming, Sr. Managing Consultant

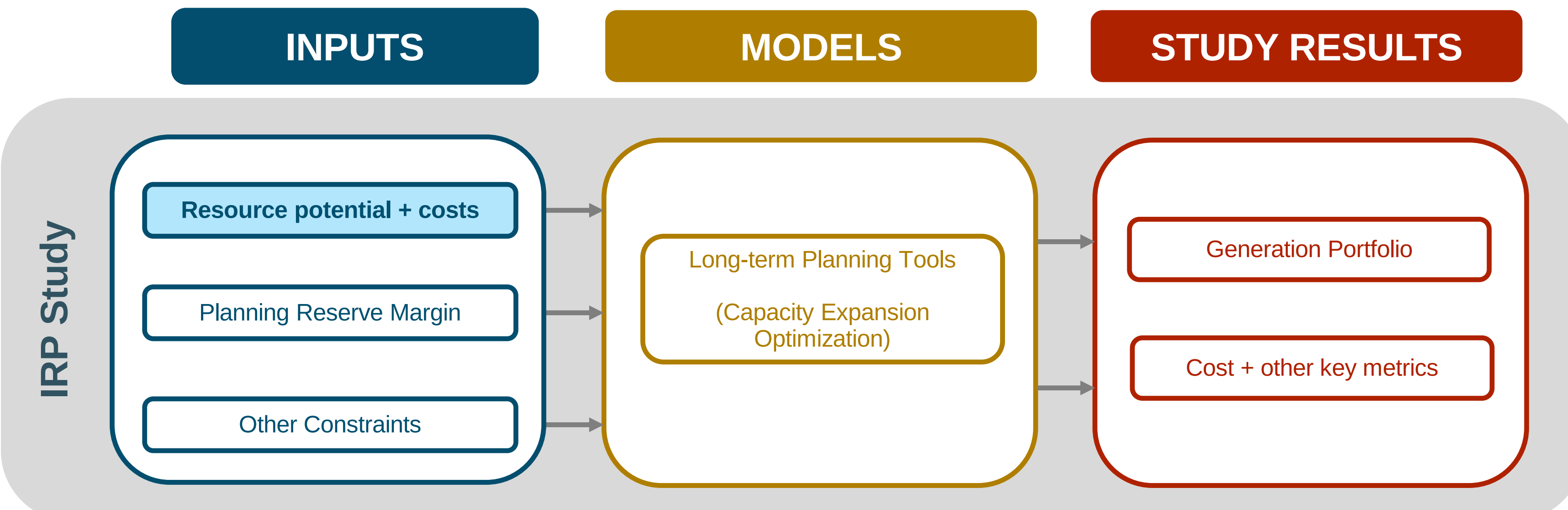
Energy+Environmental Economics

Resource options study approach

Approach

+ In preparation for its upcoming integrated resource plan, NS Power has asked E3 to provide guidance on resource costs and potential

- **Cost:** what are the costs (capital, O&M, fuel) associated with developing and operating each new resource? What future changes are expected?
- **Performance:** what are the operational constraints associated with each resource (e.g. hourly profiles for wind/solar)
- **Potential:** how much of the resource can be developed within Nova Scotia (or remotely)?



Resource Cost Modeling
Fixed vs. Variable Costs for New Resources

- **Fixed costs: expenditures required to install and maintain generating capacity, independent of operations**
  - Capital costs:
    - Overnight capital cost (equipment cost, balance of systems, development costs, etc.)
    - Construction financing
    - Nominal interconnection costs (i.e. a short spur line, not longer lines required for remote renewables)
  - Fixed O&M:
    - Operations and maintenance costs incurred independent of energy production
    - Insurance, taxes, land lease payments and other fixed costs
    - Annualized large component replacement costs over the technical life (aka sustaining capital)
- **Variable costs: marginal costs for each MWh of generation, based on modeled operations**
  - Variable O&M:
    - Operating and maintenance costs (parts, labor, etc.) incurred on a per-unit-energy basis
  - Fuel cost:
    - Commodity costs for fuel ($/MMBtu * heat rate MMBtu/MWh = $/MWh)
- **Capacity factor: annual energy production per kW of plant capacity**
  - Used to estimate variable costs as well as the spread of fixed costs over expected generation

Resource Options Considered

- **Fossil fuels:** coal-to-gas, coal-to-biomass *, natural gas (CC, CT, reciprocating engine, CC w/ carbon capture and storage)
- **Renewables:** biomass, municipal solid waste, solar PV, tidal, wind (onshore and offshore)
- **Energy storage:** li-ion batteries, compressed air, pumped hydro
- **Emerging technologies**: modular nuclear

** Conversion from coal is not an overly viable option. There has been pushback from running the existing NS Power biomass facility, so the social license for biomass in NS may not exist.*

Summary of Assumptions
Capital Costs (1 of 2) – Renewables and Storage

		Capital Cost (2019 CAD $/kW)		
Technology	**Subtechnology**	**2019**	**2030**	**% Change**
Wind	Onshore	$2,100	$1,691	-19%
	Offshore	$4,726	$3,429	-27%
Solar PV[a]	Tracking	$1,800	$1,416	-21%
Biomass	Grate	$5,300	$5,146	-3%
	Municipal Solid Waste	$8,470	$8,470	0%
Tidal	n/a	$10,000	$10,000	0%
Storage	Li-Ion Battery (1 hr)	$764	$385	-50%
	Li-Ion Battery (4 hr)	$2,125	$1,071	-50%
	Compressed air	$2,200	$2,200	0%
	Pumped Storage	$2,700	$2,700	0%

[a] Solar PV costs reported in $/kW-ac, reflecting an inverter loading ratio of 1.3

Summary of Assumptions
Capital Costs (2 of 2) – Fossil and Nuclear

		Capital Cost (2019 CAD $/kW)		
Technology	**Subtechnology**	**2019**	**2030**	**% Change**
Coal	Coal-to-gas conversion (102 – 320 MW)	$127 – 237	$127 – 237	0%
	Coal-to-biomass conversion (102 – 320 MW)	$1,313	$1,313	0%
Natural Gas	Combined Cycle (145 MW)	$1,688	$1,574	-7%
	Combined Cycle w/ carbon capture and storage (145 MW)	$3,376	$2,987	-12%
	Combustion Turbine – Frame (50 MW)	$1,080	$1,004	-7%
	Combustion Turbine – Aero (50 MW)	$1,755	$1,632	-7%
	Reciprocating Engine (50 MW)	$1,823	$1,823	0%
Nuclear	Small modular reactor (100 MW)	$9,196	$8,641	-6%

Summary of Assumptions
Operating Costs – All Technologies

Technology	Subtechnology	Operating Cost Fixed O&M ($/kW-yr)	Operating Cost Variable O&M ($/MWh)
Wind	Onshore	$59	$0
	Offshore	$165	$0
Solar PV	Tracking	$18	$0
Biomass	Grate	$155	$7
	Municipal Solid Waste	$162	$0
Tidal	n/a	$338	$0
Storage	Li-Ion Battery (1 hr)	$8	$0
	Li-Ion Battery (4 hr)	$27	$0
	Compressed air	$20	$0
	Pumped Storage	$32	$0
Coal	Coal-to-gas conversion	$37-$45	$1
	Coal-to-biomass conversion	$162	$7
Natural Gas	Combined Cycle	$15	$3
	Combustion Turbine - Frame	$17	$7
	Combustion Turbine - Aero	$17	$7
	Reciprocating Engine	$27	$9
Nuclear	Small modular reactor	$140	$0

All O&M costs assumed to escalate at 2% per year.

NS POWER CAPITAL COST SENSITIVITIES

- For certain resource types with current and future price variability/uncertainty, NS Power will model a low capital cost as a sensitivity to assess the impact on resource additions in the capacity expansion model. This is designed to reflect either lower than projected capital costs and/or serve as a proxy for lower cost of capital financing or alternative capital structure.
- While Li-Ion is listed above as the resource technology, it can be understood to be a proxy for any resultant storage options. Resultant storage options identified in high ranking portfolios would be assessed to confirm storage technology, size, and duration (e.g. Compressed Air Energy Storage, pumped hydro, etc.).

Resource Technology	Base Case (2019 $/kW)	Low Case (2019 $/kW)
Wind	$2,100	$1,500
Battery – Li-Ion (1 hr)	$764	$660
Battery – Li-Ion (4 hr)	$2,125	$1,835
Solar	$1,800	$1,515

2020 IRP: DISTRIBUTED ENERGY RESOURCES (DERs)

MARCH 11, 2020

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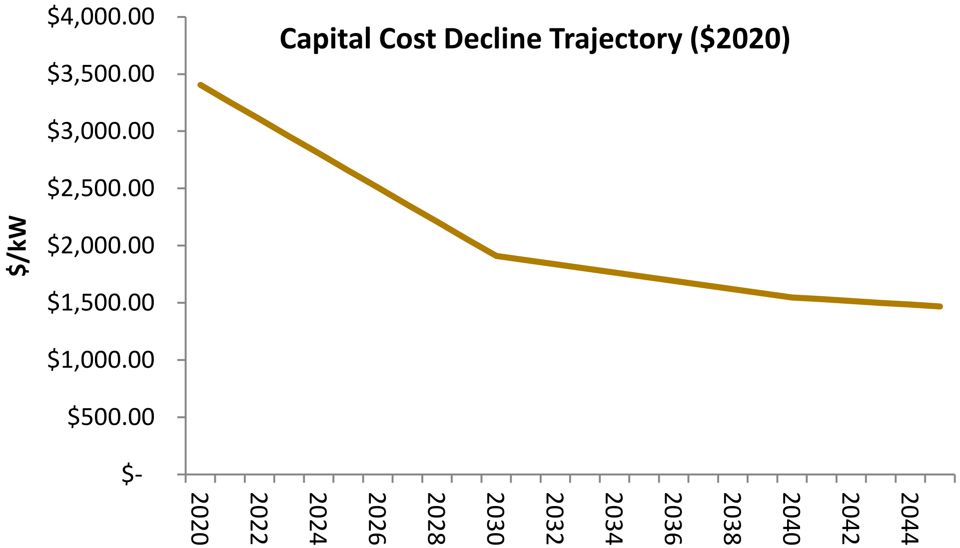
DISTRIBUTED ENERGY RESOURCES OVERVIEW

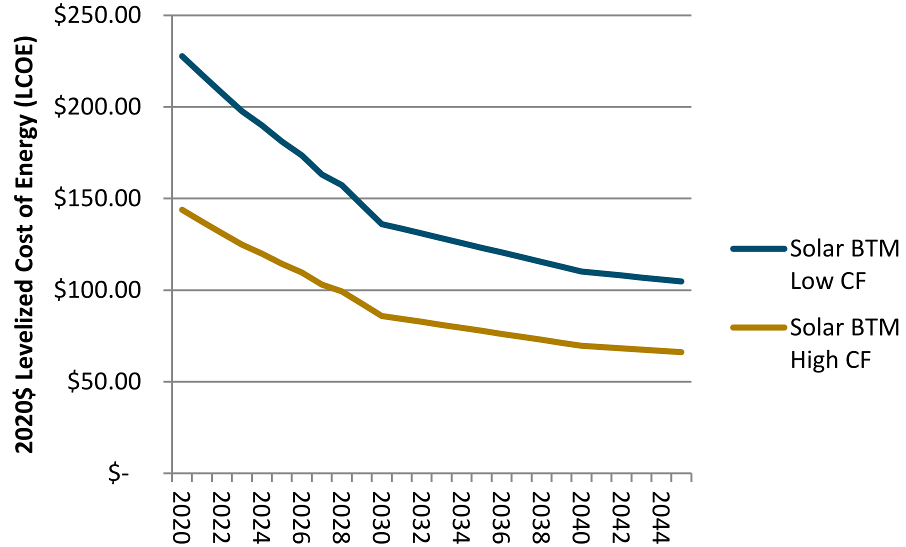
- As the grid becomes increasingly decentralized and more customers adopt distributed energy resources (DERs), long-term resource planners must address issues associated with evaluating their impact on the electricity system, including:
  - DERs introduce both system-level and distribution-level costs and benefits
  - DERs can be deployed and operated by utilities or customers and third parties
  - Although adoption and generation decisions can be influenced through incentives and rate design policy goals can also influence adoption (e.g., RPS, CO_2 targets)
  - Short panel of historical data and rapidly evolving technology costs/performance exacerbate uncertainty around these resources.
  - Capacity optimization models (as employed in the IRP) may not be granular enough to capture cost/benefits, particularly locational value.

DISTRIBUTED RESOURCES MODELING

- Given the challenges with the scale of DERs vs the granularity of IRP modeling, these resources will be examined via scenarios in the 2020 IRP (e.g. "plugs" of DERs will be mandatory in some model runs to ensure they are examined even if they would not have been economically selected based on the model constraints). See Scenario and Modeling Plan for more information.
- NS Power will work with stakeholders to ensure both the costs and benefits of DERs are evaluated at a reasonable level in the IRP.
- DERs will be accounted for in the model as a load modifier, with costs and benefits separately evaluated/discussed in the evaluation of each resource portfolio.

DISTRIBUTED SOLAR: COST ASSUMPTIONS

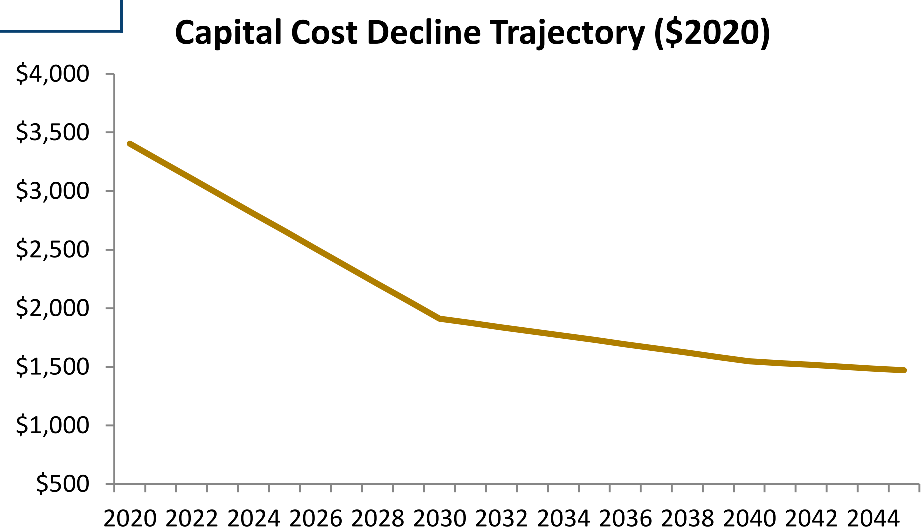




Input	Low Capacity Factor	High Capacity Factor
Capacity Factor	12%	19%
$\$/kW_{2020}$	$3405	$3405
FO&M ($/kW-Yr)	17.50	17.50
Financing Lifetime (Years)	25	25
Degradation (%/year)	0.5%	0.5%

BTM BATTERY STORAGE : COST ASSUMPTIONS

Input	1HR	4HR
$/kW$_{2020}$	$939	$2,330
FO&M ($/kW-Yr)	$7.67	25.16
Financing Lifetime (Years)	20	20
Annual Warranty (% of Capital Cost)	1.5%	1.5%
Annual Augmentation (% of Capital Cost	1.7%	2.7%



2020 IRP:
PLANNING RESERVE MARGIN

MARCH 11, 2020

*PLANNING RESERVE MARGIN AND CAPACITY VALUE STUDY

NS Power engaged E3 to undertake a PRM and capacity value study. This study provides an update to several important assumptions to be used in the IRP process to ensure an appropriate level of resource adequacy, so that it can continue to provide reliable and affordable power to its customers.

Resource adequacy is the ability of an electric power system to serve load across a broad range of weather and system operating conditions, subject to a long-run reliability standard. The resource adequacy of a system thus depends on the characteristics of its load—seasonal patterns, weather sensitivity, hourly patterns—as well as its resources—size, dispatchability, outage rates, and other limitations on availability such as the variable and intermittent production of renewable resources.

While a variety of approaches are used, the industry best practice for resource adequacy is to establish a reliability metric and target value and then calculate what quantity of planning reserves are required to achieve that reliability target.

*Planning Reserve Margin and Capacity Value Study, Energy + Environmental Economics, July 2019

PLANNING RESERVE MARGIN (PRM)

- The quantity of planning reserves that should be held above the forecast annual firm peak load, calculated as a % of annual firm peak
  - In order to meet a 0.1 days/year loss of load expectation (LOLE) target, NS Power should maintain between a 17.8% -21.0% planning reserve margin (PRM). The range in target PRM is due to a higher and lower estimate of operating reserve ("OR") requirements for the NS Power system.
  - NS Power will maintain its existing PRM of 20% as the base case assumption and iterate on portfolios to determine specific PRM requirements as illustrated in the Analysis Plan overview.

PLANNING RESERVE MARGIN (PRM)

Modeling Assumptions

- The NS Power model will use an Unforced Capacity (UCAP) method to calculate PRM during capacity expansion modeling in the 2020 IRP.
- Existing and new thermal and hydro units will be valued using the ELCC approach, consistent with the methodology being used for new renewable resources. Diversity benefits will be considered.
- During the Reliability and Operability Assessment phase of the modeling, plans will be assessed to ensure that the 0.1 Days/year Loss of Load Expectation (LOLE) metric continues to be met. This will include an iteration against an Installed Capacity (ICAP) PRM calculation. Resource portfolios will iterate through the model if required to meet reliability criteria.

2020 IRP: WIND, SOLAR, STORAGE AND DEMAND RESPONSE – EFFECTIVE LOAD CARRYING CAPACITY (ELCC)

MARCH 11, 2020

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*EFFECTIVE LOAD CARRYING CAPABILITY (ELCC)

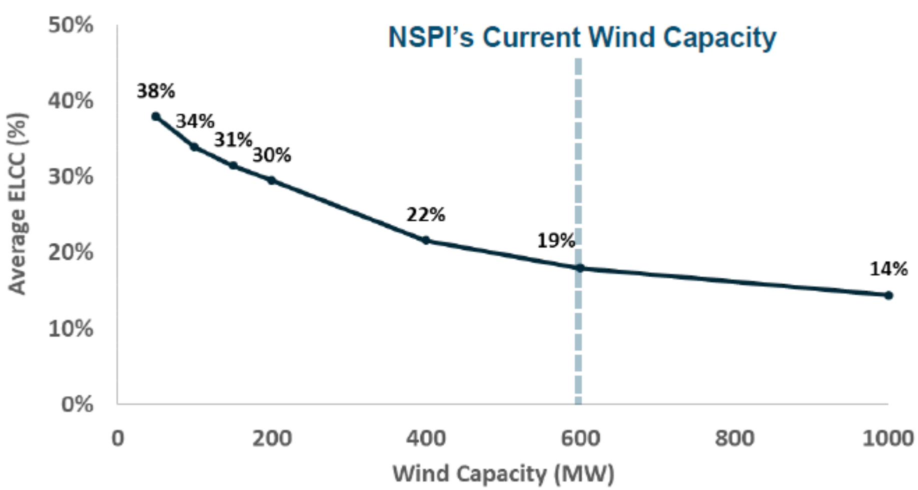
- The information from the Planning Reserve Margin and Capacity Value Study undertaken by E3 as part of the ‘Pre-IRP’ work will be used as the basis for the ELCC assumptions.
- Dispatch-limited resources like wind, solar, storage, and demand response can contribute effective load carrying capability (ELCC) toward meeting the planning reserve margin requirement, but have diminishing returns as additional capacity is added to the system to maintain reliability.
- The calculations of the ELCC for the portfolio of dispatch-limited resources are included in the full E3 Study provided with the Pre-IRP Report.

*Planning Reserve Margin and Capacity Value Study, Energy + Environmental Economics, July 2019

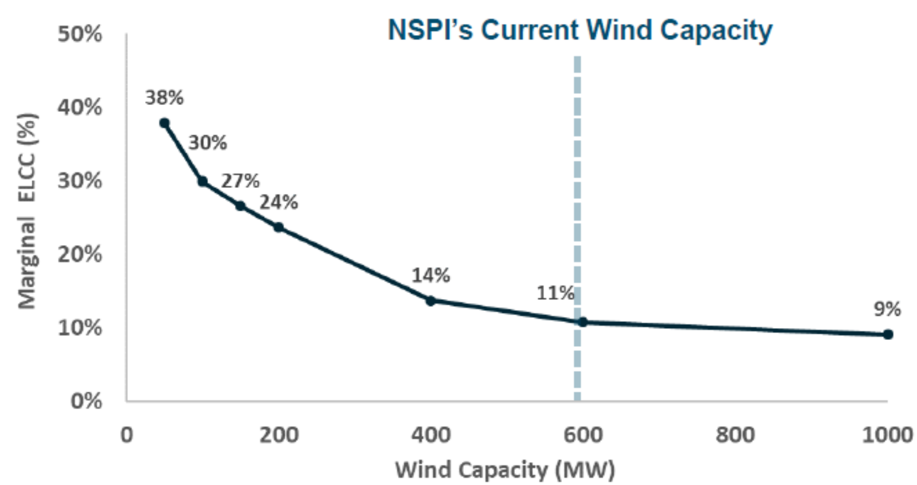
ELCC OF WIND

The average ELCC of the 596 MW of wind currently installed on the NS Power system is 19% or 111 MW. The ELCC value of adding new wind to the NS Power system is measured by the marginal ELCC and is currently at 11%, meaning that each additional MW of wind contributes 0.11 MW of firm capacity to PRM requirements.

NS Power's Average Wind ELCC

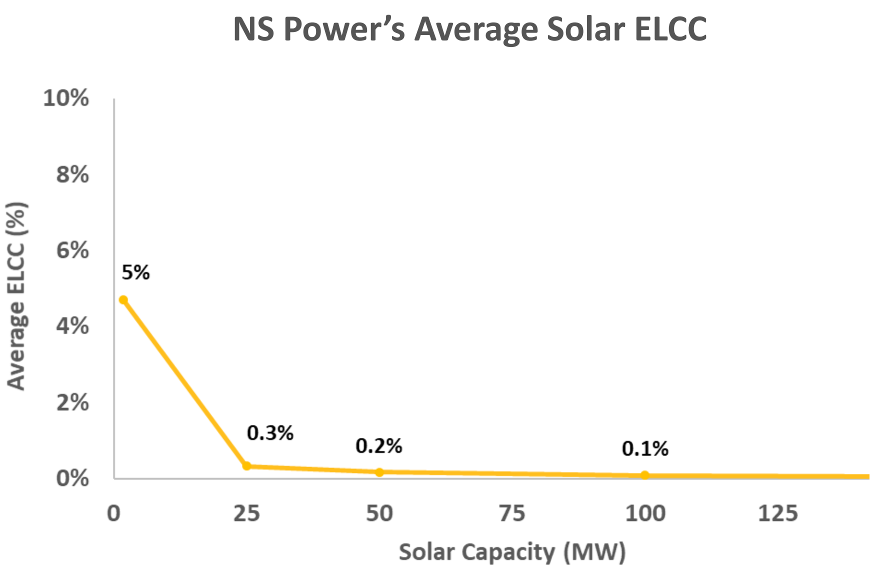


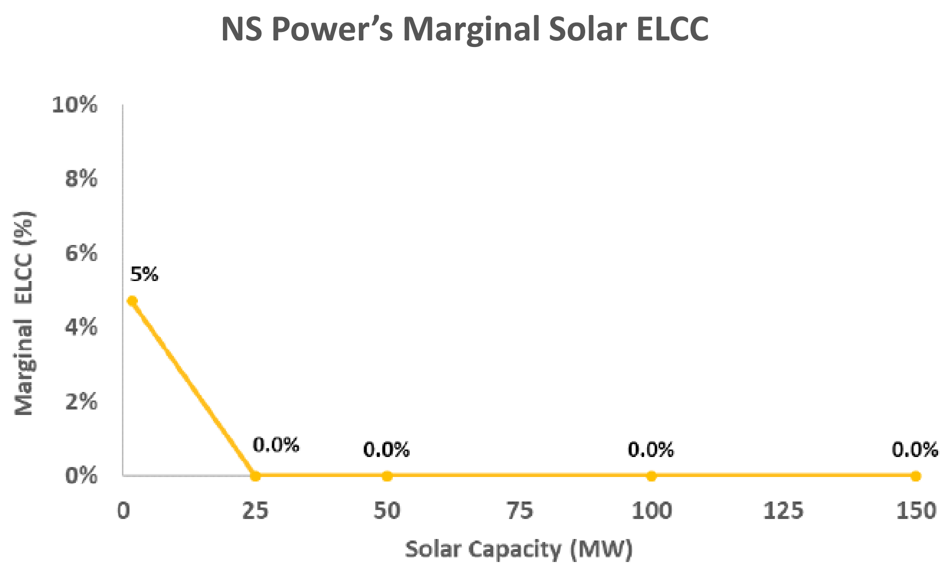
NS Power's Marginal Wind ELCC



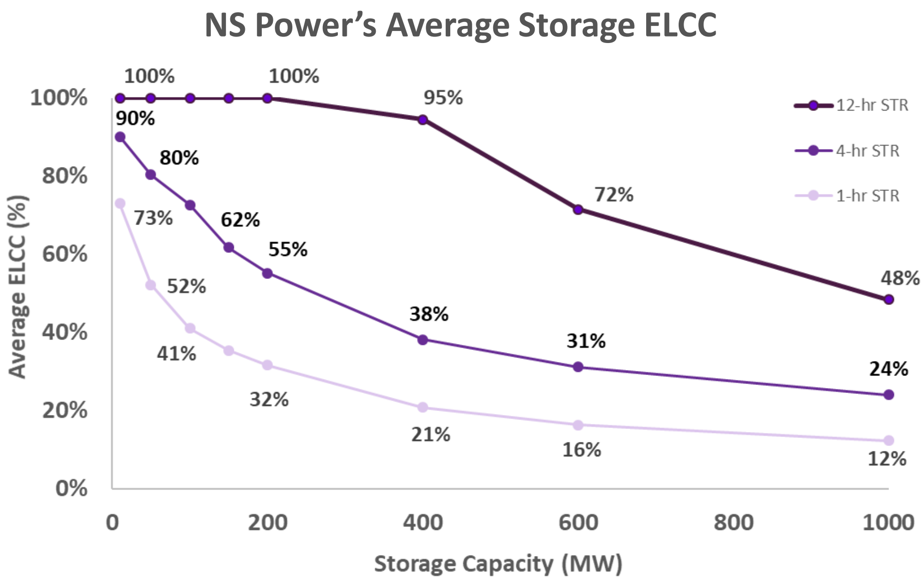
ELCC OF SOLAR

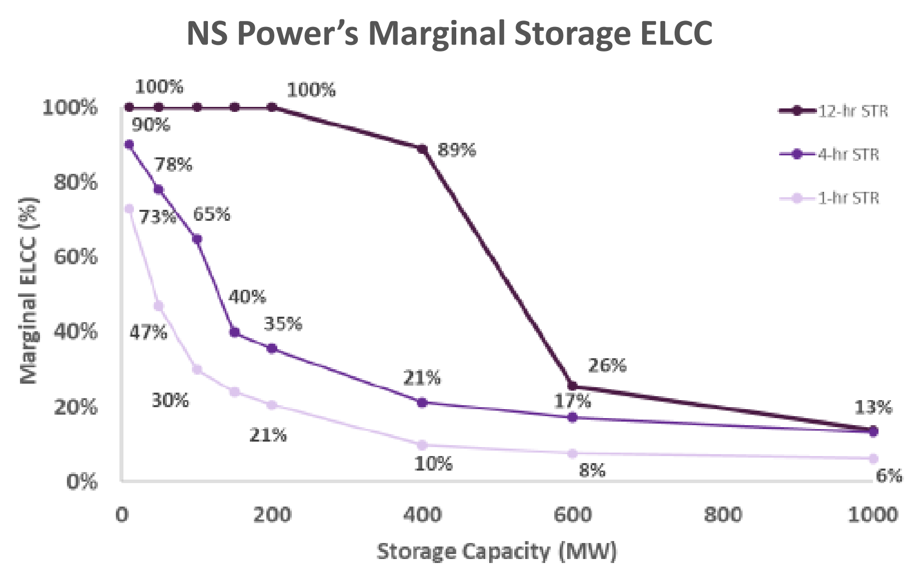
The NS Power system currently has a very small amount of solar capacity at only 1.7 MW which has an average and marginal ELCC of 5%. Solar has very limited ELCC in Nova Scotia due to poor correlation with the net peak load hours, which primarily occur on winter evenings. Beyond initial penetrations of solar capacity, the marginal capacity value declines to 0%.



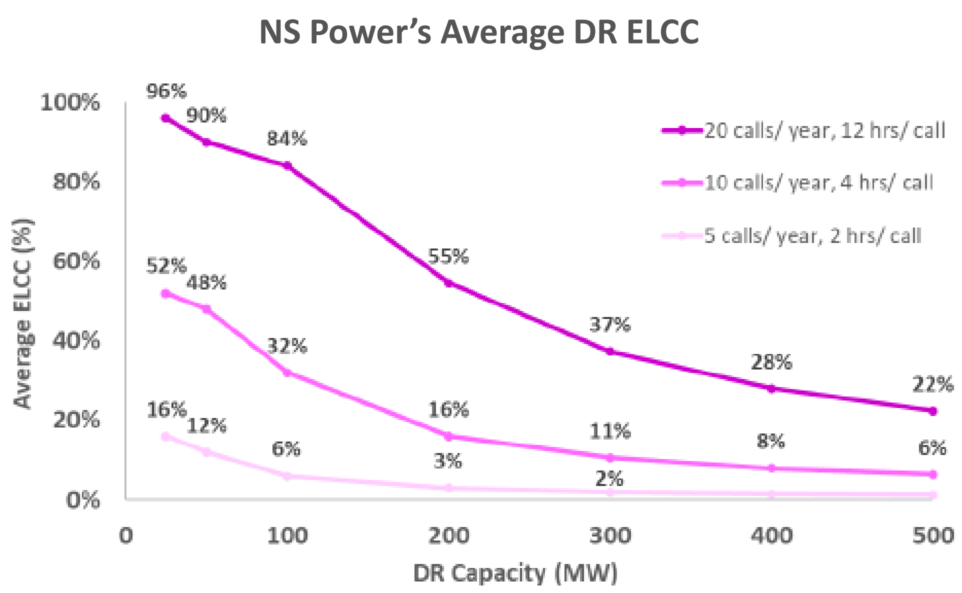


ELCC BATTERY STORAGE

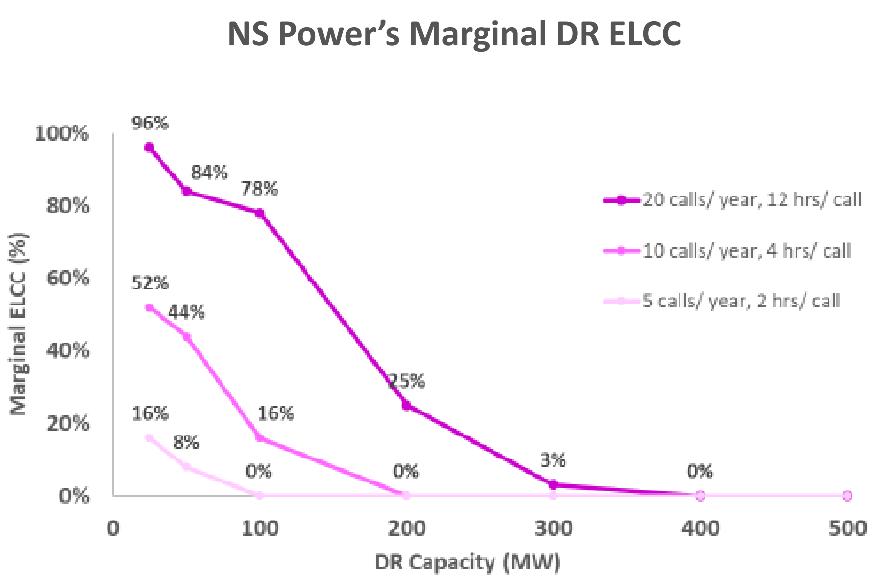




ELCC OF DEMAND RESPONSE

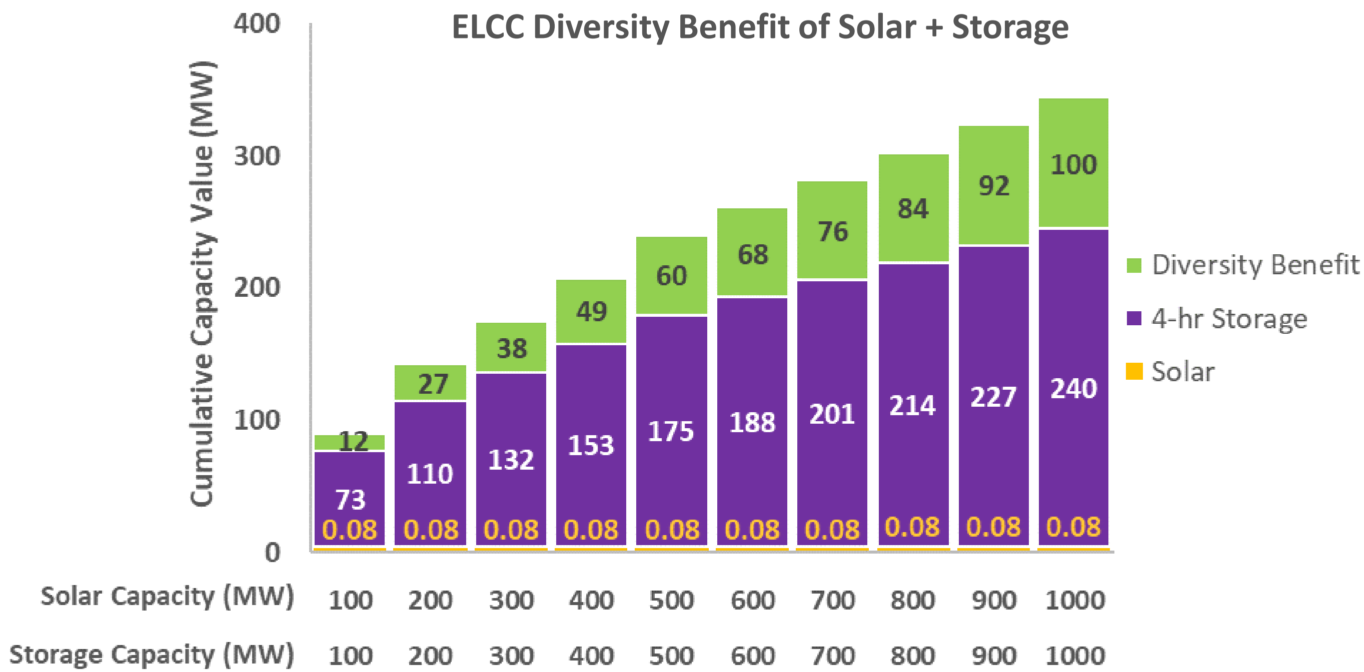


These represent illustrative demand response (DR) programs with different numbers of calls and durations. These results are not meant to map directly to specific existing DR programs but rather inform system planners of the ELCC value that a DR program with similar attributes might provide. As with all the previous results, DR exhibits diminishing average and marginal ELCC values. The ELCC of a DR program will depend on its specific characteristics.



ELCC DIVERSITY – PRM AND CAPACITY STUDY

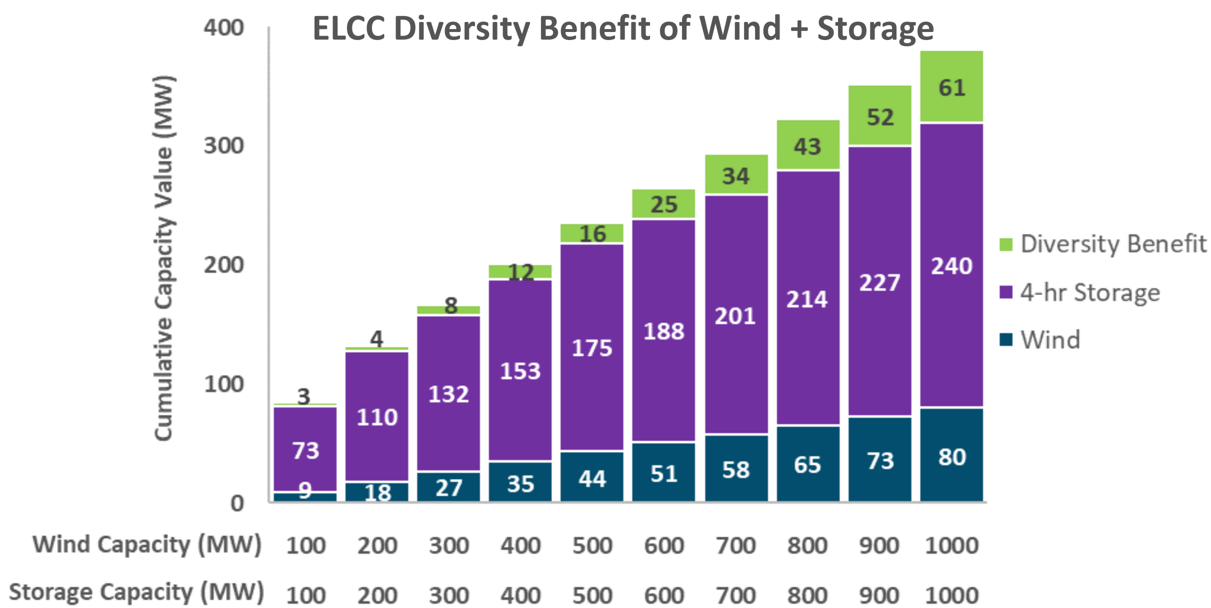
- Portfolios of dispatch-limited resource often provides a combined ELCC more than the sum of their individual parts
- Renewables + storage provide a unique set of synergies since renewables can provide the energy that storage needs to provide ELCC and storage provides the dispatchability that renewables need to provide ELCC



Planning Reserve Margin and Capacity Value Study, Nova Scotia Power, July 2019, Energy + Environmental Economics

ELCC DIVERSITY – PRM AND CAPACITY STUDY

- Because wind is more naturally coincident with the NS Power winter evening peak than solar, the incremental benefit from storage is less than in the case of solar



Planning Reserve Margin and Capacity Value Study, Nova Scotia Power, July 2019, Energy + Environmental Economics

2020 IRP:
DSM

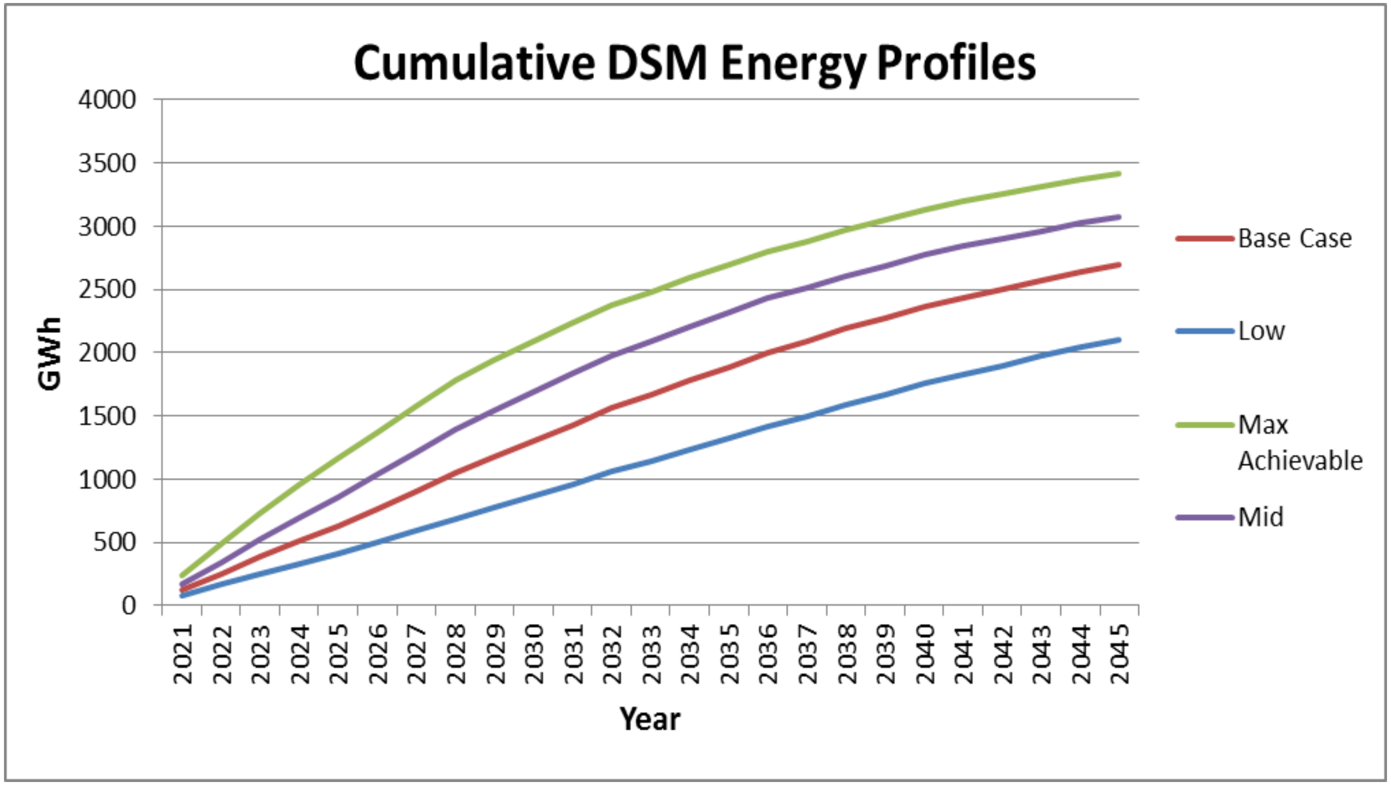
MARCH 11, 2020

*ENERGY EFFICIENCY (EE)

- The 4 DSM scenarios (Base, Low, Mid, Max Achievable) were subtracted from the "no new DSM" forecast.
- For 2021-2022, DSM amounts reflect the 2020-2022 DSM supply agreement - remaining years are held constant on an incremental basis.
- The scenarios are assumed to include all DSM, including:
    - Cost-effective electricity efficiency and conservation activities provided by the franchise holder
    - Initiatives that may be pursued by NS Power as permitted under the Public Utilities Act
    - Consumer behaviour and investments
    - Energy efficiency codes and standards
    - Initiatives undertaken by other agencies
    - Technological and market developments.

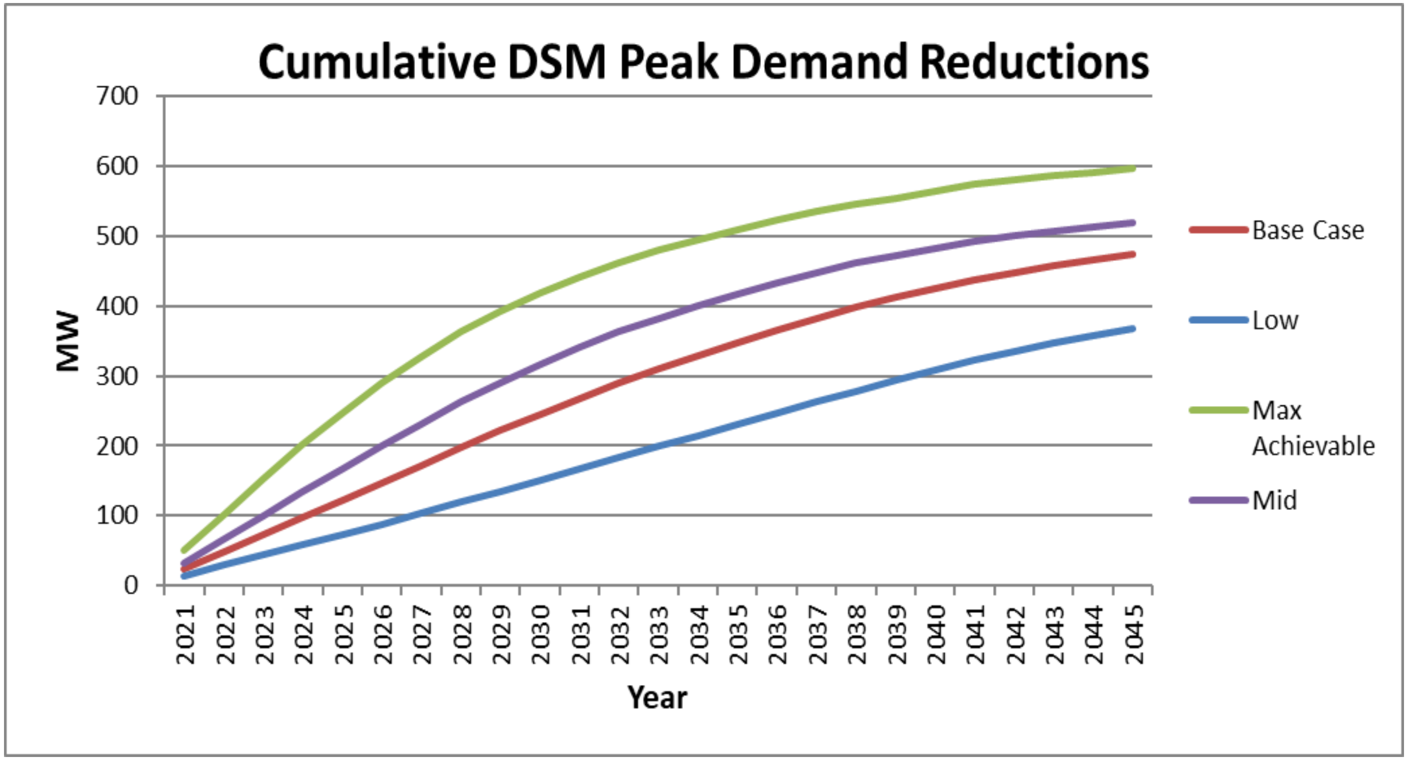
*Data Provided byE1 in 2019 Potential Study

*ENERGY EFFICIENCY (EE)



*Data Provided by E1 in 2019 Potential Study

*DSM PEAK REDUCTION



*Data Provided by E1 in 2019 Potential Study

2020 IRP:
DEMAND RESPONSE

MARCH 11, 2020

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DEMAND RESPONSE (DR)

- Demand Response (DR) programs for the 25-year period (2021-2045) have been provided by E1's Potential Study, along with the 3 specific programs developed by NS Power in the Pre-IRP Work.

- DR will be modeled as a resource option.

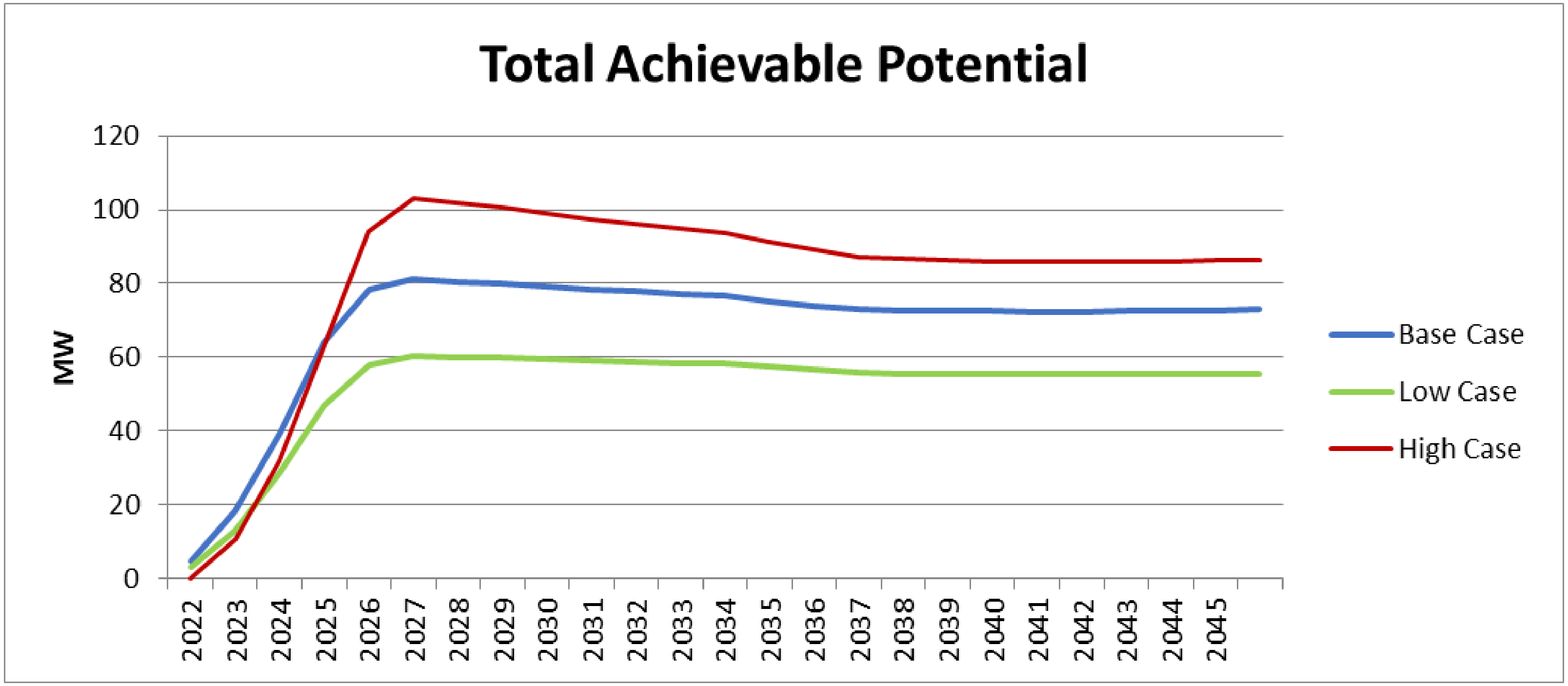
*DR OPTIONS SUMMARY (E1)

DR Option	Brief Description	Eligible Customer Classes	End Use
DLC-Direct Load Control	Control of electric loads by a thermostat and/or load control switch.	Residential Small Commercial Small Industrial	Electric Furnace [3] Heat pump [4] HVAC [5] Hot Water
BNI Curtailment	Firm capacity reduction commitment. $/kW payment based on delivered capacity, administered through third-party aggregators.	Large Commercial Large Industrial Interruptible	HVAC Lighting Water Heating Total Facility
BTM Battery Control	Use of batteries for load shifting and dispatching to the grid.	All classes	Batteries
EV Charging Control	Charging modulation to reduce EV demand during peak periods	EV	EV
Critical Peak Pricing (CPP)	A rate schedule with significantly higher peak prices to discourage consumption during peak times	All classes	Total Facility
Behavioural Demand Response (BDR)	Targeted notifications and incentives are provided to customers to encourage peak shaving	Residential	Total Facility

Source: Navigant

*Data and further details can be found in the E1 in 2019 Potential Study

E1 DR TOTAL ACHIEVABLE POTENTIAL

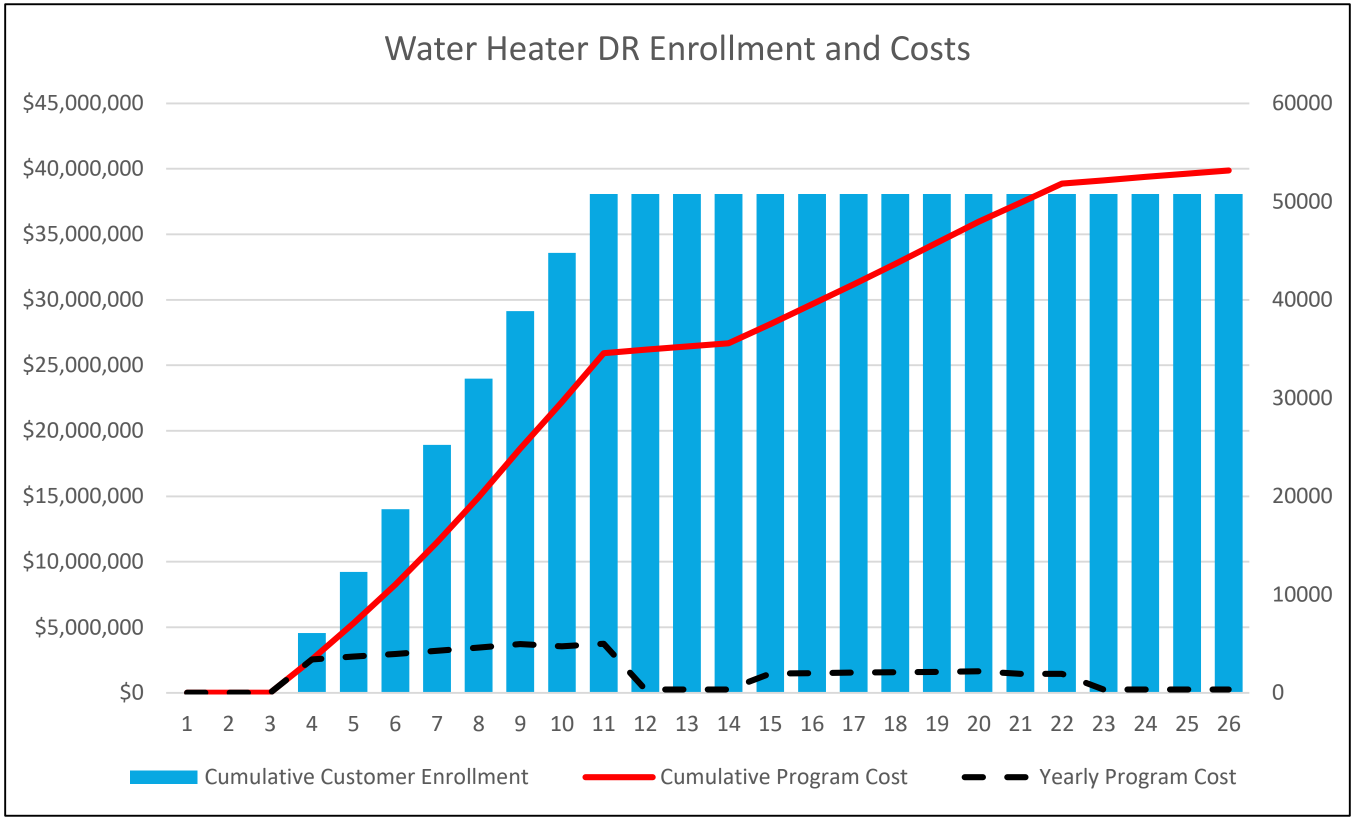


- All DR Programs from the 2019 DSM Potential Study are aggregated.
- DR program costs as per E1 Potential Study.

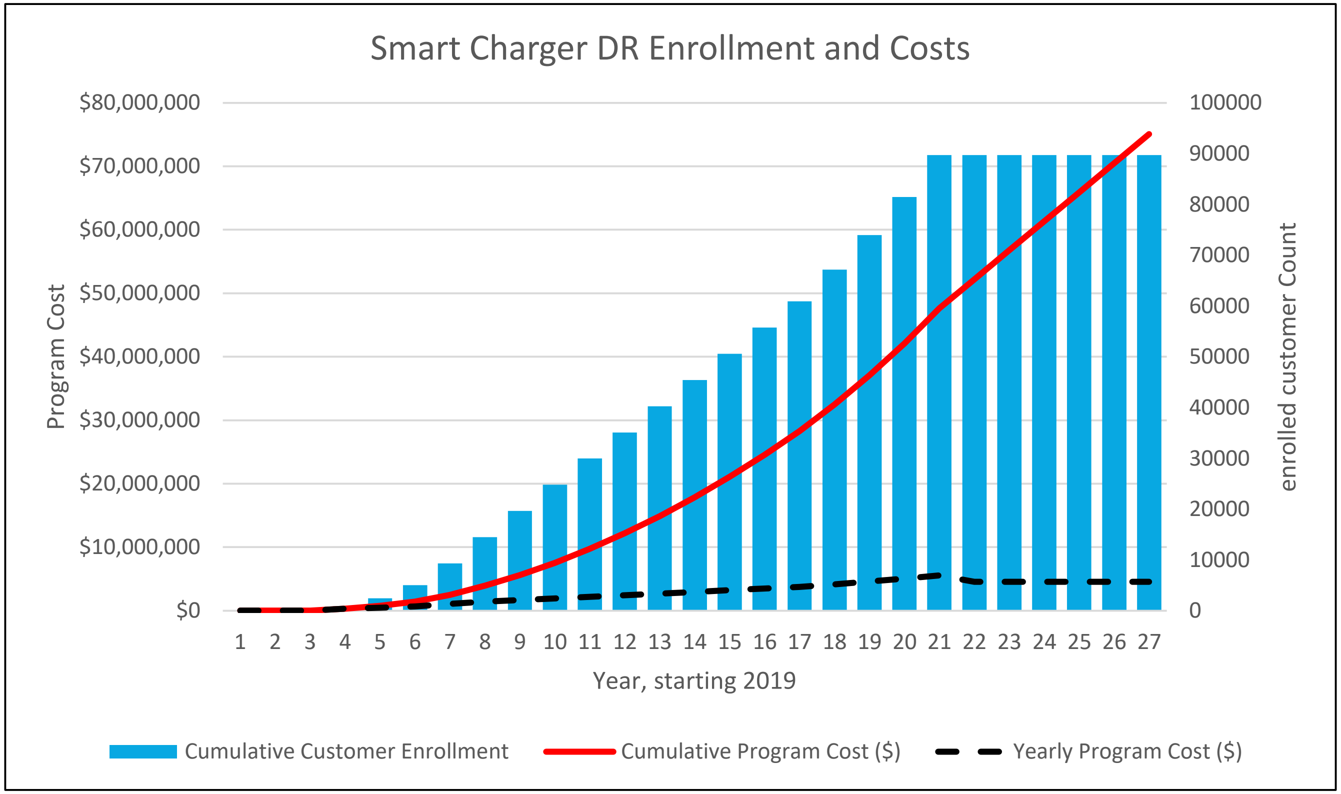
DR OPTIONS SUMMARY (NS POWER)

Device	Program	Peak shaving potential (kW/device)	Customer Incentive	Participation Scenario (in year 25)	NS Power Total Program Costs (25-yr)
Water Heater	Controller installed on customer WH and used during peak shifting events	0.5	$25 enrollment, $25/yr when compliant to program criteria	Cumulative 50,779 participants (10% of market), 27 MW peak shaving potential	$1.4M/MW
EV Supply Equipment	Customer owned and installed EVSE with peak shifting participation incentives	0.7	$150 enrollment, $50/yr when compliant to program criteria	Cumulative 89,704 participants (70% of market), 63 MW peak shaving potential	$0.75M/MW
Residential Battery	Customer contribution comparable to diesel generator installation, utility control for up to defined number of system peak events	2.5	$2500 customer contribution, Balance of battery cost covered by NS Power and funding where available.	Cumulative 4000 participants, 6.25 MW peak shaving potential	$7.16M/MW

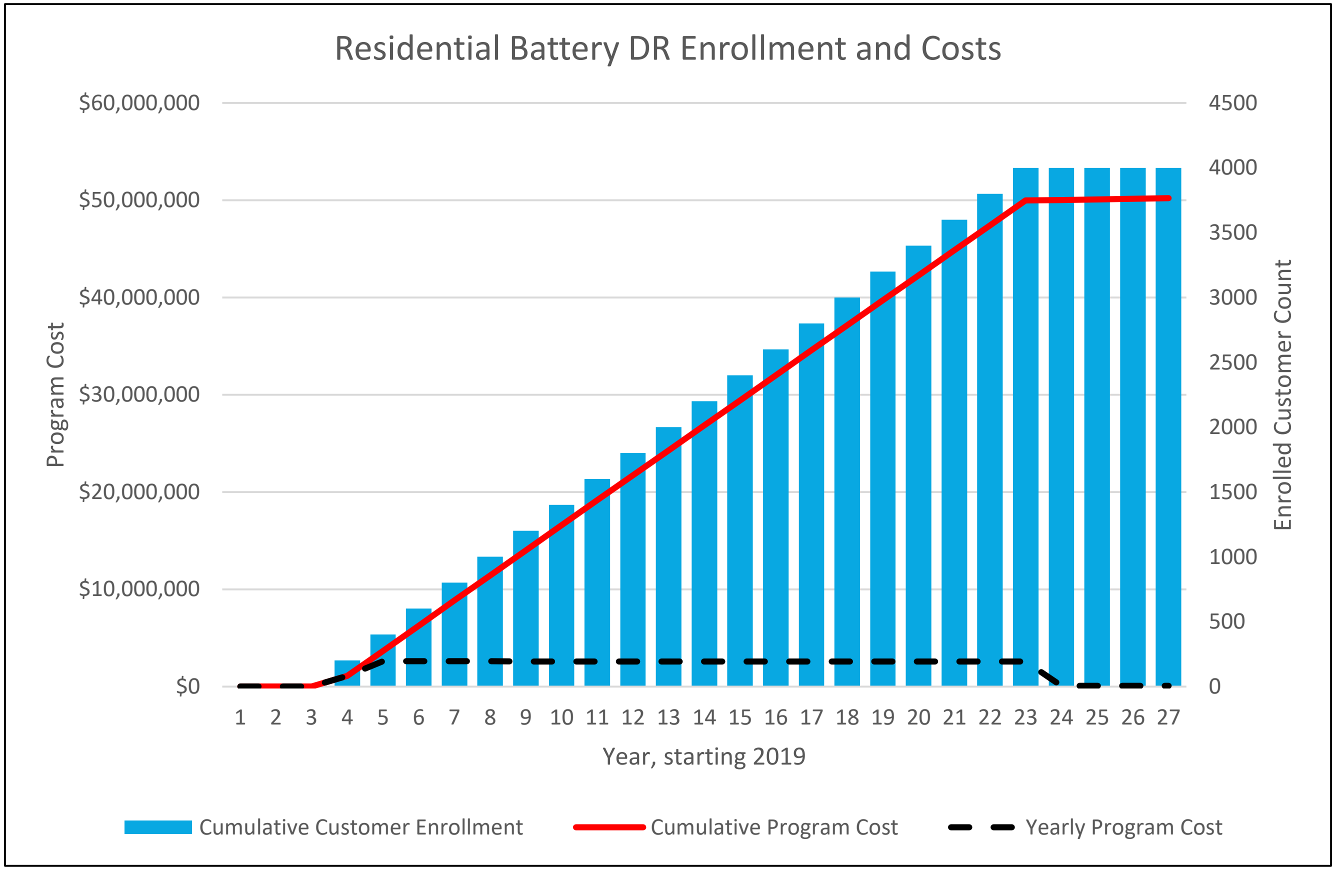
DR OPTIONS SUMMARY (NS POWER) CONT.



DR OPTIONS SUMMARY (NS POWER) CONT.



DR OPTIONS SUMMARY (NS POWER) CONT.



2020 IRP: IMPORTS

MARCH 11, 2020

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SUMMARY – IMPORTS

- Firm imports could support the transition to lower GHG emissions and the replacement of coal-fired generation capacity via greater regional interconnection.

- Firm Transmission is required for each option and is obtained via existing transmission or assumed new transmission, depending upon the import source and assumption regarding existing transmission availability.

    - Firm transmission capability is the amount of electricity that can be delivered in a reliable manner after consideration of surrounding system loads, voltages and stability conditions.

    - Non-firm transmission is the additional capability that can be used for energy delivery from time to time but is subject to curtailment under different system conditions.

SUMMARY – IMPORTS (CONT.)

Firm Import Options :

- Access to firm capacity via existing transmission up to ~150 MW; and/or
- Access to firm capacity via new transmission build up to ~450 MW.

Non-Firm Import Options:

- Import energy via existing transmission (Maritime Link and New Brunswick tieline); and/or
- Import energy via new transmission.

ENABLING TRANSMISSION INVESTMENT

The Qualitative Benefits of Transmission:

- Enhanced system reliability (voltage support, reserve sharing, etc.).
- Expansion of renewable generation integration.
- Option Value (greater market access through congestion reduction; supplier alternatives support energy purchase negotiations).
- When coupled with an energy and capacity contract, the opportunities are expanded.

Quantitative Benefits of accompanying energy and capacity contract :

- Firm capacity import enabler (to support coal capacity retirement).
- Renewable energy imports (to reduce air emissions and avoid carbon costs).
- Expanded economic energy imports.

IRP NEW TRANSMISSION COSTS

NS Power Transmission Capital Cost Estimates		
Description (New Transmission)	Total Capital Cost ($2021) [1]	NB-NS Tieline Gross Capacity (MW)
345kV Onslow-Salisbury-Coleson Cove	$600M	700
345kV Onslow-Salisbury ; HVDC to QC [2]	$1.7B	1000

- Assumptions presented here would be subject to additional feasibility study if selected during the IRP modeling.
- The transmission costs above are the assumed total capital cost of the builds and do not reflect potential cost sharing. Opportunities for cost sharing may depend on forecast utilization and will be examined during the resource screening phase.

1) Earliest in-service date is 2026
2) Costing to Quebec Border.

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PRICING FOR FIRM IMPORTS

Pricing

- Pricing for capacity provision is based on Platts Analytics forecast.
- Pricing for energy provision derived from Platts Analytics forecast.
- Emissions accounting as per Standards for Quantification, Reporting, and Verification of Greenhouse Gas Emissions (QRV Regulation)

Approach

- Reliability considerations for Resource Portfolios of interest will be considered during the Reliability and Operability Screening phase
- The model will be provided with pricing for both emitting and non-emitting sourced imports
- The model will be offered both spot market prices and firm blocks of energy tied to capacity

2020 IRP:
FUEL PRICING

MARCH 11, 2020

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SERVICE PROVIDERS

- **S&P Global Platts analytics (formerly PIRA Energy group) (Natural Gas, Oil) & Energy Ventures Analysis (EVA) (Coal, Petcoke)**
  - Long time service providers to NS Power
  - World-wide perspective and insights
  - Forecasts utilized in Maritime Link, 2014 IRP

Forecasting approach

- NS Power Fuels, Energy & Risk Management (FERM) utilized commercially available long-term prices forecasts for Natural Gas, Solid Fuel, Oil and Power which it subsequently adjusted for delivery to NS based on:
    - Current and expected transportation costs and tolls
    - Market insight and proprietary views on long-term market development, including High, Low and expected scenarios where applicable (by third parties and NS power)

2020 IRP:
FUEL PRICING - COAL & PETCOKE

MARCH 11, 2020

FUNDAMENTAL PRICE FORECASTS – COAL & PETCOKE - EVA

Commodity	Highlights	Provider
Base Case - Coal	• Continued decline in demand for coal in the US and Europe as coal power plants and other sources of coal demand are retired resulting in declining production in the US and Colombia • Asian markets remain relatively strong as new coal power generation is added in Japan and elsewhere. • Australia and Indonesia continue to be the largest exporters of coal. • Full trade with China is restored	Energy Ventures Analysis
Base Case – Petcoke	• Petcoke continues to be an available by-product from the oil refinery process. Petcoke quality is a function of crude oil type. • The largest market for fuel grade petcoke is cement kilns. Once tuned to burn petcoke, kilns will stay on petcoke unless there is a material financial incentive to switch to coal. • Power generation is also a significant market but much smaller. Power generators are more sensitive to pricing. • Petcoke prices do not correlate with any specific energy source. Rather, supply and demand at any one time determine pricing. Coal prices over time cap petcoke prices.	Energy Ventures Analysis

FUNDAMENTAL PRICE FORECASTS

Delivered Price	=	Commodity	+	Transportation
Base Case – Coal	=	Coal Source: EVA (1Q2020) Reference Case	+	Ocean Freight Source: CSL Freight rates per NS Power Contract estimated using current contract rates
2020 Contract Rates for domestic coal delivered.	=	Fully evaluated (Environmental attributes and BTU content)	+	Delivered Costs (Trucked)
Base Case – Petcoke	=	Petcoke Source: EVA (1Q2020) Reference Case	+	Ocean Freight Source: CSL Freight rates per NS Power Contract estimated using current contract rates

2020 IRP:
FUEL PRICING - NATURAL GAS

MARCH 11, 2020

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FUNDAMENTAL PRICE FORECASTS

Commodity	Pricing Point	Provider	Updated
Natural Gas	(N.A.) Henry Hub	S&P Global Platts' Analytics (formerly PIRA Energy Group) Scenario Planning Service Quarterly Update	Q4 2019
	(LNG) TTF, Spot (International Natural Gas) JKM (Asian Natural Gas)		
	AECO Basis Dawn Basis	S&P Global Platts' Analytics (formerly PIRA Energy Group) (LT) S&P Global Platts' Analytics (formerly PIRA Energy Group) (ST)	JUNE 2019 NOV 2019
Fuel Oil	New York Harbour	S&P Global Platts' Analytics (formerly PIRA Energy Group) Scenario Planning Service Quarterly Update (Brent) InterContinental Exchange (ICE)	Q4 2019 DEC 2019

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NATURAL GAS OPTIONS - SUMMARY

- NS Power's 2020 IRP will evaluate natural gas units (combustion turbines/combined cycle/reciprocating units/steam turbines) as potential capacity replacements for the aging coal fleet for either economic or policy reasons.
- Continuing improvements in natural gas plant flexibility, fuel efficiency and fuel supply are leading to, in certain jurisdictions, competitive advantages over coal, particularly given the faster pace of grid operations driven by variable generation.
- Gas typically plays a role in backing up renewables- especially during the extremes when wind and solar could be at a minimum.
- Permitting must be considered when evaluating fossil-fuel based infrastructure modification/reinforcement/expansion.

NATURAL GAS OPTIONS – SUMMARY (CONT.)

- While the installed cost of new gas units is well documented, the all-in levelized cost of energy is subject to significant uncertainty associated with the delivered cost of natural gas, particularly given the supply constraints in Nova Scotia.
- During peak winter conditions, heating demands from firm natural gas customers in the Northeastern U.S. and Eastern Canada increase natural gas demand, create upward pressure on prices, and limit the amount available to customers who do not have firm pipeline contracts.
- With the shutdown in production from domestic sources (Sable Island and Deep Panuke), Nova Scotia will be reliant on natural gas imported via U.S. pipelines, LNG tankers, or an all-Canadian Path, via Western Canada.

NATURAL GAS OPTIONS – SUMMARY (CONT.)

- New natural gas plants must have a firm source of gas supply to reliably generate power during winter peaks.
- Operational mode/utilization must be considered (i.e. primarily for capacity or for energy and capacity).
- Three supply paths have been developed that consider existing supply arrangements and compare and contrast possible new paths to move gas to Nova Scotia for possible new gas units as represented in the system optimization.

NATURAL GAS PRICE ASSUMPTIONS

The three supply paths developed are:

- **Option 1: Existing Gas (**TCPL Empress-East Hereford via North Bay Junction-tolls modelled as a fixed cost)
    - Existing 20,000 MMBtu/day pipeline capacity
- **Option 2: Peaking Gas** (LNG winter-Dawn plus tolls summer)
    - Unlimited LNG sourced from Repsol's Canaport terminal in the winter, pricing based on up to 100,000 MMBtu/day sourced at Dawn in the summer
- **Option 3: Base Loaded Gas** (New supply sourced at AECO plus tolls)
    - Pricing based on up to 100,000 MMBtu/day
    - Fixed Cost adder to be applied to gas units in model for this option.

- For each options, 3 scenarios have been priced: Base Case (Expected), High Case, and Low Case.

FUNDAMENTAL NATURAL GAS SCENARIOS (S&P GLOBAL PLATTS ANALYTICS) HENRY HUB

Case	Likelihood (S&P Global)	Highlights
Base Case (Expected)	50% 2018 – 2030	• US Demand growth expected to slow post 2020 • Gas consumption in the power sector has become saturated • More locations are banning or restricting the use of gas • The US technically recoverable resource was raised to 3,024 TCF an increase of 560 TCF, the largest change ever • Prospects for additional LNG export terminals achieving Final Investment Decision have increased with the apparent progress in US/China trade talks
High Case	25%	• Prolonged pipeline/regulatory review process impede future infrastructure expansion • Tightened environmental/regulatory policy inhibits shale gas & oil development. • Accelerated US coal/nuclear retirement and/or increased US electricity demand increase demand for gas • Increased North American LNG export capability along with less new global capability
Low Case	25%	• Associated gas tied to liquids-rich production is more abundant than currently envisioned (will have to be tied to pipeline additions) • Shale gas production surprises to the upside • Non-fossil fuel electric generation grows at a faster rate than forecast • LNG exports from the US face stiffer offshore competition • More anti-fossil fuel sentiment limits electric and industrial demand growth

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NS CASE DEVELOPMENT (NATURAL GAS)

	*Highlights
Existing Gas: TCPL North Bay Junction	-20,000 MMBtu/day pipeline capacity contracted starting Nov 1, 2021 for 15 years, with an assumed extension to cover the full IRP modeling period -Fixed tolls from Empress to North Bay Junction for the 25 years -Base/High/Low pricing
Peaking Gas: LNG Winter-Dawn Summer	-Unlimited LNG winter supply; -Swing gas for daily dispatch, no long term contract/pipeline commitment underpinning - Base/High/Low pricing
Baseload Gas: from AECO	-Pricing based on up to an additional 100,000 MMBtu/day firm contract -Base/High/Low pricing

*The modeling for Peaking Gas and Baseload Gas will not have volume restrictions on new pipelines/paths. Operational & Reliability Phase will evaluate whether actual volumes are consistent with how the pricing was developed which considered volumes. Existing Gas is volume limited.

NATURAL GAS – EXISTING GAS (TCPL NBJ 20,000 MMBTU/DAY)

Delivered Price	=	Commodity	+	Basis	+	Transportation	+	Market Premium
Base	=	Henry Hub Source: Global Platts Analytics (4Q2019) Reference Case	+	AECO Source: Global Platts Analytics (June 2019)	+	Fuel & Tolls Nova + Fuel & Tolls Westbrook to Tufts Cove modelled as variable, TCPL Empress to E. Hereford and PNGTS to Westbrook modelled as fixed costs	+	Nil
Low	=	Henry Hub Source: Global Platts Analytics (4Q2019) Low Case	+	AECO Source: Global Platts Analytics (June 2019)	+	Fuel & Tolls Nova + Fuel & Tolls Westbrook to Tufts Cove modelled as variable, TCPL Empress to E. Hereford and PNGTS to Westbrook modelled as fixed costs	+	Nil
High	=	Henry Hub Source: Global Platts Analytics (4Q2019) High Case	+	AECO Source: Global Platts Analytics (June 2019)	+	Fuel & Tolls Nova + Fuel & Tolls Westbrook to Tufts Cove modelled as variable, TCPL Empress to E. Hereford and PNGTS to Westbrook modelled as fixed costs	+	Nil

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NATURAL GAS – PEAKING GAS (LNG WINTER, DAWN SUMMER)

Delivered Price	=	Commodity	+	Basis	+	Transportation	+	Market Premium
Base Winter 2018 – 2030	=	TTF Spot Source: Global Platts Analytics (4Q2019) Reference, Low or High Case	+		+	Fuel & Tolls: Baileyville to Tufts Cove		LNG Regasification cost US $2.50/MMBtu
Base Summer	=	Henry Hub Source: Global Platts Analytics (4Q2019) Reference, Low or High Case	+	Dawn Source: Global Platts Analytics (June 2019) Reference, Low or High Case	+	Fuel & Tolls: Dawn to Tufts Cove Source: Current or negotiated Tolls		Nil

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NATURAL GAS – BASELOAD

Delivered Price	=	Commodity	+	Basis	+	Transportation	+	Market Premium
Base	=	Henry Hub Source: Global Platts Analytics (4Q2019) Reference Case	+	AECO Source: Global Platts Analytics (June 2019)	+	Tolls Nova to Tufts Cove modelled as fixed costs Fuel & Usage Nova to Tufts Cove modelled as variable costs	+	Nil
Low	=	Henry Hub Source: Global Platts Analytics (4Q2019) Low Case	+	AECO Source: Global Platts Analytics (June 2019)	+	Tolls Nova to Tufts Cove modelled as fixed costs Fuel & Usage Nova to Tufts Cove modelled as variable costs	+	Nil
High	=	Henry Hub Source: Global Platts Analytics (4Q2019) High Case	+	AECO Source: Global Platts Analytics (June 2019)	+	Tolls Nova to Tufts Cove modelled as fixed costs Fuel & Usage Nova to Tufts Cove modelled as variable costs	+	Nil

OTHER ALTERNATIVES

- Other natural gas supply arrangements are possible, however not every potential supply arrangement can be tested in an IRP model
- Other possible arrangements that are not included in the IRP model include (but are not limited to):

  1. Dual Fuel capability
  2. Natural Gas Storage
  3. LNG Alternatives

- If the IRP Action Plan indicates new investment in natural gas resources, these options would be considered in a more detailed analysis.

DUAL FUEL CAPABILITY

Given the known challenges associated with securing a cost-effective firm natural gas supply source, the economics and permit-ability of ULSD oil use in lieu of high cost of pipeline infrastructure would be considered in the future if natural gas units prove to be a no-regrets supply option in the IRP.

DUAL FUEL CAPABILITY (CONT.)

Benefits

- State-of-the-art combined-cycle plants and peakers can burn ULSD, kerosene or distillate oil efficiently without jeopardizing the cycling range and quick-start capability associated with the technologies.
- Use of oil to support a reliable fuel supply portfolio would supplant natural gas when delivery constraints arise.
- Oil supply arrangements are much more flexible than those associated with firm gas because they do not require major infrastructure expansions to enable delivery.

DUAL FUEL CAPABILITY (CONT.)

Challenges

- Duel-Fuel capability has an assumed cost adder of 7%.
- Switching on the fly from natural gas to oil or vice versa poses operational challenges and can jeopardize unit availability.
- There are increased emissions associated with burning oil in lieu of natural gas for fuel assurance.
- Oil refill during the peak heating season has proved challenging for both barge- and truck-delivery during cold snaps.

DUAL FUEL CAPABILITY (CONT.)

Challenges

- Increased Compliance Cost - Switching from gas to ULSD or HFO when pipeline constraints into or within Nova Scotia prevent the use of gas will increase CO_2 emissions during those events by a factor of roughly 50% on a tonnes per MWh basis.
- Challenges associated with tank farm permitting.
- Dual Fuel capability is challenging to assess in a long term model due to the granularity needed to test the value proposition.

NATURAL GAS STORAGE

- AltaGas is developing an underground gas storage facility in Alton, Nova Scotia, which would be connected to M&NP pipeline
- Heritage Gas Ltd. has contracted for the first phase of capacity
- It is possible that NS Power could contract for capacity – the economics of usage would need extensive analysis (e.g. the amount of turns and resultant withdrawal rates, etc.)
- As per the Dual Fuel Capability option, NS Power will study this option in detail if new gas units are part of the IRP recommendation

LNG ALTERNATIVES

As an alternative to traditional pipeline transportation, some companies have begun to develop “virtual pipelines” by shipping LNG or compressed natural gas (CNG) via truck or boat to sites that do not have pipeline connections or cannot receive gas due to pipeline constraints.

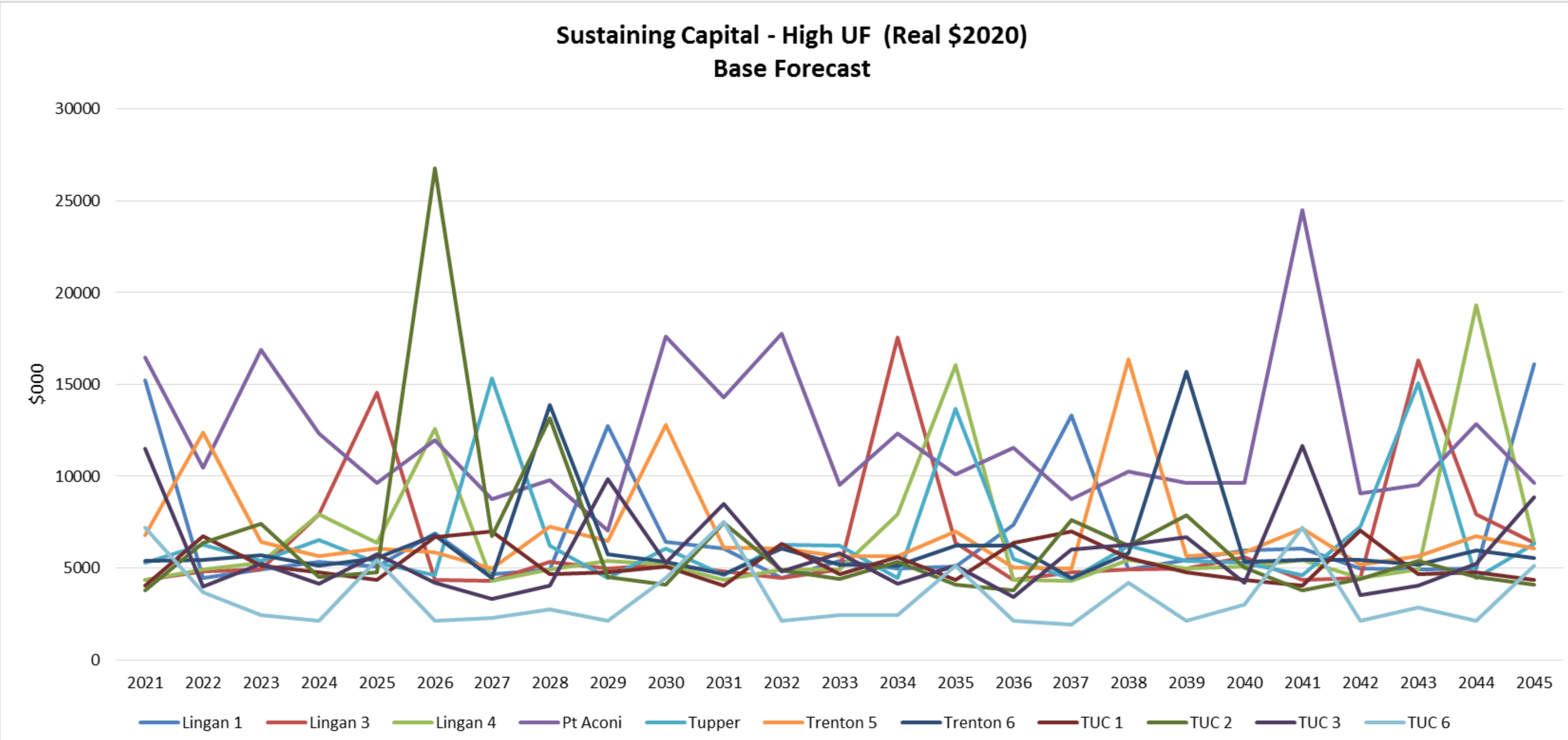
2020 IRP: SUSTAINING CAPITAL

MARCH 11, 2020

SUSTAINING CAPITAL FORECAST – COAL UNITS

- The sustaining capital cost Base forecast assumes a high utilization factor (UF) for all thermal units, which will represent the forecast investment required to address wear on components driven by a high capacity factor, cycling, operating hours, flexible use, or a combination thereof (i.e. the uses of the machines that drive the highest investment requirements)
- The high UF puts all the units on an equal basis in terms of their operation in order to appropriately compare economics.
- High sustaining capital cost sensitivities will assume the following:
  - High (or other iterative ranges) = Base + 50%

SUSTAINING CAPITAL FORECAST – THERMAL (BASE)



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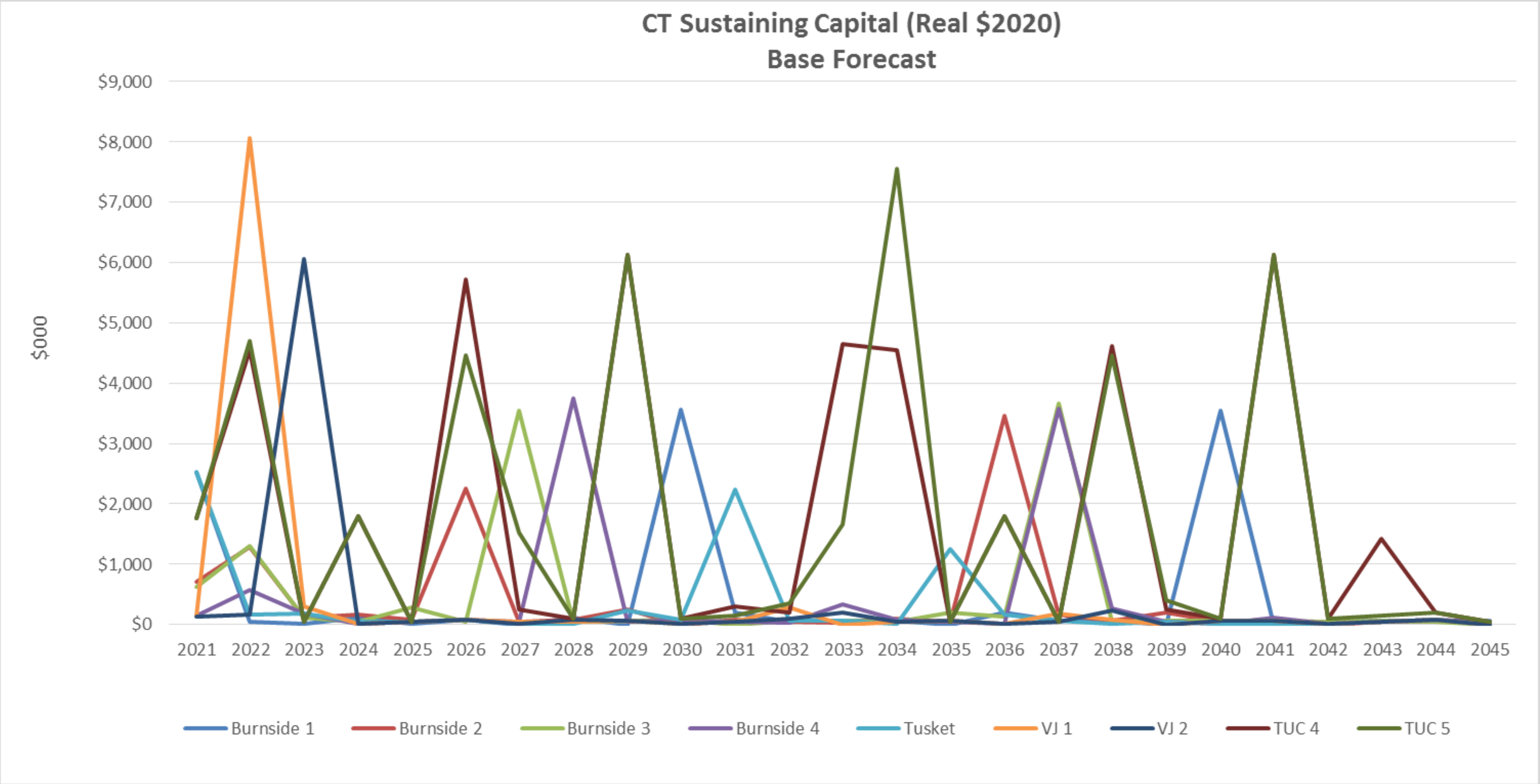
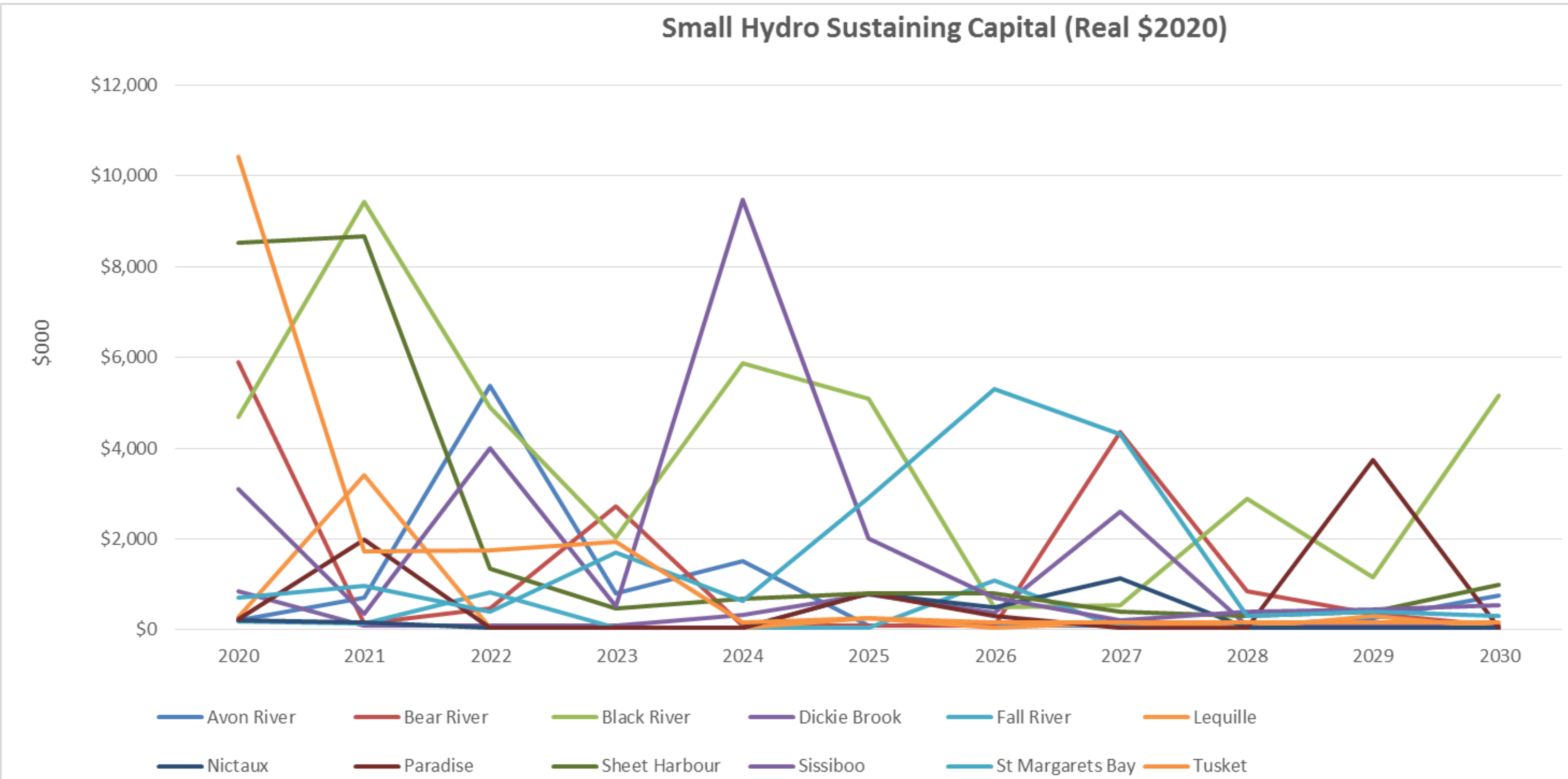
SUSTAINING CAPITAL FORECAST – CTs



SUSTAINING CAPITAL FORECAST – SMALL HYDRO

- The sustaining capital forecast for hydro assets are based on Q1 2020 Forecast



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SUSTAINING CAPITAL SCREENING

- As discussed at the February 27 stakeholder conference, during the Resource Screening phase of the modeling plan NS Power will test the sustaining capital and O&M costs against decommissioning costs and replacement costs for NS Power's existing hydro and combustion turbine fleets.

- Candidate economic retirements identified during the Resource Screening phase will be considered in the Portfolio Studies and Operability/Reliability Screening; this will assess provision of essential grid services and other system characteristics not modeled in RESOLVE.

2020 IRP: RENEWABLE INTEGRATION REQUIREMENTS

MARCH 11, 2020

Nova Scotia POWER An Emera Company

SUMMARY

- Unlike previous IRPs, the next 25 years will likely be characterized by a drastic transformation in the electric utility business as it moves further towards complete decarbonization.
- Theories and physics of power systems were developed around synchronous machines that were the backbone of the power system for a very long time.
- This IRP will test the retirement of major large synchronous generators with replacement by inverter-based non-synchronous generation (or other lower emitting generators).
- The retirement of coal fired generators will not only impact the system adequacy (capacity and energy) but will also create a major shift in the provision of essential grid services which have historically been provided as ancillary benefits of large synchronous machines.

SUMMARY (CONT.)

- For IRP modeling, assumptions about cost and operational constraints to address these services will be considered. The assumptions have been developed by NS Power and its consultants using the PSC Stability Study from the Pre-IRP Work as the basis for assumptions. Further detailed study to establish firm opportunities and constraints for inverter-based energy sources will continue to be required as the system changes.

- Dispatch cases of selected resource plans may be tested via transient stability and system dynamic studies in the “operability screening” phase of the modeling, as described in the Analysis Plan.

SUMMARY (CONT.)

- For the NS Power system, the following have been identified as the grid services that need to be addressed to accommodate additional inverter-based generation to maintain stable and secure operation of the system.
  - **Ramping reserve and net load following capabilities**
  - **System strength and short circuit ratio**
  - **Volt-Ampere-Reactive support**
  - **Kinetic energy and synchronous inertia requirement**
- A value for the minimum requirement of each of these essential grid services will be represented in the model as dynamic constraints, which will enable the model to integrate renewable resources at any level by ensuring provision of the services.

REGULATION

- Additional ramping/regulation reserve is required for dealing with increased variability and uncertainty in net load; in addition, retirement of coal units will create a ramping deficit
- 5-minute net load was studied and the 3-sigma approach was used determine the additional ramping reserve requirements (PSC Stability Study)
- With large increments of new wind additions, fast-acting generation will be required to offset the increased variability associated with high wind penetration
- For the purpose of IRP modeling, building new inverter-based generation will be linked to additional fast-acting generation to satisfy the ramping reserve constraint:

* $Y >= 0.028X + 13.455$

Where: Y is ramping reserve in MW and;

X is the inverter-based installed capacity in MW

*Nova Scotia Power Stability Study for Renewable Integration Report, PSC North America, July 2019

RENEWABLE INTEGRATION

- The stability study report has identified two possible options to integrate an additional 400 MW of inverter-based generation, represented by a wind as a proxy.
  - **Interconnection Option** : A second 345 kV AC tie between Onslow NS and Salisbury NB.
  - **Local mitigation Option** : A 200 MVA Synchronous Condenser and 200 MW Battery.
- Preliminary results showed that the system is stable with up to an additional 100 MW of wind depending on local mitigations/interconnections.

*Nova Scotia Power Stability Study for Renewable Integration Report, PSC North America, July 2019

RENEWABLE INTEGRATION COSTS

Technology	Capital Cost Estimate ($2019)	Summary
[1]Synchronous Condenser	$300/kVAR	• [Support short circuit ratio] An estimate of 30 MVAR synchronous condenser is required for each 150 MW of wind additions • [Support kinetic energy] - A minimum of 3266 MW.sec of synchronous inertia is required for steady state operation.
Switched Capacitor Bank	$50/kVAR	• 50MVAR will be required at the locations of retired synchronous generators to provide voltage support during steady state operation
345kV Onslow-Salisbury	$360M	• Reliability tie for wind integration; does not provide access to firm capacity or additional energy markets.

1) High Inertia - High inertia SC designs fitted with flywheels can provide inertia constants of ~5 MW.sec/MVA

2020 Integrated Resource Plan

Scenarios & Modeling Plan

March 11, 2020

IRP MODELING PROCESS

The 2020 IRP analysis will follow the modeling plan shown in Figure 1 below. This process is robust and flexible enough to examine the wide range of inputs and outcomes that will be considered in this IRP.

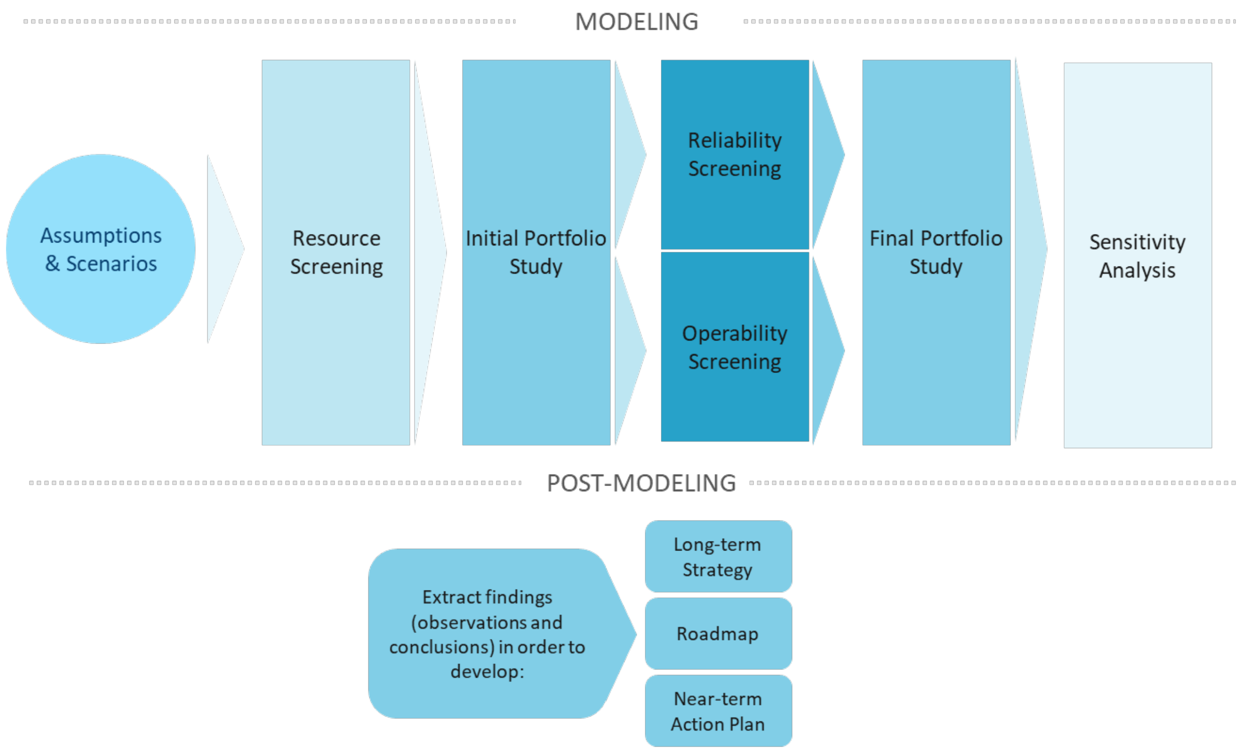


Figure 1 - IRP Modeling Plan Overview

Table 1 provides a description of each phase of the modeling plan.

Phase	Description
Resource Screening	Refine candidate resources to be available to model in each scenario (this may differ by scenario). Combination of qualitative evaluation and/or quantitative modeling using E3's RESOLVE model.
Initial Portfolio Study	Conduct capacity expansion optimization modeling with Plexos LT (supplemented with E3's RESOLVE model where required), which will result in an economically optimized resource portfolio for each scenario (e.g. the resource plan with the lowest 25 year NPV revenue requirement for that scenario's set of assumptions).
Reliability Screening	For select scenarios, evaluate the impacts on reliability parameters, including the ELCC of renewables (and diversity benefits) and the required Planning Reserve Margin for particular resource portfolios using E3's RECAP model. Identify changes to these assumptions for iteration.

Operability Screening	For select scenarios, evaluate the production costs (e.g. fuel and purchased power) and dispatch constraints using the more granular Plexos MT/ST module. Identify changes required for the portfolio for iteration.
Final Portfolio Study	Using the output of the Reliability and Operability Screening phases, if required, conduct revised capacity expansion optimization modeling with Plexos (supplemented with E3's RESOLVE model where required).
Sensitivity Analysis	Using bookend values, as identified for each scenario, test the impact of future changes to key assumptions on the cost and performance of the portfolios. In some cases, sensitivities may also require the capacity expansion optimization to be re-run within a particular scenario.

Table 1 - IRP Modeling Plan Phase Descriptions

SCENARIO DEVELOPMENT APPROACH

NS Power has used a Portfolio Development approach to create the 2020 IRP Scenarios. This approach will allow the IRP to evaluate the broad range of potential futures and then develop a Roadmap and Action Plan based on the least regrets options that are common to the largest number of scenarios.

Figure 2 outlines the process to develop candidate scenarios by considering a range of potential drivers.

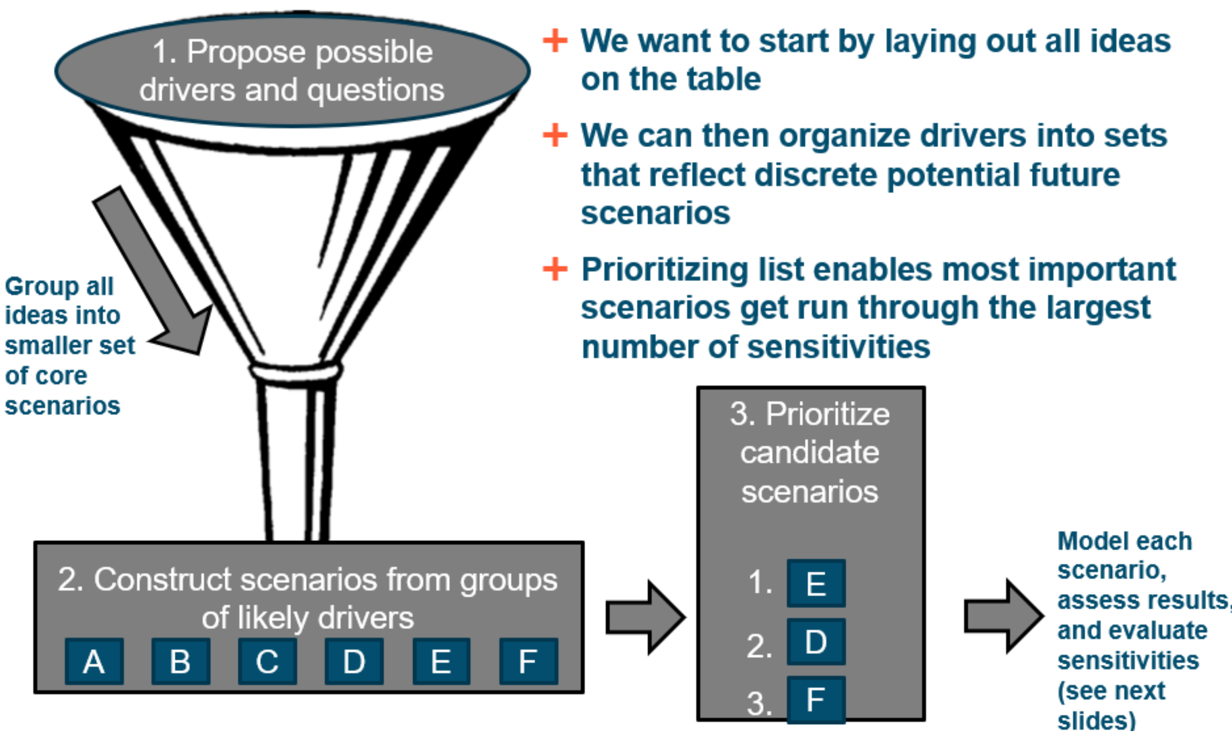


Figure 2 - Scenario Development Overview

In addition to the combinations of drivers into scenarios as illustrated above, NS Power has also proposed "Resource Strategies" to be paired with scenarios based on the feedback received from the IRP stakeholders to date, to ensure the appropriate breadth of potential future resources is captured. The modeling process for the Portfolio Study phase is illustrated in Figure 3.

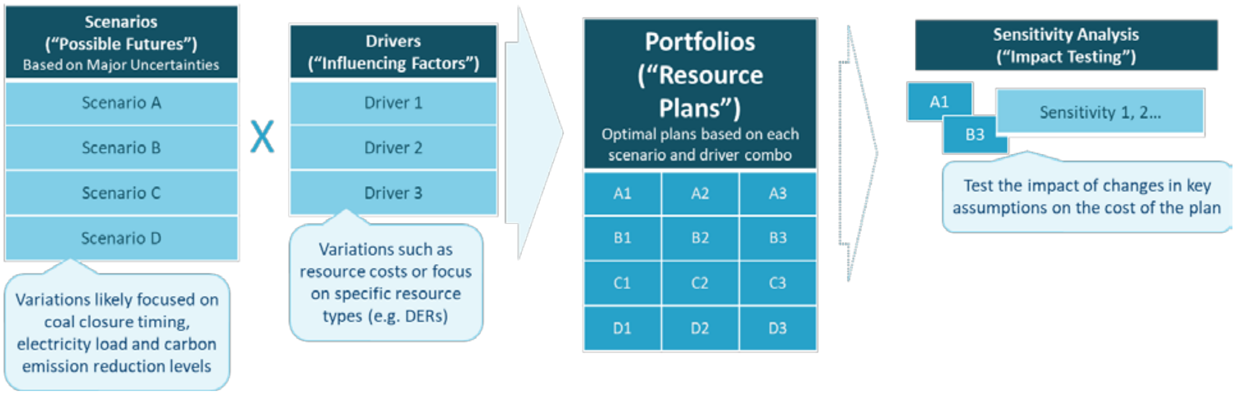


Figure 3 - IRP Portfolio Study Modeling Approach

KEY POLICY DRIVERS

NS Power is proposing three key policy drivers to form the basis of scenarios:

1. Provincial clean energy policy (e.g. Sustainable Development Goal Act)

    Policy Driver 1.1: Greenhouse gas emissions by electricity sector

    Policy Driver 1.2: Load changes driven by varying degrees of electrification

2. Federal clean energy policy:

    Policy Driver 2.1: Coal unit end dates

1. Provincial Clean Energy Policy Drivers

1.1 Greenhouse Gas Emissions by Electricity Sector

This driver represents the carbon dioxide emissions allowable by the electricity sector, which will be implemented as a constraint in the model. Based on stakeholder discussions, NS Power proposes three GHG scenarios for consideration to represent the range of the outcomes of provincial carbon policy, as shown in Figure 4 and Table 2 below.

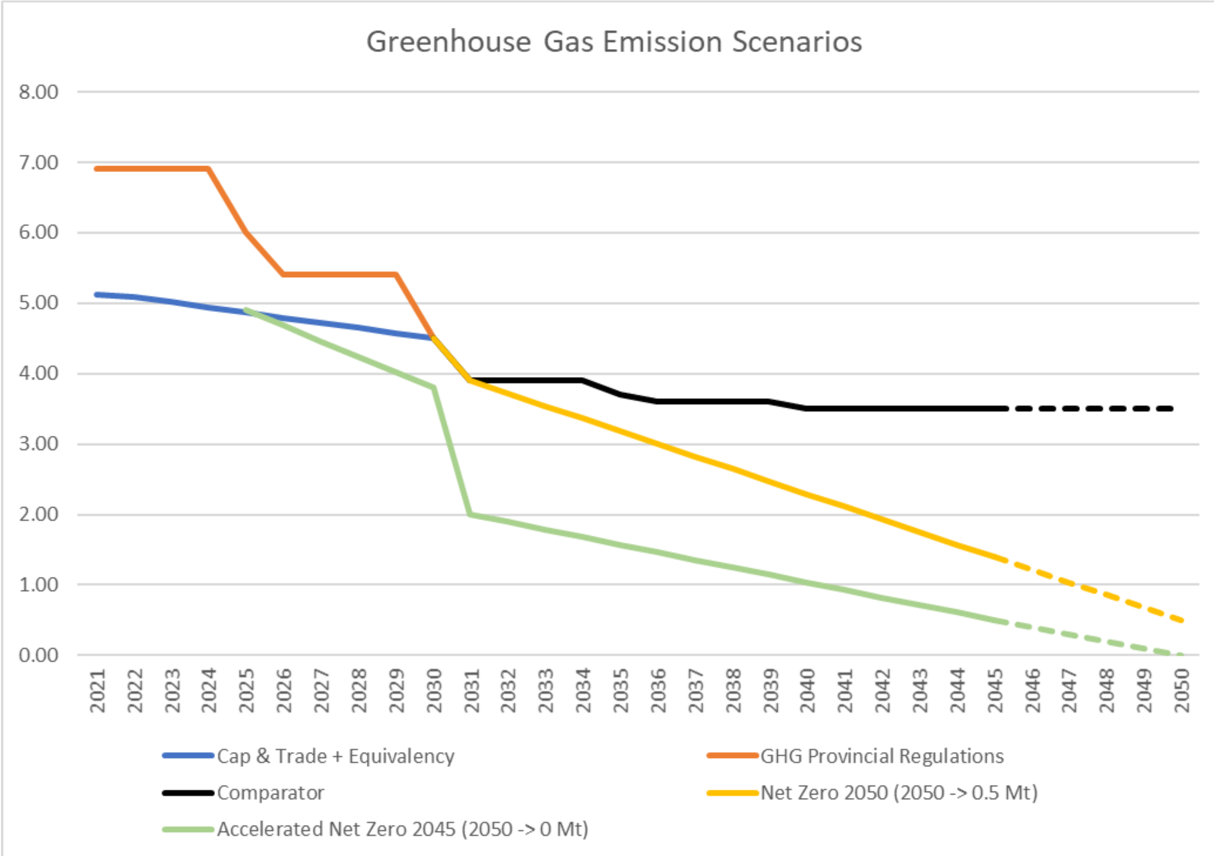


Figure 4 - Greenhouse Gas Emissions Scenarios Graph

	CO2 2030	CO2 2031	CO2 2040	CO2 2045	CO2 2050*
Comparator GHG Case	4.5	3.9	3.5	3.5	3.5
Reductions consistent with equivalency agreement and continued future decline	*(58% reduction from 2005)*	*(63% reduction from 2005)*	*(67% reduction from 2005)*	*(67% reduction from 2005)*	*(67% reduction from 2005)*
Net Zero 2050 (2050 -> 0.5 Mt)	4.5	3.9	2.3	1.4	0.5
Reduction to 0.5 Mt by 2050 (assumes achievement of "net zero" via mechanism)	*(58% reduction from 2005)*	*(63% reduction from 2005)*	*(78% reduction from 2005)*	*(87% reduction from 2005)*	*(95% reduction from 2005)*
Accelerated Net Zero 2045 (2050 -> 0 Mt)	3.8	2.0	1	0.5	0
Reduction to 0.5 Mt by 2045 with acceleration of pace beginning in 2025	*(64% reduction from 2005)*	*(81% reduction from 2005)*	*(91% reduction from 2005)*	*(95% reduction from 2005)*	*(100% reduction from 2005)*

Table 2 - Greenhouse Gas Emissions Scenarios

**Note: IRP modeling period ends in 2045; 2050 is shown here to demonstrate a potential end value of each curve (relative to SDGA 2050 target year).*

1.2 Load Changes

This driver represents the impact provincial greenhouse gas reduction and/or "net zero" policy (e.g. the Sustainable Development Goals Act or SDGA) has on the expected load for the electricity sector. The electrification cases will be based on E3's Pathways assessment of the potential impact of economy-wide decarbonization on the electricity sector. The Pathways Study contains further information on the load impact of electrification scenarios.

Three load cases are proposed for evaluation within the IRP scenarios:

- **Business as usual:** *represents the 2019 Load Forecast as filed with the UARB in April 2019 (adjusted where required to reflect E1's 2019 DSM Potential Study profiles to reflect potential demand side resources).*
- **Moderate degree of electrification:** *represents the 2019 Load Forecast, adjusted to reflect the incremental load due to partial electrification of buildings and vehicles as indicated in E3's "Moderate Electrification" Pathways scenario (adjusted where required to reflect E1's 2019 DSM Potential Study profiles to reflect potential demand side resources).*
- **High degree of electrification:** *represents the 2019 Load Forecast, adjusted to reflect the incremental load due to broad electrification of buildings and transportation as indicated in E3's "High Electrification" Pathways scenario (adjusted where required to reflect E1's 2019 DSM Potential Study profiles to reflect potential demand side resources).*

2. Federal Clean Energy Policy Drivers

2.1 Coal Closure Policy

The two states of this driver are:

- All coal units retired by 2040 – assumes retention of the ongoing Equivalency Agreement
- All coal units retired by 2030 – assumes adherence to the applicable Federal regulations

Note: Coal units can be economically retired by the IRP model in any year earlier than the end dates described above.

SCENARIO SCREENING: IDENTIFYING KEY SCENARIOS OF INTEREST

Qualitative Screening

Combining all the variants of the major scenario drivers produces 18 potential candidate scenarios, shown below in Table 3.

GHG Scenario	Load Driver	Coal End Date
Comparator GHG Case	High Electrification	2030
Comparator GHG Case	Moderate Electrification	2030
Comparator GHG Case	Business as Usual	2030
Comparator GHG Case	High Electrification	2040
Comparator GHG Case	Moderate Electrification	2040
Comparator GHG Case	Business as Usual	2040
Net Zero 2050	High Electrification	2030
Net Zero 2050	Moderate Electrification	2030
Net Zero 2050	Business as Usual	2030
Net Zero 2050	High Electrification	2040
Net Zero 2050	Moderate Electrification	2040
Net Zero 2050	Business as Usual	2040
Accelerated Net Zero 2045	High Electrification	2030
Accelerated Net Zero 2045	Moderate Electrification	2030
Accelerated Net Zero 2045	Business as Usual	2030
Accelerated Net Zero 2045	High Electrification	2040
Accelerated Net Zero 2045	Moderate Electrification	2040
Accelerated Net Zero 2045	Business as Usual	2040

Table 3 - Potential Candidate Scenarios

Qualitative screening was used to identify six key scenarios of interest (highlighted in Table 4 in green) and to eliminate scenarios with unlikely combinations of drivers. Consistent with the scenarios in E3's Pathways Report, higher levels of load are generally paired with larger carbon budgets, which reflects overall economy decarbonization resulting from the removal of emissions from other sectors.

GHG Scenario	Load Driver	Coal End Date
Comparator GHG Case	High Electrification	2030
Comparator GHG Case	Moderate Electrification	2030
Comparator GHG Case	Business as Usual	2030
Comparator GHG Case	High Electrification	2040
Comparator GHG Case	Moderate Electrification	2040
Comparator GHG Case	Business as Usual	2040
Net Zero 2050	High Electrification	2030
Net Zero 2050	Moderate Electrification	2030
Net Zero 2050	Business as Usual	2030
Net Zero 2050	High Electrification	2040
Net Zero 2050	Moderate Electrification	2040
Net Zero 2050	Business as Usual	2040
Accelerated Net Zero 2045	High Electrification	2030
Accelerated Net Zero 2045	Moderate Electrification	2030
Accelerated Net Zero 2045	Business as Usual	2030
Accelerated Net Zero 2045	High Electrification	2040
Accelerated Net Zero 2045	Moderate Electrification	2040
Accelerated Net Zero 2045	Business as Usual	2040

Table 4 – Scenarios of Interest

RESOURCE STRATEGIES

Three resource strategies are proposed to ensure the IRP analysis covers key areas of importance and interest:

A. Current Landscape
New in-province supply and demand resources available, with no new interconnections to other regions.
B. Distributed Resources
Distributed supply and demand resources are preferred where possible (e.g. distributed solar and battery storage) and high uptake of DERs is assumed.
C. Regional Integration
New interconnections to other regions and corresponding access to out-of-province resources for energy and capacity are available, in addition to in-province supply and demand resources.

SCREENING POLICY DRIVER & STRATEGY PAIRS

Building on to the screening exercise above, NS Power has qualitatively identified the key combinations of policy drivers and resources strategies to initially examine as Key Scenarios, which are shown in Table 5 below. NS Power has also paired a DSM level to each scenario to produce an associated load forecast; alternate DSM levels will be examined as sensitivities for candidate resource plans of interest.

Scenario	Features	Load Drivers	Coal Retires	Resource Strategies Tested	Key Sensitivities
1.0 **Comparator**	Equivalency GHG	Low Elec. Base DSM	2040	A - Current Landscape	
2.0 **Net Zero 2050** **Low Electrification**	GHG targets decline linearly from 2030 to 0.5Mt in 2050	Low Elec. Base DSM	2040	A - Current Landscape C - Regional Integration	• DSM Levels
2.1 **Net Zero 2050** **Mid Electrification**	GHG targets decline linearly from 2030 to 0.5Mt in 2050	Mid Elec. Base DSM	2040	A - Current Landscape B - Distributed Resources C - Regional Integration	• DSM Levels • No New Emitting • Target Case for Sensitivity Evaluation
2.2 **Net Zero 2050** **High Electrification**	GHG targets decline linearly from 2030 to 0.5Mt in 2050	High Elec. Max DSM	2040	A - Current Landscape C - Regional Integration	• DSM Levels • No New Emitting
3.1 **Accelerated Net Zero 2045** **Mid Electrification**	GHG targets decline from 2025 to 0.5Mt in 2045; path to Absolute Zero 2050	Mid Elec. Base DSM	2030	B - Distributed Resources C - Regional Integration	• DSM Levels • No New Emitting • Target Case for Sensitivity Evaluation
3.2 **Accelerated Net Zero 2045** **High Electrification**	GHG targets decline from 2025 to 0.5Mt in 2045; path to Absolute Zero 2050	High Elec. Max DSM	2030	B - Distributed Resources C - Regional Integration	• DSM Levels

Table 5 – Key Scenarios

These Key Scenarios represent the twelve initial modeling runs to be conducted in Plexos LT in the Initial Portfolio Study Phase. Consistent with the scenario screening discussed above, additional scenarios may be tested using E3's RESOLVE model to assess if they should be included as a key modeling run.

SENSITIVITY ANALYSES

Following completion of the portfolio studies and operability and reliability screening phases, NS Power will work with stakeholders to prioritize the sensitivities and identify applicable portfolios and/or scenarios for them to be paired with, based on emerging insights from the ongoing analysis throughout the IRP modeling phase.

Potential sensitivities to be evaluated include:

- Increase in Renewable Energy Standard policy
- Low capital cost of wind
- Low capital cost of storage
- Low/High pricing of import energy
- Low/High pricing of natural gas
- High Pricing of Biomass
- High Sustaining Capital Costs
- Loss of Large Industrial Load
- Mersey Hydro System retired
- No New Emitting Resources
- Fuel security sensitivities
- Resiliency testing

It should be noted that some of these sensitivities will require the capacity expansion optimization to be rerun (e.g. DSM, Sustaining Capital), while others are run on the resource plan without reoptimizing (e.g. Fuel Prices).

EVALUATION CRITERIA

NS Power has developed the following evaluation criteria against which potential plans and resource portfolios will evaluated under each scenario, as shown in Table 6 below:

Metric	Description
Minimization of the cumulative present value of the annual revenue requirements over the planning horizon (adjusted for end-effects)	25 year NPV Revenue Requirement
Magnitude and timing of electricity rate effects	10 year NPV Revenue Requirement
Reliability requirements for supply adequacy	Evaluation of PRM, resource capacity adequacy, operating reserve requirements, etc.
Provision of essential grid services for system stability and reliability	Quantitative and qualitative assessment of the status of essential grid services provision for each portfolio.
Plan robustness (the ability of a plan to withstand plausible potential changes to key assumptions)	Magnitude of the plan's exposure to changes in key assumptions (via sensitivity analysis) as well as resiliency to risks.
Reduction of greenhouse gas and/or other emissions	Quantitative reductions as output by Plexos, e.g. Mt of CO_2 reduced relative to 2005 actuals
Flexibility (limitation of constraints on future decisions arising from the selection of a particular path)	Qualitative assessment of timing of investments

Table 6 - Resource Plan Evaluation Criteria

While the primary metric of plan value will continue to be minimization of net present value of revenue requirement, by adding these additional metrics to the 2020 IRP, additional insight will be gained into the value of flexibility, reliability, and robustness which will inform the IRP Roadmap and Action Plan.

SUMMARY

The major policy drivers which emerged from scenario discussions are:

- 1. Provincial clean energy policy (e.g. Sustainable Development Goal Act)
    - Policy Driver 1.1: Greenhouse gas emissions by electricity sector
    - Policy Driver 1.2: Load changes driven by varying degrees of electrification
- 2. Federal clean energy policy:
    - Policy Driver 2.1: Coal unit end dates

Variants of these drivers have been combined to form the following "scenarios":

- Comparator Case / Low Electrification / 2040 Coal Closure
- Net Zero 2050 / Low Electrification / 2040 Coal Closure
- Net Zero 2050 / Mid Electrification / 2040 Coal Closure

- Net Zero 2050 / High Electrification / 2040 Coal Closure
- Accelerated Net Zero 2045 / Mid Electrification / 2030 Coal Closure
- Accelerated Net Zero 2045 / High Electrification / 2030 Coal Closure

The potential resource strategies, to be paired with scenarios to influence the constraints around portfolios, also emerged from scenario discussions:

A - Current Landscape

B - Distributed Resources Promoted

C - Regional Integration

Modeling scenarios with various resource strategies will result in economically optimal portfolios for each scenario/strategy combination. In Table 7 NS Power proposes ten preliminary scenario and strategy combinations for the initial portfolio modeling.

Scenario	GHG Curve	Load Driver	Resource Strategy
1.0A	Comparator	Low Electrification / Base DSM	Current Landscape
2.0A	Net Zero 2050	Low Electrification / Base DSM	Current Landscape
2.0C	Net Zero 2050	Low Electrification / Base DSM	Regional Integration
2.1A	Net Zero 2050	Mid Electrification / Base DSM	Current Landscape
2.1B	Net Zero 2050	Mid Electrification / Base DSM	Distributed Resources
2.1C	Net Zero 2050	Mid Electrification / Base DSM	Regional Integration
2.2A	Net Zero 2050	High Electrification / Max DSM	Current Landscape
2.2C	Net Zero 2050	High Electrification / Max DSM	Regional Integration
3.1B	Accelerated Net Zero 2045	Mid Electrification / Base DSM	Distributed Resources
3.1C	Accelerated Net Zero 2045	Mid Electrification / Base DSM	Regional Integration
3.2B	Accelerated Net Zero 2045	High Electrification / Max DSM	Distributed Resources
3.2C	Accelerated Net Zero 2045	High Electrification / Max DSM	Regional Integration

Table 7 – Preliminary Scenario and Resource Strategy Combinations

Additionally, several potential sensitivities to be tested on key portfolios of interest have been identified. The specific sensitivity analysis plan will be refined once the insights from the preliminary modeling have emerged.

Release Notes 2020-09-17

- The objective of the model is to illustrate the net effect on NS Power customer rates of the change in cost and load associated with varying levels of electrification, DSM, and DER deployment.

- The hypothesis is that because so much of the Company's revenue requirement is fixed (approximately 50% due to the long-term nature of the underlying investments), additional revenues provided by the higher levels of sales associated with higher levels of electrification will more than offset the incremental cost to serve the higher load, placing downward pressure on the unit cost to serve customers (i.e. rates).

- The analysis incorporates the cost and load information developed in the IRP. However because the IRP cost information includes only forward looking supply-side and demand-side costs, it is necessary to:
  - Develop an opening bundled service rate for comparison purposes; and
  - Recognize the additional fixed cost contribution provided by additional sales from higher levels of electrification.

- The Company has taken the following approach:
  - We have begun with the forward looking supply-side and demand-side annual revenue requirements developed in the IRP.
  - To this we have added the fixed cost amounts currently embedded in customer rates (from the most recent General Rate Application Test Year (2014)).
  - The total of the IRP revenue requirement and 2014 foundation produces an estimate of total annual utility revenue requirement for the analysis period.
  - To incorporate the additional FCR produced by the additional electrification sales, the Company has applied an FCR/MWh factor from the 2014 Test Year ($80/MWh) and multiplied this by the incremental sales under the various scenarios.
  - The net effect of utility revenue requirement less additional FCR recovery provides an estimate of the net revenue requirement to be recovered from customers annually under various levels of electrification.
  - A system rate is developed by dividing the total annual revenue requirement by total sales (i.e. net system requirement less losses).
  - Annual rate changes are calculated as the change in the rate year-over-year. A simple (i.e. non cumulative) average rate change is created by averaging rate changes over the analysis period.

- The analysis employs a number of simplifying assumptions including:
  - Electrification and the associated FCR is assumed to occur uniformly across customer classes. To the extent this actually occurs to a greater degree in classes with higher fixed cost recovery (e.g. the residential class), the FCR can be expected to be greater.
  - Changes in load from electrification are assumed to affect revenue proportionately (i.e. demand and energy billings increase at the same level).
  - This beginning FCR is held constant over the analysis period. Effectively this assumes that the decline in existing rate base due to depreciation is offset by ongoing additions to T&D, General Property and other utility costs not captured in the IRP.

- 2020 costs are not modeled in IRP but used as a reference year to calculate the first year's rate change; assumed a 1% decline from 2021 modeled costs under Low Electrification to produce the 2020 cost used in all cases

Release Notes 2020-11-27

- Updated model inputs to incorporate T&D Avoided Costs of DSM for all scenarios

- Updated model parameters to assume $0/MWh of additional FCR; the relative rate estimate is simplified to a "system average" rate. More complex rate modeling may be used in the future to better understand the impacts of differential load growth rates across customer classes with different FCR rates, which is anticipated to further reduce upward pressure on rates.

IRP Relative Rate Scenarios

Planning Period Year

Electrification Scenario 1	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	
IRP Revenue Requirement (Partial) ($M)	858	867	920	877	889	882	878	877	879	912	920	897	891	913	942	967	963	998	1,025	1,033	1,103	1,160	1,148	1,179	1,181	1,207	
2014 Non-fuel revenue requirement ($M)	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	
Total Revenue Requirement Pre-incremental FCR recovery ($M)	1,658	1,667	1,720	1,677	1,689	1,682	1,678	1,677	1,679	1,712	1,720	1,697	1,691	1,713	1,742	1,767	1,763	1,798	1,825	1,833	1,903	1,960	1,948	1,979	1,981	2,007	
Incremental FCR-Base																											
Cumulative Incremental Sales (GWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Incremental FCR $/MWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Incremental FCR ($M)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Net Revenue Requirement ($M)	1,658	1,667	1,720	1,677	1,689	1,682	1,678	1,677	1,679	1,712	1,720	1,697	1,691	1,713	1,742	1,767	1,763	1,798	1,825	1,833	1,903	1,960	1,948	1,979	1,981	2,007	
Load (GWh)	11,314	11,327	11,302	11,260	11,242	11,165	11,100	11,044	11,002	10,924	10,843	10,809	10,811	10,786	10,800	10,816	10,860	10,873	10,904	10,944	10,987	11,003	11,053	11,104	11,149	11,216	2.0C - Low Elec / Base DSM
Losses (6.7%)	758	759	757	754	753	748	744	740	737	732	727	724	724	723	724	725	728	728	731	733	736	737	741	744	747	752	
Sales	10,556	10,568	10,545	10,506	10,489	10,417	10,356	10,304	10,265	10,192	10,117	10,085	10,087	10,063	10,076	10,092	10,132	10,144	10,174	10,211	10,251	10,266	10,312	10,360	10,402	10,465	
Rate (cents/kWh)	**15.71**	**15.78**	**16.32**	**15.96**	**16.10**	**16.14**	**16.20**	**16.27**	**16.35**	**16.80**	**17.00**	**16.83**	**16.76**	**17.02**	**17.29**	**17.51**	**17.40**	**17.72**	**17.94**	**17.95**	**18.57**	**19.09**	**18.89**	**19.10**	**19.04**	**19.18**	**2.0C - Low Elec / Base DSM 2040 Coal**
Annual Rate Change		0.4%	3.4%	-2.2%	0.8%	0.3%	0.4%	0.4%	0.5%	2.7%	1.2%	-1.0%	-0.4%	1.5%	1.6%	1.3%	-0.7%	1.9%	1.2%	0.1%	3.4%	2.8%	-1.0%	1.1%	-0.3%	0.7%	
																										0.8%	Average Rate Change 2021-2045
																										0.8%	Average Rate Change 2021-2030

Planning Period Year

Electrification Scenario 2	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	
IRP Revenue Requirement (Partial) ($M)	858	865	922	883	906	912	923	941	946	983	996	978	1,002	1,018	1,054	1,080	1,093	1,103	1,140	1,174	1,255	1,317	1,303	1,345	1,354	1,394	
2014 Non-fuel revenue requirement ($M)	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	
Total Revenue Requirement Pre-incremental FCR recovery ($M)	1,658	1,665	1,722	1,683	1,706	1,712	1,723	1,741	1,746	1,783	1,796	1,778	1,802	1,818	1,854	1,880	1,893	1,903	1,940	1,974	2,055	2,117	2,103	2,145	2,154	2,194	
Incremental FCR-Base																											
Cumulative Incremental Sales (GWh)	-	10	28	72	133	203	262	320	375	425	472	517	562	608	653	700	750	799	847	893	935	970	1,001	1,027	1,049	1,067	
Incremental FCR $/MWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Incremental FCR ($M)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Net Revenue Requirement ($M)	1,658	1,665	1,722	1,683	1,706	1,712	1,723	1,741	1,746	1,783	1,796	1,778	1,802	1,818	1,854	1,880	1,893	1,903	1,940	1,974	2,055	2,117	2,103	2,145	2,154	2,194	
Load (GWh)	11,314	11,338	11,332	11,337	11,385	11,383	11,381	11,387	11,405	11,380	11,349	11,363	11,414	11,438	11,499	11,567	11,664	11,730	11,812	11,901	11,989	12,043	12,125	12,205	12,274	12,360	2.1C - Mid Elec / Base DSM
Losses (7%)	758	760	759	760	763	763	763	763	764	762	760	761	765	766	770	775	781	786	791	797	803	807	812	818	822	828	
Sales	10,556	10,578	10,573	10,577	10,622	10,620	10,618	10,624	10,641	10,617	10,588	10,602	10,649	10,671	10,729	10,792	10,882	10,944	11,021	11,104	11,186	11,236	11,313	11,387	11,451	11,532	
Rate (cents/kWh)	**15.71**	**15.74**	**16.29**	**15.91**	**16.06**	**16.12**	**16.23**	**16.39**	**16.41**	**16.79**	**16.96**	**16.77**	**16.92**	**17.03**	**17.28**	**17.42**	**17.40**	**17.39**	**17.60**	**17.78**	**18.37**	**18.84**	**18.59**	**18.84**	**18.81**	**19.03**	**2.1C - Mid Elec / Base DSM 2040 Coal**
Annual Rate Change		0.2%	3.5%	-2.3%	0.9%	0.4%	0.7%	1.0%	0.1%	2.3%	1.0%	-1.1%	0.9%	0.7%	1.4%	0.8%	-0.1%	0.0%	1.2%	1.0%	3.4%	2.5%	-1.3%	1.3%	-0.2%	1.2%	
																										0.8%	Average Rate Change
																										0.8%	Average Rate Change 2021-2030

Planning Period Year

Electrification Scenario 3	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	
IRP Revenue Requirement (Partial) ($M)	858	989	1,058	1,042	1,049	1,061	1,074	1,091	1,100	1,132	1,153	1,141	1,142	1,178	1,211	1,253	1,273	1,325	1,376	1,405	1,510	1,572	1,572	1,612	1,641	1,679	
2014 Non-fuel revenue requirement ($M)	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	
Total Revenue Requirement Pre-incremental FCR recovery ($M)	1,658	1,789	1,858	1,842	1,849	1,861	1,874	1,891	1,900	1,932	1,953	1,941	1,942	1,978	2,011	2,053	2,073	2,125	2,176	2,205	2,310	2,372	2,372	2,412	2,441	2,479	
Incremental FCR-Base																											
Cumulative Incremental Sales (GWh)	-	20	84	102	166	261	329	404	478	559	640	728	816	918	1,025	1,136	1,248	1,360	1,465	1,572	1,662	1,742	1,815	1,878	1,929	1,974	
Incremental FCR $/MWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Incremental FCR ($M)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Net Revenue Requirement ($M)	1,658	1,789	1,858	1,842	1,849	1,861	1,874	1,891	1,900	1,932	1,953	1,941	1,942	1,978	2,011	2,053	2,073	2,125	2,176	2,205	2,310	2,372	2,372	2,412	2,441	2,479	
Load (GWh)	11,314	11,348	11,392	11,369	11,421	11,444	11,452	11,477	11,515	11,524	11,530	11,590	11,686	11,770	11,898	12,034	12,198	12,331	12,474	12,629	12,769	12,870	12,999	13,117	13,217	13,332	2.2C - High Elec / Max DSM
Losses (7%)	758	760	763	762	765	767	767	769	771	772	772	777	783	789	797	806	817	826	836	846	856	862	871	879	886	893	
Sales	10,556	10,588	10,629	10,607	10,656	10,678	10,685	10,708	10,743	10,751	10,757	10,813	10,903	10,981	11,101	11,228	11,380	11,504	11,638	11,783	11,914	12,008	12,128	12,238	12,332	12,439	
Rate (cents/kWh)	**15.71**	**16.90**	**17.48**	**17.36**	**17.35**	**17.43**	**17.54**	**17.66**	**17.69**	**17.97**	**18.16**	**17.95**	**17.81**	**18.02**	**18.12**	**18.28**	**18.21**	**18.47**	**18.70**	**18.71**	**19.39**	**19.75**	**19.56**	**19.71**	**19.80**	**19.93**	**2.2C - High Elec / Max DSM 2040 Coal**
Annual Rate Change		7.6%	3.4%	-0.7%	-0.1%	0.5%	0.6%	0.7%	0.1%	1.6%	1.0%	-1.1%	-0.8%	1.2%	0.6%	0.9%	-0.4%	1.4%	1.2%	0.1%	3.6%	1.9%	-1.0%	0.8%	0.5%	0.7%	
																										1.0%	Average Rate Change
																										1.5%	Average Rate Change 2021-2030

Planning Period Year

Electrification Scenario 4	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	
IRP Revenue Requirement (Partial) ($M)	858	864	921	906	900	905	899	902	907	934	946	914	902	936	963	972	968	1,015	1,034	1,073	1,148	1,188	1,191	1,219	1,222	1,230	
2014 Non-fuel revenue requirement ($M)	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	
Total Revenue Requirement Pre-incremental FCR recovery ($M)	1,658	1,664	1,721	1,706	1,700	1,705	1,699	1,702	1,707	1,734	1,746	1,714	1,702	1,736	1,763	1,772	1,768	1,815	1,834	1,873	1,948	1,988	1,991	2,019	2,022	2,030	
Incremental FCR-Base																											
Cumulative Incremental Sales (GWh)	-	(59)	(67)	(53)	(47)	(57)	(114)	(170)	(262)	(405)	(570)	(589)	(599)	(612)	(616)	(620)	(610)	(602)	(583)	(566)	(553)	(548)	(548)	(553)	(563)	(578)	
Incremental FCR $/MWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Incremental FCR ($M)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Net Revenue Requirement ($M)	1,658	1,664	1,721	1,706	1,700	1,705	1,699	1,702	1,707	1,734	1,746	1,714	1,702	1,736	1,763	1,772	1,768	1,815	1,834	1,873	1,948	1,988	1,991	2,019	2,022	2,030	
Load (GWh)	11,314	11,263	11,230	11,204	11,192	11,104	10,977	10,862	10,722	10,491	10,232	10,178	10,169	10,130	10,139	10,152	10,206	10,227	10,280	10,338	10,394	10,416	10,465	10,511	10,546	10,597	2.1B - Mid Elec / Base DSM w/ DER
Losses (7%)	758	755	752	751	750	744	735	728	718	703	686	682	681	679	679	680	684	685	689	693	696	698	701	704	707	710	
Sales	10,556	10,509	10,477	10,453	10,442	10,360	10,242	10,134	10,003	9,788	9,546	9,497	9,488	9,451	9,460	9,471	9,522	9,542	9,591	9,645	9,698	9,718	9,764	9,807	9,839	9,887	
Rate (cents/kWh)	**15.71**	**15.84**	**16.43**	**16.32**	**16.28**	**16.46**	**16.59**	**16.80**	**17.07**	**17.71**	**18.29**	**18.05**	**17.94**	**18.36**	**18.64**	**18.71**	**18.57**	**19.02**	**19.12**	**19.42**	**20.09**	**20.45**	**20.39**	**20.59**	**20.55**	**20.54**	**2.1B - Mid Elec / Base DSM w/ DER 2040 Coal**
Annual Rate Change		0.8%	3.7%	-0.7%	-0.3%	1.1%	0.8%	1.2%	1.6%	3.8%	3.3%	-1.3%	-0.6%	2.4%	1.5%	0.4%	-0.7%	2.4%	0.5%	1.5%	3.5%	1.8%	-0.3%	1.0%	-0.2%	-0.1%	
																										1.1%	Average Rate Change

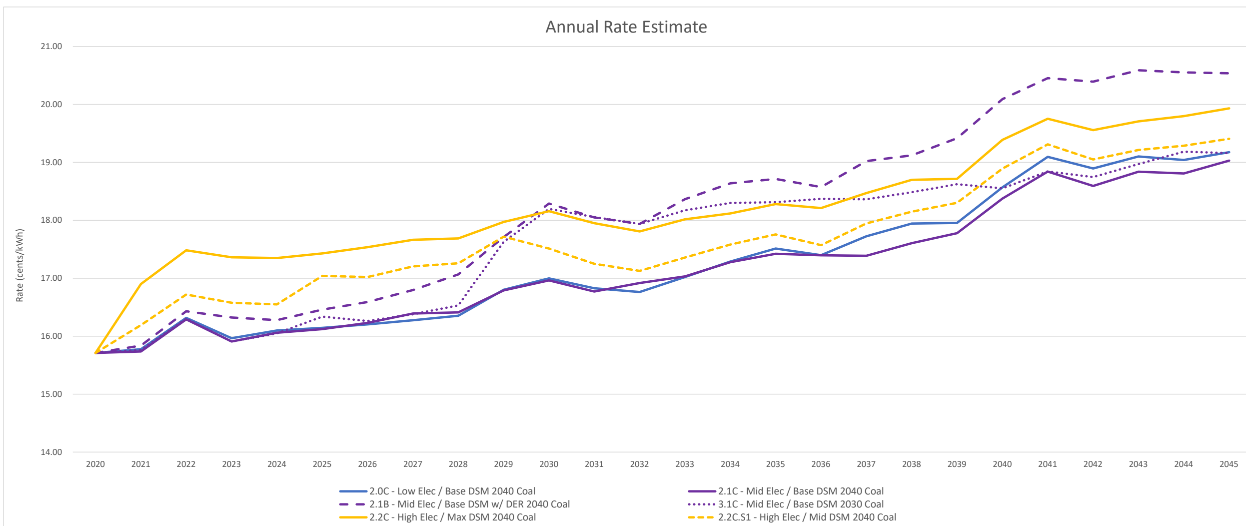
1.5% Average Rate Change 2021-2030

Planning Period Year																											
Electrification Scenario 5	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	
IRP Revenue Requirement (Partial) ($M)	858	867	923	883	905	935	927	940	959	1,072	1,127	1,114	1,110	1,139	1,163	1,176	1,199	1,210	1,237	1,268	1,275	1,317	1,321	1,360	1,397	1,410	
2014 Non-fuel revenue requirement ($M)	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	
Total Revenue Requirement Pre-incremental FCR recovery ($M)	1,658	1,667	1,723	1,683	1,705	1,735	1,727	1,740	1,759	1,872	1,927	1,914	1,910	1,939	1,963	1,976	1,999	2,010	2,037	2,068	2,075	2,117	2,121	2,160	2,197	2,210	
Incremental FCR-Base																											
Cumulative Incremental Sales (GWh)	-	10	28	72	133	203	262	320	375	425	472	517	562	608	653	700	750	799	847	893	935	970	1,001	1,027	1,049	1,067	
Incremental FCR $/MWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Incremental FCR ($M)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Net Revenue Requirement ($M)	1,658	1,667	1,723	1,683	1,705	1,735	1,727	1,740	1,759	1,872	1,927	1,914	1,910	1,939	1,963	1,976	1,999	2,010	2,037	2,068	2,075	2,117	2,121	2,160	2,197	2,210	
Load (GWh)	11,314	11,338	11,332	11,337	11,385	11,383	11,381	11,387	11,405	11,380	11,349	11,363	11,414	11,438	11,499	11,567	11,664	11,730	11,812	11,901	11,989	12,043	12,125	12,205	12,274	12,360	3.1C - Mid Elec / Base DSM
Losses (7%)	758	760	759	760	763	763	763	763	764	762	760	761	765	766	770	775	781	786	791	797	803	807	812	818	822	828	
Sales	10,556	10,578	10,573	10,577	10,622	10,620	10,618	10,624	10,641	10,617	10,588	10,602	10,649	10,671	10,729	10,792	10,882	10,944	11,021	11,104	11,186	11,236	11,313	11,387	11,451	11,532	
Rate (cents/kWh)	**15.71**	**15.76**	**16.30**	**15.91**	**16.05**	**16.34**	**16.26**	**16.38**	**16.53**	**17.63**	**18.20**	**18.06**	**17.94**	**18.17**	**18.30**	**18.31**	**18.37**	**18.36**	**18.49**	**18.62**	**18.55**	**18.84**	**18.74**	**18.97**	**19.18**	**19.16**	**3.1C - Mid Elec / Base DSM 2030 Coal**
Annual Rate Change		0.3%	3.4%	-2.4%	0.9%	1.8%	-0.5%	0.7%	0.9%	6.6%	3.2%	-0.8%	-0.7%	1.3%	0.7%	0.1%	0.3%	0.0%	0.7%	0.7%	-0.4%	1.6%	-0.5%	1.2%	1.1%	-0.1%	

0.8% Average Rate Change
1.5% Average Rate Change 2021-2030

Planning Period Year																											
Electrification Scenario 6	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	
IRP Revenue Requirement (Partial) ($M)	858	914	977	968	982	1,045	1,050	1,079	1,094	1,147	1,127	1,107	1,109	1,146	1,191	1,233	1,238	1,303	1,350	1,394	1,489	1,558	1,548	1,589	1,615	1,651	
2014 Non-fuel revenue requirement ($M)	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	
Total Revenue Requirement Pre-incremental FCR recovery ($M)	1,658	1,714	1,777	1,768	1,782	1,845	1,850	1,879	1,894	1,947	1,927	1,907	1,909	1,946	1,991	2,033	2,038	2,103	2,150	2,194	2,289	2,358	2,348	2,389	2,415	2,451	
Incremental FCR-Base																											
Cumulative Incremental Sales (GWh)	-	20	84	162	280	413	515	616	711	799	884	970	1,056	1,151	1,251	1,357	1,467	1,573	1,675	1,776	1,866	1,943	2,012	2,071	2,122	2,165	
Incremental FCR $/MWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Incremental FCR ($M)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Net Revenue Requirement ($M)	1,658	1,714	1,777	1,768	1,782	1,845	1,850	1,879	1,894	1,947	1,927	1,907	1,909	1,946	1,991	2,033	2,038	2,103	2,150	2,194	2,289	2,358	2,348	2,389	2,415	2,451	
Load (GWh)	11,314	11,348	11,392	11,434	11,542	11,608	11,651	11,704	11,764	11,781	11,791	11,849	11,943	12,019	12,141	12,271	12,432	12,559	12,700	12,848	12,987	13,086	13,209	13,324	13,424	13,537	2.2C.S1 - High Elec / Mid DSM
Losses (7%)	758	760	763	766	773	778	781	784	788	789	790	794	800	805	813	822	833	841	851	861	870	877	885	893	899	907	
Sales	10,556	10,588	10,629	10,668	10,769	10,830	10,871	10,920	10,976	10,992	11,001	11,055	11,143	11,214	11,327	11,449	11,599	11,717	11,849	11,987	12,117	12,209	12,324	12,431	12,524	12,630	
Rate (cents/kWh)	**15.71**	**16.19**	**16.72**	**16.58**	**16.55**	**17.04**	**17.02**	**17.20**	**17.26**	**17.72**	**17.51**	**17.25**	**17.13**	**17.36**	**17.58**	**17.76**	**17.57**	**17.95**	**18.15**	**18.30**	**18.89**	**19.31**	**19.05**	**19.21**	**19.29**	**19.41**	**2.2C.S1 - High Elec / Mid DSM 2040 Coal**
Annual Rate Change		3.1%	3.3%	-0.8%	-0.2%	3.0%	-0.1%	1.1%	0.3%	2.7%	-1.2%	-1.5%	-0.7%	1.3%	1.3%	1.0%	-1.0%	2.1%	1.1%	0.8%	3.2%	2.2%	-1.4%	0.9%	0.4%	0.6%	

0.9% Average Rate Change
1.1% Average Rate Change 2021-2030



NS POWER 2020 IRP
UPDATED MODELING RESULTS RELEASE

SEPTEMBER 2, 2020

UPDATED NOVEMBER 27, 2020

Nova Scotia POWER
An Emera Company

REVISIONS

SEPTEMBER 11

- Scenario 2.0C – corrected a typo in the 25-yr NPVRR (was previously reported as $12,224 – corrected to $12,234)
  - Updated on slides 13, 41, 43, & 45

SEPTEMBER 18

- For certain sensitivity runs, the metric *Total CO_2 Emissions 2031-2045 (MT)* was incorrectly reported in the summary tables in the previous release. The *Total CO_2 Emissions 2021-2030 (MT)* and *Total CO_2 Emissions 2021-2045 (MT)* metrics were not affected, and the CO_2 Emissions graphs and CO_2 Emissions data in the Modeling Results Tables are correct.
  - Updated figures are shown in purple text on slides 35, 37, 39, 41, 45, 47, 51, 57, 59, & 63

OCTOBER 30

- Added 3 new sensitivity runs on slides 64-69:
  - 2.1C.CAPEX-1 (High Sustaining Capex)
  - 2.1C.CAPEX-2 (Low Sustaining Capex)
  - 2.1C.PRICES-1 (High Import & Gas Prices)
  - Updated scenarios list on slide 33 with purple text to reflect these additions

REVISIONS

NOVEMBER 27

- Updated NPV results (all 3 metrics) for all models to incorporate Avoided T&D Costs
- Updated relative rate impact results to incorporate avoided T&D costs and removal of FCR adjustment from model
- Corrected typos in slide titles of scenarios 2.2A and 2.2C (indicated Base DSM, corrected to Max DSM)
- Updated rate model metric title for clarity and consistency with IRP Final Report (replaced “partial rate” with “relative rate”)

TABLE OF CONTENTS

FINAL PORTFOLIO STUDY RESULTS
SCENARIO RESULTS

Nova Scotia POWER An Emera Company

FINAL PORTFOLIO STUDY

- The following slides provide the Final Portfolio Study results from PLEXOS for the key scenarios (full capacity expansion runs in PLEXOS LT, and Generation / Production Cost results from PLEXOS MT/ST hourly simulations)
- The section includes detailed outputs of each scenario including energy mix, nameplate capacity installation, emissions compliance, achieved Planning Reserve Margin (PRM), several metrics of partial NPV of revenue requirement (NPVRR), Average Annual Relative Rate impact, and scenario notes
- NPVs presented in these results are partial revenue requirements that consider modeled costs (i.e. production, O&M, abatement, sustaining capital, and capital investment) and specific costs considered outside of the long-term model optimization (e.g. energy efficiency costs)

FINAL PORTFOLIO STUDY - METRICS

The following metrics are being used to evaluate each portfolio studied; updates from the Scenarios and Modeling Plan release based on ongoing work and stakeholder feedback are shown in purple text.

Metric	Description
Minimization of the cumulative present value of the annual revenue requirements over the planning horizon (with and without end-effects adjustment)	25 year NPV Revenue Requirement Average Annual Relative Rate Impact - 25-yr
Magnitude and timing of electricity rate effects	10 year NPV Revenue Requirement Average Annual Relative Rate Impact - 10-yr
Reliability requirements for supply adequacy	Evaluation of PRM, resource capacity adequacy, operating reserve requirements, etc.
Provision of essential grid services for system stability and reliability	Quantitative and qualitative assessment of the status of essential grid services provision for each portfolio. Many plans are similar in this respect, so only key differences will be noted at this time.
Plan robustness (the ability of a plan to withstand plausible potential changes to key assumptions)	Magnitude of the plan's exposure to changes in key assumptions (via sensitivity analysis) as well as resiliency to risks
Reduction of greenhouse gas and/or other emissions	Quantitative reductions as output by Plexos; total emissions over planning horizon.
Flexibility (limitation of constraints on future decisions arising from the selection of a particular path)	Qualitative assessment of timing of investments

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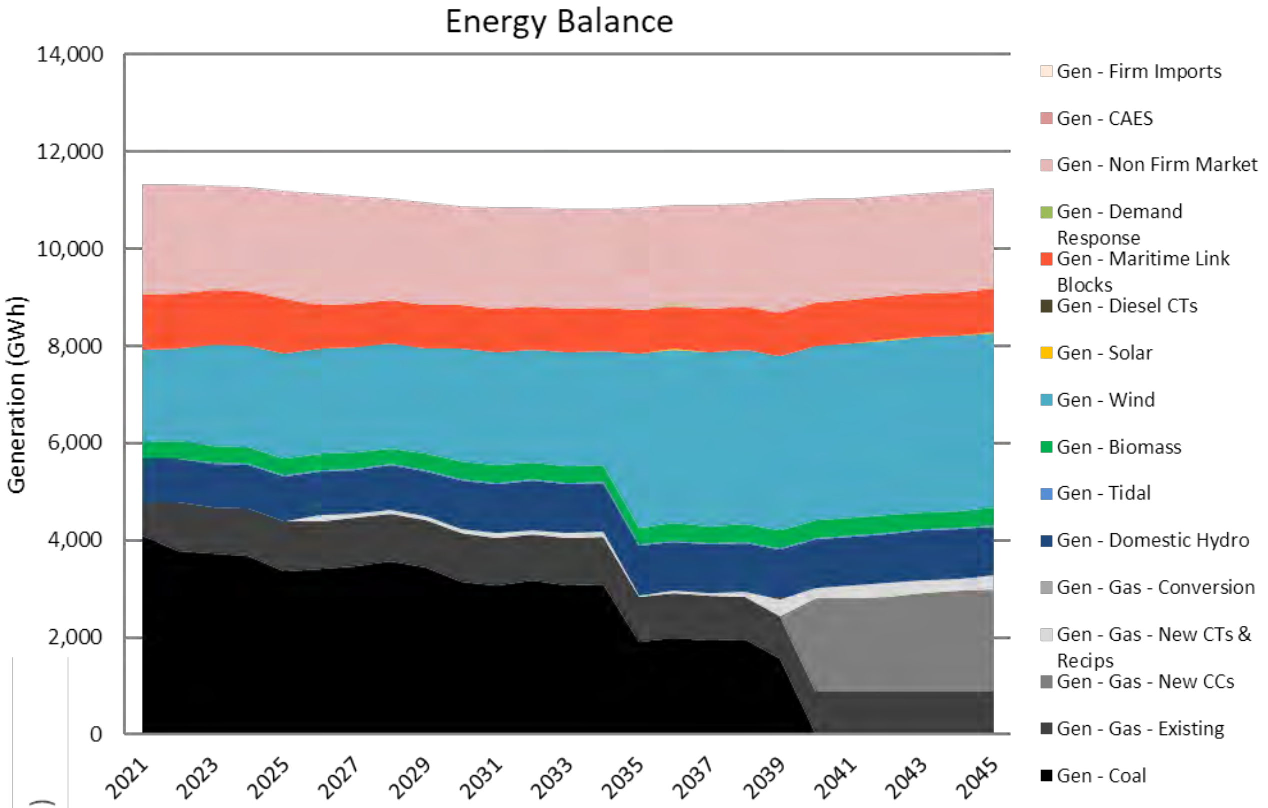
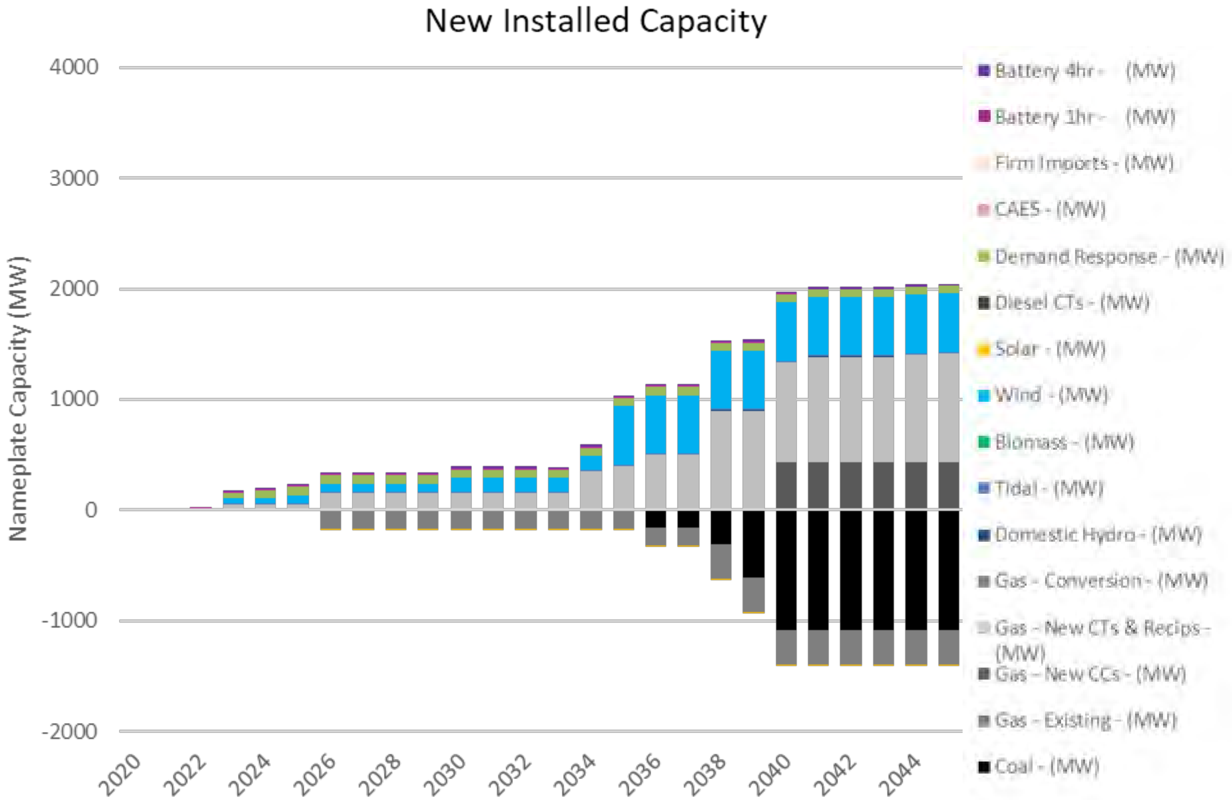
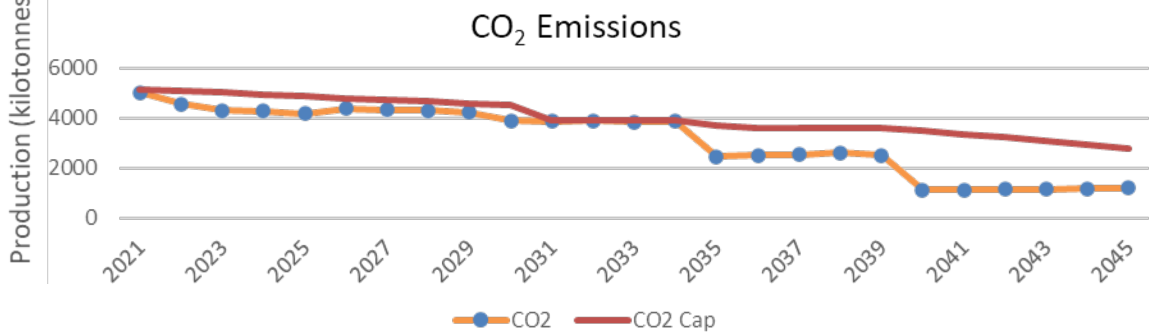
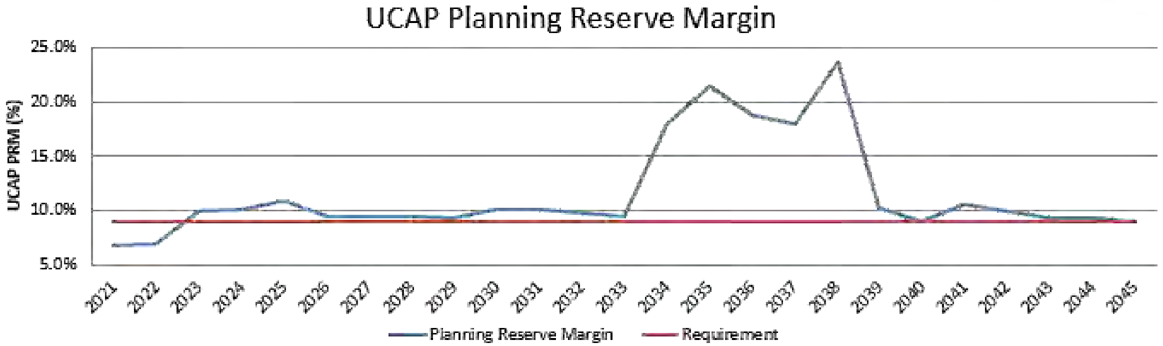
1.0A

LOW ELEC. / BASE DSM / COMPARATOR EMISSIONS / CURRENT LANDSCAPE









1.0A

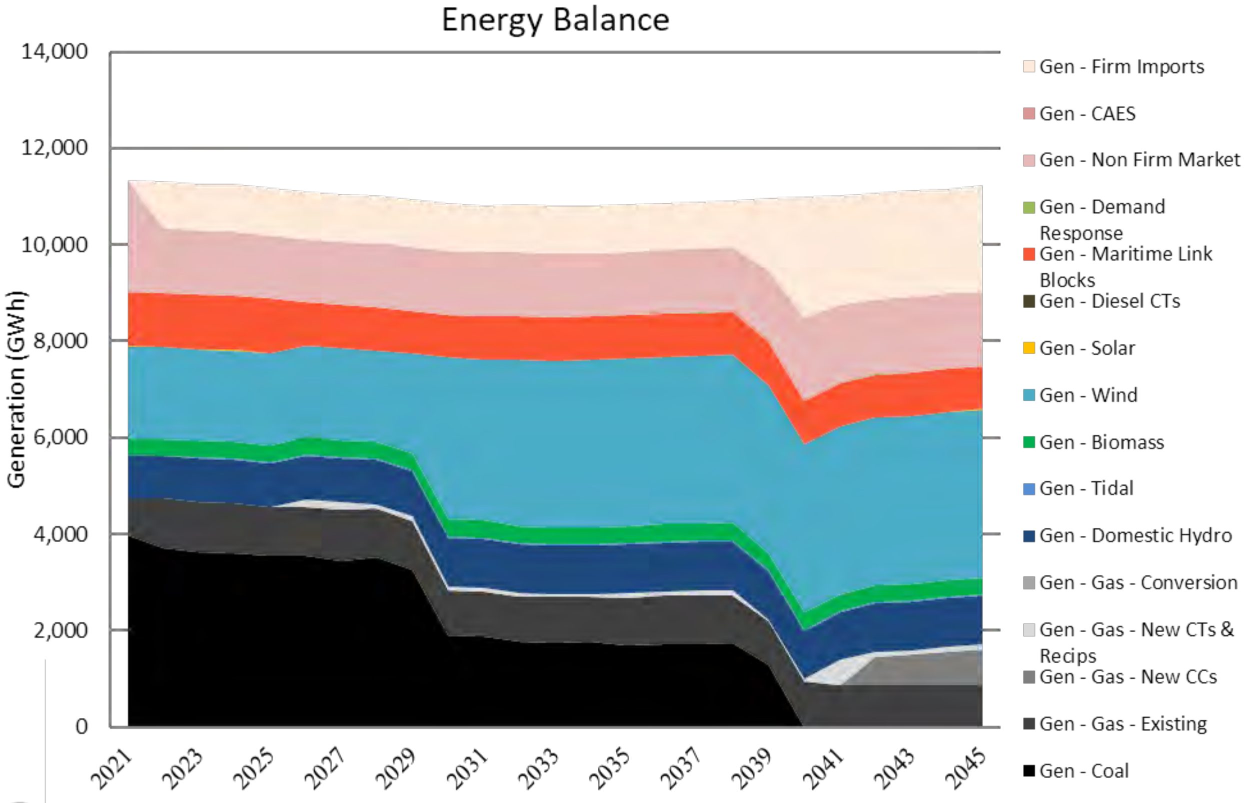
LOW ELEC. / BASE DSM / COMPARATOR EMISSIONS / CURRENT LANDSCAPE

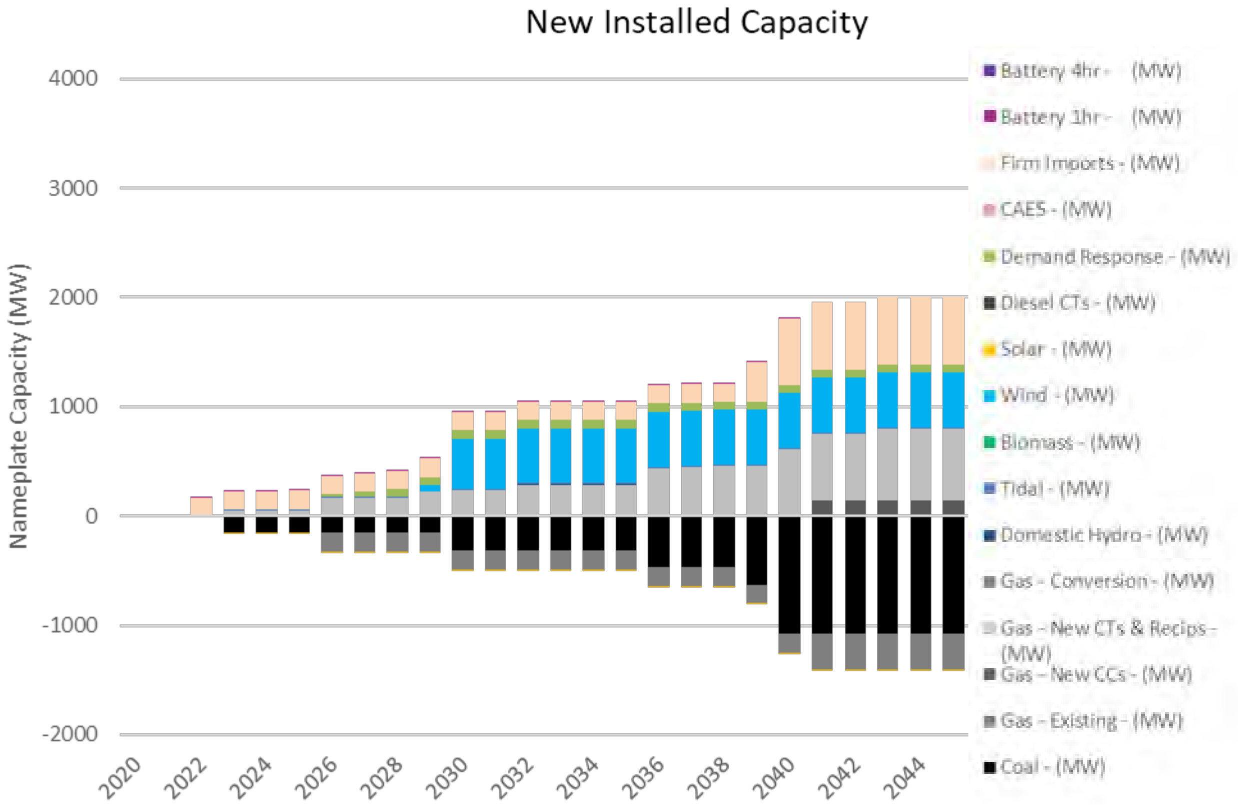
Scenario Metrics & Evaluation

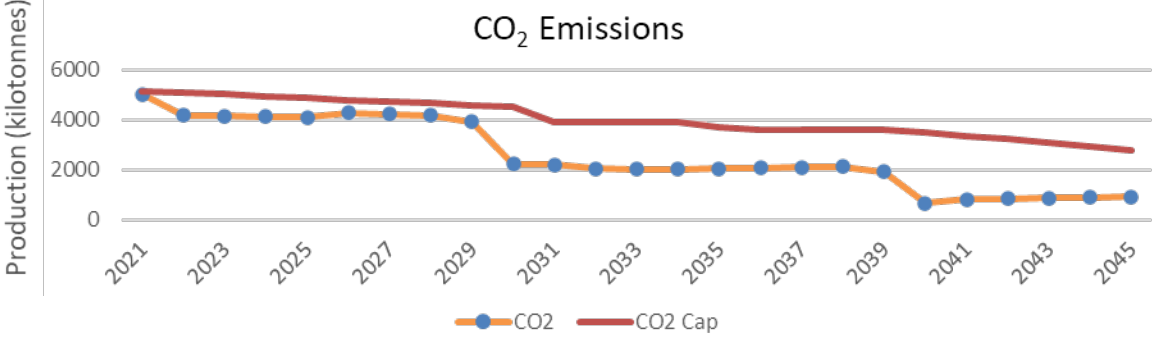
25-yr NPVRR ($MM)	$12,261	<u>General Notes</u> • Coal capacity replaced with new gas CCGT and CT units in late 2030s • Reliability Tie is built and enables additional economic wind generation in 2035
25-yr NPVRR with End Effects ($MM)	$16,431	<u>Essential Grid Services</u> • Essential Grid Service requirements are met as modeled
10-yr NPVRR ($MM)	$6,805	<u>Resource Adequacy & PRM</u> • Reliability Tie: 2035 • Regional Integration: n/a
Average Annual Relative Rate Impact 2021-2030 (%) 2021-2045 (%)	 0.8% 1.0%	<u>Plan Robustness & Flexibility</u> • No reliance on firm import energy or capacity • Not compliant with Sustainable Development Goals Act • More exposure to natural gas prices with 435MW NGCC capacity in 2040s
Total CO_2 Emissions 2021-2030 (MT) Total CO_2 Emissions 2031-2045 (MT) Total CO_2 Emissions 2021-2045 (MT)	43.5 35.0 78.5	

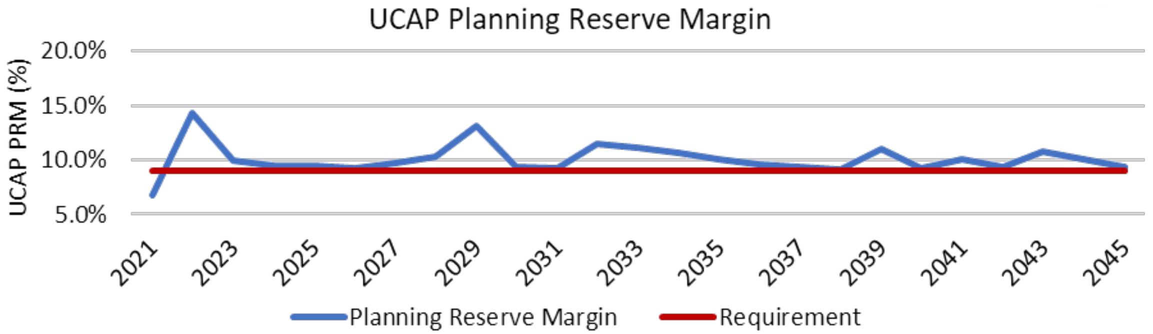
1.0C

LOW ELEC. / BASE DSM / COMPARATOR EMISSIONS / REGIONAL INTEGRATION









1.0C

LOW ELEC. / BASE DSM / COMPARATOR EMISSIONS / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

25-yr NPVRR ($MM)	$12,032
25-yr NPVRR with End Effects ($MM)	$15,906
10-yr NPVRR ($MM)	$6,766
Average Annual Relative Rate Impact	
2021-2030 (%)	0.8%
2021-2045 (%)	0.8%
Total CO_2 Emissions 2021-2030 (MT)	40.4
Total CO_2 Emissions 2031-2045 (MT)	23.5
Total CO_2 Emissions 2021-2045 (MT)	63.8

General Notes
- Incremental firm imports enable an economic coal unit retirement in the 2020s
- Reliability Tie in 2030 enables additional wind integration earlier than seen in previous results
- Regional Interconnection constructed in 2039 allows remaining coal retirements

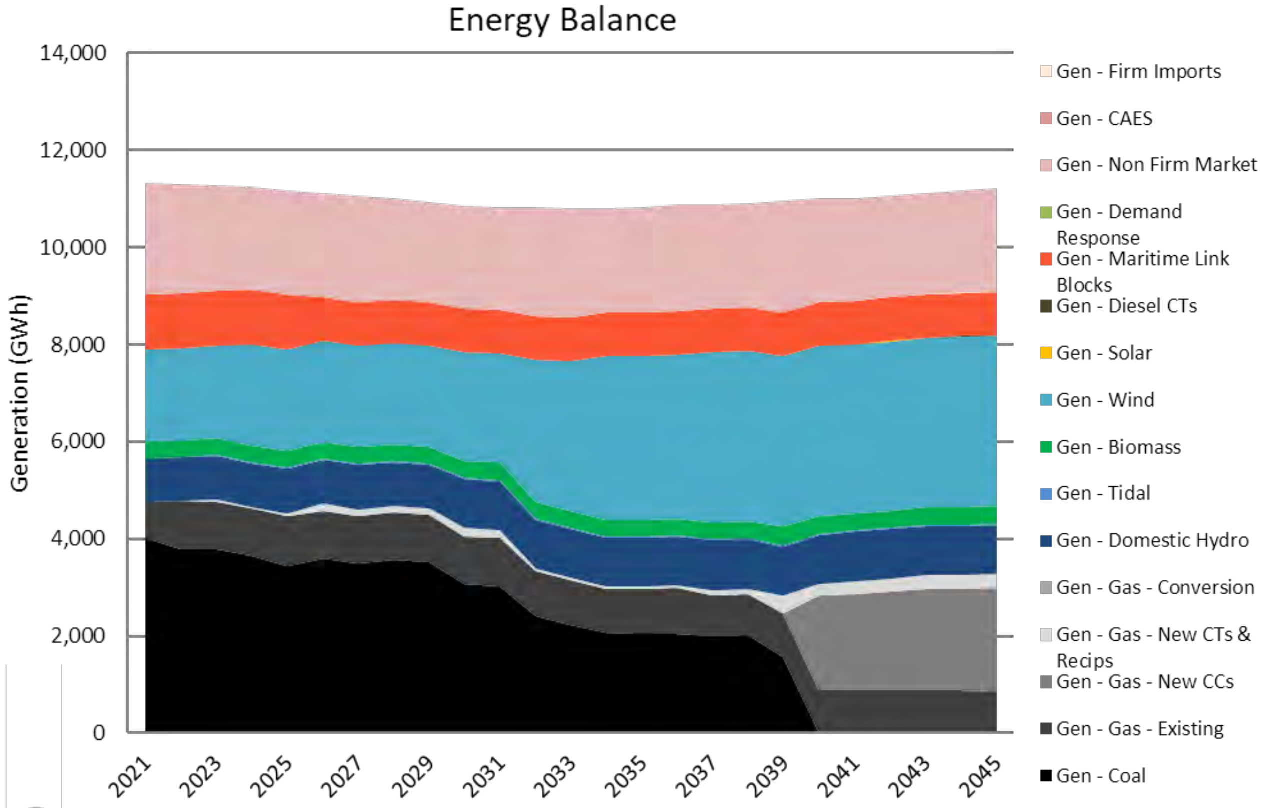
Essential Grid Services
- Essential Grid Service requirements are met as modeled

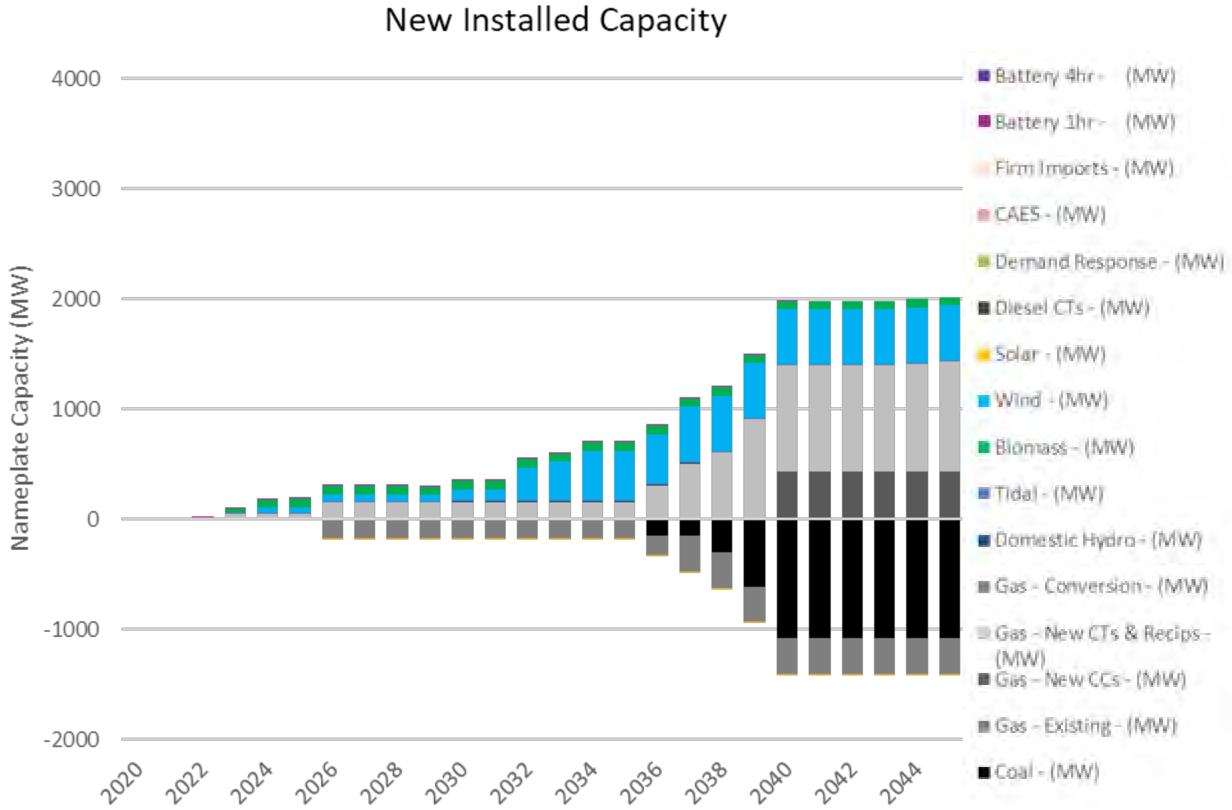
Resource Adequacy & PRM
- Reliability Tie: 2030
- Regional Integration: 2039

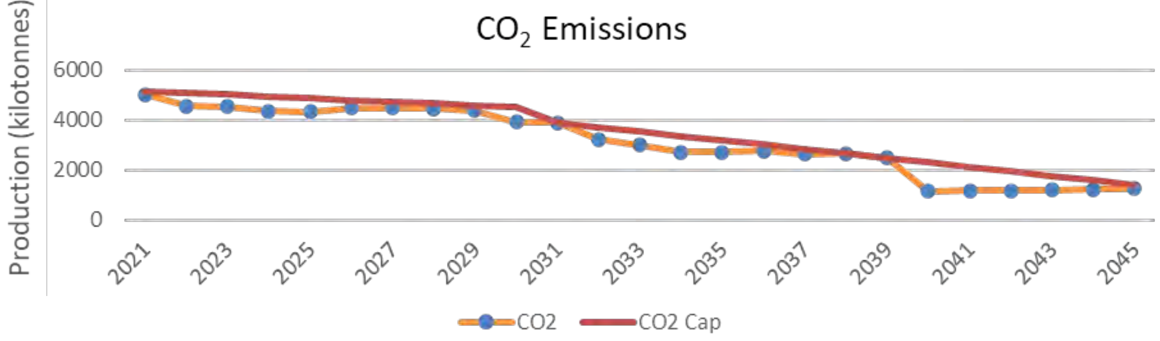
Plan Robustness & Flexibility
- Not compliant with Sustainable Development Goals Act
- Regional Integration provides flexible ability to meet emissions constraints

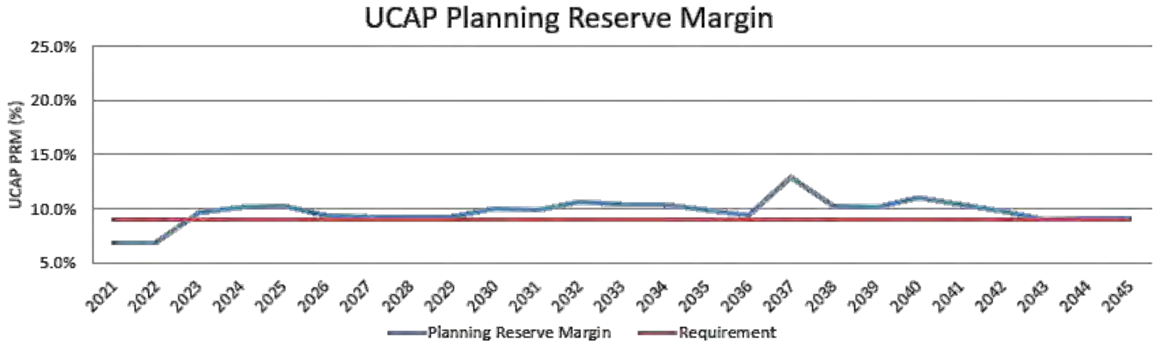
2.0A

LOW ELEC. / BASE DSM / NET ZERO 2050 / CURRENT LANDSCAPE









2.0A

LOW ELEC. / BASE DSM / NET ZERO 2050 / CURRENT LANDSCAPE

Scenario Metrics & Evaluation

25-yr NPVRR ($MM)	$12,193
25-yr NPVRR with End Effects ($MM)	$16,347
10-yr NPVRR ($MM)	$6,786
Average Annual Relative Rate Impact	
2021-2030 (%)	0.8%
2021-2045 (%)	1.0%
Total CO_2 Emissions 2021-2030 (MT)	44.5
Total CO_2 Emissions 2031-2045 (MT)	33.2
Total CO_2 Emissions 2021-2045 (MT)	77.7

General Notes
- Reliability Tie built in 2030 enables wind integration; does not provide firm capacity or energy access

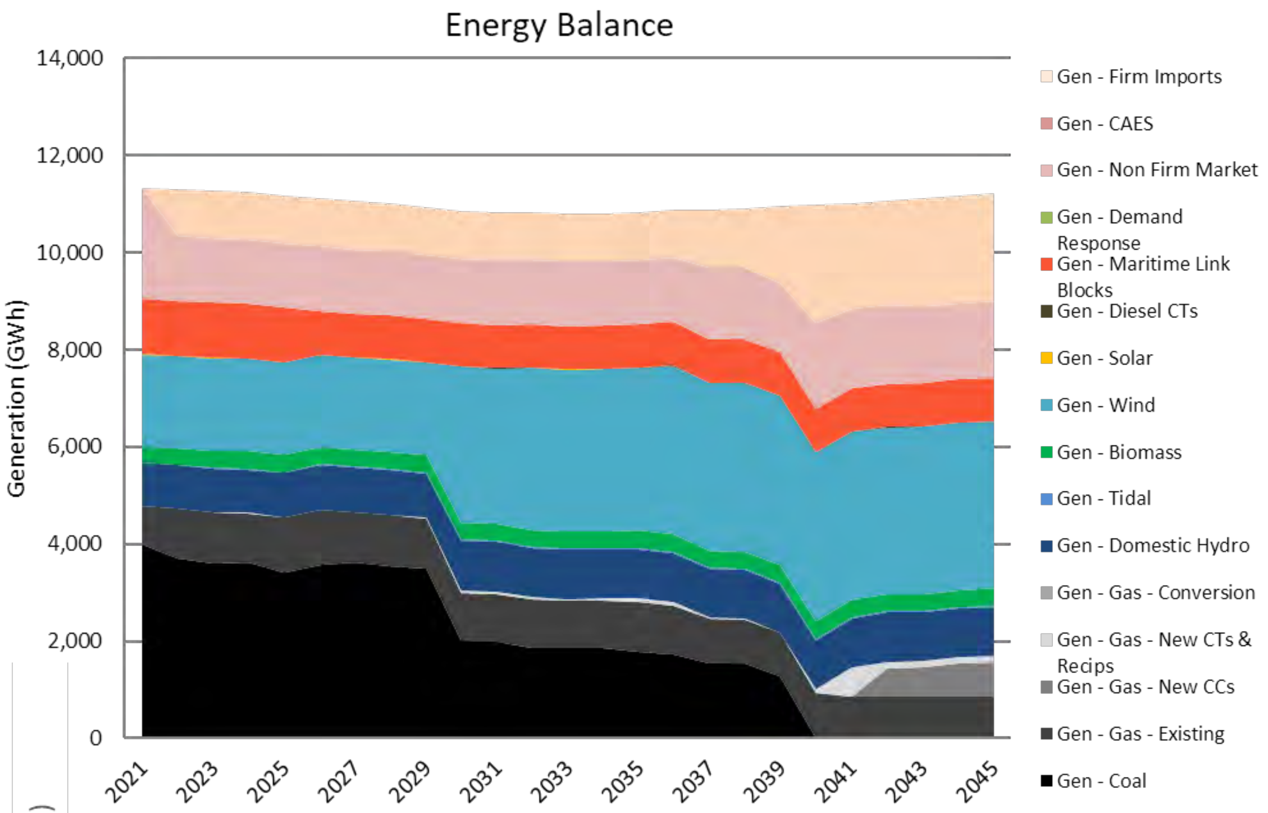
Essential Grid Services
- Essential Grid Service requirements are met as modeled

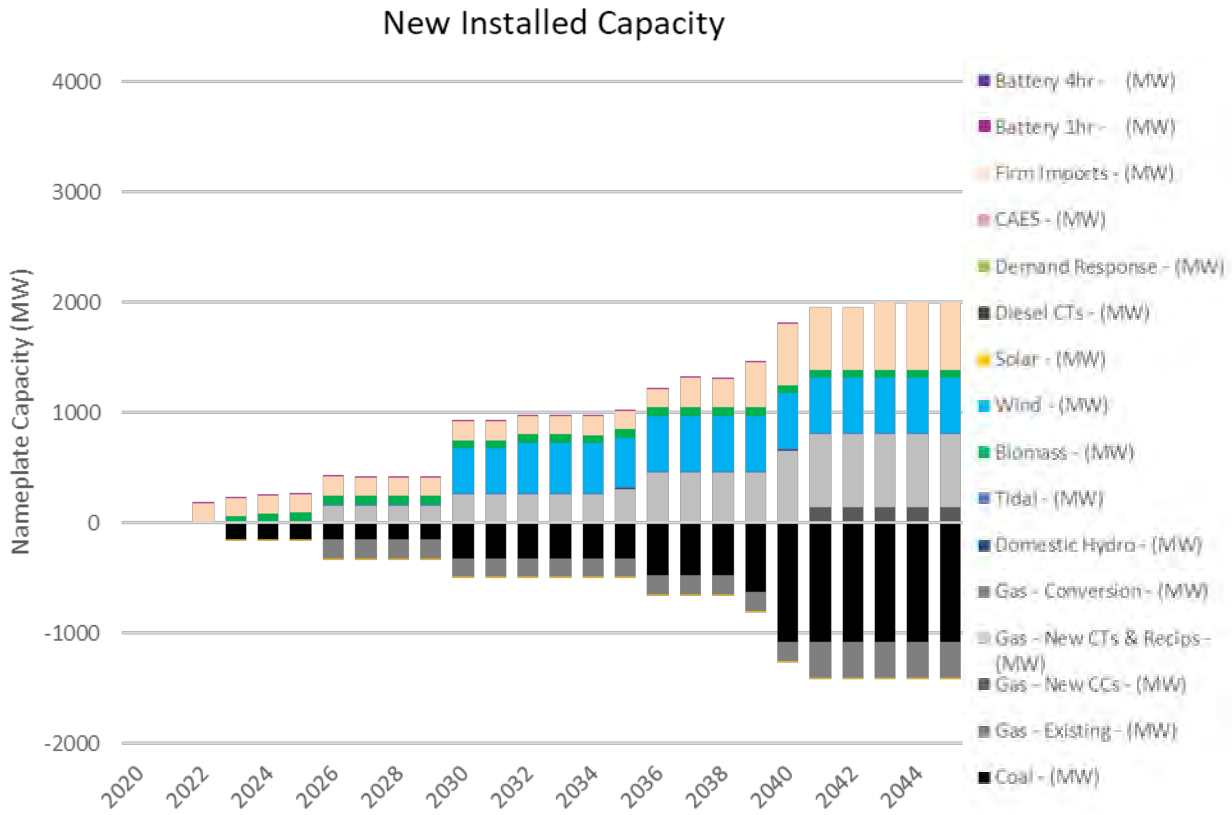
Resource Adequacy & PRM
- Reliability Tie: 2032
- Regional Integration: n/a

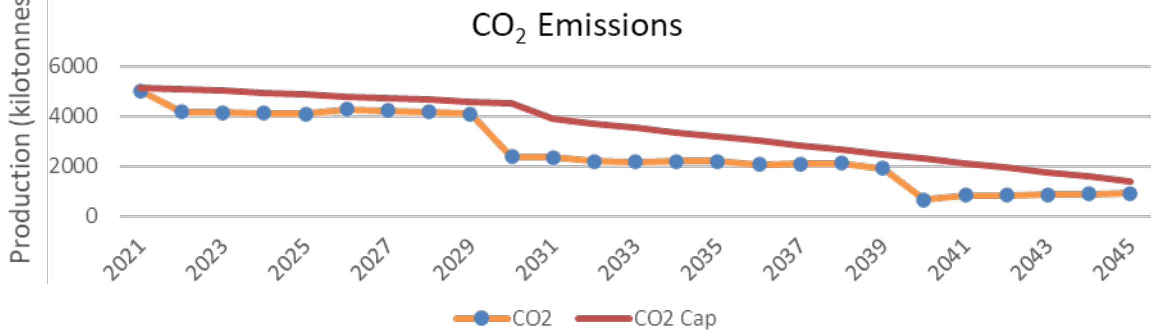
Plan Robustness & Flexibility
- No reliance on firm import energy or capacity
- More exposure to natural gas prices with 435MW NGCC capacity in 2040s

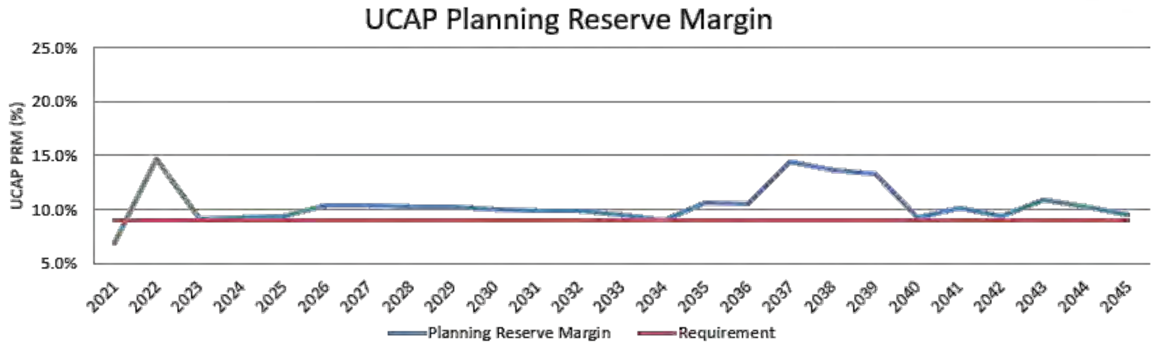
2.0C

LOW ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION









2.0C

LOW ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

25-yr NPVRR ($MM)	$12,076
25-yr NPVRR with End Effects ($MM)	$15,990
10-yr NPVRR ($MM)	$6,776
Average Annual Relative Rate Impact	
2021-2030 (%)	0.8%
2021-2045 (%)	0.8%
Total CO_2 Emissions 2021-2030 (MT)	40.7
Total CO_2 Emissions 2031-2045 (MT)	24.3
Total CO_2 Emissions 2021-2045 (MT)	65.0

General Notes
- Capacity expansion and generation are very similar to 1.0C case but with SDGA compliant GHG curve

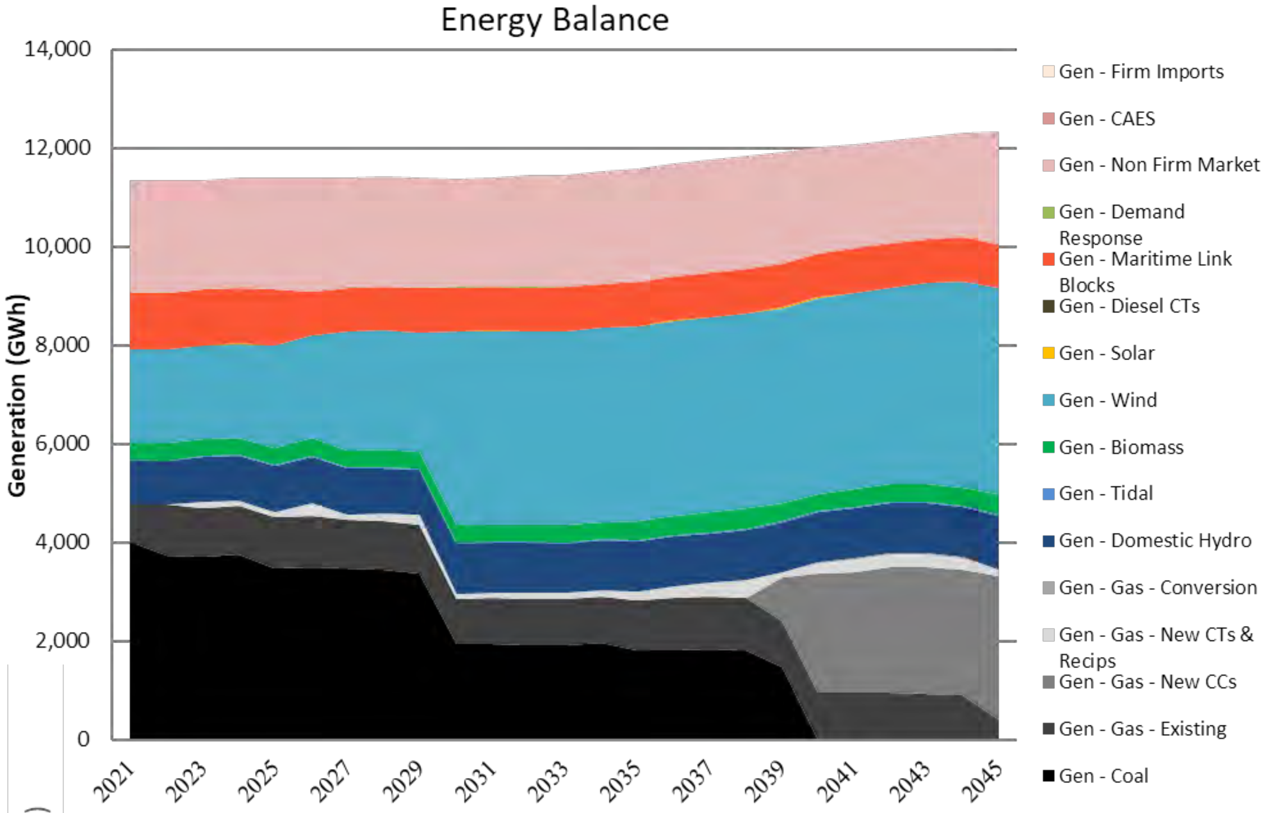
Essential Grid Services
- Essential Grid Service requirements are met as modeled

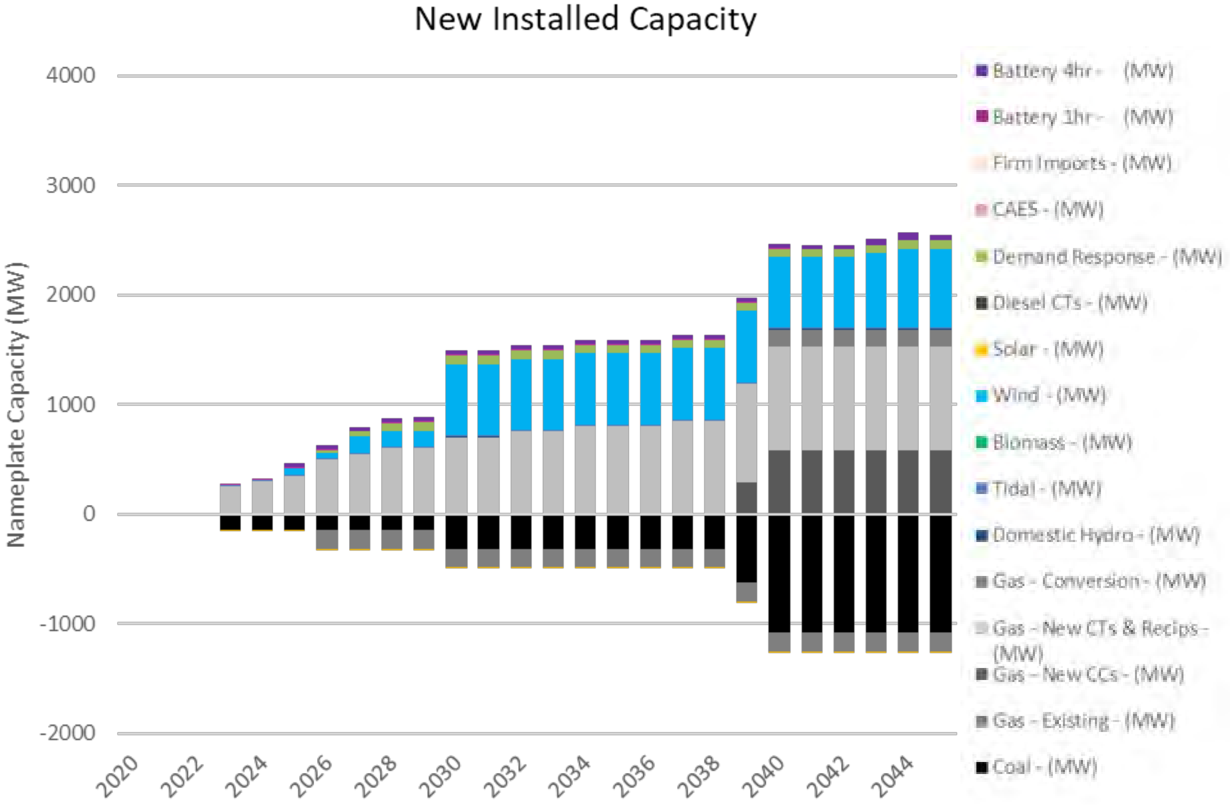
Resource Adequacy & PRM
- Reliability Tie: 2030
- Regional Integration: 2037

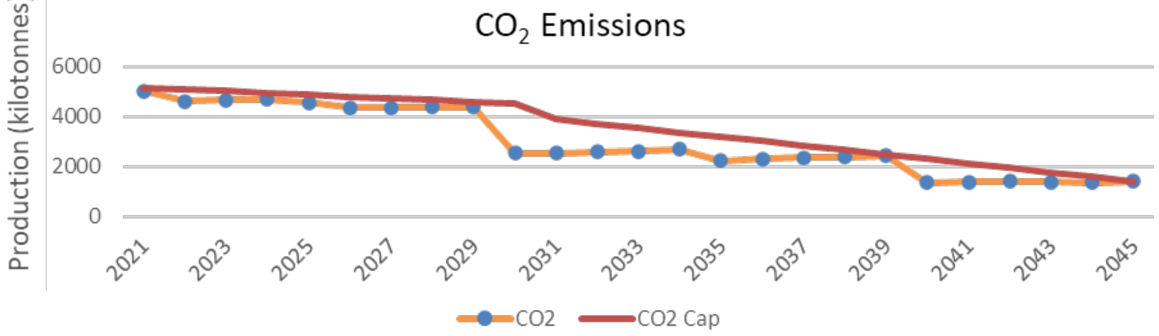
Plan Robustness & Flexibility
- Regional Integration provides flexible ability to meet emissions constraints

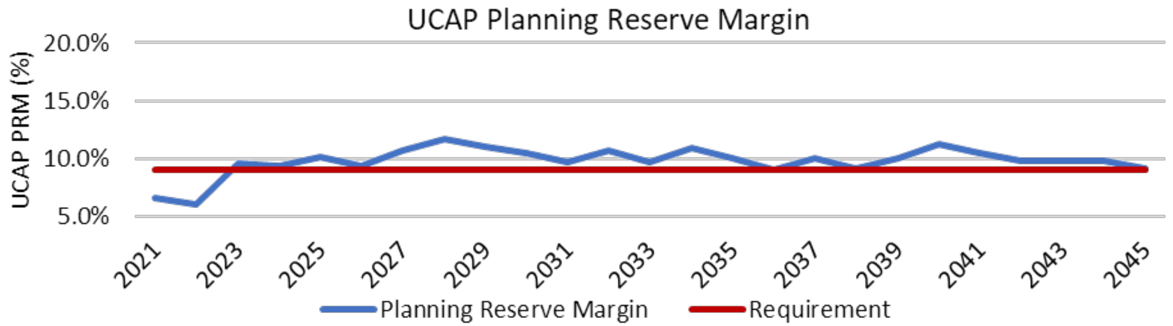
2.1A

MID ELEC. / BASE DSM / NET ZERO 2050 / CURRENT LANDSCAPE









2.1A

MID ELEC. / BASE DSM / NET ZERO 2050 / CURRENT LANDSCAPE

Scenario Metrics & Evaluation

25-yr NPVRR ($MM)	$13,195
25-yr NPVRR with End Effects ($MM)	$18,002
10-yr NPVRR ($MM)	$7,055
Average Annual Relative Rate Impact	
2021-2030 (%)	0.9%
2021-2045 (%)	0.9%
Total CO_2 Emissions 2021-2030 (MT)	43.6
Total CO_2 Emissions 2031-2045 (MT)	30.3
Total CO_2 Emissions 2021-2045 (MT)	73.9

General Notes
- Reliability Tie built in 2031 enables wind integration but does not provide firm capacity or energy access
- Gas CT builds provide capacity to support early electrification load growth; energy is supplied by wind and non-firm imports, and CCGT when coal units retire
- 1 coal unit converted to gas in 2040

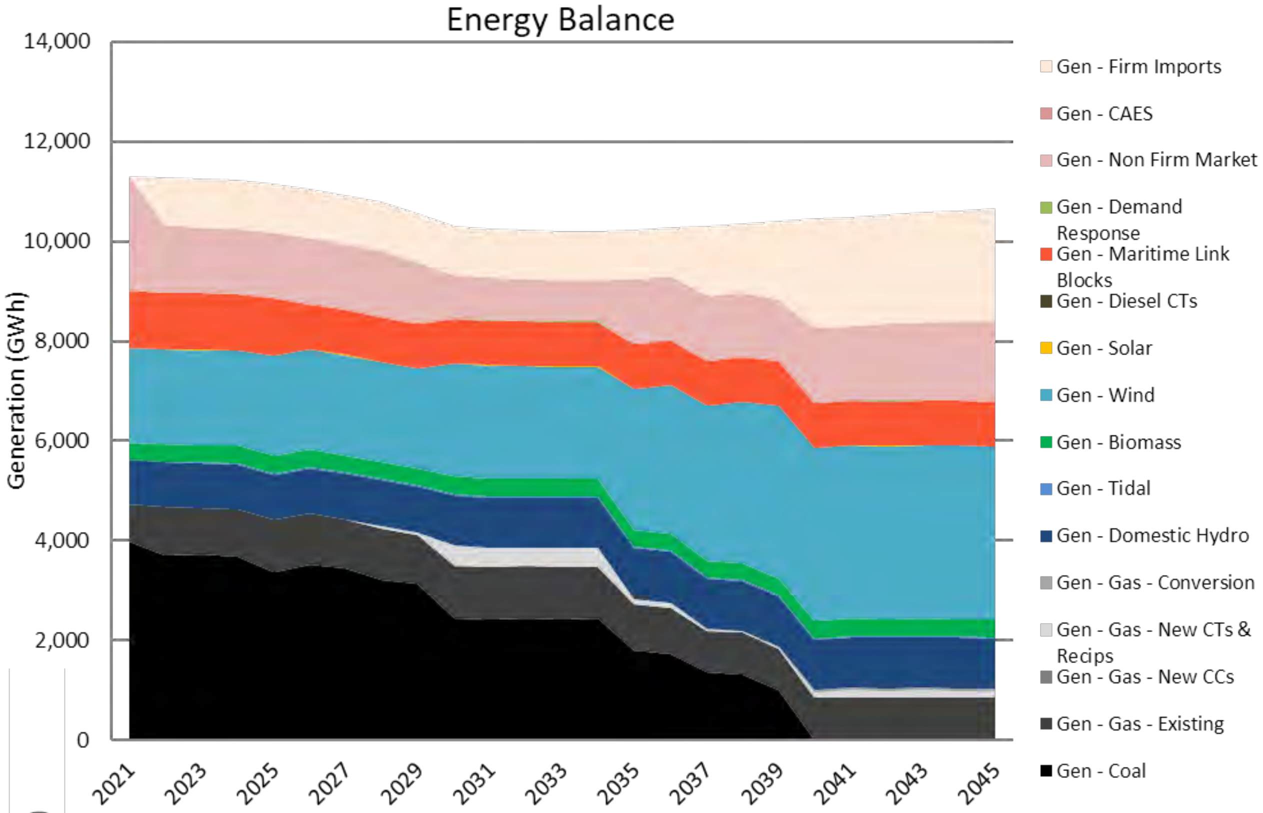
Essential Grid Services
- Essential Grid Service requirements are met as modeled

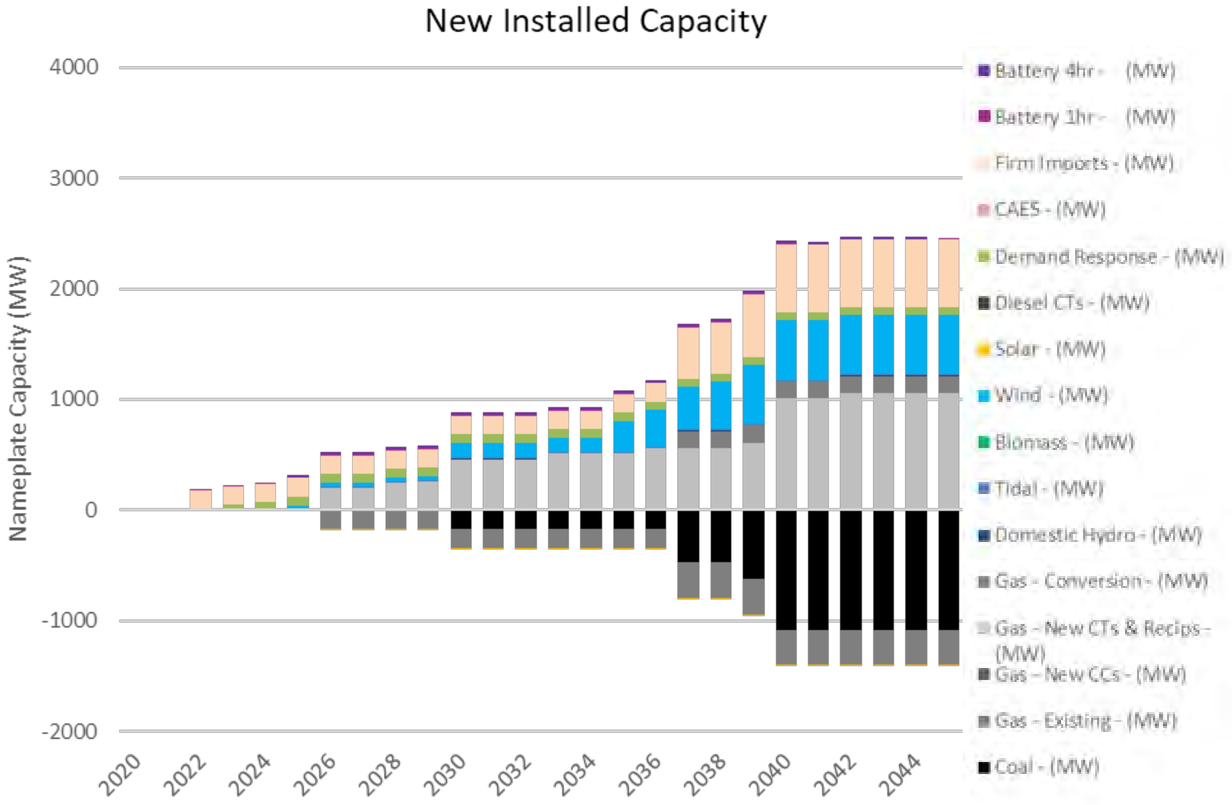
Resource Adequacy & PRM
- Reliability Tie: 2030
- Regional Integration: n/a

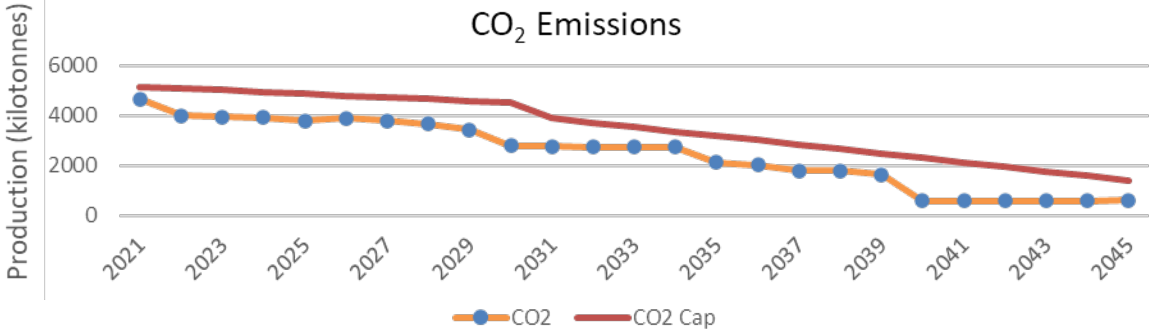
Plan Robustness & Flexibility
- No reliance on firm import energy or capacity
- More exposure to natural gas prices with 435MW NGCC capacity in 2040s

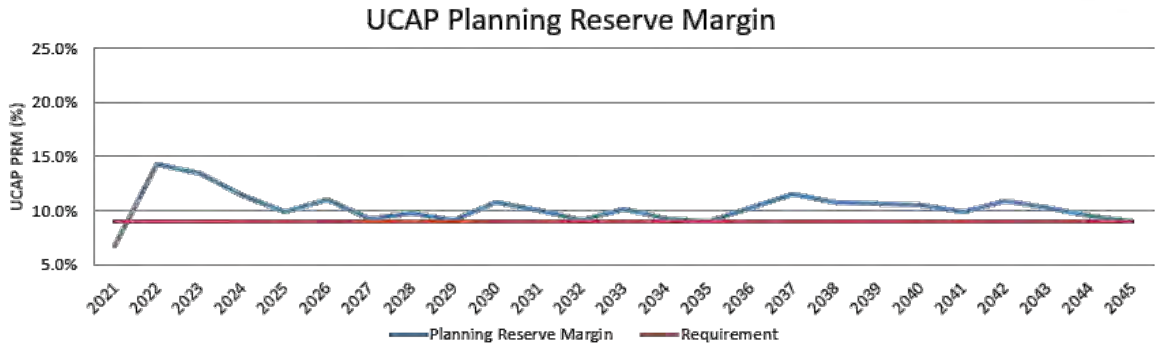
2.1B

MID ELEC. / BASE DSM / NET ZERO 2050 / DISTRIBUTED RESOURCES









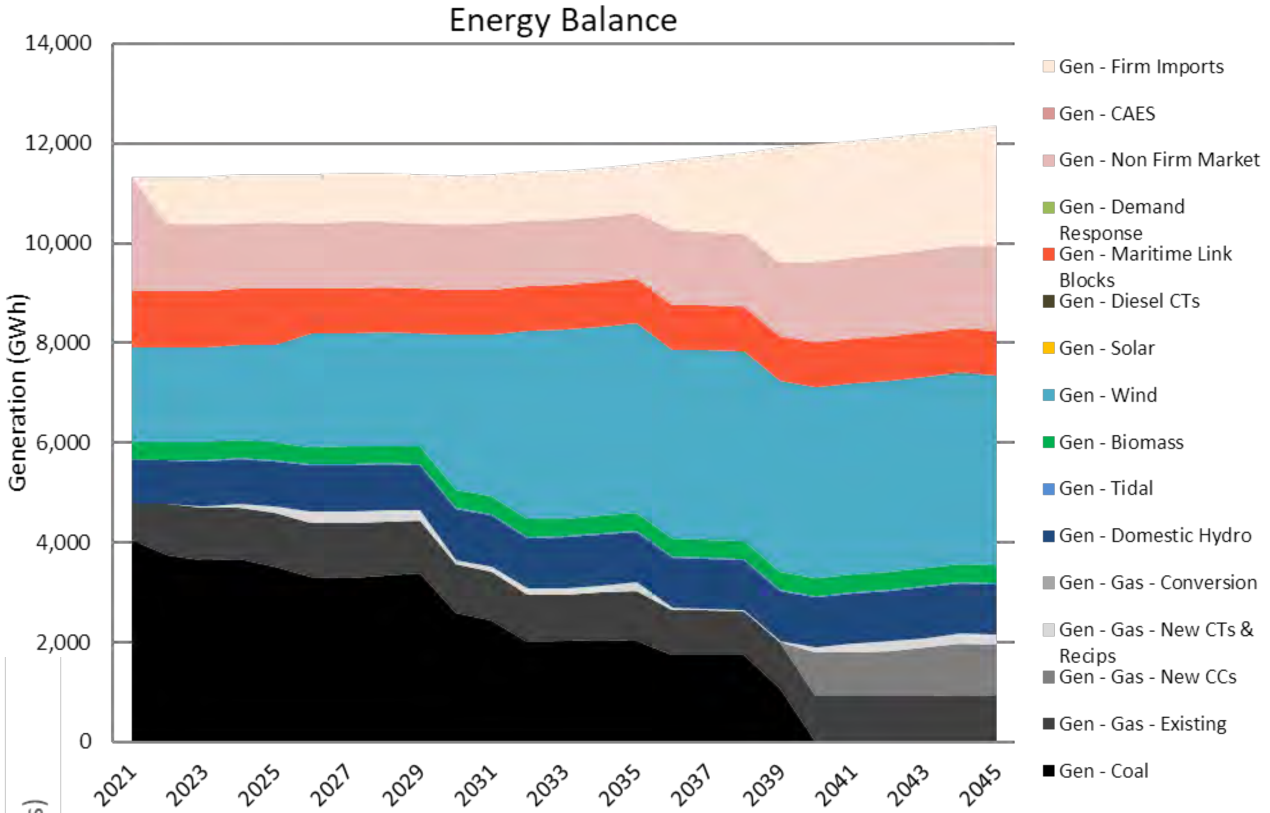
2.1B

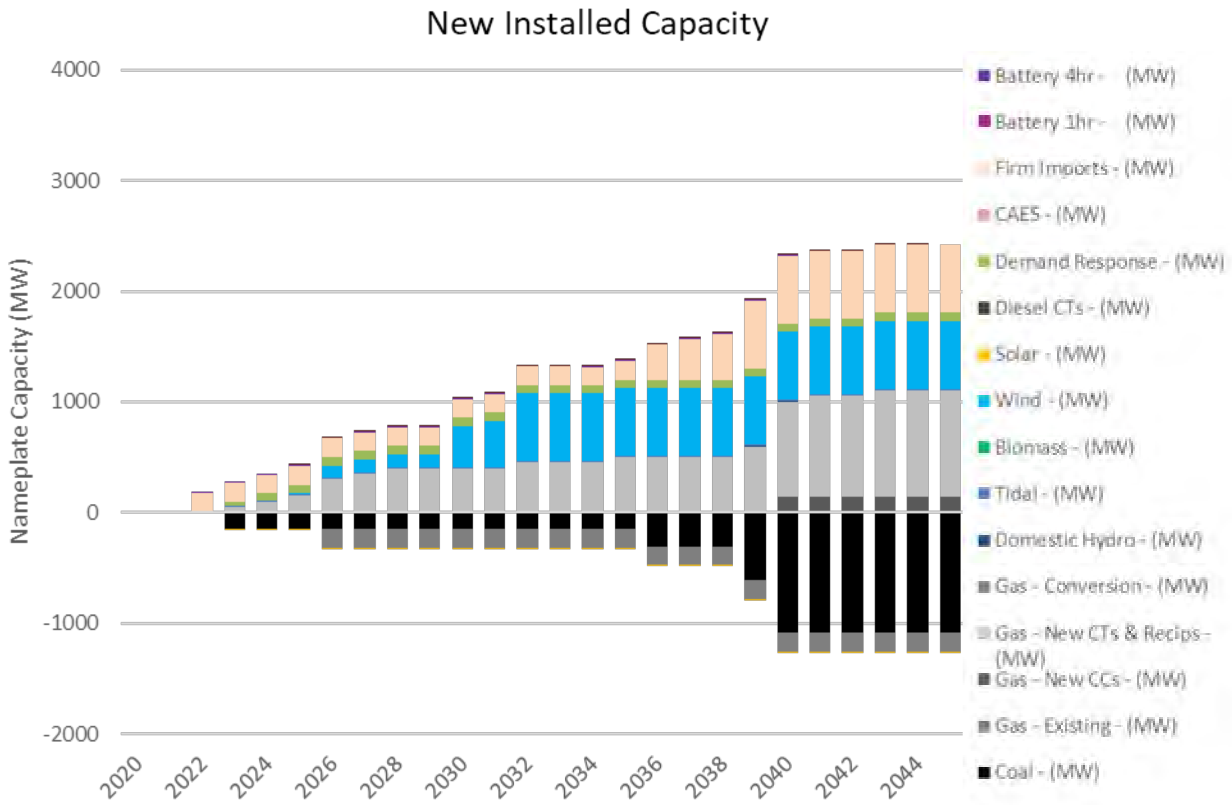
MID ELEC. / BASE DSM / NET ZERO 2050 / DISTRIBUTED RESOURCES

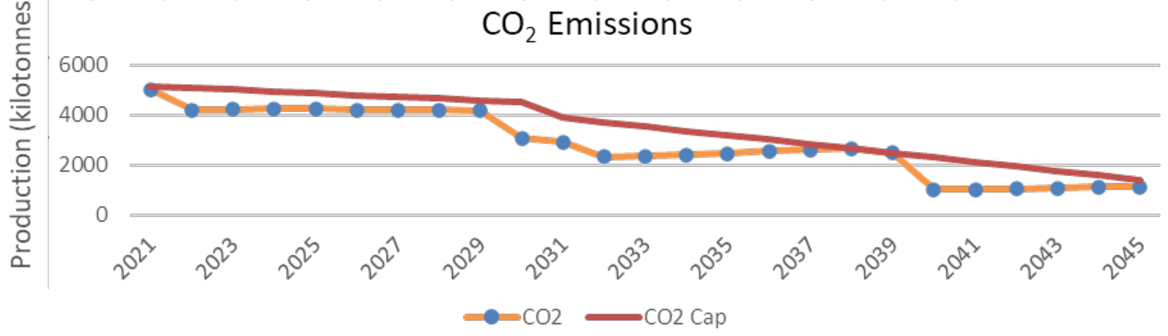
Scenario Metrics & Evaluation		
25-yr NPVRR ($MM)	$12,321	General Notes • DER is modeled as a load reduction; cost of DER resources not included in NPV calculations ($1.6B - $2.5B) • 1 coal unit converted to gas in 2037
25-yr NPVRR with End Effects ($MM)	$16,312	Essential Grid Services • Essential Grid Service requirements are met as modeled
10-yr NPVRR ($MM)	$6,904	Resource Adequacy & PRM • Reliability Tie: 2035 • Regional Integration: 2037
Average Annual Relative Rate Impact 2021-2030 (%) 2021-2045 (%)	 1.5% 1.1%	Plan Robustness & Flexibility • Regional Integration provides flexible ability to meet emissions constraints
Total CO_2 Emissions 2021-2030 (MT) Total CO_2 Emissions 2031-2045 (MT) Total CO_2 Emissions 2021-2045 (MT)	37.9 23.8 61.7	

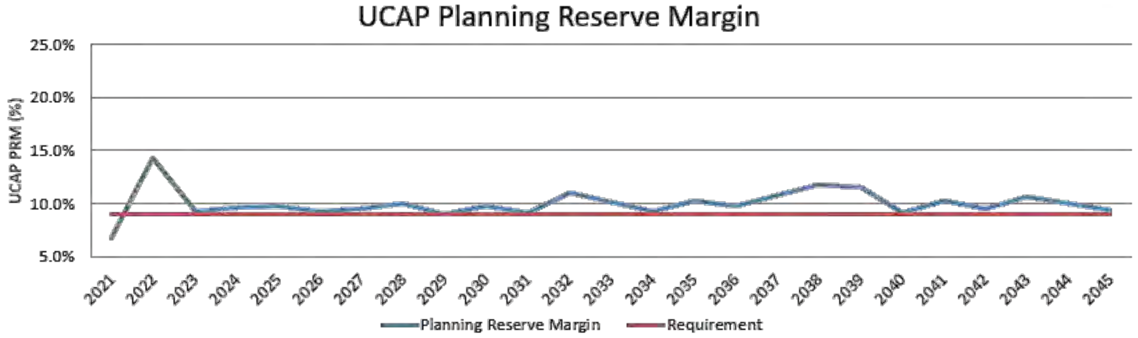
2.1C

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION









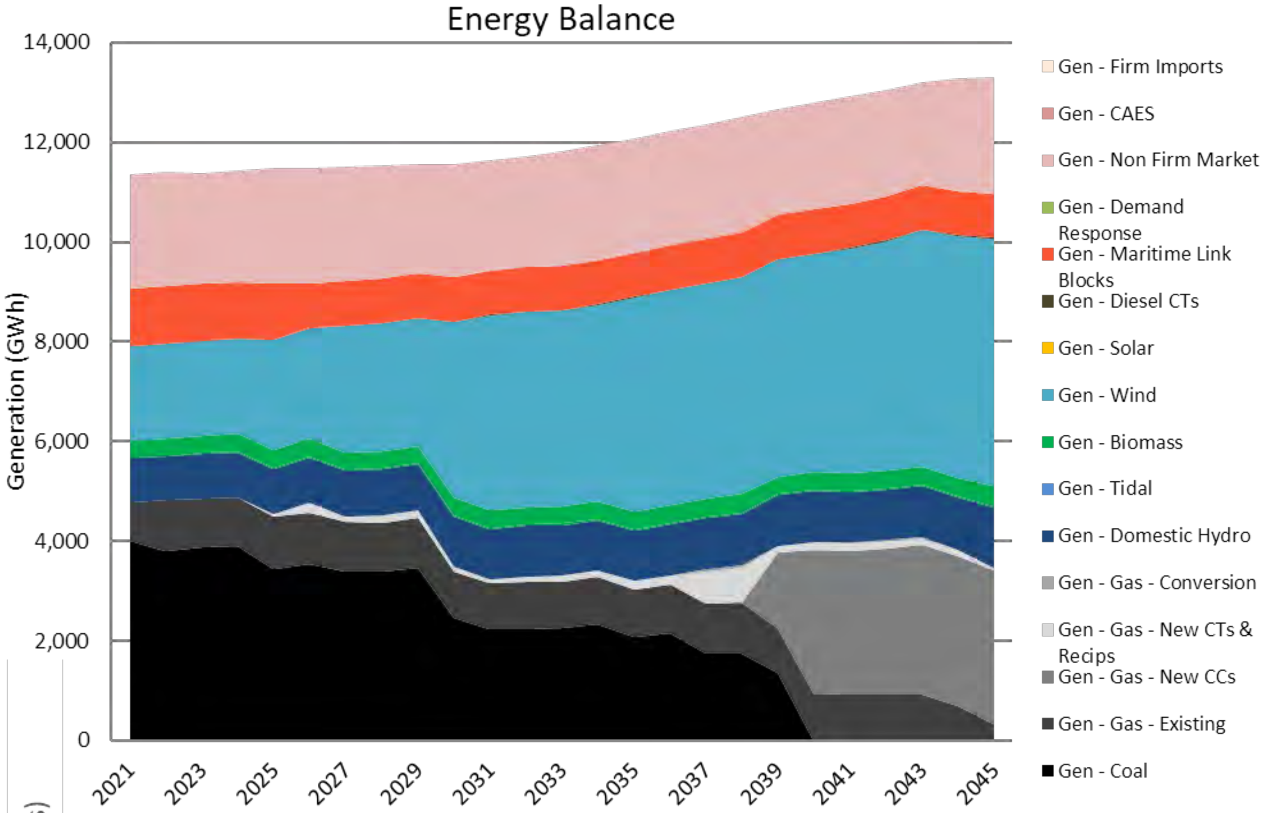
2.1C

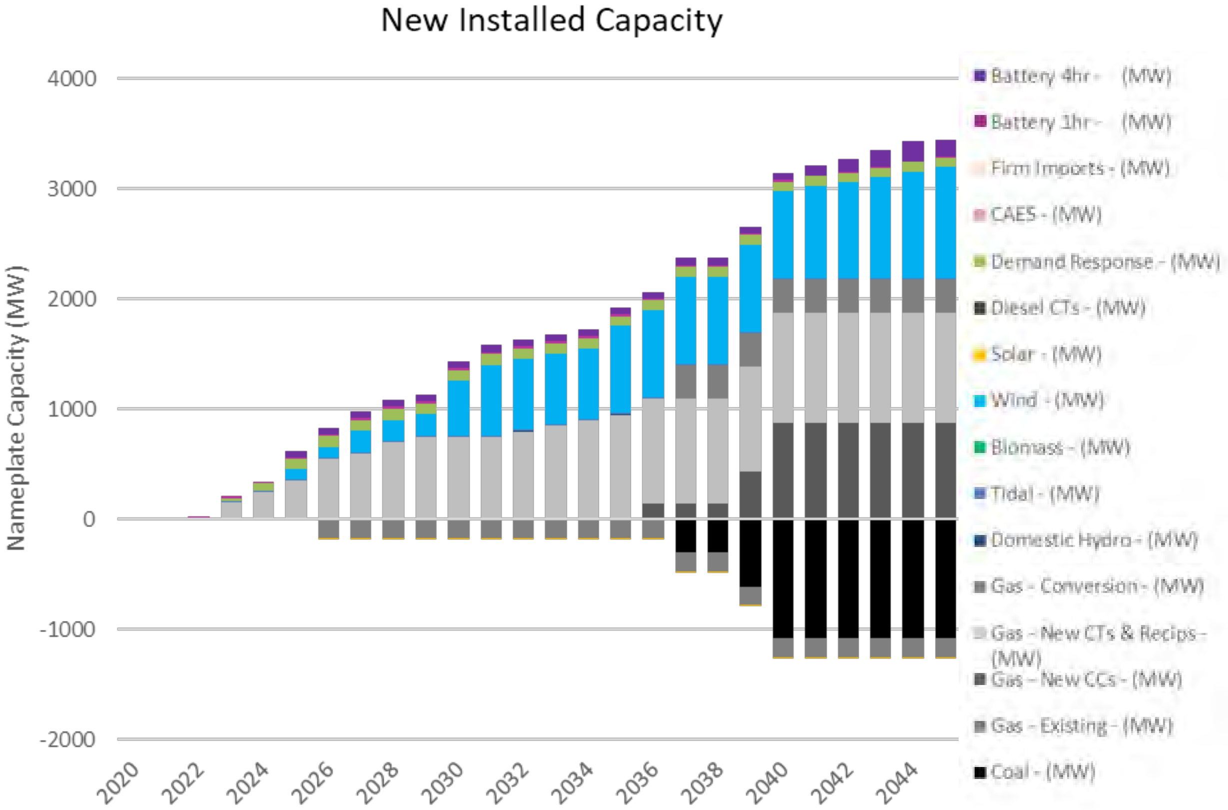
MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION

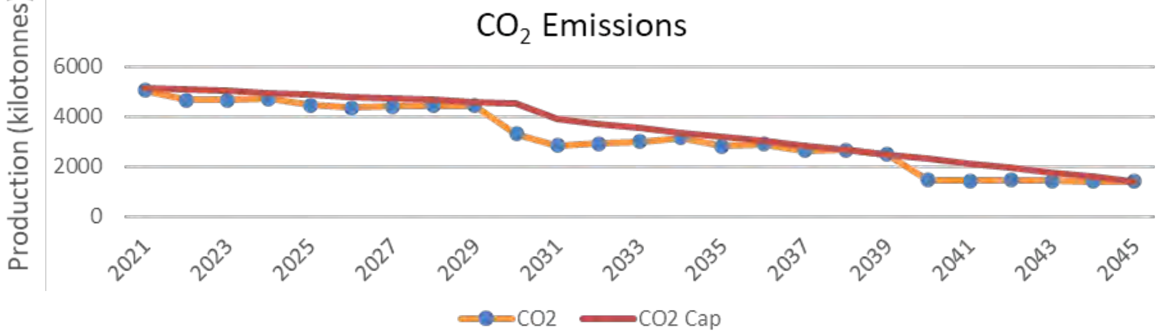
Scenario Metrics & Evaluation		
25-yr NPVRR ($MM)	$12,983	General Notes • Reliability Tie built in 2031 (earlier than previous runs) enables wind integration • 1 coal unit retired economically in 2020s • 1 less combined cycle unit in 2040 than seen in previous runs
25-yr NPVRR with End Effects ($MM)	$17,506	Essential Grid Services • Essential Grid Service requirements are met as modeled
10-yr NPVRR ($MM)	$7,022	Resource Adequacy & PRM • Reliability Tie: 2030 • Regional Integration: 2036
Average Annual Relative Rate Impact 2021-2030 (%) 2021-2045 (%)	 0.8% 0.8%	Plan Robustness & Flexibility • Regional Integration provides flexible ability to meet emissions constraints
Total CO_2 Emissions 2021-2030 (MT) Total CO_2 Emissions 2031-2045 (MT) Total CO_2 Emissions 2021-2045 (MT)	41.8 29.1 70.9	

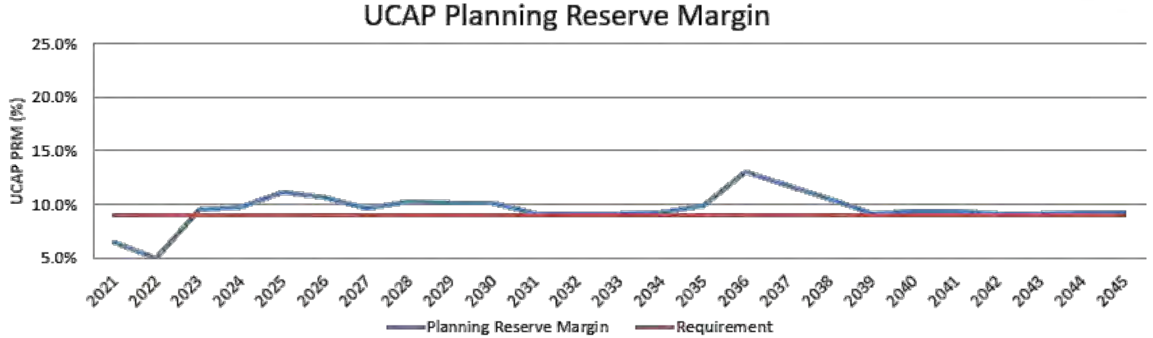
2.2A

HIGH ELEC. / MAX DSM / NET ZERO 2050 / CURRENT LANDSCAPE









2.2A

HIGH ELEC. / MAX DSM / NET ZERO 2050 / CURRENT LANDSCAPE

Scenario Metrics & Evaluation

25-yr NPVRR ($MM)	$15,448
25-yr NPVRR with End Effects ($MM)	$21,301
10-yr NPVRR ($MM)	$8,166
Average Annual Relative Rate Impact	
2021-2030 (%)	1.5%
2021-2045 (%)	1.2%
Total CO_2 Emissions 2021-2030 (MT)	44.4
Total CO_2 Emissions 2031-2045 (MT)	33.9
Total CO_2 Emissions 2021-2045 (MT)	78.3

General Notes
- Early load growth served by incremental gas CTs and non firm import energy
- Reliability Tie built in 2030 (earlier than previous runs) enables wind integration
- Additional wind is integrated with local mitigation
- 2 coal units converted to gas in 2037

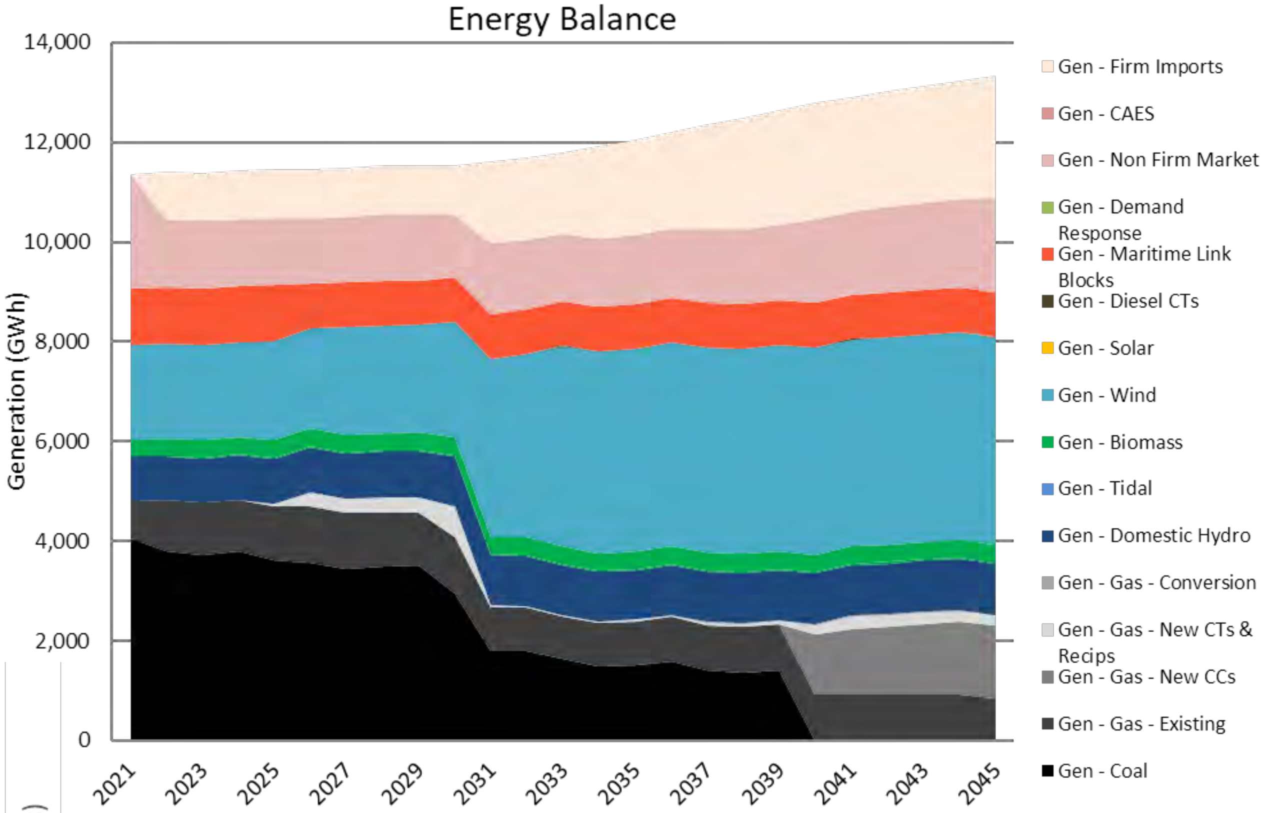
Essential Grid Services
- Essential Grid Service requirements are met as modeled

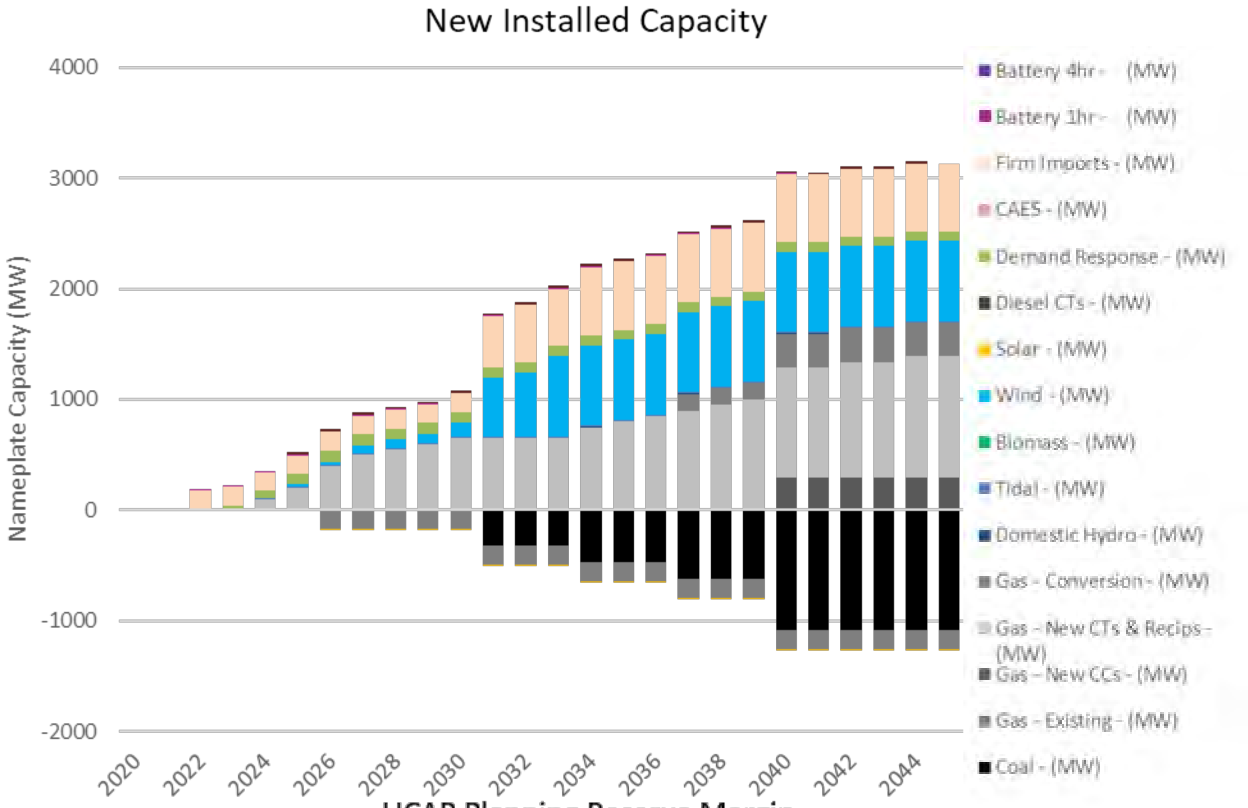
Resource Adequacy & PRM
- Reliability Tie: 2030
- Regional Integration: n/a

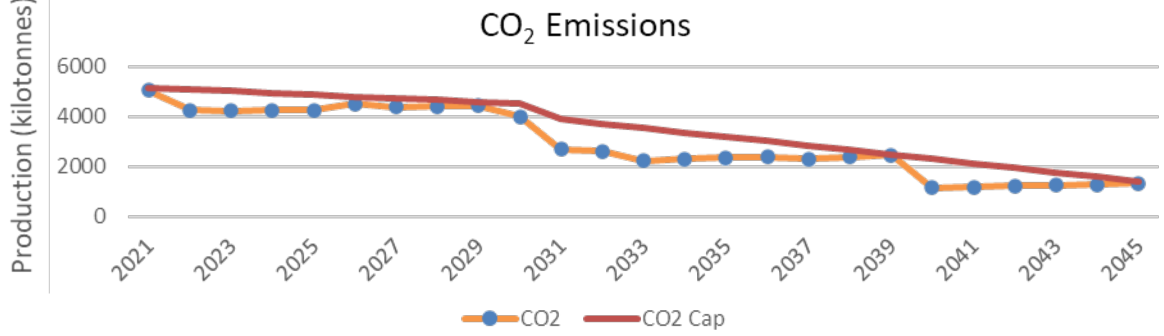
Plan Robustness & Flexibility
- No reliance on firm import energy or capacity
- Significant exposure to natural gas prices with NGCC and gas conversion builds
- Limited ability to adjust sources of supply as existing import options are maximized

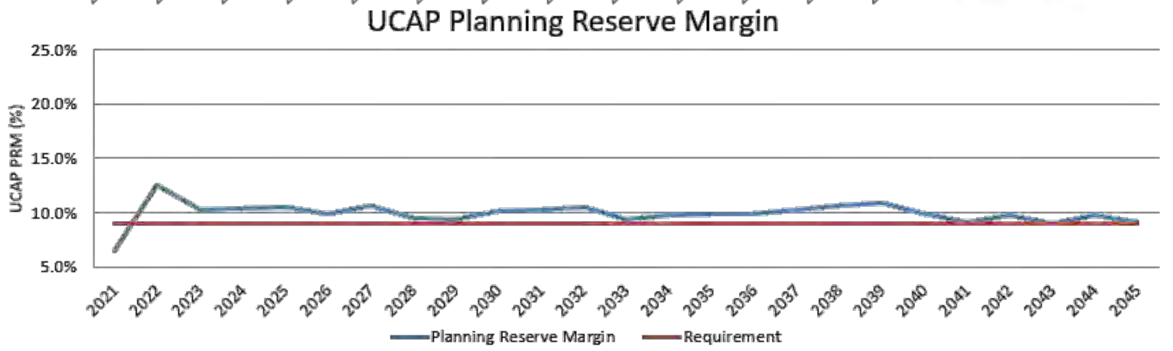
2.2C

HIGH ELEC. / MAX DSM / NET ZERO 2050 / REGIONAL INTEGRATION









2.2C

HIGH ELEC. / MAX DSM / NET ZERO 2050 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

25-yr NPVRR ($MM)	$15,172
25-yr NPVRR with End Effects ($MM)	$20,619
10-yr NPVRR ($MM)	$8,135
Average Annual Relative Rate Impact	
2021-2030 (%)	1.5%
2021-2045 (%)	1.0%
Total CO_2 Emissions 2021-2030 (MT)	43.7
Total CO_2 Emissions 2031-2045 (MT)	29.0
Total CO_2 Emissions 2021-2045 (MT)	72.7

General Notes
- Reliability Tie & Regional Interconnection built in 2031 (earlier than in previous runs)
- 2 coal to gas conversions in 2037 & 2040

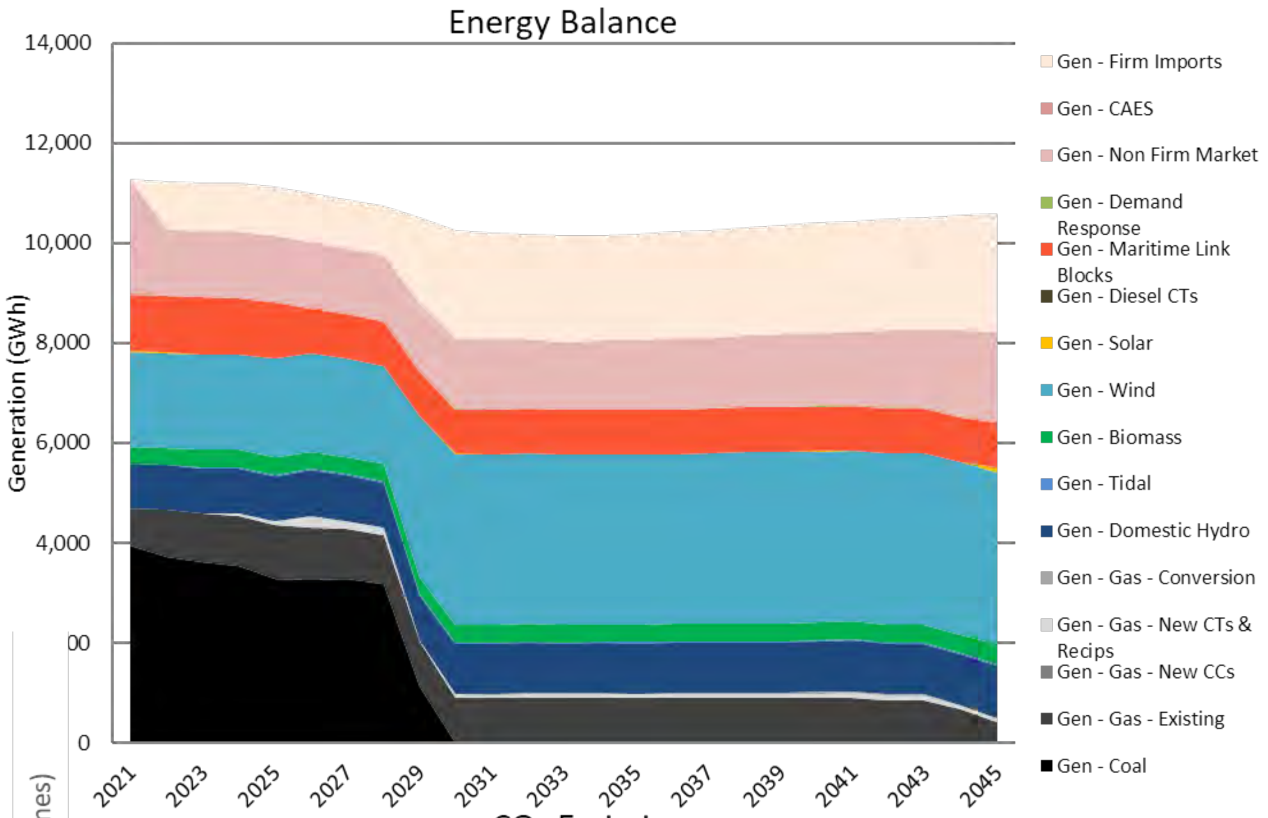
Essential Grid Services
- Essential Grid Service requirements are met as modeled

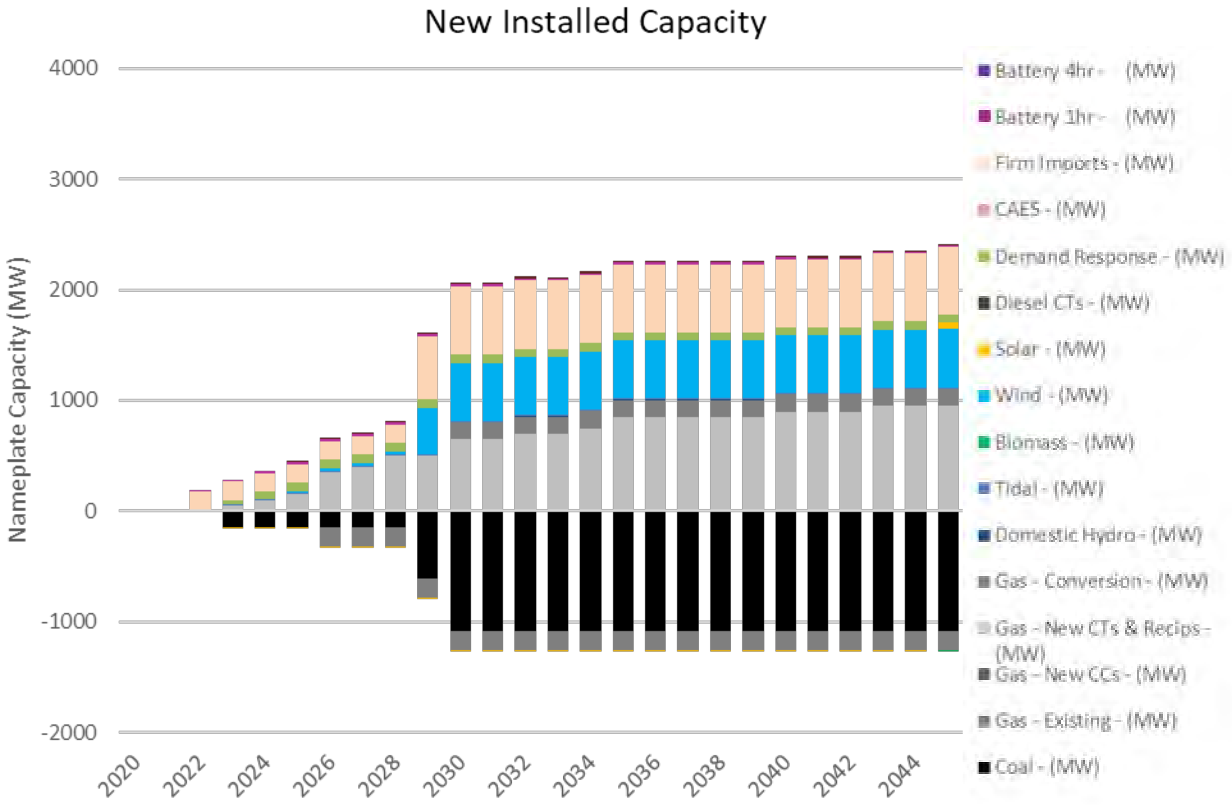
Resource Adequacy & PRM
- Reliability Tie: 2031
- Regional Integration: 2031

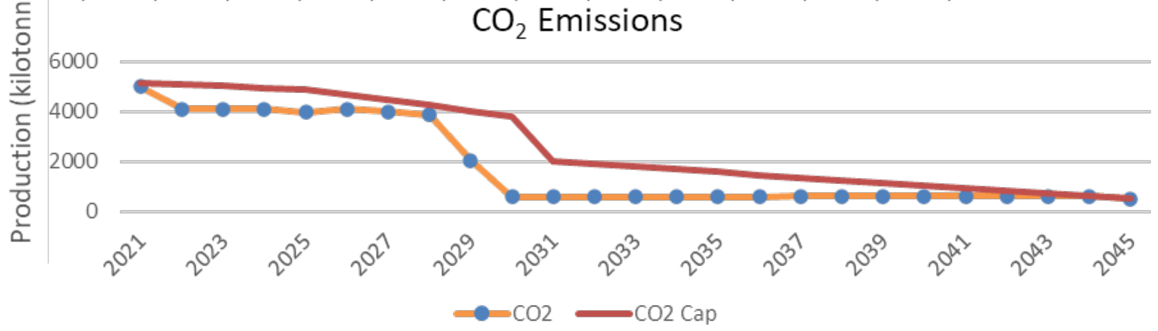
Plan Robustness & Flexibility
- Regional Integration provides flexible ability to meet emissions constraints

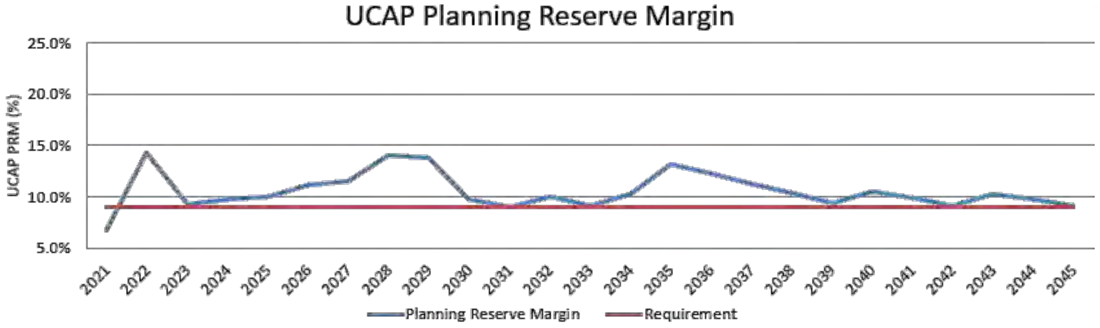
3.1B

MID ELEC. / BASE DSM / ACCEL. NET ZERO 2045 / DISTRIBUTED RESOURCES









3.1B

MID ELEC. / BASE DSM / ACCEL. NET ZERO 2045 / DISTRIBUTED RESOURCES

Scenario Metrics & Evaluation

25-yr NPVRR ($MM)	$12,540
25-yr NPVRR with End Effects ($MM)	$16,493
10-yr NPVRR ($MM)	$6,906
Average Annual Relative Rate Impact	
2021-2030 (%)	2.0%
2021-2045 (%)	1.1%
Total CO_2 Emissions 2021-2030 (MT)	35.8
Total CO_2 Emissions 2031-2045 (MT)	8.8
Total CO_2 Emissions 2021-2045 (MT)	44.7

General Notes

- DER is modeled as a load reduction; cost of DER resources not included in NPV calculations ($1.6B - $2.5B)
- Reliability Tie and Regional Interconnection built in 2029 (earlier than in previous simulations) offsets build of NGCC assets seen in previous modeling results

Essential Grid Services

- Essential Grid Service requirements are met as modeled

Resource Adequacy & PRM

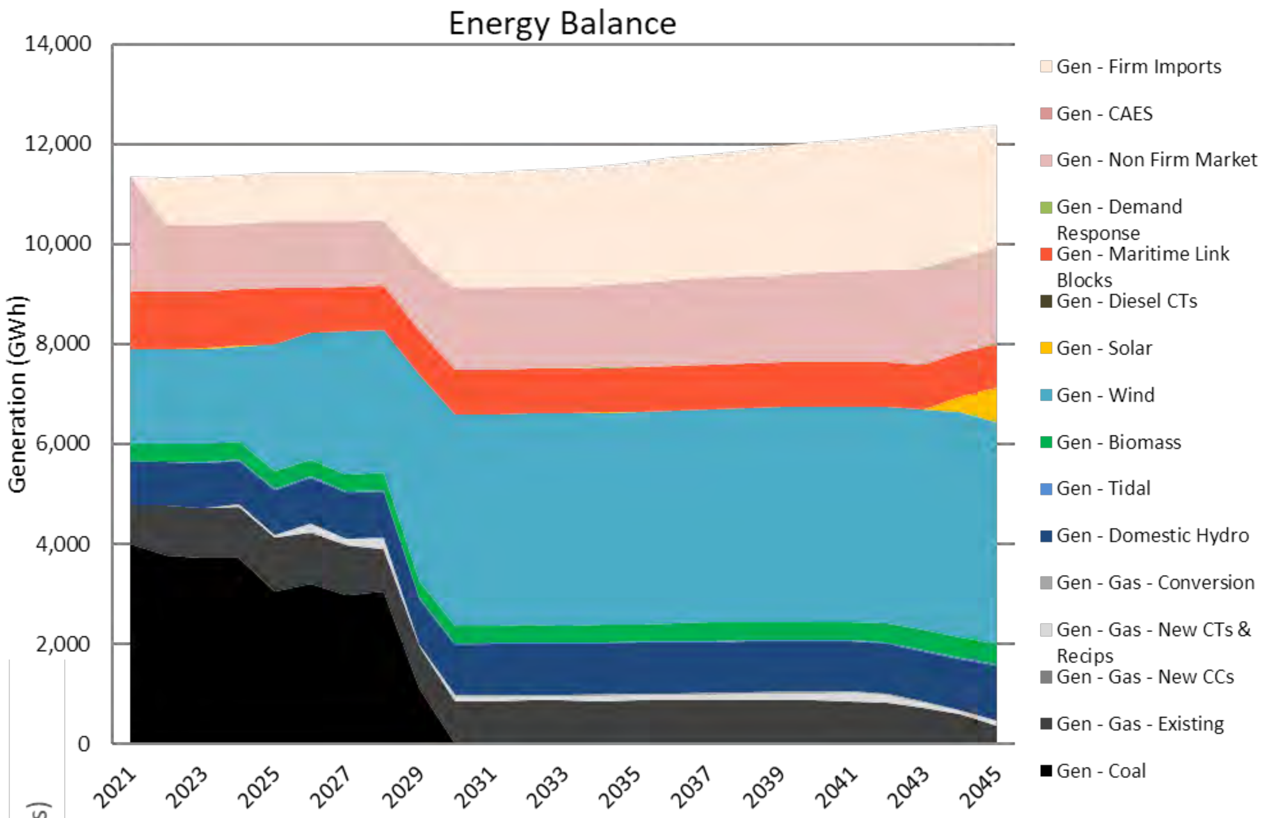
- Reliability Tie: 2029
- Regional Integration: 2029

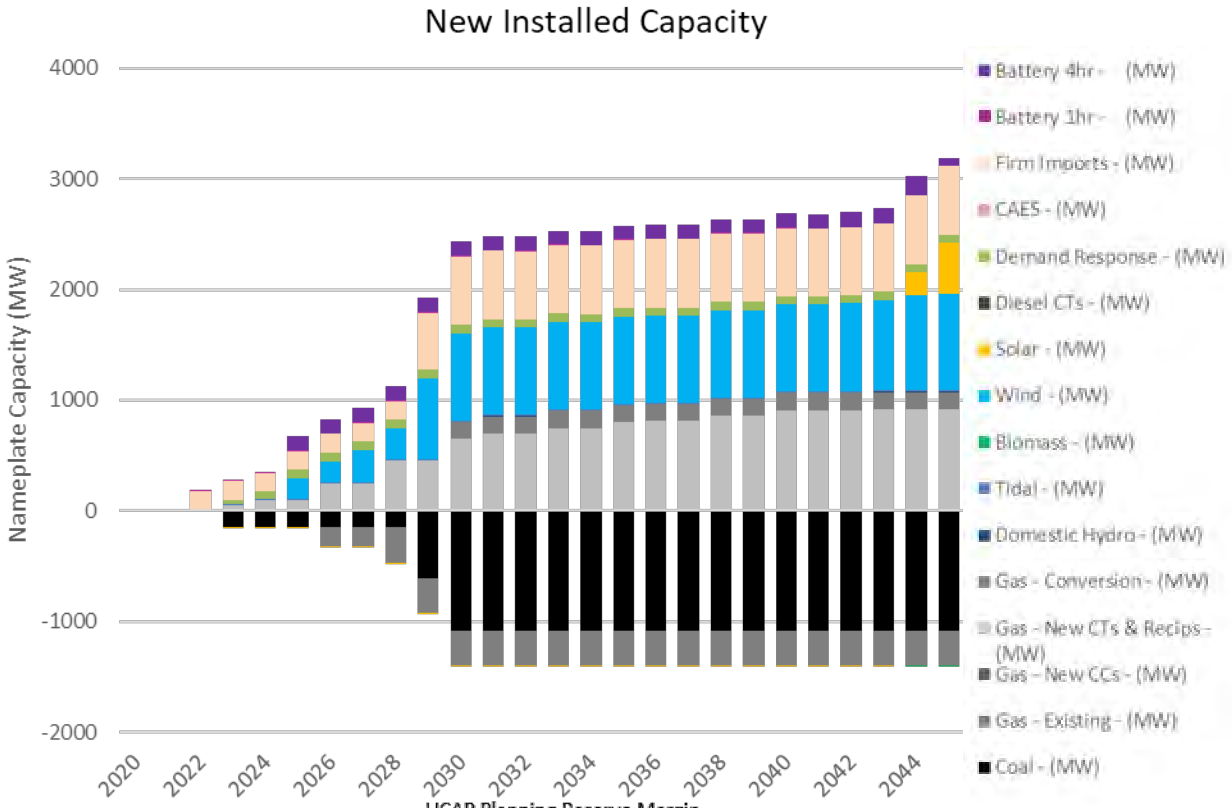
Plan Robustness & Flexibility

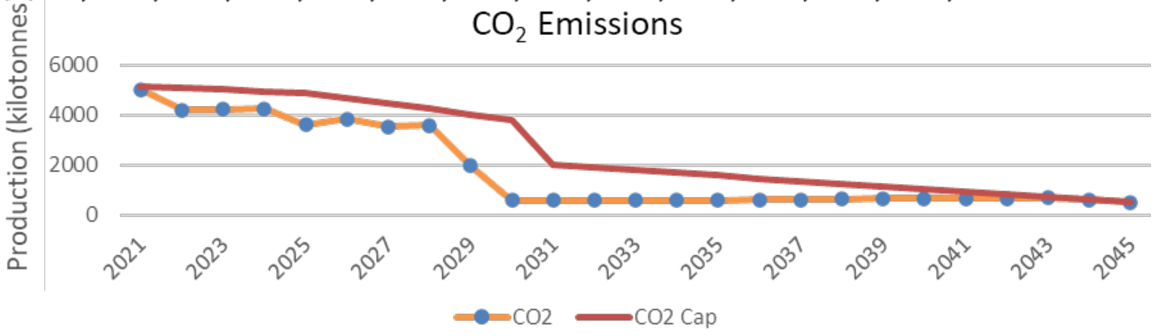
- Regional Integration provides flexible ability to meet emissions constraints

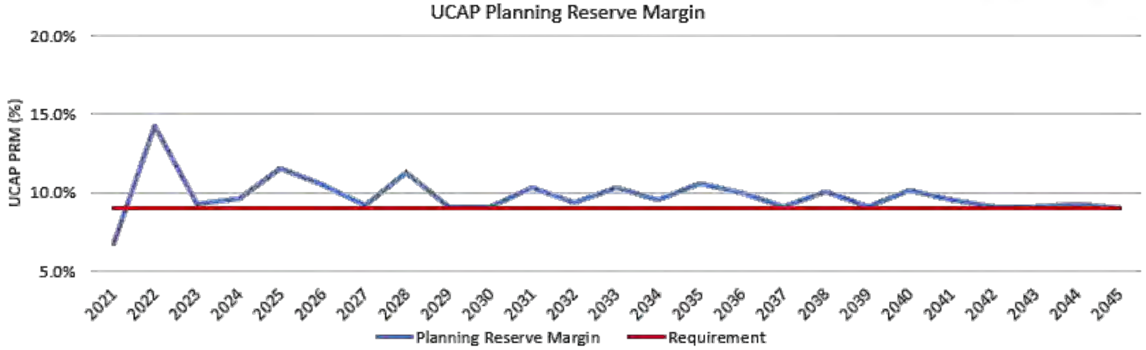
3.1C

MID ELEC. / BASE DSM / ACCEL. NET ZERO 2045 / REGIONAL INTEGRATION









3.1C

MID ELEC. / BASE DSM / ACCEL. NET ZERO 2045 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

25-yr NPVRR ($MM)	$13,576	
25-yr NPVRR with End Effects ($MM)	$18,148	
10-yr NPVRR ($MM)	$7,179	
Average Annual Relative Rate Impact		
2021-2030 (%)	1.5%	
2021-2045 (%)	0.8%	
Total CO_2 Emissions 2021-2030 (MT)	34.8	
Total CO_2 Emissions 2031-2045 (MT)	9.2	
Total CO_2 Emissions 2021-2045 (MT)	44.0	

General Notes
- 1 coal to gas conversion in 2030
- Regional Interconnection build in 2029
- Solar is added late in the period (2044) as an energy resource

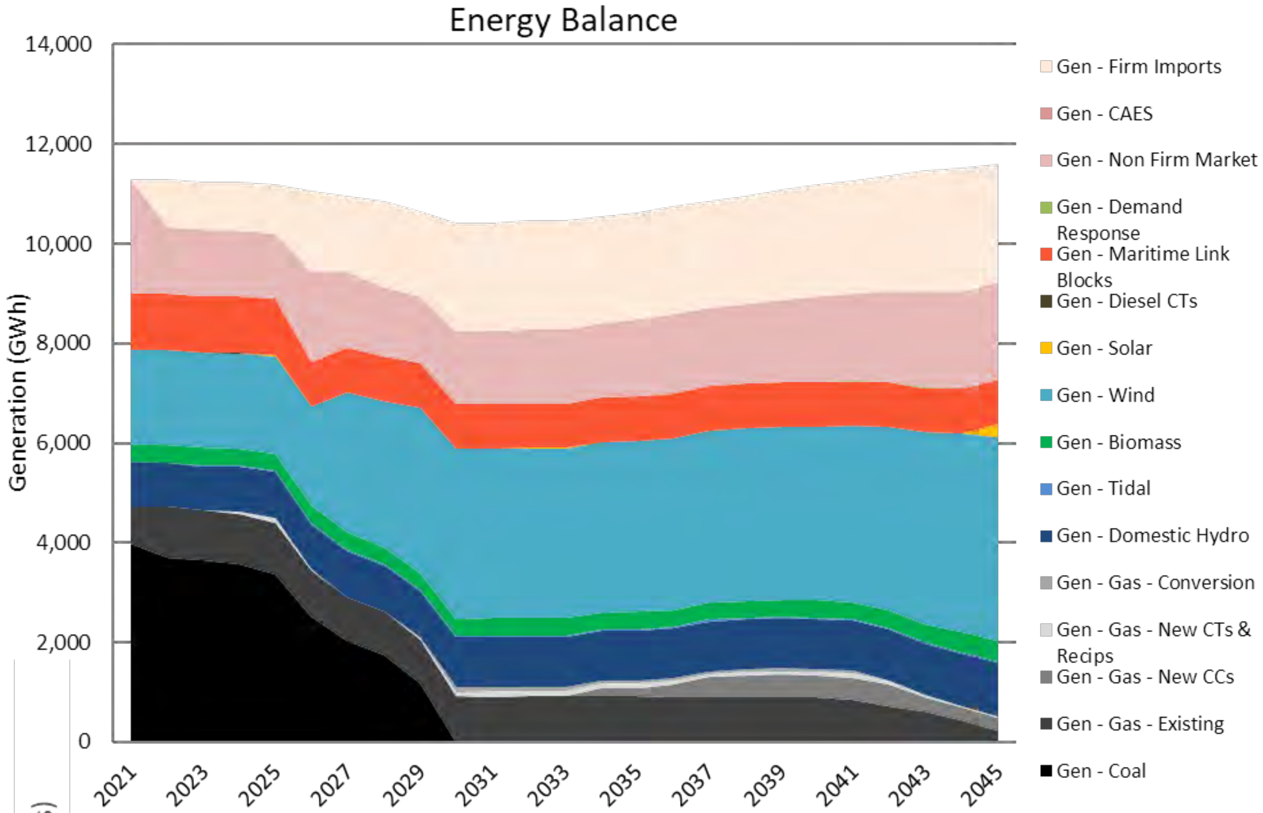
Essential Grid Services
- Essential Grid Service requirements are met as modeled

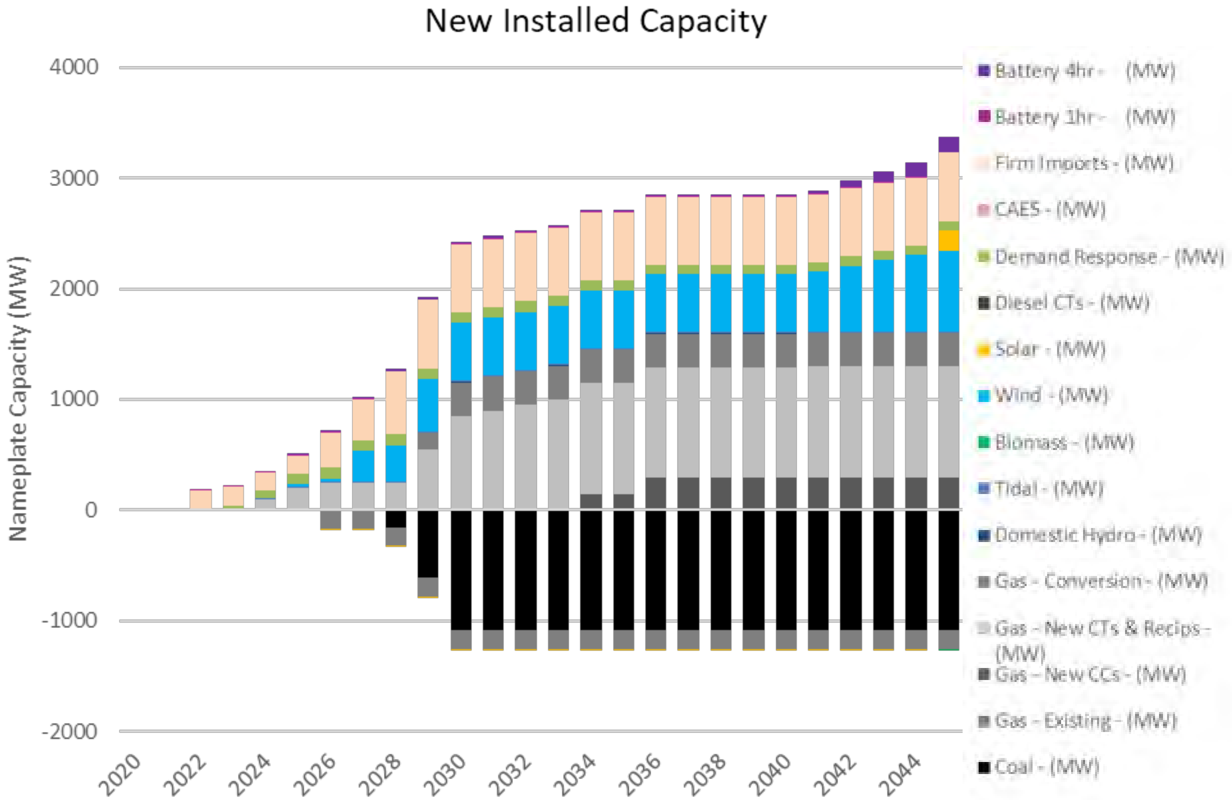
Resource Adequacy & PRM
- Reliability Tie: 2029
- Regional Integration: 2029

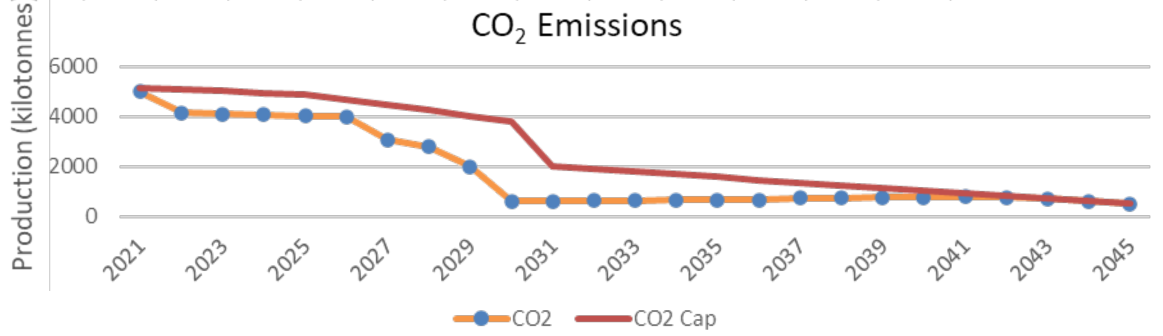
Plan Robustness & Flexibility
- Regional Integration provides flexible ability to meet emissions constraints

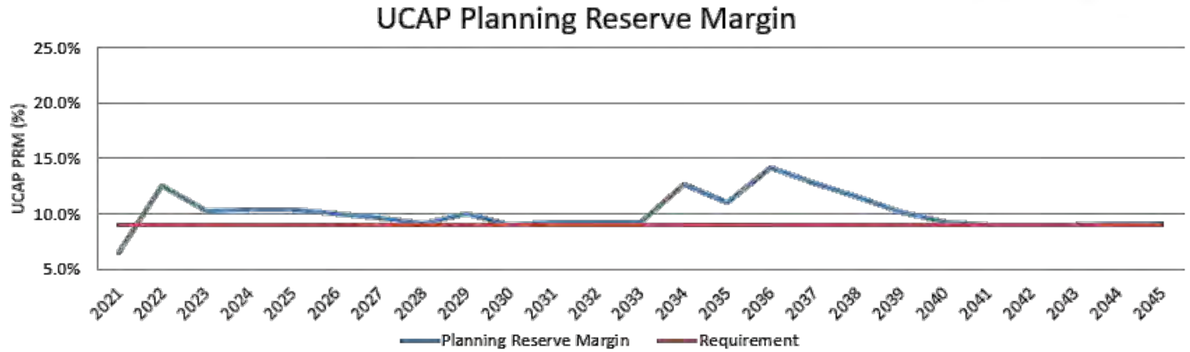
3.2B

HIGH ELEC. / MAX DSM / ACCEL. NET ZERO 2045 / DISTRIBUTED RESOURCES









3.2B

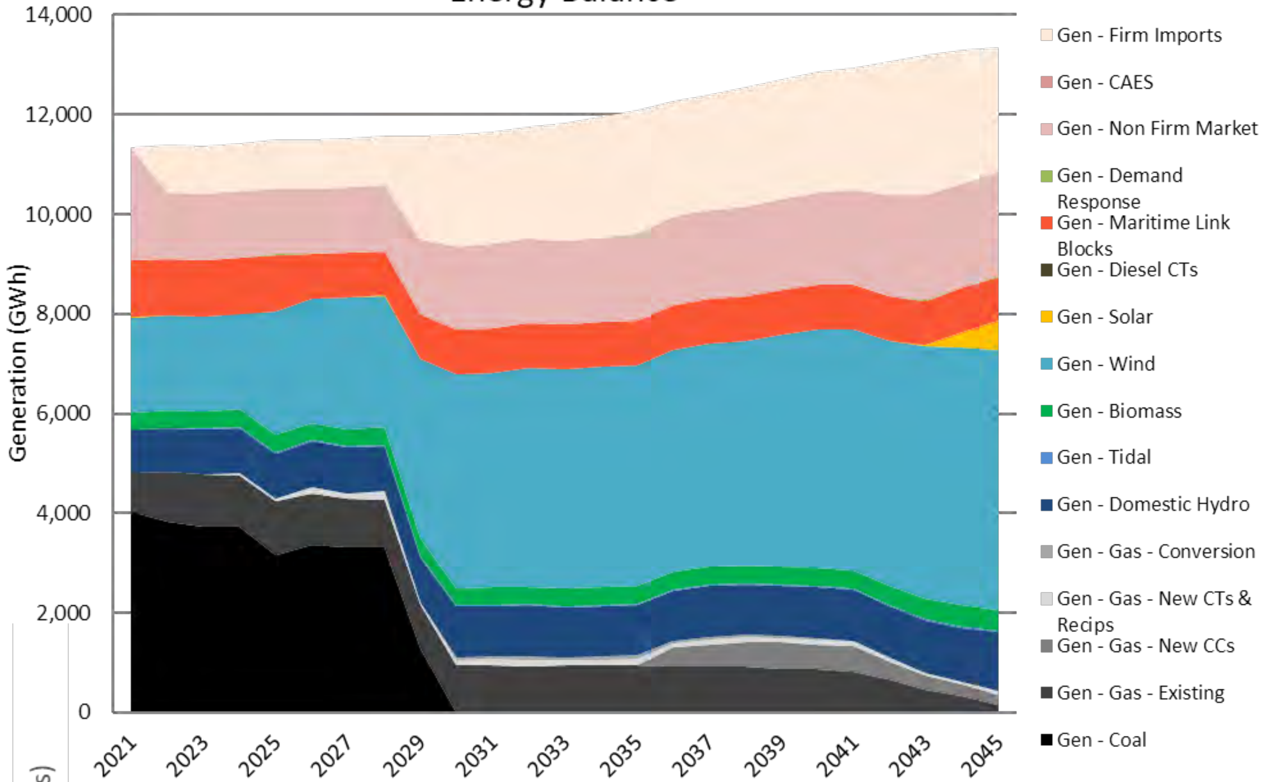
HIGH ELEC. / MAX DSM / ACCEL. NET ZERO 2045 / DISTRIBUTED RESOURCES

Scenario Metrics & Evaluation		
25-yr NPVRR ($MM)	$14,837	General Notes • DER is modeled as a load reduction; cost of DER resources not included in NPV calculations ($1.6B - $2.5B) • 2 coal to gas conversions (2029 & 2030) • Solar is added late in the period (2045) as an energy resource Essential Grid Services • Essential Grid Service requirements are met as modeled Resource Adequacy & PRM • Reliability Tie: 2026 • Regional Integration: 2026 Plan Robustness & Flexibility • Regional Integration provides flexible ability to meet emissions constraints
25-yr NPVRR with End Effects ($MM)	$19,849	
10-yr NPVRR ($MM)	$8,059	
Average Annual Relative Rate Impact 2021-2030 (%) 2021-2045 (%)	 2.7% 1.3%	
Total CO_2 Emissions 2021-2030 (MT) Total CO_2 Emissions 2031-2045 (MT) Total CO_2 Emissions 2021-2045 (MT)	33.8 10.2 44.0	

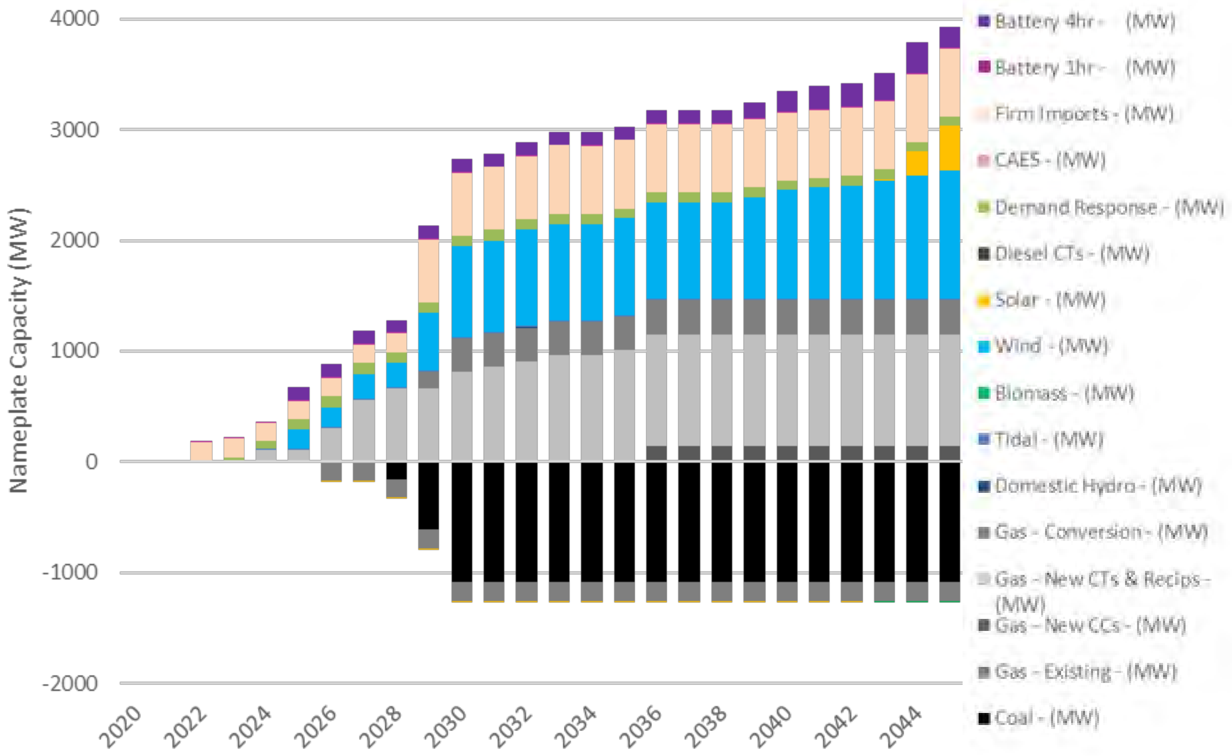
3.2C

HIGH ELEC. / MAX DSM / ACCEL. NET ZERO 2045 / REGIONAL INTEGRATION

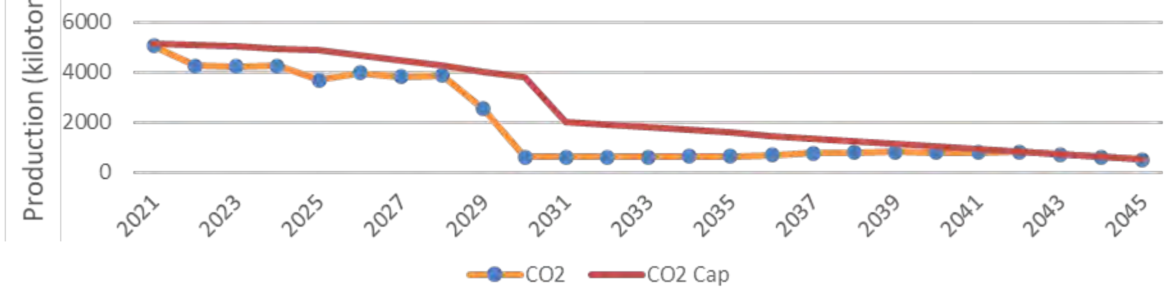
Energy Balance



New Installed Capacity



CO_2 Emissions



UCAP Planning Reserve Margin

3.2C

HIGH ELEC. / MAX DSM / ACCEL. NET ZERO 2045 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation		
25-yr NPVRR ($MM)	$15,841	General Notes • Gas CT builds and incremental firm imports support early load growth • Increased firm import energy relative to previous runs offsets NGCC generation (now see 1 unit rather than 3 in previous modeling results) Essential Grid Services • Essential Grid Service requirements are met as modeled Resource Adequacy & PRM • Reliability Tie: 2029 • Regional Integration: 2029 Plan Robustness & Flexibility • Regional Integration provides flexible ability to meet emissions constraints
25-yr NPVRR with End Effects ($MM)	$21,443	
10-yr NPVRR ($MM)	$8,289	
Average Annual Relative Rate Impact 2021-2030 (%) 2021-2045 (%)	 2.2% 1.1%	
Total CO_2 Emissions 2021-2030 (MT) Total CO_2 Emissions 2031-2045 (MT) Total CO_2 Emissions 2021-2045 (MT)	36.2 10.3 46.5	

SENSITIVITY ANALYSIS RESULTS

SENSITIVITY ANALYSIS OVERVIEW

In addition to the Final Portfolio Study, a series of model sensitivities has been studied to understand how model outputs will vary with adjustments to key input parameters of interest.

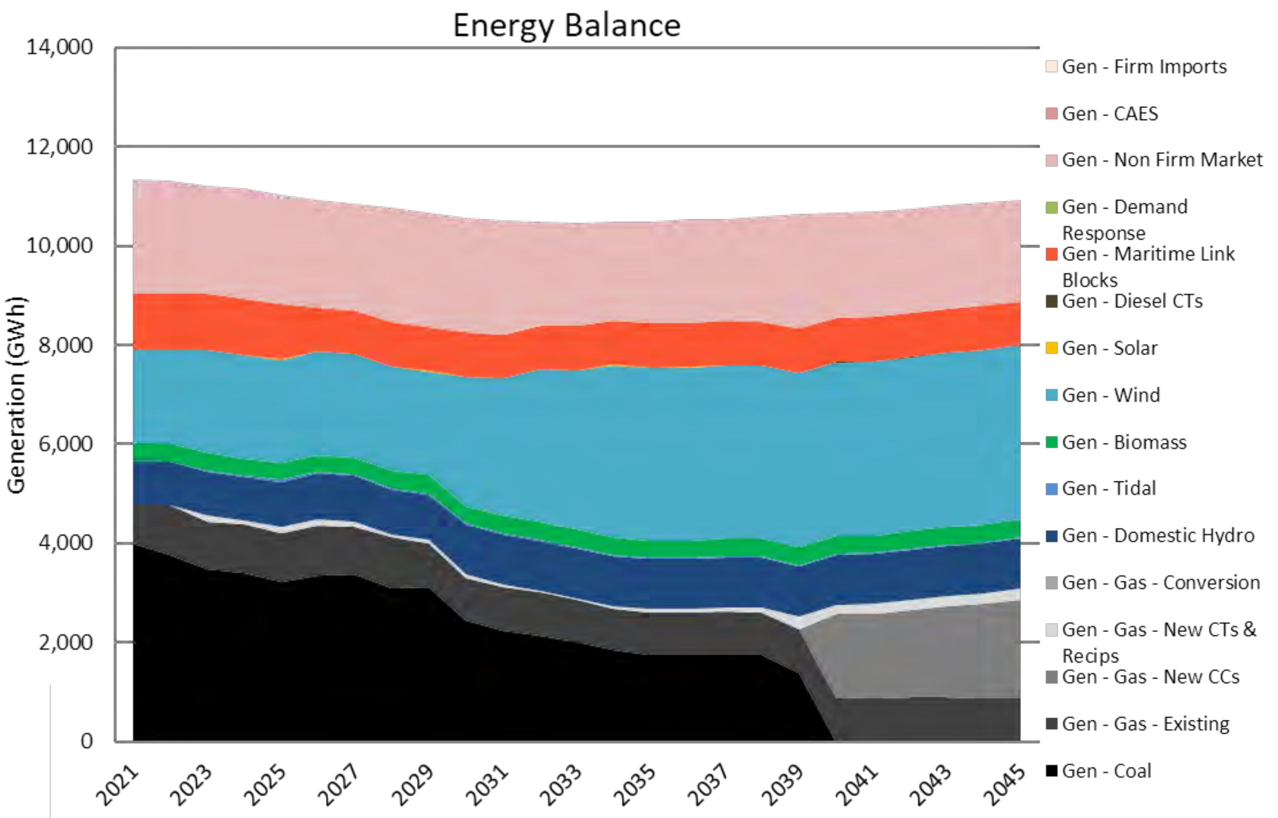
On the following slides, results are provided for each sensitivity run and are also compared to the corresponding base case in order to evaluate the impact of the change in model inputs.

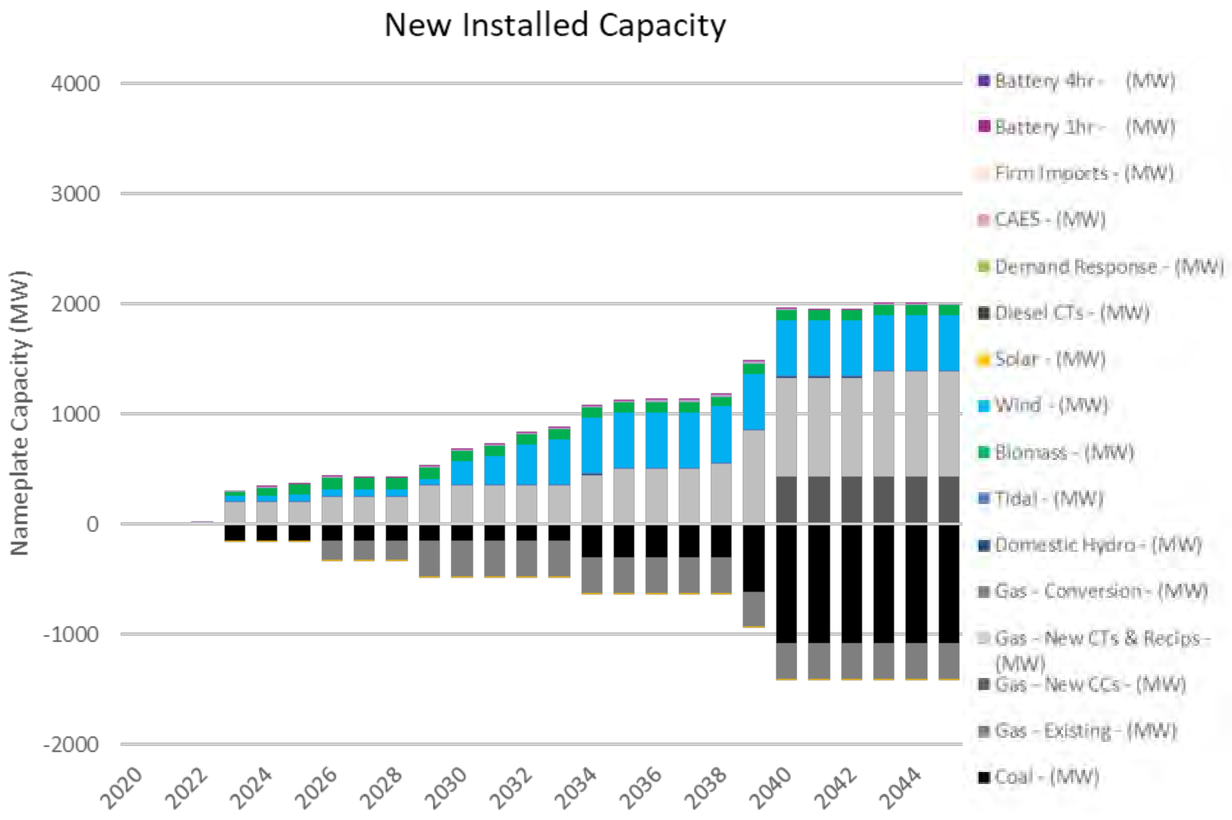
Sensitivities that are included in this results release are listed below:

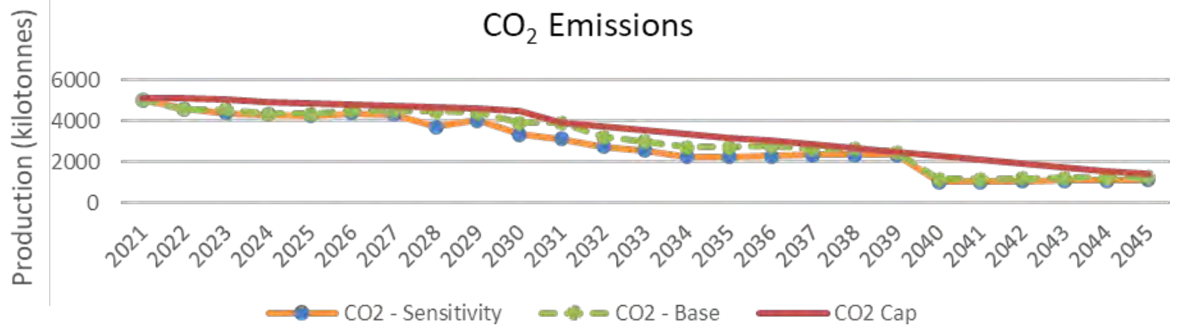
2.0A.DSM-1	Low Electrification / Mid DSM
2.1C.DSM-2	Mid Electrification / Mid DSM
2.2C.DSM-3	High Electrification / Mid DSM
2.0C.DSM-4	Low Electrification / Low DSM
2.0C.DSM-5	Low Electrification / Mid DSM
2.0C.DSM-6	Low Electrification / Max DSM
3.1C.DSM-7	Mid Electrification / Mid DSM / 2030 Coal Retirement
2.1C.Wind-1	Low Wind Cost
2.1C.Wind-2	Low Wind + Low Battery Cost
2.1C.Wind-3	Low Inertia
2.1C.Wind-4	No Inertia / No Wind Integration Requirements
2.1C.Mersey	Mersey Hydro Retired
2.1C.Import-1	Limited Non-Firm Imports
2.0A.Import-2	Current Landscape case without Reliability Tie
2.1C.Import-3	Limited Reliability Tie Inertia (provides 50% of inertia requirement)
2.1C.CAPEX-1	High Sustaining Capex
2.1C.CAPEX-2	Low Sustaining Capex
2.1C.PRICES-1	High Import & Gas Prices

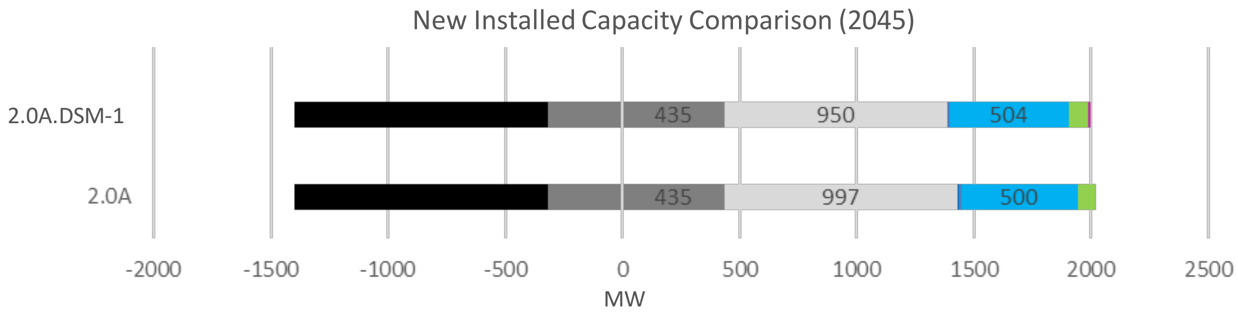
2.0A.DSM-1 (MID DSM)

LOW ELEC. / MID DSM / NET ZERO 2050 / CURRENT LANDSCAPE









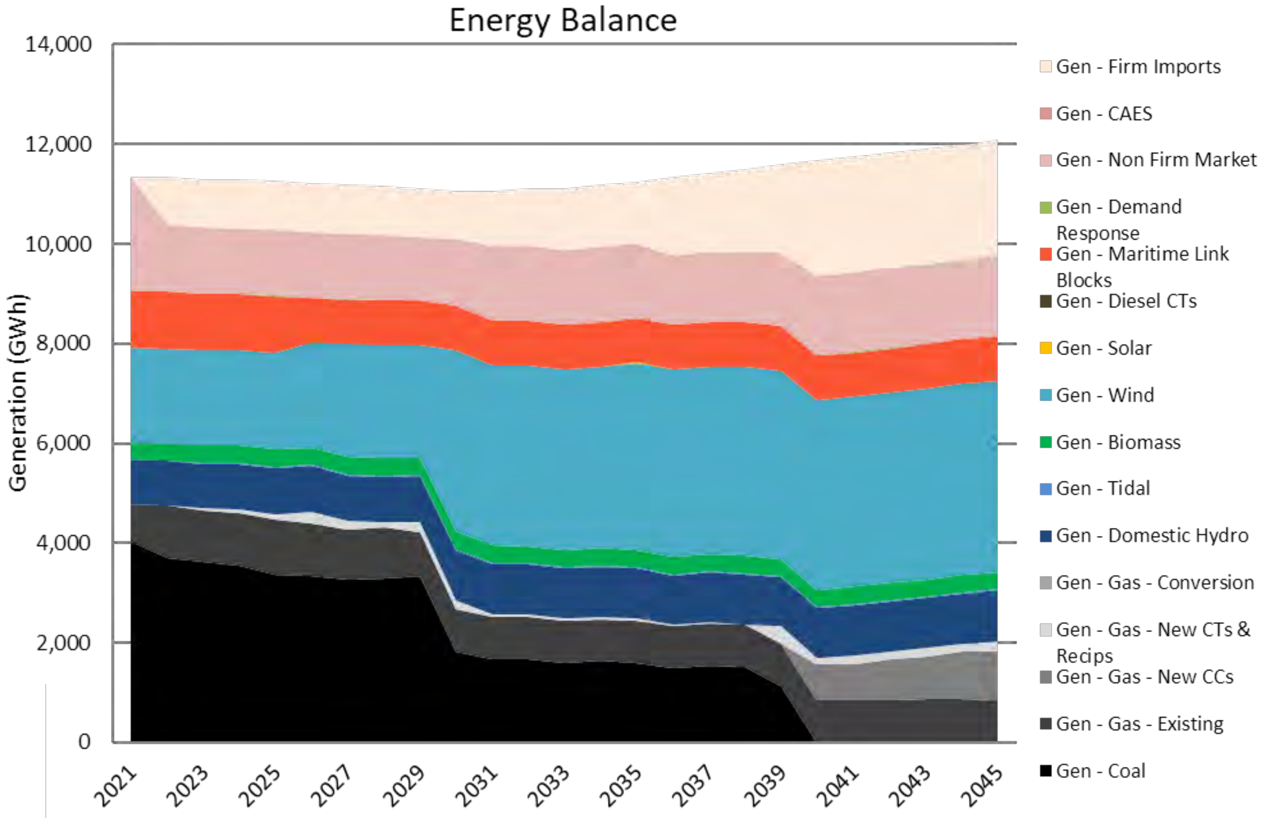
2.0A.DSM-1 (MID DSM)

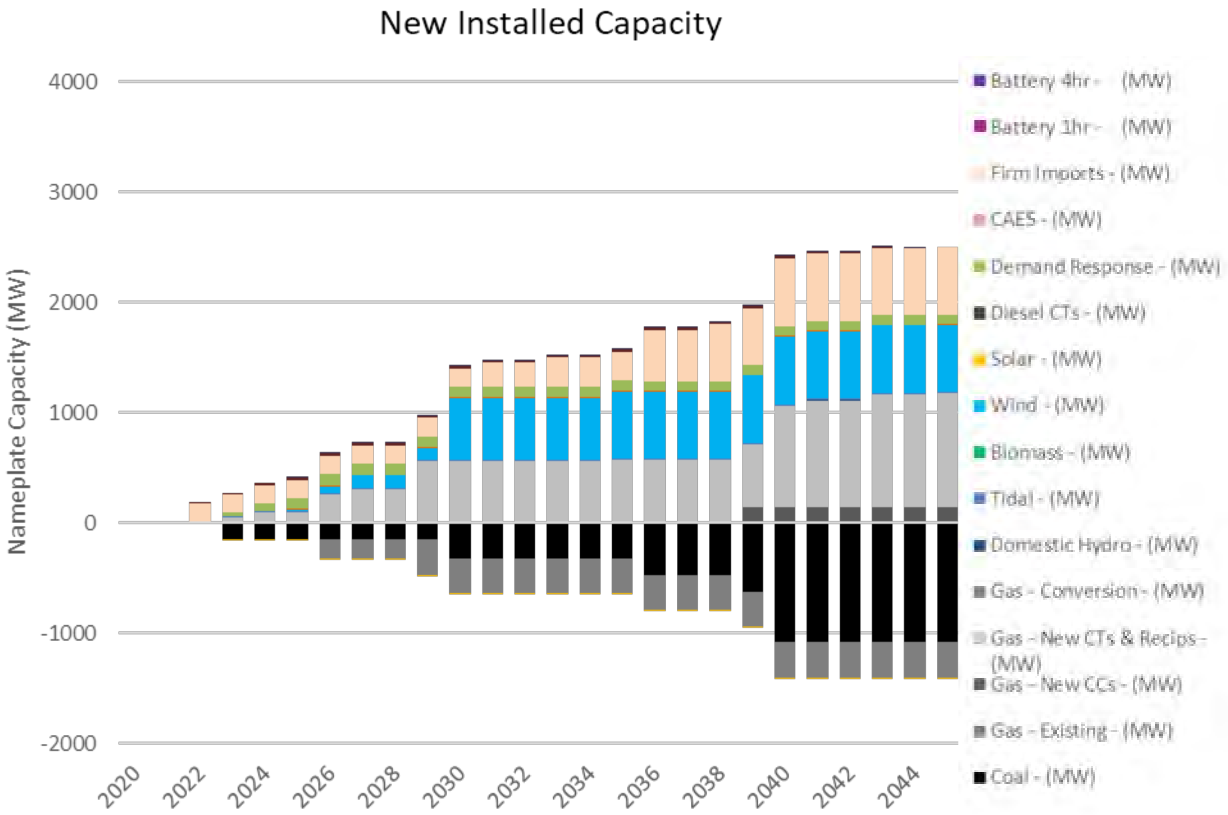
LOW ELEC. / MID DSM / NET ZERO 2050 / CURRENT LANDSCAPE

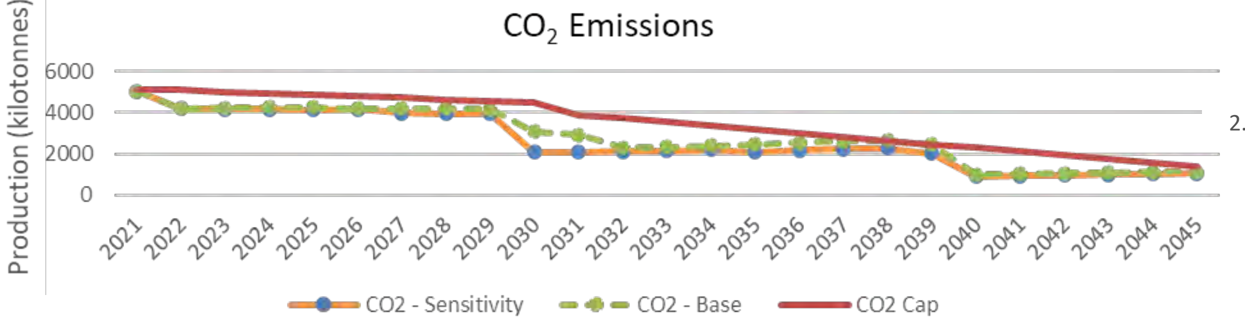
Scenario Metrics & Evaluation			
	Sensitivity	Base (2.0A)	
25-yr NPVRR ($MM)	$12,531	$12,193	General Notes • Relative to 2.0A (which includes Base DSM), 47MW fewer CT resources are built due to the reduction in peak load from the higher level of DSM and the higher capacity contribution of the DR program associated with Mid DSM (DR economically selected in both models) • NPVRR is increased relative to Base DSM case for all three time periods
25-yr NPVRR w/ End Effects ($MM)	$16,599	$16,347	
10-yr NPVRR ($MM)	$7,145	$6,786	Essential Grid Services • No significant change relative to 2.0A
Average Annual Relative Rate Impact 2021-2030 (%) 2021-2045 (%)	 1.3% 1.0%	 0.8% 1.0%	Resource Adequacy & PRM • Reliability Tie: 2028 • Regional Integration: n/a Plan Robustness & Flexibility • No significant change relative to 2.0A base
Total CO_2 Emissions 2021-2030 (MT) Total CO_2 Emissions 2031-2045 (MT) Total CO_2 Emissions 2021-2045 (MT)	42.2 28.6 70.7	44.5 33.2 77.7	

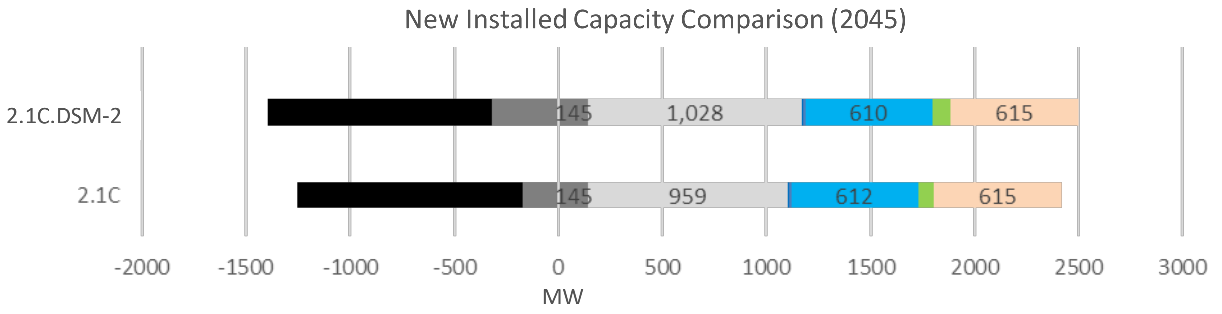
2.1C.DSM-2 (MID DSM)

MID ELEC. / MID DSM / NET ZERO 2050 / REGIONAL INTEGRATION









2.1C.DSM-2 (MID DSM)

MID ELEC. / MID DSM / NET ZERO 2050 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

	Sensitivity	Base (2.1C)
25-yr NPVRR ($MM)	$13,288	$12,983
25-yr NPVRR w/ End Effects ($MM)	$17,724	$17,506
10-yr NPVRR ($MM)	$7,342	$7,022
Average Annual Relative Rate Impact		
2021-2030 (%)	1.2%	0.8%
2021-2045 (%)	0.8%	0.8%
Total CO_2 Emissions 2021-2030 (MT)	39.9	41.8
Total CO_2 Emissions 2031-2045 (MT)	25.2	29.1
Total CO_2 Emissions 2021-2045 (MT)	65.1	70.9

General Notes

- 1 coal unit is retired earlier than in 2.1C Base; remainder of resource plan very similar
- Mid DSM case retires one additional gas steam unit vs. 2.1C Base DSM by 2045; capacity is replaced via a combination of decreased firm peak due to incremental DSM, additional combustion turbine capacity, and the higher capacity contribution of the DR program associated with Mid DSM
- NPVRR is increased relative to Base DSM case for all three time periods

Essential Grid Services

- No change relative to 2.1C

Resource Adequacy & PRM

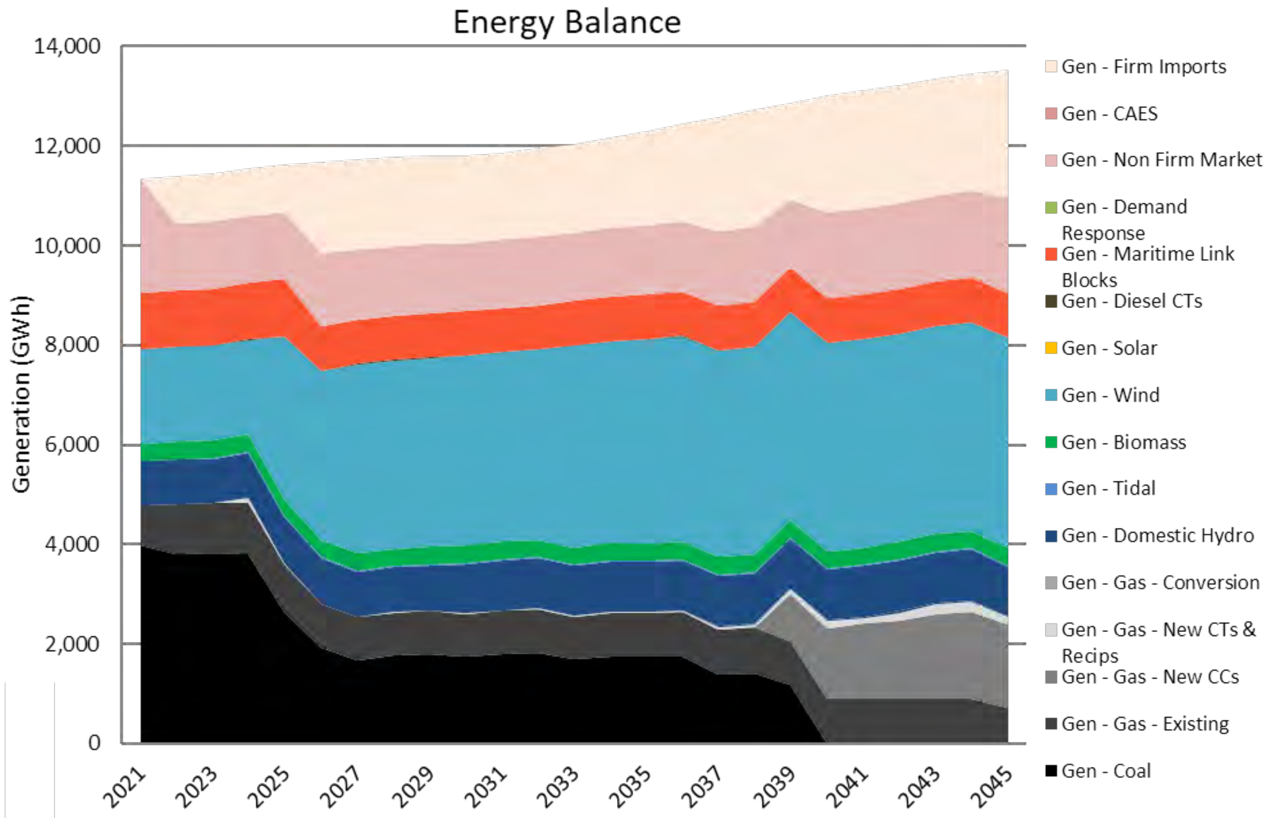
- Reliability Tie: 2030
- Regional Integration: 2031

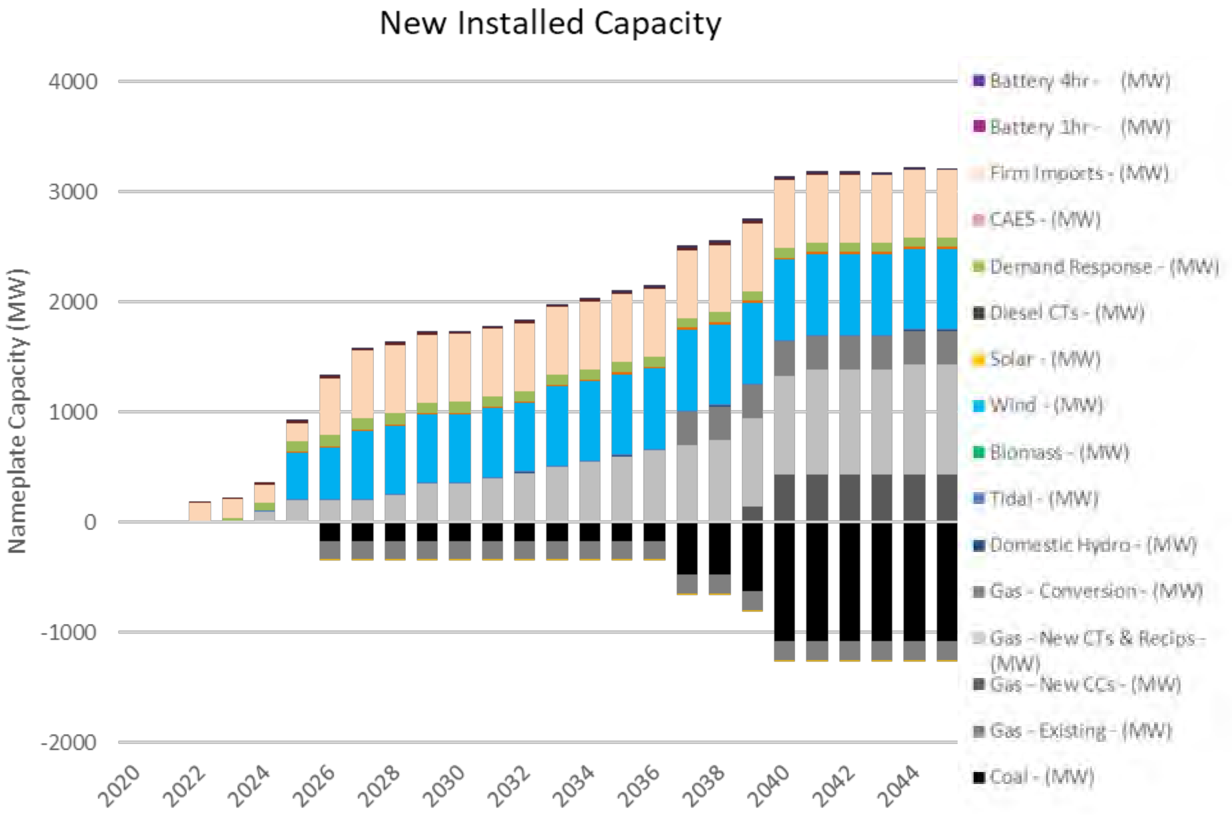
Plan Robustness & Flexibility

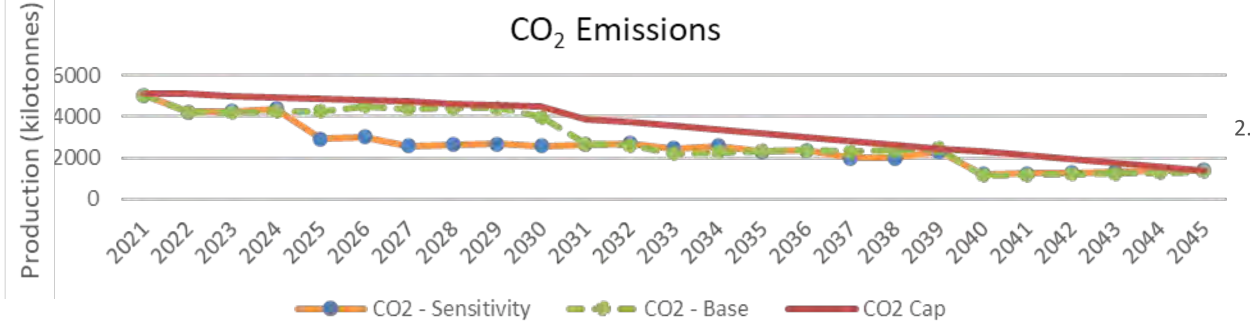
- No change relative to 2.1C Base

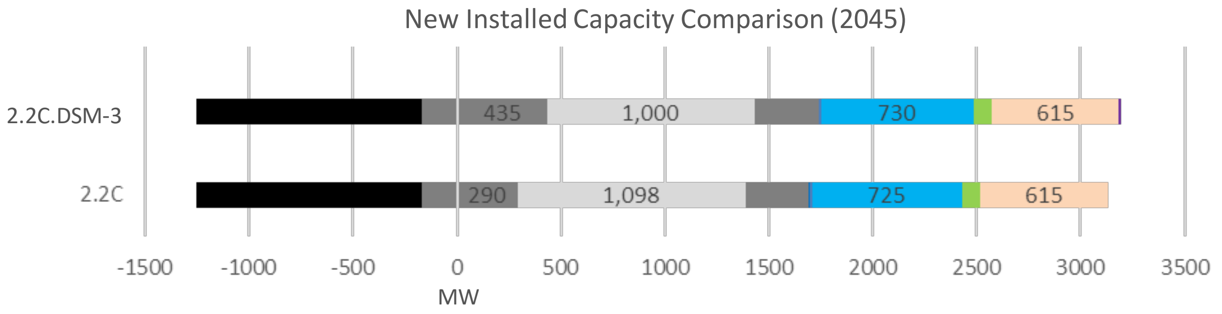
2.2C.DSM-3 (MID DSM)

HIGH ELEC. / MID DSM / NET ZERO 2050 / REGIONAL INTEGRATION









2.2C.DSM-3 (MID DSM)

HIGH ELEC. / MID DSM / NET ZERO 2050 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

	Sensitivity	Base (2.2C)
25-yr NPVRR ($MM)	$14,721	$15,172
25-yr NPVRR w/ End Effects ($MM)	$20,077	$20,619
10-yr NPVRR ($MM)	$7,817	$8,135
Average Annual Relative Rate Impact		
2021-2030 (%)	1.1%	1.5%
2021-2045 (%)	0.9%	1.0%
Total CO_2 Emissions 2021-2030 (MT)	34.4	43.7
Total CO_2 Emissions 2031-2045 (MT)	29.2	29.0
Total CO_2 Emissions 2021-2045 (MT)	63.6	72.7

General Notes

- Under the High Electrification / Mid DSM sensitivity, the Regional Interconnection is built 5 years earlier than 2.2C base case (which uses the Max DSM profile); this enables 1 earlier coal retirement in the 2030s economically and significantly reduces GHG emissions over the planning horizon
- By 2045, Mid DSM case has 1 additional NGCC unit and fewer combustion turbines for a net capacity difference of +47MW, very closely matching the firm peak increase of 41MW due to the change in DSM level
- NPVRR is decreased relative to 2.2C Max DSM case for all three time periods

Essential Grid Services

- No significant change from 2.2C

Resource Adequacy & PRM

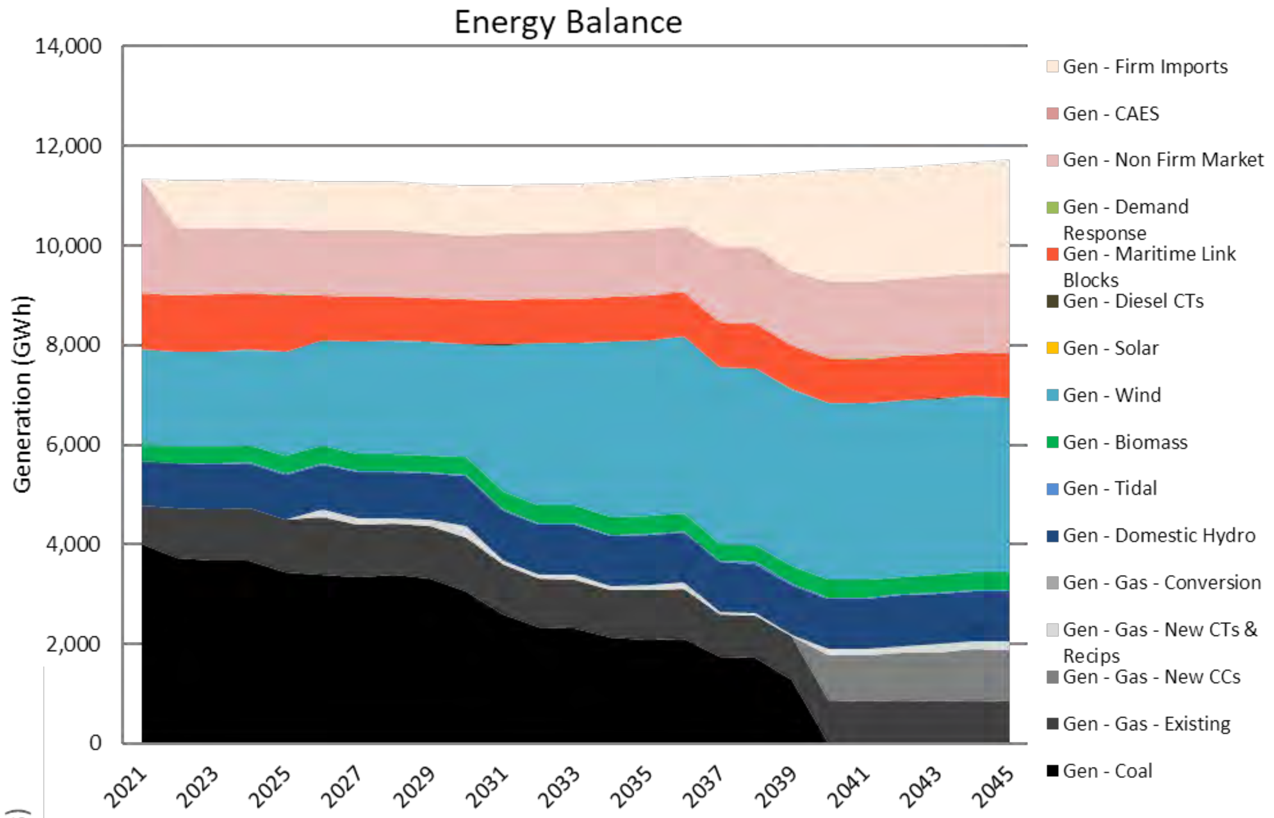
- Reliability Tie: 2025
- Regional Integration: 2026

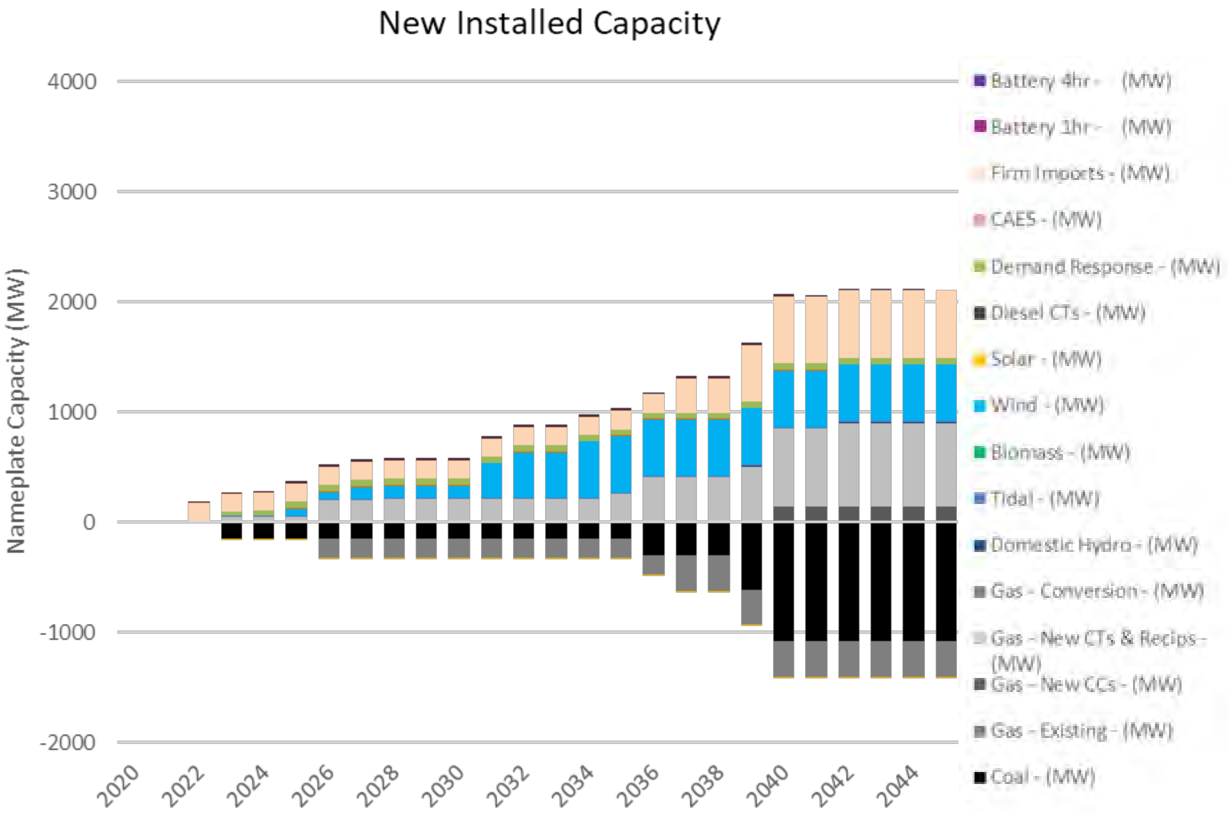
Plan Robustness & Flexibility

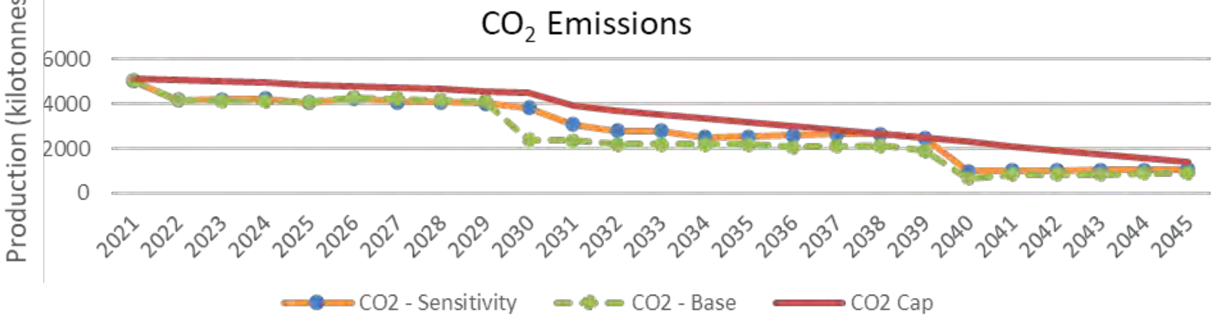
- One additional NGCC increases exposure to gas prices; total gas generation limited by emissions constraints in model scenarios

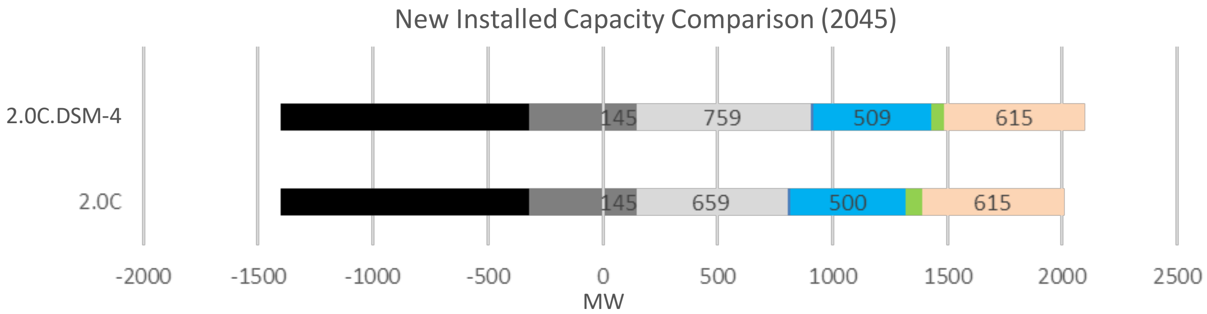
2.0C.DSM-4 (LOW DSM)

LOW ELEC. / LOW DSM / NET ZERO 2050 / REGIONAL INTEGRATION









2.0C.DSM-4 (LOW DSM)

LOW ELEC. / LOW DSM / NET ZERO 2050 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

	Sensitivity	Base (2.0C)
25-yr NPVRR ($MM)	$12,087	$12,076
25-yr NPVRR w/ End Effects ($MM)	$16,146	$15,990
10-yr NPVRR ($MM)	$6,642	$6,776
Average Annual Relative Rate Impact		
2021-2030 (%)	0.4%	0.8%
2021-2045 (%)	0.7%	0.8%
Total CO_2 Emissions 2021-2030 (MT)	41.9	40.7
Total CO_2 Emissions 2031-2045 (MT)	30.2	24.3
Total CO_2 Emissions 2021-2045 (MT)	72.1	65.0

General Notes
- Similar resource plan overall to 2.0C Base DSM; 1 economic coal retirement is delayed later into 2030s due to increased load which leads to an increase in CO_2 emissions in the 2030s
- By 2045 the Low DSM sensitivity adds 100MW incremental combustion turbine resources relative to Base DSM, closely matching the firm peak increase of 86MW (plus the associated PRM increase)
- NPVRR is decreased over the first 10 years, very similar over 25 years, and increased when end effects are considered relative to 2.0C Base DSM indicating the solutions are very close economically

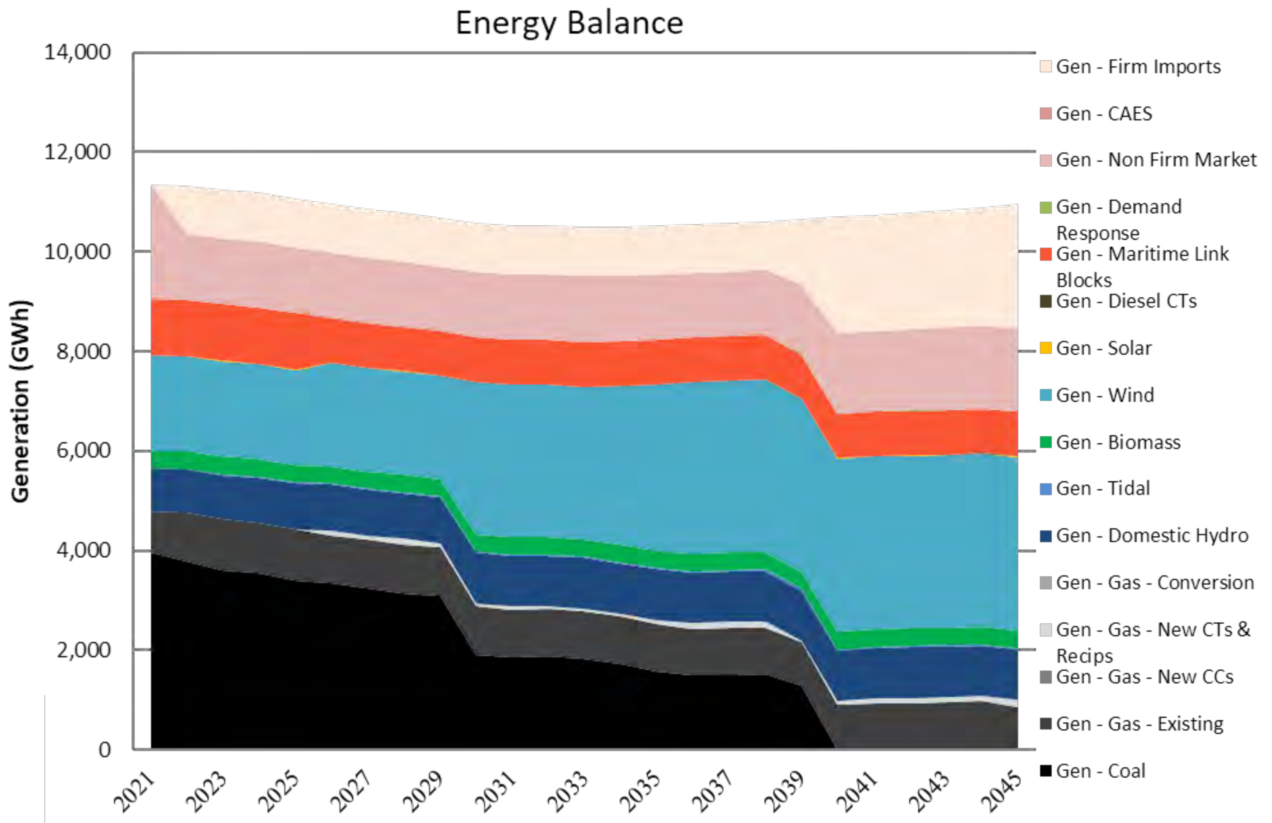
Essential Grid Services
- No change relative to 2.0C

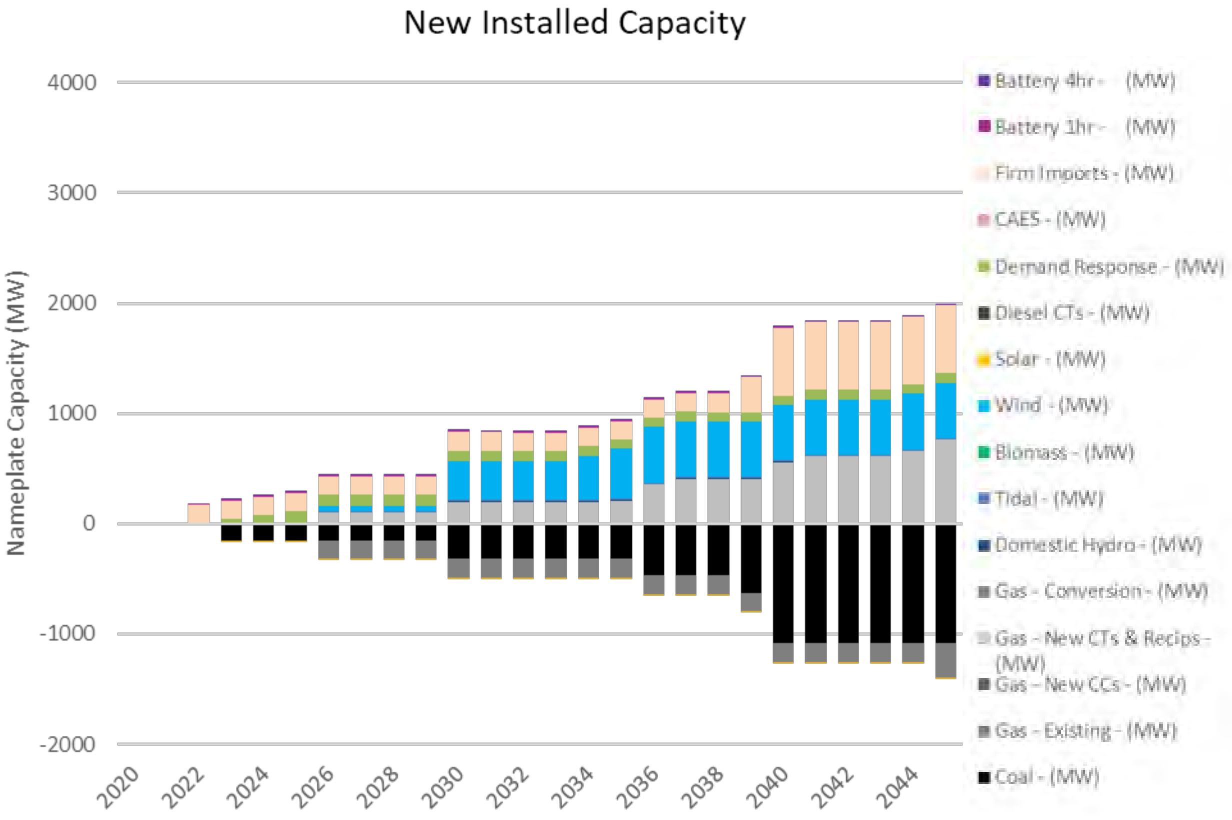
Resource Adequacy & PRM
- Reliability Tie: 2031
- Regional Integration: 2037

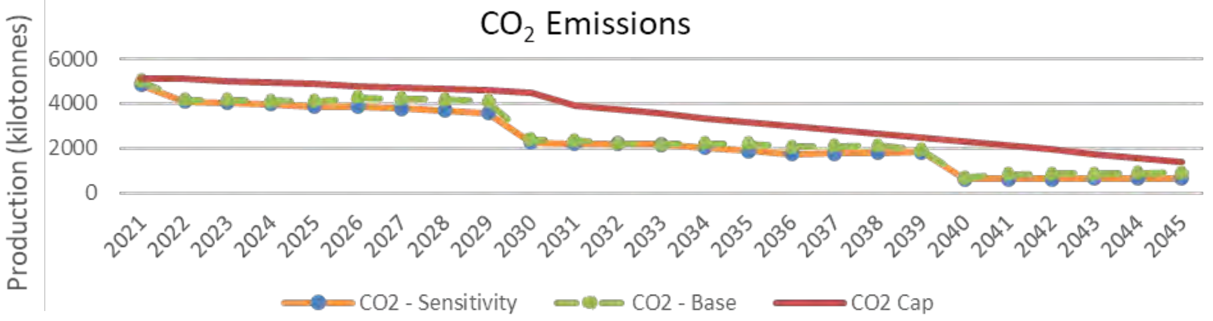
Plan Robustness & Flexibility
- No change relative to 2.0C

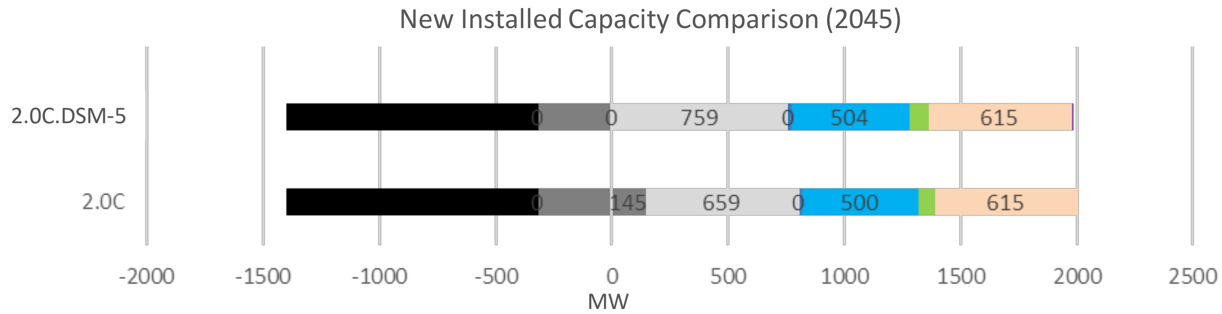
2.0C.DSM-5 (MID DSM)

LOW ELEC. / MID DSM / NET ZERO 2050 / REGIONAL INTEGRATION









2.0C.DSM-5 (MID DSM)

LOW ELEC. / MID DSM / NET ZERO 2050 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

	Sensitivity	Base (2.0C)
25-yr NPVRR ($MM)	$12,376	$12,076
25-yr NPVRR w/ End Effects ($MM)	$16,272	$15,990
10-yr NPVRR ($MM)	$7,111	$6,776
Average Annual Relative Rate Impact		
2021-2030 (%)	1.2%	0.8%
2021-2045 (%)	0.9%	0.8%
Total CO_2 Emissions 2021-2030 (MT)	38.0	40.7
Total CO_2 Emissions 2031-2045 (MT)	21.5	24.3
Total CO_2 Emissions 2021-2045 (MT)	59.4	65.0

General Notes

- Generally a similar resource plan to 2.1C
- Increased level of DSM in this sensitivity deferred Regional Integration to 2039 from 2037.
- A net of 45MW of gas generation capacity is avoided (100 MW additional combustion turbines and 145MW less NGCC relative to 2.0C Base DSM)
- NPVRR is increased relative to Base DSM case for all three time periods

Essential Grid Services

- No change relative to 2.0C

Resource Adequacy & PRM

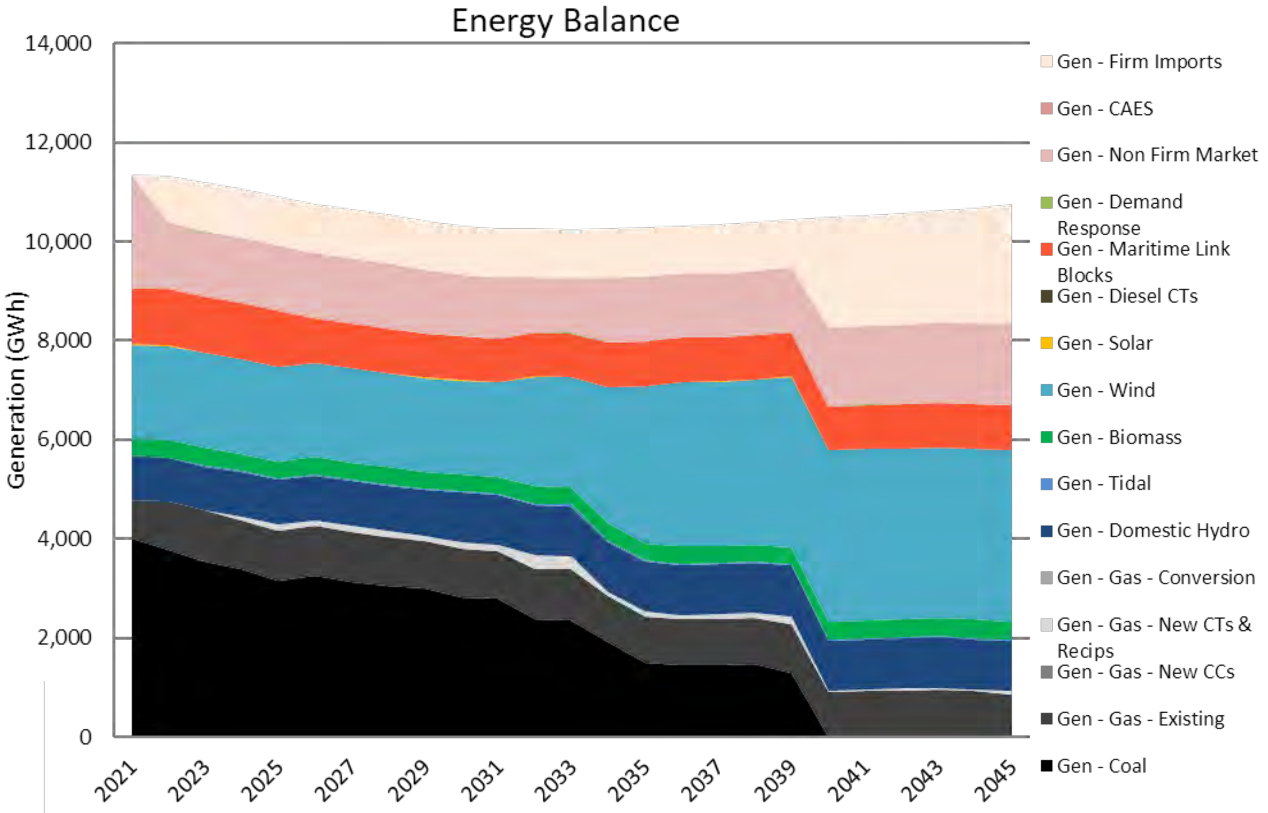
- Reliability Tie: 2030
- Regional Integration: 2039

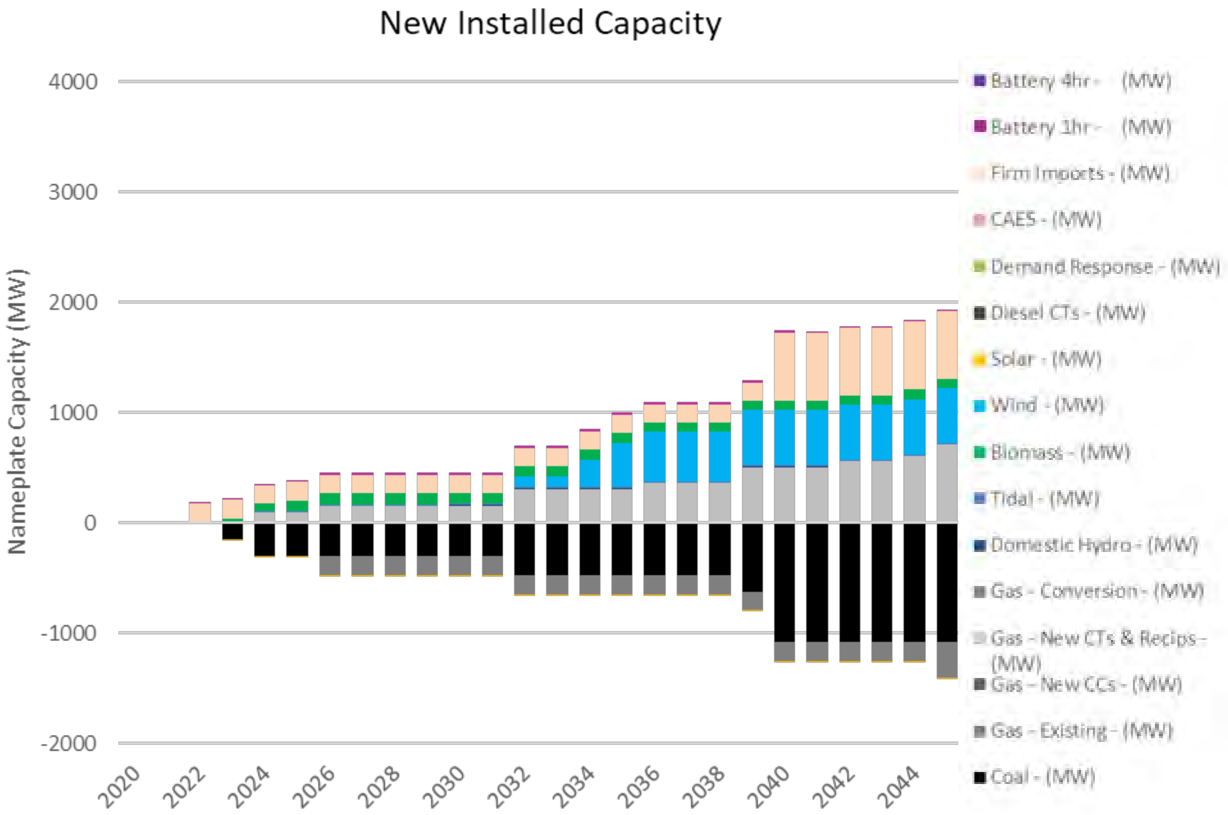
Plan Robustness & Flexibility

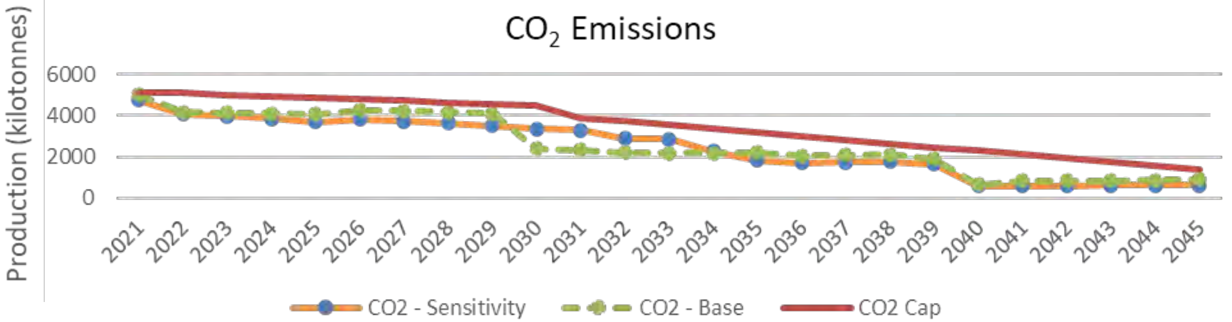
- No change relative to 2.0C

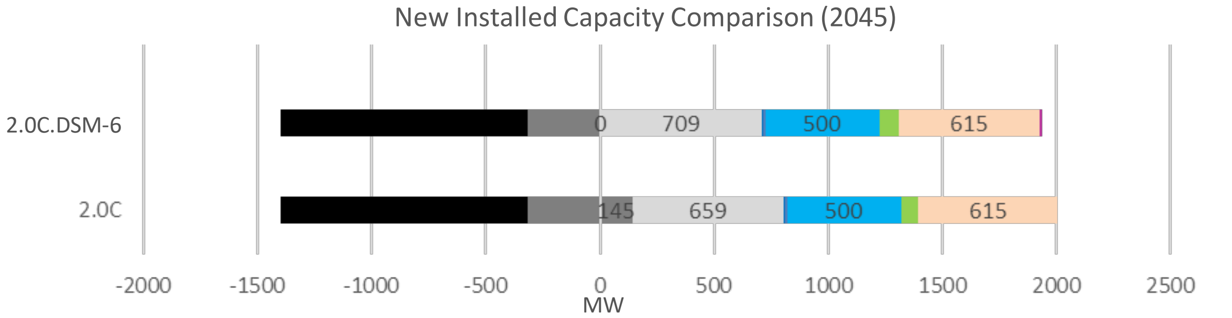
2.0C.DSM-6 (MAX DSM)

LOW ELEC. / MAX DSM / NET ZERO 2050 / REGIONAL INTEGRATION









2.0C.DSM-6 (MAX DSM)

LOW ELEC. / MAX DSM / NET ZERO 2050 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

	Sensitivity	Base (2.0C)
25-yr NPVRR ($MM)	$12,858	$12,076
25-yr NPVRR w/ End Effects ($MM)	$16,826	$15,990
10-yr NPVRR ($MM)	$7,504	$6,776
Average Annual Relative Rate Impact		
2021-2030 (%)	1.4%	0.8%
2021-2045 (%)	1.0%	0.8%
Total CO_2 Emissions 2021-2030 (MT)	38.4	40.7
Total CO_2 Emissions 2031-2045 (MT)	23.7	24.3
Total CO_2 Emissions 2021-2045 (MT)	62.1	65.0

General Notes
- Increased level of DSM deferred Reliability Tie to 2034 from 2030, and Regional Integration to 2040 from 2037.
- A net of 95MW of gas generation capacity is avoided (50 MW additional combustion turbines and 145MW less NGCC relative to 2.0C Base DSM)
- 1 additional coal unit is retired in the 2020s economically and wind build is delayed
- NPVRR is increased relative to Base DSM case for all three time periods

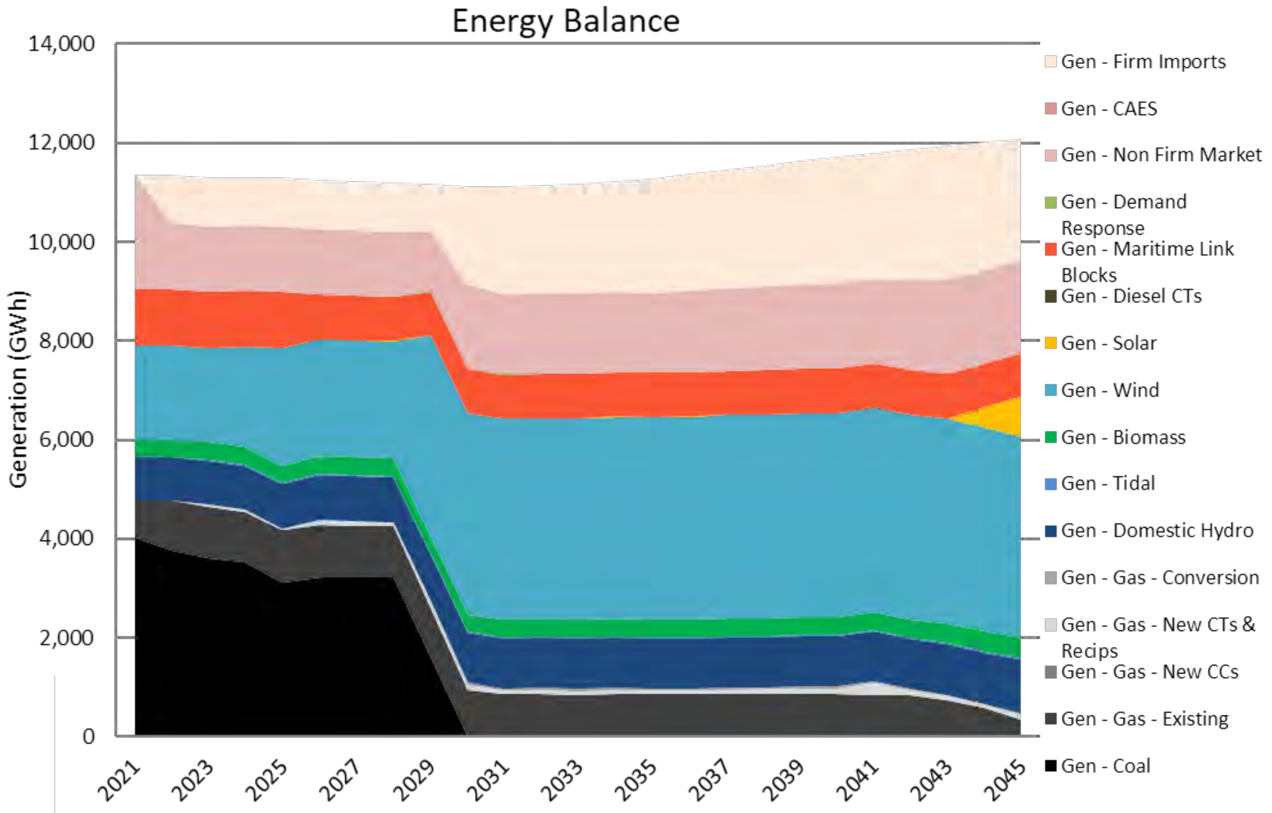
Essential Grid Services
- No change relative to 2.0C

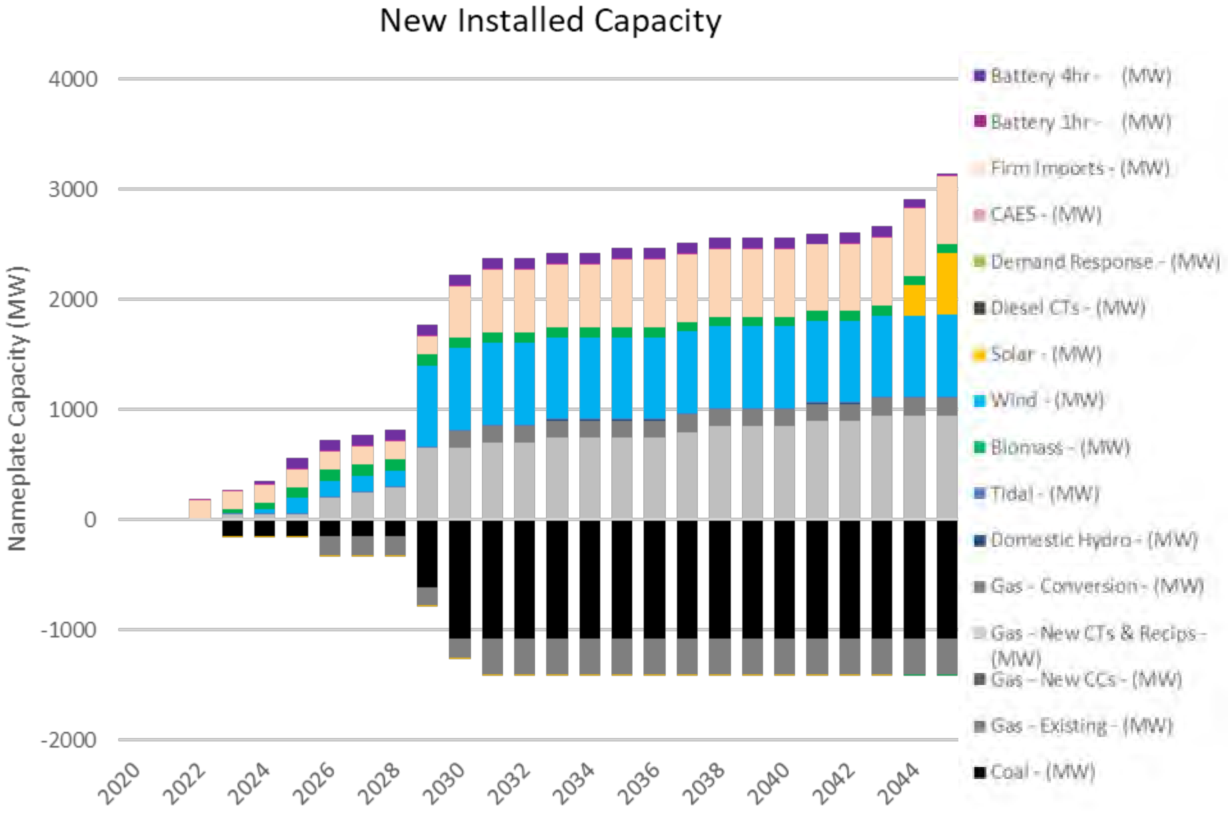
Resource Adequacy & PRM
- Reliability Tie: 2034
- Regional Integration: 2040

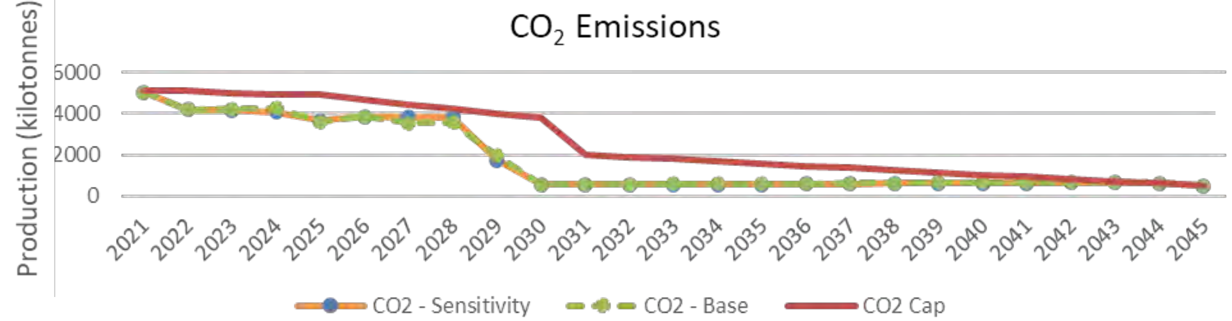
Plan Robustness & Flexibility
- No change relative to 2.0C

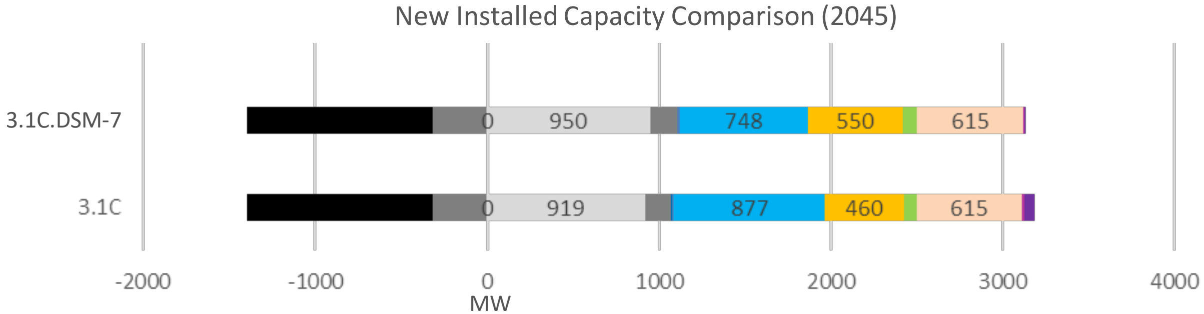
3.1C.DSM-7 (MID DSM)

MID ELEC. / MID DSM / ACCEL. NET ZERO 2045 / REGIONAL INTEGRATION









3.1C.DSM-7 (MID DSM)

MID ELEC. / MID DSM / ACCEL. NET ZERO 2045 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

	Sensitivity	Base (3.1C)
25-yr NPVRR ($MM)	$13,816	$13,576
25-yr NPVRR w/ End Effects ($MM)	$18,344	$18,148
10-yr NPVRR ($MM)	$7,470	$7,179
Average Annual Relative Rate Impact		
2021-2030 (%)	1.9%	1.5%
2021-2045 (%)	0.9%	0.8%
Total CO_2 Emissions 2021-2030 (MT)	34.9	34.8
Total CO_2 Emissions 2031-2045 (MT)	8.9	9.2
Total CO_2 Emissions 2021-2045 (MT)	43.9	44.0

General Notes
- Resource plan is largely unchanged between 3.1C and 3.1C with Mid DSM
- Slightly fewer batteries are built through the planning horizon due to lower firm capacity requirements (firm peak is 28MW lower by 2045 under Mid DSM vs. Base DSM)
- NPVRR is increased relative to Base DSM case for all three time periods

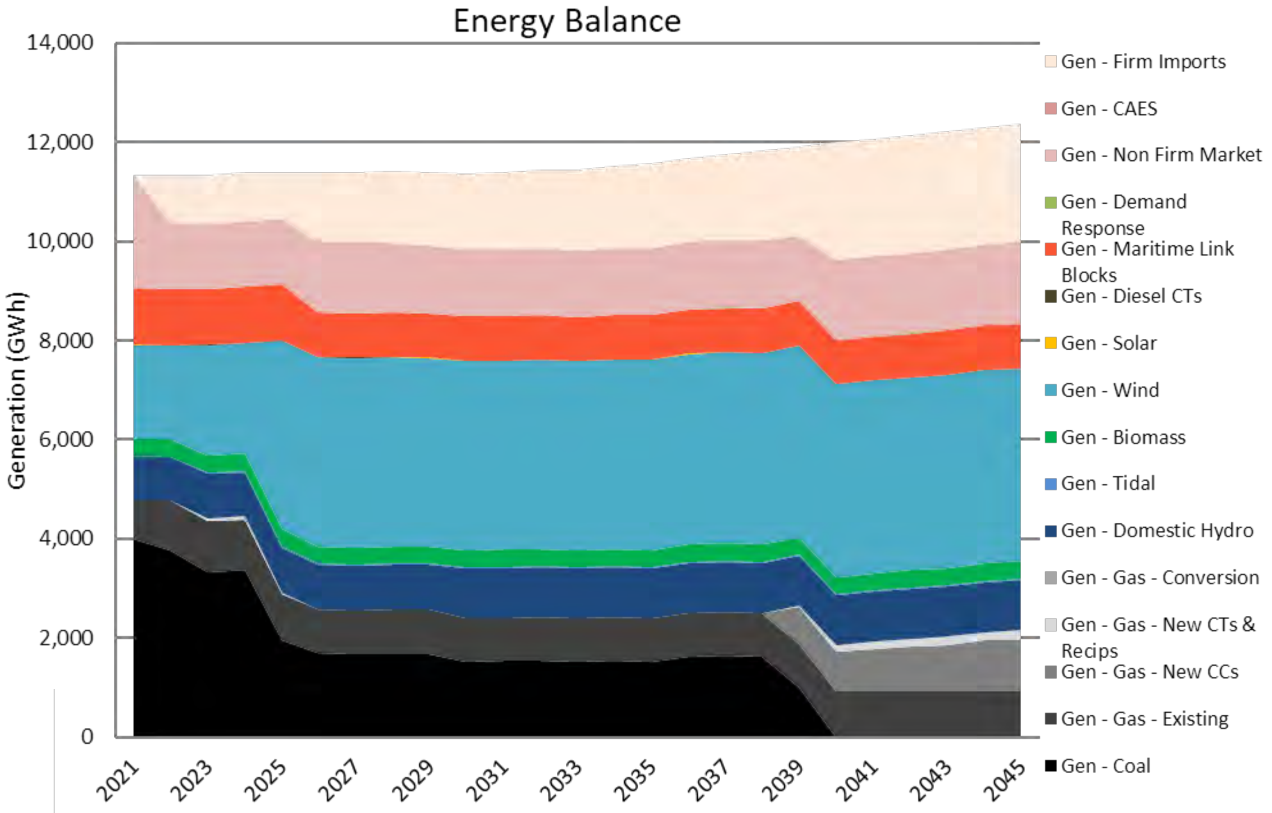
Essential Grid Services
- No change relative to 3.1C

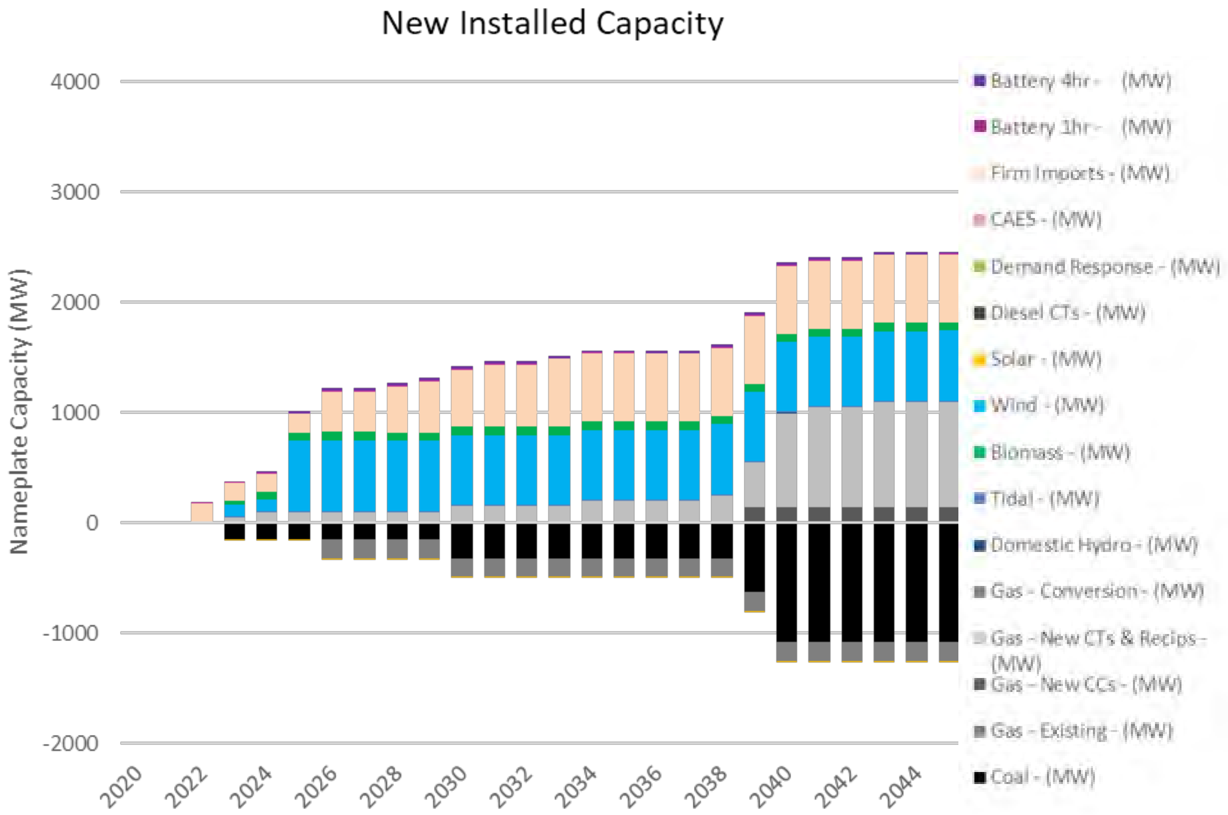
Resource Adequacy & PRM
- Reliability Tie: 2029
- Regional Integration: 2030

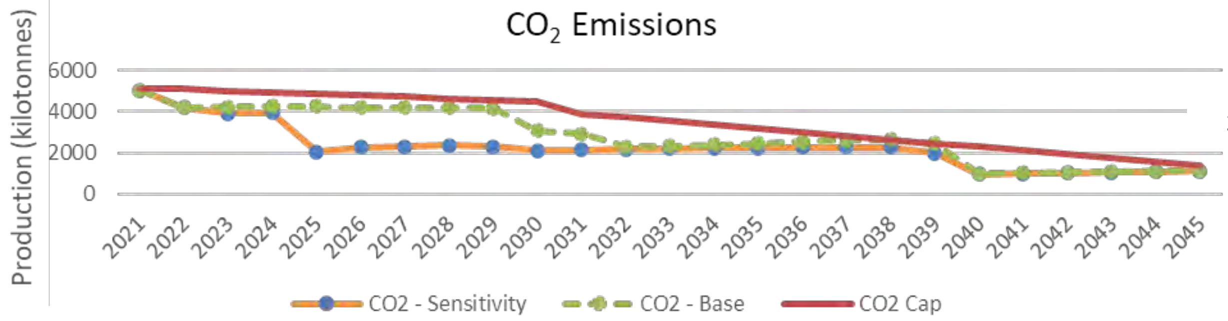
Plan Robustness & Flexibility
- No change relative to 3.1C

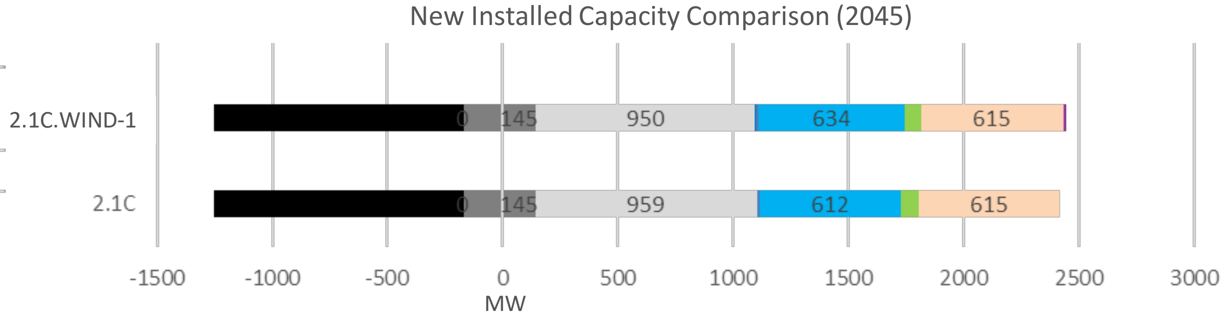
2.1C.WIND-1 (LOW WIND COST)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION









2.1C.WIND-1 (LOW WIND COST)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

	Sensitivity	Base (2.1C)
25-yr NPVRR ($MM)	$12,820	$12,983
25-yr NPVRR w/ End Effects ($MM)	$17,199	$17,506
10-yr NPVRR ($MM)	$7,087	$7,022
Average Annual Relative Rate Impact		
2021-2030 (%)	0.6%	0.8%
2021-2045 (%)	0.7%	0.8%
Total CO_2 Emissions 2021-2030 (MT)	30.5	41.8
Total CO_2 Emissions 2031-2045 (MT)	26.1	29.1
Total CO_2 Emissions 2021-2045 (MT)	56.6	70.9

General Notes

- Low wind price advances build of significant wind quantities from 2030 in base case to 2025; Reliability Tie is advanced as well to enable integration
- Earlier build of Regional Interconnection relative to 2.1C allows procurement of firm capacity and delays some combustion turbine builds
- Additional wind energy enables an additional coal unit retirement in 2030 relative to 2.1C (advanced from 2036)
- Increased wind generation and earlier Regional Interconnection enables significantly reduced CO_2 emissions in the 2020s; emissions in 2031-2045 are largely unchanged
- 2045 resource plans are effectively the same
- NPVRR is reduced relative to 3.1C in two of three metrics, slightly higher in 10-yr NPV due to advancement of investment

Essential Grid Services

- No change relative to 2.1C

Resource Adequacy & PRM

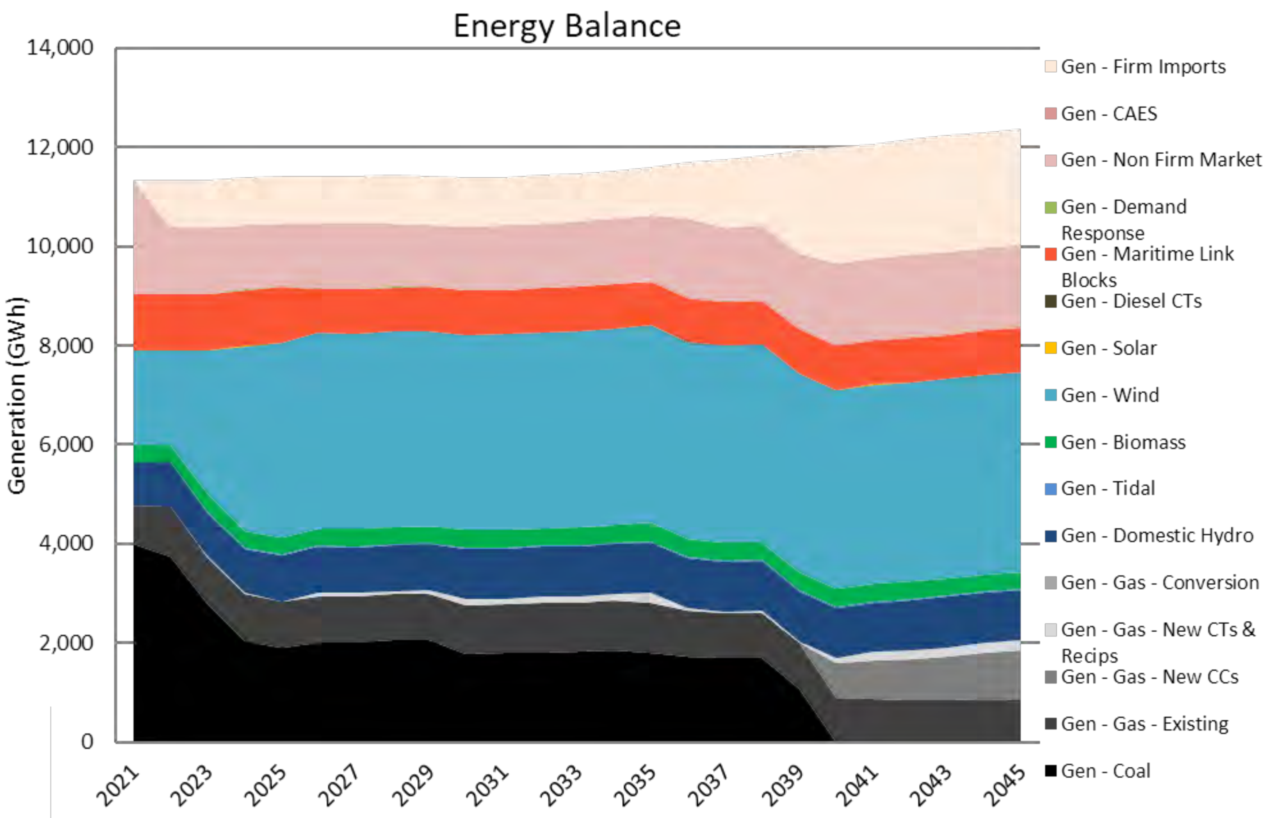
- Reliability Tie: 2025
- Regional Integration: 2026

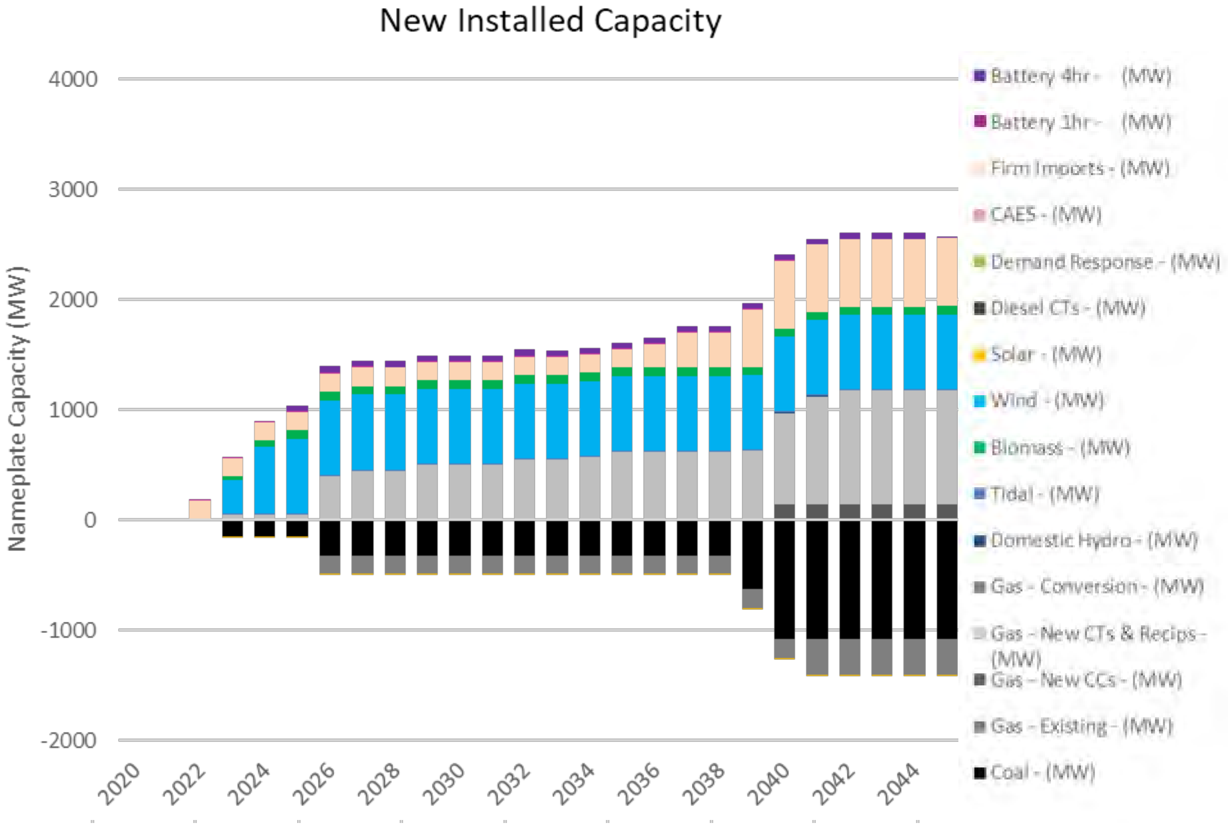
Plan Robustness & Flexibility

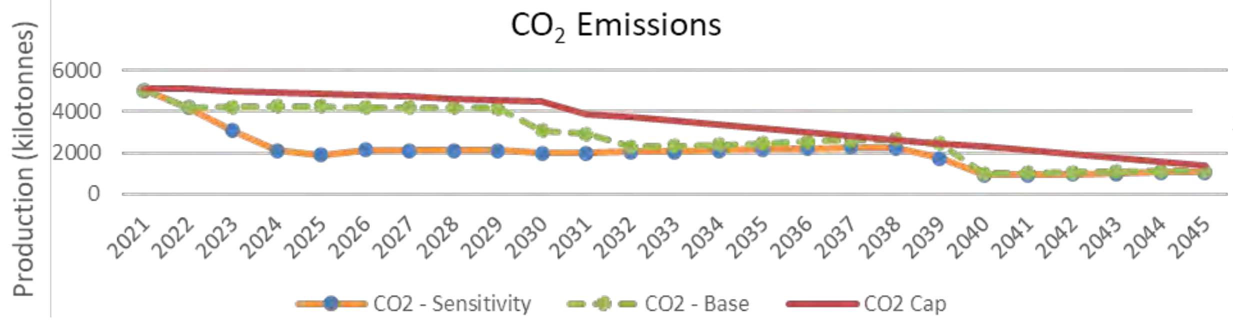
- Need further consideration on flexibility of import energy to balance increased wind capacity in the near term

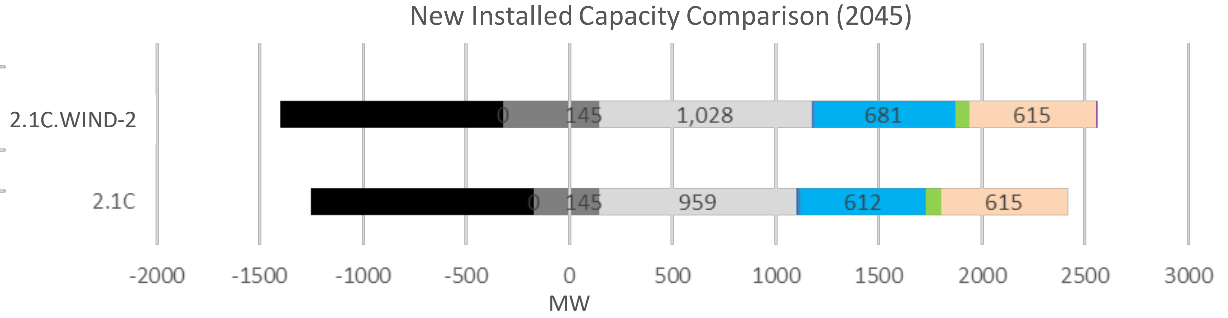
2.1C.WIND-2 (LOW WIND & BATTERY COST)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION









2.1C.WIND-2 (LOW WIND & BATTERY COST)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

	Sensitivity	Base (2.1C)
25-yr NPVRR ($MM)	$12,928	$12,983
25-yr NPVRR w/ End Effects ($MM)	$17,258	$17,506
10-yr NPVRR ($MM)	$7,132	$7,022
Average Annual Relative Rate Impact		
2021-2030 (%)	0.7%	0.8%
2021-2045 (%)	0.7%	0.8%
Total CO_2 Emissions 2021-2030 (MT)	26.8	41.8
Total CO_2 Emissions 2031-2045 (MT)	24.9	29.1
Total CO_2 Emissions 2021-2045 (MT)	51.7	70.9

General Notes

- In general, resource plan changes are similar to what is seen in 2.1C.WIND-1 sensitivity but more pronounced
- Low wind and battery prices advance build of significant wind quantities from 2030 in base case to 2024; Reliability Tie is advanced as well to enable integration along with additional integration provided by batteries
- Regional Integration is unchanged relative to 2.1C at 2036
- Additional wind energy enables an additional coal unit retirement in 2026 relative to 2.1C (advanced from 2036)
- Increased wind generation enables significantly reduced CO_2 emissions in the 2020s; emissions in 2031-2045 are largely unchanged
- 2045 resource plans show more wind and more CTs, and 1 additional retired gas steam unit
- NPVRR is reduced relative to 3.1C in two of three metrics, slightly higher in 10-yr NPV due to advancement of investment

Essential Grid Services

- No change relative to 2.1C

Resource Adequacy & PRM

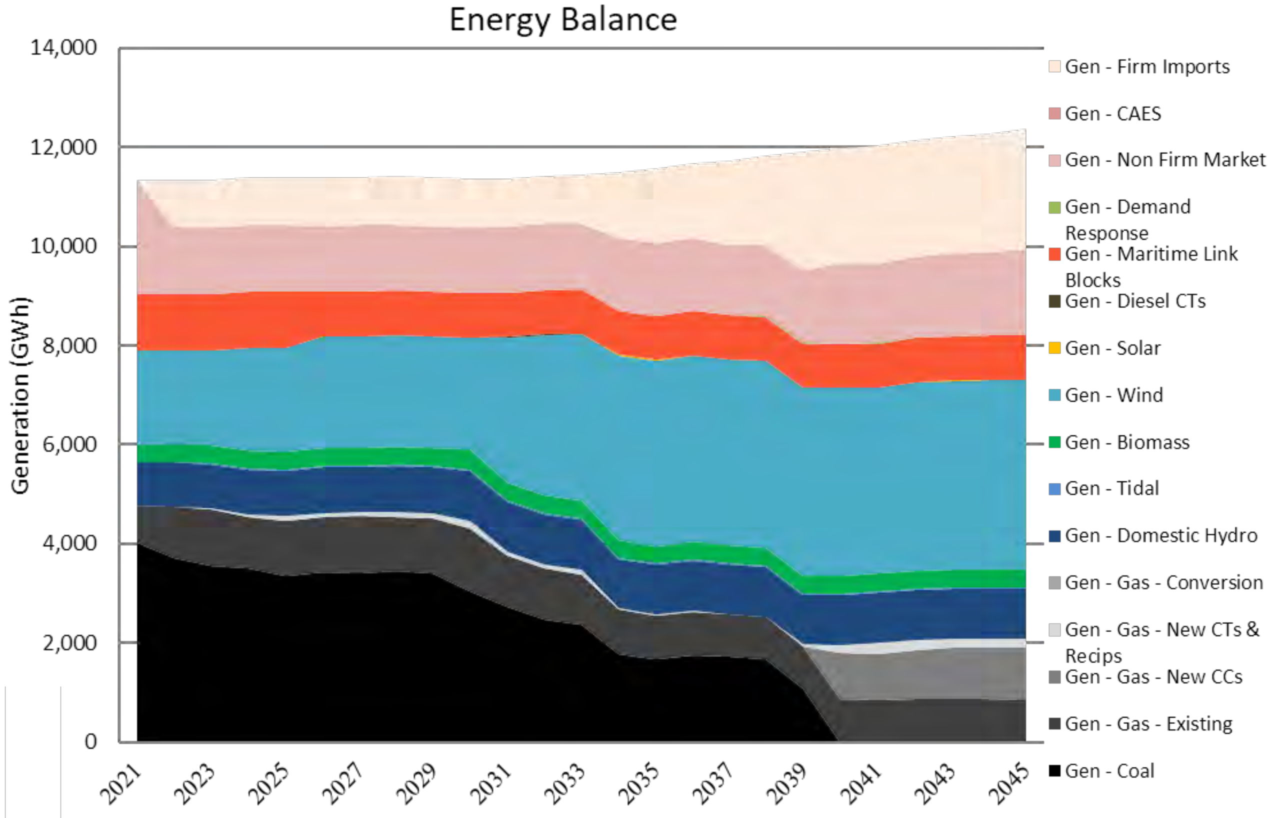
- Reliability Tie: 2023
- Regional Integration: 2036

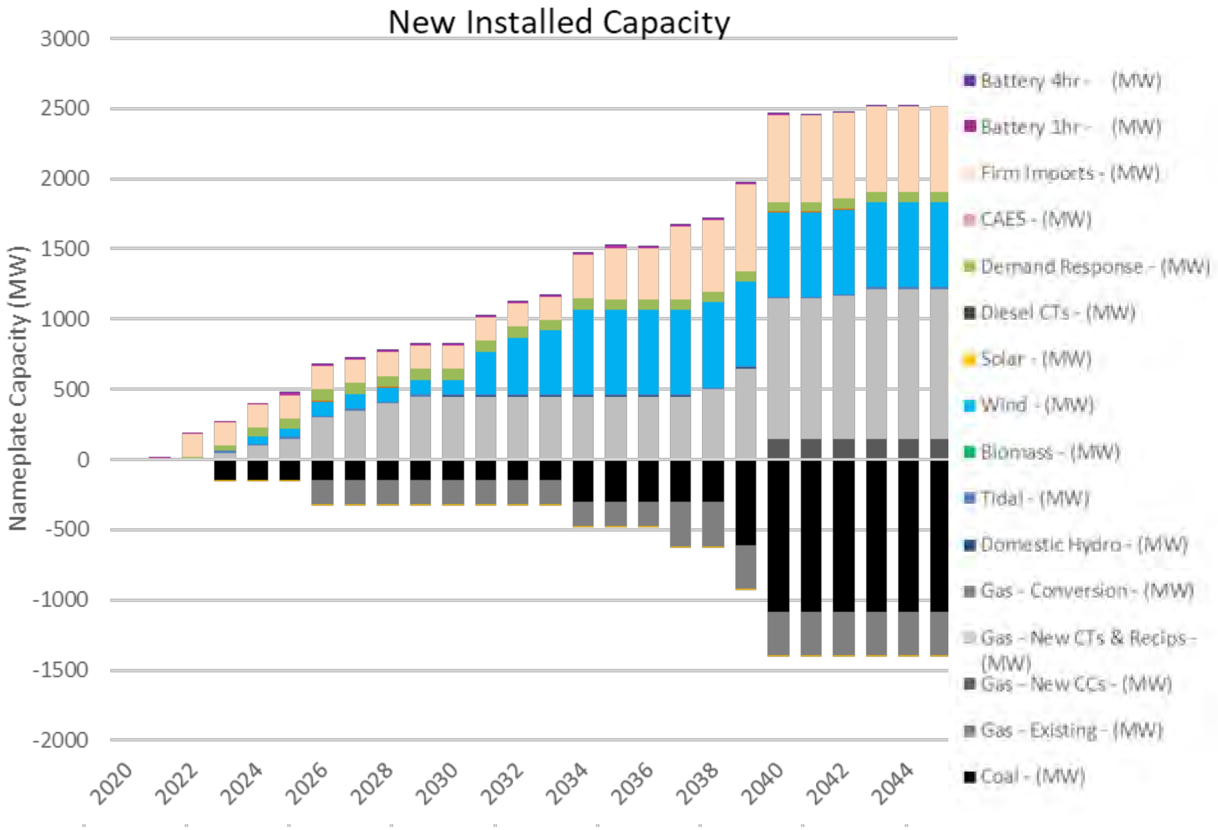
Plan Robustness & Flexibility

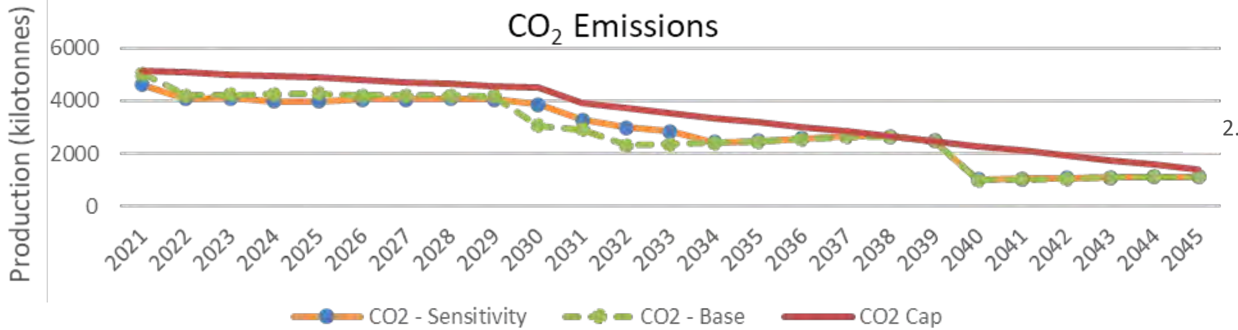
- Need further consideration on flexibility of import energy to balance increased wind capacity in the near term

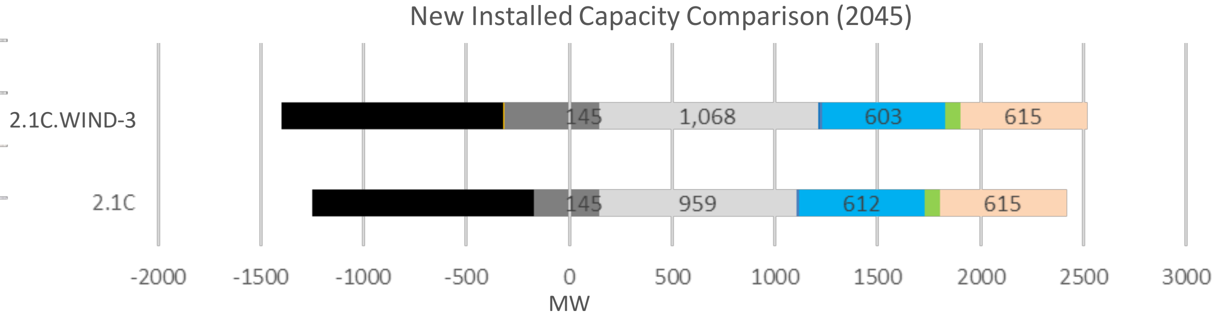
2.1C.WIND-3 (LOW INERTIA CONSTRAINT)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION









2.1C.WIND-3 (LOW INERTIA CONSTRAINT)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

	Sensitivity	Base (2.1C)
25-yr NPVRR ($MM)	$12,901	$12,983
25-yr NPVRR w/ End Effects ($MM)	$17,392	$17,506
10-yr NPVRR ($MM)	$6,955	$7,022
Average Annual Relative Rate Impact		
2021-2030 (%)	0.7%	0.8%
2021-2045 (%)	0.8%	0.8%
Total CO_2 Emissions 2021-2030 (MT)	40.8	41.8
Total CO_2 Emissions 2031-2045 (MT)	30.9	29.1
Total CO_2 Emissions 2021-2045 (MT)	71.7	70.9

General Notes

- Inertia constraint is lowered from base of 3266 MW.sec to 2200 MW.sec in all hours
- Slight change to wind profile build is observed:
  - Initial no integration build is 50MW 2024 / 50 MW 2026, vs. 100MW 2026 in 2.1C
  - Reliability Tie is built one year later and 500MW wind build is staged from 2031-2034 rather than 2030-2032 as seen in 2.1C
  - In both cases relatively little wind build via local integration option
- Incremental production cost savings are achieved via fewer thermal units online in early years of planning horizon; potential that this slightly delays the Reliability Tie build
- One additional gas steam unit is retired and replaced with incremental CT capacity
- Results suggest that lowering the inertia constraint in isolation has a limited impact on overall resource plan optimization
- Cost differences are small over all three NPV metrics

Essential Grid Services

- Current studies indicate that 2200MW.sec of online kinetic inertia is not sufficient to reliably operate the NS Power system today; additional stability studies required to confirm potential impacts and mitigations, or dynamic operating constraints based on system state

Resource Adequacy & PRM

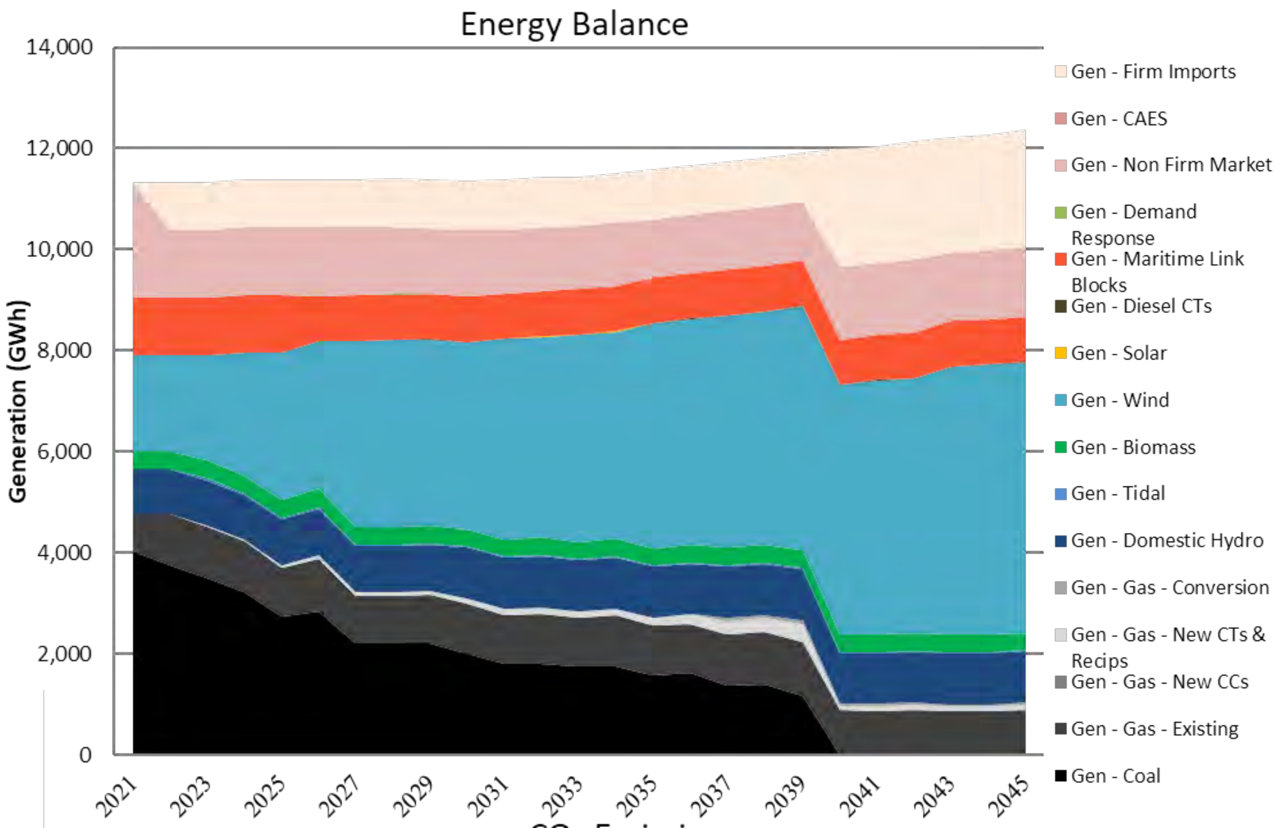
- Reliability Tie: 2031
- Regional Integration: 2034

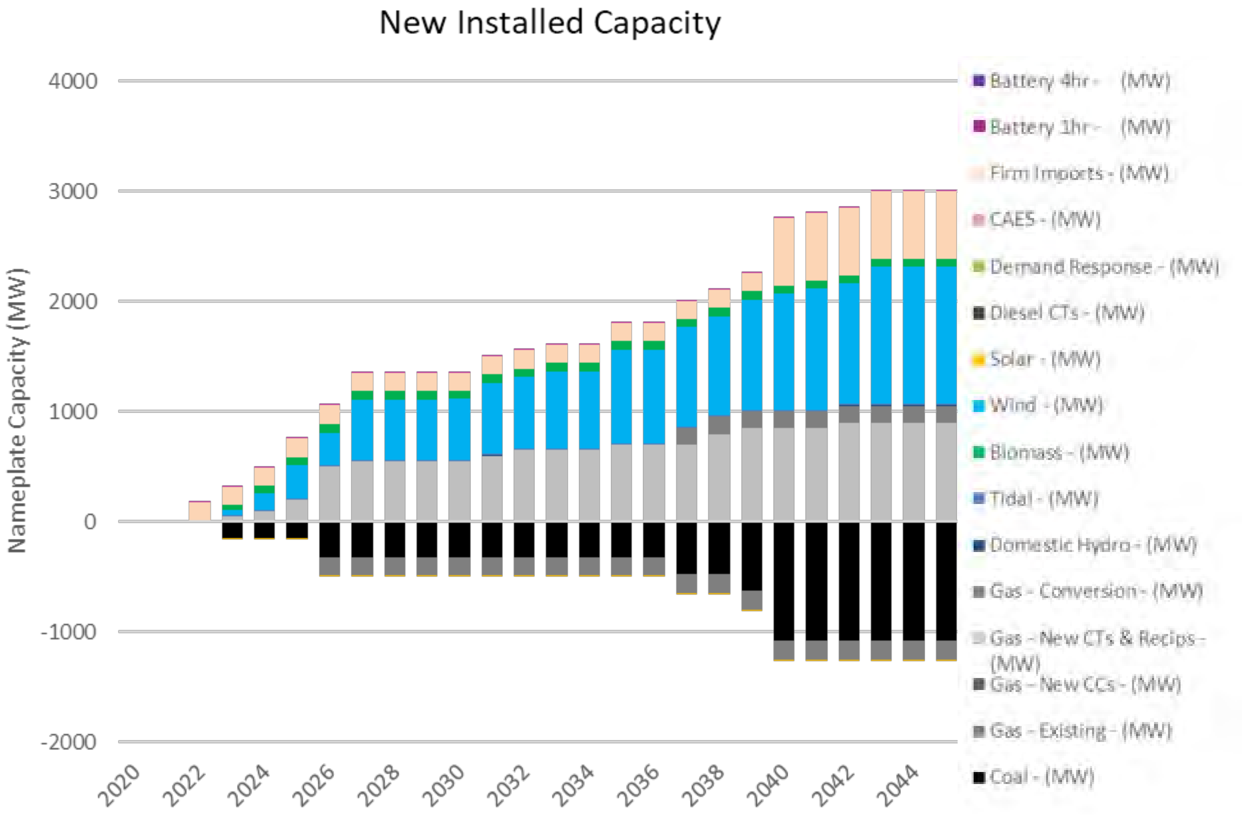
Plan Robustness & Flexibility

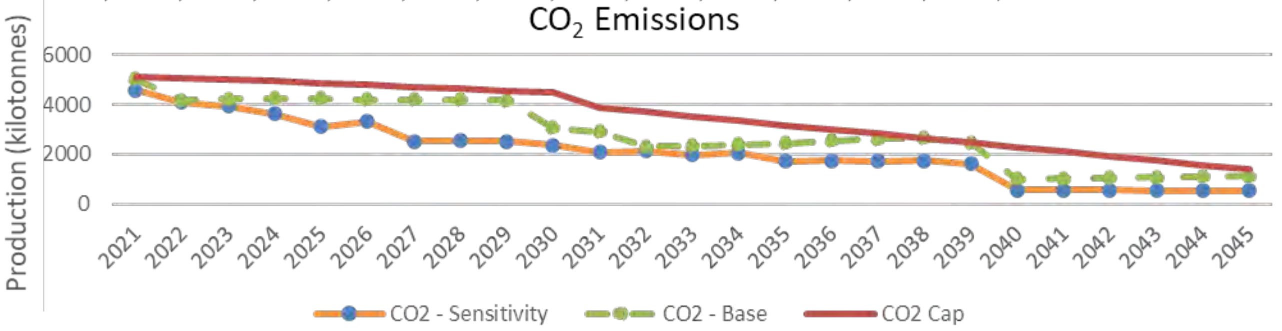
- No change from 2.1C

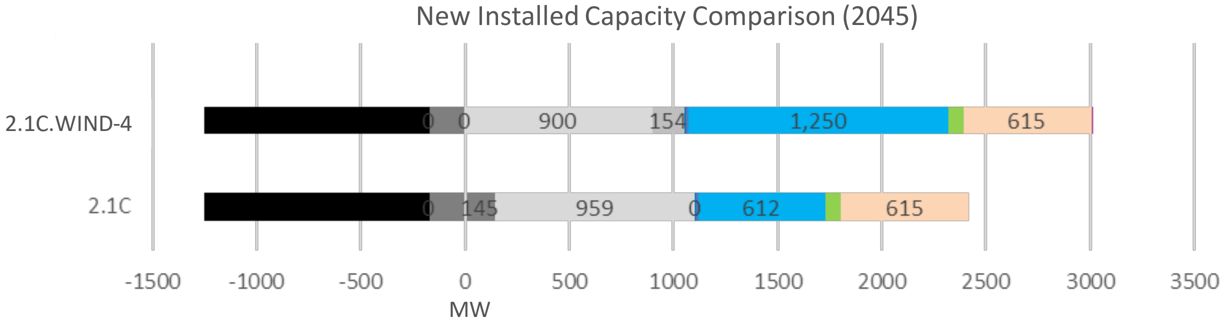
2.1C.WIND-4 (NO INERTIA / NO INTEGRATION)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION









2.1C.WIND-4 (NO INERTIA / NO INTEGRATION)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation		
	Sensitivity	Base (2.1C)
25-yr NPVRR ($MM)	$12,918	$12,983
25-yr NPVRR w/ End Effects ($MM)	$17,474	$17,506
10-yr NPVRR ($MM)	$6,996	$7,022
Average Annual Relative Rate Impact		
2021-2030 (%)	0.6%	0.8%
2021-2045 (%)	0.8%	0.8%
Total CO_2 Emissions 2021-2030 (MT)	32.7	41.8
Total CO_2 Emissions 2031-2045 (MT)	20.1	29.1
Total CO_2 Emissions 2021-2045 (MT)	52.8	70.9

General Notes
- Model builds more wind relative to base case, with 200MW incremental added by 2030 and 250MW incremental by 2035, and 638MW incremental in 2045
- 1 coal to gas conversion is selected, replacing a NGCC unit from the base case
- PLEXOS MT/ST simulations show that curtailment reached 828 GWh in 2045 (13.4%), vs. 208 GWh in 2045 (5.2%) in the 2.1C base case
- Due to curtailment and replacement energy costs, NPVs incorporating MT/ST Production Costs are not significantly lower than the base scenario 2.1C

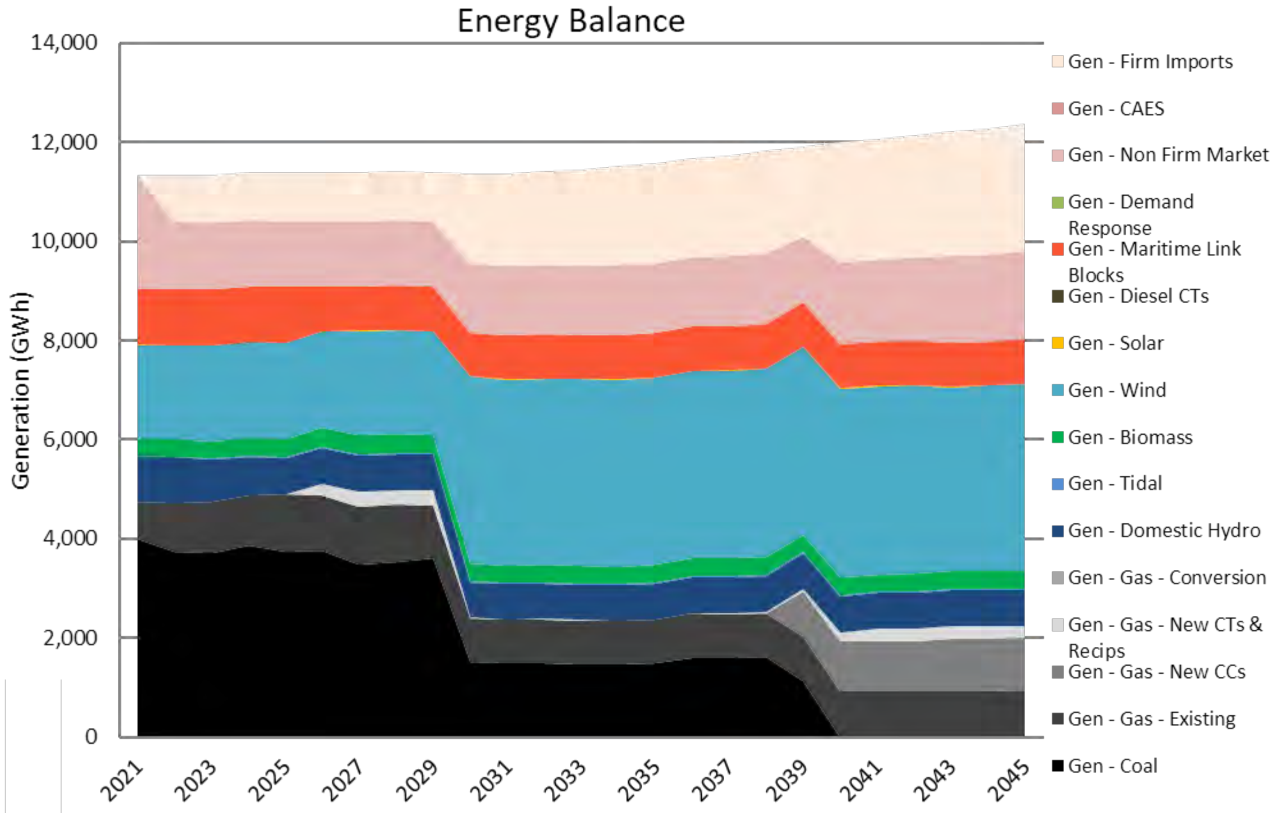
Essential Grid Services
- This run is intended as a test case to understand how the model will perform with no inertia constraint and no integration requirements for wind (i.e. Reliability Tie or Local Integration options); it is not a feasible resource plan but rather an extreme bookend

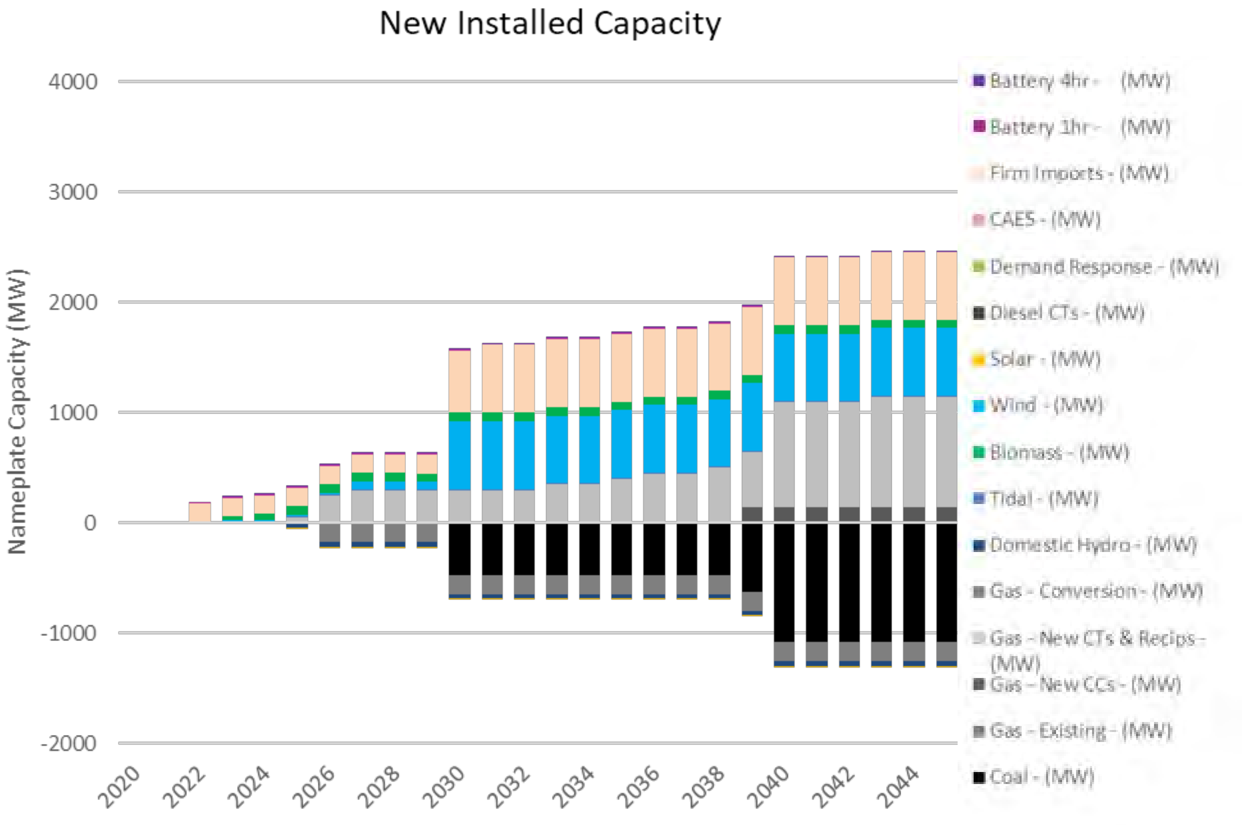
Resource Adequacy & PRM
- Reliability Tie: 2040
- Regional Integration: 2040
- Reliability Tie was built economically as part of Regional Integration to access firm capacity and energy; not required in this run for wind

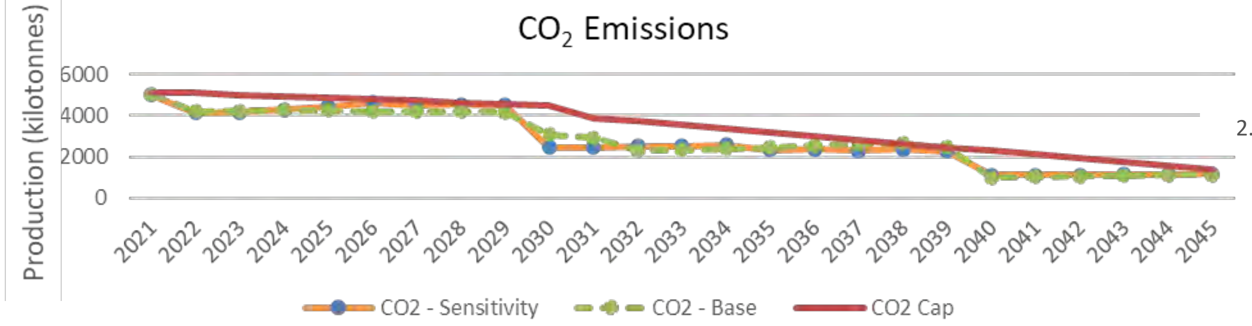
Plan Robustness & Flexibility
- Significant wind penetration could be challenging to operate under some conditions
- The plan has retained flexibility of supply by adding the Regional Integration resource

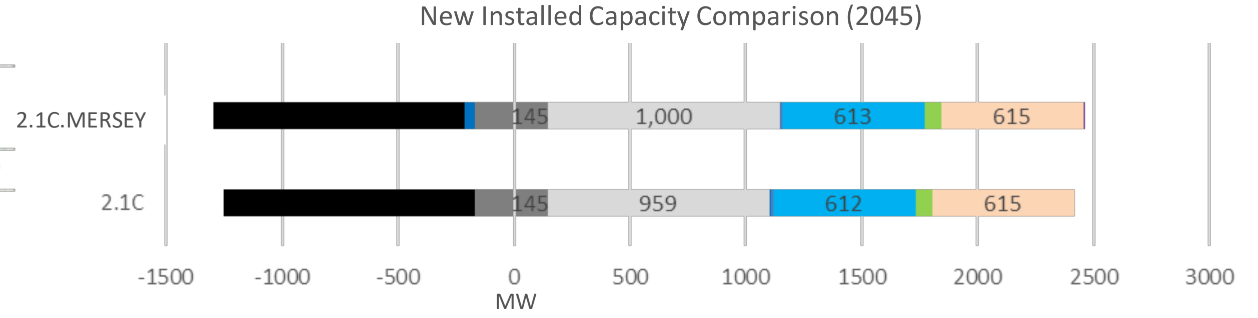
2.1C.MERSEY (MERSEY HYDRO RETIRED)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION









2.1C.MERSEY (MERSEY HYDRO RETIRED)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

	Sensitivity	Base (2.1C)
25-yr NPVRR ($MM)	$12,939	$12,983
25-yr NPVRR w/ End Effects ($MM)	$17,584	$17,506
10-yr NPVRR ($MM)	$6,840	$7,022
Average Annual Relative Rate Impact		
2021-2030 (%)	0.8%	0.8%
2021-2045 (%)	0.8%	0.8%
Total CO_2 Emissions 2021-2030 (MT)	42.7	41.8
Total CO_2 Emissions 2031-2045 (MT)	28.5	29.1
Total CO_2 Emissions 2021-2045 (MT)	71.2	70.9

General Notes
- While the Mersey system was economically retained in the screening phase, this sensitivity was completed in order to understand how capacity and energy would be replaced
- Mersey Hydro is assumed to retire in 2025 in this scenario
- Regional Integration build is advanced from 2036 to 2030, and significant wind build occurs in 2030 rather than 2032
- By the end of the planning horizon, the build is similar but with 40MW of incremental combustion turbine capacity accounting for the retirement of Mersey Hydro
- Mersey Decommissioning Cost ($227MM) is external to PLEXOS but included in Sensitivity NPV and Rate Impact results as an extrinsic cost

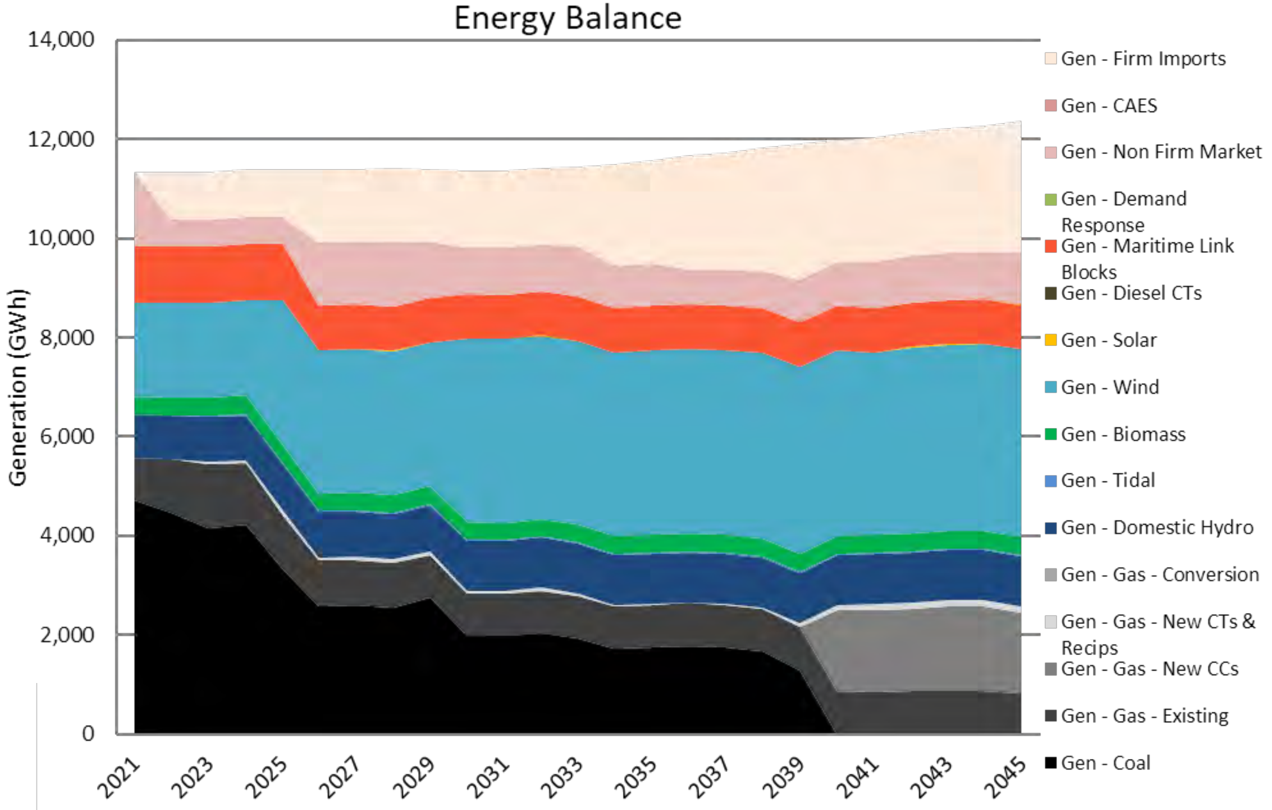
Essential Grid Services
- Decommissioning of Mersey Hydro system would require system stability studies for the Western region of Nova Scotia due to changes in essential grid service provision; cost of any mitigation not included in decommissioning NPV

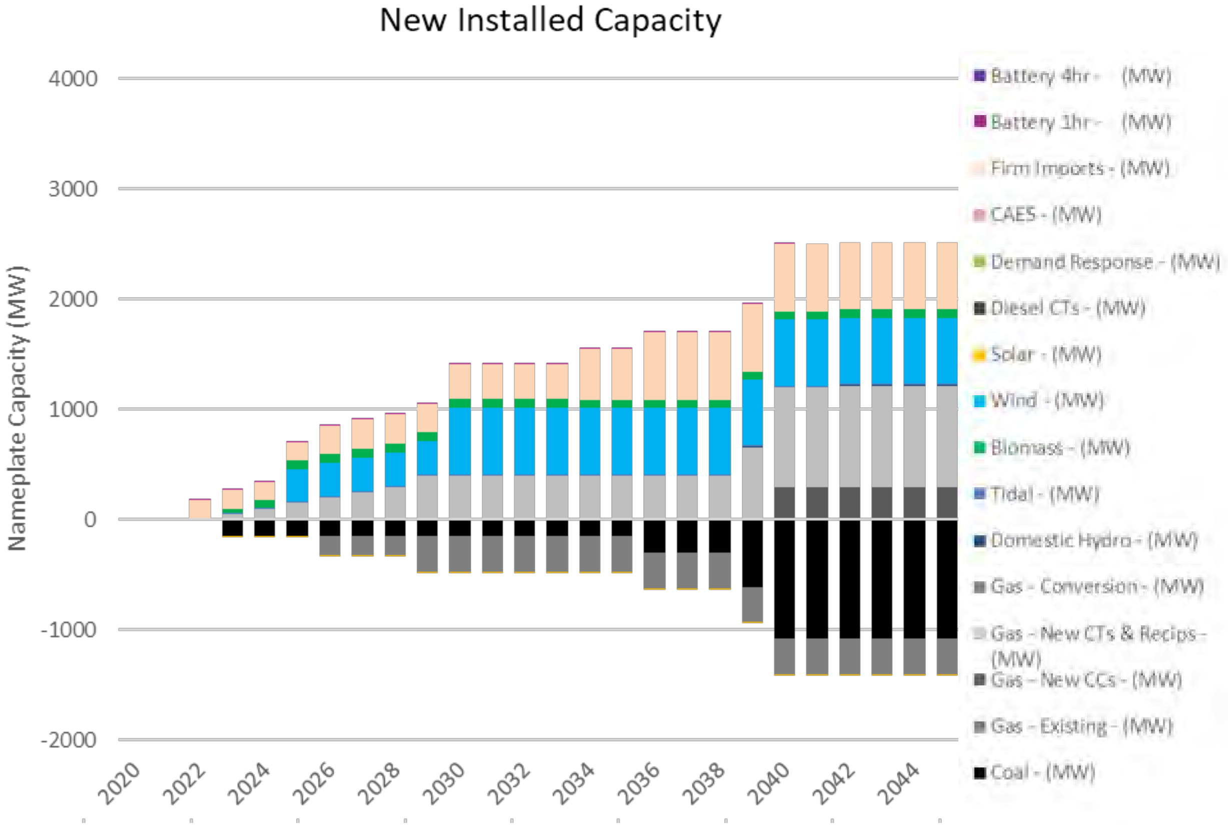
Resource Adequacy & PRM
- Reliability Tie: 2030
- Regional Integration: 2030

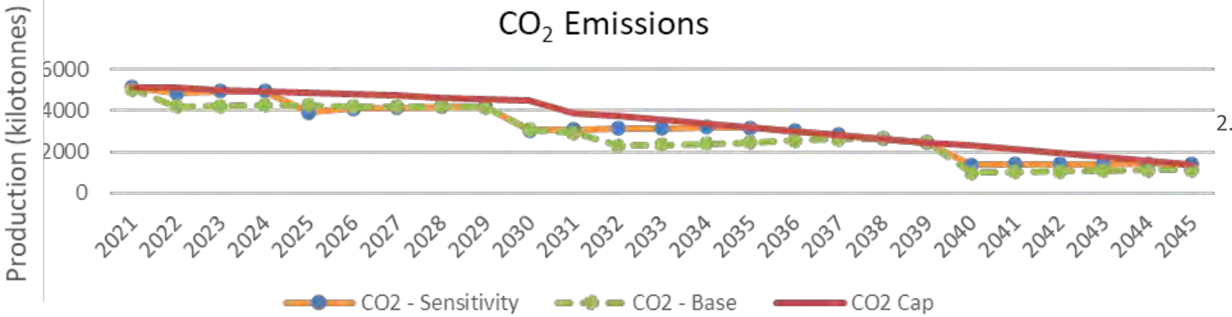
Plan Robustness & Flexibility
- Hydro assets are not subject to fuel price volatility and are located locally in Nova Scotia

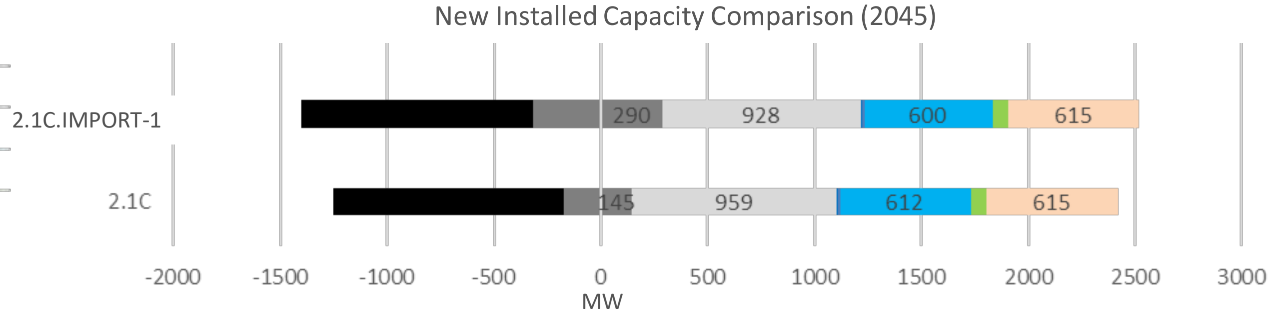
2.1C.IMPORT-1 (LIMITED NON-FIRM IMPORTS)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION









2.1C.IMPORT-1 (LIMITED NON-FIRM IMPORTS)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

	Sensitivity	Base (2.1C)
25-yr NPVRR ($MM)	$13,385	$12,983
25-yr NPVRR w/ End Effects ($MM)	$17,915	$17,506
10-yr NPVRR ($MM)	$7,328	$7,022
Average Annual Relative Rate Impact		
2021-2030 (%)	1.1%	0.8%
2021-2045 (%)	0.8%	0.8%
Total CO_2 Emissions 2021-2030 (MT)	43.5	41.8
Total CO_2 Emissions 2031-2045 (MT)	35.1	29.1
Total CO_2 Emissions 2021-2045 (MT)	78.6	70.9

General Notes

- Sensitivity reduces the maximum quantity of non-firm imports from all sources available to the model by 0.8TWh
- Model builds wind earlier in late 2020s
- Sensitivity case builds one additional NGCC and retires one additional gas steam unit but remainder of 2045 resource mix largely unchanged; generation mix sees additional procurement of firm imports to offset reduction in non-firm availability
- In general the 2.1C base resource plan is robust to a reduction in non-firm imports, but replacement energy does come at a higher cost

Essential Grid Services

- No change relative to 2.1C

Resource Adequacy & PRM

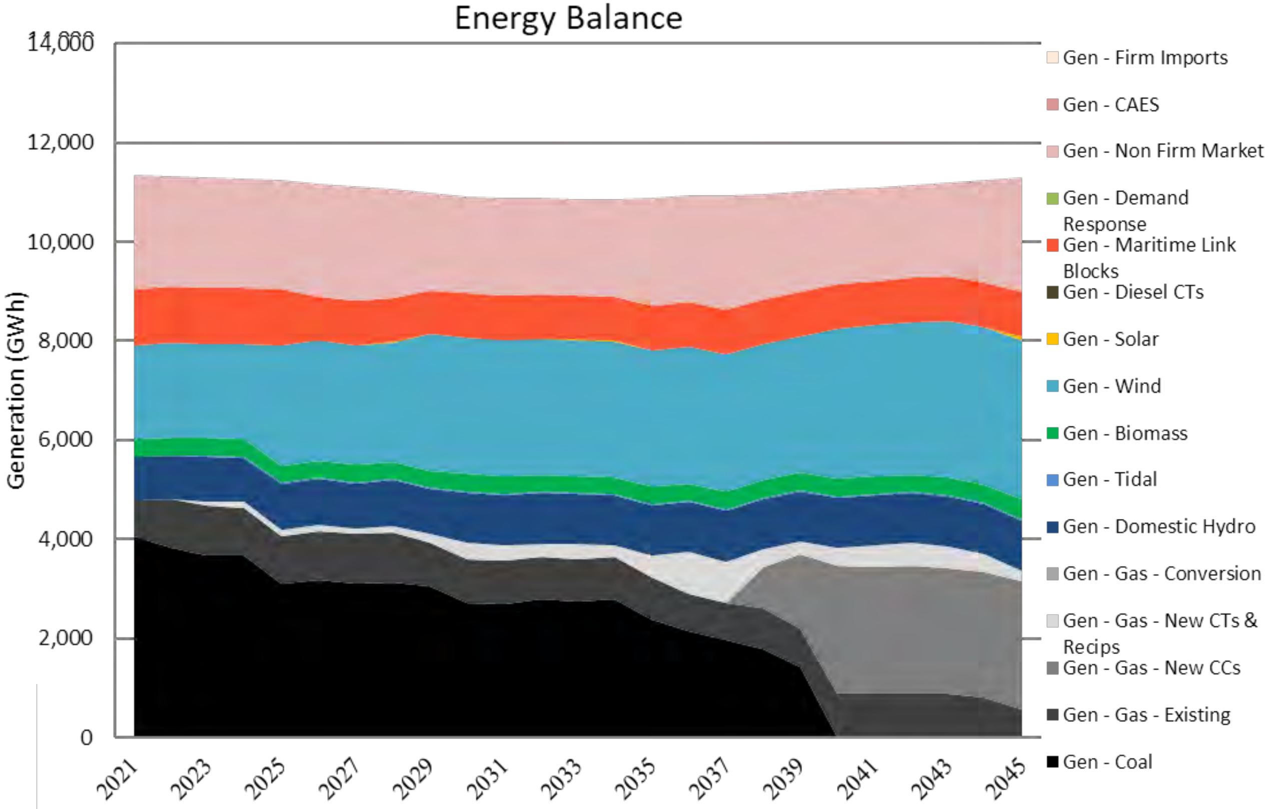
- Reliability Tie: 2024
- Regional Integration: 2026

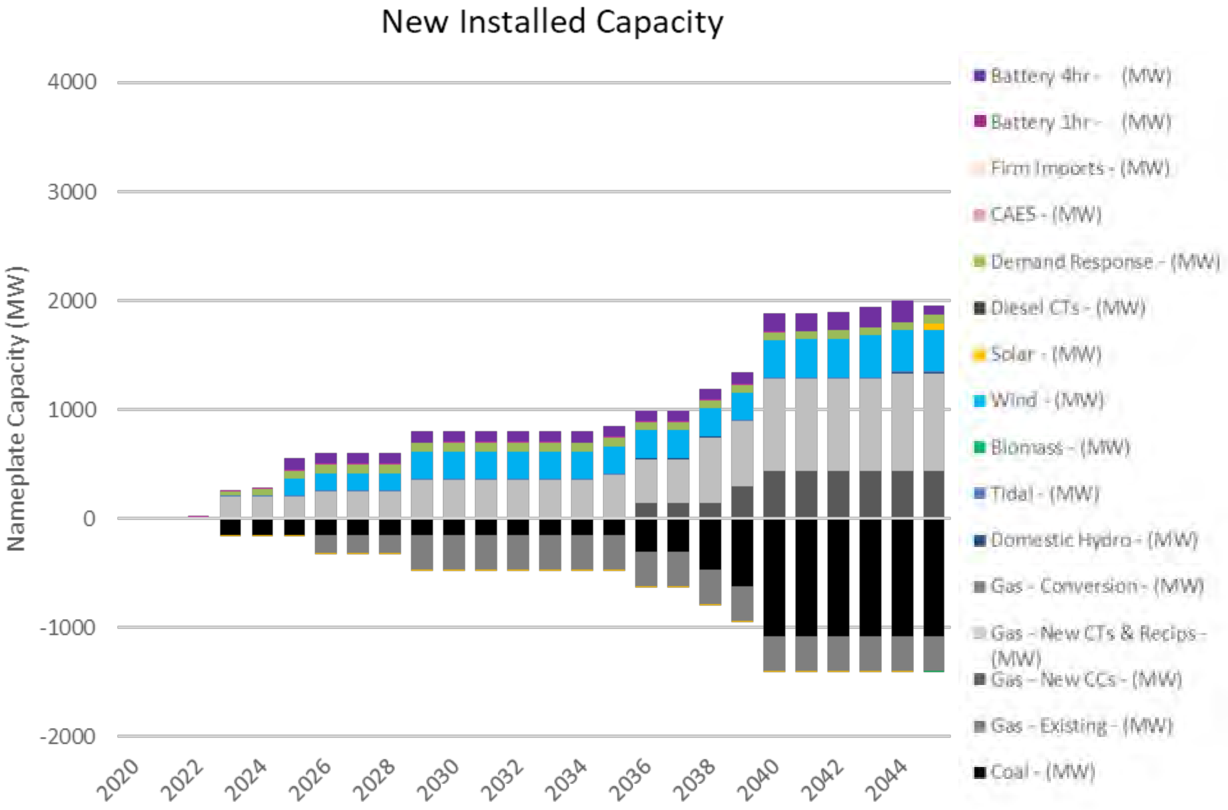
Plan Robustness & Flexibility

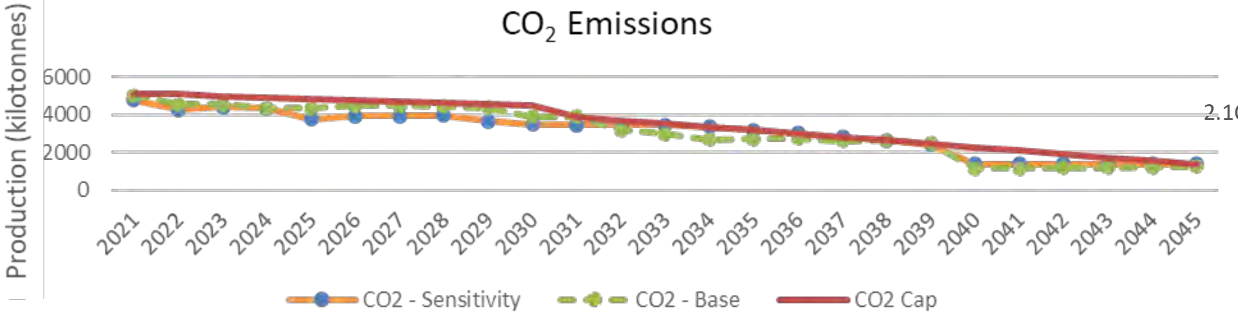
- No change relative to 2.1C

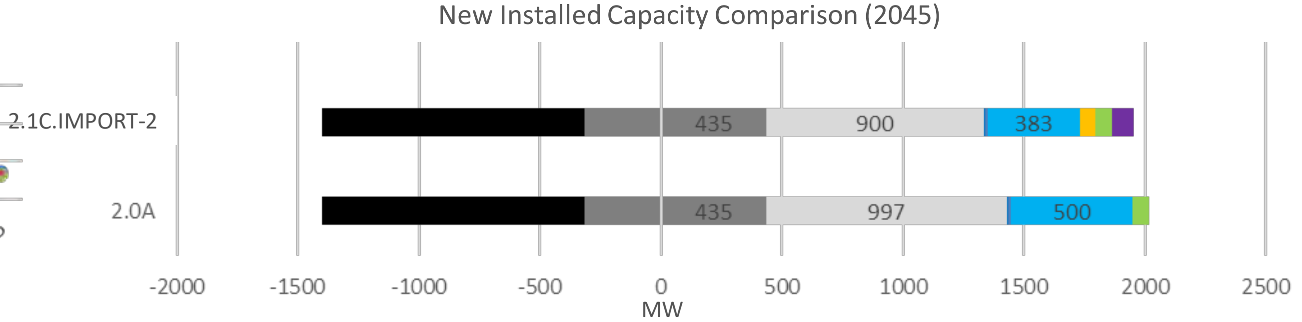
2.0A.IMPORT-2 (NO RELIABILITY TIE)

MID ELEC. / BASE DSM / NET ZERO 2050 / CURRENT LANDSCAPE









2.0A.IMPORT-2 (NO RELIABILITY TIE)

MID ELEC. / BASE DSM / NET ZERO 2050 / CURRENT LANDSCAPE

Scenario Metrics & Evaluation

	Sensitivity	Base (2.0A)
25-yr NPVRR ($MM)	$12,470	$12,193
25-yr NPVRR w/ End Effects ($MM)	$16,704	$16,347
10-yr NPVRR ($MM)	$6,906	$6,786
Average Annual Relative Rate Impact		
2021-2030 (%)	0.9%	0.8%
2021-2045 (%)	1.0%	1.0%
Total CO_2 Emissions 2021-2030 (MT)	40.6	44.5
Total CO_2 Emissions 2031-2045 (MT)	36.2	33.2
Total CO_2 Emissions 2021-2045 (MT)	76.8	77.7

General Notes
- Without the ability to build the Reliability Tie, wind is built via the local integration option (batteries + synchronous condensers), which also contribute to system inertia requirements
- Total quantity of wind built is less and batteries are added for wind integration; remainder of resource plan is similar
- Costs are higher than the base 2.0A scenario for all NPV metrics

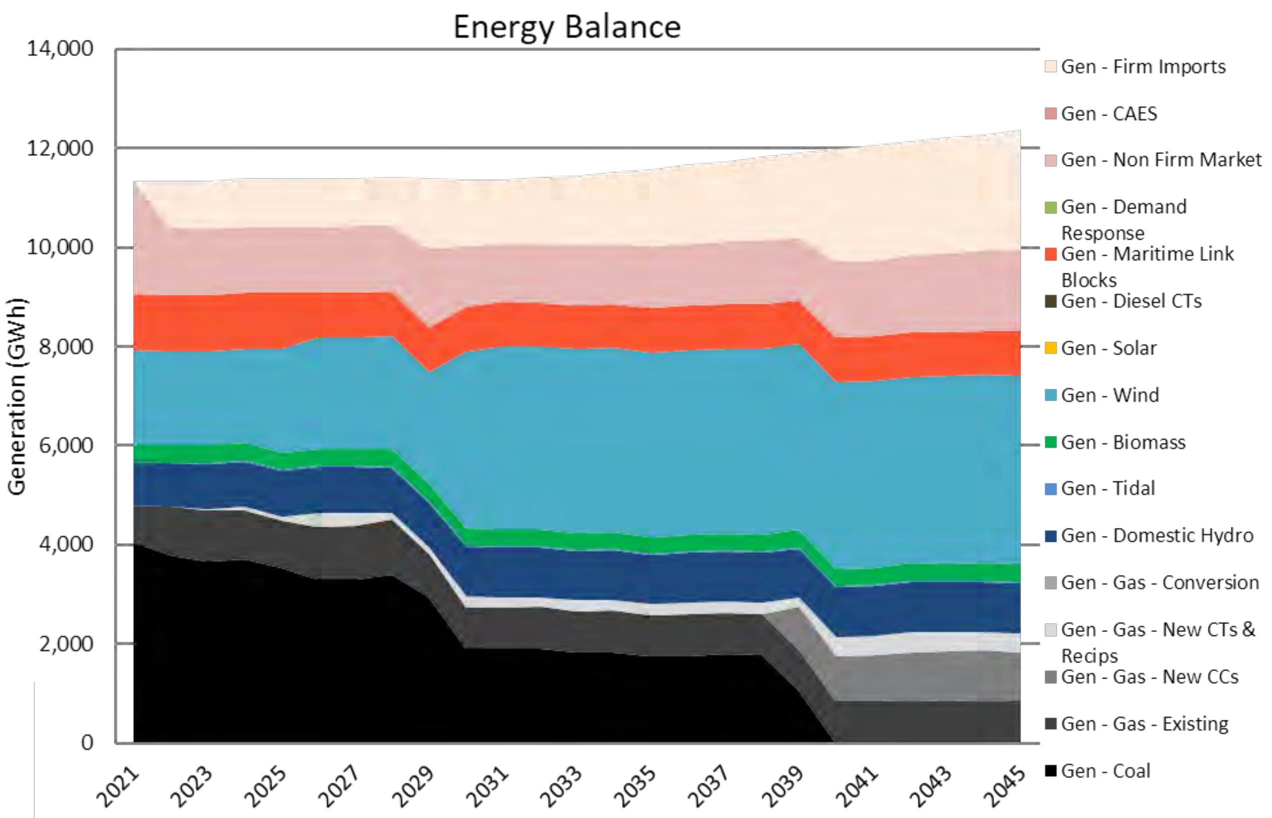
Essential Grid Services
- High inertia synchronous condensers contribute kinetic inertia in addition to online thermal generation

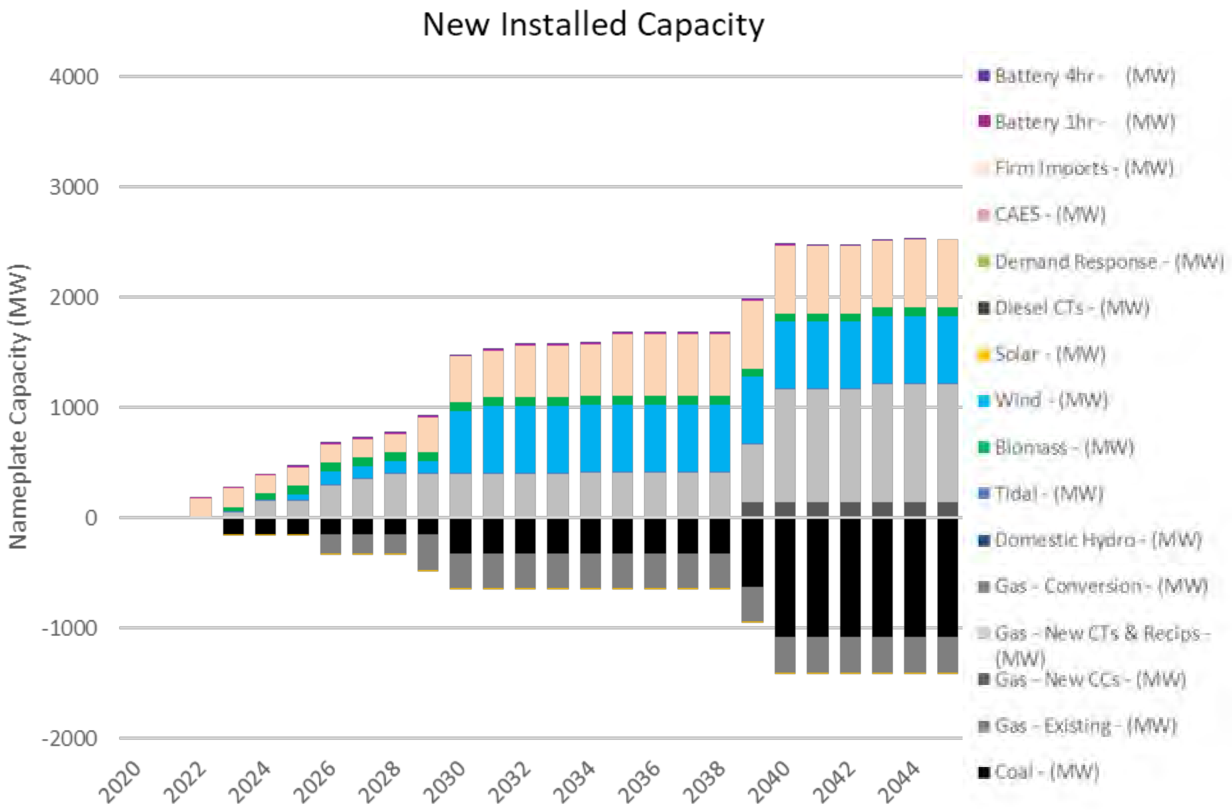
Resource Adequacy & PRM
- Reliability Tie: n/a
- Regional Integration: n/a

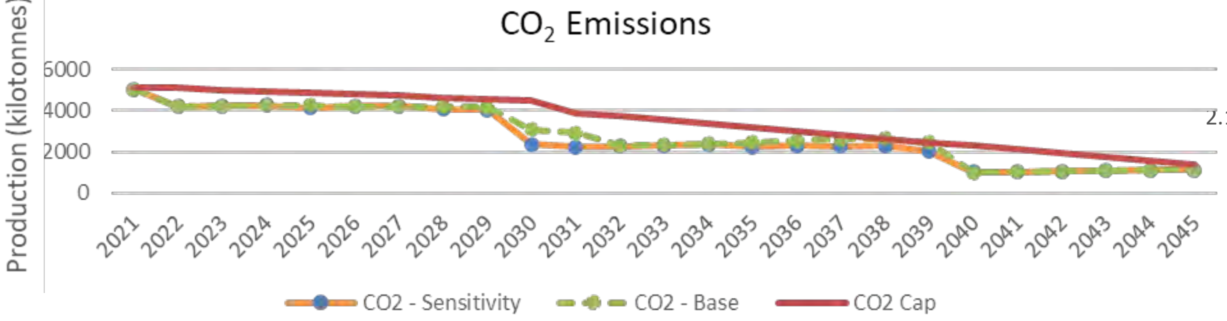
Plan Robustness & Flexibility
- No change relative to 2.0A

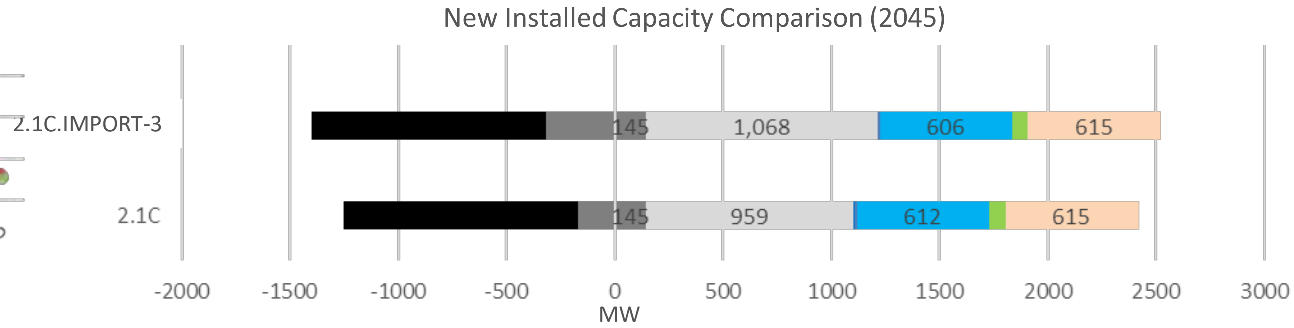
2.1C.IMPORT-3 (LIMITED RELIABILITY TIE INERTIA)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION









2.1C.IMPORT-3 (LIMITED RELIABILITY TIE INERTIA)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

	Sensitivity	Base (2.1C)
25-yr NPVRR ($MM)	$13,067	$12,983
25-yr NPVRR w/ End Effects ($MM)	$17,581	$17,506
10-yr NPVRR ($MM)	$7,066	$7,022
Average Annual Relative Rate Impact		
2021-2030 (%)	0.9%	0.8%
2021-2045 (%)	0.8%	0.8%
Total CO_2 Emissions 2021-2030 (MT)	40.8	41.8
Total CO_2 Emissions 2031-2045 (MT)	26.8	29.1
Total CO_2 Emissions 2021-2045 (MT)	67.6	70.9

General Notes

- In this scenario the Reliability Tie contributes only 50% of required system inertia once built (i.e. 1633 MW.sec); intention of scenario is to test robustness of the assumption that Reliability Tie can supply all system inertia requirements
- Reliability Tie and Regional Integration are built slightly earlier in this scenario, with some accompanying earlier retirements as well, likely because more flexible units are easier to satisfy the remaining inertia requirement with
- Generation mix is generally unchanged from 2.1C on an annual basis
- Costs are relatively close to 2.1C on all NPV metrics

Essential Grid Services

- No change from 2.1C

Resource Adequacy & PRM

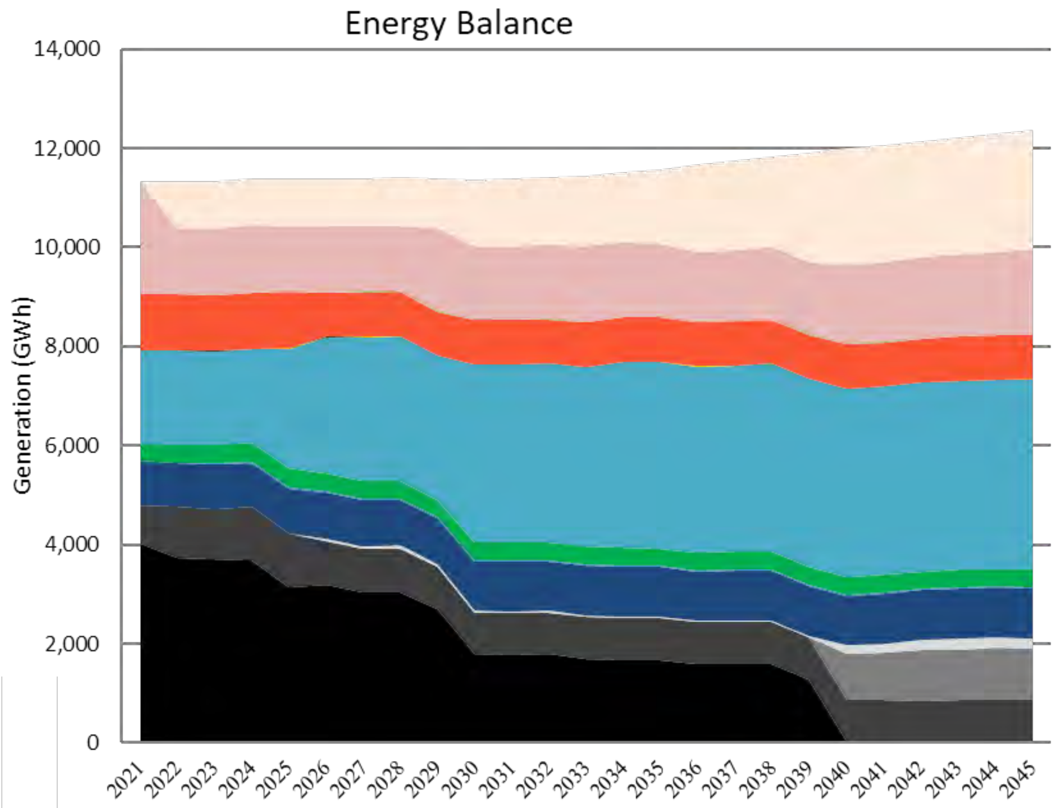
- Reliability Tie: 2028
- Regional Integration: 2029

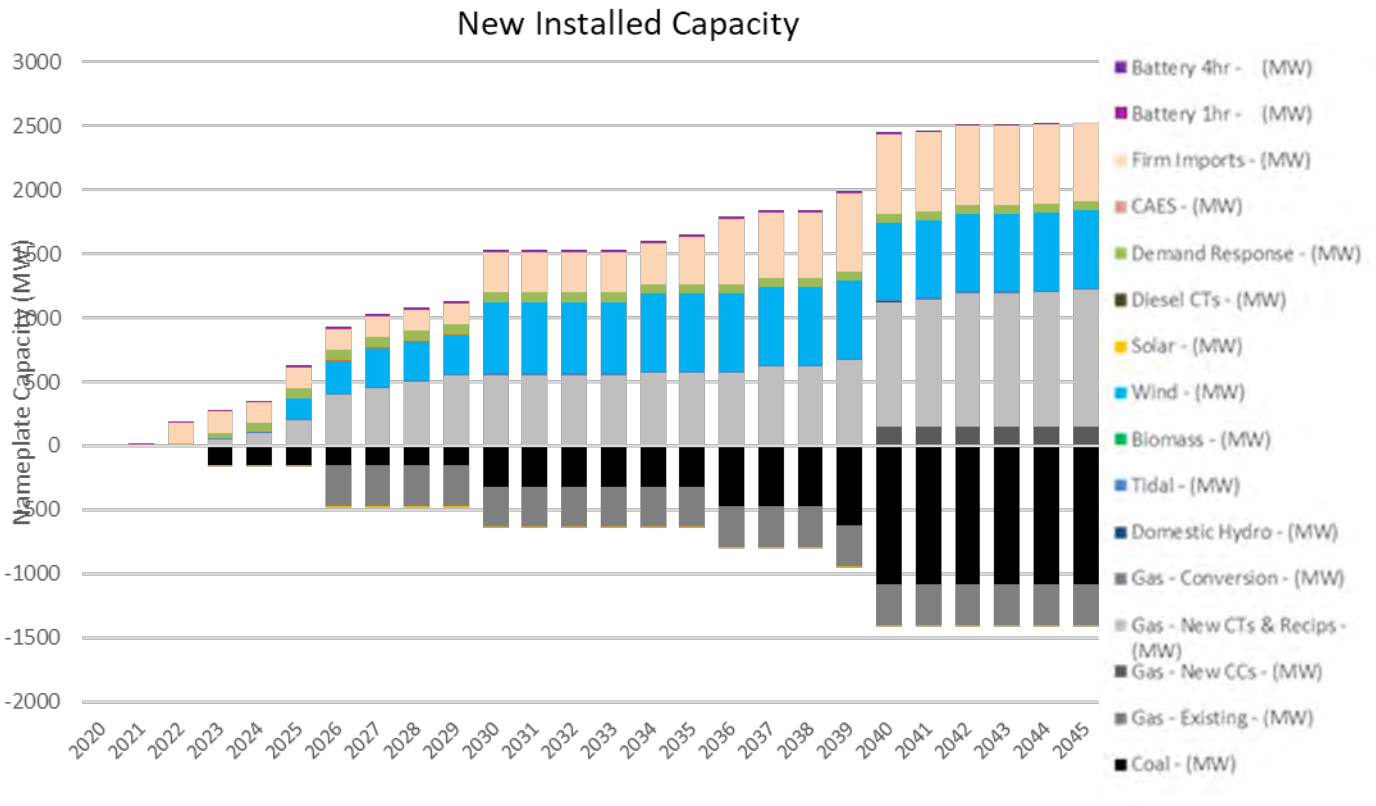
Plan Robustness & Flexibility

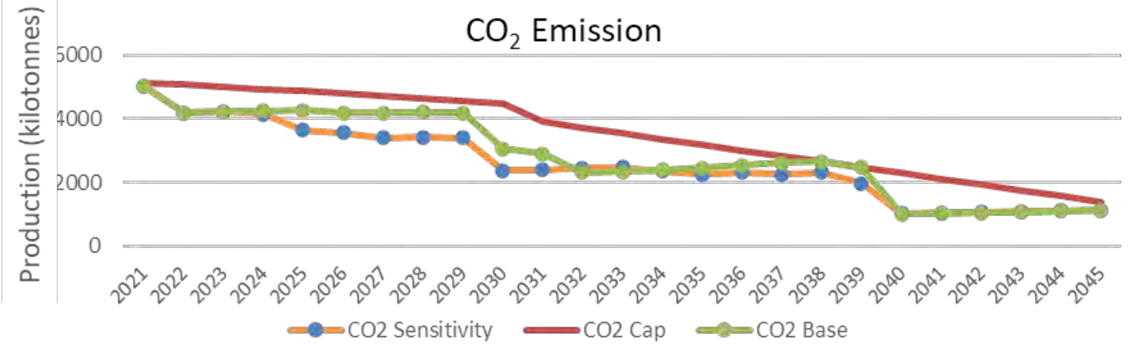
- No change from 2.1C

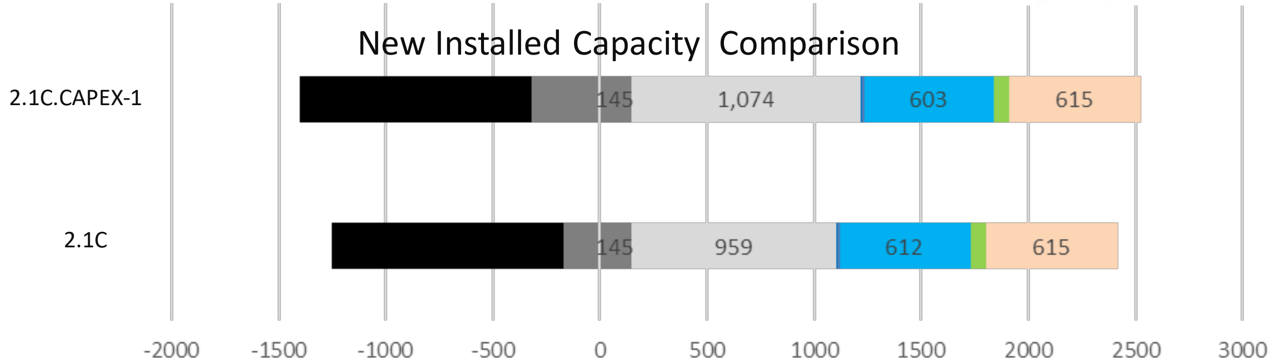
2.1C.CAPEX-1 (HIGH SUSTAINING CAPEX)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION









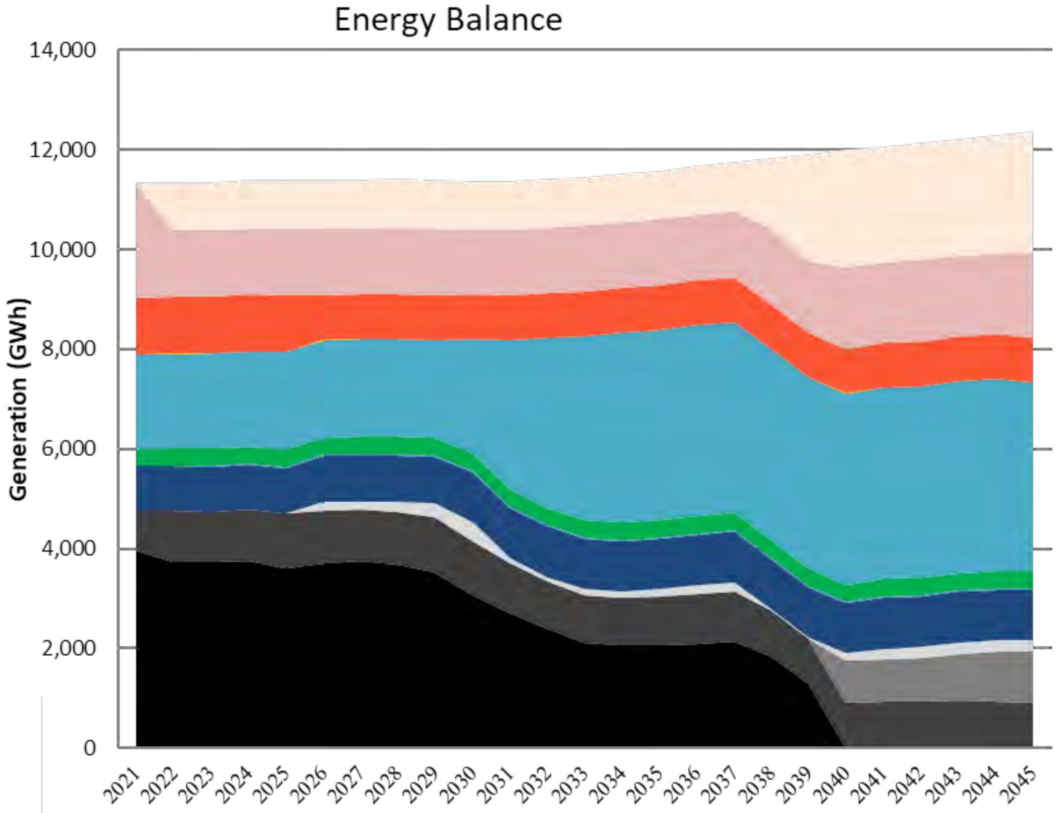
2.1C.CAPEX-1 (HIGH SUSTAINING CAPEX)

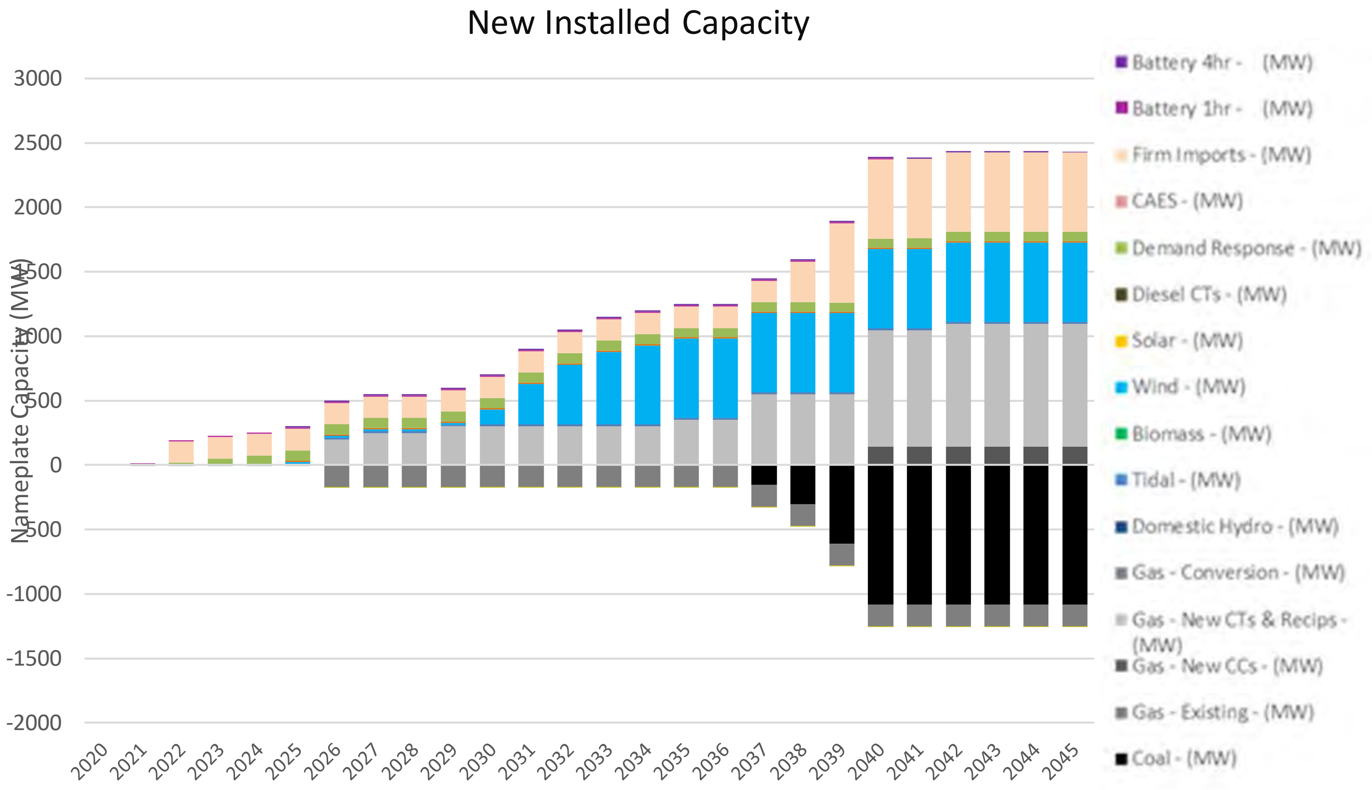
MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION

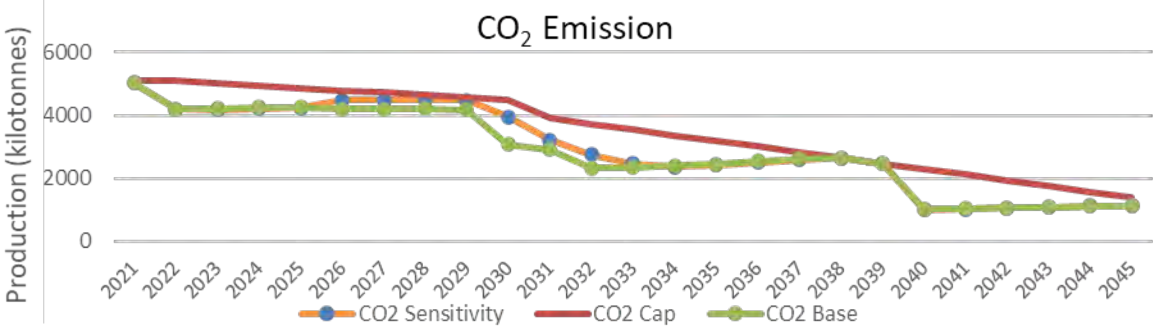
Scenario Metrics & Evaluation			
	Sensitivity	Base (2.1C)	
25-yr NPVRR ($MM)	$13,361	$12,983	General Notes • High case is modeled as a +50% increase in annual Sustaining Capital estimates for all thermal steam units (gas and coal) • Reliability Tie is built 6 years earlier and Regional Interconnection 7 years earlier vs. Base • 1 additional gas steam unit retired in 2026; capacity replaced with combustion turbines • 1 coal unit retirement advanced to 2030 from 2040; capacity replaced with firm imports via Regional Interconnection • Wind and combustion turbine builds replace capacity and energy from earlier retirements • Final resource plan is very similar other than 1 additional gas steam unit retired and replaced with combustion turbines.
25-yr NPVRR w/ End Effects ($MM)	$17,832	$17,506	
10-yr NPVRR ($MM)	$7,378	$7,022	
Average Annual Relative Rate Impact 2021-2030 (%) 2021-2045 (%)	 1.0% 0.7%	 0.8% 0.8%	Essential Grid Services • No significant change from 2.1C Resource Adequacy & PRM • Reliability Tie: 2024 • Regional Integration: 2029
Total CO_2 Emissions 2021-2030 (MT) Total CO_2 Emissions 2031-2045 (MT) Total CO_2 Emissions 2021-2045 (MT)	37.4 27.3 64.7	41.8 29.1 70.9	Plan Robustness & Flexibility • No significant change from 2.1C

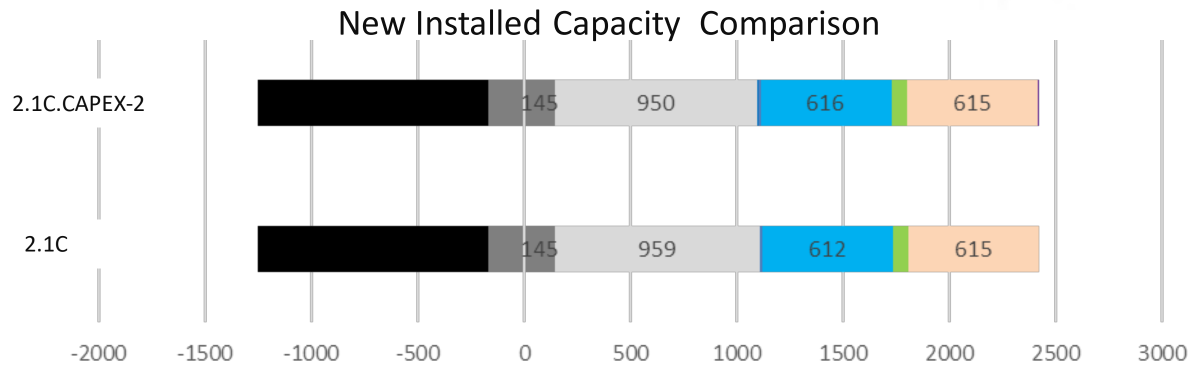
2.1C.CAPEX-2 (LOW SUSTAINING CAPEX)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION









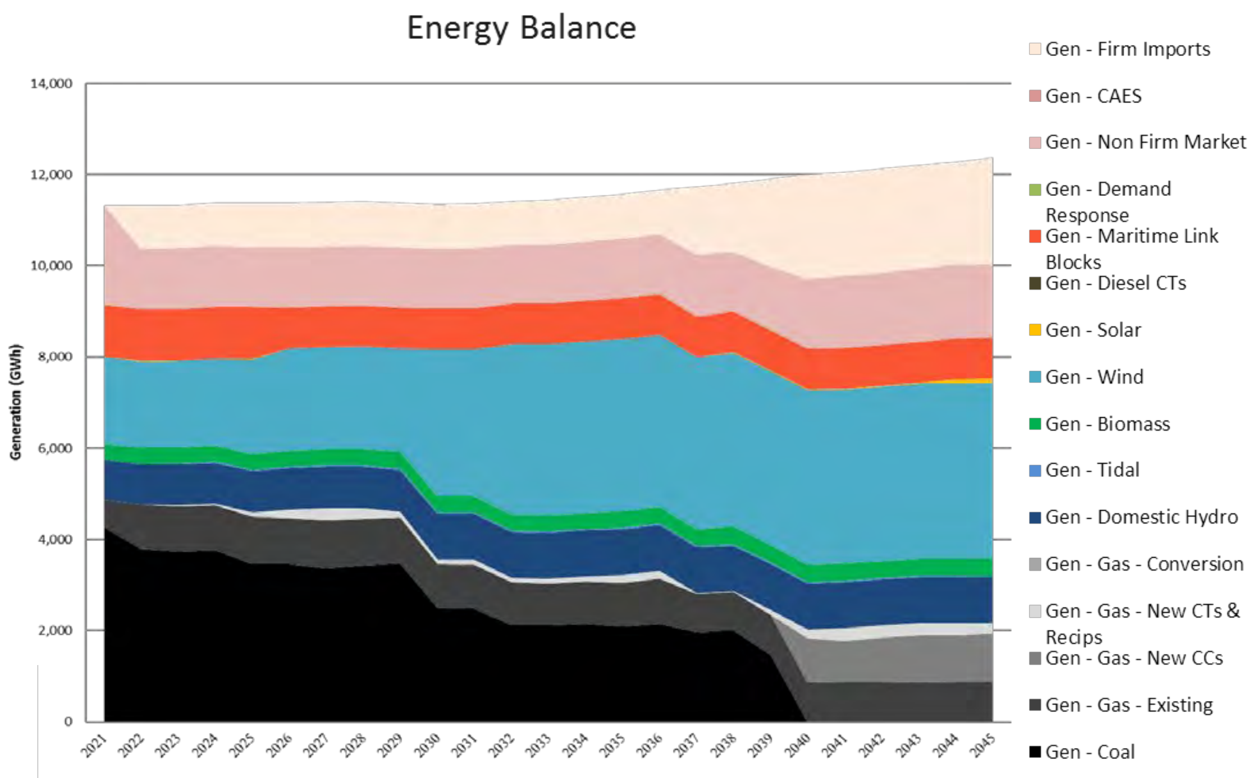
2.1C.CAPEX-2 (LOW SUSTAINING CAPEX)

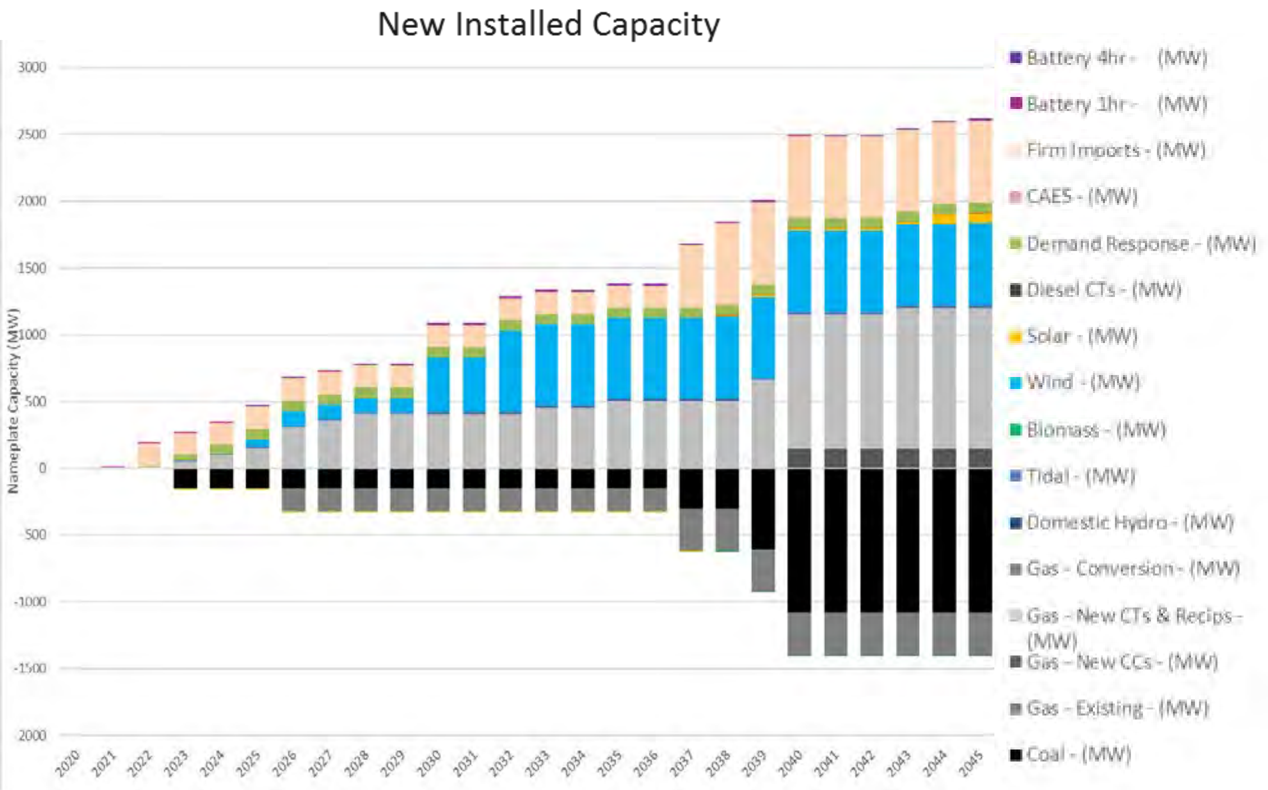
MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION

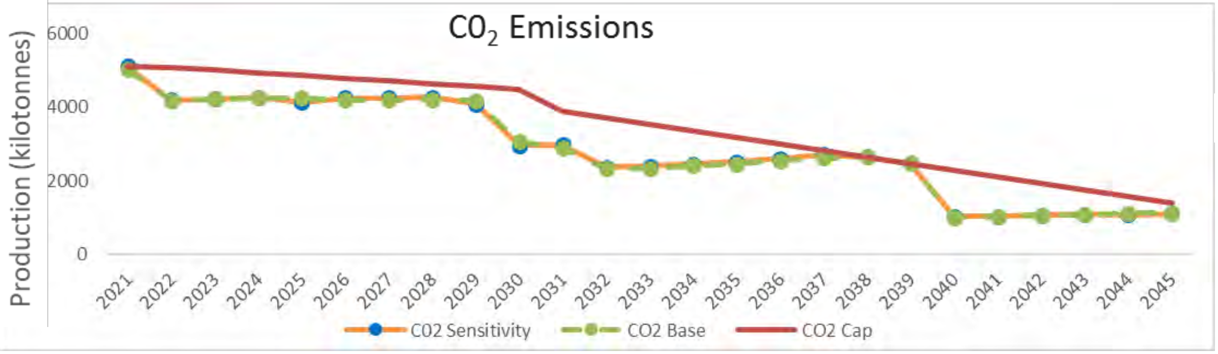
Scenario Metrics & Evaluation			
	Sensitivity	Base (2.1C)	
25-yr NPVRR ($MM)	$12,771	$12,983	General Notes • Low case is modeled as a -25% increase in annual Sustaining Capital estimates for all thermal steam units (gas and coal) • Reliability Tie is built 1 year later and Regional Interconnection 2 years later vs. Base • Gas steam retirements unchanged from Base • Early coal retirement in Base scenario is delayed until 2038 • Combustion turbine and wind builds are delayed in line with later coal unit retirement date but final resource plan is essentially unchanged from 2.1C
25-yr NPVRR w/ End Effects ($MM)	$17,304	$17,506	
10-yr NPVRR ($MM)	$6,887	$7,022	Essential Grid Services • No significant change from 2.1C
Average Annual Relative Rate Impact 2021-2030 (%) 2021-2045 (%)	 0.7% 0.8%	 0.8% 0.8%	Resource Adequacy & PRM • Reliability Tie: 2031 • Regional Integration: 2038
Total CO_2 Emissions 2021-2030 (MT) Total CO_2 Emissions 2031-2045 (MT) Total CO_2 Emissions 2021-2045 (MT)	43.8 29.8 73.6	41.8 29.1 70.9	Plan Robustness & Flexibility • No significant change from 2.1C

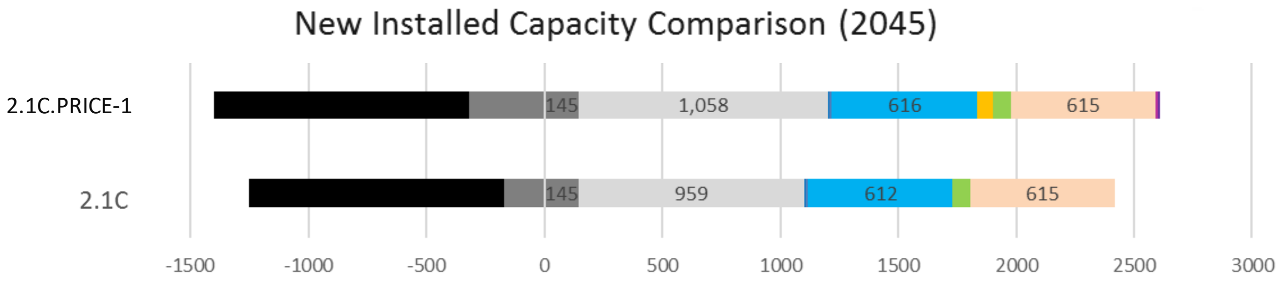
2.1C.PRICES-1 (HIGH IMPORT & GAS PRICES)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION









2.1C.PRICES-1 (HIGH IMPORT & GAS PRICES)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

	Sensitivity	Base (2.1C)
25-yr NPVRR ($MM)	$13,854	$12,983
25-yr NPVRR w/ End Effects ($MM)	$19,011	$17,506
10-yr NPVRR ($MM)	$7,349	$7,022
Average Annual Relative Rate Impact		
2021-2030 (%)	1.1%	0.8%
2021-2045 (%)	1.1%	0.8%
Total CO_2 Emissions 2021-2030 (MT)	41.8	41.8
Total CO_2 Emissions 2031-2045 (MT)	29.5	29.1
Total CO_2 Emissions 2021-2045 (MT)	71.3	70.9

General Notes

- Under this sensitivity, gas and import prices were increased to the High sensitivity case developed as part of the IRP Assumptions set
- Relatively little change is seen in the resource plan relative to the base scenario
- A small amount of solar is added late in the horizon as an energy resource, not see in the base case run
- One additional gas steam turbine retirement relative to the base case (2037), replaced with combustion turbine capacity
- Small increment to battery installed capacity late in the planning horizon
- Regional Integration resource strategy is selected one year later, indicating this strategy is robust to higher import energy prices

Essential Grid Services

- No significant change from 2.1C

Resource Adequacy & PRM

- Reliability Tie: 2029
- Regional Integration: 2037

Plan Robustness & Flexibility

- No significant change from 2.1C

Nova Scotia
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Release Notes - 2020-09-02

- The data tables in this file contain the Initial Portfolio Study results from PLEXOS LT and Plexos MT/ST for NS Power's IRP Modeling Results release dated 2020-09-02 in tabular format for:
    - Installed Capacity Changes
    - Annual Energy Balance
    - Annual Emissions

Release Notes - 2020-09-17

- Added data tables for 2.1C.Import-3 (Limited Reliability Tie Inertia) which were unintentionally omitted from the previous release

Release Notes - 2020-10-30

- Added data tables for scenarios 2.1C.CAPEX-1 (High Sustaining CapEx), 2.1C.CapEx-2 (Low Sustaining CapEx), 2.1C.PRICES-1 (high Import & Gas Prices)
- Fixed data entry error - Annual Energy Balance - 2.2C - Firm Imports (mistakenly input as 'Non Firm Imports'

Final Portfolio Study

1.0A

Emission \ Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CO_2 (k tonnes)	5,023	4,557	4,314	4,265	4,169	4,386	4,337	4,296	4,231	3,892	3,873	3,896	3,842	3,868	2,455	2,500	2,531	2,612	2,505	1,116	1,122	1,137	1,157	1,177	1,196
Hg (kg)	45	45	45	45	45	45	45	45	45	30	30	30	30	30	25	25	25	25	25	0	0	0	0	0	0
NO_x (tonnes)	11	11	11	11	10	10	10	10	10	8	8	8	8	8	6	6	6	5	4	2	2	2	2	2	2
SO_2 (tonnes)	37	37	34	34	28	26	26	26	25	20	20	20	20	20	14	14	14	14	15	0	0	0	0	0	0

1.0C

Emission \ Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CO_2 (k tonnes)	5,023	4,162	4,155	4,130	4,100	4,268	4,212	4,166	3,926	2,221	2,195	2,031	2,015	2,027	2,033	2,069	2,098	2,119	1,911	667	821	834	858	881	904
Hg (kg)	45	45	45	45	45	45	45	45	45	30	30	30	30	30	25	25	25	25	25	0	0	0	0	0	0
NO_x (tonnes)	11	10	9	9	8	8	8	8	8	5	5	4	4	4	5	5	5	5	4	1	1	1	1	1	1
SO_2 (tonnes)	37	35	33	33	28	26	26	26	25	16	16	14	14	14	14	14	15	15	15	0	0	0	0	0	0

2.0A

Emission \ Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CO_2 (k tonnes)	5,023	4,566	4,539	4,343	4,332	4,483	4,493	4,457	4,386	3,910	3,900	3,211	3,004	2,699	2,717	2,761	2,630	2,650	2,470	1,149	1,160	1,179	1,200	1,217	1,246
Hg (kg)	45	45	45	45	45	45	45	45	45	30	30	30	30	30	25	25	25	25	25	0	0	0	0	0	0
NO_x (tonnes)	11	11	11	11	10	10	10	10	10	8	8	8	7	6	6	6	6	5	4	2	2	2	2	2	2
SO_2 (tonnes)	37	37	34	34	28	26	26	26	26	20	20	18	17	15	15	15	15	14	15	0	0	0	0	0	0

2.0C

Emission \ Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CO_2 (k tonnes)	5,023	4,162	4,148	4,121	4,088	4,277	4,221	4,176	4,098	2,383	2,350	2,194	2,175	2,188	2,195	2,069	2,096	2,117	1,911	667	829	839	851	888	903
Hg (kg)	45	45	45	45	45	45	45	45	45	30	30	30	30	30	25	25	25	25	25	0	0	0	0	0	0
NO_x (tonnes)	11	10	9	9	8	8	8	8	8	5	5	5	5	5	5	5	5	5	4	1	1	1	1	1	1
SO_2 (tonnes)	37	35	33	33	28	26	26	26	26	18	17	16	15	15	15	14	14	15	15	0	0	0	0	0	0

2.1A

Emission \ Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CO_2 (k tonnes)	5,031	4,610	4,665	4,683	4,563	4,359	4,344	4,379	4,390	2,530	2,542	2,586	2,598	2,673	2,228	2,304	2,356	2,383	2,428	1,347	1,365	1,398	1,383	1,362	1,390
Hg (kg)	45	45	45	45	45	45	45	45	45	30	30	30	30	30	25	25	25	25	25	0	0	0	0	0	0
NO_x (tonnes)	11	11	10	10	9	8	8	8	8	6	6	6	6	6	5	5	5	5	6	2	2	2	2	2	2
SO_2 (tonnes)	37	38	34	34	28	26	26	26	26	19	20	20	20	20	15	15	15	15	15	0	0	0	0	0	0

2.1B

Emission \ Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CO_2 (k tonnes)	4,666	4,002	3,940	3,918	3,784	3,898	3,789	3,655	3,437	2,789	2,756	2,748	2,725	2,737	2,121	2,011	1,798	1,791	1,621	587	590	580	591	591	594
Hg (kg)	45	45	45	45	45	45	45	45	45	30	30	30	30	30	25	25	25	25	25	0	0	0	0	0	0
NO_x (tonnes)	10	10	10	10	9	9	9	9	8	7	7	7	7	7	6	5	4	4	3	0	0	0	0	0	0
SO_2 (tonnes)	31	31	30	30	24	24	23	22	22	20	20	20	20	20	14	13	15	15	15	0	0	0	0	0	0

2.1C

Emission \ Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CO_2 (k tonnes)	5,031	4,189	4,223	4,258	4,260	4,194	4,193	4,207	4,181	3,067	2,910	2,317	2,342	2,407	2,451	2,545	2,620	2,650	2,470	1,006	1,028	1,054	1,080	1,113	1,125
Hg (kg)	45	45	45	45	45	45	45	45	45	30	30	30	30	30	25	25	25	25	25	0	0	0	0	0	0
NO_x (tonnes)	11	10	9	9	8	8	8	8	8	6	6	4	5	5	5	5	5	5	4	1	1	1	1	1	1
SO_2 (tonnes)	37	35	34	34	28	26	26	26	26	18	17	12	12	13	13	14	14	15	15	0	0	0	0	0	0

2.2A

Emission \ Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CO_2 (k tonnes)	5,039	4,667	4,667	4,707	4,444	4,341	4,414	4,429	4,440	3,290	2,838	2,926	2,988	3,145	2,801	2,886	2,627	2,650	2,470	1,465	1,434	1,442	1,426	1,400	1,390
Hg (kg)	45	45	45	45	45	45	45	45	45	30	30	30	30	30	25	25	25	25	25	0	0	0	0	0	0
NO_x (tonnes)	11	12	11	11	10	9	10	10	10	8	7	7	7	7	6	6	5	5	5	3	3	3	3	2	2
SO_2 (tonnes)	37	38	34	34	28	26	26	26	26	20	17	17	18	19	15	15	15	15	12	0	0	0	0	0	0

2.2C

Emission Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CO_2 (k tonnes)	5,039	4,246	4,213	4,263	4,256	4,503	4,378	4,416	4,426	3,992	2,680	2,600	2,215	2,287	2,341	2,375	2,297	2,377	2,455	1,138	1,170	1,214	1,253	1,284	1,327
Hg (kg)	45	45	45	45	45	45	45	45	45	30	30	30	30	30	25	25	25	25	25	0	0	0	0	0	0
NO_x (tonnes)	11	11	11	11	10	10	9	10	10	8	7	7	6	6	6	6	5	5	5	2	2	2	2	2	2
SO_2 (tonnes)	37	36	34	34	28	26	26	26	26	20	20	19	15	16	15	15	15	15	15	0	0	0	0	0	0

3.1B

Emission Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CO_2 (k tonnes)	4,990	4,099	4,108	4,088	3,980	4,100	3,992	3,857	2,044	587	585	589	583	587	587	591	598	597	600	604	602	605	612	609	500
Hg (kg)	45	45	45	45	45	45	45	45	24	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NO_x (tonnes)	11	10	9	9	8	8	8	8	4	0	0	1	0	0	0	0	1	0	0	0	0	0	1	0	0
SO_2 (tonnes)	36	34	32	33	27	26	26	26	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

3.1C

Emission Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CO_2 (k tonnes)	5,031	4,189	4,223	4,256	3,618	3,851	3,539	3,581	1,962	568	569	577	580	586	593	607	619	629	646	660	667	670	685	610	500
Hg (kg)	45	45	45	45	45	45	45	45	23	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NO_x (tonnes)	11	10	9	9	7	8	7	7	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SO_2 (tonnes)	37	35	34	34	23	25	23	24	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

3.2B

Emission Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CO_2 (k tonnes)	4,990	4,153	4,093	4,076	4,023	3,981	3,063	2,793	1,989	619	619	634	630	667	646	659	732	744	760	773	775	764	710	610	500
Hg (kg)	45	45	45	45	45	45	45	40	23	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NO_x (tonnes)	11	10	10	10	9	9	7	7	4	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0
SO_2 (tonnes)	36	35	34	34	27	26	18	16	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

3.2C

Emission Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CO_2 (k tonnes)	5,039	4,246	4,213	4,250	3,692	3,975	3,822	3,860	2,520	605	610	611	611	627	640	680	752	798	809	780	779	804	710	610	500
Hg (kg)	45	45	45	45	45	45	45	45	33	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NO_x (tonnes)	11	11	11	11	9	9	9	9	5	1	0	1	0	1	1	1	1	1	1	1	1	1	1	0	0
SO_2 (tonnes)	37	36	34	34	25	25	23	23	12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Sensitivities

2.0A.DSM-1 (Mid DSM)

Emission \ Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CO_2 (k tonnes)	5,023	4,583	4,368	4,296	4,230	4,349	4,308	3,699	4,005	3,323	3,110	2,747	2,548	2,241	2,246	2,287	2,323	2,348	2,330	1,020	1,020	1,046	1,074	1,094	1,123
Hg (kg)	45	45	45	45	45	45	45	45	45	30	30	30	30	30	25	25	25	25	25	0	0	0	0	0	0
NO_x (tonnes)	11	11	9	9	8	8	8	8	8	7	6	5	5	4	4	4	4	5	4	2	2	2	2	2	2
SO_2 (tonnes)	37	38	34	34	28	26	26	24	26	19	18	15	14	11	11	11	12	12	15	0	0	0	0	0	0

2.1C.DSM-2 (Mid DSM)

Emission \ Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CO_2 (k tonnes)	5,031	4,189	4,181	4,177	4,141	4,181	3,980	3,964	3,941	2,093	2,093	2,121	2,143	2,195	2,085	2,175	2,229	2,262	2,036	908	929	955	989	1,025	1,064
Hg (kg)	45	45	45	45	45	45	45	45	45	30	30	30	30	30	25	25	25	25	25	0	0	0	0	0	0
NO_x (tonnes)	11	10	9	9	8	8	8	8	8	5	5	5	5	5	5	5	5	5	5	1	1	1	1	1	1
SO_2 (tonnes)	37	35	33	33	28	26	26	26	26	15	15	15	15	16	15	15	15	15	15	0	0	0	0	0	0

2.2C.DSM-3 (Mid DSM)

Emission \ Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CO_2 (k tonnes)	5,039	4,246	4,276	4,384	2,915	3,031	2,585	2,654	2,687	2,577	2,630	2,717	2,468	2,579	2,291	2,362	1,985	2,004	2,303	1,210	1,244	1,289	1,338	1,372	1,390
Hg (kg)	45	45	45	45	45	45	44	45	45	30	30	30	30	30	25	25	25	25	25	0	0	0	0	0	0
NO_x (tonnes)	11	11	11	11	8	8	7	7	7	7	7	7	6	7	6	6	4	4	5	2	2	2	2	2	2
SO_2 (tonnes)	37	36	34	34	22	23	19	19	20	19	19	20	18	19	15	15	15	15	15	0	0	0	0	0	0

2.0C.DSM-4 (Low DSM)

Emission \ Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CO_2 (k tonnes)	5,022	4,161	4,194	4,212	4,040	4,262	4,090	4,077	4,036	3,830	3,091	2,788	2,791	2,495	2,527	2,585	2,636	2,650	2,470	996	996	1,010	1,028	1,051	1,068
Hg (kg)	45	45	45	45	45	45	45	45	45	30	30	30	30	30	25	25	25	25	25	0	0	0	0	0	0
NO_x (tonnes)	11	10	9	9	8	8	8	8	8	7	6	6	6	5	5	5	5	5	4	1	1	1	1	1	1
SO_2 (tonnes)	37	35	33	34	27	26	26	26	26	20	18	16	16	13	13	14	14	15	15	0	0	0	0	0	0

2.0C.DSM-5 (Mid DSM)

Emission \ Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CO2 (k tonnes)	4,828	4,084	4,039	3,967	3,868	3,856	3,778	3,702	3,584	2,256	2,214	2,200	2,175	2,028	1,880	1,751	1,778	1,804	1,823	620	623	631	641	648	654
Hg (kg)	45	45	45	45	45	45	45	45	45	30	30	30	30	30	25	25	25	25	25	0	0	0	0	0	0
NO_x (tonnes)	10	10	9	9	8	8	7	7	7	5	5	5	5	4	4	4	4	4	4	1	1	1	1	1	0
SO_2 (tonnes)	33	32	30	30	26	25	23	22	23	16	16	15	15	14	12	11	11	11	15	0	0	0	0	0	0

2.0C.DSM-6 (Max DSM)

Emission \ Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CO2 (k tonnes)	4,771	4,076	3,980	3,870	3,712	3,822	3,722	3,625	3,504	3,347	3,288	2,886	2,869	2,283	1,826	1,707	1,740	1,767	1,645	592	593	604	614	621	620
Hg (kg)	45	45	45	45	45	45	45	45	45	30	30	30	30	30	25	25	25	25	25	0	0	0	0	0	0
NO_x (tonnes)	10	10	9	8	8	8	7	7	7	6	6	6	6	5	4	4	4	4	4	1	1	1	1	1	0
SO_2 (tonnes)	33	31	29	27	24	24	22	22	22	19	20	20	20	16	12	10	11	11	12	0	0	0	0	0	0

3.1C.DSM-7 (Mid DSM)

Emission \ Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CO2 (k tonnes)	5,031	4,189	4,181	4,062	3,662	3,854	3,831	3,812	1,737	572	556	558	562	567	572	581	592	616	624	637	637	661	667	610	500
Hg (kg)	45	45	45	45	45	45	45	45	21	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NO_x (tonnes)	11	10	9	9	7	8	8	7	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SO_2 (tonnes)	37	35	33	32	24	26	24	24	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

2.1C.WIND-1 (Low Wind Cost)

Emission / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CO_2 (k tonnes)	5,031	4,189	3,919	3,945	2,042	2,280	2,302	2,353	2,298	2,131	2,146	2,186	2,206	2,254	2,235	2,271	2,257	2,286	1,986	980	1,003	1,028	1,054	1,095	1,114
Hg (kg)	45	45	45	45	35	40	35	32	33	30	30	30	30	30	25	25	25	25	25	0	0	0	0	0	0
NO_x (tonnes)	11	10	8	8	5	5	5	5	5	5	5	5	5	5	5	5	5	5	4	1	1	1	1	1	1
SO_2 (tonnes)	37	35	31	32	14	17	14	12	13	16	16	16	16	17	15	15	15	15	15	0	0	0	0	0	0

2.1C.WIND-2 (Low Wind & Battery Cos

Emission / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CO_2 (k tonnes)	5,031	4,189	3,077	2,129	1,902	2,137	2,118	2,130	2,106	1,985	2,001	2,040	2,068	2,127	2,176	2,221	2,266	2,250	1,751	922	947	975	1,000	1,045	1,071
Hg (kg)	45	45	45	36	31	37	36	38	36	30	30	30	30	30	25	25	25	25	25	0	0	0	0	0	0
NO_x (tonnes)	11	10	7	5	4	5	5	5	5	4	4	5	5	5	5	5	5	5	3	1	1	1	1	1	1
SO_2 (tonnes)	37	35	23	14	12	15	15	15	15	14	14	14	15	15	15	15	15	15	15	0	0	0	0	0	0

2.1C.WIND-3 (Low Inertia Constraint)

Emission / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CO_2 (k tonnes)	4,623	4,089	4,107	3,971	3,970	4,056	4,058	4,077	4,047	3,850	3,276	2,988	2,851	2,433	2,481	2,572	2,667	2,650	2,470	1,028	1,043	1,079	1,094	1,110	1,119
Hg (kg)	45	45	45	45	45	45	45	45	45	30	30	30	30	30	25	25	25	25	25	0	0	0	0	0	0
NO_x (tonnes)	10	10	9	9	8	9	8	8	8	7	7	6	6	5	5	5	5	5	4	1	1	1	1	1	1
SO_2 (tonnes)	32	31	30	29	27	26	26	26	26	20	20	18	17	13	13	14	15	15	15	0	0	0	0	0	0

2.1C.WIND-4 (No Inertia / No Integrati

Emission / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CO_2 (k tonnes)	4,593	4,089	3,939	3,636	3,121	3,329	2,514	2,548	2,517	2,378	2,087	2,126	1,995	2,050	1,713	1,748	1,731	1,745	1,611	567	559	566	542	538	545
Hg (kg)	45	45	45	45	45	45	45	45	45	30	30	30	30	30	25	25	25	25	25	0	0	0	0	0	0
NO_x (tonnes)	11	11	9	8	7	8	6	6	6	5	5	5	4	5	4	4	4	4	3	0	0	0	0	0	0
SO_2 (tonnes)	34	31	29	27	23	26	19	20	19	18	15	15	14	15	11	11	15	15	15	0	0	0	0	0	0

2.1C.Mersey

Emission / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CO_2 (k tonnes)	5,006	4,153	4,176	4,293	4,436	4,622	4,518	4,532	4,512	2,452	2,465	2,510	2,520	2,571	2,327	2,380	2,307	2,378	2,262	1,107	1,121	1,133	1,144	1,154	1,170
Hg (kg)	45	45	45	45	45	45	45	45	45	30	30	30	30	30	25	25	25	25	25	0	0	0	0	0	0
NO_x (tonnes)	11	10	11	11	10	10	10	10	10	6	6	6	6	6	5	5	5	5	5	1	1	1	1	1	1
SO_2 (tonnes)	36	35	34	34	28	26	26	26	26	19	19	19	19	19	15	15	15	15	15	0	0	0	0	0	0

2.1C.Import-1 (Limited Non-Firm)

Emission / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CO_2 (k tonnes)	5,120	4,867	4,945	4,940	3,921	4,093	4,134	4,213	4,196	3,058	3,077	3,130	3,152	3,213	3,180	3,010	2,830	2,650	2,470	1,381	1,394	1,400	1,413	1,429	1,390
Hg (kg)	45	45	45	45	45	45	45	45	45	30	30	30	30	30	25	25	25	25	25	0	0	0	0	0	0
NO_x (tonnes)	13	12	10	10	8	8	8	9	9	6	6	6	6	7	6	6	5	5	4	2	2	2	2	2	2
SO_2 (tonnes)	42	39	34	34	25	26	26	26	26	17	17	18	18	18	15	15	15	15	15	0	0	0	0	0	0

2.0A.Import-2 (No Reliability Tie)

Emission / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CO_2 (k tonnes)	4,786	4,297	4,409	4,351	3,774	3,947	3,947	3,982	3,653	3,499	3,469	3,469	3,453	3,360	3,180	3,010	2,830	2,650	2,401	1,397	1,392	1,402	1,380	1,398	1,390
Hg (kg)	45	45	45	45	45	45	45	45	45	30	30	30	30	30	25	25	25	25	25	0	0	0	0	0	0
NO_x (tonnes)	10	11	10	9	8	8	8	8	7	7	7	7	7	7	5	6	6	6	5	2	2	2	2	2	2
SO_2 (tonnes)	33	33	34	33	24	26	26	25	22	20	20	20	20	20	15	15	15	15	15	0	0	0	0	0	0

2.1C.Import-3 (Limited Reliability Tie I

Emission / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CO_2 (k tonnes)	5,031	4,189	4,223	4,256	4,126	4,217	4,216	4,070	4,055	2,377	2,237	2,281	2,295	2,353	2,253	2,313	2,268	2,313	2,025	1,026	1,038	1,068	1,091	1,114	1,127
Hg (kg)	45	45	45	45	45	45	45	45	45	30	30	30	30	30	25	25	25	25	25	0	0	0	0	0	0
NO_x (tonnes)	11	10	9	9	8	8	8	8	8	5	5	5	5	5	5	5	5	5	4	1	1	1	1	1	1
SO_2 (tonnes)	37	35	34	34	28	26	26	26	26	18	17	17	17	18	15	15	15	15	15	0	0	0	0	0	0

2.1C.CAPEX-1 (High Sustaining CapEx)																									
Emission / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CO2 (k tonnes)	5,031	4,189	4,223	4,142	3,642	3,570	3,406	3,433	3,395	2,383	2,395	2,449	2,469	2,364	2,261	2,320	2,263	2,317	1,982	1,033	1,047	1,071	1,092	1,117	1,131
Hg (kg)	45	45	45	45	45	45	45	45	45	30	30	30	30	30	25	25	25	25	25	0	0	0	0	0	0
NOx (tonnes)	11	10	9	9	8	7	7	7	7	5	5	6	6	5	5	5	5	5	4	1	1	1	1	1	1
SO2 (tonnes)	37	35	34	31	24	24	21	21	22	18	18	19	19	18	15	15	15	15	15	0	0	0	0	0	0

2.1C.CAPEX-2 (Low Sustaining CapEx)																									
Emission / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CO2 (k tonnes)	5,031	4,189	4,181	4,222	4,235	4,488	4,487	4,499	4,476	3,956	3,219	2,757	2,464	2,363	2,413	2,502	2,581	2,650	2,470	1,002	1,023	1,049	1,074	1,110	1,121
Hg (kg)	45	45	45	45	45	45	45	45	45	30	30	30	30	30	25	25	25	25	25	0	0	0	0	0	0
NOx (tonnes)	11	10	11	11	10	10	10	10	10	8	7	7	6	6	6	6	6	5	5	1	1	1	1	1	1
SO2 (tonnes)	37	35	34	34	28	26	26	26	26	20	19	16	14	13	13	14	14	15	15	0	0	0	0	0	0

2.1C.PRICES-1 (High Import & Gas Pric																									
Emission / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CO2 (k tonnes)	5,120	4,196	4,231	4,266	4,145	4,265	4,264	4,280	4,091	2,969	2,979	2,370	2,398	2,455	2,518	2,611	2,709	2,650	2,470	1,022	1,032	1,054	1,082	1,080	1,099
Hg (kg)	45	45	45	45	45	45	45	45	45	30	30	30	30	30	25	25	25	25	25	0	0	0	0	0	0
NOx (tonnes)	12	10	9	9	8	8	8	8	8	6	6	5	5	5	5	5	5	5	4	1	1	1	1	1	1
SO2 (tonnes)	41	35	33	34	28	26	26	26	26	18	18	13	13	13	14	14	15	15	15	0	0	0	0	0	0

Final Portfolio Study

1.0A

MW/units

Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Existing Coal Retirements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1 unit	1 unit	2 units	4 units	7 units	7 units	7 units	7 units	7 units	7 units
Existing Gas Retirements	0	0	0	0	0	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 units	3 units	3 units	3 units	3 units	3 units	3 units	3 units	3 units
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	435	435	435	435	435	435
Gas - New CTs & Recips	0	0	50	50	50	150	150	150	150	150	150	150	150	350	400	500	500	900	900	900	949	949	949	968	977
Gas - Conversion	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
Biomass	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
Wind	0	0	51	51	74	74	74	74	74	124	124	124	124	124	524	524	524	524	525	525	528	528	528	528	530
Solar	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
CAES	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
Demand Response	5	18	40	64	78	81	80	80	79	78	78	77	77	75	74	73	73	73	72	72	72	72	73	73	73
Battery 1hr	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0
Battery 4hr	0	0	1	1	16	16	16	16	16	16	16	16	16	16	16	16	16	16	17	17	19	19	18	18	4

1.0C

MW/units

Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Existing Coal Retirements	0	0	1 unit	1 unit	1 unit	1 unit	1 unit	1 unit	1 unit	2 units	2 units	2 units	2 units	2 units	2 units	3 units	3 units	3 units	4 units	7 units	7 units	7 units	7 units	7 units	7 units
Existing Gas Retirements	0	0	0	0	0	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	3 units	3 units	3 units	3 units	3 units
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	145	145	145	145	145
Gas - New CTs & Recips	0	0	50	50	50	169	169	169	219	237	237	287	287	287	287	437	447	456	456	606	606	606	656	656	656
Gas - Conversion	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
Biomass	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
Wind	0	0	0	0	0	0	0	0	50	450	450	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Solar	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
CAES	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
Demand Response	0	0	0	0	5	18	40	64	78	81	80	80	79	78	78	77	77	75	74	73	73	73	72	72	72
Firm Imports	0	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	365	615	615	615	615	615	615
Battery 1hr	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0
Battery 4hr	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

2.0A

MW/units

Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Existing Coal Retirements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1 unit	1 unit	2 units	4 units	7 units	7 units	7 units	7 units	7 units	7 units
Existing Gas Retirements	0	0	0	0	0	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	3 units	3 units	3 units	3 units	3 units	3 units	3 units	3 units	3 units
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	435	435	435	435	435	435
Gas - New CTs & Recips	0	0	50	50	50	159	159	159	159	159	159	159	159	159	159	309	509	609	909	959	959	959	959	978	997
Gas - Conversion	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
Biomass	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
Wind	0	0	0	50	50	50	50	50	50	100	100	300	350	450	450	450	500	500	500	500	500	500	500	500	500
Solar	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
CAES	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
Demand Response	5	18	40	64	78	81	80	80	79	78	78	77	77	75	74	73	73	73	72	72	72	72	73	73	73
Battery 1hr	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0
Battery 4hr	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

2.0C

MW/units

Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Existing Coal Retirements	0	0	1 unit	1 unit	1 unit	1 unit	1 unit	1 unit	1 unit	2 units	2 units	2 units	2 units	2 units	2 units	3 units	3 units	3 units	4 units	7 units	7 units	7 units	7 units	7 units	7 units
Existing Gas Retirements	0	0	0	0	0	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	3 units	3 units	3 units	3 units	3 units
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	145	145	145	145	145
Gas - New CTs & Recips	0	0	9	9	9	159	159	159	159	259	259	259	259	259	309	459	459	459	459	659	659	659	659	659	659
Gas - Conversion	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
Biomass	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
Wind	0	0	0	0	0	0	0	0	0	400	400	450	450	450	450	500	500	500	500	500	500	500	500	500	500
Solar	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
CAES	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
Demand Response	5	18	40	64	78	81	80	80	79	78	78	77	77	75	74	73	73	73	72	72	72	72	73	73	73
Firm Imports	0	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	265	265	415	565	565	565	615	615	615
Battery 1hr	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0
Battery 4hr	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

2.1A	MW/units																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Existing Coal Retirements	0	0	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	4 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units
Existing Gas Retirements	0	0	0	0	0	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	290	580	580	580	580	580	580
Gas - New CTs & Recips	0	0	250	300	350	500	550	600	600	700	700	750	750	800	800	800	850	850	900	950	950	950	950	950	950
Gas - Conversion	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	154	154	154	154	154	154
Biomass	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
Wind	0	0	0	0	49	49	149	149	149	649	649	649	649	649	649	649	649	649	649	649	649	649	684	721	721
Solar	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
CAES	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
Demand Response	0	0	0	0	5	18	40	64	78	81	80	80	79	78	78	77	77	75	74	73	73	73	72	72	72
Battery 1hr	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0
Battery 4hr	0	0	0	0	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	56	81	48

2.1B	MW/units																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Existing Coal Retirements	0	0	0	0	0	0	0	0	0	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	3 Units	3 Units	4 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units
Existing Gas Retirements	0	0	0	0	0	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units
Gas - New CCs	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
Gas - New CTs & Recips	0	0	0	0	0	200	200	250	259	459	459	459	509	509	509	559	559	559	609	1,009	1,009	1,058	1,058	1,058	1,058
Gas - Conversion	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	154	154	154	154	154	154	154	154	154
Biomass	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
Wind	0	0	0	0	33	33	33	33	33	133	133	133	133	133	283	333	383	433	533	533	533	533	533	533	533
Solar	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
CAES	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
Demand Response	5	18	40	64	78	81	80	80	79	78	78	77	77	75	74	73	73	73	72	72	72	72	73	73	73
Firm Imports	0	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	465	465	565	615	615	615	615	615	615
Battery 1hr	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0	0	10
Battery 4hr	0	0	0	0	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	0

2.1C	MW/units																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Existing Coal Retirements	0	0	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	2 Units	2 Units	2 Units	4 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units
Existing Gas Retirements	0	0	0	0	0	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	145	145	145	145	145	145
Gas - New CTs & Recips	0	0	50	100	150	300	350	400	400	400	400	450	450	450	500	500	500	500	600	859	909	909	959	959	959
Gas - Conversion	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
Biomass	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
Wind	0	0	0	0	12	112	112	112	112	362	412	612	612	612	612	612	612	612	612	612	612	612	612	612	612
Solar	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
CAES	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
Demand Response	5	18	40	64	78	81	80	80	79	78	78	77	77	75	74	73	73	73	72	72	72	72	73	73	73
Firm Imports	0	165	165	165	165	165	165	165	165	165	165	165	165	165	165	315	365	415	615	615	615	615	615	615	615
Battery 1hr	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0
Battery 4hr	0	0	0	0	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	0

2.2A	MW/units																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Existing Coal Retirements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2 Units	2 Units	4 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units
Existing Gas Retirements	0	0	0	0	0	0	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	145	145	145	435	870	870	870	870	870	870
Gas - New CTs & Recips	0	0	150	250	350	550	600	700	750	750	750	800	850	900	950	950	950	950	950	1,000	1,000	1,000	1,000	1,000	1,000
Gas - Conversion	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	304	304	304	304	304	304	304	304	304
Biomass	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
Wind	0	0	0	0	90	90	190	190	190	490	640	640	640	640	790	790	790	790	790	790	839	871	920	968	1,010
Solar	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
CAES	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
Demand Response	0	11	32	63	94	103	102	101	99	97	96	95	94	91	89	87	87	86	86	86	86	86	86	86	86
Battery 1hr	10	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	10	10	10	10	10
Battery 4hr	0	0	0	0	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	93	114	147	179	147

2.2C MW/units

Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Existing Coal Retirements	0	0	0	0	0	0	0	0	0	0	2 units	2 units	2 units	3 Units	3 Units	3 Units	4 Units	4 Units	4 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units
Existing Gas Retirements	0	0	0	0	0	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	290	290	290	290	290	290
Gas - New CTs & Recips	0	0	0	100	200	400	500	550	600	650	650	650	650	750	800	850	900	950	1,000	1,000	1,000	1,049	1,049	1,098	1,098
Gas - Conversion	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	150	150	150	304	304	304	304	304	304
Biomass	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
Wind	0	0	0	0	25	25	75	75	75	125	525	575	725	725	725	725	725	725	725	725	725	725	725	725	725
Solar	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
CAES	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
Demand Response	0	11	32	63	94	103	102	101	99	97	96	95	94	91	89	87	87	86	86	86	86	86	86	86	86
Firm Imports	0	165	165	165	165	165	165	165	165	165	465	515	515	615	615	615	615	615	615	615	615	615	615	615	615
Battery 1hr	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0
Battery 4hr	0	0	0	0	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	0

3.1B MW/units

Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Existing Coal Retirements	0	0	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	4 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units
Existing Gas Retirements	0	0	0	0	0	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units
Gas - New CCs	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
Gas - New CTs & Recips	0	0	50	100	150	350	400	500	500	650	650	700	700	750	850	850	850	850	850	900	900	900	950	950	950
Gas - Conversion	0	0	0	0	0	0	0	0	0	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154
Biomass	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
Wind	0	0	0	0	21	21	21	21	421	521	521	521	521	521	521	521	521	521	521	521	521	521	521	521	524
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	60
CAES	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
Demand Response	5	18	40	64	78	81	80	80	79	78	78	77	77	75	74	73	73	73	72	72	72	72	73	73	73
Firm Imports	0	165	165	165	165	165	165	165	565	615	615	615	615	615	615	615	615	615	615	615	615	615	615	615	615
Battery 1hr	10	10	10	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	10	10	10	10	10
Battery 4hr	0	0	0	0	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	2

3.1C MW/units

Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Existing Coal Retirements	0	0	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	4 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units
Existing Gas Retirements	0	0	0	0	0	2 Units	2 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units
Gas - New CCs	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
Gas - New CTs & Recips	0	0	50	100	100	250	250	450	450	650	700	700	750	750	800	809	809	859	859	909	909	909	919	919	919
Gas - Conversion	0	0	0	0	0	0	0	0	0	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154
Biomass	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
Wind	0	0	0	0	186	186	286	286	736	786	786	786	786	786	786	786	786	786	786	786	786	799	819	861	877
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	210	460
CAES	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
Demand Response	5	18	40	64	78	81	80	80	79	78	78	77	77	75	74	73	73	73	72	72	72	72	73	73	73
Firm Imports	0	165	165	165	165	165	165	165	515	615	615	615	615	615	615	615	615	615	615	615	615	615	615	615	615
Battery 1hr	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0	0	10
Battery 4hr	0	0	0	0	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	133	146	174	61

3.2B MW/units

Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Existing Coal Retirements	0	0	0	0	0	0	0	1 Units	4 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units
Existing Gas Retirements	0	0	0	0	0	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	145	145	290	290	290	290	290	290	290	290	290	290
Gas - New CTs & Recips	0	0	0	100	200	250	250	250	550	850	900	950	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,009	1,009	1,009	1,009	1,009
Gas - Conversion	0	0	0	0	0	0	0	0	150	304	304	304	304	304	304	304	304	304	304	304	304	304	304	304	304
Biomass	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
Wind	0	0	0	0	21	21	271	321	471	521	521	521	521	521	521	521	521	521	521	521	534	588	638	686	728
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	180
CAES	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
Demand Response	0	11	32	63	94	103	102	101	99	97	96	95	94	91	89	87	87	86	86	86	86	86	86	86	86
Firm Imports	0	165	165	165	165	315	365	565	615	615	615	615	615	615	615	615	615	615	615	615	615	615	615	615	615
Battery 1hr	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Battery 4hr	0	0	0	0	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	23	59	92	124	138

3.2C	MW/units																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Existing Coal Retirements	0	0	0	0	0	0	0	1 Unit	4 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units
Existing Gas Retirements	0	0	0	0	0	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	145	145	145	145	145	145	145	145	145	145
Gas - New CTs & Recips	0	0	0	109	109	309	559	659	659	809	859	909	959	959	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009
Gas - Conversion	0	0	0	0	0	0	0	0	150	304	304	304	304	304	304	304	304	304	304	304	304	304	304	304	304
Biomass	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
Wind	0	0	0	0	171	171	221	221	521	821	821	871	871	871	871	871	871	871	916	979	1,004	1,021	1,069	1,117	1,157
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10	210	400
CAES	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
Demand Response	0	11	32	63	94	103	102	101	99	97	96	95	94	91	89	87	87	86	86	86	86	86	86	86	86
Firm Imports	0	165	165	165	165	165	165	165	565	565	565	565	615	615	615	615	615	615	615	615	615	615	615	615	615
Battery 1hr	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Battery 4hr	0	0	0	0	114	114	114	114	114	114	114	114	114	114	114	114	114	114	144	186	203	214	246	278	191

Sensitivities

2.0A.DSM-1 (Mid DSM)	MW/units																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Existing Coal Retirements	0	0	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	2 Units	2 Units	2 Units	2 Units	2 Units	4 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units
Existing Gas Retirements	0	0	0	0	0	2 units	2 units	2 units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	435	435	435	435	435	435
Gas - New CTs & Recips	0	0	200	200	200	250	250	250	350	350	350	350	350	450	500	500	500	550	850	900	900	900	950	950	950
Gas - Conversion	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
Biomass	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
Wind	0	0	50	51	54	54	54	54	54	204	254	354	404	504	504	504	504	504	504	504	504	504	504	504	504
Solar	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
CAES	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
Demand Response	0	11	32	63	94	103	102	101	99	97	96	95	94	91	89	87	87	86	86	86	86	86	86	86	86
Firm Imports	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
Battery 1hr	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	20	20	20	20	20	10	10	10	10	10
Battery 4hr	0	0	0	1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	0

2.1C.DSM-2 (Mid DSM)	MW/units																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Existing Coal Retirements	0	0	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	3 Units	3 Units	3 Units	4 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units
Existing Gas Retirements	0	0	0	0	0	2 Units	2 Units	2 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	145	145	145	145	145	145	145
Gas - New CTs & Recips	0	0	50	100	100	259	309	309	559	559	559	559	559	559	569	569	569	569	569	919	969	969	1,019	1,019	1,028
Gas - Conversion	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
Biomass	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
Wind	0	0	0	0	10	60	110	110	110	560	560	560	560	560	610	610	610	610	610	610	610	610	610	610	610
Solar	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
CAES	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
Demand Response	0	11	32	63	94	103	102	101	99	97	96	95	94	91	89	87	87	86	86	86	86	86	86	86	86
Firm Imports	0	165	165	165	165	165	165	165	165	165	215	215	265	265	265	465	465	515	515	615	615	615	615	615	615
Battery 1hr	10	10	10	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	10	10	10	0	0
Battery 4hr	0	0	0	0	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	0

2.2C.DSM-3 (Mid DSM)	MW/units																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Existing Coal Retirements	0	0	0	0	0	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	3 Units	3 Units	4 Units	4 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units
Existing Gas Retirements	0	0	0	0	0	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	145	435	435	435	435	435	435
Gas - New CTs & Recips	0	0	0	100	200	200	200	250	350	350	400	450	500	550	600	650	700	750	800	900	950	950	950	1,000	1,000
Gas - Conversion	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	304	304	304	304	304	304	304	304	304
Biomass	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
Wind	0	0	0	0	418	468	618	618	618	618	618	618	718	718	730	730	730	730	730	730	730	730	730	730	730
Solar	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
CAES	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
Demand Response	0	11	32	63	94	103	102	101	99	97	96	95	94	91	89	87	87	86	86	86	86	86	86	86	86
Firm Imports	0	165	165	165	165	515	615	615	615	615	615	615	615	615	615	615	615	615	615	615	615	615	615	615	615
Battery 1hr	10	10	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	10	10	0	0	0
Battery 4hr	0	0	0	0	12	12	12	12	12	12	12	12	12	12	20	20	20	20	20	20	20	20	20	20	8

2.0C.DSM-4 (Low DSM)	MW/units																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Existing Coal Retirements	0	0	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	2 Units	2 Units	2 Units	4 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units
Existing Gas Retirements	0	0	0	0	0	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	145	145	145	145	145	145
Gas - New CTs & Recips	0	0	50	50	50	200	200	209	209	209	209	209	209	209	259	409	409	409	509	709	709	759	759	759	759
Gas - Conversion	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
Biomass	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
Wind	0	0	0	0	59	59	109	109	109	109	309	409	409	509	509	509	509	509	509	509	509	509	509	509	509
Solar	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
CAES	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
Demand Response	3	13	29	47	58	60	60	60	59	59	59	58	58	57	57	56	56	56	55	55	55	55	55	55	55
Firm Imports	0	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	315	315	515	615	615	615	615	615	615
Battery 1hr	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0
Battery 4hr	0	0	0	0	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	0

2.0C.DSM-5 (Mid DSM)	MW/units																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Existing Coal Retirements	0	0	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	3 Units	3 Units	3 Units	4 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units
Existing Gas Retirements	0	0	0	0	0	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	3 Units
Gas - New CCs	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
Gas - New CTs & Recips	0	0	0	0	0	100	100	100	100	200	200	200	200	200	209	359	409	409	409	559	609	609	609	659	759
Gas - Conversion	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
Biomass	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
Wind	0	0	1	1	3	53	53	53	53	353	353	353	353	403	453	503	503	503	503	504	504	504	504	504	504
Solar	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
CAES	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
Demand Response	0	11	32	63	94	103	102	101	99	97	96	95	94	91	89	87	87	86	86	86	86	86	86	86	86
Firm Imports	0	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	315	615	615	615	615	615	615
Battery 1hr	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0
Battery 4hr	0	0	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	3	3	3	2	2	1

2.0C.DSM-6 (Max DSM)	MW/units																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Existing Coal Retirements	0	0	1 Unit	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	4 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units
Existing Gas Retirements	0	0	0	0	0	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	3 Units
Gas - New CCs	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
Gas - New CTs & Recips	0	0	0	100	100	159	159	159	159	159	159	309	309	309	309	359	359	359	509	509	509	559	559	609	709
Gas - Conversion	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
Biomass	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
Wind	0	0	0	0	0	0	0	0	0	0	0	100	100	250	400	450	450	450	500	500	500	500	500	500	500
Solar	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
CAES	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
Demand Response	0	11	32	63	94	103	102	101	99	97	96	95	94	91	89	87	87	86	86	86	86	86	86	86	86
Firm Imports	0	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	615	615	615	615	615	615
Battery 1hr	10	10	10	10	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	10	10	10	10	10
Battery 4hr	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

3.1C.DSM-7 (Mid DSM)	MW/units																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Existing Coal Retirements	0	0	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	4 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units
Existing Gas Retirements	0	0	0	0	0	2 Units	2 Units	2 Units	2 Units	2 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units
Gas - New CCs	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
Gas - New CTs & Recips	0	0	50	50	50	200	250	300	650	650	700	700	750	750	750	750	800	850	850	850	900	900	950	950	950
Gas - Conversion	0	0	0	0	0	0	0	0	0	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154
Biomass	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
Wind	0	0	0	31	139	139	139	139	739	739	739	739	739	739	739	739	739	739	739	739	739	739	739	739	748
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	270	550
CAES	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
Demand Response	0	11	32	63	94	103	102	101	99	97	96	95	94	91	89	87	87	86	86	86	86	86	86	86	86
Firm Imports	0	165	165	165	165	165	165	165	165	465	565	565	565	565	615	615	615	615	615	615	615	615	615	615	615
Battery 1hr	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	0	10	10	10	10
Battery 4hr	0	0	0	21	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	93	72	6

2.1C.WIND-1 (Low Wind Cost)	MW/units																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Existing Coal Retirements	0	0	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	4 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units
Existing Gas Retirements	0	0	0	0	0	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	145	145	145	145	145	145	145
Gas - New CTs & Recips	0	0	50	100	100	100	100	100	100	150	150	150	150	200	200	200	200	250	400	850	900	900	950	950	950
Gas - Conversion	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
Biomass	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
Wind	0	0	100	101	631	631	631	631	631	631	631	631	631	631	631	631	631	631	631	631	631	631	631	631	634
Solar	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
CAES	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
Demand Response	5	18	40	64	78	81	80	80	79	78	78	77	77	75	74	73	73	73	72	72	72	72	73	73	73
Firm Imports	0	165	165	165	165	365	365	415	465	515	565	565	615	615	615	615	615	615	615	615	615	615	615	615	615
Battery 1hr	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Battery 4hr	0	0	0	1	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	20	2

2.1C.WIND-2 (Low Wind & Batte	MW/units																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Existing Coal Retirements	0	0	1 Unit	1 Unit	1 Unit	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units
Existing Gas Retirements	0	0	0	0	0	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	3 Units	3 Units	3 Units	3 Units	3 Units
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	145	145	145	145	145	145
Gas - New CTs & Recips	0	0	50	50	50	400	450	450	500	500	500	550	550	569	619	619	619	619	628	828	978	1,028	1,028	1,028	1,028
Gas - Conversion	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
Biomass	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
Wind	0	0	300	600	676	676	676	676	676	676	676	676	676	676	676	676	676	676	676	676	676	676	676	676	681
Solar	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
CAES	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
Demand Response	5	18	40	64	78	81	80	80	79	78	78	77	77	75	74	73	73	73	72	72	72	72	73	73	73
Firm Imports	0	165	165	165	165	165	165	165	165	165	165	165	165	165	165	215	315	315	515	615	615	615	615	615	615
Battery 1hr	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0
Battery 4hr	0	0	0	0	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	3

2.1C.WIND-3 (Low Inertia Const	MW/units																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Existing Coal Retirements	0	0	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units
Existing Gas Retirements	0	0	0	0	0	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	2 units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	145	145	145	145	145	145
Gas - New CTs & Recips	0	0	50	100	150	300	350	400	450	450	450	450	450	450	450	450	450	500	650	1,000	1,000	1,019	1,068	1,068	1,068
Gas - Conversion	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
Biomass	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
Wind	0	0	0	50	53	103	103	103	103	103	303	403	453	603	603	603	603	603	603	603	603	603	603	603	603
Solar	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
CAES	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
Demand Response	5	18	40	64	78	81	80	80	79	78	78	77	77	75	74	73	73	73	72	72	72	72	73	73	73
Firm Imports	0	165	165	165	165	165	165	165	165	165	165	165	165	315	365	365	515	515	615	615	615	615	615	615	615
Battery 1hr	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0
Battery 4hr	0	0	0	0	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0

2.1C.WIND-4 (No Inertia / No In	MW/units																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Existing Coal Retirements	0	0	1 Unit	1 Unit	1 Unit	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	3 Units	3 Units	4 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units
Existing Gas Retirements	0	0	0	0	0	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units
Gas - New CCs	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
Gas - New CTs & Recips	0	0	50	100	200	500	550	550	550	550	600	650	650	650	700	700	700	800	850	850	850	900	900	900	900
Gas - Conversion	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	154	154	154	154	154	154	154	154	154
Biomass	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
Wind	0	0	50	150	300	300	550	550	550	550	650	650	700	700	850	850	900	900	1,000	1,050	1,100	1,100	1,250	1,250	1,250
Solar	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
CAES	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
Demand Response	5	18	40	64	78	81	80	80	79	78	78	77	77	75	74	73	73	73	72	72	72	72	73	73	73
Firm Imports	0	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	615	615	615	615	615	615
Battery 1hr	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Battery 4hr	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

2.1C.Mersey	MW/units																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Existing Coal Retirements	0	0	0	0	0	0	0	0	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	4 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units
Existing Gas Retirements	0	0	0	0	0	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	145	145	145	145	145	145	145
Gas - New CTs & Recips	0	0	0	0	50	250	300	300	300	300	300	300	350	350	400	450	450	500	500	950	950	950	1,000	1,000	1,000
Gas - Conversion	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
Biomass	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
Wind	0	0	10	10	10	10	60	60	60	610	610	610	610	610	612	612	612	612	612	612	612	612	612	612	613
Solar	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
CAES	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
Demand Response	5	18	40	64	78	81	80	80	79	78	78	77	77	75	74	73	73	73	72	72	72	72	73	73	73
Firm Imports	0	165	165	165	165	165	165	165	165	565	615	615	615	615	615	615	615	615	615	615	615	615	615	615	615
Battery 1hr	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0
Battery 4hr	0	0	7	7	7	7	7	7	7	7	7	7	7	7	8	8	8	8	8	8	8	8	1	1	2

2.1C.Import-1 (Limited Non-Firm	MW/units																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Existing Coal Retirements	0	0	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	2 Units	2 Units	2 Units	4 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units
Existing Gas Retirements	0	0	0	0	0	2 Units	2 Units	2 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	290	290	290	290	290	290
Gas - New CTs & Recips	0	0	50	100	150	200	250	300	400	400	400	400	400	400	400	400	400	400	659	909	909	928	928	928	928
Gas - Conversion	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
Biomass	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
Wind	0	0	0	0	300	300	300	300	300	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
Solar	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
CAES	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
Demand Response	5	18	40	64	78	81	80	80	79	78	78	77	77	75	74	73	73	73	72	72	72	72	73	73	73
Firm Imports	0	165	165	165	165	265	265	265	265	315	315	315	315	465	465	615	615	615	615	615	615	615	615	615	615
Battery 1hr	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0
Battery 4hr	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

2.0A.Import-2 (No Reliability Tie	MW/units																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Existing Coal Retirements	0	0	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	2 Units	2 Units	3 Units	4 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units
Existing Gas Retirements	0	0	0	0	0	2 Units	2 Units	2 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	145	145	145	290	435	435	435	435	435	435
Gas - New CTs & Recips	0	0	200	200	200	250	250	250	350	350	350	350	350	350	400	400	400	600	600	850	850	850	850	900	900
Gas - Conversion	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
Biomass	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
Wind	0	0	0	0	150	150	150	150	250	250	250	250	250	250	250	250	250	250	250	338	346	353	383	383	383
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	60
CAES	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
Demand Response	5	18	40	64	78	81	80	80	79	78	78	77	77	75	74	73	73	73	72	72	72	72	73	73	73
Firm Imports	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
Battery 1hr	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0
Battery 4hr	0	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	159	164	169	189	189	89

2.1C.Import-3 (Limited Reliabilit	MW/units																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Existing Coal Retirements	0	0	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	4 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units
Existing Gas Retirements	0	0	0	0	0	2 Units	2 Units	2 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	145	145	145	145	145	145	145
Gas - New CTs & Recips	0	0	50	150	150	300	350	400	400	400	400	400	400	409	409	409	409	409	519	1,019	1,019	1,019	1,068	1,068	1,068
Gas - Conversion	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
Biomass	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
Wind	0	0	0	0	56	106	106	106	106	556	606	606	606	606	606	606	606	606	606	606	606	606	606	606	606
Solar	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
CAES	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
Demand Response	5	18	40	64	78	81	80	80	79	78	78	77	77	75	74	73	73	73	72	72	72	72	73	73	73
Firm Imports	0	165	165	165	165	165	165	165	315	415	415	465	465	465	565	565	565	565	615	615	615	615	615	615	615
Battery 1hr	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0
Battery 4hr	0	0	0	0	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	0

2.1C.CAPEX-1 (High Sustaining C	MW/units																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Existing Coal Retirements	0	0	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	3 Units	3 Units	3 Units	4 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units
Existing Gas Retirements	0	0	0	0	0	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	145	145	145	145	145	145
Gas - New CTs & Recips	0	0	50	100	200	400	450	500	550	550	550	550	550	569	569	569	619	619	669	978	997	1,047	1,047	1,056	1,074
Gas - Conversion	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
Biomass	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
Wind	0	0	0	0	153	253	303	303	303	553	553	553	553	603	603	603	603	603	603	603	603	603	603	603	603
Solar	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
CAES	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
Demand Response	5	18	40	64	78	81	80	80	79	78	78	77	77	75	74	73	73	73	72	72	72	72	73	73	73
Firm Imports	0	165	165	165	165	165	165	165	165	315	315	315	315	315	365	515	515	515	615	615	615	615	615	615	615
Battery 1hr	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0
Battery 4hr	0	0	0	0	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0

2.1C.CAPEX-2 (Low Sustaining C	MW/units																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Existing Coal Retirements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1 Unit	2 Units	4 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units
Existing Gas Retirements	0	0	0	0	0	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	145	145	145	145	145	145
Gas - New CTs & Recips	0	0	0	0	0	200	250	250	300	300	300	300	300	300	350	350	550	550	550	900	900	950	950	950	950
Gas - Conversion	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
Biomass	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
Wind	0	0	0	0	15	15	15	15	15	115	315	465	565	615	615	615	615	615	615	615	616	616	616	616	616
Solar	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
CAES	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
Demand Response	5	18	40	64	78	81	80	80	79	78	78	77	77	75	74	73	73	73	72	72	72	72	73	73	73
Firm Imports	0	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	315	615	615	615	615	615	615	615
Battery 1hr	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0
Battery 4hr	0	0	0	0	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	11	11	11	11	1

2.1C.PRICES-1 (High Import & Ga	MW/units																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Existing Coal Retirements	0	0	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	1 Unit	2 Units	2 Units	4 Units	7 Units	7 Units	7 Units	7 Units	7 Units	7 Units
Existing Gas Retirements	0	0	0	0	0	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	2 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units	3 Units
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	145	145	145	145	145	145
Gas - New CTs & Recips	0	0	50	100	150	309	359	409	409	409	409	409	459	459	509	509	509	509	659	1,009	1,009	1,009	1,058	1,058	1,058
Gas - Conversion	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
Biomass	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
Wind	0	0	0	0	53	103	103	103	103	403	403	603	603	603	603	603	603	607	612	612	612	612	612	612	616
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10	10	10	10	10	10	70	70
CAES	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
Demand Response	5	18	40	64	78	81	80	80	79	78	78	77	77	75	74	73	73	73	72	72	72	72	73	73	73
Firm Imports	0	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	465	615	615	615	615	615	615	615	615
Battery 1hr	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0	0	10
Battery 4hr	0	0	0	0	2	2	2	2	2	2	2	2	2	2	2	2	2	5	8	8	8	8	8	8	9

Final Portfolio Study

1.0A (GWh)

Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	4,104	3,794	3,719	3,669	3,368	3,401	3,461	3,568	3,436	3,161	3,072	3,166	3,077	3,109	1,917	2,003	1,942	1,969	1,574	0	0	0	0	0	0
Gas - Existing	684	996	962	983	1,028	1,000	1,000	973	979	983	974	969	957	971	919	908	915	860	875	895	889	888	888	889	886
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,907	1,913	1,938	2,031	2,071	2,111
Gas - New CTs & Recips	0	0	0	0	0	110	79	82	82	88	108	75	116	97	37	56	51	107	344	204	256	295	263	247	277
Gas - Conversion	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
Domestic Hydro	891	893	893	893	916	915	915	915	915	1,011	1,012	1,012	1,011	1,011	1,012	1,012	1,012	1,011	1,012	1,012	1,012	1,012	1,012	1,011	1,012
Tidal	0	0	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Biomass	331	353	348	347	343	345	342	339	347	351	351	352	344	347	349	350	350	353	370	360	359	360	360	363	359
Wind	1,903	1,901	2,079	2,078	2,156	2,156	2,155	2,154	2,155	2,323	2,323	2,323	2,323	2,323	3,576	3,576	3,577	3,582	3,589	3,589	3,594	3,597	3,597	3,602	3,604
Solar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Diesel CTs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	1	4	3	4	1	2
Maritime Link Blocks	1,133	1,133	1,133	1,134	1,133	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894
Demand Response	0	1	1	2	3	3	3	3	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Non Firm Market	2277	2236	2116	2132	2221	2279	2198	2078	2116	2033	2076	2021	2063	2048	2115	2062	2134	2131	2288	2127	2085	2069	2058	2074	2072
CAES	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
Battery Generation	0.5	0.6	1.9	2.1	11.7	11.1	11.0	10.7	10.2	10.5	12.8	11.1	10.3	11.1	19.6	19.1	18.1	17.6	20.7	19.2	20.3	19.7	18.3	17.3	3.6
Firm Imports	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

1.0C (GWh)

Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	3,966	3,713	3,624	3,607	3,546	3,546	3,455	3,517	3,248	1,900	1,864	1,766	1,745	1,759	1,697	1,720	1,709	1,729	1,299	0	0	0	0	0	0
Gas - Existing	790	1,019	1,044	1,037	1,011	1,024	1,054	1,024	1,022	942	953	943	941	939	975	996	1,006	1,005	896	934	855	859	857	862	854
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	600	636	698	765
Gas - New CTs & Recips	0	0	0	0	0	145	155	79	113	79	75	61	64	59	101	93	106	108	29	60	538	96	102	104	96
Gas - Conversion	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
Domestic Hydro	894	890	892	890	913	913	914	914	915	1,011	1,011	1,011	1,010	1,012	1,010	1,011	1,010	1,011	1,000	999	992	1,002	1,002	1,003	1,005
Tidal	0	0	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Biomass	337	348	351	352	347	352	347	348	346	355	351	349	348	351	351	356	356	353	356	361	351	351	353	352	355
Wind	1,904	1,899	1,897	1,898	1,897	1,896	1,897	1,897	2,063	3,340	3,337	3,459	3,459	3,466	3,469	3,464	3,466	3,478	3,471	3,479	3,475	3,474	3,475	3,486	3,487
Solar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Diesel CTs	0	0	1	1	0	0	0	0	0	1	2	2	1	0	3	2	3	3	1	0	0	0	0	0	0
Maritime Link Blocks	1,133	1,133	1,133	1,134	1,133	894	894	894	894	894	894	894	894	894	894	894	893	894	894	894	894	893	894	894	893
Demand Response	0	0	0	0	0	1	1	2	3	3	3	3	3	2	2	3	3	3	3	2	2	2	3	3	2
Non Firm Market	2,299	1,346	1,321	1,317	1,308	1,318	1,316	1,320	1,309	1,318	1,318	1,324	1,321	1,319	1,315	1,327	1,328	1,331	1,491	1,717	1,605	1,557	1,566	1,548	1,535
CAES	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
Battery Generation	0.5	0.6	0.5	0.5	0.4	1.0	0.9	0.9	1.8	4.0	3.6	4.3	4.1	4.1	4.1	4.1	4.1	4.5	4.1	3.4	0.0	0.0	0.0	0.0	0.0
Firm Imports	0	950	968	977	979	981	984	980	984	975	975	974	974	973	973	968	966	963	1,479	2,514	2,264	2,190	2,190	2,172	2,197

2.0A (GWh)

Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	4,022	3,784	3,788	3,643	3,427	3,588	3,485	3,562	3,506	3,060	3,013	2,419	2,235	2,068	2,054	2,052	1,981	2,006	1,573	0	0	0	0	0	0
Gas - Existing	737	993	978	977	1,047	981	979	978	981	994	994	926	920	902	916	926	854	854	884	894	875	872	870	879	861
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,937	1,987	2,031	2,088	2,094	2,126
Gas - New CTs & Recips	0	0	44	42	55	149	137	128	126	166	170	39	40	36	38	57	115	116	378	239	274	284	293	282	285
Gas - Conversion	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
Domestic Hydro	892	892	892	892	915	912	914	915	914	1,007	1,008	1,008	1,009	1,008	1,009	1,012	1,010	1,009	1,011	1,011	1,010	1,010	1,011	1,013	1,013
Tidal	0	0	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Biomass	337	352	346	345	342	343	348	339	342	352	355	350	347	348	353	353	354	351	372	360	356	360	360	359	359
Wind	1,902	1,902	1,904	2,073	2,074	2,073	2,073	2,073	2,074	2,242	2,241	2,913	3,071	3,363	3,367	3,366	3,496	3,508	3,510	3,511	3,473	3,480	3,477	3,514	3,517
Solar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Diesel CTs	0	0	0	0	0	0	1	0	0	0	0	0	1	0	0	0	0	0	2	2	3	4	6	1	2
Maritime Link Blocks	1,133	1,133	1,133	1,134	1,133	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894
Demand Response	0	1	1	2	3	3	3	3	2	3	3	3	3	2	3	3	3	3	3	2	2	3	2	3	3
Non Firm Market	2,300	2,246	2,149	2,110	2,146	2,134	2,187	2,088	2,062	2,103	2,108	2,236	2,243	2,154	2,161	2,173	2,142	2,141	2,296	2,114	2,106	2,092	2,080	2,087	2,132
CAES	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
Battery Generation	0.49	0.56	0.45	1.30	1.27	1.32	1.43	1.17	1.12	1.44	1.55	1.51	1.83	2.61	2.37	2.21	2.39	2.22	2.56	2.91	0.00	0.00	0.00	0.00	0.00
Firm Imports	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

2.0C	GWh																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	4,004	3,713	3,597	3,615	3,418	3,563	3,621	3,556	3,493	2,024	2,003	1,871	1,848	1,854	1,778	1,726	1,552	1,542	1,275	0	0	0	0	0	0
Gas - Existing	774	1,020	1,057	1,020	1,116	1,131	1,021	1,036	1,037	974	970	978	977	975	1,017	990	906	905	895	931	860	854	851	858	851
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	575	612	694	711
Gas - New CTs & Recips	0	0	4	4	8	14	11	13	10	55	53	54	45	50	91	90	24	25	16	84	608	145	127	118	146
Gas - Conversion	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
Domestic Hydro	893	893	892	893	914	915	915	915	914	1,010	1,011	1,011	1,010	1,011	1,010	1,011	1,006	1,000	997	1,001	1,000	1,010	1,008	1,006	1,000
Tidal	0	0	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Biomass	331	347	352	354	348	350	349	354	348	355	354	353	352	353	361	356	348	346	359	362	354	353	353	355	350
Wind	1,902	1,899	1,898	1,900	1,900	1,897	1,898	1,899	1,896	3,203	3,195	3,326	3,329	3,333	3,339	3,467	3,457	3,463	3,469	3,478	3,456	3,436	3,434	3,443	3,443
Solar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Diesel CTs	0	0	1	1	0	6	5	6	4	4	3	2	2	2	3	5	1	1	0	1	0	4	5	4	5
Maritime Link Blocks	1,133	1,133	1,133	1,134	1,133	894	894	894	894	894	894	894	893	893	894	894	894	894	894	894	893	893	893	894	894
Demand Response	0	1	1	2	3	3	3	2	3	2	2	3	3	2	2	3	3	3	3	2	2	2	3	2	2
Non Firm Market	2,286	1,343	1,323	1,314	1,319	1,323	1,318	1,318	1,317	1,321	1,323	1,317	1,326	1,327	1,323	1,323	1,457	1,481	1,445	1,760	1,637	1,610	1,569	1,539	1,575
CAES	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
Battery Generation	0	1	1	0	1	1	1	1	1	3	3	3	3	3	3	3	3	3	3	3	0	0	0	0	0
Firm Imports	0	950	973	979	979	977	982	982	982	974	975	977	973	972	972	969	1,201	1,218	1,565	2,446	2,166	2,143	2,222	2,208	2,212

2.1A	GWh																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	4,026	3,733	3,707	3,772	3,473	3,488	3,470	3,452	3,382	1,939	1,946	1,911	1,920	1,956	1,811	1,820	1,832	1,805	1,464	0	0	0	0	0	0
Gas - Existing	755	1,034	999	974	1,029	1,060	982	993	981	921	929	938	943	942	1,002	1,046	1,058	1,077	936	966	949	956	937	894	402
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	884	2,412	2,440	2,543	2,562	2,551	2,917
Gas - New CTs & Recips	0	0	126	109	126	256	123	150	189	105	104	120	106	125	199	252	285	365	108	202	273	270	260	243	117
Gas - Conversion	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	13	29	25	26	16	0
Domestic Hydro	893	891	892	891	914	915	915	915	915	1,010	1,012	1,012	1,011	1,011	1,011	1,012	1,012	1,011	1,012	1,010	1,009	1,009	1,013	1,016	1,095
Tidal	0	0	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Biomass	335	355	347	350	349	376	341	345	345	350	348	344	346	350	396	393	398	402	362	361	360	360	360	362	414
Wind	1,903	1,902	1,903	1,904	2,072	2,072	2,413	2,412	2,411	3,922	3,923	3,921	3,929	3,934	3,942	3,947	3,952	3,961	3,965	3,971	3,968	3,967	4,070	4,179	4,181
Solar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Diesel CTs	0	1	0	0	0	0	0	0	1	1	1	2	1	1	1	1	1	2	1	0	2	2	2	1	0
Maritime Link Blocks	1,133	1,133	1,133	1,134	1,133	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894
Demand Response	0	0	0	0	0	1	1	2	3	3	3	3	3	2	3	3	3	3	3	3	3	3	3	3	3
Non Firm Market	2,289	2,278	2,200	2,220	2,270	2,300	2,232	2,227	2,244	2,193	2,194	2,259	2,275	2,272	2,298	2,285	2,284	2,283	2,262	2,146	2,105	2,084	2,071	2,119	2,282
CAES	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
Battery Generation	0.45	0.48	0.85	0.73	22.81	20.56	23.93	23.52	22.80	42.84	44.64	43.59	44.65	42.61	44.07	41.08	40.74	40.17	41.57	39.02	35.41	35.50	57.80	92.32	58.48
Firm Imports	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

2.1B	GWh																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	3,988	3,701	3,718	3,665	3,369	3,522	3,440	3,226	3,140	2,435	2,432	2,448	2,409	2,441	1,799	1,726	1,355	1,322	1,004	0	0	0	0	0	0
Gas - Existing	743	985	930	965	1,045	1,018	986	1,009	970	1,056	1,051	1,058	1,051	1,039	931	924	846	836	838	857	844	845	850	851	855
Gas - New CCs	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
Gas - New CTs & Recips	0	0	0	0	0	0	0	64	62	406	378	341	386	368	112	109	24	20	26	106	156	140	152	140	115
Gas - Conversion	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6	2	2	44	55	56	51	47	58
Domestic Hydro	894	893	893	893	915	915	915	914	914	1,006	1,006	1,006	1,007	1,004	1,011	1,011	1,011	1,006	1,005	1,007	1,011	1,011	1,010	1,010	1,008
Tidal	0	0	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Biomass	335	355	352	348	346	344	349	340	340	355	357	351	352	354	345	350	339	339	343	351	351	351	353	354	354
Wind	1,904	1,900	1,898	1,901	2,010	2,006	2,003	2,004	1,996	2,270	2,263	2,264	2,257	2,257	2,817	2,963	3,089	3,228	3,461	3,469	3,458	3,466	3,469	3,475	3,475
Solar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Diesel CTs	1	1	0	1	2	3	8	3	1	1	1	1	0	1	1	1	0	0	0	0	3	2	3	3	0
Maritime Link Blocks	1,133	1,133	1,133	1,134	1,133	894	894	894	893	893	893	894	893	893	894	894	893	894	893	894	893	893	893	894	893
Demand Response	0	1	1	2	3	3	3	3	3	3	3	3	3	3	3	3	2	3	3	3	2	3	3	3	2
Non Firm Market	2,294	1,338	1,314	1,315	1,325	1,320	1,321	1,317	1,220	858	848	857	825	836	1,294	1,282	1,305	1,275	1,227	1,509	1,487	1,543	1,562	1,577	1,617
CAES	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
Battery Generation	0.63	0.65	0.45	0.63	12.83	19.17	20.16	21.31	23.12	24.38	26.46	25.09	24.07	26.18	26.88	26.28	26.68	27.07	29.81	29.14	25.53	25.95	26.11	25.88	4.30
Firm Imports	0	951	973	977	975	980	976	978	981	979	978	977	978	975	975	973	1,385	1,386	1,566	2,185	2,185	2,186	2,196	2,221	2,244

2.1C	GWh																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	4,060	3,758	3,645	3,671	3,518	3,318	3,290	3,341	3,386	2,579	2,431	2,004	2,013	2,052	2,032	1,746	1,743	1,738	1,082	0	0	0	0	0	0
Gas - Existing	717	1,005	1,044	1,025	1,076	1,080	1,101	1,078	1,041	978	975	954	949	959	986	905	888	882	910	918	924	916	925	946	912
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	864	869	913	977	1,023	1,030
Gas - New CTs & Recips	0	0	42	83	124	228	236	230	213	95	113	123	124	126	177	43	37	21	36	121	188	196	187	205	210
Gas - Conversion	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
Domestic Hydro	893	891	893	893	914	915	915	915	915	1,011	1,011	1,011	1,011	1,011	1,011	1,006	1,007	1,004	1,003	1,006	1,006	1,010	1,011	1,008	1,009
Tidal	0	0	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Biomass	335	348	354	354	352	347	353	352	348	361	359	349	355	356	360	352	353	353	361	354	355	354	354	357	360
Wind	1,903	1,898	1,899	1,899	1,941	2,272	2,273	2,272	2,270	3,105	3,253	3,766	3,779	3,786	3,794	3,783	3,794	3,809	3,817	3,823	3,816	3,827	3,829	3,838	3,787
Solar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Diesel CTs	0	1	0	0	0	0	0	0	0	2	3	2	1	2	2	1	1	1	1	0	2	2	3	2	2
Maritime Link Blocks	1,133	1,133	1,133	1,134	1,133	894	893	894	894	894	894	894	894	894	894	894	894	893	893	894	894	894	894	894	893
Demand Response	0	1	1	2	3	3	3	3	3	3	3	3	3	2	2	3	3	3	3	2	2	3	3	2	2
Non Firm Market	2,292	1,346	1,324	1,321	1,324	1,324	1,324	1,319	1,307	1,324	1,323	1,312	1,321	1,320	1,317	1,501	1,474	1,451	1,477	1,627	1,622	1,638	1,646	1,648	1,705
CAES	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
Battery Generation	0.52	0.62	0.45	0.63	5.65	8.05	8.25	7.62	8.29	9.07	10.33	12.98	13.37	13.35	12.91	10.79	10.54	10.17	9.45	11.02	6.92	7.04	7.14	7.18	0.00
Firm Imports	0	948	972	976	973	976	975	978	980	974	974	974	966	967	970	1,408	1,515	1,635	2,295	2,356	2,341	2,350	2,353	2,326	2,421

2.2A	GWh																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	4,005	3,805	3,875	3,888	3,448	3,547	3,391	3,383	3,458	2,466	2,224	2,236	2,261	2,342	2,072	2,145	1,730	1,730	1,359	0	0	0	0	0	0
Gas - Existing	779	1,013	972	997	1,052	1,033	989	979	1,006	930	920	940	921	940	948	980	1,019	1,033	904	937	912	927	926	684	325
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,510	2,893	2,876	2,918	2,997	3,021	3,087
Gas - New CTs & Recips	0	0	0	0	38	189	116	164	165	94	91	115	131	131	182	197	645	710	123	135	154	161	144	122	62
Gas - Conversion	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	48	44	17	21	23	21	25	8	0
Domestic Hydro	892	891	893	892	914	915	914	915	915	1,011	1,012	1,011	1,011	1,011	1,008	1,012	1,012	1,031	1,010	1,008	1,012	1,012	1,013	1,039	1,186
Tidal	0	0	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Biomass	336	353	350	350	349	357	342	346	344	353	349	347	348	352	361	363	362	376	350	361	359	359	358	369	416
Wind	1,903	1,904	1,904	1,902	2,210	2,210	2,549	2,549	2,549	3,517	3,916	3,919	3,925	3,940	4,300	4,316	4,327	4,351	4,359	4,370	4,508	4,602	4,748	4,861	4,975
Solar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Diesel CTs	0	1	2	2	1	1	0	0	0	1	0	1	0	0	1	1	3	1	1	1	1	1	1	1	1
Maritime Link Blocks	1,133	1,133	1,133	1,134	1,133	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894
Demand Response	0	0	1	2	3	4	4	4	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	10
Non Firm Market	2,296	2,288	2,210	2,226	2,293	2,300	2,277	2,278	2,187	2,262	2,186	2,222	2,281	2,287	2,271	2,294	2,293	2,299	2,105	2,149	2,145	2,129	2,051	2,259	2,315
CAES	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
Battery Generation	0.56	3.04	2.82	3.20	44.03	40.07	47.13	46.69	48.02	63.98	82.04	79.05	79.53	78.70	93.34	88.78	86.92	87.72	87.14	78.84	111.94	133.53	175.97	213.05	188.66
Firm Imports	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		

2.2C	GWh																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	4,050	3,794	3,729	3,802	3,609	3,571	3,434	3,480	3,511	2,954	1,797	1,798	1,640	1,474	1,518	1,595	1,404	1,359	1,421	0	0	0	0	0	0
Gas - Existing	747	1,030	1,035	1,023	1,094	1,137	1,128	1,097	1,069	1,127	876	867	855	875	877	884	912	915	910	908	933	922	918	910	838
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,230	1,304	1,370	1,420	1,483	1,479
Gas - New CTs & Recips	0	0	0	0	34	259	282	301	303	612	36	28	27	26	31	36	54	66	70	164	243	217	220	201	188
Gas - Conversion	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	13	14	6	40	35	33	38	36	19
Domestic Hydro	892	887	892	892	914	915	915	914	915	1,010	1,008	1,004	1,002	1,005	996	1,003	1,008	1,006	1,008	1,009	1,010	1,010	1,010	1,010	1,012
Tidal	0	0	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Biomass	337	347	348	351	351	368	350	354	361	363	349	348	343	348	350	351	357	358	361	354	355	355	352	353	360
Wind	1,903	1,899	1,900	1,896	1,985	1,984	2,151	2,152	2,149	2,306	3,556	3,690	4,025	4,048	4,057	4,080	4,099	4,120	4,139	4,144	4,140	4,152	4,150	4,166	4,172
Solar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Diesel CTs	0	1	1	2	1	1	0	0	0	1	1	0	1	1	1	1	1	1	1	1	5	4	5	4	4
Maritime Link Blocks	1,133	1,133	1,133	1,134	1,133	894	894	894	894	893	893	894	893	894	893	894	894	894	894	894	894	894	894	894	894
Demand Response	0	0	1	2	3	4	4	4	3	3	3	3	3	3	3	3	3	2	3	3	3	3	3	3	3
Non Firm Market	2,282	1,348	1,346	1,325	1,328	1,324	1,327	1,325	1,326	1,266	1,407	1,379	1,348	1,359	1,378	1,391	1,463	1,484	1,513	1,687	1,663	1,707	1,744	1,769	1,875
CAES	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
Battery Generation	0.35	0.58	0.48	0.53	11.57	12.91	14.37	15.21	16.21	17.54	21.64	21.20	25.60	24.37	23.14	22.53	21.74	20.82	21.04	22.56	18.26	20.10	20.06	18.91	0.00
Firm Imports	0	950	954	968	972	975	973	974	973	977	1,645	1,657	1,614	1,848	1,911	1,941	2,105	2,237	2,285	2,317	2,266	2,312	2,342	2,371	2,455

3.1B	GWh																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	3,956	3,706	3,602	3,538	3,291	3,251	3,275	3,179	1,140	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas - Existing	745	961	994	1,003	1,064	1,051	994	978	880	902	898	909	905	911	904	899	901	901	912	895	909	858	853	667	418
Gas - New CCs	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
Gas - New CTs & Recips	0	0	0	43	70	234	170	137	19	63	64	68	66	66	69	74	73	78	73	84	99	90	91	87	78
Gas - Conversion	0	0	0	0	0	0	0	0	0	15	12	21	19	18	16	21	33	29	27	39	30	22	23	2	2
Domestic Hydro	892	888	892	893	915	915	914	912	901	1,000	1,000	1,007	995	1,002	999	1,003	1,003	1,001	997	1,005	1,009	1,008	1,009	1,011	1,038
Tidal	0	0	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Biomass	331	344	353	354	348	348	342	343	346	350	350	348	344	346	347	350	352	350	353	351	351	357	356	365	408
Wind	1,903	1,900	1,900	1,899	1,970	1,964	1,964	1,962	3,212	3,421	3,408	3,402	3,403	3,401	3,399	3,400	3,404	3,421	3,425	3,430	3,420	3,423	3,422	3,448	3,446
Solar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	92
Diesel CTs	0	0	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1
Maritime Link Blocks	1,133	1,133	1,133	1,134	1,133	894	894	894	894	894	893	894	893	893	893	894	893	893	893	894	893	893	893	894	893
Demand Response	0	1	1	2	3	3	3	3	3	3	3	3	3	3	2	2	2	2	2	3	2	3	3	3	2
Non Firm Market	2,299	1,344	1,328	1,323	1,310	1,323	1,311	1,313	1,361	1,426	1,408	1,401	1,376	1,377	1,386	1,413	1,408	1,434	1,468	1,481	1,483	1,573	1,582	1,750	1,832
CAES	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
Battery Generation	0.51	0.60	0.49	2.55	11.58	14.19	16.77	15.43	19.69	21.20	21.92	20.96	21.92	22.09	22.68	21.22	21.16	21.89	21.99	22.87	18.64	20.92	19.82	24.61	10.44
Firm Imports	0	949	970	975	979	974	974	978	1,715	2,139	2,122	2,097	2,108	2,103	2,117	2,130	2,137	2,149	2,167	2,194	2,198	2,213	2,251	2,292	2,352

3.1C	GWh																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	3,998	3,758	3,711	3,729	3,061	3,207	2,979	3,040	1,108	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas - Existing	776	999	1,016	1,008	1,078	1,035	994	856	846	855	861	869	862	855	862	871	872	880	881	874	855	826	727	581	363
Gas - New CCs	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
Gas - New CTs & Recips	0	0	0	46	33	164	136	240	16	86	85	90	89	101	106	114	106	120	130	136	170	151	105	82	91
Gas - Conversion	0	0	0	0	0	0	0	0	0	33	32	30	29	36	36	26	46	35	30	36	23	18	4	5	6
Domestic Hydro	891	892	893	892	915	915	915	915	915	1,011	1,012	1,012	1,012	1,012	1,011	1,011	1,012	1,012	1,011	1,012	1,013	1,014	1,020	1,025	1,097
Tidal	0	0	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Biomass	332	350	357	356	348	351	342	345	349	352	356	354	354	355	354	358	363	359	370	363	361	372	401	405	413
Wind	1,903	1,899	1,899	1,897	2,530	2,530	2,846	2,849	4,116	4,216	4,219	4,222	4,230	4,237	4,242	4,253	4,264	4,276	4,285	4,293	4,284	4,329	4,394	4,502	4,441
Solar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	314	676
Diesel CTs	0	1	1	1	0	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	1	1	0	1	0
Maritime Link Blocks	1,133	1,133	1,133	1,134	1,133	894	893	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	893
Demand Response	0	1	1	2	3	3	3	2	3	3	3	3	3	3	3	3	3	3	3	3	2	3	3	3	3
Non Firm Market	2,300	1,348	1,329	1,315	1,322	1,317	1,317	1,304	1,412	1,628	1,630	1,649	1,645	1,652	1,677	1,711	1,732	1,743	1,757	1,790	1,818	1,853	1,943	1,906	1,921
CAES	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
Battery Generation	0.51	0.62	0.60	0.66	66.83	65.00	87.49	90.97	137.82	150.90	154.37	151.71	150.40	144.41	146.96	144.89	142.69	138.71	139.27	143.19	144.95	160.84	192.01	225.23	108.95
Firm Imports	0	949	968	978	978	983	982	980	1,752	2,303	2,305	2,324	2,354	2,387	2,414	2,454	2,470	2,522	2,571	2,618	2,642	2,682	2,734	2,592	2,449

3.2B	GWh																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	3,975	3,698	3,658	3,582	3,367	2,525	2,023	1,748	1,192	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas - Existing	752	1,024	982	990	1,029	918	881	866	869	912	909	919	918	914	910	894	900	905	898	904	849	730	610	431	233
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	170	178	267	399	423	454	420	440	420	277	252	250
Gas - New CTs & Recips	0	0	0	59	105	20	12	10	10	91	105	109	103	84	87	69	70	72	70	82	88	71	61	39	36
Gas - Conversion	0	0	0	0	0	0	0	0	37	91	85	78	84	53	59	41	53	57	54	57	48	23	2	3	0
Domestic Hydro	893	890	893	892	912	911	914	909	911	1,004	1,008	1,005	1,003	1,008	1,006	1,008	1,004	1,002	1,003	1,007	1,007	1,014	1,024	1,041	1,079
Tidal	0	0	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Biomass	335	351	345	350	343	349	348	349	344	351	354	350	349	350	350	351	354	351	358	351	353	361	371	411	410
Wind	1,903	1,896	1,898	1,898	1,968	1,972	2,805	2,933	3,319	3,413	3,405	3,408	3,412	3,412	3,425	3,433	3,434	3,452	3,455	3,480	3,525	3,683	3,836	3,980	4,079
Solar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	268
Diesel CTs	0	1	2	1	1	2	1	1	1	1	1	1	2	1	0	0	1	1	1	1	0	1	1	0	0
Maritime Link Blocks	1,133	1,133	1,133	1,134	1,133	894	894	894	894	893	893	894	893	893	893	894	893	893	893	894	894	894	894	894	894
Demand Response	0	0	1	2	3	4	4	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Non Firm Market	2,279	1,343	1,328	1,323	1,313	1,802	1,531	1,390	1,325	1,457	1,449	1,487	1,474	1,484	1,535	1,585	1,567	1,609	1,645	1,716	1,769	1,822	1,926	1,968	1,961
CAES	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
Battery Generation	0.46	0.67	0.59	0.83	11.82	7.05	12.65	14.36	19.19	19.06	19.54	18.90	19.62	18.38	20.11	18.20	18.04	17.86	17.34	19.29	32.03	81.12	130.53	178.65	198.62
Firm Imports	0	950	966	970	972	1,630	1,521	1,707	1,710	2,178	2,173	2,168	2,202	2,144	2,154	2,175	2,130	2,154	2,211	2,238	2,246	2,306	2,421	2,473	2,347

3.2C	GWh																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	4,022	3,819	3,720	3,737	3,157	3,360	3,320	3,310	1,271	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas - Existing	776	999	1,060	1,023	1,078	1,027	963	957	892	942	953	935	937	941	953	924	932	935	884	873	821	663	457	344	139
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	379	440	484	518	500	510	368	275	227	227
Gas - New CTs & Recips	0	0	0	55	45	139	113	170	33	111	115	118	107	122	128	94	94	100	94	84	97	63	60	51	62
Gas - Conversion	0	0	0	0	0	0	0	0	2	58	64	82	56	65	69	30	56	46	33	34	10	2	4	0	2
Domestic Hydro	892	893	892	891	915	916	915	915	915	1,012	1,011	1,012	1,012	1,012	1,011	1,012	1,012	1,011	1,020	1,017	1,019	1,026	1,061	1,084	1,180
Tidal	0	0	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Biomass	334	346	345	355	351	352	348	346	359	354	360	353	354	355	354	358	364	359	363	364	366	385	410	414	417
Wind	1,903	1,900	1,897	1,899	2,479	2,479	2,638	2,641	3,592	4,279	4,283	4,378	4,398	4,414	4,431	4,458	4,475	4,498	4,638	4,781	4,839	4,912	5,055	5,176	5,211
Solar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	19	315	592
Diesel CTs	0	1	2	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0	1
Maritime Link Blocks	1,133	1,133	1,133	1,134	1,133	894	894	894	893	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894
Demand Response	0	0	1	2	3	4	4	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	4	3
Non Firm Market	2,284	1,347	1,329	1,326	1,330	1,320	1,321	1,326	1,496	1,685	1,703	1,703	1,668	1,701	1,742	1,761	1,768	1,800	1,835	1,856	1,904	2,041	2,131	2,090	2,110
CAES	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
Battery Generation	0.49	0.54	0.48	0.70	71.72	74.19	81.93	91.74	105.65	155.75	158.39	158.46	156.75	152.58	154.45	152.87	150.09	147.24	199.85	246.97	259.94	296.09	353.05	395.75	321.34
Firm Imports	0	950	962	970	969	980	979	972	2,089	2,224	2,236	2,241	2,371	2,421	2,478	2,316	2,323	2,374	2,380	2,407	2,442	2,670	2,784	2,653	2,467

Sensitivities

2.0A.DSM-1 (Mid DSM)	GWh																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	4,007	3,774	3,469	3,400	3,219	3,356	3,365	3,103	3,120	2,440	2,243	2,144	2,005	1,839	1,745	1,738	1,757	1,749	1,385	0	0	0	0	0	0
Gas - Existing	767	989	976	982	990	996	971	1,017	881	863	871	862	847	839	849	854	862	864	883	900	880	885	886	875	872
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,678	1,695	1,766	1,841	1,903	1,993
Gas - New CTs & Recips	0	0	117	69	125	142	112	50	75	65	62	46	45	56	77	79	87	89	261	175	194	198	207	216	224
Gas - Conversion	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
Domestic Hydro	893	884	891	890	914	915	915	915	914	1,006	1,008	1,008	1,007	1,011	1,006	1,009	1,009	1,009	1,011	1,004	1,008	1,012	1,012	1,010	1,012
Tidal	0	0	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Biomass	333	353	349	344	338	343	338	364	363	357	352	345	343	346	352	350	350	349	359	359	360	362	360	362	359
Wind	1,903	1,903	2,073	2,078	2,088	2,088	2,088	2,089	2,090	2,599	2,762	3,072	3,220	3,483	3,477	3,490	3,494	3,495	3,505	3,506	3,497	3,502	3,504	3,506	3,504
Solar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Diesel CTs	0	0	0	0	0	0	0	1	1	0	0	0	1	0	1	0	0	0	2	3	4	5	3	1	1
Maritime Link Blocks	1,133	1,133	1,133	1,134	1,133	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894
Demand Response	0	0	1	2	3	4	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Non Firm Market	2,287	2,262	2,175	2,223	2,192	2,161	2,121	2,292	2,284	2,295	2,279	2,087	2,067	1,969	2,054	2,081	2,061	2,100	2,295	2,122	2,132	2,097	2,071	2,063	2,040
CAES	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
Battery Generation	0.51	0.42	1.27	2.23	3.31	2.91	3.19	1.48	1.87	2.85	3.28	4.15	4.55	5.49	5.97	8.90	8.76	8.70	9.04	9.60	5.43	5.40	5.00	3.86	2.33
Firm Imports	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

2.1C.DSM-2 (Mid DSM)	GWh																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	4,044	3,696	3,618	3,552	3,372	3,341	3,264	3,287	3,334	1,818	1,676	1,662	1,601	1,634	1,594	1,489	1,538	1,504	1,136	0	0	0	0	0	0
Gas - Existing	731	1,058	1,023	1,040	1,089	1,052	1,000	1,021	868	853	844	852	834	836	840	840	839	846	838	853	850	853	860	860	850
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	705	728	804	861	955	984
Gas - New CTs & Recips	0	0	53	95	122	233	171	107	220	173	51	53	46	57	55	23	31	22	354	125	163	159	168	172	202
Gas - Conversion	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
Domestic Hydro	892	892	892	893	914	915	913	914	915	1,011	1,004	1,008	1,001	1,002	1,002	1,000	1,002	1,004	983	1,002	1,005	1,006	1,008	1,005	1,011
Tidal	0	0	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Biomass	335	351	351	354	361	346	345	344	343	352	347	343	346	348	346	347	348	351	341	353	356	355	352	354	357
Wind	1,903	1,900	1,899	1,901	1,933	2,099	2,262	2,267	2,259	3,634	3,617	3,618	3,620	3,626	3,755	3,749	3,754	3,777	3,783	3,799	3,801	3,803	3,808	3,816	3,819
Solar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Diesel CTs	0	1	1	0	1	0	1	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	1	1	0
Maritime Link Blocks	1,133	1,133	1,133	1,134	1,133	894	894	894	893	894	894	894	894	894	894	894	893	894	894	894	894	894	894	894	893
Demand Response	0	0	1	2	3	3	4	3	3	3	3	3	3	3	3	3	3	3	3	2	3	3	3	3	2
Non Firm Market	2,295	1,349	1,323	1,319	1,322	1,325	1,322	1,317	1,272	1,322	1,494	1,522	1,501	1,511	1,484	1,396	1,399	1,399	1,449	1,598	1,607	1,625	1,615	1,596	1,617
CAES	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
Battery Generation	0.48	0.57	0.54	2.40	7.35	8.48	10.52	9.66	12.08	17.81	15.98	15.90	15.01	14.88	16.82	15.77	14.76	14.67	15.58	14.77	10.76	10.22	10.44	6.28	0.00
Firm Imports	0	948	967	974	974	974	977	979	975	971	1,100	1,111	1,238	1,231	1,236	1,565	1,568	1,663	1,778	2,317	2,303	2,296	2,314	2,301	2,314

2.2C.DSM-3 (Mid DSM)	GWh																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	3,992	3,801	3,820	3,792	2,634	1,931	1,678	1,761	1,809	1,742	1,795	1,811	1,695	1,743	1,734	1,750	1,390	1,401	1,181	0	0	0	0	0	0
Gas - Existing	788	1,009	1,005	1,044	959	868	863	865	850	859	870	880	848	872	877	888	908	938	882	902	901	891	908	891	729
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	953	1,420	1,505	1,585	1,691	1,755	1,653
Gas - New CTs & Recips	0	0	0	101	32	10	6	9	13	12	16	22	21	33	31	38	52	57	91	136	122	146	193	211	151
Gas - Conversion	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	22	16	5	25	27	38	31	28	4
Domestic Hydro	894	893	892	892	914	909	907	906	909	991	999	1,003	998	1,000	999	1,007	1,004	1,008	1,004	1,005	1,008	1,009	1,010	1,009	1,016
Tidal	0	0	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Biomass	336	354	355	354	350	338	340	341	343	347	346	347	345	348	347	353	352	357	352	351	354	355	351	355	364
Wind	1,903	1,901	1,899	1,899	3,265	3,403	3,800	3,790	3,796	3,805	3,800	3,815	4,052	4,053	4,107	4,124	4,132	4,157	4,166	4,173	4,172	4,171	4,166	4,182	4,202
Solar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Diesel CTs	1	1	2	1	1	2	1	1	1	1	0	1	1	1	1	1	1	1	0	1	1	1	4	4	6
Maritime Link Blocks	1,133	1,133	1,133	1,134	1,133	894	894	894	893	893	893	894	894	894	894	894	894	893	894	894	894	894	894	894	894
Demand Response	0	0	1	2	3	4	4	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Non Firm Market	2,299	1,347	1,344	1,329	1,347	1,455	1,387	1,384	1,371	1,370	1,365	1,361	1,367	1,370	1,385	1,395	1,496	1,523	1,372	1,724	1,721	1,729	1,710	1,741	1,933
CAES	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
Battery Generation	0.56	0.69	2.31	2.56	17.19	14.81	20.35	20.25	21.13	21.14	20.91	19.51	23.61	22.21	30.57	29.59	26.61	27.26	31.07	29.99	24.78	25.14	21.03	20.10	8.41
Firm Imports	0	950	954	966	949	1,818	1,804	1,790	1,771	1,748	1,741	1,786	1,775	1,804	1,877	1,965	2,290	2,330	1,929	2,337	2,363	2,370	2,343	2,331	2,549

2.0C.DSM-4 (Low DSM)	GWh																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	4,017	3,735	3,663	3,680	3,443	3,383	3,342	3,397	3,325	3,056	2,603	2,333	2,304	2,133	2,068	2,096	1,740	1,721	1,282	0	0	0	0	0	0
Gas - Existing	766	996	1,035	1,047	1,044	1,169	1,053	1,017	1,041	1,087	986	979	991	955	1,004	1,006	847	851	865	864	847	861	858	867	850
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	920	917	950	960	1,023	1,034
Gas - New CTs & Recips	0	0	0	0	0	146	136	112	142	226	74	82	85	67	104	131	46	36	32	115	141	150	184	159	169
Gas - Conversion	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
Domestic Hydro	892	892	893	893	915	914	915	915	913	1,010	1,011	1,011	1,012	1,012	1,012	1,012	1,005	1,002	1,004	1,005	1,004	1,006	1,008	1,008	1,009
Tidal	0	0	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Biomass	333	351	356	353	348	353	345	349	347	361	364	360	361	355	357	362	356	355	359	355	353	351	355	355	355
Wind	1,903	1,897	1,898	1,901	2,096	2,095	2,262	2,266	2,262	2,258	2,938	3,245	3,250	3,519	3,531	3,530	3,526	3,531	3,536	3,542	3,534	3,532	3,531	3,538	3,493
Solar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Diesel CTs	0	1	1	1	0	1	0	0	0	1	2	2	3	2	3	1	0	0	0	0	4	4	3	3	3
Maritime Link Blocks	1,133	1,133	1,133	1,134	1,133	894	894	894	894	894	894	894	894	894	894	894	893	894	894	894	894	894	893	894	893
Demand Response	0	0	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1
Non Firm Market	2,278	1,343	1,326	1,315	1,315	1,323	1,321	1,320	1,308	1,293	1,317	1,321	1,329	1,329	1,325	1,326	1,523	1,553	1,490	1,546	1,551	1,557	1,564	1,562	1,600
CAES	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
Battery Generation	0.49	0.53	0.52	0.42	4.15	5.26	5.75	5.47	5.40	6.92	5.63	7.38	7.82	9.39	9.29	9.22	7.13	7.25	6.83	7.65	4.54	4.39	4.33	4.41	0.00
Firm Imports	0	951	970	980	978	976	976	979	977	980	976	973	971	969	974	973	1,416	1,452	1,976	2,243	2,255	2,238	2,236	2,226	2,285

2.0C.DSM-5 (Mid DSM)	GWh																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	3,952	3,773	3,608	3,560	3,385	3,335	3,233	3,137	3,089	1,916	1,854	1,876	1,823	1,736	1,568	1,488	1,498	1,518	1,277	0	0	0	0	0	0
Gas - Existing	822	981	1,014	1,003	1,046	973	985	988	976	957	954	947	958	930	949	928	937	933	880	912	924	942	948	969	861
Gas - New CCs	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
Gas - New CTs & Recips	0	0	0	0	0	90	92	116	86	68	77	59	56	53	89	125	132	129	36	65	111	100	114	110	144
Gas - Conversion	0	0	0	0	0	0	0	0	0	0	0	59	0	0	0	0	0	0	0	0	0	0	0	0	0
Domestic Hydro	894	893	892	892	915	915	915	915	915	1,011	1,011	59	1,012	1,011	1,011	1,011	1,012	1,011	1,011	1,011	1,011	1,011	1,012	1,011	1,012
Tidal	0	0	26	26	26	26	26	26	26	26	26	59	26	26	26	26	26	26	26	26	26	26	26	26	26
Biomass	339	354	356	356	345	347	339	342	345	352	354	59	355	351	349	350	346	350	347	362	358	358	359	363	363
Wind	1,904	1,900	1,906	1,904	1,909	2,075	2,073	2,074	2,070	3,053	3,053	59	3,053	3,188	3,330	3,455	3,452	3,461	3,458	3,474	3,458	3,466	3,465	3,470	3,470
Solar	4	4	4	4	4	4	4	4	4	4	4	59	4	4	4	4	4	4	4	4	4	4	4	4	4
Diesel CTs	0	1	1	1	1	0	0	0	0	1	1	59	1	1	2	1	1	0	0	0	3	3	2	3	3
Maritime Link Blocks	1,133	1,133	1,133	1,134	1,133	894	894	894	894	894	894	59	894	894	894	894	893	894	894	894	894	893	893	894	894
Demand Response	0	0	1	2	3	4	4	3	3	3	3	59	3	2	3	3	3	3	3	3	3	3	3	3	3
Non Firm Market	2,300	1,338	1,329	1,318	1,314	1,310	1,312	1,301	1,289	1,313	1,318	59	1,323	1,320	1,310	1,292	1,294	1,305	1,412	1,618	1,621	1,636	1,655	1,662	1,677
CAES	0	0	0	0	0	0	0	0	0	0	0	59	0	0	0	0	0	0	0	0	0	0	0	0	0
Battery Generation	0.55	0.50	0.90	1.04	1.37	3.11	3.51	2.99	3.36	3.98	4.26	59	4.11	4.45	5.41	6.45	5.90	6.05	5.45	5.57	2.22	2.11	1.47	1.34	0.61
Firm Imports	0	951	969	978	978	983	984	983	982	979	979	59	977	978	977	978	973	973	1,304	2,330	2,308	2,336	2,355	2,370	2,502

2.0C.DSM-6 (Max DSM)	GWh																								
Generator Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	4,007	3,766	3,558	3,384	3,167	3,253	3,139	3,049	3,006	2,832	2,791	2,385	2,367	1,906	1,512	1,444	1,450	1,468	1,304	0	0	0	0	0	0
Gas - Existing	779	987	1,014	987	1,006	1,008	995	997	956	975	972	1,011	1,020	954	928	932	929	934	987	909	932	928	952	928	863
Gas - New CCs	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
Gas - New CTs & Recips	0	0	0	86	110	111	125	117	111	116	108	276	271	63	86	92	101	102	155	35	39	50	49	46	76
Gas - Conversion	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
Domestic Hydro	892	893	893	890	913	915	915	914	915	1,009	1,011	1,010	1,010	1,012	1,011	1,011	1,012	1,011	1,011	1,011	1,011	1,011	1,011	1,009	1,012
Tidal	0	0	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Biomass	337	349	354	350	345	342	343	340	341	346	350	355	353	356	348	352	346	351	353	356	360	359	360	362	363
Wind	1,904	1,900	1,900	1,898	1,897	1,899	1,895	1,898	1,894	1,892	1,892	2,213	2,208	2,737	3,176	3,307	3,308	3,313	3,439	3,443	3,441	3,446	3,450	3,454	3,460
Solar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Diesel CTs	0	1	1	1	0	0	0	0	1	0	0	0	0	0	1	0	1	1	4	0	0	0	0	0	0
Maritime Link Blocks	1,133	1,133	1,133	1,134	1,133	894	894	894	894	894	894	894	893	894	894	894	894	894	893	894	893	894	894	894	894
Demand Response	0	0	1	2	3	3	4	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Non Firm Market	2,296	1,346	1,317	1,316	1,314	1,323	1,316	1,312	1,293	1,238	1,238	1,104	1,104	1,324	1,310	1,281	1,294	1,302	1,293	1,590	1,588	1,594	1,624	1,627	1,648
CAES	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
Battery Generation	0.55	0.68	0.50	0.81	3.38	3.15	3.93	3.48	3.48	4.12	4.75	5.78	5.75	4.77	7.84	8.30	8.56	8.11	9.66	6.96	2.97	3.07	2.86	2.87	2.83
Firm Imports	0	951	976	978	979	977	979	981	982	982	982	979	976	975	976	975	978	974	963	2,211	2,208	2,254	2,257	2,328	2,407

3.1C.DSM-7 (Mid DSM)	GWh																								
Generator Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	4,031	3,763	3,613	3,525	3,114	3,233	3,215	3,223	1,605	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas - Existing	745	1,000	1,038	1,018	1,052	1,052	1,036	1,030	989	939	853	860	840	854	859	853	864	859	863	863	845	834	746	582	357
Gas - New CCs	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
Gas - New CTs & Recips	0	0	34	50	31	94	103	80	171	109	84	91	89	102	86	84	85	100	115	115	251	111	99	87	105
Gas - Conversion	0	0	0	0	0	0	0	0	0	40	35	36	40	44	29	41	51	40	32	35	21	13	3	2	6
Domestic Hydro	894	887	893	891	914	914	915	915	915	1,009	1,009	1,011	1,010	1,012	1,011	1,010	1,011	1,011	1,011	1,012	1,012	1,013	1,014	1,023	1,088
Tidal	0	0	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Biomass	337	351	354	350	347	352	345	349	342	352	357	353	355	355	355	358	359	361	365	360	360	367	392	402	410
Wind	1,903	1,897	1,899	2,007	2,369	2,370	2,372	2,369	4,053	4,055	4,059	4,059	4,065	4,073	4,084	4,095	4,099	4,117	4,129	4,129	4,122	4,142	4,145	4,133	4,081
Solar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	399	785
Diesel CTs	1	1	0	1	0	0	0	0	3	1	1	0	0	1	1	0	0	1	0	1	9	0	0	1	1
Maritime Link Blocks	1,133	1,133	1,133	1,134	1,133	894	894	894	893	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	893
Demand Response	0	0	1	2	3	4	4	3	3	3	3	2	3	3	3	3	3	3	3	3	3	3	3	3	3
Non Firm Market	2,290	1,347	1,328	1,318	1,311	1,319	1,315	1,317	1,193	1,707	1,616	1,628	1,631	1,636	1,622	1,640	1,662	1,677	1,696	1,740	1,712	1,824	1,920	1,882	1,880
CAES	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
Battery Generation	0.65	0.62	0.59	12.20	47.16	44.81	48.17	47.84	118.09	119.46	116.56	114.69	114.62	111.95	111.59	112.00	108.18	103.00	106.55	109.00	107.95	114.13	122.82	106.44	19.01
Firm Imports	0	949	967	976	980	980	983	981	957	1,965	2,160	2,171	2,199	2,210	2,307	2,367	2,387	2,439	2,489	2,538	2,514	2,625	2,690	2,578	2,424

2.1C.WIND-1 (Low Wind Cost)	GWh																								
Generator Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	3,999	3,766	3,324	3,382	1,948	1,690	1,660	1,681	1,678	1,525	1,536	1,539	1,524	1,547	1,508	1,619	1,637	1,616	1,002	0	0	0	0	0	0
Gas - Existing	784	999	1,044	990	929	875	880	885	884	864	865	879	864	864	881	880	882	884	868	920	916	916	923	926	929
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	761	798	854	903	935	1,019	1,023
Gas - New CTs & Recips	0	0	46	81	30	12	10	4	4	4	4	4	3	6	7	9	8	6	27	131	150	159	164	177	204
Gas - Conversion	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
Domestic Hydro	894	892	890	893	915	909	912	911	910	998	1,002	1,004	998	998	998	1,003	1,006	1,000	997	1,005	1,007	1,005	1,009	1,007	1,008
Tidal	0	0	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Biomass	333	350	346	345	344	340	340	345	345	345	346	347	342	348	350	352	351	350	346	353	356	354	353	350	353
Wind	1,902	1,896	2,231	2,242	3,817	3,817	3,822	3,819	3,802	3,821	3,811	3,816	3,821	3,824	3,841	3,840	3,852	3,863	3,866	3,878	3,881	3,883	3,889	3,904	3,896
Solar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Diesel CTs	0	1	1	0	1	1	1	1	1	1	1	1	1	2	1	2	1	1	0	0	0	0	0	0	0
Maritime Link Blocks	1,133	1,133	1,133	1,134	1,133	893	893	894	893	893	894	894	894	894	893	894	894	894	894	894	894	894	894	894	894
Demand Response	0	1	1	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	2	2	3	3	2
Non Firm Market	2,289	1,341	1,318	1,310	1,295	1,431	1,443	1,385	1,356	1,343	1,341	1,339	1,344	1,346	1,353	1,349	1,366	1,377	1,324	1,628	1,619	1,626	1,642	1,621	1,641
CAES	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
Battery Generation	0.68	0.53	1.69	2.13	28.75	24.19	26.41	26.09	26.35	26.58	28.04	26.41	26.49	24.43	24.15	23.57	22.31	22.83	24.19	24.29	23.37	23.83	23.70	23.24	3.85
Firm Imports	0	950	974	979	951	1,392	1,407	1,461	1,487	1,534	1,545	1,571	1,627	1,650	1,715	1,696	1,712	1,802	1,796	2,362	2,348	2,365	2,376	2,357	2,389

2.1C.WIND-2 (Low Wind & Batte GWh																									
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	3,999	3,742	2,772	2,044	1,893	1,999	2,003	2,058	2,064	1,782	1,790	1,807	1,838	1,860	1,802	1,712	1,694	1,702	1,087	0	0	0	0	0	0
Gas - Existing	772	1,015	945	936	929	943	936	922	928	977	981	989	978	996	995	929	898	895	910	905	866	853	855	869	851
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	690	777	811	872	937	989
Gas - New CTs & Recips	0	0	13	21	17	80	76	72	82	126	121	131	126	134	223	68	42	43	41	112	170	188	188	188	207
Gas - Conversion	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
Domestic Hydro	890	891	893	893	914	915	915	915	915	1,011	1,011	1,011	1,012	1,011	1,011	1,010	1,010	1,008	1,003	1,008	1,007	1,010	1,009	1,010	1,009
Tidal	0	0	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Biomass	335	351	351	346	337	346	344	343	342	348	348	349	346	355	371	348	349	353	360	355	356	357	357	357	356
Wind	1,904	1,900	2,900	3,719	3,931	3,941	3,943	3,943	3,935	3,943	3,946	3,942	3,954	3,963	3,977	3,968	3,974	3,989	4,001	4,006	4,010	4,009	4,012	4,022	4,020
Solar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Diesel CTs	0	1	1	2	3	1	1	1	1	1	1	1	2	1	1	1	1	0	0	0	0	1	0	0	0
Maritime Link Blocks	1,133	1,133	1,133	1,134	1,133	893	894	894	894	893	894	894	894	894	894	894	894	894	894	894	893	894	893	894	894
Demand Response	0	1	1	2	3	3	3	2	2	3	3	3	3	2	2	3	3	3	3	2	2	3	2	3	2
Non Firm Market	2,300	1,347	1,349	1,313	1,271	1,295	1,304	1,281	1,242	1,291	1,296	1,312	1,315	1,314	1,320	1,592	1,496	1,520	1,546	1,660	1,645	1,671	1,671	1,644	1,650
CAES	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
Battery Generation	0.48	0.44	1.38	2.60	67.12	66.27	66.63	66.43	66.77	69.00	68.72	69.65	67.32	71.08	69.82	63.51	57.87	58.85	53.57	57.92	57.98	53.89	55.58	56.23	3.01
Firm Imports	0	949	948	947	951	964	968	972	973	973	971	973	970	969	969	1,136	1,367	1,403	2,053	2,354	2,312	2,324	2,340	2,346	2,366

2.1C.WIND-3 (Low Inertia Constr GWh																									
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	4,018	3,699	3,551	3,514	3,347	3,427	3,414	3,455	3,412	3,037	2,723	2,467	2,356	1,774	1,682	1,736	1,719	1,676	1,070	0	0	0	0	0	0
Gas - Existing	750	1,054	1,147	1,029	1,124	1,117	1,146	1,089	1,107	1,263	1,033	1,035	1,026	895	877	900	845	843	858	863	845	857	860	864	844
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	933	930	997	1,046	1,034	1,055
Gas - New CTs & Recips	0	0	19	57	93	79	71	105	109	164	85	87	89	23	19	20	13	15	44	162	242	205	187	198	194
Gas - Conversion	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
Domestic Hydro	892	893	893	893	915	915	915	915	915	1,010	1,012	1,011	1,011	1,002	999	1,007	1,006	999	1,000	1,008	1,008	1,010	1,008	1,008	1,008
Tidal	0	0	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Biomass	338	354	363	360	361	369	366	366	362	403	365	363	360	349	351	349	350	351	361	352	355	357	354	356	357
Wind	1,904	1,900	1,902	2,072	2,082	2,249	2,252	2,252	2,251	2,249	2,921	3,226	3,370	3,736	3,750	3,760	3,755	3,774	3,785	3,796	3,730	3,796	3,810	3,818	3,820
Solar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Diesel CTs	0	1	2	0	0	1	1	1	1	2	3	4	5	2	1	1	2	1	1	1	4	1	1	1	1
Maritime Link Blocks	1,133	1,133	1,133	1,134	1,133	894	894	894	894	894	894	894	894	894	894	894	893	894	894	894	893	894	894	894	893
Demand Response	0	1	1	2	3	3	3	3	3	3	3	3	3	3	3	2	2	3	2	2	2	3	3	3	2
Non Firm Market	2,299	1,345	1,349	1,347	1,330	1,326	1,329	1,330	1,329	1,325	1,327	1,327	1,327	1,457	1,463	1,469	1,400	1,421	1,484	1,606	1,625	1,630	1,660	1,681	1,728
CAES	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
Battery Generation	0.60	0.59	0.50	0.71	2.04	2.07	2.29	2.29	2.52	2.80	2.88	4.05	4.51	4.48	4.70	4.36	4.34	4.01	3.52	3.63	0.98	1.46	1.82	1.77	0.00
Firm Imports	0	949	949	949	967	974	971	970	970	975	973	972	972	1,339	1,503	1,499	1,718	1,810	2,378	2,347	2,380	2,349	2,356	2,392	2,429

2.1C.WIND-4 (No Inertia / No Int GWh																									
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	4,031	3,760	3,495	3,219	2,730	2,850	2,202	2,202	2,204	2,005	1,787	1,803	1,755	1,756	1,575	1,618	1,381	1,391	1,161	0	0	0	0	0	0
Gas - Existing	734	995	1,023	1,013	963	1,026	939	945	960	975	976	986	958	1,003	977	979	1,011	1,040	1,063	877	866	884	854	862	883
Gas - New CCs	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
Gas - New CTs & Recips	0	0	24	22	49	80	75	81	77	108	120	133	127	141	167	182	249	269	372	86	96	107	99	97	114
Gas - Conversion	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	69	73	75	44	40	41	43	42	41
Domestic Hydro	894	887	893	893	915	915	915	915	915	1,011	1,011	1,011	1,009	1,010	1,009	1,009	1,010	1,009	1,010	998	1,000	1,004	1,003	1,001	1,006
Tidal	0	0	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Biomass	338	364	369	364	351	364	350	352	350	349	342	344	343	341	337	343	355	359	350	347	348	347	346	346	345
Wind	1,904	1,901	2,072	2,413	2,915	2,920	3,684	3,689	3,687	3,691	3,968	3,967	4,096	4,097	4,450	4,467	4,588	4,600	4,821	4,938	5,030	5,046	5,309	5,348	5,347
Solar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Diesel CTs	0	1	1	1	1	2	2	3	3	2	4	4	3	5	4	4	7	5	7	4	3	2	3	4	4
Maritime Link Blocks	1,133	1,133	1,133	1,134	1,133	894	893	894	893	893	893	894	893	893	893	894	893	893	893	893	893	893	893	893	893
Demand Response	0	1	1	2	3	3	3	2	2	3	3	3	3	2	2	3	3	3	3	2	2	3	3	3	3
Non Firm Market	2,300	1,338	1,347	1,347	1,342	1,350	1,339	1,337	1,293	1,315	1,263	1,270	1,257	1,256	1,160	1,170	1,178	1,180	1,166	1,442	1,413	1,440	1,358	1,367	1,381
CAES	0.65	0.54	0.63	0.85	1.50	1.83	2.67	2.84	2.69	2.72	3.17	3.10	3.31	3.39	3.56	3.55	3.59	3.46	3.63	3.01	3.46	3.10	3.37	3.56	3.27
Battery Generation	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
Firm Imports	0	949	949	949	953	949	959	958	969	971	971	972	967	968	968	969	959	963	954	2,331	2,325	2,333	2,267	2,286	2,318

2.1C.Mersey	GWh																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	3,995	3,728	3,721	3,866	3,737	3,753	3,483	3,536	3,602	1,523	1,485	1,489	1,473	1,467	1,491	1,598	1,580	1,608	1,129	0	0	0	0	0	0
Gas - Existing	747	994	1,023	1,001	1,172	1,131	1,156	1,161	1,078	876	875	878	879	866	872	889	896	900	896	910	923	916	929	925	945
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	921	1,010	1,017	1,019	1,055	1,062	1,062
Gas - New CTs & Recips	0	0	0	0	0	231	326	289	286	12	11	14	9	12	16	17	19	21	42	195	238	259	265	256	244
Gas - Conversion	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
Domestic Hydro	930	930	853	777	722	723	723	723	723	718	718	720	715	718	715	720	722	719	717	718	723	722	723	721	721
Tidal	0	0	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Biomass	334	352	346	355	354	388	374	373	369	351	346	346	348	349	352	351	355	357	343	352	355	353	357	354	356
Wind	1,904	1,899	1,934	1,933	1,936	1,934	2,104	2,103	2,101	3,760	3,751	3,757	3,769	3,771	3,783	3,786	3,794	3,806	3,801	3,822	3,802	3,807	3,704	3,742	3,769
Solar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Diesel CTs	0	1	1	1	1	1	0	0	1	1	1	1	2	1	2	1	1	1	0	0	4	3	5	4	6
Maritime Link Blocks	1,133	1,133	1,133	1,134	1,133	894	894	894	894	894	894	894	894	893	893	894	894	894	894	894	894	893	893	894	893
Demand Response	0	1	1	2	3	3	3	3	3	3	3	3	3	2	2	3	3	3	2	2	2	2	3	3	2
Non Firm Market	2,290	1,344	1,335	1,321	1,326	1,322	1,325	1,325	1,322	1,392	1,385	1,386	1,389	1,409	1,396	1,390	1,403	1,421	1,319	1,637	1,640	1,676	1,733	1,749	1,773
CAES	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
Battery Generation	0.53	0.52	4.61	4.29	3.80	5.08	5.50	5.61	6.36	10.00	10.16	9.64	9.97	9.45	10.47	9.55	9.65	9.12	10.46	9.76	6.52	6.55	0.51	0.48	1.14
Firm Imports	0	949	962	970	974	978	975	975	978	1,796	1,872	1,901	1,935	1,985	2,022	1,990	2,041	2,060	1,814	2,426	2,421	2,450	2,513	2,539	2,560

2.1C.Import-1 (Limited Non-Firm	GWh																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	4,715	4,465	4,141	4,236	3,331	2,587	2,600	2,539	2,747	1,977	1,981	2,037	1,929	1,722	1,739	1,779	1,738	1,665	1,294	0	0	0	0	0	0
Gas - Existing	855	1,082	1,308	1,245	1,077	927	914	912	860	850	847	853	847	846	852	865	865	860	874	870	855	868	877	872	821
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,636	1,642	1,657	1,687	1,700	1,626
Gas - New CTs & Recips	0	0	53	49	114	50	60	71	88	49	53	63	64	35	39	21	27	33	62	103	128	135	131	133	127
Gas - Conversion	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
Domestic Hydro	893	891	893	894	915	911	915	912	912	1,006	1,005	1,007	1,003	1,002	1,005	987	1,000	998	1,006	1,000	1,003	1,003	1,010	1,005	1,003
Tidal	0	0	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Biomass	342	358	377	393	375	356	354	362	362	362	355	355	356	355	356	358	356	365	369	360	363	364	363	364	368
Wind	1,902	1,899	1,900	1,903	2,907	2,893	2,900	2,907	2,900	3,704	3,699	3,700	3,706	3,707	3,731	3,728	3,729	3,745	3,772	3,747	3,680	3,752	3,766	3,781	3,792
Solar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Diesel CTs	0	1	1	1	1	0	1	1	1	0	0	0	1	1	0	0	0	1	0	0	3	1	1	1	0
Maritime Link Blocks	1,133	1,133	1,133	1,134	1,133	894	893	894	894	894	894	894	894	893	894	894	894	894	894	894	894	894	893	894	893
Demand Response	0	1	1	2	3	3	3	3	2	3	3	3	3	2	2	3	3	3	3	2	2	3	2	2	2
Non Firm Market	1,493	552	553	555	555	1,273	1,261	1,284	1,154	928	950	935	1,014	855	849	703	724	750	851	889	917	941	951	963	1,050
CAES	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
Battery Generation	0.60	0.59	0.50	0.71	2.04	2.07	2.29	2.29	2.52	2.80	2.88	4.05	4.51	4.48	4.70	4.36	4.34	4.01	3.52	3.63	0.98	1.46	1.82	1.77	0.00
Firm Imports	0	948	947	945	945	1,458	1,459	1,494	1,434	1,550	1,549	1,541	1,596	2,053	2,074	2,299	2,367	2,473	2,749	2,461	2,528	2,480	2,496	2,531	2,647

2.0A.Import-2 (No Reliability Tie	GWh																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	4,051	3,826	3,664	3,660	3,089	3,177	3,105	3,128	3,060	2,721	2,697	2,797	2,743	2,793	2,367	2,135	1,954	1,785	1,428	0	0	0	0	0	0
Gas - Existing	727	977	1,010	971	978	993	995	1,007	856	864	860	849	853	849	874	751	759	826	781	890	872	879	874	796	572
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	822	1,483	2,567	2,565	2,592	2,546	2,546	2,592
Gas - New CTs & Recips	0	0	94	115	132	129	111	133	183	346	318	268	306	229	429	850	839	358	265	364	439	447	421	354	198
Gas - Conversion	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
Domestic Hydro	894	892	894	893	915	915	915	915	914	1,009	1,011	1,010	1,010	1,009	1,009	1,013	1,021	1,011	1,011	1,009	1,008	1,008	1,009	1,012	1,015
Tidal	0	0	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Biomass	338	352	351	353	346	347	344	345	340	348	349	348	338	347	356	352	374	353	355	358	358	355	358	360	411
Wind	1,904	1,904	1,904	1,904	2,411	2,414	2,415	2,414	2,751	2,749	2,745	2,743	2,747	2,743	2,748	2,750	2,751	2,749	2,746	3,027	3,040	3,064	3,161	3,182	3,192
Solar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	92
Diesel CTs	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	2	1	0
Maritime Link Blocks	1,133	1,133	1,133	1,134	1,133	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894	894
Demand Response	0	1	1	2	3	3	3	2	3	3	3	3	3	2	2	3	3	3	3	3	3	3	3	3	3
Non Firm Market	2,300	2,239	2,205	2,208	2,194	2,262	2,295	2,195	1,959	1,943	1,968	1,934	1,928	1,967	2,172	2,145	2,300	2,139	2,014	1,931	1,881	1,869	1,901	2,063	2,297
CAES	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
Battery Generation	0.46	0.55	0.73	0.87	65.24	51.19	49.70	47.94	67.00	55.30	65.30	56.87	58.14	56.92	64.31	0.00	52.70	67.56	67.27	87.91	91.19	88.48	100.34	111.61	78.02
Firm Imports	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

2.1C.Import-3 (Limited Reliabilit	GWh																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	4,044	3,777	3,651	3,713	3,528	3,300	3,286	3,410	2,935	1,898	1,890	1,906	1,822	1,828	1,749	1,760	1,787	1,770	1,052	0	0	0	0	0	0
Gas - Existing	747	984	1,038	989	965	1,064	1,096	1,107	876	834	836	840	829	838	834	843	836	838	837	853	856	857	855	866	839
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	860	884	912	960	1,004	1,006	994
Gas - New CTs & Recips	0	0	38	80	81	284	269	114	127	242	222	194	229	231	212	224	235	229	174	395	387	420	374	377	387
Gas - Conversion	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
Domestic Hydro	891	893	893	892	915	914	914	915	913	993	1,002	1,005	995	999	999	1,005	1,000	1,000	1,003	1,002	1,008	1,009	1,009	1,001	1,007
Tidal	0	0	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Biomass	335	348	356	354	347	346	348	374	356	338	335	333	334	337	339	339	339	340	346	349	351	350	353	352	355
Wind	1,903	1,898	1,899	1,900	2,086	2,251	2,252	2,262	2,260	3,573	3,692	3,688	3,709	3,705	3,723	3,731	3,727	3,752	3,747	3,763	3,764	3,763	3,779	3,793	3,798
Solar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Diesel CTs	0	1	1	0	1	1	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	1	0	0
Maritime Link Blocks	1,133	1,133	1,133	1,134	1,133	894	894	894	893	893	893	894	893	893	893	894	893	893	893	894	893	893	893	894	893
Demand Response	0	1	1	2	3	3	3	3	3	3	3	3	3	2	3	2	3	3	3	2	2	2	3	3	2
Non Firm Market	2,281	1,346	1,330	1,318	1,322	1,325	1,328	1,329	1,562	1,214	1,171	1,187	1,204	1,217	1,227	1,241	1,263	1,295	1,245	1,529	1,539	1,550	1,590	1,613	1,666
CAES	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
Battery Generation	0.49	0.51	0.65	0.61	4.58	5.15	5.23	3.31	3.12	7.94	8.52	8.22	8.24	9.25	8.78	8.67	8.33	8.06	8.85	8.08	4.00	3.88	3.90	3.92	0.00
Firm Imports	0	948	968	977	976	975	972	971	1,430	1,337	1,294	1,340	1,396	1,424	1,564	1,599	1,623	1,668	1,717	2,292	2,306	2,295	2,319	2,343	2,390

2.1C.CAPEX-1 (High Sustaining Ca	GWh																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	4,016	3,729	3,707	3,686	3,126	3,178	3,034	3,027	2,699	1,787	1,778	1,784	1,696	1,670	1,672	1,581	1,591	1,595	1,269	0	0	0	0	0	0
Gas - Existing	780	1,036	1,016	1,072	1,097	894	877	888	855	842	841	840	841	842	841	848	850	851	852	872	861	846	854	868	860
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	932	954	1,015	1,030	1,051	1,043
Gas - New CTs & Recips	0	0	0	0	0	52	58	70	53	34	35	37	40	42	32	27	27	26	36	163	188	207	218	205	208
Gas - Conversion	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
Domestic Hydro	893	891	893	893	915	915	915	915	914	999	1,006	1,004	1,004	1,004	1,002	999	1,006	1,005	999	1,000	1,002	1,008	1,009	1,008	1,008
Tidal	0	0	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Biomass	331	352	357	369	368	362	360	362	353	351	347	348	350	349	350	349	350	356	358	354	354	351	353	353	356
Wind	1,901	1,898	1,900	1,903	2,422	2,754	2,918	2,920	2,908	3,603	3,605	3,611	3,621	3,758	3,767	3,763	3,763	3,788	3,800	3,803	3,801	3,806	3,810	3,821	3,830
Solar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Diesel CTs	0	1	2	2	3	10	5	3	0	1	0	0	0	1	0	0	0	0	1	0	0	0	0	0	0
Maritime Link Blocks	1,133	1,133	1,133	1,134	1,133	893	894	894	894	893	894	894	893	893	894	894	893	893	894	894	893	894	894	894	894
Demand Response	0	1	1	2	3	3	3	3	3	3	3	3	3	2	2	3	2	3	3	2	2	2	3	3	2
Non Firm Market	2,279	1,338	1,330	1,347	1,336	1,333	1,333	1,324	1,692	1,466	1,465	1,484	1,530	1,512	1,474	1,420	1,433	1,451	1,460	1,602	1,625	1,634	1,651	1,679	1,734
CAES	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
Battery Generation	0.54	0.65	0.42	0.45	2.10	2.90	3.29	3.14	2.58	4.36	4.37	4.15	4.30	6.08	5.79	5.62	5.37	5.61	5.04	5.49	1.81	1.88	1.81	1.81	0.00
Firm Imports	0	950	969	949	953	960	965	973	984	1,345	1,364	1,383	1,432	1,399	1,506	1,755	1,789	1,817	2,204	2,341	2,335	2,335	2,356	2,367	2,395

2.1C.CAPEX-2 (Low Sustaining Ca	GWh																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	3,967	3,742	3,746	3,768	3,593	3,704	3,754	3,677	3,516	3,058	2,712	2,398	2,124	2,068	2,068	2,092	2,140	1,841	1,298	0	0	0	0	0	0
Gas - Existing	799	1,023	993	1,019	1,113	1,052	1,024	1,052	1,127	1,075	988	944	944	954	974	998	999	908	900	909	929	930	949	931	905
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	835	853	884	947	1,003	1,025
Gas - New CTs & Recips	0	0	0	0	0	184	164	226	283	390	113	87	118	115	148	180	191	44	23	154	214	223	224	228	227
Gas - Conversion	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
Domestic Hydro	892	891	892	891	913	915	915	915	915	1,009	1,012	1,012	1,011	1,011	1,011	1,012	1,011	1,003	1,002	1,001	1,009	1,008	1,010	1,009	1,010
Tidal	0	0	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Biomass	339	351	355	350	351	358	361	365	371	362	360	355	351	352	357	359	362	351	359	354	356	351	351	354	354
Wind	1,903	1,898	1,897	1,898	1,952	1,949	1,949	1,950	1,948	2,277	2,958	3,402	3,670	3,793	3,800	3,809	3,812	3,819	3,824	3,831	3,830	3,833	3,836	3,844	3,785
Solar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Diesel CTs	0	1	1	1	2	0	0	1	0	1	2	1	2	2	2	2	2	1	1	0	4	5	4	4	4
Maritime Link Blocks	1,133	1,133	1,133	1,134	1,133	894	894	894	894	894	894	894	894	894	893	894	894	893	894	894	893	894	894	894	894
Demand Response	0	1	1	2	3	3	3	3	3	3	3	3	3	2	2	2	3	3	3	2	2	3	3	3	2
Non Firm Market	2,299	1,339	1,335	1,327	1,326	1,322	1,320	1,324	1,323	1,283	1,329	1,324	1,347	1,319	1,322	1,321	1,326	1,516	1,439	1,632	1,617	1,630	1,628	1,622	1,683
CAES	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
Battery Generation	0.54	0.59	0.49	0.45	5.99	7.23	7.05	7.66	7.24	10.49	9.17	12.59	14.36	15.54	15.19	14.56	14.34	12.96	11.65	12.05	9.40	9.25	8.97	9.39	0.52
Firm Imports	0	950	955	966	974	978	980	976	977	976	971	971	952	967	967	973	968	1,412	2,136	2,353	2,312	2,343	2,336	2,359	2,446

2.1C.PRICES-1 (High Import & Ga	GWh																								
Generator / Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	4,279	3,798	3,739	3,763	3,459	3,454	3,371	3,425	3,476	2,510	2,484	2,124	2,115	2,157	2,088	2,151	1,959	2,014	1,472	0	0	0	0	0	0
Gas - Existing	591	964	982	997	1,035	1,007	1,050	1,031	1,009	945	965	932	923	924	964	986	843	842	865	863	868	867	865	880	880
Gas - New CCs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	964	907	976	1,026	1,024	1,063
Gas - New CTs & Recips	0	0	31	30	95	194	266	229	125	95	102	94	101	113	165	176	18	7	124	203	285	272	274	266	220
Gas - Conversion	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
Domestic Hydro	891	893	890	891	914	915	914	915	915	1,011	1,011	1,011	1,011	1,011	1,011	1,012	1,009	1,004	1,002	1,007	1,008	1,010	1,011	1,005	1,004
Tidal	0	0	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Biomass	342	353	353	352	347	354	351	360	380	355	355	351	353	352	365	369	365	392	380	376	374	374	373	373	374
Wind	1,904	1,899	1,897	1,899	2,078	2,239	2,239	2,242	2,254	3,225	3,227	3,744	3,754	3,757	3,771	3,775	3,776	3,801	3,813	3,830	3,823	3,827	3,838	3,842	3,867
Solar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	18	18	18	18	18	19	105	106
Diesel CTs	0	1	0	0	0	0	0	0	0	2	1	1	1	1	1	1	0	0	0	0	3	3	2	1	0
Maritime Link Blocks	1,133	1,133	1,133	1,134	1,133	894	893	894	894	894	894	894	894	894	894	894	893	894	894	894	894	894	894	894	893
Demand Response	0	1	1	2	3	3	3	3	2	3	3	3	3	3	3	2	3	3	3	3	3	3	3	2	3
Non Firm Market	2,193	1,337	1,327	1,332	1,316	1,323	1,299	1,305	1,326	1,311	1,319	1,265	1,291	1,296	1,313	1,302	1,356	1,307	1,384	1,541	1,574	1,575	1,612	1,598	1,611
CAES	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
Battery Generation	0.68	0.64	0.67	0.68	2.93	4.01	3.89	4.10	2.65	4.80	4.86	6.35	6.17	6.46	6.16	6.15	5.30	9.00	10.47	10.93	6.92	6.70	7.95	8.12	12.33
Firm Imports	0	951	954	954	977	973	974	976	972	973	976	969	968	967	969	971	1,482	1,510	1,928	2,271	2,266	2,286	2,268	2,263	2,321

IRP Participants

This list includes groups and individuals who were very engaged, attended sessions and provided feedback and comments, as well as others who wished to be on the mailing list but did not actively participate.

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Appendix H

Nova Scotia Power IRP

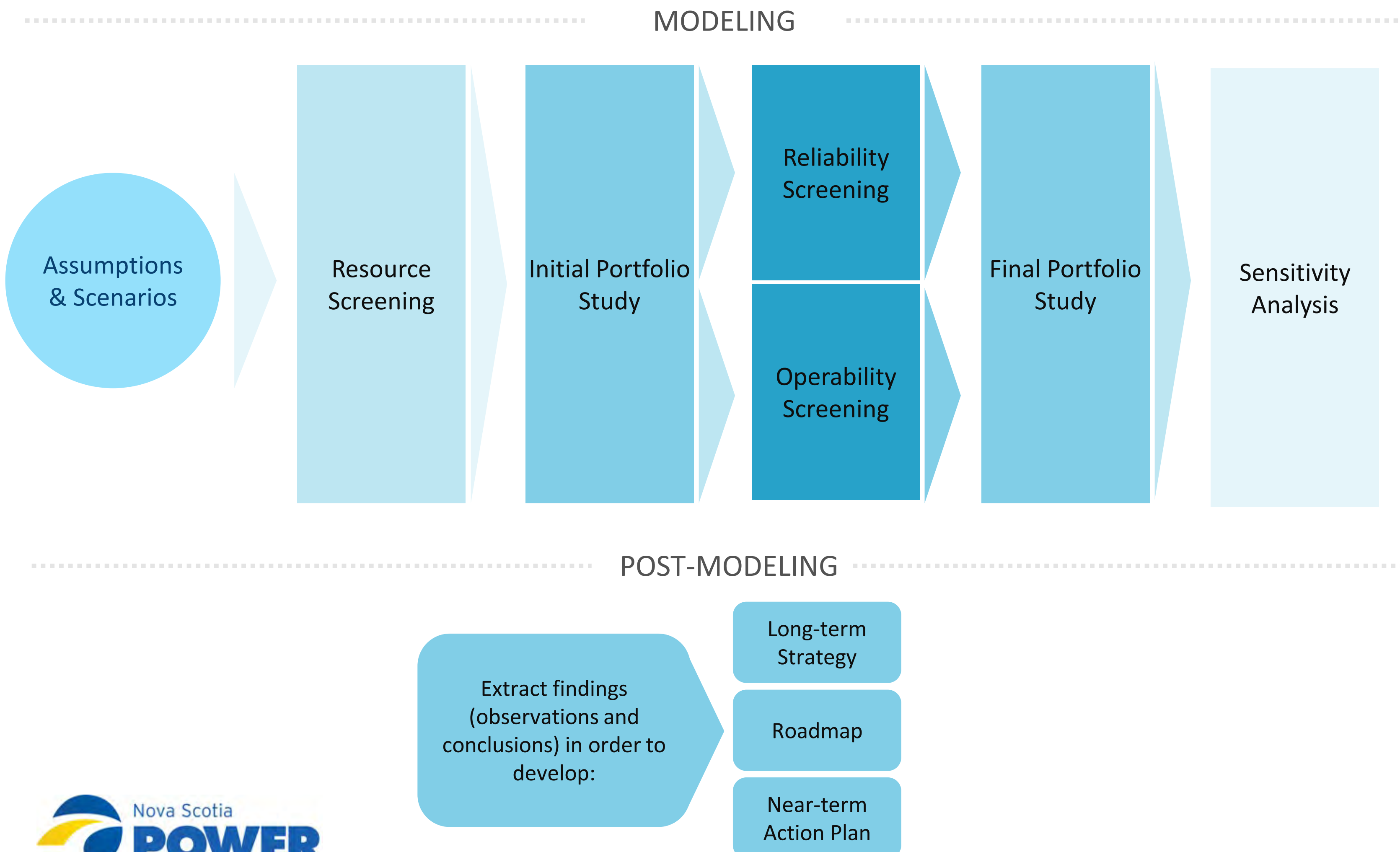
Assumptions and Analysis Plan Participant Engagement

2020 IRP
DRAFT ANALYSIS PLAN

JANUARY 20, 2020

Nova Scotia POWER An Emera Company

IRP ANALYSIS: PROCESS OVERVIEW



ANALYSIS PLAN: PHASE DESCRIPTIONS

Phase	Description
Resource Screening	Pare down candidate resources to be available to model in each scenario (this may differ by scenario). Combination of qualitative evaluation and/or quantitative modeling using E3's RESOLVE model.
Initial Portfolio Study	Conduct capacity expansion optimization modeling with Plexos LT (supplemented with E3's RESOLVE model where required), which will result in an economically optimized resource portfolio for each scenario (e.g. the resource plan with the lowest 25 year NPV revenue requirement for that scenario's set of assumptions).
Reliability Screening	For select scenarios, evaluate the impacts on reliability parameters, including the ELCC of renewables (and diversity benefits) and the required Planning Reserve Margin for particular resource portfolios using E3's RECAP model. Identify changes to these assumptions for iteration.
Operability Screening	For select scenarios, evaluate the production costs (e.g. fuel and purchased power) and dispatch constraints using the more granular Plexos MT/ST module. Identify changes required for the portfolio for iteration.
Final Portfolio Study	Using the output of the Reliability and Operability Screening phases, if required, conduct revised capacity expansion optimization modeling with Plexos LT (supplemented with E3's RESOLVE model where required).
Sensitivity Analysis	Using bookend values, as identified for each scenario, test the impact of future changes to key assumptions on the cost and performance of the portfolios.

POTENTIAL "PORTFOLIO STUDY" SCENARIO DEVELOPMENT APPROACH

Scenarios
("Possible Futures")
Based on Major Uncertainties

- Scenario A
- Scenario B
- Scenario C
- Scenario D

Variations likely focused on coal closure timing, electricity load and carbon emission reduction levels

X

Drivers
("Influencing Factors")

- Driver 1
- Driver 2
- Driver 3

Variations such as resource costs or focus on specific resource types (e.g. DERs)

Portfolios
("Resource Plans")
Optimal plans based on each scenario and driver combo

A1	A2	A3
B1	B2	B3
C1	C2	C3
D1	D2	D3

Sensitivity Analysis
("Impact Testing")

A1
B3
Sensitivity 1, 2…

Test the impact of changes in key assumptions on the cost of the plan

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PROPOSED EVALUATION CRITERIA

Metric	Description
Minimization of the cumulative present value of the annual revenue requirements over the planning horizon (adjusted for end-effects)	25 year NPV Revenue Requirement
Magnitude and timing of electricity rate effects;	10 year NPV Revenue Requirement
Reliability requirements for supply adequacy;	Evaluation of PRM, resource capacity adequacy, operating reserve requirements, etc.
Provision of essential grid services for system stability and reliability;	Quantitative and qualitative assessment of the status of essential grid services provision for each portfolio.
Plan robustness (the ability of a plan to withstand plausible potential changes to key assumptions);	Magnitude of the plan's exposure to changes in key assumptions (via sensitivity analysis).
Reduction of greenhouse gas and/or other emissions; and,	Mt of CO_2 reduced over 25 years
Flexibility (limitation of constraints on future decisions arising from the selection of a particular path).	Qualitative assessment of timing of investments.

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2020 INTEGRATED RESOURCE PLAN (IRP): DRAFT ASSUMPTIONS ADDENDUM/UPDATE

FEBRUARY 3, 2020

Nova Scotia POWER An Emera Company

INTRODUCTION

- The following materials represent a preliminary working draft of the Input Assumptions to be used in the 2020 IRP Modeling.
- These Draft Input Assumptions are being brought forward for discussion with stakeholders.
- The details of these assumptions will continue to be further refined as the IRP team addresses stakeholder feedback and reviews emerging information.

The final view of the Input Assumptions to be used in the 2020 IRP model will be circulated to stakeholders on March 5, 2020, following discussion and refinement.

SUPPLY SIDE OPTIONS OVERVIEW

- The original draft assumptions for the costs of new bulk grid scale resources (capital costs and fixed and variable operating costs) were based on the E3 Resource Options Study from the Pre-IRP Deliverables.
- Since the Pre-IRP Work was completed, several of the public sources for pricing assumptions have released late 2019 datasets. The following slides are reflect these updated data sources and subsequent pricing.
- The review of updated 2019 public sources for cost estimates lowered the "base case" resource costs for most new renewables and storage. However, the public source estimates for new wind remain higher than NS Power's original proposed assumption. Stakeholder comments to date have indicated that NSP's estimate may not be as low as expected; we remain open to receiving information from other sources that stakeholders may have.
- The following slides summarize the "base case" prices from the updated Pre-IRP work. The full report also includes "Low" price sensitivities to be tested.
- The assumptions for the cost of new distributed resources are in the following section.

Energy+Environmental Economics

NSPI Resource Options Study
2020 Updates

Nova Scotia Power

January 2020

Liz Mettetal, Sr. Consultant
Charles Li, Consultant
Aaron Burdick, Sr. Consultant
Sandy Hull, Sr. Consultant
Zach Ming, Sr. Managing Consultant

Summary of Proposed Assumptions
Capital Costs (1 of 2) – Renewables and Storage

		Capital Cost (2019 CAD $/kW)		
Technology	**Subtechnology**	**2019**	**2030**	**% Change**
Wind	Onshore	$2,100	$1,691	-19%
	Offshore	$4,726	$3,429	-27%
Solar PV[a]	Tracking	$1,800	$1,416	-21%
Biomass	Grate	$5,300	$5,146	-3%
	Municipal Solid Waste	$8,470	$8,470	0%
Tidal	n/a	$10,000	$10,000	0%
Storage	Li-Ion Battery (1 hr)	$764	$385	-50%
	Li-Ion Battery (4 hr)	$2,125	$1,071	-50%
	Compressed air	$2,200	$2,200	0%
	Pumped Storage	$2,700	$2,700	0%

[a] Solar PV costs reported in $/kW-ac, reflecting an inverter loading ratio of 1.3

Summary of Proposed Assumptions

Capital Costs (2 of 2) – Fossil and Nuclear

		Capital Cost (2019 CAD $/kW)		
Technology	**Subtechnology**	**2019**	**2030**	**% Change**
Coal	Coal-to-gas conversion (102 – 320 MW)	$127 – 237	$127 – 237	0%
Natural Gas	Combined Cycle (145 MW)	$1,688	$1,574	-7%
	Combined Cycle w/ carbon capture and storage (145 MW)	$3,376	$2,987	-12%
	Combustion Turbine – Frame (50 MW)	$1,080	$1,004	-7%
	Combustion Turbine – Aero (50 MW)	$1,755	$1,632	-7%
	Reciprocating Engine (50 MW)	$1,823	$1,823	0%
Nuclear	Small modular reactor (100 MW)	$9,196	$8,641	-6%

Summary of Proposed Assumptions
Operating Costs – All Technologies

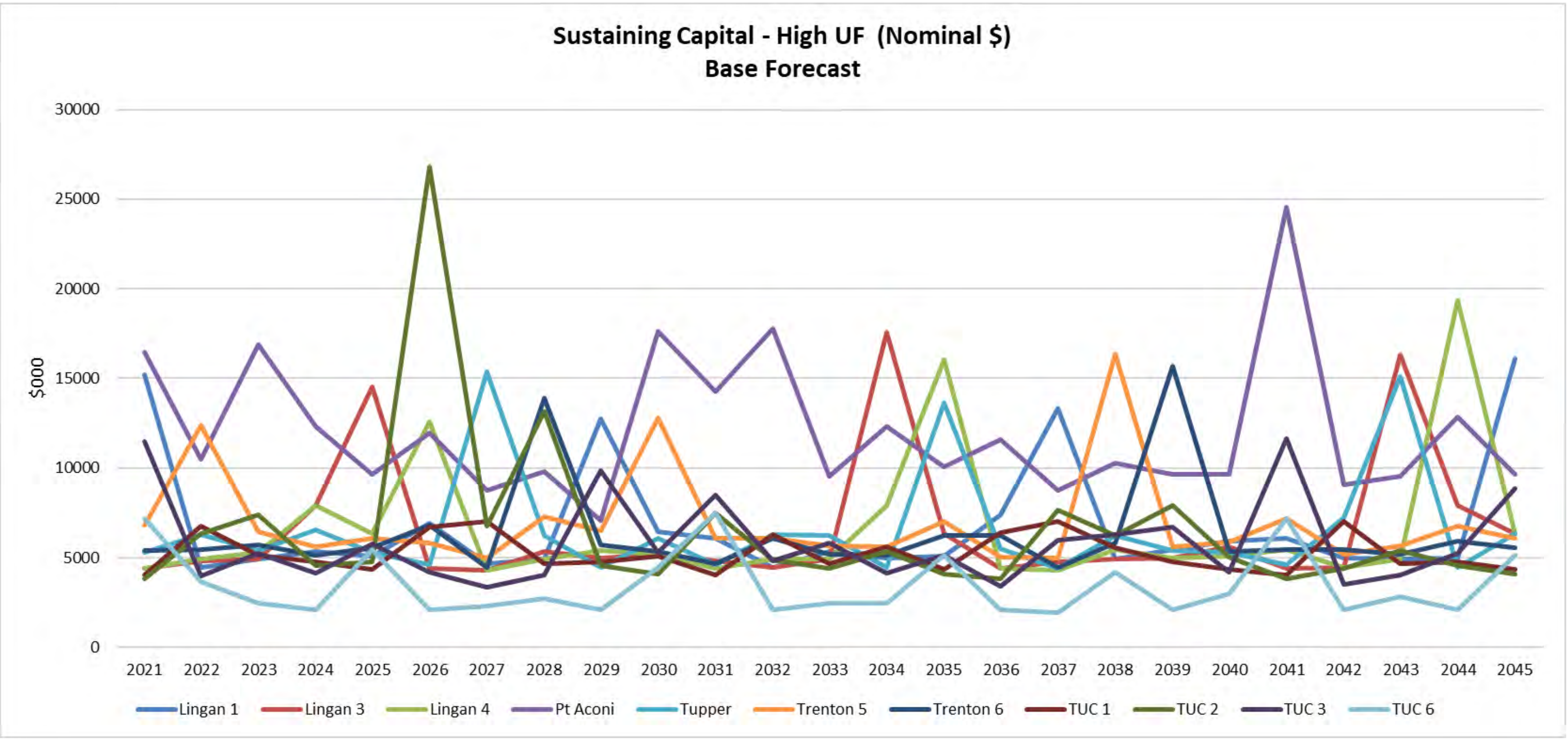
Technology	Subtechnology	Operating Cost Fixed O&M ($/kW-yr)	Operating Cost Variable O&M ($/MWh)
Wind	Onshore	$59	$0
	Offshore	$165	$0
Solar PV	Tracking	$18	$0
Biomass	Grate	$155	$7
	Municipal Solid Waste	$162	$0
Tidal	n/a	$338	$0
Storage	Li-Ion Battery (1 hr)	$8	$0
	Li-Ion Battery (4 hr)	$27	$0
	Compressed air	$20	$0
	Pumped Storage	$32	$0
Coal	Coal-to-gas conversion	$37-$45	$1
	Coal-to-biomass conversion	$152	$7
Natural Gas	Combined Cycle	$15	$3
	Combustion Turbine - Frame	$17	$7
	Combustion Turbine - Aero	$17	$7
	Reciprocating Engine	$27	$9
Nuclear	Small modular reactor	$140	$0

All O&M costs assumed to escalate at 2% per year.

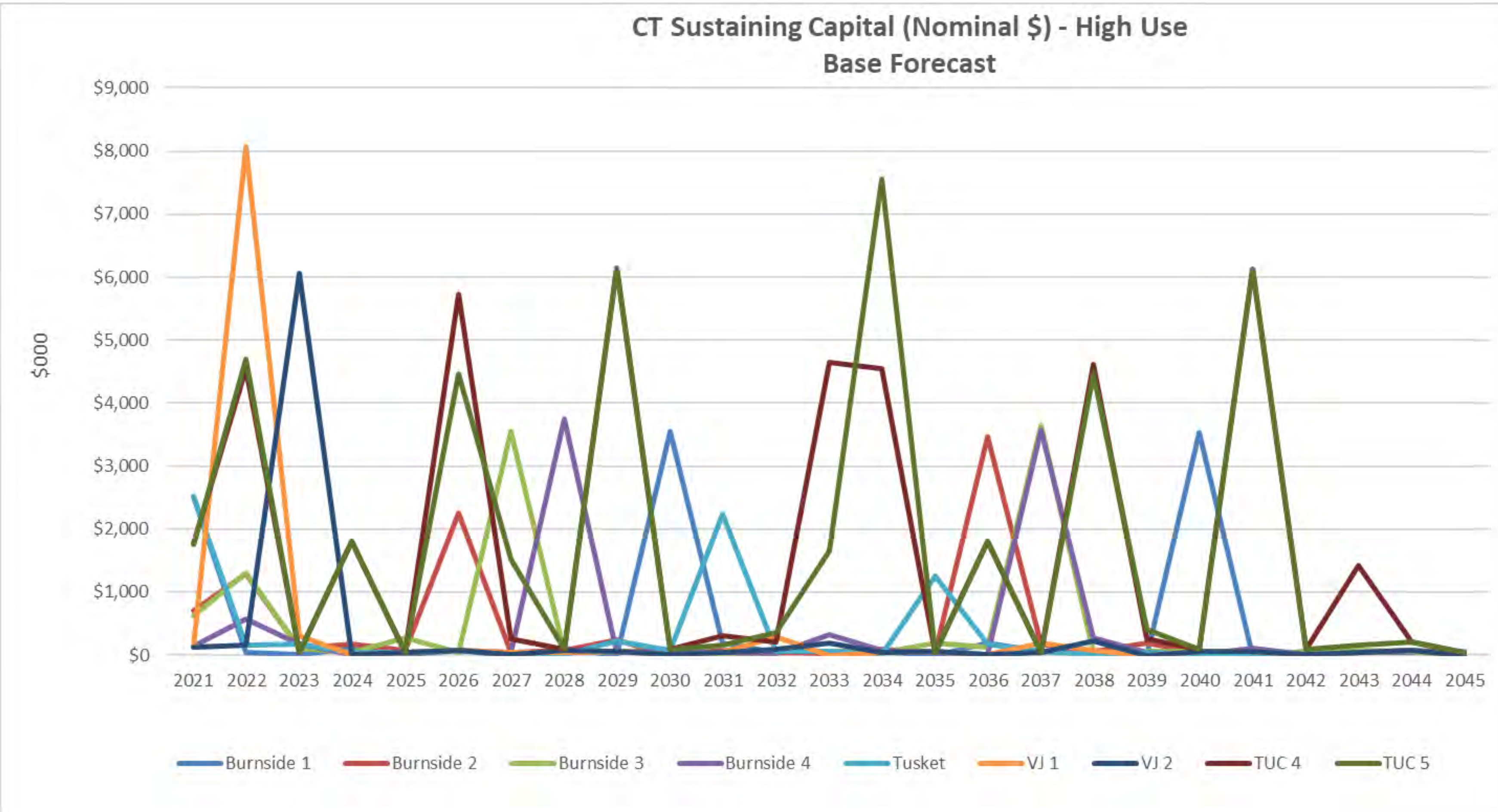
FUNDAMENTAL PRICE FORECASTS

Commodity	Pricing Point	Provider	Updated
Solid Fuel	API 2	Allegro	Q4 2019
	API 4		
	Northern Appalachian (NAPP)		
	Domestic Coal	NSP Contract Pricing, escalated for period beyond contract term.	Q4 2019

SUSTAINING CAPITAL FORECAST – THERMAL (BASE)

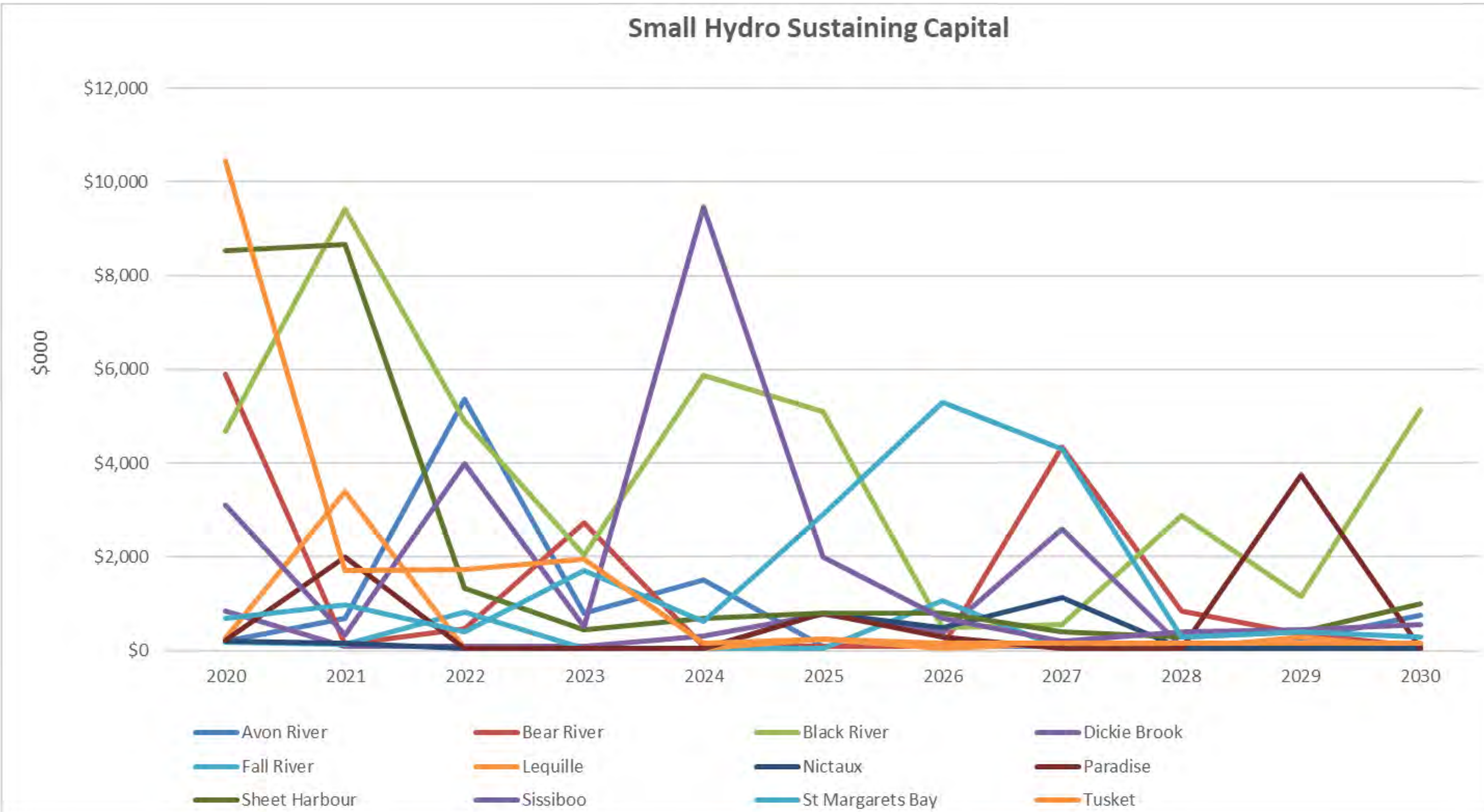


SUSTAINING CAPITAL FORECAST – CTs



SUSTAINING CAPITAL FORECAST – SMALL HYDRO

- The sustaining capital forecast for hydro assets are based on Q1 2020 Forecast (an update of the Hydro Asset Study).



INTERCONNECTION COSTS

- Integration costs, such as the construction of synchronous condensers or other transmission system stability requirements, will be modeled at a high level based on the minimum services constraints discussed in the previous slides (e.g. a resource plan with X MW of wind will require X MW of grid technology investments to provide grid services, if the combination of other resources in the plan cannot provide sufficient levels).
- Transmission interconnection costs, which are the cost to connect a resource to the grid to deliver energy/capacity, can vary significantly depending on the location of new generation and/or storage resources.
- Estimating interconnection costs based on presumed locations may not accurately reflect the cost of potential projects. As the IRP provides directional insight on the long-term resource strategy, and not decisions on specific projects, presuming a location does not provide particular value to informing the long-term strategy (and it could over or underestimate the project specific interconnection costs required).
- NSP is proposing that should resources be identified as preferable through the analysis, further detailed work can be conducted to estimate the value of various location options.

2020 INTEGRATED RESOURCE PLAN (IRP): DRAFT ASSUMPTIONS SET

JANUARY 20, 2020

Nova Scotia POWER
An Emera Company

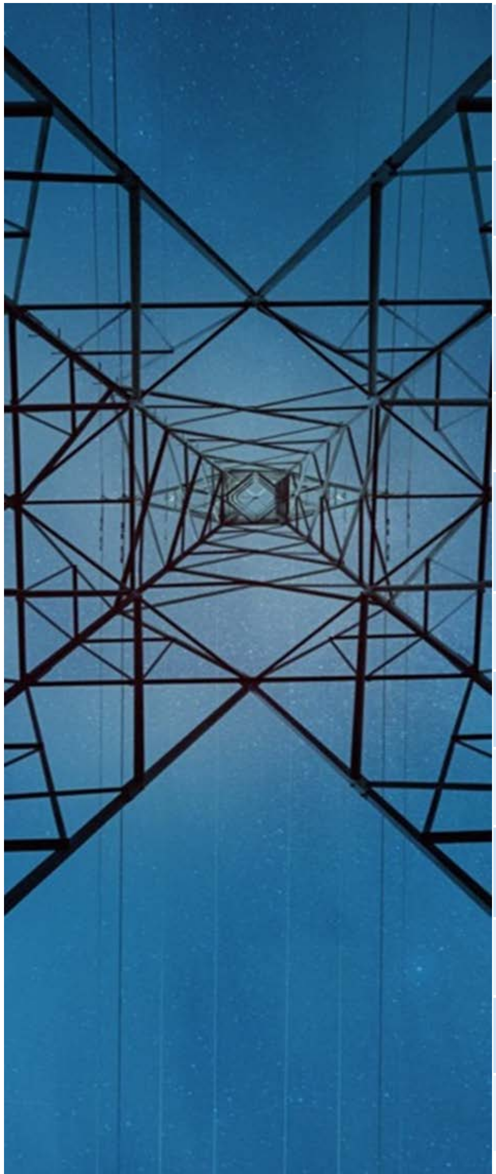
INTRODUCTION

- The following materials represent a preliminary working draft of the Input Assumptions to be used in the 2020 IRP Modeling.
- These Draft Input Assumptions are being brought forward for discussion with stakeholders.
- The details of these assumptions will continue to be further refined as the IRP team addresses stakeholder feedback and reviews emerging information.

The final view of the Input Assumptions to be used in the 2020 IRP model will be circulated to stakeholders on February 7, 2020, following discussion and refinement.

2020 IRP ASSUMPTIONS TABLE OF CONTENTS

Click on page number below to go to slide



2020 IRP:
FINANCIAL ASSUMPTIONS

JANUARY 28, 2020

FINANCIAL ASSUMPTIONS

Weighted Average Cost of Capital (WACC):*

Pre-tax = 6.62%

After-tax = 5.64%

Inflation Rate:

25-year Average = 2%

Based on Conference Board of Canada CPI growth forecast for NS

Revenue Requirement Profiles:

- Supply-side options that represent a capital investment require a revenue requirement profile
- Revenue requirement profiles for input into Plexos will be developed outside of the model using E3's Pro Forma financial model

*Utility and Review Board M09498 – Approval of pre-tax WACC/AFUDC rate for both capital and non-capital matters

EXCHANGE RATES

US Foreign Exchange Rate

Year	2021	2022	2023	2024
Forecasted USD/CAD	1.31	1.35	1.35	1.35

2020 is an average of 6 banks
2021 is an average of 5 banks
2022 and beyond is an average of 2 banks

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2020 IRP:
LOAD ASSUMPTIONS

JANUARY 20, 2020

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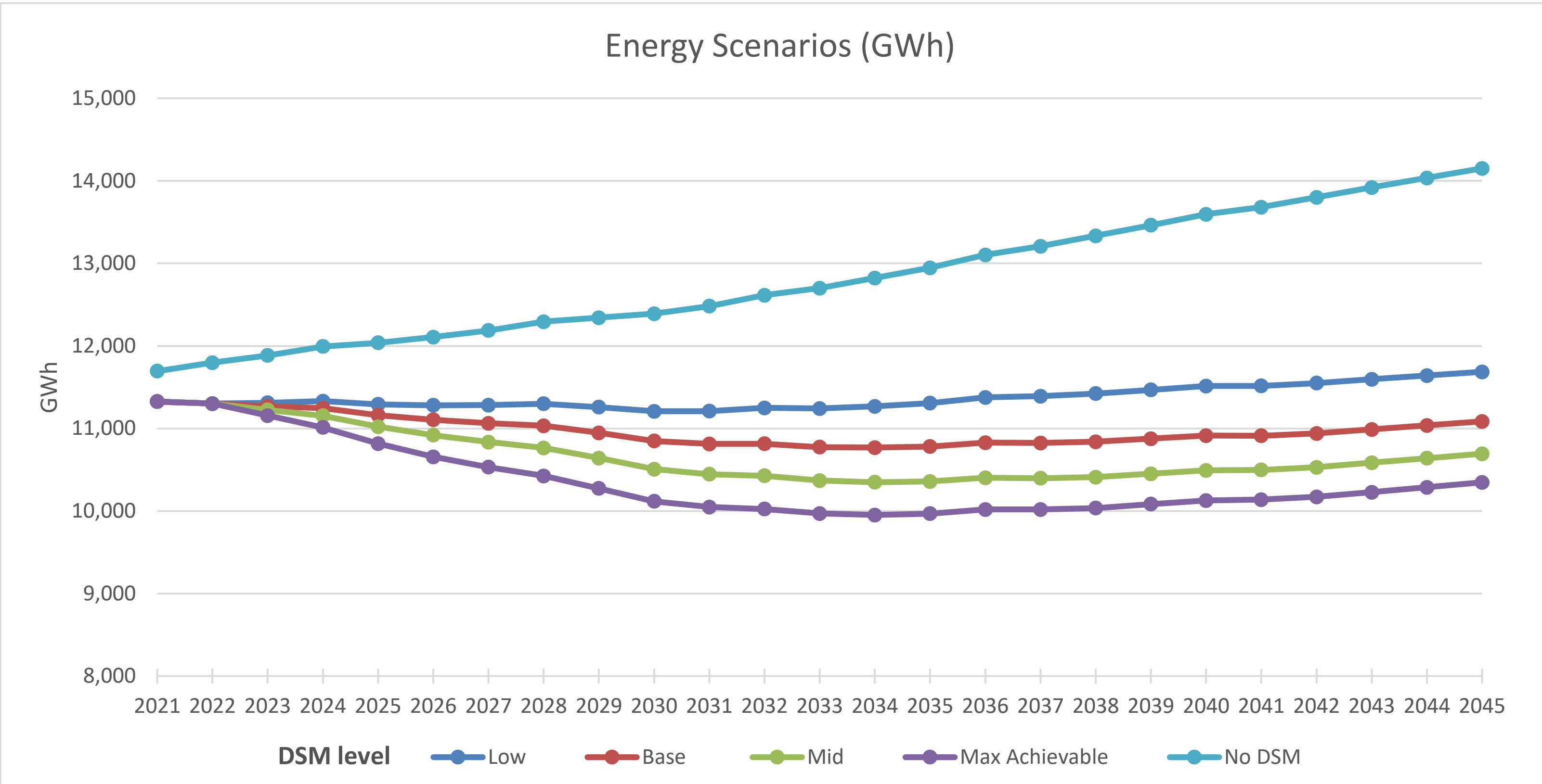
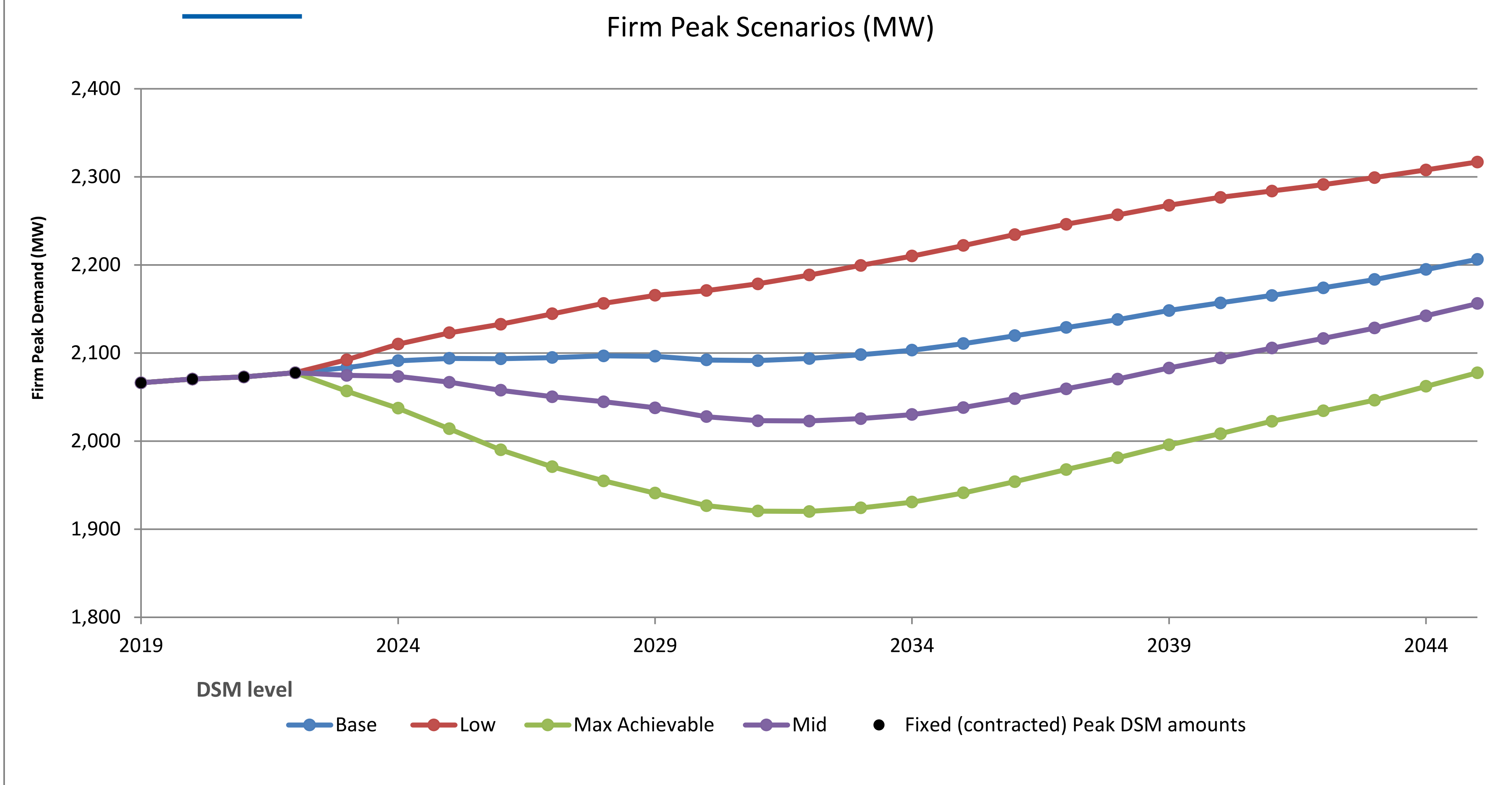
LOAD ASSUMPTIONS OVERVIEW

- The underlying data for the "Base Load Forecast" is based on NSP's annual Load Forecast Report, as filed with the UARB in 2019.
- The "Scenarios" applied to the Base Load level are the DSM scenarios from E1's Potential Study work, as well as a "No DSM" scenario, which is required for calculated the Avoided Cost of Demand Side Management.
- The Sustainable Development Goals Act (which established a "net zero" goal for all sectors by 2050) will likely drive significant electrification of other sectors (e.g. heating, transportation, etc.). NSP's consultants, E3, are working to understand the potential load impacts of these levels of electrification, and whether they fit within the bounds of the scenarios as proposed (e.g. the load with "No DSM" could in fact represent a scenario where both electrification and energy efficiency is ongoing).
- We will continue to discuss potential other scenarios with stakeholders.

BASE LOAD FORECAST WITH VARIATIONS



PEAK DEMAND FORECAST



BASE LOAD FORECAST

Base Load Forecast assumptions include:

- Economic forecast from Conference Board of Canada
- EV penetration based on conservative estimate of Electric Mobility Canada’s growth model
- EV includes estimate for peak mitigation
- 10-year average used for normal weather

DEMAND SIDE MANAGEMENT IN THE LOAD SCENARIOS

- The 4 DSM scenarios (Base, Low, Mid, Max Achievable) were subtracted from the "no DSM" forecast.
- 2020-2022 in all scenarios is based on the current 3-year supply agreement. The 4 Potential Study scenarios were shifted to a starting year of 2023, after the current agreement expires.
- The scenarios are assumed to include all DSM, including:
  - Cost-effective electricity efficiency and conservation activities provided by the franchise holder
  - Initiatives that may be pursued by NS Power as permitted under the Public Utilities Act
  - Consumer behaviour and investments
  - Energy efficiency codes and standards
  - Initiatives undertaken by other agencies
  - Technological and market developments

2020 IRP: ENVIRONMENTAL ASSUMPTIONS (EXISTING & DEFINED POLICY)

JANUARY 20, 2020

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APPLICABLE LEGISLATION

- Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations
- Regulations Limiting Carbon Dioxide Emissions from Natural Gas-Fired Generation of Electricity
- Greenhouse Gas Emissions Regulations
- Greenhouse Gas Pollution Pricing Act
- Cap and Trade Regulations
- Clean Fuel Standard

APPLICABLE LEGISLATION (CONT.)

- Air Quality Regulations
- Renewable Electricity Regulations

The following slides provide an overview of each of the regulations above as well as the current existing values of these policies. Scenarios with varying degrees of change to these values will be examined (likely mostly based on potential outcomes of the Sustainable Development Goals Act). NSP will be discussing potential scenarios with stakeholders in its January IRP workshop.

REDUCTION OF CARBON EMISSIONS FROM COAL FIRED GENERATION

These Federal regulations require coal units to meet greenhouse gas (GHG) emissions intensity of 420t/GWh (via conversion to other fuel) or shut down at the end of "useful life", as defined by the regs based on commissioning dates, and would cause conversion or retirement by the following years for the NSP fleet:

2019 Trenton 5

2021 Point Tupper

2029 Lingan 1, 2, 3 & 4

2030 Trenton 6 & Point Aconi

- Nova Scotia's Equivalency Agreement with the Federal Government enables NS Power to continue to operate coal units after these dates.
- SCENARIO NOTE: At least one modeling scenario will examine a portfolio where all coal units are retired by Dec 31, 2029 in accordance with the 2018 Federal Coal Regulations.

GREENHOUSE GAS EMISSIONS REGULATIONS

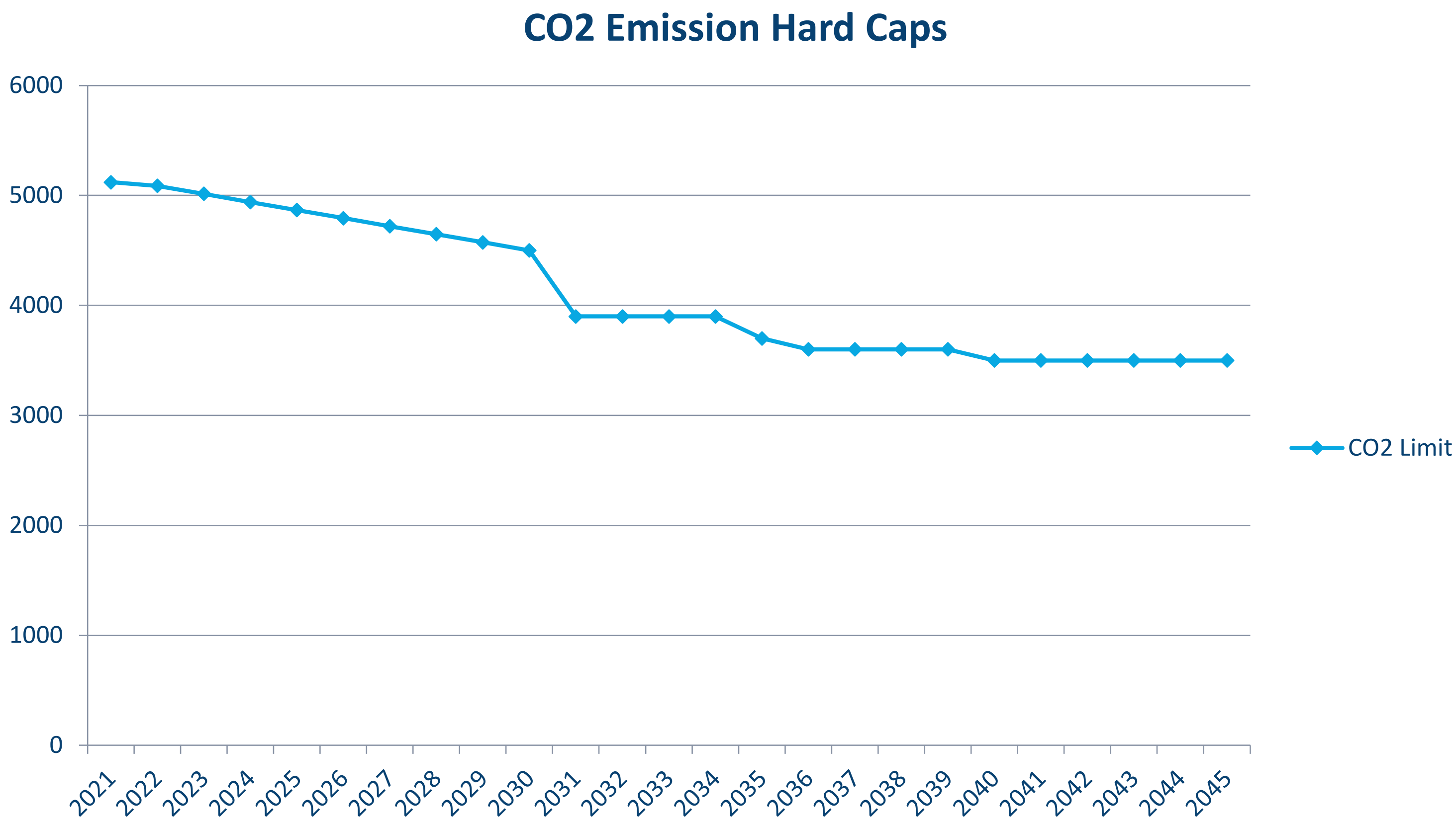
- These Provincial regulations stipulate GHG emission limits from 2010 to 2030 for all facilities in the province that emit greater than 10,000 tonnes GHG per year.

- Nova Scotia’s equivalency agreement with the Federal government enables NS Power to meet the *Greenhouse Gas Emissions Regulations* as opposed to the requirements of the *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations*

- Nova Scotia’s equivalency agreement has been renewed from 2020-2024 with agreement on future methodology from 2025-2040.

- Nova Scotia’s equivalency agreements must meet evolving Federal requirements.

FORECASTED CO2 EMISSION HARD CAPS*



*Source: Greenhouse Gas Emission Regulations & Quantitative Analysis of 2019 NS Equivalency Agreement

GREENHOUSE GAS POLLUTION PRICING ACT

- This act is the implementation of the Federal carbon pollution pricing system.
- Introduces an output-based pricing system (OBPS) for large industrial emitters.
- Provinces are free to choose an OBPS or cap-and-trade system if they meet the minimum Federal pricing and emissions reduction targets.
- Nova Scotia has opted for a cap-and-trade system, therefore, this act does not currently affect NS Power in the form of a carbon tax.

CAP AND TRADE PROGRAM REGULATIONS

- Provincial regulations that outline framework and requirements for cap and trade program.
- Stipulate free allocations for NS Power GHG emissions
- Meets the Federal *Greenhouse Gas Pollution Pricing Act* requirements

Greenhouse Gas Free Allowances 2021-2022

Year	GHG Free Allowances Million tonnes
2021	5.120
2022	5.087

CLEAN FUEL STANDARD

- Federal government published a regulatory framework for the Clean Fuel Standard which will apply to liquid, solid and gaseous fuels combusted for the purposed of creating energy.
- Coal combusted at facilities covered by *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations* will be exempt
- Draft regulations have not yet been published.
- Expecting requirements for liquids to come into force by 2022 and for gaseous fuels by 2023.
- For IRP, NSP expects "high" fuel price sensitivities to capture impact of this standard (e.g. no explicit assumption required for modeling).

AIR QUALITY REGULATIONS

- Provincial regulations that stipulate NS Power emission limits for Sulphur dioxide (SO_2), nitrogen oxides (NOx) and mercury (Hg) from 2010 to 2030.

- Outlines requirements for mercury diversion program and stipulates NS Power can use credits for compliance from 2020 to 2030.

Emissions Multi-Year Caps (SO2, NOx)

Multi-Year Caps Period	SO_2 (t)	NO_X (t)
2015 – 2019 (equal outcome)	304,500	96,140
2020	60,900	14,955
2021-2022	90,000	
2023-2024	68,000	56,000
2025	28,000	11,500
2026 – 2029	104,000	44,000
2030	20,000	8,800

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AIR QUALITY REGULATIONS (CONT.)

Emissions Annual Maximums (SO_2, NOX)

Year	SO_2 Annual Maximum (t)	NO_X Annual Maximum (t)
2015 – 2019	72,500	21,365
2021 – 2024	36,250	14,955
2026 – 2029	28,000	11,500

Individual Unit Limits (SO_2)

Year	SO_2 Individual Unit Limit (t)
2015 – 2019	42,775
2020 – 2024	17,760
2025 – 2029	13,720
2030	9,800

Mercury Emissions Caps

Year	Hg Emission Cap (kg)
2010	110
2011	100
2013	85
2014	65
2020	35
2030	30

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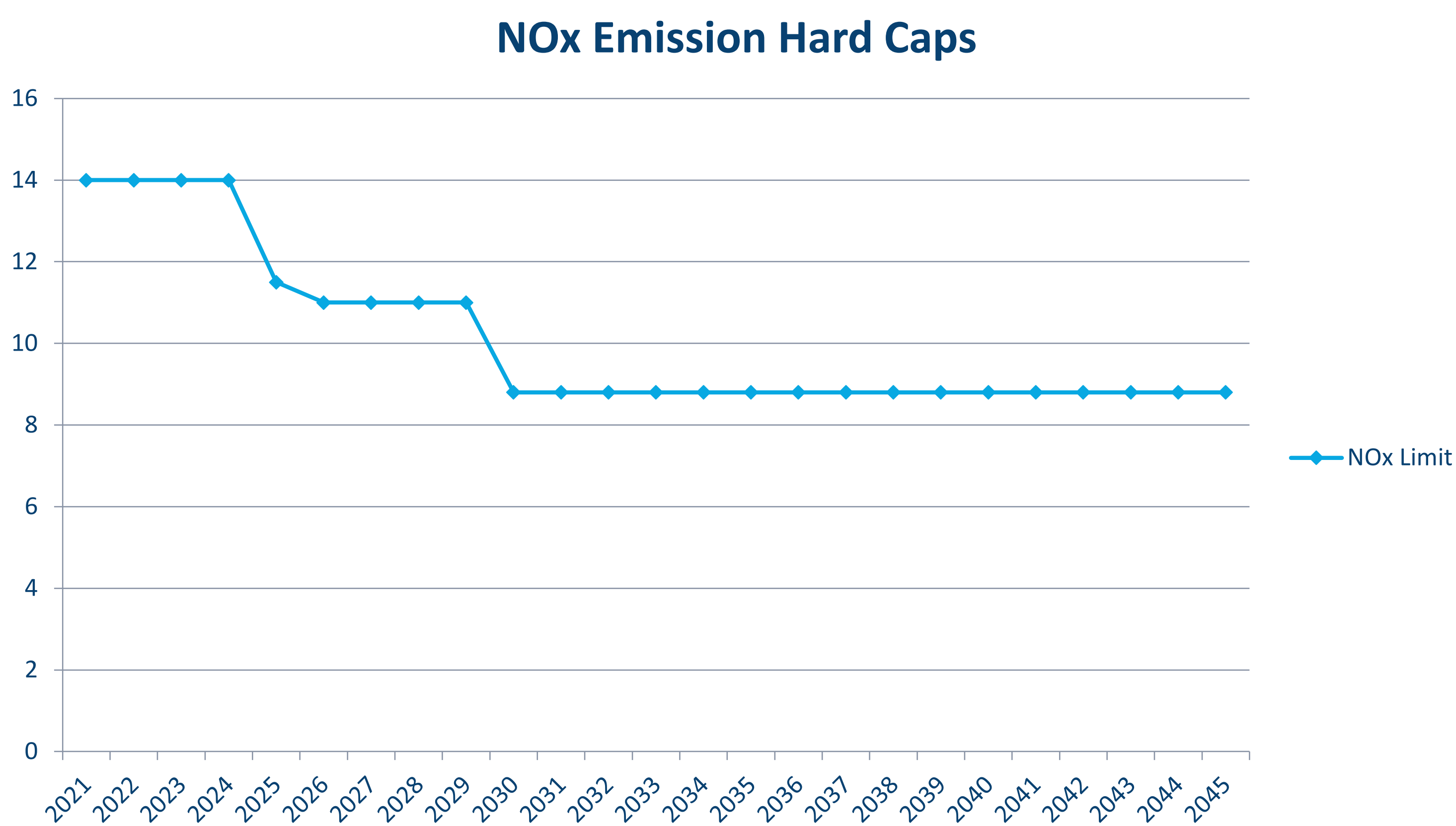
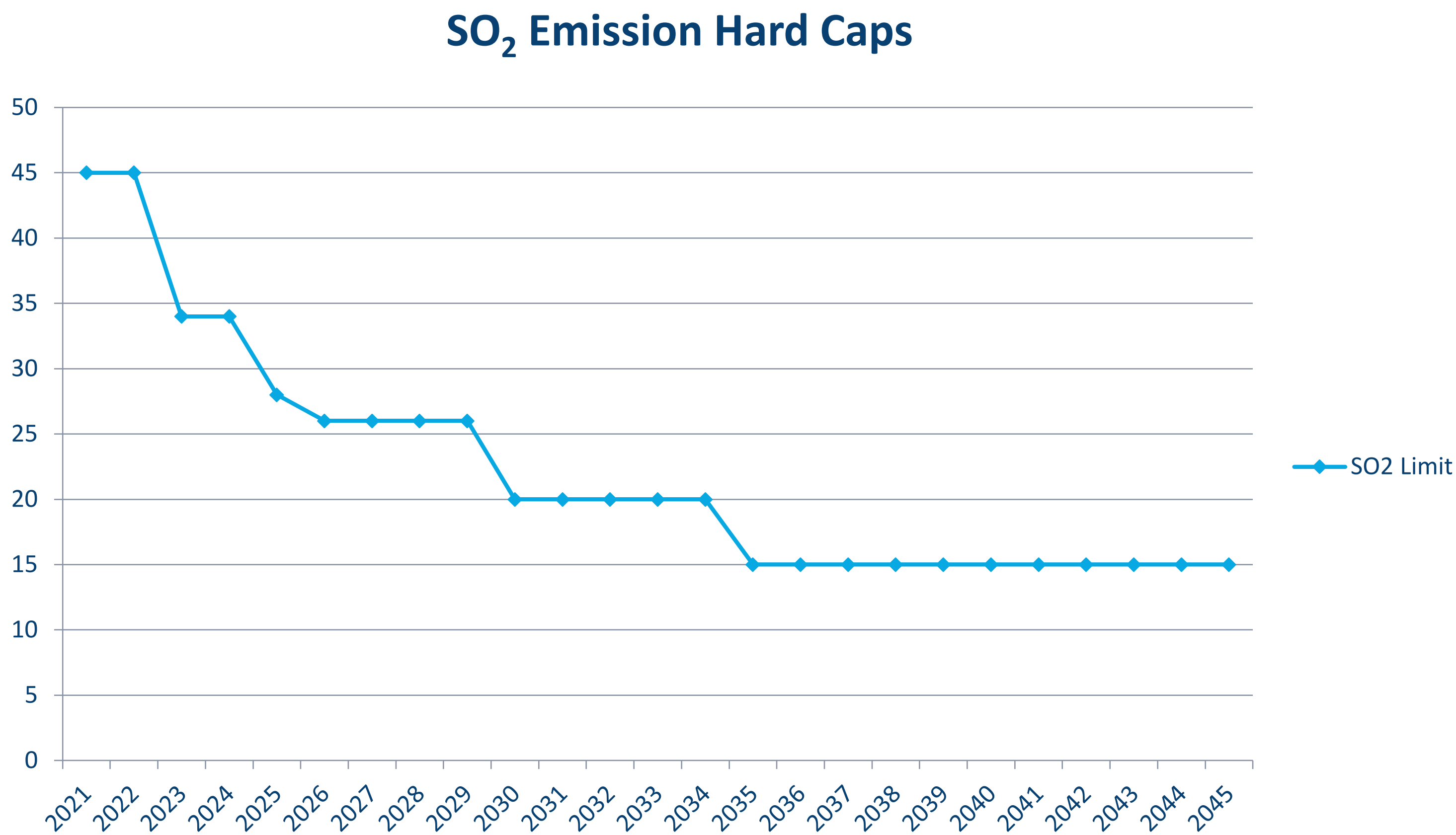
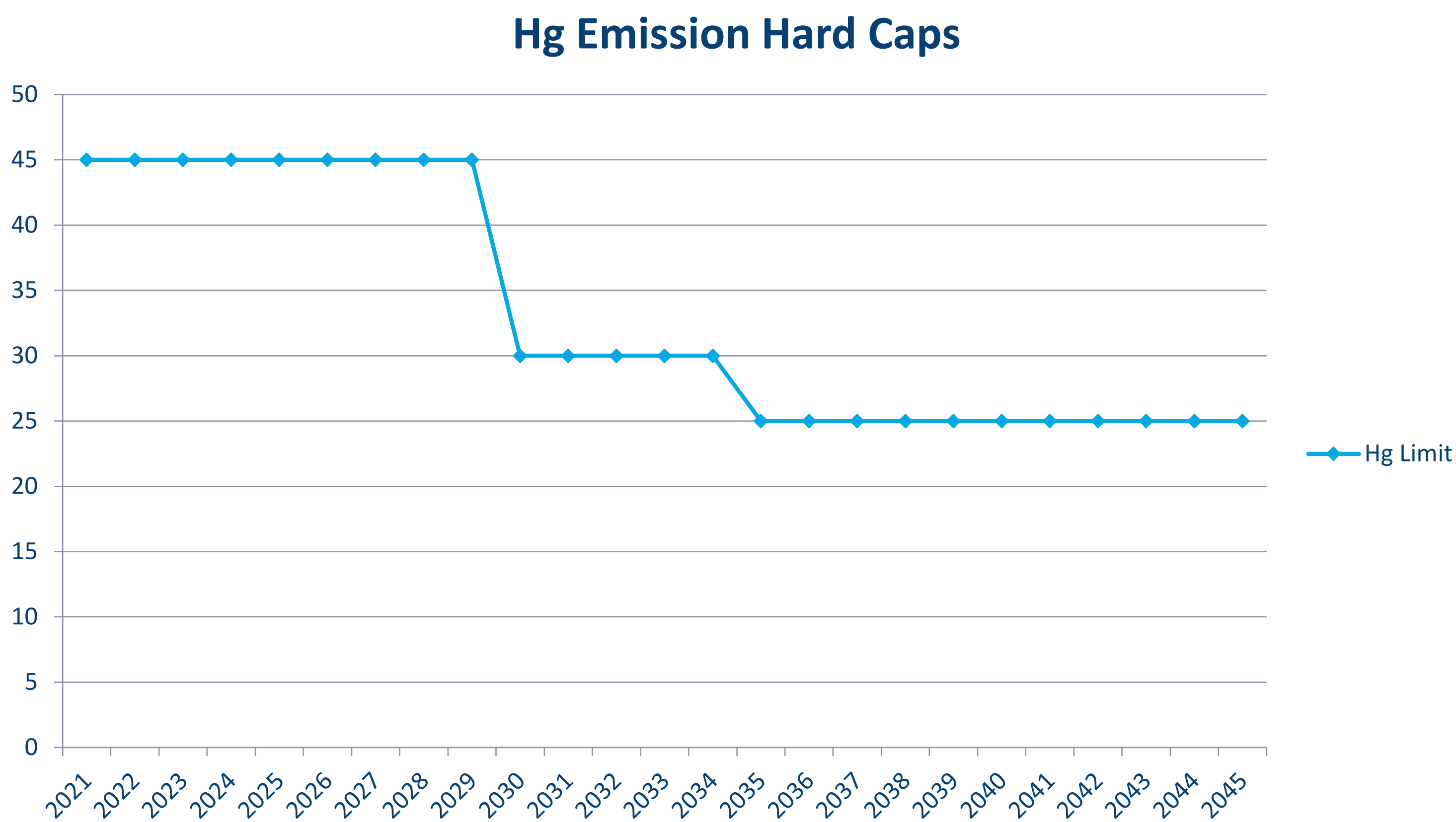
FORECAST NO_X EMISSION HARD CAPS



FORECAST SO_2 EMISSION HARD CAPS



FORECAST MERCURY EMISSION HARD CAPS*



*Air Quality Regulations outline requirements for mercury diversion program and stipulates NS Power can use credits for compliance from 2020 to 2030.

RENEWABLE ELECTRICITY REGULATIONS

- Provincial regulations that require 40% renewable energy by 2020.
- Stipulates that no more than 350,000 dry tonnes of primary forest biomass may be used annually to meet the standard.
- NS Power does not anticipate future specific renewable energy standards (RES). Intent will have been met by drive to net-zero carbon emissions from the *Sustainable Development Goals Act*.

2020 IRP:
NEW SUPPLY SIDE OPTIONS

JANUARY 20, 2020

Nova Scotia POWER An Emera Company

SUPPLY SIDE OPTIONS OVERVIEW

- The assumptions for the costs of new bulk grid scale resources (capital costs and fixed and variable operating costs) will be based on the E3 Resource Options Study from the Pre-IRP Analysis.
- Since the Pre-IRP Work was completed, several of the public sources for pricing assumptions have released late 2019 datasets. NSP and E3 are reviewing these updates and will adjust to reflect these updates where possible.
- The following slides summarize the "base case" prices from the Pre-IRP work. The full report also includes "Low" price sensitivities to be tested.
- The assumptions for the cost of new distributed resources are in the following section.

Energy+Environmental Economics

NSPI Resource Options Study

Nova Scotia Power

July 2019

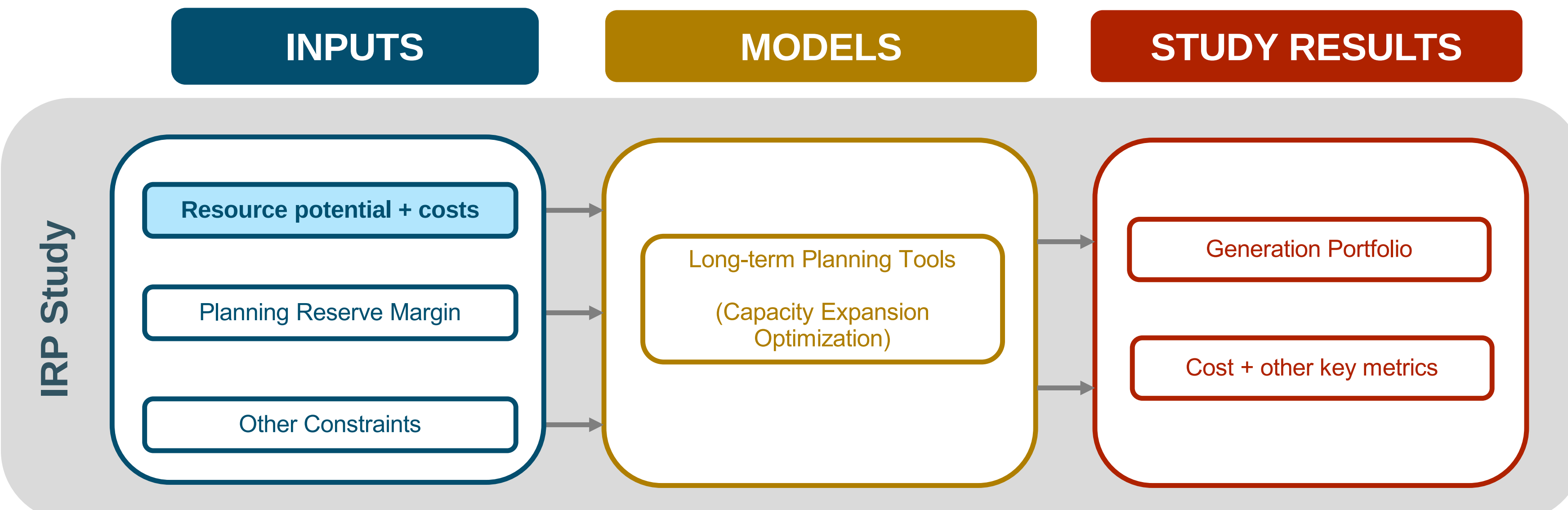
Aaron Burdick, Sr. Consultant
Charles Li, Consultant
Sandy Hull, Sr. Consultant
Zach Ming, Sr. Managing Consultant

Energy+Environmental Economics

Resource options study approach

Approach

+ **In preparation for its upcoming integrated resource plan, NSPI has asked E3 to provide guidance on resource costs and potential**
  - **Cost:** what are the costs (capital, O&M, fuel) associated with developing and operating each new resource? What future changes are expected?
  - **Performance:** what are the operational constraints associated with each resource (e.g. hourly profiles for wind/solar)
  - **Potential:** how much of the resource can be developed within Nova Scotia (or remotely)?



Resource Cost Modeling
Fixed vs. Variable Costs for New Resources

+ **Fixed costs: expenditures required to install and maintain generating capacity, independent of operations**
  - Capital costs:
    - Overnight capital cost (equipment cost, balance of systems, development costs, etc.)
    - Construction financing
    - Nominal interconnection costs (i.e. a short spur line, not longer lines required for remote renewables)
  - Fixed O&M:
    - Operations and maintenance costs incurred independent of energy production
    - Insurance, taxes, land lease payments and other fixed costs
    - Annualized large component replacement costs over the technical life (aka sustaining capital)
+ **Variable costs: marginal costs for each MWh of generation, based on modeled operations**
  - Variable O&M:
    - Operating and maintenance costs (parts, labor, etc.) incurred on a per-unit-energy basis
  - Fuel cost:
    - Commodity costs for fuel ($/MMBtu * heat rate MMBtu/MWh = $/MWh)
+ **Capacity factor: annual energy production per kW of plant capacity**
  - Used to estimate variable costs as well as the spread of fixed costs over expected generation

Resource Options Considered

- **Fossil fuels:** coal-to-gas, coal-to-biomass *, natural gas (CC, CT, reciprocating engine, CC w/ carbon capture and storage)
- **Renewables:** biomass, municipal solid waste, solar PV, tidal, wind (onshore and offshore)
- **Energy storage:** li-ion batteries, compressed air, pumped hydro
- **Emerging technologies**: modular nuclear

** Conversion from coal is not an overly viable option. There has been pushback from running the existing NSPI biomass facility, so the social license for biomass in NS may not exist.*

Resource Cost Modeling

Step 2: Pro-Forma Financial Model

Resource Costs Nova Scotia, 2019-2050	**Capital Costs (Step 1)**	O&M Costs	Fuel Prices
	+		
Resource Performance Nova Scotia specific	Local Capacity Factors	Heat Rates	Degradation
	+		
Financing Assumptions Based on NSPI Financing	NSPI Cost of Capital	Canadian Tax Incentives	Financing Terms
	=		
Levelized Cost Forecasts Costs to NSPI, 2019-2050	**Levelized Costs (Energy \$/MWh, Capacity \$/kW-yr)**		

Summary of Proposed Assumptions
Capital Costs (1 of 2) – Renewables and Storage

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	Municipal Solid Waste	$8,470	$8,470	0%
Tidal	n/a	$10,000	$10,000	0%
Storage	Li-Ion Battery (1 hr)	$814	$410	-50%
	Li-Ion Battery (4 hr)	$2,325	$1,172	-50%
	Compressed air	$2,200	$2,200	0%
	Pumped Storage	$2,700	$2,700	0%

[a] Solar PV costs reported in $/kW-ac, reflecting an inverter loading ratio of 1.3

Summary of Proposed Assumptions
Capital Costs (2 of 2) – Fossil and Nuclear

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	Combined Cycle w/ carbon capture and storage (145 MW)	$3,376	$3,101	-8%
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	Combustion Turbine – Aero (50 MW)	$1,755	$1,676	-5%
	Reciprocating Engine (50 MW)	$1,823	$1,823	0%
Nuclear	Small modular reactor (100 MW)	$8,073	$7,731	-4%

Summary of Proposed Assumptions
Operating Costs – All Technologies

Technology	Subtechnology	Operating Cost Fixed O&M ($/kW-yr)	Operating Cost Variable O&M ($/MWh)
Wind	Onshore	$54	$0
	Offshore	$108	$0
Solar PV	Tracking	$20	$0
Biomass	Grate	$162	$7
	Municipal Solid Waste	$162	$0
Tidal	n/a	$338	$0
Storage	Li-Ion Battery (1 hr)	$8	$0
	Li-Ion Battery (4 hr)	$27	$0
	Compressed air	$20	$0
	Pumped Storage	$32	$0
Coal	Coal-to-gas conversion	$37-$45	$1
Natural Gas	Combined Cycle	$14	$3
	Combustion Turbine - Frame	$12	$7
	Combustion Turbine - Aero	$17	$7
	Reciprocating Engine	$27	$9
Nuclear	Small modular reactor	$203	$0

All O&M costs assumed to escalate at 2% per year.

2020 IRP: DISTRIBUTED ENERGY RESOURCES (DERs)

JANUARY 20, 2020

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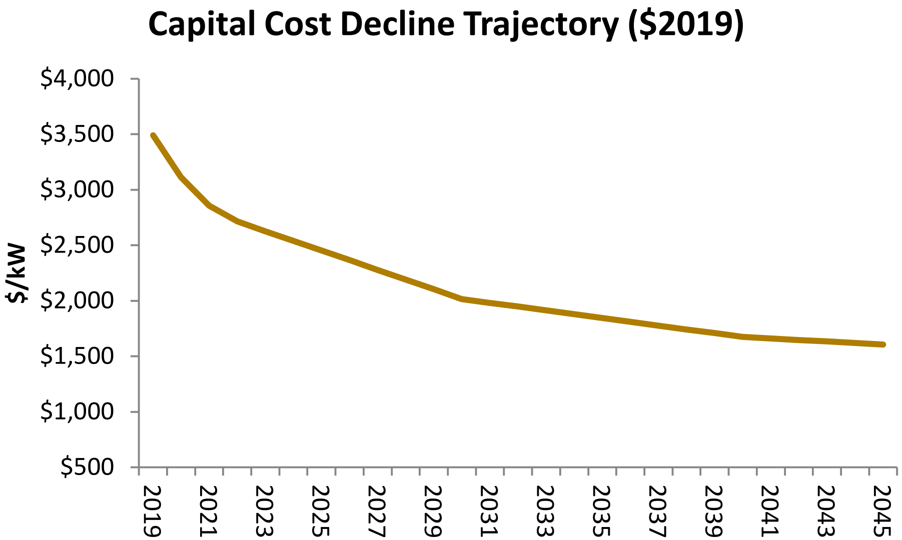
DISTRIBUTED ENERGY RESOURCES OVERVIEW

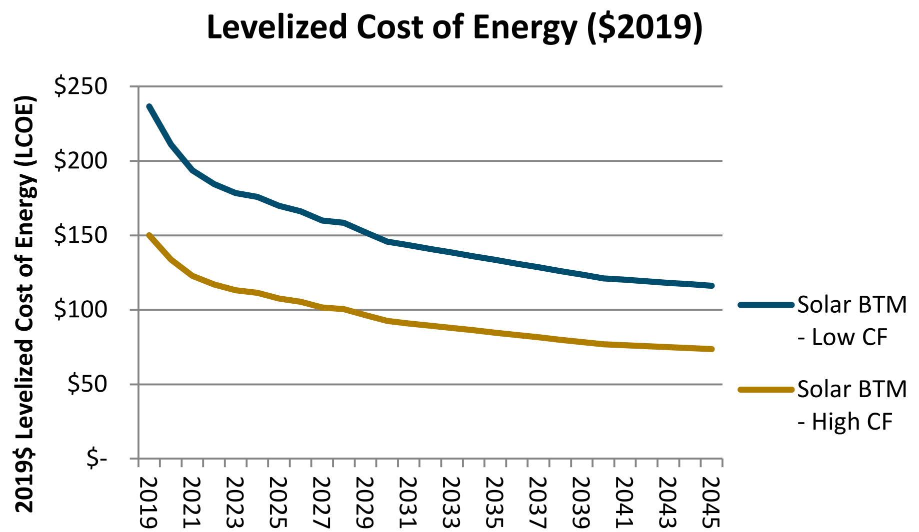
- As the grid becomes increasingly decentralized and more customers adopt distributed energy resources (DERs), long-term resource planners must address issues associated with evaluating their impact on the electricity system, including:
    - DERs introduce both system-level and distribution-level costs and benefits
    - DERs can be deployed and operated by utilities or customers and third parties
    - Although adoption and generation decisions can be influenced through incentives and rate design policy goals can also influence adoption (e.g., RPS, CO_2 targets)
    - Short panel of historical data and rapidly evolving technology costs/performance exacerbate uncertainty around these resources.
    - Capacity optimization models (as employed in the IRP), may not be granular enough to capture cost/benefits, particularly locational value.

DISTRIBUTED RESOURCES MODELING

- Given the challenges with the scale of DERs vs the granularity of IRP modeling, these resources will be examined via scenarios in the 2020 IRP (e.g. "plugs" of DERs will be mandatory in some model runs to ensure they are examined even if they would not have been economically selected based on the model constraints).
- NSP will work with stakeholders to ensure both the costs and benefits of DERs are evaluated at a reasonable level in the IRP.
- The proposed approach is for DERs to be accounted for in the model as a load modifier, with costs and benefits separately evaluated/discussed in the evaluation of each resource portfolio.

DISTRIBUTED SOLAR: COST ASSUMPTIONS



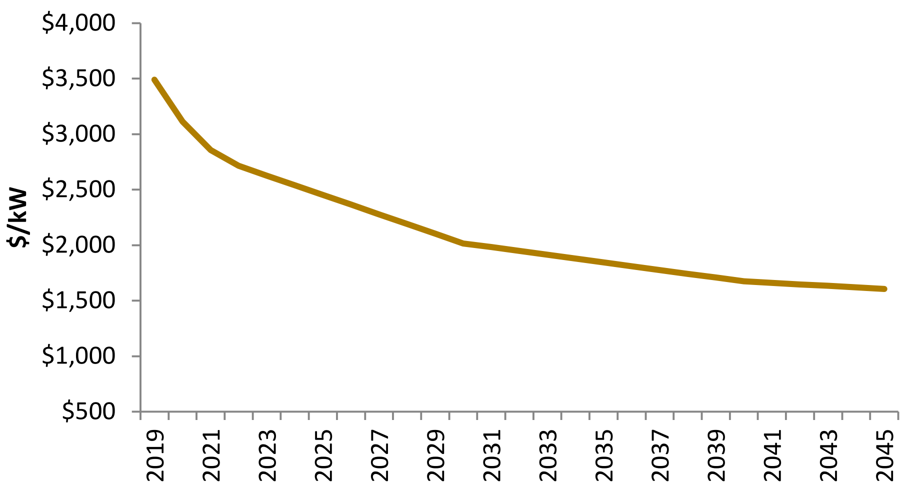


Input	Low Capacity Factor	High Capacity Factor
Capacity Factor	12%	19%
$/kW$_{2019}$	$3492	$3492
FO&M ($/kW-Yr)	21	22
Financing Lifetime (Years)	25	25
Degradation (%/year)	0.5%	0.5%

BTM BATTERY STORAGE : COST ASSUMPTIONS

Input	1HR	4HR
$\$/kW_{2019}$	$1021	$2533
FO&M ($/kW-Yr)	$8.34	27.35
Financing Lifetime (Years)	20	20
Annual Warranty (% of Capital Cost)	1.5%	1.5%
Annual Augmentation (% of Capital Cost	1.7%	2.7%

Capital Cost Decline Trajectory ($2019)



ELECTRIC VEHICLES (EVs)

- Currently, electric vehicle market share is low—across Canada penetration was about 2.2% of sales in 2018, with sales in Nova Scotia much lower, at 0.18%.*
- The pace of growth is difficult to predict and dependent on assumed cost trajectories of input commodities and components, fuel price projections, and marketing/rebate programs, among other factors
- Uncertainty around customer charging behavior in addition to adoption amounts further complicates both the energy and demand forecasts

*EV sales source: https://emc-mec.ca/wp-content/uploads/EMC-Sales-Report-Rapport-de-ventes-M%C3%89C-2018.pdf;
All vehicle sales source https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=2010000201&pickMembers%5B0%5D=1.7

ELECTRIC VEHICLES (EVs) (CONT.)

- For these reasons, some utilities are beginning to model a baseline level of EV adoption in their planning processes, usually built off established government or utility targets for near-term penetration, and then consider load growth possibilities in higher electrification scenarios
- New federal rebates for zero-emission vehicles (ZEVs) implemented in 2019, and the recent economy-wide "net neutral" by 2050 legislation, are likely to increase EV adoption during the planning period. As described in the Load Forecast section, E3 and NSP are evaluating potential impacts of this adoption.
- NS Power proposes to model bookended scenarios via load modifier approach to compare resource needs both under a baseline adoption forecast and a high electrification scenario.

2020 IRP:
PLANNING RESERVE MARGIN

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*PLANNING RESERVE MARGIN AND CAPACITY VALUE STUDY

NS Power engaged E3 to undertake a PRM and capacity value study. This study provides an update to several important assumptions to be used in the IRP process to ensure an appropriate level of resource adequacy, so that it can continue to provide reliable and affordable power to its customers.

Resource adequacy is the ability of an electric power system to serve load across a broad range of weather and system operating conditions, subject to a long-run reliability standard. The resource adequacy of a system thus depends on the characteristics of its load—seasonal patterns, weather sensitivity, hourly patterns—as well as its resources—size, dispatchability, outage rates, and other limitations on availability such as the variable and intermittent production of renewable resources.

While a variety of approaches are used, the industry best practice for resource adequacy is to establish a reliability metric and target value and then calculate what quantity of planning reserve are required to achieve that reliability target.

*Planning Reserve Margin and Capacity Value Study, Energy + Environmental Economics, July 2019

PLANNING RESERVE MARGIN (PRM)

Planning Reserve Margin (PRM)

- The quantity of planning reserves that should be held above the forecast annual firm peak load, calculated as a % of annual firm peak
- In order to meet a 0.1 days/year loss of load expectation (LOLE) target, NSPI should maintain between a 17.8% -21.0% planning reserve margin (PRM). The range in target PRM is due to a higher and lower estimate of operating reserve ("OR") requirements for the NSPI system.
- NS Power is proposing to maintain its existing PRM of 20% as the base case assumption, and iterate on portfolios to determine specific PRM requirements as illustrated in the Analysis Plan overview.

2020 IRP: WIND, SOLAR, STORAGE AND DEMAND RESPONSE – EFFECTIVE LOAD CARRYING CAPACITY (ELCC)

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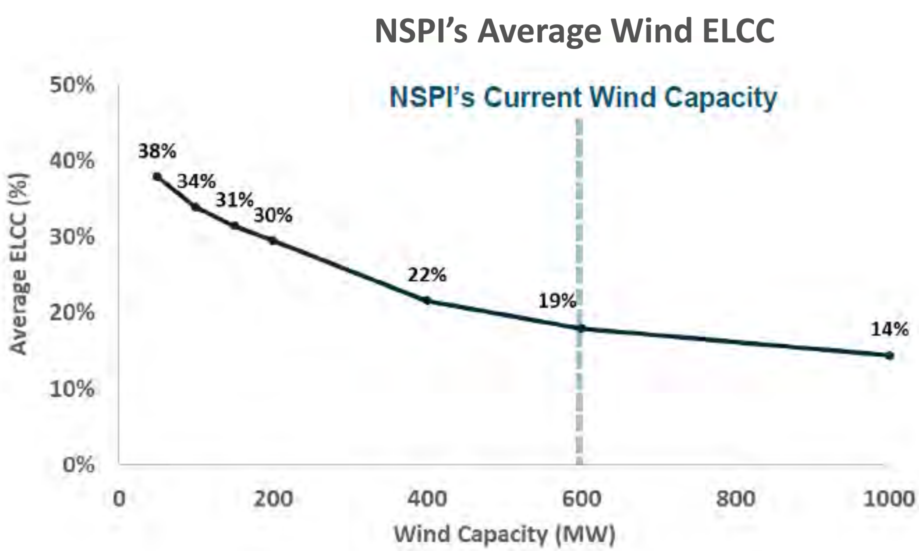
*EFFECTIVE LOAD CARRYING CAPABILITY (ELCC)

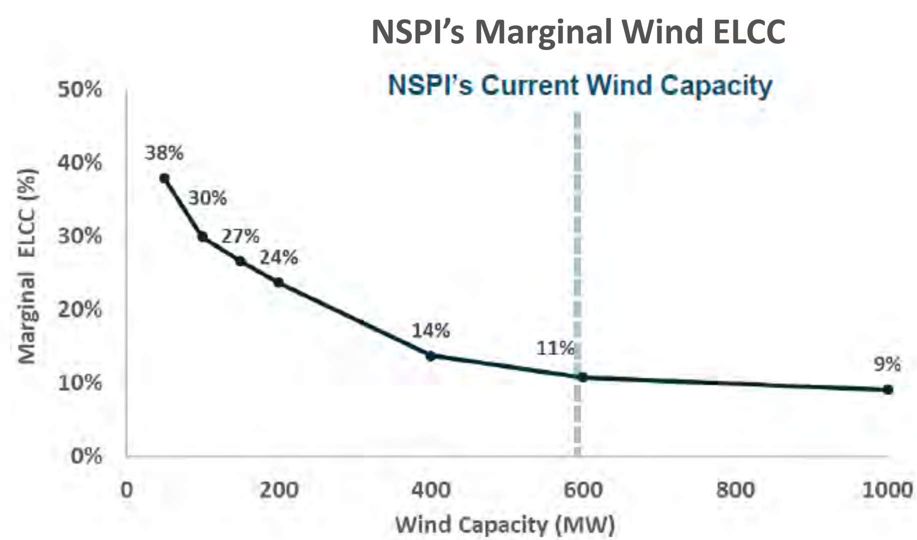
- The information from the Planning Reserve Margin and Capacity Value Study undertaken by E3 as part of the 'Pre-IRP' work will be used as the basis for the ELCC assumptions.
- Dispatch-limited resources like wind, solar, storage, and demand response can contribute effective load carrying capability (ELCC) toward meeting the planning reserve margin requirement, but have diminishing returns as additional capacity is added to the system to maintain reliability.
- The calculations of the ELCC for the portfolio of dispatch-limited resources are included in the full E3 Study provided with the Pre-IRP Report.

*Planning Reserve Margin and Capacity Value Study, Energy + Environmental Economics, July 2019

ELCC OF WIND

The average ELCC of the 596 MW of wind currently installed on the NSPI system is 19% or 111 MW. The ELCC value of adding new wind to the NSPI system is measured by the marginal ELCC and is currently at 11%, meaning that each additional MW of wind contributes 0.11 MW of firm capacity to PRM requirements.

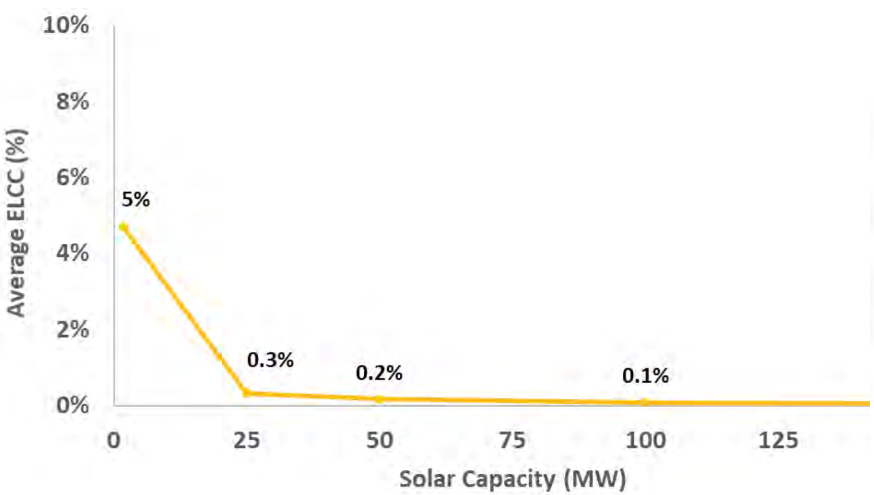




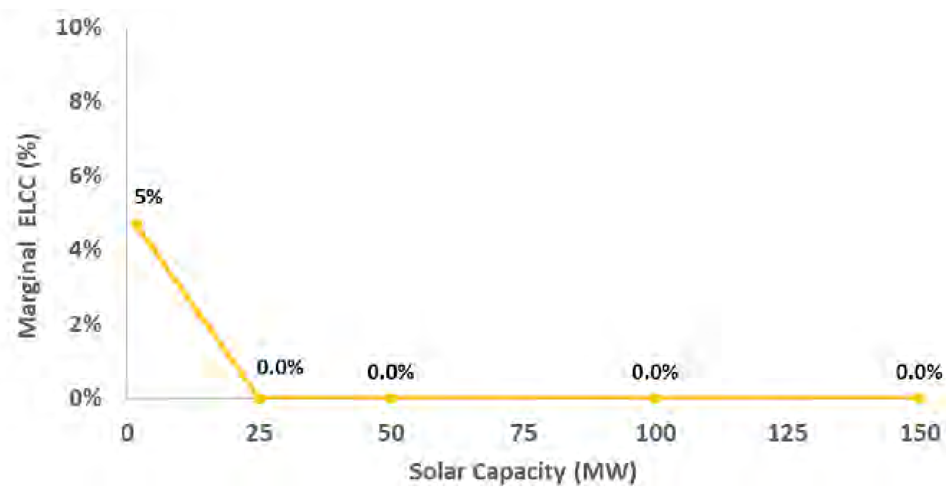
ELCC OF SOLAR

The NSPI system currently has a very small amount of solar capacity at only 1.7 MW which has an average and marginal ELCC of 5%. Solar has very limited ELCC in Nova Scotia due to poor correlation with the net peak load hours, which primarily occur on winter evenings. Beyond initial penetrations of solar capacity, the marginal capacity value declines to 0%.

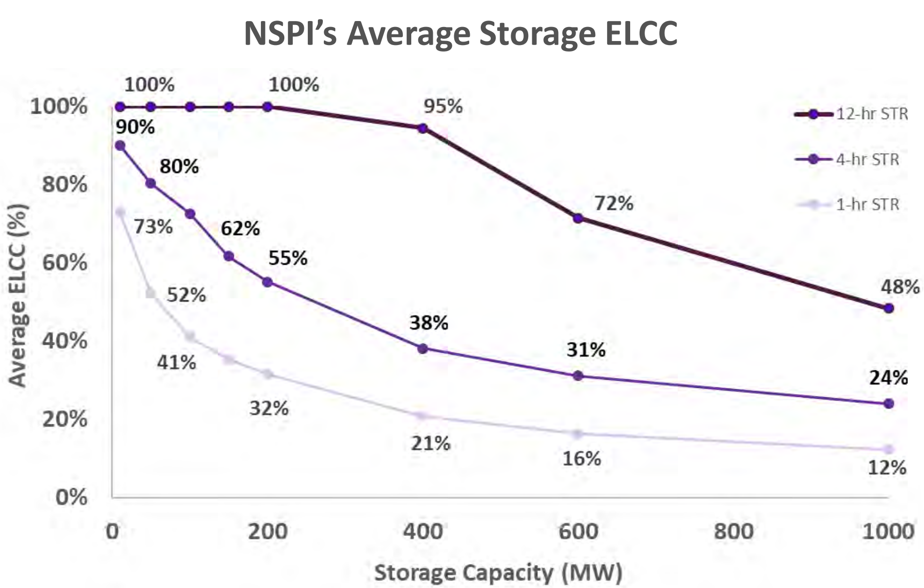
NSPI's Average Solar ELCC

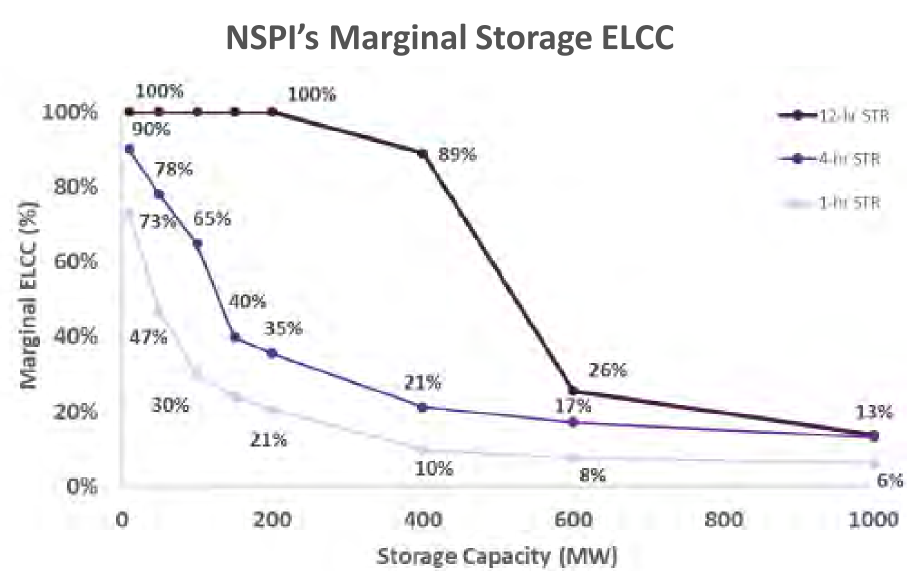


NSPI's Marginal Solar ELCC



ELCC BATTERY STORAGE

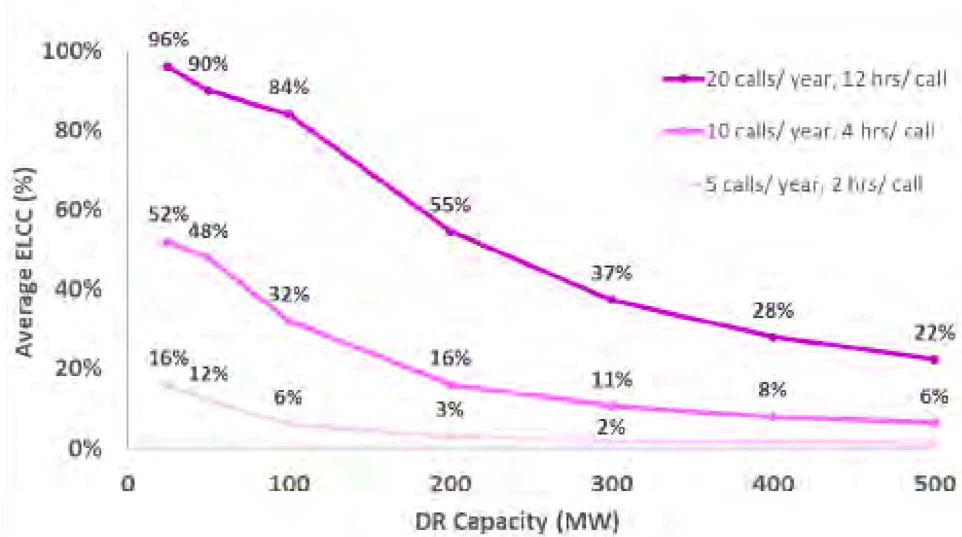




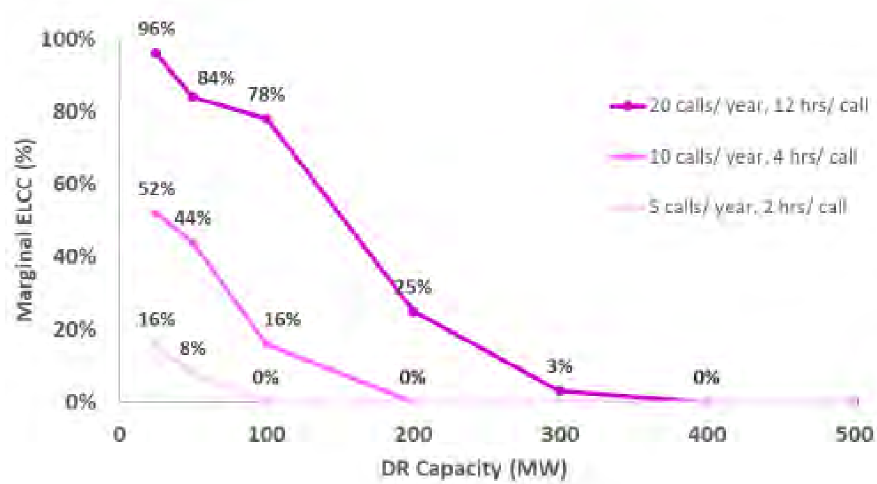
ELCC OF DEMAND RESPONSE

These represent illustrative demand response (DR) programs with different numbers of calls and durations. These results are not meant to map directly to specific existing DR programs but rather inform system planners of the ELCC value that a DR program with similar attributes might provide. As with all the previous results, DR exhibits diminishing average and marginal ELCC values. The ELCC of a DR program will depend on its specific characteristics.

NSPI's Average DR ELCC



NSPI's Marginal DR ELCC



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2020 IRP: DSM

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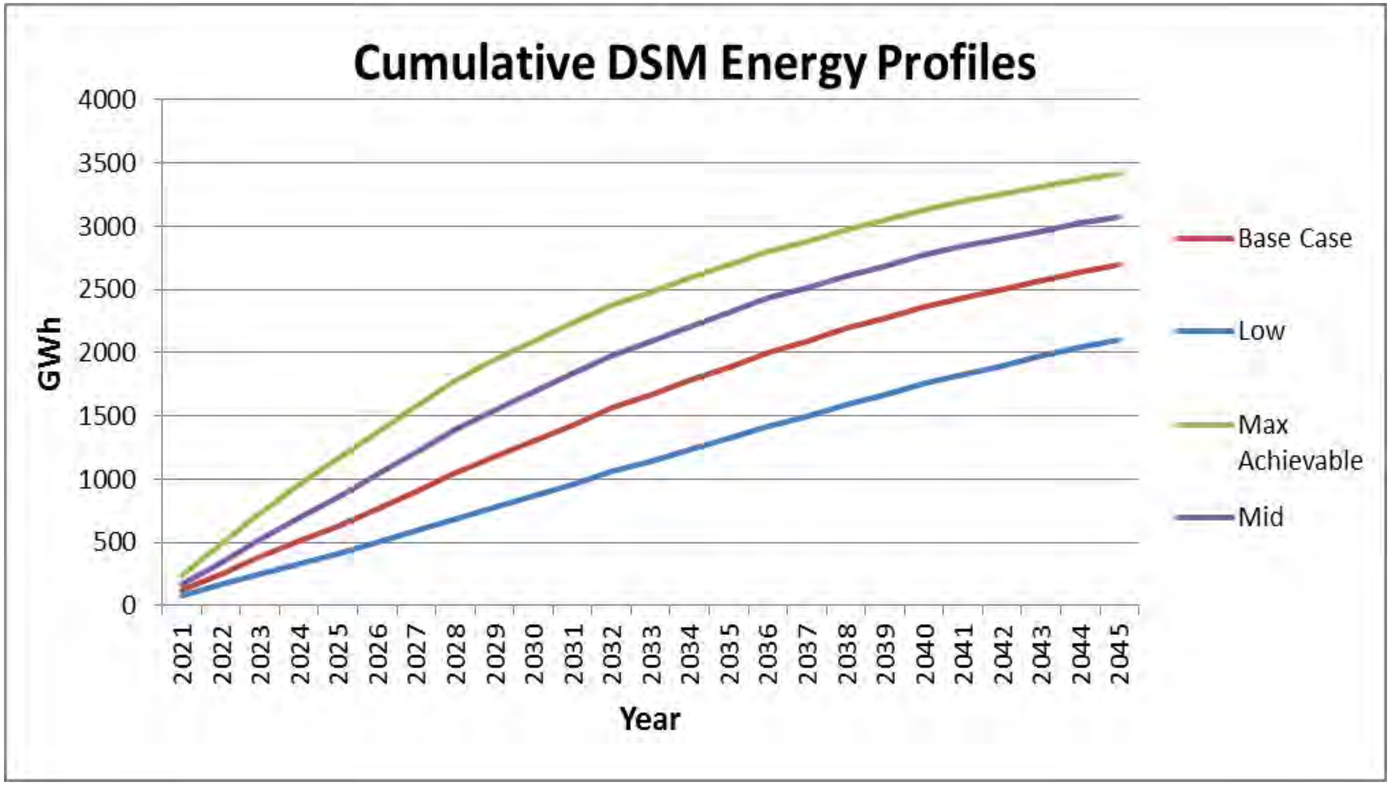
*ENERGY EFFICIENCY (EE)

- Energy Efficiency (EE) data for the 25-year period (2021-2045) provided by EfficencyOne's (E1) Potential Study.
- The data provided by E1 is proposed to be used in the IRP as a load modifier. The load modifier approach has been used in past IRP's.
- A load modifier is depicted as a decrease in energy consumption/load as a result of the increased energy efficiency.
- The scenarios are assumed to include all DSM, including:
  - Cost-effective electricity efficiency and conservation activities provided by the franchise holder
  - Initiatives that may be pursued by NS Power as permitted under the *Public Utilities Act*
  - Consumer behaviour and investments
  - Energy efficiency codes and standards
  - Initiatives undertaken by other agencies
  - Technological and market developments.

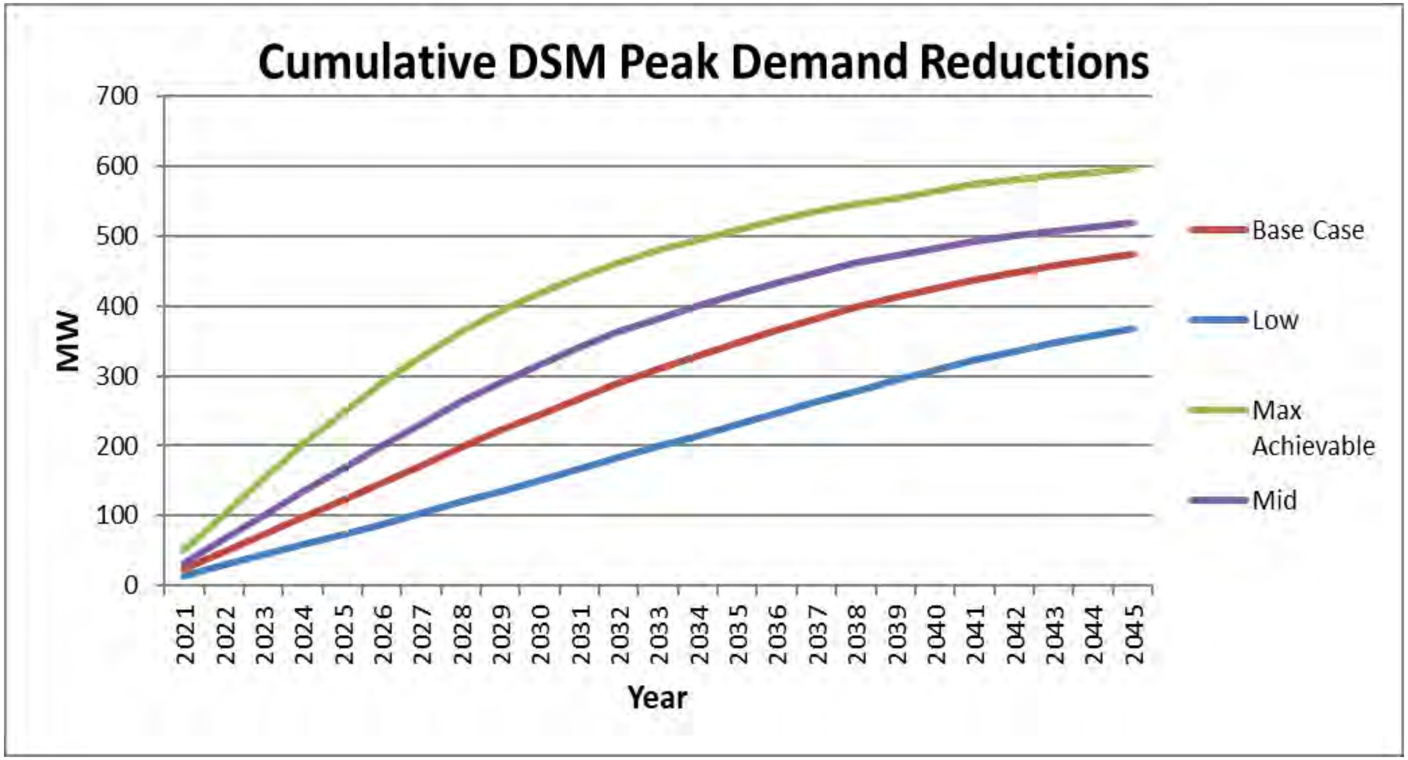
*Data Provided by EfficiencyOne(E1) in 2019 Potential Study

*ENERGY EFFICIENCY (EE)



*Data Provided by EfficiencyOne(E1) in 2019 Potential Study

*DSM PEAK REDUCTION



*Data Provided by EfficiencyOne(E1) in 2019 Potential Study

2020 IRP: DEMAND RESPONSE

JANUARY 20, 2020

*DEMAND RESPONSE (DR)

- Demand Response (DR) programs for the 25-year period (2021-2045) have been provided by E1's Potential Study, along with the 3 specific programs proposed by NSP in the Pre-IRP Work.
- The data provided by E1 could be used as a load modifier or as a resource option (bundled options).
- The load modifier approach had been used in past IRPs. A load modifier is depicted as a decrease in energy consumption/load as a results of the increased energy efficiency.

*Data Provided by EfficiencyOne(E1) in 2019 Potential Study

*DEMAND RESPONSE (DR) (CONT.)

- The resource option approach would allow Plexos to optimize which DR options to select and requires additional details/ a break down of the programs provided by E1 as well as additional time to construct the required bundling options (i.e. construct bundles, costs, profile or load reductions) when compared to the load modifier approach.

Demand Response can be largely broken into two buckets: Load Management and Demand Management.

- Load Management is often utility-controlled and dispatchable and is used to temporarily reduce peak load.
- Demand Management is usually customer-controlled and is managed by utilities in rate structures (such as Time Of Use or TOU).

*Data Provided by EfficiencyOne(E1) in 2019 Potential Study

*DR OPTIONS SUMMARY (E1)

		DR Option	Brief Description	Eligible Customer Classes	End Use
DR bundles to be screened for consideration as Plexos Optimization Resource Options.	✓	DLC-Direct Load Control	Control of electric loads by a thermostat and/or load control switch.	Residential Small Commercial Small Industrial	Electric Furnace [3] Heat pump [4] HVAC [5] Hot Water
	✓	BNI Curtailment	Firm capacity reduction commitment. $/kW payment based on delivered capacity, administered through third-party aggregators.	Large Commercial Large Industrial Interruptible	HVAC Lighting Water Heating Total Facility
	✓	BTM Battery Control	Use of batteries for load shifting and dispatching to the grid.	All classes	Batteries
	✓	EV Charging Control	Charging modulation to reduce EV demand during peak periods	EV	EV
DR bundles to be evaluated within the Load scenarios.	✗	Critical Peak Pricing (CPP)	A rate schedule with significantly higher peak prices to discourage consumption during peak times	All classes	Total Facility
	✗	Behavioural Demand Response (BDR)	Targeted notifications and incentives are provided to customers to encourage peak shaving	Residential	Total Facility

Source: Navigant

*Data and further details can be found in the EfficiencyOne(E1) in 2019 Potential Study

DR OPTIONS SUMMARY (NS POWER)

Device	Program	Peak shaving potential (kW/device)	Customer Incentive [1]	Participation Scenario (in year 25)	NSP Total Program Costs (25-yr)
Water Heater	Controller installed on customer WH and used during peak shifting events	0.5	$25 enrollment, $25/yr when compliant to program criteria	Cumulative 50,779 participants (10% of market), 27 MW peak shaving potential	$1.4M/MW
EV Supply Equipment	Customer owned and installed EVSE with peak shifting participation incentives	0.7	$150 enrollment, $50/yr when compliant to program criteria	Cumulative 89,704 participants (70% of market), 63 MW peak shaving potential	$0.75M/MW
Residential Battery	Customer contribution comparable to diesel generator installation, utility control for up to defined number of system peak events	2.5	$2500 customer contribution, Balance of battery cost covered by NSP and funding where available.	Cumulative 4000 participants, 6.25 MW peak shaving potential	$7.16M/MW

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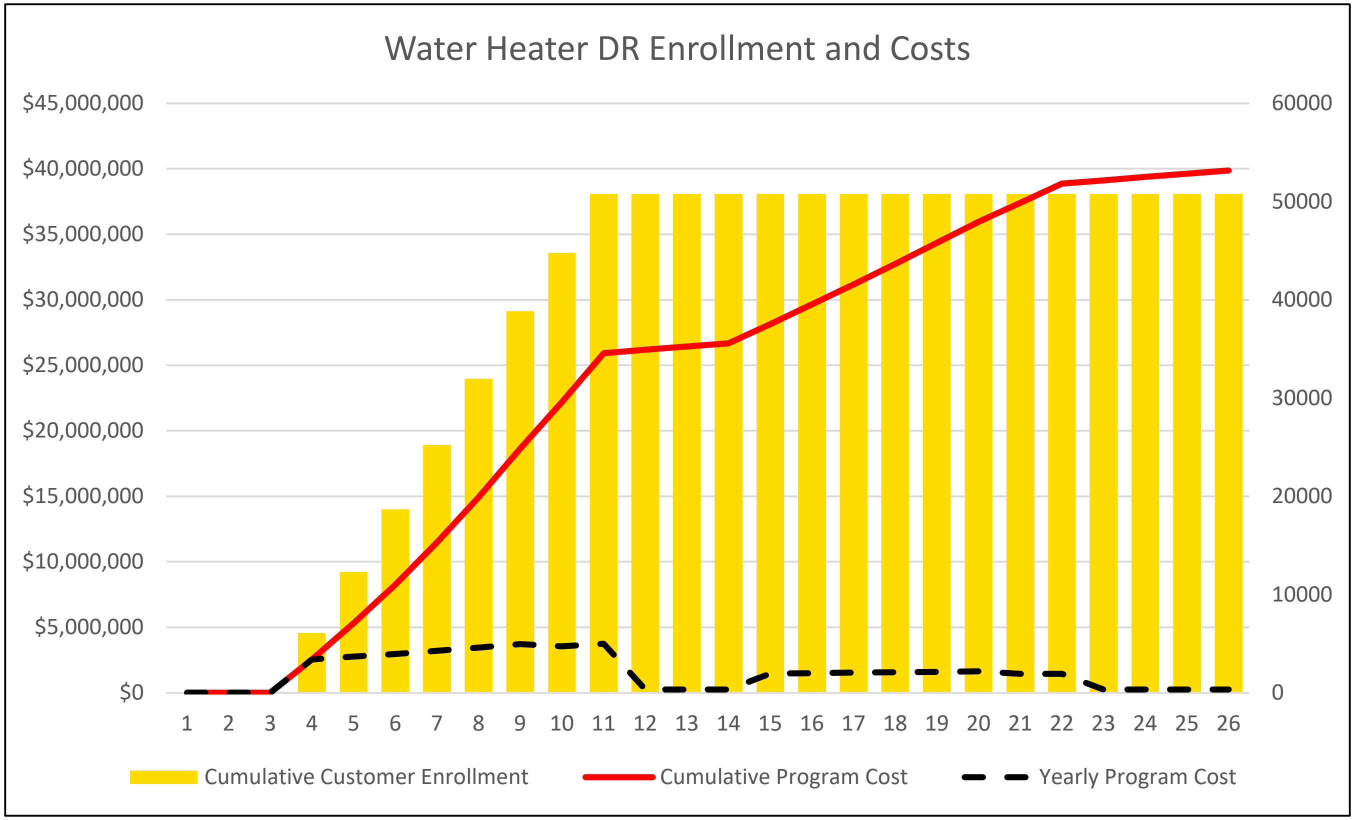
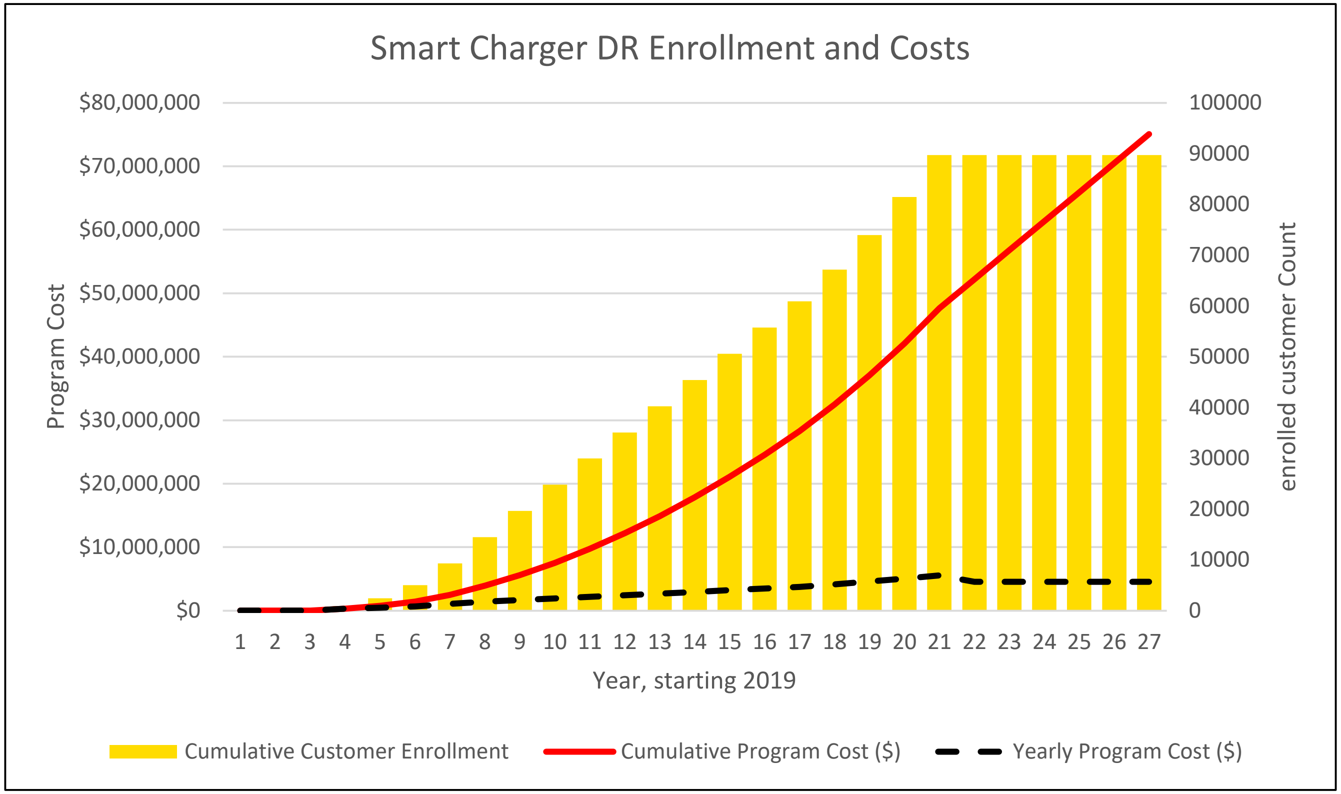
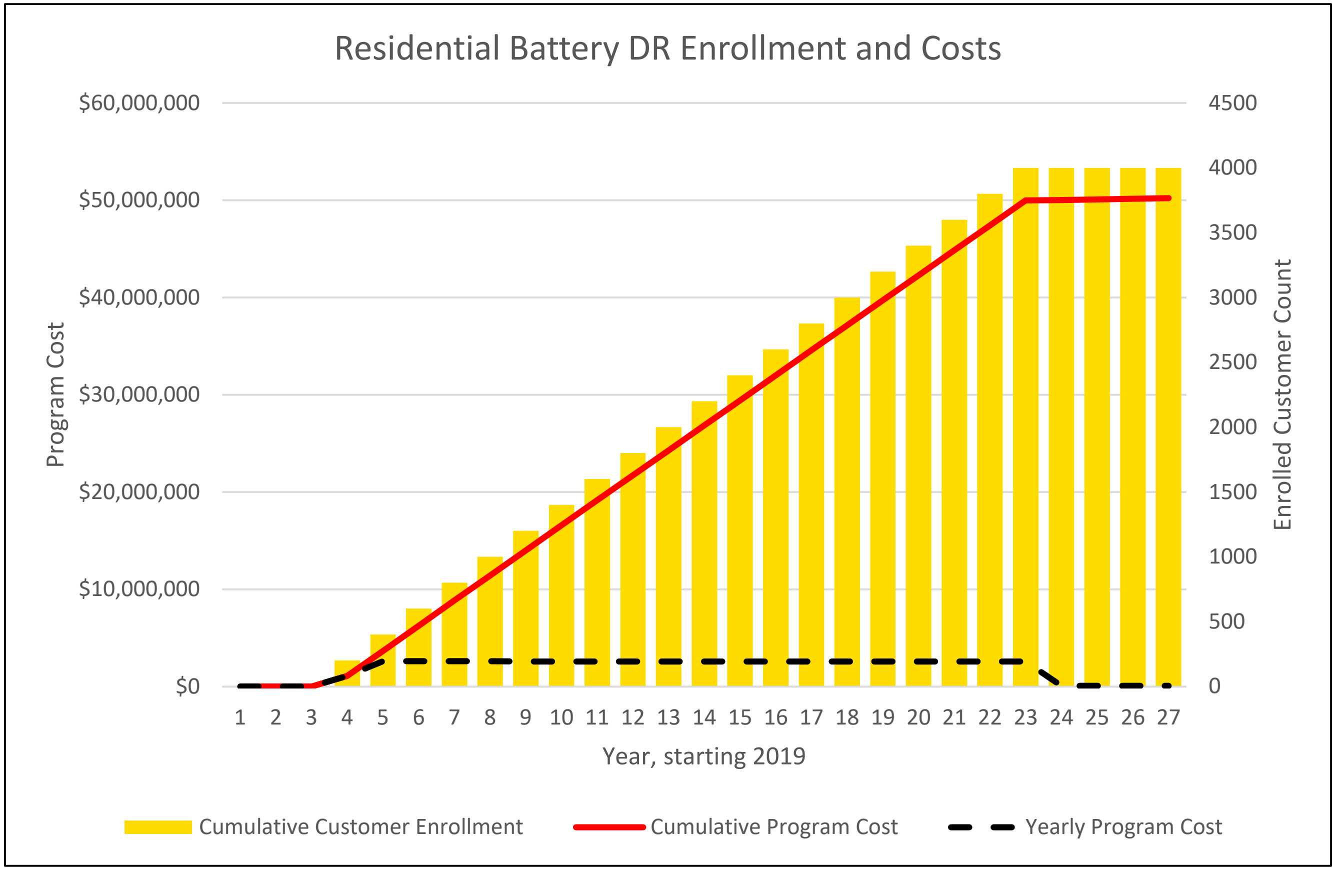
DR OPTIONS SUMMARY (NS POWER) CONT.



DR OPTIONS SUMMARY (NS POWER) CONT.



DR OPTIONS SUMMARY (NS POWER) CONT.



2020 IRP: IMPORTS

JANUARY 20, 2020

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SUMMARY – FIRM IMPORTS

- Firm imports could support the transition to lower GHG emissions and the replacement of coal-fired generation capacity via greater regional interconnection.

- Firm Transmission is required for each option and is obtained via existing transmission or assumed new transmission, depending upon the import source and assumption regarding existing transmission availability.

  - **Firm transmission capability is the amount of electricity that can be delivered in a reliable manner after consideration of surrounding system loads, voltages and stability conditions.**

  - **Non-firm transmission is the additional capability that can be used for energy delivery from time to time but is subject to curtailment under different system conditions.**

SUMMARY – FIRM IMPORTS (CONT.)

Firm Import Options :

- Access to firm capacity via existing transmission up to ~150 MW firm; and/or,
- Access to firm capacity via new transmission build up to ~800 MW firm.

Non-Firm Import Options:

- Import energy via existing transmission (Maritime Link and New Brunswick tie-line); and/or,
- Import energy via new transmission per above.

ENABLING TRANSMISSION INVESTMENT

The Qualitative Benefits of Transmission:

- Enhanced system reliability (voltage support, reserve sharing, etc.).
- Expansion of renewable generation integration.
- Option Value (greater market access through congestion reduction; supplier alternatives support energy purchase negotiations).
- When coupled with an energy and capacity contract, the opportunities are expanded.

Quantitative Benefits of accompanying energy and capacity contract :

- Firm capacity import enabler (to support coal capacity retirement).
- Renewable energy imports (to reduce air emissions and avoid carbon costs).
- Expanded economic energy imports.

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PRICING FOR FIRM IMPORTS

- Pricing for capacity provision is based on Platts Analytics forecast.
- Pricing for energy provision derived from Platts Analytics forecast.
- All import energy options will be priced as sourced by “clean energy” options (i.e. no associated carbon dioxide emissions)

2020 IRP:
FUEL PRICING

JANUARY 20, 2020

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SERVICE PROVIDER

S&P Global Platts analytics (formerly PIRA Energy group)

- Long time service provider to NSPI
- World-wide perspective and insight
- Forecasts utilized in Maritime Link, 2009 IRP and 2014 IRP

Forecasting approach

- NS Power Fuels, Energy & Risk Management (FERM) utilised commercially available long-term prices forecasts for 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)

FUNDAMENTAL PRICE FORECASTS

Commodity	Pricing Point	Provider	Updated
Nat. Gas	(N.A.) Henry Hub	S&P Global Platts' Analytics (formerly PIRA Energy Group) Scenario Planning Service Quarterly Update	Q4 2019
	(LNG) TTF, Spot (International Natural Gas) JKM (Asian Natural Gas)		
	AECO Basis Dawn Basis	S&P Global Platts' Analytics (formerly PIRA Energy Group) (LT) S&P Global Platts' Analytics (formerly PIRA Energy Group) (ST)	JUNE 2019 NOV 2019
Fuel Oil	New York Harbour	S&P Global Platts' Analytics (formerly PIRA Energy Group) Scenario Planning Service Quarterly Update (Brent) InterContinental Exchange (ICE)	Q4 2019 DEC 2019

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2020 IRP:
FUEL PRICING (NATURAL GAS)

JANUARY 20, 2020

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NATURAL GAS OPTIONS - SUMMARY

- NS Power's 2020 IRP will evaluate natural gas units (combustion turbines/combined cycle/reciprocating units/steam turbines) as potential capacity replacements for the aging coal fleet for either economic or policy reasons;
- Continuing improvements in natural gas plant flexibility, fuel efficiency and fuel supply is leading to, in certain jurisdictions, competitive advantages over coal, particularly given the faster pace of grid operations driven by variable generation;
- Gas typically plays a role in backing up renewables- especially during the extremes when wind and solar could be at a minimum;

NATURAL GAS OPTIONS – SUMMARY (CONT.)

- While the installed cost of new gas units are well documented, the all-in levelized cost of energy is subject to significant uncertainty associated with the delivered cost of natural gas, particularly given the supply constraints in Nova Scotia;

- During peak winter conditions, heating demands from firm natural gas customers in the Northeastern U.S. and Eastern Canada increase natural gas demand, create upward pressure on prices, and limit the amount available to customers who do not have firm pipeline contracts;

- With the shutdown in production from domestic sources (Sable Island and Deep Panuke), Nova Scotia will be reliant on natural gas imported via U.S. pipelines, LNG tankers, or an all Canadian Path, via Western Canada;

NATURAL GAS OPTIONS – SUMMARY (CONT.)

- New natural gas plants must have a firm source of gas supply to reliably generate power during winter peaks;
- Operational Mode/utilization must be considered (i.e. primarily for capacity or for energy and capacity);
- Three supply paths have been developed that consider existing supply arrangements and compare and contrast possible new paths to move gas to Nova Scotia for possible new gas units as represented in the system optimization.

NATURAL GAS PRICE ASSUMPTIONS

The three supply paths developed are:

- **Option 1: Existing Gas (**TCPL Empress-East Hereford via North Bay Junction- tolls modelled as a fixed cost)
  - Existing 20,000 MMBtu/day pipeline capacity
- **Option 2: Peaking Gas** (LNG Winter-Dawn plus Tolls Summer)
  - Unlimited LNG sourced from Repsol's Canaport terminal in the winter, up to 100,000 MMBtu/day sourced at Dawn in the summer
- **Option 3: Base Loaded Gas** (New supply sourced at AECO plus tolls)
  - Up to 100,000 MMBtu/day
  - Fixed Cost adder to be applied to gas units in model for this option.

- For each options, 3 scenarios have been priced: Base Case (Expected), High Case, and Low Case.

FUNDAMENTAL NAT GAS SCENARIOS (S&P GLOBAL PLATTS ANALYTICS) HENRY HUB

	Likelihood (S&P Global)	Highlights
Base Case (Expected)	50%	-US Demand growth expected to slow post 2020 -Gas consumption in the power sector has become saturated -More locations are banning or restricting the use of gas -The US technically recoverable resource was raised to 3,024 TCF an increase of 560 TCF, the largest change ever -Prospects for additional LNG export terminals achieving FID have increased with the apparent progress in US/China trade talks
High Case	25%	-Prolonged pipeline/regulatory review process impede future infrastructure expansion -Tightened environmental/regulatory policy inhibits shale gas & oil development. -Accelerated US coal/nuclear retirement and/or increased US electricity demand increase demand for gas -Increased N. American LNG export capability along with less new global capability
Low Case	25%	-Associated gas tied to liquids rich production is more abundant than currently envisioned (will have to be tied to pipeline additions) -Shale gas production surprises to the upside -Non-fossil fuel electric generation grows at a faster rate than forecast -LNG exports from the US face stiffer offshore competition -More anti-fossil fuel sentiment limits electric and industrial demand growth

NS CASE DEVELOPMENT (NAT GAS)

	Highlights
Existing Gas: TCPL North Bay Junction	-20,000 MMBtu/day pipeline capacity contracted starting Nov 1, 2021 for 15 years, with an assumed extension to cover the full IRP modeling period -Fixed tolls from Empress to North Bay Junction for the 25 years -Base/High/Low pricing
Peaking Gas: LNG Winter-Dawn Summer	-Unlimited LNG winter supply; 100,000 summer supply -Swing gas for daily dispatch, no long term contract/pipeline commitment underpinning - Base/High/Low pricing
Baseload Gas: from AECO	-Up to an additional 100,000 MMBtu/day firm contract -Base/High/Low pricing

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NATURAL GAS – EXISTING GAS (TCPL NBJ 20,000 MMBTU/DAY)

Delivered Price	=	Commodity	+	Basis	+	Transportation	+	Market Premium
Base	=	Henry Hub Source: Global Platts Analytics (4Q2019) Reference Case	+	AECO Source: Global Platts Analytics (June 2019)	+	Fuel & Tolls Nova + Fuel & Tolls Westbrook to Tufts Cove modelled as variable, TCPL Empress to E. Hereford and PNGTS to Westbrook modelled as fixed costs	+	Nil
Low	=	Henry Hub Source: Global Platts Analytics (4Q2019) Low Case	+	AECO Source: Global Platts Analytics (June 2019)	+	Fuel & Tolls Nova + Fuel & Tolls Westbrook to Tufts Cove modelled as variable, TCPL Empress to E. Hereford and PNGTS to Westbrook modelled as fixed costs	+	Nil
High	=	Henry Hub Source: Global Platts Analytics (4Q2019) High Case	+	AECO Source: Global Platts Analytics (June 2019)	+	Fuel & Tolls Nova + Fuel & Tolls Westbrook to Tufts Cove modelled as variable, TCPL Empress to E. Hereford and PNGTS to Westbrook modelled as fixed costs	+	Nil

NATURAL GAS – PEAKING GAS (LNG WINTER, DAWN SUMMER)

Delivered Price	=	Commodity	+	Basis	+	Transportation	+	Market Premium
Base Winter	=	TTF Spot Source: Global Platts Analytics (4Q2019) Reference, Low or High Case	+		+	Fuel & Tolls: Baileyville to Tufts Cove		LNG Regasification cost US $2.50/MMBtu
Base Summer	=	Henry Hub Source: Global Platts Analytics (4Q2019) Reference, Low or High Case	+	Dawn Source: Global Platts Analytics (June 2019) Reference, Low or High Case	+	Fuel & Tolls: Dawn to Tufts Cove Source: Current or negotiated Tolls		Nil

NATURAL GAS – BASELOAD

Delivered Price	=	Commodity	+	Basis	+	Transportation	+	Market Premium
Base	=	Henry Hub Source: Global Platts Analytics (4Q2019) Reference Case	+	AECO Source: Global Platts Analytics (June 2019)	+	Tolls Nova to Tufts Cove modelled as fixed costs Fuel & Usage Nova to Tufts Cove modelled as variable costs	+	Nil
Low	=	Henry Hub Source: Global Platts Analytics (4Q2019) Low Case	+	AECO Source: Global Platts Analytics (June 2019)	+	Tolls Nova to Tufts Cove modelled as fixed costs Fuel & Usage Nova to Tufts Cove modelled as variable costs	+	Nil
High	=	Henry Hub Source: Global Platts Analytics (4Q2019) High Case	+	AECO Source: Global Platts Analytics (June 2019)	+	Tolls Nova to Tufts Cove modelled as fixed costs Fuel & Usage Nova to Tufts Cove modelled as variable costs	+	Nil

OTHER ALTERNATIVES

- Other possible natural gas supply arrangements are possible, however not every potential supply arrangement can be tested in an IRP model, as it would result in modeling complexity that may prove unsolvable

- Other possible arrangements that are not included in the IRP include (but are not limited to):

    1. Dual Fuel capability
    2. Natural Gas Storage
    3. LNG Alternatives

- Should the IRP Action Plan indicate further investment in natural gas resources, these options can be considered in a more detailed analysis to determine optimal supply sources following the conclusion of the IRP.

DUAL FUEL CAPABILITY

Given the known challenges associated with securing a cost-effective firm natural gas supply source, the economics and permit ability of ULSD oil use in lieu of high cost of pipeline infrastructure would be considered in the future if natural gas units prove to be a no-regrets supply option in the IRP.

DUAL FUEL CAPABILITY (CONT.)

Benefits

- State-of-the-art combined-cycle plants and peakers can burn ULSD, kerosene or distillate oil efficiently without jeopardizing the cycling range and quick-start capability associated with the technologies
- Use of oil to support a reliable fuel supply portfolio would supplant natural gas when delivery constraints arise
- Oil supply arrangements are much more flexible than those associated with firm gas because they do not require major infrastructure expansions to enable delivery

DUAL FUEL CAPABILITY (CONT.)

Challenges

- Duel-Fuel capability has an assumed cost adder of 7%
- Switching on the fly from natural gas to oil or vice versa poses operational challenges and can jeopardize unit availability
- Increased emissions associated with burning oil in lieu of natural gas for fuel assurance
- Oil refill during the peak heating season has proved challenging for both barge- and truck-delivered oil supply during cold snaps

DUAL FUEL CAPABILITY (CONT.)

Challenges

- Increased Compliance Cost - Switching from gas to ULSD or HFO when pipeline constraints into or within Nova Scotia prevent the use of gas will increase CO_2 emissions during those events by a factor of roughly 50% on a tonnes per MWh basis
- Tank farm permitting
- Challenging to model in the long term due to the granularity needed to test value proposition

NATURAL GAS STORAGE

- AltaGas is developing an underground gas storage facility in Alton, Nova Scotia, which would be connected to M&NP pipeline
- Heritage Gas Ltd. has contracted for the first phase of capacity
- It is possible that NS Power could contract for capacity – the economics of usage would need extensive analysis (e.g. the amount of turns and resultant withdrawal rates, etc.)
- As per the Dual Fuel Capability option, NS Power will study this option in detail if new gas units are part of the IRP recommendation

LNG ALTERNATIVES

As an alternative to traditional pipeline transportation, a number of companies have begun to develop “virtual pipelines” by shipping LNG or compressed natural gas (CNG) via truck or boat to sites that do not have pipelines connections or cannot receive gas due to pipeline constraints.

2020 IRP:
SUSTAINING CAPITAL

JANUARY 28, 2020

Nova Scotia
POWER
An Emera Company

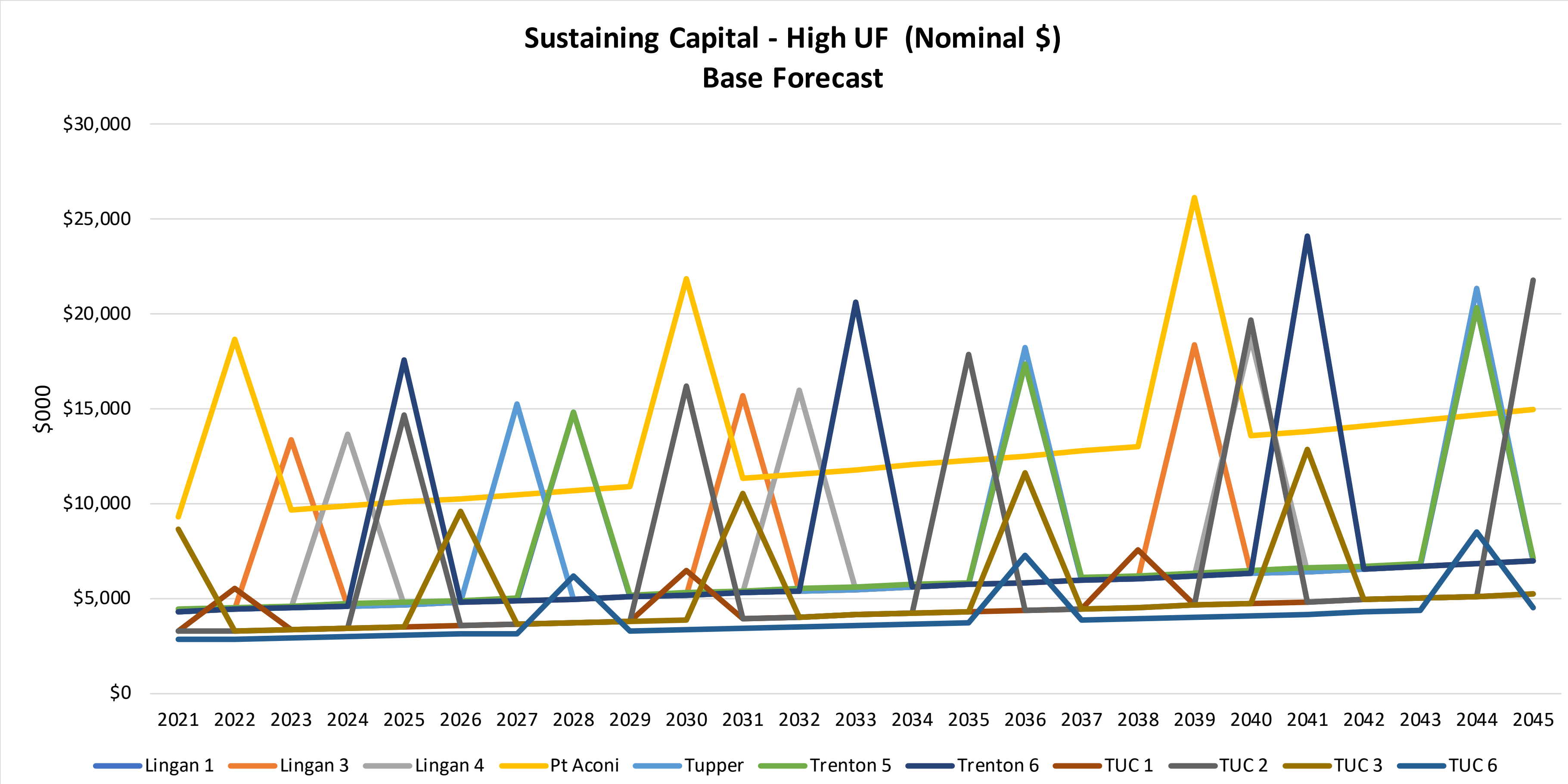
SUSTAINING CAPITAL FORECAST – COAL UNITS

- The sustaining capital cost Base forecast assumes a high utilization factor (UF) for all thermal units, which will represent the forecast investment required to address wear on components driven by a high capacity factor, cycling, operating hours, flexible use, or a combination thereof (i.e. the uses of the machines that drive the highest investment requirements)

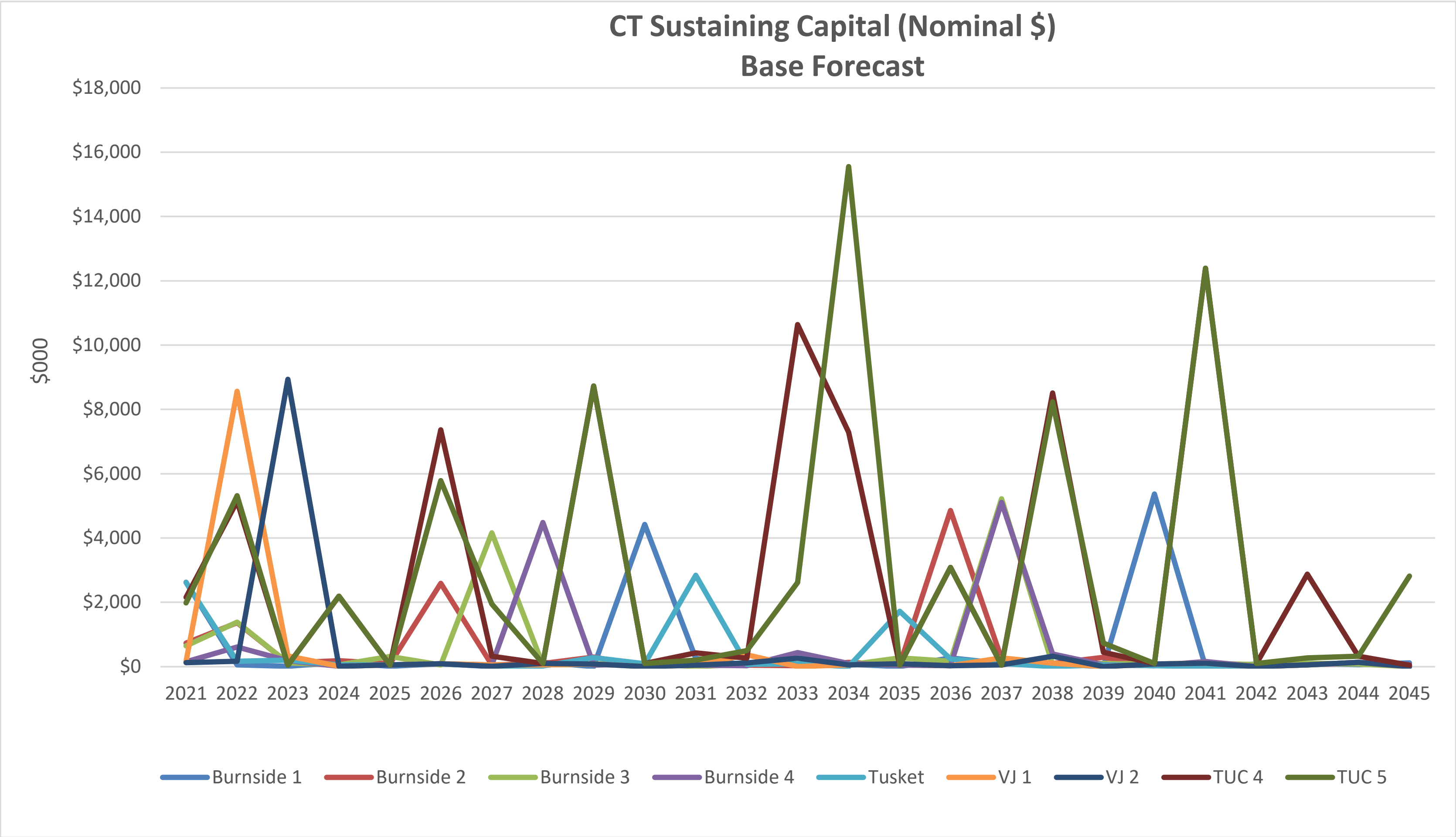
- The high UF puts all the units on an equal basis in terms of their operation in order to appropriately compare economics.

- NSP proposes that the High and Low sustaining capital cost sensitivities will assume the following:
    - High = Base + 50%
    - Low = Base – 25%

SUSTAINING CAPITAL FORECAST – COAL (BASE)

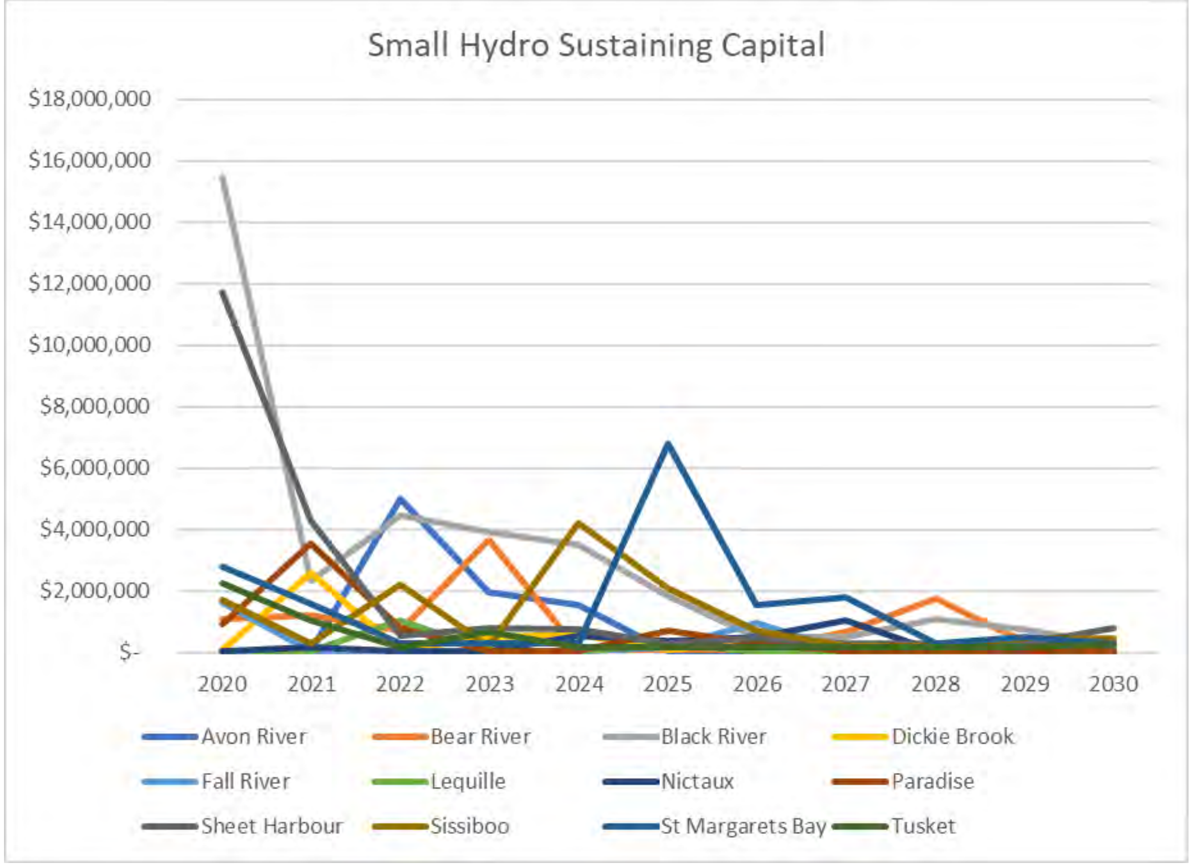


SUSTAINING CAPITAL FORECAST – CTs



SUSTAINING CAPITAL FORECAST – SMALL HYDRO

- The sustaining capital forecast for hydro assets will be based on the Hydro Asset Study.*



*Updated project cost estimates for Wreck Cove LEM and Mersey redevelopment projects will be provided to stakeholders during the Assumptions workshop.

2020 IRP:
RENEWABLE INTEGRATION REQUIREMENTS

JANUARY 20, 2020

Nova Scotia
POWER
An Emera Company

SUMMARY

- Unlike previous IRPs, the next 25 years will likely be characterized by a drastic transformation in the electric utility business as it moves further towards complete decarbonization.

- Theories and physics of Power Systems were developed around synchronous machines that were the backbone of the power system for a very long time.

- This IRP will test the retirement of major large synchronous generators with replacement by inverter-based non-synchronous generation (or other lower emitting generators).

- The retirement of coal fired generators will not only impact the system adequacy (capacity and energy) but also will create a major shift in the provision of essential grid services which have historically been provided as ancillary benefits of large synchronous machines.

SUMMARY (CONT.)

- For IRP modeling, assumptions about cost and operational constraints to address these services will be considered. The assumptions have been developed by NS Power and its consultants using the PSC Stability Study from the Pre-IRP Work as the basis for assumptions. Further detailed study to establish firm opportunities and constraints for inverter-based energy sources will continue to be required as the system changes.

- Dispatch cases of selected resource plans will be tested via transient stability and system dynamic studies in the “operability screening” phase of the modeling, as described in the Analysis Plan.

SUMMARY (CONT.)

- For the NS Power system, the following has been identified as the grid services that need to be addressed to accommodate additional inverter-based generation to maintain stable and secure operation of the system.
  - **Ramping reserve and net load following capabilities**
  - **System strength and short circuit ratio**
  - **Volt-Ampere-Reactive support**
  - **Kinetic energy and synchronous inertia requirement**
- A value for the minimum requirement of each of these essential grid services will be represented in the model as dynamic constraints, which will enable the model to integrate renewable resources at any level by ensuring provision of the services.

Alternative
RESOURCE ENERGY AUTHORITY

Mila Milojevic
Manager System Planning
Nova Scotia Power Inc
Delivered via email to mila.milojevic@nspower.ca

14 February 2020

Re: Letter of Comment Regarding Current IRP's Input Assumptions

Dear Mila,

The Alternative Resource Energy Authority (AREA) would like to thank NSPI for soliciting feedback on its input assumptions for the integrated resource plan (IRP). We offer the following written comments to (i) complement our verbal input during the in-person sessions, (ii) restate some items we feel remain unaddressed and (iii) to provide our perspective on IRP work that NSPI has alluded to using to alter rates utilized by our organization and our affiliates.

Thank you for confirming that NSPI understands that local developers believe that wind and solar facilities can be constructed for prices lower than the estimates proposed for the base case. It is our understanding that NSPI believes that publicly available reports cannot confirm the estimates provided by local stakeholders. While we welcome NSPI's inclusion of the local construction estimates as a "low cost of renewables case", we continue to feel that this designation leads the reader to believe that such a scenario has a lower probability of occurring. If NSPI can clearly state in future reports that local developers strongly believe that the "low cost of renewables" scenario prices are easily achievable, AREA will accept the way NSPI proposes to advance. AREA also believes that the provided documentation does not indicate at what project size the costing is associated, which would be helpful to the reader.

AREA continues to stress that we believe the process provides no consideration for lower-cost, non-NSPI financing. We note that NSPI lists this AREA-identified issue in prior materials submitted by NSPI to the NS Utility and Review Board, but we can only find assumptions related to NSPI's financing costs in the updated documentation for which you seek comments by 14 February 2020. Therefore, AREA believes NSPI has not fully incorporated our request to study alternative, lower costs of capital and if the use of such enables Nova Scotia to decarbonize quicker than using NSPI's ownership assumptions.

Paul Chernick, President of Resource Insight and representing the Consumer Advocate, in his email dated 7 February 2020 highlights important and germane issues associated with NSPI's inequitable treatment of renewable generation's ELCC relative to conventional generation. AREA supports the process to seek answers to Mr. Chernick's rightly identified issues, which should conclude before the scenario modelling commences.

AREA believes that ratepayers would realize financial benefit from NSPI exceeding targets and selling surplus environmental attributes into various markets or other sectors of the local economy. Specific to Nova Scotia and as one example, NSPI could enable the Province to achieve overall carbon reduction targets because decarbonization efforts are more cost effective in the electricity sector than in the transportation sector. Therefore, it is likely that the transportation sector could purchase environmental attributes from NSPI at prices cheaper than it could otherwise and such additional revenue streams could benefit NSPI ratepayers. AREA staff proposed this concept during the latest in-person meeting but we believe it was confused with the concept of calculating the cost of carbon in scenarios that focus only on NSPI's constraints. AREA requests that NSPI consider modelling additional decarbonization efforts in each scenario and at what price other sectors would need to pay NSPI to affect such additional decarbonization.

Alternative Resource Energy Authority, c/o Town of Antigonish
274 Main Street, Antigonish NS B2G2C4

Alternative
RESOURCE ENERGY AUTHORITY

With respect to IRP work that NSPI has alluded to using to alter various rates, Page 49 of Nova Scotia Power's 2020 IRP Assumption Set states the following:

- The information from the Planning Reserve Margin and Capacity Value Study undertaken by E3 as part of the 'Pre-IRP' work will be used as the basis for the ELCC assumptions.
- Dispatch-limited resources like wind, solar, storage, and demand response can contribute effective load carrying capability (ELCC) toward meeting the planning reserve margin requirement, but have diminishing returns as additional capacity is added to the system to maintain reliability.
- The calculations of the ELCC for the portfolio of dispatch-limited resources are included in the full E3 Study provided with the Pre-IRP Report.

And Page 50 of the Assumption Set states:

> The average ELCC of the 596 MW of wind currently installed on the NSPI system is 19% or 111 MW. The ELCC value of adding new wind to the NSPI system is measured by the marginal ELCC and is currently at 11%, meaning that each additional MW of wind contributes 0.11 MW of firm capacity to PRM requirements.

In its recent 2020 Annually Adjusted Rates Application filed with the Nova Scotia Utility and Review Board on October 22, 2019, Nova Scotia Power stated at Pages 16 and 17 as follows:

> "As in previous years, NS Power proposes to continue to use 32 percent capacity contribution factor for wind generation for the billing purposes in 2020. This factor has been approved for use by the Board in 2009 on the basis of the then used premise by NS Power that the capacity factor of wind generation represented a proxy for its contribution to the system peak. NS Power has revisited its methodology since then in favor of a statistically measured direct contribution of wind generation to the system peak. As a result, the capacity contribution of wind generation used by NS Power's generation planning was lowered to 17 percent for its existing wind resources, both ERIS and NRIS. NS Power has recently completed a pre-Integrated Resource Planning Capacity Study concerned with calculation of the Effective Load Carrying Capability (ELCC) of wind and other renewable energy generators, both for the existing and potential new wind resources. Once 2020 IRP process is completed, NS Power will revisit justification for the continued applicability of the 32 percent capacity contribution factor for BUTU billing purposes."

We wish to specifically note that the 2020 IRP process is not the appropriate avenue for consideration of the applicable value to be used in the Back-Up/Top-Up (BUTU) Tariff, as the IRP is a generic planning process rather than a rate design process. Regardless of what capacity contribution of wind generation for Nova Scotia Power's overall generation planning is utilized in the IRP process this should not be considered the appropriate figure to be used for the BUTU Tariff which is designed for a specific purpose and tied to specific non-Nova Scotia Power generation facilities.

We wish to make it clear that we will not be addressing matters directly related to the BUTU Tariff as part of the IRP process nor do we see the IRP process as the appropriate venue for consideration of such issues.

Thank you for considering our input.

Regards,

Aaron Long
Director of Business Services

Cc:

Lia MacDonald, Senior Director Enterprise Asset Management, NSPI
Nicole Godbout, Director of Regulatory Affairs, NSPI
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2020 NOVA SCOTIA POWER INTEGRATED RESOURCE PLAN

COMMENTS ON THE ASSUMPTIONS AND THE DRAFT ANALYSIS PLAN

Submitted jointly by the Canadian Wind Energy Association (CanWEA) and the Canadian Solar Industries Association (CanSIA), February 14, 2020

About CanWEA and CanSIA

The Canadian Wind Energy Association (CanWEA), is the voice of Canada's wind energy industry, actively promoting the responsible and sustainable growth of wind energy. A national non-profit association, CanWEA is Canada's leading source of information on wind energy's social, economic, health and environmental benefits for Canadian communities and provincial economies. Established in 1984, CanWEA represents the wind energy community — organizations and individuals who are directly involved in the development and application of wind energy technology, products and services

The Canadian Solar Industries Association (CanSIA) is a national trade association that represents the solar energy industry throughout Canada. Since 1992, CanSIA has worked to develop a strong, efficient, ethical and professional Canadian solar energy industry with capacity to provide innovative solar energy solutions and to play a major role in the global transition to a sustainable, clean-energy future.

On November 28th, 2019, the members of both CanSIA and CanWEA voted overwhelmingly to amalgamate the two organizations into a new multi-technology association focused on wind energy, solar energy and energy storage. The new organization will officially launch on July 1, 2020. In the meantime, CanSIA and CanWEA will work hand-in-hand to represent wind, solar and energy storage in Nova Scotia.

Comments

The Canadian Wind Energy Association (CanWEA) and Canadian Solar Industries Association (CanSIA) appreciates the opportunity to present these comments on Nova Scotia Power's (NS Power's) 2020 Integrated Resource Plan (IRP). The comments offered below pertain to the 2020 IRP Draft Analysis Plan and the 2020 IRP Draft Assumptions Set, both of which were discussed in a webinar and meeting held on January 28, 2020. Specifically, we offer comments on four issues: (1) the proposed IRP evaluation criteria; (2) ensuring appropriate assumptions regarding wind and solar integration alternatives; (3) contrasting LCOEs for different resource alternatives with market data and available price benchmarks; and (4) outlining the rationale for the natural gas pricing scenarios.

The 2020 IRP Draft Analysis Plan contained seven proposed evaluation criteria on page 4: (1) minimization of the cumulative present value of annual revenue requirements; (2) magnitude and timing of electricity rates; (3) reliability requirements to ensure supply adequacy; (4) provision of essential grid services for system stability and reliability; (5) plan robustness or ability of plan to withstand plausible changes to assumptions; (6) reduction of greenhouse gas and other emissions; and (7) flexibility. CanWEA and CanSIA are generally supportive of these evaluation criteria. However, we are concerned that risk might not be receiving sufficient attention. We understand that plan robustness will assess risk by evaluating how changes to assumptions affect the performance of other criteria. Nonetheless, economic and price considerations are reinforced by the consideration of two metrics (i.e., revenue requirements and rates) as are reliability considerations (reliability requirements and essential grid services). We understand that ultimately the critical issue will be the weight given to plan robustness as well as how the sensitivity analyses that will be used to assess plan robustness are applied. It will be important to ensure that these sensitivities reflect the underlying potential variability of these different key assumptions and recognize how the modular nature and extensive experience with respect to some technologies dramatically reduce their underlying risks and potential variability of their costs.

A number of parties participating in the January 28th webinar commented on the importance of utilizing realistic assumptions regarding wind integration strategies and their corresponding costs. There's a considerable body of evidence regarding wind and solar integration best practices. It is essential that NS Power's IRP reflects these best practices given that E3 analysis indicates that onshore wind is the least-cost resource today (E3, NSPI Resource Options Study, p. 15). This includes the application of the full possible range of wind and solar integration strategies including:

(1) ensuring system operations reflect best practices including employing an expanded balancing footprint and joint system operations. CanWEA and CanSIA understand that NS Power and NB Power employ joint system operations. Broader geographic areas facilitate wind and solar integration. While CanWEA recognizes that there is limited geographic diversity offered by the wind regimes in New Brunswick and Nova Scotia, a broader electricity market should assist with wind and solar integration and needs to be recognized in wind and solar integration studies, particularly given the joint dispatch arrangement between NS Power and NB Power.

However, further expansion is possible recognizing the size of the ISO-NE market and the diversity offered by better integration with that market. In addition, sub-hourly scheduling and dispatch such as the Ontario IESO employs would reduce wind and solar integration costs. Finally, ensuring that real-time forecasts of wind and solar energy output reflect best practices and minimize the resulting forecast error and corresponding requirements for regulation reserve also will minimize wind and solar integration costs.

(2) utilizing demand response strategies to facilitate the integration of wind and solar energy. This includes using space and water heating as a form of energy storage with space and water heating devices switching on during high wind output periods or switching off when wind generation drops significantly. NS Power participated in the PowerShift Atlantic project, which used load and wind forecasting and aggregation capabilities to perform near real-time load shifting of commercial and residential loads and provide new ancillary services to the grid.

Electrification of Nova Scotia's space and water heating end-uses as well as its transportation sectors are likely to be fundamental elements of the Province's strategy to achieve net zero GHG emissions by 2050. Configuring these end uses with load control devices can allow them to be part of a demand response framework that can facilitate the integration of renewable energy resources. This can significantly reduce wind and solar integration costs.

(3) curtailing wind and solar generation when they are surplus can also be a part of a least cost wind and solar integration strategy. Furthermore, at higher levels of wind and solar electrolysis of wind and solar

generation that can't be integrated into the NS Power system or for which there isn't sufficient export capacity to produce hydrogen can be another element of a wind and solar integration strategy.

(4) hydro imports offer a relatively high degree of flexibility, particularly those flowing over the Maritime Link which can used to assist with wind and solar integration and has the ability to vary output. As an HVDC interconnection, the Maritime Link is not a synchronous connection to Newfoundland such as would be provided by AC facilities where power flows are instantaneous. However, HVDC stations have very fast acting controls that can respond almost instantly to a contingency, similar to a fast responding generating unit (e.g., a hydro generator). Under the Energy and Capacity Agreement for the Muskrat Falls project, it is expected that 20 MW of regulation capacity will be under automatic generator control at the Nova Scotia end of the Maritime Link. These regulation signals will help off-set any generation/load imbalance in the NS Power system. Such imbalances could be from rapid changes in wind and solar generation or any generation surplus or shortage.

The IRP presents a series of assumptions for technology costs including capital costs and operating costs (both fixed and variable) of a wide range of possible technologies. These assumptions along with financing costs, project useful life and capacity factors will yield LCOEs or "revenue requirement profiles for input into Plexos". Capital or operating cost assumptions on their own can be reasonable, but when combined along with these other assumptions can yield revenue requirement profiles that don't align with reasonable expectations as supported by market data (e.g., RFP results). LCOEs were provided in E3's NSPI Resource Options Study. However, these were presented in figures, making the values more illustrative. CanWEA notes that there are a number of price benchmarks that are available that can be used to assess the reasonableness of these various IRP assumptions on an aggregate basis based on a direct comparison of these LCOEs with the various resource price benchmarks. A more explicit identification of these LCOE values would facilitate such direct comparisons and enhance the transparency of the IRP and ideally confirmation of the reasonableness of these assumptions.

A wide range of natural gas-fired generation technologies are identified as a resource in the IRP. It is important to understand the rationale for natural gas pricing and availability scenarios. The vast majority of Nova Scotia's natural gas supplies are delivered through New England where there are major natural gas pipeline constraints and the inability to build additional natural gas pipelines. These constraints can limit the ability to supply natural gas volumes to new natural gas resources. The Canaport LNG facility is typically available to address peak period requirements. However, its role may change with the proliferation of LNG supply projects in the US. Insights into these questions and what underlies the various natural gas price and supply scenarios could be contribute greater confidence in the reasonableness of IRP results.

Resource Insight Inc.

MEMORANDUM

To: Linda Lefler, Senior Project Manager, Regulatory Affairs

Nova Scotia Power

From: John D. Wilson and Paul Chernick

Date: February 14, 2020

Subject: Input on Draft Assumptions Set

On behalf of the Consumer Advocate, Resource Insight would like to submit some initial suggestions related to scenarios and evaluation criteria. Also, we have no additional comments on the Draft Analysis Plan since the comments we sent you on February 5.

We appreciated the webinar on February 7, which clarified a number of points.

1. Load Assumptions

We appreciated Mr. Olsen's response to our question regarding EV load shapes. It is our understanding that the assumed EV load shape will represent customer behavior without influence from rate design. If that load shape seems significant enough to influence model results, then E3 would recommend an "ideal" load shape without any specific rate design or policy commitment to achieve that ideal in order to test the potential impact. We agree with this approach, so long as the effects of the "ideal" load shape (if needed) is reflected in the capacity expansion model and not just as a sensitivity in production cost modeling.

The load assumptions section doesn't provide any information on how NS Power views potential uncertainty in load (other than varying levels of DSM programs and EV loads). In addition to providing a sense of how much NS Power thinks load could vary from the baseline forecast (and why), we are also interested in whether NS Power thinks that the system load shape could change over time due to changes in load mix (industry shifts, changes in space- and water-heating technology, increased large-commercial air-conditioning load, etc.).

2. New Supply Side Options

Depending on the supply side resource, there can be a substantial difference between the costs of utility-built resource and a contract with an independent power producer to build and operate a generating unit. Ideally, once the IRP is completed, any recommendations for procurement would be tested in an all-source procurement that allows self-build options to compete with private developer offerings.

We were somewhat surprised to learn that decommissioning costs are not considered in the model, except for nuclear (which does not appear to be a serious option). Since the construction of a power plant creates a removal liability, it makes sense to include an allowance for decommissioning.[1]

While escalating and discounting the decommissioning costs for a reasonable life (like 30 years) may result in relatively small contributions to total fixed costs of the resource, NS Power should try to evaluate resources on an equivalent full-cost basis in the IRP. If an initial analysis indicates that the decommissioning cost for most resources are small enough to get lost in the round-off of other components, NS Power can make that showing.

Supply side capacity options should include flexible solar (which would give the utility dispatch control for ancillary services)[2] and hybrid (renewable + storage) resources.[3] The projected levelized cost of capacity is not included in the Assumptions Set, but was included in the resource options study. Flexible solar and hybrid resources are absent from the list of capacity resources in that presentation.[4]

Even if the entire reliability constraint occurs during the winter season, solar resources (particularly flexible solar and hybrid resources) can be relevant to the capacity need. These resources can provide relatively inexpensive regulating and operating reserves during many hours of the year. Adding these resources to the

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[1] This may be inconsistent with NS Power accounting policies, which appear to require creation of a cost-of-removal liability upon putting a facility into service. NS Power, Response to NSUARB IR-5, *2020 Annual Capital Expenditure Plan*, Docket M09499 (January 30, 2020).

[2] Energy and Environmental Economics, Inc., *Investigating the Economic Value of Flexible Solar Power Plant Operation* (October 2018).

[3] Mark Ahlstrom, *Hybrid Storage Resources – Implications for Grid Services and Market Design*, presentation to US Federal Energy Regulatory Commission, Technical Conference: Increasing Real-Time and Day-Ahead Market Efficiency and Enhancing Resilience through Improved Software (June 25-27, 2019). The E3 Capacity Study discusses the benefits of combining solar and storage (e.g., Tables 28 and 29)

[4] Energy+Environmental Economics, *NS Power Resource Options Study* (July 2019). Note that NS Power intends to study the effectiveness and value of utility-managed curtailment. NS Power responses to CA IR-3 and IR-4, *Smart Grid Nova Scotia Project*, Docket M09519 (January 30, 2020).

capacity expansion model may affect the selection of the optimal capacity resources.

Regarding the supply-side cost assumptions, we would like to see more information about how those costs were developed and supported. NS Power's assumed renewable and storage project costs seem to be higher than those reported by Lazard. Benchmarking for gas-fired and nuclear generation tends to be lower, although a couple of the cost estimates seem to be on the high side. In the table below, costs that are high relative to Lazard are highlighted in orange, and lower costs are highlighted in blue.

Table 1: Comparison of NS Power Assumptions to Lazard Estimates (2019 CND$)

Technology	Subtech	Draft Assumptions Set[5]			Lazard[6]		
		Capital (2019) $/kW	Fixed O&M $/kw-yr	Variable O&M $/MWh	Capital (2019) $/kW	Fixed O&M $/kw-yr	Variable O&M $/MWh
Wind	Onshore	$2,100	$54	$0	$1,485-2,025	$38-49	$0
	Offshore	$4,726	$108	$0	$3,173-4,793	$108-149	$0
Solar PV	Tracking	$2,250	$20	$0	$1,485	$16	$0
Storage	Battery (1 hr)	$814	$8	$0	$378-693		$.3-5
	Battery (4 hr)	$2,325	$27	$0	$1,212-2,530		$.3-5
Natural Gas	Combined Cycle	$1,688	$14	$3	$945-1,755	$15-18	$4-5
	Frame Combustion Turbine	$1,080	$12	$7	$945-1,283	$7-28	$6-8
Nuclear	SMR	$8,073	$203	$0	$9,315-16,470	$146-180	$5-6

According to the US NREL Annual Technology Baseline for solar PV, the capital cost estimate of $2,250 / kW is inconsistent with all but a few very high recent estimates. [7] As shown below, those forecasts showing similar costs in 2019 were

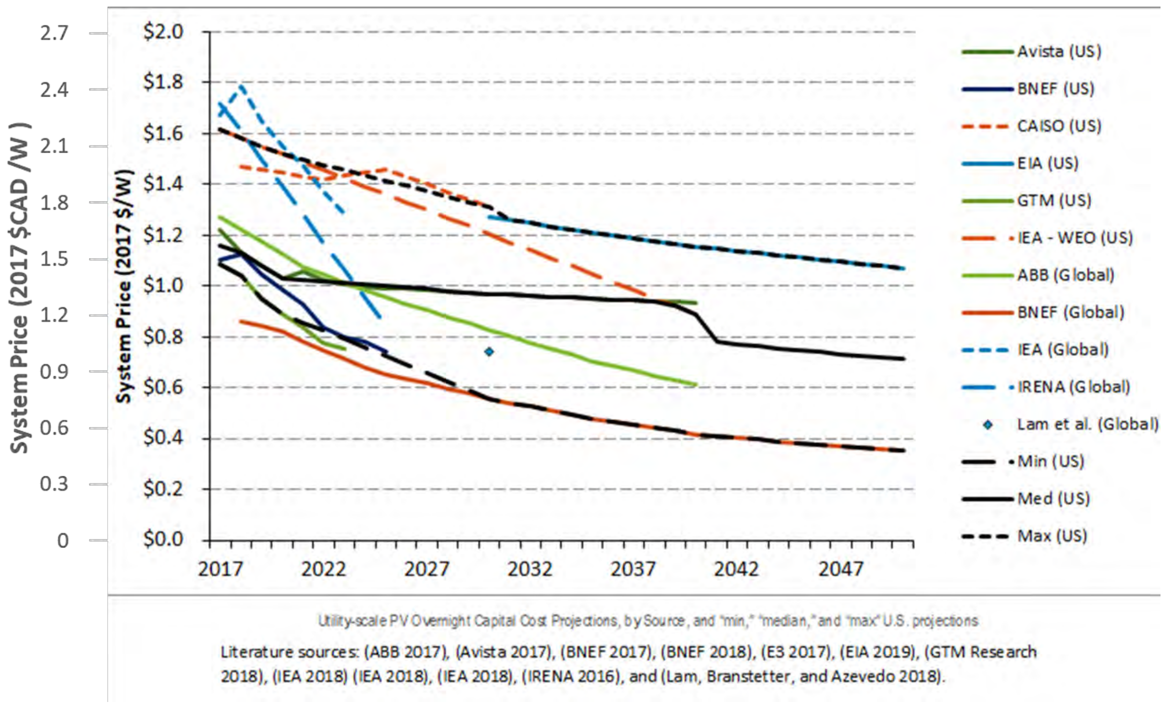
[5] NS Power, *Draft Assumptions Set* (January 20, 2020), Slides 35-37.

[6] Lazard, *Lazard's Levelized Cost of Energy Analysis – Version 13.0* (November 2019); Lazard, *Lazard's Levelized Cost of Storage Analysis – Version 5.0* (November 2019), restated to Canadian $.

[7] National Renewable Energy Laboratory, *Annual Technology Baseline: Electricity, Utility-Scale PV* (2019).

(a) generally created over two years ago and (b) associated with rapidly declining costs.

Figure 1: Solar PV Cost Projections



Source: National Renewable Energy Laboratory, *Annual Technology Baseline: Electricity, Utility-Scale PV* (2019). Prices restated to Canadian $.

Similarly, for combined-cycle natural gas, the NREL ATB suggests costs at least 20% lower than NS Power's estimate. Of the sources reviewed by NREL, all but a few suggest CCNG costs lower than NS Power's estimate. The NREL ATB suggests that capital costs for combined-cycle and combustion-turbine plants are very similar.[8]

With respect to storage technologies, Lazard suggests that O&M should be treated as variable rather than fixed. Also, the assumptions should also include the charging cost and charging cost escalator, unless these values are calculated within the system planning models.

There may well be Nova Scotia specific cost data that justify these particular assumptions, we would like to better understand these assumptions or see them aligned with other sources.

[8] National Renewable Energy Laboratory, *Annual Technology Baseline: Electricity, Natural Gas Plants* (2019).

3. Distributed Energy Resources

Distributed energy resources can offer low-cost resources for providing generating energy and capacity, avoiding line losses, avoiding T&D upgrades and providing backup service to host customers. They may result in positive or negative effects on revenue requirements. Any representation of DERs in the model should either

- include the full cost of the resources (not just the portion paid by NS Power incentives) and reduce those gross costs to reflect the T&D and non-energy benefits (including backup and other customer values), or
- if NS Power cannot estimate the non-energy benefits, just the costs paid by NS Power, reduced by T&D benefits (reduced line losses, avoided investments).

4. Planning Reserve Margin and Capacity Value Study - Generation

During the webinar, we asked about Port Hawkesbury's DAFOR and the lack of maintenance de-rate assumptions for several units. (E3 Capacity Value Study, p. 42)

Using the historical DAFORs from the Fuel Stability Plan filing (OP-9, Att 1), it appears that the DAFORs in the E3 study are the historical averages for 2016–2018. (E3 Capacity Value Study, p. 42) That seems reasonable in most cases. However, TC 1&2 performed much worse in 2018 than in recent years. Unless there is reason to believe that the units are permanently damaged and thus unreliable, perhaps a longer averaging period should be used. Using the 7 years from the FSP, the averages would be 19% and 11%, not 36% and 19%. Similarly, the TC3 DAFOR was over 8% in 2012-18, much higher than the 2% in the assumptions.

In Table 17, thermal units coal are reported to have an effective load-carrrying capacity of 100%, while wind is at 19%, as computed in the study. (E3 Capacity Value Study, pp. 55-56) We all agree that the thermal plants cannot carry load equal to their nameplate ratings. NS Power indicated that the capacity of the thermal units would be derated for capacity planning by the DAFORs used in the E3 study. Mr. Olsen agreed that nameplate capacity derated by DAFOR could be significantly higher than ELCC for the thermal units, especially the larger ones. Since ELCC is used for rating variable generation, the other types of generation should be de-rated using methods that are identical or produce essentially identical results.

The thermal plant contribution to reliability contributions appear to fall into a few buckets, based on the size and DAFOR data in Table 9:

- Large, low-DAFOR (TC 3, Lingan 1, PT 2)

- Large, mid-DAFOR (Lingan 3&4, Trenton 5&6)
- Smaller, very-high-DAFOR (TC 1 &2)
- Very small, high-DAFOR (CTs)
- The odd mix of TC 4-6

ELCC should vary among these units. Replacing a MW of TC 1 or 2 should require less capacity than a MW of Trenton 5, which should require less capacity than a MW of PT 2.

We also suggest revisiting assumptions around hydro ELCC. The E3 study says:

> For hydro resources that can be dispatched by the system operator without any substantial limits to maximum time limits (e.g. 1 week or more), E3 generally models these resources equivalently to firm dispatchable resources such as nuclear, coal, oil, and gas. (E3 Capacity Value Study, p. 30)
>
> All hydro resources except for Wreck Cove are modeled as dispatchable resources because they are deemed to have sufficient pondage such that they are equivalent to firm resources from a reliability perspective." (E3 Capacity Value Study, p. 43)

It is difficult to exactly match hydro plant capacity with energy output. Our best estimates for January projected capacity factors for 2020 are:

- 28% for Dickie Brook,
- 30-40% for Bear River and St. Margaret's, and
- 40-50% for Lequille and Sissiboo/Weymouth.

It is hard to believe that these plants can operate at full power for the entire period with non-zero LOLP in Figure 27 (6 AM to 2 AM on an average day). In addition to the storage issue, there are droughts. We understand that Nova Scotia experienced a drought in 2016.

We recommend that NS Power review its capacity value assumptions related to its hydro assumption, considering:

- Storage capacity by system, in terms of hours of full-load generation
- Time to recharge the storage from inflow in Nov-Mar
- Capacity factors for each of the hydro resources during winter peak hours (hours with any LOLP) in each of the last several years
- Effect of the 2016 drought (or other hydrological events) on effective hydro capacity over long winter peaks
- Historical frequency of droughts that have affected NS hydro capacity

Also, please make visible the numerical values behind Figure 27. (E3 Capacity Value Study, p. 55)

We also recommend that NS Power consider whether feeder circuit outages could significantly affect DAFOR for any generation units. According to one data response, the Wreck Cove Hydro feeder 85S-401 had a Circuit Average Interruption Frequency Index of 5.75, 17.45 and 7.64 in 2017, 2018 and 2019, respectively, placing it in the worst 5% of feeders in each year.[9]

During the webinar, Mr. Olsen explained that adding more EE would only change the ELCCs of various resources, especially DR over the long winter peak, if that EE changed the resulting load shape significantly. Mr. Olsen explained that one way to do reflect this possibility is to model EE programs individually, rather than as a block load modifier as planned for this IRP. We suggest that even as a block load modifier, if the program load shape is significantly different than the load shape assumed in the forecast, then the overall scale of EE resource investment could shift the load shape. This would be particularly true if EV resources are also affecting the load shape.

Our concern here is that the forecast marginal ELCC values may be missing diversity benefits associated with a mix of resources. This could result in the analysis selecting too much of the resources with high ELCC values in the E3 study and too little of other resources.

5. Planning Reserve Margin and Capacity Value Study - Load

The Capacity Value Study explains that hourly load profiles are a combination of actual hourly loads from the past 5-10 years, and weather data from the past 30-60 years. (E3 Capacity Value Study, pp. 25-26) We would like to review more details regarding the methods and key diagnostic outputs. Here are some examples of the questions we have:

- How are hourly loads related to weather data? What assumptions are made about weather conditions that did not occur during the past 5-10 years and load? Provide methods and data outputs (e.g., scatter plot of actual weather vs load compared to modeled weather vs load).
- What weather conditions are considered in the relationship between weather and load (e.g., temperature, wind, humidity, precipitation, etc.)?

[9] NS Power, Response to NSUARB IR-37, *2020 Annual Capital Expenditure (ACE) Plan*, Docket M09499 (January 30, 2020). Wreck Cove Hydro feeder 85S-402 and Ruth Falls Hydro feeders 96H-411 and 412 are also cited in these data, and have similar poor performance on Circuit Average Duration Index.

- What consideration, if any, is given to weather trends in the long-term weather dataset? For example, if there is a trend towards more wind (or less), is that reflected in the forecast? Similarly, are there any trends in rainfall, snowpack and hydro resources (p. 31)?
- Have weather conditions (mostly temperature) been correlated with generation outages (p. 42), efficiency (heat rate), or capacity?

6. Imports

We would like to see the following import-related issues addressed:

- How will the modeling reflect the correlation of temperature and load among Newfoundland, Nova Scotia and New Brunswick, and hence the availability and cost of imports (p. 48)?
- As discussed on the webinar, the assumptions set does not provide information on the potential cost of new transmission (slide 68), or how that would be dealt with in the analysis.
- How would the modeling reflect a new 800 MW tie line becoming the largest contingency, with associated reserve requirements?
- Discussion on the webinar highlighted concern that modeling all import energy options as clean energy options would either understate the emissions from New Brunswick coal or New England gas (and hence the cost of meeting emission limits), or ignore economic imports of fossil generation.

7. Fuel Pricing - Natural Gas

We previously asked about an additional fuel firming cost that might need to be assumed, if the gas-fired plants were assumed to be supplied by unreliable or constrained pipelines. We believe the question about new gas supply sources was clarified as follows:

> If the model selects new baseload (or intermediate) gas units, supply would be provided according to option 3. (Slide 78) The alternative gas supply options would be potential substitutes for option 3 that would be evaluated after the IRP. (Slide 84) The alternative gas supply options would not be necessary for the feasibility of any gas units evaluated in the IRP, since option 3 is considered feasible and sufficient.

Do we have that right?

8. Sustaining Capital for Existing Units

We have several questions about this forecast.

- Please confirm or correct our understanding of the discussion about the utilization factor. We understand that the base forecast assumes capital investments that would occur if each unit operated at what NS Power considers to be a high utilization factor for that unit. We think you are defining "high" utilization as the most demanding experience of the unit in some recent historical period, as opposed defining "high" by the same metric for all units (e.g., 80% capacity factor). Thus, if the IRP results forecast relatively low utilization factors for some units, compared to the historical base, NS Power would expect future capital investments to be lower than the base assumptions included in the IRP.
    - Do we have that right?
    - Did NS Power use a particular period to define the high utilization for each unit?
- NS Power has prepared forecasts of sustaining capital for the IRP and the 2020 ACE plan. (2020 ACE Plan, p. 17) Is the ACE plan sustaining capital forecast based on different utilization factors than the IRP? How does the approach to setting the utilization factors for the ACE plan forecast differ from that for the IRP forecast.
- Does projected sustaining capital for each unit simply reflect historical experience plus inflation, or is the projected capital cost increased to reflect the age of the plant?

9. Renewable Integration

The renewable integration section, including both the "assumptions about cost and operational constraints" and the "operability screening," leaves a lot unexplained. For example, what technology options will the model have to meet the minimum requirements for essential grid services, such as hybrid resources or flexible dispatch of solar?

We suggest that NS Power host a webinar to explain this topic and solicit feedback from stakeholders.

Resource Insight Inc.

MEMORANDUM

To: Linda Lefler, Senior Project Manager, Regulatory Affairs
Nova Scotia Power

From: John D. Wilson and Paul Chernick

Date: February 26, 2020

Subject: Input on Draft Analysis Plan

On behalf of the Consumer Advocate, Resource Insight would like to submit some additional comments on the draft analysis plan.

Previously, we suggested including resiliency testing related to a major natural disaster. We have reflected on this and, while we think the model could be used to explore such a potential future, it may not be the best way to address this issue.

Instead, we suggest adding a new section or subsection to the IRP discussing the potential impact of an extreme natural disaster on Nova Scotia's energy supplies. We suggest imagining if sea level rise accelerates at the high end of projections over the next 10–15 years, and a category 5 hurricane makes it as far north as Nova Scotia (or a similarly destructive winter storm). Our thinking is guided in part by the hurricane that has left Puerto Rico in such dire circumstances.

Of course, NS Power's equipment and staffing are better than PREPA's, and likely to fare better in similar circumstances. Nonetheless, decisions about resource planning may help NS Power prepare better for events that cannot be dismissed, given the surprising rate at which some climate changes are occurring.

The review would consider:

- Which thermal plants are most likely to be damaged by flooding?
- Would the hydro system assets function adequately under worst-case flooding?
- How much damage might solar and wind facilities incur?
- What would be the potential impact on Nova Scotia's transmission and distribution infrastructure of winds and flooding?
- Would power-plant fuel supplies be disrupted?
- How long would restoration of the T&D system take?
- Would restoration be affected by damage to other energy supplies or key infrastructure?
- Would adequate generation be available to serve load as the T&D system is restored?

These questions could be answered in the context of evaluating the strategies that NS Power is considering in the IRP. Are some strategies more resilient than others? Are there specific investments or technology choices that would be preferred? Would BTM solar and storage (or even wind and storage) improve resilience?

Resource Insight Inc.

MEMORANDUM

To: Linda Lefler, Senior Project Manager, Regulatory Affairs
Nova Scotia Power

From: John D. Wilson and Paul Chernick

Date: February 26, 2020

Subject: Input on Draft Scenarios, Strategies and Sensitivities

---

On behalf of the Consumer Advocate, Resource Insight would like to submit some comments on the draft scenarios, strategies and sensitivities.

Scenarios

As we understand the plan, NS Power intends to use Plexos for its full modeling, but it will also use E3's RESOLVE capacity expansion model to pre-screen the scenarios. As we understand it, the intent is to use RESOLVE to test whether the different scenarios produce significantly different capacity expansion plans. We strongly support this idea, as we have observed too many IRPs test scenarios that result in almost identical capacity expansion plans.

We recommend considering the following scenario instead of Scenario 2 (Net Zero – High Electrification):

- Accelerated 1.0 Mt 2050 / High Electrification + Higher Industrial/Marine Demand / Coal End 2030

We infer that Scenario 2 is probably the maximum build case. Our suggested modifications would further differentiate this scenario, expanding the decision space in a useful manner. We are suggesting three rationales.

First, we suggest this scenario should have an early coal end. Policies to achieve high electrification would logically be promoted in concert with accelerated coal phase-out. The argument for switching load to electricity is much stronger if the electric supply is cleaner. A 1.0 Mt target seems realistic, given the rate of load growth and required renewable buildout.

Second, the Pathways report excluded the industrial and marine sectors from electrification or other drivers of load growth. Global technology trends will tend to shift more industrial energy use to electricity, for 3D printing, automation and the like. The improvements in batteries and electric propulsion that promote electric road vehicles will also support electrification of marine vessels and such industrial vehicles as forklifts. Offshore wind development around Nova Scotia could further increase the development of battery-powered support vessels. From the perspective of the IRP, industrial and marine electrification would be modeled as higher loads, with high load factors and/or largely off-peak charging.

Third, NSP has not proposed to test the early coal closure date with the "current landscape" strategy, only with the "regional integration" strategy. Phasing out coal early may be economic (or have only a small incremental cost), even without major changes in policy or utility infrastructure plans. Our alternative scenario suggestion, above, would address that gap. If NSP does not want to add a scenario to consider this option, some scenario/strategy pairing(s) should be modified to get at this question.

Strategies

The strategies seem to cover an appropriate range of policy directions. We would like to better understand the components of the regional integration strategy; we may have further comments, once we see more detail.

We question the decision to test only one strategy under the comparator case.[1] The comparator case is the scenario that best reflects current clean energy policy. The Board should be provided with information about the relative performance of several resource strategies under the current policy scenario.

The "no new emitting resources" strategy might be better tested as a portfolio sensitivity to other strategies, rather than a distinct strategy. It is currently included in only one of the preliminary modeling runs, paired only with regional integration. It might make sense to hold it out and see what new emitting resources are built in the modeling runs, then apply it as a portfolio sensitivity to a few selected runs to see what the non-emitting alternative would be in those scenario/strategy pairs. Depending on how diverse the results were, one or more of those alternative portfolios could then be carried forward.

This may increase the number of preliminary modeling runs. However, as stated above, we support the concept of using RESOLVE to assess the modeling runs and narrow them down to ensure that resources are devoted to assessing significantly different portfolios.

Sensitivities

Regarding sensitivities, should there be a sensitivity regarding the price paid for power exported *from* Nova Scotia? Is that price modeled to follow import price? Is

[1] Also, the term "comparator case" isn't as clear as the rest of the scenario descriptions.

there a reasonable future in which Nova Scotia will have significant exports, such as increased transmission and wind development?

We also appreciate the suggestion to include resiliency testing, which appears to be a response to one of our "spliced scenarios." As we understand it, the idea is to test the impact of a net zero carbon constraint policy on a portfolio built to the "comparator case" scenario. We suggest that the reverse sensitivity should also be tested: test the impact of "comparator case" policy on a portfolio built to one of the "net zero" scenarios. In each case, the idea would be to test the cost of anticipating the wrong scenario.

DALHOUSIE UNIVERSITY
Office of Sustainability

February 14, 2020

RE: 2020 IRP Assumptions

IPCC goals outline significant greenhouse gas targets for the globe. Given the context of rapid climatic change the following comments are made regarding the IRP assumptions.

- Organizations have climate change goals and targets that may exceed the existing regulatory targets. How will the IRP process model scenarios and options for this cluster of customers.
- Given the rapid need to decarbonize energy systems and changing targets and demands, a more aggressive carbon scenario should be outlined that pushes past current regulatory targets and models a net zero state.
- Scenarios that introduce more grid sharing from provinces that have available hydro resources and micro-grid structures.
- Grid resiliency is becoming an increasingly important issue with wilder weather. How is this modelled into the scenario plans.

Thank you for the opportunity to comment.

Sincerely,

Rochelle Owen
Executive Director - Sustainability Office

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Page 1

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Organization & Title

Municipality of the District of Digby

Upload Documents (.DOC/X, .XLS/X, .PDF)

PDF 2016 En Conv Mng EV chg for ren en integration on grid

Browse...

Subject *

Introduction of Electric Vehicles as a means to create demand at the Conway Sub

Message *

This is a study that the Municipality of Digby conducted in order to assess the capacity of the Conway substation to accept more uptake of electric vehicles. It describes the challenges and opportunities.

February 9, 2012

Clerk of the Board
Nova Scotia Utility and Review Board
Box 1692, Unit “M”
Halifax,
Nova Scotia.
B3J 3S3

Subject; Proposed Annual Capital Expenditure Plan (ACE Plan 2012) (NSPI)

Dear Sir/Madam;

Nova Scotia Power Inc., is applying for approval of its upcoming ACE Plan for the province. I am writing today to voice our concern regarding these expenditures with regards to the lack of emphasis being placed either on upgrades to our transmission line (69kv) in the Annapolis Valley or in investments to other areas of our grid system for improved efficiency.

Our grid system in Nova Scotia is antiquated and over time the upgrades in the system have been limited. It has been stated that the traditional North American grid system which we are part of, was conceived by Edison, designed by Eisenhower and installed by Nixon. This puts into perspective the nature of our archaic grid system in an era of modern technological advances both in hardware and in communications capabilities. Our region is actively pursuing the introduction of renewable energy technologies as a way to stimulate economic development in our region; a region facing difficult economic challenges, diminishing population and dwindling resources. In an effort to develop these opportunities in renewable energy developments, we engaged the services of Lockheed Martin to assess our ability to develop a CHP (combined heat and power) plant that would serve to generate electricity for the grid through the COMMFIT (community feed-in-tariff) program and to deliver inexpensive heat to several key facilities in Digby; namely the hospital, two schools, government buildings, an arena and private commercial properties. Not only would this investment allow these facilities to hedge against rising fuel costs in the future, but the overall reduction of GHG would be a significant benefit to the province as a whole.

The consultants findings are summarized as follows; **“…there is significant risk that distribution interconnection may not be available, or that specialized interconnection equipment to mitigate the transmission impacts could be required in order to implement this project. It is not possible to further quantify the risk at this time”**. The consultants concluded that the current operational design of the transmission and distribution grid along with the age of the system has inherent flaws which prohibit the introduction of new electricity generating capacity coming from renewable energy projects including our efforts to establish a CHP plant.

The ability of the utility system to accommodate renewable energy technologies is very much driven by the degree of variability of these sources of energy and the utility's requirements to maintain reliability and voltages within mandated ranges. We are mindful that the rules and regulations that are in place are based on many years of operational experience and very difficult to change unless there are significant benefits. The variability of some renewable energy sources is often cited as the most challenging. Energy storage provides a way to overcome many of these challenges, but it still not very economical at this stage. Smart Grid technologies could also help with controlling voltage and redirecting power flows where possible. The requirement to regulate voltage in the future will be a deviation from the normal practice on the distribution system where only the utility has been allowed to do so, but the flicker and effects on voltage profiles on the feeders may ultimately lead to distributed voltage or reactive power flow control.

We are concerned as well, that as the province develops opportunities accruing from the Muskrat Falls project that it will see these investments as meeting its renewable energy targets established under the Environmental Goals and Prosperity Act and will serve to send a negative message to the utility about further upgrades to our valley transmission lines. **NO PLANNED INVESTMENT IN THE VALLEY REGION IS PROJECTED THIS YEAR NOR IN THE FORESEEABLE FUTURE**. This is troubling from a municipal perspective given our attempts to create economic development through the introduction of renewable energy technologies in tidal, wind and biomass. Our wish is to see evidence that the utility is genuinely concerned about the same issues and that there is a willingness on their part to invest in the types of upgrades that would accommodate the introduction of renewable energy technologies in the future.

Sincerely

Terry Thibodeau
Coordinator
Renewable Energy and Climate Change

2020-02-14 15:48:04

Page 1

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Municipality of the District of Digby

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Electric vehicle charging to support renewable energy integration in a capacity constrained electricity grid

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ABSTRACT

Digby, Nova Scotia, is a largely rural area with a wealth of renewable energy resources, principally wind and tidal. Digby's electrical load is serviced by an aging 69 kV transmission line that often operates at the export capacity limit because of a local wind energy converter (WEC) field. This study examines the potential of smart charging of electric vehicles (EVs) to achieve two objectives: (1) add load so as to increase export capacity; (2) charge EVs using renewable energy.

Multiple survey instruments were used to determine transportation energy needs and travel timing. These were used to create EV charging load timeseries based on "convenience", "time-of-day", and idealized "smart" charging. These charging scenarios were evaluated in combination with high resolution data of generation at the wind field, electrical flow through the transmission system, and electricity load.

With a 10% adoption rate of EVs, time-of-day charging increased local renewable energy usage by 20% and enables marginal WEC upgrading. Smart charging increases charging by local renewable energy by 73%. More significantly, it adds 3 MW of load when power exports face constraints, allowing enough additional renewable electricity generation capacity to fully power those vehicles.

1. Introduction

The Municipality of Digby (Fig. 1, left) is embarking on an ambitious strategy to alter its energy consumption and production, for greater utilization of locally produced renewable energy. Transportation represents a major energy end-user, totalling 38% of all energy used in Nova Scotia [1]. This energy comes almost entirely in the form of gasoline and diesel. While Canada has significant fossil fuel resources, there is no petroleum production in Nova Scotia, so transportation fuels represent a significant economic trade deficit for the region. In contrast, Nova Scotia in general, and the Digby area in particular, have superb renewable energy resources consisting principally of wind and tidal flows [2,3]. Electric vehicles (EVs) which have greatly increased efficiency compared with internal combustion engines, thus represent an opportunity to not only vastly reduce energy consumption for transportation, but also to transition from imported fossil fuels to locally produced renewable energy.

The electrical transmission system of the area is shown in Fig. 1 (right). It consists of 69 kV lines servicing the Town of Digby via Conway Substation. Other 69 kV lines connect nearby communities and collect from small hydroelectric facilities inland. In 2010 a 30 MW wind energy converter (WEC) field, consisting of twenty GE 1.5 MW units, was commissioned on the Digby Neck, causing Digby to become a net exporter of electricity. This 30 MW wind field was sized to meet summertime transmission export limits when local loads are at their minimum. As a consequence, further development of renewable electricity generation is not permitted, absent one of three conditions: Either (1) the transmission system is upgraded to increase the export capacity, (2) renewable generation must be curtailed when transmission limits are reached, or (3) electrical load must be added locally, so that the additional power produced can be used locally and not contribute to overloading of the transmission system.

Option 1 is not being considered by the provincial electricity system manager in short or long term planning because it would be prohibitively expensive. Option 2, while not presently supported by the grid manager, is a reactive approach that is undesirable due to the loss in renewable energy caused by curtailment. It is under the premise of Option 3 that this study is conducted. The addition of EVs adds load to the local electricity network. By evaluating the time-dependent load of charging EVs and their interaction with existing loads and generation, this study will quantify the influence of EVs on the electricity grid for a local region, and the use of renewable electricity generation for powering those EVs.

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http://dx.doi.org/10.1016/j.enconman.2015.11.066
0196-8904/

Nomenclature

EV	electric vehicle
TOD	time of day; electric rates that vary ($/kW h) on a fixed schedule
WEC	wind energy converter (wind turbine)

The use of energy storage and dispatchable load to manage variations in renewable energy output is a problem of nearly universal concern in utility management as non-dispatchable renewable energy sources become a significant contributor to total energy and grid instability [4–7]. Applying the possible grid management benefits of EV charging to achieve a specific grid management objective is of great interest to governments and utilities [8,9], so this case study, which benefits from well-defined grid constraints and precise grid loading data, may be of particular interest to policy makers.

The interaction of EVs that plug into the electrical system, and the electrical system itself rely entirely on an accurate understanding of when EVs are used, how much energy they consume when they are used, and when they are returned to a location where they can plug in and charge. The significance of the driving patterns is made doubly important when one considers three possible effects of EVs on the energy system [10]. One possibility is an undesirable evening peak in load that could occur if charging rates and timing are unconstrained, referred to here as "convenience charging". The second is to respond to "time of day" (TOD) electricity rates with a charge timer, in which case an evening load peak is avoided and loads overnight are increased, but no more finely tailored benefits can be realized [11,12]. The third possibility is "smart charging", which is managed by grid operator intelligence and real-time control, in which EV charging loads become a controllable resource providing valuable grid services.

Any charging strategies that are successful in reducing or controlling the export transmission loads could correspondingly permit increased local generation capacity. General Electric (GE), the manufacturer of the WECs in use at the wind field have developed a control software update titled WindBOOST, which increases the maximum power output by 10%, from 1.5 MW to 1.65 MW. This modification could be implemented at negligible cost, and would increase WEC field power capability to 33 MW, and annual average energy production by roughly 4% [13,14]. As an objective, this study investigates the potential of adding controlled EV charging, thus allowing the WindBOOST upgrade, with the intent that the added energy production would be sufficient to provide the necessary energy to charge the EVs, making them a net benefit to Nova Scotia's grid.

2. Data sources/research methods

To conduct a thorough investigation of EVs and their impacts upon the electrical grid requires an understanding of the present transportation fleet in Digby with respect to both vehicle populations and vehicle use. Specifically, to understand the energy requirements of vehicles, it is necessary to know (1) how many vehicles of various types are in use in the area, (2) how much energy these vehicles use each day (how far they drive and how much fuel is consumed to do so), and (3) during what period of the day, and particularly when at the end of the working day, they are parked, indicating when vehicles would plug into the electricity grid. With those data and an assumed adoption rate of EVs, grid impacts can be estimated.

The following subsections describe the regions of analysis, the data sources related to vehicle populations in the area, the survey tools used to gather vehicle use information, and the data available on grid loading and renewable electricity generation.

2.1. Vehicle populations

The total vehicle population in Digby comes from Provincial vehicle registration data [15], however, the population served by

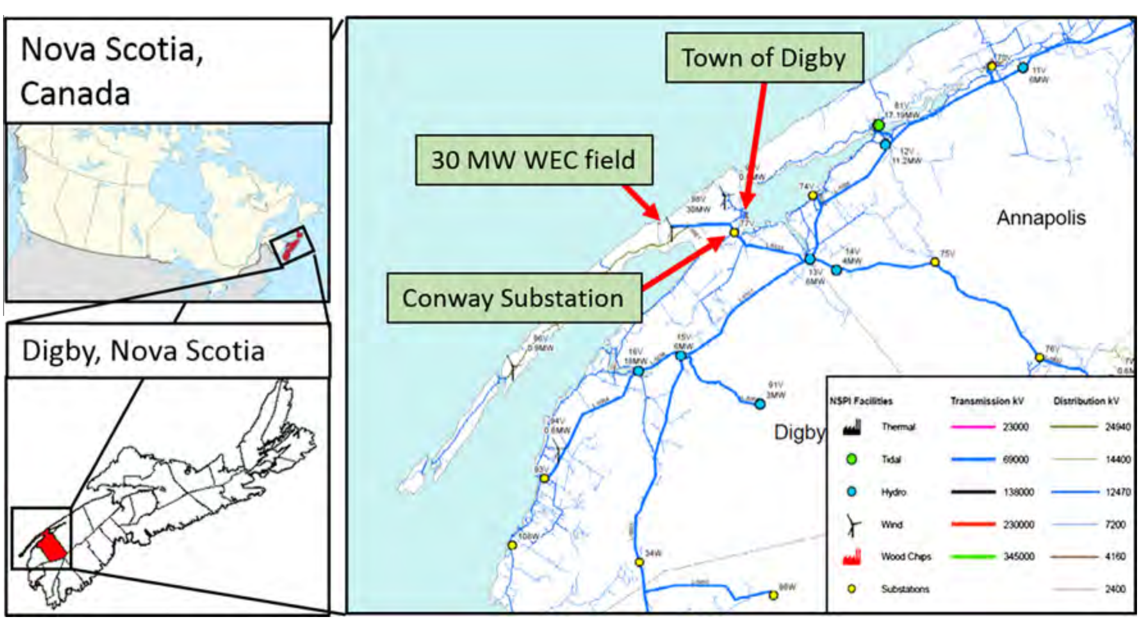

Fig. 1. Location of Digby (left) and transmission and distribution maps (right).

the Conway electrical substation (Fig. 1) does not correspond to a specific Provincial jurisdiction. The inferred population of vehicles must therefore be computed by scaling data from:

- The Town of Digby with an area of approximately 3 km^2 and a population of 2152.
- Digby County, consisting of the Town (above) and two Municipal Districts which combined have an area of approximately 2515 km^2 and a population of 18,036.

To establish the population served by Conway, estimates of Town and Municipal population were combined with a building count using satellite imagery. The resulting population estimate for the Conway service area is 9000 people. Table 1 groups the transportation fleet of Digby by vehicle type, lists how many of each type are registered in the Town and in the County, and gives the proportional vehicle population serviced by Conway Substation (Fig. 1, right), corresponding to this population estimate.

Table 1
Classes of vehicles, estimated numbers that operate in the regions of analysis in Digby.

Vehicle type	Digby Town (count)	Conway Area (estimate)	Digby County (count)
Population	2152	9000	18,036
Motorcycle	74	316	646
Small car	353	1275	2151
Medium car	347	1238	2053
Large car	247	884	1472
Van/SUV	131	504	921
Pickup	370	1577	3218
ATV	76	401	971
Bus (diesel)	0	9	38
School bus (diesel)	0	3	13
Freight van (diesel)	105	356	546

2.2. Vehicle use

To gather information on vehicle use, energy consumption, and the timing when EVs would be plugged-in, a variety of survey techniques were used.

To gather information on business vehicles, a selection of businesses in Digby County were interviewed by telephone. The selection of business types called for this study was made based on the perceived likelihood that they would have commercial vehicles (i.e. registered vehicles used exclusively or primarily by the business). Forty-seven business were interviewed by phone. Respondents were asked what business vehicles they used, how much they were used, and when during the day such use took place. Where specific information was not provided, average values for the vehicle type were used.

To gather the corresponding information about Digby area household vehicle use, both telephone and online survey methods were used. A total of 22 households were interviewed in depth in telephone surveys. In addition, there were 79 unique responses to an online survey that was promoted on the Municipality's web-site, and a newspaper advertisement.

2.3. Renewable generation and load

A variety of data concerning local, regional, and provincial electrical system conditions, including WEC field production, were available for this research, supplied by the provincial utility, Nova Scotia Power Inc. or its affiliates. The variables available to this research are shown in Table 2 (refer also to Fig. 1, right, for a map of electrical grid infrastructure). Note that for most of the system loading analysis, power transmitted on L5581 is used for the WEC field output, rather than the turbine data referred to in the first line of Table 2.

3. Analytical methods

In this section, the steps taken to transform the survey and energy system data into an impact analysis are described.

3.1. Annual electricity consumption of a Digby electric vehicle population

In order to determine the cumulative impacts of EVs in Digby, we assume an adoption rate corresponding uniformly to all vehicle classes of 10% (approximately 600 count). Although aggressive, it is attainable over the medium term given both local and provincial transportation electrification policies [16]. Regardless of technological advances and economies of scale of EVs to support consumer purchase, an adoption rate of 10% takes significant time because of the role-over time of the existing fleet.

These adoption rates do not take into account the differences in behaviors of commercial and private vehicle owners. Commercial vehicle owners may have the financial tools to amortize a high upfront cost and recoup it through operational savings, where private vehicle owners may not; however, private vehicle owners presently have a more comprehensive market and more local dealer engagement. Estimating how these aspects will play off against each other in the coming years is a challenge, so we have defaulted to the equal adoption assumption.

3.2. Electric vehicle charging scenarios

There are three scenarios of EV charging control that represent a range of technology and vehicle – grid interactivity. In this section they are described in the context of how they might operate in the Digby area.

3.2.1. Scenario: Convenience charging

The "convenience charging" case is conceptually similar to mobile phones, in that the vehicle is plugged in and charged right away upon reaching a charge station, without regard to the time of day or the effect on the grid. In this scenario, EVs are likely plugged in immediately upon arriving at a destination, typically home, and are charged until they are full. The control logic for this charging scenario is detailed in Fig. 2. The effect of this charging behavior would not be very different in Digby than in other regions where this scenario results in a charging load peak between 17 h and 19 h [17,18], unless there are systematic differences in the driving patterns of vehicles. The majority of EVs presently in Nova Scotia charge using convenience charging, because no provincial or utility policy exists to motivate any other behavior.

3.2.2. Scenario: Time of day charging

Nova Scotia has in place a "time of day" (TOD) residential electricity tariff, presently available to households with electric-thermal-storage. Three different rates are applied to electrical energy consumed at different times of the day, week, and year. The three rates represent a significant variation in price, especially during the winter peaking months of December through February, as illustrated in Fig. 3 [19].

While the rate structure shown in Fig. 3 is somewhat complex, for the purposes of this analysis the assumed response by EV drivers to this TOD charging scenario will be to delay charging through the use of a charge timer until after 23 h if possible,

Table 2
Digby electricity infrastructure measured data points and sampling rates.

Category	Name	Detail	Variables	Sampling rate	Data collection period
Generation	WEC field	30 MW capacity	Wind speed, wind direction, ambient temperature, real power, etc.	10 min	Jan 2011–Dec 2013
Transmission	Line L-5581	Connects WEC field to Conway	Real power, reactive power	20 s	Jan 2014–Jun 2014
	Line L-5533	Connects Conway to Provincial grid			
Distribution	Distribution lines 301 302, 303	Connects Conway to Digby loads	3-phase currents		
Substation	Conway (77 V)	Transformer	Primary voltage	1 min	

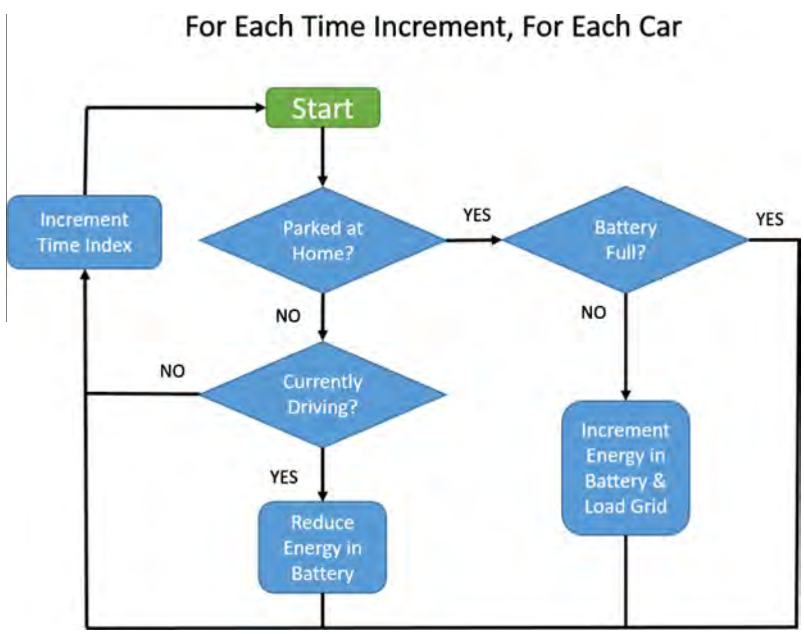

Fig. 2. Logic diagram for "Simple Charging" algorithm. The output is a load profile of each vehicle, which are then aggregated to become fleet charging loads.

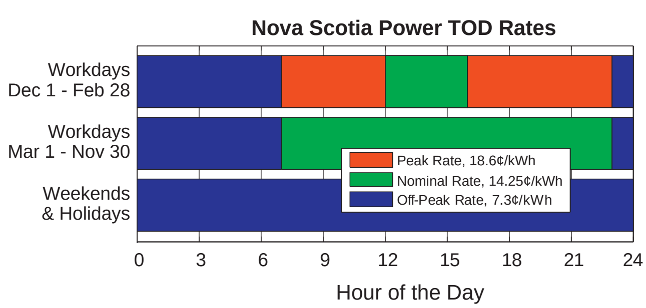

Fig. 3. Nova Scotia Power domestic service time-of-day electricity tariff schedule.

regardless of the day of the week, or the season of the year. While a more complex response is possible, it is unlikely that charge timing would differentiate between workdays and weekends, and so is uniformly applied for this study. The control logic for this charging scenario is detailed in Fig. 4. It is almost identical in structure to that used for simple charging, with the added test to insure charging does not take place during the day.

3.2.3. Scenario: Smart charging

In a "smart charging" scenario, the EV is responsive to conditions and constraints which exist on the electricity grid or in electricity markets. In Digby, the constraint of interest is power export on transmission line L-5533 (see Fig. 1). When the WEC field is at maximum generating capacity (30 MW), and the Digby load is low, the transmission line reaches its export limitation. With real-time monitoring, coupled with signalling, the net export on this transmission line could be used to signal EVs the preferred time to charge, and how fast to charge. When signalled, all the EVs with any flexible or discretionary charging capacity (i.e., those vehicles that are plugged in but not already charging) could begin charging, thereby increasing the Digby load and decreasing the net electricity export.

To model the effects of such a strategy, each 24 h period (noon to noon, so overnight discontinuities are avoided) was examined in isolation, and charging loads were added to periods when export power was at its highest for the period. The control logic for the smart charging scenario is detailed in Fig. 5. The logical structure of this scenario is significantly different from those of the previous two (Figs. 2 and 4), most notably because the unit of analysis is the 24 h period, rather than each vehicle. It should be noted that in the model as configured, a perfect response to this signal was used. In reality, any charging signal based on either a fixed schedule (TOD), or based on some real-time external signal, would only be a suggestion or a price difference, not a strict command. By default, when the vehicle requires charging for an imminent trip, charging will take place regardless of the grid impacts.

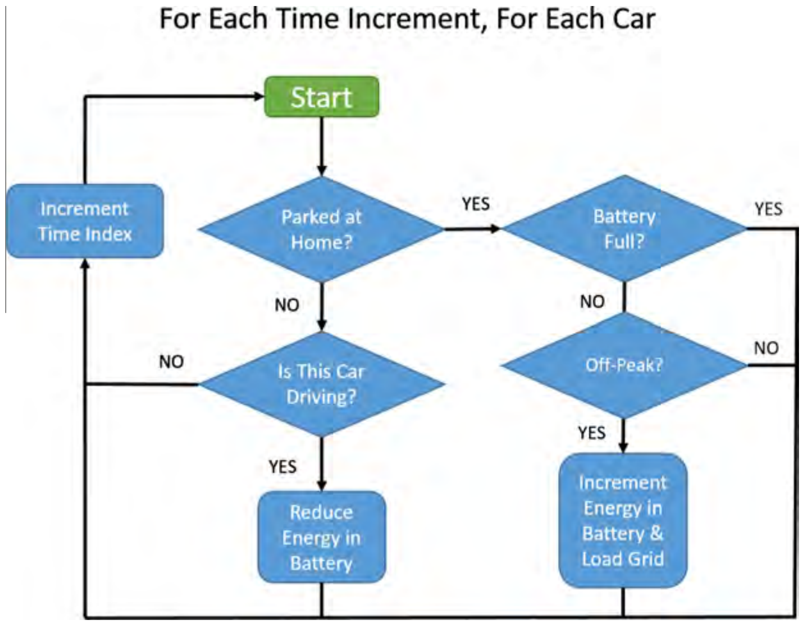

Fig. 4. Logic diagram for "TOD Charging" algorithm. Output is load profile of each vehicle, which are then aggregated to become fleet charging loads.

3.3. Creating load profiles

Based on the vehicle counts in Table 1 and coverage of the Conway Substation in Fig. 1, we assume 6000 vehicles exist in the area, and that the 10% adoption rate gives 600 EVs. Based on the survey of driving patterns, and vehicle class specific energy needs, Digby's EVs would need an average of 15 kW h per day, representing a fleet average of passenger and commercial vehicles. While this value is 2–3 times the daily energy needs assumed by some previous studies [9,20], this difference can be largely attributed to the assumption made here of proportional EV adoption across all vehicle classes, while those studies focused on small and mid-sized passenger cars.

The outputs of the vehicle use surveys were a set of individual vehicle use patterns and average daily energy needs on generic weekdays and generic weekend days. For each vehicle, these outputs were used to construct individual charging load profiles for convenience charging by drawing electrical load right away when returned to a home parking location, or for TOD charging by drawing load at 23 h if parked at home (refer to Section 3.2).

For the class of private vehicles and the class of business EVs, the average loads of all survey respondents' vehicles were proportioned equally to that of the total population of privately owned and commercial vehicles, respectively. Commercial and private charging load profiles were then multiplied by the presumed adoption fraction for each class (10% for both), and summed together to produce a regional vehicle fleet charging load for each day class, for each of the first two charging scenarios.

To produce a smart charging load profile, the sum of vehicle energy was used to 'fill' the points of greatest export power in each noon to noon 'day'. For example, at a historical export power peak of −25 MW, a modified peak export power of −24.99 MW was specified, and the difference in energy between an export power timeseries bottoming out on the modified peak and one following the historical data was computed. If that summed energy was less than the necessary driving energy for the fleet, then the modified peak export power was increased again to −24.98 MW. This process was iterated until the difference between the original and 'capped' export energy curves was equal to the energy needs of the EV fleet. This process is illustrated as a flow diagram in Fig. 5.

This methodology for smart charging could, in theory, require charging at any time, and possibly when a significant fraction of the fleet was not parked. However, this does not adversely affect the analytical results, because problematic peaks in power export

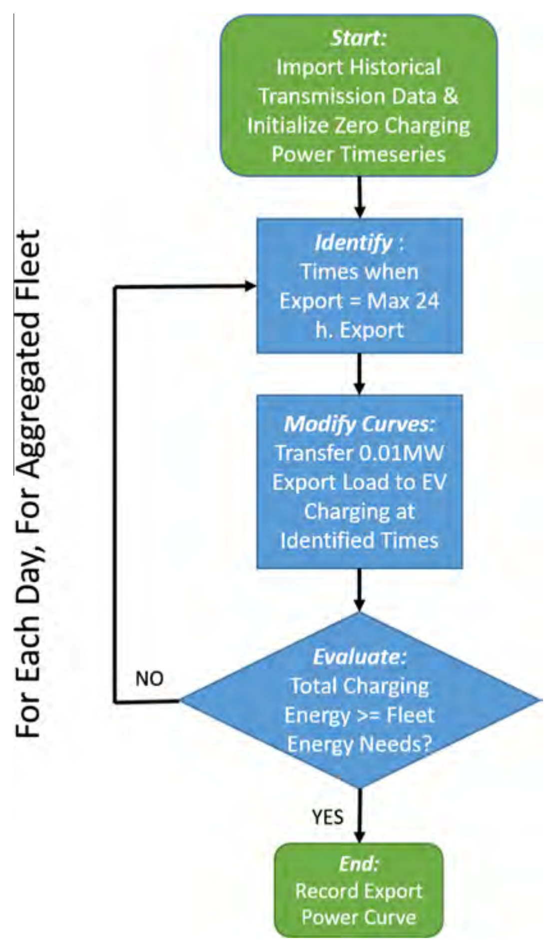

Fig. 5. Logic diagram for "Smart Charging" algorithm. Output is load profile of each 24 h period, which are then compiled in sequence to become fleet charging loads.

can only occur when *both* wind production is high *and* when local loads are low, and the later condition occurs only at night. Thus the test points for the system, the times at which the transmission system nears capacity limit, can only be at night when most vehicles are parked.

4. Results

In this section, the interactions and influence of EVs on the electric grid are discussed, with a focus on how they would relate to renewable electricity generation in Digby.

4.1. Description of existing conditions

Fig. 6 shows monthly average, and maximum and minimum electricity load in Digby, and generation at the WEC field. These data are from 2014, and 2012 through 2013 respectively, and it can be noted that only six months of data are available for Digby as the substation monitoring equipment was recently installed. These various years are not expected to affect the trending shown in Fig. 6.

In general, load in winter is higher than the load in summer, due to increased need for space- and water-heating, and increased need for artificial light as daylight hours recede. Similarly, winds are stronger in winter, and thus WEC field generated electricity follows a similar seasonal pattern. The WEC field generation averages 13 MW, while Digby averages roughly 8.8 MW of load, meaning the Digby region is an annual net exporter of electricity. Also shown on Fig. 6 are monthly maximum and minimum values as range bars about the averages. It can be seen that Digby's load can reach well above 18 MW, though only briefly, and can also drop to zero (during a power outage). The WEC field's output is continuously variable, achieving slightly more than its rated capacity of 30 MW and also becoming a small net load (<0 MW) within every month.

Of greater interest for EVs charging and grid management, Fig. 7 shows the hourly average load for each of six pairs of months, and shows how load and wind generation vary throughout the day. The different colored lines show different daily profiles characteristic of different seasons. From Fig. 7, the load in Digby (top), in both cold and warm months can be seen to drop by 2–3 MW overnight, with a minimum occurring between 2 h and 4 h. During the winter months, loads peaks twice daily, in the late morning and again in evening. This is characteristic of areas with electric heat that is often turned down at night when businesses are empty and people are asleep, and in homes during the day when people are at work.[1]

The hourly average electricity generation of 30 MW WEC field (Fig. 7, bottom) exhibits a different pattern. Wind turbine generation is typically higher during the night and lower during the day. This is especially apparent in Jul–Aug, when average wind output averages just over 5 MW (17% of nameplate capacity) at 12 h, and a peaks at 12 MW at 21–22 h. This is substantial variation considering it is an average over 120 days (two months for two years).

As Fig. 7 suggests, the probability of Digby exporting electricity, is a function of both the season and the time of day. This probability is more fully described in Fig. 8. Both heating loads and wind production increase during the winter, but the frequency of exporting power are more closely tied to the variations in WEC power output, so in colder months, exports are more common. Over the day, the negative correlation between load, which peaks during the day, and WEC output, which peaks at night, mean that exports are always 20–25% more likely at night.

Of course Figs. 7 and 8 represent general trends only, and at any given time of the year, the WEC field might be producing nothing, or might be at its maximum output of 30+ MW.

4.2. Impact of EV charging on the electricity grid

To illustrate the impacts of the three charging scenarios on the electricity grid we examine the first week of June, 2014, as shown in Fig. 9. During this period, Digby Load ([2]red, right axis) was quite low at 4–8 MW. The WEC field's generation (green, left axis) experienced both periods of low generation (such as June 3) and high generation (June 6). Consequently, Transmission Line L-5533 (blue, left axis) experiences periods of net import (positive values, e.g. June 3), and net export (negative values, e.g. June 6). The reader should note that export values approaching −26 MW are of concern because of transmission constraints.

In Fig. 10, the fleet charging load profiles described in Section 3.2 are plotted as a timeseries for the same week in June, 2014, along with the unmodified export power timeseries from Fig. 9. Charging loads for convenience charging (yellow), TOD charging (cyan) and ideal smart charging (magenta) are read on the right axis, while unmodified export power on L-5533 (blue) is read on the left axis to clearly illustrate times of concern for export.

Fig. 10 shows that convenience charging (yellow) adds about 2 MW of load quite consistently, with the load somewhat normally distributed around 17 h. This is the likely EV load scenario if no policy and/or tariff is put in place to encourage EVs to charge at specific times. The TOD charging scenario (cyan) will add over 4 MW of load (slightly less on weekends), which ramps up quickly every night beginning at 23 h. The smart charging scenario (magenta) can add as much as 6 MW of load (10 kW per vehicle), coordinated precisely with each day's peak exports on L-5533. It is evident that smart charging is highly variable in power, which will cause EVs to charge at various rates when signalled. It is likely that EV owners would be willing to accept such signals given an appropriate tariff or incentive, so long as they occurred overnight, thus having minimal impact on vehicle readiness for travel.

Note that, when the assumed smart charging logic is applied to June 3 (a low wind day) it causes the majority of the charging to occur in the morning when vehicles are likely in use. As previously stated, this unrealistic behavior is not problematic for the overall results, because such conditions, when local loads are not at their minimum, do not negatively impact the export transmission infrastructure.

Examining the loads within the local distribution area, the three charging algorithms result in significantly modified load profiles, shown in Fig. 11. This is an aggressive case (10% adoption rate) used to demonstrate the trends and impacts of EVs on the electricity grid.

The size of these changes to the local load profile is striking. The magnitude of these responses is due to the relative scales of variations in local load and variations in wind output. Convenience charging (yellow) adds significantly to the evening loads, causing the daily load variability to increase from about 4 MW (peak to trough) to 5 or 6 MW. TOD charging (cyan) adds load when they are low overnight, and it can be clearly identified that these start at 23 h with the drop in electricity cost. Load due to smart charging (magenta), is both inconsistent in timing, and abrupt, though Fig. 11 shows that it does exhibit some correspondence to charging at times of low load.

[1] A comparison to Provincial load data suggest that Jul–Aug and Sep–Oct load curves would likely be similar to those of May–Jun, while the load curve for Nov–Dec would lie between those of Jan–Feb and Mar–Apr.

[2] For interpretation of color in Figs. 9–13, the reader is referred to the web version of this article.

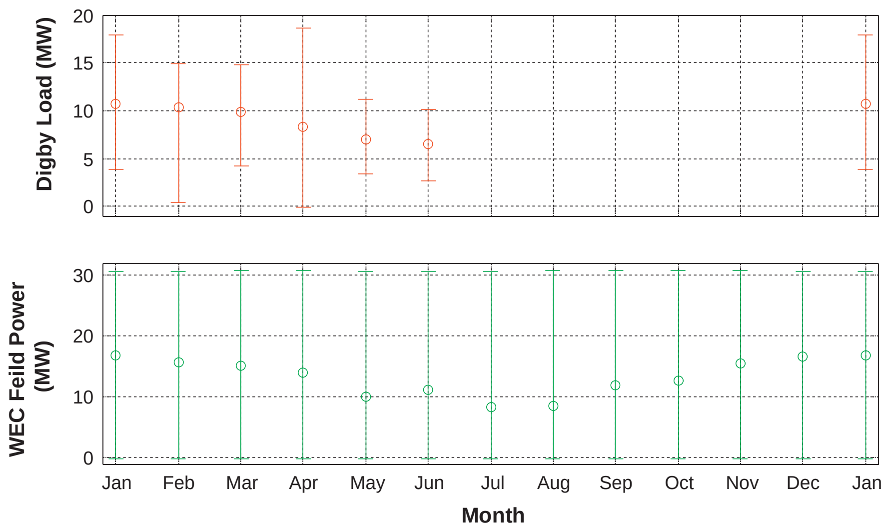

Fig. 6. Monthly average electricity power shown with 5 min maximum and minimum values as range bars for Digby load (top, red), and 30 MW WEC field generation (bottom, green). (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

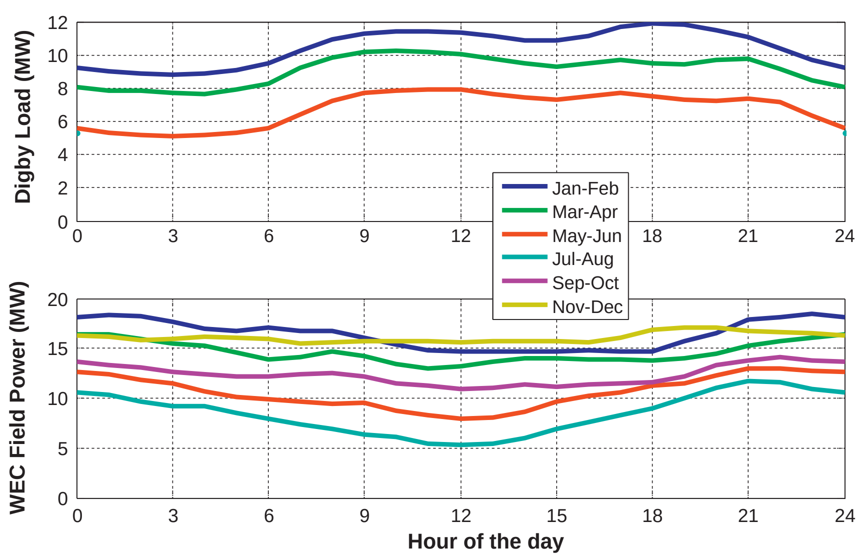

Fig. 7. Average electricity power as a function of month pairs (colored) for Digby load (top), and 30 MW WEC field generation (bottom). (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

To determine how EVs might actually help provide load to address the grid constraint on Transmission L-5533, their influence is directly applied to L-5533 power to create a modified load time-series in Fig. 12.

In Fig. 12, it can be seen that convenience charging (yellow) does modify the L-5533 export. On June 4, it is not helpful, adding load when L-5533 was importing electricity already. On June 5 convenience charging happens to reduce relatively high exports, but not reduce the maximum exports of the day. TOD charging (cyan) also provides helpful load to modify L-5533. It reduced exports from −23 MW to −21 MW on June 5. It is also helpful on June 6. Smart charging (magenta) is seen in Fig. 12 to cause highly controlled load variation on L-5533. This can be noted by the horizontal magenta lines delineating modified exports. On June 5 it reduces export from −23 MW to −19 MW. On June 6 it reduces export from −24 MW to −22 MW. These modification occur precisely when required, as this is an idealized implementation.

To more broadly quantify the effects of charging algorithm, each was applied to every day during the first half of 2014, the period

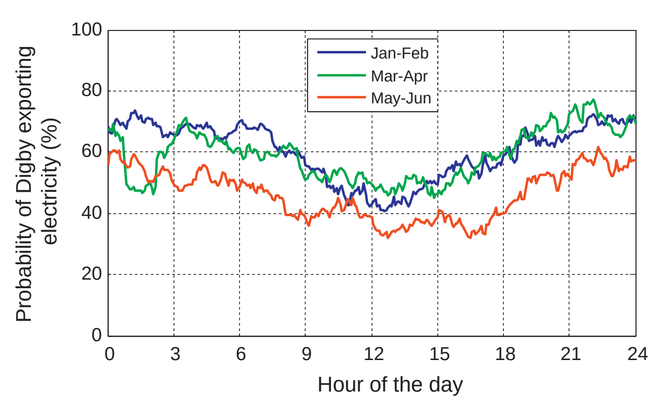

Fig. 8. Probability of Digby exporting electricity through the year.

for which detailed generation output and transmission system data were available. The original export power curve and the three resulting modified export power curves were then sorted into

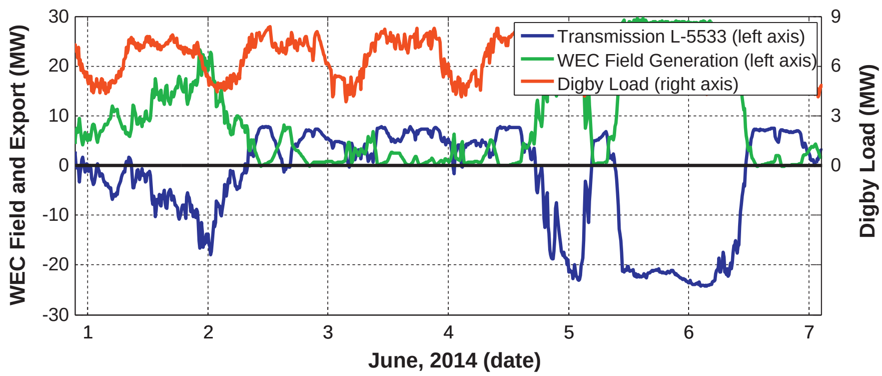

Fig. 9. Electricity flows of transmission, generation, and load in Digby in June.

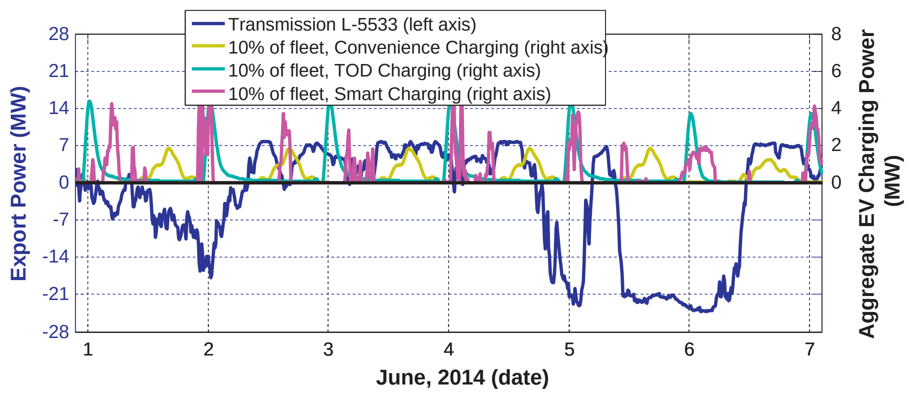

Fig. 10. Electricity profiles of convenience, TOD, and smart charging compared with unmodified Transmission L-5533 in June.

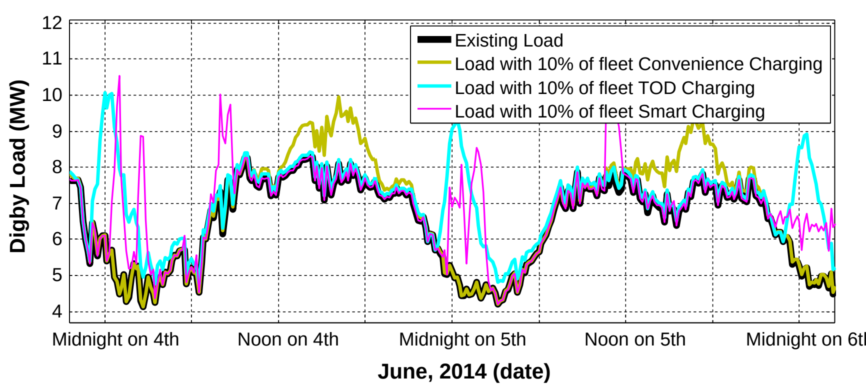

Fig. 11. Time-series plot of electricity demand on the distribution lines out of Conway substation (77 V) in the first week of June, 2014, given three possible EV charging scenarios being implemented by 10% of the vehicle fleet.

exceedance probability curves, which are presented in Fig. 13 in linear (left) and logarithmic (right) plots.

The plot on the left of Fig. 13 shows a broad range of export powers, and shows that all charging algorithms reduce the frequency of exports somewhat compared to the existing export exceedance probability (black line). However, export powers below about 23 MW are of no concern since they do not challenge the transmission capacity. In the right plot of Fig. 13 the same data are shown in greater detail, showing only exports between 22 MW and 27 MW, which correspond to exceedance probabilities of about 2% and less, and using a logarithmical distribution for the *y*-axis. From the right plot of Fig. 13, it is evident that convenience charging (yellow) has very little effect on the most challenging export conditions. In contrast, TOD charging (cyan) reduces the worst exports by about 0.6 MW, while Ideal Smart Charging (magenta) reduces the worst exports by 3 MW.

5. Discussion

Because of the high probability that Digby will be a net exporter of renewable energy at any given time (as shown in Fig. 8), any EV charging in Digby will often be using locally generated renewable electricity. Specifically, even using the convenience charging algorithm, about 49% of EVs' energy would be from local WEC output. Using the TOD charging strategy, this fraction is improved to 59%, as charging events are pushed to the overnight hours when exports are more likely (Fig. 8). Using real-time control to find each day's

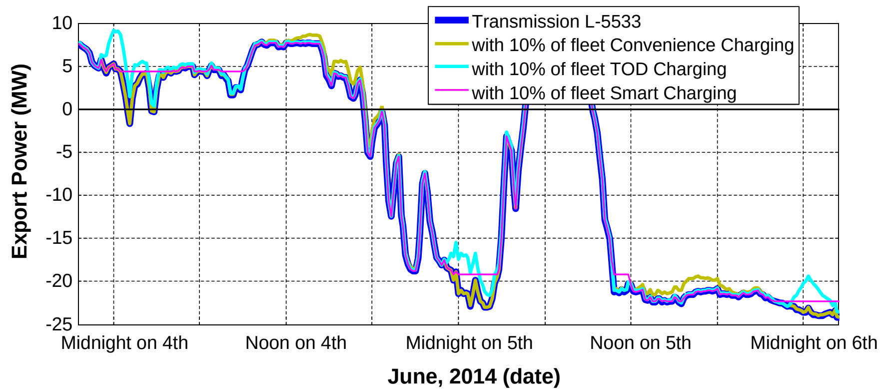

Fig. 12. Time-series plot of electricity exports out of the Digby Neck area in the first week of June, 2014. The unmodified line power (black line), and line power resulting from three EV charging algorithms are shown (green, red, and cyan). (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

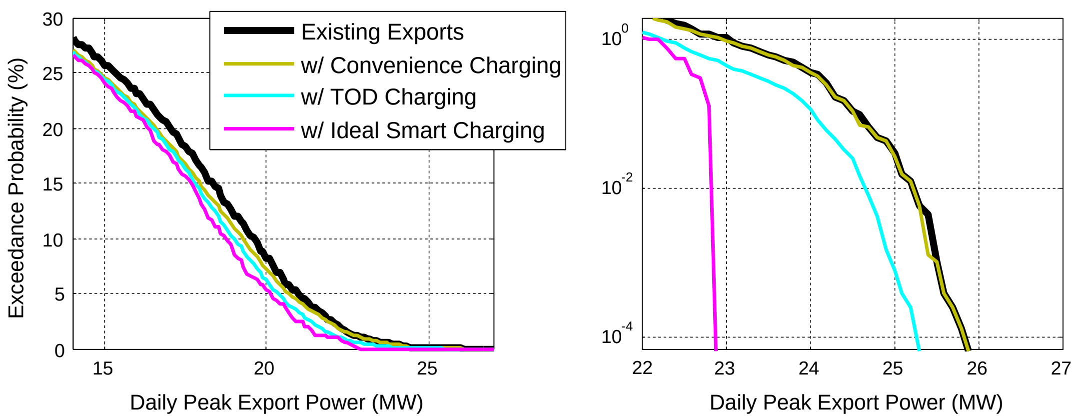

Fig. 13. Line 5533 export power, exceedance probability, showing effects of three charging strategies applied to 10% of Digby vehicle fleet.

period of peak export in the smart charging algorithm means that 85% of the time EVs would charge from local WEC-sourced power.

While these fractions make EVs seem attractive for local consumers, it is worth noting that any renewable electricity subtracted from the greater grid supply will require additional generation elsewhere [21]. Thus the greater question is whether any charging strategies can facilitate adding increased renewables to the grid, and whether such additional capacity can make up for the additional energy demand to power the EV fleet. This question can be answered from the preceding analysis, as shown in Fig. 14 and discussed below.

The TOD charging strategy, implemented for 10% of Digby's vehicle fleet, has been found to reduce export peaks by about 0.6 MW. At the same time, the fleet consumes about 9 MW h of electricity each day. In order for 0.6 MW of additional capacity to provide the annual energy to power such a fleet, it would need to have an annual capacity factor of about 62%. Thus the answer to the question of whether these additional cars can be powered from local renewable electricity is, unfortunately, 'no', unless an exceptionally good renewable resource, significantly better than the existing WEC field, can be found.

The smart charging strategy, in contrast, could free up 3 MW of export capacity. An additional renewable energy resource with an annual average capacity factor of just 12% would therefore fully power the fleet of smart charging vehicles. As has been discussed, the load profile derived from the smart charging scenario is idealized and could not fully be realized as it requires 100% participation, arbitrarily high charging power per vehicle, and vehicles to be plugged in and ready to accept charge precisely when needed.

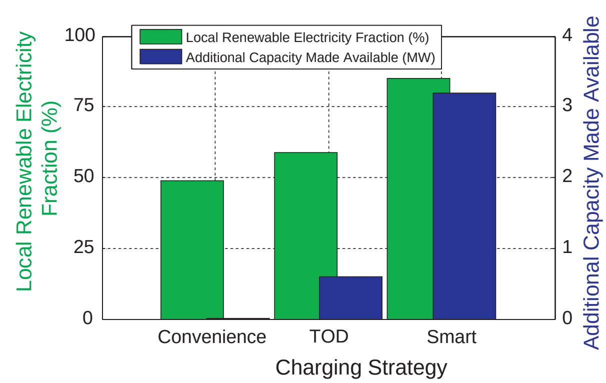

Fig. 14. Synopsys of effects of charging strategies.

Determining exactly how such an idealized algorithm would translate into a real world response is beyond the scope of this paper and would require an extremely detailed knowledge about not only drive cycles but about vehicle owners' responses to whatever incentive structure is put in place.

That being said, it seems reasonable to assume that the export attenuation resulting from real world smart charging would be more effective at the stated goal of capping export power than the convenience TOD response. If real world smart charging could attenuate export peaks by 1 MW (compared to 3 MW for ideal smart charging), and thereby free up 1 MW of transmission capacity to new generation, then that renewable resource would have to produce at 37% capacity factor to produce all of the 9 MW h/day needed by the vehicle fleet. Since the existing WEC produces at a similar capacity factor, this is a very favorable finding.

6. Conclusions

Digby is a region with abundant renewable energy resources, but has existing electricity grid constraints. Digby has articulated an ambitious goal to alter its energy consumption and production to better utilize locally produced renewable energy. Many such regions presently exist, and many more will develop given the ubiquity of renewable energy generation policy. Electric vehicles can support such policy as they reduce energy consumption for transportation, and can use locally generated electricity from renewable resources, while acting as controllable loads. The objective of this study was to determine the impact that EVs have on the electricity grid for various charging control strategies, and if this is complementary to renewable energy generation.

Three charging strategies were evaluated for their effect on the interaction between renewable electricity generation and export transmission constraints. Convenience charging (not signalled) will occur in absence of any policy or electricity tariff. This will add electricity load to Digby, but will do so at existing peak load periods (17 h) when export capacity is of no concern. The use of either time of day charging (scheduled) or smart charging (signalled) will incent drivers to charge overnight, or when additional load is most needed to alleviate electricity grid constraints.

Scheduled and signalled charging strategies would increase the fraction of transportation energy sourced from local renewable electricity generators from an already high 49% for convenience charging, to 59% for TOD charging, or 85% for smart charging. More importantly, these strategies were shown to be effective at addressing grid considerations: Using a 10% EV adoption rate, such charging algorithms could provide 0.6–3 MW of additional transmission capacity. This could enable new renewable energy generation, such as a negligible cost WEC field control strategy upgrade, that on an annualized basis could provide all the energy needed to power the vehicle fleet.

Acknowledgements

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Page 1

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Organization & Title

Municipality of the District of Digby

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Message *

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Page 1

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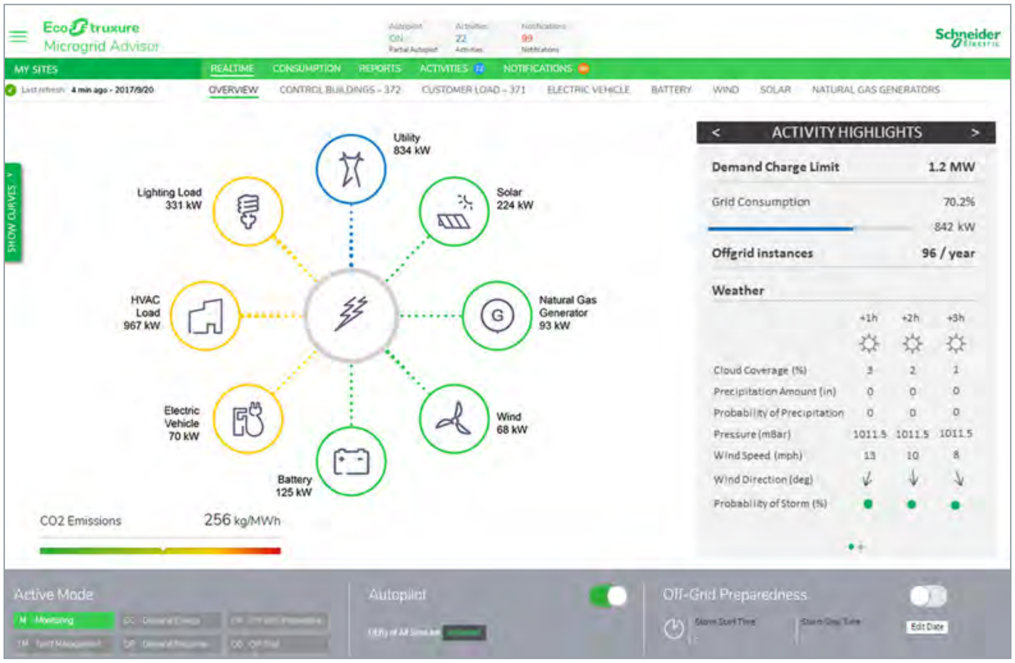

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- Secured connection through your on-site IT network (LAN) or dedicated ADSL lines
  - » Cyber secure testing in white box mode using NIKTO, DIRBUSTER, SQLMAP, and BURP to secure EcoStruxure Microgrid Advisor from session hijacking, XSS, and SQL injection

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Baseline	$85,433
Savings total	$22,464
Optimum Start Stop	$3,567
Tariff Management	$12,397
Demand Charge	$4,555
Autoconsumption	$1,945
Earnings total	$2,587
FeedIn Tariff	$2,587
Adjusted Baseline	$60,382

< ENVIRONMENTAL REPORT >	
CO_2 emissions	701,485 Tons
CO_2 savings	203,993 Tons
CO_2 emissions adjusted	497,492 Tons

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Subject *

Energy Storage

Message *

Here is a study that the Municipality conducted as a means to identify how we could put more electrons into the current grid in order to reduce GHG emissions at some of the major facilities in the area. The implementation of this project would allow for the local grid to use the storage device to smooth out load and peak load requirements. The device allows the facilities in question to create a thermal load from electrons. The hospital would be the benficary of the the direct thermal load coming from the CAES unit.

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1 Introduction

Sigma Energy Storage proposes a prefeasibility study to evaluate Digby's energy profile and identify solutions to maximize its renewable resources and minimize its fossil fuel consumption.

The Municipality of the District of Digby relies on the electrical energy from Nova Scotia grid and fuel oil for heating uses. Currently the municipality is considering to maximize the opportunities in renewable energy but these resources are non-dispatchable and they do not necessary follow grid demand Energy Storage System can offer dispatchable power solutions, which store electricity when it produced and regenerate when power is required.

On the other hand, Digby uses oil to heat several of its large facilities. Eight buildings, including the local Arena, Elementary and High Schools, RCMP, Hospital, Digby Lockup, Court House and Provincial building consume more than 370 m^3 of oil each year for heating. Thermal storage solution can store wind energy and delivers it to the buildings in form of heating services.

The goal of this project is to evaluate the fit and identify potential benefits of energy storage systems in balancing Digby's grid, optimizing the utilization of renewable resources, and assessing the impact of a thermal energy storage unit to provide low-cost heat to community buildings. The product will be a report detailing the potential of energy storage for Digby.

2 Municipality of the District of Digby

The Municipality of the District of Digby is located at the western end of the Annapolis Valley, Nova Scotia, on the southern coast of the Bay of Fundy. Situated between the District of Clare and Annapolis County, the Municipality encompasses Digby Neck, Long Island, Brier Island and the eastern half of Digby County (Figure 1) [1]. Digby is a great touristic destination. Nestled in a protected inlet off the Bay of Fundy, this area is known for its scallops, mild climate and daily ferry to Saint John, NB. Settled by United Empire Loyalists in 1783, it's now home to the largest fleet of scallop boats in the world [2].

2.1 Demographics

the Municipality of the District of Digby recorded a population (Figure 2) of 7,107 living in 3,264 of its 4,048 total private dwellings, a change of −4.8% from its 2011 population of 7,463. With a land area of 1,657.33 km^2, it had a population density of 4.3/km^2 in 2016 [3].

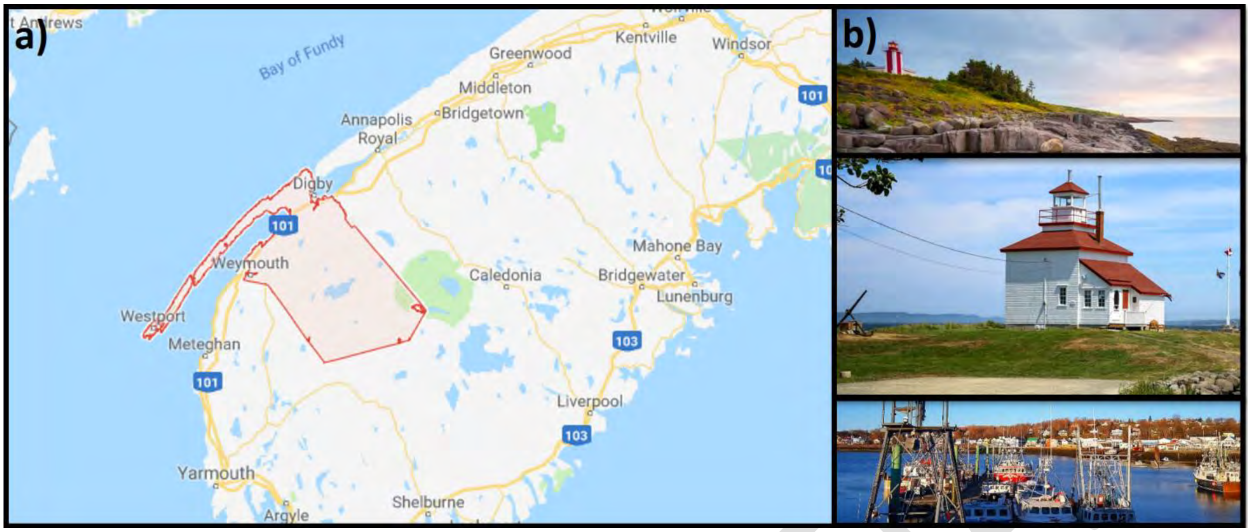

Figure 1. Municipality of the District of Digby location: **a)** Location [4]; **b)** Some tourist attractions [5].

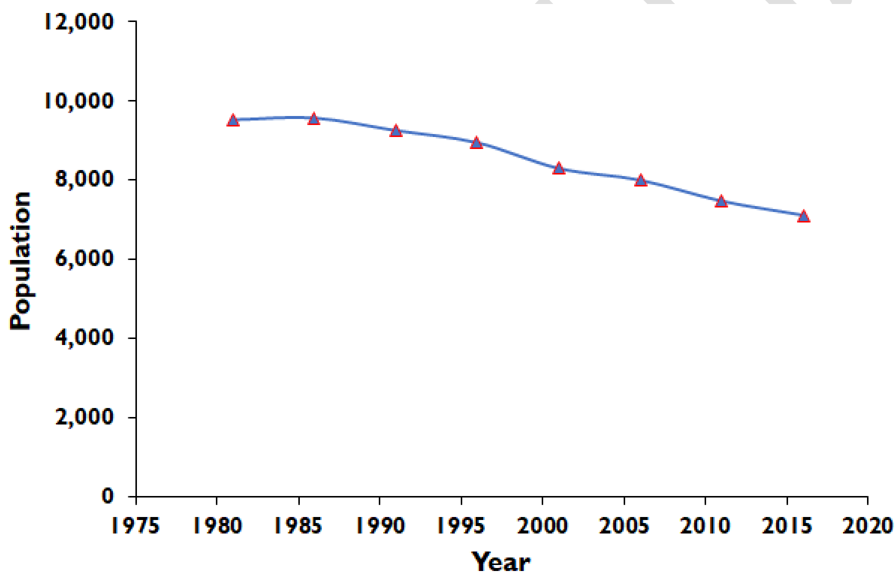

Figure 2. Municipality of the District of Digby Population from 1981 to 2016 [3]

The majority of people who leave the community are young people aged 20 to 30 years, resulting in an older community with a higher proportion of middle-aged and retired residents. Subsequently, the median age in the Municipality was 44 years in 2006, higher than the provincial median age of 41.8 and the Canadian median age of 39.5 [3].

2.2 Strategic Plan Overview

The Government of Canada has committed to transfer a portion of gas tax funds to municipalities. In 2005, the Province of Nova Scotia entered into a Gas Tax Agreement (GTA) with the Federal Government, under the New Deal for Cities and Communities. The Province then entered into Municipal Funding Agreements (MFA) with individual municipalities in order to deliver this federal funding to local governments and other appropriate recipients, for eligible environmentally sustainable municipal infrastructure and capacity building projects. As a part of these funding agreements, Nova Scotia municipalities are required to develop Integrated Community Sustainability Plans by 2010. Creating an Integrated Community Sustainability Plan (ICSP) is an important step in creating a more sustainable community. As part of the GTA, the Federal Government requires ICSPs to Integrate economic, environmental, social and cultural sustainability principles [1].

Related to the energy section, following goals have been included in the Municipality of the District of Digby Strategic Plan [6]:

- Maximizing the opportunities in renewable energy
- Reducing the carbon footprint
- Managing energy for a marketable Industrial Park

2.3 Possible Opportunities

The strategic goals defined by Municipality of the District of Digby the are based on the four pillars outlined in the municipality's Integrated Community Sustainability Plan (ICSP): Economic, Environment, Social/Community and Culture/Heritage [6]. These goals can be reached through specific plans such as building ecotourism and eco industrial park in the Municipality of the District of Digby.

Ecotourism is a form of tourism involving visiting fragile, pristine, and relatively undisturbed natural areas. It means responsible travel to natural areas, conserving the environment, and improving the well-being of the local people [7]. Natural resource management can be utilized as a specialized tool for the development of ecotourism [8]. Digby is rich in history and natural habitat, both of which can draw visitors and even new residents to the Municipality. Historical industries such as fishing and farming are supported by the area's wilderness and natural eco-systems, which also may attract tourists who enjoy the area's beauty and outdoor recreation opportunities. As part of the Southwest Nova Biosphere Reserve – a large region of South-western Nova Scotia spanning several counties where sustainable use, protection and enjoyment of natural resources are encouraged and fostered – the Municipality is going to promote the value of sustainability for the region [1]. Without the sustainable use of certain resources, they are destroyed, and floral and faunal species are becoming extinct. Ecotourism programs can be introduced for the conservation of these resources [9]. Using more renewable resources and managing the GHG emission can help the municipality to protect the environment and also to increase financial efficiency of the tourism industry in Digby.

An Eco Industrial Park (EIP) is a community of manufacturing and service businesses seeking enhanced environmental and economic performance through collaborating in the management of environmental and resource issues [10]. Following steps should be taken to create an EIP:

- Creating energy/material pooling and to help tackle the problem of local resource scarcity;
- Decreasing energy/material consumption and, as a consequence, the expenses for energy/material purchase;
- Reducing the cost of required energy/material
- Valorizing industrial energy/material waste;
- Decreasing environmental pollution [11].

Historically, the economy of the Municipality of the District of Digby has been tied to resource sectors of fishing, forestry and agriculture. Fur farming, particularly mink farming, is the largest contributor to the Municipality's agricultural industry. [1]. Currently the municipality is considering the growth of the industrial site located south of Highway 217 which is bounded by industrial lots, residential lots, and institutional uses [5]. At this time, the area is approximately 60% occupied. Creating an EIP can encourage other industries to move to this location because of low energy/materials cost and less environmental effects. More industrial investment leads to faster economic growth in the both short term and long run. It creates jobs especially for young generation and prevents population decline.

Figure 3 shows how the potential EIP and Ecotourism for the Municipality of the District of Digby align with the current strategic plan.

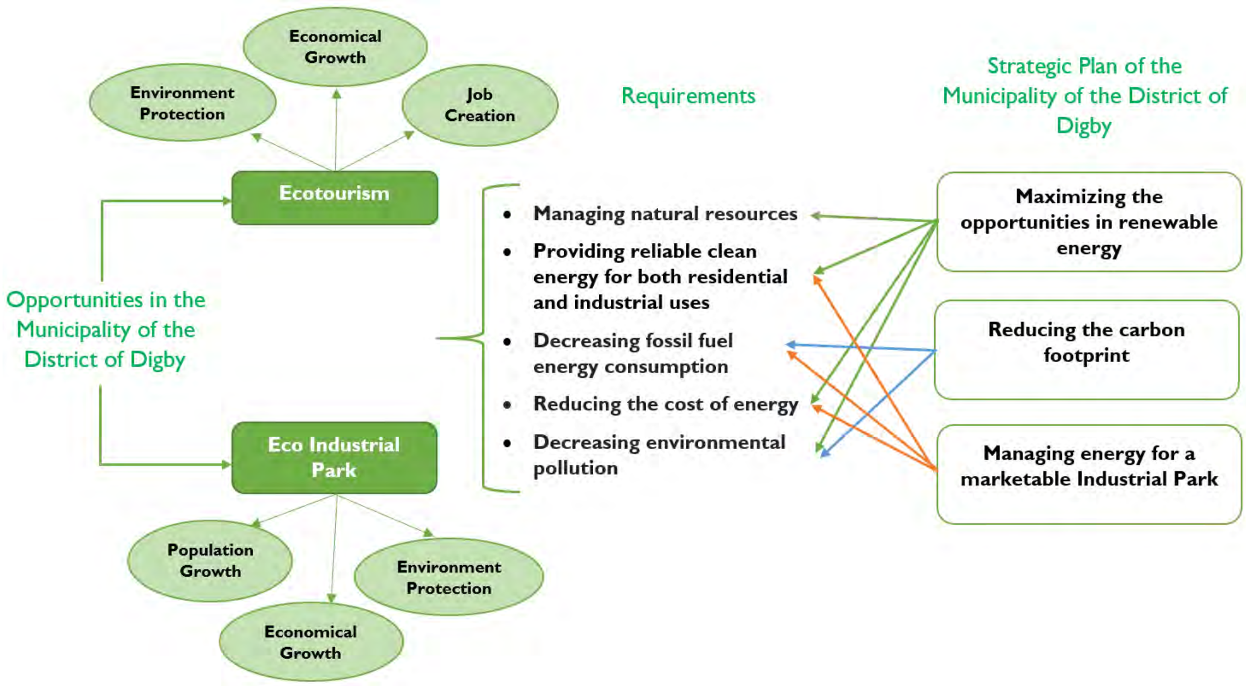

Figure 3. Opportunities along with the Digby strategic plan

The suitable location of the Municipality of the District of Digby (Figure 4) provide access to abundance of natural renewable resources such as Wind, Tidal, Hydropower, Biomass and Solar energy. Although no single resource can supply all the energy demand and the electricity from fossil fuels may continue to play a role but the municipality can reduce that role and create a diverse mix of energy resources. Renewables fit into the generation mix as do energy storages.

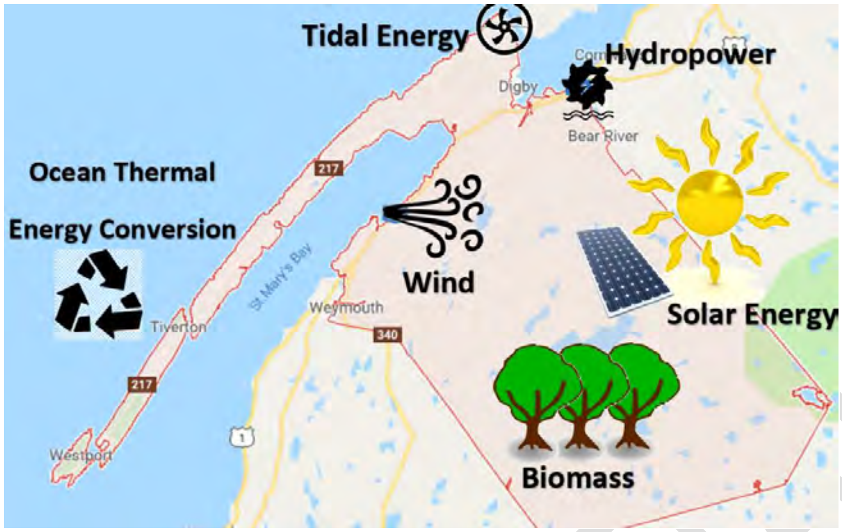

Figure 4. Available renewable resources in the municipality of the district of Digby

3 Ecotourism Opportunity

The district of Digby is rich in history and natural habitat, both of which draw visitors and new residents to the Municipality. Ecotourism which respect the area's wilderness and natural eco-systems, attracts more tourists who enjoy the area's beauty and outdoor recreation opportunities. To reach this goal, the Municipality of the District of Digby needs

(*i*) To reduce the fossil fuel consumption and GHG emissions. It can be achieved by providing clean energy from renewable sources to local facilities.

(*ii*) To reuse waste materials for energy generation. Recycling and processing waste wood and other waste materials from plants and animals to generate energy can support the local economy and a healthy environment.

3.1 Energy Demand Analysis

The large public buildings in the municipality use more energy than residential buildings, consuming about 80% of the total delivered energy. Energy is used in the high demand facilities for a wide range of purposes, such as heating and cooling, and lighting and air conditioning. There are eight high demand facilities in the municipality (Figure 5):

1. Hospital
2. Area Recreation Facility (Arena)
3. High School
4. Elementary School
5. RCMP Office
6. Courthouse
7. Digby Lock-up
8. Provincial Buildings

The average yearly electrical and heat demands for these facilities, based on Lockheed Martin study [12], are presented in Figure 6. Most of these facilities use Fuel oil for heating purposes but Arena uses Electric

Heat for main arena rink. The average yearly oil consumption for the eight facilities is presented in Figure 7. The yearly GHG emissions is presented in Figure 8. Only hospital and two schools produce more than 750 tonnes CO_2e each year.

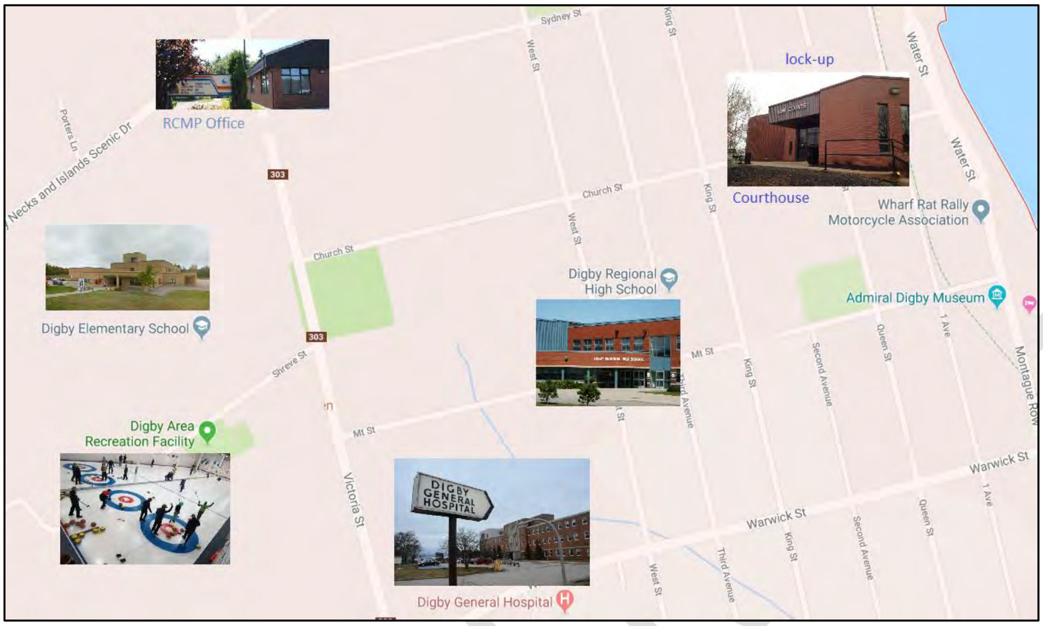

Figure 5. High demand facilities in the municipality

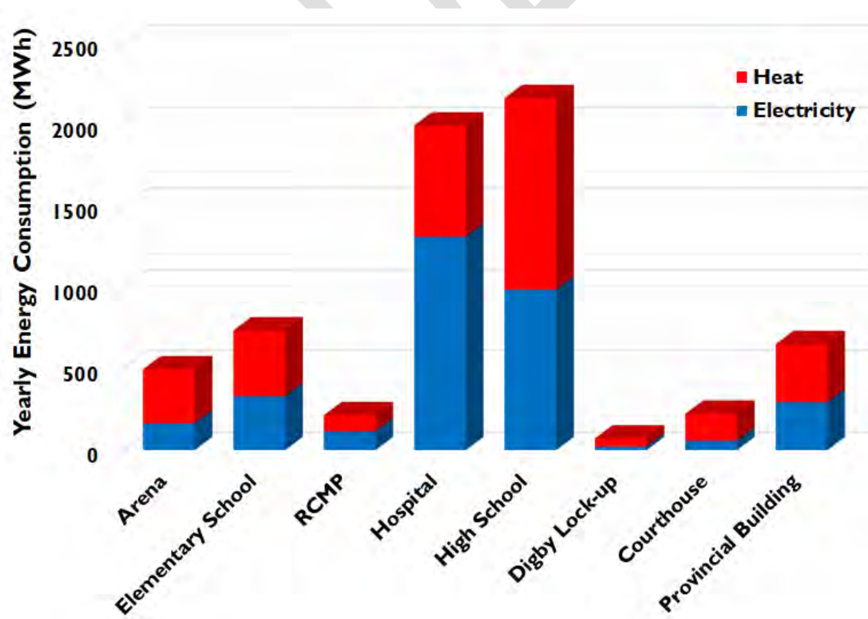

Figure 6. Average yearly demand for the high-demand facilities [12]

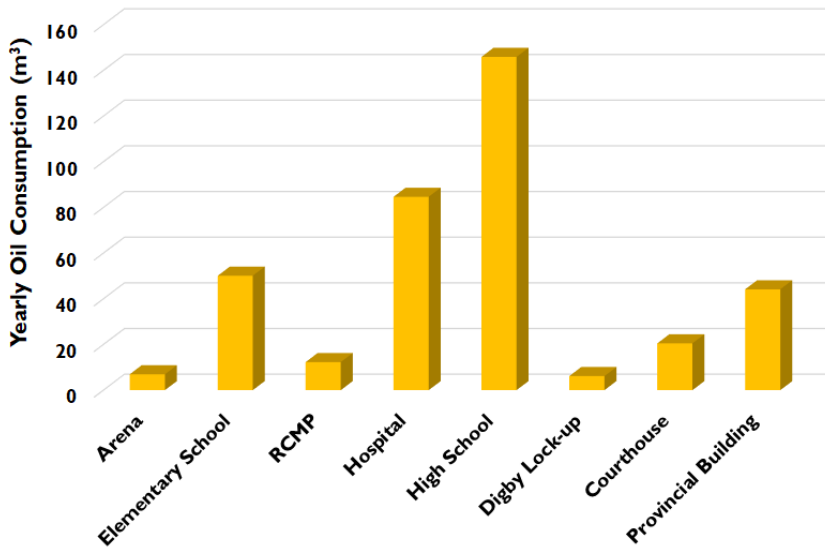

Figure 7. Average yearly oil consumption for the high-demand facilities [12]

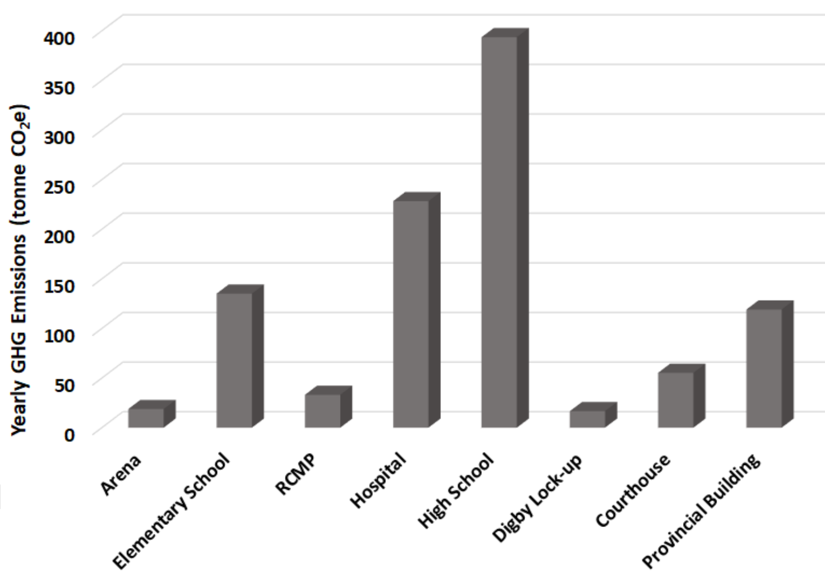

Figure 8. Average yearly GHG emissions from high-demand facilities

The two large facilities with the highest energy demand are the hospital and the high school with 1314 and 988-MWh annual electricity consumption and 85 and 146 m³/year fuel oil consumption respectively. Digby General Hospital is located at 75 Warwick Street is open 24 hours a day, seven days a week. Its energy consumption peak hours are between 11 a.m. and 8 p.m. according to their official website [13]. The hospital's last ten-year energy consumptions, from Nova Scotia Power's data [14] shows an almost unchanging annual trend, as shown in Figure 9. Average energy daily consumption starts to grow in June, reaches a maximum sometime between mid-July and mid-August, and decreases until early October. It seems in the summer time; more electricity is used for cooling. The only exception was 2016 in which the maximum daily energy demand occurred in mid-March and relatively low demand was observed in the summer.

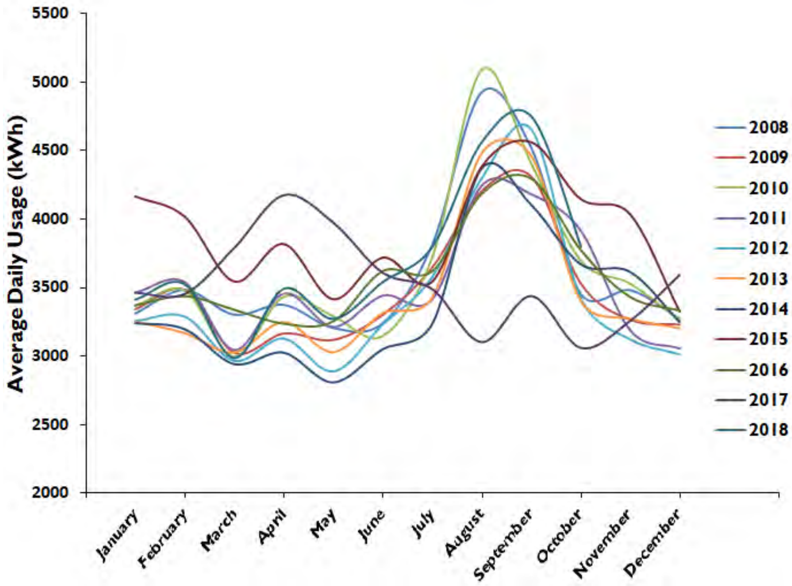

Figure 9. Average daily electricity consumption by the hospital over the last ten years

Digby Regional High School (DRHS) which is home to roughly under 500 students and staff, is located at 53 Mount St. DRHS is part of the Tri-County Regional School Board and is the only high school in the town of Digby. The average school day runs from 7:30 a.m. to 5 p.m. [15]. Average monthly energy consumption for the hospital and for the high school are presented in Figure 10. For both the hospital and the school have less heat demand during summer, from June to September. Since heat energy in hospital is also used for sterilization, autoclaves and ventilation processes [16], there are always a need for heat (Figure 10b). The highest monthly electricity consumption for the hospital (Figure 10a), happening in July and August because of cooling equipment [16], is around 137-147 MWh. The high school uses less electricity in May, probably because of no school days for all students. The minimum demand for the high school is 38 MWh in May and the peak demand is 98 MWh in February. The information presented in Figure 10 are used to design the energy storage for this facility.

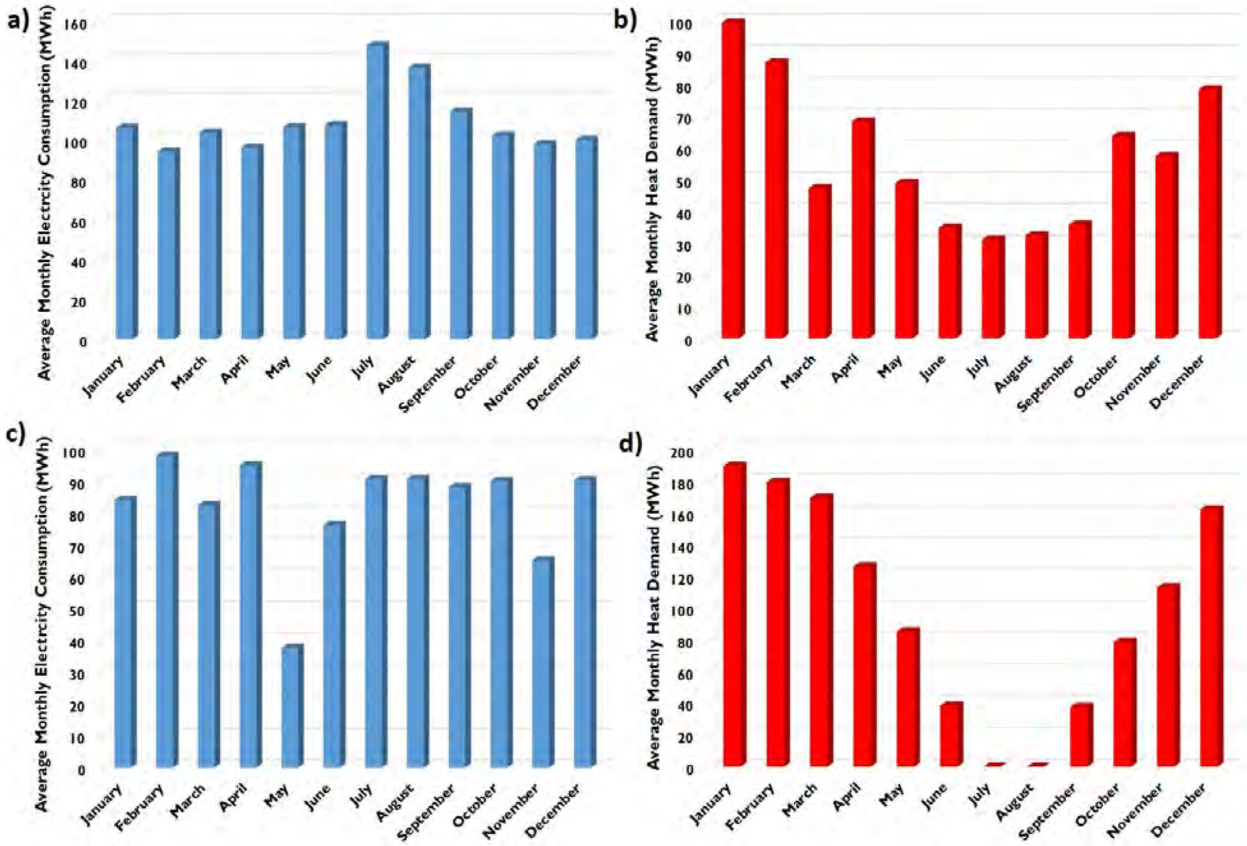

Figure 10. Average monthly energy consumption for Digby hospital: **a)** Electricity, **b)** Heat; and Average monthly energy consumption for Digby high school: **c)** Electricity, **d)** Heat [12]

3.2 Waste Materials and Biomass

The Municipality of the District of Digby has a organized process to manage waste materials disposal, recycling and compost [17]. Some of these waste materials that comes from plants and animals are considered as a renewable source of energy, called biomass. When biomass is burned, the chemical energy in biomass is released as heat. Biomass can be burned directly or converted to liquid biofuels or biogas that can be burned as fuels. Some example of biomass, available in the local area, and their potential use are

(*i*) Wood and wood processing wastes: It is burned to heat buildings, to produce process heat in industry, and to generate electricity

(*ii*) Agricultural crops and waste materials: Can be used as a fuel or converted to liquid biofuels

(*iii*) Food, yard, and wood waste in garbage: It can be burned to generate electricity in power plants or converted to biogas in landfills

(*iv*) Animal manure and human sewage: It is converted to biogas, which can be burned as a fuel [18].

One of ongoing renewable project in Digby is the biomass project. The Southwest Eco Energy Ltd. facility outside of Weymouth, Digby County, uses biomass composed of mink farm waste and municipal green bin waste as feedstock to an Anaerobic Digester to produce biogas (Figure 11). The Municipality has a plan to use this biogas to generate electricity which can be exported onto the local grid, generating revenue under the COMFIT program. Such revenue could offset or lower property taxes in the future. Also, Université Sainte-Anne in Digby County uses renewable energy sources including a biomass furnace fueled by locally-sourced wood chips [19].

Figure 11. Digby mink farm (left) and the biomass facility based on biofuel produced from the mink farm [20,21]

Since the Municipality of the District of Digby has access to waste wood materials, an interesting option can be generating electricity though a biopower plant. The proposed process burns wood chips directly to produce high-pressure steam that drives a turbine generator to make electricity. The extra heat from the power plant is also used to heat local buildings. These combined heat and power (CHP) systems greatly increase overall energy efficiency to approximately 80%, from the standard biomass electricity-only systems with efficiencies of approximately 20%.

3.3 Energy Storage Systems

Energy storage is a dominant factor in renewable energy plants. It can mitigate power variations, enhances the system flexibility, and enables the storage and dispatching of the electricity generated by variable renewable energy sources. Both electrical and thermal energy storage system help the Municipality of the District of Digby provide a reliable and dispatchable energy to the residential and industrial buildings.

Electrical Energy storage systems provide a wide array of technological approaches to managing the power supply in order to create a more resilient energy infrastructure and bring cost savings to utilities and consumers [22]. There is a very wide variety of storage technologies for stationary applications, but no technology is suited to serve all applications. A comparison of storage technologies makes sense only with respect to a certain application. Comparison is very difficult anyway, because of the numerous parameters that define the technical and economical performance of a storage system. Therefore, it is necessary to use classification systems. Generally, the classification can be made based on the way energy is stored, e.g., mechanical, electrical, or chemical [23].

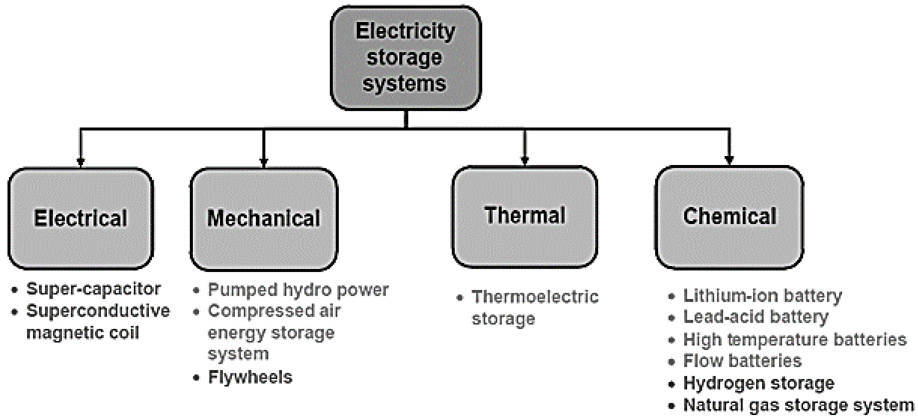

Figure 12. Classification of storage technologies [23].

Figure 12 shows the classification of electrical storage technologies. Below is a short description of the most developed systems:

- *Compressed Air Energy Storage*: utilizing compressed air to create a potent energy reserve
- *Solid State Batteries*: a range of electrochemical storage solutions, including advanced chemistry batteries and capacitors
- *Flow Batteries*: the energy is stored directly in the electrolyte solution for longer cycle life, and quick response times
- *Flywheels*: mechanical devices that harness rotational energy to deliver instantaneous electricity
- *Pumped Hydro-Power*: creating large-scale reservoirs of energy with water [22].

Thermal energy storage (TES) is a technology that stocks thermal energy by heating or cooling a storage medium so that the stored energy can be used at a later time for heating and cooling applications [24]. Advantages of using TES in an energy system include an increase in overall efficiency and better reliability, and it can lead to better economics, reductions in investment and running costs, and less pollution of the environment, i.e., fewer GHG emissions [25]. TES combined with photovoltaic panels are industrially mature [26] and utilize a major part of the Sun's thermal energy during the day. During the low or no solar radiation hours, TES is charged using low cost electricity.

Different Types of the thermal energy storage are presented in Figure 13. Following characteristics can be used to choose an appropriate TES system:

- **Capacity** defines the energy stored in the system and depends on the storage process, the medium, and the size of the system;
- **Power** defines how fast the energy stored in the system can be discharged (and charged);
- **Efficiency** is the ratio of the energy provided to the user to the energy needed to charge the storage system. It accounts for the energy loss during the storage period and the charging/discharging cycle;
- **Storage period** defines how long the energy is stored and lasts hours to months (i.e., hours, days, weeks, and months for seasonal storage);
- **Charge and discharge time** defines how much time is needed to charge/discharge the system; and
- **Cost** refers to either capacity (¢/kWh) or power (¢/kW) of the storage system and depends on the capital and operation costs of the storage equipment and its lifetime [26].

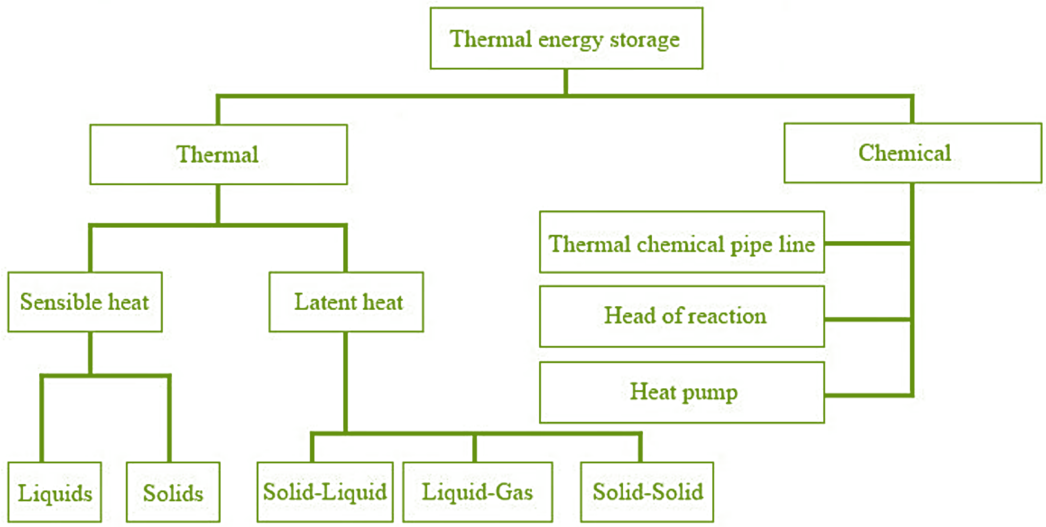

Figure 13. Types of solar thermal energy storage [24].

3.4 Grants and Financial Supports

Several Governmental foundations and programs support deployment of green energy production system across Canada such as NRCan, SDTC and provincial programs.

Natural Resources Canada (NRCan) seeks to enhance the responsible development and use of Canada's natural resources and the competitiveness of Canada's natural resources products. Clean Energy Innovation Program of NRCan focuses on renewable resources, smart grid and storage systems; reducing fossil fuel consumption; methane and VOC emission reduction; reducing greenhouse gas emissions in the building sector; and improving industrial efficiency [27].

Sustainable Development Technology Canada (SDTC) is a foundation created by the Government of Canada to support Canadian companies with the potential to become leaders in developing and demonstrating new environmental technologies that address climate change, clean air, clean water and clean soil [28].

Low Carbon Communities grant is a part of program that the Nova Scotia Department of Energy and Mines has designed to help communities to create long lasting greenhouse gas (GHG) reductions and to develop bright ideas for low-carbon, clean energy projects. Grants will be provided up to $75,000 up to $75,000 to a maximum of 75 per cent of project costs [29].

3.5 Recommended Solutions

The recommended solutions to achieve the goal of ecotourism, is based on the development of renewable energies align with energy storage systems. The main goal is to reduce fossil fuels consumption and to reduce GHG emissions. The recommended solutions can not only make good sense environmentally, but also economically.

3.5.1 PV-Thermal Energy Storage for Local Facilities

As a PV-thermal energy storage, buffer water storage tanks are good options for residential/small industries space heating applications. This system, presented in Figure 14, produces hot water for domestic needs to buffer variable rates of energy supply and demand [23]. The most common used PV-TES configurations are immersed tubes or immersed coils in the tank, backup external heater and a narrow annular jacket around the storage tank [24].

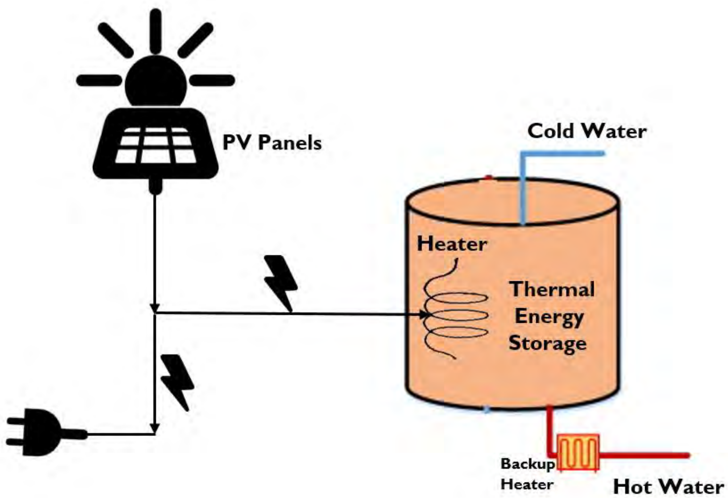

Figure 14. Typical schematic of a solar-thermal energy storage.

The proposed system uses water as the storage medium. At low–medium temperature, water is one of the best storage media: it has relatively high specific heat capacity, is chemically stable and is both widely available and cheap. Its main inconvenience is its limited temperature range (20–95°C) but, for building applications (our purpose), this is sufficient for space heating and domestic hot water production [23].

Ideas to improve water tank storage for solar systems providing both space heating and hot water production (so-called 'solar combi-systems') have been reviewed within the IEA 'Solar Heating and Cooling' (SHC) program in Task 32 'Advanced storage concepts for solar and low energy buildings', Subtask D 'Water tank solutions' [25].

To conduct a technical and financial analysis for installing TES systems in eight large facilities, we considered following assumptions which are mainly realistic to optimistic:

- Space is available with no cost
- Electricity to be purchased from the grid at 12 ¢/kWh
- Cost of Fuel oil is $1.05/liter, escalated at 2% per year
- Cost of PV panels is $1.4/W including engineering and installation
- O&M cost is 2% of the total materials cost and increases at 2% per year
- Water is available at no cost
- The project is eligible for NS Low Carbon Communities Grant

This grant is a part of program that the Nova Scotia Department of Energy and Mines has designed to help communities to create long lasting greenhouse gas (GHG) reductions and to develop bright ideas for low-carbon, clean energy projects. Grants will be provided up to $75,000 [26].

Table 1 shows yearly cost and GHG emissions for the current installed heating system in eight high-demand facilities.

Table 1. Current heating systems

Facility	Fuel oil consumption	Fuel oil Energy cost	Heat Load	Current cost
	liters/year	$/kWh	kWh / year	K$ / year
Arena	**6955**	**$0.13**	**56259**	**7**
Elementary School	**50092**	**$0.13**	**405194**	**53**
RCMP	**12273**	**$0.13**	**99279**	**13**
Hospital	**84650**	**$0.13**	**684734**	**89**
High School	**145902**	**$0.13**	**1180201**	**153**
Digby Lock-up	**6158**	**$0.13**	**49812**	**6**
Court House	**20474**	**$0.13**	**165614**	**21**
Provincial Building	**44149**	**$0.13**	**357121**	**46**

The output power of PV panels is estimated based on the model described in appendix I. Installing 40 kW PV panels can generate 56 MWh energy per year. The systems were design to result in a positive net present value for the project after 4 to 5 years.

The financial and environmental benefits of installing a solar thermal energy storage for the high-demand facilities are presented in Table 2 and Figure 15.

Table 2. Financial and environmental benefits of solar thermal energy storage systems

Facility	S-TES Heat Generation	Fuel oil Saving	GHG reduction	Fuel cost saving	Net Benefit (subsidized)	Payback* (subsidized)
	kWh / year	liters / year	tonne/year	K$ / year	K$/year	years
Arena	**56259**	**7032**	**16**	**$7.30**	**$6.11**	**3.9**
Elementary School	**56400**	**7050**	**16**	**$7.32**	**$6.13**	**3.9**
RCMP	**56400**	**7050**	**16**	**$7.32**	**$6.13**	**3.9**
Hospital	**56400**	**7050**	**16**	**$7.32**	**$6.13**	**3.9**
High School	**56400**	**7050**	**16**	**$7.32**	**$6.13**	**3.9**
Digby Lock-up	**49812**	**6226**	**14**	**$6.47**	**$5.27**	**4.5**
Court House	**56400**	**7050**	**16**	**$7.32**	**$6.13**	**3.9**
Provincial Building	**56400**	**7050**	**16**	**$7.32**	**$6.13**	**3.9**

* Considering NS Low Carbon Communities Grant

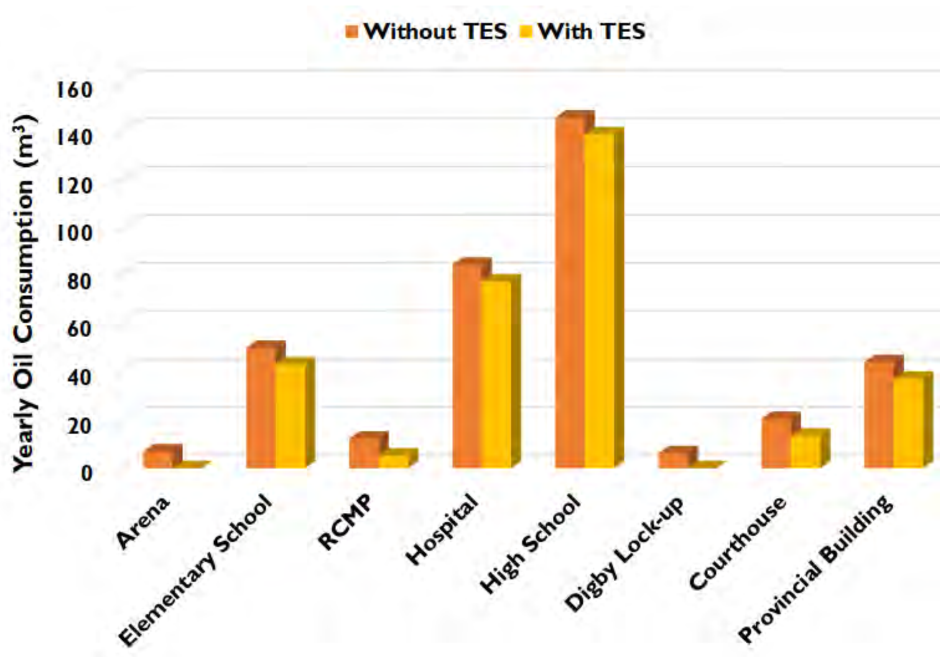

Figure 15. Yearly Oil consumption reduction for 40 kW PV panel

Figure 15 shows the difference between the yearly oil consumption with and without TES systems. Since the heat demand of hospital and schools are high, installing only 40 kW PV is not very effective. We did a more detailed techno-economical analysis for Digby General Hospital and Digby Regional High School. Heat consumption for the hospital and the high school are presented in Figure 10. Hourly and daily solar irradiation were calculated and used to size the appropriate solar thermal energy storage system for these two facilities. Considering 15 years payback period, the recommended design is presented in Table 3:

Table 3. Recommended design of solar thermal energy storage for the hospital and for the high school

Facility	PV Panel (kW)	TES (kWh)	Oil Saving (%)	GHG Reduction (tonne/y)	Payback Period (Years)
Hospital	485	**1500**	**52**	**100**	**15**
High School	350	**2000**	**22**	**71**	**15**

Figure 16 compares the heat generated by PV panels and heat demand for both the hospital and the high school. It can be seen that during the summer time, the heat generation is much more than the heat demand. One solution can be designing a multi-purpose system which can deliver also electricity, especially during the summer time. In that case, the module can deliver 194 MWh electricity per year for the hospital and 143 MWH for the high school (Table 4).

Table 4. Delivered energy by PV-TES system for the hospital and for the high school

Facility	Total Delivered Heat (MWh)	Total Delivered Electricity (MWh)
Hospital	358	194
High School	252	143

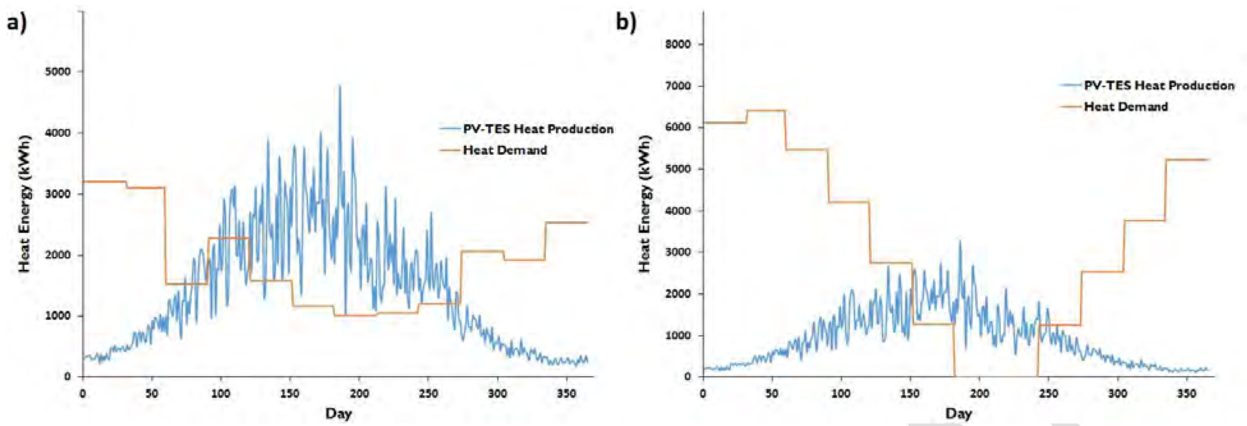

Figure 16. Annual Heat generation vs heat demand for **a)** Digby General Hospital; **b)** Digby Regional High School

The extra electricity can be used for cooling purposes. For example, during the summer time (mid-July to mid-August), PV-TES system can deliver around 114 MWh electricity for the hospital which is enough to run an 8000 BTU air conditioner in 42 rooms [30].

3.5.2 Biomass Direct Combustion System

Using available biomass resources in the Municipality of the District of Digby, we can obtain both heat and electricity at the same time. This combined heat and power system is illustrated in Figure 17. Steam turbines work on the principle of the Rankine cycle, which consists of a heat source (boiler) that converts water into high-pressure steam. A multistage turbine allows the high-pressure steam to expand, which lowers its pressure. The steam is then transported to a condenser, which is like a vacuum chamber and thus has negative pressure and converts, or condenses, the steam into water. Also, the steam can be transported to a distribution system that delivers steam at intermediate temperatures for different applications (district heating system) [31]. Seasonal heating requirements will impact the CHP system efficiency [32]. The condensate from the condenser or from the steam utilization system may return to the feed water pump, and the cycle continues. Cold water from the ocean or Bay of Fundy can be used to condensate the steam after the turbine which reduce the total capital cost of the system (Figure 17).

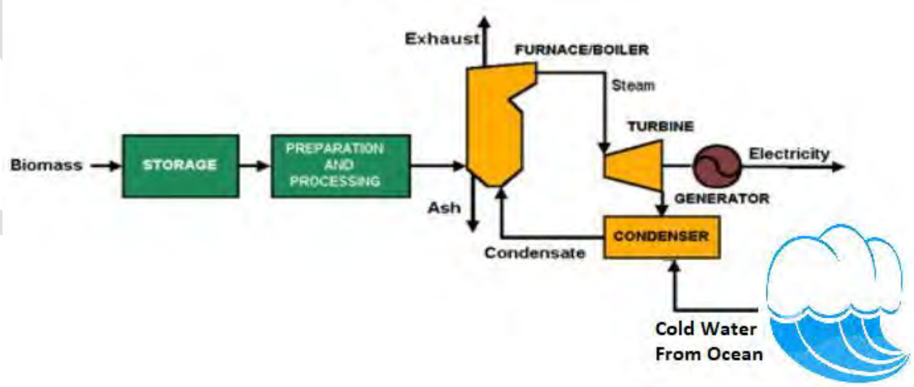

Figure 17. Biomass direct combustion system

A typical biomass energy generation system is made up of several key components. For a steam cycle, we consider the combination of the following items:

(i) Wood chip storage and handling equipment

(ii) Combustor / furnace

(iii) Boiler

(iv) Pumps

(v) Fans

(vi) Steam turbine

(vii) Generator

(viii) Condenser

Direct combustion systems feed a biomass feedstock into a combustor or furnace, where the wood chips are burned with excess air to heat water in a boiler to create steam. Steam from the boiler is then expanded through a steam turbine, which spins to run a generator and produce electricity [32].

To conduct a technical and financial analysis for a biomass energy generation system for the local facilities, we considered following assumptions:

- Space is available with no cost
- Cost of wood fuel is $35.0/tonnes, escalated at 2% per year
- Financing for 20 years at the interest rate of 6.5%
- O&M cost of the systems is 2% of the total materials cost and increases at 2% per year
- Electricity can be delivered to the large facilities (Hospital and High School)
- Heat can be delivered to both the large facilities and the residential buildings

Electrical demand for the hospital and the high school are presented in Figure 10. The average hourly demand for these large facilities is 345 kWh. Considering a 40% variance, the peak demand is estimated 482 kWh, so we designed a 500-kW system. The details are presented in Table 5.

Table 5. Recommended biomass direct combustion system for local facilities

Required Steam Turbine (kW)	500
Required Wood (38% moisture) (tonne/year)	1240
Deliverable Electrical Energy (MWh/y)	875
Deliverable Heat Energy (MWh/y)	2628
Installed cost (M$)	3.08
levelized cost of energy (¢/kWh)	8.5

Because of access to wood waste martials at low cost, our proposed system costs less than similar small-scale biomass electric plants (100 to 1500 kW) in the US (Table 6) [32]:

Table 6. Small-scale biomass electric plants (100 to 1500 kW) in the US

Installed cost per kW ($)	3000 to 4000
levelized cost of energy (¢/kWh)	8 to 15

The environmental benefits of the biomass direct combustion system are listed in Table 7. 2628 MWh heat energy can save 325 m^3 fuel oil each year. Also, the local facilities may consume less electricity from Nova Scotia Grid which is generated from a variety of sources including coal, pet coke, natural gas, oil [33]. The generation mix which can be seen in Figure 18 was used to estimate the reduction in the amount of coal and natural gas consumption.

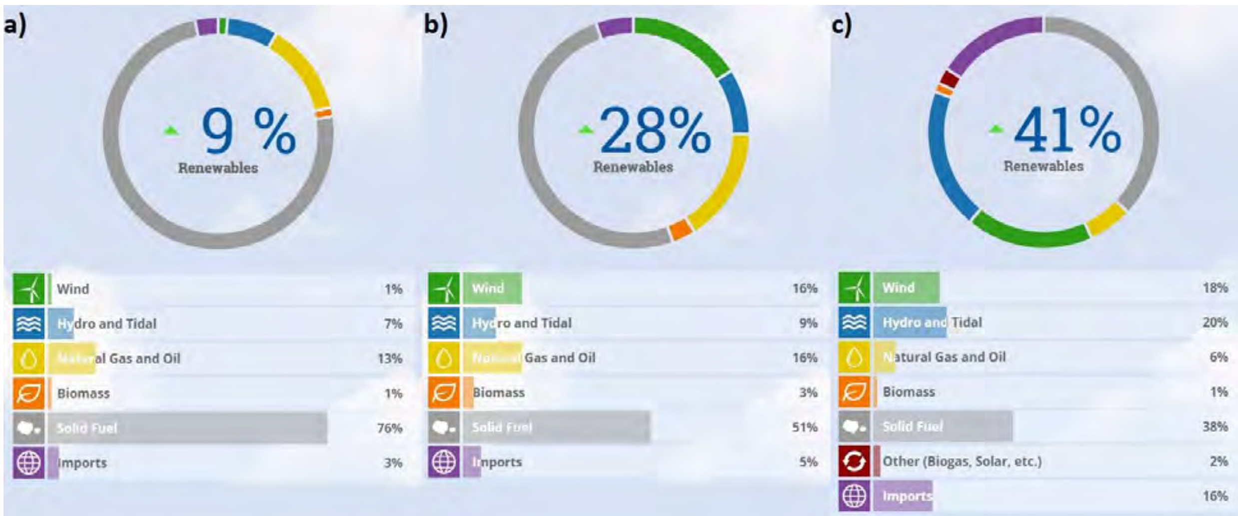

Figure 18. Nova Scotia Sources of Electricity: **a)** in 2007; **b)** 2018 Year-to-Date; **c)** 2020 Forecast.

Table 7. Environmental benefits of the 500-kW biomass direct combustion system

Coal Saving (tonne/year)	135-196
Natural Gas Saving ($10^3 m^3$/year)	17-43
Fuel Oil Saving (m^3/year)	325
GHG Emission Reduction (tonne/year)	1041-1211

Considering following assumptions:

- Cost of Fuel oil is \$1.05/liter, escalated at 2% per year
- Cost of Coal is \$0.078/kg, escalated at 2% per year
- Cost of Natural Gas is \$0.154/m^3, escalated at 2% per year
- Carbon tax of \$20 on every tonne of greenhouse gas emission starting in 2019, rising by \$10 each year to \$50 a tonne by 2022 [34].

We estimated the total revenue for both the Municipality of the District of Digby and Nova Scotia:

Table 8. Economical benefits of the 500-kW biomass direct combustion system

Revenue for the Municipality (k\$/y)	356-534
Revenue for Nova Scotia (k\$/y)	32-57

3.5.3 Energy Storage for Tidal Energy

Tidal Energy is classed as a renewable energy source, as the Earth uses the gravitational forces of both the moon and the sun every day to move vast quantities of water around the oceans and seas producing tides. Tidal energy, just like hydro energy transforms water in motion into a clean energy. The motion of the tidal water, driven by the pull of gravity, contains large amounts of kinetic energy in the form of strong tidal currents called tidal streams. The daily ebbing and flowing, back and forth of the ocean's tides along a coastline and into and out of small inlets, bays or coastal basins can generate considerable amount of energy [35].

The Bay of Fundy has the highest tides in the world (up to 16m), and holds the greatest potential for a tidal energy development in North America [36]. The tidal currents in the Bay of Fundy are fast, reaching 10 knots (5.1 m/s) at peak surface speed [37]. Oceanographers attribute it to tidal resonance resulting from a coincidence of timing: the time it takes a large wave to go from the mouth of the bay to the inner shore and back is practically the same as the time from one high tide to the next. During the 12.4-hour tidal period, 160 billion tonnes of water flow in and out of the bay [38]. The estimated total extractable energy is 2500 MW (out of about 7,000 megawatts of potential) without significant environmental effects [36]. Several sites have been identified in the Bay of Fundy as viable locations for tidal power generation projects including the Grand Passage (500 kW), Petit Passage (500 kW), and Digby Gut (1.95 MW). These specific projects have been accepted for COMFITs by Nova Scotia Power.

The predicted tide heights for the Digby Gut, 8.5 km away from the city of Digby, vary from the low of 2 meters to a high of 7.6 meters (see Figure 19). In addition to the daily period, the tides show a lunar monthly periodic behavior during which the maximum tide height varies between 7 and 7.6 meters.

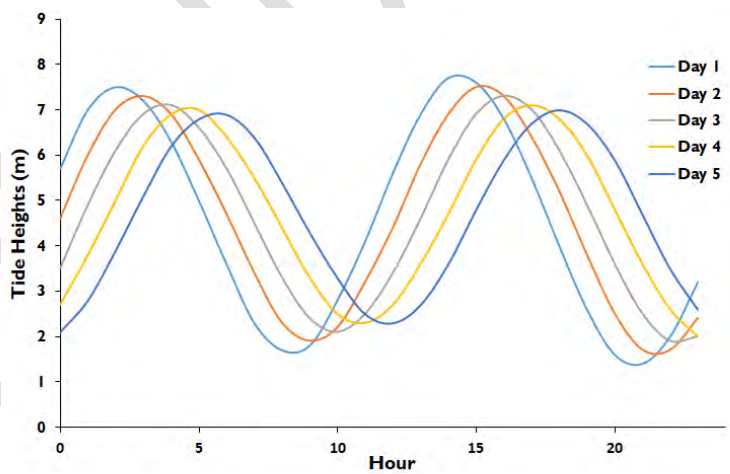

Figure 19. Predicted hourly heights [39]

Digby has been identified as the port of choice for tidal power development [40]. The Port of Digby is the most accessible, deep water, ice-free Bay of Fundy port in Nova Scotia. Its proximity to the Bay of Fundy's designated deployment area for tidal power development makes the Port a strong location for this emerging industry [41].

Figure 20. Placed turbine in the Bay of Fundy in 2009 [42]

Currently Fundy Tidal and Clean Current Power Systems Inc. have an agreement to test and demonstrate a 3.5-meter diameter 65kW tidal turbine. This turbine will take kinetic energy from the flowing tidal waters rather than water stored behind a dam to generate electricity. In-stream turbines pose less risk to the local ecosystem. The project of 1.95-megawatt tidal energy in Digby Gut was expected to last 12 months but it is not in service yet. Under the COMFIT program, Nova Scotia Power will buy energy produced from those turbines for the next 20 years at a price of 65.2 cents per kilowatt [36].

Since Tidal energy is non-dispatchable due to its fluctuating nature, an energy storage system can increase both the reliability and efficiency of the energy production system. A Hybrid thermal-compressed air energy storage (HT-CAES) System is an energy storage system based on air compression and air storage in high pressure tanks or geological underground voids (Figure 21). During operation, the available electricity is used to compress air into a high-pressure storage at pressures up to 75 bar. The heat produced during the compression cycle is stored using Thermal Energy Storage (TES), while the air is pressed into the air storage. When the stored energy is needed, this compressed air is used to generate power in a turbine while simultaneously recovering the heat from the thermal storage [43]. The opportunity of installing a compressed air energy storage technology for Nova Scotia Power has been investigated before by SNC-Lavalin [44].

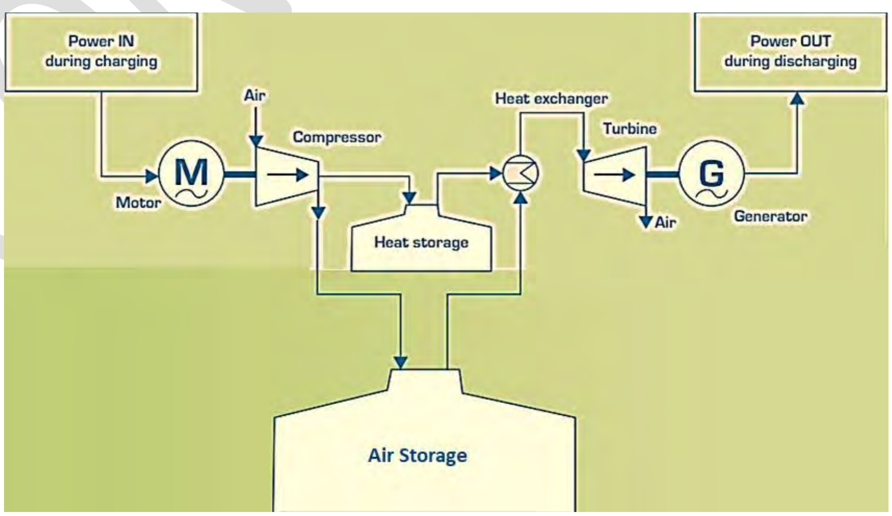

Figure 21. Hybrid thermal-compressed air energy storage (HT-CAES) [Adopted from Ref. [43]]

To design an appropriate energy storage system for available tidal projects, we considered following assumptions:

- Space is available with no cost
- Line restriction is 900 kW for Grand and Petit Passage
- Line restriction is 1950 kW for Digby Gut
- Electricity from Tidal is available to store at no cost
- The efficiency of HT-CAES system is 40%
- Charging and discharging are variable
- O&M cost of Tidal and HT-CAES systems is 2% of the total materials cost and increases at 2% per year

Th recommended HT-CAES systems for three locations are presented in Table 12. It can be seen that for small tidal turbines (500 kW), the contribution of the storage to total production is small but for the large tidal system (1.95 MW), the effect of HT-CAES is significant.

Table 9. Tidal energy system anchored with HT-CAES

Location		Grand/Petit Passage	Digby Gut
Nominal Power	kW	500	1950
Optimum Tidal Power	kW	644	2450
Turbo-Expander Power	kW	500	1950
Compressor Power	kW	550	2040
Storage Capacity	kWh	550	2040
Power Generation Improvement by HT-CAES	%	18.4	17.4
Additional Power Generation by HT-CAES	MWh/y	542	1988
Deliverable Heat Energy	MWh/y	677	2485
HT-CAES Operation	Hr./Month	90.4	85
Unit Cost	$ M	5.75	19.60
Payback Period	Years	13.8	13

Assuming the electricity produced by the combined system (Tidal - HT-CAES) will send directly to the grid, HT-CAES system can reduce the consumption of coal and natural gas and also GHG emissions. The generated heat will deliver to local users which reduces the fuel oil consumption. The economical and environmental benefit of the system are presented in Table 10. Installing an HT-CAES system in Grand or Petit Passage can reduce GHG emissions up to 294 tonne/year while generating revenue for both the Municipality of the District of Digby and Nova Scotia. For Digby Gut reduction in GHG emissions is 692-1079 tonne/year.

Table 10. Environmental and economical benefits of Tidal – HT-CAES system

Location	Grand/Petit Passage	Digby Gut
Coal Saving (tonne/year)	83-121	307-444
Natural Gas Saving ($10^3 m^3$/year)	10.5-26	39-97
Fuel Oil Saving (m^3/year)	84	307
GHG Emission Reduction (tonne/year)	188-294	692-1079
Revenue for the Municipality (k$/y)	91-138	336-504
Revenue for Nova Scotia (k$/y)	19-35	71-128

3.5.4 Socio-economic benefits

Integrating renewables with energy storage into a microgrid results in short-term and long-term job creation. A job is equivalent to the resources required to employ 1 person for 12 months [45].

Construction, operation and the energy saving generated by the investment can create opportunities for workers (see Figure 22).

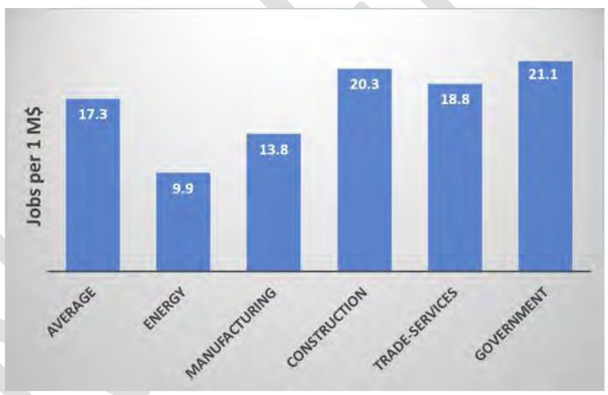

Figure 22. Jobs per million dollars of revenue by key sectors (Adopted from Ref.)

The number of jobs created during each phase of proposed systems is estimated from the money spent for manufacturing, engineering, construction, operation and maintenance of our system (direct jobs) and the costs saved by reduction in the energy price (indirect jobs). The number of jobs related to manufacturing is estimated from capital costs. For the engineering and construction phases, a portion of capital cost (usually 30%) is considered to estimate impact on job creation. The estimated number of jobs for the recommended systems are presented in table

Table 11. Total direct and indirect Jobs created for each recommended solution (person per year).

System	Manufacturing Phase	Construction Phase	Engineering Phase	Total Direct Jobs	Total Indirect Jobs

PV-TES for Hospital & High School	10	5	2	17	9
Biomass Direct Combustion System	14	8	6	28	23
Energy Storage for Tidal Energy (500 kW)	24	10	5	39	43
Energy Storage for Tidal Energy (1950 kW)	84	37	18	139	147

4 Eco Industrial Park Opportunity

Eco-industrial parks may offer the economical advantages of traditional industrial parks while also using resources more efficiently, improving productivity, supporting the achievement of eco-social goals, and lowering exposure to climate change risks. To reach this goal, the Municipality of the District of Digby needs to reduce the cost of energy by providing clean cheap energy from renewable sources to local industries.

4.1 Energy Demand Analysis

The industrial park is approximately 22 acres in area and is generally located south of Highway 217 and is bounded by industrial lots, residential lots, and institutional uses. At this time, the area is approximately 60% occupied. The remaining available lands (in yellow in Figure 23) total roughly 10 acres and are surrounded with streets that include municipal services including sanitary sewer, water distribution system, overhead electrical, and paved roads with roadside ditches and culverts for drainage [5]. Figure 7 shows our current knowledge of current industries located in this site.

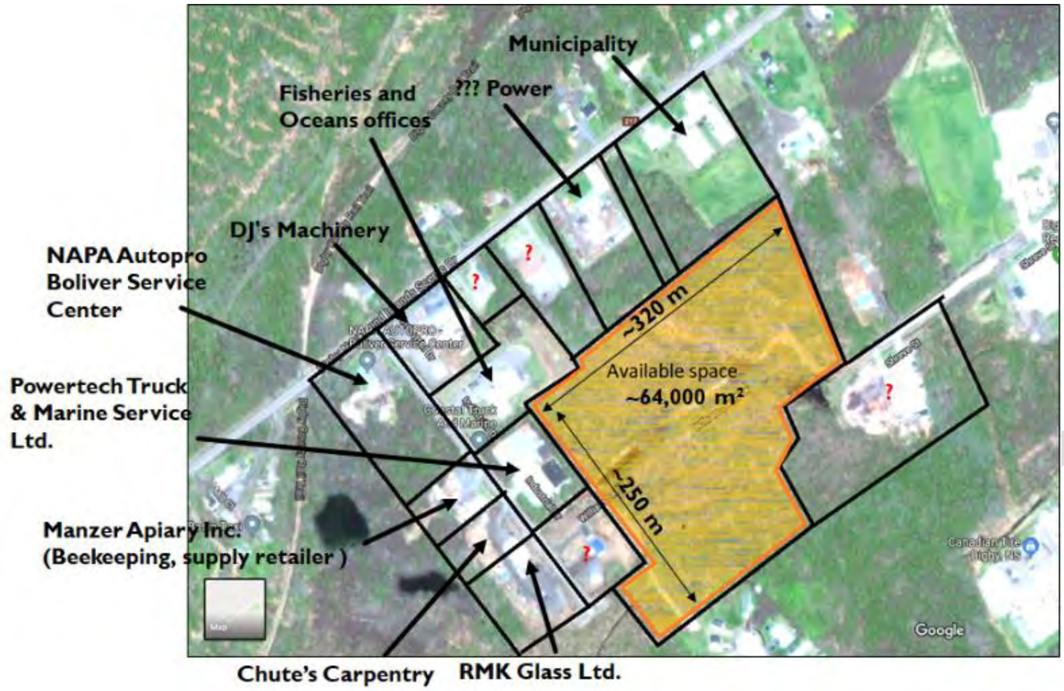

Figure 23. Municipality of Digby industrial park [5][46]

Assuming 8 working hours per day and 261 working days per year, we estimated the energy demand of the industrial park based on the type of industries. Table 12 shows our estimation of the energy consumption.

Table 12. The estimated energy demand for the industrial park

Energy Consumption (MWh/year)	Avg. Electricity Demand (kW)	Peak Electricity Demand (kW)
2577	788	2126

4.2 Recommended Solutions

The recommended solutions to achieve the goal of eco industrial park, is based on the development of biomass energies. The main goal is to reduce fossil fuels consumption and to reduce GHG emissions. The recommended solution can not only have environmental benefits, but also economically.

4.2.1 Clean Microgrid with Biomass CHP System

Using wood waste to generate electricity as well as heat (combined heat and power (CHP) system), is a suitable option for the industrial park which can run as a microgrid with zero carbon emission. Currently, more than 55% of NS grid electricity comes from coal which results in many tonnes GHG emissions each year. On the other hand, wood waste is technically a renewable energy resource because trees can be replanted after they're harvested. And because trees store carbon as they grow, replacement forests will gradually remove the carbon dioxide emitted when the previous trees were burned for energy. In this way, the whole process is carbon neutral, putting no net emissions into the atmosphere [47].

The advantage of the Clean microgrid system anchored with TES can be listed as follow:

- Has **abundant, dispatchable** energy capacity
- **Enables greater use of renewable power**
- Is stable and **dependable**
- Brings cost of electricity to **below grid average**
- **Reduces fuel oil** consumption and therefore
- **Reduces GHG emissions** and black soot
- Releases **no harmful chemicals** into the environment
- Captures and **redistributes waste heat**
- Lasts for **40+ years**
- **Pays for itself** and its replacement
- Directly creates **long-term** jobs for locals
- Provides energy stability to **encourage economic and social development**

To conduct a technical and financial analysis for a microgrid system for the industrial park, we considered following assumptions:

- Space is available with no cost
- Cost of Fuel oil is $1.05/liter, escalated at 2% per year
- Cost of Coal is $0.078/kg, escalated at 2% per year
- Cost of Natural Gas is $0.154/m^3, escalated at 2% per year
- Cost of wood fuel is $35.0/tonnes, escalated at 2% per year
- Cost of PV panels is $1.4 /W including engineering and installation
- O&M cost of the systems is 2% of the total materials cost and increases at 2% per year
- Carbon tax of $20 on every tonne of greenhouse gas emission starting in 2019, rising by $10 each year to $50 a tonne by 2022 [34]
- Financing for 20 years at the interest rate of 6.5%

Our optimization method aims to design a microgrid system including renewables to minimize the average energy cost while meeting the demand (Table 12). We assume that the peak demand occurs between 8 am to 4 pm and it is 2126 kW. The average daily demand is 788 kW. The details are presented in Table 13.

Table 13. Recommended biomass direct combustion system for the industrial park

Required Steam Turbine (kW)	2200
Required Wood (38% moisture) (tonne/year)	12846
Deliverable Electrical Energy (MWh/y)	7258
Deliverable Heat Energy (MWh/y)	21790
Installed cost (M$)	5.73
levelized cost of energy (¢/kWh)	7.2

Comparing Table 5 and Table 13 shows that levelized cost of energy cost intensity tends to decrease as the system size increases. Small systems have higher O&M costs per unit of energy generated and lower efficiencies than large systems [18].

Assuming the current electricity source for the industrial park is the NS grid and also local industries use fuel oil for heating purposes, the clean microgrid can reduce up to 3950 tonne GHG emissions each year while saving coal, natural gas and oil fuel (Table 14). Saving on fossil fuels and also carbon tax can bring revenue for both the Municipality of the District of Digby (up to $145k/year) and Nova Scotia Power (up to $4.2M/year) (Table 15).

Table 14. Environmental benefits of the 2.2 MW biomass direct combustion system

Coal Saving (tonne/year)	1121-1622
Natural Gas Saving ($10^3 m^3$/year)	142-353
Fuel Oil Saving (m^3/year)	2694
GHG Emission Reduction (tonne/year)	8363-9374

Table 15. Economical benefits of the 2.2 MW biomass direct combustion system

Revenue for the Municipality (M$/y)	2.5-4.2
Revenue for Nova Scotia (M$/y)	0.12-0.14

The energy cost for the next 20 years is shown in Figure 24. The residential energy price form NS power is higher than the energy production cost by the recommended microgrid. The cost of deliverable energy by the clean microgrid system is 7.2 ¢/kWh in 2019 which will reach to 8.9 ¢/kWh in 2038. Lower energy cost can encourage more industries to move to the industrial park.

The number of jobs created by deployment of a clean microgrid for the industrial park is presented in Table 16. In addition to people coming to invest in the industrial park, building and installing a clean microgrid can create 26 direct short term and 20 indirect long-term jobs.

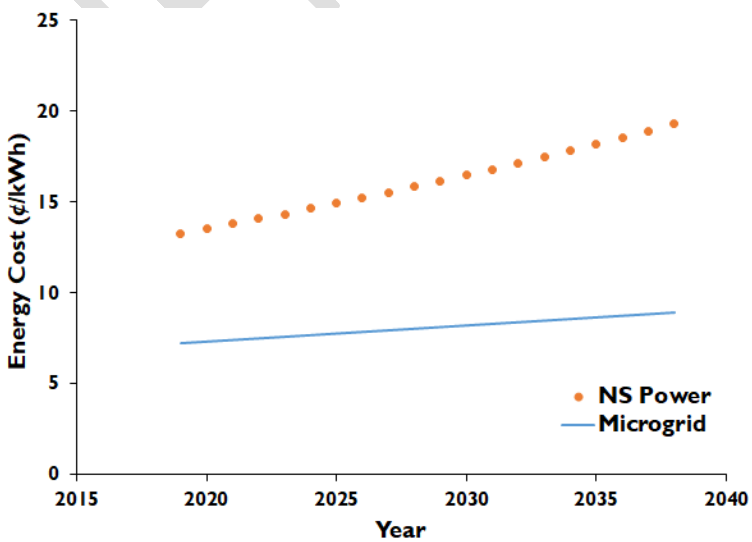

Figure 24. Microgrid energy cost versus energy price in NS

Table 16. Total direct and indirect Jobs created for each recommended solution (person per year).

System	Manufacturing Phase	Construction Phase	Engineering Phase	Total Direct Jobs	Total Indirect Jobs
Clean Microgrid	23	10	5	38	40

5 Other Possible Opportunities

5.1 An Electrical Port

5.2 Solar Energy

Solar energy, radiation from the Sun capable of producing heat, causing chemical reactions, or generating electricity [48]. Solar power is the conversion of sunlight into electricity, using photovoltaics (PV), or into heat using concentrated solar power (CSP). CSP systems use lenses or mirrors and tracking systems to focus a large area of sunlight into a small beam. PV converts light into electric current using the photoelectric effect [49]. Solar cell efficiency refers to the portion of energy in the form of sunlight that can be converted via photovoltaics into electricity. The efficiency of the solar cells used in a PV or CSP systems, in combination with latitude and climate, determines the annual energy output of the system [50].

The annual average energy production potential for PV solar panels in Canada is presented in Figure 25a. Digby County has some of the better photovoltaic potential in Nova Scotia (Figure 25b), and numerous residents have installed solar photovoltaic or solar thermal systems on their homes [51].

The solar map shows that Digby is located in the medium range: 1,100-1,200 kWh/kW/yr. It means that for example a PV power generation project of 100 kW will generate 1,10-1,20 MWh of solar energy per year. It is equivalent to an average capacity factor of 12.8% – 14%.

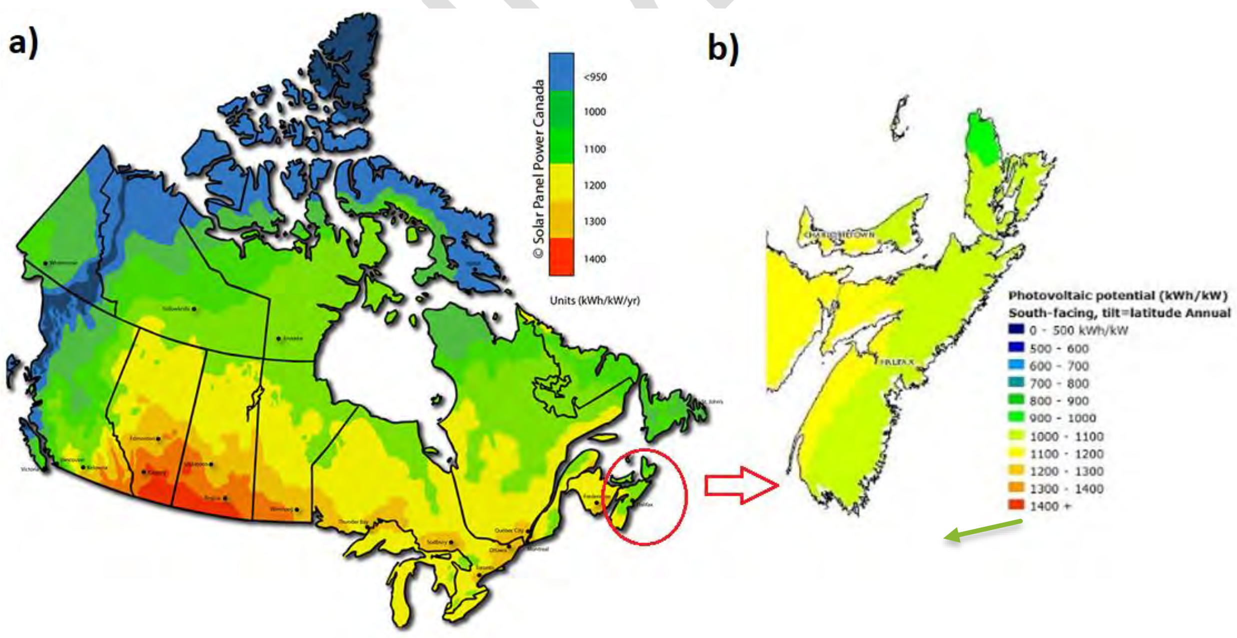

Figure 25. Annual average energy production potential for a solar panels in a) Canada [52] b) Nova Scotia (photo taken from www.nrcan.ca)

In the province's 2015 Electricity Plan: Our Electricity Future [53], Nova Scotia committed to introducing a new solar energy program. This program would help Nova Scotia move to a clean electricity system in a cost-effective way; while encouraging and enabling community participation in renewable energy generation [54].

However, installing a large capacity of PV panels especially for large facilities and the industrial park is an unexplored opportunity. The historical data for solar irradiation was available only in daily resolution [55]. To estimate the PV panel production, the hourly radiation was estimated to a second-order accuracy using the sunrise and sunset times [56]. Considering a typical 110 W PV panel, we estimate the yearly production for PV panels at Digby location (Figure 26). Assuming the cost of PV panels is \$1.4/W including engineering and installation, the levelized cost of energy for PV panels is estimated as 9-10 ¢/kWh.

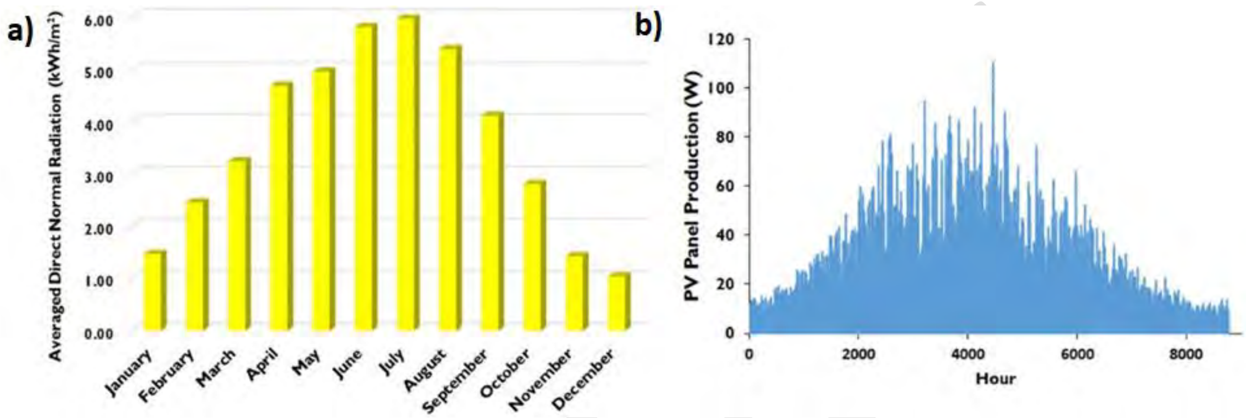

Figure 26. **a)** Average direct normal radiation for Digby over the last 10 years [57]; **b)** Hourly power output of a 110 W PV panel for over a year.

5.3 Ocean Thermal Energy Conversion (OTEC)

Ocean thermal energy conversion (OTEC) is a process for producing energy by harnessing the temperature differences (thermal gradients) between ocean surface waters and deep ocean waters. Energy from the sun heats the surface water of the ocean (here Bay Fundy). During summer day times, the surface water can be much warmer than deep water. In winter, the deep water is usually warmer than the surface water. Temperature differences of at least 25°C can be used to produce electricity using a thermoelectric module.

Alternatively, the cold deep water can be used as a cold source for an Organic Rankine Cycle (ORC) to produce electricity. Warm surface water is pumped through an evaporator containing a pressurized working fluid. The pressurized vaporized fluid drives a turbine-generator set to produce electricity. The fluid loses pressure in this process. Later, it is liquefied in a condenser cooled with the cold water pumped from deeper in the ocean [58].

The mean depth of the Bay of Fundy and Gulf of Maine is presented in Figure 27a [59]. The deepest spot in the study area is 366 meters, found in the middle of Georges Basin, but only 1.5% of the Gulf is deeper than 300 m. The closest deep spot to Digby is 200 m which is located in 60 km distance. Figure 20b shows how temperature decreases with increasing the ocean depth. The thermocline are layers of water where the temperature changes rapidly with depth [60].

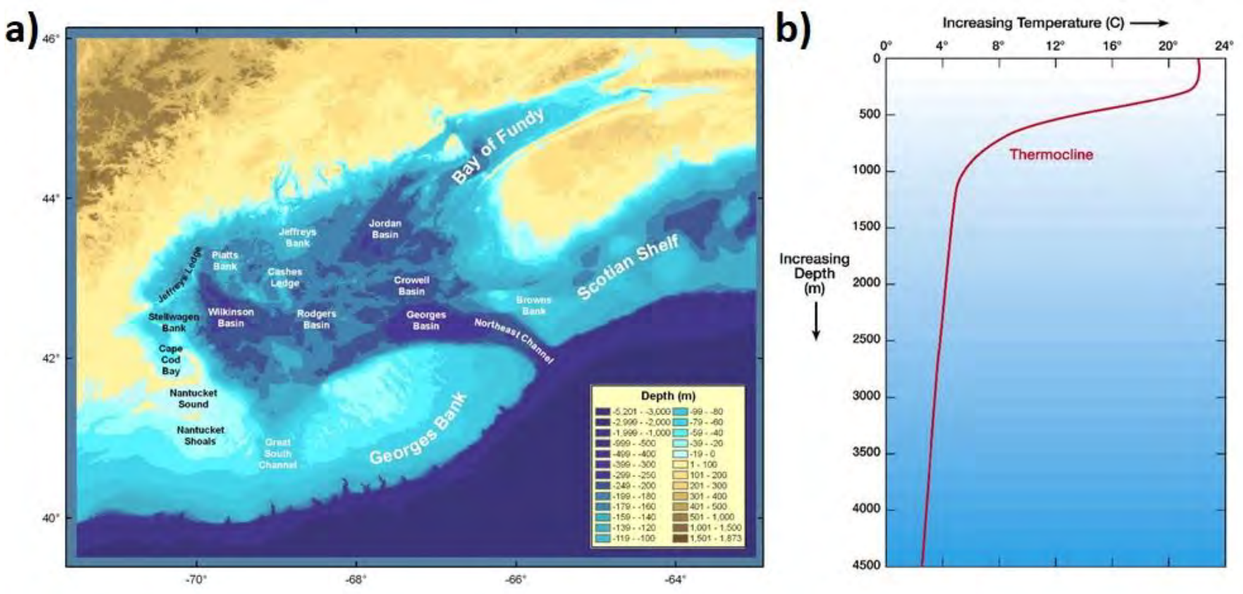

Figure 27. **a)** The mean depth of the Bay of Fundy and Gulf of Maine [59]; **b)** a typical temperature-depth ocean water profile [60].

Monthly average surface water temperature for Bay Fundy varies from -4°C in February to 17°C in August (see Figure 28a) [55]. Considering a typical Bismuth Telluride-based thermoelectric module [61] and the temperature 4 at the ocean depth as the cold source, we estimate the output power for 100 unit of 12-volt, 1.5 ampere thermoelectric power generator. The results are presented in Figure 28b. The generator efficiency was estimated around 1%. Although the natural power output and generation efficiency maybe very low, using a waste heat source at 300°C (such as biomass generator exhaust) can increase the efficiency to 40%.

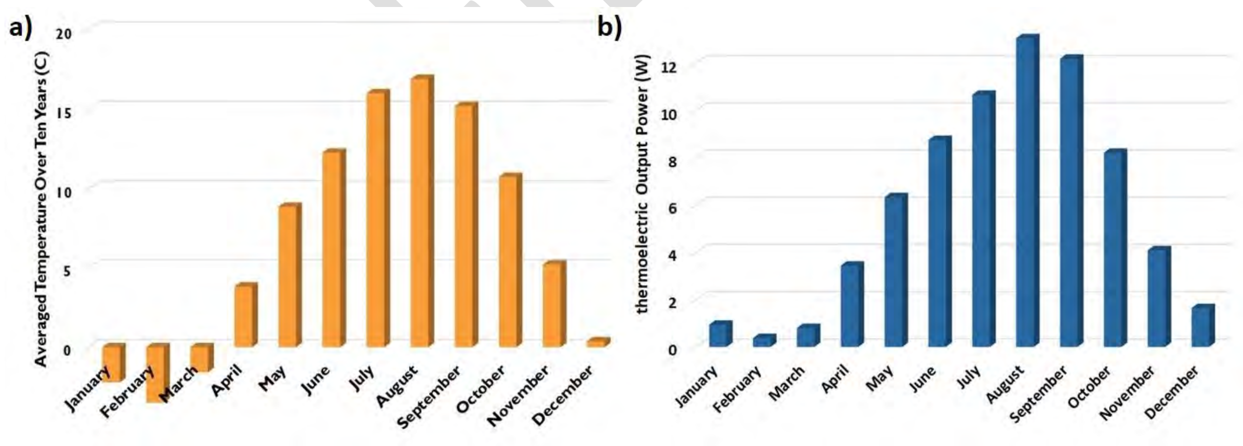

Figure 28. **a)** Average surface water temperature for Bay Fundy over the last 10 years; **b)** The output power for thermoelectric power generator.

5.4 Batteries

The largest battery energy storage systems use sodium–sulfur batteries, whereas the flow batteries and especially the vanadium redox flow batteries are used for smaller battery energy storage systems [62].

Li-ion batteries have been deployed in a wide range of energy-storage applications, ranging from energy-type batteries of a few kilowatt-hours in residential systems with rooftop photovoltaic arrays to multi-megawatt containerized batteries for the provision of grid ancillary services, but require some re-engineering for grid applications [62,63].

Figure 29 shows the charging and discharging process in Li-ion batteries. When the battery is charging up, the lithium oxide, positive electrode gives up some of its lithium ions, which move through the electrolyte to the negative, graphite electrode and remain there. When the battery is discharging, the lithium ions move back across the electrolyte to the positive electrode, producing the energy that powers the battery [64].

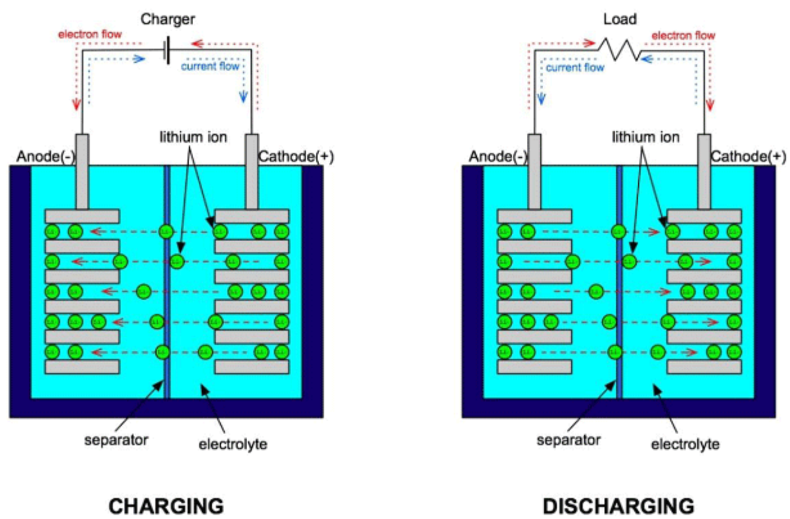

Figure 29.. Charging and discharging process in Li-ion batteries [65]

5.4.1 Life Cycle Analysis of CP-TES Compared to Batteries

To understand the relative impacts of a HT-CAES system compared to Li-ion batteries and conventional compressed air energy storage (CAES) we performed a Life Cycle Assessment (LCA). The analysis is conducted using OpenLCA software [66]. Each phase of the life-cycle has been considered (materials, construction, usage, and end-of-life phase) and the impacts are presented in four separate categories: Ecosystem Quality, Human Health, Resources and Climate Change. In all four categories, the HT-CAES system has the smallest environmental footprint (Figure 30).

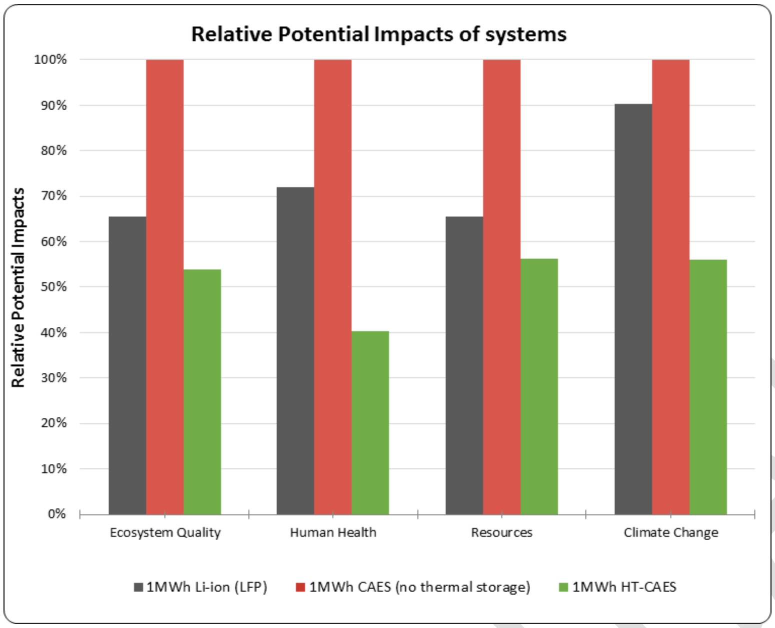

Figure 30: Life-cycle assessment comparison of CAES, Li-ion batteries, and HT-CAES

Compared to an equivalent Lithium-ion (Li-ion) battery storage system, an HT-CAES system reduces potential environmental impacts by 18% for ecosystem quality, 44% for human health, 14% for natural resources, and 38% for climate change. Comparison of HT-CAES system with an equivalent CAES system shows that environmental impacts of HT-CAES is lower: 46% for ecosystem quality (Terrestrial Ecotoxicity), 60% for human health (Ionizing Radiation & Respiratory Effects), 44% for natural resources (Non-Renewable & Mineral Extraction), and 44% for climate change.

5.4.2 Life Cycle Analysis of CP-TES Compared to Batteries

This life cycle analysis compares the environmental impacts of three energy storage technologies: $LiFePO_4$ Battery (Li-ion), Vanadium Redox Battery (VRB) and CP-TES. The study presents the impacts of each system for the delivery of 1 MWh. The dimensions of each system modelled have been scaled to fit this function (lifespan, materials, etc.) for comparison on the same basis. Each phase of the life cycle has been considered (materials, construction, usage, and end-of-life) and the impacts are presented in four separate categories: Ecosystem Quality, Human Health, Resources, and Climate Change. In all four categories, the CP-TES system is less damageable for the environment, as illustrated in Figure 31 and Table 17.

Overall, the Li-ion Battery presents the highest relative impacts, followed by VRB. This can mostly be attributed to the fact that many chemical components are required for them to function, requiring intensive mineral extraction and end-of-life landfilling that is harmful for both human health and the environment. This aspect is mostly visible in the Resources impact category. Another factor that plays against both battery storage options, but especially Li-ion, is their short lifespan. More batteries are

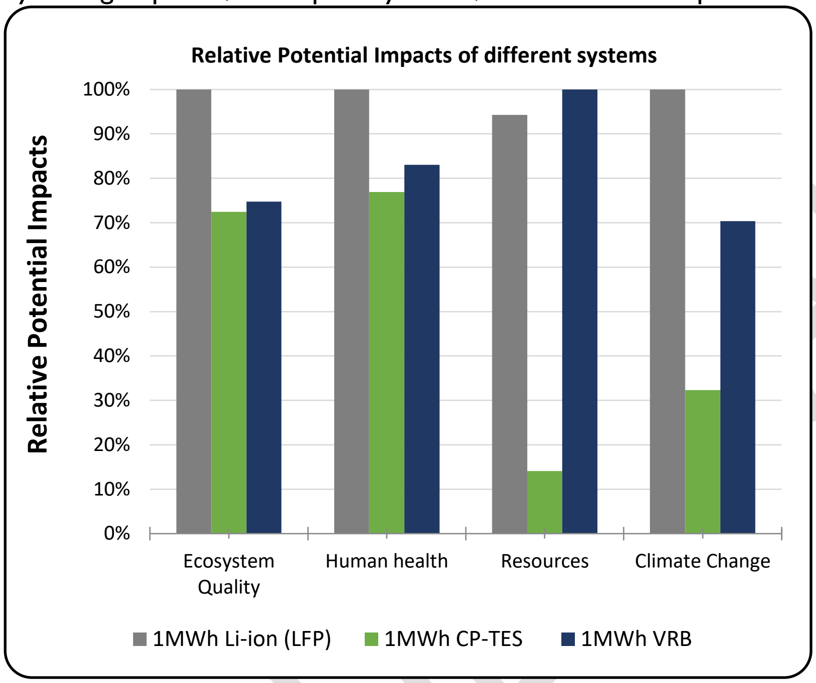

Figure 31 - Relative potential impacts for Li-ion battery, VRB, and the CP-TES.

required to accomplish the same task as one CP-TES system, so more extraction and landfilling of chemical materials is necessary to provide similar service. Additionally, Vanadium is extremely toxic and must be handled with extreme care. A major advantage for CP-TES system is the fact that minimal external electricity is required for the process. This reduces emissions during the usage phase.

In summary, compared to CP-TES process, a Li-ion solution causes more damage in the categories of Ecosystem Quality, Human Health, Resources and Climate Change by 39%, 30%, 671% and 312%, respectively.

Table 17- Comparison of the impacts of the Li-ion battery and the CP-TES

	1MWh Li-ion (LFP)	1MWh CP-TES	1MWh VRB
Ecosystem Quality	100%	72%	75%
Human health	100%	77%	83%
Resources	94%	14%	100%
Climate Change	100%	32%	70%

6 Conclusions

Energy storage is a valuable tool for reducing electric bills, making facilities resilient, and earning revenue, especially when it combined with renewable resources.

As a part of Nova Scotia Integrated Community Sustainability Plan (ICSP), Municipality of the District of Digby is committed to maximize the opportunities in renewable energy and to reduce its carbon footprint. These goals can be reached through specific plans such as building ecotourism and eco industrial park in the Municipality of the District of Digby.

Deploying renewable resources align with energy storage have a great economic and environmental benefits. By improving the overall efficiency of the grid, storage accelerates the broader adoption of renewable energy. The recommended solutions have no emissions, so it can be placed anywhere in a high-demand facility with no immediate environmental or air quality impacts. These solutions also provide low energy price to both residential and industrial costumers which improves the people quality of life and also attracts more business. More industrial investment leads to faster economic growth in the both short term and long run. It creates jobs especially for young generation and prevents population decline.

In this study we focused on four different systems as follows:

- PV-Thermal Energy Storage for Local Facilities
- Biomass Direct Combustion System
- Energy Storage for Tidal Energy
- Clean Microgrid with Biomass CHP System

The summary of technical and financial analyses for mentioned systems are presented in Table 18.

Table 18- Summary of the technical and financial analyses

Recommended System	**Goal**	**Environmental Benefits**	**Economical Benefits**	**Socio-economic benefits**
PV-Thermal Energy Storage for Local Facilities	Ecotourism	<u>For the hospital:</u> <u>52% fuel oil saving</u> 100 tonne/y <u>For the high school:</u> 22% fuel oil saving 71 tonne/y	Up to $52,500 for the hospital and up to $36,400 for the high school	17 person per year direct jobs and 9 person per year indirect job
Biomass Direct Combustion System	Ecotourism	Reduction Fossil fuel consumption: - Fuel oil (up to 325 m^3/year) - Coal (up to 196 tonne/year)	LCOE: 8.5 ¢/kWh Revenue for the Municipality: Up to $534,000 per year	28 person per year direct jobs and 23 person per year indirect job

		- Natural Gas (up to 43,000 m^3/year) - Reduce the GHG emissions (up to 1211 tonne/year)	Revenue for Nova Scotia: Up to $57,000 per year	
Energy Storage for Tidal Energy	Ecotourism	For Grand/Petit Passage: Reduction Fossil fuel consumption: - Fuel oil (up to 84 m^3/year) - Coal (up to 121 tonne/year) - Natural Gas (up to 26,000 m^3/year) - Reduce the GHG emissions (up to 294 tonne/year) For Digby Gut: Reduction Fossil fuel consumption: - Fuel oil (up to 307 m^3/year) - Coal (up to 444 tonne/year) - Natural Gas (up to 97,000 m^3/year) - Reduce the GHG emissions	For Grand/Petit Passage: Revenue for the Municipality: Up to $138,000 per year Revenue for Nova Scotia: Up to $35,000 per year For Digby Gut: Revenue for the Municipality: Up to $504,000 per year Revenue for Nova Scotia: Up to $128,000 per year	For Grand/Petit Passage: 39 person per year direct jobs and 43 person per year indirect job For Digby Gut: 139 person per year direct jobs and 147 person per year indirect job

		(up to 1079 tonne/year)		
Clean Microgrid with Biomass CHP System	Eco Industrial Park	Reduction Fossil fuel consumption: - Fuel oil (up to 2694 m^3/year) - Coal (up to 1622 tonne/year) - Natural Gas (up to 353,000 m^3/year) - Reduce the GHG emissions (up to 9374 tonne/year)	LCOE: 7.2 ¢/kWh Revenue for the Municipality: Up to \$4.2M per year Revenue for Nova Scotia: Up to \$0.14M per year	38 person per year direct jobs and 40 person per year indirect job

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Page 1

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Organization & Title

Municipality of the District of Digby

Upload Documents (.DOC/X, .XLS/X, .PDF)

PDF SE Microgrid REIDS Project

Browse...

Subject *

Micro/Smart Grid Opportunities for Digby County

Message *

Given the abundance of the natural resources we think that the utility is a very good position to introduce large, utility scale projects that will create a county that is totally powered by renewable energy. We think that the upcoming Cap and Trade program which NSP is one of the Program Participants, that Digby is perfectly situated to work with NSP to achieve the goals under this program and to create the right stimulus to move economic development forward.

Schneider Electric's role

Development of the microgrid energy management system, to balance short-term loads

Engineering expertise

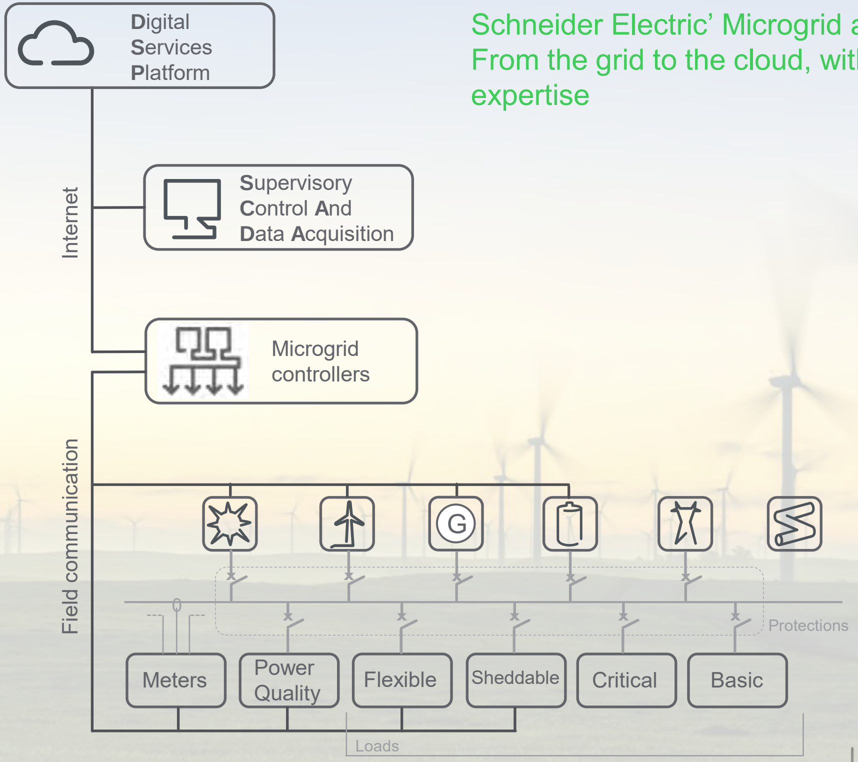
Cloud services
- Ancillary services
- Optimization Services
- Information Services

Supervision, HMI & Data Management
- Data Management
- Communication
- User and local Interfaces

Microgrid control
- Energy Management
- Power Management
- Control algorithms

Distributed Energy Resources
- Multi-fluid energies, heat & gas
- Electricity

Protections & Metering
- Protections
- Loads



Schneider Electric' Microgrid architecture: From the grid to the cloud, with engineering expertise

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Innovation At Every Level

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Connect, monitor, and control your facility's Distributed Energy Resources (DER) to optimize performance

Features

- Provides visibility and control to all of your DER in a single platform
  - Solar power
  - EV charging stations
  - Batteries
  - Wind energy
  - Back-up generators
  - HVAC systems
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  - Uninterruptible Power Supply (UPS)
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Benefits

- Single platform: connect, monitor, and control all DER from a single interface
- Demand control: shift and prioritize loads to avoid utility demand charges
- Storm hardening mode: leverage weather forecasts to reduce downtime
- Demand response: participate in utility programs to generate new revenue streams
- Tariff management: manage price through seasonal, day- and hour-ahead pricing
- Self-consumption: charge batteries with excess solar energy during peak periods
- Cyber secure platform: protect site and related data from external hacks

Distributed renewables and efficient on-site generation are changing the grid faster than ever before.

With EcoStruxure™ Microgrid Advisor, users can now take advantage of autonomous and dynamic control of energy production and consumption.

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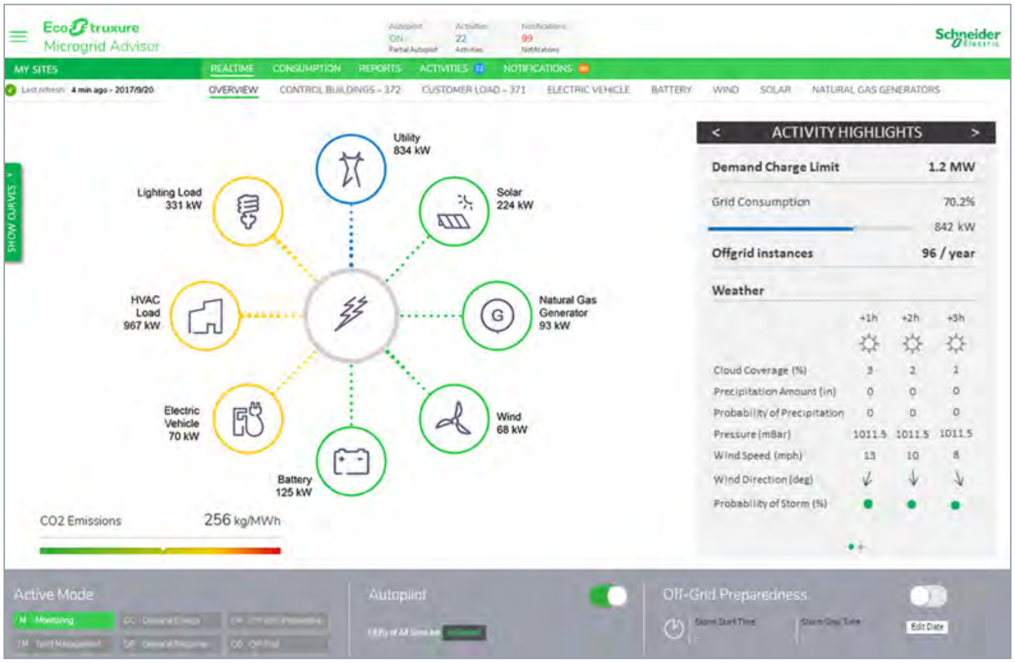
Access real-time DER system operation



The cloud-based software platform enables you to monitor your power consumption, production, and energy usage by date. Export the data into an Excel™ file for a deeper analysis. Custom configurations and web services can be developed based upon your specific requirements.

Access and connectivity

Compatible devices and web browsers

- Use your PC, tablet, or smartphone to stay informed of site conditions and usage
- Compatible with Chrome™, Firefox™, and Internet Explorer™ internet browsers

Third-party and DER database connectivity

- Native OpenADR2.0 communication protocol seamlessly exchanges information, including utility information systems and commercial aggregators
- Standard web services API for cloud connectivity
- Communication with DER via
  - » Modbus RTU
  - » IP and LonWorks
  - » TCP/IP, BACNet MSTP
  - » HTTP/JSON

Connection to the hardware

- Secured connection through your on-site IT network (LAN) or dedicated ADSL lines
  - » Cyber secure testing in white box mode using NIKTO, DIRBUSTER, SQLMAP, and BURP to secure EcoStruxure Microgrid Advisor from session hijacking, XSS, and SQL injection

FINANCIAL REPORT	
Baseline	$85,433
Savings total	$22,464
Optimum Start Stop	$3,567
Tariff Management	$12,397
Demand Charge	$4,555
Autoconsumption	$1,945
Earnings total	$2,587
FeedIn Tariff	$2,587
Adjusted Baseline	$60,382

ENVIRONMENTAL REPORT	
CO_2 emissions	701,485 Tons
CO_2 savings	203,993 Tons
CO_2 emissions adjusted	497,492 Tons

Provides real-time savings and earnings data (above) as well as CO_2 emissions (below).

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Schneider Electric's role

Development of the microgrid energy management system, to balance short-term loads

Engineering expertise

Cloud services
- Ancillary services
- Optimization Services
- Information Services

Supervision, HMI & Data Management
- Data Management
- Communication
- User and local Interfaces

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- Power Management
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Distributed Energy Resources
- Multi-fluid energies, heat & gas
- Electricity

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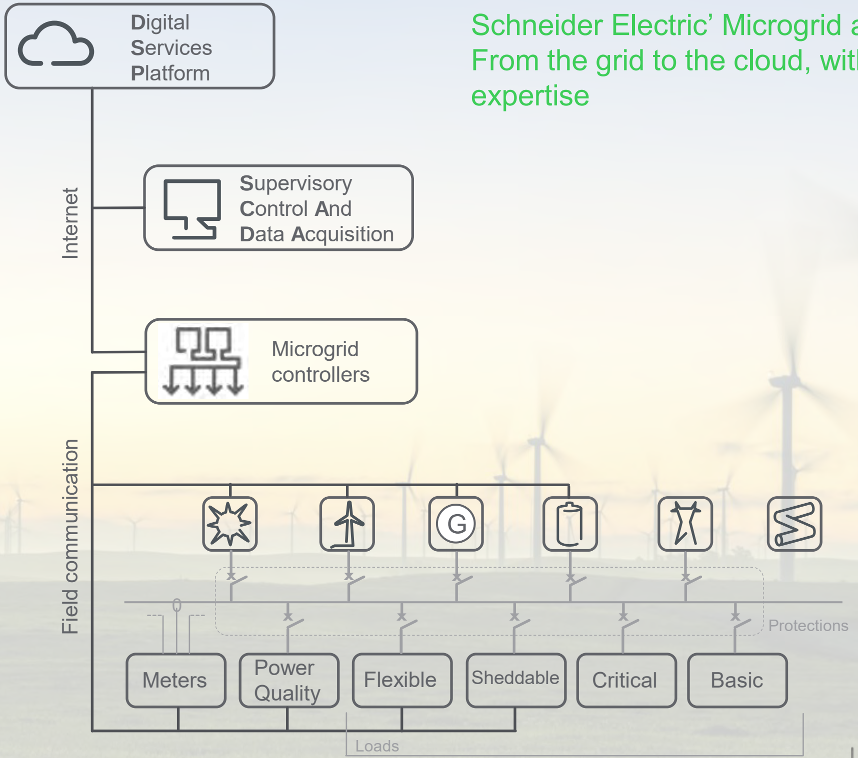
- Protections
- Loads



Schneider Electric' Microgrid architecture: From the grid to the cloud, with engineering expertise

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Submitted Comments Regarding 2020 IRP Assumptions

February 14, 2020

The Ecology Action Centre (EAC) welcomes the opportunity to participate as a stakeholder in the 2020 Integrated Resource Plan process. We submit the below comments in response to the Draft Assumptions Set and Draft Analysis Plan released for stakeholder comment, and discussed at the IRP stakeholder session on January 28, 2020. Specifically, this submission is in response to the below documents:

i) *2020 IRP Draft Assumptions Set (Jan 20, 2020)*
ii) *2020 IRP Draft Assumptions Addendum/Update (Feb 3, 2020)*
iii) *2020 IRP Draft Analysis Plan*

It is also important to note in this submission that the capacity of EAC to engage in this process is greatly reduced due to the design and process of the 2020 IRP, and the lack of availability for stakeholder funding and support through the NSUARB, through the NSPI-led process, or through the Nova Scotia Department of Energy and Mines. This is true for other organizations who advocate on behalf of climate mitigation, environmental concerns and energy affordability concerns, who do not have staff regulatory or legal counsel capacity to engage in this important energy planning process.

Although NSPI has made every effort to make the 2020 IRP process accessible to stakeholders, we regret the lack of financial and structural support for organizations to participate. The EAC feels that this problem in ongoing NSPI and NSUARB processes will continue until the Department of Energy and Mines, or Nova Scotia Power create an updated mandate to support climate change and environmental concerns in a way similar to the Consumer Advocate or the Small Business Advocate.

The EAC believes that setting clear, ambitious climate targets is critical to building the low-carbon economy and avoiding the worst of the threats that climate change poses to our coastal province. The phase out of coal-fired electricity is a critical policy that can help ensure affordable, clean electricity for Nova Scotians and help to avoid the worst climate impacts and ongoing human health impacts of burning coal.

With regional electricity planning, federal policy commitments and the established opportunities in affordable renewable energy and energy efficiency, the time has never been better to commit to a timeline and process for a full phase-out of coal-fired electricity in Nova Scotia, and a clear pathway to support coal workers and communities in the just transition to a prosperous, low-carbon economy.

The EAC welcomes the opportunity to submit written comments to this process, and acknowledges the time and effort of Nova Scotia Power staff in answering our questions during the pre-IRP and IRP periods thus far.

Thank you,

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1. Submission of EAC Report on Coal Phase-Out and Electricity System Transition

The EAC would like to take the opportunity to submit our November 2019 report into the discussion around the 2020 IRP Draft Assumptions Set.

The report was submitted to Nova Scotia Power staff in November 2019, and is entitled '*Accelerating the Coal Phase Out: Nova Scotia and the Climate Emergency A technical report and modelling analysis of a low-**carbon transition for Nova Scotia's electricity and energy systems by 2030***'

The report offers a low-carbon scenario based on an end-use model of Nova Scotia's electricity system. Compared against a 2019 base year, this report is technical and modelling exercise for what an electricity grid with more than 90% renewable electricity, and a complete transition away from coal-fired electricity generation by 2030 would look like in Nova Scotia.

Key measures and results from the low-carbon pathway in the report include:

- Overall electricity demand dropping by about 7% in the province between 2019 and 2030.
- Substantial increases in energy efficiency programming by the year 2030 include: 80% of residential and commercial buildings receive deep-energy retrofits; major shifts to heat pumps for space heating and hot water; shifts away from oil and natural gas heating; and efficiency gains in lighting and other appliances.
- By 2030 25% of personal vehicles will be plug-in hybrid, and 15% fully battery-electric vehicles.
- The addition of 120 MW / 480 MWh of energy storage
- A generation mix of about 43% wind, 5% solar, 43% hydro and 9% natural gas by 2030.
- A doubling of wind power in Nova Scotia, with the addition of 600 to 800 MW
- Significantly increasing solar power in Nova Scotia, with the addition of about 480 MW
- Building a second transmission link to New Brunswick, and importing about 200MW of existing hydroelectricity capacity from Quebec.

Although this report is not primarily an economic report, it does perform high-level economic analysis on the key measures proposed as part of this low-carbon pathway with a result of net annual cost of about $200 million. This does not suggest all incremental costs are put on the rate base. To put this in context, $200 million is about half of one percent of Nova Scotia's economic output, or about 10% of the revenue the government collects every year in sales tax.

The EAC looks forward to submitted a number of these key measures and results for consideration as elements of the 2020 IRP scenario options.

The measures of the report result in significant overall greenhouse gas emissions reductions in Nova Scotia. Including the emission reductions in the scope of this report lead to a provincial total of more than 69% below 2005 levels by 2030 – as seen in the sample figure below.

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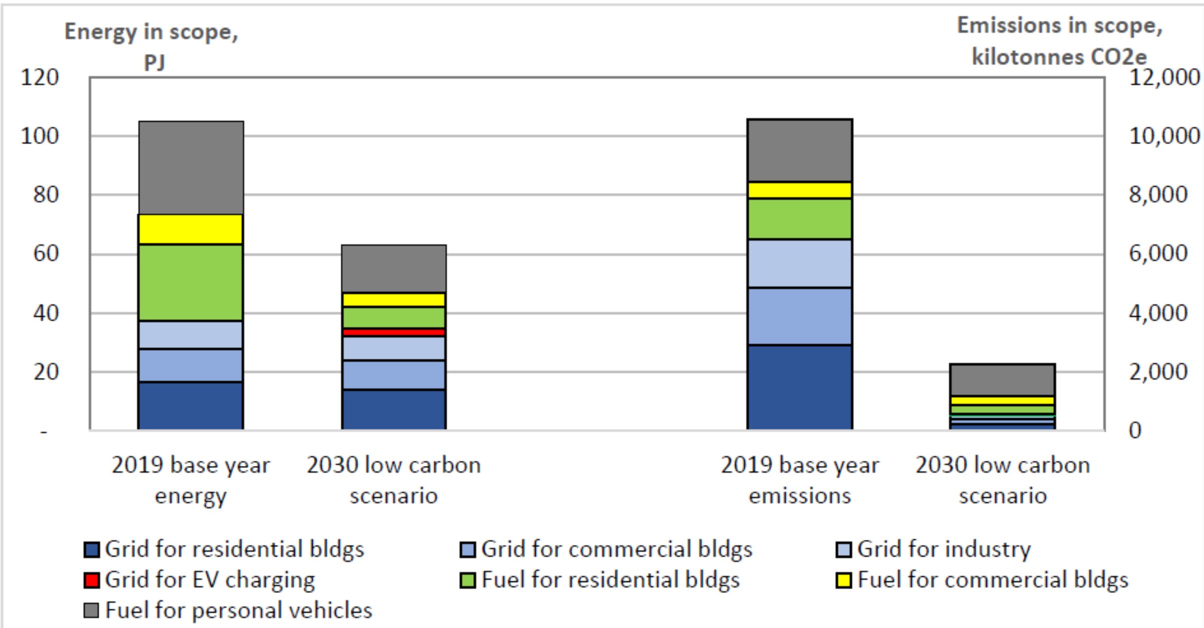

Figure ES- 2. Energy (bars on the left) and emissions (bars on the right) included in scenario, 2019 baseline vs. 2030 low carbon scenario.

The report can be found at the link below:
https://ecologyaction.ca/sites/default/files/images-documents/EAC%20Coal%20Phaseout%20Report%20-%20Final%20-%20191120.pdf

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2. Greenhouse Gas Reductions Assumptions

Overall, the EAC believes that more ambition in greenhouse gas emissions reductions should be considered.

As mentioned on Page 14 of the 2020 IRP Assumptions Set, the EAC agrees that the Sustainable Development Goals Act and subsequent regulations will have the potential to significantly increase the level of ambition from the currently regulated hard caps out to 2030 in Nova Scotia. With an overall provincial emissions reduction target of 53% below 2005 levels by 2030, it can reasonably be expected that a portion of these new reductions from the Sustainable Development Goals Act will come from the electricity sector, beyond the existing hard caps.

Further, the federal government is set to review and likely increase the level of ambition as part of the federal carbon pricing system during the 2020 midterm review. This may result in further emissions reductions being required from Cap and Trade jurisdictions in the post-2022 period. Additionally, the Federal Government's commitment to exceed the federal emissions reduction target of 30% below 2005 by 2030 is likely to drive continued reductions regionally across Canada.

The ambition of potential scenarios from HaliFACT 2050 – Halifax's municipal climate action plan process – may be another early driver of further need for decarbonisation of the electricity system beyond the existing hard caps presented in the 2020 IRP Assumptions Set.

3. Renewable Electricity Target Assumptions

The EAC believes that renewable electricity targets or renewable energy standards (RES) may be part of the future regulatory landscape in Nova Scotia. The EAC therefore disagrees with the assertion on Page 26 of the 2020 IRP Assumptions Set that no future RES regulations are anticipated. Although the Sustainable Development Goals Act states a goal of net-zero by 2050, step-goals in the milestone years of 2025, 2030, 2035, 2040, 2045 and so on may be likely as a regulatory framework toward the net-zero goal.

Further, if this is not already considered, the stated commitments and agreements regarding the Federal government's goal of reaching 100% renewable electricity for all Federal government buildings by 2025 should be considered in it's interaction with the NS electricity system.

4. Coal Phase-Out Equivalency Agreement Assumptions

Since November 2016, the Federal Government has had an established policy goal to phase out all coal-fired electricity generation across Canada by 2030, as a key emissions reduction pillar of the Pan-Canadian Framework on Clean Growth and Climate Change.

The Federal Government finalized its amended regulations for emissions from coal-fired electricity generation on November 30, 2018. The final regulations articulated emissions reductions from the electricity sector and showed that phasing out coal electricity in Nova Scotia by 2030 would avoid 89 premature deaths, 8,000 asthma episodes and 58,000 days of breathing difficulty for Nova Scotians, among other benefits.

a. The Renewed 2020-2025 Equivalency Agreement
   The renewed equivalency agreement, released for comment on March 30th, 2019 and finalized in November 2019 is a renewal of the existing 'Canada-Nova Scotia Equivalency Agreement Regarding Greenhouse Gas Emissions from Electricity Producers', which came into force on July 1,

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2015. The existing equivalency agreement expired after a five-year period on Dec 29, 2019. This renewed agreement is accompanied by a 'Quantitative analysis of equivalency determination consultation: carbon dioxide emissions from coal-fired generation' which gives supplementary information and highlights analysis of future emissions pathways out to 2040.

Although the quantitative analysis shows emissions targets between 2015 and 2040 to gain a high-level and long-term perspective of emissions pathways, the proposed renewed equivalency agreement itself would only be valid for a five-year period between January 1, 2020 and December 31, 2024.

Emissions targets for the 2025-2029 period are also shown in the proposed renewed equivalency agreement and are regulated in Nova Scotia under the Environment Act's Greenhouse Gas Emissions Regulations. However the targets in this period are outside the five-year term of the proposed equivalency agreement and would have to be agreed upon by the Federal and Provincial governments in 2024 to enter a renewed agreement at that time.

The quantitative analysis also includes a forward-looking picture of Nova Scotia's plans for what the Province would submit to be equivalent emissions reductions for the 2030-2040 period. Importantly, this lays out a path and sets expectations for the 2030-2040 period, but is not binding for emissions pathways past 2024, or past the 5-year period of the Equivalency Agreement itself. Our understanding from the provincial government is that a new, separate equivalency agreement will be needed for the 2030-2040 period.

The lack of ambition in the proposed long-term emissions pathway proposed in the 2030-2040 pathway is the EAC's main point for criticism of this equivalency agreement renewal process.

Therefore, the EAC believes that the forecast CO2 emissions hard caps presented on Page 17 of the 2020 IRP Draft Assumptions Set are the least ambitious emissions reductions pathway scenario that should be modelled, and all other scenarios should increase in emissions reductions ambition from this set of hard caps.

b. Targets for 2030 and Beyond:
   It is the understanding of the EAC that the articulated greenhouse gas emissions pathway for the 2030-2040 period within the quantitative analysis of the proposed equivalency agreement is simply the business-as-usual case articulated by Nova Scotia Power Inc. to continue burning coal for electricity generation until well into the 2040 decade, until at least 2042[i].

   If this emissions pathway were to be accepted, there would be <u>no incremental emissions reductions beyond the business-as-usual case for Nova Scotia resulting from the amended federal regulations on coal-fired electricity, or this proposed equivalency agreement</u>. In the view of the EAC, this is not acceptable, and certainly does not meet the intent of the federal policy.

   The figure below shows the proposed pathway of the Nova Scotia Government showing Nova Scotia over-achieving emission reductions compared with the federal regulations through the 2015-2029 period, and proposing it be allowed to be deficient with federal regulations and emit more greenhouse gases in the 2030-2040 period[ii]. Although this carefully selected timeframe results in approximately the same emissions reductions over the total 2015-2040 period when compared with

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the modelled baseline, this proposal of banking emissions credits over a 25-year period is fundamentally problematic and does not lead to increased overall ambition.

Success in achieving past policy goals should be celebrated, but should not be used as a tool to ensure weakened future ambition. Over achievement during the duration of the term of one equivalency agreement should not be used to balance deficiencies in the outcomes of a future equivalency agreement.

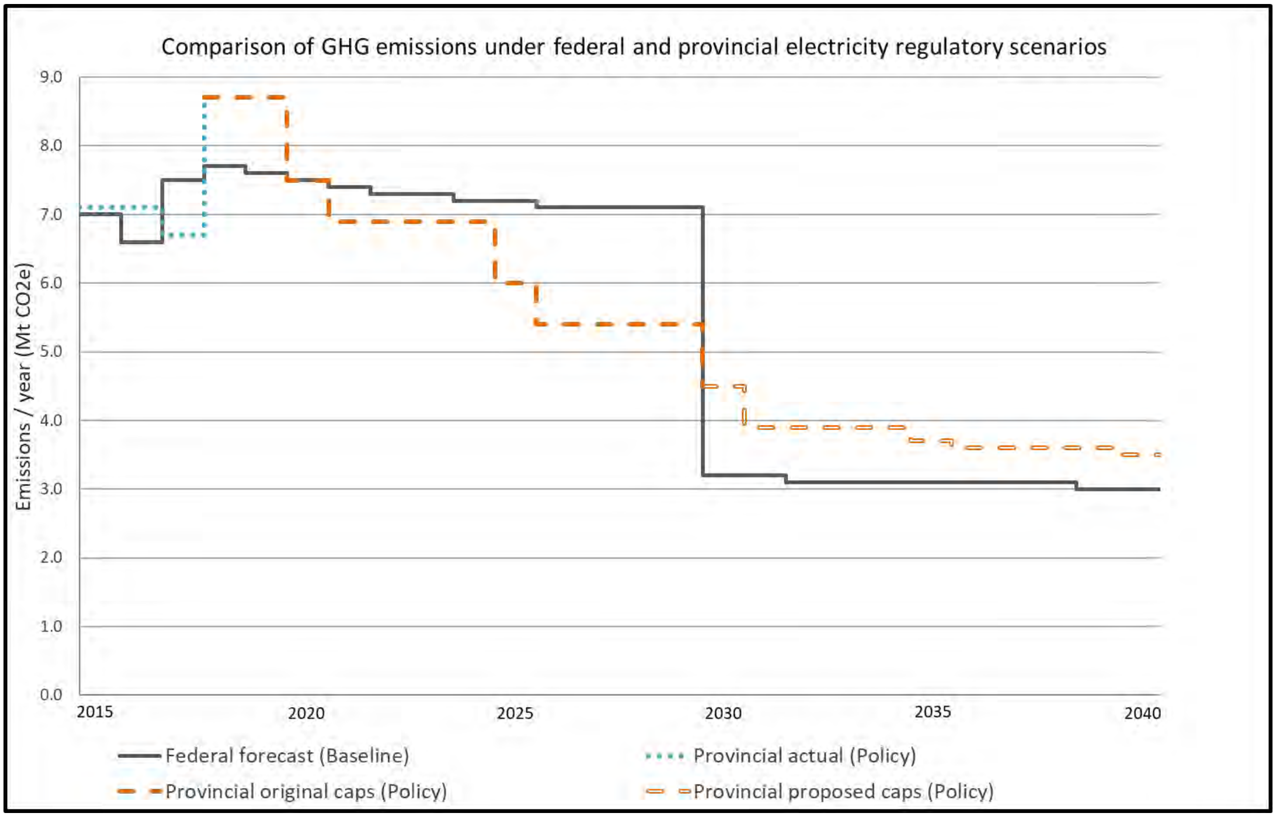

Figure 1 from **'Quantitative analysis of equivalency determination consultation: carbon dioxide emissions from coal**-fired **generation'**[iii].

It is the view of the EAC that the federal government should not accept the proposed emissions pathway for the 2030-2040 period. An emissions pathway that is compliant with the federal regulations of approximately 3.0 Mt of CO2e for the 2030-2040 period should be proposed by Nova Scotia, or the 2030-2040 period should be removed from this analysis entirely until such a time that clarity on future equivalency for the post-2030 period can be reached.

c. Complete Coal Phase-Out Scenario
Given the uncertainty with future Equivalency Agreements, the EAC agrees with the 'Scenario Note" on page 15 of the 2020 IRP Draft Assumptions Set that at least one modelling scenario should examine a portfolio where all coal units are retired by Dec 31, 2029 in accordance with the 2018-19 Federal regulations.

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5. Moving Forward

The EAC believes that Nova Scotia still has an opportunity to set long-term ambition, and commit to phasing out coal-fired electricity in Nova Scotia.

We need to ensure that low and middle-income Nova Scotians, coal workers and communities all benefit from this change in our electricity system, and the EAC believes that this transition is possible in an affordable, just and timely way.

The EAC looks forward to continued participation in the 2020 IRP stakeholder process, and ongoing conversations regarding Nova Scotia's electricity future.

Ecology Action Centre is committed to continuing to ensure Nova Scotia sets a pathway to phasing out coal-fired electricity generation, and looks forward to working with all partners toward the just transition to a prosperous, green economy.

Thank you for your consideration,

Stephen Thomas
Energy Campaign Coordinator
Ecology Action Centre
stephen@ecologyaction.ca

See Also:
Ecology Action Centre's Electricity Report and Ongoing Work on Coal Phase-Out:
https://ecologyaction.ca/electricityreport

Setting Expectation for Robust Equivalency Agreements in Canada (April 2019)
Climate Action Network Canada | Canadian Association of Physicians for the Environment | Centre québécois du droit de l'environnement | Ecology Action Centre | Environmental Defence | Pembina Institute
https://ecologyaction.ca/sites/ecologyaction.ca/files/images-documents/CAN-Rac-Equivalency-Paper-2019-web.pdf

The Just Transition Task Force on Coal Workers and Communities Final Report:
https://www.canada.ca/en/environment-climate-change/news/2019/03/government-of-canada-welcomes-report-from-just-transition-task-force-for-canadian-coal-power-workers-and-communities.html

Ecology Action Centre's Electricity Report and Ongoing Work on Coal Phase-Out:
https://ecologyaction.ca/electricityreport

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[i] Synapse Energy Economics, Inc. for Nova Scotia Utility and Review Board: *Nova Scotia Power Inc. Thermal Generation and Utilization and Optimization - M08059* | May 1, 2018 | https://uarb.novascotia.ca/fmi/webd/UARB15

[ii] ECCC: *Quantitative analysis of equivalency determination consultation: carbon dioxide emissions from coal-fired generation* | March 30, 2019 | https://www.canada.ca/en/environment-climate-change/services/canadian-environmental-protection-act-registry/agreements/equivalency/canada-nova-scotia-consultation-carbon-dioxide-electricity/quantitative-analysis-equivalency-determination.html

[iii] ECCC: *Quantitative analysis of equivalency determination consultation: carbon dioxide emissions from coal-fired generation* | March 30, 2019 | https://www.canada.ca/en/environment-climate-change/services/canadian-environmental-protection-act-registry/agreements/equivalency/canada-nova-scotia-consultation-carbon-dioxide-electricity/quantitative-analysis-equivalency-determination.html

Introduction

EfficiencyOne appreciates the opportunity to provide comments on NS Power's 2020 Integrated Resource Plan (IRP) draft Analysis Plan and Assumptions Set.

EfficiencyOne submits the following comments, questions and recommendations. The comments of Energy Futures Group, consultant to EfficiencyOne are included as Attachment "A" and are incorporated by reference to EfficiencyOne's submissions.

1. Evaluation Criteria

Slide four of the draft Analysis Plan described seven proposed evaluation criteria that NS Power will use to rank Candidate Resource Plans (CRPs). EfficiencyOne understands that minimizing the 25-year NPV revenue requirement will be the primary metric for evaluation. However, it is unclear how the remaining metrics will be utilized or what importance will be given to them. Before moving into the modelling stage, it is critical that all stakeholders have a clear understanding of exactly how the evaluation criteria will be measured, when resource plans will be screened out, and what the criteria for screening will be. EfficiencyOne does not advocate for weightings to be applied to any criteria. NS Power weighting each criterion would be inherently arbitrary and therefore should not be used in this process.

EfficiencyOne strongly recommends the following:

- NS Power defines how each evaluation criteria metric will be quantified, so that it is clear to all stakeholders how the resource plans will be scored.
- NS Power commit to quantitively scoring all CRPs that pass the operability and reliability screening phases on all of the evaluation criteria so that stakeholders can have a complete view of resource plans.
- NS Power provides alongside the ranking of all CRPs the rationale for the ranking, detailing how the scores of the evaluation criteria were considered.

EfficiencyOne's comments on specific evaluation criteria as proposed by NS Power are as follows:

I. <u>Minimization of NPV of the annual revenue requirements over 25 years (slide four, row one)</u>

EfficiencyOne agrees that this is an appropriate evaluation criterion.

II. <u>Magnitude and timing of electricity rate effects (slide four, row two)</u>

EfficiencyOne is unclear how the stated evaluation metric of the 10-year NPV revenue requirement assesses the timing and magnitude of rate effects. Further, EfficiencyOne is unclear why a 10-year NPV revenue requirement is an important metric to evaluate, and if it is the best proxy for the magnitude and timing of electricity rate effects.

EfficiencyOne requests the following:

- Detail why a simple 10-year NPV of revenue requirement be used to evaluate rate impacts of the IRP.

III. <u>Reliability requirements for supply adequacy (slide four, row three)</u>

EfficiencyOne recommends the following:

- all CRPs that do not meet reliability requirements should be eliminated at the reliability screening stage; i.e., if they are truly "requirements" they should be evaluated on a pass/fail basis and not included in evaluation criteria.

The description for this evaluation criteria lists a number of metrics for consideration "PRM, resource capacity, operating reserve requirements, etc."

EfficiencyOne requests the following:

- NS Power confirm whether all metrics to be considered for this evaluation criteria are listed on slide 4, row three of the Draft Analysis Plan document. If not, please list all metrics that will be considered.

IV. Provision of essential grid services for system stability and reliability (slide four, row four)

E1 recommends the following:

- all CRPs that do not meet requirements for essential grid services be eliminated at the reliability and/or operability screening stages; i.e. if they are truly "essential" they should be evaluated on a pass/fail basis and not included in the post-analysis evaluation criteria.
- Any required integration costs (e.g. requirements for additional or supplementary grid services) to be considered in the cost of the IRP NPV.
- All grid services being assessed to be listed, and the specific evaluation criteria or thresholds assigned to each to be clearly defined.

V. Plan robustness (slide four, row five)

It is unclear how 'robustness' will be measured via a sensitivity analysis.

EfficiencyOne submits the following question:

- NS Power to confirm if it is possible to combine this metric with the 25-year NPV revenue requirement metric by assessing the NPV revenue requirement under both a high and low sensitivity analysis?

VI. Reduction of greenhouse gas and/or other emissions (slide four, row six)

EfficiencyOne agrees the emissions performance of plans is relevant, although some additional clarity is required if a comparative analysis is contemplated.

EfficiencyOne recommends the following:

- Total emissions for each CRP to be quantified and presented.
- Total emissions for each CRP be considered rather than the reductions compared to some undefined base case.
- If other types of emissions are to be considered as criteria such as mercury, SOx, NOx, these emission types to be listed, and metrics assigned.

VII. Flexibility

It is unclear how a "qualitative assessment of timing of investments" will be used as an evaluation criterion. EfficiencyOne appreciates that there may be benefit in not being locked into one path for investment timing; however there is a risk that this could simply push all major decisions to 25-

years out, and delay benefits of grid modernization and GHG emission reductions that cannot be captured in a revenue requirement.

DSM is a flexible resource in terms of the ability to adjust activity levels in response to changes in current conditions. It is unclear to EfficiencyOne how DSM is being considered in terms of its flexibility.

EfficiencyOne requests the following:

- NS Power clarify the specific metric that will be used to evaluate flexibility.
- NS Power clarify how flexibility will be scored for DSM (including energy efficiency and demand response).

2. Analysis Plan

EfficiencyOne requests the following additional detail on the draft Analysis Plan shared by NS Power:

- Clarify at which steps in the analysis, potential CRPs are being assessed for removal. For ease of reference, the stages of the analysis EfficiencyOne is referencing are found on slide one of the draft Analysis Plan document.
- Define the long-term strategy, roadmap, and near-term action plan in terms of their objective and how they will be used by NS Power for planning purposes.
- Clarify the data relationship between the long-term strategy, roadmap, and near-term action plan (i.e. how will the analysis results, and predecessor documents, "feed" into the subsequent documents described.) Does NS Power plan to base these reports on the quantitative findings of the modelling phase?
- Describe the process NS Power will follow in the event government passes more stringent environmental regulations relating to GHG emissions after the IRP is complete. How will it be determined if this change is a "decision gate"? If it is determined to be a "decision gate" would this lead to a reassessment of CRPs and a change in the Preferred Resource Plan?

3. Environmental

EfficiencyOne requests clarification on the following questions regarding NS Power's environmental assumptions:

- Does NS Power expect to sell excess GHG credits resulting from lower emissions? If yes, how will the cost of carbon (e.g. the market price of carbon reductions) be captured in the modeling process. Will revenues from the sale of carbon credits be accounted for in the revenue requirement calculation for each scenario?
- Is NS Power considering the CO2 emission hard caps as laid out in slide 17 of the assumptions set as business-as-usual? Will the Sustainable Development Goals Act be considered in a business-as-usual scenario?
- EfficiencyOne's understanding is that current air quality regulations go out to 2030. What causes the drop in emission hard caps for SO2 (slide 24) and mercury (slide 25) in 2035?

4. Calculation of DSM Avoided Costs Through a Preferred Resource Plan

EfficiencyOne understands that avoided costs due to DSM will be handled in the IRP as follows:

- Avoided energy and avoided capacity costs will be an output of the IRP, calculated through a difference-in-revenue-requirements (DIRR) method;
- Avoided transmission and distribution (T&D) costs will be an input to the IRP, extrapolating values calculated based on historical growth-related T&D expenditures; and
- Avoided costs of environmental compliance will be inherently included in the avoided energy costs, as any revenues or expenses associated with the sale or purchase of carbon credits would be included in the IRP as fuel-related costs.

If any part of the above description is incorrect or undecided, EfficiencyOne requests that NS Power provide clarification before the IRP modelling process proceeds.

<u>Importance of the Preferred Resource Plan</u>

It is critical that an output of the IRP is a Preferred Resource Plan. EfficiencyOne presumes this would be the highest ranked CRP based on the evaluation criteria NS Power has provided. EfficiencyOne understands the selection of a Preferred Resource Plan to be one of the primary objectives of an IRP. In correspondence to NS Power in the course of the 2014 IRP process, the Nova Scotia Utility and Review Board stated:

> "The value in conducting a long term IRP exercise is its ability to consider the potential impact of all decisions both to add capital and to add DSM over the longer term. The reference to test that in future decisions is the Preferred Resource Plan. Without a Preferred Resource Plan against which to test decisions, there is a risk uneconomic decisions may be made. That is the whole point of the exercise."[1]

Importantly, the selection of a Preferred Resource Plan is necessary for the calculation of DSM avoided costs of energy and capacity. During the stakeholder session on 7 February 2020 (Q&A Session – Assumptions), NS Power clarified that a) the Reference Plan, referenced in their Draft Analysis Plan is not the Preferred Resource Plan , but a business-as-usual resource plan, and b) this Reference Plan would be used to calculate the avoided costs of DSM, by comparison to the highest-ranked plan. Since DSM would be included in a business-as-usual plan, this will drastically underestimate the avoided costs of DSM, which play a critical role in the approval and evaluation of DSM investments.

This problem is clearly illustrated by the example of the business-as-usual CRP being the winning CRP. If this were the case, the DSM energy and demand savings, as well as annual revenue requirements would be identical in both the Preferred and Reference plans. In any given year, the avoided costs would be calculated as the difference in revenue requirement between the plans (a difference of $0) divided by the difference in savings (a difference of 0 GWh and 0 MW). Therefore, the avoided costs would be zero, which is clearly producing a flawed outcome.

EfficiencyOne strongly recommends the following:

- A single Preferred Resource Plan is an outcome of the 2020 IRP.

EfficiencyOne requests the following:

- NS Power to clarify whether or not there will be one highest-ranked CRP identified as an outcome of the 2020 IRP process.
- If there will not be one winning CRP (i.e. a single Preferred Resource Plan) as an outcome of the 2020 IRP process, please describe how DSM avoided costs will be calculated.

[1] M05522, November 5, 2014 Board correspondence to NSPI.

Difference-in-Revenue-Requirements Method

Avoided energy and avoided capacity costs were calculated through a DIRR method in the 2014 IRP and is the standard industry practice.[2] Two CRPs are necessary for the calculation using this method– the 'winning' Preferred Resource Plan, which presumably will include DSM as it is the lowest-cost energy resource, and a Reference Plan that contains no new DSM. Persistent load effects of past DSM should be present in all CRPs in equal proportion, so any plan with "no DSM" should be interpreted as no *new* DSM.

This method requires selection of a comparator CRP that does not include DSM. In theory this should be the highest-ranking CRP that does not contain any DSM, as it would be the optimal resource plan if all DSM activities were halted and would therefore provide the best estimate of the avoided costs. An alternative is to back out any DSM from the Preferred Resource Plan and re-run the generation optimization within, but this is less desirable as it will not produce an optimized No New DSM plan, and will therefore overestimate the avoided costs of DSM.

EfficiencyOne recommends the following:

- DSM avoided costs of energy and capacity to be calculated through a DIRR method through comparison of the Preferred Resource Plan and the highest-ranked CRP without any DSM.

Avoided Transmission and Distribution Costs

EfficiencyOne understands that the transmission and distribution systems are not being modeled in the IRP, and thus their avoided costs cannot be produced via a DIRR method. EfficiencyOne further understands that transmission and distribution costs will be an input for the IRP modelling. As of 2016, NS Power has calculated avoided transmission and avoided distribution costs and shared them with EfficiencyOne and the DSMAG. Along with the figures themselves, NS Power has shared a general description of the method to develop the estimates, but not the calculations themselves.

[2] Baatz, B. Everyone Benefits: Practices and Recommendations for Utility System Benefits of Energy Efficiency, ACEEE June 2015, at Page 5, para. 2.

As of February 2019, NS Power has been aware of an error in the avoided T&D calculations it had been providing to EfficiencyOne and the DSMAG since 2016, which appears to result in the avoided costs being understated by a factor of 30 to 100, as estimated by Paul Chernick in February 2019[3]. Multiple requests by EfficiencyOne and Synapse in filings before the UARB have requested the error to be addressed.[4] To date, NS Power has not addressed the issue, other than to say that "the methodology for calculating the avoided costs of transmission and distribution due to DSM will be discussed during the IRP process, but NS Power expects the outputs of this calculation will be outside of the IRP model".[5]

Excerpts from EfficiencyOne's reply to stakeholder comments on its 2019 RBIA are included here, which explain the significance of the problem, and its relationship to the 2020 IRP. To be clear, unless this issue with respect to T&D avoided costs is addressed urgently in the context of the IRP, there exists the strong potential for sub-optimal amounts of DSM to be selected through the IRP process, by virtue of an underestimation of avoided costs.

> "EfficiencyOne estimates that with avoided T&D costs on the low end of Paul Chernick's estimate, an additional 15 MW of DR potential would be economic and achievable by 2045 (including behind-the meter battery control and behavioural DR). Additionally, for energy efficiency measures, these potentially more accurate avoided T&D costs would produce total avoided costs on the order of 50 percent higher overall (energy, capacity, and T&D combined), with the result that current achievable potential may be underestimated in a material manner. This would translate to the four Potential Study scenarios used as an input to the 2020 IRP potentially being higher, with the result that more DSM be included in the Preferred Resource Plan. This, in turn, would inform and result in a higher target level of investment for future DSM Plans."

> "Through discussions with NS Power, EfficiencyOne understands that the error in avoided

[3] Resource Insight Inc., *Memorandum Re: Comments on RBIA Enhancements*, 11 February 2019.
[4] M09471, E-1, 2019 Rate and Bill Impact Analysis, Filed October 31, 2019, at Pages 31-33. M09471, E-3, Comments of Synapse Energy Economics, Filed December 5, 2019, at Page 1. M09471, E-6, 2019 Rate and Bill Impact Analysis Reply to Stakeholder Comments, Filed December 19, 2019, at Pages 1-5.
[5] M08929, NS Power, Integrated Resource Planning (IRP) Draft Terms of Reference

T&D costs identified by Paul Chernick exists. As stated in EfficiencyOne's 2019 RBIA: "If they cannot be produced through the upcoming 2020 IRP it is recommended that NS Power update and correct the values produced outside of the IRP and provide the full calculations to the DSMAG for review".[6] EfficiencyOne supports Synapse and Resource Insight's view that NS Power must provide the corrected avoided T&D costs, as well as their full calculations. EfficiencyOne urges that these corrections be addressed and reviewed by all stakeholders prior to the initiation of modelling the 2020 IRP."

EfficiencyOne strongly recommends the following:

- NS Power correct the error in their current calculation of T&D avoided costs described above, prior to them being used as an input in the 2020 IRP.
- NS Power provide stakeholders the calculations and full description of the methodology of the corrected T&D avoided costs to be used in the 2020 IRP.

5. DSM

On slide 11 of the Assumptions deck, NS Power proposes to shift the DSM Potential Study scenarios ahead to a starting year of 2023 and replace 2020-2022 with the current 3-year supply agreement.

EfficiencyOne understands the motivation to align the near-term years of the IRP to current expectations. EfficiencyOne recommends an alternative approach, wherein in lieu of "shifting" DSM ahead – the 2021 and 2022 years of the Potential Study scenarios are replaced by their respective amounts contained within the 2020-2022 Supply Agreement, and the remaining years are held constant (on an incremental basis, as opposed to cumulative). This is due to the sensitivity the DSM Potential Study has to predicted temporal conditions. For example, building stock forecasts that drive participation (in part), are based on temporally sensitive Statistics Canada data that varies by year.

[6] M09471, Exhibit 1, EfficiencyOne, 2019 Rate and Bill Impact Analysis and Model [October 31, 2019] at page 33, line 7-9.

To maintain the fidelity of the DSM Potential Study, EfficiencyOne strongly recommends NS Power consider the above approach.

On slide 11, NS Power also indicates that the DSM Potential Study cases are assumed to include:

- Cost-effective electricity efficiency and conservation activities provided by the franchise holder
- Initiatives that may be pursued by NS Power as permitted under the Public Utilities Act
- Consumer behaviour and investments
- Energy efficiency codes and standards
- Initiatives undertaken by other agencies
- Technological and market developments

EfficiencyOne wishes to clarify that the DSM Potential Study contains only the impacts that result from programmatic DSM (bullet one, and potentially bullet two above in the case of Demand Response).

"Consumer behaviour and investments", as well as "technological and market developments" are removed from DSM Potential Study through the use of net energy savings (i.e. free-riders are excluded from savings estimates). The aforementioned factors are reflected within base load forecast quantification via the NS Power Load Forecast.

Savings attributed to "energy efficiency codes and standards" are also explicitly subtracted from DSM Potential Study savings through a sub-model within the broader DSMSim model. This sub-model allows for the calculation of effects on programmatic DSM as a result of likely future Codes and Standards.

As EfficiencyOne has the exclusive franchise for certain DSM activities in Nova Scotia, other agency direct involvement in electricity DSM is considered immaterial in Nova Scotia, outside of the regulated environment.

As described above consumer behaviour and investments, energy efficiency codes and standards, initiatives undertaken by other agencies, and technological and market developments are part of NS Power's Before DSM load forecast, which EfficiencyOne understands is currently the case. EfficiencyOne requests that NS Power confirm these factors or alternatively provide appropriate support for any contrary position.

EfficiencyOne recommends the following:

- The 2021 and 2022 years of the Potential Study scenarios are replaced by their respective amounts contained within the 2020-2022 Supply Agreement, and the remaining years are held constant (on an incremental basis, as opposed to cumulative).

6. "Before DSM" Load Forecast

For the purposes of the IRP, EfficiencyOne understands that NS Power is using a 2019 "Before DSM" Load Forecast. EfficiencyOne is unclear whether the 2019 "Before DSM" Load Forecast as filed by NS Power with the NSUARB on April 30, 2019 is being used directly or if it has been modified in some way.

EfficiencyOne has concerns if NS Power is using the as filed 2019 "Before DSM" Load Forecast because it does not exclude all DSM.

Each year NS Power produces a load forecast that includes a scenario called "Before DSM". NS Power has stated on the record that its "Before DSM" scenario includes roughly half of DSM but continues to use the term "Before DSM".[7]

In NS Power's annual "Before DSM" Load Forecast, EfficiencyOne understands that forward-looking DSM has been introduced through the use of USEIA data from the US Northeast in the NS Power Load Forecast, a geographic area with high levels of DSM activity. Precedent exists for the process of removing future DSM influences (from USEIA data) from the load forecast of a

[7] M09191, N-1, 2019 Load Forecast, Filed April 30, 2019, at Pages 38-40.

Canadian utility, namely through work undertaken by BC Hydro in 2011, which may be useful to review.[8]

In addition, EfficiencyOne has reviewed the base load forecast NS Power presented in slide 8 of the assumptions set, and has the following questions:

- In comparing the "Before DSM" scenario to the 2019 load forecast it appears that load has been increased (i.e. 2029 load increased from 11,797 GWh in the 2019 load forecast to ~12,300 GWh). Please fully describe all modifications that were made to the 2019 load forecast for use in the IRP. Please clarify in particular, whether all embedded DSM has now been removed from the "Before DSM" scenario (our position is that it must be removed, or the load forecast will be artificially low).
- Have the DSM Potential Study scenarios been modified in any way, other than the "shift" that has been applied to account for approved DSM activity in 2021 and 2022?
- Please provide an excel version of the base load forecast including DSM scenarios (slide 8) and peak demand forecast including DSM scenarios (slide 9) from the assumptions set.

7. DSM and Risk

At the IRP Analysis Plan Technical Conference, there was a discussion regarding conducting a sensitivity analysis around DSM performance; namely, investigating a scenario where DSM savings were reduced and spending was held constant.

EfficiencyOne submits that the notion of DSM as a "risky" resource option is antiquated, and not supported by modern experiences. Moreover, DSM can serve to mitigate risk from supply-side options, making it a valuable risk reduction tool, as described below:

> "DSM evolved during the 1970s as economic, political, social, technological, and resource supply factors combined to change the electricity sectors' operating environment and its outlook for the future. Ever since then there have been staggering capital requirements for new plants, significant fluctuations in demand and energy growth rates, declining financial performance of electric utilities, power

[8] BC Hydro IRP Appendix 2B – DSM/Load Forecast Integration, August 29, 2011, at page 17.

> producers and energy service providers, and regulatory and consumer concern about rising prices. DSM has been viewed as an effective way of mitigating these risks when it was invented and still viewed so today."[9]

NERC also provides comments relating to the issue:

> "DSM resources lead to reductions in supply-side and transmission requirements to meet total internal demand. They can be considered in long term planning exercises as a supplement to long-term planning reserves, and provide operational reliability through operating reserves and flexibility. DSM resources can also be used to manage the risk associated with construction and operations of traditional supply-side resources as well as a variety of new operating characteristics associated with variable renewable resources."[10]

In addition, at the energy consumer-level, DSM can serve as a hedging mechanism to exposure to future energy price risk.

EfficiencyOne requests that DSM variability be excluded from sensitivity runs exploring supply-side risk. Although complex, it may be beneficial to explore its risk mitigation effects through examining the effects of supply-side risk with and without DSM as part of the IRP as well.

8. Resource Options Study

EfficiencyOne requests the following:

- Please provide details on the assumption "access to firm capacity via new transmission build up to ~800 MW firm". What is the basis for this assumption, what are the estimated costs, and will the costs be included in modelling? Will this assumption be used in all scenarios or only a high transmission scenario? EfficiencyOne assumes that significantly different scenarios such as this one will produce a broad range of transmission and distribution costs which should be considered in the overall cost of each study.

[9] Gellings, Clark, Evolving practice of demand-side management, Journal of Modern Power Systems and Clean Energy 5, 1-9 (2017).

[10] NERC, Data Collection for Demand-Side Management for Quantifying its Influence on Reliability, December 2007, at Page 1.

9. Demand Response

Upon reviewing the Assumptions for Demand Response (DR), EfficiencyOne has concern associated with separating individual DR options from each of three DR cases analyzed as part of the DSM Potential Study, as suggested in the assumptions methodology. Each of the three market potential cases for DR should be treated as one trajectory for DR spending and savings. DR programs are highly interrelated, as described by Navigant in their DSM Potential Study Report:

> For achievable potential estimates, Navigant accounted for participation overlaps among different DR options offered to the same customer class through a participation hierarchy represented in Figure 10-17.
>
> The participation hierarchy helps avoid double counting of potential through common load participation across multiple programs and is necessary to arrive at an aggregate potential estimate for an entire portfolio of DR programs. CPP is considered lower in the hierarchy than the incentive-based options. The hierarchy order is based on the dispatchability of the options and the reliability around the load reductions, with the most reliable and dispatchable resource placed at the top and the least reliable resource at the bottom.[11]

This interdependence produces unreliable estimates of potential when scenarios are disaggregated, or aggregated with other resource options. This, in combination with the temporal continuity of the DR Potential cases (i.e. marketing and recruitment phases, steady-state phases, re-marketing phases present) results in the diminished utility of modelling the DR cases as a resource option (or some DR options as resource options, some as load modifiers).

EfficiencyOne recommends the following:

- modelling the three DR Potential Study cases as load modifiers throughout the entirety of the period, potentially as "drivers" within the analysis plan context.

10. Other Questions

[11] M08929, N-1, 2019 DSM Potential Study, Filed August 14, 2019, at Page 98.

Following is a list of additional questions, some of which were previously raised in the TOR stage and deferred by NS Power to the Analysis Plan stage:

- Does NS Power plan to do any stochastics and if so, on which variables?
- How will end effects be handled in the IRP model?
- How are Municipal Electric Utilities modeled? How much load and peak demand is included in the load forecast for MEUs, and will any adjustments need to occur?

Closing

EfficiencyOne thanks NS Power for the opportunity to comment on the draft Analysis Plan and Assumptions Set and looks forward to continued work with NS Power and stakeholders.

Attachment A: Comments from Energy Futures Group

ENERGY FUTURES GROUP

energyfuturesgroup.com

NSP 2020 IRP Draft Analysis Plan

1. How NSP will use E3's RESOLVE model in combination with PLEXOS LT Plan

We're unclear how NSP intends to use both PLEXOS LT Plan and RESOLVE. Both models perform capacity expansion modeling and both models have their limitations, especially with respect to storage resources. Specifically, our questions are:

- Is there a particular situation in which NSP expects to use RESOLVE and why?
- If both models are used in a given scenario, how will each be used?
- How would the results of both models be combined, if at all?

2. Use of PLEXOS ST Schedule

Since PLEXOS is a market model, resources are dispatched against a market price rather than against load. Since there is no meaningful market for energy in Nova Scotia NSP has said to us in prior conversations that it intended to arrive at a market price that is akin to the shadow price of each portfolio it models. We understood this to be an iterative process that would necessitate the use of PLEXOS ST Schedule to derive an accurate shadow price. Further, NSP acknowledged the issues that PLEXOS LT Plan has with simulating resources, particularly highly chronologically dependent ones and said it would rerun all portfolios in ST Schedule. We'd like to clarify that this is still indeed what NS Power intends to do and, if so, clarify why the "operability screening" is a necessary additional step.

3. Release of modeling information

Does NSP plan to provide modeling information to stakeholders after the conclusion of all analysis phases or will modeling be shared in between the phases? We believe that in order for this process to be a collaborative one with stakeholders, NSP can't wait until the end of the process to share input/output files with stakeholders. Sharing modeling files early on will help ensure that stakeholders' concerns and questions can be addressed while the modeling is being finalized.

4. Proposed evaluation criteria

Based on the information NSP provided for its proposed evaluation criteria, it is not clear how NSP intends to use the different metrics to evaluate the different portfolios or what each metric is measuring. EFG believes that NSP should not assign weights or color codes to the evaluation criteria. Doing so is inherently arbitrary – weights can be assigned to make any portfolio rise to the top and are entirely subjective. It would be much more meaningful to stakeholders to provide the actual values measured by each metric so stakeholders can see explicitly how each portfolio compares. Furthermore, if any of the evaluation criteria are going to be used to screen out portfolios, NSP should advise stakeholders of this now, rather than waiting for the conclusion of the modeling. In order to ensure clarity on the meaning of the metrics we also seek more information regarding the 10 year NPV Revenue Requirement to look at the magnitude and timing of electricity rate effects. Will NSP attempt to calculate rate impacts by class and if not, why not? And will system costs be translated into annual revenue requirements instead of, for example, carrying charges which would smooth out the rate impact?

5. Unit sizing and derivation of avoided costs

We view the IRP as fundamental to the construction of the avoided costs for screening future DSM. NSP doesn't intend to run PLEXOS so that it captures all the benefits of DSM, e.g, avoided transmission and distribution costs and non-energy benefits. But it can give an avoided energy and capacity stream of costs that can be used for DSM screening. Therefore, it is very important that each scenario also have a concomitant run with no future DSM, i.e. no incremental DSM additions. It is also important that the model inputs be flexible enough to "right-size" supply-side additions as additional DSM is added. This can be done by modeling new resources in small chunks, e.g. 10 – 25 MW or by iterating runs to arrive at the portfolio that least overbuilds NSP's system.

NSP 2020 IRP Draft Assumptions

6. Natural gas pricing

We're interested in some additional specifics around NSP's gas pricing:

- In the past, PIRA has refused to allow stakeholders to see its price forecasts even under NDA, will that be an issue here too?
- What are the specific assumptions around pricing and timing for a new pipeline in Nova Scotia?
- What are the specific assumptions are liquefaction and transportation costs for LNG?
- Will the gas price forecast capture the seasonal differences (winter versus summer) in natural gas prices?
- Why wouldn't NSP model at least a sensitivity that is pegged to New England gas prices since that is the primary way it can currently procure natural gas?

Introduction

On February 14th, 2020, NS Power released a study conducted by Energy+Environmental Economics ("E3") titled "Deep Decarbonization in Nova Scotia: Phase 1 Report", as well as a document titled "Draft Scenarios & Modeling Plan". EfficiencyOne understands the E3 document (referred to as the "Decarbonization Study") is intended to inform electrification assumptions in the IRP, and that the Draft Scenarios document provides an indication of what scenarios may be modeled in the IRP.

EfficiencyOne offers its comments on these two documents in the following sections of this submission, which should be considered as additional and incremental with respect to the comments submitted by EfficiencyOne on February 14th, 2020.

EfficiencyOne's recommendations are summarized as:

1. Quantitative comparisons of revenue requirements across electrification "scenarios" not be conducted due to incompatibility.
2. NS Power select one electrification scenario on the basis of perceived likelihood of each electrification scenario occurring.
3. NS Power select a Preferred Resource Plan from within the 'most likely' electrification scenario (electrification is included in the 2019 NS Power Load Forecast and EfficiencyOne considers it to be one of the electrification scenarios along with moderate and high).
4. NS Power confirm E1's understanding of modifications to the 2019 load forecast based on the items outlined in section 1.3.
5. NS Power confirm E1's understanding of electrification assumptions based on the items outlined in section 2.0.
6. NS Power confirm that the levels of achievable, cost effective EE and DR in the 2019 DSM Potential Study are likely underestimated for the electrification scenarios being considered in the IRP, as E1's Potential Studies are based on levels of electrification assumed in NS Power's 2019 Load Forecast.
7. The suggested EE and DR pairings represented in Table 1 form the EE and DR scenarios for the 10 cases as proposed.

8. Enhanced analysis take place for EE and DR combinations contained within high-performing Candidate Resource Plans, with the consultation of EfficiencyOne.
9. NS Power confirm EfficiencyOne's understanding of how T&D avoided costs will be addressed.

1.0 E3 Pathways Report: Electrification Scenarios

1.1 Purpose of Electrification Scenarios

Following the filing of NS Power's 2019 Load Forecast on April 30, 2019, the NS Government ("the Province") passed the *Sustainable Development Goals Act* (SDGA), which includes a goal of achieving net zero greenhouse gas (GHG) emissions by 2050. The degree to which electrification will be used in a Provincial strategy to achieve this economy-wide goal is unknown. EfficiencyOne understands that NS Power did not consider the electrification assumptions in their 2019 Load Forecast (e.g. electric vehicles, solar, heat pumps etc.) to be at the level required to meet the subsequent provincial net zero by 2050 goal. In other words, NS Power is assuming that in order for the Province to meet their SDGA goals, electrification in significantly higher levels than was assumed in the 2019 Load Forecast may be required. EfficiencyOne agrees with the examination of higher levels of electrification, given the uncertainty around how SDGA legislation will be translated into GHG regulations for the electricity system. EfficiencyOne understands that NS Power intends to treat electrification as a load modifier in the 2020 IRP using the electrification scenarios outlined in E3's Decarbonization study.

As currently planned, NS Power intends to model various levels of electrification without considering any related utility costs. The electrification scenarios developed in E3's Decarbonization study are essentially "scenarios" within which NS Power will explore different generation, energy efficiency (EE) and demand response (DR) resource options. As Synapse correctly pointed out at the Feb 27 technical conference, since the utility costs of electrification will not be accounted for in the Revenue Requirement, it would be inappropriate to quantitatively compare the resulting revenue requirements between any two CRPs that rely on different electrification assumptions. EfficiencyOne agrees with Synapse that comparability will be problematic across different electrification scenarios, as the partial revenue requirements will exclude any electrification program administration and incentive costs as well as transmission and distribution costs, which are expected to vary significantly between electrification scenarios. It will also exclude costs that are external to the electricity system (e.g. federal incentives), which are different for each electrification scenario, and likely necessary to achieve the GHG targets the electrification scenarios were designed to achieve.

EfficiencyOne recommends:

- Quantitative comparisons of revenue requirements across electrification scenarios not be conducted, as the comparisons will be not be meaningful since any two plans occupying different "Scenarios" do not truly compete against each other.

1.2 Selecting a Lowest-Cost Plan for DSM Purposes

Given that EfficiencyOne requires a single avoided cost value for each of energy and capacity, as stated in previous comments, the selection of a single Preferred Resource Plan (PRP) (i.e a CRP with the lowest 25-year Revenue Requirement) is an essential IRP activity for EfficiencyOne. Through the 2014 IRP the NSUARB reinforced the importance of choosing a single PRP against which future decisions can be compared, calling it "the whole point of the exercise".[1]

While EfficiencyOne recognizes the value of modelling differing electrification scenarios, it should be noted that this modelling decision seems likely to complicate the selection of a PRP. Since the IRP will consist of three different electrification scenarios (including the reference electrification scenario), there will essentially be three PRPs, with each representing the highest-ranking Candidate Resource Plan within each of the three electrification scenarios. NS Power has committed to ultimately choosing a single 25-year Revenue Requirement minimized plan; however, it is not clear to EfficiencyOne on what criteria NS Power intends to make this decision, or how IRP model results will produce information that helps NS Power make this decision.

[1] M05522, November 5, 2014 Board correspondence to NSPI

With this issue in mind, EfficiencyOne recommends that:

- NS Power select one electrification scenario on the basis of perceived likelihood of each scenario occurring. This determination should be made by NS Power and E3, with opportunity for comment and input from Stakeholders.
- NS Power then select a PRP from within the 'most likely' electrification scenario.

EfficiencyOne believes the above to represent a fair and transparent means of PRP selection.

1.3 Addition of Pathways Electrification to Load Forecasts

EfficiencyOne has the following current understanding of the mechanics associated with modifying the 2019 Load Forecast for the effects of electrification from the Decarbonization study:

- NS Power will first remove the 40% of future EE & DR from the 'before DSM' scenario from the 2019 Load Forecast, while retaining lasting impacts of previously-delivered programs.z
- NS Power will look to the E3 Decarbonization study to ascertain the level of incremental electrification associated with both the Moderate and High electrification cases from the E3 study. NS Power will then adopt consistent inputs associated with those cases, within its 2019 Load Forecast end-use model to produce a modified 2019 Load Forecast that accounts for electrification, before EE and DR. No data from the Pathways model will be directly used.

If any part of that understanding is incorrect, EfficiencyOne requests that NS Power clarify in response.

2.0 E3 Pathways Report: General Clarification

In addition to the above recommendations, EfficiencyOne requests confirmation of its understanding on the following points:

- The E3 Pathways Study is agnostic toward the level of costs, mechanisms (i.e. policy designs), and delivery entity/ies for electrification scenarios.

3.0 Treatment of EE and DR in Draft Scenarios and Modelling Plan

As evidenced by the E3 Decarbonization study – energy efficiency has a large role to play in any potential decarbonization approach, and in addition, the 2020 IRP provides the first opportunity for systematic evaluation of demand response techniques in a Nova Scotia IRP context.

3.1 Inconsistent Modelling of DSM Resources

The available potential of each form of DSM explored in this IRP (EE, DR and electrification) is highly dependent on the assumptions for the other forms of DSM. For example, a scenario where all oil furnaces are converted to heat pumps has vastly more potential for heat pump energy efficiency (e.g. higher COP, better cold climate performance) than a scenario without that level of electrification.

EfficiencyOne's 2019 EE and DR Potential Studies assumed a single electrification forecast; that assumption came from NS Power's 2019 Load Forecast. Therefore, all four scenarios of EE and DR (Low, Base, Mid, Max Achievable) assume the same level of electrification. This was intentional, as the scenarios were designed to only vary the ratepayer-funded impacts from EE and DR while holding all else equal.

E3's Decarbonization study took a markedly different approach, modeling economy-wide emissions and allowing many parameters to vary between scenarios in order to achieve a specific total emissions reduction profile. In order to achieve that profile, high levels of energy efficiency had to be paired with high levels of electrification. However, NS Power's intent is to extract only the electrification impacts from the study for use in the IRP model as load modifiers. These electrification scenarios, which all require very "significant energy efficiency"[2] in order to meet

[2] Nova Scotia Power Inc, Deep Decarbonization in Nova Scotia: Phase 1 Report, February 2020, At Page 17.

net zero 2050 targets, will be paired in the IRP model with the EE & DR scenarios from EfficiencyOne's potential study, which were all based on much lower levels of electrification. EfficiencyOne understands NS Power will also require the IRP model to meet the mandated GHG emission reductions from (or similar to) the Decarbonization study[3]. The result, for any CRP with more electrification than the 2019 Load Forecast, will be that:

a) The levels of EE & DR will be artificially low, as Navigant simply did not model EE & DR scenarios based on such high levels of electrification; and that
b) The levels of non-emitting supply side options may become artificially high, as the IRP model will likely fill the gap with low-carbon or zero carbon generation to serve the high electrification loads, under GHG emissions constraints that Pathways chose to serve with EE (presumably on the basis of cost). These foregone DSM activities may well have been cost-effective when measured against non-emitting supply side options.

It would be possible, through a DSM Potential Study, to model different electrification, energy efficiency and demand response together, producing scenarios that properly account for the interactive effects between the three. However, it seems the best path forward for the 2020 IRP, given the current data and desire to explore electrification scenarios, is to allow the four DSM Potential Study scenarios to be paired with the three electrification scenarios, while acknowledging that the resulting CRPs will not contain truly optimal levels of electrification, EE, DR or renewables.

3.2 Pairing EE & DR Scenarios with CRPs

It is important to recognize the number of possible solutions has gone from three in the 2014 IRP (Low-Low, Base, High), to 16 in the 2020 IRP, accounting for differing combinations of DR and EE. The existence of three electrification scenarios further constrains the level of possible analysis in each given IRP "scenario". EfficiencyOne notes that sufficient exploration of EE and DR in this context will be challenging, but is essential given that the 2020 IRP will inform DSM-decision-

[3] *Ibid, Page 3.*

making on a go-forward basis through the general IRP results, and the development of avoided costs.

With the above in mind, and recognizing a full exploration of the EE and DR solution space may not be possible given the sheer number of possible cases to be explored, EfficiencyOne is suggesting EE and DR pairings for the proposed scenarios as follows, as well as suggesting three additional combinations for consideration:

Table 1 - Suggested EE and DR Scenarios for Inclusion

Case Number	Scenario	Driver	EE Scenario	DR Scenario
1A	Comparator	Current Landscape	Base	Base
2A	Net Zero – High Electrification	Current Landscape	High	High
2B	Net Zero – High Electrification	Distributed Resources Promoted	High	High
2C	Net Zero – High Electrification	Regional Integration	Base	Base
3C	Net Zero – Moderate Electrification with Early Coal Closure	Regional Integration	Mid	Base
4A	Net Zero – Moderate Electrification	Current Landscape	Mid	High
4B	Net Zero – Moderate Electrification	Distributed Resources Promoted	Mid	High
4C	Net Zero – Moderate Electrification	Regional Integration	Base	Base
5C	Absolute Zero World	Regional Integration	Mid	Base
5D	Absolute Zero World	No New Emitting Resources	Mid	High
1A-2	Comparator	Current Landscape	Mid	High
2C-2	Net Zero – High Electrification	Regional Integration	Mid	High

4C-2	Net Zero – Moderate Electrification	Regional Integration	Mid	High

EfficiencyOne developed the above pairings with a focus on generally exploring differing levels of EE and DR, while at the same time suggesting pairings that may be more likely to be aligned with the existing scenario and driver (e.g. high electrification, high EE, and high DR).

Following the emergence of clear high-performing Candidate Resource Plans, EfficiencyOne requests that additional exploration of optimal EE and DR levels be conducted. EfficiencyOne can provide recommendations on priority inclusions for this enhanced analysis, should all 16 EE and DR case combinations not be possible to model.

These two recommendations, should they be adopted, will provide sufficient exploration of EE and DR for stakeholders to assess.

EfficiencyOne recommends:

- The suggested EE and DR pairings represented in Table 1 above form the EE and DR scenarios for the ten cases as proposed as well as the three additional scenarios.
- Enhanced analysis take place for EE and DR combinations contained within high-performing Candidate Resource Plans, with the consultation of EfficiencyOne.

4.0 Avoided Costs of Transmission and Distribution

There is general agreement from NS Power that the T&D avoided costs will be addressed as part of the overall IRP process and NS Power will establish a separate process for this aspect of the IRP. EfficiencyOne understands that NS Power will develop a process, with involvement from stakeholders, to calculate the avoided cost of T&D, and consider the development of an approach and alternate methodology than currently exists for the calculation. This process will occur in parallel with the IRP and will conclude during the course of the IRP. EfficiencyOne appreciates this effort and looks forward to participation in the process.

NS Power expects to be able to calculate avoided T&D costs on a narrower set of Candidate Resource Plans later in the IRP process and sharing those with stakeholders. EfficiencyOne also understands that these costs cannot be calculated using the IRP model and will not be an input to the IRP model.

Finally, EfficiencyOne wishes to reiterate the importance of accurate avoided costs of Transmission and Distribution be provided. A number of key work products, analysis and planning decisions depend on the accurate assessment of all avoided costs, including Efficiency Nova Scotia's Rate and Bill Impact Analysis.

All of which is respectfully submitted

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February 14, 2020

Re: M08929 – Integrated Resource Planning – IRP Assumptions for Renewable Energy Resources and Considerations for Distributed Energy Resources

Dear Ms. Godbout and Ms. Fris:

Envigour Policy Consulting Inc. has been retained by QUEST and Marine Renewables Canada as their consultant in this matter. We have participated in the discussions regarding assumptions and have had the opportunity to explore the role of Distributed Energy Resources in contributing to Nova Scotia's transition to a lower carbon future.

We are generally supportive of Nova Scotia Power's approach on these matters, but our client, Marine Renewables Canada would take issue with some assumptions regarding instream tidal energy future costs and their concern over the modelling of the evolving value of offshore wind. This submission will outline the areas where we believe the modelling should reflect different assumptions. We will also elaborate on our client QUEST's research, findings and expectations on how to account for the emerging role of DER.

Bruce Cameron
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c.c. Tonja Leach, Executive Director QUEST
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Current and Future CAPEX for Instream Tidal Resources

Definition of Technologies Considered

Unlike conventional hydro or tidal barrages, Instream tidal devices exploit the speed of the tidal currents rather than the height of the tidal range. As such they are completely different technologies with respect to economics, environmental impacts and form of deployment. Accordingly, for the purposes of the IRP, cost comparisons between instream tidal devices and tidal range or hydro dams are irrelevant, and potentially misleading.

Types of Tidal Devices and their Deployment

In Nova Scotia, current and proposed licence and permit holders have technologies that roughly fall into three categories:

Large Scale

DP Energy's Uisce Tapa Project with 6 1.5 MW Andritz Hammerfest Hydro turbines for a total deployment of 9 MW at FORCE[1]. The project is similar to the Maygen project in Scotland, the world's first array with bottom mounted turbines.

The former Cape Sharpe Project with 2 MW OpenHydro turbines was also large-scale with turbines mounted on the bottom. The project was abandoned when the parent company went bankrupt.

Small Scale

Sustainable Marine Energy (SME) is using its PLAT-I floating platform and SCHOTTEL Hydro's turbines to build a smaller scale project. Each PLAT-1 platform will have multiple turbines with a total capacity of 420 kw on each PLAT-I for their Pempa'q Project at FORCE[2]. The first phase will use 3 PLAT-I for a total of 1.26 MW with plans to build up to 9 MW at FORCE. SME is currently refining designs for PLAT-I next generation through testing in Grand Passage.

Nova Innovation is working toward a 1.5 MW tidal energy array in Petite Passage. The first 500 kw deployment will be split into two phases[3]. Nova Innovation has the distinction of completing the world's first tidal array project. It has extensive experience with bottom mounted smaller scale turbines., Their first project in the Shetland Islands consisted of 100 kw bottom-mounted turbines.

Unconventional

Big Moon Power has a Demonstration Permit to test a 100 kw device in the Minas Passage and a second Permit which will allow the company to grow the project to a total of 5 MW and sell power to NS Power at a rate of \$0.35 kwh[4] which implies a CAPEX of well below \$10 m per MW. Big Moon is using a unique system of a barge connected by cables to a land-based generator where the barge moves the cable as the tidal current ebbs and flows.[5]

[1] https://www.dpenergy.com/projects/canadauiscetapa/
[2] https://sustainablemarine.com/news/pempaq-project
[3] https://www.novainnovation.com/petitpassage
[4] https://novascotia.ca/news/release/?id=20180412001
[5] https://marineenergy.biz/2018/02/06/big-moon-power-outlines-bay-of-fundy-tidal-plans/

Jupiter Hydro also holds a Demonstration Permit for a non-grid connected 1 MW device and a Permit to 2 MW with electricity connected to the grid and sold to NS Power at $0.50 kwh[6] at a site near, but not at FORCE. Jupiter uses helical screw[7]s to capture the force of the tidal current to drive a generator. The technology is surface mounted.

Global Industry Perspective

Given the wide range of technologies and approaches being tested/demonstrated in Nova Scotia it is not easy to establish cost structures and direction for change over the course of the next decade. However, a 2018 Market Study[8] report by industry group, Ocean Energy Europe to the European Union, provides insight into global trends and energy thinking. This report suggests significant declines in cost as technology deployments take place. They also see a significant increase in deployments, with the most pessimistic case still delivering 700 MW of capacity globally by 2030. Table 13 of thier report shows as technology matures to a Technology Readiness Level (TRL) between 7 and 9 (with 9 being completely commercialized) deployments in the 5 to 20 MW range are expected to have a capital cost per MW of 4.3 m Euros or $6.4 million.

Those costs represent the average of all technologies. Those using unconventional approaches and technologies argue their costs will deliver projects below that, although those arguments have yet to be proven. However, the small-scale technology developed by Schotell Hydro and deployed on Sustainable Marine Energy floating systems has had years of experience and offers the following statement for the development of IRP assumptions:

"There are many variables to consider, many of which are unknown at this stage, but the simple assumption that we use in our internal forecasting is that we can achieve a learning rate of 15%. We feel this is fairly conservative when industries like wind (onshore and offshore) have achieved 16-18%, and of course once a technology reaches maturity this rate slows down a bit, but I don't see us reaching this point by 2030.

So if you were to look at just our technology and plans, and assumed that we could continue deploying capacity in the Minas Passage beyond our current project, and assume a constant deployed rate of ~5MW/year after we get the initial 9MW deployed, then we could feasibly get down to ~$3.5m/MW by the time we have ~100 units deployed (have also not taken into account any scaling of the size of the systems.

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[6] https://marineenergy.biz/2018/02/06/big-moon-power-outlines-bay-of-fundy-tidal-plans/
[7] http://jupiterhydro.com
[8] https://www.oceanenergy-europe.eu/wp-content/uploads/2018/07/KL0118657ENN.en-1.pdf

Year	MW deployed	Cumulative deployed	Cum no. Units Deployed	CapEx/MW (mCAD)	CapEx/ unit (mCAD)
2021	1.26	1.26	3	10.00	4.20
2022	2.52	3.78	9	7.73	3.25
2023	5.04	8.82	21	5.97	2.51
2024	5.04	13.86	33	4.90	2.06
2025	5.04	18.9	45	4.41	1.85
2026	5.04	23.94	57	4.10	1.72
2027	5.04	28.98	69	3.88	1.63
2028	5.04	34.02	81	3.71	1.56
2029	5.04	39.06	93	3.57	1.50
2030	5.04	44.1	105	3.46	1.45

Envigour then, on behalf of MRC suggests that maintaining a $10 m CAPEX estimate out to 2030 is not sustained by evidence that is specific to the instream tidal sector. Furthermore, the underpinning of the NS Power consultant's assumptions that tidal technology deployed and to be deployed in Nova Scotia is equivalent to a custom-designed hydro project is in fact erroneous.

Furthermore, although any and all predictions about future prices 10 year out will in fact likely be wrong, and even though the cost of instream tidal will likely still be above the cost of other renewables at this point, this technology has its own unique advantageous (predictable energy flows and production times), and a post 2030 future may need all developable renewable energy resources to meet climate change goals. In that case it would be prudent to accept that there could well be a case for continued development and an outcome as outlined by SME. Therefore, we suggest the IRP use the lower number of $3.46 m CAPEX per MW for 2030, and we further suggest NS Power watch global volume deployments and cost decline history closely in the next decade.

Value of Offshore Wind

The IRP assumptions call for a decline in capex over the next decade, and we have discussed the numbers used with our colleagues in America and we find no issue with the numbers per se.. However, we are raising the issue of whether the modelling will capture the full value that comes from the growth in the size of the offshore wind towers, blades and turbines.

GE is now producing what it calls the world's most powerful offshore wind turbines.[9] With a capacity factor of 63%, we believe this is would likely offer significant additional value to the NS electricity system. Our concern is that the model captures this value as well as the gross decrease in the levelized cost of energy. It would be helpful to the process if NS Power and/or its consultant could provide explicit assurance the modelling will capture the value of such a high capacity factor.

[9] https://www.ge.com/renewableenergy/wind-energy/offshore-wind/haliade-x-offshore-turbine

Considerations for Distributed Energy Resources

QUEST and Pollution Probe collaborated on an assessment of the pace of change in energy technologies and the ability of the policy and regulatory frameworks to adapt. [10] Envigour was the lead author of this report entitled: Canada's Energy Transformation – Evolution or Revolution? A Discussion Paper for Canadian Policymakers, Utilities, Regulators and Key Stakeholders on Managing Risk and Creating Opportunities as We Build Low-emission Energy Systems.

This report documents the rapid rise in innovation for energy systems driven by a public policy desire to reduce carbon emissions that contribute to climate change. With the desire to develop new cost-effective technologies and new business models has come dramatic cost reductions – at a pace that was unanticipated just a few years ago. Many of the changes are associated with distributed energy resources which we have defined in the report as technologies for energy efficiency, renewable and other local supplies of energy, energy storage and management, and microgrids (including electric vehicle charging stations).

We submit the report and its extensive referencing/documentation for energy prices and trends to the IRP through the link noted below as footnote 10. With this submission we also provide a caution: the numbers referenced are now nearly a year old and the references need updating. This is not a weakness in our submission, but rather the main point: the major challenge we face when considering the price and value of all renewables and carbon-reduction technologies, including DER is that many of the variables are in constant motion.

Technology prices decline as production and deployments become more wide-spread e.g. L-ion battery prices decline as EV production using those batteries grow, new technologies emerge that disrupt the incumbent technologies (e.g. Lithium-ion or L-ion batteries vs emerging flow batteries or the use of low cost zinc particles for storage), and new business models and pairing of technologies result in new possibilities stand-alone EV chargers may cost more than networked ones. A heightened emphasis on the need for <u>rapid</u> achievement of low carbon goals drives innovation from the lab to consumers more quickly than ever.

Above all, businesses may catch the attention of consumers to find unexpected value in their technologies driving rapid rates of adoption. The possible pace of change can be seen in the evolution of the iPod into the iPhone into the more general smartphone and the explosion of applications over the course of just one decade.

The needs of the market may change as well. For example, as weather conditions become more variable, stressing the outer limits of the grid to manage, and outages become more frequent, even if only for a few hours at a time, resiliency and reliability become more important. Those values may lead to a more rapid uptake in batteries/storage. Consumer purchases for resiliency may offer an improved business case for distributed storage to meet grid needs for demand management including peak shaving.

We recognize and submit that traditional planning that is directed top-down by utility investment and operations is being turned on its head as consumers are able to make energy choices and influence planning bottom up. Clearly this makes planning for change increasingly difficult. With rapidly changing assumptions, we need new approaches.

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[10] https://drive.google.com/file/d/1P-JkLrs2eJNVlxgtWckL7bC-mcWwJXxg/view

We also need a great deal more information on the value of new and evolving technologies. As we noted in our earlier filing for this process, it is not just a matter of monitoring price – it is also a matter of understanding the value of a technology when that price changes. For example, the current IRP should include scenarios that explore what happens when storage for days or weeks emerges – perhaps through hydrogen from renewable energy that becomes cost-effective. Knowing how this would impact other assumptions now would help us understand the value of price declines in the future. We have noted a number of technologies to monitor for value in our earlier submission.

The Role of Climate Change in Planning

First and foremost, all prudent energy planning needs to be based upon the assumption that climate change is a current and future imperative for energy policy. In Nova Scotia the Sustainable Development Goals Act[11] has set a goal of net-zero by 2050 in law. Although not specific to the electricity sector it is illogical to think that the electricity sector would be immune. In fact, most likely pathways to achieving this goal depend upon a significant amount of electrification and thus the assumption that the electricity will be net-zero carbon logically follows.

While there can and will be considerable debate about how to achieve net-zero, in practical terms that will likely require something above 85-90% carbon free, with the expectation that part of that amount or an additional amount could come from systems that contain carbon today (natural gas pipelines) but would be carrying net carbon free fuels (a combination of hydrogen, renewable natural gas and carbon offsets) by 2050, as long as the generating technologies are flexible enough to use such combinations.

Implications for Inequality

It is important to note that efforts to address climate change and the related drive for innovation in DER have implications for inequality and potential for increasing energy poverty. This comes about as energy users with capital or access to capital move to invest in their own energy systems and leave behind those in poverty.

Energy efficiency DER investments supported by ratepayers already see this inequity. Almost all cost-effective ratepayer investments are cost-effective because they leverage consumer capital investments. This dilemma for people without the means to make such investments is recognized by the taxpayer and utility investments in the Home Warming program. However, we would argue that the essential inequity remains. Low-income ratepayers must pay a share of efficiency spending without equal access to the direct program incentives. We would expect the evolving electricity rate-design and program designs to take this inequity into account, and not simply leave it in the hands of taxpayers to resolve.

Principles for Risk Reduction in IRP

Under conditions of rapid and disruptive change several principles regarding risk emerge:

First and foremost, all other things being equal, a strategy of no regrets emerges. This type of strategy would assume flexible and adaptive investments with shorter term paybacks are less risky than ones requiring long-term paybacks. A PPA with a 15 to 20-year term may turn out to be less economical than expected, but the consequences are felt for that 15 to 20 years. On the other hand, a bad investment in a project that takes 40 to 60 years to recover that investment could have adverse impacts for many decades.

[11] https://novascotia.ca/news/release/?id=20191023003

A risk adverse planning system would also take as a given that the electricity sector itself faces a net-zero energy future for 2050, and an ongoing need for additional electricity supplies. Therefore, in general, new investments in carbon-emitting resources are more risky than renewable and other clean energy technologies. This principle is not absolute - a case may be made for “peaker” natural gas generators especially ones that could be converted to hydrogen or use a combination of hydrogen and renewable natural gas.

A risk-adverse planning framework would also recognize the rise of DER results in the rise of consumer choice. Planning that includes solutions that support customer choice and an environment where third parties and utilities both compete for customer value and loyalty are preferred. Supporting customers is more realistic as change is coming and it better to embrace than resist. Supporting customers is also more likely to improve consumer satisfaction. The real risk is that a failure to anticipate, integrate, and embrace DER is likely to frustrate customers and raise the possibility of revolt.

How the Principles Influence Decisions for the IRP

From a no-regrets, risk reduction perspective, the IRP should embrace the idea that all prudent scenarios should comply with net zero by 2050 with net-zero implying a minimum of ~ 90% non-emitting supplies. It may be useful to understand the costs and consequences of accelerating that goal, but scenarios that suggest significant investments in or maintenance of significant carbon-emitting resources that have a useful life beyond 2050 should be deemed risky, imprudent and non-viable for future planning. Again our caveat is that some generators that use fossil fuels today that could become clean fuels in the future should still be considered, but the larger the scale and investment, the larger the risk. DER tends to have short-term paybacks and thus support resiliency and customer choice. These values should not be ignored or rejected when considering only lowest-cost compliant scenarios. Ones that include DER should be preferred against ones that do not, especially when the levelized costs are not far apart.

After the IRP

The IRP assumptions need frequent updating in a transparent and inclusive manner. We suggest consideration should be given to holding regular forums with input from Nova Scotia, Canadian and other experts who can contribute knowledge, experience and expertise on short to medium term commercial trends on renewables in general, and DER in particular – based upon Nova Scotia’s energy transformation, policy and regulatory frameworks. Current and future expectations of policy drivers such as carbon policies should also be examined. The output from these forums should then influence a new set of assumptions – and when those assumptions have changed in a meaningful way, the IRP should be updated.

The next five years should continue to have focus on testing programs and strategies to develop evidence for the value of current and emerging DER. Pilots to test new concepts to reduce energy poverty should also be supported. This evidence needs to be gathered and shared in a more extensive inclusive manner – particularly within communities that are planning for low-carbon futures. Building knowledge and sharing it widely is fundamental to achieving a more rapid and less costly transition to a lower-carbon future.

Smart Energy Community Policy and Technical Factors

In closing we also reference QUEST’s experience and leanings regarding the development of Smart Energy Communities. QUEST has long-standing policy and thinking on distributed energy resources and the opportunity to support the development of smart energy communities. The detailed technical and policy thinking behind their work is attached to this report.

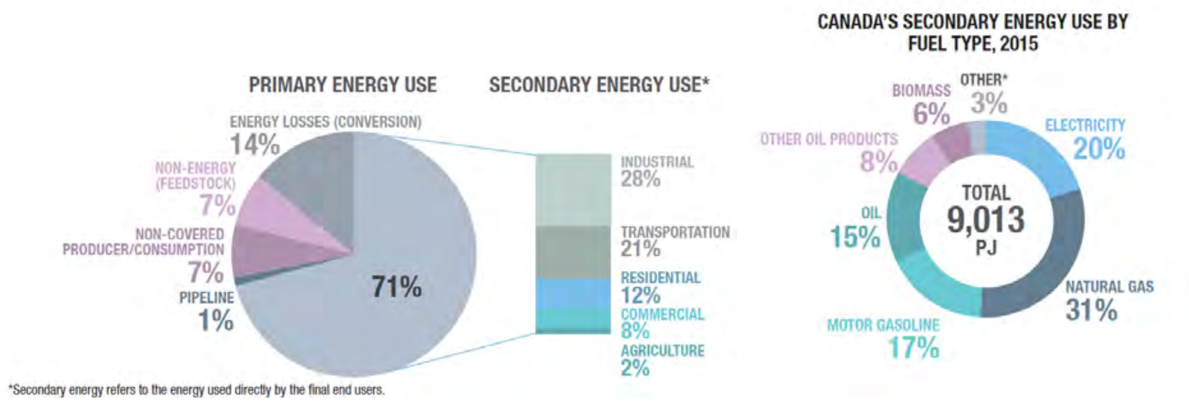
A Smart Energy Community understands the compelling challenge of climate change while recognizing the reality of community energy needs and priorities. It seamlessly integrates local, renewable, and conventional energy sources to efficiently, cleanly, and affordably meet its energy needs. By shifting the conversation toward Smart Energy Communities we start talking about what matters to Canadians in their day to day lives – more sustainable energy systems, new economic opportunities, improved local environmental quality, more resilient infrastructure, and affordability. This shift makes energy and climate policy constructive and concrete as opposed to a sometimes abstract, almost always divisive political debate.

Table 1: QUEST's Technical & Policy Principles

Technical Principles	**Policy Principles**
. Improve efficiency – first, reduce the energy input required for a given level of service	Match land use needs and mobility options – understand the energy implication of land use, infrastructure for water and wastewater, waste management, personal mobility, goods movement, and building design decisions
. Optimize exergy – avoid using high-quality energy in low-quality applications	Match energy options to local context – local climate, building on land use choices, industrial structure, availability of local sources of waste and renewables
. Manage heat – capture all feasible thermal energy and use it, rather than exhaust it	Send clear and accurate price signals – consumers should see and pay full real costs, including external costs
. Reduce waste – use all available resources, such as landfill gas and municipal, agricultural, industrial, and forestry wastes	Manage risks and be flexible – maintain technological and fuel diversity; pursue cost-effective opportunities first and incorporate learning; assume the need to adapt quickly to market and technological surprises
. Use renewable energy resources – tap into local opportunities for geoexchange systems, small-scale hydro, biomass, biogas, solar, wind energy, and opportunities for inter-seasonal storage	Emphasize performance and outcomes in policy and regulations – avoid prescribing fuels and technologies
. Use energy delivery systems strategically – optimize use of energy delivery systems and use them as a resource to ensure reliability and for energy storage to meet varying demands	Pursue policy and program stability – maintain a consistent and predictable decision-making environment to sustain investor confidence

A New Way of Framing the Issue
We are approaching thirty years from initial agreement on the Framework Convention on Climate Change in Rio in 1992 and the energy and climate discussion in Canada has only resulted in limited action. We think a useful way to frame the discussion going forward is around four "systems" or sets of issues. Two of those sets of issues - energy exports and upstream electricity production - have received virtually all of the public's attention. A third, equally important issue is the widespread implications for the resource and industrial economy, which receives little attention. All of these connect in various ways to the fourth set of issues, involving **local energy solutions** and which needs to be further explored and brought into the mainstream discussion.[1]

Local Energy Delivery and End Use
Local energy delivery and end use which has in the past been mainly about building, equipment and vehicle energy efficiency but increasingly centers on a whole different concept, what we call Smart Energy Communities.[2]



Much of the energy future is to be found in Canadian communities (large urban, medium, small rural, remote, resource-based & indigenous) where we use approximately 60 percent of our energy and emit about half of our greenhouse gases.

A new direction
We can frame the problem around six key challenges and why smart energy communities and QUEST offer real solutions:

1) Building climate change policy on a foundation of sound energy policy[3]
Almost thirty years of limited results on greenhouse gas management should tell us something is wrong. Part of what is wrong is that our climate aspirations stand precariously on a foundation of awareness of energy fundamentals that often ranges from incomplete, to wasteful and ineffective to, at worst, destructive of both public and investor confidence. Smart Energy Communities are founded on

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[1] Typically the transport sector is treated as a distinct set of issues but for QUEST local transport is embedded in the concept of smart energy communities and for purposes of this note we treat transport – transport infrastructure, energy use, emissions and related controversies and solutions - as integral to and part of the other systems.

[2] https://questcanada.org/pathways/

[3] M. Cleland & M. Gattinger, "Canada's Energy Future In An Age Of Climate Change: How Partisanship, Polarization And Parochialism Are Eroding Public Confidence", Positive Energy, University of Ottawa, March 2019

recognition that energy consumers and citizens first value the fundamental integrity of their energy delivery systems: safe, reliable, secure, resilient and affordable. Beyond that, the evidence points to communities generally placing more weight on local environmental and social issues (impacts on air, water, land and cultural heritage) than on the abstract concept of climate.[4,5] Canadians want climate solutions but they want them built on secure foundations and that is where Smart Energy Communities fit in.

2) Driving technological change while avoiding technological determinism
The objective is results, not methods. We have no way of knowing exactly what technological solutions might underlie a low emissions Canada in midcentury. We need to better understand the potential impacts of different technological solutions on utilities and other energy service providers, consumers, and investors. Rather than pushing for the latest technology, policy needs to emphasize accurate and complete price signals, setting performance standards, creating conditions for investment in infrastructure, and inviting both consumers and investors to choose options based on their particular conditions at a given point in time.[6] This principle is nowhere more evident than at the community level where local conditions are almost always unique whether due to different energy efficiency options, opportunities to manage waste heat, opportunities to make assets out of local waste (domestic, agricultural or industrial) or diverse local renewable energy options. Smart Energy Communities figure this out and select what works best for them.

3) Maximizing the value of all our assets, both existing and new
Electrification is no doubt a solution in several quarters but it is not obviously the only one in the medium term and the established energy networks - electrical, natural gas, fuels for mobility - have long lives still to live and many options for solid incremental improvement, especially building on the potential for diverse networks to work together. In any event, in a world where all the evidence tells us that new infrastructure will be risky and expensive, needing careful, deliberate discussion to bring citizens along and, inevitably, slow to build[7], we can't afford to waste what we have. Smart Energy Communities know this and use their assets accordingly.

4) Emphasizing institutional innovation
Technological change is clearly of immense importance and Canada is doing its share to create such change in our energy systems from upstream to down. But what is missing from the technological conversation is a whole field of innovation concerned with the institutions that will oversee change and deployment of new technologies. What are the right roles for local governments? How does a regulatory system that has served us well get a lot better, in terms of who decides and how, as well as how it adapts to the new business and regulatory models that follow from the emergence of new technological options? How do policy makers find answers to these questions, answers which have the weight of concurring citizens standing behind them? QUEST through focusing on Smart Energy Communities can

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[4] M. Cleland & M. Gattinger, "Canada's Energy Future In An Age Of Climate Change: How Partisanship, Polarization And Parochialism Are Eroding Public Confidence", Positive Energy, University of Ottawa, March 2019
[5] M. Cleland et al., "A Matter of Trust, The Role of Communities in Energy Decision Making", Positive Energy, University of Ottawa, November 2016
[6] https://questcanada.org/pathways/#principles Principles for Smart Energy Communities.
[7] Trottier Energy Futures Project "Canada's Challenge & Opportunity: Transformations for major reductions in GHG emissions", April 2016

and does bring all the relevant stakeholders together in ways that make the answers more apparent and with stronger and more widespread support[8].

5) Reducing policy uncertainty through alignment and sense of community
Local energy debates emphasizing all the energy related needs of local communities while adding to climate solutions and built around a shared sense of community can offer improved prospects for civil dialogue and more stable conditions for change. Smart Energy Communities, by definition, spend less time shouting at each other and more on building the future.

6) Restoring public trust and confidence in decision making institutions
It is more likely that trust and confidence will be gradually restored if citizens can see progress through decision processes that engage them and their local communities. Smart Energy Communities are also more energy literate communities and more likely to be constructive contributors to the larger energy decisions that occur outside their immediate areas of responsibility.

DERS

The power grid is considered by some to be the largest machine in the world, spanning continents and providing generated power over 100s and thousands of kilometers of wires. The power is delivered to end users at the exact second they need it, in an an incredibly balanced, complex, and synchronized manner. Despite some failures and events, it is remarkably reliable at delivering energy to us all, almost every second of every day.

However, the centralized, top-down grid and delivery system and stable business model for utilities that has endured the last century is being disrupted by a number of drivers, causing adaptation an evolution in how we produce, move, and use energy. The drivers at the community level include :

- need for local and system resilience in the face of increased climate events causing prolonged outages - causing $ to leave communities and costing utilities in outage management
- rise of smart, cleaner technologies that offer new ways to generate and manage energy at the local level - digitization, automation
- A global drive to reduce GHG emissions
- Local revenue generation and energy cost security and stability

Communities have new energy solutions available to them, changing the relationship utilities have with their customers, and their business model, as well as how energy moves on the grid, causing potential description on the balancing side of things. As generators, storage, and controls — get cheaper and more powerful," end-use customer will be able to get a major portion of their energy on-site or in the community. That touches every level of the electric system.

Challenges for Stakeholder Groups

Energy Service Providers/Utilities

- Disruption to traditional business model, potential loss of business
- Adapting business model and service offering - staying relevant
- Changing relationship with customers, tech providers
- Value proposition

[8] QUEST Smart Energy Leaders' Dialogue, Working Groups and QUESTtalks www.questcanada.org

- Alignment with customers, solutions, regulators, government, etc.
- Understanding municipal, institutional processes and governance
- Matching the right solutions

System Operators, Regulators

- Disruption to the grid architecture, balance
- Ensuring right source - right place - right time
- Energy reliability, security, planning
- Existing robust systems
- Who managing distributed sources - management models

Distribution Consumer Challenges (Muni's, institutions/campuses, remote sites)

- Understanding of the technologies, its capabilities, benefits, and risks
- Understanding the energy project development process
- Different business/management/partnership model (Ownership, O&M)
- Restrictive policy or regulation
- Value proposition/ROI/financing
- Community buy-in/council approval (municipalities) - quantifying benefits
- Changes in government incentives, programs, funding, support, etc.

Developer/Solution Provider/Consultants

- Understanding municipal, institutional processes and governance
- Identifying the right solutions (popularity vs. function)
- Restrictive procurement policies
- Timing of funding programs with planning and budget cycle
- Risk adversity

Heritage Gas

February 14, 2020

Nicole Godbout
Director, Regulatory Affairs
Nova Scotia Power Inc.
PO Box 910
Halifax, NS B3J 2W5

RE: M08929 - NSPI Integrated Resource Planning – Draft Analysis & Assumptions Comments

Heritage Gas is the regulated provider of natural gas distribution service to Nova Scotia residents and businesses. Our interest in understanding Nova Scotia Power Inc.'s ("NSPI") Integrated Resource Plan ("IRP") is its interplay with overall long-term energy planning for the next 25 years in the province.

Heritage Gas has been attending stakeholder meetings and workshops with NSPI, Energy+Environmental Economics ("E3") and other stakeholders throughout 2019 and 2020. On January 28, 2020, NSPI held a stakeholder session to address the Draft Analysis Plan where Heritage Gas and others had the opportunity to listen, comment, and provide feedback.

Following that stakeholder session, Heritage Gas and NSPI met independently to discuss the Draft Assumptions Set for the IRP, of which Heritage Gas' comments were generally in relation to the following topics:

- **Electrification load contribution to peak load.**
    - Heritage Gas sees it as imperative to incorporate the contribution of newly electrified technologies (i.e. EV's, heat pumps, etc.) in the calculation to peak, both in terms of system build-out and GHG contributions. Heritage Gas sees a significant potential opportunity over a 25-year period for the natural gas distribution system to relieve some of the upward pressure on the electrical system peak. Heritage Gas understood from NSPI that E3 was developing an assumptions set and alternative options for electrification scenario modelling which would be provided to stakeholders for review and comment. Heritage Gas looks forward to receipt of this information.
- **Coal plant conversions to natural gas.**

Heritage Gas

- Heritage Gas received confirmation from NSPI that the final supply side modelling assumptions will include coal-to-gas conversion and that although the base loaded gas price assumptions (slide 78) refers to 100,00 MMBtu/day the model will not have a specific supply constraint on natural gas.

- **Continued use & reliability of Combustion Turbines ("CTs") within NSPI's fleet.**
  - Heritage Gas received confirmation that new natural gas-fired CTs would be included in the supply options and available to the model, and that NSPI would be considering the reliability over the IRP study period of existing CTs from a fuel security, general reliability and start-up perspective, potentially in the proposed reliability screening or earlier phases of the IRP.
  - NSPI also indicated it would review the CT Sustaining Capital costs in its February 3, 2020 slide 95 revision as against its original January 20 assumptions set and provide explanations for the changes, particularly in light of the vertical axis revisions. Heritage Gas looks forward to the receipt of this information.

Heritage Gas appreciates the continued open and collaborative process with all stakeholders to date on this IRP. While various other issues related to the above matters were discussed with NSPI, Heritage Gas felt it appropriate to highlight the foregoing points for all stakeholders at this stage in the process. We look forward to the continued dialogue on the inputs, modelling, analysis, screening and planning stages of the IRP, including receipt of the final detailed data assumptions to be used in the upcoming modeling stages.

Kindest Regards,

John Hawkins

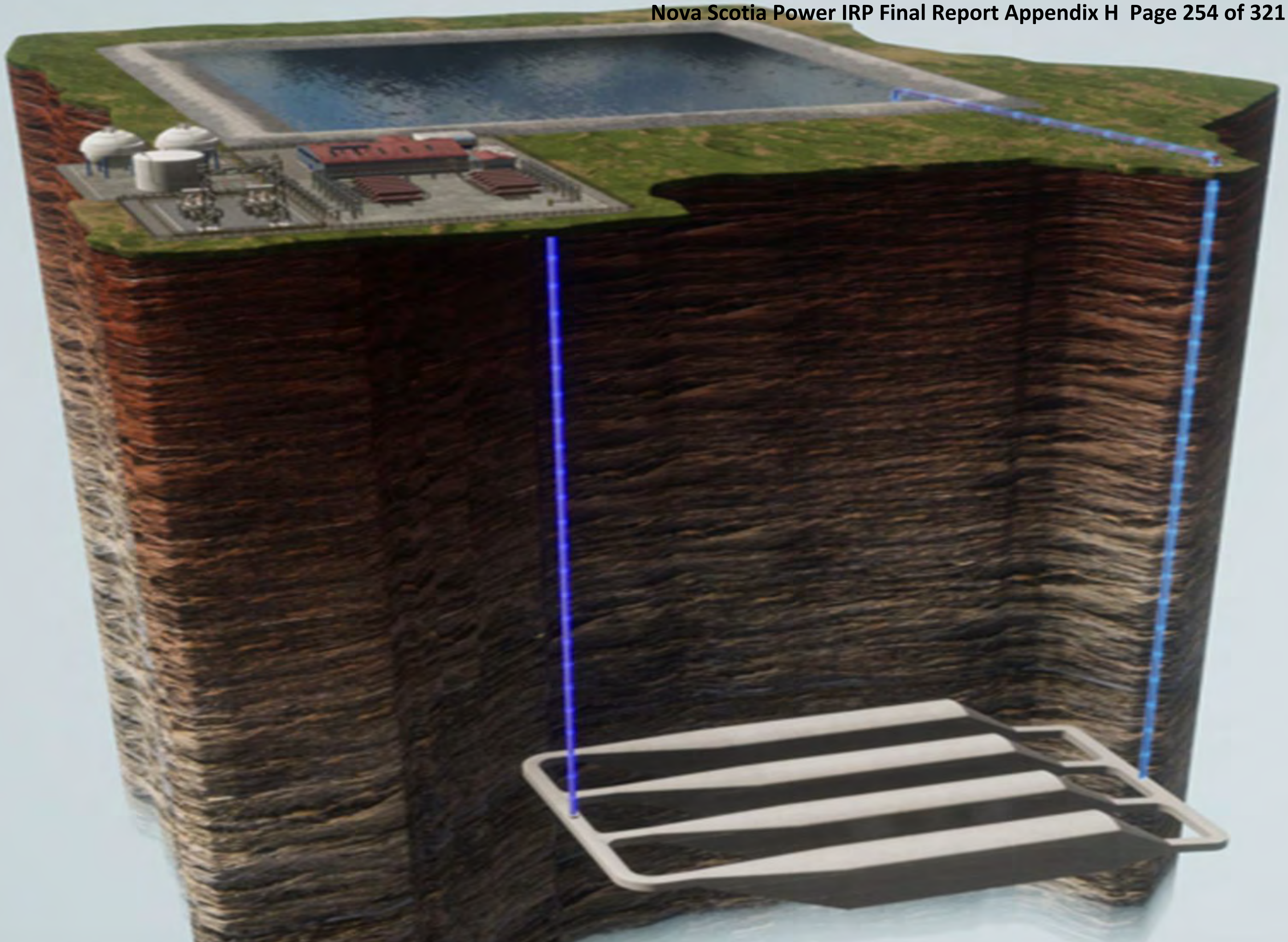
cc: M08929 Participants

To: Nova Scotia Power (NSP) – Integrated, Resource Planning Team
From: Jon Sorenson, Hydrostor
Re: Advanced Compressed Air Energy Storage (A-CAES)

As communicated on our teleconference, Hydrostor, provides Advanced Compressed Air Energy Storage, which is a patent pending technology that can be incredibly advantageous to Nova Scotia Power in its Integration Planning effort, as you retire assets, focus on renewable energy but must have balance and reliability with new intermittent connected assets. Please see attached pdf included in the download and please note the following for some of the benefits of the Hydrostor technology:

- **Siting Flexibility:** A-CAES assets can be sited flexibly, meaning they can be constructed at the site of decommissioned / decommissioning coal plants to take advantage of the existing robust interconnection capacity and provide dispatchable generation where it is required (unliked pumped hydro which might).
- **Superior Economics:** To replace the reliability provide by coal plants through the use of energy-storage assets, long storage durations are required (8–12+ hours). With very low marginal costs for storage capacity, the economics of A-CAES are superior to alternative storage solutions for providing these long-duration reliability services at scale.
- **Analogous Grid Security Services:** Similar to coal-fired power stations, A-CAES facilities generate power using synchronous generators, meaning they provide all of the same grid security services previously provided by traditional generators, such as synchronous inertia, reactive voltage support, and system strength / fault-current contribution, as well as providing a higher power quality, without harmonics (unliked inverter-based generation). A-CAES systems can even operate their generators as synchronous condensers when they are not otherwise generating, providing these security services on an uninterrupted basis.
- **Flexible Capacity for Grid Balancing:** With abundant storage capacity and flexible turbomachinery, A-CAES assets can operate through a wide range of net power export to balance the grid. As an example, a system with a 500-MW charge rating and a 500-MW discharge rating, could operate across a 1000-MW range (500 MW import to 500 MW export) to balance supply and demand, effectively integrating abundant amounts of low-cost, intermittent renewable generation (e.g. on- or off-shore wind), while maintaining reliability and security of supply.

Additionally, we believe that a portfolio based on A-CAES and wind generation would be capital intensive but would have much lower operating costs relative to something based on flexible gas-fired generation. This means that the NSP rate base / regulated asset base, on which you typically earn a rate of return, would be greater, while still offering a highly competitive cost of supply to all of your customers. This model would be a better economic model for rate payers as you would not be passing through the costs of the gas that your purchase without any approved mark-ups for administrating the gas. If NSP can only earn profits on their capital assets, in the form of a regulated rate of return, then the deployment of wind combined with A-CAES makes strong economic sense to both the utility and the rate payers.



HYDROSTOR

Advanced Compressed Air Energy Storage:
Technical Inputs Summary

January 2020

Table of Contents

Executive Summary

Hydrostor has undertaken extensive research, development, and prototyping, leading to the development of Advanced Compressed Air Energy Storage (A-CAES). This technology is now one of the leading bulk-scale energy storage solutions globally. Much like traditional compressed air energy storage (CAES) systems, the technology functions by using electricity to compress air into underground caverns, storing the energy for later use. Later, when energy is required, the air is released back to the surface, where it drives a turbine, generating electricity.

Innovative A-CAES Technology

Traditional CAES technology has been around for over forty years: the first CAES plant was developed in Huntorf, Germany in 1978 and is still in operation. The implementation of CAES, however, has been hindered by two major impediments:

1. Much of the energy used to compress the air in the process is wasted, leading to the need to burn natural gas to heat the air that is used to drive the turbine and generate power onto the grid; and
2. The caverns used to store air for traditional CAES can only be deployed cost effectively in domal salt formations, which are rare and not necessarily aligned with the areas where energy storage is required.

Hydrostor's innovations enable A-CAES to recycle much of the energy consumed during charging, enhancing its efficiency, eliminating the need for natural gas combustion in the process, and facilitate the development of air storage caverns in many geologies, including both salt and common hard rock.

When a CAES system charges, compressing air into the storage cavern, both the pressure and temperature of the air increase. In traditional CAES, the heat that is developed (the "heat of compression") is exhausted to the atmosphere, as the air cannot be stored at high temperatures. This wastes much of the energy that is used to compress the air. Later, when the plant is discharging and the air flows through the turbine, both the air pressure and air temperature decrease. To provide adequate power to the turbine, the air must be heated through the combustion of natural gas, generating emissions and exposing the plant to volatile natural gas prices or costly long-term gas supply contracts. To address this issue, A-CAES systems are designed to capture and store the heat of compression for later re-use during discharging.

Traditional CAES systems store air in fixed-volume salt caverns. The pressure within the cavern increases as more air is pumped into the same volume and decreases as air is released. Both the cavern and the turbomachinery—the compressors and turbines—have limits on the operating pressures within which they can operate. The resulting range of acceptable pressures limits the amount of air that can be compressed into or extracted from the cavern, reducing the volumetric energy density. Consequently, these caverns must be developed for very low prices per unit of volume in order to be cost effective, which can typically only be accomplished in domal salt formations, through a process called solution mining. Because these salt formations are rare, this greatly limits the geographic range within which these systems can be developed, preventing the use of CAES for bulk-scale energy storage in many high-value applications.

A-CAES, in contrast, uses the principle of hydrostatic compensation to maintain a constant pressure within the storage cavern. This is accomplished by connecting the cavern to a water reservoir at surface level through a large conduit, resulting in a flooded cavern pressurized by the weight of water. As air is compressed into the cavern, it displaces water up the conduit and into the water reservoir. As air is released from the cavern, the water floods back into the cavern, displacing the air to the surface. Throughout each process, the movement of water into and out of the cavern results in a near-constant pressure within the cavern. This hydrostatic compensation greatly enhances the volumetric energy density of these caverns, enabling systems to use caverns with a higher capital cost per unit of volume excavated. Taking advantage of this, Hydrostor A-CAES can be developed cost effectively in most geologies, using mined hard-rock caverns.

Once constructed, A-CAES systems operate in much the same manner as natural gas–fired generating stations and, through the use of analogous turbines, can deliver the same suite of ancillary services and capacity, without any greenhouse-gas emissions. Specifically, A-CAES systems can provide frequency regulation, spinning and non-spinning reserve, demand response, voltage support, synchronous inertia, and black-start capability, serving as an effective replacement for much of the traditional fossil fuel–fired generating stations that are being decommissioned—forced out of operation by increasingly stringent environmental regulations, including carbon pricing, and an inability to compete with low-marginal-cost generators such as wind and solar.

Importantly, A-CAES operation is a mechanical process and is not plagued by the same issues inherent to inverter-based generators based on electrochemical reactions, such as batteries and photovoltaic solar: A-CAES performance does not degrade over its lifespan, there are no depth-of-discharge restrictions, and the system does not cause damaging harmonics on the grid when generating power. The caverns and turbomachinery employed by A-CAES can have a 50+ year asset life with appropriate maintenance.

While the current A-CAES design is already capable of being deployed at industry-leading capital costs, with strong performance characteristics, flexible siting, and a long lifespan, Hydrostor's technical team continues to collaborate with its consultants and suppliers to identify opportunities for improvement. Through these efforts, Hydrostor has already identified a list of viable value-engineering opportunities, which it is currently pursuing, and continues to add to this list. These efforts will result in steady improvements in capital and operating costs, technical performance, delivery schedule, and siting flexibility.

A-CAES Overview

Hydrostor's A-CAES technology is uniquely suited to enable the transition to a cleaner, more reliable electricity grid. As a flexibly-sited, long duration, and synchronous storage resource, A-CAES provides grid services that, in aggregate, are not readily replicated by other storage technologies. It is a highly flexible and customizable tool to address bulk electricity system needs for dispatchable capacity, renewable integration and grid optimization, and as such it is already finding application globally as a near-term resource with a well-proven supply chain to directly replace fossil fuel plants and act as a cost-effective transmission alternative.

A-CAES delivers low-cost, long-duration bulk energy storage (hundreds of MW's, 4-24+ hours) that is 100% emissions-free and can be flexibly located where required by the grid. It does so with large-scale rotating generators that deliver traditional grid stability services sought by utilities such as spinning reserves, voltage support, and synchronous inertia, while also being able to deliver reliable capacity (resource adequacy) as a long duration storage resource. Importantly, A-CAES can typically be constructed in places where other forms of large-scale synchronous storage cannot (like pumped hydro and traditional CAES) and provides grid benefits that other forms of non-synchronous storage cannot (like batteries).

A-CAES utilizes standard, off-the-shelf equipment that has been rigorously deployed in a variety of other applications and industries (e.g. pipeline compressor and let-down stations) and is supplied exclusively by Tier 1 original equipment manufacturers (e.g. Baker Hughes is a global leading supplier of core equipment and is an invested corporate partner to the Consortium on delivery of its systems). Capital investment for A-CAES is significantly lower per kWh than other storage technologies, in part because of its significant economies-of-scale, and by combining the well-established expertise and supply chains of the mining sector with those of proven, bankable, industry-standard generating and process equipment to offer a compelling solution at scale.

Large-scale deployment of energy storage technologies has been challenged by several factors, including total installed cost, scalability, and/or geographic constraints (such as topography and footprint). In the case of traditional CAES, it has been further constrained by the reliance on burning fossil fuels. Hydrostor's A-CAES technology has been specifically designed to address these factors relying only on a well-proven supply chain and the use of standard industrial equipment/construction approaches. A-CAES is based conceptually on the same basic design and process as traditional CAES with its multi-decade operating history, and incorporates two key improvements to allow it to be emissions-free and flexibly-sited: 1) the development of a patented thermal storage system that eliminates the need for a fuel source, and 2) the construction of hydrostatically compensated, hard rock air storage caverns.

Electrical Conversion	▪ A-CAES uses standard electrically driven air processing equipment (compressors, motors, turbines, and generators) routinely used in power and oil & gas applications, where they offer exceptional reliability ▪ Tier 1 original equipment manufacturers (Baker Hughes, MAN Energy Solutions, Hanwha Power Systems) offer best-in-class warranties and performance guarantees ▪ Established supply chains and global support services for this equipment mean that they can be deployed on any scale at a competitive cost
Fuel Free Operation ***Unique to Hydrostor***	▪ Hydrostor has developed an adiabatic process, enabling fossil fuel-free and emission-free CAES ▪ The thermal management subsystem captures heat developed as the air is compressed, stores it, and reinjects it into the air on expansion, boosting electricity production and system efficiency ▪ While the system is proprietary, it relies on well-proven, industry-standard heat processing equipment available from Tier 1 original equipment manufacturers (Alfa Laval, Therco-Serck, Exchanger Industries)
Flexibly Sited Air Storage ***Unique to Hydrostor***	▪ A-CAES stores air in purpose-built mined caverns, analogous to those used for the storage of hydrocarbons, enabling siting flexibility in almost all common geologies ▪ Mined caverns are a mature storage solution with 190 deployments worldwide with design and construction by global experts (Geostock, Agapito Associates, Lane Power Solutions) ▪ Hydrostor's storage solution uses a water flooded cavern, which drastically reduces the mined volume required and enables fully recoverable, near constant pressure air storage

Figure 1: A-CAES Sub-systems

How A-CAES Works

As the A-CAES system is charged, off-peak or surplus electricity from the grid (or a renewable source) is used to power an air compressor, which converts the electrical energy into potential energy and heat stored by the compressed air. The heat generated during compression is captured by a set of heat exchangers and stored separately for later use. The air stream is compressed to match the pressure needed to inject it into a constructed underground storage cavern. Once in the cavern, the air can be stored until electricity is required.

Hydrostatic compensation (using water head, analogous to a pumped hydro facility, in order to maintain a constant air pressure underground) is provided by a surface reservoir of water, connected to the cavern through the construction access facilities (either a shaft or a helical decline, depending on geology). As air is charged into the storage cavern, water is displaced up the access decline or shaft and into the surface reservoir, storing substantial potential energy in the large elevation difference. With hydrostatic compensation, the air pressure within the cavern is maintained at a near constant level. This is essential for the efficient performance of the air handling equipment (whereas in traditional CAES the storage pressure varies significantly, which limits system efficiency and performance).

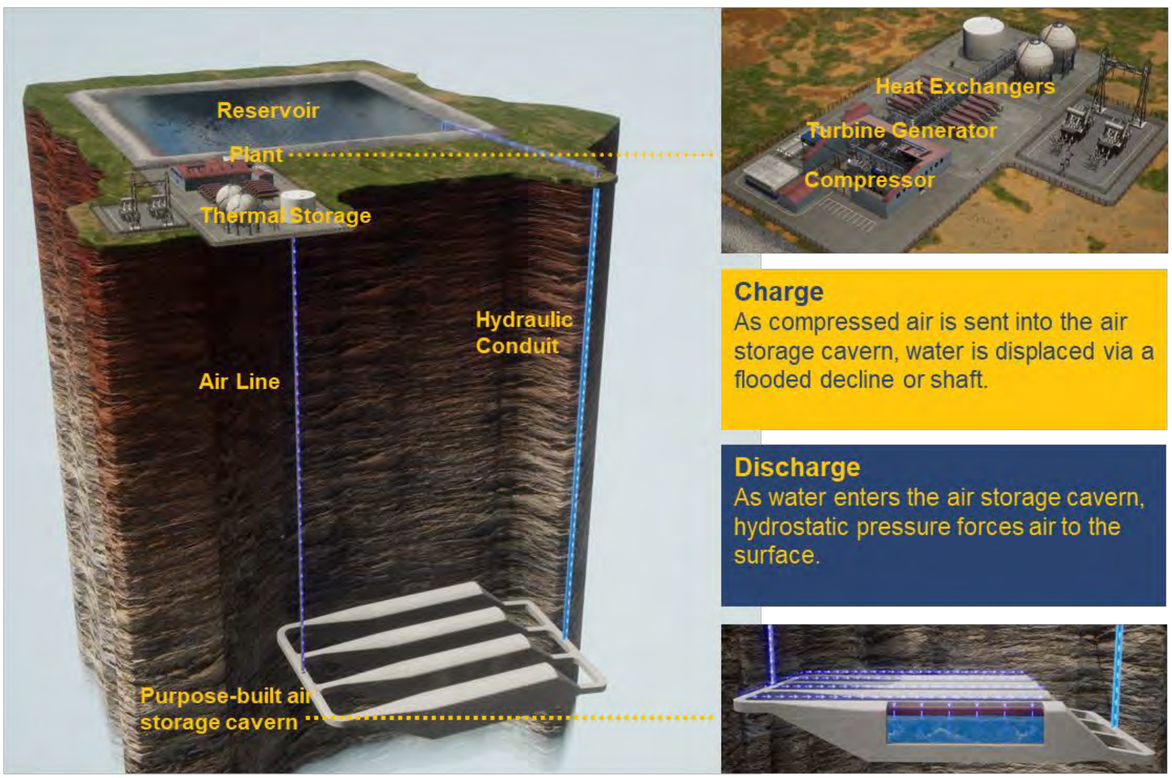
When energy is required, the compressed air is permitted to flow back to surface, which it does so under the process of the compensation water re-flooding the cavern. The stored heat is reinjected through the same heat exchangers before the compressed air is used to drive a turbine, generating electricity and supplying it back to the grid. As turbines require heat for both adequate power production and thermal protection, it is only through the use of the thermal storage system that Hydrostor's A-CAES can be fossil fuel and emissions free.

Because of the use of hydrostatic compensation, all of the stored air is fully recoverable; this is unlike traditional CAES which requires a substantial portion of the air to maintain a minimum storage pressure for either cavern protection or turbine operation. This drastically reduces storage volume requirements. Therefore, hydrostatic compensation enables Hydrostor's A-CAES to utilize economically-constructed mined storage caverns (at lower volume requirements) and benefit from the ability to be constructed in most geologies.

An animation illustrating how Hydrostor's A-CAES system works can be found at hydrostor.ca.

How Advanced Compressed Air Energy Storage (A-CAES) Works

1 Compress Air Using Electricity	2 Capture Heat in Thermal System	3 Store Compressed Air	4 Convert Compressed Air to Electricity
Off-peak or surplus electricity from the grid or a renewable source is used to operate a compressor that produces heated compressed air.	Heat is extracted from the air stream and stored inside proprietary thermal store. This adiabatic process increases overall efficiency and eliminates the need for burning fossil fuels during expansion.	Air is stored in purpose-built storage caverns where hydrostatic compensation is used to maintain the system at a constant pressure during operation.	Hydrostatic pressure forces air to the surface where it is recombined with the stored heat and expanded through a turbine to generate electricity on demand.



Industry-proven air and heat processing equipment with decades of operational history in power and oil & gas sectors.	Well-established mining techniques for storage cavern construction based on precedents of more than 190 analogous storage caverns globally.	Proven application of hydrostatic compensation and thermal management systems.

Figure 2: How A-CAES Works

Benefits of Hydrostor A-CAES Technology

The characteristics of Hydrostor's A-CAES technology provide it with a competitive advantage over other technologies in several applications. The key benefits of Hydrostor's technology are summarized below:

- **Long Asset Life:** The hard-rock caverns and turbomachines at the heart of Hydrostor's A-CAES system have exceptionally long service lives of 50+ years, with appropriate design and maintenance.
- **Project Siting Flexibility:** Hydrostor's proprietary use of hard-rock caverns for air storage untethers A-CAES from the need for sites with suitable salt formations, enabling the development of bulk storage in areas where geological, topographical, and regulatory conditions do not permit the development of traditional CAES or pumped-hydro storage projects.
- **Low Cost:** At full scale (100+ MW), Hydrostor A-CAES offers one of the lowest installed costs on a dollar-per-kWh basis available today for bulk energy storage. Notably, A-CAES has *the* lowest installed cost of any bulk energy storage solution that can be flexibly sited.
- **Proven, Reliable Equipment:** The Hydrostor A-CAES solution uses only proven equipment that has been used in industry for decades and is provided by competing Tier 1 equipment suppliers. Hydrostor has a strong supply chain relationship with these suppliers.
- **Scalability:** By using industry-standard equipment, Hydrostor leverages the significant economies of scale, well-established supply chains and expertise of the mining and oil-and-gas sectors, enabling deployment of A-CAES on a massive scale without the need to develop new supply chains.
- **Fuel and Emission Free:** Hydrostor's proprietary thermal management system is environmentally friendly, uses no hazardous chemicals, and enables fossil-fuel-free CAES, resulting in a zero-emission system with greatly reduced overall operating costs.
- **Ancillary Grid Services:** A-CAES provides ancillary services by leveraging synchronous generation to deliver voltage support whilst also providing frequency regulation where required for improved power quality, as well as offering black-start capability.
- **Synchronous Generation:** Hydrostor A-CAES utilizes large-scale rotating synchronous generators (and motors) that deliver traditional grid stability services sought by utilities, including voltage support and synchronous inertia[1], while also reducing damaging harmonics produced by battery and solar PV inverters. As thermal generation facilities retire, removing synchronous generators from the grid, A-CAES can play a vital role in minimizing impacts to the grid by delivering these essential services, often in the very same locations as the retiring assets.
- **Flexible, Dispatchable Capacity:** Hydrostor's technology can help maintain system reliability as the penetration of intermittent generators, like wind and solar, increases and as thermal generators are retired. Hydrostor A-CAES has the flexibility to provide fast ramp rates and long-duration dispatchable capacity to meet the increasingly unpredictable requirements of the grid more cost effectively than gas-fired generators. The system can also be paired directly with large intermittent generators to optimize renewables integration and avoid curtailed power output.
- **System Design Flexibility:** Charge, discharge, and storage capacities can be set independently of each other to optimize system design, reduce costs, and maximize efficiency. In addition, modularity in design (i.e., using several smaller units versus one larger unit) and equipment selection allows for built-in redundancy and the ability to operate over a wider range, depending on the system's intended use.

1. Synchronous inertia refers to the rotational inertia of a spinning synchronous generator that is coupled to the electrical grid and its resistance to changes in grid frequency which are caused by supply and demand imbalances. This resistance results in a reduction in the rate of change of frequency, affording grid operators time to correct before an outage.

Technical and Performance Specifications

The performance of Hydrostor's A-CAES is similar to other rotating power generation equipment such as natural gas–fired facilities. Specific performance metrics for a typical full-scale (100+ MW) A-CAES project are shown in Table 2. Many of these metrics can be optimized to meet project requirements.

Table 2: Performance Specifications & System and Site Specifications

Summary of A-CAES Performance Specifications		Performance(1)
Response Time	Time from signal to charge (electrical power consumption)	3-5 min
	Time from signal to initial discharge (electrical power generation)	5 min (2)
Response Time with Hybrid Battery	A short duration battery system can provide rapid power consumption or delivery during charge and discharge response	100 ms
Synchronous Condenser Mode	Auxiliary power draw to operate the system as a synchronous condenser for continuous voltage support and provide faster response times.	0.5–2% of power rating
Parasitic Losses	Auxiliary and standby power requirements under regular (standby) operating mode.	Negligible (included in RTE)
Ramp Rate	Maximum rate of change on electrical consumption / generation	25% / min (2)
Reactive Power Delivery	Maximum reactive power during charge or discharge (3)	1.6 MVA_r/MW
	Maximum reactive power during standby in synchronous condenser mode (3)	1.75 MVA_r/MW
Efficiency	Steady-state round-trip efficiency (AC-to-AC), including all auxiliary loads, assuming daily cycle	>60%
Lifetime	Cycle life	20,000 cycles (4)
	Equipment useful life (with appropriate maintenance)	30–50+ years
Inertia, System Strength	Provided by compressor and turbine while charging, discharging, or in synchronous condenser mode	

(1) *Metrics can be optimized to meet project requirements.*
(2) *Response times can be improved to meet customer needs at FEED stage.*
(3) *Based on machines with a power factor of 0.8; reactive power delivery per machine of ~0.75 MVAr/MW during operation and ~0.88 MVAr/MW while acting as a synchronous condenser*
(4) *Cycle life can be extended with standard maintenance overhaul for turbomachinery (included in 50 year project option).*

Siting Criteria

The A-CAES surface footprint can be divided into four categories:

1. Base system: the electrical conversion equipment, thermal management system (excluding fluid storage) and building,
2. The thermal fluid storage, if utilizing an above-ground thermal storage design,
3. The surface reservoir, and
4. On-site waste rock storage, if waste rock cannot be reused or an off-take cannot be secured.

Approximate surface footprints for 100, 250, 300, and 500 MW A-CAES installations with 8 hours of discharge duration are outlined in Table 1.

Table 1: Surface Footprints for A-CAES Components (in acres)

System Size	Base System	Thermal Fluid Storage	Reservoir	Waste Rock Pile
100 MW / 800 MWh	3.3	1.5	8.4	4.1
250 MW / 2,000 MWh	6.0	3.1	14.3	10.7
300 MW / 2,400 MWh	6.9	3.8	16.0	12.9
500 MW / 4,000 MWh	10.5	6.1	22.8	21.6

Fresh, salt or non-potable water, including the use of groundwater where available, can be used as compensation water to provide hydrostatic pressure. This can be done as an open-loop system if an existing water source is nearby or as a closed-loop system with a purpose-built reservoir.

- If a nearby natural body of water is to be used for compensation:
  - Water should be accessible at high flow rates.
  - No temperature or chemical impact on water should occur in the cavern.
  - Space and easement must be available for a water channel or underground pipes.
- Otherwise, if a compensation reservoir will be constructed:
  - The area required for the surface reservoir will depend on the depth and storage capacity of the system (see table for typical requirements).
  - One-time water requirement includes necessary freeboard for closed-loop systems:
    - 100 MW / 800 MWh: 120,000 m^3 (100 acre-ft)
    - 250 MW / 2,000 MWh: 300,000 m^3 (240 acre-ft)
    - 300 MW / 2,400 MWh: 360,000 m^3 (290 acre-ft)
    - 500 MW / 4,000 MWh: 595,000 m^3 (480 acre-ft)
  - Annual top-up as required for evaporative losses. Evaporative losses are site-specific, and in some cases, precipitation exceeds evaporative losses, particularly if the pond is doubled as a stormwater reservoir for the overall site.

Geology

For a greenfield site, the subsurface location is dictated solely by the geology and geotechnical properties of the rock. For a preliminary assessment of the site, sufficient public/private data must be available, otherwise, an exploratory program, including borehole investigation, must be carried out to determine viability. More information about the requirements of an exploratory drilling program can be found in the data room.

Available data sources may include but are not limited to:

- Regional geographic mapping & cross-sections.
- Local/regional water well data.
- Local/regional borehole data.
- Local/regional geophysical data.

A FEED study of a greenfield site uses boreholes and detailed analysis to confirm existing geotechnical characteristics.

Overburden

Depending on its nature, increased overburden (unconsolidated material above bedrock) thickness can increase the cost of cavern construction. A minimal amount of overburden is preferred and a thickness of less than 50 m of overburden of any nature is considered feasible for siting depending on other costs and factors. However, overburdens which contain a high clay content or highly consolidated soils do not pose the same difficulties as loose, unconsolidated soils and can support development of caverns even with overburden depths of a few hundred meters, as long as the cavern itself is situated in consolidated rock.

Geotechnical

The subsurface components of the Hydrostor A-CAES system can be constructed and installed in a variety of geotechnical conditions. Preference is given to sites with hard-rock geology, given the structural stability and integrity of open excavations in these rock types under unsupported or minimal-support conditions.

Locations with soft-rock (lower strength rock, such as certain types of sedimentary) geology could be considered; however, considerations will need to be made for additional support to satisfy the structural requirements inside the air storage and thermal storage caverns, which may increase capital costs.

Below is a summary of geo-tech requirements to consider when siting potential A-CAES systems:

- Preference for hard-rock and high rock strength.
- Preference for rock types with low permeability.
- Preference for rock masses with minor jointing and cracks.
- Avoid crossing faults with a history of high magnitude seismic events.
- Areas with limited time dependency/swelling potential.
- Sub-surface geology where low in-situ stresses exist. Suggested max horizontal stress is 15 MPa for suitable locations.
- Avoid intersecting aquifers in the air storage region to minimize dewatering cost and avoid possible regulatory issues.

Project Capital Costs

The economies of scale that are achievable for the major components of A-CAES enable it to be a leading low-cost storage solution for large-scale (100+ MW) storage applications with a service life of over 50 years. To demonstrate the varying cost of A-CAES systems, Hydrostor has developed cost estimates for hard-rock cavern A-CAES systems ranging from 200 MW to 500 MW of discharge power capacity, with discharge durations from 4 to 12 hours, which are shown below in Figures 3 and 4 (for salt geology) and in Figures 5 and 6 (for hard-rock geology).

These numbers represent all-in capital costs, incorporating all engineering, procurement, construction, commissioning, and interconnection costs as well as substantial contingency reserves and other project-delivery costs such as bonding and insurance. Similar to the base costs above, a range of costs has been shown where the upper end of each range represents the cost at which Hydrostor can deliver projects today in average geological conditions, while the lower end of each range represents the cost at which Hydrostor anticipates delivering projects in the future—accounting for technological and project-delivery improvements—in above-average geological conditions. Further savings can be achieved in situations with brownfield infrastructure such as existing caverns or interconnection infrastructure.

Salt Geology

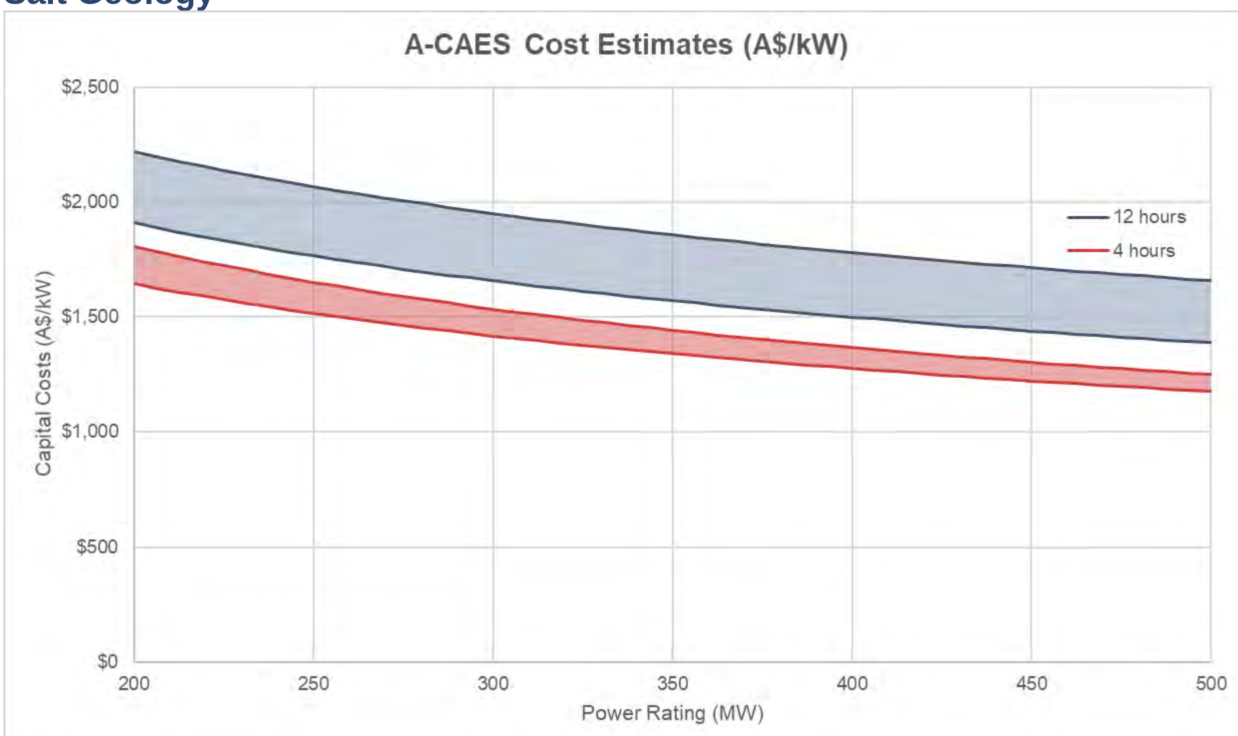


Figure 3: Salt-Based A-CAES All-in Capital Cost Estimates (US$/kW)

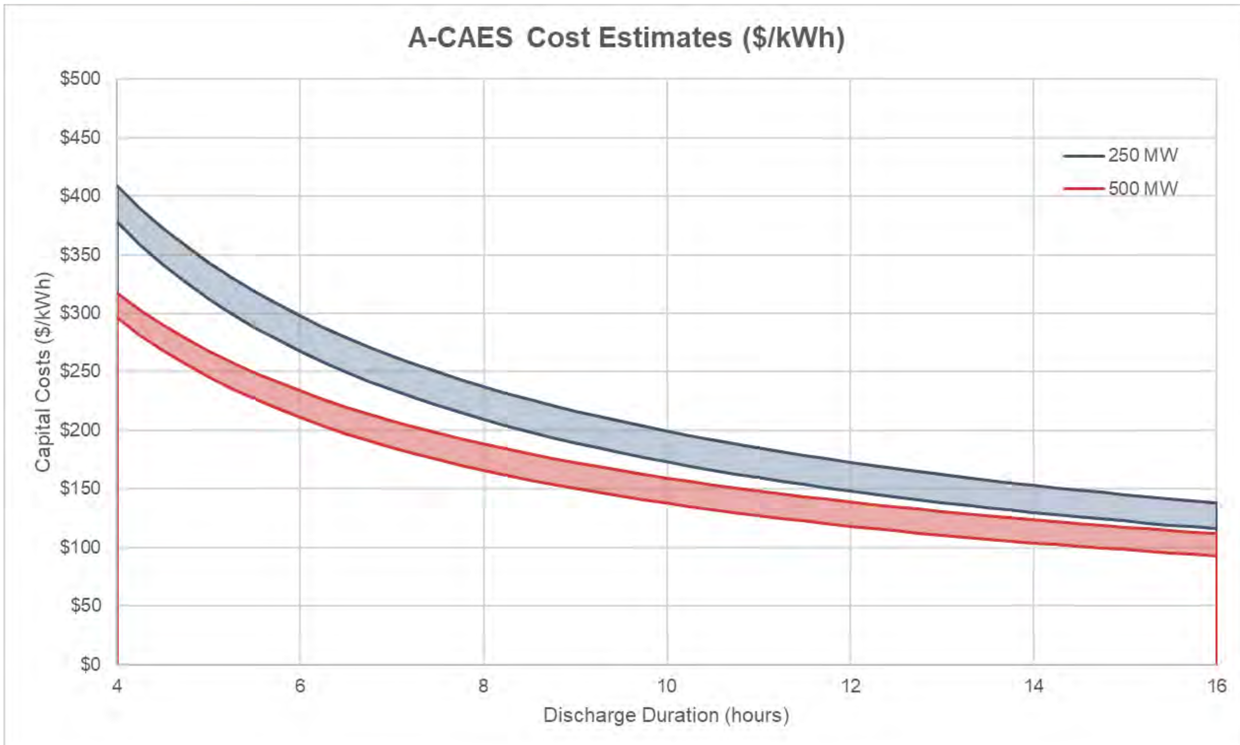


Figure 4: Salt-Based A-CAES All-in Capital Cost Estimates (US$/kWh)

Hard Rock Geology

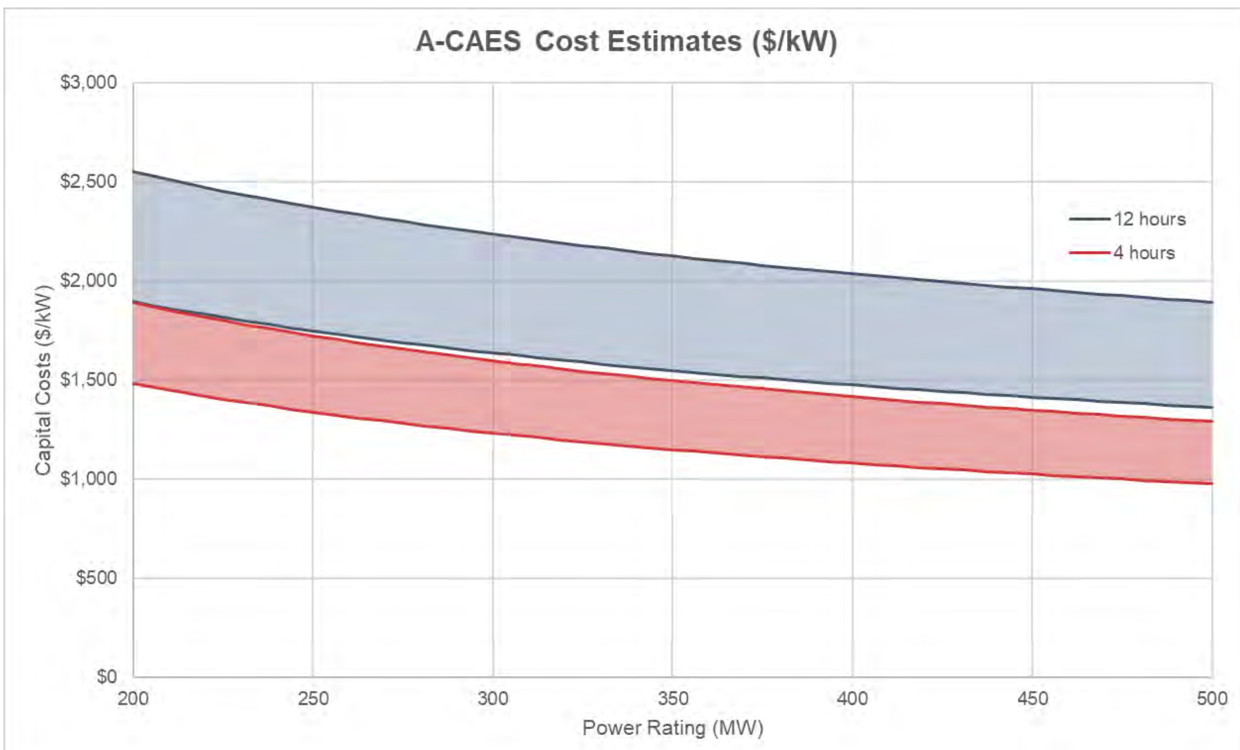


Figure 5: Hard-Rock-Based A-CAES All-in Capital Cost Estimates (US$/kW)

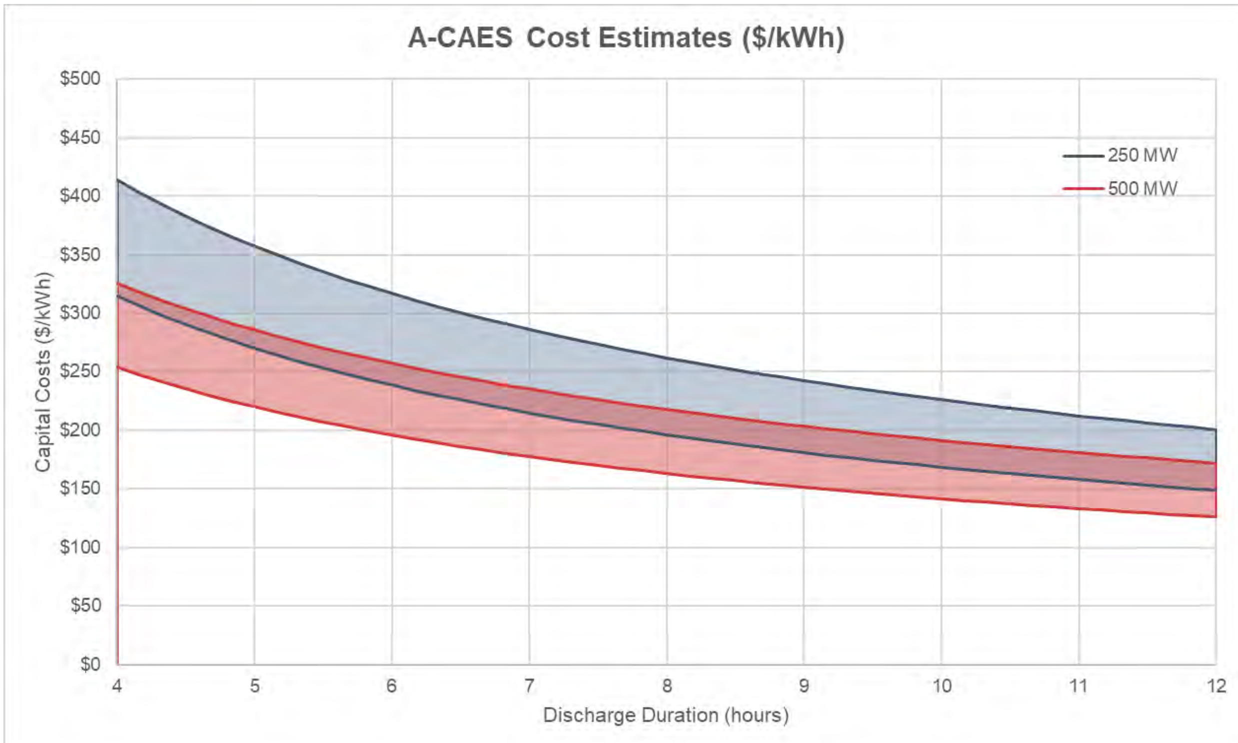


Figure 6: Hard-Rock-Based A-CAES All-in Capital Cost Estimates (US$/kWh)

Operating Costs

Due to the similarities between the configuration of an A-CAES process plant and that of a simple-cycle gas-turbine plant ("SCGT"), the annual operations and maintenance ("O&M") costs of the two are comparable. While non-fuel annual O&M costs for an SCGT vary between 1% and 2% of the plant's capital cost, depending on factors such as the local labour costs and the plant's capacity factor[2], the equivalent costs for an A-CAES plant are expected to differ for two primary reasons: a lack of combustion in the process and a large portion of capital cost being related to subsurface infrastructure with negligible maintenance costs.

Because no combustion occurs in the A-CAES process, the system's equipment cycles through a much lower temperature range when alternating between operating states. Whereas SCGTs experience internal temperatures up to 1200°C, A-CAES infrastructure is never exposed to temperatures greater than 250°C. Additionally, because no combustion occurs in the process, no combustion by-products accumulate in the system's turbine, significantly reducing maintenance requirements.

The capital costs to develop the subsurface infrastructure of an A-CAES plant are on the order of 50% of the overall system capital cost, depending on the system parameters. The O&M costs for this subsurface infrastructure are negligible, so, as a percentage of overall system capital costs, the O&M costs of an A-CAES plant is projected to be substantially lower than those for an SCGT.

The all-in O&M costs for an A-CAES plant are thus estimated at 1% of the full-system capital costs (equivalent to roughly 2% of the capital cost for the aboveground infrastructure) per annum.

For direct-sale opportunities on which Hydrostor provides long-term maintenance services, the costs of providing these services would not include many of the costs that would be incurred for self-developed opportunities, such as operators, land leases, insurance, and capital projects. Thus, it is reasonable to estimate the costs of providing these services at 0.5% of the full-system capital costs per annum.

Hybrid A-CAES / Lithium-Ion Options

A-CAES can be paired with lithium-ion batteries in order to deliver enhanced services to end-users. Improvements offered by a hybrid A-CAES / lithium-ion solution include optimized delivery timelines and improved performance (e.g. reduced operational response times to enable frequency response, and potential efficiency improvements). Hybridizing with a lithium-ion battery will make the Project dispatchable in <1 second, positioning it as a long-duration storage solution that can also provide frequency regulation and control services. The size of the lithium-ion battery can be tailored to meet grids specific requirements for these types of services to minimize this option's incremental cost. An option is also provided to enable improved round-trip efficiency for the combined A-CAES/battery system.

~ end of memo ~

[2] 2017 PSE Integrated Resource Plan – Gas-Fired Resource Costs;
Fuel and Technology Cost Review Report, ACIL Allen, June 2014;
Lazard's Levelized Cost of Energy – Version 12.0, November 2018;

natural forces

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Doreen Friis,
Regulatory Affairs Officer/Clerk
Nova Scotia Utility and Review Board
1601 Lower Water Street, 3rd Floor
P.O. Box 1692, Unit "M"
Halifax, NS B3J 3S3

February 14, 2020

-SENT VIA EMAIL-

RE: 2020 Integrated Resource Plan Terms of Reference

Dear Ms. Friis,

Natural Forces Services Inc. welcomes the opportunity to input comments on the IRP process and Draft Assumption Set (DAS). We note that at this point of the process, there are clearly a lot of details still to be worked out; accordingly, our comments in some areas are of necessity also at a more general level. We look forward to continuing to engage in the process with NSPI and other stakeholders, as more details of the methodology and assumptions are developed. We have for convenience, set out our comments below under several headings.

Electricity Demand projections

The demand projections (DAS page 8) are mostly clustered around an assumption of demand regression, based on DSM/efficiency measures. DSM scenarios range from around a 17% reduction in the "Low" case, to approaching 30% in the "Maximum Achievable" case. While DSM is an important objective, these assumptions appear ambitious.

It is also important to consider the potential (as seen in other countries) for electricity demand growth through increased electrification of transport and heat sectors (as the electricity sector is decarbonised, it becomes a vehicle to assist decarbonisation of the transport and heat sectors). Increased electrification of the transport and heat sectors has the potential to significantly increase electricity demand.

It is also important in general in an IRP process, that the selected scenarios represent a spread of credible, but significantly different possible futures. This supports assessment of the robustness of different portfolio outcomes to different possible futures.

We strongly recommend that a wider spread of demand projections is included, potentially retaining some of the "demand regression" scenarios but adding scenarios with significant demand growth.

Emissions modelling and limits

Emissions modelling (DAS page 13 and later) appears to relate to meeting specific emissions limits, rather than ascribing any value to further reductions. Further reductions are not monetised (e.g. $/tonne CO2 or similar), nor is any strategic benefit recognised.

Additional emissions savings within the alternative scenarios, even if beyond the current legislative requirements, does have a value (either as a general "public good" or as a step to meeting likely future emissions restrictions). Additional emissions savings should be captured as a benefit, and potentially monetised.

Risk premium

There should be some recognition - even if not initially directly monetised - of the risk premium (e.g. implementation risk) associated with different scenarios. For example, scenarios which rely on new/unproven technology, or very ambitious DSM achievements, may carry additional risk regarding implementation and risk of failure.

Operational Constraints associated with Renewable Integration (Ref. DAS page 96 and later.)

There are several important elements in modelling operational constraints in the IRP process, including:

1. Identifying the key operational constraints (or required "grid services") to include in the model;
2. Setting appropriate parameters (or limits) for the selected operational constraints;
3. Setting assumptions regarding the capability of the resource pool (existing and new) to provide system services;
4. Assessing the resultant portfolios to determine if they provide adequate operational flexibility and security (or indeed to see if they are unnecessarily conservative). This step is described in the IRP Draft Analysis Plan as "Operability Screening".

The proposed Grid Services to be included in the model are set out in the DAS (page 99), as follows:

> *For the NS Power system, the following has been identified as the grid services that need to be addressed to accommodate additional inverter-based generation to maintain stable and secure operation of the system.*
>
> - *Ramping reserve and net load following capabilities*
> - *System strength and short circuit ratio*
> - *Volt-Ampere-Reactive support*
> - *Kinetic energy and synchronous inertia requirement*
>
> *A value for the minimum requirement of each of these essential grid services will be represented in the model as dynamic constraints, which will enable the model to integrate renewable resources at any level by ensuring provision of the services.*

We suggest inclusion of VAR support as a key operational parameter should be reconsidered. While we are not questioning its importance, if it is in fact a binding constraint in some portfolios, it can usually be resolved by other solutions which are at relatively low costs and easy to implement (e.g. installation of SVCs or synchronous condensers).

The parameterisation (i.e. setting the required minimum levels) for the remaining requirements will be of critical importance. In reality, most are not “static” requirements, for example the synchronous inertia requirement will depend significantly on the largest system infeed (or outfeed) at a point in time. It will be presumably not be possible to model this degree of sophistication within the IRP model; more likely, single static values will be adopted.

We note the references in the DAS to (page 98) drawing on the Nova Scotia Power Stability Study for Renewable Integration Report (the “Stability Study”), prepared by PSC North America on behalf of Nova Scotia Power Inc. (24th July 2019), as a source for determining the relevant levels of grid services. This is somewhat concerning as the Stability Study, by its nature, examined a small number of “stressed” system conditions, and applied severe contingencies in order to test the limits of the system. Therefore, while there may be learnings that can be taken from it, care must be applied as the scenarios modelled in the Stability Study do not reflect “normal” system conditions and normal grid service requirements.

We would appreciate further understanding of the proposed levels/limits of Grid Services to be included in the IRP model. We strongly suggest that if anything the limits should be set low rather than high; if they are set too high, potential economic portfolio options may be excluded from consideration; on the other hand is they are set too low, this will be picked up at the “operability screening” stage. If some shortfalls are identified at that stage, there may indeed be other solutions to fill any gaps or shortfalls (such as SVCs or synch comps, as mentioned above).

Regarding the capability of the portfolio of potential resources to contribute to Grid Services requirements, it is important not to automatically default to assuming existing levels of performance. Experience in other systems has shown that:

- existing generation plant can often significantly improve its flexibility and contribution to system services, in areas such as ramping, minimum stable output, start times and reserves.
- new generation plants can be configured to optimally provide certain grid services, depending on the specific needs of the system;
- renewable plants in other systems are also an important source of grid services (some examples are described in the Stability Study); and,
- widening of the supply base for grid services has also been very successful (e.g. demand side contribution to short-term operating reserves has been very successful. This can also offset or contribute to ramping requirements.).

We would welcome further information on the assumptions proposed in regard to Grid Service capability. If this cannot be provided for specific plants, at least description of the assumptions for different classes of plant would be helpful.

Interconnectors

Treatment of interconnectors in the IRP modelling will be critically important. There is currently little information in the DAS on this aspect. It is noted that imports (particularly firm imports) could support a transition to lower GSG emissions, but on the other hand fixed import schedules can cause reduction in wind output/capacity as it “squeezes” the space available for RES and local thermal/synchronous plants. Also, with the current interconnection arrangements, the AC interconnector to New Brunswick can often be (depending on its flow) the most severe contingency on the Nova Scotia system, thus determining the grid services requirements (for at least some grid services) within Nova Scotia. Further description of the proposed modelling of interconnector flows would be appreciated.

We hope you find these helpful and that they will receive due consideration, and please revert to us at any time if we can provide further clarification or elaboration. We look forward to working closely with you in the continuing stages of the IRP process.

Sincerely,

Presented for, and on behalf of, Natural Forces Services Inc.

Halifax, Nova Scotia.

Blackburn Law

VIA EMAIL

February 14, 2020

Linda Lefler
Nova Scotia Power

Dear Ms. Lefler,

Re: M08929 – IRP Assumptions Comments

The Small Business Advocate (SBA) attended the IRP Stakeholder meeting on January 27, 2020 and our expert, Jeff Bower, participated in the conference call on February 7, 2020. Below are some questions and comments from the SBA for consideration at the next stakeholder meeting scheduled for February 27, 2020.

Demand Side Management (DSM):

NSPI noted during the February 7, 2020 stakeholder discussion that DSM is going to be considered as a load modifier in the IRP analysis, and will only be considered as scenarios (Low, Base, Mid, Max Achievable). This appears to be treating DSM as an exogenous factor rather than integrated resource options.

This seems to suggest that the selection of DSM program implementation efforts will not be an output of the IRP portfolio optimization process, but rather the DSM scenarios that change the load that will be used as inputs to the model used to develop the portfolios. The concern of using this approach is that:

1. It does not test the economics of the different amounts of DSM;
2. It does not look at the potential focus differences among DSM options such as peak reducing versus energy reducing (which affects environmental emissions reduction benefits) or Summer versus winter peak targeting;
3. It does not capture the dynamic effects between DSM penetration and avoided cost (with avoided costs varying by scenario assumptions and between resource portfolios being evaluated).

NSP needs to discuss how it will choose which bundle of DSM is incorporated into specific scenarios. This should be analytically consistent and not random sensitivities.

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Further, if the DSM adoption scenarios rely on the comparison of program cost to avoided cost, a methodology which uses the DSM adoption scenarios as an input does not recognize the fact that the avoided cost changes with the supply-side resource buildout.

In addition, some energy efficiency measures may encourage electrification, and thus could increase electric load. It is not clear if this effect is captured in NSPI's methodology.

There needs to be specificity as to how the revenue requirements will be determined for annual expenditures, ie multi-year amortization. A question that then arises is whether it is a variable.

The SBA believes that the incorporation of DSM is an important issue and requires further discussion. We suggest that there be a specific meeting on DSM assumptions and integration into the scenarios and portfolio evaluations, or at a minimum this should be addressed at the February 27th meeting.

Distributed Generation:

During the February 7th call it was mentioned that distributed generation, such as Behind the Meter Solar, will not be included as an Option since it would not be selected by the model due to cost. In a long range planning exercise such as an IRP this seems like a significant short-coming. There needs to be a recognition of the existence of Renewable to Retail Sales in the modeling and portfolio strategies recognizing different economic signals.

As well, it should be understood that behind the meter generation is installed based upon customer economics of avoiding or being compensated at retail rates, not solely a generation savings. This needs to be modeled consistently, perhaps crediting savings against rates inside the model. The various solar ratemaking and net metering policies should be tested as well.

The SBA would like confirmation about what analysis will be used to vary DER penetration across scenarios and portfolios.

As referenced above with respect to DSM, additional time needs to be provided to discuss DER more fully, including time for open for dialogue and input from stakeholders.

Sustaining Capital Forecast:

The original set of draft IRP assumptions (dated January 20, 2020) was revised on February 3, 2020. The revised assumptions included significant changes to the sustaining capital forecast for coal, CT, and small hydro units.

NSPI should provide the original and revised data in tabular form so stakeholders can better compare the two forecasts. NSPI should also provide a detailed explanation for the source of the modifications, and any supporting studies from which the sustaining capital forecasts were derived.

Please let me know if you have any questions or require any clarification.

Yours truly,

BLACKBURN LAW

Melissa P. MacAdam
for
E.A. Nelson Blackburn, Q.C.
Small Business Advocate

VERSCHUREN CENTRE
For Sustainability in Energy and the Environment

February 14th, 2020

Nova Scotia Power – IRP Team
Nicole Godboot, Lia MacDonald, Mila Milojevic, Brendan Matheson, Linda Lefler

Via email

Re: Comments regarding initial IRP Assumptions

Thank you for the opportunity to participate in the Integrated Resources Plan engagement session. In response to the Assumptions provided on January 21, 2020 and February 3, 2020, we offer the following comments, questions and suggestions:

1. **Energy Storage**

The Verschuren Centre engaged industry partners for updated capital cost and O&M cost of Lithium Ion Battery systems. The data are broken down by size, to help facilitate a more granular substation-level perspective, as discussed in more detail later in this letter.

	2019	
	CapEx ($/kW)	Fixed O&M ($/kW-yr)
Residential Li-Ion Battery (3hr) (scalable to any size)	$3000	$100
Li-Ion Battery (1hr) (1 – 10MW)	$700	$18
Li-Ion Battery (1hr) (10 – 100MW)	$500	$13
Li-Ion Battery (2hr) (1 – 10MW)	$1100	$21
Li-Ion Battery (2hr) (10 – 100MW)	$900	$17
Li-Ion Battery (4hr) (1 – 10MW)	$1900	$25
Li-Ion Battery (4hr) (10 – 100MW)	$1700	$21

We are also interested to learn more detail regarding how energy storage will be considered in the Plexos model. Energy storage systems can provide multiple value streams including: energy; capacity; ancillary services such as frequency regulation, operating and spinning reserves; demand response; load following and other benefits enabling increased efficiencies of existing grid assets. Much of the value of energy storage comes from its ability to respond extremely quickly with no ramp rates and provide flexibility as both a load and a generator. For example, a 100MW energy storage facility can act as both 100MW of generation and 100MW of load, providing a total of 200MW of flexibility to the grid. It is important that the model consider all potential value streams for energy storage systems, and how they can be stacked; to most accurately determine the lowest cost solution for ratepayers. This importance has been confirmed by FERC through the passing of Rule 841 requiring fair market access for energy storage resources (over 100kW) in RTO jurisdictions. Please provide more detail regarding how the various value streams of energy storage will be accounted for in Plexos.

2. Electrification

We think it is critically important that this Integrated Resource Plan consider an appropriate amount of electrification. There is a significant body of research that suggests that electrification will be the most cost effective pathway to zero emissions. It is reasonable to suggest, therefore, that electrification will be the most cost effective pathway for Nova Scotia to achieve the targets of the Sustainable Development Goals Act.

The Verschuren Centre has calculated the 2017 total final energy requirement in Nova Scotia to be 4.7TWh for transportation and 9.6TWh for fossil fuel based space heating.

Many major economies are planning to ban the sale of internal combustion engines within the next 5 to 20 years. Therefore, it would be reasonable to assume that by 2050, 80-100% of transportation will be either directly electric, or powered through an electric fuel cell or other electricity derived source.

For space heating, heat pump technology is already cost competitive compared to most alternatives, and technologies are only improving over time. Therefore, electrification of space heating of 80%-100% by 2050 would also be reasonable. It is also important to note that the coefficient of performance of heat pumps will reduce the final impact of the space heating energy on the grid significantly. Space heating loads are also aligned with current electricity demand peaks, and therefore, electrification of space heating presents significant capacity concerns as well.

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3. Distribution

On its own merits, it is clear that this IRP should take into account substation level capacity considerations. The electrification suggestions above will only accelerate this need.   Recent locational studies filed with the UARB show a list of 34 heavily loaded substations transformers that are near or over their capacity. (M07815 – 2018 Locational Pilot Update – Table 1, Page 5). Some of these substations have associated transmission restraints as well.

Most of the transportation and space heating electrification will take place at the end of the line, and therefore, place additional load on this fleet of already heavily loaded substations.

To facilitate this analysis, a suite of distribution scale energy and capacity assumptions should be considered (1-10MW). We have provided data points for lithium battery and thermal storage, and inputs from the wind and solar industries should be sought as well.

4. Thermal Storage

As noted in our August 2019 letter to NS Power as part of the pre-IRP engagement, and subsequent meeting, The Verschuren Centre is suggesting that thermal energy storage be given closer consideration in the IRP. Broadly speaking, thermal energy storage includes any technology that has the potential to store heat or cold onsite behind the meter, to offset future heating and cooling needs. Considering that peak demand on the NS Power grid is highly aligned with space heating, and that electric space heating demands are likely to grow significantly over the next 20-30 years, it makes it clear that there is significant value in having flexibility in that demand.

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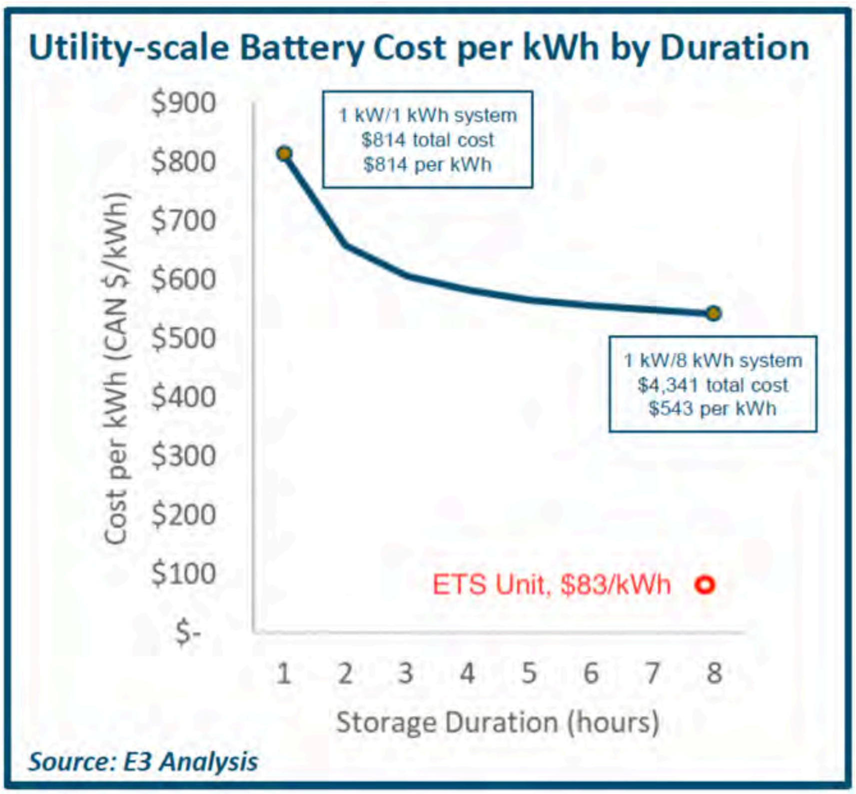
Thermal storage technologies are very cost completive with other sources of capacity (~$520/kW), and even more competitive compared per kWh (~$83/kWh). A typical ETS unit, upon which this pricing is based, can provide 12+ hours of storage. In simple terms, the materials used to provide thermal storage; brick, water, salt, concrete, etc; are all inexpensive and durable long term. See the following graphic comparing the ETS cost per kwh versus the Utilities Scale battery cost data from E3's pre-IRP documentation.



Based on this data, we feel that thermal storage should be considered separately from other forms of energy storage and demand control in the IRP model. Thermal storage does not have all the abilities of other electrical storage technologies, but it also has more potential, and higher ELCC, than other demand control technologies.

It should also be noted that thermal energy storage could be the best solution for balancing wind energy, as both wind energy and space heating needs are generally aligned during the year. See figure below.

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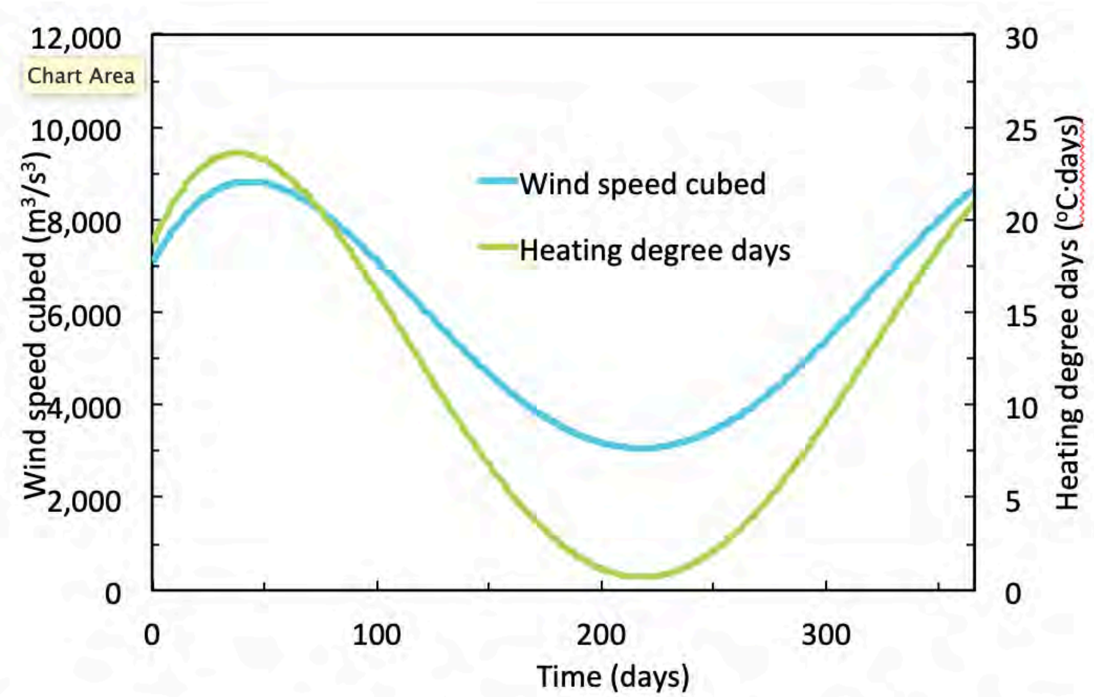
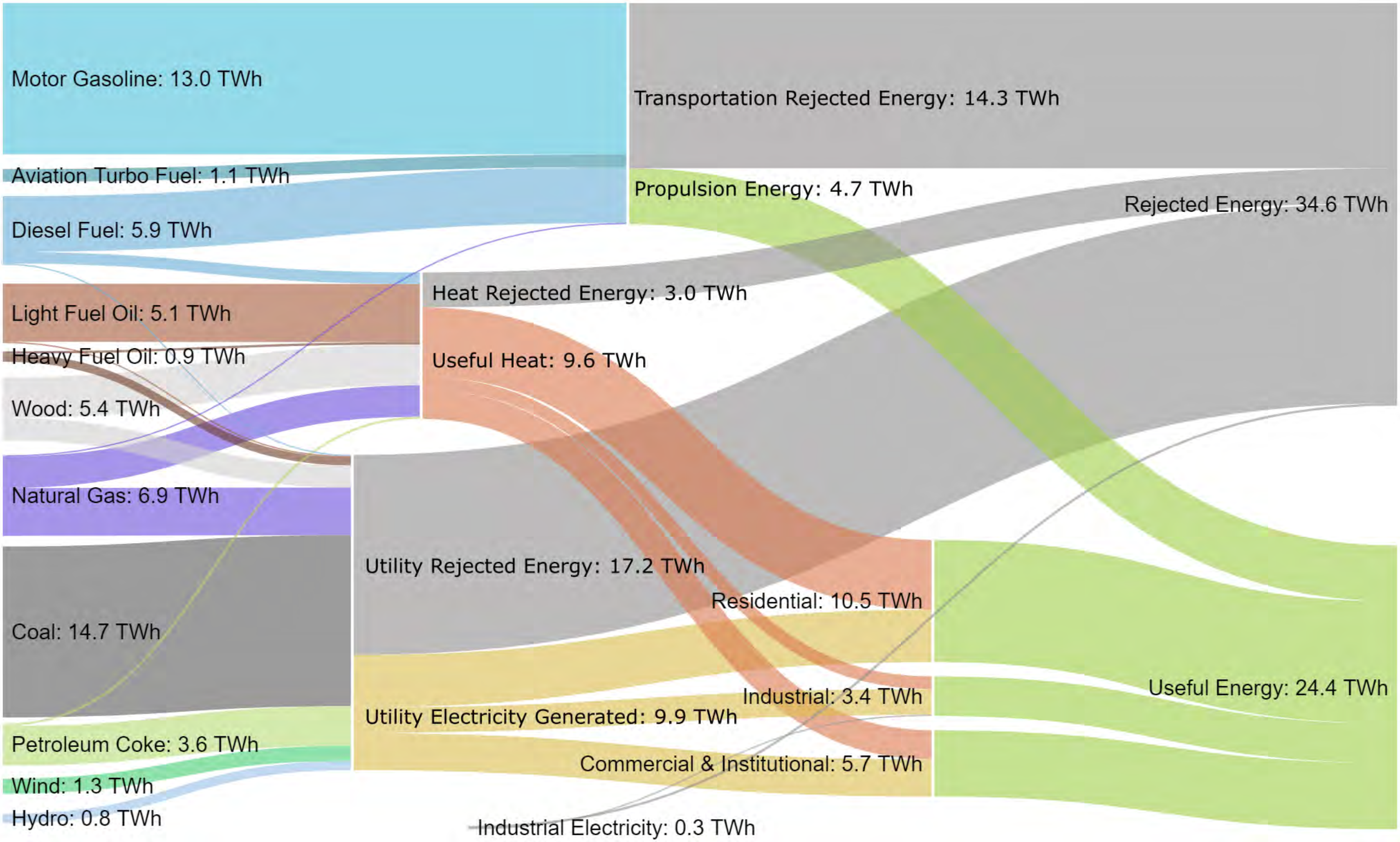


Figure 2. Wind speed cubed and heating degree days for Environment and Climate Change Canada's weather station at Sydney Airport. Data were averaged from 2008 to 2017.

Thank you again for the opportunity to participate in this process, and we are happy to discuss any of the topics above in more detail with NSPI and E3.

Sincerely,

Daniel Roscoe, P.Eng
Lead – Renewable Energy
Verschuren Centre for Sustainability in Energy and the Environment


Motor Gasoline: 13.0 TWh
Aviation Turbo Fuel: 1.1 TWh
Diesel Fuel: 5.9 TWh
Light Fuel Oil: 5.1 TWh
Heavy Fuel Oil: 0.9 TWh
Wood: 5.4 TWh
Natural Gas: 6.9 TWh
Coal: 14.7 TWh
Petroleum Coke: 3.6 TWh
Wind: 1.3 TWh
Hydro: 0.8 TWh
Transportation Rejected Energy: 14.3 TWh
Propulsion Energy: 4.7 TWh
Heat Rejected Energy: 3.0 TWh
Useful Heat: 9.6 TWh
Utility Rejected Energy: 17.2 TWh
Utility Electricity Generated: 9.9 TWh
Industrial Electricity: 0.3 TWh
Residential: 10.5 TWh
Industrial: 3.4 TWh
Commercial & Institutional: 5.7 TWh
Rejected Energy: 34.6 TWh
Useful Energy: 24.4 TWh

Category	Participant	Assumption Comment	NS Power Response
1. Financial	CanWEA/SIA	Ensure sensitivities reflect variability of assumptions and recognize how modular nature and experience w/ some technologies reduce underlying risks and potential variability of costs	Low and High capital cost sensitivities for wind and storage will allow for a broad range of potential costs to be considered. Assumptions set was updated to reflect more sharply declining cost estimates over time using recent 2019 industry cost data.
2. Load	CA (Chernick & Wilson)	Effects of ideal EV load shape should be reflected in capacity expansion model and not just as a sensitivity in production cost modelling	As part of the developing the IRP load shapes, NS Power has included the effect of EV peak shifting capability.
2. Load	CA (Chernick & Wilson)	No indication of how potential uncertainty in load viewed How much could load vary from baseline forecast [and why] Could load shape change over time due to changes in load mix (industry shifts, changes in space/water heating technology, increased large commercial air conditioning load, etc.)	Range of load curves was presented at Stakeholder Conference on February 27; a broad range is being considered, informed by the Pathways study and E1 DSM Potential Study. NS Power will work with E3 on potential impact of changes to load shape and how to model, in particular for scenarios where the monthly peak and energy requirements are significantly different from what our 2018 actual 8760 load shape would reflect.
2. Load	Heritage Gas	Incorporate contribution of electrification technologies in calculation to peak (system build-out and emissions contributions) Understood E3 developing assumptions and alternative options for electrification scenario modelling to be provided to stakeholders for review & comment	NS Power's load forecast assumptions consider the impacts of electrification on peak loads, under several different scenarios. These were reviewed at the February 27 stakeholder meeting and have been provided with the final assumptions set.

Category	Participant	Assumption Comment	NS Power Response
2. Load	Natural Forces	DSM scenarios of 17% reduction in low case to 30% in max achievable case appear ambitious Consider demand growth from electrification Include a wider spread of demand projections, potentially retaining some demand regression scenarios but adding scenarios w/ significant demand growth	NS Power's DSM assumptions are informed by the E1 Potential Study; a range of Load and DSM forecasts will be tested on the main scenarios. The load forecast assumptions were informed by the PATHWAYS work, which considers several electrification scenarios for the Nova Scotia economy that produce a wide range of long-term outcomes in terms of both peak and energy requirements.
2. Load	Verschuren Centre	Need to consider appropriate amount of electrification, which is most cost-effective pathway to zero emissions Reasonable to assume 80-100% of transportation electric (direct, fuel cell or other derived source) by 2050 Reasonable to assume 80-100% of space heating via heat pump by 2050 Space heating load aligned with demand peaks and electrification of space heating presents capacity concerns	The load forecast assumptions were informed by the PATHWAYS work, which considers several electrification scenarios for the Nova Scotia economy that produce a wide range of long-term outcomes in terms of both peak and energy requirements.
2. Load	E1 (March 6)	Request confirmation that - Load Forecast to be modified by Pathways by removing 40% of future EE and DR from "before DSM" scenario from 2019 Load Forecast while retaining lasting impacts of previously delivered programs. NS Power will look to Pathways report to ascertain level of incremental electrification w/ high & mod electrification. NS Power will then adopt consistent inputs to produce modified 2019 Load Forecast accounting for electrification before EE and DR; no data from Pathways model to be used directly in IRP model.	The 2019 System Outlook future DSM amounts have a coefficient applied that accounts for embedded DSM and the "before DSM" in the System Outlook only adds back this adjusted amount rather than the full DSM. For the IRP scenarios, the No DSM forecast includes the full future DSM added back in so that the basis for comparison is the same when the various E1 DSM scenarios are subtracted out. Please refer to NS Power's Final Assumptions and Scenarios and Modeling Plan.

Category	Participant	Assumption Comment	NS Power Response
3. Environmental Assumptions	AREA	NSP should consider modelling decarbonization efforts in each scenario and at what price other sectors would need to pay NSP to effect such decarbonization [NSP should model exceeding environmental targets and selling surplus attributes to various markets/sectors]	The load forecast assumptions were informed by the PATHWAYS work, which considers several electrification scenarios for the Nova Scotia economy that produce a wide range of long-term outcomes in terms of both peak and energy requirements. NS Power will consider the option to sell surplus GHG emissions into the Nova Scotia Cap and Trade Market in the initial screening work, to determine if it warrants inclusion in the Plexos LT models (i.e. if it changes the optimal resource buildout plan).
3. Environmental Assumptions	Dalhousie	How to model for organizations w/ climate change goals and targets which exceed existing regulatory targets Need a more aggressive carbon scenario beyond regulatory targets and which models net zero	The load forecast assumptions were informed by the PATHWAYS work, which considers several electrification scenarios for the Nova Scotia economy that produce a wide range of long-term outcomes in terms of both peak and energy requirements. The Final Scenario and Modeling Plan contains GHG trajectories more stringent than current regulatory requirements.
3. Environmental Assumptions	E1 (February 14)	Does NSP expect to sell excess credits from lower emissions; if so, how will carbon cost be captured and will revenues from carbon credits be accounted for in revenue requirement for each scenario?	NS Power will incorporate cap and trade market revenue from sales of excess GHG allowances during the screening phase of the modeling work for some key scenarios. If market revenue is found to affect the preferred resource plan selection, then a determination will be made as to how to incorporate the cap and trade market in the full IRP modeling phase.
3. Environmental Assumptions	E1 (February 14)	Considering C02 caps business as usual? Will SDGA be considered in business as usual scenario? [comparator scenarios?]	The Comparator scenario is not consistent with the SDGA and is intended to be informational in nature only.

Category	Participant	Assumption Comment	NS Power Response
3. Environmental Assumptions	E1 (February 14)	Air quality regs to 2030; what causes drop in hard caps for SO2 and Hg in 2035	The drops post 2030 are assumptions by NS Power that further SO_2 and Hg emissions limit reductions are likely post-2030. These assumptions are consistent with what was modeled as “Scenario B” in the 2014 IRP.
3. Environmental Assumptions	EAC	Consider more ambition in GHG reductions (increased because of SDGA) because reductions to come from electricity sector Fed government may require further reductions in cap & trade jurisdictions	The Final Scenario and Modeling Plan contains GHG trajectories more stringent than current regulatory requirements.
3. Environmental Assumptions	EAC	Consider further Renewable Energy targets and RES requirements Consider need to comply w/ federal green building standards	A sensitivity to analyze an increased RES standard has been proposed as part of the Modeling Plan.
3. Environmental Assumptions	EAC	Consider enhanced / extended equivalency agreement w/ feds and associated emissions reductions (2025 forward) and need for new equivalency agreement 2030-2040 Hard caps on p. 17 of Assumptions should be the lowest / least aggressive level for consideration in IRP	The proposed scenarios incorporate a range of GHG emissions profiles, which are designed to be compliant with the SDGA and provide a range of potential rates of emissions reduction including GHG trajectories more stringent than current regulatory requirements.
3. Environmental Assumptions	EAC	NSP should propose emissions pathway compliant with federal regs of 3.0 MT /C02 for 2030-2040	In the final Modeling Plan NS Power has included a GHG Scenario with limits below 3.0MT CO_2e after 2030 (“Accelerated Net Zero 2045” case), please see the Scenarios and Modeling Plan for details.
Environmental Assumptions	EAC	CO_2 pre 2030; 0 by 2040 4.5 MT 2030 vs 3.0 – Is equivalency the reason for this?	In the final Modeling Plan NS Power has included a GHG Scenario with limits below 3.0MT CO_2e after 2030 (“Accelerated Net Zero 2045” case); this case also includes emissions reductions that start pre-2030 as suggested. Please see the Scenarios and Modeling Plan for details.

Category	Participant	Assumption Comment	NS Power Response
3. Environmental Assumptions	Envigour (Bruce Cameron)	Need to assume net-zero is ≥ 85-90% carbon-free (using existing pipelines with carbon-free fuels ie hydrogen, renewable natural gas and carbon offsets) by 2050	The scenarios incorporate a range of GHG emissions profiles, which are designed to be compliant with the SDGA and provide a range of potential rates of emissions reduction and GHG trajectories more stringent than current regulatory requirements.
3. Environmental Assumptions	EAC	At least one scenario should examine portfolio where all units retired by end of 2029 in accordance with 2018-19 federal regs	NS Power has included a key driver on coal closure dates including scenarios where all coal units are retired by Dec. 31, 2029.
3. Environmental Assumptions	Natural Forces	Emissions modelling relates to meeting limits rather than ascribing value to further reductions; reductions not monetized and strategic benefits not recognized Need additional emissions savings w/in alternative scenarios – capture as benefit and monetize	NS Power will incorporate cap and trade market revenue from sales of excess GHG allowances during the screening phase of the modeling work for some key scenarios. If market revenue is found to affect the preferred resource plan selection, then a determination will be made as to how to incorporate the cap and trade market in the full IRP modeling phase.
4. Supply Side Options	AREA	Will support NSP proposal if NSP will clearly state in future reports that developers believe “low cost of renewables” scenario prices are easily achievable NSP should indicate at what project size the costing is associated	NS Power’s capital cost estimates for wind are based on a facility of 50MW to 100MW installed capacity.
4. Supply Side Options	AREA	Need to consider alternative non-NSP lower costs of capital	The proposed sensitivities on capital costs (e.g. low/high wind cost, low/high storage cost, etc.) are representative for modeling purposes of potential alternative capital structures.

Category	Participant	Assumption Comment	NS Power Response
4. Supply Side Options	CA (Chernick & Wilson)	Should include allowance for decommissioning Evaluate resources on an equivalent full-cost basis	NS Power confirms that decommissioning costs are not included in the capital cost estimates for any of the new resources presented in the supply option assumptions. Decommissioning costs are difficult to estimate due to the potential for further life extensions, salvage value, re-powering, etc. of any new asset built during the IRP Planning Horizon. For these reasons, the present value of the future decommissioning costs for new assets is assumed to be immaterial to the IRP analysis.
4. Supply Side Options	CA (Chernick & Wilson)	Supply side capacity options should include flexible solar (for dispatch control for ancillary services) and hybrid (renewable + storage) resources. Need to list flexible solar and hybrid resources from projected levelized cost of capacity resources	The model will be free to select combinations of renewable generators and energy storage when optimal to meet system needs; post-modeling analysis of the model runs could indicate whether there are good candidates for hybrid sites with similar build times and capacities.
4. Supply Side Options	CA (Chernick & Wilson)	Request more information about how NSP supply-side cost assumptions were developed and supported [NSP showing higher renewable and storage costs and lower gas-fired and nuclear] Solar PV costs have come down in last 2 years; CC natural [and CT] gas costs should be 20% lower per NREL ATB Storage technologies O&M should be variable and not fixed; should include charging cost and charging cost escalator unless values calculated w/in system planning models	Details are available in the NS Power Resource Options Study by E3, completed in July 2019 as part of the Pre-IRP work, and finalized following stakeholder comments in October 2019. Additional detail is available in the full report document including comparisons of various source data available. Certain of these assumptions were updated early in 2020 based on 2019 actual data that became available after the original study was completed. Charging cost for storage is calculated by the dispatch model and applied as an incremental production cost.

Category	Participant	Assumption Comment	NS Power Response
4. Supply Side Options	CanWEA/SIA	Capex and Opex for technologies should be combined with assumptions (financing, useful life, cap factors) and may yield revenue requirement profiles unsupported by market data Explicitly identify LCOE values from E3 Resource Options Study	LCOEs were provided in the E3 supply options study but were not included in the NS Power Assumptions slides as this is not an input to the modeling tool.
4. Supply Side Options	Dalhousie	Scenarios w/ more grid sharing from provinces w/ hydro and micro-grid structures	NS Power has added a Regional Integration resource strategy to explicitly analyze the value of additional integration with neighbouring jurisdictions. Microgrids are not being modeled in the IRP as the distribution system is not considered by the model.
4. Supply Side Options	Heritage Gas	Final assumptions to include coal-to-gas conversion, and despite base loaded gas price assumption of 100,000 MMBtu/day, no supply constraint on natural gas in the model	Confirmed.
4. Supply Side Options	Heritage Gas	New nat gas-fired CTs to be included in the supply options, and 25-year IRP study period to consider reliability of existing CTs from fuel security, general reliability and start-up perspective (in reliability screening phase or earlier)	The sustaining capital assumptions being used in the IRP model represent NS Power's estimate of the capital required to maintain current levels of reliability from the diesel CT units.
4. Supply Side Options	JFS Hydrostor	Consider compressed air energy storage (stored in underground caverns and released to surface turbine to generate electricity); consider a lower price or sensitivity for compressed air storage.	The IRP will consider sensitivities on both Low and High Capital Cost of Storage which will encompass the range of costs submitted by Hydrostor.
4. Supply Side Options	Envigour (Bruce Cameron)	Consider in-stream tidal as supply side option. Costs to decline as technology deploys. NSP assumption is too high for instream tidal (vs bottom turbine).	Industry experience in tidal generation is so far limited and unlike wind and solar, costs appear to be site specific and tied to construction costs with limited opportunities for economies of scale. Technological and commercial readiness level in Nova Scotia is still uncertain.

Category	Participant	Assumption Comment	NS Power Response
4. Supply Side Options	Envigour (Bruce Cameron)	No issue with assumption of wind capex declining, but need to consider offshore wind which has a capacity factor of 63%. Need assurance that modelling will capture the value (incl. decrease in levelized cost of energy) of such a high capacity factor.	E3 used CanWEA data to generate offshore wind capacity factors of 37%-45% as part of the Supply Options Study; these capacity factors drive the capital cost assumptions for offshore wind being used in the IRP.
4. Supply Side Options	Natural Forces	The cost of wind $2100 is 15% higher than Natural Forces experience on slide 35.	The low wind sensitivity included in the final assumption set is $1500/kW which is in line with the 2019 Lazard low costs.
4. Supply Side Options	Digby	Energy storage and smart grid technologies could assist w/ controlling voltage and redirecting power flows; important for areas like Digby w/ inadequate transmission (69kV line).	The DER resource strategy will consider options such as behind the meter energy storage and distributed solar.
4. Supply Side Options	Digby	Introduce EVs as means to create demand at Conway substation. EV charging supports renewable energy integration in capacity-constrained grid.	The IRP does not consider the specific programs that could be used to incent electrification; the effect of electrification on load is assumed to be exogenous to the NS Power system (e.g. policy driven)
4. Supply Side Options	Digby	Tidal energy will require management of generation and load; creation of micro grid and load balancing will create background for energy storage. Installation of solar garden suggested.	Microgrids are not considered in the IRP as it does not model NS Power's distribution system. NS Power has included costs for solar generation in our supply options based on the E3 Supply Options Study.

Category	Participant	Assumption Comment	NS Power Response
4. Supply Side Options	Verschuren Centre	Consider updated capex and opex costs of lithium ion battery systems Value of storage is in ability to respond quickly w/ no ramp rates and provide flexibility as load and generator Model should consider all potential value streams for energy storage systems and how can be stacked; provide detail re how this accounted for in PLEXOS	NS Power updated capital and FO&M cost estimates for Li Ion storage with 2019 data in early 2020; these appear to be slightly higher than, but in the general range of, the data supplied by the Verschuren Centre in their written comments. NS Power will work with stakeholders through the IRP process to develop a methodology for Avoided T&D Costs which could be associated with substation level or distributed storage resources; if applicable this approach could be added outside of the model in the Distributed Resources Promoted scenario which NS Power has included in the Modeling Plan. Storage in PLEXOS allows these resources to provide capacity, energy, and operating reserves. Charging cost is calculated in the production model dynamically. Battery Storage contributions to essential grid services will be considered both inside of and outside the PLEXOS model during the Reliability and Operability screening phases of the IRP.
4. Supply Side Options	E1 (February 14)	Re Pathways (E3 Resource Options Study) - Provide details on assumption re access to firm capacity via new transmission up to 800 MW – basis and costs?	Under the Regional Integration resource strategy the model will have access to transmission via HVDC to the Quebec / New Brunswick border. The assumptions consider a 1000MW bi-pole design, which would allow 450MW firm capacity to be considered towards the NS PRM requirements. The capital cost estimates are NS Power internal and represent the total capital cost of the new transmission facilities.

Category	Participant	Assumption Comment	NS Power Response
5. DER (Distributed Energy Resources)	CA (Chernick & Wilson)	DER should include full cost of resources (and not just portion paid by NSP incentives) and reduce gross costs to reflect T&D and NEBs (incl. backup and other customer values). If NS Power can't estimate NEBs, DER should be just NS Power costs reduced by T&D benefits (line losses, avoided investment).	The IRP evaluates the costs and benefits of utility resources to derive revenue requirement and utility benefits. DER costs evaluated would be NS Power costs. The IRP does not consider Non-Energy Benefits. Current assumptions do not include utility-funded DER. Methodology for estimating avoided T&D costs will be developed through this IRP process.
5. DER (Distributed Energy Resources)	Envigour (Bruce Cameron)	Changes in pricing decrease costs of DER; technology prices declining as production and deployments more widespread.	NS Power agrees that DERs will have a declining cost trajectory. The DER resource strategy assumes widespread penetration of DER installations that would be consistent with declining prices.
5. DER (Distributed Energy Resources)	SBA	Behind the meter (BTM) is not included as an option because won't be selected by model due to cost is a shortcoming. Needs to be recognition of existence of Renewable to Retail sales recognizing different economic signals. BTM generation installed based on customer economics related to retail rates, not just generation savings; credit savings against rates. Need to test solar ratemaking and net metering policies. Need to confirm what analysis to be used to vary DER penetration across scenarios & portfolios.	The Distributed Resources scenario will provide information as to the potential impacts of these technologies will have on how NS Power serves peak and energy requirements.
5. DER (Distributed Energy Resources)	Verschuren Centre	IRP should consider BTM thermal energy storage (to address need for flexibility and increased demand) vs utility scale battery (cheaper and longer duration) Cost competitive w/ other capacity sources ($520/kW; $83/kWh), and ETS can provide 12 hours of storage	The Distributed Resources Promoted scenario will consider BTM approaches as a load modifier.

Category	Participant	Assumption Comment	NS Power Response
6. Planning Reserve Margin (Generation)	CA (Chernick & Wilson)	Use longer averaging period for TUC DAFOR (7 years vs 3)	To avoid subjectivity, NS Power selected a three year average for all units in order to compare them on an even footing. Upon review of the initial modeling results, should there be any outliers that require further examination, we may consider this recommendation again.
6. Planning Reserve Margin (Generation)	CA (Chernick & Wilson)	Re Table 17: since ELCC used for rating variable generation, other types of generation (non-thermal) should be de-rated using methods that are identical/produce identical results Thermal treatment (ELCC/ UCAP) with DAFOR Adjustments; ICAP method results in a PRM of 20%; UCAP method results in a PRM of 7%to 9%. Dynamic under capacity expansion with incremental build; circle back to PRM.	NS Power will use the ELCC calculation for thermal units contribution to PRM in the capacity expansion portion of the model. Once resource portfolios are identified, NS Power and E3 will evaluate against an ELCC PRM with an ICAP PRM consistent with NS Power's PRM calculation approach and confirm that reliability obligations (i.e. 0.1 days/year LOLE) are maintained in all years of the plan; will iterate if required.
6. Planning Reserve Margin (Generation)	CA (Chernick & Wilson)	Revisit hydro ELCC assumptions, looking at storage capacity by system (hours of full-load generation), time to recharge from inflow (Nov-Mar), capacity factors during winter peak hours x last several years, effect of 2016 drought or other events on effective hydro capacity over long winter peaks, historical frequency of droughts.	This suggestion requires extensive evaluation. For the purpose of the IRP, we do not believe it will significantly impact the ELCC of hydro units.
6. Planning Reserve Margin (Generation)	CA (Chernick & Wilson)	Make visible numerical values behind Figure 27 (LOLP by month and hour).	Please refer to Attachment 1.

Category	Participant	Assumption Comment	NS Power Response
6. Planning Reserve Margin (Generation)	CA (Chernick & Wilson)	Consider whether feeder circuit outages could significantly affect DAFOR for any generation units.	Distribution Feeder outage events do not affect the capacity value of any NS Power thermal or hydro generation units; in the example cited of Wreck Cove / 85S, outages to the distribution feeders supplied from the 85S substation do not impact the ability of the Wreck Cove Hydro units to provide energy or capacity to the NS Power system. Multiple transmission circuits, separated from the Distribution Feeders, connect that station to the provincial transmission system.
6. Planning Reserve Margin (Generation)	CA (Chernick & Wilson)	If EE program load shape is different from load shape in forecast, then overall scale of EE resource investment could shift load shape, particularly if EV resources affecting load shape	NS Power will work with E3 to assess any modifications required to load shapes, particularly in scenarios where peak and energy assumptions are significantly different than the 2018 actuals on which the load shape is based.
6. Planning Reserve Margin (Generation)	CA (Chernick & Wilson)	Forecast marginal ELCC values may be missing diversity benefits from resource mix and could result in selection of too many resources with high ELCC values and too little of other resources	The diversity benefit to ELCC will be computed as part of the Reliability and Operability phases of the IRP analysis; this will address any over- or under-build of capacity resources that could be caused by the ELCC curves being considered in isolation.
6. Planning Reserve Margin (Load)	CA (Chernick & Wilson)	Want more details regarding methods and key diagnostic outputs for capacity value study: • How are hourly loads related to weather data / what assumptions not in last 5-10 years / provide methods and data outputs (scatter plot re actual & modeled vs load) • Weather conditions considered in relationship b/w weather & load (temp, wind, humidity, precipitation) • What consideration of long-term weather trends (> wind, what about precipitation) • Weather conditions (temp) correlated with outages, efficiency (heat rate) or capacity?	The Capacity Study was issued to stakeholder in July 2019 and finalized following stakeholder comment in October 2019. This is an extensive request and NS Power will follow up directly to discuss these comments.

Category	Participant	Assumption Comment	NS Power Response
7. ELCC (Wind, Solar, Battery and DR – Effective Load Carrying Capability)	Verschuren Centre	ETS should be considered separately from other forms of energy storage and demand control. ETS has more potential and higher ELCC than other technologies. Could be best solution for balancing wind energy.	NS Power's ETS program participation is considered in the 2019 Load Forecast. The load modifications assoc with the DR strategy, while not included in the current set of DR assumptions, could be viewed as incorporating a portion of ETS the specific program which would be determined. The DR assumptions presented can be viewed as a proxy for other DR programs that may be pursued in the future, dependent on technical capabilities and cost.
8. DSM	E1 (February 14)	Confirm avoided DSM costs: • Avoided energy & capacity will be output • Avoided T&D costs will be input, using values based on historical growth-related spending • Avoided environmental compliance costs included in avoided energy, as carbon credit $ included as fuel-related costs	• Confirmed that avoided energy and capacity will be output • Avoided T&D costs will not be an input to the IRP model; methodology for estimating avoided T&D costs will be developed through this IRP process. • Confirmed that environmental avoided costs will be included with fuel
8. DSM	E1 (February 14)	For 2021-2022, use DSM amounts in the 2020-2022 DSM supply agreement and hold remaining years constant on an incremental basis	Confirmed.
8. DSM	E1 (March 6)	Confirm levels of achievable cost-effective EE and DR in Potential Study are estimated for electrification scenarios considered in IRP because Potential Study levels based on 2019 Load Forecast	NS Power used the cost-effective EE and DR from the Potential Study as described in the Scenario Modeling Plan.
8. DSM	E1 (February 14)	Confirm or explain behaviour, codes, other agency initiatives, and market developments are part of the before DSM load forecast	Energy efficiency and demand response may come from a variety of sources. The IRP is agnostic as to the provider. The DSM Potential Study is being used for EE and DR potential assumptions; however actual delivery may come from a variety of sources as noted in the Assumptions.

Category	Participant	Assumption Comment	NS Power Response
8. DSM	E1 (February 14)	Confirm whether NSP using 2019 “Before DSM” load forecast which does not exclude all DSM	Confirmed.
8. DSM	E1 (February 14)	What modifications were made to 2019 load forecast for use in IRP; clarify whether embedded DSM removed from “Before DSM” scenario. Have potential study scenarios been modified other than shift for DSM activity 2021-2022? Provide Excel version of base load forecast and peak demand forecast including DSM scenarios.	Please refer to the Load Assumptions Overview in the final Assumptions set. The 2019 System Outlook future DSM amounts have a coefficient applied that accounts for embedded DSM and the “before DSM” in the System Outlook only adds back this adjusted amount rather than the full DSM. For the IRP scenarios, the No New DSM forecast includes the full future DSM added back in so that the basis for comparison is the same when the various E1 DSM scenarios are subtracted out. The Potential study scenarios have not been modified other than shift for DSM activity 2021-2022 and the above noted modification. These details have now been included in the Load Assumptions.
8. DSM	E1 (February 14)	Exclude DSM variability from supply-side risk sensitivity runs; may be beneficial to explore DSM risk mitigation effects by examining supply-side risk with and without DSM.	NS Power will follow up with E1 to better understand this suggestion.

Category	Participant	Assumption Comment	NS Power Response
8. DSM	SBA	Treating DSM as load modifier and only considering low, base, mid, max scenarios treats it as exogenous factor rather than integrated resource option. Suggests selection of DSM program implementation efforts will not be output of IRP optimization, but DSM scenarios that change load will be used as model inputs. Concerns with this approach: • Economics of different DSM amounts not tested • Doesn't look at potential focus differences (peak reduction vs energy reduction [which affects emissions] or summer vs winter peaking) • Doesn't capture dynamic effects between DSM penetration and avoided cost	NS Power acknowledges these points. The data provided through the Potential Study warrants treating DSM as a load modifier.
8. DSM	SBA	If DSM adoption depends on comparison of program cost to avoided cost, using DSM as input does not recognize that avoided cost changes with supply-side resource buildout.	Treating DSM as a load modifier does enable the quantification of avoided costs. Altering the level of DSM programming will result in different capacity expansion plans with different fuel and power purchase costs and distinct avoided DSM costs.
8. DSM	SBA	Some EE measures encourage electrification and could increase load – not clear whether captured in NS Power methodology.	NS Power agrees. Efficient electrification is captured within the Pathways Analysis.
8. DSM	SBA	Need specificity re how revenue requirements to be determined for annual DSM expenditures. i.e. multi-year amortization period. A question that arises is whether it is a variable.	Current annual program spending for DSM programs is treated as an expense in the IRP modeling. NS Power is open to alternative considerations as to how DSM recovery is matched to the benefits profile.

Category	Participant	Assumption Comment	NS Power Response
9. Demand Response	E1 (February 14)	Each market potential case for DR should be treated as one trajectory for spending and savings. Model the 3 DR Potential Study cases as load modifiers, potentially as drivers within Analysis Plan context.	Based on conversations with E1, NS Power has aggregated E1's DR programs into one trajectory for spending and savings for each case. NS Power will model the DR Potential Study cases as resource options.
10. Imports	CA (Chernick & Wilson)	Reflect correlation of temperature & load (NL, NS & NB) and availability /cost of imports.	This type of granularity is not included in NS Power's long term planning model.
10. Imports	CA (Chernick & Wilson)	Potential cost of new transmission or how impact analysis	This information has been provided in the final Assumptions.
10. Imports	CA (Chernick & Wilson)	Impact of 800 MW tie line becoming largest contingency w/ associated reserve requirements	Many factors in the design of a tie line would contribute to the ability of the line to provide firm peak capacity, and what its contribution to reserve requirements would be as a result of contingency modeling. Reliability considerations for candidate resource plans of interest will be considered during the Reliability and Operability Screening phase of the modeling.
10. Imports	CA (Chernick & Wilson)	Assuming imports clean understates emissions from NB coal or NE gas (and cost of meeting emission limits) or ignore economic imports of fossil generation	The model will be provided with pricing for both emitting (with REC / carbon price) and non-emitting sourced imports
12. Fuel Pricing (Gas)	CA (Chernick & Wilson)	Confirm if model selects new gas units, supply per option 3; alternatives would be potential substitutes to be evaluated post-IRP; alternative options not necessary for feasibility of gas units in IRP since option 3 feasible & sufficient	Confirmed for builds with a high capacity factor (i.e. combined cycle units)

Category	Participant	Assumption Comment	NS Power Response
12. Fuel Pricing (Gas)	CanWEA/SIA	Consider natural gas constraints through NE Will role of Canaport LNG in addressing peak change w/ proliferation of LNG in US	The 3 tiers of gas pricing based on incremental volumes and adjusted for seasonality are designed to capture the effects of natural gas pipeline constraints and reliance on LNG in some periods at some volumes.
13. Sustaining Capital	CA (Chernick & Wilson)	Please confirm or correct our understanding of the discussion about the utilization factor. We understand that the base forecast assumes capital investments that would occur if each unit operated at what NS Power considers to be a high utilization factor for that unit. We think you are defining “high” utilization as the most demanding experience of the unit in some recent historical period, as opposed defining “high” by the same metric for all units (e.g., 80% capacity factor). Thus, if the IRP results forecast relatively low utilization factors for some units, compared to the historical base, NS Power would expect future capital investments to be lower than the base assumptions included in the IRP.	Confirmed. The high utilization does generally imply the most demanding experience of the unit, however not necessarily indicative of a high capacity factor. NS Power agrees that if units are utilized at a lower utilization factor, NS Power would expect to see lower sustaining capital costs on those units.
13. Sustaining Capital	CA (Chernick & Wilson)	Are IRP and 2020 ACE sustaining capital forecasts based on different UF? Does sustaining capital for each unit reflect historical experience + inflation or is it increased to reflect age of the plant?	Yes. The ACE Plan is based on the annual bottom-up view and projected utilization, whereas in the IRP the high UF method puts all the units on an equal basis in terms of their operation in order to appropriately compare economics. As described in the Assumptions set, High and Low (or other iterative ranges) will be evaluated. The sustaining capital estimates in the final Assumptions set are presented in real 2020 dollars. For modeling inflation is included.
13. Sustaining Capital	Heritage Gas	NSP to review sustaining capital costs from slide 95 (Feb 3) against original (Jan 20) assumptions set; explain changes, esp. in light of revisions to vertical axis.	As discussed in the February 27 workshop, the change reflects basis of presentation (nominal to real dollars)

Category	Participant	Assumption Comment	NS Power Response
13. Sustaining Capital	SBA	Revised assumptions included significant changes to sustaining capital forecast for coal, CTs and small hydro.	The more significant change in basis of presentation was associated with the change from nominal to real dollars for the CTs. The other revisions reflect updated forecasts from June 2019 to January 2020.
14. Renewable Integration	CA (Chernick & Wilson)	What technology options will model have to meet minimum requirements for essential grid services such as hybrid resources or flexible solar? Suggest NSP host tech conference to explain and solicit feedback	Options available to the model to enable various levels of wind integration include a second 345kV AC tie line between Onslow, NS and Salisbury, NB or a 200 MVA Synchronous Condenser and 200 MW Battery located in Nova Scotia.
14. Renewable Integration	CanWEA/SIA	Need realistic assumptions re wind and solar integration strategies and costs: • Use expanded balancing footprint and joint system operations (NS/NB); better integration w/ NE market; sub-hourly scheduling and dispatch; real-time forecasts to reflect best practices • Use DR strategies to facilitate wind/solar energy integration (incl. space/H20 heating as storage w/ switching devices) • Curtail surplus wind / solar generation; electrolysis (if not enough export capacity to produce H) as element of solar integration • Flexible ML hydro imports to offset generation/load imbalances	Wind and Solar integration are being considered in the IRP, informed by the PSC Stability Study Pre-IRP deliverable.
14. Renewable Integration	Natural Forces	Reconsider inclusion of VAR support as key operational parameter (constraint could be resolved by easier cheaper solutions – installation of SVCs or synchronous condensers)	Synchronous Condensers are being considered as one method of integrating additional wind on the NS Power system; additional analysis on VAR and other essential grid services will be conducted during the Reliability and Operability phase of the IRP modeling process.

Category	Participant	Assumption Comment	NS Power Response
14. Renewable Integration	Natural Forces	Setting required minimum levels for remaining requirements important - synchronous inertia requirement will depend on largest system infeed/outfeed; Not likely able to model this degree of sophistication in IRP – will adopt single static values.	NS Power agrees that these more detailed wind integration requirements are important but are difficult to include in the capacity expansion portion of the model; these items will be examined during the Reliability and Operability assessment phases of the IRP Modeling Plan.
14. Renewable Integration	Natural Forces	Although there may be learnings from the PSC Renewable Integration study, have to take care as scenarios modelled in it don't reflect normal system conditions and grid service requirements.	The intent of the PSC Stability study was to model via transient analysis particular contingencies which the system must be able to survive in order to reliably service customers. Additional analyses on the integration of high levels of variable generation will be completed during the Reliability and Operability assessment phases of the IRP modeling plan.
14. Renewable Integration	Natural Forces	Proposed grid service level limits should be low rather than high, but don't want to exclude economic portfolio options, but this will be picked up in operability screening.	NS Power agrees; resource portfolios with high levels of variable generation will be analyzed during the Reliability and Operability assessment phases of the IRP modeling plan.
14. Renewable Integration	Natural Forces	Don't default to assumed existing levels of performance for capability of portfolio of resources to contribute to grid services. Considerations from elsewhere: • Generation units can improve flexibility and contribution to system services (ramping, min stable output, start times, reserves) • New generation can be configured to provide grid services optimally • Renewable plants are also important source of grid services • Widening supply base successful (demand side contribution to s/t operating reserves)	NS Power is interested to examine how variable generators can provide additional ancillary services during the Operability and Reliability screening phases; additional information and discussion on this front would be helpful.

Category	Participant	Assumption Comment	NS Power Response
15. Interconnection & T&D	Natural Forces	Treatment of interconnectors critical. Firm imports could support transition to lower GHG emissions, but fixed import schedules can reduce wind output/capacity as it squeezes space available for RES and local thermal/synchronous plants. Intertie to NB can be the most severe contingency on the system, determining grid services requirements. Request further description of proposed modelling of interconnector flows.	NS Power agrees that additional transmission interconnections are an enabler of further wind integration. Additional assumptions supporting renewable integrations have been included in the final Assumptions set.
15. Interconnection & T&D	Digby	Risk that distribution interconnection may not be available, which limits Digby's ability to introduce new generation capacity from renewable energy projects.	The capacity expansion modeling of the IRP is, in general, not location or project specific; therefore candidate locations for new generation resources would be considered as part of specific project planning post-IRP.
15. Interconnection & T&D	Verschuren Centre	IRP should take into account substation level capacity considerations (some of which have Transmission restraints as well). Most electrification will take place at end of line and place additional load on substations. Consider suite of distribution scale energy and capacity assumptions (1-10MW).	The IRP model does not consider the Distribution system explicitly however NS Power will be considering a methodology for avoided T&D costs as part of the IRP process. Once developed, this could be applied outside of the model to understand its impact.

Category	Participant	Comment	NSP Response
1.0 Analysis Plan General	E1 – Feb 14 2020	Clarify at what steps plans are assessed for removal from consideration Clarify data relationship among long term strategy, roadmap and action plan – will they be based on quantitative modelling findings What process if emissions regulations are more stringent after IRP? How determine whether decision gate, and if so, how reassess plans?	Please refer to the final Scenarios and Modeling Plan for additional details on the process and modeling phases. NS Power will bring both qualitative insights and quantitative results from the modeling phases into the Roadmap and Action Plan NS Power's approach to the 2020 IRP is to model a wide range of potential futures in order to identify options that are robust across many outcomes, including emissions profiles that are SDGA compliant and more stringent than current emissions limits.
1.1 Analysis Plan Evaluation Criteria General	E1 – Feb 14 2020	How will evaluation criteria be measured, when will resource plans be screened, and what are screening criteria?	NS Power confirms that NPV of Revenue Requirement will be the primary metric on which candidate resource plans are scored for a particular modeling scenario. NS Power also considers other factors to be important which is why additional metrics have been proposed for qualitative consideration during the preparation of the Roadmap and Action Plan.
1.2 Analysis Plan Evaluation Criteria Rate effects	E1 – Feb 14 2020	Not clear how 10-year NPV revenue requirement assesses timing & magnitude of rate effects – show why important metric and whether best proxy	To the extent that a shorter NPV period provides insight on near term rate effects, NS Power will consider this metric as one of the Evaluation Criteria used in the 2020 IRP.

Category	Participant	Comment	NSP Response
1.2 Analysis Plan Evaluation Criteria Rate effects	CA - Resource Insight	Revise to bill effects metric (customers more concerned about bills than rates): • Allocate RRQ to customer classes w/ simplified allocation metric Calculate average monthly bill by class based on forecast count and demand by class	NS Power will use the 10-year NPV evaluation criteria as a method of understanding near-term rate impacts of various resource portfolios.
1.3 Analysis Plan Evaluation Criteria Reliability requirements	E1 – Feb 14 2020	Eliminate plans that do not meet reliability requirements Confirm all metrics to be considered are listed on slide 4 row 3 or list all others	NS Power agrees that plans which do not meet the standards of the Resource and Operability Screening phases will not be considered as viable resource portfolios. NS Power's evaluation criteria are included in the Final Scenarios and Modeling Plan document.
1.4 Analysis Plan Evaluation Criteria Essential grid services	E1 – Feb 14 2020	Eliminate plans at reliability/operability screening if they do not meet requirements for essential grid services Consider integration costs (additional/supp grid services) in cost of NPV List grid services and evaluation criteria or thresholds assigned to each	NS Power agrees that plans which do not meet the standards of the Resource and Operability Screening phases will not be considered as viable resource portfolios. NS Power agrees and will be considering integration costs of wind at levels defined in the PSC Stability Study. Examples of grid services to be considered in the Reliability and Operability Screening phases are listed in the final Assumptions document.
1.5 Analysis Plan Evaluation Criteria Plan robustness	E1 – Feb 14 2020	Confirm if possible to combine plan robustness with 25-year NPV by assessing NPV rev req under high and low sensitivity analysis	Due to the number of potential sensitivities requested by stakeholders, NS Power does not believe that this combination would yield appropriate results to generate relative rankings of resource plans.

Category	Participant	Comment	NSP Response
1.5 Analysis Plan Evaluation Criteria Plan robustness	CA - Resource Insight	Calculate explicit measure of risk. Consider using stochastic analytics capability to model financial risk or uncertainty re plan cost risk Use stochastic analysis capability to determine how driver uncertainty affects portfolio cost; calculate risk/benefit ratio by comparing cost of greater than average cost outcomes with benefit of less than average cost outcomes	Risk elements are considered as part of the Plan Robustness evaluation which will consider how resource portfolios perform against different sensitivity assumptions. NS Power will consider opportunities to run stochastics if appropriate
1.5 Analysis Plan Evaluation Criteria Plan robustness	E1 – Feb 14 2020	Will NSP do stochastics and if so, on what variables? How will end effects be handled?	NS Power will consider opportunities to run stochastics if appropriate
1.6 Analysis Plan Evaluation Criteria Emissions reduction	E1 – Feb 14 2020	Quantify / provide total emissions per plan Consider total emissions per plan rather than reductions compared to a[n undefined] base case	Total NS Power fleet emissions of CO_2, Hg, NO_x, and SO_2 under each plan will be considered and quantified. NS Power is quantifying CO_2 reductions relative to 2005 actual emissions as a metric of reduction magnitude.
1.7 Analysis Plan Evaluation Criteria: Flexibility	E1 – Feb 14 2020	How will qualitative assessment of timing of investments be used? Risk of pushing all decisions out 25 years and delaying benefits of grid modernization / emission reductions not captured in rev requirement	NS Power will review the timing of capital investments in each plan to better understand the practicalities associated with their implementation.
1.7 Analysis Plan Evaluation Criteria: Flexibility	E1 – Feb 14 2020	Specify metric to evaluate DSM flexibility Clarify how flexibility to be scored for DSM (incl. EE and DR)	NS Power is not proposing to evaluate DSM flexibility as part of the evaluation criteria. Timing of DSM investments will be considered along with capital spend timing in the qualitative evaluation of a given resource plan's flexibility.

Category	Participant	Comment	NSP Response
1.8 Analysis Plan Evaluation Criteria **New metric**	CA - Resource Insight	Add qualitative resiliency metric considering how leading portfolio alternative perform in two resiliency scenarios Could use simple quantitative metrics to inform review, but judgment call because no good method for quantifying scenario probability	NS Power has added this consideration as part of the qualitative evaluation of Plan Robustness included in the final Scenarios and Modeling Plan document.
2.0 Scenarios General	CA - Resource Insight	Test "spliced" scenarios to see which portfolios most resilient	NS Power will evaluate a number of Scenarios paired with different Resource Strategies and Sensitivities in order to evaluate a broad range of potential outcomes during the IRP process.
2.0 Scenarios General	CA - Resource Insight	Objective should be to spread out portfolios so each portfolio tested under all scenarios.	NS Power does not believe it would be valuable to test all portfolios under all scenarios, as some may be incompatible (e.g. resource plan developed for a particular scenario may not be able to serve the load contained in another scenario). NS Power will examine a broad range of outcomes as part of this IRP and will focus sensitivity analysis on the scenarios which show the most commonality to all plans or have other attributes of significant interest.
2.0 Scenarios General	Natural Forces	Should be recognition of risk premium (implementation risk) associated w/ different scenarios (reliance on new/unproven technology, ambitious DSM) - additional implementation risk and risk of failure	Plan Robustness is a qualitative metric that NS Power has included in the Evaluation Criteria in order to provide a mechanism to consider the risks associated with a particular resource plan.

Category	Participant	Comment	NSP Response
2.0 Scenarios General	E1 – March 6 2020	Should not conduct quantitative comparisons of revenue requirement across electrification scenarios because of incompatibility [plans occupying different scenarios do not compete against each other] Since utility costs of electrification will not be accounted for in revenue requirement, inappropriate to quantitatively compare resulting revenue requirement between any two CRPs that rely on different electrification assumptions.	NS Power agrees that it would not be consistent to directly compare the NPV of Revenue Requirement associated with serving different electrification scenarios.
2.1 Scenarios Drivers GHG	CA - Resource Insight	Generate very diverse portfolios for evaluation If portfolios perform well tested against other scenarios, infer resilient to natural disaster or sudden carbon shifts	NS Power will evaluate a number of Scenarios paired with different Resource Strategies and Sensitivities in order to evaluate a broad range of potential outcomes during the IRP process. NS Power has also added Resiliency considerations as part of the qualitative evaluation of Plan Robustness included in the final Scenarios and Modeling Plan document.
2.2 Scenarios Drivers Load Avoided T&D Costs	E1 – February 14 2020	Consider avoided T&D costs and how calculated in order to avoid sub-optimal DSM amounts in IRP	Avoided T&D costs will not be an input to the IRP model; methodology for estimating avoided T&D costs will be developed through this IRP process.

Category	Participant	Comment	NSP Response
2.2 Scenarios Drivers Load Avoided T&D	E1 – March 6 2020	Avoided T&D costs part of separate process; NSP to calculate avoided T&D costs on narrower set of portfolios. Confirm avoided T&D costs cannot be calculated using IRP model and will not be an input to IRP model.	Please see above
2.2 Scenarios Drivers Load	E1 – February 14 2020	How are municipal electrical utilities modeled? How much load & peak demand in these forecasts and should there be any adjustments	Please refer to the 2019 Load Forecast for details on how municipal utility load has been forecasted; no adjustments have been made to this component of the IRP load forecast.
2.2 Scenarios Drivers Load	E1 – March 6 2020	Select one electrification scenario on basis of likelihood of each electrification scenario occurring; determination by E3 and NSP with opportunity for Stakeholder input	NS Power will evaluate a number of Scenarios paired with different Resource Strategies and Sensitivities in order to evaluate a broad range of potential outcomes during the IRP process.
2.2 Scenarios Drivers Load T&D	Digby	Transmission grid (69 kV line) from Tremont to Yarmouth impedes area's ability to contribute to greening of environment & sustainable solutions	The capacity expansion modeling of the IRP is, in general, not location or project specific; therefore candidate locations for new generation resources would be considered as part of specific project planning post-IRP.
2.2 Scenarios Drivers Load	CA - Resource Insight	Consider Electrification of building & transportation	The load forecast assumptions were informed by the PATHWAYS work, which considers several electrification scenarios for the Nova Scotia economy that produce a wide range of long-term outcomes in terms of both peak and energy requirements.
2.2 Scenarios Drivers Load	E1 – March 6 2020	Confirm Pathways agnostic regarding costs, mechanisms and delivery entities for electrification	Confirmed

Category	Participant	Comment	NSP Response
2.2 Scenarios Drivers Load	E1 – March 6 2020	It seems the best path forward for the 2020 IRP, given the current data and desire to explore electrification scenarios, is to allow the four DSM Potential Study scenarios to be paired with the three electrification scenarios	Due to the complexity of modeling NS Power is not able to test all DSM profiles across all modeling scenarios. Please see the Scenario and Modeling Plan for additional details on DSM sensitivities.
2.2 Scenarios Drivers Load	CA - Resource Insight	Test all 4 DSM levels across all scenarios	Due to the complexity of modeling NS Power is not able to test all DSM profiles across all modeling scenarios. Please see the Scenario and Modeling Plan for additional details on DSM sensitivities.
2.2 Scenarios Drivers Load	E1 – March 6 2020	Allow 4 DSM scenarios to be paired with 3 electrification scenarios	Please see above
2.5 Scenarios Candidate Scenarios	CA - Resource Insight	Instead of Scenario 2 – Net zero – high electrification suggest: Accelerated 1.0 Mt 2050; high electrification + higher industrial/marine demand / coal end 2030 High electrification logical w/ coal phase-out Pathways excluded industrial & marine sectors from electrification or other load growth drivers but technology trends will shift more industrial use to electricity. Supply-side option development will also support electrification of marine vessels and other equipment. Marine load higher electrification w/ high load factors or off-peak charging. Test early coal closure w/ current landscape strategy (not just renewable integration). Phasing out coal may otherwise be economic.	Please refer to the final Scenarios and Modeling plan as well as the Final Assumptions for how stakeholder feedback on scenarios has been incorporated. NS Power's intention is to test a broad range of scenarios in the IRP modeling in order to capture the uncertainty of potential futures. The IRP model will be able to retire coal units when economic; the Current Landscape scenario with coal closure in 2040 will allow this option to be tested.

Category	Participant	Comment	NSP Response
3.1 Screening Reliability	Dalhousie	Need to show how grid resiliency modelled in scenarios	Applicable reliability targets will be met by viable resource portfolios. Transmission & Distribution considerations for storm hardening and resiliency are not considered by the IRP model as it is in general not location specific.
4.0 Strategies General	CA - Resource Insight	Why test only one strategy under comparator case? Provide information re relative performance of several resource strategies under current policy scenario	Since the Comparator case is non-compliant with the SDGA, NS Power does not believe it would add value to consider additional Resource Strategies under the Comparator scenario. NS Power has added Scenario 2.0 which combines a Low Electrification load with an SDGA compliant GHG trajectory which will be tested against both the Current Landscape and Regional Integration resource strategies.
5.0 Portfolios	E1 – February 14 2020	Request a preferred resource plan as directed by UARB in 2014 IRP Preferred resource plan necessary to calculate DSM avoided energy & capacity costs	In their subsequent comments on March 6 2020 E1 stated they "recommend[s] that NS Power select one electrification scenario on the basis of perceived likelihood of each scenario occurring. This determination should be made by NS Power and E3, with opportunity for comment and input from Stakeholders. NS Power then select a PRP from within the 'most likely' electrification scenario. E1 believes the above to represent a fair and transparent means of PRP selection." This appears to be a reasonable approach and will continue to discuss with stakeholders as the modeling phase progresses.

Category	Participant	Comment	NSP Response
6.4 Sensitivities No New Emitting	CA - Resource Insight	No new emitting might be better tested as sensitivity rather than distinct strategy. See what new emitting resources arise from modeling runs and apply as portfolio sensitivity to runs to see what non-emitting alternative is.	NS Power agrees with this approach and has made this adjustment in the final Scenarios and Modeling Plan.
6.5 Sensitivities Pricing	CA - Resource Insight	Consider sensitivity for price paid for power exported from NS. Model to follow import price? Will there be significant exports (> Tx and wind)?	NS Power's base assumption is that due to the correlated nature of wind in the Maritimes, times of peak generation (and most significant opportunity for exports) will be correlated with times of peak generation in neighbouring jurisdictions, depressing any export prices.

2020 IRP
SCENARIOS AND MODELING PLAN

FEBRUARY 27, 2020

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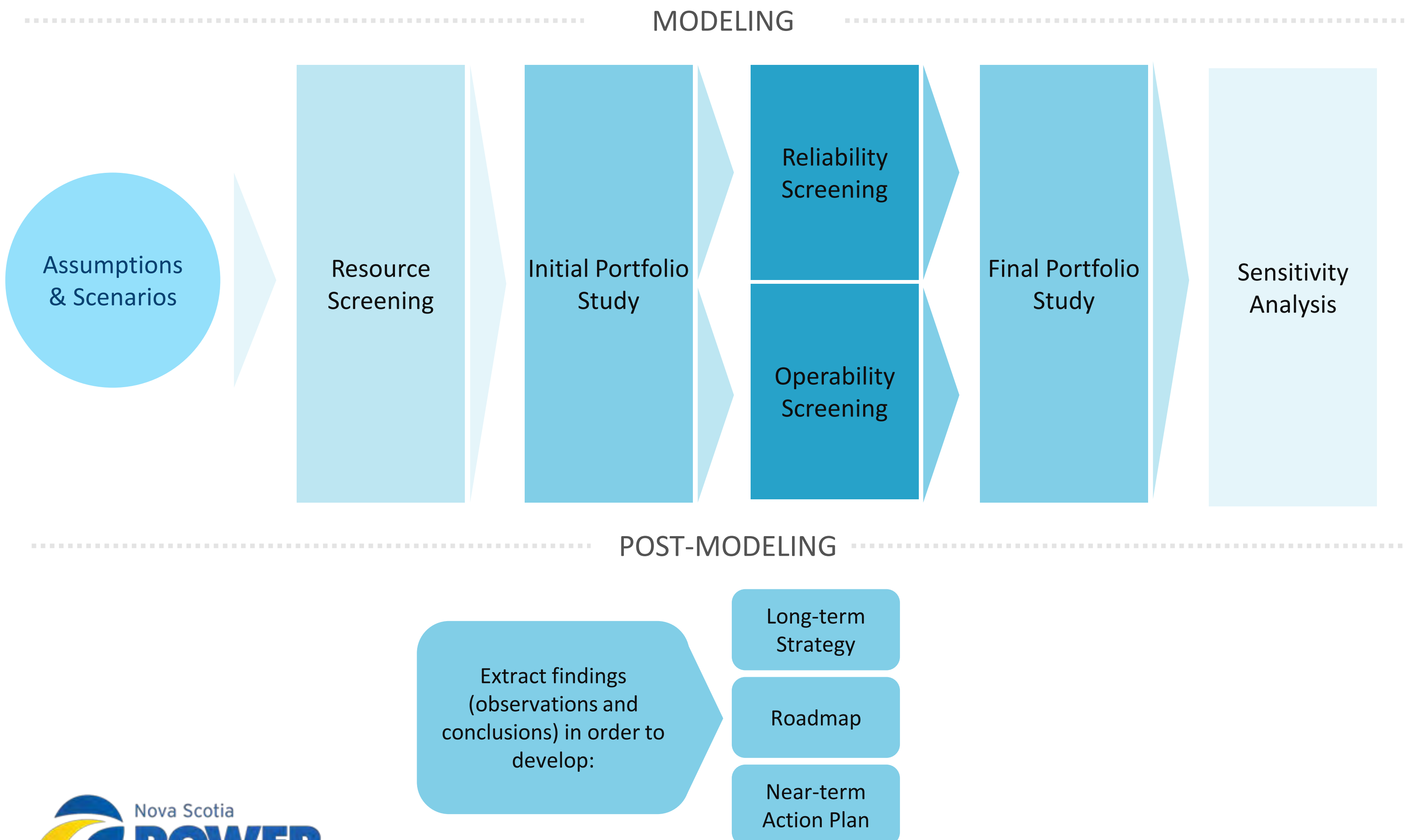
IRP ANALYSIS: PROCESS OVERVIEW



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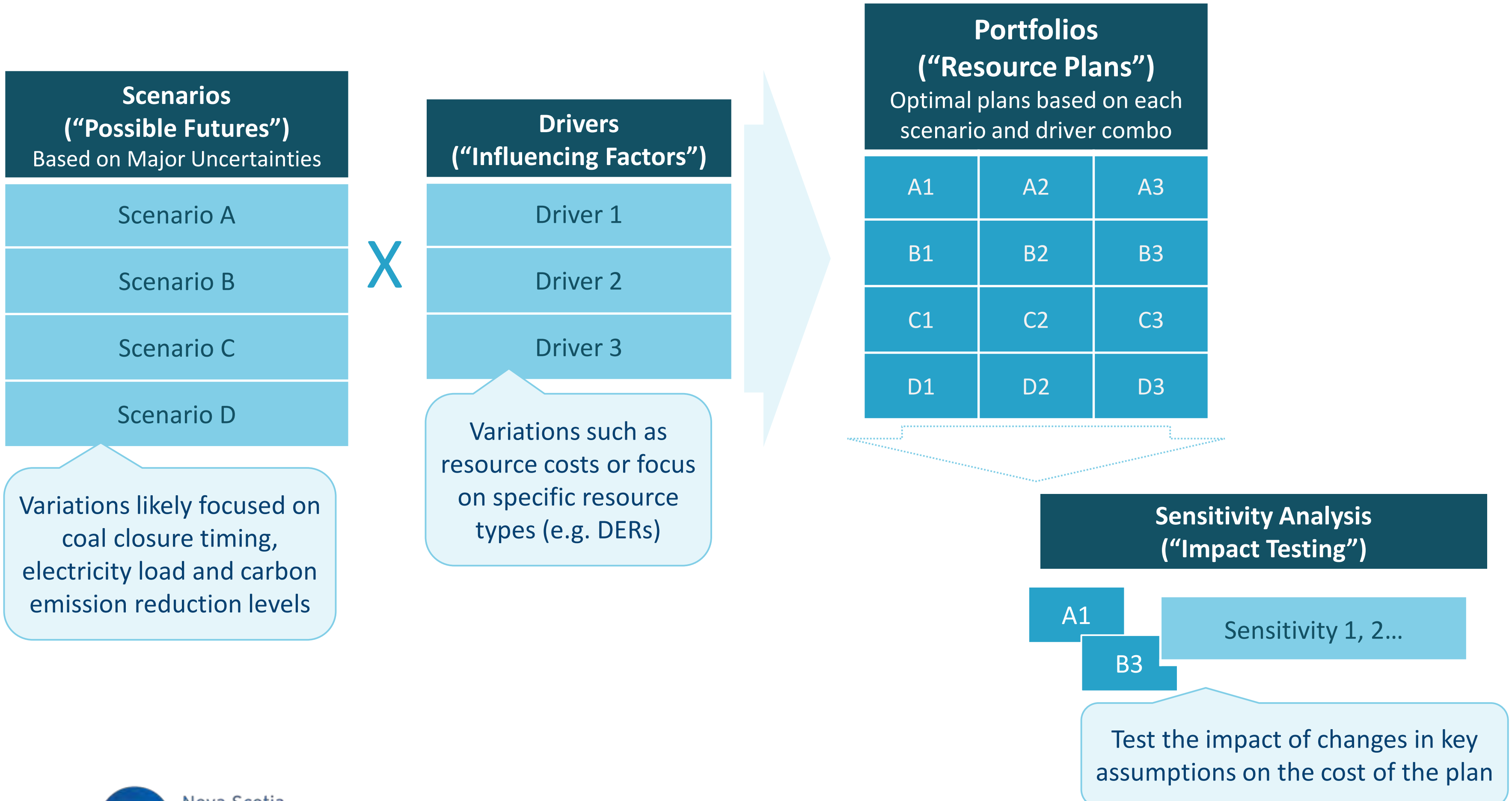
PORTFOLIO STUDY SCENARIO DEVELOPMENT APPROACH



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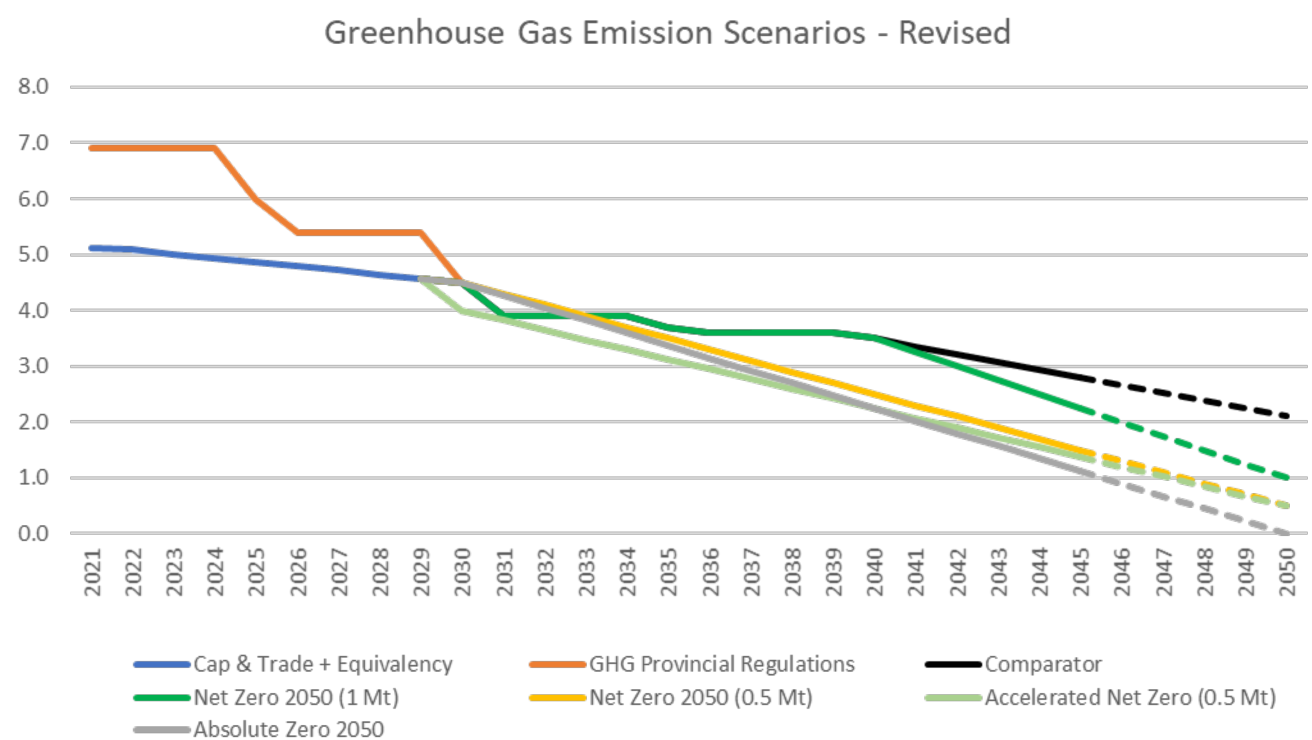
KEY POLICY DRIVERS

GREENHOUSE GAS EMISSIONS BY ELECTRICITY SECTOR

	CO2 2030	CO2 2040	CO2 2045	CO2 2050*
Comparator GHG Case	4.5	3.5	2.8	2.1
Reductions consistent with equivalency agreement and continued future decline	*(58% reduction from 2005)*	*(67% reduction from 2005)*	*(74% reduction from 2005)*	*(80% reduction from 2005)*
Net Zero 2050 (1 Mt)	4.5	3.5	2.3	1.0
Reduction to 1 Mt by 2050 (assumes achievement of "net zero" via mechanism)	*(58% reduction from 2005)*	*(67% reduction from 2005)*	*(78% reduction from 2005)*	*(91% reduction from 2005)*
Net Zero 2050 (0.5 Mt)	4.5	3.5	2.0	0.5
Reduction to 0.5 Mt by 2050 (assumes achievement of "net zero" via mechanism)	*(58% reduction from 2005)*	*(67% reduction from 2005)*	*(81% reduction from 2005)*	*(95% reduction from 2005)*
Accelerated Net Zero 2050 (0.5 Mt)	4.0	2.3	1.4	0.5
Reduction to 0.5 Mt by 2050 with acceleration of pace beginning in 2030	*(62% reduction from 2005)*	*(78% reduction from 2005)*	*(87% reduction from 2005)*	*(95% reduction from 2005)*
Absolute Zero 2050 (0 Mt)	4.5	2.3	1.1	0
Reduction to 0 Mt by 2050	*(58% reduction from 2005)*	*(78% reduction from 2005)*	*(90% reduction from 2005)*	*(100% reduction from 2005)*

KEY POLICY DRIVERS

GREENHOUSE GAS EMISSIONS BY ELECTRICITY SECTOR



KEY POLICY DRIVERS

LOAD CHANGES

Business as Usual
- 2019 Load Forecast

Moderate Electrification
- Moderate Space and Water Heating
- Moderate EV

High Electrification
- High Space & Water Heating
- High EV

Applied DSM Scenarios

COAL CLOSURE POLICY

All Units Retired 2030
- Adherence to Federal Regulations

All Units Retired 2040
- Ongoing Equivalency Agreements

KEY SCENARIOS

	2050 GHG (MT)	Load Driver	Coal Closure
Comparator Case	2.1	BAU	2040
Net Zero – High Electrification	1.0	High Elec.	2040
Net Zero – Moderate Electrification (with Early Coal Closure)	0.5	Moderate Elec.	2030
Net Zero – Moderate Electrification	0.5	Moderate Elec.	2040
Absolute Zero World	0	Moderate Elec.	2030

Additional scenarios of interest to screen using RESOLVE include:

- Accelerated 0.5 Mt 2050 / Moderate Electrification / Coal End 2030
- Net Zero – 1 Mt 2050 / High Electrification / Coal End 2030
- Net Zero – 0.5 Mt 2050/ Business as Usual / Coal End 2040
- Net Zero – 0.5 Mt 2050 / Moderate Electrification / Coal End 2030

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RESOURCE STRATEGIES

Current Landscape	Distributed Resources Promoted	Regional Integration	No New Emitting Resources
• New In-Province Resources (Supply & Demand) • No new Interconnections	• Distributed supply and demand resources are preferred where possible • DER are prioritized in the resource screening stage	• New In-Province Resources (Supply & Demand) • New Inter-connections and corresponding access to energy and capacity	• New in-province and imported supply and demand resources must be non-emitting

- Designed to ensure the IRP analysis covers key areas of importance / interest
- Serve to promote or limit certain resource options to allow them to be evaluated

KEY PAIRS: SCENARIOS & STRATEGIES

Scenario	Resource Strategy
Comparator Case	Current Landscape
Net Zero – High Electrification	Current Landscape
Net Zero – High Electrification	Distributed Resources Promoted
Net Zero – High Electrification	Regional Integration
Net Zero – Moderate Electrification	Current Landscape
Net Zero – Moderate Electrification	Distributed Resources Promoted
Net Zero – Moderate Electrification	Regional Integration
Net Zero – Moderate Electrification w/ ECC	Regional Integration
Absolute Zero World	Regional Integration
Absolute Zero World	No New Emitting Resources

- These pairs represent the proposed ten preliminary modeling runs to be conducted in Plexos LT in the Initial Portfolio Study Phase
- Additional combinations of scenarios and strategies can be tested using E3's RESOLVE model to assess if they should be included as a key modeling run

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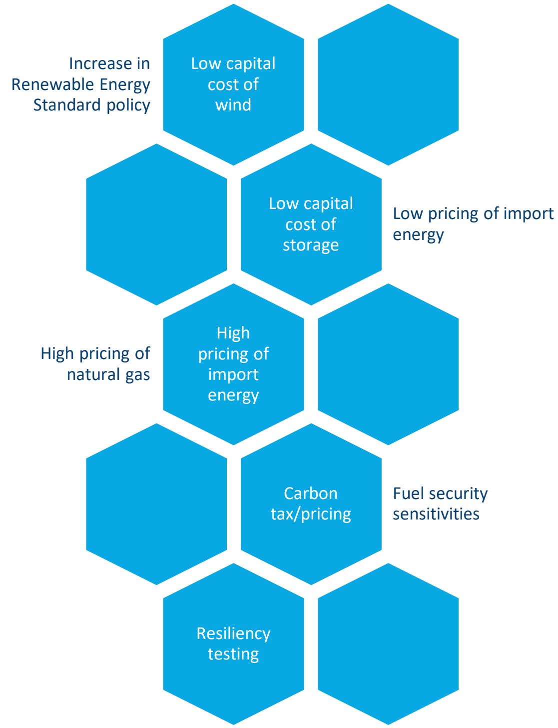
SENSITIVITY ANALYSIS



- Run against a resource portfolio to determine how it responds to changes in assumptions
- Prioritized with Stakeholders based on emerging insights from the ongoing analysis

PROPOSED EVALUATION CRITERIA

Metric	Description
Minimization of the cumulative present value of the annual revenue requirements over the planning horizon (adjusted for end-effects)	25 year NPV Revenue Requirement
Magnitude and timing of electricity rate effects	10 year NPV Revenue Requirement
Reliability requirements for supply adequacy	Evaluation of PRM, resource capacity adequacy, operating reserve requirements, etc.
Provision of essential grid services for system stability and reliability	Quantitative and qualitative assessment of the status of essential grid services provision for each portfolio.
Plan robustness (the ability of a plan to withstand plausible potential changes to key assumptions)	Magnitude of the plan's exposure to changes in key assumptions (via sensitivity analysis)
Reduction of greenhouse gas and/or other emissions	Mt of CO2 reduced over 25 years
Flexibility (limitation of constraints on future decisions arising from the selection of a particular path)	Qualitative assessment of timing of investments

Appendix I

Nova Scotia Power IRP

Interim Modeling Update Participant Engagement

2020 IRP INTERIM MODELING PROGRESS WORKSHOP

APRIL 28, 2020

Nova Scotia POWER An Emera Company

AGENDA

- INTRODUCTIONS & SAFETY MOMENT
- PROCESS UPDATE & WORK COMPLETED
- KEY ASSUMPTIONS & POLICY DRIVERS
  - Environmental
  - Electrification & Load Growth
  - Resource Strategies
- KEY MODELING SCENARIOS
- MODELING PLAN & STATUS UPDATE
  - Resource Screening Update
  - Initial Portfolio Study Update & Results Preview
- T&D AVOIDED COSTS METHODOLOGY UPDATE
- NEXT STEPS

PROCESS UPDATE & WORK COMPLETED

- Recap: Since the Summer/Fall of 2019, NSP has finalized the Terms of Reference, Scenarios & Modeling Plan, and Assumptions and has begun modeling work
- Stakeholder consultation and engagement continues to be a priority for the IRP team

UARB NSP Pre-IRP
Deliverables

- Capacity Study
- Supply Options Study
- Demand Response Assumptions
- Stability Study

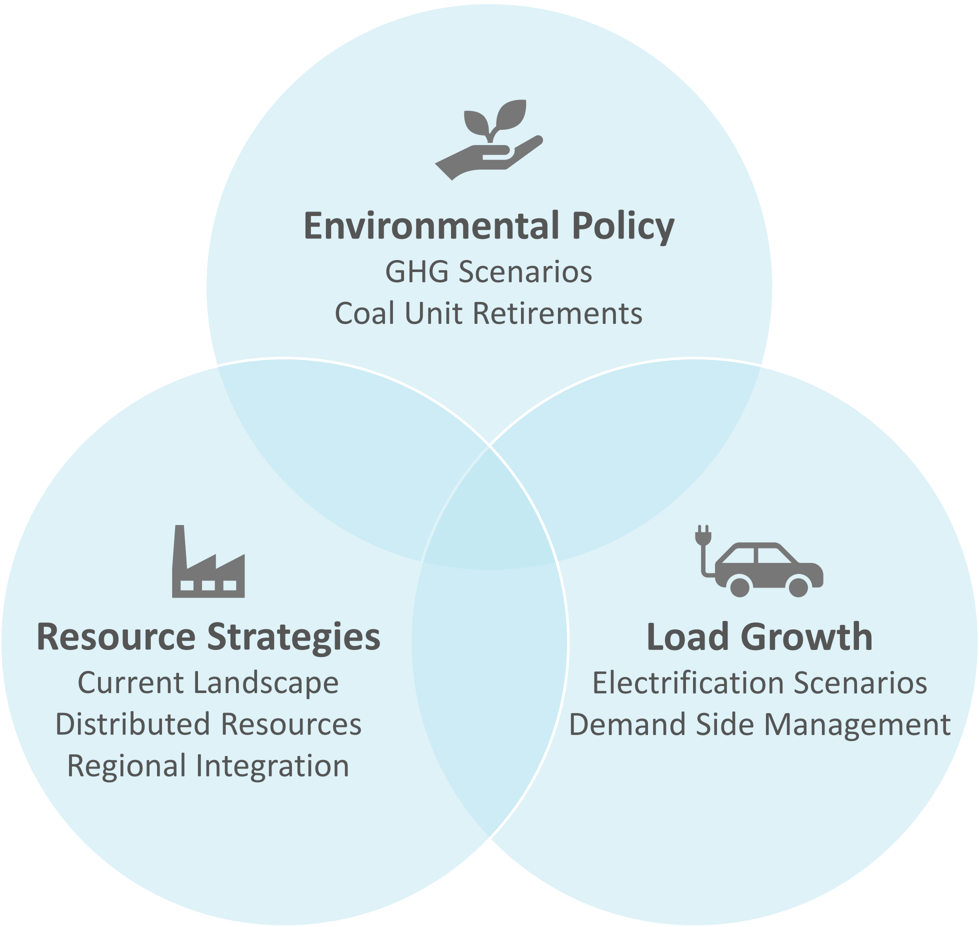
Core IRP Process
resulting in Final Report

Sept 2020

- Terms of Reference
- Scenario Development
- Modeling Plan
- Assumptions
- Modeling
- Analysis/Conclusions
- Report, Roadmap, & Action Plan

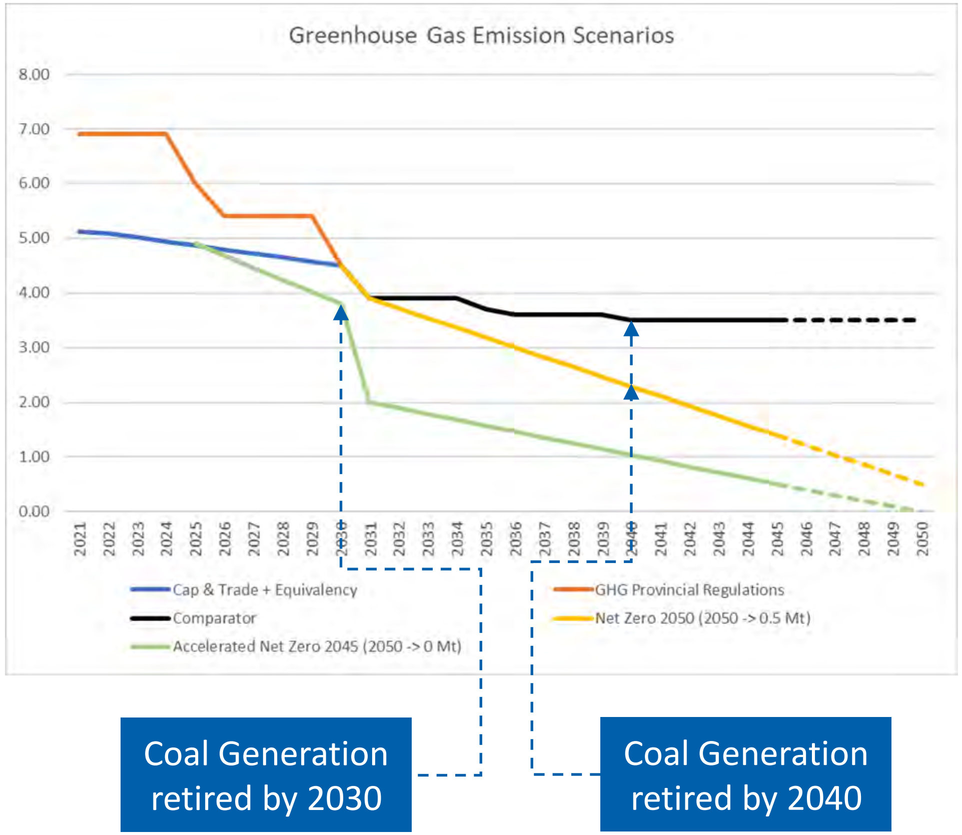
Previously completed
Completed since last update
In Progress

KEY ASSUMPTIONS & POLICY DRIVERS



- NS Power has developed assumptions for all major inputs to the IRP model:
  - Financial
  - Load
  - Demand Side Management
  - Supply Options
  - Distributed Energy Resources
  - Planning Reserve Margin
  - Environmental
  - Demand Response
  - Imports & Transmission
  - Fuel Pricing
  - Sustaining Capital
  - Renewable Integration
- The comprehensive assumption set will allow the IRP to analyze the sensitivity of the resource plans to changes in assumptions, and build a series of key insights and signposts to monitor
- Stakeholder input incorporated into the development of the assumptions, scenarios, and modeling plan
- Written responses to over 160 individual questions and comments on these topics

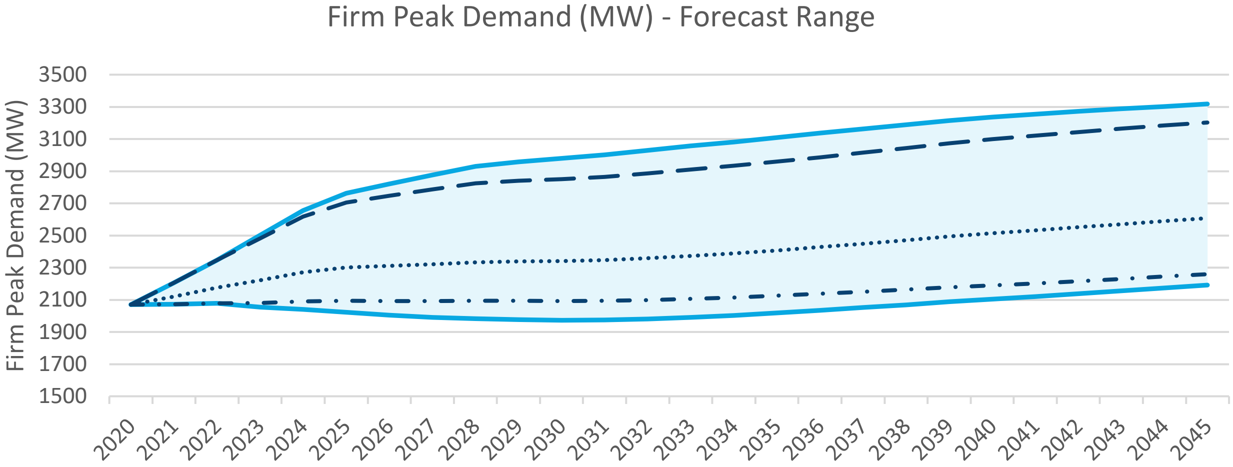
ENVIRONMENTAL ASSUMPTIONS

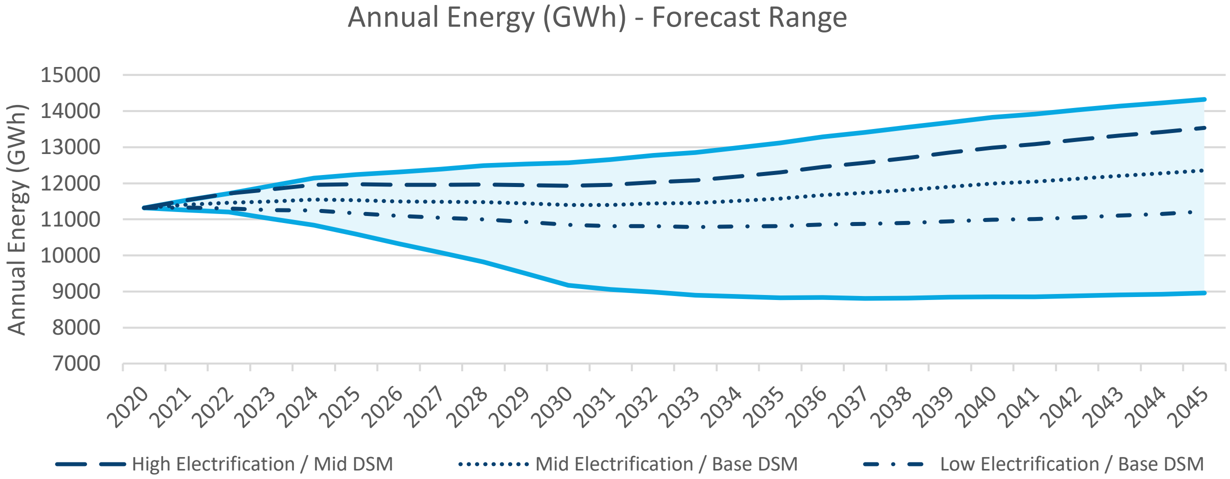


- NS Power has developed three Greenhouse Gas scenarios which reflect potential future federal and provincial carbon policies
- The *Net Zero 2050* and *Accelerated Net Zero 2045* scenarios are both SDGA* compliant and represent different possible rates of decarbonization of the electricity sector
- Each scenario incorporates mandatory coal unit retirements by no later than 2030 or 2040; earlier retirement is possible if economic

**Sustainable Development Goals Act (Nova Scotia)*

ELECTRIFICATION & LOAD GROWTH





- A key driver for the IRP is the interplay of de-carbonization and electrification in the Nova Scotia economy
- NS Power has developed a series of IRP load forecasts by combining four components:

- The E3 PATHWAYS study produced various electrification scenarios based on decarbonization of building and transportation energy use
- EfficiencyOne produced a series of DSM* scenarios via their 2019 DSM Potential Study
- The various combinations of these inputs produce the wide range of outcomes of Firm Peak Demand (MW) and Annual Energy (GWh) by the end of the IRP planning horizon:
    - Annual Energy: 9,000 – 14,300 GWh
    - Firm Peak Demand: 2,200 – 3,300 MW

Demand Side Management

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RESOURCE STRATEGIES

- Three resource strategies will be modeled to ensure the IRP examines a broad range of supply and demand side options; this will enable analyses of the value and cost deltas inherent in each of these approaches including sensitivities and interplay among the strategies

Current Landscape

Serve customer load and meet environmental requirements via in-province supply and demand resources

Distributed Resources

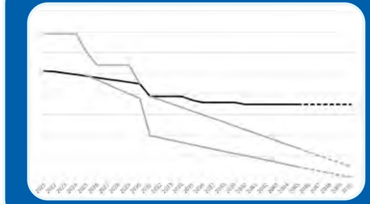
Promote the uptake of Distributed Energy Resources (e.g. rooftop solar)

Regional Integration

New Transmission Interconnections enable access to energy and firm capacity resources outside of Nova Scotia

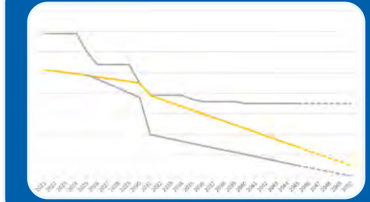
KEY MODELING SCENARIOS

- NS Power has identified key combinations of assumptions, policy drivers, and resource strategies to examine
- The first runs from these key scenarios are being run now as part of the Initial Portfolio Study



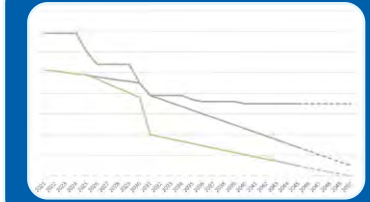
Comparator

- Not SDGA* compliant; Federal equivalency maintained & minimal CO_2 reductions post-2030
- Provides a basis for comparison of CO_2 policy options & enables model validation against previous studies (e.g. 2018 Generation Utilization & Optimization)



Net Zero 2050

- SDGA compliant; will test key combinations of electrification and DSM scenarios against all three resource strategies
- Base case for sensitivity analysis in the IRP (e.g. fuel prices, capital costs, etc.)



Accelerated Net Zero 2045

- SDGA compliant; allows testing of more aggressive assumptions for GHG reductions and coal generation retirements; potential for absolute zero CO_2 emissions by 2050
- Represents feedback from several stakeholder groups

Sustainable Development Goals Act (Nova Scotia)

KEY MODELING SCENARIOS

Scenario	Features	Load Drivers	Coal Retires	Resource Strategies Tested	Key Sensitivities
1.0 **Comparator**	Equivalency GHG	Low Elec. Base DSM	2040	A - Current Landscape	
2.0 **Net Zero 2050** **Low Electrification**	GHG targets decline linearly from 2030 to 0.5Mt in 2050	Low Elec. Base DSM	2040	A - Current Landscape C - Regional Integration	• DSM Levels
2.1 **Net Zero 2050** **Mid Electrification**	GHG targets decline linearly from 2030 to 0.5Mt in 2050	Mid Elec. Base DSM	2040	A - Current Landscape B - Distributed Resources C - Regional Integration	• DSM Levels • No New Emitting • Target Case for Sensitivity Evaluation
2.2 **Net Zero 2050** **High Electrification**	GHG targets decline linearly from 2030 to 0.5Mt in 2050	High Elec. Max DSM	2040	A - Current Landscape C - Regional Integration	• DSM Levels • No New Emitting
3.1 **Accelerated Net Zero 2045 Mid Electrification**	GHG targets decline from 2025 to 0.5Mt in 2045; path to Absolute Zero 2050	Mid Elec. Base DSM	2030	B - Distributed Resources C - Regional Integration	• DSM Levels • No New Emitting • Target Case for Sensitivity Evaluation
3.2 **Accelerated Net Zero 2045 High Electrification**	GHG targets decline from 2025 to 0.5Mt in 2045; path to Absolute Zero 2050	High Elec. Max DSM	2030	B - Distributed Resources C - Regional Integration	• DSM Levels

IRP MODELING PLAN

MODELING

Assumptions & Scenarios

Resource Screening

In Progress

Initial Portfolio Study

In Progress

Reliability Screening

Operability Screening

Final Portfolio Study

Sensitivity Analysis

POST-MODELING

Extract findings (observations and conclusions) in order to develop:

- Long-term Strategy
- Roadmap
- Near-term Action Plan

MODEL STATUS UPDATES

WORK COMPLETED TO DATE

- Final Assumptions have been entered into both RESOLVE and PLEXOS models
- Significant volume of test runs undertaking to confirm model functionality and optimize execution parameters
- Comparison of results between PLEXOS and RESOLVE has enabled detailed testing of both models – benefit of our parallel approach
- Focus of initial modeling has been on two key scenarios:
  - 1.0A Comparator – Current Landscape
  - 2.1C Net Zero 2050 – Regional Integration

INITIAL MODELING NOTES

- The quality of the PLEXOS LT model is sensitive to execution time; we are factoring this into our modeling plan
- Initial Portfolio Study runs (PLEXOS) and Resource Screening runs (RESOLVE) are now in progress

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RESOURCE SCREENING UPDATE

The Resource Screening phase is designed to support key assumptions in the Initial Portfolio Study by testing key model assumptions.

- Using E3's RESOLVE model allows a sets of runs to be executed quickly due to the faster execution time of the model
- The methodology for screening is to do an "in-and-out" analysis of the resource being tested, and then to compare NPV RR across key scenarios
- Resources that screen "in" can be fixed in the PLEXOS model for the Initial Portfolio Study; this reduces the number of variables and improves execution time and solution quality for those runs

As part of the IRP, NS Power is undertaking 3 screening analyses:

- Diesel CT Screening
- Hydro Screening
- Carbon Price Screening

RESOLVE MODEL STRUCTURE

+ RESOLVE co-optimizes investments and operations to minimize total NPV of electric system cost

- Investments and operations optimized in a single stage
- Single-stage optimization directly captures linkages between investment decisions and system operations
- Relies on hourly dispatch for a subset of representative days, with a parameterization of sub-hourly impacts

Objective Function

+ Fixed Costs
  - *Renewables*
  - *Energy storage*
  - *EE & DR*
  - *Thermal*
  - *Transmission*

+ Variable Costs
  - *Variable O&M*
  - *Start costs*
  - *Fuel costs*
  - *Carbon*

Decisions

Investments

System Operations

Constraints

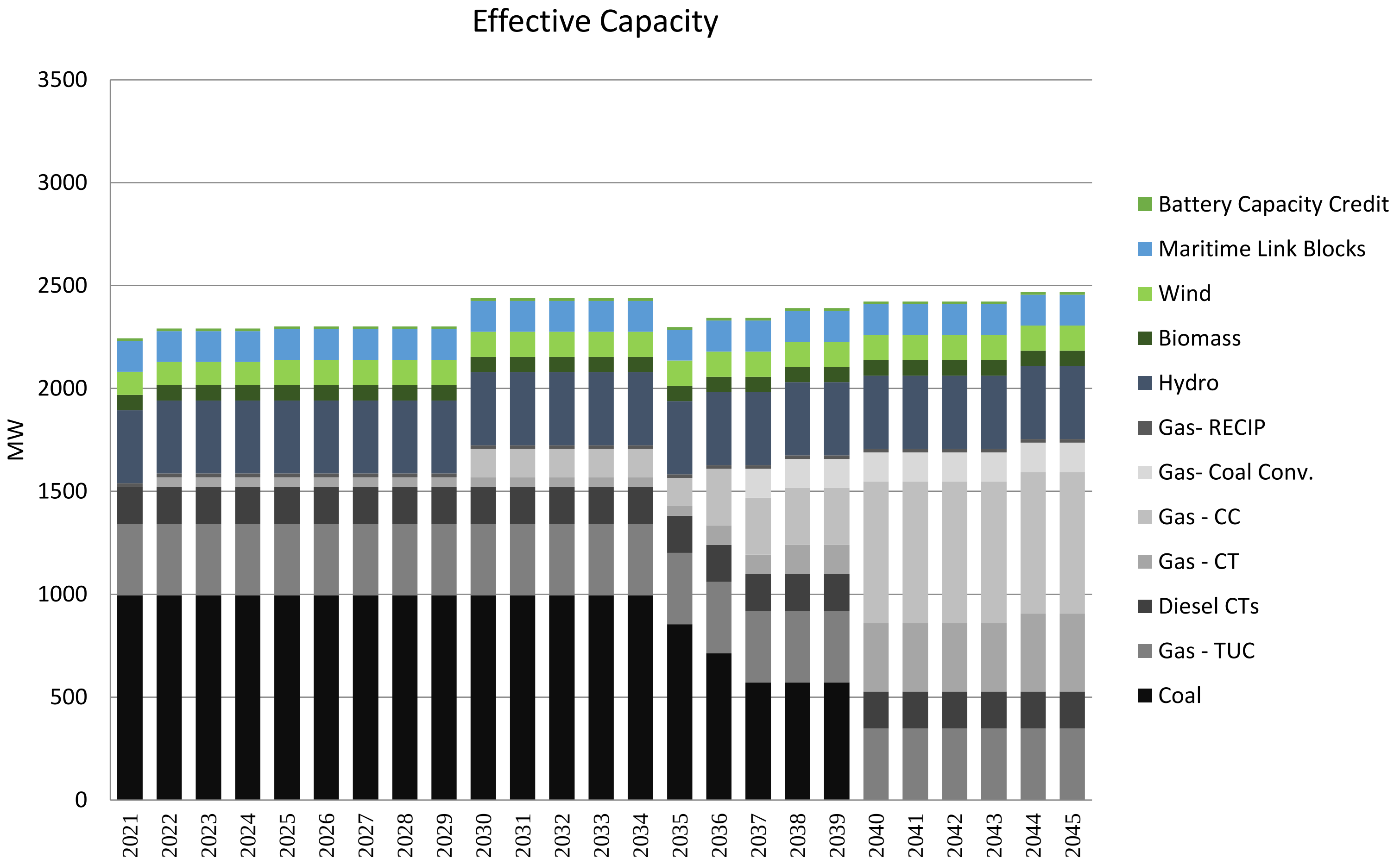
- RPS Target
- GHG Target
- PRM
- Operations
- Resource Limits

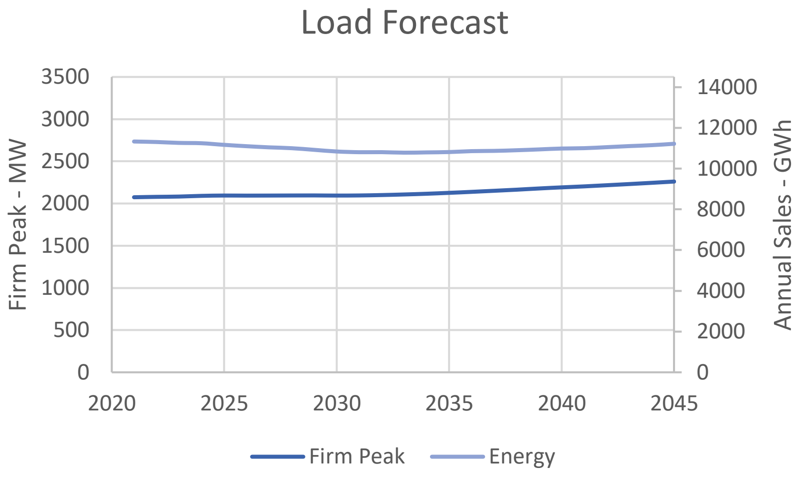
INITIAL PORTFOLIO STUDY UPDATE

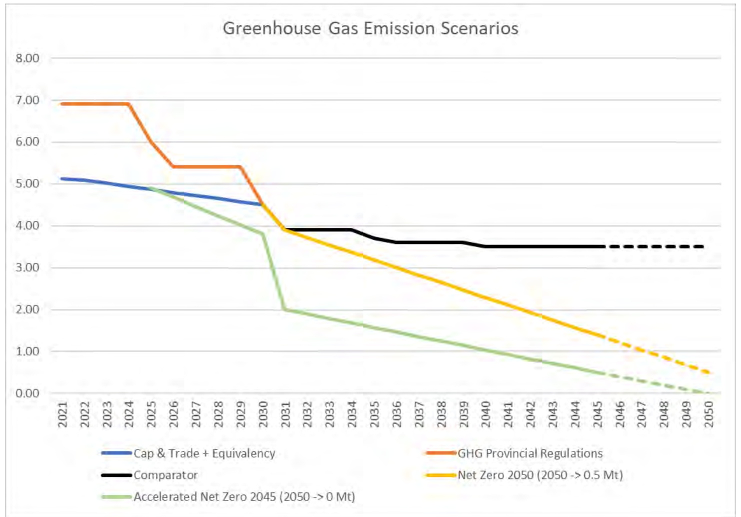
- Initial Portfolio Study runs are currently underway
- To begin, focus has been on the 1.0A Comparator – Current Landscape scenario

- The results on the following slides are preliminary and intended to provide a view of the modeling work completed to date to IRP participants
  - They are not considered final and are subject to be updated through the remainder of the IRP modeling phase

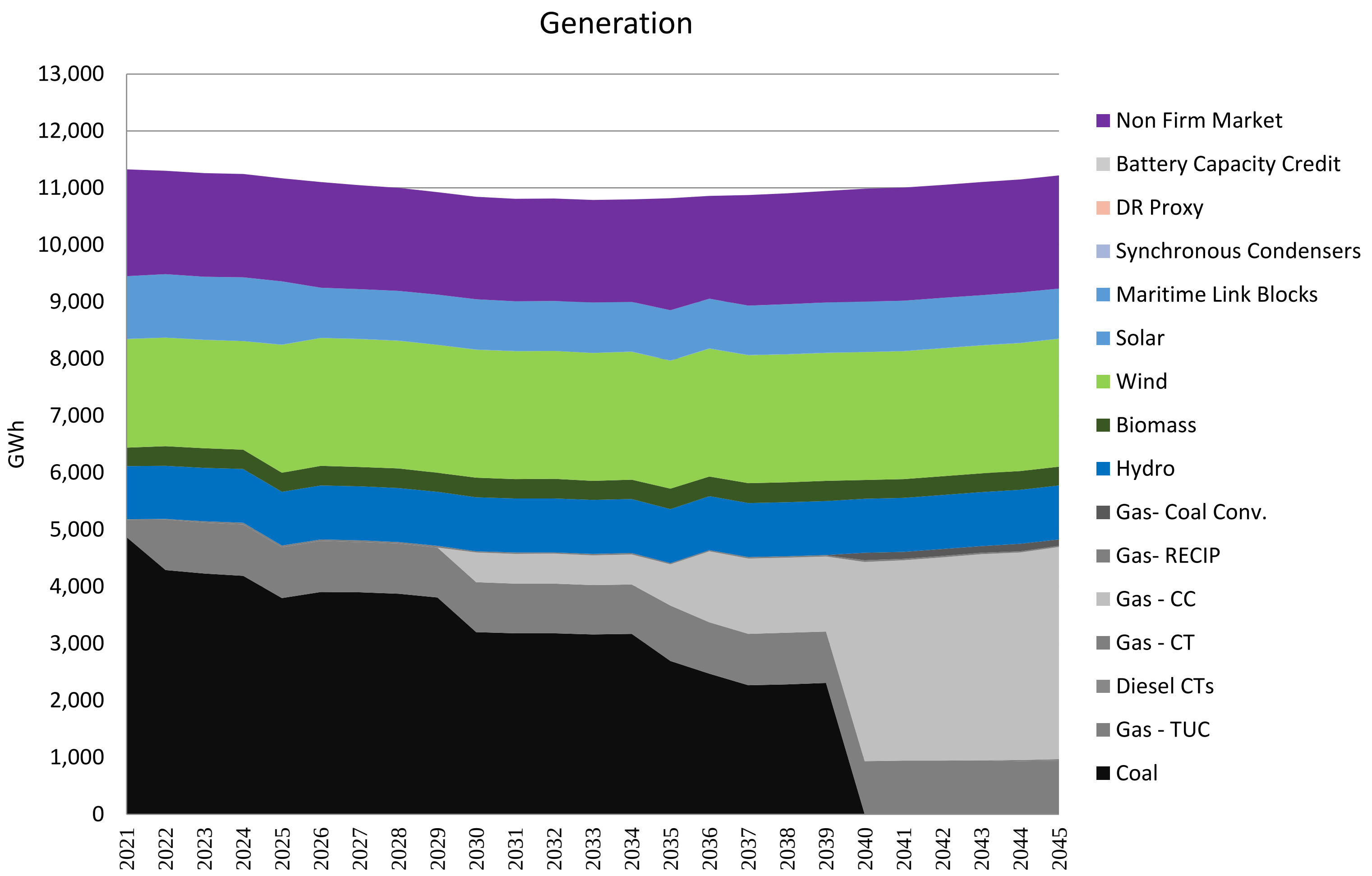
PRELIMINARY RESULTS PREVIEW: 1.0A COMPARATOR (CURRENT LANDSCAPE)

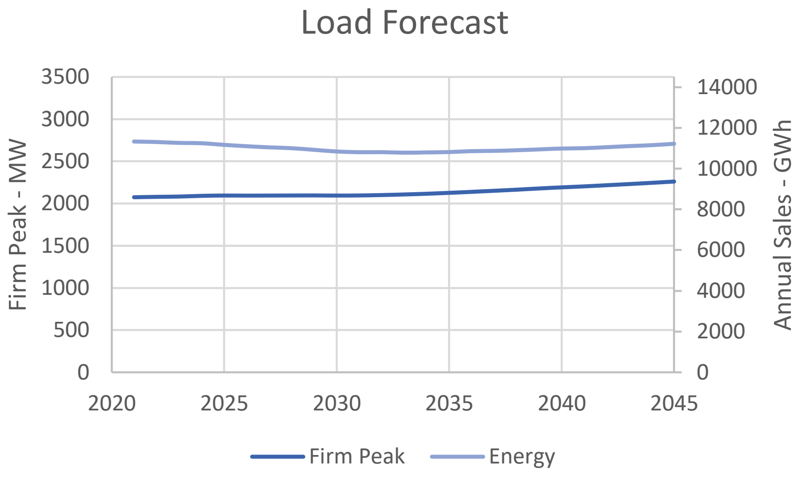


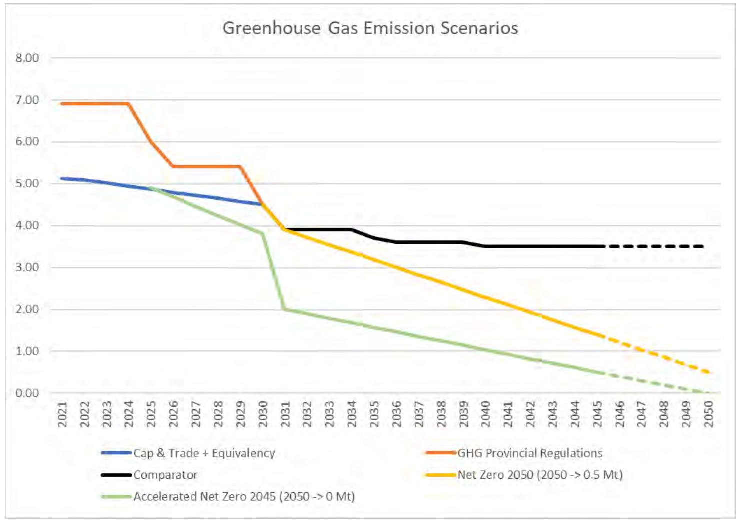




PRELIMINARY RESULTS PREVIEW: 1.0A COMPARATOR (CURRENT LANDSCAPE)







T&D AVOIDED COST METHODOLOGY UPDATE

NS Power's T&D Avoided Cost methodology will be reviewed during the 2020 IRP Process

BACKGROUND

- NS Power has calculated and provided Avoided T&D Costs as part of DSM Rate and Bill Impact Analysis (RBIA) processes since 2015. In order to develop Avoided T&D Costs, the Annual Capital Expenditure (ACE) Plans from 2007 onward were used as the primary data source
  - Each ACE Plan was reviewed to break out the T&D capital investments by category (load growth, non-load growth, etc.)
  - Load growth investments were deemed to include any investment that enables additional load to be served by the transmission or distribution system (i.e. line rebuilds, feeder reconfigurations, reconductoring projects)
  - These investments provide additional T&D system capacity, often due to new construction standards and equipment capabilities, whether or not that incremental capacity is currently required based on the load forecast for that system
  - The costs of projects determined to be load growth-related (including carry-over) were then summed and used to create a ratio for total spend; this ratio was then applied to forecast future projected ACE Plan investments to calculate a forecast of future load growth-related investment on an annual basis going forward
  - This value was divided by the anticipated generation load forecast (firm peak) and the weighted investment/firm peak was then averaged to determine the values used in the RBIA calculations

T&D AVOIDED COST METHODOLOGY UPDATE

CONSIDERATIONS

- There is no universally accepted methodology for calculating Avoided T&D Costs
- A methodology which examines capital investments justified based on identified or forecast load growth (rather than capacity growth) could be appropriate when paired with forecast incremental firm peak load growth
- A new approach should also consider non-linear nature of T&D investments and fluctuations in load in a given year by considering averages over time
  - NS Power proposes to consider transmission-related investments against system-wide load growth
  - Where possible, NS Power proposes to consider distribution-related investments against local (i.e. substation level) load growth where the data is available and useable.
- It may be more accurate to consider the savings achieved via potential project deferrals, rather than avoided project costs, as the identified T&D investments will likely still be required at some point in the future
  - If Demand Side Management or other technologies can defer such investments forward to future years and achieve a net present value savings, value is achieved for NS Power customers

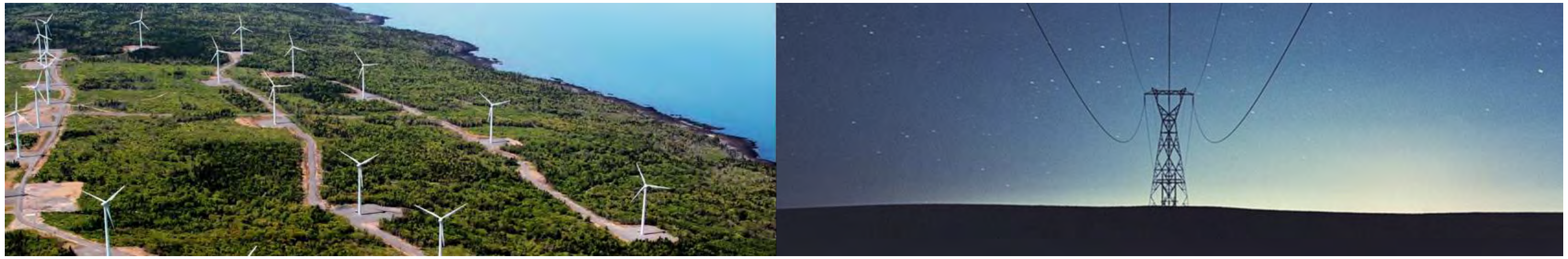
NEXT STEPS

- Further discussion will occur in parallel with IRP timeline, with the revision concluded by Sept. 15, 2020

NEXT STEPS

UPCOMING TERMS OF REFERENCE MILESTONES

• Modeling Results circulated	June 5	*(workshop and stakeholder feedback cycle follows)*
• Draft Findings, Roadmap & Action Plan circulated	July 9	*(workshop and stakeholder feedback cycle follows)*
• Draft IRP Report circulated for comment	August 20	
• Final IRP Report filed	September 30	



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Resource Insight Inc.

MEMORANDUM

To: Linda Lefler, Senior Project Manager, Regulatory Affairs
Nova Scotia Power

From: John D. Wilson and Paul Chernick

Date: May 7, 2020

Subject: Comments on Interim Modeling Progress

1. NS Power's planned reflection of the recession is inadequate.

The current economic downturn will reduce NS Power's load this year. Already, FAM data show that NS Power's retail sales are down by roughly 5%, which is consistent with impacts across the North American power sector.

North American utilities are seeing residential loads increase, while commercial and industrial loads are seeing sharp decreases. As the recession deepens, residential loads may be maintained at above-average levels but the impact on commercial and industrial loads is only likely to worsen.

NS Power will not be able to directly observe the effect of the recession on peak demand until next winter. But it is possible to infer the range of likely outcomes from current trends and historical reactions to economic shocks.

Residential contribution to system peak loads are not likely to increase by the same percentage as energy use. Anecdotal evidence suggests that most increased residential demand is due to end uses such as plug load, hot water, and other uses that tend to be spread broadly through the day, rather than being concentrated in the evening winter peak. Home-heating loads, which are the peakiest residential load, are unlikely to increase substantially due to stay-at-home orders (since most people would be home in the evening, anyway, and additional afternoon occupancy will tend to leave homes warmer going into the evening peak) and unemployment (since tighter budgets will encourage customers to reduce thermostat settings).

In contrast, commercial and industrial load decreases will likely reduce peak demand. Since many theatres, restaurants, stores, offices and factories will be closed, their loads (whether for lighting, space heating, or other equipment) will tend to fall at system peak hours, along the rest of the day. Business closures, many of which may be permanent, will radically reduce or even eliminate customer loads.

Absent an unlikely full medical and economic recovery by late fall, we cannot expect peak demand to return to pre-recession levels this winter. Experience indicates that load does not bounce back rapidly from deep downturns. The Great Recession's impacts on North American electric demand are particularly instructive as to how the post-COVID economic recovery might unfold.

The residential sector was the least affected by the Great Recession, but it took several years for residential electricity use to return to pre-recession levels. Today, the impact of the recession on demand is obscured by the demand bump due to stay-at-home guidance. When people return to work and other activities, the impact of the recession on residential loads will become more apparent, and residential demand will likely drop below pre-recession levels, at least until there is a significant economic recovery.

Commercial sales, which had been growing quickly before the Great Recession, bounced back, but then remained stable at roughly pre-recession levels. The much steeper downturn in business activity in the pandemic is likely to result in significant numbers of business closures, as well as depleted cash reserves for businesses and customers, even when economic recovery begins.

Industrial demand dropped the most during the Great Recession and never recovered. There is no reason to assume the current recession is not likely to be similar, leaving industrial demand below pre-recession levels for some years.[1]

In summary, each customer class appears likely to remain below pre-recession levels at least until the economy has substantially recovered. In total, probably for at least several years after the economic growth restarts.

NS Power's proposed approach to the recession's impact on load consists of the following:

- Selecting portfolios based on (among other options) the previously defined lower-load forecast cases, without any adjustment for the economic decline.
- Late in the process, evaluate the portfolios with even lower load sensitivities, to "validate" the results.

We do not believe these process adjustments are adequate.

[1] Efforts to shorten and diversify supply chains may shift the location of some manufacturing; it is not clear how this trend might affect Nova Scotia.

It is going to take a long time for electricity demand to recover to any of the three forecasts being used to develop resource portfolios in the IRP. Given the impact of the recession on electricity demand, the "Mid Electrification / Base DSM" and "High Electrification / Mid DSM" forecasts are unlikely to provide useful guidance for the next 5-10 years, at least. Without modification, the effort to model these two forecasts could be wasted effort.

Even the "Low Electrification/Base DSM" forecast may not be relevant to near- or mid-term resource planning decisions. A 5% drop in annual energy in 2020, followed by a 1% per year growth rate, would return to the low forecast in roughly 2026. A 10% drop in annual energy in 2020 would require a 2% per year growth rate to return to that path in 2026. At best, peak demand could return to the "Low Electrification / Base DSM" path within a 2-3 years.

If no changes are made to the three load forecasts, the resulting resource portfolios will not be optimized to the most plausible electricity demand in the near- and mid-term. Sensitivity runs to validate these portfolios under even lower load conditions could entirely miss a more optimal resource plan.

It could be argued that heating-driven peaks will be more resistant to economic downturn than energy use. In this scenario, system load factors would be different. Some generating units would be used much less. This could alter the cost-effectiveness of continuing to invest sustaining capital and fixed O&M in some existing units. It may be more cost-effective to meet capacity needs by advancing future resource investments.

If peak loads also remain significantly below pre-recession levels, then the resulting excess capacity could create conditions that would favor retiring existing units, especially coal units and the Mersey hydro system.

In either case, with unrealistic load forecasts, the portfolios may have uneconomic, excessive generation which will lead to inaccurate, low avoided costs. For that reason, the model is unlikely to provide useful guidance for near- and mid-term DSM investment decisions.

Accordingly, we recommend that NS Power develop a more expansive response to the impacts of the recession on present and future load.

2. *Further concerns about the load forecast.*

Based on information NS Power shared with us on April 8 and during the April 28 workshop, we continue to be concerned about the load shapes associated with electrification. Based on the graph shared on April 28, it appears that the energy added to shift from mid to high electrification has a load factor of roughly 50%. This seems appropriate for building electrification, but for transportation, there would likely be very little on-peak generation during a winter peak event, especially if rate design is updated to utilize the smart meters NS Power is installing.

Based on an email exchange with Chris Milligan following up on the April 8 call, we understand that NS Power is relying on a 2015 NYSERDA report to develop its peak load assumptions for some EVs, and the general system load shape for the rest.

It is difficult to understand how NS Power is applying the NYSERDA study to the load forecast. The load forecast states that there will be an average on-peak load of 1.3 kW/vehicle without mitigation measures and 0.6 kW/vehicle with some mechanism to discourage charging on peak.

According to the NYSERDA study, EV charging peaks in the early evening at about 1 kW per vehicle (p. 56). The 1.3 kW / vehicle figure corresponds to the off-peak scenario (p. 66) with the EV charging peak occurring in the hour ending at 1 AM. Off-peak charging levels in the NYSERDA that are coincident with NS Power's early winter evening peak would be around 0.25 kW per vehicle.

Furthermore, the 0.6 kW/vehicle figure doesn't seem to correspond to any of the aggregate charging load profiles in the NYSERDA study. Figure 25 shows a 0.6 kW/vehicle peak load for PHEVs a controlled charging scenario, with the peak occurring in the hour ending 6 PM. If this is the source for the 0.6 kW/vehicle figure, we don't understand the relevance.

We would like to see the load shape graph(s) for EV charging compared to the NS Power peak day load shape. The load forecast (Figure 13) gives two columns of peak data but there really isn't a clear explanation of how NS Power has mapped this to the baseline forecast, and definitely not an explanation of how this will be used in the electrification scenarios.

We also note that in its response to comments on IRP assumptions, NS Power did not respond to our suggestion to consider electrification in the industrial and marine sectors. **As NSP continues to refine the electrification assumptions, it should also evaluate electrification in the industrial and marine sectors.**

3. *Flexible solar and hybrid resource technology options should be added to the model.*

Previously, NSP declined to adopt our recommendation to add flexible solar and hybrid (RE+storage) resources to the model. This reduces the reliability and operational flexibility of renewable and storage resources, resulting in a greater preference for gas-fueled resources.

Flexible solar (e.g., solar that is curtailed in advance in order to provide upward dispatch flexibility in addition to downward dispatch), provides operational reserves that may be less expensive than operation of peaker units. In terms of reliability, NS Power's system inertia constraint will affect evaluation of must-take, uncoupled renewables, which do not provide inertia. More advanced wind and solar technologies would likely provide inertia.

We raised this issue in discussion with NS Power on April 8 and NS Power agreed to speak with Arne Olsen, their E3 consultant who happens to be the authority on flexible solar. **NSP should update intervenors as it explores this topic further.** We appreciate NS Power's willingness to explore this topic further and look forward to an update.

On a related note, we also raised the issue of the potential for wind and solar to be screened out in the initial capacity expansion modeling due their low assumed capacity benefit. Even though the "diversity benefit" will be assessed during the Reliability and Operability phases, it is not clear that there is a process for considering higher levels of wind and solar at that point if they have already been screened out. In the April 8 discussion, we received some assurance that NS Power will be sensitive to this point during the evaluation. **We request that this issue be explicitly tracked and documented as the evaluation proceeds.**

4. ELCC for other units.

During discussion, NS Power indicated that it has calculated ELCC values such that renewable and non-renewable resources are handled on an equivalent basis. We request that NS Power share these assumptions as soon as feasible.

On a related note, NSP previously declined to adopt our recommendation to use a longer averaging period for TUC DAFOR "to avoid subjectivity." We don't see the question as being one of subjectivity, but of realism. If the recent experience is a good predictor for the future, the recent DAFOR should be used in modeling. If the cause of recent reliability issues at TUC is unlikely to be repeated in any particular future year, a longer averaging period should be used. Overestimating DAFOR may result in an unnecessarily high reserve requirement, accelerated retirement of the gas steam plants, and excessive capacity acquisition. We raised this issue in discussion with NS Power on April 8 and NS Power indicated that this could be explored in a sensitivity test. **Unless NS Power has some reason for treating the recent high DAFOR as the base case, a longer base line should be used, and the recent anomaly should be treated as a sensitivity.**

5. *Minimum inertia constraint.*

In the follow-up from the April 8 call, NS Power explained that the minimum system inertia constraint is provided on p. 111 of the assumptions document. (We had interpreted that box as referring to the performance requirement for the synchronous condenser.) **Now that we have that clarification about the constraint, it would be useful for NS Power to provide the modeling assumptions for the inertia constraint**, especially how much each resource contributes to meeting this requirement and the nature of any operational restrictions (such as ramp rates, or the effect of generation output on inertia contribution) on that limit the contribution of each resources to meeting the constraint.

To: Nicole Godbout

From: John Esaiw

Date: May 12, 2020

Re: 2020 IRP - Interim Modelling Update Comments

On April 27th, 2020, NS Power released materials relating to an interim modelling update, as listed in the approved Terms of Reference for the 2020 Integrated Resource Plan ("IRP"). On April 28, 2020, NS Power hosted a technical session relating to these materials, which provided a forum for stakeholders and NS Power to discuss these interim results.

EfficiencyOne is pleased to provide comments relating to the interim modelling results released by NS Power in the sections below, together with comments on key issues.

The following recommendations and requests are detailed in relation to the information provided by NS Power:

1. Provide further updates on scenario modelling with draft results at such point as they become available, which would allow for a more substantive review in advance of the next stakeholder session.
2. Provide stakeholders with all inputs and outputs for Plexos LT for a sample Candidate Resource Plan, as part of the June 5 release of IRP modelling results.
3. NS Power draft, and provide, a schedule of engagement to the DSMAG for the facilitation of the Avoided Costs of T&D process. It is recommended the process meet certain minimum requirements in terms of stakeholder engagement, as further detailed in the body of this memorandum.
4. Modify qualitative assumptions for the contents of the DSM Potential Study, clarifying that the DSM Potential Study contains only estimates of programmatic DSM. NS Power's current assumptions do not reflect the methodology used to develop the 2019 DSM Potential Study.
5. Confirm the scope contemplated for energy efficiency (EE) through sensitivity analyses will include in many cases Mid DSM. In the event EfficiencyOne's understanding is incorrect, we request that NS Power use a sensitivity analysis methodology that, at minimum, meets the characteristics set out in the body of this document.
6. A recommendation that only one demand response (DR) case be permitted for selection for each eligible Candidate Resource Plan.

7. A recommendation against the use of small fragments of the DR cases (e.g. operation for a few years, cessation, restart), on the basis that costs and potential estimated were reflective of continuous operation as opposed to frequent starts and stops.
8. A recommendation that cost estimates be put in place for DER resource strategies.
9. Confirmation from NS Power that it will avoid cost comparisons across differing electrification scenarios, and to provide their stated means of selection amongst scenarios for the purposes of generating the avoided costs of capacity and energy – key inputs for DSM in Nova Scotia.

Substantive Modelling Progress and the Opportunity for Comment

NS Power has begun the modelling process associated with the 2020 IRP, and the 2020 IRP is leveraging new modelling software and analysis methods, which presumably increase the amount of time required for front-end model configuration, and other related tasks.

It is understood that the comparator case is substantially complete, and that some draft results for that case have been developed as part of the interim modelling update.

Given the lack of draft or interim modelling results available at this point in time, EfficiencyOne is requesting that NS Power provide scenario outputs and results to stakeholders as they become available.

Timely provision of this information would allow stakeholders to assess results from cases within the IRP, and to contemplate any potential desired revisions well in advance of the release of full modelling results, which form the quantitative core of the 2020 IRP. EfficiencyOne is concerned that without this interim provision of data, the time allotted for review, comment and discussion in June will not be sufficient to allow stakeholders to provide constructive and meaningful feedback to this process.

Data Transparency

Subject to the comments above regarding modelling progress, EfficiencyOne requests that all inputs and outputs for a sample Candidate Resource Plan be made available to stakeholders, accompanying any other data intended to be reviewed starting on that date. In particular, the requested information comprises all Plexos LT input and output data for a sample Candidate Resource Plan modelled and a sample treatment of DSM (based on Potential Study input scenarios). Any data that is considered proprietary can be treated on a confidential basis within the stakeholder group, or redacted in cases where required.

The release of input and output data will provide greater transparency to stakeholders regarding the fidelity of modelling relative to published assumptions, and allow for detailed review of modelling results. EfficiencyOne understands from its consultants that release of modelling data in a transparent fashion is common in other IRP related settings.

Development of T&D Avoided Costs

In its interim modelling update, NS Power has provided an update on its proposal for next steps with respect to the development of revised estimates for Transmission and Distribution Avoided Costs. As directed by the NSUARB[1], it is understood that the DSM Advisory Group (DSMAG) is intended to be the main forum for discussion of the development of these revised estimates, as clarified during the April 28 technical session.

In keeping with the process set out by the NSUARB, EfficiencyOne requests that NS Power provide a draft schedule of engagement to the DSMAG, as soon as reasonably practical, to aid in the facilitation of this process. EfficiencyOne is prepared to work with NS Power to assist in coordination of the process through the DSMAG.

The following key activities are recommended to be included in such a process:

1. Establishment of Terms of Reference for the development of T&D Avoided Costs, with direct input of the DSMAG.
2. Opportunity for substantive DSMAG discussion and a comment period leading to a consensus agreement of the DSMAG (if possible) in relation to the appropriate methodology for development of these avoided costs. Such a methodology should be reflective of broader industry practices, or best practices where possible.
3. All candidate methodologies to be presented prior to adoption (i.e. all quantitative details, calculations, etc.), in a manner where they can be recreated using publicly available information (e.g. ACE Plans).
4. The methodology also should include a defined process and timing for future updating and the administration of the new methodology for avoided costs of T&D.

Adoption of these measures in the development of avoided costs of T&D will provide stakeholder confidence in the use of these inputs in future regulatory proceedings including development of future DSM Resource Plans.

Interpretation of the DSM Potential Study

[1] M09471, 80788, Board Letter Re: Revised Methodology Should not Await Completion of IRP Process, Issued April 2, 2020, at Page 2.

EfficiencyOne remains concerned that NS Power's assumptions, surrounding what is, and what is not, contained in the scope of the 2019 DSM Potential Study, are not accurate and do not align with the development of the DSM Potential Study.

Page 55 of NS Power's Draft Assumptions Slide Deck, released January 20, 2020, notes the following:

- *The [2019 DSM Potential Study] scenarios are assumed to include all DSM, including:*
    - *Cost-effective electricity efficiency and conservation activities provided by the franchise holder*
    - *Initiatives that may be pursued by NS Power as permitted under the Public Utilities Act*
    - *Consumer behaviour and investments*
    - *Energy efficiency codes and standards*
    - *Initiatives undertaken by other agencies*
    - *Technological and market developments.*

On February 14th 2020, EfficiencyOne provided comments regarding this assumption. These comments were intended to correct this assumption and be reflective of the 2019 DSM Potential Study, which limits quantified impacts to programmatic DSM, and specifically excludes "natural DSM" (e.g. customer behaviour and investments, technological and market developments) and codes and standards.

In the final assumptions document, released March 11, 2020, there is reference to the same statement on page 59. This assumption is incorrect and should be updated to include only "Cost-effective electricity efficiency and conservation activities provided by the franchise holder" as part of the DSM Potential Study energy efficiency cases. Similarly, for demand response cases, the results should also be assumed to include "Initiatives that may be pursued by NS Power as permitted under the Public Utilities Act"; recognizing the role both parties have in pursuing demand response activities.

Inclusion of Mid-DSM in Scenarios

On March 6, 2020, in response to the Scenarios and Pathways documents released on February 14th, 2020, EfficiencyOne provided its suggested combinations of EE and DR cases from the 2019 DSM Potential Study associated with each scenario as proposed by NS Power. Related to those suggestions was the recommendation that enhanced analysis of DSM cases should be completed for high-performing DSM Resource Plans.

In response to our suggested inclusions, NS Power produced some modifications to the scenarios and cases initially proposed for modelling. The changes made are appreciated, however there remains a concern with respect to the lack of inclusion of the Mid-DSM energy efficiency scenario in any of the proposed cases. Mid-DSM is viewed as a more competitive scenario relative to Max DSM. Similar to the low-case scenario, Max-DSM serves as a "bookend" case. Max-DSM requires very high incentives and marketing activity to achieve the results found in the scenario.

NS Power advised stakeholders that it intends to perform a substantial portion of the exploration of DSM through a sensitivity analysis. In particular, that energy efficiency cases from the DSM potential study will be adjusted "up and down" by one level for each IRP scenario analyzed (i.e. for scenarios that contain Base EE, Low and Mid EE will be examined through sensitivity).

The approach addresses our concerns in terms of the exploration of DSM in the IRP, however, without any additional margin for further reductions to the scope of analysis.

It is understood that the sensitivity analysis methodology will have the following characteristics:

- Allow for the replacement of the original DSM (EE) case within the analysis with another explicitly defined DSM case (e.g. Base);
- Allow for optimization of the supply mix and reserve margin with each differing DSM (EE) case.
- Allow for the production of the avoided costs of energy and capacity using EE cases and scenarios as explored in the sensitivity analyses.
- Allow for the identification of a lowest NPV revenue requirement Candidate Resource Plan from within the sensitivity analysis (for a given electrification and distributed generation 'world').

Simply scaling costs and benefits by a multiplier is not deemed an adequate approach as it would involve the analysis of DSM levels not analyzed or provided by the 2019 DSM Potential Study, and without the support of the coherent analysis that the Potential Study was intended to provide. Without this validation, any conclusions founded on the sensitivity analysis results would not be reliable.

It is requested that the use a sensitivity analysis methodology, at minimum, meets the characteristics outlined above.

DR as a Resource Option

EfficiencyOne notes that NS Power plans to model the DR cases within the DSM Potential Study as a resource option rather than a load modifier. Clarification is requested on the following:

- Is NS Power maintaining the continuous (25-year) nature of the DR cases from the 2019 DSM Potential Study? If not, is there any tolerable bound to how fragmented DR operation is 'allowed' to become?
- How will the NS Power generated cases compete against cases from the Potential Study?
- Will all DR cases be allowed to compete in every scenario?
- Can multiple DR cases be allowed to stack? (e.g. one NS Power case, and one Potential Study case).

DR cases from the 2019 DSM Potential Study were intended to be used "one-at-a-time", as opposed to with any other DR activity present (e.g. the Base and High DR cases were not intended to be 'stacked'). For this reason, we are recommending only one DR case be allowed to be selected for each eligible Candidate Resource Plan.

In addition, we recommend against the use of small fragments of the DR cases (e.g. operation for a few years, cessation, restart), as the costs and potential estimated were reflective of continuous operation as opposed to frequent starts and stops.

Electrification and DG

EfficiencyOne is seeking clarification concerning inclusion of costs relating to Distributed Generation. In its final assumption set, NS Power indicated that "DERs will be accounted for in the model as a load modifier, with costs and benefits separately evaluated/discussed in the evaluation of each resource portfolio."

This assumption seemingly contradicts a comment from April 28, 2020, responding to a query, which indicated that such costs would not be included for DERs.

Clarification is requested on the approach to be used.

Should cost information not be included within DER resource strategies, this will likely require similar treatment as used for electrification scenarios, as revenue requirements will be incomparable for any case containing differing levels of DERs or electrification scenarios.

Having one of three resource strategies (i.e. DERs) incomparable to the other two (in-province generation, regional integration) within each incomparable scenario has the potential to void useful insights from the IRP modelling. For this reason, we strongly recommend that some form of cost estimate be included for DER resource strategies.

Confirmation is requested that NS Power will avoid cost comparisons across differing electrification scenarios, and to provide their stated means of selection amongst scenarios for the purposes of generating the avoided costs of capacity and energy – key inputs for DSM in Nova Scotia.

EfficiencyOne appreciates this opportunity to provide input to the development of the 2020 Integrated Resource Plan and looks forward to NS Power's response to the issues raised in these submissions.

Blackburn Law

VIA EMAIL

May 14, 2020

Linda Lefler
Nova Scotia Power

Dear Ms. Lefler,

Re: M08929 – April 28th, 2020 Stakeholder Session – SBA Comments

The Small Business Advocate (SBA) participated in the online IRP Stakeholder meeting on April 28th, 2020 and has the following comments about the update slideshow that was presented.

Slide 7 – Key Modeling Scenarios

The Comparative Scenario is a good scenario from which to start the planning. It should be thought of as more than just a comparison. It is important to have a scenario to evaluate resource options (multiple portfolios evaluated) that is not driven by any particular carbon reduction strategy beyond compliance with known regulations. The best portfolio under that scenario would be the pure least cost portfolio (the "Least Cost Portfolio").

Slide 8 – Key Modeling Scenarios (Table)

Consistent with our concern that there needs to be a Least Cost Portfolio developed under the Comparator Scenario, there is something lacking if there is no evaluation of the full use of economic DSM and economic Regional Integration under these scenario assumptions. Without a Comparator Scenario Least Cost Portfolio, NS Power will not be able to communicate the cost or value of the alternate strategies as well as making a fully informed decision.

It is unclear why is there no cases in in Scenario 2 or Scenario 3 without Regional Integration. Without a case that does not use Regional Integration we will not know the cost or value of Regional Integration. Is it that NSPI cannot meet the objectives of these Scenarios without Regional Integration? If so, that should be explicitly stated and an explanation provided as to why that is. We also require that details be provided about all costs performance and potential amounts of the various distributed generation that are assumed to be available when NSPI refers to Distributed Generation. It may have already provided, so if you could provide a direction to where that information is located, that would be of assistance.

Slide 12 – Resolve Model Structure

The SBA is concerned that we do not fully understand how Resolve co-optimizes investments and operations. Over what period of years are the economics tested? If you could point to materials that describe this process in detail, as per the manner in which NSPI are setting its models to run, that would be beneficial.

Slides 17& 18 – T & D Avoided Cost Methodology Update/Next Steps

It appears that the next time we will see the T&D Avoided Cost analysis results is September, as per the bottom of slide 18. This is problematic. Stakeholders must see this information in the June modeling review sessions.

We believe these items are crucial in order to have the most informative IRP analysis possible. Please let me know if you have any questions or require any clarification.

Yours truly,

BLACKBURN LAW

S. Darling. for

E.A. Nelson Blackbum, Q.C.
Small Business Advocate

NS Power Interim Modeling Results Stakeholder Feedback (May 2020)

No.	Topic	Comment	NS Power Response
CA-1	Load	Recession - Residential loads will increase and commercial and industrial loads will decrease. It will take years to recover from recession. "Given the impact of the recession on electricity demand, the "Mid Electrification / Base DSM" and "High Electrification / Mid DSM" forecasts are unlikely to provide useful guidance for the next 5-10 years, at least. Without modification, the effort to model these two forecasts could be wasted. Even the "Low Electrification/Base DSM" forecast may not be relevant to near- or mid-term resource planning decisions. A 5% drop in annual energy in 2020, followed by a 1% per year growth rate, would return to the low forecast in roughly 2026. A 10% drop in annual energy in 2020 would require a 2% per year growth rate to return to that path in 2026. At best, peak demand could return to the "Low Electrification / Base DSM" path within a 2-3 years. If no changes are made to the three load forecasts, the resulting resource portfolios will not be optimized to the most plausible electricity demand in the near- and mid-term. Sensitivity runs to validate these portfolios under even lower load conditions could entirely miss a more optimal resource plan." Recommend that NS Power develop a more expansive response to the recession.	NS Power has closely followed the ongoing effects of the COVID-19 pandemic in order to assess potential impacts on medium- and long-term load growth. While the effects of the pandemic are still very uncertain, NS Power has made the following adjustments to the IRP load forecast that reflect potential impacts; these adjustments will continue to ensure that the IRP tests a robust and appropriate range of potential outcomes, both in terms of load and firm peak. • The Low Electrification forecast remains unchanged at all DSM levels • The Mid and High Electrification forecasts are adjusted to moderate the original steep ramp up in electrification over the first 10 years of the forecast; the end points remain unchanged as they are consistent with the established SDGA goals (as modeled in the PATHWAYS study) • The added COVID-19 Low sensitivity will test the robustness of certain resource plans to potential pandemic load impacts in the first 5 years (a reduction of 1% in firm peak and 5% in net system requirement in year one, returning to the base Low Electrification forecast by 2026)

NS Power Interim Modeling Results Stakeholder Feedback (May 2020)

CA-2	Load	Load shapes associated with Electrification. Difficult to correlate with the NYSERDA inputs. We would like to see the load shape graph(s) for EV charging compared to the NS Power peak day load shape. NS Power should evaluate electrification in the industrial and marine sectors	NS Power has not developed separate load shapes for electric vehicles, either as part of IRP modeling or other work. The NYSERDA inputs provide a range of potential peak load impacts for EVs based on the amount of peak mitigation assumed via rate structures or other methods. NS Power has selected a mid-range value for EV peak impact, which assumes that some level of EV peak mitigation will occur in the base case in order to avoid potentially over-stating the peak load effects of increased EV penetration.
CA-3	Technology options	Flexible solar and hybrid resource technology options should be added to the model. Update stakeholders on this discussion. Also consider the possibility of wind and solar being screened out too early because of low capacity benefit.	NS Power has continued to work closely with our consultant E3 on this item. E3's work has shown that, in general, wind and batteries do not pair quite as effectively as wind and solar but that there can still be some benefit. NS Power's PLEXOS assumptions did not model a downward ramping reserve requirement as this can be provided by renewables without pre-curtailing, assuming sufficient controls are in place. NS Power has considered the effects of diversity benefits on Planning Reserve Margin calculations.

CA-4	ELCC Tufts Cove	Share NS Power's calculated ELCC values such that renewable and non-renewable resources are handled on an equivalent basis. Longer averaging period for TUC DAFOR. Unless NS Power has some reason for treating the recent high DAFOR as the base case, a longer base line should be used, and the recent anomaly should be treated as a sensitivity.	Please see Page 7 – 'ELCC Factors for Existing Resources' from NS Power's *2020 IRP Modeling Results Release – June 26, 2020* NS Power believes using a three-year average produces a good forecast of TUC Performance based on the current asset risks and how the company manages these risks. NS Power has however updated its DAFOR calculations to the most recent three-year period (2017-2019). These updated DAFORs are reflected in the calculated UCAP firm capacity assumptions used in the capacity expansion modeling. For the TUC units in particular, the updated DAFORs has resulted in the removal of the anomalously high DAFOR for TUC1 in 2016. These updated DAFOR forecasts were used in the reliability/operability study using E3s RECAP tool, which evaluate the required Planning Reserve Margin to meet the reliability standard for select resource portfolios from the capacity expansion modeling.
CA-6	Inertia	Provide the modeling assumptions for the inertia constraint, especially how much each resource contributes to meeting this requirement and the nature of any operational restrictions (such as ramp rates, or the effect of generation output on inertia contribution) on that limit the contribution of each resources to meeting the constraint.	Please see Page 8 – 'Inertia Constraint' from NS Power's 2020 IRP Modeling Results Release – June 26, 2020. The only inertia constraint is that units that can contribute to the aggregation of the minimum online requirement (3266MW) must be generating or flowing (in the case of transmission interconnections) at unit minimum output. In the case of synchronous condensers, units are assumed to always contribute.

No.	Topic	Comment	NS Power Response
SBA-1	Scenarios	Least Cost Portfolio should be the comparative/ comparator scenario; consider modeling 1.0C	NS Power has added the 1.0C scenario as part of the set of scenarios being examined in the 2020 IRP.
SBA-2	Scenarios	No evaluation of the full use of economic DSM and economic Regional Integration under these scenario assumptions. Why are there no cases in in Scenario 2 or Scenario 3 without Regional Integration. Is Regional integration a given and if so provide explanation.	In all scenarios with Regional Integration (resource strategy "C"), the tie lines that provide access to firm capacity and energy from outside of Nova Scotia are available to the model, but must be selected economically. This means the model could select a resource portfolio equivalent to the Current Landscape resource strategy by choosing not to build interconnections. In addition there are several Scenario 2 (Net Zero 2050) scenarios that do not allow Regional Integration (2.0A, 2.1A, 2.2A); this structure allows us to compare with equivalent scenarios 2.0C, 2.1C, and 2.2C to understand the value of Regional Integration. NS Power has incorporated model runs using the Low, Base, Mid, and Max DSM profiles in the modeling plan.

NS Power Interim Modeling Results Stakeholder Feedback (May 2020)

No.	Topic	Comment	NS Power Response
SBA-3	Scenarios	Provide details about all costs performance and potential amounts of the various distributed generation that are assumed to be available when NSPI refers to Distributed Generation.	The DER Promoted Scenarios ("Scenario Bs") assume NS Power's Net System Requirement load is partially displaced by behind the meter generation. The calculated Partial Net Present Value of Revenue Requirements for Scenario Bs does not calculate costs associated with developing this generation nor avoided costs to the utility. Please see page 41 – *Distributed Energy Resources (DERs) of the 2020 Integrated Resource Plan (IRP): Final Assumptions Set – March 11, 2020* for cost and operational estimates for DERs. The range of costs estimated for Scenario Bs in the *Initial Portfolio Study Results* (page 51) of the *NS Power 2020 IRP modeling Results Release – June 26, 2020* are based on the Behind the Meter solar cost assumptions (High and Low Capacity Factor).
SBA-4	Resolve	How Resolve co-optimizes investments and operations. Over what period of years are the economics tested?	E3's Resolve model completes runs in 5 year increments and then produces an NPV cost stream by weighting the 5 year runs proportionally to estimate the costs for intermediate years. End effects are calculated as an increased weighting on the final model year (2045).
SBA-5	T&D	Stakeholders must see T&D Avoided Cost information in the June modeling review sessions.	Consultations respecting the T&D Avoided Cost methodology development have been ongoing through the Demand Side Management Advisory Group (DSMAG). NS Power will advise the IRP stakeholders on the outcomes of the methodology discussions.
E1-1	Modeling results	Provide further updates on scenario modelling with draft results at such point as they become available, which would allow for a more substantive review in advance of the next stakeholder session.	NS Power provided a detailed results release on June 26, ahead of the July 9 stakeholder workshop and continued to accept feedback from stakeholders on those results and provided additional modeling results were provided in September in advance of the stakeholder workshop.

NS Power Interim Modeling Results Stakeholder Feedback (May 2020)

No.	Topic	Comment	NS Power Response
E1-2	Modeling results / data transparency	Provide stakeholders with all inputs and outputs for Plexos LT for a sample Candidate Resource Plan, as part of the June 5 release of IRP modelling results.	Subsequent to submitting these written comments, E1 inquired if NS Power would agree as a compromise to provide a detailed tutorial on the Plexos LT model for E1 and its consultant. NS Power agreed and a session was held on July 22, 2020.
E1-3	T&D at DSMAG	NS Power to provide a schedule of engagement to the DSMAG for the facilitation of the Avoided Costs of T&D process. It is recommended the process meet certain minimum requirements in terms of stakeholder engagement, as further detailed in the body of this memorandum. (included list of activities)	Consultations respecting the T&D Avoided Cost methodology development have been ongoing through the Demand Side Management Advisory Group (DSMAG). NS Power will advise the IRP stakeholders on the outcomes of the methodology discussions.
E1-4	DSM Potential	Modify qualitative assumptions for the contents of the DSM Potential Study, clarifying that the DSM Potential Study contains only estimates of programmatic DSM. NS Power's current assumptions do not reflect the methodology used to develop the 2019 DSM Potential Study.	NS Power has used the E1 DSM Potential Study estimates of programmatic DSM as its modeling assumptions.
E1-5	Mid-DSM	Confirm the scope contemplated for energy efficiency (EE) through sensitivity analyses will include in many cases Mid DSM. In the event EfficiencyOne's understanding is incorrect, we request that NS Power use a sensitivity analysis methodology that, at minimum, meets the characteristics set out in the body of this document.(list provided)	NS Power completed 7 DSM sensitivities which reflected E1's input on additional appropriate DSM sensitivities to prioritize.

No.	Topic	Comment	NS Power Response
E1-6	Demand Response	A recommendation that only one demand response (DR) case be permitted for selection for each eligible Candidate Resource Plan. Is NS Power maintaining the continuous (25-year) nature of the DR cases from the 2019 DSM Potential Study? If not, is there any tolerable bound to how fragmented DR operation is 'allowed' to become? How will the NS Power generated cases compete against cases from the Potential Study? Will all DR cases be allowed to compete in every scenario? Can multiple DR cases be allowed to stack? (e.g. one NS Power case, and one Potential Study case).	NS Power has matched DR Cases with Energy Efficiency cases, as recommended by E1. NS Power has allowed the optimizer to choose a DR resource in 2021, 2025 or 2030. The cost and performance characteristics have not been modified (other than costs were escalated at inflation to the in-service year for the case with a 2030 start year.) NS Power generated DR cases have not been offered to the model. A DR case is allowed to compete in every scenario, as applicable to the EE case. Only a single DR case, as developed by E1, is offered for each IRP scenario, as applicable to the Energy Efficiency case.
E1-7	Demand Response	A recommendation against the use of small fragments of the DR cases (e.g. operation for a few years, cessation, restart), on the basis that costs and potential estimated were reflective of continuous operation as opposed to frequent starts and stops.	NS Power has not modeled fragments of DR. If a program is chosen, the full annual cost and performance characteristics are incurred as applicable (note- if the resource is chosen in 2030, only the first 15 years of costs and benefits are modeled.).

NS Power Interim Modeling Results Stakeholder Feedback (May 2020)

No.	Topic	Comment	NS Power Response
E1-8	DER	A recommendation that cost estimates be put in place for DER resource strategies.	NS Power has estimated a range of costs estimated for Scenario Bs in the *Initial Portfolio Study Results* (pg. 51) of the *NS Power 2020 IRP modeling Results Release – June 26, 2020* which are based on the Behind the Meter solar cost and operational assumptions (High and Low Capacity Factor). These costs are not part of the calculated partial net present value of revenue requirement as this is not currently modeled as a utility cost.
E1-9	Electrification	Confirmation that NS Power will avoid cost comparisons across differing electrification scenarios, and to provide their stated means of selection amongst scenarios for the purposes of generating the avoided costs of capacity and energy - key inputs for DSM in Nova Scotia.	NS Power recognizes that comparisons of NPV across different electrification levels could be misleading and will endeavour to structure all results presentation to ensure this is properly recognized. Per the Terms of Reference, as part of the IRP process, NS Power will select a Reference Plan on which to base avoided costs of capacity and energy for DSM.

Appendix J

Nova Scotia Power IRP

Modeling Results Phase Participant Engagement

NS POWER 2020 IRP MODELING RESULTS RELEASE

JUNE 26, 2020

Nova Scotia POWER
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TABLE OF CONTENTS

PROCESS UPDATE & WORK COMPLETED

UARB NSP Pre-IRP
Deliverables

- Capacity Study
- Supply Options Study
- Demand Response Assumptions
- Stability Study

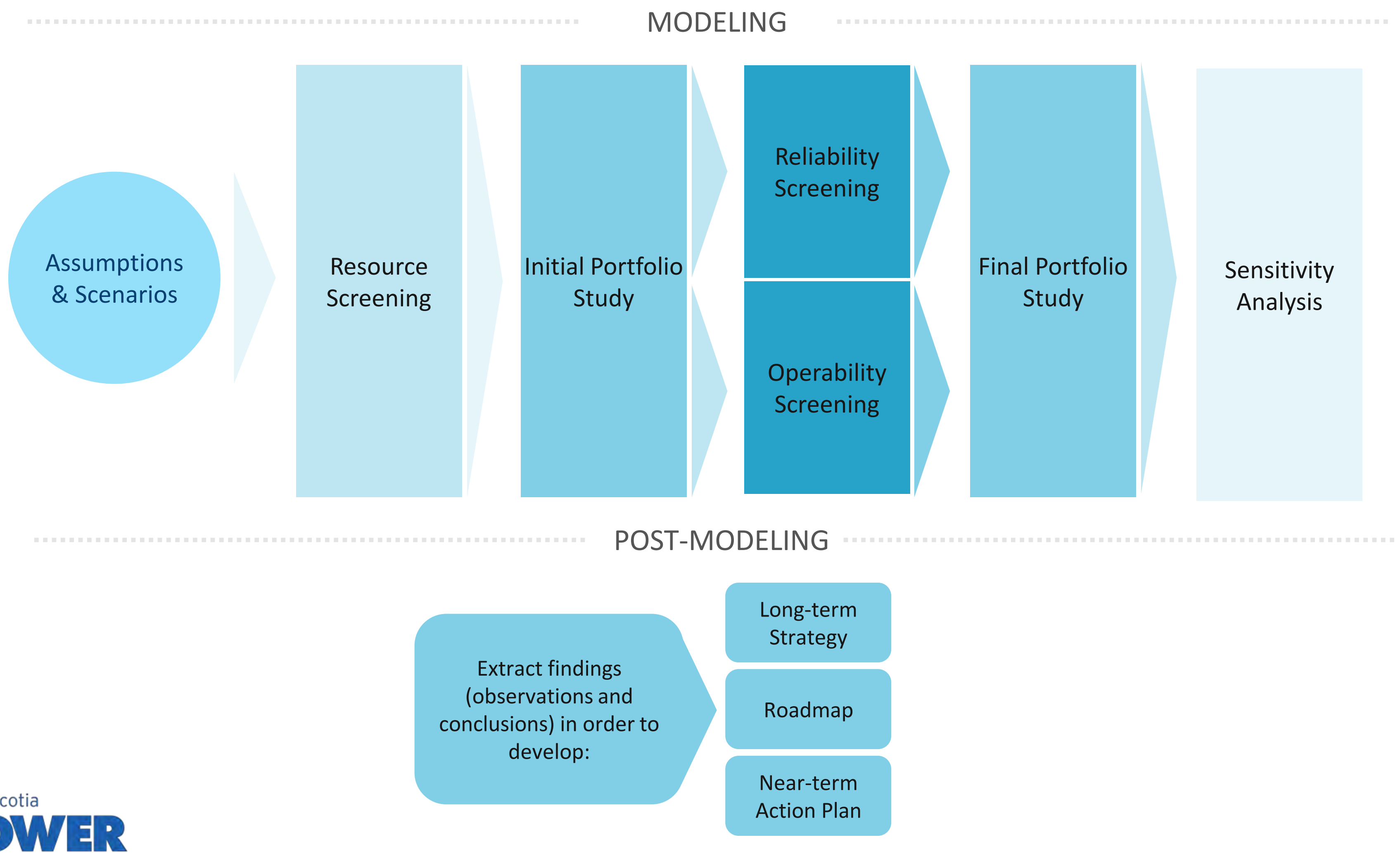
Core IRP Process
resulting in Final Report

- Terms of Reference
- Scenario Development
- Modeling Plan
- Assumptions
- Modeling
- Analysis/Conclusions
- Report, Roadmap, & Action Plan

Sept 2020

Previously completed
Completed since last update
In Progress

IRP MODELING PLAN



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ASSUMPTION & KEY SCENARIO UPDATES

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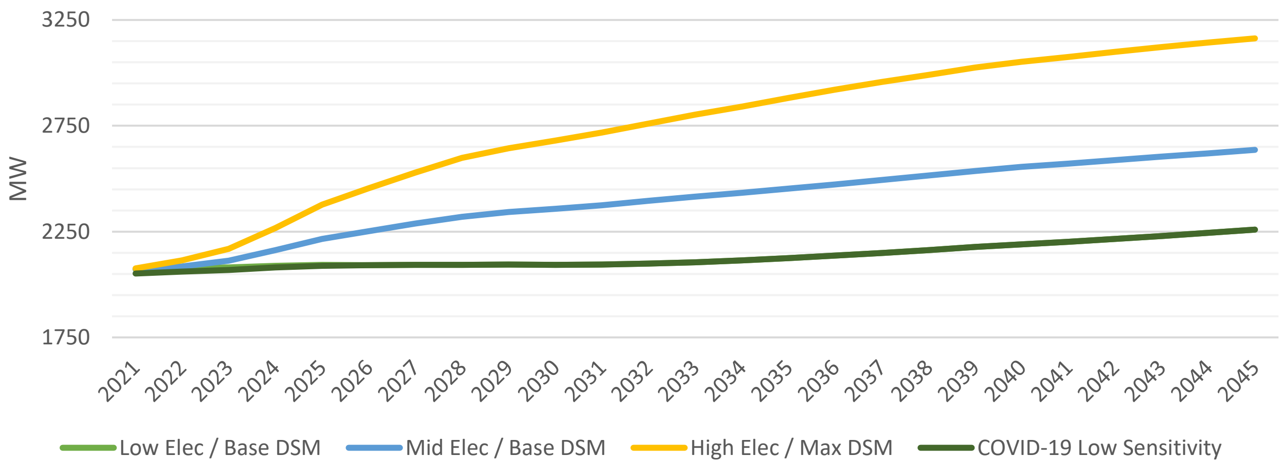
ADJUSTMENTS TO IRP LOAD FORECASTS

Based feedback from some stakeholders and observations from the modeling runs completed to date, NS Power has made the following adjustments to reflect potential impacts of the COVID-19 pandemic:

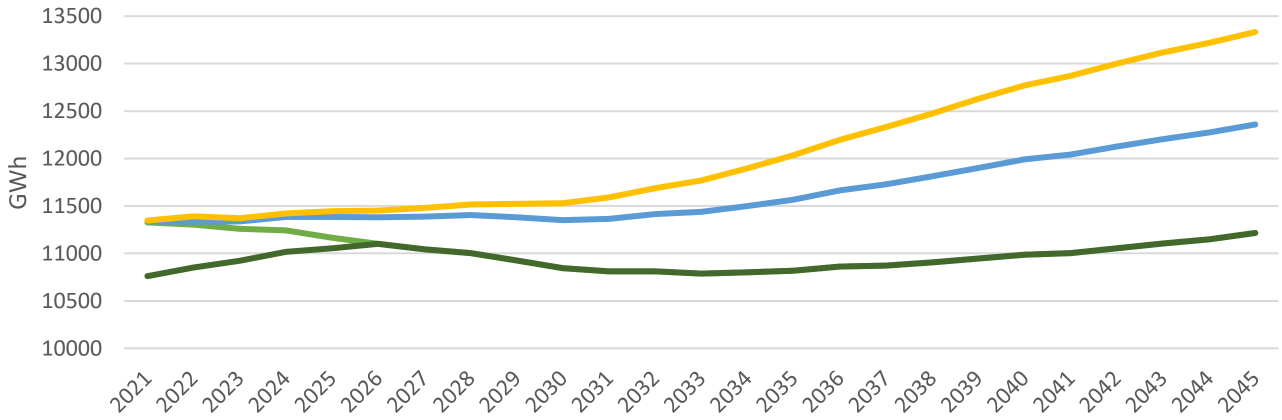
- The Low Electrification forecast remains unchanged at all DSM levels
- The Mid and High Electrification forecasts are adjusted to moderate the original steep ramp up in electrification over the first 10 years of the forecast; the end points remain unchanged as they are consistent with the established SDGA goals (as modeled in the PATHWAYS study)
- The added COVID-19 Low forecast will test the robustness of certain resource plans to potential pandemic load impacts in the first 5 years (a reduction of 1% in firm peak and 5% in net system requirement in year one, returning to the base Low Electrification forecast by 2026)

The resulting load forecasts continue to explore a wide range of potential scenarios, which will allow the IRP to continue to appropriately test the robustness of potential resource strategies to these various loads.

Adjusted Firm Peak Forecasts



Adjusted Net System Requirement Forecasts



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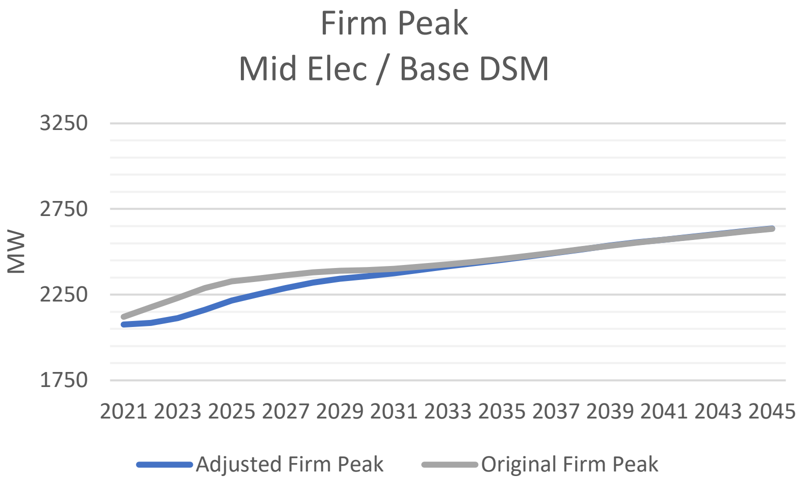
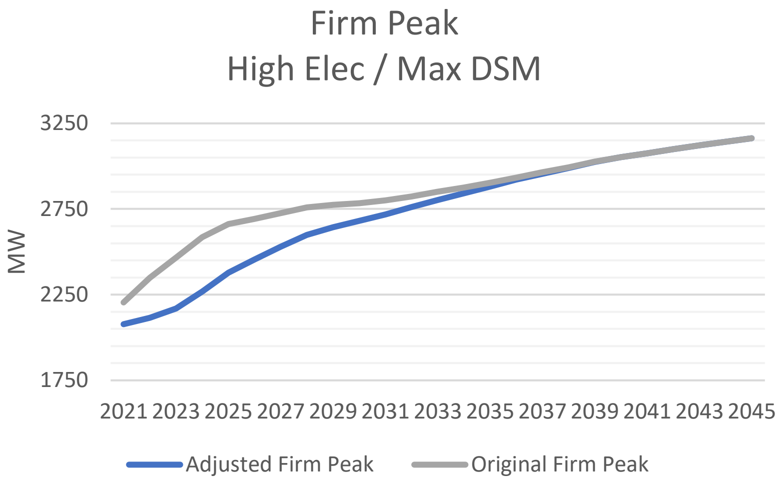
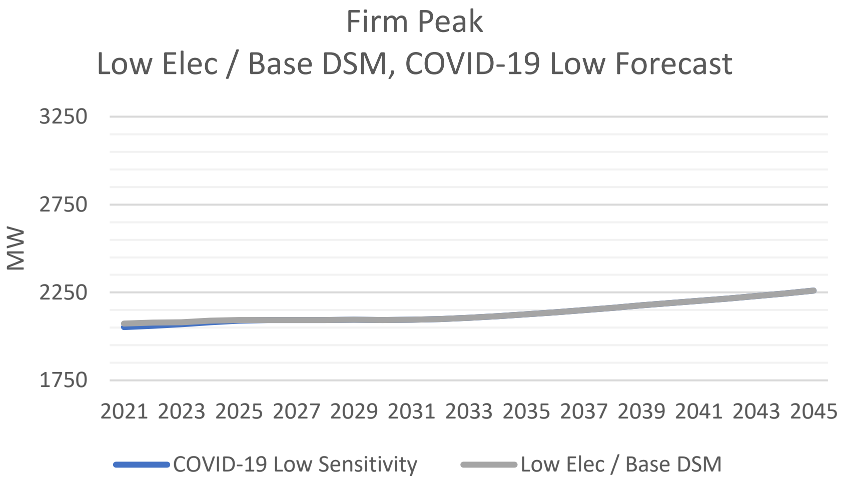
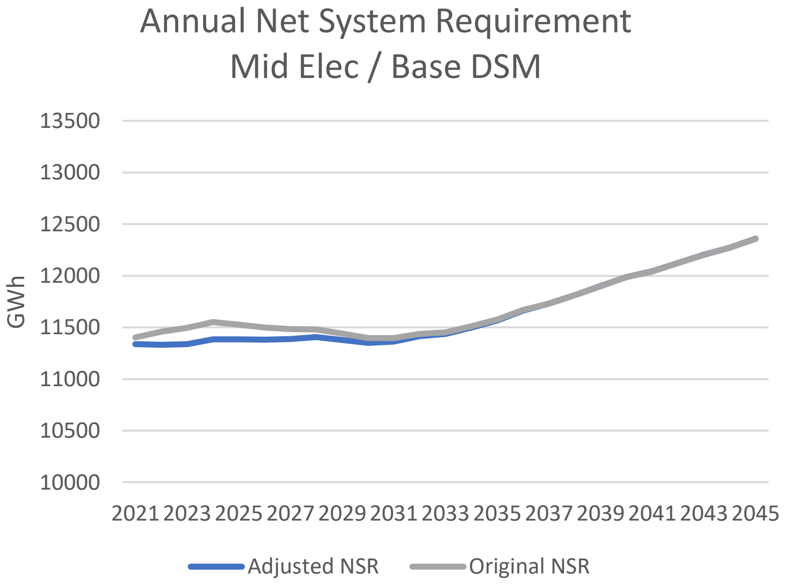
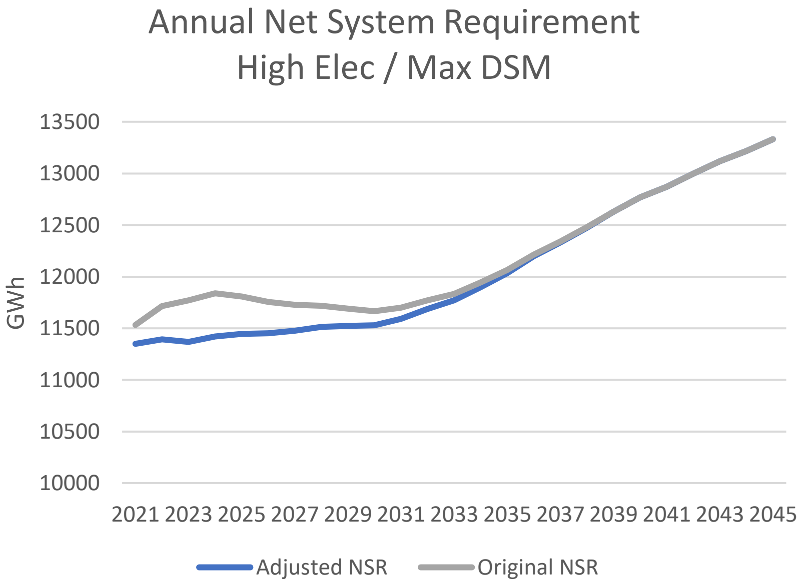
ADJUSTED LOAD FORECAST - COMPARISONS

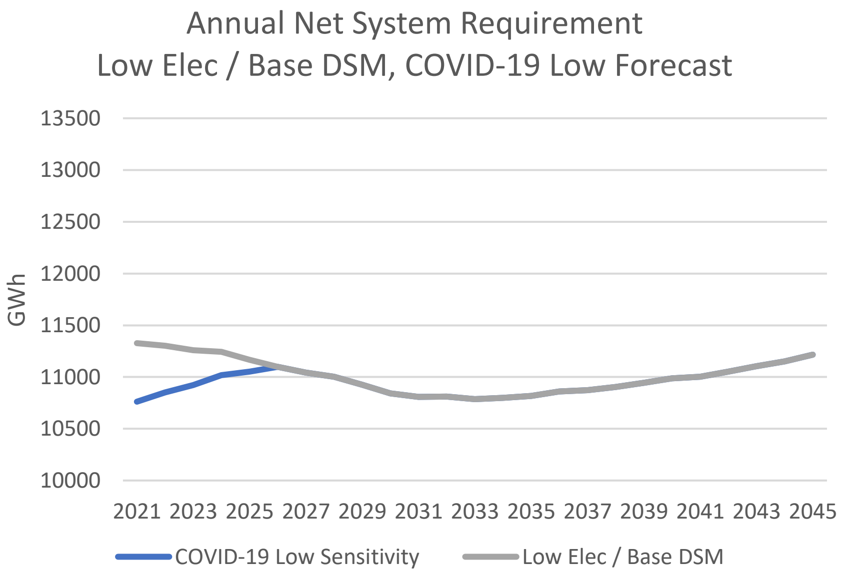












ELCC FACTORS FOR EXISTING RESOURCES

- NS Power has adopted the ELCC methodology for both existing and new generation resources which is used in calculating unit contributions to Planning Reserve Margins
- ELCC Factors for existing resources have been calculated as follows, using the most recent 3-year average DAFOR rates

ELCC Factors

	Net Operating Cap. (MW)	ELCC Factor	UCAP Firm Cap. (MW)	Notes
Coal	1081	90%	976	No LIN-2
HFO/Gas	318	73%	232	
Gas CTs	144	93%	133	
LFO CTs	231	77%	178	
Biomass	43	95%	41	
Hydro	374	95%	355	
Wind	595	19%	113	
Other IPPs	34	95%	32	No Wind
ML Base	153	98%	150	
Total	2972		2211	

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INERTIA CONSTRAINT

- The kinetic inertia constraint is modeled at 3266 MW.sec minimum online requirement
  - This is derived as allowing an approximate contingency of 500 MW.sec (~1 unit) above the level of 2766 MW.sec that was found to be required for stability in the 2019 PSC Study
- Unit provisions are shown in the table on the right for existing and new resource types available to the model

Source	Inertia Contribution (MW.sec)
Generators (01 - Lingan 1)	814
Generators (02 - Lingan 2)	814
Generators (03 - Lingan 3)	797
Generators (04 - Lingan 4)	797
Generators (05 - Point Aconi)	933
Generators (06 - Point Tupper)	777
Generators (07 - Trenton 5)	620
Generators (08 - Trenton 6)	771
Generators (11 - Tufts Cove 1)	403
Generators (12 - Tufts Cove 2)	412
Generators (13 - Tufts Cove 3)	768
Generators (14 - Tufts Cove 4)	245
Generators (15 - Tufts Cove 5)	245
Generators (16 - Tufts Cove 6)	245
Generators (270 - New_50MW Pump Strg)	100
Generators (320 - New_Tre 5 NGas)	620
Generators (321 - New_Tre 6 NGas)	771
Generators (322 - New_TUP NGas)	777
Generators (040 - New_RECIP - 9.3 MW)	45
Generators (050 - New_ CT 50 MW Aero)	250
Generators (052 - New_CC 145 MW)	750
Generators (054 - New_CC 253 MW)	1265
Generators (056 - New_CT 34 MW Aero)	170
Generators (058 - New_CT 33 MW Frame)	165
Generators (059 - New_CT 50 MW Frame)	250
Generators (CAES_Air Component)	100
Generators (H01 - Wreck Cove)	424
Generators (Sync Cond _1)	5 (per MVA of SC)
Lines (670-NB 2nd 345kV Intertie_Basic)	3266

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KEY MODELING SCENARIOS

Scenario	Features	Load Drivers	Coal Retires	Resource Strategies Tested	Key Sensitivities
1.0 **Comparator**	Equivalency GHG	Low Elec. Base DSM	2040	A - Current Landscape C – Regional Integration*	
2.0 **Net Zero 2050** **Low Electrification**	GHG targets decline linearly from 2030 to 0.5Mt in 2050	Low Elec. Base DSM	2040	A - Current Landscape C - Regional Integration	• DSM Levels
2.1 **Net Zero 2050** **Mid Electrification**	GHG targets decline linearly from 2030 to 0.5Mt in 2050	Mid Elec. Base DSM	2040	A - Current Landscape B - Distributed Resources C - Regional Integration	• DSM Levels • No New Emitting • Target Case for Sensitivity Evaluation
2.2 **Net Zero 2050** **High Electrification**	GHG targets decline linearly from 2030 to 0.5Mt in 2050	High Elec. Max DSM	2040	A - Current Landscape C - Regional Integration	• DSM Levels • No New Emitting
3.1 **Accelerated Net Zero 2045 Mid Electrification**	GHG targets decline from 2025 to 0.5Mt in 2045; path to Absolute Zero 2050	Mid Elec. Base DSM	2030	B - Distributed Resources C - Regional Integration	• DSM Levels • No New Emitting • Target Case for Sensitivity Evaluation
3.2 **Accelerated Net Zero 2045 High Electrification**	GHG targets decline from 2025 to 0.5Mt in 2045; path to Absolute Zero 2050	High Elec. Max DSM	2030	B - Distributed Resources C - Regional Integration	• DSM Levels

*Based on stakeholder feedback, the scenario highlighted in blue was added to the set of key scenario runs

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RESOURCE SCREENING RESULTS DIESEL COMBUSTION TURBINES

RESOURCE SCREENING – DIESEL COMBUSTION TURBINES

- Screening of existing Diesel CTs was conducted by E3 using RESOLVE
- During screening the model was free to re-optimize the resource portfolio and to select any available supply options to replace the CT capacity (e.g. new gas CTs/CCGTs, batteries, firm imports, etc.)
- Analysis was completed on two key scenarios (1.0A and 2.1C)
- Screening results showed that sustaining the existing diesel CT fleet is economic vs. replacement alternatives; Diesel CTs will be assumed “in” in the Initial Portfolio Study runs
- This result was robust to testing with a lower Planning Reserve Margin (PRM) and to testing a single unit retirement

Approach to Screening Diesel CTs

+ **The diesel CT screening analysis evaluates the system value of NSP's diesel CT assets**
+ **E3 performed capacity expansion optimization of NSP's IRP scenarios in RESOLVE, with diesel CTs "in" and "out"**
  - The "in" cases reflect the NSP system, including all existing diesel CTs within the model
  - The "out" cases remove the diesel CTs from NSP's existing portfolio and allow the system to perform capacity expansion without the units
+ **The difference in costs reflects the net system value (or cost) of the diesel CTs**

1. **Run the "In" Case:** Run RESOLVE with all existing units in the model to identify optimal future resource portfolio that meets reliability and GHG goals while minimizing customer costs
   Outputs: System Costs (RR), Capacity Additions, Energy Generation, Retirements, etc.

2. **Run the "Out" Case:** Run RESOLVE with existing units except the diesel CTs in the model to identify optimal future resource portfolio that meets reliability and GHG goals while minimizing customer costs, but without the diesel CTs available
   Outputs: System Costs (RR), Capacity Additions, Energy Generation, Retirements, etc.

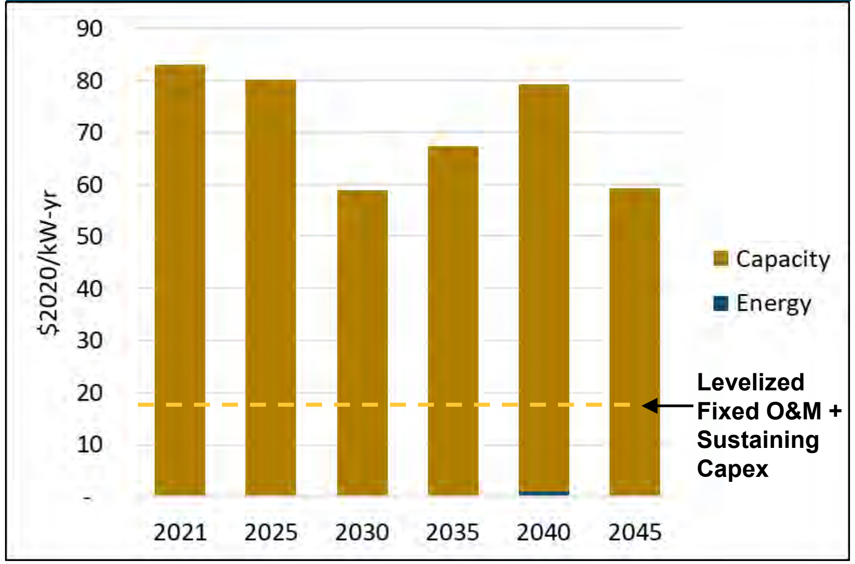
3. ***The incremental cost of the portfolio (or savings) reflects the net system benefit (or cost) associated with the diesel CTs****

* Assuming all major system costs and benefits associated with the diesel CTs are within the model.

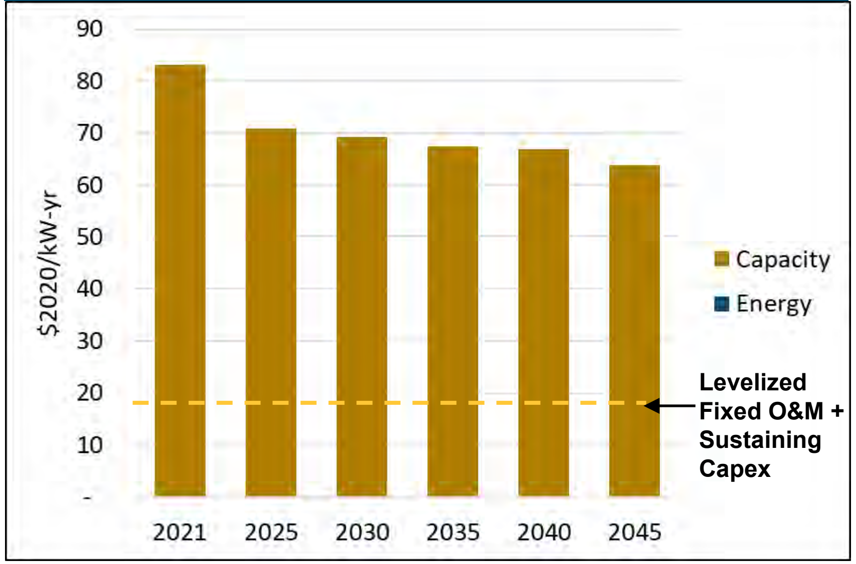
What value do diesel CTs provide?

+ Diesel CTs provide capacity value, which reflects the net costs of new capacity. By maintain the existing Diesel CT fleet, investment in new CTs can be avoided while maintain capacity contributions toward peak loads
+ In addition, diesel CTs provide non-spinning reserve capacity service, the value of which is not shown in the charts below
+ Diesel CTs are not run often because of their relatively higher fuel costs relative to alternative resource options; as such replacement energy does not factor into these calculations

Diesel Peakers Marginal Value - 1.0.A



Diesel Peakers Marginal Value – 2.1.C

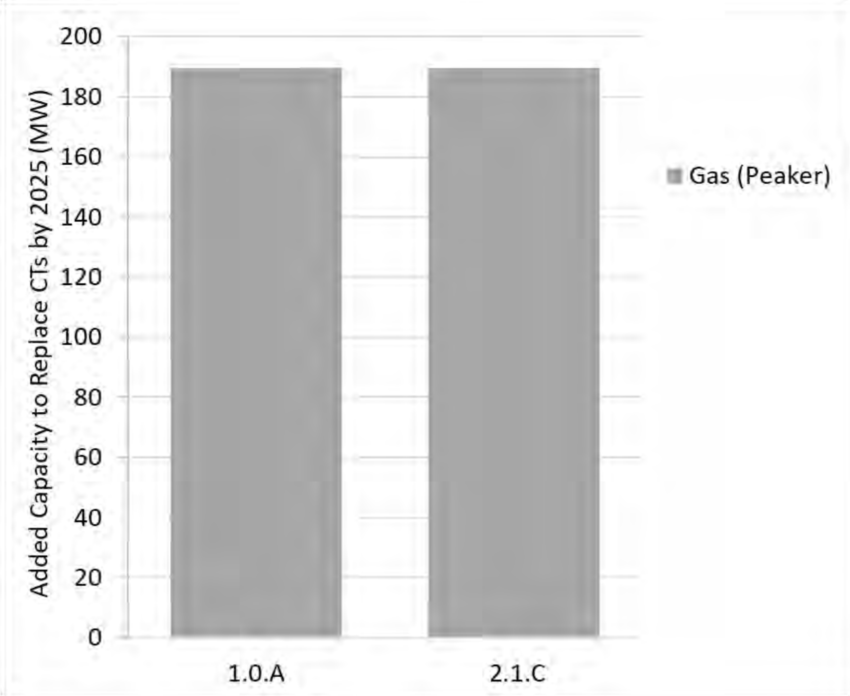


Incremental Capacity Additions when Diesel CTs Removed from the System

- **The 231 MW diesel CTs are largely used to provide capacity and ancillary services when included in the system**
  - They are not run frequently (<1% CF)
- **When diesel CTs are removed, RESOLVE builds new gas peakers to replace lost capacity**
  - Note that higher ELCC* for replacement gas peakers means less than 231 MW is needed for an equivalent reliability contribution
  - The gas peaker replacement resource is selected economically ahead of other potential replacement options (e.g. battery storage or NGCC units)
- **On aggregate, maintaining the existing diesel CTs is worth about ~$186 MM (no end effects) and ~$240 MM (with end effects) to the system on an NPV basis**

**Effective Load Carrying Capacity*

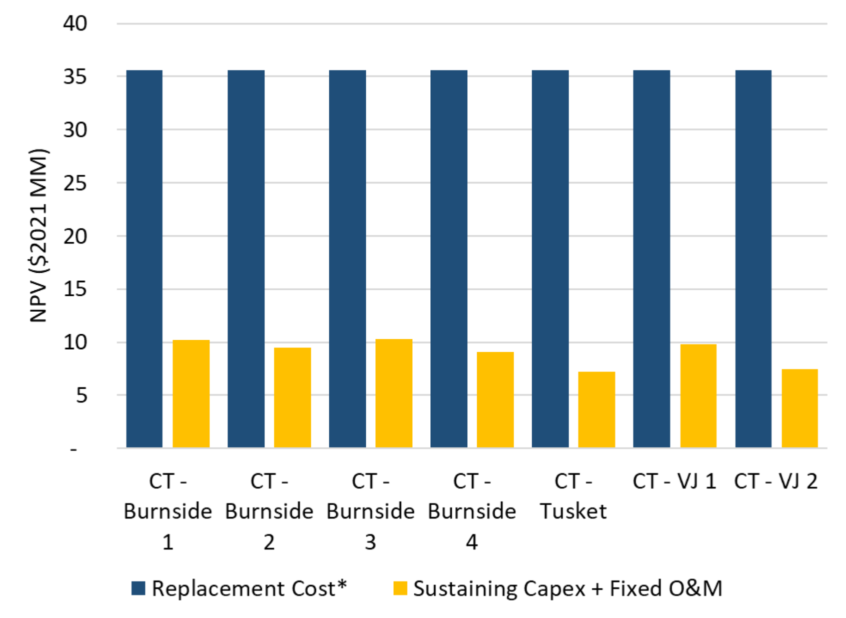
Added Capacity to Replace Diesel CT by 2025



System Value of Diesel CTs - 1.0.A

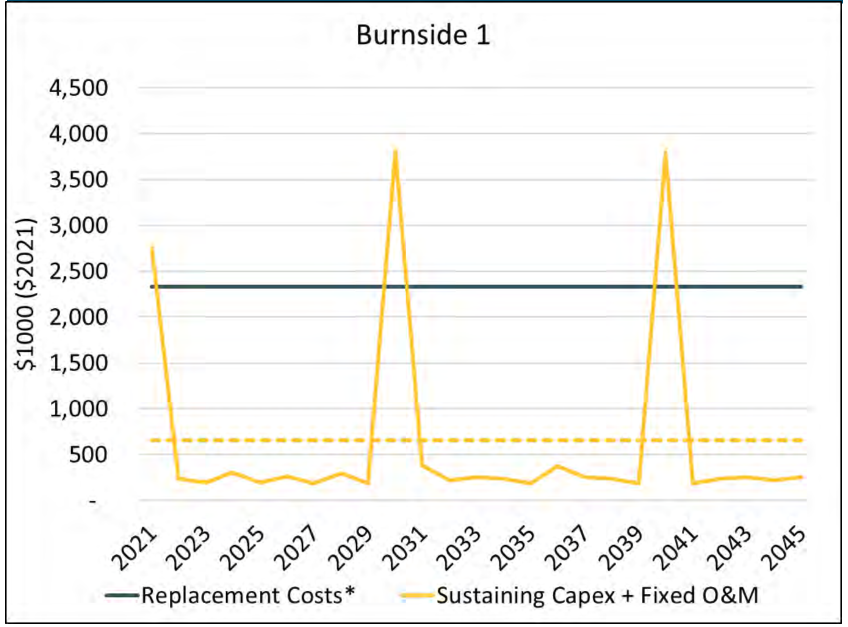
- **While the sustaining costs of maintaining diesel CTs are higher in certain years of investment, this analysis shows the costs to replace with alternative resources exceeds the costs to retain the resources over the planning horizon on an NPV basis**
- **The difference between the blue and yellow bars/lines reflects the net system value**

Cost to Replace Diesel CT vs Sustaining Capex (1.0.A)



** Replacement energy and capacity costs reflect net system savings adjusted for avoided sustaining capital and fixed O&M*

Sustaining Capex vs Replacement Cost by Years

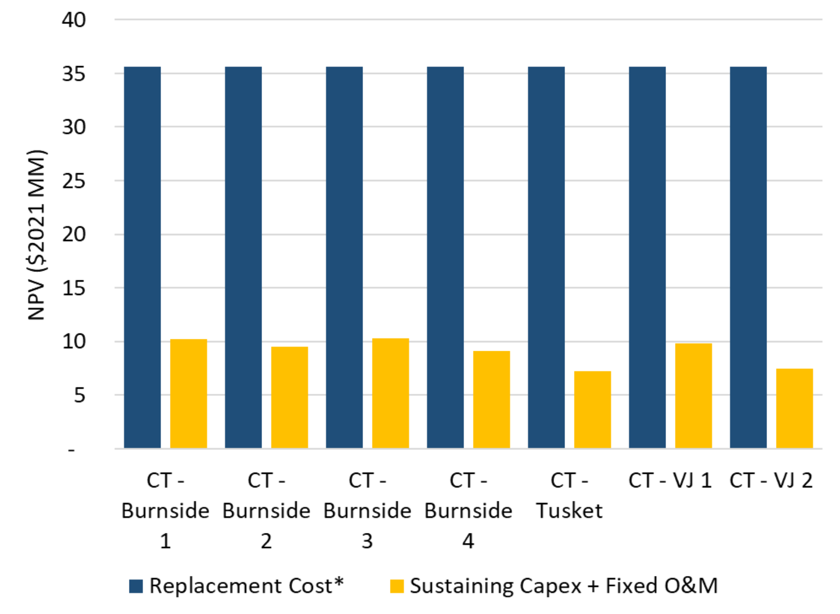


Dotted line reflects the levelized sustaining capital expenditures and fixed O&M

System Value of Diesel CTs – 2.1.C

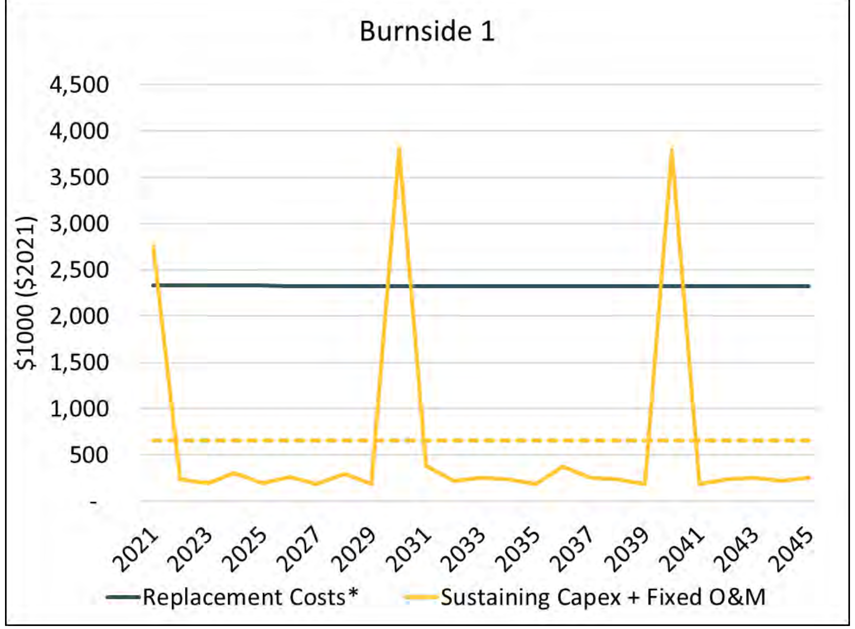
+ **Results remain the same under 2.1.C., given similar replacement builds required to provide required system capacity**

Cost to Replace Diesel CT vs Sustaining Capex



** Replacement energy and capacity costs reflect net system savings adjusted for avoided sustaining capital and fixed O&M*

Sustaining Capex vs Replacement Cost by Years



Dotted line reflects the levelized sustaining capital expenditures and fixed O&M

System Value of Diesel CTs – 2.1.C - Lower PRM Requirement

+ The value of the diesel CT units does not change with a lower PRM
+ When diesel CTs were removed, the model still replaces the peakers with 190 MW of new gas CTs

+ Removing a 33 MW of diesel CT from the model under the lower PRM sensitivity resulted in a total system cost NPV that was higher than when the unit was sustained through the planning horizon

RESOURCE SCREENING RESULTS
HYDRO

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RESOURCE SCREENING – HYDRO

- Screening of the existing hydro systems was conducted by E3 using RESOLVE
- During screening the model was free to re-optimize the resource portfolio and to select any available supply options to replace the hydro capacity and energy (e.g. new gas CTs/CCGTs, batteries, firm and non-firm imports, wind, etc.)
- Analysis was completed on two key scenarios (1.0A and 2.1C)
- Sustaining and Decommissioning costs were taken from NS Power's most recent Hydro Asset Study
- Wreck Cove and Mersey were modeled individually and remaining systems were modeled in two groups with similar operating characteristics
- Screening results showed that sustaining the existing hydro systems is economic vs. replacement alternatives; existing hydro will be assumed "in" in the Initial Portfolio Study runs
- NS Power will conduct a capacity expansion run in PLEXOS with the Mersey hydro system retired

Overview of Hydro Screening Analysis

- **The hydro screening analysis assesses the value of NSP's hydro assets**
- **E3 performed "in" and "out" cases in RESOLVE under core IRP scenarios**
  - "In" Cases: Model the NSP system under the given IRP scenario, with all existing hydro units assumed to continue operating
  - "Out" Cases: Removes a given hydro unit/ group from the model and performs capacity expansion without the asset, replacing the system services provided to meet demand at lowest cost subject to model constraints
- **The hydro asset's value is based on the costs to sustain versus decommission the unit**
- **Comparison done over 40 years given timeframe of input data on sustaining capital and decommissioning costs**

1. **Run the "In" Case:** Run RESOLVE with all existing units in the model to identify optimal future resource portfolio that meets reliability and GHG goals while minimizing customer costs

2. **Run the "Out" Case:** Run RESOLVE with existing units except the hydro asset in the model to identify optimal future resource portfolio that meets reliability and GHG goals while minimizing customer costs, but without those units available

3. **Organize modeled and non-modeled costs:**

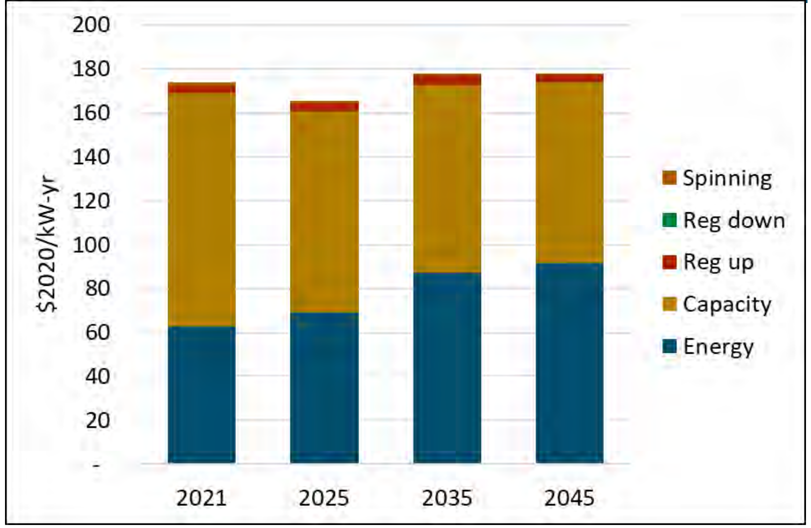
Sustaining/Operating Asset:	Decommissioning Asset:
- Sustaining Capital (in RESOLVE) - Fixed O&M (in RESOLVE)	- Decommissioning Costs (outside RESOLVE) - Replacement System Costs (in RESOLVE)

The difference between decommissioning and sustaining/operating reflects the system benefit (or cost if negative) associated with the hydro asset

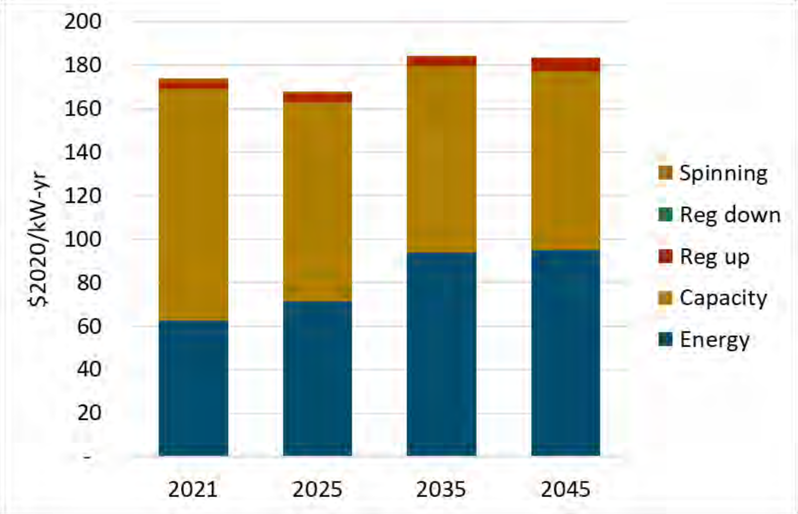
Wreck Cove Hydro: System value provided by Wreck Cove in RESOLVE

+ Wreck Cove provides incremental energy and capacity value to the system; the energy value are higher in later years as emissions become binding and coal units are retired
+ Wreck Cove is slightly more valuable in the 2.1.C. scenario, which has higher loads and lower carbon targets, but access to emissions-free imports

Wreck Cove – Modeled Valued in RESOLVE 1.0.A.



Wreck Cove – Modeled Valued in RESOLVE 2.1.C.

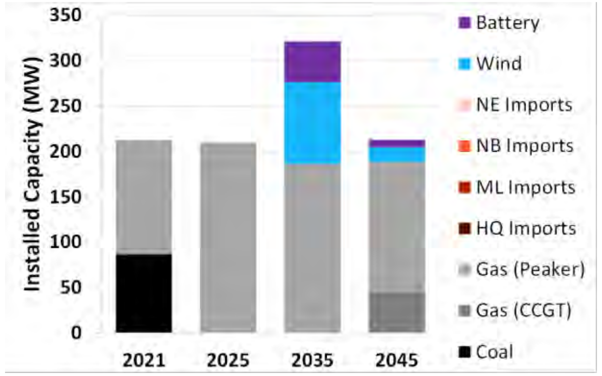


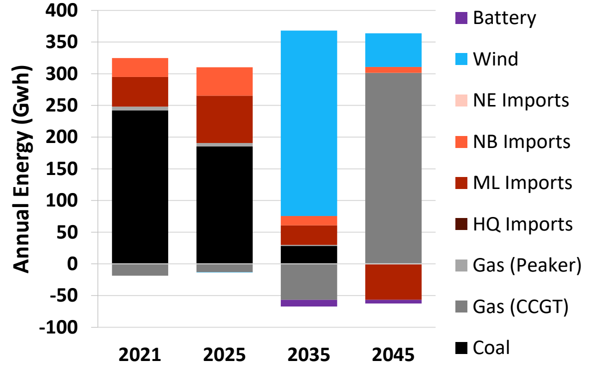
Wreck Cove: Replacement capacity and energy when Wreck Cove removed from the model

+ **When Wreck Cove is removed from the system, the model builds gas peakers for replacement capacity**

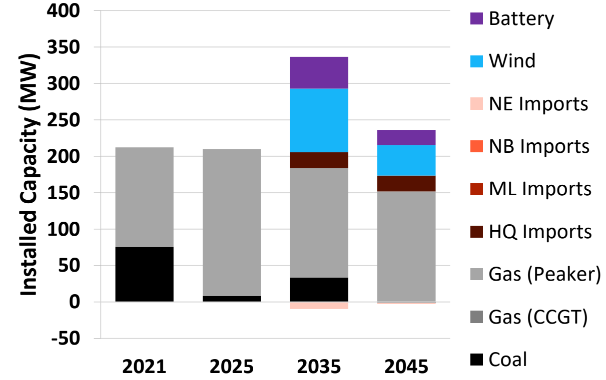
+ **The model replaces Wreck Cove's energy primarily with coal before 2030 when emissions are not binding, and with wind, imports, and gas CCGT after 2035 when emissions become more constrained**

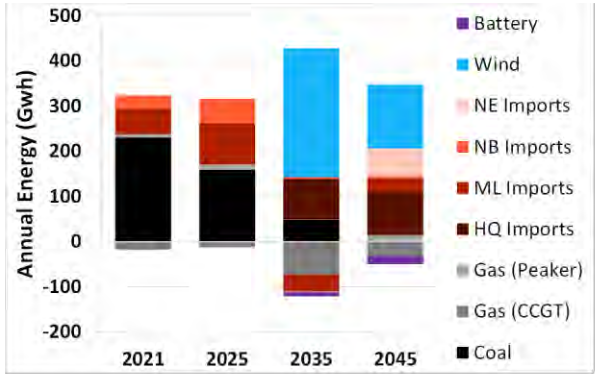
Replacement Capacity and Energy when Wreck Cove Removed – 1.0.A.





Replacement Capacity and Energy when Wreck Cove Removed – 2.1.C.

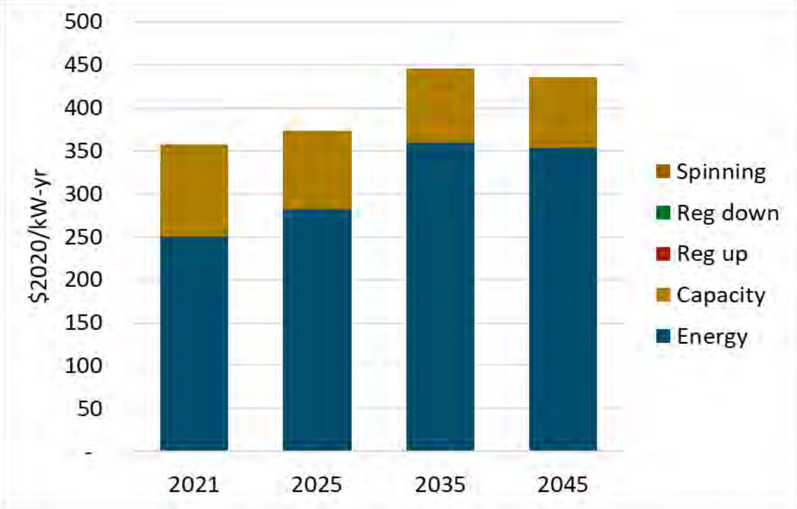




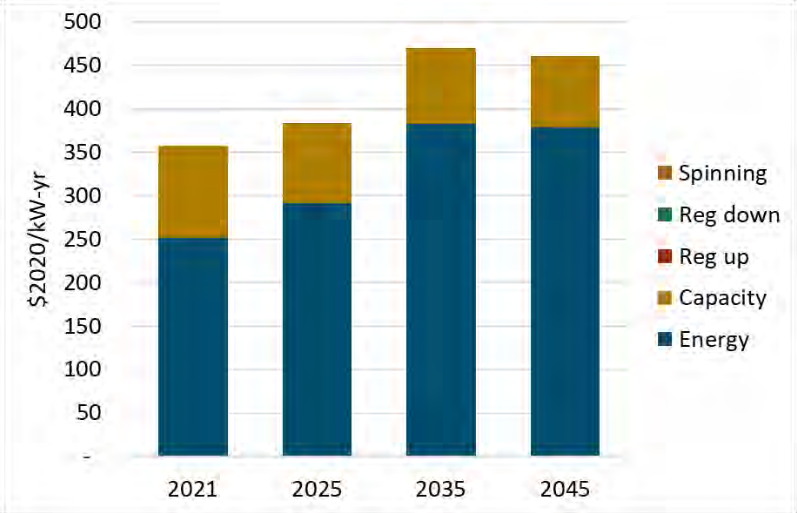
Mersey Hydro: System value provided by Mersey in RESOLVE modeling

+ Mersey provides significant energy value to the system, as well as some incremental capacity value; the energy value are higher in later years as emissions become binding and coal units are retired
+ Mersey is slightly more valuable in the 2.1.C. scenario, which has higher loads and lower carbon targets, but access to emissions-free imports

Mersey – Modeled Valued in RESOLVE 1.0.A.



Mersey – Modeled Valued in RESOLVE 2.1.C.

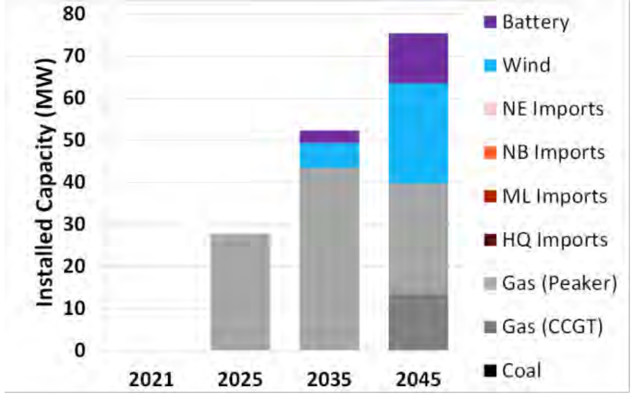


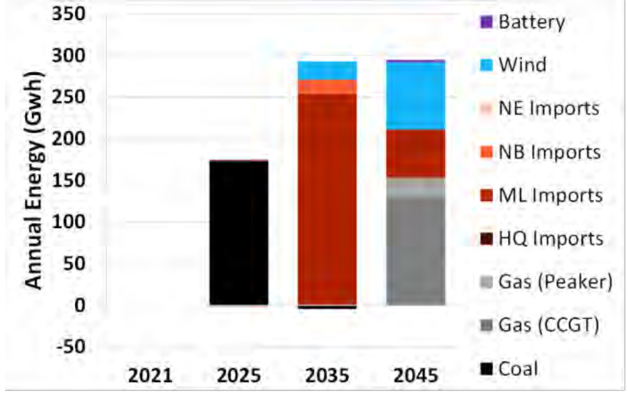
Mersey: Replacement capacity and energy when Mersey removed from the model

+ **When Mersey is removed from the system, the model initially builds gas peakers for replacement capacity**

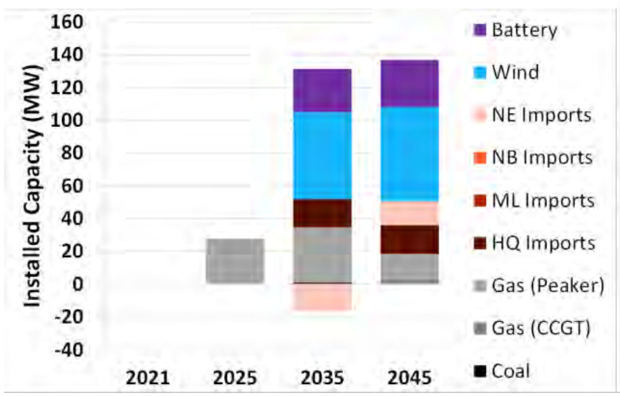
+ **The model replaces Mersey's energy primarily with coal before 2030, and with wind, imports, and gas CCGT after 2035 when emissions become more constrained**

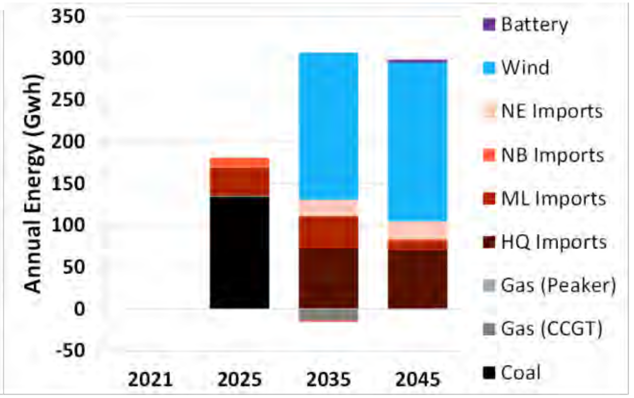
Replacement Capacity and Energy when Mersey Removed – 1.0.A.





Replacement Capacity and Energy when Mersey Removed – 2.1.C.

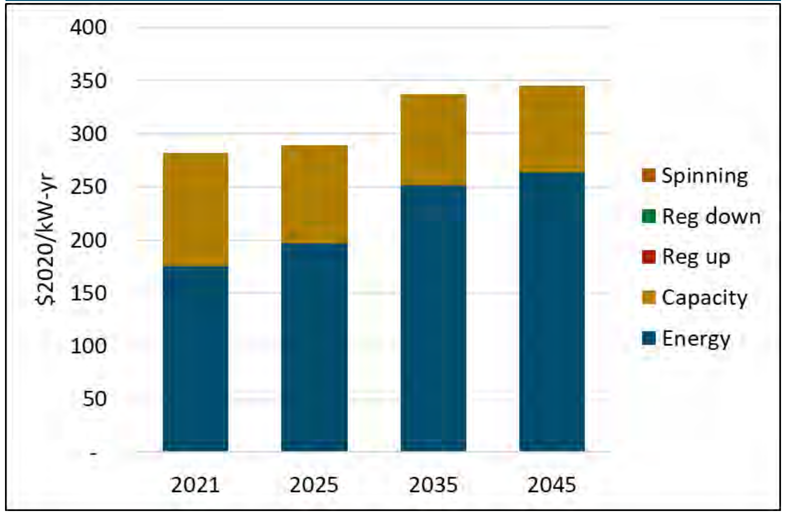




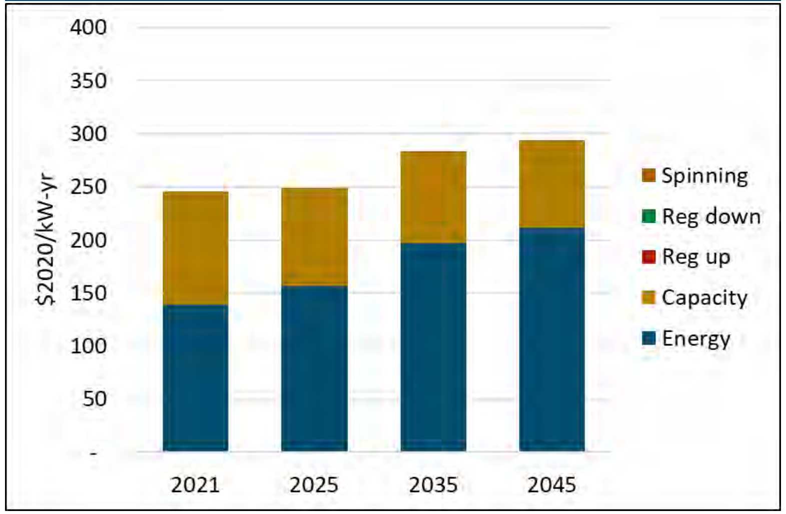
Small Hydro Groups: System value provided by Hydro Assets in RESOLVE modeling

- Several smaller hydro systems in Nova Scotia provide energy value to the system, as well as some incremental capacity value
- In total, hydro assets within Group 1 provided more energy value than Group 2 units due to its higher capacity factor in winter when loads are high
- The energy values are higher in later years as emissions become binding and coal units are retired
- Small hydro systems are slightly more valuable in the 2.1.C. scenario, which has higher loads and lower carbon targets, but access to emissions-free imports

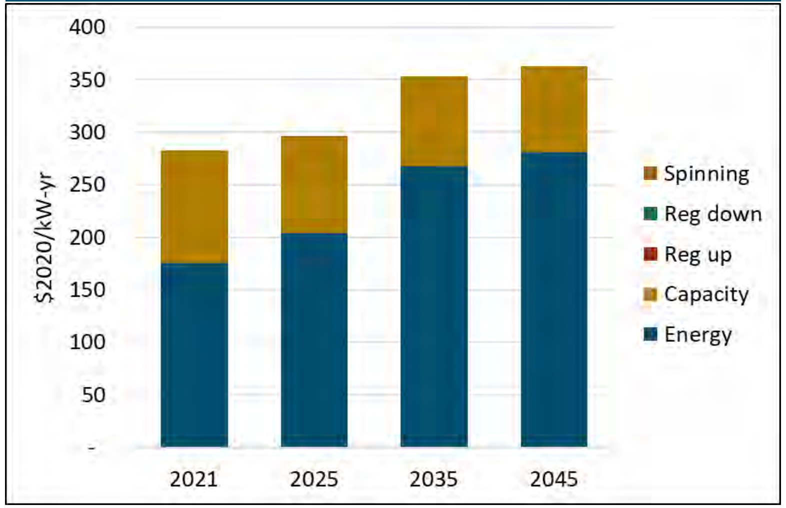
Modeled Valued in RESOLVE 1.0.A – Group 1



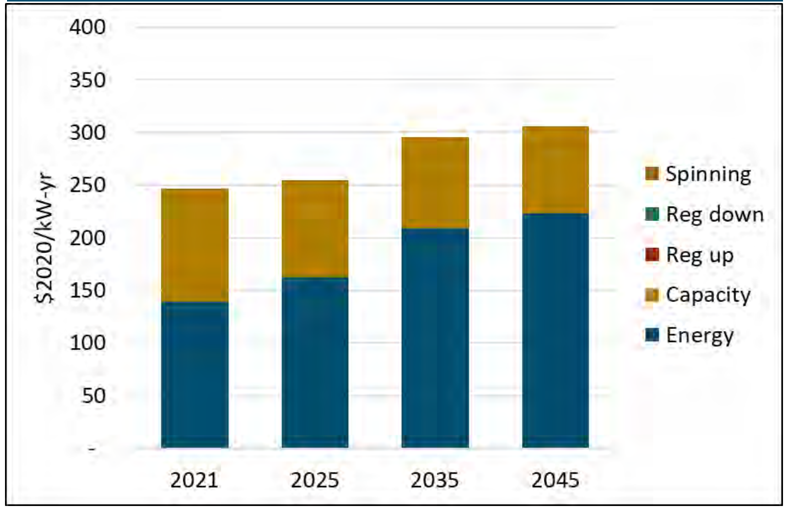
Modeled Valued in RESOLVE 1.0.A - Group 2



Modeled Valued in RESOLVE 2.1.C - Group 1



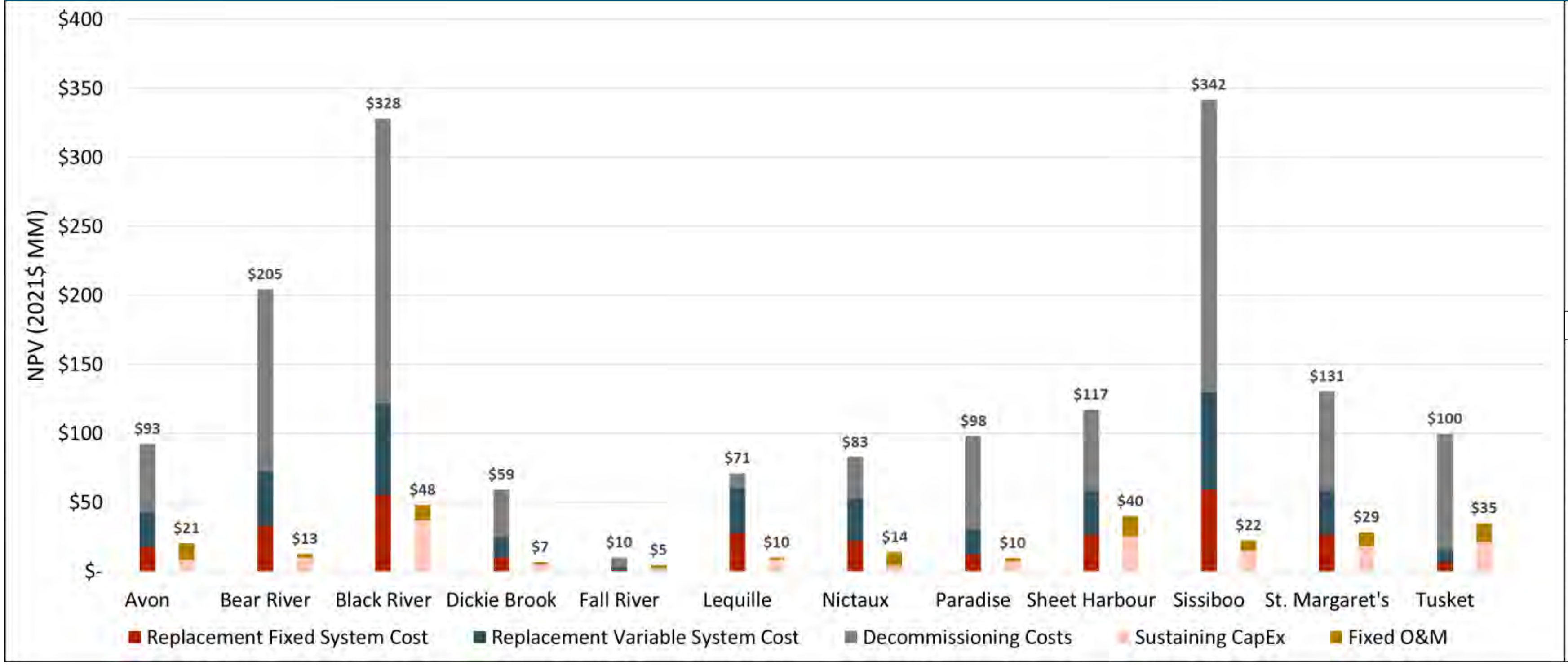
Modeled Valued in RESOLVE 2.1.C. - Group 2

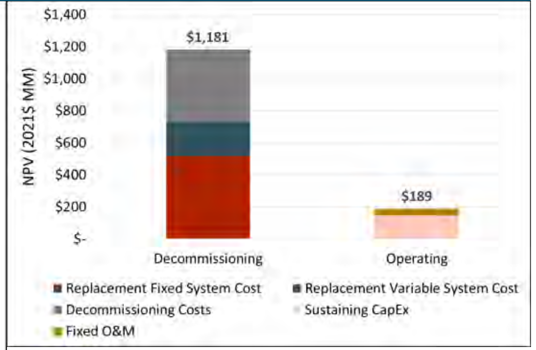


Hydro Assets: Total decommissioning costs relative to sustaining operations – 1.0.A

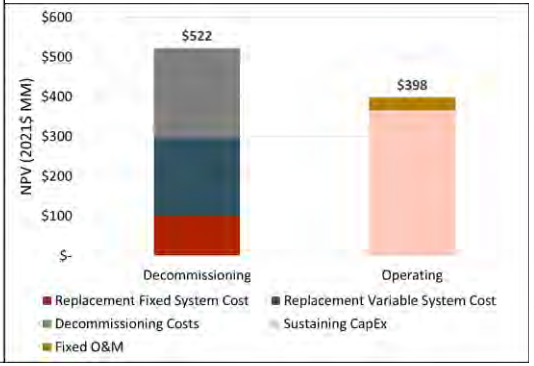
+ **This analysis indicates the cost to replace individual hydro assets with alternative resources exceeds the costs to retain the resource over a 40-year planning horizon on an NPV basis**

Cost to Replace Small Hydro Assets vs Sustaining Capex (1.0.A)





Wreck Cove

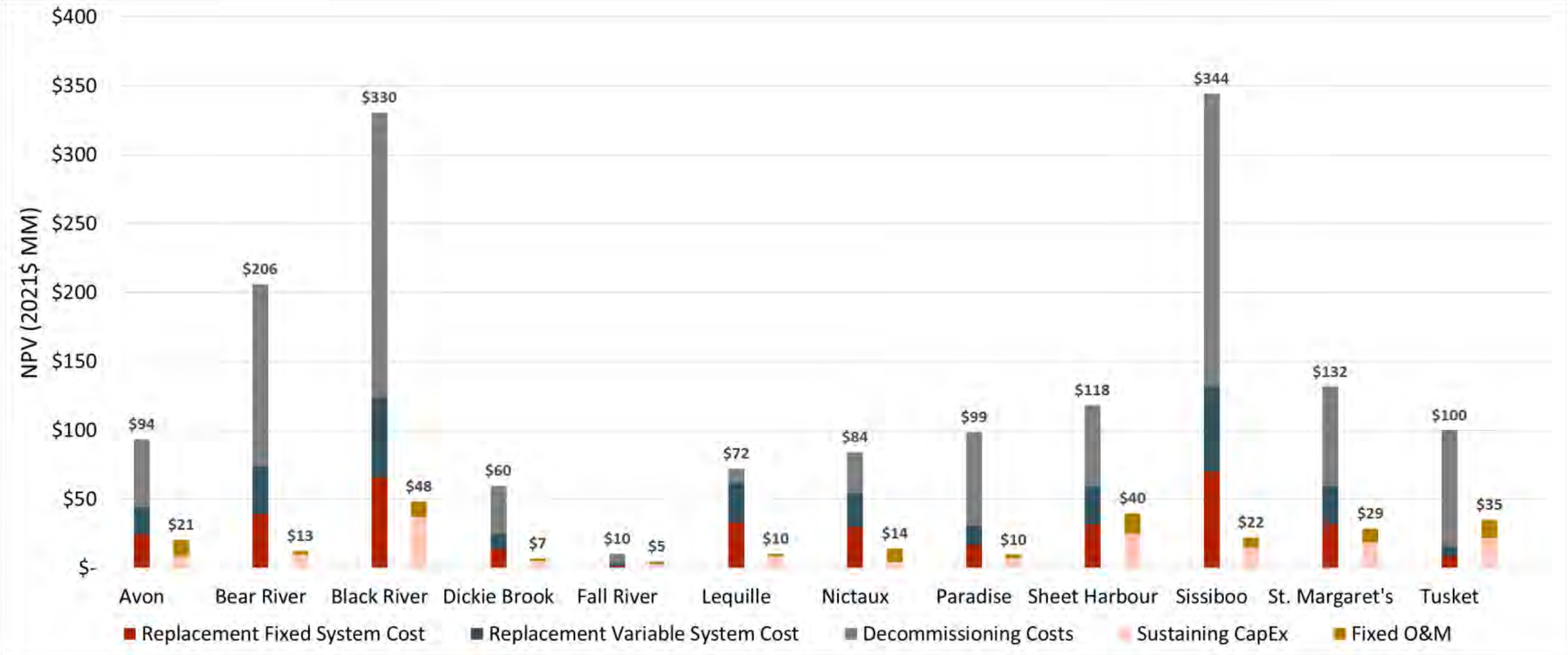


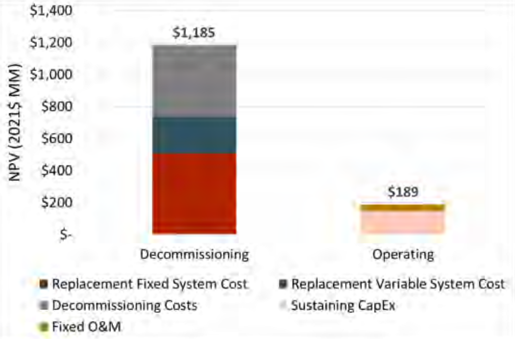
Mersey

Hydro Assets: Total decommissioning costs relative to sustaining operations – 2.1.C

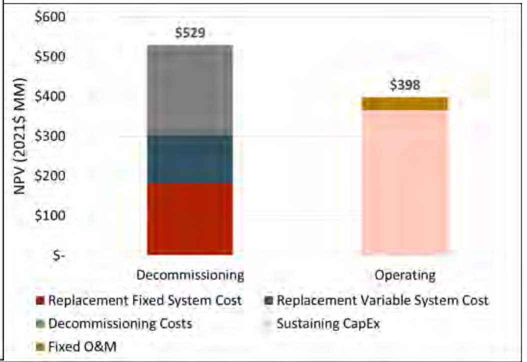
+ **Similar results are found for the 2.1C scenario where the more constrained emissions and higher load results in higher replacement costs for renewable hydro capacity**

Cost to Replace Small Hydro Assets vs Sustaining Capex (2.1.C)





Wreck Cove



Mersey

RESOURCE SCREENING RESULTS
KEY SCENARIOS

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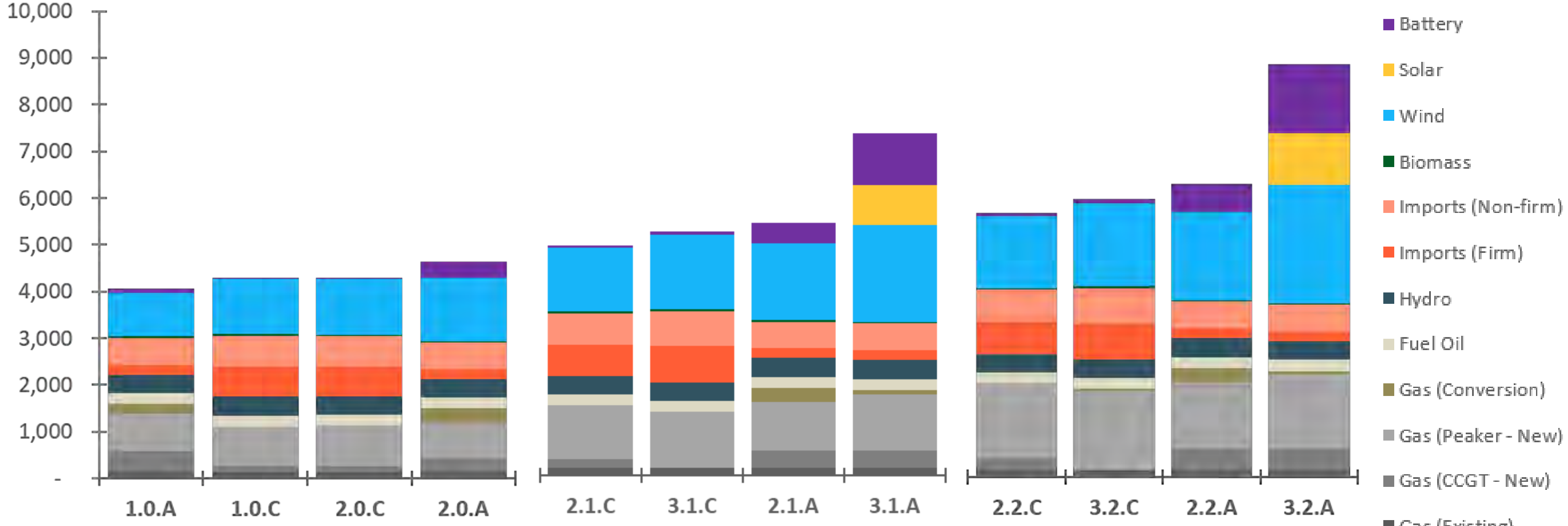
RESOURCE SCREENING – KEY SCENARIOS

- Initial runs of select key scenarios and sensitivities were conducted by E3 using RESOLVE
- Early runs in both PLEXOS and RESOLVE were used to validate the construction of the two models concurrently, providing insights by comparing runs of the same scenario across both tools
- Based on the results of the screening results, the supply options available to the PLEXOS Initial Portfolio Study runs were further refined
- NPVs presented in these results are partial revenue requirements that consider modeled costs (i.e. production, O&M, abatement, sustaining capital, and capital investment) and costs considered outside of the long-term model optimization (i.e. energy efficiency costs)

2045 Installed Capacity Across Current Landscape and Regional Integration Cases

- Higher loads and more stringent decarbonization targets drive greater renewable builds, though access to greater regional imports (“C” Regional Integration cases) slightly mitigates builds and costs

Installed Capacity (MW) Low/Base Electrification and Base DSM	Installed Capacity (MW) Mid Electrification and Base DSM	Installed Capacity (MW) High Electrification and Max DSM



	1.0.A	1.0.C	2.0.C	2.0.A	2.1.C	3.1.C	2.1.A	3.1.A	2.2.C	3.2.C	2.2.A	3.2.A
NPV* ($MM) (2021-2045)	$12,257	$12,193	$12,215	$12,275	$12,954	$13,468	$13,049	$13,607	$14,948	$15,372	$15,057	$15,854
Avg. Generation Cost (¢/kWh)	7.6	7.6	7.6	7.7	7.7	8.0	7.8	8.1	8.6	8.9	8.7	9.2

1.0.A - Case Summary

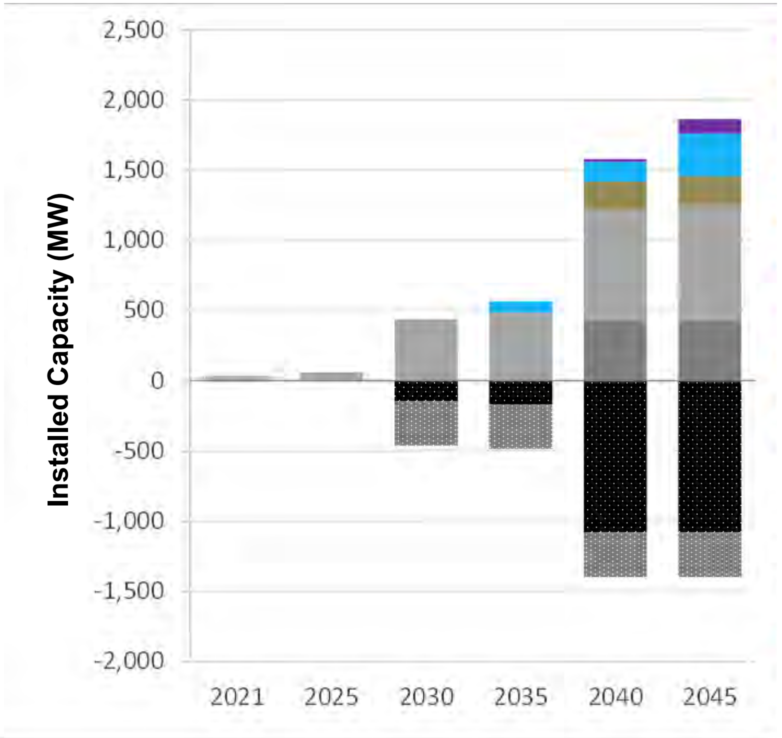
Comparator, Low Elec./Base DSM, Current Landscape

Key Observations

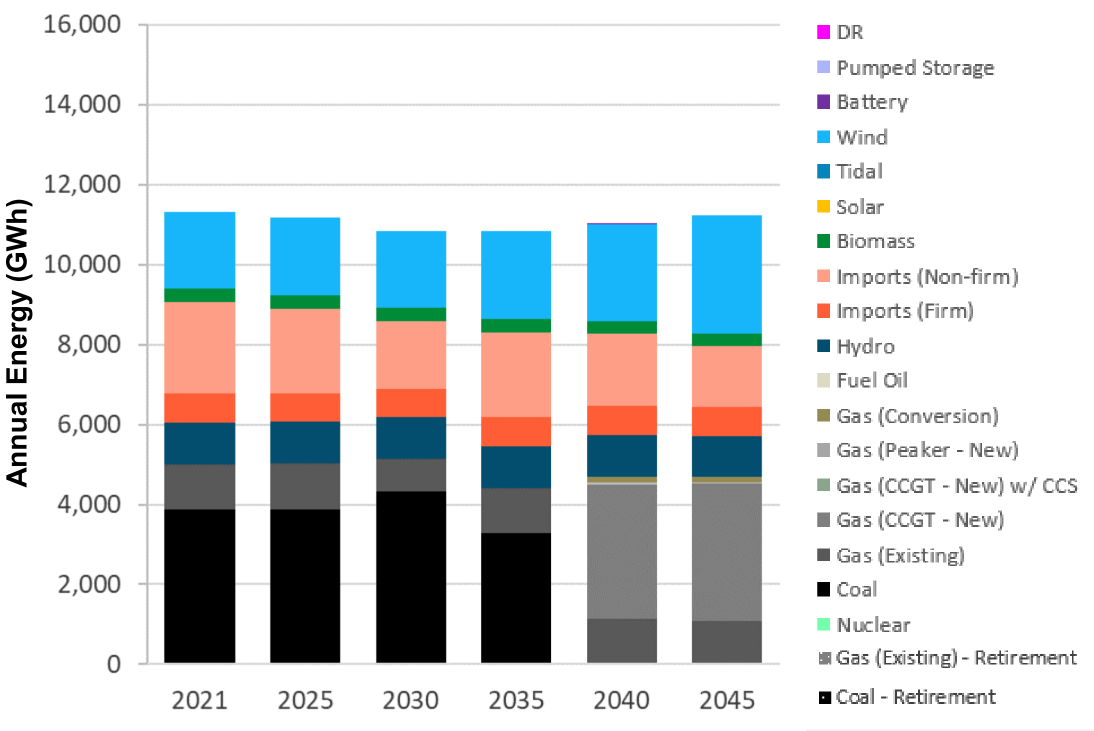
- A combination of gas peakers, gas CCGT, and wind is built to replace the retired coal capacity
- ~300 MW of new wind is built by 2045

Metric	2035	2045
GHG Emissions (MMT)	3.7	2.2
GHG Marginal Abatement Cost ($/ton)	$16	$0
NPV ($2021)	$12,257	
NPV ($2021) – with 20-year end effects	$15,989	
Average Generation Cost (c/kWh)	7.6	

Capacity Addition (+) and Retirement (-) (MW)



Energy Balance (GWh)



1.0.C - Case Summary

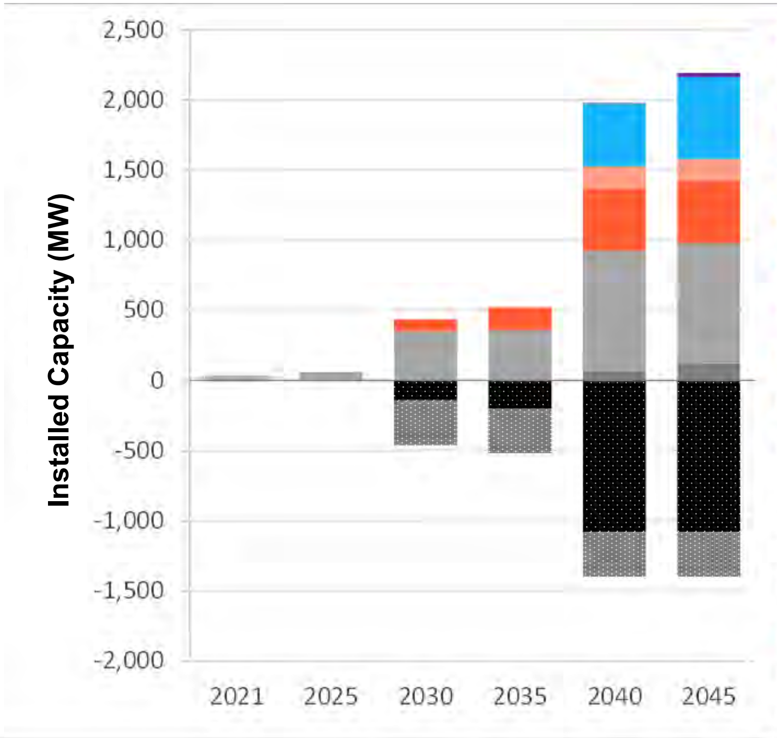
Comparator, Low Elec./Base DSM, Regional Integration

Key Observations

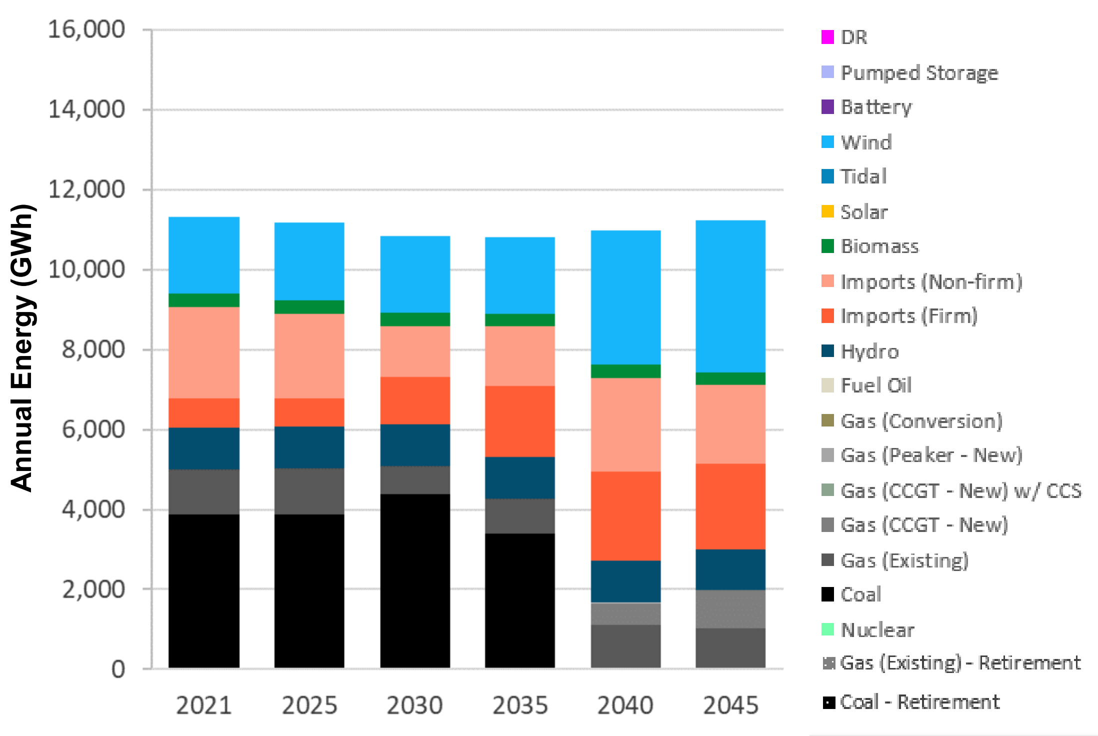
- Model selects firm imports when available; ~600 MW of transmission line is built to access imports in the later years
- New wind capacity is higher than 1.0.A. The new transmission lines allow for more wind integration without a large storage build
- New transmission lines help drop 2045 annual GHG emissions to just 1 MMT

Metric	2035	2045
GHG Emissions (MMT)	3.7	1.0
GHG Marginal Abatement Cost ($/ton)	$12	$0
NPV ($2021)	$12,193	
NPV ($2021) – with 20-year end effects	$15,862	
Average Generation Cost (c/kWh)	7.6	

Capacity Addition (+) and Retirement (-) (MW)



Energy Balance (GWh)

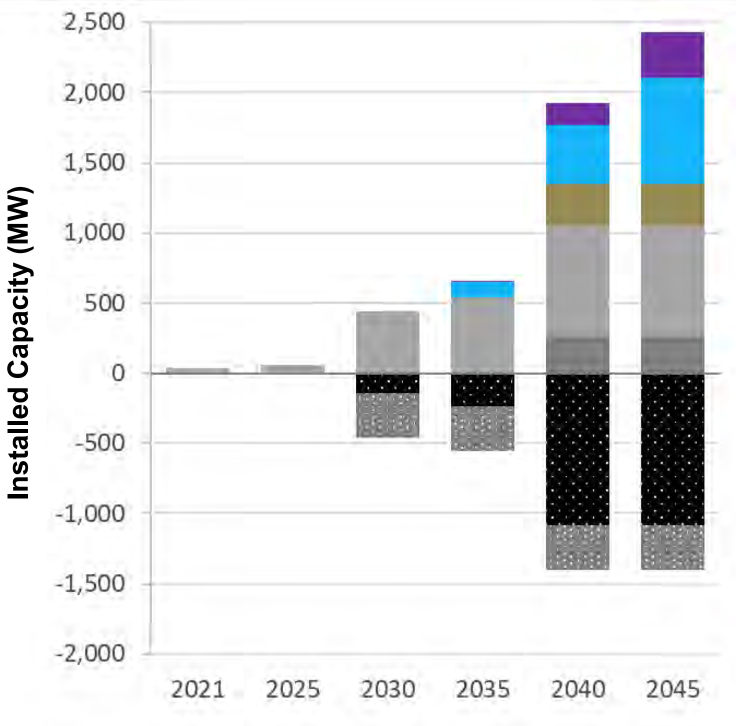


2.0.A - Case Summary
Net Zero, Low Elec./Base DSM, Current Landscape

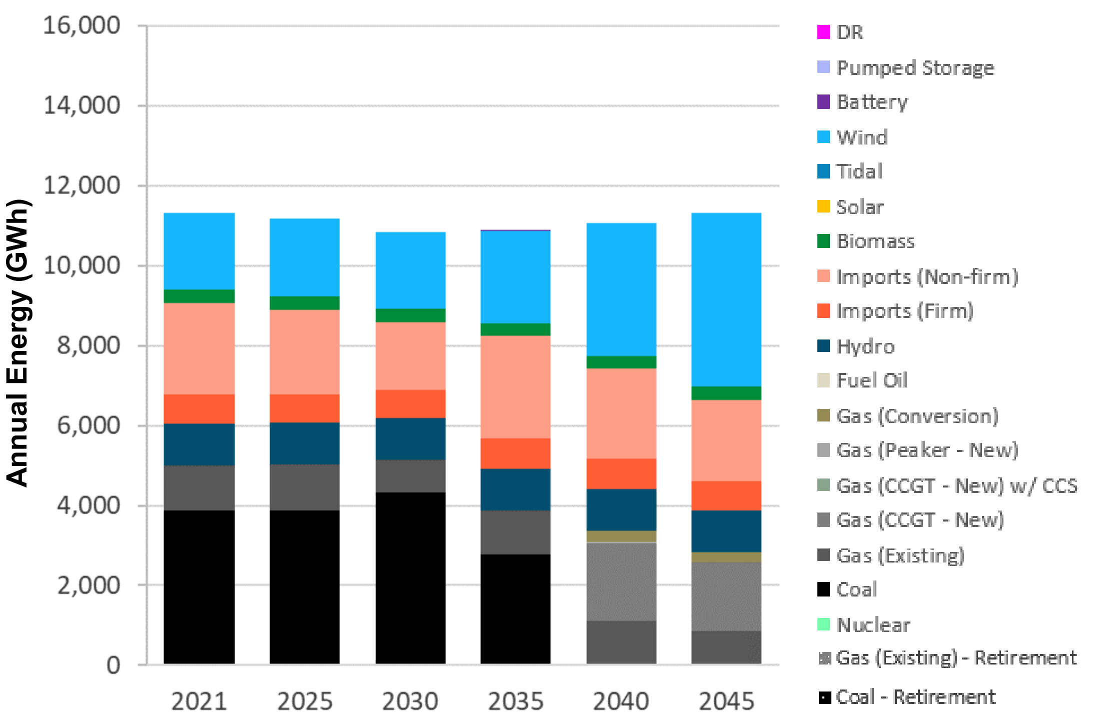
Key Observations
+ The net zero case has more stringent GHG constraints compared to the comparator case
+ Compared to 1.0A, the system relies less on gas peakers and more on wind and imports

Metric	2035	2045
GHG Emissions (MMT)	3.2	1.4
GHG Marginal Abatement Cost ($/ton)	$21	$33
NPV ($2021)	$12,275	
NPV ($2021) – with 20-year end effects	$16,040	
Average Generation Cost (c/kWh)	7.7	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



2.0.C - Case Summary

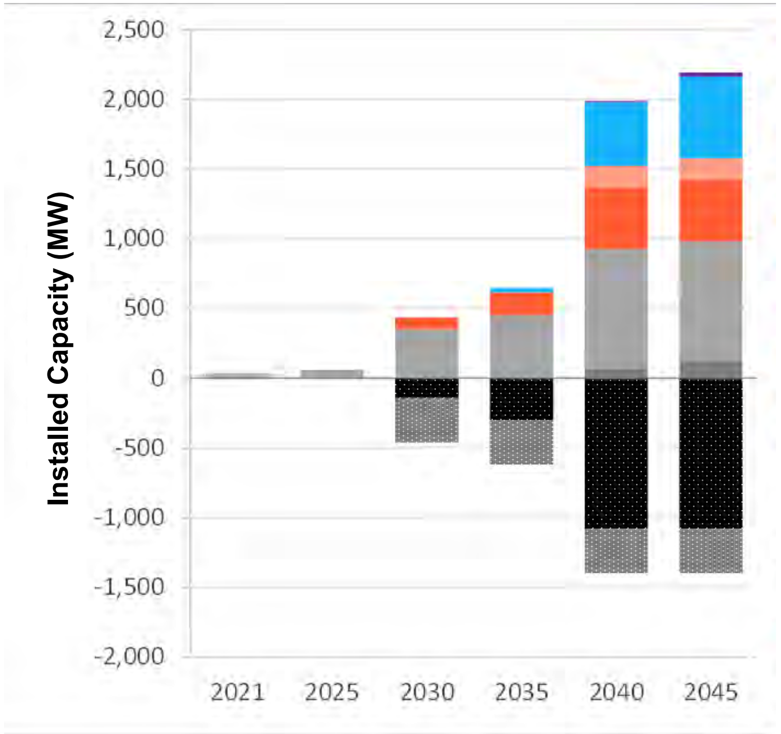
Net Zero, Low Elec./Base DSM, Regional Integration

Key Observations

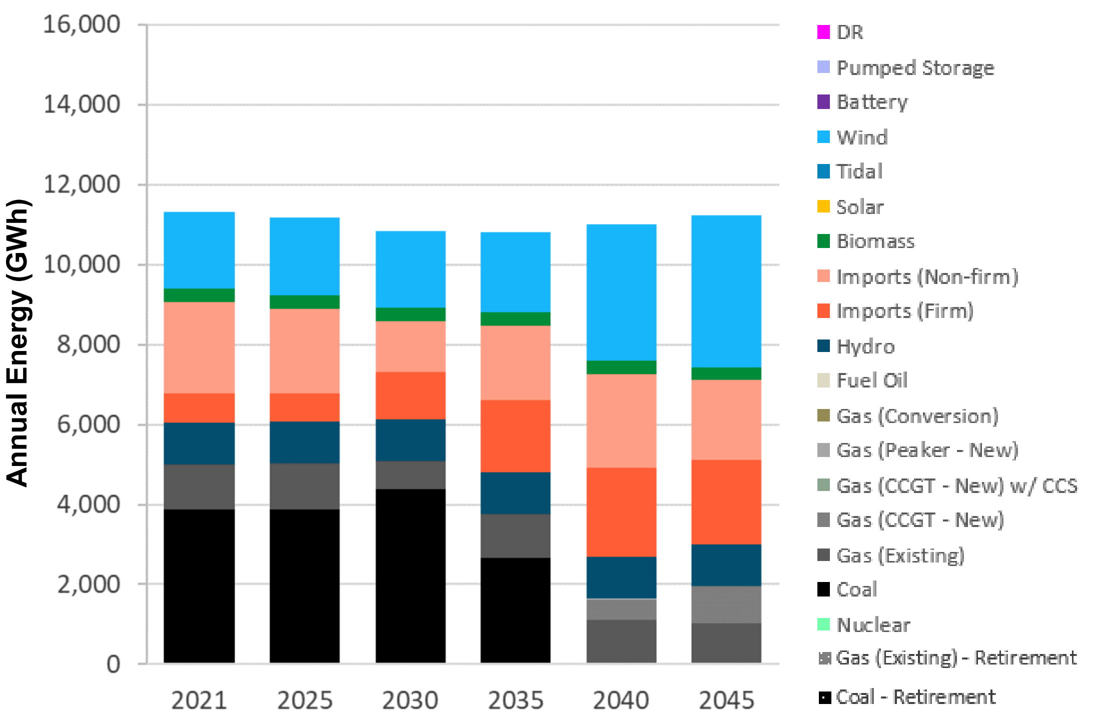
- Compared to 2.0.A we see less wind and more imports, while also requiring fewer batteries for wind balancing. About 30 MW of batteries are built by 2045 which helps balance the system and provide ancillary services
- System cost is similar to 1.0A

Metric	2035	2045
GHG Emissions (MMT)	3.2	1.0
GHG Marginal Abatement Cost ($/ton)	$24	$0
NPV ($2021)	$12,215	
NPV ($2021) – with 20-year end effects	$15,885	
Average Generation Cost (c/kWh)	7.6	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



2.1.A - Case Summary

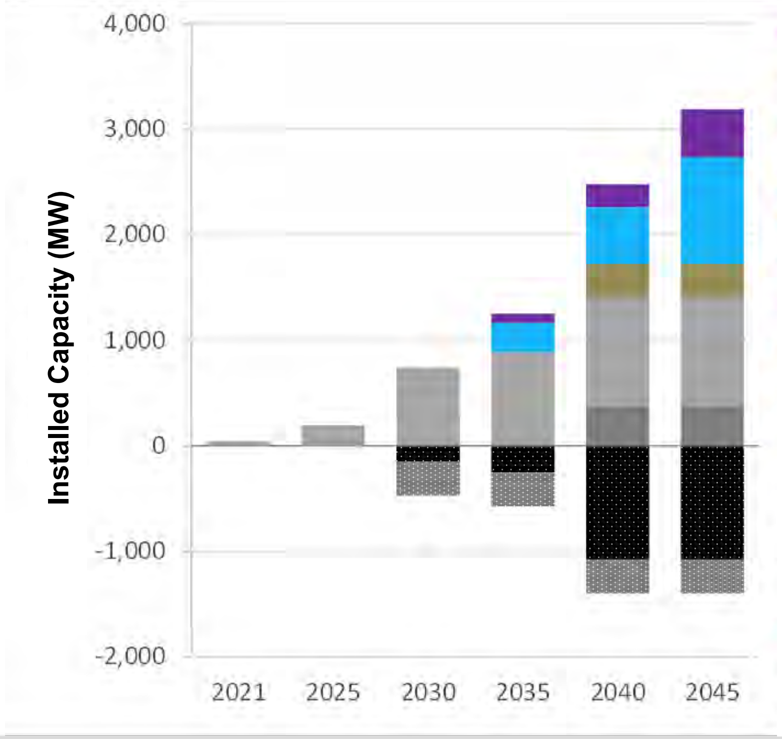
Net Zero, Mid Elec./Base DSM, Current Landscape

Key Observations

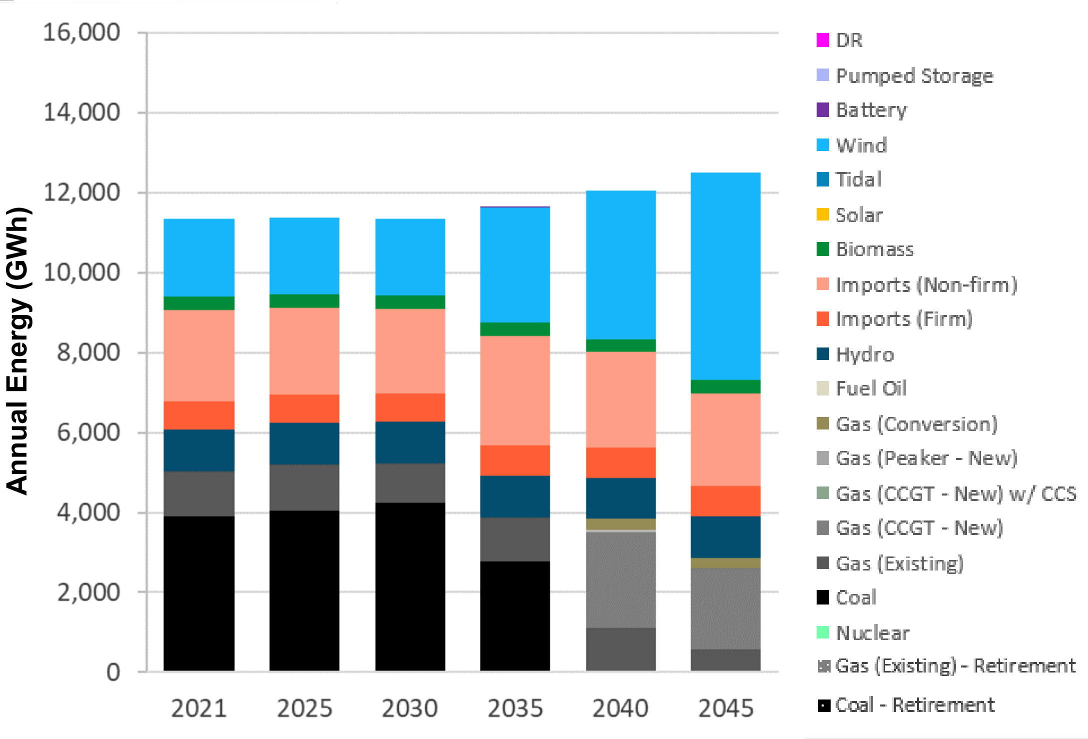
+ Higher loads than 2.0.A leads to about ~260 MW more gas peaker build; ~105 MW more CCGT build; ~260 MW more wind build; and~130 MW more battery build
+ The average generation cost also increases because the load is peakier and thus more expensive to serve
+ Over 40% of total generation comes from wind by 2045, and about 25% of total generation comes from imports

Metric	2035	2045
GHG Emissions (MMT)	3.2	1.4
GHG Marginal Abatement Cost ($/ton)	$23	$44
NPV ($2021)	$13,049	
NPV ($2021) – with 20-year end effects	$17,315	
Average Generation Cost (c/kWh)	7.8	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



2.1.B - Case Summary

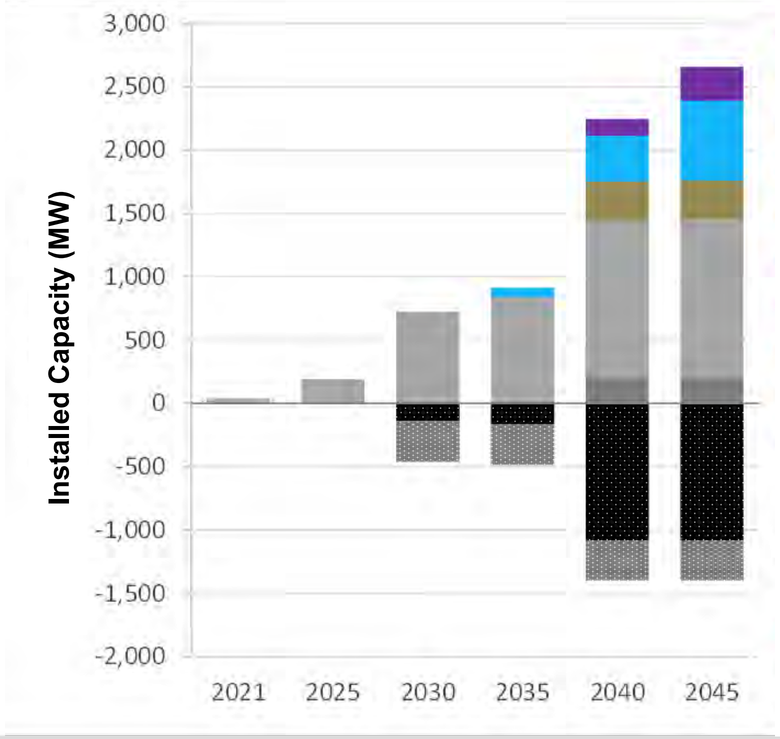
Net Zero, Mid Elec./Base DSM, Distributed Resources

Key Observations

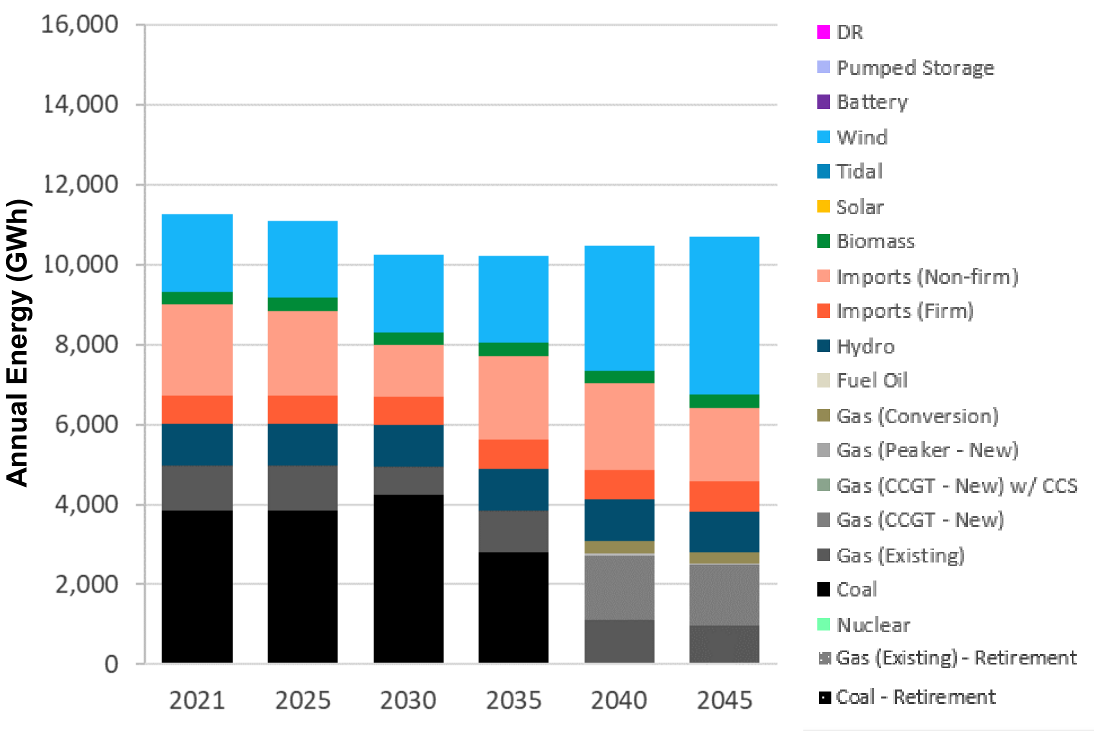
+ Although total NPV is lower (reflecting less load served), the average generation cost is higher relative to 2.1A, reflecting system costs spread over less kWh
+ DER is modeled as a load reduction; cost of DER resources not included in NPV calculations ($1.6B-$2.5B)

Metric	2035	2045
GHG Emissions (MMT)	3.2	1.4
GHG Marginal Abatement Cost ($/ton)	$14	$24
NPV ($2021)	$12,264	
NPV ($2021) – with 20-year end effects	$16,017	
Average Generation Cost (c/kWh)	7.9	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



2.1.C - Case Summary

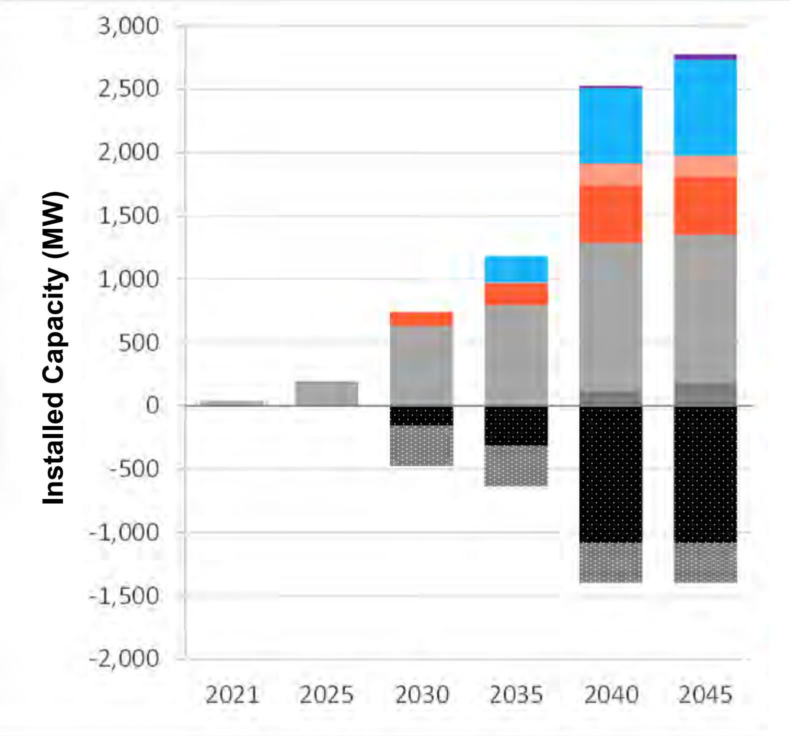
Net Zero, Mid. Elec./Base DSM, Current Landscape

Key Observations

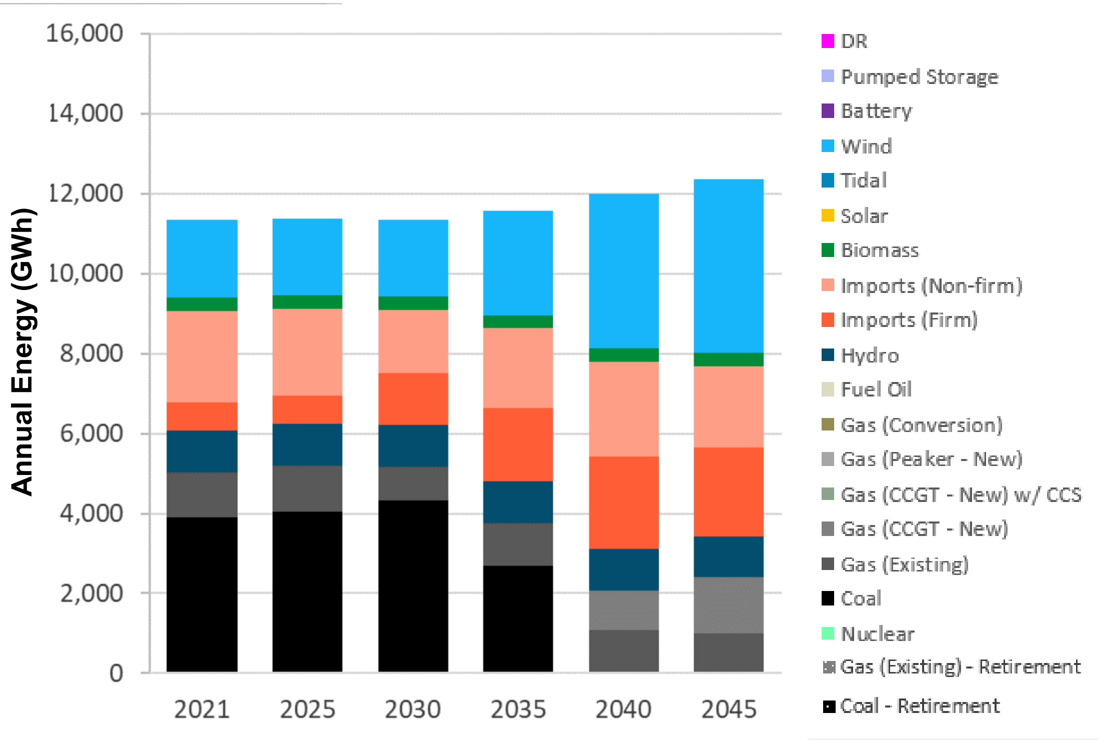
+ With access to firm import options, the model chooses incremental firm imports which reduce total system cost
+ Greater import access results in ~370 MW less gas build, ~260 MW less wind build and ~400 MW less battery build
+ Regional integration lowers NPV of system costs relative to 2.1A

Metric	2035	2045
GHG Emissions (MMT)	3.2	1.2
GHG Marginal Abatement Cost ($/ton)	$26	$0
NPV ($2021)	$12,954	
NPV ($2021) – with 20-year end effects	$17,072	
Average Generation Cost (c/kWh)	7.7	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



2.2.A - Case Summary

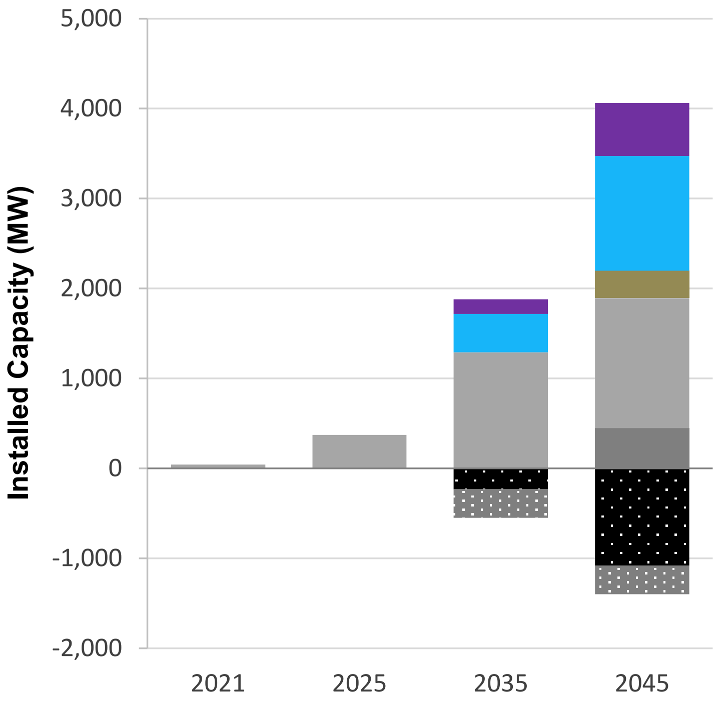
Net Zero, High Elec./Max DSM, Current Landscape

Key Observations

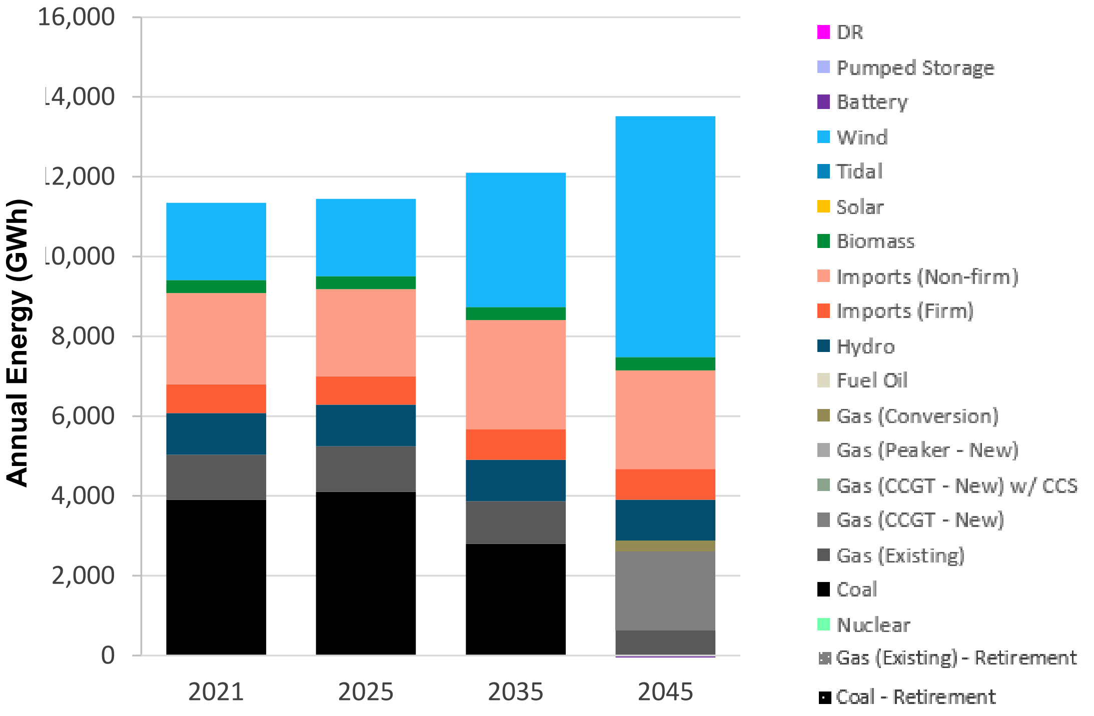
- The high electrification forecast creates the need for nearly 1 GW of additional nameplate capacity (~600 MW firm) in 2045, relative to 2.1.A
- This additional capacity is sourced in roughly equal parts from new gas CCGTs, CTs, wind, and batteries
- The average generation cost increases significantly (~12%) relative to 2.1.A

Metric	2035	2045
GHG Emissions (MMT)	3.2	1.4
GHG Marginal Abatement Cost ($/ton)	$24	$51
NPV ($2021)	$15,057	
NPV ($2021) – with 20-year end effects	$20,068	
Average Generation Cost (c/kWh)	8.7	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



2.2.B - Case Summary

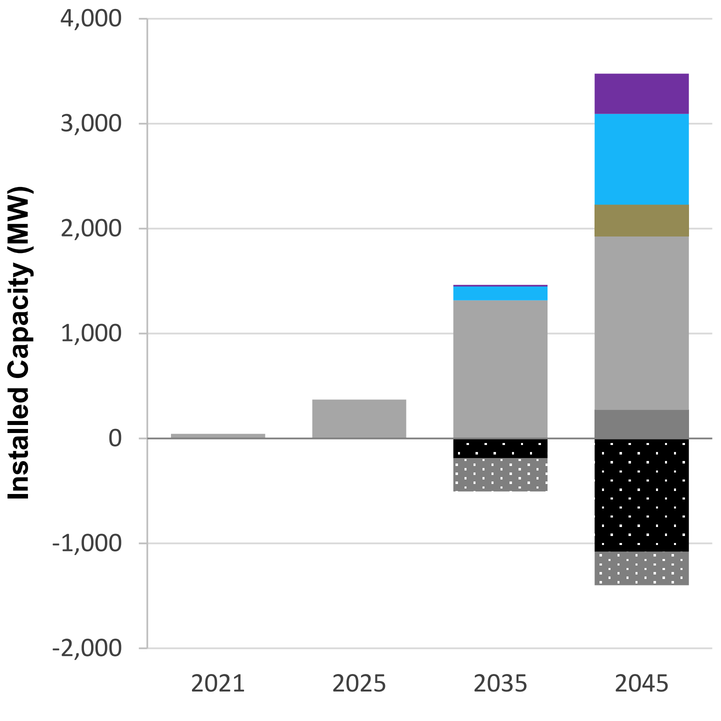
Net Zero, High Elec./Max DSM, Distributed Resources

Key Observations

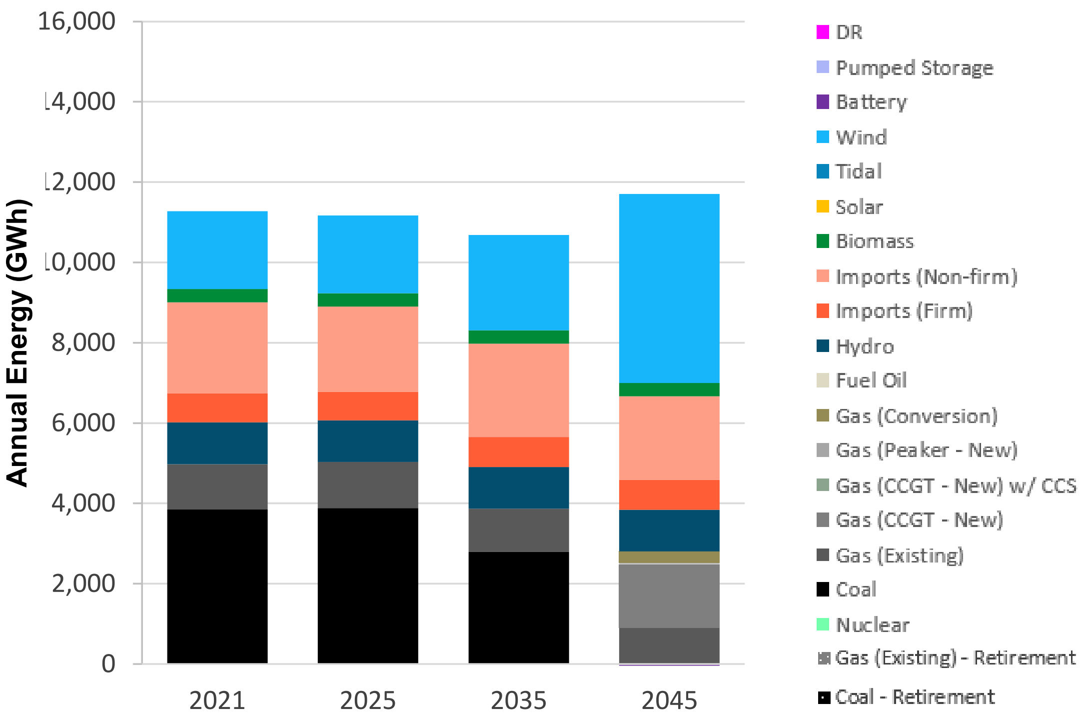
- The addition of DER's mitigates the capacity and energy needs of the high electrification forecast
- Average generation cost increases relative to 2.2A and 2.2C
- DER is modeled as a load reduction; cost of DER resources not included in NPV calculations ($1.6B-$2.5B)

Metric	2035	2045
GHG Emissions (MMT)	3.2	1.4
GHG Marginal Abatement Cost ($/ton)	$18	$29
NPV ($2021)	$14,291	
NPV ($2021) – with 20-year end effects	$18,766	
Average Generation Cost (c/kWh)	8.9	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



2.2.C - Case Summary

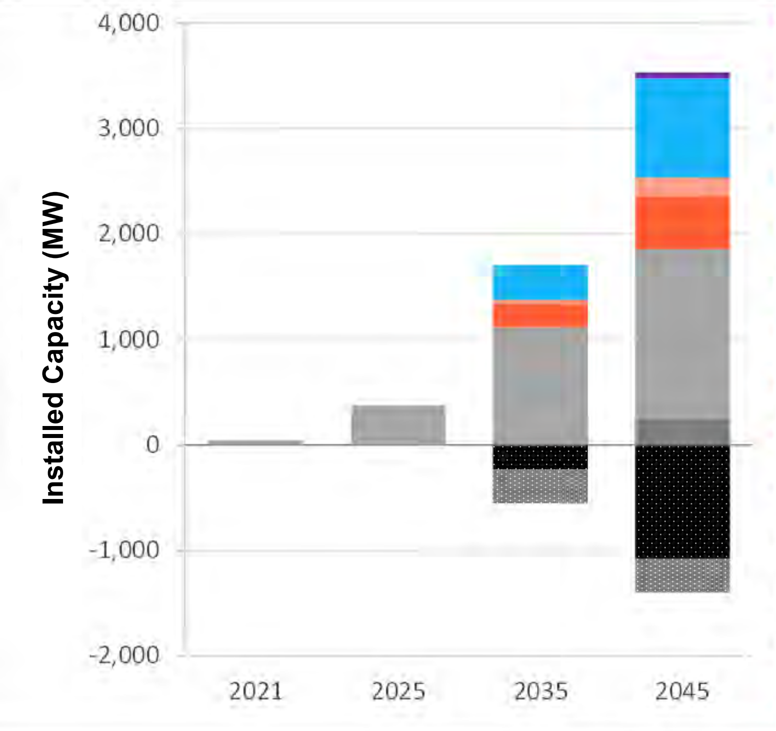
Net Zero, High Elec./Max DSM, Regional Integration

Key Observations

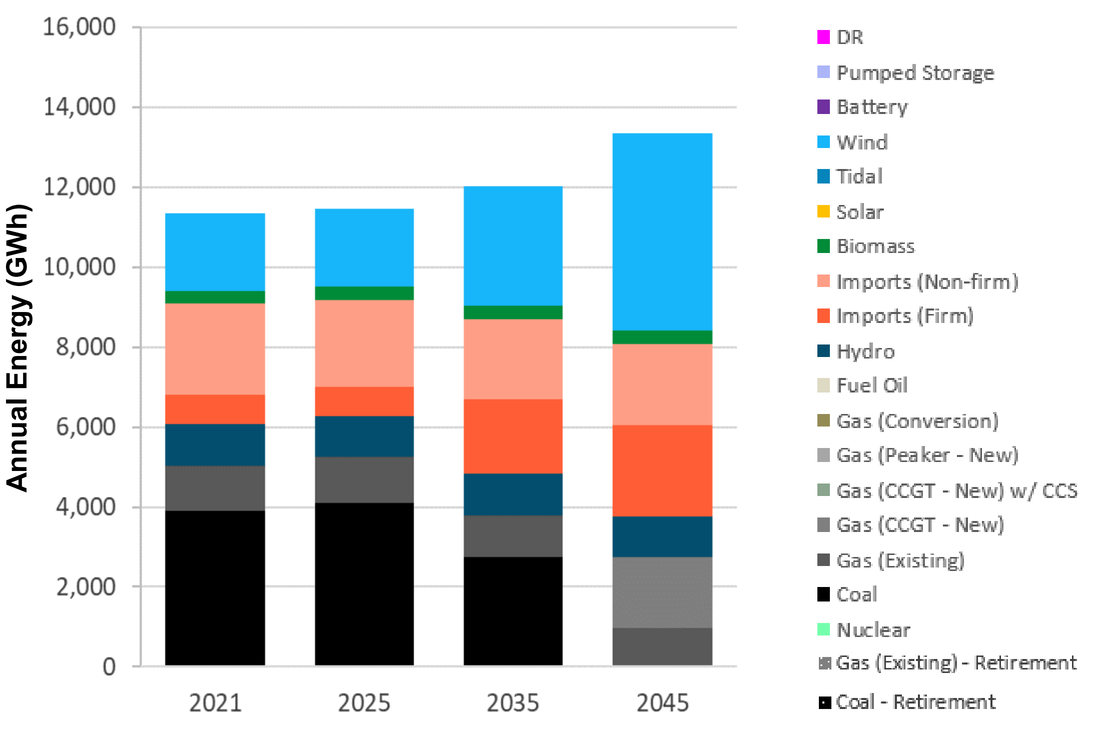
+ Additional import access helps meet the higher capacity and energy needs under high electrification. Costs decline relative to 2.2.A as the model selects cheaper import capacity, and integrates more wind
+ The average generation cost also increases relative to 2.1.C, reflecting the increased cost of serving high electrification load under the same GHG cap

Metric	2035	2045
GHG Emissions (MMT)	3.2	1.4
GHG Marginal Abatement Cost ($/ton)	$22	$3
NPV ($2021)	$14,948	
NPV ($2021) – with 20-year end effects	$19,770	
Average Generation Cost (c/kWh)	8.6	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



3.1.A - Case Summary

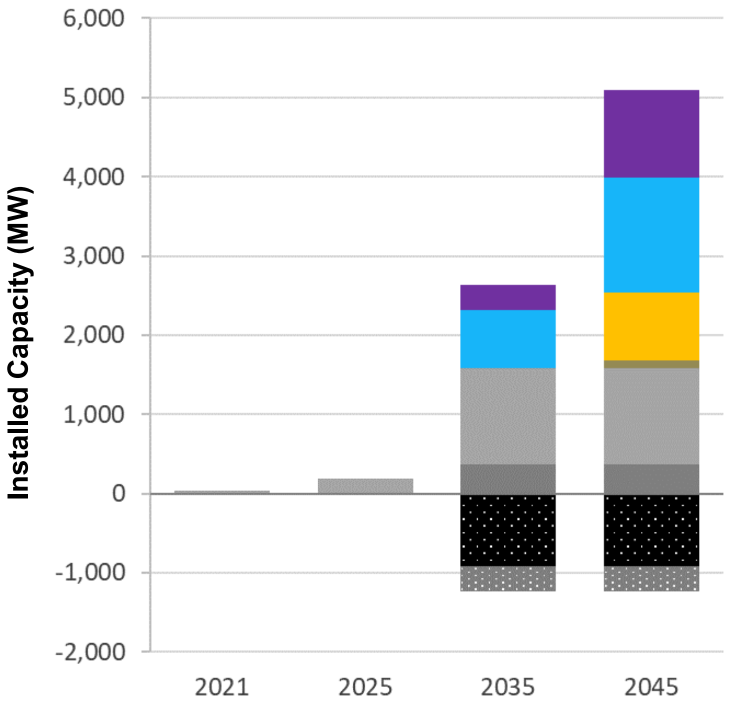
Accel. Net Zero, Mid Elec./Base DSM, Current Landscape

Key Observations

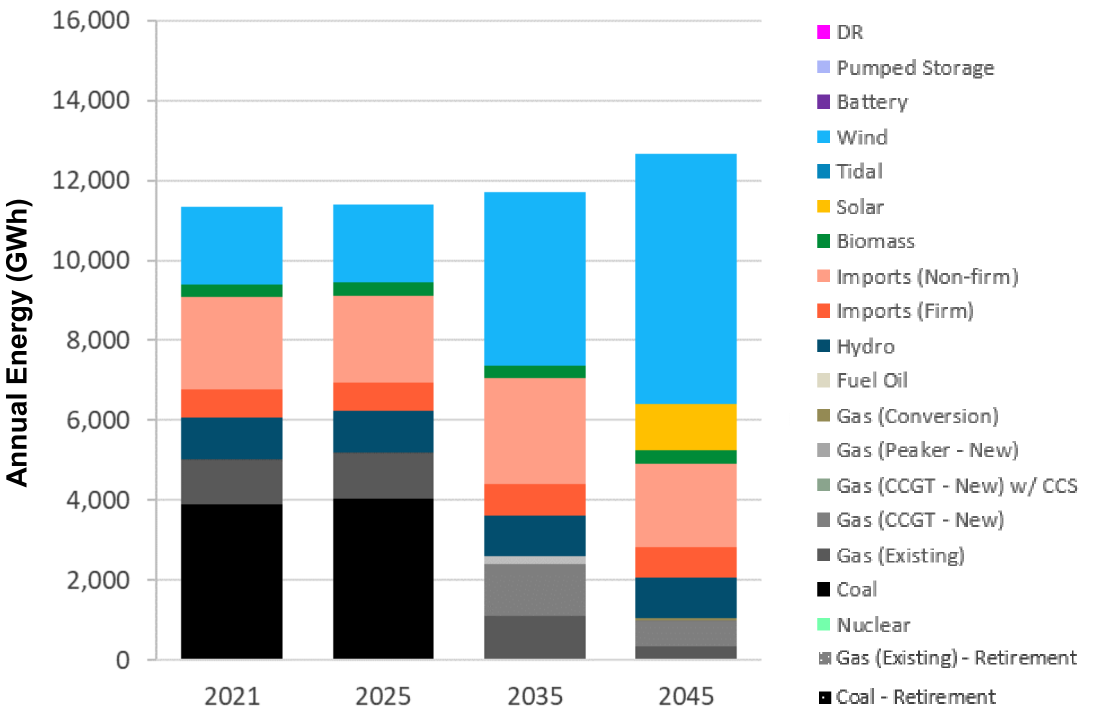
- The system builds more wind, solar, and batteries instead of gas to meet the lower GHG emissions target
- Alternative cases run with emerging technologies (CCS and SMR) resulted in similar costs; the results shown here are without SMR and CCS

Metric	2035	2045
GHG Emissions (MMT)	1.3	0.5
GHG Marginal Abatement Cost ($/ton)	$0	$275
NPV ($2021)	$13,607	
NPV ($2021) – with 20-year end effects	$18,189	
Average Generation Cost (c/kWh)	8.1	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



3.1.B - Case Summary

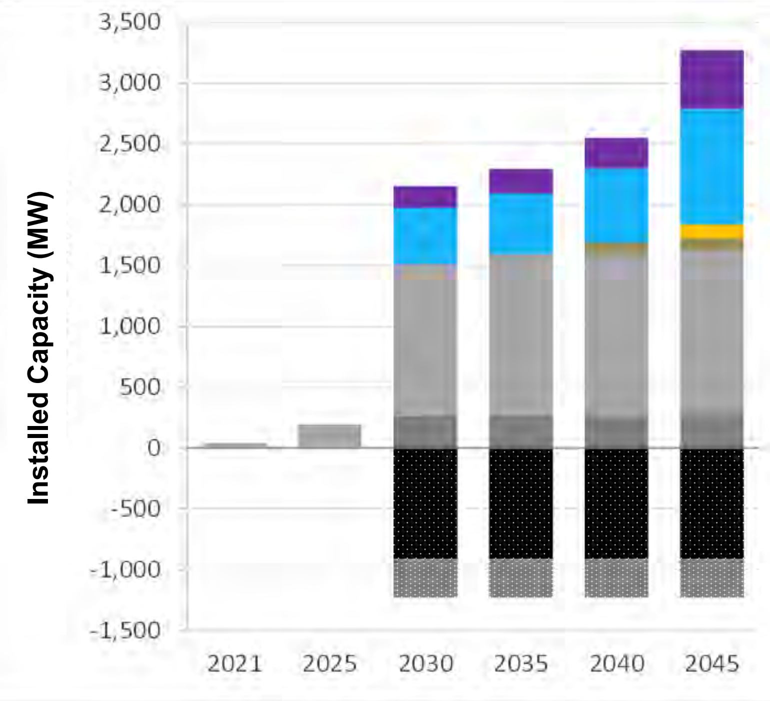
Accel. Net Zero, Mid Elec./Base DSM, Distributed Resources

Key Observations

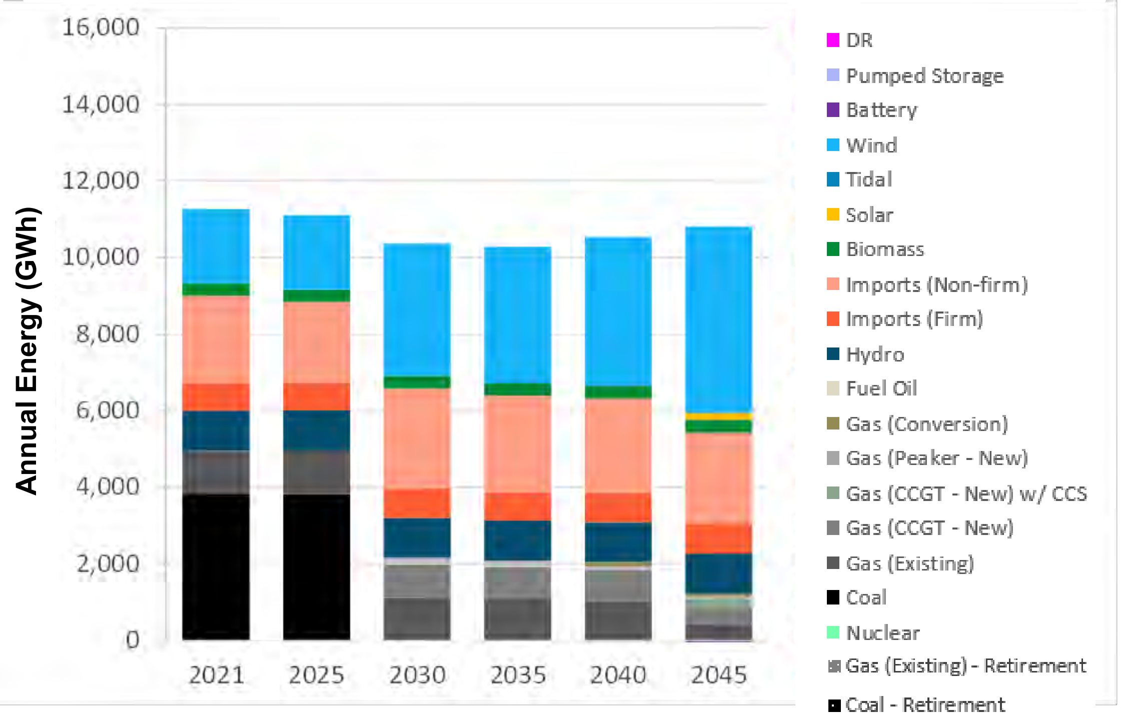
- The addition of DER's mitigates the capacity and energy needs of the high electrification forecast
- Total capacity needs in this case resemble the 3.1.A amounts, with an even lower energy forecast reminiscent the low electrification cases
- DER is modeled as a load reduction; cost of DER resources not included in NPV calculations ($1.6B-$2.5B)

Metric	2035	2045
GHG Emissions (MMT)	1.1	0.5
GHG Marginal Abatement Cost ($/ton)	$0	$82
NPV ($2021)	$12,888	
NPV ($2021) – with 20-year end effects	$16,831	
Average Generation Cost (c/kWh)	8.3	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



3.1.C - Case Summary

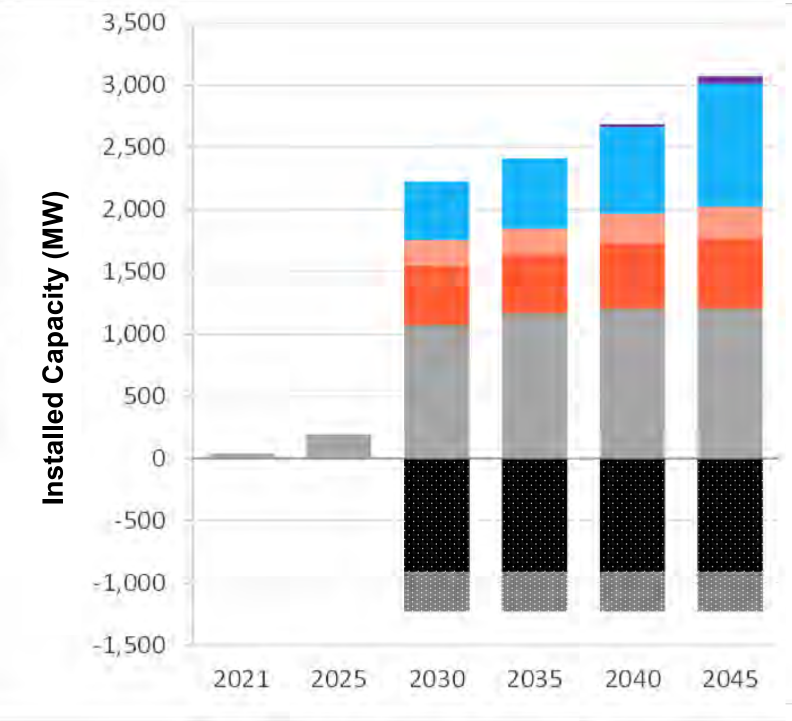
Accel. Net Zero, Mid Elec./Base DSM, Regional Integration

Key Observations

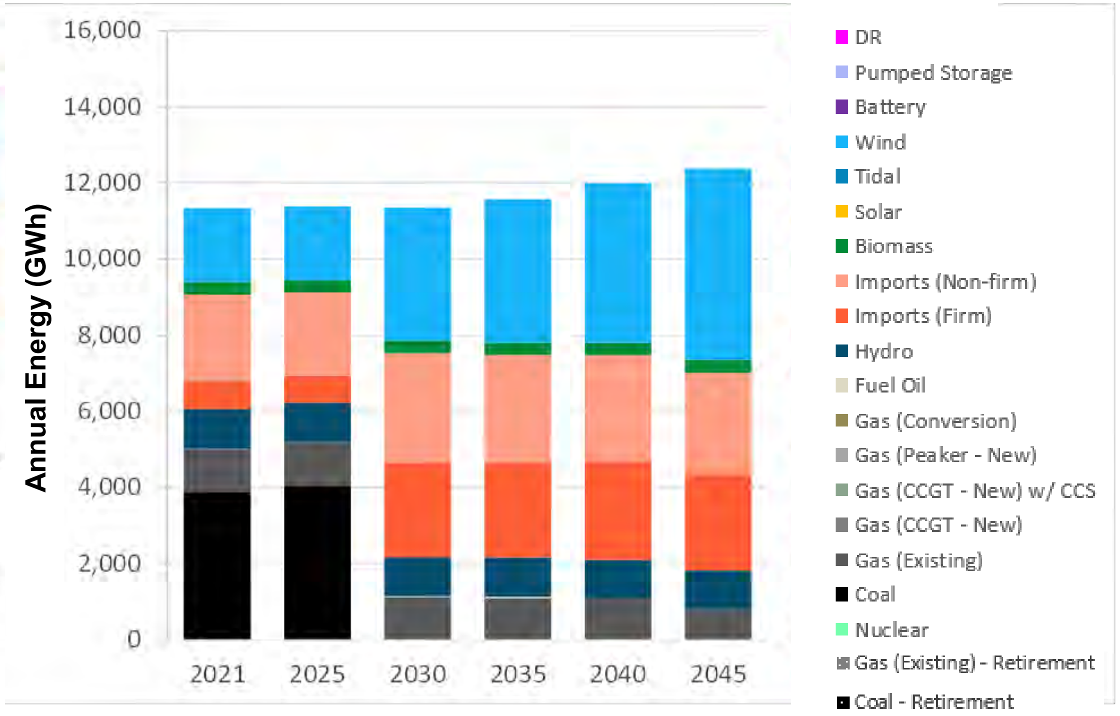
+ System costs decrease relative to 3.1.A when imports from neighboring regions are available
+ ~570 MW of firm and ~250 MW of non-firm import capacity is built to provide cleaner energy and capacity
+ When regional imports are available, the system builds ~ 850 MW less solar, ~500 MW less wind, ~1 GW less batteries, and ~400 MW less CCGT by 2045

Metric	2035	2045
GHG Emissions (MMT)	0.7	0.5
GHG Marginal Abatement Cost ($/ton)	$0	$29
NPV ($2021)	$13,468	
NPV ($2021) – with 20-year end effects	$17,684	
Average Generation Cost (c/kWh)	8.0	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



3.2.A - Case Summary

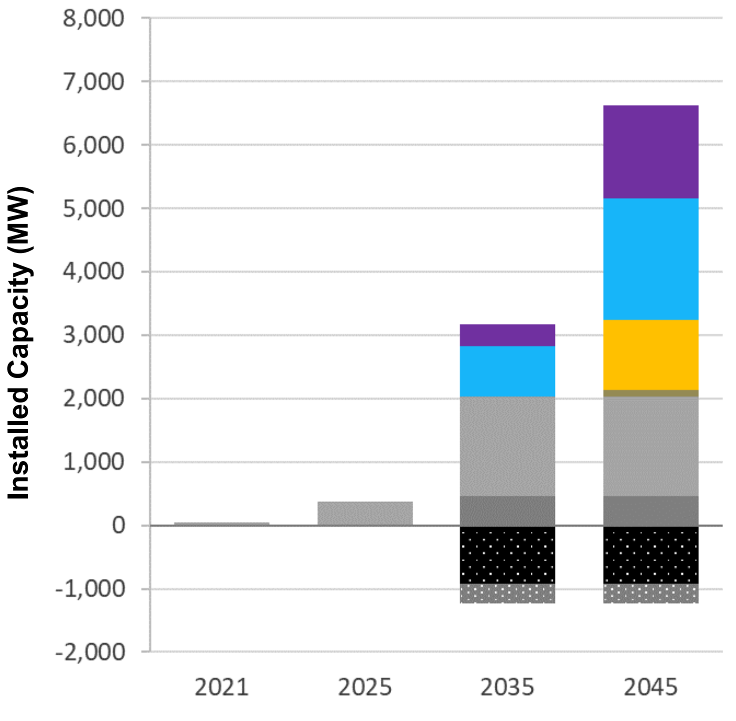
Accel. Net Zero, High Elec./Max DSM, Current Landscape

Key Observations

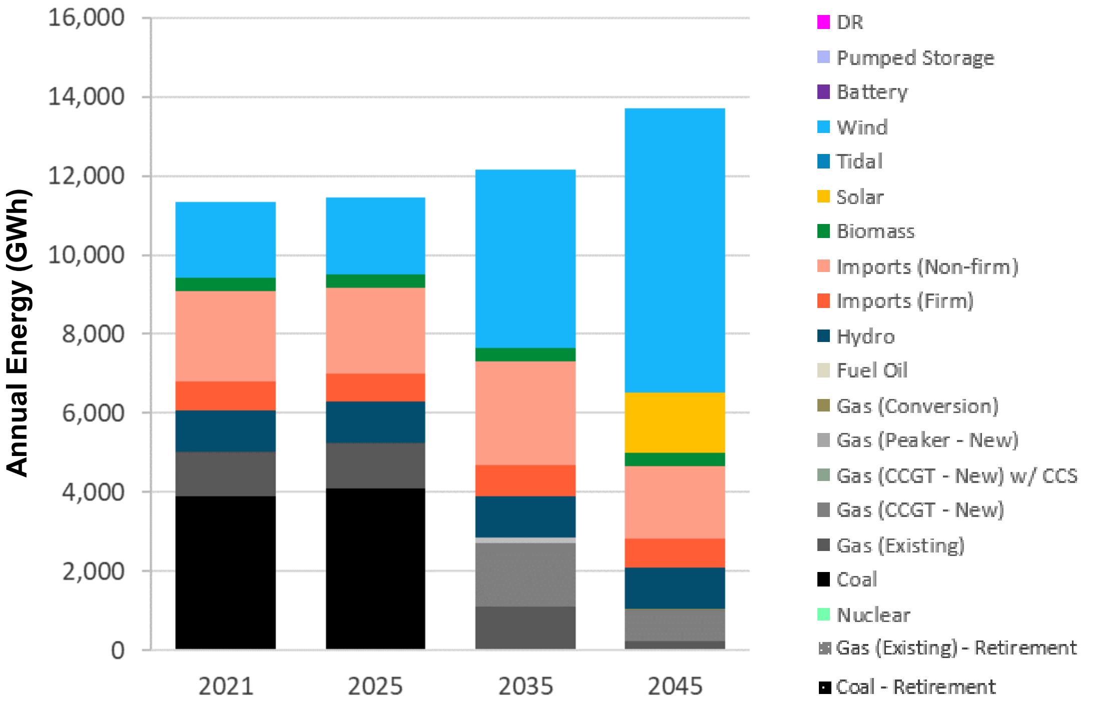
- The system relies on wind, solar, and batteries to meet the additional capacity and energy requirements.
- The system is overbuilt - renewable curtailment in 2045 is 16.4%
- Average generation cost increases significantly relative to 3.1.A
- Cases with/without emerging technologies (CCS and SMR) resulted in similar costs, but results shown here show results without SMR and CCS

Metric	2035	2045
GHG Emissions (MMT)	1.4	0.5
GHG Marginal Abatement Cost ($/ton)	$0	$498
NPV ($2021)	$15,584	
NPV ($2021) – with 20-year end effects	$21,383	
Average Generation Cost (c/kWh)	9.2	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



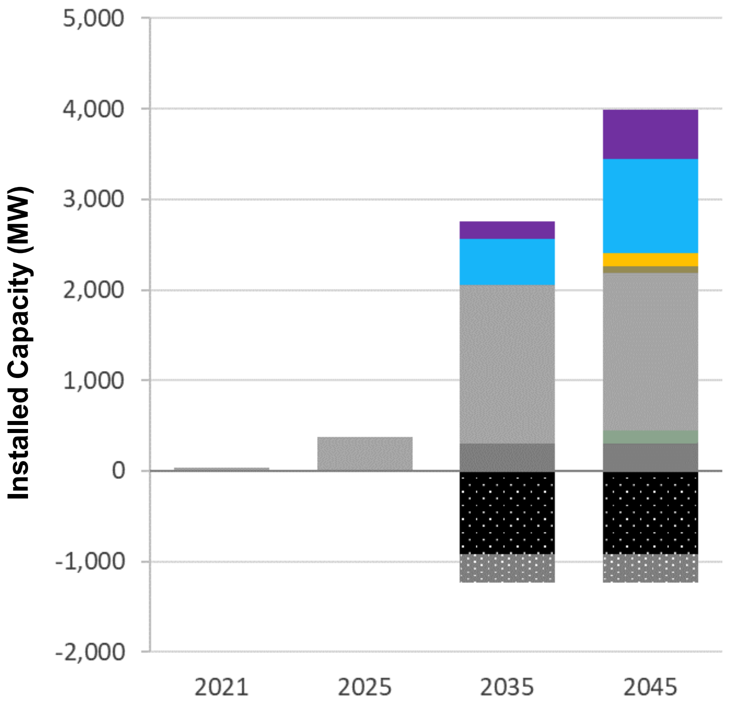
3.2.B - Case Summary
Accel. Net Zero, High Elec., Max DSM, Distributed Resources

Key Observations

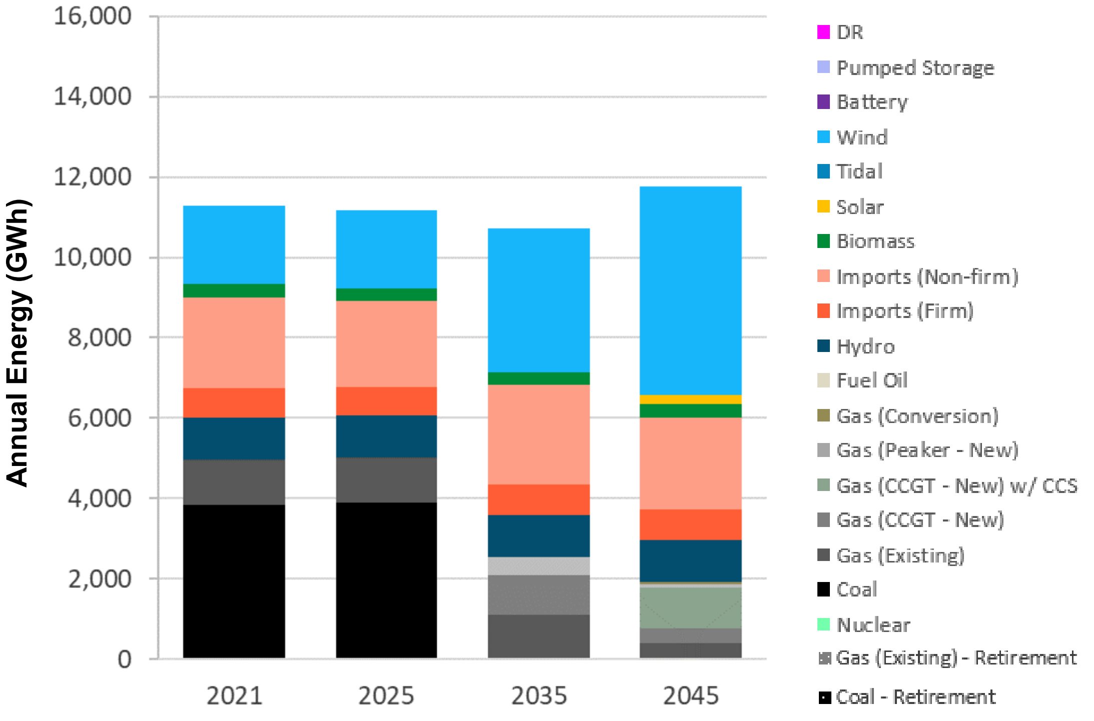
- Due to the load reduction provided by DER, less new capacity is needed to meet the electrification load
- The average generation cost, however, increases because the lower load factor
- DER is modeled as a load reduction; cost of DER resources not included in NPV calculations ($1.6B-$2.5B)

Metric	2035	2045
GHG Emissions (MMT)	1.3	0.5
GHG Marginal Abatement Cost ($/ton)	$0	$101
NPV ($2021)	$14,877	
NPV ($2021) – with 20-year end effects	$19,601	
Average Generation Cost (c/kWh)	9.3	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



3.2.C - Case Summary

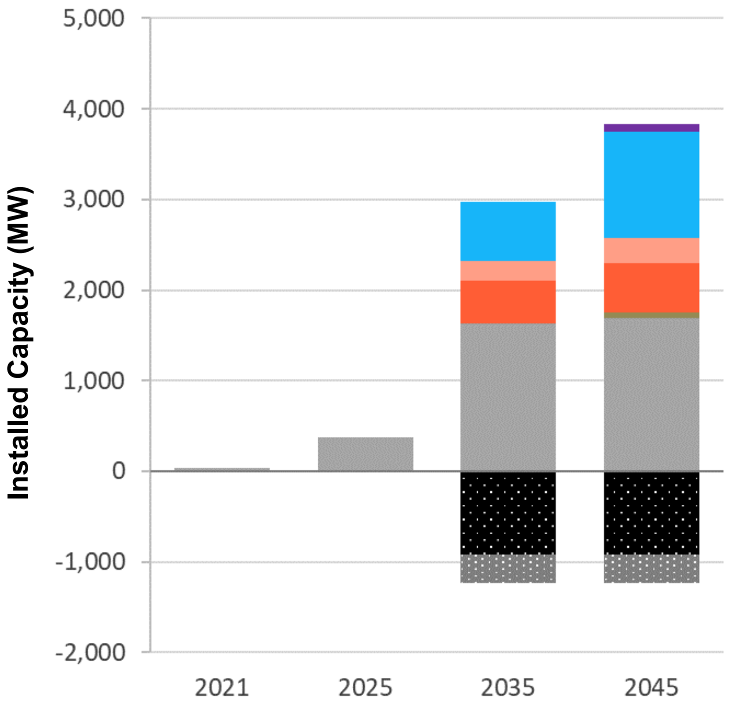
Accel. Net Zero, High Elec./Max DSM, Regional Integration

Key Observations

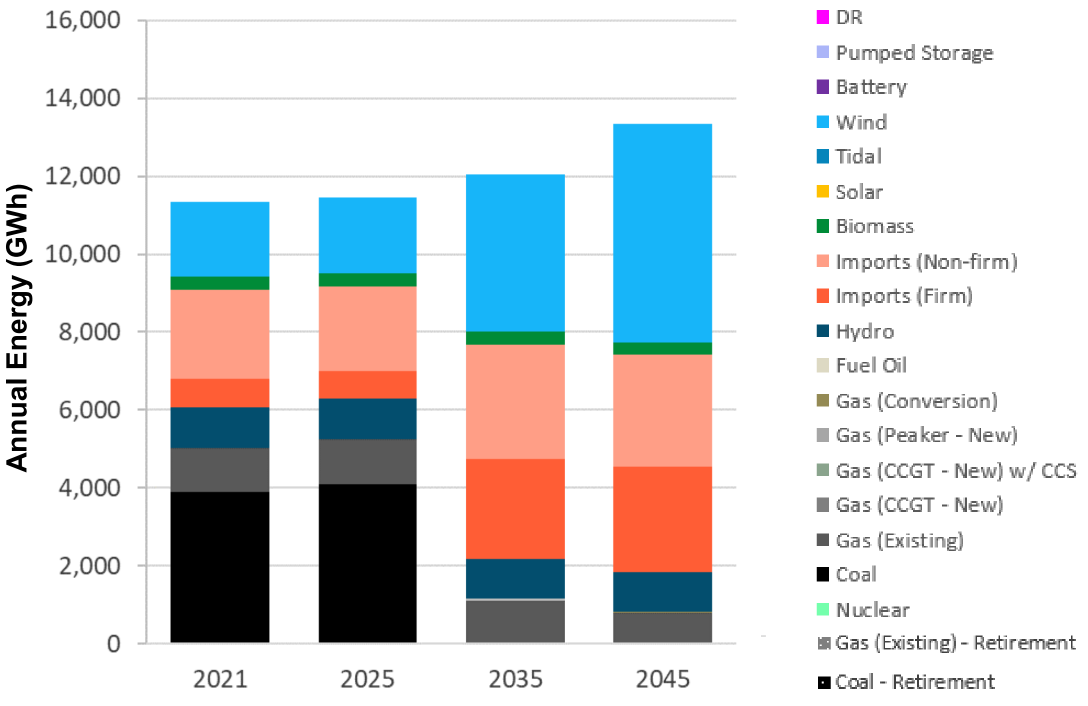
- System costs decrease when imports from neighboring regions are available
- ~550 MW of firm and ~270 MW of non-firm import capacity is built to provide cleaner energy and capacity
- When regional imports are available, the system builds significantly less solar, batteries, wind, and gas by 2045 (relative to 3.2A)

Metric	2035	2045
GHG Emissions (MMT)	0.7	0.5
GHG Marginal Abatement Cost ($/ton)	$0	$30
NPV ($2021)	$15,372	
NPV ($2021) – with 20-year end effects	$20,296	
Average Generation Cost (c/kWh)	8.9	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



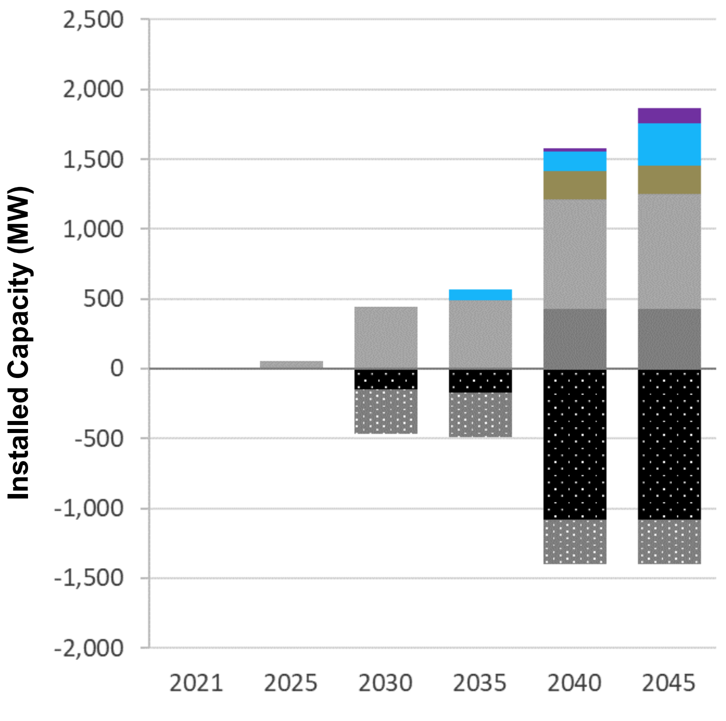
1.0.A with Low COVID Forecast

Comparator, Low COVID Load, Current Landscape

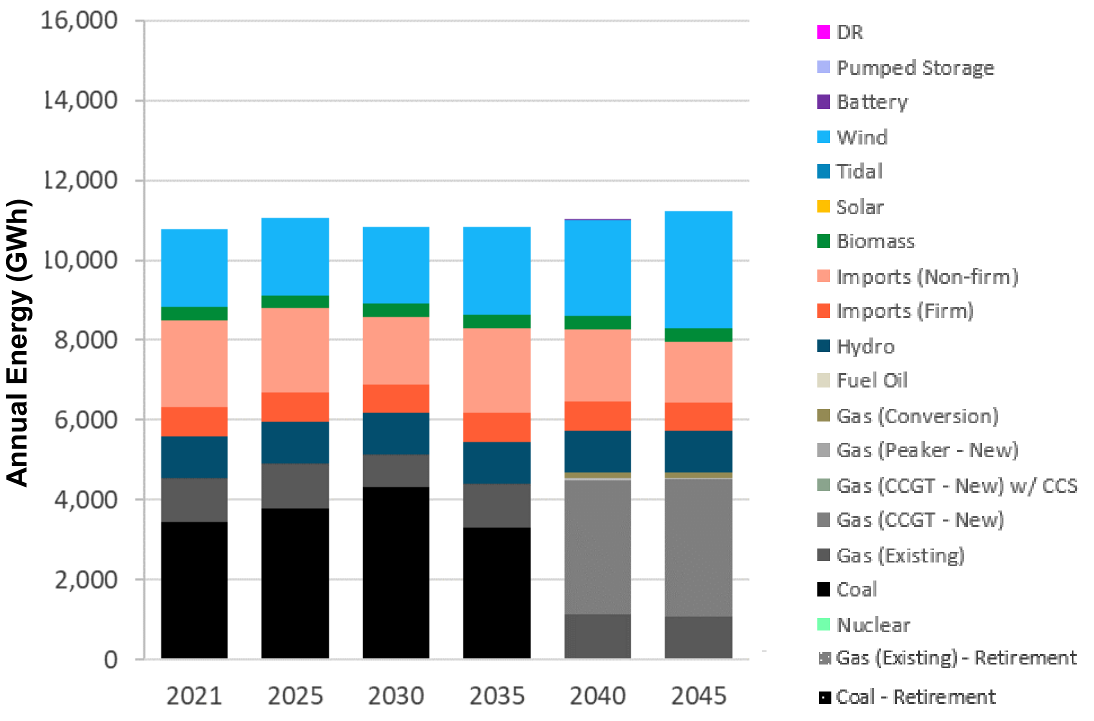
Key Observations
+ The slight reduction in load has little impact on the capacity addition decision
+ The overall system costs changes only slightly

Metric	2035	2045
GHG Emissions (MMT)	3.7	2.2
GHG Marginal Abatement Cost ($/ton)	$16	$0
NPV ($2021)	$12,178	
NPV ($2021) – with 20-year end effects	$15,910	
Average Generation Cost (c/kWh)	7.7	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



2.0.A with Low COVID Forecast

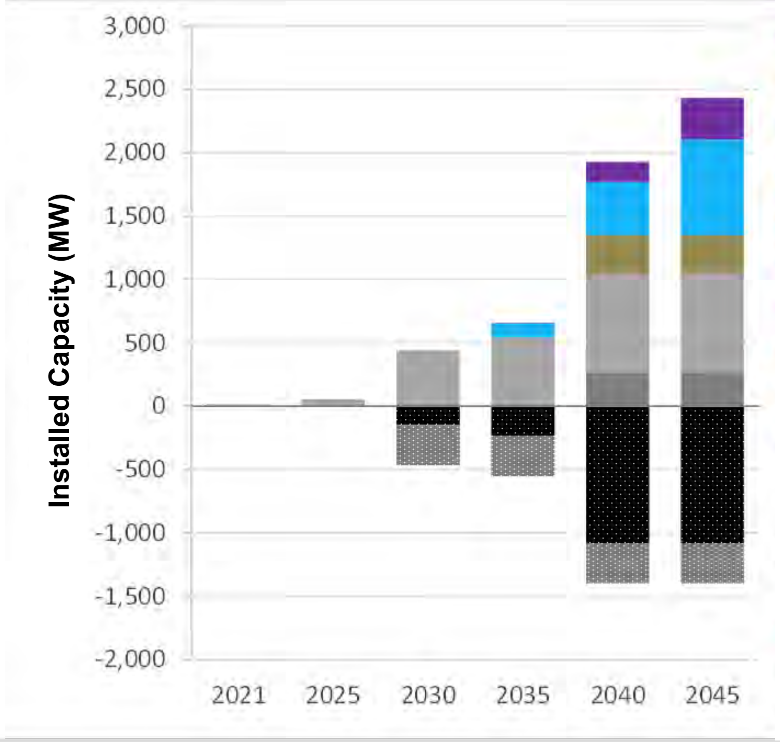
Net Zero, Low COVID Load, Current Landscape

Key Observations

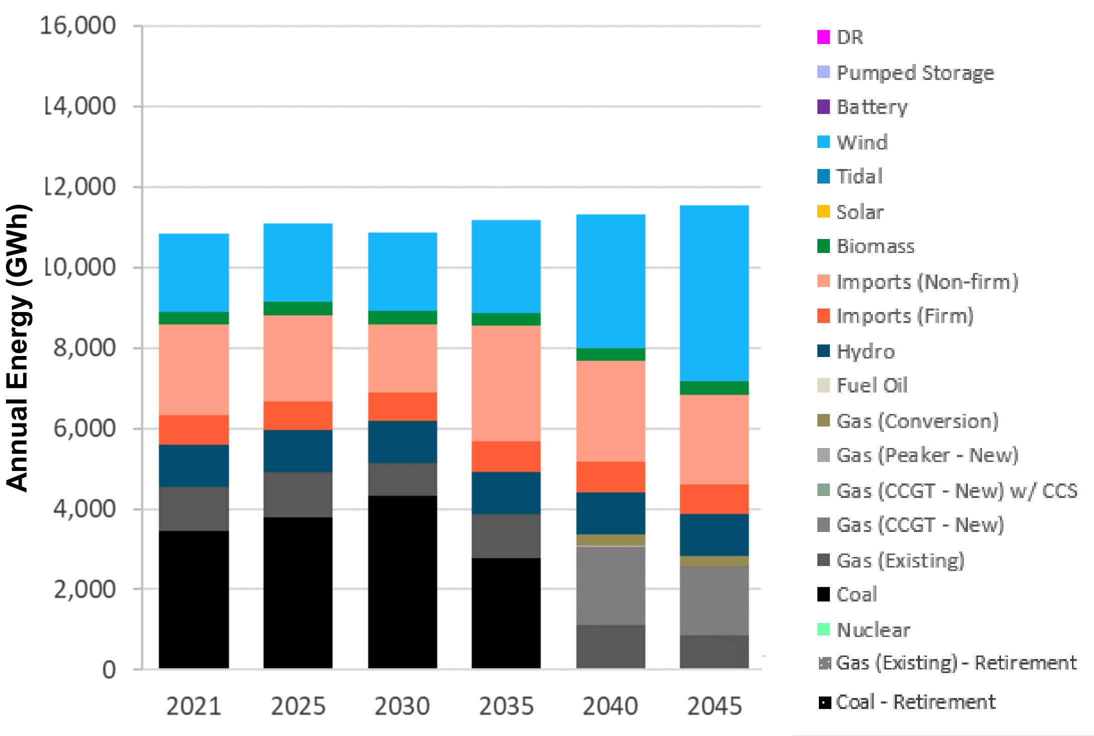
- The slight reduction in load has little impact on the capacity addition decision
- The overall system costs changes only slightly

Metric	2035	2045
GHG Emissions (MMT)	3.2	1.4
GHG Marginal Abatement Cost ($/ton)	$21	$33
NPV ($2021)	$12,196	
NPV ($2021) – with 20-year end effects	$15,961	
Average Generation Cost (c/kWh)	7.7	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



2.0.C with Low COVID Forecast

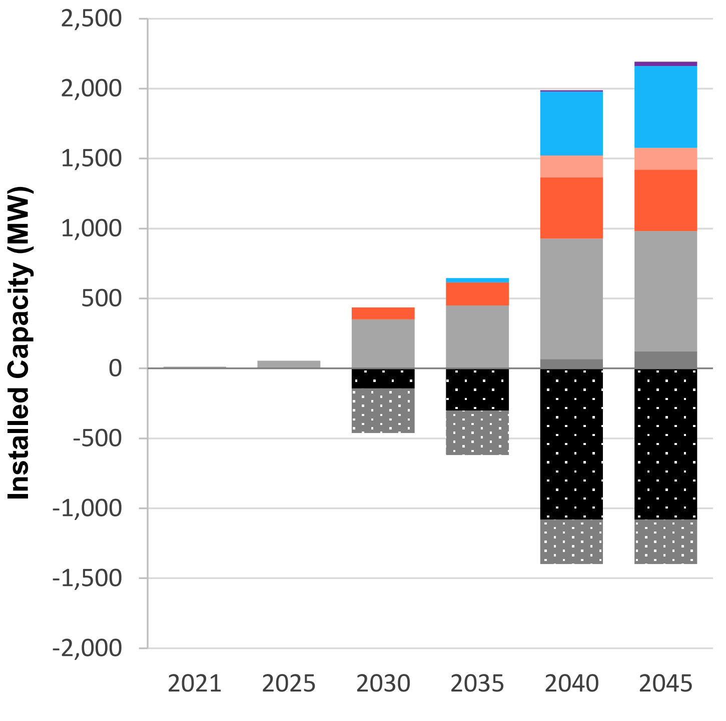
Net Zero, Low COVID Load, Regional Integration

Key Observations

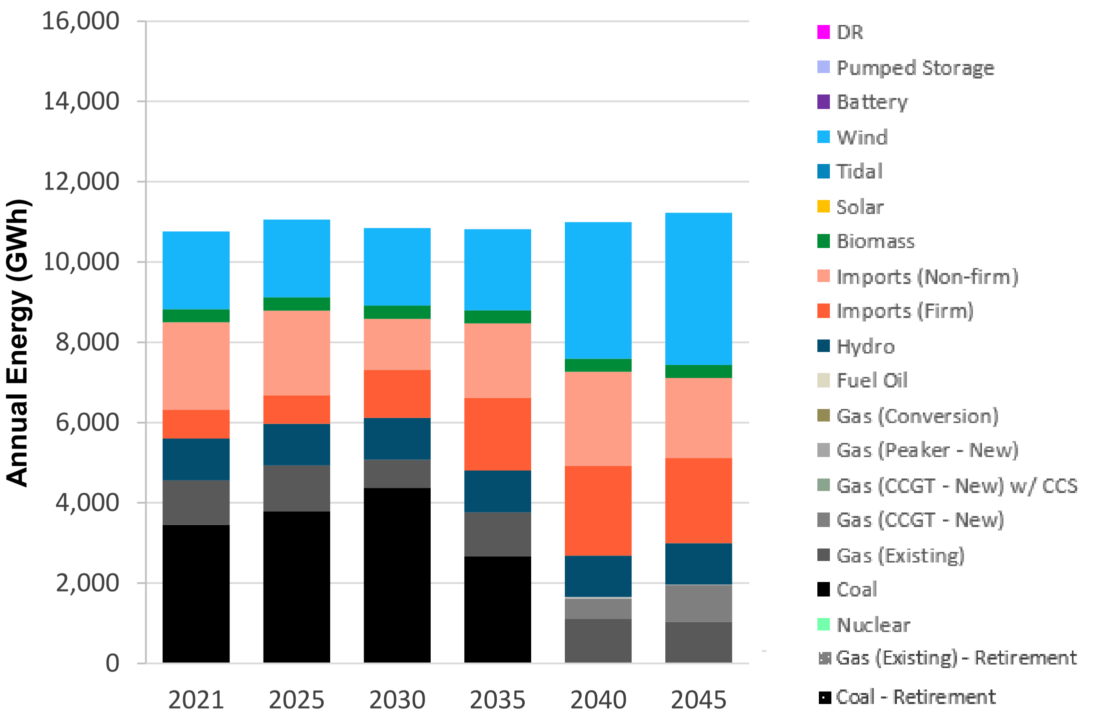
+ The slight reduction in load has little impact on the capacity addition decision
+ The overall system costs changes only slightly

Metric	2035	2045
GHG Emissions (MMT)	3.2	1.0
GHG Marginal Abatement Cost ($/ton)	$24	$0
NPV ($2021)	$12,138	
NPV ($2021) – with 20-year end effects	$15,808	
Average Generation Cost (c/kWh)	7.7	

Capacity Addition and Retirement (MW)



Energy Balance (GWh)



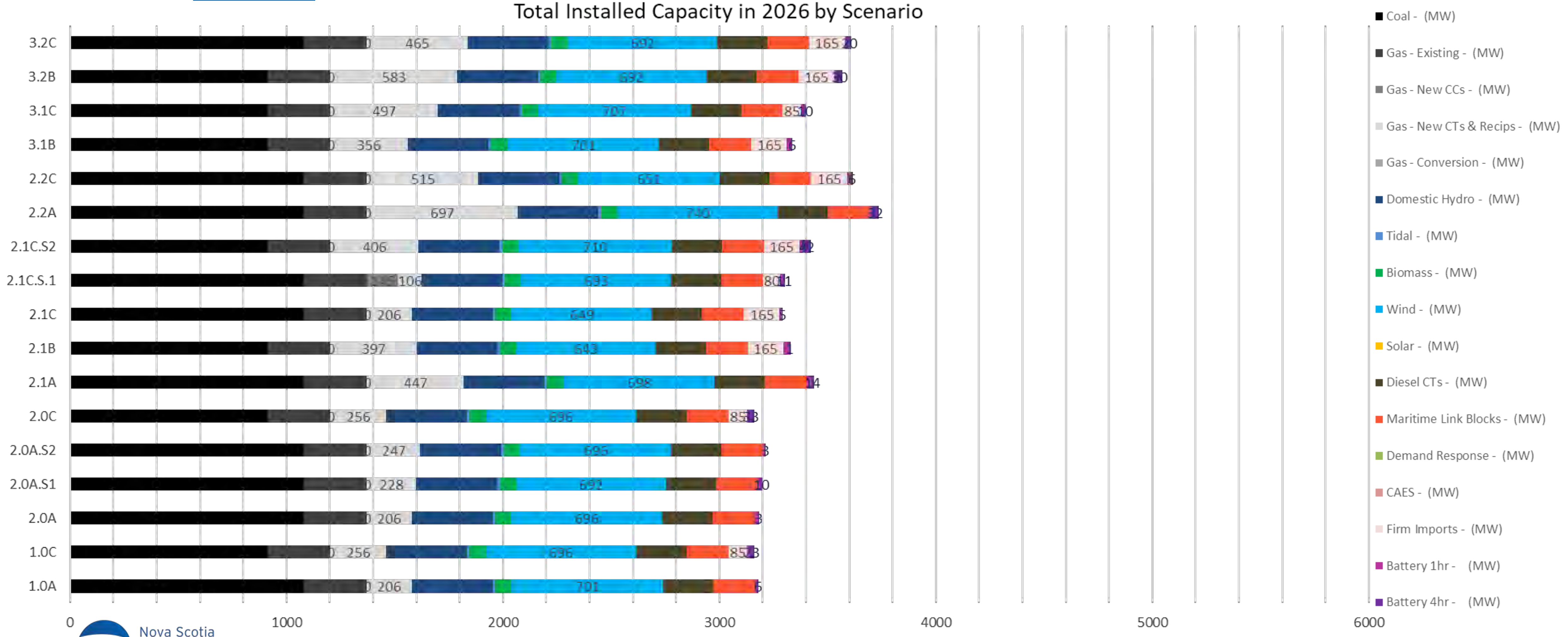
INITIAL PORTFOLIO STUDY RESULTS

Nova Scotia
POWER
An Emera Company

INITIAL PORTFOLIO STUDY

- The following slides provide the Initial Portfolio Study results from PLEXOS LT for the key scenarios as well for select sensitivities (full capacity expansion runs)
- The section includes several summary comparison slides as well as detailed outputs of each scenario including energy mix, nameplate capacity installation, emissions compliance, several metrics of NPV of partial revenue requirement, and scenario notes
- NPVs presented in these results are partial revenue requirements that consider modeled costs (i.e. production, O&M, abatement, sustaining capital, and capital investment) and costs considered outside of the long-term model optimization (i.e. energy efficiency costs)
- NS Power will continue to refine these scenarios as we move through the Operability / Reliability Assessment and Final Portfolio Study phases of the Modeling Plan

NEAR TERM RESOURCE PORTFOLIOS (2026)



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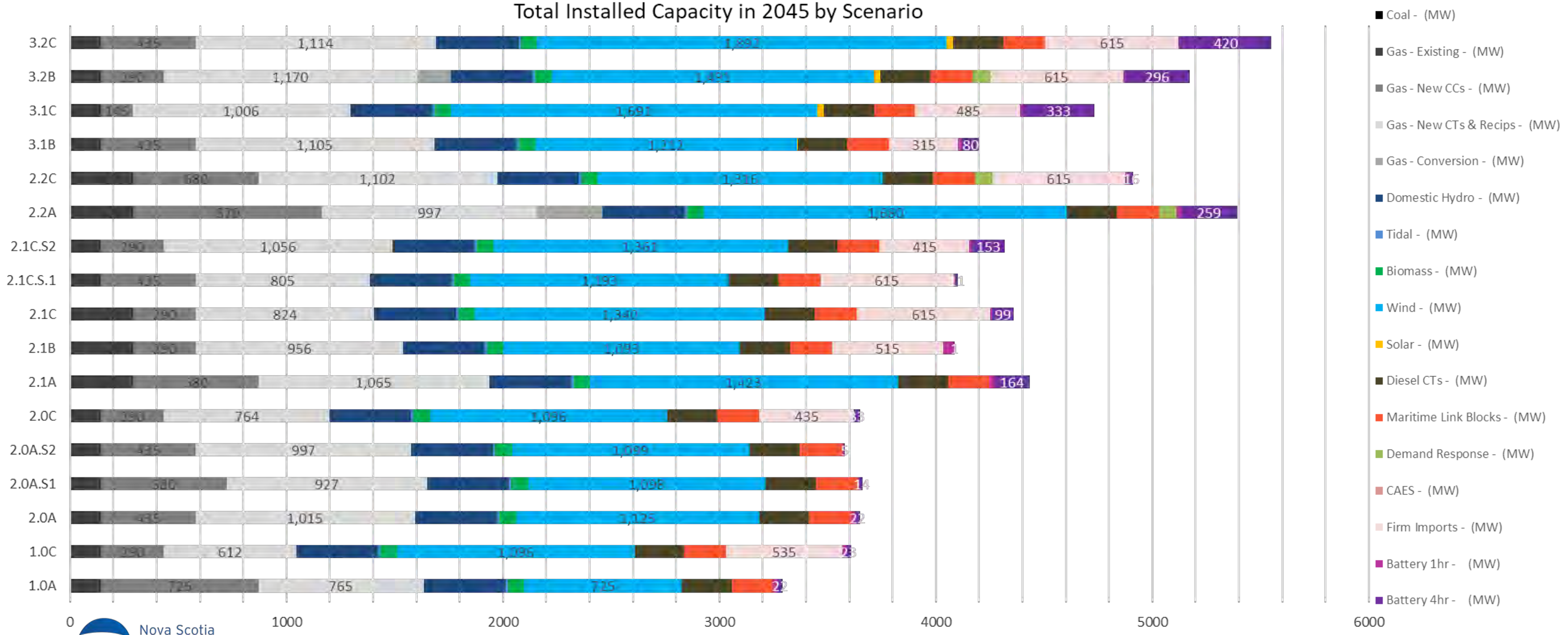
LONG TERM RESOURCE PORTFOLIOS (2045)



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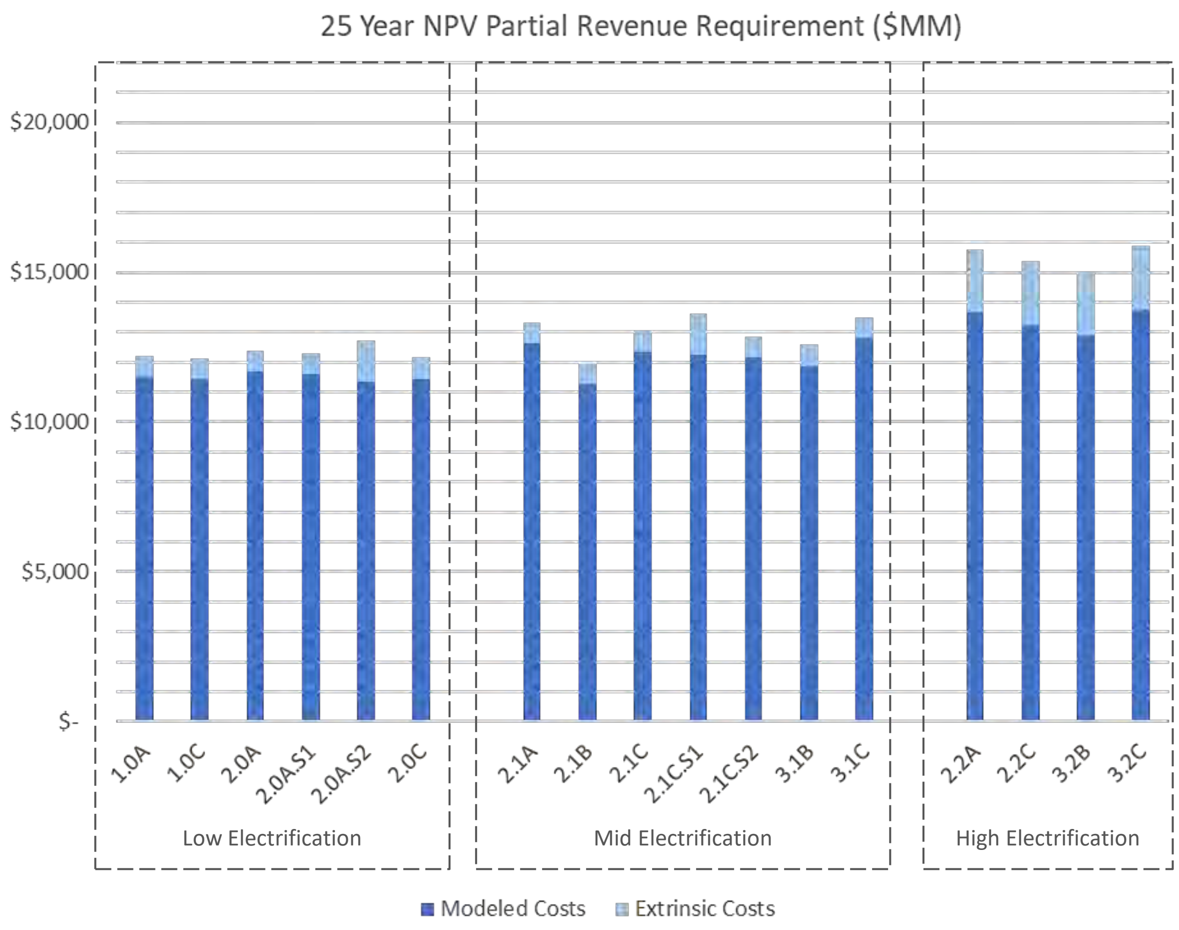
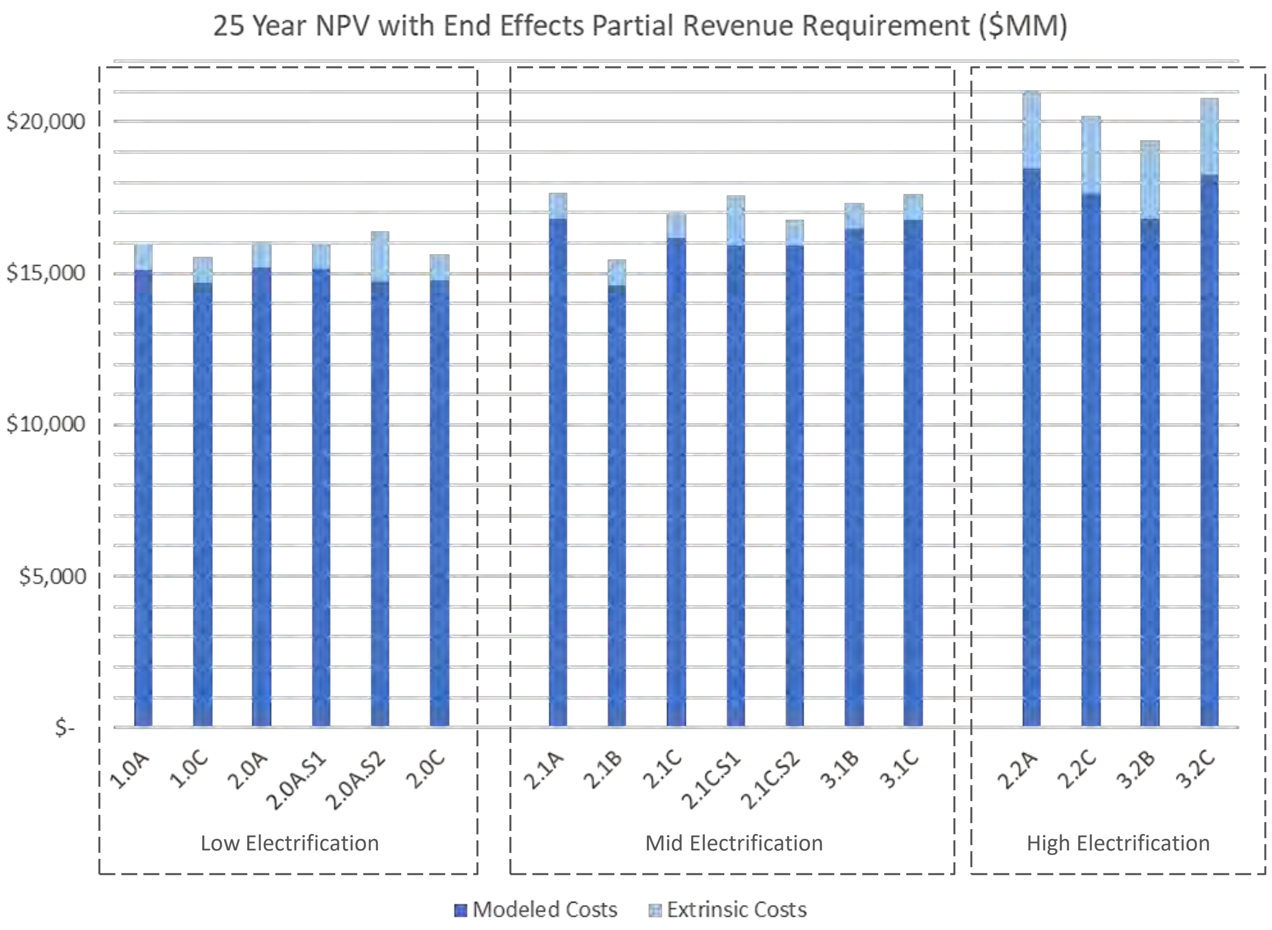
NPV PARTIAL REVENUE REQUIREMENT COMPARISON





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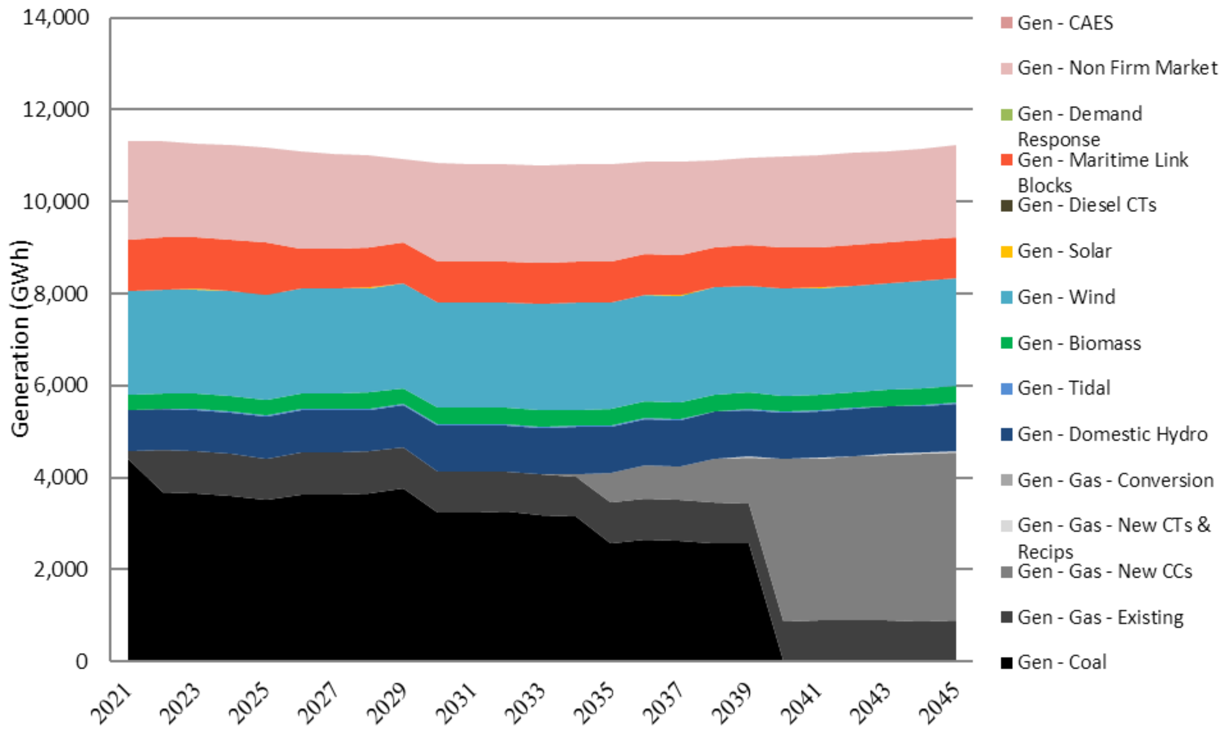
Due to differences in forecast system load affecting production costs, resource plan partial revenue requirement results should not be compared across electrification scenarios

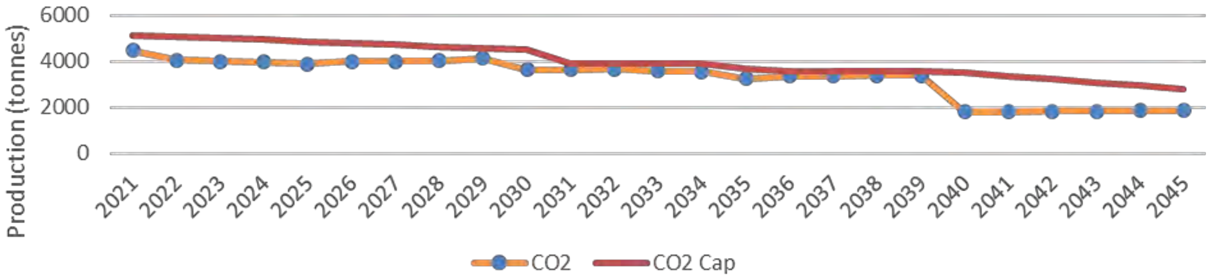
1.0A

LOW ELEC. / BASE DSM / COMPARATOR EMISSIONS / CURRENT LANDSCAPE

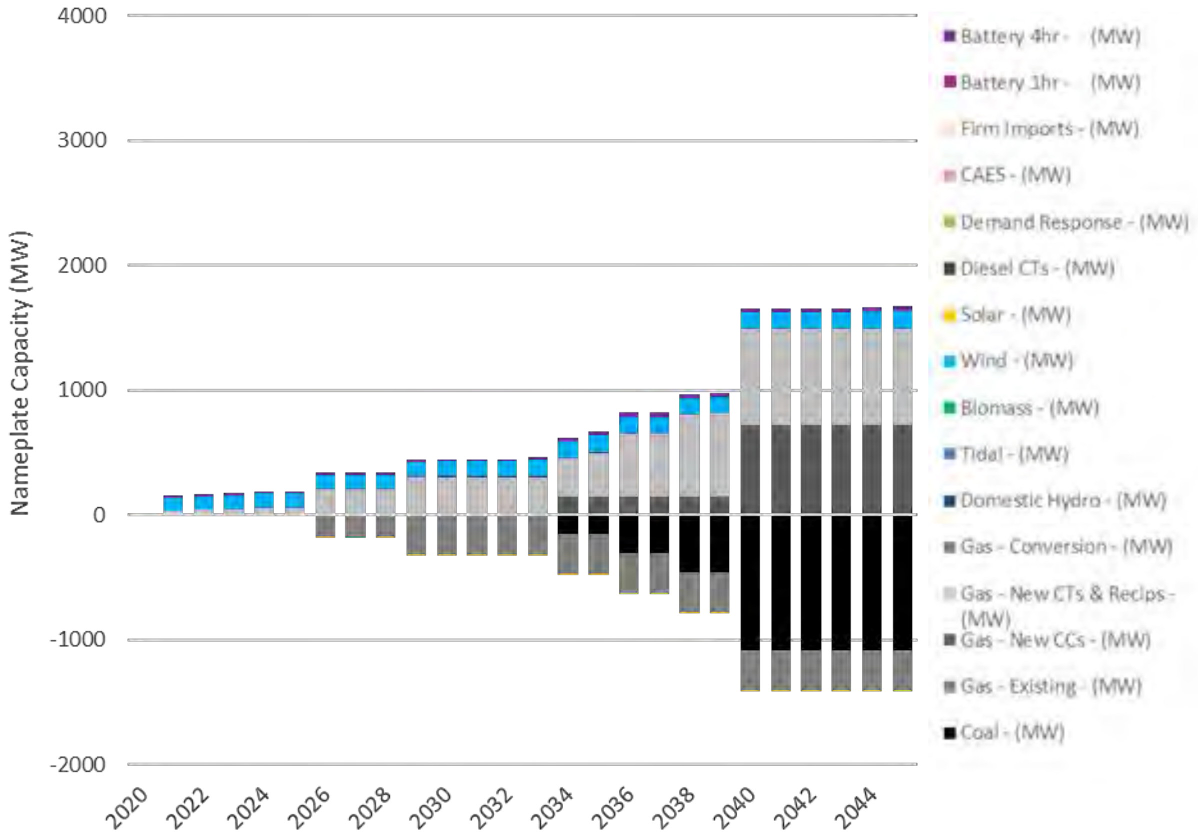
Energy Balance



CO_2 Emissions



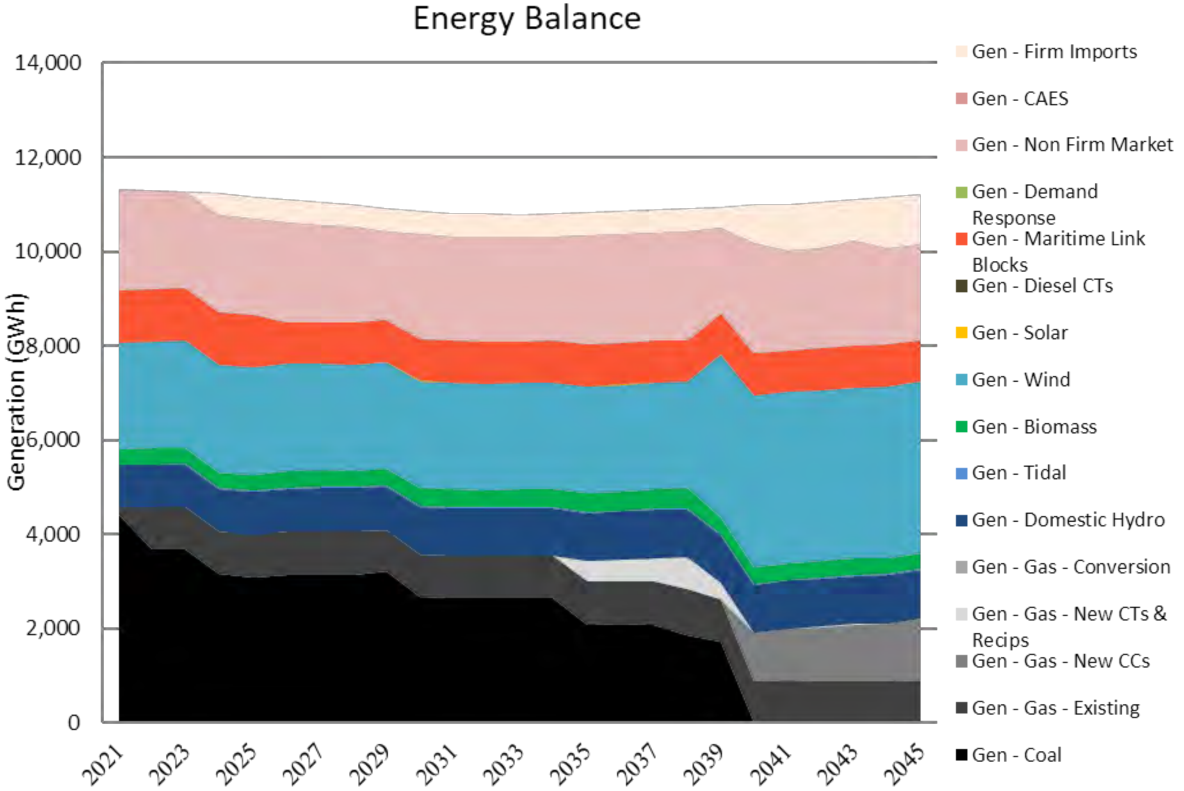
Installed Capacity Changes

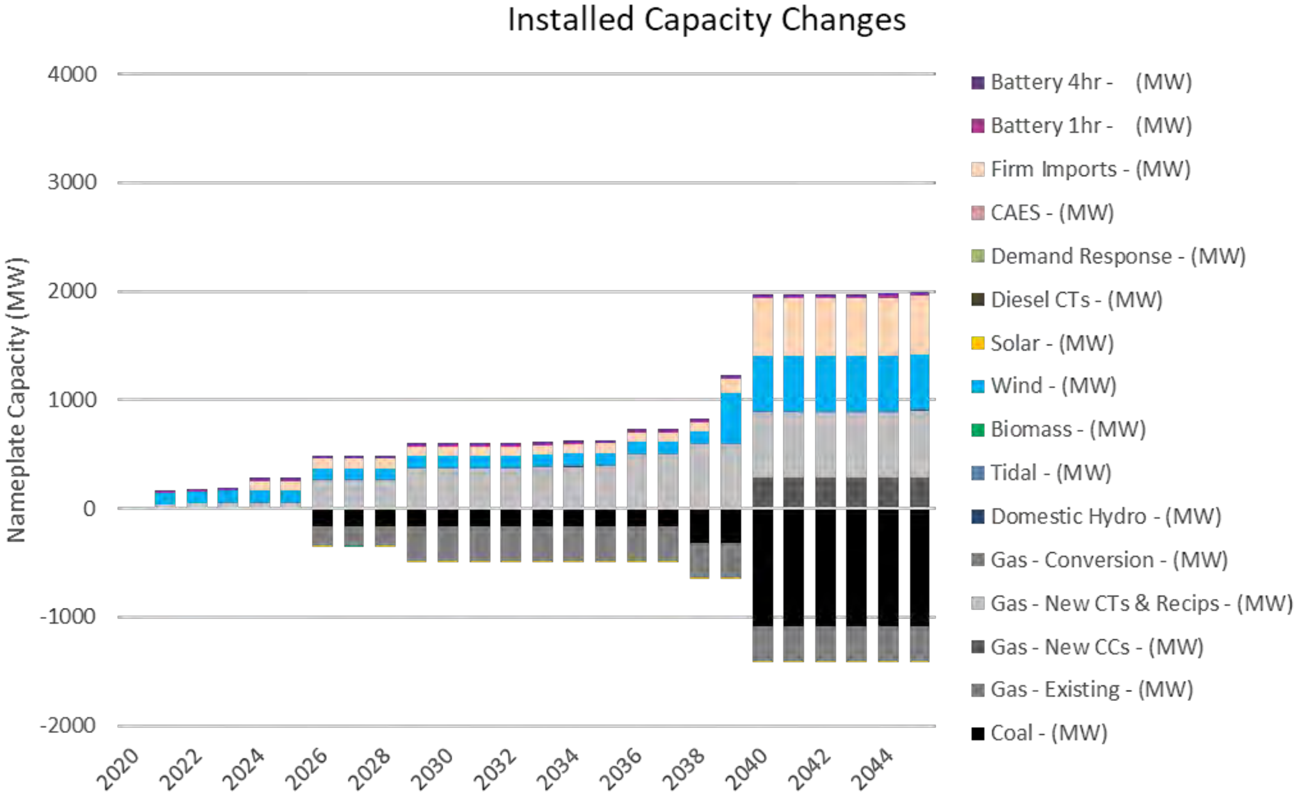


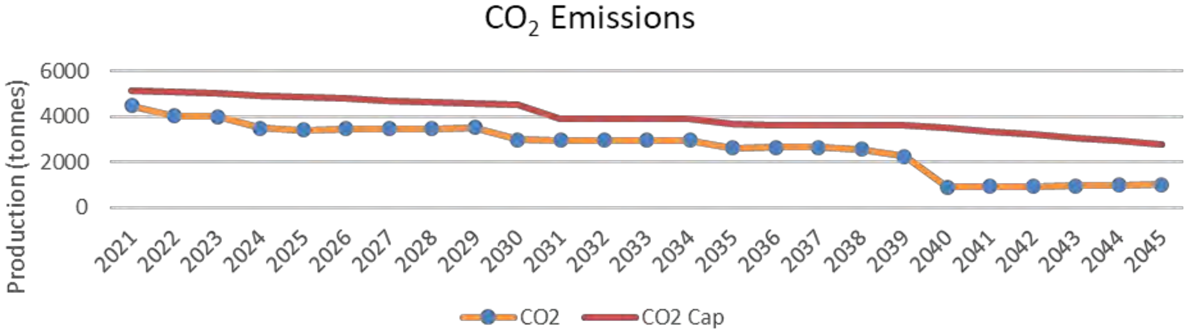
	$MM	Scenario Notes
25-yr NPVRR	$12,204	• Coal capacity replaced with new gas CCGT and CT units
25-yr NPVRR w/ EE	$15,976	
10-yr NPVRR	$6,884	

1.0C

LOW ELEC. / BASE DSM / COMPARATOR EMISSIONS / REGIONAL INTEGRATION



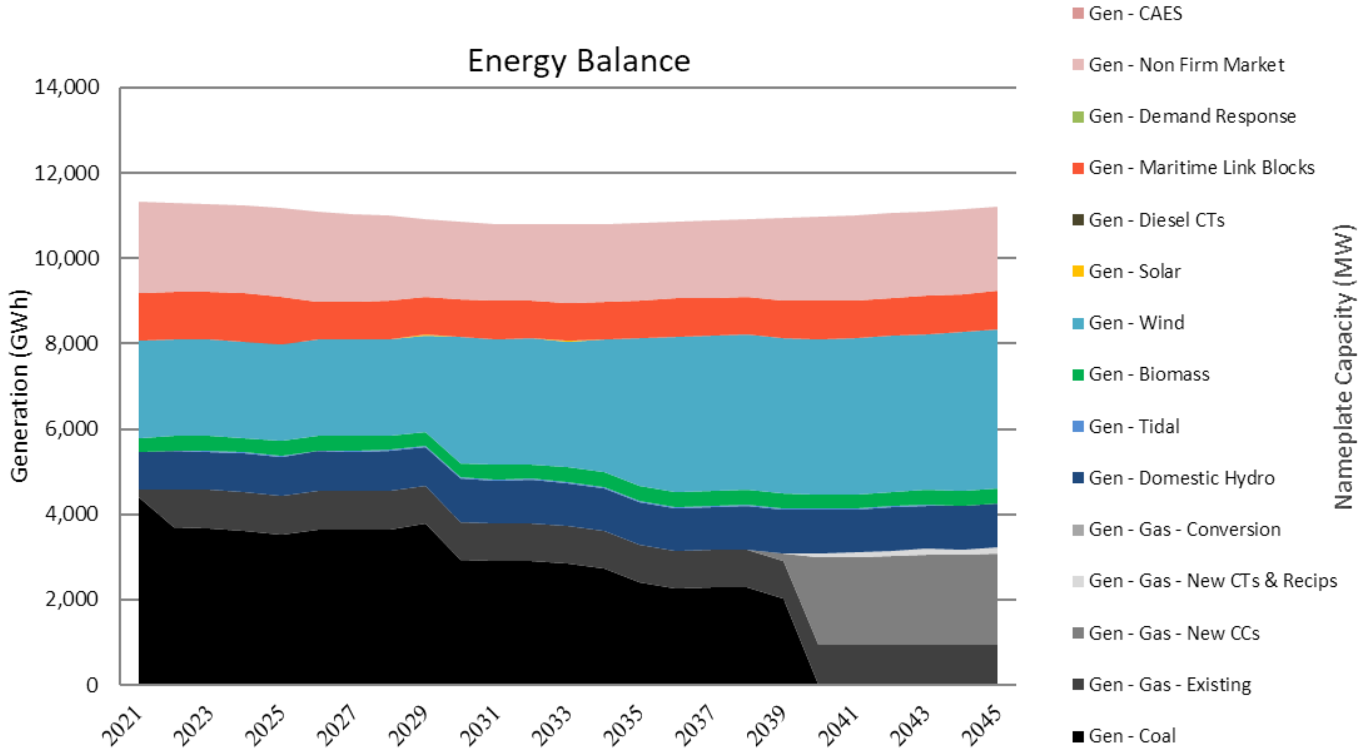


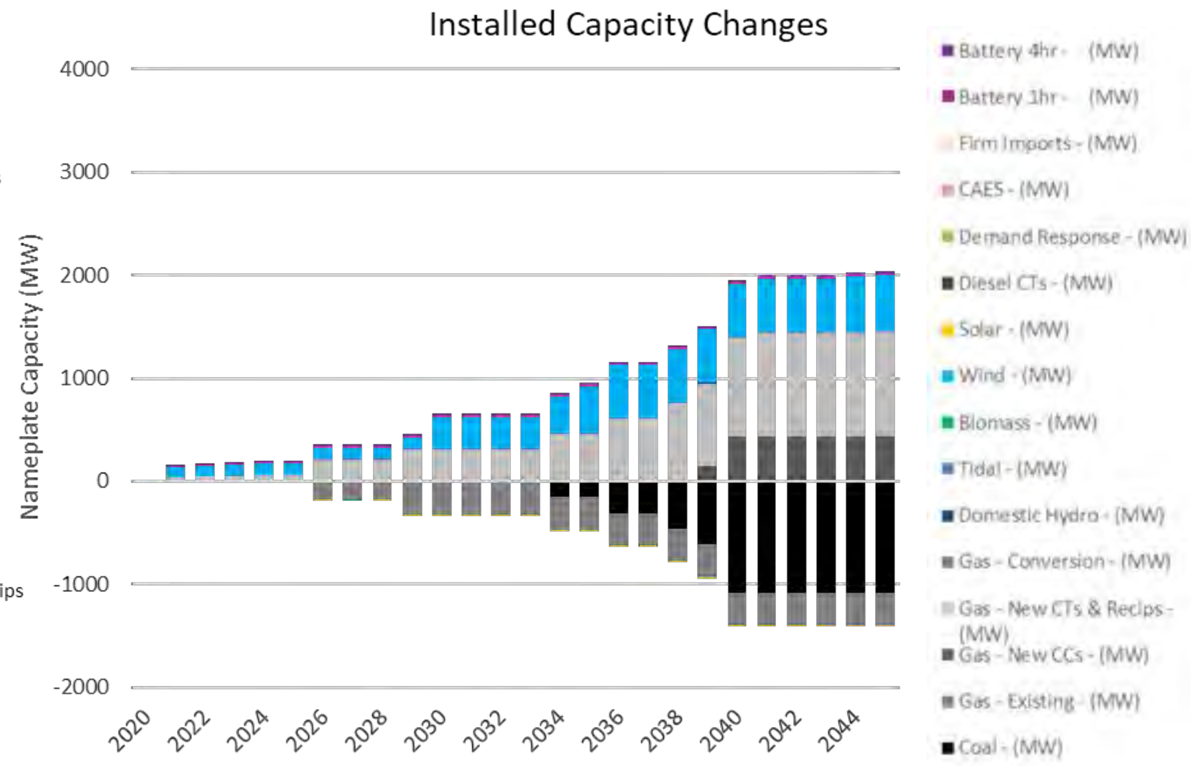


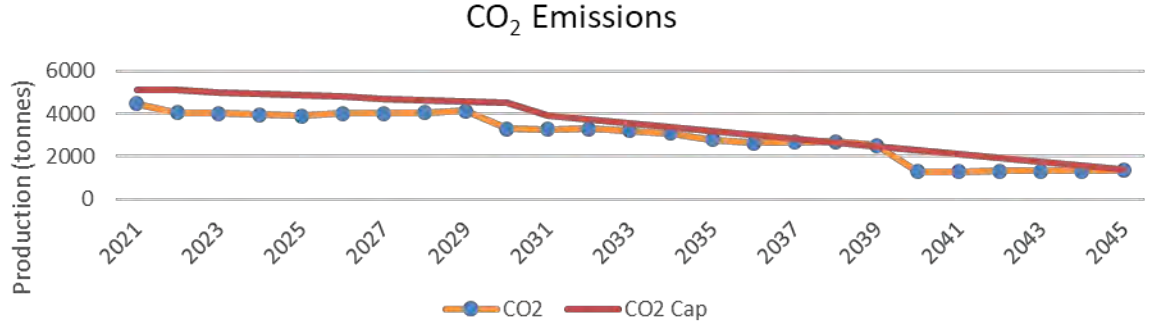
	$MM	Scenario Notes
25-yr NPVRR	$12,107	• Incremental firm imports enable an early coal unit retirement • Regional Interconnection constructed in 2039 allows remaining coal retirements and wind integration
25-yr NPVRR w/ EE	$15,541	
10-yr NPVRR	$6,785	

2.0A

LOW ELEC. / BASE DSM / NET ZERO 2050 / CURRENT LANDSCAPE



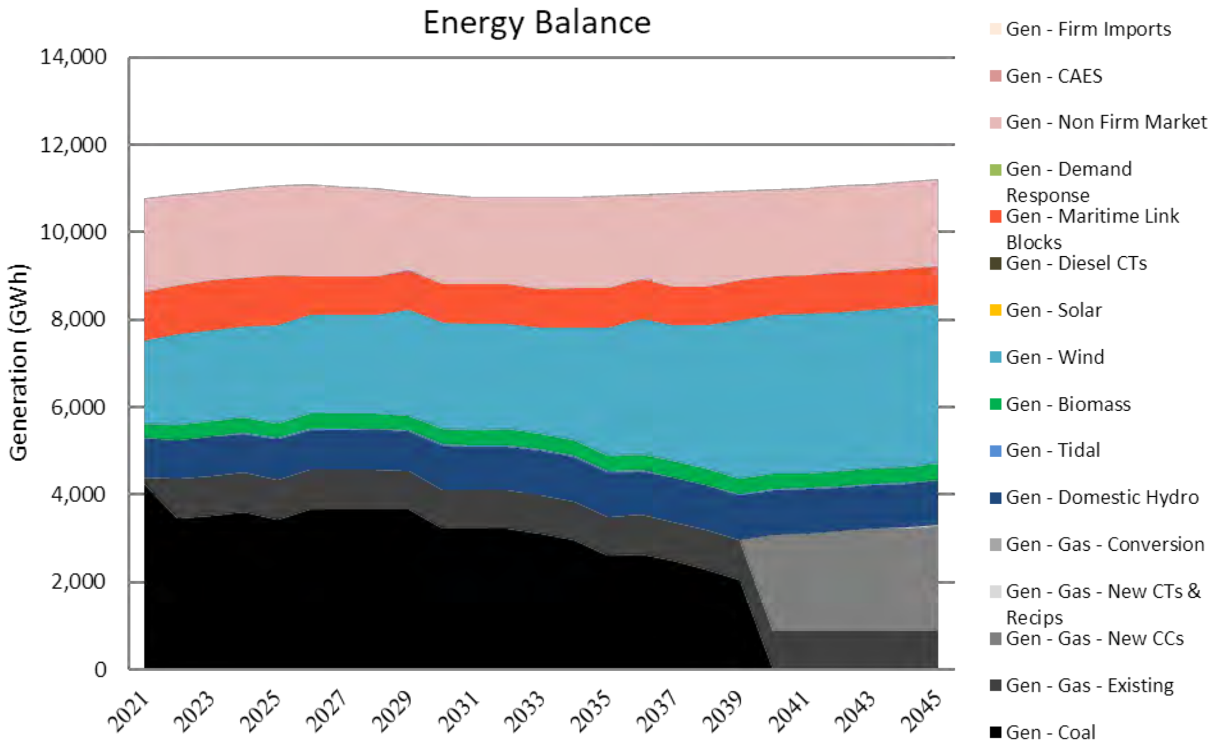


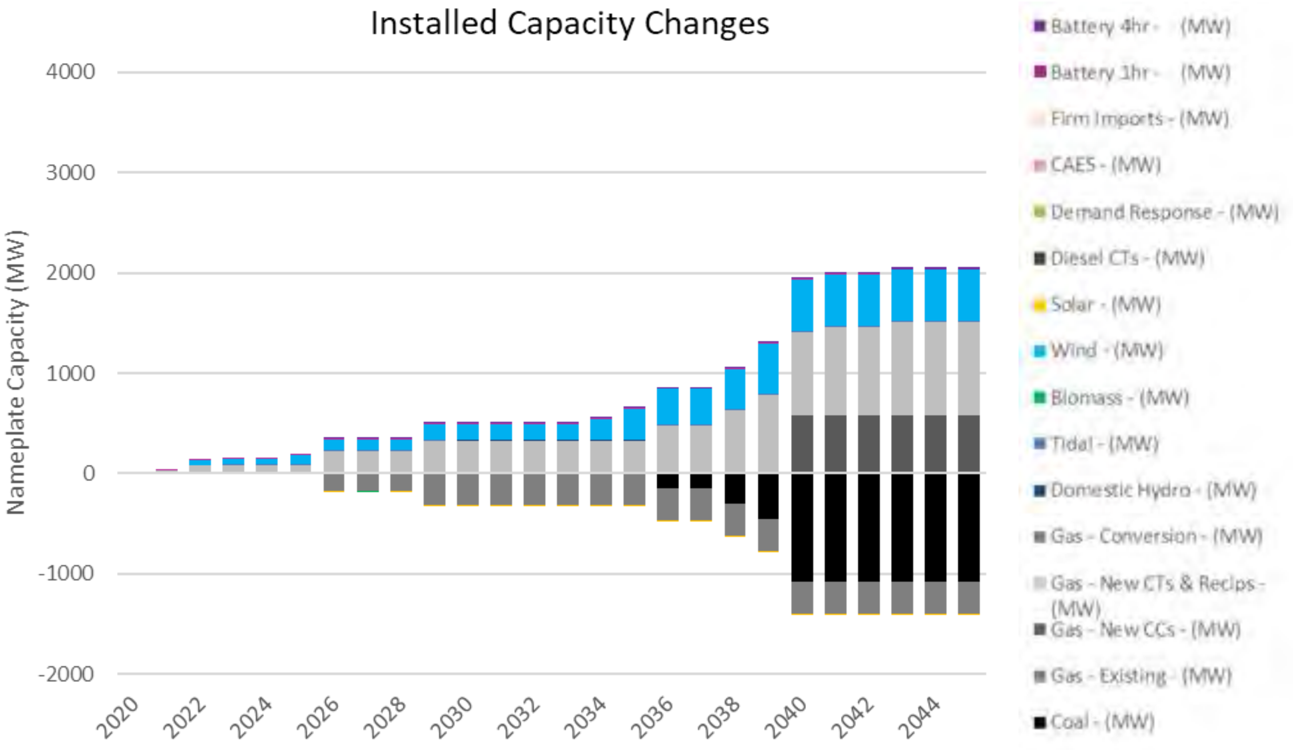


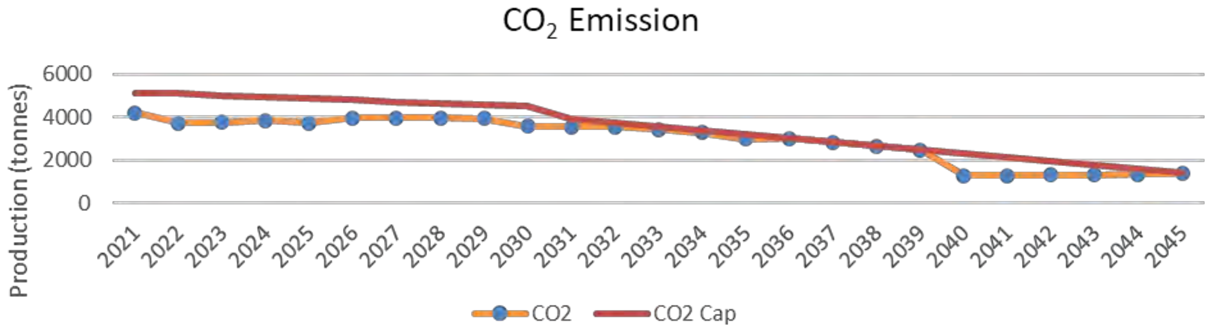
	$MM	Scenario Notes
25-yr NPVRR	$12,392	• Reliability Tie built in 2030 enables wind integration but does not provide firm capacity or energy access • Wind and CT capacity increase and CCGT capacity decreases relative to 1.0A (due to lower GHG cap)
25-yr NPVRR w/ EE	$16,039	
10-yr NPVRR	$7,151	

2.0A.S1 (COVID LOW LOAD)

LOW ELEC. + COVID LOW / BASE DSM / NET ZERO 2050 / CURRENT LANDSCAPE



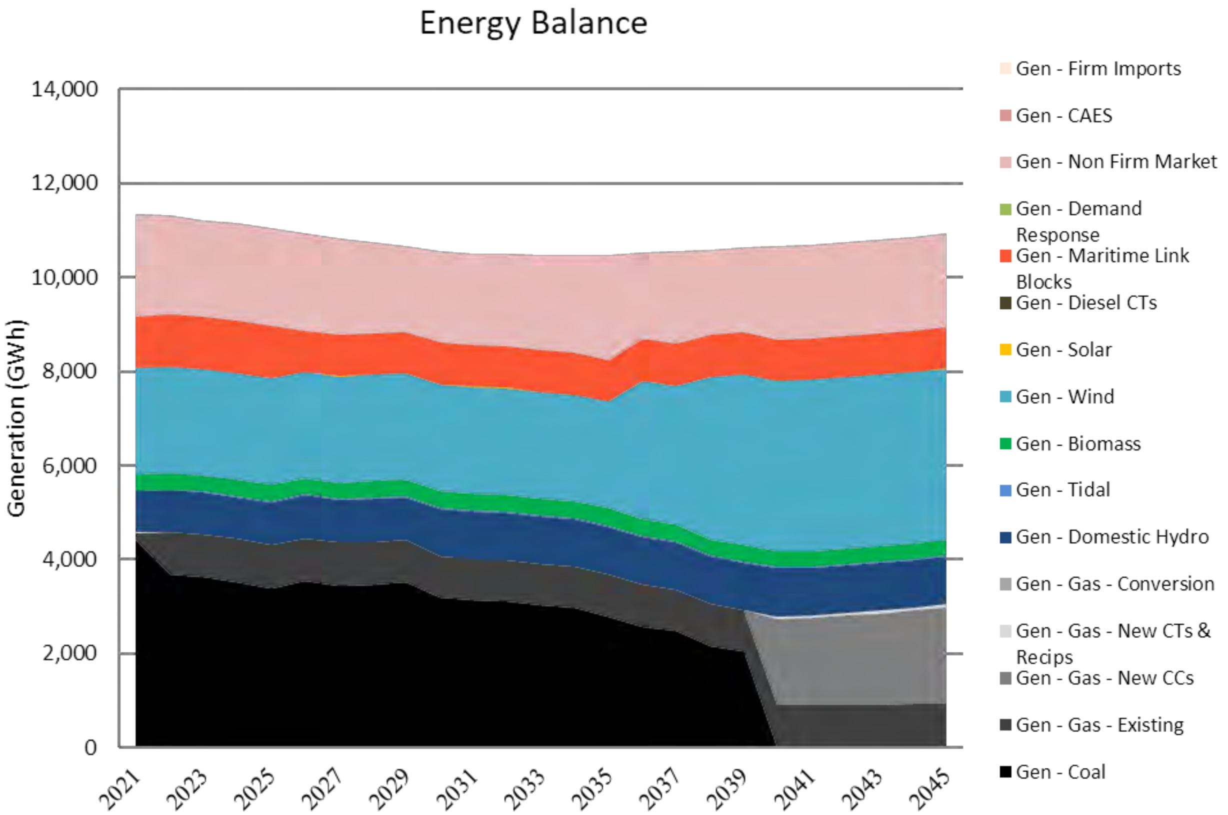


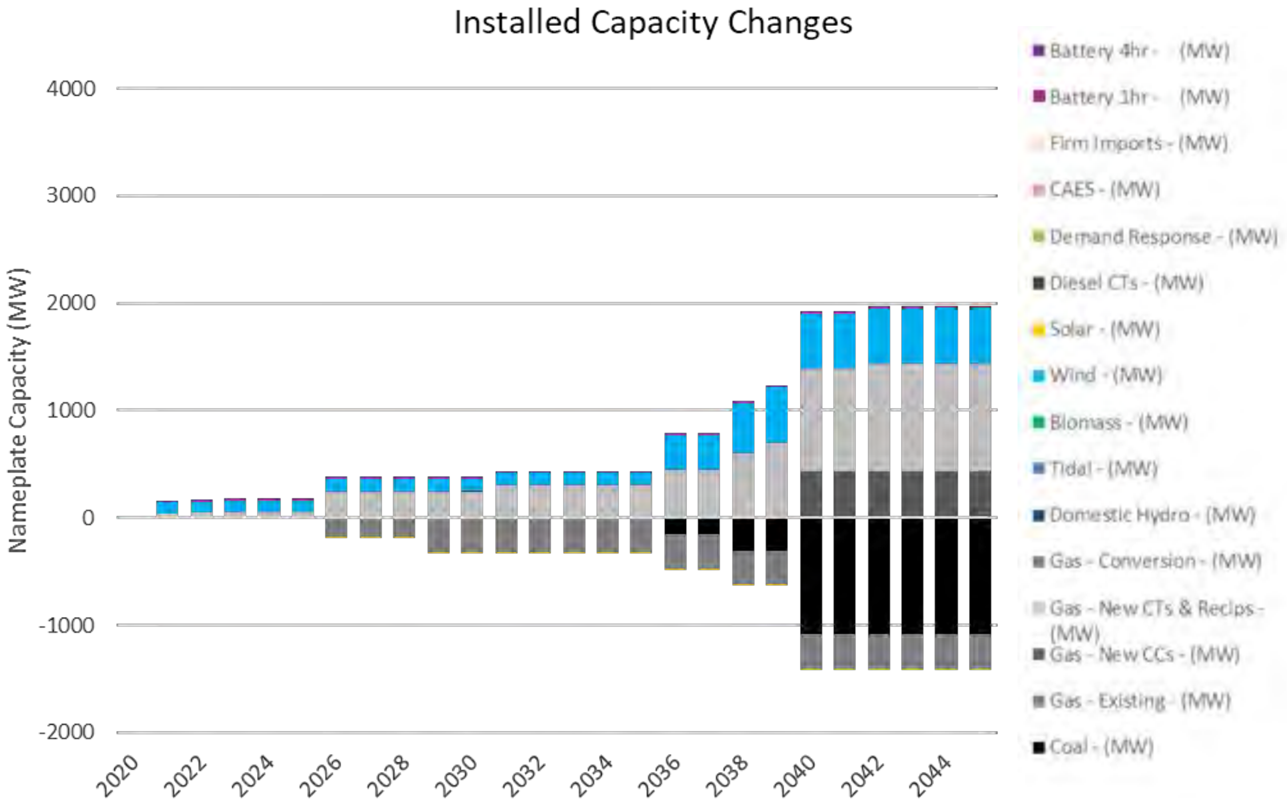


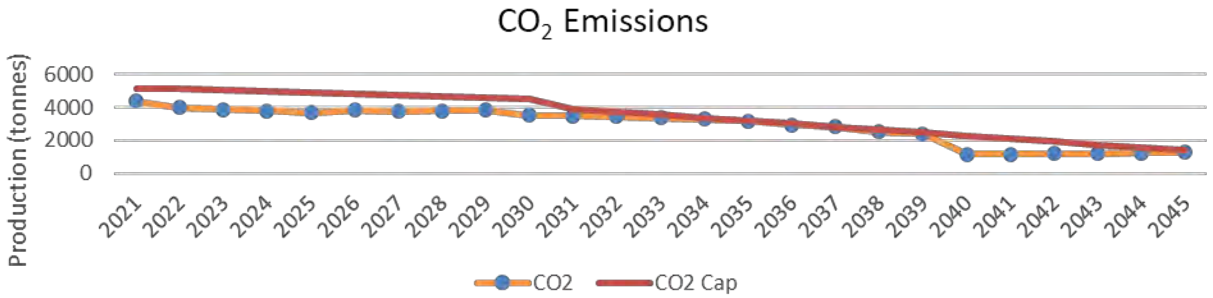
	$MM	Scenario Notes
25-yr NPVRR	$12,288	• Resource plan is essentially unchanged from 2.0A base case; lower production costs in first 5 years due to load reduction lead to a slightly lower NPV
25-yr NPVRR w/ EE	$15,984	
10-yr NPVRR	$7,019	

2.0A.S2 (MID DSM)

LOW ELEC. / MID DSM / NET ZERO 2050 / CURRENT LANDSCAPE



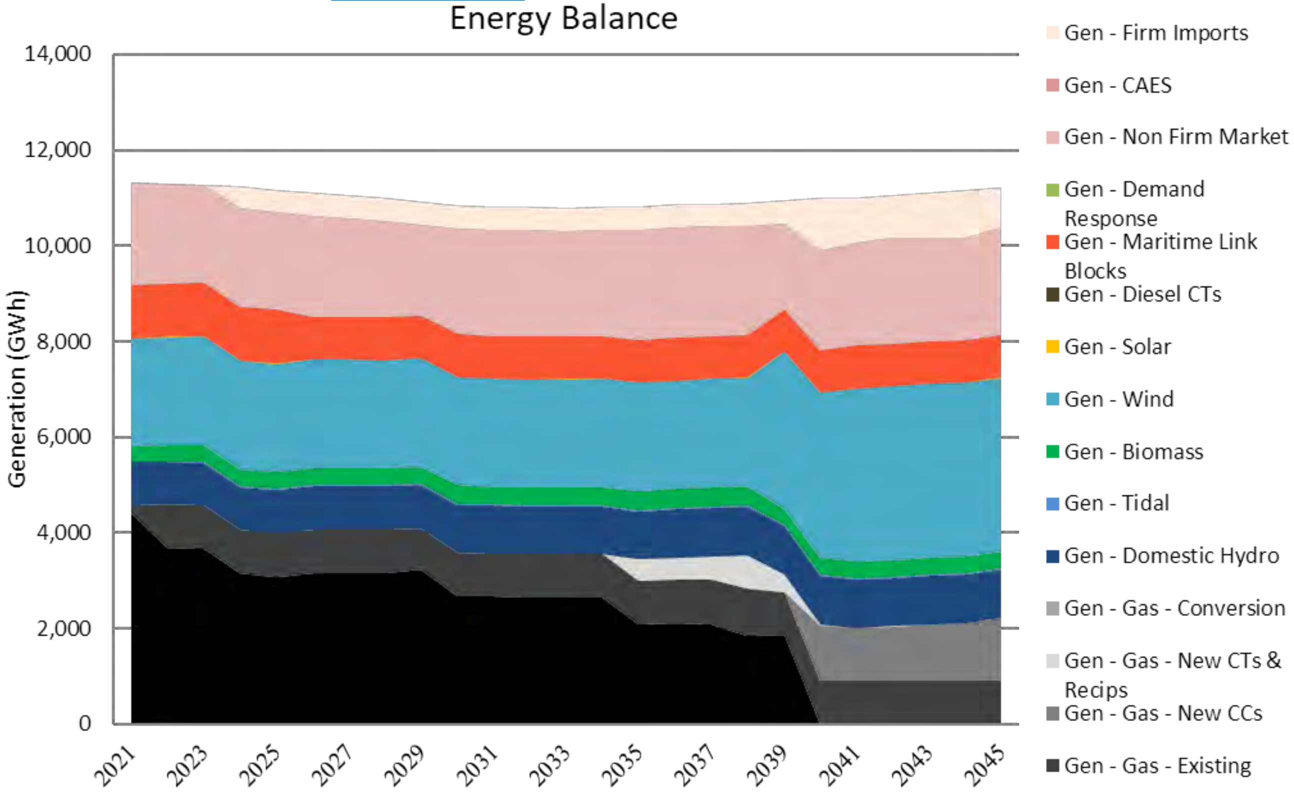


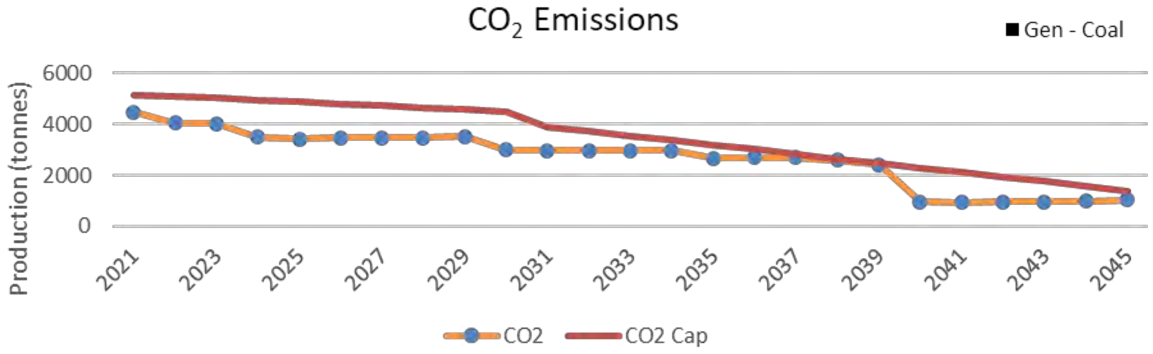


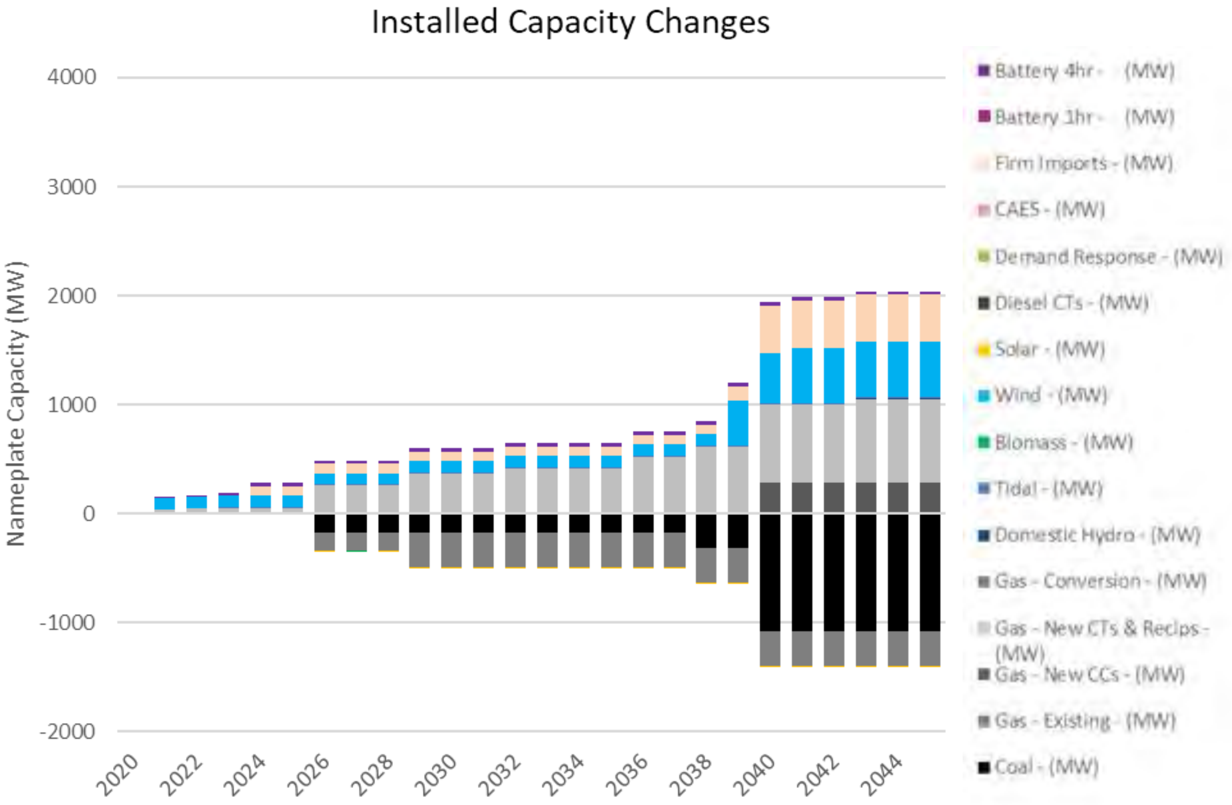
	$MM	Scenario Notes
25-yr NPVRR	$12,732	• Reliability Tie built in 2036 enables wind integration but does not provide firm capacity or energy access • Reduction in gas and wind builds relative to 2.0A
25-yr NPVRR w/ EE	$16,376	
10-yr NPVRR	$7,257	

2.0C

LOW ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION



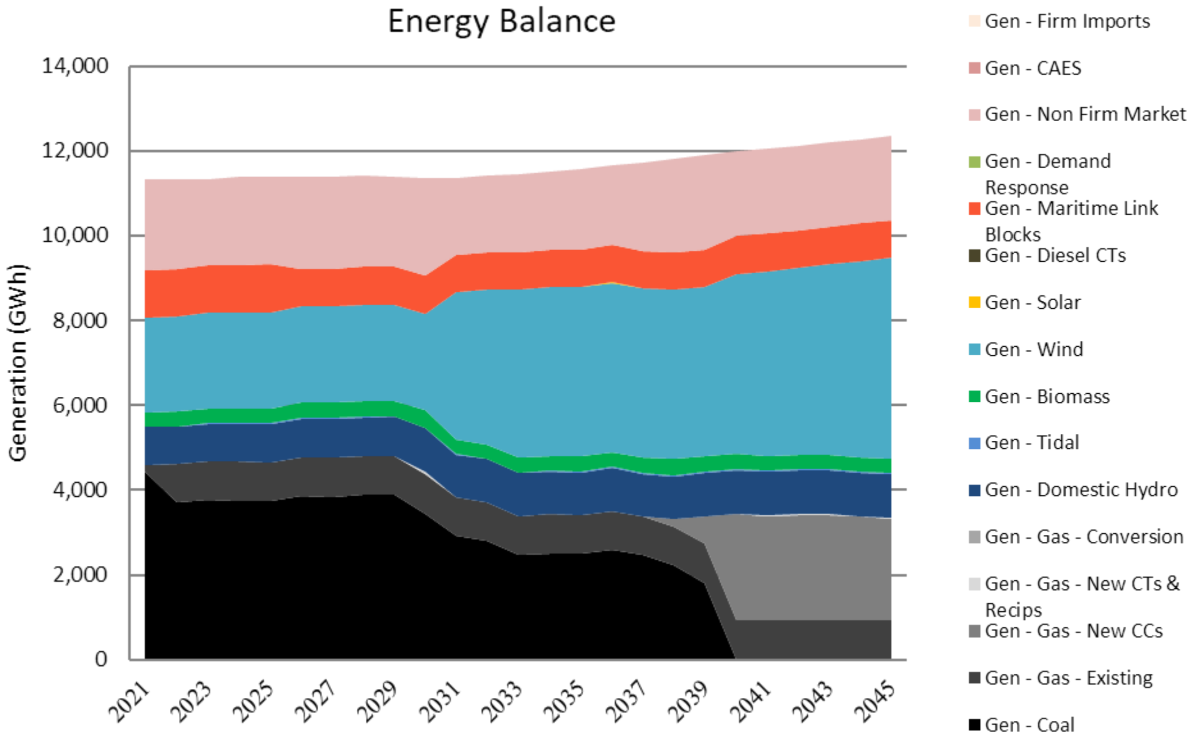


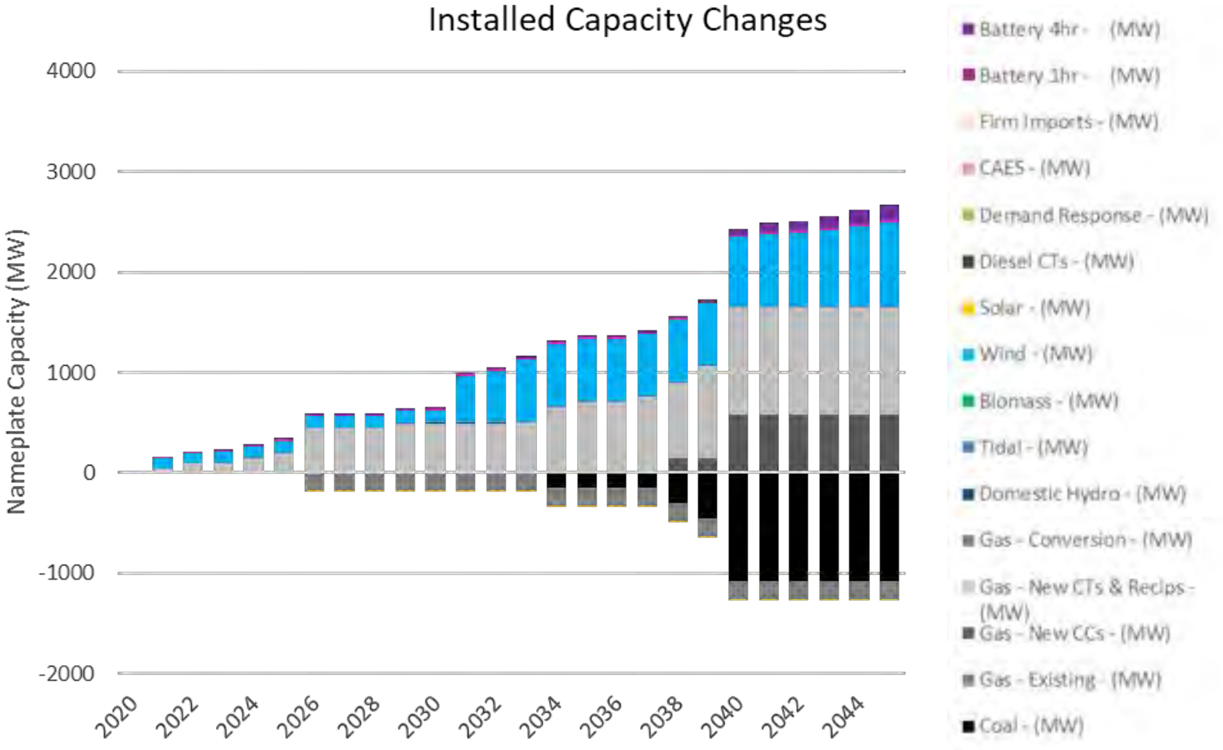


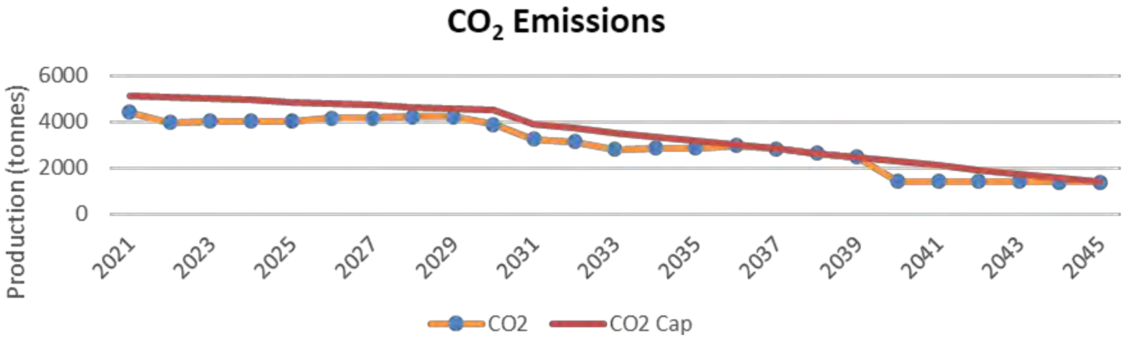
	$MM	Scenario Notes
25-yr NPVRR	$12,146	• Capacity expansion and generation are very similar to 1.0C case but with SDGA compliant GHG curve
25-yr NPVRR w/ EE	$15,624	
10-yr NPVRR	$6,780	

2.1A

MID ELEC. / BASE DSM / NET ZERO 2050 / CURRENT LANDSCAPE



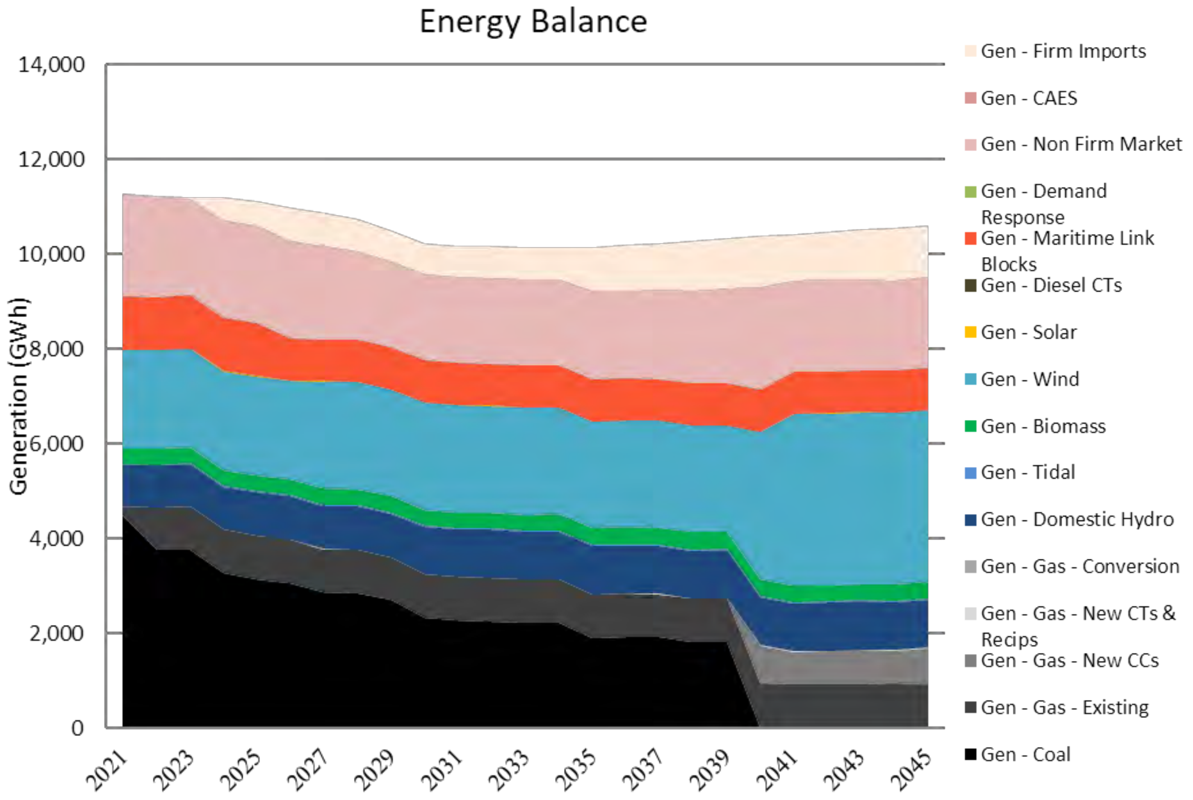


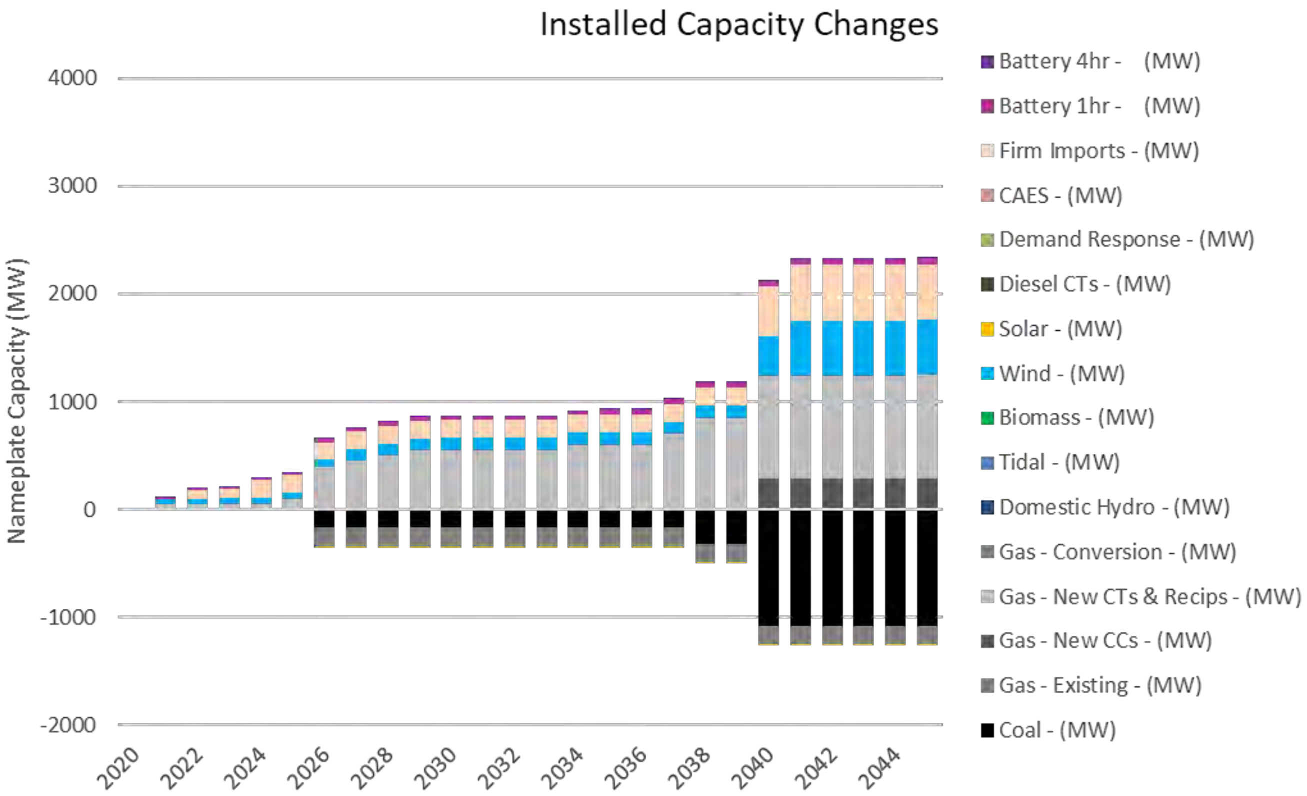


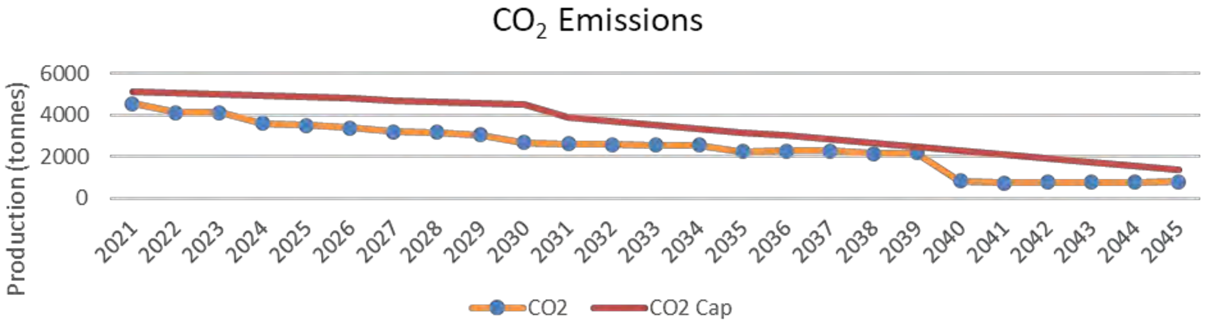
	$MM	Scenario Notes
25-yr NPVRR	$13,306	• Reliability Tie built in 2031 enables wind integration but does not provide firm capacity or energy access • Gas CT builds provide capacity to support early electrification load growth; energy is supplied by wind and non-firm imports, and CCGT when coal units retire
25-yr NPVRR w/ EE	$17,631	
10-yr NPVRR	$7,140	

2.1B

MID ELEC. / BASE DSM / NET ZERO 2050 / DISTRIBUTED RESOURCES



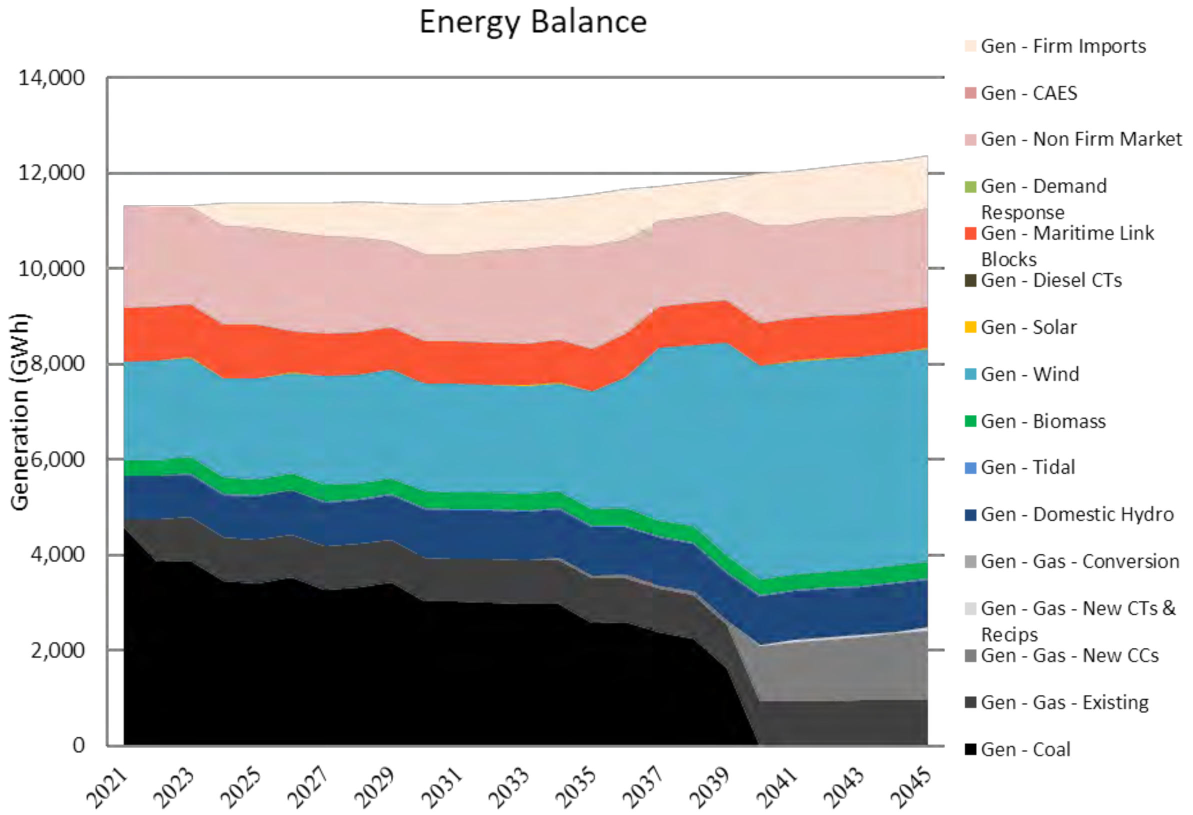


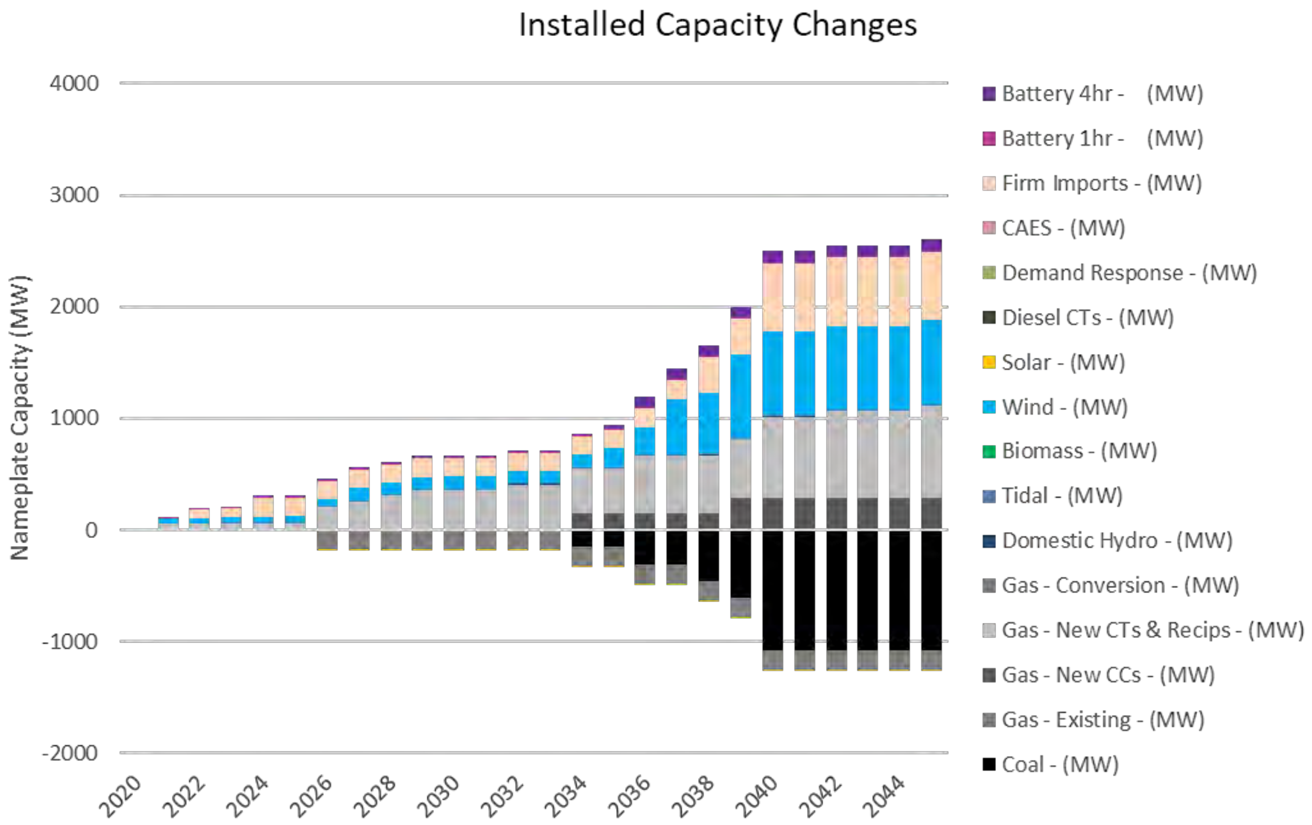


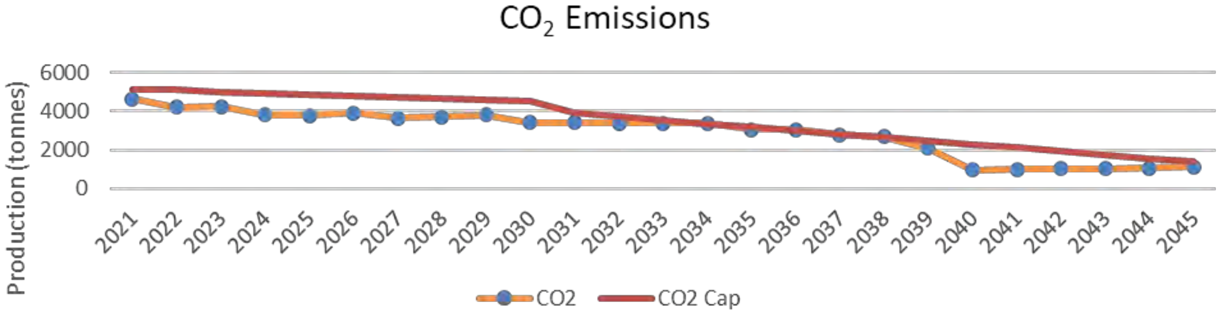
	$MM	Scenario Notes
25-yr NPVRR	$11,958	• Regional Interconnection built in 2040 with coal unit retirements • DER is modeled as a load reduction; cost of DER resources not included in NPV calculations ($1.6B-$2.5B)
25-yr NPVRR w/ EE	$15,477	
10-yr NPVRR	$6,724	

2.1C

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION



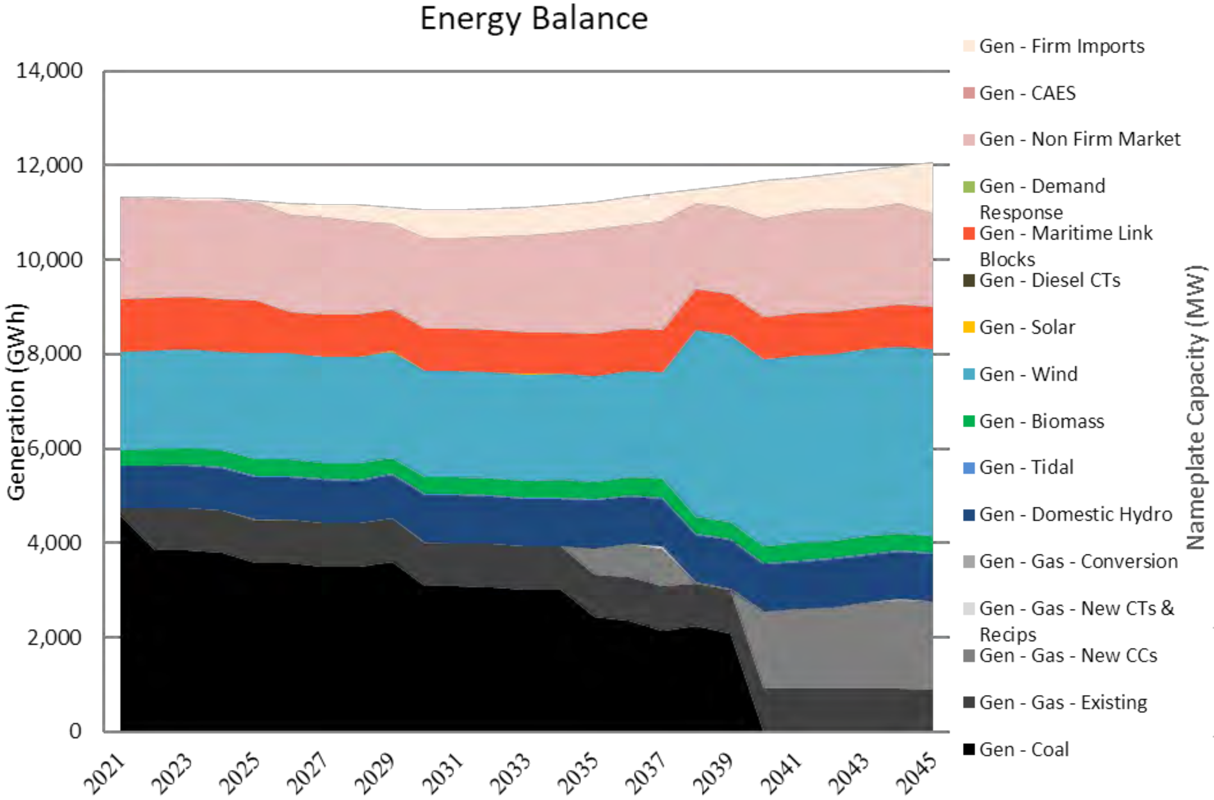


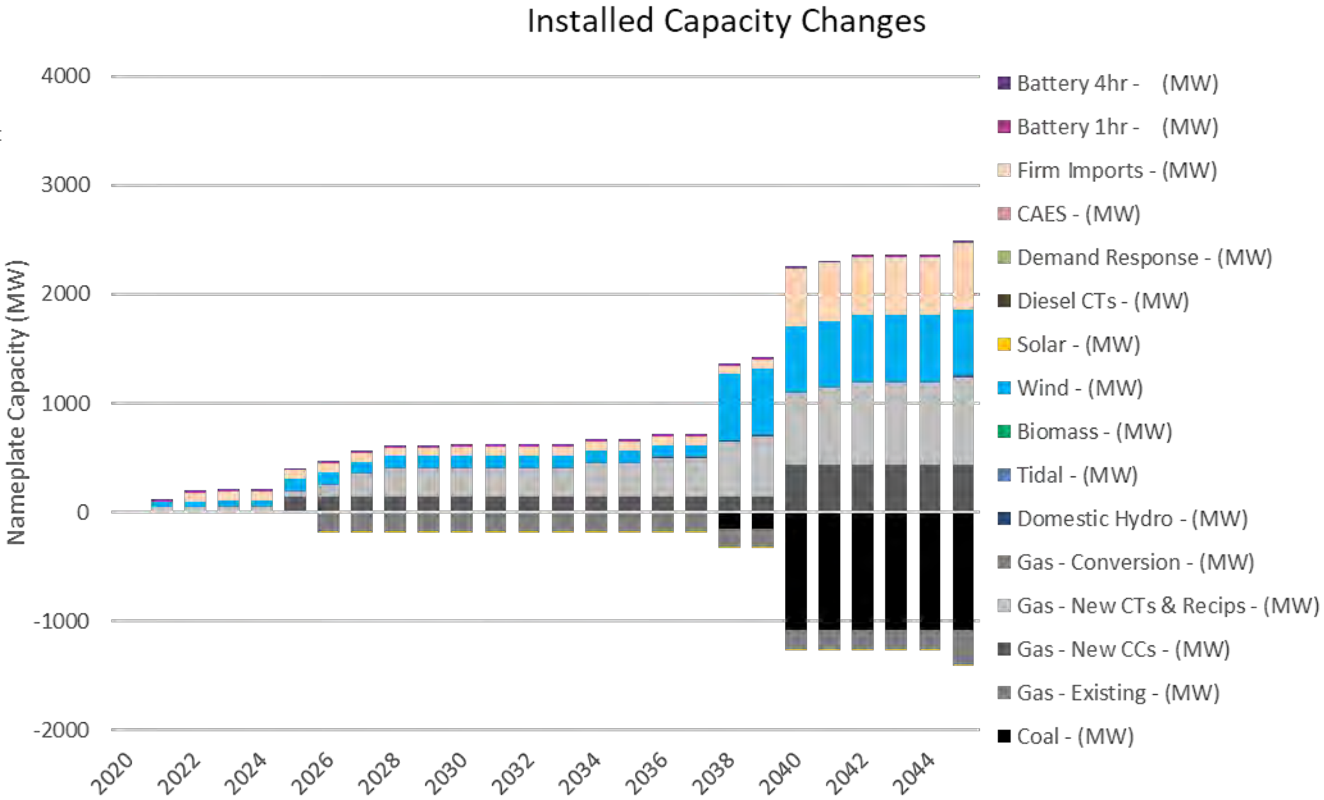


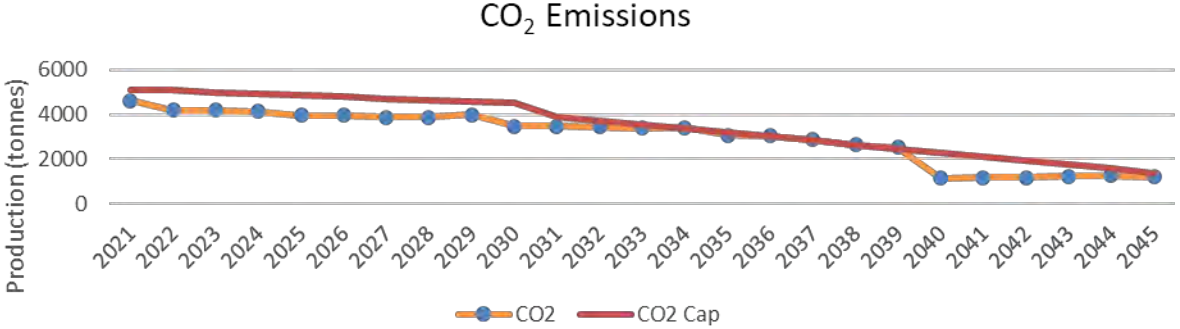
	$MM	Scenario Notes
25-yr NPVRR	$13,037	• Reliability Tie built in 2037 enables wind integration • Regional Interconnection built in 2038 to access firm imports (staged from reliability tie)
25-yr NPVRR w/ EE	$17,029	
10-yr NPVRR	$7,019	

2.1C.S1 (MID DSM)

MID ELEC. / MID DSM / NET ZERO 2050 / REGIONAL INTEGRATION





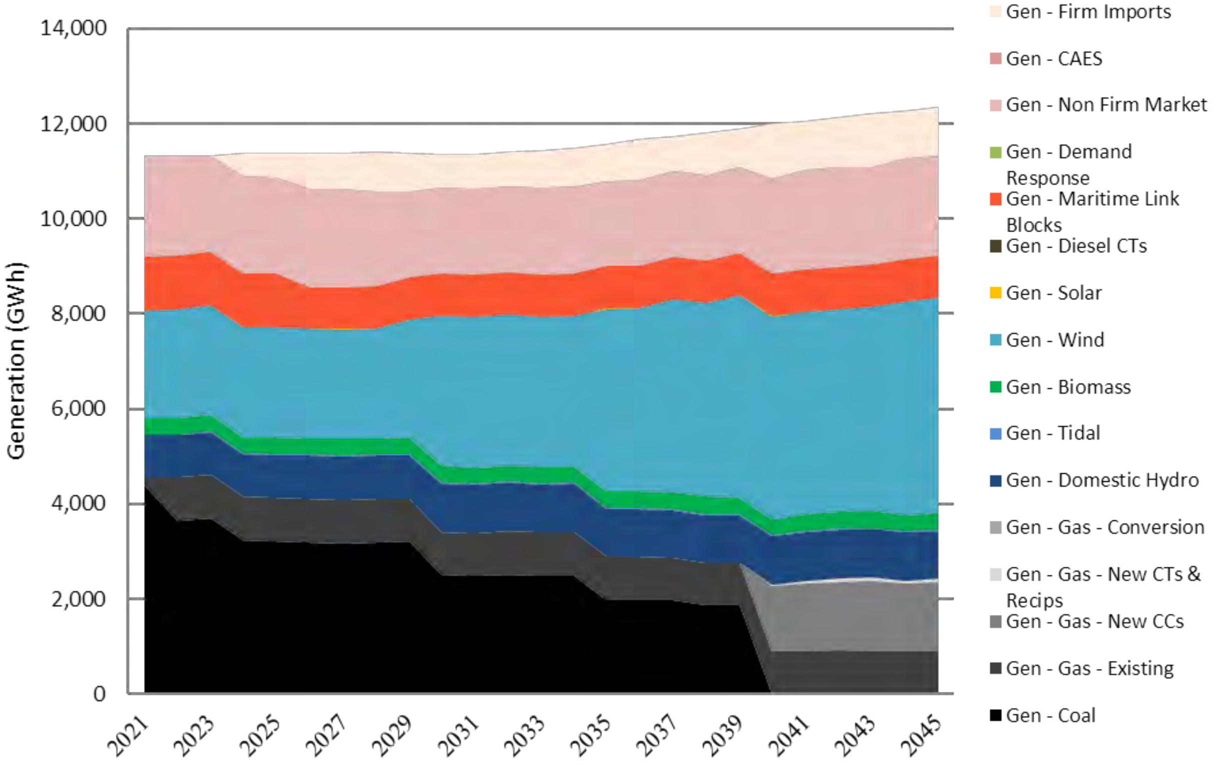


	$MM	Scenario Notes
25-yr NPVRR	$13,608	• Reliability Tie built in 2038 enables wind integration • Regional Interconnection built in 2040 to access firm imports (staged from reliability tie)
25-yr NPVRR w/ EE	$17,563	
10-yr NPVRR	$7,487	

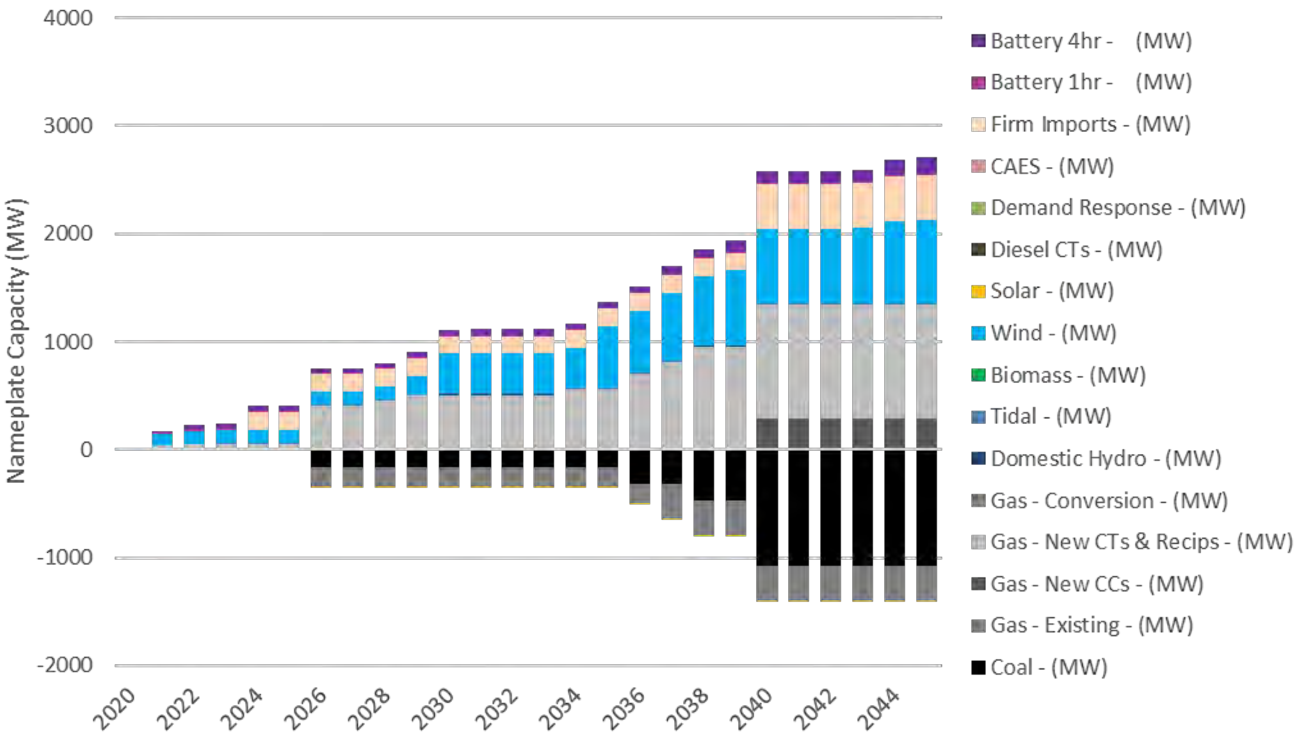
2.1C.S2 (LOW WIND COST)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION

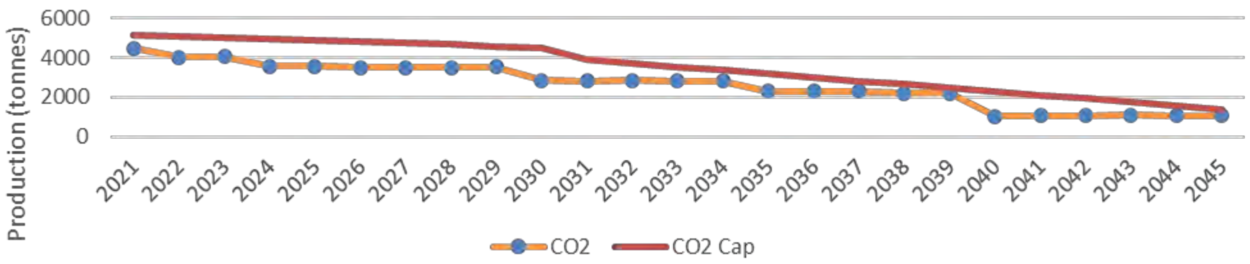
Energy Balance



Installed Capacity Changes



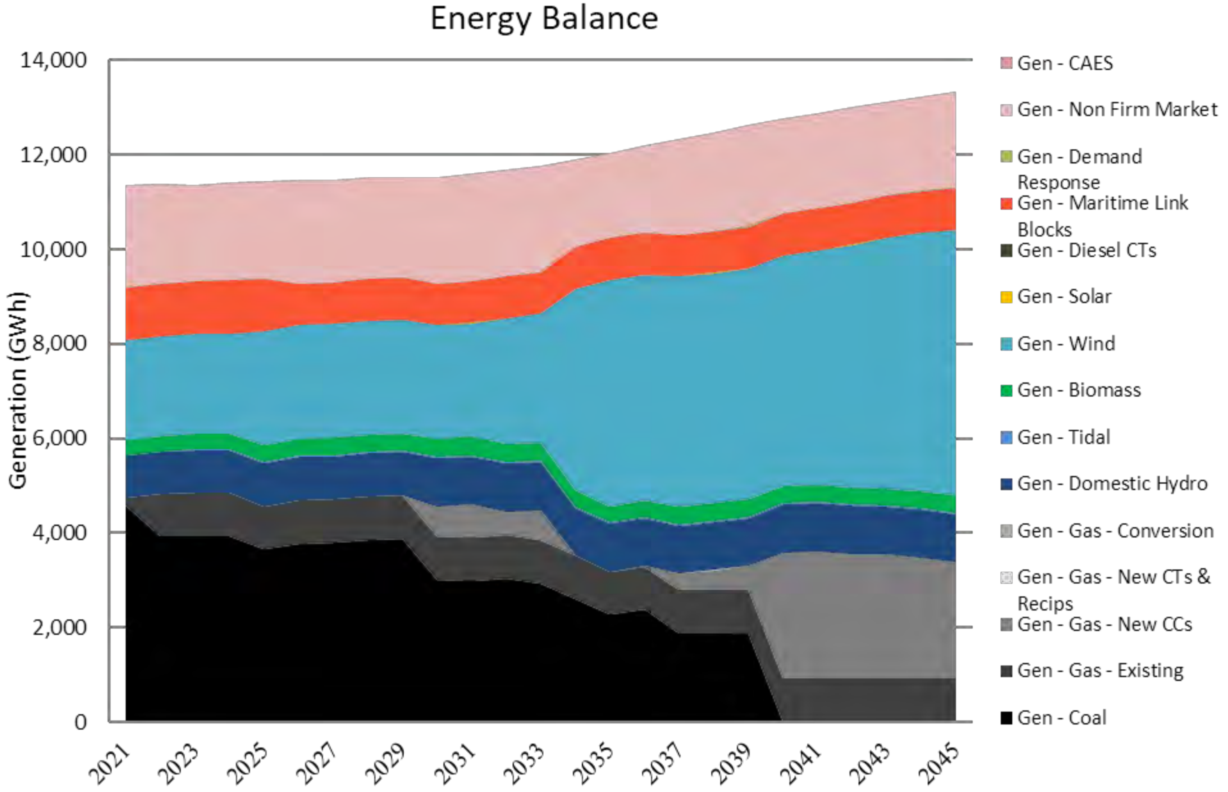
CO_2 Emission

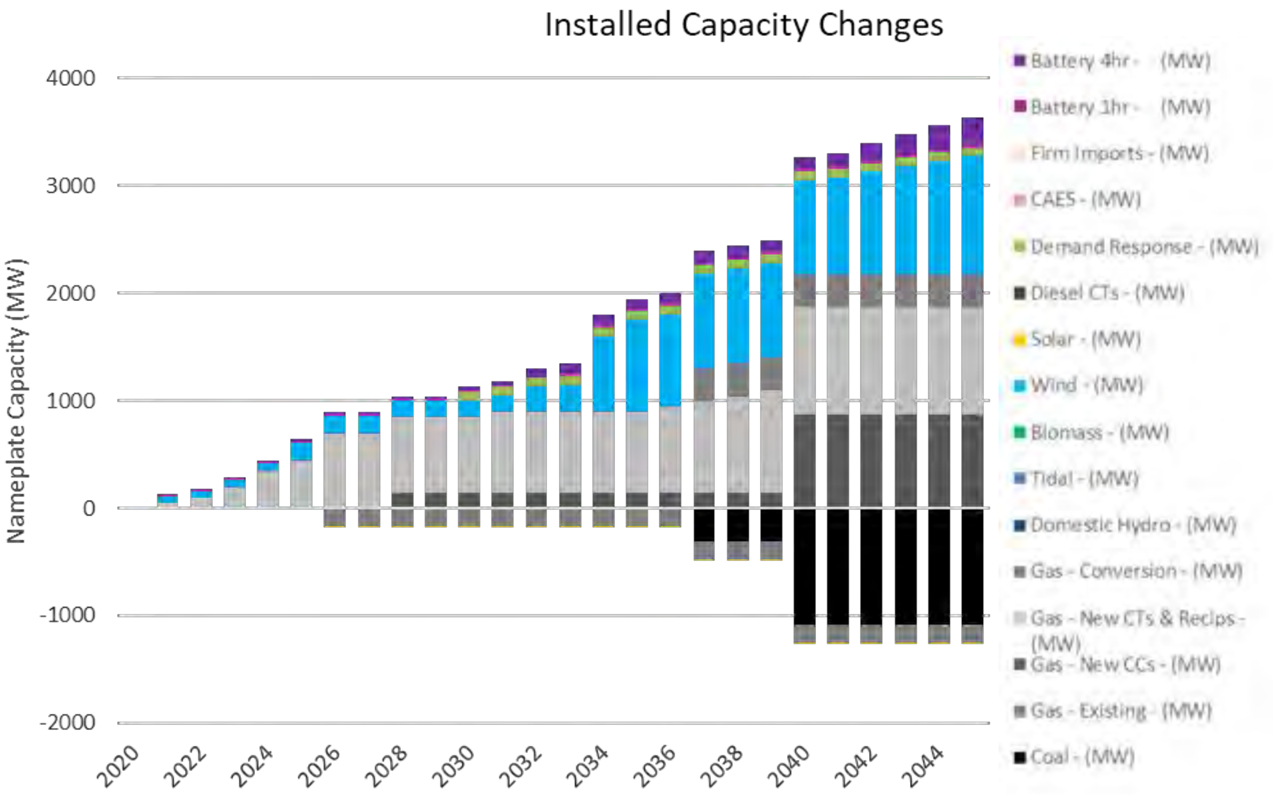


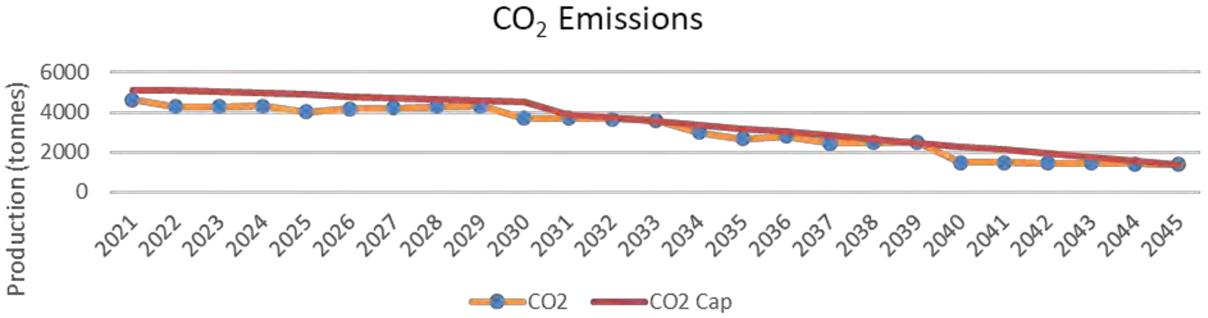
	$MM	Scenario Notes
25-yr NPVRR	$12,852	• Total wind build very similar to 2.1C but larger wind additions start earlier (2030 vs. 2037) • Reliability Tie built in 2029 enables wind integration • Regional Interconnection built in 2040 to access firm imports (staged from Reliability Tie)
25-yr NPVRR w/ EE	$16,760	
10-yr NPVRR	7,249	

2.2A

HIGH ELEC. / MAX DSM / NET ZERO 2050 / CURRENT LANDSCAPE



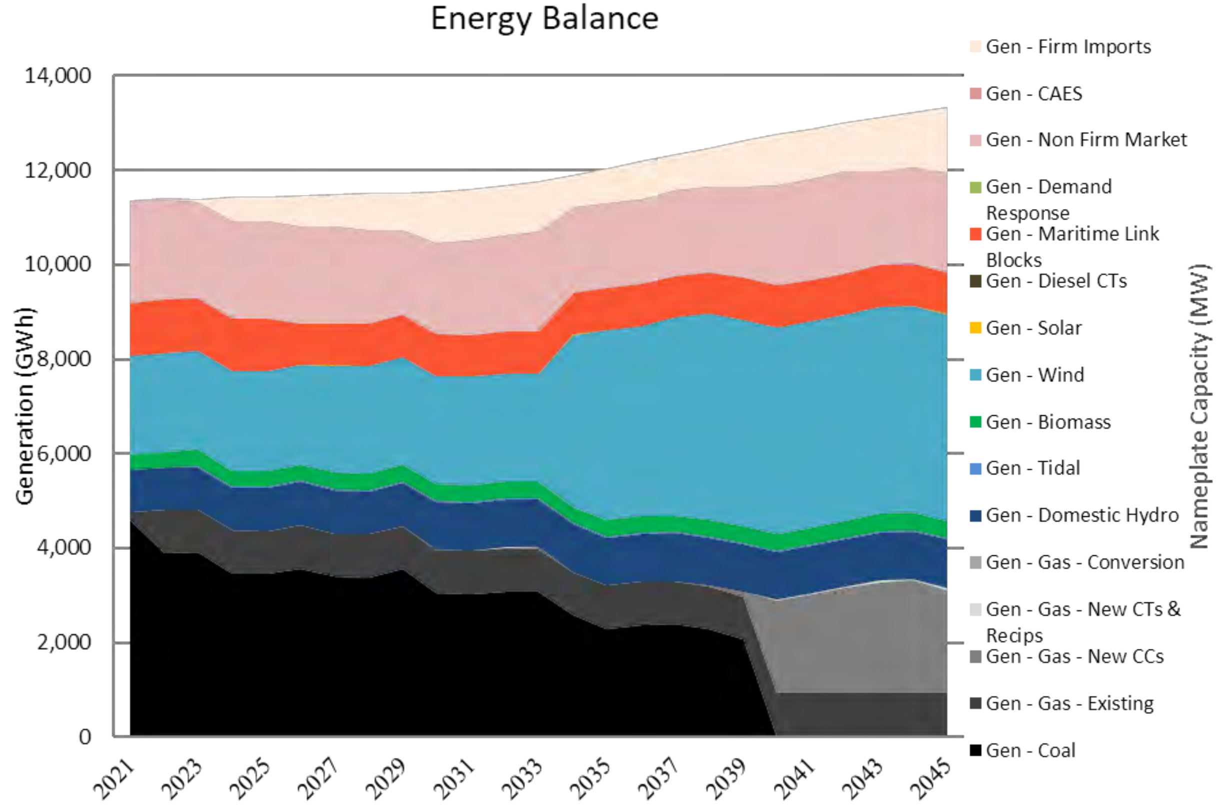


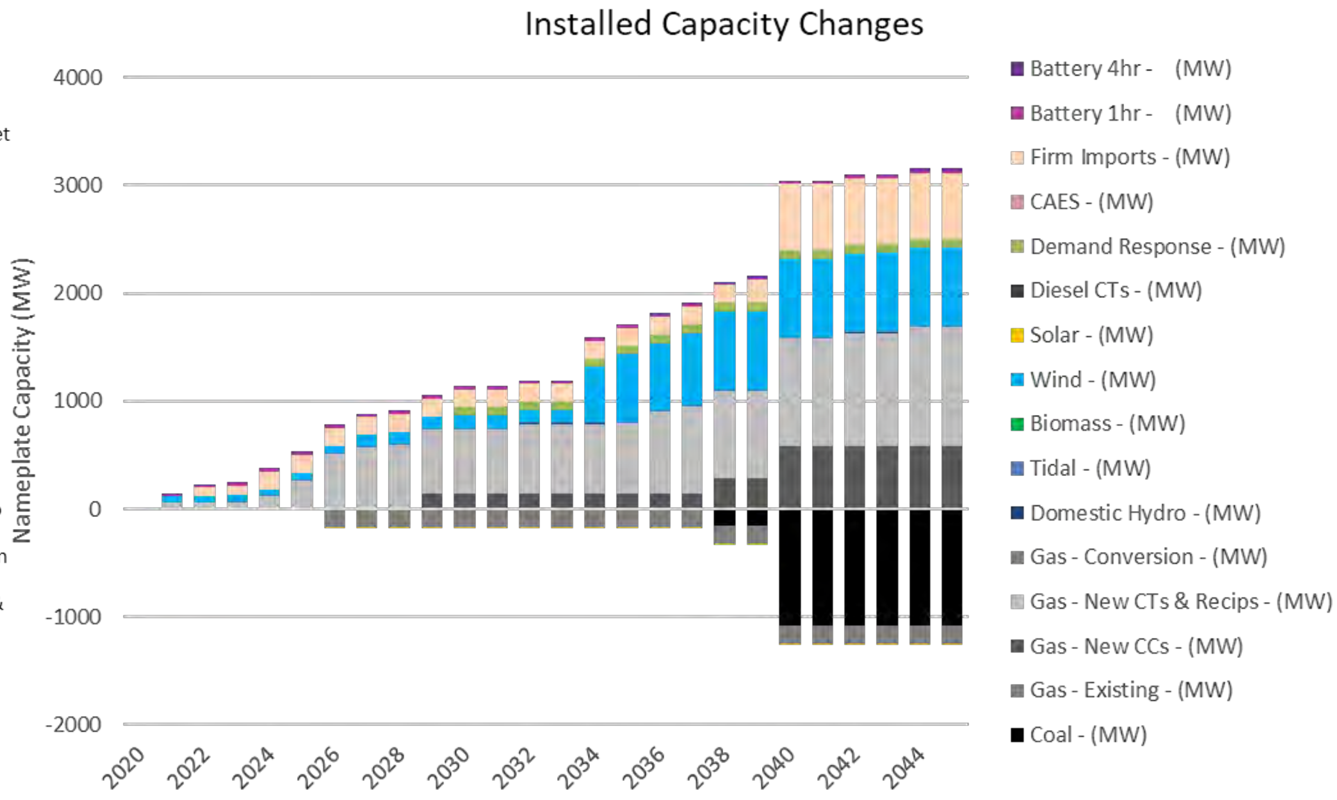


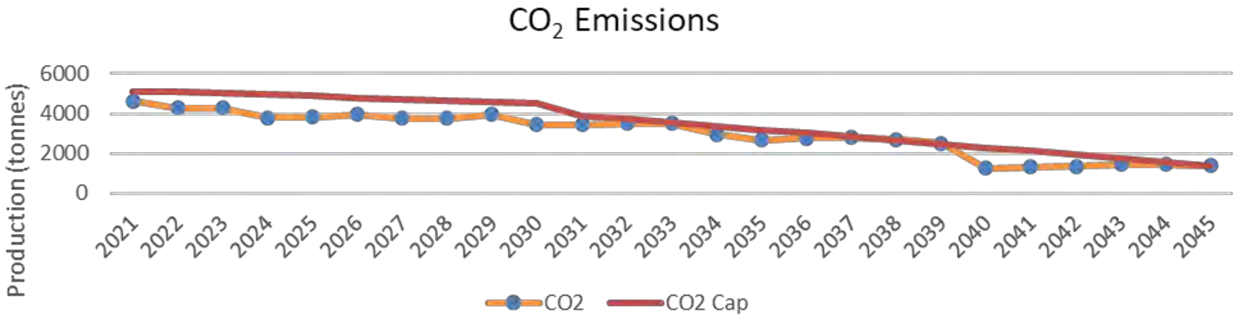
	$MM	Scenario Notes
25-yr NPVRR	$15,763	• Early load growth served by incremental gas CTs and non-firm import energy • Reliability Tie built in 2034 enables wind integration • Additional wind is integrated with local mitigation • DR resources selected starting in 2030
25-yr NPVRR w/ EE	$21,020	
10-yr NPVRR	$8,364	

2.2C

HIGH ELEC. / MAX DSM / NET ZERO 2050 / REGIONAL INTEGRATION



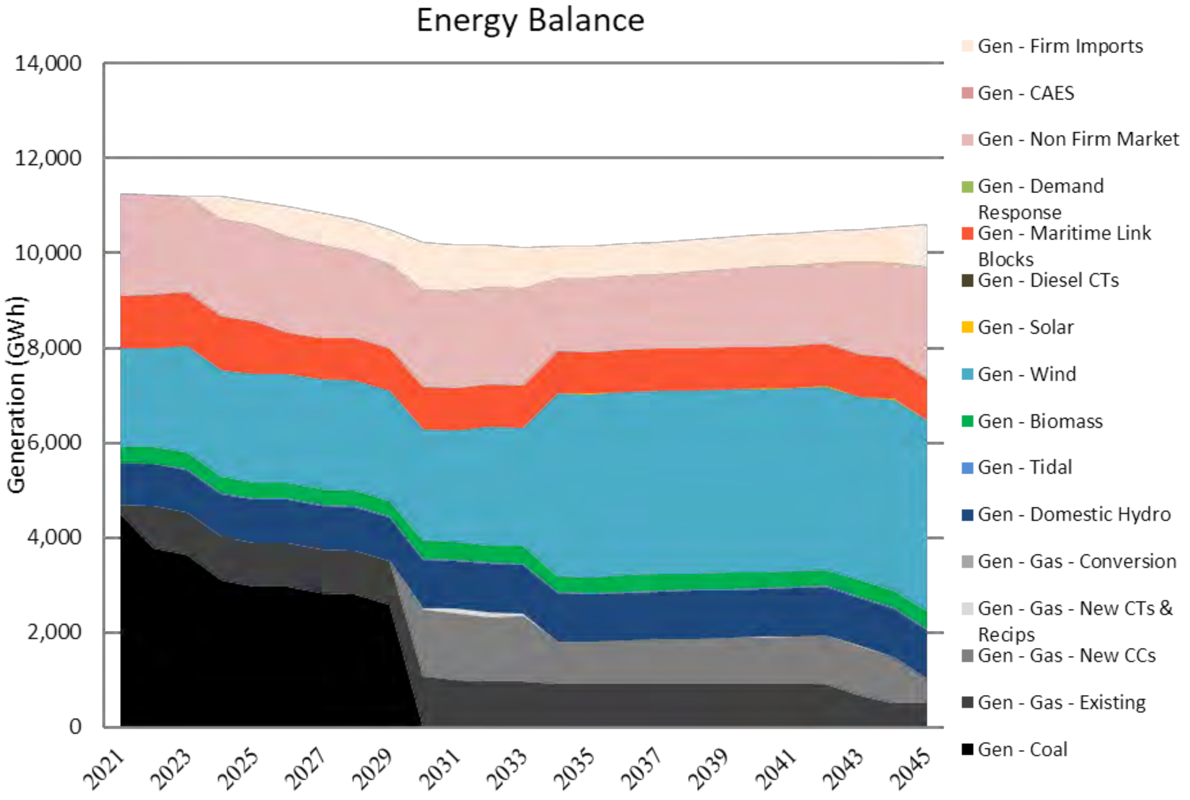


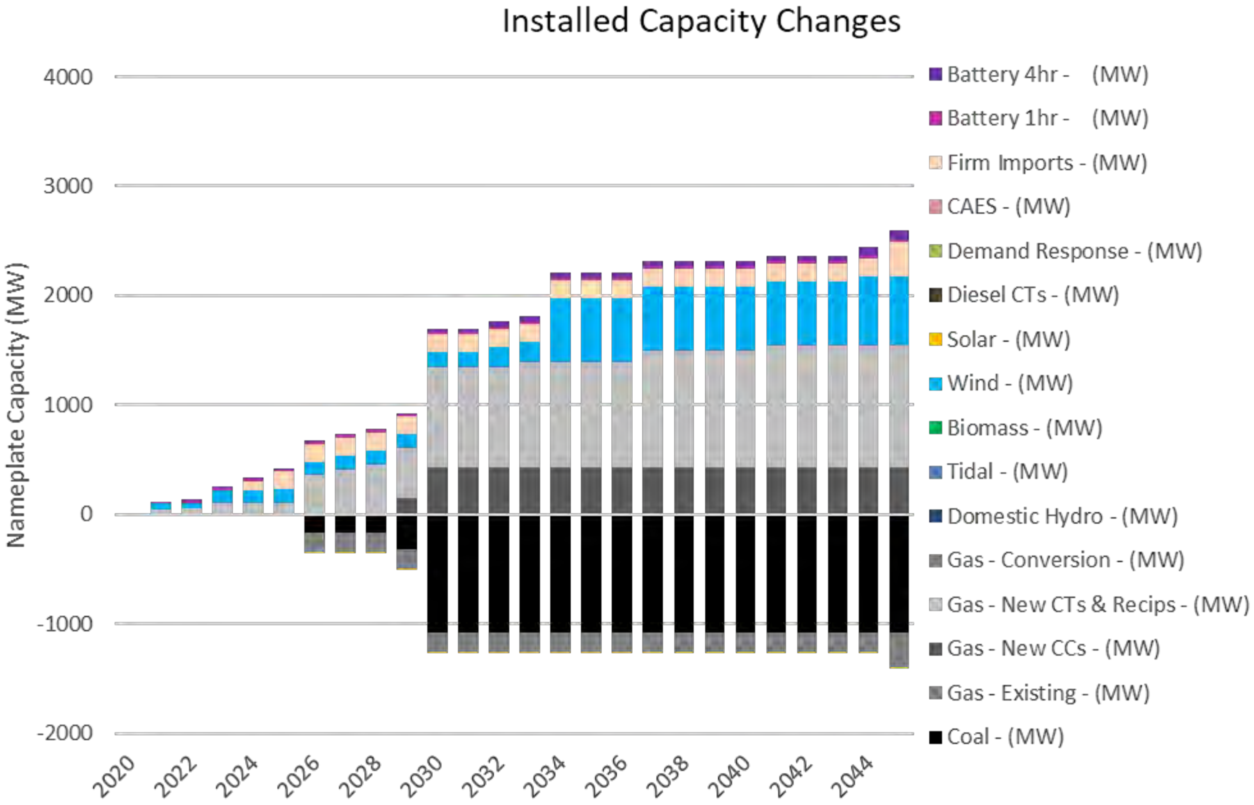


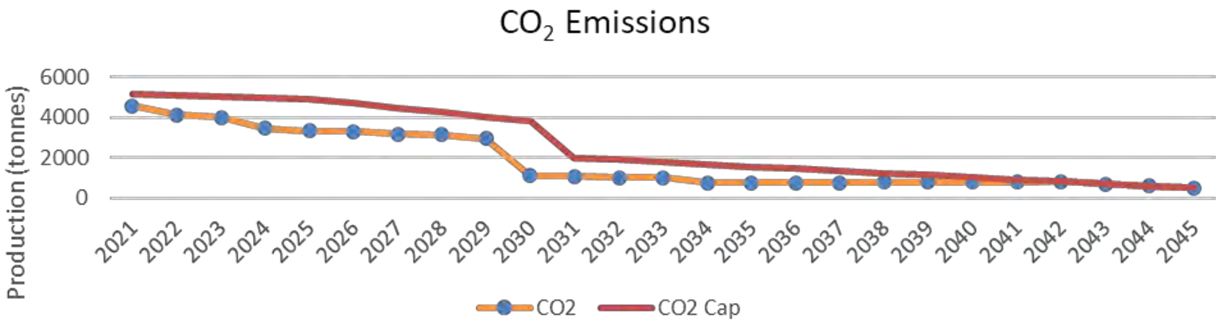
	$MM	Scenario Notes
25-yr NPVRR	$15,353	• Reliability Tie built in 2034 enables wind integration • Regional Interconnection built in 2039 to access firm imports (staged from reliability tie) • DR selected beginning in 2030
25-yr NPVRR w/ EE	$20,205	
10-yr NPVRR	$8,212	

3.1B

MID ELEC. / BASE DSM / ACCEL. ZERO 2045 / DISTRIBUTED RESOURCES





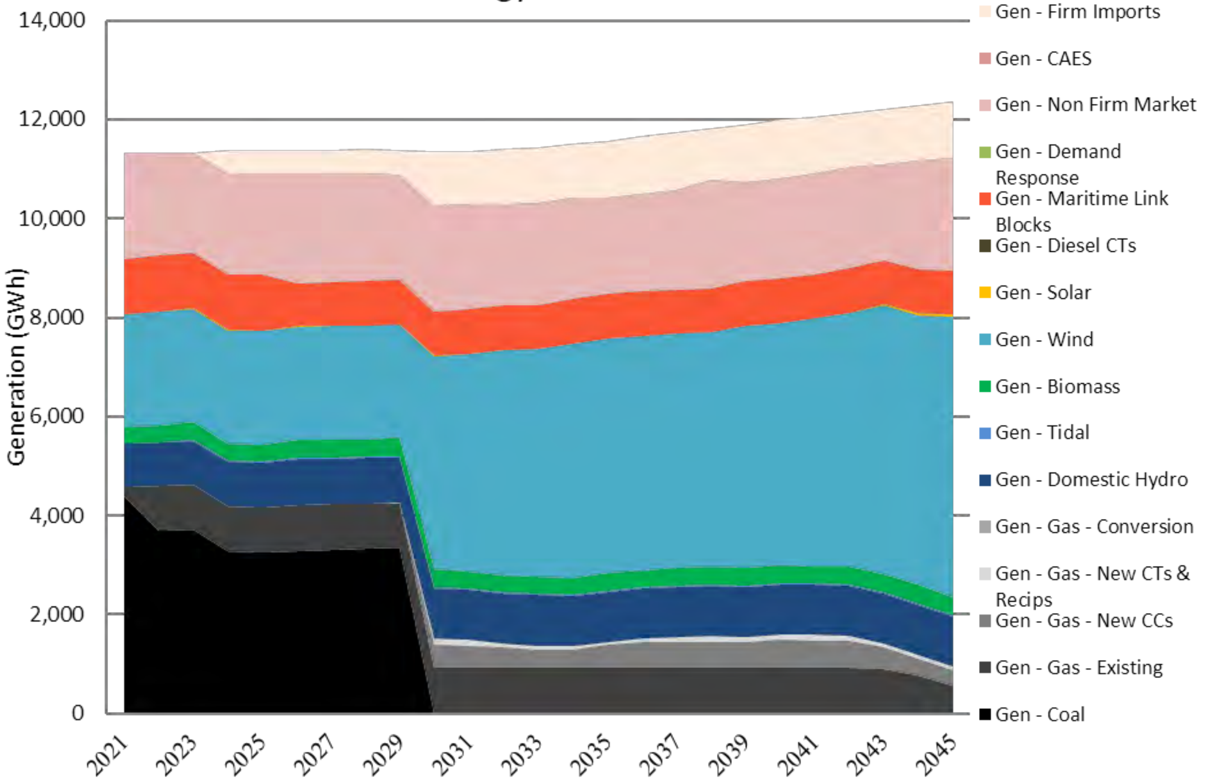


	$MM	Scenario Notes
25-yr NPVRR	$12,575	• Reliability Tie build in 2034 enabled wind integration • Regional Interconnection built in 2045 to access firm imports (staged from reliability tie) • DER is modeled as a load reduction; cost of DER resources not included in NPV calculations ($1.6B-$2.5B)
25-yr NPVRR w/ EE	$17,311	
10-yr NPVRR	$6,827	

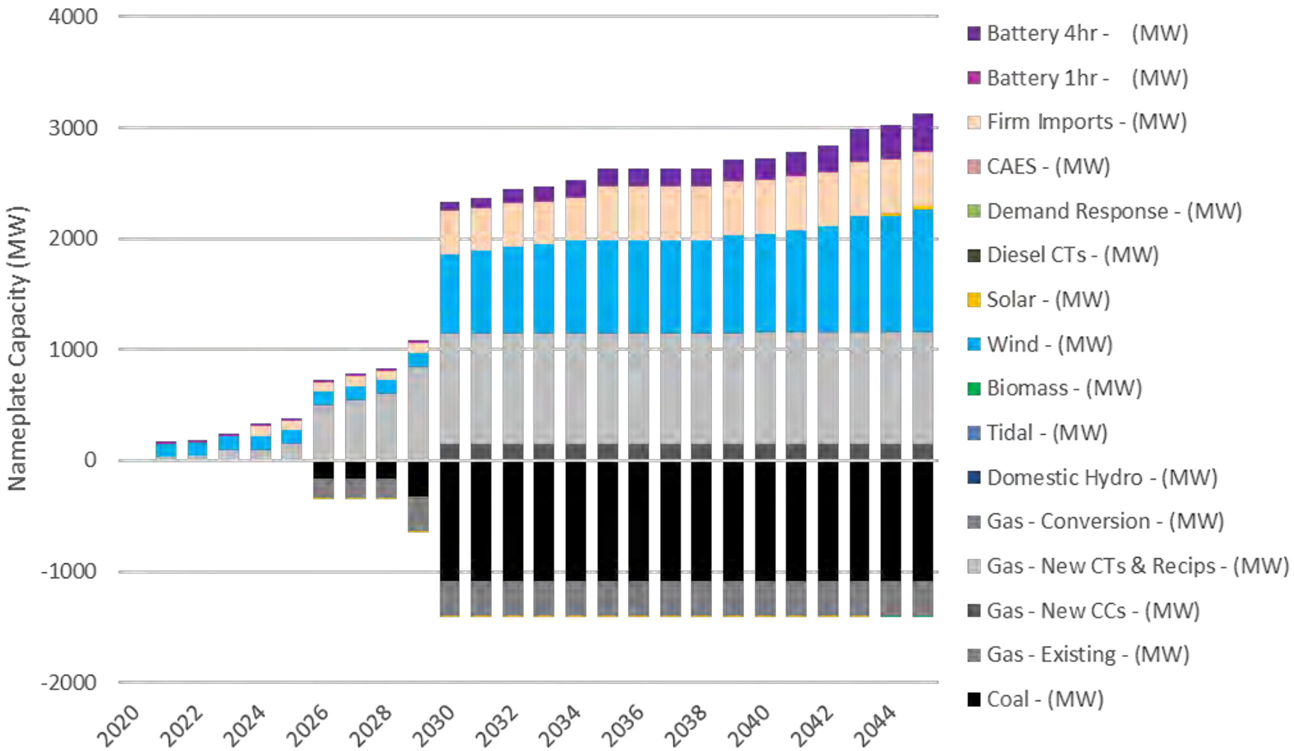
3.1C

MID ELEC. / BASE DSM / ACCEL. ZERO 2045 / REGIONAL INTEGRATION

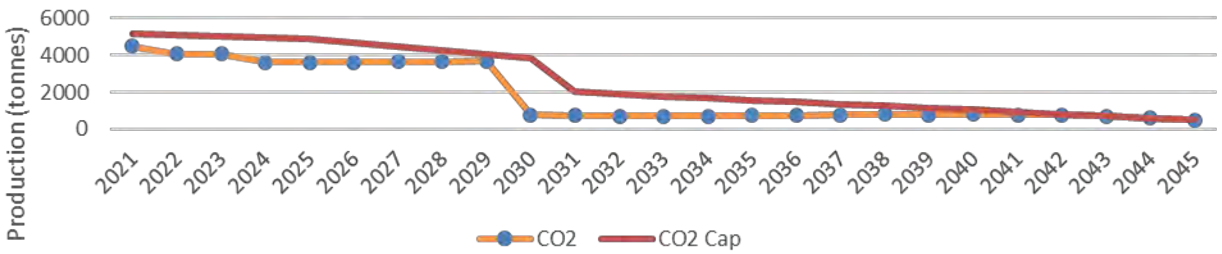
Energy Balance



Installed Capacity Changes



CO_2 Emissions

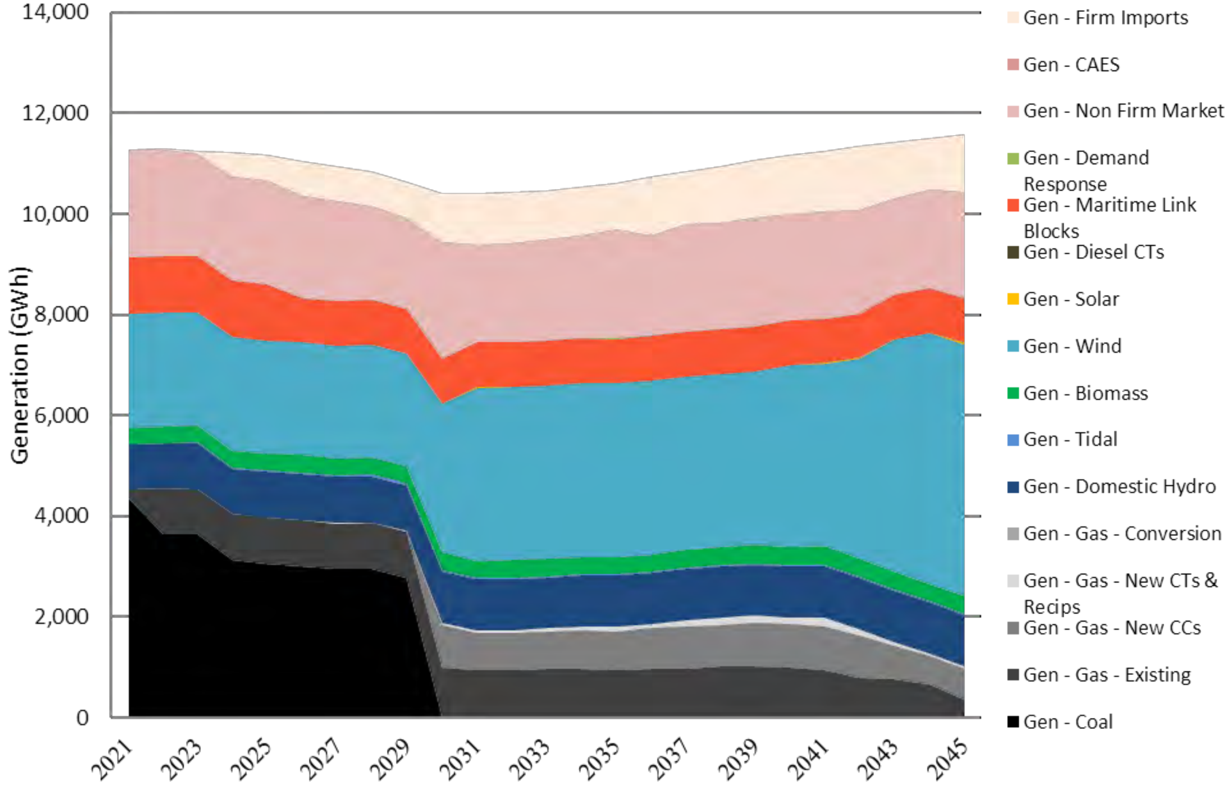


	$MM	Scenario Notes
25-yr NPVRR	$13,477	• Full Regional Interconnection built in 2030 enables firm imports and wind integration • Local mitigations (4hr batteries and synchronous condensers) enable additional wind builds to 2045
25-yr NPVRR w/ EE	$17,619	
10-yr NPVRR	$7,505	

3.2B

HIGH ELEC. / MAX DSM / ACCEL. ZERO 2045 / DISTRIBUTED RESOURCES

Energy Balance



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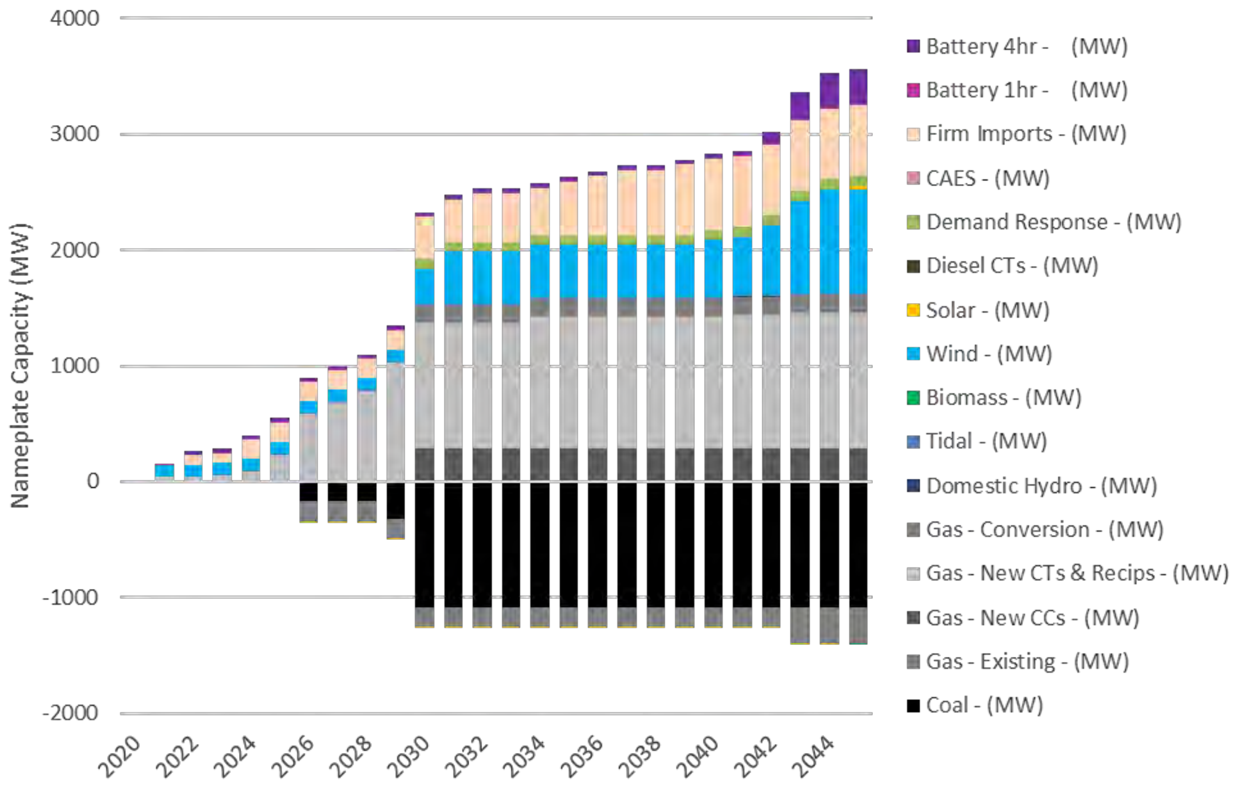
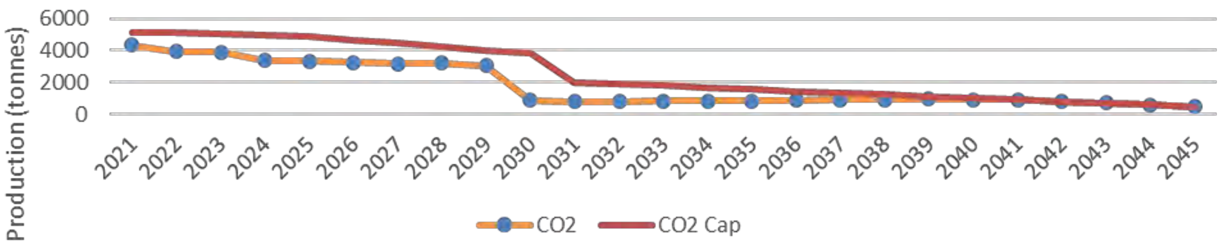


CO_2 Emissions



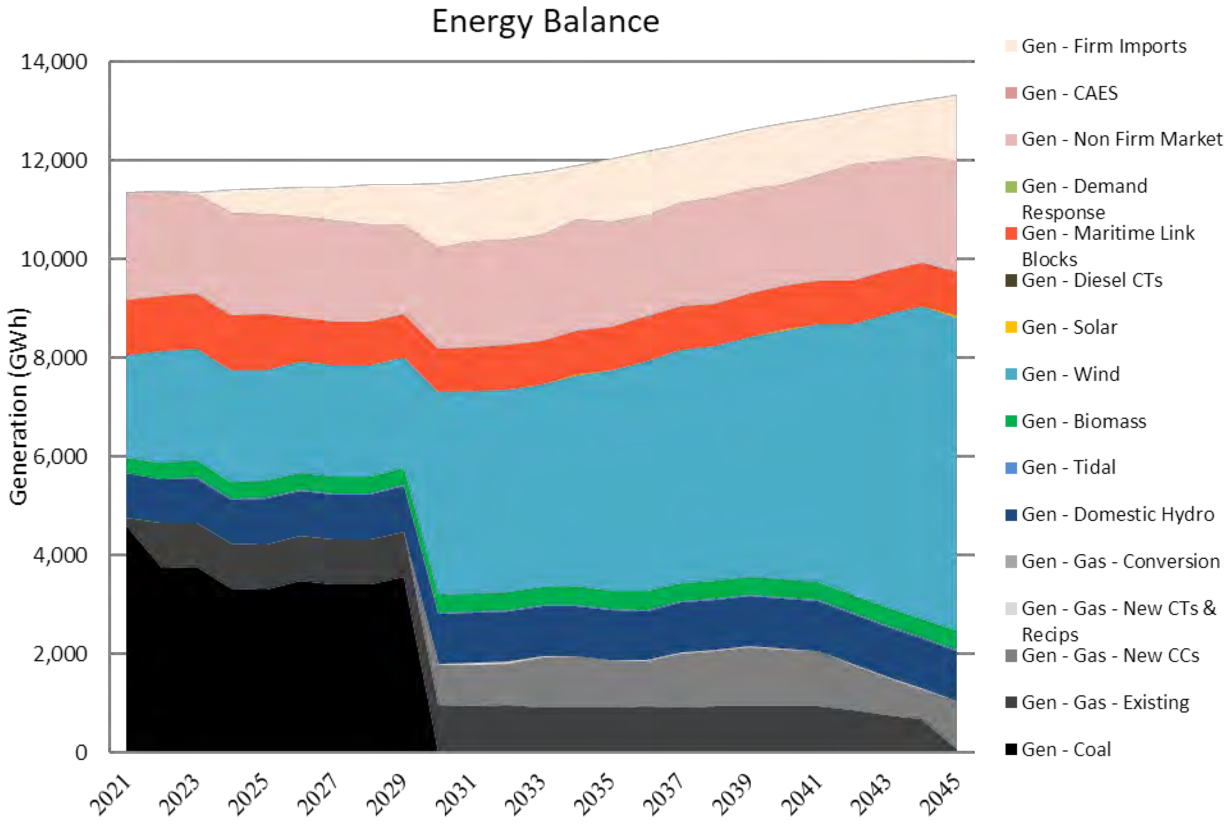
	$MM
25-yr NPVRR	$15,015
25-yr NPVRR w/ EE	$19,365
10-yr NPVRR	$8,436

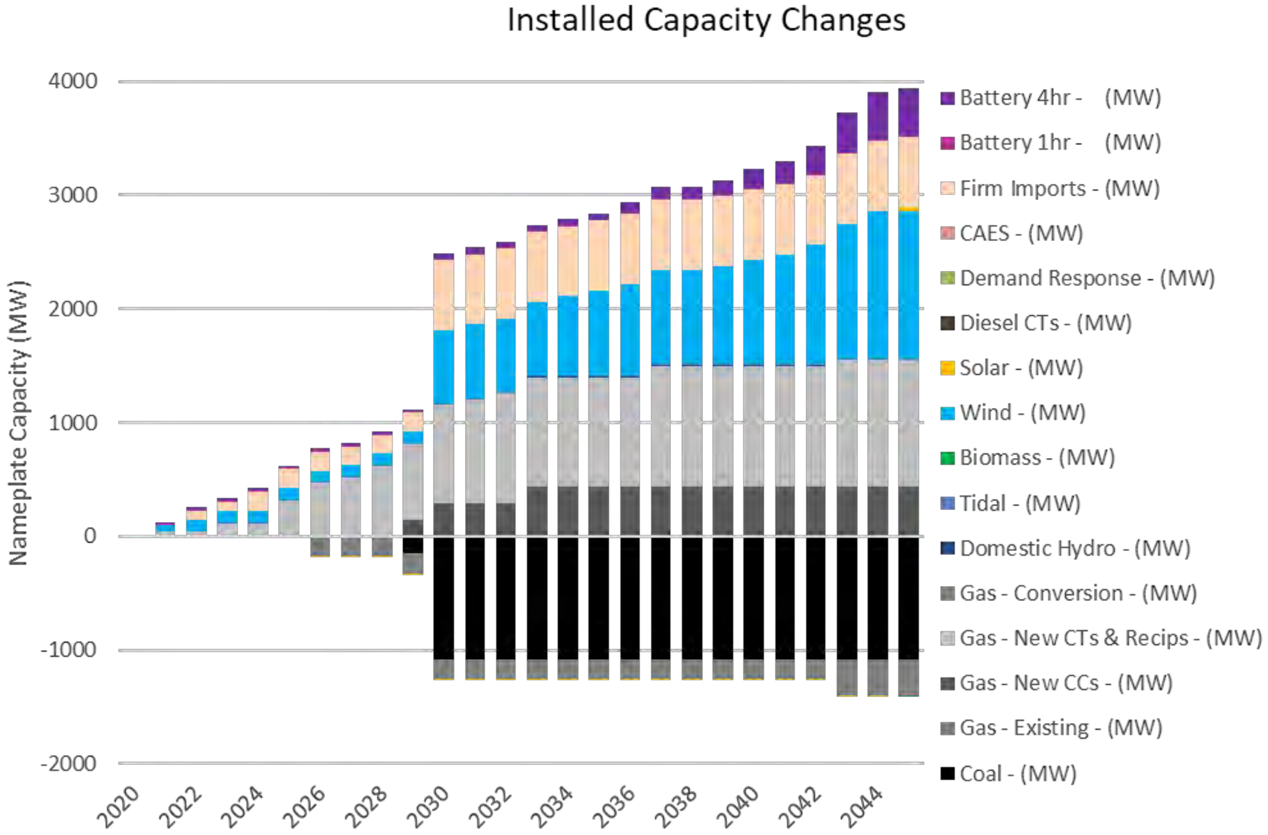
Scenario Notes

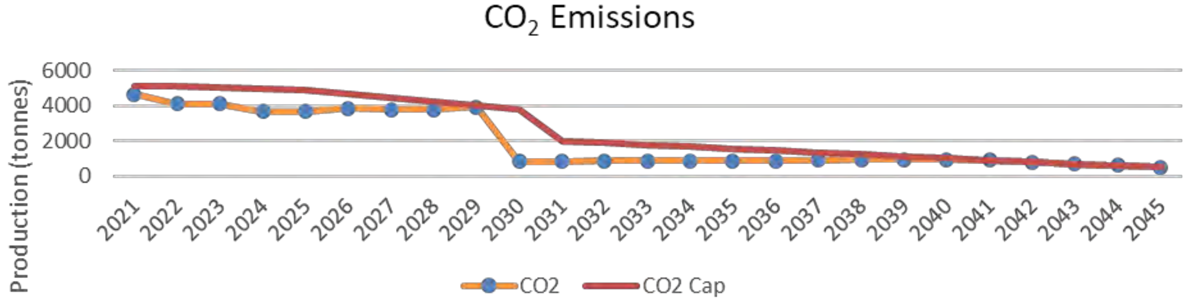
- Full Regional Interconnection built in 2030 enables firm imports and wind integration
- DR selected starting in 2030
- DER is modeled as a load reduction; cost of DER resources not included in NPV calculations ($1.6B-$2.5B)

3.2C

HIGH ELEC. / MAX DSM / ACCEL. ZERO 2045 / REGIONAL INTEGRATION



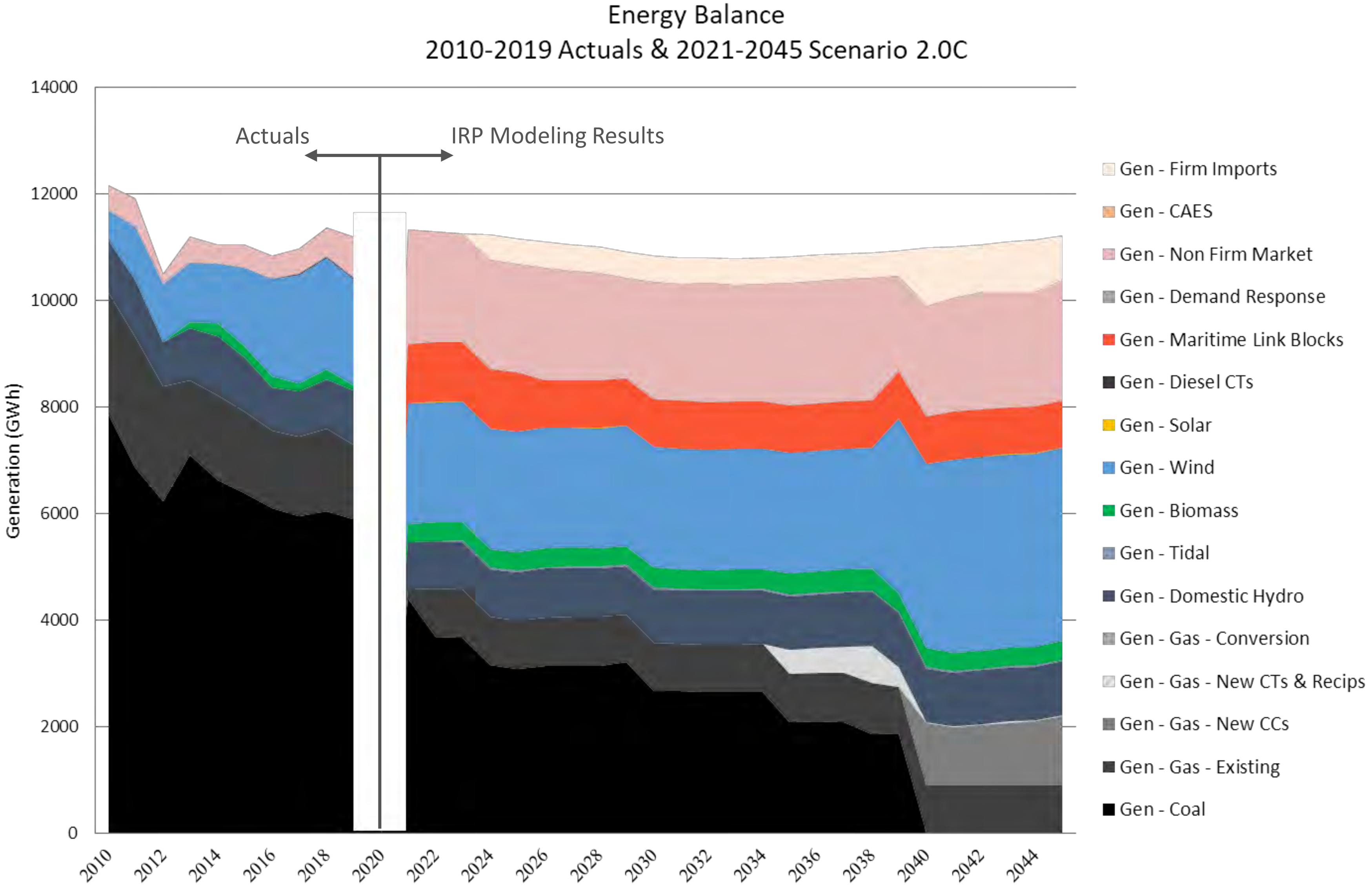




	$MM	Scenario Notes
25-yr NPVRR	$15,857	• Gas CT builds and incremental firm imports support early load growth • Full Regional Interconnection built in 2030 enables firm imports and wind integration; local mitigation allows additional wind builds to 2045
25-yr NPVRR w/ EE	$20,790	
10-yr NPVRR	$8,704	

IRP IN THE CONTEXT OF ONGOING GENERATION TRANSFORMATION

- The graph to the right includes actual annual generation for 2010-2019 and forecast generation from PLEXOS LT for 2021-2045 (2020 is left blank)
- This chart highlights the increasing penetration of renewables on the Nova Scotia system since 2010 as well as the anticipated changes due to the availability of energy over the Maritime Link beginning in 2021



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NS POWER 2020 IRP
MODELING RESULTS WORKSHOP

JULY 9, 2020

Nova Scotia POWER An Emera Company

AGENDA

ASSUMPTION & KEY SCENARIO UPDATES

INITIAL PORTFOLIO STUDY RESULTS

- COMPARISONS & INSIGHTS
- SCENARIO RESULTS

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PROCESS UPDATE & WORK COMPLETED

UARB NSP Pre-IRP Deliverables

- Capacity Study
- Supply Options Study
- Demand Response Assumptions
- Stability Study

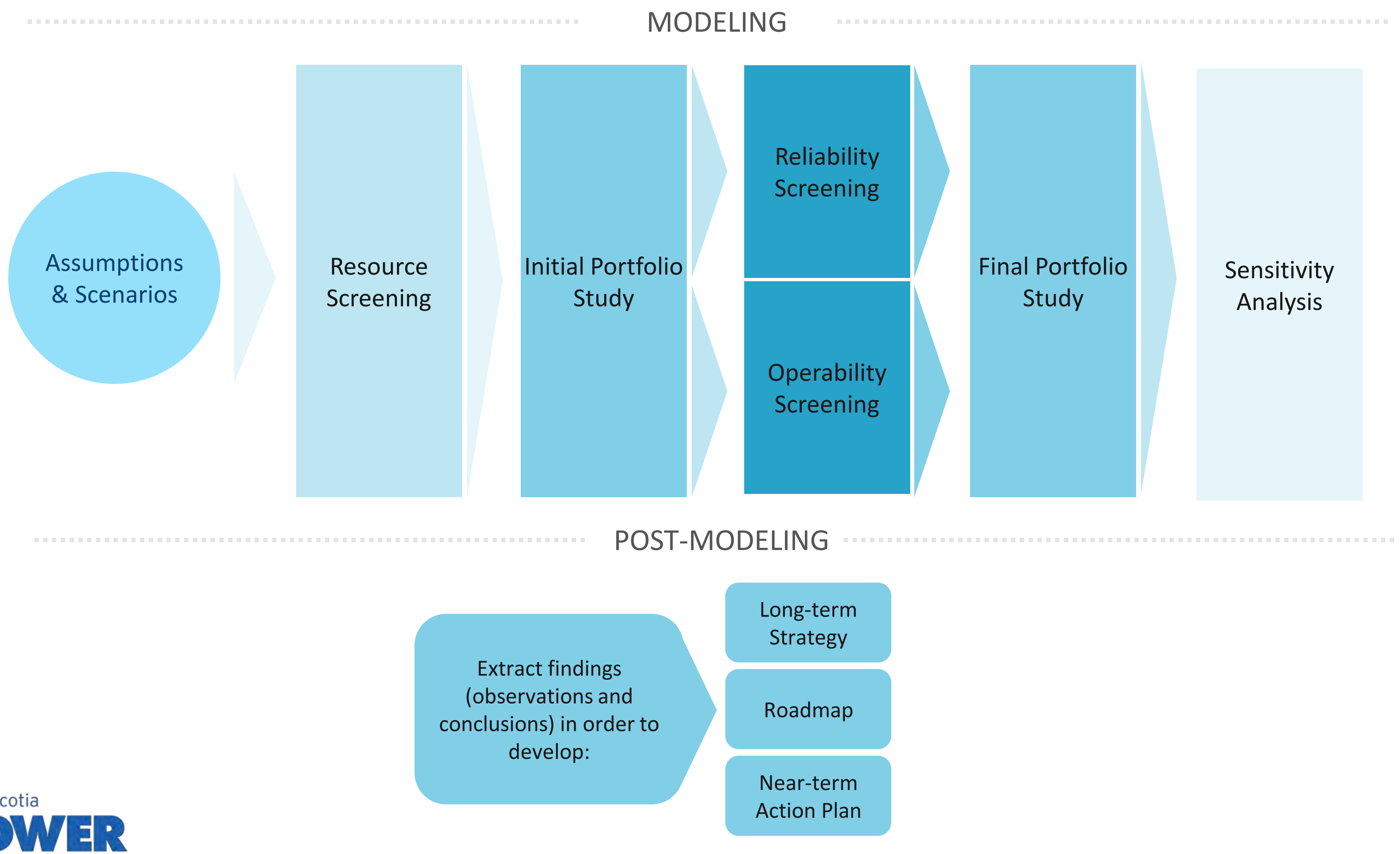
Core IRP Process resulting in Final Report

Sept 2020

- Terms of Reference
- Scenario Development
- Modeling Plan
- Assumptions
- Modeling
- Analysis/Conclusions
- Report, Roadmap, & Action Plan

Previously completed
Completed since last update
In Progress

IRP MODELING PLAN



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ASSUMPTION & KEY SCENARIO UPDATES

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ASSUMPTIONS & KEY SCENARIO UPDATES

Note: NS Power reviewed slides 5-9 from Modeling Results release 2020-06-26

QUESTIONS & DISCUSSION ASSUMPTIONS & SCENARIOS

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INITIAL PORTFOLIO STUDY COMPARISONS & INSIGHTS

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RESOURCE SCREENING – DIESEL COMBUSTION TURBINES

- Screening of existing Diesel CTs was conducted by E3 using RESOLVE
- During screening the model was free to re-optimize the resource portfolio and to select any available supply options to replace the CT capacity (e.g. new gas CTs/CCGTs, batteries, firm imports, etc.)
- Analysis was completed on two key scenarios (1.0A and 2.1C)
- Screening results showed that sustaining the existing diesel CT fleet is economic vs. replacement alternatives; Diesel CTs will be assumed “in” in the Initial Portfolio Study runs
- This result was robust to testing with a lower Planning Reserve Margin (PRM) and to testing a single unit retirement

RESOURCE SCREENING – HYDRO

- Screening of the existing hydro systems was conducted by E3 using RESOLVE
- During screening the model was free to re-optimize the resource portfolio and to select any available supply options to replace the hydro capacity and energy (e.g. new gas CTs/CCGTs, batteries, firm and non-firm imports, wind, etc.)
- Analysis was completed on two key scenarios (1.0A and 2.1C)
- Sustaining and Decommissioning costs were taken from NS Power's recent Hydro Asset Study
- Wreck Cove and Mersey were modeled individually and remaining systems were modeled in two groups with similar operating characteristics
- Screening results showed that sustaining the existing hydro systems is economic vs. replacement alternatives; existing hydro will be assumed "in" in the Initial Portfolio Study runs
- NS Power will conduct a capacity expansion run in PLEXOS with the Mersey hydro system retired

INITIAL PORTFOLIO STUDY NOTES

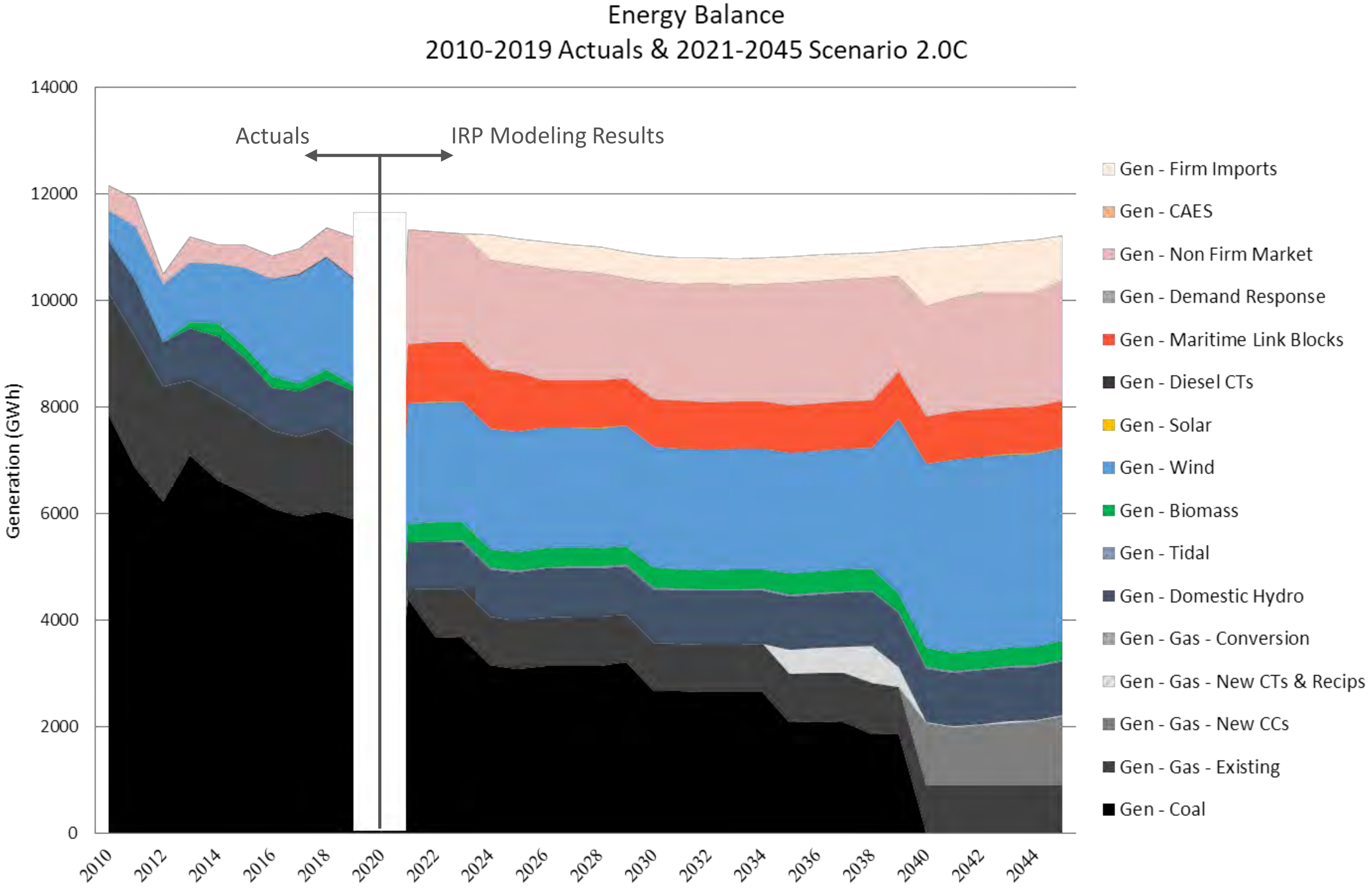
- The following slides provide the Initial Portfolio Study results from PLEXOS LT for the key scenarios as well for select sensitivities (full capacity expansion runs)

- The section includes several summary comparison slides as well as detailed outputs of each scenario including energy mix, nameplate capacity installation, emissions compliance, several metrics of NPV of partial revenue requirement, and scenario notes

- NPVs presented in these results are partial revenue requirements that consider modeled costs (i.e. production, O&M, abatement, sustaining capital, and capital investment) and costs considered outside of the long-term model optimization (i.e. energy efficiency costs)

IRP IN THE CONTEXT OF ONGOING GENERATION TRANSFORMATION

- The graph to the right includes actual annual generation for 2010-2019 and forecast generation from PLEXOS LT for 2021-2045 (2020 is left blank)
- This chart highlights the increasing penetration of renewables on the Nova Scotia system since 2010 as well as the anticipated changes due to the availability of energy over the Maritime Link beginning in 2021



KEY MODELING SCENARIOS

Scenario	Features	Load Drivers	Coal Retires	Resource Strategies Tested	Key Sensitivities
1.0 **Comparator**	Equivalency GHG	Low Elec. Base DSM	2040	A - Current Landscape C – Regional Integration	
2.0 **Net Zero 2050** **Low Electrification**	GHG targets decline linearly from 2030 to 0.5Mt in 2050	Low Elec. Base DSM	2040	A - Current Landscape C - Regional Integration	• DSM Levels
2.1 **Net Zero 2050** **Mid Electrification**	GHG targets decline linearly from 2030 to 0.5Mt in 2050	Mid Elec. Base DSM	2040	A - Current Landscape B - Distributed Resources C - Regional Integration	• DSM Levels • No New Emitting • Target Case for Sensitivity Evaluation
2.2 **Net Zero 2050** **High Electrification**	GHG targets decline linearly from 2030 to 0.5Mt in 2050	High Elec. Max DSM	2040	A - Current Landscape C - Regional Integration	• DSM Levels • No New Emitting
3.1 **Accelerated Net Zero 2045 Mid Electrification**	GHG targets decline from 2025 to 0.5Mt in 2045; path to Absolute Zero 2050	Mid Elec. Base DSM	2030	B - Distributed Resources C - Regional Integration	• DSM Levels • No New Emitting • Target Case for Sensitivity Evaluation
3.2 **Accelerated Net Zero 2045 High Electrification**	GHG targets decline from 2025 to 0.5Mt in 2045; path to Absolute Zero 2050	High Elec. Max DSM	2030	B - Distributed Resources C - Regional Integration	• DSM Levels

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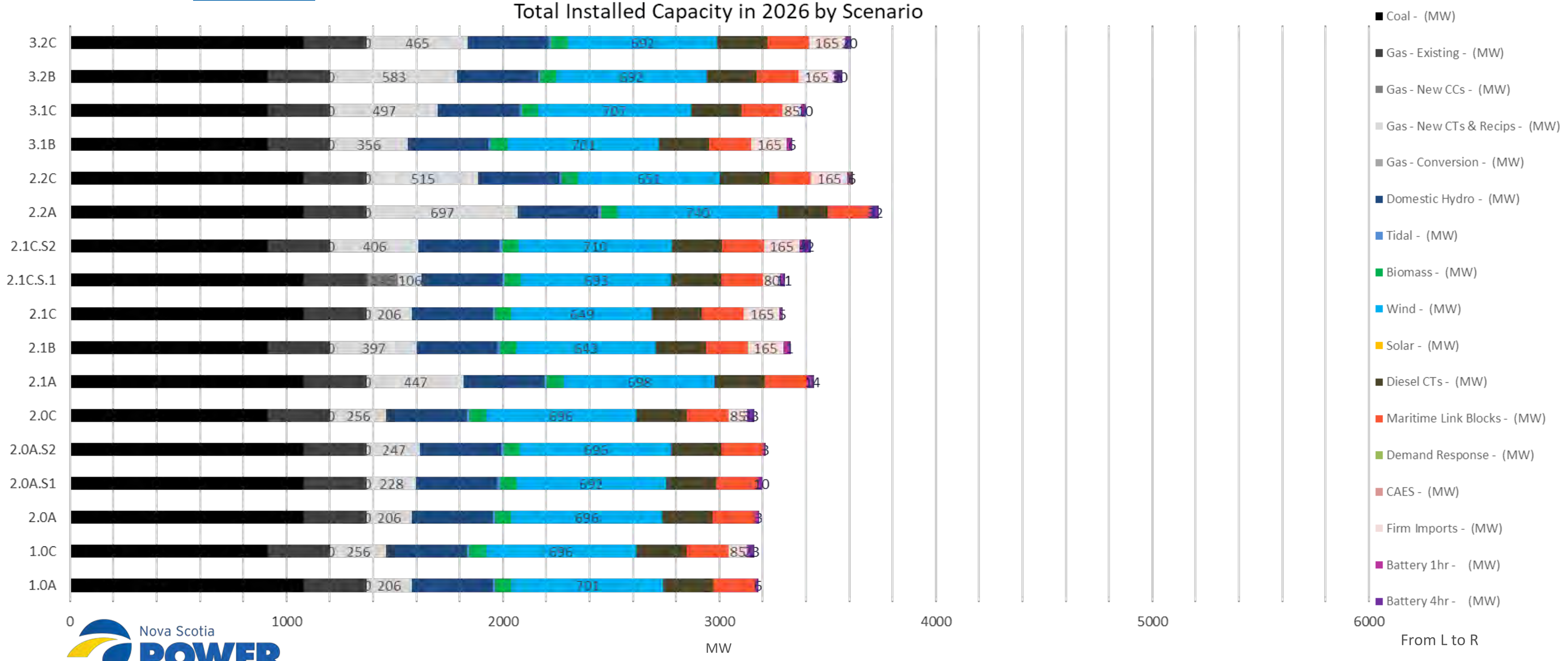
NEAR TERM RESOURCE PORTFOLIOS (2026)



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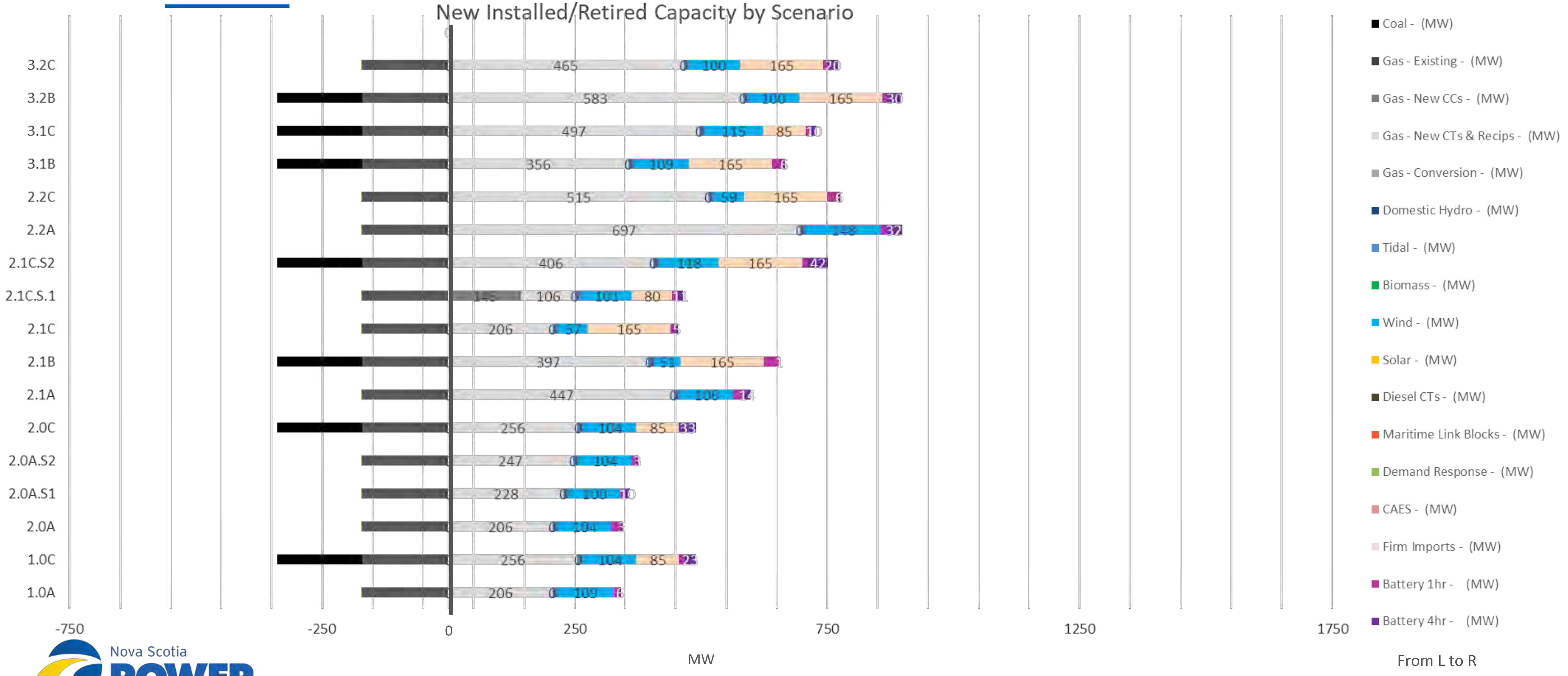
NEAR TERM RESOURCE CHANGES (2026)



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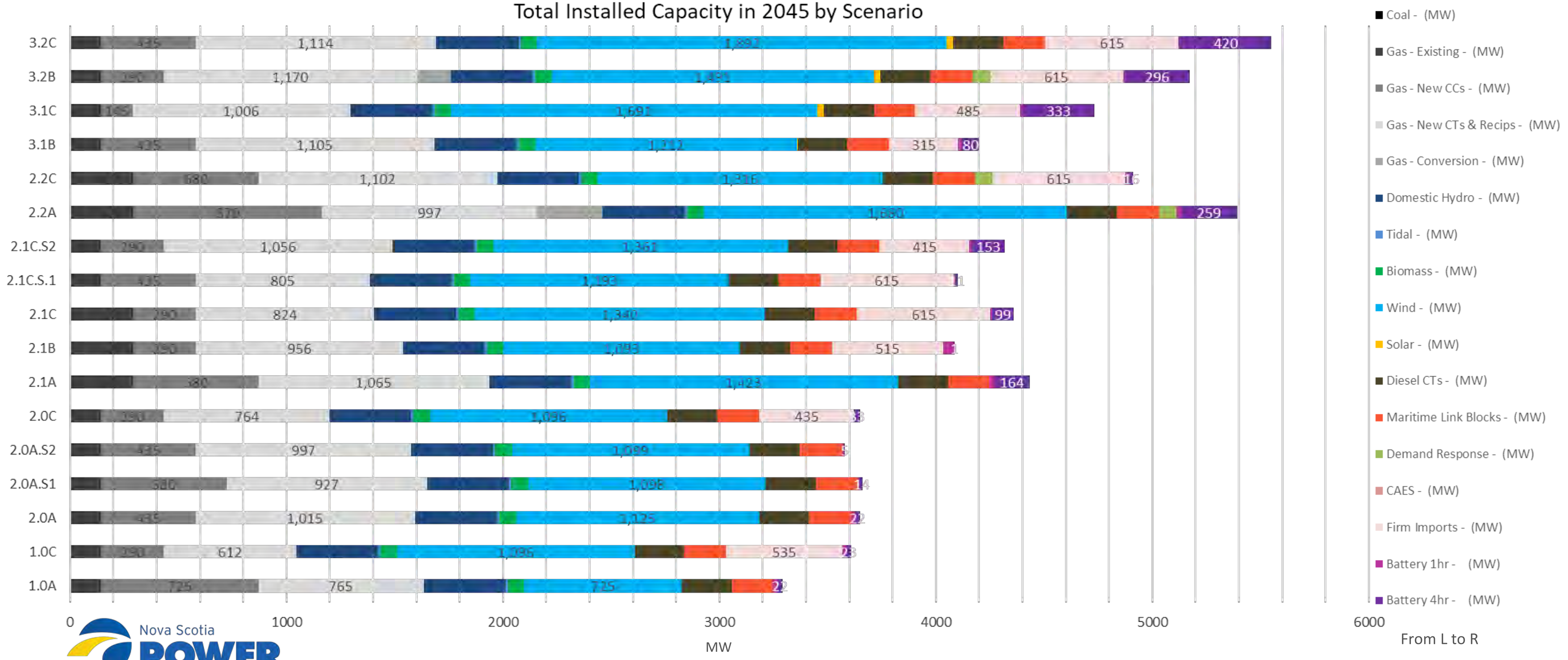
LONG TERM RESOURCE PORTFOLIOS (2045)



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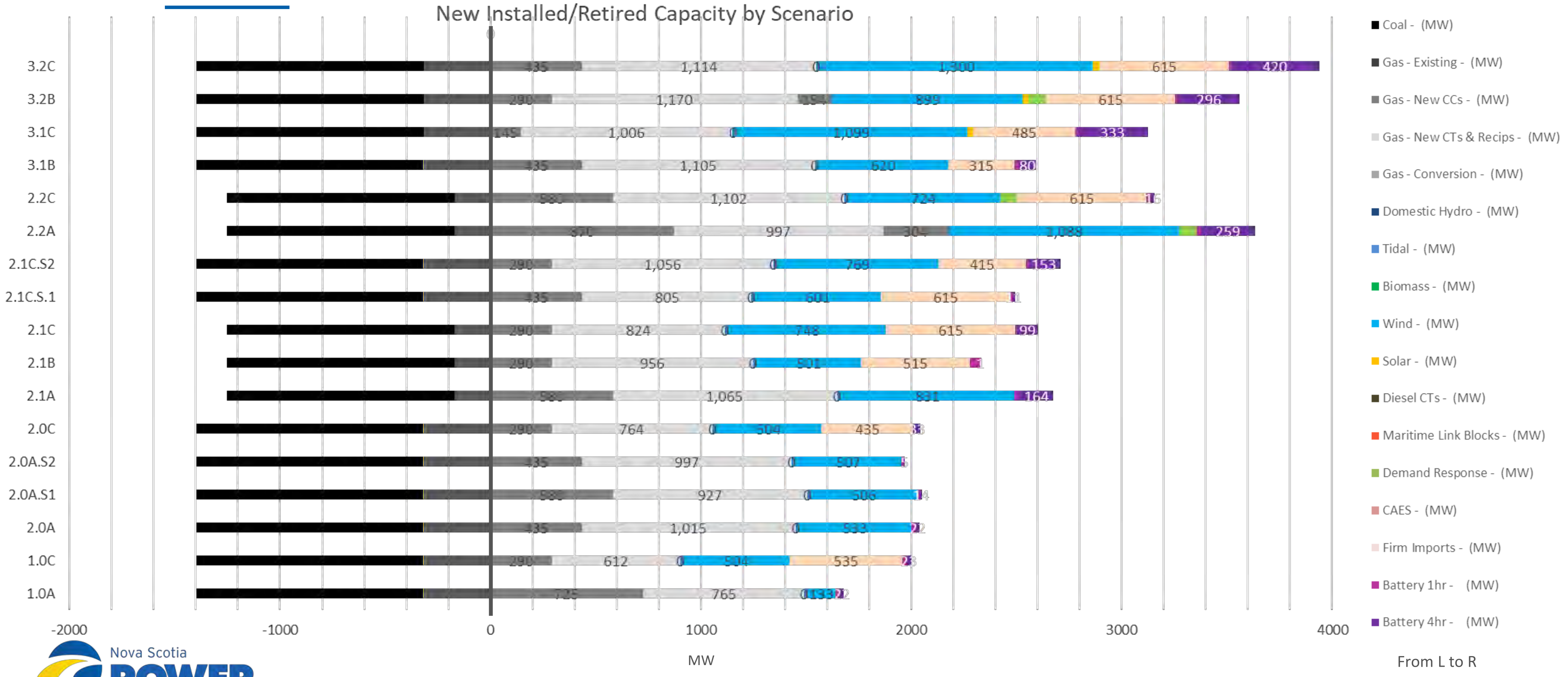
LONG TERM RESOURCE CHANGES (2045)



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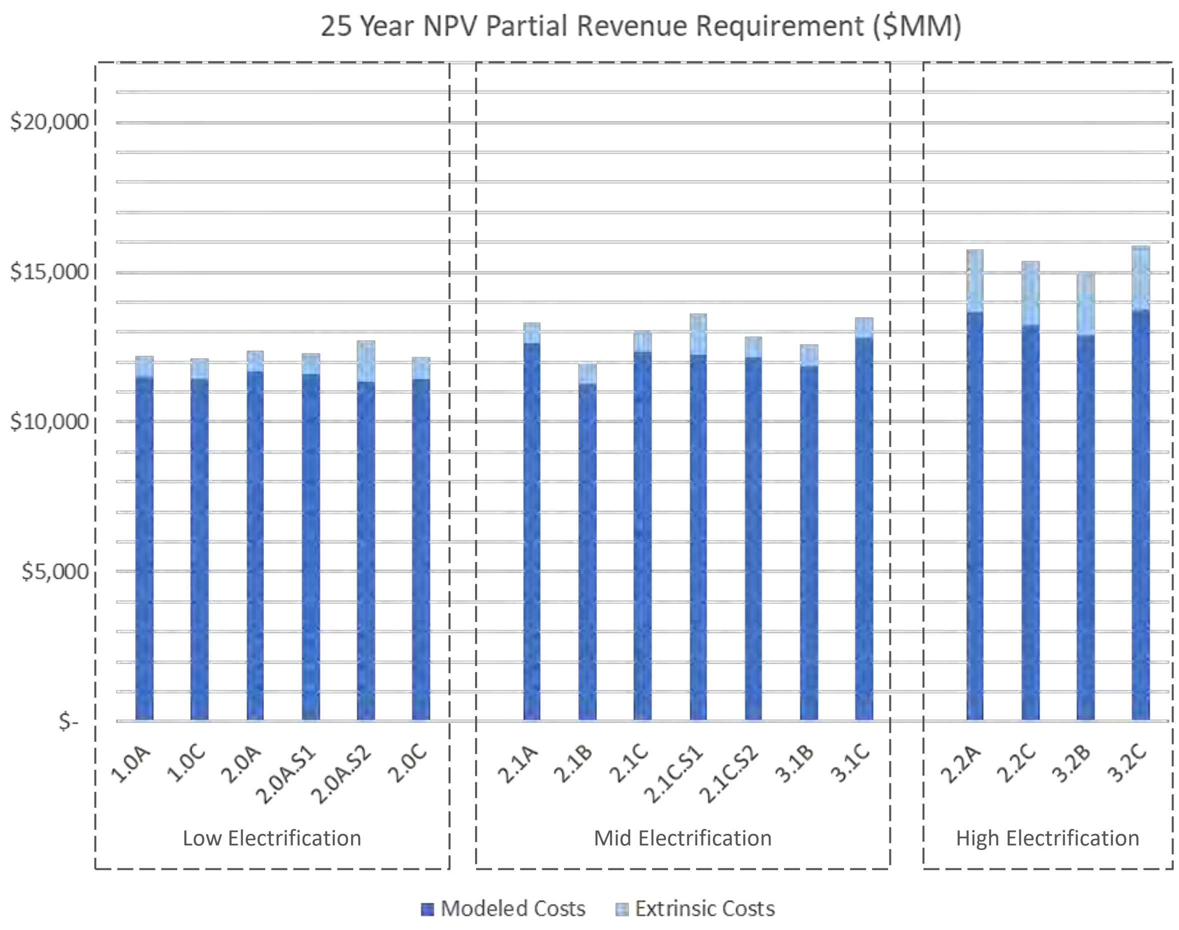
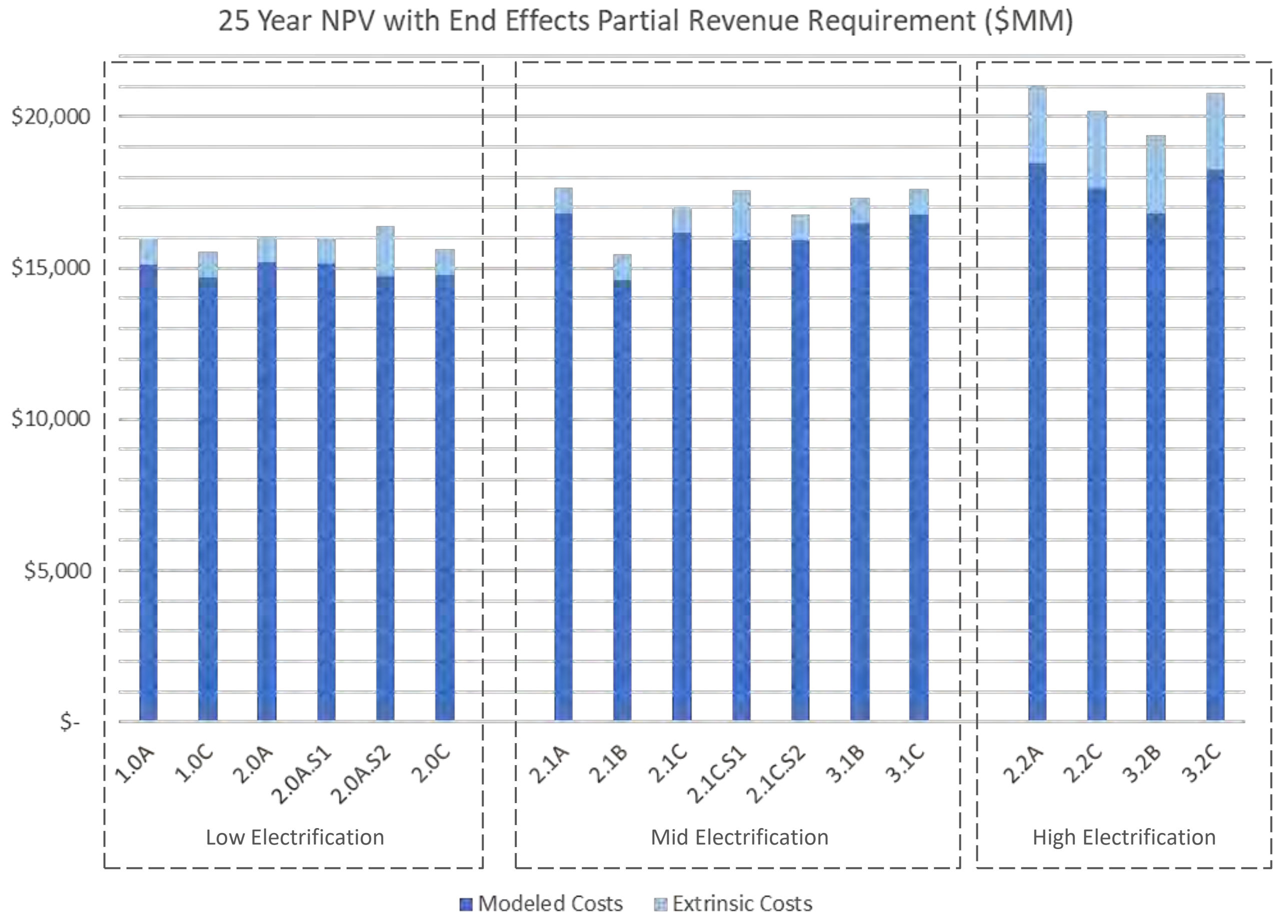
NPV PARTIAL REVENUE REQUIREMENT COMPARISON





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Due to differences in forecast system load affecting production costs, resource plan partial revenue requirement results should not be compared across electrification scenarios

QUESTIONS & DISCUSSION
INITIAL PORTFOLIO COMPARISONS

REGIONAL INTERCONNECTION

- Reliability Tie enabling wind integration was selected in all scenarios other than 1.0A Comparator
  - Could occur in advance of a Regional Interconnection or simultaneously (see table)
  - Available under all scenarios
- Incremental firm imports are selected when offered via a Regional Interconnection
  - Available under all "B" and "C" scenarios
- Both firm and non-firm imports play a significant role to meeting energy requirements in all scenarios examined

Scenario	Reliability Tie Selected	Regional Interconnection Selected
3.2C	2030	2030
3.2B	2029	2030
3.1C	2030	2030
3.1B	2034	2045
2.2C	2034	2039
2.2A	2034	Not Offered
2.1C.S2	2029	2040
S.1C.S1	2038	2040
2.1C	2037	2038
2.1B	2040	2040
2.1A	2031	Not Offered
2.0C	2039	2039
2.0A.S2	2036	Not Offered
2.0A.S1	2029	Not Offered
2.0A	2030	Not Offered
1.0C	2039	2039
1.0A	X	Not Offered

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RENEWABLE GENERATION

- Onshore wind energy selected in all scenarios as the most economic type of domestic renewable generation
- Construction of a Reliability Tie (new 345kV line from Onslow, NS to Salisbury, NB) is preferentially selected as a method of wind integration
  - This option was offered to the model in all scenarios, including “A” (Current Landscape)
- Domestic integration (batteries + synchronous condensers) was selected when the limits of what could be integrated using the Reliability Tie were reached
- The combination of Reliability Tie integration and domestic integration was not examined in the PSC reliability study as part of the Pre-IRP work but was selected in several scenarios after 2030; this will need to be studied further

Available Wind (Nameplate MW)	No Integration Requirements*	Reliability Tie*	Domestic Integration* (Batteries + Sync. Condenser)	Total Available
Low Electrification	100	400	400	900
Mid Electrification	100	500	500	1,100
High Electrification	100	600	600	1,300

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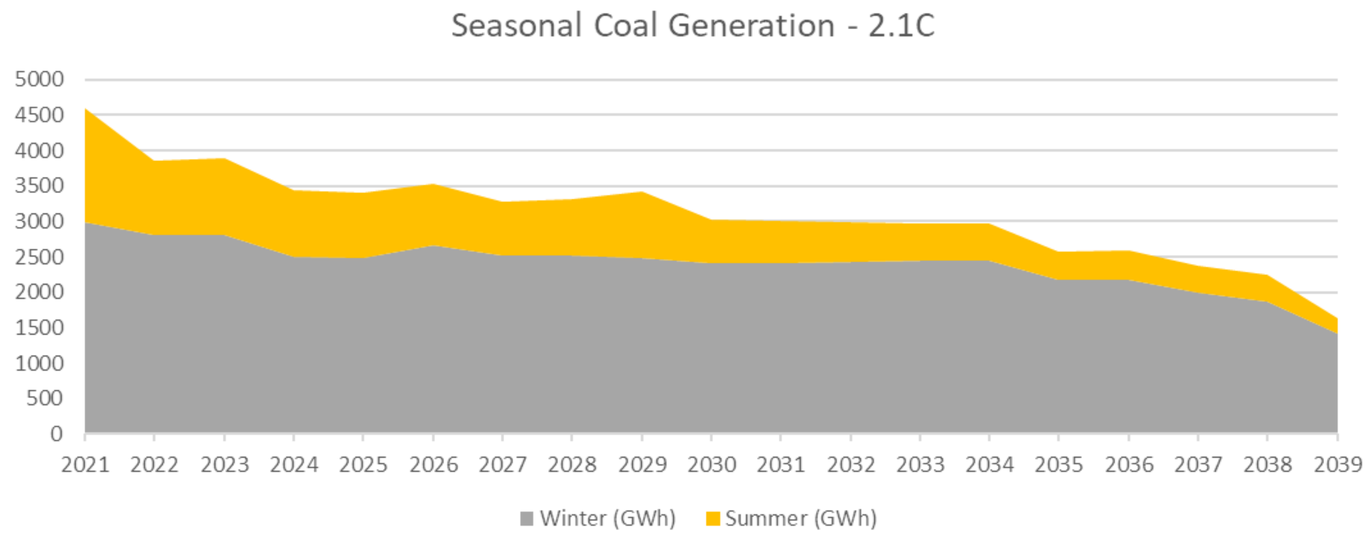
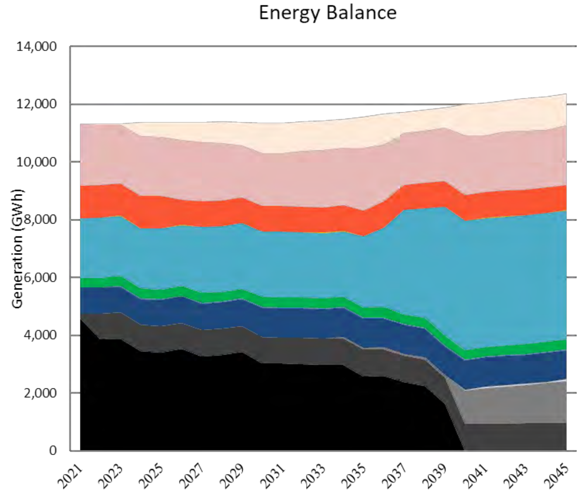
**Local Integration requirements would be determined via specific System Impact Studies*

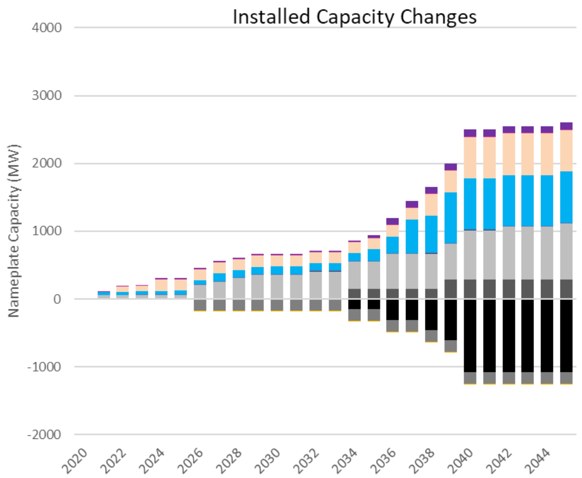
COAL UNITS

- Annual generation declines with emissions limits through the planning horizon
- Coal generation increasingly shifts to winter months (November through March) later in the planning horizon



2.1C

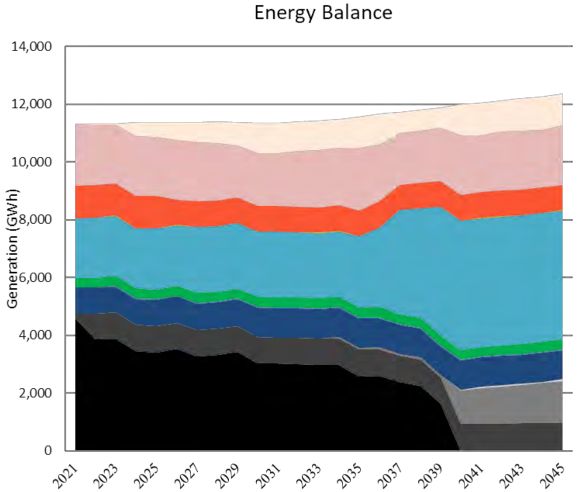


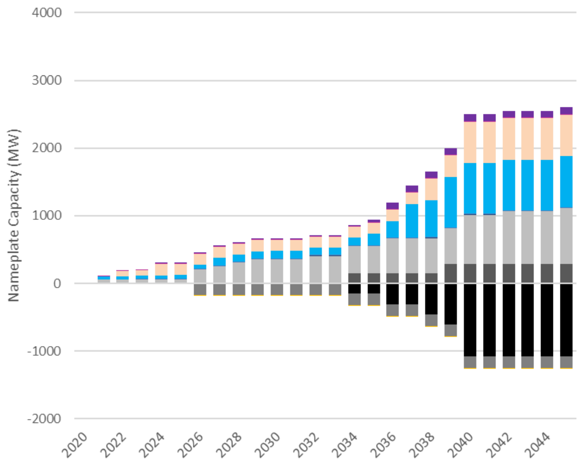


GAS UNITS

- New gas units selected are predominately combustion turbines
- At least one combined cycle unit was selected economically in each scenario (late 2020s-early 2030s)
- For all new gas units, the expansion model selected an economic gas supply option:
  - Combined Cycle units generally select the baseload gas option (with fixed annual transportation cost)
  - Combustion Turbine units generally select the peaking gas option
- Coal to Gas conversion was selected economically in some scenarios
- Small early build of CT / Reciprocating resources resolves existing PRM deficiency (~30MW)
  - Consistent with NS Power's 2020 10-year system outlook

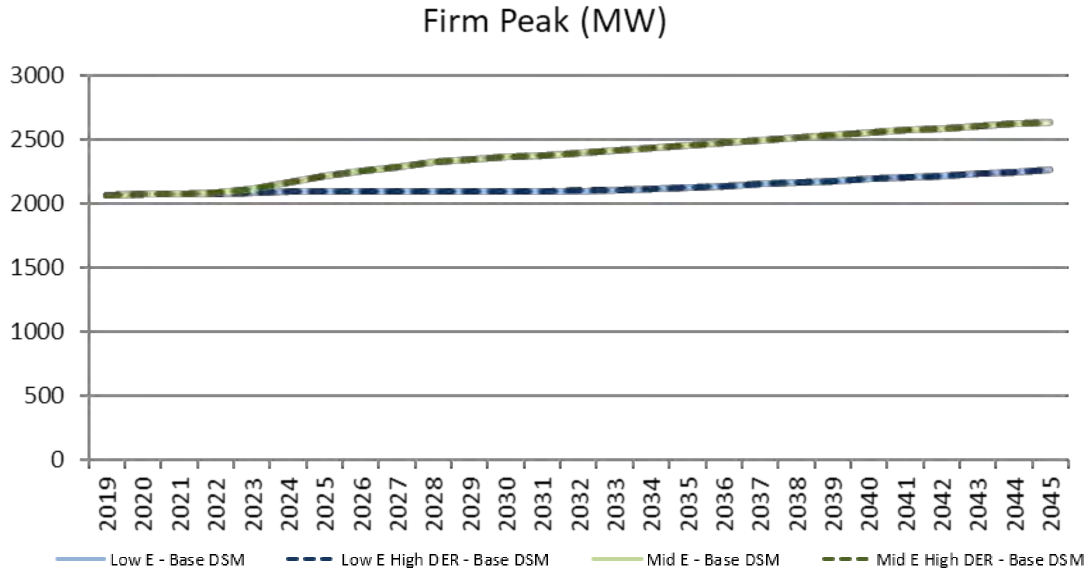
2.1C

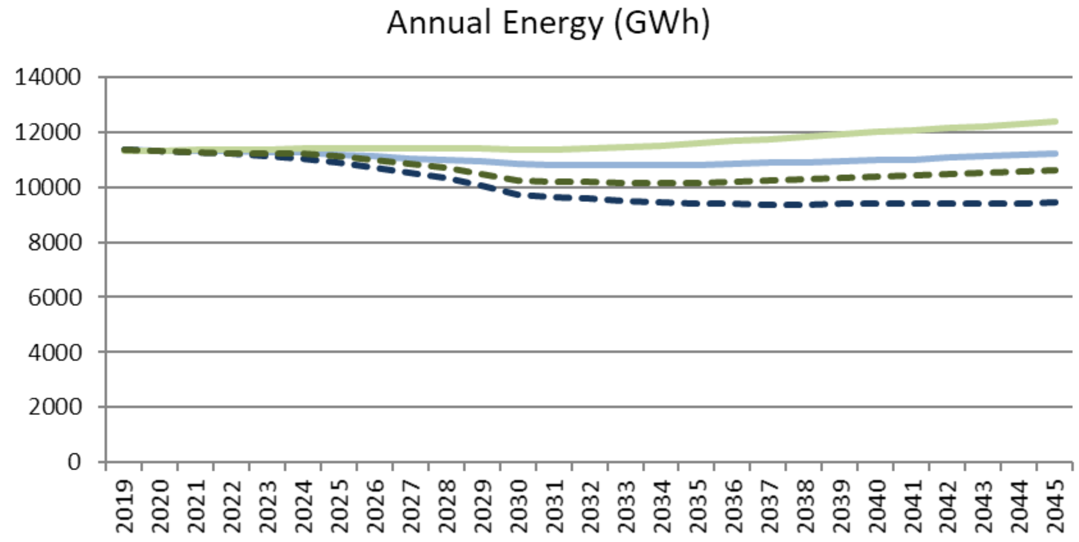




DISTRIBUTED ENERGY RESOURCES

- Distributed Energy Resources (DERs) were included in "B" scenarios and modeled as rooftop solar installations
- Scenarios with DER resources had lower annual energy volumes but the same requirement for firm peak capacity
  - In the resource plans, this leads to lower quantities of wind being selected and lower gas and import generation
  - Resources providing firm capacity (firm imports, gas CTs/CCGTs, batteries) are selected in similar aggregate amounts to meet Planning Reserve Margin requirements
- The cost of DER resources was not included in model NPV calculations; total cost of DERs using IRP assumptions was $1.6B-$2.5B on a 25-year NPV basis
  - In all cases, adding the low DER cost estimate ($1.6B) to the 25-year NPV of the "B" case makes it more expensive than the least cost comparable "A" or "C" scenario





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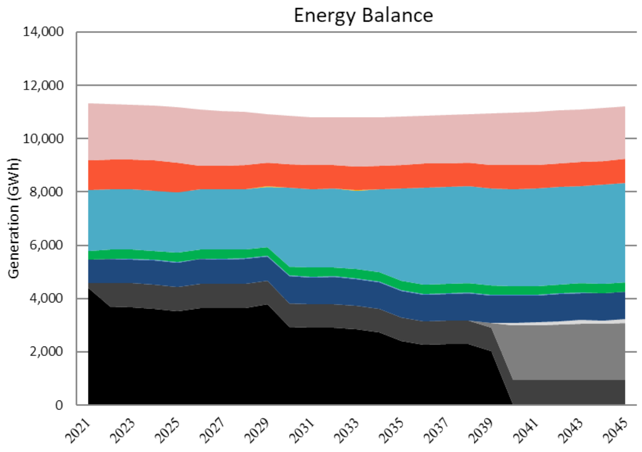
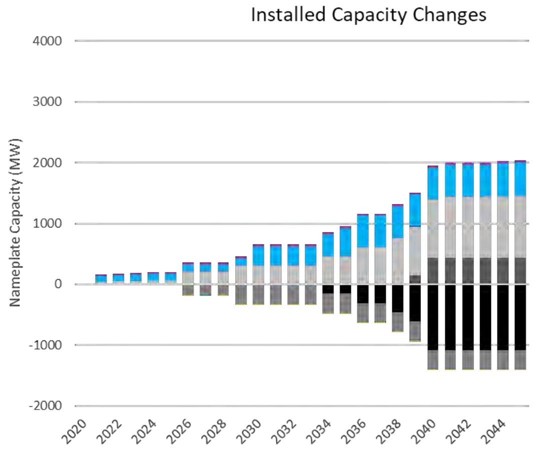
DECOUPLING OF FIRM CAPACITY & ENERGY SUPPLY

- All scenarios show a trend toward decoupling of sources of Firm Capacity and Energy
  - Capacity is generally provided by Combustion Turbines, Firm Imports, Batteries, CCGT
  - Energy sourced from Non-Firm Markets, Wind, CCGT

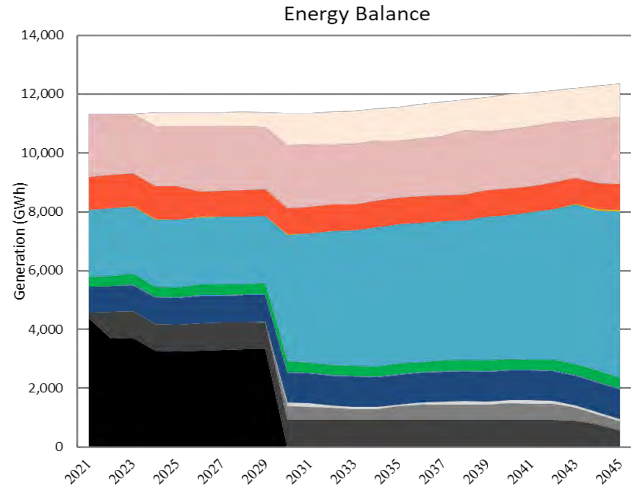
- This becomes more pronounced later in the planning horizon, and under higher load or lower carbon scenarios

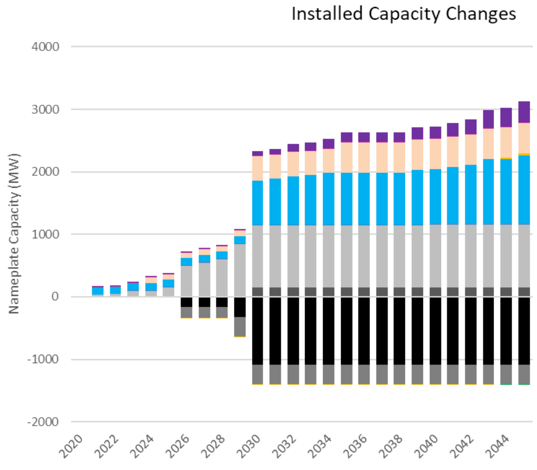
2.0A





3.1C





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QUESTIONS & DISCUSSION
INITIAL PORTFOLIO INSIGHTS

Nova Scotia POWER An Emera Company

NEXT STEPS

- Stakeholder Comments on Modeling Results are invited (requested by July 17 – next Friday)
- Draft Findings, Roadmap and Action Plan – July 29

- Ongoing:
  - Completion of sensitivities
  - Operability studies (PLEXOS MT/ST)
  - Reliability studies (RECAP)

QUESTIONS & DISCUSSION
GENERAL

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Resource Insight Inc.

MEMORANDUM

To: Linda Lefler, Senior Project Manager, Regulatory Affairs
Nova Scotia Power

From: John D. Wilson and Paul Chernick

Date: July 17, 2020

Subject: Comments on Initial Modeling Results

Thank you for a very informative report and presentation on July 9th. We appreciate the opportunity to comment on the results so far. Our comments below are divided into three sections. First, we request some further documentation or potentially modification to methods. Second, we suggest some enhancements to the scenarios or sensitivities to address emerging findings. Third, we make some observations regarding the initial results.

At a high level, the analysis so far suggests that the IRP will set up some significant decisions for NS Power and the Board, but that additional work may be needed to reach those decisions. Those key pre-2030 decisions appear to be whether to retire some coal units, whether to build more than 100 MW of wind, whether to plan and build the reliability tie, and whether to start the inter-provincial process of siting and planning the reliability tie and regional interconnection.

We also recognize that there are many other significant decisions that the IRP may inform, including the level of DSM investment, approaches to distributed resources, life extension for the Mersey hydro system, and planning for electrification.

None of these decisions are so time-sensitive that NS Power must be conclude its work within the current schedule for submitting a final IRP report to the Board. We strongly encourage NS Power to take the time necessary to explore these key issues thoroughly, whether by seeking a delay in the final IRP or by supplemental analyses and consultation following that filing.

I. Methods

Reserve margin: During the discussion of the new ELCC factors (slide 7), NS Power explained that instead of a planning reserve margin of 21% of installed capacity (with downward adjustments to the effective capacity for wind and some other resources), NS Power was imposing a minimum reserve of 9% in ELCC terms. Our understanding was that one MW of ELCC would support one MW of firm load. We are unable to locate any documentation for the conclusion that reliable supply requires capacity with a cumulative ELCC of 109% of peak load. We suggest that NS Power should provide that derivation and identify what drives the need for an ELCC reserve margin of 9%.

End effects: During the explanation of the end effects, we learned that NS Power was calculating end effects as the present value of 25 years of the 2045 revenue requirements. Those end effects are included in the objective function for the model optimization. The end effects are quite large and vary significantly by portfolio. For example, in the portfolios that include medium electrification and base DSM, the end effects range from $3.5 to $4.7 billion.

We are concerned that this end-effects calculation may significantly distort the differences among cases. For example, the regional interconnection has a cost of $1.7 billion (Assumptions Set, p. 74) and its various portfolios add the interconnection between 2030 and 2045. The 2045 net plant (and hence the annual revenue requirements) of the connection will be much higher if it is built in 2045 than if it is built in 2030. The 2045 revenue requirements of the 2030 connection would be lower than those of the 2045 tie because (1) the 2030 tie would be less expensive in nominal dollars and (2) it would be substantially depreciated by 2045. It seems to us that holding post-2045 revenue requirements at the 2045 level for 25 years overstates the end-effects costs of the plans with large capital investments near the end of the modeling period, compared to plans dominated by higher fuel or other expenses.

We would like to see an analysis of whether the differences in end effects among the initial IRP results reasonably reflect differences in costs between options. If the variation in end effects among cases appears to be correct, but the magnitude is overstated, NS Power should consider shifting to a shorter end effect period (e.g., 10 or 15 years), or eliminating it altogether.

Distributed resource costs: As we commented in February, we are concerned by NS Power's decision to ignore the costs for the distributed energy resources in cases 2.1B and 3.1B. Determining the value to customers of DERs (especially storage, which adds resiliency) is difficult, so it would be hard to estimate the net cost of the DERs. We suggest that NS Power be careful to indicate each time it presents costs for these cases to indicate that they do not include any allowance for BTM costs.

Those BTM costs do not fit neatly into the NPVRR calculation, since they do not represent utility revenue requirements. Nor should the full cost of DERs comparable to the utility costs, since DERs (especially paired solar and storage) provide additional benefits, particularly resiliency. If NS Power decides to incorporate some BTM costs into its reported cost metric, we suggest using a modest placeholder value. If Plexos produces marginal hourly energy costs, those could be used for the assumed DER load shape. Otherwise, NS Power might use some appropriate forecast estimate (average fuel cost, monthly marginal energy cost).

Bill metric: As the discussion with the stakeholders demonstrated, it is very difficult to compare plans with divergent load forecasts. NPVRR may be low for cases with high DSM and high for cases with lots of electrification, since the NPVRR does not reflect the benefit of fossil fuels avoided by electrification. The other economic metric in the interim results, the partial generation cost per MWh, does not provide much information about rate effects, since it does not reflect the spreading of sunk generation costs and all T&D and administrative costs over fewer MWh of sales with high DSM and more sales with high electrification.

As we suggested previously, a typical bill metric might be more meaningful than the partial cost per kWh. A typical bill metric should not include end effects. Clearly, the report will need to explain that the estimation of residual revenue requirements and any class cost allocation is drastically simplified from what might be presented in a rate case but is useful in terms of comparing portfolios to each other.

T&D costs: NS Power staff explained that the projection of revenue requirements excludes T&D costs, which would be affected by electrification and DSM. Please consider providing a rough estimate of the potential sensitivity of T&D costs to these scenarios in the IRP report even if estimates cannot be provided by scenario.

Capital cost: In conjunction with our concerns about the end-effects treatment, we would like more detail on the manner in which the "revenue requirement profiles" for the "supply-side options that represent a capital investment" are computed in the objective function of the long-term Plexos model (2020 IRP: Financial Assumptions, March 11, 2020). In particular, we are interested in whether you use annual, nominally-levelized or real-levelized revenue requirements, and how income taxes are reflected in the revenue requirements computation, in addition to book depreciation and return (which we assume is included at the 6.62% pre-tax rate). A display of the assumed revenue requirements from a combustion turbine, a wind installation and the reliability tie would be useful to ensure that we understand what you are doing.

II. Scenarios & Sensitivities

We suggest four changes to the scenarios (or sensitivities) that will be run for the IRP.

Natural gas price capacity plan sensitivity: The most recent FAM report suggests that there has been a shift from coal to gas driven by changes in fuel price. We suggest that NS Power should develop a capacity expansion plan that explores what level (or duration) of fuel price changes might trigger an economic decision to implement early coal retirements or otherwise affect the capacity build.

No-transmission sensitivity: Since the reliability tie and regional interconnection were selected in every scenario (except the comparator case), we suggest that there should be a capacity plan with steam retirements but without the major transmission options, to identify what resources would be selected.

It may be appropriate to study the interactions of the natural gas price and transmission sensitivities with the wind analysis discussed below. We observed that early coal retirements occurred in the net zero 2050 scenarios with distributed resources or low wind costs, indicating that coal plants are at least somewhat sensitive to low-cost energy.

Hydro avoided costs sensitivity: We understand that there will be a specific "without Mersey" case. In addition, we suggest that NS Power develop three additional expansion plans in order to develop avoided costs for Wreck Cove and the two small hydro system groups. These avoided costs would them be used in future economic assessment model (EAM) runs during capital project filings. This could be completed after all other modeling is done, as we do not believe these model runs are likely to have any other significant role in the final IRP analysis.

III. Observations

HalifACT 2050 plan: The HalifACT 2050 plan was discussed on the stakeholder call. A participant pointed out that the IRP should provide adequate study of plans that would be consistent with the HalifACT 2050 plan, particularly the 2030 goals. NS Power indicated that its scenarios at least roughly covered the goals of HalifACT 2050.

Our understanding of the HalifACT 2050 plan is that it includes four main elements that are relevant to the IRP.

- CO_2 emissions target: roughly 0.5 $MtCO_2e$ by 2030[1]
- Rooftop and other HRM solar, with storage: 1,600 MW by 2030 (also 200 MW wind)[2]

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[1] Halifax Regional Municipality, *Low-Carbon Technical Report* (March 2020), p. 28.

[2] Halifax Regional Municipality, *Low-Carbon Technical Report* (March 2020), p. 45. We understand the 1,300 MW of rooftop solar to be a technical feasibility estimate, and that HRM would view other resources as potentially replacing this component.

- 100% EV sales by 2030
- Every building retrofitted (electrified and efficient) by 2040

With the partial exception of the electrification goals, our review of the IRP modeling indicates that NS Power is correct that it has scenarios that address these points.

With respect to the CO_2 emissions target, all of the accelerated zero 2045 scenarios (e.g., 3.1B) appear to have emissions at or below 1 MtCO2e in 2030, which is consistent with the HRM goal, since HRM represents roughly half of Nova Scotia electric demand.[3]

With respect to the renewable energy goals, the IRP modelling suggests it will be more economical to rely on wind and firm imports than on solar.[4] NS Power will allow the model to select either both emitting and non-emitting resources (Assumptions Set, p. 75); the results reported to date do not break down that split. Scenarios 3.1C, 3.2B, and 3.2C have capacity builds that are consistent with the HRM goal, given the energy production from wind and firm energy imports (assuming those are renewable).

However, with respect to the electrification goals in HaliFACT 2050, it does not appear that NS Power's electrification scenarios in the load forecast are as ambitious as the HRM's goals. The limited description of the high-electrification scenario in the IRP make it difficult to determine how closely the two plans track. But the divergence in the electrification assumptions appears to occur mostly after 2030, so the high-electrification scenarios are likely to be adequate to develop an action plan consistent with HRM's electrification goals. Even a fairly aggressive program (whether sponsored by HRM, NS Power or some other entity) is unlikely to substantially exceed the levels of EVs and building electrification in the high electrification scenario before NSP's next IRP, which we assume will be completed around 2025. At that time, if vehicle and building electrification were progressing consistent with HRM's goals, then NS Power would need to adopt significantly higher assumptions for building electrification.

Whether NS Power commits resources reach the levels of electrification in HaliFACT 2050 is a matter for the Board to determine.

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[3] A precise comparison is not possible because neither the draft IRP modeling results nor the HalifACT 2050 plan include specific CO_2 emissions figures for 2030.

[4] Of course, the IRP does not reflect the benefits of distributed solar in reducing the T&D loads in summer-peaking Halifax, nor the resiliency benefits of solar plus storage.

Wind costs and constraints: NS Power's assumptions and modeling methods may be unreasonably constraining near-term wind builds in the model. The issues relate to NSP's cost assumptions for wind and the reliability constraints imposed during modeling.

Regarding costs, we noted in our previous comments that NS Power's 2019 capital cost of $2,100 per kW is outside the cost envelope suggested by Lazard. Synapse and Natural Forces also indicated that the $2,100 per kW cost was not reflective of the market. NS Power's response includes a single scenario in which the 2019 capital cost is reduced from $2,100 per kW to $1,500 per kW. This scenario results in a significantly higher near-term wind capacity procurement (118 MW in 2.1C.S2 vs 57 MW in 2.1C).

We understand that New Brunswick is adding wind resources; if those costs are available, NS Power should compare its assumptions to the contract prices in New Brunswick. If New Brunswick costs are lower than NS Power's assumption, then either the model cost assumption should be revised, or NS Power should explain how Nova Scotia conditions (mostly wind resources, but perhaps other cost drivers) would differ from New Brunswick conditions and justify the higher cost assumption.

Second, NS Power caps the wind build at 100 MW (700 MW total installed) unless either reliability tie or a battery + synchronous condenser capital investment (referred to as domestic integration) is made to support reliability. The model selects the less expensive reliability tie. This limitation is derived from the PSC study, which found that during periods of high wind and high imports, the loss of an intertie could cause stability issues.

NS Power's use of the PSC study finding to require a reliability tie or domestic integration ignores two alternative operational responses to accommodate additional wind. First, under hourly conditions of high wind and high imports without the reliability tie, wind generation could be capped at 700 MW. Second, under conditions of high wind, a minimum conventional (thermal or hydro) online capacity requirement could be established,[5] which would both provide additional local inertia and reduce imports, avoiding the high wind/high import combination. NS Power may be able to model these operational constraints (curtailments or minimum commitment requirements) in its planning models, in which case the model could directly compare the cost of the operational constraints to the reliability tie and to the benefit of higher wind capacity. Alternatively, NS Power may need to exogenously estimate the amount of curtailment or uneconomic

[5] Or, if an existing minimum conventional capacity requirement exists, then it could be increased during high wind hours.

commitment to deal with extreme conditions, and the cost of those actions, and use that cost in lieu of the reliability-tie cost.

The combination of the cost assumption and reliability requirements may be resulting in misleading model results. In the low wind cost scenario (2.1C.S2), the reliability tie is built in 2029, the earliest year of tie construction in any scenario, to allow addition of 20 MW of additional wind in 2030.[6] If the model were allowed to build additional wind with operational constraints, it might well choose to add that wind earlier than 2029 and defer the reliability tie until later in the study period.

This seems to be a critical policy question that the IRP should frame properly in the following sequence. The various scenarios include roughly 50–100 MW of wind in 2021, so NS Power should soon have market price bids for wind.

a) Under the assumption that operational restraints are used, and low wind costs are available in the market, at what dates does the model suggest building more wind than the operational constraints can accommodate, requiring the reliability tie?
b) What additional reliability and operational studies are needed to verify the performance and cost-effectiveness of using operational constraints to address the high wind/high import issue?
c) If wind prices are attractive enough to go beyond the wind capacity that can be facilitated with the operational constraints, how long a lead time would NS Power require to make a build or defer decision for the reliability tie?

Since the IRP process does not include an opportunity to further investigate the cost of wind resource development or further study the practicality of operational constraints, it is essential that the final modeling scenarios appropriately examine these questions to provide the Board with the context it needs to evaluate the need for and potential scheduling of the reliability tie.

DSM impacts – There are two case pairs that contrast base and mid DSM. The 2.0A pair has a NPVRR difference of $337m and the 2.1C pair has a difference of $544m. Why is the difference so substantial based on the electrification level? Why is the mid DSM incremental cost more than the supply resources it replaces? Would the avoided T&D costs associated with a higher level of DSM potentially offset the cost difference?

The model is making changes that seem counter-intuitive when shifting from base to mid DSM. The shift from base to mid DSM in case 2.1C (vs S1) results in an

[6] This raises a question not addressed in the Assumption Set: In what year has NS Power allowed the model to build the reliability tie?

early build of an NGCC unit, reducing gas peaker capacity, and reducing firm imports. Is there something about the way firm imports are characterized that needs to be reconsidered? Why is the model suggesting that it is economic to build a unit that produces more energy when there is less energy to serve?

Regional Interconnection – It appears that the regional interconnection is built in 2030 if the more aggressive climate policy is selected, except in the mid-electrification case with high distributed resources. Otherwise, it is built in 2038–2045. Perhaps a sensitivity to one of the 2040 or 2045 build cases should be run that forces the build in 2030. It would be interesting to see if the cost difference is significant. Building or postponing this upgrade well beyond 2030 is a significant near-term decision point, and NS Power should determine whether it should move forward with planning on this project, since it would require cooperation with New Brunswick and possibly Quebec.

Storage – It appears that in most cases with near-term wind procurement over 100 MW, there is a relatively large amount of 4 hr battery storage selected as well. If that is correct, the final plan should recommend that wind procurement should generally proceed in combination with a storage procurement.

Combined Cycle Gas – It is surprising to see a combined cycle built so late in the 2.2A and 2.2C cases, as well as being built in the 3.1 and 3.2 cases. We are concerned because it is our understanding that the objective function of the model includes costs and benefits at 2045 operational levels through 2070 via end effects. Given the 2050 climate targets assumed in these cases, but not really represented in the model, we believe there may need to be modifications to the model to ensure that combined cycle plants are financially viable without an assumption that the plants will operate beyond 2050.

Ideally, NS Power would simply limit the useful life of a combined cycle to 2050. However, there are at least two reasons why this simple approach may not be practical in the current modeling environment. First, this may result in creating a unique resource for each year in the model, which may result in too much model complexity. Second, the end effects associated with a gas plant retirement in 2050 may result in the model considering costs and benefits of the gas plant in 2045 continuing through 2070 – which is clearly inconsistent with the net zero carbon scenarios.

NS Power should identify a workable approach that allows the benefits and costs of a combined cycle plant to be reflected in a way that approximates retirement by 2050. As discussed above, it may make sense to limit or eliminate end effects calculations as part of the objective function. If that was done, then the number of resource options could be limited by offering units with 25, 20, and 15-year lifetimes, with no combined cycle plants built after 2039.

Resource Insight Inc.

MEMORANDUM

To: Linda Lefler, Senior Project Manager, Regulatory Affairs
Nova Scotia Power

From: John D. Wilson and Paul Chernick

Date: August 4, 2020

Subject: Comments on modeling of wind and hydro in the IRP

This comment letter supplements our prior comments on the IRP assumptions and initial modeling results. These comments respond to understandings we have developed as NS Power has shared additional details about its reliability constraints and based on our analysis of four years of operating history for the NS Power system. Specifically, the Consumer Advocate has commissioned a review of NSP's renewable integration report, and we have analyzed some operational data provided by NS Power.

Renewable Integration

First, we attach a review of the reliability constraints that NS Power has derived from the Power Systems Consulting, Inc. (PSC) Renewable Integration report. Telos Energy recommends that "*NSP should conduct capacity expansion plan modeling with no inertia constraint and/or with a 1500MW-s inertia constraint to show the sensitivity to the inertia constraint.*"

Telos Energy's findings raise important substantive questions about how NS Power is viewing the potential for near- and mid-term expansion of wind energy. As demonstrated by the low wind-cost scenario, the model results are very sensitive to the cost of wind. The cost of adding wind above the 700-MW threshold is greatly affected by the cost of the reliability tie; the need and timing of the tie depend entirely on NS Power's application of the PSC report's reliability findings.

We recommend that NS Power provide results in its final report that apply alternative inertia constraints. Assuming the differences are significant, further study after the final IRP report is issued could clarify the inertia constraint and other relevant reliability considerations so that NS Power can determine the appropriate level of wind development that may be supported prior to investing in the reliability tie.

Effective Load Carrying Capability

Second, wind development is also affected by the ELCC values assumed in the IRP. Our analysis of the historical generation data recently provided by NS Power to the Consumer Advocate does not seem consistent with the ELCC values being assumed in the IRP for wind and hydro. The wind plants appear to contribute more output at high-load periods than implied by the ELCC results, and the various hydro resources appear to contribute less output lower than the assumed ELCC.

Our findings suggest that the assumed ELCC values for wind and hydro understate and overstate, respectively, the UCAP Firm Capacity estimates for existing resources. If appropriate to revise or consider alternate ELCC values in the final IRP, then we recommend that the final IRP include modeling that reflects those adjustments.

Our Analysis

We calculated four metrics from hourly dispatch data supplied by NS Power for 2016 through 2019. These data are shown by type of plant in Table 1.

- **Annual Capacity Factor** – The average ratio of hourly generation to operating capacity. To calculate capacity factors, we did not have unit capacities matched to the units in the hourly generation data, except for the wind capacity which was provided in the heading. For the remaining units and resource categories, we sourced the operating capacity values from the E3 Capacity Study, pp. 42-43.
- **Winter Capacity Factor** – Average of the monthly capacity factors for December – March.
- **Average Capacity Factor for Peak Events** – Average capacity factor for all hours during peak events. Peak Events are defined as one or more consecutive days in which the load for one hour is in the top 1.1% of all hours.
- **Average Capacity Factor for Peak Hours** – Average capacity factor, top 1.1% of hours (386 hours over the four years), and top 0.1% (35 hours). The average capacity factor for the top 1.1% of hours is a recognized metric for calculating capacity credit from historical data.[1]

[1] The average capacity factor is equivalent to the load duration curve method for a marginal resource increment. The equivalency of the load duration curve method to ELCC is discussed in: Andrew D. Mills and Pia Rodriguez, *Drivers of the Resource Adequacy Contribution of Solar and Storage for Florida Municipal Utilities*, Lawrence Berkeley National Laboratory (October 2019).

Table 1: NS Power Generating Unit Capacity Factors

	Annual	Winter	Peak Events	Peak 1.1% Hours	Peak 0.1% Hours
Coal	60.0 %	79.6 %	89.1 %	95.9 %	98.8 %
Gas CC	46.0 %	37.2 %	31.7 %	48.4 %	33.2 %
Gas/HFO Steam	34.7 %	28.3 %	38.6 %	46.6 %	62.4 %
Diesel CT	0.5 %	0.6 %	1.9 %	3.7 %	4.5 %
Biomass	40.5 %	44.2 %	48.0 %	55.4 %	60.4 %
Wind	36.1 %	43.6 %	51.1 %	55.8 %	61.3 %
Wreck Cove	16.0 %	19.2 %	20.2 %	39.1 %	48.2 %
Mersey	58.4 %	74.2 %	73.7 %	70.6 %	66.2 %
Annapolis	10.3 %	11.5 %	20.8 %	45.9 %	69.6 %
Other Hydro	30.8 %	46.3 %	44.9 %	45.7 %	39.1 %

For each type of capacity, Table 2 shows the operating capacity from the E3 study, the maximum hourly output from the data provided by NS Power, operating capacity from the IRP Assumptions document, UCAP Firm Capacity (which NS Power defines as ELCC × IRP capacity) from the IRP Assumptions document, and Capacity Credit, calculated as the IRP capacity × capacity factor for the top 1.1% hours. The first two columns of data include Lingan 2 in the coal category.

Table 2: Operating and Firm Capacity (MW) for NS Power Units

	Operating Capacity (E3)	Max Hourly Generation [2]	Operating Capacity (IRP)	UCAP Firm Capacity	Calculated Capacity Credit
Coal	1,234	1,299	1,081	976	1,037
Gas CC	144	146	144	133	70
Gas/HFO Steam	318	337	318	232	148
Diesel CT	231	172	231	178	9
Biomass	43	50	43	41	24
Wind	404	387	595	113	332
Wreck Cove	212	207	212	201	83
Mersey	43	42	43	40	30
Annapolis	19	23	-	-	-
Other Hydro	121	98	121	115	55
Total	2,769	2,762	2,788	2,030	1,787

[2] Max Hourly Generation is the hourly dispatch for the single highest hour that the group of units is dispatched, i.e. a coincident maximum. It is presented as a reference to compare with the operating capacity values.

Observations and Questions

1. Unlike the thermal plants, the wind plants operate almost any time they are available. According to the E3 Capacity Value Study, wind resources only offer a 19% ELCC and the capacity factor for wind is generally in the 10-40% range during high load factor hours, as illustrated in that report's Figure 13.

Figure 13: Maintenance of Correlations Between Load and Renewable Production in RECAP's Day-Matching Algorithm

Time-Synchronous Load & Renewable Profiles

Load Factor (% of 1-in-2 Peak)	Wind Capacity Factor (% of Nameplate) 0-10%	10-20%	20-30%	30-40%	40-50%	50-60%	60-70%	70-80%	80-90%	90-100%
30-40%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
40-50%	3.3%	4.3%	4.7%	4.6%	4.1%	2.9%	2.2%	1.2%	0.4%	0.1%
50-60%	5.9%	6.6%	6.6%	6.3%	5.6%	4.1%	3.2%	2.2%	1.0%	0.3%
60-70%	3.3%	3.1%	3.0%	3.2%	2.7%	2.1%	1.6%	0.8%	0.3%	0.0%
70-80%	1.1%	1.0%	1.0%	1.1%	1.0%	0.8%	0.4%	0.1%	0.0%	0.0%
80-90%	0.4%	0.4%	0.5%	0.5%	0.5%	0.3%	0.1%	0.0%	0.0%	0.0%
90-100%	0.1%	0.2%	0.3%	0.2%	0.1%	[illegible]	0.0%	0.0%	0.0%	0.0%
100-110%	0.0%	0.0%	0.0%	0.0%	0.0%	[illegible]	0.0%	0.0%	0.0%	0.0%

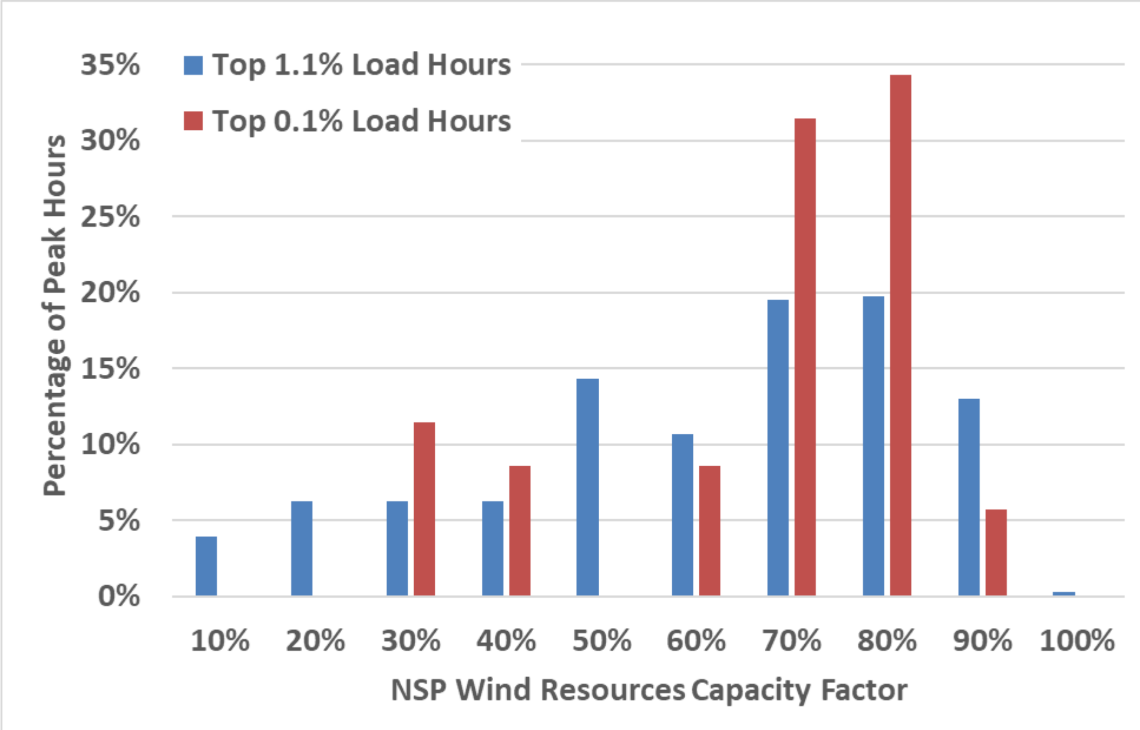
RECAP Synthetic Load & Renewable Profiles

Load Factor (% of 1-in-2 Peak)	Wind Capacity Factor (% of Nameplate) 0-10%	10-20%	20-30%	30-40%	40-50%	50-60%	60-70%	70-80%	80-90%	90-100%
30-40%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%
40-50%	3.5%	4.7%	5.2%	5.2%	4.4%	3.2%	2.3%	1.4%	0.5%	0.1%
50-60%	5.9%	6.5%	6.5%	6.4%	5.4%	4.2%	3.4%	2.3%	1.1%	0.3%
60-70%	2.9%	2.7%	2.5%	2.8%	2.5%	2.0%	1.5%	0.8%	0.3%	0.1%
70-80%	0.8%	0.8%	0.8%	1.0%	1.0%	0.8%	0.4%	0.1%	0.0%	0.0%
80-90%	0.2%	0.3%	0.4%	0.4%	0.4%	0.3%	0.1%	0.0%	0.0%	0.0%
90-100%	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
100-110%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

RECAP's day-matching algorithm captures key correlations between load and renewable production, including (1) tendency of wind to produce at low levels of output during very high load events, and (2) low loads during periods of high wind output

The generation data supplied by NS Power are significantly different from those presented in Figure 13 of the E3 Capacity Value Study. As shown in Table 1 and Figure 1, the generation data supplied by NS Power indicates that the average capacity factor during those hours was over 50% in the years for which data was provided, and at or below the 19% ELCC Factor assumed by NS Power for the IRP only about 10% of the time.

Figure 1: Wind Resources Capacity Factor Histogram



The IRP relies on the ELCC for two related purposes, valuing the capacity provided by existing wind generation and valuing the capacity provided by incremental wind resources. It is important to get both correct, since the existing wind generation counts towards meeting the planning reserve margin.

The E3 Capacity Value study indicates that the wind ELCC drops from 38% at near-zero capacity to 19% at NSP's current wind capacity (E3 Capacity Value Study, p. 58). We agree with the E3 report that the capacity credit for wind and other renewable resources should decrease as additional wind is installed. This strongly implies that existing resources should receive a higher credit that incremental resources. However, the current IRP assumptions appear to give an ELCC value of 19% for both installed and incremental wind capacity.

With respect to the installed wind capacity, we believe that the ELCC should be higher for three reasons.

- As noted above, the wind resource modeled by E3 performs far worse during peak hours than indicated by the data provided by NS Power.
- Our calculations, following the LBNL method (see footnote 1), suggest existing resources should have an ELCC of about 25%, as described below.
- E3's calculation of a 19% ELCC at current wind levels may be a marginal value (reflecting incremental system resources), not an average value (reflecting existing system resources).

With respect to incremental resources, the capacity credit calculation should be performed based on net demand, considering the top net peak hours after deducting wind resources.[3] Our findings using this analysis are compared to the net peak hour analysis in Table 3.

Table 3: NS Power Generating Unit Capacity Factors

	Peak Hours		Net Peak Hours	
	Top 1.1%	**Top 0.1%**	**Top 1.1%**	**Top 0.1%**
Coal	95.9 %	98.8 %	99.2 %	97.5 %
Gas CC	48.4 %	33.2 %	55.4 %	59.1 %
Gas/HFO Steam	46.6 %	62.4 %	51.4 %	62.5 %
Diesel CT	3.7 %	4.5 %	8.1 %	12.3 %
Biomass	55.4 %	60.4 %	62.9 %	65.1 %
Wind	55.8 %	61.3 %	19.7 %	14.8 %
Wreck Cove	39.1 %	48.2 %	45.7 %	57.6 %
Mersey	70.6 %	66.2 %	71.6 %	77.3 %
Annapolis	45.9 %	69.6 %	42.3 %	39.3 %
Other Hydro	45.7 %	39.1 %	47.6 %	53.6 %

As Table 3 indicates, after taking into consideration the capacity credit associated with wind, the capacity factor for wind in the top 1.1% of peak hours drops from 61.3% to 19.7% in the top 1.1% of net peak hours.

In the 4-year dataset provided by NS Power, the top 1.1% hours are those hours with load of 1,840 MW or with a net load of 1,697 MW. This indicates that the 595 MW of wind reduced load by about 143 MW, or a 25% capacity credit.

Thus, while our analysis supports the use of a 19% ELCC for incremental resources, *we find that the existing wind resources should have a UCAP Firm Capacity of 143 MW rather than 113 MW*.

2. The E3 study assessed hydroelectric capacity as a dispatchable resource using a net dependable capacity of 95% (E3 Capacity Value Study, Table 17). This appears to have been retained for the IRP. However, as shown in Table 1 and Table 3, this is not well supported by the historical generation data.

3. While Wreck Cove's capacity factor increases somewhat as demand peaks, the average capacity factor is only 58% for the top 0.1% net peak hours, as shown in Table 3. In fact, during the top 1.1% net peak hours, Wreck Cove was

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[3] Arguably, the net peak hours should also take into consideration must-run hydro resources. However, we lack sufficient information about the must-run requirements of specific hydro resources to make this adjustment.

dispatched over 75% in only 39 out of the 386 hours. In contrast, Mersey was dispatched at over 75% in 247 hours of those 386 hours.

We understand that Wreck Cove serves multiple functions on the NS Power system and has limited storage capacity, both of which may require that it be dispatched sparingly in many high-load hours.

Can NS Power explain why Wreck Cove operates so little in high-load hours? Does NS Power normally hold a large portion of Wreck Cove in reserve at peak? Does Wreck Cove have available energy resources to support a 95% ELCC value, given the long evening winter peaks?

While the Mersey units are dispatched more reliably than Wreck Cove in high-load hours, its dispatch does not match the UCAP/ELCC that NS Power claims for this system. Its capacity factor also declines from the winter, to peak days, and to net peak hours. *Does Mersey have enough flexibility in dispatch to be held in reserve at peak, or does the system simply produce less energy in the hours that tend to have high loads?*

4. The smaller run-of-the-river units are also dispatched well below their 95% ELCC factor during peak and net peak hours. As shown in Table 3, these hydro units have an average capacity credit of 48%, and were dispatched above a 75% capacity factor in only 3 of the top 1.1% net peak hours. We understand these units to have limited flexibility, so they would not appear to be held in reserve as is Wreck Cove. We also understand their capacity and energy output to be limited in low-water years.

   Why would these units merit a 95% ELCC value?

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Nova Scotia IRP Technical Review and Commentary

Prepared for the Nova Scotia Consumer Advocate

August 4, 2020

Introduction

The purpose of this document is to capture the commentary from a technical review of materials prepared by and for Nova Scotia Power (NSP) as part of their Integrated Resource Plan (IRP). The focus is on grid reliability, grid stability, and grid services and their impact on IRP modeling and conclusions, with emphasis on the Power Systems Consulting, Inc. (PSC) Renewable Integration report.

The materials reviewed for this effort include:

- Nova Scotia Power Stability Study for Renewable Integration Report, PSC North America (NOTE: Tables A-D and figure C were not available in the version of the report reviewed)
- NSP IRP Modeling Results - Grid Services Representation in RESOLVE and PLEXOS
- NSP IRP Modeling Results - June 26, 2020
- NSP IRP Modeling Results - July 9, 2020

Organization of this document is as follows:

1. Summary of Key Points
2. Observations, Clarifications, and Commentary on the PSC Study by topic area

Summary of Major Points

Overall, NSP's application of the PSC report appears to place unreasonable constraints on wind resource deployment in the IRP. As discussed below, the initial conditions in the four cases selected by NSP for evaluation by PSC, certain assumptions in the modeling, and constraints on potential solutions combine in a manner that is very unfavorable to wind. The report does not provide sufficient analysis to provide alternate conclusions. For purposes of IRP analysis, NSP should conduct capacity expansion plan modeling with no inertia constraint and/or with a 1500MW-s inertia constraint to show the sensitivity to the inertia constraint.

- The four cases selected by NSP for evaluation represent a very narrow set of grid operations that is particularly severe. The dispatch conditions are not likely representative of actual system dispatch conditions and the contingencies evaluated appear to be inconsistent across the four cases evaluated. The initial conditions and simulated events directly impact the resulting inertia requirement for the system.
- The case selection did not consider the probability of occurrence of operating conditions. The scenarios evaluated should be viewed as highly conservative and it is likely that the stability

challenges could be avoided with small changes to operations rather than new investment or a moratorium on new wind development.

- The frequency stability and inertia evaluation considered wires, battery storage, and synchronous condensers, and it failed to consider many other effective alternatives, including use of the Maritime HVDC Link for frequency response, synthetic inertia from wind turbines, and fast demand-side response.
- The PSC report did not state the status (commitment and dispatch) of the Wreck Cove Hydro Plant in the cases evaluated. It is our understanding based on prior modeling analysis of NSP's grid that Wreck Cove is a large (~218 MW) and flexible plant that is routinely utilized for grid services like regulation reserves, inertia (424 MW-s), and primary frequency response. It is recommended to explicitly state how this plant was modeled and dispatched in this analysis.
- The grid strength analysis was not available (Figure C not included in the version of the report reviewed) or inadequately documented in the PSC report for drawing any conclusions. The apparent interpretation of the grid strength requirement of 0.67MVAr synchronous condensers per 1 MW of wind diverges significantly from current industry practices on evaluating and mitigating grid strength.

Identification and Explanation of Findings

Case Selection & Clarity
Case 1: The contingency event considers a simultaneous loss of both AC ties (345kV and 138kV). This is not N-1, but N-2 (the "N-X" denotes X elements of the power system are placed out-of-service, and typical planning criteria is for N-1). However, the PSC report also states that there's a remedial action scheme to prevent loss of the 138kV in the loss of the 345kV by adjusting transfer over the Maritime Link (as described in Section 5.1, case 3, page 41). This indicates that there is a special scheme already implemented to avoid the simultaneous loss of both 345kV and 138kV AC links to New Brunswick. Further, Section 7 (page 59) states that the thermal line limits have been "...set based on the loss of a single tie to New Brunswick..." The contingency event involving the AC lines to New Brunswick should be clarified, assessed for validity, and held consistent across all cases and simulations.

Case 1: At the time of event, the power flowing through the AC links from New Brunswick is 250 MW importing and 200 MW is being exported to Newfoundland via the HVDC link, according to Table 5-2. A reduced import (and similarly reduced export) would have substantially reduced the severity of the event where all AC connections to New Brunswick are lost. The reasons for selecting this initial condition, or why NSP would be willing to operate in this combination of imports and exports, are not provided. The behavior of the HVDC link following the event is not discussed. These aspects are critical, as a fast run-back of the HVDC link during this event could have mitigated instability of the grid. Furthermore, the PSC report states that "the only synchronous machines in the island are small hydro units" with an aggregate online inertia of 387 MW-s. It appears that the Wreck Cove Hydro unit (at 424 MW-s) was not online, as it would have more than doubled the system inertia online. It is not clear why a stabilizing and economic plant like Wreck Cove (or if Wreck Cove was not available, some thermal capacity) was not committed.

Case 2: The contingency evaluated was the loss of 1 of 2 poles of Maritime HVDC link at its maximum import (~240 MW). Section 5.1 (page 41) states that "Although NPCC requires the system to survive the loss of both poles of the Maritime Link (475 MW or 39% of total load), this study included loss of one pole only." The report later recommends that the loss of both poles be evaluated. Absent other changes to the system, the loss of both poles simultaneously would be far worse for the system. This lends further doubt as to the reasons for -- and validity of -- the cases selected for evaluation. If it is determined that loss of only one pole of the HVDC link is considered credible for evaluation (and not the simultaneous loss of both poles), then it is expected that the power flow on both poles will be balanced (50% power flow on each), which will reduce the maximum contingency size if one pole is lost.

Case 2: This case assumes that NS is already disconnected and islanded from the NB grid. A trip of the largest generator would constitute an N-2 contingency and should not be considered in the same comparison as the N-1 contingency analysis.

Case 1 and Case 4: Both cases assume high imports from New Brunswick even during high wind events, and this is particularly extreme in Case 1 where system load is also very low. This level of import is unlikely during high wind and low load conditions and appears overly challenging to system operations. Reduced imports via utilization of generation within Nova Scotia would likely be the most prudent operational strategy.

Probability of Occurrence of Scenarios

There is no context or reasoning provided for the selection of the four cases evaluated: why NSP would operate in this fashion, how frequently these conditions might be expected to occur, or how frequently similar conditions (recognizing that large imports from NL have not been possible) have occurred in the past. To evaluate mitigations, it is important to understand the frequency and duration for which the grid would be operated in the pre-event conditions. (Note that an additional probability factor would be multiplied, representing the probability that the contingency event actually occurs during the time the grid is operating in the specified condition.) The answer may range from very infrequent and short-duration conditions to frequent and long-duration conditions. The answer can dominate the economic cost/benefit of proposed mitigations. For instance, infrequent (worst-case) scenarios that happen for a few hours a year and can be operationally mitigated at very low cost would not justify large investments. On the other hand, conditions that would occur very frequently (100s or 1000s hours/year) and require expensive or unreliable operational mitigation may warrant a significant capital expenditure.

Frequency Stability & Inertia Requirements

Existing System (Section 5.1)

Case 1: This case is key because it was used to determine the 2766 MW-s inertia minimum, which was later used in NSP's IRP modeling. However, the resulting minimum inertia from this simulation is highly suspect for the reasons described in the Case Selection section for Case 1.

Case 4: The results of the simulation show that after the contingency event, there is a relatively slow dynamic sequence of increasing voltage, leading to increasing load, which leads to a system frequency instability. If there was a means of better regulating voltage during this time frame (for instance, utilizing the reactive capabilities of wind turbines and/or augmenting that capability with other assets like shunts, STATCOMs, or SVC), it is possible interrupt this sequence of events and improve system stability with a relatively economic mitigation alternative.

With Added Wind (End of Section 5.1)

Case 3: The simulation fails to run, presumably due to non-convergence of the software algorithm. While non-convergence of the software algorithm is often associated with an infeasible operating point of the power system, this is not necessarily so. It could simply be a problem with the model and/or the simulation parameters. No comments were provided to indicate if additional checks were performed to try to confirm that the result was indeed due to an infeasible operating condition. Therefore it is difficult to draw a defendable conclusion here.

Case 4: Additional wind was added by backing down the Maritime HVDC link. The report states that the tripping of the AC tie (apparently both 345kV and 138kV as it states the Nova Scotia becomes islanded) results in all load-shedding stages to be triggered and "this major issue requires additional system reinforcements to accommodate increase [sic] of wind beyond present levels." There are several issues with this:

- The contingency appears to be a loss of both AC (345kV and 138kV) ties simultaneously, which is N-2 (simultaneous loss of two elements of the power system)
- The contingency size (in this case, power flowing through the AC ties when tripped) is unstated. However, if the power flowing through were reduced, for instance, by not backing down the Maritime HVDC link as much, then the load shedding impact would be reduced.
- The resulting load shedding is stated to be a "major issue" and "requires additional system reinforcements" but the level of acceptable load shedding for a contingency of the severity simulated is not defined.

System with Additional 345kV Line (Section 5.2)

This section was not given a high level of scrutiny at this time because the base cases (covered in Section 5.1, "Existing System") on which this analysis is based raises so many questions.

System with Synchronous Condenser and BESS (Section 5.3)
This section was not given a high level of scrutiny at this time because the base cases (covered in Section 5.1, "Existing System") on which this analysis is based raises so many questions.

However, the proposed mitigations of a 200 MVA synchronous condenser and a 200 MW BESS were not sufficiently justified because they were not tied to any performance criteria and not evaluated with adequate clarity. Further, the synchronous condenser was noted to have little impact on the load shedding incurred and its rating and rationale were not supported by analysis, like a grid strength study.

Meanwhile, the analysis did not mention Wreck Cove Hydro, which is a relatively large (218 MW) and flexible hydro asset that could be effectively used to mitigate load shedding and grid-strength concerns simultaneously as it is function similar, but larger than the combined proposed mitigation of 200 MVA synchronous condenser and 200 MW BESS.

Alternative Mitigations Not Considered:
Many alternative mitigations were not considered beyond the use of a synchronous condenser and BESS:

- Utilization of the Maritime HVDC Link for short-term contingency support -- HVDC systems are exceptionally fast-responding and can provide critical fast-frequency response (FFR) services. The Maritime HVDC system also has a very high rating (475MW) and even a partial allocation of its capability for emergency grid services can be very effective. The report noted that remedial action schemes (RAS) with the HVDC are already in use. It is acknowledged that any such schemes will have an impact on the Newfoundland power system, which would need to be considered.
- Utilization of synthetic inertia from wind power plants should be considered. The use of synthetic inertia does not require pre-curtailment of the resource. Ireland has introduced a market for grid services like synthetic inertia (called FFR, POR) as part of their DS3 Program, which has been operating since 2018 [1]. HydroQuebec has mandated the use of synthetic inertia for new wind plants on their system [2].
- Utilization of curtailment from wind power plants. When the curtailment is implemented as a fast-frequency response (FFR) function for over-frequency, wind plants can quickly and automatically reduce power output in the event of a contingency (for instance, a sudden loss of export capability or loss of load) to help the grid remain stable. Nearly all new wind plants offer this capability, and many modern wind plants installed in recent years may be able to adopt this functionality through software upgrades. The Electric Reliability Council of Texas (ERCOT) has been requiring this functionality for many nears from its wind turbine fleet.
- Utilization of under-frequency FFR from wind power plants that are curtailed. This functionality enables wind turbines which have already been curtailed to respond quickly and automatically to contingency events like a loss of import or loss of generation to improve stability and mitigate under-frequency load-shedding. Like FFR for over-frequency response (fast curtailment), this

functionality is available on nearly all new wind plants and most modern wind plants (perhaps with upgrades), and has been routinely used in ERCOT for many years.

- Utilization of demand-side resources to provide frequency response. Demand response has been around for decades, and more recently, there has been a growing segment providing very fast demand response, which is capable of acting quickly to mitigate or avoid load shedding. ERCOT has been operating a responsive reserve market for several years, and has introduced a fast-response (FFR) version open to load resources earlier in 2020 [3].
- Utilization of the Wreck Cove Hydro Plant -- It is not clear to what degree the Wreck Cove Hydro Plant was considered in the dispatch scenarios, but this plant is sufficiently large (~218MW, 424MW-s of inertia) and flexible as to have a substantial impact on the stability of the power system. Its status and utilization in the study work should be made explicit because of its potential importance to the system.

Short-Circuit Strength

Short-circuit strength was only discussed qualitatively and did not appear to be a binding constraint for the Nova Scotia system. The report version reviewed did not quantify that support for grid strength is needed.

In the “Wind Integration” line item from NSP’s “Grid Services and Renewable Integration -- Modeling Requirements” slide, it appears that NSP arrived at a ratio of 0.67MVAr of synchronous condensers for every MW of wind turbines installed based on a section of the PSC report that analyzed 300MW of additional wind with the addition of 200MVAr of synchronous condensers [4]. But there is no connection or attributed causation here. The apparent interpretation (ratio method) by NSP of a poorly constructed simulation scenario is technically unsubstantiated and far from industry-accepted methods and practices for assessing and mitigating risks associated with low grid strength. Industry-accepted methods involve a screening process, potentially followed by a detailed study, which PSC alludes to in their report. The physics of weak grid instability issues is highly non-linear and cannot be reduced to a simple ratio for extrapolation to significantly different grid conditions or resource mixes.

Power Quality

Power quality is mentioned in the PSC report and recommended for further study. However, power quality is generally not considered a systemic issue but rather an application-specific issue with application-specific mitigations. There is no evidence to suggest that power quality analysis is warranted as part of long-range planning efforts. While it’s correct that weak grids can exacerbate the problem, it often is in conjunction with resonances on the system, for instance due to long, high-voltage cable.

Regulation Reserve

It is unclear why PSC included a regulation reserve analysis at all, as it does not significantly influence the transient stability analysis, the minimum inertia levels, or the need for synchronous machines. The timeframe of regulation reserves (several minutes) is longer than the timeframe analyzed by the PSC simulations. Nova Scotia is part of the much larger Eastern Interconnection and thus will not see fluctuations in frequency due to wind variability when it is interconnected to New Brunswick.

It should be noted that all power systems require some level of regulation reserves, regardless of installed wind capacity, to cover normal load variability. The introduction of wind variability can increase the amount of regulation reserves required. Overall, the PSC analysis included a reasonable analysis of historical net load variability to develop a regulation requirement, but there are a couple limitations.

First, PSC utilized a 3-sigma standard deviation for variability, which covers 99.7% of all wind variability on the system. There was limited discussion on how three standard deviations were selected; that level is potentially conservative. For example, a 95% confidence interval could significantly reduce the amount of regulation required. For example, the National Renewable Energy Laboratory's (NREL) *Eastern Renewable Generation Integration Study* (ERGIS),[5] used *"confidence intervals that covered 95% of the forecast errors. These requirements approximate levels of coverage used in past integration studies.* The 95% confidence interval is also supported by Ibanez, et al.,*"The regulation reserves were calculated using 10-min time and 95% confidence intervals for the entire footprint."*[6] Limiting wind output to the 95th percentile may have very small costs.

Second, the PSC analysis assumed a proportional increase in variability for wind additions to 1,000 MW. In reality, there would be at least some increased diversity of the wind profile as new wind is added to the system. However, Nova Scotia is relatively small with over 500 MW of wind currently installed, so this effect is likely relatively small.

Overall, the assumed regulation requirement is relatively small, will not influence the PSC stability analysis, and will have a relatively small effect on the IRP modeling. It should be given lower priority than the other stability analysis comments.

Curtailment

The second phase of the study, beginning with Section 5.2 states that "Under the base cases of Case 01 and 02, adding wind to Nova Scotia is not feasible assuming the wind needs to be curtailed due to lack of enough load or export limit." However, the level of curtailment is not quantified. While high levels of curtailment are not economic, some curtailment is likely and can be used for productive purposes when necessary.

None of the cases were evaluated with curtailed wind, which could occur when wind is added to the system. This is especially true during light-load, high-wind conditions where transient stability is most challenged. When curtailed, wind can be a highly flexible and fast responding resource to respond to a loss-of-generation event. In addition, wind can also be used during over-frequency events (loss of the tie-line during export conditions) to rapidly curtail and provide fast frequency response.

References

1. EirGrid DS3 System Services Protocol – Regulated Arrangements, May 2019 http://www.eirgridgroup.com/site-files/library/EirGrid/DS3-System-Services-Protocol-Regulated-Arrangements-v2.0.pdf
2. HydroQuebec: Technical Requirements for the Connection of Generating Stations to the Hydro-Québec Transmission System, January 2019 http://www.hydroquebec.com/transenergie/fr/commerce/pdf/2_Requirements_generating_stations_D-2018-145_2018-11-15.pdf
3. ERCOT NPRR863: Creation of ERCOT Contingency Reserve Service and Revisions to Responsive Reserve http://www.ercot.com/mktrules/issues/NPRR863#summary
4. NSP IRP Grid Services and Renewable Integration - Modeling Requirements (see Appendix)
5. Bloom, et al., *Eastern Renewable Generation Integration Study,* National Renewable Energy Laboratory, August 2016, *available at* https://www.nrel.gov/grid/ergis.html.
6. Ibanez, et al., *A Solar Reserve Methodology for Renewable Energy Integration Studies Based on Sub-Hourly Variability Analysis, National Renewable Energy Laboratory, November 2012, available at* https://www.nrel.gov/docs/fy12osti/56169.pdf.

Appendix

Slide excerpts for NSP IRP Grid Services and Renewable Integration - Modeling Requirements:

GRID SERVICES AND RENEWABLE INTEGRATION – MODELING REQUIREMENTS

	RESOLVE Modeling			PLEXOS Modeling		
Requirement Category	**Requirement in RESOLVE**	**Can be provided by**	**Renewables role**	**Requirement in PLEXOS**	**Can be provided by**	**Renewables role**
10-min non-spin reserve	Not modeled*			168 MW (Spinning reserve counts towards 10-min reserve)	Same as for Spinning. Only CTs, Recips and Hydro can count towards reserve if off-line. Other units must be on-line.	Can't be provided by renewables
30-min non-spin reserve	Not modeled*			75 MW	Same as for Spinning.	Can't be provided by renewables
Inertia	3266 MW.sec	All existing thermal; new gas plants; pumped hydro; batteries; CAES; large hydro + SC + Synchronized AC interties	Can't be provided by renewables	3266 MW.sec	All existing thermal; new gas plants; pumped hydro; batteries; CAES; large hydro + SC + Synchronized AC interties	Can't be provided by renewables
Wind Integration	2nd AC 345 kV tie or 0.67 MVAR of SC + 0.67 MW of 4-hour battery for each MW of wind capacity over 100 MW new build			2nd AC 345 kV tie or 0.67 MVAR of SC + 0.67 MW of 4-hour battery for each MW of wind capacity over 100 MW new build		

*Spinning reserve can be counted toward 10-min non-spin. Non-spinning reserves are not modeled in RESOLVE because existing diesel peakers can provide those.

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Viewing CHRIS MILLIGAN's s...

GRID SERVICES AND RENEWABLE INTEGRATION – MODELING REQUIREMENTS

	RESOLVE Modeling			PLEXOS Modeling		
Requirement Category	**Requirement in RESOLVE**	**Can be provided by**	**Renewables role**	**Requirement in PLEXOS**	**Can be provided by**	**Renewables role**
Regulation up	13.455 MW + 0.028 * installed capacity (MW) for wind and solar	Most existing thermal; new gas plants; pumped hydro; batteries; CAES; and Wreck Cove hydro	Can't be provided by renewables	15 MW	Most existing thermal; new gas plants; pumped hydro; batteries; CAES; and Wreck Cove hydro	Can't be provided by renewables
Regulation down	13.455 MW + 0.028 * installed capacity (MW) for wind and solar	All of the above + renewables	Up to 50% of renewables installed capacity	15 MW	All of the above	Can't be provided by renewables
Ramp Reserve	Incorporated into regulation constraint			0.028 * Hourly Wind Generation (MW) for wind	New Recips, Aero CTs, Batteries	Can't be provided by renewables
Spinning reserve	64 MW	All existing thermal; new gas plants; pumped hydro; batteries; CAES; Wreck Cove hydro; other hydro plants	Can't be provided by renewables	64 MW	All existing thermal; new gas plants; pumped hydro; batteries; CAES; Wreck Cove hydro; other hydro plants	Can't be provided by renewables

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July 17, 2020

Jennifer Ross
Manager Regulatory Strategy
Nova Scotia Power **via email**

Canadian Renewable Energy Association submission to Nova Scotia Power re: Integrated Resource Plan Modelling

Dear Ms. Ross,

The Canadian Renewable Energy Association is pleased to present this submission in response to the Nova Scotia Power Inc. (NSPI) 2020 Integrated Resource Plan (IRP). We appreciate the efforts that NSPI has taken to provide stakeholders an opportunity to comment on its 2020 IRP, including the detailed modeling presentation provided on July 9, 2020.

On July 1, 2020, the members of the Canadian Wind Energy Association and the Canadian Solar Industries Association, merged to become the Canadian Renewable Energy Association (CanREA), with a new mandate representing companies active in the wind energy, solar energy and energy storage industries in Canada.

Our technologies are uniquely positioned to deliver clean, low-cost, reliable, flexible and scalable solutions for Canada's energy needs and as such we are well positioned to put forward this submission to NSPI, responding to the 2020 IRP.

We are providing this input with a view to ensuring that the IRP analysis and results can be a strong foundation for future policy development or electricity sector infrastructure investment in Nova Scotia.

Wind represents an Attractive Resource for Nova Scotia

NSPI's 2020 IRP has consistently shown that wind represents the most attractive clean energy resource for Nova Scotia. Slide 20 in NSPI's July 9th presentation indicated that "Onshore wind energy selected in all scenarios as the most economic type of domestic renewable generation".[1] The July 9th presentation indicates that near term (by 2026) wind additions range from 51 to 148 MW and long term (2045) additions range from about 125 to 1,300 MW , recognizing that approximately 600 MW of wind generation capacity is currently available in Nova Scotia.[2]

NSPI has noted that there are challenges associated with integrating additional volumes of onshore wind in Nova Scotia. The PSC Renewable Integration study, which was conducted for NSPI's pre-IRP work, was performed in part to assess how much additional wind could be developed in Nova Scotia with and without additional investment to support its integration.[3] The PSC study objective was identified in its report as being:

> "To assess the integration of increased levels of renewable generation in Nova Scotia and to form recommendations for reinforcement and/or for further investigations required to enable this

[1] NSPI, 2020 IRP Modeling Results Workshop, July 9, 2020, (July 9th Presentation)
[2] July 9th Presentation, p. 14-15.
[3] *Nova Scotia Power Stability Study for Renewable Integration Report*, July 2019. (PSC Study)

integration. The Nova Scotia power system like any other power system is limited in its ability to accommodate an increasing number of power electronic interfaced generation”[4]

CanREA believes that in addition to the positive outlook for wind presented in the IRP modeling, wind energy can provide additional benefits to the grid that help address the subsequent concerns associated with integrating more wind, particularly as noted in the PSC work. It is likely that additional analysis would demonstrate that the need for more infrastructure investment to support wind integration is less a deterrent because the benefits provided by the procurement of the additional services would lessen the need for such infrastructure investments. As such, we are recommending that additional analysis be conducted to consider how these specific capabilities of wind energy, coupled with other technologies like storage, will in fact, enable more, cost effective wind energy to be integrated to the grid without significantly more infrastructure investment. Some of these additional benefits are outlined below.

Wind Integration in NSPI’s IRP

At the July 9th, 2020 stakeholder session, NSPI reviewed some of the high-level modeling assumptions. One of these slides (presented below) reviewed the inertia constraint that was an element of the PSC work that was used to assess how much wind could be added to the Nova Scotia electricity system. The PSC study noted that “the main question that was answered by the simulations in this study was if the Nova Scotia system, upon disconnecting from the AC interconnection or losing one DC pole, will be able to survive the transients and remain stable.”[5]

The PSC modeling indicates that the Nova Scotia electricity system requires a certain level of inertia to maintain system frequency and avoid under-frequency load shedding due to the loss of Nova Scotia’s intertie when it is importing energy from New Brunswick. As indicated below, the 2,766 MW.sec estimated in the PSC Study was increased to 3,266 MW.sec to cover the contingency of the loss of a generating unit representing an estimated 500 MW.sec. CanREA notes that one stakeholder questioned the reasonableness of the resulting stringency of this 3,266 MW.sec intertia threshold. We do not address that issue here.

INERTIA CONSTRAINT

- The kinetic inertia constraint is modeled at 3266 MW.sec minimum online requirement
  - This is derived as allowing an approximate contingency of 500 MW.sec (~1 unit) above the level of 2766 MW.sec that was found to be required for stability in the 2019 PSC Study
- Unit provisions are shown in the table on the right for existing and new resource types available to the model

Source	Inertia Contribution (MW.sec)
Generators (01 - Lingan 1)	814
Generators (02 - Lingan 2)	814
Generators (03 - Lingan 3)	797
Generators (04 - Lingan 4)	797
Generators (05 - Point Aconi)	933
Generators (06 - Point Tupper)	777
Generators (07 - Trenton 5)	620
Generators (08 - Trenton 6)	771
Generators (11 - Tufts Cove 1)	403
Generators (12 - Tufts Cove 2)	412
Generators (13 - Tufts Cove 3)	768
Generators (14 - Tufts Cove 4)	245
Generators (15 - Tufts Cove 5)	245
Generators (16 - Tufts Cove 6)	245
Generators (270 - New_50MW Pump Strg)	100
Generators (320 - New_Tre 5 NGas)	620
Generators (321 - New_Tre 6 NGas)	771
Generators (322 - New_TUP NGas)	777
Generators (040 - New_RECIP - 9.3 MW)	45
Generators (050 - New_ CT 50 MW Aero)	250
Generators (052 - New_CC 145 MW)	750
Generators (054 - New_CC 253 MW)	1265
Generators (056 - New_CT 34 MW Aero)	170
Generators (058 - New_CT 33 MW Frame)	165
Generators (059 - New_CT 50 MW Frame)	250
Generators (CAES_Air Component)	100
Generators (H01 - Wreck Cove)	424
Generators (Sync Cond _1)	5 (per MVA of SC)
Lines (670-NB 2nd 345kV Intertie_Basic)	3266

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[4] PSC Study, p. 1
[5] PSC Study, p. 5

Recognizing the Contribution that Wind can Play in Reducing Inertia Requirements

In response to a question by Dan Roscoe regarding this slide and why it didn't reflect the fact that synthetic inertia can be provided by wind projects, Chris Milligan noted that the synthetic inertia that inverter based projects (i.e., wind generation) provide is effectively Fast Frequency Response (FFR) and is distinct from synchronous inertia.

CanREA notes that these issues are the subject of concurrent work that was initiated by the Offshore Energy Research Association (OERA) on behalf of the Nova Scotia Department of Energy and Mines. CanREA offered comments to the consultant that OERA engaged to perform this study (Power Advisory LLC) and as part of this effort reviewed work in other jurisdictions on the role that existing non-synchronous/inverter-based resources such as wind can play in providing frequency response services and by so doing reduce Nova Scotia's inertia constraint.

CanREA agrees that FFR and synchronous inertia are technically distinct services given that they respond in different timescales. However, as the Australian Energy Market Operator (AEMO) noted when developing an FFR specification for its market, "FFR can compensate for, and help to mitigate, the effects of reduced synchronous inertia on power system frequency control by providing a wider range of options for meeting the frequency operating standards (depending upon a co-optimised consideration of the availability and costs of both services)".[6] AEMO noted that "This suggests that enabling FFR services in the NEM [Australia's National Energy Market] may allow the frequency operating standards to be met with a lower level of synchronous inertia." CanREA notes that the same is true for Nova Scotia. The provision of FFR by inverter-based generating resources and energy storage can play a significant role in helping to meet Nova Scotia's system reliability needs in the context of diminishing synchronous inertia.

In a recent report from the US National Renewable Energy Laboratory (NREL)[7] on maintaining system reliability in a low synchronous-generation power grid, Denholme et al. note that while a higher penetration of inverter-based generating resources and energy storage reduces available inertia, an increased proportion of these resources also reduce the need for inertia, noting that the rapid response of inverter-based resources can in effect supersede traditional frequency-responsive reserves. The authors note the well-established use of extracted wind kinetic energy from the rotating mass of the blades, shaft, and generator to rapidly inject real power into the grid (as has been utilized in the Hydro Quebec transmission system since 2009), along with the proven ability of inverter-based variable generation to provide FFR much faster than conventional generators.

CanREA members understand that one issue being evaluated in this IRP process is whether such obligations (e.g., the provision of FFR and Primary Frequency Response) should be placed on new and existing non-synchronous/inverter-based resources in Nova Scotia. Based on experience elsewhere and input from various CanREA members (e.g., wind turbine manufacturers who were able to advise on the costs of such requirements), we understand that such obligations are likely to be placed on these resources, including wind.

ERCOT has required wind generators to have frequency-responsive capability beginning since 2012[8], and in 2018, the Federal Energy Regulatory Commission (FERC) required new utility-scale wind and solar PV plants to have frequency-responsive capabilities[9]. The net result of such an obligation could

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[6] Australian Energy Market Operator, *Fast Frequency Response Specification*, 2017, p. 1.
[7] Denholm, Paul, Trieu Mai, Rick Wallace Kenyon, Ben Kroposki, and Mark O'Malley. 2020. Inertia and the Power Grid: A Guide Without the Spin. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6120-73856. https://www.nrel.gov/docs/fy20osti/73856.pdf.
[8] NERC Essential Reliability Services Task Force Report (2015)
[9] FERC (2018). Order No. 842: Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response, Issued February 15, 2018. https://cdn.misoenergy.org/2018-02-15%20162%20FERC%20%C2%B6%2061,128%20Docket%20No.%20RM16-6-000133298.pdf.

be reduced requirements for synchronous generating units during specific operating conditions, with an increased ability to integrate additional wind generation, with corresponding reductions in costs to customers. In fact, this is likely to be a primary objective of placing such an obligation on these resources – the added benefit of enhanced decarbonization should also be noted.

As the slide from the July 9th Presentation shown below indicates, NSPI estimates that under current conditions approximately 100 MW of additional wind can be reliably integrated without major infrastructure investment (i.e., Reliability Tie or Batteries and Synchronous Condenser). However, with the implementation of an obligation on new and existing wind projects to provide FFR, it may be economic and feasible to add additional wind generation well beyond 100 MW without major infrastructure investment.

Therefore, CanREA believes that it is critical to consider these changes in this IRP. Specifically, the potential implications of such obligations of wind resources and the consequent impact on Nova Scotia's ability to accommodate additional volumes of wind without major system investments (e.g., a Reliability Tie such as identified in the slide shared below).

The importance of considering the impact of this obligation on Nova Scotia's inertial constraint is reinforced by the fact IRPs are conducted in Nova Scotia on a somewhat sporadic basis. Furthermore, one potential purpose of the IRP could be to inform policymakers regarding appropriate targets for near-term renewable resource procurements.

RENEWABLE GENERATION

- Onshore wind energy selected in all scenarios as the most economic type of domestic renewable generation
- Construction of a Reliability Tie (new 345kV line from Onslow, NS to Salisbury, NB) is preferentially selected as a method of wind integration
  - This option was offered to the model in all scenarios, including "A" (Current Landscape)
- Domestic integration (batteries + synchronous condensers) was selected when the limits of what could be integrated using the Reliability Tie were reached
- The combination of Reliability Tie integration and domestic integration was not examined in the PSC reliability study as part of the Pre-IRP work but was selected in several scenarios after 2030; this will need to be studied further

Available Wind (Nameplate MW)	No Integration Requirements*	Reliability Tie*	Domestic Integration* (Batteries + Sync. Condenser)	Total Available
Low Electrification	100	400	400	900
Mid Electrification	100	500	500	1,100
High Electrification	100	600	600	1,300

Next Steps: Consider New Obligations to Provide FFR on Wind Integration

Chris Milligan indicated that one of the next steps in the IRP process was to assess the operability of different portfolios. We understand that this operability analysis is likely to be test scenarios that were evaluated in PLEXOS to ensure that they do not adversely affect reliability.

CanREA encourages NSPI to ensure that these analyses consider at minimum the impact of new frequency response provision requirements for non-synchronous/inverter-based resources in terms of enabling additional wind generation in Nova Scotia in the near term without major infrastructure investments.

Forecasted near-term reductions in both the levelized cost of wind generation[10], and competitive system costs of inverter-based generating resources and energy storage as compared to a synchronous generation-based system[11], suggest that increased volumes of these resources could reduce costs for Nova Scotia consumers while advancing the Province's environmental goals.

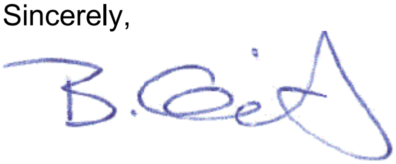
Additional Considerations: Importance of Increased Transparency with respect to Analysis

NSPI has shared summary information regarding the results on the underlying model runs. This includes the capacity mix of the various resource portfolios, partial revenue requirements and case summaries. The limited details make it difficult for stakeholders to discern key drivers of modeling results. This undercuts the transparency of the analysis and undermines confidence in the results. Key unexplained results that are surprising and appear counter-intuitive are the high levels of gas turbine build and relatively low levels of battery build.
This raises a number of questions:

- How were ancillary service provision by various resources modeled?
  - Does this modeling reflect the underlying higher performance of ancillary service provision that batteries and other non-synchronous/inverter-based resources can achieve relative to conventional resources including thermal generation? Experience in other electricity markets (e.g., PJM etc.) indicates that the quality of AGC service provided by batteries is such that it can reduce the underlying requirements for these resources to provide this service, reducing costs to customers.
- Does the end effects analysis adequately consider additional costs of fossil-based resources relative to renewable resources recognizing that carbon constraints and costs associated with exceeding these are likely to become increasingly significant?
  - Does the end effects analysis adequately reflect future operating constraints on fossil-based resources?
  - How were the prospects of increasingly stringent carbon constraints imposed after fossil investments are made considered in the analysis?
  - How was the loss of flexibility or these cost penalties considered?
- Where the potential benefits of hybrid projects (wind/energy storage or solar/energy storage with storage embedded behind the meter) adequately considered? Experience in other markets shows that hybrid projects can provide required ancillary services (e.g., frequency response services) at lower cost by avoiding opportunity costs associated with the provision of some frequency response services as well as provide a desired capacity resource at a relatively low effective cost.

The Canadian Renewable Energy Association appreciates the opportunity to provide feedback to the NSPI 2020 IRP modeling presentation. Please do not hesitate to contact the undersigned for additional clarity or required follow-up. We remain available as an engaged stakeholder and look forward to the next steps on this file.

Sincerely,



Brandy Giannetta
Senior Director, Ontario and Atlantic Canada
Canadian Renewable Energy Association

[10] Lazard's Levelized Cost of Energy Analysis – Version 13.0
[11] Denholm *et al*.

Memorandum

To: IRP Development Team, Nova Scotia Power

From: EfficiencyOne

Date: July 17, 2020

Re: 2020 IRP – June 26 Modelling Results Comments

On June 26th, 2020, NS Power released its IRP Modelling Results. This followed the release of interim modelling results on April 27th, 2020, on which EfficiencyOne (E1) provided comments in a previous memorandum.

On July 9th, 2020, a technical session was hosted related to release of 2020 IRP modelling results. E1 appreciates the opportunity for the discussion and clarity provided during this session, as well as the effort NS Power has put forth in demonstrating a concern for issues as they arise in responding to E1 feedback over the course of the IRP process to-date. The efforts made to accommodate requests for meetings as well as information sharing in separate technical meetings has been very helpful for enhancing the ongoing understanding of approaches and providing clarity throughout the IRP process.

As a summary, E1 has the following recommendations and requests:

The need for additional sensitivities with respect to DSM

1. Model additional sensitivities with respect to differing DSM cases. Modelling additional sensitivities is required to adequately test DSM's impact in the context of the various 2020 IRP scenarios. The requested sensitivities in each scenario are detailed on pages 3-4 of this memo.
2. Confirmation that full resource re-optimization is occurring for all sensitivity runs, including re-optimization of the planning reserve margin.

Limited Value of Distributed Generation Cases

3. Continue to refine the cost estimates for Distributed Resources, as they currently span a wide uncertainty range. Existing and planned data, including

costs, from Smart Grid Atlantic and NS Power's Smart Grid project may be useful in doing so.

4. With respect to Distributed Resources cases, define the portion of the NPV revenue requirement that will be ratepayer-funded, and include it within NPV revenue requirements.

Levelization of DSM Costs

5. Re-run DSM scenarios with an amortized capital cost stream, similar to the treatment for supply-side resources. The rationale for this is described further in this memo.

Demand Response

6. Allow the introduction of Demand Response (DR) in 2021, 2025, 2030, and 2035. This would provide a better balance and consistency in model runs, and more accurately estimate the value of DR in Nova Scotia.
7. Re-run all scenarios allowing DR to economically compete against new and existing natural gas peaking infrastructure.

The Availability of Detailed Information

8. Provide quantitative inputs and outputs from Plexos in tabular format, as initially requested on May 12, 2020 with a priority for the Comparator cases 1.0A and 1.0C. To note, requests for release of data have been addressed by NS Power through an alternative arrangement for a technical session with E1 and its consultant, where PLEXOS model parameters and data can be examined.

Critical Importance of Transparent Evaluation Process

9. With respect to the remaining evaluation of Candidate Resource Plans:
    a. Provide findings for each evaluation category for each candidate resource plan considered.
    b. When selection decisions are being made regarding specific candidate resource plans, or groups of similar plans, justification should be provided on the basis of evaluation criteria, and the relative importance of each criterion in making such a determination.

Capacity Value of Non-Firm Imports

10. Clarify any ongoing modelling impacts associated with the use of non-firm imports in RESOLVE. Confirm that the PLEXOS LT runs do not count any non-firm imports as capacity.
11. Provide additional information and support regarding firm import assumptions to allow stakeholders to assess the reasonableness of these assumptions.
12. Clarify which candidate resource plans depend on the addition of 450 MW of firm imports from Quebec, or portions of this capacity if Plexos did not take the entire volume in any given scenario.
13. Include a sensitivity analysis run that limits market imports (both firm and non-firm) to 110% of recent historical averages, excluding the Maritime Link NS block. This inclusion would provide the benefit of a view with limited expansion of market opportunities, which E1 believes warrants consideration.

New Natural Gas Capacity and Pricing

14. A proxy for new gas supply should also include a sensitivity relating to the Algonquin City Gates Hub (AGT) as the commodity price for new winter (and summer) natural gas capacity, with the inclusion of energy cost and tolls reflecting transport from AGT to Tufts Cove, as it would address some of the uncertainties associated with the current approach of acquiring gas and transportation from Alberta (AECO), Dawn or LNG via Amsterdam (TTF).
15. Sensitivity analyses that explores the constrained availability of natural gas for the NS electricity system should be included, at least in terms of incremental capacity additions beyond 20,000 MMBtu per day. Put another way, constrain the model to only allow for consumption of 20,000MMBtu per day, thus allowing the model to economically select other resources other than natural gas beyond the currently contracted firm supply.

The above requests and recommendations are described in more detail below.

The need for additional sensitivities with respect to DSM

Two key sensitivities with respect to DSM levels have been modelled to date. These two sensitivities represent:

- A variation of energy efficiency levels from the Base DSM trajectory to the Mid DSM trajectory, within case 2.1C. This case represents a net-zero emissions trajectory (non-accelerated), with mid-level electrification and a regional integration resource strategy.

- A variation of energy efficiency levels from the Base DSM trajectory to the Mid DSM trajectory, within case 2.0A. This case represents a net-zero emissions trajectory (non-accelerated), with reference-level electrification and a “current landscape” resource strategy.

While these results do provide insight on mid-DSM levels in these two specific cases, these runs do not provide a full set of expected sensitivities as presented in slide nine of the materials released on June 26, 2020.[1] Additional sensitivities will provide further and necessary insight on the appropriate DSM trajectory for Nova Scotia. At minimum, results should be provided from:

- Completion of a DSM sensitivity examining Mid-DSM levels within case 2.0C (Net-Zero, Reference Electrification, Regional Integration). This plan is currently outperforming 2.0A in terms of both Planning Period, and Planning Period with End-Effects, NPV revenue requirement, and exploration of Mid-DSM in this case may be valuable, as it is a seemingly high-value candidate resource plan.
- A DSM sensitivity examining Mid-DSM levels within case 3.1C (Accelerated Net-Zero, Mid-Electrification, Regional Integration) would be useful to test Mid-DSM levels in an accelerated net-zero context under intermediate increased loading from electrification.
- A DSM sensitivity examining Mid-DSM levels within case 3.2C (Accelerated Net-Zero, High-Electrification, Regional Integration) would be useful to test Mid-DSM levels in an accelerated net-zero context under the most aggressive increased load from electrification.
- A DSM sensitivity examining Mid-DSM levels within case 2.2C (Net-Zero, High-Electrification, Regional Integration) would be useful. With a less restrictive GHG profile as compared to other high-electrification cases, this candidate resource plan may well form the most competitive view of a high-electrification world. Testing Mid-DSM in this case may further improve the competitiveness of this plan, due to the high incentives required by the Max-DSM case.

In addition, should the distributed energy versions (X.XB) of the above remain in consideration following further analysis, they should also receive similar sensitivity treatment as outlined in the bulleted list above.

Also, please confirm that full resource re-optimization is occurring within the context of sensitivity runs, including re-optimization of the planning reserve margin to levels that satisfy, but do not greatly exceed NERC requirements.

Limited Value of Distributed Generation Cases

[1] NS Power 2020 IRP Modeling Results Release, June 26, 2020, at slide 9.

Numerous cases in the IRP depend on a large growth in renewable distributed energy resources. It is understood that there are two scenarios being examined for distributed energy resources:

- Cases with the notation X.XA and X.XC have levels of distributed energy resources consistent with the 2019 NS Power load forecast.
- Cases with the notation X.XB employ a Distributed Resource resource strategy. This is understood to represent additional solar PV integration beyond the levels envisioned in the 2019 Load Forecast.

Basic information has been provided relating to the envisioned costs for these additional resources – described as "$1.6-2.5B" on an NPV basis.[2] These costs have not been directly included in the NPV revenue requirement of any modelling scenario.

These cost estimates should continue to be refined, and existing and planned data from Smart Grid Atlantic and NS Power's Smart Grid project may be useful in doing so.

The difficulty in estimating which portion of the NPV costs will be attributable to ratepayers is understandable – current solar PV offerings in Nova Scotia do not leverage ratepayer investment, and no such programs have been planned to date.

Given that there already exist three differing and incomparable sets of revenue requirements within the IRP (reference, mid and high levels of electrification), having three incomparable cases through DER levels is cumbersome, and will likely stifle clear determinations about effective resource strategies.

Some portion of the NPV revenue requirement should be defined as ratepayer related and included within NPV revenue requirements. The current SolarHomes rebate limit of 25% of installed costs could provide a reasonable proxy for the portion of investment sourced from ratepayers. The limitation in this method is that current rebate levels may produce a trajectory more consistent with reference levels of DER, which already include considerable growth in PV to 2030, as opposed to the higher levels envisioned by the High DER case.

Levelization of DSM Costs

At the July 9, 2020 technical session, it was confirmed that supply-side resources are being amortized as part of the methodology associated with modelling within the IRP. The amortization of supply-side assets may not be especially impactful, since WACC is being used for both the amortization of assets, as well as the calculation of NPV revenue requirements.

Where amortization does have material effect on the NPV revenue requirement is in the domain of the end of planning period, as well as the end-effects calculations

[2] *Ibid.*, at slide 62.

performed as part of the broader study period (25-year Planning period + 20 year End Effects period).

In an illustrative example, a $100M investment in a combined-cycle (CC) Natural Gas generator is introduced in year 2040 of the IRP. Table 1 below shows the financial treatment of that generator under an amortization model and one without amortization, with a 50-year life estimated for the generator and WACC as the discount rate:

Table 1 - Amortization Effects in IRP

Year	Cost with Amortization ($M)	Cost without Amortization ($M)
2040	$3.89	$100
2041	$3.89	$0
2042	$3.89	$0
2043	$3.89	$0
2044	$3.89	$0
2045	$3.89	$0
Planning Period Costs	$23.32	$100
NPV Planning Period Costs (2021)	$5.66	$28.27

Very large financial differences exist as a result of the interaction of the planning period's finite duration and the existence of resource additions later in the planning period. For longer-lived supply-side measures, any resource addition will not have its full costs included due to the duration of the study period.

To reinforce the point, these differences are not a result of the amortization itself, rather the interaction of amortization and the planning period of the IRP.

Presently, DSM is being modelled within the IRP on an expensed basis, as opposed to an amortized basis. Based on the treatment of supply-side resources on an amortized basis, the DSM scenarios should be re-run with this similar treatment. E1 can assist in this by providing an amortized cost stream which reflects the amortization across the average measure life of each year's potential DSM activities (this cost stream would extend into the end effects period).

Through this revision, stakeholders can be provided with more accurate information regarding the true competitiveness of DSM, as opposed to a result which may include artifacts from the differing financial treatment of DSM.

The amortization of DSM in the context of the IRP does not need to speak to appropriateness of amortizing DSM in reality, since amortization itself does not affect

NPV revenue requirements (rather the interaction of amortization and the conclusion of the planning period does).

This change could be rapidly implemented without extensive effort, since DSM costs are included in the analysis through an extrinsic set of values.

Demand Response

Two aspects of the Demand Response (DR) modelling require further analysis:

1) DR was only allowed to compete at two discrete points in time (2021 and 2030).
2) DR was not permitted to retire or replace natural gas peaking resources in the analysis.

Both of the above issues constrain the competitiveness of DR and create a bias favouring supply-side peaking capacity. These treatments were justified to stakeholders on the basis that they reduced complexity in the model.

With respect to DR being constrained to two time periods, E1 appreciates the complexity that offering DR to the model in each year would produce. However, a more appropriate balance would be to allow its introduction in 2021, 2025, 2030, and 2035. This would provide a better balance in model complexity and a more consistent application of DR while more accurately reflecting the value of DR in Nova Scotia.

It is understood that the continued operation of peaking capacity against DR and other approaches was tested in the Resolve modelling before hard-coding the continued operation of the combustion turbine fleet in NS.

This method:

1) Prevents inspection of the detailed RESOLVE analysis by Stakeholders, as no modelling information has been made available.
2) Prevents the investigation of combustion turbine retirements in the Plexos LT environment.

The scenarios should be re-run without a fixed trajectory for combustion CTs, and allow DR to compete against those assets.

Additionally, please clarify on the following points relating to how DR was modelled:

1) In scenarios where DR is selected, it appears that 82MW of capacity is in place in year 1 (2030).
    a) Does the model assume that level of DR remains in place until 2045 with no changes in capacity?
    b) What is the DR profile for the remaining years?

c) Is there a ramp-up built into the DR assumptions as is the case with the 2019 DSM Potential Study?

2) Was DR available to the model in place of selecting the build-out of ~37MW capacity of new gas combustion turbines and reciprocating units in 2021?

The Availability of Detailed Information

In its May 12th Letter of Comment, E1 requested detailed inputs and outputs relating to a sample candidate resource plan, or at minimum those inputs and outputs related to DSM.[3]

Quantitative data regarding candidate resource plans' energy balances and new capacity additions was released on June 26, alongside the modelling results presentation – E1 appreciates this additional data.

E1 also appreciates that NS Power has made arrangements for a technical session with E1, where PLEXOS model parameters and data can be examined. This session may reduce or eliminate concerns that E1 and its consultant have regarding the release of data.

The availability of detailed quantitative information associated with IRP modelling results continues to be concerning. The graphical presentation of IRP modelling results is useful in a presentation context, but insufficient for the review of key findings by stakeholders and technical consultants. The Regulatory Assistance Project states:

> A proper IRP will include discussion of the inputs and results, and appendices with full technical details. Only items that are truly sensitive business information should be treated as confidential, because such treatment can hinder important stakeholder input processes.[4]

A full set of inputs and outputs associated with the 2019 DSM Potential Study, in the context of the work product being a single input to the broader IRP process. This level of transparency is needed for effective stakeholder input on the broader effort represented by the 2020 IRP itself.

Inputs and outputs from Plexos in tabular format for at least the Comparator cases (1.0A and 1.0C) are being requested. These data would allow for the quantitative review of items such as planning reserve margin (no results have been presented), the modelled costs of resources, model settings and other important factors.

Critical Importance of Transparent Evaluation Process

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[3] EfficiencyOne memorandum to NS Power – Interim Modelling Results, May 12, 2020.
[4] Wilson, R et al, Best Practices in Electric Utility Integrated Resource Planning, Prepared by Synapse Energy Economics for the Regulatory Assistance Project, June 2013, at Page 32.

The Analysis Plan[5] evaluation metrics included:

1. Minimization of the cumulative present value of the annual revenue requirements over the planning horizon (adjusted for end-effects);
2. Magnitude and timing of electricity rate effects;
3. Reliability requirements for supply adequacy;
4. Provision of essential grid services for system stability and reliability;
5. Plan robustness (the ability of a plan to withstand plausible potential changes to key assumptions);
6. Reduction of greenhouse gas and/or other emissions; and,
7. Flexibility (limitation of constraints on future decisions arising from the selection of a particular path).

With the latest information release, stakeholders now possess information relating to items one, four and seven. The remaining items appear to be part of the next phase of analysis planned, the reliability screening phase.

A large amount of analysis is yet to be undertaken on the candidate resource plans presented in this current release of information, and that analysis may be quite time-consuming and subjective.

To avoid a challenging, qualitative evaluation process that stakeholders may not be able to fully recreate, it is recommended that:

1. Within the written deliverables (Draft Findings, Roadmap & Action Plan) to be released (per the Terms of Reference), provide findings for each evaluation category for each candidate resource plan considered. This will allow stakeholders to better follow the more qualitative aspects of the evaluation process
2. When selection decisions are being made regarding specific candidate resource plans, or groups of similar plans, justification should be provided on the basis of evaluation criteria, and the relative importance of each criteria in making such a determination.

Additionally, stakeholders should be notified of the remaining planned dates for stakeholder consultation up to the end of September, and if any further overall extension to the process is being considered. The IRP process is behind schedule based on the Terms of Reference (due to beneficial additional length of comment periods) and several sensitivities are yet to be tested and released for stakeholder consideration. Please confirm whether the current IRP schedule is to be revised.

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[5] 2020 IRP Analysis Plan – Draft, Provided January 20th, 2020 at Slide 4. *Note: No final version of this document exists, per EfficiencyOne's understanding.*

Capacity Value of Non-Firm Imports

The modelling results appear to indicate that non-firm resources are being modelled as a source of capacity. Slide 30 of the Modelling Results information package (2045 Installed Capacity Across Current Landscape and Regional Integration Cases) shows material additions in system capacity associated with non-firm imports.

Since the Resolve models as presented on slide 30 are intended to represent those fed to Plexos LT to be further refined, this foundational work is seemingly important to overall flow of information within the IRP.

Given that it was clarified at the Technical Session that no particular source or market was being targeted for imports, it is difficult to make any assessment regarding the availability of capacity and energy from non-firm imports.

With this in mind, E1 requests:

1. Clarify any ongoing modelling impacts associated with the use of non-firm imports in RESOLVE.
2. Confirmation that the PLEXOS LT runs do not count any non-firm imports as capacity.
3. Clarify which candidate resource plans depend on the addition of 450 MW of firm imports from Quebec, or portions of this capacity if Plexos did not take the entire volume in any given scenario.
4. A sensitivity analysis run that limits market imports (both firm and non-firm) to 110% of recent historical averages, excluding firm commitments from Muskrat Falls. This inclusion would provide the benefit of a view with limited expansion of market opportunities, which E1 believes warrants consideration.

Given the significant volumes that firm and non-firm imports have within this IRP, the additional sensitivity will provide further information to all stakeholders to allow them to determine whether reasonable assumptions are in place for this aspect of the analysis.

New Natural Gas Capacity and Pricing

All candidate resource plans contain large amounts of new natural gas capacity, and associated energy production from these facilities. The minimum energy production in the year 2045 from incremental new natural gas facilities (not existing today) is 388 GWh, but many scenarios (70%) have in excess of 1000 GWh of energy production in 2045 from natural gas, with the average across candidate resource plans being 1679 GWh.

Given that the use of new natural gas generators is featured so prominently in the 2020 IRP, additional information and analysis is warranted on future natural gas pricing assumptions.

On the general topic of natural gas pricing in the 2020 IRP:

> With the shutdown in production from domestic sources (Sable Island and Deep Panuke), Nova Scotia will be reliant on natural gas imported via U.S. pipelines, LNG tankers, or an all-Canadian Path, via Western Canada.[6]

Additionally, it is stated that additional Baseload Gas pricing from would be based on "up to an additional 100,000 MMBtu/day firm contract"[7] from AECO.

The above reflects continued uncertainty regarding the future availability and pricing of natural gas in general, and especially in the case of incremental gas supply that is currently not contracted. This risk and uncertainty are not currently reflected in natural gas fuel price projections.

In the final assumptions set state that Peaking Winter Gas Pricing would be based on the following:[8]

1. TTF Spot Commodity Pricing (4Q2019).
2. Fuel & Tolls for delivery from Baileyville to Tufts Cove.
3. A market premium of $2.50/MMBtu for regasification.

No cost estimate has been made associated with the transportation of LNG from its point of title transfer to the Canaport facility in Saint John, NB.

In addition, the use of TTF Spot commodity pricing and future pricing is difficult to contextualize, given the likely requirement of a long-term supply agreement for the incremental new gas generation in each IRP scenario, even for use as Winter Peaking Gas.

For Baseload Gas, the following supply pricing structures are assumed:[9]

1. Henry Hub Commodity Pricing
2. AECO Basis
3. Tolls from Nova to Tufts Cove

Given that no contracts have been established, aside from precedent agreements associated with an initial 20,000 MMBtu/day of gas from Alberta for existing facilities, it is unclear as to the availability of pipeline capacity and commodity pricing certainty for such an analysis to be made.

The 2020-2022 Fuel Stability Plan submission indicates:

[6] 2020 IRP Final Assumptions Set, March 11, 2020, at Slide 8.
[7] *Ibid,* at slide 88.
[8] *Ibid.,* at slide 90.
[9] *Ibid,* at slide 91.

> The primary driver for the [Natural Gas] requirements is supply availability at prices competitive with solid fuel, the availability of imports via the Maritime Link and gas being a lower emitting fuel than solid fuel. Gas Swap contracts are financial instruments used to lower volatility in pricing terms for a supply contract. Forward price curves refer to a graph of future prices decided upon by both buyer and seller for any given commodity.
>
> Gas supply either has to be sourced from the TransCanada Pipeline Ltd. (TCPL) system and shipped across multiple pipelines or sourced from the Algonquin system once the Atlantic Bridge expansion is fully placed in service, which is forecast to occur in 2021 and provides a limited amount of additional capacity into the Maritimes & Northeast Pipeline.[10]

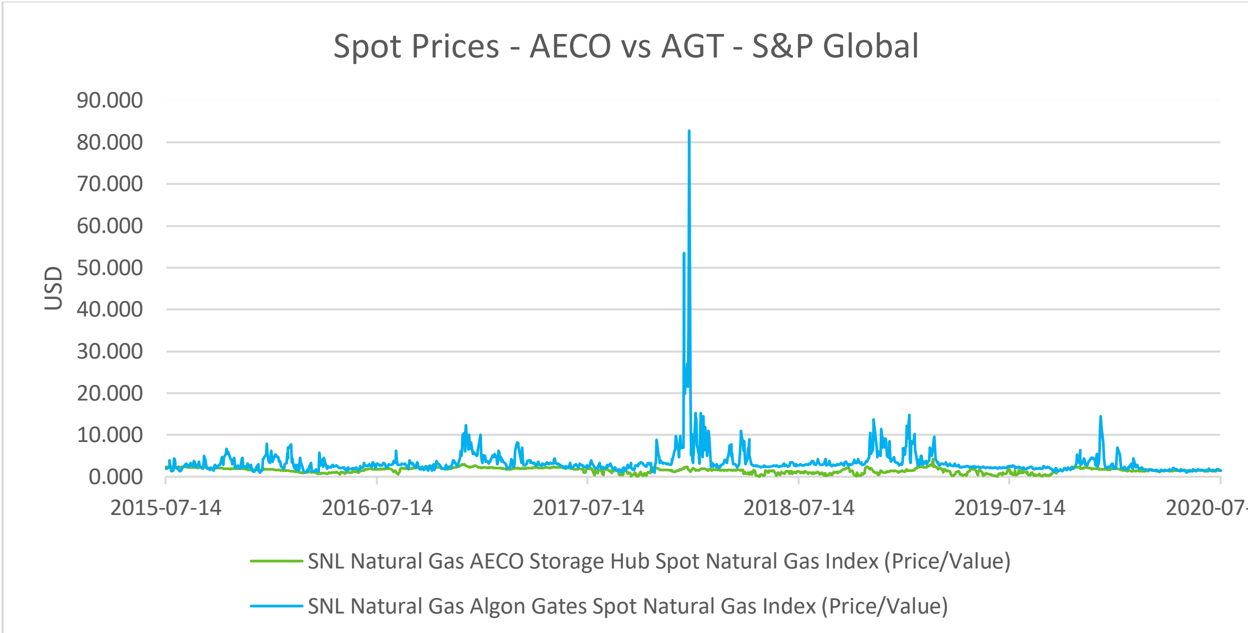
As an illustration of the complexity and risk associated with sourcing gas from the TCPL system, as of August 2019, supply contracts for gas assuming to be flowing in 2021 had not been secured, nor included the costs of transportation in modelling associated with the 2020-2022 Fuel Stability Plan.[11]

The assumption that new gas plant infrastructure will be constructed with a combination of TTF sourced LNG and uncommitted AECO gas introduces a large degree of risk, both in terms of using spot-sourced LNG (an IRP and operational risk) and uncommitted AECO gas (an IRP risk). Assumption sets which possess less risk should be examined, as suggested below:

1. An appropriate additional proxy for new gas supply, due to its physical location and connection to the Maritimes and Northeast natural gas pipeline system, and its presence in the 2020-2022 Fuel Stability Plan, would be to use the Algonquin Gates (AGT) as the commodity price for new natural gas capacity (both peaking and baseload), with the inclusion of energy and tolls reflecting transport from AGT to Tufts cove.

   Figure 1 below provides a comparison of AGT and AECO historical spot prices:[12]

[10] 2020-2022 Fuel Stability Plan at Pages 52-53.
[11] M09288, N-3, NSPI to Bates White RIRs, Filed August 8, 2019, at RIR-08 a).
[12] S&P Market Intelligence – Spot Nat Gas Index



The historical AGT prices are generally higher than AECO spot prices, especially so during periods of higher winter pipeline demand in the US Northeast. The use of future pricing from AGT may provide higher overall gas prices than the Canaport LNG/AECO combination, but this source of supply should be considered. The pipeline demand and availability for 100,000 MMBtu of AECO gas will also likely be an issue, but these challenges are not precisely understood by stakeholders. The use of AGT pricing would provide greater transparency to a source of supply that is already being assessed based on the Rate Stability Plan, with less dependence on forward-looking complexity of obtaining gas supply from AECO and TTF.

2. In addition, sensitivity analyses that explores the constrained availability of natural gas for the NS electricity system should be included, at least in terms of incremental capacity additions beyond 20,000 MMBtu per day. Put another way, constrain the model to only allow for consumption of 20,000MMBtu per day, thus allowing the model to economically select other resources other than natural gas beyond the currently contracted firm supply.
3. Gas price sensitivities can then appropriately explore higher or lower pricing scenarios that impact future capacity additions to the system, and differing limits on the availability of gas.

   The Final Assumptions set indicate that:

   If the IRP Action Plan indicates new investment in natural gas resources, [Dual Fuel Capability, Natural Gas Storage, and LNG Alternatives] would be considered in a more detailed analysis.[13]

[13] *Ibid.,* at slide 92.

These fundamental questions regarding natural gas pricing and availability must be answered in the context of the IRP prior to it being finalized, if the IRP results are to show the degree of sensitivity to commodity costs. They will fundamentally affect pricing and the selection of resources, which will not be reflected in an after-the-fact analysis.

E1 appreciates the opportunity to provide ongoing comments in relation to the 2020 IRP, and is available for discussion on any of the comments made.

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Submitted Comments Regarding 2020 IRP Modelling Results

July 17, 2020

The Ecology Action Centre (EAC) welcomes the opportunity to participate as a stakeholder in the 2020 Integrated Resource Plan process. We submit the below comments and questions in response to the Modelling Results released for stakeholder comment, and discussed at the IRP stakeholder session on July 9, 2020. Specifically, this submission is in response to the below documents:

i) *NS Power 2020 IRP Modeling Results Release*
ii) *2020 IRP Final Assumption Set*

It is also important to note in this submission that the capacity of EAC to engage in this process is greatly reduced due to the design and process of the 2020 IRP, and the lack of availability for stakeholder funding and support through the NSUARB, through the NSPI-led process, or through the Nova Scotia Department of Energy and Mines.

The EAC feels very strongly that this process should not be considered just another Integrated Resource Plan. Nova Scotia Power Incorporated (NSPI) is the third most polluting energy utility in Canada. We have the opportunity to make NSPI one of the least polluting energy utilities in Canada and limited time to make these decisions with significant long term consequences for emissions and especially for utility ratepayers.
.
Two significant gaps remain in the scenarios undergoing analysis.

Firstly, the study is inconsistent with GHG trajectories needed to align with international, federal, provincial, and local emissions reductions plans. No zero emission scenarios are studied, although the study mentions that mid- and high-electrification scenarios follow SDGA 2050 end points, and there are delayed zero emission targets; perhaps never achieving zero emissions will limit the opportunities for other sectors to rapidly decarbonize.

Secondly, the study restricts the model's ability to add firm imports and as such biases the result towards gas turbine construction, continued natural gas purchases and GHG emissions from both direct combustion and upstream fugitive methane emissions (which are not currently accounted for under this process). Long decarbonization trajectories endorse the replacement of coal generation with natural gas resources and it is not clear if these generators will be cost effective when utility emissions are regulated to zero. Faster trajectories to zero electric utility emissions may be more cost effective over the study period and the related end-effects time frame.

The EAC welcomes the opportunity to submit written comments to this process, and acknowledges the time and effort of Nova Scotia Power staff in answering our questions in the pre-IRP and IRP periods.

Thank you,

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The Roadmap for our Future

We are not continuing the long-term planning process from 2007 and 2017. There are many external influences that are occurring right now in Nova Scotia that we have never encountered before. There are federal and provincial greenhouse gas emission targets that must be considered in this integrated resource plan and adhered to in order for our province to thrive. In the last five months, we have encountered increased instability in energy consumption and production, and a global pandemic that will shape the future of energy production in our province. We have restricted this consultation process to a timeline that requires a submission to the Utility and Review Board by September 30, 2020. Considering the exceptional circumstances that the world is in right now, we urge all stakeholders involved in this process to consider an extended timeline that would allow more stakeholder consultation and a final submission deadline to the UARB of **November 30, 2020.**

To address gaps in GHG trajectory analysis and modelling bias, the EAC recommends the following actions to close these gaps and yield an IRP that can provide input to GHG planning activities beyond the electrical utility landscape rather than react as GHG requirements become increasingly strict. Proactive planning will, in the long run, minimize costs to ratepayers.

Action 1) Model scenarios that achieve zero GHG emissions.

Consider examining cases for 2050, 2045 and 2035. Zero emission cases will provide an assessment of the costs required to operate from imports, sequestered carbon emissions and renewable energy. Increased costs to the utility add value to efforts across the regional GHG reductions landscape by maximizing the impact of electrification. The modeled scenarios, at present, all incorporate a replacement fleet of combined cycle natural gas infrastructure. A zero emissions study enables the model to compare the costs of adding carbon sequestration to these generators against the costs of increased clean imports. It is not clear from the scenarios studied that replacement of coal thermal plants with natural gas infrastructure is the lowest long-term pathway to a zero emission state. Modelling accelerated zero emission timelines may well reveal lower long-term cost solutions. Accelerated net zero timelines can and should analyze multiple energy mixes.

Description (New Transmission)	Total Capital Cost ($2021) [1]	NB-NS Tieline Gross Capacity (MW)
345kV Onslow-Salisbury-Coleson Cove	$600M	700
345kV Onslow-Salisbury ; HVDC to QC [2]	$1.7B	1000

- Assumptions presented here would be subject to additional feasibility study if selected during the IRP modeling.
- The transmission costs above are the assumed total capital cost of the builds and do not reflect potential cost sharing. Opportunities for cost sharing may depend on forecast utilization and will be examined during the resource screening phase.

1) Earliest in-service date is 2026
2) Costing to Quebec Border.

Nova Scotia POWER An Emera Company

2020 IRP FINAL ASSUMPTIONS SET 74

Source: Page 74- https://irp.nspower.ca/files/key-documents/assumptions-and-analysis-plan/20200311-IRP-Assumptions-Final.pdf

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Action 2) Report the detailed operational profiles of natural gas and diesel generation assets (number of operations per year, their durations and power and energy associated with each unit).

This data will be useful in using these model choices as proxies for identifying cost effective alternate generation or storage solutions in the future. These may include long duration battery storage or tidal power, among others, as technologies mature. One specific example would be the recent announcement of a 150 hour duration battery demonstration by Form Energy and Great River Energy in Minnesota (https://www.electric.coop/great-river-energy-co-op-test-groundbreaking-battery-energy-storage-system/). Industry is working across a broad technological landscape and the utility, regulator and stakeholders must be in a position to evaluate emerging solutions.

Action 3) Ensure that the model's portfolio of assets always includes the ability to add an additional transmission line through New Brunswick to Quebec as identified in the IRP assumptions set (IRP Update Appendix C Page 75 of 136).

Action 4) Call upon the Board and the Provincial Government to fund a Sustainability Advocate to participate in future hearings with resources similar to those available to the Consumer Advocate and Small Business Advocate.
There is no dispute that controlling costs for consumers and small business is important but without well resourced review from a regional sustainability perspective, net costs to consumers and small businesses may not be fully understood.

These actions will ensure that this 2020 IRP positions the utility, the regulator and citizens of Nova Scotia to make informed and timely choices in the immediate future.

Gaps and Opportunities in IRP 2020.

Zero Emission Planning and Planning Alignment
While the models address several so-called net zero scenarios, the term is simply aspirational. No carbon credit purchase costs are included to bring these cases to net zero. As such, these cases should be labeled Near-Zero rather than Net-Zero.

The declining slopes of the emissions curves all cross zero outside the planning window. While a regulatory plateau may come to pass, it is more likely that the lines will ultimately reach zero and reserve economy wide emissions for more intractable fossil fuel applications. Moreover, it is entirely possible that future GHG regulations may encourage negative emission curves to incentivize atmospheric capture of carbon. For example, carbon sequestration of the CO2 emissions from biomass could create a negative emissions condition. In any event, the slopes in the planned trajectories will all cross zero between 2065 (Comparator case) and 2052 (Net Zero 2050) but the modeled scenarios do not consider this near certainty.

What will the utility look like when actual emissions must be zero (or less)? Do the trailing end effect costs include carbon sequestration from the operational gas plants at the end of the study period? Because no zero emissions case within the study period has been considered and all near zero cases build combined cycle gas to work with intermittent wind resources, these predictable costs are not identified.

It is clear that in the face of dramatically reduced emissions limits, the model first chooses interconnection over generation. It is entirely plausible that a zero emissions limit at 2050, 2045 or 2035 would react the same

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provided it had access within the model to more regional interconnection. It may be that greatly reduced generation is built and that zero emissions are achieved faster for limited additional expense to the utility and avoided rate base costs to the ratepayer. The last thing this process should plan for is a new life cycle of generation that will require expensive upgrades or premature retirement. Only a zero emission scenario can fully determine if this is truly cost effective.

The costs to the ratepayer are not fully comparable between scenarios. High electrification cases presume that consumers are replacing fossil fuel costs for heating and transport with electrical costs and there is substantial potential that this transition will provide significant savings to consumers.

Present electric vehicles provide 100 km of electric transport for 15 – 20 kWh of electricity and for a cost of less than $3.20. At a Canadian average of 8.9 liters of gasoline per 100 km (https://www.cer-rec.gc.ca/nrg/ntgrtd/mrkt/snpsht/2019/07-05hwdscndrnk-eng.html), and today's depressed prices (97.8 cents per liter 2020/07/10), the same 100 km using gasoline costs $8.70. For a 16,000 km per year consumer the savings today amount to $880.00 per year. While the consumer would see an additional $85.33 per bi-monthly electricity bill, they would avoid a $231.99 gasoline expense over the same time period.

Accounting for the difference in average generation cost summarized on page 30 of the results, the cost of 100 km of electric transport rises to $3.52 and the annual net savings to a consumer declines to $828.80 per year. For an estimated annual use of 15,000 kWHr/year, an added 1.6 cents per kWHr would add $240 in costs, still well below the savings from operating an electric vehicle. The scenarios with high electrification envisage substantial vehicle electrification. Page 8 of the E3 study reports the values in the excerpt (Figure 5, below). 150,000 EV's on the road in 2030, 590,000 in 2050. Direct consumer financial benefit will be substantial. Further accounting of health benefits would likewise represent long term financial savings to the province.

Clearly, a structured and measured assessment of this benefit is an important part of the net present value to ratepayers.

The same high electrification rate conditions likewise underestimate benefits and projected savings from building heating and electrification. While the E3 Pathways report contemplates electrification of heating systems, it does not account for improved building quality beginning in 2030 from new construction, nor is there an assumption around the rate at which older building stock may be renovated as cladding and window systems approach replacement age.

These measures form an integral part of Canada's Building Strategy as currently envisioned by the federal government under the Pan-Canadian Framework on Clean Growth and Climate Change (https://www.nrcan.gc.ca/energy-efficiency/energy-efficiency-buildings/canadas-building-strategy/20535).

These federal initiatives have the stated goal:

"Federal, provincial, and territorial governments will work to develop and adopt increasingly stringent model building codes, starting in 2020, with the goal that provinces and territories adopt a "net-zero energy ready" model building code by 2030."

https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/emmc/pdf/Building_Smart_en.pdf

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Assumptions aligned with these goals are included in modelling efforts such as those used for HalifACT planning and can dramatically reduce energy demand and also present an opportunity for cost effective demand response.

The distinction is critical. These structures require substantially reduced heating load, so the high electrification scenarios may overstate load growth. Likewise a high performance structure's low heat requirements enable demand response in heating systems. Measurements on winter loss of heat conditions in high performance buildings regularly take several weeks for the internal temperature to drop to stable values near 12C. Low heat rate losses enable cost effective demand response using hot water and existing ETS technology. None of these opportunities are represented in these cases.

The recently issued HalifACT report plans for reduced emissions sooner and most transition strategies frontload emissions reductions on electrical utilities to enhance the impact of electrification. This has been our experience in the past where diverse governments across the political spectrum turned to the electrical sector to lead emissions transition

The IRP must consider scenarios that align with these goals, if for no other reason, to advise Halifax on the implicit costs (or savings).

Import and Natural Gas Trade-offs:

Scenarios that modeled regional integration indicate that the Reliability Tie (345 kV Onslow - Salisbury) and the Regional Interconnection (345 kV Salisbury to Coleson Cove) are selected early when seeking solutions to declining GHG limits. The proposed March 11, 2020 IRP Assumptions (IRP Update Appendix C Page 75 of 136) listed a third interconnection (Salsbury - Quebec HVDC) and it is not clear that this was an active option in all of the modeled scenarios or just the regional integration scenarios. If it were available, it is not clear that, if presented with a zero emissions case in the study window, the model might well choose it over gas generation with carbon sequestration.

In addition, there is a risk that planning gas turbine construction and continued natural gas purchases will ultimately carry a higher carbon emissions factor. The North American natural gas supply has additional emissions associated with upstream fugitive methane emissions. While not currently accounted for under this IRP process, there is a clear risk that at some point in time they will be included as regulators seek to achieve real emissions reductions. Multiple studies indicate that fully accounting for these emissions brings the natural gas supply close to emissions intensities associated with coal combustion. (Assessment of Methane Emissions From the U.S. Oil and Gas Supply Chain, By Ramón A. Alvarez, Daniel Zavala-Araiza, David R. Lyon, David T. Allen, Zachary R. Barkley, Adam R. Brandt, Kenneth J. Davis, Scott C. Herndon, Daniel J. Jacob, Anna Karion, Eric A. Kort, Brian K. Lamb, Thomas Lauvaux, Joannes D. Maasakkers, Anthony J. Marchese, Mark Omara, Stephen W. Pacala, Jeff Peischl, Allen L. Robinson, Paul B. Shepson, Colm Sweeney, Amy Townsend-Small, Steven C. Wofsy, Steven P. Hamburg, Science13, Jul 2018 : 186-18) (https://www.bloomberg.com/news/articles/2020-01-23/gas-exports-have-dirty-secret-a-carbon-footprint-rivaling-coal-s)

There is risk that the emissions ratings of combined cycle natural gas systems will be raised.

Non-zero emissions allowances and optimistic emissions factors for natural gas create conditions where building natural gas fired systems is the most cost effective response to declining GHG levels. The concern is that when

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emission limits fall to absolute zero, significant (approximately doubling - IRP Update Appendix C Page 39 of 136) costs will be incurred to sequester the carbon output of these plants.

Please ensure that all models can add multiple interconnections and run scenarios that study zero GHG conditions.

It is critical that this IRP fully assess the import options available to Nova Scotia.

Generation Operational Data

The combined cycle and regular gas turbine systems that are frequently selected in the studied scenarios are selected for their functional characteristics and low costs. As mature technology, these systems represent the best in class low emissions fossil fuel generation equipment today. It is not clear that this will be the case over the full extent of the study period. Already solar dominated utilities are choosing utility solar and battery systems over natural gas systems. While these systems benefit from low battery durations and matched renewable resource and loads (Hot sunny days store more energy to power evening air conditioning), Long duration energy storage employing low cost battery materials, flow batteries and other concepts are active development areas. Tidal resources within Nova Scotia are substantial and it remains a possibility that these systems will mature within the time frame of the study period as well. It is entirely likely that viable alternatives to lithium battery systems will emerge within the first half of the study period.

For this reason, it is important to characterize the operation of the gas combustion resources selected by the model as a proxy for the cost threshold and performance that alternate systems will be required to meet. Knowing the cost, typical operational profile and duration of these systems will provide ready early evaluation of emerging solutions as applied to specific operational conditions in Nova Scotia.

Sustainability Advocate

The capacity of EAC to engage in this process is greatly reduced due to the design and process of the 2020 IRP, and the lack of availability for stakeholder funding and support through the NSUARB, through the NSPI-led process, or through the Nova Scotia Department of Energy and Mines. This is true for other organizations who advocate on behalf of climate mitigation, environmental concerns and energy affordability concerns, who do not have staff regulatory or legal counsel capacity to engage in this important energy planning process. Rather these organizations rely on a patchwork of volunteers over a multi-year timeline.

Although NSPI has made every effort to make the 2020 IRP process accessible to stakeholders, we regret the lack of financial and structural support for organizations to participate. The EAC feels that this problem is ongoing. NSPI and NSUARB processes will continue with ad hoc sustainability oversight until the Department of the Environment, Department of Energy and Mines, or Nova Scotia Power create an updated mandate to support climate change and environmental concerns in a way similar to the Consumer Advocate or the Small Business Advocate.

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Moving Forward

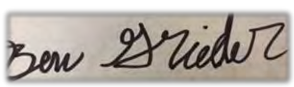
The EAC believes that Nova Scotia still has an opportunity to set long-term ambition, and commit to phasing out coal-fired electricity in Nova Scotia. This IRP process will determine the future of our electricity grid in ways that will hinder or facilitate a just transition in Nova Scotia.

We need to ensure that low and middle-income Nova Scotians, coal workers and communities all benefit from this change in our electricity system, and the EAC believes that this transition is possible in an affordable, just and timely way.

The EAC looks forward to continued participation in the 2020 IRP stakeholder process, and ongoing conversations regarding Nova Scotia's electricity future.

Ecology Action Centre is committed to continuing to ensure Nova Scotia sets a pathway to phasing out coal-fired electricity generation, and looks forward to working with all partners toward the just transition to a prosperous, green economy.

Thank you for your consideration,



Ben Grieder
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See Also:
Ecology Action Centre's Electricity Report and Ongoing Work on Coal Phase-Out:
https://ecologyaction.ca/electricityreport

Setting Expectation for Robust Equivalency Agreements in Canada (April 2019)
Climate Action Network Canada | Canadian Association of Physicians for the Environment | Centre québécois du droit de l'environnement | Ecology Action Centre | Environmental Defence | Pembina Institute
https://ecologyaction.ca/sites/ecologyaction.ca/files/images-documents/CAN-Rac-Equivalency-Paper-2019-web.pdf

The Just Transition Task Force on Coal Workers and Communities Final Report:
https://www.canada.ca/en/environment-climate-change/news/2019/03/government-of-canada-welcomes-report-from-just-transition-task-force-for-canadian-coal-power-workers-and-communities.html

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And

Crystal Henwood
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Via Email: Crystal.Henwood@novascotia.ca

July 17, 2020

Re: M08929 – Integrated Resource Planning – Response to Initial Run of Scenarios

Dear Ms. Godbout and Ms. Fris:

Envigour Policy Consulting Inc. has been retained by QUEST and Marine Renewables Canada as their Consultant in this matter. We have participated in the discussions regarding the initial outcomes from the scenarios.

We have found the information and discussion to be useful and insightful. To maintain the value of this extensive planning process, we suggest the following matters be explored before closing the IRP and developing the Roadmap.

1. DERs are considered a reduction in system demand without a cost to the system. We would want to understand how this assumption fits within the requirement to allow for Enhanced Net-metering by customers. Also, to simply assume DERs as reduced demand for system electricity, likely undervalues the potential positive contribution to the system that could come from a combination of DERs such as solar PV and storage by customers. We understand NS Power is exploring this potential through the NS Smart Grid project and related initiatives.

   The benefits from resiliency and reliability offered by DERs may be part of your planned next step runs and scenario testing. If so, information from that process may help gain insights into the value of DERs, especially when combined with storage. However, we believe there will likely be the need for additional discussions on these matters, and how to incorporate them into the Roadmap.

   Also, several NS Municipalities have expressed interest in Community Solar PV Gardens. It would be useful to discuss whether this concept is the same as DERs from the model's perspective and, if not, how it may be considered as well.

2. The model did not select several potential technologies such as offshore wind, tidal or hydrogen. It would be useful to know what the gap was between these technologies and the ones are chosen. It would help us understand the degree price reduction required to make them competitive in the future. Furthermore, it would be useful to know how the model would have valued any of the unique properties associated with these technologies, such as the predictability of tidal. If they were not valued, what process or opportunity might we see in the future to gain better insight?

3. Several runs chose natural gas solutions. It is difficult to see precisely what was selected as the options are shown in 5 shades of grey. Nevertheless, the narrative suggests a CCGT solution appears in several runs. We recommend there be a fuller discussion of the costs and benefits associated with an investment in this area. We would consider what kind of pathways/solutions would be necessary to achieve a net-zero electricity system by 2050 with a CCGT investment to be a priority. We would also want to identify and quantify the risk to electricity reliability from a dependence on a single natural gas pipeline. Identifying the risk of not being able to have local storage of natural gas should also be explored from a reliability perspective.

4. Each of the scenarios has a different impact on the NS GDP. Will the IRP process be able to differentiate which scenarios would more likely use NS sourced goods and services on a CAPEX and an OPEX basis?

Bruce Cameron
Principal Consultant,
Envigour Policy Consulting Inc.

c.c. Tonja Leach, Executive Director QUEST
Via Email: tleach@questcanada.org

Elisa Obermann, Executive Director of Marine Renewables Canada
Via Email: elisa@marinerenewables.ca

Heritage Gas

July 17, 2020

Nicole Godbout
Director, Regulatory Affairs
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RE: M08929 – NSPI Integrated Resource Planning – Modeling Results Comments

Heritage Gas is the regulated provider of natural gas distribution service to Nova Scotia residents and businesses. Heritage Gas has been attending stakeholder meetings and workshops with Nova Scotia Power Inc. ("NSPI"), Energy+Environmental Economics ("E3") and other stakeholder groups. Heritage Gas is interested in understanding NSPI's Integrated Resource Plan ("IRP") and its interplay with long-term overall energy planning for the province over the next 25 years.

Natural gas has played an important role in electrical generation in the province for many years beginning with capital investments at Tufts Cove in 1999 that facilitated the use of natural gas as a fuel for the three generating units at that station. Reliance on natural gas further increased with the addition of the combined cycle combustion turbines at Tufts Cove. The modeling results distributed to interested stakeholders on June 26, 2020 and presented on July 9, 2020 indicate reliance on natural gas will continue to increase over the next 25-year period. The results show that increased natural gas capacity will be necessary to meet peak energy requirements and environmental targets while also providing critical ancillary services. The use of natural gas is robust across all scenarios in the Modeling Results.

Increased Reliance on Natural Gas and Planning Reserve Margin Issues

Heritage Gas notes that near-term resource changes in 2026 have included the need for "*New Gas CTs & Recips*" in every scenario provided by NSPI[1]. The more aggressive environmental targets being modeled

[1] Page 14 –IRP Modeling Results Workshop – 2020/07/09.

Heritage Gas

within various scenarios increase the demand for natural gas given the intermittent nature of more renewables.

At least one Combined Cycle ("CC") gas unit has been selected in each scenario in the late 2020's and early 2030's (slide 22). Heritage Gas notes that "late 2020s-early 2030s" is very close in the planning horizon. As NSPI is aware, assets were constructed by Heritage Gas for the purpose of providing service to NSPI that can provide various options for items identified throughout the modeling in the IRP.

As well, the long-term resource changes emphasize the need for additional natural gas resources, where some additional coal-to-gas conversions have been selected by the model[2].

Finally on this point, NSPI identified ~30MW deficiency in Planning Reserve Margin ("PRM") remains and NSPI has identified that a "*small early build of CT / Reciprocating resources resolves existing PRM deficiency*"[3].

<u>Reliability of Liquid-Fueled Combustion Turbines ("CTs")</u>

The liquid-fueled CT's provide a variety of critical ancillary services including 10- and 30-minute operating reserve, voltage support and black start capability in the event of a partial or total loss of the electrical grid[4]. The units are now over 40 years old. The model scenarios include the continued use of these units to 2045[5], by which time they will have been in service for over 60 years. Heritage Gas understands that fuel delivery to these units is by tanker trucks and, as a result, replenishment of the tanks that support these units is reliant on the availability of a limited pool of tanker trucks. This pool is further constrained in winter months when the units are more likely to be called upon. Availability of fuel supply has decreased following the closure of local refineries. Reliability issues associated with maintaining units out to their

[2] Page 16 – IRP Modeling Results Workshop #4 – 2020/07/09.
[3] Page 22 – IRP Modeling Results Workshop #4 – 2020-07-09.
[4] M09560 – NSUARB Decision – NSPI Approval of 2020 Capital Work Order (March 23, 2020).
[5] Page 15 – IRP Modeling Results Workshop #4 – 2020/07/09.

sixth decade of operation should be considered independently of the economics of replacement vs sustaining capital costs. Reliability test results should be made available to IRP stakeholders.

<u>Electrification Contribution to Peak Load & Associated Transmission & Distribution ("T&D") Costs</u>

NSPI's Modeling shows the potential for large increases in peak energy demand[6]. Increased electric load and increases in peak demand will have significant cost implications for NSPI's transmission and distribution ("T&D") assets. Heritage Gas understands that these are issues that have not had to be significantly considered in previous IRPs. NSPI's consideration of T&D cost implications appears limited to avoided T&D Costs with respect to DSM[7] and regional integration.

Given that IRP outcomes can influence long-term capital investments and policy directions, the total cost implications of IRP outcomes for rate payers should be examined in the Action Plan. Increased electrification (e.g. building heat, transportation) will contribute to peak energy demand. A number of studies have shown that natural gas distribution systems can cost effectively assist in meeting peak energy demand while still meeting GHG targets. The nature of the results of the IRP analysis and the significant reliance on natural gas going forward in all scenarios provides an opportunity for Heritage Gas to work with all stakeholders to ensure the most cost-effective energy supply system in the province going forward.

Heritage Gas appreciates the continued open and collaborative process with all stakeholders to date on this IRP. While various other issues related to the above matters were discussed with NSPI, Heritage Gas felt it appropriate to highlight the foregoing points for all stakeholders. We look forward to the continued dialogue with all stakeholders throughout the remaining elements of the IRP, including the development of the Action Plan.

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[6] Page 9 – 2020 IRP Assumptions Set (January 20, 2020).
[7] E-ENS-R-19– M09471 – Efficiency One – 2019 Historical Rate and Bill Impact Analysis (March 27, 2020 Letter).

Heritage Gas

Regards,

HERITAGE GAS LIMITED

John Hawkins
Cc: M08929 Participants

Question No.	Part a,b,c,...	Subject	Topic	IRP Reference	Pages	Quoted Materials	Preamble	Information Request / Clarification
1	a	Demand	Load Forecasts	NS Power 2020 IRP Modeling Results Release June 26, 2020	5-6	*The Mid and High Electrification forecasts are adjusted to moderate the original steep ramp up in electrification over the first 10 years of the forecast; the end points remain unchanged as they are consistent with the established SDGA goals (as modeled in the PATHWAYS study)*	The decision to maintain the endpoints requires further justification. Historically, the effect of substantive economic contraction on electricity demand is a modest to substantial downward (or rightward) shift in the demand curve following the recession, for both energy and peak capacity. Not accounting for this shift in the load forecast potentially creates a systemic bias across all findings in the IRP.	Provide a tabular and graphical summary of NSPI energy (GWh/year) and firm capacity (MW) load forecasts over the prior 20 years, illustrating the effects of the prior recession (i.e. of 2008-2010) on load and on load forecasts for the NSPI service area pre- and post-recession.
	b							Discuss the findings of the data from part a) and explain and justify how the current IRP load forecasts have been appropriately adjusted to reflect long-term (and not only medium-term) recessionary effects on demand.
	c							Provide the data in excel format for the load forecasts illustrated graphically in the Modelling Results Release (p.5) or indicate where they are publicly available.
2		System	Inertia	NS Power 2020 IRP Modeling Results Release June 26, 2020	8		The table includes Lingan 2 as providing an inertia contribution though this unit appears to have been omitted from other analyses in the IRP since it is replaced by the Maritime Link.	Clarify the inertia contribution of Lingan 2 prior to and following replacement by the Maritime Link, and indicate effects (if any) on the inertia analyses.
3	a	Supply	Diesel CTs	NS Power 2020 IRP Modeling Results Release June 26, 2020	11-17	*The 231 MW diesel CTs are largely used to provide capacity and ancillary services when included in the system* *• They are not run frequently (<1% CF)* *When diesel CTs are removed, RESOLVE builds new gas peakers to replace lost capacity* *• Note that higher ELCC* for replacement gas peakers means less than 231 MW is needed for an equivalent reliability contribution* *• The gas peaker replacement resource is selected economically ahead of other potential replacement options (e.g. battery storage or NGCC units)*	The cost of carbon ($/tCO2e) considered in the analysis is not provided for the diesel CTs or for the lowest-cost alternative, namely natural gas CTs, potentially due to the infrequent operation of these facilities. The cost of replacing the diesel CTs with the lowest-cost non-emitting capacity alternative (e.g. batteries, capacity expansion at existing hydro facilities, pumped storage, additional non-emitting firm capacity imports, demand response, some combination, etc.) is not provided. In addition, it is unclear whether the lowest-cost alternative changes (e.g. due to anticipated cost declines in battery storage, increasing carbon costs, or other reasons) prior to the date when significant sustaining capital expenditures are anticipated for the diesel CTs.	Provide the carbon costs used in the analysis of the system value of the diesel CTs shown in the Modeling Results Release. Explain and justify these carbon costs, and indicate whether they differed for different analyses in the IRP.
	b							Produce graphs similar to those on the left side of pp. 15-16 of the Modelling Results Release illustrating the following: - the NPV of the replacement cost of the lowest-cost non-emitting alternative capacity resource (or combination of resources) to diesel CTs; and - the NPV of the replacement cost of natural gas (blue bars) and diesel CTs (yellow bars) inclusive of carbon costs For this analysis: - assume carbon costs (in $2020 CAD/tCO2e) of $50 in 2022, rising to $200 in 2030 and $500 in 2050, or explain and justify an alternative series of carbon costs; and - identify any assumptions concerning the future costs of the analyzed resources
	c							For the analysis in part b), identify the dates (if they occur prior to 2050) when: - natural gas is no longer the lowest-cost alternative or combination of alternatives to diesel CTs; - diesel CTs no longer have an NPV cost advantage over natural gas; and - diesel CTs no longer have an NPV cost advantage over the lowest-cost non-emitting alternative or combination of alternatives
	d							For the initial analysis and for the analyses in part b), how sensitive are the findings to: - the assumed dates for significant expenditures on the diesel CTs (e.g. if they occur on a cycle 5 years earlier than anticipated)? - discount rates - cost declines in battery storage
4	a	Supply	Hydro	NS Power 2020 IRP Modeling Results Release June 26, 2020	19-27	*During screening the model was free to re optimize the resource portfolio and to select any available supply options to replace the hydro capacity and energy (e.g. new gas CTs/CCGTs, batteries, firm and non firm imports, wind, etc.) ...* *Wreck Cove and Mersey were modeled individually and remaining systems were modeled in two groups with similar operating characteristics*	For Wreck Cove, the RESOLVE results indicate the significant value of both energy and capacity, and modest value of regulation (up) provided by the facility in both scenarios throughout the planning period. It is not clear whether the model was free to also consider capacity expansion at Wreck Cove (e.g. capacity additions, pumped storage), or changes in operations (e.g. trading off energy benefits for capacity benefits, etc.) that could potentially add greater value.	Clarify what analysis was undertaken during or prior to the IRP process to investigate the merits of capacity expansion, pumped storage additions or operational adjustments to increase value from the Wreck Cove facility.

Question No.	Part a,b,c,...	Subject	Topic	IRP Reference	Pages	Quoted Materials	Preamble	Information Request / Clarification
							It is understood that planning for redevelopment of the Mersey system is currently underway. As with Wreck Cove, it is not clear whether the model was free to consider capacity expansion within the Mersey system (e.g. capacity additions), or changes in operations (e.g. trading off energy benefits for capacity benefits, altering downstream flow requirements, etc.) that could potentially add greater value.	Clarify what analysis was undertaken during or prior to the IRP process to investigate the merits of capacity expansion or operational adjustments to increase value from the Mersey system.
							The analysis would benefit from the consideration of uncertainty. This is particularly the case for the Mersey system where the NPV cost of continuing to operate these facilities is not overwhelming less than decommissioning and replacing the assets, as illustrated on pp. 26-27. It is also quite conceivable that there are quantitative and qualitative environmental costs and benefits to decommissioning these facilities that appear to go unaddressed in the analysis of these hydro assets.	Identify and quantify potential cost uncertainties associated with decommissioning, developing replacement resources, and continuing to operate the Mersey facilities. What event or series of events would need to occur in order to result in a NPV cost benefit for decommissioning these facilities? Discuss the likelihood of these events occurring, and the risks to NSPI of proceeding with redevelopment. Discuss the potential environmental costs and benefits that could result from decommissioning the Mersey facilities.
5	a	Supply	Imports	NS Power 2020 IRP Modeling Results Workshop July 9, 2020	19	*Incremental firm imports are selected when offered via a Regional Interconnection ...* *Both firm and non firm imports play a significant role to meeting energy requirements in all scenarios examined*	Information is lacking concerning the proposed firm and non-firm imports. In general, the delays in commissioning the Muskrat Falls Project and Labrador-Island Link illustrate the differential costs and risks associated with reliance on imported electricity developed in other jurisdictions compared to reliance on resources developed within Nova Scotia.	Please provide additional information concerning the firm and non-firm imports contemplated for meeting future requirements in all future scenarios in the IRP, including: - the additional generation resource(s) that would be developed in neighbouring jurisdictions, including their costs and development timeframes; - the operational emissions (if any) associated with these generation sources; and - the costs and development timeframes associated with transmission necessary to deliver this imported electricity.
	b							Discuss the risks to NSPI ratepayers of reliance on significant quantities of imports in all scenarios for meeting future energy requirements. What contingency plans are in place to meet future energy requirements in the event that imported resources are unavailable at the costs or on the timeframes contemplated in the IRP?
6		Supply	Natural Gas CCGTs	NS Power 2020 IRP Modeling Results Workshop July 9, 2020	22	*At least one combined cycle unit was selected economically in each scenario (late 2020s-early 2030s)*	Unlike natural gas peakers, which operate infrequently and produce minimal GHG emissions, natural gas CCGTs typically have much higher capacity factors and produce substantial GHG emissions as a result. There is a considerable body of literature suggesting that the future development of CCGTs in North America - regardless of their economic advantages - beyond 2025 or even beyond 2020 is imprudent considering the need to essentially eliminate GHG emissions from electricity by 2050. The basis for these dates follows from the potential for these assets to be stranded before the end of their useful lives. It would be beneficial for the IRP to consider scenarios in which the development of future CCGTs is precluded after 2025 to inform the development and implications of future policy options and to assist the utility in evaluating future risks of developing additional CCGTs.	For the scenario(s) considered most appropriate (e.g. 2.1, 2.2, 3.1 and 3.2, with or without regional integration) undertake comparative analyses by imposing a development restriction on any new CCGTs beyond 2025. Discuss the cost implications of such an approach to mitigating the risks associated with stranding these assets in order to achieve net-zero emissions by 2050.
7		Methodology	End Effects	NS Power 2020 IRP Modeling Results Workshop July 9, 2020; IRP Scenarios and Modeling Plan - Participant Comments			Methodologies for addressing end effects vary and tend to be particularly sensitive to input assumptions and selected timeframe. In the participant comments on the IRP Scenarios a request was made to describe the approach to addressing end effects, but no response was provide by NSPI.	Please explain and justify the approach to handling end effects, or identify the location in the IRP documents where the approach is described, including the: - overall objective; - timeframe; - key parameters; and - economic treatment of GHG emissions following 2050.
8		Presentation	Distributed Energy Resources	NS Power 2020 IRP Modeling Results Workshop July 9, 2020	17, 23	*The cost of DER resources was not included in model NPV calculations; total cost of DERs using IRP assumptions was \$1.6B --\$2.5B on a 25 year NPV basis* *In all cases, adding the low DER cost estimate (\$1.6B) to the 25 year NPV of the "B" case makes it more expensive than the least cost comparable "A" or "C" scenario*	The "NPV Partial Revenue Requirement Comparison" graph indicates that the NPV costs of the Distributed Resources scenarios is less than for the Current Landscape and Regional Integration scenarios. While this is the case from the limited perspective of the utility, it is somewhat misleading to present this graph without also presenting the costs of the distributed resources that are an integral part of the Distributed Resources scenarios.	Consider redesigning or replacing the "NPV Partial Revenue Requirement Comparison" graph to: - illustrate the additional costs associated with the Distributed Resources scenarios; - define what is included in "modelled costs"; and - define what is included in "extrinsic costs".

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To: Linda Lefler P.Eng, Senior Project Manager - Regulatory Affairs, Nova Scotia Power

From: Jon Sorenson, Executive Consultant, Hydrostor Inc.

Date: 17th of July 2020

Re: A-CAES as a Solution for Nova Scotia

Memorandum

As we have communicated to the Nova Scotia Power team, Hydrostor is a Canadian technology provider and global developer of energy storage facilities that uses commercially proven Advanced Compressed Air Energy Storage (A-CAES) technology. We have been following Nova Scotia Power's IRP process with great interest and were disappointed to learn that long duration energy storage technology was not included in the preferred portfolio. We note that Nova Scotia Power has instead opted for a portfolio that calls for new transmission and fossil fuel assets to meet balancing and peaking requirements. We believe that long duration Energy Storage, and A-CAES in particular, is a credible, market-ready solution that can address the issues solved by these assets in a cleaner and more cost-effective way.

Nova Scotia Power's A-CAES Cost Assumptions

Based on our review of Nova Scotia Power's IRP assumptions, we believe that A-CAES's capital costs were inaccurately modelled. We believe that this played a decisive factor in it not being selected as a preferred resource. In particular, we found that in your cost analysis, the model used a $/kW cost of CAD $2,200. This was in effect, the mid point of our $/kW cost estimates for a 200MW facility with a duration of 12 hours that we had previously provided to you (See Appendix 1). This was then compared to the cost of a lithium-ion system with 1 and 4 hours of duration. (See Figure 1 below).

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Technology	Subtechnology	Capital Cost (2019 CAD $/kW) 2019	2030	% Change
Wind	Onshore	$2,100	$1,691	-19%
	Offshore	$4,726	$3,429	-27%
Solar PV[a]	Tracking	$1,800	$1,416	-21%
Biomass	Grate	$5,300	$5,146	-3%
	Municipal Solid Waste	$8,470	$8,470	0%
Tidal	n/a	$10,000	$10,000	0%
Storage	Li-Ion Battery (1 hr)	$764	$385	-50%
	Li-Ion Battery (4 hr)	$2,125	$1,071	-50%
	Compressed air	$2,200	$2,200	0%
	Pumped Storage	$2,700	$2,700	0%

[a] Solar PV costs reported in $/kW-ac, reflecting an inverter loading ratio of 1.3

Figure 1

Our concern is that this was not an apples-to-apples comparison as it accounts for the additional cost of a longer duration facility but ignores the additional value such a system provides. Additionally, by choosing to use the costs for a 200MW system, this did not account for the significant economies of scale that come with larger sized A-CAES facilities. If you consider a 500MW facility with a 4-hour duration, the cost works out to an average of US$1125/kW[1]. We believe that this is a much fairer comparison to a 4-hour lithium-Ion system for the short duration market.

However A-CAES's cost advantage is most apparent in the long-duration market where it can act as a non-wires alternative to traditional transmission for improving reliability or as a solution for integrating and time-shifting Nova Scotia's wind resources onto the grid. To illustrate this point, we compared the bid prices that we recently submitted for a 300MW 6 hour and 12 hour facility to a utility in California to what an equivalent lithium system would cost based on prices provided by Lazard's Levelized Cost of Storage Analysis 5.0. For the 6-hour system we found that lithium ion prices would have to drop 7%-50% from 2019 in order to achieve cost parity. Whereas, for the 12-hour facility we found that lithium ion would have to decrease their cost by a further 41%-70% in order to achieve cost parity.

A-CAES is a Reliable Solution for Nova Scotia's Needs

Advanced Compressed Air Energy Storage, uses equipment, construction techniques and technology proven and optimized in the oil and gas sector to deliver a bankable and market-ready solution that can be delivered at scale. The technology benefits from large economies of scale which allow it to offer the lowest per kwh cost the energy storage

[1] [1] We also note there was a conversion error as our costs were presented to Nova Scotia power in US$ but were displayed here in $CA. We therefore question whether this conversion error applied to other technologies listed here.

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market for system sizes larger than 250MW and at durations ranging from 4 to 12 hours or more. Because of our exclusive use of equipment produced by Tier 1 manufacturers such as Baker Hughes, Hydrostor can deliver facilities backed by global supply chains, comprehensive maintenance packages and performance guarantees. With no degradation or disposal liabilities, flexible expansion options, and a service life of 50+ years that give it unique advantages over batteries and makes it the ideal storage solution for integrating Nova Scotia's considerable wind resources into the grid.

It is also important to note that since A-CAES uses spinning turbines it can meet the grid's need for inertia and synchronous generation that is currently provided by Nova Scotia Power's coal fired generation facilities. Furthermore, unlike pumped hydro or fossil assets, A-CAES can be flexibly sited where the grid needs it. It is a benign technology that has minimal impact on its local environment while producing major economic benefits for local communities, reducing permitting risk and allowing it to be safely sited close to population centres. Furthermore, Hydrostor has studied the geology of Nova Scotia and New Brunswick and found the region to be highly suitable for A-CAES, making it even easier to site. For these reasons, we believe A-CAES is the right solution for accelerating the retirement of coal assets and avoiding further investment into fossil fuels.

We note that Nova Scotia Power intends to make considerable investment in transmission infrastructure to improve the reliability of the system. Again, we believe that A-CAES should be seriously considered by Nova Scotia Power as a lower-cost alternative that could save the utility 10's to 100's of millions of dollars. We have proposed this kind of solution to regulators and transmission companies in Chile, Australia, and California and would be happy to provide you with an indication of what the cost savings could look like for an A-CAES facility sited near the source or load instead of build a new transmission line.

In short, we believe that a Canadian designed A-CAES facility built to a scale of 300 to 500MW with a long duration of 6, 8,10, 12 hours or beyond can assist Nova Scotia Power in its Integrated Resource Plan in the following areas:

- Be a cost-effective non-wire alternative solution for transmission that is easier to permit and more cost effective than large transmission projects
- Be a clean source of synchronous generation capacity with similar system benefits and operating characteristics as coal that can be used to advance coal retirements and be located on or near the sites of former plants while retaining many of the plant's employees
- Be used to balance intermittent resources such as wind and solar or instead of natural gas fired plants, as a peaking asset

We would be very interested to better understand your thoughts on A-CAES and hope to address any questions or concerns. We would also invite Nova Scotia Power and its consultants to take part in a virtual or in-person tour (situation permitting) at our soon-to-be officially commissioned Goderich, Ontario facility soon. I thank you for your consideration and look forward to working with you further to explore this option for Nova Scotia's energy future.

HYDROSTOR

Please do not hesitate to reach out.

Thank you and Best Regards,

Jon Sorenson
Executive Consultant
Hydrostor Inc

Appendices

Appendix 1: A-CAES Technical Inputs Summary (Previously submitted to NS Power)

HYDROSTOR

ADVANCED COMPRESSED AIR ENERGY STORAGE

Hydrostor Introduction

April 2020

About Hydrostor

Hydrostor is the global leader in Advanced Compressed Air Energy Storage (A-CAES)

Founded 2010

Offices Toronto, Canada (primary)
Adelaide, Australia (satellite)

Headcount 35

Operating Facilities
2 (Canada – Toronto Hydro; Canada – IESO)

Facilities Under Construction
1 (Australia – NEM)

Project Pipeline
~400 MW commercially bid, 4 GW project pipeline (focused on US, Canada, Australia, Chile)

A-CAES is a breakthrough for large-scale energy storage:

- Uses only water, pressurized air and standard equipment with proven supply chain to provide long-duration, emissions-free storage.
- Provides similar characteristics to pumped hydro storage, but with the key advantage of being able to flexibly site where the grid needs it.

Compressed Air Energy Storage

Compressed Air Energy Storage is a utility-scale electrical energy storage solution with a history of over 40 years of successful operation.

- There are two large-scale examples of compressed-air energy storage in operation:
    - 290-MW Huntorf CAES Plant (Germany, commissioned in 1978)
    - 110-MW McIntosh CAES Plant (Alabama, commissioned in 1991)
- Hydrostor builds on the CAES platform and improves it with well-established systems that are innovatively deployed for storage: 1) a proprietary thermal management system, and 2) purpose-built hard-rock air-storage caverns. This enables both **emission-free operation** and **siting flexibility**.

Huntorf CAES Plant in Elsfleth, Germany

McIntosh CAES Plant in McIntosh, Alabama

How Advanced-CAES Works

A-CAES integrates proven technologies and construction approaches in innovative ways to produce a superior long-duration grid-scale energy storage solution.

Step 1

Compress air using electricity

Electricity runs a compressor to produce heated compressed air

Unique to Hydrostor

Step 2

Capture heat in thermal store

Heat is extracted from the air stream and stored in a proprietary thermal store

Unique to Hydrostor

Step 3

Store compressed air in purpose-built cavern

Air is stored in a purpose built cavern using water to maintain constant pressure

Step 4

Convert the air to electricity

Water forces air to the surface where recombined with heat and expanded through a turbine

- ***Electrical Conversion:*** Relies on off-the-shelf synchronous generating equipment, including compressors, expanders, heat exchangers, available in a variety of sizes and configurations and that have decades run-time experience across multiple industry applications (e.g., oil & gas).
- ***Underground:*** Simple and cost-effective purpose-built underground cavern construction using industry standard and well-proven mining techniques with large precedent in hydrocarbon storage industry (i.e., 100s of rock caverns, dozens with hydrostatic compensation).

HYDROSTOR

A Proven and Bankable Solution

Significant Precedent:

- 200+ MW conventional-CAES plants reliably operated for over 30 years.
- 100+ rock caverns storing hydrocarbons with dozens using hydrostatic compensation.
- All major equipment proven for intended application with long reliability histories.

Backed by Proven A-CAES Facilities and Significant Engineering:

- Hydrostor projects – 3 A-CAES plants in Canada and Australia with directly analogous operations to pipeline.
- Independent engineering complete.
- Supply chain partners in-place experienced delivering sub-systems at all system scales.
- Bonding and performance guarantees for full-scale systems in place.

Technical due diligence already cleared with Tier 1 development companies, government-funded entities, and supply chain partners

Goderich A-CAES Facility


Australia project - Photo within air storage section


Storage cavern construction, India, accessed by a mine shaft in a gallery configuration with a water curtain


Storage cavern construction, Portugal, accessed by a helical decline in a gallery configuration

HYDROSTOR

Full Delivery Capabilities

Curtis VanWalleghem
CEO, Co-Founder, Board Member
Bruce Power
Deloitte

Jon Norman
President & COO
Brookfield
Ontario Ministry of Energy

Jordan Cole
Chief Commercial Officer
Brookfield
Enwave

Sid Meloney
EVP Engineering & Projects
Williams Energy
TransCanada

Greg Allen
Managing Director, Australia
Carnegie Clean Energy
Wesfarmers Energy

Development Project Finance Partner

meridiam infrastructure

Equipment Supply Partner

Baker Hughes

Design & Construction Relationships

AECOM

TMCC THYSSEN MINING

wsp

Agapito Associates, Inc. Mining & Civil Engineers & Geologists

GEOSTOCK ENTREPOSE

Project Bonding & Warranty Partners

EDC

NEW ENERGY RISK

HYDROSTOR

Confidential

A-CAES Compelling for Long Duration

This provides a strong advantage over competing solutions, especially given A-CAES flexible siting capability:

	Hydrostor A-CAES	Gas Turbine	Traditional CAES	Pumped Hydro	Li-Ion Battery	Flow Battery
Size (MW)	50 – 500+	>100	150 – 500+	>100	1 – 100+	1 – 20
Duration (hours)	>6	N/A	>6	>6	1–4	4–6
Efficiency	>60%	N/A	30 – 40%	70 – 85 %	85%	70%
Emissions	None	Emitting	Emitting	None	None	None
Lifecycle (cycles)	>20,000	>20,000	>20,000	>20,000	5,000	10,000
CAPEX (US$/kW)	$1,000–$3,000	$1,000	$1,500–$2,500+	>$2,500	$3,000+**	$5,000
CAPEX (US$/kWh)*	$150–$300*	N/A	$150–$250+	>$250	$300+**	$500
Operating Costs	Low -Medium	High (fuel costs)	High (fuel costs)	Low -Medium	Medium	Low -Medium
Siting Flexibility	Medium-High	Medium (emissions)	Low (salt, emissions)	Low (topography)	High	High

** Assumes 10-hour discharge for storage, fully-delivered system with BOP. Additional cost reductions possible where infrastructure can be repurposed.*
*** Li-ion costs based on Lazard LCOS v4.0 adjusted to 10-hour discharge using CPUC methodology in order to show equivalency with 10-hour A-CAES*

Hydrostor has strong advantages in situations with the following conditions:

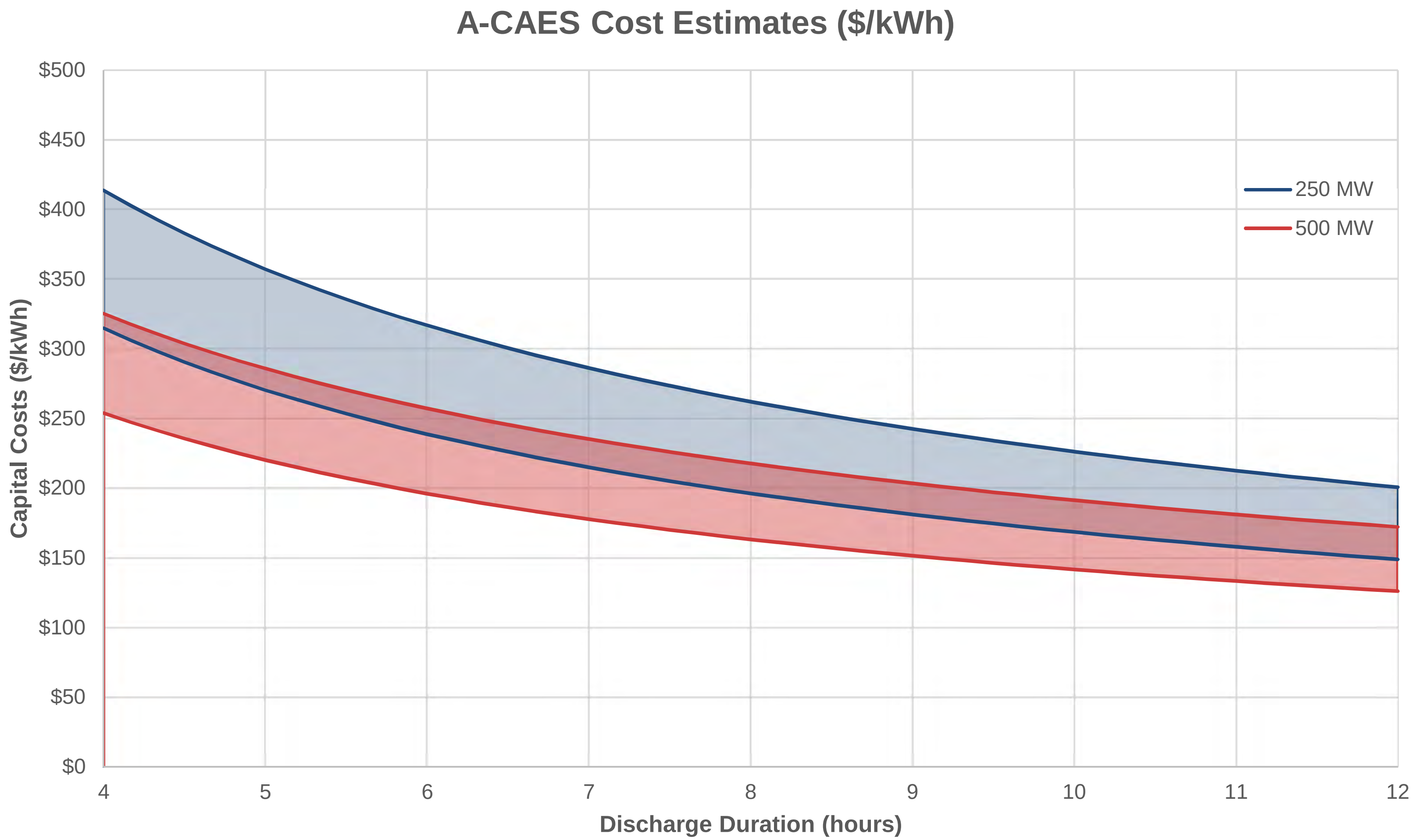
a) Difficulty permitting gas (e.g. California, urban centers) or high-cost gas markets (e.g. Australia),

b) Requirement for long-duration >4 hours (e.g. transmission deferral, capacity/reliability, high renewable),

c) Scale in excess of 200 MW

HYDROSTOR

Lower Cost & Longer Life vs Li-Ion

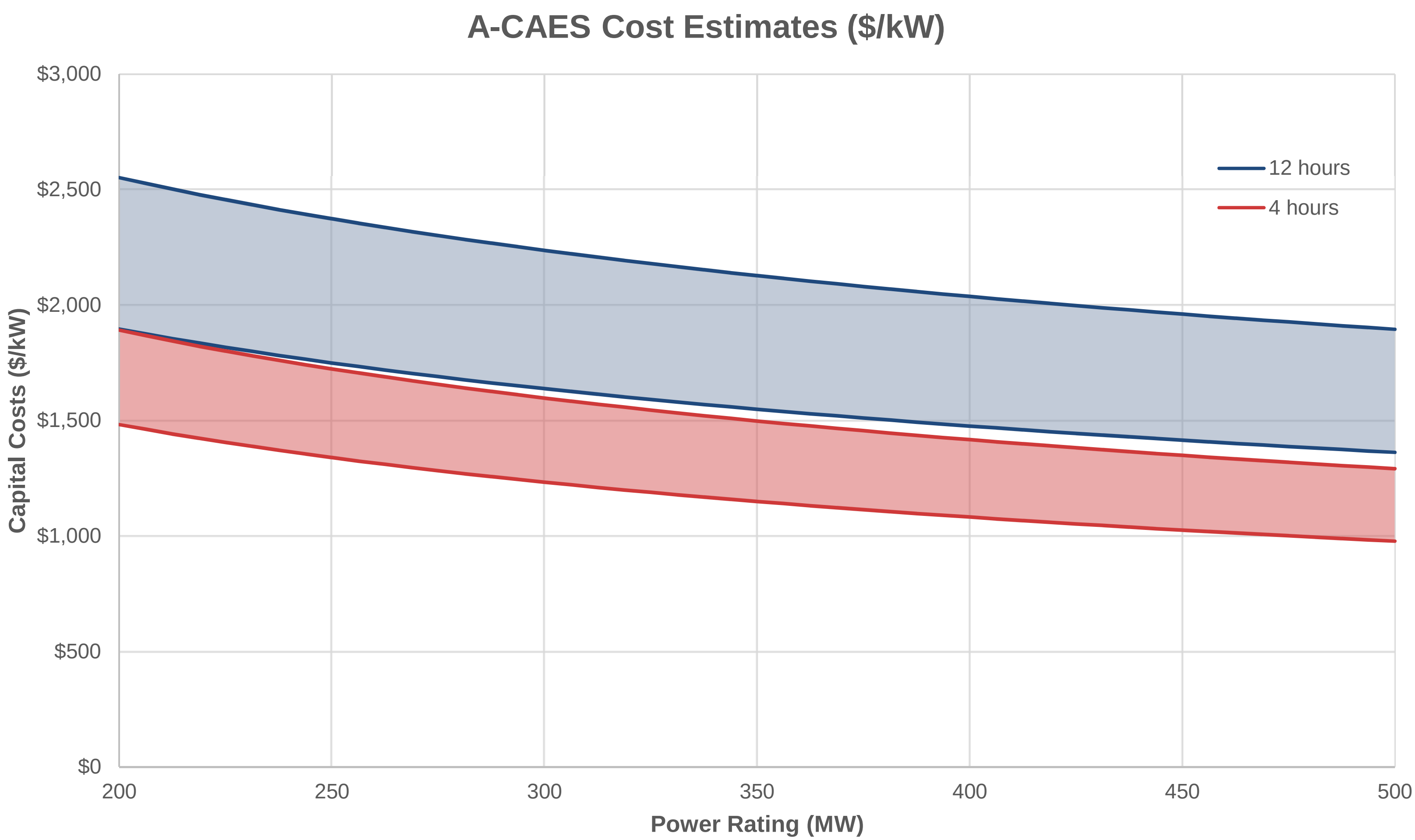


Installed cost at scale significantly below all-in delivered costs for Li-ion batteries. The levelized cost for A-CAES is even further below that of Li-ion for long duration applications due greater life of A-CAES (i.e. A-CAES more than 4x cycle life of Li-ion, which can be cost-effectively extended even longer to allow a 30-50+ asset life).

HYDROSTOR

** Note: Costs shown are overnight costs for an open loop system.*

Emission-Free & Similar Cost vs Gas



The levelized cost for A-CAES is often similar to new natural gas (CCGT) given the ongoing fuel costs of natural gas relative to the off-peak electricity rate in many markets. Most importantly, A-CAES is emission-free and often can be sited where natural gas cannot be permitted.

HYDROSTOR

** Note: Costs shown are overnight costs for an open loop system.*

A-CAES Value Proposition

	**Fossil Plant Replacement**	• Synchronous dispatchable generation, and A-CAES long duration enables reliable capacity replacement, with flexible siting at the exact location needed. • Alternative to new natural gas (no emissions and often less permitting hurdle, lower fuel costs in many markets with high RE, access additional ancillary services on charging) • Can leverage existing interconnection & infrastructure and defer fossil plant remediation costs
	**Transmission Deferral**	• Non-wires alternatives to defer grid network investment • Long-duration alleviates grid congestion during peak periods, and enables transmission alternatives requiring longer-term outage management • Locatable reliable power for critical areas and infrastructure
	**Renewable Integration**	• Provide dispatchable or baseloaded renewables at rates ~$70-120/MWh • Optimize large solar/wind project economics through time-shifting to reduce curtailment

- Ability to Site Where Needed
- Low Cost at Scale; Long Life
- Flexible Design
- Bankable
- Emission Free
- Ancillary Services

HYDROSTOR

Growing Project Pipeline

Hydrostor has three projects in operation or under construction in Canada and Australia that total more than 25 MWh of storage capacity.

The Company is continually developing its pipeline of future opportunities which currently includes 15+ projects in various development stages across North America, Australia and Chile that range in size up to 500 MW, 4 gigawatt hours (GWh) per project.

1

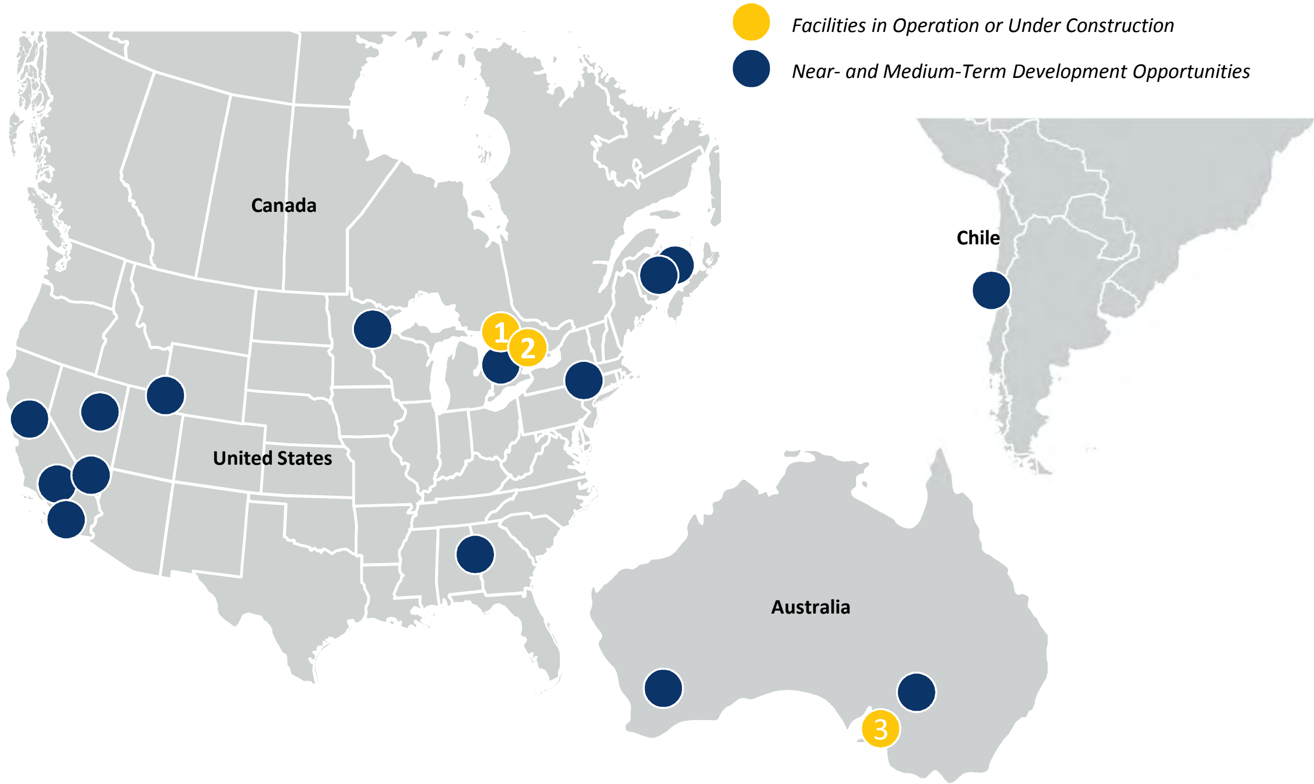
Goderich A-CAES Facility

2

Toronto A-CAES Facility

3

Angas A-CAES Project



HYDROSTOR

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natural forces

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Doreen Friis, July 17, 2020

Regulatory Affairs Officer/Clerk
Nova Scotia Utility and Review Board
1601 Lower Water Street, 3rd Floor
P.O. Box 1692, Unit "M"
Halifax, NS B3J 3S3

-SENT VIA EMAIL-

RE: 2020 Integrated Resource Plan Initial Modelling Review

Dear Ms. Friis,

Natural Forces Services Inc. welcomes the opportunity to input comments on the IRP process. We note that again the time for comments to this process are extremely tight and it makes it very difficult for us to fully process the information that is being submitted by NSPI.

In general, there are two large issues we would like to comment on and several smaller issues. The key issues are

- The Cost of wind (capex, opex and capacity factor)
- The limits on wind installed capacity

As well we would comment on

- Synchronous Inertia minimum requirement
- Demand projections
- Requirement for transitioning plan
- Interconnector Flows; treatment of exports
- ELCC contribution from interconnectors

We have for convenience, set out our comments below under several headings.

The Cost of Wind

This point has been brought up several times by several stakeholders, however NSPI staff still feel that the pricing that they are using for wind energy is correct. NSPI's assumption is that

Wind

- Capital cost $1691 / kW

- O&M $59 / kW / year

This is not close to what current pricing would suggest is for wind in Canada. Natural Forces is currently building medium sized project across the country and these prices are not reflective of our data. From recent public calls of power, Alberta is currently pricing wind between 3 and 4 c/kWh. While the capital cost is high as well as the O&M, it is really the capacity factor that is estimated to be much too low which leads to a false number This is a fundamental issue in the IRP and presents a bias in the results that are coming from the modelling. NSPI has strong opinion on this issue and it is suggested that it would make sense to test the sensitivity of this pricing. The model should be run with a sensitivity of a reduction in cost of 30% at a minimum.

Hard limit on Wind installed capacity

It is our understanding from the presentation of the modelling results on 9th July, that in effect, a "hard cap" of 700 MW has been applied to wind installed capacity, i.e. that no increase in wind installed capacity is permitted without the addition of major capital investment in a second AC intertie and/or in battery storage and synch condensers. The capital cost of the associated investments have the effect of making wind a non-viable proposition for at least the first ten years or so of the model period.

If this understanding is correct, firstly, this is contradictory from our previous understanding based on direct discussions on the modelling approach and assumptions. More importantly, we believe this approach to be fundamentally flawed and biased towards less renewables and higher costs.

PSC study

The 700 MW "limit" on installed capacity is derived from the PSC study[1].

As we noted before, the PSC study analysed the performance and stability of the Nova Scotia system under four scenarios, specifically selected to examine the resilience of the system under the most stressful conditions likely to be encountered. It is fairly typical for technical studies of this nature, to include scenarios that represent more stressful system conditions, thus giving insights on the operation of the system at or near to its operational limits. This might include for example, minimum system demand cases, as is "Case 01" in the PSC study. The PSC Report itself acknowledges that the Study covers:

"simulations of 4 different cases that represent stressed conditions in the Nova Scotia power system and applying several severe contingencies, it was concluded that the existing Nova Scotia power system can support 600 MW of wind generation." [emphasis added]

What must be remembered though is that such scenarios are not representative of more "normal" system conditions that exist for the vast majority of the time. There is arguably nothing wrong with that, as that is not the primary purpose of the such studies. However, it also means that the findings of the studies must be recognised for what they are. Specifically the findings cannot be extrapolated or implied to apply

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[1] "Nova Scotia Power Stability Study for Renewable Integration Report", prepared by PSC North America on behalf of Nova Scotia Power Inc. (24th July 2019).

to the more normal or typical system conditions that will exist the remainder of the time. A finding that the system is reaching limits of operation with 600 or 700 MW of wind generation in some or all of the "stressed conditions" scenarios, certainly does not mean that much higher levels of wind could not be accommodated at other times. In contrast, significantly greater levels of wind could be accommodated under other, more typical system conditions.

The wind "limit" identified from the PSC study derives mainly from two study cases:

- Case 1: minimum demand case; high wind; 250 MW import on AC intertie;
- Case 4: high demand case; high wind; 417 MW import on AC intertie.

In both cases, the loss of the AC intertie at high import appears (not surprisingly) to be the most severe contingency. The high wind output coupled with the high import is "squeezing" the space for conventional (synchronous) generation needed on-line to provide SIR and other services. The assumed remedial action is to reduce or limit the wind, whereas reducing the AC import would be a more effective remedy; reduction of the import level has the double benefit of creating more space for conventional generation, while at the same time reducing the severity of the contingency.

In effect, wind is being limited in order to facilitate high levels of import. In most jurisdictions tie lines are regularly limited when there are stressful events on the system and internal resources (particularly renewables) are prioritized. This should be considered from a policy perspective.

Installed wind capacity vs. operational limitations

In the section above we have made a number of observations on the PSC study scenarios and findings, which indicate that more wind could potentially be accommodated even in the "stressed conditions" selected for the study. However even accepting the PSC study findings to be broadly correct, it is critical that the study findings are recognised for what they are (and what they are not).

The Study findings do not conclude that the wind installed capacity must be limited to 700 MW. All that they conclude, is that in certain stressed system conditions, the output of the wind should be temporarily limited to 700 MW. [2]

These scenarios will only arise for a few hours per year. Even when the system conditions (demand, import levels) apply, it may or may not be the case that wind output will be high at the same time[3]. It is common practice (in fact one could say almost universal) in systems with RES ambitions, to accept that wind output will have to be operationally curtailed from time to time, specifically in the small number of hours when stressed system conditions and high wind output coincide.

[2] Notwithstanding the fact that reducing the import level would be a more effective means of ameliorating the problems.

[3] In fact evidence suggests that there is a positive correlation between wind output and demand, reducing the likelihood of occurrences of high wind output at time of low demand.

It was mentioned in the discussion on the 9th July webinar, that the occurrence of these stressful events was unpredictable. It is correct to say that the occurrence of contingencies (such as the loss of the AC intertie) is unpredictable. However the system conditions under which the contingencies are problematic, are entirely predictable. The stressful cases are a combination of demand conditions and high imports on the AC intertie. These conditions will be known and identified in operational planning and dispatch timescales, and mitigating actions (e.g. curtailment of wind, or curtailment of imports) can be implemented to ensure that the contingencies, should they occur, do not unacceptably impact on system security. This is that approach commonly adopted in all power systems with renewable ambitions.

International practice

As noted, all systems with high RES ambitions which we are aware of, adopt the approach of accepting that wind output will be curtailed from time to time, when stressed system conditions and high wind outputs coincide. The alternative approach of limiting the amount of wind which can be installed to the amount of wind output that the system can safely accommodate in the most stressful system conditions would, quite frankly, not even enter consideration.

To take Ireland as an example; both Ireland and Northern Ireland, operate as an integrated synchronous system and market. The total wind connected is currently about 5,200 MW, and further wind projects have network connection agreements and are currently in development. Ireland is expected to meet its 2020 target of 40% of generation from renewable sources in 2020 (of which over 90% is from wind).

Wind in Ireland can reach up to 70% of the system demand on an instantaneous basis. It is necessary to curtail wind output at times, particularly when high wind output coincides with low demand.

If lreland imposed a limitation on wind installed capacity in the manner contemplated in the IRP study (i.e. limiting installed capacity to the amount of wind that could be accommodated under all system conditions, including “stress” cases), then the installed capacity would be limited to somewhere in the region of 1700 MW (compared to the current installed capacity of 5,200 MW). Note that Ireland is not unique in this regard; the approach of accepting additional renewable installed capacity and limiting the output at times when necessary to ensure security of system against plausible contingencies, is fairly universal.

Synchronous Inertial Response (SIR) minimum requirement

The IRP model is set to require a minimum of 3,266 MW-sec of SIR. This is stated to be based off the PSC study but adds in a safety margin of 500 MW-sec, approximating to a requirement for one additional generation unit. The figure of 2,766 MW-sec from the PSC study is from Case 01 (revised), which had three thermal generation units on-line. However the PSC report also notes that the system would be stable with only two units.

It is also worth noting once more, that the contingency event which is driving the SIR requirement in the PSC study, is the loss of the AC intertie at high levels of import. If the flow on the AC intertie was reduced, this level of SIR would not be required. In this regard PSC study Case 2 is very informative; in Case 2 the

AC intertie is out of service, and the Nova Scotia system is noted to be stable with only 1,788 MW-sec of SIR. The PSC report state that:

"Therefore, it seems that once Nova Scotia is operating in an islanded mode, two thermal units can provide enough inertia for it to survive the transients caused by the studied internal contingencies."

Of course, it is almost certainly not the fact of islanding that make the system stable with much lower SIR, but rather the fact that there is no large import on the AC intertie to deal with as a contingency event. If the AC intertie were in service but at a lower MW level, the results would be at least as good, or indeed better.

In summary, in relation to the minimum SIR requirement:

- The minimum level of 3,266 MW is not well substantiated based on the PSC study. It appears that there is a safety margin of one thermal generation unit included in the PSC study, and then a further safety margin approximating to one thermal generator added in the IRP study. This appears on face value, to be unduly conservative.
- The SIR requirement is arising from high imports on the AC intertie. At times of lower import levels, the SIR requirement would be expected to be much lower.

Demand projections

The slide deck distributed on 27th June includes revised demand projections, apparently based on revisions due to the COVID-19 pandemic. The changes in demand assumptions appear to be quite severe and certainly prolonged, with an assumption that it will take 10 years to return to the original demand trajectories. Of course, there is inevitable a degree of uncertainly regarding COVID, but this is certainly much longer than would be assumed in other countries. To our knowledge, most countries are predicting recovery to earlier trajectories within two to five years.

Requirement for transitioning plan

As way of a comment, it is understood that the IRP model does not address the complexity of adding units instantaneously to the system or quickly retiring units, so it can be forgiven for the large swings in generation sources in 2030 and 2040. As the new plant cannot realistically be added "instantaneously", as it is in the current model, there will be a need for a transition plan where the new plant is brought on progressively over a period of up to ten years. This may lead to more quickly retiring coal plants and adding more renewable sources sooner. It may serve to force the model to ramp the coal plants down over multiple years so that it can take this into account, or it will have to be manually estimated, which may be problematic if we are looking for the best solution.

As a second part to this issue, as any transition plan is likely to involve adding wind year-by-year over the period up to 2030, determining the correct results from the SIR requirement and the hard cap on wind until a 2nd intertie is of crucial importance. If the position is maintained that wind installed capacity in excess of 700 MW must be accompanied by either the 2nd AC intertie or by BES/synch comps, then these would have to be built out in tandem with the wind. This could result in a premature and/or unnecessary level of capital expenditure, increasing costs to consumers.

Interconnector Flows; treatment of exports

The spreadsheet provided by NSPI showing the modeling results, contains interconnector energy flows by year for each scenario, under the headings of "Maritime Link Blocks", "Firm Imports" and "Non-form market". For each of these, only an aggregate quantity is given; we assume that in at least some cases, there are both import and export quantities underlying the data. Can the import and export energy flows be provided?

We would also appreciate clarity on the assumptions regarding pricing of exports. It may be that this is covered somewhere within earlier documents, but we have been unable to identify it.

ELCC contribution from interconnectors

It is our understanding that in the IRP model, only firm imports are assumed to contribute to ELCC. There was mention at the 9th July webinar of this being due to NERC rules. If this is the case and it is a mandatory requirement that non-firm imports cannot be considered to contribute ELCC, it may not be open to amendment at this time.

It is worth noting that the approach in other regions, for example in Europe , is very different. The ability to share capacity resources is accepted as one of main benefits of interconnection, and need not be underpinned by "firm" imports. By way of example, the two 500 MW HVDC interconnectors from Ireland to GB, are credited with an ELCC quantity in each interconnected system. In Ireland, each of the 500 MW interconnectors is credited with 220 MW ELCC, even though there are no firm import arrangements (interconnector flows follow the market). This approach significantly reduces the generation installed capacity requirement in each system, and in aggregate.

Emulated or Synthetic inertia

The points brought up to NSPI during the workshop discussing Emulated or Synthetic inertia is of great interest. We agree that HVDC interconnectors and also energy sources connected through power electronics (such as wind, solar, batteries) do not provide SIR. However it is worth noting that there is currently a great deal of effort going in to getting HVDC and RES connected through power electronics to provide "inertia-like" services (typically referred to as "synthetic" or "emulated" inertia). Developments in this area could be a significant "game-changer" in the future, so it is important to continue to monitor progress closely.

Sincerely,

Presented for, and on behalf of, Natural Forces Services Inc. Halifax, Nova Scotia.

Blackburn Law

VIA EMAIL

July 17, 2020

Linda Lefler
Nova Scotia Power

Dear Ms. Lefler,

Re: M08929 – July 9, 2020 Stakeholder Session – SBA Comments

The Small Business Advocate (SBA) participated in the online IRP Stakeholder meeting on July 9th, 2020, along with its experts from Daymark Energy Advisors, John Athas and Jeff Bower. Please find a memo from Mr. Athas and Mr. Bower attached, setting out comments and questions regarding the modeling results that were presented.

Please let me know if you have any questions or require any clarification.

Yours truly,

BLACKBURN LAW

E.A. Nelson Blackburn, Q.C.
Small Business Advocate

T: 902-835-8544 F: 902-835-4310 E: info@blackburnlaw.ca www.blackburnlaw.ca
SUITE 231 BEDFORD HOUSE, SUNNYSIDE MALL, 1595 BEDFORD HIGHWAY, BEDFORD, NOVA SCOTIA B4A 3Y4

DAYMARK ENERGY ADVISORS

TO: Nelson Blackburn and Melissa MacAdam, Nova Scotia Small Business Advocate

FROM: John Athas and Jeff Bower

DATE: July 17, 2020

SUBJECT: Comments on NSPI modeling results

This memo summarizes Daymark's comments regarding NSPI's IRP modeling results, dated June 26, 2020. We have included questions associated with areas of uncertainty, and highlighted areas in which additional analysis should be provided by the Company so the conclusions can be fully evaluated by stakeholders. Finally, we provided some suggestions related to how the Company can continue the valuable stakeholder engagement process it has maintained thus far in the IRP process.

I. Modeling Questions, Concerns and Suggestions

a. **System Inertia-Based Generation Requirements:** Since the system inertia requirement is a constraint in the modeling, the Company should provide more analysis and detail supporting the assumptions. The PSC study provided initial results, but the Company acknowledged several shortcomings at the time. The IRP analysis would be more complete with the following:
    - More information on derivation of requirements and cost of alternatives to generation such as synchronous condensers, and information on any limitations on the amount of these that the system can rely upon.
    - Additional analysis supporting the inertia benefits ascribed to the Reliability Tie. The modeling currently assumes the reliability tie would provide all system inertia requirements for system. Are there limitations to this assumption, or are there system conditions (in NS or NB) under which the tie would not provide the claimed inertia benefits?
    - NSPI should conduct additional analysis to identify the minimum amount of inertia requirements in province under different system conditions. The 3266 MW.sec requirement was based on specific load conditions resulting in a 2766 MW.sec requirement, plus a 500 MW.sec generic additional requirement. Additional analysis would allow for more dynamic modeling of this requirement and provide additional insight on the inertial need over time as load, DSM, and supply-side portfolio mix changes. Since ascribing this benefit of providing all the inertia requirements is uncertain and very valuable to the evaluation we would like to see a sensitivity if the inertia benefits of the tie is substantially lower than assumed, such as providing only half of system inertia need.

DAYMARK
ENERGY ADVISORS

JULY 17, 2020

- Provide information regarding whether the battery + synchronous condenser option for system inertia would also provide system capacity.

b. **Reliability Tie and Regional Integration – Treatment of risk:** The Reliability Tie and Regional interconnection are significant components of the initial modeling results and would represent substantial investments. Given the scope of the investment it is important to understand the risks associated with the investment, and the cost of alternatives.
   - What additional studies will be required if the reliability tie or regional integration plan is selected? What would be the schedule for those studies?
   - For each portfolio that selects a transmission upgrade as part of a least-cost plan, NSPI should provide results demonstrating the incremental cost of the non-transmission option so the Board can balance the cost against the risk if the transmission investment is not fully utilized or if a lower cost option becomes available. This should be clearly considered within the decision process to choose a preferred portfolio.

c. **Renewable resource selection:** The Company assumes onshore wind is the primary renewable resource as part of the future portfolio. Other areas on the Atlantic coast of North America are focusing on offshore wind to provide resource diversity.
   - Did the Company's analysis fully incorporate the benefits of diversity of timing of production (e.g. through the ELCC analysis)?
   - If the costs of offshore wind come down considerably over the study period, are there planning decisions (such as transmission investments or conventional capacity additions) included in this IRP that would be rendered unnecessary? The Company should provide sensitivity modeling that would help understand this issue.

II. **Metrics**

a. **Stakeholder Input:** The metrics used for evaluating portfolios are critical assumptions to the IRP process. Now that the initial modeling is complete and stakeholders have greater understanding of the inputs and analysis, it would be useful to have a stakeholder exchange or technical session and the opportunity for written comments specifically focused on proposed metrics from NS Power. We offers the following additional comments:
   - Current proposed metrics appear to be revenue requirement minimization over a long horizon since the modeling calculated PVRR utilizing a real levelized capital cost recovery factor in modeling. We would like to see the corresponding values utilizing nominal accounting cost recovery or revenue requirements.
   - GHG metrics presented with initial modeling results include totals over the study period and includes some GHG Marginal abatement cost. The Company should provide annual GHG production metrics in tons and in percent of a baseline historical year emissions.

- The preliminary results included a metric calculating an average cost of generation, but the Company was uncertain as to whether it would be used going forward. The Company should provide metrics to help provide insight on affordability of each portfolio, perhaps showing annual cost of electricity impacts utilizing nominal capital cost carrying charges.
- Generally, the more capital a company commits to invest in a portfolio the greater the risk. The Company should provide a metric calculating total average capital investment requirements over the first five years, ten years and twenty years.
- It is important to have visibility on how much NS Power will be relying upon imported power as a metric, such as average annual imports over the first five years, ten years and twenty years.

b. **Metric Definitions:** The Company should provide written formulas and examples for the calculation of each metric used in the portfolio analysis.

c. **Scoring or Metric Trade-off Analysis:** The portfolio analysis will likely utilize some method of weighing (explicitly or implicitly) the various metrics when choosing or creating a preferred portfolio. The Company should provide a detailed description of how the various metrics will be used.

III. **Stakeholder engagement:** The Company has maintained extensive communication and stakeholder engagement efforts during the development of the pre-IRP deliverables, and we hope that going forward the process will remain transparent and collaborative. To that end, we recommend technical sessions or the opportunity for written comments on the following areas:

a. **Metrics choice** – Recommend written comments exchange after distribution of NS Power proposal. It is critical to finalize the metrics collaboratively before reviewing modeling results for findings.

b. **Detailed review of analytical results** – Recommend technical session, in particular detailing results of any analysis of system operations.

c. **NS Power initial findings and conclusions** – Recommend the Company issue findings and conclusions, solicit comments, and hold a stakeholder feedback and discussion session.

d. **Road Map & Action Plan** - Recommend the Company issue drafts, solicit comments, and perhaps hold a stakeholder discussion session. Assure that road map lays out all studies and approvals necessary and key decision points.

e. **Report** – Recommend the Company issue draft receive comments, incorporate comments into final and have all comments in an Appendix.

VERSCHUREN CENTRE
For Sustainability in Energy and the Environment

July 17th, 2020

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RE: Comments on initial IRP modeling results

The following are comments from the Verschuren Centre for Sustainability in Energy and the Environment regarding the Initial Modeling results of the 2020 Integrated Resource Plan.

Stranded Assets

It seems counterintuitive that in modeling various net zero scenarios that the model has determined that building 764-1170MW of additional fossil fuel capacity is most appropriate. It should be expected that all of these assets would have minimal economic value in a zero carbon system, or after 2050.

Question:

1. Does the plexus model consider stranded assets in 2050 (beyond the planning horizon), especially for those units installed in 2040 in 2.x Scenarios?

Inertia

It seems that satisfying the inertia requirement of 3266 MW.sec minimum online requirement is a binding constraint in much of the IRP model decision making. The table on Page 8 of the modeling results indicates that inertia factors for wind energy and energy storage were not considered in the model. As wind energy and batteries are low cost sources of energy and carbon free capacity, the decision to exclude them will have negative impacts for customers. There is a growing body of evidence that suggests both technologies can contribute to system inertia.

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For Wind Energy, Hydro Quebec has been using wind turbines to provide synthetic inertia since 2015. [1] Many of the existing fleet of Nova Scotia wind turbines, including some of those owned by NS Power, are inverter-based machines that could provide this service. There are other examples of gearbox-based turbines being able to provide more physical inertia as well. Future requests for renewable energy could provide an adder for turbines that can provide this service going forward.

Since all Lithium Ion Battery systems would also have an inverter-based interface with the grid, they too would be able to provide synthetic inertia to the grid. Some utilities in North America are already seeing proven results from this effort, and others are starting additional testing:

- **Pacific Gas and Electric Company (PG&E) – NREL[2]**
    - EPIC 2.05 report – February 2019
    - From Page 10: "*The EPIC 2.05 project gave a more definitive form to a looming issue facing the evolving power system. A high penetration level of renewable energy significantly decreases the inertia of the PG&E transmission system and increases the occurrence of frequency violations during contingency scenarios. The project demonstrated great potential for novel control methods to enable inverter-based renewables to address this problem.*"
- **North America Electricity Reliability Corporation[3]**
    - Fast Frequency Response Concepts and Bulk Power System Reliability Needs – White Paper
    - Simulation results showing fast reaction response of inverters can provide enhanced frequency control in a low inertia environment compared to a synchronous resources system. – Page 11.
- **Independent Electricity System Operator – IESO – Ontario[4]**

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[1] IEEE Spectrum – "Can Synthetic Inertia from Wind Power Stabilize Grids?" – 2016 https://spectrum.ieee.org/energywise/energy/renewables/can-synthetic-inertia-stabilize-power-grids -

[2] EPIC Final Report – PG&E – March 2019 https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-2.05.pdf .

[3] Fast Frequency Response Concepts and Bulk Power System Reliability Needs - NERC Inverter-Based Resource Performance Task Force (IRPTF) - White Paper March 2020 https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf

[4] IESO - http://www.ieso.ca/en/Get-Involved/Innovation/Projects

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- Demonstration Project- Alternative technologies for regulation (ATR) program
- Purpose: Use ongoing work of ATR program to determine the merits of two new wholesale market products that leverage the fast-ramping capabilities of energy storage: fast regulation service and synthetic inertia service.

Questions/Requests:

2. Please provide indication of where in the modelling the Inertia Constraint was binding and resulted in a choice of fossil fuel generator over batteries
3. Did the inertia constraint impact the decision process of the Diesel CT Screening?
4. Please consider a screening, which evaluates a 3.x scenario with inertia qualities applied to existing wind turbines, future wind turbines, demand control and battery resources.

Thank you in advanced for the continued opportunity to contribute to this Integrated Resource Plan process, and we look forward to continuing the process later this summer,

Sincerely,

Daniel Roscoe, P.Eng
Lead – Renewable Energy
Verschuren Centre for Sustainability in Energy and the Environment

Category	Comment #	Comment	NS Power Response
Reserve Margin	CA-01 Consumer Advocate	Instead of a planning reserve margin of 21% of installed capacity (with downward adjustments to the effective capacity for wind and some other resources), NS Power was imposing a minimum reserve of 9% in ELCC terms. Our understanding was that one MW of ELCC would support one MW of firm load. We are unable to locate any documentation for the conclusion that reliable supply requires capacity with a cumulative ELCC of 109% of peak load. We suggest that NS Power should provide that derivation and identify what drives the need for an ELCC reserve margin of 9%.	The ICAP method, which produces a 20% PRM, accounts for both thermal forced outages and extreme weather than the 1-in2 peak. The PRM under the UCAP method, which counts thermal generators at their ELCC, only needs to account for more extreme weather than 1-in-2 peak, resulting in a lower UCAP PRM. The detailed derivation of the IRP PRM assumptions was presented in the Capacity Study which was completed during the pre-IRP stage and is available on the IRP website. The decision to constrain the model to the UCAP (ELCC) PRM, rather than the ICAP PRM, was informed by stakeholder feedback during the Assumptions stage of the modeling process.

Category	Comment #	Comment	NS Power Response
End effects	CA-02 Consumer Advocate	NS Power modeling end effects as the present value of 25 years of the 2045 revenue requirements. This may significantly distort the differences among cases. Holding post-2045 revenue requirements at the 2045 level for 25 years overstates the end-effects costs of the plans with large capital investments near the end of the modeling period, compared to plans dominated by higher fuel or other expenses. Request analysis of whether the differences in end effects among the initial IRP results reasonably reflect differences in costs between options. If the variation in end effects among cases appears to be correct, but the magnitude is overstated, NS Power should consider shifting to a shorter end effect period (e.g., 10 or 15 years), or eliminating it altogether.	For clarity, the end effects period is modeled as a perpetuity of the 2045 costs (not a 25-year period) The cumulative present value of the 25-year planning horizon with end effects is one metric for cost evaluation. NS Power agrees it is not the only metric to consider when assessing the modeling results. NS Power has provided additional metrics as outlined in the Terms of Reference and provided with the September 2 Findings release to allow for a robust consideration of the modeling results. Costs for investments for new resources are annuitized in Plexos based on the depreciable life of the asset and the appropriate discount rate. This process for calculating annualized build costs serves to minimize or eliminate this potential bias in the 2045 End Effects period (i.e. incurring the full capital cost in the year built). NS Power agrees that both metrics (25-yr NPV with and without end effects) have positive and negative attributes and that is why both are presented for all scenarios and sensitivities.

Category	Comment #	Comment	NS Power Response
Distributed Resources	CA-03 Consumer Advocate	We are concerned by NS Power's decision to ignore the costs for the distributed energy resources in cases 2.1B and 3.1B. Determining the value to customers of DERs (especially storage, which adds resiliency) is difficult, so it would be hard to estimate the net cost of the DERs. We suggest that NS Power be careful to indicate each time it presents costs for these cases to indicate that they do not include any allowance for BTM costs. Those BTM costs do not fit neatly into the NPVRR calculation, since they do not represent utility revenue requirements. Nor should the full cost of DERs comparable to the utility costs, since DERs (especially paired solar and storage) provide additional benefits, particularly resiliency. If NS Power decides to incorporate some BTM costs into its reported cost metric, we suggest using a modest placeholder value. If Plexos produces marginal hourly energy costs, those could be used for the assumed DER load shape. Otherwise, NS Power might use some appropriate forecast estimate (average fuel cost, monthly marginal energy cost).	NS Power has provided this information for all DER cases when presenting NPV results. NS Power's rate impact calculation provides additional insight into the impacts of the DER (x.xB) resource strategy results.
Metrics	CA-04 Consumer Advocate	it is very difficult to compare plans with divergent load forecasts. NPVRR may be low for cases with high DSM and high for cases with lots of electrification, since the NPVRR does not reflect the benefit of fossil fuels avoided by electrification. The other economic metric in the interim results, the partial generation cost per MWh, does not provide much information about rate effects.	Based on feedback respecting challenges associated with comparing scenarios reflecting differing load levels due to electrification, NS Power has provided a relative rate analysis with the draft Findings release to provide a better comparison across plans to understand implications for ratepayers.

Category	Comment #	Comment	NS Power Response
T&D	CA-05 Consumer Advocate	NS Power staff explained that the projection of revenue requirements excludes T&D costs, which would be affected by electrification and DSM. Please consider providing a rough estimate of the potential sensitivity of T&D costs to these scenarios in the IRP report even if estimates cannot be provided by scenario.	The Avoided T&D cost estimates, being developed in parallel to the IRP with the DSM Advisory Group, will provide some insight into potential costs of electrification, particularly in constrained areas that are already experiencing load growth.
Capital cost	CA-06 Consumer Advocate	Request more detail on how the “revenue requirement profiles” for the “supply-side options that represent a capital investment” are computed in the objective function of the long-term Plexos model (2020 IRP: Financial Assumptions, March 11, 2020). Do you use annual, nominally-levelized or real-levelized revenue requirements, and how are income taxes are reflected in the revenue requirements computation, in addition to book depreciation and return (which we assume is included at the 6.62% pre-tax rate). A display of the assumed revenue requirements from a combustion turbine, a wind installation and the reliability tie would be useful to ensure that we understand what you are doing.	NS Power has provided this information in prior materials releases however, will reach out to the CA to confirm if additional explanation is desired.

Scenarios	CA-07 Consumer Advocate	We suggest four changes to the scenarios (or sensitivities) that will be run for the IRP. Natural gas price capacity plan sensitivity: The most recent FAM report suggests that there has been a shift from coal to gas driven by changes in fuel price. We suggest that NS Power should develop a capacity expansion plan that explores what level (or duration) of fuel price changes might trigger an economic decision to implement early coal retirements or otherwise affect the capacity build. No-transmission sensitivity: Since the reliability tie and regional interconnection were selected in every scenario (except the comparator case), we suggest that there should be a capacity plan with steam retirements but without the major transmission options, to identify what resources would be selected. It may be appropriate to study the interactions of the natural gas price and transmission sensitivities with the wind analysis discussed below. We observed that early coal retirements occurred in the net zero 2050 scenarios with distributed resources or low wind costs, indicating that coal plants are at least somewhat sensitive to low-cost energy. Hydro avoided costs sensitivity: We understand that there will be a specific “without Mersey” case. In addition, we suggest that NS Power develop three additional expansion plans in order to develop avoided costs for Wreck Cove and the two small hydro system groups. These avoided costs would them be used in future economic assessment model (EAM) runs during capital project filings. This could be completed after all other modeling is done, as we do not	NS Power has now conducted a High import/High Gas price sensitivity on scenario 2.1C. Since these resources were selected widely across key scenarios, NS Power agreed it was important to understand the robustness of this resource selection. These results have been released with the Draft Report. The Regional Integration option (i.e. large firm imports via new transmission) was only enabled as candidate resources in a subset of scenarios (X.X.C). The Current Landscape Scenarios (X.X.A) did not have access to large firm imports. All scenarios had access to the Reliability Tie as a candidate resource to enable wind integration. Based on stakeholder feedback, NS Power did undertake a sensitivity to test the value of this interconnection, by specifically excluding this interconnection from the candidate resources. Sensitivity 2.0A Import-2 examines this scenario. NS Power did undertake a No Mersey Plexos sensitivity, please see 2.1C.Mersey. NS Power will consider the suggested Hydro avoided cost analysis upon completion of the IRP.

Category	Comment #	Comment	NS Power Response
		believe these model runs are likely to have any other significant role in the final IRP analysis.	
Electrification/ HalifACT	CA-08 Consumer Advocate	While the scenarios are mostly consistent with HalifACT, With respect to the electrification goals in HalifACT 2050, it does not appear that NS Power's electrification scenarios in the load forecast are as ambitious as the HRM's goals. The limited description of the high-electrification scenario in the IRP make it difficult to determine how closely the two plans track. But the divergence in the electrification assumptions appears to occur mostly after 2030, so the high-electrification scenarios are likely to be adequate to develop an action plan consistent with HRM's electrification goals. Even a fairly aggressive program (whether sponsored by HRM, NS Power or some other entity) is unlikely to substantially exceed the levels of EVs and building electrification in the high electrification scenario before NSP's next IRP, which we assume will be completed around 2025. At that time, if vehicle and building electrification were progressing consistent with HRM's goals, then NS Power would need to adopt significantly higher assumptions for building electrification.	NS Power agrees with this interpretation.

Category	Comment #	Comment	NS Power Response
Wind costs	CA-09 Consumer Advocate	NS Power's 2019 [wind] capital cost of $2,100 per kW is outside the cost envelope suggested by Lazard and others have commented it is higher than market. NS Power's response includes a single scenario in which the 2019 capital cost is reduced from $2,100 per kW to $1,500 per kW. This scenario results in a significantly higher near-term wind capacity procurement (118 MW in 2.1C.S2 vs 57 MW in 2.1C). Recommendation: Compare assumptions to the contract prices in New Brunswick if possible. If New Brunswick costs are lower than NS Power's assumption, then either the model cost assumption should be revised, or NS Power should explain how Nova Scotia conditions would differ from New Brunswick conditions and justify the higher cost assumption.	As detailed in the Supply Options Study, completed during the Pre-IRP phase, NS Power's wind cost assumptions were informed by market indices such as the NREL ATB and WECC surveys, and by looking at regional data such as NB Power IRP assumptions. NS Power has proposed an Action Plan item to solicit Nova Scotia market based information for wind.

Category	Comment #	Comment	NS Power Response
Wind integration	CA-10 Consumer Advocate	NS Power caps the wind build at 100 MW (700 MW total installed) unless either reliability tie or a battery + synchronous condenser capital investment (referred to as domestic integration) is made to support reliability. The PSC study found that during periods of high wind and high imports, the loss of an intertie could cause stability issues. There are two alternative operational responses to accommodate additional wind. First, under hourly conditions of high wind and high imports without the reliability tie, wind generation could be capped at 700 MW. Second, under conditions of high wind, a minimum conventional (thermal or hydro) online capacity requirement could be established, which would both provide additional local inertia and reduce imports, avoiding the high wind/high import combination.	IRP runs consistently show economic utilization of non-firm imports in the early years of the planning horizon which indicate a significant percentage of hours could be classified as high imports. However, NS Power has established in its Action Plan to further study system stability and associated constraints as it pertains to wind or other invertor based renewable energy integration, particularly under normal or "non-stressed" conditions as was recommended in conversations with stakeholders.

Category	Comment #	Comment	NS Power Response
Inertia	CA-11 Consumer Advocate	NSP should conduct capacity expansion plan modeling with no inertia constraint and/or with a 1500MW-s inertia constraint to show the sensitivity to the inertia constraint. The model results are very sensitive to the cost of wind. The cost of adding wind above the 700-MW threshold is greatly affected by the cost of the reliability tie; the need and timing of the tie depend entirely on NS Power's application of the PSC report's reliability findings. We recommend that NS Power provide results in its final report that apply alternative inertia constraints. Assuming the differences are significant, further study after the final IRP report is issued could clarify the inertia constraint and other relevant reliability considerations so that NS Power can determine the appropriate level of wind development that may be supported prior to investing in the reliability tie.	NS Power has accepted these recommendations and included additional sensitivities in the Final Portfolio Study. In particular, 2.1C.Wind-3 was modeled with a lower inertia constraint (2200MW.sec) and 2.1C.Wind-4 was modeled as a boundary case with no inertia constraint modeled, as well as no integration requirements for wind energy (i.e. Reliability Tie or Domestic Integration). As recommended, NS Power has included further refinement of these constraints, including additional studies of normal operating conditions, in its IRP Action Plan.

Category	Comment #	Comment	NS Power Response
ELCC	CA-12 Consumer Advocate	The E3 Capacity Value study indicates that the wind ELCC drops from 38% at near-zero capacity to 19% at NSP's current wind capacity (E3 Capacity Value Study, p. 58). We agree with the E3 report that the capacity credit for wind and other renewable resources should decrease as additional wind is installed. This strongly implies that existing resources should receive a higher credit that incremental resources. However, the current IRP assumptions appear to give an ELCC value of 19% for both installed and incremental wind capacity. With respect to the installed wind capacity, we believe that the ELCC should be higher for three reasons. • As noted above, the wind resource modeled by E3 performs far worse during peak hours than indicated by the data provided by NS Power. • Our calculations, following the LBNL method (see footnote), suggest existing resources should have an ELCC of about 25%, as described below. • E3's calculation of a 19% ELCC at current wind levels may be a marginal value (reflecting incremental system resources), not an average value (reflecting existing system resources).	NS Power provides a 19% capacity value for the existing approx. 600MW of wind, as derived in the E3 Capacity Value Study. NS Power's IRP modeling assumption for capacity value from incremental wind is to model it linearly at 10%; this is a linearization designed to capture the range of 11% marginal capacity value at 600MW total installed capacity to 9% at 1000MW total capacity, as shown in the IRP Assumptions on slide 52.

Category	Comment #	Comment	NS Power Response
Wind integration	CA-13 Consumer Advocate	NS Power may model these operational constraints (curtailments or minimum commitment requirements) in its planning models, in which case the model could directly compare the cost of the operational constraints to the reliability tie and to the benefit of higher wind capacity. Alternatively, NS Power may need to exogenously estimate the amount of curtailment or uneconomic commitment to deal with extreme conditions, and the cost of those actions, and use that cost in lieu of the reliability-tie cost. If the model were allowed to build additional wind with operational constraints, it might well choose to add that wind earlier than 2029 and defer the reliability tie until later in the study period. Under the assumption that operational restraints are used, and low wind costs are available in the market, at what dates does the model suggest building more wind than the operational constraints can accommodate, requiring the reliability tie? What additional reliability and operational studies are needed to verify the performance and cost-effectiveness of using operational constraints to address the high wind/high import issue? c) If wind prices are attractive enough to go beyond the wind capacity that can be facilitated with the operational constraints, how long a lead time would NS Power require to make a build or defer decision for the reliability tie?	NS Power has proposed an IRP Action Plan item related to continued refinement of synchronized inertia requirements, including examining dynamic modeling options, for post-IRP work. The assumptions have been developed using the PSC Stability Study from the Pre-IRP work as the basis for assumptions. The i) Reliability Tie and ii) Local Mitigation options were identified as enablers of larger increments of wind. NS Power has proposed an Action Plan item to solicit Nova Scotia market based information for wind, which will inform future wind procurement. Future procurement for the Reliability tieline, with the primary objective of integrating more domestic wind, would assess a broader array of potential integration alternatives.

Category	Comment #	Comment	NS Power Response
ELCC	CA-14 Consumer Advocate	ELCC of incremental wind After taking into consideration the capacity credit associated with wind, the capacity factor for wind in the top 1.1% of peak hours drops from 61.3% to 19.7% in the top 1.1% of net peak hours. In the 4-year dataset provided by NS Power, the top 1.1% hours are those hours with load of 1,840 MW or with a net load of 1,697 MW. This indicates that the 595 MW of wind reduced load by about 143 MW, or a 25% capacity credit. Thus, while our analysis supports the use of a 19% ELCC for incremental resources, we find that the existing wind resources should have a UCAP Firm Capacity of 143 MW rather than 113 MW.	See response to CA-12 above. NS Power has discussed with the CA its use of the ELCC analysis to determine the capacity value of both new and existing wind generation on the Nova Scotia system. ELCC analysis looks at the contribution of wind to firm capacity on an 8760 basis rather than just looking at a small number few peak hours.
Wind integration	CA-15 Consumer Advocate	Since the IRP process does not include an opportunity to further investigate the cost of wind resource development or further study the practicality of operational constraints, it is essential that the final modeling scenarios appropriately examine these questions to provide the Board with the context it needs to evaluate the need for and potential scheduling of the reliability tie.	NS Power has expanded the sensitivity analysis completed as part of the Final Portfolio Study per the recommendations of the CA and other IRP Participants; please see responses to CA-07, CA-09, and CA-11 for more information.

Category	Comment #	Comment	NS Power Response
DSM impacts	CA-16 Consumer Advocate	The 2.0A pair has a NPVRR difference of $337m and the 2.1C pair has a difference of $544m. Why is the difference so substantial based on the electrification level? Why is the mid DSM incremental cost more than the supply resources it replaces? Would the avoided T&D costs associated with a higher level of DSM potentially offset the cost difference? The model is making changes that seem counter-intuitive when shifting from base to mid DSM. The shift from base to mid DSM in case 2.1C (vs S1) results in an early build of an NGCC unit, reducing gas peaker capacity, and reducing firm imports. Is there something about the way firm imports are characterized that needs to be reconsidered? Why is the model suggesting that it is economic to build a unit that produces more energy when there is less energy to serve?	The Final Portfolio Study results show 2.0A difference of $360M and 2.1C difference of $327M. A number of enhancements were made to the model since the initial set of runs to fine tune the results, including incorporating PLEXOS MT/ST hourly production costs into the scenario NPVs. The Mid DSM costs are approximately double the Base DSM costs but provide only a 10-15% increase in energy and demand savings. Given the small increase in demand savings with Mid DSM it is unlikely the cost difference would be offset. The latest results show an additional 147 MW of NG steam retirements in 2.1C Mid DSM (in 2029) compared to the 2.1C Base DSM. The 145 MW NGCC is built one year earlier in the Mid DSM case due to the additional retirement. Gas peaker capacity is about the same, firm import is 5 years earlier in the Mid DSM case due to the additional retirement.

Category	Comment #	Comment	NS Power Response
ELCC	CA-17 Consumer Advocate	ELCC of Wreck Cove and Mersey Can NS Power explain why Wreck Cove operates so little in high-load hours? Does NS Power normally hold a large portion of Wreck Cove in reserve at peak? Does Wreck Cove have available energy resources to support a 95% ELCC value, given the long evening winter peaks? While the Mersey units are dispatched more reliably than Wreck Cove in high-load hours, its dispatch does not match the UCAP/ELCC that NS Power claims for this system. Its capacity factor also declines from the winter, to peak days, and to net peak hours. Does Mersey have enough flexibility in dispatch to be held in reserve at peak, or does the system simply produce less energy in the hours that tend to have high loads?	Wreck Cove is an energy-limited peaking plant and an important source of ancillary grid services such as reserve. When modeled in the capacity study in the pre-IRP phase, Wreck Cove was modeled as a dispatch limited resource with a daily energy budget equivalent that varied by month. The ELCC analysis completed under these assumptions supported the 95% ELCC rating for the Wreck Cove facility. Mersey was also examined in the pre-IRP capacity study and determined to have an ELCC of 95% via that model; the system was modeled as having sufficient pondage to cover any duration of peak event due to storage at Lake Rossignol.
Regional Integration	CA-18 Consumer Advocate	The regional interconnection is built in 2030 if the more aggressive climate policy is selected, except in the mid-electrification case with high distributed resources. Otherwise, it is built in 2038– 2045. Run a sensitivity to one of the 2040 or 2045 build cases that forces the build in 2030. It would be interesting to see if the cost difference is significant. Building or postponing this upgrade well beyond 2030 is a significant near-term decision point, and NS Power should determine whether it should move forward with planning on this project, since it would require cooperation with New Brunswick and possibly Quebec.	NS Power will refine the timing of the Regional Interconnection transmission builds as part of the development of a Regional Integration Strategy as identified in the IRP Action Plan. The proposed discussions with neighbouring jurisdictions will inform this work as well.

Category	Comment #	Comment	NS Power Response
Storage	CA-19 Consumer Advocate	It appears that in most cases with near-term wind procurement over 100 MW, there is a relatively large amount of 4 hr battery storage selected as well. If that is correct, the final plan should recommend that wind procurement should generally proceed in combination with a storage procurement.	The Draft Findings provide that batteries can enable wind integration while providing firm capacity and energy storage; however, their ability to substitute for firm capacity resources is limited by its relatively short duration. Up to 120MW of storage by 2045 is selected in the portfolios with deployments of 30-60MW by 2025 in many plans. The draft Roadmap provides that NS Power will track the installed costs of energy storage and will solicit Nova Scotia market-based information which would inform this as needed.

Category	Comment #	Comment	NS Power Response
Combined Cycle Gas	CA-20 Consumer Advocate	It is surprising to see a combined cycle built so late in the 2.2A and 2.2C cases, as well as being built in the 3.1 and 3.2 cases. We are concerned because it is our understanding that the objective function of the model includes costs and benefits at 2045 operational levels through 2070 via end effects. Given the 2050 climate targets assumed in these cases, but not really represented in the model, we believe there may need to be modifications to the model to ensure that combined cycle plants are financially viable without an assumption that the plants will operate beyond 2050. Ideally, NS Power would simply limit the useful life of a combined cycle to 2050. However, there are at least two reasons why this simple approach may not be practical in the current modeling environment. First, this may result in creating a unique resource for each year in the model, which may result in too much model complexity. Second, the end effects associated with a gas plant retirement in 2050 may result in the model considering costs and benefits of the gas plant in 2045 continuing through 2070 – which is clearly inconsistent with the net zero carbon scenarios. NS Power should identify a workable approach that allows the benefits and costs of a combined cycle plant to be reflected in a way that approximates retirement by 2050. As discussed above, it may make sense to limit or eliminate end effects calculations as part of the objective function. If that was done, then the number of resource options could be limited by offering units with 25, 20, and 15-year lifetimes, with no combined cycle plants built after 2039.	NS Power agrees that the treatment of late period builds is challenging and notes that there is considerable uncertainty associated with these builds, including what offsets may be available under a net-zero compliance approach and whether low or zero emission fuels or fuel blends may be available (e.g. hydrogen, biofuels). NS Power has not limited the model from building these late resources but believes they do not have a significant influence on the near-term resource plan (5-10 years) based on the timing of other resource additions (e.g. regional integration capacity) and late period unit retirements.

Category	Comment #	Comment	NS Power Response
Wind	CanREA-01 Canadian Renewable Energy Association	Recommendation: more analysis be conducted to consider how these specific capabilities of wind energy, coupled with other technologies like storage, will in fact, enable more, cost effective wind energy to be integrated to the grid without significantly more infrastructure investment. With the implementation of an obligation on new and existing wind projects to provide FFR, it may be economic and feasible to add additional wind generation well beyond 100 MW without major infrastructure investment.	NS Power has provided two additional model runs as part of the Sept 2 modeling results release; one models a lower system inertia requirement of 2200MW.sec and one has no inertia constraint or wind integration requirements. NS Power has also proposed an IRP Action Plan item related to continued refinement of synchronized inertia requirements, including examining dynamic modeling options, for post-IRP work. Based on stakeholder feedback, in the Final Portfolio Study NS Power allowed new wind resources to contribute to the system ramp down reserves when online, reflecting potential enhanced contributions to ancillary services from new wind resources.

Category	Comment #	Comment	NS Power Response
Wind	CanREA-02 Canadian Renewable Energy Association	We understand that the operability analysis is likely to be test scenarios that were evaluated in PLEXOS to ensure that they do not adversely affect reliability. CanREA encourages NSPI to ensure that these analyses consider at minimum the impact of new frequency response provision requirements for non-synchronous/inverter-based resources in terms of enabling additional wind generation in Nova Scotia in the near term without major infrastructure investments. Forecasted near-term reductions in both the levelized cost of wind generation, and competitive system costs of inverter-based generating resources and energy storage as compared to a synchronous generation-based system, suggest that increased volumes of these resources could reduce costs for Nova Scotia consumers while advancing the Province's environmental goals.	The Operability Assessment completed as part of the IRP is not able to reflect the type of dynamic/transient analysis that would capture new wind contributions to Fast Frequency Response services. NS Power has identified this area of additional work as a proposed post-IRP Action Plan item.

Analysis	CanREA-03 Canadian Renewable Energy Association	Key unexplained results that are surprising and appear counter-intuitive are the high levels of gas turbine build and relatively low levels of battery build How were ancillary service provision by various resources modeled? • Does this modeling reflect the underlying higher performance of ancillary service provision that batteries and other non-synchronous/inverter-based resources can achieve relative to conventional resources including thermal generation? Experience in other electricity markets (e.g., PJM etc.) indicates that the quality of AGC service provided by batteries is such that it can reduce the underlying requirements for these resources to provide this service, reducing costs to customers. Does the end effects analysis adequately consider additional costs of fossil-based resources relative to renewable resources recognizing that carbon constraints and costs associated with exceeding these are likely to become increasingly significant? • Does the end effects analysis adequately reflect future operating constraints on fossil-based resources? • Does the end effects analysis adequately reflect increasingly stringent carbon constraints imposed after fossil investments are made • How was the loss of flexibility or these cost penalties considered? Were the potential benefits of hybrid projects (wind/energy storage or solar/energy storage with storage embedded behind the meter) adequately considered?	Plexos LT module optimizes resource plans constrained by all ancillary services (reserve) constraints, co-optimized with unit commitment and dispatch. The suite of the new resources including wind and batteries are contributing to certain modeled ancillary services. Namely, wind resources are part of the regulation lower service. Batteries contribute to all types of reserve including regulation (raise and lower), spinning and non-spinning. The quality of AGC service provision is too granular to be modeled in a capacity expansion model. NS Power notes that the ELCC of battery storage declines relatively quickly with installed capacity on the Nova Scotia system, in part due to the more variable nature of the wind resource (e.g. multi-day periods of either high or low wind generation) that the batteries are supporting as compared with a more predictable daily solar profile. The End Effects treatment assumes the 2045 resource portfolio has an infinite reinvestment horizon. It does not consider alternative environmental compliance requirements beyond this year. NS Power notes that the capacity factors of the combustion turbine resources added for capacity are very low (less than 10% per year in the vast majority of cases, and in many years less than 5%) and has added monitoring low and zero carbon fuel development (e.g. Hydrogen, Biofuels) to its IRP Roadmap The IRP did not model hybrid projects for storage behind the meter but provided both storage and renewable generation options separately

Category	Comment #	Comment	NS Power Response
		• hybrid projects can provide required ancillary services (e.g., frequency response services) at lower cost by avoiding opportunity costs associated with the provision of some frequency response services as well as provide a desired capacity resource at a relatively low effective cost.	

Category	Comment #	Comment	NS Power Response
DSM sensitivities	E1-01 Efficiency One	Model additional sensitivities with respect to differing DSM cases. Modelling additional sensitivities is required to adequately test DSM's impact in the context of the various 2020 IRP scenarios. The requested sensitivities in each scenario are detailed on pages 3-4 of this memo. Two sensitivities were modeled . These runs do not provide a full set of expected sensitivities. Additional sensitivities will provide further and necessary insight on the appropriate DSM trajectory for Nova Scotia. At minimum, results should be provided from: Completion of a DSM sensitivity examining Mid-DSM levels within case 2.0C (Net-Zero, Reference Electrification, Regional Integration) A DSM sensitivity examining Mid-DSM levels within case 3.lC (Accelerated Net- Zero, Mid-Electrification, Regional Integration) A DSM sensitivity examining Mid-DSM levels within case 3.2C (Accelerated Net- Zero, High-Electrification, Regional Integration) A DSM sensitivity examining Mid-DSM levels within case 2.2C (Net-Zero, High- Electrification, Regional Integration) In addition, should the distributed energy versions (X.XB) of the above remain in consideration following further analysis, they should also receive similar sensitivity treatment as outlined in the bulleted list above.	NS Power completed the following additional DSM sensitivities and released them with its updated modeling results release on September 2; this list of DSM sensitivities was developed in collaboration with E1. 2.0A.DSM-1 Low Electrification / Mid DSM 2.1C.DSM-2 Mid Electrification / Mid DSM 2.2C.DSM-3 High Electrification / Mid DSM 2.0C.DSM-4 Low Electrification / Low DSM 2.0C.DSM-5 Low Electrification / Mid DSM 2.0C.DSM-6 Low Electrification / Max DSM 3.1C.DSM-7 Mid Electrification / Mid DSM / 2030 Coal Retirement

Category	Comment #	Comment	NS Power Response
DSM sensitivities	E1-02 Efficiency One	2. Confirmation that full resource re-optimization is occurring for all sensitivity runs, including re-optimization of the planning reserve margin to levels that satisfy, but do not greatly exceed NERC requirements.	Confirmed.

Category	Comment #	Comment	NS Power Response
Distributed Resources	E1-03 Efficiency One	3. Continue to refine the cost estimates for Distributed Resources, as they currently span a wide uncertainty range. Existing and planned data, including costs, from Smart Grid Atlantic and NS Power's Smart Grid project may be useful in doing so. Basic information has been provided relating to the envisioned costs for renewable DERs - described as "$1.6-2.5B" on an NPV basis. These costs have not been directly included in the NPV revenue requirement of any modelling scenario. Continue to refine, and use data from Smart Grid Atlantic and NS Power's Smart Grid project. Current solar PV offerings in Nova Scotia do not leverage ratepayer investment, and no such programs have been planned to date. Given that there already exist three differing and incomparable sets of revenue requirements within the IRP (reference, mid and high levels of electrification), having three incomparable cases through DER levels is cumbersome, and will likely stifle clear determinations about effective resource strategies. 4. With respect to Distributed Resources cases, define the portion of the NPV revenue requirement that will be ratepayer-funded, and include it within NPV revenue requirements.	NS Power has provided a range of cost estimates sufficient for understanding the directional impact of these costs when added to the NPV calculations. Continued refining of cost estimates for DERs is beyond the scope of the IRP exercise. Inclusion of DER scenarios was determined through consultation with stakeholders on the Analysis Plan and Scenarios (in February 2020). Based on feedback respecting challenges associated with comparing scenarios reflecting differing load levels due to electrification and consideration of DER scenarios, NS Power has provided a rate analysis with the draft Findings release to provide a better comparison across plans to understand implications for ratepayers. For the purposes of IRP analysis, the costs of investment in DERs is outside of the utility model.

Category	Comment #	Comment	NS Power Response
DSM costs	E1-04 Efficiency One	Levelization of DSM Costs 5. Re-run DSM scenarios with an amortized capital cost stream, similar to the treatment for supply-side resources. Presently, DSM is being modelled within the IRP on an expensed basis, as opposed to an amortized basis. Based on the treatment of supply-side resources on an amortized basis, the DSM scenarios should be re-run with this similar treatment. El can assist in this by providing an amortized cost stream which reflects the amortization across the average measure life of each year's potential DSM activities (this cost stream would extend into the end effects period). This will provide more accurate information regarding the true competitiveness of DSM, as opposed to a result which may include artifacts from the differing financial treatment of DSM.	Upon discussion with E1, E1 advised that it was withdrawing this request. The modeling approach is aligned with the current treatment of DSM costs as an expense.

Category	Comment #	Comment	NS Power Response
Demand Response	E1-05 Efficiency One	6. Allow the introduction of Demand Response (DR) in 2021, 2025, 2030, and 2035. This would provide a better balance and consistency in model runs, and more accurately estimate the value of DR in Nova Scotia. 7. Re-run all scenarios allowing DR to economically compete against new and existing natural gas peaking infrastructure Additionally, please clarify on the following points relating to how DR was modelled: In scenarios where DR is selected, it appears that 82MW of capacity is in place in year 1 (2030). Does the model assume that level of DR remains in place until 2045 with no changes in capacity? What is the DR profile for the remaining years? Is there a ramp-up built into the DR assumptions as is the case with the 2019 DSM Potential Study? Was DR available to the model in place of selecting the build-out of ~37MW capacity of new gas combustion turbines and reciprocating units in 2021?	In the Final Portfolio Study NS Power offered the DR resources in 2021/2025/2030. In all scenarios, DR was selected economically prior to 2035. The DR Profiles reflect the ramp up in nameplate capacity and cost profile, as provided by E1 for Low/Base/High DR cases. The DR programing provided by E1 covers the period 2021-2045. For all entry points, there is DR capacity savings in 2045, as applicable to the entry year (e.g. if selected in 2021, the 2045 capacity savings would be equal to the 2045 DR capacity savings provided by E1. If selected at another entry point, the capacity savings is shifted later accordingly). Yes, DR was modeled as a supply side resource available along with natural gas units and other resources in this round of modeling. In the Final Portfolio Study, DR was available for selection in 2021, however, gas units were not available to the model until 2023. The PRM constraint was not enforced in 2021 or 2022 in the Final Portfolio Study in order to better manage this model behaviour.

Category	Comment #	Comment	NS Power Response
Plexos Information	E1-06 Efficiency One	Provide quantitative inputs and outputs from Plexos in tabular format, as initially requested on May 12, 2020 with a priority for the Comparator cases l.0A and l.0C. To note, requests for release of data have been addressed by NS Power through an alternative arrangement for a technical session with El and its consultant, where PLEXOS model parameters and data can be examined.	As noted, E1 considers this request to have been addressed by NS Power through an alternative arrangement for a technical session with E1 and its consultant where Plexos model parameters and data were examined in detail.
	E1-07 Efficiency One	Within the written deliverables (Draft Findings, Roadmap & Action Plan) to be released (per the Terms of Reference), provide findings for each evaluation category for each candidate resource plan considered. This will allow stakeholders to better follow the more qualitative aspects of the evaluation process. When selection decisions are being made regarding specific candidate resource plans, or groups of similar plans, justification should be provided on the basis of evaluation criteria, and the relative importance of each criteria in making such a determination.	NS Power has provided its draft Findings, Roadmap & Action Plan which are based on the metrics that have been established for the process.

Category	Comment #	Comment	NS Power Response
Capacity Value of Non-Firm Imports	E1-08 Efficiency One	Clarify any ongoing modelling impacts associated with the use of non-firm imports in RESOLVE. Confirm that the PLEXOS LT runs do not count any non- firm imports as capacity. Provide additional information and support regarding firm import assumptions to allow stakeholders to assess the reasonableness of these assumptions. Clarify which candidate resource plans depend on the addition of 450 MW of firm imports from Quebec, or portions of this capacity if Plexos did not take the entire volume in any given scenario. Include a sensitivity analysis run that limits market imports (both firm and non- firm) to 110% of recent historical averages, excluding the Maritime Link NS block. This inclusion would provide the benefit of a view with limited expansion of market opportunities, which El believes warrants consideration.	There are no ongoing modeling impacts. Confirmed. All information respecting firm import assumptions were provided with the Final Assumptions release in March. Stakeholders were provided the opportunity to comment on Assumptions before they were finalized. Detailed information on import selection, including price and quantities, that can be tied to a single counterparty is not being provided for competitive reasons. Sufficient information has been provided in a manner that protects commercially sensitive details for the benefit of customers. NS Power modeled a sensitivity that limits non firm imports available to the model; please see 2.1C.Import-1.

Category	Comment #	Comment	NS Power Response
Natural Gas	E1-09 Efficiency One	A proxy for new gas supply should also include a sensitivity relating to the Algonquin City Gates Hub (AGT) as the commodity price for new winter (and summer) natural gas capacity, with the inclusion of energy cost and tolls reflecting transport from AGT to Tufts Cove, as it would address some of the uncertainties associated with the current approach of acquiring gas and transportation from Alberta (AECO), Dawn or LNG via Amsterdam (TTF). Sensitivity analyses that explores the constrained availability of natural gas for the NS electricity system should be included, at least in terms of incremental capacity additions beyond 20,000 MMBtu per day. Put another way, constrain the model to only allow for consumption of 20,000MMBtu per day, thus allowing the model to economically select other resources other than natural gas beyond the currently contracted firm supply. 3. Gas price sensitivities can then appropriately explore higher or lower pricing scenarios that impact future capacity additions to the system, and differing limits on the availability of gas. These fundamental questions regarding natural gas pricing and availability must be answered in the context of the IRP prior to it being finalized if the IRP results are to show the degree of sensitivity to commodity costs. They will fundamentally affect pricing and the selection of resources, which will not be reflected in an after-the-fact analysis.	When developing a plan for assumptions that would require a firm gas supply, NS Power's analysis indicated that volumes would not be available from AGT that could potentially be required. AGT is treated as opportunistic gas, as there is limited firm transportation available. Further, because AGT experiences more severe winter prices than AECO, and NS Power is a winter peaking utility, it was deemed that the supply source modeled in the IRP is likely more economic. As per the Final Assumptions document, gas supply options were developed on the basis of new natural gas units economically selecting firm access to a gas supply to operate at significant capacity factors. NS Power does not feel that the LNG Winter-Dawn summer pricing alternative would be constrained in this regard. The supply path from AECO (Path 3) considered transportation upgrades to firmly supply Nova Scotia (and a fixed cost adder applied to gas units in the model for this option). A High Natural Gas / High Import Price sensitivity was modeled based on stakeholder feedback and released with the Draft Report.

Category	Comment #	Comment	NS Power Response
Scenarios - GHG emissions	EAC-01 Ecology Action Centre	Model scenarios that achieve zero GHG emissions The study is inconsistent with GHG trajectories needed to align with international, federal, provincial, and local emissions reductions plans. No zero emission scenarios are studied, although the study mentions that mid- and high-electrification scenarios follow SDGA 2050 end points, and there are delayed zero emission targets; perhaps never achieving zero emissions will limit the opportunities for other sectors to rapidly decarbonize. Model zero-emission cases for 2050, 2045 and 2035. A zero emissions study enables the model to compare the costs of adding carbon sequestration to these [natural gas] generators against the costs of increased clean imports. It is not clear from the scenarios studied that replacement of coal thermal plants with natural gas infrastructure is the lowest long-term pathway to a zero emission state. Modelling accelerated zero emission timelines may well reveal lower long-term cost solutions. Accelerated net zero timelines can and should analyze multiple energy mixes.	The GHG scenarios being modeled incorporate significant emissions reductions, from ~5MT at the beginning of the study period to 1.4-0.5MT in 2045 under the 2.x and 3.X emissions curves. This requirement includes a mandatory phaseout of all coal generation within the planning horizon. The Accelerated Net Zero 2045 case (0.5MT in 2045) represents NS Power's view of a path to absolute zero in 2050.

Category	Comment #	Comment	NS Power Response
Scenarios	EAC-02 Ecology Action Centre	The study restricts the model's ability to add firm imports and as such biases the result towards gas turbine construction, continued natural gas purchases and GHG emissions from both direct combustion and upstream fugitive methane emissions (which are not currently accounted for under this process). Long decarbonization trajectories endorse the replacement of coal generation with natural gas resources and it is not clear if these generators will be cost effective when utility emissions are regulated to zero. Faster trajectories to zero electric utility emissions may be more cost effective over the study period and the related end-effects time frame.	In the Regional Integration scenarios, the model is able to select both limited quantities of firm import capacity and energy over existing transmission assets as well as more significant quantities of capacity and energy which require transmission build-out. In addition, non-firm energy imports are available to the model over existing and new transmission infrastructure. This provides the model with the ability to source a significant portion of required energy and capacity from outside Nova Scotia, if economic. Significantly larger quantities of firm imports than currently modeled could represent a reliability and self sufficiency challenge, as NS Power must be able to accommodate the loss of its largest generator or firm import, and so are not considered in this IRP.

Category	Comment #	Comment	NS Power Response
Natural gas and Diesel generators	EAC-03 Ecology Action Centre	Report the detailed operational profiles of natural gas and diesel generation assets (number of operations per year, their durations and power and energy associated with each unit). This data will be useful in using these model choices as proxies for identifying cost effective alternate generation or storage solutions in the future. These may include long duration battery storage or tidal power, among others, as technologies mature. One specific example would be the recent announcement of a 150 hour duration battery demonstration by Form Energy and Great River Energy in Minnesota.	NS Power continues to provide generation results from unit classes as part of modeling releases, e.g. total generation by year from both Natural Gas and Diesel combustion turbines. Samples of natural gas and diesel combustion turbine outputs were provided as part of the Operating NS Power will continue to monitor developments in storage technology, including long duration storage solutions and its economic competitiveness vis-à-vis other primarily capacity-oriented resources.
Timeline	EAC-04 Ecology Action Centre	Recommend an extension for more stakeholder interaction, to November 30, 2020.	NS Power and the Board have adjusted the final deliverable date to accommodate additional analysis and stakeholder interaction. NS Power looks forward to continued stakeholder engagement over the reminder of the IRP process.
Transmission	EAC-05 Ecology Action Centre	Ensure that the model's portfolio of assets always includes the ability to add an additional transmission line through New Brunswick to Quebec as identified in the IRP assumptions set.	Confirmed that this firm import option is available in all Regional Integration scenarios ("C" models).

Category	Comment #	Comment	NS Power Response
Scenarios – net zero	EAC-06 Ecology Action Centre	No carbon credit purchase costs are included to bring the net zero cases to net zero. As such, these cases should be labeled Near-Zero rather than Net-Zero. Negative emission curves are possible but not addressed. The scenarios that proceed to net zero do so outside the planning period. Do the trailing end effect costs include carbon sequestration from the operational gas plants at the end of the study period? Because no zero emissions case within the study period has been considered and all near zero cases build combined cycle gas to work with intermittent wind resources, these predictable costs are not identified. It is plausible that a zero emissions limit at 2050, 2045 or 2035 would choose interconnection over generation if it had access within the model to more regional interconnection. It may be that greatly reduced generation is built and that zero emissions are achieved faster for limited additional expense to the utility and avoided rate base costs to the ratepayer. The last thing this process should plan for is a new life cycle of generation that will require expensive upgrades or premature retirement. Only a zero emission scenario can fully determine if this is truly cost effective.	The trailing end effects costs do not include the cost of carbon sequestration. An earlier absolute zero target would require a fulsome change in assumptions and significantly more study. As suggested, a reliance on imports for the majority of Nova Scotia's peak demand requirements and the associated impacts on affordability, reliability and self sufficiently would need to be thoroughly studies to provide meaningful modeling inputs. NS Power has focused the efforts of this IRP on modeling a deep decarbonization of the electricity system, representing an 87-95% reduction from 2005 levels, while simultaneously supporting decarbonization of other sectors of the economy via electrification. NS Power believes these scenarios will continue to be of interest in future planning studies. In the majority of scenarios, high utilization combined cycle gas units are not built until late in the planning horizon. The economics of these units could change in the interim. Such material changes to the current IRP assumptions will be monitored in NS Power's IRP Evergreen process. NS Power has also proposed examining low and zero carbon fuel blends (e.g. hydrogen, biofuels) as part of it's IRP Action Plan and Roadmap.

Category	Comment #	Comment	NS Power Response
Electrification benefits	EAC-07 Ecology Action Centre	The costs to the ratepayer are not fully comparable between scenarios. High electrification cases presume that consumers are replacing fossil fuel costs for heating and transport with electrical costs and there is substantial potential that this transition will provide significant financial benefit to consumers, and health benefits to the province, which are not captured in the scenarios. This includes transportation and building heating and electrification. While the E3 Pathways report contemplates electrification of heating systems, it does not account for improved building quality beginning in 2030 from new construction, nor is there an assumption around the rate at which older building stock may be renovated, and more efficient buildings are more capable of demand response as well, so the load in high electrification scenarios may be overstated.	NS Power agrees that there are economic costs and benefits associated with electrification that are not included in the IRP analysis. NS Power is interested to continue to explore these as part of the Electrification Strategy that has been proposed in the IRP Action Plan. NS Power has provided a rate impact analysis with its draft Findings release to enable better comparison across differing load scenarios.

Import and Natural Gas	EAC-08 Ecology Action Centre	Import and Natural Gas Trade-offs: Scenarios that modeled regional integration indicate that the Reliability Tie (345 kV Onslow - Salisbury) and the Regional Interconnection (345 kV Salisbury to Coleson Cove) are selected early when seeking solutions to declining GHG limits. The March 11, 2020 IRP Assumptions listed a third interconnection (Salisbury - Quebec HVDC) and it is not clear that this was an active option in all of the modeled scenarios or just the regional integration scenarios. If it were available, it is not clear that, if presented with a zero emissions case in the study window, the model might well choose it over gas generation with carbon sequestration. In addition, there is a risk that continued natural gas purchases will ultimately carry a higher carbon emissions factor due to upstream fugitive methane emissions. While not currently accounted for under this IRP process, there is a clear risk that at some point in time they will be included as regulators seek to achieve real emissions reductions. Multiple studies indicate that fully accounting for these emissions brings the natural gas supply close to emissions intensities associated with coal combustion. Non-zero emissions allowances and optimistic emissions factors for natural gas create conditions where building natural gas fired systems is the most cost effective response to declining GHG levels. The concern is that when emission limits fall to absolute zero, significant (approximately doubling) costs will be incurred to sequester the carbon output of these plants. Please ensure that all models can add multiple interconnections and run scenarios that study zero GHG	The Salisbury - Quebec HVDC resource option was offered to the model in all Regional Integration scenarios; both the Quebec and Coleson Cove transmission expansions fall into the definition of Regional Interconnection as used in the IRP. NS Power, through the standards for Quantification, Verification and Reporting, does not account for upstream fugitive emissions. Should this become legislation and the impacts material, any future planned natural gas units would be re-evaluated. NS Power will continue to monitor regulatory developments in this area and update its analysis, via the evergreen IRP process, as appropriate. NS Power agrees that assessing import options continues to be critical to future resource planning and intends to continue this work via the Regional Integration Strategy proposed in the IRP Action Plan.

Category	Comment #	Comment	NS Power Response
		conditions. It is critical that this IRP fully assess the import options available to Nova Scotia.	
Load Forecast Data Requests	Hendriks-01 Richard Hendriks	Detailed historical data requests, additional analyses and comments seeking information on items already covered through the stakeholder engagement process, or Assumptions already finalized through stakeholder consultation. The decision to maintain the endpoints consistent with the established SDGA goals requires further justification. Historically, the effect of substantive economic contraction on electricity demand is a modest to substantial downward (or rightward) shift in the demand curve following the recession, for both energy and peak capacity. Not accounting for this shift in the load forecast potentially creates a systemic bias across all findings in the IRP. Requested last 20 years of load forecasts; analysis of recessionary effects on demand.	The requestor advised that he is a PhD student at the University of Toronto and did not identify an interest related to electricity planning within Nova Scotia. In many instances the information sought is found within materials released to stakeholders earlier in this process. The detailed data requests and additional analyses and explanations sought are beyond the scope of the IRP.

Category	Comment #	Comment	NS Power Response
CTs	HG-01 Heritage Gas	The liquid-fueled CT's are now over 40 years old. The model scenarios include the continued use of these units to 2045, by which time they will have been in service for over 60 years. Heritage Gas understands that fuel delivery to these units is by tanker trucks and, as a result, replenishment of the tanks that support these units is reliant on the availability of a limited pool of tanker trucks. This pool is further constrained in winter months when the units are more likely to be called upon. Availability of fuel supply has decreased following the closure of local refineries. Reliability issues associated with maintaining units out to their sixth decade of operation should be considered independently of the economics of replacement vs sustaining capital costs. Reliability test results should be made available to IRP stakeholders.	As discussed at the July IRP workshop, NS Power has invested in the diesel CT units over the last several years to enable continued reliable operation. The Resource Screening results show that the capacity provided by these units continues to be required and is lower cost than alternative capacity sources by a wide margin.
Electrification	HG-02 Heritage Gas	Given that IRP outcomes can influence long-term capital investments and policy directions, the total cost implications of IRP outcomes for rate payers should be examined in the Action Plan. Increased electrification will contribute to peak energy demand. A number of studies have shown that natural gas distribution systems can cost effectively assist in meeting peak energy demand while still meeting GHG targets. The nature of the results of the IRP analysis and the significant reliance on natural gas going forward in all scenarios provides an opportunity for Heritage Gas to work with all stakeholders to ensure the most cost-effective energy supply system in the province going forward.	Based on feedback respecting challenges associated with comparing scenarios reflecting differing load levels due to electrification, NS Power has provided rate analysis with the draft Findings release to provide a better comparison across plans to understand implications for ratepayers.

Category	Comment #	Comment	NS Power Response
Compressed Air Storage	Hydrostor-01 JFS Hydrostor	We believe that A-CAES's capital costs were inaccurately modelled. We believe that this played a decisive factor in it not being selected as a preferred resource. In particular, we found that in your cost analysis, the model used a $/kW cost of CAD $2,200. This was in effect, the mid point of our $/kW cost estimates for a 200 MW facility with a duration of 12 hours that we had previously provided to you. This was then compared to the cost of a lithium-ion system with 1 and 4 hours of duration…. If you consider a 500 MW facility with a 4-hour duration, the cost works out to an average of US$1125/kW. We believe that this is a much fairer comparison to a 4-hour lithium-Ion system for the short duration market. CAES can act as a non-wires alternative to traditional transmission for improving reliability or as a solution for integrating and time-shifting Nova Scotia's wind resources onto the grid. A-CAES uses spinning turbines it can meet the grid's need for inertia and synchronous generation. Furthermore, unlike pumped hydro or fossil assets, A-CAES can be flexibly sited where the grid needs it.	NS Power's Final Assumptions provided ranges for costs for storage options which may be provided by a variety of technologies/sources. Hydrostor's specific technology was determined to be within this range. As previously stated, the resource technology selection is indicative for the specific scenario. For future resource procurement, NS Power would undertake a detailed Alternatives Analysis to target the specific technology if there are competing alternatives with similar attributes (e.g. RECIP vs CT, battery vs other storage option, etc.).

Category	Comment #	Comment	NS Power Response
Wind cost	NF-01 Natural Forces	Price of wind is overstated compared to observed current pricing. NS Power should reduce by 30 percent at a minimum. Capacity factor used is much too low leading to the high price. NSPI has strong opinion on this issue and it is suggested that it would make sense to test the sensitivity of this pricing. The model should be run with a sensitivity of a reduction in cost of 30% at a minimum.	NS Power undertook two Low Wind Price Sensitivities (see 2.1C.Wind-1, 2.1C.Wind-2) which both include wind capital costs at 29% below the base case assumption. Capacity factor assumptions were developed by E3 based on CanWEA pan-Canada wind integration study and reflect higher capacity factor assumptions than current operational wind farms in Nova Scotia.

Category	Comment #	Comment	NS Power Response
Wind cap	NF-02 Natural Forces	Wind is capped at 700 MW unless tie, batteries, condensers built. PSC study was based on stressed conditions and severe contingencies and does not apply to typical system conditions. Wind is being limited to allow larger amounts of import. Consider prioritizing internal resources during system stress. The capital cost of the associated investments have the effect of making wind a non-viable proposition for at least the first ten years or so of the model period. PSC study doesn't recommend limiting wind installed capacity. Its findings can be addressed via operational practice during stressed or contingency occurrences. Example from Ireland. The Study findings do not conclude that the wind installed capacity must be limited to 700 MW. All that they conclude, is that in certain stressed system conditions, the output of the wind should be temporarily limited to 700 MW.	Contingencies are not scheduled, and therefore the system cannot be pre-set to manage these contingencies. Contingencies can occur at any time and without warning. To pre-set the system to be capable of surviving a contingency, wind output could have to be curtailed, potentially at all times depending upon the amount installed, or the import would not be scheduled. Such a structure would imply that load is not being economically served. Pre-curtailment of imports is not economic based on the significant quantities of non-firm imports that are being economically dispatched in all scenarios. NPCC and NERC criteria state the contingencies for which the system must be operated at all times in preparation for. NS Power's draft findings concluded that further work is required to assess system stability at significant invertor based renewable energy penetrations and determine whether additional dynamic system inertia constraints or other ancillary services can enable higher levels of integration on the Nova Scotia system. This study will further refine system integration requirements (e.g. the requirement for new integration assets, operational practices or enabled through existing technology on new resources).

Category	Comment #	Comment	NS Power Response
Inertia	NF-03 Natural Forces	System inertial response requirement is over-stated. The minimum level of 3,266 MW is not well substantiated based on the PSC study. It appears that there is a safety margin of one thermal generation unit included in the PSC study, and then a further safety margin approximating to one thermal generator added in the IRP study. This appears on face value, to be unduly conservative. The SIR requirement is arising from high imports on the AC intertie. At times of lower import levels, the SIR requirement would be expected to be much lower. Monitor industry developments around synthetic inertia.	NS Power agrees that it will monitor industry developments around synthetic inertia. NS Power met with interested stakeholders and completed modeled a sensitivity that lowered the inertia constraint to 2200MW.sec (2.1C.WIND-3) which found that lowering this constraint did not have a significant effect on the resulting optimal resource plan.
Load forecast	NF-04 Natural Forces	Covid effects are too severe and prolonged. Should use something like 2-5 years instead of 10 years.	The pandemic load sensitivity was determined to provide a reasonable low-end sensitivity in consultation with IRP stakeholders.

Category	Comment #	Comment	NS Power Response
Transition plan and wind adds	NF-05 Natural Forces	Transition plans are needed to replace generation, which doesn't happen instantaneously - a new build and a retirement take place over long periods. Any transition plan is likely to involve adding wind year-by-year over the period up to 2030, determining the correct results from the SIR requirement and the hard cap on wind until a 2nd intertie is of crucial importance. If the position is maintained that wind installed capacity in excess of 700 MW must be accompanied by either the 2nd AC intertie or by BES/synch comps, then these would have to be built out in tandem with the wind. This could result in a premature and/or unnecessary level of capital expenditure, increasing costs to consumers	NS Power agrees that the system transformations indicated in the IRP scenarios will require cautious planning. The draft Findings release has recognized this point. Based on this and similar feedback, modeling assumptions were updated between the Initial Portfolio Study and Final Portfolio Study to limit the number of steam units that could retire in a single year. NS Power will continue to study wind/invertor based renewable energy integration requirements and how changes could impact the optimal quantity and timing of these resources.
Interconnection energy flows	NF-06 Natural Forces	Interconnection energy flows shown in aggregate. Can the import and export energy flows be provided? Also pricing of exports.	Information has been provided in a manner that protects commercially sensitive details for the benefit of customers.
ELCC of imports	NF-07 Natural Forces	Only firm imports are assumed to contribute to the ELCC. This is not the case in Europe.	Only firm imports can contribute to the capacity requirement established via the firm peak forecast and Planning Reserve Margin requirement. Without a firm import arrangement with a market or counterparty and firm transmission access to deliver, NS Power could not reliably expect access to capacity/energy during a peak event.

Distributed Resources	Quest-01 Envigour / QUEST/ Marine Renewables Canada	DERs are considered a reduction in system demand without a cost to the system. How does this assumption fit within the requirement to allow for Enhanced Net-metering by customers. Assuming DERs as reduced demand for system electricity likely undervalues the potential positive contribution to the system that could come from a combination of DERs such as solar PV and storage by customers. We understand NS Power is exploring this potential through the NS Smart Grid project and related initiatives. The benefits from resiliency and reliability offered by DERs may be part of your planned next step runs and scenario testing. If so, information from that process may help gain insights into the value of DERs, especially when combined with storage. However, we believe there will likely be the need for additional discussions on these matters, and how to incorporate them into the Roadmap. Also, several NS Municipalities have expressed interest in Community Solar PV Gardens. It would be useful to discuss whether this concept is the same as DERs from the model's perspective and, if not, how it may be considered as well.	The NEM arrangement allows customers to offset their consumption with the production from their DER (primarily solar PV) and sell excess surplus energy to NS Power. Site installations are sized to offset annual generation (maximum size); thus excess sales to NS Power are very limited. NS Power's Distributed Resources Promoted resource strategy would be consistent with this program, wherein the Net System Requirement (Load) is reduced by high DER uptake. While solar (both utility scale and BTM) is not cost competitive in the near to mid-term with other candidate resources, as indicated by the lack of economically selected utility-scale solar in the IRP scenarios, this Resource Strategy was reflected how the NEM program could incentivize installations; being able to offset consumption at the retail rate. Other factors (e.g. ESG, technology advancement, policy, financing structures, etc.) could also lead to more DER uptake. NS Power agrees that it does not account for possible value sources from paired solar PV with battery storage. Without a firm understanding of NS Power's access to customer sited battery installations, and under what conditions, it would be highly speculative to model such value sources. NS Power agrees that the Smart Grid Atlantic Project and a continued analysis on the potential of DERs to provide distribution level savings will be important as these technologies develop and mature.

Category	Comment #	Comment	NS Power Response
			NS Power did not distinguish between rooftop solar and community solar gardens.
Future Generation Technologies	Quest-02 Envigour / QUEST/ Marine Renewables Canada	The model did not select several potential technologies such as offshore wind, tidal or hydrogen. It would be useful to know what the gap was between these technologies and the ones are chosen. It would help us understand the degree price reduction required to make them competitive in the future. Furthermore, it would be useful to know how the model would have valued any of the unique properties associated with these technologies, such as the predictability of tidal. If they were not valued, what process or opportunity might we see in the future to gain better insight?	NS Power did not have detailed assumptions for resources powered by hydrogen. NS Power has proposed to monitor low and zero carbon fuels in its IRP Action Plan and Roadmap The nature of the optimization in an IRP process does not lend itself to this type of analysis. A dedicated optimization process would need to be undertaken to assess these non-traditional resources, which is outside the scope of this IRP.

Category	Comment #	Comment	NS Power Response
Natural Gas	Quest-03 Envigour / QUEST/ Marine Renewables Canada	The narrative suggests a CCGT solution appears in several runs. We recommend there be a fuller discussion of the costs and benefits associated with an investment in this area. We would consider what kind of pathways/solutions would be necessary to achieve a net-zero electricity system by 2050 with a CCGT investment to be a priority. We would also want to identify and quantify the risk to electricity reliability from a dependence on a single natural gas pipeline. Identifying the risk of not being able to have local storage of natural gas should also be explored from a reliability perspective.	As part of NS Power's draft Action Plan, it has proposed to develop a plan for the redevelopment or replacement of existing natural gas-powered steam turbines to provide low-cost, fast-acting generating capacity to the Nova Scotia system. Fuel flexibility is a component of this work, including consideration for low/zero carbon alternative fuels. In the higher priority scenarios (e.g. 2.0.C, 2.1.C), combined cycle units are not built until 2040. By this time, there will be greater certainty on the viability of this resource given the associated carbon policy and/or developments in alternative fuel sources which minimize this risk (e.g. hydrogen or CCS) NS Power agrees that the economics and permitting considerations of natural gas storage vs pipeline reservation and reliability considerations of n-1 contingency would need to be considered.
Contribution to NS economy	Quest-04 Envigour / QUEST/ Marine Renewables Canada	Each of the scenarios has a different impact on the NS GDP. Will the IRP process be able to differentiate which scenarios would more likely use NS sourced goods and services on a CAPEX and an OPEX basis?	This is not within the scope of the IRP.

Inertia	SBA-01 Small Business Advocate	Since the system inertia requirement is a constraint in the modeling, the Company should provide more analysis and detail supporting the assumptions. The PSC study provided initial results, but the Company acknowledged several shortcomings at the time. The IRP analysis would be more complete with the following: More information on derivation of requirements and cost of alternatives to generation such as synchronous condensers, and information on any limitations on the amount of these that the system can rely upon. Additional analysis supporting the inertia benefits ascribed to the Reliability Tie. The modeling currently assumes the reliability tie would provide all system inertia requirements for system. Are there limitations to this assumption, or are there system conditions (in NS or NB) under which the tie would not provide the claimed inertia benefits? NSPI should conduct additional analysis to identify the minimum amount of inertia requirements in province under different system conditions. The 3266 MW.sec requirement was based on specific load conditions resulting in a 2766 MW.sec requirement, plus a 500 MW. eg generic additional requirement. Additional analysis would allow for more dynamic modeling of this requirement and provide additional insight on the inertial need over time as load, DSM, and supply-side portfolio mix changes. Since ascribing this benefit of providing all the inertia requirements is uncertain and very valuable to the evaluation we would like to see a sensitivity if the inertia benefits of the tie is substantially lower than assumed, such as providing only half of system inertia need. Provide information regarding whether the battery+ synchronous condenser option for system inertia would also provide system capacity.	NS Power will continue to advance modeling of system inertia constraints. As part of its updated modeling results released with the draft Findings, the following additional constraints were tested: -A Low Inertia test case was included (at 2200 MW.sec) -A No inertia / no integration requirement test case -a case where the Reliability Tie provides 50% of system inertia requirement (1633 MW.sec) The IRP model does not limit the quantity of online inertia that can be supplied via synchronous condensers; this limit will be recommended for examination in future work. Dynamic modeling of this constraint is also an opportunity for future work post-IRP. When wind is integrated using the Battery + Sync. Condenser option, the batteries do provide firm capacity according to their ELCC curve and contribute to the PRM.

Category	Comment #	Comment	NS Power Response
Reliability Tie and Regional Integration	SBA-02 Small Business Advocate	Treatment of risk: The Reliability Tie and Regional interconnection are significant components of the initial modeling results and would represent substantial investments. Given the scope of the investment it is important to understand the risks associated with the investment, and the cost of alternatives. What additional studies will be required if the reliability tie or regional integration plan is selected? What would be the schedule for those studies? For each portfolio that selects a transmission upgrade as part of a least-cost plan, NSPI should provide results demonstrating the incremental cost of the non-transmission option so the Board can balance the cost against the risk if the transmission investment is not fully utilized or if a lower cost option becomes available. This should be clearly considered within the decision process to choose a preferred portfolio.	The Reliability Tie and Regional Interconnection options have been selected in multiple plans, indicating that they provide value for customers over alternative resource options. NS Power has proposed an Action Plan item for post-IRP evaluation that would include detailed Transmission Planning Analysis, route options analysis, construction cost studies, and engagement with other jurisdictions.

Category	Comment #	Comment	NS Power Response
Renewable Resource	SBA-03 Small Business Advocate	The Company assumes onshore wind is the primary renewable resource as part of the future portfolio. Other areas on the Atlantic coast of North America are focusing on offshore wind to provide resource diversity. Did the Company's analysis fully incorporate the benefits of diversity of· timing of production (e.g. through the ELCC analysis)? If the costs of offshore wind come down considerably over the study period, are there planning decisions (such as transmission investments or conventional capacity additions) included in this IRP that would be rendered unnecessary? The Company should provide sensitivity modeling that would help understand this issue.	Onshore wind has been economically selected in all IRP resource plans as a low-cost local source of renewable generation The E3 supply options study (from the Pre-IRP work) indicated that the cost of offshore wind was approximately 2.25 times greater than onshore wind per installed kW in Nova Scotia, although the cost decline over the planning horizon was larger. Ongoing O&M costs are estimated to be 2 times more expensive than onshore wind. In addition, the Capacity Factor midpoint is estimated to be 41% for offshore wind, 2% higher than the 39% assumed in the IRP for new onshore wind. From an integration perspective, offshore wind would have similar integration requirements as onshore wind and so could be integrated in future resource plans in place of other inverter-based variable renewable generation if costs or other factors were to significantly change.

Metrics	SBA-04 Small Business Advocate	Now that the initial modeling is complete and stakeholders have greater understanding of the inputs and analysis, it would be useful to have a stakeholder exchange or technical session and the opportunity for written comments specifically focused on proposed metrics from NS Power. We offer the following additional comments: Current proposed metrics appear to be revenue requirement minimization over a long horizon since the modeling calculated PVRR utilizing a real levelized capital cost recovery factor in modeling. We would like to see the corresponding values utilizing nominal accounting cost recovery or revenue requirements. GHG metrics presented with initial modeling results include totals over the study period and includes some GHG Marginal abatement cost. The Company should provide annual GHG production metrics in tons and in percent of a baseline historical year emissions. The preliminary results included a metric calculating an average cost of generation, but the Company was uncertain as to whether it would be used going forward. The Company should provide metrics to help provide insight on affordability of each portfolio, perhaps showing annual cost of electricity impacts utilizing nominal capital cost carrying charges. Generally, the more capital a company commits to invest in a portfolio the greater the risk. The Company should provide a metric calculating total average capital investment requirements over the first five years, ten years and twenty years. It is important to have visibility on how much NS Power will be relying upon imported power as a metric, such as average	NS Power has refined the definition of several metrics as part of the September 2, 2020 draft Findings release, and has incorporated much of the feedback noted here, as well as that received from other stakeholders and during subsequent discussions with individual IRP participants. NS Power uses nominal input values, and thus a nominal discount rate when calculating NPVRR. The model levelizes new capital investments via an annuity method, while other costs (e.g. fuel, OM&G) are expensed in the year incurred) to be as consistent as practical with actual accounting treatment. In particular, rate impact estimates, GHG production, and reliance on imported power (as a component of plan robustness) have all been included with the draft Findings release.

Category	Comment #	Comment	NS Power Response
		annual imports over the first five years, ten years and twenty years.	
Metrics	SBA-05 Small Business Advocate	Metric Definitions: The Company should provide written formulas and examples for the calculation of each metric used in the portfolio analysis. Scoring or Metric Trade-off Analysis: The portfolio analysis will likely utilize some method of weighing (explicitly or implicitly) the various metrics when choosing or creating a preferred portfolio. The Company should provide a detailed description of how the various metrics will be used.	Additional refinement to metric definitions is included in the September 2 release.

Category	Comment #	Comment	NS Power Response
Process	SBA-06 Small Business Advocate	The Company has maintained extensive communication and stakeholder engagement efforts during the development of the pre-IRP deliverables, and we hope that going forward the process will remain transparent and collaborative. To that end, we recommend technical sessions or the opportunity for written comments on the following areas: a. Metrics choice - Recommend written comments exchange after distribution of NS Power proposal. It is critical to finalize the metrics collaboratively before reviewing modeling results for findings. b. Detailed review of analytical results - Recommend technical session, in particular detailing results of any analysis of system operations. c. NS Power initial findings and conclusions - Recommend the Company issue findings and conclusions, solicit comments, and hold a stakeholder feedback and discussion session. d. Road Map & Action Plan - Recommend the Company issue drafts, solicit comments, and perhaps hold a stakeholder discussion session. Assure that road map lays out all studies and approvals necessary and key decision points. e. Report- Recommend the Company issue draft comments, incorporate comments into final and have all comments in an Appendix.	NS Power has continued the significant participant engagement that has occurred so far during the IRP process. This has included opportunities for participants to comment on the updated modeling results, Draft Findings/Action Plan / Roadmap, and Draft Final Report in advance of the Final Report being submitted. All comments will be provided in an Appendix to the Final Report.

Category	Comment #	Comment	NS Power Response
Stranded Assets	VC-01 Verschuren Centre	It is counterintuitive that building 764-1170 MW of additional fossil fuel capacity is most appropriate. It should be expected that all of these assets would have minimal economic value in a zero carbon system, or after 2050. Does the Plexos model consider stranded assets in 2050 (beyond the planning horizon), especially for those units installed in 2040 in 2.x Scenarios?	As part of NS Power's draft Action Plan for the redevelopment or replacement of existing natural gas-powered steam turbines to provide low-cost, fast-acting generating capacity to the Nova Scotia system. Fuel flexibility is a component of this work, including consideration for low/zero carbon alternative fuels. Resource technologies utilizing natural gas feedstock were not excluded as candidate resources. In scenarios that build the high utilization Combined Cycle gas units, do so late in the modeling horizon (e.g. 2040 for 2.1.C). By this time, it is anticipated that there will be more certainty on the viability of this resource given the prevailing carbon policy and/or developments in alternative resources or fuel sources which could minimize this risk (e.g. hydrogen or CCS). The Plexos model does not consider stranded assets beyond the planning horizon.

Inertia	VC-02 Verschuren Centre	The table on Page 8 of the modeling results indicates that inertia factors for wind energy and energy storage were not considered in the model. As wind energy and batteries are low cost sources of energy and carbon free capacity, the decision to exclude them will have negative impacts for customers. There is a growing body of evidence that suggests both technologies can contribute to system inertia. Many of the existing fleet of Nova Scotia wind turbines, including some of those owned by NS Power, are inverter-based machines that could provide synthetic inertia. Future procurement of wind turbines could include this. Lithium Ion Battery systems would also have an inverter-based interface with the grid, they too would be able to provide synthetic inertia to the grid. Some utilities in North America are already seeing proven results from this effort, and others are starting additional testing. Please provide indication of where in the modelling the Inertia Constraint was binding and resulted in a choice of fossil fuel generator over batteries 3. Did the inertia constraint impact the decision process of the Diesel CT Screening? 4. Please consider a screening, which evaluates a 3.x scenario with inertia qualities applied to existing wind turbines, future wind turbines, demand control and battery resources.	As part of its updated modeling results released with the draft Findings, the following additional constraints were tested: -A Low Inertia test case was included (at 2200 MW.sec) -A No inertia / no integration requirement test case -A case where the Reliability Tie provides 50% of system inertia requirement (1633 MW.sec) The IRP model does not limit the quantity of online inertia that can be supplied via synchronous condensers; this limit will be recommended for examination in future work. Dynamic modeling of this constraint is also planned for future work post-IRP. Plexos LT module optimizes candidate plans constrained by all ancillary services (reserve) constraints. This is achieved by integrating reserve constraints into the mathematical framework for dispatch and pricing. The suite of the new resources including batteries and wind are contributing to certain modeled ancillary services. Batteries contribute to all types of reserve including regulation (raise and lower), spinning and non-spinning. Transient system stability studies, which assess FFR in timescales of seconds (or less), are outside the scope of long-term planning studies. As FFR was not assessed in the Plexos framework, its presence or absence is not expected to have an impact on expansion/retirement decisions. However, if FFR services are found to reduce the synchronous inertia constraint as modeled, the plan could change.

Category	Comment #	Comment	NS Power Response
			The draft Roadmap item included in the draft Report provides: 2. Complete detailed system stability studies under various current and future system conditions, reflective of both stressed system states and normal operating conditions, while considering higher quantities of installed wind capacity as seen in the IRP modeling results. This work will also consider the impacts of grid service provision from inverter-based generators such as wind turbines and how the introduction of new services like Fast Frequency Response might affect existing requirements such as Synchronized Inertia. Monitor results for significant divergence from wind integration assumptions modeled in the IRP and trigger an update as needed.

Appendix K

Nova Scotia Power IRP

Draft Findings, Action Plan and Roadmap Participant Engagement

NS POWER 2020 IRP
DRAFT FINDINGS RELEASE

SEPTEMBER 2, 2020

Nova Scotia
POWER
An Emera Company

TABLE OF CONTENTS

Note: In parallel with this release, NS Power has also provided a separate Modeling Results deliverable containing model output and metrics for each Scenario

PROCESS UPDATE & WORK COMPLETED

UARB NSP Pre-IRP Deliverables

- Capacity Study
- Supply Options Study
- Demand Response Assumptions
- Stability Study

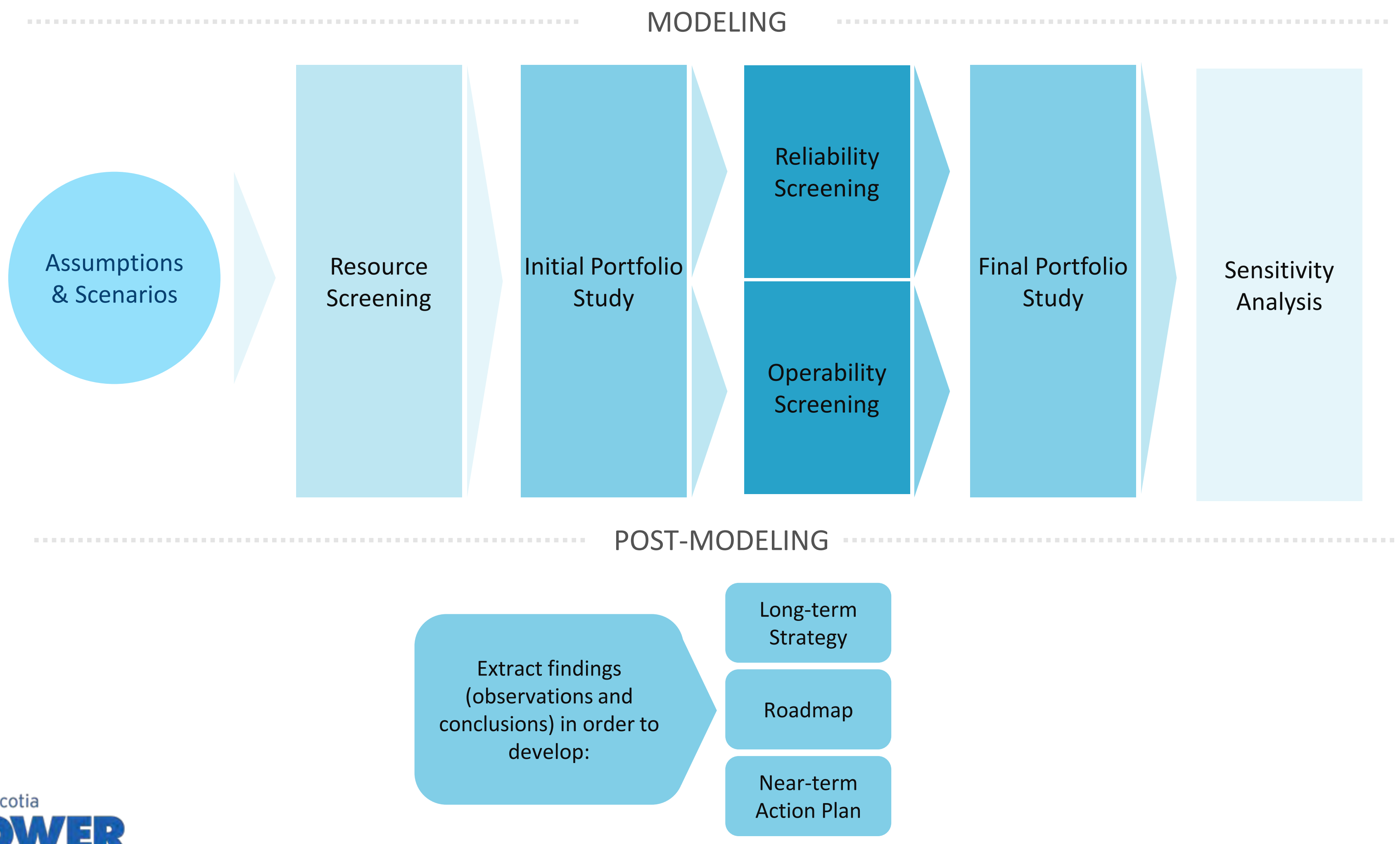
Core IRP Process resulting in Final Report

Oct 2020

- Terms of Reference
- Scenario Development
- Modeling Plan
- Assumptions
- Modeling
- Analysis/Conclusions
- Report, Roadmap, & Action Plan

Completed – Pre-IRP
Completed
In Progress

IRP MODELING PLAN



RELIABILITY SCREENING

RELIABILITY SCREENING OVERVIEW

The Reliability Screening phase of the IRP evaluated several future resource plans against reliability criteria to confirm that resource plan changes have not lowered the reliability of the future system.

For the 2020 IRP, NS Power working with E3 completed reliability analyses on the following three resource plans from the June 26 Modeling Results release:

- 2.0C – Low Electrification / Base DSM / Net Zero 2050 / Regional Integration
- 2.1C – Mid Electrification / Base DSM / Net Zero 2050 / Regional Integration
- 3.2C – High Electrification / Max DSM / Accelerated Net Zero 2045 / Regional Integration

These three resource plans represent significant evolutions of NS Power's generation mix and include the highest levels of wind and storage penetration that were selected in the original model runs, and as a result are important test cases for reliability modeling.

The Reliability screening work concludes that:

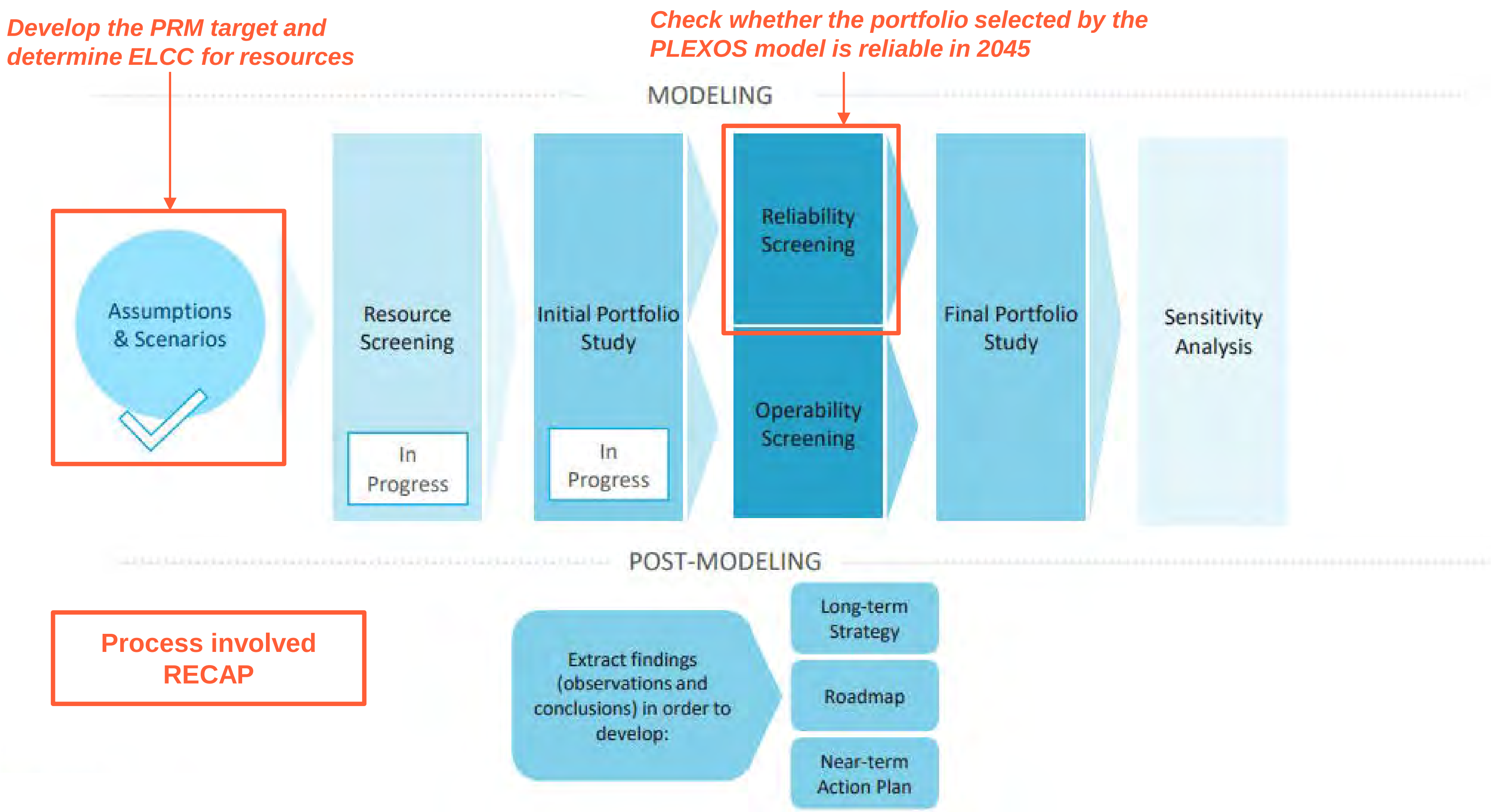
- All three resource plans met the stated reliability criteria (i.e. 1 day in 10 years Loss of Load Expectation)
- A Planning Reserve Margin target of 8-9% on a UCAP basis continues to be appropriate in 2045 under these 3 scenarios

Energy+Environmental Economics

Overview of RECAP Model and Inputs

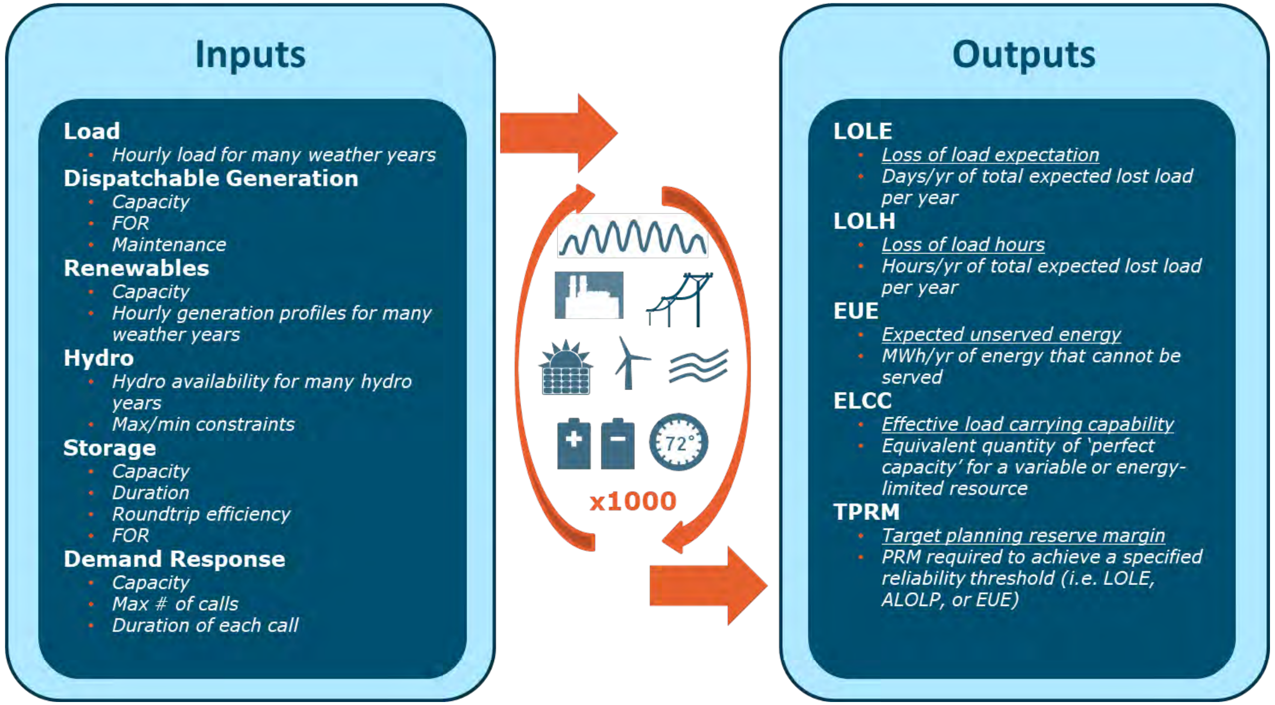
Modeling Process

+ **NS Power relied on E3's loss-of-load probability model (RECAP) to estimate a planning reserve margin and effective load capacity contributions in the pre-IRP phase, and to check the reliability of select PLEXOS portfolios in 2045**



RECAP: E3's Renewable Energy Capacity Planning Model

+ **RECAP is a loss-of-load probability (LOLP) model used to test the resource sufficiency of electricity system portfolios**
  - This study uses a 1-day-in-10-year standard (0.1 days/yr LOLE) to determine the target PRM
+ **RECAP evaluates sufficiency through time-sequential simulations over thousands of years of plausible load, renewable, and stochastic forced outage conditions**
  - Captures thermal resource and transmission forced outages
  - Captures variable availability of renewables & correlations to load
  - Tracks hydro and storage state of charge



Information about E3's RECAP model can be found here:
https://www.ethree.com/tools/recap-renewable-energy-capacity-planning-model/

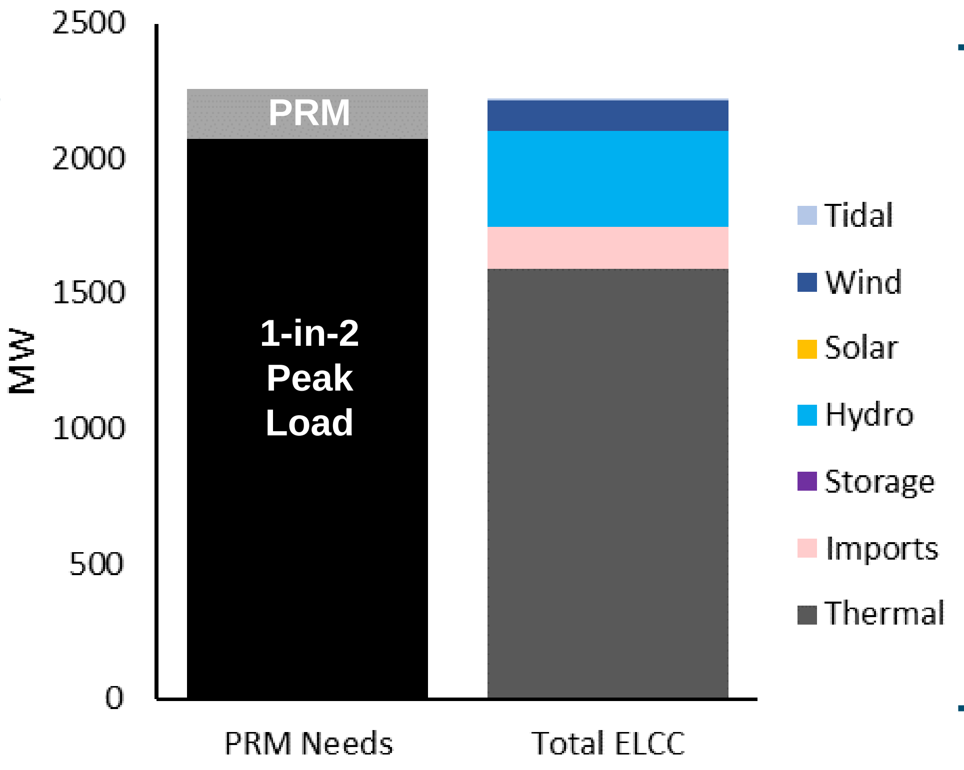
Planning Reserve Margin

+ **To satisfy NS Power's reliability target, RECAP calculates a Planning Reserve Margin required to meet a one-day-in-ten-year standard (LOLE= 0.1 days/year)**
  - PRM based on Installed Capacity (ICAP): 20%
  - PRM based on Unforced Capacity (UCAP): 9%

Used as constraint in capacity expansion modeling

A UCAP planning reserve margin of 9%, or 186 MW, is necessary to ensure reliability

The 1-in-2 net peak load was forecast by NS Power to be 2070 MW in 2020



In UCAP PRM, all resources are de-rated to account for their contribution of "perfect" or "100% firm" capacity

RECAP is used to test the reliability of the final PLEXOS portfolios

- **RECAP calculates inputs for capacity expansion modeling**
  - Planning Reserve Margin (PRM) to help ensure PLEXOS and RESOLVE select enough capacity for an adequate system
  - Contribution of various resources toward resource adequacy using Effective Load-Carrying Capability (ELCC) values consistent with PRM calculation
- **Use of RECAP inputs does not guarantee a reliable portfolio**
  - Because of the dynamic nature of ELCC values (ELCCs change with the portfolio), the PRM achieved by the selected portfolio may not be precisely what is needed to achieve LOLE of 0.1 days/year
- **A final test is performed using RECAP to ensure that the portfolios selected are reliable**

Energy+Environmental Economics

Scenarios Evaluated

2045 Installed Capacity in PLEXOS Model Runs

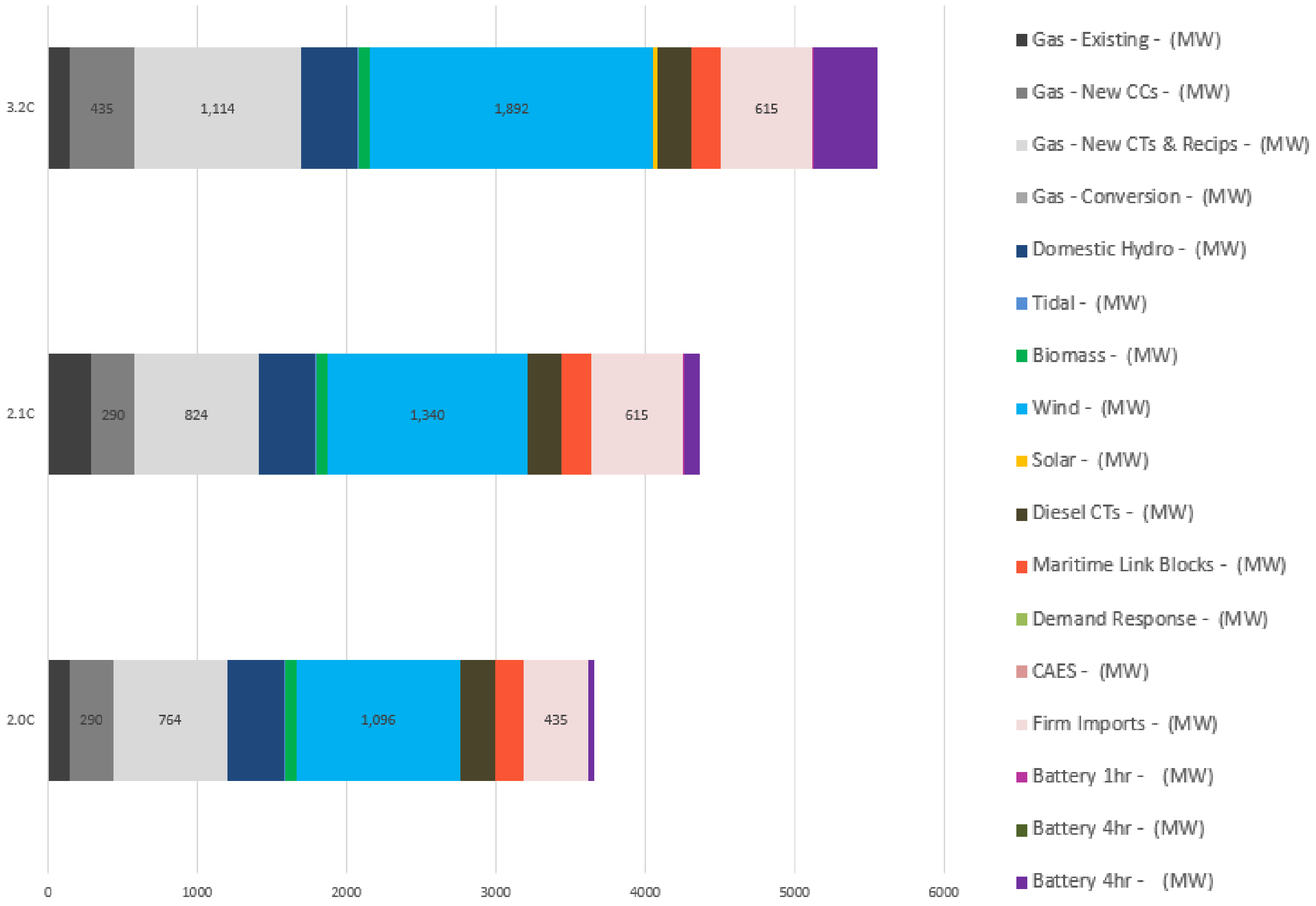
+ **After the initial PLEXOS modeling, RECAP tested the reliability of the system in 2045 under three different PLEXOS scenarios, reflecting increasingly aggressive carbon targets, electrification loads, and resulting renewable build**

Total Installed Capacity in 2045 by Scenario

3.2.C. Accelerated Net Zero, High Electrification, and Regional Integration

2.1.C. Net Zero, Mid Electrification, and Regional Integration

2.0.C. Net Zero, Low Electrification, and Regional Integration



Energy+Environmental Economics

Results

Results Summary

+ **The 2045 portfolios are tested against the 0.1 days/year LOLE target**
+ **Target UCAP PRM varies slightly by scenario due to load shapes**
  - Loads are scaled for 2045 using PLEXOS methods (based on annual peak and energy)
  - Synchronized reserves based on estimated requirements for spinning, regulation up, and ramping reserves (modeled to scale with renewable capacity)
+ **All scenarios achieve the LOLE target**

Key Reliability Statistics for NSP 2045 System

	2.0.C	2.1.C	3.2.C
LOLE Target (days/yr)	0.10	0.10	0.10
Achieved LOLE (days/yr)	0.06	0.02	0.06
Achieved LOLh (hrs/yr)	0.18	0.08	0.21
PRM Target (UCAP)*	8%	8%	9%
Achieved PRM (UCAP)	9%	11%	10%
Excess Capacity (MW)	32	77	40

* RECAP estimates a PRM target endogenously given the scenario load characteristics and reserves in 2045, thus it may differ slightly from the PRM target estimated for the 2020 system.

All scenarios remain reliable in 2045, with small amounts of excess capacity

Scenario 2.0.C. Detailed 2045 RECAP results

- E3 modeled NSP's 2045 PLEXOS installed capacity and load in RECAP for 2.0.C, generating a UCAP target of 8%
- RECAP modeled ELCCs reflect 2045 loads and incorporate diversity impacts

Firm Demand (GWh)	10,084
Firm 1-in-2 Peak (MW)	2,260
Synchronized Reserves (MW)	87
LOLE Target	0.1 days/yr
LOLE Achieved	0.06 days/yr
PRM Target (UCAP)	8%

	Installed Capacity (MW)	ELCC (MW) / UCAP	ICAP (MW)
Dispatchable	1,505	1,418	1,505
Firm Imports	588	527	588
DR	-	-	-
Storage	33	27	27
Variable	1,132	152	152
Hydro	366	342	366
Total Portfolio ELCC	3,624	2,467	2,639
Achieved PRM (UCAP) (%)	9%		
Achieved PRM (ICAP) (%)	17%		
Capacity Surplus (MW)	32		

Includes all thermal units

Includes only firm imports

Thermal, imports and hydro are counted at nameplate in ICAP

Capacity in excess of the minimum needed to hit the target LOLE

Note: RECAP estimates a PRM target endogenously given the scenario load characteristics and reserves in 2045, thus it may differ slightly from the PRM target estimated for the 2020 system. Similarly, ELCCs are also a function of the load shape and portfolio and thus won't match estimates based on 2020 curves precisely.

Scenario 2.1.C. Detailed 2045 RECAP results

- **E3 modeled NSP's 2045 PLEXOS installed capacity and load in RECAP for 2.1.C, generating a UCAP target of 8%**
- **RECAP modeled ELCCs reflect 2045 loads and incorporate diversity impacts**

Firm Demand (GWh)	11,228
Firm 1-in-2 Peak (MW)	2,636
Synchronized Reserves (MW)	103
LOLE Target	0.1 days/yr
LOLE Achieved	0.02 days/yr
PRM Target (UCAP)	8%

	Installed Capacity (MW)	ELCC (MW) / UCAP	ICAP (MW)
Dispatchable	1,713	1,633	1,713
Firm Imports	768	682	768
DR	0	0	0
Storage	109	92	92
Variable	1,376	180	180
Hydro	366	337	366
Total	4,331	2,924	3,118
Achieved PRM (UCAP) (%)	11%		
Achieved PRM (ICAP) (%)	18%		
Capacity Surplus (MW)	77		

Note: RECAP estimates a PRM target endogenously given the scenario load characteristics and reserves in 2045, thus it may differ slightly from the PRM target estimated for the 2020 system. Similarly, ELCCs are also a function of the load shape and portfolio and thus won't match estimates based on 2020 curves precisely.

Scenario 3.2.C. Detailed 2045 RECAP results

- E3 modeled NSP's 2045 PLEXOS installed capacity and load in RECAP for 3.2.C, generating a UCAP target of 9%
- RECAP modeled ELCCs reflect 2045 loads and incorporate diversity impacts

Firm Demand (GWh)	12,200
Firm 1-in-2 Peak (MW)	3,162
Synchronized Reserves (MW)	130
LOLE Target	0.1 days/yr
LOLE Achieved	0.06 days/yr
PRM Target (UCAP)	9%

	Installed Capacity (MW)	ELCC (MW) / UCAP	ICAP (MW)
Dispatchable	2,000	1,889	2,000
Firm Imports	768	721	768
DR	0	0	0
Storage	430	305	305
Variable	1957	278	278
Hydro	366	279	366
Total	5,521	3,472	3,717
Achieved PRM (UCAP) (%)	10%		
Achieved PRM (ICAP) (%)	18%		
Capacity Surplus (MW)	40		

Note: RECAP estimates a PRM target endogenously given the scenario load characteristics and reserves in 2045, thus it may differ slightly from the PRM target estimated for the 2020 system. Similarly, ELCCs are also a function of the load shape and portfolio and thus won't match estimates based on 2020 curves precisely.

2.0.C. Average Month-Hour Load and LOLP

- Loss of load events may be triggered by any combination of high load, low renewable generation, or unit outages
- For NS Power's system, the probability of loss of load correlates well with periods of high load

Avg Month-Hr Load (MWh)

	1	2	3	4	5	6	7	8	9	10	11	12
0	1358	1374	1189	924	725	622	638	638	602	710	944	1238
1	1308	1329	1153	895	694	591	606	606	577	679	897	1182
2	1275	1301	1139	890	688	583	592	592	568	669	868	1147
3	1266	1293	1146	908	702	590	592	595	575	681	863	1137
4	1279	1311	1189	969	750	617	615	628	626	740	889	1151
5	1339	1377	1307	1108	870	723	690	702	746	880	976	1212
6	1486	1528	1442	1241	1020	879	825	824	878	1029	1131	1354
7	1621	1657	1524	1301	1097	972	945	943	961	1098	1253	1488
8	1686	1711	1545	1309	1122	1018	1026	1026	1009	1125	1301	1558
9	1704	1709	1529	1294	1124	1044	1074	1073	1035	1132	1305	1583
10	1694	1687	1508	1278	1123	1061	1104	1103	1053	1134	1298	1580
11	1681	1666	1485	1258	1110	1057	1106	1106	1049	1120	1288	1571
12	1672	1649	1444	1214	1078	1037	1093	1093	1031	1092	1271	1562
13	1629	1599	1395	1176	1049	1015	1075	1075	1016	1066	1238	1525
14	1598	1561	1373	1172	1049	1019	1073	1076	1026	1072	1226	1502
15	1618	1573	1395	1203	1080	1046	1095	1100	1058	1111	1265	1530
16	1706	1637	1428	1217	1092	1051	1095	1099	1061	1143	1371	1652
17	1837	1734	1445	1191	1057	1005	1047	1051	1033	1172	1463	1776
18	1822	1783	1505	1209	1048	979	1012	1022	1053	1193	1428	1736
19	1780	1760	1532	1267	1077	974	1001	1042	1055	1150	1383	1693
20	1722	1708	1471	1224	1075	986	1012	1015	970	1066	1321	1640
21	1630	1619	1369	1112	966	898	923	908	853	952	1224	1550
22	1505	1497	1276	1023	857	784	807	797	744	851	1109	1418
23	1422	1425	1220	967	775	686	699	694	654	771	1018	1319

Avg Month-Hr LOLP (frac hrs w/ lost load)

	1	2	3	4	5	6	7	8	9	10	11	12
0	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
1	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
2	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
3	0.000%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
4	0.000%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
5	0.000%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
6	0.039%	0.032%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
7	0.000%	0.021%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
8	0.020%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
9	0.000%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
10	0.020%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
11	0.020%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
12	0.020%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
13	0.010%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
14	0.010%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.010%
15	0.010%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.020%
16	0.010%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.020%
17	0.020%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.039%
18	0.039%	0.032%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.020%
19	0.020%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.020%
20	0.020%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.010%
21	0.010%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.010%
22	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
23	0.010%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%

2.1.C. Average Month-Hour Load and LOLP

Avg Month-Hr Load (MWh)

	1	2	3	4	5	6	7	8	9	10	11	12
0	1534	1554	1328	1005	762	636	655	654	611	742	1028	1387
1	1473	1499	1284	969	723	598	616	616	581	705	971	1320
2	1434	1464	1266	963	716	587	598	599	569	693	936	1277
3	1422	1455	1276	985	733	596	599	602	578	708	930	1264
4	1438	1477	1329	1059	792	629	627	642	640	780	962	1282
5	1511	1557	1472	1229	938	759	719	734	787	951	1068	1356
6	1691	1743	1637	1391	1122	950	883	882	948	1132	1257	1529
7	1856	1900	1737	1465	1216	1063	1030	1027	1049	1217	1406	1694
8	1936	1965	1763	1474	1247	1119	1129	1129	1108	1250	1464	1778
9	1956	1963	1743	1456	1249	1150	1188	1186	1140	1259	1470	1809
10	1945	1937	1717	1437	1247	1172	1224	1223	1162	1261	1461	1806
11	1929	1911	1689	1412	1231	1167	1226	1226	1157	1244	1449	1794
12	1918	1889	1639	1359	1192	1143	1210	1210	1135	1209	1428	1784
13	1865	1828	1580	1313	1157	1116	1189	1189	1116	1178	1388	1738
14	1828	1782	1553	1307	1157	1120	1187	1190	1129	1185	1373	1710
15	1852	1798	1580	1345	1195	1154	1213	1220	1168	1232	1421	1745
16	1960	1876	1620	1363	1210	1159	1213	1218	1171	1272	1550	1894
17	2119	1994	1640	1330	1167	1103	1155	1159	1137	1308	1663	2046
18	2101	2054	1714	1352	1156	1071	1112	1124	1162	1333	1620	1996
19	2050	2026	1747	1424	1191	1066	1098	1148	1164	1280	1565	1943
20	1979	1962	1673	1371	1188	1080	1112	1116	1060	1178	1489	1878
21	1866	1853	1548	1233	1055	973	1003	985	918	1038	1371	1769
22	1715	1704	1434	1126	922	833	861	849	785	915	1230	1608
23	1613	1616	1366	1057	822	713	730	723	675	817	1119	1486

Avg Month-Hr LOLP (frac hrs w/ lost load)

	1	2	3	4	5	6	7	8	9	10	11	12
0	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
1	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
2	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
3	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
4	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
5	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
6	0.010%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
7	0.010%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
8	0.010%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
9	0.010%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
10	0.010%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
11	0.010%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
12	0.010%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
13	0.010%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
14	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
15	0.010%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
16	0.010%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
17	0.020%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.020%
18	0.010%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.010%
19	0.010%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.010%
20	0.010%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.010%
21	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.010%
22	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
23	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.010%

3.2.C. Average Month-Hour Load and LOLP

Avg Month-Hr Load (MWh)

	1	2	3	4	5	6	7	8	9	10	11	12
0	1722	1749	1454	1031	713	549	574	573	517	688	1062	1531
1	1643	1677	1396	984	663	499	524	523	477	640	987	1443
2	1591	1632	1373	976	654	486	500	501	462	624	941	1387
3	1576	1620	1385	1005	677	497	501	505	473	643	934	1370
4	1598	1648	1454	1102	753	540	538	557	555	737	975	1393
5	1693	1753	1642	1324	944	710	658	677	746	961	1113	1490
6	1927	1995	1857	1536	1184	959	872	871	956	1198	1361	1716
7	2143	2200	1988	1632	1307	1107	1064	1060	1089	1309	1555	1931
8	2247	2286	2021	1644	1347	1181	1194	1194	1166	1351	1631	2041
9	2274	2283	1996	1621	1350	1221	1270	1268	1208	1363	1639	2082
10	2259	2248	1962	1596	1348	1249	1318	1316	1236	1366	1627	2077
11	2238	2215	1925	1563	1327	1243	1320	1320	1230	1344	1611	2062
12	2225	2187	1860	1494	1276	1211	1300	1300	1201	1299	1584	2049
13	2155	2107	1782	1433	1230	1176	1272	1272	1177	1257	1532	1989
14	2107	2047	1748	1426	1230	1182	1269	1273	1194	1266	1513	1952
15	2138	2067	1783	1476	1279	1226	1303	1312	1244	1328	1575	1998
16	2278	2169	1835	1499	1299	1233	1303	1309	1248	1380	1744	2192
17	2487	2324	1862	1456	1243	1159	1227	1233	1204	1427	1890	2391
18	2463	2402	1958	1485	1229	1118	1171	1186	1237	1460	1835	2326
19	2397	2365	2000	1579	1275	1111	1153	1219	1240	1390	1763	2257
20	2304	2282	1904	1509	1271	1130	1171	1176	1104	1257	1663	2172
21	2157	2140	1741	1330	1097	989	1028	1005	917	1075	1510	2029
22	1958	1945	1592	1189	923	807	844	828	744	914	1325	1820
23	1826	1830	1503	1099	793	650	672	663	600	786	1180	1660

Avg Month-Hr LOLP (frac hrs w/ lost load)

	1	2	3	4	5	6	7	8	9	10	11	12
0	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
1	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
2	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
3	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
4	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
5	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
6	0.000%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
7	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
8	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
9	0.000%	0.021%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
10	0.010%	0.021%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
11	0.010%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
12	0.010%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
13	0.020%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
14	0.020%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
15	0.020%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
16	0.029%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
17	0.029%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.020%
18	0.068%	0.043%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.020%
19	0.049%	0.021%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.020%
20	0.049%	0.032%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.029%
21	0.029%	0.021%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.020%
22	0.010%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.010%
23	0.020%	0.011%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.010%

Energy+Environmental Economics

Conclusions

Conclusions

- **All portfolios meet their LOLE reliability targets, indicating that the PLEXOS portfolios are reliable in all three cases tested in 2045 (2.0.C., 2.1.C., 3.2.C)**
- **While the data provides confidence that the system is sufficiently reliable, more detailed modeling of the electrification load shapes is recommended to develop a robust assessment of how electrification changes the PRM target in the long-term**
  - The reliability assessment is based on load shapes utilized in PLEXOS, which scale load and peak load using the 2018 load shape and projected monthly energy and peak demands
  - A rigorous assessment of how electrification changes the PRM target from the 2020 target of 9% UCAP would involve:
    - More detailed modeling of the peak impacts of electrification loads (particularly in buildings) as a function of expected extreme weather events
    - Detailed assessment of the extent to which vehicle charging load would coincide with peak events and potential means to ensure flexible charging to avoid such coincidence

OPERABILITY SCREENING

OPERABILITY SCREENING OVERVIEW

The Operability Screening phase of the Modeling Plan allowed NS Power to examine the behaviour of the optimized resource plans for certain scenarios at an hourly level of granularity. This enabled the verification that the proposed resource plan was operable with all hourly constraints considered, including:

- System Operability Constraints were met (e.g. system inertia, import limitations, emissions limits, etc.)
- Unit Operability Constraints were met (e.g. minimum thermal unit up/down times, combustion turbine operation, etc.)
- System Reserve Requirements were met (e.g. spinning, ramping, and non-spinning reserve, etc.)

Data from Operability Screening was also used in the refinement of sustaining capital assumptions (e.g. number of operating hours, number of unit starts per year)

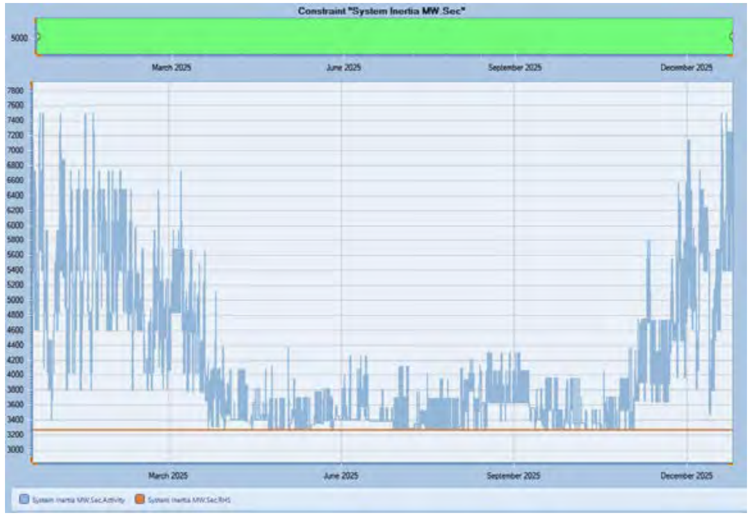
Operability Screening was conducted on the following models:

- 2.0C – Low Electrification / Base DSM / Net Zero 2050 / Regional Integration
- 2.1C – Mid Electrification / Base DSM / Net Zero 2050 / Regional Integration
- 3.1C – Mid Electrification / Base DSM / Accelerated Net Zero 2045 / Regional Integration
- 3.2C – High Electrification / Base DSM / Accelerated Net Zero 2045 / Regional Integration

The results of the Operability Screening led to additional refinements which were incorporated into the final round of modeling to ensure that all constraints were accurately represented while enabling the model to find feasible solutions

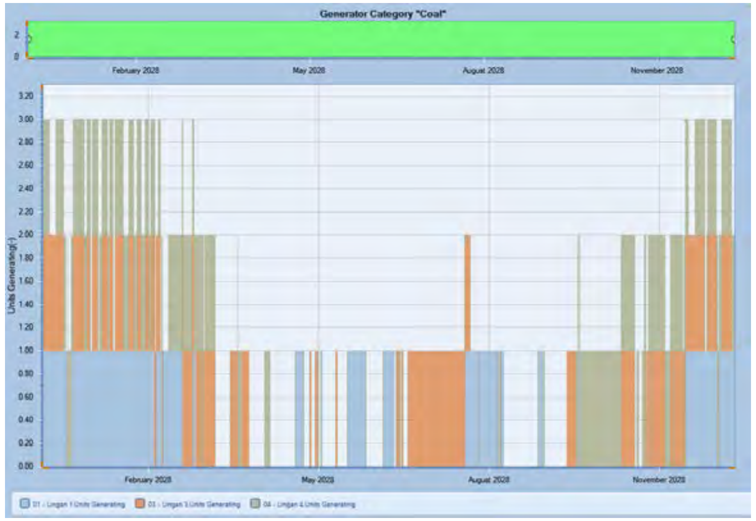
INERTIA CONSTRAINT

- The graphs below show the hourly output of the system inertia constraint as modeled, with a lower bound of 3266 MW.sec, for two years of Scenario 2.1C:
  - 2025 (pre-Reliability Tie & Regional Interconnection) *(Left, below)*
  - 2038 (post-Reliability Tie & Regional Interconnection) *(Right, below)*
- It can be seen that the simulation is respecting the constraint in all hours of both years
- The constraint appears to have more influence on unit dispatch during the summer (light load) months, while in the winter sufficient thermal units are online to serve load that the constraint is generally not binding



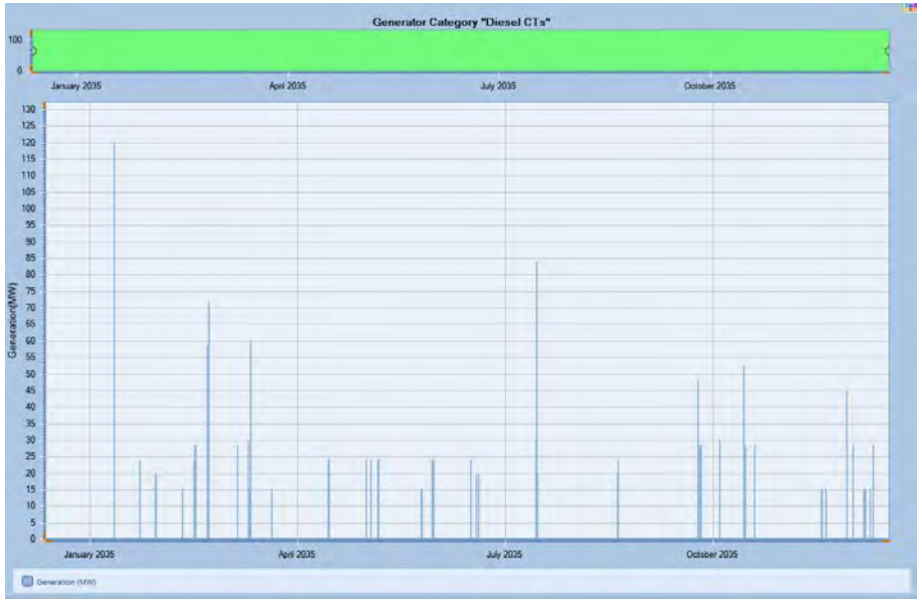
THERMAL UNIT OPERATING CONSTRAINTS

- PLEXOS models minimum up and downtime constraints on thermal units; the graphs below show when units are online at an hourly level for one sample year.
- The results show that the constraints have been respected under the new resource plans, in this case from Scenario 2.1C for two groupings of coal units:



COMBUSTION TURBINE OPERATION

- Because they operate only during a limited number of hours each year, combustion turbine operation can be difficult to evaluate using PLEXOS LT results
- PLEXOS MT/ST is more likely to call on these resources to operate; if they are operating at a high capacity factor, it may indicate that the PLEXOS LT module has found a solution which is not operable when examined in the hourly model
- All of the modeling results included with this modeling release used PLEXOS MT/ST hourly dispatch simulations to produce generation data as well as production costs that were incorporated into financial analysis
- The model output below shows hourly Diesel CT operation (left) and new Natural Gas CT operation (right) for Scenario 2.1C in 2035:



ADDITIONAL MODELING UPDATES

ADDITIONAL MODELING UPDATES

Based on the stakeholder workshop held in July as well as comments received following the modeling results release, NS Power has implemented enhancements in IRP modeling in two areas to improve results and be responsive to stakeholder input:

- PLEXOS capacity expansion model enhancements
- Development of a rate impact model

KEY PLEXOS MODEL UPDATES

1. Do not allow new supply-side builds in 2021 / limited new resource availability in 2022; allow Planning Reserve Margin violation in first 2 years
2. Added ability of model to select local firm imports on 3-year terms; remove local firmed energy from non-firm availability when selected
3. Allow new wind generation to provide ramp down reserve service
4. Allow a maximum of 3 steam unit retirements per year
5. Correct DR program cost representation; offer at 3 entry points - 2021/2025/2030
6. Add additional (existing) units that can contribute to ramping reserve constraint (scales with wind additions) – Tufts Cove Units 4 & 5
7. Complete sustaining capital profile review based on observed unit utilization
8. Input two sustaining capital cost profiles for coal units – aligned with 2030 and 2040 retirement dates

RATE IMPACT MODEL

NS Power has developed a simplified calculation of rate impact that uses the cost and load outputs of the optimized IRP resource plans to provide illustrative effects of various levels of electrification and Distributed Energy Resources.

The rate model considers the following inputs:

- IRP Partial Revenue Requirement by year for each scenario modeled
- Estimate of non-IRP Revenue Requirement from most recent rate proceeding
- Estimate of marginal contribution of incremental / decremental load to non-IRP Revenue Requirement ($80/MWh)
- Load forecast by year for each scenario, net of losses (assumed at 6.7% average per 2020 Load Forecast Report)

Assumptions and limitations underlying this approach include:

- All load gained or lost between scenarios contributes to Revenue Requirement at the marginal contribution rate
- Rates should be viewed as relative to one another rather than absolute and are approximate in nature
- Actual rates will differ from forecast both with respect to items included in the analysis and factors not included (e.g. new cost pressures, other asset additions, etc.)

Comparison of the rate impact for select scenarios is presented on slide 42 and results for each scenario are included in the Modeling Results file

FINAL PORTFOLIO STUDY RESULTS
SCENARIO COMPARISONS

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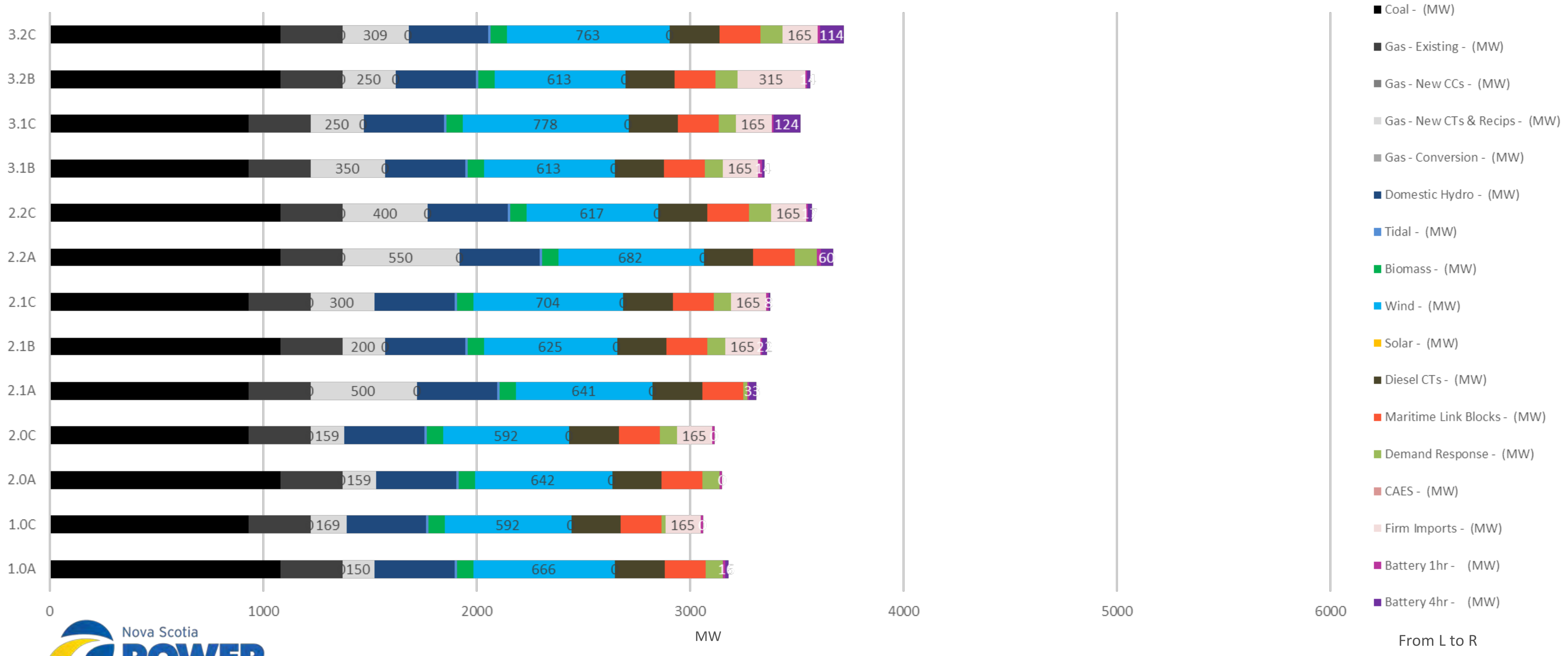
FINAL PORTFOLIO STUDY

- The following slides provide an overview comparison of the Final Portfolio Study results from PLEXOS for the key scenarios
- Outputs presented here consist of capacity expansion optimizations in PLEXOS LT, supplemented by hourly production cost simulations in PLEXOS MT/ST
- The section includes several summary comparison slides; detailed model outputs for each run are provided in a second presentation *"IRP Modeling Results 2020-09-02"* and in the accompanying data tables
- NPVs presented in these results are partial revenue requirements that consider modeled costs (i.e. production, O&M, abatement, sustaining capital, and capital investment) and specific costs considered outside of the long-term model optimization (i.e. energy efficiency costs)

RESOURCE PORTFOLIO COMPARISON (2026)



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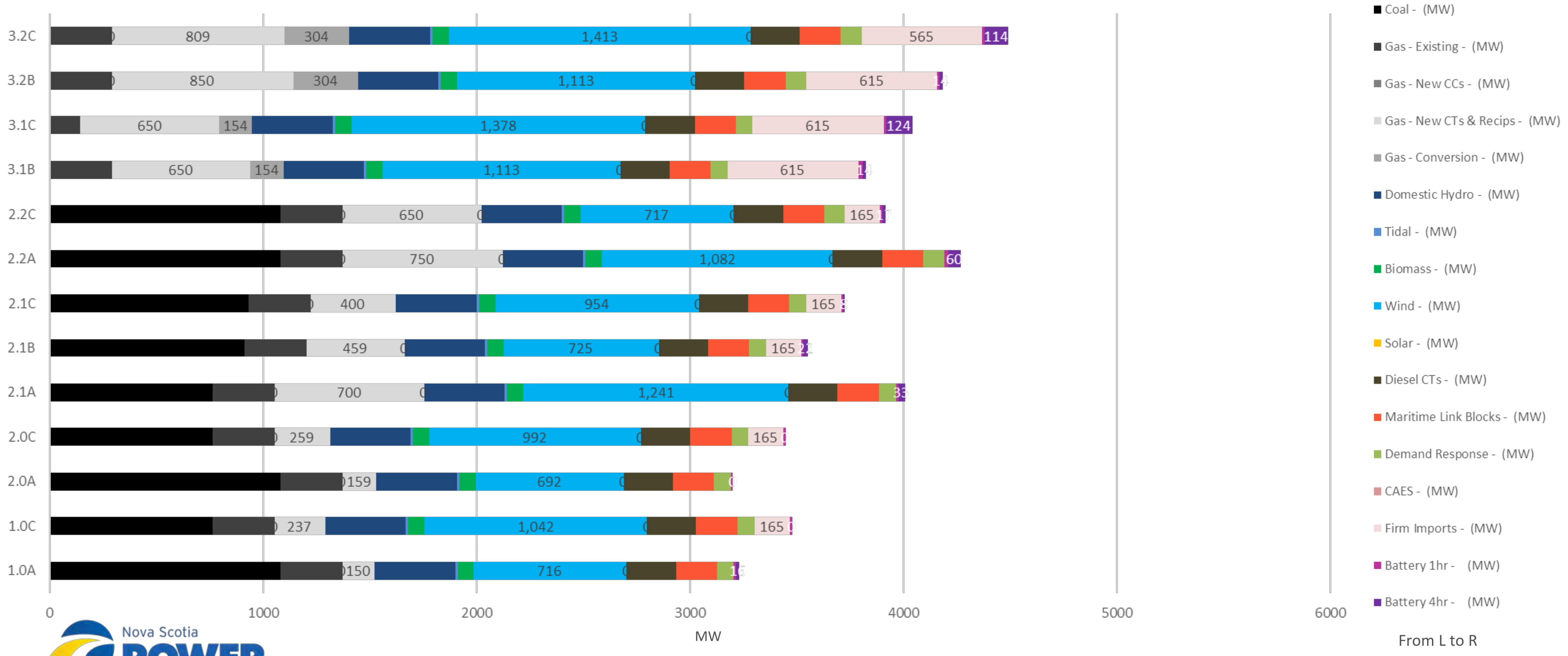
RESOURCE PORTFOLIO COMPARISON (2030)



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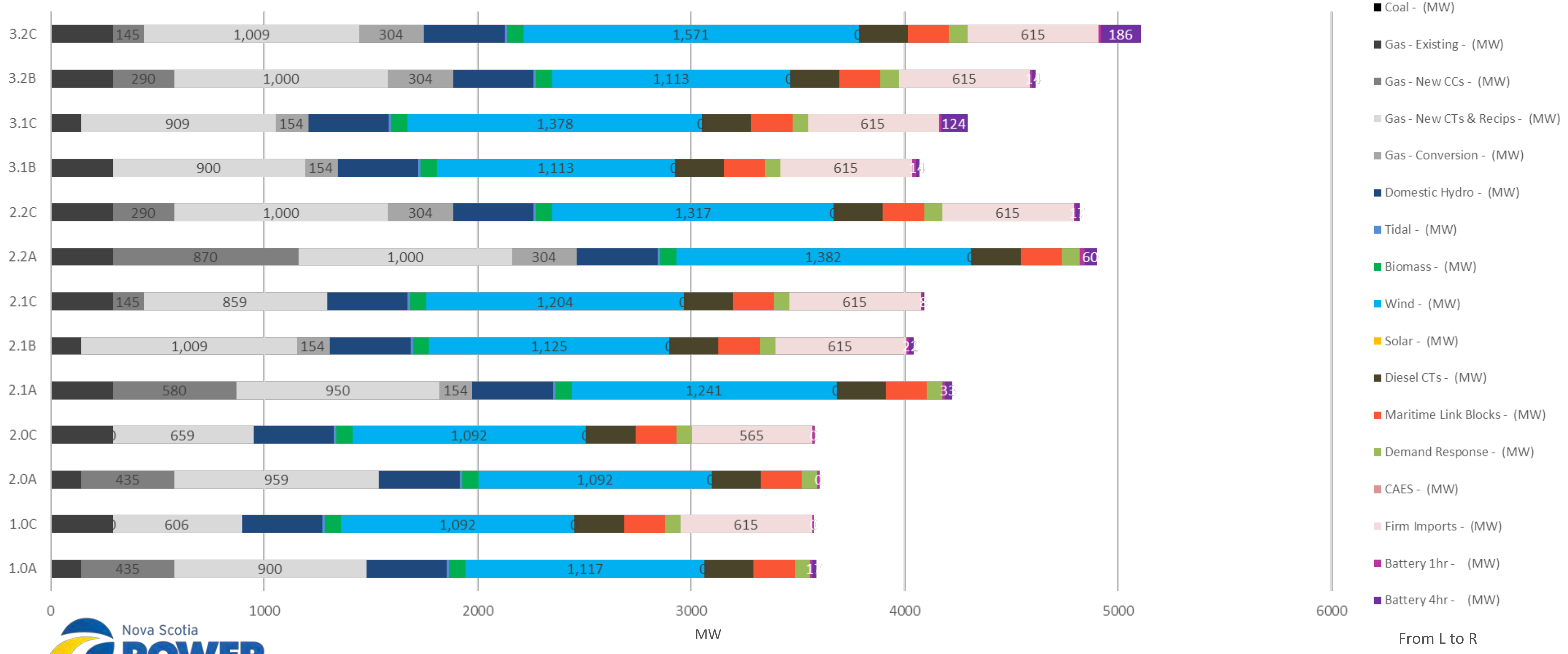
RESOURCE PORTFOLIO COMPARISON (2040)



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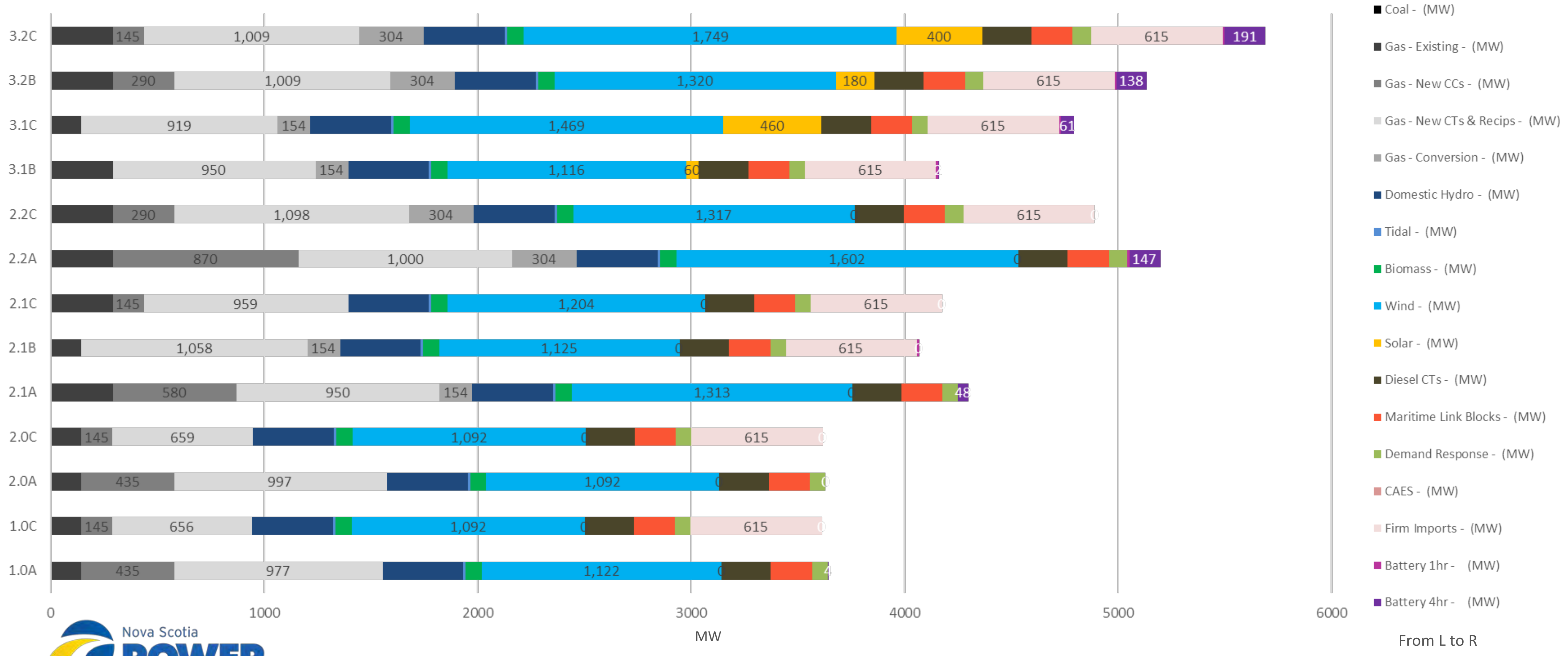
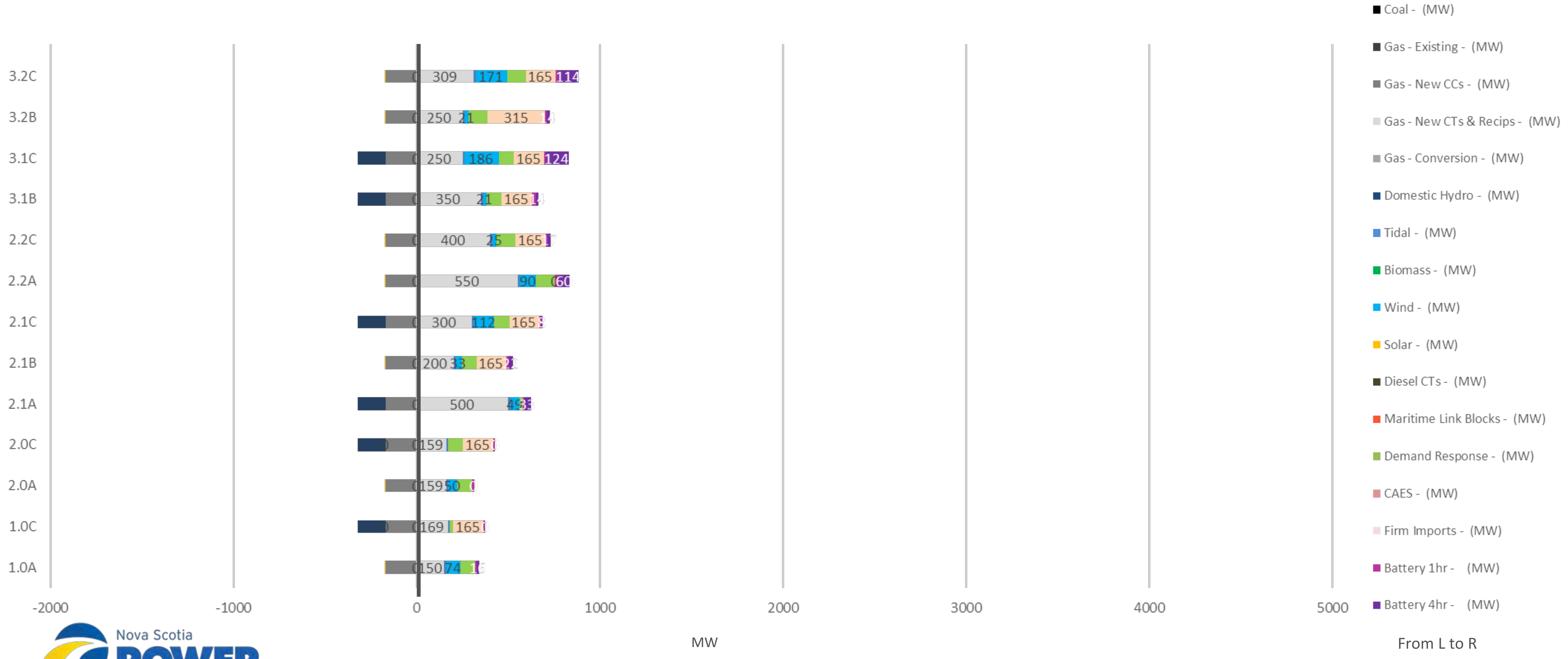
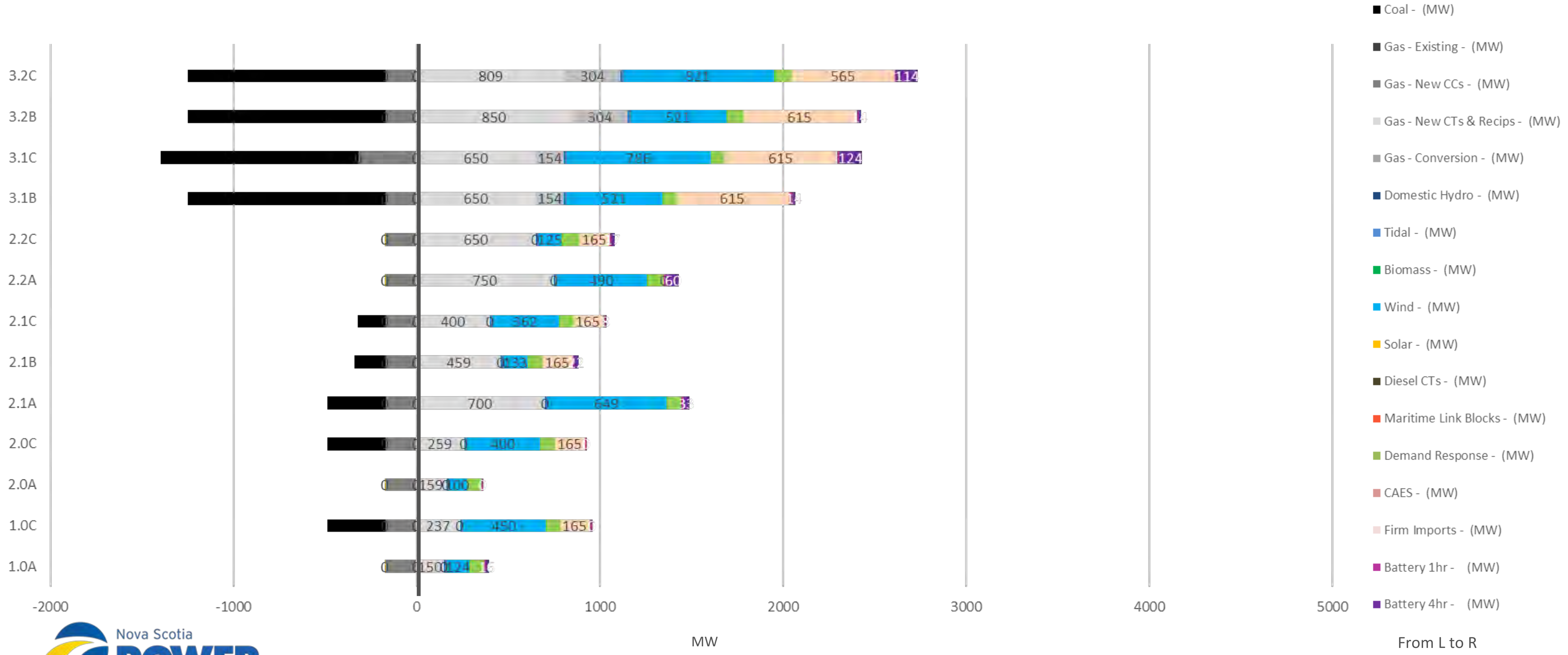
RESOURCE PORTFOLIO COMPARISON (2045)



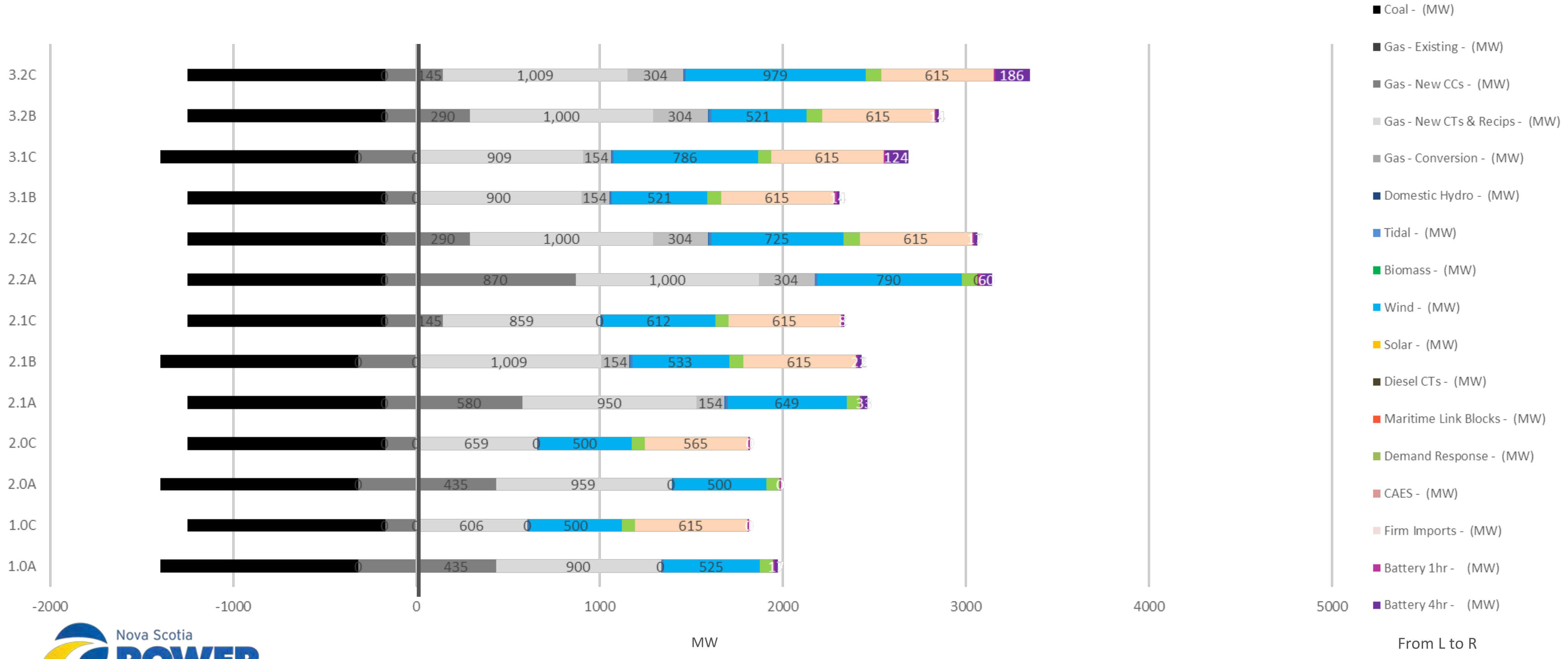
RESOURCE PORTFOLIO CHANGES (2026)



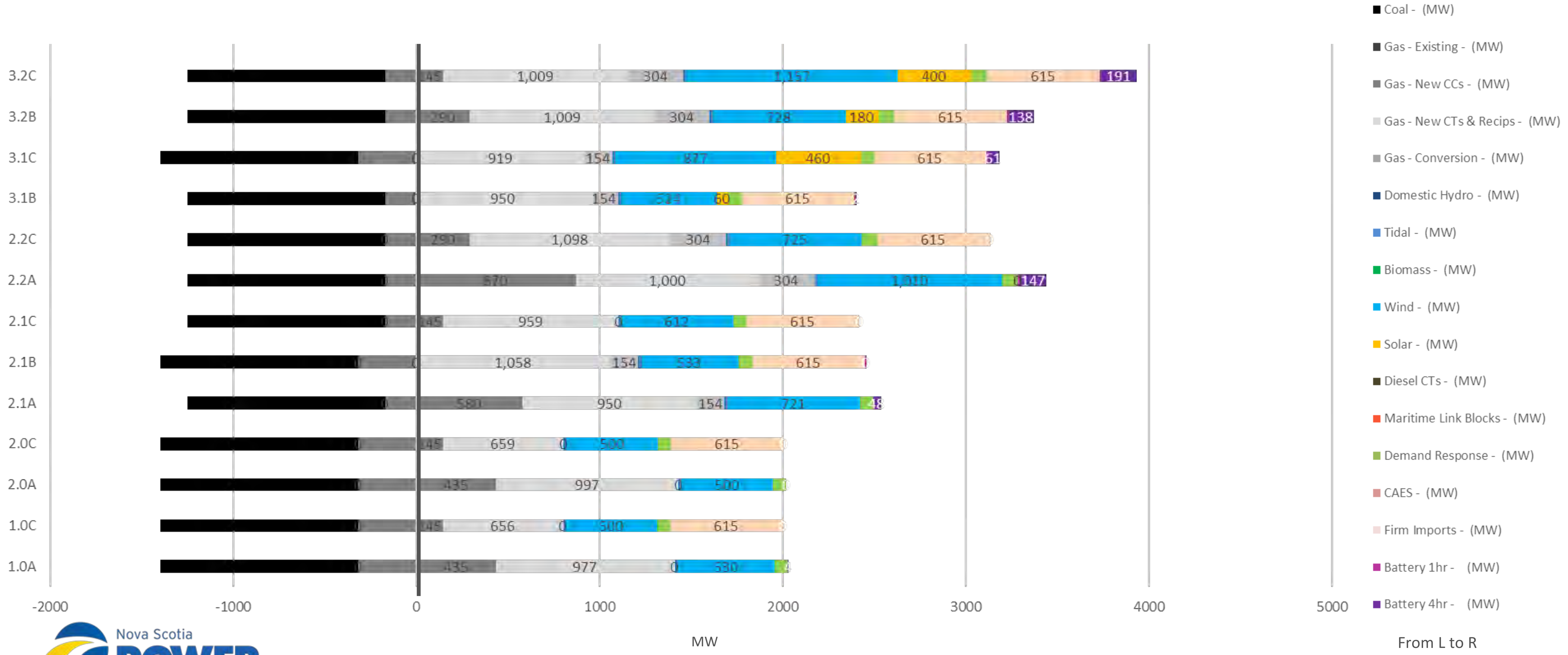
RESOURCE PORTFOLIO CHANGES (2030)



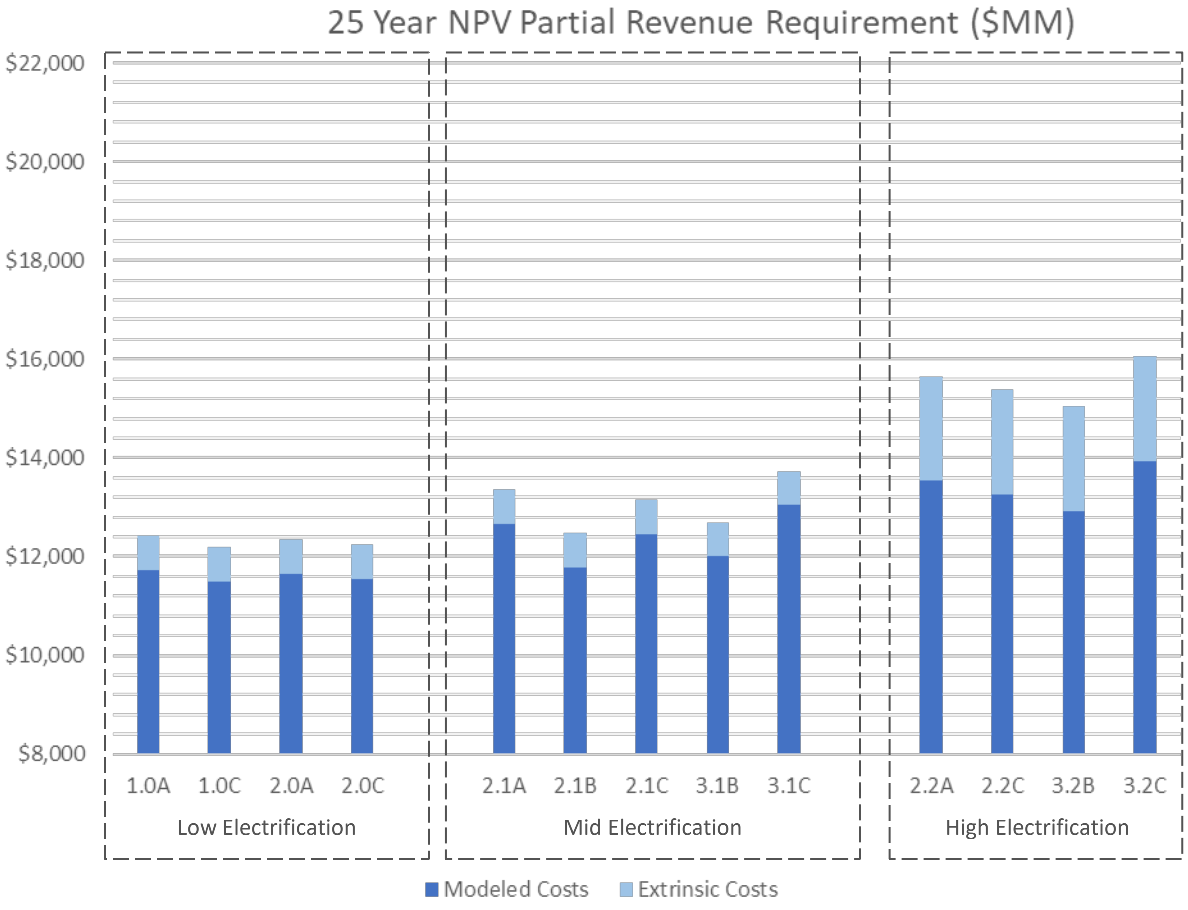
RESOURCE PORTFOLIO CHANGES (2040)

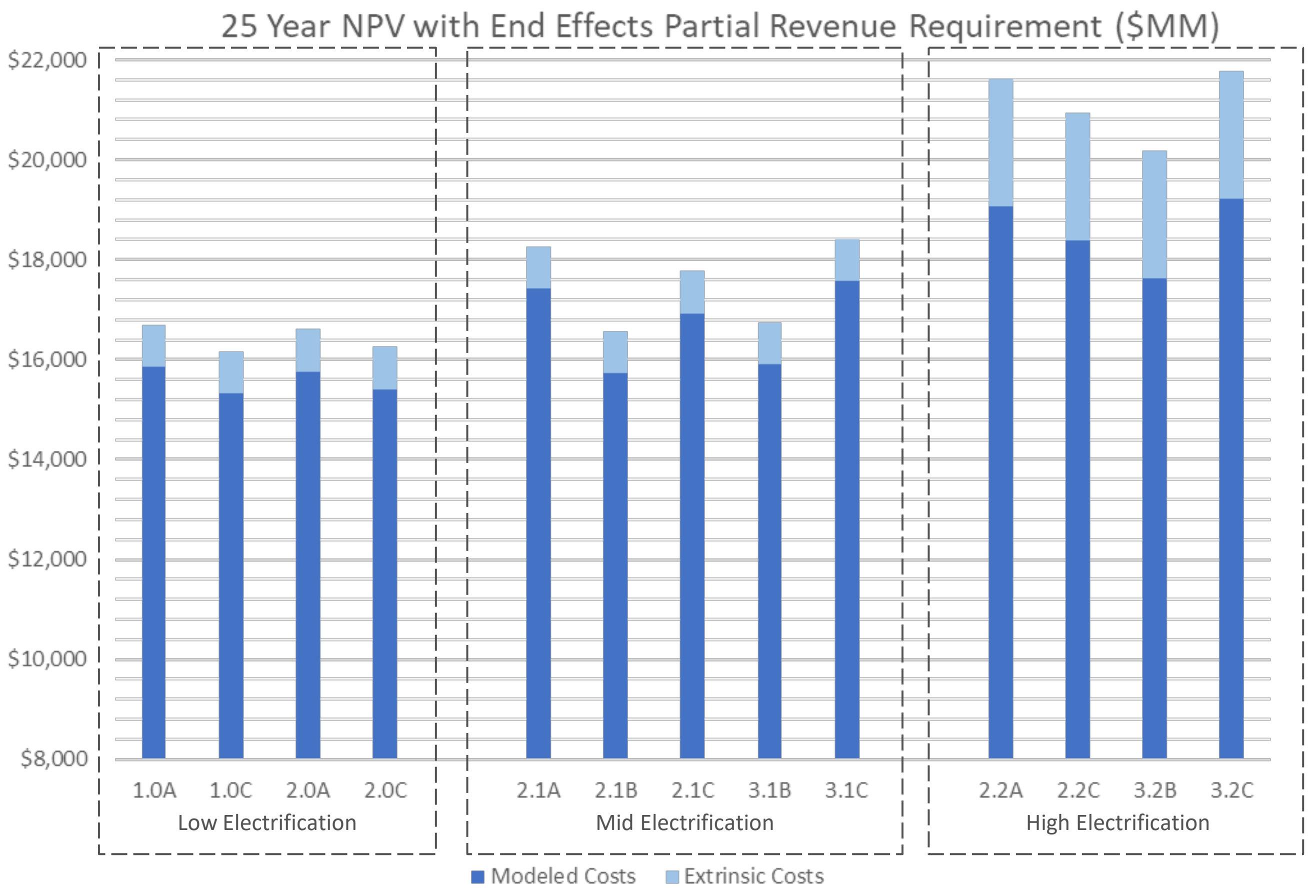


RESOURCE PORTFOLIO CHANGES (2045)



NPV PARTIAL REVENUE REQUIREMENT COMPARISON





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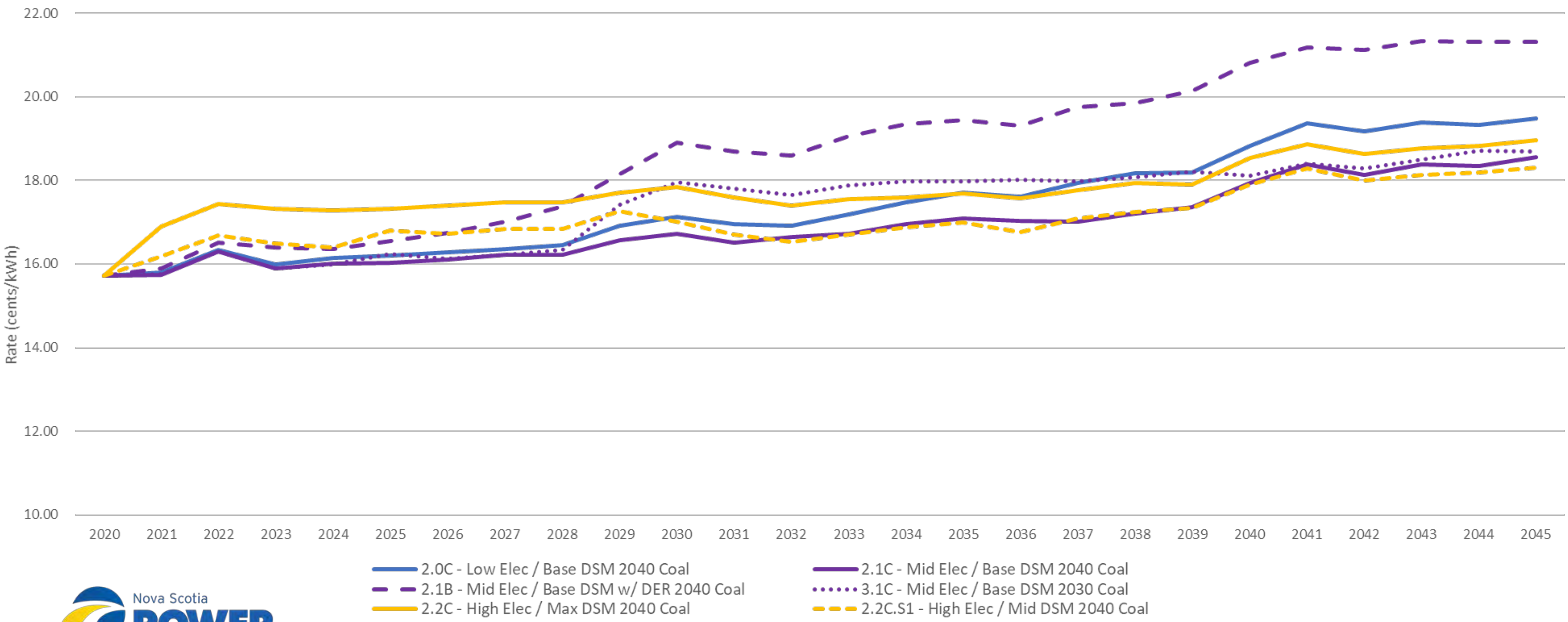
Due to differences in forecast system load affecting production costs, resource plan partial revenue requirement results should not be compared across electrification scenarios

RATE IMPACT COMPARISON (SELECT SCENARIOS)



DRAFT FINDINGS

IRP FINDINGS OVERVIEW

The summary of Findings is a key output of the 2020 IRP. As described in the 2020 IRP Terms of Reference, the results and observations of the modeling work will form a summary of findings, which will guide the development of a long-term electricity strategy.

The Draft Findings summarized in the following section include insights and ranges informed by the model outputs, as analyzed across the scenario plans. These continue to be reviewed and interpreted and should be understood in terms of their orders of magnitude or directional time frames.

NS Power looks forward to receiving stakeholder comments on these Draft Findings, which will then be refined for inclusion in the IRP Final Report.

DRAFT FINDINGS

1. Steeply **reducing carbon emissions** in line with Nova Scotia's Sustainable Development Goals Act will require significant efforts from each sector of the economy, with the **electricity sector playing a major role**.

a) Key pillars of **economy-wide decarbonization** include greater reliance on non-emitting electricity supplies, focused demand side management, and electrification of end uses currently reliant on fossil fuels.

b) Increased electricity sales due to electrification can help to **reduce upward pressure on electricity rates** while **facilitating carbon reductions** in other sectors.

c) Nova Scotia Power's direct carbon emissions are reduced to between 0.5 Mt and 1.4 Mt per year by 2045 in all resource plans, representing **an 87%-95% reduction from 2005 levels**. Earlier emissions reductions are possible at incremental cost relative to the lowest cost plans.

DRAFT FINDINGS

2. Decarbonizing Nova Scotia Power's electricity supply will require investment in a **diverse portfolio of non- and low-emitting resources**.

a) Regional Integration (i.e. investment in stronger interconnections to other jurisdictions) is an economic component of the least-cost plans under each load scenario. Both the **Reliability Tie**, which strengthens our connection to the North American electrical grid, and a **Regional Interconnection**, which enables access to firm capacity and energy imports, are shown to have value.

b) **Wind is the lowest cost domestic source of renewable energy** and is selected preferentially over solar in all resource plans. Incremental wind capacity of 500 - 800MW is selected by the model over the period, with major installations paired with coal retirement dates to provide replacement emissions-free energy. Further work is required to assess system stability at these significant penetrations and determine whether additional dynamic system inertia constraints can enable this level of additional wind integration on the Nova Scotia system.

DRAFT FINDINGS

2. CONTINUED Decarbonizing Nova Scotia Power's electricity supply will require investment in a **diverse portfolio of non- and low-emitting resources**.

c) Coal units are generally sustained economically until their model-imposed retirement date, with capacity factors falling in line with declining emissions caps. Many resource plans incorporate economic **retirement of one coal unit in the near term,** as early as 2023 if replacement capacity and energy can be procured. **New generating capacity** is required to offset retiring coal units, to **lower carbon emission intensity**, and to **meet growing electricity demand** in all scenarios.

d) NS Power's existing **domestic Hydro** resources provide economic benefit to customers and are **economically sustained** through the planning horizon with appropriate reinvestment requirements.

e) **DSM energy efficiency programs** consistent with a range of the "Low" to "Base" profiles, consistent with the E1 Potential Study, are shown to be most economic relative to other options evaluated.

DRAFT FINDINGS

3. Firm capacity resources will be a key requirement of the developing NS Power system in both the near and long term.

a) **New combustion turbines, operating at low capacity factors,** are the lowest cost domestic source of firm capacity and replace retiring thermal capacity in all resource plans. These units are also fast-acting, meaning they can quickly respond to changes in wind and non-firm imported energy. 50-150MW is required by 2025, while 600-1000MW of new capacity is required by 2045 to support retirement of steam units.

b) NS Power's existing Combustion Turbine resources provide economic benefit to customers and are **economically sustained** through the planning horizon with appropriate reinvestment requirements.

c) Low-cost, low-emitting generating capacity may be provided economically through **redevelopment of existing natural gas-powered steam turbines or coal unit conversions**. Fuel flexibility, including low/zero carbon alternative fuels, may also be an option for new and redeveloped resources.

DRAFT FINDINGS

3. CONTINUED Firm capacity resources will be a key requirement of the developing NS Power system in both the near and long term.

d) **Battery storage** can enable wind integration while providing firm capacity and energy storage; however, its ability to substitute for firm capacity resources is limited by its relatively short duration. Up to 120MW of storage by 2045 is selected in the portfolios with deployments of 30-60MW by 2025 in many plans.

e) The aggregated **Demand Response** (DR) programs modeled in the IRP have economic value to the Nova Scotia system, offsetting firm generation capacity requirements. A DR program with a target final nameplate capacity of approximately 70MW is shown to have value.

f) A Planning Reserve Margin (PRM) of 9% (on a UCAP basis, consistent with 20% 1 in 10 year ICAP method) is found to **maintain supply reliability** across the studied range of resource plans and electrification scenarios.

DRAFT FINDINGS

4. **Similar resource plans are selected** when considering both 2030 and 2040 coal unit retirement dates. The earlier retirement scenarios are less economic on an NPV basis but have similar cumulative rate implications by 2045.

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DRAFT ACTION PLAN

ACTION PLAN OVERVIEW

The Action Plan is a key output of the 2020 IRP. As described in the 2020 IRP Terms of Reference, the Action Plan identifies the critical undertakings required over the near-term to implement the long-term electricity strategy.

The Draft Action Plan summarized in the following section includes insights and ranges informed by the model outputs and Draft Findings, as analyzed across the scenario plans. These continue to be reviewed and interpreted and should be understood in terms of their orders of magnitude or directional time frames.

NS Power looks forward to receiving stakeholder comments on this Draft Action Plan, which will then be refined for inclusion in the IRP Final Report.

DRAFT ACTION PLAN

1. Develop a **Regional Integration Strategy** to provide access to firm capacity and low carbon energy, increase the reliability of Nova Scotia's interconnection with North America, and enable economic coal unit retirements. This strategy will include:

a) Identifying opportunities for near term firm imports over existing transmission infrastructure

b) Conducting detailed engineering and economic studies for firm import options requiring new transmission investment and strengthened regional interconnections, including evaluations of availability and security of supply and dispatch flexibility

c) Based on the results of this detailed work, commence the development of a Reliability Tie and Regional Interconnection via an appropriate regulatory process with target in-service dates as follows:

i. Reliability Tie: 2025-2029

ii. Regional Interconnection: 2028-2035

DRAFT ACTION PLAN

2. Electrification is a key variable in this IRP and results indicate that under economic resource plans it can **support provincial decarbonization** while **reducing upward pressure on electricity rates** for customers. NS Power proposes several action plan items from this IRP related to electrification:

a) Initiate an electrification strategy to understand options for encouraging economic electrification with the goals of maintaining rate stability while decarbonizing the Nova Scotia economy in parallel with the Sustainable Development Goals Act.

b) Monitor electrification growth in Nova Scotia so that NS Power can understand at what point the provincial load profile starts to move from Low, to Mid, to High levels of electrification.

c) Initiate a program to collect detailed data, including data on the quantity, flexibility and hourly load shape of incremental electrification demand, to assist with further system planning work.

d) Address electrification impacts on the Transmission & Distribution system as additional experience and data become available.

DRAFT ACTION PLAN

3. Initiate a **Thermal Plant Retirement, Redevelopment and Replacement Plan** including:

a) Develop a plan for the retirement of Trenton 5, targeting 2023-2025 while identifying replacement capacity and energy in parallel; begin decommissioning studies for NS Power's other coal assets and develop and execute a coal retirement plan including associated regulatory approval process; this coal retirement plan will include significant engagement with affected employees and communities.

b) Develop a plan for the redevelopment or replacement of existing natural gas-powered steam turbines to provide low-cost, fast-acting generating capacity to the Nova Scotia system. Fuel flexibility is a component of this work, including consideration for low/zero carbon alternative fuels.

c) Initiate a wind procurement strategy, targeting 50-100MW new installed capacity by 2025 and up to 350MW by 2030.

DRAFT ACTION PLAN

4. Create a **Demand Response Strategy** with a target capacity of 75MW, for deployment by 2025. The strategy will build on learnings from NS Power's Smart Grid Project, NS Power's Time Varying Pricing application, the DR Joint Working Group between NS Power and Efficiency One, the ELIADC tariff, and the Large Industrial Interruptible Rider.

DRAFT ROADMAP

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ROADMAP OVERVIEW

The Roadmap is a key output of the 2020 IRP. As described in the 2020 IRP Terms of Reference, the Roadmap identifies additional work that supports the long-term electricity strategy, beyond the items in the Action Plan.

The Draft Roadmap summarized in the following section includes insights and ranges informed by the model outputs and Draft Findings, as analyzed across the scenario plans. These continue to be reviewed and interpreted and should be understood in terms of their orders of magnitude or directional time frames.

NS Power looks forward to receiving stakeholder comments on this Draft Roadmap, which will then be refined for inclusion in the IRP Final Report.

DRAFT ROADMAP

1. Advance engineering study work on coal to gas conversions at Trenton and Point Tupper Generating Stations.

2. Complete detailed system stability studies under various current and future system conditions, reflective of both stressed system states and normal operating conditions, while considering higher quantities of installed wind capacity as seen in the IRP modeling results.

3. Pursue economic reinvestment in existing hydro and combustion turbines with individual business cases as applicable.

4. Complete a thermal plant Depreciation Study to update depreciation rates and a recovery strategy to better align depreciation with updated useful lives for generation assets.

DRAFT ROADMAP

5. Monitor the development of **low/zero carbon fuels** that could replace natural gas in powering generating units to provide firm, in-province capacity beyond 2050.

6. Continue to track the installed costs of wind, solar, and energy storage to look for variations from the trajectories established in the IRP (in particular, monitoring for divergence from the "Base" to the "Low" pricing scenarios).

7. Continuously refine these Findings and Action Plan items via an evergreen IRP process. This process should facilitate regular updating of the IRP model as conditions change and technology or market options develop.

NEXT STEPS

NEXT STEPS

1. Stakeholder Workshop – September 10
2. Comments on Draft Findings, Action Plan, Roadmap – September 18
3. Draft Final Report
4. Final Report, Action Plan, Roadmap

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NS POWER 2020 IRP
DRAFT FINDINGS WORKSHOP

SEPTEMBER 10, 2020

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AGENDA

SAFETY MOMENT

RELIABILITY & OPERABILITY SCREENING

FINAL PORTFOLIO STUDY

- COMPARISONS, METRICS & INSIGHTS
- SENSITIVITY ANALYSIS

DRAFT FINDINGS

DRAFT ACTION PLAN

DRAFT ROADMAP

PROCESS UPDATE & WORK COMPLETED

UARB NSP Pre-IRP Deliverables

- Capacity Study
- Supply Options Study
- Demand Response Assumptions
- Stability Study

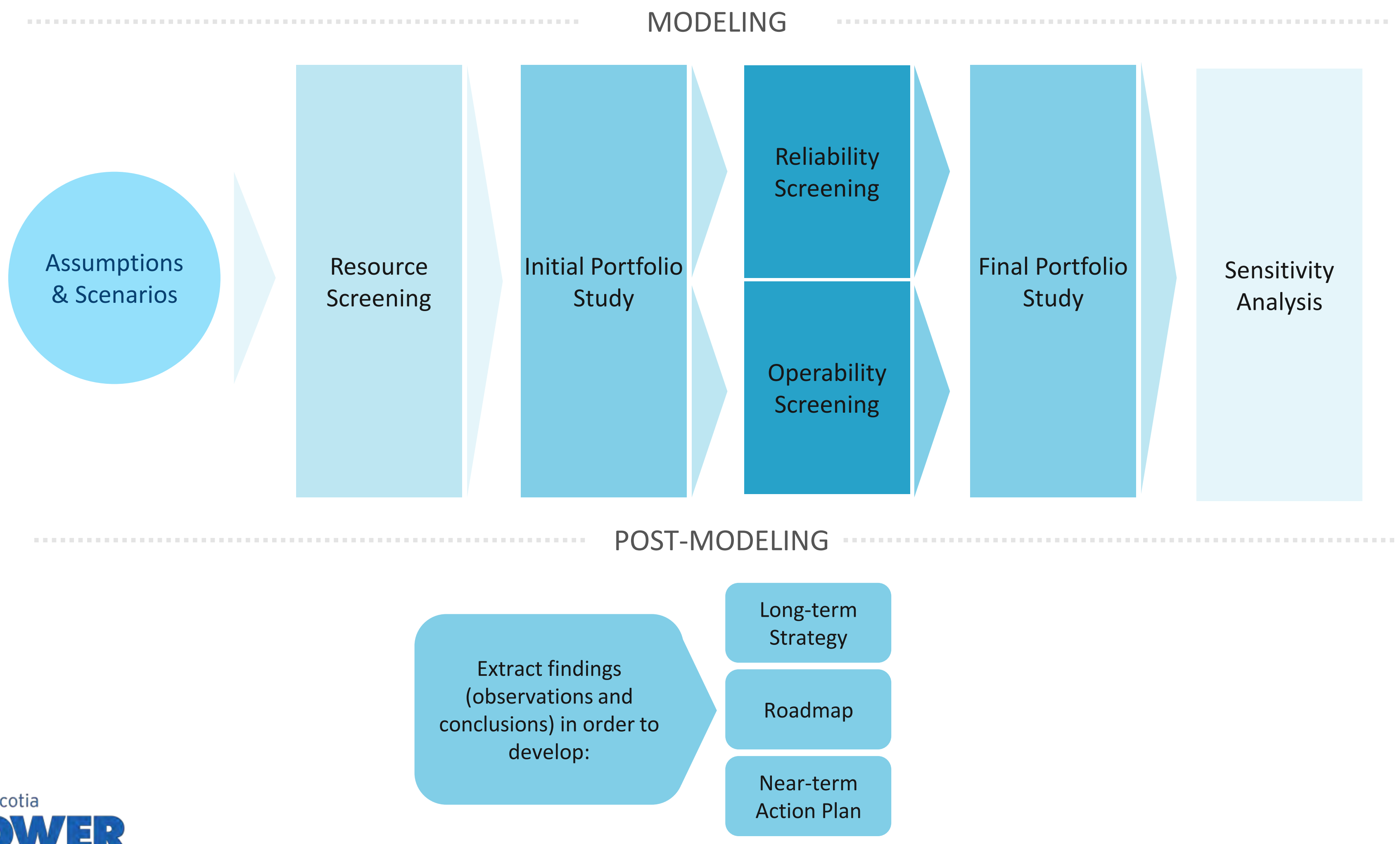
Core IRP Process resulting in Final Report

- Terms of Reference
- Scenario Development
- Modeling Plan
- Assumptions
- Modeling
- Analysis/Conclusions
- Report, Roadmap, & Action Plan

Oct 2020

- Completed – Pre-IRP
- Completed
- In Progress

IRP MODELING PLAN



RELIABILITY AND OPERABILITY SCREENING

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RELIABILITY & OPERABILITY SCREENING

NS Power reviewed sections of slides 5-27 from Draft Findings release 2020-09-02

QUESTIONS & DISCUSSION

RELIABILITY & OPERABILITY SCREENING

FINAL PORTFOLIO STUDY & SENSITIVITY ANALYSIS

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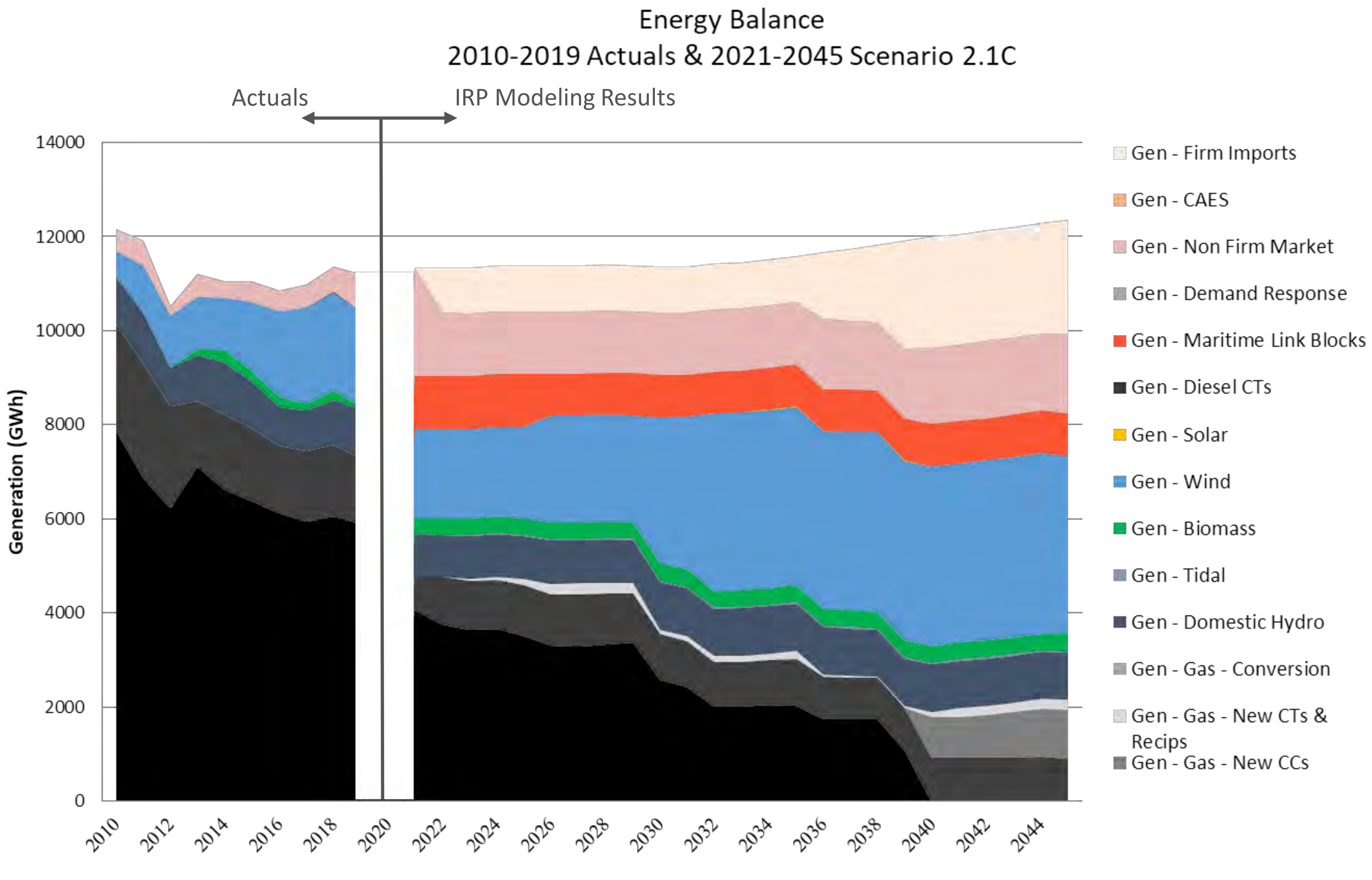
FINAL PORTFOLIO STUDY

- The following slides provide an overview comparison of the Final Portfolio Study results from PLEXOS for the key scenarios
- Outputs presented here consist of capacity expansion optimizations in PLEXOS LT, supplemented by hourly production cost simulations in PLEXOS MT/ST
- The section includes several summary comparison slides; detailed model outputs for each run are provided in a second presentation *"IRP Modeling Results 2020-09-02"* and in the accompanying data tables
- NPVs presented in these results are partial revenue requirements that consider modeled costs (i.e. production, O&M, abatement, sustaining capital, and capital investment) and specific costs considered outside of the long-term model optimization (i.e. energy efficiency costs)

IRP IN THE CONTEXT OF ONGOING GENERATION TRANSFORMATION

- The graph to the right includes actual annual generation for 2010-2019 and forecast generation from PLEXOS MT/ST for 2021-2045 (2020 is left blank)
- This chart highlights the increasing penetration of renewables on the Nova Scotia system since 2010 as well as the anticipated changes due to the availability of energy over the Maritime Link beginning in 2021



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IRP RESOURCE PLAN INSIGHTS

Regional Integration

Reliability Tie* and Regional Interconnection investments enable incremental renewable integration as well as new access to firm capacity & energy imports (respectively), and are common to low-cost resource plans.

Electrification

Increased electricity sales due to electrification can help to reduce upward pressure on electricity rates while facilitating carbon reductions in other sectors.

Firm Capacity Resources

New firm capacity resources will be a key requirement of the developing power system; efficient combustion turbines replace retiring thermal capacity to quickly respond to changes in wind output & non-firm imported energy and ensure reliability.

Coal Retirements

Coal units operate with declining capacity factors in line with GHG emissions caps. Many resource plans incorporate economic retirement of one coal unit in the near term (as early as 2023 if replacement capacity and energy can be procured).

Wind Energy

Wind energy continues to increase in all IRP resource plans; new wind is assumed to contribute to grid essential services (e.g. ramping reserve, SCADA control) to enable additional renewable integration.

Solar Energy

There is very limited solar generation in the resource plans due to low capacity factor (relative to wind), lower winter output, and lack of firm capacity contribution; limited solar is built in 2043+ in the most aggressive GHG reduction scenarios.

Demand Response & Efficiency

The aggregated Demand Response programs modeled in the IRP have economic value to the Nova Scotia system, offsetting requirements for firm generation capacity with controllable customer load. Focused DSM is required.

Hydro Resources

NS Power's existing Hydro resources provide economic benefit to customers and are retained through the planning horizon with appropriate sustaining investment as a source of renewable generation.

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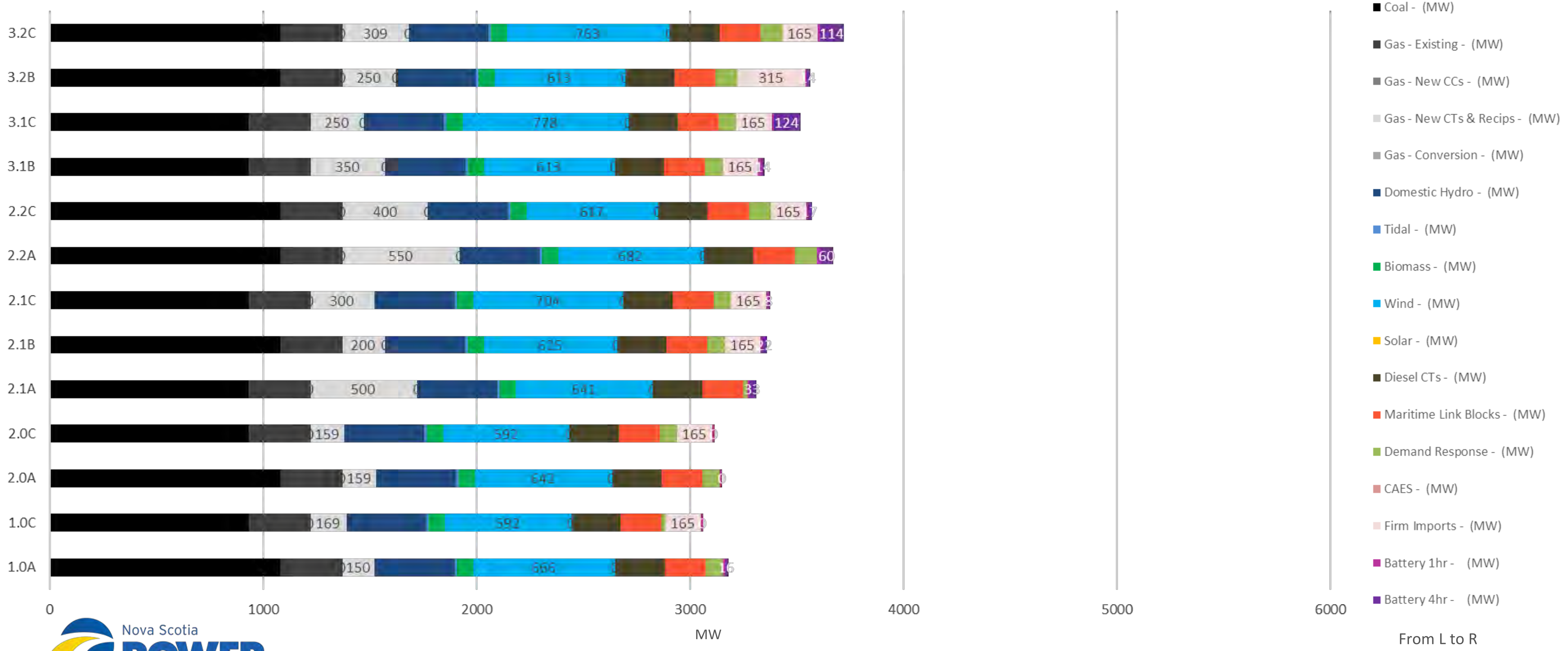
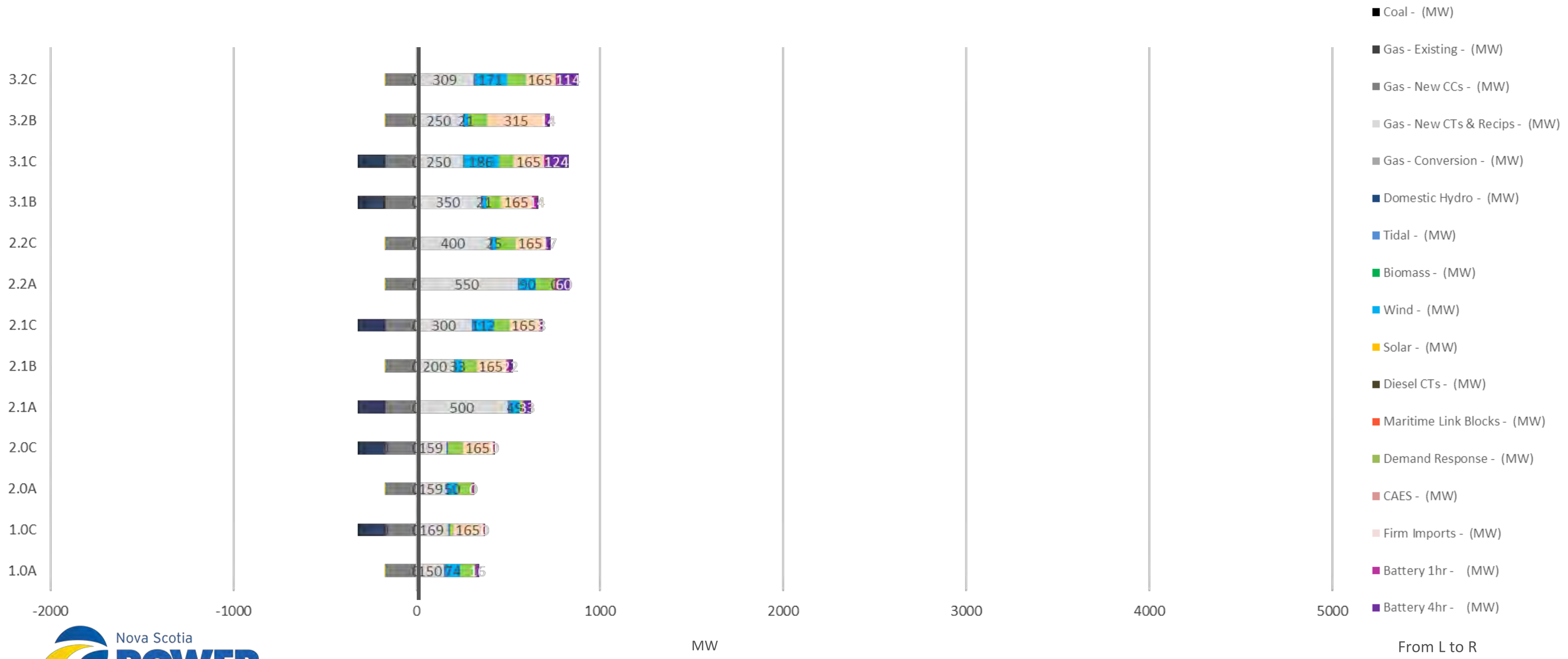
**The Reliability Tie is the term used in the 2020 IRP for a 2nd 345kV AC Transmission Line between Onslow, NS and Salisbury, NB*

RESOURCE PORTFOLIO COMPARISON (2026)



RESOURCE PORTFOLIO CHANGES (2026)



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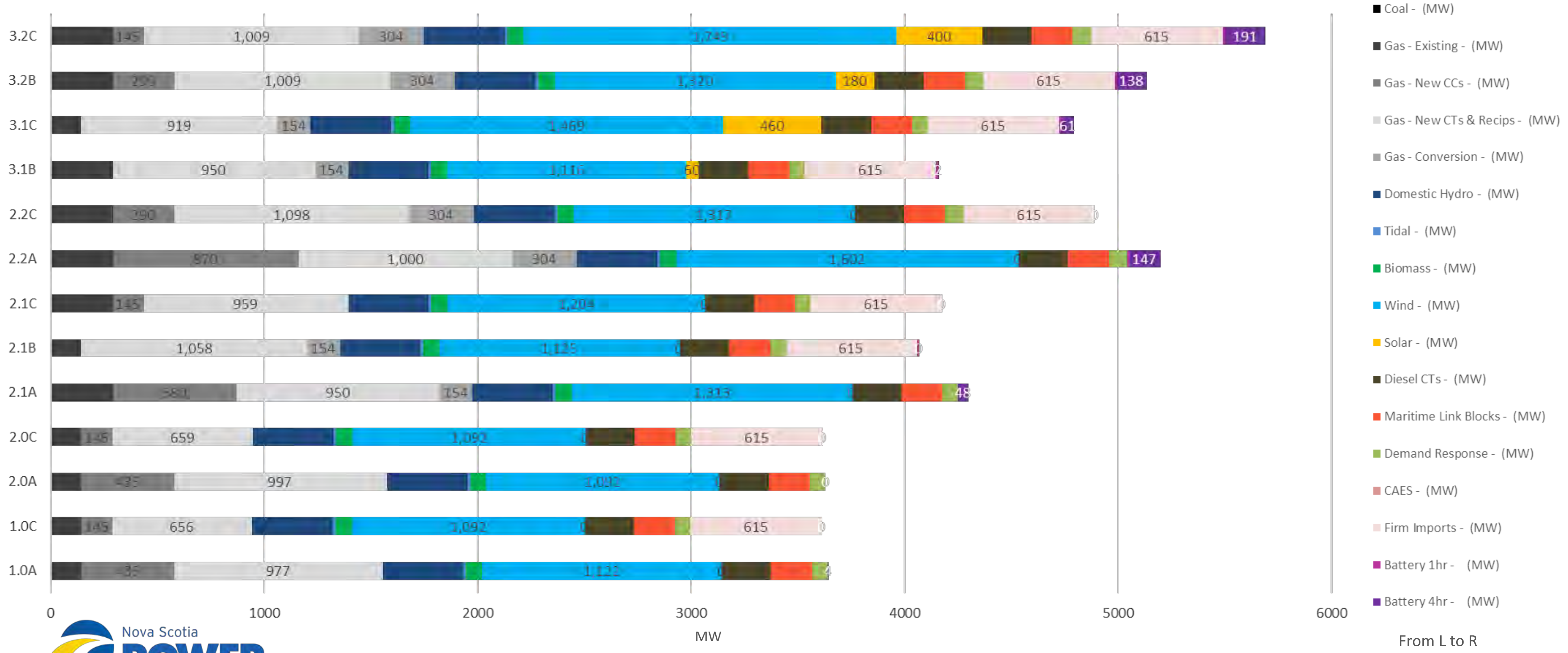
RESOURCE PORTFOLIO COMPARISON (2045)



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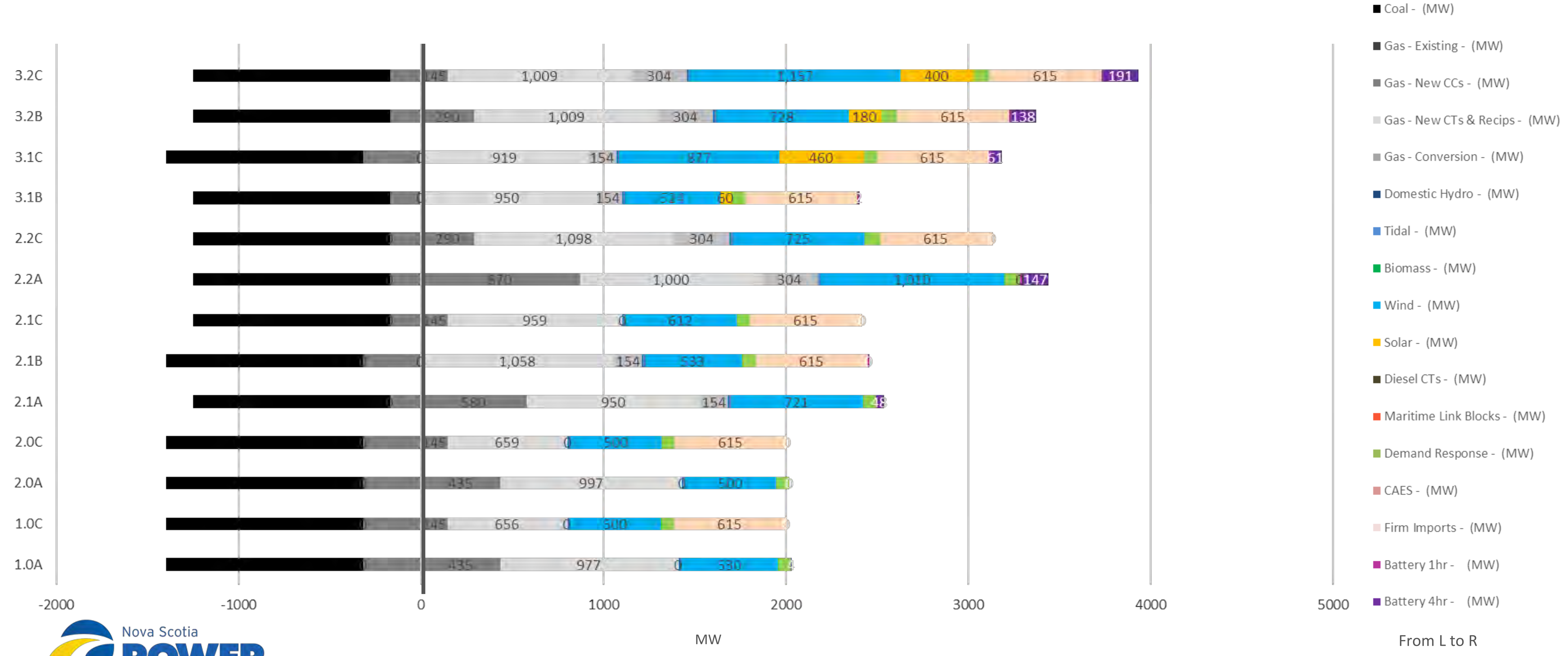
RESOURCE PORTFOLIO CHANGES (2045)



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QUESTIONS & DISCUSSION

RESOURCE PLAN INSIGHTS

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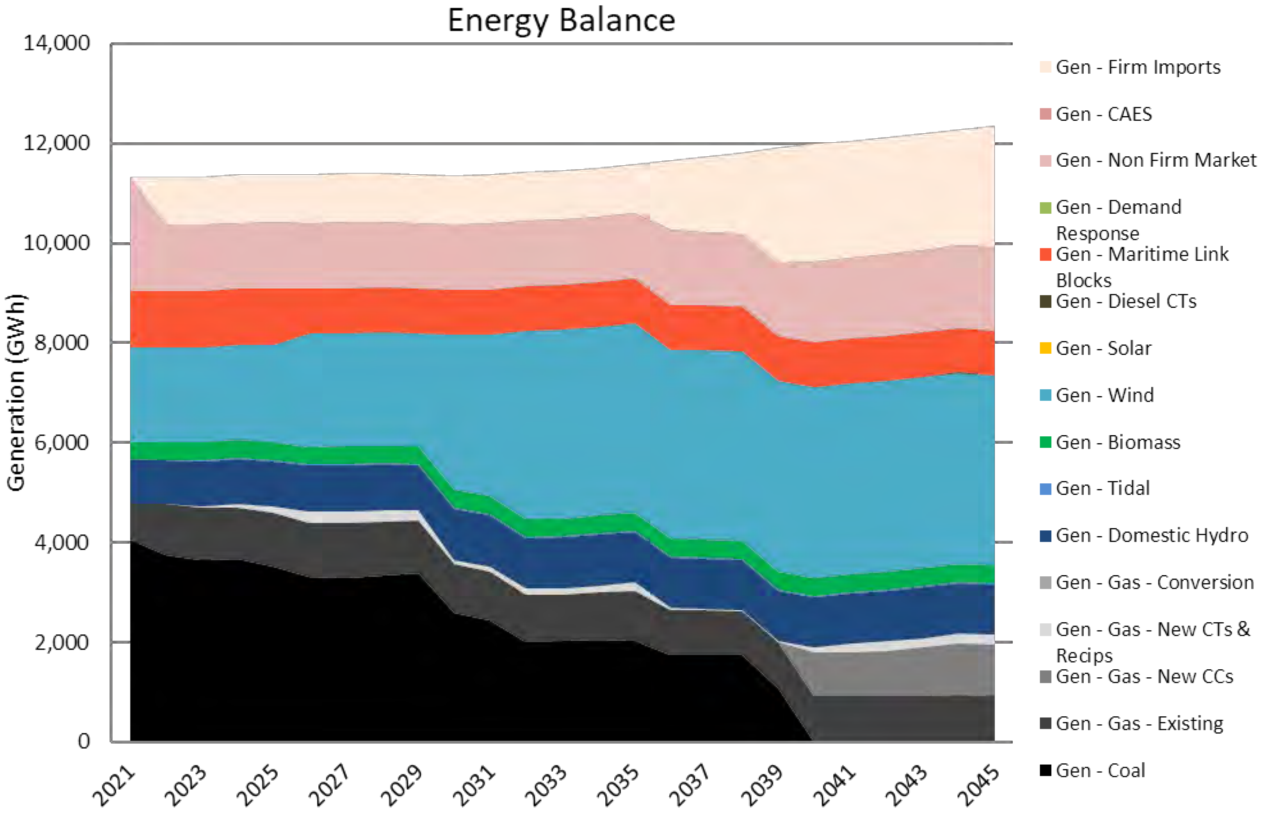
FINAL PORTFOLIO STUDY - METRICS

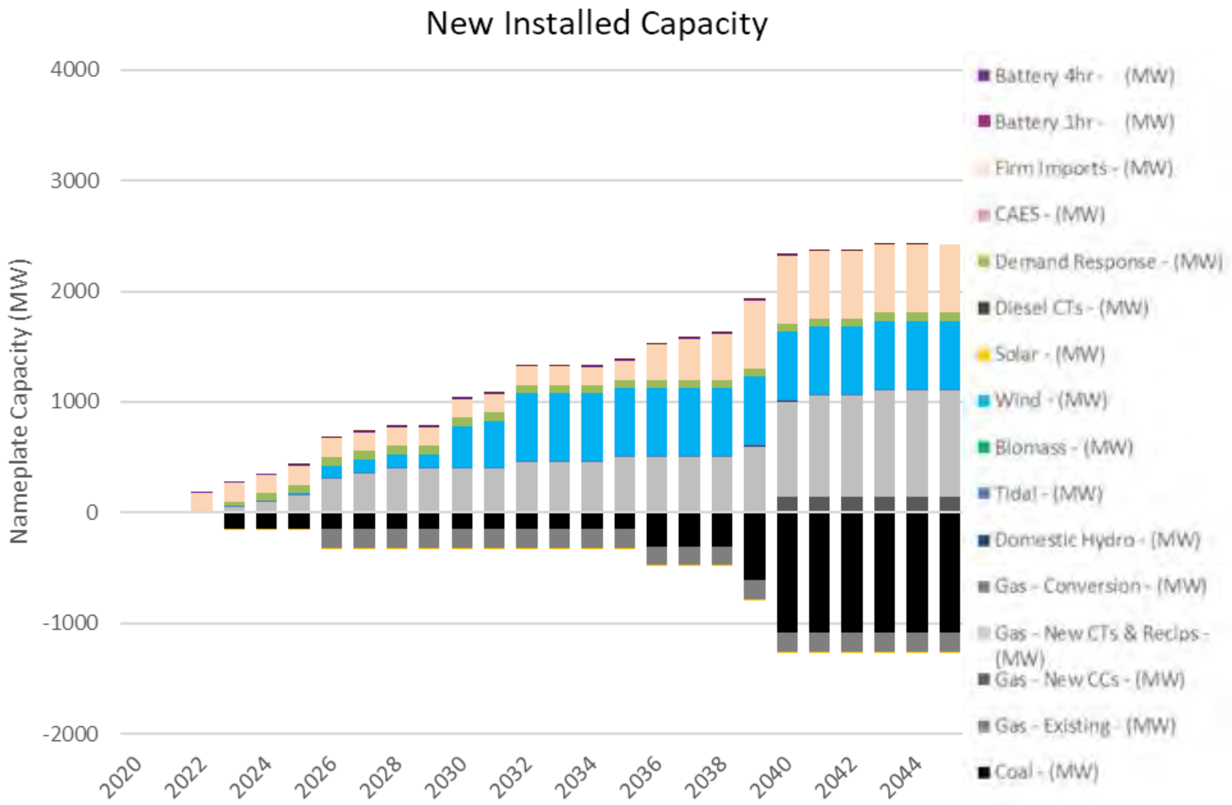
The following metrics are being used to evaluate each portfolio studied; updates from the Scenarios and Modeling Plan release based on ongoing work and stakeholder feedback are shown in purple text.

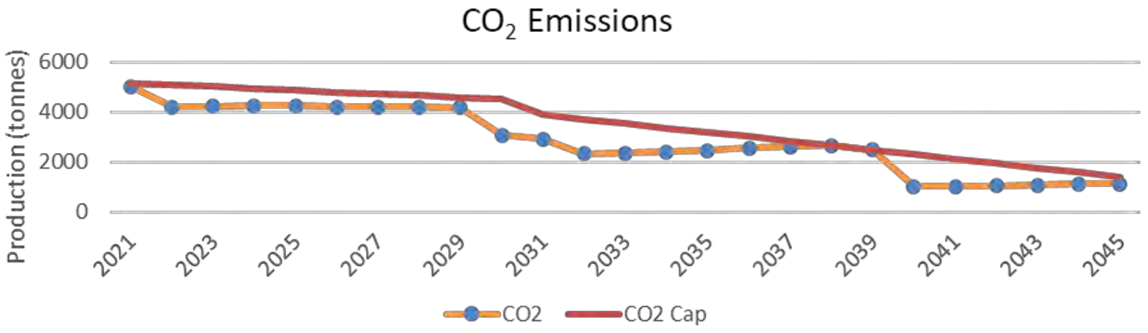
Metric	Description
Minimization of the cumulative present value of the annual revenue requirements over the planning horizon (with and without end-effects adjustment)	25 year NPV Revenue Requirement Average Annual Partial Rate Impact - 25-yr
Magnitude and timing of electricity rate effects	10 year NPV Revenue Requirement Average Annual Partial Rate Impact - 10-yr
Reliability requirements for supply adequacy	Evaluation of PRM, resource capacity adequacy, operating reserve requirements, etc.
Provision of essential grid services for system stability and reliability	Quantitative and qualitative assessment of the status of essential grid services provision for each portfolio. Many plans are similar in this respect, so only key differences will be noted at this time.
Plan robustness (the ability of a plan to withstand plausible potential changes to key assumptions)	Magnitude of the plan's exposure to changes in key assumptions (via sensitivity analysis) as well as resiliency to risks
Reduction of greenhouse gas and/or other emissions	Quantitative reductions as output by Plexos; total emissions over planning horizon.
Flexibility (limitation of constraints on future decisions arising from the selection of a particular path)	Qualitative assessment of timing of investments

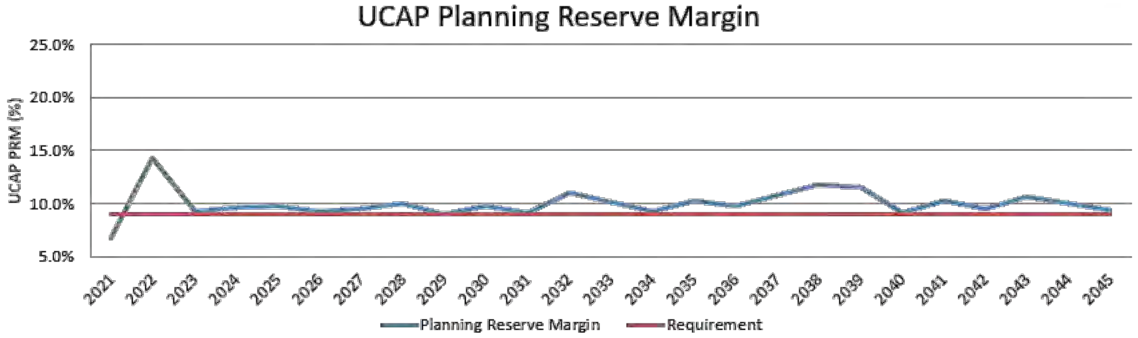
2.1C

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION







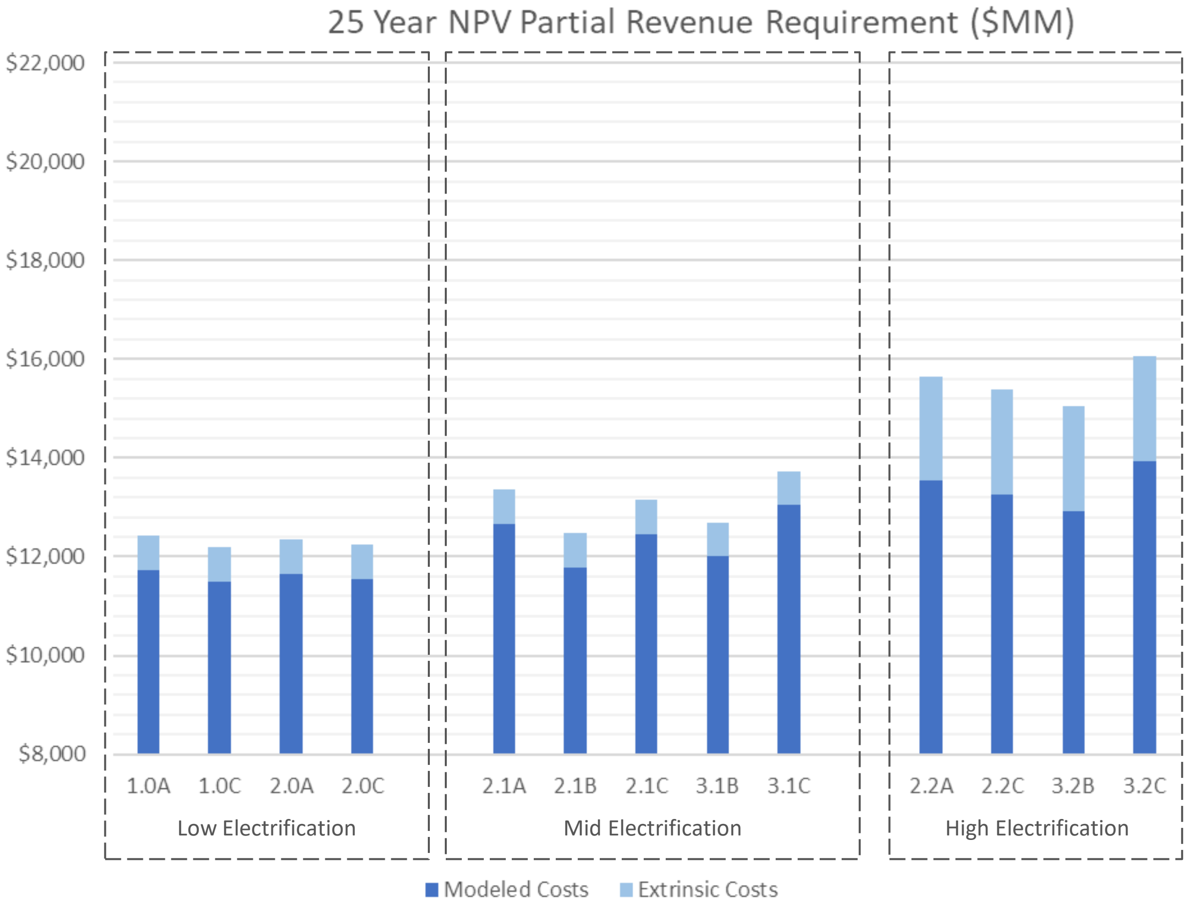


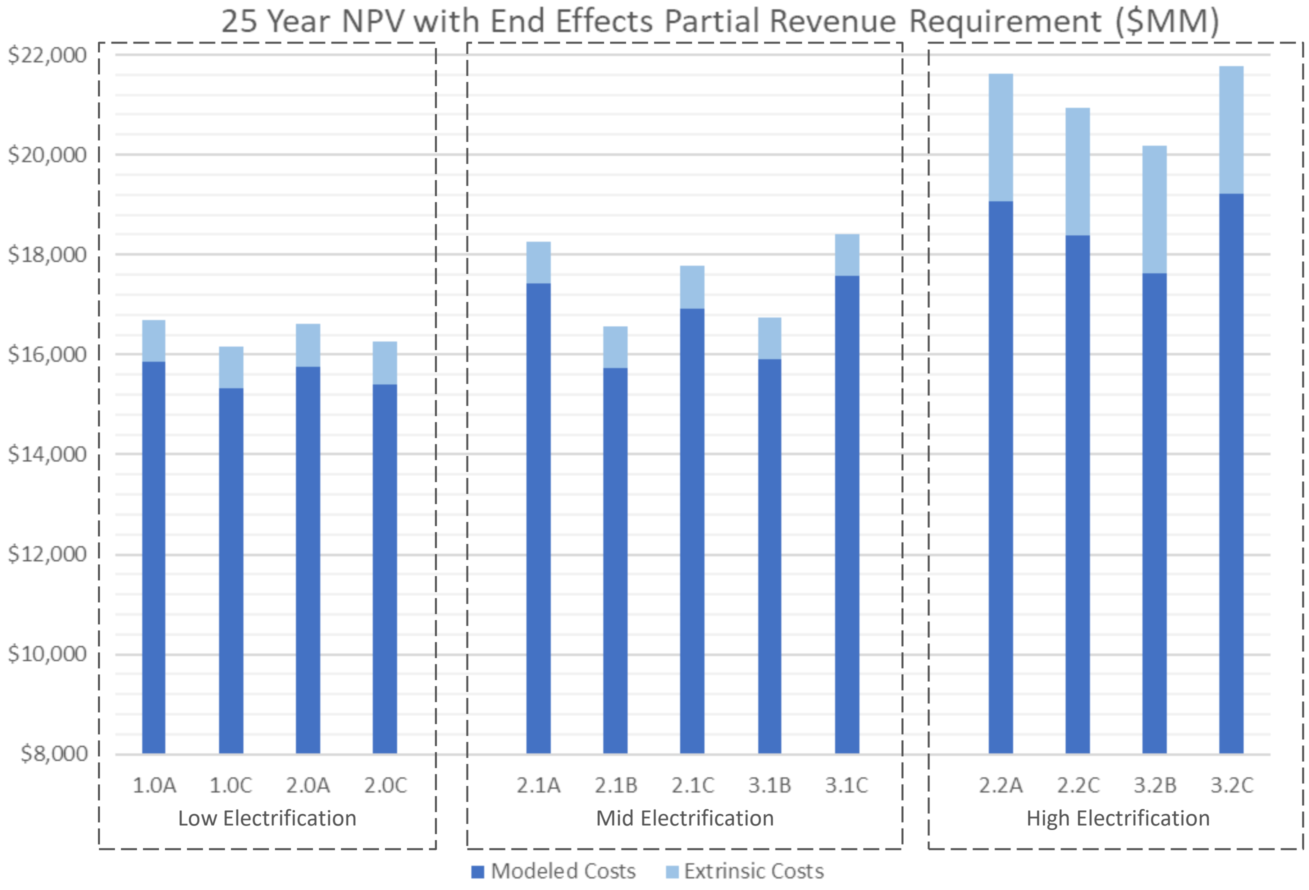
2.1C

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation		
25-yr NPVRR ($MM)	$13,141	General Notes • Reliability Tie built in 2031 (earlier than previous runs) enables wind integration • 1 coal unit retired economically in 2020s • 1 less combined cycle unit in 2040 than seen in previous runs Essential Grid Services • Essential Grid Service requirements are met as modeled Resource Adequacy & PRM • Reliability Tie: 2030 • Regional Integration: 2036 Plan Robustness & Flexibility • Regional Integration provides flexible ability to meet emissions constraints
25-yr NPVRR with End Effects ($MM)	$17,767	
10-yr NPVRR ($MM)	$7,067	
Average Annual Partial Rate Impact 2021-2030 (%) 2021-2045 (%)	 0.6% 0.7%	
Total CO_2 Emissions 2021-2030 (MT) Total CO_2 Emissions 2031-2045 (MT) Total CO_2 Emissions 2021-2045 (MT)	41.8 29.1 70.9	

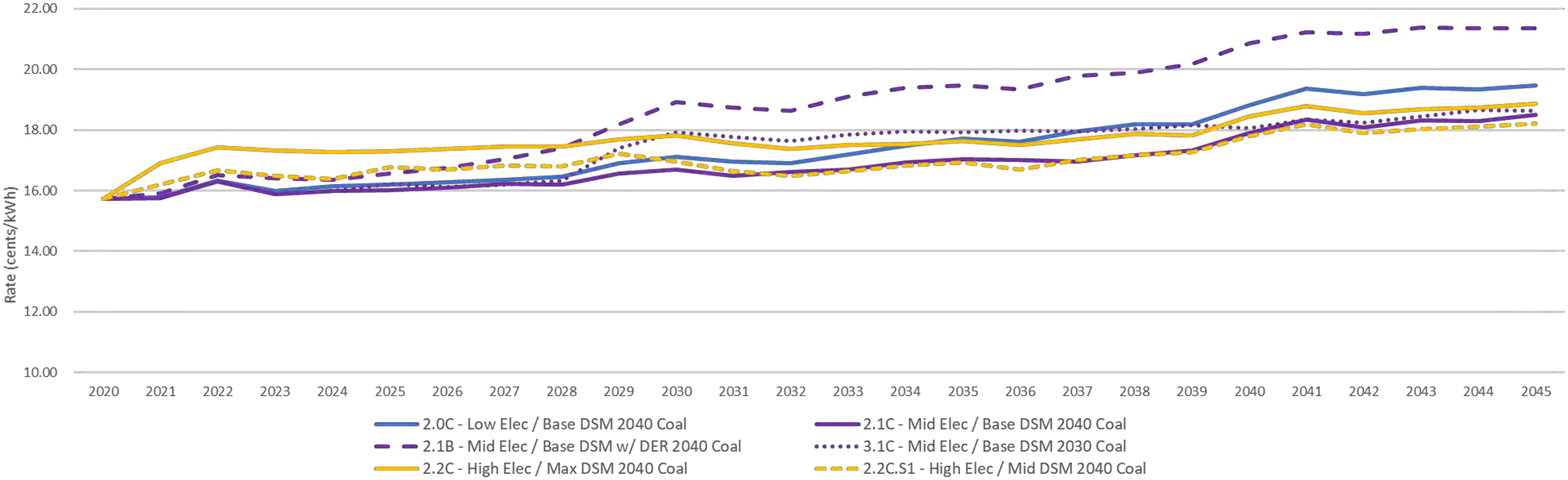
NPV PARTIAL REVENUE REQUIREMENT COMPARISON





Due to differences in forecast system load affecting production costs, resource plan partial revenue requirement results should not be compared across electrification scenarios

RELATIVE RATE IMPACT COMPARISON



This analysis approximates the resource plan impact to customer rates over time, incorporating the effects of load changes due to Electrification and Resource Strategy.

- Higher levels of electrification, when paired with appropriate DSM investments, leads to lower rates for customers over time
- Conversely, significant penetration of DER (Distributed Energy Resources, e.g. rooftop solar) will lead to increased rate pressure
    - Note that the cost of the DER installations modeled in this scenario is not included in the calculation shown here and would be incremental
- 2030 and 2040 coal closures will have similar rate impacts by 2045, but the 2030 closure date has added pressure during the 2030s without other mitigation

QUESTIONS & DISCUSSION

FINAL PORTFOLIO STUDY & METRICS

Nova Scotia POWER An Emera Company

SENSITIVITY ANALYSIS OVERVIEW

In addition to the Final Portfolio Study, a series of model sensitivities has been studied to understand how model outputs will vary with adjustments to key input parameters of interest.

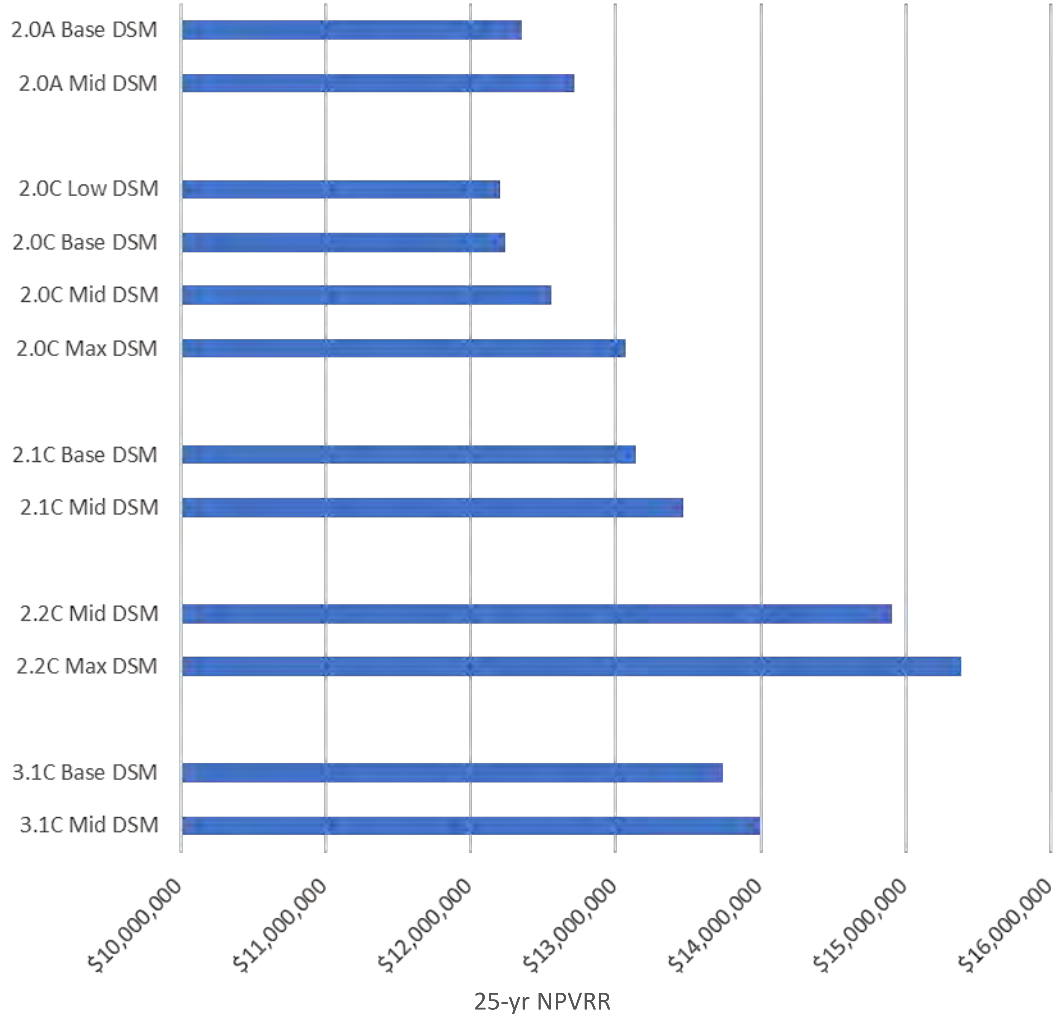
The IRP Modeling Results Release (2020-09-02) includes the full output of these sensitivity runs.

Sensitivities that are included in this results release are listed below:

2.0A.DSM-1	Low Electrification / Mid DSM
2.1C.DSM-2	Mid Electrification / Mid DSM
2.2C.DSM-3	High Electrification / Mid DSM
2.0C.DSM-4	Low Electrification / Low DSM
2.0C.DSM-5	Low Electrification / Mid DSM
2.0C.DSM-6	Low Electrification / Max DSM
3.1C.DSM-7	Mid Electrification / Mid DSM / 2030 Coal Retirement
2.1C.Wind-1	Low Wind Cost
2.1C.Wind-2	Low Wind + Low Battery Cost
2.1C.Wind-3	Low Inertia
2.1C.Wind-4	No Inertia / No Wind Integration Requirements
2.1C.Mersey	Mersey Hydro Retired
2.1C.Import-1	Limited Non-Firm Imports
2.0A.Import-2	Current Landscape case without Reliability Tie
2.1C.Import-3	Limited Reliability Tie Inertia (provides 50% of inertia requirement)

SENSITIVITY ANALYSIS – DSM LEVELS

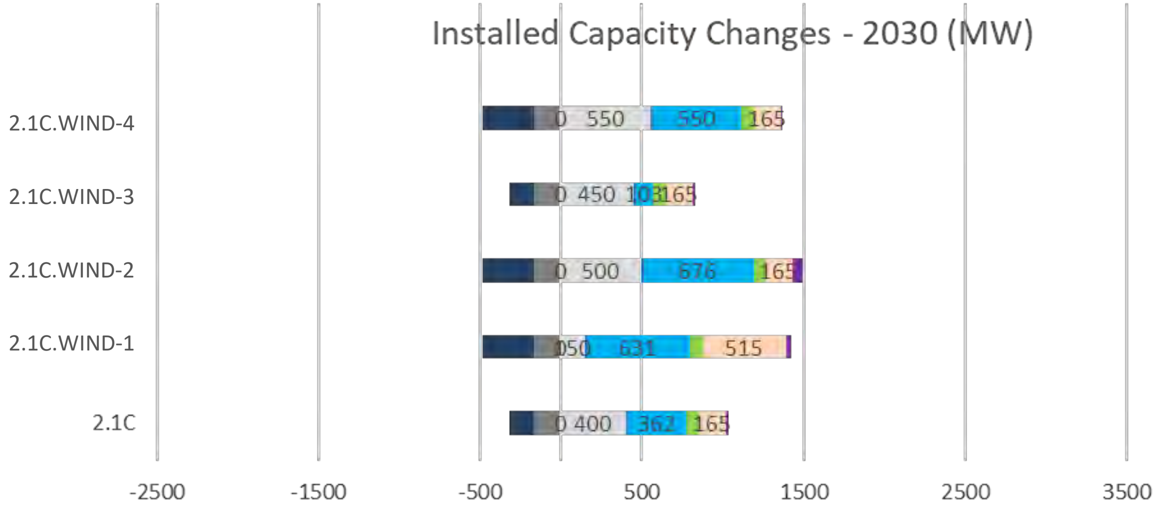
- 7 Sensitivities for DSM were completed, including runs selected in collaboration with E1, to evaluate combinations of DSM level and Electrification level
  - Under **Low Electrification**, Base DSM and Low DSM are very close in cost while Mid DSM and Max DSM have higher NPVs
  - Under **Mid Electrification**, Mid DSM has a higher NPV than Base DSM
  - Under **High Electrification**, Mid DSM has a lower NPV than Max DSM
- Conclusions hold under 2030/2040 coal retirement and under Current Landscape and Regional Integration resource strategies

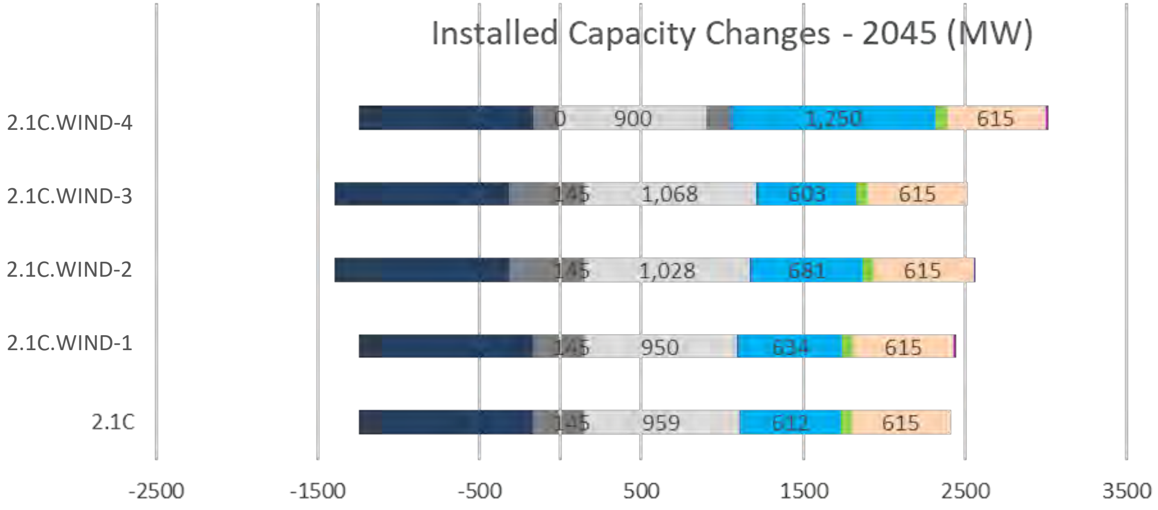


SENSITIVITY ANALYSIS – WIND ASSUMPTIONS

- 4 model sensitivities and test runs completed on wind pricing, system inertia constrain, and wind integration:
  - 2.1C.WIND-1 – Low Wind Price
  - 2.1C.WIND-2 – Low Wind & Battery Price
  - 2.1C.WIND-3 – Low Inertia Constraint
  - 2.1C.WIND-4 – No Inertia / No Integration*
- General model behaviour is that under lower wind and wind battery prices, the ultimate wind build out does not change but it does start earlier in the Planning Horizon (excluding 2.1C.WIND-4)
- Effect of reducing inertia constraint was limited
- Significant wind penetrations (beyond what was modeled in the PSC study) will require additional study work to confirm system stability
  - Identified in Draft IRP Action Plan

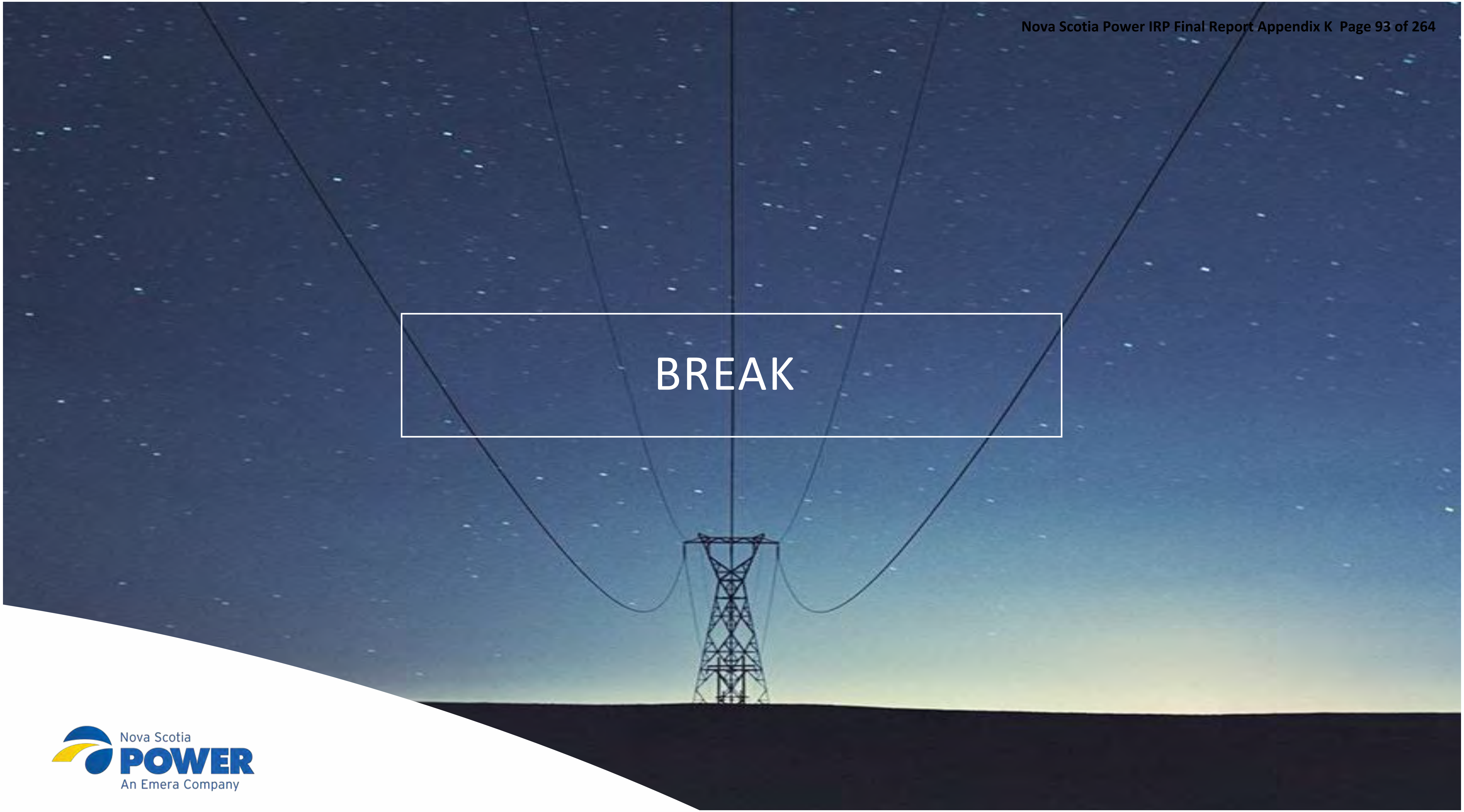
**This run is an assumption test case and is not considered an operable system configuration currently*





QUESTIONS & DISCUSSION

SENSITIVITY ANALYSIS



BREAK

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DRAFT FINDINGS

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POWER
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IRP DRAFT FINDINGS - SUMMARY

1	Steeply **reducing carbon emissions** in line with Nova Scotia's Sustainable Development Goals Act will require significant efforts from each sector of the economy, **with the electricity sector playing a major role**.
2	Decarbonizing Nova Scotia Power's electricity supply will require investment in a **diverse portfolio of non- and low-emitting resources**.
3	**Firm capacity resources** will be a key requirement of the developing NS Power system in both the near and long term.
4	**Similar resource plans are selected** when considering both 2030 and 2040 coal unit retirement dates. The earlier retirement scenarios are higher cost on an NPV basis but have similar cumulative rate implications by 2045.

IRP DRAFT FINDINGS

NS Power reviewed slides 45-51 from Draft Findings release 2020-09-02

QUESTIONS & DISCUSSION

DRAFT FINDINGS

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DRAFT ACTION PLAN

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IRP DRAFT ACTION PLAN - SUMMARY

1	Develop a **Regional Integration Strategy** to provide access to firm capacity and low carbon energy, increase the reliability of Nova Scotia's interconnection with North America, and enable economic coal unit retirements.
2	**Electrification** is a key variable in this IRP and results indicate that under economic resource plans it can **support provincial decarbonization** while **reducing upward pressure on electricity rates** for customers.
3	Initiate a **Thermal Plant Retirement, Redevelopment and Replacement Plan**
4	Create a **Demand Response Strategy** with a target capacity of 75MW, for deployment by 2025.

IRP DRAFT ACTION PLAN

NS Power reviewed slides 53-57 from Draft Findings release 2020-09-02

QUESTIONS & DISCUSSION

DRAFT ACTION PLAN

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DRAFT ROADMAP

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IRP DRAFT ROADMAP

NS Power reviewed slides 59-61 from Draft Findings release 2020-09-02

QUESTIONS & DISCUSSION

DRAFT ROADMAP

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NEXT STEPS

- Stakeholder Comments on Draft Findings are invited (requested by Sept. 18– next Friday)
- Draft IRP Report Circulated – Sept. 29

QUESTIONS & DISCUSSION

GENERAL

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NS POWER 2020 IRP
UPDATED MODELING RESULTS RELEASE

SEPTEMBER 2, 2020

UPDATED SEPTEMBER 18, 2020

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REVISIONS

SEPTEMBER 11

- Scenario 2.0C – corrected a typo in the 25-yr NPVRR (was previously reported as $12,224 – corrected to $12,234)
  - Updated on slides 13, 41, 43, & 45

SEPTEMBER 18

- For certain sensitivity runs, the metric *Total CO_2 Emissions 2031-2045 (MT)* was incorrectly reported in the summary tables in the previous release. The *Total CO_2 Emissions 2021-2030 (MT)* and *Total CO_2 Emissions 2021-2045 (MT)* metrics were not affected, and the CO_2 Emissions graphs and CO_2 Emissions data in the Modeling Results Tables are correct.
  - Updated figures are shown in purple text on slides 35, 37, 39, 41, 45, 47, 51, 57, 59, & 63

TABLE OF CONTENTS

FINAL PORTFOLIO STUDY RESULTS
SCENARIO RESULTS

Nova Scotia POWER An Emera Company

FINAL PORTFOLIO STUDY

- The following slides provide the Final Portfolio Study results from PLEXOS for the key scenarios (full capacity expansion runs in PLEXOS LT, and Generation / Production Cost results from PLEXOS MT/ST hourly simulations)

- The section includes detailed outputs of each scenario including energy mix, nameplate capacity installation, emissions compliance, achieved Planning Reserve Margin (PRM), several metrics of partial NPV of revenue requirement (NPVRR), average annual partial rate impact, and scenario notes

- NPVs presented in these results are partial revenue requirements that consider modeled costs (i.e. production, O&M, abatement, sustaining capital, and capital investment) and specific costs considered outside of the long-term model optimization (e.g. energy efficiency costs)

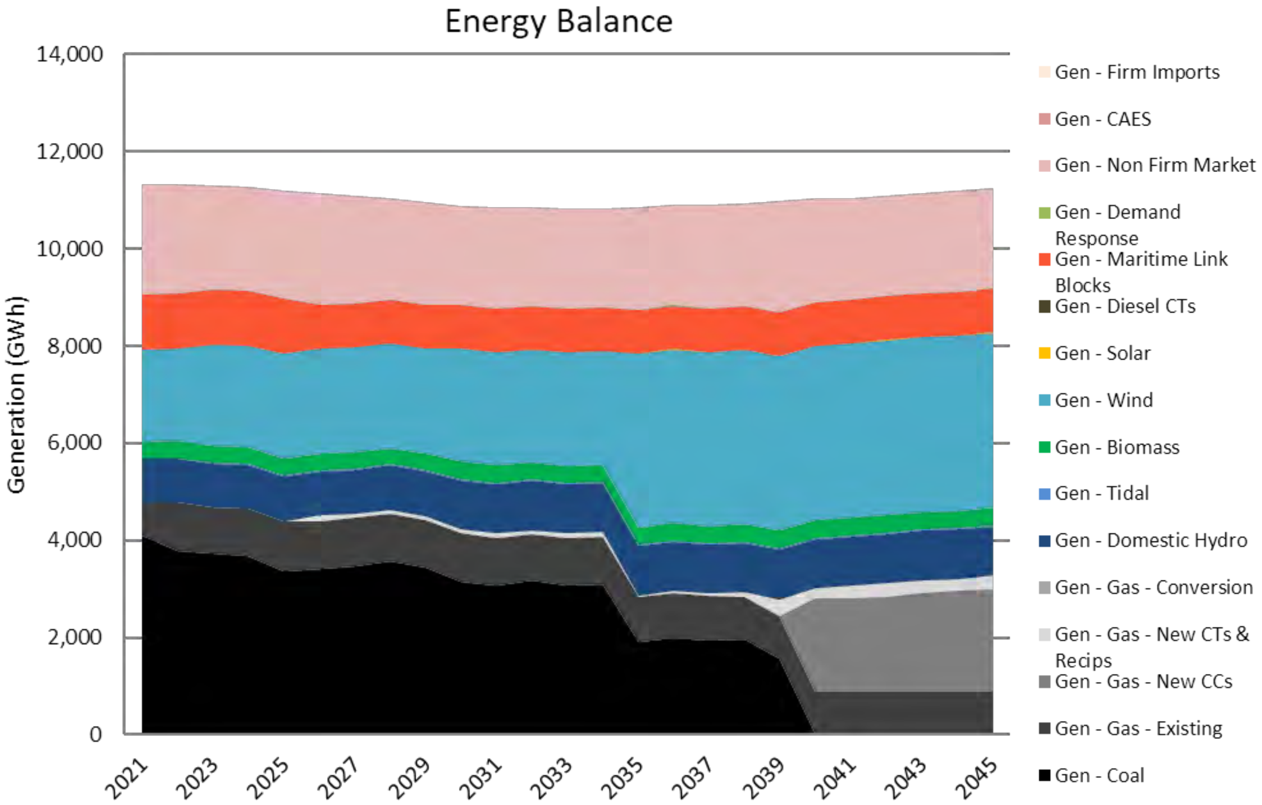
FINAL PORTFOLIO STUDY - METRICS

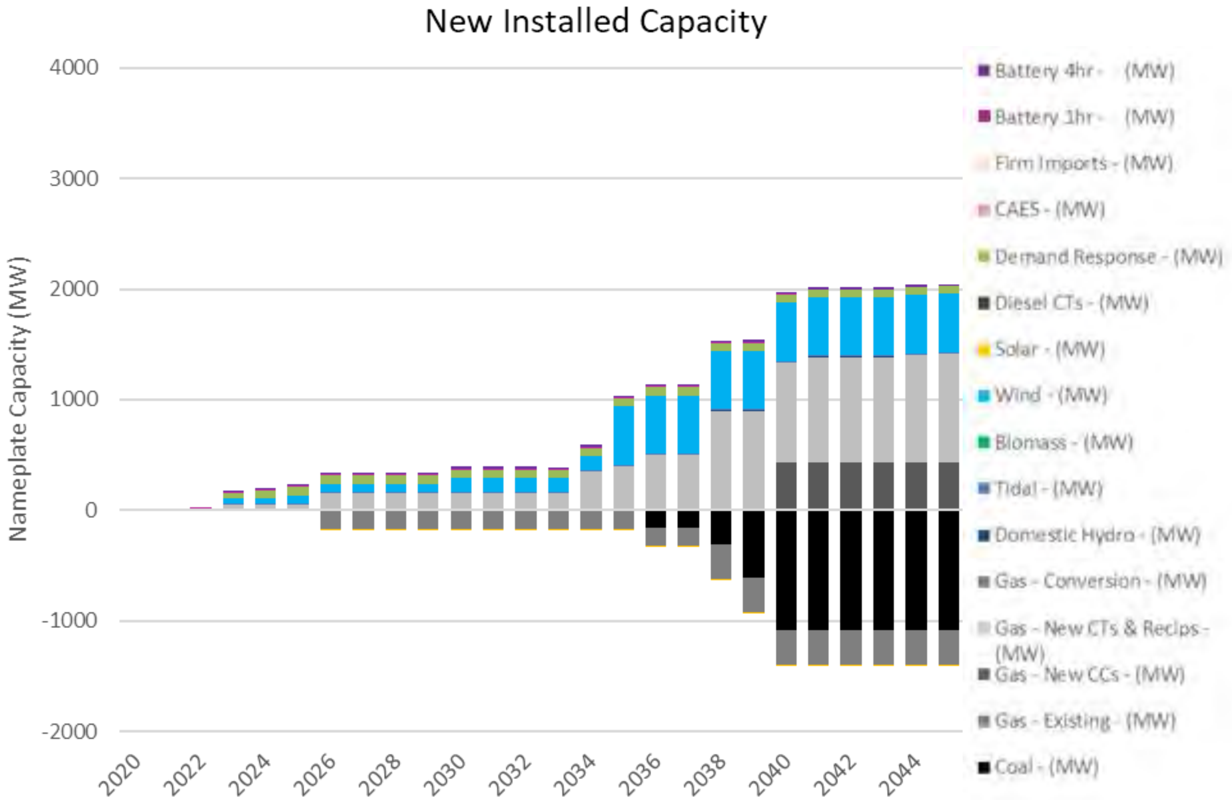
The following metrics are being used to evaluate each portfolio studied; updates from the Scenarios and Modeling Plan release based on ongoing work and stakeholder feedback are shown in purple text.

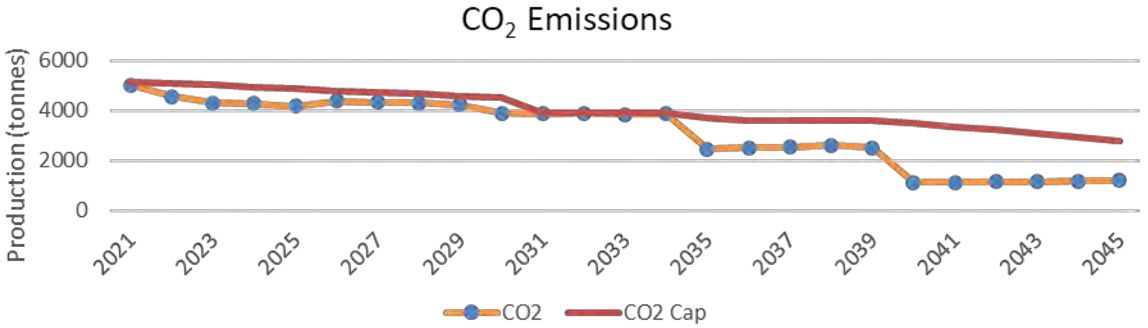
Metric	Description
Minimization of the cumulative present value of the annual revenue requirements over the planning horizon (with and without end-effects adjustment)	25 year NPV Revenue Requirement Average Annual Partial Rate Impact - 25-yr
Magnitude and timing of electricity rate effects	10 year NPV Revenue Requirement Average Annual Partial Rate Impact - 10-yr
Reliability requirements for supply adequacy	Evaluation of PRM, resource capacity adequacy, operating reserve requirements, etc.
Provision of essential grid services for system stability and reliability	Quantitative and qualitative assessment of the status of essential grid services provision for each portfolio. Many plans are similar in this respect, so only key differences will be noted at this time.
Plan robustness (the ability of a plan to withstand plausible potential changes to key assumptions)	Magnitude of the plan's exposure to changes in key assumptions (via sensitivity analysis) as well as resiliency to risks
Reduction of greenhouse gas and/or other emissions	Quantitative reductions as output by Plexos; total emissions over planning horizon.
Flexibility (limitation of constraints on future decisions arising from the selection of a particular path)	Qualitative assessment of timing of investments

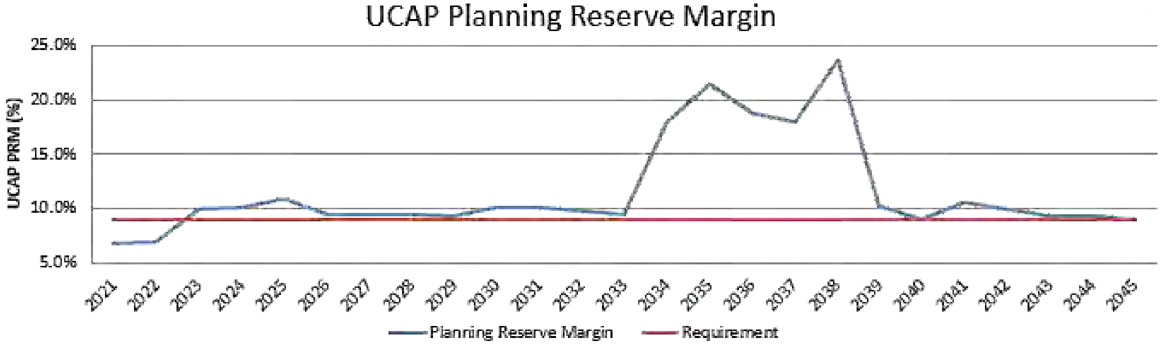
1.0A

LOW ELEC. / BASE DSM / COMPARATOR EMISSIONS / CURRENT LANDSCAPE









1.0A

LOW ELEC. / BASE DSM / COMPARATOR EMISSIONS / CURRENT LANDSCAPE

Scenario Metrics & Evaluation

25-yr NPVRR ($MM)	$12,419	
25-yr NPVRR with End Effects ($MM)	$16,692	
10-yr NPVRR ($MM)	$6,850	
Average Annual Partial Rate Impact		
2021-2030 (%)	0.8%	
2021-2045 (%)	1.0%	
Total CO_2 Emissions 2021-2030 (MT)	43.5	
Total CO_2 Emissions 2031-2045 (MT)	35.0	
Total CO_2 Emissions 2021-2045 (MT)	78.5	

General Notes
- Coal capacity replaced with new gas CCGT and CT units in late 2030s
- Reliability Tie is built and enables additional economic wind generation in 2035

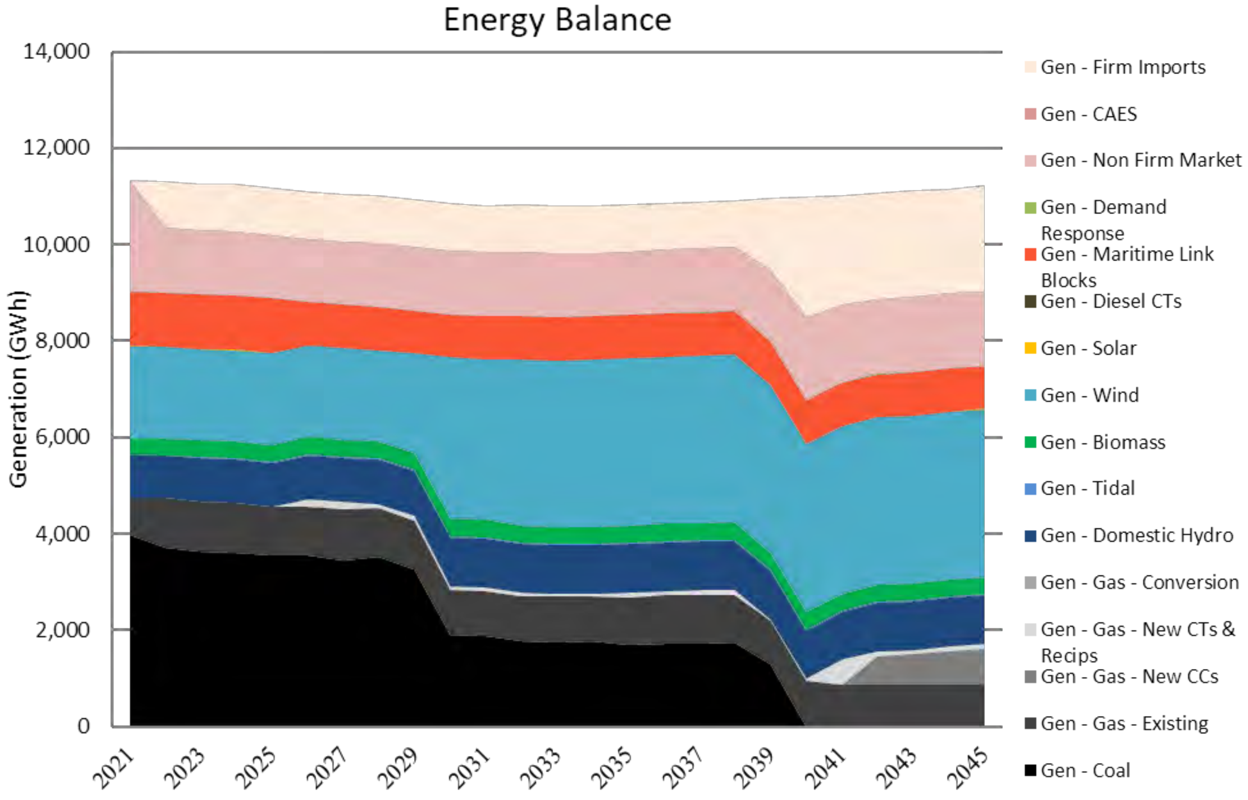
Essential Grid Services
- Essential Grid Service requirements are met as modeled

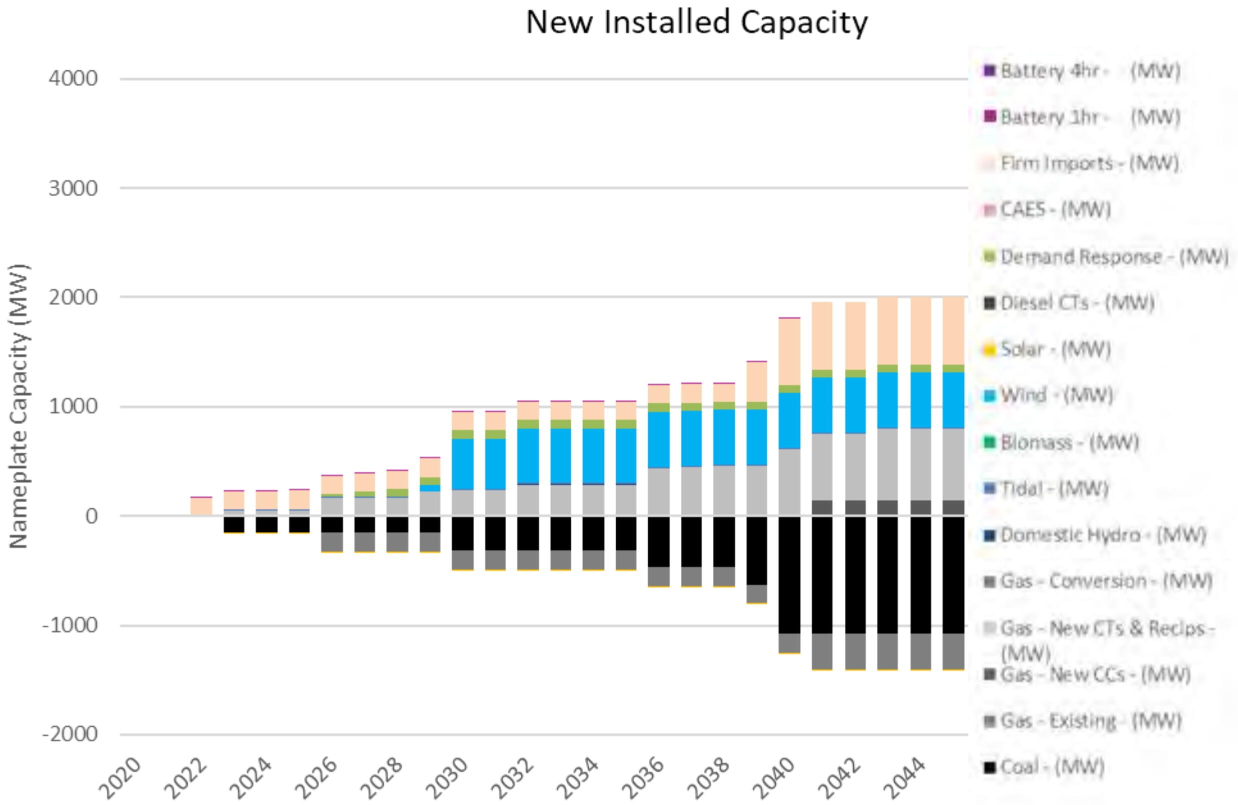
Resource Adequacy & PRM
- Reliability Tie: 2035
- Regional Integration: n/a

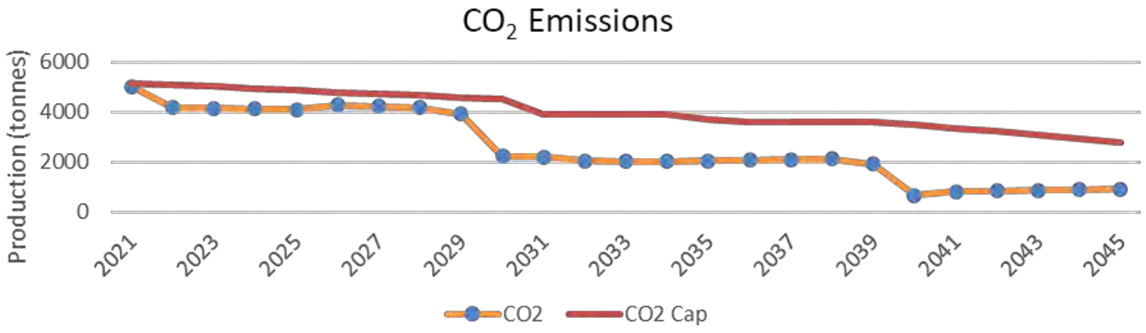
Plan Robustness & Flexibility
- No reliance on firm import energy or capacity
- Not compliant with Sustainable Development Goals Act
- More exposure to natural gas prices with 435MW NGCC capacity in 2040s

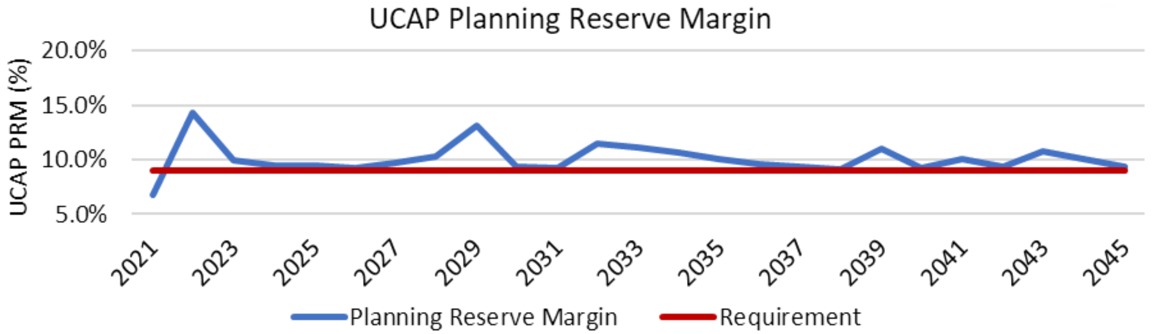
1.0C

LOW ELEC. / BASE DSM / COMPARATOR EMISSIONS / REGIONAL INTEGRATION









1.0C

LOW ELEC. / BASE DSM / COMPARATOR EMISSIONS / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

25-yr NPVRR ($MM)	$12,190
25-yr NPVRR with End Effects ($MM)	$16,167
10-yr NPVRR ($MM)	$6,811
Average Annual Partial Rate Impact	
2021-2030 (%)	0.9%
2021-2045 (%)	0.8%
Total CO_2 Emissions 2021-2030 (MT)	40.4
Total CO_2 Emissions 2031-2045 (MT)	23.5
Total CO_2 Emissions 2021-2045 (MT)	63.8

General Notes
- Incremental firm imports enable an economic coal unit retirement in the 2020s
- Reliability Tie in 2030 enables additional wind integration earlier than seen in previous results
- Regional Interconnection constructed in 2039 allows remaining coal retirements

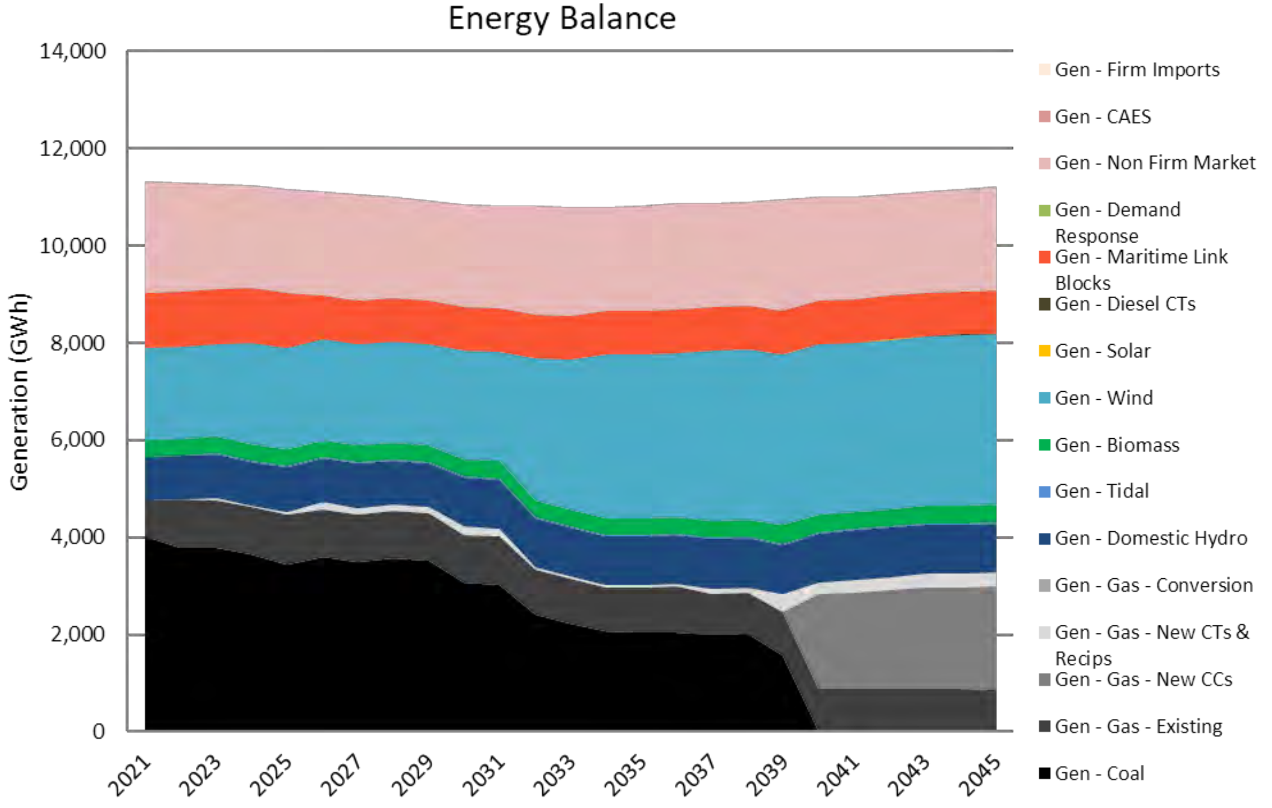
Essential Grid Services
- Essential Grid Service requirements are met as modeled

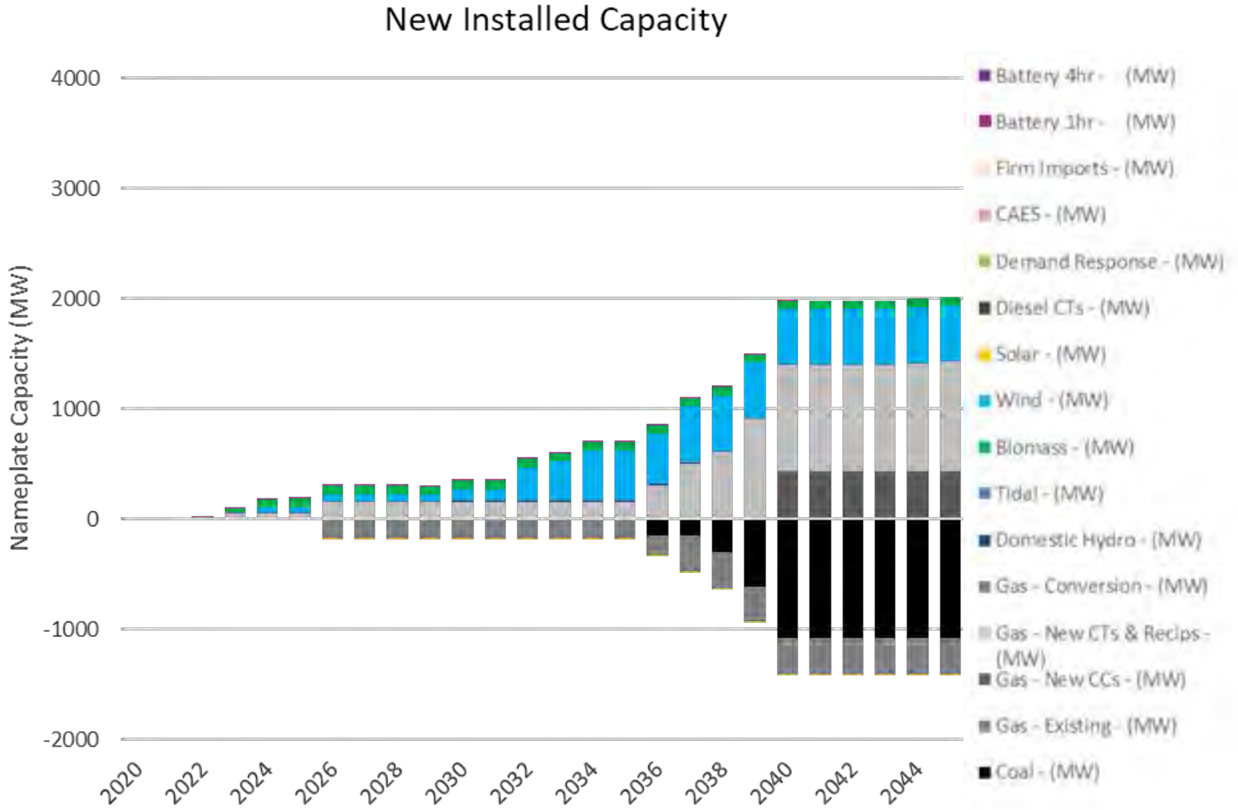
Resource Adequacy & PRM
- Reliability Tie: 2030
- Regional Integration: 2039

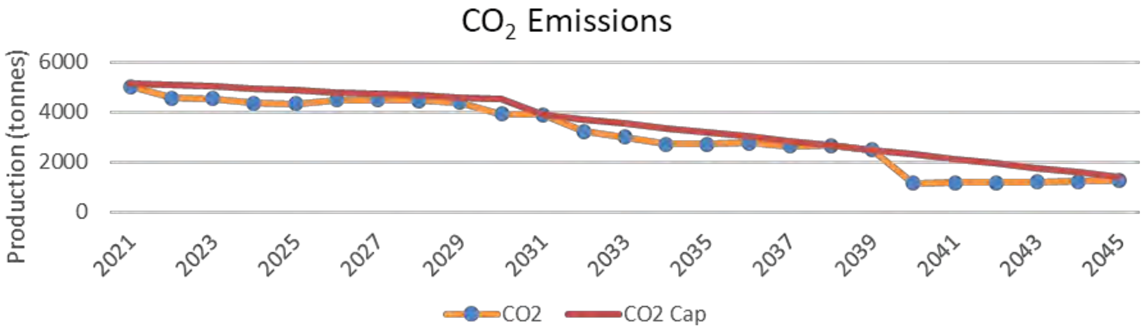
Plan Robustness & Flexibility
- Not compliant with Sustainable Development Goals Act
- Regional Integration provides flexible ability to meet emissions constraints

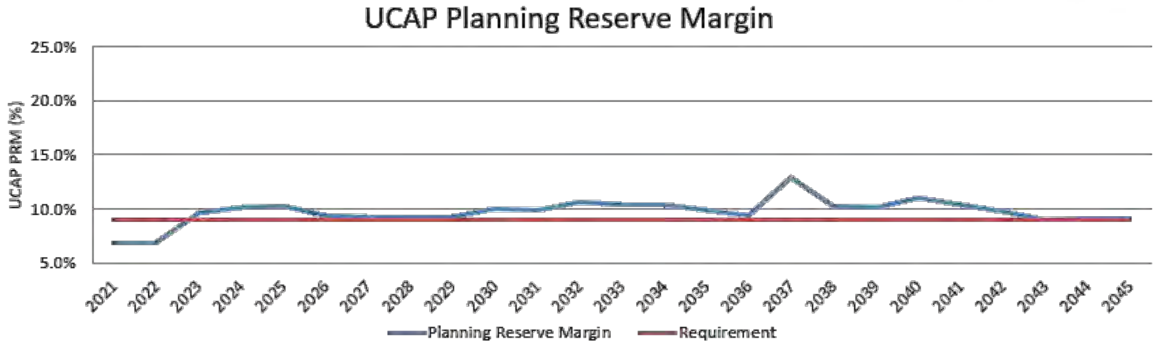
2.0A

LOW ELEC. / BASE DSM / NET ZERO 2050 / CURRENT LANDSCAPE









2.0A

LOW ELEC. / BASE DSM / NET ZERO 2050 / CURRENT LANDSCAPE

Scenario Metrics & Evaluation

25-yr NPVRR ($MM)	$12,351
25-yr NPVRR with End Effects ($MM)	$16,609
10-yr NPVRR ($MM)	$6,831
Average Annual Partial Rate Impact	
2021-2030 (%)	0.9%
2021-2045 (%)	1.0%
Total CO_2 Emissions 2021-2030 (MT)	44.5
Total CO_2 Emissions 2031-2045 (MT)	33.2
Total CO_2 Emissions 2021-2045 (MT)	77.7

General Notes
- Reliability Tie built in 2030 enables wind integration; does not provide firm capacity or energy access

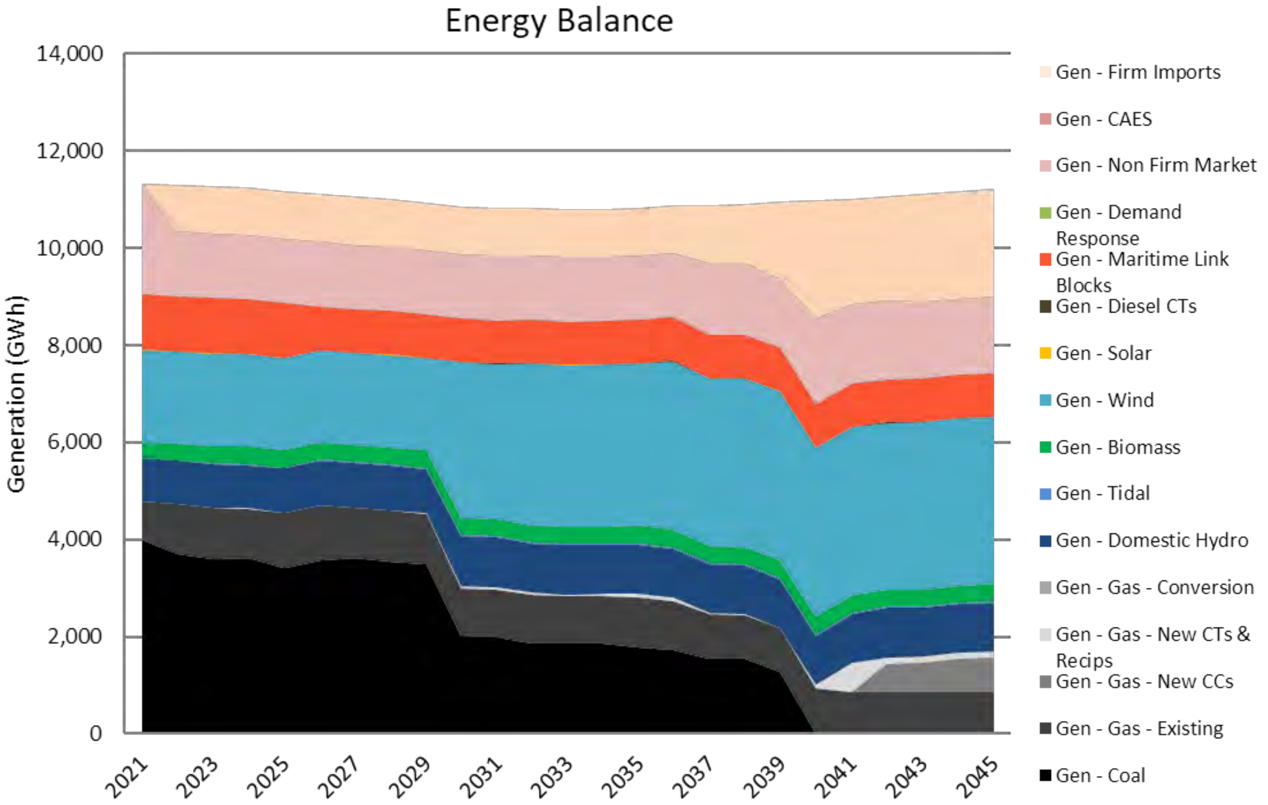
Essential Grid Services
- Essential Grid Service requirements are met as modeled

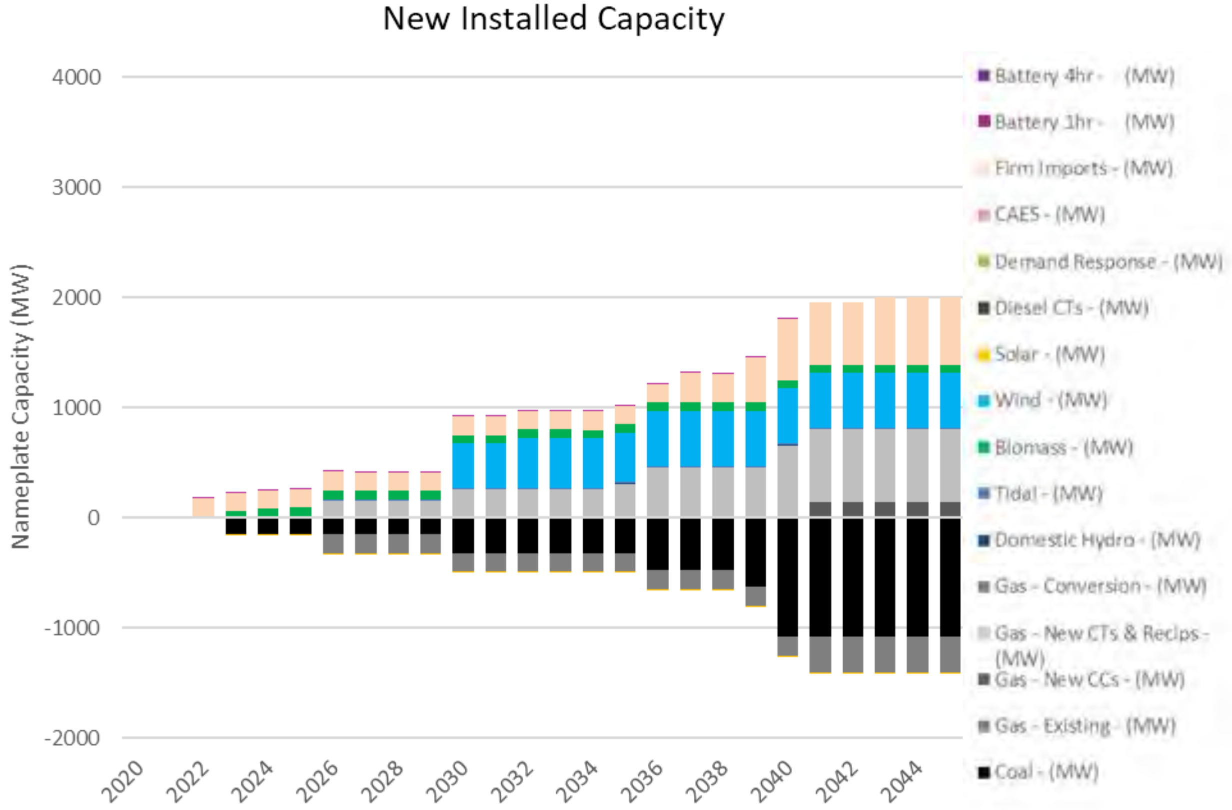
Resource Adequacy & PRM
- Reliability Tie: 2032
- Regional Integration: n/a

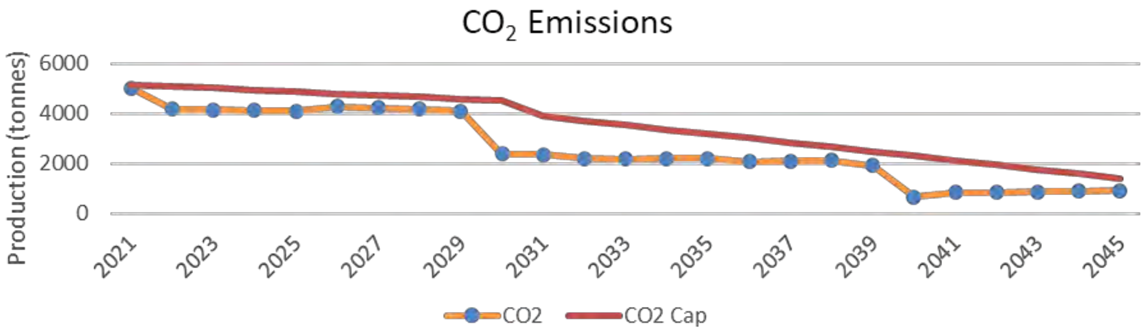
Plan Robustness & Flexibility
- No reliance on firm import energy or capacity
- More exposure to natural gas prices with 435MW NGCC capacity in 2040s

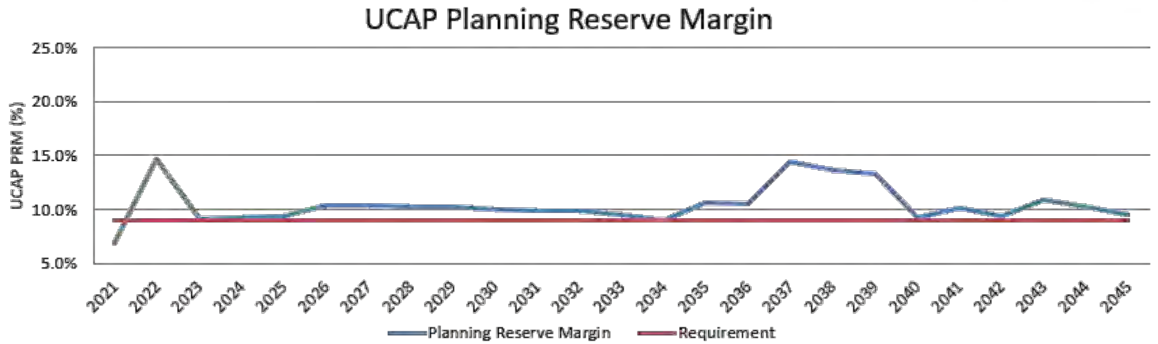
2.0C

LOW ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION









2.0C

LOW ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

25-yr NPVRR ($MM)	$12,234	
25-yr NPVRR with End Effects ($MM)	$16,241	
10-yr NPVRR ($MM)	$6,820	
Average Annual Partial Rate Impact		
2021-2030 (%)	0.9%	
2021-2045 (%)	0.9%	
Total CO_2 Emissions 2021-2030 (MT)	40.7	
Total CO_2 Emissions 2031-2045 (MT)	24.3	
Total CO_2 Emissions 2021-2045 (MT)	65.0	

General Notes
- Capacity expansion and generation are very similar to 1.0C case but with SDGA compliant GHG curve

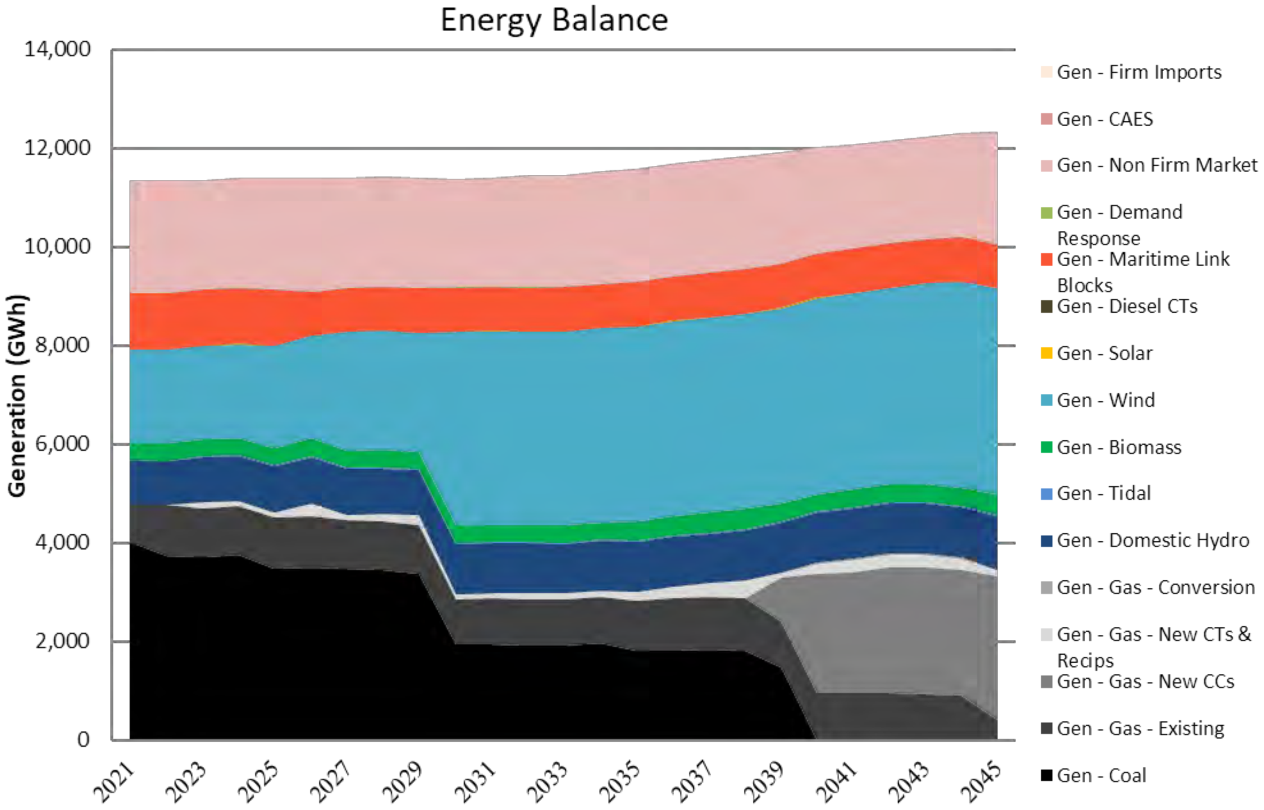
Essential Grid Services
- Essential Grid Service requirements are met as modeled

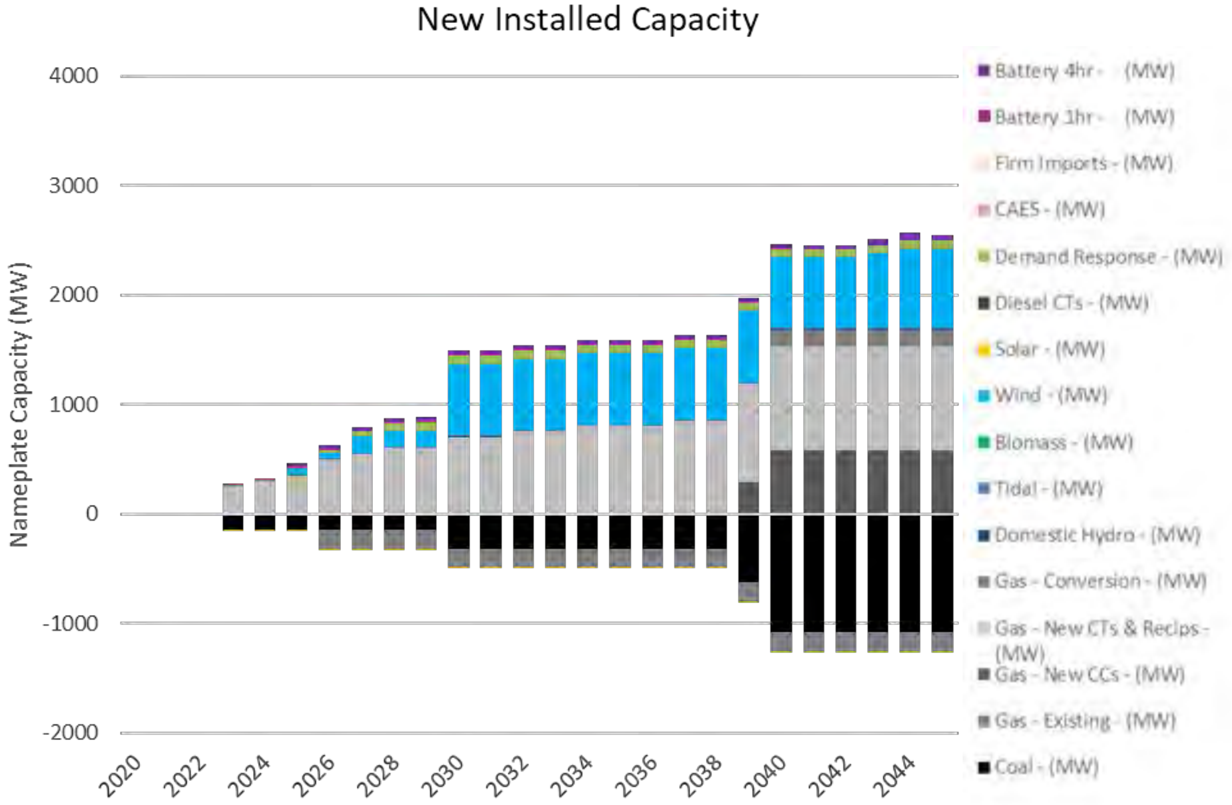
Resource Adequacy & PRM
- Reliability Tie: 2030
- Regional Integration: 2037

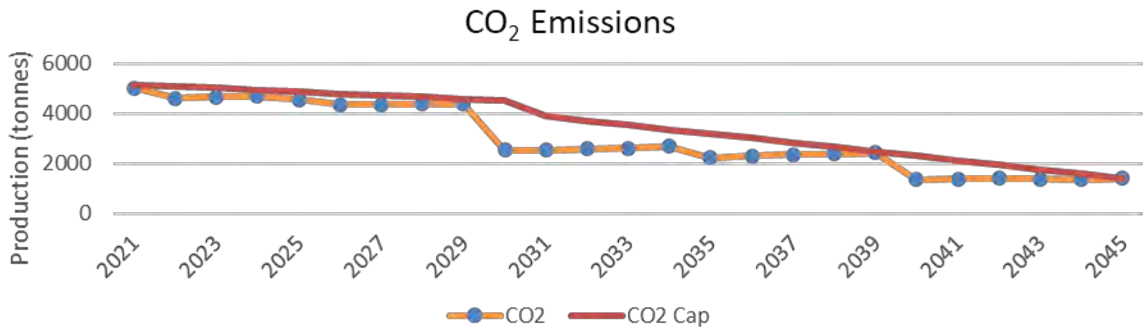
Plan Robustness & Flexibility
- Regional Integration provides flexible ability to meet emissions constraints

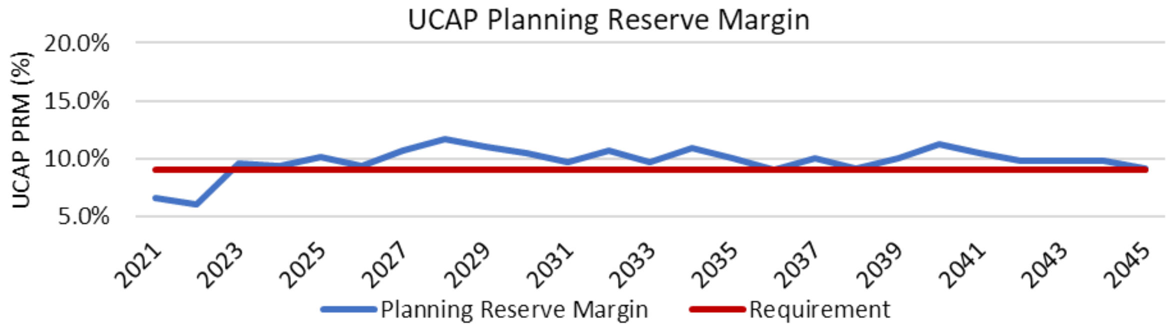
2.1A

MID ELEC. / BASE DSM / NET ZERO 2050 / CURRENT LANDSCAPE









2.1A

MID ELEC. / BASE DSM / NET ZERO 2050 / CURRENT LANDSCAPE

Scenario Metrics & Evaluation

25-yr NPVRR ($MM)	$13,353
25-yr NPVRR with End Effects ($MM)	$18,264
10-yr NPVRR ($MM)	$7,100
Average Annual Partial Rate Impact	
2021-2030 (%)	0.8%
2021-2045 (%)	0.8%
Total CO_2 Emissions 2021-2030 (MT)	43.6
Total CO_2 Emissions 2031-2045 (MT)	30.3
Total CO_2 Emissions 2021-2045 (MT)	73.9

General Notes
- Reliability Tie built in 2031 enables wind integration but does not provide firm capacity or energy access
- Gas CT builds provide capacity to support early electrification load growth; energy is supplied by wind and non-firm imports, and CCGT when coal units retire
- 1 coal unit converted to gas in 2040

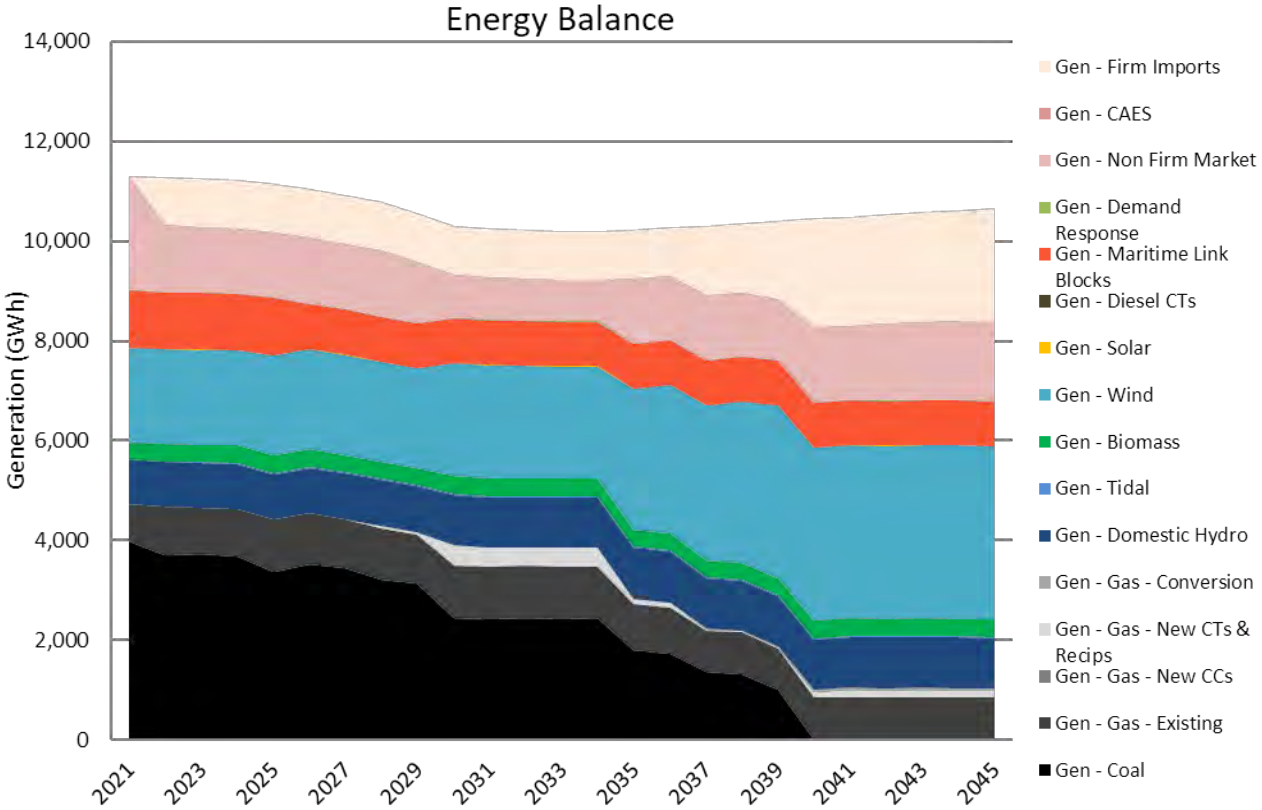
Essential Grid Services
- Essential Grid Service requirements are met as modeled

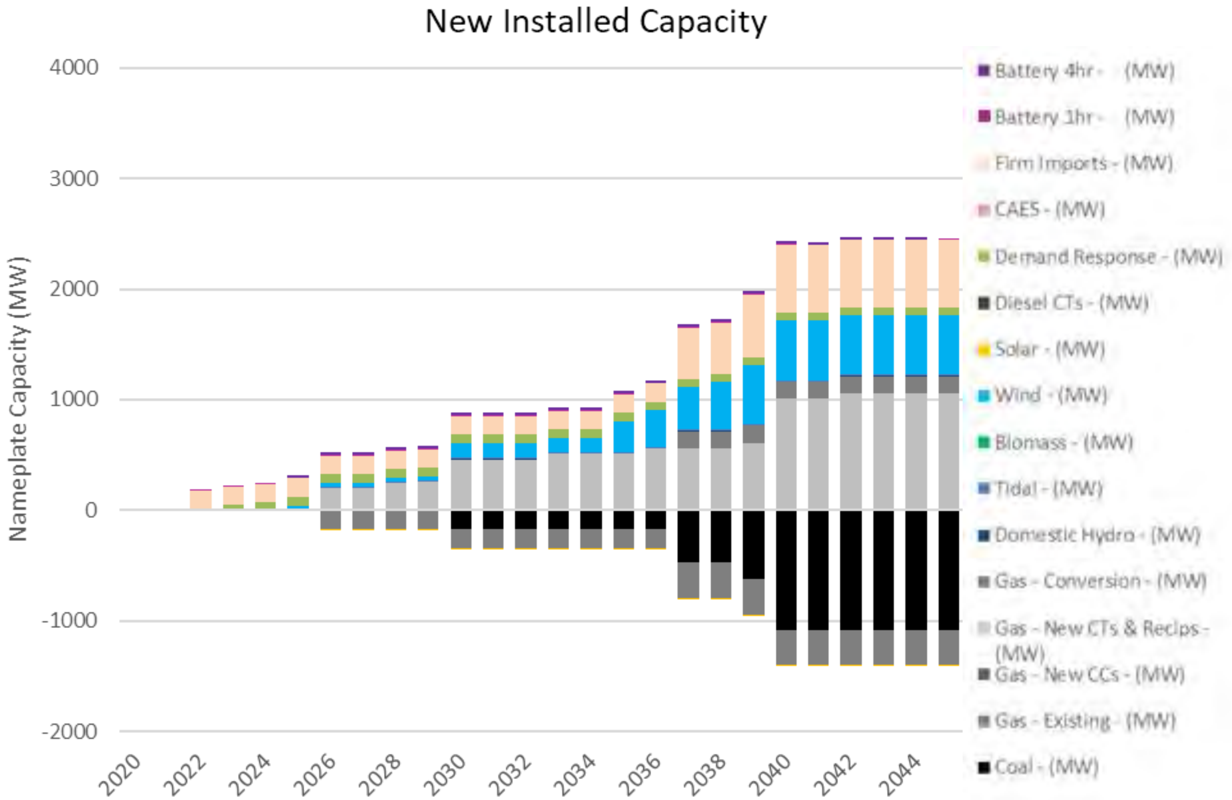
Resource Adequacy & PRM
- Reliability Tie: 2030
- Regional Integration: n/a

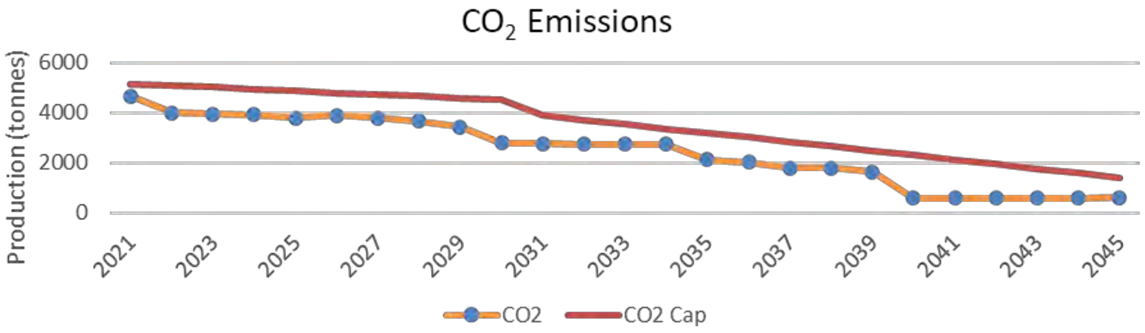
Plan Robustness & Flexibility
- No reliance on firm import energy or capacity
- More exposure to natural gas prices with 435MW NGCC capacity in 2040s

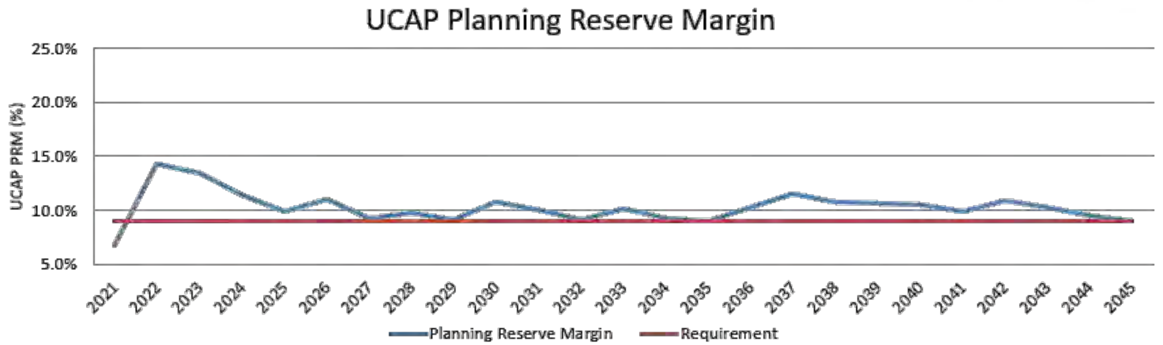
2.1B

MID ELEC. / BASE DSM / NET ZERO 2050 / DISTRIBUTED RESOURCES









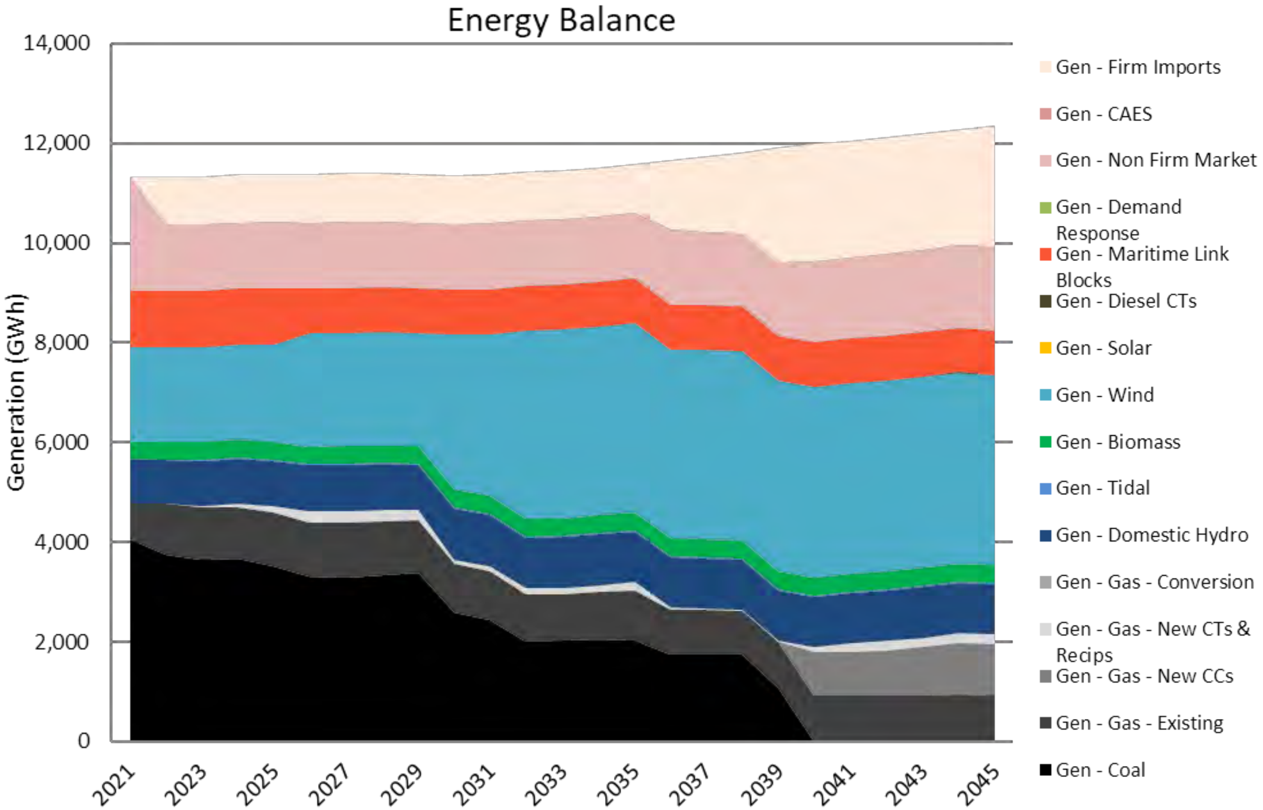
2.1B

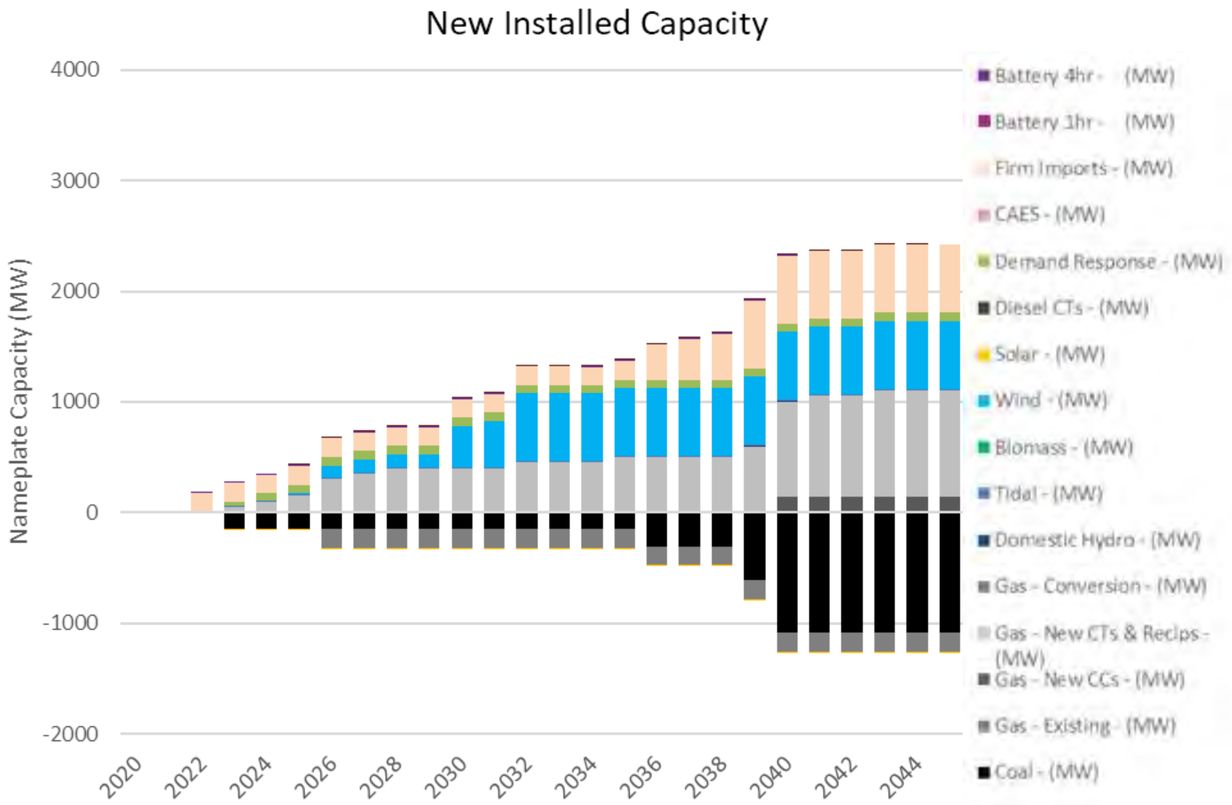
MID ELEC. / BASE DSM / NET ZERO 2050 / DISTRIBUTED RESOURCES

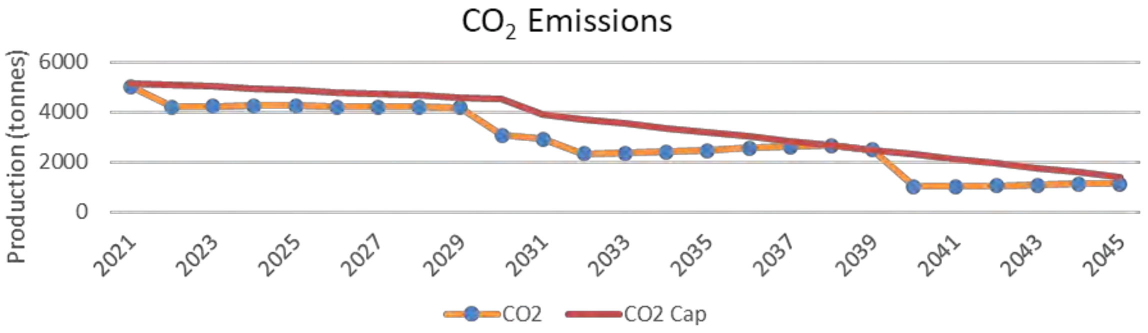
Scenario Metrics & Evaluation		
25-yr NPVRR ($MM)	$12,479	General Notes • DER is modeled as a load reduction; cost of DER resources not included in NPV calculations ($1.6B - $2.5B) • 1 coal unit converted to gas in 2037 Essential Grid Services • Essential Grid Service requirements are met as modeled Resource Adequacy & PRM • Reliability Tie: 2035 • Regional Integration: 2037 Plan Robustness & Flexibility • Regional Integration provides flexible ability to meet emissions constraints
25-yr NPVRR with End Effects ($MM)	$16,573	
10-yr NPVRR ($MM)	$6,949	
Average Annual Partial Rate Impact 2021-2030 (%) 2021-2045 (%)	 1.9% 1.2%	
Total CO_2 Emissions 2021-2030 (MT) Total CO_2 Emissions 2031-2045 (MT) Total CO_2 Emissions 2021-2045 (MT)	37.9 23.8 61.7	

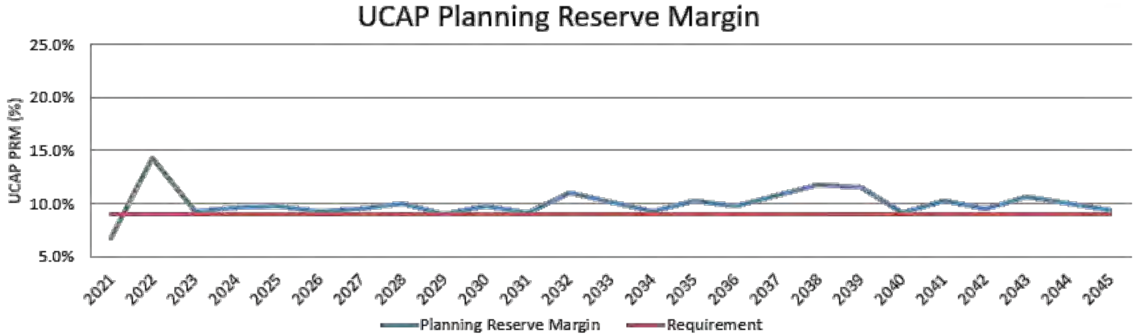
2.1C

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION









2.1C

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

25-yr NPVRR ($MM)	$13,141	
25-yr NPVRR with End Effects ($MM)	$17,767	
10-yr NPVRR ($MM)	$7,067	
Average Annual Partial Rate Impact 2021-2030 (%) 2021-2045 (%)	 0.6% 0.7%	
Total CO_2 Emissions 2021-2030 (MT) Total CO_2 Emissions 2031-2045 (MT) Total CO_2 Emissions 2021-2045 (MT)	41.8 29.1 70.9	

General Notes
- Reliability Tie built in 2031 (earlier than previous runs) enables wind integration
- 1 coal unit retired economically in 2020s
- 1 less combined cycle unit in 2040 than seen in previous runs

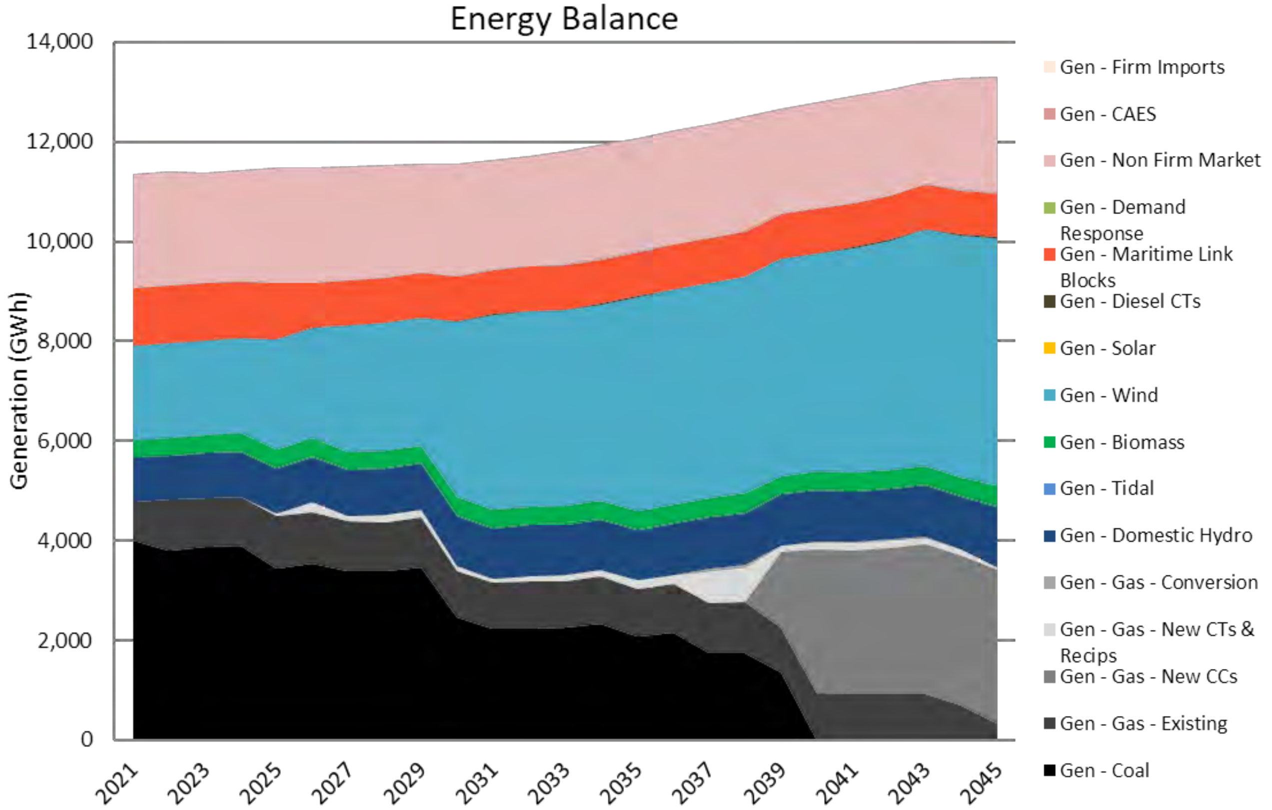
Essential Grid Services
- Essential Grid Service requirements are met as modeled

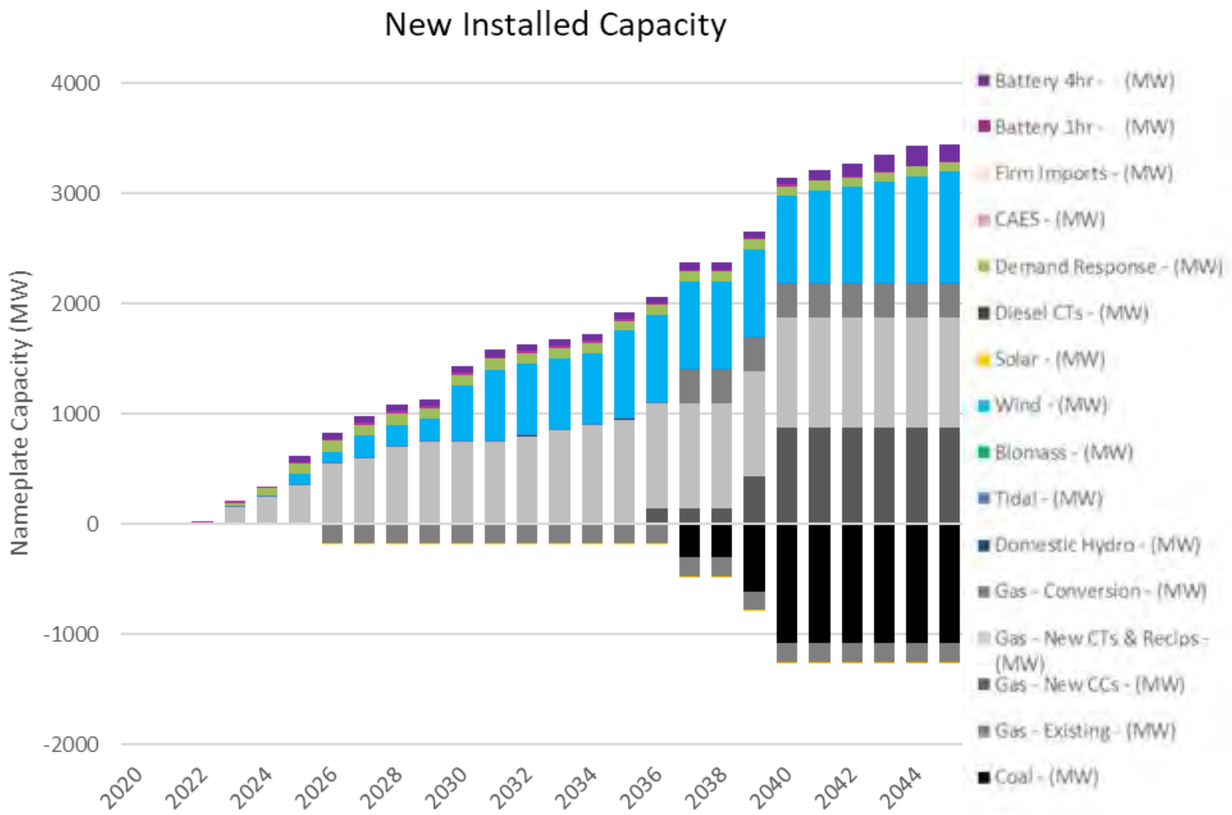
Resource Adequacy & PRM
- Reliability Tie: 2030
- Regional Integration: 2036

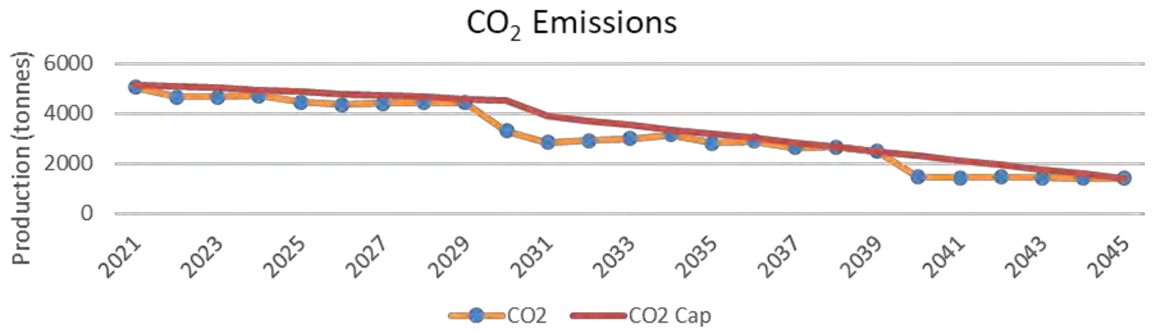
Plan Robustness & Flexibility
- Regional Integration provides flexible ability to meet emissions constraints

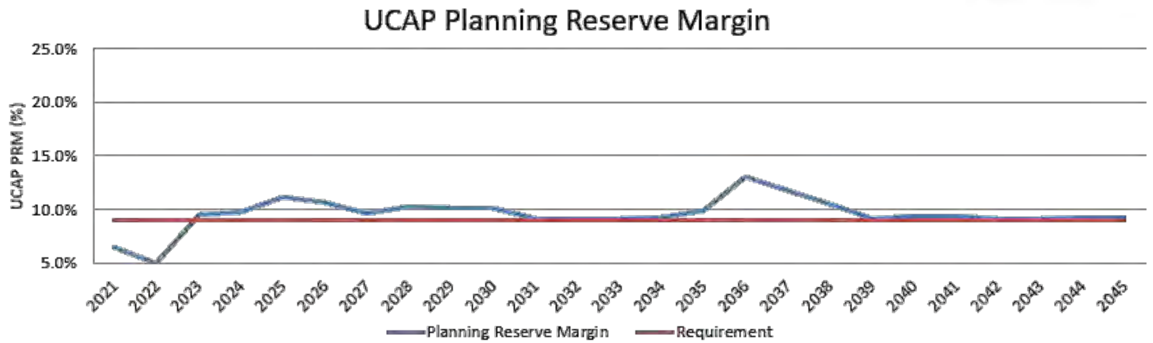
2.2A

HIGH ELEC. / BASE DSM / NET ZERO 2050 / CURRENT LANDSCAPE









2.2A

HIGH ELEC. / BASE DSM / NET ZERO 2050 / CURRENT LANDSCAPE

Scenario Metrics & Evaluation

25-yr NPVRR ($MM)	$15,656
25-yr NPVRR with End Effects ($MM)	$21,627
10-yr NPVRR ($MM)	$8,232
Average Annual Partial Rate Impact	
2021-2030 (%)	1.4%
2021-2045 (%)	1.0%
Total CO_2 Emissions 2021-2030 (MT)	44.4
Total CO_2 Emissions 2031-2045 (MT)	33.9
Total CO_2 Emissions 2021-2045 (MT)	78.3

General Notes
- Early load growth served by incremental gas CTs and non firm import energy
- Reliability Tie built in 2030 (earlier than previous runs) enables wind integration
- Additional wind is integrated with local mitigation
- 2 coal units converted to gas in 2037

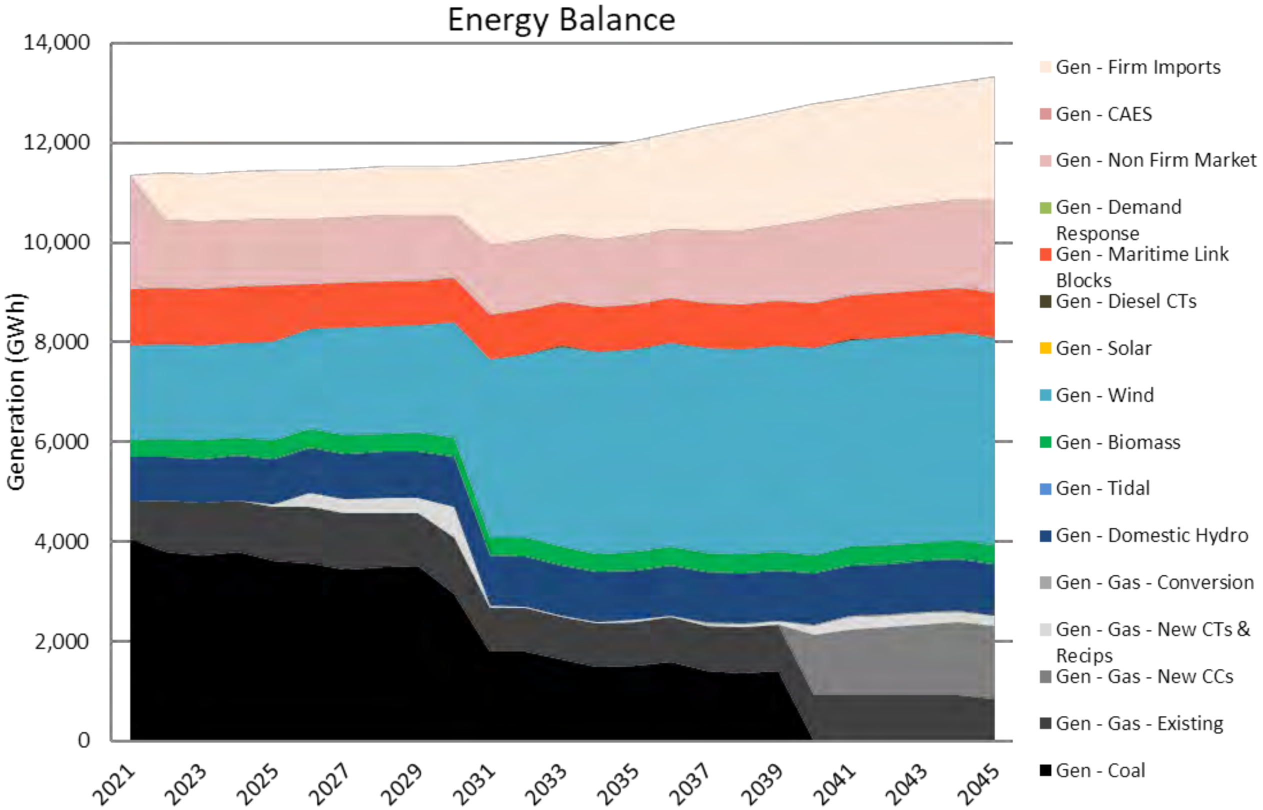
Essential Grid Services
- Essential Grid Service requirements are met as modeled

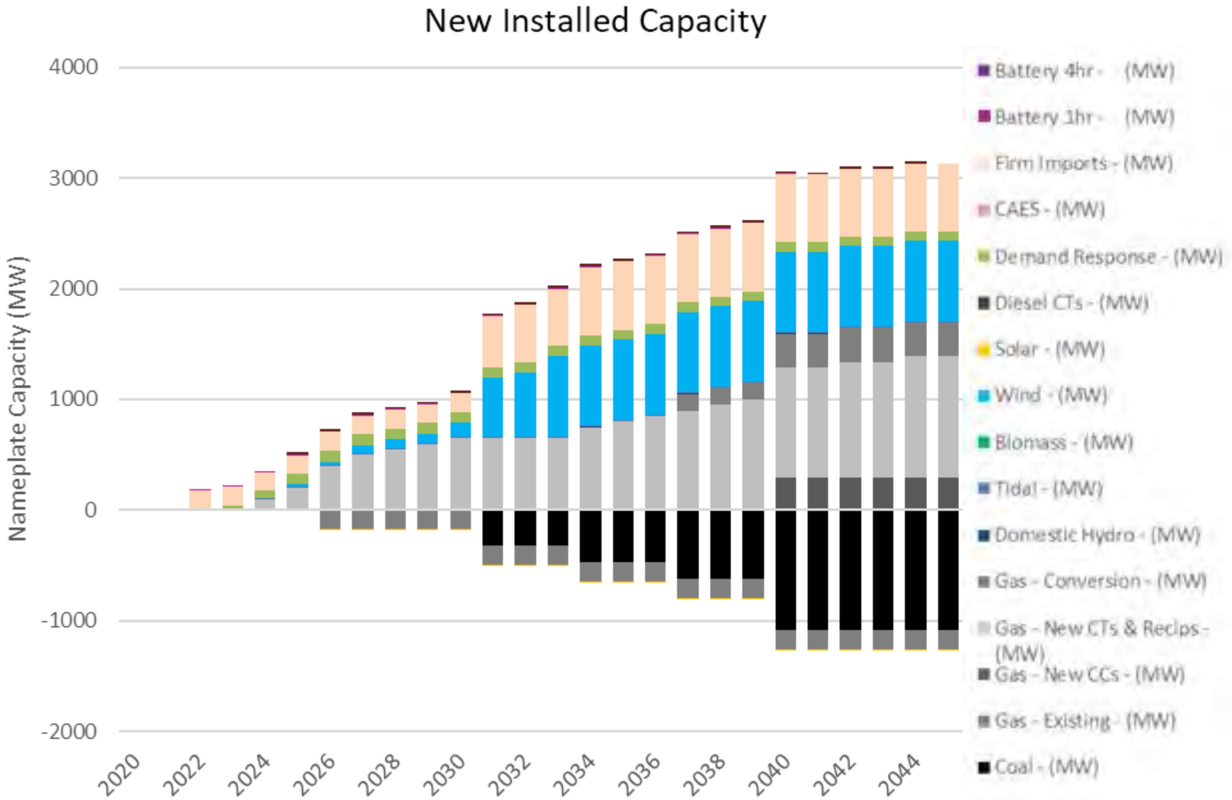
Resource Adequacy & PRM
- Reliability Tie: 2030
- Regional Integration: n/a

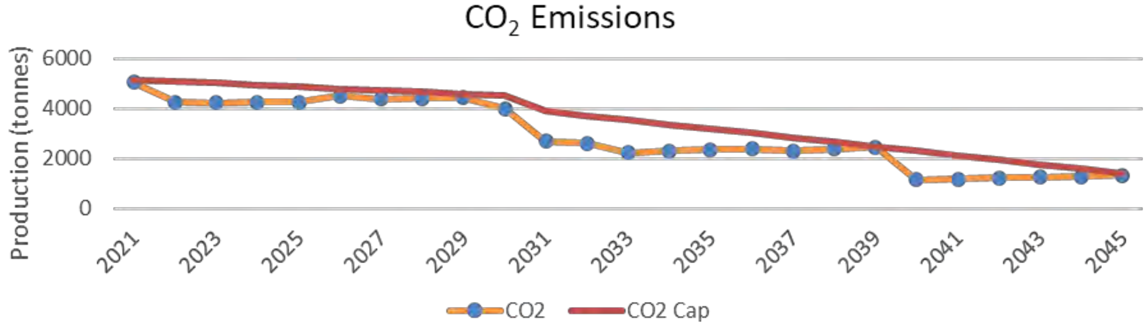
Plan Robustness & Flexibility
- No reliance on firm import energy or capacity
- Significant exposure to natural gas prices with NGCC and gas conversion builds
- Limited ability to adjust sources of supply as existing import options are maximized

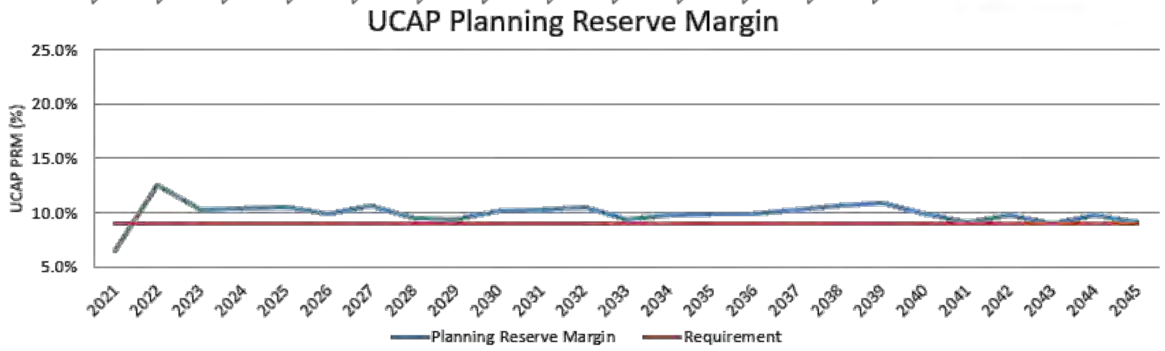
2.2C

HIGH ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION









2.2C

HIGH ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

25-yr NPVRR ($MM)	$15,380
25-yr NPVRR with End Effects ($MM)	$20,945
10-yr NPVRR ($MM)	$8,201
Average Annual Partial Rate Impact	
2021-2030 (%)	1.3%
2021-2045 (%)	0.8%
Total CO_2 Emissions 2021-2030 (MT)	43.7
Total CO_2 Emissions 2031-2045 (MT)	29.0
Total CO_2 Emissions 2021-2045 (MT)	72.7

General Notes

- Reliability Tie & Regional Interconnection built in 2031 (earlier than in previous runs)
- 2 coal to gas conversions in 2037 & 2040

Essential Grid Services

- Essential Grid Service requirements are met as modeled

Resource Adequacy & PRM

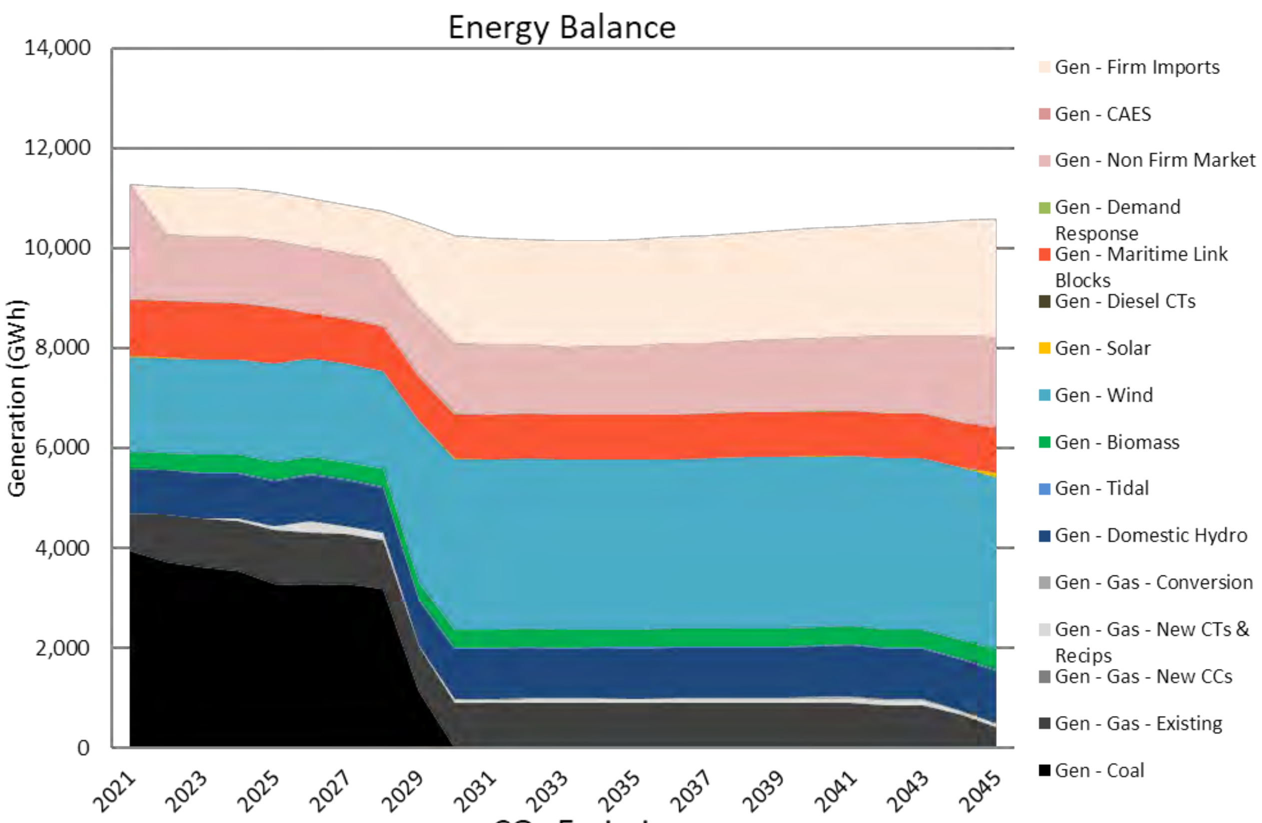
- Reliability Tie: 2031
- Regional Integration: 2031

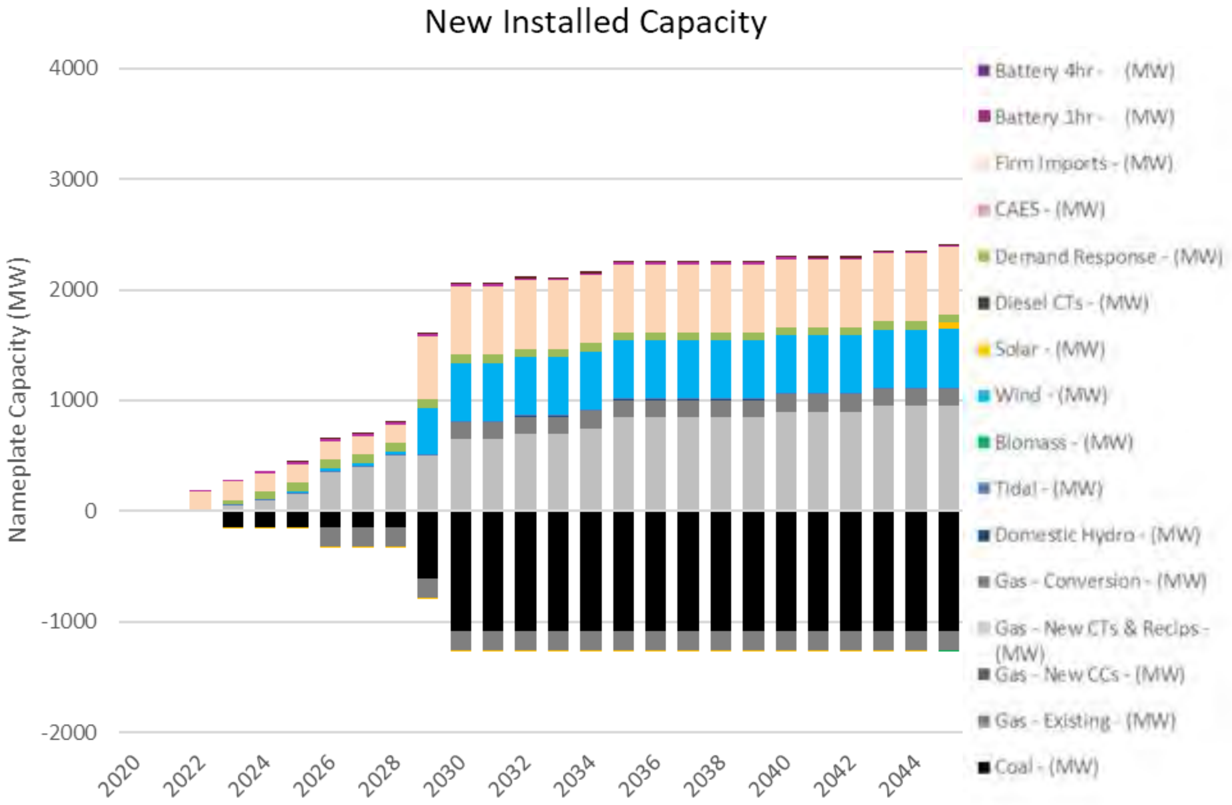
Plan Robustness & Flexibility

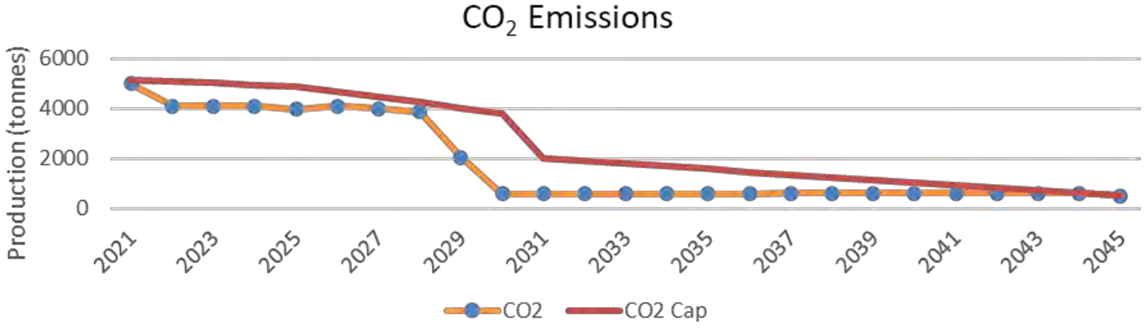
- Regional Integration provides flexible ability to meet emissions constraints

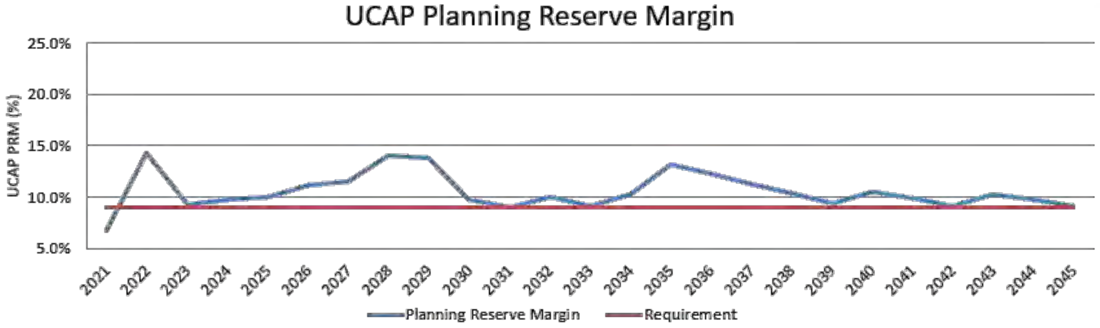
3.1B

MID ELEC. / BASE DSM / ACCEL. NET ZERO 2045 / DISTRIBUTED RESOURCES









3.1B

MID ELEC. / BASE DSM / ACCEL. NET ZERO 2045 / DISTRIBUTED RESOURCES

Scenario Metrics & Evaluation

25-yr NPVRR ($MM)	$12,698
25-yr NPVRR with End Effects ($MM)	$16,754
10-yr NPVRR ($MM)	$6,950
Average Annual Partial Rate Impact	
2021-2030 (%)	2.3%
2021-2045 (%)	1.2%
Total CO_2 Emissions 2021-2030 (MT)	35.8
Total CO_2 Emissions 2031-2045 (MT)	8.8
Total CO_2 Emissions 2021-2045 (MT)	44.7

General Notes
- DER is modeled as a load reduction; cost of DER resources not included in NPV calculations ($1.6B - $2.5B)
- Reliability Tie and Regional Interconnection built in 2029 (earlier than in previous simulations) offsets build of NGCC assets seen in previous modeling results

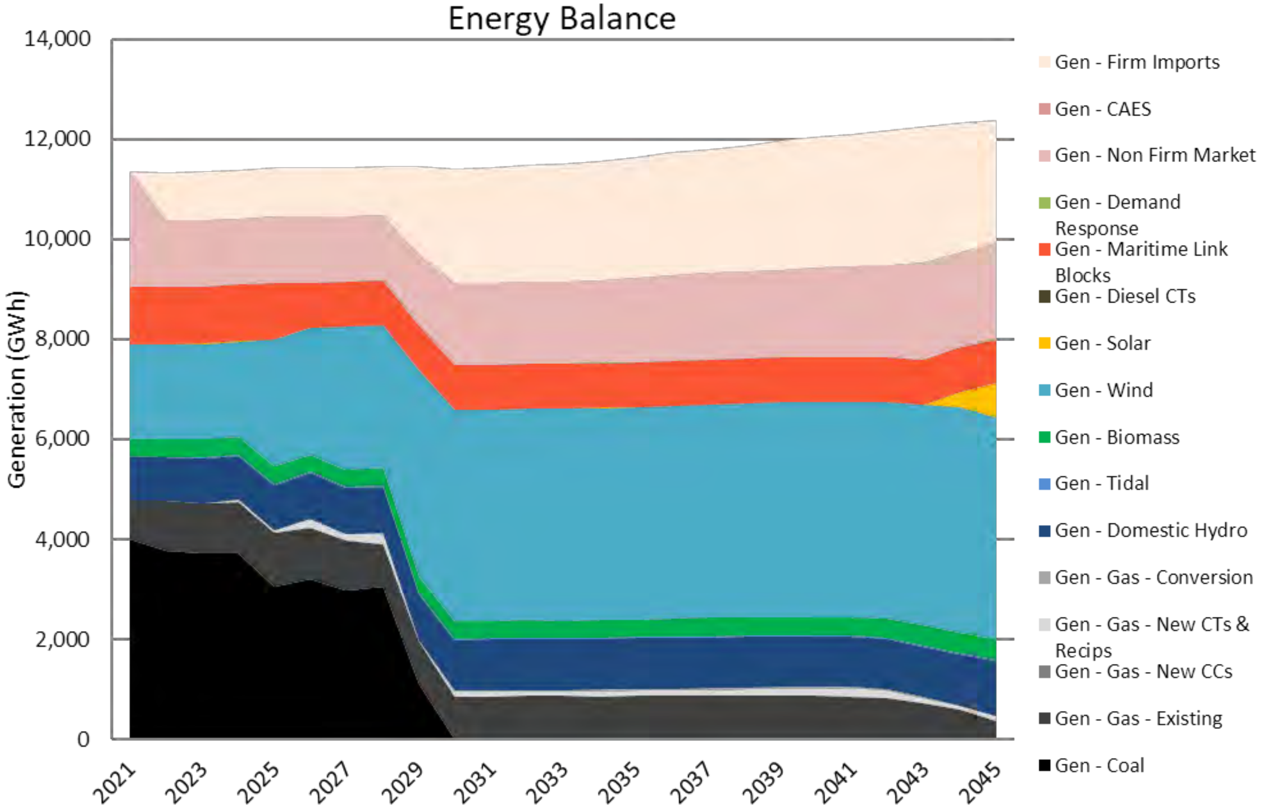
Essential Grid Services
- Essential Grid Service requirements are met as modeled

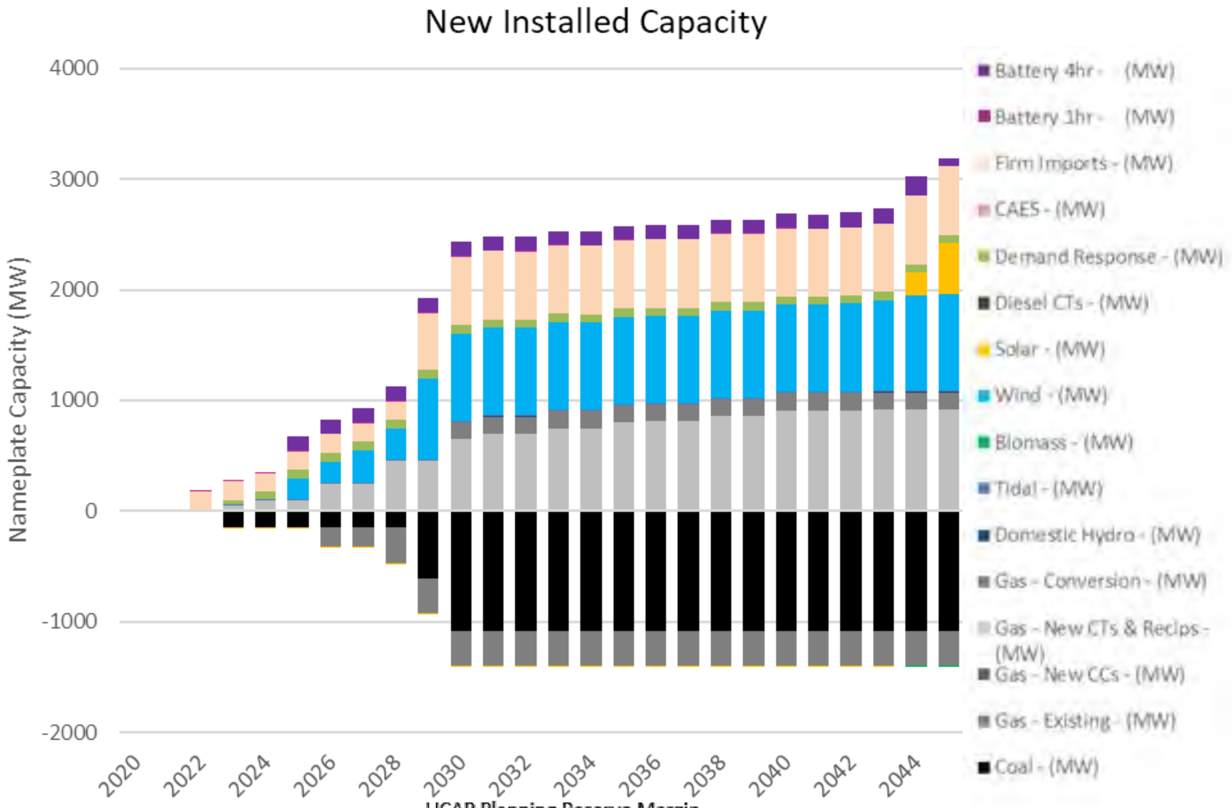
Resource Adequacy & PRM
- Reliability Tie: 2029
- Regional Integration: 2029

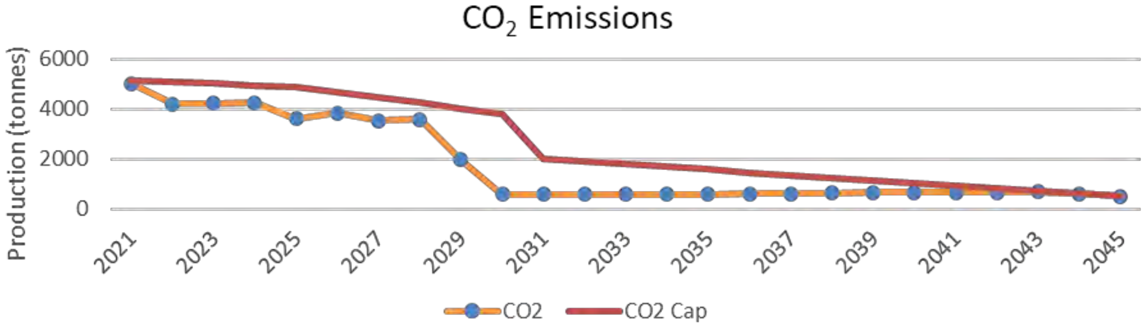
Plan Robustness & Flexibility
- Regional Integration provides flexible ability to meet emissions constraints

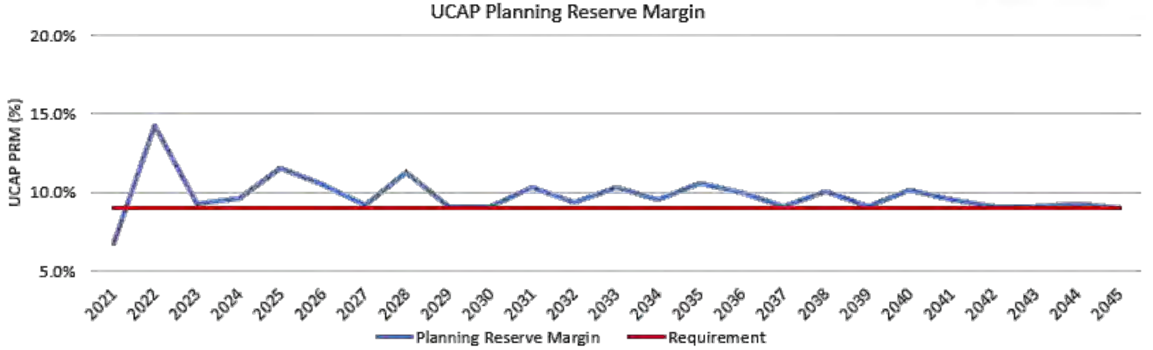
3.1C

MID ELEC. / BASE DSM / ACCEL. NET ZERO 2045 / REGIONAL INTEGRATION









3.1C

MID ELEC. / BASE DSM / ACCEL. NET ZERO 2045 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

25-yr NPVRR ($MM)	$13,734
25-yr NPVRR with End Effects ($MM)	$18,409
10-yr NPVRR ($MM)	$7,224
Average Annual Partial Rate Impact	
2021-2030 (%)	1.4%
2021-2045 (%)	0.7%
Total CO_2 Emissions 2021-2030 (MT)	34.8
Total CO_2 Emissions 2031-2045 (MT)	9.2
Total CO_2 Emissions 2021-2045 (MT)	44.0

General Notes
- 1 coal to gas conversion in 2030
- Regional Interconnection build in 2029
- Solar is added late in the period (2044) as an energy resource

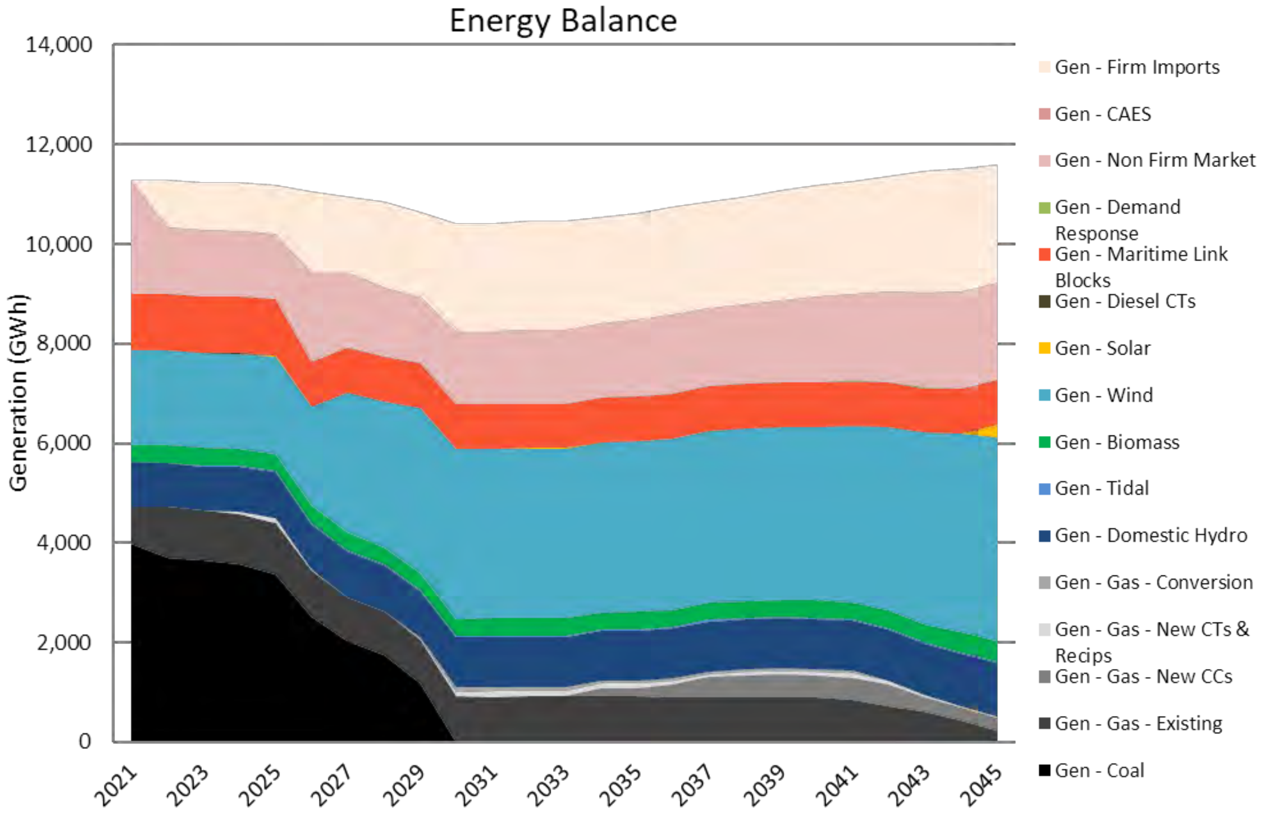
Essential Grid Services
- Essential Grid Service requirements are met as modeled

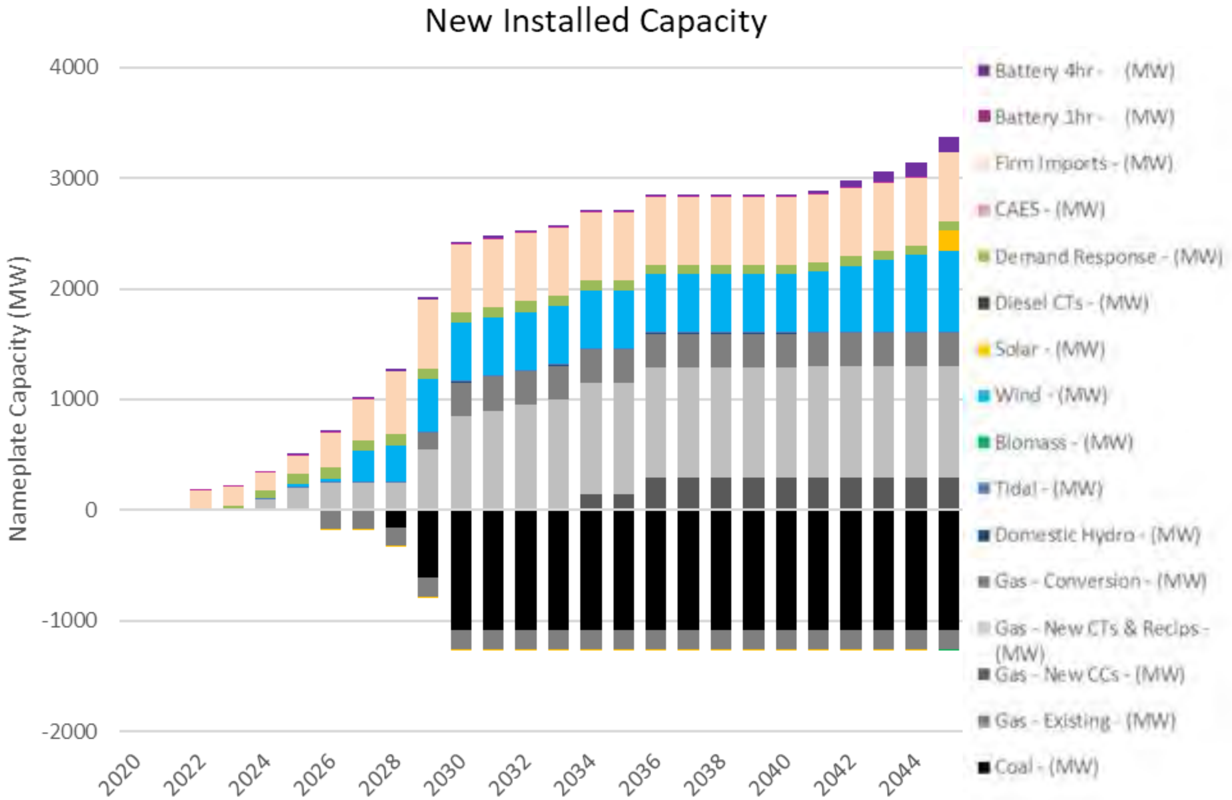
Resource Adequacy & PRM
- Reliability Tie: 2029
- Regional Integration: 2029

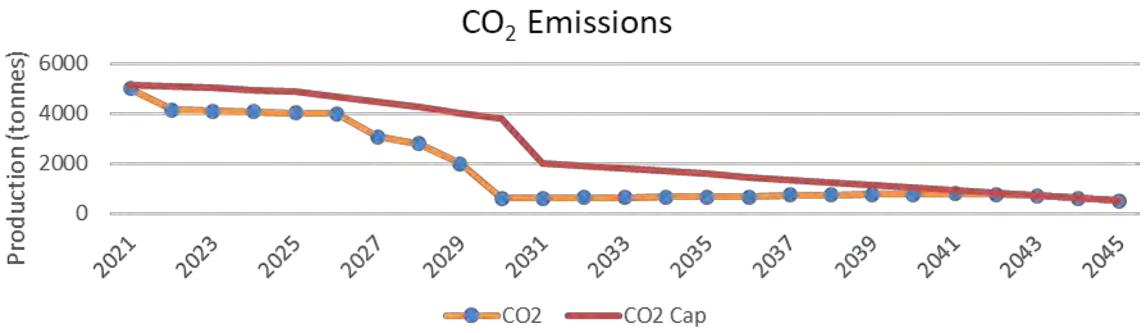
Plan Robustness & Flexibility
- Regional Integration provides flexible ability to meet emissions constraints

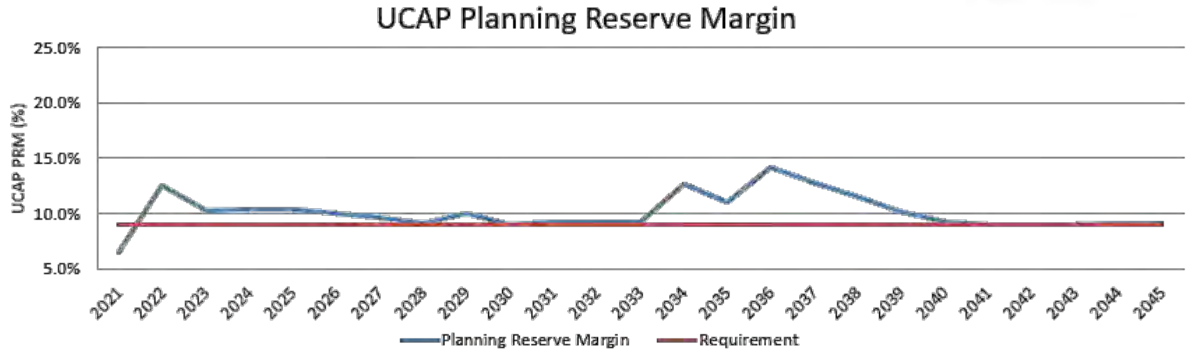
3.2B

HIGH ELEC. / MAX DSM / ACCEL. NET ZERO 2045 / DISTRIBUTED RESOURCES









3.2B

HIGH ELEC. / MAX DSM / ACCEL. NET ZERO 2045 / DISTRIBUTED RESOURCES

Scenario Metrics & Evaluation

25-yr NPVRR ($MM)	$15,045	
25-yr NPVRR with End Effects ($MM)	$20,176	
10-yr NPVRR ($MM)	$8,125	
Average Annual Partial Rate Impact 2021-2030 (%) 2021-2045 (%)	 2.9% 1.3%	
Total CO_2 Emissions 2021-2030 (MT) Total CO_2 Emissions 2031-2045 (MT) Total CO_2 Emissions 2021-2045 (MT)	33.8 10.2 44.0	

General Notes
- DER is modeled as a load reduction; cost of DER resources not included in NPV calculations ($1.6B - $2.5B)
- 2 coal to gas conversions (2029 & 2030)
- Solar is added late in the period (2045) as an energy resource

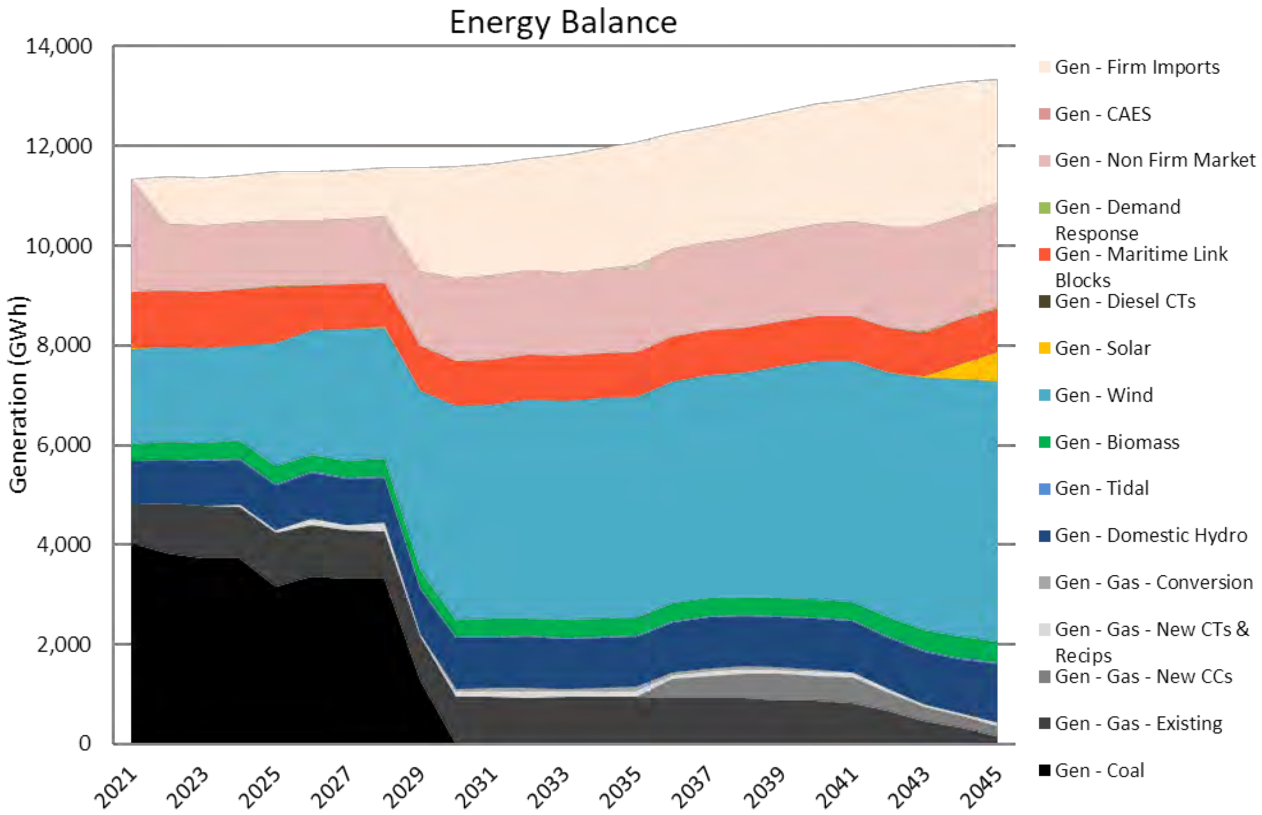
Essential Grid Services
- Essential Grid Service requirements are met as modeled

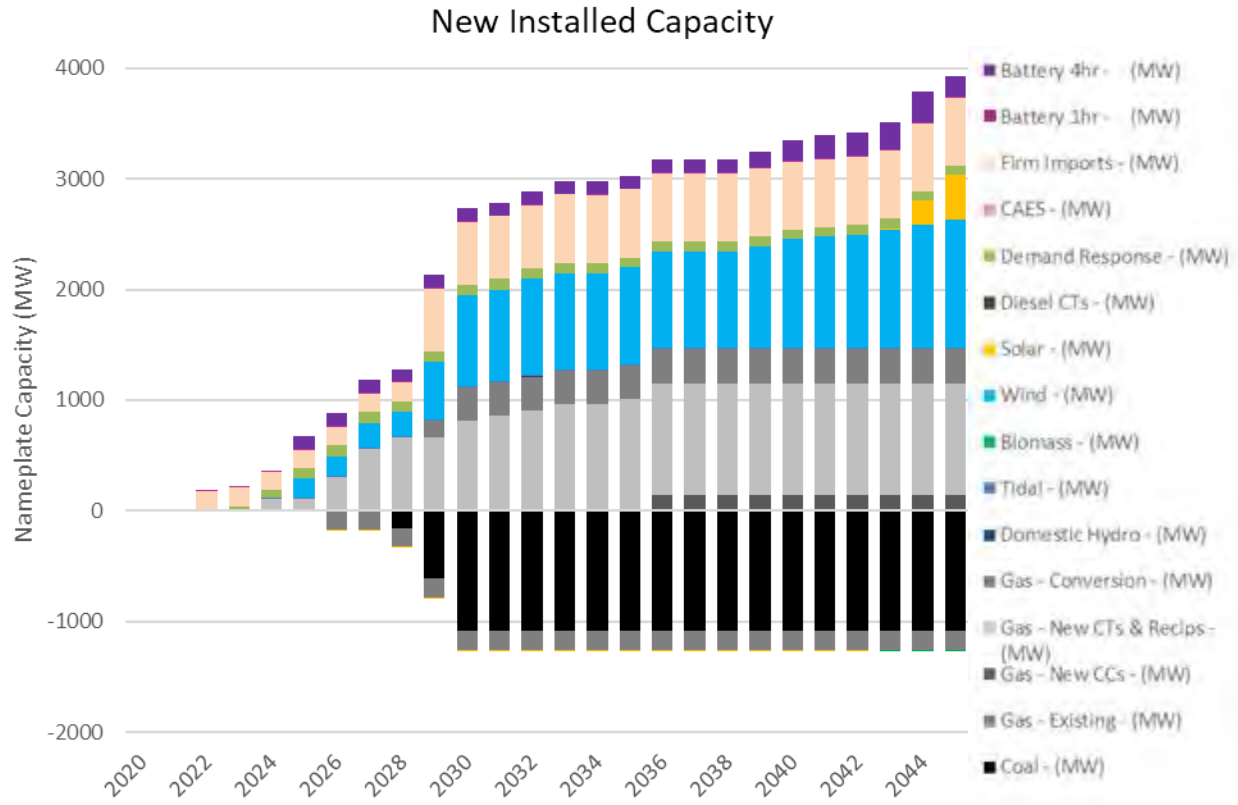
Resource Adequacy & PRM
- Reliability Tie: 2026
- Regional Integration: 2026

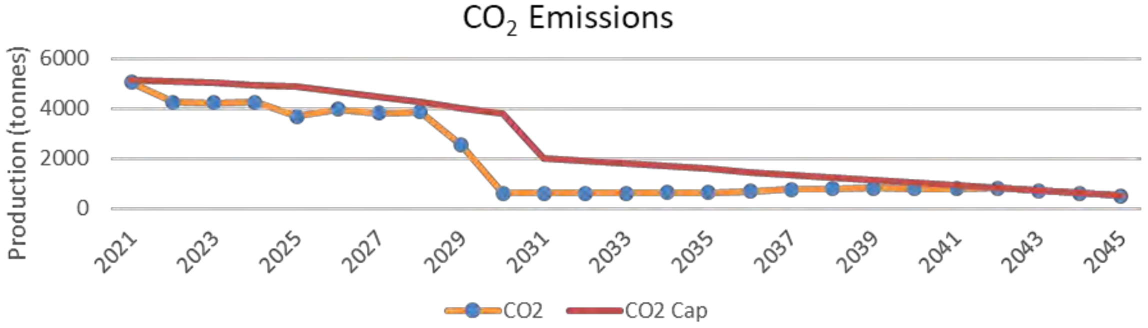
Plan Robustness & Flexibility
- Regional Integration provides flexible ability to meet emissions constraints

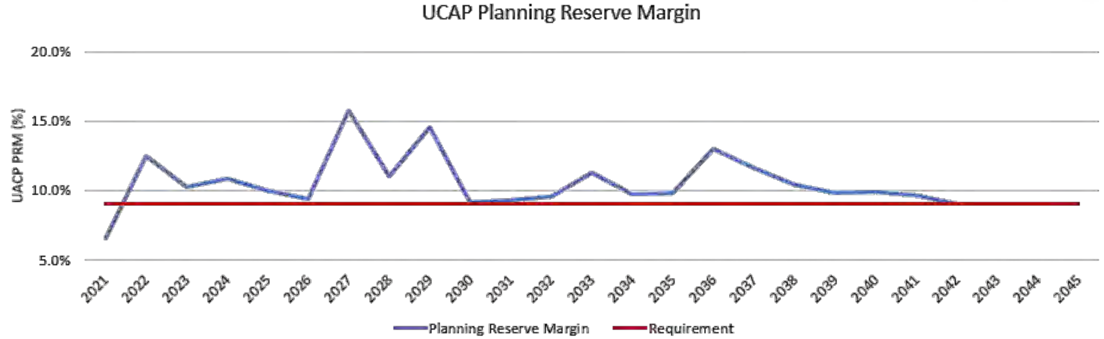
3.2C

HIGH ELEC. / MAX DSM / ACCEL. NET ZERO 2045 / REGIONAL INTEGRATION









3.2C

HIGH ELEC. / MAX DSM / ACCEL. NET ZERO 2045 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation		
25-yr NPVRR ($MM)	$16,049	General Notes • Gas CT builds and incremental firm imports support early load growth • Increased firm import energy relative to previous runs offsets NGCC generation (now see 1 unit rather than 3 in previous modeling results) Essential Grid Services • Essential Grid Service requirements are met as modeled Resource Adequacy & PRM • Reliability Tie: 2029 • Regional Integration: 2029 Plan Robustness & Flexibility • Regional Integration provides flexible ability to meet emissions constraints
25-yr NPVRR with End Effects ($MM)	$21,770	
10-yr NPVRR ($MM)	$8,355	
Average Annual Partial Rate Impact 2021-2030 (%) 2021-2045 (%)	 2.0% 0.9%	
Total CO_2 Emissions 2021-2030 (MT) Total CO_2 Emissions 2031-2045 (MT) Total CO_2 Emissions 2021-2045 (MT)	36.2 10.3 46.5	

SENSITIVITY ANALYSIS RESULTS

Nova Scotia
POWER
An Emera Company

SENSITIVITY ANALYSIS OVERVIEW

In addition to the Final Portfolio Study, a series of model sensitivities has been studied to understand how model outputs will vary with adjustments to key input parameters of interest.

On the following slides, results are provided for each sensitivity run and are also compared to the corresponding base case in order to evaluate the impact of the change in model inputs.

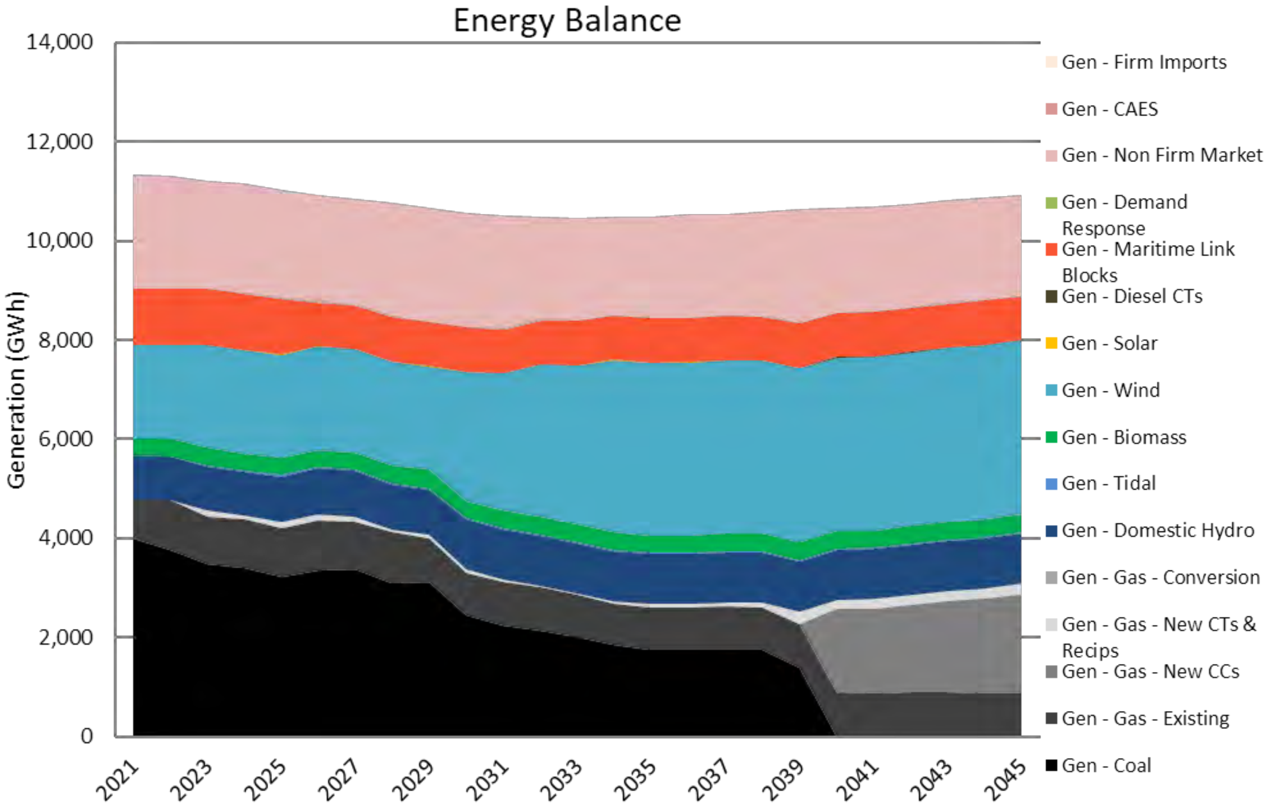
Sensitivities that are included in this results release are listed below:

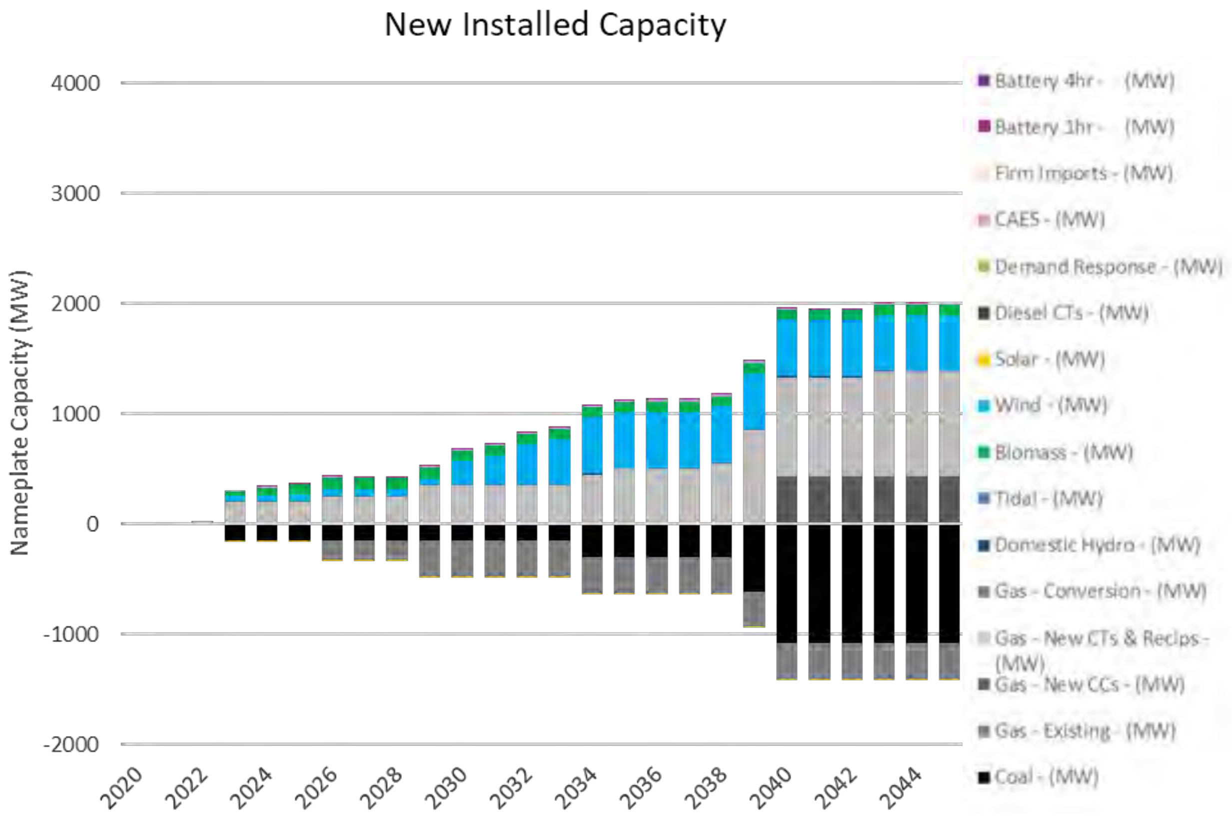
2.0A.DSM-1	Low Electrification / Mid DSM
2.1C.DSM-2	Mid Electrification / Mid DSM
2.2C.DSM-3	High Electrification / Mid DSM
2.0C.DSM-4	Low Electrification / Low DSM
2.0C.DSM-5	Low Electrification / Mid DSM
2.0C.DSM-6	Low Electrification / Max DSM
3.1C.DSM-7	Mid Electrification / Mid DSM / 2030 Coal Retirement
2.1C.Wind-1	Low Wind Cost
2.1C.Wind-2	Low Wind + Low Battery Cost
2.1C.Wind-3	Low Inertia
2.1C.Wind-4	No Inertia / No Wind Integration Requirements
2.1C.Mersey	Mersey Hydro Retired
2.1C.Import-1	Limited Non-Firm Imports
2.0A.Import-2	Current Landscape case without Reliability Tie
2.1C.Import-3	Limited Reliability Tie Inertia (provides 50% of inertia requirement)

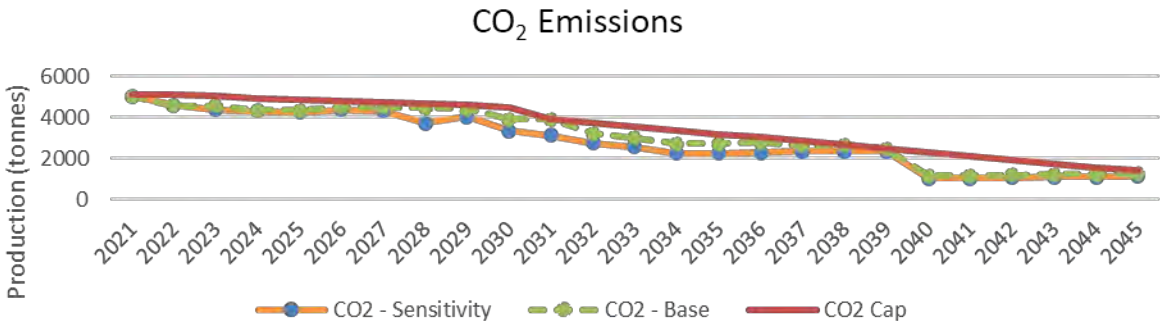
Nova Scotia POWER An Emera Company

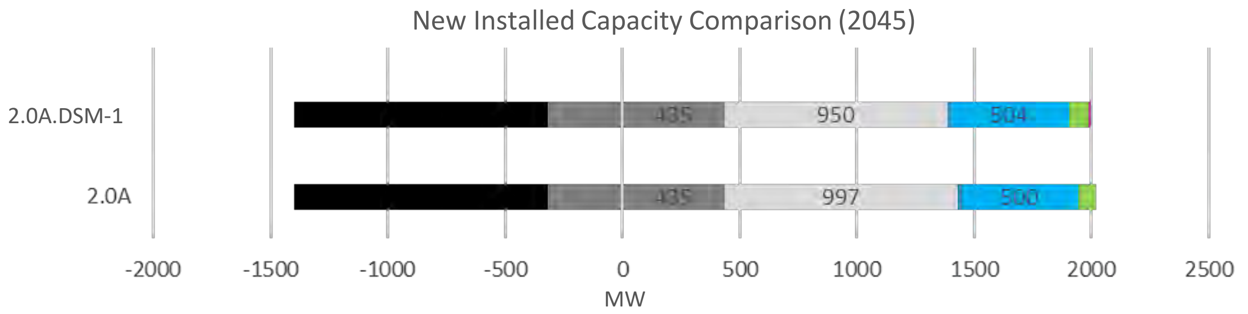
2.0A.DSM-1 (MID DSM)

LOW ELEC. / MID DSM / NET ZERO 2050 / CURRENT LANDSCAPE









2.0A.DSM-1 (MID DSM)

LOW ELEC. / MID DSM / NET ZERO 2050 / CURRENT LANDSCAPE

Scenario Metrics & Evaluation			
	Sensitivity	Base (2.0A)	
25-yr NPVRR ($MM)	$12,711	$12,351	
25-yr NPVRR w/ End Effects ($MM)	$16,888	$16,609	
10-yr NPVRR ($MM)	$7,199	$6,831	
Average Annual Partial Rate Impact 2021-2030 (%) 2021-2045 (%)	 1.5% 1.1%	 0.9% 1.0%	
Total CO_2 Emissions 2021-2030 (MT) Total CO_2 Emissions 2031-2045 (MT) Total CO_2 Emissions 2021-2045 (MT)	42.2 28.6 70.7	44.5 33.2 77.7	

General Notes
- Relative to 2.0A (which includes Base DSM), 47MW fewer CT resources are built due to the reduction in peak load from the higher level of DSM and the higher capacity contribution of the DR program associated with Mid DSM (DR economically selected in both models)
- NPVRR is increased relative to Base DSM case for all three time periods

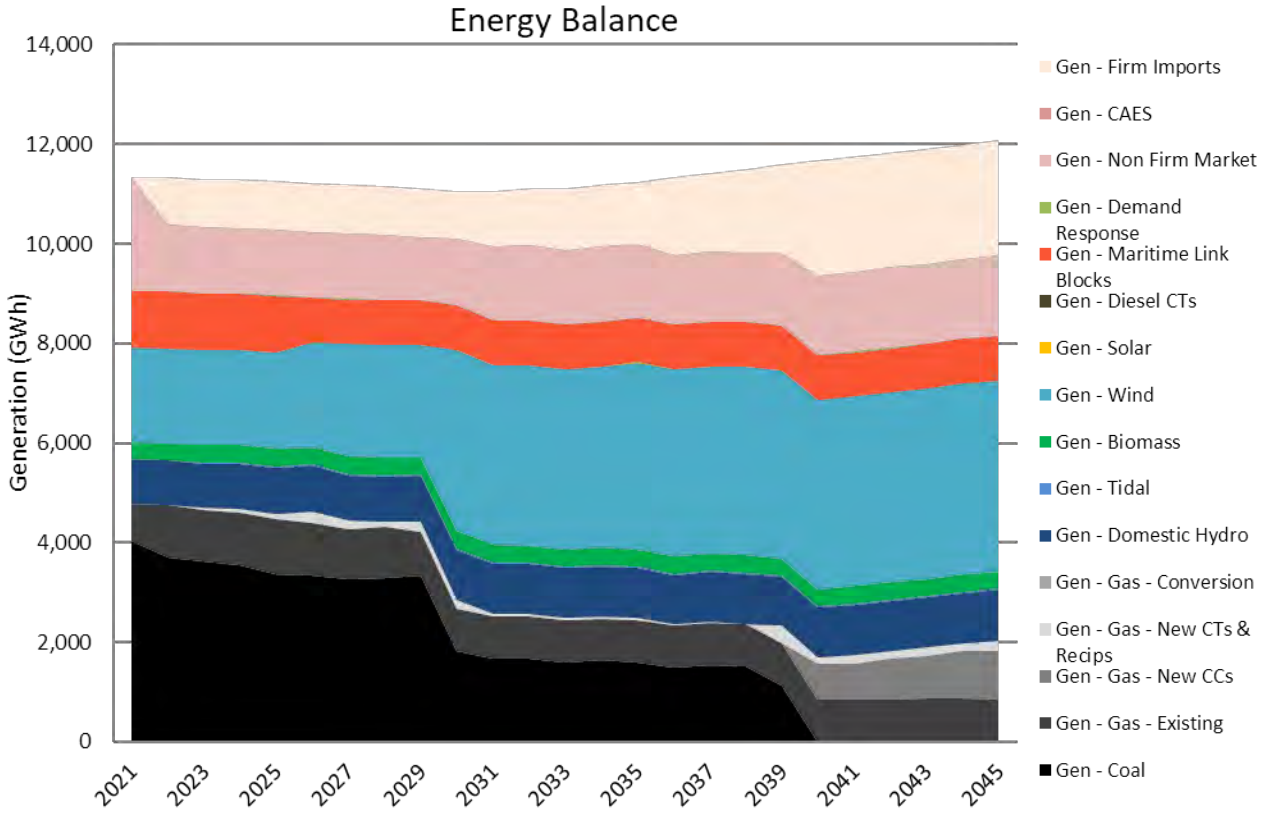
Essential Grid Services
- No significant change relative to 2.0A

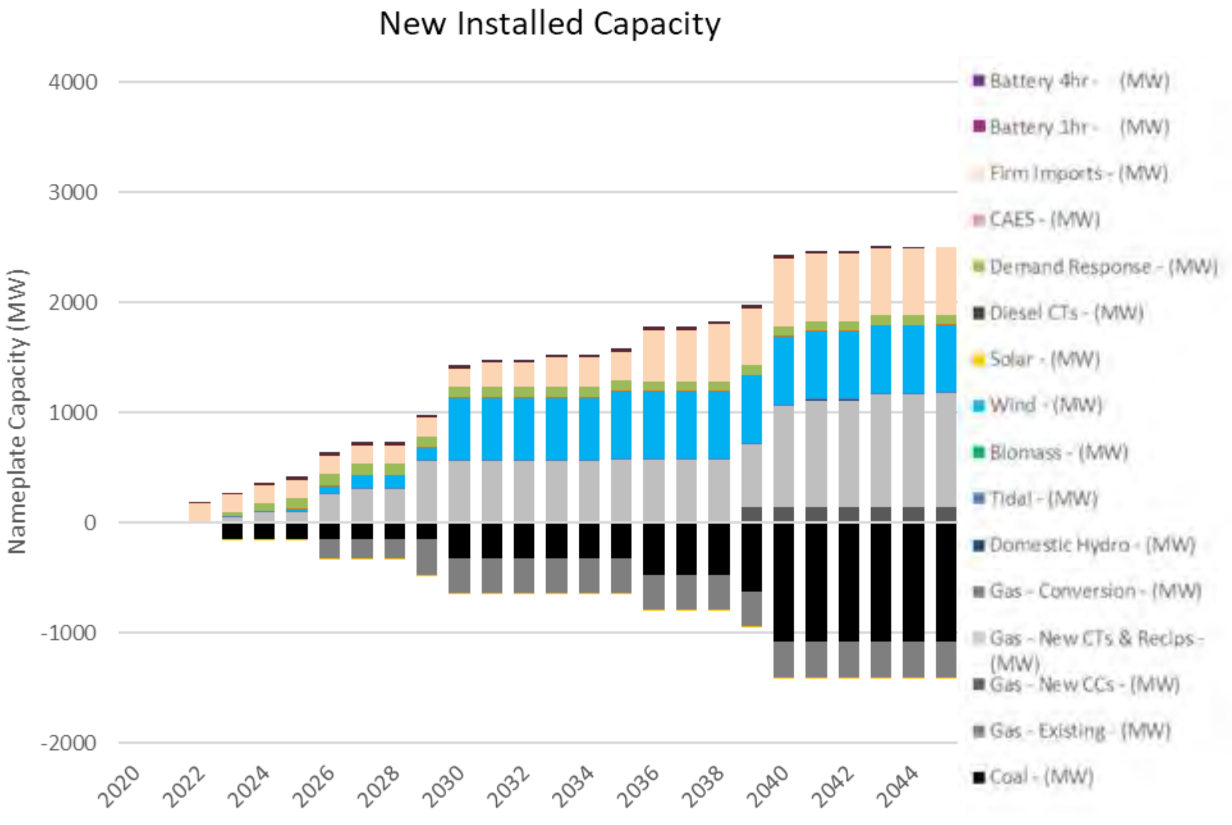
Resource Adequacy & PRM
- Reliability Tie: 2028
- Regional Integration: n/a

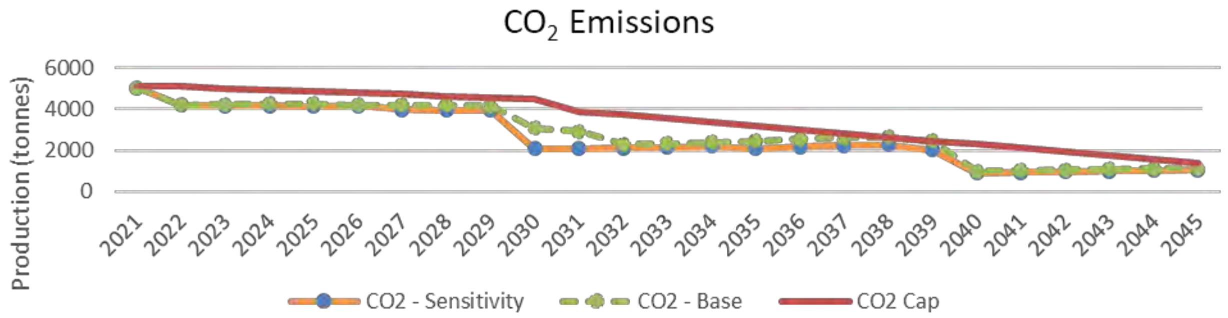
Plan Robustness & Flexibility
- No significant change relative to 2.0A base

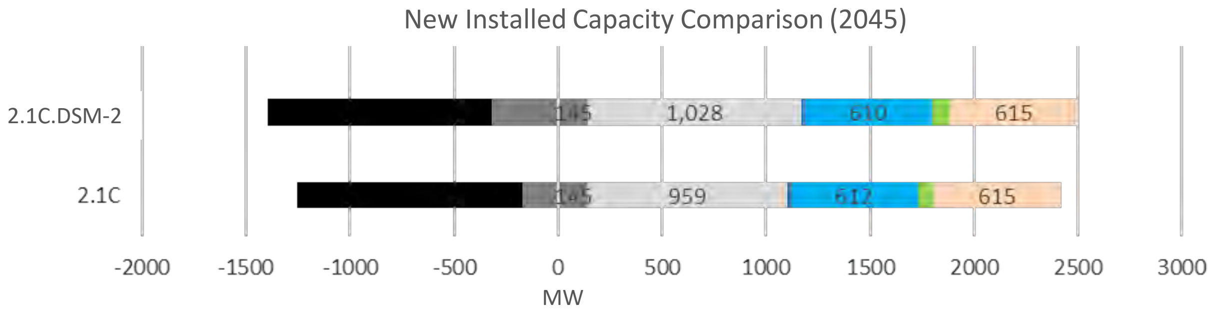
2.1C.DSM-2 (MID DSM)

MID ELEC. / MID DSM / NET ZERO 2050 / REGIONAL INTEGRATION









2.1C.DSM-2 (MID DSM)

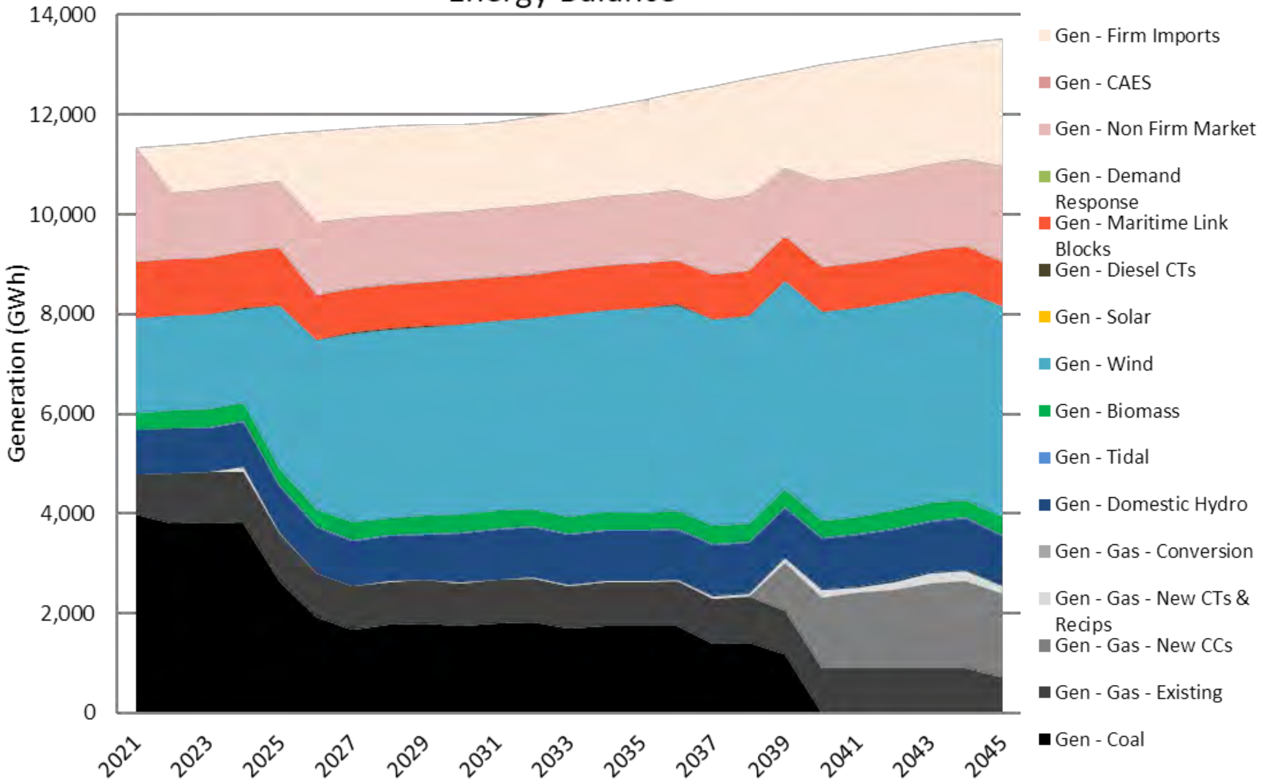
MID ELEC. / MID DSM / NET ZERO 2050 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation			
	Sensitivity	Base (2.1C)	
25-yr NPVRR ($MM)	$13,468	$13,141	<u>General Notes</u> • 1 coal unit is retired earlier than in 2.1C Base; remainder of resource plan very similar • Mid DSM case retires one additional gas steam unit vs. 2.1C Base DSM by 2045; capacity is replaced via a combination of decreased firm peak due to incremental DSM, additional combustion turbine capacity, and the higher capacity contribution of the DR program associated with Mid DSM • NPVRR is increased relative to Base DSM case for all three time periods <u>Essential Grid Services</u> • No change relative to 2.1C <u>Resource Adequacy & PRM</u> • Reliability Tie: 2030 • Regional Integration: 2031 <u>Plan Robustness & Flexibility</u> • No change relative to 2.1C Base
25-yr NPVRR w/ End Effects ($MM)	$18,013	$17,767	
10-yr NPVRR ($MM)	$7,396	$7,067	
Average Annual Partial Rate Impact 2021-2030 (%) 2021-2045 (%)	 1.2% 0.8%	 0.6% 0.7%	
Total CO_2 Emissions 2021-2030 (MT) Total CO_2 Emissions 2031-2045 (MT) Total CO_2 Emissions 2021-2045 (MT)	39.9 25.2 65.1	41.8 29.1 70.9	

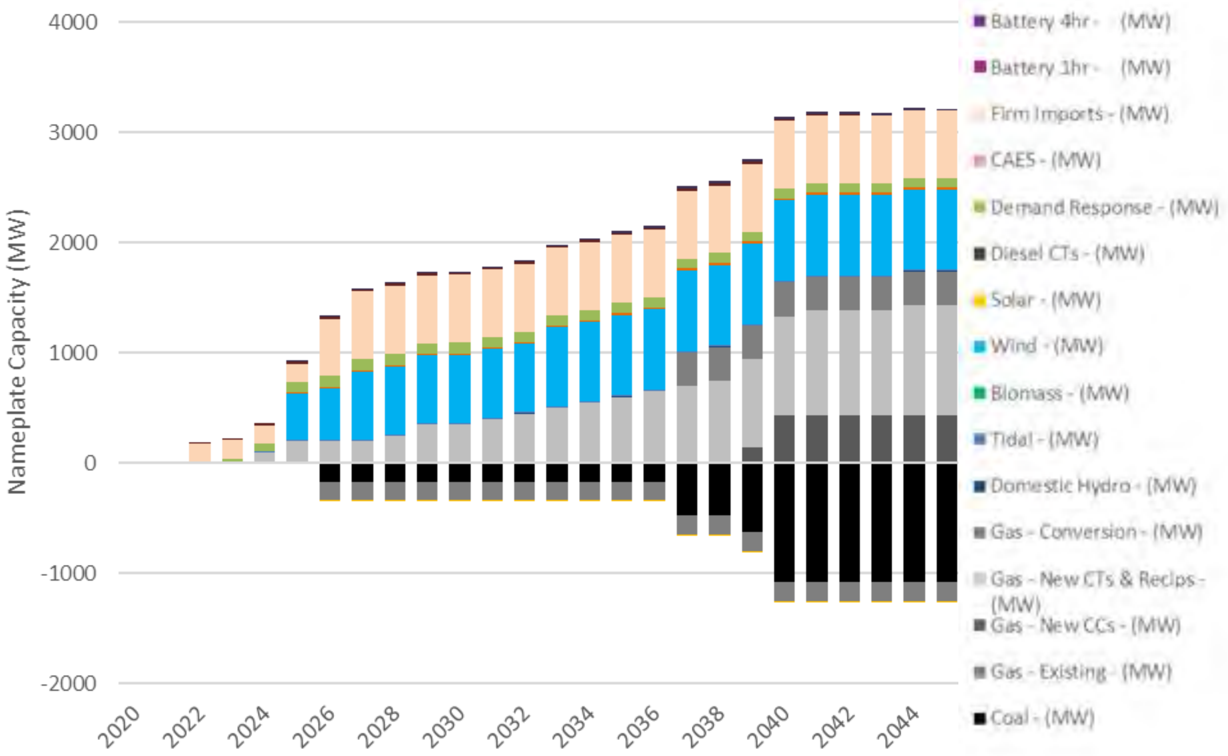
2.2C.DSM-3 (MID DSM)

HIGH ELEC. / MID DSM / NET ZERO 2050 / REGIONAL INTEGRATION

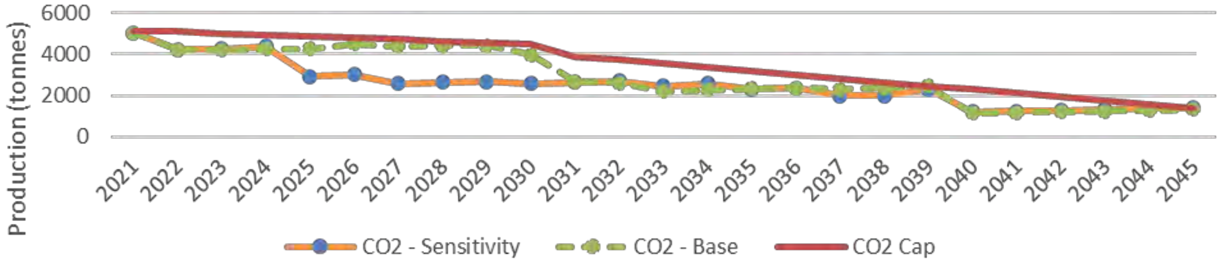
Energy Balance



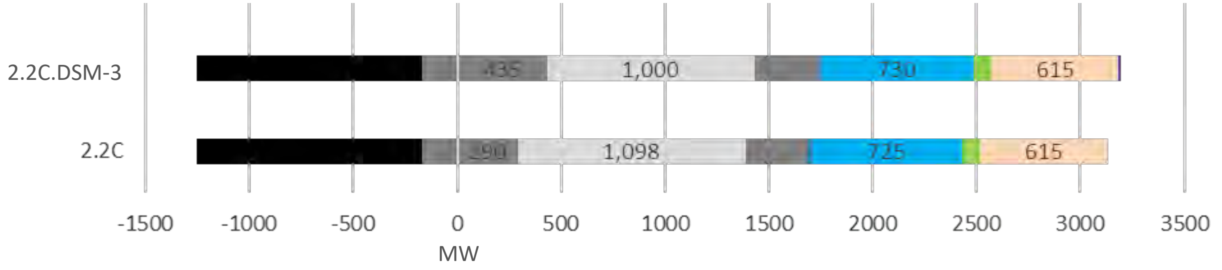
New Installed Capacity



CO_2 Emissions



New Installed Capacity Comparison (2045)



2.2C.DSM-3 (MID DSM)

HIGH ELEC. / MID DSM / NET ZERO 2050 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

	Sensitivity	Base (2.2C)
25-yr NPVRR ($MM)	$14,901	$15,380
25-yr NPVRR w/ End Effects ($MM)	$20,366	$20,945
10-yr NPVRR ($MM)	$7,871	$8,201
Average Annual Partial Rate Impact		
2021-2030 (%)	0.8%	1.3%
2021-2045 (%)	0.6%	0.8%
Total CO_2 Emissions 2021-2030 (MT)	34.4	43.7
Total CO_2 Emissions 2031-2045 (MT)	29.2	29.0
Total CO_2 Emissions 2021-2045 (MT)	63.6	72.7

General Notes
- Under the High Electrification / Mid DSM sensitivity, the Regional Interconnection is built 5 years earlier than 2.2C base case (which uses the Max DSM profile); this enables 1 earlier coal retirement in the 2030s economically and significantly reduces GHG emissions over the planning horizon
- By 2045, Mid DSM case has 1 additional NGCC unit and fewer combustion turbines for a net capacity difference of +47MW, very closely matching the firm peak increase of 41MW due to the change in DSM level
- NPVRR is decreased relative to 2.2C Max DSM case for all three time periods

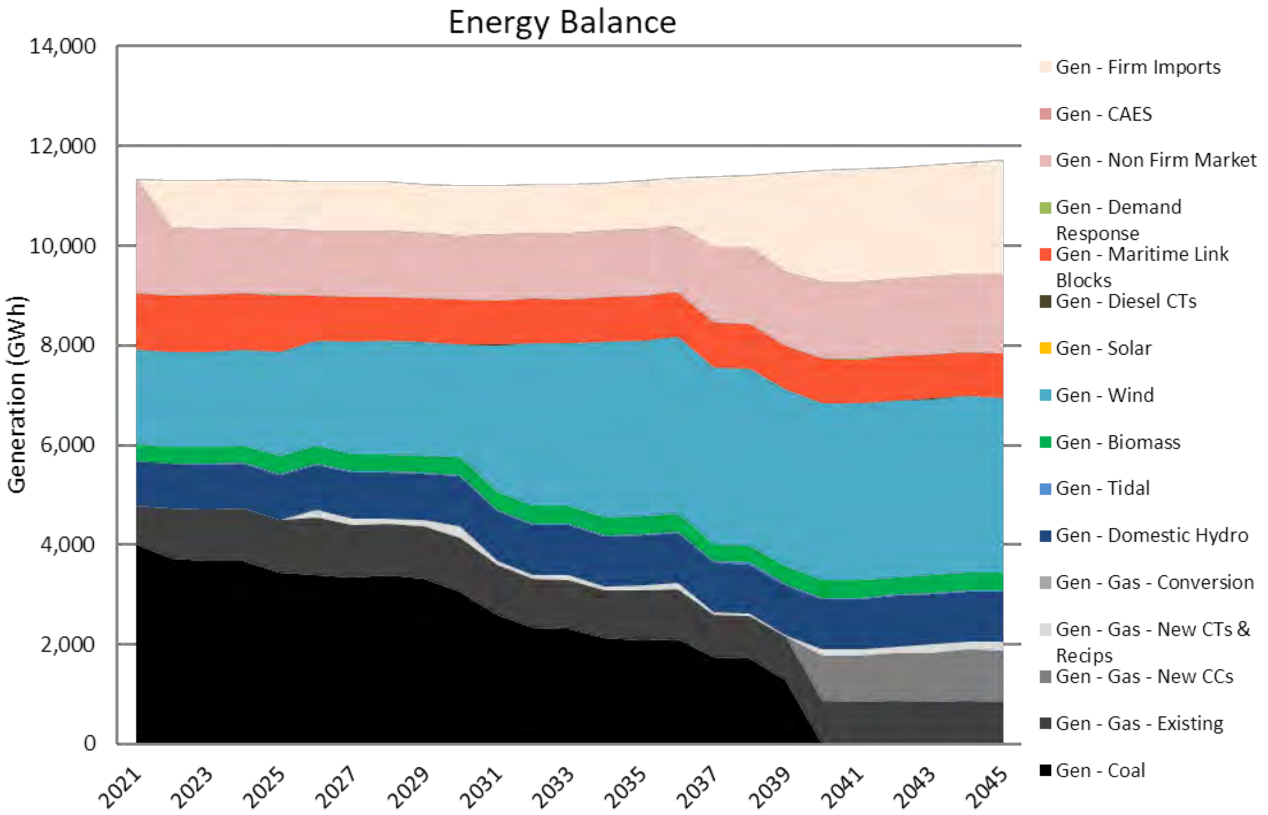
Essential Grid Services
- No significant change from 2.2C

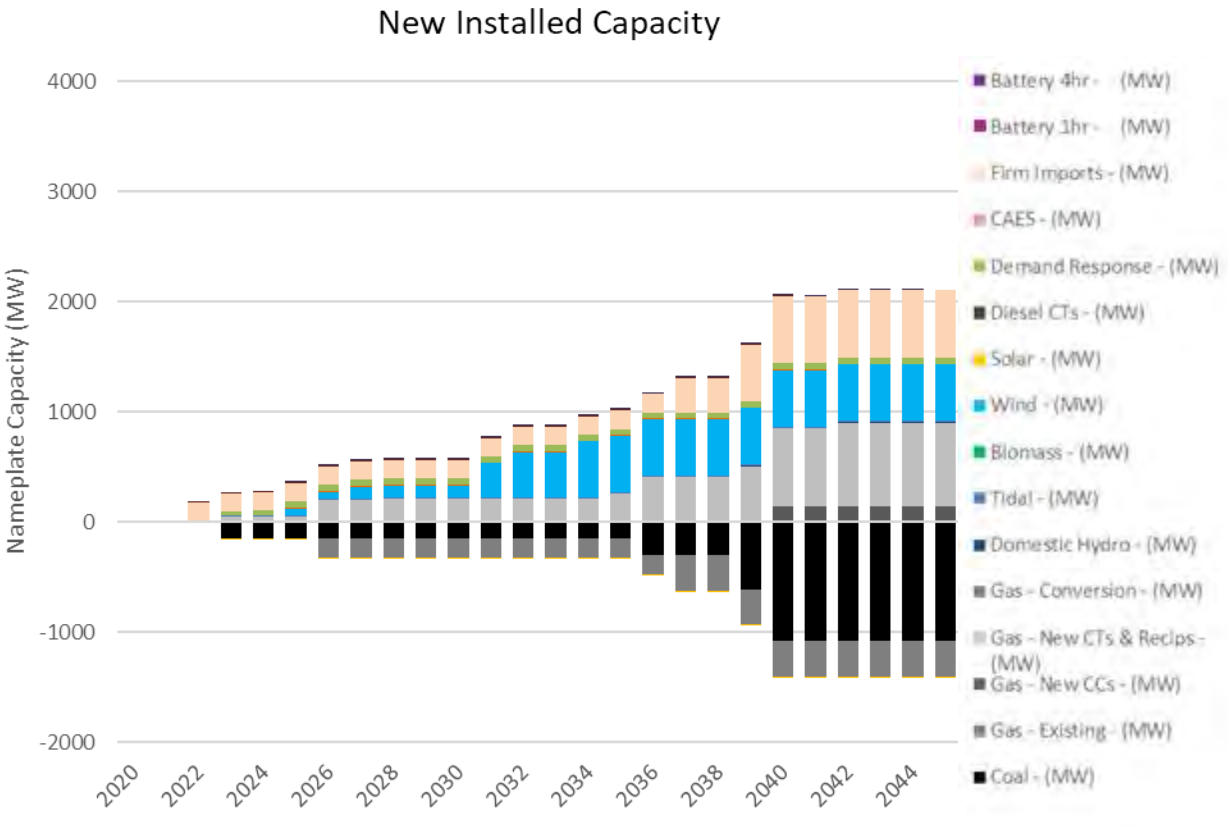
Resource Adequacy & PRM
- Reliability Tie: 2025
- Regional Integration: 2026

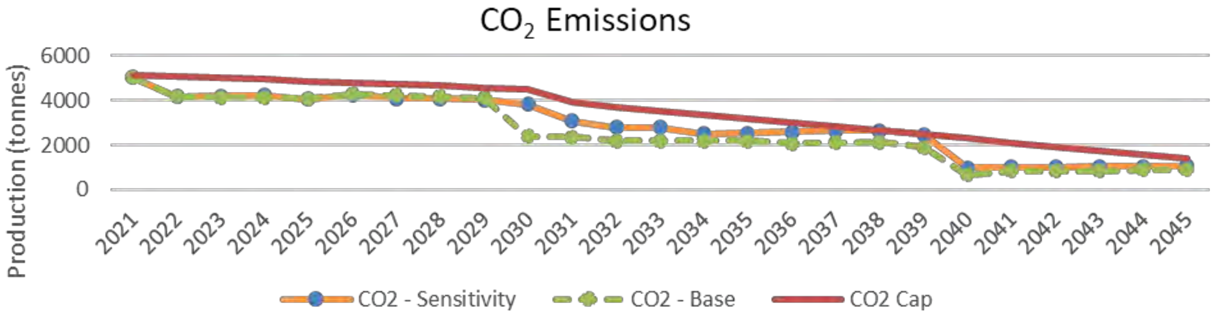
Plan Robustness & Flexibility
- One additional NGCC increases exposure to gas prices; total gas generation limited by emissions constraints in model scenarios

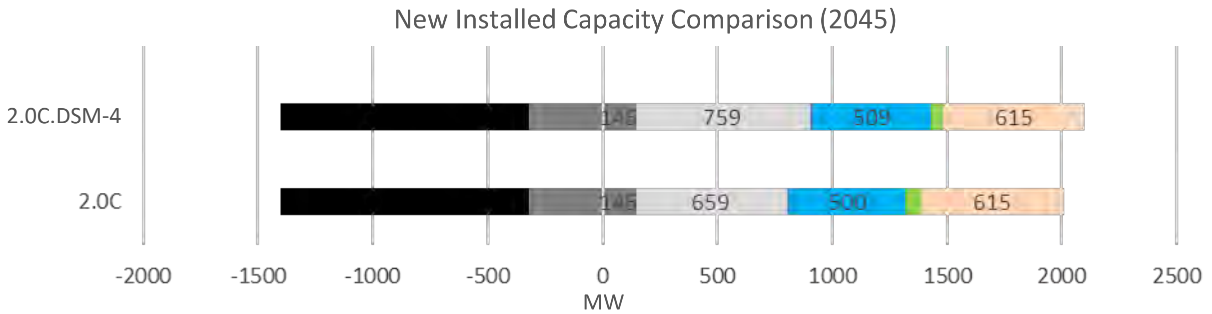
2.0C.DSM-4 (LOW DSM)

LOW ELEC. / LOW DSM / NET ZERO 2050 / REGIONAL INTEGRATION









2.0C.DSM-4 (LOW DSM)

LOW ELEC. / LOW DSM / NET ZERO 2050 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

	Sensitivity	Base (2.0C)
25-yr NPVRR ($MM)	$12,206	$12,234
25-yr NPVRR w/ End Effects ($MM)	$16,350	$16,241
10-yr NPVRR ($MM)	$6,676	$6,820
Average Annual Partial Rate Impact		
2021-2030 (%)	0.3%	0.9%
2021-2045 (%)	0.7%	0.9%
Total CO_2 Emissions 2021-2030 (MT)	41.9	40.7
Total CO_2 Emissions 2031-2045 (MT)	30.2	24.3
Total CO_2 Emissions 2021-2045 (MT)	72.1	65.0

General Notes
- Similar resource plan overall to 2.0C Base DSM; 1 economic coal retirement is delayed later into 2030s due to increased load which leads to an increase in CO_2 emissions in the 2030s
- By 2045 the Low DSM sensitivity adds 100MW incremental combustion turbine resources relative to Base DSM, closely matching the firm peak increase of 86MW (plus the associated PRM increase)
- NPVRR is decreased over the first 10 years, very similar over 25 years, and increased when end effects are considered relative to 2.0C Base DSM indicating the solutions are very close economically

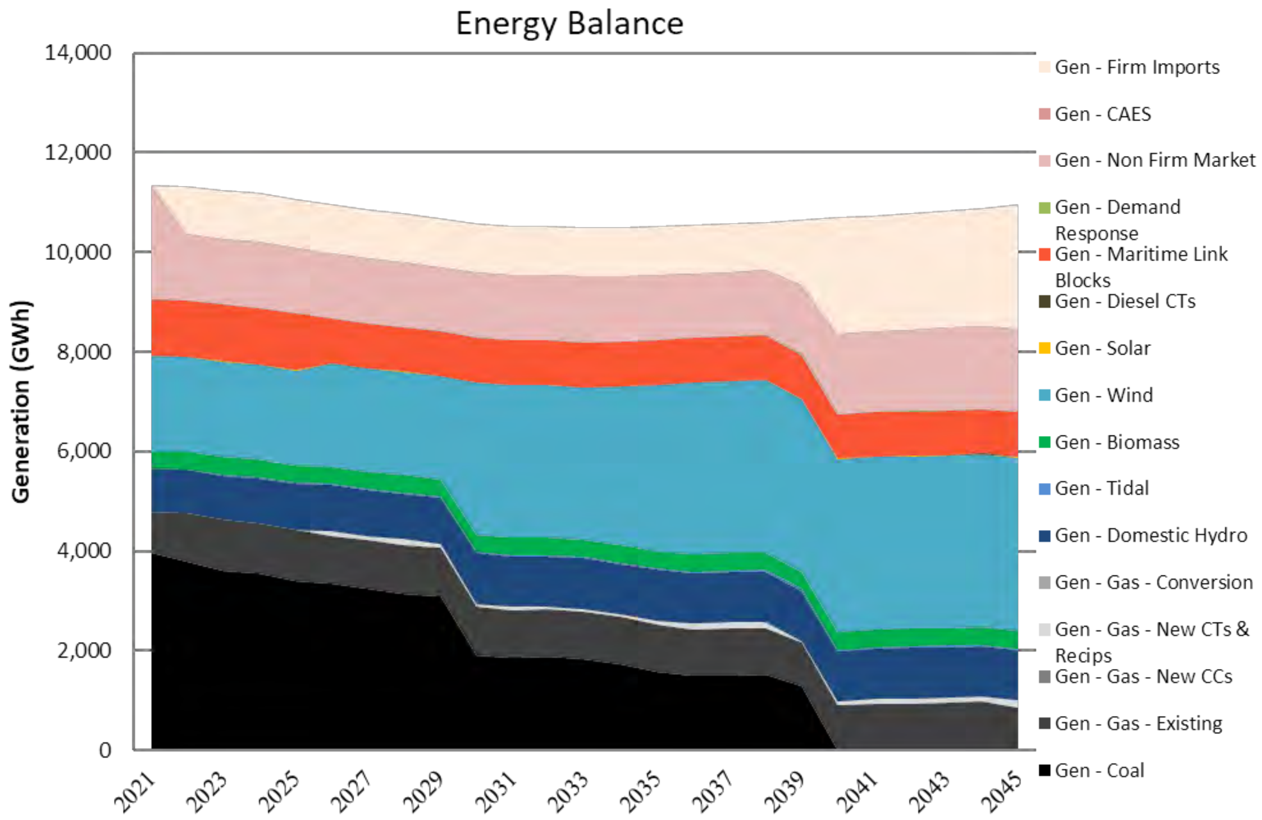
Essential Grid Services
- No change relative to 2.0C

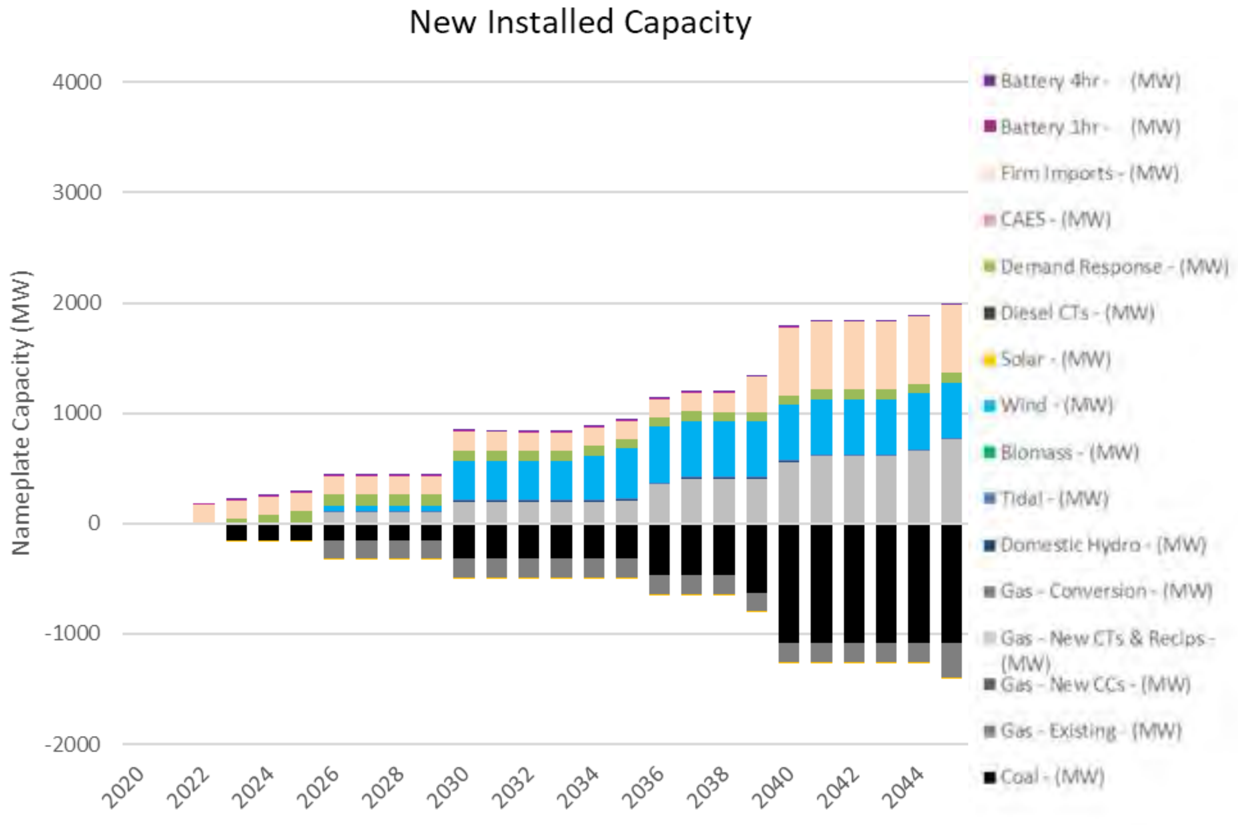
Resource Adequacy & PRM
- Reliability Tie: 2031
- Regional Integration: 2037

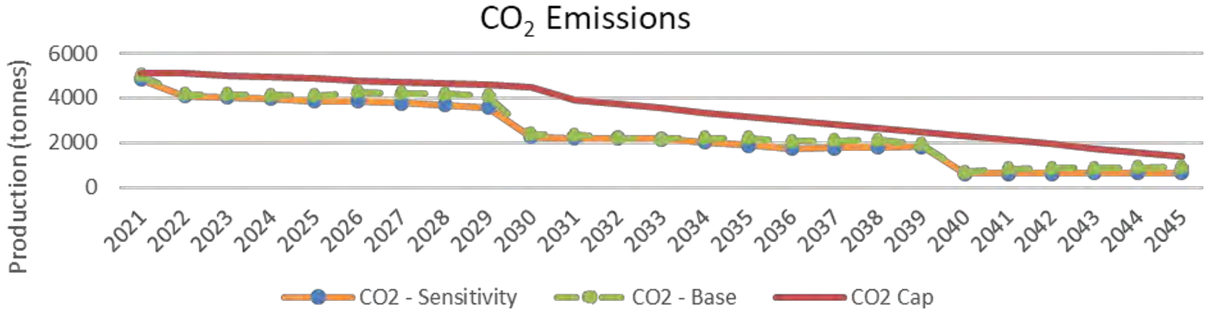
Plan Robustness & Flexibility
- No change relative to 2.0C

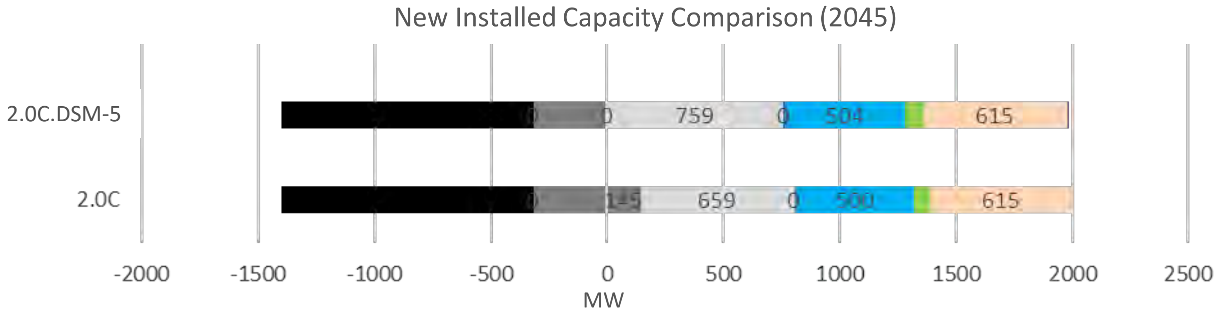
2.0C.DSM-5 (MID DSM)

LOW ELEC. / MID DSM / NET ZERO 2050 / REGIONAL INTEGRATION









2.0C.DSM-5 (MID DSM)

LOW ELEC. / MID DSM / NET ZERO 2050 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

	Sensitivity	Base (2.0C)
25-yr NPVRR ($MM)	$12,556	$12,234
25-yr NPVRR w/ End Effects ($MM)	$16,561	$16,241
10-yr NPVRR ($MM)	$7,164	$6,820
Average Annual Partial Rate Impact		
2021-2030 (%)	1.4%	0.9%
2021-2045 (%)	1.0%	0.9%
Total CO_2 Emissions 2021-2030 (MT)	38.0	40.7
Total CO_2 Emissions 2031-2045 (MT)	21.5	24.3
Total CO_2 Emissions 2021-2045 (MT)	59.4	65.0

General Notes
- Generally a similar resource plan to 2.1C
- Increased level of DSM in this sensitivity deferred Regional Integration to 2039 from 2037.
- A net of 45MW of gas generation capacity is avoided (100 MW additional combustion turbines and 145MW less NGCC relative to 2.0C Base DSM)
- NPVRR is increased relative to Base DSM case for all three time periods

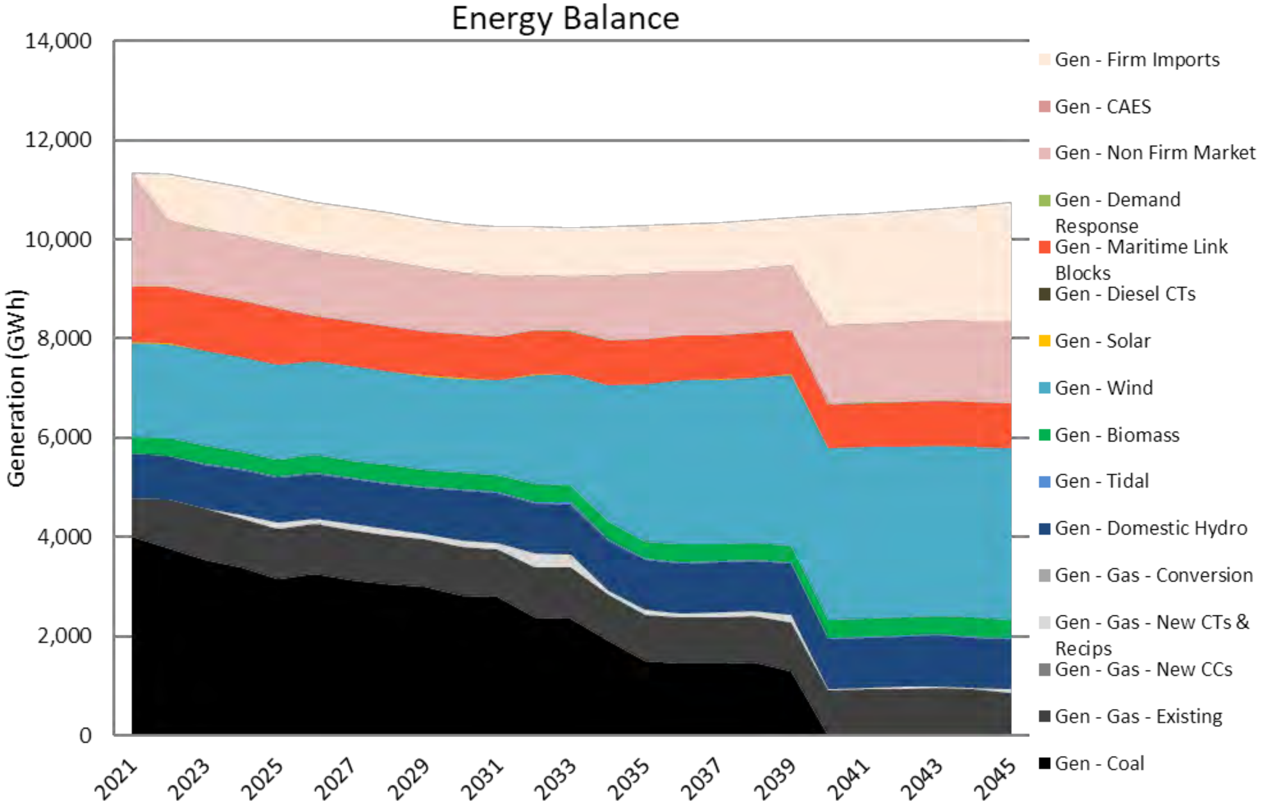
Essential Grid Services
- No change relative to 2.0C

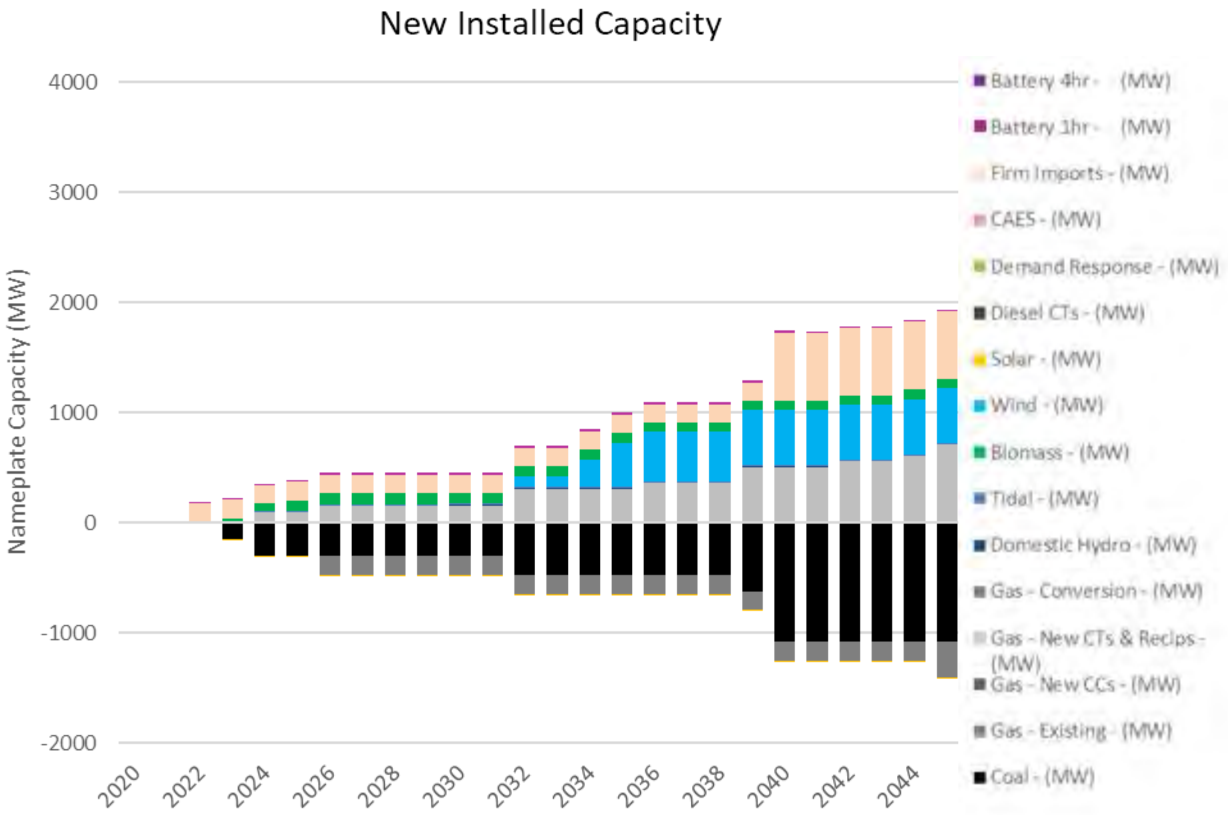
Resource Adequacy & PRM
- Reliability Tie: 2030
- Regional Integration: 2039

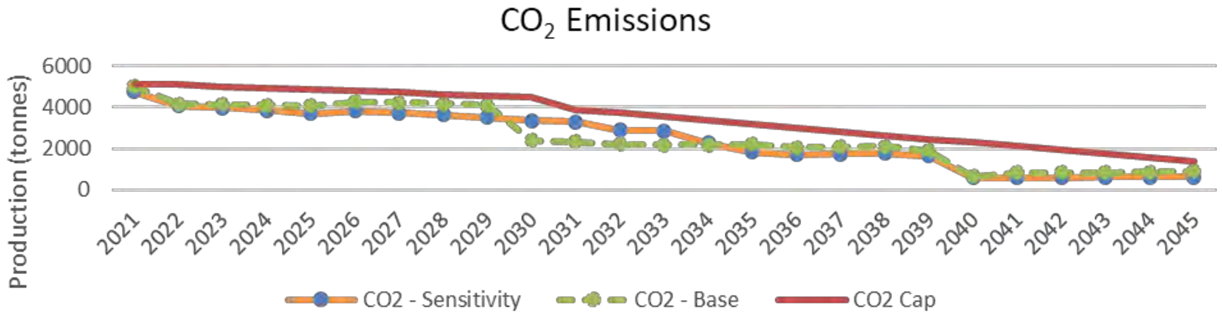
Plan Robustness & Flexibility
- No change relative to 2.0C

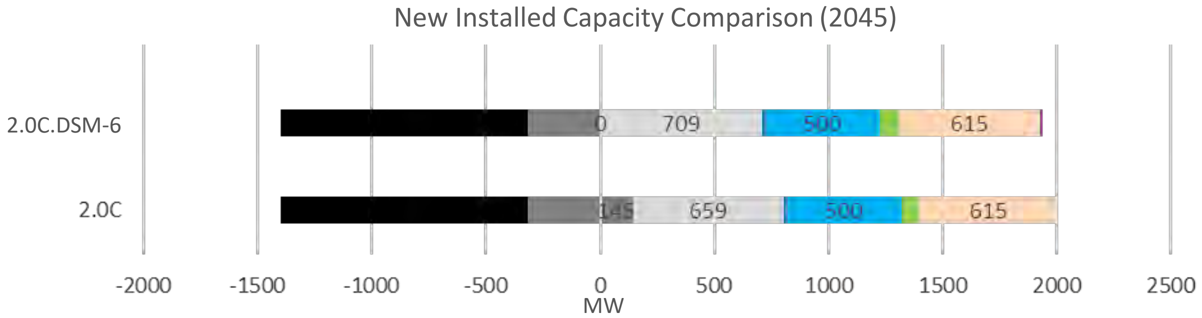
2.0C.DSM-6 (MAX DSM)

LOW ELEC. / MAX DSM / NET ZERO 2050 / REGIONAL INTEGRATION









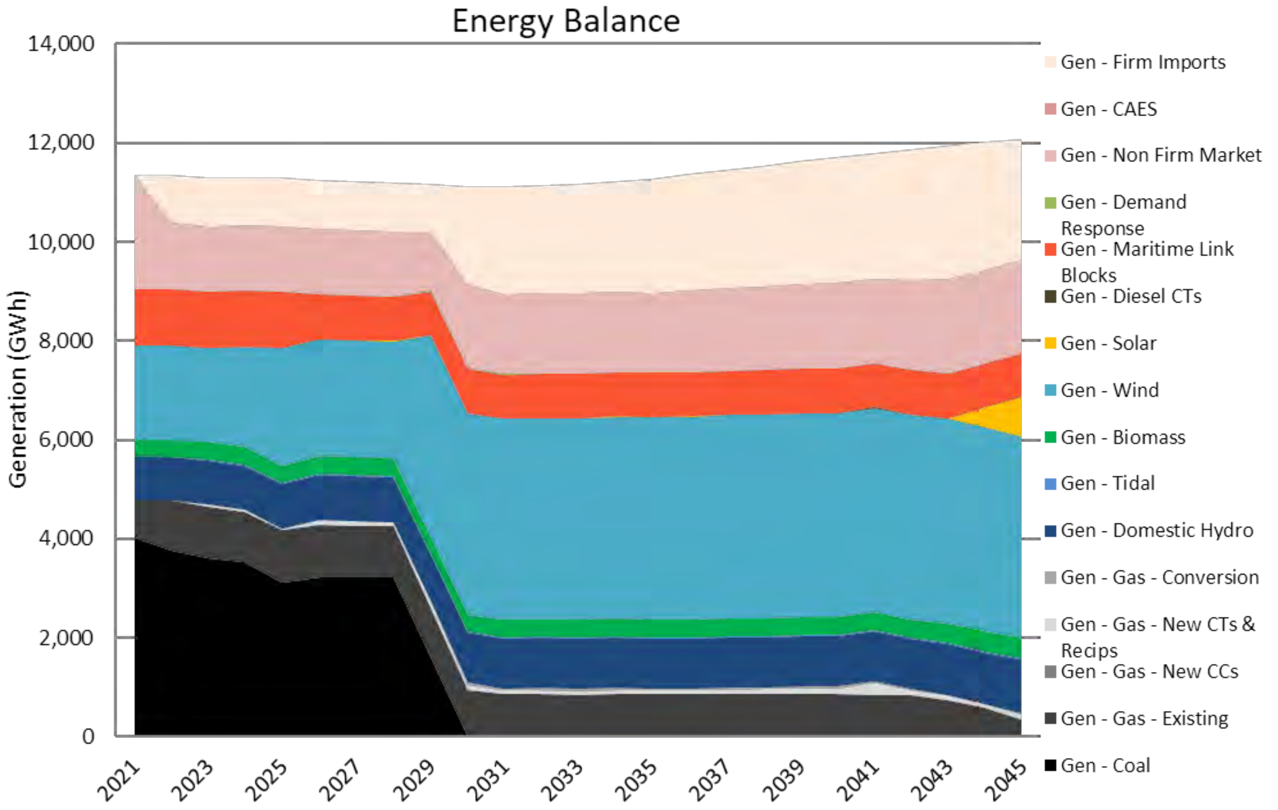
2.0C.DSM-6 (MAX DSM)

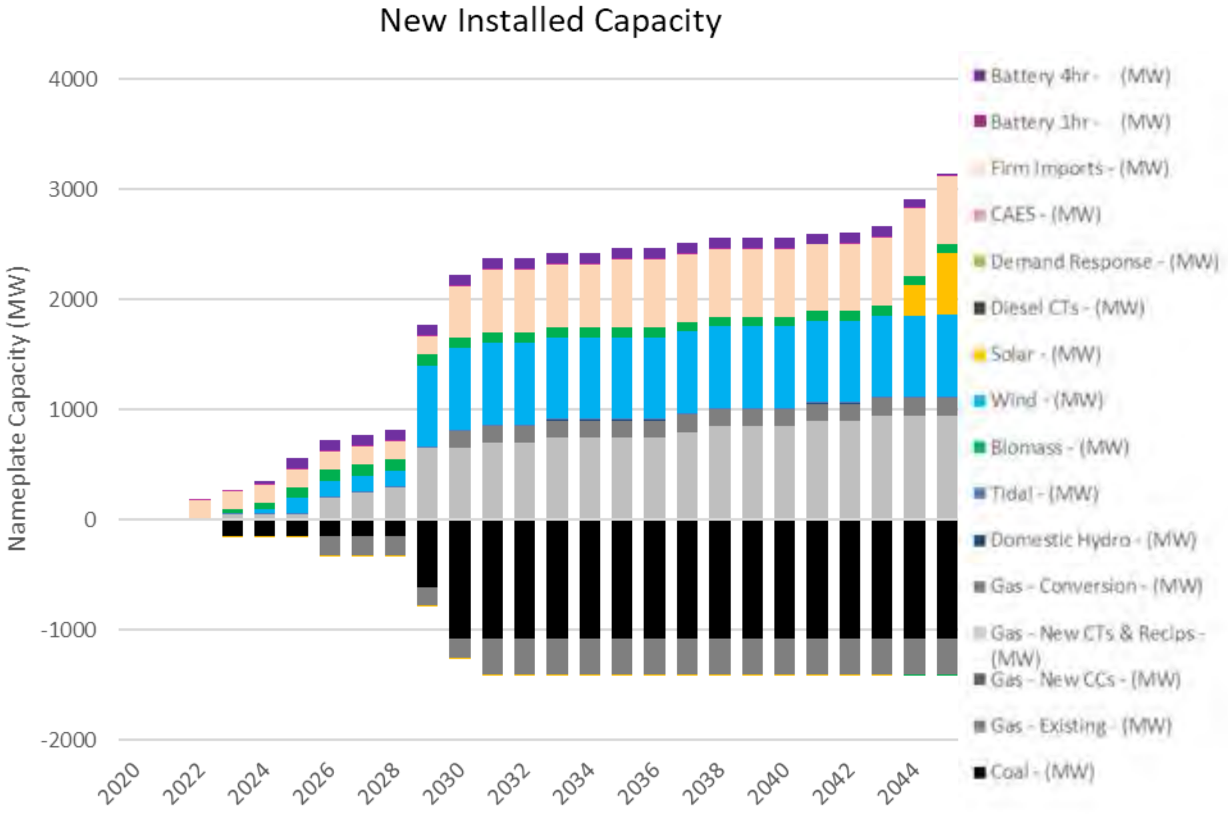
LOW ELEC. / MAX DSM / NET ZERO 2050 / REGIONAL INTEGRATION

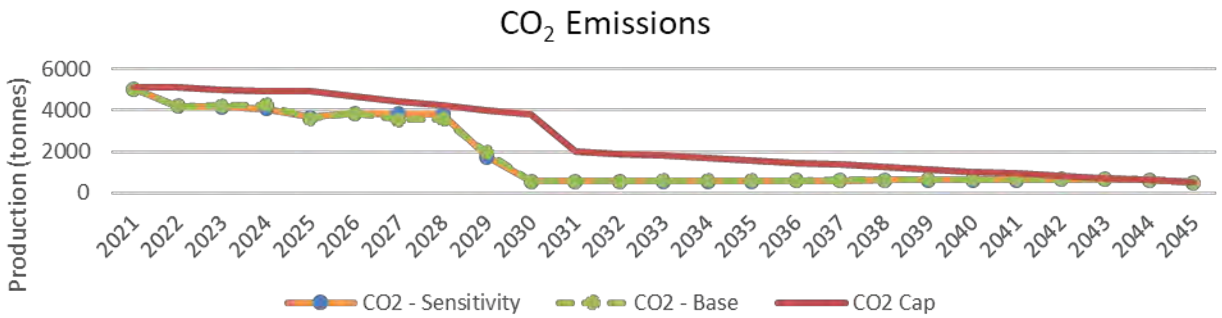
Scenario Metrics & Evaluation	Sensitivity	Base (2.0C)	
25-yr NPVRR ($MM)	$13,066	$12,234	General Notes • Increased level of DSM deferred Reliability Tie to 2034 from 2030, and Regional Integration to 2040 from 2037. • A net of 95MW of gas generation capacity is avoided (50 MW additional combustion turbines and 145MW less NGCC relative to 2.0C Base DSM) • 1 additional coal unit is retired in the 2020s economically and wind build is delayed • NPVRR is increased relative to Base DSM case for all three time periods
25-yr NPVRR w/ End Effects ($MM)	$17,153	$16,241	
10-yr NPVRR ($MM)	$7,570	$6,820	Essential Grid Services • No change relative to 2.0C
Average Annual Partial Rate Impact 2021-2030 (%) 2021-2045 (%)	 1.8% 1.2%	 0.9% 0.9%	Resource Adequacy & PRM • Reliability Tie: 2034 • Regional Integration: 2040
Total CO_2 Emissions 2021-2030 (MT) Total CO_2 Emissions 2031-2045 (MT) Total CO_2 Emissions 2021-2045 (MT)	38.4 23.7 62.1	40.7 24.3 65.0	Plan Robustness & Flexibility • No change relative to 2.0C

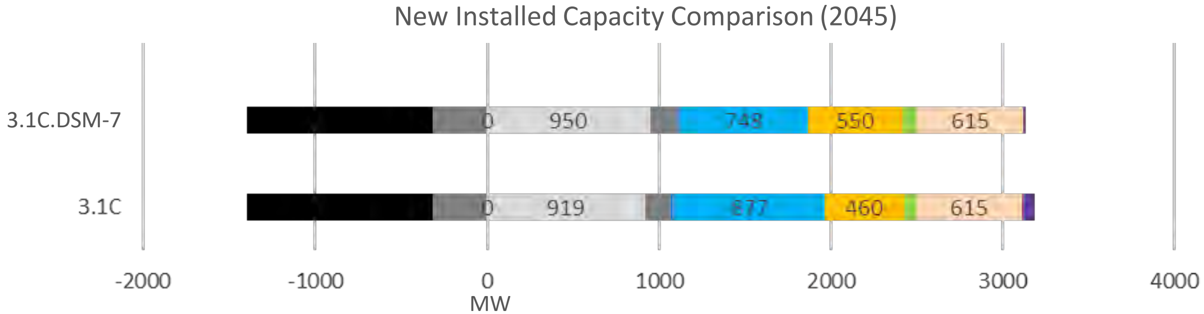
3.1C.DSM-7 (MID DSM)

MID ELEC. / MID DSM / ACCEL. NET ZERO 2045 / REGIONAL INTEGRATION









3.1C.DSM-7 (MID DSM)

MID ELEC. / MID DSM / ACCEL. NET ZERO 2045 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

	Sensitivity	Base (3.1C)
25-yr NPVRR ($MM)	$13,996	$13,734
25-yr NPVRR w/ End Effects ($MM)	$18,633	$18,409
10-yr NPVRR ($MM)	$7,524	$7,224
Average Annual Partial Rate Impact		
2021-2030 (%)	1.9%	1.4%
2021-2045 (%)	0.8%	0.7%
Total CO_2 Emissions 2021-2030 (MT)	34.9	34.8
Total CO_2 Emissions 2031-2045 (MT)	8.9	9.2
Total CO_2 Emissions 2021-2045 (MT)	43.9	44.0

General Notes
- Resource plan is largely unchanged between 3.1C and 3.1C with Mid DSM
- Slightly fewer batteries are built through the planning horizon due to lower firm capacity requirements (firm peak is 28MW lower by 2045 under Mid DSM vs. Base DSM)
- NPVRR is increased relative to Base DSM case for all three time periods

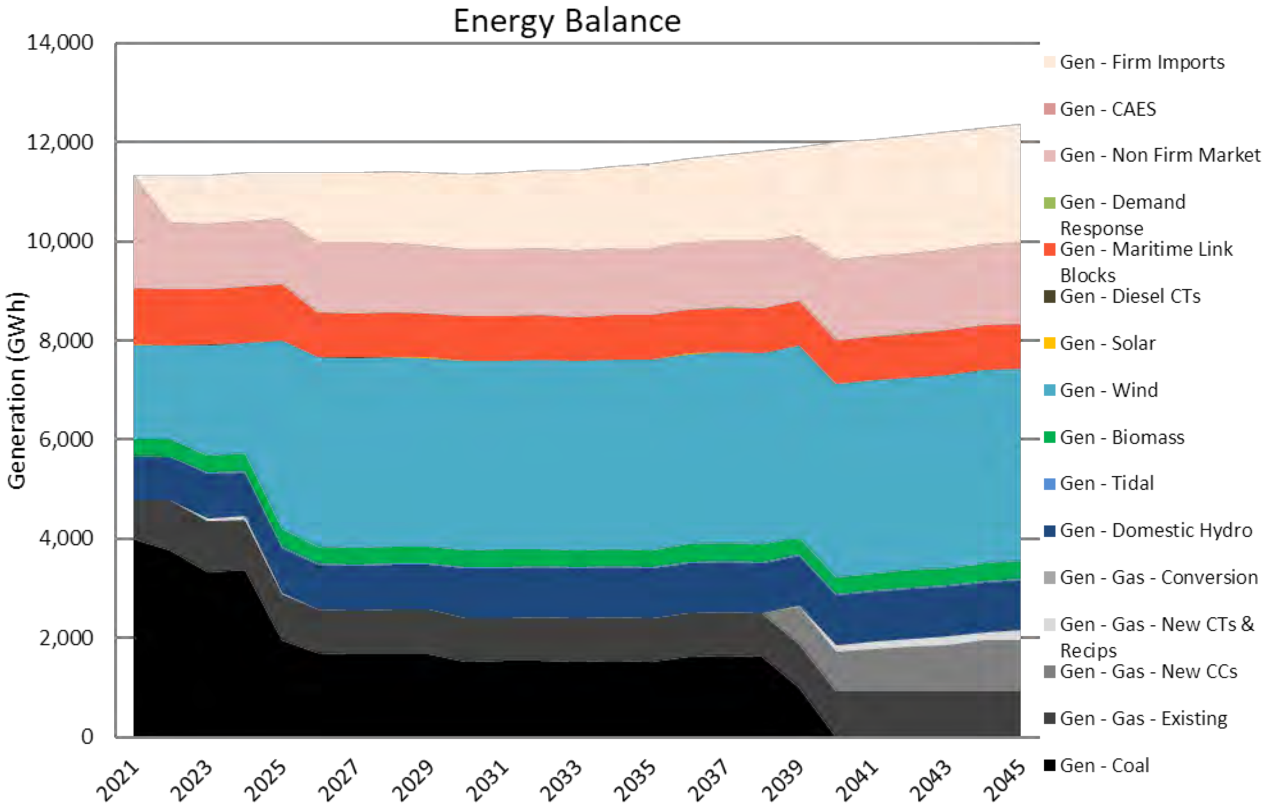
Essential Grid Services
- No change relative to 3.1C

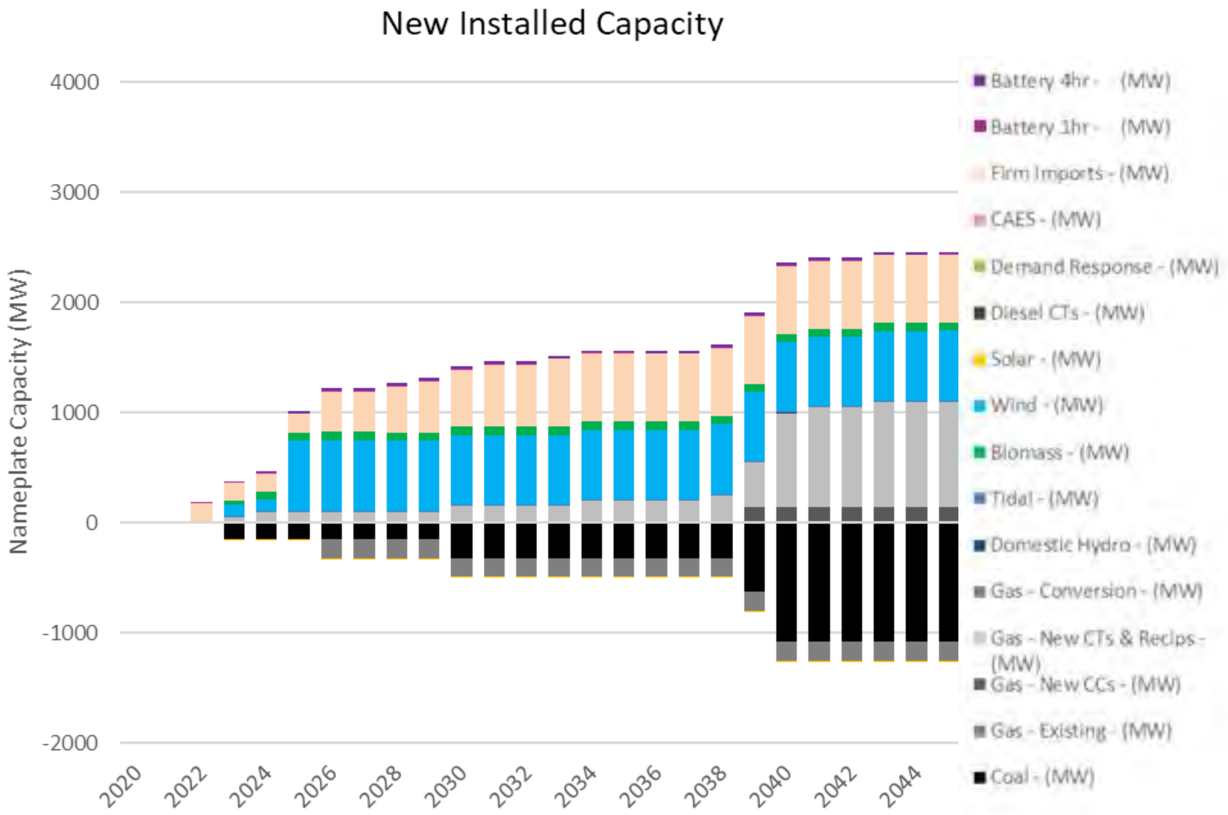
Resource Adequacy & PRM
- Reliability Tie: 2029
- Regional Integration: 2030

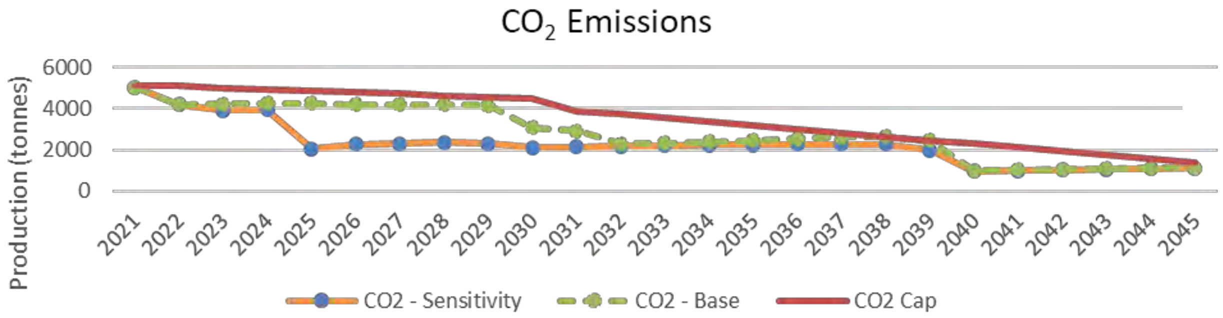
Plan Robustness & Flexibility
- No change relative to 3.1C

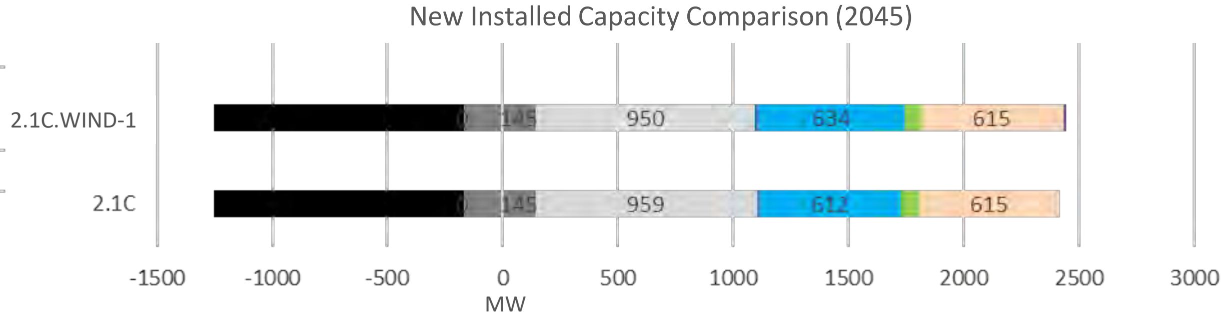
2.1C.WIND-1 (LOW WIND COST)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION









2.1C.WIND-1 (LOW WIND COST)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

	Sensitivity	Base (2.1C)
25-yr NPVRR ($MM)	$12,978	$13,141
25-yr NPVRR w/ End Effects ($MM)	$17,460	$17,767
10-yr NPVRR ($MM)	$7,132	$7,067
Average Annual Partial Rate Impact		
2021-2030 (%)	0.5%	0.6%
2021-2045 (%)	0.6%	0.7%
Total CO_2 Emissions 2021-2030 (MT)	30.5	41.8
Total CO_2 Emissions 2031-2045 (MT)	26.1	29.1
Total CO_2 Emissions 2021-2045 (MT)	56.6	70.9

General Notes
- Low wind price advances build of significant wind quantities from 2030 in base case to 2025; Reliability Tie is advanced as well to enable integration
- Earlier build of Regional Interconnection relative to 2.1C allows procurement of firm capacity and delays some combustion turbine builds
- Additional wind energy enables an additional coal unit retirement in 2030 relative to 2.1C (advanced from 2036)
- Increased wind generation and earlier Regional Interconnection enables significantly reduced CO_2 emissions in the 2020s; emissions in 2031-2045 are largely unchanged
- 2045 resource plans are effectively the same
- NPVRR is reduced relative to 3.1C in two of three metrics, slightly higher in 10-yr NPV due to advancement of investment

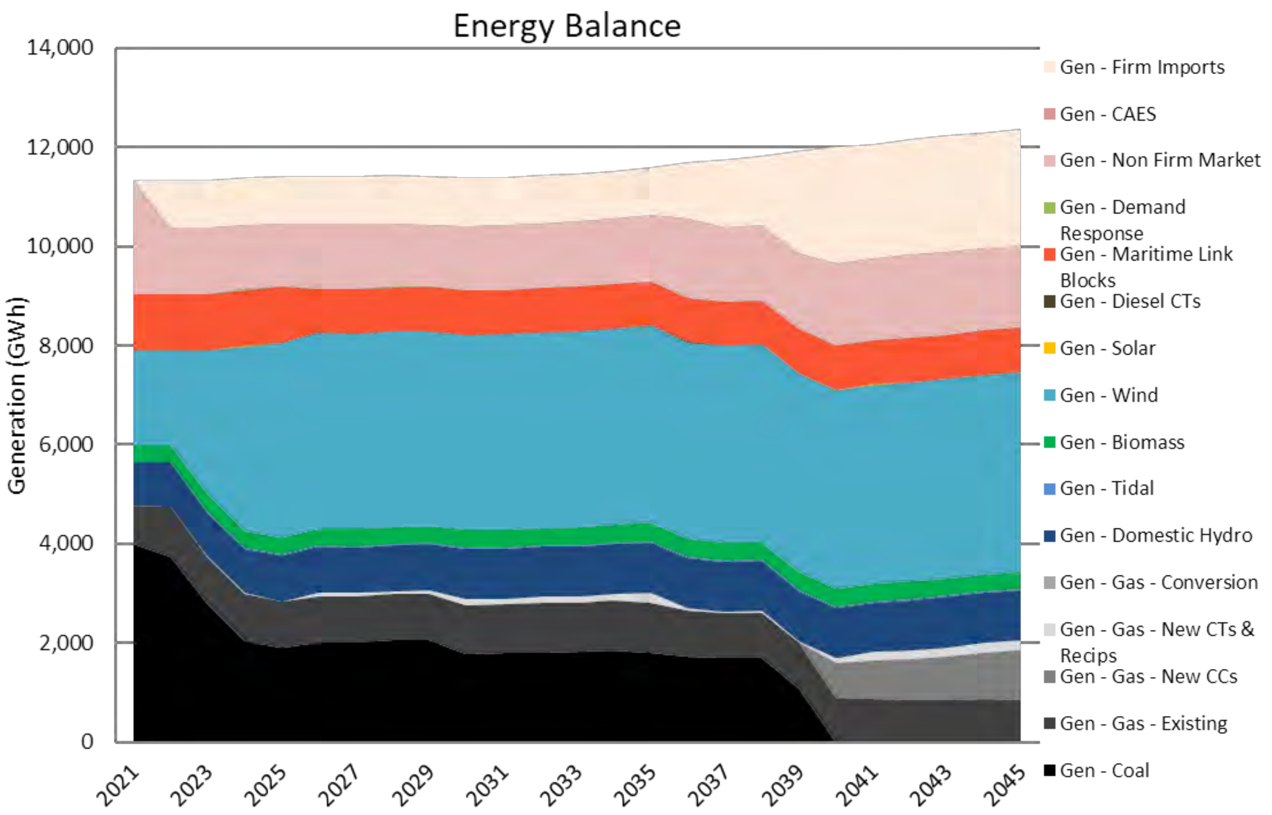
Essential Grid Services
- No change relative to 2.1C

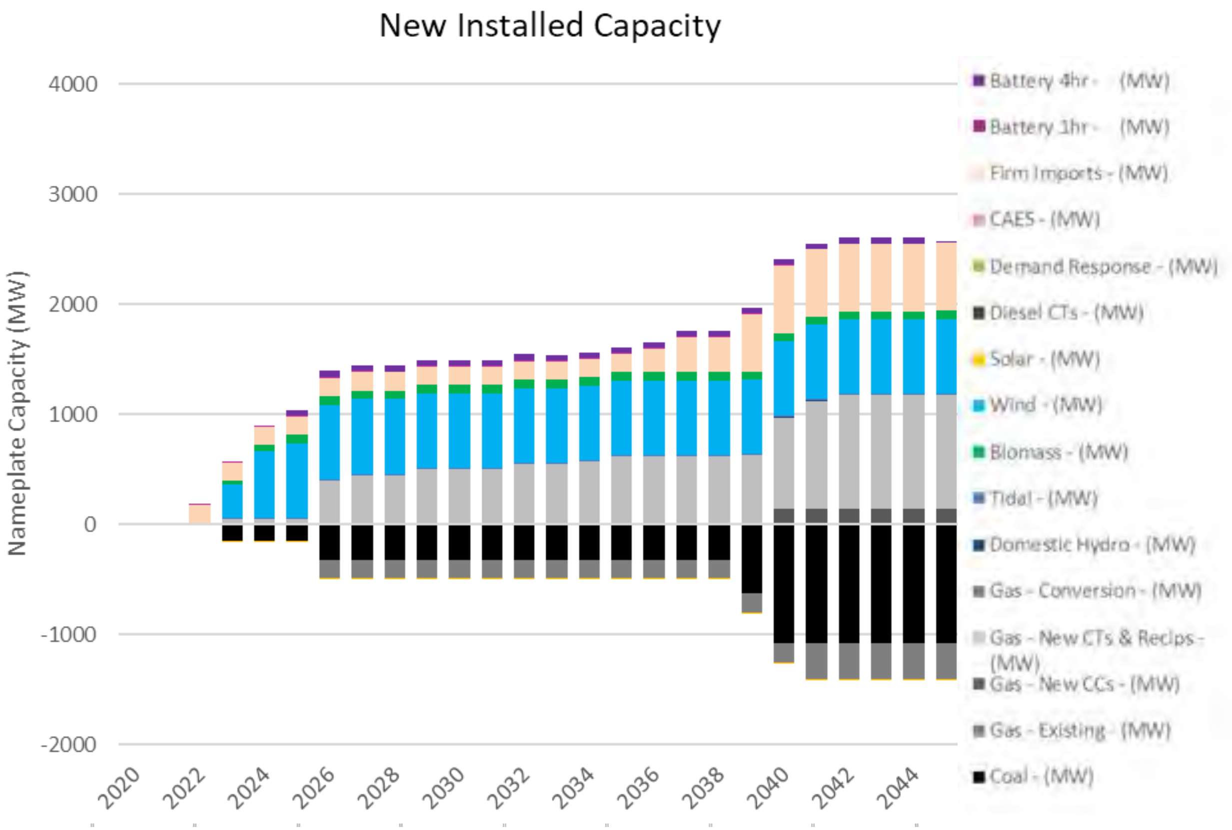
Resource Adequacy & PRM
- Reliability Tie: 2025
- Regional Integration: 2026

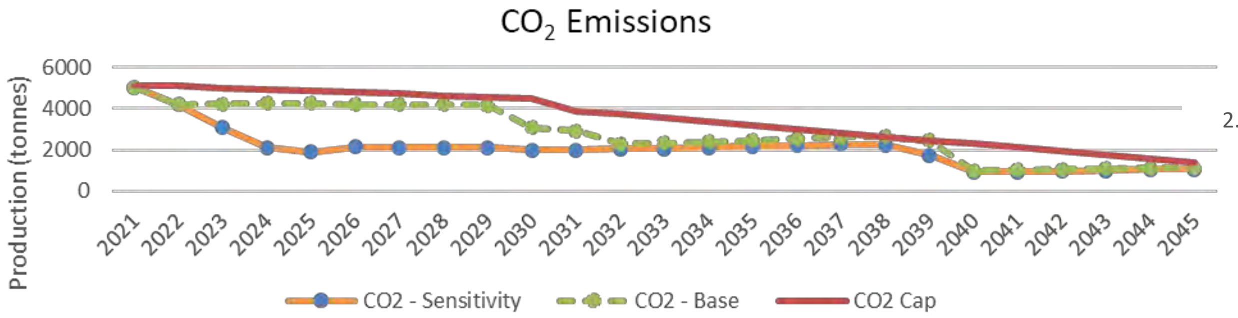
Plan Robustness & Flexibility
- Need further consideration on flexibility of import energy to balance increased wind capacity in the near term

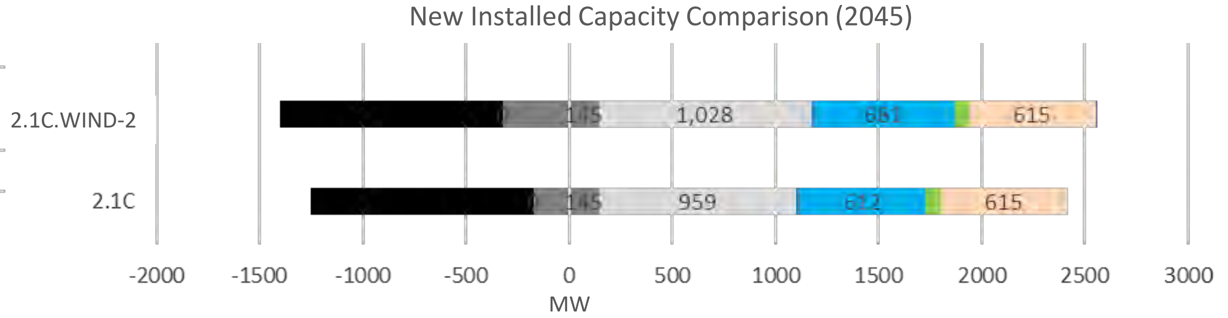
2.1C.WIND-2 (LOW WIND & BATTERY COST)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION









2.1C.WIND-2 (LOW WIND & BATTERY COST)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

	Sensitivity	Base (2.1C)
25-yr NPVRR ($MM)	$13,086	$13,141
25-yr NPVRR w/ End Effects ($MM)	$17,519	$17,767
10-yr NPVRR ($MM)	$7,177	$7,067
Average Annual Partial Rate Impact		
2021-2030 (%)	0.5%	0.6%
2021-2045 (%)	0.6%	0.7%
Total CO_2 Emissions 2021-2030 (MT)	26.8	41.8
Total CO_2 Emissions 2031-2045 (MT)	24.9	29.1
Total CO_2 Emissions 2021-2045 (MT)	51.7	70.9

General Notes
- In general, resource plan changes are similar to what is seen in 2.1C.WIND-1 sensitivity but more pronounced
- Low wind and battery prices advance build of significant wind quantities from 2030 in base case to 2024; Reliability Tie is advanced as well to enable integration along with additional integration provided by batteries
- Regional Integration is unchanged relative to 2.1C at 2036
- Additional wind energy enables an additional coal unit retirement in 2026 relative to 2.1C (advanced from 2036)
- Increased wind generation enables significantly reduced CO_2 emissions in the 2020s; emissions in 2031-2045 are largely unchanged
- 2045 resource plans show more wind and more CTs, and 1 additional retired gas steam unit
- NPVRR is reduced relative to 3.1C in two of three metrics, slightly higher in 10-yr NPV due to advancement of investment

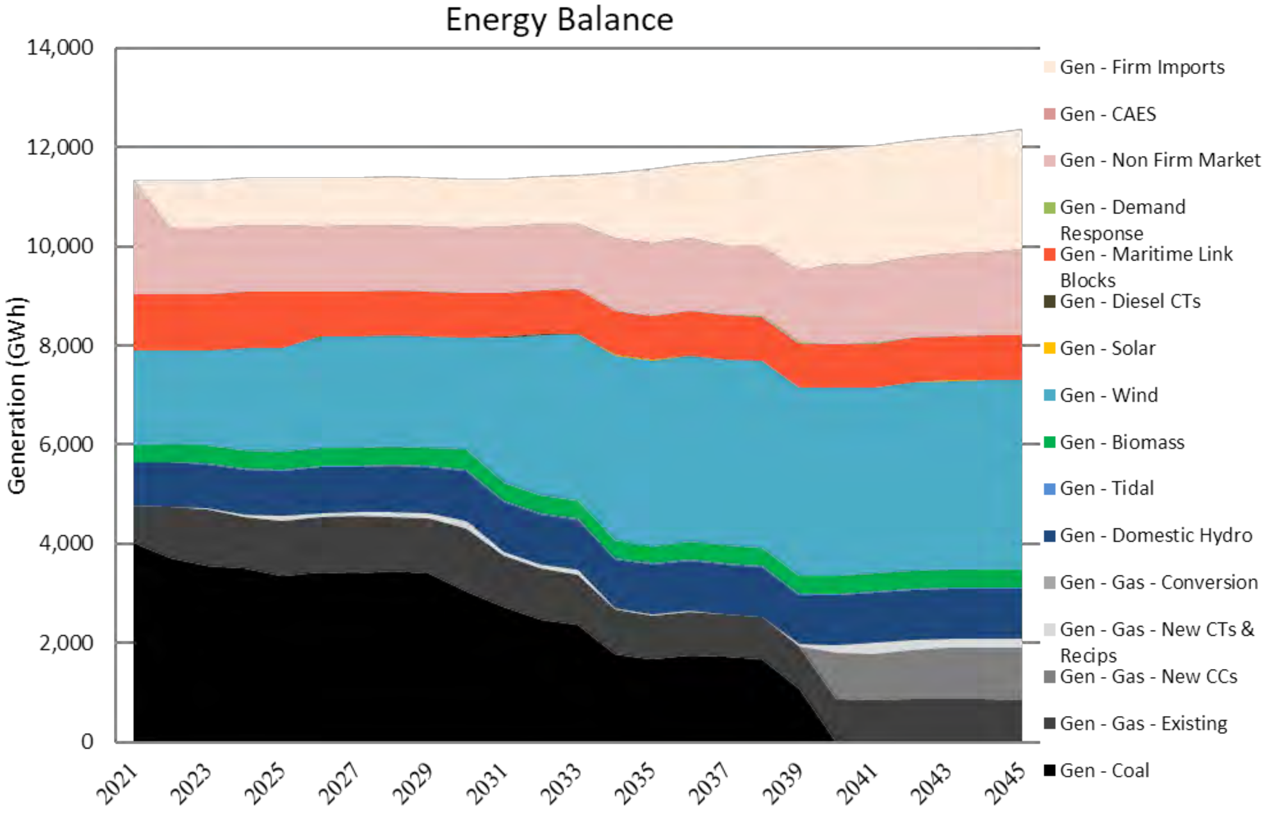
Essential Grid Services
- No change relative to 2.1C

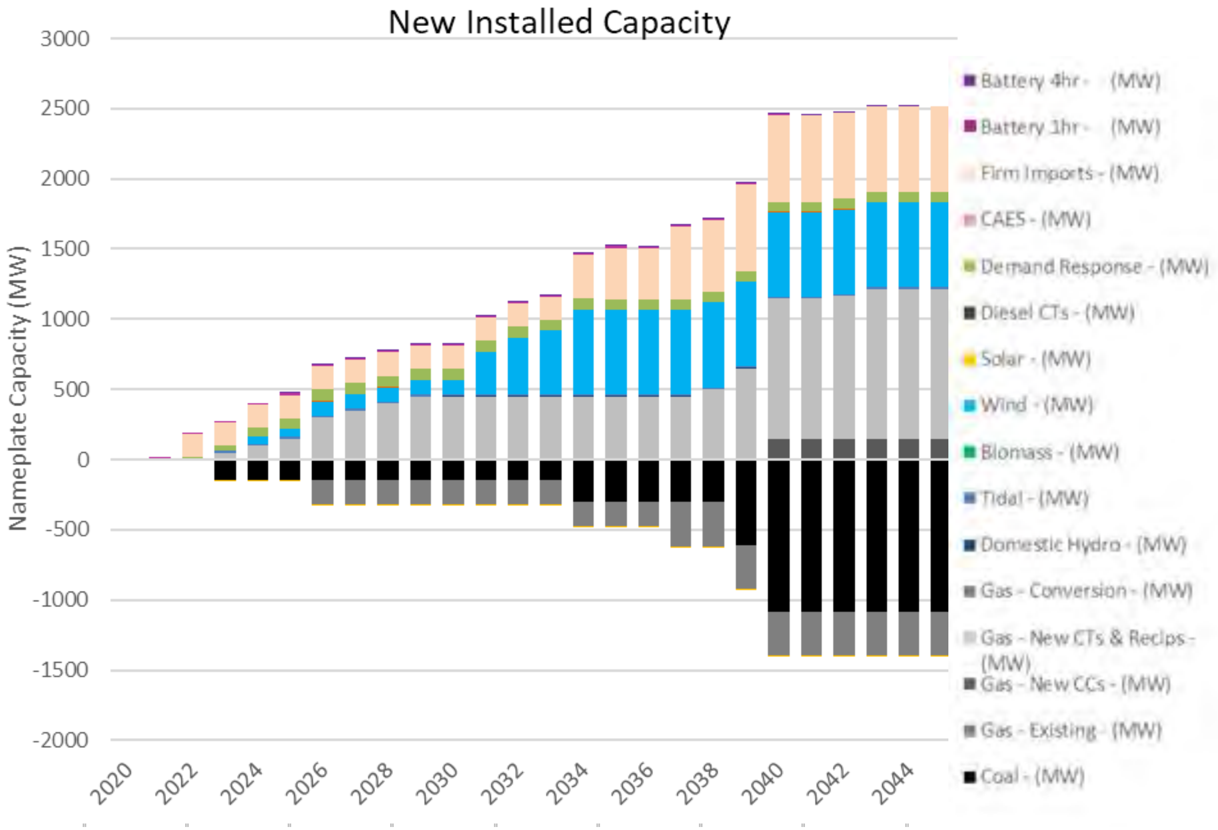
Resource Adequacy & PRM
- Reliability Tie: 2023
- Regional Integration: 2036

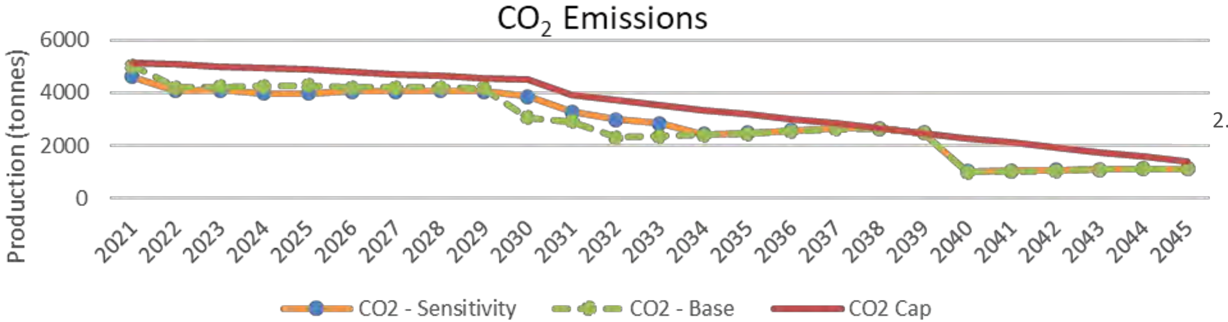
Plan Robustness & Flexibility
- Need further consideration on flexibility of import energy to balance increased wind capacity in the near term

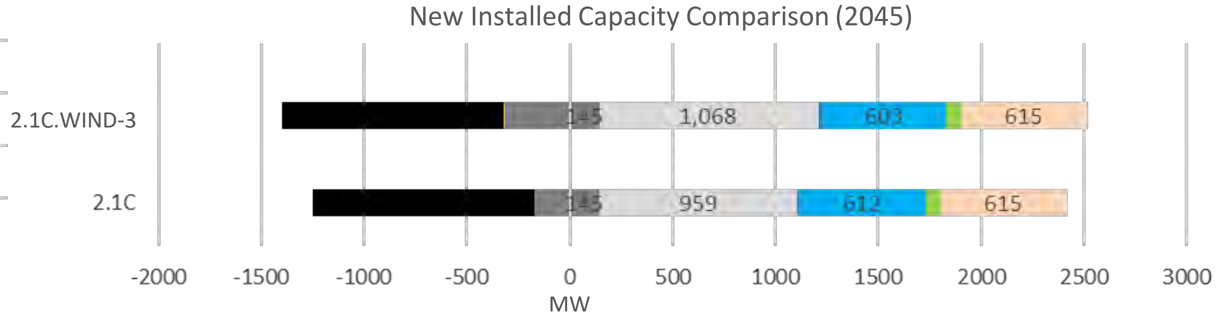
2.1C.WIND-3 (LOW INERTIA CONSTRAINT)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION









2.1C.WIND-3 (LOW INERTIA CONSTRAINT)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

	Sensitivity	Base (2.1C)
25-yr NPVRR ($MM)	$13,059	$13,141
25-yr NPVRR w/ End Effects ($MM)	$17,653	$17,767
10-yr NPVRR ($MM)	$7,000	$7,067
Average Annual Partial Rate Impact		
2021-2030 (%)	0.5%	0.6%
2021-2045 (%)	0.7%	0.7%
Total CO_2 Emissions 2021-2030 (MT)	40.8	41.8
Total CO_2 Emissions 2031-2045 (MT)	30.9	29.1
Total CO_2 Emissions 2021-2045 (MT)	71.7	70.9

General Notes

- Inertia constraint is lowered from base of 3266 MW.sec to 2200 MW.sec in all hours
- Slight change to wind profile build is observed:
  - Initial no integration build is 50MW 2024 / 50 MW 2026, vs. 100MW 2026 in 2.1C
  - Reliability Tie is built one year later and 500MW wind build is staged from 2031-2034 rather than 2030-2032 as seen in 2.1C
  - In both cases relatively little wind build via local integration option
- Incremental production cost savings are achieved via fewer thermal units online in early years of planning horizon; potential that this slightly delays the Reliability Tie build
- One additional gas steam unit is retired and replaced with incremental CT capacity
- Results suggest that lowering the inertia constraint in isolation has a limited impact on overall resource plan optimization
- Cost differences are small over all three NPV metrics

Essential Grid Services

- Current studies indicate that 2200MW.sec of online kinetic inertia is not sufficient to reliably operate the NS Power system today; additional stability studies required to confirm potential impacts and mitigations, or dynamic operating constraints based on system state

Resource Adequacy & PRM

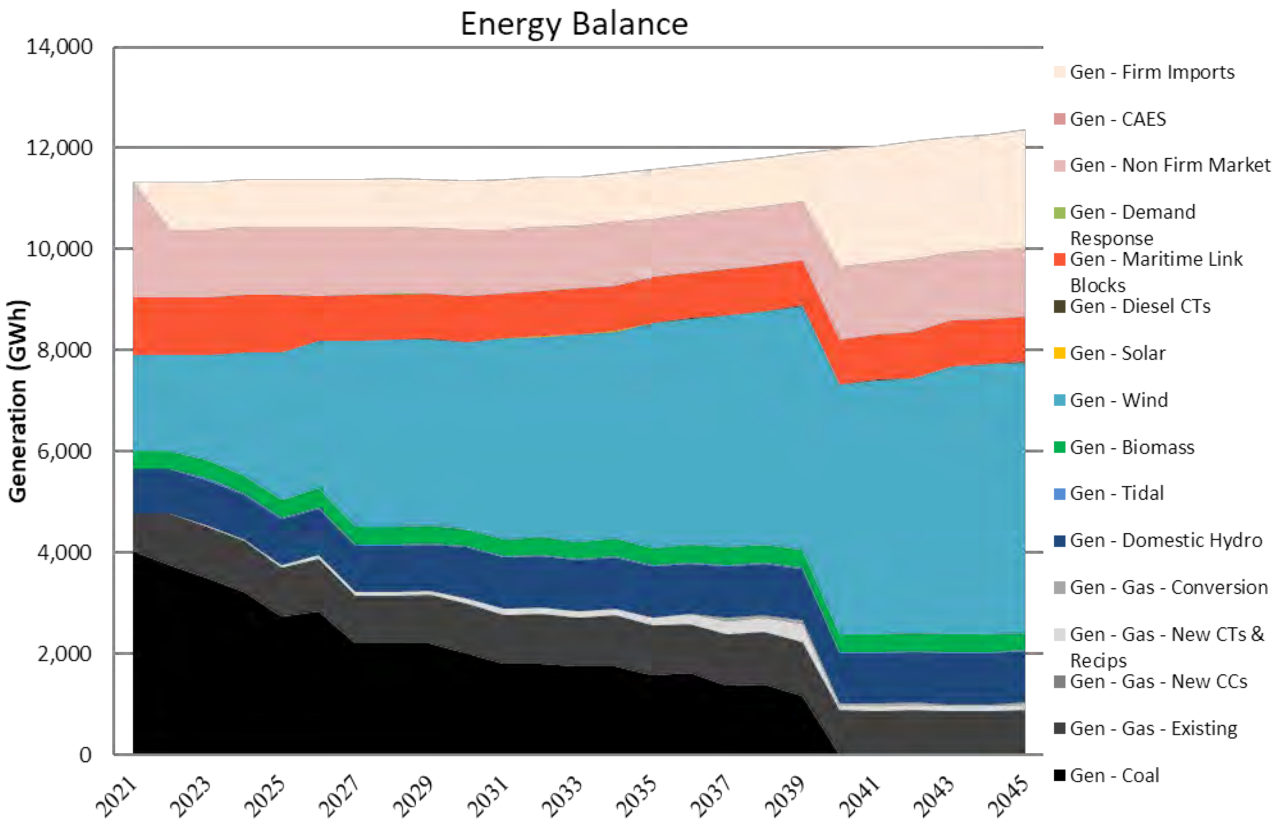
- Reliability Tie: 2031
- Regional Integration: 2034

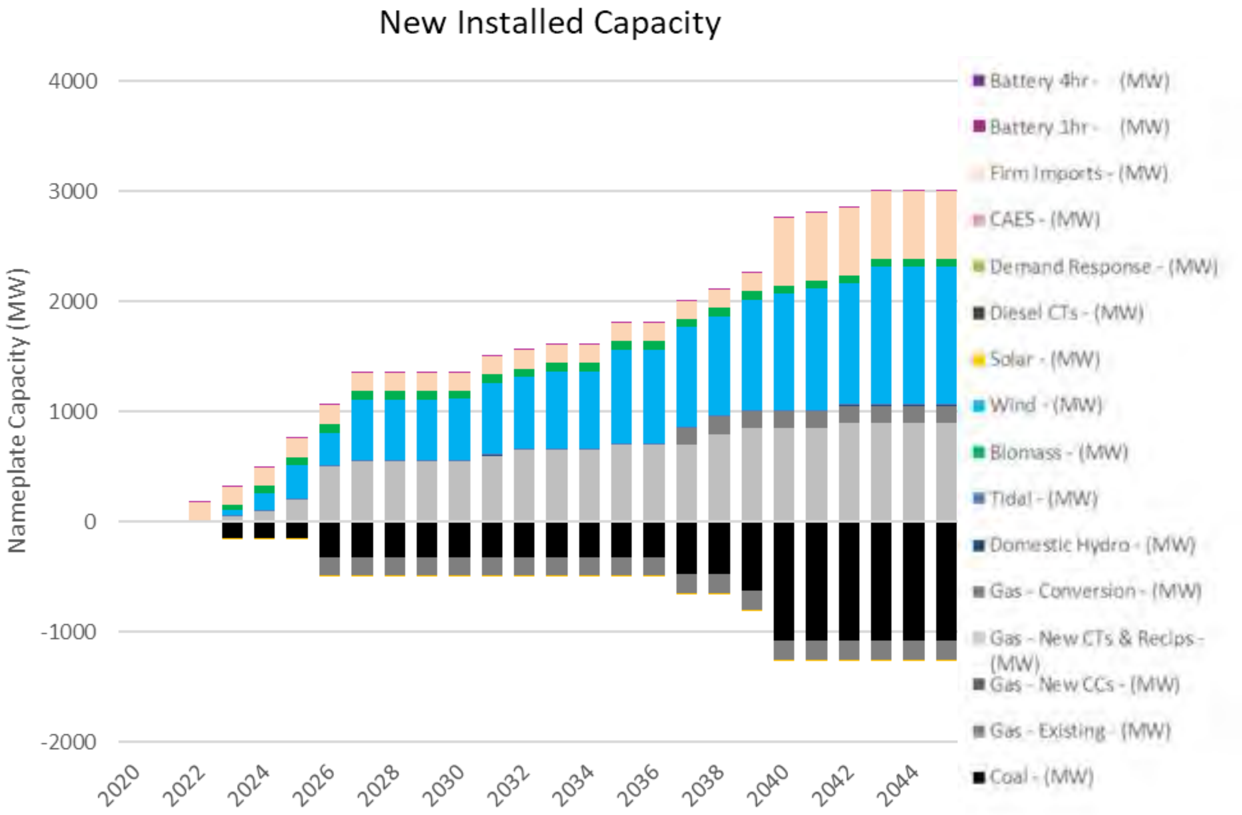
Plan Robustness & Flexibility

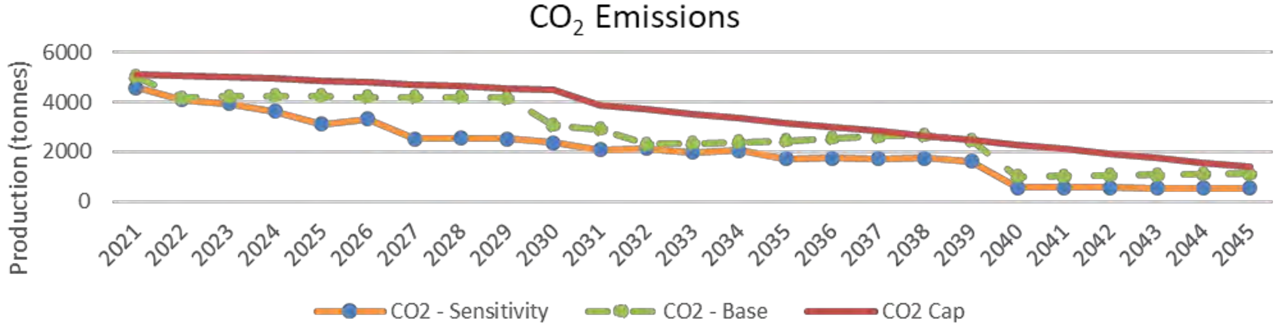
- No change from 2.1C

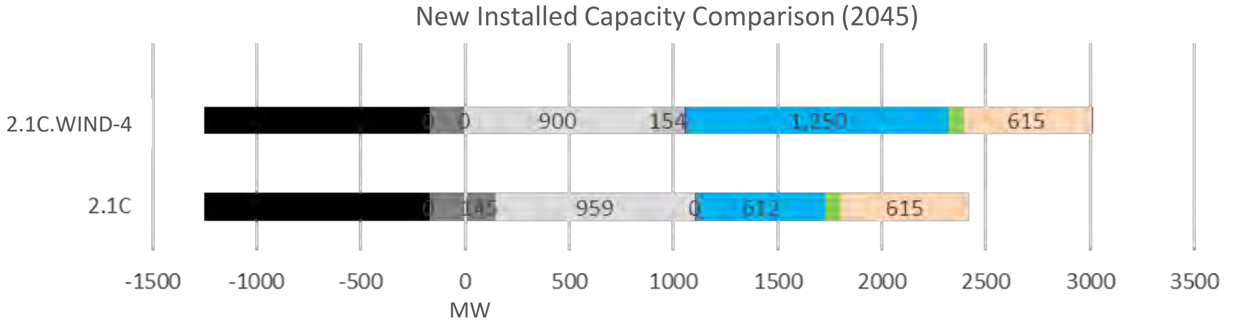
2.1C.WIND-4 (NO INERTIA / NO INTEGRATION)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION









2.1C.WIND-4 (NO INERTIA / NO INTEGRATION)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

	Sensitivity	Base (2.1C)
25-yr NPVRR ($MM)	$13,076	$13,141
25-yr NPVRR w/ End Effects ($MM)	$17,734	$17,767
10-yr NPVRR ($MM)	$7,049	$7,067
Average Annual Partial Rate Impact		
2021-2030 (%)	0.4%	0.6%
2021-2045 (%)	0.7%	0.7%
Total CO_2 Emissions 2021-2030 (MT)	32.7	41.8
Total CO_2 Emissions 2031-2045 (MT)	20.1	29.1
Total CO_2 Emissions 2021-2045 (MT)	52.8	70.9

General Notes
- Model builds more wind relative to base case, with 200MW incremental added by 2030 and 250MW incremental by 2035, and 638MW incremental in 2045
- 1 coal to gas conversion is selected, replacing a NGCC unit from the base case
- PLEXOS MT/ST simulations show that curtailment reached 828 GWh in 2045 (13.4%), vs. 208 GWh in 2045 (5.2%) in the 2.1C base case
- Due to curtailment and replacement energy costs, NPVs incorporating MT/ST Production Costs are not significantly lower than the base scenario 2.1C

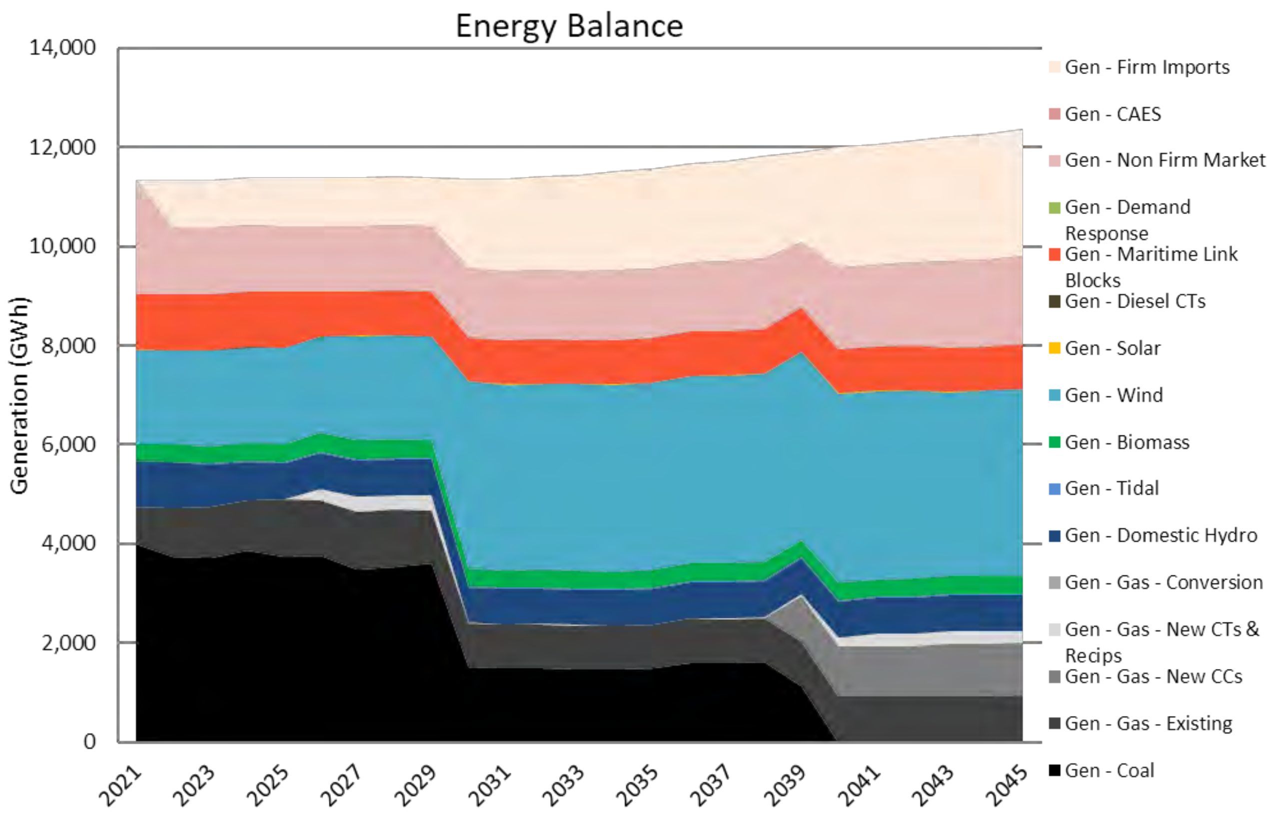
Essential Grid Services
- This run is intended as a test case to understand how the model will perform with no inertia constraint and no integration requirements for wind (i.e. Reliability Tie or Local Integration options); it is not a feasible resource plan but rather an extreme bookend

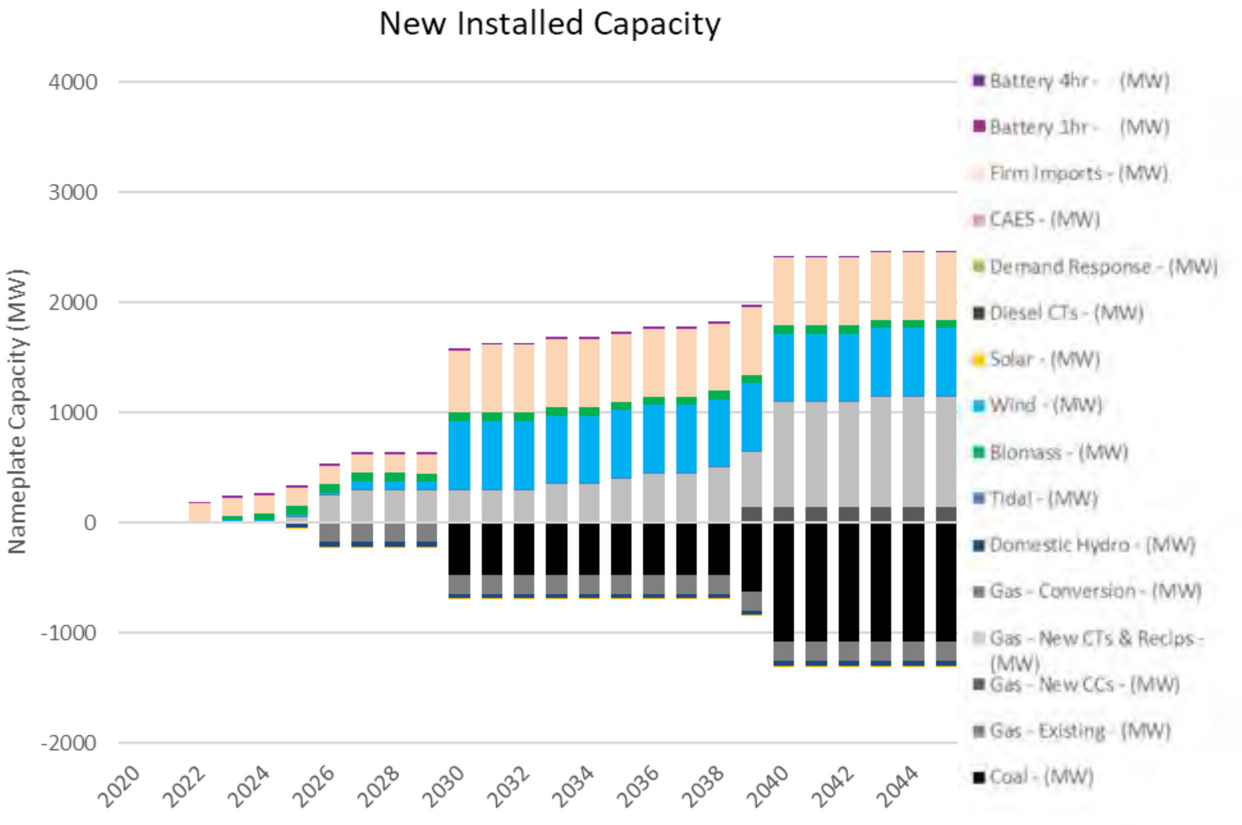
Resource Adequacy & PRM
- Reliability Tie: 2040
- Regional Integration: 2040
- Reliability Tie was built economically as part of Regional Integration to access firm capacity and energy; not required in this run for wind

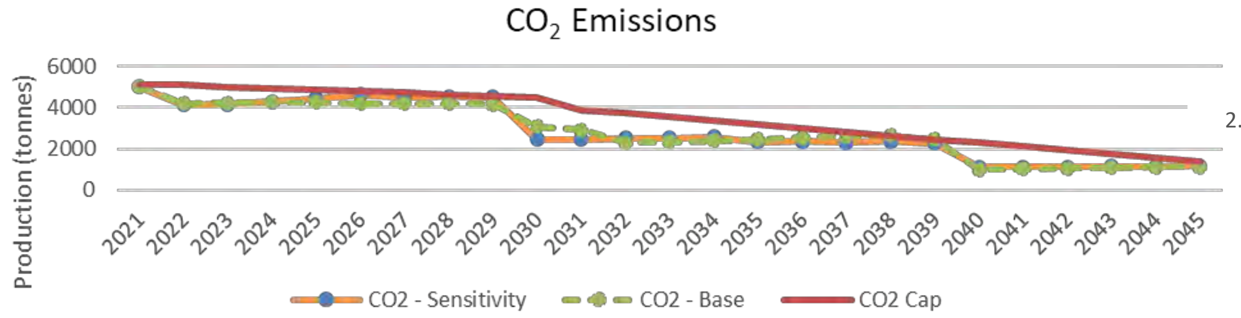
Plan Robustness & Flexibility
- Significant wind penetration could be challenging to operate under some conditions
- The plan has retained flexibility of supply by adding the Regional Integration resource

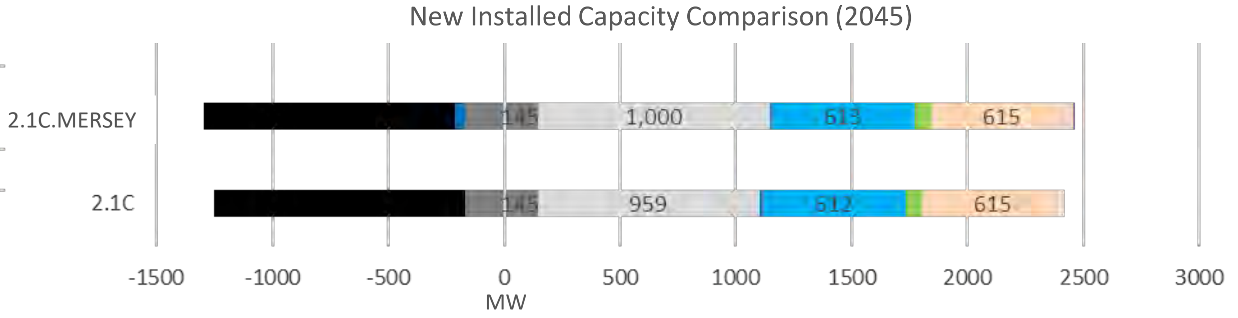
2.1C.MERSEY (MERSEY HYDRO RETIRED)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION









2.1C.MERSEY (MERSEY HYDRO RETIRED)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

	Sensitivity	Base (2.1C)
25-yr NPVRR ($MM)	$13,097	$13,141
25-yr NPVRR w/ End Effects ($MM)	$17,845	$17,767
10-yr NPVRR ($MM)	$6,885	$7,067
Average Annual Partial Rate Impact		
2021-2030 (%)	0.6%	0.6%
2021-2045 (%)	0.7%	0.7%
Total CO_2 Emissions 2021-2030 (MT)	42.7	41.8
Total CO_2 Emissions 2031-2045 (MT)	28.5	29.1
Total CO_2 Emissions 2021-2045 (MT)	71.2	70.9

General Notes

- While the Mersey system was economically retained in the screening phase, this sensitivity was completed in order to understand how capacity and energy would be replaced
- Mersey Hydro is assumed to retire in 2025 in this scenario
- Regional Integration build is advanced from 2036 to 2030, and significant wind build occurs in 2030 rather than 2032
- By the end of the planning horizon, the build is similar but with 40MW of incremental combustion turbine capacity accounting for the retirement of Mersey Hydro
- Mersey Decommissioning Cost ($227MM) is external to PLEXOS but included in Sensitivity NPV and Rate Impact results as an extrinsic cost

Essential Grid Services

- Decommissioning of Mersey Hydro system would require system stability studies for the Western region of Nova Scotia due to changes in essential grid service provision; cost of any mitigation not included in decommissioning NPV

Resource Adequacy & PRM

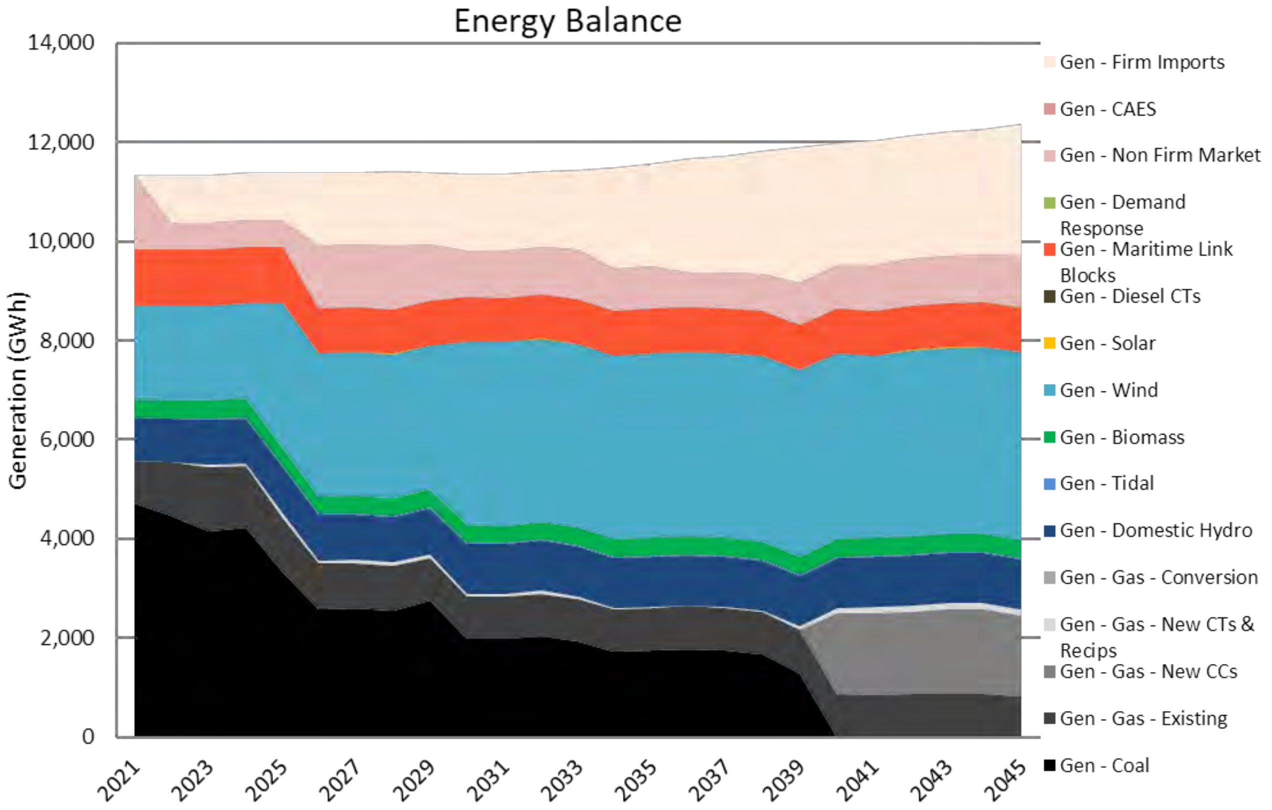
- Reliability Tie: 2030
- Regional Integration: 2030

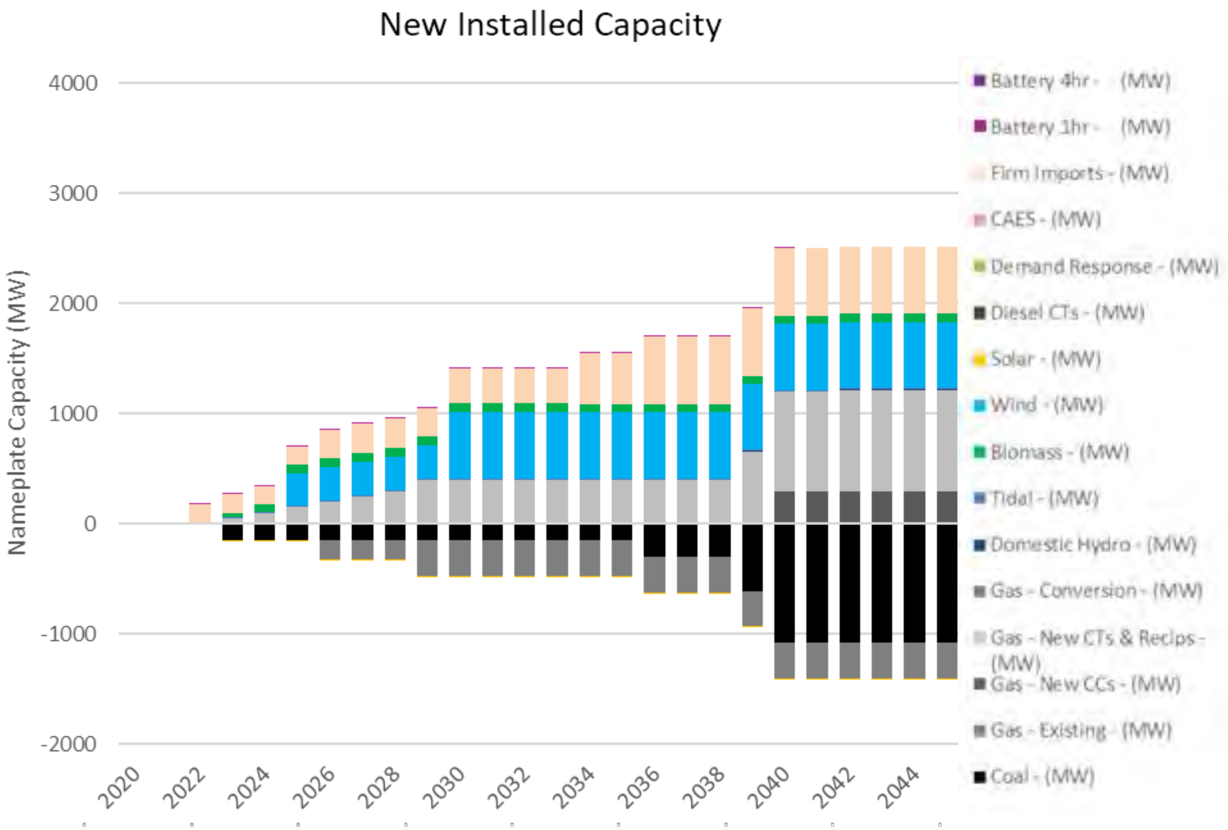
Plan Robustness & Flexibility

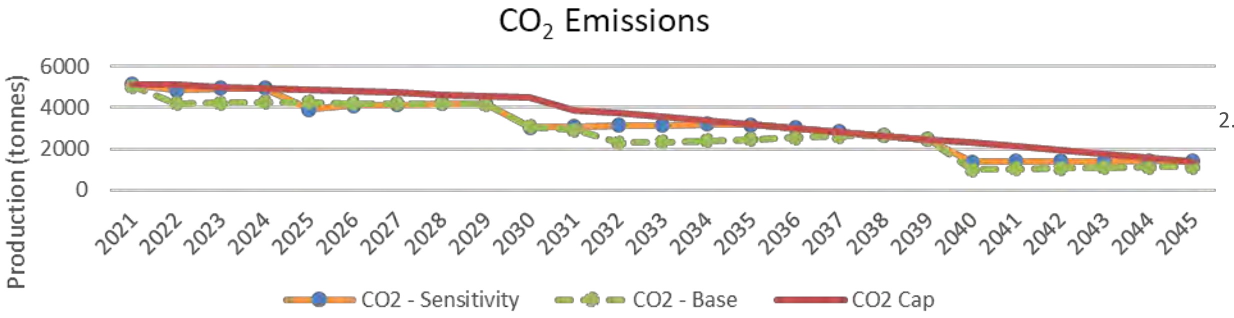
- Hydro assets are not subject to fuel price volatility and are located locally in Nova Scotia

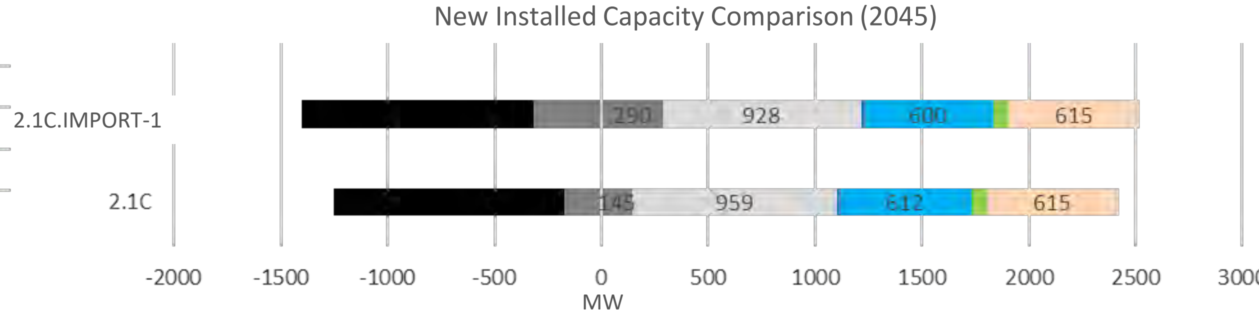
2.1C.IMPORT-1 (LIMITED NON-FIRM IMPORTS)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION









2.1C.IMPORT-1 (LIMITED NON-FIRM IMPORTS)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

	Sensitivity	Base (2.1C)
25-yr NPVRR ($MM)	$13,543	$13,141
25-yr NPVRR w/ End Effects ($MM)	$18,176	$17,767
10-yr NPVRR ($MM)	$7,373	$7,067
Average Annual Partial Rate Impact		
2021-2030 (%)	0.9%	0.6%
2021-2045 (%)	0.7%	0.7%
Total CO_2 Emissions 2021-2030 (MT)	43.5	41.8
Total CO_2 Emissions 2031-2045 (MT)	35.1	29.1
Total CO_2 Emissions 2021-2045 (MT)	78.6	70.9

General Notes

- Sensitivity reduces the maximum quantity of non-firm imports from all sources available to the model by 0.8TWh
- Model builds wind earlier in late 2020s
- Sensitivity case builds one additional NGCC and retires one additional gas steam unit but remainder of 2045 resource mix largely unchanged; generation mix sees additional procurement of firm imports to offset reduction in non-firm availability
- In general the 2.1C base resource plan is robust to a reduction in non-firm imports, but replacement energy does come at a higher cost

Essential Grid Services

- No change relative to 2.1C

Resource Adequacy & PRM

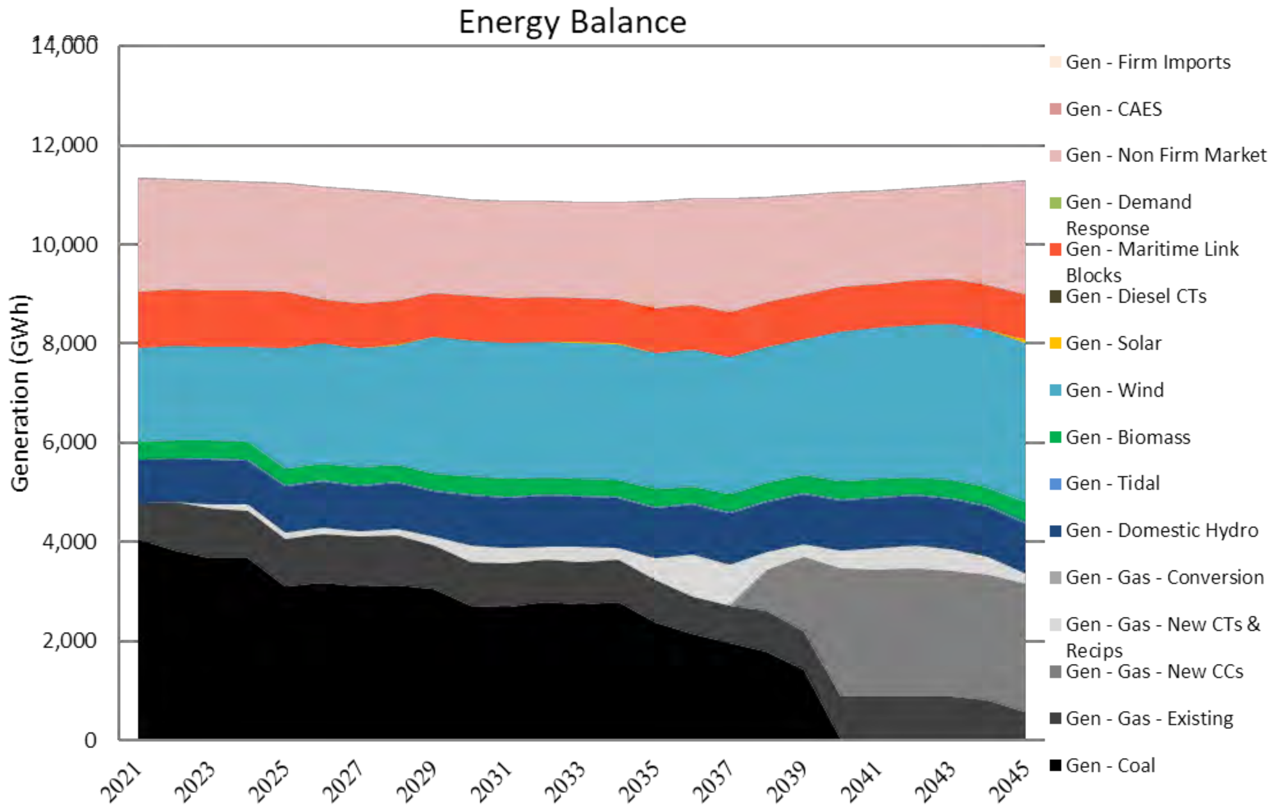
- Reliability Tie: 2024
- Regional Integration: 2026

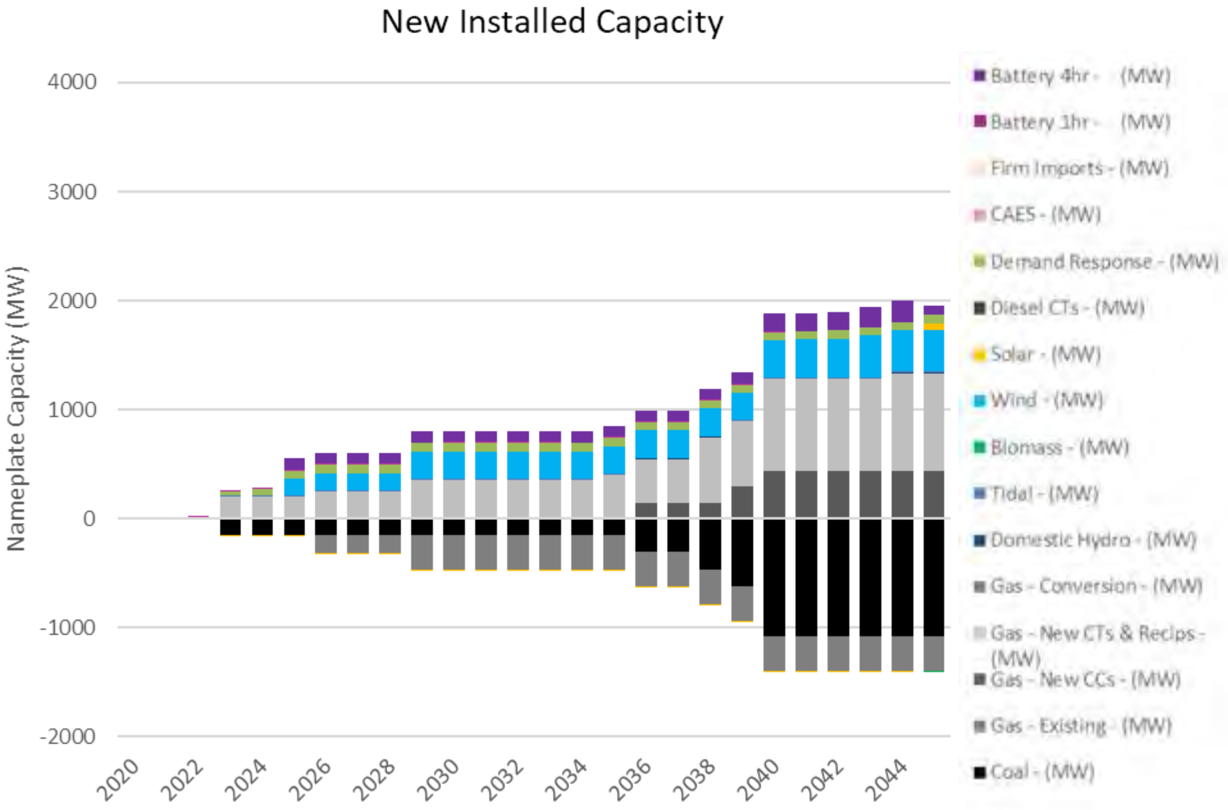
Plan Robustness & Flexibility

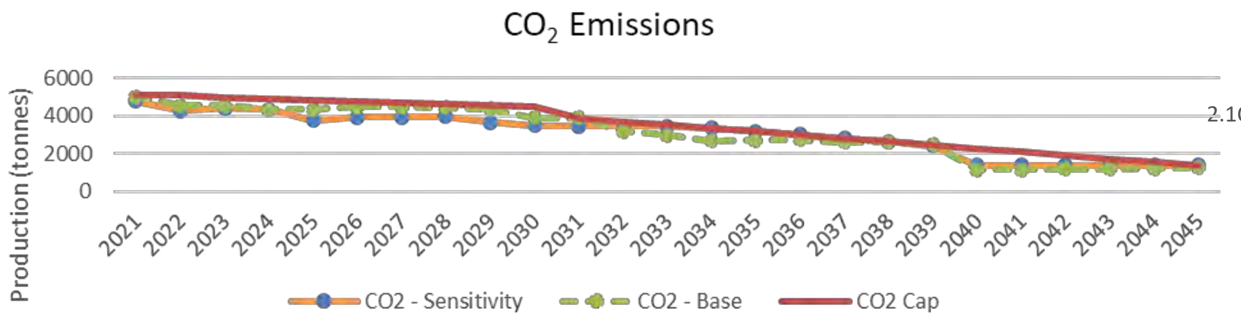
- No change relative to 2.1C

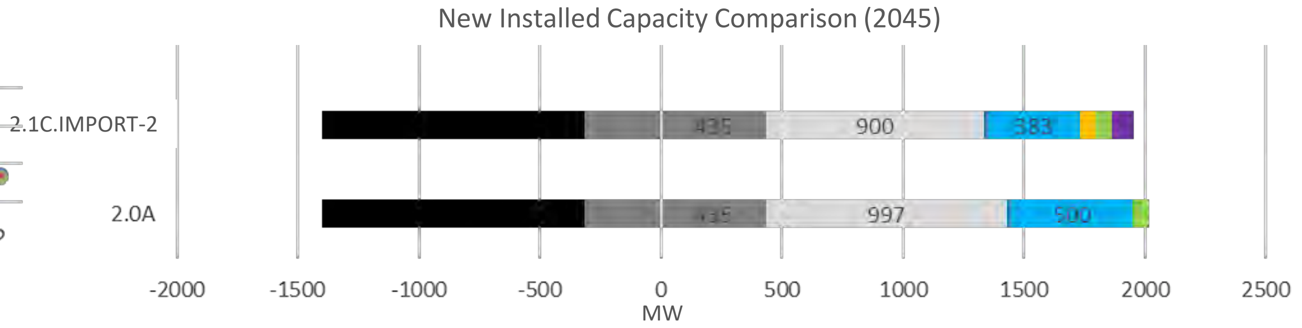
2.0A.IMPORT-2 (NO RELIABILITY TIE)

MID ELEC. / BASE DSM / NET ZERO 2050 / CURRENT LANDSCAPE









2.0A.IMPORT-2 (NO RELIABILITY TIE)

MID ELEC. / BASE DSM / NET ZERO 2050 / CURRENT LANDSCAPE

Scenario Metrics & Evaluation

	Sensitivity	Base (2.0A)
25-yr NPVRR ($MM)	$12,628	$12,351
25-yr NPVRR w/ End Effects ($MM)	$16,965	$16,609
10-yr NPVRR ($MM)	$6,951	$6,831
Average Annual Partial Rate Impact		
2021-2030 (%)	1.0%	0.9%
2021-2045 (%)	1.1%	1.0%
Total CO_2 Emissions 2021-2030 (MT)	40.6	44.5
Total CO_2 Emissions 2031-2045 (MT)	36.2	33.2
Total CO_2 Emissions 2021-2045 (MT)	76.8	77.7

General Notes

- Without the ability to build the Reliability Tie, wind is built via the local integration option (batteries + synchronous condensers), which also contribute to system inertia requirements
- Total quantity of wind built is less and batteries are added for wind integration; remainder of resource plan is similar
- Costs are higher than the base 2.0A scenario for all NPV metrics

Essential Grid Services

- High inertia synchronous condensers contribute kinetic inertia in addition to online thermal generation

Resource Adequacy & PRM

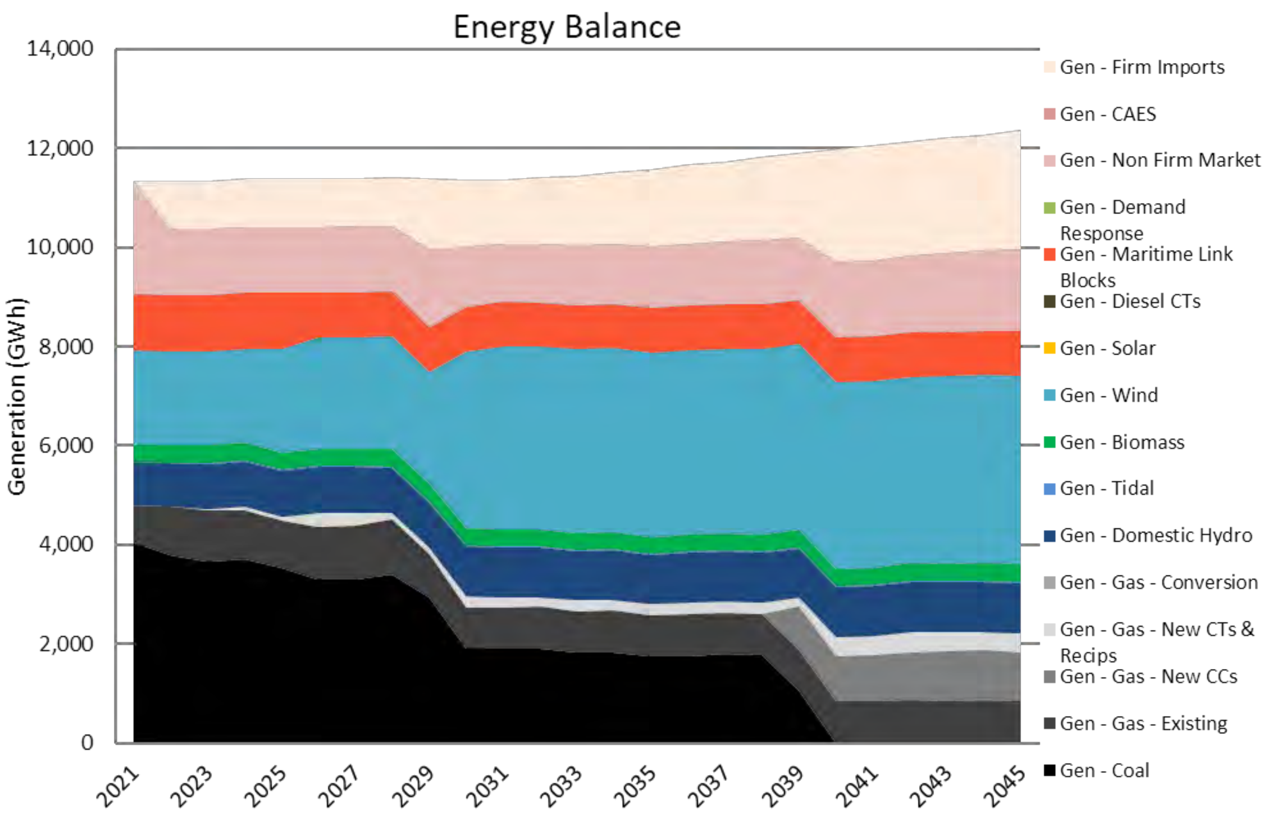
- Reliability Tie: n/a
- Regional Integration: n/a

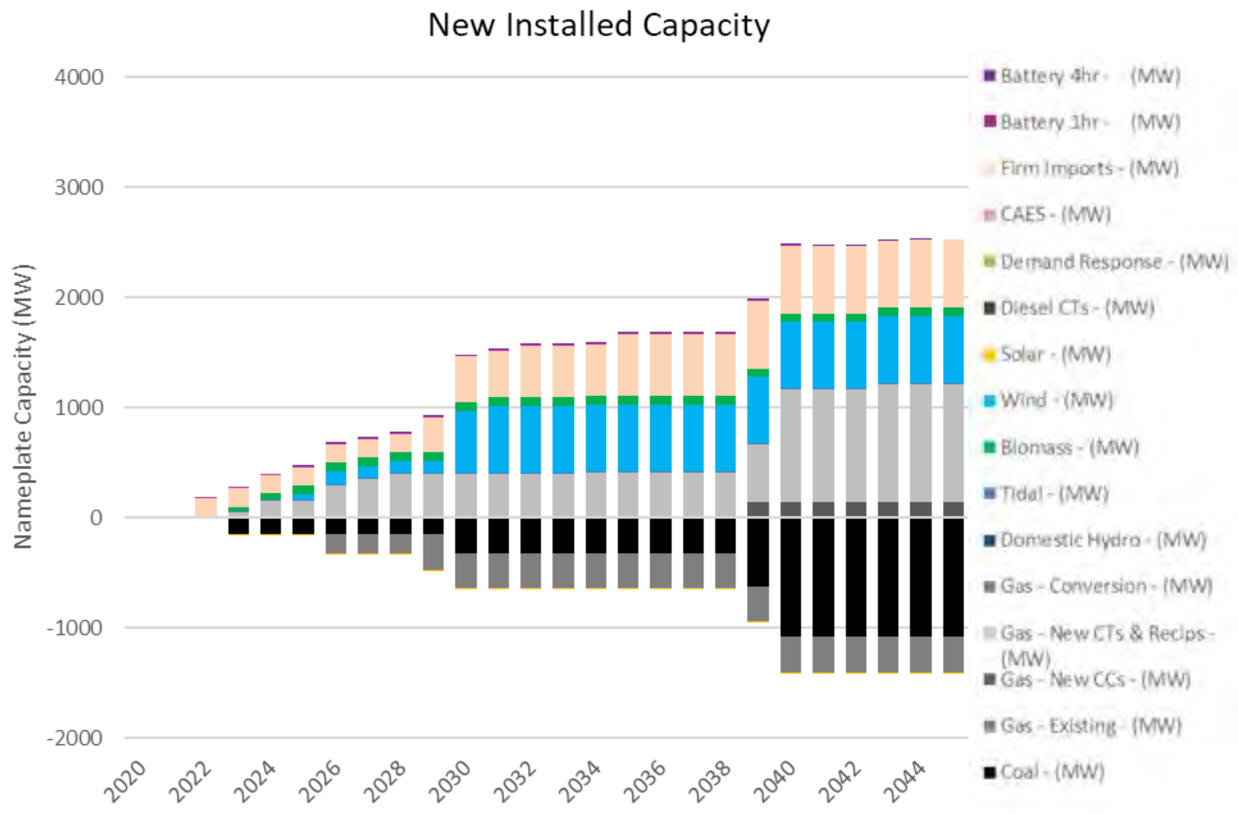
Plan Robustness & Flexibility

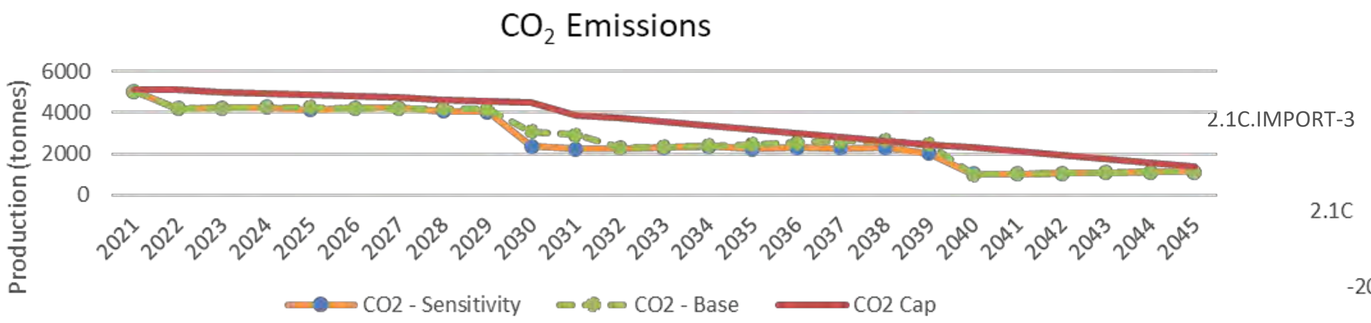
- No change relative to 2.0A

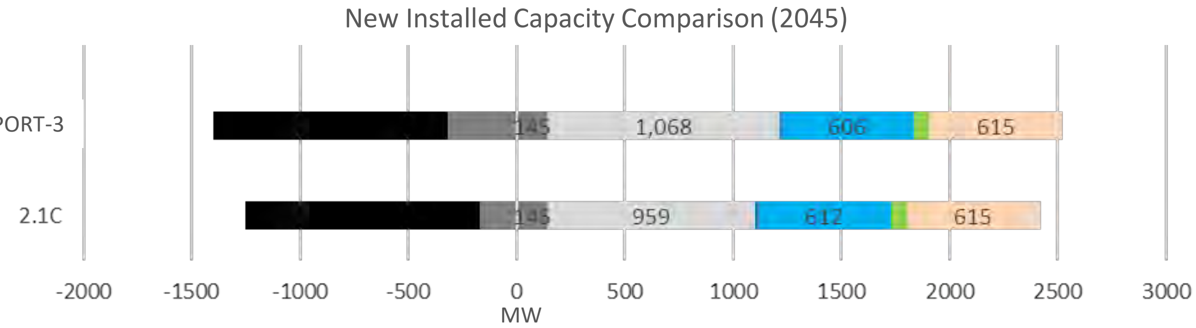
2.1C.IMPORT-3 (LIMITED RELIABILITY TIE INERTIA)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION









2.1C.IMPORT-3 (LIMITED RELIABILITY TIE INERTIA)

MID ELEC. / BASE DSM / NET ZERO 2050 / REGIONAL INTEGRATION

Scenario Metrics & Evaluation

	Sensitivity	Base (2.1C)
25-yr NPVRR ($MM)	$13,225	$13,141
25-yr NPVRR w/ End Effects ($MM)	$17,842	$17,767
10-yr NPVRR ($MM)	$7,111	$7,067
Average Annual Partial Rate Impact		
2021-2030 (%)	0.8%	0.6%
2021-2045 (%)	0.7%	0.7%
Total CO_2 Emissions 2021-2030 (MT)	40.8	41.8
Total CO_2 Emissions 2031-2045 (MT)	26.8	29.1
Total CO_2 Emissions 2021-2045 (MT)	67.6	70.9

General Notes

- In this scenario the Reliability Tie contributes only 50% of required system inertia once built (i.e. 1633 MW.sec); intention of scenario is to test robustness of the assumption that Reliability Tie can supply all system inertia requirements
- Reliability Tie and Regional Integration are built slightly earlier in this scenario, with some accompanying earlier retirements as well, likely because more flexible units are easier to satisfy the remaining inertia requirement with
- Generation mix is generally unchanged from 2.1C on an annual basis
- Costs are relatively close to 2.1C on all NPV metrics

Essential Grid Services

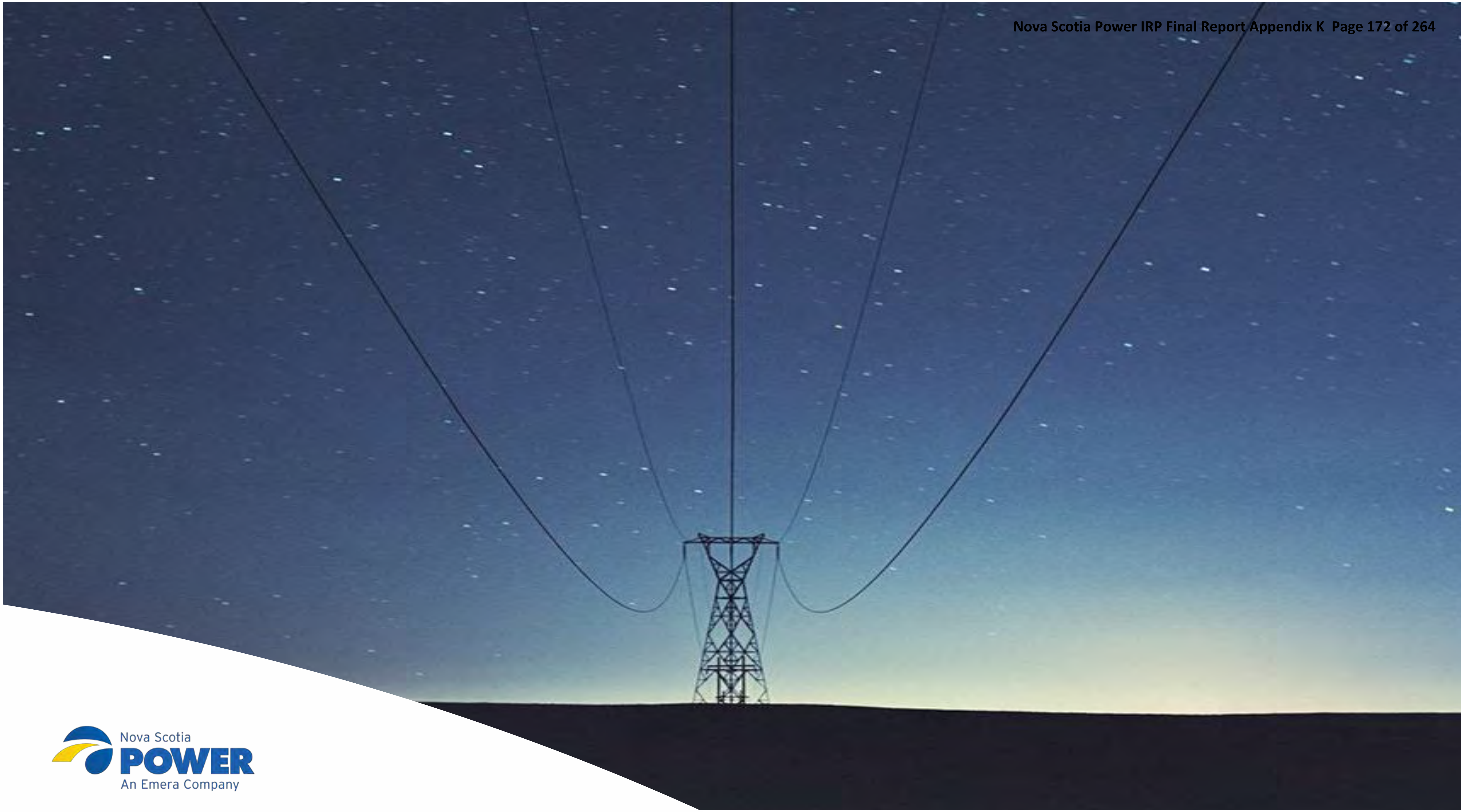
- No change from 2.1C

Resource Adequacy & PRM

- Reliability Tie: 2028
- Regional Integration: 2029

Plan Robustness & Flexibility

- No change from 2.1C



Alternative
RESOURCE ENERGY AUTHORITY

Nicole Godbout
Director of Regulatory Affairs
Nova Scotia Power Inc
Delivered via email to nicole.godbout@nspower.ca

25 September 2020

Re: Letter of Comment Regarding IRP's Draft Findings, Action Plan and Roadmap

Dear Ms. Godbout,

The Alternative Resource Energy Authority (AREA) has reviewed the Draft Findings, Action Plan, and Roadmap circulated to stakeholders by Nova Scotia Power Inc. (NS Power) on September 2, 2020. Due to other commitments, AREA was not able to meet the September 18, 2020 deadline for written comments on these materials. AREA has now had the benefit of reviewing the comments filed by Natural Forces Services Inc. (Natural Forces) on September 18, 2020, including the report of its technical advisor, Cooke Energy & Utility Consulting (Cooke), and requests that NS Power also consider the following brief comments filed on AREA's behalf.

AREA is in general agreement with the comments and technical report submitted by Natural Forces. In particular, AREA fully supports the key point emphasized by Natural Forces regarding the cost of wind that has been modeled in the IRP. AREA also agrees with the comments at page 2 of Cooke's report that NS Power's modeling analysis of intermittent wind should allow wind to be installed on an economic level, and accepting that on rare occasions it may be necessary to curtail wind output to ensure the system remains stable.

As noted in AREA's February 14 comments on the Input Assumptions, AREA continues to believe that alternative, lower-cost, non-NS Power financing models need to be fully considered as part of the transformation of Nova Scotia's electricity system. NSPI previously indicated that such ownership structures are captured in the "low case" scenarios. AREA believes that too many realistic individual market conditions (lower wind installed costs, higher wind net capacity factors, lower costs of capital, etc) are blended into the "low case" making it difficult to separate and study their specific effects on the pace of cost-effective decarbonization.

AREA looks forward to receipt of NS Power's Draft IRP report on September 29, 2020, and hopes that it will address the specific points raised by Natural Forces and Cooke. AREA expects it will submit additional comments for NS Power's consideration following review of the Draft IRP Report.

Thank you for considering our input.

Regards,

Aaron Long

Aaron Long
Director of Business Services

Alternative Resource Energy Authority, c/o Town of Antigonish
274 Main Street, Antigonish NS B2G2C4

Resource Insight Inc.

MEMORANDUM

To: Linda Lefler, Senior Project Manager, Regulatory Affairs
Nova Scotia Power

From: John D. Wilson and Paul Chernick

Date: September 18, 2020

Subject: Comments on latest IRP materials

Thank you for the opportunity to comment on the draft findings, action plan, and related materials. We also appreciate the stakeholder engagement which has contributed substantially to our understanding of the plans. NS Power has demonstrated significant responsiveness to input from stakeholders.

Our specific questions and recommendations are numbered throughout this memo.

Clarifications and additional information

In the IRP plan, we anticipated that there would be cost sensitivities for selected portfolios, such as fuel cost sensitivities.

1. Will those cost sensitivities be performed?

The individual model run results refer to “average annual partial rate impact” but the summary slide “relative rate impact comparison” does not reference the word “partial.”

2. Is there a difference between what is being shown on the relative comparison slide and the individual model run result summaries?

Resource Questions and Comments

The wind, battery, inertia, and transmission related sensitivities address some, but not all, of the issues that need resolution to reach clear findings and have a well supported action plan. Below, we discuss some of the resource-specific questions that NS Power should address.

Two technical issues that we would raise at a general level. First, it is not clear whether Plexos makes unit commitment decisions to satisfy operating reserve requirements and meet inertia constraints sequentially or through co-optimization. Regardless of the answer, the interaction between these two requirements seems to be a significant driver of model output, and NS Power should verify that it has configured its model in a manner that handles all of the sensitivities in a reasonable manner.

Second, other more general model configuration decisions may affect sensitivity runs in ways that were not evident in the testing for the main cases. For example, the chronologies used in Plexos LT testing may have been optimal under the default assumptions around inertia but may not capture the different challenges of operating with lower inertia constraints, which are only tested for the 2.1C case.

3. Please provide discussion of the issues NS Power has evaluated in its model configuration decisions.

Wind resources

The sensitivities indicate that the near-term benefit of wind procurement depends strongly on price. NS Power has also evaluated the capability of the system to operate reliably with a high level of near-term wind procurement (prior to completing the reliability tie), which NS Power believes may depend on either the cost-effectiveness of battery storage or on the development of operational practices that address the reliability. Either battery storage or operational practices would have some impact on the economics of the wind procurement.

Our review of the model results suggests that wind resource pricing is a more significant driver than considerations of reliability. Reducing the inertia requirement advances a small amount of early wind (2.1C v 2.1C.WIND-3), but also *delays* wind investment in the 2030–2033 period. Accordingly, in our discussion of the action plan below, RII recommends an aggressive near-term all-source request for proposals (RFP), including an opportunity for up to 700 MW of wind[1] by 2025, to be conditioned on price and performance thresholds.[2]

If the resources that bid into the RFP reflect NS Power's baseline assumptions regarding cost and performance, then the procurement would likely result in a more limited amount of resources, e.g., wind in the range of 100–300 MW by 2026.

4. RII recommends that NS Power adopt a finding that because the primary driver of wind resource procurement levels is price, the most important step NS Power can take to identify the appropriate level of wind investment is to conduct an all-source RFP.

[1] In addition to new wind, the RFP should also be open to repowered wind.

[2] The results may affect the timing of the reliability tie.

Battery resources

In contrast to wind, price is not the main constraint for battery storage resources. While RII recommends that battery resources should be eligible for the all-source procurement, NS Power's primary focus for this technology should be to understand better the value that battery resources may have for the system in the near term. Case 2.1C suggests that the base case for battery resource acquisition at current price levels is relatively modest. The sensitivity results suggest there seems to be a tradeoff between imported power and battery resources.

Surprisingly, Case 2.0A.Import-2 indicates that both batteries and CTs are procured at relatively high levels, allowing additional retirements of steam units. This suggests some interesting interplay between battery resources and thermal unit operations that the modeling may not have explored fully. As was discussed on a call with NS Power, the model did not value synthetic inertia and other advanced applications of battery storage that could have a significant effect on advancing retirement decisions for steam units in favor of advancing new resource acquisitions.

We also noticed that in some scenarios, battery capacity drops in 2045.

5. Please explain why battery capacity drops in 2045, identify the resources the model substitutes for battery capacity, and discuss implications of late-model treatment of battery storage in the end effects calculation.

Transmission and system inertia

The modeling raises more questions than it answers about the need for transmission projects and the role of system inertia constraints.

First, the results do not show the expected effects on the timing of the reliability intertie as its inertia benefits change. The reliability intertie is built earlier when the level of inertia it provides is reduced (2.1C.IMPORT-3) or the price of batteries, an alternative source of inertia, is reduced (2.1C.WIND-1 vs WIND-2).

On the other hand, some model results indicate that the timing of the reliability intertie reflects the demand for inertia. Reducing the need for inertia results in delaying the reliability tie (2.1C vs 2.1C.WIND-3 and WIND-4).

Second, we see extraordinary sensitivity to relatively modest drivers. For example, lowering the battery cost results in delaying regional integration by 10 years (2.1C.WIND-1 vs WIND-2), even though the additional battery capacity is negligible compared to the imports available through regional integration.

During our discussion with NS Power regarding wind pricing and inertia sensitivity results, NS Power staff indicated that the model might be seeking to optimize a transition to a more adaptive resource mix, and that some of these interactions might be enabling higher retirements of “slow inertia” units. This concept is consistent with the model output from 2.1C.IMPORT-3: with the reliability tie providing less inertia, more “slow inertia” steam units retire, to be replaced by additional imports, combustion turbines, and wind (presumably for the energy). It appears that the domestic CTs are being utilized more heavily for inertia and other services in this scenario.

6. Please discuss the tradeoffs of the benefits and indirect impacts of transmission and related reliability measures.
7. Please clarify how the concept of “slow inertia” modifies the inertia values by unit that NS Power provided previously. Does “slow inertia” refer to the long startup times of steam units before they can provide inertia? How does inertia vary with the operating level of a steam unit?
8. Are unit commitment costs for inertia and/or operating reserves a driver in determining the transition pace from existing to 2040 resources?

It was our understanding that the reliability intertie provided no operating or planning reserves, only inertia. However, the reliability intertie does seem to enable the system to rely more on imports.

9. Does the reliability tie provide any services other than inertia, such as reserves or load following?
10. Is the increase of imports with the reliability tie a result of the reduced need to commit domestic steam units?

Understanding this relationship will be critical prior to issuing an all-source RFP, since non-domestic resources may wish to bid into the RFP based on varying assumptions about the completion date for a reliability intertie.

11. Either NS Power should present more evidence and findings on this topic in its final report, or its action plan should set out a plan for investigating these issues further before investing in planning for the reliability intertie.

Additional Findings Needed

Solar resource analysis

In the workshop presentation, NS Power provided a brief summary explaining why there is “very limited solar generation in the resource plans.” This should be reflected in the findings, where solar is barely mentioned.

While we are unsurprised that wind outperforms solar, we wonder whether that is the only reason that the model does not select much solar for the portfolio. One other factor that NS Power should discuss in its findings is the role of firm and non-firm imports in meeting the carbon emission limits. It is our understanding that NS Power assumes that imports are exclusively or primarily low- or zero-carbon resources.

12. Are the import prices based on the costs of renewables in other provinces?
13. If imported power has some significant level of carbon emissions, would solar be more attractive?

Impact of COVID-19 recession on load

This is a topic that will be of interest to many even if it is of modest importance in the action plan.

14. RII suggests that the findings include a discussion of the impacts of the current global economic recession on NS Power's load and the implications of that recession for the resource plan.

Optimal planning reserve margin

It is our understanding that NS Power's findings regarding the optimal planning reserve margin are based on the E3 study from July 2019. During the course of the IRP process, numerous adjustments have been made to the key inputs to the RECAP model. Questions about the ELCC of hydro units and operating surpluses, discussed below, would be relevant to estimating the target planning reserve margin.

15. RII recommends that NS Power verify the findings of the July 2019 study using the updated modeling environment and include a clearer resolution of the planning reserve margin question in the final IRP report.[3]

Analysis of the combustion turbine fleet

In the 2016-2017 FAM audit process, NS Power agreed to "include an evaluation of the costs and benefits of the combustion turbines in its fleet in the upcoming 2019 IRP."[4] In the draft action plan, NS Power indicates that it will "Develop a plan" to redevelop or replace its existing gas/oil-fueled steam units, but does not address the combustion turbine fleet. In the draft findings, NS Power suggests that its existing combustion turbine fleet is cost-effective.

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[3] NS Power has agreed to resolve this matter in response to an audit recommendation by Bates White. Bates White, *Audit of Nova Scotia Power, Inc.'s Fuel Adjustment Mechanism for 2018-2019*, Exhibit N-1 Matter No. M09548 (August 21, 2020), p. 225.

[4] Bates White, *Audit of Nova Scotia Power, Inc.'s Fuel Adjustment Mechanism for 2018-2019*, Exhibit N-1 Matter No. M09548 (August 21, 2020), p. 229.

16. RII recommends that the findings include a specific discussion of the economics of replacing the current CT fleet with newer CTs or another type of fast ramping generation, including a summary of the modeling evidence in support of its findings and any constraints on the options that were evaluated that may suggest a need for further analysis.[5]

Operating surpluses and inefficient dispatch

In the two most recent FAM audits, Bates White found "evidence that NSPI was carrying surpluses of operating reserves and that this may increase costs to FAM customers."[6] Bates White found that "the Day-Ahead and Real-Time schedules created by the marketing desk frequently differ substantially and persistently from the actual dispatch of the generating units." Bates White's audit discusses several findings that could be leading to inefficient dispatch, which are also related to the surpluses of operating reserves.

Bates White states that NS Power has agreed to document instances of high operating-reserve surpluses, to help inform the IRP process to resolve the apparent surpluses of operating reserves.[7]

17. RII recommends that NS Power verify that its IRP model assumptions and settings reflect good operating practice with respect to these topics, update the findings section to address this topic, and share relevant detailed supporting data with stakeholders.
18. If operating reserves were maintained at the target levels (rather than the higher levels reported by Bate White, would NS Power be able to dispatch additional hydro during periods with high operating costs?

Mersey hydro retirement evaluation and hydro system value

The Board recognized the importance of evaluating the continued operation of NS Power's hydroelectric facilities in the IRP process in the recent Annual Capital Expenditure Plan review.[8] NS Power also committed to IRP review in support of

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[5] For example, model assumptions regarding the need to acquire additional gas pipeline capacity for new CT units and the opportunity to repurpose existing capacity rights to new units.

[6] Bates White, *Audit of Nova Scotia Power, Inc.'s Fuel Adjustment Mechanism for 2018-2019*, Exhibit N-1 Matter No. M09548 (August 21, 2020), pp. 185, 257.

[7] *Id.*, pp. 267-268.

[8] NSUARB, *Decision Approving Nova Scotia Power's Annual Capital Expenditure Plan for 2020*, Matter No. M09499 (June 25, 2020), p. 15.

the Mersey Redevelopment project, with an anticipated total budget of $161 million, anticipated to be submitted later this year.[9]

In the June 26, 2020 interim modeling results, NS Power shared initial analysis of system value provided by hydro assets as modeled by E3. It is our understanding that this modeling will be finalized by NS Power using Plexos and will provide key inputs into the replacement energy cost for hydro generation used in the Company's economic analysis model.

In the September 2, 2020 modeling results, NS Power shared the Mersey hydro retirement scenario. This sensitivity appears to indicate that customers would experience a slightly higher cost ($44 million) to retain Mersey through 2045, even with a $227 million cost to decommission Mersey.

Although redevelopment of Mersey hydro does not provide customer benefits during the planning period, NS Power staff highlighted that customers do benefit in the long run. The end effects calculation shows an economic advantage to retaining Mersey beyond 2045. NS Power staff have expressed the view that the redevelopment project could provide a very long-lived asset, on the order of a hundred years. If Mersey could last another 100 years with no unusual capital investments, then we would agree. But if Mersey might require another significant redevelopment investment, perhaps in 30-40 years, then that cost would not be considered by the end effects calculation and thus the analysis might not be reaching the correct conclusion.

Furthermore, the end effects calculation does not take into account the likelihood that Mersey would eventually be decommissioned.

We understand that the IRP is not the venue for making a decision on the potential redevelopment of Mersey hydro. Nonetheless, NS Power has committed to reviewing this issue in the IRP and using that as an input into its submission for capital investment at Mersey. It is appropriate that there be a thoughtful discussion of the findings so that it is clear what evidence may be drawn from the IRP study.

19. RII recommends that the findings include an explicit discussion of the hydro system value and the retirement analysis of Mersey in particular, including discussion of the treatment of post-2045 costs (including redevelopment and decommissioning) and the risk that either redevelopment or decommissioning could have significantly higher costs than currently estimated.

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[9] *Id.*, p. 10.

Rate Impact Model

Thank you for sharing the rate impact model. We have reviewed the model, and believe that for two reasons the model may exaggerate the rate impacts overall, and the differences among the cases.

Incorrect removal of incremental fixed cost recovery

While NS Power's estimate of incremental fixed cost revenues is a reasonable approximation, for purposes of determining approximate average rates, these incremental revenues should not be deducted from the rate estimate. The average rate should be total revenues divided by total sales. There is no reason to exclude a portion of revenues from the average rate calculation.

Our first case – "Correction" – presents just the impact of removing this portion of the model.

Treatment of existing non-fuel revenues

NS Power's use of 1994 non-fuel revenues is an appropriate starting point for the adjustment to obtain a reasonable total revenue requirement. We interpret these non-fuel revenues as including sunk costs of existing generation, T&D capital investment, and utility operating costs.

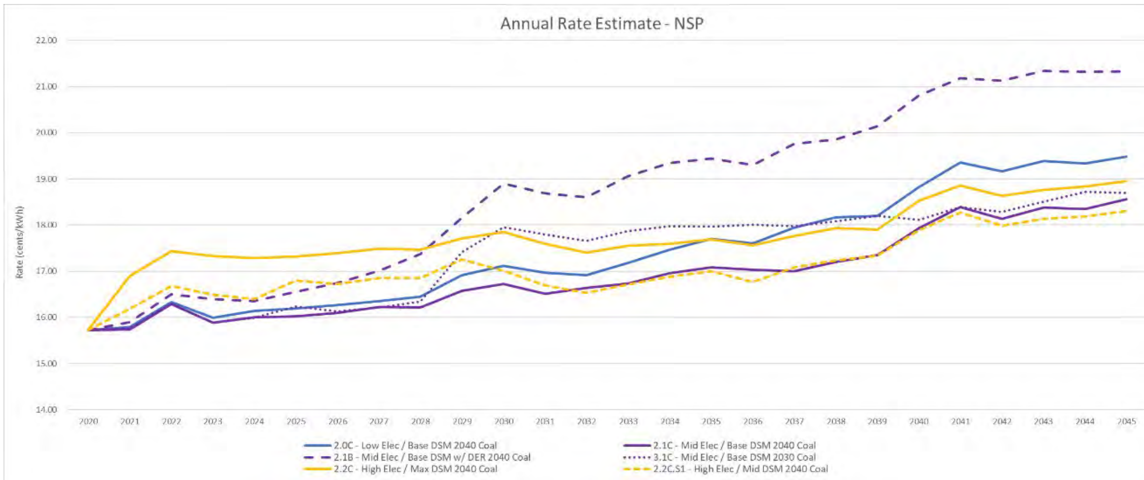
- Sunk costs of existing generation: These costs will depreciate, and are replaced by investments that are captured within the IRP revenue requirement. Accordingly there should be some downward adjustment.
- T&D capital investment: These costs will depreciate, but will be replaced by investments that are not captured within the IRP revenue requirement. Under higher load scenarios, a somewhat greater level of T&D capital investment may be required, but this would be hard to estimate.
- Utility operating costs: These costs should remain roughly stable in nominal terms.

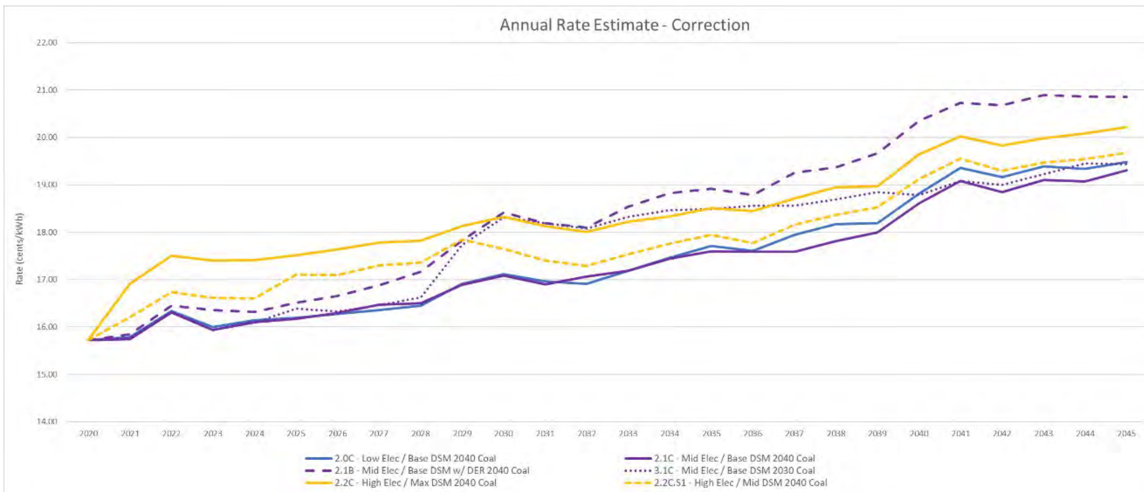
As a sensitivity, we suggest an annual reduction of 1.5% in these revenues. The net effect of this and the IRP revenues remains an increasing revenue requirement under every scenario.

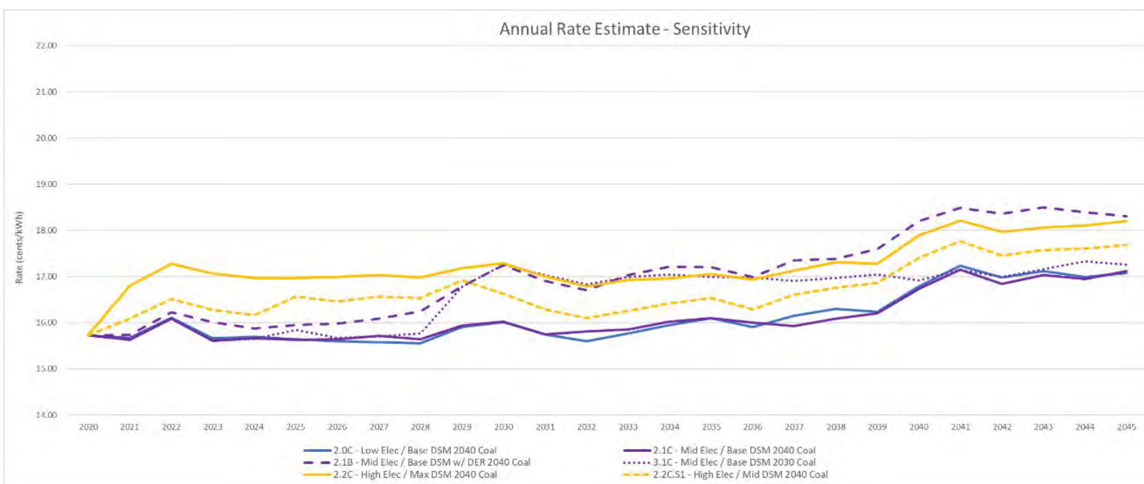
Findings

Below, we provide all three charts – NSP, Correction, and Sensitivity. The Sensitivity includes both the correction and our 1.5% annual reduction in the existing non-fuel revenue requirement.

These charts demonstrate that NSP's rate impact model exaggerated the overall trend in rate increases and also exaggerated the differences among the different model scenarios.







Action Plan

All-source request for proposals

The draft action plan's resource procurement strategy should be significantly revised. NS Power suggests a wind procurement strategy and a plan for redevelopment or replacement of steam turbines with combustion turbines.

As discussed above, the most significant uncertainty in determining the timing and scale of new resources for NS Power is the cost of wind power and battery storage. Under the most favorable cost assumptions, NS Power could acquire as much as 300 MW of wind in 2023 and 676 MW of wind by 2026. The wind and battery price sensitivities also affect the timing and size of near-term CT procurements.

20. RII recommends that the draft action plan be revised to pursue an all-source RFP procurement process. NS Power should plan to conduct bid evaluation using its IRP models. Prior to issuing the RFP, relevant issues (e.g., load and DSM forecast, planning reserve margins, ELCCs, etc.) should be resolved in a transparent manner and the bid evaluation process should be clearly articulated in a submission to the Board.

The suitability of various levels of wind and other resources will depend on the schedule for construction of the reliability tie and regional integration. These decisions should be co-optimized. It should be recognized that if a high level of wind resources are procured, and those resources depend on the reliability tie, then any schedule delays affecting the reliability tie can be managed with temporary operating constraints on the wind projects.

21. RII recommends that planning for potential transmission projects proceed in parallel to an all-source RFP. Cost estimates for completion of the reliability tie for different in-service dates (several options, covering the range from the earliest feasible date to 2032) should be developed for use in bid evaluation. The regional interconnection should be handled similarly, except that there will be need for fewer in-service date options and accompanying cost estimates since the near-term resource acquisitions should be less sensitive to the exact date and cost estimate. Given some of the sensitivity results, the potential in-service dates for this project should be expanded to cover 2028-2040.

Electrification plan investment strategy

The analysis of electrification presumes that NS Power would not bear any costs, such as program incentives to encourage transportation electrification, for example. It is our understanding that NS Power anticipates that it would need to operate electrification programs at some level of cost in order to achieve the higher levels of electrification studied in the IRP, but that such programs have not yet been studied or costs developed.

RII recommends that NS Power include in its action plan an "order of magnitude" estimate for the level of cost that might be appropriate for its customers to bear to promote electrification. As noted in the draft findings, "Increased electricity sales due to electrification can help to reduce upward pressure on electricity rates while facilitating carbon reductions in other sectors."

22. What level of program investment in electrification would result in no net change in electricity rates for a given level of electrification?

Given the diversity of the possible futures, RII recognizes that this question cannot be answered with certainty or exactitude. However, an order of magnitude estimate of the annual investment that might begin to cause upward pressure on rates would be informative to the Board and stakeholders.

While upward pressure on rates is an important consideration, we would also encourage the Board to consider that electrification may also have significant benefits to participants – such as cost savings for other fuels – and to Nova Scotia at large – by facilitating carbon reductions across all sectors. This may be viewed as a total resource cost perspective. While this is clearly beyond the scope of the IRP, we encourage NS Power to make note that these benefits exist to avoid creating the impression that rates should be a singular basis for deciding how much electrification may be considered affordable.

While many electric utilities in North America have already initiated significant electrification programs, it would still be prudent for NS Power to begin with pilot programs across the range of electrification opportunities. Some modest efforts have, in fact, already begun. Electrification should not be limited to residential, commercial, and on-road transportation. The industrial and maritime sectors also provide opportunities and should be involved early in the development of electrification programs.

23. Nova Scotia Power should propose a more intentional and comprehensive electrification pilot program strategy, with the intention of setting the stage for potentially launching larger programs in three to five years.

Evergreen IRP process

RII recommends that NS Power engage with those stakeholders who have been most active in the IRP process to better define what an "evergreen IRP process" might look like. It is our understanding that in the past, NS Power has considered a two-year IRP cycle as potentially too frequent. The term "evergreen" suggests an even more frequent update process, with many small changes rather than a singular long process. This is an interesting idea, and we look forward to its further exploration.

Remaining Concerns about Assumptions

ELCC for run-of-river hydro units

In our memo of August 4, RII questioned the 95% ELCC for run-of-river hydro units. It is our understanding that this ELCC is based on DAFOR only, and that operational limitations were not factored into this finding. Our most recent analysis supports a lower ELCC for run-of-river hydro units.

As shown in **Table 1**, dispatch of hydro units increases from peak hours to the hours representing the highest 1.1% of net loads (i.e., load minus wind output), and then again to the top 0.1% of net peak hours. This supports a finding that system operators are increasing small-hydro dispatch in response to resource needs.

Table 1: NS Power Generating Unit Capacity Factors

	Peak Hours		**Net Peak Hours**	
	Top 1.1%	**Top 0.1%**	**Top 1.1%**	**Top 0.1%**
Mersey	70.6 %	66.2 %	71.6 %	77.3 %
Hydro Group 1	69.2 %	69.0 %	71.3 %	77.1 %
Hydro Group 2	51.1 %	52.5 %	55.0 %	63.2 %

We are struck by how much the capacity factors in peak hours differ from the 95% ELCC that NS Power estimates. Perhaps low reservoir levels reduce the capacity of the plants in some years, or limited water flow limits the number of hours for which the dispatchable units can operate. Especially if water supply is limited, these units may be held for operating reserves.

24. Can NS Power explain the discrepancy between the claimed ELCC and the actual performance of the small hydro units?
25. If these units are being held for system reserve, why is this the most economic system dispatch? Wouldn't it make sense to fully dispatch these units at peak hours and reduce the use of gas/oil steam and diesel CT dispatch?
26. Does Plexos reflect NS Power's actual operating practice?

Resolving the dispatch and reliability contribution of the small hydro units may not result in substantial changes to the modeled resource plans. Nonetheless, these issues are relevant to the cost-effective operation of the NS Power system.

With respect to Wreck Cove, which is highly dispatchable and has very limited daily water availability in Surge Pond, we understand that its relatively low dispatch during peak hours is due to its use for operating reserve. Given NS

Power's long winter peaks, Wreck Cove may not be able to operate at full load for the entire peak period of a day, limiting its contribution to reliability. This limitation should be considered in combination with DAFOR in determining its ELCC and the overall system planning reserve margin.

Sustaining capital cost profiles

According to the draft findings presentation, NS Power updated the Plexos model with new sustaining capital cost profiles for coal units.

27. Please share those updated assumptions with stakeholders.

Furthermore, RII has identified some inconsistencies between the original capital cost profile assumptions for Point Aconi and information provided in the recent FAM audit by Bates White. The audit states that Pt. Aconi personnel indicated that "major generator work (2022) and turbine overhaul (2024) will require substantial sustaining capital investment."[10] This language suggests above-average investment levels. The original capital cost profile assumptions for Point Aconi do not include above-average investment levels, and the higher investment years in that forecast do not match the information provided in the FAM audit. Furthermore, Point Aconi may require an expansion of its limestone mine in eight years, which could require significant additional investment that does not appear to be reflected in the IRP capital cost profile assumptions.

RII recommends that NS Power verify that its updated capital cost profile assumptions reflect the correct sustaining capital cost forecasts for all units, including Point Aconi.

28. Please provide the sustaining capital cost profiles and underlying assumptions in depth. The final report should include a comparison of the cost of continued operation (including fixed OM&A and sustaining capital) for each of the thermal plants.

[10] Bates White, *Audit of Nova Scotia Power, Inc.'s Fuel Adjustment Mechanism for 2018-2019*, Exhibit N-1 Matter No. M09548 (August 21, 2020), p. 222.

Canadian Renewable Energy Association | Association canadienne de l'énergie renouvelable

CanREA Comments on September 2, 2020 Draft IRP

The Canadian Renewable Energy Association (CanREA) is pleased to present this submission in response to the Nova Scotia Power Inc. (NSPI) 2020 Integrated Resource Plan (IRP). CanREA is the voice for wind energy, solar energy and energy storage solutions that will power Canada's energy future. We work to create the conditions for a modern energy system through stakeholder advocacy and public engagement. Our diverse members are uniquely positioned to deliver clean, low-cost, reliable, flexible and scalable solutions for Canada's energy needs.

CanREA appreciates the efforts that NSPI has taken to provide stakeholders an opportunity to comment on its 2020 IRP, as well as the apparent refinements to the IRP draft assumptions and models to reflect comments from stakeholders regarding prior work elements of the IRP. Recognizing that the IRP is in draft form, CanREA offers the following comments on the September 2nd Updated Modeling Results Release, Draft Findings Release and September 10th Draft Findings Workshop presentation.

Non-synchronous/Inverter-based Resource Integration

A major focus of our comments is the recent work that CanREA understands has been completed for the Offshore Energy Research Association (OERA) on behalf of the Nova Scotia Department of Energy and Mines on the ability of non-synchronous/inverter-based resources (i.e., wind, solar and battery storage projects) to provide various ancillary services and support the integration of additional volumes of such generation. CanREA commented on a draft of the report and various members participated in interviews with OERA's consultant, Power Advisory LLC.
In the Draft Findings Workshop presentation NSPI indicates that "Wind energy continues to increase in all IRP resource plans; new wind is assumed to contribute to grid essential services (e.g. ramping reserve, SCADA control) to enable additional renewable integration." (Slide 10) Furthermore, in the Draft Findings Workshop presentation NPSI notes

> "Wind is the lowest cost domestic source of renewable energy and is selected preferentially over solar in all resource plans. Incremental wind capacity of 500 -800MW is selected by the model over the period, with major installations paired with coal retirement dates to provide replacement emissions-free energy. Further work is required to assess system stability at these significant penetrations and determine whether additional dynamic system inertia constraints can enable this level of additional wind integration on the Nova Scotia system." (Slide 47)

CanREA observes that NSPI focuses on constraints to wind integration, questioning whether "additional dynamic system inertia constraints can enable this level of additional wind integration" rather than acknowledging that the ability of wind generation to provide various frequency response services including fast frequency response (FFR) and primary frequency response has not been fully considered. The provision of FFR by wind generation arrests the frequency decline after a system event and can reduce requirements for synchronous inertia. CanREA understands that additional work needs to be done to determine the impact of FFR provision by wind turbines on requirements for system inertia in Nova Scotia, but as the OERA work demonstrates there is a considerable body of work demonstrating this capability and its adoption by system operators in other jurisdictions. This is a critical issue because the IRP indicates that wind generation is the most economic type of domestic renewable generation and therefore can play an important role in assisting NSPI backout coal-fired generation.

The IRP Draft Findings Presentation indicated that one of the "Key Plexos Model Updates" was to "Allow new wind generation to provide ramp down reserve service" (Slide 30) Chris Milligan confirmed that this was a refinement that flowed from the OERA work. CanREA notes that this is just one ancillary service that wind generation is capable of providing. By focusing on just this ancillary service NSPI failed to consider the range of ancillary services that are critical to enabling the integration of additional wind generation in Nova Scotia as demonstrated by the work performed for OERA. A ramp down service can assist with managing surplus wind generation during low load high wind output periods. However, as the OERA study indicates the critical ancillary services are frequency response services that allow NSPI to dispatch off thermal generating units and rely on the fast frequency response capability that wind generators offer. Chris Milligan noted that NSPI's modeling has not considered this capability and also has not considered the ability of battery energy storage projects to provide a similar service.

CanREA encourages NSPI to continue to integrate the findings from the OERA report on how the ancillary service provision capabilities of wind, solar and battery resources (i.e., non-synchronous /inverter-based resources) can be utilized. Given the low energy costs offered by wind resources recognizing this capability is likely to reduce costs to customers, while enhancing system reliability. The low cost of wind relative to other resources also creates an opportunity to operate at a reduced capacity to provide head room to offer ancillary services (e.g., the provision of primary frequency response) under some operating conditions.

CanREA acknowledges that the September 2nd IRP Results includes a sensitivity that reflected a lower inertia constraint (2.1C.WIND-3 (LOW INERTIA CONSTRAINT)) and another that eliminated the inertia constraint all together (2.1C.WIND-4 (NO INERTIA / NO INTEGRATION)). These sensitivities help advance the understanding regarding the impact of inertia requirements on the amount of wind generation that can be integrated. Additional background regarding insights from these sensitivities would be helpful.

The Draft IRP also notes that "significant wind penetrations (beyond what was modeled in the PSC study) will require additional study work to confirm system stability" (Draft IRP Findings Workshop, September 10, 2020, p. 26). Given the recent work by OERA, CanREA encourages NSPI to update the PSC study and when doing so to provide an opportunity for stakeholder input or alternatively to have committee of experts advise on modeling assumptions and protocols. This will help ensure that there is stakeholder support for the findings of this work.

Regional Integration

The Draft IRP appropriately focuses on Regional Integration as a key strategy for decarbonizing Nova Scotia's electricity supply: "Regional Integration (i.e. investment in stronger interconnections to other jurisdictions) is an economic component of the least-cost plans under each load scenario." (Slide 47) The first element of the Draft Action Plan is to "Develop a Regional Integration Strategy to provide access to firm capacity and low carbon energy, increase the reliability of Nova Scotia's interconnection with North America, and enable economic coal unit retirements." CanREA agrees that this is an appropriate element of such an Action Plan. As NSPI's IRP has indicated greater regional integration is critical to unlocking the potential of wind generation to provide the required renewable energy to enable coal unit retirements. CanREA encourages NSPI to accelerate this element of its Action Plan. Additionally, The inclusion of solar energy and energy storage applications will need to increasingly be factored in to planning scenarios. CanREA notes that Regional Integration investments are likely to offer multiple benefits including lower costs, enhanced reliability, and greater flexibility.

Resource Procurement

One of sensitivities evaluated was a low wind price. This sensitivity advanced the "build of significant wind quantities from 2030 in base case to 2025." CanREA notes that the last major procurement of wind energy resources in Nova Scotia was over eight years ago and that the cost of wind generation has fallen by an estimated 42% on a levelized cost basis during this time, while wind turbine technologies have advanced significantly[1]. The majority of the IRP cases reflect modest near-term wind additions. With these wind additions likely to occur through competitive procurement processes, NSPI will then have a reliable estimate of the cost/price of wind in Nova Scotia that can be used to determine if the low wind price sensitivity is a better reflection of the actual cost of wind generation. One element of the Draft Roadmap is "to continue to track the installed costs of wind, solar, and energy storage to look for variations from the trajectories established in the IRP (in particular, monitoring for divergence from the "Base" to the "Low" pricing scenarios)." CanREA agrees this is a best practice, such monitoring as well as evaluating the results of various renewable energy procurement efforts is appropriate.

Another element of the draft action plan was a wind procurement strategy, "targeting 50-100MW new installed capacity by 2025 and up to 350MW by 2030." CanREA believes that the 50 to 100 MW new installed capacity by 2025 is likely to be low given the various issues identified with NSPI's failure to fully consider in its modeling of the ability wind generation resources to provide frequency response services.

CanREA recommends that one element of this wind procurement strategy be an indicative schedule of future wind procurements based on the results of the IRP. We understand that such may need to be modified as additional information becomes available on load growth, technology costs, integration analyses. Nonetheless establishing such a procurement schedule will signal to the development community future procurement activity that will give them the confidence to invest in project development and the local supply chain, which can derisk future project development and reduce wind costs benefiting Nova Scotia consumers and its economy.

NSPI has indicated that it will be preparing its final report in the coming weeks. CanREA urges NSPI to acknowledge the potential for additional modeling and consideration of solar energy and energy storage for future iterations of integrated planning as two additional technologies that wil complement the projected wind energy contributions and provide NSPI with the tools to satisfy multiple objectives supported by Nova Scotia's electricity system. As costs continue to decline and the technology evolves, the next iteration of planning will ideally include consideration for the contributions that all renewable energy and energy storage technologies can provide, including hybrid projects.

Thank you for your consideration of this submission, we look forward to additional dialogue on this important file and we remain availbe to meet at any time to discuss further.

Sincerely,

Brandy Giannetta
Senior Director Ontario & Atlantic Canada
Canadian Renewable Energy Association

[1] See Lazard Levelized Cost of Energy and Levelized Cost of Storage 2019, https://www.lazard.com/perspective/lcoe2019

Memorandum

To: Nicole Godbout

From: John Esaiw

Date: September 18, 2020

Re: 2020 IRP – September 2, 2020 – Release of "Final Modelling Results" and "Draft IRP Findings and Action Plan"

EfficiencyOne is pleased to offer comments on NS Power's 2020 Integrated Resource Plan (IRP) Modeling Results, Draft Findings, and Action Plan, as released on September 2, 2020. These comments are summarized below, followed by a more detailed discussion of each.

1. The 2020 IRP Report must define a Preferred Resource Plan in line with quantitative results of the IRP modelling process, using the 25-year Revenue Requirement, adjusted for End Effects. Qualitative discussion should reflect these findings.
2. The IRP results should modify the NPV revenue requirement calculation on the basis of expected carbon revenues, as they are now a key differentiator in many cases and may affect the selection of a lowest cost plan.
3. Absent quantified impacts, it is important that the final report clearly indicate the qualitative effects on T&D investments from increased or decreased levels of DSM.
4. Provide more context on the results of the DSM sensitivity analyses for the electrification scenario in which they took place. The final report should include a qualitative assessment of how higher levels of DSM could provide increased ratepayer value with higher levels of electrification.
5. Provide an assessment of the risks associated with large capital investments such as a regional intertie and the use of non-firm imports. The 2020 IRP Report should confirm that DSM mitigates the risks associated with NS Power's plan to reduce GHG emissions within the IRP Findings and Action Plan.
6. Provide an assessment of risk in Natural Gas pricing assumptions within the Findings and Action Plan.

7. The rate effect metrics (10-year NPVRR and estimated rates) will not contribute to achieving the general purpose of the IRP process as set out by the UARB and should receive limited consideration.
8. Provide stakeholders with a proposed approach (technical and process-related) for calculating the avoided costs of capacity and energy associated with DSM. It is important that this approach quantifies avoided costs prior to the IRP Report being filed with the UARB.
9. Publish responses to all stakeholder comments and questions following the submission of comments on September 18^{th}. Stakeholder comments and questions and NS Power's responses help inform all stakeholders.

A detailed description of the above recommendations and their rationale follows.

1. Identify the Preferred Resource Plan

Slide 48 of the "Draft Findings Release" presentation includes the following statement:

> *DSM energy efficiency programs consistent with a range of the "Low" to "Base" profiles, consistent with the E1 Potential Study, are shown to be most economic relative to other options evaluated.*

This statement does not appear to reflect the quantitative findings of the IRP scenarios as modelled.

Table 1 shows the Revenue Requirement with End Effects for each of the DSM sensitivities examined as part of case 2.0C, which is a key case for informing the findings and action plan (perhaps with contributions from case 2.1C, a similar case in the mid-electrification world). This information is taken from the "Updated Modelling Results Release".

Table 1 - DSM Sensitivity Results - 2.0C

Case	RR w EE (NPV 2021) ($M)	% Difference relative to 2.0C
2.0C (Original w/ Base)	$16,241	N/A
2.0C.Low DSM	$16,350	0.7%
2.0C.Mid DSM	$16,561	2.0%
2.0C.Max DSM	$17,153	5.6%

Case 2.0C (Original – Base DSM) produces the lowest NPV revenue requirement (adjusted for end-effects).

The presentation of the final portfolio study metrics (i.e. the metrics used to evaluate each portfolio studied in the Final Modelling Results) is stated as "with and without End Effect adjustment" – this is distinct from the UARB-approved Terms of Reference, which state that End Effects are included.

End effects should be included when making these determinations, for the reasons summarized below:

1. The NPV of revenue requirements with energy efficiency is the primary metric in guiding IRP results, as stated in the following excerpt from the IRP Approved Terms of Reference (emphasis added):

   Traditionally, the primary decision criterion used for IRP modeling has been the minimization of the cumulative present value of the annual revenue requirements over the ***25 year planning horizon (adjusted for end-effects).***

   NS Power will continue to use this primary metric to guide resource planning*, and will also assess others of increasing importance, including:*

   - *Magnitude and timing of electricity rate effects;*
   - *Reliability requirements for supply adequacy;*
   - *Provision of essential grid services for system stability and reliability;*
   - *Plan robustness (the ability of a plan to withstand plausible potential changes to key assumptions);*
   - *Reduction of greenhouse gas and/or other emissions; and,*
   - *Flexibility (limitation of constraints on future decisions arising from the selection of a particular path).*[1]

2. It is a best practice, as suggested by the Regulatory Assistance Project and Synapse Energy Economics, on the basis that late resource additions are treated more equitably under this approach. DSM is both an example of a late resource addition (in that it occupies continuous investment trajectories), and subject to less-than-ideal competitive treatment associated with other late resource-additions.[2]

It is critical that the 2020 IRP provide clarity on the Preferred Resource Plan, for the purposes of making a determination regarding economically optimal DSM levels. The

[1] M08929, IRP Terms of Reference, Filed December 16, 2019, at Appendix A, Page 7.
[2] Synapse Energy Economics for Regulatory Assistance Project, Best Practices in Electric Utility Integrated Resource Planning, June 2013, at Page 31.

Preferred Resource Plan is used to provide avoided cost information which informs future determinations of appropriate DSM Resource Plan inclusions and levels, in part.

The 2020 IRP Report must define a Preferred Resource Plan in line with quantitative results of the IRP modelling process, using the 25-year Revenue Requirement, adjusted for End Effects. Qualitative discussion should reflect these findings.

2. Modify Revenue Requirement Calculations based on Carbon Pricing

As part of its feedback on the Assumptions and Analysis Plan, EfficiencyOne asked the following:

> *Does NSP expect to sell excess credits from lower emissions; if so, how will carbon cost be captured and will revenues from carbon credits be accounted for in revenue requirement for each scenario?*
>
> NS Power's responded with the following:
>
> *NS Power will incorporate cap and trade market revenue from sales of excess GHG allowances during the screening phase of the modeling work for some key scenarios. If market revenue is found to affect the preferred resource plan selection, then a determination will be made as to how to incorporate the cap and trade market in the full IRP modeling phase.*

NS Power's verbal update on this analysis at a Technical Session indicated that the initial modelling was conducted, and the results indicate that economic dispatch was not altered due to carbon pricing revenue, so no further analysis was required.

Several modelled cases produce emissions profiles below the requirements of regulations and below the "Net-Zero by 2050" profile (GHG Profile "2") requirements.

Table 2 shows the total cumulative carbon emissions for the DSM sensitivities examined by NS Power and the nominal (not NPV) impacts of certain pricing assumptions on revenue requirement. For clarity, the differences in carbon emissions (i.e. CO_2e Cumulative Planning Period Emissions) are taken from the Final Modelling Results deliverable, while the estimation of monetary value has been performed by EfficiencyOne.

Table 2 - Nominal RR Impacts of Carbon Pricing

Case	CO_2e Cumulative Planning Period Emissions	Difference relative to 2.0C	Change in RR relative to Base – Nominal - $20 per Tonne	Change in RR relative to Base – Nominal - $50 per Tonne
2.0C (Original w/ Base)	65 MT	N/A	N/A	N/A

2.0C.Low DSM	72 MT	7 MT	$140M	$350M
2.0C.Mid DSM	59.4 MT	-5.6 MT	-$112M	-$280M
2.0C.Max DSM	62.1 MT	-2.9 MT	-$58M	-$145M

Mid and Low DSM follow the trend that higher amounts of DSM produce incremental carbon reductions, and it is unclear why Max DSM results in higher cumulative emissions than Mid-DSM. Given a potential difference between Low DSM and Mid DSM of $630M (undiscounted) in potential carbon revenues (assuming $50 per tonne), carbon pricing merits full consideration in the IRP.

Absent forecasts of carbon prices, the Federal Government's "floor" for carbon pricing is $50 per tonne in 2022. Given that Nova Scotia's inaugural cap and trade auction resulted in a settlement price of $24 per tonne, assuming levels below $24 would not seem reasonable for projections extending out 25 years.

The IRP results should modify the NPV revenue requirement calculation on the basis of expected carbon revenues, as they are now a key differentiator in many cases and may affect the selection of a lowest cost plan.

3. Assess the Impacts of DSM on the Costs of T&D

NS Power has indicated that modelling of all T&D impacts is not feasible in an IRP process. Regardless, it is important to note that from an IRP methodological perspective, T&D is no longer an *"all-else equal"* item as it was in the past, and the varying levels of T&D investment across the modeled scenarios need to be recognized.

Energy efficiency and other forms of DSM are known to produce savings on the T&D system. The IRP needs to reflect this fact to clearly indicate the plan that provides most value to ratepayers.

The methodology for quantifying T&D avoided costs from DSM is now being developed by NS Power in consultation with stakeholders. Absent quantified impacts, it is important that the final report clearly indicate the qualitative effects on T&D investments from increased or decreased levels of DSM.

4. Provide Context on the Analyses of DSM Sensitivities

The full range of DSM sensitivities was explored only for the reference electrification scenario, which is the least aggressive of three electrification scenarios. Absent further analyses of sensitivities of DSM in other scenarios, it is unclear how DSM would compete in these worlds.

Higher amounts of electrification will likely require more generation on the system, given the average load and incremental peak load outputs of the Pathways studies, and hence could climb the cost curve of available supply-side resource options. It is expected that DSM would produce results that are in line with the reference electrification scenario, but with enhanced competitiveness.

Recognizing that further sensitivity analyses would be difficult to complete within the established IRP timelines, NS Power should provide more context on the results of its DSM sensitivity analyses for the electrification scenario in which they took place. The final report should include a qualitative assessment of how higher levels of DSM could provide increased ratepayer value with higher levels of electrification.

5. Assess the Risks Inherent in Interties and Non-Firm Imports

The Updated Modelling Results include sensitivities related to reductions in intertie service (reliability interties) as well as reductions in the availability of non-firm imports. Those sensitivities and their end-effect adjusted NPV Revenue Requirements are shown in Table 3.

Table 3 - Import Sensitivities

Case	Description	% Increase NPVRR (with end-effects) relative to original case
2.1C.Import-1	Reduces non-firm imports from all sources available to 0.8TWh	2.3%
2.0A.Import-2	No reliability Tie	2.1%
2.1C.Import-3	Limited reliability Tie Inertia	0.4%

The results demonstrate material sensitivity to the removal of some non-firm imports. Stakeholders do not have access to information relating to further constraint of non-firm imports (beyond 0.8 TWh of final availability); presumably, the costs would further escalate in such cases.

The mitigations selected by the model in these sensitivities for 2.1C. Import-1 are:

- Construction of one additional Natural Gas Combined Cycle unit (NGCC).
- More firm imports to replace non-firm imports.

These mitigation options do not appear to fully reduce the risk of reduced intertie capacity and in fact, could create new risks such as:

- The construction of an additional NGCC unit will place additional pressure to procure winter baseload natural gas. This mitigation option could add to the risks around existing natural gas assumptions, which are already heavily risked. In addition the Plexos ST runs indicate there is much more cycling of CTs, adding additional operational risk. These costs are not known and could be material with the additional wind that may come onto the system. If not already accounted for, in Plexos, there should be some factors added in the model that consider this type of operation.

- Market conditions may be such that challenges with obtaining non-firm imports may be interrelated with obtaining firm imports.
- Large capital projects have inherent risks. Investments such as strengthening the NB intertie, adding a new interconnection with other markets, or further delays to Muskrat Falls in-service date all pose material risks.

The added risks associated with NS Power's mitigation plans for interties and non-firm imports should be described qualitatively (if a quantitative analysis is not possible within the schedule) as part of the IRP Draft Findings and Action Plan.

DSM is known to have lower risk than large capital items such as those described above. This is recognized by the North American Electric Reliability Corporation (NERC):

> *DSM resources lead to reductions in supply-side and transmission requirements to meet total internal demand. They can be considered in long term planning exercises as a supplement to long-term planning reserves, and provide operational reliability through operating reserves and flexibility. DSM resources can also be used to manage the risk associated with construction and operations of traditional supply-side resources as well as a variety of new operating characteristics associated with variable renewable resources.*[3]

The 2020 IRP Report should provide an assessment of the risks associated with large capital investments such as a regional intertie and the use of non-firm imports. The report should also confirm that DSM mitigates the risks associated with NS Power's plan to reduce GHG emissions within the IRP Findings and Action Plan.

6. Respond to Questions Regarding Natural Gas Assumptions

In its July 10th Letter of Comment, EfficiencyOne made the following recommendations related to natural gas assumptions in the IRP:

- A proxy for new gas supply should also include a sensitivity relating to the Algonquin City Gates Hub (AGT) as the commodity price for new winter (and summer) natural gas capacity, with the inclusion of energy cost and tolls reflecting transport from AGT to Tufts Cove, as it would address some of the uncertainties associated with the current approach of acquiring gas and transportation from Alberta (AECO), Dawn or LNG via Amsterdam (TTF).
- Sensitivity analyses that explore the constrained availability of natural gas for the NS electricity system should be included, at least in terms of incremental capacity additions beyond 20,000 MMBtu per day. Put another way, constrain the model to only allow for consumption of

[3]NERC, Data Collection for Demand-Side Management for Quantifying its Influence on Reliability, December 2007, at Page 1.

> 20,000 MMBtu per day, thus allowing the model to economically select other resources other than natural gas beyond the currently contracted firm supply.

These requests, as far as we understand, have not been addressed, and IRP stakeholders do not have knowledge of other stakeholder positions relative to natural gas pricing assumptions. At minimum, NS Power should provide an assessment of risk in Natural Gas pricing assumptions within the Findings and Action Plan.

7. Recognize the Cursory Nature of the Rate Effects Analysis

The Draft Findings and Action Plan describe qualitative and quantitative case assessments related to rate effects. The Final Portfolio Study section notes that the description for the "Magnitude and timing of electricity rate effects" is a 10-Year Revenue Requirement. The study then presents a high-level rate analysis. On September 17, 2020, an accompanying excel representation of the rate effects model was distributed to stakeholders.

The methodology described in the model is substantively different compared to the relatively more mature Rate and Bill Impact Assessment model, which has been reviewed by stakeholders and the UARB several times in Nova Scotia, and continuously improved.

Further, the IRP provides the only opportunity for analysis of the long-term revenue requirement associated with the NS electricity system. This long-term view is critical in determining the lowest cost electricity system into the future, which is a complex question to answer, given the degree of changes taking place in the electricity, and broader energy, system today. The UARB spoke to this important purpose of the IRP in the 2016-2018 DSM Resource Plan decision:

> The general purpose of the IRP process is to identify a plan which utilizes both supply-side and demand-side resources to reliably serve the electrical requirements within Nova Scotia at the lowest long-term cost to ratepayers.[4]

The outcome of the IRP should be primarily informed by the lowest long-term cost to ratepayers. Affordability should be examined as part of the lowest cost long-term trajectory, as short-term rate impacts have many influences such as fuel costs which are subject to the vagaries of the market. Many affordability considerations are affected by near-term cost pressures and the timing of investments, matters not examined in a detailed fashion as part of the IRP.

The rate effect metrics (10-year NPVRR and estimated rates) will not contribute to achieving the general purpose of the IRP process as set out by the UARB, and should receive limited consideration.

8. Propose a Methodology for Calculating Avoided Costs

[4] M06733, 2015 NSUARB 204, UARB Decision, Issued August 12, 2015. At para 93.

Beyond the remaining decisions relating to the selection of the Preferred Resource Plan, the generation of avoided costs remains an outstanding issue associated with the completion of the 2020 IRP. The determination of avoided costs must take place as part of the IRP process. While avoided costs are critical inputs to DSM planning, they are also meaningful and important to other stakeholders engaged in DSM proceedings.

The technical decisions and tasks associated with the calculation of avoided costs involve:

1. The designation of at least one comparator Plan for use in the Difference in Revenue Requirements method of avoided cost generation.
2. Decisions relating to what DSM elements will be included in a given avoided cost run (if more than one). For example, will Demand Response (DR) activities be aggregated with energy efficiency (EE) as a single avoided cost run.
3. The final form of avoided cost results.

These questions and decisions should be resolved as part of the IRP stakeholder engagement process. In each of the points above there are nuances and subtle changes in approach which stakeholders should generally understand.

NS Power should prepare the resource plan that is to be compared with the Preferred Resource Plan through removal of DSM load modification, and allow the model to re-run resource additions in Plexos LT. The comparator plan should then be checked for reliability and operability, such that stakeholders are assured that the comparison is performed on two viable IRP cases; each viable on their own merits, and only separated by DSM.

Furthermore, the 70MW of economically selected DR should be grouped with the End Effects case or cases being examined. EfficiencyOne is interested in NS Power's and other stakeholders views on this approach, but it seems that grouping these aspects of DR will avoid the requirement for the separate generation of avoided costs for DR and EE, and will provide inherently the interaction between EE and DR, which is consistent with how the 2019 DSM Potential Study was modelled (i.e. in that DR and EE were modelled as interacting in the DSM Potential Study).

Finally, the avoided cost data should be presented in the format used for the 2014 IRP. The key elements from the 2014 approach EfficiencyOne would like to see maintained on a public basis are:

1. The provision of annual avoided cost streams for both generation and energy.
2. The provision of levelized values over the planning period.
3. Key input assumptions (e.g. WACC).

In addition to the technical aspects discussed above, there does not seem to be a clear process for developing avoided costs as part of the this and future IRPs. The IRP Action Plan should propose a technical approach and process for quantifying avoided costs, taking into account the comments provided above. This proposed approach should be reviewed with all IRP stakeholders and updated according to their feedback. The process should allow for the initial draft production of avoided costs as part of the Draft Final Report deliverable. EfficiencyOne is strongly in favor of an approach that allows for resolving avoided costs prior to an IRP-associated regulatory process, on the basis of transparency and ensuring continued participation by the IRP stakeholder group.

9. General Responses to Comments

NS Power provided written responses to stakeholder comments on the Assumptions and Analysis Plan (December 27, 2019) and the Terms of Reference (March 12, 2020). NS Power has been readily available to discuss specific questions when requested by EfficiencyOne and has made every effort to meet and discuss results and issues, but it has not published responses to stakeholder comments since March 12. Responses to all stakeholder comments and questions should be published following the submission of comments on September 18th. NS Power's views on these comments are important to all stakeholders.

EfficiencyOne appreciates NS Power's continued openness to formally and informally discussing technical issues and stakeholder concerns throughout this IRP process.

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SUBMITTED COMMENTS REGARDING 2020 IRP DRAFT FINDINGS, ACTION PLAN AND ROADMAP

September 18, 2020

The Ecology Action Centre (EAC) welcomes the opportunity to participate as a stakeholder in the 2020 Integrated Resource Plan process. We submit the below comments and questions in response to the Draft Findings, Action Plan and Roadmap released for stakeholder comment on September 2, 2020 and discussed at the stakeholder session on September 10, 2020. Specifically, this submission is in response to the below document:

1) NS Power IRP 2020 Draft Findings, Action Plan and Roadmap

The EAC feels very strongly that this process should not be considered just another Integrated Resource Plan. Nova Scotia Power Incorporated (NSPI) is the third most polluting energy utility in Canada. This is an opportunity for us to make NSPI one of the least polluting energy utilities in Canada and there is limited time to make these decisions with significant long-term consequences for emission, especially for utility ratepayers.

The EAC appreciates the opportunity to participate and submit written comments in the IRP process, and help strengthen the energy system in Nova Scotia.

Thank you,

G. Gurprasad

Gurprasad Gurumurthy
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Comments on Draft Findings:

1. Nova Scotia's Sustainable Development Goals Act is a significant milestone in the province's climate plans, and actions adhering to these emission goals is a welcome scenario. The EAC supports the notion of a steep reduction in reducing carbon emissions in the province. While scenarios have comprehensively studied emissions reaching between 0.5 Mt and 1.4 Mt, the EAC expresses concern that no "zero" emissions scenario was studied. Zero emission cases will provide an assessment of the costs required to operate from imports, sequestered carbon emissions and renewable energy. Increased costs to the utility add value to efforts across the regional GHG reductions landscape by maximizing the impact of electrification. In addition, near-future regulatory benchmarks will dictate provincial emissions to align with net-zero carbon scenario. Therefore, it would be prudent to have a future-proof plan ready for deployment.
2. Access to firm capacity imports from the Maritime provinces and Quebec would be highly beneficial to the ratepayers, and draft findings statement 2 echo the same. At the same time, the Reliability Tie is a welcome move, which would strengthen the province's grid further. However, it is not shown if the study explored fully replacing coal generation with building interconnection infrastructure and investing in clean firm imports. Wind will play a key role in the region's renewable portfolio, and addition of an incremental 500-800 MW capacity is a welcome move.
3. Adding and relying on Gas turbine infrastructure and natural gas purchases run the risk of an upward carbon emission trend. The North American natural gas supply has additional emissions associated with upstream fugitive methane emissions. While not currently accounted for under this IRP process, there is a clear risk that at some point in time they will be included as regulators seek to achieve real emission reductions. Multiple studies indicate that fully accounting for these emissions brings the natural gas supply close to emissions intensities associated with coal combustion [Assessment of Methane Emissions From the U.S. Oil and Gas Supply Chain] & [Gas Exports Have a Dirty Secret: A Carbon Footprint Rivaling Coal's]. It would greatly benefit the study if complete replacement of planned natural gas/gas turbine infrastructure with regional transmission interconnection is analyzed fully.
4. The EAC appreciates that an accelerated coal phase-out scenario was considered in the analysis. It is encouraging to see that both 2030 and 2040 coal phase-out plans will have similar rate implications for ratepayers by 2045. While the findings indicate a higher initial cost for an accelerated 2030 coal phase-out, it is worthwhile to indicate here that the province would reap immense health and economic benefits from pursuing this target. As presented in the "Nova Scotia Environmental Goals and Sustainable Prosperity Act Economic Costs and Benefits for Proposed Goals" report, rapid decarbonization in Nova Scotia would result in the creation of around 15, 000 full-time jobs by 2030. In addition, the Federal Government's

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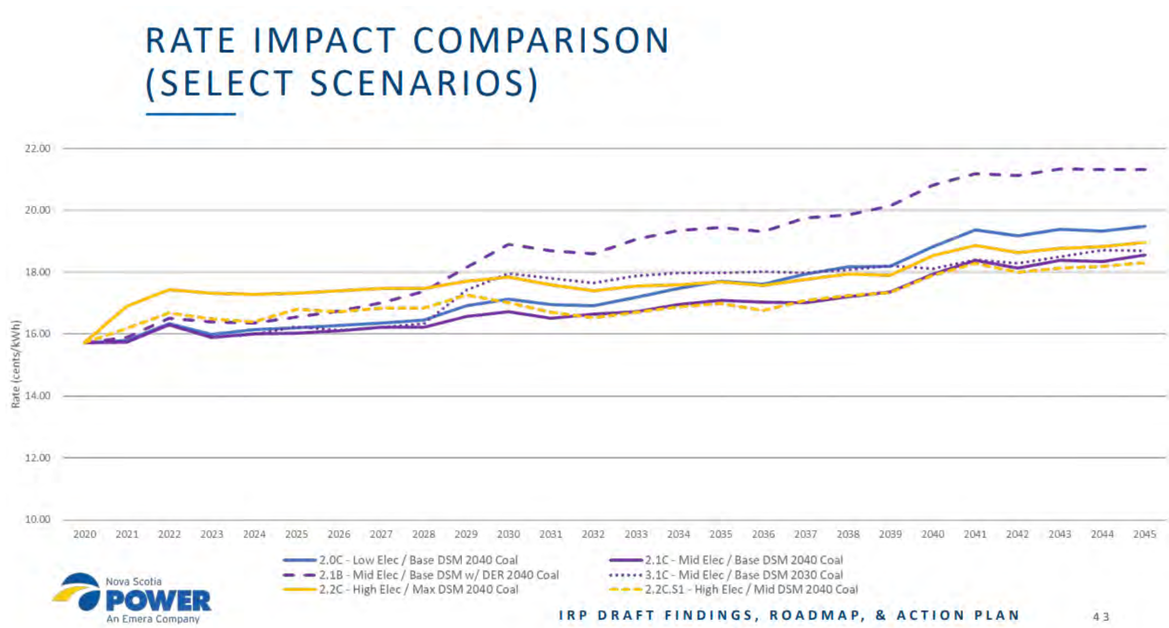
analysis indicates that an accelerated phase-out would avoid 89 premature deaths, 8,000 asthma episodes and 58,000 days of breathing difficulty for Nova Scotians, among other benefits [Ref]. Therefore, an accelerated phase-out of coal by 2030 would be a favorable long-term strategy for the province and its peoples.

Comments on Draft Action Plan:

1. Draft Action Plan statement 1 is highly desirable, and the EAC welcomes Nova Scotia Power's notion to develop a Regional Integration Strategy. This will be highly beneficial to the province and ensure a stable and reliable grid. Once again, it would be wise to link the addition of transmission infrastructure and phase-out of fossil fuel based (including natural gas turbines) infrastructure.
2. Electrification of the grid will have significant impacts overall and create opportunities for other sectors, such as transportation and small-to-medium-scale industries operating on carbon intensive fuels.

   Draft Action Plan statement 2 and Finding 1 b) are significant and would stand to benefit from stronger advocacy:

   "Increased electricity sales due to electrification can help to reduce upward pressure on electricity rates while facilitating carbon reductions in other sectors"



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According to the Rate impact Comparison (Select Scenarios), it is shown that High Electrification scenarios 2.2 C and 2.2 C S1 achieve lower rates as compared to select Low and Mid-Electrification scenarios. This indicates that electrifying the grid has key benefits. While, this comparison is comprehensive in terms of rate implications for ratepayers, it would be prudent to demonstrate economic benefit of switching to electric transport and electric heating through heat pump technology.

3. Decommissioning of the thermal unit at Trenton 5 is essential. As a significant number of units will reach end-of-life much earlier than 2040, earlier preparation for depreciation of these units is warranted. Accordingly, a comprehensive plan indicating the retirement scenario for all coal units is needed. Wind addition to the system is essential, but it would be necessary to consider a higher than stated "350 MW" of additional capacity. Consideration must be given to maximizing wind addition in combination with battery storage. It is clear in other jurisdictions (USA, UK, etc.) that this has worked successfully at a non-significant additional cost. Considering future examinations of upstream methane emissions from natural gas powered fast acting peakers would reveal that battery storage would be the right direction to proceed in terms of reaching carbon neutrality.

Comments on Draft Roadmap:

1. Statement 7: "Continuously refine these Findings and Action Plan items via an evergreen IRP process. This process should facilitate regular updating of the IRP model as conditions change and technology or market options develop."

   The capacity of EAC to engage in this process is greatly reduced due to the design and process of the 2020 IRP, and the lack of availability for stakeholder funding and support through the Nova Scotia UARB, through the NSPI-led process, or through the Nova Scotia Department of Energy and Mines. This is true for other organizations who advocate on behalf of climate mitigation, environmental concerns and energy affordability concerns, who do not have staff regulatory or legal counsel capacity to engage in this important energy planning process.

   Although Nova Scotia Power has made every effort to make the 2020 IRP process accessible to stakeholders and is planning to adopt an "evergreen" IRP going forward, we regret the lack of financial and structural support for organizations to participate. The EAC feels that this problem is ongoing. NSPI and the Nova Scotia UARB processes will continue with ad hoc sustainability oversight until the Department of the Environment, Department of Energy and Mines, or Nova Scotia Power create an updated mandate to support climate change and

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environmental concerns in a way similar to the Consumer Advocate or the Small Business Advocate.

The EAC believes that Nova Scotia still has an opportunity to set long-term ambition, and commit to phasing out coal-fired electricity in Nova Scotia. This IRP process will determine the future of our electricity grid in ways that will hinder or facilitate a just transition in Nova Scotia.

We need to ensure that low and middle-income Nova Scotians, coal workers and communities all benefit from this change in our electricity system, and the EAC believes that this transition is possible in an affordable, just and timely way. The EAC looks forward to continued participation in the 2020 IRP stakeholder process, and ongoing conversations regarding Nova Scotia's electricity future.

Ecology Action Centre is committed to continuing to ensure Nova Scotia sets a pathway to phasing out coal-fired electricity generation, and looks forward to working with all partners toward the just transition to a prosperous, green economy.

Thank you for your consideration,

G. Gurprasad

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And

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September 17, 2020

Re: M08929 – Integrated Resource Planning

Dear Ms. Godbout and Ms. Fris:

Envigour Policy Consulting Inc. has been retained by QUEST and Marine Renewables Canada as their Consultant in this matter. We have reviewed the IRP Draft Findings, Action Plan and Roadmap. We have participated in the process for more than a year now. We wish to congratulate all those who have participated in this extensive and likely expensive process. We also believe the IRP has been comprehensive within the terms of the relevant legislation and regulatory practice.

However, as we begin to end this phase of the work, we suggest that we consider some context and acknowledge what the process did not include. First of all, the IRP is taking place within a rapidly changing public policy and technology environment.: one that will likely evolve in unexpected directions and produce technology breakthroughs for prices and solutions not anticipated in the IRP assumptions and modelling.

Secondly, the IRP of necessity had gaps when considering the broader energy and climate change agenda. It did not purport to be an energy IRP and thus did not evaluate the full benefits as customers shifted energy needs to the electricity system from other systems. It also did not assess the supply risks associated with dependence on imports of natural gas or environmental compliance implications of using back-up diesel. It also did not consider the opportunities for the grid from the customer purchase of batteries. And it, of course, did not assess the policy benefits of early action on decarbonization as that is the purview of the governments.

We would also note that the IRP attracted more interest and participation from stakeholders than usual with peak on-line call registration in the range of 170. In particular, Municipalities were interested in how the IRP conclusions and implementations align with their policy and program goals.

Finally, we observe that the measures under the actions and roadmap to ensure the plan is evergreen is not spelled out. It may be prudent to offer more clarity on that process using principles of inclusion, science-based conclusions, and a broad range of expert opinions and thinking tested for practicability in the Nova Scotia policy/regulatory environment.

On behalf of QUEST and Marine Renewables Canada, and after consultation with the Smart Grid Innovation Network, the following model is suggested for future engagement on matters associated with future adjustments to the electricity IRP.

A Potential Pathway

To enable a transparent and inclusive process, we suggest an annual or semi-annual extended workshop on climate change and clean technology policies and programs informed by expert views on trends for electricity technologies and costs. The declining costs for technologies such as wind, solar, offshore wind and storage should be a particular focus. The workshop could also include cross-over fuels such as RNG and hydrogen.

The first part of the workshop would be broad stakeholder-based and designed to inform participants and the utility's customers. Key national/global, as well as local/regional thinkers, could be invited. The workshop organization group might also commission papers. Following this event, there could be a more technical session to understand how all this impacts the IRP assumptions and advise on the impact to the 2020 IRP, and whether it is time to do a modelling update.

The first more public-facing workshop could be managed by a not-for-profit organization or a coalition of not for profits on a cost-recovery basis. Sponsors could also be sought with conference surpluses dedicated to research in matters associated with managing the energy transformation agenda.

From this, we suggest that the final Roadmap and Action Plan reference the need for a regular and inclusive informative process to examine changes in the technologies, business models and best practices, and the policies and program initiatives that could impact the IRP assumptions and scenarios. These regular workshop updates could provide useful context and information for broader public engagement needs and the more formal IRP stakeholder engagement process.

Bruce Cameron
Principal Consultant,
Envigour Policy Consulting Inc.

c.c. Tonja Leach, Executive Director QUEST
Via Email: tleach@questcanada.org

Elisa Obermann, Executive Director of Marine Renewables Canada
Via Email: elisa@marinerenewables.ca

Greg Robart, CEO Smart Grid Innovation Network
Via Email: greg@sgin.ca

Heritage Gas

September 18, 2020

Nicole Godbout
Director, Regulatory Affairs
Nova Scotia Power Inc.
PO Box 910
Halifax, NS B3J 2W5

RE: M08929 – NSPI Integrated Resource Planning – Draft Findings, Action Plan & Roadmap

Heritage Gas is the regulated provider of natural gas distribution service to Nova Scotia residents and businesses. Heritage Gas has been attending stakeholder meetings and workshops with Nova Scotia Power Inc. ("NSPI"), Energy+Environmental Economics ("E3") and other stakeholder groups. Heritage Gas has been fully engaged and interested in understanding NSPI's Integrated Resource Plan ("IRP") and its interplay with long-term overall energy planning for the province for the next 25 years.

The Draft Findings, Action Plan and Roadmap results distributed to interested stakeholders on September 2, 2020 and presented on September 10, 2020 further indicate a required need and reliance for natural gas in the province over the next 25-year period. The results presented show that natural gas will provide electrical grid reliability, critical ancillary services, an economic energy source, and a lower carbon energy source to meet the province's environmental goals.

<u>Reliability of Liquid-Fueled Combustion Turbines ("CTs")</u>

In Draft Finding 3(b), NSPI describes retaining these units for another 25 years, at which point they will have been in operation for nearly 70 years:

> *"NS Power's existing CT resources provide economic benefit to customers and are economically sustained through the planning horizon with appropriate reinvestment requirements."*[1]

[1] NS Power 2020 IRP Draft Findings Release, September 2, 2020, page 49.

Throughout the IRP process, Heritage Gas has had several discussions with NSPI and the larger stakeholder group on the reliability of the CT units. Our concerns with keeping 1970's-era units to the end of the IRP planning horizon have been further underscored by the findings in the recent FAM Audit conducted by Bates White Economic Consulting ("Bates White"). Some of the issues identified within the report included:

> *"Second, the entries above also demonstrate a key point regarding NSPI's seven combustion turbines at Burnside, Victoria Junction, and Tusket. That is, during periods of high ambient temperatures, the units failed to sustain operations at a time when they were needed most. Worse, the tendency for these units to overheat, trip, and thus remain locked out from further operation was anticipated and expected by NSPI personnel. This suggests that the reliability of these units is limited and those limitations are understood by those who operate NSPI's system.*
>
> *NSPI's seven 33 MW combustion turbines' performance during the Audit Period saw, in some cases, elevated DAFOR rates and low Availability Factors […] NSPI also noted that DAFOR industry averages for gas turbines of this size are typically quite high (60.8% in 2018) and that over half of NSPI's combustion turbine fleet outperformed the average. We agree, but note that these resources are relied upon to provide power when it is most needed, when system conditions are tightest."*[2]

The concerns ultimately led to Bates White developing conclusions specifically related to the reliability of the units. The report also concluded that NSPI has significantly underestimated the frequency that these units would be called upon to provide critical grid services:

> "***Conclusion IX-16:*** *The seven LFO-fired combustion turbines are called upon to produce energy far more than forecasted by NSPI; actual output exceeded forecasted output by over 1,300%.*
>
> ***Conclusion IX-17****: The seven LFO-fired combustion turbines had elevated DAFORs in some cases and suffered reduced reliability during periods of high ambient temperatures. NSPI's recent investments in oil cooling systems are intended to address this latter concern; data on the impact of these investments is inconclusive at this point and should be monitored."*[3]

[2] M09548 – (Exhibit N-1) Audit of Nova Scotia Power, Inc.'s Fuel Adjustment Mechanism for 2018–2019, Page 205.
[3] M09548 – (Exhibit N-1) Audit of Nova Scotia Power, Inc.'s Fuel Adjustment Mechanism for 2018–2019, page 231.

Heritage Gas also notes that in Draft Finding 3(a), NSPI discusses the requirement to add significant new CT capacity:

> "*New combustion turbines, operating at low capacity factors, are the lowest cost domestic source of firm capacity and replace retiring thermal capacity in all resource plans. These units are also fast-acting, meaning they can quickly respond to changes in wind and non-firm imported energy. 50-150MW is required by 2025, while 600- 1000MW of new capacity is required by 2045 to support retirement of steam units.*"[4]

As previously mentioned, Heritage Gas has natural gas distribution infrastructure in very close proximity to the four diesel-fueled Burnside CT's. The conversion or replacement of the now 45-year old CT's provides an opportunity to both address the reliability issues with the existing CT's and address the need for additional CT capacity. The replacement of the Burnside CT's should be strongly considered. Heritage Gas recommends that a specific Action Item be identified in the final report to address the reliability issues identified by Bates White and the cost-effective utilization of existing infrastructure to meet the needs for additional CT capacity.

<u>Conversion of Coal-to-Gas</u>

As previously mentioned in the Modelling Results, the long-term resource changes emphasize additional natural gas resources including coal-to-gas conversions.[5] The Draft Finding 3(c) shows natural gas as a key requirement of the developing electricity system in both the near and long term:

> "*Low-cost, low-emitting generating capacity may be provided economically through redevelopment of existing natural gas-powered steam turbines or coal unit conversions. Fuel flexibility, including low/zero carbon alternative fuels, may also be an option for new and redeveloped resources*."[6]

Draft Roadmap item 1 discusses the need for "advance engineering study work on coal to gas conversions at Trenton and Point Tupper Generating Stations"[7]. The Action Plan should reflect a timeline of

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[4] NS Power 2020 IRP Draft Findings Release, September 2, 2020, page 49.
[5] IRP Modeling Results Workshop #4 – July 9, 2020, page 16.
[6] NS Power 2020 IRP Draft Findings Release, September 2, 2020, page 49.
[7] NS Power 2020 IRP Draft Findings Release, September 2, 2020, page 60.

completion of this study and scope of the work included in the coal-to-gas conversion scenario. Heritage Gas also notes that an increase of this size in natural gas consumption in the region requires long-term natural gas transportation commitment planning, which should also be reflected in the Action Plan.

Electrification and Associated Transmission & Distribution ("T&D") Costs

This IRP is unique in contrast to previous IRP's in that very significant investments will be required in NSPI's transmission and distribution assets. This investment is driven by potential increased electrification of end-use energy, such as transportation and building heat, and the need to meet the lower environmental targets specified in the Sustainable Development Goals Act ("SDGA"). Significant investment in T&D is also expected to arise from the large potential increases in peak energy demand[8].

Heritage Gas understands that there is an ongoing process through DSM Matter No. M09471, to agree on the avoided T&D costs of Demand Side Management ("DSM"). This matter considers only a fraction of total T&D costs and so, it would be prudent to discuss these findings with the larger stakeholder group and also include a continued study of T&D costs in the context of the increasing electrical load envisioned in the IRP.

Natural Gas Supports the Transition to Low Carbon Fuels

Heritage Gas acknowledges that electrification in certain sectors of the economy will assist in moving Nova Scotia toward a lower carbon economy. However, electrification alone will not substantially reduce the GHG emissions in the province in order to meet the SDGA net-zero 2050 target.

Heritage Gas notes that in the Roadmap, NSPI anticipates ongoing research in this area:

> "*Monitor the development of low/zero carbon fuels that could replace natural gas in powering generating units to provide firm, in-province capacity beyond 2050.*"[9]

Recently the Offshore Energy Research Association ("OERA"), Liberty Utilities, Heritage Gas, and the provincial Department of Energy & Mines engaged Zen Energy Solutions to determine the future potential

[8] 2020 IRP Assumptions Set (January 20, 2020), page 9.
[9] NS Power 2020 IRP Draft Findings Release, September 2, 2020, page 61.

uses of hydrogen in Nova Scotia[10]. Hydrogen is increasingly seen as imperative in meeting the net-zero goals established in the Sustainable SDGA and NSPI should specifically identify hydrogen within the action plan and roadmap.

Recommendations for the Final Action Plan

- The Action Plan should specially consider the replacement of the liquid-fueled CT's in Burnside with gas-fired CT's as a cost-effective means to reliably meet the incremental capacity requirements identified in the IRP.
- The Action Plan should identify the specific timeline and scope of the engineering study regarding coal-to-gas conversions. The assumptions on long-term natural gas transportation contracts should also be included within this action item.
- A timetable should be established for estimating the incremental T&D costs associated with the various electrification scenarios. The IRP stakeholders should be kept fully informed as these cost estimate are developed
- The Action Plan and Roadmap should specifically identify hydrogen as a means to assist the province in meeting the GHG reduction targets established in the SDGA.

General Comments

The assumptions and scenario modelling used in this IRP reflect the need for continued monitoring of the development of the electric and broader energy sectors in the Province. Unlike past IRP's this IRP suggests some possible fundamental differences in the future electric sector in Nova Scotia. These fundamental changes include for the first time a general future separation of capacity from energy, a potential focus on electricity growth versus general DSM (still dependent on full costing of such an approach) with a continued requirement for focused DSM and Demand Response on peak, the potential requirement for significant new regional transmission to allow both increased firm and non-firm energy imports, the requirement for more fast acting generation to support increased renewable development and provide peak response capability, and the need to significantly monitor over time the take up of new technologies such as electric vehicles, distributed generation, battery or other storage options, etc. Of these changes, one of the most significant is the availability of significant volumes of firm dispatchable imports that are

[10] https://oera.ca/news/news-release-feasibility-study-evaluate-hydrogen-production-storage-distribution-and-use

incremental to those available through the Maritime Link. To meet the lower carbon intensities for electrical generation in the low to high electrification scenarios highlighted in the Draft Findings[11], the study assumes that the Nova Scotia electrical grid will need to rely on between 435 and 615 MW's of firm dispatchable energy and the required investment in NS-NB tie-line to accommodate this energy. NSPI has not provided any of the key assumptions associated with these imports including costs or carbon intensity and they have indicated that there are no commercial agreements in place to underpin the incremental imports.

As such, it is important that all stakeholders are kept apprised over the next number of years of the data collection, study results and future opportunities that might present themselves, so that the electricity sector in Nova Scotia works in concert with other sources of energy and opportunities in the wider energy sector in the Province, to ensure a sustainable competitive energy sector which will benefit all stakeholders. In consideration of these potential fundamental changes all parties will need to closely monitor developments in the electric and broader energy sectors to ensure Nova Scotian residents and business have access to competitive alternative energy supplies and to cost effectively meet the goals of the Province.

Heritage Gas appreciates the opportunity to comment on the Draft Findings, Roadmap and Action Plan, and the continued collaboration with all stakeholders. We especially recognize the effort by NSPI to continue an open process, and look forward to the consideration of these comments being reflected in the final Action Plan and submission to the Board.

Regards,
HERITAGE GAS LIMITED

John Hawkins
Cc: M08929 Participants

[11] NS Power 2020 IRP Draft Findings Release, September 2, 2020, page 12.

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To: Linda Lefler P.Eng, Senior Project Manager - Regulatory Affairs, Nova Scotia Power

From: Jon Sorenson, Executive Consultant, Hydrostor Inc.

Date: 17th of July 2020; REVISED 09/18/20

Re: A-CAES as a Solution for Nova Scotia

Memorandum

Thank you for your consideration and review. As we have communicated to the Nova Scotia Power team, Hydrostor is a Canadian technology provider and global developer of energy storage facilities that uses commercially proven Advanced Compressed Air Energy Storage (A-CAES) technology. **Recently, a well-established energy consulting firm working for a large US utility, gave Hydrostor and it's A-CAES technology, a TRL (Technology Readiness Level) ranking of 9, the highest possible score. This means our process, compressing air and storing electricity is considered a proven technology and ready to deploy.** As you know, we have been following Nova Scotia Power's IRP process with great interest and continue to be frustrated or disappointed to learn that long duration energy storage technology is not and has note been given its due in the preferred portfolio solution into the future. We would like to continue to reiterate the following, that Hydrostor:

- Be a cost-effective non-wire alternative solution for transmission that is easier to permit and more cost effective than large transmission projects or pumped-hydro projects
- As a clean source of synchronous generation capacity with similar system benefits and operating characteristics as coal that can be used to advance coal retirements and be located on or near the sites of former coal plants while retaining many of the plant's employee (this concept is now being considered in other areas of North America)
- Can be used to balance intermittent resources such as wind and solar or instead of natural gas fired plants, as a peaking asset

We note that Nova Scotia Power has instead opted for a portfolio that calls for new transmission and fossil fuel assets to meet balancing and peaking requirements. We believe that long duration Energy Storage, and A-CAES in particular, is a credible market-ready solution that can address the issues solved by these assets in a cleaner and more cost-effective way.

Nova Scotia Power's A-CAES Cost Assumptions

Based on our review of Nova Scotia Power's IRP assumptions, we believe that A-CAES's capital costs were inaccurately modelled. We believe that this played a decisive factor in it not being selected as a preferred resource. In particular, we found that in your cost analysis, the model used a $/kW cost of CAD $2,200. This was in effect, the mid

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point of our per KW cost estimates for a 200MW facility with a duration of 12 hours that we had previously provided to you. This was then compared to the cost of a lithium-ion system with 1 and 4 hours of duration. (See Figure 1 below).

		Capital Cost (2019 CAD $/kW)		
Technology	**Subtechnology**	**2019**	**2030**	**% Change**
Wind	Onshore	$2,100	$1,691	-19%
	Offshore	$4,726	$3,429	-27%
Solar PV[a]	Tracking	$1,800	$1,416	-21%
Biomass	Grate	$5,300	$5,146	-3%
	Municipal Solid Waste	$8,470	$8,470	0%
Tidal	n/a	$10,000	$10,000	0%
Storage	Li-Ion Battery (1 hr)	$764	$385	-50%
	Li-Ion Battery (4 hr)	$2,125	$1,071	-50%
	Compressed air	$2,200	$2,200	0%
	Pumped Storage	$2,700	$2,700	0%

[a] Solar PV costs reported in $/kW-ac, reflecting an inverter loading ratio of 1.3

Figure 1

Our concern is that this was not an apples-to-apples comparison as it accounts for the additional cost of a longer duration facility but ignores the additional value such a system provides. Additionally, by choosing to use the costs for a 200MW system, this did not account for the significant economies of scale that come with larger sized A-CAES facilities. **If you consider a 500MW facility with a 4-hour duration, the cost works out to an average of US$1125/kW[1]. We believe that this is a much fairer comparison to a 4-hour lithium-Ion system for the short duration market**.

However A-CAES's cost advantage is most apparent in the long-duration market where it can act as a non-wires alternative to traditional transmission for improving reliability or as a solution for integrating and time-shifting Nova Scotia's wind resources onto the grid. To illustrate this point, we compared the bid prices that we recently submitted for a 300MW 6 hour and 12 hour facility to a utility in California to what an equivalent lithium system would cost based on prices provided by Lazard's Levelized Cost of Storage Analysis 5.0. For the 6 hour system we found that lithium ion prices would have to drop 7%-50% from 2019 in order to achieve cost parity. Whereas, for the 12 hour facility we found that lithium ion would have to decrease their cost by a further 41%-70% in order to achieve cost parity.

A-CAES is a Reliable Solution for Nova Scotia's Needs

Advanced Compressed Air Energy Storage, uses equipment, construction techniques

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[1] [1] We also note there was a conversion error as our costs were presented to Nova Scotia power in US$ but were displayed here in $CA. We therefore question whether this conversion error applied to other technologies listed here.

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and technology proven and optimized in the oil and gas sector to deliver a bankable and market-ready solution that can be delivered at scale. The technology benefits from large economies of scale which allow it to offer the lowest per kwh cost the energy storage market for system sizes larger than 250MW and at durations ranging from 4 to 12 hours or more. Because of our exclusive use of equipment produced by Tier 1 manufacturers such as Baker Hughes, Hydrostor can deliver facilities backed by global supply chains, comprehensive maintenance packages and performance guarantees. With no degradation or disposal liabilities, flexible expansion options, and a service life of 50+ years that give it unique advantages over batteries and makes it the ideal storage solution for integrating Nova Scotia's considerable wind resources into the grid.

It is also important to note that since A-CAES uses spinning turbines it can meet the grid's need for inertia and synchronous generation that is currently provided by Nova Scotia Power's coal fired generation facilities. Furthermore, unlike pumped hydro or fossil assets, A-CAES can be flexibly sited where the grid needs it. It is a benign technology that has minimal impact on its local environment while producing major economic benefits for local communities, reducing permitting risk and allowing it to be safely sited close to population centres. Furthermore, Hydrostor has studied the geology of Nova Scotia and New Brunswick and found the region to be highly suitable for A-CAES, making it even easier to site. For these reasons, we believe A-CAES is the right solution for accelerating the retirement of coal assets and avoiding further investment into fossil fuels.

We note that Nova Scotia Power intends to make considerable investment in transmission infrastructure to improve the reliability of the system. Again, we believe that A-CAES should be seriously considered by Nova Scotia Power as a lower-cost alternative that could save the utility 10's to 100's of millions of dollars. We have proposed this kind of solution to regulators and transmission companies in Chile, Australia, and California and would be happy to provide you with an indication of what the cost savings could look like for an A-CAES facility sited near the source or load instead of build a new transmission line. Please note that recently, Transgrid Utilities in Australia chose Hydrostor over competing technologies to provide its renewable energy storage technology now and into the future.

https://bdtruth.com.au/main/news/article/11997-Air-power-proposal-to-back-up-supply.html#:~:text=Transgrid%20has%20chosen%20a%20150,the%20USA%20and%20South%20Australia.

In short as communicated at the onset of this memorandum, we believe that a Canadian designed A-CAES facility built to a scale of 300 to 500MW with a long duration of 6, 8,10, 12 hours or beyond can assist Nova Scotia Power in its Integrated Resource Plan in the following areas:

- Be a cost-effective non-wire alternative solution for transmission that is easier to permit and more cost effective than large transmission projects
- As a clean source of synchronous generation capacity with similar system benefits and operating characteristics as coal that can be used to advance coal

HYDROSTOR

retirements and be located on or near the sites of former coal plants while retaining many of the plant's employees
- Can be used to balance intermittent resources such as wind and solar or instead of natural gas fired plants, as a peaking asset

We would be very interested to better understand your thoughts on A-CAES and hope to address any questions or concerns. We would also invite Nova Scotia Power and its consultant, E3 to schedule a call to discuss A-CAES and in addition, take part in a virtual tour of our recently commissioned Goderich facility (Ontario) in the nearest future. We want to thank you for your consideration but do ask that you seriously evaluate and look at A-CAES instead of traditional means, as we and many others believe A-CAES can be a definitive resource option for Nova Scotia and its' energy future.

Please do not hesitate to contact me/us and again welcome the opportunity to provide a virtual tour of the now operating Goderich facility.

Thank you and Best Regards,

Jon Sorenson
Executive Consultant
Hydrostor Inc.
617-800-9392
Jon.sorenson@hydrostor.ca

Appendices

Appendix 1: A-CAES Technical Inputs Summary (Previously submitted to NS Power)

natural forces

Natural Forces Services Inc. | 1801 Hollis Street | Suite 1205 | Halifax | NS | B3J 3N4 | T: (902) 422 9663 | F: (902) 422 9780

Doreen Friis,
Regulatory Affairs Officer/Clerk
Nova Scotia Utility and Review Board
1601 Lower Water Street, 3rd Floor
P.O. Box 1692, Unit "M"
Halifax, NS B3J 3S3

September 18, 2020

-SENT VIA EMAIL-

RE: 2020 Integrated Resource Plan Initial Modelling Review

Dear Ms. Friis,

Natural Forces Services Inc. welcomes the opportunity to once again input comments on the IRP process. We note that again the time for comments to this process are extremely tight and it makes it very difficult for us to fully process the information that is being submitted by NSPI.

To simplify the process, we have attached our direct report from our technical advisor, Andrew Cooke directly.

The key point that Natural Forces wishes to emphasize is on the cost of wind that has been modeled by NSPI. As the board may know, Natural Forces is active across the country and is actively building out wind project currently and over the next few years, so the prices and energy numbers from today's and tomorrow's wind projects are well known to us. Two comments:

- the price per MW installed is much closer to the 1.5 million per MW; and
- the capacity factors are closer to mid 40% than the number stated by NSPI.

This does lead us to believe that more wind now is the answer, and that the way to unlock these saving for the rate payers and the utility is to look to other jurisdictions that have large wind resources in use and adopt some of their operating procedures in order to keep the system stable and allow for more wind on the system.

Thank

Sincerely,

Presented for, and on behalf of, Natural Forces Services Inc. Halifax, Nova Scotia.

Cooke Energy and Utility Consulting Ltd.

27 Willans Way
Ongar Green
Dublin 15

Email cookea59@gmail.com

Review of IRP Modelling Results and Draft Findings

This Report is prepared by Cooke Energy & Utility Consulting on behalf of Natural Forces.

The report sets out a high-level review of the IRP Modelling Results and Draft Findings presented by Nova Scotia Power, principally in the following documents:

- NS Power 2020 IRP Updated Modeling Results Release (2nd September 2020)
- NS Power 2020 IRP Draft Findings Release (2nd September 2020)
- NS Power 2020 IRP Inertia and Constraint Modeling (15th September 2020)
- IRP Modeling Results Table (2020-09-02).

Key observations are summarised in the Executive Summary below. Issues are discussed in more detail in sections 1 through 5.

Executive Summary

- **A major transformation of the existing generation resource base is required**. As Nova Scotia Power has remarked, significant efforts are required to achieve the level of carbon emissions reductions in line with Nova Scotia's Sustainable Development Goals Act. A major transformation of the existing generation resource base is required, including the integration of significantly higher volumes of intermittent, non-synchronous renewable energy resources. However similar transitions have been successfully achieved in other jurisdictions.

- **Higher electrification scenarios are beneficial to electricity consumers through lower rates, and will also support cost-effective achievement of broader emissions policy objectives.** NSP has identified that higher electrification is beneficial to reducing electricity rates. It is presumably also beneficial to achievement of Nova Scotia's broader emissions policy goals, as it supports decarbonisation of other sectors (transport, heat). It is recommended that this point is emphasised strongly in the findings and is considered in NSP's action plan.

- **Sensitivities with lower wind costs profoundly affect the resource plan and need significant further analysis**. The sensitivities with lower wind costs have a profound effect on the resource build-out plan. Much larger quantities of wind capacity (c. 600 MW) are being added by 2023 to 2025. These scenarios also have the benefit of lower CO_2 emissions than comparative scenarios. As these scenarios are based on very credible wind cost projections (and disassociation of battery costs would also contribute to lowering the effective cost of wind) it is of critical importance that further analysis is undertaken in this area, including gaining an understanding of the price point(s) at which transition occurs. [Refer section 2]

- **The suggested build out rate for wind in NSP's initial draft action plan, is understated**. NSP's proposed/draft action plan item 3(c) states: *"Initiate a wind procurement strategy, targeting 0-100 MW new installed capacity by 2025 and up to 350 MW by 2030".* This is unduly limiting at this stage, particularly as regards the implied cap of 350 MW by 2030. Even before consideration of the "low wind cost" sensitivities, several scenarios, including those identified as resulting in lower electricity rates, have substantially higher wind volumes.

- **CO2 levels vary widely between scenarios.** There is a wide variation in the CO2 levels (both annual and cumulative) between the different scenarios. Even if not directly monetizable, there is a definite value in lower CO2 emissions:

  a) as a risk mitigation strategy against upward pressure on emissions levels from additional demand growth, or further downward revisions in emission targets; and,

  b) as can be observed from experience in other jurisdictions, lower carbon intensity of the electricity sector (lower CO2/MWh) promotes electrification of other sectors (heat, transport), which is identified as lowering electricity rates and will also contribute to achievement of broader emissions policy objectives.

  The differences in CO2 levels should be highlighted clearly in the results, to that individual stakeholders and stakeholder groups can consider the impacts. [Refer section 3]

- **Consideration of Risk.** There is merit in giving further consideration to risk assessment, as a tool for identifying scenarios and/or actions which show strong performance (in terms of low cost) across a range of future sensitivities. It is likely that scenarios with higher renewables and/or lower CO2 emissions would tend to be more favourable under such an examination, as they are "proofed", to a considerable extent, against potential variables such as high fossil fuel costs, high emission costs (or tightening of emissions limits), or higher demand growth/electrification (potentially resulting in breaches of emissions limits). It is recommended that this type of analysis is considered further. [Refer section 4]

- **NSP's continued adherence to allowing further wind capacity to be installed only in association with capital intensive batteries & synch comps, or the 2nd AC intertie**. This has been discussed at length before, and NSP's adherence to this position is quite frankly, rather baffling. The standard practice today in other systems integrating higher levels of intermittent, asynchronous renewable resources (such as wind) is to allow wind to install to an economic level, and accept that on rare occasions, it may be necessary to curtail (dispatch down) wind output to a level that ensures the system remains stable. The precise extent to which wind capacity is being "held back" due to the NSP approach is difficult to quantify (though it could be assessed through the modeling by disassociating the requirement for batteries/synch comps). However I believe it can be stated with certainty that the NSP approach will result in some level of higher costs to electricity consumers (as compared to the standard approach adopted in other power systems integrating comparatively high levels of intermittent and non-synchronous renewable generation). [Refer section 5]

  NSP has not (to date) provided justification for continuing with this approach, and should be requested to set out clearly, its reasons for not adopting what is best practice (and indeed increasingly standard practice) in other jurisdictions integrating higher levels of intermittent, non-synchronous renewables.

1. Overall results and Wind capacity levels

As Nova Scotia Power has remarked, significant efforts are required to achieve the level of carbon emissions reductions in line with Nova Scotia's Sustainable Development Goals Act. A major transformation of the existing generation resource base is required, including the integration of significantly higher volumes of intermittent, non-synchronous renewable energy resources. However similar transitions have been successfully achieved in other jurisdictions.

It is helpful that that there is a significant degree of commonality in the main "building blocks" selected in each of the scenarios, those being (for the main part): wind capacity; gas-fired CTs; the 2nd AC intertie, and regional integration. The scenarios differ in the order and rate at which the new resources are deployed, and the rate at which certain existing resources (principally the coal-fired units) are retired.

The build out rate of new wind capacity from the initial cases (i.e. not including the low wind cost sensitivities) is set out in the following graph:

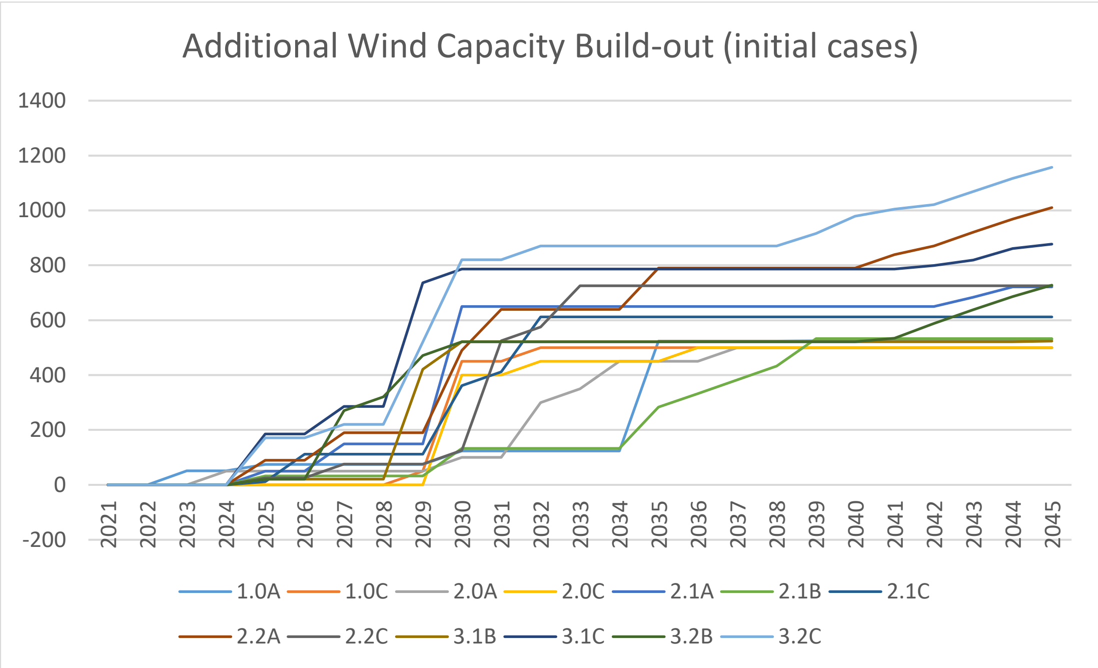

Figure 1: Build-out of additional Wind Capacity in the initial Scenarios.

As can be observed, several scenarios have approximately 200 MW of new wind capacity coming on by 2025 to 2027, and amounts ranging from 400 to 800 MW by 2029/2030. The higher wind capacities are generally arising in the cases based on higher electrification, as might be expected.

NSP has identified that higher electrification is beneficial to reducing electricity rates (and it is presumably also beneficial to achievement of Nova Scotia's broader emissions policy goals).

In light of the above, NSP's proposed/draft action plan item 3(c) viz:

> *"Initiate a wind procurement strategy, targeting 0-100 MW new installed capacity by 2025 and up to 350 MW by 2030"*

seems unduly limiting, particularly as regards the implied "upper limit" of 350 MW by 2030. Several scenarios, including those identified as resulting in lower electricity rates, have substantially higher wind volumes.

Another key point to note is that many scenarios are introducing some level of additional wind capacity, even with the imposed requirement that wind installed capacity of greater than 700 MW must be accompanied by either batteries/synch comps, or the second AC intertie. This has the effect of imposing an entirely unnecessary and inappropriate additional capital cost on wind (i.e. the associated capital cost of the batteries/synch comps), which is very likely reducing the level of wind being installed in many of these cases. It is difficult to be precise about the level of additional costs being imposed through this requirement as the batteries will bring some other benefits (such as energy arbitrage) which will act to off-set the added capital costs. However approximations suggest it may be adding in the region of 5 to 10% to the effective cost of additional wind capacity.

The continued insistence on the part of NSP to adhere to this position is rather baffling. The precise extent to which wind capacity is being "held back" due to this approach is difficult to quantify (though of course it could be assessed by disassociating the requirement for batteries/synch comps in the modeling). However I believe it can be stated with certainty that the NSP approach will inevitably result in some level of higher costs to electricity consumers (as compared to the standard approach adopted in other power systems integrating comparatively high levels of intermittent and non-synchronous renewable generation). This is discussed further in section 5.

2. Low wind cost sensitivity cases

The sensitivity cases undertaken with lower wind (and battery) costs[1] are or particular interest, and result in a fundamentally different build-out plan.

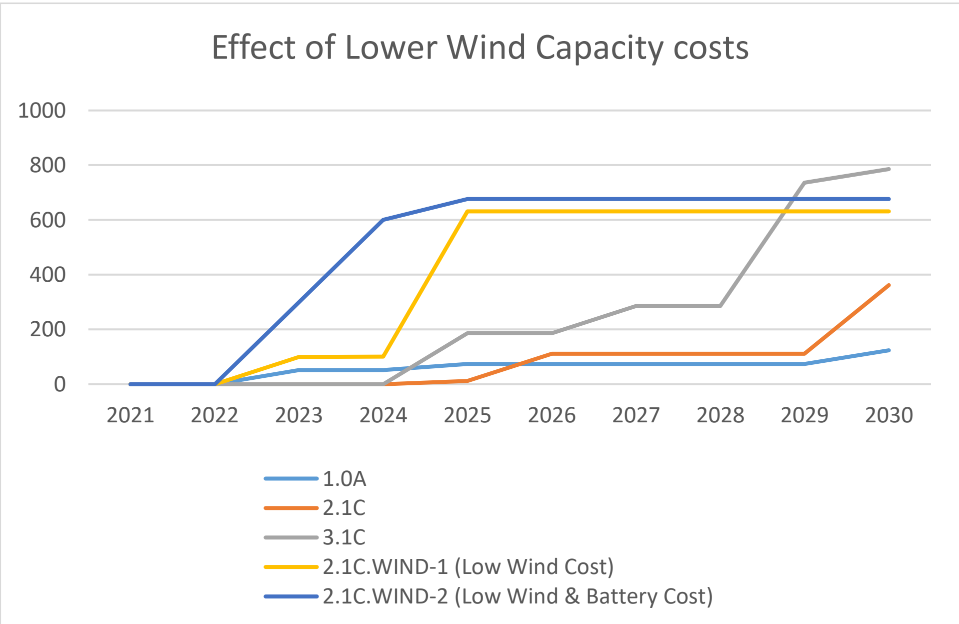

Figure 2: Build-out of additional Wind Capacity in the initial Scenarios.

As can be seen, the lower wind costs have a profound effect on the resource build out plan, even compared to the "original" scenarios with higher wind build-out (such as Case 3.1C). Much larger

[1] Cases "2.1C WIND 1 (Low Wind Cost)" and "2.1C WIND 2 (Low Wind and Battery Cost)"

quantities of wind capacity (c. 600 MW) are being added by 2025, and even earlier in Case "2.1C WIND-2" which also has lower battery costs[2].

Given that this has such a fundamental impact, coupled with the fact that lower wind costs are a highly credible scenario, further investigation of this scenario is critical. At present it tells us that changing the wind costs from the "Base Case Wind Cost" ($2,100/kW) to the "Low Wind Cost" ($1,500/kW) has a major impact on the timing of the deployment of additional wind capacity. However it does not tell us at what wind cost does this major change occur[3]. If it happens (in whole or in part) at a higher wind cost (somewhere between $2,100 and $1,500), it further increases the confidence level that the benefits of the "lower wind cost" cases are achievable.

Once more, the unnecessary association of the battery costs with increased wind (until the advent of the 2nd AC intertie) is also an important consideration. The reduction in wind costs required to create the change to a more rapid wind build-out plan, could be arrived at through a combination of lower wind capital costs and savings from disassociating the battery requirements.

There are also benefits (not currently monetised) from reduced CO2 submissions in the cases with higher wind build-out. This is discussed further in section 4.

In summary, the findings from the "low wind cost" scenarios are much too significant to ignore, and it is of critical importance that further analysis is undertaken to understand the price point(s) at which transition occurs. It is also strongly recommended that the association of battery and synch comp costs with additional wind capacity, is discontinued for these (as well as other) scenarios.

3. CO2 emissions variations

While all scenarios are intended to meet emissions limits, there is a wide variation in the CO2 levels (both annual and cumulative) between the different scenarios. As can be seen from the graphs included in the NSP presentation of Modelling Results, some scenarios track the CO2 allowed emissions limits quite closely, whereas others are significantly below it (at least for periods of time).

For example in the "low wind cost" cases, the CO2 emissions are (as might be expected) significantly lower than the comparative "base case (2.1C) in the period 2023 to 2030.

[2] Strongly suggesting that if the batteries were dissociated from the wind, then wind build out would be further increased/advanced.

[3] There may not be a single "threshold wind price" at which this change happens (though as the larger wind volumes are accompanied by the 2nd intertie, it is mostly likely to relate to a specific price point.

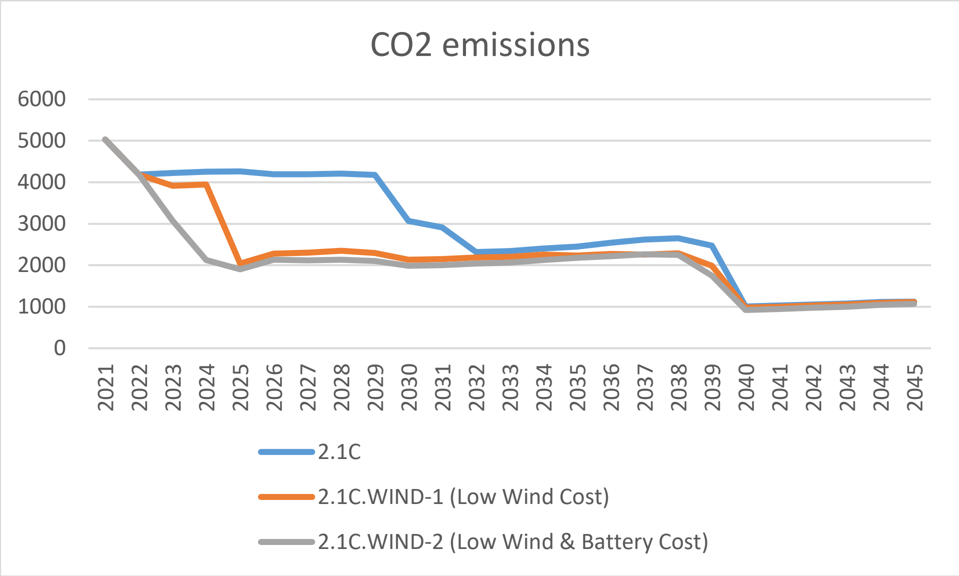

Figure 3: Annual CO2 emissions for "low wind" cost cases and comparative "base case".

WIND & IMPORT SENSITIVITY COMPARISON

	Description	Reliability Tie	Regional Integration	CO_2 Emissions 2021-2045	25-yr NPVRR ($MM)	10-yr NPVRR ($MM)
2.0A	Low Elec / Current Landscape	2032	n/a	77.7	$12,351	$6,831
2.1C	Mid Elec / Regional Integration	2030	2036	70.9	$13,141	$7,067
2.1C.WIND-1	Low Wind Cost	2025	2026	56.6	$12,978	$7,132
2.1C.WIND-2	Low Wind & Battery Cost	2023	2036	51.7	$13,086	$7,177
2.1C.WIND-3	Low Inertia (2200 MW.sec)	2031	2034	71.7	$13,059	$7,000
2.1C.WIND-4	No Inertia / No Integration	2040	2040	52.8	$13,076	$7,049
2.1C.IMPORT-1	Limited Non-Firm Imports	2024	2026	78.6	$13,543	$7,373
2.0A.IMPORT-2	No Reliability Tie	n/a	n/a	76.8	$12,628	$6,951
2.1C.IMPORT-3	Limited Reliability Tie Inertia (50%)	2028	2029	67.6	$13,225	$7,111

Figure 4: Cumulative CO2 emissions (source "NS Power 2020 IRP Inertia Constraint Modelling" – slide 2)

To the best of my knowledge, the benefits of a lower level of CO2 emissions is nor currently monetised in the IRP modelling approach. This is of course dependent on the emissions framework applicable to the jurisdiction. In Europe for example, the approach would be to directly monetise the benefit of a lower CO2 emission level[4].

[4] Every two years ENTSO-E (the European Network of Transmission System Operators in Electricity, an association which is vested with key statutory responsibilities under European and National Law) produces a "Scenario Report" including, among other things, forecast prices for CO2. The scenarios, which are widely consulted upon and ultimately approved by ACER (umbrella association for European national electricity regulators) and the EU, are used for the purpose of carrying out comparative analysis of "Projects of Common Interest", which mainly comprise proposed international interconnector projects and large-scale storage projects. The aim is that the projects are assessed on a common basis (so can be "ranked" for purposes such as European grant funding) , and to present a sufficiently diverse range of scenarios to test the robustness of the projects to a variety of futures. In the 2018 Scenario report, CO2 price projections varied across the scenarios between €27/tonne and €84.3/tonne.

Even if that is not appropriate within the current framework applicable in Nova Scotia, it is suggested that the differentiation between the scenarios in terms of CO2 levels is a significant factor which should be highlighted to a greater extent. Individual stakeholders or stakeholder groups may wish to take their own views on the value of lower CO2 levels, including in relation to overall emissions policy goals.

Also even if not directly monetizable, there is a definite value in lower CO2 scenarios as a risk mitigation strategy:

- In a scenario where CO2 is "only just" below the required limit, then there is a risk that in the event of, say, higher demand growth and/or greater levels of electrification, that the limits would then be breached (or that meeting them – if even possible – would involve suboptimal and expensive strategies).
- If emissions limits are revised downwards, the additional actions and costs required to achieve them (starting from a lower CO2 base), are likely to be much less significant.

It can also be observed from experience in other jurisdictions, that the lower the carbon intensity (CO2/MWh) of the electricity sector, the more it becomes a "strategy of choice" for other sectors (transport, heat) to achieve their emissions-reduction objectives. Aside from assisting in achievement of Nova Scotia's emissions policy objectives more generally, lower CO2 intensity is likely to promote higher electrification, which is identified by NSP as contributing to lower electricity rates.

Note that this point is applicable generally, and not only to the "low wind cost" scenarios used to illustrate the point here.

4. Consideration of Risk

NSP has aimed at identifying certain actions which are generally common to all or most scenarios, and has proposed these within its initial draft action plan.

A common approach is also to look for scenarios and/or actions which are "low regret" scenarios, i.e. a scenario which is not necessarily the "lowest cost" in a given set of circumstances, but shows strong performance (in terms of low cost) across a range of future sensitivities[5]. It could be likely that scenarios with higher renewables and/or low CO2 emissions would tend to be more favourable under such an examination, as they are "proofed", to a considerable extent, against potential variables such as high fossil fuel costs, high emission costs (or tightening of emissions limits), or higher demand growth/electrification (potentially causing breaches of emissions limits).

It is recommended that this type of analysis is considered further.

5. Continuation of association of battery and synch comp costs with additional wind capacity.

It is noted the NSP continues to insist on limiting the amount of installed wind capacity to 700 MW, allowing additional wind to be installed only if accompanied by capital-intensive batteries and synch

[5] There are various techniques which can be applied such as testing candidate capacity build-out scenarios across a range of future scenario projections (e.g. demand growth, fossil fuel costs, CO2 costs etc.). Results can be assessed on a more qualitative basis, or using techniques such as "least-worst-regrets" methodologies.

comps, or the 2nd AC intertie. This has been discussed at length before, and NSP's adherence to this position is quite frankly, rather baffling. The standard practice today in other systems integrating higher levels of intermittent, asynchronous renewable resources (such as wind) is to allow wind to install to an economic level, and accept that on rare occasions (such as the extreme system conditions modeled in the earlier "Power System Stability Study" [6]), it may be necessary to curtail (dispatch down) wind output to a level that ensures the system remains stable.

A compounding factor is that the "stressed system cases" used for the purpose of the technical analysis in the Power System Stability Study seem particularly unlikely to occur, and an initial analysis of 2019 data suggests that such conditions not only did not occur, but indeed were not even remotely approached. However as noted in our previous submissions and discussions on this point, this is a secondary issue. The key point is that if the conditions do occur, they can be managed by simply curtailing the wind output to an appropriate, safe, level.

The precise extent to which wind capacity is being "held back" due to this approach is difficult to quantify (though of course it could be done by disassociating the requirement for batteries/synch comps in the model). The effect may be less relevant in the cases with much larger volumes of wind integration, as these will tend to be associated with the 2nd AC intertie. The effect of the unnecessary association of the battery costs may in fact be more significant in scenarios/years with more modest levels of additional wind (c. 100 to 300 MW). However I believe it can be stated with certainty that the NSP approach will inevitably result in some level of higher costs to electricity consumers (as compared to the standard approach adopted in other power systems integrating comparatively high levels of intermittent and non-synchronous renewable generation).

Approved:

Andrew Cooke
Cooke Energy & Utility Consulting
17th September 2020

[6] "Nova Scotia Power Stability Study for Renewable Integration Report", prepared by PSC North America on behalf of Nova Scotia Power Inc. (24th July 2019)

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Our File: 179164
September 18, 2020

Ms. Nicole Godbout
Director, Regulatory Affairs
Nova Scotia Power
1223 Lower Water Street
Halifax, NS B3J 3S8

Dear Ms. Godbout:

Re: Integrated Resource Plan (IRP) 2020 – Draft Findings, Action Plan, and Roadmap

Port Hawkesbury Paper LP ("PHP") has reviewed the Updated Modeling Results and the Draft Findings, Action Plan and Roadmap circulated to stakeholders as part of the 2020 IRP process. Representatives of PHP also participated in Nova Scotia Power Inc.'s ("NS Power") September 10th technical conference to discuss these materials in detail.

PHP does not have any specific comments with respect to NS Power's proposed Findings, Action Plan and Roadmap as currently drafted. Rather, PHP would like to take this opportunity to emphasize the importance of the following key principles that should continue to guide NS Power's long-term strategy going forward:

1. Ongoing Stakeholder Engagement
2. Flexibility
3. Rate Impacts

1. Ongoing Stakeholder Engagement

PHP is appreciative of NS Power's efforts to actively and fully engage all stakeholders as part of its long-term planning processes. The IRP results clearly demonstrate the significant changes to the Nova Scotia electricity system that are expected to occur over the next 25 years. In this regard, the Draft Action Plan and Roadmap identify the need to initiate and develop several new strategies, plans, and programs in the near term. PHP supports this approach, as well as NS Power's plans to continuously refine the Findings and Action Plan items via an evergreen IRP process, on the basis that NS Power will continue to hold regular and transparent engagement sessions. Such sessions will ensure stakeholders have the opportunity to provide valuable feedback that can be incorporated in the transition of the electricity system, particularly as circumstances evolve and updated information becomes available.

2. Flexibility

In contrast to prior IRPs (which specifically sought to develop a long-term “Preferred Resource Plan” from among a set of candidate resource plans), the 2020 IRP results provide a comparison of various resource portfolios across a range of electrification scenarios. Maintaining maximum flexibility in the near term is needed to ensure that NS Power’s long-term strategy best accommodates the current uncertainty regarding future electric load growth in the Province. Preserving such flexibility will also enable NS Power to consider any subsequent changes in technology and/or government policy, as well as the results of ongoing costing analysis of generation and transmission options. These items will impact the economics of important long-term decisions regarding the timing and extent of (i) coal retirements, (ii) new capacity additions, and (iii) new renewable energy generation. Further, the significant potential investments in regional integration will require careful and strategic consideration and coordination with other jurisdictions in the region to ensure Nova Scotia stakeholders receive the intended benefits.

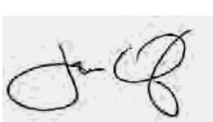
3. Rate Impacts

In its Updated Modeling Results and Draft Findings, NS Power developed a rate impact calculation using IRP partial revenue requirements for each scenario to illustrate the long-term effects of various levels of electrification. PHP believes that consideration of the potential overall impacts on future rates should remain a central consideration of NS Power’s long-term strategy and planning processes. The cost of electricity, as well as the stability and predictability of electricity rates, remain critical issues for all stakeholders, particularly industrial customers that compete globally and require ongoing capital investment.

As parties are aware, earlier this year, the Board approved NS Power’s Application for approval of the Extra Large Industrial Active Demand Control Tariff. This innovative rate structure, developed following extensive collaboration with the utility, provides NS Power with a new demand response service that allows the utility to better operate its electricity system for the benefit of all customers. The 2020 IRP results indicate that firm capacity resources will continue to be a key requirement of the developing NS Power system in both the near and long term, demonstrating the inherent value in demand response-type approaches going forward. Continuing to pursue deeper levels of collaboration and innovative solutions, whether through rate design approaches or otherwise, will help ensure that the transition to Nova Scotia’s electricity future can be achieved in an environmentally and economically sustainable manner for NS Power and its customers.

Thank you for the opportunity to submit these comments. PHP hopes the above points are helpful to NS Power in preparing the draft IRP report, and looks forward to reviewing it when available.

Yours truly,



James MacDuff

Blackburn Law

VIA EMAIL

September 17, 2020

Linda Lefler
Nova Scotia Power

Dear Ms. Lefler,

Re: M08929 – Draft Findings, Action Plan, and Roadmap – SBA Comments

The Small Business Advocate (SBA) and its experts from Daymark Energy Advisors, John Athas and Jeff Bower have reviewed the IRP Draft Findings, Action Plan and Roadmap.. Please find a memo from Mr. Athas and Mr. Bower attached, setting out comments and questions regarding the modeling results that were presented.

Please let me know if you have any questions or require any clarification.

Yours truly,

BLACKBURN LAW

N Dunning. for

E.A. Nelson Blackburn, Q.C.
Small Business Advocate

TO: Nelson Blackburn and Melissa MacAdam, Nova Scotia Small Business Advocate

FROM: John Athas and Jeff Bower

DATE: September 18, 2020

SUBJECT: Comments on NSP Findings, Action Plan, and Roadmap

This memo summarizes Daymark's comments regarding draft IRP Findings, Action Plan, and Roadmap, dated September 2, 2020 and presented by Nova Scotia Power (NSP) to stakeholders on September 10.

Connect Findings with model results

NSP has conducted extensive modeling and analysis in support of the IRP analysis. However, in the presentation of the draft findings, it was not always clear precisely how each finding was supported by the modeling analysis. In the full IRP, we encourage NSP to support the findings with specific references to model runs and related analyses.

Specify the schedule for additional analyses on reliability

A major topic of discussion throughout the stakeholder process has been the system inertia requirements and the capability of the system to integrate higher penetrations of inverter-based resources. The IRP analysis relied on conclusions of the 2019 PSC study, but NSP has acknowledged that additional analysis will be needed to more fully understand the inertia requirements in the future.

The draft Finding #2 acknowledges this, noting that "Further work is required to assess system stability at these significant penetrations and determine whether additional dynamic system inertia constraints can enable this level of additional wind integration on the Nova Scotia system" (Slide 47). The draft Roadmap item #2 also states that NSP will "Complete detailed system stability studies…while considering higher quantities of installed wind capacity…" (Slide 60).

The modeling of the inertia requirement has supported certain resource decisions, in particular the addition of the Reliability Tie which is assumed to provide all the system inertia needed by the NSP system. However, this conclusion requires some further investigation. Additionally, NSP has previously noted that it has not evaluated the possibility that wind projects could provide fast frequency response, which is a method of addressing system inertia concerns used in other regions.

We recommend that as part of the IRP, NSP should provide a concrete plan for conducting the additional analyses needed to assess the system needs, and the ability of different resources to address these needs (conventional generators, the Reliability Tie, Maritime Link, advanced wind turbines, and load resources). While the draft analysis indicates that the assumed system inertia requirement is not binding for several years, it is possible that cost declines for wind capacity or other factors could advance the timeline for wind development, hastening the need for a solution to the reliability need.

Address potential coordination with New Brunswick

Most IRP scenarios include the selection of the Reliability Tie and Regional Integration as part of the optimal portfolio. Implementing this strategy will require significant coordination with New Brunswick and availability of supply. Given the primary role of the transmission solutions in NSP's plan for a reliable and economic supply portfolio, the Company should prepare a specific timeline and plan for the steps required in Action Plan Item #1 to ensure that this is a feasible solution to deliver the benefits assumed in the IRP.

Provide clear interpretation of rate impact analysis

We appreciate NSP developing the rate impact model to help assess the implications of various portfolios for customers (Slide 31). We believe this provides important information in the consideration of various strategies. The summary of results provided in the draft Findings presentation (Slide 43) contain interesting conclusions, particularly related to the rate impact under high electrification scenarios. This slide was accompanied with important discussion during the stakeholder session which provided context on rate trends.

We recommend that NSP provide sufficient context in the IRP to communicate the implications of the rate impact analysis on customers, specifically as it relates to Finding 1b ("Increased electricity sales due to electrification can help to reduce upward pressure on electricity rates while facilitating carbon reductions in other sectors.")

Electrification data strategy

Increased electrification and advanced technology can provide enhanced capabilities to NSP to manage some of the challenges introduced by higher penetrations of non-dispatchable resources. Action Plan Item #2c calls for a data collection program related to electrification. We support this program, and encourage NSP to pursue it rapidly so that any insights can be incorporated into the next IRP.

Provide additional details on Demand Response Strategy

Demand Response resources can provide cost effective capacity or grid services. NSP's Action Plan calls for the creation of a Demand Response Strategy with a target capacity of 75 MW (Slide 57). We caution on the limitation placed by identifying Demand Response potential of only 75MW. This resource needs more examination to understand its true size potential and cost for different levels of DR.

From:	Omar Bhimji
To:	Lefler, Linda
Cc:	Devin Lake
Subject:	RE: NS Power IRP Workshop
Date:	Monday, September 21, 2020 10:41:18 AM
Attachments:	image001.png wolfville comments on 2020 IRP Draft Findings Action Plan and Roadmap.pdf

This is an external email from: obhimji@wolfville.ca - exercise caution

Hi Linda,

Please find attached our comments on the IRP Draft Findings, Action Plan and Road Map.

(I apologize that it arrives late. I finished it as my last task on Friday afternoon, hit send, and apparently closed down my computer before it actually left my inbox)

We appreciate the rigour of the process, and the opportunity to participate and provide comment. However, I want to echo something I noticed was included in the letter of comment provided by EAC that doesn't directly pertain to the Draft Findings, Action Plan and Road Map: small communities like Wolfville lack both the resources and expertise to meaningfully engage in a necessarily complex and lengthy process like the IRP. We've been very fortunate to receive patient and expert guidance from a number of helpful individuals and groups, but still don't feel terribly confident that we've fully understood and engaged with the process. You and your colleagues have made every effort to make the IRP process accessible to us, but we believe that our efforts, and those of communities throughout Nova Scotia endeavouring to address climate change, would be well served by an updated mandate to support climate change and environmental concerns within the IRP process in a way similar to the Consumer Advocate or the Small Business Advocate.

Regards,

Omar Bhimji
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wolfville

Submitted comments re. the 2020 IRP Draft Findings, Action Plan and Roadmap

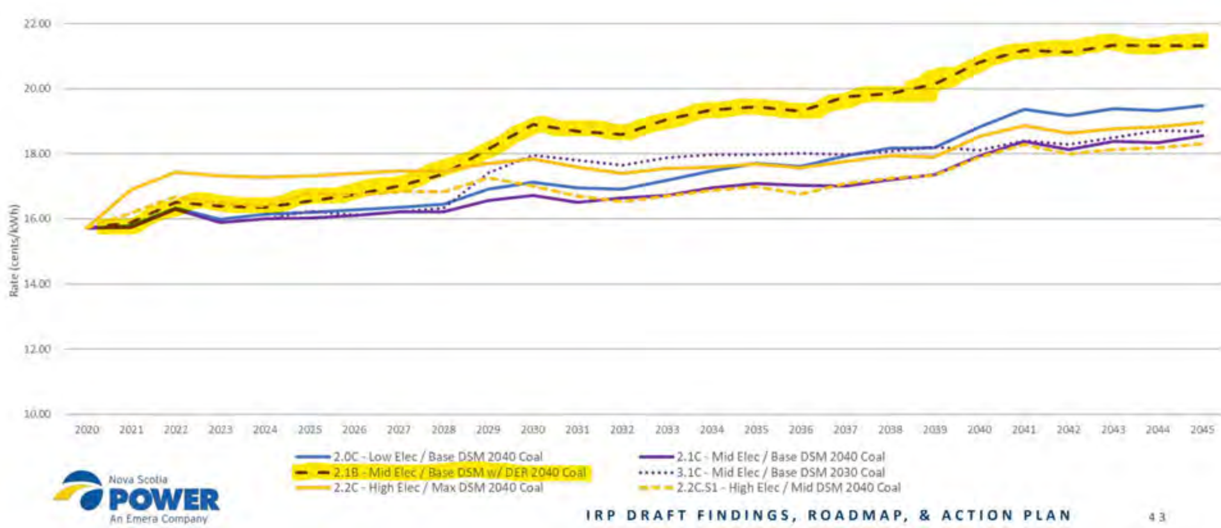
The Town of Wolfville appreciates the opportunity to patriciate in the 2020 Integrated Resource Planning process. We submit the below comments in response to the Draft Findings, Action Plan and Roadmap released for comment on September 2, 2020 and discussed at the stakeholder session on September 10, 2020.

Comments on Draft Findings.

1. It was encouraging to learn that all scenarios under consideration in the IRP process satisfy NS Power's reliability target. Reliable and predictable access to electricity is vitally important to Nova Scotians and will be become increasingly so as efforts to electrify transportation and heating systems in communities proceed.

2. The Town of Wolfville appreciates that an accelerated coal phase out scenario was considered as part of the IRP process. We note that, in the rate impact comparison, substantially similar scenarios that included coal phase-out by 2030 and 2040 were projected to have similar rate implications by 2040. There are both short- and long-term benefits to an accelerated phase out of coal and other fossil fuels: it has recently been confirmed that we have drastically underestimated the health impacts of air pollution on human health; the latest air quality research suggests that in the US, the health benefits alone are enough to justify an immediate transition away from fossil fuels.

3. The rate impact comparison also illustrates the inequitable economic implications associated with high levels of Distributed Energy Resource (DER) adoption. By 2040, the models suggest that high DER uptake could increase electricity costs by 10%, or 2 cents/kWh:



While this increase would be experienced by all rate payers, under the current regulatory regime governing Distributed Energy Resources – which limits the scope and scale of electricity-producing resources that can be connected to local distribution system –its impact would not be equitably distributed. For example, Nova Scotians with the financial capacity to both own their own homes and invest in solar PV systems would experience significantly less impact that those not in a financial position to do so. The possibility that public policy not only enables this, but is in fact subsidizing such investments, facilitating access to reduced energy costs by the wealthiest members of our society with the modelled implication of increasing the burden on the less affluent, is in urgent need of re-examination and consideration.

4. The Town of Wolfville appreciates the clarity and directness of the 1st Draft Finding, which states that "[s]teeply reducing carbon emissions in line with Nova Scotia's Sustainable Development Goals Act will require significant efforts from each sector of the economy, with the electricity sector playing a major role."

   Wolfville is currently working with the Sustainability Solutions Group (SSG) to develop its Climate Change Mitigation Plan. As part of this work, staff developed a set of working targets relating to activities and conditions in Wolfville both responsible for our GHG emissions and within the Town's regulatory and policy ambit to address or influence. These include targets such as:

   - increasing active transportation mode share from 23% (current) to 40% in 2030 and 50% in 2050 through programming and infrastructure investment;
   - increasing residential density through upzoning to decrease the average dwelling size in Town by 36% by 2050; and
   - reducing thermal and electric energy use to achieve 50% thermal savings and 50% electrical savings in 100% of all existing dwellings by 2040 by facilitating energy efficiency retrofits for current buildings through the implementation of a Property Assessed Clean Energy program.

   Wolfville's targets are ambitious, reflecting the climate change emergency declared by the Town's Mayor and Council in May 2019 and the urgency of the crisis posed to its citizens and the world by global climate change.

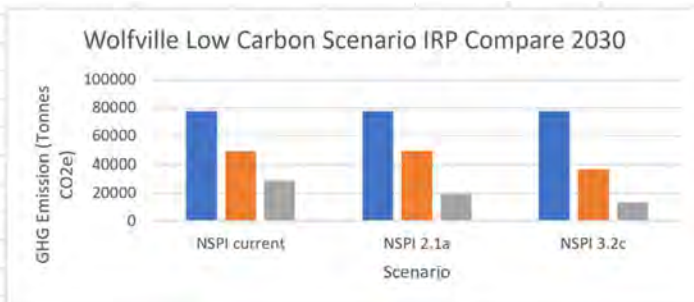
   SSG used the CityInSight modelling tool to project the emission-reductions that Wolfville could realize should it achieve its targets for both 2030 and 2050 under 2 of the scenarios currently being considered as part of the IRP process, along with the scenario included in the most recent National Inventory Report based on the National Energy Board's (NEB) 2018 Energy Supply and Demand Projections.

   1. NEB 2018
   2. Net Zero 2050 / Mid Electrification / Current Landscape (2.1a)

3. Accelerated Net Zero 2045 / High Electrification / Regional Integration (3.2c)

SSG's modelling projects that, under scenario 3.2c, should the Town of Wolfville achieve the working targets in its draft climate change mitigation plan, it would achieve a 53% reduction in GHG emissions by 2030, in-line with the emissions reductions goal legislated by the Province in the Sustainable Development Goals Act (2019):

	GHG Emissions (Tonnes CO2e)		
Scenario	2020	2030	2050
NSPI current	77678	49252	28897
NSPI 2.1a	77678	49352	19291
NSPI 3.2c	77678	36610	13513
	% Reduction from Peak Emissions		
Scenario	2020	2030	2050
NSPI current	100%	37%	63%
NSPI 2.1a	100%	36%	75%
NSPI 3.2c	100%	53%	83%



It also projected that the Town's climate change mitigation efforts would realize essentially identical emissions reductions under both the NEB 2018 and Net Zero 2050 / Mid Electrification / Current Landscape scenarios – both of which would fall far short of the provincial emissions reductions goal mandated by the Sustainable Development Goals Act (2019).

Thank you for this opportunity to comment and for your consideration,

Omar Bhimji

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Category	Participant	Comment	NSP Response / Consideration for Final Report
Sensitivity	CA	(1) Will cost sensitivities be performed on selected portfolios (e.g. fuel costs)?	Yes. In addition to the sensitivities previously published, NS Power has added three new cost-related sensitivities to the Modeling Results in parallel with the release of the Draft Report. Two sensitivities were added examining high and low sustaining capital costs for existing thermal units, and a third was completed which examined a high cost sensitivity on pricing for Natural Gas and Import prices, since those resources were seen to have a prominent role in most of the key scenarios and sensitivity optimal resource plans. Additional details on the results and interpretation are available in the updated Modeling Results file on the IRP website.
Rate impact	CA	(2) The individual model run results refer to "average annual partial rate impact" but the summary slide "relative rate impact comparison" does not reference the word "partial." Is there a difference between what is being shown on the relative comparison slide and the individual model run result summaries?	No. The average annual partial rate impact from the individual model runs have been calculated using the *Rate Impact Model* described in Section 5.3.4 of the Draft Report.
Operating Reserve	CA	It is not clear whether Plexos makes unit commitment decisions to satisfy operating reserve requirements and meet inertia constraints sequentially or through co-optimization. Regardless of the answer, the interaction between these two requirements seems to be a significant driver of model output, and NS Power should verify that it has configured its model in a manner that handles all of the sensitivities in a reasonable manner.	PLEXOS co-optimizes the energy dispatch and provision of ancillary services in both the PLEXOS LT and PLEXOS MT/ST modules.
Sensitivity	CA	General model configuration decisions may affect sensitivity runs in ways that were not evident in the testing for the main cases. For example, the chronologies used in Plexos LT testing may have been optimal under the default assumptions around inertia but may not capture the different challenges of operating with lower inertia constraints, which are only tested for the 2.1C case. (3) Please provide discussion of the issues NS Power has evaluated in its model configuration decisions.	NS Power has input consistent model configuration parameters for all scenarios and sensitivities modeled in the Final Portfolio Study; this is important in ensuring that output results are comparable from one scenario to another.

Category	Participant	Comment	NSP Response / Consideration for Final Report
Wind	CA	Either battery storage or operational practices would have some impact on the economics of the wind procurement. Our review of the model results suggests that wind resource pricing is a more significant driver than considerations of reliability. Reducing the inertia requirement advances a small amount of early wind (2.1C v 2.1C.WIND-3), but also delays wind investment in the 2030–2033 period. (4) RII recommends that NS Power adopt a finding that because the primary driver of wind resource procurement levels is price, the most important step NS Power can take to identify the appropriate level of wind investment is to conduct an all-source RFP. The draft action plan's resource procurement strategy should be significantly revised. NS Power suggests a wind procurement strategy and a plan for redevelopment or replacement of steam turbines with combustion turbines. As discussed above, the most significant uncertainty in determining the timing and scale of new resources for NS Power is the cost of wind power and battery storage. Under the most favorable cost assumptions, NS Power could acquire as much as 300 MW of wind in 2023 and 676 MW of wind by 2026. The wind and battery price sensitivities also affect the timing and size of near-term CT procurements. RII recommends that the draft action plan be revised to pursue an all-source Wind, reliability tie and regional integration decisions should be co-optimized. It should be recognized that if a high level of wind resources are procured, and those resources depend on the reliability tie, then any schedule delays affecting the reliability tie can be managed with temporary operating constraints on the wind projects. (21) Planning for transmission should proceed in parallel to an all-source RFP. Cost estimates for completion of the reliability tie for different in-service dates (several options, covering the range from the earliest feasible date to 2032) should be developed for use in bid evaluation. The regional interconnection should be handled similarly, except that there will be need for fewer in-service date options and accompanying cost estimates since the near-term resource acquisitions should be less sensitive to the exact date and cost estimate. Given some of the sensitivity results, the potential in-service dates for this project should be expanded to cover 2028-2040.	NS Power agrees that the modeling indicates that the low wind pricing has a larger impact on expansion decisions than the reliability inertia constraint. NS Power has updated IRP Roadmap item #8 to indicate that "NS Power will solicit Nova Scotia-based market information" to inform installed costs of wind. This is also captured in additions to IRP Action Plan item #3d which indicates that the wind procurement strategy "will solicit Nova Scotia-based market pricing information which will inform the selected wind capacity profile and timing, informed by the IRP wind sensitivities". The IRP scope does not include findings or recommendations on specific procurement approaches. Wind, reliability tie and regional integration decisions have been co-optimized in the IRP modeling results. NS Power has updated its Action Plan to reflect comments on wind integration requirements in parallel or prior to, the in-service date of the Reliability Tie. Please see Action Plan item #3d. NS Power will consider the comment on assessing costs for different in-service dates for the Reliability Tie and how it could impact future resource procurement/expansion decisions, and whether different operating limits could be enforced in advance of wind integration measures such as the Reliability Tie.
	CA	There seems to be a trade-off between imported power and battery resources. Surprisingly, Case 2.0A.Import-2 indicates that both batteries and CTs are procured at relatively high levels, allowing additional retirements of steam units. This suggests some interesting interplay between battery resources and thermal unit operations that the modeling may not have explored fully. As was discussed on a call with NS Power, the model did not value synthetic inertia and other advanced applications of battery storage that could have a significant effect on advancing retirement decisions for steam units in favor of advancing new resource acquisitions.	Sensitivity case 2.0A.IMPORT-2 assesses the absence of the ability to build the Reliability Tie – a wind integration resource/asset. The other option for integration of more than 100 MW of wind, as developed during the Renewable Stability Study, is the domestic option which consists of incremental battery and synchronous condenser resources. NS Power interprets the additional battery storage seen in this sensitivity as a method of wind integration in the absence of the Reliability Tie. As suggested, gas and the incremental batteries discussed above are providing firm capacity, which enables earlier coal retirement than the Base scenario. While the optimization algorithm appears to be finding synergies between battery and gas capacity and coal retirement, a portion of the battery additions is mandated for the wind additions (along with synchronous condensers). The overall scenario appears to be higher cost than the base case; the batteries are required for wind integration in the absence of the Reliability Tie and the model utilizes the firm capacity they provide to enable incremental retirements to reduce the cost gap to the base case.

Category	Participant	Comment	NSP Response / Consideration for Final Report
			The PLEXOS LT module optimizes candidate plans constrained by all ancillary services and reserve constraints. This is achieved by integrating reserve constraints into the mathematical framework for dispatch and pricing. The suite of the new resources including batteries is contributing to certain modeled ancillary services. Batteries contribute to all types of reserve including regulation (raising and lowering), spinning and non-spinning. Transient system stability studies, which assess fast frequency response (FFR) in timescales of seconds (or less), are outside the scope of long-term planning studies. As FFR was not directly modeled in this IRP, its presence or absence is not expected to have an impact on coal retirement decisions. However, if FFR services are found to reduce the synchronous inertia constraint, the economics of coal retirement with battery replacement may improve (based on the FFR requirement and a battery's specific contribution). NS Power believes that effective load carrying capacity (ELCC), capital and operating costs, provision of reserves, and the amount of variable renewable energy on the system are the primary drivers of battery additions in the IRP modeling.
Battery	CA	(5) Please explain why battery capacity drops in 2045, identify the resources the model substitutes for battery capacity, and discuss implications of late-model treatment of battery storage in the end effects calculation.	Capacity reductions (or removals) of battery storage resources in the late years are the result of a battery(s) reaching the end of its modeled 20-yr technical life. Replacement of retired battery capacity is based on economics and/or the planning reserve margin (PRM) constraint, and thus, it is not necessarily replaced or may have been replaced with a different resource type. The PLEXOS LT formulation includes an attribute that accounts for end effects. The model assumes that last year of the horizon is repeated an infinite number of times. The objective function is expanded by the cost of the years after the final horizon year (2045). The exogenous calculation of end effects only includes costs of the 2045 portfolio. Thus, if there are no operating battery resources in this year, end effects would not assume any future costs for battery resources.
Transmission	CA	Results do not show the expected effects on the timing of the reliability intertie as its inertia benefits change. The reliability intertie is built earlier when the level of inertia it provides is reduced (2.1C.IMPORT-3) or the price of batteries, an alternative source of inertia, is reduced (2.1C.WIND-1 vs WIND-2). On the other hand, some model results indicate that the timing of the reliability intertie reflects the demand for inertia. Reducing the need for inertia results in delaying the reliability tie (2.1C vs 2.1C.WIND-3 and WIND-4). RII recommends that planning for potential transmission projects proceed.	NS Power notes that the magnitude of timing changes noted here is relatively minor in a resource planning context; for example, moving from 2.1C to 2.1C.IMPORT-3 (Limited Reliability Tie Inertia) advances the build of the Reliability Tie by 2 years, while moving from 2.1C to 2.1C.WIND-3 (Low Inertia Constraint) delays the build by 1 year. NS Power also notes that batteries do not provide a source of synchronous inertia in the IRP modeling assumptions; batteries as modeled are not an alternative source of inertia. NS Power believes it is generally appropriate that the Reliability Tie would be advanced in cases with low-cost wind, as this is generally seen as the lowest-cost integration asset (for large wind resource additions). NS Power agrees with the recommendation for transmission planning to proceed and is this is reflected in Action Plan item #1 for both the Reliability Tie and the Regional Interconnection.

Category	Participant	Comment	NSP Response / Consideration for Final Report
Wind sensitivity	CA	We see extraordinary sensitivity to relatively modest drivers. For example, lowering the battery cost results in delaying regional integration by 10 years (2.1C.WIND-1 vs WIND-2), even though the additional battery capacity is negligible compared to the imports available through regional integration. NS Power indicated that the model might be seeking to optimize a transition to a more adaptive resource mix, and that some of these interactions might be enabling higher retirements of "slow inertia" units. This concept is consistent with the model output from 2.1C.IMPORT-3: with the reliability tie providing less inertia, more "slow inertia" steam units retire, to be replaced by additional imports, combustion turbines, and wind (presumably for the energy). It appears that the domestic CTs are being utilized more heavily for inertia and other services in this scenario. (6) Please discuss the trade-offs of the benefits and indirect impacts of transmission and related reliability measures. (7) Please clarify how the concept of "slow inertia" modifies the inertia values by unit that NS Power provided previously. Does "slow inertia" refer to the long start-up times of steam units before they can provide inertia? How does inertia vary with the operating level of a steam unit? (8) Are unit commitment costs for inertia and/or operating reserves a driver in determining the transition pace from existing to 2040 resources?	From a reliability perspective, NS Power has modeled the contribution of the Reliability Tie to the synchronized inertia constraint and has used it as a mechanism to enable wind integration. Firm imports accessed via the Regional Interconnection contribute to system reliability via the PRM. No other reliability benefits of transmission are modeled in the IRP PLEXOS model, although they do exist from a contingency analysis perspective (not in IRP scope). There is no differentiation between different inertia types in the model (e.g. "slow inertia" as discussed in the letter of comment); rather, the model is constrained by steam unit minimum up and down times (and is penalized by unit start costs) which would suggest that a more flexible system could meet the inertia constraint as modeled at a lower cost. Inertia provision from generating units does not vary with unit output; the contribution from each unit (as provided previously to stakeholders) is constant as long as the unit is online. Unit commitment costs are integrated into the optimization model and co-optimized with generator dispatch and ancillary service provision; it is likely that inertia and reserve constraints have an influence on retirement pace for this reason. More broadly, as the system transitions to a resource mix with more variable generation, the benefits of more flexible units become apparent both for meeting ancillary service requirements and for dispatching against higher levels of renewables.
Reliability tie	CA	(9) Does the reliability tie provide any services other than inertia, such as reserves or load following?	It is modeled only as providing synchronized inertia and enabling wind integration beyond an incremental 100 MW. It may provide additional benefits that were not assumed for modeling purposes.
Reliability tie	CA	(10) Is the increase of imports with the reliability tie a result of the reduced need to commit domestic steam units?	This is a logical correlation, as with the inertia provided by the Reliability Tie there is less requirement to keep steam units online at lower loads. This energy could be replaced by imported energy. NS Power looked at several scenarios, and the difference in imported energy in the year prior to and the year following construction of the Reliability Tie was generally a relatively small increase, e.g. in Scenario 2.0A comparing 2031 and 2032 or Scenario 2.0C from 2029 to 2030.
Reliability tie	CA	Understanding the relationship (transmission, wind, battery, inertia) will be critical prior to issuing an all-source RFP, since non-domestic resources may wish to bid into the RFP based on varying assumptions about the completion date for a reliability intertie.	NS Power has stated in the Action Plan that the development of the Reliability Tie will commence immediately following the conclusion of the IRP, in order to continue to develop this information as quickly as possible and inform future resource procurement and development activities. NS Power has committed to further develop its Regional Integration Strategy to assess what path offers the greatest value to customers.
Solar	CA	Wind outperforms solar, but is that the only reason that the model does not select much solar for the portfolio. NS Power should discuss in its findings the role of firm and non-firm imports in meeting the carbon emission limits. It is our understanding that NS Power assumes that imports are exclusively or primarily low- or zero-carbon resources. (12) Are the import prices based on the costs of renewables in other provinces?	The IRP model assumes Canadian-sourced imports are emissions free, as emissions are accounted for in the producing jurisdiction via provincial regulations. Sources from non-Canadian markets have an emissions profile consistent with the Quantification, Reporting and Verification Regulations (QRV) that NS Power currently follows for emissions accounting. The firm imports via new transmission have an emissions profile based on jurisdictional emissions forecasts, adjusted via the pricing forecasts for the Regional Greenhouse Gas Initiatives (RGGI), consistent with QRV guidelines.

Category	Participant	Comment	NSP Response / Consideration for Final Report
		(13) If imported power has some significant level of carbon emissions, would solar be more attractive?	Pricing for energy and capacity available via the Regional Interconnection was provided via a fundamental forecast by Platts Analytics and is based on forward NEPOOL prices. Solar's emissions-free energy profile would be considered against firm/non-firm imports with and without emissions and all other resource options in the optimization process. NS Power notes that in the few cases where solar appears, it is selected in the late years of the 3.X Accelerated Net-Zero 2045 scenarios when emissions are most constrained; this suggests that emissions reductions under very limited GHG caps are a primary driver of solar additions in the model.
Covid	CA	Include impacts of current global economic recession on NS Power's load and the implications of that recession for the resource plan.	As requested, NS Power has provided an update on load impacts observed from the effects of the COVID-19 pandemic in the Draft Report (Section 4.1.5).
PRM	CA	Adjustments have been made to key inputs. RII recommends that NS Power verify the findings of the July 2019 study using the updated modeling environment and include a clearer resolution of the planning reserve margin question in the final IRP report.	NS Power updated DAFOR rates for a small number of thermal units based on discussions with stakeholders in order to use more recent and representative data; updated ELCC contributions were calculated using the RESOLVE model that was developed as part of the 2019 Capacity Study which determined the target PRM. NS Power believes these minor data updates do not invalidate the significant effort undertaken in the original study as other key inputs to determining the target PRM such as load shapes and wind shapes, target reliability criteria, and other generating unit parameters have not changed. Further, the updated PRM calculations completed on the three 2045 resource portfolios showed that the 9% UCAP PRM was sufficient and did not introduce significant excess capacity even under these very different resource portfolios; this provides further confidence that the minor assumption updates made during the IRP process will not significantly affect the target PRM calculations.
CTs	CA	In the draft action plan, NS Power indicates that it will "Develop a plan" to redevelop or replace its existing gas/oil-fueled steam units, but does not address the combustion turbine fleet. In the draft findings, NS Power suggests that its existing combustion turbine fleet is cost-effective. (16) RII recommends that the findings include a specific discussion of the economics of replacing the current CT fleet with newer CTs or another type of fast ramping generation, including a summary of the modeling evidence in support of its findings and any constraints on the options that were evaluated that may suggest a need for further analysis.	NS Power completed a detailed Resource Screening exercise prior to the start of the Initial Portfolio Study which determined that sustaining the existing CT fleet is the most economic firm capacity option for customers. This analysis is described in the Draft Report in Section 4.2.2.1; additional data was also provided to stakeholders as part of the June 26 modeling results release and the July 9 stakeholder workshop. In the Resource Screening, the existing CTs are forced to retire and the model economically replaces them with an equivalent ELCC capacity of new gas combustion turbine resources, as suggested. The 25-year NPV of the replacement scenario was $240M more expensive than the base case where the diesel units were sustained. Because the firm capacity requirements are increasing throughout the planning horizon of the IRP, both due to load growth and firm coal generation retirements, significant additional CT resources are selected in addition to sustaining the existing units. Retiring the existing fleet would further increase this PRM deficiency and require incremental CT resources, at a higher cost than sustaining the existing fleet.
Dispatch and operating reserve	CA	Day-Ahead and Real-Time schedules created by the marketing desk frequently differ substantially and persistently from the actual dispatch of the generating units. BW documented instances of high operating-reserve surpluses. (17) RII recommends that NS Power verify that its IRP model assumptions and settings reflect good operating practice with respect to these topics, update the findings section to address this topic, and share relevant detailed supporting data with stakeholders.	NS Power's PLEXOS model incorporates system operating requirements and generating unit properties and constraints which are the same as those used by the Day Ahead / Real Time scheduling group, other than where differences are required due to the different modeling software used for each purpose. In both the capacity expansion and the production cost optimizations, reserve provision is co-optimized with other variables such as generation cost and capital investment, ensuring that any reserve above minimum requirements that is available via capacity expansion or dispatched via production cost simulation is still optimal in terms of lowest total cost to customers.

Category	Participant	Comment	NSP Response / Consideration for Final Report
		(18) If operating reserves were maintained at the target levels (rather than the higher levels reported by Bate White, would NS Power be able to dispatch additional hydro during periods with high operating costs?	
Hydro	CA	Mersey hydro retirement evaluation and hydro system value: June 26, 2020 NS Power shared initial analysis of system value provided by hydro assets as modeled by E3. Will this modeling be finalized by NS Power using Plexos, to provide key inputs into the replacement energy cost for hydro generation used in the Company's economic analysis model? NS Power expressed the view that the redevelopment project could provide a very long-lived asset, on the order of a hundred years. If Mersey could last another 100 years with no unusual capital investments, then we would agree. But if Mersey might require another significant redevelopment investment, perhaps in 30-40 years, then that cost would not be considered by the end effects calculation and thus the analysis might not be reaching the correct conclusion. Furthermore, the end effects calculation does not take into account the likelihood that Mersey would eventually be decommissioned. (18) RII recommends that the findings include an explicit discussion of the hydro system value and the retirement analysis of Mersey in particular, including discussion of the treatment of post-2045 costs (including redevelopment and decommissioning) and the risk that either redevelopment or decommissioning could have significantly higher costs than currently estimated.	NS Power has examined the value of its existing hydro systems through both the Resource Screening phase, and via a specific analysis of the Mersey Hydro system conducted during the Final Portfolio Analysis phase. The Resource Screening was conducted over a 40-year timeframe and indicated that sustaining the existing hydro assets, with the modeled levels of investment, was economic relative to decommissioning in all cases. The anticipated long life of these hydro assets introduces added complexity and uncertainty into the analysis, as described by RII. This is noted in the evaluation of the Mersey Hydro PLEXOS sensitivity, where the ranking of scenarios changes depending on the inclusion of end effects – again pointing to the effects of the long life of hydro assets. As noted in the Findings, justification for re-investment and sustaining the Mersey system will be evaluated as part of the justification provided for a capital application. NS Power has added additional clarity on this in several sections of the IRP Draft Report including in Section 6.8.3, Finding #2d, and Roadmap item #3. NS Power will consider the suggested potential changes to replacement energy cost calculations after the conclusion of the IRP.
Rate Impact model	CA	While NS Power's estimate of incremental fixed cost revenues is a reasonable approximation, for purposes of determining approximate average rates, these incremental revenues should not be deducted from the rate estimate. The average rate should be total revenues divided by total sales. There is no reason to exclude a portion of revenues from the average rate calculation. Our first case – "Correction" – presents just the impact of removing this portion of the model.	NS Power has provided additional detail on the relative rate impact model in Section 5.3.4 of the Draft Report. It is important to note that NS Power has not provided this analysis for the purposes of determining approximate average rates, as suggested by the comment. Future rates forecasts are understood to be subject to a number of factors outside of the scope of the IRP. We have attempted to illustrate the general pressure (upward or downward) created by differing levels of electrification which requires consideration of fixed cost recovery embedded in the base year.

Category	Participant	Comment	NSP Response / Consideration for Final Report
Rate Impact model	CA	NS Power's use of 1994 non-fuel revenues is an appropriate starting point for the adjustment to obtain a reasonable total revenue requirement. We interpret these non-fuel revenues as including sunk costs of existing generation, T&D capital investment, and utility operating costs. Sunk costs of existing generation: These costs will depreciate and are replaced by investments that are captured within the IRP revenue requirement. Accordingly, there should be some downward adjustment. T&D capital investment: These costs will depreciate but will be replaced by investments that are not captured within the IRP revenue requirement. Under higher load scenarios, a somewhat greater level of T&D capital investment may be required, but this would be hard to estimate. Utility operating costs: These costs should remain roughly stable in nominal terms. As a sensitivity, we suggest an annual reduction of 1.5% in these revenues. The net effect of this and the IRP revenues remains an increasing revenue requirement under every scenario. See charts provided by RII.	NS Power notes that 2014 non-fuel revenues were used (correction from 1994 in the RII memo). NS Power expects that utility operating costs would remain relatively stable in real terms, but would see some escalation (due to inflation) in nominal terms; the costs in the relative rate model are treated in nominal terms. NS Power considered this factor in its base assumption that the non-modeled costs stay consistent during the planning horizon for modeling purposes.
Electrification	CA	NS Power would need to operate electrification programs at some level of cost in order to achieve the higher levels of electrification studied in the IRP, but that such programs have not yet been studied or costs developed. NS Power should include in its action plan an "order of magnitude" estimate for the level of cost that might be appropriate for its customers to bear to promote electrification. As noted in the draft findings, "Increased electricity sales due to electrification can help to reduce upward pressure on electricity rates while facilitating carbon reductions in other sectors." (22) What level of program investment in electrification would result in no net change in electricity rates for a given level of electrification? Electrification may also have significant benefits to participants – such as cost savings for other fuels – and to Nova Scotia at large – by facilitating carbon reductions across all sectors. This may be viewed as a total resource cost perspective. While this is clearly beyond the scope of the IRP, we encourage NS Power to make note that these benefits exist to avoid creating the impression that rates should be a singular basis for deciding how much electrification may be considered affordable. it would be prudent for NS Power to begin with pilot programs across the range of electrification opportunities. Some modest efforts have, in fact, already begun. Electrification should not be limited to residential, commercial, and on-road transportation. The industrial and maritime sectors also provide opportunities and should be involved early in the development of electrification programs.	Consideration of an order of magnitude for costs of electrifying to be borne by the utility was not in the scope of the IRP exercise. Consideration of the cost of potential programs relative to benefits will be important in creating an electrification strategy, which is detailed in IRP Action Item #2. NS Power notes the comments of the CA and others respecting potential to consider benefits beyond those within the scope of the IRP, as well as comments respecting areas of potential focus for development of electrification programs. NS Power will seek to engage the CA and other interested parties in design considerations for advancing this strategy as part of this Action Plan item.

Category	Participant	Comment	NSP Response / Consideration for Final Report
		(23) Nova Scotia Power should propose a more intentional and comprehensive electrification pilot program strategy, with the intention of setting the stage for potentially launching larger programs in three to five years.	
Evergreen process	CA	Define what an "evergreen IRP process" might look like. It is our understanding that in the past, NS Power has considered a two-year IRP cycle as potentially too frequent. The term "evergreen" suggests an even more frequent update process, with many small changes rather than a single long process.	NS Power has added detail on this to roadmap item #8; this process envisions continuous updates to the IRP model and annual reporting on Action Plan progress and Roadmap item status. As changes to the planning environment are observed via the Roadmap process, additional studies may be triggered – specific examples noted in the Draft Report include updates to DSM Avoided Cost calculations and triggering of PRM studies, for example.
Hydro assumptions	CA	ELCC for run-of-river hydro units: In our memo of August 4, RII questioned the 95% ELCC for run-of-river hydro units. It is our understanding that this ELCC is based on DAFOR only, and that operational limitations were not factored into this finding. Our most recent analysis supports a lower ELCC for run-of-river hydro units. (see chart in submission) We are struck by how much the capacity factors in peak hours differ from the 95% ELCC that NS Power estimates. Perhaps low reservoir levels reduce the capacity of the plants in some years, or limited water flow limits the number of hours for which the dispatchable units can operate. Especially if water supply is limited, these units may be held for operating reserves. (24) Can NS Power explain the discrepancy between the claimed ELCC and the actual performance of the small hydro units? (25) If these units are being held for system reserve, why is this the most economic system dispatch? Wouldn't it make sense to fully dispatch these units at peak hours and reduce the use of gas/oil steam and diesel CT dispatch? (26) Does Plexos reflect NS Power's actual operating practice?	The Capacity Study, completed as part of the pre-IRP deliverables, provides detail on the modeling of hydro in that study. Other than Wreck Cove, which was modeled as an energy-limited resource with daily energy limits (set monthly), it was determined that the other hydro assets on the NS Power system include sufficient pondage as to be equivalent to firm capacity for RECAP modeling purposes. This resulted in the assignment of a 95% ELCC to existing hydro assets. In NS Power's PLEXOS model, each of the 16 hydro systems is configured using a wide range of parameters used to shape the hydro energy to match historical production as accurately as possible. These parameters, depending on the hydro system, include: • Maximum monthly generation constraints, to reflect average historical water inflows • Minimum monthly generation constraints, to reflect limited inter-month storage at most sites • Maximum daily generation constraints, to prevent the model from "shaping" energy into peak days more than is reasonable based on system operating characteristics • Minimum hourly load constraints, to maintain riparian flows on certain systems in certain seasons • Maximum rating constraints, limiting the maximum hourly output of the systems. On smaller systems which are less dispatchable, these maximum ratings work in concert with the maximum monthly energy constraints to ensure that hydro energy is not unrealistically shaped into peak demand periods The majority of these parameters have monthly values to reflect changes in operational capabilities and practices across different seasons. Actual dispatch will depend on other operating parameters such as environmental limits, local system constraints and operating requirements, unit availability, water availability and forecast inflows, and other real-time factors. NS Power believes the IRP model accurately represents the capabilities of the NS Power hydro system and the actual dispatch patterns observed in historical data, subject to the notes above.
Wreck Cove	CA	During NS Power's long winter peaks, Wreck Cove may not be able to operate at full load for the entire peak period of a day, limiting its contribution to reliability. This limitation should be considered in combination with DAFOR in determining its ELCC and the overall system planning reserve margin.	This was considered in the original Capacity Study completed during the pre-IRP period; Wreck Cove was modeled in RECAP as an energy-limited resource with the daily energy budget varying by month based on historical data.
Coal sustaining costs	CA	NS Power updated the Plexos model with new sustaining capital cost profiles for coal units. (27) Please share those updated assumptions with stakeholders.	These estimates are provided following this matrix. NS Power will make these available to interested stakeholders. The adjustments made were as follows: • An increase in TRE-5 sustaining capital to reflect the utilization observed in the Initial Portfolio Study runs; higher operating hours and unit starts triggered additional investment requirements

Category	Participant	Comment	NSP Response / Consideration for Final Report
			• A decrease in Point Aconi sustaining capital to reflect the utilization observed in the Initial Portfolio Study runs; lower capacity factors observed were used to reduce the anticipated investment required. The development of separate sustaining cost trajectories for the 2030 and 2040 coal retirement scenarios was modeled in the IRP; the 2030 sustaining capital trajectories avoid any major investment (i.e. turbine/generator overhauls) in the final few years prior to retirement. These maintenance interval extensions would be managed via enhanced asset management and operating practices to reduce risks to unit reliability.
Point Aconi	CA	The audit states that "major generator work (2022) and turbine overhaul (2024) will require substantial sustaining capital investment." This suggests above-average investment levels. The original capital cost profile assumptions for Point Aconi do not include above-average investment levels, and the higher investment years in that forecast do not match the information provided in the FAM audit. Furthermore, Point Aconi may require an expansion of its limestone mine in eight years, which could require significant additional investment that does not appear to be reflected in the IRP capital cost profile assumptions. NS Power should verify that its updated capital cost profile assumptions reflect the correct sustaining capital cost forecasts for all units, including Point Aconi. (28) Please provide the sustaining capital cost profiles and underlying assumptions in depth. The final report should include a comparison of the cost of continued operation (including fixed OM&A and sustaining capital) for each of the thermal plants.	The IRP Sustaining capital forecasts include additional investment for turbine and generator work profiled in 2021 and 2023; ongoing asset management activities and dynamic maintenance intervals may shift the timing of these investment, for example to 2022 and 2024 as identified in the RII comment. Potential long-term capital requirements for limestone supply are not included in the sustaining capital forecast. Revised sustaining capital assumptions, as updated prior to the Final Portfolio Study, will be shared with stakeholders.
Wind/inertia/FFR	CanREA	CanREA observes that NSPI focuses on constraints to wind integration, questioning whether "additional dynamic system inertia constraints can enable this level of additional wind integration" rather than acknowledging that the ability of wind generation to provide various frequency response services including fast frequency response (FFR) and primary frequency response has not been fully considered. The provision of FFR by wind generation arrests the frequency decline after a system event and can reduce requirements for synchronous inertia. CanREA understands that additional work needs to be done to determine the impact of FFR provision by wind turbines on requirements for system inertia in Nova Scotia, but as the OERA work demonstrates there is a considerable body of work demonstrating this capability and its adoption by system operators in other jurisdictions. This is a critical issue because the IRP indicates that wind generation is the most economic type of domestic renewable generation and therefore can play an important role in assisting NSPI backout coal-fired generation.	NS Power's Action Plan includes completing further system stability studies to determine whether additional dynamic system inertia constraints, operational limits, and/or provision of alternative services like Fast Frequency Response (FFR, are required to enable higher levels of wind integration on the Nova Scotia system, particularly in advance of the commissioning of integration measures, such as the Reliability Tie. Based on stakeholder feedback, NS Power undertook two sensitivities, 2.1C.WIND-3 Low Inertia Constraint and 2.1C.WIND-4 No Inertia / No Integration to assess how the resource expansion plan would change with reduced needs for synchronous inertia. These sensitivities indicated that the wind expansion profile was not particularly sensitive to these parameters.
Wind/inertia/FFR	CanREA	Modification to Allow new wind generation to provide ramp down reserve service" (Slide 30) was a refinement that flowed from the OERA work. Modification to "Allow new wind generation to provide ramp down reserve service" (Slide 30) was a refinement that flowed from the OERA work. This is just one ancillary service that wind generation is capable of providing. By focusing on just this ancillary service NSPI failed to consider the range of ancillary services that are critical to enabling the integration of additional wind generation in Nova Scotia as demonstrated by the work performed for OERA. A ramp down service can assist with managing surplus wind generation during low load high wind output periods. However, as the OERA study indicates the critical ancillary services are frequency response	The PLEXOS LT module optimizes resource plans constrained by all ancillary services (reserve) constraints. This is achieved by integrating reserve constraints into the mathematical framework for dispatch and pricing. The suite of the new and existing resources, including wind and batteries, contributes to certain modeled ancillary services. Wind resources are part of the regulation lowering service. Batteries contribute to all types of reserve including regulation (raising and lowering), spinning and non-spinning. Transient system stability studies, which assess FFR in timescales of seconds (or less), are outside the scope of long-term planning studies. As FFR was not assessed in the PLEXOS framework, its presence or

		services that allow NSPI to dispatch off thermal generating units and rely on the fast frequency response capability that wind generators offer. NSPI's modeling has not considered this capability and also has not considered the ability of battery energy storage projects to provide a similar service.	absence is not expected to have an impact on coal retirement decisions. However, if FFR services are found to reduce the synchronous inertia constraint, which was modeled, the economics of coal retirement with some combination of battery and wind replacement (or other) may improve (based on the FFR requirement and the resource's specific contribution). NS Power has committed to further study in this area as part of its IRP Action Plan and Roadmap.
Wind/inertia/FFR	CanREA	Continue to integrate the findings from the OERA report on how the ancillary service provision capabilities of wind, solar and battery resources (i.e., non-synchronous /inverter-based resources) can be utilized. Given the low energy costs offered by wind resources recognizing this capability is likely to reduce costs to customers while enhancing system reliability. The low cost of wind relative to other resources also creates an opportunity to operate at a reduced capacity to provide headroom to offer ancillary services (e.g., the provision of primary frequency response) under some operating conditions.	NS Power's Action Plan has committed to further system stability studies.
Wind/inertia/FFR	CanREA	Sensitivities (2.1C.WIND-3 (LOW INERTIA CONSTRAINT)) and (2.1C.WIND-4 (NO INERTIA / NO INTEGRATION)) help advance the understanding regarding the impact of inertia requirements on the amount of wind generation that can be integrated. Additional background regarding insights from these sensitivities would be helpful.	Additional insights on these sensitivities is provided in the Draft Report in Section 6.8.2.
Wind/inertia/FFR	CanREA	Re more study needed to understand understanding of increased penetration of wind: Given the recent work by OERA, CanREA encourages NSPI to update the PSC study and when doing so, to provide an opportunity for stakeholder input or alternatively to have committee of experts advise on modeling assumptions and protocols.	NS Power's IRP Action Plan includes completing further system stability studies to determine whether additional dynamic system inertia constraints, operational limits, and/or provision of alternative services like FFR, can enable higher levels of wind integration on the Nova Scotia system, particularly in advance of the availability of other resources that support wind integration such as the Reliability Tie..
Wind/inertia/FFR	CanREA	Regional Integration is critical to unlocking the potential of wind energy and CanREA encourages NSPI to accelerate this element of its Action Plan.	NS Power acknowledges these comments and has indicated in its IRP Action Plan that work on the Reliability Tie and Regional Interconnection should begin following the conclusion of the IRP process NS Power agrees.
Wind procurement	CanREA	Wind procurement strategy, "targeting 50-100 MW new installed capacity by 2025 and up to 350 MW by 2030." CanREA believes this is likely to be low given the various issues identified with modeling of the ability wind generation resources to provide frequency response services. CanREA recommends NSP provide an indicative schedule of future wind procurements based on the results of the IRP. We understand that such may need to be modified as additional information becomes available on load growth, technology costs, integration analyses. Nonetheless, establishing such a procurement schedule will signal to the development community future procurement activity that will give them the confidence to invest in project development and the local supply chain, which can de-risk future project development and reduce wind costs benefiting Nova Scotia consumers and its economy.	NS Power has provided indicative timing for procurement/development of resources which is appropriate for the purposes of establishing a near-term Action Plan. More detailed project execution strategies will be advanced within these timelines.
Solar, storage	CanREA	CanREA urges NSPI to acknowledge the potential for additional modeling and consideration of solar energy and energy storage for future iterations of integrated planning as two additional technologies that will complement the projected wind energy contributions and provide NSPI with the tools to satisfy multiple objectives supported by Nova Scotia's electricity system.	NS Power in its Roadmap has committed to refine the Action Plan and Roadmap items via an evergreen IRP process. This process will facilitate annual updates as conditions change and technology or market options develop and as Action Plan items are completed. NS Power will include a summary of updates as part of its IRP Action Plan reporting.
Preferred Resource Plan	E1	(1) The 2020 IRP Report must define a Preferred Resource Plan in line with quantitative results of the IRP modelling process, using the 25-year Revenue Requirement, adjusted for End Effects. Qualitative discussion should reflect these findings. End effects should be included when making these determinations, for the reasons summarized below.	The SDGA-compliant key scenario which minimizes the cumulative present value of the annual revenue requirement of the 25-year planning horizon (adjusted for end effects) is 2.0C (Low Electrification / Base DSM / Net Zero 2050/ Regional Integration), which will serve as the Reference Plan for calculating avoided costs of DSM.

NPV	E1	(2) The IRP results should modify the NPV revenue requirement calculation on the basis of expected carbon revenues, as they are now a key differentiator in many cases and may affect the selection of a lowest cost plan. Mid and Low DSM follow the trend that higher amounts of DSM produce incremental carbon reductions, and it is unclear why Max DSM results in higher cumulative emissions than Mid-DSM. Given a potential difference between Low DSM and Mid DSM of $630M (undiscounted) in potential carbon revenues (assuming $50 per tonne), carbon pricing merits full consideration in the IRP. Absent forecasts of carbon prices, the Federal Government's "floor" for carbon pricing is $50 per tonne in 2022. Given that Nova Scotia's inaugural cap and trade auction resulted in a settlement price of $24 per tonne, assuming levels below $24 would not seem reasonable for projections extending out 25 years. The IRP results should modify the NPV revenue requirement calculation on the basis of expected carbon revenues, as they are now a key differentiator in many cases and may affect the selection of a lowest cost plan.	In the Roadmap, NS Power has committed to tracking the ongoing development of the Nova Scotia Cap--and-Trade Program, including auction results and developing regulations. In particular, NS Power will monitor GHG market size for indications that value from incremental allowance sales (beyond the projected economic emissions reductions shown in the IRP results) can be incorporated into long-term resource planning decisions with greater certainty. Significant changes in the value of incremental GHG reductions could influence resource plan components including non-emitting generation procurement, DSM levels, and coal retirement trajectories.
T&D	E1	The methodology for quantifying T&D avoided costs from DSM is now being developed by NS Power in consultation with stakeholders. Absent quantified impacts, it is important that the final report clearly indicate the qualitative effects on T&D investments from increased or decreased levels of DSM.	The determination of the appropriate methodology for quantifying T&D Avoided Costs of DSM is being finalized in consultation with the DSMAG per E1's request. As a generation-focused modeling exercise, the IRP does not specifically evaluate optimization of T&D investments. Both the T&D Avoided Cost estimates and the IRP key scenario and sensitivity results for various levels of DSM can be used to inform future DSM procurement activities.
DSM	E1	(4) Provide more context on the results of the DSM sensitivity analyses for the electrification scenario in which they took place. The final report should include a qualitative assessment of how higher levels of DSM could provide increased ratepayer value with higher levels of electrification. Higher amounts of electrification will likely require more generation on the system, given the average load and incremental peak load outputs of the Pathways studies, and hence could climb the cost curve of available supply-side resource options. It is expected that DSM would produce results that are in line with the reference electrification scenario, but with enhanced competitiveness. Recognizing that further sensitivity analyses would be difficult to complete within the established IRP timelines, NS Power should provide more context on the results of its DSM sensitivity analyses for the electrification scenario in which they took place. The final report should include a qualitative assessment of how higher levels of DSM could provide increased ratepayer value with higher levels of electrification.	The updated Modeling Results release provides a quantification of how various levels of DSM impact the various cost measures. Additional discussion has also been provided in Section 6.8.1 of the Draft Report. These results indicate that DSM energy efficiency programs and costs consistent with a range of the "Low" to "Base" profiles are shown to be most economic relative to other options evaluated when considering both NPVRR and the relative rate impact analysis. Higher levels of DSM in resource plan sensitivities do lead to reduced capacity needs and lower emissions, but DSM potential study costs do not indicate such plan are cost-effective.
Capital risk	E1	(5) Provide an assessment of the risks associated with large capital investments such as a regional intertie and the use of non-firm imports. The 2020 IRP Report should confirm that DSM mitigates the risks associated with NS Power's plan to reduce GHG emissions within the IRP Findings and Action Plan. The added risks associated with NS Power's mitigation plans for interties and non-firm	Quantification of risks associated with capital investments outside of the scope of the IRP. NS Power undertook a quantitative analysis of reduced access to non-firm imports as requested. Please see 2.1C.IMPORT-1 and section 6.8.4 of the Draft Report for more information. IMPORT-1 for more information.

		imports should be described qualitatively (if a quantitative analysis is not possible within the schedule) as part of the IRP Draft Findings and Action Plan.	
Natural Gas pricing risk	E1	(6) Provide an assessment of risk in Natural Gas pricing assumptions within the Findings and Action Plan. In its July 10th Letter of Comment, EfficiencyOne made the following recommendations related to natural gas assumptions in the IRP: • A proxy for new gas supply should also include a sensitivity relating to the Algonquin City Gates Hub (AGT) as the commodity price for new winter (and summer) natural gas capacity, with the inclusion of energy cost and tolls reflecting transport from AGT to Tufts Cove, as it would address some of the uncertainties associated with the current approach of acquiring gas and transportation from Alberta (AECO), Dawn or LNG via Amsterdam (TTF). • Sensitivity analyses that explore the constrained availability of natural gas for the NS electricity system should be included, at least in terms of incremental capacity additions beyond 20,000 MMBtu per day. Put another way, constrain the model to only allow for consumption of 20,000 MMBtu per day, thus allowing the model to economically select other resources other than natural gas beyond the currently contracted firm supply. These requests, as far as we understand, have not been addressed, and IRP stakeholders do not have knowledge of other stakeholder positions relative to natural gas pricing assumptions. At minimum, NS Power should provide an assessment of risk in Natural Gas pricing assumptions within the Findings and Action Plan.	When developing a plan for assumptions that would require a firm gas supply, NS Power's analysis indicated that volumes that could potentially be required would not be available from AGT. AGT is treated as opportunistic gas, as there is limited firm transportation available. Further, because AGT experiences more severe winter prices than AECO, and NS Power is a winter peaking utility, it was deemed that this supply source is likely more economic. As reflected in the Final Assumptions document, gas supply options were developed on the basis of new natural gas units requiring firm access to a gas supply to operate reliability during the winter peaks. NS Power understands that the LNG Winter-Dawn summer would not be constrained in this regard. Similarly, the supply path from AECO (Path 3) considered firm transportation costs to supply Nova Scotia (modeled as a fixed cost adder applied to gas units in the model which select this option). In addition, NS Power undertook an additional sensitivity modeling high gas and import power prices (2.1C.PRICES-1). This optimal resource plan developed under this assumption showed only minor adjustments relative to the base case in the face of higher commodity prices, indicating that the base plan is robust to potential changes in natural gas prices.

Rate effects	E1	(7) The rate effect metrics (10-year NPVRR and estimated rates) will not contribute to achieving the general purpose of the IRP process as set out by the UARB and should receive limited consideration. The methodology described in the rate effects model is substantively different compared to the relatively more mature Rate and Bill Impact Assessment model, which has been reviewed by stakeholders and the UARB several times in Nova Scotia, and continuously improved. Further, the IRP provides the only opportunity for analysis of the long-term revenue requirement associated with the NS electricity system. This long-term view is critical in determining the lowest cost electricity system into the future, which is a complex question to answer, given the degree of changes taking place in the electricity, and broader energy, system today. The UARB spoke to this important purpose of the IRP in the 2016-2018 DSM Resource Plan decision: The general purpose of the IRP process is to identify a plan which utilizes both supply-side and demand-side resources to reliably serve the electrical requirements within Nova Scotia at the lowest long-term cost to ratepayers. The outcome of the IRP should be primarily informed by the lowest long-term cost to ratepayers. Affordability should be examined as part of the lowest cost long-term trajectory, as short-term rate impacts have many influences such as fuel costs which are subject to the vagaries of the market. Many affordability considerations are affected by near-term cost pressures and the timing of investments, matters not examined in a detailed fashion as part of the IRP.	Per the Terms of Reference, minimization of Net Present Value (NPV) is the primarily metric for evaluating future plans, in addition to other metrics of increasing importance, including magnitude and timing of electricity rate effects. Additionally, it was discussed throughout the development of the IRP modeling that due to the challenges of comparing plans with different assumptions for annual load and peak demand, relying solely on the NPV metric was insufficient. Numerous stakeholders requested the development of a rate metric for the IRP which NS Power then implemented. NS Power has presented the Rate Impact model as a simplified model to illustrate relative general upward or downward pressure on rates when comparing plans.
DSM avoided costs	E1	(8) Provide stakeholders with a proposed approach (technical and process-related) for calculating the avoided costs of capacity and energy associated with DSM. It is important that this approach quantifies avoided costs prior to the IRP Report being filed with the UARB. The determination of avoided costs must take place as part of the IRP process. While avoided costs are critical inputs to DSM planning, they are also meaningful and important to other stakeholders engaged in DSM proceedings. The technical decisions and tasks associated with the calculation of avoided costs involve: 1. The designation of at least one comparator Plan for use in the Difference in Revenue Requirements method of avoided cost generation. 2. Decisions relating to what DSM elements will be included in a given avoided cost run (if more than one). For example, will Demand Response (DR) activities be aggregated with energy efficiency (EE) as a single avoided cost run. 3. The final form of avoided cost results.	NS Power has identified plan 2.0C as the Reference Plan for the purposes of calculated avoided energy and capacity costs and has confirmed it will also provide avoided energy and capacity costs for 2.1C for additional reference. Once the final IRP Report is accepted by the UARB, confirming the selection of the Reference Plan as identified above, NS power will calculate and provide the avoided capacity and energy costs.

		These questions and decisions should be resolved as part of the IRP stakeholder engagement process. In each of the points above there are nuances and subtle changes in approach which stakeholders should generally understand. NS Power should prepare the resource plan that is to be compared with the Preferred Resource Plan through removal of DSM load modification, and allow the model to re-run resource additions in Plexos LT. The comparator plan should then be checked for reliability and operability, such that stakeholders are assured that the comparison is performed on two viable IRP cases; each viable on their own merits, and only separated by DSM. Furthermore, the 70 MW of economically selected DR should be grouped with the End Effects case or cases being examined. EfficiencyOne is interested in NS Power's and other stakeholders views on this approach, but it seems that grouping these aspects of DR will avoid the requirement for the separate generation of avoided costs for DR and EE, and will provide inherently the interaction between EE and DR, which is consistent with how the 2019 DSM Potential Study was modelled (i.e. in that DR and EE were modelled as interacting in the DSM Potential Study). Finally, the avoided cost data should be presented in the format used for the 2014 IRP. The key elements from the 2014 approach EfficiencyOne would like to see maintained on a public basis are: 1. The provision of annual avoided cost streams for both generation and energy. 2. The provision of levelized values over the planning period. 3. Key input assumptions (e.g. WACC). The IRP Action Plan should propose a technical approach and process for quantifying avoided costs, taking into account the comments provided above. This proposed approach should be reviewed with all IRP stakeholders and updated according to their feedback. The process should allow for the initial draft production of avoided costs as part of the Draft Final Report deliverable. EfficiencyOne is strongly in favor of an approach that allows for resolving avoided costs prior to an IRP-associated regulatory process, on the basis of transparency and ensuring continued participation by the IRP stakeholder group.	
Process	E1	(9) Publish responses to all stakeholder comments and questions following the submission of comments on September 18. Stakeholder comments and questions and NS Power's responses help inform all stakeholders.	NS Power has published its responses to stakeholder comments on the IRP website.
Zero emissions	EAC	While scenarios have comprehensively studied emissions reaching between 0.5 Mt and 1.4 Mt, the EAC expresses concern that no “zero” emissions scenario was studied. Zero emission cases will provide an assessment of the costs required to operate from imports, sequestered carbon emissions and renewable energy. Increased costs to the utility add value to efforts across the regional GHG reductions landscape by maximizing the impact of electrification. In addition, near-future regulatory benchmarks will dictate provincial	NS Power developed several emissions profiles in consultation with stakeholders during the Assumptions phase of the IRP, two of which incorporated trajectories designed to achieve the goals of the SDGA as currently defined. Building on this base, NS Power has focused its modeling efforts on achieving an 87%-95% reduction in GHG emissions by 2045, relative to 2005 levels. NS Power acknowledges that there remains additional potential study on how to move from a 95% reduction to a 100% reduction as the enabling technologies and policy and legislative frameworks become better defined.

		emissions to align with net-zero carbon scenario. Therefore, it would be prudent to have a future-proof plan ready for deployment.	
Transmission	EAC	Access to firm capacity imports from the Maritime provinces and Quebec would be highly beneficial to the ratepayers, as stated in draft findings statement 2. At the same time, the Reliability Tie would strengthen the province's grid further. However, it is not shown if the study explored fully replacing coal generation with building interconnection infrastructure and investing in clean firm imports. Wind will play a key role in the region's renewable portfolio, and addition of an incremental 500-800 MW capacity is a welcome move.	NS Power acknowledges the comment and the IRP Findings demonstrate that Regional Integration and the Reliability Tie offer value to electricity customers. All of the scenarios fully replace coal generation by the end of the planning horizon. The model was offered up to 615 MW of new firm import capacity, which was economically selected by 2045 in all Regional Integration scenarios. In addition, NS Power has already contracted for 153 MW of clean firm imports via the Maritime Link. This represents a transformational shift to the current generation mix. Even greater firm capacity imports could be economic in the future, as suggested; however, further analysis would be required (e.g. reliability, self sufficiency, policy certainty, etc.).
Natural Gas emissions	EAC	The North American natural gas supply has additional emissions associated with upstream fugitive methane emissions. While not currently accounted for under this IRP process, there is a clear risk that at some point in time they will be included as regulators seek to achieve real emission reductions. Multiple studies indicate that fully accounting for these emissions brings the natural gas supply close to emissions intensities associated with coal combustion [reference articles]. It would greatly benefit the study if complete replacement of planned natural gas/gas turbine infrastructure with regional transmission interconnection is analyzed fully.	NS Power, through the standards for Quantification, Verification and Reporting, does not account for upstream fugitive emissions at this time. If this were to change in the future, any future planned natural gas units would be re-evaluated incorporating this requirement. NS Power will continue to monitor regulatory developments in this area and update its analysis as appropriate. NS Power has also added the exploration of low and zero carbon alternative fuels to its IRP Action Plan.
Accelerated coal phase-out	EAC	Both 2030 and 2040 coal phase-out plans will have similar rate implications for ratepayers by 2045. While the findings indicate a higher initial cost for an accelerated 2030 coal phase-out, it is worthwhile to indicate here that the province would reap immense health and economic benefits from pursuing this target. Per EAC report, Rapid decarbonization in Nova Scotia would result in the creation of around 15, 000 full-time jobs by 2030. In addition, the Federal Government's analysis indicates that an accelerated phase-out would avoid 89 premature deaths, 8,000 asthma episodes and 58,000 days of breathing difficulty for Nova Scotians, among other benefits. An accelerated phase-out of coal by 2030 would be a favorable long-term strategy for the province and its peoples.	NS Power acknowledges the comment, however, the potential health and economic benefits referenced are outside of the scope of the IRP analysis.
Regional Integration	EAC	The EAC welcomes Nova Scotia Power's notion to develop a Regional Integration Strategy. This will be highly beneficial to the province and ensure a stable and reliable grid. Once again, it would be wise to link the addition of transmission infrastructure and phase-out of fossil fuel based (including natural gas turbines) infrastructure.	NS Power agrees. The optimization model does consider both the economic opportunity to retire coal and the mandated coal retirement dates when committing to transmission investments to access low or zero-carbon replacement energy and capacity.
Electrification	EAC	Electrification of the grid will have significant impacts overall and create opportunities for other sectors, such as transportation and small-to-medium-scale industries operating on carbon intensive fuels. Draft Action Plan statement 2 and Finding 1 b) are significant and would stand to benefit from stronger advocacy: "Increased electricity sales due to electrification can help to reduce upward pressure on electricity rates while facilitating carbon reductions in other sectors"	NS Power acknowledges these statements. However, quantification of benefits outside the electricity sector was not within the scope of the IRP. NS Power has noted that electrification is a key enabler of economy-wide decarbonization in support of provincial goals and targets.

		According to the Rate impact Comparison (Select Scenarios), it is shown that High Electrification scenarios 2.2 C and 2.2 C S1 achieve lower rates as compared to select Low and Mid-Electrification scenarios. This indicates that electrifying the grid has key benefits. While, this comparison is comprehensive in terms of rate implications for ratepayers, it would be prudent to demonstrate economic benefit of switching to electric transport and electric heating through heat pump technology.	
Trenton 5, wind/battery	EAC	Decommissioning of the thermal unit at Trenton 5 is essential. As a significant number of units will reach end-of-life much earlier than 2040, earlier preparation for depreciation of these units is warranted. Accordingly, a comprehensive plan indicating the retirement scenario for all coal units is needed. Wind addition to the system is essential, but it would be necessary to consider a higher than stated "350 MW" of additional capacity. Consideration must be given to maximizing wind addition in combination with battery storage. It is clear in other jurisdictions (USA, UK, etc.) that this has worked successfully at a non-significant additional cost. Considering future examinations of upstream methane emissions from natural gas powered fast acting peakers would reveal that battery storage would be the right direction to proceed in terms of reaching carbon neutrality.	NS Power has committed to a developing a plan for the retirement and replacement of Trenton 5, targeting 2023, while securing required replacement capacity and energy. It is also committed to beginning decommissioning studies for NS Power's other coal assets and developing and executing a coal retirement plan including associated regulatory approval processes. NS Power's capacity expansion optimization software co-optimizes wind and storage. It appears that battery storage's ability to substitute for firm capacity resources is currently limited in Nova Scotia by its relatively short duration, coupled with the wider variability of wind resources (as compared to more predictable renewable sources such as solar). NS Power will continue to monitor opportunities for new storage technologies, including longer duration storage, to support retirement of its coal generation assets. NS Power welcomes more specific examples of successful wind and battery integration at non-significant cost. As discussed above, the regulatory framework for NS Power's emissions accounting does consider upstream methane emissions.
Funding to participate	EAC	The capacity of EAC and other organizations that advocate for climate mitigation, environmental concerns and energy affordability concerns, to engage in this process is greatly reduced due to the design and process of the 2020 IRP, and the lack of availability for stakeholder funding and support through the Nova Scotia UARB, through the NSPI-led process, or through the Nova Scotia Department of Energy and Mines NSPI and the Nova Scotia UARB processes will continue with ad hoc sustainability oversight until the Department of the Environment, Department of Energy and Mines, or Nova Scotia Power create an updated mandate to support climate change and environmental concerns in a way similar to the Consumer Advocate or the Small Business Advocate.	Interest group funding is a policy matter beyond the scope of NS Power's IRP exercise. NS Power thanks the EAC for its participation in this process.
Policy/Environment	Envigour (Quest / Marine Renewables)	The IRP is taking place within a rapidly changing public policy and technology environment: one that will likely evolve in unexpected directions and produce technology breakthroughs for prices and solutions not anticipated in the IRP assumptions and modelling.	NS Power will continue to track policy and technology updates; the IRP Roadmap contains many aspects of the planning environment which NS Power will monitor and which may trigger updated planning studies via the evergreen process.
Overall IRP	Envigour (Quest / Marine Renewables)	Secondly, the IRP of necessity had gaps when considering the broader energy and climate change agenda. It did not purport to be an energy IRP and thus did not evaluate the full benefits as customers shifted energy needs to the electricity system from other systems. It also did not assess the supply risks associated with dependence on imports of natural gas or environmental compliance implications of using back-up diesel. It also did not consider the opportunities for the grid from the customer purchase of batteries. And it, of course, did not assess the policy benefits of early action on decarbonization as that is the purview of the governments.	NS Power acknowledges that there are additional consumer benefits of associated with shifting energy needs to the electricity system that are not captured in the IRP modeling. The IRP scope includes modeling of the electricity system impacts of decarbonization and electrification, however, NS Power acknowledges the qualitative point made by Envigour and other interested parties about the benefits to the province more broadly. NS Power confirms that diesel generation (from the existing CT fleet) contributed to the overall modeling of NS Power's emissions compliance; the impact is not significant due to the low capacity factors of these generating units.
Stakeholder Engagement	Envigour (Quest /	We would also note that the IRP attracted more interest and participation from stakeholders than usual with peak on-line call registration in the range of 170. In particular,	NS Power is pleased with and appreciates the level of stakeholder engagement and believes this has improved the IRP process throughout.

	Marine Renewables)	Municipalities were interested in how the IRP conclusions and implementations align with their policy and program goals.	
Roadmap/Action Plan	Envigour (Quest / Marine Renewables)	Finally, we observe that the measures under the actions and roadmap to ensure the plan is evergreen is not spelled out. It may be prudent to offer more clarity on that process using principles of inclusion, science-based conclusions, and a broad range of expert opinions and thinking tested for practicability in the Nova Scotia policy/regulatory environment.	NS Power has provided additional detail on the evergreen process as part of IRP Roadmap item #8; this process will facilitate annual updates on Action Plan progress/completion and Roadmap items as conditions change and technology or market options develop. NS Power will include a summary of updates as part of its IRP Action Plan reporting.
Future Steps	Envigour (Quest / Marine Renewables)	To enable a transparent and inclusive process, we suggest an annual or semi-annual extended workshop on climate change and clean technology policies and programs informed by expert views on trends for electricity technologies and costs.	This type of workshop would be outside the scope of the IRP process; NS Power observes and understands the increasing desire for stakeholder engagement on matters related to energy planning and looks for opportunities to participate where appropriate.
Roadmap/Action Plan	Envigour (Quest / Marine Renewables)	From this, we suggest that the final Roadmap and Action Plan reference the need for a regular and inclusive informative process to examine changes in the technologies, business models and best practices, and the policies and program initiatives that could impact the IRP assumptions and scenarios.	The Roadmap will address the longer-term needs for process updates; the action plan is a near-term document setting out immediate steps.
Natural Gas (more)	Heritage Gas	The Draft Findings, Action Plan and Roadmap results distributed to interested stakeholders on September 2, 2020 and presented on September 10, 2020 further indicate a required need and reliance for natural gas in the province over the next 25-year period. The results presented show that natural gas will provide electrical grid reliability, critical ancillary services, an economic energy source, and a lower carbon energy source to meet the province’s environmental goals.	NS Power agrees that natural gas continues to be a source of energy and firm capacity during the IRP planning horizon.
CTs (additional firm capacity)	Heritage Gas	in Draft Finding 3(a), NSPI discusses the requirement to add significant new CT capacity. As previously mentioned, Heritage Gas has natural gas distribution infrastructure in very close proximity to the four diesel-fueled Burnside CTs. The conversion or replacement of the now 45-year old CTs provides an opportunity to both address the reliability issues with the existing CTs and address the need for additional CT capacity. The replacement of the Burnside CTs should be strongly considered. Heritage Gas recommends that a specific Action Item be identified in the final report to address the reliability issues identified by Bates White and the cost-effective utilization of existing infrastructure to meet the needs for additional CT capacity.	NS Power has made investments into the diesel CT fleet to resolve reliability issues, including the oil cooling systems mentioned in Heritage’s comments. NS Power’s IRP analysis has conclusively shown that sustaining the existing Diesel CT fleet is the most economic firm capacity option for customers. The gas CT capacity requirements noted by Heritage are incremental capacity in addition to the existing diesel CT fleet, which is sustained in the IRP. The existing site would need to be evaluated in the context for suitability. Many considerations for new and/or replacement gas generating units will be considered as part of the work under IRP Action Item #3c, “Develop a plan for the redevelopment or replacement of existing natural gas-powered steam turbines to provide low-cost, fast-acting generating capacity to the Nova Scotia system.”
Coal to Gas conversion	Heritage Gas	In the Modelling Results, the long-term resource changes emphasize additional natural gas resources including coal-to-gas conversions. The Draft Finding 3(c) shows natural gas as a key requirement of the developing electricity system in both the near and long term. Draft Roadmap item 1 discusses the need for “advance engineering study work on coal to gas conversions at Trenton and Point Tupper Generating Stations”. The Action Plan should reflect a timeline of completion of this study and scope of the work included in the coal-to-gas conversion scenario. Heritage Gas also notes that an increase of this size in natural gas consumption in the region requires long-term natural gas transportation commitment planning, which should also be reflected in the Action Plan.	NS Power has provided several natural gas pricing options to the model, some of which incorporate firm long-term agreements while others rely on (generally higher) spot market pricing for lower capacity factor units such as the coal-to-gas conversions as modeled.
Electrification	Heritage Gas	This IRP is unique in contrast to previous IRP’s in that very significant investments will be required in NSPI’s transmission and distribution assets. This investment is driven by potential increased electrification of end-use energy, such as transportation and building heat, and the need to meet the lower environmental targets specified in the Sustainable	NS Power acknowledges that increasing levels of economy-wide electrification could have impacts on the requirements of the Transmission and Distribution (T&D) systems, and IRP Action Plan item #2c indicates that these impacts will continue to be monitored and addressed during the IRP Action Plan period. In addition, Roadmap Item #7 will monitor ongoing electrification-related load growth in Nova Scotia and will allow NS Power to identify when the load on the system starts to trend toward a “Mid” level of

		Development Goals Act ("SDGA"). Significant investment in T&D is also expected to arise from the large potential increases in peak energy demand.	electrification from the current "Base" level. An observed transition will trigger additional work to quantify T&D impacts based on early observed system impacts.
Avoided T&D Costs	Heritage Gas	Heritage Gas understands that there is an ongoing process through DSM Matter No. M09471, to agree on the avoided T&D costs of Demand Side Management ("DSM"). This matter considers only a fraction of total T&D costs and so, it would be prudent to discuss these findings with the larger stakeholder group and also include a continued study of T&D costs in the context of the increasing electrical load envisioned in the IRP.	NS Power is currently working with the DSMAG to update the current methodology used for calculating Avoided T&D Costs of DSM. The current draft methodology considers all T&D capital expenditures related to load growth, and so should capture the costs that might be incurred in expanding the T&D system to support electrification load.
Emissions (Low Carbon)	Heritage Gas	Electrification in certain sectors of the economy will assist in moving Nova Scotia toward a lower carbon economy. However, electrification alone will not substantially reduce the GHG emissions in the province in order to meet the SDGA net-zero 2050 target. // Recently the Offshore Energy Research Association ("OERA"), Liberty Utilities, Heritage Gas, and the provincial Department of Energy & Mines engaged Zen Energy Solutions to determine the future potential uses of hydrogen in Nova Scotia. Hydrogen is increasingly seen as imperative in meeting the net-zero goals established in the Sustainable SDGA and NSPI should specifically identify hydrogen within the action plan and roadmap.	The Pathways study released to stakeholders at the start of the IRP showed that electrification was a significant contributor to the overall economy-wide decarbonization. NS Power will continue to monitor new technologies that can contribute to firm capacity and energy production for the Nova Scotia system, and has included consideration for fuel flexibility and low/zero carbon fuels, such as hydrogen, in Action Plan item #3c which will develop a plan for the redevelopment or replacement of existing natural gas-powered steam turbines to provide low-cost, fast-acting generating capacity to the Nova Scotia system.
Action Plan	Heritage Gas	• The Action Plan should specially consider the replacement of the liquid-fueled CTs in Burnside with gas-fired CTs as a cost-effective means to reliably meet the incremental capacity requirements identified in the IRP. • The Action Plan should identify the specific timeline and scope of the engineering study regarding coal-to-gas conversions. The assumptions on long-term natural gas transportation contracts should also be included within this action item. • A timetable should be established for estimating the incremental T&D costs associated with the various electrification scenarios. The IRP stakeholders should be kept fully informed as these cost estimates are developed • The Action Plan and Roadmap should specifically identify hydrogen as a means to assist the province in meeting the GHG reduction targets established in the SDGA.	NS Power's IRP analysis has demonstrated that sustaining the existing Diesel CT fleet is the most economic firm capacity option for customers. NS Power's Findings and Action Plan have identified that additional CT capacity will be a key source of firm capacity in all the optimal resource plans modeled, enabling coal retirements and providing Ancillary Grid Services. NS Power is currently working with the DSMAG to update the current methodology used for calculating Avoided T&D Costs of DSM. The current draft methodology considers all T&D capital expenditures related to load growth, and so should capture the costs that might be incurred in expanding the T&D system to support electrification load. NS Power will continue to monitor new technologies that can contribute to firm capacity and energy production for the Nova Scotia system, and has included consideration for fuel flexibility and low/zero carbon fuels, such as hydrogen, in Action Plan item #3c which will develop a plan for the redevelopment or replacement of existing natural gas-powered steam turbines to provide low-cost, fast-acting generating capacity to the Nova Scotia system.
General	Heritage Gas	The assumptions and scenario modelling used in this IRP reflect the need for continued monitoring of the development of the electric and broader energy sectors in the Province. Unlike past IRP's this IRP suggests some possible fundamental differences in the future electric sector in Nova Scotia. These fundamental changes include for the first time a general future separation of capacity from energy, a potential focus on electricity growth versus general DSM (still dependent on full costing of such an approach) with a continued requirement for focused DSM and Demand Response on peak, the potential requirement for significant new regional transmission to allow both increased firm and non-firm energy imports, the requirement for more fast acting generation to support increased renewable development and provide peak response capability, and the need to significantly monitor over time the take up of new technologies such as electric vehicles, distributed generation, battery or other storage options, etc. Of these changes, one of the most significant is the availability of significant volumes of firm dispatchable imports that are incremental to those	Firm Imports via a Regional Interconnection have been economically selected by the model in all the Regional Integration cases where that supply option was available; this supply option was not forced or assumed into any of the Regional Integration scenarios or sensitivities. NS Power has identified as an Action Plan item the development of a Regional Integration Strategy following the conclusion of the IRP, and this will update the UARB and interested parties on a regular basis as described in Roadmap item #8.

		available through the Maritime Link. To meet the lower carbon intensities for electrical generation in the low to high electrification scenarios highlighted in the Draft Findings[11], the study assumes that the Nova Scotia electrical grid will need to rely on between 435 and 615 MW of firm dispatchable energy and the required investment in NS-NB tie line to accommodate this energy. NSPI has not provided any of the key assumptions associated with these imports including costs or carbon intensity and they have indicated that there are no commercial agreements in place to underpin the incremental imports. As such, it is important that all stakeholders are kept apprised over the next number of years of the data collection, study results and future opportunities that might present themselves, so that the electricity sector in Nova Scotia works in concert with other sources of energy and opportunities in the wider energy sector in the Province, to ensure a sustainable competitive energy sector which will benefit all stakeholders. In consideration of these potential fundamental changes all parties will need to closely monitor developments in the electric and broader energy sectors to ensure Nova Scotian residents and business have access to competitive alternative energy supplies and to cost effectively meet the goals of the Province.	
Supply-side (Compressed Air Storage)	JFS Hydrostor	JFS Hydrostor's process, compressing air and storing electricity is considered a proven technology and ready to deploy. As you know, we … continue to be frustrated or disappointed to learn that long duration energy storage technology is not and has not been given its due in the preferred portfolio solution into the future. … Nova Scotia Power has instead opted for a portfolio that calls for new transmission and fossil fuel assets to meet balancing and peaking requirements. • Hydrostor is a cost-effective non-wire alternative solution for transmission that is easier to permit and more cost effective than large transmission projects or pumped-hydro projects. • As a clean source of synchronous generation capacity with similar system benefits and operating characteristics as coal that can be used to advance coal retirements and be located on or near the sites of former coal plants while retaining many of the plant's employee (this concept is now being considered in other areas of North America). • Can be used to balance intermittent resources such as wind and solar or instead of natural gas fired plants, as a peaking asset.	NS Power has offered compressed air energy storage (CAES) technology and other storage technologies to the IRP model, but they have not been selected by the model as part of the optimal resource strategies for the key scenarios and sensitivities studied in the IRP. NS Power notes that optimal portfolios are an output of the capacity expansion model and are not produced manually by NS Power.
Supply-side (compressed air storage) assumptions	JFS Hydrostor	Based on our review of Nova Scotia Power's IRP assumptions, we believe that ACAES's capital costs were inaccurately modelled. We believe that this played a decisive factor in it not being selected as a preferred resource. In particular, we found that in your cost analysis, the model used a $/kW cost of CAD $2,200. This was in effect, the mid point of our per KW cost estimates for a 200 MW facility with a duration of 12 hours that we had previously provided to you. This was then compared to the cost of a lithium-ion system with 1 and 4 hours of duration.	NS Power's IRP model treats CAES and battery storage as independent resource options available to the model, each with its own properties including capital cost, ongoing costs, firm and nameplate capacity, available storage duration, round trip efficiency, and other parameters necessary to model the resource. The model evaluates all these parameters together as part of generating an optimal resource plan, and does not strictly compare prices on a $/kW basis as appears to be noted in the comment. NS Power notes that overall, storage quantities selected in the key scenarios are rather modest and interprets this as being related to a combination of factors including cost of storage resources, storage ELCC factor (which has a more significant impact for short duration storage), the increased variability of

		Our concern is that this was not an apples-to-apples comparison as it accounts for the additional cost of a longer duration facility but ignores the additional value such a system provides. Additionally, by choosing to use the costs for a 200 MW system, this did not account for the significant economies of scale that come with larger sized A-CAES facilities. If you consider a 500 MW facility with a 4-hour duration, the cost works out to an average of US$1125/kW1. We believe that this is a much fairer comparison to a 4-hour lithium-Ion system for the short duration market. However, A-CAES's cost advantage is most apparent in the long-duration market where it can act as a non-wires alternative to traditional transmission for improving reliability or as a solution for integrating and time-shifting Nova Scotia's wind resources onto the grid. To illustrate this point, we compared the bid prices that we recently submitted for a 300 MW 6 hour and 12 hour facility to a utility in California to what an equivalent lithium system would cost based on prices provided by Lazard's Levelized Cost of Storage Analysis 5.0. For the 6-hour system we found that lithium ion prices would have to drop 7%-50% from 2019 in order to achieve cost parity. Whereas, for the 12-hour facility we found that lithium ion would have to decrease their cost by a further 41%-70% in order to achieve cost parity.	wind integration vs. more predictable solar generation cycles seen in other jurisdictions (i.e. several consecutive days of very limited wind duration), and availability of competitive options such as firm imports and CTs that can also support variable renewable generation and provide Ancillary Grid Services.
Wind (general)	Natural Forces (Andrew Cooke)	Natural Forces is active across the country and is actively building out wind project currently and over the next few years, so the prices and energy numbers from today's and tomorrow's wind projects are well known to us. Two comments: • the price per MW installed is much closer to the 1.5 million per MW; and • the capacity factors are closer to mid 40% than the number stated by NSPI. This does lead us to believe that more wind now is the answer, and that the way to unlock these saving for the rate payers and the utility is to look to other jurisdictions that have large wind resources in use and adopt some of their operating procedures in order to keep the system stable and allow for more wind on the system.	NS Power modeled a range of prices to understand the sensitivity of the model to this variable; this has been incorporated into the final report. NS Power's capacity factor assumptions were based on publicly available CanWEA data (see Supply Options Study and IRP Assumptions for more details). NS Power has identified the need for additional stability studies regarding operating limits into its IRP Action Plan as a component of Action Item 3d.
Wind (general)	Natural Forces (Andrew Cooke)	A major transformation of the existing generation resource base is required. As Nova Scotia Power has remarked, significant efforts are required to achieve the level of carbon emissions reductions in line with Nova Scotia's Sustainable Development Goals Act. A major transformation of the existing generation resource base is required, including the integration of significantly higher volumes of intermittent, non-synchronous renewable energy resources. However similar transitions have been successfully achieved in other jurisdictions. It is helpful that that there is a significant degree of commonality in the main "building blocks" selected in each of the scenarios, those being (for the main part): wind capacity; gas-fired CTs; the 2nd AC intertie, and regional integration. The scenarios differ in the order and rate at which the new resources are deployed, and the rate at which certain existing resources (principally the coal-fired units) are retired. As can be observed, several scenarios have approximately 200 MW of new wind capacity coming on by 2025 to 2027, and amounts ranging from 400 to 800 MW by 2029/2030. The higher wind capacities are generally arising in the cases based on higher electrification, as might be expected.	NS Power agrees that there is a high degree of commonality among the various optimal resource plans studied under both the key scenarios and sensitivities; this commonality has informed the IRP Action Plan. NS Power's wording in Action Plan item 3d, "Initiate a wind procurement strategy, targeting 50-100 MW new installed capacity by 2025 and up to 350 MW by 2030", is built around the ranges found in the optimal resource plans of several key scenarios in those years, including plans 2.0C (0 MW 2026 / 400 MW 2030) and 2.1C (112 MW 2026 / 362 MW 2030). As noted, higher levels of electrification and earlier mandated coal retirement dates are generally correlated with higher levels of installed wind generation in any given year. NS Power's IRP Roadmap contains items to monitor regarding both trends so that the resource strategy can shift as required.

		NSP has identified that higher electrification is beneficial to reducing electricity rates (and it is presumably also beneficial to achievement of Nova Scotia's broader emissions policy goals). In light of the above, NSP's proposed/draft action plan item 3(c) viz: "Initiate a wind procurement strategy, targeting 0-100 MW new installed capacity by 2025 and up to 350 MW by 2030" seems unduly limiting, particularly as regards the implied "upper limit" of 350 MW by 2030. Several scenarios, including those identified as resulting in lower electricity rates, have substantially higher wind volumes.	
Wind (cost) DERs Regional integration	Natural Forces (Andrew Cooke)	Another key point to note is that many scenarios are introducing some level of additional wind capacity, even with the imposed requirement that wind installed capacity of greater than 700 MW must be accompanied by either batteries/synch comps, or the second AC intertie. This has the effect of imposing an entirely unnecessary and inappropriate additional capital cost on wind (i.e. the associated capital cost of the batteries/synch comps), which is very likely reducing the level of wind being installed in many of these cases. It is difficult to be precise about the level of additional costs being imposed through this requirement as the batteries will bring some other benefits (such as energy arbitrage) which will act to off-set the added capital costs. However approximations suggest it may be adding in the region of 5 to 10% to the effective cost of additional wind capacity. The continued insistence on the part of NSP to adhere to this position is rather baffling. The precise extent to which wind capacity is being "held back" due to this approach is difficult to quantify (though of course it could be assessed by disassociating the requirement for batteries/synch comps in the modeling). However I believe it can be stated with certainty that the NSP approach will inevitably result in some level of higher costs to electricity consumers (as compared to the standard approach adopted in other power systems integrating comparatively high levels of intermittent and non-synchronous renewable generation). This is discussed further in section 5.	NS Power has modeled numerous sensitivities on wind integration assumptions, including a boundary case where the integration requirements (and other system requirements such as constraints on synchronized inertia) were removed from the model to help understand behaviour under these circumstances. NS power also notes that many key scenarios, including 2.0A, 2.0C, 2.1A, 2.2A, and 2.2C do not fully subscribe the 100 MW of wind that the model was able to add without the integration requirements referenced (Reliability Tie or batteries and synchronous condensers); this suggests that regardless of integration requirements, the modeled wind integration requirements are not significantly affecting the resource plan in the near term (i.e. within the five-year IRP Action Plan timeframe).
Electrification	Natural Forces (Andrew Cooke)	Higher electrification scenarios are beneficial to electricity consumers through lower rates, and will also support cost-effective achievement of broader emissions policy objectives. NSP has identified that higher electrification is beneficial to reducing electricity rates. It is presumably also beneficial to achievement of Nova Scotia's broader emissions policy goals, as it supports decarbonisation of other sectors (transport, heat). It is recommended that this point is emphasised strongly in the findings and is considered in NSP's action plan.	NS Power agrees that electrification as modeled is beneficial both in terms of customer relative rate impact and ability to integrate additional variable renewable generation. NS Power has included the development of an Electrification Strategy as a core component of its IRP Action Plan (Action Plan Item 2).
Wind (additional sensitivities)	Natural Forces (Andrew Cooke)	Sensitivities with lower wind costs profoundly affect the resource plan and need significant further analysis. The sensitivities with lower wind costs have a profound effect on the resource build-out plan. Much larger quantities of wind capacity (c. 600 MW) are being added by 2023 to 2025. These scenarios also have the benefit of lower CO_2 emissions than comparative scenarios. As these scenarios are based on very credible wind cost projections (and disassociation of battery costs would also contribute to lowering the effective cost of wind) it is of critical importance that further analysis is undertaken in this area, including gaining an understanding of the price point(s) at which transition occurs. [Refer section 2]	NS Power has incorporated elements and learnings of the Low Wind Price sensitivity (2.1C-WIND-1) into the IRP Final Report and Action Plan. In particular, NS Power has noted in IRP Roadmap Item #5 that Nova Scotia-based market information will inform whether market pricing is more consistent with the "Base" or "Low" trajectories for wind.

		The sensitivity cases undertaken with lower wind (and battery) costs[1] are or particular interest, and result in a fundamentally different build-out plan. As can be seen, the lower wind costs have a profound effect on the resource build out plan, even compared to the "original" scenarios with higher wind build-out (such as Case 3.1C). Much larger quantities of wind capacity (c. 600 MW) are being added by 2025, and even earlier in Case "2.1C WIND-2" which also has lower battery costs. Given that this has such a fundamental impact, coupled with the fact that lower wind costs are a highly credible scenario, further investigation of this scenario is critical. At present it tells us that changing the wind costs from the "Base Case Wind Cost" ($2,100/kW) to the "Low Wind Cost" ($1,500/kW) has a major impact on the timing of the deployment of additional wind capacity. However it does not tell us at what wind cost does this major change occur3. If it happens (in whole or in part) at a higher wind cost (somewhere between $2,100 and $1,500), it further increases the confidence level that the benefits of the "lower wind cost" cases are achievable. Once more, the unnecessary association of the battery costs with increased wind (until the advent of the 2nd AC intertie) is also an important consideration. The reduction in wind costs required to create the change to a more rapid wind build-out plan, could be arrived at through a combination of lower wind capital costs and savings from disassociating the battery requirements. // In summary, the findings from the "low wind cost" scenarios are much too significant to ignore, and it is of critical importance that further analysis is undertaken to understand the price point(s) at which transition occurs. It is also strongly recommended that the association of battery and synch comp costs with additional wind capacity, is discontinued for these (as well as other) scenarios.	
Wind	Natural Forces (Andrew Cooke)	The suggested build out rate for wind in NSP's initial draft action plan, is understated. NSP's proposed/draft action plan item 3(c) states: "Initiate a wind procurement strategy, targeting 0-100 MW new installed capacity by 2025 and up to 350 MW by 2030". This is unduly limiting at this stage, particularly as regards the implied cap of 350 MW by 2030. Even before consideration of the "low wind cost" sensitivities, several scenarios, including those identified as resulting in lower electricity rates, have substantially higher wind volumes.	Please see the response above.
Emissions and CO_2 monetization	Natural Forces (Andrew Cooke)	CO2 levels vary widely between scenarios. There is a wide variation in the CO2 levels (both annual and cumulative) between the different scenarios. Even if not directly monetizable, there is a definite value in lower CO2 emissions: a) as a risk mitigation strategy against upward pressure on emissions levels from additional demand growth, or further downward revisions in emission targets; and,	NS Power has provided annual emissions results in both graphical and tabular (electronic) format, as well as summary metrics of total emissions over two different time periods, for all key scenarios and all sensitivities modeled. NS Power has not monetized incremental reductions in GHG emissions in the IRP model; and additional discussion on this topic is provided in the IRP Final Report. NS Power notes that many key scenarios have economically emitted below the modeled hard caps, and agrees this does provide a buffer against load growth or changes in emissions limits.

		b) as can be observed from experience in other jurisdictions, lower carbon intensity of the electricity sector (lower CO2/MWh) promotes electrification of other sectors (heat, transport), which is identified as lowering electricity rates and will also contribute to achievement of broader emissions policy objectives. The differences in CO2 levels should be highlighted clearly in the results, to that individual stakeholders and stakeholder groups can consider the impacts. [Refer section 3] There are also benefits (not currently monetised) from reduced CO2 submissions in the cases with higher wind build-out. This is discussed further in section 4. // To the best of my knowledge, the benefits of a lower level of CO2 emissions is nor currently monetised in the IRP modelling approach. This is of course dependent on the emissions framework applicable to the jurisdiction. In Europe for example, the approach would be to directly monetise the benefit of a lower CO2 emission level. Even if that is not appropriate within the current framework applicable in Nova Scotia, it is suggested that the differentiation between the scenarios in terms of CO2 levels is a significant factor which should be highlighted to a greater extent. Also even if not directly monetizable, there is a definite value in lower CO2 scenarios as a risk mitigation strategy: • In a scenario where CO2 is “only just” below the required limit, then there is a risk that in the event of, say, higher demand growth and/or greater levels of electrification, that the limits would then be breached (or that meeting them – if even possible – would involve suboptimal and expensive strategies). • If emissions limits are revised downwards, the additional actions and costs required to achieve them (starting from a lower CO2 base), are likely to be much less significant. It can also be observed from experience in other jurisdictions, that the lower the carbon intensity (CO2/MWh) of the electricity sector, the more it becomes a “strategy of choice” for other sectors (transport, heat) to achieve their emissions-reduction objectives. Aside from assisting in achievement of Nova Scotia’s emissions policy objectives more generally, lower CO2 intensity is likely to promote higher electrification, which is identified by NSP as contributing to lower electricity rates.	NS Power agrees that many customers are interested in lower emission electricity; this transformation has been a foundational aspect of this IRP, and meeting this customer demand is likely to support incremental electrification which the IRP has shown has a positive impact on electricity rates.
Risk Assessment	Natural Forces (Andrew Cooke)	Consideration of Risk. There is merit in giving further consideration to risk assessment, as a tool for identifying scenarios and/or actions which show strong performance (in terms of low cost) across a range of future sensitivities. It is likely that scenarios with higher renewables and/or lower CO2 emissions would tend to be more favourable under such an examination, as they are “proofed”, to a considerable extent, against potential variables such as high fossil fuel costs, high emission costs (or tightening of emissions limits), or higher demand growth/electrification (potentially resulting in breaches of emissions limits). It is recommended that this type of analysis is considered further. [Refer section 4]	NS Power has taken the approach of developing an IRP Action Plan and Roadmap based on the outputs of multiple low-cost scenarios (e.g. 2.0C, 2.1C, 3.1C, and informed by 2.1C.WIND-1); these scenarios are selected on the basis of their lower NPV Revenue Requirement (NPVRR) and relative rate impact compared to other scenarios and together cover multiple assumptions for electrification level, coal retirement date, emissions trajectory, and wind pricing.

		A common approach is also to look for scenarios and/or actions which are "low regret" scenarios, i.e. a scenario which is not necessarily the "lowest cost" in a given set of circumstances, but shows strong performance (in terms of low cost) across a range of future sensitivities. It could be likely that scenarios with higher renewables and/or low CO2 emissions would tend to be more favourable under such an examination, as they are "proofed", to a considerable extent, against potential variables such as high fossil fuel costs, high emission costs (or tightening of emissions limits), or higher demand growth/electrification (potentially causing breaches of emissions limits). It is recommended that this type of analysis is considered further.	
Stakeholder Engagement	PHP	PHP is appreciative of NS Power's efforts to actively and fully engage all stakeholders as part of its long-term planning processes. The IRP results clearly demonstrate the significant changes to the Nova Scotia electricity system that are expected to occur over the next 25 years. In this regard, the Draft Action Plan and Roadmap identify the need to initiate and develop several new strategies, plans, and programs in the near term. PHP supports this approach, as well as NS Power's plans to continuously refine the Findings and Action Plan items via an evergreen IRP process, on the basis that NS Power will continue to hold regular and transparent engagement sessions. Such sessions will ensure stakeholders have the opportunity to provide valuable feedback that can be incorporated in the transition of the electricity system, particularly as circumstances evolve and updated information becomes available.	NS Power appreciates the comment and agrees that stakeholder interaction during the IRP process has been valuable in developing the Findings, Action Plan, and Roadmap items presented in the Draft Report. As part of the continuous refinement of the Findings and Action Plan items via an evergreen IRP process, NS Power has committed to providing annual updates on the status of various Action Plan and Roadmap items. These updates would be shared with interested stakeholders and NS Power may engage stakeholders on items as appropriate.
Flexibility	PHP	In contrast to prior IRPs (which specifically sought to develop a long-term "Preferred Resource Plan" from among a set of candidate resource plans), the 2020 IRP results provide a comparison of various resource portfolios across a range of electrification scenarios. Maintaining maximum flexibility in the near term is needed to ensure that NS Power's long-term strategy best accommodates the current uncertainty regarding future electric load growth in the Province. Preserving such flexibility will also enable NS Power to consider any subsequent changes in technology and/or government policy, as well as the results of ongoing costing analysis of generation and transmission options. These items will impact the economics of important long-term decisions regarding the timing and extent of (i) coal retirements, (ii) new capacity additions, and (iii) new renewable energy generation. Further, the significant potential investments in regional integration will require careful and strategic consideration and coordination with other jurisdictions in the region to ensure Nova Scotia stakeholders receive the intended benefits.	NS Power agrees and acknowledges the importance of maintaining flexibility. NS Power acknowledges the specific need for direct discussions and engagement with neighbouring jurisdictions as part of the development of the Regional Integration strategy contemplated in the IRP Action Plan and has added wording to this effect in the Draft Report.
Rate Impact	PHP	In its Updated Modeling Results and Draft Findings, NS Power developed a rate impact calculation using IRP partial revenue requirements for each scenario to illustrate the long-term effects of various levels of electrification. PHP believes that consideration of the potential overall impacts on future rates should remain a central consideration of NS Power's long-term strategy and planning processes. The cost of electricity, as well as the stability and predictability of electricity rates, remain critical issues for all stakeholders, particularly industrial customers that compete globally and require ongoing capital investment.	The relative rate impact model that has been developed has been a valuable addition to this IRP, particularly when used to examine impacts over different timeframes (e.g. the 10-year and 25-year average annual impact metrics presented in the IRP Modeling Results). This approach has also shown value by allowing the comparison of scenarios that vary in terms of electrification levels and/or the presence of non-utility DER resources not otherwise captured in NPV calculations.
Demand Response	PHP	As parties are aware, earlier this year, the Board approved NS Power's Application for approval of the Extra Large Industrial Active Demand Control Tariff. This innovative rate structure, developed following extensive collaboration with the utility, provides NS Power	NS Power agrees with the comment that firm capacity will continue to be a key requirement of the Nova Scotia system and has incorporated this into IRP Finding #3.

		with a new demand response service that allows the utility to better operate its electricity system for the benefit of all customers. The 2020 IRP results indicate that firm capacity resources will continue to be a key requirement of the developing NS Power system in both the near and long term, demonstrating the inherent value in demand response-type approaches going forward. Continuing to pursue deeper levels of collaboration and innovative solutions, whether through rate design approaches or otherwise, will help ensure that the transition to Nova Scotia's electricity future can be achieved in an environmentally and economically sustainable manner for NS Power and its customers.	NS Power also agrees that the IRP has shown that DR resources, as modeled in the IRP, have economic value to the system and to electricity customers and has integrated this into Finding #3e and Action Plan item #4.
Findings / Results	SBA / Daymark	NSP has conducted extensive modeling and analysis in support of the IRP analysis. However, in the presentation of the draft findings, it was not always clear precisely how each finding was supported by the modeling analysis. In the full IRP, we encourage NSP to support the findings with specific references to model runs and related analyses.	NS Power agrees with this comment and has integrated this into the presentation of Findings in the IRP Final Report.
System Inertia	SBA / Daymark	The draft Finding #2 acknowledges this, noting that "Further work is required to assess system stability at these significant penetrations and determine whether additional dynamic system inertia constraints can enable this level of additional wind integration on the Nova Scotia system" (Slide 47). The draft Roadmap item #2 also states that NSP will "Complete detailed system stability studies…while considering higher quantities of installed wind capacity…" (Slide 60). The modeling of the inertia requirement has supported certain resource decisions, in particular the addition of the Reliability Tie which is assumed to provide all the system inertia needed by the NSP system. However, this conclusion requires some further investigation. Additionally, NSP has previously noted that it has not evaluated the possibility that wind projects could provide fast frequency response, which is a method of addressing system inertia concerns used in other regions. We recommend that as part of the IRP, NSP should provide a concrete plan for conducting the additional analyses needed to assess the system needs, and the ability of different resources to address these needs (conventional generators, the Reliability Tie, Maritime Link, advanced wind turbines, and load resources). While the draft analysis indicates that the assumed system inertia requirement is not binding for several years, it is possible that cost declines for wind capacity or other factors could advance the timeline for wind development, hastening the need for a solution to the reliability need.	NS Power has identified future work related to wind stability studies at higher penetrations in the Findings and this is discussed in the Action Plan and Roadmap. With regard to system inertia, NS Power notes that it added a sensitivity under which the Reliability Tie provided only half the required synchronized inertia and this resource was still selected by the model; the optimal resource plan was largely unchanged from the base case. NS Power has not expressly modeled a FFR requirement, which is a service that is separate from synchronized inertia (it performs a similar function but is slower acting that synchronized inertia; see for example Michael Milligan, "Sources of grid reliability services," The Electricity Journal Volume 31 Issue 9, November 2018). NS Power understands that wind resources can provide various levels of FFR services. NS Power has stated that FFR is not a constraint in its capacity expansion or dispatch models, as transient system stability studies assess FFR in timescales of seconds (or less). However, NS Power agrees that if FFR services on certain generators (e.g. wind) are found to reduce the synchronous inertia constraint, the economics of building more variable renewable energy could improve (absolute additions and/or timing). NS Power has committed to such study. NS Power has incorporated the development and execution of this plan into the IRP Action Plan phase.
Regional Integration / Reliability Tie	SBA / Daymark	Most IRP scenarios include the selection of the Reliability Tie and Regional Integration as part of the optimal portfolio. Implementing this strategy will require significant coordination with New Brunswick and availability of supply. Given the primary role of the transmission solutions in NSP's plan for a reliable and economic supply portfolio, the Company should prepare a specific timeline and plan for the steps required in Action Plan Item #1 to ensure that this is a feasible solution to deliver the benefits assumed in the IRP.	NS Power agrees with this and has included language respecting the need for coordination and collaboration with neighbouring jurisdictions as part of its re-worded Action Plan item #1c in the Draft Report; this item also speaks to evaluations of supply availability (and additionally, security of supply, emissions intensity, and dispatch flexibility). Project timelines within the overall Action Plan timelines will be developed as part of the execution of the Action Plan.
Rate Impact	SBA / Daymark	We appreciate NSP developing the rate impact model to help assess the implications of various portfolios for customers (Slide 31). We believe this provides important information in the consideration of various strategies. The summary of results provided in the draft Findings presentation (Slide 43) contain interesting conclusions, particularly related to the rate impact under high electrification scenarios. This slide was accompanied with important discussion during the stakeholder session which provided context on rate trends.	NS Power agrees that this analysis has been instructive and has added value to the IRP process and findings. NS Power has added additional discussion and support to this finding (1b) in the Draft Report. The Draft Report also includes details on the rate modeling approach in Section 5.3.4 and more discussion of the results of the relative rate analysis in Section 6.5.

		We recommend that NSP provide sufficient context in the IRP to communicate the implications of the rate impact analysis on customers, specifically as it relates to Finding 1b ("Increased electricity sales due to electrification can help to reduce upward pressure on electricity rates while facilitating carbon reductions in other sectors.")	
Electrification	SBA / Daymark	Increased electrification and advanced technology can provide enhanced capabilities to NSP to manage some of the challenges introduced by higher penetrations of non-dispatchable resources. Action Plan Item #2c calls for a data collection program related to electrification. We support this program, and encourage NSP to pursue it rapidly so that any insights can be incorporated into the next IRP.	NS Power will consider timing as part of the Action Plan and agrees that this data will be valuable (note that in the Draft Report, this has been updated to item #2b).
Demand Response	SBA / Daymark	Demand Response resources can provide cost effective capacity or grid services. NSP's Action Plan calls for the creation of a Demand Response Strategy with a target capacity of 75 MW (Slide 57). We caution on the limitation placed by identifying Demand Response potential of only 75 MW. This resource needs more examination to understand its true size potential and cost for different levels of DR.	NS Power accepts this feedback and has re-worded Action Plan item #4 accordingly, adding "Available resource cost, flexibility, and reliability may inform pursuit of additional Demand Response capability."
IRP Process / Overall IRP	Town of Wolfville	[S]mall communities like Wolfville lack both the resources and expertise to meaningfully engage in a necessarily complex and lengthy process like the IRP. We've been very fortunate to receive patient and expert guidance from a number of helpful individuals and groups, but still don't feel terribly confident that we've fully understood and engaged with the process. You and your colleagues have made every effort to make the IRP process accessible to us, but we believe that our efforts, and those of communities throughout Nova Scotia endeavouring to address climate change, would be well served by an updated mandate to support climate change and environmental concerns within the IRP process in a way similar to the Consumer Advocate or the Small Business Advocate.	Interest group/community funding is a policy matter beyond the scope of NS Power's IRP exercise. NS Power thanks the Town of Wolfville for its participation in this process.
Reliability	Town of Wolfville	It was encouraging to learn that all scenarios under consideration in the IRP process satisfy NS Power's reliability target. Reliable and predictable access to electricity is vitally important to Nova Scotians and will be become increasingly so as efforts to electrify transportation and heating systems in communities proceed.	NS Power Acknowledges and agrees with this. NS Power views the addition of a Reliability Screening phase to this IRP process as positive.
Fossil Fuel Generation	Town of Wolfville	The Town of Wolfville appreciates that an accelerated coal phase out scenario was considered as part of the IRP process. We note that, in the rate impact comparison, substantially similar scenarios that included coal phase-out by 2030 and 2040 were projected to have similar rate implications by 2040. There are both short- and long-term benefits to an accelerated phase-out of coal and other fossil fuels: it has recently been confirmed that we have drastically underestimated the health impacts of air pollution on human health; the latest air quality research suggests that in the US, the health benefits alone are enough to justify an immediate transition away from fossil fuels.	The scope of the IRP does not extend to health impacts of pollution; however, NS Power has indirectly included this in its IRP metrics by providing data on emissions reductions over various portions of the IRP planning horizon.
Rate Impact Policy	Town of Wolfville	The rate impact comparison also illustrates the inequitable economic implications associated with high levels of Distributed Energy Resource (DER) adoption. By 2040, the models suggest that high DER uptake could increase electricity costs by 10%, or 2 cents/kWh. While this increase would be experienced by all rate payers, under the current regulatory regime governing Distributed Energy Resources – which limits the scope and scale of electricity-producing resources that can be connected to local distribution system –its impact would not be equitably distributed. For example, Nova Scotians with the financial capacity to both own their own homes and invest in solar PV systems would experience significantly less impact that those not in a financial position to do so. The possibility that public policy not only enables this, but is in fact subsidizing such investments, facilitating access to reduced energy costs by the wealthiest	NS Power Acknowledges these points. The Company's current rate design, with the significant recovery of fixed costs in the variable energy charges, does create a cross-subsidy of customers who self-generate by customers who do not self-generate. Though outside the scope of the IRP, it is understood that with the potential for continued growth of DER in the province, revision to the Company's rate structures will be required to address this cross-subsidization and to provide better price signals for customers considering self-generation as to the value of the generation to the system and for all customers.

		members of our society with the modelled implication of increasing the burden on the less affluent, is in urgent need of re-examination and consideration.	
Emissions Reduction	Town of Wolfville	SSG's modelling projects that, under scenario 3.2c, should the Town of Wolfville achieve the working targets in its draft climate change mitigation plan, it would achieve a 53% reduction in GHG emissions by 2030, in-line with the emissions reductions goal legislated by the Province in the Sustainable Development Goals Act (2019). It also projected that the Town's climate change mitigation efforts would realize essentially identical emissions reductions under both the NEB 2018 and Net Zero 2050 / Mid Electrification / Current Landscape scenarios – both of which would fall far short of the provincial emissions reductions goal mandated by the Sustainable Development Goals Act (2019).	NS Power notes that the Net Zero 2050 emissions trajectory is designed to achieve 1.4MT of GHG emissions in 2045, and would be on a path to continue toward 0.5MT of GHG emissions in 2050 which has been assumed to meet the criteria of net-zero, with the 0.5MT of emissions being offset by another policy or action in the province.

2020 IRP - Sustaining Capital Forecast (Nominal $) (k$) - 2040 Mandatory Retirement Profile												
	Lingan 1	Lingan 2	Lingan 3	Lingan 4	Pt Aconi	Tupper	Trenton 5	Trenton 6	TUC 1	TUC 2	TUC 3	TUC 6
2021	$ 15,521	$ -	$ 4,465	$ 4,465	$ 15,719	$ 5,386	$ 6,931	$ 5,480	$ 4,130	$ 3,875	$ 11,718	$ 7,322
2022	$ 4,642	$ -	$ 5,006	$ 5,110	$ 9,794	$ 6,532	$ 12,865	$ 5,675	$ 7,030	$ 6,614	$ 4,129	$ 3,806
2023	$ 5,228	$ -	$ 5,228	$ 5,622	$ 16,797	$ 5,721	$ 28,040	$ 6,059	$ 5,449	$ 7,837	$ 5,552	$ 2,596
2024	$ 5,780	$ -	$ 8,579	$ 8,579	$ 12,196	$ 7,091	$ 6,095	$ 5,561	$ 5,175	$ 4,905	$ 4,492	$ 2,282
2025	$ 5,626	$ -	$ 16,047	$ 7,025	$ 9,454	$ 5,859	$ 6,683	$ 6,139	$ 4,782	$ 5,266	$ 6,356	$ 5,996
2026	$ 7,784	$ -	$ 4,929	$ 14,156	$ 12,250	$ 5,215	$ 6,570	$ 7,656	$ 7,535	$ 30,180	$ 4,719	$ 2,374
2027	$ 5,383	$ -	$ 4,931	$ 4,931	$ 8,817	$ 17,632	$ 5,740	$ 5,101	$ 8,049	$ 7,762	$ 3,830	$ 2,635
2028	$ 5,772	$ -	$ 6,233	$ 5,772	$ 10,231	$ 7,307	$ 8,528	$ 16,281	$ 5,470	$ 15,406	$ 4,731	$ 3,215
2029	$ 15,217	$ -	$ 5,938	$ 6,436	$ 7,923	$ 5,332	$ 7,736	$ 6,852	$ 5,714	$ 5,415	$ 11,782	$ 2,519
2030	$ 7,835	$ -	$ 6,297	$ 6,297	$ 20,190	$ 7,412	$ 15,605	$ 6,520	$ 6,203	$ 4,975	$ 6,472	$ 5,453
2031	$ 7,544	$ -	$ 5,961	$ 5,442	$ 16,426	$ 5,758	$ 7,579	$ 5,810	$ 5,034	$ 9,292	$ 10,554	$ 9,318
2032	$ 5,658	$ -	$ 5,658	$ 6,219	$ 21,168	$ 7,962	$ 7,684	$ 7,718	$ 7,999	$ 6,160	$ 6,133	$ 2,673
2033	$ 6,944	$ -	$ 6,373	$ 6,373	$ 10,968	$ 8,036	$ 7,338	$ 6,701	$ 6,040	$ 5,716	$ 7,521	$ 3,164
2034	$ 6,556	$ -	$ 23,186	$ 10,458	$ 14,867	$ 5,887	$ 7,429	$ 6,779	$ 7,389	$ 7,062	$ 5,476	$ 3,223
2035	$ 6,858	$ -	$ 8,564	$ 21,581	$ 12,119	$ 18,383	$ 9,421	$ 8,384	$ 5,829	$ 5,492	$ 6,899	$ 6,931
2036	$ 10,132	$ -	$ 6,009	$ 6,009	$ 14,423	$ 7,551	$ 6,918	$ 8,561	$ 8,754	$ 5,215	$ 4,692	$ 2,894
2037	$ 18,622	$ -	$ 6,667	$ 6,011	$ 10,748	$ 6,188	$ 6,997	$ 6,218	$ 9,811	$ 10,678	$ 8,382	$ 2,715
2038	$ 7,036	$ -	$ 7,036	$ 7,745	$ 13,141	$ 8,907	$ 23,360	$ 8,290	$ 7,931	$ 8,882	$ 8,984	$ 5,993
2039	$ 7,962	$ -	$ 7,238	$ 7,238	$ 13,444	$ 7,843	$ 8,203	$ 22,868	$ 6,965	$ 11,502	$ 9,739	$ 3,071
2040	$ 8,827	$ -	$ 8,309	$ 7,571	$ 12,724	$ 7,885	$ 8,681	$ 7,948	$ 6,436	$ 7,434	$ 6,251	$ 4,444
2041	$ 9,196	$ -	$ 6,634	$ 8,250	$ 35,548	$ 7,018	$ 10,851	$ 8,222	$ 6,137	$ 5,758	$ 17,659	$ 10,880
2042	$ 7,711	$ -	$ 6,898	$ 6,898	$ 12,389	$ 11,217	$ 7,986	$ 8,433	$ 10,877	$ 6,788	$ 5,415	$ 3,259
2043	$ 7,768	$ -	$ 25,724	$ 7,768	$ 13,370	$ 23,779	$ 8,946	$ 8,168	$ 7,362	$ 8,509	$ 6,367	$ 4,486
2044	$ 7,992	$ -	$ 12,749	$ 31,115	$ 18,969	$ 7,176	$ 10,870	$ 9,545	$ 7,691	$ 7,288	$ 8,436	$ 3,391
2045	$ 26,414	$ -	$ 10,439	$ 10,439	$ 14,049	$ 10,406	$ 9,931	$ 9,122	$ 7,105	$ 6,695	$ 14,498	$ 8,450

2020 IRP - Sustaining Capital Forecast (Nominal $) (k$) - 2030 Mandatory Retirement Profile												
	Lingan 1	Lingan 2	Lingan 3	Lingan 4	Pt Aconi	Tupper	Trenton 5	Trenton 6	TUC 1	TUC 2	TUC 3	TUC 6
2021	$ 15,521	$ -	$ 4,465	$ 4,465	$ 15,719	$ 5,386	$ 6,931	$ 5,480	$ 4,130	$ 3,875	$ 11,718	$ 7,322
2022	$ 4,642	$ -	$ 5,006	$ 5,110	$ 9,794	$ 6,532	$ 12,865	$ 5,675	$ 7,030	$ 6,614	$ 4,129	$ 3,806
2023	$ 5,228	$ -	$ 5,228	$ 5,622	$ 16,797	$ 5,721	$ 28,040	$ 6,059	$ 5,449	$ 7,837	$ 5,552	$ 2,596
2024	$ 5,780	$ -	$ 8,579	$ 8,579	$ 12,196	$ 7,091	$ 6,095	$ 5,561	$ 5,175	$ 4,905	$ 4,492	$ 2,282
2025	$ 5,626	$ -	$ 8,042	$ 7,025	$ 9,454	$ 5,859	$ 6,683	$ 6,139	$ 4,782	$ 5,266	$ 6,356	$ 5,996
2026	$ 7,784	$ -	$ 4,929	$ 5,992	$ 3,678	$ 5,215	$ 6,570	$ 7,656	$ 7,535	$ 30,180	$ 4,719	$ 2,374
2027	$ 5,383	$ -	$ 4,931	$ 4,931	$ 2,512	$ 6,547	$ 5,740	$ 5,101	$ 8,049	$ 7,762	$ 3,830	$ 2,635
2028	$ 5,772	$ -	$ 6,233	$ 5,772	$ 2,872	$ 7,307	$ 8,528	$ 6,614	$ 5,470	$ 15,406	$ 4,731	$ 3,215
2029	$ 6,595	$ -	$ 5,938	$ 6,436	$ 2,459	$ 5,332	$ 7,736	$ 6,852	$ 5,714	$ 5,415	$ 11,782	$ 2,519
2030	$ 7,835	$ -	$ 6,297	$ 6,297	$ 3,241	$ 7,412	$ 7,487	$ 6,520	$ 6,203	$ 4,975	$ 6,472	$ 5,453

Appendix L

Nova Scotia Power IRP

Draft Report Participant Engagement

Canadian Renewable Energy Association | Association canadienne de l'énergie renouvelable

November 13, 2020

CanREA Comments on Nova Scotia Power's Draft Integrated Resouce Plan Report

Introduction

The Canadian Renewable Energy Association (CanREA) is pleased to present this submission in response to the Nova Scotia Power's (NS Power's) 2020 Integrated Resource Plan (IRP) Draft Report. We appreciate the considerable work done by NS Power to develop this IRP as well as the opportunities provided throughout the process for stakeholder input. We believe that this has enhanced the IRP. Nonetheless, CanREA also believes that valuable input wasn't always given the consideration that it warranted and that this has implications for the veracity of the findings and the ability to rely on the results of the IRP for future resource planning decisions.

CanREA believes that this is particularly significant because the IRP finds that "wind is the lowest-cost domestic source of renewable energy". However, the Action Plan indicates relatively modest procurement targets for wind (50 to 100 MW) even though its cost is considerably below NS Power's current fuel charges for customers, suggesting that the procurement of additional wind would result in immediate fuel cost savings for customers.[1] As discussed further below, CanREA believes that the IRP has overstated the cost of wind and the constraints associated with integrating additional volumes of wind.

Wind LCOEs indicate Wind Assumptions Overstate Cost of Wind

In comments offered regarding the IRP assumptions CanREA (operating at that time as the Canadian Wind Energy Association) requested that NS Power indicate as part of the IRP assumptions the LCOEs for the various renewable energy resource additions.[2] NS Power responded that "LCOEs were provided in the E3 supply options study but were not included in the NS Power assumptions slides as this is not an input to the modeling tool."[3] The LCOE's shown in the E3 Supply Options Study for wind were presented graphically as a range for low and high capacity factors.[4] With a range graphically presented, it was difficult to discern how

[1] The Generation – Fuel costs in dollars per MWh vary by customers class from $56/MWh for Large Industrial Firm customers to $65/MWh for domestic customers. See Rate Breakdown by Cost of Service by Functional Areas, https://www.nspower.ca/docs/default-source/default-document-library/20200226-rate-breakdown-pie-charts-2019-aar-rates.pdf?sfvrsn=bc85c314_0

[2] LCOEs were provided in the "E3 supply options study but were not included in the NSPI Assumptions slides as this is not an input to the modeling tool."

[3] NS Power Response to IRP Comments, March 11, 2020. https://irp.nspower.ca/files/key-documents/assumptions-and-analysis-plan/20200311-IRP-Assumptions-Response-to-Comments.pdf

[4] NS Power Resource Options Study, July 2019, p. 15.

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these assumptions would be reflected in the IRP modeling and the implications on the modeling results.

The Draft IRP Report presents the LCOEs for wind that were previously requested and these are shown below in the table. These LCOEs indicate that cost of wind appears to be overstated relative to other regional price benchmarks (e.g., NB Power LORESS program and Saint John Energy Burchill Project pricing). CanREA's assessment is supported by other IRP participants. The Consumer Advocate noted that "in our previous comments that NS Power's 2019 capital cost of $2,100 per kW is outside the cost envelope suggested by Lazard. Synapse and Natural Forces also indicated that the $2,100 per kW cost was not reflective of the market." (Comments on Initial Modeling Results, p. 6 of 9). CanREA notes that Natural Forces is actively pursuing wind project development opportunities in the Maritimes and secured a long-term PPA for a 42 MW wind project in New Brunswick and based on this experience poses valuable insights regarding the current cost of wind in the Maritimes.

LCOE for Wind in Nova Scotia ($2019/MWh)

Year	Onshore	Offshore
2021	$56	$113
2030	$50	$91
2045	$44	$59

Source: Draft IRP Report, p. 76.

The fact that cost of wind appears to be overstated is significant because sensitivity analysis conducted as part of the IRP indicates that additional wind is selected when wind prices are lower. The Draft IRP Report indicates "the availability of low priced wind is shown to accelerate the wind buildout in the mid-2020s, with up to 600 MW selected under the modeled low wind price, mid-electrification sensitivity."[5]

NS Power proposes to conduct a market test to assess the cost of onshore wind. Given the apparent overstatement of the cost of wind in the IRP, CanREA believes that NS Power should commit to conducting this "market test" expeditiously. CanREA also wonders what form this market test will take, given that it's common practice in NS to rely on a procurement administrator to procure wind. Therefore, it is not clear how this market test will be performed and how NS Power can ensure that reliable pricing information will be secured. This market test is also intended to consider the cost of solar and battery energy storage systems. CanREA believes that securing more market-based pricing information for these other clean energy resources would be valuable given the pricing trends for solar and energy storage.

Furthermore, to the degree that this market pricing information indicates that the cost of these resources are lower than the assumptions reflected in the IRP, this should cause NS Power to reassess the role of solar and energy storage in its resource mix. CanREA acknowledges that this is a part of the Roadmap outlined by NS Power in its Draft IRP Report: "Continue to track the installed costs of wind, solar, and energy storage to look for variations from the trajectories established in the IRP (in particular, monitoring for divergence from the "Base" to the "Low"

[5] (p. 125)

pricing scenarios). NS Power will solicit Nova Scotia-based market information which will inform this as needed." (p. 135)

Wind Procurement Strategy calls for System Stability Studies

Another area where CanREA offered comments that weren't adequately addressed by NS Power is with respect to the ability of wind and other non-synchronous inverter-based resources to provide frequency response services and by so doing to reduce the inertia constraints and resulting requirements for fossil generating units to be available to provide inertia. CanREA offered a series of comments on the ability of wind to provide regulation services that could allow wind to reduce the inertial constraint that NS Power identified. NS Power made one modest change in how it modeled wind recognizing that wind can provide a regulation down service.

A number of parties also critiqued the PSC study that was used to establish the constraint of 700 MW of wind without additional infrastructure investment. These parties assert that how NSPI has reflected the findings from this study in its modeling as overly conservative. (See in particular comments offered by Telos Energy on behalf of the Consumer Advocate.)[6]

In the PSC Study the loss of the New Brunswick intertie during high levels of imports is the most severe contingency. To mitigate operating risks, PSC evaluates scenarios that reduce or limit wind generation and increase thermal generation to provide inertia to cover the potential loss of the tie. CanREA notes that reducing imports over the NB intertie may be a more effective remedy than reducing wind given that these imports will have a higher incremental cost than the wind generation and reducing these flows on the tie will reduce the severity of the contingency.

To address these and other issues, NSPI includes as part of its Wind Procurement Strategy a plan to conduct system stability studies to evaluate how much additional wind can be added. To achieve greater consensus regarding such studies CanREA recommends that NSPI conduct such a study with stakeholder input similar to the IRP. This is best practice and should increase stakeholder confidence in the findings from the study. CanREA encourages NSPI to begin work on these studies soon given the value that additional wind offers Nova Scotia customers.

Finally, CanREA observes when conducting such a study appropriate consideration should be given to various operating strategies to more cost-effectively manage identified operating constraints. For example, the PSC Study doesn't support that the <u>installed capacity of wind</u> must be limited to 700 MW, but that under certain operating conditions, which actually appear to be quite rare, the <u>output of wind</u> should be limited to 700 MW. Therefore, CanREA believes that more than 100 MW of additional wind could be procured (The approximate quantity identified by NS Power in its Wind Procurement Strategy, but which very likely will increase when appropriate consideration is given to the ability of wind resources to provide regulation services and other deficiencies in the PSC Study are addressed.), but when more than 700 MW was available during system conditions that posed reliability risks (e.g., low loads) then

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[6] NS Power, IRP Comments received from Participants in response to Modeling Results. https://irp.nspower.ca/files/key-documents/modeling-results/IRP-Participant-Comments-Modeling-Results-July-2020.pdf

wind output greater than 700 MW could be constrained down after imports were reduced. When curtailed, these wind turbines would be available to provide primary frequency response, offsetting at least in part costs associated with such a curtailment.

While there would be a cost to this, this cost can be assessed. However, the fact that wind generation is the lowest cost domestic renewable generation resource and the limited number of hours when the conditions occur suggests that even with this incremental cost, additional wind is likely to be economically attractive.

In Summary

CanREA appreciates this opportunity to comment on the Draft IRP Report and welcomes the opportunity to work with NS Power in implementing the various initiatives identified in the IRP.

Thank you for your consideration of this submission, we look forward to additional dialogue on this important file and we remain availbe to meet at any time to discuss further.

Sincerely,

Brandy Giannetta
Senior Director Ontario & Atlantic Canada
Canadian Renewable Energy Association

Resource Insight Inc.

MEMORANDUM

To: Nicole Godbout, Director, Regulatory Affairs
Nova Scotia Power

From: John D. Wilson and Paul Chernick

Date: November 16, 2020

Subject: Comments on Draft IRP Report

Thank you for the opportunity to comment on the Draft IRP Report. We also appreciate the stakeholder engagement which has contributed substantially to our understanding of the plans. NS Power has demonstrated significant responsiveness to input from stakeholders.

Although the Draft IRP Report and the response to comments did not resolve many of our most important concerns, we have gained a better understanding of NS Power's current thinking and we hope that an improved articulation of our concerns will convince NS Power to adopt our recommendations.

Summary of RII Recommendations

1. Short-Term Action Plan

a. NS Power should plan for an aggressive near-term all-source request for proposals (RFP), including an opportunity for up to 700 MW of wind by 2025, to be conditioned on price and performance thresholds, and evaluated in coordination with transmission and system inertia solutions. (Page 4)

b. NS Power's action plan should commit to planning for potential transmission projects in parallel to both additional study of wind integration as well as the recommended all-source RFP. Using an improved understanding of system inertia and other reliability service topics, the resulting costs and capabilities of the Reliability Tie, operating practices for wind integration, and domestic technology options (battery storage/synchronous condensers) should be used in the evaluation of the all-source RFP bids. (Page 6)

c. NS Power should incorporate updated data from resource procurement and transmission planning into any capital application for redevelopment of the Mersey hydroelectric facilities. Any resulting delay would be justified given the uncertain value of the redevelopment project. (Page 8)

d. NS Power's action plan should include a specific commitment to develop and propose transportation and building electrification pilot projects. (Page 10)

e. NS Power should include in the Final IRP Report an order of magnitude estimate of the level of cost that might be tolerable for its customers to bear to promote electrification, as well as a discussion of cost savings for other fuels and other non-electric system benefits. (Page 11)

f. NS Power should update its action plan to include the development of T&D cost forecasts involving electrification and DSM at varying levels. (Page 11)

2. Board Requirements

a. NS Power should update its planning reserve margin findings to reflect the final IRP modeling assumptions. (Page 12)

b. NS Power should undertake several actions to confirm and periodically re-evaluate its findings regarding the diesel combustion turbine fleet. (Page 13)

c. NS Power should fully document a resolution to the issue of high operating-reserve surpluses raised in the FAM audit process.(Page 14)

3. Editorial and Unresolved Technical Comments

a. NS Power should adopt a definition of electrification and principles for maximizing its benefits as developed by the Regulatory Assistance Project. (Footnote 18)

b. NS Power should net avoided transmission and distribution costs from DSM costs based on methods developed in the DSM advisory group. (Page 15)

c. NS Power should verify that model performance of run-of-river hydro units is consistent with the operational record, and consider any appropriate adjustments to ELCC values and model results. (Page 15)

d. NS Power should address the omission of potential limestone quarry expansion costs from the sustaining capital estimates for Point Aconi. (Page 17)

e. In future IRP modeling analyses, NS Power should incorporate a shadow price for CO_2 emissions. (Page 17)

f. NS Power should engage with stakeholders to better define an "evergreen IRP process." (Page 17)

g. NS Power should better explain its findings regarding the role of solar generation in its IRP. (Page 18)

4. Rate Impact Model

a. NS Power should correct its rate impact model, as incremental fixed cost recovery should not be deducted from the revenue requirement when forecasting system rates. (Page 19)

b. NS Power should include a sensitivity reflecting the likelihood that the revenue requirement associated with existing non-fuel costs will decline over time. (Page 19)

c. NS Power should not rely upon the relative rate impact comparison analysis as the basis for recommending any level of DSM program investments. (Page 20)

Short-Term Action Plan

RII concurs with a substantial portion of the Short-Term Action Plan, including the treatment of plant retirements, demand response, and DSM avoided cost calculation methods.[1] We have some discussion of further steps and improvements that NS Power should consider including in the final IRP report below.

In this section, we emphasize areas where we think NS Power needs to significantly adjust its IRP plan in order to ensure that it maximizes the opportunities for cost savings consistent with the ongoing system transformation that NS Power has laid out. The major decisions to be made in the next few years relate to additional resource procurement, investments in transmission and wind integration strategies, and whether or not to redevelop the Mersey hydro facilities.

RII recommends that NS Power develop a more definitive strategy in each of these three areas, in order to ensure that appropriate investment decisions are made in a coordinated fashion. Furthermore, we recommend that as part of the "Evergreen" approach to resource planning, NS Power should explicitly commit to conducting an updated IRP modeling analysis as part of any major strategy updates in these three areas and definitely as part of related capital investment applications. In the case of Mersey, the normal ACE Plan Economic Analysis Model should not be considered sufficient considering that the decision of Mersey life extension is a close call economically.

[1] As discussed below, NS Power should net avoided transmission and distribution costs from DSM costs based on methods developed in the DSM advisory group. RII also concurs with EfficiencyOne that the DSMAG is a logical venue for completing the determination of avoided costs for DSM planning.

We also identify some additional structure that we believe should be added to the electrification strategy.

Near-Term Resource Procurement

RII recommends that NS Power should plan for an aggressive near-term all-source request for proposals (RFP), including an opportunity for up to 700 MW of wind[2] by 2025, to be conditioned on price and performance thresholds, and evaluated in coordination with transmission and system inertia solutions as discussed below.[3] The much smaller, wind-only procurement described in the Draft IRP Report excludes the potential near-term savings opportunity from a larger procurement that would be merited if bid prices are lower than expected. NS Power should not merely "solicit Nova Scotia-based market pricing information" but should pursue potential near-term opportunities to reduce system costs.[4]

NS Power has maintained a lower, near-term procurement cap even though "NS Power agrees that the modeling indicates that the low wind pricing has a larger impact on expansion decisions than the reliability inertia constraint."[5] RII believes this finding is as robust as the support for the Reliability Tie and should receive equal emphasis. Appropriate edits should be made throughout the report.

Simply soliciting "Nova Scotia-based market pricing information" is insufficient; it is our understanding that NS Power considered such information in adopting its

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[2] Model cases 2.1C.WIND-1 and WIND-2 suggested 631 MW and 676 MW of wind in 2025, respectively. In addition to new wind, the RFP should also be open to repowered wind.

[3] RII disagrees with NS Power's statement that "The IRP scope does not include findings or recommendations on specific procurement approaches." The overall design of near-term resource procurements is very much a key task to implement the strategy identified in NS Power's IRP. The IRP would be deficient if it failed to identify how NS Power expected to proceed with near-term actions in a manner that is specific enough for the Board to hold it accountable should it fail to act accordingly. RII recommends an all-source procurement in which no resource technology is excluded. The identified goal should be to fulfill the load forecast and unit retirement forecast of NS Power in a manner that reduces costs and maintains (or improves) reliability. As discussed later in these comments, these objectives should be co-optimized with the parallel transmission and system inertia planning activities.

[4] The Draft IRP Report states that NS Power will, "Initiate a wind procurement strategy, targeting 50-100 MW new installed capacity by 2025 and up to 350 MW by 2030. This strategy will solicit Nova Scotia-based market pricing information which will inform the selected wind capacity profile and timing, informed by the IRP wind sensitivities." Draft IRP Report, p. 133.

[5] Stakeholder Comments Matrix (November 6, 2020), p. 2.

IRP pricing assumptions. Since NS Power agrees that new installed capacity by 2025 is desirable, engaging in a solicitation with the stated intent (but not requirement) to procure up to 700 MW of wind by 2025, depending on pricing and other considerations, is a no-lose proposition for NS Power customers.

In addition to wind, it is also critical to test the market for firm imports and gas peakers. Most scenarios suggest that NS Power will find it economical to procure about 165 MW of firm imports, but a wide range of near-term gas peaker procurements are indicated. In the Low Wind Cost scenario, the model indicates a benefit from procuring 365 MW of firm imports in 2026 and relatively low gas peaker procurements. Yet in the Low Wind & Battery Cost scenario, those firm imports are replaced by 400 MW of new gas CTs. These indications of how resource costs can have divergent results in the overall combination demonstrate that a series of single-source procurements is not advisable because the most economical mix of resources will depend on actual bids.

If the resources that bid into the RFP are more advantageous than NS Power's baseline assumptions regarding cost and performance,[6] then NS Power will not only have the necessary market pricing information, but the opportunity to act on that information immediately to the benefit of its customers. The appropriate level and pricing of any acquisitions can be confirmed through further Plexos modeling of the bids, reflecting the necessary wind integration strategy, as discussed below.

In contrast to wind, the modeling results suggest that price is not the main determinant of the role of battery storage resources. While battery resources should be eligible for the all-source procurement, NS Power's primary focus for this technology should be to understand better the value that battery resources may have for the system in the near term.[7] Case 2.1C suggests that only relatively modest battery resources are economic at current price levels. The sensitivity results a tradeoff between imported power and battery resources. Thus, even though battery storage is unlikely to make up a large share of NS Power's

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[6] It is unlikely that NS Power will receive uncompetitive proposals. NS Power's commendable transparency during the IRP process should provide potential bidders with a clear indication as to the approximate price ceiling and unit performance guarantees required for success in any solicitation.

[7] Although the IRP modeling did not indicate that compressed air energy storage would be economical for the NS Power system, Hydrostor argues that the cost and performance assumptions used in the model constrained the opportunity for a more favorable review. Hydrostor comments (September 18, 2020), pp. 1-2. An all-source procurement would provide Hydrostor and any other competing developers of such resources the opportunity to define the costs and performance characteristics of such technologies for further evaluation.

portfolio in the near term, it should be included in the all-source procurement process because successful battery storage bids could influence the relative value of other bids, including the reliability link.

Transmission and wind integration planning

RII recommends that NS Power's action plan should commit to planning for potential transmission projects in parallel to both additional study of wind integration as well as the recommended all-source RFP.[8] Cost estimates for completion of the Reliability Tie for various in-service dates (covering the range from the earliest feasible date to 2032) should be developed. The costs and capabilities of various other wind integration strategies should also be planned. The resulting costs for all of these options should be used in evaluating the all-source RFP bids in order to co-optimize generation resources, grid investments, and operating practices.

The IRP Report does not provide conclusive evidence as to the optimal strategy for wind integration. In part, this is because the IRP process did not evaluate the role of curtailments, fast frequency response, and other operational practices and technologies that could facilitate higher levels of wind integration. NS Power emphasized its concern about maintaining adequate system inertia during unusual operating conditions.

RII supports further planning and evaluation of three strategies to provide for wind integration and other reliability benefits, including:

- An early in-service date for the Reliability Tie;
- Operating practices such as application of fast frequency response technology, reliability curtailments, and pre-curtailment of wind resources for operating reserve purposes;[9] and
- A combination of lower battery prices and synchronous condensers.[10]

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[8] NS Power mischaracterized this comment by truncating it and placing it out of context. Please correct the characterization. Stakeholder Comments Matrix (November 6, 2020), p. 3.

[9] RII appreciates that "NS Power will consider the comment on … whether different operating limits could be enforced in advance of wind integration measures …" Stakeholder Comments Matrix (November 6, 2020), p. 2.

[10] It is worth noting that the synchronous condensers were included in the results from only one model run, the No Reliability Tie sensitivity. This could indicate that synchronous condensers are a poor economic fit for the NS Power system, but the cost difference between the sensitivity and base case was relatively small. This technology solution has been frequently adopted by other utilities, and thus should not be discarded

These three strategies may be employed in combination. One approach could be to sequence their deployment, relying on operating practices during the early stages of expanded wind development that could result in relatively large curtailments, with subsequent installation of the Reliability Tie[11] and other technologies enabling fuller use of the energy produced by wind turbines.

Ideally, these three strategic options would be cost out through an RFP or via engineering estimates by potential suppliers. However, it may be advisable to use less refined cost estimates for purposes of narrowing options and making decisions regarding procurements from the all-source RFP. The timing of these activities will need to be coordinated to balance the need to move forward with some procurements against the time required to develop a full understanding of transmission and wind integration options.

As part of the evergreen planning process, more in-depth investigation of the system inertia question is called for. The CA provided NS Power with comments from Telos Energy questioning some of the scenario selections in the PSC Reliability Study. To a significant extent, Telos Energy's findings support the idea that operating constraints could resolve many, if not all, of the concerns raised regarding system inertia. This analysis should be coordinated with further Plexos modeling since, as NS Power acknowledges, some of the IRP results do not demonstrate the expected relationship between inertia and modeled in-service dates.[12]

If the inertial constraints can be satisfied by a combination of wind curtailment and other operating limits, additional battery storage (especially if battery prices are lower than assumed in the IRP), and synchronous condensers, NS Power could develop operating experience demonstrating that the system can be operated reliably with early retirement of additional thermal units. NS Power comments that "…it is likely that inertia and reserve constraints have an influence on retirement

prematurely. With further study, NS Power may identify a role for synchronous condensers in combination with measures not studied in the IRP.

[11] A later in-service date for the Reliability Tie could be desirable since NS Power would be able to defer costs until the impacts of the electrification strategy are manifest, minimizing customer bill impacts.

[12] In response to RII's comment on the relationship between in-service date for the reliability tie and system inertia sensitivity assumptions, NS Power acknowledged that the Limited Reliability Tie Inertia sensitivity advanced the build of the Reliability Tie by 2 years. Since the Reliability Tie provides fewer benefits in this sensitivity at the same cost, an earlier in-service date is a counter-intuitive result that could indicate some issue with the modeling environment. Stakeholder Comments Matrix (November 6, 2020), p. 3.

pace…"[13] Exploration of options other than transmission connections may reveal that NS Power can retire steam plants sooner and acquire more wind resources, while reducing costs to customers.

While NS Power notes that it modeled the Reliability Tie as providing only synchronized inertia (enabling additional wind integration), it may provide other benefits, such as reserves, load following, or non-firm import capability. Furthermore, the modeling suggests that the inertia provided by the Reliability Tie reduces the need to keep steam units online at minimum load. Comparing several model runs, it appears that when fewer unit commitments for reliability purposes are needed, the reduction in unit commitments results in a shift from domestic thermal generation to less-expensive imported energy.

These direct and indirect effects of the Reliability Tie should be further explored in the planning analysis, with initial findings coordinated with the recommended all-source RFP. If non-domestic supplies are enabled by the Reliability Tie, developers of such resources may wish to bid into the RFP based on varying assumptions about the completion date for the Reliability Tie.

Planning for the Regional Interconnection should be handled similarly, except that there will be need for fewer in-service date options and accompanying cost estimates since the near-term resource acquisitions should be less sensitive to the exact date and cost estimate. In light of some of the sensitivity results, the potential in-service dates for this project should be expanded to cover 2028–2040. NS Power should obtain design and construction pricing for an in-service date of 2028, and then use that cost information to develop informed estimates of costs for later in-service dates.

Mersey hydro retirement evaluation

The Board recognized the importance of evaluating the continued operation of NS Power's hydroelectric facilities in the IRP process in the recent Annual Capital Expenditure Plan review.[14] NS Power also committed to IRP review in support of the Mersey Redevelopment project, with an anticipated total budget of $161 million, anticipated to be submitted later this year.[15]

It is our understanding that NS Power intends to use the results of its Plexos modeling for the 2.1C.Mersey case to provide key inputs into the replacement

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[13] Stakeholder Comments Matrix (November 6, 2020), p. 4.

[14] NSUARB, *Decision Approving Nova Scotia Power's Annual Capital Expenditure Plan for 2020*, Matter No. M09499 (June 25, 2020), p. 15.

[15] *Id.*, p. 10.

energy cost for hydro generation used in the Company's economic analysis model. This sensitivity appears to indicate that customers would experience a slightly higher cost ($44 million) to retain Mersey through 2045, even with a $227 million cost to decommission Mersey.

Although redevelopment of Mersey hydro does not provide customer benefits during the planning period, NS Power staff highlighted that customers could benefit in the long run. The end effects calculation shows an economic advantage to retaining Mersey beyond 2045, assuming that the redevelopment project could provide a very long-lived asset, on the order of a hundred years. We are not convinced that extrapolating the 2045 revenue requirement indefinitely is realistic. Mersey might require additional capital projects, or even further redevelopment investment. Furthermore, the end effects calculation does not take into account the likelihood that Mersey would eventually be decommissioned. Additional consideration of Mersey's long-term costs is thus warranted..

We understand that the IRP is not the venue for making a decision on the potential redevelopment of Mersey hydro. Nonetheless, NS Power has committed to reviewing this issue in the IRP and using that as an input into its submission for capital investment at Mersey. The final IRP report should include a thoughtful discussion of the findings, clarifying the limits to the conclusion that should be drawn from the IRP study.

Instead, the Draft IRP Report appears to begin with the presumption that the Mersey redevelopment will go forward.[16] This is the case even though the Draft IRP Report acknowledges that the benefit-cost comparison, when considered over different durations, leads to different and "very close" results.

It is also worth emphasizing that this analysis was conducted using the base case assumptions for the cost of wind. As Mersey provides primarily energy benefits to the NS Power system,[17] the evaluation of any capital applications for Mersey system refurbishment must rely on better understanding of wind and transmission development costs.

In summary, RII recommends that NS Power should conduct further modeling using updated data from resource procurement and transmission development

[16] For example, "The specifics of the redevelopment plan and the business case supporting this investment will be outlined in a future capital work order and regulatory filing." Draft IRP Report, p. 73.

[17] RII is not yet convinced that Mersey merits a 95% ELCC value, and NS Power notes that the impacts of retiring Mersey are primarily on wind and the Regional Integration project.

planning be conducted, rather than simply relying on the Economic Analysis Model when filing any capital application. RII recognizes that waiting for further data may introduce delay into the capital application process, but given the uncertain value of the redevelopment project, RII suggests that such a delay may avoid a poorly made decision.

Electrification plan investment strategy

NS Power is to be commended for making electrification a central part of its IRP. The Draft IRP Report provides appropriate policy, business, and analytic support for giving high-level strategic attention to electrification.[18]

Nonetheless, the Draft IRP Report does not present a sufficiently detailed action plan to implement its electrification strategy. The Draft IRP Short Term Action Plan proposes three steps: “understand options,” “collect detailed data,” and address transmission and distribution (T&D) impacts. NS Power should add a fourth step, propose pilot programs, as well as providing additional detail, especially regarding potential T&D impacts.

The action plan should specifically commit NS Power to develop and propose pilot projects. Of course, some modest efforts have, in fact, already begun. RII recommends that the action plan include a commitment to develop and propose pilot programs to offer incentives or direct installation of transportation electrification infrastructure and similar investments in building electrification across a range of markets. Furthermore, electrification should not be limited to residential, commercial, and on-road transportation. The industrial and maritime sectors also provide opportunities and should be involved early in the development of electrification programs. Nonetheless, the pilot programs should be limited in scale, designed to provide insights into options for NS Power and the Province as well as customer response.

Looking beyond the scope of the near-term action plan, it is reasonable to assume that higher levels of electrification will require NS Power to make even more substantial investments. These investment costs are likely to come in two areas, full electrification programs (transportation and building, and potentially other sectors), and T&D investments.

[18] In its comments filed on November 13, EfficiencyOne suggests that NS Power should adopt a definition of electrification and principles for maximizing its benefits as developed by the Regulatory Assistance Project. RII concurs with this editorial suggestion.

Longer-term electrification program costs

We expect (and we believe NS Power agrees) that some funding of electrification programs would be required to achieve the higher levels of electrification studied in the IRP. Ratepayers are likely to bear the costs of those programs, but they have not yet been studied or costs developed.

Nonetheless, the IRP Report should not remain silent on the question of longer term electrification programs even as it speaks to longer term generation portfolios. Electrification is a key part of most greenhouse gas reduction strategies. For example, we understand that the Halifax Municipality has ambitious goals with respect to electrification. We believe that the IRP is an appropriate document from which to set out an initial understanding of what level of program costs might be reasonable from a rate impact perspective.

RII recommends that NS Power include in its Final IRP Report an order-of-magnitude estimate for the level of cost that might be tolerable for its customers to bear to promote electrification. As noted in the draft findings, "Increased electricity sales due to electrification can help to reduce upward pressure on electricity rates while facilitating carbon reductions in other sectors."

The design and costing of potential programs is out of the scope of the IRP. We are recommending that NS Power utilize its rate impact model (as discussed below) to identify the impacts on rates that might result from plausible levels of program investment in electrification.

Given the diversity of the possible futures, RII recognizes that this question cannot be answered with certainty or exactitude. However, an order of magnitude estimate of the annual investment that might begin to cause upward pressure on rates would be informative to the Board and stakeholders.

While upward pressure on rates is an important consideration, we would also encourage the Board to consider that electrification may also have significant benefits to participants – such as cost savings for other fuels – and to Nova Scotia at large – by reducing the pressure for carbon reductions in other sectors. The perspective of the province as a whole can be captured in a total resource cost test. While this is clearly beyond the scope of the IRP, we encourage NS Power to acknowledge – perhaps with an illustrative graph – that these benefits exist, to avoid creating the impression that rates should be a singular basis for deciding how much electrification may be considered affordable.

T&D requirements

The other area of significant costs related to electrification will be T&D costs. While the Draft IRP Report discusses the intent to "address electrification impacts on the T&D system," much more is needed over the near term. One significant shortcoming of this IRP analysis is that it lacked a meaningful way to estimate the costs of additional T&D required to fulfill the varying levels of electrification.

The costs of expanding the T&D system to accommodate load growth is a topic of discussion in the DSMAG, where considerable effort has been expended to develop an improved estimate of the T&D costs avoided by DSM programs. Looking forward, one obvious way to manage the cost of electrification-driven T&D is to implement DSM programs that offset some or all of the additional load.[19] To a very real extent, T&D and DSM programs will complement each other, and NS Power needs to identify meaningful tools to conduct the planning that optimizes that balance correctly.

RII recommends that NS Power update recommendation 2c, and commit to development of T&D cost forecasts for several of the different scenarios involving electrification and DSM at varying levels. This will be necessary to inform those program investment decisions.

Status of Board Requirements

Optimal planning reserve margin

NS Power has agreed to resolve the question of its optimal planning reserve margin in response to an audit recommendation by Bates White.[20] NS Power's position is that the E3 study from July 2019 adequately resolves this question.[21] NS Power asserts that the updated DAFOR rates for thermal units and updated ELCC contributions are "minor data updates" and that as other key inputs to determining the target PRM have not changed, the study remains valid. NS Power further asserts that the updated PRM calculations completed on the three 2045 resource portfolios showed that the 9% UCAP PRM was sufficient.

If NS Power identifies further issues with respect to the ELCC for run-of-river hydro units, as discussed below, these would be additional "minor data updates" that could potentially affect the PRM calculation.

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[19] It may also be possible to reduce the T&D costs of electrification if the new uses can be controlled in a manner that minimizes the additional stress of T&D equipment.

[20] Bates White, *Audit of Nova Scotia Power, Inc.'s Fuel Adjustment Mechanism for 2018-2019*, Exhibit N-1 Matter No. M09548 (August 21, 2020), pp. 225-226.

[21] Stakeholder Comments Matrix (November 6, 2020), p. 5.

The July 2019 study may well approximate NS Power's required planning reserve margin. However, it is not clear that the analysis is sufficient to demonstrate that NS Power has achieved an "optimal" planning reserve margin.[22]

It should be a relatively simple matter to utilize the RESOLVE model, as currently configured (or corrected for any errors in the ELCC for run-of-river hydro units), to repeat the essential elements of the July 2019 study and verify or correct the findings, as appropriate. This will provide the Board with assurance that future procurements and capital investment activities are evaluated while relying on optimal assumptions.

Analysis of the combustion turbine fleet

In the 2016–2017 FAM audit process, NS Power agreed to "include an evaluation of the costs and benefits of the combustion turbines in its fleet in the upcoming 2019 IRP."[23] In Section 4.2.2.1 of the Draft Report, NS Power asserts that there is a conclusive case in favor of the continued operation of the diesel CT fleet.

Meanwhile, evidence in the 2018–2019 FAM audit indicates that these units were less reliable than expected; nonetheless, the combustion turbines were being called on more often than NS Power forecasted.[24] The evidence from the FAM audit and the analysis in the Draft IRP Report leaves us with two concerns about the future of the combustion turbine fleet, and whether the IRP reasonably forecasts the continued operation of all the units throughout the planning period.

First, NS Power mentions ongoing investments in the diesel combustion turbine fleet, such as oil cooling systems. It is not yet clear how that these investments have corrected the poor reliability of these units, or how long they can maintain adequate combustion turbine performance.

Second, if the combustion turbines continue to operate more than estimated in the Plexos modeling, the O&M and sustaining capital costs may be higher than Plexos reports. Depending on the amount that the combustion turbines are used and the resulting costs, as well as the future cost of distillate oil, adding new storage or other resources may be less expensive than continued operation and rebuilding of the combustion turbines.

To be clear, we agree with the Draft IRP Report that the combustion turbines are likely to be worth maintaining over the near term. The questions of longer-term

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[22] Bates White, *Audit of Nova Scotia Power, Inc.'s Fuel Adjustment Mechanism for 2018-2019*, Exhibit N-1 Matter No. M09548 (August 21, 2020), p. 225.

[23] *Id.*, p. 229.

[24] *Id.*, pp. 205-207.

maintenance and the consistency of the Plexos model with operational practices require further consideration.

Accordingly, RII recommends that NS Power:

- Provide further evidence in the FAM audit proceeding regarding the performance of its refurbished diesel combustion turbine units;
- Provide data to RII and other interested stakeholders data comparing the modeled operational profile (capacity factor, operating hours, number of unit starts, etc.) to recent historical data;
- Further evaluate the longer-term sustaining capital forecast for the diesel CT fleet as part of its evergreen IRP process; and
- Periodically re-evaluate CT economics as the cost of storage falls, and especially if the units are using substantial amounts of fuel and the cost of their fuel rises significantly.

Operating surpluses and inefficient dispatch

In the two most recent FAM audits, Bates White found "evidence that NSPI was carrying surpluses of operating reserves and that this may increase costs to FAM customers."[25] Bates White found that "the Day-Ahead and Real-Time schedules created by the marketing desk frequently differ substantially and persistently from the actual dispatch of the generating units." Bates White's audit discusses several findings that could be leading to inefficient dispatch, which overlaps with the surplus operating reserve issue.

Bates White states that NS Power has agreed to document instances of high operating-reserve surpluses, to help inform the IRP process and resolve the apparent operating-reserves surplus.[26] We have not seen the information in the IRP process that would resolve this issue.

In addition to Bates White's concerns about overall reserve levels, some of those operating reserves are held at hydroelectric facilities. Maintaining operating reserves at those facilities during periods with high operating costs may result in unnecessary dispatch of higher cost thermal units; conversely, using hydro facilities to provide operating reserves may reduce the need to commit steam plants for reserve.

RII recommends that NS Power resolve the FAM audit issue prior to publishing the Final IRP Report, or commit to resolve the issue in a timely manner.

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[25] *Id.*, pp. 185, 257.

[26] *Id.*, pp. 267-268.

Unresolved Technical Comments

T&D avoided costs

As discussed in EfficiencyOne's comments of November 13, the recently agreed-to avoided costs of T&D could easily be applied to the modelling metrics (NPVRR and rate impact results). RII concurs with EfficiencyOne, and recommends that NS Power update the Final IRP Report to include a credit for DSM for avoided T&D costs .

ELCC for run-of-river hydro units

In two prior memos, we questioned the 95% ELCC for run-of-river hydro units. NS Power has clarified that its staff believes that other than Wreck Cove, "all other hydro assets on the NS Power system include sufficient pondage as to be equivalent to firm capacity."[27] It is our understanding that the run-of-river hydro unit ELCCs are derated for DAFOR only, leaving such operational limitations as reduced capacity at multiple units in dry years and the limited hours of daily operation at full load to other aspects of modeling. Other utilities rate hydro facilities based on their performance under drought conditions, and for output levels that can be sustained through the daily peak period.

NS Power's response to our concerns discusses how its modeling also includes various constraints that reflect operational capabilities. As we noted in our prior comments, our analysis supports a lower ELCC for run-of-river hydro units.

As shown in Table 1, dispatch of hydro units increases from peak hours to the hours representing the highest 1.1% of net loads (i.e., load minus wind output), and then again to the top 0.1% of net peak hours. This supports a finding that system operators are increasing small-hydro dispatch in response to resource needs.

Table 1: NS Power Generating Unit Capacity Factors

	Peak Hours		**Net Peak Hours**	
	Top 1.1%	**Top 0.1%**	**Top 1.1%**	**Top 0.1%**
Mersey	70.6 %	66.2 %	71.6 %	77.3 %
Hydro Group 1	69.2 %	69.0 %	71.3 %	77.1 %
Hydro Group 2	51.1 %	52.5 %	55.0 %	63.2 %

We are struck by how much the capacity factors in peak hours differ from the 95% ELCC that NS Power estimates. Perhaps low reservoir levels reduce the capacity of the plants in some years, or limited water flow limits the number of hours for which the dispatchable units can operate in a day or year.

[27] Stakeholder Comments Matrix (November 6, 2020), p. 8.

It may be that the discrepancy between the claimed ELCC and the actual performance of the small hydro units can be explained by the modeling of the reserve constraints. One way that this could be tested would be to report the maximum hourly capacity factors and average net-peak-hour capacity factors for each unit in the Plexos modeling. NS Power should provide these data to RII and any other interested stakeholders.

For context, here are some possible outcomes of the analysis.

If the modeling data are consistent with the values identified in Table 1, the discrepancy between the claimed ELCC and the actual performance can be explained by:

- Economic withholding of small hydro for reserves at times of net peak, or
- Water resource limitations that limit both the model and actual operations from fully utilizing the full capacity represented by the claimed ELCC.

If the water resource limitations are the main explanation, then it appears to us that the claimed ELCC leads to an inconsistent impression as to the actual level of capacity that can be relied upon.[28] In this case, NS Power should follow up to determine how the water resource limits reduce the ELCC in normal and dry years in order to present the ELCC in a consistent manner for all intermittent resource types.

On the other hand, if the modeling data and historical performance data are inconsistent, then NS Power should determine whether the inconsistency is due to:

- Suboptimal operating practices, in which case NS Power should improve its operating practices; or
- Incorrect modeling assumptions and constraints, in which case NS Power should revise its assumptions or constraints in Plexos and RESOLVE.

We do not expect that any necessary changes would substantially affect the short-term action plan or the overall findings of the IRP, but any necessary refinements could reduce the benefit of keeping marginal hydro units on line, support slightly different quantities or types of near-term procurements, or increase the value of energy storage.

[28] In the case of wind, resource limitations are considered in determining the ELCC, so it would seem inconsistent if water resource limitations are not a factor in determining the ELCC for run-of-river hydro.

Sustaining capital cost for Point Aconi

We previously commented on an inconsistency between the capital cost profile assumptions for Point Aconi and information provided in the recent FAM audit by Bates White.[29] Point Aconi may require an expansion of its limestone mine in eight years, which could require significant additional investment. NS Power confirmed does not appear to be reflected in the IRP capital cost profile assumptions.[30] The Final IRP Report should at least acknowledge this omission and indicate whether avoiding the costs of the mine expansion might make Point Aconi an earlier candidate for retirement, among the coal units.

Monetize CO_2 emissions reductions

The vast majority of the model results indicate that it will be cost-effective for NS Power to operate with lower CO_2 emissions than required by regulation and law. These emissions reductions have value, as recognized by NS Power's adoption of a shadow price for CO_2 emissions in its dispatch practices.[31] Optimization of the capacity and production cost forecasts depends on accurate representation of any costs or values that may occur in practice.

On the other hand, forecasting such a shadow price involves significant assumptions—more significant than those involved in fuel cost forecasts, for example. The market structure for valuing excess CO_2 emissions is still evolving, it will be difficult to construct a market-based forecast for that value. In its response to comments, NS Power commits to tracking and monitoring this issue.[32]

We recommend that NS Power go further, incorporating a CO_2 price into its future IRP modeling. Such a CO_2 value may well be material to the evaluation of bids in an all-source RFP, for example.

Evergreen IRP process

This IRP is being completed six years after the previous IRP, which is clearly far too long between planning updates. In the Draft IRP Report, NS Power suggests and evergreen planning process, with "annual updates … and as Action Plan items are completed." It is unclear what NS Power meant by Action Plan items being

[29] Bates White, *Audit of Nova Scotia Power, Inc.'s Fuel Adjustment Mechanism for 2018-2019*, Exhibit N-1 Matter No. M09548 (August 21, 2020), p. 222.

[30] Stakeholder Comments Matrix (November 6, 2020), p. 9.

[31] Bates White, *Audit of Nova Scotia Power, Inc.'s Fuel Adjustment Mechanism for 2018-2019*, Exhibit N-1 Matter No. M09548 (August 21, 2020), p. 236.

[32] Stakeholder Comments Matrix (November 6, 2020), p. 11.

completed, considering the ongoing scope of most of the Action Plan items. The term “evergreen” suggests a frequent update process, with many small changes, rather than a long process cycle.

This is an interesting idea, and we look forward to its further development, including a description of the scope of the annual updates, the consultation process, and the nature of developments that would trigger more detailed or extensive review.

NS Power should engage with those stakeholders who have been most active in the IRP process to better define what an “evergreen IRP process” might look like. The outcome of this stakeholder engagement should be taken to the Board for its comment or direction.

Solar resource analysis

In the workshop presentation, NS Power provided a brief summary explaining why there is “very limited solar generation in the resource plans.” While this topic is adequately explored at various points throughout the draft report, there is no prominent section of the report that adequately explains this finding to the public. This will be of considerable interest to many stakeholders.

RII recommends that Section 1.9 be edited significantly. First, there is no clear delineation between the Action Plan and the Roadmap. Second, this would be an appropriate place to explain why solar generation is not a significant element in the Action Plan and Roadmap. This could be done in a text box, or in a short subsection. In either case, NS Power may also wish to note that its IRP analysis is not specific regarding the technologies that may supply the emissions-free Canadian-sourced imported energy, and thus solar may be a significant, albeit non-specified, resource for NS Power in the future via non-firm imports.

Rate Impact Model

RII is appreciative of NS Power’s approach to rate impacts in the IRP. The IRP is not the place for a detailed examination of long-term rate trends. We acknowledge and support the very simple approach that NS Power has taken in this respect, just as we also work with NS Power and other parties to design appropriately sophisticated rate impact forecasts in other venues.

Nonetheless, RII recommends that NS Power make two changes to its rate impact model. RII understands that the purpose of the model is to illustrate the general pressure on rates that may be created by differing levels of electrification. The model presented in the Draft IRP Report may exaggerate the rate impacts overall, and the differences among the cases.

Incorrect removal of incremental fixed cost recovery

While NS Power's estimate of incremental fixed cost revenues is a reasonable approximation, for purposes of illustrating approximate system rates, these incremental revenues should not be deducted from the rate estimate.[33] The average rate should be total revenues divided by total sales. There is no reason to exclude a portion of revenues from the average rate calculation. NS Power should correct its rate impact model, as incremental fixed cost recovery should not be deducted from the revenue requirement when forecasting system rates.

Our first case – "Correction" – presents just the impact of removing this portion of the model, and is illustrated below. RII recommends that NS Power revise the rate impact model and correct its application throughout the Draft IRP Report and in its modeling results slide deck.

Treatment of existing non-fuel revenues

NS Power's use of 2014 non-fuel revenues is an appropriate starting point for the adjustment to obtain a reasonable total revenue requirement. We interpret these non-fuel revenues as including sunk capital costs of existing generation, transmission and distribution, and fixed operating costs.

- Sunk costs of existing generation: These costs will depreciate and be replaced by investments that are captured within the IRP revenue requirement. Accordingly, there should be some downward adjustment.
- T&D capital investment: These costs will depreciate, to be replaced by more expensive investments that are not captured within the IRP revenue requirement. Under higher load scenarios, a somewhat greater level of T&D capital investment could be required.
- Utility operating costs: NS Power suggests that these costs should remain roughly stable in real terms, with some escalation in nominal terms.

Of these three, the first is most important. By assuming that non-modeled costs stay consistent during the planning horizon, NS Power is effectively assuming that the escalation of utility operating costs and T&D capital investment cancels out the depreciation of existing plant. This seems unlikely as a base case assumption.

[33] RII understands that NS Power's intent in making this adjustment is to reflect the differential impact of electrification on residential rates. This intent was not made clear in prior presentations and documents. RII does not agree that this adjustment accomplishes the stated goal. A significantly more complex model would be required to appropriately distinguish rate impacts by customer class.

While NS Power's base case holds non-modeled costs level in nominal terms, we recommend that NS Power also include a sensitivity in which the revenue requirement for non-IRP costs declines over time. We suggest an annual reduction of 1.5% in these revenues. The net effect of this reduction and the IRP revenues remains an increasing revenue requirement under every scenario. The suggested, or some similar sensitivity analysis, will provide an indication of the uncertainty in NS Power's rate impact forecast.

Revised rate impact model findings

Below, we provide all three charts – NSP, Correction, and Sensitivity in Figure 1, Figure 2, and Figure 3, respectively. The Sensitivity includes both the correction and a sensitivity case with a 1.5% annual reduction in the existing non-fuel revenue requirement.

These charts demonstrate that NSP's rate impact model exaggerates the overall trend in rate increases and also exaggerates the differences among the different model scenarios. Our analysis suggests that there are a variety of paths forward with relatively similar rate impacts.

NS Power should not rely upon the relative rate impact comparison analysis as the basis for recommending the level of DSM program investments or electrification target. Specifically, RII recommends against relying upon the relative rate impact comparison analysis in Figure 54 of the Draft IRP Report,[34] particularly as it includes a substantial error in netting incremental fixed cost recovery from the total annual revenue requirement and also including the incremental sales in calculating the system rate. As this secondary measure is the only support NS Power offers in its analysis for the Low DSM case, RII recommends that NS Power not suggest that the IRP offers analysis that supports a Low DSM investment level.[35]

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[34] Draft IRP Report, p. 117.

[35] Furthermore, this analysis should have been presented to stakeholders much earlier in the process for group discussion. This is a rare example of a late-analysis surprise that is not characteristic of NS Power's generally open and transparent approach to analysis in this process. In its comments filed on November 13, 2020, EfficiencyOne notes that the secondary metrics used in the Draft IRP Report differ from those adopted in the Terms of Reference. While RII does not categorically object to the evolution of secondary metrics during the IRP process, EfficiencyOne raises a valid point regarding the emphasis given in the Draft IRP Report to certain primary and secondary metrics, and the lack of attention given to others in reaching conclusions.

Figure 1: Annual Rate Estimate, NSP Draft IRP Report

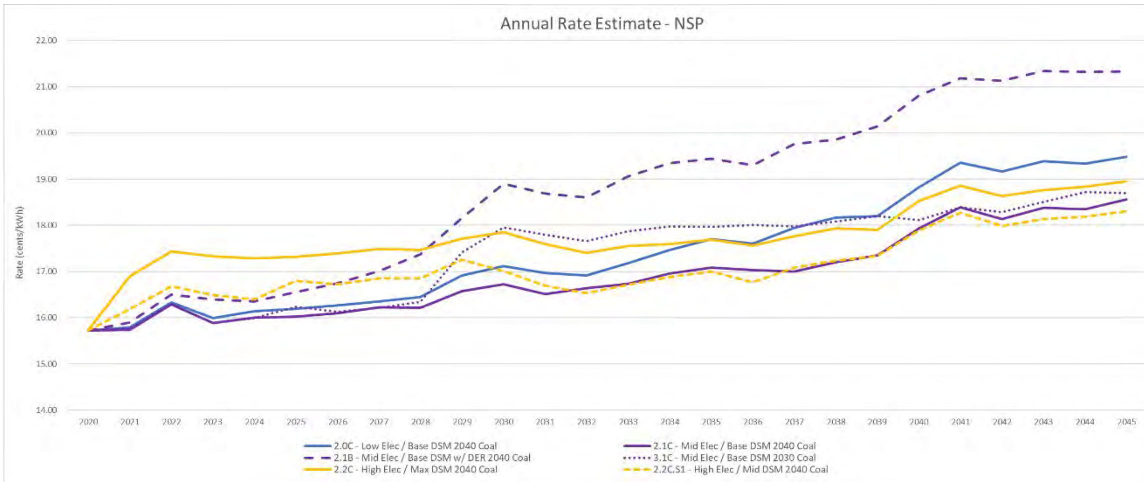


Figure 2: Annual Rate Estimate, Correction by RII

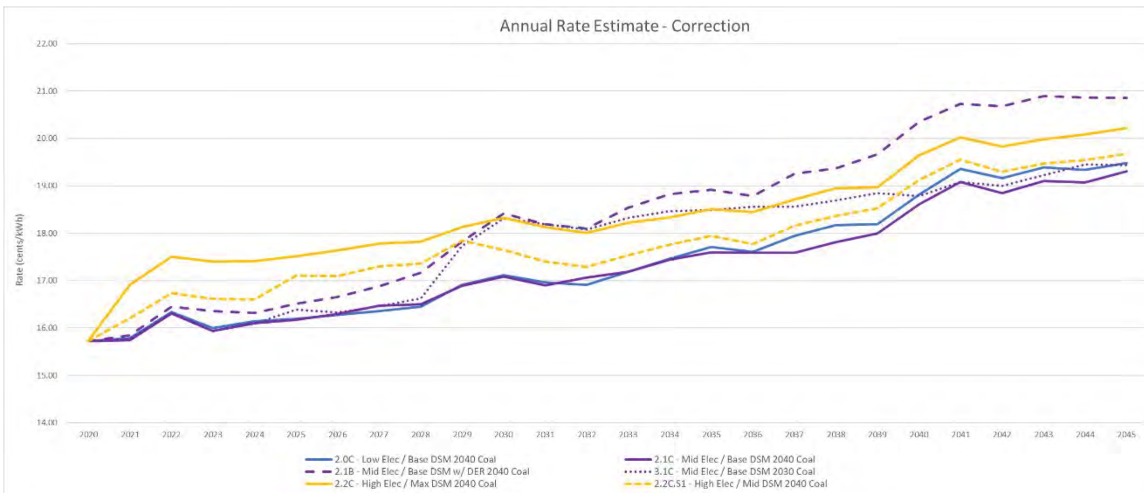
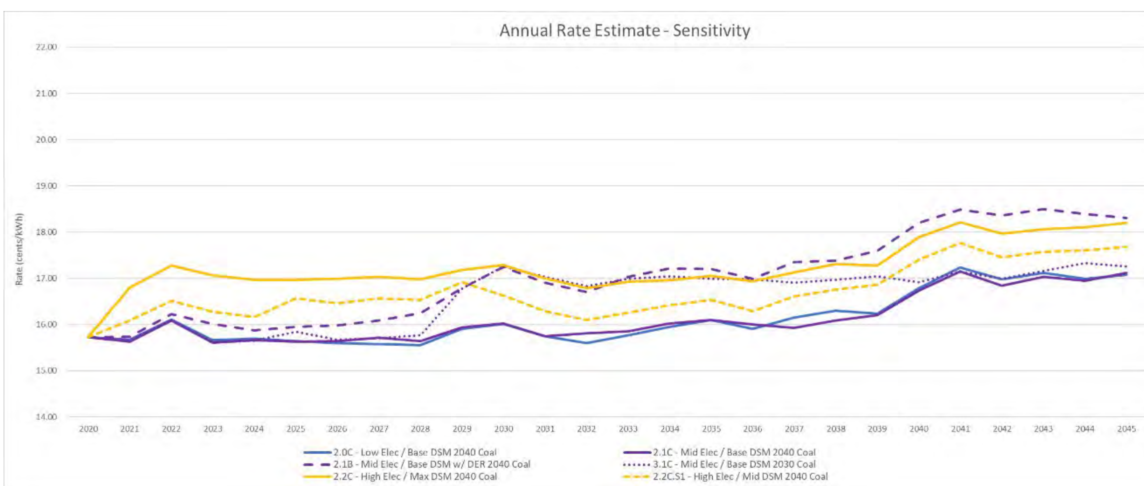


Figure 3: Annual Rate Estimate, Correction and Sensitivity Case by RII



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SUBMITTED COMMENTS REGARDING 2020 IRP DRAFT REPORT

November 13, 2020

The Ecology Action Centre (EAC) welcomes the opportunity to participate as a stakeholder in the 2020 Integrated Resource Plan process. We submit the below comments and recommendations in response to the Draft Report released for stakeholder comment on October 30, 2020. Specifically, this submission is in response to the below document:

1) NS Power IRP 2020 Draft Report

The EAC would like to begin by highlighting that we are facing a climate emergency. The province's environmental policy, including current and future resource planning processes must be designed with rapid decarbonization and net-zero in mind. With over 60% of the energy mix still reliant on coal, oil and natural gas, Nova Scotia Power Incorporated (NSPI) is the third most polluting energy utility in Canada. This is an opportunity for all key stakeholders involved in the IRP 2020 to decarbonize NSPI and make it one of the least polluting energy utilities in Canada.

Given the declarations of climate emergency from the federal government, provincial government and many municipalities in Nova Scotia, it is prudent to continue planning for increased ambition for emissions reductions in the electricity sector, moving forward. EAC is concerned that this IRP does not go far enough to plan reasonable increases in this ambition. Given the Clean Power Roadmap process; the development of the Atlantic Loop; the federal government's commitment for 90% of electricity generation to come from non-emitting sources by 2030; the federal government's commitment to increase the national 2030 emissions reduction target; and the as-of-yet undetermined electricity sector targets under Nova Scotia's Sustainable Development Goals Act, we feel this IRP misses a major opportunity to plan for what is to come. There is no doubt that vital decisions must be made quickly with affordability, reliability and sustainability as its core pillars, and to mitigate adverse impacts on environment and human health.

The EAC appreciates the opportunity to participate and submit written comments in the IRP process, and help strengthen the energy system in Nova Scotia.

Thank you,

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The EAC presents the following comments & recommendations in response to the IRP 2020 Draft Report:

Nova Scotia's Sustainable Development Goals Act is a significant milestone in the province's climate plans, and actions proposed in the IRP that adhere to these emission goals are welcome. The EAC strongly supports the notion of achieving steep reduction in carbon emissions in the province. At the same time, the EAC expresses deep concern that **no "zero" e**missions scenarios were studied in the IRP 2020. The planning objectives are overly cautious and without examination of accelerated zero emission plans it is not clear that a safe scenario has been studied and that the process has considered an adequate range of planning scenarios through this omission, given the urgency of climate action. Moreover, since electricity sector-specific targets are not yet fully developed in the SDGA, it weakens the confidence that these scenarios are SDGA compliant.

While retiring coal earlier would provide a strong case for decarbonization, replacing it with and operating natural gas at low capacity factors beyond 2050 however, would not allow the energy system to reach net zero and result in redundant and expensive stranded assets beyond the 2050 timeframe. SDGA is designed to create an impetus for clean growth in the province, which gives NSPI the perfect opportunity to aggressively pursue deep decarbonization before provincial targets. As in other comparable jurisdictions, the electricity sector is perceived as an enabler, which has the capacity to accommodate, empower and create pathways for other challenged sectors such as forestry, transportation, agriculture and marine. Therefore, a scenario for fully decarbonized utility with real net-zero emissions and the resulting cost requirements must be examined fully.

Agreed that regional interconnection will be vital in transitioning the province off coal. Transformative ideas such as the Atlantic Loop presented in the Speech from the Throne and the $10 billion Canada Infrastructure Bank announcement to support transitioning regions, underpin the idea of pursuing enhanced transmission connections and upgrades, since these will clearly be the least cost options and have the capability for faster clean transition. The plans fall short of "optimal" as the software was presented with limited regional integration opportunities. Incremental transmission builds must be examined fully in future studies.

As highlighted in EAC's previous comments, reaching high electrification levels will be most beneficial for the province both in terms of environmental advantages and economic rate implications in the long-term. However, this electrification must be achieved without reliance on natural gas builds. The provincial energy system, starting today must be envisioned as a combination of clean firm imports, renewable electricity, energy storage, demand side management, maximizing building efficiency and electrification of transport. This will help us align well with the principles of just recovery and sustainability. In addition, it is important to understand the avoided costs of max DSM and transport fuel in high electrification scenarios, and therefore, must be included in future studies.

There is no doubt that further planning is required as an ongoing activity and must continue to be transparent and inclusive. The EAC and other key stakeholders believe that future iterations of this

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process would stand to benefit from being managed by an independent third party, with environmental advocacy and the pillars of affordability, reliability and sustainability as core principles.

The EAC believes that Nova Scotia still has an opportunity to set long-term ambition and commit to phasing out coal-fired electricity by 2030. We need to ensure that low and middle-income Nova Scotians, indigenous groups, coal workers, other vulnerable groups and communities all benefit from this change in our electricity system. The EAC looks forward to the careful and considerate review that the Nova Scotia Utility and Review Board will take before approving this Integrated Resource Plan. The EAC believes that under the current Public Utilities Act and Electricity Act the Nova Scotia Utilities and Review Board has a legal obligation to regulate NSPI and ensure that it is following all legislation proclaimed by the Nova Scotia Government.

Ecology Action Centre is committed to continuing to ensure Nova Scotia sets a pathway to phasing out coal-fired electricity generation, and looks forward to working with all partners toward the just transition to a prosperous, green economy.

Thank you for your consideration.

G. Gurprasad

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Memorandum

To: Nicole Godbout, Director, Regulatory Affairs, Nova Scotia Power

From: John Esaiw, Chief Strategy and Technical Officer, EfficiencyOne

Date: November 13, 2020

Re: Letter of Comment – Draft Integrated Resource Plan Report

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On October 30, 2020, NS Power released its Draft Integrated Resource Plan Report ("Draft Report"), as well as Updated Modelling Results (with three additional sensitivities), stakeholder comments and responses for the Interim and Final Modelling Results phases, and stakeholder comments associated with the Draft Findings, Action Plan and Roadmap. On November 6, 2020, responses to stakeholder comments were released on the Draft Findings, Action Plan and Roadmap. Comments to the Draft Report are requested to be provided by November 13th, 2020.

EfficiencyOne, in collaboration with its consultant, Energy Futures Group, has reviewed the materials issued including the Draft Report and associated links to other documents and appreciates the opportunity to provide comment on this important phase of the IRP Process.

It is important that statements characterizing the range of "Low to Base" DSM be removed prior to the production of the Final Report, as these statements have been constructed from an arbitrary weighting of the primary and secondary objective functions, use a very basic and inaccurate methodology, and are applied selectively to DSM and electrification effects. This change would clarify the presentation of the lowest NPVRR w/EE plan for the purposes of DSM.

The following is a full summary of comments and recommendations on the Draft Report:

Support for the Sustainable Development Goals Act (SDGA)

1. EfficiencyOne strongly supports the goals and vision of the SDGA, and is well positioned to support its implementation. This legislation and achievement of net zero by 2050 was the cornerstone to much of the analysis and modelling in the 2020 IRP.

Electrification in the IRP

2. Stakeholders, NS Power and the NSUARB should consider a definition of beneficial electrification offered by the Regulatory Assistance Project (RAP):[1]

    1. Saves consumers money over the long run;

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[1] Farnsworth et al., Regulatory Assistance Project, Beneficial Electrification: Ensuring Electrification in the Public Interest, June 2018.

2. Enables better grid management; and
3. Reduces negative environmental impacts.

As well, RAP's four key principles for maximizing electrification benefits should be followed.

3. EfficiencyOne is well-positioned to administer initiatives and programs to increase the amount and / or pace of electrification occurring in Nova Scotia.
4. Development of an electrification strategy as defined in the IRP action plan must take place as part of stakeholder-driven process.

Demand Response

5. Near-term Demand Response (DR) is well positioned to provide cost savings against other short-term peaking resources – as found through the selection of DR as part of model operation.
6. The DR strategy development process should proceed through the DSMAG.

IRP Results – Secondary Evaluation Criteria

7. The secondary metrics used in the IRP process should remain consistent with those presented in the original Terms of Reference, since that document has been explicitly approved through a regulatory process.
8. Minimize or remove objective decision-making within the process associated with the use of secondary metrics.

Rate Effects

9. Revise Action Plan item 2e to read:

> DSM energy efficiency programs and costs in the range of the "Base" profile, per the EfficiencyOne 2019 Potential Study, are shown to be most economic relative to other options evaluated under the primary IRP metric of 25-year NPV of Revenue Requirement (with end effects). A focus on peak demand mitigation is indicated and could be optimized into future DSM planning. Other levels of DSM in resource plan sensitivities show higher NPVRR with end effects, as well as mixed effects on other metrics, when compared to Base DSM; Low DSM levels are shown to reduce relative rate impact, while Mid DSM levels are shown to reduce new capacity requirements and GHG emissions, both at a higher NPVRR. Due to the discrete nature of the DSM profiles modeled in the IRP, future DSM program development should incorporate the learnings obtained from the full range of sensitivities and metrics considered in the IRP.

and;

> DSM has been an important variable in this IRP, and Nova Scotia Power has modeled numerous DSM scenarios in both the key scenarios and sensitivities, incorporating significant engagement with EfficiencyOne as discussed in section 6.8.1. The Base DSM profile is shown to be economic when compared using the 25-year NPVRR with end effects metrics, relative to other DSM levels.

Other similar language should also be adjusted accordingly.

Further Adjustment to NPVRR w/ End Effects Results – Market Price of Carbon

10. Provide the impacts of carbon at both ends of a reasonable range ($24 to $50 per tonne), and include the results in the final report and updated modelling results.

Transmission and Distribution

11. The IRP should quantitatively consider the recently agreed-to avoided costs of T&D as decrements to NPVRR with EE for all cases, based on the level of DSM included. Any re-ranking from the aggregate effect of carbon prices and avoided T&D should be reflected in the final report if present.

Risk Analysis

12. Create and include a roadmap item to carefully monitor and estimate the expected capital costs, inclusive of transmission, distribution, energy and capacity, and reliability upgrades associated with a regional interconnection strategy, and report finding to stakeholders on an bi-annual basis. When and if those costs are anticipated to materially exceed the assumptions in the IRP, the assumption that regional interconnection remains economic should be re-tested through updated modelling.
13. Qualitatively describe the risk reduction potential of DSM activities in the IRP Report.

Avoided Costs

14. The DSMAG is a logical venue for completing the process of avoided cost of generation – there is currently a DSMAG discussion scheduled for early 2021, and this is intended to determine the methodology and timing for the generation of avoided costs for future DSM planning.

Signposts for DSM

15. DSM should be included in Roadmap item five.

Evergreen IRP

16. As DSM Resource Plans are developed and approved on a three-year schedule, a three-year update cycle for key IRP inputs would be beneficial in the context of an “evergreen” IRP process.

Other Comments

17. Limit the use of the term “cost-effective” to situations where it can be used consistent to the definition of formal “cost-effectiveness” in Nova Scotia (i.e. a Total Resource Cost test of 1.0 or greater).
18. On page 13, the Draft Report states “Nova Scotia Power has significantly reduced greenhouse gas emissions at fossil power plants as other energy resources have become available and plans to continue that trend.” This statement appears unclear in whether it is referring to decreased emissions intensity, or decreased usage of the plants. Please clarify this statement.

Introduction

The 2020 IRP process represents a significant investment of time and resources for NS Power, the IRP Working Group, and stakeholders participating in the process. In addition, the 2020 IRP has added complexity when compared against previous IRP processes in Nova Scotia, further adding to the challenges involved in the modelling process.

NS Power’s dedication to facilitating stakeholder comment and engagement in the process to date, given the large number of stakeholders in the process and the complexity of the materials being discussed, has been assistive. The “nine public workshops, six rounds of formal submission from stakeholders, independent expert analysis, and ongoing consultation with participants"[2] represented a significant degree of effort for which EfficiencyOne is appreciative.

The large amount of stakeholder consultation undertaken in the process has not, nor could it have been expected to, remedy every issue raised by stakeholders. Nevertheless, key issues need further attention and resolution to enable an accurate and meaningful IRP process. Important remaining issues are presented in this memo which require careful consideration in advance of the preparation of any final report materials.

Support for the SDGA

In 2019, Nova Scotia introduced *An Act to Achieve Environmental Goals and Sustainable Prosperity*, or the *Sustainable Development Goals Act* (SDGA). This act intends to drive sustainable prosperity through carbon reductions of 53% by 2030, and the attainment of net zero emissions by 2050. These efforts will require further decarbonization of the electricity system, and the electrification of currently non-electric end uses.

The SDGA awaits consultative processes for the development of associated regulations, which are understood to have been delayed by the COVID-19 pandemic.

EfficiencyOne strongly supports the goals and vision of the SDGA, and is well positioned to support its implementation. In particular, DSM (and energy efficiency in particular) can provide incremental GHG reductions from previously electric end-uses, with some of the lowest costs of GHG abatement available amongst technology options.[3] DSM is also "shovel-ready" in Nova Scotia, meaning its utility to produce near-term CO_2e reductions is unparalleled amongst resource options. Finally, DSM's granular nature gives it an excellent risk profile in the context of economy-wide decarbonization.[4]

Electrification in the IRP

In addition to the role discussed above in reference to traditional energy efficiency activities, another form of DSM exists in the IRP in electrification. For clarity on whether electrification as DSM fits within a sound technical view, the following updated definition of DSM is offered by Clark Gellings, P.E., one of the engineers involved in the original conceptual development of DSM at the Electric Power Research Institute:

> "Demand-side management is the planning, implementation, and monitoring of those utility activities designed to influence customer use of electricity in ways that will produce desired changes in the utility's load shape, that is, changes in the time pattern and magnitude of a utility's load. Utility programs falling under the umbrella of demand-side management include: load management, new uses, strategic conservation, electrification, customer generation, and adjustments in market share." [5]

Three electrification trajectories have been established as part of the IRP and modelled as part of the development of Load Scenarios. These trajectories are:[6]

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[2] NS Power Draft IRP Report, Page 1.
[3] McKinsey & Company, Global GHG Abatement Cost Curve v2.1, 2010, at page 8.
[4] NERC, Data Collection for Demand-Side Management for Quantifying its Influence on Reliability, December 2007, at Page 1.
[5] Clark W Gellings, The Smart Grid: Enabling Energy Efficiency and Demand Response, Fairmont Press, 2009, at page 138.
[6] *Supra Note 1*, Page 63.

- Low Electrification represents the 2019 Load Forecast as filed with the NSUARB in April 2019 with no further modification.

- Mid Electrification represents the 2019 Load Forecast, adjusted to reflect the incremental load anticipated due to partial electrification of buildings and vehicles as indicated in E3's "Moderate Electrification" Pathways scenario.

- High Electrification represents the 2019 Load Forecast, adjusted to reflect the incremental load anticipated due to broad electrification of buildings and transportation as indicated in E3's "High Electrification" Pathways scenario.

It is further understood that the impacts of these electrification trajectories have been computed using E3's Pathways study, and ultimately produced adjustments to IRP load forecasts.

It's understood that the Low Electrification case is representative of the current trajectory for electrification in Nova Scotia, and that higher levels of electrification may be reflective of DSM interventions, whereby market interventions are contemplated to change end user behaviour and the use of electricity. No explicit costs or incentives have been currently contemplated for these electrification activities in the IRP.

In the Draft Report, key findings 1a and 1b speak to the importance of electrification in the future IRP loads, as well as it more broadly as it relates to economy-wide decarbonization:

> Key pillars of economy-wide decarbonization include greater reliance on non-emitting electricity supplies, focused demand side management, and electrification of end uses currently reliant on fossil fuels.[7]

and;

> The IRP rate analysis demonstrates the importance of managing the relative growth of peak and energy requirements, highlighting the need to pursue beneficial electrification.[8]

Two key points in the above are very important, namely:

1. The electrification of end-uses currently reliant upon fossil fuels will be tremendously important to future attainment of SDGA goals (as will energy efficiency and conservation).
2. The need to pursue beneficial electrification will be critical in minimizing costs and adverse effects associated with electrification.

It's recommended that stakeholders consider a definition of beneficial electrification offered by the Regulatory Assistance Project (RAP):[9]

1. Saves consumers money over the long run;
2. Enables better grid management; and

[7] *Ibid.*, at page 123.
[8] *Ibid.*, at page 124.
[9] Farnsworth et al., Regulatory Assistance Project, Beneficial Electrification: Ensuring Electrification in the Public Interest, June 2018.

3. Reduces negative environmental impacts.

In addition, RAP offers key principles for maximizing the benefits of beneficial electrification efforts:

1. Put efficiency first.
2. Recognize the value of flexible load for grid operations.
3. Understand the emissions effects of changes in load.
4. Use emissions efficiency to measure the air impacts of beneficial electrification.

All of the principles above are critical for maximizing the benefits of electrification, and it is recommended that any electrification effort follow these foundational principles.

EfficiencyOne is well-positioned to administer any initiatives and programs to increase the amount and / or pace of electrification occurring in Nova Scotia, given that the organization:

1. Has an established trade network for industry professionals supplying and installing efficient electrical equipment.
2. Actively operates program structures which could be readily adopted for electrification efforts.
3. Has a strong NS market presence; and strong relationships and communication channels with electricity customers.
4. Is a trusted source for accurate information on energy efficient technologies.
5. Possess significant expertise around the operation of diffuse market-based programs designed to influence patterns of energy consumption.
6. Can achieve economies of scale, as electrification efforts would benefit from shared administrative costs with other organizational activities.

While the inclusion of electrification measures would expand DSM efforts beyond existing energy efficiency activities – operationally, this effort would be quite similar to existing energy efficiency activities, meaning that entry into electrification activities could be relatively rapid. Efficiency Vermont has followed this path, and now offers electrification measures.

In the Action Plan section of the report, it states:

> Initiate an Electrification Strategy to understand options for encouraging beneficial electrification with the goals of maintaining rate stability while decarbonizing the Nova Scotia economy consistent with the Sustainable Development Goals Act.[10]

Developing a cohesive electrification strategy for Nova Scotia is a sound objective; development of such a strategy must take place as part of stakeholder-driven process.

Electrification fundamentally alters the site-consumed energy mix in Nova Scotia – its effects on the building stock and the electricity system are substantial. Given the breadth of effects from potential electrification efforts, stakeholders should be engaged in a process that is transparent, evidence-based and allows the appropriate time and consideration for such an important initiative.

Demand Response

[10] *Supra Note 1*, at page 132.

The 2020 IRP results show inclusions of demand response to be economic across all modelled scenarios, in varying amounts and times of introduction. The variability is a result of the fact that demand response activities were allowed to be economically selected by Plexos LT, as opposed to being included as load modifiers as part of the IRP process.

In the Action Plan section of the Final Report, it is suggested to:

> Create a Demand Response Strategy targeting 75 MW of capacity, for deployment by 2025. Available resource cost, flexibility, and reliability may inform pursuit of additional Demand Response capability.[11]

We agree with this recommendation in the Action Plan in principle, in that near-term DR is well positioned to provide cost savings against other short-term peaking resources – as found through the selection of DR as part of model operation.

Similar to electrification, EfficiencyOne is well positioned to administer many aspects of demand response programs, including customer enrollment, technology installation and enablement, measurement, marketing and customer education, among other aspects. Capabilities and expertise in these areas are a product of our existing experience designing and implementing energy efficiency and demand reduction programs and services.

It is recommended that this strategy development process proceed through the DSMAG.

IRP Results - Evaluation Criteria

The IRP used one primary evaluation criterion, alongside seven other criteria. From the approved Terms of Reference, these criteria are:

> The IRP process will seek to identify the least-cost, least-risk portfolio. Traditionally, the primary decision criterion used for IRP modeling has been the minimization of the cumulative present value of the annual revenue requirements over the 25 year planning horizon (adjusted for end-effects).
>
> NS Power will continue to use this primary metric to guide resource planning, and will also assess others of increasing importance, including:
>
> - Magnitude and timing of electricity rate effects;
> - Reliability requirements for supply adequacy;
> - Provision of essential grid services for system stability and reliability;
> - Plan robustness (the ability of a plan to withstand plausible potential changes to key assumptions);
> - Reduction of greenhouse gas and/or other emissions; and,

[11] *Ibid*, at Page 133.

- Flexibility (limitation of constraints on future decisions arising from the selection of a particular path).[12]

There are a few differences between this list and the evaluation criteria presented on page 100 of the Draft Report. These secondary evaluation metrics have changed since the presentation of the Terms of Reference:

- Resource Plan Cost;
- Rates;
- Resource Adequacy;
- Stability and Reliability;
- GHG Emissions; and
- Robustness and Flexibility

It is unclear why or how these metrics may have changed – however, the secondary metrics used should remain consistent with those presented in the original Terms of Reference, since that document has been subject to stakeholder engagement and a regulatory process.

In addition, how the secondary criteria will be used to inform an overall evaluation of a given case/scenario has been a point of concern since the time of development of the Terms of Reference. In EfficiencyOne's December 6, 2019 letter of comment on the matter, it was stated:

> The draft ToR specifies that the Analysis Plan will establish how six secondary metrics will be used as evaluation criteria for the IRP modelling, in addition to the "primary metric" of cumulative present value of the annual revenue requirements over the planning horizon. It is important to note that the primary metric is readily quantifiable and easily understood, while the other six are not. For example, measuring and comparing the "flexibility" and "robustness" of different resource plans will be difficult and possibly contentious, as will determining the appropriate weighting of these six metrics against each other and against the primary metric.
>
> It's recommended that if NS Power intends to use these six metrics in addition to the primary metric, it objectively define exactly how it will do so in the ToR. Not making this decision now leaves the door open for stakeholders to put inconsistent emphases on a subset of these metrics down the road, or to abandon them entirely.[13]

There are now challenges arising associated with the inconsistent emphasis, and unclear definition of the many metrics used. For clarity, the challenges most prominently include:

1. The inability to follow any implicit (as it was unstated) weighting being used to combine the various secondary evaluation criteria.

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[12] M08929, N-4, Terms of Reference, Approved January 21, 2020, at page 6.
[13] EfficiencyOne Letter of Comment – IRP Terms of Reference, December 6, 2019, at page

2. The inability to assess the weighting relationship between the primary objective of developing a plan that seeks to minimize the cumulative present value of the annual revenue requirements over the 25-year planning horizon (adjusted for end-effects), and secondary metrics.
3. A lack of understanding of criteria used to evaluate some of the metrics in detail.

As an example, one can compare the treatment of GHG emissions and rates in the IRP context. On GHG emissions, little attention is drawn to the specific differences in plans in terms of their GHG emissions, beyond the original three broad trajectories outlined. On rates, the Draft Report appears to seek a great degree of differentiation – these are not products of quantitative analysis, rather they are reflective of editorial decisions associated with presentation of results in the Draft Report.

Given that stakeholder understanding of the particular methodology used cannot be readily achieved – it is recommended to minimize or remove objective decision-making within the process associated with the use of secondary metrics. This is not to say that these metrics do not provide contextual value as part of the process – they do, and should do so appropriately.

This step would be aligned with the notion that the IRP process in Nova Scotia represents an opportunity to analyse the lowest-cost path for the electricity system in the long term. This finding is important, as it provides a sort of "least-cost-anchor" from which other determinations can be considered, weighed against other factors as relevant in a particular process (e.g. short-term rate effects).

Rate Effects

The Draft Report presents a unique use of a secondary evaluation criterion via its rate analysis information. The results of this analysis are presented on pages 112 and 113 of the draft IRP report, while the methodology is presented on pages 98 and 99. There are issues associated with the use of rate effects, which are specific examples of the general issues described in the preceding section:

1. The use of rates in this manner in an IRP context.
2. The methodology is overly simplistic for determination on rates.
3. It is applied unevenly across different areas of analysis.

These issues are explored below.

The use of rates in an IRP context

The Draft Report highlights the estimated rate impacts of part of the broader evaluation methodology. As explained in the section above, losing visibility on the least cost, long term, path forward as identified in an IRP, causes concern.

Further, to place determinations around rates as a key part of the IRP process could prejudice other important rate making exercises, such as general rate applications. In the case of DSM, discussions and determinations around the affordability of DSM activities already form a statutory inclusion within short-term planning process for DSM, as laid out in the *Public Utilities Act*.[14] To display and perform decision-making using rates in this manner is prejudicial toward subsequent determinations of, among other things, DSM levels. Discussions of affordability should remain in the realm of DSM planning; it is not appropriate to pre-empt those discussions through observations in the IRP.

[14] Public Utilities Act, RSNS 1989, c 380, s.79L(9).

The Methodology for Rate Impact is Inconsistent with Accepted Methodologies

A written description of the methodology for its rate analysis as part of the final report was provided, as well as results and analysis. The methodology documented in the Draft Report has a number of flaws:

- Its treatment of fixed costs differs from its recommendations associated with the Rate and Bill Impact Analysis (RBIA), and is much less sophisticated.
- The notion that a single fixed cost ratio ($80/MWh) can be recovered from new electricity sales, or must be additionally recovered from lost sales due to DSM is flawed, and not reflective of the RBIA methodology, developed by stakeholder consensus.
- The "2014 foundation" is held fixed through a lengthy future study period.
- It appears the value of transmission and distribution avoided costs, which reduce fixed cost recoveries, have not been included in the analysis.
- From the smooth nature of the rate impacts, it appears that the analysis may be measuring carrying charges as opposed to the revenue requirement in each year.

The Rate and Bill Impact analysis has been produced since 2013, and has been reviewed, improved and debated on by members of the DSMAG since that time, over the course of numerous regulatory processes. Building upon the above discussion – not only would determinations based on rates be prejudicial in this setting, but they risk being made on a methodology that has not been well considered by stakeholders.

The Application of Rate Effects

Despite rate effects forming a secondary evaluation metric in the whole of the IRP, the Draft Report has used of the metric to:

1. Demonstrate that increasing levels of electrification can decrease rates.
2. Demonstrate that increasing levels of DSM can increase rates.

It appears these two particular areas are a focus for the evaluation of rates, when seemingly each IRP case would possess its own rate trajectory. For example, sensitivities around import pricing, energy and capacity contracts, reliability interties, interjurisdictional transmission and differences between the cases themselves could have been explored; they were not. This is another example of the consequence of an unclear definition of the application of a secondary metric used in evaluation of the IRP.

As an example of the decision-making relating to DSM based on rates, the Action Plan states:

> DSM energy efficiency programs and costs consistent with a range of the "Low" to "Base" profiles are shown to be most economic relative to other options evaluated.

and;

> When comparing the Low and Base DSM profiles under low electrification, the Base DSM profile is economic when compared using the 25-year NPVRR with end effects metrics

> while the Low DSM profile is economic on other metrics; in particular there is a significant difference noted in the relative rate impacts.[15]

It is being implied that since low DSM was "most economic on rates" and Base was most economic on NPVRR w/EE, that either could bookend a range of acceptable DSM levels.[16]

On the basis of all of the preceding, it is requested that Action Plan item 2e be revised to read:

> DSM energy efficiency programs and costs in the range of the "Base" profile, per the EfficiencyOne 2019 Potential Study, are shown to be most economic relative to other options evaluated under the primary IRP metric of 25-year NPV of Revenue Requirement (with end effects). A focus on peak demand mitigation is indicated and could be optimized into future DSM planning. Other levels of DSM in resource plan sensitivities show higher NPVRR with end effects, as well as mixed effects on other metrics, when compared to Base DSM; Low DSM levels are shown to reduce relative rate impact, while Mid DSM levels are shown to reduce new capacity requirements and GHG emissions, both at a higher NPVRR. Due to the discrete nature of the DSM profiles modeled in the IRP, future DSM program development should incorporate the learnings obtained from the full range of sensitivities and metrics considered in the IRP.
>
> and;
>
> DSM has been an important variable in this IRP, and Nova Scotia Power has modeled numerous DSM scenarios in both the key scenarios and sensitivities, incorporating significant engagement with EfficiencyOne as discussed in section 6.8.1. The Base DSM profile is shown to be economic when compared using the 25-year NPVRR with end effects metrics, relative to other DSM levels.

In addition, it is requested that revision to other very similar language throughout this report that references a range of "Low" to "Base" DSM to reflect the economic finding that Base possess the lowest NPVRR w/EE, and removing inappropriate references to affordability, which will be adjudicated as part of subsequent DSM Resource Plan processes, as has always been the case.

Further Adjustment to NPVRR w/ End Effects Results – Market Price of Carbon

In its September 18, 2020 letter of comment, EfficiencyOne recommended that:

> The IRP results should modify the NPV revenue requirement calculation on the basis of expected carbon revenues, as they are now a key differentiator in many cases and may affect the selection of a lowest cost plan.

The response to these comments was:

> In the Roadmap, NS Power has committed to tracking the ongoing development of the Nova Scotia Cap-and-Trade Program, including auction results and developing regulations. In particular, NS

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[15] *Ibid*, at Pages 127-128.

[16] It is unclear why Low DSM possessing lower rate effects (subject to all arguments herein) allows it to be an "equal" of Base DSM – this is yet another example of the challenges an unclear evaluation methodology cause.

Power will monitor GHG market size for indications that value from incremental allowance sales (beyond the projected economic emissions reductions shown in the IRP results) can be incorporated into long-term resource planning decisions with greater certainty.

Significant changes in the value of incremental GHG reductions could influence resource plan components including non-emitting generation procurement, DSM levels, and coal retirement trajectories.

The response above is agreeable – it is prudent to continue to monitor the ongoing cap and trade market and how it develops over time; however, the response fails to address the fundamental question of what monetary value should be captured in the 2020 IRP.

There exists today:

1. A current market for GHGs today in Nova Scotia;
2. A defined federal pricing trajectory that will inform cap and trade pricing for the next three years;
3. A legislative commitment from the Province to reach net zero emissions by 2050; and
4. A 2019 Federal government commitment "to further strengthen existing and introduce new greenhouse gas reducing measures in order to exceed Canada's current 2030 emissions reduction goal. In addition, Canada will develop a plan to achieve net-zero emissions by 2050 and will set legally-binding, five-year emissions reduction milestones, based on the advice of experts and consultations with Canadians."[17]

With current pricing established, and a strong policy environment that appears to favour continued and perhaps strengthened carbon pricing, the IRP should consider these potential ratepayer revenues in the planning environment.

Further, when asked about the potential for carbon revenue inclusion earlier in the IRP process, any apprehension of the further existence of the market was not mentioned:

NS Power will incorporate cap and trade market revenue from sales of excess GHG allowances during the screening phase of the modeling work for some key scenarios. If market revenue is found to affect the preferred resource plan selection, then a determination will be made as to how to incorporate the cap and trade market in the full IRP modeling phase.[18]

Stakeholders now find themselves in a situation where the selection of the preferred resource plan may well be influenced by these revenues, and they should be immediately considered and included in IRP results, and any qualitative outcomes relating to those results. Levels between $24 (first NS auction) and $50 per tonne (2022 federal backstop) form a reasonable range for consideration.

[17] Environmental and Climate Change Canada, News Release, December 20, 2019, https://www.canada.ca/en/environment-climate-change/news/2019/12/government-of-canada-releases-emissions-projections-showing-progress-towards-climate-target.html.
[18] NS Power response to IRP Assumptions – Participant Comments, March 11, 2020, at Page 3.

The qualitative reporting of DSM's effects within the IRP Report is appreciated, acknowledging that:

> Higher DSM programs also generally resulted in earlier coal retirement, less new-built gas capacity by 2045, and lower CO_2 emissions over time because the overall load level is lower.[19]

Given the importance of these qualitative findings, the general jurisdictional or societal value of carbon reductions, and the existence of an explicit market, further quantitative study is appropriate and essential to providing an accurate IRP result.

T&D

The incorporation of transmission and distribution effects in the IRP, or lack thereof, continues to be a concern. In response to a request for the further consideration of these effects:

> As a generation-focused modeling exercise, the IRP does not specifically evaluate optimization of T&D investments. Both the T&D Avoided Cost estimates and the IRP key scenario and sensitivity results for various levels of DSM can be used to inform future DSM procurement activities.[20]

This sensitivity to the exercise being "generation-focused" does not appear in other conclusions the IRP seems be drawing, and is inconsistent in the context of an IRP where the main conclusions drawn are the need for regional interconnections to provide reliability and capacity needs. Other areas where the IRP includes a system focus are rates (T&D costs are assumed to be invariant between cases). To have DSM compete in a "generation-focused" IRP effectively means that established T&D benefits of DSM are being ignored, and valued at zero.

The assessment that both T&D avoided costs and the IRP can inform future DSM procurement activities also does not recognize the fact that pronouncements regarding economic levels of DSM are currently be made in the IRP Report, thus prejudicing subsequent determinations.

The recently agreed-to avoided costs of T&D as decrements to NPVRR w EE for all cases, based on the level of DSM included, should be quantitatively considered. These effects have been calculated by EfficiencyOne as:

Table 1 - T&D Effects NPVRR w/ EE[21]

Energy Efficiency Case	**NPVRR w/EE Decrement ($M)**	**NPVRR w EE – w/ T&D effects – 2.0C ($M)**
Low	$142.3	$16,208
Base	$200.8	$16,040

[19] *Supra Note 1*, at Page 127.
[20] NS Power Response to IRP Draft Action Plan comments, November 6, at Page 11.
[21] This analysis uses WACC as the discount rate (6.84%), a T&D price of $40/kW-year, and assumes DSM effects remain constant in the end-effects period.

Mid	$236.4	$16,325
Max	$291.8	$16,937

The middle column above represents the application of T&D avoided costs across the planning and end-effects periods, in millions of dollars Net Present Value, and are a negative (avoided) cost against the original NPVRR w/EE of the 2.0C sensitivity cases originally studied. The right-most column shows the adjusted total NPVRR w/EE after considering the avoided costs.

The aggregate effects of carbon pricing and T&D may produce a re-ranking of plan results (note that estimated T&D impacts do not result in an alteration of ranking in isolation). This re-ranking should be reflected in the final report if present.

Risk Analysis

The IRP draft report frames the first objective of the IRP as:

> … develop a robust, risk-weighted, least-cost long-term electricity strategy that delivers energy in a safe and reliable manner, continues provincial decarbonization via non-emitting resources, and maintains affordability for customers across a range of foreseeable future scenarios.[22]

The heavy focus on market-based imports, coupled with large capital investments to access those imports, and untested means of obtaining natural gas imports, presents a large concentration of risk.

Exemplifying these risks is the 2.1C.PRICES-1 sensitivity run. This sensitivity explored the impacts of higher natural gas and import pricing assumptions, and in particular the adoption of the High Sensitivity values from the IRP Assumptions.

The results of this sensitivity analysis indicate that this outcome would produce an 8.5% increase to revenue requirements, or an NPVRR w/EE of $M 19,272. This is well in excess of the results for 2.1A ($M 18,264).

These results indicate that increases to price assumptions would render the regional integration plan uneconomic, relative to a plan that more greatly emphasises local resource development.

Further, it is unclear at this time that the IRP has costed all regional integration capital expenditures in a fulsome manner, including potential system upgrades required on the NB system associated with increased receipt of energy and firm capacity at Salisbury.

These risks do not lead to a recommendation to abandon the regional interconnection strategy in its entirety. Rather, it is recommended to increase careful monitoring within the context of the IRP Action Plan.

In particular, the IRP should create and include a roadmap item to carefully monitor the wide range expected capital costs and import opportunities associated with a regional interconnection strategy and

[22] *Supra Note 1*, at Page 28.

report findings to stakeholders on a bi-annual basis. When and if those costs are anticipated to materially exceed the assumptions in the IRP, the assumption that regional interconnection remains economic should be re-tested through updated modelling.

This roadmap item should include quantitative leading and lagging indicators, a recommendation which applies to all the current roadmap items, as this explicit treatment would offer additional clarity on when certain decisions would be triggered. A key example is for the electrification trajectory – the addition of quantitative indicators could improve the value of such a signpost.

Finally, our existing recommendation to qualitatively describe the risk reduction potential of DSM activities in the IRP Report remains. This phenomenon is well-established and should be recognized in the report. Additional reference material is available in previous comments.

Avoided Costs

An additional Action Plan item has been added as part of the IRP Draft Report which states:

> NS Power will calculate Avoided Costs of DSM (capacity and energy) for scenarios 2.0C and 2.1C. 2.0C will be used as the Reference Plan and 2.1C will be available for additional reference.[23]

This inclusion should be further expanded to indicate the timing of the development process, and the stakeholder process that will accompany development of these avoided costs.

The DSMAG is a logical venue for completing the process of avoided cost generation – there is currently a DSMAG discussion scheduled for early 2021, and this is intended to determine the methodology and timing for the generation of avoided costs for future DSM planning.

Signposts for DSM

Roadmap item 5, offered in the Draft Report, states:

> Continue to track the installed costs of wind, solar, and energy storage to look for variations from the trajectories established in the IRP (in particular, monitoring for divergence from the "Base" to the "Low" pricing scenarios). NS Power will solicit Nova Scotia-based market information which will inform this as needed.[24]

DSM should be included in this roadmap item. The 2019 DSM Potential Study examines forecasted potential energy and capacity savings, as well as the investment required to achieve them. The investment per unit of savings (i.e. unit cost) for the Base and Mid levels of DSM Potential are currently well above operational unit costs for DSM in Nova Scotia. This is not to suggest the potential study cases are incorrect, rather that DSM unit costs are in a period of change, and these changes should continued to be monitored relative to IRP assumptions, just as for the supply-side resource options listed above.

Evergreen IRP

Action item eight within the IRP describes an evergreen IRP process being envisioned for the future. More frequent updates to the assumptions and results of the IRP, as well as avoided costs, would be beneficial

[23] *Supra Note 1*, at Page 133.
[24] *Supra note 1*, at Page 135.

for DSM in Nova Scotia. As DSM Resource Plans are developed and approved on a three-year schedule, a three-year update cycle for key IRP inputs would be beneficial in the context of an "evergreen" IRP process.

Other Comments

In addition, please refer to the following miscellaneous comments:

- The use of the term "cost-effective" is used throughout the report in an ambiguous way, to represent general notions of financial findings. It's recommended to limit the use of the term to situations where it can used consistent to the definition of formal "cost-effectiveness" in Nova Scotia (i.e. a Total Resource Cost test of 1.0 or greater).
- The use of the word "economic" is used to represent findings related to rate impacts[25]. Although not incorrect, this may be confusing for some readers. A more suitable word may be "favourable".
- On Page 102 of the report, paragraph 3, the description for scenario 2.0C appears to be missing its descriptor for DSM, which should be "Base DSM".
- On page 13, it states "Nova Scotia Power has significantly reduced greenhouse gas emissions at fossil power plants as other energy resources have become available and plans to continue that trend." This statement appears unclear in whether it is referring to decreased emissions intensity, or decreased usage of the plants. Please clarify this statement.

EfficiencyOne appreciates the opportunity to provide comments on the Draft IRP Report, the significant an ongoing effort of NS Power and stakeholders, and looks forward to further discussion and the presentation of the Final IRP Report.

[25] *Supra note 1*, at Page 117.

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November 13, 2020

Re: M08929 – Integrated Resource Planning

Dear Ms. Godbout and Ms. Friis:

As we have noted in previous submissions, Envigour Policy Consulting Inc. has been retained by QUEST and Marine Renewables Canada as their Consultant in this matter. We have reviewed the final IRP Draft Findings, Action Plan and Roadmap. We have participated in the process for more than a year now. We again wish to congratulate all those who have participated in this lengthy and through examination of options for Nova Scotia's electricity system.

As we have previously noted, this process is only a part, albeit a very important part, of developing a roadmap for Canada and Nova Scotia to achieve net-zero energy emissions by 2050. As the final IRP conclusions acknowledge, decarbonizing the electricity system is a foundational requirement to achieving that objection. Our conclusion would be that this decarbonizing take place as soon as practicable, with appropriate public policy and funding support from governments. Having set out what is feasible and practicable, we would now encourage leadership from the Governments of Canada and Nova Scotia.

In the meantime, much good work can be continued through an evergreen IRP process and an associated public education agenda.

We continue to be concerned that the underlying assumptions for the IRP modelling are too conservative. This concern is mitigated by an evergreen IRP process. However, we also strongly advocate for parallel processes to engage the public and interested parties. Due to the rapid change in prices, technologies and business models, we suggest planning for an evergreen process to begin now with a view to broad stakeholder engagement in Q2 or Q3, 2022.

That timeframe would enable practical discussion on the results from:

- Imports on the Maritime Link (Base Block and Market Electricity), the scale, and implications for integration of other renewables;
- New assumptions on the cost and value of renewable energy resources, including onshore and offshore wind and solar PV, and the cost and value of storage;
- New assumptions on technology, consumer interest and cost associated with Distributed Energy Resources and the initial outcomes from the NS Power Smart Grid project; and
- Initial findings on the value of Time Varying Pricing.

In addition to our general observations about a rapidly evolving energy landscape, we would also wish to make some specific observations about offshore wind.

The Government of Canada is continuing to establish a regulatory framework for the development of these resources. As that work matures, industry is beginning to identify the specific steps required to make such investments feasible. One of the steps is to establish the cost and value of such resources. We understand such work is now underway, and by the spring of 2022 we believe the case for considering offshore wind as delivering near baseload capacity (greater than 60% capacity) which should result in a much different analysis of its value.

Furthermore, we also note that even the high-electrification scenarios do not assume a great deal of growth in the need for electricity. New population and GDP growth patterns as well as new industrial opportunities in a clean carbon economy may drive demand higher than forecast. This outcome would raise new questions on where the resources to meet such demands (in excess of demand forecasts from all scenarios) may come from.

We would note that while onshore wind and imported renewables provide low-cost solutions for current demand forecasts, their growth and availability may well be constrained by public concerns. Considering the longer-term options for the next best source of near-base load electricity – offshore wind – would be prudent.

A similar case may be made for the rapidly evolving world of DERs, including customer driven efficiency measures, storage, and trends for electric vehicles. With assumptions on these matters baked into the IRP with 2019 knowledge, it would seem reasonable that those assumptions should be updated with 2022 knowledge available in the spring of 2022.

We would note that the value of DER is not only an issue of price. There will also be benefits from re-engineering legacy utility designs and processes. The NS Smart Grid Project will only begin to touch the surface of understanding innovation from new products and services, and the evolution of utility capabilities. Evaluating new utility capabilities and opportunities for investments in grid monitoring and control, customer engagement, DER valuation etc. are all needed to be continually updated to enable DERs to provide full benefits for ratepayers.

We will continue to help advance the agenda for a lower carbon future, and we view the evergreen IRP and associated processes to be a priority for us. We thank everyone who has made the current IRP a success. A success in terms of identifying pathways to a lower carbon future, but also in broadening the base of knowledge among many stakeholders.

Bruce Cameron
Principal Consultant,
Envigour Policy Consulting Inc.

c.c. Tonja Leach, Executive Director QUEST
Via Email: tleach@questcanada.org

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Greg Robart, CEO Smart Grid Innovation Network
Via Email: greg@sgin.ca

November 13, 2020

Nova Scotia Power
1223 Lower Water Street, Halifax, NS
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Attention: **Linda Lefler, P.Eng. Senior Project Manager, Regulatory Affairs**

Re: **NSPI Draft IRP Report**

Dear Ms. Lefler,

Thank-you for the opportunity to review and comment on the NSPI 2020 Integrated Resource Plan Draft Report ("Draft IRP") dated October 30, 2020 and recently filed with the NSUARB.

Further to my email correspondence of July 17, 2020, my interest in this proceeding stems from my ongoing doctoral research and my prior participation in regulatory proceedings related to electricity system planning, hydroelectric development and system decarbonization. As part of a national research effort, I am currently engaged in the development and application of open-source capacity expansion and production cost models of the provincial electricity systems with a focus on hydroelectric renewal, long-term electricity infrastructure planning and economic risk. In my capacity as an independent energy consultant, I have testified in the following proceedings:

- British Columbia Utilities Commission – Inquiry Respecting Site C (2017)
- National Energy Board Modernization Expert Panel (2017)
- EA Expert Panel Review of Federal Environmental Assessment Processes (2016-2017)
- NL Public Utilities Board – NLH Amended General Rate Application (2015)
- Manitoba PUB – NFAT Review, Keeyask and Conawapa Projects (2013-2014)
- Joint Review Panel, Site C Clean Energy Project (2013-2014)
- Legislative Assembly of Alberta, Standing Committee on Resource Stewardship – Review of the Potential for Expanded Hydroelectric Energy Production in Northern Alberta (2013)
- Joint Review Panel, Lower Churchill Project (2011-2012)
- Alberta Utilities Commission – Inquiry on Hydroelectric Power Generation (2010)

My comments below (see also Appendix A) relate primarily to load forecasting matters initially raised in my comments of July 17, 2020 (see Appendix B) with references to the Draft IRP.

1 LOAD FORECASTING

NSPI's future requirements for electrical energy and capacity are inherently uncertain. The rate of growth (stagnation or contraction) in these requirements can be influenced by multiple, highly variable factors, including the following:

- rates of economic and income change;
- population and demographic changes;
- long-term changes in climate conditions;

- sectoral (residential, commercial and industrial) electricity consumption changes;
- shifts in the economy towards services, which generally consume less energy;
- the cost of alternative energy sources, including the influence of carbon pricing, and cross-price elasticity effects on electricity demand;
- the price of electricity and own-price elasticity effects on demand;
- the use of self-generated electricity supply resources that reduce requirements for electricity from the interconnected grid;
- demand-side management, including technological evolution and costs; and
- the extent of low-carbon electrification.

Given these multiple highly variable factors, no forecast will be entirely accurate at predicting requirements, particularly many years into the future. However, **recent experience in other jurisdictions across Canada suggests that inadequate consideration of the factors influencing future electricity requirements has tended to result in substantial overestimates of future electricity requirements**. While the case of the Muskrat Falls Project and the overestimates of future electricity requirements in Newfoundland & Labrador will be well known to participants in the NSPI IRP process, similar overforecasts have occurred in British Columbia in relation to the Site C Project, and in Ontario following coal replacement and the feed-in tariff program.

Clearly, forecasts that are too low may result in energy or capacity shortfalls that trigger additional costs to import or operate more costly generation during peak demand periods or, in extreme circumstances, impact system reliability. However, forecasts that are too high often result in advancing supply-side resources prior to actual needs, resulting in additional and unnecessary costs to ratepayers, curtailment of investments in lower-cost demand-side management in order to lower revenue requirements, and export of surplus energy at prices below the costs of production.

Utilities treat these reliability and overforecasting risks asymmetrically, since underestimating future requirements involves a risk to reliability that overestimating does not. However, it is not good utility practice to overforecast in order to reduce this risk. A P50 forecast should endeavour to be a P50 forecast.

2 NSPI FORECASTS VS. ACTUALS

> ***Prior request**: Provide a tabular and graphical summary of NSPI energy (GWh/year) and firm capacity (MW) load forecasts over the prior 20 years, illustrating the effects of the prior recession (i.e. of 2008-2010) on load and on load forecasts for the NSPI service area pre- and post-recession.*

The purpose of this request was to investigate the historic accuracy of NSPI forecasting in an attempt to reveal potential biases in forecasting. In a long-term forward-looking process like an IRP, it is important to look far back into the past so as to see more clearly and confidently into the future. In reviewing NSPI's most recent load forecast, I am aware that the Board has "raised concerns about the accuracy and consistency of NS Power's forecasting on previous occasions."[1]

A response to this information request was not received from NSPI, and Figure 1 and Figure 2 below were created to illustrate the accuracy of NSPI base load forecasts for both Net System Requirements

[1] Nova Scotia Utility and Review Board. November 5, 2019. Board Decision Letter. MO9191 – Nova Scotia Power Inc. – 2019 Load Forecast Report – P-194.

(NSR) and Net System Peak (NSP), respectively. Data were located for the period 2008 through 2019, inclusive, and obtained from the NSPI 10-Year System Outlook reports filed annually with the NSUARB. The base load forecasts presented in the System Outlook reports are understood to be P50 forecasts, inclusive of the effects of demand-side management (DSM) and therefore suitable for direct comparison to actual requirements for energy and capacity.

Figure 1: NSPI Net System Requirements

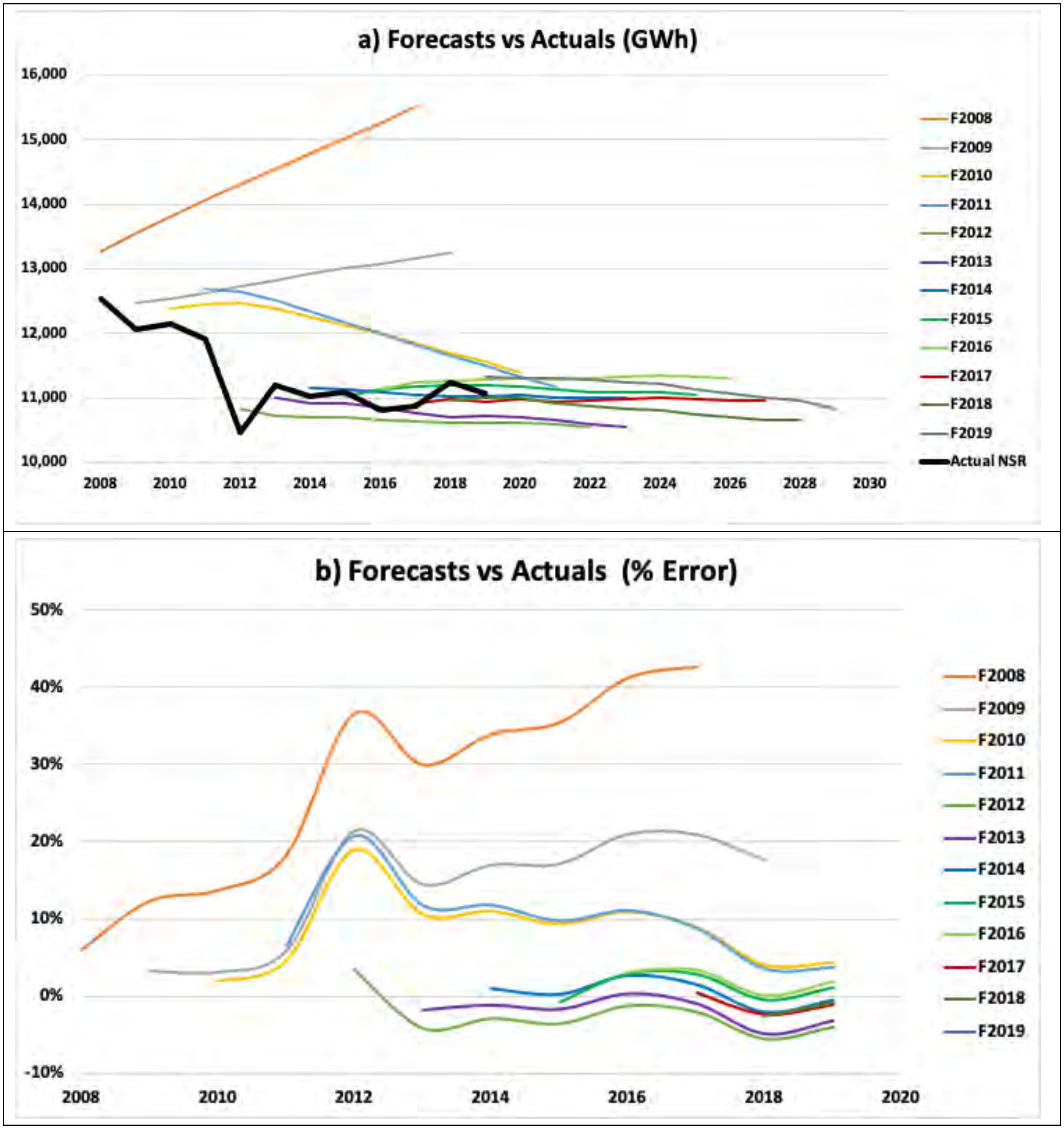
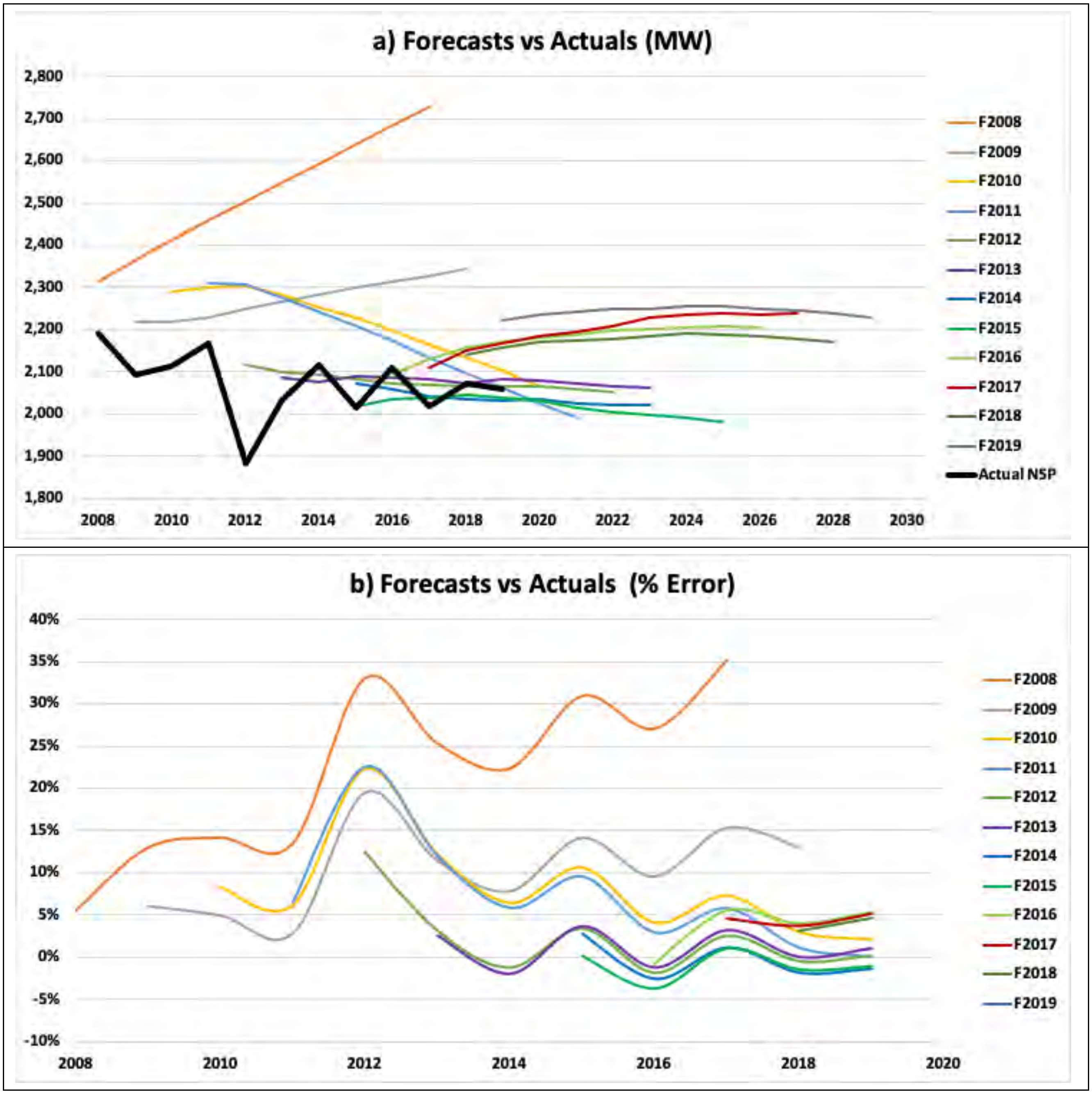


Figure 2: NSPI Net System Peak



Several observations can be made from these figures:

- **Declining requirements**: as evidenced by the black lines, actual NSR and actual NSP have been declining over the past decade, a trend not uncommon in many Canadian provinces.
- **Pre-recession accuracy**: The historic baseload forecasts of future NSR and NSP for the years prior to the 2008-2009 recession substantially overestimated actual system requirements on the order of 4,700 GWh/year and 700 MW, with forecasting errors expanding over time.
- **Post-recession accuracy**: The historic forecasts of both NSR and NSP since 2012 have reasonably predicted actual requirements, at least to date.

These observations tempt one to conclude that NSPI forecast accuracy was the victim of an unlikely and extreme recessionary event, and any necessary adjustments to forecasting methods have since been implemented. The ongoing concerns of the Board respecting NSPI load forecasting, and the experiences of other Canadian utilities suggest such a conclusion would be premature. Figure 3 illustrates the pattern of overestimation and underestimation in the NSPI forecasts.

Figure 3: NSPI – Forecasts vs Actuals

a) Net System Requirements (NSR)

Forecast Year	F2008	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	TOTAL	RATIO
2008	5.85%													
2009	12.19%	3.35%												
2010	13.60%	3.20%	1.97%											
2011	18.12%	5.95%	4.51%	6.56%										
2012	36.57%	21.48%	19.05%	20.74%	3.48%									
2013	29.91%	14.53%	10.61%	11.73%	-4.23%	-1.70%								
2014	33.90%	17.04%	11.04%	11.80%	-2.96%	-1.09%	1.02%							
2015	35.40%	17.19%	9.36%	9.74%	-3.65%	-1.61%	0.26%	-0.68%						
2016	41.22%	21.03%	10.96%	11.09%	-1.30%	0.41%	2.68%	2.93%	3.09%					
2017	42.61%	21.00%	8.93%	8.82%	-2.09%	-0.88%	1.53%	2.88%	3.34%	0.38%				
2018		17.70%	4.04%	3.56%	-5.63%	-4.82%	-2.02%	-0.40%	0.09%	-2.34%	-2.58%			
2019			4.36%	3.75%	-4.09%	-3.10%	-0.48%	1.18%	1.85%	-1.13%	-0.70%	2.29%		
Overestimated	10	10	10	9	1	1	4	3	4	1	0	1	**54**	**72.00%**
Underestimated	0	0	0	0	7	6	2	2	0	2	2	0	**21**	**28.00%**

b) Net System Peak (NSP)

Forecast Year	F2008	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	TOTAL	RATIO
2008	5.47%													
2009	12.95%	6.07%												
2010	14.14%	4.97%	8.33%											
2011	13.47%	2.86%	6.13%	6.55%										
2012	33.05%	19.50%	22.32%	22.64%	12.49%									
2013	25.33%	11.46%	12.25%	12.00%	3.20%	2.56%								
2014	22.38%	7.84%	6.42%	5.85%	-1.18%	-1.94%								
2015	30.97%	14.14%	10.62%	9.58%	3.42%	3.67%	2.83%	0.20%						
2016	27.10%	9.57%	4.07%	2.94%	-1.80%	-1.18%	-2.51%	-3.65%	-0.85%					
2017	35.23%	15.31%	7.28%	5.80%	2.58%	3.22%	1.19%	1.09%	5.55%	4.56%				
2018		13.02%	2.94%	1.11%	-0.43%	0.05%	-1.78%	-1.40%	4.00%	3.67%	3.18%			
2019			2.09%	0.05%	0.24%	1.07%	-1.31%	-1.02%	5.34%	5.15%	4.71%	7.82%		
Overestimated	10	10	10	9	5	5	2	2	3	3	2	1	**62**	**83.78%**
Underestimated	0	0	0	0	3	2	3	3	1	0	0	0	**12**	**16.22%**

Two key issues arise from this pattern:

- **Insufficient data**: With only 12 years of forecasts available for review, the longer-term pattern of NSPI load forecasting remains hidden from review by the Board and interveners.
- **No long-term underestimates**: Despite the limited data, no forecast of NSR or NSP produces an overestimate 10 years into the future, and longer-term forecasts are unavailable.

In other words, the broader pattern of NSPI forecasting is unknown. Has the utility ever produced a 10-year forecast base case (P50) load forecast that underestimated requirements 10 years into future? Or 20 years into the future? To illustrate one potential answer to this question, Figure 4 presents the pattern of load forecasting by BC Hydro for the years 1998-2009.

Figure 4: BC Hydro Total Gross System Requirements – Forecasts vs Actuals 1998-2009 (% Error)[2]

Forecast Year	F1998	F1999	F2000	F2001	F2002	F2003	F2004	F2005	F2006	F2007	F2008	F2009	TOTAL	RATIO
1998	4.91%													
1999	2.48%	1.70%												
2000	3.54%	2.60%	0.11%											
2001	1.70%	2.31%	0.49%	-0.18%										
2002	4.62%	5.41%	3.43%	1.76%	0.37%									
2003	5.24%	6.43%	3.08%	1.86%	-0.73%	1.32%								
2004	3.87%	4.20%	0.61%	-0.17%	-1.24%	-0.57%	-0.89%							
2005	4.58%	6.00%	1.06%	-0.44%	-0.98%	0.60%	-1.80%	0.37%						
2006	4.30%	4.95%	-0.94%	-1.61%	-2.63%	-1.04%	-4.35%	-2.02%	-0.10%					
2007	3.48%	4.66%	0.70%	-0.64%	-2.07%	-0.47%	-4.84%	-2.45%	0.24%	0.34%				
2008	4.10%	4.83%	1.79%	0.27%	-1.34%	0.15%	-5.02%	-3.14%	-0.02%	0.74%	-0.80%			
2009	8.29%	8.89%	5.78%	4.79%	3.26%	4.52%	-1.86%	0.22%	3.54%	4.71%	3.47%	0.58%		
Overestimated	12	11	9	4	2	4	0	2	2	3	1	1	51	65.38%
Underestimated	0	0	1	5	6	3	6	3	2	0	1	0	27	34.62%

The pattern of BC Hydro forecasting errors of Total Gross System Requirements[3] over the period 1998-2009 is similar to the pattern of NSPI forecasting errors of both NSR and NSP over the period 2008-2019. In the BC Hydro case, one plausible explanation is that the utility's load forecasting was the victim of recessionary conditions and other factors influencing domestic and export requirements several years into the future, and that any necessary adjustments to forecasting methods were implemented over the following years.

Such a conclusion would be incorrect. Figure 5 below illustrates the longer-term pattern of BC Hydro load forecasting based on data filed over the past several years with the BC Utilities Commission. Over the period 1981-2018, BC Hydro produced thirty 20-year load forecasts,[4] six 10-year forecasts and two 5-year forecasts. Key observations are as follows:

- **Forecasting pattern**: the forecasting pattern of the 1998-2009 period was not indicative of the broader pattern, which is much more skewed towards overforecasting (83% of the time) for almost all forecasts in all years within the 1981-2009 forecasting period.
- **Overforecasting magnitude**: The magnitude of overforecasting becomes more extreme in the latter years of the BC Hydro forecasts, typically on the order of 20%-30% above actuals. The potential for such long-term overforecasting cannot be determined from 10-year forecasts such as those developed by NSPI. These are significant overestimates of the kind that typically trigger (and have triggered) long-term, long lead-time, capital-intensive investments in large-scale hydroelectric, nuclear or inter-regional transmission that later prove to be premature, unnecessary or higher cost than the alternative solutions whose costs decline in the interim.
- **Year 1 accuracy**: In the first year following the forecast, 14 of the BC Hydro forecasts underestimated requirements while 14 overestimated requirements, suggesting that the base load forecasts could defensibly be claimed to be P(50) forecasts, at least for the first year.

[2] For data sources, see Appendix A.

[3] The equivalent of NSPI Net System Requirements

[4] Several of which were 30-year forecasts

Figure 5: BC Hydro Total Gross System Requirements – Forecasts vs Actuals 1981-2018 (% Error)[5]

Forecast Year	F1981	F1982	F1983	F1984	F1985	F1986	F1987	F1988	F1989	F1990	F1991	F1992	F1993	F1994	F1995	F1996	F1997	F1998	F1999	F2000
1981	0.94%																			
1982	5.57%																			
1983	18.49%	14.75%	3.35%																	
1984	24.47%	18.88%	5.45%	3.52%																
1985	21.90%	15.90%	1.31%	-0.62%																
1986	22.94%	16.74%	1.70%	0.31%	-5.70%	-2.15%														
1987	25.98%	20.52%	5.19%	1.54%	-3.97%	-0.63%	0.57%													
1988	25.34%	18.67%	3.25%	-2.80%	-8.27%	-6.92%	-4.22%	-2.04%												
1989	24.73%	18.25%	2.44%	-3.67%	-9.49%	-8.10%	-6.34%	-3.01%	-0.69%											
1990	26.53%	20.79%	3.98%	-3.24%	-7.60%	-8.26%	-6.43%	-2.99%	0.47%	1.78%										
1991	25.71%	19.57%	3.24%	-5.23%	-9.70%	-9.97%	-8.35%	-5.49%	-1.76%	0.53%	-0.03%									
1992	34.21%	26.64%	9.96%	-0.47%	-5.37%	-5.35%	-4.13%	-1.62%	2.71%	6.19%	5.60%	7.13%								
1993	35.20%	27.92%	9.60%	-0.26%	-6.69%	-5.79%	-5.12%	-2.47%	1.09%	5.40%	4.03%	3.67%	6.89%							
1994	40.58%	33.10%	13.02%	2.98%	-5.48%	-5.12%	-3.37%	-0.50%	3.45%	8.32%	7.10%	6.43%	5.69%	-1.25%						
1995	43.81%	36.24%	15.01%	4.07%	-5.30%	-4.42%	-2.95%	0.37%	4.51%	9.43%	10.16%	6.98%	7.99%	0.67%	-1.31%					
1996	46.45%	38.43%	16.42%	4.90%	-4.35%	-4.89%	-2.61%	0.62%	5.05%	10.25%		6.53%	6.04%	0.71%	0.24%	0.49%				
1997	47.36%	38.81%	16.34%	4.21%			-3.49%	-0.43%	3.97%	9.40%		4.36%	2.62%	-0.13%	-0.07%	-0.44%	-1.59%			
1998	59.70%	49.56%	25.15%	11.70%				6.08%	11.04%	16.19%		10.88%	7.52%	6.65%	7.51%	6.83%	5.07%	4.91%		
1999	57.77%	46.96%	22.80%	9.63%					8.63%	13.17%		7.36%	4.51%	4.08%	5.84%	3.33%	3.77%	2.48%	1.70%	
2000	61.84%	50.00%	25.16%	11.00%						14.33%		8.33%	5.84%	4.55%	8.42%	4.33%	4.84%	3.54%	2.60%	0.11%
2001	63.28%	50.63%	25.34%	11.18%								8.01%	4.97%	4.34%	9.08%	4.50%	3.89%	1.70%	2.31%	0.49%
2002	70.64%	56.56%	30.12%	15.09%								10.97%	8.35%	8.47%	11.69%	7.70%	6.81%	4.62%	5.41%	3.43%
2003		59.11%	32.09%	16.51%								11.17%	7.96%	8.93%	11.86%	8.54%	7.43%	5.24%	6.43%	3.08%
2004				16.07%								9.34%	6.82%	8.11%	10.32%	6.87%	5.88%	3.87%	4.20%	0.61%
2005												9.73%	7.66%	9.43%	11.10%	7.53%	7.05%	4.58%	6.00%	1.06%
2006												8.19%	6.18%	7.71%	9.72%	6.13%	7.03%	4.30%	4.95%	-0.94%
2007												8.95%	7.84%	9.08%	10.14%	6.82%	7.12%	3.48%	4.66%	0.70%
2008												9.06%	9.00%	9.61%	10.11%	7.71%	7.79%	4.10%	4.83%	1.79%
2009												13.18%	13.51%	13.88%	14.06%	12.57%	12.42%	8.29%	8.89%	5.78%
2010												19.33%	20.30%	20.38%	20.34%	19.66%	19.13%	14.47%	15.00%	11.67%
2011												21.36%	23.17%	23.00%	22.16%	22.18%	21.48%	16.51%	17.01%	13.61%
2012												19.19%	22.04%	21.46%	19.81%	20.67%	19.87%	14.79%	15.24%	11.86%
2013													25.82%	24.57%	22.22%	23.86%	22.73%	17.50%	17.05%	13.58%
2014														24.05%	21.22%	23.37%	21.86%	16.52%	15.57%	12.06%
2015															26.86%	29.61%	27.69%	21.96%	21.30%	17.54%
2016																31.90%	29.60%	23.45%	23.15%	19.33%
2017																	29.13%	22.97%	22.98%	19.28%
2018																		21.87%	22.17%	18.58%
2019																			26.08%	22.48%
2020																				
Overestimated	22	21	21	14	0	0	1	3	9	11	4	21	21	19	19	20	20	21	21	19
Underestimated	0	0	0	7	11	11	10	8	2	0	1	0	0	2	2	1	1	0	0	1

Forecast Year	F2001	F2002	F2003	F2004	F2005	F2006	F2007	F2008	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020	TOTAL	RATIO
1981																						
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1999																						
2000																						
2001	-0.18%																					
2002	1.76%	0.37%																				
2003	1.86%	-0.73%	1.32%																			
2004	-0.17%	-1.24%	-0.57%	-0.89%																		
2005	-0.44%	-0.98%	0.60%	-1.80%	0.37%																	
2006	-1.61%	-2.63%	-1.04%	-4.35%	-2.02%	-0.10%																
2007	-0.64%	-2.07%	-0.47%	-4.84%	-2.45%	0.24%	0.34%															
2008	0.27%	-1.34%	0.15%	-5.02%	-3.14%	-0.02%	0.74%	-0.80%														
2009	4.79%	3.26%	4.52%	-1.86%	0.22%	3.54%	4.71%	3.47%	0.58%													
2010	11.11%	9.29%	11.13%	3.09%	4.85%	9.34%	10.56%	8.56%	5.67%	-0.90%												
2011	13.07%	11.26%	13.21%	4.41%	6.89%	11.15%	12.93%	9.14%	6.45%	4.09%	1.89%											
2012	10.98%	9.71%	11.27%	2.32%	4.22%	9.46%	11.74%	5.14%	2.91%	1.88%	1.42%	-1.50%										
2013	12.70%	11.59%	13.14%	4.80%	6.75%	12.13%	14.84%	7.86%	4.69%	3.09%	3.43%	1.28%	-0.57%									
2014	11.26%	10.26%	11.72%	4.26%	6.29%	11.75%	14.30%	8.64%	4.34%	1.99%	2.72%	2.12%	-1.16%	-0.95%								
2015	16.81%	15.83%	17.37%	9.46%	11.84%	15.85%	18.44%	15.06%	7.86%	6.68%	11.00%	7.68%	3.54%	5.64%	4.02%							
2016	18.68%	17.68%	19.34%	11.22%	13.83%	17.95%	20.43%	16.68%	5.97%	7.03%	13.45%	11.43%	4.97%	7.73%	4.98%	2.77%						
2017	18.69%	17.69%	19.40%	11.15%	14.03%	18.07%	20.54%	16.75%	4.25%	6.03%	12.88%	15.57%	4.02%	10.63%	4.78%	1.00%						
2018	18.04%	17.09%	18.86%	10.53%	13.54%	17.44%	19.80%	16.02%	2.32%	4.24%	11.12%	16.98%	7.70%	11.98%	4.30%	-0.96%						
2019	21.98%	21.06%	22.87%	14.21%	17.55%	21.27%	23.78%	19.89%	3.98%	6.27%	13.43%	20.08%	16.17%	15.75%	8.81%	2.46%		1.71%				
2020																						
Overestimated	14	12	14	10	12	12	13	11	11	9	9	7	5	5	5	3	0	1	0	0	440	**83.18%**
Underestimated	5	6	3	6	3	2	0	1	0	1	0	1	2	1	0	1	0	0	0	0	89	**16.82%**

5 For data sources, see Appendix A.

- **Year 10 accuracy**: Of the 29 forecasts for which the 10-year forecasts can be compared to actuals, only 3 forecasts underestimated requirements, suggesting systemic patterns of forecasting bias regardless of short-term conditions (e.g. recessions, market shifts, etc.).
- **Year 20 accuracy**: Of the 13 forecasts for which the 20-year forecast can be compared to actuals, none of forecasts underestimated requirements. Although BC Hydro forecasts, much like NSPI forecasts, produced overestimates in some early years, no BC Hydro forecasts produced underestimates in the 20-year forecast. BC Hydro's 20-year forecasts have been P(100) forecasts with a 100% chance that the forecast would exceed actual requirements.

3 POTENTIAL CAUSES OF OVERFORECASTING

To be clear, the pattern of overcasting is not unique to BC Hydro. Our research reveals that other utilities and system operators also persistently and substantially overestimate long-term requirements. Why might this be occurring and how is it relevant to the NSPI IRP process?

- **Risk asymmetry bias**: Reliability is the primary mandate of the utility, ultimately superseding other considerations such as cost-effectiveness and environmental protection. In a historic context where the alternatives consisted solely of large-scale, long-lead time, capital-intensive, supply-side alternatives (large-scale hydro, nuclear and coal) a strong bias towards reliability and away from overforecasting was likely prudent. Coupled with high domestic demand growth and high export market prices capable of absorbing Canadian utility largess, overforecasting carried manageable (and disguisable) risks. This is no longer the case. Export market prices are low and anticipated to remain that way into the foreseeable future, and domestic demand is flat with growth rates under low-carbon electrification still modest by historical standards. Additionally, the energy and capacity alternatives today consist of a breadth of affordable, portable and modular demand-side and supply-side alternatives that can be rapidly mobilized in the event of higher than forecasted increases in demand. As we are witnessing in several provinces across Canada, the propensity for overforecasting is triggering very high cost and largely premature (if not unnecessary) investments in supply-side generation and transmission resources, contributing to substantial rate increases, and potentially undermining the low-carbon electrification transition. This issue is of particular relevance to the timing of decisions to develop, procure or contract firm capacity resources and enhanced inter-regional transmission, such as that contemplated in the Draft IRP.
- **Underestimating price effects**: One of the main concerns raised in the regulatory review of BC Hydro's Site C Project was the utility's estimate of the price elasticity of demand for electricity.[6] Over the long-term and in the context of meaningful increases in real electricity rates expected during the low-carbon transition, the selection of an appropriate price elasticity significantly impacts forecasts of future requirements. The result of this concern was a subsequent doubling of BC Hydro's price elasticity from -0.05 to -0.10 as an outcome of its

[6] BC Hydro defines price elasticity of demand as the measure of the responsiveness of quantity demand to a change in price expressed as the percent change in quantity demanded to a one percent change in price

most recent revenue requirements proceeding.[7] The long-term effect of this change for the 20-year load forecast will become known as BC Hydro completes its ongoing IRP process.

- **DSM end-of-history illusion**: The common approach used by utilities for DSM planning is to set out DSM measures in short-term plans, forecast the savings over the life of each measure (typically 10-15 years), and then presume no additional DSM savings thereafter. While this is reasonable for a short-term planning exercise such as a revenue requirements or ratemaking procedure, it is entirely unsuitable for a longer-term planning process such as an IRP, and can result in substantial overestimates of long-term requirements. Time has not permitted a detailed review of the DSM methodologies employed for this IRP; however, the lack of a quantification of the avoided costs of DSM during this proceeding, coupled with the tell-tale "swoosh" graph (see Figure 4 of the Draft IRP) in which future energy requirements rapidly ascend (while the effects of DSM rapidly descend or disappear) approximately 10-years beyond the load forecast start date are not promising signs that DSM has been adequately considered in the Draft IRP. This is somewhat surprising considering the acknowledgement in the sensitivity analysis in the most recent 2019 Load Forecast that "DSM represents a much larger source of variability when compared to the potential impact of weather or economics".
- **Exclusion of recessions**: Typical of many Canadian utilities, NSPI makes use of Conference Board of Canada economic drivers and projections in its load forecasts. These projections generally exclude the potential for and impacts of economic recessions, presumably because of their stochastic nature. While the timing and depth of individual recessions are difficult to predict, the potential for one or more recessions within the 30-year planning horizon used in the Draft IRP seems highly certain if not inevitable. Yet, it does not appear that such an eventuality has been considered in the Draft IRP or in NSPI's most recent load forecast, omissions that will contribute to long-term overforecasting to the extent that such recessionary events actually occur.

4 RECOMMENDATIONS

My recommendations to NSPI and the NSUARB further to my comments above are as follows:

- **NSPI Load Forecasts**. The Board needs to request and the NSPI needs to provide its load forecasts dating back for as many years as are available so that they can be reviewed by the Board and interveners to determine the overall propensity and reasons for potential overforecasting. In the event that the utility has been producing longer-term internal forecasts not currently make available to the Board, these should also be provided.
- **20-year Forecasts**. The current requirement for NSPI to file a 10-year forecast on an annual basis should be continued. Extending the forecasting period to 20 years would allow for the exploration of additional scenarios related to long-term resource planning in support of long-term generation and transmission investments like those contemplated in the Draft IRP. While

[7] BCUC. October 2, 2020. British Columbia Hydro and Power Authority F2020 to F2021 Revenue Requirements Application. Decision and Order G-246-20. (https://www.bcuc.com/Documents/Proceedings/2020/DOC_59355_2020-10-02-BCH-F2020-F2021-RRA-Decision.pdf)

longer-term forecasts are inherently more variable, in their absence it is not possible to determine whether lurking within the NSPI 10-year forecasts are biases towards long-term overforecasting that left unexamined may result in the development of resources in advance of actual needs and at higher costs than future alternatives, as has been the case in other jurisdictions.

- **Methodological review**. Depending on the initial findings of the review of NSPI historical forecast accuracy, the Board could consider a formal review of matters related to NSPI historical forecasting accuracy, potentially pursuant to its review of NSPIs next load forecast.

Thanks for the opportunity to submit these comments. I look forward to reading the comments of other reviewers and to reviewing a final version of the NSPI Integrated Resource Plan.

Sincerely,

Richard Hendriks

Heritage Gas

November 13, 2020

Nicole Godbout
Director, Regulatory Affairs
Nova Scotia Power Inc.
PO Box 910
Halifax, NS B3J 2W5

RE: M08929 – NSPI Integrated Resource Planning – Draft IRP Report

Heritage Gas has reviewed the Draft IRP Report, distributed to stakeholders on October 30, 2020, and notes that it continues to reiterate the need for, and reliance on, natural gas in the province over the next 25-year period. The IRP highlights the *need for additional firm generating capacity to ensure that the system is reliable with sufficient supply available to meet expected demand, especially during periods of low renewable generation and peak loads.*[1] Natural gas based generation also provides critical ancillary services needed to support increased levels of renewable energy:

> *"The IRP analysis has shown that combustion turbines are the lowest-cost domestic source of new firm capacity; they replace retiring thermal capacity in all resource plans. These units are also fast-acting, meaning they can quickly respond to changes in wind and non-firm imported energy."*[2]

Natural Gas Supports the Transition to Net-Zero Emissions

As shown in the Draft IRP Report, natural gas is a low-carbon source of electrical generation and will be necessary in supporting renewable integration in the province:

> *"Low-cost, low emitting generating capacity may also be provided economically through redevelopment of existing natural gas-powered steam turbines or coal unit conversions."*[3]

Heritage Gas acknowledges that renewable electrification in certain sectors of the economy will be important for decarbonization in Nova Scotia. However, electrification unaccompanied with other clean

[1] Nova Scotia Power Inc. 2020 Integrated Resource Plan DRAFT REPORT, Page 18.
[2] Nova Scotia Power Inc. 2020 Integrated Resource Plan DRAFT REPORT, Page 20.
[3] Nova Scotia Power Inc. 2020 Integrated Resource Plan DRAFT REPORT, Page 20.

energy options will not be sufficient to meet the Sustainable Development Goals Act ("SDGA") Net-Zero 2050 target.

The Offshore Energy Research Association ("OERA"), Liberty Utilities, Heritage Gas, Atlantic Canada Opportunities Agency ("ACOA") and the provincial Department of Energy & Mines engaged Zen Energy Solutions to determine the future potential uses of hydrogen in Nova Scotia. Governments around the world increasingly see hydrogen as imperative in meeting the Net-Zero targets[4] - such as those described in the European Hydrogen Roadmap "*the EU will require hydrogen at large scale. Without it, the EU would miss its decarbonization objective.*"[5] The study by Zen supports the development of a hydrogen economy in Atlantic Canada and shows that hydrogen could deliver up to 22% of the end-use energy by 2050.[6] In addition to having an important role in building heat and energy storage, hydrogen can serve a central role in areas that are challenging to cost-effectively electrify. These include heavy vehicle transportation, industrial and institutional processes.

Therefore, in addition to the role of natural gas in supporting the transition of the electrical grid, the introduction of hydrogen and renewable natural gas ("RNG") into natural gas infrastructure will further support the province in reaching the net-zero emissions target set out in the SDGA.

Integrated Energy System Efficiencies

While natural gas underpins the transition of the electric grid to lower carbon intensity, natural gas infrastructure can also play an important role in supporting the transformation over the next 25-30 years in the province. There is an increasing awareness of the opportunity to accelerate the reduction in GHGs, increase reliability and lower energy costs for Nova Scotians by integrating the electrical grid with the existing natural gas pipeline network, for a more efficient and circular use of resources in the province.

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[4] A Feasibility Study of Hydrogen Production, Storage, Distribution, and Use in the Maritimes, page ii.
[5] Fuel Cells and Hydrogen Joint Undertaking, Hydrogen Roadmap Europe - A Sustainable Pathway for the European Energy Transition, 2019.
[6] A Feasibility Study of Hydrogen Production, Storage, Distribution, and Use in the Maritimes, page x.

An integrated energy system supports the production of more renewable energy including wind power, solar, green hydrogen, and RNG. It can also reduce Nova Scotia's reliance on other jurisdictions and promote local economic growth and energy independence, further improve energy resiliency and flexibility, effectively manage peak demand, and lower costs to Nova Scotian energy ratepayers.

NSPI has noted its view that "*electrification is a key enabler of economy wide decarbonization in support of provincial goals and targets*"[7]. However, by its nature, the IRP process reviewed the electric system alone and did not evaluate other non-electric opportunities to cost-effectively enable energy solutions consistent with provincial goals and targets. The IRP analysis reviewed a broad spectrum of assumptions, and many of those, such as EV uptake for example only, could well play out in very different ways in the coming years, and the IRP is clear that NSPI's transition to a significantly less coal based carbon intensive system will require a number of years to occur. Heritage Gas believes that NSPI's approach to an evergreen IRP will be valuable in this regard, so that all parties can continue to participate as NSPI conducts the numerous follow-up analysis the IRP calls for and the status of underlying assumptions becomes clearer. That said, it is critically important for the province as a whole and for the achievement of the sustainable development called for by the SDGA that there are vibrant competitive alternatives to electricity available in the marketplace. Heritage Gas believes it is imperative for all energy providers in the province to work together and with government and other stakeholders to ensure the most cost effective, competitive, and sustainable energy solutions are put in place.

Heritage Gas is open to collaborating with NSPI on the process to achieving an integrated energy system, which will achieve lower emissions and reduce costs to the benefit of all ratepayers.

<u>Conversion of Coal-to-Gas</u>

Roadmap item 1 discusses the need for "*advance engineering study work on coal to gas conversions at Trenton and Point Tupper Generating Stations. Monitor cost outputs of this work relative to IRP assumptions and update the balance of new and converted capacity resources accordingly*"[8]. Heritage Gas

[7] Nova Scotia Power Inc. 2020 Integrated Resource Plan DRAFT REPORT, Page 14.
[8] Nova Scotia Power Inc. 2020 Integrated Resource Plan DRAFT REPORT, Page 134.

reiterates that the Action Plan should reflect a timeline of completion of this study and scope of the work included in the coal-to-gas conversion scenario, and should keep stakeholders engaged and apprised in this process.

Regional Intertie/Integration

The Draft IRP Report identified the need for further study on the Intertie to provide firm capacity and ancillary services:

> *"Nova Scotia Power notes that any resource plans which go beyond the findings of the pre-IRP stability study will require further analysis to confirm they can be operated reliably."*[9]

Given that the Regional Integration and Reliability Ties play a key role in many of the optimal resource plans developed for the key scenarios, these studies should be undertaken in the near term.

The tie line connection to New Brunswick will be exposed to the increasing frequency and severity of storms related to climate change impacts. The influence of increased dependence on the electrical grid and regional interconnections associated with increased electrification needs to be considered with respect to energy security and reliability for the province.

General Comments

Heritage Gas notes that NSPI distributed reply comments on November 6, 2020 to the stakeholder group, which addressed comments on the Draft Findings, Action Plan and Roadmap. The comments previously raised by Heritage Gas include those discussed in this letter, and those previously raised with respect to Transmissions & Distribution ("T&D") costs associated with electrification, and the reliability of the now 45-year old liquid-fueled combustion turbines ("CTs"). Considering the importance to all stakeholders of understanding the potential full costs of electrification, Heritage Gas suggests that NSPI's final IRP Report establish a rigorous timeline for a robust T&D study completion, as the results from this study will be necessary to further inform the potential major investments in regional interconnection and transmission build-out cost implications that NSPI is planning by 2030. Heritage Gas will continue to engage in the

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[9] Nova Scotia Power Inc. 2020 Integrated Resource Plan DRAFT REPORT, Page 48.

process as the results from the work to address electrification impacts on the T&D system become available and the Thermal Plant Depreciation study results are published.

With respect to the existing CTs, NSPI has stated that its analysis has "conclusively shown" that the sustaining capital for the LFO-fired CTs is the most economic approach. Heritage Gas has already provided comments regarding the potential concerns with reliance on units of this vintage even with sustaining capital, and notes that Bates White in its August 21, 2020 Audit Report on NSPI's 2018-2019 FAM, noted in its Conclusion IX-17 on page 231 that data on the impact of certain investments in the LFO-fired CTs was at that time inconclusive and should be monitored based on concerns noted in the Audit Report that could bear on the ultimate reliability of those units. Heritage Gas believes that such ongoing monitoring is very important considering the recent history and vintage of these units and that the IRP should specifically provide for such monitoring and reporting on the results during the evergreen nature of the IRP, particularly in light of the value of new gas fired CTs evidenced by the IRP analysis.

In consideration of these fundamental changes all parties will need to closely monitor developments in the electric and broader energy sectors to ensure Nova Scotian residents and business have access to competitive alternative energy supplies and to cost effectively meet the goals of the Province.

Heritage Gas appreciates the opportunity to comment on the Draft IRP Report and the continued collaboration with all stakeholders. We especially recognize the effort by NSPI to continue an open process, and look forward to the consideration of these comments reflected in the final IRP submission to the Board.

Regards,

HERITAGE GAS LIMITED

John Hawkins
Cc: M08929 Participants

Nova Scotia Power
1223 Lower Water Street | Halifax, NS B3J 3S8
Attn: Integrated Resource Plan Development Team

November 13, 2020

Integrated Resource Plan Development Team, Nova Scotia Power
Re: Comments on Draft Integrated Resource Plan Report

Thank you for the opportunity to provide feedback and participate in the overall development of the 2020 Integrated Resource Plan (IRP). We also appreciate the strong partnership and valuable input provided by Nova Scotia Power during the development of the Municipality's climate action plan, HalifACT, which was unanimously approved by Halifax Regional Council on June 23, 2020.

As the primary electric utility for the Province, we recognize that Nova Scotia Power will be a key player in the success of HalifACT through grid decarbonization and robust infrastructure deployment to accommodate the high levels of building and vehicle electrification identified as key actions of HalifACT. Therefore, continued and meaningful collaboration is key to the successful implementation of each plan.

In reviewing the draft report, we offer the following questions for your consideration:

1. The E3 and IRP scenarios were developed prior to HalifACT and the Sustainable Development Goals Act (SDGA). Will Nova Scotia Power produce an updated scenario that aligns with the 2050 net-zero carbon emission target of the SDGA?
2. Success of HalifACT requires high levels of distributed energy resources (DER), primarily solar, in order to more rapidly reduce the emissions factor of our electricity. What are the implications for the IRP if the DER described in HalifACT is implemented?
3. Do the carbon intensities of the IRP scenarios provide the opportunity for HalifACT to reduce the level of DER deployed, given that the E3 scenarios do not reflect the level of deep energy retrofits and building and vehicle electrification required in HalifACT?
4. To achieve the deep emission reductions of HalifACT, high rates of building and vehicle electrification are needed, combined with distributed renewables to reduce emissions from electricity. How would HalifACT achieve its objectives without high DER and with the high emissions factor as indicated in the IRP reference scenario?
5. Are the electrification scenarios defined in the E3 study identical to the electrification levels in the IRP scenarios? For example, is the level of heat pump adoption in residential buildings specified in the E3 scenarios the same in the corresponding IRP electrification scenarios?

6. What would the impact on electricity demand be if the thermal and electrical energy demand of the existing building stock was reduced by 50% rather than by the levels assumed in the E3 scenario analysis?
7. If greater building efficiencies are achieved, what would the impact be on total building energy expenditures in the context of more rapid decarbonization of electricity generation and/or more rapid electrification of transportation and heating?
8. The share of the residential stock with heat pumps grows to approximately 50% and 100% in the mid and high electrification scenarios, respectively (E3 report, Figure 12 and 13). The E3 report (p.25) also indicates that building shell and weatherization measures reduce the space conditioning requirements of the residential stock by "up to 20%" however it is not clear if this maximum improvement applies to new and/or existing housing. What is the assumed percent reduction of the space heating intensity of the existing (base year) residential building stock by 2030 and by 2045? Is this level of improvement common in all scenarios?
9. Please provide a breakdown of the Nova Scotia housing stock by type according to average thermal intensity for space heat, fuel share (resistance, heat pump, oil, wood, other), and heating system efficiency for the base year, 2030 and 2045 for each of the IRP scenarios.
10. COVID economic recovery strategies are emphasizing green investments like energy retrofits and vehicle electrification. Will Nova Scotia Power produce a scenario in which both efficiency and electrification are accelerated in the 2020's to understand the impact of this on household energy costs, emissions and the electricity system?
11. In what circumstances would the minimization of electricity rates be inconsistent with the minimization of the total cost of energy service and amenity (heat and comfort, mobility and access) for Nova Scotia households and firms?

As Nova Scotia Power and Halifax move forward together towards critical climate action, we appreciate your continued support, collaboration and partnership.

Sincerely,

Pete Duncan

Peter Duncan, P.Eng.
Manager, Infrastructure Planning
Planning & Development
Halifax Regional Municipality

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November 13, 2020

Doreen Friis,
Regulatory Affairs Officer/Clerk
Nova Scotia Utility and Review Board
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P.O. Box 1692, Unit "M"
Halifax, NS B3J 3S3

-SENT VIA EMAIL-

RE: 2020 Integrated Resource Plan (Draft Report 30th October 2020)

Dear Ms. Friis,

Natural Forces Services Inc. once again welcomes the opportunity to input comments on the IRP process. The process to date has delivered some key findings and it is important that these are fully understood by all stakeholders and policy makers. At the same time however, it is also clear that there are a number of factors which have a fundamental impact on the results, particularly with regard to the pace at which wind capacity is added to the system over the next decade. These include:

- level of demand growth (particularly the potential from further electrification);
- capital costs of wind;
- association of batteries/synch comps with additional wind capacity (which we contend is unnecessary), and
- potential value of reductions in emissions in excess of that required to strictly meet compliance standards.

In this regard we welcome the identification in the IRP Report of a number of "signposts", relating to the above and other topics. We recognize that for some of these issues, it may take some time for clarity to emerge, for example in relation to demand growth and value of emissions reductions. However, others can be addressed in a shorter timescale. These would be:

1. Examination of system stability issues and consideration of optimum operational strategies to address system reliability with higher levels of wind generation;
2. An RFP to determine the actual cost of new wind to be added to the system.

We believe it is important to set out a clear program of work associated with these issues, with target dates for completion and including engagement with stakeholders when and as appropriate. Natural Forces confirms its commitment to continue to work constructively with NSP through this process.

The remainder of our response is set out under four main headings:

1. **Clarity of Key Findings.** There are a number of important findings which are discussed within sections of the report, but are not always clear in the summary sections, for example in "Overview of Key Findings" in section 1.8. We recommend further attention is given to the presentation of key findings (specific examples are given later).

2. **Comparison of Scenarios and Resource Portfolios.** NSP correctly identifies that there are elements that are common to all or most scenarios, which can then be considered as "no regret" steps. It is also the case that the level of wind capacity installed toward the end of the study period is often broadly similar in most scenarios. There are however significant differences in regard to the pace of build-out of further wind capacity, particularly over the next decade. The decision on wind capacity build-out in the shorter term (over the next several years) is undoubtedly one of the most important issues emerging from the IRP report.

   One can identify two broad "clusters" of scenarios, being:

   a. Those which have very limited build-out of wind capacity until at least 2030. These are generally cases based on higher wind capital costs, association of battery/synch comps with related additional capital costs, and lower demand levels;
   b. Scenarios which show more significant build out of wind capacity progressively through the 2020s. These are generally cases with some or all of more competitive wind costs; disassociation with requirement for batteries/synch comps, and higher demand levels (mainly due to further electrification)[1].

   The appropriate pace of build-out of wind is clearly one of the most important issues arising from the study to date, and it is critical that the outstanding issues are addressed at the earliest opportunity.

3. **Selection of Reference Plan, and "Signposts".** The resource plan optimized for Scenario 2.0C (Low Electrification / Net Zero 2050 / Regional Integration) is nominated as the "Reference Plan", primarily as it indicates a lower total cost than other scenarios[2]. We are not entirely clear what the implications of nominating the reference plan are, but it must be noted that other scenarios have potentially with lower rates to electricity customers as well as other policy benefits (supporting decarbonization through electrification). Therefore the "reference plan" may not be the "optimal plan". Also of course as identified by NSP in the report, there are a number of key factors which will influence the "optimal" portfolio in any case.

[1] It is also worth noting that attribution of a monetary value to reduced emissions levels (not included to date for reasons outlined by NSP in the report), would also, when applied, favour earlier build-out of wind capacity.
[2] On this criteria of course a scenario with lower demand levels would almost certainly be selected, even if it results in higher rates for electricity customers that other scenarios – as is the case here.

The "signposts" identified within the Report are key to determining which trajectory is followed particularly for wind capacity build-out through the next decade. Considerable focus should be given to moving these forward as soon as possible.

4. **Miscellaneous comments.**

The remainder of this response provides further detail under each of the above headings.

1. Clarity of Key Findings.

There are a number of important findings which are discussed within sections of the report, but are not always clear in the summary sections. In particular section 1.8 ("Overview of Key Findings") presents the Key Findings in a shortened form, which risks reviewers overlooking some of the most important findings.

Key Finding 1 (page 16)

Steeply reducing carbon emissions in line with Nova Scotia's Sustainable Development Goals Act will require significant efforts from each sector of the economy, with the electricity sector playing a major role.

While this is almost certainly correct, we suggest the more important finding from this IRP Study is that the electricity sector can facilitate decarbonisation of other sectors (heat, transport) through increased electrification without placing upward pressure on electricity rates. In fact, high electrification appears to tend to reduce electricity rates, which is a win-win scenario.

This is certainly mentioned within the report, but is somewhat buried in the text. It is a key point which should be highlighted in any summary of findings or conclusions.

Key Finding 4 (page 22)

The SDGA-compliant key scenario which minimizes the cumulative present value of the annual revenue requirement of the 25-year planning horizon (adjusted for end effects) is 2.0C (Low Electrification / Base DSM / Net Zero 2050 / Regional Integration).

We recognise that identification of the scenario with the lowest cumulative NPV is consistent with the originally-stated objectives of the IRP process. However this criteria will generally always select a scenario with lowest electricity demand, so is not particularly informative.

We believe that at least similar emphasis should be given to scenarios based on the lowest level of rates to electricity customers. Scenarios with higher levels of electrification tend to have lower rates and also of course have the benefit of facilitating broader policy objectives for emissions reductions (while at the same time reducing prices to electricity customers).

This is discussed further in the IRP report in section 3.2 "Maintaining Affordability" (page 48), but should be highlighted in any summary of findings and conclusions.

Findings regarding Distributed Resources Strategy.

Section 6.5 (page 112) of the Report states that

> *"the scenario modeled with the Distributed Resources strategy (2.1B) is shown to have a significantly higher relative rate impact over the planning horizon",*

and further notes that

> *"the cost of the DER resources themselves is not included in these rate impact calculations but could be expected to add additional rate pressure if modeled."*

We suggest that this is a significant finding which should be included in the "Key Findings" of the study.

2. Comparison of Scenarios and Resource Portfolios.

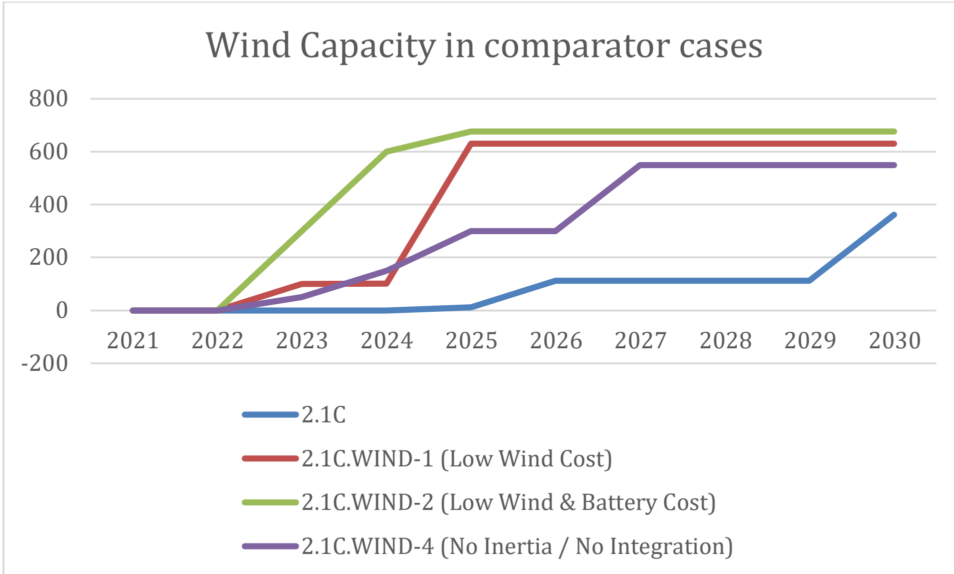
NSP correctly identifies that there are elements that are common to all or most scenarios, which can then be considered as "no regret" steps. It is also the case that the level of wind capacity installed toward the end of the study period is often broadly similar in most scenarios. There are however significant differences in regard to the pace of build-out of further wind capacity, particularly over the next decade. The decision on wind capacity build-out in the shorter term (over the next several years) is undoubtedly one of the most important issues emerging from the IRP report.

One can identify two broad "clusters" of scenarios, being:

a. Those which have very limited build out of wind capacity until at least 2030. These are generally cases based on higher wind capital costs, association of battery/synch comps with additional capital costs, and lower demand levels;
b. Scenarios which show more significant build out of wind capacity progressively through the 2020s. These are generally cases with some or all of more competitive wind costs; disassociation with requirement for batteries/synch comps, and higher demand levels (mainly due to further electrification)[3].

The scenarios show clearly that (a) capital cost of wind and/or (b) association of wind with batteries/synch comps, are very material to the amount of wind selected in the optimised portfolios during the next decade. This is illustrated in the graph below, showing comparative wind deployment in the relevant sensitivity cases.

[3] It is also worth noting that attribution of a monetary value to reduced emissions levels (not included to date for reasons outlined by NSP in the report), would also, when applied, favour earlier build-out of wind capacity.



Clearly lower wind capital costs (scenarios 2.1C.WIND-1 and 2.1C.WIND-2) result in much more rapid build out of wind capacity than 2.1C. Alternatively, the disassociation of the battery & synch comp costs (scenario 2.1C.WIND-4) also results in more rapid wind deployment. As noted in previous submissions, some combination of these two factors will deliver similar, or potentially even higher wind deployment during the period.

We believe the characterisation of scenario 2.1C.WIND-4 within the draft IRP report is incorrect. The report states that

> *The boundary case of no synchronized inertia constraint + no wind integration requirements (2.1C.WIND-4) indicates that these constraints do not significantly affect the wind build seen in both the base and low price sensitivities until the mid-2030s;*

Unless we are misinterpreting the results, it can be seen from the above graph that there is a significant difference in the extent of wind deployment during the 2020s, from the alternative scenario 2.1C.

The report also notes regarding scenario 2.1C.WIND-4:

> *This run is intended as a test case to understand how the model performs with no synchronized inertia constraint and no integration requirements for wind; it is not considered to be a feasible resource plan based on these assumptions.*

Again, we believe this is fundamentally incorrect. It is a feasible resource plan. Of course, the system must be operated securely, which requires respecting ancillary services and other system constraints including system inertial requirements – this is not in dispute. The scenario as run does not respect system inertia requirements; this however does not mean that the portfolio is not feasible, but only that the results may marginally understate the costs. Including minimum system inertial requirements (which can be modelled) may mean that in the case of this portfolio, the level of wind output (and/or imports) needs to be constrained on rare occasions in order to provide “space” in the dispatch for the conventional units needed to provide inertia. However, this will arise very infrequently and the imposition of a reasonable SIR constraint will not add materially to the costs.

The report acknowledges the need for further work on examining inertial requirements and operational strategies to meet them, and we urge that this is undertaken as soon as possible, in order to prevent this issue continuing to inappropriately constrain decisions on the optimum resource portfolio.

3. Selection of Reference Plan, and "Signposts".

The resource plan optimized for Scenario 2.0C (Low Electrification / Net Zero 2050 / Regional Integration) is nominated as the "Reference Plan", primarily as it indicates a lower total cost than other scenarios[4]. We are not entirely clear what the implications of nominating the reference plan are, but it must be noted that other scenarios have potentially with lower rates to electricity customers as well as other policy benefits (supporting decarbonization through electrification). Therefore the "reference plan" may not be the "optimal plan". Also of course as identified by NSP in the report, there are a number of key factors which will influence the "optimal" portfolio in any case.

We very much welcome the identification of the "signposts" presented along with the roadmap. They cover a number of important issues to be kept under ongoing review, which would require the plan to be reviewed/amended.

We particularly note:

- **System Stability Studies**: Commitment to *"**Complete detailed system stability studies** under various current and future system conditions, reflective of both stressed system states and normal operating conditions, while considering higher quantities of installed wind capacity as seen in the IRP modeling results."* This work should also **fully consider alternative operational strategies** (in particular dispatch-based solutions) to ensure system reliability during "stressed" system states, as an alternative to imposing additional capital costs. Such approaches are widely deployed on other power systems.

- **Capital costs of Wind**: Tracking of the **installed costs of wind**, solar, and energy storage to look for variations from the trajectories established in the IRP (in particular, monitoring for divergence from the "Base" to the "Low" pricing scenarios). Natural Forces strongly believes that **the capital costs of wind assumed in the so-called "Low" pricing scenarios are more realistic**, and if this is the case, it supports a much more rapid build out of wind than in the currently-proposed "reference plan". The solicitation of Nova Scotia-based market information will, we believe, support this conclusion.

- **Consideration of potential monetary value of emissions reduction**: Recognition of importance of tracking the ongoing development of the Nova Scotia Cap-and-Trade Program, and in

[4] On this criteria of course a scenario with lower demand levels would almost certainly be selected, even if it results in higher rates for electricity customers that other scenarios – as is the case here.

particular, **monitoring the GHG market size for indications that value from incremental allowance sales (beyond the projected economic emissions reductions shown in the IRP results) can be incorporated into long-term resource planning decisions with greater certainty.** We fully agree that recognising a value of incremental GHG reductions could influence the optimal resource plan, particularly as regards non-emitting generation procurement. We also consider that it would be very useful to apply conceptual values to incremental emissions in the different IRP scenarios, to indicate the impact on NPV costs and ranking of different scenarios under a range of emissions monetary values.

We again emphasise that even if no monetary value is currently ascribed to lower emissions levels, it is worth highlighting that there is distinct value (even if not quantified) in lower emissions due to:

- Hedging against developments which put emissions compliance under stress, such as higher growth rates (in this regard we note that "risk-weighting" is an objective of the IRP).
- The potential future value under new valuation or trading mechanisms.
- Generally, being more environment-beneficial and supporting the climate-change agenda.

- **Demand growth:** Monitoring electrification growth in Nova Scotia to understand at what point the provincial load profile starts to move from Low, to Mid, to High levels of electrification. The potential for a wide variation in demand growth, particularly arising from potential electrification as a means to decarbonising transport and heat (as is being experienced on other countries), is identified in the report as a significant influence on the portfolio selection.

The "signposts" identified within the Report are key to determining which trajectory is followed particularly for wind capacity build-out through the next decade. **Considerable focus should be given to moving these forward as soon as possible. This requires, in our view, setting out a clear plan with target dates, and ongoing engagement with stakeholders during its delivery.**

4. Miscellaneous comments.

Differentiation of allowed wind capacity with demand growth

Section 3.1.3.3 of the report states that

> *Nova Scotia Power recognizes that load growth is an effective tool for wind integration and so developed assumptions that allowed for additional wind integration at the Mid and High electrification levels.*

We agree with this point, but again we note that this differentiation (i.e. allowing more wind installed capacity in higher demand scenarios) has only been included in scenarios which include the batteries/synch comps or the 2nd tie-line. In these cases, more wind capacity is allowed in higher demand scenarios. But in the case without these, the same wind capacity limits are imposed in all demand cases (ref Figure 15 of the report).

Figure 15 IRP Wind Integration Options

Available Wind (Nameplate MW)	No Integration Requirements*	Reliability Tie*	Domestic Integration* (Batteries + Sync. Condenser)	Total Incremental Wind Available
Low Electrification	100	400	400	900
Mid Electrification	100	500	500	1,100
High Electrification	100	600	600	1,300

**Local Integration requirements would be determined via specific System Impact Studies*

It is not clear to us why allowed wind does not also increase with demand in the "No Integration Requirements" case. This is particularly important on the context of the current reference case (on which the action plan is primarily based). However, it may be overtaken by events on the assumption that further system stability studies (indicated as a "sign-post" in the plan) are undertaken as a priority. This should, we believe, significantly alter the wind limits in any case.

Minor edit point:
Figure 8 (page 20): Scenario 2(c) is labelled "mid-electrification" – should be "low electrification"

We believe that one of the most important factors in the short term, is the rate of wind deployment appropriate over the coming years. Natural Forces believes that developments in relation to the "signposts" identified in the report will confirm that higher wind trajectories are beneficial to rate payers and to furtherance of broader policy objectives, and we urge that a clear plan is developed for this analysis, and it is completed as soon as possible. Natural Forces confirms its commitment to contribute constructively to the process and encourages NSP to continue to build on the stakeholder engagement efforts undertaken to date.

Finally, Natural Forces again wishes to thank NSP for the opportunity to respond to the draft IRP report and participate in the process. The timeframes at times have been tight, but the engagement from the staff at NSPI has been excellent.

Thank

Sincerely,

Presented for, and on behalf of, Natural Forces, Halifax, Nova Scotia.

MCINNES COOPER

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Our File: 179164

November 13, 2020

Nicole Godbout
Director, Regulatory Affairs
Nova Scotia Power Inc.
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Halifax, NS B3J 2W5

Re: Draft Integrated Resource Plan Report: Comments

Port Hawkesbury Paper LP ("PHP") has had the opportunity to review both Nova Scotia Power Inc.'s ("NSPI") Draft Integrated Resource Plan Report dated October 30, 2020 and its reply document published November 6, 2020 to comments received on the draft findings/roadmap/action plan. PHP was pleased to see NSPI's general concurrence with its comments on the draft findings/roadmap/action plan, and submits the following comments on the Draft Integrated Resource Plan Report.

The Draft Report, building on the prior findings/road map/action plan document, confirms there is a general path forward which is robust across numerous scenarios. However, the timing and scope of specific actions that should occur over the study term of the IRP remains subject to ongoing studies and greater clarity on how key assumptions will eventually play out. As such, PHP appreciates that NSPI has acknowledged the necessity for flexibility going forward and especially its determination that this should be an evergreen IRP with regular updating to stakeholders.

Based on the results of the future studies called for in the Draft Report, and future information to help solidify key assumptions in what is a very dynamic period in the energy sector in the Province, regionally, and internationally, it will be important for NSPI and all stakeholders to remain flexible and to take advantage of opportunities to potentially accelerate the rate of change in the electricity sector where circumstances and economics warrant.

As such, PHP recommends that together with annual updating on the status of the IRP, that NSPI also endeavor to bring forward the results of the planned ongoing study work, and other information relevant to opportunities that may arise to advance the goals of the IRP and the Province in the electricity sector, when such information becomes available, so that its implications can be evaluated in a timely manner and input provided by stakeholders.

As opportunities may arise in a host of areas, such as the ability to cost share transmission infrastructure build outs with neighboring jurisdictions or the Federal government, the ability to economically advance renewable capacity, advancements in energy storage and demand response, etc., it is more important than ever that information and opportunities are shared in a timely fashion to achieve the sustainable development goals of the Province in the least cost manner. This can be best achieved by collaboration among stakeholders, and PHP believes the open sharing of information that has occurred throughout the IRP process should continue for the foreseeable future to ensure a vibrant and sustainable energy sector in the Province which will accrue to the benefit of all stakeholders.

PHP looks forward to receipt of the Final IRP Report and staying engaged with all parties as the follow-up roadmap and action plan unfolds, and appreciates the opportunity to provide these comments.

Yours very truly,

David S. MacDougall

Blackburn Law

VIA EMAIL

November 13, 2020

Linda Lefler
Nova Scotia Power

Dear Ms. Lefler,

Re: M08929 – Draft Findings, Action Plan, and Roadmap – SBA Comments

The SBA has reviewed the draft IRP prepared by Nova Scotia Power (NSPI) and offers the following comments to enhance the clarity of the final document, as well as identify future issues that will need to be addressed as NSPI moves to implement the Roadmap and Action Plan detailed in the document.

Evergreen IRP Process

The draft IRP provides a detailed review of NSPI's extensive planning efforts conducted over the last 18 months. The multiple analyses, along with the detailed assumptions developed by NSPI as inputs into the analyses, have demonstrated to stakeholders the increasing complexity of the utility investment environment, as well as the sensitivity of optimal resource decisions to the analytical inputs. This indicates that as system conditions evolve and resource costs change over time, there will be a need to continually update assumptions and refresh analysis when needed.

NSPI acknowledges this need by discussing an "evergreen IRP process" to continuously monitor and update investment plans as conditions change. NSPI indicates that one element of this will be regular updates as part of the IRP Action Plan reporting. NSPI should clarify in the final IRP what types of information will be reported in those updates, such as changes to resource cost or operational assumptions, electrification or load changes, and import/export market changes. NSPI should also propose options for stakeholder involvement in the evergreen IRP process.

The draft IRP identifies a number of "signposts" that NSPI will monitor as the IRP is implemented. Signposts are very important to resource planning, particularly when there is no set schedule for filing a new comprehensive IRP. The signposts that are identified in the draft IRP are vague, and most include "monitoring" certain conditions. The document currently does not lay out a procedure for how information gathered from this monitoring would trigger a change in resource plan or a proceeding before the Board. The final IRP should elaborate on the use of signposts and provide more detailed procedures.

IRP issues requiring clarification

While the draft IRP provides sufficient detail for a strategy document, as NSPI moves to implement the Action Plan detailed in the IRP, there will significant additional study that will be needed to ensure that resource decisions are in the best interests of customers.

There are several areas in which resource decisions will need to be supported by additional analysis. Our intent in identifying these areas is not to suggest NSPI needs to address all areas in the final IRP. Rather, the SBA recommends that NSPI more specifically acknowledge how market and system developments over time will change the relative economics of certain decisions in ways that could require deviation from the Roadmap and Action Plan.

- Energy efficiency scenarios: The draft IRP notes that the IRP scenarios will yield avoided cost levels that will be passed on to E1 to use in developing Energy Efficiency (EE) strategies. It is unclear how this approach will be implemented. For example, will NSPI procure all EE measures that are cost-effective given a certain avoided cost scenario? Will E1 be given guidance on how to use the avoided cost values to structure EE programs? How will the parties consider the dynamic nature of the impact of EE savings on avoided cost levels? How will the electrification progress be incorporated into the analytical steps on an ongoing basis?

- Coal retirements: The IRP has evaluated multiple options for coal retirement schedules over the next twenty years. These retirements represent critical, irreversible resource decisions, and each will be the subject of a NSUARB proceeding. While the IRP provides results of the long-term planning model, it is not clear what the review framework will be for each individual resource retirement decision. For example, will there be refreshed or additional economic analysis conducted at the time of the proposed retirement? How will NSPI incorporate new information about alternative firm capacity options when assessing a proposed retirement? What will be the decision metrics that will be used to determine retirement timing?

- Gas conversions: The draft IRP notes that coal-to-gas conversions are selected economically in most of the key scenarios. As noted above, however, the analysis is reliant on a multitude of input assumptions. NSPI should develop a framework to review the economics of these conversions to ensure that the additional investment in GHG-emitting resources does not quickly become a stranded cost if non-emitting alternatives (firm imports, storage, etc.) become more economical in the near future. Is there a "breakeven" point where NSPI would pursue non-emitting options instead? How will NSPI balance the priority of investing in low-carbon options with the economics of the conversions, and what analysis will support the decision-making?

- Regional Integration and Reliability Tie: The draft Findings, Roadmap, and Action Plan appeared to conclude that the Reliability Tie and Regional Integration strategy was a common component of top-performing plans and should be investigated for future consideration. The draft IRP used more concrete language about immediately pursuing this option, and implementing it more quickly than indicated by the IRP models if feasible. This strategy appears economically beneficial given the analysis conducted to date, and the SBA supports further investigation. However, not all aspects of this strategy have been fully vetted and there is additional analysis that must be conducted to determine if this is technically feasible and economically beneficial. This includes the determination of the availability of firm capacity from other regions, which may be challenging as all regions in eastern Canada and the northeastern United States are actively seeking clean, dispatchable capacity to support decarbonization efforts. In addition, the technical analysis conducted by PSC on the inertia needs of the system provided an important initial assessment, but will need to be supplemented by additional study prior to relying on firm imports for reliability. These issues need to be addressed in advance of any significant investment commitment, and the draft IRP should explicitly acknowledge the additional work needed prior to pursuing the option.

Yours truly,

BLACKBURN LAW

E.A. Nelson Blackburn, Q.C.
Small Business Advocate

Submitted comments re. the NS Power Integrated Resource Plan Draft Final Report

The Town of Wolfville appreciates the opportunity to patriciate in and offer comment on the 2020 Integrated Resource Planning process. In May 2019, our Mayor and Council declared a Climate Change Emergency. An outcome of this declaration was the Town's recommitment to the Federation of Canadian Municipalities' Partners for Climate Protection (PCP) program, which the Town first joined in 2006, and to working through its five-step Milestone Framework to guide us in taking action against climate change by reducing emissions in our municipality.

Steps 2 and 3 of the PCP program involved setting emissions reduction targets and developing an action plan to achieve those targets. To align its plan and targets, Wolfville is working with the Sustainability Solutions Group (SSG) to model versions of its action plan and project the reductions and emissions that could be realized. Through these efforts, we hope to gain insight into the emissions-related impacts and implications of decisions and investments within the Town's purview.

In addition to its utility as a planning aid, our modelling work has revealed the extent to which the outcomes of Wolfville's climate change mitigation efforts will depend on the choices and investments made by other actors. 80% of GHG emissions generated by our community stem from stationary energy use, i.e. the energy needed to heat and provide electricity for our buildings. A significant proportion of this energy use and the resulting emissions can be eliminated through investments in energy efficiency. However, for the Town to achieve a reduction of emissions in line with targets set by the Intergovernmental Panel on Climate Change in its 2018 Special Report on the impacts of global warming of 1.5 °C, or the Nova Scotia Provincial Government in its 2019 Sustainable Development Goals Act, it will require access to sources of low- or zero-emission energy. This requirement goes beyond decarbonizing the stationary energy sector; as the IPCC Draft Report acknowledges, "electrification of energy end uses in other sectors is an important tool to achieve deep decarbonization affordably."

Given this requirement, the Town of Wolfville applauds the development of the 2020 Integrated Resource Plan (IRP), in which "Nova Scotia Power puts forward a long-term strategy for delivering safe, reliable, affordable and clean electricity to customers across Nova Scotia. At its core, the plan illustrates Nova Scotia Power's commitment to supporting provincial decarbonization as outlined in the Nova Scotia Sustainable Development Goals Act (SDGA), both by transitioning to a cleaner electricity grid and by enabling electrification of other sectors, such as transportation and heating." Particularly, Wolfville appreciates that, in recognition of the rapidly changing and uncertain resource planning environment in which the IRP process is taking place, Nova Scotia Power explored a diverse set of environmental policy scenarios by evaluating a range of resource plans that integrate different amounts of renewable energy and achieve a range of decarbonization targets.

The Town of Wolfville questions the Draft Report's contention that Nova Scotia Power's environmental policy scenario 2.0C (Low Electrification / Base DSM / Net Zero 2050 / Regional Integration) is "SDGA-compliant". Given the Draft Report's finding that "steeply reducing carbon emissions in line with Nova Scotia's Sustainable Development Goals Act will require significant efforts from each sector of the economy, with the electricity sector playing a major role"; its recognition of the rapidly changing and uncertain environment in which the IRP process is taking place; that, owing to the Covid-19 pandemic and state of emergency, the public consultation process to develop the goals in regulation of the SDGA has not even begun; and that Province has yet to develop the "Climate Change Plan for Clean Growth", through which it will achieve the greenhouse gas emission targets set out in the SDGA; declaring any of the IRP's environmental policy scenarios to be compliant with the emission targets legislated by the Act would seem premature.

The Draft Report asserts that "during the Action Plan 5-year horizon, resource plans 2.0C and 2.1C (among others) include many common resource investments and retirement trajectories. This commonality informs NS Power's IRP Action Plan and ensures the resulting long-term electricity strategy is robust to a broad range of potential futures." Given that the carbon intensity projected for resource plan 2.0C is almost 300% greater in 2030 – a critical deadline for substantial emission reduction – than in other scenarios, Wolfville questions the decision to designate 2.0C the Reference Plan that will inform Nova Scotia Power's "no regrets" IRP Action Plan and Roadmap.

Wolfville expects that Nova Scotia Power's scenarios, Action Plan, and Roadmap will be vetted for actual compliance with Provincial environmental law once the Climate Change Plan for Clean Growth has been created via the evergreen IRP process laid out in Roadmap Item #8. Until then, we will continue to develop our community emissions reduction plan in expectation that Nova Scotia Power's commitment to supporting provincial decarbonization is, as the Draft Report asserts, at the core of the 2020 Integrated Resource Plan.

Thank you for this opportunity to participate and comment,

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NS Power Response to Participant Comments on Draft Integrated Resource Plan (IRP) Report

Category	Participant	Comment	NS Power Response
Procurement	Consumer Advocate (1a)	Conduct an RFP for up to 700 MW of wind by 2025, to be conditioned on price and performance thresholds, and evaluated in coordination with transmission and system inertia solutions. The smaller, wind-only procurement described in the Draft IRP Report excludes the potential near-term savings of a larger procurement if bid prices are lower than expected. Test the market for firm imports and gas peakers. Most scenarios suggest that NS Power will find it economical to procure about 165 MW of firm imports, but a wide range of near-term gas peaker procurements are indicated. Battery storage should be included in the all-source procurement process because successful battery storage bids could influence the relative value of other bids, including the reliability link.	NS Power has committed to soliciting Nova Scotia-based pricing information as part of its Wind Procurement Strategy; please see Action Item 3d. In addition, Roadmap Item 5 also incorporates the use of Nova Scotia-based market information as needed to update wind, solar, and energy storage costs. NS Power acknowledges the suggestion to examine an all-source RFP for future procurement of capacity and/or energy, either to meet load growth or to replace retiring resources. The Company's strategy with respect to the long-term replacement of energy and capacity associated with thermal retirements remains to be determined.
Wind integration	Consumer Advocate (1b)	Plan for potential transmission projects in parallel to both additional study of wind integration as well as the recommended all-source RFP. The costs of Regional Integrations and costs and capabilities of various other wind integration strategies should also be planned. Further planning and evaluation of three strategies to provide for wind integration and other reliability benefits, including: • An early in-service date for the Reliability Tie; • Operating practices such as application of fast frequency response technology, reliability curtailments,	NS Power will continue transmission planning (for both the Reliability Tie and Regional Interconnect), wind integration studies (including operating practices), and the other elements of the wind procurement strategy in parallel as identified in both Action Item 1c and Action Item 3d. Further evaluation of system inertia considerations is incorporated into the wind integration and stability study work planned in Action Item 3d.

Category	Participant	Comment	NS Power Response
		and pre-curtailment of wind resources for operating reserve purposes; and • A combination of lower battery prices and synchronous condensers. More in-depth investigation of the system inertia question is called for. If inertial constraints can be satisfied by a combination of wind curtailment and other operating limits, additional battery storage and synchronous condensers, NS Power could develop operating experience demonstrating that the system can be operated reliably with early retirement of additional thermal units. Review the Reliability Tie/ If it is providing only synchronized inertia (enabling additional wind integration), it may provide other benefits, such as reserves, load following, or non-firm import capability.	Additional potential benefits of the Reliability Tie not captured in the IRP will be identified and studied as part of Action Item 1b.
Mersey	Consumer Advocate (1c)	Conduct further modeling with updated data from resource procurement and transmission planning for any capital application for redevelopment of the Mersey hydroelectric facilities. NS Power intends to use the results of its Plexos modeling for the 2.1C.Mersey case to provide key inputs into the replacement energy cost for hydro generation used in the Company's economic analysis model. This sensitivity appears to indicate that customers would experience a slightly higher cost ($44 million) to retain Mersey through 2045, even with a $227 million cost to decommission Mersey. Additional consideration of Mersey's long-term costs	NS Power will incorporate IRP findings and modeling results into the economic analysis of Mersey redevelopment. This work will also consider a robust range of wind energy and storage costs in order to test the robustness of results to low prices. NS Power is considering options to incorporate the IRP modeling results into Replacement Energy and Capacity Cost calculations, both from the Mersey sensitivity and from the base case runs.

Category	Participant	Comment	NS Power Response
		is thus warranted. The evaluation must rely on better understanding of wind and transmission development costs.	
Electrification	Consumer Advocate (1d)	NS Power's action plan should include a specific commitment to develop and propose transportation and building electrification pilot projects.	NS Power has added additional detail on the Electrification Strategy approach to the IRP Action Plan, including specific commitments to develop programs and pilots. Please see IRP Action Item 2a.
Electrification	Consumer Advocate (1e)	Provide an estimate of the cost that might be tolerable for customers to bear to promote electrification, as well as a discussion of cost savings for other fuels and other non-electric system benefits. Use the rate impact model to identify the impacts on rates that might result from plausible levels of program investment in electrification. We encourage NS Power to acknowledge that province-wide benefits (such as reducing the carbon reduction pressure in other sectors) exist with electrification, to avoid creating the impression that rates should be a singular basis for deciding how much electrification may be considered affordable.	NS Power has added this estimate to the IRP Final Report; please see Section 6.5 of the IRP Final Report. NS Power agrees that electrification produces province-wide benefits as described by the CA and has added this acknowledgement to Section 6.5 of the IRP Final Report.
T&D costs	Consumer Advocate (1f)	Update the Action Plan to include the development of T&D cost forecasts involving electrification and DSM at varying levels. Update recommendation 2c, and commit to development of T&D cost forecasts for several of the different scenarios involving electrification and DSM at varying levels. This will be necessary to inform those program investment decisions.	This recommendation has been incorporated into IRP Action Plan item 2c.
PRM	Consumer Advocate (2a)	Update planning reserve margin findings to reflect the final IRP modeling assumptions. it is not clear that the	This analysis update was completed and is presented in Section 6.6 of the IRP Final Report.

Category	Participant	Comment	NS Power Response
		2019 E3 PRM analysis is sufficient to demonstrate that NS Power has achieved an “optimal” planning reserve margin. Use the RESOLVE model to repeat the essential elements of the July 2019 study and verify or correct the findings, as appropriate.	
Combustion Turbines	Consumer Advocate (2b)	Confirm and periodically re- evaluate the findings regarding the diesel combustion turbine fleet. • Provide further evidence in the FAM audit proceeding regarding the performance of refurbished diesel combustion turbine units; • Provide data to RII and other interested stakeholders data comparing the modeled operational profile (capacity factor, operating hours, number of unit starts, etc.) to recent historical data; • Further evaluate the longer-term sustaining capital forecast for the diesel CT fleet as part of its evergreen IRP process; and • Periodically re-evaluate CT economics as the cost of storage falls, and especially if the units are using substantial amounts of fuel and the cost of their fuel rises significantly.	Item 1 – NS Power will review the performance of its refurbished CTs as part of the FAM Audit or as part of its capital planning, as appropriate. Item 2 - NS Power will make the requested data available to interested stakeholders Item 3 – NS Power will continue to review the long-term sustaining capital investment in the diesel CTs, consistent with IRP Roadmap Item 3 Item 4 – this would be considered in future planning work, as triggered by IRP Roadmap Item 5
Operating Reserves	Consumer Advocate (2c)	Fully document a resolution to the issue of high operating-reserve surpluses raised in the FAM audit process. Bates White, in the FAM audit, found that NS Power is carrying surpluses of operating reserves and that this may increase costs to FAM customers.	This analysis was completed and is discussed in Section 6.7.1 of the IRP Final Report.

Category	Participant	Comment	NS Power Response
Electrification	Consumer Advocate (3a)	Adopt a definition of electrification and principles for maximizing its benefits as developed by the Regulatory Assistance Project.	NS Power has adjusted IRP Action Plan Item 2a to specify that this work will incorporate industry best practices, such as the Regulatory Assistance Project paper mentioned, as well as other relevant work, for example, electrification programs in other jurisdictions and the details already contained in the Deep Decarbonization Pathways report.
T&D	Consumer Advocate (3b)	NS Power should net avoided transmission and distribution costs from DSM costs based on methods developed in the DSM advisory group.	NS Power has incorporated T&D Avoided Costs in the IRP Final Report and accompanying Model Results. This incorporation did not change the relative ranking of any of the IRP Scenarios or Sensitivities.
Hydro	Consumer Advocate (3c)	NS Power should verify that model performance of run-of-river hydro units is consistent with the operational record, and consider any appropriate adjustments to ELCC values and model results.	NS Power acknowledges and appreciates the analysis completed by RII on historical small hydro generation data. NS Power also reviewed these figures and notes that some operational impacts may be influencing these results, similar to those noted by RII: • There is relatively little diesel generation included in the peak hours analyzed by RII, suggesting that other water optimization considerations may have been considered as sufficient capacity was available on the system without maximizing hydro • As RII noted that there is a finding that small hydro resources are dispatched according to resource needs, as the dispatch increases in net peak hours • Water management to maximize annual energy production is an important consideration in the management of hydro dispatch, not included in the production cost model

Category	Participant	Comment	NS Power Response
			NS Power acknowledges that further analyses are required to refine the small hydro ELCC in the context of operational practice, and NS Power will undertake this work as part of system planning model continuous improvement activities. As RII notes, the impact on the IRP results if the ELCC of the domestic hydro units were found to be marginally lower than that assumptions used would not be significant. There would be two primary impacts: i) NS Power's existing Planning Reserve Margin deficit would increase by the change in ELCC of small hydro (if applicable). This would require additional resource procurement early in the planning horizon, however the impact is thought to be relatively modest. As an example calculation, moving small hydro from a 95% ELCC to a 70% ELCC would increase the PRM deficit by approximately 40MW. ii) The quantity of replacement capacity required to replace existing domestic hydro as part of the Hydro Screening analysis could be reduced. This effect can be approximated using the figures provided in the existing analysis. Please see Figure 28 of the Final Report (Total Decommissioning Costs of Hydro Assets Relative to Sustaining Operations (Scenario 2.1C). It would be expected that the *Replacement Fixed System Cost* would decrease, given the requirement to replace less capacity. Conceptually, even if

Category	Participant	Comment	NS Power Response
			these costs were reduced by 50%, the economic decision would not change to retain the Small Hydro Fleet. The actual change would be expected to be less, as some components of replacement energy (i.e. wind capital costs) are included in the fixed cost number.
Point Aconi	Consumer Advocate (3d)	NS Power should address the omission of potential limestone quarry expansion costs from the sustaining capital estimates for Point Aconi.	Based on the forecast capacity factors for Point Aconi from the IRP key scenarios, and the currently available resource at the existing limestone quarry, NS Power estimates that no significant investment will be required for quarry expansion prior to a 2040 unit retirement date. There are no limestone quarry expansion costs included in the IRP model.
CO_2 costs	Consumer Advocate (3e)	In future IRP modeling analyses, NS Power should incorporate a shadow price for CO_2 emissions. Such a CO_2 value may well be material to the evaluation of bids in an all-source RFP, for example.	NS Power has included the monitoring of the cap-and-trade market into its IRP Roadmap under item 6. As more certainty develops in the current GHG cap-and-trade market framework and future auction results and GHG allowance estimates are better understood, NS Power will evaluate incorporation of GHG reduction value as part of the evergreen process or as part of the next IRP.
Evergreen Process	Consumer Advocate (3f)	Engage with stakeholders to better define an “evergreen IRP process.”	NS Power has added additional wording on this topic to IRP Roadmap Item 8.
Solar	Consumer Advocate (3g)	NS Power should better explain its findings regarding the role of solar generation in its IRP.	NS Power has added additional discussion on this topic to IRP Finding 2b based on the IRP scenario results.
Rate Impact model	Consumer Advocate (4a)	Correct the rate impact model, as incremental fixed cost recovery should not be deducted from the revenue requirement when forecasting system rates.	NS Power has removed the FCR adjustment from the relative rate model and incorporated these results into the IRP Final Report and accompanying Model Results.

Category	Participant	Comment	NS Power Response
		Incremental fixed cost recovery should not be deducted from the revenue requirement when forecasting system rates. Correct its application throughout the Draft IRP Report and in its modeling results slide deck.	
Revenue Requirement	Consumer Advocate (4b)	Include a sensitivity reflecting the likelihood that the revenue requirement associated with existing non-fuel costs will decline over time. While NS Power's base case holds non-modeled costs level in nominal terms, we recommend that NS Power also include a sensitivity in which the revenue requirement for non-IRP costs declines over time. We suggest an annual reduction of 1.5% in these revenues. The net effect of this reduction and the IRP revenues remains an increasing revenue requirement under every scenario. The suggested, or some similar sensitivity analysis, will provide an indication of the uncertainty in NS Power's rate impact forecast.	NS Power has included discussion on this topic in IRP Final Report section 5.3.4.
DSM	Consumer Advocate (4c)	NS Power should not rely upon the relative rate impact comparison analysis as the basis for recommending any level of DSM program investments.	NS Power has adjusted its finding to focus on the primary IRP metric of 25-yr NPVRR with end effects; please see updated Finding 2e.
Wind	CanREA	[T]he IRP finds that "wind is the lowest-cost domestic source of renewable energy". However, the Action Plan indicates relatively modest procurement targets for wind (50 to 100 MW) even though its cost is considerably below NS Power's current fuel charges for customers, suggesting that the procurement of additional wind would result in immediate fuel cost savings for customers. As discussed further below, CanREA believes that the IRP has overstated the cost of	The LCOE of wind using the base capital cost assumption and capacity factor for wind is slightly higher than the marginal cost of NS Power's coal generation and is lower cost than more expensive, peaking generators. NS Power agrees that new wind resources, in quantities identified in the IRP (for base or sensitivity cases as applicable) will contribute to an optimal, lowest cost portfolio. However, caution is warranted when comparing the cost of energy for variable renewable energy and the average variable cost of dispatchable-

Category	Participant	Comment	NS Power Response
		wind and the constraints associated with integrating additional volumes of wind.	synchronous generators. New wind generation is expected to be highly correlated to existing wind generation, when the marginal price of electricity supply is generally lower. Dispatchable generators also provide a more comprehensive suite of ancillary grid services. NS Power's PLEXOS optimizer comprehensively considers these impacts when making resource addition/retirement decisions As noted in IRP Action Item 3d, realized market pricing information will inform the ultimate economic resource buildout, informed by the IRP key scenarios and sensitivities.
Wind	CanREA	The Draft IRP Report presents the LCOEs for wind that were previously requested and these are shown below in the table. These LCOEs indicate that cost of wind appears to be overstated relative to other regional price benchmarks (e.g., NB Power LORESS program and Saint John Energy Burchill Project pricing). CanREA's assessment is supported by other IRP participants. The Consumer Advocate noted that "in our previous comments that NS Power's 2019 capital cost of $2,100 per kW is outside the cost envelope suggested by Lazard. Synapse and Natural Forces also indicated that the $2,100 per kW cost was not reflective of the market." (Comments on Initial Modeling Results, p. 6 of 9). CanREA notes that Natural Forces is actively pursuing wind project development opportunities in the Maritimes and secured a long-term PPA for a 42 MW	NS Power's action plan and roadmap states that it will iinitiate a wind procurement strategy, targeting 50-100 MW new installed capacity by 2025 and up to 350 MW by 2030. This strategy will solicit Nova Scotia-based market pricing information which will inform the selected wind capacity profile and timing, informed by the IRP wind sensitivities. Refer to Action Plan Item 3d and Roadmap Item 5. In addition to the base pricing referenced here, NS Power did evaluate low sensitivity pricing of wind and the potential impacts of this on the resource mix are discussed in Final Report section 6.8.2.

Category	Participant	Comment	NS Power Response
		wind project in New Brunswick and based on this experience poses valuable insights regarding the current cost of wind in the Maritimes.	
Wind	CanREA	NS Power proposes to conduct a market test to assess the cost of onshore wind. Given the apparent overstatement of the cost of wind in the IRP, CanREA believes that NS Power should commit to conducting this "market test" expeditiously. CanREA also wonders what form this market test will take, given that it's common practice in NS to rely on a procurement administrator to procure wind. Therefore, it is not clear how this market test will be performed and how NS Power can ensure that reliable pricing information will be secured. This market test is also intended to consider the cost of solar and battery energy storage systems. CanREA believes that securing more market-based pricing information for these other clean energy resources would be valuable given the pricing trends for solar and energy storage.	NS Power will initiate procurement processes consistent with the timing of resource additions identified in the IRP scenarios and IRP Action Plan. Determining the final form of this test is outside the scope of the IRP but will be completed as part of the execution of the IRP Action Plan. The Evergreen process will assess potential pricing updates for other resources, including solar and storage resources.
Wind	CanREA	Furthermore, to the degree that this market pricing information indicates that the cost of these resources are lower than the assumptions reflected in the IRP, this should cause NS Power to reassess the role of solar and energy storage in its resource mix. CanREA acknowledges that this is a part of the Roadmap outlined by NS Power in its Draft IRP Report.	NS Power's evergreen process commits to annual updates as conditions change and technology or market options develop. This would include material pricing discrepancies from the pricing assumptions in the IRP (including storage and solar resources). Tracking of costs for wind, solar, storage, and DSM resources is discussed in IRP Roadmap Item #5.
Wind / Inertia Constraints	CanREA	Another area where CanREA offered comments that weren't adequately addressed by NS Power is with respect to the ability of wind and other non-synchronous inverter-based resources to provide frequency response services and by so doing to reduce	NS Power's Action Plan and Roadmap commits to completing detailed system stability studies under various current and future system conditions, reflective of both stressed system states and normal operating conditions, while considering higher quantities of

Category	Participant	Comment	NS Power Response
		the inertia constraints and resulting requirements for fossil generating units to be available to provide inertia. CanREA offered a series of comments on the ability of wind to provide regulation services that could allow wind to reduce the inertial constraint that NS Power identified. NS Power made one modest change in how it modeled wind recognizing that wind can provide a regulation down service.	installed wind capacity as seen in the IRP modeling results. This work will also consider the impacts of grid service provision from inverter-based generators (such as wind turbines) and how the introduction of new ancillary services like Fast Frequency Response might affect existing modeled services such as Synchronized Inertia. NS Power has committed to monitoring the results from this study for significant divergence from wind integration assumptions modeled in the IRP and t update as needed. NS Power also tested a boundary case, 2.1C.WIND-4, which removed synchronous inertia and wind integration constraints. Under this resource plan, wind additions beyond 100MW begin in 2024 and continue in 2025, timing which is aligned with IRP Action Item 3d and suggests that any significant change in constraints identified by the study would not affect the timing of initial resource procurements.
Wind / PSC Study	CanREA	A number of parties also critiqued the PSC study that was used to establish the constraint of 700 MW of wind without additional infrastructure investment. These parties assert that how NSPI has reflected the findings from this study in its modeling as overly conservative.	As noted above, NS Power has committed to further system stability study to assess IRP Modeling assumptions. NS Power believes that it utilized the best information available from the PSC study when developing capacity expansion constraints for the IRP. This study was also reviewed with stakeholders as part of the pre-IRP process. NS Power does agree that further study is

Category	Participant	Comment	NS Power Response
			required to confirm and/or expand the conclusions from the PSC Study, given the limited number of cases studied.
Wind / PSC Study	CanREA	In the PSC Study the loss of the New Brunswick intertie during high levels of imports is the most severe contingency. To mitigate operating risks, PSC evaluates scenarios that reduce or limit wind generation and increase thermal generation to provide inertia to cover the potential loss of the tie. CanREA notes that reducing imports over the NB intertie may be a more effective remedy than reducing wind given that these imports will have a higher incremental cost than the wind generation and reducing these flows on the tie will reduce the severity of the contingency.	NS Power agrees that in some cases, reducing the import could be more economic than reducing wind and committing a thermal unit. However, a policy of pre-curtailment of imports is unlikely to be economic based on the significant quantities of non-firm imports that are being economically dispatched in all scenarios. Further, imports could be providing other grid services (dispatchability, synchronous inertia). NS Power as identified the development of dynamic operating constraints, which might serve to enable this type of optimization, as part of IRP Action Item 3d.
Wind / System Stability Studies	CanREA	To address these and other issues, NSPI includes as part of its Wind Procurement Strategy a plan to conduct system stability studies to evaluate how much additional wind can be added. To achieve greater consensus regarding such studies CanREA recommends that NSPI conduct such a study with stakeholder input similar to the IRP. This is best practice and should increase stakeholder confidence in the findings from the study. CanREA encourages NSPI to begin work on these studies soon given the value that additional wind offers Nova Scotia customers.	NS Power will provide updates on this work as part of IRP Action Plan updates, which include opportunity for stakeholder participation.
Wind / system stability studies	CanREA	Finally, CanREA observes when conducting such a study appropriate consideration should be given to various operating strategies to more cost-effectively manage identified operating constraints. For example, the PSC Study doesn't support that the installed capacity of wind must be limited to 700 MW, but that under certain	NS Power's Action Plan and Roadmap incorporate the completion of detailed system stability studies under various current and future system conditions, reflective of both stressed system states and normal operating conditions, while considering higher quantities of installed wind capacity as seen in the IRP modeling

Category	Participant	Comment	NS Power Response
		operating conditions, which actually appear to be quite rare, the output of wind should be limited to 700 MW. Therefore, CanREA believes that more than 100 MW of additional wind could be procured (The approximate quantity identified by NS Power in its Wind Procurement Strategy, but which very likely will increase when appropriate consideration is given to the ability of wind resources to provide regulation services and other deficiencies in the PSC Study are addressed.), but when more than 700 MW was available during system conditions that posed reliability risks (e.g., low loads) then wind output greater than 700 MW could be constrained down after imports were reduced. When curtailed, these wind turbines would be available to provide primary frequency response, offsetting at least in part costs associated with such a curtailment. While there would be a cost to this, this cost can be assessed. However, the fact that wind generation is the lowest cost domestic renewable generation resource and the limited number of hours when the conditions occur suggests that even with this incremental cost, additional wind is likely to be economically attractive.	results. This work will also consider the impacts of grid service provision from inverter-based generators (such as wind turbines) and how the introduction of new ancillary services like Fast Frequency Response might affect existing services such as Synchronized Inertia. Should the findings of this study confirm that additional wind can be accommodated with no further integration assets, but via operational practices which are evaluated to be more economic, such operational constraints would be modeled to determine the timing and capacity of wind additions.
Emissions Reduction	EAC	Given the declarations of climate emergency from the federal government, provincial government and many municipalities in Nova Scotia, it is prudent to continue planning for increased ambition for emissions reductions in the electricity sector, moving forward. EAC is concerned that this IRP does not go far enough to plan reasonable increases in this ambition. Given the Clean Power Roadmap process; the development of the Atlantic Loop; the federal government's commitment	As per previous responses, NS Power developed several emissions profiles in consultation with stakeholders during the Assumptions phase of the IRP, two of which incorporated trajectories designed to achieve compliance with the SDGA as currently known. Building on this base, NS Power has focused its modeling efforts on achieving an 87%- 95% reduction in GHG emissions by 2045, relative to 2005 levels.

Category	Participant	Comment	NS Power Response
		for 90% of electricity generation to come from non-emitting sources by 2030; the federal government's commitment to increase the national 2030 emissions reduction target; and the as-of-yet undetermined electricity sector targets under Nova Scotia's Sustainable Development Goals Act, we feel this IRP misses a major opportunity to plan for what is to come. There is no doubt that vital decisions must be made quickly with affordability, reliability and sustainability as its core pillars, and to mitigate adverse impacts on environment and human health.	
No Absolute Zero Scenarios	EAC	[T]he EAC expresses deep concern that no "zero" emissions scenarios were studied in the IRP 2020. The planning objectives are overly cautious and without examination of accelerated zero emission plans it is not clear that a safe scenario has been studied and that the process has considered an adequate range of planning scenarios through this omission, given the urgency of climate action. Moreover, since electricity sector-specific targets are not yet fully developed in the SDGA, it weakens the confidence that these scenarios are SDGA compliant. While retiring coal earlier would provide a strong case for decarbonization, replacing it with and operating natural gas at low capacity factors beyond 2050 however, would not allow the energy system to reach net zero and result in redundant and expensive stranded assets beyond the 2050 timeframe. SDGA is designed to create an impetus for clean growth in the province, which gives NSPI the perfect opportunity to aggressively pursue deep decarbonization before	As above, NS Power has focused its modeling efforts on achieving an 87%- 95% reduction in GHG emissions by 2045, relative to 2005 levels. A move to modeling absolute zero emissions would rely on non-conventional or early technological readiness level resources. The costs and characteristics of such resources, and their interaction with grid services and reliability are not well established. Thus, such a scenario would be highly speculative. As enabling technologies and/or legislative frameworks become more certain, NS Power could revisit modeling an absolute zero emissions budget with a reasonable range of uncertainty. As 'Net-Zero' has yet to be fully defined, NS Power believes that some emissions budget in the electricity sector will be available with a mechanism to offset emissions above absolute zero. As technological readiness levels of an absolute zero electrical grid emerge (with characteristics reasonably similar to Nova Scotia), NS Power could assess this plan within the evergreen

Category	Participant	Comment	NS Power Response
		provincial targets. As in other comparable jurisdictions, the electricity sector is perceived as an enabler, which has the capacity to accommodate, empower and create pathways for other challenged sectors such as forestry, transportation, agriculture and marine. Therefore, a scenario for fully decarbonized utility with real net-zero emissions and the resulting cost requirements must be examined fully.	process, with a reasonable level of precision and accuracy. NS Power agrees with the comments of the electrical sector enabling decarbonization of other sectors. This has been a focal point of this integrated resource plan, whereby NS Power is decarbonizing concurrently with growing loads.
Regional Interconnection	EAC	Agreed that regional interconnection will be vital in transitioning the province off coal. Transformative ideas such as the Atlantic Loop presented in the Speech from the Throne and the $10 billion Canada Infrastructure Bank announcement to support transitioning regions, underpin the idea of pursuing enhanced transmission connections and upgrades, since these will clearly be the least cost options and have the capability for faster clean transition. The plans fall short of "optimal" as the software was presented with limited regional integration opportunities. Incremental transmission builds must be examined fully in future studies.	As stated previously, all scenarios fully replace coal generation by the end of the planning horizon. The model was offered up to 615 MW of new firm import capacity, which was economically selected by 2045, and much earlier in many cases, in all Regional Integration scenarios. In addition, NS Power has already contracted long term for 153 MW of clean firm imports via the Maritime Link. This potential level of imports represents a transformational shift to the historic generation mix. Even greater firm capacity imports could be economic in the future, as suggested; however, further analysis would be required (e.g. reliability, self-sufficiency, policy certainty, etc.).
Electrification Levels	EAC	As highlighted in EAC's previous comments, reaching high electrification levels will be most beneficial for the province both in terms of environmental advantages and economic rate implications in the long-term. However, this electrification must be achieved without reliance on natural gas builds. The provincial energy system, starting today must be envisioned as a combination of clean firm imports, renewable electricity, energy storage, demand side management, maximizing building efficiency and electrification of	NS Power agrees that high electrification levels will be most beneficial for the province both in terms of environmental advantages and economic rate implications in the long-term. During the assumptions development process, natural gas generation technologies were not excluded from the list of candidate resource options.

Category	Participant	Comment	NS Power Response
		transport. This will help us align well with the principles of just recovery and sustainability. In addition, it is important to understand the avoided costs of max DSM and transport fuel in high electrification scenarios, and therefore, must be included in future studies.	Determining savings in gasoline consumption from the transport sector is outside the scope of an integrated resource plan. However, NS Power agrees that such society-wide costs are important to consider.
Future Process	EAC	There is no doubt that further planning is required as an ongoing activity and must continue to be transparent and inclusive. The EAC and other key stakeholders believe that future iterations of this process would stand to benefit from being managed by an independent third party, with environmental advocacy and the pillars of affordability, reliability and sustainability as core principles.	NS Power believes it conducted a transparent and collaborative study. In the pre-IRP phase, it held four technical conferences with participants, and after the Terms of Reference were finalized, NS Power held technical conferences or workshops at every major stage of the IRP (Assumptions and Analysis Plan, Scenarios and Modeling, Interim Modeling Results, and Draft Findings, Action Plan and Roadmap. In addition to these stakeholder engagement sessions, NS Power held individual meetings with stakeholders and consultants on a number of occasions. All IRP information and documentation has been made available to the public via the IRP website (irp.nspower.ca) The IRP examined a broad range of environmental policies, including committing to full coal retirement during the planning period, and assumptions consistent with net zero greenhouse gas emission levels by 2050 in accordance with the Sustainable Development Goals Act, as well as affordability, reliability and sustainability as core principles. Further the UARB and its consultants, Synapse Energy Economics and Bates White were actively engaged in all facets of the IRP assumptions development, modeling and analysis.

Category	Participant	Comment	NS Power Response
			NS Power believes its in-house expertise, with access to the full spectrum of NS Power's departments and expert knowledge of the power system, make it most capable of undertaking such a study.
Future Process	Envigour	We continue to be concerned that the underlying assumptions for the IRP modelling are too conservative. This concern is mitigated by an evergreen IRP process. However, we also strongly advocate for parallel processes to engage the public and interested parties. Due to the rapid change in prices, technologies and business models, we suggest planning for an evergreen process to begin now with a view to broad stakeholder engagement in Q2 or Q3, 2022. That timeframe would enable practical discussion on the results from: • Imports on the Maritime Link (Base Block and Market Electricity), the scale, and implications for integration of other renewables; • New assumptions on the cost and value of renewable energy resources, including onshore and offshore wind and solar PV, and the cost and value of storage; • New assumptions on technology, consumer interest and cost associated with Distributed Energy Resources and the initial outcomes from the NS Power Smart Grid project; and • Initial findings on the value of Time Varying Pricing.	NS Power appreciates that many of the assumptions are rapidly changing and evolving. Many of the primary modeling assumptions (e.g. pricing for new resources) were provided by a third-party consultant (E3), which largely relied on publicly available industry sources, in some cases with local pricing adjustments. However, based on stakeholder feedback on specific assumptions, NS Power did undertake several sensitivities on base assumptions (e.g. capital cost of wind and batteries – both independently and stacked, high fuel costs, system stability requirements and DSM levels). NS Power has committed to an evergreen process and appreciates the feedback.

Category	Participant	Comment	NS Power Response
Wind (offshore)	Envigour	The Government of Canada is continuing to establish a regulatory framework for the development of these resources. As that work matures, industry is beginning to identify the specific steps required to make such investments feasible. One of the steps is to establish the cost and value of such resources. We understand such work is now underway, and by the spring of 2022 we believe the case for considering offshore wind as delivering near baseload capacity (greater than 60% capacity) which should result in a much different analysis of its value.	NS appreciates the comment and agrees that offshore wind has the potential to be an economic resource at some point in the future. If offshore wind can provide a stable, high capacity factor energy profile, as suggested, its economic competitiveness would be enhanced. NS Power will monitor this developing resource for changes from base IRP assumptions. The E3 supply options study (from the Pre-IRP work) indicated that the cost of offshore wind was approximately 2.25 times greater than onshore wind per installed kW in Nova Scotia, although the cost decline over the planning horizon was larger than for onshore. Ongoing O&M costs are estimated to be 2 times more expensive than onshore wind. In addition, the Capacity Factor midpoint is estimated to be 41% for offshore wind, 2% higher than the 39% assumed in the IRP for new onshore wind. From an integration perspective, offshore wind would have similar integration requirements as onshore wind and so could be integrated in future resource plans in place of other inverter-based variable renewable generation if costs or other factors were to significantly change.
Electrification	Envigour	Furthermore, we also note that even the high-electrification scenarios do not assume a great deal of growth in the need for electricity. New population and GDP growth patterns as well as new industrial	NS Power agrees that drivers other than the electrification of space heating and transport could drive higher levels of electrification. NS Power is proactively planning the system to that it can accommodate

Category	Participant	Comment	NS Power Response
		opportunities in a clean carbon economy may drive demand higher than forecast. This outcome would raise new questions on where the resources to meet such demands (in excess of demand forecasts from all scenarios) may come from.	electrified loads as they materialize and has committed to monitor and further analyze the impacts of electrification (i.e. impact to load shape).
Wind	Envigour	We would note that while onshore wind and imported renewables provide low-cost solutions for current demand forecasts, their growth and availability may well be constrained by public concerns. Considering the longer-term options for the next best source of near-base load electricity – offshore wind – would be prudent.	As noted above, NS Power agrees that offshore wind could play a role in the future power system. NS Power will continue to monitor this technology and assess its operational effectiveness and cost with NS Power's transitioning generation portfolio.
DERs / Assumptions	Envigour	A similar case may be made for the rapidly evolving world of DERs, including customer driven efficiency measures, storage, and trends for electric vehicles. With assumptions on these matters baked into the IRP with 2019 knowledge, it would seem reasonable that those assumptions should be updated with 2022 knowledge available in the spring of 2022. We would note that the value of DER is not only an issue of price. There will also be benefits from re-engineering legacy utility designs and processes. The NS Smart Grid Project will only begin to touch the surface of understanding innovation from new products and services, and the evolution of utility capabilities. Evaluating new utility capabilities and opportunities for investments in grid monitoring and control, customer engagement, DER valuation etc. are all needed to be continually updated to enable DERs to provide full benefits for ratepayers.	NS Power agrees that the rapidly evolving DER field will require continual assessment.

Category	Participant	Comment	NS Power Response
Natural Gas	Heritage Gas	The IRP highlights the need for additional firm generating capacity to ensure that the system is reliable with sufficient supply available to meet expected demand, especially during periods of low renewable generation and peak loads. Natural gas-based generation also provides critical ancillary services needed to support increased levels of renewable energy…	NS Power agrees that new generation resources utilizing natural gas fuel are a consistent part of the IRP optimal resource plans. The GHG emissions trajectory and availability of other sources, such as firm imports, largely dictates the type of technology and associated utilization. NS Power agrees that natural gas generation resources contribute to essential grid services and or other variable renewable energy requirements support periods of low wind generation.
Natural Gas	Heritage Gas	As shown in the Draft IRP Report, natural gas is a low-carbon source of electrical generation and will be necessary in supporting renewable integration in the province… Heritage Gas acknowledges that renewable electrification in certain sectors of the economy will be important for decarbonization in Nova Scotia. However, electrification unaccompanied [by] other clean energy options will not be sufficient to meet the Sustainable Development Goals Act ("SDGA") Net-Zero 2050 target.	NS Power acknowledges that different sectors of the economy can electrify more easily and readily than other sectors. In sectors that cannot efficiently electrify given the state of technology or other prohibitive factors, other clean options, including carbon capture, may be required to meet the SDGA target.
Hydrogen	Heritage Gas	The Offshore Energy Research Association ("OERA"), Liberty Utilities, Heritage Gas, Atlantic Canada Opportunities Agency ("ACOA") and the provincial Department of Energy & Mines engaged Zen Energy Solutions to determine the future potential uses of hydrogen in Nova Scotia. Governments around the world increasingly see hydrogen as imperative in meeting the Net-Zero targets. … The study by Zen supports the development of a hydrogen economy in Atlantic Canada and shows that hydrogen could deliver	NS Power agrees that hydrogen and/or renewable natural gas could play a meaningful role in achieving SDGA emissions targets in the future based on applicable economics. This has been incorporated into IRP Action Item #3c.

Category	Participant	Comment	NS Power Response
		up to 22% of the end-use energy by 2050.6 In addition to having an important role in building heat and energy storage, hydrogen can serve a central role in areas that are challenging to cost-effectively electrify. These include heavy vehicle transportation, industrial and institutional processes. Therefore, in addition to the role of natural gas in supporting the transition of the electrical grid, the introduction of hydrogen and renewable natural gas (“RNG”) into natural gas infrastructure will further support the province in reaching the net-zero emissions target set out in the SDGA.	
Natural Gas Infrastructure	Heritage Gas	While natural gas underpins the transition of the electric grid to lower carbon intensity, natural gas infrastructure can also play an important role in supporting the transformation over the next 25-30 years in the province. There is an increasing awareness of the opportunity to accelerate the reduction in GHGs, increase reliability and lower energy costs for Nova Scotians by integrating the electrical grid with the existing natural gas pipeline network, for a more efficient and circular use of resources in the province. An integrated energy system supports the production of more renewable energy including wind power, solar, green hydrogen, and RNG. It can also reduce Nova Scotia’s reliance on other jurisdictions and promote local economic growth and energy independence, further improve energy resiliency and flexibility,	NS Power agrees that natural gas infrastructure is an important component of this IRP, and is interested to explore options such as those mentioned that might enable additional renewable energy in Nova Scotia.

Category	Participant	Comment	NS Power Response
		effectively manage peak demand, and lower costs to Nova Scotian energy ratepayers.	
Electrification	Heritage Gas	NSPI has noted its view that "electrification is a key enabler of economy wide decarbonization in support of provincial goals and targets". However, by its nature, the IRP process reviewed the electric system alone and did not evaluate other non-electric opportunities to cost-effectively enable energy solutions consistent with provincial goals and targets. The IRP analysis reviewed a broad spectrum of assumptions, and many of those, such as EV uptake for example only, could well play out in very different ways in the coming years, and the IRP is clear that NSPI's transition to a significantly less coal-based carbon intensive system will require a number of years to occur.	Electrification is a cost efficient enabler of decarbonization as discussed in the PATHWAYS report. However, difficult to electrify sectors may also consider other alternatives (see PATHWAYS). NS Power agrees that the trajectory of electrification load growth and the underlying components (e.g. EV, space heating penetration) have a high degree of uncertainty. This is why NS Power studied a wide range of load assumptions for this IRP.
Future Process	Heritage Gas	Heritage Gas believes that NSPI's approach to an evergreen IRP will be valuable in this regard, so that all parties can continue to participate as NSPI conducts the numerous follow-up analysis the IRP calls for and the status of underlying assumptions becomes clearer.	NS Power acknowledges the comment and has integrated stakeholder feedback as part of Roadmap Item #8.
Coal to gas conversion	Heritage Gas	[t] the Action Plan should reflect a timeline of completion of this study and scope of the work included in the coal-to-gas conversion scenario, and should keep stakeholders engaged and apprised in this process.	The first coal-to-gas conversion optimized by the IRP is in-service in 2029, indicating that this is an upcoming but not urgent requirement. Nova Scotia Power intends to complete this work within the near-term Action Plan period but has not yet determined more specific timing.
Regional Integration	Heritage Gas	Given that the Regional Integration and Reliability Ties play a key role in many of the optimal resource plans developed for the key scenarios, these studies should be undertaken in the near term.	NS Power concurs that the Regional Integration and Reliability Tie options were robust across the wide range of assumptions and sensitives tested and will be the subject of engineering studies in the near term, per IRP Action Item #1.

Category	Participant	Comment	NS Power Response
		The tie line connection to New Brunswick will be exposed to the increasing frequency and severity of storms related to climate change impacts. The influence of increased dependence on the electrical grid and regional interconnections associated with increased electrification needs to be considered with respect to energy security and reliability for the province.	NS Power concurs that reliability implications will be assessed as part of scenarios relying on large firm imports.
Diesel CTs	Heritage Gas	Concerns with reliance on LFO-fired CTs because of their age, even with sustaining capital. There should be ongoing monitoring of these units and the IRP should specifically provide for such monitoring and reporting on the results during the evergreen nature of the IRP, particularly in light of the value of new gas fired CTs evidenced by the IRP analysis.	The economics of the LFO CT fleet were substantiated in the IRP process. Like other IRP assumptions, if the input assumptions were to materially change as a result of higher forecasted sustaining costs, lower competing technology costs or some combination thereof, NS Power would re-evaluate the economics of maintaining these units.
Future Steps	Heritage Gas	all parties will need to closely monitor developments in the electric and broader energy sectors to ensure Nova Scotian residents and business have access to competitive alternative energy supplies and to cost effectively meet the goals of the Province.	NS Power acknowledges this comment.
Net-Zero	HRM	The E3 and IRP scenarios were developed prior to HalifACT and the Sustainable Development Goals Act (SDGA). Will Nova Scotia Power produce an updated scenario that aligns with the 2050 net-zero carbon emission target of the SDGA?	[HRM comments are more in the form of questions about impacts of the IRP and analysis on the HRM HalifACT plan] As noted in the IRP report, even achieving an 80% reduction in GHGs by 2045 is not a given, but NS Power will continue to plan its system with a goal of achieving net-zero emissions by 2050. At the time of engaging E3, the SDGA framework was not established. The 80% CO2 reductions below 2005 levels by 2050 was chosen as it is considered to be "deep

Category	Participant	Comment	NS Power Response
			decarbonization". Notwithstanding the Pathways analysis, all of NS Power's scenarios are considered to be SDGA compliant (with the exception of the Comparator Scenario). The IRP modeling period covers 2021-2045, with the emissions reductions trajectories from end of period to 2050, indicating an emissions profile of 0.5 to 0MT of CO2. NS Power notes that the Net Zero definition is still being determined.
DERs	HRM	Success of HalifACT requires high levels of distributed energy resources (DER), primarily solar, in order to more rapidly reduce the emissions factor of our electricity. What are the implications for the IRP if the DER described in HalifACT is implemented?	NS Power acknowledges the specific questions raised by HRM, and has engaged with HRM to discuss the concerns. The IRP is directional and not prescriptive, and is not intended to address the specific questions about alignment with HalifACT. NS Power draws attention to its Distributed Energy Promoted ("B") scenarios and the associated analyses. This analyses assessed rooftop solar installations in quantities similar to the HalifACT study.
DERs	HRM	Do the carbon intensities of the IRP scenarios provide the opportunity for HalifACT to reduce the level of DER deployed, given that the E3 scenarios do not reflect the level of deep energy retrofits and building and vehicle electrification required in HalifACT?	Please see the comments above.
Electrification	HRM	To achieve the deep emission reductions of HalifACT, high rates of building and vehicle electrification are needed, combined with distributed renewables to reduce emissions from electricity. How would HalifACT achieve its objectives without high DER and with the high emissions factor as indicated in the IRP reference scenario?	Please see the comments above.

Category	Participant	Comment	NS Power Response
Electrification	HRM	Are the electrification scenarios defined in the E3 study identical to the electrification levels in the IRP scenarios? For example, is the level of heat pump adoption in residential buildings specified in the E3 scenarios the same in the corresponding IRP electrification scenarios?	Please see the comments above.
Demand	HRM	What would the impact on electricity demand be if the thermal and electrical energy demand of the existing building stock was reduced by 50% rather than by the levels assumed in the E3 scenario analysis?	Please see the comments above.
Electrification	HRM	If greater building efficiencies are achieved, what would the impact be on total building energy expenditures in the context of more rapid decarbonization of electricity generation and/or more rapid electrification of transportation and heating?	Please see the comments above.
Electrification	HRM	The share of the residential stock with heat pumps grows to approximately 50% and 100% in the mid and high electrification scenarios, respectively (E3 report, Figure 12 and 13). The E3 report (p.25) also indicates that building shell and weatherization measures reduce the space conditioning requirements of the residential stock by "up to 20%" however it is not clear if this maximum improvement applies to new and/or existing housing. What is the assumed percent reduction of the space heating intensity of the existing (base year) residential building stock by 2030 and by 2045? Is this level of improvement common in all scenarios?	Please see the comments above.
Electrification	HRM	Please provide a breakdown of the Nova Scotia housing stock by type according to average thermal intensity for space heat, fuel share (resistance, heat pump, oil, wood,	Please see the comments above

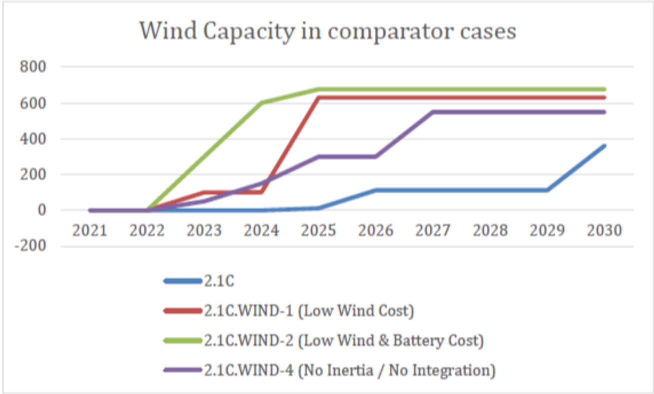
Category	Participant	Comment	NS Power Response
		other), and heating system efficiency for the base year, 2030 and 2045 for each of the IRP scenarios.	
Covid Impact	HRM	COVID economic recovery strategies are emphasizing green investments like energy retrofits and vehicle electrification. Will Nova Scotia Power produce a scenario in which both efficiency and electrification are accelerated in the 2020's to understand the impact of this on household energy costs, emissions and the electricity system?	Please see the comments above.
Rates	HRM	In what circumstances would the minimization of electricity rates be inconsistent with the minimization of the total cost of energy service and amenity (heat and comfort, mobility and access) for Nova Scotia households and firms?	Please see the comments above.
Signposts	Natural Forces	Items to be addressed on a shorter timescale: 1. Examination of system stability issues and consideration of optimum operational strategies to address system reliability with higher levels of wind generation; 2. An RFP to determine the actual cost of new wind to be added to the system. We believe it is important to set out a clear program of work associated with these issues, with target dates for completion and including engagement with stakeholders when and as appropriate.	NS Power has committed to initiating a procurement strategy which will solicit Nova Scotia-based market pricing information. This will inform size and timing of procurement. NS Power has committed to completing a detailed system stability study, which will include operational strategies.
Key Findings	Natural Forces	Clarity of Key Findings. There are a number of important findings which are discussed within	NS Power acknowledges the suggestion. The final report updated the Key Findings for further clarity.

Category	Participant	Comment	NS Power Response
		sections of the report, but are not always clear in the summary sections, for example in "Overview of Key Findings" in section 1.8. We recommend further attention is given to the presentation of key findings (specific examples are given later).	
Wind scenarios	Natural Forces	Comparison of Scenarios and Resource Portfolios. NSP correctly identifies that there are elements that are common to all or most scenarios, which can then be considered as "no regret" steps. It is also the case that the level of wind capacity installed toward the end of the study period is often broadly similar in most scenarios. There are however significant differences in regard to the pace of build-out of further wind capacity, particularly over the next decade. The decision on wind capacity build-out in the shorter term (over the next several years) is undoubtedly one of the most important issues emerging from the IRP report. One can identify two broad "clusters" of scenarios, being: a. Those which have very limited build-out of wind capacity until at least 2030. These are generally cases based on higher wind capital costs, association of battery/synch comps with related additional capital costs, and lower demand levels; b. Scenarios which show more significant build out of wind capacity progressively through the 2020s. These are generally cases with some or all of more competitive wind costs; disassociation with requirement	Please see the comment below.

Category	Participant	Comment	NS Power Response
		for batteries/synch comps, and higher demand levels (mainly due to further electrification). The appropriate pace of build-out of wind is clearly one of the most important issues arising from the study to date, and it is critical that the outstanding issues are addressed at the earliest opportunity.	
Roadmap /Signposts	Natural Forces	Selection of Reference Plan, and "Signposts". The resource plan optimized for Scenario 2.0C (Low Electrification / Net Zero 2050 / Regional Integration) is nominated as the "Reference Plan", primarily as it indicates a lower total cost than other scenarios. We are not entirely clear what the implications of nominating the reference plan are, but it must be noted that other scenarios have potentially with lower rates to electricity customers as well as other policy benefits (supporting decarbonization through electrification). Therefore the "reference plan" may not be the "optimal plan". Also of course as identified by NSP in the report, there are a number of key factors which will influence the "optimal" portfolio in any case. The "signposts" identified within the Report are key to determining which trajectory is followed particularly for wind capacity build-out through the next decade. Considerable focus should be given to moving these forward as soon as possible.	NS Power agrees that each scenario has a unique and optimal resource plan, and thus has focused the findings of the IRP around commonality and no-regrets action plan. 2.0C is selected as the Reference Plan on the basis of its having the lowest cost NPVRR, which is the established primary metric for NS Power's IRP. It is important to note that this scenario is representative of many of the other low-cost resource plans modeled, particularly in the first ten years of the plan, and as a result it is this commonality that will inform Nova Scotia Power's "no-regrets" IRP Action Plan and Roadmap.
Key Finding 1	Natural Forces	[T] the more important finding from this IRP Study is that the electricity sector can facilitate decarbonization of other sectors (heat, transport) through increased electrification without placing upward pressure on	NS Power acknowledges and agrees with the statement. NS power has updated its rate model, which has resulted in reduced benefits. However, the general conclusions remain. Please see section 6.5 for more information.

Category	Participant	Comment	NS Power Response
		electricity rates. In fact, high electrification appears to tend to reduce electricity rates, which is a win-win scenario. This is certainly mentioned within the report, but is somewhat buried in the text. It is a key point which should be highlighted in any summary of findings or conclusions.	
Key Finding 4	Natural Forces	We recognize that identification of the scenario with the lowest cumulative NPV is consistent with the originally-stated objectives of the IRP process. However this criteria will generally always select a scenario with lowest electricity demand, so is not particularly informative. We believe that at least similar emphasis should be given to scenarios based on the lowest level of rates to electricity customers. Scenarios with higher levels of electrification tend to have lower rates and also of course have the benefit of facilitating broader policy objectives for emissions reductions (while at the same time reducing prices to electricity customers). This is discussed further in the IRP report in section 3.2 "Maintaining Affordability" (page 48), but should be highlighted in any summary of findings and conclusions.	NS Power acknowledges and agrees with the statement. As provided above, It is important to note that this scenario is representative of many of the other low-cost resource plans modeled, particularly in the first ten years of the plan, and as a result it is this commonality that will inform Nova Scotia Power's "no regrets" IRP Action Plan and Roadmap.
Findings re DER	Natural Forces	Scenario modeled with DER (2.1B) has a significantly higher rate impact over the planning horizon and the cost of DER is not included in rate impact calculations but could be expected to add additional rate pressure.	NS acknowledges and generally agrees with the comment, however given the early stage of this nascent industry and potential for future avoided cost savings, NS Power does not feel that this is a "key finding" of the IRP.

Category	Participant	Comment	NS Power Response
		We suggest that this is a significant finding which should be included in the "Key Findings" of the study.	
Wind Capacity build-out	Natural Forces	One can identify two broad "clusters" of scenarios, being: a. Those which have very limited build out of wind capacity until at least 2030. These are generally cases based on higher wind capital costs, association of battery/synch comps with additional capital costs, and lower demand levels; b. Scenarios which show more significant build out of wind capacity progressively through the 2020s. These are generally cases with some or all of more competitive wind costs; disassociation with requirement for batteries/synch comps, and higher demand levels (mainly due to further electrification). The scenarios show clearly that (a) capital cost of wind and/or (b) association of wind with batteries/synch comps, are very material to the amount of wind selected in the optimised portfolios during the next decade. This is illustrated in the graph below, showing comparative wind deployment in the relevant sensitivity cases.	NS Power agrees that the size and pace of wind installations is being driven by capital cost and wind integration assumptions and, as such, has committed to completing further detailed system stability study to determine which "cluster" or combination of clusters is optimal for minimizing costs for ratepayers. NS Power has clarified the finding on 2.1C.S4 in the final report to state, "The boundary case of no synchronized inertia constraint + no wind integration requirements (2.1C.WIND-4) indicates that the removal of these constraints does not enable a wind buildout beyond the range identified between the base and low price sensitivities until the mid-2030s"; results beyond that point suggest that further analysis is required for significant wind additions beyond those modeled in the base cases.

Category	Participant	Comment	NS Power Response
Wind Capacity	Natural Forces	 Clearly lower wind capital costs (scenarios 2.1C.WIND-1 and 2.1C.WIND-2) result in much more rapid build out of wind capacity than 2.1C. Alternatively, the disassociation of the battery & synch comp costs (scenario 2.1C.WIND-4) also results in more rapid wind deployment. As noted in previous submissions, some combination of these two factors will deliver similar, or potentially even higher wind deployment during the period. We believe the characterisation of scenario 2.1C.WIND-4 within the draft IRP report is incorrect. The report states that *The boundary case of no synchronized inertia constraint + no wind integration requirements (2.1C.WIND-4) indicates that these constraints do not significantly affect the wind build seen in both the base and low price sensitivities until the mid-2030s*; Unless we are misinterpreting the results, it can be seen from the above graph that there is a significant	

Category	Participant	Comment	NS Power Response
		difference in the extent of wind deployment during the 2020s, from the alternative scenario 2.1C.	
Wind	Natural Forces	The report also notes regarding scenario 2.1C.WIND-4:*This run is intended as a test case to understand how the model performs with no synchronized inertia constraint and no integration requirements for wind; it is not considered to be a feasible resource plan based on these assumptions.* Again, we believe this is fundamentally incorrect. It is a feasible resource plan. Of course, the system must be operated securely, which requires respecting ancillary services and other system constraints including system inertial requirements – this is not in dispute. The scenario as run does not respect system inertia requirements; this however does not mean that the portfolio is not feasible, but only that the results may marginally understate the costs. Including minimum system inertial requirements (which can be modelled) may mean that in the case of this portfolio, the level of wind output (and/or imports) needs to be constrained on rare occasions in order to provide “space” in the dispatch for the conventional units needed to provide inertia. However, this will arise very infrequently and the imposition of a reasonable SIR constraint will not add materially to the costs. The report acknowledges the need for further work on examining inertial requirements and operational strategies to meet them, and we urge that this is undertaken as soon as possible, in order to prevent this	NS Power has modified the statement from a ‘feasible’ to an ‘operable’ resource plan on the basis of all electric utility grids requiring some minimum amount of synchronous inertia, which this scenario did not have. While NS Power generally agrees that there is no theoretical limit to wind installations, given that one can curtail wind during certain time periods and/or curtail when reaching a percent of load (or other similar measures), further study is required to assess operational practices and/or enabling investments required to maintain system stability during a broad sampling of system conditions. At this stage, NS Power does not believe it is appropriate to project “marginal” incremental costs and/or curtailments on “rare occasions” with such significant volumes of installed wind.

Category	Participant	Comment	NS Power Response
		issue continuing to inappropriately constrain decisions on the optimum resource portfolio.	
Signposts / Wind Capital costs	Natural Forces	Capital costs of Wind: Tracking of the installed costs of wind, solar, and energy storage to look for variations from the trajectories established in the IRP (in particular, monitoring for divergence from the "Base" to the "Low" pricing scenarios). Natural Forces strongly believes that the capital costs of wind assumed in the so-called "Low" pricing scenarios are more realistic, and if this is the case, it supports a much more rapid build out of wind than in the currently-proposed "reference plan". The solicitation of Nova Scotia-based market information will, we believe, support this conclusion.	NS Power has committed to price discovery/market pricing information which will inform the selected wind capacity profile and timing, informed by the IRP wind sensitivities.
Signposts / GHG Allowances	Natural Forces	Consideration of potential monetary value of emissions reduction: Recognition of importance of tracking the ongoing development of the Nova Scotia Cap-and-Trade Program, and in particular, monitoring the GHG market size for indications that value from incremental allowance sales (beyond the projected economic emissions reductions shown in the IRP results) can be incorporated into long-term resource planning decisions with greater certainty. We fully agree that recognising a value of incremental GHG reductions could influence the optimal resource plan, particularly as regards non-emitting generation procurement. We also consider that it would be very useful to apply conceptual values to incremental emissions in the different IRP scenarios, to indicate the impact on NPV costs and ranking of different scenarios under a range of emissions monetary values.	At this stage, NS Power does not feel there is enough certainty for long-term resource procurement decisions to apply conceptual values to incremental emissions in the IRP scenarios. As NS Power has provided the cost and emissions profiles for all Scenarios, interested parties could undertake such an analysis independently.

Category	Participant	Comment	NS Power Response
		We again emphasise that even if no monetary value is currently ascribed to lower emissions levels, it is worth highlighting that there is distinct value (even if not quantified) in lower emissions due to: • Hedging against developments which put emissions compliance under stress, such as higher growth rates (in this regard we note that "risk-weighting" is an objective of the IRP). • The potential future value under new valuation or trading mechanisms. • Generally, being more environment-beneficial and supporting the climate-change agenda.	
Signposts / Demand Growth	Natural Forces	Demand growth: Monitoring electrification growth in Nova Scotia to understand at what point the provincial load profile starts to move from Low, to Mid, to High levels of electrification. The potential for a wide variation in demand growth, particularly arising from potential electrification as a means to decarbonising transport and heat (as is being experienced on other countries), is identified in the report as a significant influence on the portfolio selection. The "signposts" identified within the Report are key to determining which trajectory is followed particularly for wind capacity build-out through the next decade. Considerable focus should be given to moving these forward as soon as possible. This requires, in our view, setting out a clear plan with target dates, and ongoing engagement with stakeholders during its delivery.	NS Power has committed to incorporating industry best practices such as those identified by the Regulatory Assistance Project as well as other relevant work, for example, electrification programs in other jurisdictions and the details already contained in the Nova Scotia Deep Decarbonization report. Further, NS Power plans to develop and propose pilots and/or programs that focus initially on the transportation and building electrification sectors as key targets for early electrification adoption. These pilots and programs will be subject to UARB oversight. NS Power cautions that while it does have a role in enabling and promoting beneficial electrification for the dual benefits of decarbonization and rate stability, the pace of general electrification will largely be determined by technological development and/or government initiatives (e.g. EV subsides, etc.).

Category	Participant	Comment	NS Power Response
Wind Capacity and Demand Growth	Natural Forces	[Refers to s. 3.1.3.3. re load growth as effective tool for wind integration] We agree with this point, but again we note that this differentiation (i.e. allowing more wind installed capacity in higher demand scenarios) has only been included in scenarios which include the batteries/synch comps or the 2nd tie-line. In these cases, more wind capacity is allowed in higher demand scenarios. But in the case without these, the same wind capacity limits are imposed in all demand cases (ref Figure 15 of the report). [Reference to Figure 15 IRP Wind Integration Options] It is not clear to us why allowed wind does not also increase with demand in the "No Integration Requirements" case. This is particularly important on the context of the current reference case (on which the action plan is primarily based). However, it may be overtaken by events on the assumption that further system stability studies (indicated as a "sign-post" in the plan) are undertaken as a priority. This should, we believe, significantly alter the wind limits in any case.	There is no MW limit imposed on the no-integration requirement sensitivity (2.1.C.Wind-4). Per Figure 15, the Mid electrification base case maximum wind constraint is 1100 MW. This scenario added 1,250 MW.
Signposts	Natural Forces	We believe that one of the most important factors in the short term, is the rate of wind deployment appropriate over the coming years. Natural Forces believes that developments in relation to the	NS Power acknowledges the statement.

Category	Participant	Comment	NS Power Response
		"signposts" identified in the report will confirm that higher wind trajectories are beneficial to rate payers and to furtherance of broader policy objectives, and we urge that a clear plan is developed for this analysis, and it is completed as soon as possible. Natural Forces confirms its commitment to contribute constructively to the process and encourages NSP to continue to build on the stakeholder engagement efforts undertaken to date.	
Future Process	PHP	The Draft Report, building on the prior findings/road map/action plan document, confirms there is a general path forward which is robust across numerous scenarios. However, the timing and scope of specific actions that should occur over the study term of the IRP remains subject to ongoing studies and greater clarity on how key assumptions will eventually play out. As such, PHP appreciates that NSPI has acknowledged the necessity for flexibility going forward and especially its determination that this should be an evergreen IRP with regular updating to stakeholders. Based on the results of the future studies called for in the Draft Report, and future information to help solidify key assumptions in what is a very dynamic period in the energy sector in the Province, regionally, and internationally, it will be important for NSPI and all stakeholders to remain flexible and to take advantage of opportunities to potentially accelerate the rate of change in the electricity sector where circumstances and economics warrant.	NS Power acknowledges the comment. NS Power has committed to refining the Action Plan and Roadmap items via an evergreen IRP process. This process will facilitate annual updates as conditions change and technology or market options develop, and as Action Plan items are completed or significantly advanced. Per IRP Roadmap Item #8, this will include a process for stakeholder input and participation.

Category	Participant	Comment	NS Power Response
		As such, PHP recommends that together with annual updating on the status of the IRP, that NSPI also endeavor to bring forward the results of the planned ongoing study work, and other information relevant to opportunities that may arise to advance the goals of the IRP and the Province in the electricity sector, when such information becomes available, so that its implications can be evaluated in a timely manner and input provided by stakeholders.	
Future Process / Collaboration	PHP	As opportunities may arise in a host of areas, such as the ability to cost share transmission infrastructure build outs with neighboring jurisdictions or the Federal government, the ability to economically advance renewable capacity, advancements in energy storage and demand response, etc., it is more important than ever that information and opportunities are shared in a timely fashion to achieve the sustainable development goals of the Province in the least cost manner. This can be best achieved by collaboration among stakeholders, and PHP believes the open sharing of information that has occurred throughout the IRP process should continue for the foreseeable future to ensure a vibrant and sustainable energy sector in the Province which will accrue to the benefit of all stakeholders.	NS Power acknowledges the comment, please see notes above as well IRP Finding 4b.
Future Process	SBA	[A]s system conditions evolve and resource costs change over time, there will be a need to continually update assumptions and refresh analysis when needed. NSPI acknowledges this need by discussing an "evergreen IRP process" to continuously monitor and update investment plans as conditions change. NSPI	Nova Scotia Power will include a summary of updates as part of IRP Action Plan reporting and will incorporate the opportunity for stakeholder comment and feedback as part of the update process. The intention of the evergreen process is to focus on those planning inputs which are changing or evolving in the complex resource planning environment, rather than to provide a comprehensive update of all assumptions used in the

Category	Participant	Comment	NS Power Response
		indicates that one element of this will be regular updates as part of the IRP Action Plan reporting. NSPI should clarify in the final IRP what types of information will be reported in those updates, such as changes to resource cost or operational assumptions, electrification or load changes, and import/export market changes. NSPI should also propose options for stakeholder involvement in the evergreen IRP process.	2020 IRP, for example. NS Power believes this approach will necessitate a dynamic and nimble process, rather than one which is fully defined in advance.
Roadmap / Signposts	SBA	The draft IRP identifies a number of "signposts" that NSPI will monitor as the IRP is implemented. Signposts are very important to resource planning, particularly when there is no set schedule for filing a new comprehensive IRP. The signposts that are identified in the draft IRP are vague, and most include "monitoring" certain conditions. The document currently does not , lay out a procedure for how information gathered from this monitoring would trigger a change in resource plan or a proceeding before the Board. The final IRP should elaborate on the use of signposts and provide more detailed procedures.	The Roadmap sets out a series of signposts that, if observed, may indicate a need to alter the system planning strategy. The final report lists eight areas where a change in the assumption(s) could have a meaningful impact on the capacity expansion/retirement decision(s). For quantitative planning inputs, the IRP Final Report has been clarified to indicate that monitoring will be for deviations from the base case IRP Assumption set. While change from the base assumption in many areas is likely, NS Power intends to monitor for measurable change from these variables identified as having high significance to resource planning decisions and thus, highly sensitive influence on modeling results . NS Power will include a summary of updates as part of its IRP Action Plan reporting and will incorporate the opportunity for stakeholder comment and feedback as part of the update process.
Future steps / DSM	SBA	Energy efficiency scenarios: The draft IRP notes that the IRP scenarios will yield avoided cost levels that will be passed on to EI to use in developing Energy Efficiency (EE) strategies. It is unclear how this approach will be implemented. For example, will NSPI procure all EE measures that are cost-effective given a certain avoided cost scenario? Will EI be given guidance on how to use	Avoided Costs of DSM are inputs to the DSM procurement process and will be utilized in that venue when the next procurement takes place. Additional information from the IRP, including some of the impacts of DSM sensitivities on both primary and secondary metrics, will also be used to inform that process.

Category	Participant	Comment	NS Power Response
		the avoided cost values to structure EE programs? How will the parties consider the dynamic nature of the impact of EE savings on avoided cost levels? How will the electrification progress be incorporated into the analytical steps on an ongoing basis?	
Future steps / thermal retirements	SBA	Coal retirements: The IRP has evaluated multiple options for coal retirement schedules over the next twenty years. These retirements represent critical, irreversible resource decisions, and each will be the subject of a NSUARB proceeding. While the IRP provides results of the long-term planning model, it is not clear what the review framework will be for each individual resource retirement decision. For example, will there be refreshed or additional economic analysis conducted at the time of the proposed retirement? How will NSPI incorporate new information about alternative firm capacity options when assessing a proposed retirement? What will be the decision metrics that will be used to determine retirement timing?	NS Power anticipates all unit retirement decisions will require a full regulatory filing with associated economic analyses. Like other capital projects applications, an economic analysis will be the primary method NS Power uses when evaluating alternatives.
Future steps / Coal to gas	SBA	Gas conversions: The draft IRP notes that coal-to-gas conversions are selected economically in most of the key scenarios. As noted above, however, the analysis is reliant on a multitude of input assumptions. NSPI should develop a ·framework to review the economics of these conversions to ensure that the additional investment in GHG-emitting resources does not quickly become a stranded cost if non-emitting alternatives (firm imports, storage, etc.) become more economical in the near future. Is there a "breakeven" point where NSPI would pursue non-emitting options instead? How will NSPI balance the priority of investing in low-carbon options	NS Power has committed to advancing the engineering study work on these units and monitoring the cost outputs relative to IRP assumptions. Updates from this work, along with other changes in the evergreen process, would inform whether conversion of these units is optimal. NS Power is dedicated to balancing affordability with providing low-carbon, reliable electricity. A capital filing to build a generation asset would present details of the alternative analyses undertaken.

Category	Participant	Comment	NS Power Response
		with the economics of the conversions, and what analysis will support the decision-making?	
Future steps / Regional interconnection	SBA	Regional Integration and Reliability Tie: The draft Findings, Roadmap, and Action Plan appeared· to conclude that the Reliability Tie· and Regional Integration strategy was a common component of top-performing plans and should be investigated for future consideration. The draft IRP used more concrete language about immediately pursuing this option, and implementing it more quickly than indicated by the IRP models if feasible. This strategy appears economically beneficial given the analysis conducted to date, and the SBA supports further investigation. However, not all aspects of this strategy have been fully vetted and there is additional analysis that must be conducted to determine if this is technically feasible and economically beneficial. This includes the determination of the availability of firm capacity from other regions, which may be challenging as all regions in eastern Canada and the northeastern United States are actively seeking clean, dispatchable capacity to support decarbonization efforts. In addition, the technical analysis conducted by PSC on the inertia needs of the system provided an important initial assessment, but will need to be supplemented by additional study prior to relying on firm imports for reliability. These issues need to be addressed in advance of any significant investment commitment, and the draft IRP should explicitly acknowledge the additional work needed prior to pursuing the option.	NS Power agrees that the underlying assumptions in the IRP for transmission expansion require validation and reassessment. NS Power's Action Plan Item #1, and in particular Item #1c, incorporate many of the points raised here which would be considered as part of the development of the Regional Integration Strategy.
Reference Plan	Town of Wolfville	It is premature to assert that Nova Scotia Power's environmental policy scenario 2.0C (Low Electrification /	NS Power acknowledges that the electricity sector specific targets of the SDGA are not yet set, but NS Power

Category	Participant	Comment	NS Power Response
		Base DSM / Net Zero 2050 / Regional Integration) is "SDGA-compliant" as the SDGA as the SDGA's goals and regulations have not yet been developed	has designed the compliant GHG trajectories to be consistent with a net-zero 2050 goal. Please see Section 3.3.1 of the IRP Final Report.
Reference Plan	Town of Wolfville	Given that the carbon intensity projected for resource plan 2.0C is almost 300% greater in 2030 – a critical deadline for substantial emission reduction – than in other scenarios, Wolfville questions the decision to designate 2.0C the Reference Plan that will inform Nova Scotia Power's "no regrets" IRP Action Plan and Roadmap.	2.0C is the Reference Plan on the basis of its having the lowest cost NPVRR, which is the established primary metric for NS Power's IRP. It is important to note that this scenario is representative of many of the other low-cost resource plans modeled, particularly in the first ten years of the plan, and as a result it is this commonality that will inform Nova Scotia Power's "no-regrets" IRP Action Plan and Roadmap.
Future Process	Town of Wolfville	Wolfville expects that Nova Scotia Power's scenarios, Action Plan, and Roadmap will be vetted for actual compliance with Provincial environmental law once the Climate Change Plan for Clean Growth has been created via the evergreen IRP process laid out in Roadmap Item #8.	NS Power agrees that if its Reference Plan or elements of its IRP Action Plan are no longer consistent with government environmental policy, NS Power would need to update the plan via the evergreen IRP process.
	Richard Hendriks	Focused on load forecasting methodology; finds that across Canada load forecasts over-estimate future requirements for both firm peak and energy e.g. Muskrat Falls Analyzed NS Power forecast accuracy based on historic public data No allowance made for significant coal retirement or electrification	NS Power acknowledges the comment. The load forecasting methodology is not within the scope of the IRP at its current stage of development. The load forecast scenarios and approach were reviewed with stakeholders at various workshops (Jan. 28, Feb. 27 and April 28th respectively). NS Power has evaluated a broad range of load forecasts, including adjustments for electrification, DSM, and DER effects; the proposed IRP Action Plan is based on the commonality of those resource plans, indicating a robustness to variation in the load forecast.

Category	Participant	Comment	NS Power Response
	Efficiency One	"Low to Base" language should be removed (done)	NS Power has incorporated suggested wording from E1 into IRP Finding #2e.
	Efficiency One Item 2	Define "Beneficial Electrification" (RAP) 1. Saves consumers money over the long run; 2. Enables better grid management; and 3. Reduces negative environmental impacts. RAP's four key principles for maximizing electrification benefits should be followed	NS Power has incorporated this into IRP Action Plan item #2a, referring to this specific source as well as other relevant work and sources of industry best practice.
	Efficiency One Item 3 -6	E1 are positioned to administer electrification initiatives Near term Demand Response will deliver savings Support DR, via DSMAG & implemented by E1 Electrification strategy should be a stakeholder process	The development and administration of future electrification programs is yet to be determined. NS Power agrees that based on the cost and operational characteristics of the aggregated DR programs modeled, Demand Response programs are economic (see Finding #3e and IRP Action Plan item #4).
	Efficiency One Item 7- 8	Concern w/ other metrics (e.g. relative rate impact) The secondary metrics used in the IRP process should remain consistent with those presented in the original Terms of Reference, since that document has been explicitly approved through a regulatory process. Minimize or remove objective decision-making within the process associated with the use of secondary metrics Revise Action Plan 2e wording with respect to DSM	NS Power has been clear and transparent throughout the IRP that it will consider and present several metrics. Consideration of other metrics beyond the traditional minimization of net present value has been requested by stakeholders throughout the IRP process. This IRP process has experienced an unprecedented amount of stakeholder participation throughout the various stages of the process. This led to improved modeling and analyses, including metrics from which to better evaluate scenarios that have fundamentally different assumptions. NS Power believes this

Category	Participant	Comment	NS Power Response
			stakeholder engagement has improved the overall process. NS Power agrees with the modifications to Action Plan Item 2e and has updated the Final Report accordingly.
	Efficiency One Item 9	Rate Impacts - Discussions of affordability should remain in the realm of DSM planning; it is not appropriate to pre-empt those discussions through observations in the IRP. Remove refs to affordability Rate Impacts methodology is flawed	The IRP is a strategic analysis designed to inform future investment decisions. Affordability is a criteria for evaluation of DSM procurement, and as the IRP supports those efforts it is appropriate to consider via the metric of affordability and timing of electricity rates, which was included in the IRP Terms of Reference.
	Efficiency One Item 10	Market price of carbon. Show results with GHG price ($24 & $50) in report	NS Power has not modeled the monetization of GHG credits in this IRP as discussed in Section 3.3.1. NS Power has incorporated future evaluation of this item into its IRP Roadmap Item #6.
	Efficiency One Item 11	Show results with Avoided T&D costs in report as decrements to NPVRR with EE for all cases, based on the level of DSM included. Any re-ranking from the aggregate effect of carbon prices and avoided T&D should be reflected in the final report if present. The aggregate effects of carbon pricing and T&D may produce a re-ranking of plan results (note that estimated T&D impacts do not result in an alteration of ranking in isolation). This re-ranking should be reflected in the final report if present.	NS Power has updated the cost and rate results in the final report to include Avoided T&D costs. The inclusion of these costs did not change the relative rankings of the key scenarios or DSM sensitivities.
	Efficiency One Item 12	Bi-annual analysis of Regional Integration costs vs. IRP assumptions w/ reported to stakeholders If those costs	NS Power has committed to an annual evergreen process, which would include updates on assumptions which,

Category	Participant	Comment	NS Power Response
		are anticipated to materially exceed the assumptions in the IRP, the assumption that regional interconnection remains economic should be re-tested through updated modelling.	through future post-IRP work, are found to vary significantly from the base case assumption set evaluated in the 2020 IRP.
	Efficiency One Item 13	Include risk reduction benefits of DSM in report	Potential risk reduction benefits of DSM are beyond the scope of the IRP.
	Efficiency One Item 14	The DSMAG is a logical venue for completing the process of avoided cost of generation – The DSMAG discussion scheduled for early 2021 is intended to determine the methodology and timing for the generation of avoided costs for future DSM planning.	NS Power agrees that the DSMAG is an appropriate place to review the development of the avoided costs of capacity and energy per IRP Action Item #5.
	Efficiency One Item 15	DSM should be included in Roadmap item five	NS Power has incorporated this into IRP Roadmap Item #5, indicating it will work collaboratively with E1 to monitor achieved unit costs of DSM.
	Efficiency One	3-yr Evergreen updates to align w/ DSM procurement As DSM Resource Plans are developed and approved on a three-year schedule, a three-year update cycle for key IRP inputs would be beneficial in the context of an "evergreen" IRP process.	NS Power will consider ways to ensure key model updates are considered ahead of DSM procurement processes as part of its evergreen approach to system planning.
	Efficiency One Item 17	Use of "cost effective" - limit to situations where it can be used consistent to the definition of formal "cost-effectiveness" in Nova Scotia (i.e. a Total Resource Cost test of 1.0 or greater).	NS Power agrees and has updated the language in the IRP accordingly throughout the IRP Final Report to avoid confusion.

Category	Participant	Comment	NS Power Response
	Efficiency One Item 18	Clarify page 13 - "Nova Scotia Power has significantly reduced greenhouse gas emissions at fossil power plants as other energy resources have become available and plans to continue that trend." - decreased emissions intensity, or decreased usage of the plants.	Emissions reductions are the result of decreased unit utilization; this has been updated in the IRP Final Report for clarity

Nova Scotia Power IRP
Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

Draft Findings, Action Plan and Roadmap wording was provided to stakeholders for comment on September 2, 2020 and after further revisions, again on October 30, 2020 as part of the draft Report. Below is Nova Scotia Power's summary of stakeholder comments as they relate to the specific Findings, Action Plan and Roadmap contained in the Final IRP Report. The below is not intended to provide a complete record of stakeholder comments on a topic, but rather to synthesize comments generally relative to the Findings, Action Plan and Roadmap for ease of reference. For complete copies of Stakeholder comments on the draft Findings, Action Plan and Roadmap, and the draft IRP Report, as well as NS Power's responses to Stakeholder comments, please refer to the Stakeholder Engagement Appendices, H through L.

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
1. Steeply **reducing carbon emissions** in line with Nova Scotia's Sustainable Development Goals Act will require significant efforts from each sector of the economy, with the electricity sector playing a major role	AREA	No comment	n/a
	CA	Supportive: -'NS Power is to be commended for making electrification a central part of its IRP. The Draft IRP Report provides appropriate policy, business, and analytic support for giving high-level strategic attention to electrification.'	2020-11-16; p.10/21
	CanREA	No comment	n/a
	EAC	Supportive but should evaluate zero emissions cases: -'Nova Scotia's Sustainable Development Goals Act is a significant milestone in the province's climate plans, and actions adhering to these emission goals is a welcome scenario.' - 'Increased costs to the utility add value to efforts across the regional GHG reductions landscape by maximizing the impact of electrification.' -'EAC expresses concern that no "zero" emissions scenario was studied. Zero emission cases will provide an assessment of the costs required to operate from imports, sequestered carbon emissions and renewable energy.'	2020-09-18; p. 1/5 2020-11-13; p. 2/3
	E1	Supportive: -'EfficiencyOne strongly supports the goals and vision of the SDGA, and is well positioned to support its implementation. This legislation and achievement of net zero by 2050 was the cornerstone to much of the analysis and modelling in the 2020 IRP.'	2020-11-13; p.1/6
	Envigour	Supportive:	2020-11-13; p.1/3

Nova Scotia Power IRP
Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
		'As we have previously noted, this process is only a part, albeit a very important part, of developing a roadmap for Canada and Nova Scotia to achieve net-zero energy emissions by 2050. As the final IRP conclusions acknowledge, decarbonizing the electricity system is a foundational requirement to achieving that objection (sic).'	
	Halifax Regional Municipality	Supportive: 'As the primary electric utility for the Province, we recognize that Nova Scotia Power will be a key player in the success of HalifACT through grid decarbonization and robust infrastructure deployment to accommodate the high levels of building and vehicle electrification identified as key actions of HalifACT. Therefore, continued and meaningful collaboration is key to the successful implementation of each plan.'	2020-11-13; p.1/2
	Hendricks	No comment	n/a
	Heritage Gas	Generally supportive with comments respecting role of other energy providers: -'Heritage Gas acknowledges that renewable electrification in certain sectors of the economy will be important for decarbonization in Nova Scotia. However, electrification unaccompanied with other clean energy options will not be sufficient to meet the Sustainable Development Goals Act ("SDGA") Net-Zero 2050 target.' -'…it is critically important for the province as a whole and for the achievement of the sustainable development called for by the SDGA that there are vibrant competitive alternatives to electricity available in the marketplace. Heritage Gas believes it is imperative for all energy providers in the province to work together and with government and other stakeholders to ensure the most cost effective, competitive, and sustainable energy solutions are put in place. Heritage Gas is open to collaborating with NSPI on the process to achieving an integrated energy system, which will	2020-11-13; p.1/5

Nova Scotia Power IRP
Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
		achieve lower emissions and reduce costs to the benefit of all ratepayers.'	
	JFS Hydrostor	No comment	n/a
	Natural Forces	Supportive: -'While this is almost certainly correct, we suggest the more important finding from this IRP Study is that the electricity sector can facilitate decarbonisation of other sectors (heat, transport) through increased electrification without placing upward pressure on electricity rates.' -'As Nova Scotia Power has remarked, significant efforts are required to achieve the level of carbon emissions reductions in line with Nova Scotia's Sustainable Development Goals Act. A major transformation of the existing generation resource base is required, including the integration of significantly higher volumes of intermittent, non-synchronous renewable energy resources. However similar transitions have been successfully achieved in other jurisdictions.'	2020-11-13; p. XX 2020-09-18; p.2/9
	PHP	-'PHP does not have any specific comments with respect to NS Power's proposed Findings, Action Plan and Roadmap as currently drafted. Rather, PHP would like to take this opportunity to emphasize the importance of the following key principles that should continue to guide NS Power's long-term strategy going forward: 1. Ongoing Stakeholder Engagement 2. Flexibility 3. Rate Impacts' -' Based on the results of the future studies called for in the Draft Report, and future information to help solidify key assumptions in what is a very dynamic period in the energy sector in the Province, regionally, and internationally, it will be important for NSPI and all stakeholders to remain flexible	2020-09-18; p.1/2 2020-11-13; p.1/2

Nova Scotia Power IRP

Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
		and to take advantage of opportunities to potentially accelerate the rate of change in the electricity sector where circumstances and economics warrant.’	
	SBA	No comment	
	Town of Wolfville	Supportive: - “..the Town of Wolfville applauds the development of the 2020 Integrated Resource Plan (IRP), in which “Nova Scotia Power puts forward a long-term strategy for delivering safe, reliable, affordable and clean electricity to customers across Nova Scotia. At its core, the plan illustrates Nova Scotia Power’s commitment to supporting provincial decarbonization as outlined in the Nova Scotia Sustainable Development Goals Act (SDGA), both by transitioning to a cleaner electricity grid and by enabling electrification of other sectors, such as transportation and heating.” Particularly, Wolfville appreciates that, in recognition of the rapidly changing and uncertain resource planning environment in which the IRP process is taking place, Nova Scotia Power explored a diverse set of environmental policy scenarios by evaluating a range of resource plans that integrate different amounts of renewable energy and achieve a range of decarbonization targets.” -The Town of Wolfville questions the Draft Report’s contention that Nova Scotia Power’s environmental policy scenario 2.0C (Low Electrification / Base DSM / Net Zero 2050 / Regional Integration) is “SDGA-compliant”. Given the Draft Report’s finding that “steeply reducing carbon emissions in line with Nova Scotia’s Sustainable Development Goals Act will require significant efforts from each sector of the economy, with the electricity sector playing a major role”; its recognition of the rapidly changing and uncertain environment in which the IRP process is taking place; that, owing to the Covid-19 pandemic and state of emergency, the public consultation process to develop the goals n	2020-11-13; p.1/2-2/2

Nova Scotia Power IRP

Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
		regulation of the SDGA has not even begun; and that Province has yet to develop the "Climate Change Plan for Clean Growth", through which it will achieve the greenhouse gas emission targets set out in the SDGA; declaring any of the IRP's environmental policy scenarios to be compliant with the emission targets legislated by the Act would seem premature.'	
1a. Key pillars of economy-wide decarbonization include greater reliance on non-emitting electricity supplies, focused **demand side management**, and **electrification** of end uses currently reliant on fossil fuels.	AREA	No comment	n/a
	CA	See comments on overall Finding 1	n/a
	CanREA	No comment	n/a
	EAC	Supportive: -As highlighted in EAC's previous comments, reaching high electrification levels will be most beneficial for the province both in terms of environmental advantages and economic rate implications in the long-term. However, this electrification must be achieved without reliance on natural gas builds. The provincial energy system, starting today must be envisioned as a combination of clean firm imports, renewable electricity, energy storage, demand side management, maximizing building efficiency and electrification of transport. This will help us align well with the principles of just recovery and sustainability. In addition, it is important to understand the avoided costs of max DSM and transport fuel in high electrification scenarios, and therefore, must be included in future studies.'	2020-11-13; p. 2/3
	E1	Supportive: -'In the Draft Report, key findings 1a and 1b speak to the importance of electrification in the future IRP loads, as well as it more broadly as it relates to economy-wide decarbonization: Key pillars of economy-wide decarbonization include greater reliance on non-emitting electricity supplies, focused demand side management, and electrification of end uses currently reliant on fossil fuels. and;	2020-11-13; p.5/16

Nova Scotia Power IRP

Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
		The IRP rate analysis demonstrates the importance of managing the relative growth of peak and energy requirements, highlighting the need to pursue beneficial electrification. Two key points in the above are very important, namely: 1. The electrification of end-uses currently reliant upon fossil fuels will be tremendously important to future attainment of SDGA goals (as will energy efficiency and conservation). 2. The need to pursue beneficial electrification will be critical in minimizing costs and adverse effects associated with electrification.'	
	Envigour	See comment on overall Finding 1.	n/a
	Halifax Regional Municipality	See comment on overall Finding 1.	n/a
	Henricks	No comment	n/a
	Heritage	See comment on overall Finding 1.	n/a
	JFS Hydrostor	No comment	n/a
	Natural Forces	See comment on overall Finding 1.	n/a
	PHP	See comment on overall Finding 1.	
	SBA	No comment	
	Town of Wolfville	See comment on overall Finding 1.	
1b. Increased electricity sales due to electrification can help to reduce upward pressure on electricity rates while facilitating carbon reductions in other sectors. The IRP rate analysis demonstrates the importance of managing the relative growth of peak and energy requirements, highlighting the need to pursue **beneficial electrification**.	AREA	No comment	n/a
	CA	Supportive but with recommendations for 2 adjustments to initial rate analysis respecting calculation of fixed cost recovery. -'RII is appreciative of NS Power's approach to rate impacts in the IRP. The IRP is not the place for a detailed examination of long-term rate trends. We acknowledge and support the very simple approach that NS Power has taken in this respect, just as we also work with NS Power and other parties to design appropriately sophisticated rate	2020-11-16; p. 18-21-19/21. Note: Nova Scotia Power reflected feedback from the CA respecting calculation of fixed cost recovery in amending its rate analysis for

Nova Scotia Power IRP

Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
		impact forecasts in other venues. Nonetheless, RII recommends that NS Power make two changes to its rate impact model. RII understands that the purpose of the model is to illustrate the general pressure on rates that may be created by differing levels of electrification. The model presented in the Draft IRP Report may exaggerate the rate impacts overall, and the differences among the cases.'	inclusion with the Final Report.
	CanREA	No comment	n/a
	EAC	No comment	n/a
	E1	See comments on Finding 1a.	n/a
	Envigour	See comments on overall Finding 1.	n/a
	Halifax Regional Municipality	No comment	n/a
	Henricks	No comment	n/a
	Heritage	See comments on overall Finding 1.	n/a
	JFS Hydrostor	No comment	n/a
	Natural Forces	See comments on overall Finding 1.	
	PHP	Supportive of use of rate impact analysis: 'In its Updated Modeling Results and Draft Findings, NS Power developed a rate impact calculation using IRP partial revenue requirements for each scenario to illustrate the long-term effects of various levels of electrification. PHP believes that consideration of the potential overall impacts on future rates should remain a central consideration of NS Power's long-term strategy and planning processes. The cost of electricity, as well as the stability and predictability of electricity rates, remain critical issues for all stakeholders, particularly industrial customers that compete globally and require ongoing capital investment.'	2020-09-18; p.2/2
	SBA	Supportive: -'We appreciate NSP developing the rate impact model to help assess the implications of various portfolios	2020-09-18; p.3/3

Nova Scotia Power IRP
Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
		for customers (Slide 31). We believe this provides important information in the consideration of various strategies. The summary of results provided in the draft Findings presentation (Slide 43) contain interesting conclusions, particularly related to the rate impact under high electrification scenarios. This slide was accompanied with important discussion during the stakeholder session which provided context on rate trends. We recommend that NSP provide sufficient context in the IRP to communicate the implications of the rate impact analysis on customers, specifically as it relates to Finding 1b ("Increased electricity sales due to electrification can help to reduce upward pressure on electricity rates while facilitating carbon reductions in other sectors.")'	
	Town of Wolfville	See comment on overall Finding 1.	n/a
1c. Nova Scotia Power's direct **carbon emissions** are **reduced** to between 0.5 Mt and 1.4 Mt per year **by 2045** in all resource plans, representing an 87-95 percent reduction from 2005 levels. Earlier emissions reductions are possible at incremental cost relative to the lowest cost plans.	AREA	No comment	n/a
	CA	No comment	n/a
	CanREA	No comment	n/a
	EAC	Does not challenge Finding but states: 'a scenario for fully decarbonized utility with real net-zero emissions and the resulting cost requirements must be examined fully.'	2020-11-13; p.2/3
	E1	No comment	n/a
	Envigour	No comment	n/a
	Halifax Regional Municipality	No comment	n/a
	Henricks	No comment	n/a
	Heritage	See comments on overall Finding 1.	n/a
	JFS Hydrostor	No comment	n/a
	Natural Forces	-'CO2 levels vary widely between scenarios. There is a wide variation in the CO2 levels (both annual and cumulative) between the different scenarios. Even if not directly monetizable, there is a definite value in lower CO2 emissions:	2020-09-18; p.3/9.

Nova Scotia Power IRP

Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
		a) as a risk mitigation strategy against upward pressure on emissions levels from additional demand growth, or further downward revisions in emission targets; and, b) as can be observed from experience in other jurisdictions, lower carbon intensity of the electricity sector (lower CO2/MWh) promotes electrification of other sectors (heat, transport), which is identified as lowering electricity rates and will also contribute to achievement of broader emissions policy objectives. The differences in CO2 levels should be highlighted clearly in the results, to that individual stakeholders and stakeholder groups can consider the impacts.	
	PHP	No comment	n/a
	SBA	No comment	n/a
	Town of Wolfville	No specific comment on Finding but provides comments on the Town's emissions reduction scenarios relative to Nova Scotia Power's IRP. States that it expects Nova Scotia Power's plan will be vetted for compliance with environmental law and that until then it will continue to develop its community emissions reduction plan in expectation that Nova Scotia Power's commitment to supporting provincial decarbonization is, as the Draft Report Asserts, at the core of the 2020 Integrated Resource Plan.'	2020-09-21; p.3/4, 4/4 2020-11-13; p.2/2
2. Decarbonizing Nova Scotia Power's electricity supply will require investment in **a diverse portfolio of non- and low-emitting resources**.	AREA	No comment	n/a
	CA	No comment	n/a
	CanREA	No comment	n/a
	EAC	Supportive with exception natural gas beyond 2050: -:While retiring coal earlier would provide a strong case for decarbonization, replacing it with and operating natural gas at low capacity factors beyond 2050 however, would not	2020-11-13, p. 2/3

Nova Scotia Power IRP

Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
		allow the energy system to reach net zero and result in redundant and expensive stranded assets beyond the 2050 timeframe."	
	E1	No comment	n/a
	Envigour	No comment	n/a
	Halifax Regional Municipality	No comment	n/a
	Henricks	No comment	n/a
	Heritage	Supportive: -'…in addition to the role of natural gas in supporting the transition of the electrical grid, the introduction of hydrogen and renewable natural gas ("RNG") into natural gas infrastructure will further support the province in reaching the net-zero emissions target set out in the SDGA."	2020-11-13; p.2/5.
	JFS Hydrostor	No comment	n/a
	Natural Forces	No comment	n/a
	PHP	Generally supportive with comments on importance of flexibility and collaboration: -'As opportunities may arise in a host of areas, such as the ability to cost share transmission infrastructure build outs with neighboring jurisdictions or the Federal government, the ability to economically advance renewable capacity, advancements in energy storage and demand response, etc., it is more important than ever that information and opportunities are shared in a timely fashion to achieve the sustainable development goals of the Province in the least cost manner. This can be best achieved by collaboration among stakeholders, and PHP believes the open sharing of information that has occurred throughout the IRP process should continue for the foreseeable future to ensure a vibrant and sustainable energy sector in the Province which will accrue to the benefit of all stakeholders.'	2020-11-13; p.1/2-2/2
	SBA	No comment	n/a

Nova Scotia Power IRP

Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
	Town of Wolfville	No comment	n/a
2a. Regional Integration (i.e. investment in stronger interconnections to other jurisdictions) is an economic component of the least-cost plans under each load scenario. Both the **Reliability Tie**, which strengthens our connection to the North American electrical grid, and a **Regional Interconnection**, which enables access to firm capacity and energy imports, are shown to have value.	AREA	No comment	n/a
	CA	Supportive of additional steps to be taken to consider through Action Plan: - RII recommends that NS Power's action plan should commit to planning for potential transmission projects in parallel to both additional study of wind integration as well as the recommended all-source RFP.8 Cost estimates for completion of the Reliability Tie for various in-service dates (covering the range from the earliest feasible date to 2032) should be developed. The costs and capabilities of various other wind integration strategies should also b e plan ed The resulting costs for all of these options should be used in evaluating the all-source RFP bids in order to co- optimize generation resources, grid investments, and operating practices.' -' While NS Power notes that it modeled the Reliability Tie as providing only synchronized inertia (enabling additional wind integration), it may provide other benefits, such as reserves, load following, or non-firm import capability. Furthermore, the modeling suggests that the inertia provided by the Reliability Tie reduces the need to keep steam units online at minimum load. Comparing several model runs, it appears that when fewer unit commitments for reliability purposes are needed, the reduction in unit commitments results in a shift from domestic thermal generation to less-expensive imported energy. These direct and indirect effects of the Reliability Tie should be further explored in the planning analysis, with initial findings coordinated with the recommended all-source RFP. If non-domestic supplies are enabled by the Reliability Tie, developers of such resources may wish to bid into the RFP based on varying assumptions about the completion date for the Reliability Tie.	2020-11-16, 6/21, 8/21

Nova Scotia Power IRP

Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
		Planning for the Regional Interconnection should be handled similarly, except that there will be need for fewer in-service date options and accompanying cost estimates since the near-term resource acquisitions should be less sensitive to the exact date and cost estimate. In light of some of the sensitivity results, the potential in-service dates for this project should be expanded to cover 2028–2040. NS Power should obtain design and construction pricing for an in-service date of 2028, and then use that cost information to develop informed estimates of costs for later in-service dates.’	
	CanREA	Supportive: -‘The Draft IRP appropriately focuses on Regional Integration as a key strategy for decarbonizing Nova Scotia’s electricity supply: “Regional Integration (i.e. investment in stronger interconnections to other jurisdictions) is an economic component of the least-cost plans under each load scenario.” (Slide 47) The first element of the Draft Action Plan is to “Develop a Regional Integration Strategy to provide access to firm capacity and low carbon energy, increase the reliability of Nova Scotia’s interconnection with North America, and enable economic coal unit retirements.” CanREA agrees that this is an appropriate element of such an Action Plan. As NSPI’s IRP has indicated greater regional integration is critical to unlocking the potential of wind generation to provide the required renewable energy to enable coal unit retirements. CanREA encourages NSPI to accelerate this element of its Action Plan. Additionally, the inclusion of solar energy and energy storage applications will need to increasingly be factored in to planning scenarios. CanREA notes that Regional Integration investments are likely to offer multiple benefits including lower costs, enhanced reliability, and greater flexibility.	2020-09-18; p.2/3
	EAC	Supportive: -‘Access to firm capacity imports from the Maritime provinces and Quebec would be highly beneficial to the	2020-09-19; p. 2/5 2020-11-13; p. 2/3

Nova Scotia Power IRP

Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
		ratepayers, and draft findings statement 2 echo the same. At the same time, the Reliability Tie is a welcome move, which would strengthen the province's grid further. However, it is not shown if the study explored fully replacing coal generation with building interconnection infrastructure and investing in clean firm imports. Wind will play a key role in the region's renewable portfolio, and addition of an incremental 500-800 MW capacity is a welcome move.' -'Agreed that regional interconnection will be vital in transitioning the province off coal. Transformative ideas such as the Atlantic Loop presented in the Speech from the Throne and the $10 billion Canada Infrastructure Bank announcement to support transitioning regions, underpin the idea of pursuing enhanced transmission connections and upgrades, since these will clearly be the least cost options and have the capability for faster clean transition. The plans fall short of "optimal" as the software was presented with limited regional integration opportunities. Incremental transmission builds must be examined fully in future studies.'	
	E1	Concerned about risks of capital investment and potential for price increases in natural gas and imports to affect economics of regional integration findings.	2020-11-13; p. 14/16
	Envigour	No comment	n/a
	Halifax Regional Municipality	No comment	n/a
	Henricks	No comment	n/a
	Heritage	Supportive of additional analysis noted in Action Plan: -'The Draft IRP Report identified the need for further study on the Intertie to provide firm capacity and ancillary services: *"Nova Scotia Power notes that any resource plans which go beyond the findings of the pre-IRP stability study will require further analysis to confirm they can be operated reliably."*	2020-11-13; p.4/5

Nova Scotia Power IRP

Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
		Given that the Regional Integration and Reliability Ties play a key role in many of the optimal resource plans developed for the key scenarios, these studies should be undertaken in the near term. The tie line connection to New Brunswick will be exposed to the increasing frequency and severity of storms related to climate change impacts. The influence of increased dependence on the electrical grid and regional interconnections associated with increased electrification needs to be considered with respect to energy security and reliability for the province.	
	JFS Hydrostor	No comment	n/a
	Natural Forces	No comment	
	PHP	No comment	
	SBA	Supportive: -'The draft Findings Roadmap and Action Plan appeared to conclude that the Reliability Tie and Regional Integration Strategy was a common component of top-performing plans and should be investigated for future consideration. The draft IRP used more concrete language about immediately pursuing this option, and implementing it more quickly than indicated if feasible. This strategy appears economically beneficial given the analysis conducted to date, and the SBA supports this investigation. However, not all aspects of this strategy have been fully vetted and there is additional analysis that must be conducted to determine if this is technically feasible and economically beneficial. This includes determination of the available firm capacity from other regions, which may be challenging as all regions in eastern Canada and the northeastern United States are actively seeking clean, dispatchable capacity to support decarbonization efforts. In addition, the technical analysis conducted by PSC on the inertia needs of the system provided an important initial assessment, but will need to	2020 11-13; p. 3/3

Nova Scotia Power IRP

Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
		be supplemented by additional study prior to relying on firm imports for reliability.'	
	Town of Wolfville	No comment	n/a
2b. **Wind** is the lowest cost domestic source of renewable energy and is selected preferentially over solar in all resource plans. **Incremental wind capacity** in the range of 500 - 800 MW is selected by the model by 2045, with major installations paired with coal retirement dates to provide replacement emissions-free energy. The availability of lower priced wind is shown to accelerate the wind buildout in the mid-2020s, with **up to 600 MW** selected under the modeled low wind price, mid-electrification sensitivity.	AREA	-'AREA is in general agreement with the comments and technical report submitted by Natural Forces. In particular, AREA fully supports the key point emphasized by Natural Forces regarding the cost of wind that has been modeled in the IRP. AREA also agrees with the comments at page 2 of Cooke's report that NS Power's modeling analysis of intermittent wind should allow wind to be installed on an economic level, and accepting that on rare occasions it may be necessary to curtail wind output to ensure the system remains stable. -'AREA continues to believe that -alternative, lower-cost, non-NS Power financing models need to be fully considered as part of the transformation of Nova Scotia's electricity system. NSPI previously indicated that such ownership structures are captured in the "low case" scenarios. AREA believes that too many realistic individual market conditions (lower wind installed costs, higher wind net capacity factors, lower costs of capital, etc) are blended into the "low case" making it difficult to separate and study their specific effects on the pace of cost-effective decarbonization.'	2020-09-25; p.1/1
	CA	Supportive of opportunity for up to 700MW of wind by 2025 undertaken through an all source procurement: -'RII recommends that NS Power should plan for an aggressive near-term all-source request for proposals (RFP), including an opportunity for up to 700 MW of wind by 2025, to be conditioned on price and performance thresholds, and evaluated in coordination with transmission and system inertia solutions as discussed below. The much smaller, wind-only procurement described in the Draft IRP Report excludes the potential near-term savings opportunity from a	2020-11-16; p. 4/21

Nova Scotia Power IRP

Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
		larger procurement that would be merited if bid prices are lower than expected.'	
	CanREA	States that assumed market price for wind appears to be overstated and that an additional wind could be procured: -'CanREA notes that Natural Forces is actively pursuing wind project development opportunities in the Maritimes and secured a long-term PPA for a 42 MW wind project in New Brunswick and based on this experience poses valuable insights regarding the current cost of wind in the Maritimes.' -'The fact that cost of wind appears to be overstated is significant because sensitivity analysis conducted as part of the IRP indicates that additional wind is selected when wind prices are lower. The Draft IRP Report indicates "the availability of low priced wind is shown to accelerate the wind buildout in the mid-2020s, with up to 600 MW selected under the modeled low wind price, mid-electrification sensitivity.' -CanREA believes that more than 100 MW of additional wind could be procured (The approximate quantity identified by NS Power in its Wind Procurement Strategy, but which very likely will increase when appropriate consideration is given to the ability of wind resources to provide regulation services and other deficiencies in the PSC Study are addressed.), but when more than 700 MW was available during system conditions that posed reliability risks (e.g., low loads) then wind output greater than 700 MW could be constrained down after imports were reduced. When curtailed, these wind turbines would be available to provide primary frequency response, offsetting at least in part costs associated with such a curtailment. While there would be a cost to this, this cost can be assessed. However, the fact that wind generation is the lowest cost domestic renewable generation resource and the limited number of hours when the conditions occur	2020-11-13; p. 2/4

Nova Scotia Power IRP
Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
		suggests that even with this incremental cost, additional wind is likely to be economically attractive.	
	EAC	Supportive: -'Wind will play a key role in the region's renewable portfolio, and addition of an incremental 500-800 MW capacity is a welcome move.'	2020-09-18; p.2/5
	E1	No comment	n/a
	Envigour	-'We would note that while onshore wind and imported renewables provide low-cost solutions for current demand forecasts, their growth and availability may well be constrained by public concerns. Considering the longer-term options for the next best source of near-base load electricity – offshore wind – would be prudent.'	2020-11-13, p. 2/3
	Halifax Regional Municipality	No comment	n/a
	Henricks	No comment	n/a
	Heritage	No comment	n/a
	JFS Hydrostor	No comment	n/a
	Natural Forces	Supportive of various Action Plan items expected to confirm that higher wind trajectories are beneficial to rate payers: -'We believe that one of the most important factors in the short term, is the rate of wind deployment appropriate over the coming years. Natural Forces believes that developments in relation to the "signposts" identified in the report will confirm that higher wind trajectories are beneficial to rate payers and to furtherance of broader policy objectives, and we urge that a clear plan is developed for this analysis, and it is completed as soon as possible. Natural Forces confirms its commitment to contribute constructively to the process and encourages NSP to continue to build on the stakeholder engagement efforts undertaken to date.'	2020-11-13; p. 8/8
	PHP	No comment	

Nova Scotia Power IRP

Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
	SBA	Supportive of Action Plan item for further analysis: -:While the draft analysis indicates that the assumed system inertia requirement is not binding for several years, it is possible that cost declines for wind capacity or other factors could advance the timeline for wind development, hastening the need for a solution to the reliability need.'	2020-09-18; p.2/3
	Town of Wolfville	No comment	n/a
2c. Coal units are generally sustained economically until **their model-imposed retirement date**, with capacity factors falling in line with declining emissions caps. Many resource plans incorporate economic retirement of one coal unit in the near term, as early as 2023, and some plans see economic retirement of a second coal-fired unit in 2030. **New firm capacity** is required to offset retiring coal units, to lower carbon emission intensity, and to meet growing electricity demand in all scenarios.	AREA	No comment	n/a
	CA	Supportive generally though if re other constraints can be satisfied, may be able to retire additional units: -'RII concurs with a substantial portion of the Short-Term Action Plan, including the treatment of plant retirements, demand response, and DSM avoided cost calculation methods.' -'If the inertial constraints can be satisfied by a combination of wind curtailment and other operating limits, additional battery storage (especially if battery prices are lower than assumed in the IRP), and synchronous condensers, NS Power could develop operating experience demonstrating that the system can be operated reliably with early retirement of additional thermal units.' -'Exploration of options other than transmission connections may reveal that pace…"Exploration of options other than transmission connections may reveal that NS Power can retire steam plants sooner and acquire more wind resources, while reducing costs to customers.'	2020-11-16; p. 3/21; 7/21-8/21
	CanREA	No comment	n/a
	EAC	Supportive and need to consider additional value outside of the model associated with 2030 retirement date: -'The EAC appreciates that an accelerated coal phase-out scenario was considered in the analysis. It is encouraging to see that both 2030 and 2040 coal phase-out plans will have similar rate implications for ratepayers by 2045. While the findings indicate a higher initial cost for an accelerated 2030	2020-09-18; p. 2/4,3/4. 2020-11-13; p.3/3

Nova Scotia Power IRP

Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
		coal phase-out, it is worthwhile to indicate here that the province would reap immense health and economic benefits from pursuing this target. As presented in the "Nova Scotia Environmental Goals and Sustainable Prosperity Act Economic Costs and Benefits for Proposed Goals" report, rapid decarbonization in Nova Scotia would result in the creation of around 15, 000 full-time jobs by 2030. In addition, the Federal Government's analysis indicates that an accelerated phase-out would avoid 89 premature deaths, 8,000 asthma episodes and 58,000 days of breathing difficulty for Nova Scotians, among other benefits. Therefore, an accelerated phase-out of coal by 2030 would be a favorable long-term strategy for the province and its peoples. -"The EAC believes that Nova Scotia still has an opportunity to set long-term ambition and commit to phasing out coal-fired electricity by 2030. We need to ensure that low and middle-income Nova Scotians, indigenous groups, coal workers, other vulnerable groups and communities all benefit from this change in our electricity system."	
	E1	No comment	n/a
	Envigour	No comment	n/a
	Halifax Regional Municipality	No comment	n/a
	Henricks	No comment	n/a
	Heritage	No comment	n/a
	JFS Hydrostor	No comment	n/a
	Natural Forces	No comment	n/a
	PHP	No comment	n/a
	SBA	No comment	n/a
	Town of Wolfville	Supportive and need to consider additional value outside of the model associated with 2030 retirement date:	2020-11-13; p. 2/4.

Nova Scotia Power IRP
Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
		-'The Town of Wolfville appreciates that an accelerated coal phase out scenario was considered as part of the IRP process. We note that, in the rate impact comparison, substantially similar scenarios that included coal phase-out by 2030 and 2040 were projected to have similar rate implications by 2040. There are both short- and long-term benefits to an accelerated phase out of coal and other fossil fuels: it has recently been confirmed that we have drastically underestimated the health impacts of air pollution on human health; the latest air quality research suggests that in the US, the health benefits alone are enough to justify an immediate transition away from fossil fuels.'	
2d. Nova Scotia Power's existing domestic **Hydro resources** provide economic benefit to customers and are economically sustained through the planning horizon with the modeled level of sustaining capital investment. **Economic justification** as part of a capital application will be required to confirm decision to **pursue Mersey hydro redevelopment**, following the completion of the IRP.	AREA	No comment	n/a
	CA	-'NS Power should incorporate updated data from resource procurement and transmission planning into any capital application for redevelopment of the Mersey hydroelectric facilities. Any resulting delay would be justified given the uncertain value of the redevelopment project.' -'NS Power should verify that model performance of run-of-river hydro units is consistent with the operational record, and consider any appropriate adjustments to ELCC values and model results.'	2020-11-16; p. 1/21;8/21; 15/21
	CanREA	No comment	n/a
	EAC	No comment	n/a
	E1	No comment	n/a
	Envigour	No comment	n/a
	Halifax Regional Municipality	No comment	n/a
	Henricks	No comment	n/a
	Heritage	No comment	n/a
	JFS Hydrostor	No comment	n/a
	Natural Forces	No comment	n/a

Nova Scotia Power IRP
Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
	PHP	No comment	n/a
	SBA	No comment	n/a
	Town of Wolfville	No comment	n/a
2e. DSM energy efficiency programs and costs in the range of the "Base" profile, per the EfficiencyOne 2019 Potential Study, are shown to be most economic relative to other options evaluated under the primary IRP metric of 25-year NPV of Revenue Requirement (with end effects). A focus on peak demand mitigation is indicated and could be optimized into future DSM planning. Other levels of DSM in resource plan sensitivities show higher NPVRR with end effects, as well as mixed effects on other metrics, when compared to Base DSM; Low DSM levels are shown to reduce relative rate impact, while Mid DSM levels are shown to reduce new capacity requirements and GHG emissions, both at a higher NPVRR. Due to the discrete nature of the DSM profiles modeled in the IRP, future DSM program development should incorporate the learnings obtained from the full range of sensitivities and metrics considered in the IRP.	AREA	No comment	n/a
	CA	Supportive: -'NS Power should not rely upon the relative rate impact comparison analysis as the basis for recommending any level of DSM program investments.'	2020-11-16; p.20 Note: subsequent to receipt of CA's comments, NS Power revised its relative rate impact analysis to correct for fixed cost recovery deduction and also amended final language in this Finding.
	CanREA	No comment	n/a
	EAC	No comment	n/a
	E1	Supportive of language in amended Finding. Does not believe observations about rates analysis should be included in IRP: -'DSM has been an important variable in this IRP, and Nova Scotia Power has modeled numerous DSM scenarios in both the key scenarios and sensitivities, incorporating significant engagement with EfficiencyOne as discussed in section 6.8.1. The Base DSM profile is shown to be economic when compared using the 25-year NPVRR with end effects metrics, relative to other DSM levels. On the basis of all of the preceding, it is requested that Action Plan item 2e be revised to read: DSM energy efficiency programs and costs in the range of the "Base" profile, per the EfficiencyOne 2019 Potential Study, are shown to be most economic relative to other options evaluated under the primary IRP metric of 25-year NPV of Revenue Requirement (with end effects). A focus on peak demand mitigation is indicated and could be optimized into future DSM planning. Other levels of DSM in resource	2020-11-13, p. 9/16-10/16. Note: Final wording in IRP report on this Finding reflects comments from and engagement with E1 following their review of the earlier draft Report.

Nova Scotia Power IRP
Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
		plan sensitivities show higher NPVRR with end effects, as well as mixed effects on other metrics, when compared to Base DSM; Low DSM levels are shown to reduce relative rate impact, while Mid DSM levels are shown to reduce new capacity requirements and GHG emissions, both at a higher NPVRR. Due to the discrete nature of the DSM profiles modeled in the IRP, future DSM program development should incorporate the learnings obtained from the full range of sensitivities and metrics considered in the IRP. and; In addition, it is requested that revision to other very similar language throughout this report that references a range of “Low” to “Base” DSM to reflect the economic finding that Base possess the lowest NPVRR w/EE, and removing inappropriate references to affordability, which will be adjudicated as part of subsequent DSM Resource Plan processes, as has always been the case.’ -‘The Draft Report highlights the estimated rate impacts of part of the broader evaluation methodology. As explained in the section above, losing visibility on the least cost, long term, path forward as identified in an IRP, causes concern. Further, to place determinations around rates as a key part of the IRP process could prejudice other important rate making exercises, such as general rate applications. In the case of DSM, discussions and determinations around the affordability of DSM activities already form a statutory inclusion within short-term planning process for DSM, as laid out in the *Public Utilities Act*.14 To display and perform decision-making using rates in this manner is prejudicial toward subsequent determinations of, among other things, DSM levels. Discussions of affordability should remain in the realm of DSM planning; it is not appropriate to pre-empt those discussions through observations in the IRP.’	
	Envigour	Supportive re importance of resources to meet demand from growth:	2020-11-13; p.2/3

Nova Scotia Power IRP
Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
		-'New population and GDP growth patterns as well as new industrial opportunities in a clean carbon economy may drive demand higher than forecast. This outcome would raise new questions on where the resources to meet such demands (in excess of demand forecasts from all scenarios) may come from.'	
	Halifax Regional	No comment	n/a
	Hendricks	-'..approach of DSM forecasting savings over the life of each measure with no additional savings thereafter can result in overestimates of long-term requirements in an IRP lack of quantification of avoided costs plus increased future energy requirements may indicate DSM has not been adequately considered.'	2020-11-12, p.9/10
	Heritage	No comment	n/a
	JFS Hydrostor	No comment	n/a
	Natural Forces	No comment	n/a
	PHP	No comment	n/a
	SBA	No challenge to Finding but provides comments respecting guidance for Action Plan respecting how energy efficiency will be procured	2020-11-13; p. 2/3
	Town of Wolfville	No comment	n/a
3. Firm capacity resources will be a key requirement of the developing Nova Scotia Power system in both the near and long term.	All	No challenges to overall Finding 3	n/a
3a. New combustion turbines, operating at low capacity factors, are currently the lowest- cost domestic source of firm capacity and replace retiring thermal capacity in all resource plans. These units	AREA	No comment	n/a
	CA	States importance of testing the market for new combustion turbines	2020-11-16; p. 5/21.
	CanREA	No comment	n/a

Nova Scotia Power IRP
Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
are also fast-acting, meaning they can quickly respond to changes in wind and non-firm imported energy. 50-150 MW is required by 2025, while 600-1000 MW of new capacity is required by 2045 to support retirement of steam units.	EAC	Concerned re fossil based investment to replace capacity over long term: -'While retiring coal earlier would provide a strong case for decarbonization, replacing it with and operating natural gas at low capacity factors beyond 2050 however, would not allow the energy system to reach net zero and result in redundant and expensive stranded assets beyond the 2050 timeframe.'	2020-11-13; p.2/3.
	E1	Concerns re natural gas pricing and cycling of CTs.	2020-11-13; p. 14/16.
	Envigour	No comments	n/a
	Halifax Regional Municipality	No comments	n/a
	Henricks	No comments	n/a
	Heritage	Supportive: -'The IRP highlights the *need for additional firm generating capacity to ensure that the system is reliable with sufficient supply available to meet expected demand, especially during periods of low renewable generation and peak loads.* Natural gas based generation also provides critical ancillary services needed to support increased levels of renewable energy: *"The IRP analysis has shown that combustion turbines are the lowest-cost domestic source of new firm capacity; they replace retiring thermal capacity in all resource plans. These units are also fast-acting, meaning they can quickly respond to changes in wind and non-firm imported energy."'*	2020-11-13; p. 1/5
	JFS Hydrostor	No comments	n/a
	Natural Forces	No comments	n/a

Nova Scotia Power IRP

Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
	PHP	No comments	n/a
	SBA	No comments	n/a
	Town of Wolfville	No comments	n/a
3b Nova Scotia Power's existing combustion turbine resources provide economic benefit to customers and are economically sustained through the planning horizon with the modeled levels of sustaining capital investment.	AREA	No comments	n/a
	CA	Supportive in near term, with additional assessment for long term: -'To be clear, we agree with the Draft IRP Report that the combustion turbines are likely to be worth maintaining over the near term. The questions of longer-term maintenance and the consistency of the Plexos model with operational practices require further consideration. Accordingly, RII recommends that NS Power: • Provide further evidence in the FAM audit proceeding regarding the performance of its refurbished diesel combustion turbine units; • Provide to RII and other interested stakeholders data comparing the modeled operational profile (capacity factor, operating hours, number of unit starts, etc.) to recent historical data; • Further evaluate the longer-term sustaining capital forecast for the diesel CT fleet as part of its evergreen IRP process; and • Periodically re-evaluate CT economics as the cost of storage falls, and especially if the units are using substantial amounts of fuel and the cost of their fuel rises significantly.'	2020-11-16; p.13/21-14/21
	CanREA	No comment	n/a
	EAC	Concerned re fossil based investment to replace capacity over long term	2020-11-13; p.2/3
	E1	No comments	n/a
	Envigour	No comments	n/a

Nova Scotia Power IRP
Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
	Halifax Regional Municipality	No comments	n/a
	Hendricks	No comments	n/a
	Heritage	Supportive with ongoing monitoring: -'With respect to the existing CTs, NSPI has stated that its analysis has "conclusively shown" that the sustaining capital for the LFO-fired CTs is the most economic approach. Heritage Gas has already provided comments regarding the potential concerns with reliance on units of this vintage even with sustaining capital, and notes that Bates White in its August 21, 2020 Audit Report on NSPI's 2018-2019 FAM, noted in its Conclusion IX-17 on page 231 that data on the impact of certain investments in the LFO-fired CTs was at that time inconclusive and should be monitored based on concerns noted in the Audit Report that could bear on the ultimate reliability of those units. Heritage Gas believes that such ongoing monitoring is very important considering the recent history and vintage of these units and that the IRP should specifically provide for such monitoring and reporting on the results during the evergreen nature of the IRP, particularly in light of the value of new gas fired CTs evidenced by the IRP analysis.'	2020-11-13; p. 5/5
	JFS Hydrostor	No comments	n/a
	Natural Forces	No comments	n/a
	PHP	No comments	n/a
	SBA	No comments	n/a
	Town of Wolfville	No comments	n/a
	AREA	No comments	n/a

Nova Scotia Power IRP
Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
3c Low-cost, low emitting generating capacity may be provided economically from coal- to- gas unit conversions, which are selected economically in many resource plans	CA	No comments	n/a
	CanREA	No comments	n/a
	EAC	Concerned re fossil based investment to replace capacity over long term	2020-11-13; p.2/3
	E1	Concerned re risks re natural gas pricing	2020-11-13; p.14/16
	Envigour	No comments	n/a
	Halifax Regional Municipality	No comments	n/a
	Henricks	No comments	n/a
	Heritage	Supportive: -'Roadmap item 1 discusses the need for "*advance engineering study work on coal to gas conversions at Trenton and Point Tupper Generating Stations. Monitor cost outputs of this work relative to IRP assumptions and update the balance of new and converted capacity resources accordingly*"' Heritage Gas reiterates that the Action Plan should reflect a timeline of completion of this study and scope of the work included in the coal-to-gas conversion scenario, and should keep stakeholders engaged and apprised in this process.'	2020-11-13; p. 3/5
	Natural Forces	No comments	n/a
	PHP	No comments	n/a
	SBA	-'The draft IRP notes that coal-to-gas conversions are selected economically in most key scenarios. As noted above, however, the analysis is reliant on a multitude of input assumptions. NSPI should develop a framework to review the economics of these conversions to ensure that the additional GHG-emitting resources do not quickly become a stranded cost if non-emitting alternatives (firm imports, storage, etc.) become more economical in the near future.'	2020-11-12; p. 2/3.

Nova Scotia Power IRP

Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
	Town of Wolfville	No comments	n/a
3d. Battery storage can enable wind integration while providing firm capacity and energy storage; however, its ability to substitute for firm capacity resources is limited by its relatively short duration. Up to 120 MW of storage by 2045 is selected in the portfolios with deployments of 30-60 MW by 2025 in many plans.	AREA	Supports comments from Natural Forces	2020-09-25; p.1
	CA	Supportive but should include in an all-source procurement as it may influence relative value of other bids: -'In contrast to wind, the modeling results suggest that price is not the main determinant of the role of battery storage resources. While battery resources should be eligible for the all-source procurement, NS Power's primary focus for this technology should be to understand better the value that battery resources may have for the system in the near term.7 Case 2.1C suggests that only relatively modest battery resources are economic at current price levels. The sensitivity results a trade-off between imported power and battery resources. Thus, even though battery storage is unlikely to make up a large share of NS Power's portfolio in the near term, it should be included in the all-source procurement process because successful battery storage bids could influence the relative value of other bids, including the reliability link.'	2020-11-16; p. 5/21-6/21
	CanREA	Should be re-assessed with benefit of market pricing information: -'..to the degree that this market pricing information indicates that the cost of these resources are lower than the assumptions reflected in the IRP, this should cause NS Power to reassess the role of solar and energy storage in its resource mix.'	2020-11-13; p. 2/4
	EAC	No comments	n/a
	E1	No comments	n/a
	Envigour	DER assumptions should be updated in 2022.	2020-11-13; p. 2/3

Nova Scotia Power IRP
Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
	Halifax Regional Municipality	No comments	n/a
	Henricks	No comments	n/a
	Heritage	No comments	n/a
	Natural Forces	More rapid wind build out could be achieved if wind was disassociated from battery requirements.	2020-09-18; p.6/9
	PHP	No comments	n/a
	SBA	No comments	n/a
	Town of Wolfville	No comments	n/a
3e. The aggregated Demand Response programs modeled in the IRP have economic value to the Nova Scotia system, offsetting firm generation capacity requirements. A DR program with a target final nameplate capacity of approximately 75 MW is shown to have value across all resource plans under IRP cost assumptions, while higher DR capacity is shown to be economic under high electrification scenarios.	AREA	No comments	n/a
	CA	Supportive: -'RII concurs with a substantial portion of the Short-Term Action Plan, including the treatment of plant retirements, demand response, and DSM avoided cost calculation methods.'	2020-11-16, p. 3/21
	CanREA	No comments	n/a
	EAC	No comments	n/a
	E1	Supportive: -'The 2020 IRP results show inclusions of demand response to be economic across all modelled scenarios, in varying amounts and times of introduction. The variability is a result of the fact that demand response activities were allowed to be economically selected by Plexos LT, as opposed to being included as load modifiers as part of the IRP process. In the Action Plan section of the Final Report, it is suggested to: Create a Demand Response Strategy targeting 75 MW of capacity, for deployment by 2025. Available	2020-11-13; p. 7/16

Nova Scotia Power IRP

Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
		resource cost, flexibility, and reliability may inform pursuit of additional Demand Response capability. We agree with this recommendation in the Action Plan in principle, in that near-term DR is well positioned to provide cost savings against other short-term peaking resources – as found through the selection of DR as part of model operation.'	
	Envigour	No comments	n/a
	Halifax Regional Municipality	No comments	n/a
	Henricks	No comments	n/a
	Heritage	No comments	n/a
	Natural Forces	No comments	n/a
	PHP	Supportive: -'As parties are aware, earlier this year, the Board approved NS Power's Application for approval of the Extra Large Industrial Active Demand Control Tariff. This innovative rate structure, developed following extensive collaboration with the utility, provides NS Power with a new demand response service that allows the utility to better operate its electricity system for the benefit of all customers. The 2020 IRP results indicate that firm capacity resources will continue to be a key requirement of the developing NS Power system in both the near and long term, demonstrating the inherent value in demand response-type approaches going forward. Continuing to pursue deeper levels of collaboration and innovative solutions, whether through rate design approaches or	2020-09-18; p.2/2

Nova Scotia Power IRP
Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
		otherwise, will help ensure that the transition to Nova Scotia's electricity future can be achieved in an environmentally and economically sustainable manner for NS Power and its customers.'	
	SBA	No comment	n/a
	Town of Wolfville	No comment	n/a
3f. A **Planning Reserve Margin** of 9 percent (on a UCAP basis, consistent with 20 percent on an ICAP basis for the current resource mix) is found to maintain supply reliability across the studied range of resource plans and electrification scenarios.	CA	Nova Scotia Power should verify E3 July 2019 study results and include more clear resolution of PRM in final report; update PRM findings to reflect modeling assumptions	2020-09-18; p.5/13 2020-11-16; p. 2/21 Note: Nova Scotia Power confirms this work was completed and included in Final Report.
	Other Stakeholders	No comments	n/a
4. The SDGA-compliant key scenario which minimizes the cumulative present value of the annual revenue requirement of the 25-year planning horizon (adjusted for end effects) is 2.0C (Low Electrification / Base DSM / Net-Zero 2050 / Regional Integration).	Natural Forces	Questions the selection of this plan as the reference plan: -'The resource plan optimized for Scenario 2.0C (Low Electrification / Net Zero 2050 / Regional Integration) is nominated as the "Reference Plan", primarily as it indicates a lower total cost than other scenarios. We are not entirely clear what the implications of nominating the reference plan are, but it must be noted that other scenarios have potentially with lower rates to electricity customers as well as other policy benefits (supporting decarbonization through electrification). Therefore the "reference plan" may not be the "optimal plan". Also of course as identified by NSP in the report, there are a number of key factors which will influence the "optimal" portfolio in any case.	2020-11-13; p. 2/8
	Town of Wolfville	Questions whether this plan is SDGA compliant:	2020-11-16; p.2/2

Nova Scotia Power IRP

Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
		The Town of Wolfville questions the Draft Report's contention that Nova Scotia Power's environmental policy scenario 2.0C (Low Electrification / Base DSM / Net Zero 2050 / Regional Integration) is "SDGA-compliant". Given the Draft Report's finding that "steeply reducing carbon emissions in line with Nova Scotia's Sustainable Development Goals Act will require significant efforts from each sector of the economy, with the electricity sector playing a major role"; its recognition of the rapidly changing and uncertain environment in which the IRP process is taking place; that, owing to the Covid-19 pandemic and state of emergency, the public consultation process to develop the goals in regulation of the SDGA has not even begun; and that Province has yet to develop the "Climate Change Plan for Clean Growth", through which it will achieve the greenhouse gas emission targets set out in the SDGA; declaring any of the IRP's environmental policy scenarios to be compliant with the emission targets legislated by the Act would seem premature.	
	Other Stakeholders	No comments	n/a
4a. During the Action Plan 5-year horizon, resource plans 2.0C and 2.1C (among others) include many common resource investments and retirement trajectories. This commonality informs Nova Scotia Power's IRP Action Plan and ensures the resulting long-term electricity strategy is robust to a broad range of potential futures.	Natural Forces	'NSP correctly identifies that there are elements that are common to all or most scenarios, which can then be considered as "no regret" steps. It is also the case that the level of wind capacity installed toward the end of the study period is often broadly similar in most scenarios. There are however significant differences in	2020-11-13; p. 2/8

Nova Scotia Power IRP

Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

FINDING	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
		regard to the pace of build-out of further wind capacity, particularly over the next decade.' 2	
	PHP	Supportive: -'The Draft Report, building on the prior findings/road map/action plan document, confirms there is a general path forward which is robust across numerous scenarios. However, the timing and scope of specific actions that should occur over the study term of the IRP remains subject to ongoing studies and greater clarity on how key assumptions will eventually play out. As such, PHP appreciates that NSPI has acknowledged the necessity for flexibility going forward and especially its determination that this should be an evergreen IRP with regular updating to stakeholders.'	2020-11-13; p. ½
	Other Stakeholders	No comments	n/a
4b Similar resource plans are selected when considering both 2030 and 2040 coal unit retirement dates. The earlier retirement scenarios are less economic on an NPV basis but have similar cumulative rate implications by 2045.	CA, EAC, Town of Wolfville	See comments on Finding 2c	
	Other Stakeholders	No comments	n/a

Nova Scotia Power IRP

Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

ACTION PLAN ITEM	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
1. Develop a Regional Integration Strategy to provide access to firm capacity and low carbon energy while increasing the reliability of Nova Scotia's interconnection with North America. This Strategy will include: **1a**. Identifying opportunities for near term firm imports over existing transmission infrastructure **1b**. Immediately commencing the development of a Reliability Tie and Regional Interconnection via an appropriate regulatory process with target in-service dates as follows: • Reliability Tie: 2025-2029 (or earlier if practical and feasible) • Regional Interconnection: 2027-2035 **1c**. In parallel with Regional Interconnection development, and working with neighbouring jurisdictions, conducting detailed engineering and economic studies for firm import options requiring new transmission investment and strengthened regional interconnections, including evaluations of availability and security of supply, emissions intensity, and dispatch flexibility.	CA	See comments above re Finding 2a	
	CanREA	Supportive: See comments on Finding 2a.	
	EAC	Supportive: See comments on Finding 2a.	
	E1	Concerned re risks. See comments on Finding 2a.	
	Heritage	Supportive of additional analysis noted in Action Plan. See comments on Finding 2a.	
	SBA	Supportive: see comments on Finding 2a.	
	Other Stakeholders	No comment	
2 Electrification is a key variable in this IRP and results indicate that under economic resource plans it can support provincial decarbonization while reducing upward pressure on electricity rates for customers. Nova Scotia Power proposes several Action Plan items from this IRP related to electrification: **2a** Initiate an Electrification Strategy to develop options for encouraging beneficial electrification with the goals of maintaining rate stability while decarbonizing the Nova Scotia economy consistent with the Sustainable Development Goals Act. The Electrification Strategy will:	CA	Supports: -'NS Power is to be commended for making electrification a central part of its IRP. The Draft IRP Report provides appropriate policy, business, and analytic support for giving high-level strategic attention to electrification. Nonetheless, the Draft IRP Report does not present a sufficiently detailed action plan to implement its electrification strategy. The Draft IRP Short Term Action Plan proposes three steps: "understand options," "collect detailed data," and address transmission and distribution (T&D) impacts. NS Power should add a fourth step, propose pilot	2020-11-16; p.10/21-11/21 Note: In the Final Report, Nova Scotia Power made changes consistent with these recommendations.

Nova Scotia Power IRP

Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

ACTION PLAN ITEM	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
-Incorporate industry best practices such as those identified by the Regulatory Assistance Project as well as other relevant work, for example, electrification programs in other jurisdictions and the details already contained in the Deep Decarbonization Pathways report. -Develop and propose pilots and/or programs that focus initially on transportation and building electrification sectors as identified in the Deep Decarbonization Pathways report as key sectors for early electrification adoption. These pilots and programs will be subject to NSUARB oversight. **2b** Initiate a program to collect detailed data, including data on the quantity, flexibility and hourly load shape of incremental electrification demand, to assist with further system planning work. **2c** Address electrification impacts on the Transmission & Distribution system as additional experience and data become available. This will include an analysis of available and projected T&D capacity at varying levels of electrification as well as identification of potential mitigation options and cost estimates. This analysis will leverage data from the Nova Scotia Power's AMI implementation as it becomes available.		programs, as well as providing additional detail, especially regarding potential T&D impacts. The action plan should specifically commit NS Power to develop and propose pilot projects. Of course, some modest efforts have, in fact, already begun. RII recommends that the action plan include a commitment to develop and propose pilot programs to offer incentives or direct installation of transportation electrification infrastructure and similar investments in building electrification across a range of markets. Furthermore, electrification should not be limited to residential, commercial, and on-road transportation. The industrial and maritime sectors also provide opportunities and should be involved early in the development of electrification programs. Nonetheless, the pilot programs should be limited in scale, designed to provide insights into options for NS Power and the Province as well as customer response. Looking beyond the scope of the near-term action plan, it is reasonable to assume that higher levels of electrification will require NS Power to make even more substantial investments. These investment costs are likely to come in two areas, full electrification programs (transportation and building, and potentially other sectors), and T&D investments.' -'RII recommends that NS Power include in its Final IRP Report an order-of-magnitude estimate for the level of cost that might be tolerable for its customers to bear to promote electrification. As noted in the draft findings, "Increased electricity sales due to electrification can help to reduce upward pressure on electricity rates while facilitating carbon reductions in other sectors." The design and costing of potential programs is out of the scope of the IRP. We are recommending that NS Power utilize its rate impact model (as discussed	

Nova Scotia Power IRP
Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

ACTION PLAN ITEM	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
		below) to identify the impacts on rates that might result from plausible levels of program investment in electrification. Given the diversity of the possible futures, RII recognizes that this question cannot be answered with certainty or exactitude. However, an order of magnitude estimate of the annual investment that might begin to cause upward pressure on rates would be informative to the Board and stakeholders. While upward pressure on rates is an important consideration, we would also encourage the Board to consider that electrification may also have significant benefits to participants – such as cost savings for other fuels – and to Nova Scotia at large – by reducing the pressure for carbon reductions in other sectors. The perspective of the province as a whole can be captured in a total resource cost test. While this is clearly beyond the scope of the IRP, we encourage NS Power to acknowledge – perhaps with an illustrative graph – that these benefits exist, to avoid creating the impression that rates should be a singular basis for deciding how much electrification may be considered affordable.'	
	E1	Supports: -'Stakeholders, NS Power and the NSUARB should consider a definition of beneficial electrification offered by the Regulatory Assistance Project (RAP): 1. Saves consumers money over the long run; 2. Enables better grid management; and 3. Reduces negative environmental impacts. As well, RAP's four key principles for maximizing electrification benefits should be followed. 3. EfficiencyOne is well-positioned to administer initiatives and programs to increase the amount and / or pace of electrification occurring in Nova Scotia.	2020-11-13; p. 1/16-2/16.

Nova Scotia Power IRP
Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

ACTION PLAN ITEM	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
		4. Development of an electrification strategy as defined in the IRP action plan must take place as part of stakeholder-driven process.'	
	SBA	Supports: -'Increased electrification and advanced technology can provide enhanced capabilities to NSP to manage some of the challenges introduced by higher penetrations of non-dispatchable resources. Action Plan Item #2c calls for a data collection program related to electrification. We support this program, and encourage NSP to pursue it rapidly so that any insights can be incorporated into the next IRP.'	2020-09-18, p. 3/3
	Heritage	Supports continued study of T&D costs	2020-09-12; p. 4/6, 6/6
	Other Stakeholders	No comments	n/a
3.0 Initiate a Thermal Plant Retirement, Redevelopment and Replacement Plan including: **3a** Develop a plan for the retirement and replacement of Trenton 5, targeting 2023, while identifying required replacement capacity and energy in parallel. Begin decommissioning studies for Nova Scotia Power's other coal assets and develop and execute a coal retirement plan including associated regulatory approval process; this coal retirement plan will include significant engagement with affected employees and communities. **3b** Complete a thermal plant Depreciation Study to update depreciation rates and a recovery strategy to better align depreciation with updated useful lives for generation assets. Invest sustaining capital into individual thermal units appropriate to their retirement categorization. **3c** Develop a plan for the redevelopment or replacement of existing natural gas-powered steam turbines to provide low-cost, fast-acting generating	CA	Generally supports however, recommends all-source RFP rather than wind procurement. Action Plan Item 3c: 'RII recommends that the findings include a specific discussion of the economics of replacing the current CT fleet with newer CTs or another type of fast ramping generation, including a summary of the modeling evidence in support of its findings and any constraints on the options that were evaluated that may suggest a need for further analysis.' Item 3d: '[recommends] action plan should commit to planning for potential transmission projects in parallel to both additional study of wind integration as well as the recommended all-source RFP. Using an improved understanding of system inertia and other reliability service topics, the resulting costs and capabilities of the Reliability Tie, operating practices for wind integration, and domestic technology options (battery	2020-09-18; p. 2/13, 10/13 2020-09-18; p. 6/13 2020-11-16; p. 1/21

Nova Scotia Power IRP
Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

ACTION PLAN ITEM	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
capacity to the Nova Scotia system. Fuel flexibility is a component of this work, including consideration for low/zero carbon alternative fuels. **3d** Initiate a wind procurement strategy, targeting 50-100 MW new installed capacity by 2025 and up to 350 MW by 2030. This strategy will solicit Nova Scotia-based market pricing information which will inform the selected wind capacity profile and timing, informed by the IRP wind sensitivities. In parallel with other elements of the wind procurement strategy, complete system stability studies to determine whether additional dynamic system inertia constraints, operating limits, and/or provision of alternate services like Fast Frequency Response (FFR), are required to enable higher levels of wind integration on the Nova Scotia system, particularly in advance of the commissioning of integration measures such as the Reliability Tie.		storage/synchronous condensers) should be used in the evaluation of the all-source RFP bids.	
	EAC	Supports Item 3a and agrees that decommissioning of Trenton 5 is essential and a comprehensive retirement plan for all coal units is needed. Suggests giving consideration to maximizing wind addition in combination with battery storage.	2020-09-18; p. 4/5
	Heritage Gas	Supports the need for natural gas as a cleaner fuel source. -'The Draft Findings, Action Plan and Roadmap results distributed to interested stakeholders on September 2, 2020 and presented on September 10, 2020 further indicate a required need and reliance for natural gas in the province over the next 25-year period. The results presented show that natural gas will provide electrical grid reliability, critical ancillary services, an economic energy source, and a lower carbon energy source to meet the province's environmental goals.' Supports item 3c: -'The conversion or replacement of the now 45-year old CT's provides an opportunity to both address the reliability issues with the existing CT's and address the need for additional CT capacity. The replacement of the Burnside CT's should be strongly considered. Heritage Gas recommends that a specific Action Item be identified in the final report to address the reliability issues identified by Bates White and the cost-effective utilization of existing infrastructure to meet the needs for additional CT capacity.'	2020-09-18; p. 1/6 2020-09-18; p. 3/6

Nova Scotia Power IRP
Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

ACTION PLAN ITEM	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
		Supports the conversion of coal-to-gas and notes 'that an increase of this size in natural gas consumption in the region requires long-term natural gas transportation commitment planning, which should also be reflected in the Action Plan.'	2020-09-18; p. 6/6
	CanREA	Supports, but thinks the target could be increased. Suggests the costs and integration constraints of wind are overstated. Suggests the ability of wind to provide ancillary grid services is understated.	2020-09-18; p. 3/3 2020-11-13; p. 1/4 2020-11-13; p. 3/4
	Natural Forces	Supports but says build-out rate is understated. Suggests the 350 MW limit is unduly limiting. Recommends RPF to determine cost of new wind to system. Work should fully consider alternative operational strategies	2020-09-18; p. 2/9 2020-09-18; p. 3/9 2020-09-18; p. 4/9; p 9/9 2020-11-13; p. 1/8 2020-11-13; p. 6/8
	SBA	SBA: Supports	2020-09-18; p. 2/3
4. Create a Demand Response Strategy targeting 75 MW of capacity, for deployment by 2025. Available resource cost, flexibility, and reliability may inform pursuit of additional Demand Response capability. **4a**. The strategy will be closely linked to the Electrification Strategy being developed in parallel. The strategy will build on learnings from NS Power's Smart Grid Project, NS Power's Time Varying Pricing application, the DR Joint Working Group between NS Power and Efficiency One, the ELIADC tariff, and the Large Industrial Interruptible Rider.	E1	E1: Supports, but suggests development process should proceed through DSMAG	2020-11-13; p. 2/16
	SBA	Supports, but wants more examination to understand true size and cost potential; may not want to limit to 75 MW.	2020-09-18, p. 3/3

Nova Scotia Power IRP

Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

ACTION PLAN ITEM	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
5. NS Power will calculate Avoided Costs of DSM (capacity and energy) for scenarios 2.0C and 2.1C. 2.0C will be used as the Reference Plan and 2.1C will be available for additional reference.	EAC	Suggests need to understand avoided costs of Max DSM and transportation fuel in high-electrification scenarios	2020-11-13; p. 2/3
	E1	Suggests avoided generation costs should be dealt with in DSMAG forum	2020-11-13; p. 3/16
	Natural Forces	Suggests other scenarios have potentially lower rates and policy benefits; reference plan may not be optimal plan	2020-11-13; p. 1/3
	Wolfville	Questions the use of 2.0C as the reference plan	2020-11-16; p. 2/2

Nova Scotia Power IRP
Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

ROADMAP ITEM	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
1. Advance engineering study work on coal-to-gas conversions at Trenton and Point Tupper Generating Stations. Monitor cost outputs of this work relative to IRP assumptions and update the balance of new and converted capacity resources accordingly.	Heritage Gas	Supports and suggests a timeline and stakeholder engagement.	2020-11-16; p. 4/5
2. Complete detailed system stability studies under various current and future system conditions, reflective of both stressed system states and normal operating conditions, while considering higher quantities of installed wind capacity as seen in the IRP modeling results. This work will also consider the impacts of grid service provision from inverter-based generators (such as wind turbines) and how the introduction of new ancillary services like Fast Frequency Response might affect existing services such as Synchronized Inertia. Monitor results for significant divergence from wind integration assumptions modeled in the IRP and trigger an update as needed.	CanREA	Feels more could be done to address wind and non-synchronous inverter-based resources to provide ancillary grid services.	2020-11-13; p. 3/4
	Natural Forces	Says capital costs of wind in low-pricing scenarios are more realistic and support more rapid build-out of wind than 2.0C	2020-11-13, p. 6/8
	SBA	Supports	2020-09-18; p. 2/3
3. Pursue economic reinvestment in existing hydro and combustion turbines with individual capital applications as applicable; economic justification as part of a capital application will be required to confirm decision to pursue Mersey hydro redevelopment. Continue sustaining capital investment in thermal units, aligned with their projected retirement classification. Monitor required levels of sustaining capital investment for significant changes from IRP assumptions and, if observed, trigger a unit-specific analysis of alternatives. Monitor unit reliability for significant changes from IRP assumptions and, if observed, trigger an ELCC calculation and/or PRM study as required.	CA	Supports and recommends that sustaining capital costs be updated and that there be a comparison of costs for continued thermal plant operation; Says to incorporate any updated transmission planning and resource procurement data in any Mersey applications; Suggests verifying modeled hydro with operational record and adjusting ELCC values.	2020-09-18; p. 13/13 2020-11-16; p. 1/21 2020-11-16; p. 2/21
	Heritage Gas	Suggests ongoing monitoring of existing CT fleet	2020-11-16; p. 4/5
4. Monitor the development of low/zero carbon fuels that could replace natural gas in powering generating units to provide firm, in-province capacity.	E1	Suggests providing assessment of natural gas pricing risk	2020-09-18; p. 8/10
	Heritage Gas	Supports investigation of hydrogen	2020-09-18; p. 5/6
	JF Hydrostor	Urges investment in compressed energy air storage as a clean/green alternative to new transmission and fossil fuels	2020-09-18; p. 1/4

Nova Scotia Power IRP
Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

ROADMAP ITEM	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
5. Continue to track the installed costs of wind, solar, and energy storage to look for variations from the trajectories established in the IRP (in particular, monitoring for divergence from the "Base" to the "Low" pricing scenarios). NS Power will solicit Nova Scotia-based market information which will inform this as needed.	CA	Need to explain lack of solar in resource plans	2020-09-18; p 4/13
	CanREA	Agrees this is best practice. Acknowledges effect of wind price on solar and energy storage solutions.	2020-09-18; p. 3/3 2020-11-03; p. 2/4
	E1	Suggests including DSM as a signpost in this Roadmap item.	2020-11-13; p. 3/16
	Wolfville	Notes inequitable economic (rate) implications associated with high levels of DER adoption.	2020-09-18, p. 2/4
6. Track the ongoing development of the Nova Scotia Cap-and-Trade Program, including auction results and developing regulations. In particular, monitor GHG market size for indications that value from incremental allowance sales (beyond the projected economic emissions reductions shown in the IRP results) can be incorporated into long-term resource planning decisions with greater certainty. Significant changes in the value of incremental GHG reductions could influence resource plan components including non-emitting generation procurement, DSM levels, and coal retirement trajectories.	CA	Suggests incorporating shadow price for emissions.	2020-11-16; p. 2/21
	E1	Says carbon pricing and revenues merits full consideration; suggest pricing should be ≥$24/tonne; Suggests availability (sale) of carbon allowances may affect selection of a lowest cost plan; supports monitoring allowance pricing but notes monetary value not addressed.	2020-09-18; p. 5/10 2020-11-13; p. 12/16
	Natural Forces	Says benefits of lower emissions should be monetized, but value in lower $C0_2$ as risk mitigation strategy; Supports monitoring market size for indications that value from incremental sales can be incorporated into long-term planning decisions.	2020-09-18; p. 7/9 2020-11-13; p. 7/8
7. Monitor electrification growth in Nova Scotia to understand at what point the provincial load profile starts to move from Low, to Mid, to High levels of electrification. An observed transition will, among other impacts, inform the use of DSM avoided costs in related proceedings and trigger a PRM study using actual peak, energy, and load shape data.	CA	Supports, suggests including specific commitment to building transportation and building electrification. Also suggests including estimate of tolerable cost levels and savings benefits.	2020-11-16; p. 2/21
8. Continuously refine the Action Plan and Roadmap items via an evergreen IRP process. This process should facilitate annual updates as conditions change and technology or market options develop, and as Action Plan items are completed. NS Power will include a summary of updates as part of IRP Action Plan reporting.	CA	Supports, but suggests increased frequency with smaller changes. Says to engage with stakeholders to define evergreen process.	2020-09-18; p. 11-12/13 2020-11-16; p. 2/21
	EAC	Supports, but suggests funding necessary for stakeholder participation.	2020-09-18, p. 4/5

Nova Scotia Power IRP

Summary of Stakeholder Comments specific to Findings, Action Plan and Roadmap

ROADMAP ITEM	STAKEHOLDER	STAKEHOLDER COMMENT	REFERENCE
		Agrees further transparent and inclusive planning is required, but suggests it should be managed by a third party	2020-11-13; p. 3/3
	E1	Supports a three-year cycle for key IRP inputs in evergreen process.	2020-11-13; p. 3/16
	Envigour	Supports regular stakeholder engagement for additional updates and trends; Suggests planning evergreen process to start in Q4 2020 with a view to broader stakeholder engagement in Q2 or Q3 2022; views the evergreen process as a priority.	2020-09-16; p. 2/3 2020-11-13; p. 2/3
	Heritage Gas	Supports, saying approach is valuable. Suggests monitoring existing CT fleet as part of evergreen process.	2020-11-16; p. 3/5 2020-11-16, p. 5/5
	PHP	Supports and suggests continued stakeholder engagement. Also suggests annual update on IRP status.	2020-09-18; p. 1/2 2020-11-16; p.1/2
	SBA	Suggests clarifying what types of information to be reported in updates and proposes stakeholder engagement options	2020-11-16; p. 1/3
	Wolfville	Echoes previous EAC comments about challenges of smaller entities in participating. Assumes Action Plan and Roadmap items will be vetted for compliance with provincial legislation and policy under the evergreen IRP process	2020-09-18; p. 1/4 2020-11-16, p. 2/2

NS Power's Response to IRP Report Directives and Suggestions

Request / Directive	Originator	Status	NS Power Comments
Per IRP and GUO letter from NSUARB about pre-IRP deliverables: 1. Confirm costs and achievable potential for incremental energy efficiency. As seen, energy efficiency displaces higher cost energy sources in the province (gas, oil, imports) and the IRP must fully reflect this resource option.	NSUARB M08059 letter October 5, 2018	Complete	Please refer to EfficiencyOne's 2019 Potential Study Report, filed August 14, 2019 (M08929, Exhibit N-1).
Per IRP and GUO letter from NSUARB about pre-IRP deliverables: 2. Determine costs and achievable potential for peak-load reducing demand response. Construct specific cost and quantity curves to allow for either resource selection (in Plexos) based on specific demand side resources, or scenario analysis utilizing alternative peak load and annual energy projections.	NSUARB M08059 letter October 5, 2018	Complete	Please refer to EfficiencyOne's 2019 Potential Study Report, filed August 14, 2019 (M08929, Exhibit N-1).
Per IRP and GUO letter from NSUARB about pre-IRP deliverables: 3. Monitor and comprehensively investigate costs for bulk-scale battery storage of different durations. The Plexos results indicate economic battery builds in different scenarios and reflect the importance of this resource to serve as peaking capacity.	NSUARB M08059 letter October 5, 2018	Complete.	As part of its pre-IRP deliverables, E3 prepared a Supply Options which provided forecast costs for bulk-scale battery storage of different durations. These options were integrated into the IRP including forward cost trajectories and pricing sensitivities.
Per IRP and GUO letter from NSUARB about pre-IRP deliverables: 4. Monitor, track and project sustaining capital costs for the thermal fleet. Sustaining capital costs incurred a range of 6.5% to 10.4% of total NPVRR costs in our main scenarios. It is critical to continue to assess the pattern of these costs and project future costs.	NSUARB M08059 letter October 5, 2018	Complete	As part of its pre-IRP deliverables, Nova Scotia Power prepared projected sustaining costs for its thermal fleet. Nova Scotia Power will continue to monitor and track sustaining costs. High and low sensitivities on sustaining capital were evaluated to evaluate the robustness of resource plans across a wide range of sustaining capital requirements.

NS Power's Response to IRP Report Directives and Suggestions

Request / Directive	Originator	Status	NS Power Comments
Per IRP and GUO letter from NSUARB about pre-IRP deliverables: 5. Establish requirements to allow increased levels of wind on NSPI system. Two threshold criteria to allow increased levels of cost-effective wind resources are completion of a second 345 kV intertie to New Brunswick, and assessment of NSPI's Provincial transmission system and related support services (to maintain stability and voltage criteria). NSPI should determine, with specificity, the set of technical improvements required to allow different increments of additional wind on their system. This should include the effect of additional transmission capacity to New Brunswick, the presence of the Maritime Link, and the ability to further increase wind penetration through transmission grid reinforcement. This should also recognize that the introduction of bulk scale battery storage as a possible capacity resource that can provide co-benefits associated with stability and voltage support.	NSUARB M08059 letter October 5, 2018	Complete	As part of its pre-IRP deliverables, Nova Scotia Power engaged PSC to complete a Renewables Stability Study to better explore and define these issues. This work led to multiple options for wind integration, including NB transmission and domestic battery and synchronous condenser capacity, that were defined in the IRP model and available for economic selection. System stability requirements were modeled dynamically and resources other than generation assets were able to contribute to meeting these requirements. As the IRP progressed, these integration criteria were substantially amended and tested by: • Allowing both the Reliability Tie and Domestic Integration options to contribute to additional wind integration simultaneously • Increasing wind integration levels for higher load scenarios • Enabling some ancillary grid service provision by wind generators • Modeling sensitivities that reduced and eliminated the wind integration requirements and system stability constraints, in order to understand the sensitivity of resource planning to these items. Future work in this area is specified in the IRP Action Plan to continue the advancement of this work.

NS Power's Response to IRP Report Directives and Suggestions

Request / Directive	Originator	Status	NS Power Comments
Per IRP and GUO letter from NSUARB about pre-IRP deliverables: 6. Continue joint dispatch efforts and investigate increased planning, unit commitment and reserve sharing opportunities with New Brunswick, Newfoundland and Prince Edward Island. Increased coordination among the Maritime Provinces is likely required to maintain reliability with increased wind resource utilization.	NSUARB M08059 letter October 5, 2018	Complete	Nova Scotia Power has continued to pursue these opportunities as part of its operations.
Per IRP and GUO letter from NSUARB about pre-IRP deliverables: 7. Determine the capacity and unit commitment requirements needed in association with the Tufts Cove thermal units, to allow appropriate parameterization in Plexos to enable possible economic retirement.	NSUARB M08059 letter October 5, 2018	Complete	This was evaluated as part of the IRP Scenarios. Tufts Cove units were enabled for retirement and this was observed for some units in the resource plan results.
Per IRP and GUO letter from NSUARB about pre-IRP deliverables: 8. Identify candidates for the "next" coal retirement alternative after Lingan 2. Consider "rank ordering" the units to establish a priority order reflecting best-to-worst economic performers across the thermal fleet. While projecting sustainable capital needs is an uncertain exercise, the potential to avoid significant major expenses at different points in time over the next decade illustrates the importance of establishing such a ranking.	NSUARB M08059 letter October 5, 2018	Complete	Refer to Draft Finding 2(a); Draft Action Plan 3(a), (b), and (c); and Draft Roadmap item 1. Refer also to sections 3.2.3, 4.2.2 and 4.4.3 of the Report.
Per IRP and GUO letter from NSUARB about pre-IRP deliverables: 9. Monitor natural gas price and availability trends in the Maritimes.	NSUARB M08059 letter October 5, 2018	Ongoing	This is an ongoing activity and NS Power updates stakeholders through the quarterly FAM Small Working Group meetings. Also included in Draft Action Plan item 3(c). Multiple options for natural gas pricing and source were incorporated into the IRP supply side options and modeling to explore a range of potential outcomes.

NS Power's Response to IRP Report Directives and Suggestions

Request / Directive	Originator	Status	NS Power Comments
In addition, the following items noted in the Bates White fuel audit report likely should be addressed during the first phase of the IRP process: • Continue to evaluate new and existing wind resources in order to establish an appropriate firm capacity value for each installation. • The 2013 CT Asset Optimization Study does not fully inform the decision to invest in the preservation of these units vis-a-vis replacing them with more modern CTs or another type of fast ramping generation unit. NSPI should compare the economics of replacing them with newer CTs or another type of fast ramping generation. • Determine the extent of any capital investment that may be required at Trenton 6 or the Point Tupper Marine Terminal after the current supply of domestic coal is no longer available at the end of 2019. • Complete a detailed analysis to determine the lowest planning reserve margin necessary to meet NPCC requirements, rather then just assessing if 20% remains in compliance. Considering that NERC's current North American references range between 10.6% and 23.7%, perhaps the analysis should assess reliability and economics for a range of planning reserve margins.	NSUARB M08059 letter October 5, 2018	Complete	Pre-IRP deliverables included the PSC Renewable Integration study, the E3 Capacity study, the E3 Supply Options study. Documentation can be found on the IRP website. The Capacity Study established the firm capacity contribution of existing wind and new wind specifically for the Nova Scotia system. NS Power and E3 undertook an evaluation of the diesel CT fleet as part of the Resource Screening phase of the IRP which incorporated analysis of replacement by new CTs as well as other resource types like battery storage. Based on anticipated capacity factors at Trenton Generating Station, additional investment due to the transition from domestic coal supply is not forecast at this time. Refer to section 3.3 and 3.3.2 specifically with respect to planning reserve margin.

NS Power's Response to IRP Report Directives and Suggestions

2018 FAM Audit Recommendation IX-1 (b) Determine the optimal planning reserve margin, not just reconsider whether a 20% planning reserve margin adequately meets NPCC or NERC standards. This will ensure that NSPI will be regularly determining the lowest planning reserve margin possible to meet NPCC requirements, rather than just assessing if "20%" remains in compliance.	Bates White 2018 FAM Audit Report p. 178	Complete	The Pre-IRP work confirmed via LOLP modeling that a PRM of 17-21% nameplate over firm peak was required in order to meet the NPCC reliability requirement of 1 day in 10 years (ICAP methodology). Based on stakeholder feedback, NS Power used the UCAP methodology for capacity expansion modeling in the 2020 IRP in order to fully consider the reliability characteristics of new and existing firm capacity as well as renewable generation. The findings of the pre-IRP capacity study were used for the Initial Portfolio Study capacity expansion models. NS Power then selected three scenarios (2.0C, 2.1C and 3.2C) for reliability assessment and determination of the appropriate PRM. For each case, the 2045 optimized resource portfolio and projected load were analyzed in E3's RECAP (loss of load probability) model. All three cases analyzed during the Reliability Assessment were found to meet the target reliability criterion and LOLE metric, and further it was found that the excess capacity on the system was near to or less than the size of the lowest cost capacity resource (50MW combustion turbine). Finally, the pre-IRP study was updated for assumptions that had been updated or modified during the IRP process including load forecast and unit availability and forced outage rates, and was re-run on the 2021 resource plan. This update again confirmed a 21% ICAP/9% UCAP PRM.

NS Power's Response to IRP Report Directives and Suggestions

Request / Directive	Originator	Status	NS Power Comments
			In the IRP Roadmap, NS Power has committed to periodically re-evaluating the target PRM as key input variables, such as electrification impacts and ongoing reliability performance of existing units for significant changes from IRP assumptions. Refer to sections 3.3, 3.3.2, 5.3.2 and 6.6 specifically.
2018 FAM Audit Recommendation IX-1 (c) Provide a transparent forecast of peak load that can be fully vetted by the Board, the Board's consultants, and stakeholders, as applicable	Bates White 2018 FAM Audit Report p. 178	Complete	NS Power developed load assumptions in collaboration with the IRP Working Group and IRP participants. The Low Electrification forecast was developed from the 2019 Load Forecast Report, filed with the UARB with significant supporting details, and for which a separate regulatory proceeding was held with IRs and intervenor and Board consultant evidence. Additionally, the mid and high electrification forecasts were developed using the results of a comprehensive economic decarbonization analysis during the pre-IRP work (the PATHWAYS study). All load forecast scenarios used for the IRP were provided to IRP participants for review and comment before finalization. These load forecasts were then updated in consultation with the Working Group and reviewed with IRP participants to reflect the impacts of the COVID-19 pandemic which began while the IRP was in progress. Refer to section 4.1 of the Report.

NS Power's Response to IRP Report Directives and Suggestions

Request / Directive	Originator	Status	NS Power Comments
2018 FAM Audit Recommendation IX-1 (d) Consider the full costs and benefits of all investment alternatives, including firm import capacity; transmission expansion; demand-side management; additional domestic and external hydro resources, including pumped hydro storage and additional hydro delivered over the Maritime Link; natural gas infrastructure investments; and emerging technologies as alternatives to traditional maintenance of existing generation or expansion of NSPI's portfolio.	Bates White 2018 FAM Audit Report p. 178	Complete	Please refer to Assumptions, Modeling Results, Findings, Analysis Plan, Action Plan, and Roadmap.
2018 FAM Audit Recommendation IX-1 (e) Regarding natural gas infrastructure investments (e.g., natural gas-fired combined cycle generation, firm pipeline capacity), include use the variable cost of gas (commodity, fuel, and variable pipeline charges) as the input into PLEXOS model runs, and not include the capital costs of the investment in commitment and dispatch costs, but instead add the fixed costs to the cost of generation subsequent to the PLEXOS runs. NSPI should also evaluate potential changes to its generation fleet by including updated, combined-cycle technology as a generation option.	Bates White 2018 FAM Audit Report p. 178	Complete	NS Power developed a natural gas model that includes three gas prices: the existing contracted gas supply (TCPL gas), and two options for incremental gas supply – peaking and base-loaded. The peaking supply does not incorporate firm pipeline commitments and as such has a higher variable fuel cost. The base-loaded supply option has a capacity cost, which is incorporated into NPV cost results but is not a factor in unit dispatch pricing. The PLEXOS model NS Power developed is able to optimize the selection of gas supply source for each new gas generation resource. Refer to sections 4.2.2, 4.4.3, 6.1.2, 6.5.1, and 7.1.1 of the Report.

NS Power's Response to IRP Report Directives and Suggestions

Request / Directive	Originator	Status	NS Power Comments
2018 FAM Audit Recommendation IX-1 (f) Explicitly address the effect of PHP load. The LRT requires that NSPI exclude PHP from its planning considerations. NSPI should assess the effect of incorporating PHP load in resource planning to ensure that PHP load does not impose net costs on FAM customers over a longer time horizon.	Bates White 2018 FAM Audit Report p. 178	Complete	PHP is no longer served on the Load Retention Tariff. Subsequent to this FAM Audit Recommendation, the NSUARB approved a new tariff, the Extra-Large Industrial Active Demand Control Tariff, to serve PHP, in the interests of all customers. Under the ELIADC tariff, PHP continues to be a priority interruptible customer. As a priority interruptible customer, PHP load does not contribute to firm capacity requirements. This is reflected in the firm peak assumptions modeled. PHP is a native load customer served under a Board approved standard tariff. Nova Scotia Power has included PHP's energy requirement and load profile designed to capture the benefits of Active Demand Control in its load forecast assumptions.

NS Power's Response to IRP Report Directives and Suggestions

Request / Directive	Originator	Status	NS Power Comments
2018 FAM Audit Recommendation IX-1 (g) Consider the full costs and benefits of maintaining all of NSPI's existing generating assets. This would include the environmental costs/benefits, the sustaining capital costs, OM&G projections, capital expenditures to address fuel transportation and handling infrastructure, decommissioning costs, NSPI's return of and on capital related to each plant, and FAM cost impacts, among potentially many others.	Bates White 2018 FAM Audit Report p. 178	Complete	NS Power's modeling assumptions include the costs of maintaining existing generating assets, including the items listed in the recommendation except the following: - Unit decommissioning costs – these are not included in the capacity expansion model. All NS Power's coal units will be decommissioned within the planning horizon and so there is no decision to be made with respect to the incurring of these costs. During the resource screening stage, decommissioning costs were included in the calculations for existing hydro sites. - Operating costs for transportation infrastructure were included in the model. Capital expenditures to address fuel transportation and handling infrastructure are not currently considered in the IRP model. These costs were provided to Bates White for review. These items are considered in each of the model runs. Refer specifically to sections 4.2.2, 4.4.3, 6.1.2, 6.5.1, and 7.1.1 of the Report.
2018 FAM Audit Recommendation IX-1 (h) Determine a reasonable effective load carrying capability for both existing and new wind resources.	Bates White 2018 FAM Audit Report p. 178	Complete	The ELCC of existing and new wind was determined as part of the Pre-IRP work using LOLE studies via E3's RECAP model. A marginal ELCC value specific to the existing NS Power system was calculated, which is being used for all new wind. Refer to the E3 Capacity Study completed as part of the pre-IRP deliverables.

NS Power's Response to IRP Report Directives and Suggestions

Request / Directive	Originator	Status	NS Power Comments
2018 FAM Audit Recommendation XIV-6: Subject to identifying the need for peaking and fast ramping resources in that study, NSPI should compare the economics of preserving the serviceability of its CT current fleet to the economics of replacing them with newer CTs or another type of fast ramping generation.	Bates White 2018 FAM Audit Report p. 295	Complete	NS Power and E3 undertook an evaluation of the diesel CT fleet as part of the Resource Screening phase of the IRP. This work confirmed that, if forced to retire, the existing diesel CT fleet would be replaced with new gas combustion turbines and that this replacement would increase costs to customers under both the Low and Mid Electrification load forecasts. These results were shared with stakeholders as part of the June 26 IRP results release. Based on specific feedback from Bates White during the resource screening analysis, the following additional sensitivities were included in this work: • Specific analysis of the Victoria Junction combustion turbine site, conducted both with and without addition of locational effects relative to load centre in Halifax (i.e. adjustment for transmission losses) • Sensitivities considering various assumptions for the PRM requirement under both UCAP and ICAP calculations to confirm resource adequacy and lack of capacity surplus in the near term • Additional capacity expansions in RESOLVE using a 7% UCAP PRM (vs. base assumption of 9% UCAP) CTs and related capital investments are addressed in sections 4.2.2 and 4.4.3.

NS Power's Response to IRP Report Directives and Suggestions

Request / Directive	Originator	Status	NS Power Comments
In subsequent response to Bates White's rebuttal that existing units would continue to perform at the same level as they age, nor new additional wind turbines exhibit no performance improvement over that of the existing wind IPPs, NSPI agreed to monitor wind variability for longer (10 year) periods within the Integrated Resource Planning (IRP) process the NSUARB directed NSPI to undertake for completion by mid-2020 (Matter M08929). Bates White considered this matter closed for the purpose of the 2016-2017 FAM Audit proceeding and intends to monitor this item in the context of the ongoing 2020 IRP process.	Bates White 2020 FAM Audit Report p. 57	Complete	Forecast wind generation in the IRP is based on a recent 3-year average for existing wind sites. For new wind resources, E3 developed an assumption of a 39% capacity factor based on data in the CanWEA pan-Canadian wind survey. NS Power will continue to monitor for declining production trends and incorporate when evident.
In our previous audit report, we addressed in more detail the observed operating reserve surpluses. NSPI is currently undertaking an IRP process in response to our previous audit report and a directive from the Board. The IRP is the proper forum to consider NSPI's resource portfolio; thus, we make no further recommendations regarding these observed operating reserve surpluses here, other than to note that they remained in place during this Audit Period.	Bates White 2020 FAM Audit Report p. 185	Complete	Operating reserves are included in the discussion of reliability (section 3.1.3 and 3.1.3.1) and an examination of Operating Reserve provision in IRP runs is provided in Section 6.7.1.

NS Power's Response to IRP Report Directives and Suggestions

Request / Directive	Originator	Status	NS Power Comments
Recommendation XIV-5: NSPI should perform a standalone analysis to determine the value of the Biomass Plant to FAM customers, looking forward, in the absence of PHP load. Such a study would establish whether any of the costs of the facility are appropriately considered incremental to PHP load and would inform considerations of how to shield FAM customers from such costs. NSPI accepted this recommendation and said it would review the cost of providing service from the biomass plant as part of its assessments in advance of the conclusion of the PHP LRT on December 31, 2019. NSPI also stated that it would "incorporate the analysis of the PH Biomass Plant in the 2019 IRP and determine the value of the PH Biomass Plant in the long term as a part of the integrated system in Nova Scotia."701 Subsequently, the Board approved the ELIADC tariff, which eliminates PHP's explicit option to access generation from the biomass plant.	Bates White 2020 FAM Audit Report p. 372	n/a	Biomass as a component of the renewable electricity supply is addressed in section 4.4.1.3, but the PH Biomass plant is not specifically addressed. However, because of the transfer of Port Hawkesbury Paper to the ELIADC (active demand control) tariff, NS Power is able to control its load and demand and can make the best dispatch decisions (including decisions about when to run the PH Biomass plant) based on system need, resources and demand.