2020 INTEGRATED RESOURCE PLAN (IRP): FINAL ASSUMPTIONS SET

MARCH 11, 2020

Nova Scotia POWER
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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.

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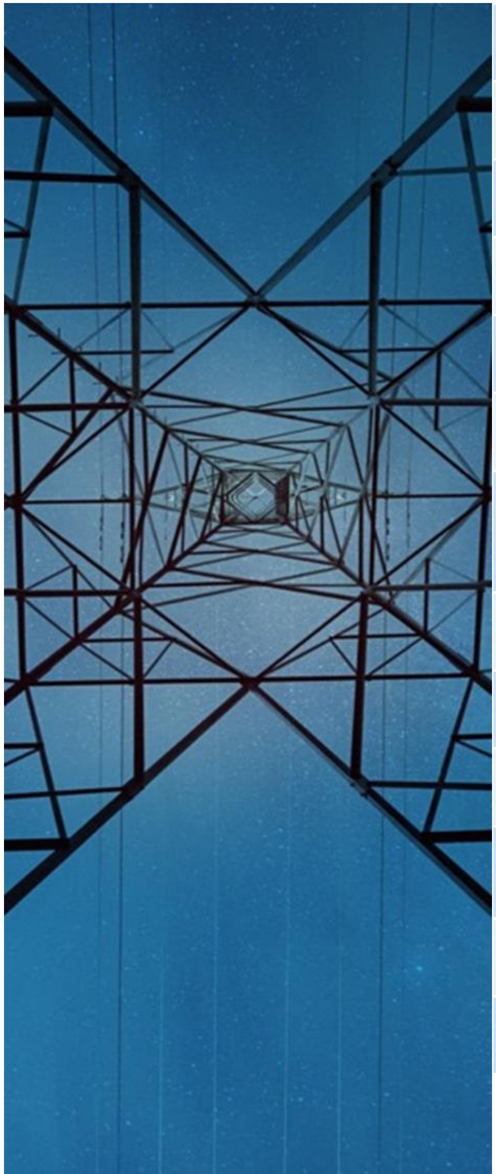

2020 IRP:
FINANCIAL ASSUMPTIONS

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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

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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:

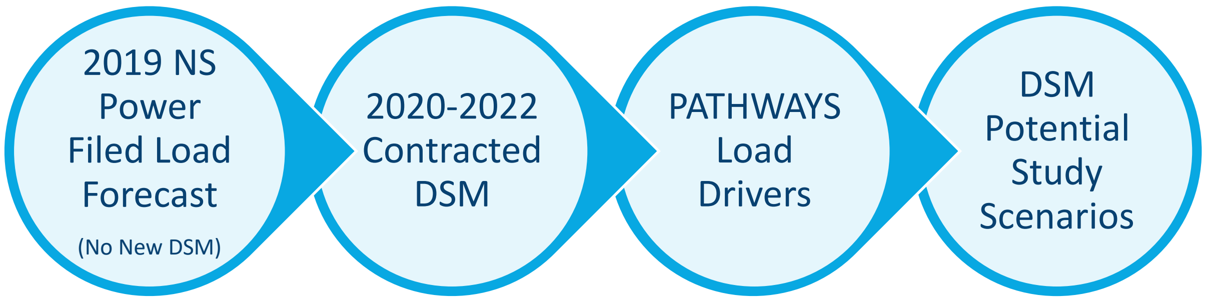
- Economic forecast from Conference Board of Canada
- Electric Vehicle (EV) penetration based on conservative estimate of Electric Mobility Canada's growth model
- EV includes estimate for peak mitigation
- 10-year average used for normal weather

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

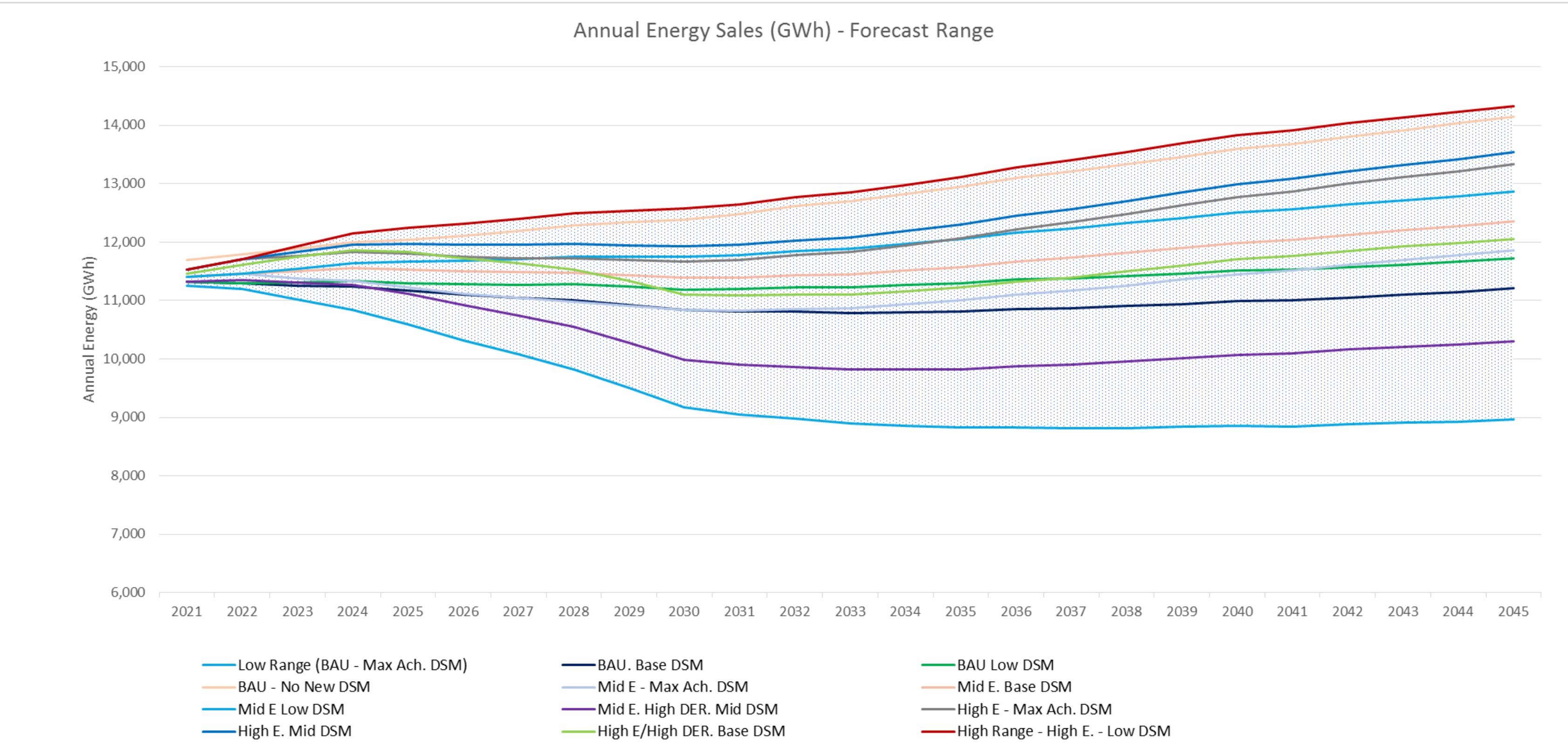
- NS Power has developed IRP load forecasts to integrate 4 sources of data:



- 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.



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IRP LOAD FORECAST SCENARIOS ANNUAL ENERGY

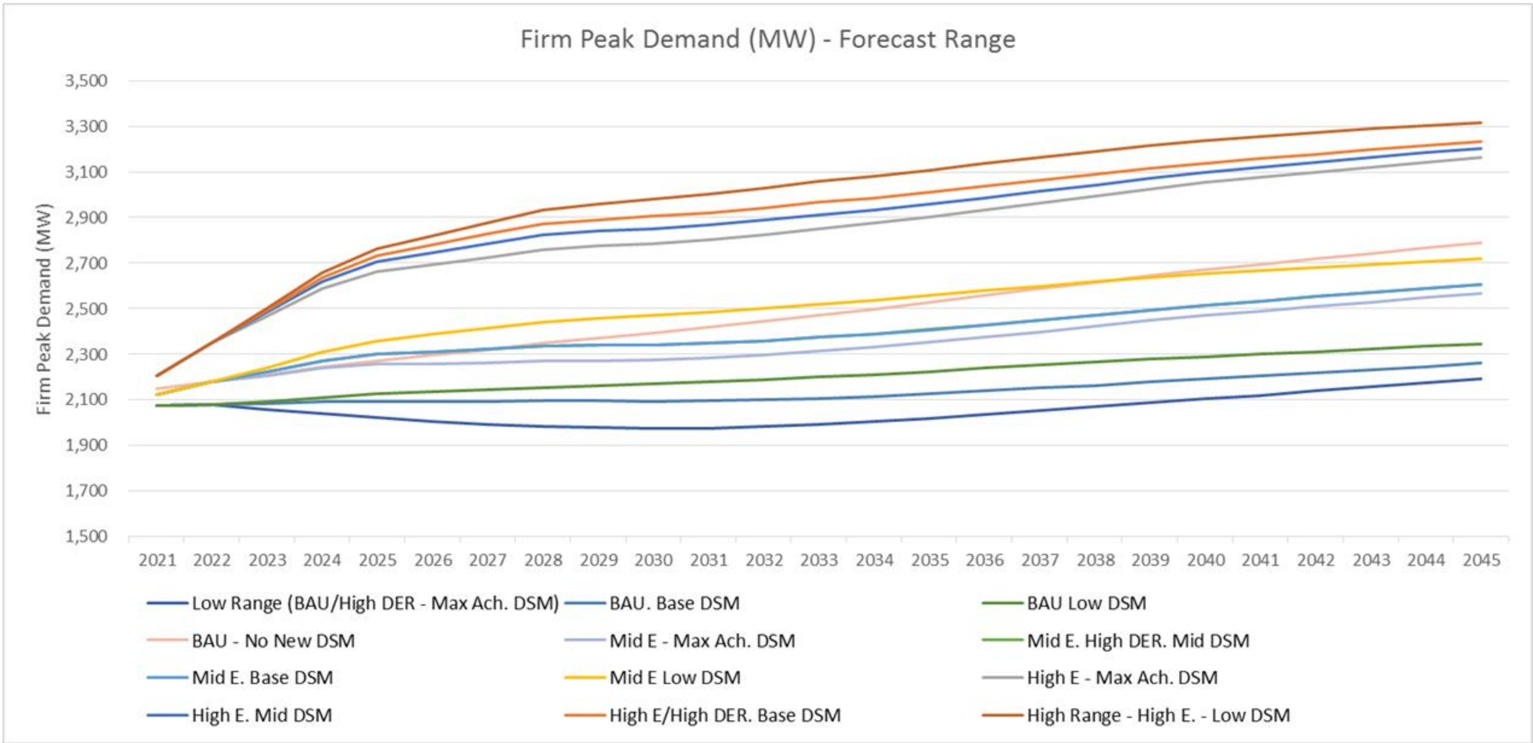
Year	Low Range (BAU/High DER - Max Ach. DSM)	BAU. Base DSM	BAU Low DSM	BAU - No New DSM	Mid E. Base DSM	Mid E Low DSM	Mid E. High DER. Mid DSM	Mid E - Max Ach. DSM	High E/High DER. Base DSM	High E. Mid DSM	High E - Max Ach. DSM	High Range - High E. - Low DSM
2021	11,252	11,327	11,327	11,695	11,403	11,403	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.



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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

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2020 IRP:
ENVIRONMENTAL ASSUMPTIONS (EXISTING & DEFINED POLICY)

MARCH 11, 2020

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

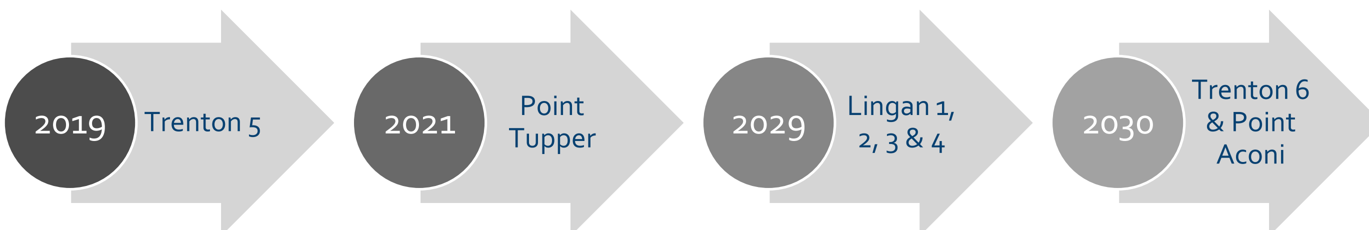
APPLICABLE LEGISLATION (CONT.)

- 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.

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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.

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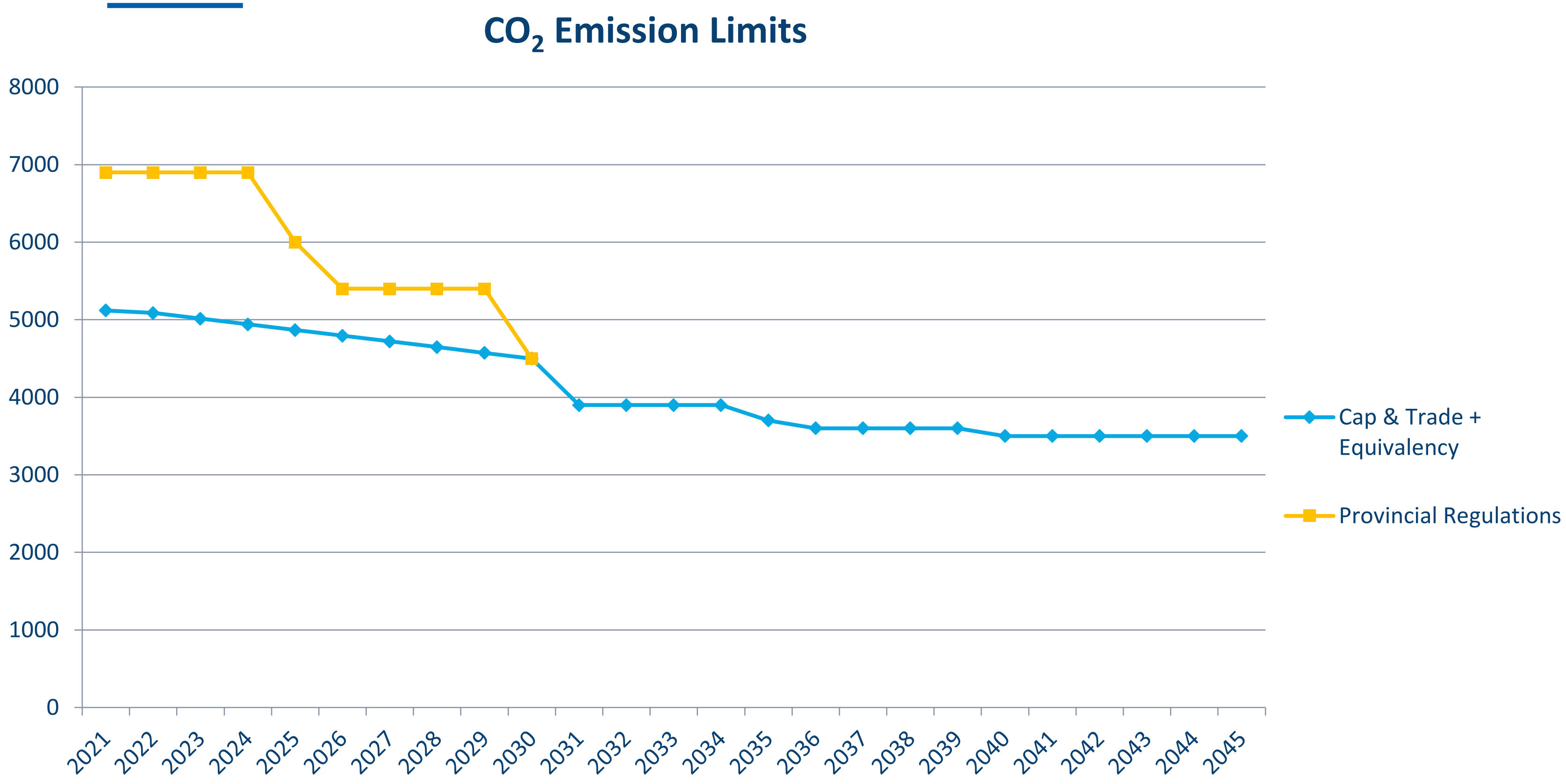
FORECAST CO_2 EMISSION HARD CAPS*



*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

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>104,00
0</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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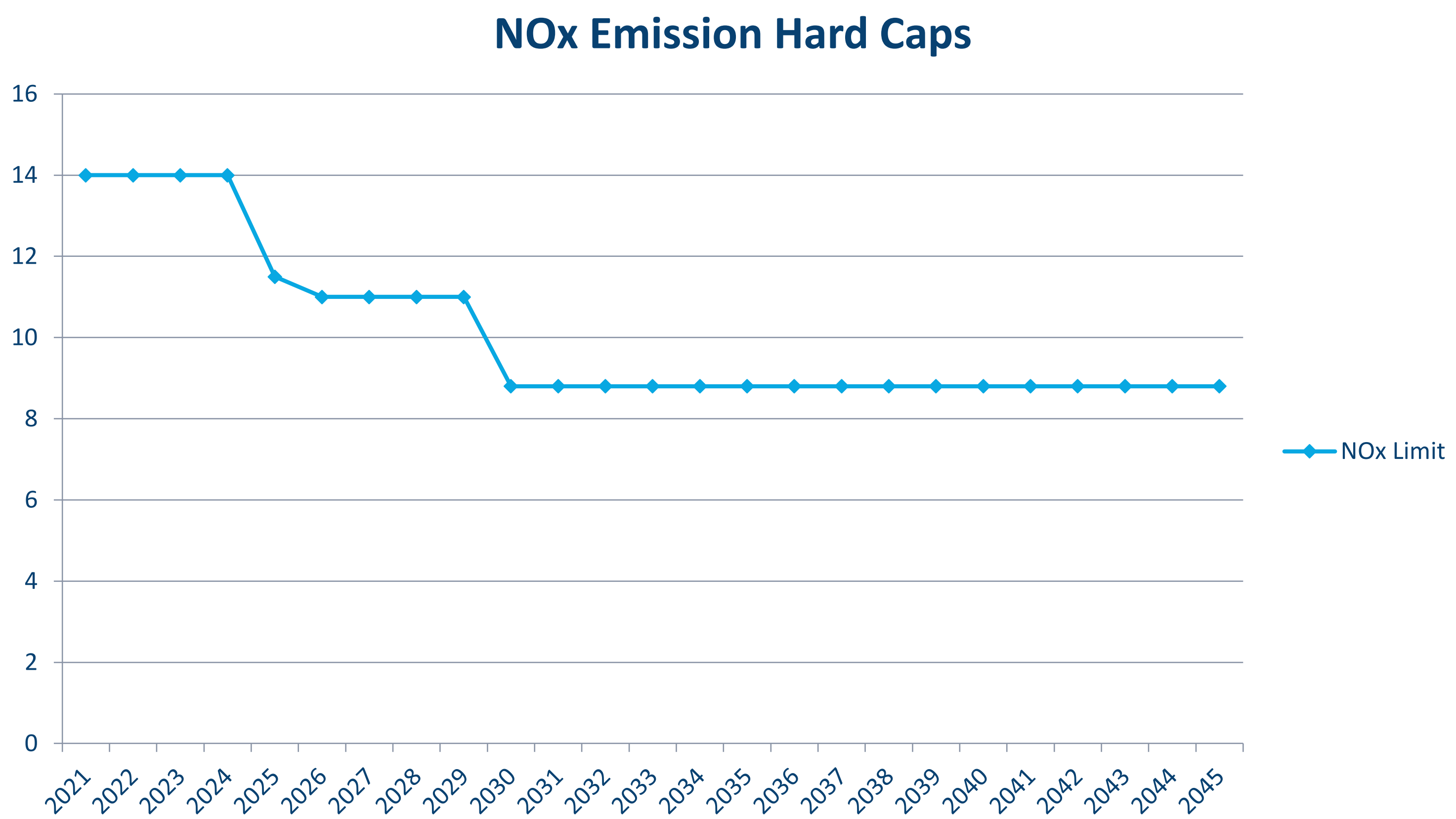
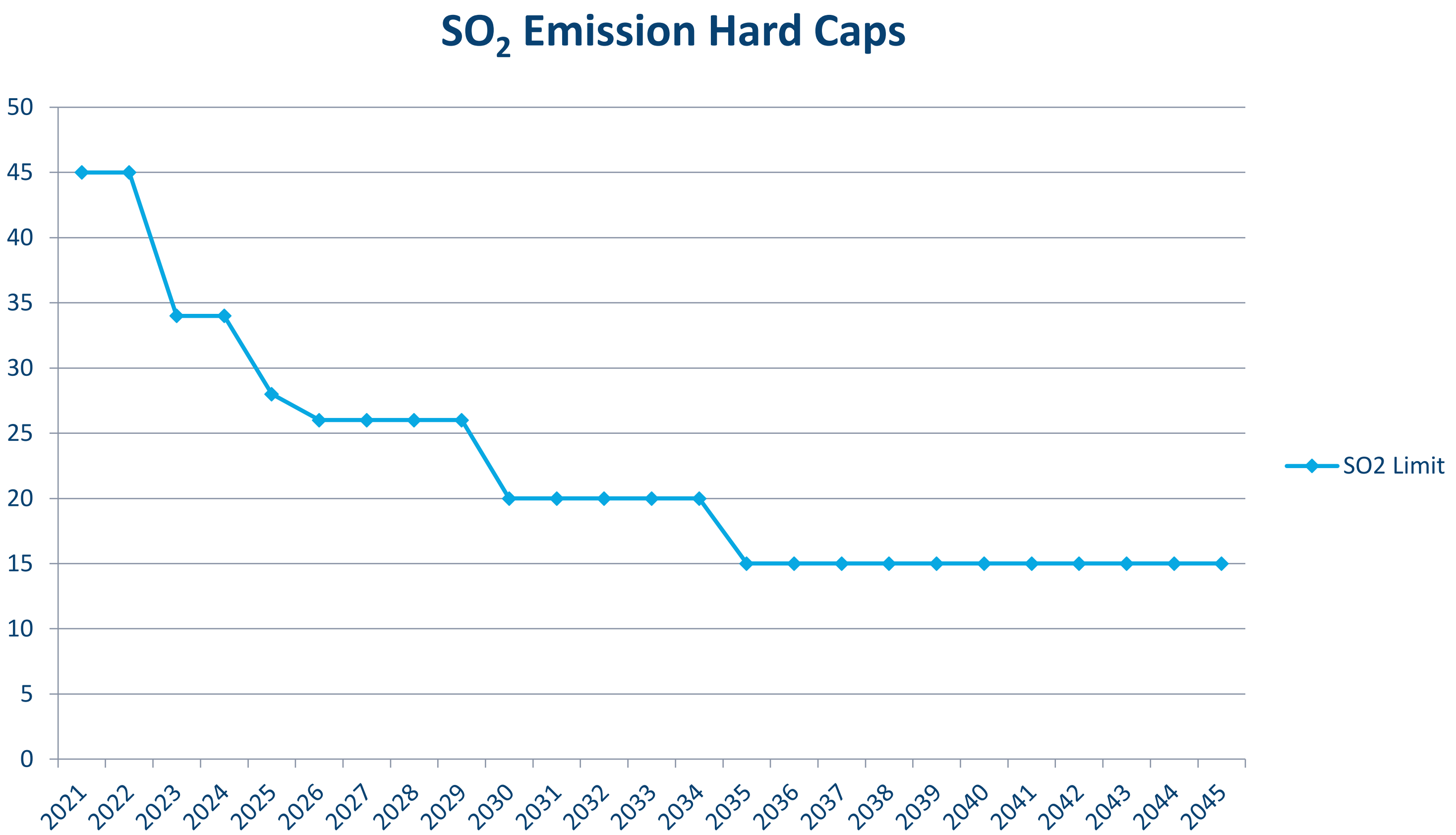
FORECAST NO_X EMISSION HARD CAPS

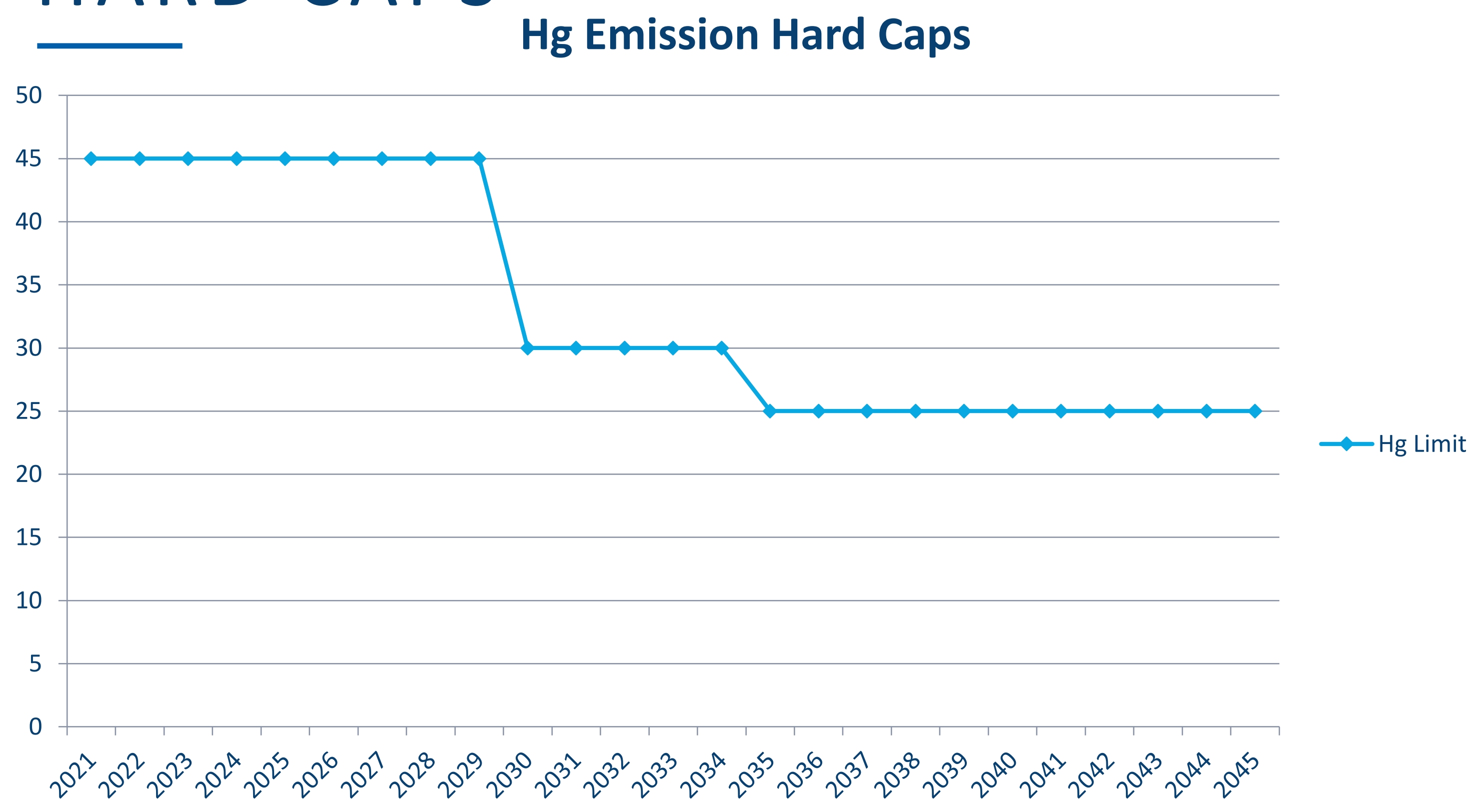


FORECAST SO_2 EMISSION HARD CAPS



*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.

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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.

NS Power Resource Options Study
2020 Updates

Nova Scotia Power

March 11, 2020

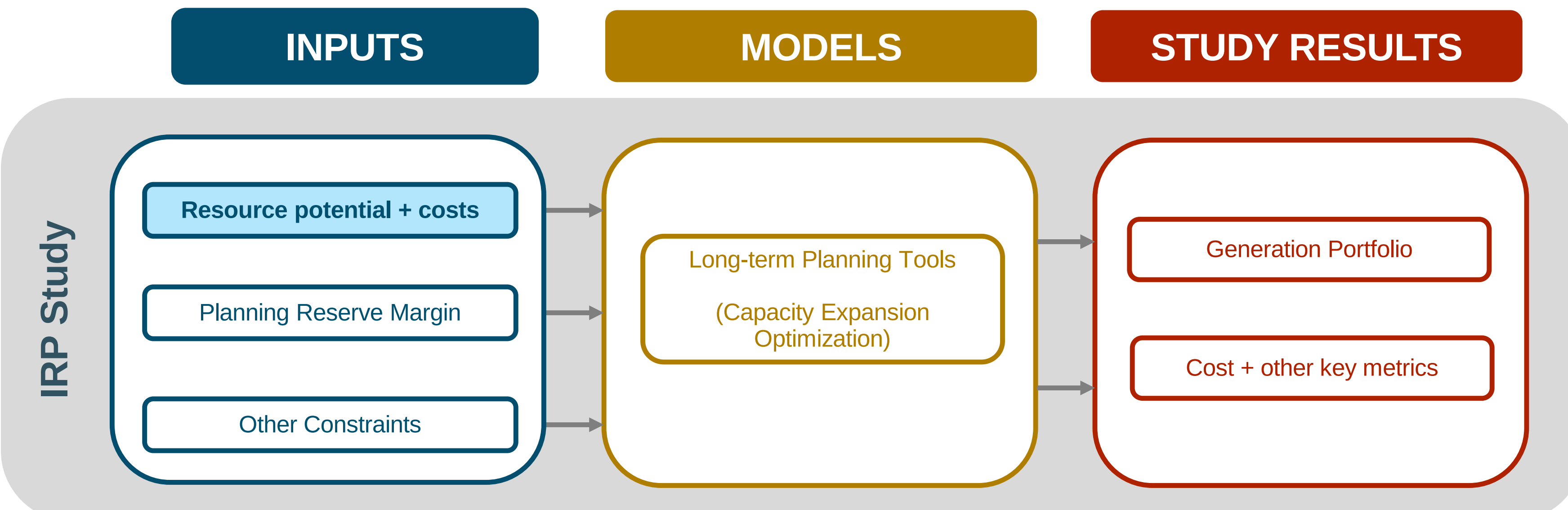
Liz Mettetal, Sr. Consultant
Charles Li, Consultant
Aaron Burdick, Sr. Consultant
Sandy Hull, Sr. Consultant
Zach Ming, Sr. Managing Consultant

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

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2020 IRP:
DISTRIBUTED ENERGY RESOURCES (DERs)

MARCH 11, 2020

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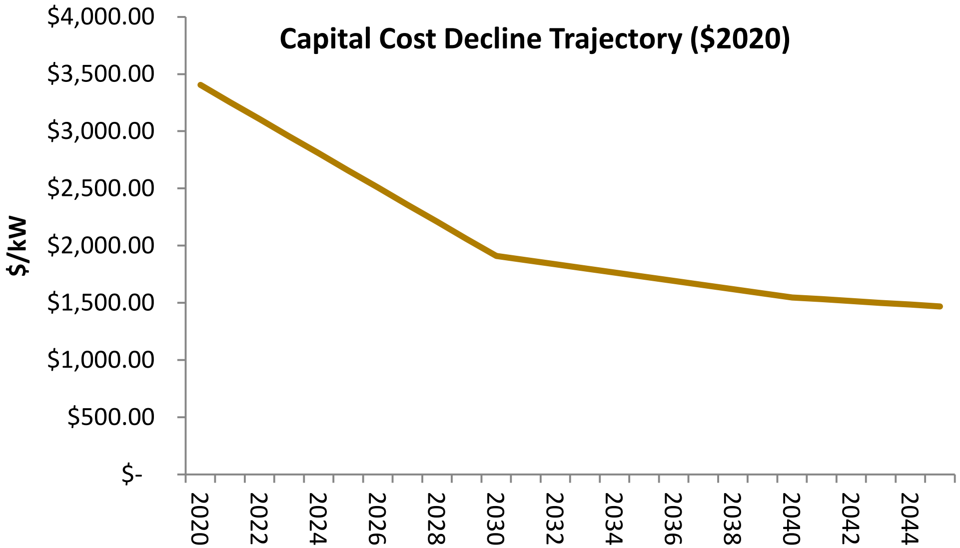
DISTRIBUTED ENERGY RESOURCES OVERVIEW

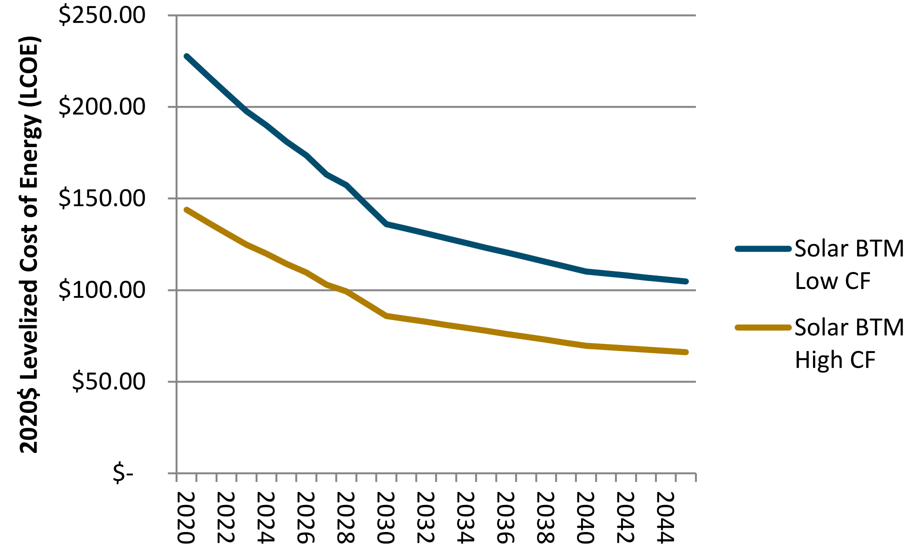
- As the grid becomes increasingly decentralized and more customers adopt distributed energy resources (DERs), long-term resource planners must address issues associated with evaluating their impact on the electricity system, including:
    - DERs introduce both system-level and distribution-level costs 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



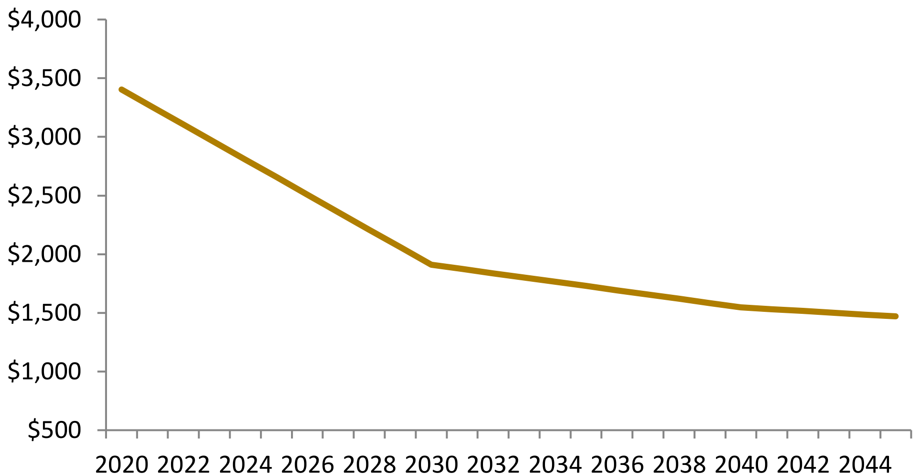


Input	Low Capacity Factor	High Capacity Factor
Capacity Factor	12%	19%
$\$/kW_{2020}$	$3405	$3405
FO&M ($/kW-Yr)	17.50	17.50
Financing Lifetime (Years)	25	25
Degradation (%/year)	0.5%	0.5%

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%

Capital Cost Decline Trajectory ($2020)



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2020 IRP:
PLANNING RESERVE MARGIN

MARCH 11, 2020

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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 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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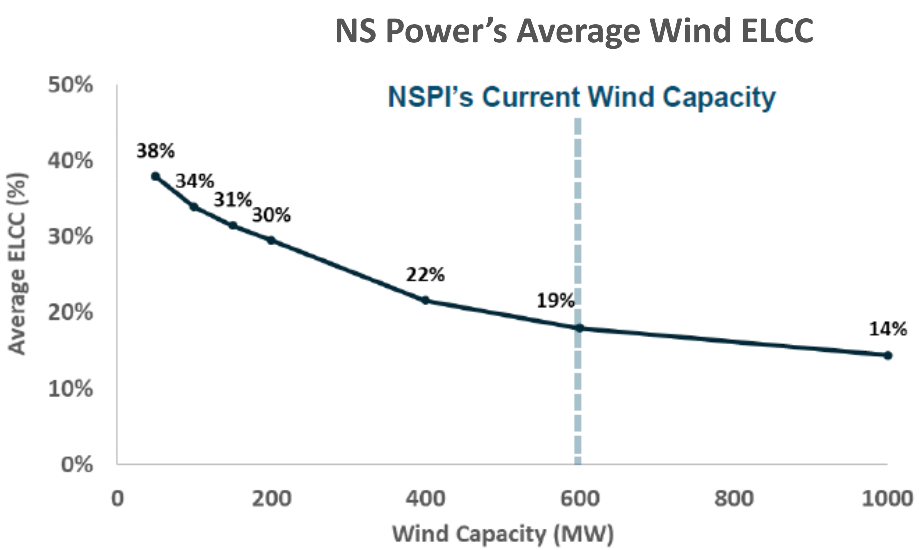
*EFFECTIVE LOAD CARRYING CAPABILITY (ELCC)

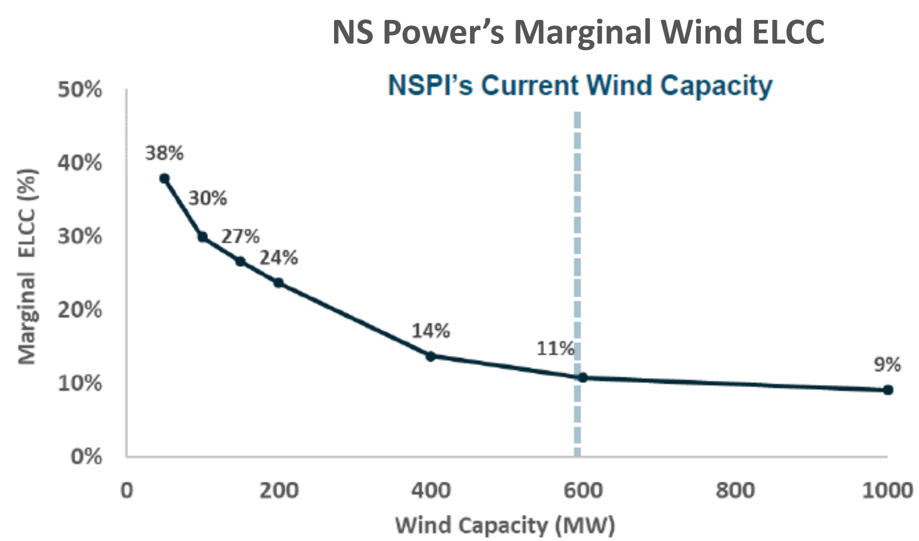
- The information from the Planning Reserve Margin and Capacity Value Study undertaken by E3 as part of the ‘Pre-IRP’ work will be used as the basis for the ELCC assumptions.
- Dispatch-limited resources like wind, solar, storage, and demand response can contribute effective load carrying capability (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

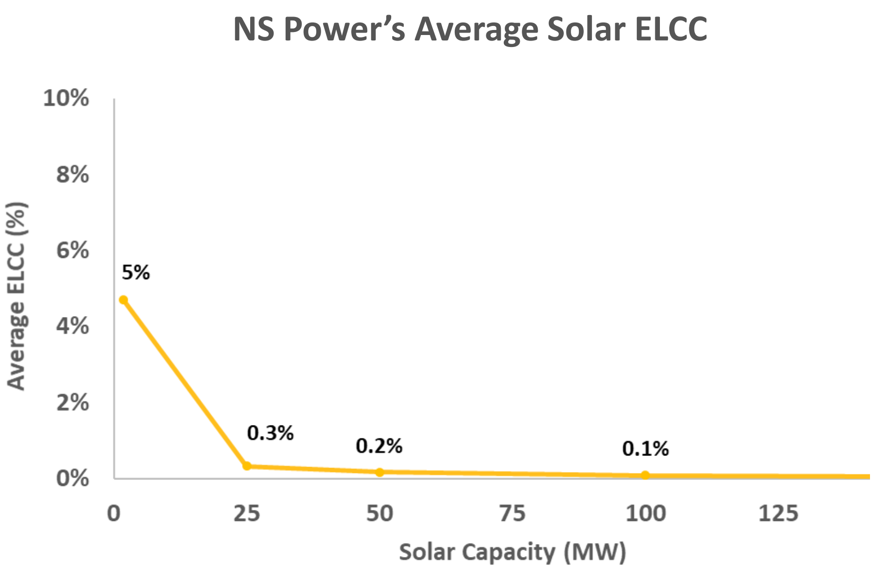
The average ELCC of the 596 MW of wind currently installed on the NS Power system is 19% or 111 MW. The ELCC value of adding new wind to the NS Power system is measured by the marginal ELCC and is currently at 11%, meaning that each additional MW of wind contributes 0.11 MW of firm capacity to PRM requirements.

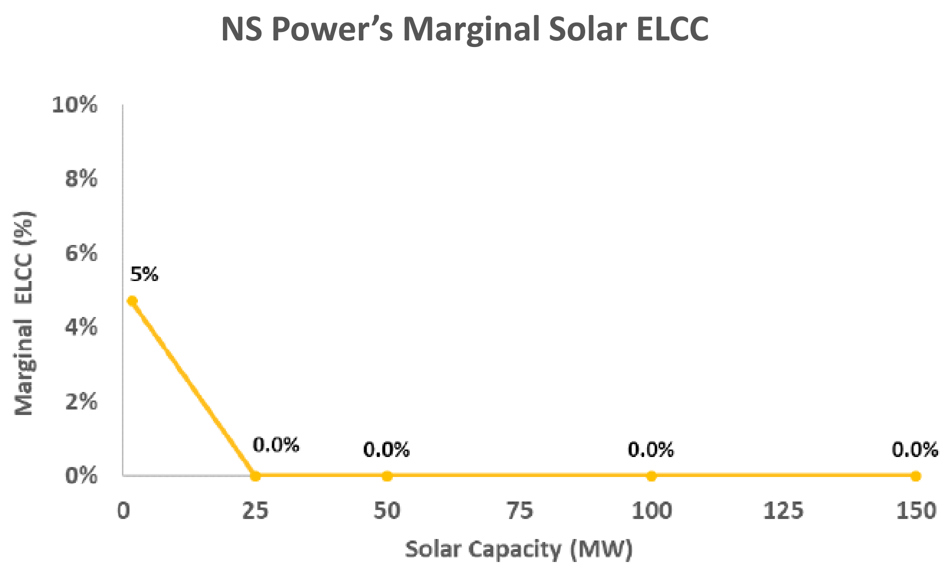




ELCC OF SOLAR

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%.





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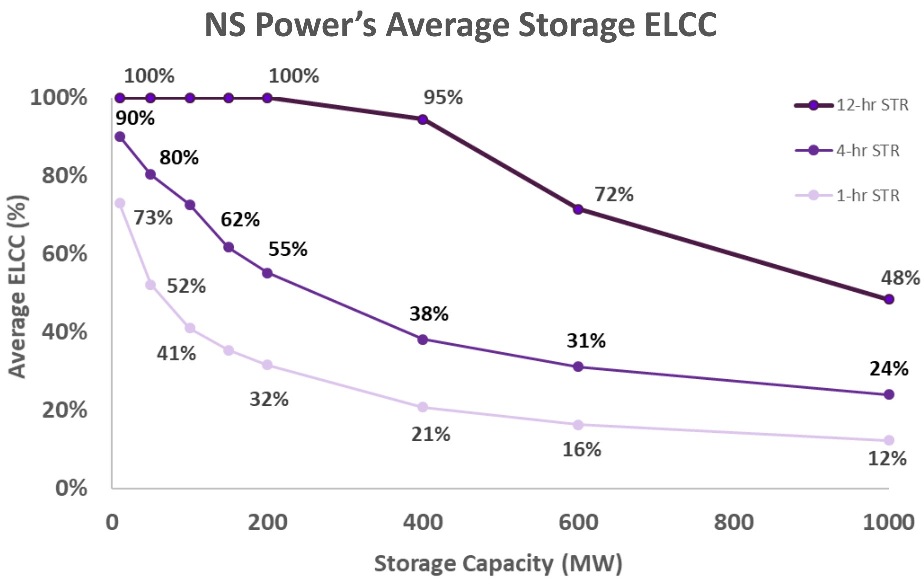
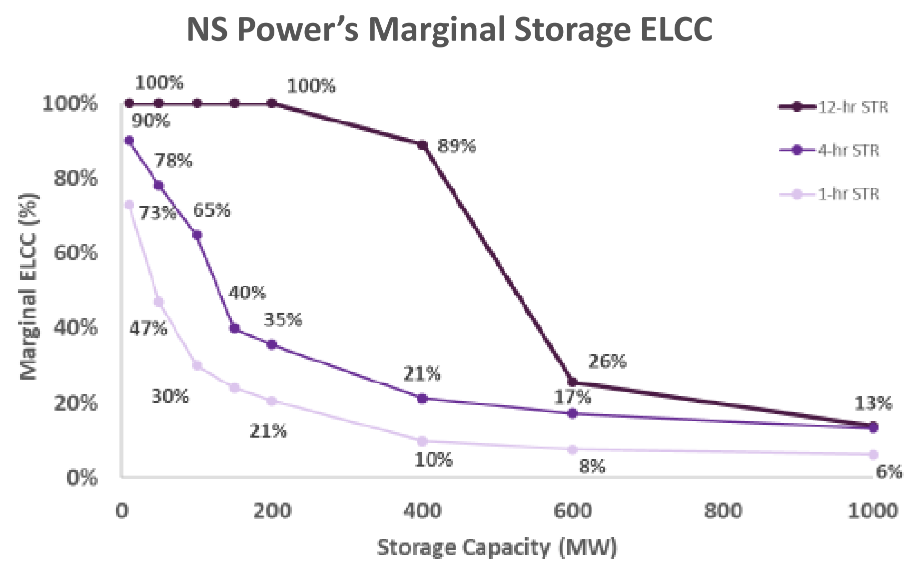
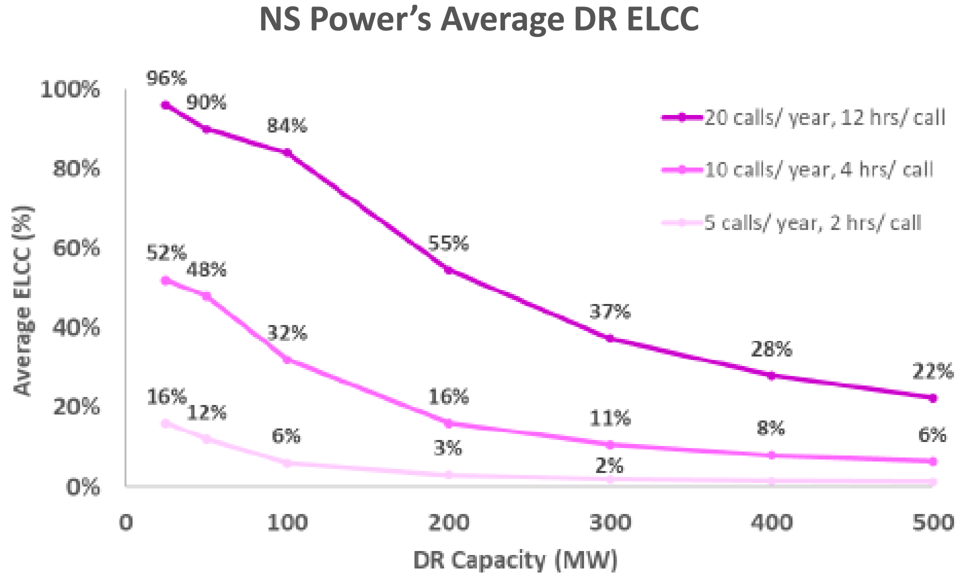
ELCC BATTERY STORAGE

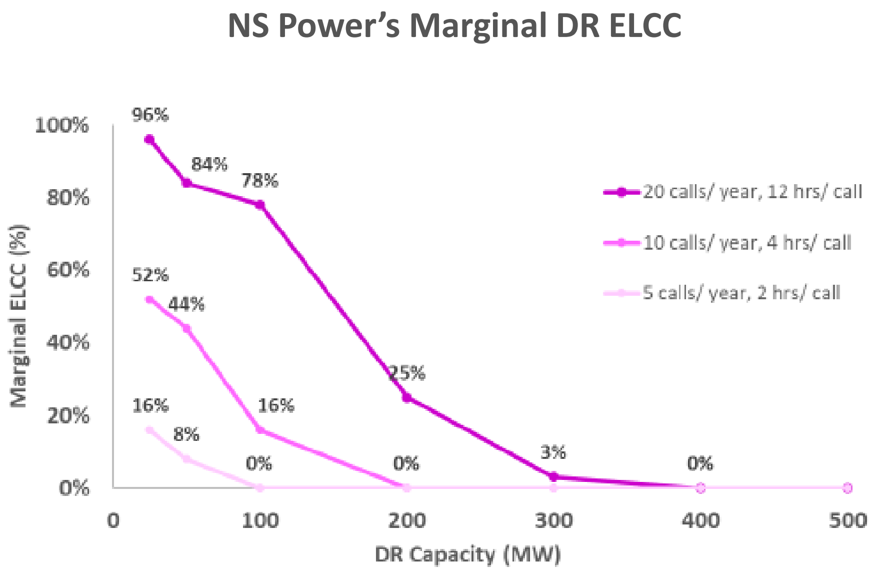




ELCC OF DEMAND RESPONSE

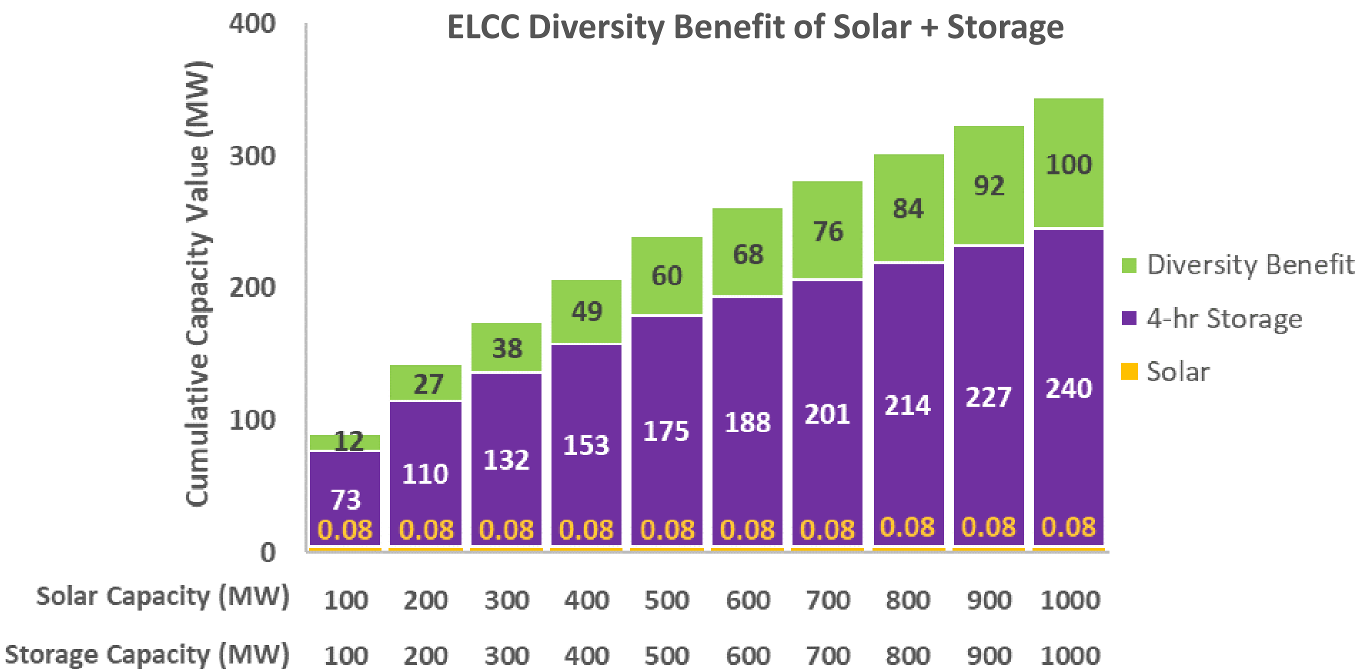


These represent illustrative demand response (DR) programs with different numbers of calls and durations. These results are not meant to map directly to specific existing DR programs but rather inform system planners of the ELCC value that a DR program with similar attributes might provide. As with all 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

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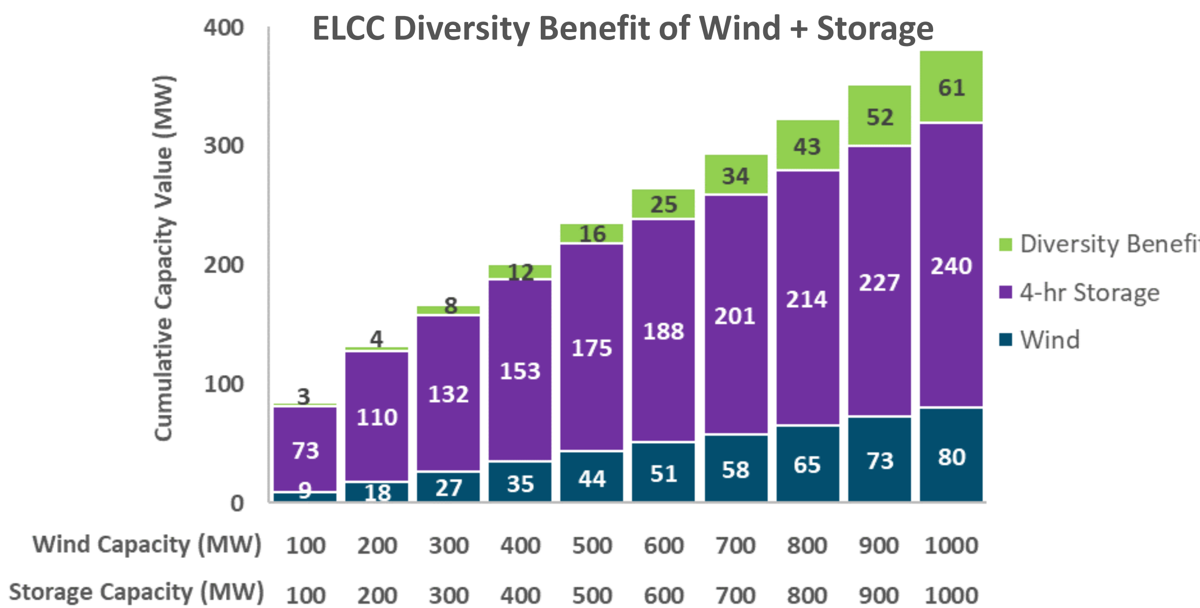
ELCC DIVERSITY – PRM AND CAPACITY STUDY

- 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

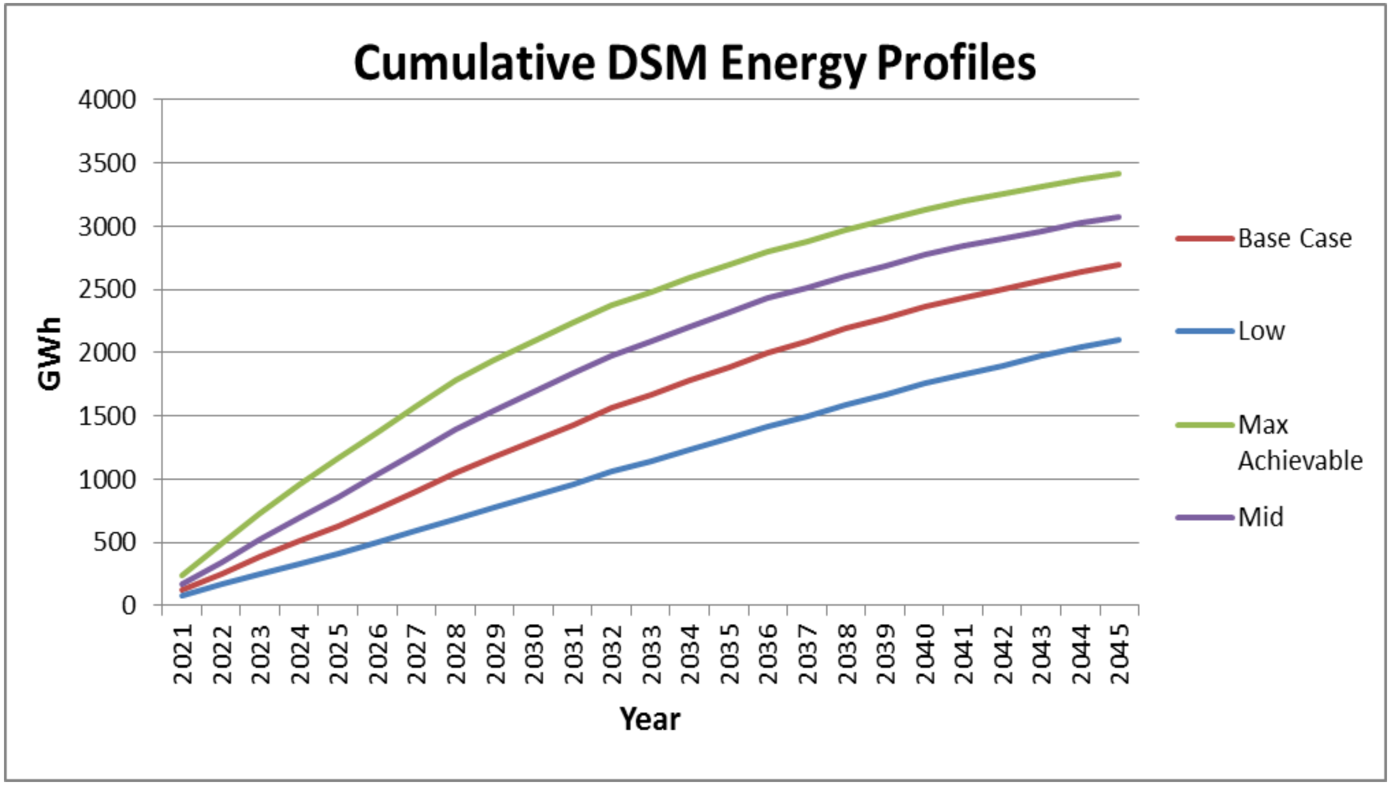
MARCH 11, 2020

*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.

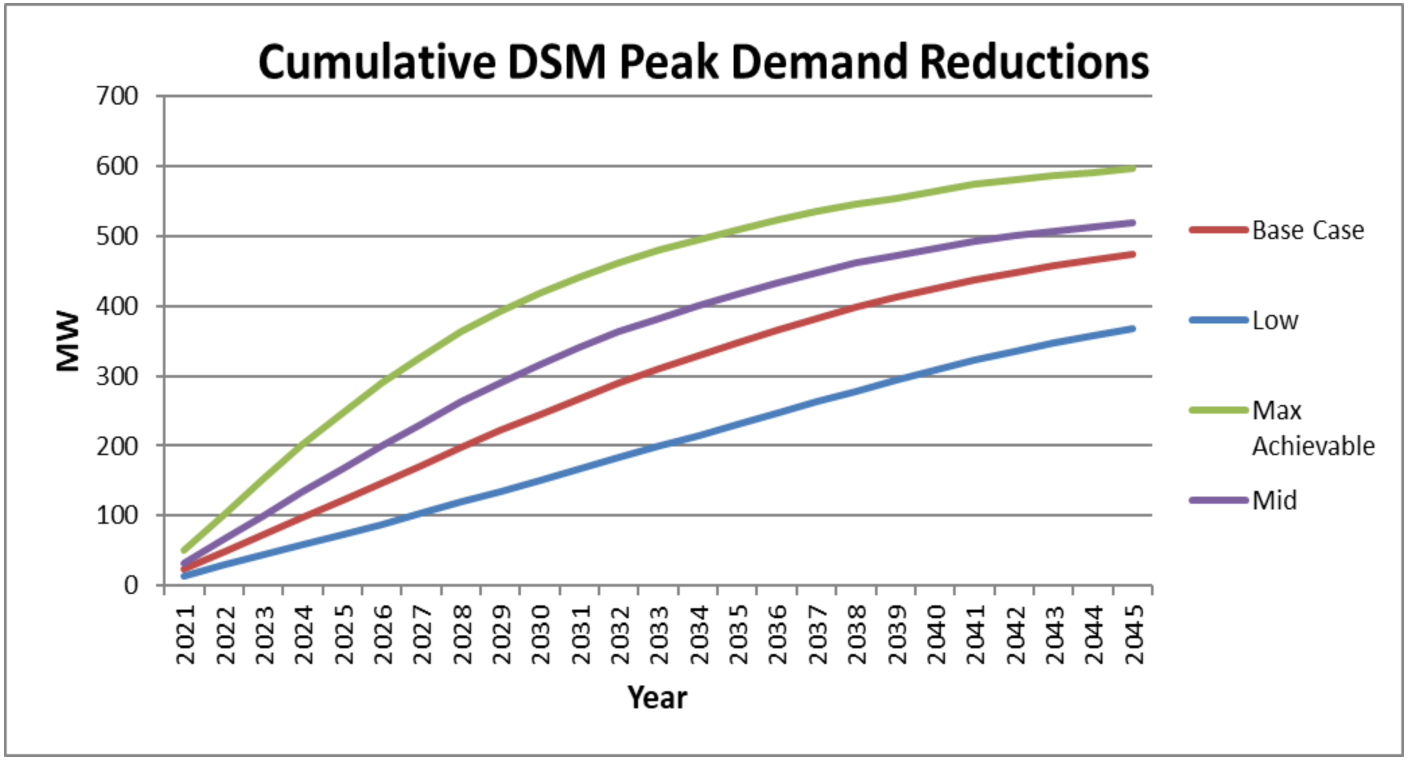
*Data Provided byE1 in 2019 Potential Study

*ENERGY EFFICIENCY (EE)



*Data Provided by E1 in 2019 Potential Study

*DSM PEAK REDUCTION



*Data Provided by E1 in 2019 Potential Study

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2020 IRP:
DEMAND RESPONSE

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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

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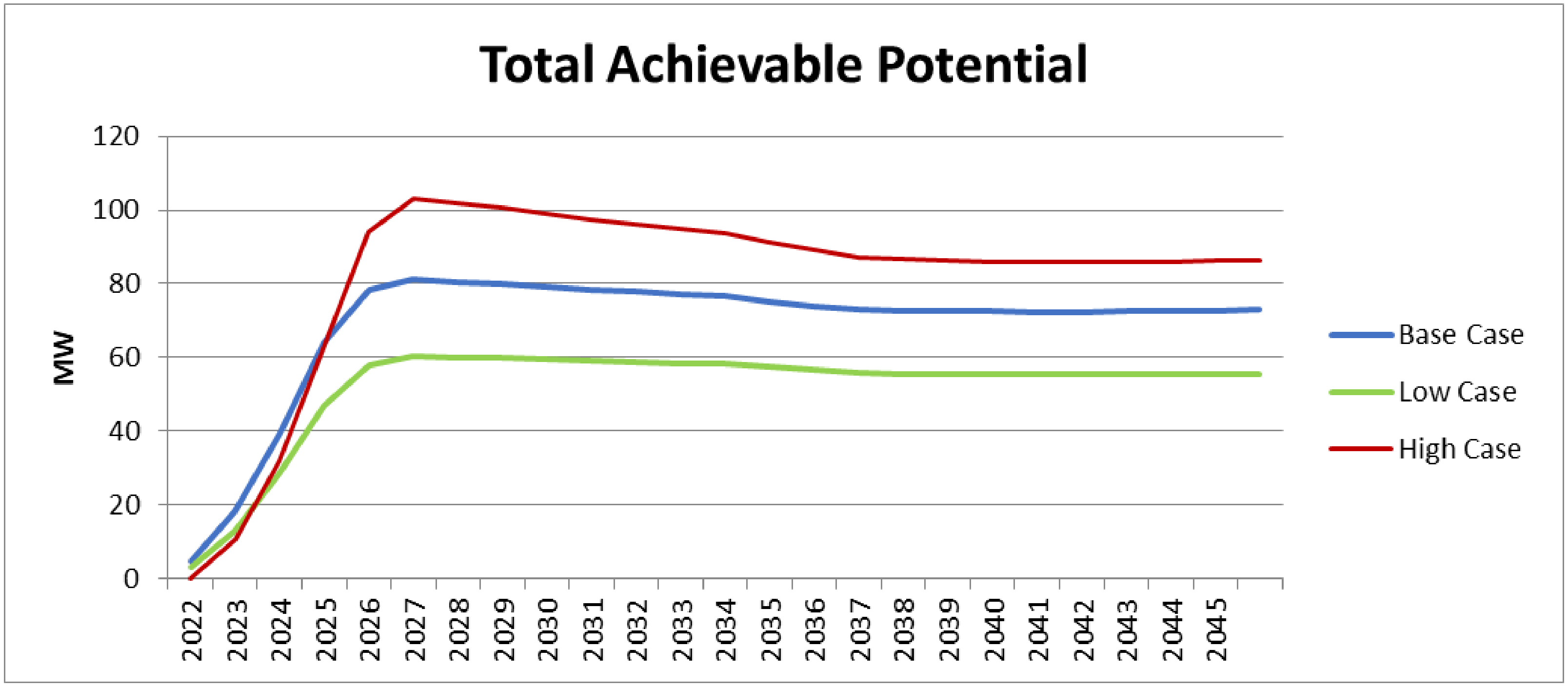
*Data and further details can be found in the E1 in 2019 Potential Study

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

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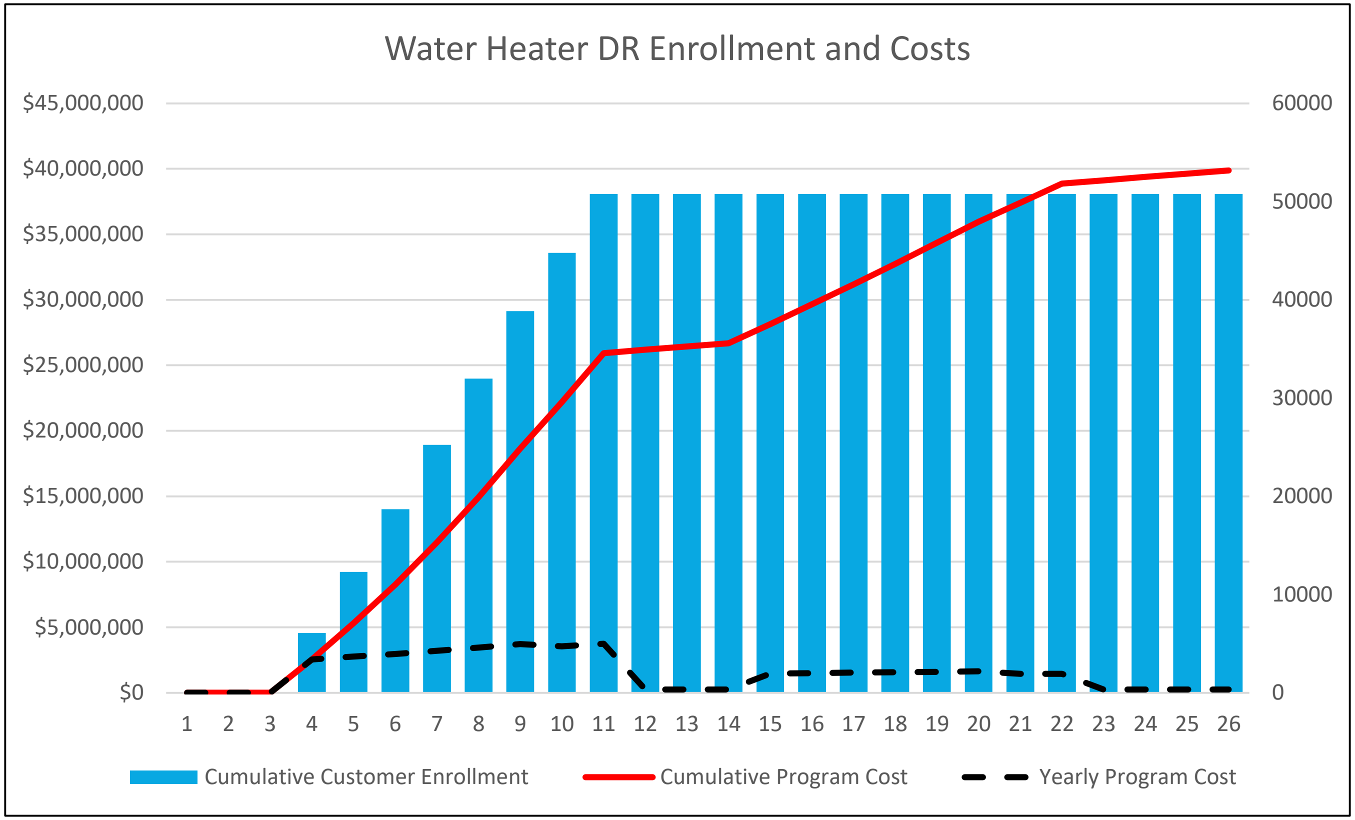
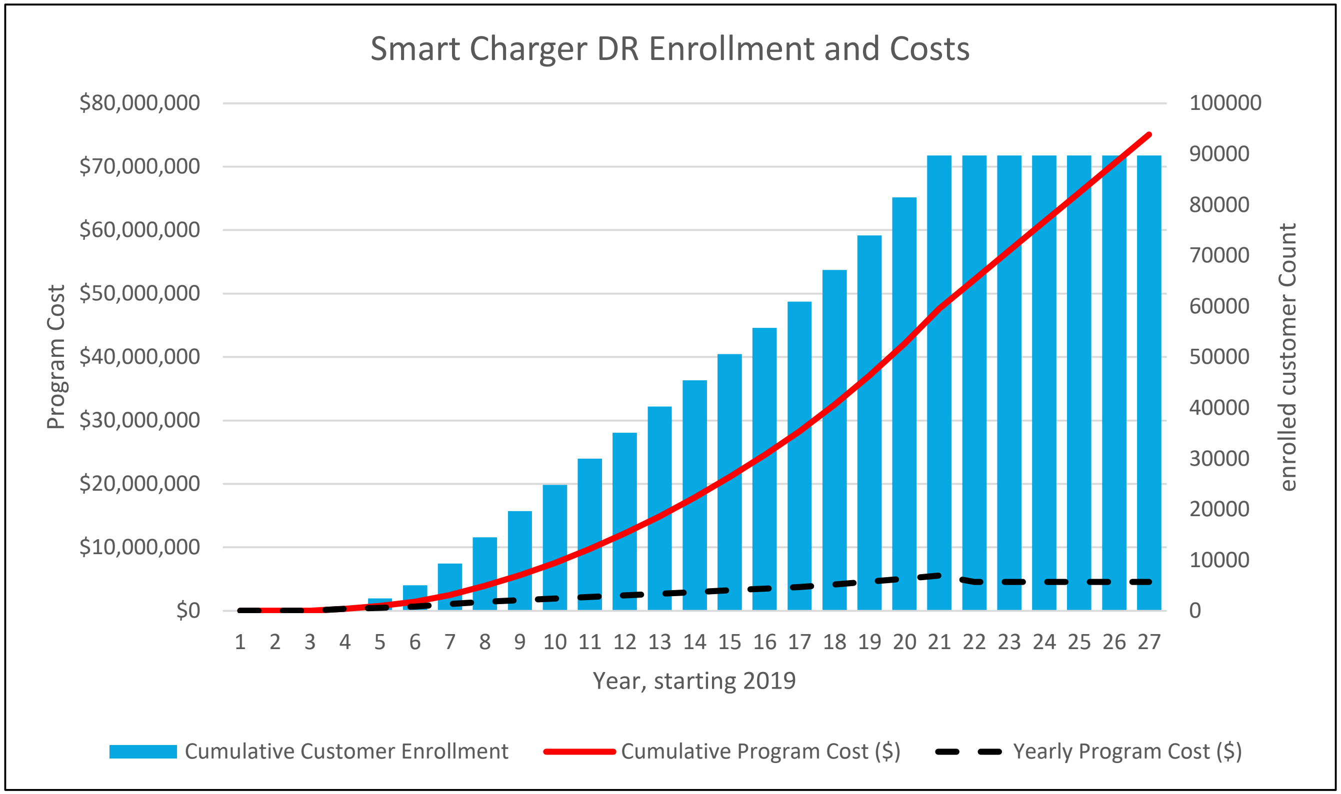
DR OPTIONS SUMMARY (NS POWER) CONT.



DR OPTIONS SUMMARY (NS POWER) CONT.



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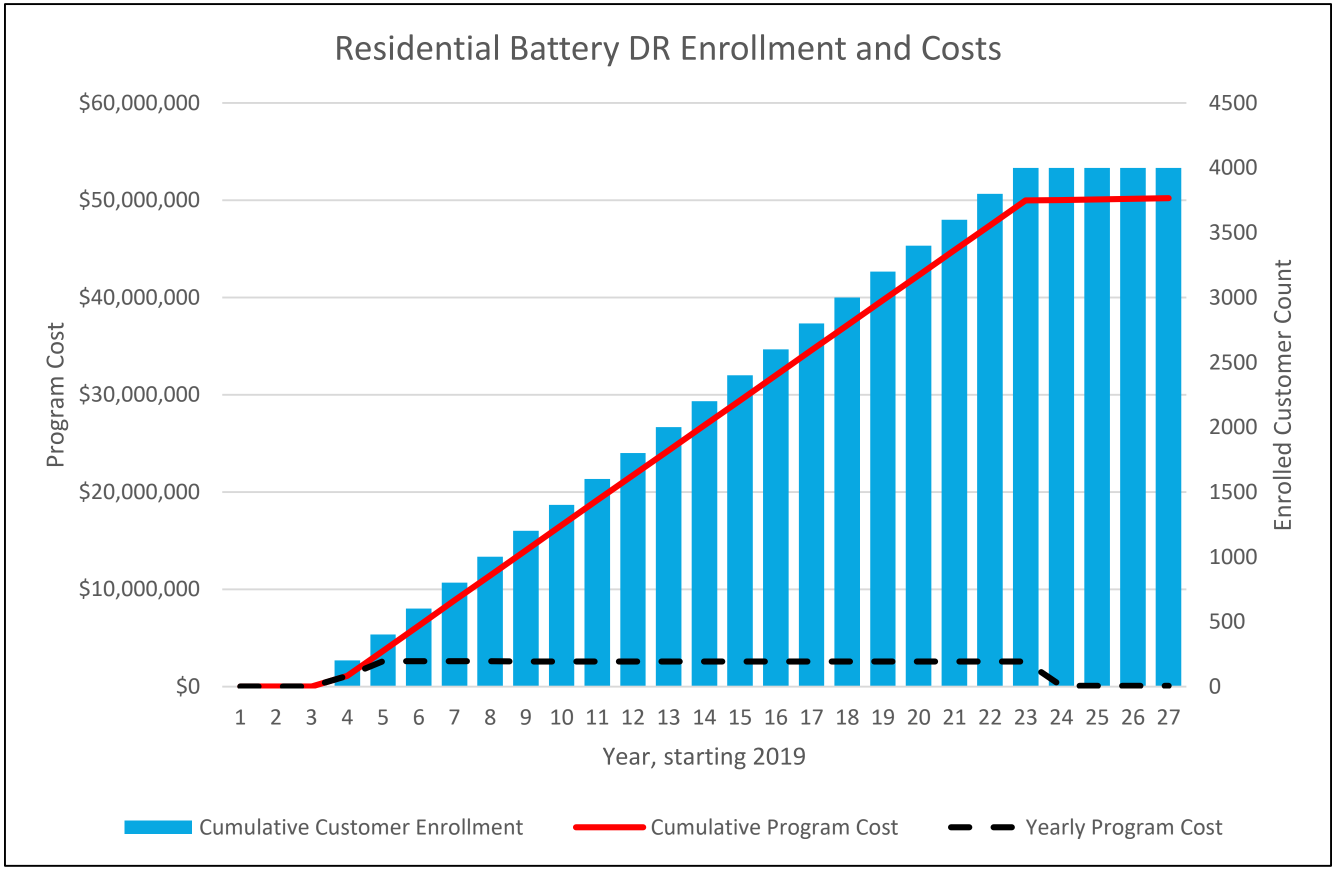
DR OPTIONS SUMMARY (NS POWER) CONT.



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.

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

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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 (LNG) TTF, Spot (International Natural Gas) JKM (Asian Natural Gas)	S&P Global Platts' Analytics (formerly PIRA Energy Group) Scenario Planning Service Quarterly Update	Q4 2019
	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

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

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

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

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SUSTAINING CAPITAL FORECAST – COAL UNITS

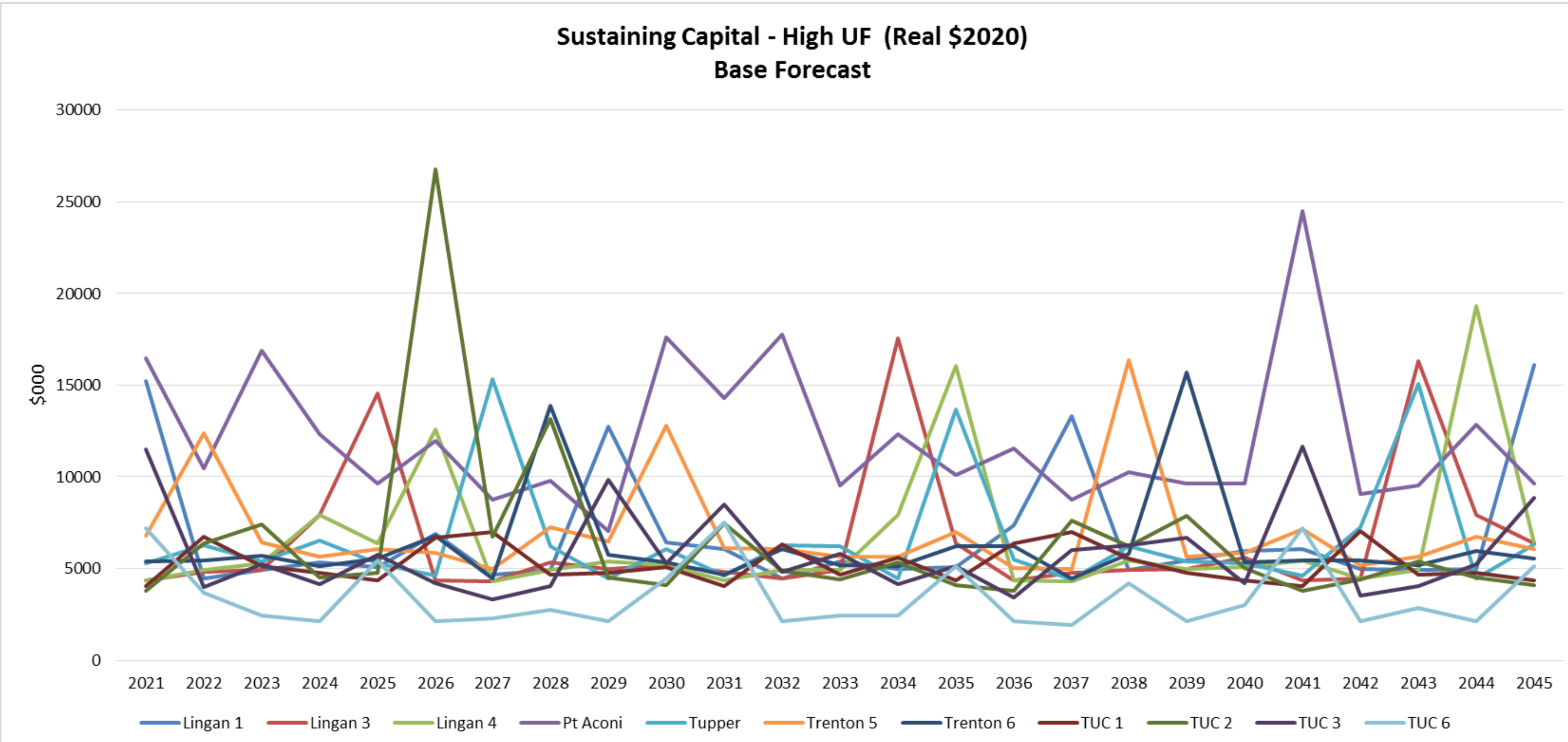
- The sustaining capital cost Base forecast assumes a high utilization factor (UF) for all thermal units, which will represent the forecast investment required to address wear on components driven by a high capacity factor, cycling, operating hours, flexible use, or a combination thereof (i.e. the uses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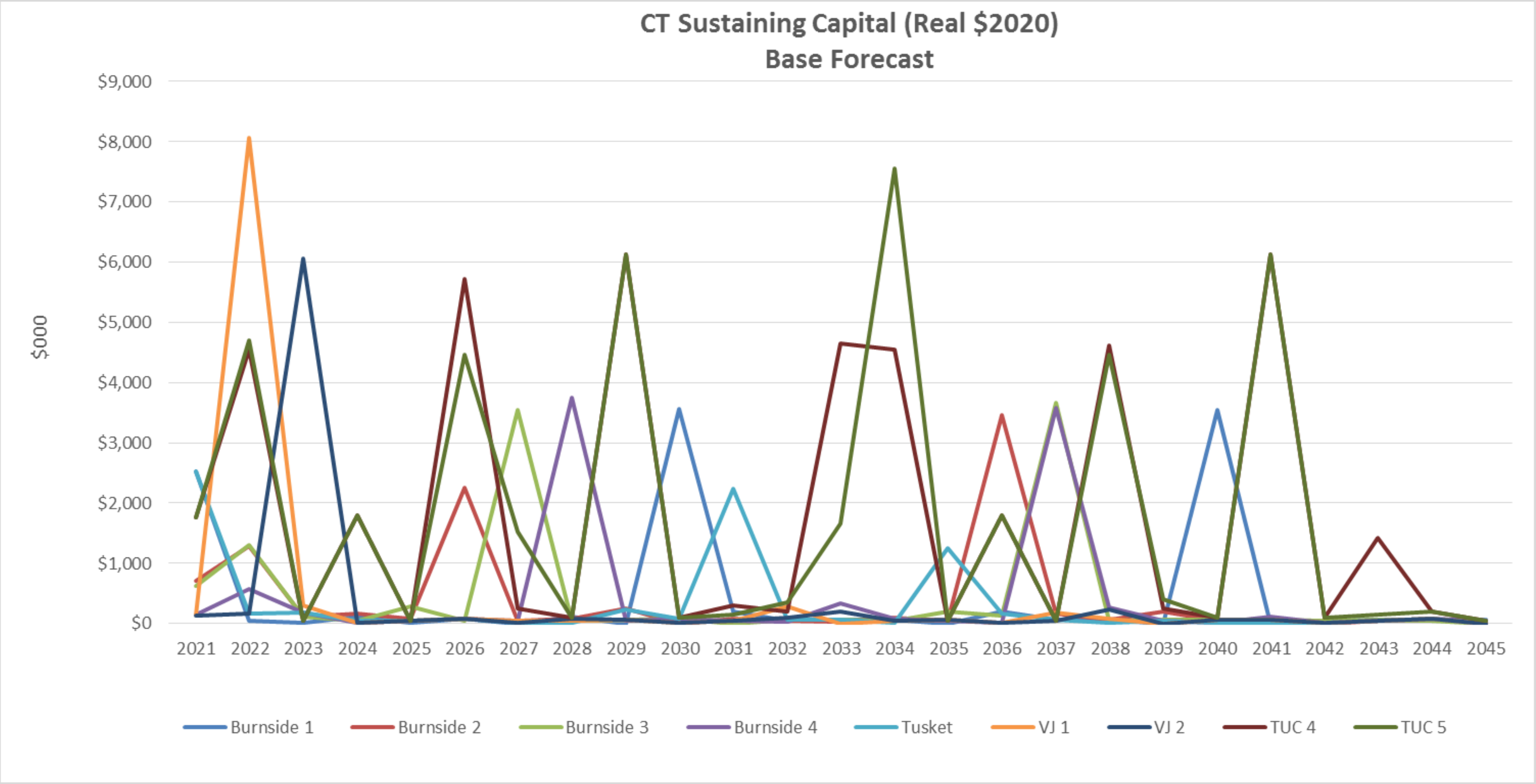
SUSTAINING CAPITAL FORECAST – CTs



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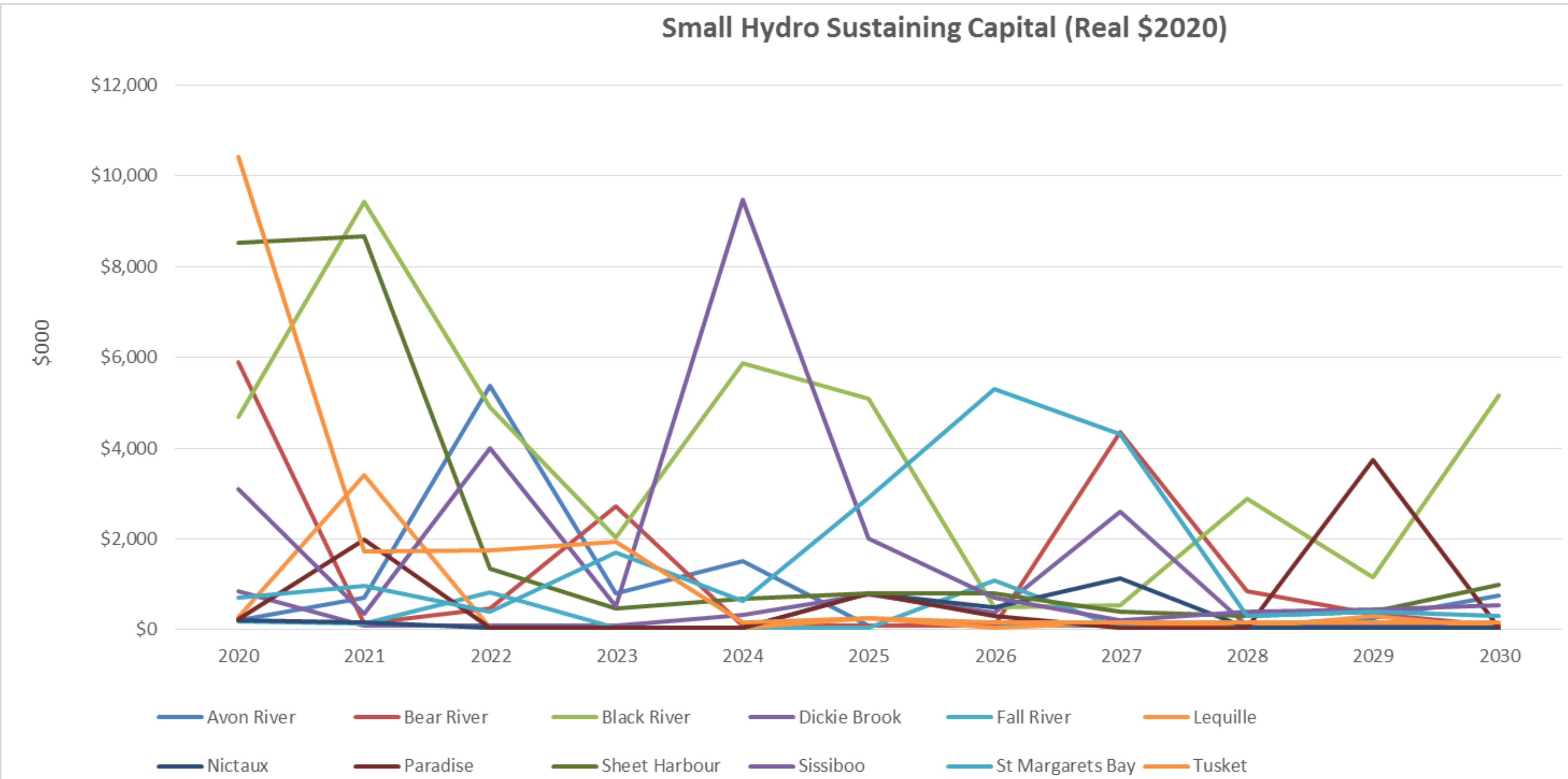
SUSTAINING CAPITAL FORECAST – SMALL HYDRO

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



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
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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

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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