Nova Scotia Power Inc. Thermal Generation Utilization and Optimization

Economic Analysis of Retention of Fossil-Fueled Thermal Fleet To and Beyond 2030 – M08059

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EXECUTIVE SUMMARY

Purpose

The purpose of the Generation Optimization and Utilization study is to determine the extent to which it is cost-effective to ratepayers to retain Nova Scotia Power Inc.'s (NSPI) thermal (steam) fleet through, and possibly beyond, 2030.

The thermal fleet consists of the Tufts Cove oil and gas fired units 1 through 6 and the remaining seven coal-fired units anticipated in service after retirement of the Lingan 2 unit. Lingan 2 retirement is slated to occur after the Nova Scotia Block, delivered via the Maritime Link, is in service; this is currently estimated to occur midway through 2020.

Methodology

Synapse utilized the Plexos modeling environment to conduct both "capacity expansion" long-term (LT) resource planning analysis and short-term (ST) production cost modeling (unit commitment and dispatch for each year), sequentially implemented within the model's structure for each scenario. This allows for a mathematical optimization (within each scenario) that is intended to capture the longer-term economic effects of resource build and retirement decisions. This optimization is subject to core inputs associated with resource build costs and production costs (including fixed, variable, and fuel). It is also subject to key constraints such as the Province's declining power sector emissions schedule and underlying power system technical constraints (primarily, transmission and operating reserves criteria).

Modeling Plan and Input Assumptions

Synapse developed a modeling plan and a set of input assumptions, based primarily on our understanding of the overall set of technical and economic issues that frame the utilization of NSPI's thermal resource fleet and informed by stakeholder input. We structured a set of scenarios to reflect different possible conditions associated with the following parameters: (i) peak load and annual energy consumption; (ii) the level of capacity credit assigned to wind resources; (iii) whether expanded transmission to New Brunswick (seemingly a requirement to significantly expand wind resource development in Nova Scotia) could be in place; and (iv) sustaining capital expenditure estimates for the thermal fleet. We also defined early (next decade) coal plant retirement scenarios to bookend our analysis, serving as a gauge for the range of costs that could be expected if such a more aggressive resource transformation approach was considered for the electric power sector.

Input assumption development was based on existing information available for fuel costs, new resource construction costs, real cost decline trajectories for newer technologies (e.g., bulk battery storage; wind and solar PV), and NSPI's load forecast.

Major Findings

The results of our analyses indicate the following specific major findings:

- The net present value of wholesale[1] system revenue requirements (NPVRR, 2018-2042 period) across the modeled scenarios is clearly seen to be lowest for scenarios incorporating moderate ("medium") levels of demand-side management (DSM), reflecting an increase to existing efforts up to a level eventually (within 4 years, as modeled) reaching incremental annual energy efficiency achievements equal to 2 percent of NSPI's retail sales. This occurs even when using first-year costs of incremental saved energy that is on the order of twice as expensive (per unit) as the efficiency savings Efficiency One currently procures.

- Scenario 8 (medium DSM with 20 percent wind capacity credit), scenario 14 (medium DSM, New Brunswick transmission, 600 MW additional wind, and NSPI reference wind capacity credit) and scenario 17 (medium DSM, 600 MW additional wind, New Brunswick transmission, and 20 percent wind capacity credit) exhibit the lowest costs of all planning scenarios tested, with NPVRR ranging from 5.2 to 5.5 percent lower cost than the reference scenario. <u>All</u> other scenarios (except scenario 4—reference load and high sustaining capital costs) exhibit lower NPVRR costs than the reference scenario. This result illustrates the value of wind and energy efficiency resources in comparison to gas, oil, and import energy, which in general are otherwise the marginal energy sources.

- All scenarios utilizing a load forecast that reflects medium DSM levels signal the retirement of a second coal unit by 2033 at the latest (scenario 5). Scenarios 2, 8, and 17 retire the second coal unit earlier—in 2031, 2027, and 2024, respectively. The effect of increased energy efficiency on the peak load[2] and the resulting planning reserve requirement is significant. Energy efficiency alone decreases the planning reserve requirement 157 MW by 2029, without accounting for any other parameters. As noted, scenario 17—which includes medium DSM but also assumes greater wind builds, a higher wind capacity credit, and new transmission to New Brunswick—indicates a second coal unit retirement in 2024.

- Retention of the thermal fleet (all coal units except Lingan 2 and the Tufts Cove units) is indicated through 2030 under scenario 1's parameters, which included: Load levels from NSPI's 2017 load forecast and 2017 sustaining capital forecast; NSPI's indicated wind capacity crediting structure; and an assumption that no more than 100 MW of additional wind is feasible on NSPI's system. (To maximize economic benefits, Plexos selects more wind than this in all scenarios). However, as noted, all other scenarios demonstrate lower NPVRR costs than this reference case, illustrating the critical

[1] In this context, "wholesale" implies supply and energy-efficiency resource requirements to meet overall energy and peak demand. It includes some new transmission, new generation, new DSM, and the operational costs of all existing resources and net purchase requirements, plus the fixed costs of the Maritime Link. It excludes existing transmission and distribution system costs and "downstream" retail service related costs.

[2] To the extent that peak load reductions of similar magnitude could arise from demand response opportunities instead of energy efficiency effects, we would expect similar 2nd coal unit retirement indications by 2030. This was noted during the technical conference.

importance of looking at alternative resources—peak load reduction through energy efficiency and incremental wind, in these instances—when considering whether, or when, to designate the next coal unit for retirement.

Notably, this result also indicates a need to construct a new combined cycle (CC) unit in 2023, even though its utilization as an energy resource remains relatively low through 2030. This outcome reflects the economic foresight explicitly incorporated into the capacity expansion algorithm in the Plexos modeling platform. There is no CC unit built in any of the medium DSM scenarios without forced coal retirements (scenario 26 does include a CC unit build). This is reflective of lower peak load and planning reserve requirements in these scenarios.[3] For the reference Scenario 1, two additional coal unit retirements are indicated over the following decade (in 2033 and 2038), along with new battery and combustion turbine builds.

- Using the reference scenario loads while modifying other parameters leads to a second coal unit retirement in the next decade in two of the four scenarios (scenario 4 and scenario 16). This reflects the effect of either high sustaining capital costs or increased wind installations and wind capacity crediting in the Plexos retirement decision.

- The presence of fossil-fleet emission constraints drives down the energy utilization (as registered by annual capacity factor) of the coal fleet in all scenarios, a reasonably expected outcome. Under these constraints, Plexos first incorporated any additional wind energy "allowed" in the scenario and accounted for the effect of DSM in the medium DSM scenarios. The constraints ultimately lead to an increasing dependence on gas and oil-sourced replacement energy (from Tufts Cove and from new CT or CC units) and Surplus Energy imports from the Maritime Link. Coal fleet retention reflects the ongoing need to ensure firm capacity resources to meet current planning reserve margin requirement. The value of such retention under reference assumptions is clear. As noted, though, those reference assumptions do not lead to the lowest-cost outcome, reinforcing the importance of carefully examining alternative resource scenarios that incorporate higher levels of peak load reduction and/or wind energy, as feasible.

Coupled with this emission-constraint-driven outcome, however, is the economic selection of additional wind resources in all scenarios to the maximum extent allowed in our Plexos setup—up to an incremental 600 MW for scenarios with New Brunswick transmission. And, the lowest NPVRR outcomes (scenarios 14 and 17) reflect higher levels of wind on Nova Scotia's system. This result illustrates how imperative it is to assess system requirements and determine the specific mechanisms and costs associated with continuing to increase the level of wind generation capable of connection to and operation on NSPI's system. Absent this energy, the emission constraints effectively demand utilization of fossil energy more expensive than coal (oil and gas) or surplus import energy. Comparing the NPVRR results between specific scenarios provides a rough measure of the range of economic headroom—i.e, the overall NPVRR savings—available to "cover" the costs of incremental transmission system upgrades beyond those directly associated with a 2nd transmission tie to New Brunswick. These upgrades include inertia/stability support and dynamic reactive support requirements or other grid-flexibility-

[3] Excepting Scenario 2, which builds a new CC unit in 2042, but along with retirement of a third coal unit.

enhancing investment. As seen in Table 9a, that range of costs is $90 million to $570 million (NPV).[4] The illustrative comparisons are between scenario 1 and scenario 13 or scenario 16 and between scenario 2 and scenario 14 or 17.

- Low battery cost sensitivity results for scenario 1 and 13 (reference case load) show earlier-year second coal unit retirement (2019). They also show additional battery build and a 100 MW CT build (for scenario 1). Low battery cost sensitivity results for scenario 8 (medium DSM load) show a 2027 second coal unit retirement, the same as in the base scenario 8. In those two sensitivity cases (1 and 8), and in scenario 4, Plexos retires a second coal unit immediately in 2019, simultaneous with a 100 MW battery build. This illustrates the critical role of projected battery cost in build/retirement decisions. Sensitivities using low battery costs changed the build and retirement optimization within the two reference load scenarios tested (1 and 13). In scenario 8, lower peak loads resulted in no earlier year battery build and no earlier-year retirement, although the second unit is still retired within the decade. These results demonstrate the importance of carefully analyzing battery system costs and performance, since battery energy storage systems can replace the increasingly peaking nature of the energy provided by the least cost-effective of the coal fleet resources.

- The bookend scenarios (25, 26) with accelerated coal plant retirement both show lower NPVRR than the reference case. Scenario 25 (reference load) is 0.3 percent lower cost than the reference scenario. Scenario 26 reflects higher NPVRR than its comparative scenario 2 (2.3 pecent), demonstrating the higher marginal value of energy efficiency resources, as the retirement path bookend is not as attractive as the retirement path bookend absent the medium DSM resource. The NPVRR cost differences are very small across this 25-year planning period. That the Plexos optimization engine did not retire the coal units *en masse* on its own demonstrates that there may be soft-constraint violations in these scenario 25 and 26 results.[5] However, they do pointedly show that alternative resource scenarios, including accelerated retirement of (at least) part of the coal-fired fleet (with attendant fixed cost and sustaining capital cost savings) is a potential economic alternative or at least reflects costs that are likely within the “noise” of a planning modeling exercise.[6]

- Gas price sensitivity results do not change the overall pattern of build/retirements significantly and do not change the essence of the observations we make in the above points. We do note two additional observations:

  Under the low gas price sensitivity, Scenario 13 (high wind, but with reference level capacity crediting) is more expensive (+ 2.3 percent NPVRR) under the low gas scenario 1. For base level

[4] $90 million is the difference between the NPVRR for scenario 17 and scenario 2. $570 million is the difference between the NPVRR for scenario 16 and scenario 1.

[5] Soft constraints effectively penalize violations of certain criteria such as operating reserve violations. We note that all results indicate no “unserved energy”—all load requirements are met.

[6] We note that this result is different than the Draft Report illustrated for NPVRR. This was due to an inadvertent double-counting of new wind costs in the draft report analysis, which has since been corrected. See section 4 for further explanation.

gas prices, that scenario was less expensive than the reference case (- 2.3 percent). However, under the high gas price sensitivity, Scenario 13 is even less costly than the high gas scenario 1 on an NPVRR basis (-5.2 percent).

Under the low gas price sensitivity, Scenario 2 (medium DSM load) builds a new CC unit in 2022 and retires a Lingan unit in 2028. Scenario 2 base level gas prices did not retire a second unit until 2031 and did not build a new CC until 2042, concurrent with retirement of a third coal unit. Also, under low gas prices and high sustaining capital costs (Scenario 4LG), Plexos does not retire a second unit and build a new battery and CT resource early in the period (as in Scenario 4), but instead builds a CC resource and retains the second coal unit.

These sensitivities illustrate the marginal nature of the resource build and retirement decisions in Plexos, indicating the sensitivity of “optimal” results to input assumptions that come with some uncertainty.

1. INTRODUCTION

1.1. Purpose

The purpose of the Generation Optimization and Utilization study is to determine the extent to which it is cost-effective to ratepayers to retain Nova Scotia Power Inc.'s (NSPI) thermal (steam) fleet through, and possibly beyond, 2030.

The thermal fleet consists of the Tufts Cove oil and gas fired units 1 through 6 and the seven remaining coal-fired units[10] anticipated in service after retirement of the Lingan 2 unit. Lingan 2 retirement is slated to occur after the Nova Scotia Block, delivered via the Maritime Link, is in service. This is currently estimated to occur midway through 2020.[11]

1.2. Terms of Reference

The Terms of Reference for the Study included the following objective:

> The main objective of the analysis will be to determine the extent to which it is cost-effective to ratepayers to retain NSPI's thermal fleet[12] through 2030, and possibly beyond. Critically, this will require comparison of the costs of retention of the thermal fleet to alternative options. Alternative options will include some mix of thermal unit retirement (i.e., less than full retention of the fleet), capacity utilization and energy provision from the remaining portion of the thermal fleet, and capacity and energy supply (or avoidance of supply) from replacement resources (i.e., demand-side and supply side options). The analysis will strive to address all reasonable alternatives, including those that require transmission system reinforcement and/or expansion. The analysis will assess the sensitivity of the results to input assumptions that will exhibit different degrees of uncertainty. [August 1, 2017 Terms of Reference]

The Terms of Reference document was circulated to stakeholders in July 2017; in response to stakeholder comments, a revised and finalized version was circulated on August 1, 2017. The primary change made based on stakeholder comments was to include additional rounds for stakeholder responses to the input assumptions and to the initial modeling results. Appendix 5.1 contains the final Terms of Reference.

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[10] Lingan 1, 3 and 4; Point Aconi; Point Tupper; and Trenton 5 and 6. These units can also burn petcoke and heavy fuel oil.

[11] We understand the NS Block is estimated to commence on July 1, 2020.

[12] Reference case assumptions will likely include presumed retirement of one Lingan unit in or around 2020, commensurate with the availability of the Nova Scotia Block via the Maritime Link.

1.3. Overview of Study

The background for undertaking the Generation Optimization and Utilization study includes NSPI's 2014 Integrated Resource Plan (IRP) efforts, recent versions (2016, 2017) of NSPI's 10-Year System Outlook Reports, including reporting on the 2014 IRP Action Plan, and discussion at and following the April 2017 technical conference on the 2016 10-Year System Outlook plan. Given NSPI's aging thermal fleet and provincial regulations that require declining emissions from the electric power sector, the Nova Scotia Utility and Review Board charged Synapse Energy Economics (Synapse) with undertaking a modeling exercise to shed light on the overall economic implications of continued reliance on the existing thermal fleet to meet electric load requirements.

Based on the Terms of Reference and the overall purpose of the study, Synapse licensed the Plexos modeling tool, requested and received data from NSPI, developed a modeling plan, defined input assumptions, and proceeded to model the array of scenarios (plus some limited sensitivities). Scenarios were set out in the final Modeling Plan and Input Assumptions memo of October 16, 2017 and clarified in the Response to Stakeholders memo of December 29, 2017.[13]

Synapse developed a spreadsheet tool to collect the outputs of the Plexos modeling. These outputs were used as part of a construction of a revenue requirements proxy metric, as a means to understand the economic impacts of various going-forward electric system scenarios.

[13] Synapse memo, "Response to Stakeholder Comments on Key Input Assumptions and Modeling Plan for Plexos Optimization Analysis," December 29, 2017. Attached as Appendix 5.3.

2. MODELING PLAN AND INPUT ASSUMPTIONS

Synapse developed the modeling and input assumptions during the summer/fall of 2017. After reviewing stakeholder comments, Synapse described the final plan and assumptions in a memo dated October 16, 2017. Additional updates to these assumptions, also based on stakeholder comments, were provided in December 2017 memo. The key aspects are described below.

2.1. Modeling Methodology

Plexos

Synapse used the PLEXOS Integrated Energy Model (Plexos) to simulate various scenarios representing different energy futures for Nova Scotia. The Plexos model conducts (1) long-term (LT) capacity expansion resource planning analysis, simultaneously building new resources and retiring existing resources under its cost minimization algorithm, and (2) short-term (ST) production cost modeling with unit commitment and dispatch for each year, sequentially conducted with the LT expansion followed by ST production cost. In the LT module, the Plexos optimization captures the longer-term economic effects of resource build and retirement decisions, subject to the following:

1. Assumptions about capital and production costs—including fixed, variable, and fuel—for various new build resources offered to the model;
2. System constraints, such as the Nova Scotia's declining power sector emissions limits; and
3. System technical constraints, such as transmission and operating reserves criteria.

The LT module produces a single "optimal" plan for NSPI that includes new resource builds and existing resource retirements. Plexos then executes the ST module to simulate unit commitment and economic dispatch to meet load requirements in the region. The ST module considers Maritime Link contractual quantities (NS Block and Supplemental Energy) and allows for both Maritime Link Surplus Energy to be available for purchase and for incremental non-firm imports (and exports) to New Brunswick.

Synapse developed a modeling plan and a set of input assumptions based on our understanding of the technical and economic issues that frame the utilization of NSPI's thermal resource fleet and informed by stakeholder feedback. NSPI provided a Plexos database that it had created to conduct LT optimization planning, which, when combined with updated fuel cost information from November 2017, formed the basis for the Reference Case (Scenario 1). The most significant change to NSPI's dataset was that we included the Company's estimates of sustaining capital for its thermal units as an annual per unit fixed operating and maintenance (FO&M) charge, with costs expected to continue in a repeating pattern beyond the 10-year period for which NSPI provided data. Available new capacity included one 253 megawatt (MW) natural gas combined cycle (NGCC) unit (available in 2022), one combustion turbine (CT) unit (100 MW, available in 2021), one wind unit (101.2 MW, available in 2020), up to 200 MW of solar beginning in 2020, and up to 200 MW of battery storage beginning in 2018. For scenarios assuming completion of a second 345 kilovolt (kV) tie to New Brunswick, up to 500 MW of additional wind (600 MW total) was made available to Plexos. Plexos was able to retire NSPI's coal units, subject to the steam constraints that were initially present in NSPI's database.[14] Synapse set the Plexos model to maintain a 20 percent reserve margin in all years when making build/retire decisions, in accordance with Northeast Power Coordinating Council (NPCC) reliability criteria.

Additional modeling scenarios were designed to reflect different possible conditions associated with the following parameters: (1) peak load and annual energy consumption; (2) the level of capacity credit assigned to wind resources; (3) whether expanded transmission to New Brunswick (seemingly a requirement to significantly expand wind resource development in Nova Scotia) could be in place; (4) sustaining capital expenditure estimates for the thermal fleet, (5) sensitivity to lower capital costs for battery storage resources, and (6) sensitivity to low and high gas prices.

We also defined early coal plant retirement scenarios to bookend our analysis, which examines retirement of four additional steam units between 2018 and 2025. These scenarios are intended to demonstrate the range of costs that could be expected if such a faster and more aggressive approach to coal retirements was considered for NSPI's electric power system. Lastly, based on initial results that indicated very low annual utilization of the Tufts Cove 3 and Trenton 5 units by the mid-2020s, we conducted three sensitivities forcing the retirement of Tufts Cove 3 (in 2026) and Trenton 5 (in 2030).

More information about the input assumptions is found in Section 2.3 of this report.

Post-Processing

The Plexos model can publish a series of user-selected key data outputs into Excel. To analyze, understand, and compare the various modeled scenarios and sensitivities, it is important to post-process these data outputs for two key reasons: first, to standardize the format of the data to facilitate analysis, and, second, to build a revenue requirement calculation in order to compare the overall net present values of the various scenarios and sensitivities.

As a first step, Synapse takes the raw outputs from Plexos and converts the data into a more readily useful format in Excel. This step is merely an intermediate process that involves no calculations or adjustment to the data; rather, it converts columns of mixed output data into a series of individual, category-specific tables by unit and by year. These tables include firm capacity, generation, and individual cost metrics by unit by year. The transformed but unadjusted data are copied into an output summary comparison sheet.

The second post-processing step occurs entirely within the output summary comparison sheet, relying upon the transformed data for every scenario and sensitivity completed in Plexos. The output summary comparison workbook allows Synapse to compare scenarios across high level results—such as overall

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[14] Plexos is unable to consider retirement of Tufts Cove 1, 2, and 3 due to model limitations that restrict single-unit generators with two mutually exclusive fuels to be part of capacity expansion modeling decisions. Plexos developers plan to resolve this issue in the next version release of the Plexos model. Synapse anticipates—and recommends—that prior to the next IRP process, overall system constraints associated with operation of the Tufts Cove units be given careful consideration, and transmission solutions that could relax existing commitment and operational concerns be evaluated.

capacity and generation, or overall operating costs of the system—as well as more detailed, unit or plant-specific results—such as unit capacity factor as compared to the maximum and minimum for that unit across all different scenarios and sensitivities.

In the output summary comparison workbook, Synapse calculates the annual revenue requirement of each scenario. This calculation includes cost outputs directly from Plexos—fuel costs, variable O&M costs, startup and shutdown costs, and the net cost of interchange—as well as cost streams that are calculated exogenously by Synapse—fixed O&M, sustaining capital costs, new build costs, incremental demand-side management (DSM) costs, New Brunswick transmission costs, and Nova Scotia Maritime Link fixed payments.

Fixed O&M is calculated by multiplying the nameplate capacity by unit with the $/kW-year assumption for each individual unit. Sustaining capital costs are represented by an annualized stream of costs, assuming that ongoing capital costs are recovered as a long-lived capital asset. If a unit is retired in Plexos, we no longer include incremental sustaining capital requirements for that unit, but we do continue to account for annualized costs associated with prior year sustaining capital costs. New build costs are based upon the capital cost trajectories for new combined cycle (CC), CT, wind, and battery energy storage in $/kW. These costs are multiplied by the nameplate capacity built in a given year as well as a cost recovery factor to develop an ongoing stream of annualized capital costs for new builds. Incremental DSM costs are representative of the cost to procure saved energy beyond what is included in the Reference case. Likewise, New Brunswick transmission costs are only included in cases that build out that interconnection, annualizing and splitting the total costs for that connection between New Brunswick and Nova Scotia.

2.2. Modeling Plan

Our modeling plan consists of running Plexos for a set of scenarios and for defined sensitivities. As time allowed, we ran additional sensitivities beyond the main low battery cost and gas price runs. These other sensitivities allowed us to see the capacity expansion, dispatch, and unit commitment results with relaxed steam and transmission constraints for selected changes to CT and CC costs and availability. They also enabled us to test the effect of selected forced retirements of one Tufts Cove unit and one of the Trenton units.

Scenarios

An initial set of 30 scenarios to model was reduced to 12 scenarios for the purpose of developing results to review and discuss at the technical conference. Additional sensitivity or updated scenarios analyses were also conducted to assess the effect of potential lower battery costs, based on the release of the Lazard 3.0 cost of energy storage report; to assess high and low gas prices; to incorporate updated NSPI cost estimates for CC and CT technologies;[15] and to examine the build, retirement, and dispatch response when Plexos steam and transmission constraint parameters are relaxed.[16]

Table 1. Modeling Scenarios

Scen. #	Scenario Name	Load	Sust Capital	Wind CapCredit	NB Trans	HardCode RetirePath
1	Ref	Ref	Ref	Ref	No	No
2	Med DSM	Med DSM	Ref	Ref	No	No
4	Ref/HighSusCap	Ref	High	Ref	No	No
5	Med DSM/HighSusCap	Med DSM	High	Ref	No	No
7	Ref/HighWindCapCredit	Ref	Ref	High	No	No
8	Med DSM/HighWindCapCredit	Med DSM	Ref	High	No	No
13	Ref/NB Trans	Ref	Ref	Ref	Yes	No
14	MedDSM/NB Trans	MedDSM	Ref	Ref	Yes	No
16	Ref/NB Trans/HighWindCapCredit	Ref	Ref	High	Yes	No
17	Med DSM/NB Trans/HighWindCapCredit	Med DSM	Ref	High	Yes	No
Bookends - with Partial Coal Fleet Retirement						
25	Ref/RetirePath1	Ref	Ref	Ref	Yes	Yes
26	Med DSM/RetirePath1	Med DSM	Ref	Ref	Yes	Yes

Note: "RetirePath1" reflects additional forced retirements of coal plants beyond Lingan 2 in 2020/21. It reflects sequential retirement in Plexos of Lingan 4 (2023), Lingan 3 (2024), Lingan 1 (2025), and Trenton 5 (2026).

Sensitivities

We ran four battery cost sensitivities, seven natural gas price sensitivities, three sensitivities forcing out thermal units, three sensitivities modifying the cost and availability of CT/CC units, and nine sensitivities exploring the effect of relaxing steam and transmission constraints in Plexos.

[15] NSPI November 2017 stakeholder comments indicated lower per unit costs for combustion turbines and higher per-unit cost for combined cycle units, compared to the original Plexos setup file.

[16] This last set of sensitivities was run to allow exploration of dispatch, commitment, and capacity expansion efficiency gains under scenarios where the NSPI system would be more "flexible" than is currently the case. This would reflect increased availability of dynamic reactive and system inertial support, mitigation of any significant thermal or voltage-based transmission constraints, and the ability to potentially increase reliance on external system support under contingency situations that might otherwise have negative reliability consequences, such as requiring firm load shed. Relaxation of these modeling constraints could be considered under situations where peak load was lowered, flexible resources such as new batteries or CTs were added, additional transmission system reinforcement was undertaken (voltage and inertial support), a second NB transmission tie was completed, and the Maritime Link was available to provide capacity support beyond current contractual conditions.

Table 2. Modeling Sensitivities

Scen./ Sens. #	Sensitivity Name	Load	Sust Capital	Wind CapCredit	NB Trans	Comment
Low Battery Cost Sensitivities						
1-LB	Ref Low Battery Cost	Ref	Ref	Ref	No	
8-LB	Med DSM High Wind Cap Cred Low Batt Cost	Med DSM	Ref	High	No	
13-LB	Ref NB Trans Low Batt Cost	Ref	Ref	Ref	Yes	
26-LB	Med DSM Retire Path1 Low Batt Cost	Med DSM	Ref	Ref	Yes	
Gas Price Sensitivities						
1-LG	Ref Low Gas	Ref	Ref	Ref	No	
1-HG	Ref High Gas	Ref	Ref	Ref	No	
2-LG	Med DSM Low Gas	Med DSM	Ref	Ref	No	
4-HG	Ref/HighSusCap High Gas	Ref	High	Ref	No	
4-LG	Ref/HighSusCap Low Gas	Ref	High	Ref	No	
13-LG	Ref/NB Trans Low Gas	Ref	Ref	Ref	Yes	
13-HG	Ref/NB Trans High Gas	Ref	Ref	Ref	Yes	
Forced Retirement – Tufts Cove 3 / Trenton 5						
1-FR	Ref RetireTC3	Ref	Ref	Ref	No	
1-FR	Ref RetireTC3 RetireTr5	Ref	Ref	Ref	No	
2-FR	Med DSM RetireTC3 RetireTr5	Med DSM	Ref	Ref	No	
CC/CT Cost or Availability to Model - Updated						
1CCTcst	Ref Changed CT and CC Costs	Ref	Ref	Ref	No	No changes to ref case build until mid-2030s. Minimal NPVRR change.
1CTavail	Ref CT Availability in Plexos	Ref	Ref	Ref	No	
1Combo	Ref Changed Costs and CT Avail	Ref	Ref	Ref	No	
Other						
Relax steam and transmission constraints in Plexos – various scenarios – 9 model runs, combination of no steam constraints and/or no transmission constraints. Exploratory only.						

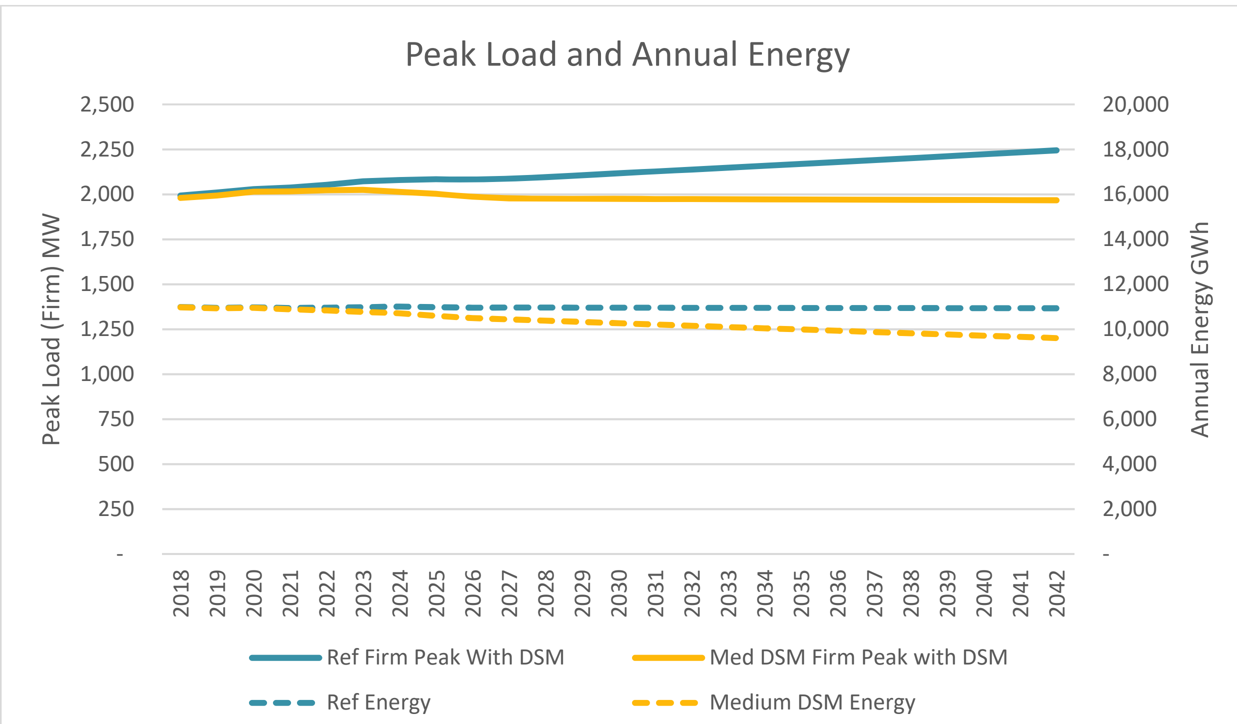
2.3. Input Assumptions

The detailed input assumptions were finalized for the modeling exercise in a memo to stakeholders on October 16, 2017, updated based on stakeholder comments, and revised in a December 29, 2017 memo. The input assumption memo is included as Appendix 5.2, and the stakeholder comment memo is included as Appendix 5.3. The key assumptions used in the modeling are as follows.

Load

Table 3 below lists the projected peak load and annual energy levels for Nova Scotia. The firm peak represents the load level for resource planning—interruptible or non-firm loads are not included when considering new resource requirements. The annual energy listed includes both NSPI native load and non-firm load requirements. DSM contribution to peak reduction is shown. DSM contribution to reduced energy requirements is embedded in the energy projections listed. Reference scenario peak and annual energy are based directly on NSPI's 2017 Load Forecast. Medium DSM levels are estimated based on assumed increased spending and savings targeting by Efficiency One. The current level of DSM savings achievement was assumed to increase to a level equaling roughly 2 percent of NSPI sales, in line with the DSM achievements of the best-performing DSM utilities. As seen, peak load reduction increases are seen to roughly double, after an initial ramping period.

Figure 1. Firm Peak Load and Annual Energy



Source: Table 3.

Table 3. Peak Load, DSM Contribution, and Annual Energy – Reference and Medium DSM Scenarios

	All Scenarios		Reference DSM Scenarios			Medium DSM Scenarios			Annual GWh Energy	
Year	Firm Peak No DSM MW	Inter-ruptible Loads MW	Annual Increm. Peak DSM MW	Peak DSM Cum Total MW	Ref Firm Peak MW	Annual Increm . Peak DSM MW	Peak DSM Cum Total MW	Med DSM Firm Peak MW	Reference DSM Scenarios GWh	Medium DSM Scenarios GWh
2018	2,014	156		21	1,993		34	1,980	10,987	10,977
2019	2,043	156	12	33	2,010	16	50	1,993	10,952	10,935
2020	2,077	155	15	48	2,029	13	63	2,014	10,976	10,951
2021	2,099	155	13	61	2,038	20	82	2,017	10,947	10,888
2022	2,128	155	14	75	2,053	23	106	2,022	10,958	10,839
2023	2,161	154	13	88	2,073	31	136	2,025	10,983	10,773
2024	2,181	154	13	101	2,080	31	167	2,014	11,010	10,712
2025	2,199	154	14	115	2,084	29	196	2,003	10,980	10,598
2026	2,212	153	14	129	2,083	29	225	1,987	10,958	10,500
2027	2,230	153	15	144	2,086	28	253	1,977	10,967	10,442
2028	2,255	153	15	159	2,096	26	279	1,976	10,965	10,385
2029	2,280	153	15	174	2,107	26	304	1,976	10,963	10,327
2030	2,306	153	15	189	2,117	26	331	1,975	10,960	10,270
2031	2,331	153	15	204	2,127	26	357	1,974	10,958	10,213
2032	2,357	153	16	220	2,138	27	384	1,974	10,956	10,157
2033	2,383	153	16	235	2,148	27	411	1,973	10,954	10,100
2034	2,410	153	16	251	2,159	27	438	1,972	10,951	10,045
2035	2,437	153	16	268	2,169	27	465	1,972	10,949	9,989
2036	2,464	153	16	284	2,180	28	493	1,971	10,947	9,934
2037	2,491	153	17	301	2,190	28	521	1,970	10,945	9,879
2038	2,519	153	17	318	2,201	28	549	1,970	10,943	9,824
2039	2,547	153	17	335	2,212	29	578	1,969	10,940	9,770
2040	2,575	153	17	352	2,223	29	607	1,968	10,938	9,716
2041	2,604	153	18	370	2,234	29	636	1,968	10,936	9,662
2042	2,633	153	18	388	2,245	30	666	1,967	10,934	9,608
CAGR	1.1%				0.5%			0.0%	0.0%	-0.6%

Source: Ref: NSPI Reference Forecast, 2017. Med DSM: Synapse estimate of DSM effects to produce Med DSM trends.

Fuel and Market Prices

Gas and coal price projections reflect NSPI's estimates as of November 2017. Oil and New Brunswick and Newfoundland import/export market prices reflect NSPI's estimates as of September 2017. Confidential Appendix 5.6 contains the fuel and market prices.

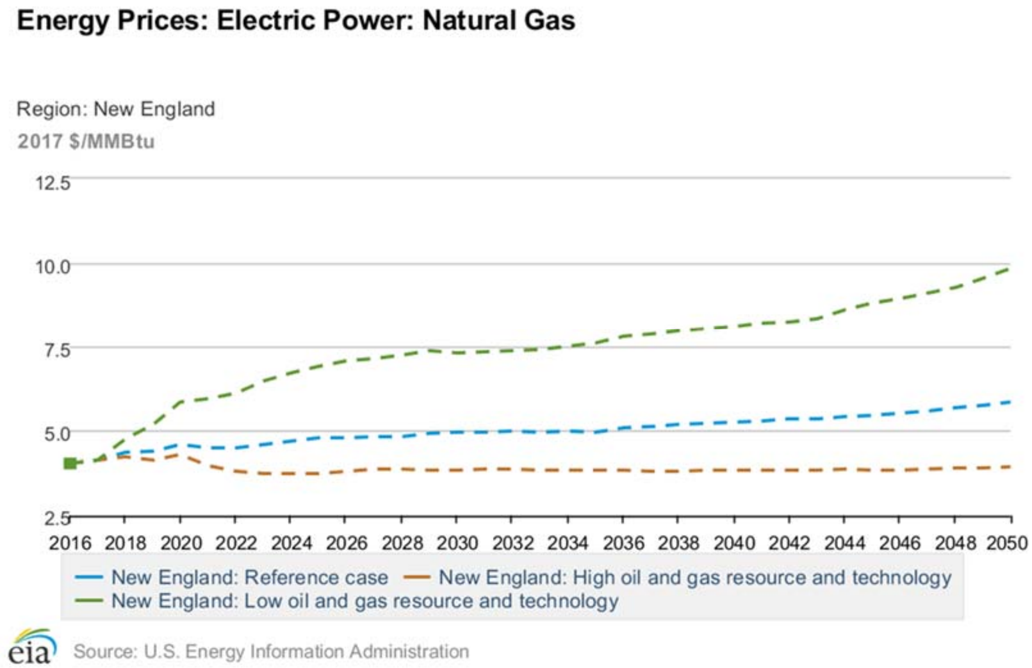
Generally, the cost of import energy from New Brunswick is tied to energy market prices in New England, which are dependent on natural gas market prices. The cost of import energy from Newfoundland—which is, by definition, Maritime Link Surplus Energy—is associated with the market price of energy in New England but excludes New Brunswick transmission tariff effects.

Sensitivity runs were exercised using an estimate for high natural gas price and low natural gas price, based upon information publicly available from the United States Energy Information Administration (U.S. EIA) Annual Energy Outlook (AEO).[17] We modified the direct, monthly (or annual, for the "incremental" gas price)[18] natural gas price forecast series for Nova Scotia using the ratio of reference to high gas price (for the high gas sensitivities) and the ratio of reference to low gas price (for the low gas price sensitivities). The benchmark information used to construct the ratio was the forecast of annual delivered price to electric power sector end users in New England (i.e., New England electric generators) under reference, high natural gas price (i.e., low oil and gas resource and technology), and low natural gas price (i.e., high oil and gas resource and technology) scenarios. Figure 2 shows the forecast series used to construct the price ratios for the sensitivity runs.

[17] U.S. EIA. *Annual Energy Outlook 2018*. Available at https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-AEO2018&region=1-1&cases=ref2018~highrt~lowrt&start=2016&end=2050&f=A&linechart=~~~~ref2018-d121317a.38-3-AEO2018.1-1~highrt-d121317a.38-3-AEO2018.1-1~lowrt-d121317a.38-3-AEO2018.1-1&map=highrt-d121317a.3-3-AEO2018.1-1&ctype=linechart&sourcekey=0.

[18] NSPI, November 2017 stakeholder comment memo.

Figure 2. US EIA 2018 AEO Forecast Reference, High and Low New England Delivered (Electric Power Sector) Natural Gas Prices Used to Develop Ratio for High and Low Gas Price Sensitivity Fuel Price Assumptions



Source: US EIA AEO 2018. *https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-AEO2018&region=1-1&cases=ref2018~highrt~lowrt&start=2016&end=2050&f=A&linechart=~~~~ref2018-d121317a.38-3-AEO2018.1-1~highrt-d121317a.38-3-AEO2018.1-1~lowrt-d121317a.38-3-AEO2018.1-1&map=highrt-d121317a.3-3-AEO2018.1-1&ctype=linechart&sourcekey=0*

Maritime Link Energy

The Maritime Link Nova Scotia Block is assumed in service on July 1, 2020, at annual delivery levels of 895 gigawatt hours (GWh), or 153 MW at 16 hours a day (peak hours), 365 days/year. Supplemental Energy from the Maritime Link is also assumed in service in mid-2020 and is scheduled as winter-period-only (off-peak hours) energy (five months, November through March) totaling 260 GWh per year, for the first five years (July 2020 through June 2025).

Maritime Link Surplus Energy is made available and scheduled by the model according to pricing parameters in line with the Energy Access Agreement. Essentially, as noted, the pricing in the Plexos model assumes a "netback" pricing in Nova Scotia where the energy is priced at the New England Massachusetts hub pricing node, less the costs of transmission and losses through New Brunswick, corrected to Canadian currency values.

New Brunswick Energy and Newfoundland Recall Energy

New Brunswick energy flows are represented through market prices for either import or export opportunistic energy purchase or sale.

Newfoundland recall energy is made available to the model in limited amounts (roughly 500 GWh per year) for just 2018 and 2019. This aligns both with agreements that provide for NSPI's use of the

Maritime Link to flow energy to Newfoundland in winter prior to Muskrat Falls completion, if needed, and with Newfoundland's agreement to allow recall energy to flow to Nova Scotia during non-winter months.[19]

Transmission/Unit Commitment/Reserve Provision Constraints

In response to discovery served on NSPI, Synapse received Plexos setup files that included the key constraints associated with NSPI's transmission system and its steam system constraints that affect unit commitment decisions. While the setup file structure is complex, the essence of the coding is to ensure that Plexos respects the thermal and voltage limits associated with different segments of NSPI's transmission system, such as the major constraints for flow out of Cape Breton and flow into the load centers in the middle portions of the Province. The coding respects NSPI's current need to have some minimum level of generation online to support system needs but also includes reductions that account for the presence of the Maritime Link and its effect on lowering such needs.[20] The Plexos model is structured to ensure that sufficient firm capacity is available to meet NPCC reserve planning requirements, which mandate a 20 percent reserve margin above NSPI's firm winter peak load in all years of the analysis.

Emission Constraints

The applicable emission constraints used directly in the Plexos modeling are as listed in the table below.

Table 4. Emission Constraints as Modeled in Plexos

	CO2 mmT	SO2 kT	NOx kT	Hg Kg		CO2 mmT	SO2 kT	NOx kT	Hg Kg
2018	8.02	60.9	19.2	63	**2031**	4.4	20.0	8.8	30
2019	8.02	60.9	19.2	63	**2032**	4.3	20.0	8.8	30
2020	7.50	36.3	15.0	35	**2033**	4.2	20.0	8.8	30
2021	6.88	34.0	14.0	35	**2034**	4.1	20.0	8.8	30
2022	6.88	34.0	14.0	35	**2035**	3.9	20.0	8.8	25
2023	6.88	34.0	14.0	35	**2036**	3.8	15.0	8.8	25
2024	6.88	34.0	14.0	35	**2037**	3.7	15.0	8.8	25
2025	6.00	28.0	11.5	35	**2038**	3.6	15.0	8.8	25
2026	5.38	26.0	11.0	35	**2039**	3.5	15.0	8.8	25
2027	5.38	26.0	11.0	35	**2040**	3.4	15.0	8.8	25
2028	5.38	26.0	11.0	35	**2041**	3.3	15.0	8.8	25
2029	5.38	26.0	11.0	35	**2042**	3.2	15.0	8.8	25
2030	4.50	20.0	8.8	30					

[19] Maritime Link Interim Cost Assessment M07718.

[20] NSPI, response to discovery request DR-15.

Note: Multi-year constraints have been averaged to reflect a single value for each year. Source: NSPI.

Available Resource New Build Costs

Resources available to the Plexos capacity expansion model included wind, gas CC, gas CT, battery storage, and solar photovoltaics (PV).

The costs for construction of those new resources were included in the Plexos setup files. Those costs are shown in the table below. We accounted for those costs in our revenue requirements modeling by annualizing the costs of any new builds. We created a fixed charge rate based on the economic life of the units, the capital cost (in $2017/kW), and a weighted average cost of capital for NSPI (7 percent). Our modeling results include new build costs by unit and across each scenario.

Table 5. New Build Resource Costs

Resource	2017 Cost, $/kW	Real Cost Escalation	Economic Life	Comments
253 MW Combined Cycle – Gas	$1,580 [$1690]	0	25	Cost in [parentheses] is NSPI updated cost (11/17). Three sensitivity runs conducted using updated costs. No major change in results.
100 MW CT – Gas	$1,315 [$1240]	0	25	
101.2 MW Wind	$2,000 [$2,200]	2%/yr decline, for 10 years	20	First plant available 2020. 2nd through 6th available 2023 first year. NSPI estimated higher initial cost [in parentheses] in November 2017.
20 MW, 4-Hour Storage Battery	$3,750	5%/yr decline, for 15 years	10	No battery build allowed until 2019.
Low Battery Cost Sensitivity	$1,485	0	10	No battery build allowed until 2019.
Solar PV	$2,750	2.5%/year decline for 10 years	20	None built.

Source: NSPI, Synapse assumptions.

Solar PV

The capacity expansion module of Plexos did not build out any solar PV resources. Solar PV resources do not provide capacity credit in the winter-peaking region, unlike wind. It is likely that additional behind-the-meter solar PV will be installed in the Province, and any forecasts of such a build out should be explicitly included in the annual energy forecasts made by NSPI. We also note that smaller-scale storage complementing Nova Scotia solar PV resource output can contribute to reducing winter peak loads. Future IRP resource options could consider separate "coupled" components as a resource option.[21]

Sustaining Capital Costs

Sustaining capital cost estimates for the thermal fleet by unit and by type of component, in $2017 real currency, were provided by NSPI in the 2017 10-Year System Outlook report. NSPI provided the data to Synapse in Excel format. Table 6 contains the sustaining capital cost estimates.

Table 6. Sustaining Capital Cost Estimate – by Unit - $ Millions ($2017 Real)

Unit	Size, MW	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Ten-Yr Total	Ave Per Year/kW
PHBM	43	2.23	2.23	3.95	2.36	2.26	2.62	2.23	2.55	2.36	2.20	25.0	58.1
CTs	231	3.90	3.90	3.90	3.90	3.90	3.90	3.90	3.90	3.90	3.90	39.0	16.9
Lin1	153	2.95	2.98	3.73	3.83	12.59	2.95	2.98	3.08	3.99	2.49	41.6	27.2
Lin2	153	3.79	3.82	5.84	-	0.07	0.16	0.46	0.16	-	0.07	14.4	9.4
Lin3	153	3.79	3.82	3.92	3.37	3.43	11.79	6.10	4.89	3.37	3.30	47.8	31.2
Lin4	153	3.79	3.82	3.92	3.37	3.43	3.79	14.10	4.89	3.37	3.30	47.8	31.2
TC4-5	98	3.47	3.77	3.47	3.25	3.31	3.47	3.81	3.47	3.25	3.31	34.6	35.3
POA	168	5.58	5.12	5.64	9.22	16.92	5.58	7.72	5.64	7.14	4.96	73.5	43.8
POT	150	5.80	8.93	4.08	3.56	4.83	4.15	3.43	4.08	3.56	3.40	45.8	30.6
Tr5	150	4.30	3.03	3.19	3.35	2.66	2.20	2.17	2.50	1.72	1.72	26.8	17.9
Tr6	154	5.92	3.95	4.11	3.59	3.55	3.11	3.08	3.40	3.92	9.57	44.2	28.7
TC1	78	1.68	1.57	1.42	1.31	1.74	5.33	1.60	1.42	1.31	3.62	21.0	27.0
TC2	93	9.20	2.89	2.74	2.63	26.05	3.00	2.91	2.74	2.63	4.87	59.7	64.1
TC3	147	3.13	12.84	3.13	8.53	2.66	3.00	6.91	3.13	2.63	2.53	48.5	33.0
TC6	46	2.38	2.53	2.77	7.77	2.30	2.64	2.55	4.72	2.27	2.17	32.1	69.8
	1,970	61.89	65.22	55.81	60.03	89.71	57.68	63.95	50.58	45.41	51.43	601.7	30.5

Source: NSPI, 2017 10 Year System Outlook Report.

Note: Common costs applied proportionately across units (Synapse).

Annualized Sustaining Capital Costs

Revenue requirements for sustaining capital costs are treated as a stream of costs based on an estimate of capital recovery factor. For the purpose of development proxy revenue requirements, we annualized each year's incremental sustaining capital expenditure using an estimated fixed charge rate of 0.1, which roughly aligns with NSPI's revenue recovery mechanisms for long-lived assets. We accumulated each years' sustaining capital expenditure on a unit-specific basis and only included the incremental charge if

[21] "Solar plus storage" is increasingly seen as a potentially economic alternative resource option, according to the United States National Renewable Energy Laboratory (NREL). See NREL's "Solar Plus: A Holistic Approach to Distributed Solar PV," June 2017, available at https://www.nrel.gov/docs/fy17osti/68371.pdf and "Evaluating the Technical and Economic Performance of PV Plus Storage Power Plants," available at https://www.nrel.gov/docs/fy17osti/68737.pdf.

the unit was still in operation. After retirement, we included earlier year costs as recurring annualized costs. Thus, any retirement of thermal fleet units captured future year sustaining capital expenditure savings. We do note that if revenue recovery for sustaining capital expenditures is accelerated relative to the depreciation treatment usually afforded production assets with long lives, then we have likely underestimated the effect of sustaining capital expenditure savings for coal plant retirement seen throughout the scenarios modeled.

Sustaining capital costs were considered within the Plexos environment as an addition to fixed O&M costs, but as an expense adder and not as an annualized cost stream. To develop the revenue requirement proxy, we directly used the conventional O&M components of cost, and the separately-annualized sustaining capital expenditure stream.

Wind Capacity Credit

The reference case scenarios all use NSPI's default wind capacity credit value of 17 percent for new resources. Existing wind resources use either 17 percent (NRIS) or 0 percent (ERIS); in aggregate, the existing resource base (roughly 584 MW) is modeled with an effective capacity credit of 12.4 percent, based on a weighting of 17 percent for NRIS resources and zero for ERIS resources. For all "high wind capacity credit" scenarios (7, 8, 16, 17) a value of 20 percent is used for the capacity credit for all wind resources.

The differential capacity credits associated with considering all of Nova Scotia's existing wind base at the full NRIS value of 17 percent (instead of the average of 12.4 percent) is roughly 27 MW. If considering all of Nova Scotia's wind at a 20 percent capacity credit, the differential value is 44 MW. Having a wind resource interconnected at ERIS instead of NRIS does not signify that it does not, or cannot, contribute to winter capacity needs at NRIS-levels. This depends on whether or not the limiting factor is local interconnection or bulk system constraints. Under any scenario with increased retirements of Eastern Nova Scotia coal units—presuming the wind plants are (electrically) west of the coal units—the transmission system should be "less limiting." Coal plant retirements open up the opportunity for wind to contribute to winter peak period capacity.

Even prior to considering additional wind addition in Nova Scotia, resolving the question of which capacity credit value to use leads to materially different outcomes. Under any scenario of increased wind resource deployment in Nova Scotia, the accumulating capacity value contribution from wind will have an effect on capacity resource balancing and the planning reserve margin "headroom" available for any given incremental coal unit retirement consideration.

The recent (October 2016) Pan-Canadian GE Wind Integration study includes an aggregate, Maritimes (inclusive of New Brunswick, Nova Scotia, Prince Edward Island, and Newfoundland) wind capacity credit range of 28.2 percent to 31.6 percent for the high penetration scenario (35 percent of annual energy provided by wind, equal to roughly 1,110-1,200 MW of Nova Scotia wind).[22] The study used a NERC-approved, Expected Load Carrying Capability (ELCC) methodology.

The 2013 Nova Scotia GE Wind Integration Study found a range of ELCC values depending on the "wind block" studied, with an aggregate level of roughly 21 percent for a system with 942 MW of wind.[23]

The 2008 Hatch Wind Integration study for the Nova Scotia Department of Energy found that aggregate, modeled capacity factors of high penetrations of wind in Nova Scotia (at the 981 MW level) were greater than 40 percent (42.69 percent) during the "winter 10% highest load hours." While the authors did not explicitly recommend a specific capacity credit value, did not conduct a stochastic analysis, and did caveat their findings (see pages 4-9), the Hatch study nonetheless provides a useful data point for assessing what capacity credit value should be considered for resource adequacy purposes.[24]

New Brunswick Transmission

For the New Brunswick transmission scenarios, Synapse made two adjustments in the modeling structure.

First, the Plexos LT expansion mechanism was enabled to allow increased wind resource buildout. In reference scenarios, no more than one additional wind plant—at 101.2 MW—was allowed to be built, in consideration of expressed limitations on the ability of Nova Scotia to absorb more wind prior to increasing the transmission connection capacity to New Brunswick. In the NB transmission scenarios (13, 14, 16, 17, 25, and 26) up to 607.2 MW of wind could be added to the system, at one-year intervals beginning in 2020 for the first unit. Notably, as discussed in the results section, Plexos always chooses to install as much wind as is made available to the system, generally as soon as possible.

The second change was to include a separate cost stream in the computation of revenue requirements for those scenarios that include the NB transmission option. The cost stream was developed based on an estimated cost of new transmission ($400 million, in $2018); 2 percent inflation; an estimated first year of cost recovery (2022); assumed cost sharing with New Brunswick load of 50 percent, given the benefits accruing to NB from such 345 kV reinforcement; a book life of 30 years, a cost of capital of 7 percent, and a resulting fixed charge rate of 8.06 percent.

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[22] GE. 2016. "Pan Canadian Wind Integration Study." Section 10: Wind Capacity Valuation. Table 10-7: Capacity Value (As Percentage of Nameplate Capacity) By Data Year, Province and Scenario, page 24. Available at https://canwea.ca/wp-content/uploads/2016/07/pcwis-section10-windcapacityvaluation.pdf.

[23] GE. 2013. *Nova Scotia Renewable Energy Integration Study*. Final Report, June 28, 2013. Redacted. See Table 51 and Figure 220. Synapse computation of weighted average capacity credit value based on this table and figure. Available at https://www.nspower.ca/site/media/Parent/2013COSS_CA_DR-14_SUPPLEMENTAL_REISFinalReport_REDACTED.pdf

[24] Hatch. 2008. "Nova Scotia Wind Integration Study." Table 4-3: Capacity Factor of Proposed Levels of Wind Power Integration, page 4-15. Available at https://energy.novascotia.ca/sites/default/files/NS-Wind-Integration-Study-FINAL.pdf.

Coal Plant Retirement Path Bookend

We have executed Plexos modeling scenarios for two "retirement path" modeling bookends to determine the build path, resource use, and overall costs associated with a coal plant retirement path that includes the gradual retirement of five units, over the next eight years. These scenarios serve as bookends to gauge the range of costs that would be incurred if Nova Scotia was to consider a more aggressive thermal plant retirement path than that seen under our reference or Medium DSM case scenario results. Uncertainties associated with Canadian and Nova Scotian government policy on carbon emissions, and other uncertainties (sustaining capital costs; alternative resource cost declines) render these bookend scenarios valuable. At a minimum, they provide a bounding estimate on a more aggressive coal plant retirement policy option.

Sensitivities

We have run additional sensitivities reflecting changes to battery costs (noted in Table 5), changes to natural gas prices, and cost and availability options for CC and CT units (also noted in Table 5). We also ran Plexos runs after "forcing out" Tufts Cove 3 or Tufts Cove 3 combined with Trenton 5 after initial results showed extremely low energy utilization for those units towards the middle of the next decade. Lastly, we ran a series of investigatory sensitivities relaxing steam and/or transmission constraints in the model. This exercise allowed us to gauge the range of potential dispatch and unit commitment efficiency savings under circumstances where the Nova Scotia system is more flexible in response to contingency concerns, has reinforced certain components of its transmission system to allow greater responsiveness to stability and voltage concerns, and/or has increased the transmission capability to or from New Brunswick.

As noted above under the "Fuel and Market Prices" subsection, high and low gas price were developed by using NSPI's reference price as a baseline and adjusting this reference price up or down by a fixed ratio. The adjustment depended on the relative price forecast for reference, high, and low gas prices seen in the U.S. EIA 2018 Annual Energy Outlook for gas delivered to New England electric power generators. This serves as a rough proxy for Nova Scotia gas price movement, given the region's proximity to the New England pipeline system.

3. MODELING RESULTS

3.1. Capacity Balance, Build and Retirement Results

Planning Reserve Requirements – Capacity Resource Balance

Figures 4a through 4c contain the planning reserve margins (PRM) by scenario, key sensitivity, and year. The PRMs provide one high-level measure of the amount of generation capacity relative to the NPCC 20 percent planning reserve margin requirement. PRM is defined as the amount of firm capacity available over the planning peak load. Notably, the NPCC constraint is not the only constraint that dictates how much capacity might be required on the system. Plexos' ability to model hourly dispatch requirements means that any ramping requirements must be met with adequate capacity. Also, the presence of annual emissions constraints combined with the multi-fossil-fuel environment in which the thermal fleet operates (coal, oil, gas) leads to capacity requirements that could exceed thresholds needed to meet either NPCC reserve or ramping requirements. The integrated aspect of the model (long-term planning and short-term dispatch) is intended to allow capture of all these moving parts when optimizing retirement and build decisions.

Table 7 contains the results of the planning reserve margin by scenario and by year.

Plant Optimization - Model Retirements and Builds

The LT module of Plexos is a capacity expansion framework that simultaneously builds new resources and retires existing resources if called for by the overall cost minimization algorithm employed in the model. Table 8a below lists the retirement and the build results for the initial scenarios executed; Table 8b lists the retirement and build results for the low battery cost and fuel price sensitivity runs.

Figure 4a. Planning Reserve Margin Trends by Scenario – Main Scenarios

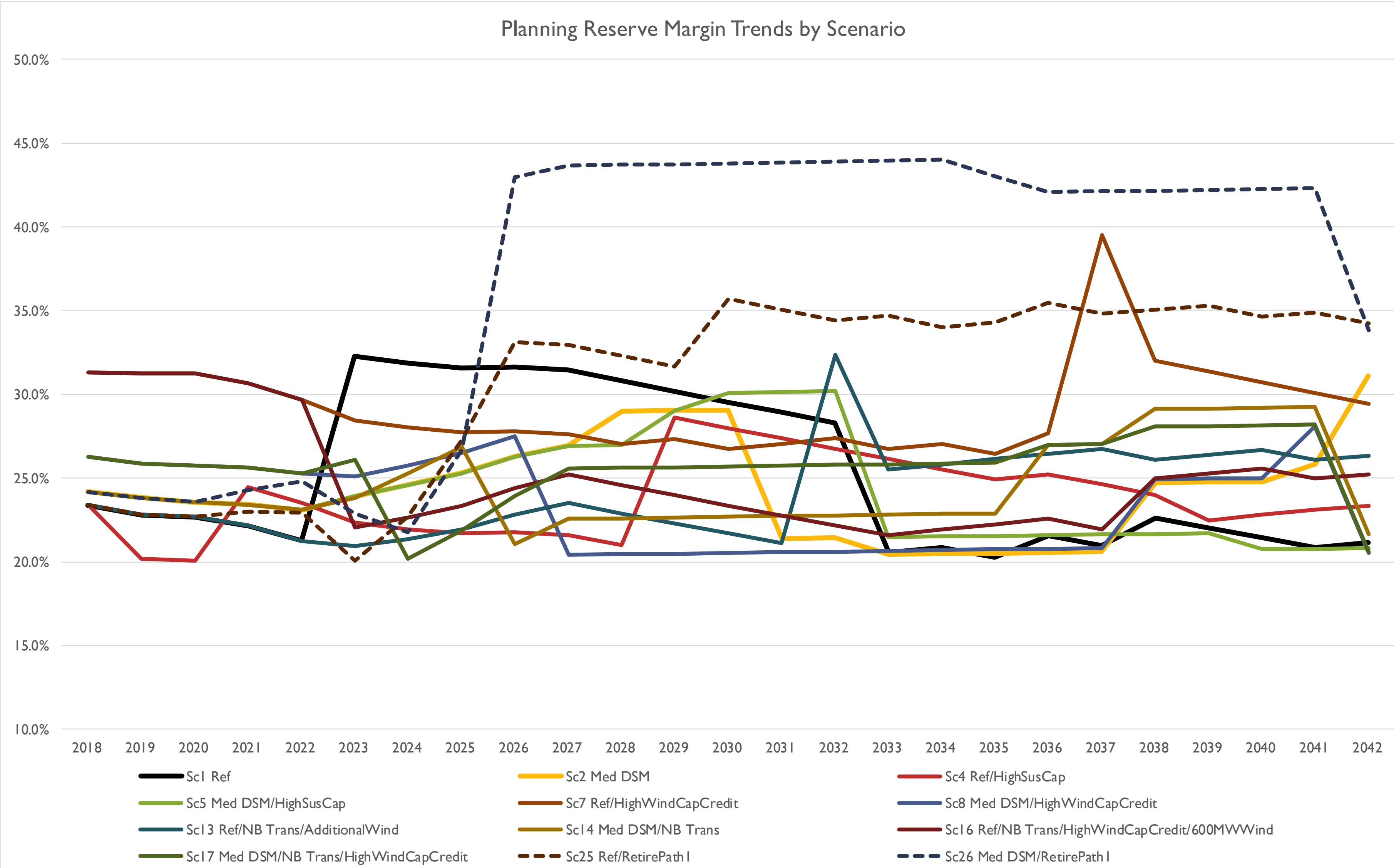


Figure 4b. Planning Reserve Margin Trends by Scenario –Low Battery Price Sensitivities

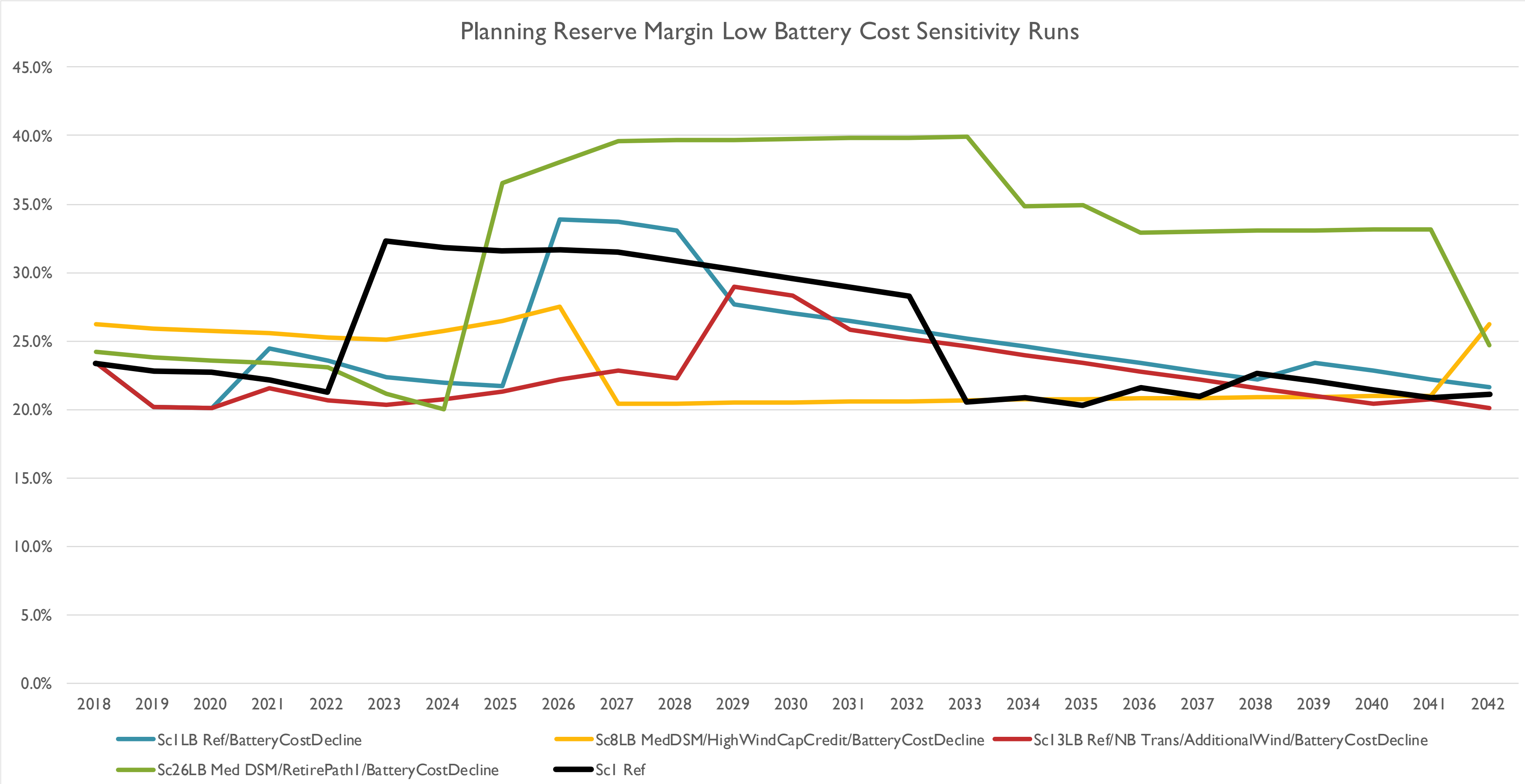


Figure 4c. Planning Reserve Margin Trends by Scenario – Gas Price Sensitivities

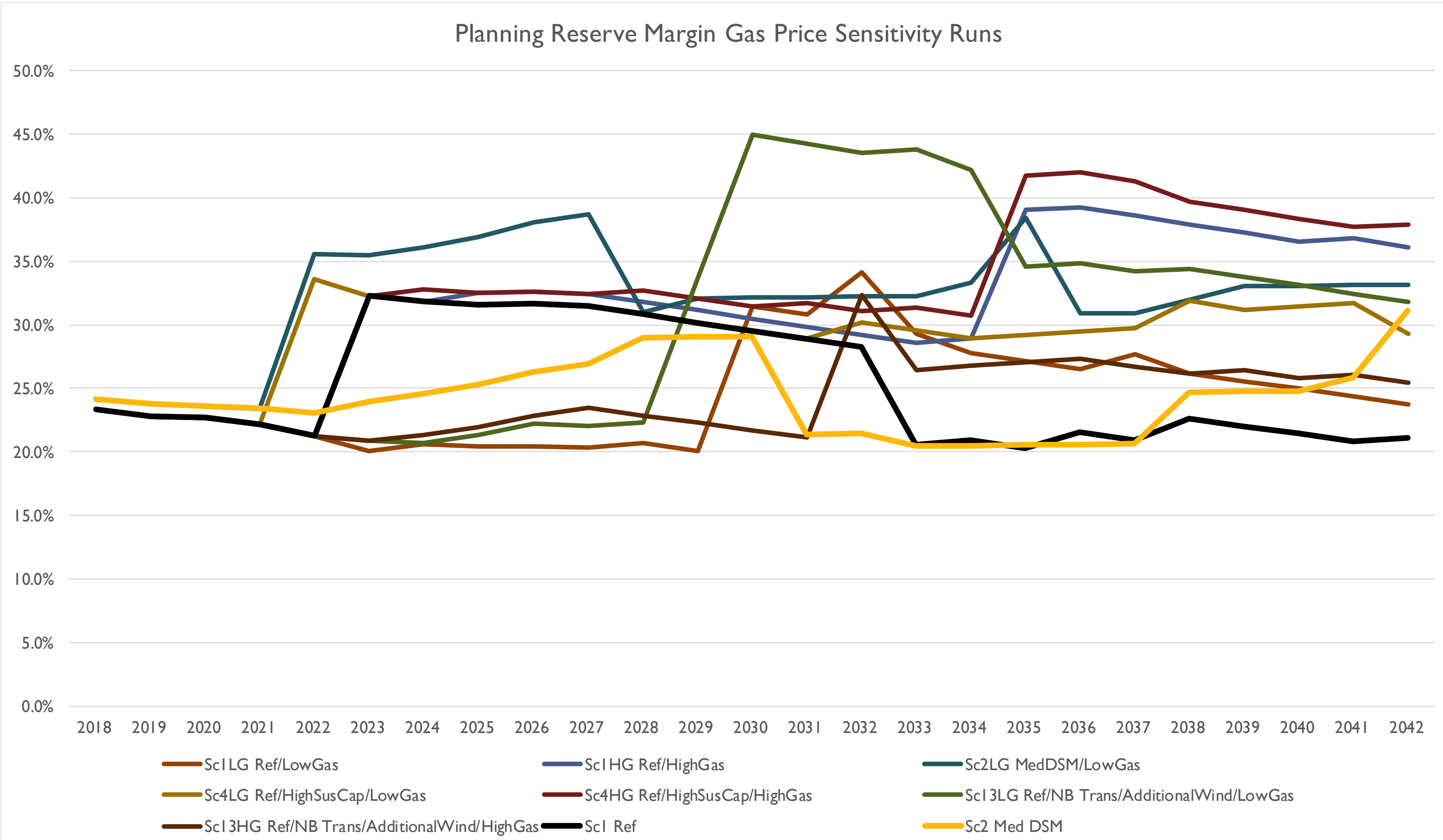


Table 7. Planning Reserve Margin Trends by Scenario and Sensitivity – Through 2030

Main Scenarios	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Sc1 Ref	23.4%	22.8%	22.7%	22.1%	21.3%	32.3%	31.8%	31.6%	31.7%	31.5%	30.8%	30.2%	29.5%
Sc2 Med DSM	24.2%	23.8%	23.6%	23.4%	23.1%	23.9%	24.6%	25.3%	26.3%	26.9%	29.0%	29.0%	29.1%
Sc4 Ref/HighSusCap	23.4%	20.2%	20.1%	24.5%	23.5%	22.4%	21.9%	21.7%	21.8%	21.6%	21.0%	28.6%	28.0%
Sc5 Med DSM/HighSusCap	24.2%	23.8%	23.6%	23.4%	23.1%	23.9%	24.6%	25.3%	26.3%	26.9%	27.0%	29.0%	30.1%
Sc7 Ref/HighWindCapCredit	31.3%	31.3%	31.2%	30.6%	29.7%	28.4%	28.0%	27.8%	27.8%	27.6%	27.0%	27.3%	26.7%
Sc8 Med DSM/HighWindCapCredit	26.3%	25.9%	25.8%	25.6%	25.3%	25.1%	25.8%	26.5%	27.5%	20.4%	20.4%	20.5%	20.5%
Sc13 Ref/NB Trans/AdditionalWind	23.4%	22.8%	22.7%	22.1%	21.3%	20.9%	21.3%	21.9%	22.8%	23.5%	22.9%	22.3%	21.7%
Sc14 Med DSM/NB Trans	24.2%	23.8%	23.6%	23.4%	23.1%	23.8%	25.3%	26.9%	21.1%	22.6%	22.6%	22.6%	22.7%
Sc16 Ref/NB Trans/HighWindCapCredit/600MWWind	31.3%	31.3%	31.2%	30.6%	29.7%	22.0%	22.6%	23.4%	24.4%	25.2%	24.6%	24.0%	23.4%
Sc17 Med DSM/NB Trans/HighWindCapCredit	26.3%	25.9%	25.8%	25.6%	25.3%	26.1%	20.2%	21.9%	23.9%	25.6%	25.6%	25.6%	25.7%
Sc25 Ref/RetirePath1	23.4%	22.8%	22.7%	23.0%	22.9%	20.0%	22.7%	27.3%	33.1%	32.9%	32.3%	31.6%	35.7%
Sc26 Med DSM/RetirePath1	24.2%	23.8%	23.6%	24.3%	24.8%	22.9%	21.8%	26.7%	42.9%	43.6%	43.7%	43.7%	43.8%
Low Battery Cost Sensitivities													
Sc1LB Ref/BatteryCostDecline	23.4%	20.2%	20.1%	24.5%	23.5%	22.4%	21.9%	21.7%	33.9%	33.7%	33.1%	27.7%	27.0%
Sc8LB MedDSM/HighWindCapCredit/BatteryCostDecline	26.3%	25.9%	25.8%	25.6%	25.3%	25.1%	25.8%	26.5%	27.5%	20.4%	20.4%	20.5%	20.5%
Sc13LB Ref/NB Trans/AdditionalWind/BatteryCostDecline	23.4%	20.2%	20.1%	21.5%	20.6%	20.3%	20.7%	21.3%	22.2%	22.9%	22.3%	28.9%	28.3%
Sc26LB Med DSM/RetirePath1/BatteryCostDecline	24.2%	23.8%	23.6%	23.4%	23.1%	21.2%	20.0%	36.6%	38.0%	39.6%	39.7%	39.7%	39.7%
Gas Price Sensitivities													
Sc1LG Ref/LowGas	23.4%	22.8%	22.7%	22.1%	21.3%	20.1%	20.6%	20.4%	20.5%	20.3%	20.7%	20.1%	31.4%
Sc1HG Ref/HighGas	23.4%	22.8%	22.7%	22.1%	21.3%	32.3%	31.8%	32.5%	32.6%	32.4%	31.8%	31.1%	30.5%
Sc2LG MedDSM/LowGas	24.2%	23.8%	23.6%	23.4%	35.6%	35.4%	36.1%	36.9%	38.0%	38.7%	31.0%	32.1%	32.1%
Sc4LG Ref/HighSusCap/LowGas	23.4%	22.8%	22.7%	22.1%	33.6%	32.3%	31.8%	31.6%	31.7%	31.5%	30.8%	30.2%	29.5%
Sc4HG Ref/HighSusCap/HighGas	23.4%	22.8%	22.7%	22.1%	21.3%	32.3%	32.8%	32.5%	32.6%	32.4%	32.7%	32.1%	31.4%
Sc13LG Ref/NB Trans/AdditionalWind/LowGas	23.4%	22.8%	22.7%	22.1%	21.3%	20.9%	20.7%	21.3%	22.2%	22.0%	22.3%	33.7%	45.0%
Sc13HG Ref/NB Trans/AdditionalWind/HighGas	23.4%	22.8%	22.7%	22.1%	21.3%	20.9%	21.3%	21.9%	22.8%	23.5%	22.9%	22.3%	21.7%

Table 8a. Builds and Retirements, Main Scenarios, 2018-2040

Sc.	Name	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	**Ref**			Wind 100	Ret Lin 2		New CC253										Ret Lin 4	Batt 20		Batt 40		Ret Pt Tupp New CT100 Batt 100		
2	**Med DSM**			Wind 100	Ret Lin 2		Batt 20					Batt 40			Ret Lin 4		Ret Batt 20					Ret Batt 40 Batt 120		
4	**Ref/HighSusCap**		Ret Lin 3 Batt 100	Wind 100	Ret Lin 2 New CT100								New CC253 Ret Batt 100 Batt 20							Batt 20				Batt 20
5	**Med DSM/HighSusCap**			Wind 100	Ret Lin 2		Batt 20						Batt 40	Batt 20			Ret Lin 4 Ret Batt 20						Ret Batt 40 Batt 40	Ret Batt 20
7	**Ref/HighWindCapCredit**			Wind 100	Ret Lin 2								Batt 20		Batt 20	Batt 20		Batt 20		Batt 40	New CC253 Batt 20	Ret Pt Tupp	Ret Batt 20 Batt 20	
8	**Med DSM/HighWindCapCredit**			Wind 100	Ret Lin 2						Ret Lin 4											Batt 80		
13	**Ref/NB Trans/AdditionalWind**			Wind 100	Ret Lin 2		Wind 100	Wind 100	Wind 100	Wind 100	Wind 100					New CC253	Ret Lin 4 Batt 20	Batt 20	Batt 20	Batt 20	Batt 20		Batt 20	Batt 20
14	**Med DSM/NB Trans**			Wind 100	Ret Lin 2		Wind 100	Wind 100	Wind 100	Ret Lin 4 Wind 100	Wind 100									Batt 80		Batt 40		
16	**Ref/NB Trans/HighWindCapCredit/600MWWind**			Wind 100	Ret Lin 2		Ret Lin 4 Wind 100	Wind 100	Wind 100	Wind 100	Wind 100							Batt 20	Batt 20	Batt 20		Batt 80	Batt 20	Batt 20
17	**Med DSM/NB Trans/HighWindCapCredit**			Wind 100	Ret Lin 2		Wind 100	Ret Lin 4 Wind 100	Wind 100	Wind 100	Wind 100									Batt 20		Batt 20		
25	**Ref/RetirePath1**			Wind 100	Ret Lin 2 Wind 100	Wind 100	Ret Lin 4 New CT100 Wind 100	Ret Lin 3 New CT200 Wind 100	Ret Lin 1 New CC253	Ret Tren 5 New CC253 Wind 100				New CT100			Batt 20		Batt 20	Batt 40		Batt 20	Batt 20	
26	**Med DSM/RetirePath1**			Wind 100	Ret Lin 2 Wind 100	Wind 100	Ret Lin 4 New CT100 Wind 100	Ret Lin 3 New CT100 Wind 100	Ret Lin 1 New CT200 Wind 100 Batt 20	Ret Tren 5 New CC253 New CT100 Batt 100									Ret Batt 20	Ret Batt 100 Batt 80				

Table 8b. Builds and Retirements, Low Battery Cost, Gas Price, and Forced Retirement Sensitivity Runs, 2018-2040

	Sc.	Name	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Low Battery Cost Sensitivities	1LB	**Ref/BatteryCostDecline**		Ret Lin 4 Batt 100	Wind 100	New CT100					New CC253			Ret Batt 100											
	8LB	**MedDSM/HighWindCapCredit/BatteryCostDecline**			Wind 100	Ret Lin 2						Ret Lin 4													
	13LB	**Ref/NB Trans/AdditionalWind/BatteryCostDecline**		Ret Lin 4 Batt 100	Wind 100	Ret Lin 2 Batt 40		Wind 100	Wind 100	Wind 100	Wind 100	Wind 100		New CC253 Ret Batt 100		Ret Batt 40									
	26LB	**Med DSM/RetirePath1/BatteryCostDecline**			Wind 100	Ret Lin 2		Ret Lin 4 New CT100 Wind 100	Ret Lin 3 Wind 100 Batt 100	Ret Lin 1 New CC253 New CT200 Wind 100	Ret Tren 5 New CT100 Wind 100 Batt 40	Wind 100							Ret Batt 100		Ret Batt 40				
Gas Price Sensitivities	1HG	**Ref/HighGas**			Wind 100	Ret Lin 2		New CC253		Batt 20									Batt 20	New CC253 Ret Batt 20	Batt 20				
	1LG	**Ref/LowGas**			Wind 100	Ret Lin 2			Batt 20				Batt 20		New CC253		New CC253	Ret Pt Tupp Batt 60	Ret Batt 20			Batt 40	Ret Batt 20		
	2LG	**MedDSM/LowGas**			Wind 100	Ret Lin 2	New CC253						Ret Lin 4	Batt 20					Batt 20	Batt 100	Ret Pt Tupp		Batt 20	Ret Batt 20 Batt 40	
	4HG	**Ref/HighSusCap/HighGas**			Wind 100	Ret Lin 2		New CC253	Batt 20				Batt 20			Batt 20		Batt 20	Ret Batt 20 Batt 20	New CC253	Batt 20		Ret Batt 20		
	4LG	**Ref/HighSusCap/LowGas**			Wind 100	Ret Lin 2	New CC253										Batt 40			Batt 20	Batt 20	Batt 20	Batt 60		Batt 20
	13HG	**Ref/NB Trans/AdditionalWind/HighGas**			Wind 100	Ret Lin 2		Wind 100	Wind 100	Wind 100	Wind 100	Wind 100					New CC253	Ret Lin 4 Batt 40	Batt 20	Batt 20	Batt 20			Batt 20	
	13LG	**Ref/NB Trans/AdditionalWind/LowGas**			Wind 100	Ret Lin 2		Wind 100	New CT100 Wind 100	Wind 100	Wind 100		Wind 100	New CC253	New CC253			Batt 20	Ret Batt 40 Batt 20	Ret Pt Tupp	Batt 20		Batt 20		
Tufts Cove 3 / Trenton 5 Forced Retirement	1TC3	**Ref/RetireTuftsCove3**			Wind 100	Ret Lin 2			Batt 20		Ret Tf Cv3 New CC253 Batt 60							Batt 20	Ret Batt 20 Batt 20		Ret Batt 60 Batt 60	Batt 20			
	1TC3TR5	**Ref/RetireTuftsCove3/RetireTrenton5**			Wind 100	Ret Lin 2			Batt 20		Ret Tf Cv3 New CC253				Ret Tren 5 New CC253			Batt 20	Ret Batt 20	Batt 20	Batt 40		Batt 20	Batt 20	
	2TC3TR5	**MedDSM/REtireTuftsCove3/RetireTrenton5**			Wind 100	Ret Lin 2					Ret Tf Cv3 Batt 60			Batt 20	Ret Tren 5 New CC253	Ret Lin 4					Ret Batt 60 Batt 100			Ret Batt 20	

3.2. Wholesale Revenue Requirements

Overview - Revenue Requirement Proxy

The Plexos environment as structured does not directly compute a revenue requirements metric. To develop a proxy for the revenue requirements associated with system production, including the effects of all new builds and retirements, we computed components outside of the modeling results for certain components, described in the table below. This proxy excludes costs associated with collecting revenue for existing transmission and distribution and excludes other downstream costs not associated with the wholesale production and delivery of energy and firm peak loading requirements.

Table 8. Revenue Requirement Proxy Computation

Component	Description/Definition	Comment
Computed/Accounted for within Plexos		
Fuel	Coal, Oil, Gas burn costs	Plexos Dispatch Cost.
Variable O&M	Based on per MWh for thermal fleet; total costs for renewable energy	Most of VOM costs reflect total renewable energy contract costs. Conventional VOM for thermal fleet a small share of total VOM.
Startup and Shutdown	Thermal fleet, $	Plexos Unit Commitment Costs based on fuel requirements for startup
Fixed O&M	Per KW-year based	Conventional Costs for thermal fleet and new builds.
Net Interchange Purchases	Per MWh	Market-Based – Energy Access Agreement (ML Surplus) and NB market prices
Computed/Accounted for Outside of Plexos		
Incremental DSM Costs	Per MWh saved relative to reference energy forecast.	Based on first-year per kWh costs for increment above reference levels, varied over planning period.
NB Transmission Costs	Annualized fixed costs	Estimated based on share of costs to NS.
Maritime Link Costs	Fixed costs	Per Maritime Link case – stream of Rev. Rqmts.
New Build Costs	Annualized fixed costs	Per assumptions memo (see Table 5 above).
Sustaining Capital Costs	Annualized fixed costs	Per assumptions memo (see Table 6 above).

Plexos Production Cost - Fuel, VO&M, FO&M, Startup, and Net Interchange Purchase

The majority of the costs reflected in our revenue requirements computation come from the fixed and variable operating costs, fuel costs, and Maritime Link Surplus and New Brunswick net imports purchase costs as reflected in the Plexos production cost modeling. These costs also include Newfoundland recall energy in 2018 and 2019 only. These costs range from roughly 64 percent to 74 percent of the total net present value of revenue requirements (NPVRR) across the scenarios.

Maritime Link Costs

To approximate the contribution to revenue requirements associated with the Maritime Link, we used information available from the Maritime Link Interim Cost Assessment case to estimate the fixed costs associated with NS Block and Supplemental Energy. These costs comprise roughly 14-16 percent of the total NPVRR and are the same for all scenarios. These costs were not modeled within Plexos; only the scheduled energy for the NS Block and Supplemental Energy flows was reflected in the model. Surplus Energy flows over the Maritime Link were modeled within Plexos using market price criteria, and the costs are included as part of the total interchange purchase costs.

Sustaining Capital Costs

Sustaining capital costs were provided by NSPI as part of their 2017 10-Year System Outlook report. To develop an estimate of those costs' contribution to revenue requirements, we annualized the projected expenditures, using a simplified annualization process and assuming the sustaining capital is treated as a relatively long-lived asset. For those scenarios where one or more of the thermal fleet units was retired, or for relevant units in scenarios 25 and 26 (the modeling bookends), the sustaining capital stream was reduced, reflecting retirement (no additional, incremental sustaining capital), and the amortization of earlier-year capital continued. No explicit accounting for either salvage value or decommissioning costs was assumed for any of the retirements.

Incremental DSM Costs

Reference load scenarios (1, 4, 7, 13, 16, 25) assumed NSPI's 2017 load forecast and incorporated their projections of DSM effects. Scenarios 2, 5, 8, 14, 17, and 26 used a "medium DSM" load projection, which contains a lower trajectory of annual energy requirements than the reference scenario, effectively incorporating an incremental level of DSM energy and peak load savings. Figure 5 below shows the trajectory differences and incremental cost estimates.

The Incremental DSM costs assumed for the Medium DSM scenarios are based in part on the information available from Efficiency One on estimated first-year costs for incremental achievable savings ("high case").[25] The cost assumptions take into account that the fraction of incremental achievable savings represented by the Medium DSM scenario, as a percentage of Navigant's "high case" achievable savings, varies considerably year-to-year and on average is 36 percent of the high case achievable savings total. This indicates that even though the total average cost Efficiency One's estimates in the "high case" of the Navigant study is 60 cents per kWh (first year savings cost), actual per unit Medium DSM scenario costs will likely be lower because the modeled level of DSM savings is considerably lower than the "high case" total savings.[26]

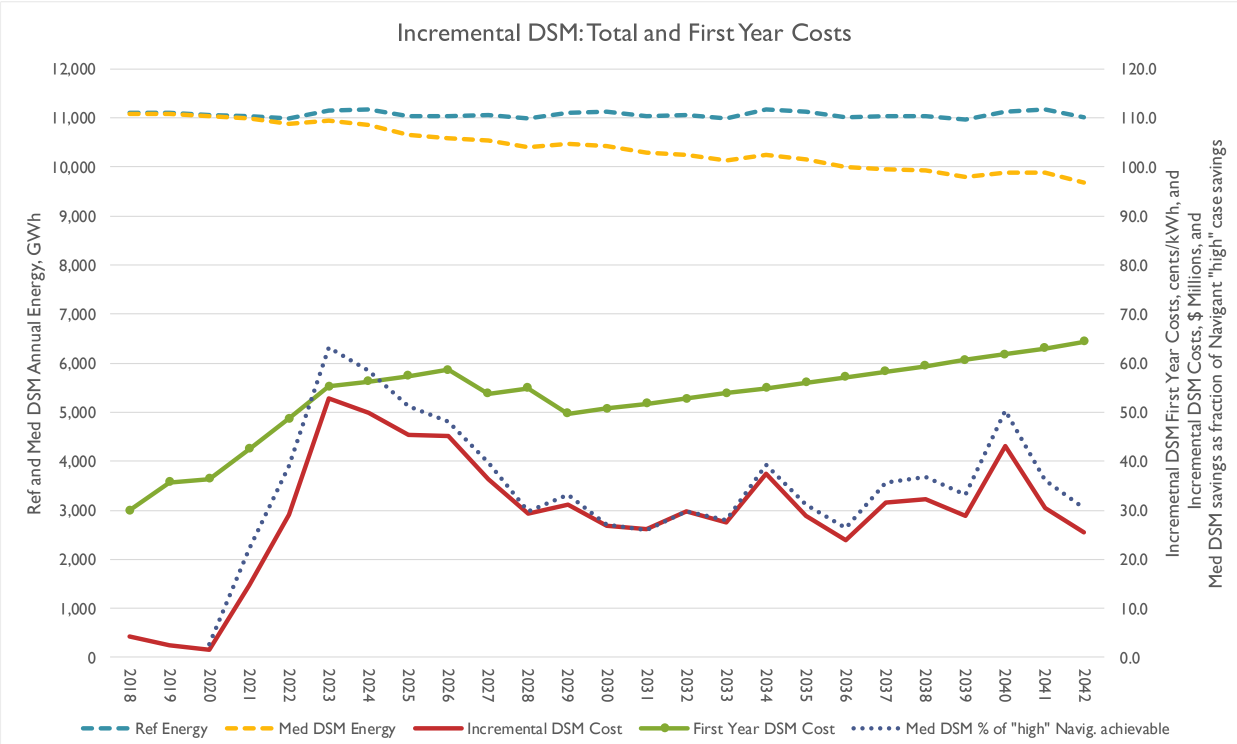
We estimated the costs using a range of first-year costs that increases rapidly from 2018 up to 2026—reflecting the ramping that would be required—and then continues on a more modest trajectory. The nominal per-unit and total costs are seen in Figure 5. The costs are considerably higher than actual first-

[25] Gogan, J. R. 2018. "Comments from Efficiency One." Letter dated April 9, 2018 and updated letter dated April 12, 2018. The "high case" represents Navigant's estimate of achievable efficiency savings under a "high" achievable DSM case.

[26] As noted, modeled DSM savings in the Med DSM case average 36 percent of Efficiency One's "high case" achievable savings, reaching a maximum of 63 percent of the achievable savings in 2023, as seen in Figure 5.

year DSM costs for 2017, as noted in NSPI's 2017 Business Plan.[27] Figure 5 shows average Medium DSM cost increments of roughly $29 million are seen in the 2018-2042 period. As seen in our NPVRR results, these costs are a relatively small fraction (2.9 percent - scenario 2) of overall wholesale resource revenue requirements.

Figure 5. Annual Energy Trajectories, Reference and Medium DSM Scenarios, and Incremental DSM Costs



Source: Synapse estimate of incremental DSM costs. Note: First year savings and incremental DSM costs are in nominal dollars.

New Brunswick Transmission Costs

For the purpose of estimating the effects on Nova Scotia's system of incorporating increasing levels of wind energy, we assumed an ability for a second 345 kV tie to New Brunswick to be in place by roughly 2022/2023.[28] Our analysis does not account for the considerable uncertainty associated with obtaining agreement from New Brunswick to complete such an undertaking, nor do we know if 2022/2023 is a reasonable estimate for completion. However, we did not assume any increase in firm imports sourced from New Brunswick or New England; we essentially add the costs of such a tie to the overall revenue requirements to allow for the inclusion of more wind energy on the system. Since this increase in interconnection capacity would extend back into New Brunswick considerably (we assumed a total cost

[27] First-year DSM costs for 2017 were estimated as a range of $0.241 – 0.253 $/kWh, or $241-$253/MWh. Page 7.

[28] We begin collecting costs in 2022 and we allow increments of wind beyond the first 100 MW to commence in 2023.

of $400 million to complete reinforcement back to Coleson Cove), it would provide benefits to the New Brunswick system. As such, we assumed a cost sharing of 50 percent with New Brunswick.

New Build Costs

Based on the capacity expansion results from the Plexos modeling, we computed an annualized revenue requirement associated with the newly built resources based on installed costs (Table 5), an economic life for each resource, and a weighted average cost of capital of 7 percent for NSPI. New build costs are seen across the scenarios for wind (in 101.2 MW blocks), CTs (in 100 MW blocks), combined cycle units (in a 253 MW block), and battery energy storage systems (in 20 MW blocks). Fuel, fixed O&M, and variable O&M for new build units are incorporated in the Plexos unit commitment and dispatch costs.

Cost Exclusions

Excluded from the computation of the revenue requirement proxy is additional transmission system support investment (within Nova Scotia) that could be required under scenarios of increased thermal unit retirement and/or increased wind energy installations. Information available from NSPI indicates that some combination of dynamic reactive support and system inertial support would be required.[29] Reactive power support costs vary, but recent experience with conversion of steam-fired equipment indicates costs on the order of $30,000 - $50,000/MVAR ($US), which equates to roughly $3.5 to $6 million ($CA), for synchronous condensers. More sophisticated reactive support devices, such as an SVC or Statcom, would be more expensive on a per unit basis; simpler static reactive devices are less expensive. Broadly speaking, the order of magnitude of costs and the conventionality of this equipment does not preclude its use as part of NSPI's system transformation going forward. As NSPI relies on greater amounts of renewable energy and lower levels of fossil-fueled energy, in part to meet emission requirements, investing in a more robust transmission system will likely be required. We note that "headroom" that ranges between $90 million and $570 million (NPVRR) exists between the reference scenario costs, and the costs indicated for the higher wind scenarios 13, 14, 16, and 17. See footnote 4.

3.3. NPV and Revenue Requirements Results

Figures 6a and 6b below show the overall NPVRR across the main scenarios and for four sensitivities reflecting low battery costs (6a); and across the gas price sensitivities and the Tufts Cove 3 / Trenton 5b forced retirement sensitivities (6b). Both are shown by component of NPVRR. Tables 9a and 9b contain the data used in Figures 6a and 6b. Tables 10a and 10b show the NPVRR component percentage of total NPVRR costs across the scenarios and sensitivities. Figure 7 shows the annual, nominal revenue requirement streams across a selection of scenarios (1, 2, 5, 8, 17, and 26) to demonstrate the temporal differences of revenue requirement streams across the scenarios.

[29] See response to discovery questions DR-15.

Figure 6a. NPV of Revenue Requirements by Scenario and by Component, 2018-2042, Main Scenarios and Low Battery Cost Sensitivities

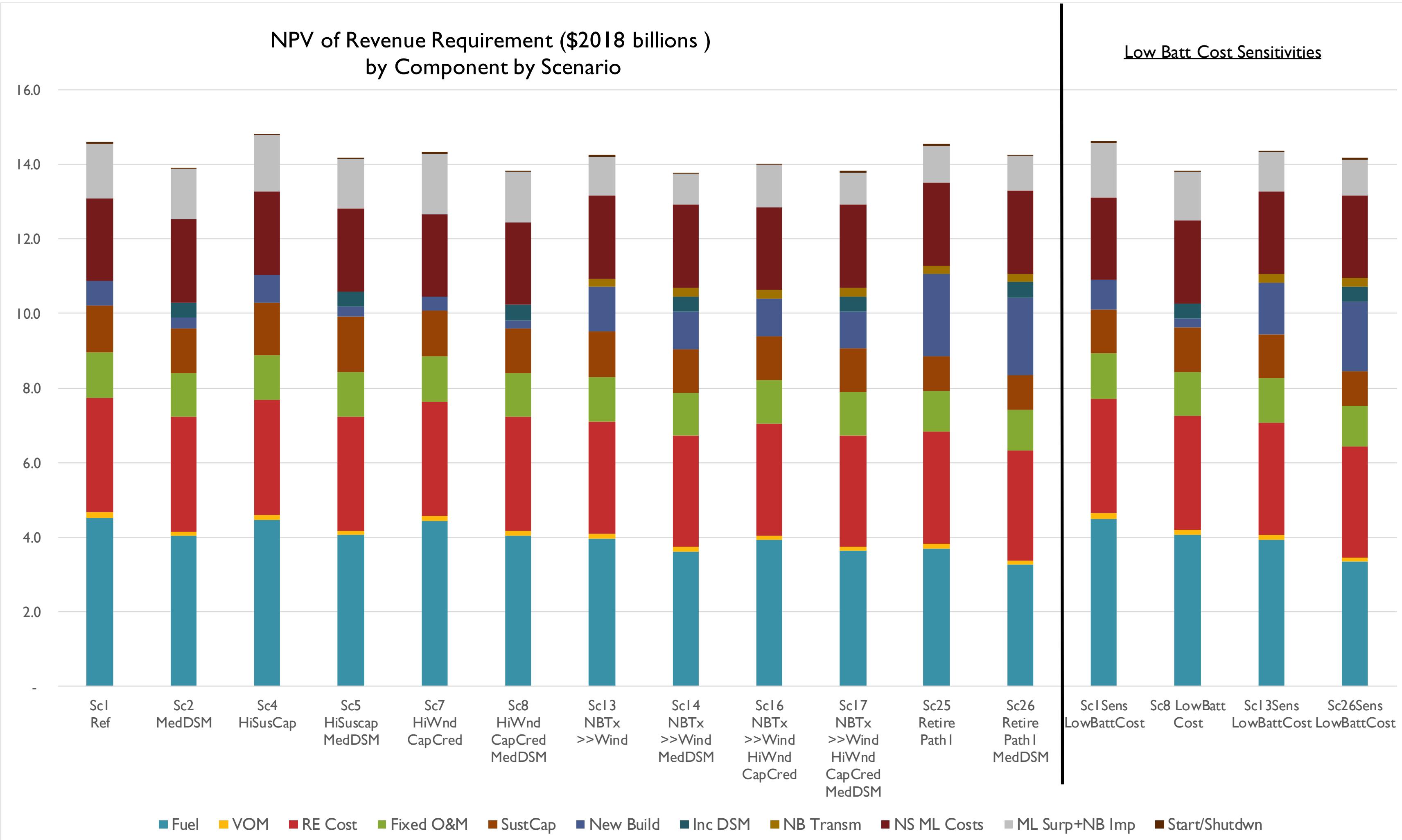


Figure 6b. NPV of Revenue Requirements by Scenario and by Component, 2018-2042, Gas Price Sensitivities and TC3/Tr5 Forced Retirement Sensitivities

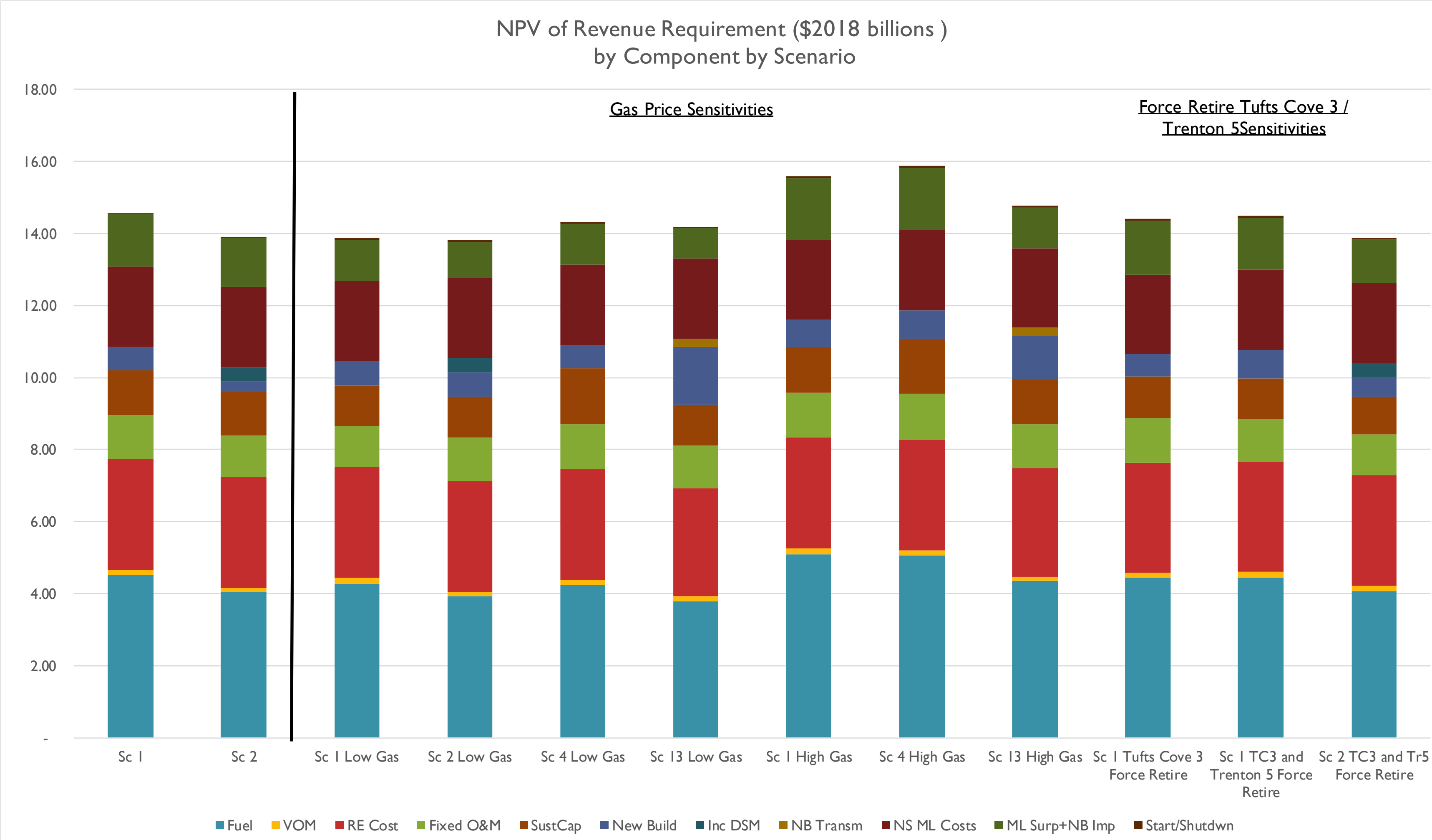


Table 9a. Data for Figure 6 - NPV of Revenue Requirements by Component ($2018 billions) – Main Scenarios and Low Battery Cost Sensitivities

													Low Battery Cost Sensitivities			
Component	Sc1 Ref	Sc2 Med DSM	Sc4 HiSus Cap	Sc5 HiSus Cap Med DSM	Sc7 HiWnd Cap Cred	Sc8 HiWnd Cap Cred Med DSM	Sc13 NBTx >Wind	Sc14 NBTx >Wind Med DSM	Sc16 NBTx >Wind HiWnd Cap Cred	Sc17 NBTx >Wind HiWnd Cap Cred Med DSM	Sc25 Retire Path1	Sc26 Retire Path1 Med DSM	Sc1Sens LowBatt Cost	Sc8Sens LowBatt Cost	Sc13Sens LowBatt Cost	Sc26Sens LowBatt Cost
Fuel	4.52	4.03	4.46	4.05	4.44	4.05	3.96	3.62	3.93	3.64	3.69	3.26	4.50	4.08	3.94	3.34
VOM	0.15	0.13	0.15	0.13	0.14	0.13	0.13	0.12	0.12	0.12	0.14	0.12	0.15	0.13	0.13	0.12
RE Cost	3.07	3.07	3.07	3.07	3.07	3.06	3.00	2.98	3.00	2.98	2.99	2.96	3.07	3.06	3.00	2.97
Fixed O&M	1.23	1.18	1.21	1.19	1.20	1.17	1.21	1.17	1.16	1.16	1.09	1.08	1.21	1.17	1.19	1.08
SustCap	1.25	1.19	1.42	1.47	1.23	1.17	1.21	1.17	1.17	1.16	0.95	0.94	1.16	1.17	1.16	0.94
New Build	0.65	0.29	0.74	0.27	0.37	0.23	1.20	1.00	1.01	0.99	2.19	2.07	0.79	0.24	1.39	1.85
Inc DSM	-	0.41	-	0.41	-	0.41	-	0.41	-	0.41	-	0.41	-	0.41	-	0.41
NB Transm	-	-	-	-	-	-	0.23	0.23	0.23	0.23	0.23	0.23	-	-	0.23	0.23
NS ML Costs	2.22	2.22	2.22	2.22	2.22	2.22	2.22	2.22	2.22	2.22	2.22	2.22	2.22	2.22	2.22	2.22
ML Surp+NB Imp	1.46	1.36	1.52	1.35	1.63	1.35	1.05	0.83	1.13	0.87	0.99	0.94	1.47	1.32	1.05	0.96
Start/Shutdwn	0.04	0.03	0.04	0.03	0.04	0.03	0.04	0.04	0.04	0.04	0.05	0.04	0.05	0.03	0.05	0.03
Total	14.59	13.90	14.82	14.18	14.32	13.83	14.25	13.79	14.01	13.82	14.54	14.26	14.63	13.84	14.37	14.17
Change from Sc 1	0.0%	-4.7%	1.6%	-2.8%	-1.8%	-5.2%	-2.3%	-5.5%	-3.9%	-5.3%	-0.3%	-2.2%	0.3%	-5.1%	-1.5%	-2.9%
Change from Sc 2		0.0%		2.0%		-0.5%		-0.9%		-0.6%		2.6%				1.9%

Source: Synapse Revenue Requirement Calculations

Table 9b. Data for Figure 6 - NPV of Revenue Requirements by Component ($2018 billions) – Gas Price Sensitivities and TC3/Tr5 Forced Retire

	Original		Gas Price							Tufts Cove 3 Trenton 5 Force Retire		
Component	**Sc 1**	**Sc 2**	**Sc 1 Low Gas**	**Sc 2 Low Gas**	**Sc 4 Low Gas**	**Sc 13 Low Gas**	**Sc 1 High Gas**	**Sc 4 High Gas**	**Sc 13 High Gas**	**Sc 1 Tufts Cove 3 Force Retire**	**Sc 1 TC3 and Trenton 5 Force Retire**	**Sc 2 TC3 and Tr5 Force Retire**
Fuel	4.52	4.03	4.27	3.92	4.23	3.79	5.09	5.05	4.34	4.43	4.44	4.08
VOM	0.15	0.13	0.16	0.14	0.15	0.13	0.16	0.16	0.14	0.15	0.15	0.14
RE Cost	3.07	3.07	3.07	3.07	3.07	3.01	3.07	3.07	3.00	3.07	3.08	3.07
Fixed O&M	1.23	1.18	1.16	1.21	1.27	1.19	1.26	1.26	1.21	1.22	1.17	1.13
SustCap	1.25	1.19	1.11	1.14	1.54	1.13	1.26	1.54	1.26	1.17	1.13	1.06
New Build	0.65	0.29	0.69	0.66	0.65	1.61	0.75	0.78	1.20	0.61	0.80	0.52
Inc DSM	-	0.41	-	0.41	-	-	-	-	-	-	-	0.41
NB Transm	-	-	-	-	-	0.23	-	-	0.23	-	-	-
NS ML Costs	2.22	2.22	2.22	2.22	2.22	2.22	2.22	2.22	2.22	2.22	2.22	2.22
ML Surp+NB Imp	1.46	1.36	1.14	1.00	1.15	0.85	1.70	1.74	1.12	1.49	1.44	1.21
Start/Shutdwn	0.04	0.03	0.05	0.04	0.05	0.04	0.06	0.06	0.06	0.05	0.05	0.04
Total	14.59	13.90	13.88	13.81	14.33	14.20	15.59	15.89	14.78	14.41	14.49	13.88
Change from Sc1LG	5.1%		0.0%	-0.5%	3.2%	2.3%						
Change from Sc 1HG	-6.4%						0.0%	1.9%	-5.2%			
Change from Sc1	0.0%									-1.2%	-0.7%	
Change from Sc 2		0.0%										-0.2%

Source: Synapse Revenue Requirement Calculations

Table 10a. Share of NPV RR by Component and by Scenario - Main Scenarios and Low Battery Cost Sensitivities

													Low Battery Cost Sensitivities			
Component	Sc1 Ref	Sc2 Med DSM	Sc4 HiSus Cap	Sc5 HiSus Cap Med DSM	Sc7 HiWnd Cap Cred	Sc8 HiWnd Cap Cred Med DSM	Sc13 NBTx >Wind	Sc14 NBTx >Wind Med DSM	Sc16 NBTx >Wind HiWnd Cap Cred	Sc17 NBTx >Wind HiWnd Cap Cred Med DSM	Sc25 Retire Path1	Sc26 Retire Path1 Med DSM	Sc1Sens LowBatt Cost	Sc8Sens LowBatt Cost	Sc13Sens LowBatt Cost	Sc26Sens LowBatt Cost
Fuel	31.0%	29.0%	30.1%	28.6%	31.0%	29.3%	27.8%	26.3%	28.0%	26.3%	25.4%	22.8%	30.8%	29.5%	27.4%	23.6%
VOM	1.0%	0.9%	1.0%	0.9%	1.0%	0.9%	0.9%	0.8%	0.9%	0.8%	0.9%	0.8%	1.1%	0.9%	0.9%	0.9%
RE Cost	21.0%	22.0%	20.7%	21.6%	21.4%	22.2%	21.1%	21.6%	21.4%	21.6%	20.6%	20.7%	21.0%	22.1%	20.9%	21.0%
Fixed O&M	8.4%	8.5%	8.1%	8.4%	8.4%	8.5%	8.5%	8.5%	8.3%	8.4%	7.5%	7.6%	8.3%	8.5%	8.3%	7.6%
SustCap	8.6%	8.6%	9.6%	10.4%	8.6%	8.5%	8.5%	8.5%	8.3%	8.4%	6.5%	6.6%	8.0%	8.5%	8.1%	6.6%
New Build	4.4%	2.1%	5.0%	1.9%	2.6%	1.7%	8.4%	7.3%	7.2%	7.1%	15.1%	14.5%	5.4%	1.7%	9.7%	13.1%
Inc DSM	0.0%	3.0%	0.0%	2.9%	0.0%	3.0%	0.0%	3.0%	0.0%	3.0%	0.0%	2.9%	0.0%	3.0%	0.0%	2.9%
NB Transm	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.6%	1.7%	1.7%	1.7%	1.6%	1.6%	0.0%	0.0%	1.6%	1.6%
NS ML Costs	15.2%	16.0%	15.0%	15.7%	15.5%	16.1%	15.6%	16.1%	15.9%	16.1%	15.3%	15.6%	15.2%	16.1%	15.5%	15.7%
ML Surp+NB Imp	10.0%	9.8%	10.2%	9.5%	11.4%	9.8%	7.3%	6.0%	8.0%	6.3%	6.8%	6.6%	10.0%	9.6%	7.3%	6.7%
Start/Shutdwn	0.3%	0.2%	0.3%	0.2%	0.2%	0.2%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.2%	0.3%	0.2%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

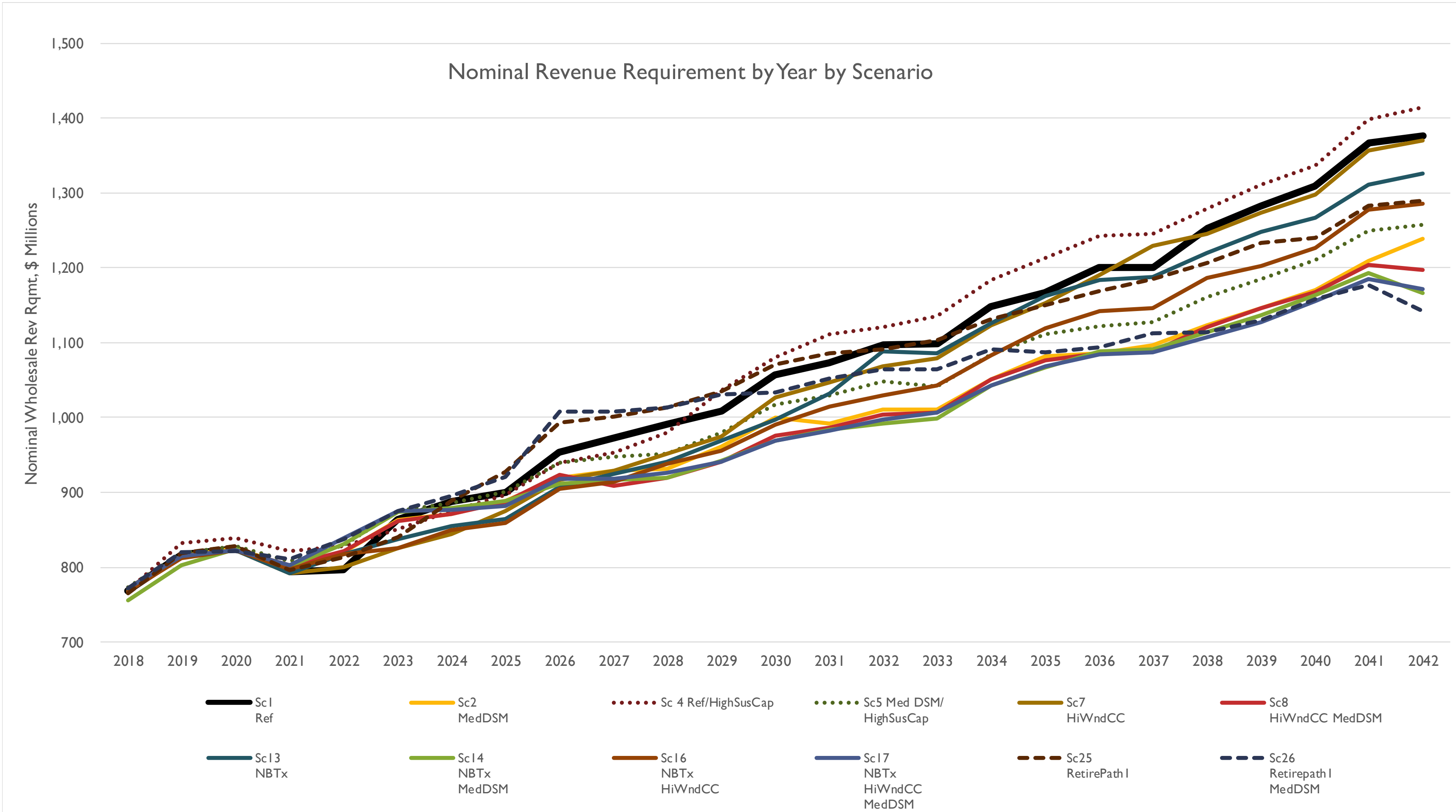
Source: Synapse Revenue Requirement Calculations

Table 10b. Share of NPV RR by Component and by Scenario - Gas Price Sensitivities and TC3/Tr5 Forced Retire

	Original		Gas Price							Tufts Cove 3 Trenton 5 Force Retire		
Component	Sc 1	Sc 2	Sc 1 Low Gas	Sc 2 Low Gas	Sc 4 Low Gas	Sc 13 Low Gas	Sc 1 High Gas	Sc 4 High Gas	Sc 13 High Gas	Sc 1 Tufts Cove 3 Force Retire	Sc 1 TC3 and Trenton 5 Force Retire	Sc 2 TC3 and Tr5 Force Retire
Fuel	31.0%	29.0%	30.8%	28.4%	29.5%	26.7%	32.6%	31.8%	29.4%	30.7%	30.6%	29.4%
VOM	1.0%	0.9%	1.1%	1.0%	1.1%	0.9%	1.0%	1.0%	0.9%	1.0%	1.1%	1.0%
RE Cost	21.0%	22.0%	22.1%	22.2%	21.4%	21.2%	19.7%	19.4%	20.3%	21.3%	21.2%	22.1%
Fixed O&M	8.4%	8.5%	8.3%	8.8%	8.8%	8.4%	8.1%	7.9%	8.2%	8.5%	8.1%	8.2%
SustCap	8.6%	8.6%	8.0%	8.3%	10.8%	7.9%	8.1%	9.7%	8.5%	8.1%	7.8%	7.6%
New Build	4.4%	2.1%	5.0%	4.8%	4.5%	11.3%	4.8%	4.9%	8.1%	4.2%	5.5%	3.8%
Inc DSM	0.0%	3.0%	0.0%	3.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.0%
NB Transm	0.0%	0.0%	0.0%	0.0%	0.0%	1.6%	0.0%	0.0%	1.6%	0.0%	0.0%	0.0%
NS ML Costs	15.2%	16.0%	16.0%	16.1%	15.5%	15.6%	14.2%	14.0%	15.0%	15.4%	15.3%	16.0%
ML Surp+NB Imp	10.0%	9.8%	8.2%	7.3%	8.0%	6.0%	10.9%	11.0%	7.5%	10.4%	10.0%	8.7%
Start/Shutdwn	0.3%	0.2%	0.4%	0.3%	0.3%	0.3%	0.4%	0.4%	0.4%	0.3%	0.4%	0.3%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Source: Synapse Revenue Requirement Calculations

Figure 7. Nominal Revenue Requirements by Scenario by Year, 2018-2042



3.4. Energy Balances

Plant Utilization – Capacity Factors – Coal and Tufts Cove Units

Figures 8 through 11 contain the utilization of the aggregate coal fleet (as measured by annual capacity factors) and, separately, the older steam units at Tufts Cove (units 1-3, in aggregate) and the newer CC units (units 4-6, in aggregate). We present results for a subset of the main scenarios (i.e., 1, 2, 16, 17). Appendix 5.4 contains figures for aggregate utilization for the remainder of the scenarios.

The figures illustrate the broad patterns that persist across all scenarios over the years: (1) lower utilization for energy production of the coal fleet, in response to the declining Province-wide sulfur dioxide (SO_2) and carbon dioxide (CO_2) emissions requirement, and (2) gradually changing utilization of energy production from Tufts Cove. In the reference load and reference wind level scenario (Scenario 1), the utilization at Tufts Cove units 1-3 initially declines slightly after Lingan 2's retirement, then flattens out, and finally increases aggregate output post-2030. Units 4-6, which are more efficient, see generally increasing output, with year-to-year fluctuations. For scenarios with lower load or more wind, the overall patterns are somewhat similar, but at lower average annual capacity factors because the wind and the saved energy displaces what would otherwise be marginal energy generation at the Tufts Cove facility, in addition to displacing economy imports.

Tables 11 through 14, which follow the utilization graphs, contain unit-specific modeling outputs for the thermal fleet, and any new fossil-fuel unit builds, for Scenarios 1, 2, 16, and 17. The differences across these four scenarios can be attributed to the effects of lower load (scenarios 2 and 17 use Medium DSM load) and higher levels of wind on the system (scenarios 16 and 17 use 600 MW of additional wind by 2027). Appendix 5.4 contains the tables of unit-specific output for the remainder of the scenarios.

Figure 8: Utilization - Scenario 1, Reference Case

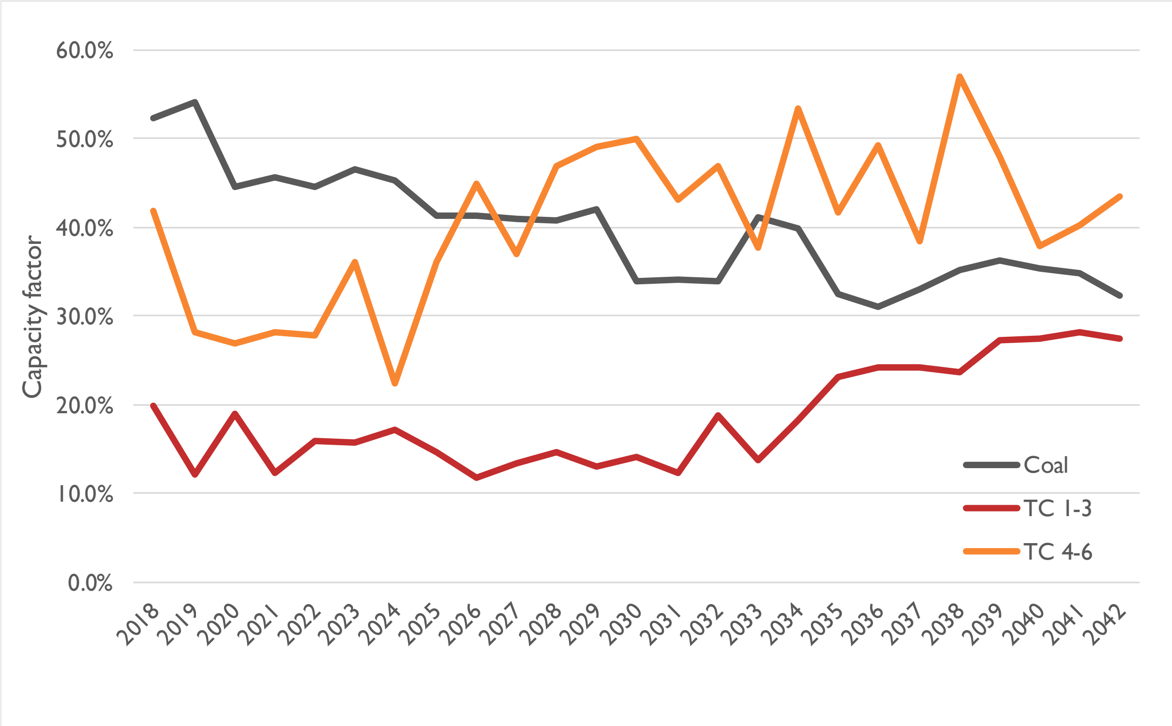


Figure 9: Aggregate Utilization - Scenario 2, Medium DSM

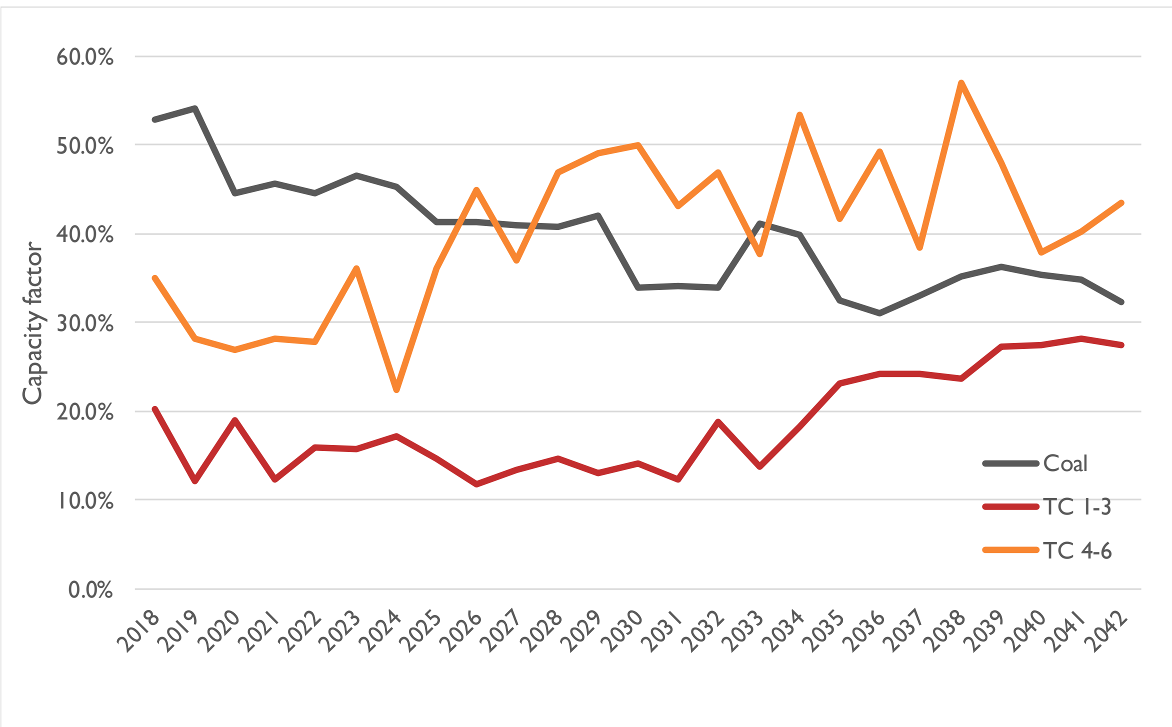


Figure 10: Aggregate Utilization - Scenario 16, NB Transmission, High Wind Capacity Credit, 600 MW Wind

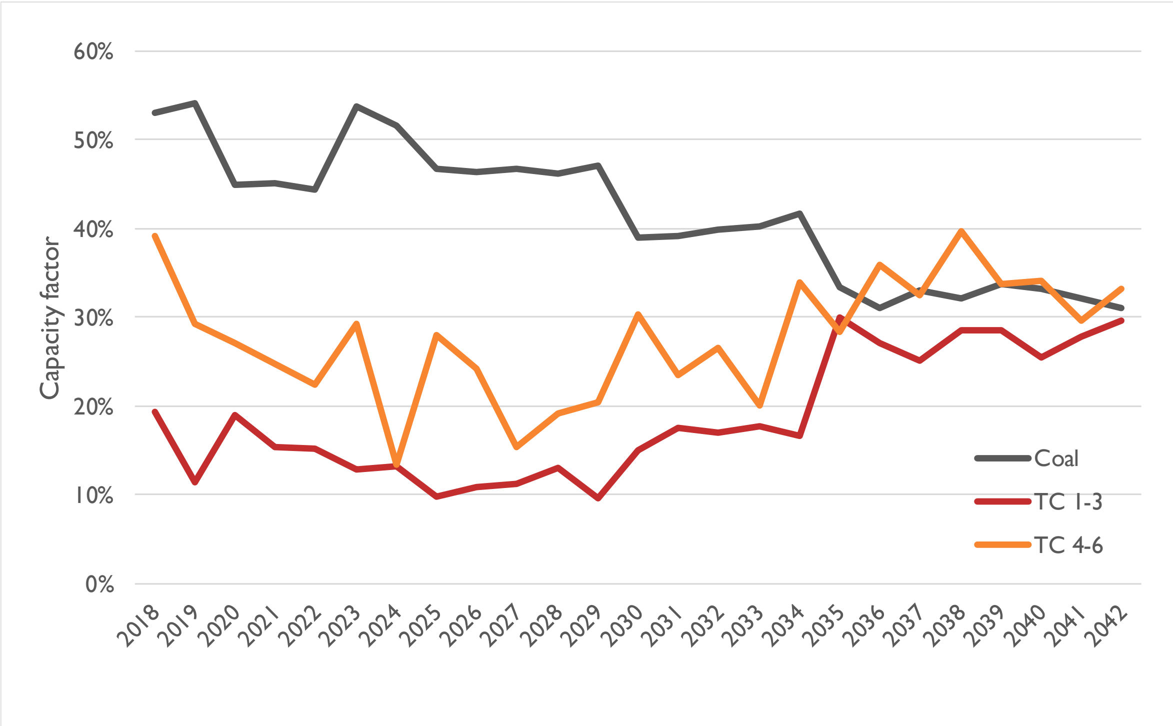
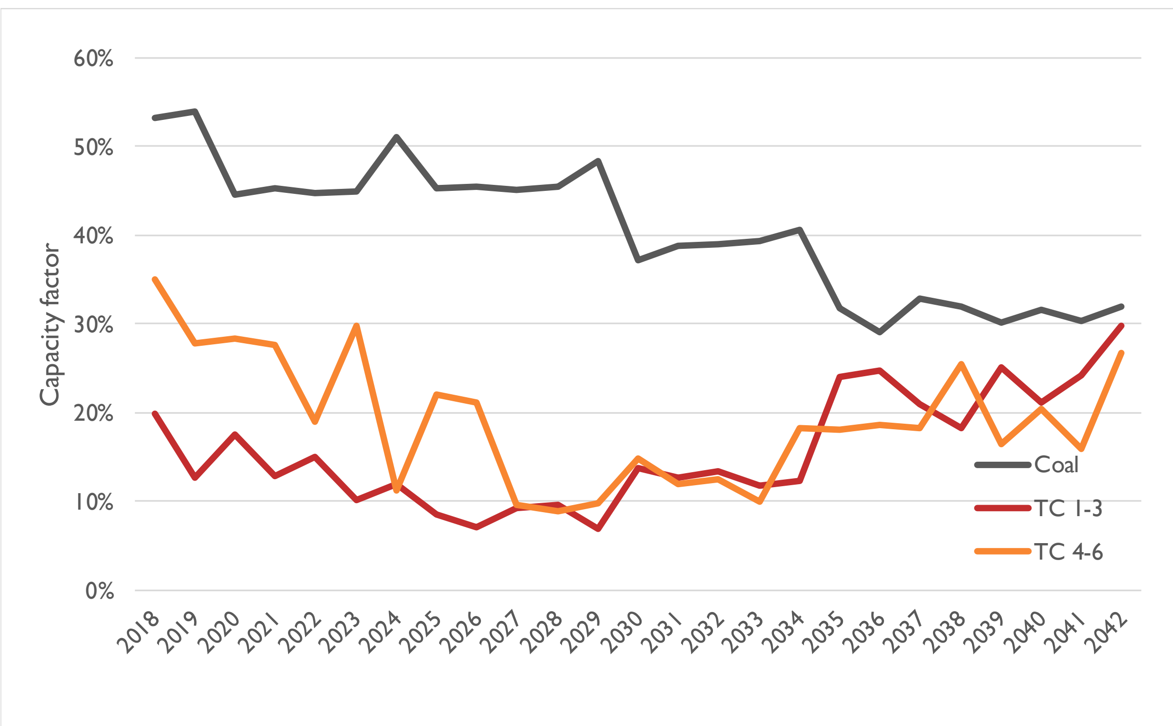


Figure 11: Aggregate Utilization - Scenario 17, Medium DSM, NB Transmission, High Wind Capacity Credit



Source: Plexos Generation Output

Table 11: Capacity Factors – Thermal Fleet

Scenario 1, Reference Case

Capacity Factors - Thermal Units	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
01 - Lingan 1	30%	43%	30%	24%	23%	24%	17%	15%	13%	11%	12%	17%	3%	4%	6%	15%	22%	11%	20%	12%	19%	14%	22%	17%	27%
02 - Lingan 2	20%	18%	15%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
03 - Lingan 3	56%	56%	38%	38%	26%	41%	34%	38%	33%	39%	38%	38%	35%	36%	31%	37%	34%	34%	29%	32%	32%	36%	31%	39%	31%
04 - Lingan 4	48%	53%	36%	37%	38%	32%	33%	35%	25%	28%	28%	22%	19%	16%	18%	-	-	-	-	-	-	-	-	-	-
05 - Point Aconi	75%	72%	59%	78%	77%	72%	81%	72%	81%	86%	78%	85%	72%	74%	78%	80%	74%	77%	65%	77%	86%	77%	73%	78%	63%
06 - Point Tupper	72%	72%	81%	69%	64%	73%	64%	60%	75%	66%	69%	72%	62%	57%	63%	58%	61%	48%	51%	53%	-	-	-	-	-
07 - Trenton 5	40%	39%	24%	16%	26%	27%	21%	13%	5%	6%	2%	2%	0%	2%	1%	9%	4%	2%	1%	1%	1%	6%	3%	3%	5%
08 - Trenton 6	76%	76%	71%	55%	56%	54%	62%	53%	52%	46%	54%	53%	42%	46%	37%	43%	42%	18%	17%	20%	32%	43%	43%	33%	33%
09 - PHBM	58%	53%	53%	54%	52%	49%	53%	54%	52%	50%	42%	50%	50%	47%	49%	48%	49%	55%	51%	52%	50%	49%	54%	48%	55%
11 - Tufts Cove 1	33%	13%	20%	20%	18%	32%	27%	21%	17%	11%	20%	22%	22%	16%	25%	31%	33%	32%	26%	32%	28%	34%	42%	28%	36%
12 - Tufts Cove 2	26%	22%	23%	22%	27%	22%	35%	22%	26%	29%	24%	21%	24%	24%	27%	18%	26%	37%	37%	30%	22%	35%	39%	44%	41%
13 - Tufts Cove 3	9%	6%	16%	2%	8%	3%	0%	7%	0%	5%	6%	3%	4%	3%	10%	2%	5%	9%	15%	17%	23%	19%	13%	18%	14%
14 - Tufts Cove 4	46%	33%	30%	34%	34%	42%	29%	42%	52%	45%	54%	58%	57%	50%	54%	44%	62%	50%	57%	45%	66%	55%	44%	45%	51%
15 - Tufts Cove 5	54%	37%	32%	33%	32%	44%	25%	43%	53%	43%	55%	57%	60%	50%	56%	45%	63%	48%	58%	46%	67%	56%	44%	50%	50%
16 - Tufts Cove 6	25%	14%	19%	17%	17%	21%	13%	22%	28%	23%	30%	32%	32%	28%	30%	24%	34%	26%	32%	24%	37%	31%	25%	25%	29%
New CC	-	-	-	-	-	1%	2%	4%	13%	13%	13%	16%	22%	23%	27%	29%	31%	40%	37%	43%	41%	47%	45%	42%	46%
New CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6%	3%	3%	9%	12%

Table 12: Capacity Factors – Thermal Fleet

Scenario 2, Medium DSM

Capacity Factors - Thermal Units	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
01 - Lingan 1	31%	41%	28%	23%	17%	21%	31%	14%	9%	14%	14%	19%	5%	19%	22%	17%	23%	10%	26%	17%	12%	11%	19%	19%	24%
02 - Lingan 2	21%	18%	14%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
03 - Lingan 3	57%	56%	38%	42%	27%	33%	42%	26%	35%	39%	41%	38%	38%	38%	38%	37%	31%	35%	23%	28%	32%	35%	29%	29%	30%
04 - Lingan 4	49%	50%	35%	37%	42%	34%	29%	38%	23%	23%	30%	20%	25%	-	-	-	-	-	-	-	-	-	-	-	-
05 - Point Aconi	76%	78%	67%	78%	79%	72%	80%	63%	78%	83%	76%	84%	57%	74%	63%	79%	81%	80%	65%	80%	82%	79%	72%	74%	68%
06 - Point Tupper	71%	72%	78%	71%	68%	74%	60%	49%	64%	66%	63%	64%	63%	55%	54%	59%	63%	49%	48%	50%	49%	45%	50%	51%	-
07 - Trenton 5	36%	40%	28%	14%	25%	33%	20%	21%	19%	8%	9%	11%	0%	3%	4%	7%	3%	4%	4%	3%	2%	1%	1%	0%	4%
08 - Trenton 6	79%	78%	68%	52%	49%	55%	47%	52%	56%	45%	53%	52%	29%	46%	42%	49%	45%	22%	17%	20%	20%	21%	23%	16%	37%
09 - PHBM	60%	54%	52%	55%	50%	48%	53%	50%	51%	51%	47%	44%	51%	46%	51%	46%	50%	54%	54%	53%	50%	46%	57%	48%	53%
11 - Tufts Cove 1	33%	14%	23%	16%	19%	21%	8%	20%	9%	12%	9%	14%	21%	16%	24%	19%	19%	35%	25%	25%	14%	33%	34%	29%	21%
12 - Tufts Cove 2	29%	21%	29%	21%	24%	22%	32%	31%	11%	35%	22%	29%	28%	31%	24%	18%	23%	38%	38%	35%	28%	36%	35%	44%	38%
13 - Tufts Cove 3	8%	3%	8%	2%	7%	6%	3%	4%	5%	0%	5%	3%	15%	4%	14%	6%	7%	12%	19%	22%	24%	28%	12%	10%	11%
14 - Tufts Cove 4	38%	32%	31%	30%	33%	41%	30%	51%	49%	43%	45%	47%	47%	45%	48%	31%	52%	48%	57%	44%	53%	41%	44%	38%	36%
15 - Tufts Cove 5	45%	34%	32%	30%	31%	40%	27%	51%	49%	41%	46%	44%	54%	45%	47%	31%	52%	51%	57%	43%	53%	38%	44%	42%	39%
16 - Tufts Cove 6	21%	16%	20%	16%	16%	20%	13%	28%	27%	21%	23%	25%	28%	23%	25%	12%	27%	24%	33%	24%	29%	19%	26%	22%	19%
New CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38%
New CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Table 13: Capacity Factors – Thermal Fleet

Scenario 16, NB Transmission, High Wind Capacity Credit, 600 MW Wind

Capacity Factors - Thermal Units	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
01 - Lingan 1	34%	41%	30%	23%	21%	37%	44%	32%	28%	29%	29%	30%	20%	25%	20%	20%	21%	15%	22%	18%	15%	11%	21%	18%	21%
02 - Lingan 2	21%	17%	15%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
03 - Lingan 3	56%	55%	39%	42%	34%	45%	40%	42%	41%	44%	44%	42%	37%	35%	36%	39%	35%	32%	27%	29%	31%	36%	31%	28%	33%
04 - Lingan 4	48%	50%	37%	37%	37%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
05 - Point Aconi	77%	77%	61%	76%	77%	66%	78%	70%	66%	80%	75%	67%	68%	66%	76%	70%	78%	78%	67%	76%	77%	75%	72%	74%	63%
06 - Point Tupper	76%	73%	82%	66%	58%	76%	65%	56%	66%	71%	67%	73%	60%	60%	62%	63%	64%	40%	46%	48%	42%	51%	43%	50%	49%
07 - Trenton 5	33%	41%	22%	18%	25%	37%	24%	19%	23%	10%	13%	20%	9%	5%	6%	8%	6%	6%	5%	2%	3%	4%	4%	3%	4%
08 - Trenton 6	77%	77%	72%	50%	55%	61%	55%	57%	52%	43%	47%	48%	37%	40%	36%	37%	43%	25%	16%	19%	20%	21%	25%	16%	13%
09 - PHBM	58%	52%	53%	55%	52%	48%	51%	50%	50%	50%	45%	45%	48%	45%	47%	47%	48%	48%	53%	52%	47%	45%	56%	44%	50%
11 - Tufts Cove 1	34%	13%	19%	26%	26%	23%	5%	14%	10%	5%	5%	9%	9%	17%	20%	27%	22%	29%	17%	26%	25%	31%	30%	19%	28%
12 - Tufts Cove 2	25%	21%	23%	29%	28%	19%	31%	11%	14%	27%	29%	16%	27%	28%	34%	19%	25%	39%	41%	35%	33%	38%	38%	42%	42%
13 - Tufts Cove 3	8%	5%	16%	1%	2%	3%	6%	7%	9%	4%	8%	6%	11%	11%	5%	12%	9%	25%	24%	19%	27%	21%	16%	23%	23%
14 - Tufts Cove 4	44%	32%	29%	29%	27%	35%	15%	32%	29%	19%	24%	26%	36%	27%	30%	23%	41%	32%	40%	39%	46%	40%	39%	33%	38%
15 - Tufts Cove 5	49%	38%	32%	30%	28%	34%	17%	34%	29%	18%	22%	24%	35%	28%	35%	25%	39%	35%	44%	37%	47%	39%	40%	36%	39%
16 - Tufts Cove 6	24%	16%	20%	15%	12%	17%	7%	16%	14%	8%	11%	11%	19%	14%	14%	11%	20%	17%	23%	21%	25%	21%	23%	18%	22%
New CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Table 14: Capacity Factors – Thermal Fleet

Scenario 17, Medium DMS, NB Transmission, High Wind Capacity Credit

Capacity Factors - Thermal Units	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
01 - Lingan 1	40%	43%	31%	23%	23%	31%	36%	36%	27%	29%	33%	30%	27%	21%	19%	23%	23%	13%	24%	12%	17%	15%	25%	16%	26%
02 - Lingan 2	21%	17%	15%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
03 - Lingan 3	50%	50%	36%	42%	34%	46%	47%	40%	39%	45%	43%	41%	38%	39%	37%	39%	34%	36%	30%	32%	27%	35%	31%	34%	34%
04 - Lingan 4	50%	51%	40%	38%	34%	25%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
05 - Point Aconi	75%	85%	61%	76%	76%	61%	80%	62%	66%	75%	69%	79%	57%	64%	72%	64%	70%	70%	59%	77%	78%	62%	59%	65%	61%
06 - Point Tupper	70%	73%	78%	69%	60%	74%	58%	63%	70%	71%	66%	72%	56%	55%	64%	57%	64%	41%	38%	49%	48%	42%	45%	42%	-
07 - Trenton 5	39%	43%	25%	16%	30%	29%	23%	17%	20%	10%	11%	19%	4%	4%	9%	11%	7%	4%	1%	1%	1%	3%	4%	1%	7%
08 - Trenton 6	80%	68%	68%	52%	52%	46%	59%	52%	48%	39%	49%	46%	39%	46%	30%	40%	42%	22%	18%	22%	16%	20%	23%	22%	28%
09 - PHBM	59%	53%	53%	56%	50%	46%	50%	53%	52%	52%	44%	45%	47%	45%	52%	49%	48%	50%	48%	48%	46%	46%	53%	47%	51%
11 - Tufts Cove 1	33%	18%	21%	22%	29%	13%	11%	10%	1%	0%	3%	4%	13%	11%	12%	14%	11%	31%	18%	30%	19%	25%	24%	27%	27%
12 - Tufts Cove 2	29%	23%	24%	23%	24%	17%	24%	16%	12%	22%	15%	15%	23%	22%	30%	21%	19%	38%	39%	33%	32%	35%	32%	41%	41%
13 - Tufts Cove 3	7%	4%	12%	2%	1%	4%	5%	4%	8%	6%	10%	3%	8%	8%	4%	4%	9%	12%	19%	9%	9%	19%	13%	12%	24%
14 - Tufts Cove 4	38%	31%	30%	33%	24%	36%	14%	26%	26%	14%	11%	12%	17%	14%	15%	12%	22%	22%	22%	22%	30%	20%	24%	18%	31%
15 - Tufts Cove 5	45%	35%	34%	32%	22%	35%	13%	27%	25%	10%	11%	12%	18%	15%	16%	12%	22%	21%	22%	22%	31%	20%	23%	20%	32%
16 - Tufts Cove 6	20%	17%	21%	17%	11%	18%	6%	13%	12%	5%	5%	6%	9%	7%	6%	6%	10%	11%	11%	11%	14%	10%	14%	9%	17%
New CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Energy by Fuel Type

The presence of the continually declining emissions constraints over the planning horizon causes an ongoing shift away from higher-carbon fuels and towards lower carbon fuels in all scenarios. The mix in any given year for any given scenario depends on the least-cost dispatch results, which account for the emission constraints[30] and the monthly variance in fuel prices, availability of hydro and wind energy (which is on a fixed schedule for all scenarios), and the pricing associated with surplus energy from the Maritime Link and pricing for New Brunswick import energy. Table 15 illustrates the pattern of declining energy shares for coal/petcoke units and demonstrates that under high wind scenarios gas/oil and import-based energy is lower (both energy from New Brunswick and surplus energy from Newfoundland). Figures 12 and 13 show representative energy supply patterns for scenarios 1 and 13. The graphs of energy by fuel type for the remaining scenarios are contained in Appendix 5.5.

Table 15. Share of Annual Energy by Fuel – Reference and High Wind Scenarios

Share of Annual Energy by Fuel	2018-2025	2026-2030	2031-2035	2036-2042
Scenario 1 - Reference				
Coal/Petcoke	42.3%	34.0%	28.3%	22.1%
Maritime Link Incl. NF Recall	12.6%	17.1%	18.4%	20.1%
Oil/Gas	7.7%	11.6%	15.4%	20.7%
Wind	17.7%	18.4%	18.3%	18.5%
Hydro/Other RE	13.8%	13.4%	14.2%	14.5%
NB Imports	5.9%	5.3%	5.4%	4.1%
Total	100.0%	100.0%	100.0%	100.0%
Scenario 13 - High Wind				
Coal/Petcoke	42.1%	33.4%	28.4%	23.0%
Maritime Link Incl. NF Recall	12.1%	13.3%	15.2%	15.6%
Oil/Gas	6.8%	5.3%	8.5%	13.8%
Wind	19.9%	31.4%	31.6%	31.9%
Hydro/Other RE	13.7%	13.7%	13.8%	14.0%
NB Imports	5.4%	2.8%	2.4%	1.6%
Total	100.0%	100.0%	100.0%	100.0%

[30] The emission constraints are on an annual basis. The Plexos environment uses the "MT" or medium-term scheduling processes coupled with the ST dispatch to determine a solution.

Figure 12. Scenario 1 Reference Annual Energy by Fuel Type

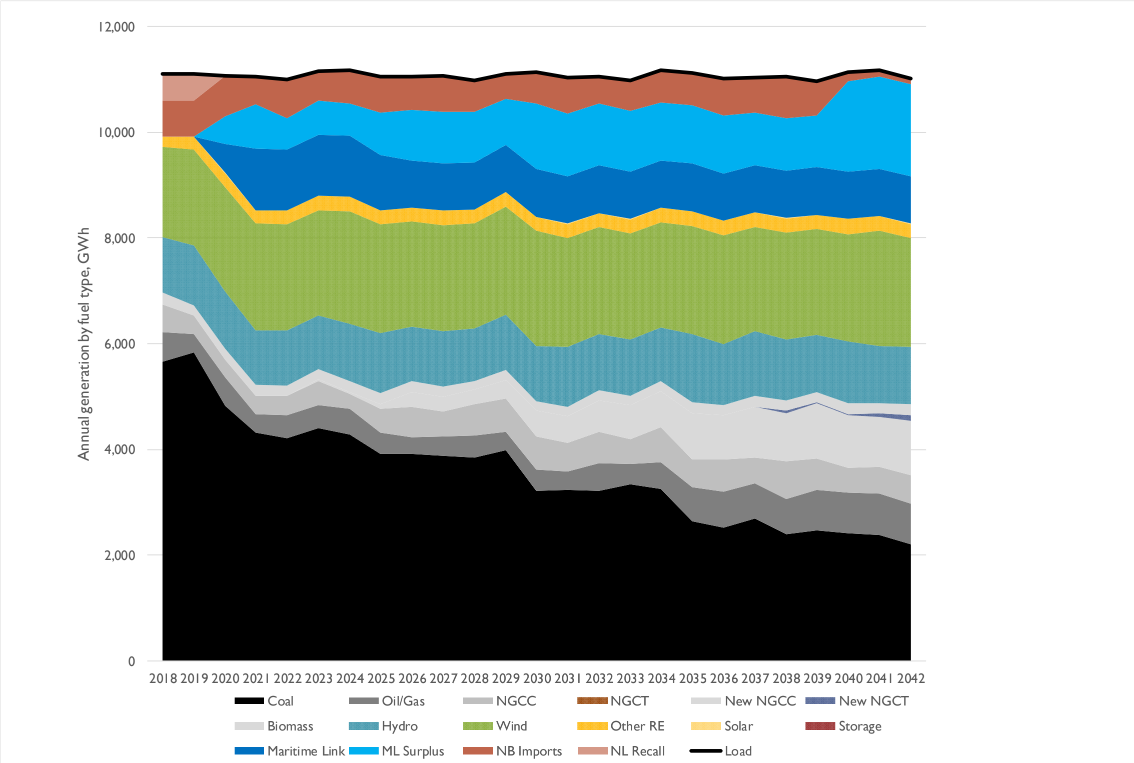
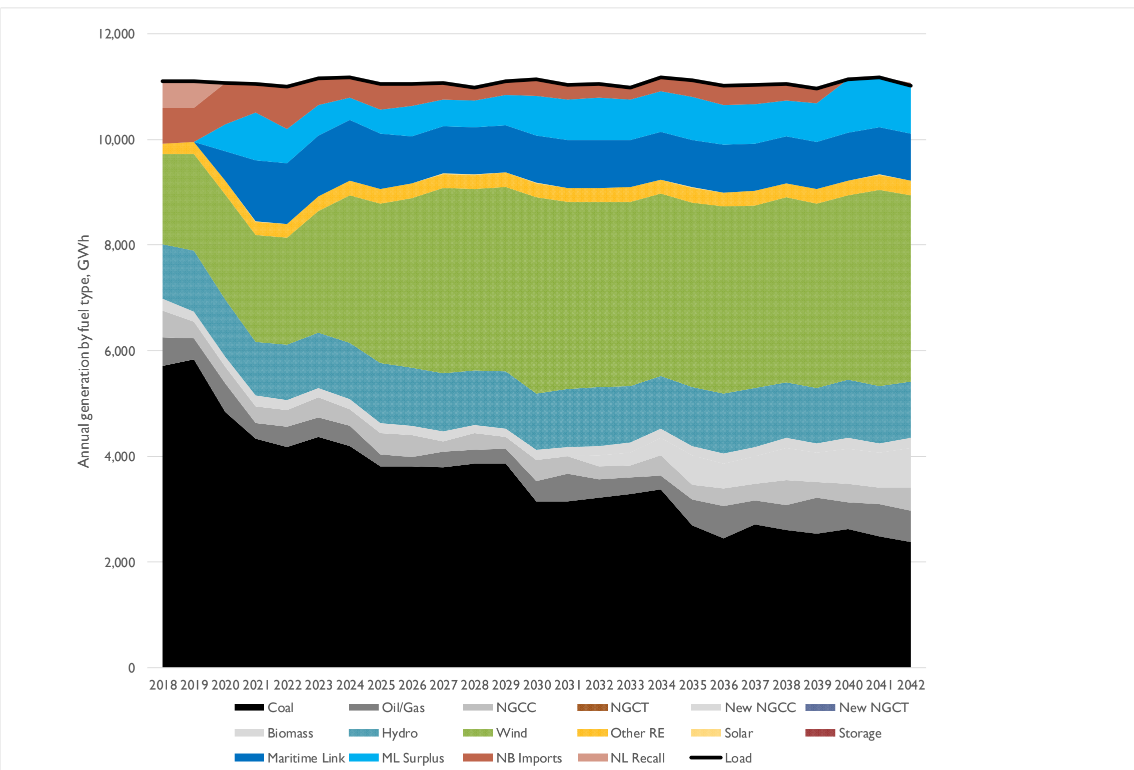


Figure 13. Scenario 13 Reference / NB Transmission / High Wind Annual Energy by Fuel Type



3.5. Emissions

Plexos solves for the unit commitment and dispatch solutions while respecting the emissions constraints listed in the assumptions section. The results indicate that in the LT capacity expansion solution, the input constraints are not exceeded. In the ST production cost model, there is some variation in the exact solution, leading to emission exceedances. In future modeling work, we anticipate refining the exact nature of the emissions constraints in order to ensure a Plexos ST solution that does not violate any constraints. While the likely effect will be solutions that use less coal, and potentially less oil, we don't anticipate that the thrust of our major findings will change when using more exact criteria.

Figure 15. CO_2 Emissions by Scenario

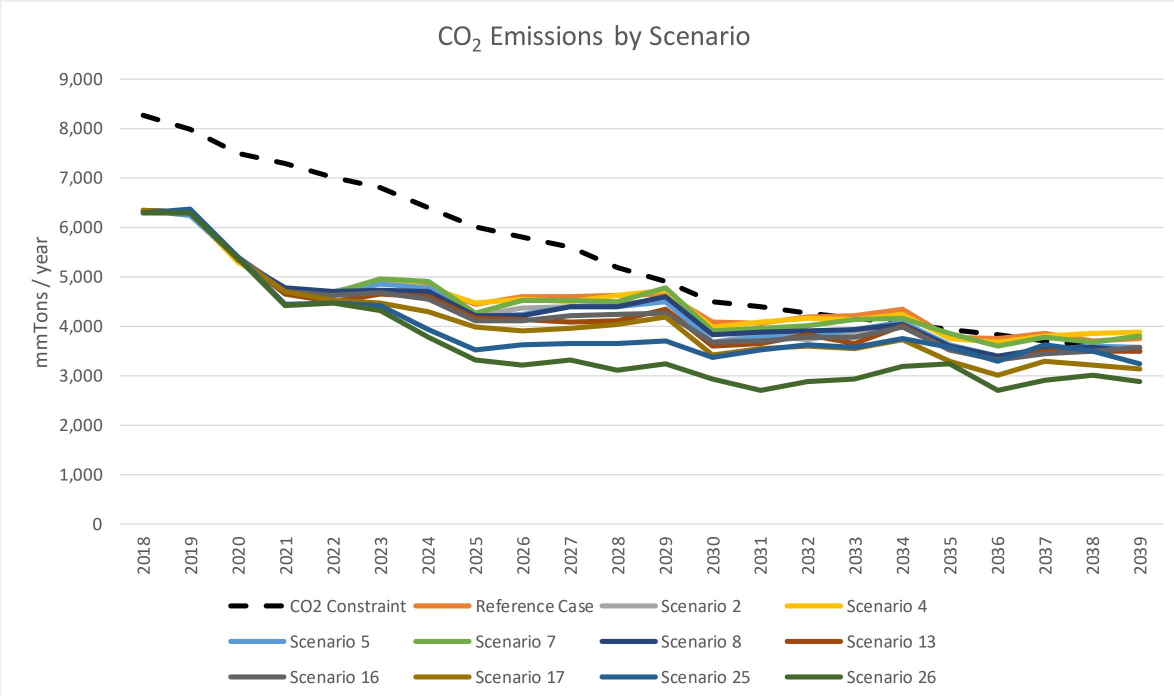


Figure 16. SO_2 Emissions by Scenario

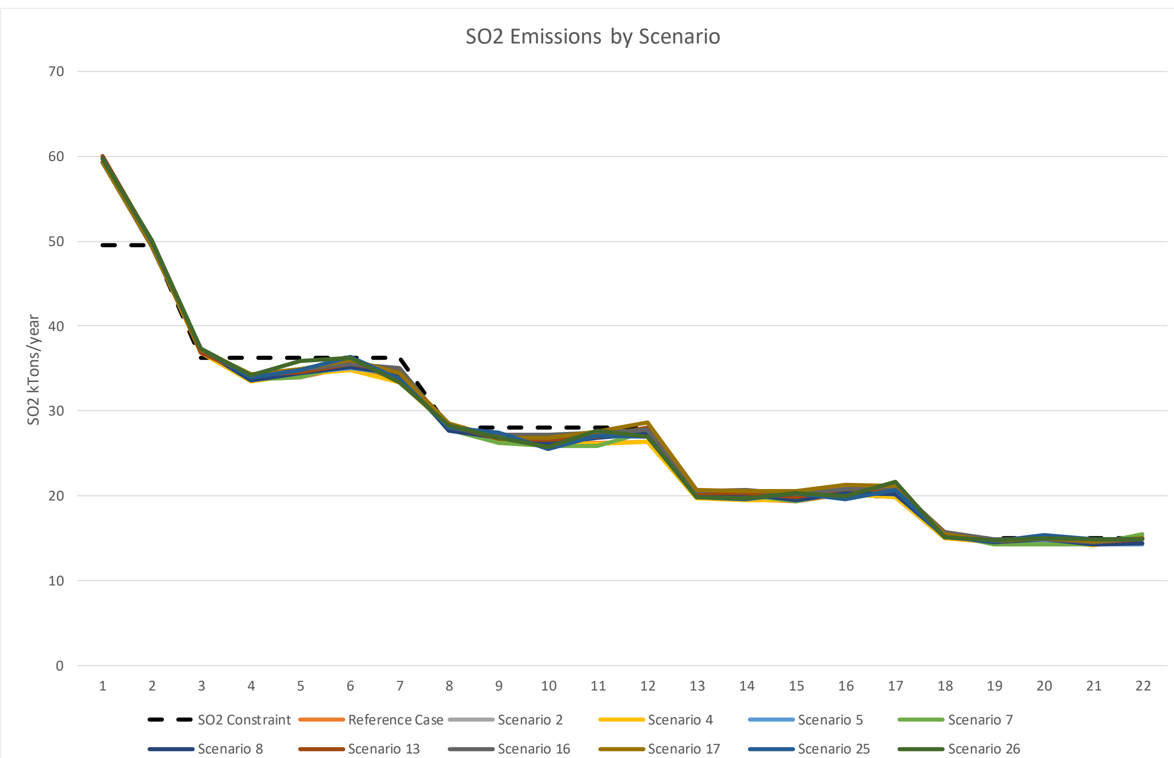


Figure 17. NOx Emissions by Scenario

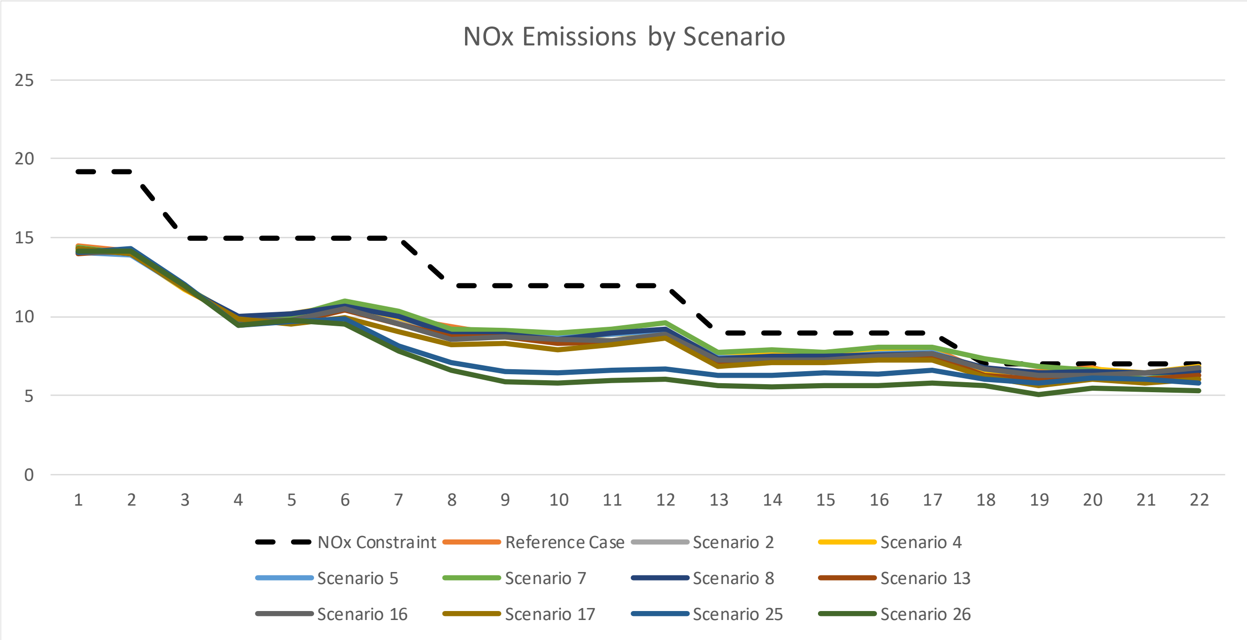
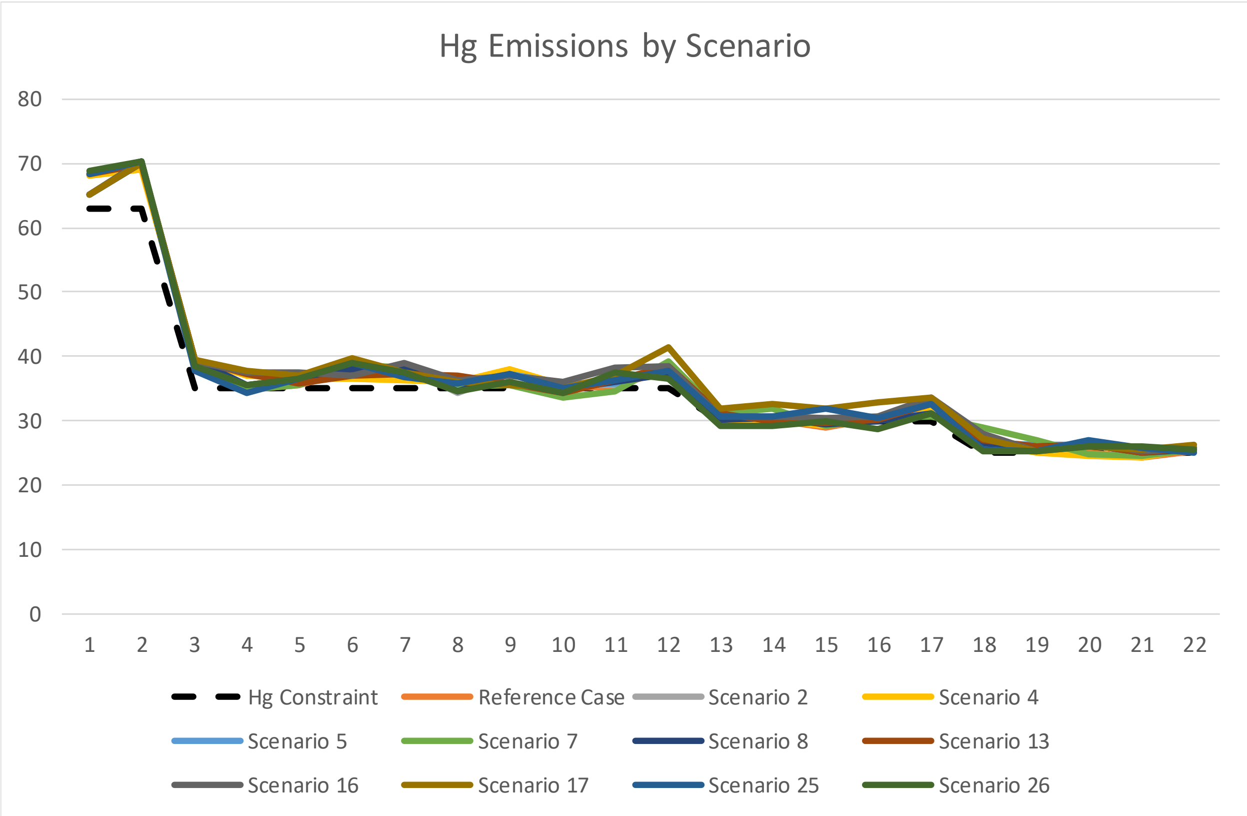


Figure 18. Mercury Emissions by Scenario



3.6. Sensitivities

Low Battery Costs

Synapse executed four low battery cost sensitivity runs. The results are presented in Figure 6a and Tables 9a and 10a above. Those model runs resulted from a review of the Lazard Levelized Cost of Storage Analysis, Version 3.0[31] which was available in December 2017. That study indicated an even lower battery cost outlook than our initial reference inputs. All sensitivities used the same performance parameters (4-hour duration, 10-year economic life). Bulk system battery storage is dispatachable, exhibits cost economies of scale relative to distribution or end-user sized battery storage, can provide nearly-instantaneous frequency response and voltage support, and typically provides its highest value by first providing regulation services to the system. Simultaneously, it can serve as a capacity resource to address resource adequacy needs. We assume higher economies of scale by offering a 20 MW system for Plexos' optimization engine, though we note that smaller size units installed further downstream at distribution system levels can provide additional benefits that in some circumstances could offset higher per-unit costs due to the scale economy effects.

High and Low Gas Prices

Seven sensitivities were executed to test the effect of (1) high natural gas prices on the extent of CT and CC builds and (2) low natural prices on the extent to which increased retirements or additional gas-fueled builds are seen. In both high and low gas price scenarios, we also adjust the market prices for import and export energy between Nova Scotia, Newfoundland, and New Brunswick. Figure 6b and Tables 9b and 10b show the results.

Other Sensitivities

We also conducted three sensitivities tied to forcing out thermal units, two based on the reference (scenario 1) loads, and one based on Medium DSM (scenario 2) loads. We forced out Tufts Cove 3 (in 2026); forced out Tufts Cove 3 (2026) and Trenton 5 (2030); and forced out both units in those same years but under Medium DSM loading (Scenario 2). This was done to assess the effect when very low energy utilization units were removed from the mix of resources. These results are seen in Figure 6b and Tables 9b and 10b.

As noted, we also conducted sensitivities (only to the reference scenario 1) to CT and CC costs, to the availability for those units, and to the combination of cost changes and availability. Lastly, we ran nine sensitivities examining the effect of relaxing transmission and steam constraints in Plexos.

We have not conducted further sensitivity runs on wind costs, even though RFP results in at least two jurisdictions suggest wind resource costs lower than those used in our reference setup. At the end of 2017, Alberta reported results of an RFP for wind resources that indicated average prices below $50 per

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[31] Lazard's Levelized Cost of Storage Analysis, Version 3.0. November 2017, p. 15. Available at https://www.lazard.com/media/450338/lazard-levelized-cost-of-storage-version-30.pdf.

MWh ($CA) for utility-scale wind.[32] Colorado's Xcel reported results for wind and solar resource procurements with relatively low costs ("unprecedented low prices for solar and wind paired with storage"), even after accounting for the effect of the U.S. tax treatment for wind.[33] The lower wind costs only bolster the case for NSPI proceeding with resource planning that incorporates more wind, in line with the scenario results seen in this analysis that are lower cost than reference cases. The low costs for renewable resources paired with storage suggests the importance of reviewing battery storage options including those of varying duration.

We also did not conduct sensitivities or scenarios reflecting further reduction in peak load (beyond our Medium DSM scenarios) through demand response or small-scale storage resources. We discuss the importance of including additional resource alternatives for peak load reduction, such as demand response and storage, in the next section of this report. Lastly, we did not test the effect of any potential increases in the emissions requirements beyond that noted in our input assumptions section.

[32] Canwea. News release, January 2018. Available at https://canwea.ca/news-release/2018/01/30/record-low-price-tops-wind-energy-news-2017/

[33] See Green Tech Media article at https://www.greentechmedia.com/articles/read/record-low-solar-plus-storage-price-in-xcel-solicitation#gs.8UZxasA.

4. DISCUSSION AND RECOMMENDATIONS

4.1. Discussion

Updates Since Technical Conference

Additional modeling runs were conducted using high and low gas prices. As noted in the report, Synapse utilized the most recent US EIA Annual Energy Outlook (2018) forecast of delivered New England natural gas prices to the electric power sector to construct a ratio between reference and high or low gas prices. This ratio was then applied to the actual gas prices used in the model, which reflected NSPI's specific delivered price estimates. The ratio was also applied to the market costs of New Brunswick imports, and Surplus energy from Newfoundland, as those costs are generally tied to the price of natural gas in the region.

The DSM cost accounting and the report section have been updated to incorporate additional information from Efficiency One on their preliminary estimate of the costs to achieve incremental DSM savings beyond that reflected in the reference scenario load. We note that Efficiency One's reference (at the technical conference) to first-year costs for incremental DSM savings on the order of 60 cents per kWh is applicable to the total incremental achievable savings obtained from the Navigant potential report.[34] The total incremental savings significantly exceeds the level of DSM savings Synapse assumed in its Plexos modeling for "medium DSM" scenarios. On average over the 2020-2042 period, the medium DSM scenario load we modeled reflected incremental DSM equal to just 36% of the total incremental savings from the updated Navigant report estimate, to which Efficiency One ascribed the 50-60 cent/kWh first-year savings cost. Thus, we adjusted (downward) the incremental costs from Efficiency One's 60 cent/kWh value, based on an expectation that increases to efficiency spending in Nova Scotia would first attain the lower-cost increments that are available. Nonetheless, our total DSM costs for medium DSM scenarios are increased to ~$410 million (NPV RR), compared to the ~$330 million reported in our Draft Report and at the technical conference.

The Draft Report and the technical conference presentation slides contained a post-processing error that double counted the costs of new Nova Scotia wind, which significantly affected the NPVRR costs associated with all scenarios with increased wind levels, Scenario 13, 14, 16, 17, 25, and 26. The resulting NPVRR costs seen in this report reflect this correction. We note that the build/retirement decisions are not affected by this correction; however, the overall NPVRR for all of the scenarios with wind buildout (13, 14, 16, 17, 25, 26) are lower than the reference scenario. When accounting for the medium DSM loading level, scenarios 14 and 17 are also lower cost than scenario 2, and scenario 26 under the low battery cost sensitivity is roughly the same as scenario 2.

[34] See Efficiency One's April 9 and April 12 (2018) letters concerning the Navigant report achievable savings estimates as updated by Efficiency One.

Demand Side Options

We have limited out assessment to two different loading scenarios, one based on NSPI's reference forecast (2017 load forecast), and one utilizing increased levels of DSM. Any further reductions to peak load through demand response or related "shifting" of peak load will impact the optimal capacity mix needed to meet the planning reserve requirement, and to meet operational reserve and ramping needs for the NSPI system. This is clearly seen in the changed pattern of resource buildout and retirement across the scenarios with, or without, further load reduction from increased DSM levels. Forestalling any need to build additional gas-fired capacity, and potentially earlier retirement of a second coal unit is seen with the medium DSM scenarios.

NB Transmission and Additional Wind Resources

As noted in the report, we have assumed a second 345 kV transmission tie in place that would allow increased levels of Nova Scotia wind resources to connect to the Provincial grid. The low cost of incremental wind and its ability to help lower NPVRR for ratepayers illustrates the critical importance of continuing investment in determining how a second tie could be completed. In addition, the success of the Joint Dispatch pilot project with New Brunswick points to possible increased savings in other areas – unit commitment and long-term planning – if enhanced cooperation could be established. We anticipate that the Regional Electricity Cooperation and Strategic Infrastructure Investment (RECSI) report will shed more light on options for the Province to consider.

4.2. Recommendations

Based on our analysis of the economics of the thermal fleet in Nova Scotia and the build/retirement and NPVRR results we've seen; and in consideration of the limitations and uncertainties associated with the input assumptions used in the modeling exercise, we recommend the following as next steps for NSPI:

Prior to the Next Integrated Resource Planning (IRP) Exercise

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.

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.

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.

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.

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.

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.

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.

Ongoing

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.

9. Monitor natural gas price and availability trends in the Maritimes.

5. APPENDICES

5.1. Terms of Reference (8/1/2017)

5.2. Public Input Assumptions Memo (10/16/2017)

5.3. Response to Stakeholder Comments Memo (12/29/2017)

5.4. Detailed Scenario Results - Thermal Fleet Annual Capacity Factor Tables

5.5. Detailed Scenario Results – Energy by Fuel Type

5.6. Confidential Input Assumptions Memo