Response to Stakeholder Comments on Proposed Terms of Reference
Plexos Optimization Analysis / NSPI Thermal Fleet Retention
August 1, 2017

Synapse has reviewed comments received in response to the June 29, 2017 Proposed Terms of Reference[1] for a Plexos Optimization Analysis to assess the cost-effectiveness of retention of NSPI's thermal fleet through and possibly beyond 2030. We have modified the proposed Terms of Reference in response to those comments, and we include herein an amended Proposed Terms of Reference.

In summary, to address the thrust of all comments received, Synapse will:

1) Adjust the timeline to allow additional stakeholder comment and additional modeling, if needed.
2) Add a stakeholder comment period following our issuance of draft input assumptions. These assumptions will lay out the demand and supply side resource cost and quantity assumptions, and related assumptions such as fuel prices, to be used for reference scenario and "change case" scenarios. The data sources upon which the assumptions rely will also be provided. Change case scenarios will use changes in one or multiple variables to estimate an optimal resource path under an assumption set different from that used for a reference case.
3) Include a specific modeling analysis plan along with the draft input assumptions, identifying with specificity the scenarios to be considered; and explaining any limitations in the total number and makeup of scenarios to execute. In short, the approach will be to define a set of scenarios to run to determine "optimal" resource plans resulting from the modeling, across a range of future assumptions.
4) Finalize the scenario analysis / modeling approach and input assumption sets after review of comments by stakeholders and discussion with NS UARB staff.
5) Allow for another round of modeling after the technical conference, if needed.

The overall timeframe for the analysis and the intended purpose – to broadly identify the extent of cost-effectiveness of thermal fleet retention – prevents Synapse from running all potential resource configurations. We also note that this is a planning exercise, not an operational assessment; we will not be able to prospectively account for every operational detail that may be required to run a future power system with a given set of resources. We will use NSPI's input parameters to ensure that major constraints on power system operation – such as adequate reserve margin, adherence to major transmission transfer limitations, and provision of sufficient ancillary service support (e.g., capacity for regulation and operating reserves) – are respected.

[1] We reviewed the submittals from NPSI, the Consumer Advocate, the Small Business Advocate, the Industrial Group, and Port Hawkesbury Paper Limited Partnership (PHP).

Proposed Terms of Reference - Amended

Plexos Optimization Analysis

Cost-Effectiveness of Retaining NSPI Thermal Resources Through and Possibly Beyond 2030

Synapse Energy Economics

August 1, 2017

Introduction

The Nova Scotia Utility and Review Board's May 5, 2017 letter in M08059 - Generation Utilization and Optimization indicated an engagement with Synapse, to produce an independent analysis of what constitutes an optimal utilization of NSPI's thermal generation fleet. The Board noted a need to assess generation utilization and optimization issues, including accounting for projected sustaining capital expenditures on thermal facilities, and considering potential storage options and wind capacity contributions. The analysis should examine which resource options are most economical for Nova Scotia ratepayers.

These Terms of Reference set out the Objective, Approach, Scope, and Timeline of such analysis. As noted in the Board's letter, the focus of the engagement will be Synapse utilization of the Plexos modeling system to assess optimal use of NSPI's thermal fleet, with data files and technical information concerning system stability and operating constraints provided to Synapse by NSPI.

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[2] 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.

Approach

Synapse's approach will entail use of Energy Exemplar's Plexos modeling framework (portfolio optimization and long-term capacity expansion module) to estimate an economically optimum resource path. The capacity expansion analysis will seek to determine the lowest-cost means to secure sufficient

[2] 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.

capacity and energy to reliably meet Nova Scotia electricity load in all years of the analysis. It will include a time frame of at least 20-25 years (through 2038-2043).

Our initial use of the modeling framework will entail determining a number of different optimal resource paths depending on the underlying set of assumptions used in any given model run. Different model runs will be executed after identifying and specifying assumptions for a number of different scenarios, including a reference scenario and numerous "change case" scenarios (such as, but not limited to, high and low gas prices, different capacity contributions from wind, different levels of sustaining capital). We anticipate specification of different sets of parameter assumptions for key variables, to allow for a comprehensive picture of how optimal resource paths could change depending on the underlying assumptions. The table below illustrates this concept. Something akin to a "candidate resource plan"[3] would result from running Plexos with different combinations of the input assumption sets illustrated below. Due to time limitations, we will not define scenarios for all possible permutations of input assumptions.

Illustrative Matrix: Example of key parameters and range of assumptions

Alternative assumptions: **Parameter:**	**Set 1**	**Set 2**	**Set 3**
Load – Peak and Annual Energy	Current Fcst and EE	Increased EE	Highest EE
Sustaining Capital Requirements	Current (e.g., 2014 IRP projection)	Increased sustaining capital	Highest level of sustaining capital
Gas price (availability)	Med (M&N)	Low (M&N)	High (M&N)
Transmission to NB – import path	500 MW (new 345 kV line)	150 MW (no new line)	800 MW (new line + NB reinforcements)
Wind resource cost trajectory	EIA/NREL/Lazard - Med	EIA/NREL/Lazard – Low	EIA/NREL/Lazard - High
Wind Capacity Contribution	NSPI - Low	GE – Med	GE - High
Demand response potential/cost	Med	Low	High
Storage option costs	Lazard - Med	Lazard – Low	Lazard - High
Carbon costs / constraints	Current trajectory	>carbon price	>>carbon price
Coal / oil prices	Med	Low	High
Balancing area construct	NS	Increased Maritimes coordination	NS+NB+NL highest coordination

M&N: Maritimes and Northeast gas availability / Nova Scotia delivery

Synapse will refine the above approach, developing and documenting the sets of input assumptions to use during July and August.

[3] A "candidate resource plan" was the terminology used in the 2014 IRP process to define alternative resource paths.

The process involved in executing each model run in capacity expansion mode will entail the following steps:

a. Specify load forecast.
b. Specify cost and quantities for demand, supply, and transmission system resources.
c. Specify import and export path parameters.
d. Specify Maritime Link NS Block quantities, and price/quantity pair options for surplus energy.
e. Specify fuel prices, O&M costs, and sustaining capital costs for NSPI fleet.
f. Specify balancing area constructs to model.
g. Specify any other parameters required to conduct a robust analysis, including incorporation of system stability and other operating constraints that are tied to the minimum number of generation units online, system stability or voltage, operating reserves, or related parameters.
h. Execute model runs, iterate as necessary, post-processing of results.

Scope

The scope of work will encompass refining a modeling plan, receiving input from NSPI, specifying input parameters, receiving stakeholder input on the modeling plan and the input assumptions, executing the Plexos model, iterating as required, developing a draft report on results, presenting the results at a technical conference, obtaining stakeholder feedback on the results, conducting additional modeling if needed, and developing a final report. We also understand that the outcome of the modeling process might be subject to a hearing in the early part of 2018. The steps below further itemize this scope.

a. Refine modeling plan – create scenarios/sensitivities as necessary to reflect use of Plexos optimization and capacity expansion modules, and to bound the results given the uncertainties of certain input assumptions. This will include developing a "reference" case set of assumptions, and a set of scenarios that each entail a modification or modifications to the assumption set used for the reference case.

b. Specify the load forecast, accounting for firm and non-firm load (including consistency in the interruptible nature of non-firm industrial load and the demand response resource assumptions). Note load forecast interdependence with assumptions made about demand-side options for energy efficiency and peak load shaving beyond those associated with interruptible industrial load.

c. Research and develop detailed cost and performance assumptions for resources for use in the Plexos modeling environment. This will include all reasonable demand-side and supply-side resources, and the extent of, and constraints on, transmission interconnection capacity between NS and NB and NL. Use NSPI documents and other public documents to inform resource cost trajectories.

d. Specify fuel, O&M, and sustaining capital costs for the thermal fleet. Capture, as reasonably able, both the uncertainty in sustaining capital costs and the likely variation in costs that will depend on the operating requirements or outcomes (e.g., actual ramping characteristics and actual annual capacity factors) of the model runs.

e. Specify balancing area constructs to model. Research and develop alternatives to model balancing area constructs over the longer-term (e.g., NS alone, with import paths from NB and NL; or combined Maritime provincial balancing regions with greater coordination of unit commitment, dispatch, and reserve planning than is currently the case).

f. Include additional constraints in NS as needed to reflect stability, voltage, inertia, minimum unit commitment, operation reserve requirements, or related technical concerns. Obtain information from NSPI in support of defining such constraints for use in Plexos.

g. Develop and deliver "inputs assumption" memorandum. Receive comments on input assumptions memo, and refine as appropriate. This phase, and the underlying research to inform the key analytical inputs, will include both NS UARB staff input and review of stakeholder comments.

h. Execute Plexos modeling runs in concert with the modeling plan and final input assumptions. Review results, discuss with project team, conduct quality assurance, iterate internally as needed; external review will be available with the draft results report.

i. Conduct stand-alone / parallel spreadsheet analysis as needed to support Plexos input assumptions, and to process the raw output results.

b. Prepare draft report on the results of the modeling analysis.

c. Present draft results at day-long technical conference in Halifax; solicit feedback at conference and from post-conference comments.

d. Conduct additional modeling if necessary to refine results and address stakeholder feedback.

e. Prepare final report post technical conference, addressing feedback.

f. Attend hearing on final report.

<u>Discussion of Critical Steps – Modeling Plan and Resource Cost and Quantity Assumptions</u>

Three critical steps include establishing a modeling plan using the Plexos tools, determining the resource cost assumptions to use as inputs to the Plexos optimization modeling, and incorporating a load forecast.

The modeling plan will detail how Synapse will employ the Plexos tool. We anticipate two primary uses of the Plexos tool: unit commitment and dispatch of the system, on an hourly basis, for a selected number of years; and use of the capacity expansion module, to determine the optimal resource portfolio needed to provide required capacity and energy. These will be used in concert with each other. The capacity expansion module allows for long-term optimization of resources, accounting for all costs of all resources, and the time value of money. The unit commitment and dispatch features will ensure that lowest production costs are seen during any given year given the assets in place, and will ensure that load is served, and all ramping requirements and other ancillary service requirements (such as operating reserve needs) are always met. There are a number of different approaches to take in employing the two modes; and as with any modeling exercise, there are different assumptions sets to use to properly bound the analyses. Developing the modeling plan will flesh out these details.

The cost of resources and the profile of resource output serve as critical, fundamental inputs to the modeling process. We will ensure that each of the following resource categories are carefully specified for use in Plexos; we anticipate that early provision (July) by NSPI of detailed Plexos input files in Plexos configuration will be of particular value:

- Existing coal, oil and gas thermal resources, including fixed and variable O&M and any required sustaining capital, and the costs of fuel. If applicable, emission costs.[4]
- Existing hydro and wind resource output profiles and operating costs, including fixed and variable O&M costs and any projected sustaining capital needs.
- Existing biomass resource costs and output profiles, including fixed and variable O&M and biomass fuel costs.
- Existing and new import opportunities. This will be carefully evaluated for Newfoundland and New Brunswick/Quebec/New England paths.
- New fossil resource capital, fixed and variable O&M, and fuel costs. New resource attributes such as generation start up and operational parameters (flexibility, ramp rate, heat rate, emissions rate, etc.).
- New wind resource costs and attributes, and new hydro, tidal, solar PV, and biomass resource cost and attributes.
- New storage resource costs.
- Transmission system reinforcement / expansion costs.
- Demand side costs and attributes: energy efficiency and demand response, especially peak shaving technologies such as direct load control.

The load forecast will be based on NSPI's most recently available forecast. We will ensure consistency between the use of the load forecast, and the parameters considered for demand side resources, either energy efficiency or demand response.

Sources for input data include NSPI, NREL, Lawrence Berkeley Laboratories, US EIA, Lazard, Canadian Electricity Association, International Energy Association, GE reports, NERC, and other publicly available and current data on cost trajectories, price forecasts, and related parameters.

Timeline for Analysis

The table below contains a list of and schedule for key project milestones. Generally, these milestones assume on-time delivery of key data from NSPI, including primarily the Plexos modeling files and also responses to specific inquiries concerning system operation constraints that could affect future resource alternatives, such as operations with fewer rotating steam units, additional interconnection capacity, and reinforced transmission system elements; and general inquiries (e.g., discovery questions on resource inputs).

Milestone	Estimated Date	Comments/Deliverables
Terms of Reference	Final – August 1	Document.
Input Assumptions	July/August finalization	Assumes early July receipt of modeling files from NSPI – Memo. Incorporate stakeholder feedback.
Model Execution - Start	July-Early August	
Initial Model Execution – Finish	October/November	Requires efficient development of modeling plan, scenario/sensitivity specification, and execution.
Model Post Processing and Results	November	Memo.
Draft Report	December/January	Report.
Technical Conference	January/February	Presentation Slides.
Modeling refinements	Post technical conf.	Update memo or presentation slides
Final Report	Early 2018	Report w/ appendices as necessary.

[4] These may already be accounted for in the capped emission requirements for the Province.

Appendix – Synapse Comments After April 2017 Technical Conference

Introduction

These comments are provided in response to the technical conference held at NSPI on April 13, 2017. They address a number of issues concerning the future plan for thermal resources currently in operation on the NSPI system. They are anchored in part on the expectations arising from the 2014 IRP Action Plan, for further analysis of the optimal level of sustaining capital expenditures for the thermal fleet. They also reflect the concerns expressed in the set of NS UARB information requests (October 2016) in regards to NSPI's 2016 10-Year System Outlook Report.

Summary – NSPI's Outlook on the Thermal Steam Fleet

NSPI plans for continuing operation of all thermal steam units except Lingan 2 (retired in 2020 commensurate with Maritime Link availability) through the winter of 2025/26, with an expectation that they would continue to operate through 2030, and possibly beyond 2030. Figure 24 in the 10-Year System Outlook report shows no other planned unit retirements beyond Lingan 2. NSPI notes that Tufts Cove 1 (TUC1) is not projected to retire in 2025, contrary to the 2014 IRP assumption. This is because the 2016 Load Forecast projected an increase in peak load that NSPI claims would require TUC1 in 2025 in order to maintain required resource adequacy. Projections of sustaining capital for Tufts Cove 1 (response to NS UARB IR-6, Attachment 1, page 2) show planned expenditures only through 2024. If TUC1 is not retired in 2025, it is reasonable to expect additional sustaining capital requirements.

Sustaining capital investment in the thermal fleet is currently projected by NSPI at $445 million over the 2017-2026 period (constant dollars, uninflated), as seen in the table on the following page. The 2017 ACE plan contained significantly higher levels of sustaining capital in 2017 compared to what is seen in the table for 2017; the difference for that year was explained in the ACE plan, but critically, no additional information was available on the confidence of the projections for future years.

NSPI has not provided any sensitivity analysis around this projection of sustaining capital expenditure; it is reasonable to surmise significant uncertainty likely exists around this projected amount, given the age of the plants. Notable in the projection of costs is the occasional need for larger-than-average capital injection levels (e.g., $10 million, Lingan 3, 2020; $10 million, Lingan 4, 2024; $13 million, Point Aconi, 2021; $9 million, Trenton 5, 2020; $15 million, Trenton 6, 2025). The 2014 IRP representation did not directly consider the unit-specific, year-to-year requirements for sustaining capital, but instead used a levelized approach to reflect these costs. Any impending year-over-year pattern of expenditures for the steam plants should be directly considered when analyzing an optimal or near-optimal (i.e., ratepayer least cost) plan for sustaining capital investment.

NSPI Sustaining Capital Projections – Thermal Fleet, 2017-2026

NOTE: Forecast as of 2016 10-Year System Outlook Report. Actual Capital Filing for 2017 will be provided in 2017 Annual Capital Expenditure Plan.											
Figure 12	**Investment Year**										
Unit	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**Grand Total**
BGT	$ 5,000,000										$ 5,000,000
Biomass	$ 1,440,000	$ 1,715,000	$ 1,715,000	$ 1,965,000	$ 4,815,000	$ 1,740,000	$ 2,015,000	$ 1,715,000	$ 1,965,000	$ 1,815,000	$ 20,900,000
CTs	$ 3,000,000	$ 6,000,000	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 3,000,000	$ 33,000,000
LIN0			$ 1,000,000					$ 1,000,000			$ 2,000,000
LIN1	$ 1,980,000	$ 2,236,250	$ 2,017,500	$ 1,478,750	$ 1,647,500	$ 660,000	$ 1,066,250	$ 672,500	$ 978,750	$ 1,022,500	$ 13,760,000
LIN2	$ 660,000										$ 660,000
LIN3	$ 2,640,000	$ 2,915,000	$ 2,690,000	$ 10,015,000	$ 2,590,000	$ 2,640,000	$ 9,915,000	$ 2,690,000	$ 3,765,000	$ 4,090,000	$ 43,950,000
LIN4	$ 2,640,000	$ 2,915,000	$ 2,690,000	$ 3,015,000	$ 6,590,000	$ 2,640,000	$ 2,915,000	$ 10,440,000	$ 3,015,000	$ 4,090,000	$ 40,950,000
LMs	$ 5,000,000	$ 2,500,000	$ 2,500,000	$ 5,000,000	$ 2,500,000	$ 2,500,000	$ 2,500,000	$ 2,500,000	$ 2,500,000	$ 2,500,000	$ 30,000,000
POA	$ 6,915,000	$ 6,290,000	$ 4,940,000	$ 5,340,000	$ 13,090,000	$ 7,015,000	$ 4,290,000	$ 5,940,000	$ 4,340,000	$ 5,490,000	$ 63,650,000
POT	$ 4,465,000	$ 6,690,000	$ 12,640,000	$ 3,140,000	$ 3,715,000	$ 3,715,000	$ 3,190,000	$ 2,640,000	$ 3,140,000	$ 2,740,000	$ 46,075,000
TRN0			$ 500,000					$ 500,000			$ 1,000,000
TRN5	$ 3,601,875	$ 3,836,250	$ 2,617,500	$ 8,973,750	$ 2,573,750	$ 7,036,250	$ 2,311,250	$ 2,055,000	$ 2,505,000	$ 1,980,000	$ 37,490,625
TRN6	$ 9,477,500	$ 4,740,000	$ 3,540,000	$ 3,915,000	$ 3,140,000	$ 3,227,500	$ 3,065,000	$ 2,790,000	$ 14,665,000	$ 3,690,000	$ 52,250,000
TUC0			$ 1,000,000					$ 1,000,000			$ 2,000,000
TUC1	$ 2,343,125	$ 768,125	$ 530,625	$ 568,125	$ 505,625	$ 824,375	$ 768,125	$ 543,125			$ 6,851,250
TUC2	$ 2,330,625	$ 1,768,125	$ 530,625	$ 568,125	$ 505,625	$ 824,375	$ 768,125	$ 543,125	$ 568,125	$ 505,625	$ 8,912,500
TUC3	$ 824,375	$ 793,125	$ 3,280,625	$ 868,125	$ 1,255,625	$ 524,375	$ 768,125	$ 543,125	$ 868,125	$ 505,625	$ 10,231,250
TUC6	$ 1,822,500	$ 1,997,500	$ 4,847,500	$ 2,297,500	$ 4,747,500	$ 1,822,500	$ 2,197,500	$ 1,897,500	$ 3,797,500	$ 1,747,500	$ 27,175,000
Grand Total	$ 54,140,000	$ 45,164,375	$ 50,039,375	$ 50,144,375	$ 50,675,625	$ 38,169,375	$ 38,769,375	$ 40,469,375	$ 45,107,500	$ 33,176,250	$ 445,855,625

Source: NSPI, response to NS UARB IR-6, Attachment 1.

Expectations from IRP Action Plan that Influence the Economics of Thermal Fleet Sustaining Capital Investment

The 2014 IRP Action Plan contains action items that are directly relevant to the economic outlook for NSPI's operation of its thermal fleet, because they affect either the level of peak demand (which is a primary driver of underlying resource adequacy requirements), or they affect the capacity contributions available from existing and potentially new alternative capacity resources. The eight action items are characterized below:

1. Optimize the level of sustaining capital expenditures for the fossil-fueled thermal fleet, and include projections of possible retirement paths.
2. Conduct additional system studies to estimate requirements to ensure reliability at higher levels of wind penetration (increased Provincial wind to 750 and 900 MW), including transmission reinforcement, the presence of dynamic and static reactive power facilities, and any other technical innovations that would affect operations. This latter phrasing encompasses the ability for bulk storage resources to provide capacity support.
3. Continue to discuss and explore regional coordination opportunities with Newfoundland and New Brunswick, including exploration of mechanisms to advance efficient regional unit commitment, dispatch and operating reserve sharing.
4. Evaluate ERIS wind resources for capacity value, and in general evaluate the coincidence of all NS wind generation to better gauge the winter capacity value of wind assets.
5. Monitor cost-effective market opportunities (imports and exports). This would include the cost and availability of capacity purchase options.
6. Assess the availability of cost-effective Demand Response opportunities.
7. Obtain DSM resource commitments consistent with the IRP analysis.
8. Evaluate options for Mersey Development, and the potential to add 30 MW of capacity to the system.

In addition to these IRP action items, continuing reductions in the costs of bulk storage resources, wind, and solar PV resources[5] could affect the overall economics of using older coal steam units for capacity provision. Availability and cost of traditional gas-fired peaking/intermediate resource capacity (combustion turbine or combined cycle) is also an important consideration.

A Listing of Specific Concerns with NSPI's Current Assertions that Retention of Seven of Eight Coal Units Through and Possibly Beyond 2030 is Economically Optimal for Ratepayers

<u>1 – Optimize Sustaining Capital Expenditures</u>

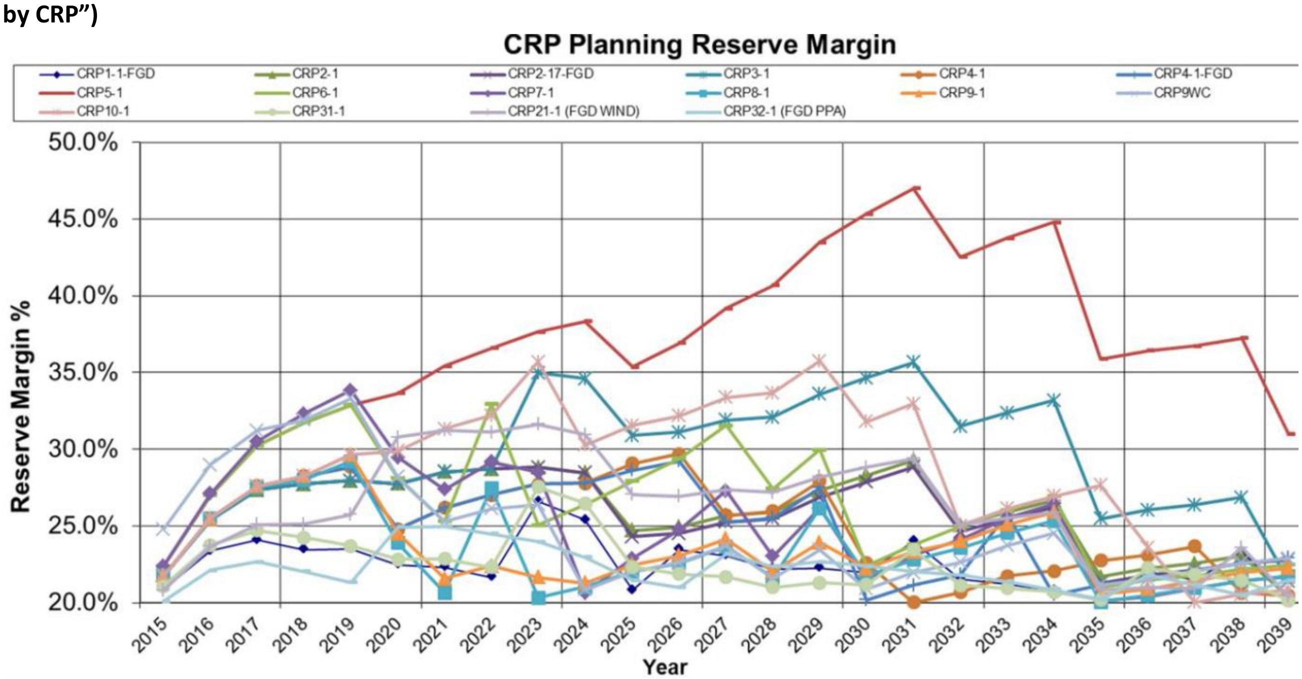
NSPI has not yet conducted a rigorous quantitative analysis of the economically optimal path for sustaining capital investment in the thermal fleet. NSPI stated that "The 2014 IRP results concluded that

[5] While solar PV resources do not directly provide capacity support for winter peak, their presence in the Province affects energy requirements from fossil resources all year long, and could bear on economic issues under scenarios of off-peak seasonal layup of coal plants.

most of the economic options involved longer retention of coal units" (4/13/2017 presentation, slide 27). However, the 2014 IRP did not rigorously examine whether or not longer retention of the coal fleet was economically optimal.

Instead, the 2014 IRP analyses included - *as inputs* - assumptions for sustaining capital costs for each candidate resource plan. The resulting comparison of different plans did not account for the difference in surplus capacity associated with each plan. If the differences were minor, NSPI's conclusion would not be unreasonable, subject to the certainty of sustaining capital cost assumptions. However, the differences were not minor – the plans with higher levels of peak load reduction resulted in surplus capacity levels that were significantly higher than those associated with lower peak load reduction plans, because no adjustment was made in sustaining capital contribution to allow for retirement of surplus capacity. This is shown in the graph below from the IRP report.

Reserve Margin Results from Various Candidate Resource Plans – 2014 IRP ("Figure 3. Planning Reserve Margin by CRP")



Source: 2014 IRP Report (page 1064 of pdf). Original source: NSPI, slide 34, 9/12/2014 technical conference presentation.

This critical aspect of the 2014 IRP analysis illustrates that NSPI's conclusion, as re-stated at the 4/13/2017 technical conference, is not well-supported. It is not at all clear that lengthy retention of the coal units was the most economic option arising from the 2014 IRP analysis.[6]

[6] A truer optimization, given the modeling construct employed during the 2014 IRP, would have required an iterative approach when analyzing the performance of each candidate resource plan. This would have allowed for an apples-to-apples comparison across plan results, in this case because the resulting surplus capacity across the plans varied significantly. Among the best-performing candidate resource plans were those with higher levels of peak demand reduction through DSM, which resulted in significant surplus capacity in the outer years of the

Optimizing sustaining capital expenditures implies that the costs of alternative means of securing capacity must be carefully examined along with the cost of retaining the coal plant capacity. In Nova Scotia, alternative capacity can be obtained through greater levels of peak demand reduction through energy efficiency implementation, through appropriate valuation of the capacity contributions from wind resources, from assessment of capacity purchase options (from existing resources, e.g. imports), from new resources such as wind, storage capacity, or conventional incremental hydro (e.g., Mersey) or gas-fired capacity, and – critically – through programmatic efforts to achieve peak demand reduction through demand response options beyond those currently obtained via interruptible industrial load.

2 – Conduct Additional System Studies

NSPI has not yet conducted any updates to studies that analyzed higher levels of wind penetration in the Province.[7] Nor has NSPI reported on any additional studies to determine the type, magnitude, or costs of additional transmission system support that might be required in such a higher wind penetration scenario. Such support could include 1) further transmission line reinforcements, 2) additions of dynamic or static reactive supply, including the use of SVCs and synchronous condensers, 3) short-duration storage capacity, and 4) other advanced technologies such as but not limited to synthetic inertial support.[8] All of these alternatives could help ensure a reliable system that would operate with fewer online steam units after 2020. NSPI does indicate that a reduction in the number of steam units required to be online is expected by 2020, but further analysis is needed to test system needs under different scenarios of coal plant retirement. The combination of continuing declines in the real costs of wind resources and declines in the projected costs of storage resources[9] is particularly important in assessing the economics of different options under the scenarios that see lower total energy provision from coal plants in Nova Scotia.

NSPI briefly addressed storage alternatives during the technical conference. In response to a question from the Board as part of the 2017 Annual Capital Expenditure Plan (M07745), NSPI indicated that storage options "are not cost competitive" compared to traditional solutions.[10] However, this conclusion was based on an assessment of the Levelized Electricity Cost to Grid,[11] and did not capture

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analysis (e.g., during the 2020s). An iterative modeling approach – which was not available because of time constraints - would have allowed for additional retirement of coal units (to effectively draw down the surplus), and would have resulted in lower total plan costs. Effectively, such iterative techniques would have in theory converged on the best (i.e., lowest cost) solution. Other modeling approaches, for use in future IRPs, can avoid this limitation through careful design.

[7] The GE wind integration study from 2013 is the latest comprehensive NS-specific study available.

[8] Synthetic inertial support could serve as a substitute for inertial support currently provided by online steam units. It is not widely used at this time in the industry. See, e.g., a recent IEEE article concerning Quebec's use of synthetic inertia, available at http://spectrum.ieee.org/energywise/energy/renewables/can-synthetic-inertia-stabilize-power-grids.

[9] See Attachment 1, the Executive Summary from Lazard's Levelized Cost of Storage Analysis ("LCOS 2.0") from December 2016. The full study is available at https://www.lazard.com/media/438042/lazard-levelized-cost-of-storage-v20.pdf, and the Executive Summary is also available at https://www.lazard.com/media/438041/lazard-lcos-20-executive-summary.pdf.

[10] Response to NS UARB IR-37, M07745.

[11] Ibid.

the value associated with using storage resources in an optimal manner. In particular, there was no recognition of the value from storage for regulation/frequency response, and no discussion of the general attributes of storage resources to provide capacity and ancillary services (shorter-duration energy storage requirements) vs. energy services (longer duration energy storage requirements). As noted in an EPRI study on storage (summary presentation attached as Attachment 2), using a levelized cost of energy metric for storage cost comparison is "misleading for energy storage because storage is not a net energy producing device, and LCOE does not capture the value of storage capacity and flexibility".[12]

As also noted in the newest Lazard energy storage cost study,

"Further, our current analysis indicates that the midpoint levelized costs for lithium-ion technologies have already decreased vs. last year's study by ~12%, ~24%, and ~11% for peaker replacement, transmission investment deferral and residential use cases, respectively, partially attributable to declining capital costs, among other factors. **Far from being "something in the distance", certain energy storage technologies and use cases are currently in the midst of rapid cost declines that will likely persist**." (Executive Summary, page 3, **emphasis added**)

<u>3- Regional Coordination Options</u>

Continuing regional coordination has synergistic benefits. Sharing reserves, joint dispatch, and consideration of common unit commitment across Nova Scotia, New Brunswick, and Newfoundland would lead to more efficient operational and planning outcomes. Significant, additional increases in wind penetration in Nova Scotia will likely require a second 345 kV tie to New Brunswick; combined with the presence of the Maritime Link in 2020, the resulting strengthened Maritimes region grid could support increased wind and greenhouse gas reduction more effectively if greater technical cooperation was in existence. The operational impacts of increased wind are more easily mitigated if the three balancing regions across the four Provinces worked more closely on unit commitment and dispatch accounting for wind output variation across the broader region, rather than just within each respective balancing region.

<u>4 – Wind Resources – Capacity Contribution</u>

NSPI continues to utilize relatively small winter capacity credits for wind resources. The overall effect of NSPI's approach is to value the aggregate wind capacity in Nova Scotia at 12%, significantly lower than New Brunswick's use of 20% for resource planning purposes, and lower than Northern Maine's use of 26% to 46% of capacity and Quebec's use of 30%.[13] The contribution of wind resources to capacity requirements must continue to be carefully examined; if Nova Scotia was to use a capacity credit of 20%

[12] EPRI, Energy Storage Cost Summary for Utility Planning:Executive Summary, November 2016, page 17. Available at http://www.tdworld.com/sites/tdworld.com/files/uploads/2016/04/energy-storage-epri-report.pdf.
[13] See Attachment 3, NPCC 2016 Long Range Resource Adequacy Overview, Appendix C – Maritimes (December 2016). Notably, this report also includes information on the relative surplus of capacity that exists in the broader region.

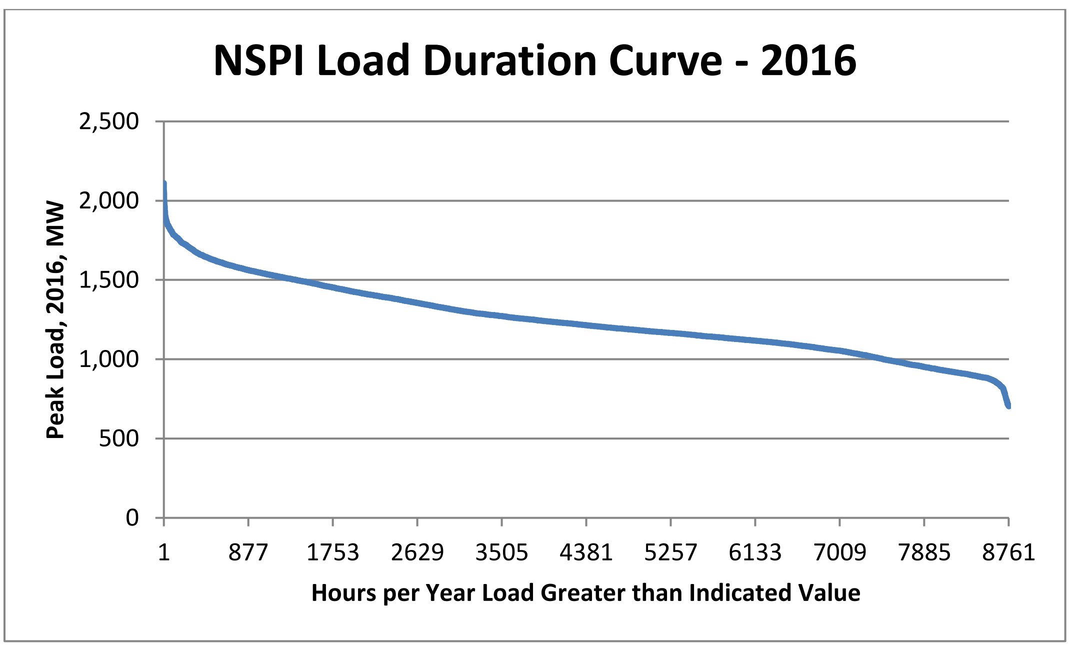
for all its wind resources, the overall increase in contribution towards resource adequacy requirements would be on the order of 48 MW.[14]

5 – Import Capacity

With the planned completion of the Maritime Link, and the possible availability of increased capacity connections with New Brunswick under any future with a second 345 KV tie, the availability of potential purchase of import capacity should be carefully explored. Nova Scotia does not attribute any tie benefits (i.e., recognition of capacity availability in neighboring regions to support resource adequacy needs) to its interconnections, and thus it is important to assess if economical firm purchase arrangements can help to meet any shortfalls in resource adequacy that might arise under different coal plant retirement paths. Additional firm capacity could also be available across the Maritime Link to meet resource adequacy needs.

6 – Demand Response and DSM Resource Commitments through Energy Efficiency Programs

NSPI's need for capacity resources is premised on meeting the peak load. The peak load need exists for a very small fraction of winter hours. In 2016, as in other years, the duration of the highest winter peak loads is infrequent, as seen below in the load duration curve for 2016. To the extent that demand response mechanisms can be incorporated into NSPI's resource base, the need for the last 150 MW – or the last 300 MW – is diminished.



Source: NSPI OASIS, Hourly Load Data, 2016.

[14] Based on 600 MW * (20% - 12%).

In the most recent load forecast, NSPI projects increasing peak load. In response to the Board's question on the mechanism used to integrate DSM into the forecast, NSPI referred to Synapse's recent report which finds the adjustments used "reasonable",[15] for development of the *energy* projections. However, the Synapse report recommended that NSPI should "review and refine the peak load calculations, taking into consideration that the historical peak loads have been essentially flat". The report further notes that NSPI's method led to much greater increase in peak load projection than in energy projection. This nuance in interpretation of Synapse's finding concerning NSPI's shift to using end-use load forecasting methods in place of econometric load forecasting methods is crucial. For the purposes of system planning, a careful review of peak load forecast drivers is imperative.

Suggested Resolution

NSPI rightly indicated at the technical conference that transforming the electrical infrastructure in Nova Scotia to accommodate increased levels of renewable generation and to meet the Province and Canada's goals for greenhouse gas reduction should not be done too fast. However, given the significant impending investments to sustain the thermal steam fleet, it is imperative to analyze options as quickly as possible to determine if investment in the aged coal fleet, compared to alternative investments, is the least-cost means to ensure reliable service for NSPI customers. A portfolio of alternatives, rather than a single substitution of new capacity for coal plants,[16] is likely the lowest cost among competing alternatives to coal plant retention.

We suggest a rigorous analytical approach that fully accounts for all the potential alternatives to operating the entire coal fleet (absent Lingan 2 post 2020). The PLEXOS modeling tool has the capability to conduct a capacity expansion analysis that allows for a more detailed approach than was used during the 2014 IRP.

It will be crucial to comprehensively and accurately address both demand-side and supply side alternatives, to carefully reflect expected changes in costs over time, and properly account for the marginal value of greenhouse gas reduction.[17] Peak load reduction through energy efficiency programs and demand response mechanisms has the potential to reduce going-forward needs for capacity resources relative to NSPI's projected requirements. Any analysis must first rigorously explore the cost and capability of demand side options, and accurately represent their attributes in any capacity expansion exercise.

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[15] NSPI response to NS UARB IR-2 (b-c).

[16] NSPI's example (given at the technical conference) of substituting a combustion turbine for a coal plant to provide equivalent capacity is an oversimplification of the issue. The assumptions listed in that example – the pattern of expenditures for sustaining capital, the capacity factor requirement for substitutes, the initial capital requirements, and even the fuel costs, could all be subject to variation; thus the example does not illustrate a robust outcome. The locational aspects of close-to-load peak load reduction or peaking capacity, compared to (e.g.) Lingan unit operation during peak periods is also not addressed; economic efficiencies associated with marginal loss reduction could be an important factor in locating winter peaking substitutes closer to load than the Lingan station. See Appendix C to NSPI's presentation, slides 34-36.

[17] The presence of any Provincial – Federal agreements on carbon reduction and coal plant closure does not imply limited value in further exploration of continuing reduction in the use of coal, especially for capacity purposes.

Supply side alternatives must include the most up-to-date cost and performance assumptions. The analytical approach must be able to address not only the ramping requirements associated with Nova Scotia's current system, but also ramping and ancillary service requirements under different scenarios of increased penetration of wind resources and utilization of, for example, storage resources.

Supply-side assessment for future years must consider the likely availability and cost of winter gas, sourced from New England. All New England states have stringent requirements or targets for greenhouse gas reduction that would lead to significant reduction in natural gas use for energy generation, making its availability and price for winter use in the Maritimes potentially more economical than is currently considered.

Attachments

1. Lazard Cost of Storage Analysis 2.0, Executive Summary and Full Study (December 2016)
2. EPRI Energy Storage Cost Summary for Utility Planning: Executive Summary (November 2016)
3. NPCC 2016 Long-Range Adequacy Overview – Appendix C, Maritimes (December 2016)

Memorandum

TO: M08059 GENERATION UTILIZATION AND OPTIMIZATION STAKEHOLDERS

FROM: BOB FAGAN, RACHEL WILSON, DAVID WHITE – SYNAPSE ENERGY ECONOMICS

DATE: OCTOBER 16, 2017

RE: KEY INPUT ASSUMPTIONS AND MODELING PLAN FOR PLEXOS OPTIMIZATION ANALYSIS – DRAFT FOR COMMENT

This memo describes a modeling plan and the set of key input assumptions for use in the Generation Utilization and Optimization study. Synapse welcomes all stakeholder comments on the approach and the specific parameter values under consideration, especially those associated with the costs for future energy storage, wind and solar resources; and on the reasonableness of the alternative load scenarios, which incorporate different levels of incremental energy efficiency and demand response (combined, the "DSM" level of the scenario).

We note that the Generation Utilization and Optimization analysis is not intended to produce an integrated resource plan, although the approach contains IRP-like modeling. Primarily, we are attempting to gauge the overall longer-term costs of retention of NSPI's thermal fleet, and compare those costs to maintaining resource adequacy using different mixes of resources. Our aim is to provide a modeling analysis that shows the costs of retention versus the costs of alternative resource plans that use a different mix of resources to meet capacity needs.

The analysis proceeds in an electric sector world where wind, solar, and battery resource costs are declining, energy efficiency continues to be installed in Nova Scotia, and heat pumps begin to replace electric heating and some oil heat. Simultaneously, the average per-unit cost of energy from NS coal resources is increasing relative to historical trends, because of lower overall energy utilization (i.e., capacity factor) of the fleet and aging and operational-related costs. Sustaining capital costs are uncertain. One key question is whether the coal resources continue to remain an economically viable means to meet capacity needs when they produce less energy. The analysis also occurs during a time when electric and gas infrastructure that supports Nova Scotia is changing: the addition of the Maritime Link next year leads to the availability of energy and capacity from the Link in 2020; and ongoing uncertainty about the cost/price and availability of gas from both the Maritimes and Northeast pipeline and Eastern Canadian production sources renders the cost of gas capacity alternatives uncertain. The modeling also proceeds with year-over-year decreases in allowed carbon emissions, throughout the entire period (2018-2042).

Modeling Plan

The table below lists the initial set of scenarios that we will run using the PLEXOS LT (long-term) module. It includes 30 scenarios with varying combinations of core input assumptions, and it includes “bookend” runs that seek to illustrate system costs under two different prescriptive thermal retirement scenarios; these bookends are included for comparison purposes. Potential additional runs under sensitivity cases will be accommodated if/as time allows; and it is possible that resource constraints may not allow us to execute all of these scenarios.

We first define a reference plan using mostly NSPI assumptions, although as we describe below some input assumptions will vary from NSPI’s initial estimates. We then define an additional 29 scenarios to gauge how the PLEXOS capacity expansion plan changes under different core input combinations. Each of these 30 model runs will produce an “optimal” capacity expansion plan from the PLEXOS LT module.

Subsequent to the LT module runs, we will employ the ST module in full production cost mode and conduct model runs for a subset of the scenarios –the lower cost scenarios - to more finely assess production costs and test resource adequacy in a more temporally granular environment. We will plan to run in this mode for five different years of the study period (2020, 2025, 2030, 2035, 2040), and interpolate between these years to create a stream of production costs for the full 25-year period.

Table 1. Initial Scenarios to Test in PLEXOS LT Module

			Key Input Parameters Specification				
Scenario #	**Notation**	**Scenario Name**	**Load**	**Sust Capital**	**Wind CapCredit**	**NB Trans**	**HardCode RetirePath**
1	NSPI Reference	Ref	Ref	Ref	Ref	No	No
2	Change Case	Med DSM	Med DSM	Ref	Ref	No	No
3	Change Case	High DSM	High DSM	Ref	Ref	No	No
4	Change Case	Ref/HighSusCap	Ref	High	Ref	No	No
5	Change Case	Med DSM/HighSusCap	Med DSM	High	Ref	No	No
6	Change Case	High DSM/HighSusCap	High DSM	High	Ref	No	No
7	Change Case	Ref/HighWindCapCredit	Ref	Ref	High	No	No
8	Change Case	Med DSM/HighWindCapCredit	Med DSM	Ref	High	No	No
9	Change Case	High DSM/HighWindCapCredit	High DSM	Ref	High	No	No
10	Change Case	Ref/HighSusCap/HighWindCapCredit	Ref	High	High	No	No
11	Change Case	Med DSM/HighSusCap/HighWindCapCredit	Med DSM	High	High	No	No
12	Change Case	High DSM/HighSusCap/HighWindCapCredit	High DSM	High	High	No	No
13	Change Case	Ref/NB Trans	Ref	Ref	Ref	Yes	No
14	Change Case	Med DSM/NB Trans	Med DSM	Ref	Ref	Yes	No
15	Change Case	High DSM/NB Trans	High DSM	Ref	Ref	Yes	No
16	Change Case	Ref/NB Trans/HighWindCapCredit	Ref	Ref	High	Yes	No
17	Change Case	Med DSM/NB Trans/HighWindCapCredit	Med DSM	Ref	High	Yes	No
18	Change Case	High DSM/NB Trans/HighWindCapCredit	High DSM	Ref	High	Yes	No
19	Change Case	Ref/HighSusCap/NB Trans	Ref	High	Ref	Yes	No
20	Change Case	Med DSM/HighSusCap/NB Trans	Med DSM	High	Ref	Yes	No
21	Change Case	High DSM/HighSusCap/NB Trans	High DSM	High	Ref	Yes	No
22	Change Case	Ref/NB Trans/HighWindCapCredit/HighSustCap	Ref	High	High	Yes	No
23	Change Case	Med DSM/NB Trans/HighWindCapCredit/HighSustCap	Med DSM	High	High	Yes	No
24	Change Case	High DSM/NB Trans/HighWindCapCredit/HighSustCap	High DSM	High	High	Yes	No
Bookends - with Retirement							
25	Change Case	Ref/RetirePath1	Ref	Ref	Ref	Yes	Yes
26	Change Case	Med DSM/RetirePath1	Med DSM	Ref	Ref	Yes	Yes
27	Change Case	High DSM/RetirePath1	High DSM	Ref	Ref	Yes	Yes
28	Change Case	Ref/RetirePath2	Ref	Ref	Ref	Yes	Yes
29	Change Case	Med DSM/RetirePath2	Med DSM	Ref	Ref	Yes	Yes
30	Change Case	High DSM/RetirePath2	High DSM	Ref	Ref	Yes	Yes

Table 2. Primary Modeling Parameters for Scenarios and Possible Sensitivity Cases

Core Scenario Variables	Reference Values	Alternative Values for Scenarios	Possible Sensitivity Cases
Load Forecast - Bounding Cases	1-2017 NSPI Fcst, 2-Med DSM, 3-High DSM	Three different peak/energy scenarios	Higher load case to reflect increased electrification and EVs beyond what is already in reference plan
Sustaining Capital Costs	NSPI 2017 10-Yr System Plan – Extrapolated to years after 2027	NSPI 2017 Plus 50%	+25%, +100%
Wind Capacity Contribution	2017 NSPI 0% ERIS, 17% NRIS	20% All Wind	25% All Wind (GE Study)
NB Transmission	NSPI 2017 $400 Million + New Eng. Capac. Market Costs	Either With or Without NB incremental transmission	Smaller intertie connection, different NS costs
Retire Path 1 Bookend	Synapse: 5 Coal + TC1 by 2026	Only for Scen. 25-27	High Wind Cap Credit, NB Transmission
Retire Path 2 Bookend	Synapse: All Coal + TC1 by 2030	Only for Scen. 28-30	High Wind Cap Credit, NB Transmission

Description/Explanation of Load Forecast Scenarios and Modeling Parameters

The modeling plan includes scenarios with three different “net” load levels. Peak shaving and increased energy efficiency resources in Nova Scotia are critical resources that cannot be as well-represented in PLEXOS as the supply-side alternatives. To minimize the complexity of using PLEXOS and to capture the demand-side potential, we are proceeding with a scenario approach that focuses first on the level of NSPI system load (annual energy and firm peak) that needs to be met by the supply and import resources.

The load forecast table (Table 3 below) outlines the three scenarios used – NSPI reference load, mid DSM, and high DSM. The choice of mid DSM and high DSM is predicated on feasible increments to both energy efficiency implementation in Nova Scotia, and measures to reduce system firm peak, such as direct load control, demand response in addition to currently-available interruptible load, time-of-use rate structures, and enabling technologies that could be used with any AMI installations that may occur over time.

The “med DSM” scenario incorporates solely incremental energy efficiency, tied to increases that target savings at a 2.0%/year (retail sales) level. This level is less than the achieved EE levels seen in the highest tier of US utilities implementing EE. The “high DSM” scenario incorporates this same 2.0%/year EE level, plus an additional peak shaving from a portfolio of demand response measures that could be implemented through conventional and more innovative approaches, such as but not limited to AMI. The table also shows the incremental DSM contributions for peak load reduction (from EE) for the reference, medium and high DSM cases. The 2014 IRP parameters for base case DSM increments, and the base case annual energy, are shown for comparison.

The costs of these load scenarios will be accounted for outside of PLEXOS and will be based on a to-be-determined utility cost per MWh saved (energy) and utility cost per kW of firm peak reduction. We have not estimated these costs at this point in the project, but will do so, with stakeholder feedback, over the course of the modeling. The PLEXOS modeling can proceed without having a firm estimate for these costs; the envelope of quantity reductions is the key input assumption.

As noted, the mid DSM scenario includes ramping up the current energy efficiency programs to achieve a 2.0%/year savings (energy); this includes peak savings that are roughly double the adjusted net peak savings seen in the reference case.

The “high DSM” case incorporates the same level of increased energy efficiency and associated peak reduction as the medium DSM case, but in addition assumes specific increases in peak shaving (demand response). The profile of increased peak savings from demand response is estimated to lead to achieved reductions equal to 5% of net peak load within 10 years, to allow for installation of enabling technologies, and time for customer adaption of such technologies.

We welcome input especially on the trajectory of peak load and energy load reductions that can be achieved through energy efficiency and demand response programs.

These two DSM cases are meant to demonstrate comparative capacity expansion paths under two increasingly more aggressive demand-side approaches to meeting Nova Scotia’s load requirements.

Sustaining capital costs use NSPI’s current estimates, with extrapolations through to 2042 based on the same pattern of expenditures seen in NSPI’s 10 year System Outlook report. To assess the sensitivity of the analysis to higher costs, we define alternative scenarios that assume these costs will be 50% higher. Sensitivities around these values can be considered to test how critical a factor these costs are to overall economics of retention of the thermal units.

Wind capacity contribution effects will be tested by using NSPI’s current values for the reference case (which use 0% capacity contribution for ERIS resources, and 17% for NRIS resources), and using 20% of the installed capacity of all wind as a capacity contribution for alternative scenarios. These values could also be tested as a sensitivity; for example, the recent 2016 GE Pan-Canadian wind reports suggests higher values could be considered.

Scenarios assuming a second 345 kV tie to New Brunswick will be run with different combinations of the other core scenario inputs.

Lastly, to provide an envelope around, or bookend to, the analysis, we will determine capacity expansion paths and alternative costs for aggressive retirement scenarios for the coal fleet and the Tufts Cove 1 plant, as seen in the table below.

	Calendar Year Beginning	
Unit	**Retire Path 1**	**Retire Path 2**
Lingan 2	2020	2020
Lingan 1	2021	2021
Tufts Cove 1	2022	2022
Lingan 3	2023	2023
Lingan 4	2024	2024
Trenton 5	2025	2025
Trenton 6		2026
Point Tupper		2028
Point Aconi		2030

The other key variables incorporated into the PLEXOS modeling system are alternative resource costs, fuel and O&M costs, and import costs. Table 4 (following, below) summarizes the input assumptions, presents options for possible sensitivities, and includes comments.

Table 3. Load Forecast Scenarios

	All Cases		Reference Case MW			Medium DSM Case MW			High DSM Case MW			Compare	Annual GWh Energy		Compare
Year	Firm Peak No DSM	Inter-ruptible Loads	Annual Increm. Peak DSM	Peak DSM Cum Total	Firm Peak With DSM	Peak DSM Cum Total	Annual Increm. Peak DSM	Firm Peak with DSM	Add'l Demand Response Peak	Peak DSM+DR Cum Total	Firm Peak with DSM+DR	2014 IRP - Base Case Annual Increm. DSM Peak Save	Reference	Medium and High DSM (Same)	2014 IRP - Base Case Annual Energy
2018	2,014	156		21	1,993	38		1,976	0	38	1,976	26	10,987	10,955	11,022
2019	2,043	156	12	33	2,010	63	25	1,980	10	73	1,970	25	10,952	10,864	11,024
2020	2,077	155	15	48	2,029	91	28	1,986	20	111	1,966	23	10,976	10,805	9,966
2021	2,099	155	13	61	2,038	121	30	1,978	30	151	1,948	22	10,947	10,690	9,922
2022	2,128	155	14	75	2,053	150	29	1,978	40	189	1,939	23	10,958	10,615	9,922
2023	2,161	154	13	88	2,073	179	30	1,982	50	229	1,932	22	10,983	10,554	9,931
2024	2,181	154	13	101	2,080	209	30	1,972	59	268	1,913	23	11,010	10,497	9,961
2025	2,199	154	14	115	2,084	237	29	1,962	69	306	1,893	20	10,980	10,388	9,933
2026	2,212	153	14	129	2,083	266	28	1,946	78	344	1,868	23	10,958	10,293	9,929
2027	2,230	153	15	144	2,086	293	27	1,937	87	380	1,850	29	10,967	10,240	9,889
2028	2,255	153	15	159	2,096	322	30	1,933	97	419	1,836	28	10,965	10,164	9,884
2029	2,280	153	15	174	2,107	352	30	1,928	96	448	1,832	32	10,963	10,088	9,802
2030	2,306	153	15	189	2,117	382	30	1,924	96	478	1,827	33	10,960	10,012	9,744
2031	2,331	153	15	204	2,127	412	30	1,919	96	508	1,823	33	10,958	9,937	9,690
2032	2,357	153	16	220	2,138	443	31	1,914	96	539	1,819	32	10,956	9,863	9,640
2033	2,383	153	16	235	2,148	474	31	1,910	95	569	1,814	31	10,954	9,789	9,595
2034	2,410	153	16	251	2,159	505	31	1,905	95	600	1,810	30	10,951	9,716	9,555
2035	2,437	153	16	268	2,169	536	31	1,901	95	631	1,806	29	10,949	9,644	9,523
2036	2,464	153	16	284	2,180	568	32	1,896	95	662	1,802	27	10,947	9,572	9,497
2037	2,491	153	17	301	2,190	599	32	1,892	95	694	1,797	24	10,945	9,500	9,484
2038	2,519	153	17	318	2,201	632	32	1,887	94	726	1,793	26	10,943	9,429	9,469
2039	2,547	153	17	335	2,212	664	32	1,883	94	758	1,789	24	10,940	9,359	9,463
2040	2,575	153	17	352	2,223	697	33	1,878	94	791	1,785		10,938	9,289	
2041	2,604	153	18	370	2,234	730	33	1,874	94	824	1,780		10,936	9,219	
2042	2,633	153	18	388	2,245	763	34	1,870	93	857	1,776		10,934	9,150	
CAGR '18-'27	**1.1%**				**0.5%**			**-0.2%**			**-0.7%**		**0.0%**	**-0.7%**	
CAGR '18-'42	**1.1%**				**0.5%**			**-0.2%**			**-0.4%**		**0.0%**	**-0.7%**	

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Table 4. Other Variable Values, Performance, Escalation, Comments, and Sensitivity Options

Other Variables	Source - Costs	2017 Value ($CA)	Perform -ance	Real Cost Escalation Rate	Comments	Possible Sensitivity Cases
Battery Costs – average LCOS, peaker replacement (4-hour duration)	Lazard 2.0	$541/kWh	92% RT eff.	-9%/year	Ave. value peaker replacement $433/kWh $US. Ave. escalation rate for power/energy sources.	Low: Lazard 2.0 low end, or lower duration (2 hrs. vs. 4 hrs.)
Gas Price Delv'd. M&N	NSPI 2017	Conf.		Long-term flat.		Low: EIA AEO 2017 Low Gas
Wind Costs – installed	NSPI 2017	$2,000/kW	40% CF, Utility Scale	-2.0%/year	LBL, Lazard similar costs. Estimated cost trend. Estimated performance best available sites. Recent cost declines > than 2%/yr.	Lower/higher installed costs, performance
NB Transmission	NSPI 2017	$400 million			345 kV back to Coleson Cove.	
Imports via NB: NE Market Capacity Costs + Transmission	Synapse: Recent FCM + NSPI for NB Transm. Costs	FCM=$6.61/kW -month		0%/year	NE FCM 2020 clearing price $5.30/kW-mo. $US	Lower transmission costs – partial build or different cost allocation
Imports via ML: NE Market Capacity Costs	Synapse: Recent FCM	FCM=$6.61/kW -month		0%/year	NE FCM 2020 clearing price $5.30/kW-mo. $US	Negotiated pricing - NFL
Solar PV Costs	LBL 2016 Utility Scale Solar Report, Lazard 10.0	$2.75/watt (AC) median	18.3% CF (AC)	-2.5%/year	$US 2.2/watt (AC) Lazard, LBL similar values. 0.15/watt adder single axis tracking	Higher/lower costs
Coal Prices	NSPI 2017	See Figure 2.				
Oil Prices	NSPI 2017	See Figure 3.				
Carbon / CO2 emissions	NSPI 2017	See NSPI 2017 10-Yr. System Outlook p. 34			Declining cap per regulations through 2030, and continuing @ ~2.5%/yr thereafter.	2030-2042 Steeper Cap Decline (5%/year)
SO2, NOx, Hg	NSPI 2017	See NSPI 2017 10-Yr. System Outlook p. 35-36.			Declining cap per regs. thru 2030. NOx constant after. SO2, Hg step declines - 2035.	
Gas-Fired CT, CC Costs	NSPI 2017	See Table 5.		0%/year	250 MW CC, 100 MW CT, 93 MW RICE	
Fixed and Variable O&M Costs	NSPI 2017	Varies		0%/year	Sustaining capital costs pick up related cost increases	
Wreck Cove Pumped Stor.	NSPI 2017	Confidential				

Figure 1. Average Annual Natural Gas Prices – Nominal and Real. Winter and Summer Nominal Natural Gas Prices.

Figure redacted

Real price estimated using 2% inflation. Source: NSPI Plexos inputs.

Figure 2. Coal Prices

Figure 2 redacted.

Source: NSPI Plexos inputs.

Figure 3. Heavy Oil Prices

Figure 3 redacted.

Source: NSPI Plexos inputs.

Table 5. New Fossil Fuel Generation Costs

	Capacity (MW)	Heat Rate (btu/kWh)	Capital Cost (2017 $/kW) Low	Base	High	Fixed O&M ($/kw-yr)	Variable O&M ($/MWh)	Lead Time (years)
Combustion Turbine	100	8,700	$1,180	$1,315	$1,500	$12.00	$6.00	2-4
Combustion Turbine	49	9,600	$1,180	$1,315	$1,500	$12.00	$6.00	2-4
Conventional CC (1 x 1)	253	7,200	$1,425	$1,580	$2,000	$16.00	$3.50	3-5

	Capacity (MW)	Heat Rate (btu/kWh)	Capital Cost (2017 $/kW) Low	Base	High	Fixed O&M ($/kw-yr)	Variable O&M ($/MWh)	Lead Time (years)
Phased-in Conversion CC (Add HRSG)	150	8,000	$1,620	$1,800	$2,075	$16.00	$3.75	4-7
Conventional CC (1 x 1)	145	7,200	$1,460	$1,620	$1,860	$16.00	$3.50	3-5
Reciprocating Engine (10 x 9.3 MW)	93	8,520	$1,400	$1,560	$1,800	$12.00	$10.50	2-3

Source: NSPI

Time Frame

- 25 Years (2018-2042) for capacity expansion runs.

- At least five individual years for ST production cost (8760 hour) runs (2020, 2025, 2030, 2035, and 2040).

Specific Capacity Resource Options to be Considered in Capacity Expansion/Retirement Analysis

The following resource options will be made available to PLEXOS in capacity expansion optimization mode. Cost parameters are listed in Table 4.

1. Existing thermal fleet (less Lingan 2, retired in 2020): Lingan 1, 3 and 4, Pt. Tupper, Trenton 5 and 6, Point Aconi, Tufts Cove 1, 2 and 3, and Tufts Cove 4, 5 and 6. Sustaining capital costs will be incorporated into the O&M cost representation in PLEXOS to allow for these costs to be directly considered in the optimization.

2. Onshore wind 100 MW increments. Annual capacity factor = 40%.

3. Solar PV – Utility Scale w/ single-axis tracking – 5 MW increments. Annual capacity factor = 18.3% (AC).

4. Bulk System Li-ion Battery Storage 20 MW increment, 2-hour duration costing.

5. Bulk System Li-ion Battery Storage 20 MW increment, 4-hour duration costing.

6. Pumped Storage – Wreck Cove expansion scenario, 6-hour duration costing.

7. Combined cycle unit (gas/oil) 250 MW.

8. Combustion turbine unit (gas/oil) 100 MW.

9. Reciprocating Engine (gas/oil) 93 MW (9.3 MW x 10 units).

10. Import capacity 10 MW increments – via Newfoundland – beyond NS Block commitment – up to 150 MW.

11. Import capacity 10 MW increments – via New Brunswick if new transmission – up to 300 MW.

Baseline Resource Mix

All scenarios will assume the following resources remain:

- CTs (Burnside 1-4, Vict
  oria Junction, Tusket) – 231 MW total (includes Burnside 4).

- All current hydro/tidal (377.1 MW) plus 30 MW increment at Mersey. Assume 10 MW increment at Wreck Cove (Source: NSPI).

- All current NSPI renewables (wind, biomass) remain in place at existing MW levels.

- All current IPP facilities remain in place at existing MW levels (wind, small hydro, biomass, tidal, including FIT).
- ML Block, Supplemental, quantities commencing in 2020.
- ML Surplus energy (NSPI pricing - MA hub pricing).
- NB import/export paths, existing capability (NSPI pricing based on MA hub).

Other Constraints

Plexos modeling constraints will include the following:

- Allow up to 600 MW of additional wind in NS only with NB transmission option, no earlier than 2022 for new transmission.
- Allow up to 100 MW of additional wind in NS after Maritime Link in place, to test wind addition economics in the absence of new NB transmission.
- 20% planning reserve margin over firm peak.
- Various transmission path flow constraints.
- Various unit commitment constraints (e.g., minimum number of thermal units online).
- Operating reserve/ancillary service constraints – e.g., ramping, spinning, regulation.

Sustaining Capital Costs

Sustaining capital costs for the reference case will be as reflected in NSPI's 2017 10 Year System Outlook. The alternative case scenario will assume sustaining capital costs are 50% higher than those costs. Synapse will extrapolate these annual costs for all remaining years of the study period beyond the values available from NSPI in the 2017 outlook report.

Key Sources

1. NSPI, 2017 10-Year System Outlook, 2017 Load Forecast, responses to discovery questions (M08059).
2. Lazard's Levelized Cost of Energy Analysis, Version 10.0, December 2016. https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf
3. Lazard's Levelized Cost of Storage Analysis, Version 2.0, December 2016. https://www.lazard.com/media/438042/lazard-levelized-cost-of-storage-v20.pdf
4. EIA AEO 2017 Natural Gas Price Projections for Electric Power Sector, New England Region, https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-AEO2017&region=1-1&cases=ref2017&start=2015&end=2050&f=A&linechart=~ref2017-d120816a.38-3-AEO2017.1-0&map=ref2017-d120816a.4-3-AEO2017.1-0&ctype=linechart&sourcekey=0

5. LBL Wind Technologies Report 2016. https://energy.gov/sites/prod/files/2017/08/f35/2016_Wind_Technologies_Market_Report_0.pdf
6. Lawrence Berkeley Laboratories, Utility Scale Solar 2016. https://emp.lbl.gov/sites/default/files/utility-scale-solar-2016-report.pdf
7. NREL PV Watts for estimate of annual capacity factor from single-axis tracking solar PV. Shearwater, NS location. http://pvwatts.nrel.gov/
8. Pan Canadian Wind Integration Study, Revision 3 (October 2016). http://canwea.ca/wp-content/uploads/2016/07/pcwis-fullreport.pdf

Memorandum

TO: M08059 GENERATION UTILIZATION AND OPTIMIZATION STAKEHOLDERS

FROM: BOB FAGAN, RACHEL WILSON, DAVID WHITE – SYNAPSE ENERGY ECONOMICS

DATE: DECEMBER 29, 2017

RE: RESPONSE TO STAKEHOLDER COMMENTS ON KEY INPUT ASSUMPTIONS AND MODELING PLAN FOR PLEXOS OPTIMIZATION ANALYSIS

This memo responds to the set of stakeholder comments provided in November in response to Synapse's October 16, 2017 "Key Input Assumptions and Modeling Plan" memo. Synapse received formal comments from NSPI, Efficiency One, the Industrial Group, Port Hawkesbury Paper, and the Small Business Advocate. Synapse received a less formal inquiry from the Ecology Action Center. In aggregate the comments included suggestions for modifying input assumptions and simplifying the modeling plan. We agree that simplifying the modeling plan would be a useful step and we will reduce the total number of scenarios to twelve (from 30) for our initial set of runs. We also address input assumption concerns and note associated changes to be instituted in the model runs.

We anticipate that our initial modeling results memorandum will be available by the end of January, a draft report in February, with a technical conference to follow in 2-3 weeks after the draft report is available. We anticipate additional modeling runs following discussion and input at the technical conference, with a final report available as soon as possible after the conference, reflecting results from all subsequent model runs.

Modeling Plan Changes in Response to Comments – Initial Set of Scenarios Reduced to 12

- Reduce initial load scenarios to two, a reference case and a "Med DSM" case.
- Reduce the number of permutations of sustaining capital, wind capacity credit, and NB transmission inputs for the initial set of runs. Run just two scenarios with "high" sustaining capital costs, but continue to test higher wind capacity contribution (20%) associated with scenarios where increased transmission to NB is in place.
- Reduce the number of "Bookends – with Retirement" to reflect only "Retire Path 1" for the reference and Med DSM scenarios. The Retire Path 1 bookend retains three coal units and retires five coal units and Tufts Cove 1.

At this time, we will retain the use of demand side and NB transmission as scenario options rather than allowing PLEXOS to choose these as resource options, in order to see thermal fleet retention effects arising from PLEXOS optimization if these fairly major infrastructure and loading scenarios were in place. The revised table below indicates which runs will be prioritized in our initial set.

Table 1. Revision to Initial Scenarios to Test in PLEXOS LT Module

LT Capacity Expansion Scenario Runs							
Greyed field indicates lower priority scenario - not run in initial set			Key Input Parameters Specification				
Scenario #	Notation	Scenario Name	Load	Sust Capital	Wind CapCredit	NB Trans	HardCode RetirePath
1	NSPI Reference	Ref	Ref	Ref	Ref	No	No
2	Change Case	Med DSM	Med DSM	Ref	Ref	No	No
3	Change Case	High DSM	High DSM	Ref	Ref	No	No
4	Change Case	Ref/HighSusCap	Ref	High	Ref	No	No
5	Change Case	Med DSM/HighSusCap	Med DSM	High	Ref	No	No
6	Change Case	High DSM/HighSusCap	High DSM	High	Ref	No	No
7	Change Case	Ref/HighWindCapCredit	Ref	Ref	High	No	No
8	Change Case	Med DSM/HighWindCapCredit	Med DSM	Ref	High	No	No
9	Change Case	High DSM/HighWindCapCredit	High DSM	Ref	High	No	No
10	Change Case	Ref/HighSusCap/HighWindCapCredit	Ref	High	High	No	No
11	Change Case	Med DSM/HighSusCap/HighWindCapCredit	Med DSM	High	High	No	No
12	Change Case	High DSM/HighSusCap/HighWindCapCredit	High DSM	High	High	No	No
13	Change Case	Ref/NB Trans	Ref	Ref	Ref	Yes	No
14	Change Case	Med DSM/NB Trans	Med DSM	Ref	Ref	Yes	No
15	Change Case	High DSM/NB Trans	High DSM	Ref	Ref	Yes	No
16	Change Case	Ref/NB Trans/HighWindCapCredit	Ref	Ref	High	Yes	No
17	Change Case	Med DSM/NB Trans/HighWindCapCredit	Med DSM	Ref	High	Yes	No
18	Change Case	High DSM/NB Trans/HighWindCapCredit	High DSM	Ref	High	Yes	No
19	Change Case	Ref/HighSusCap/NB Trans	Ref	High	Ref	Yes	No
20	Change Case	Med DSM/HighSusCap/NB Trans	Med DSM	High	Ref	Yes	No
21	Change Case	High DSM/HighSusCap/NB Trans	High DSM	High	Ref	Yes	No
22	Change Case	Ref/NB Trans/HighWindCapCredit/HighSustCap	Ref	High	High	Yes	No
23	Change Case	Med DSM/NB Trans/HighWindCapCredit/HighSustCap	Med DSM	High	High	Yes	No
24	Change Case	High DSM/NB Trans/HighWindCapCredit/HighSustCap	High DSM	High	High	Yes	No
Bookends - with Retirement							
25	Change Case	Ref/RetirePath1	Ref	Ref	Ref	Yes	Yes
26	Change Case	Med DSM/RetirePath1	Med DSM	Ref	Ref	Yes	Yes
27	Change Case	High DSM/RetirePath1	High DSM	Ref	Ref	Yes	Yes
28	Change Case	Ref/RetirePath2	Ref	Ref	Ref	Yes	Yes
29	Change Case	Med DSM/RetirePath2	Med DSM	Ref	Ref	Yes	Yes
30	Change Case	High DSM/RetirePath2	High DSM	Ref	Ref	Yes	Yes

Input Assumptions Changes in Response to Comments

We will make the following changes to input assumptions:

- The “High Sustaining Capital” costs will reflect a 25% increase over NSPI’s 2017 estimates, instead of a 50% increase.
- We will incorporate Efficiency One’s recommendation to reduce the amount of savings that could be expected from DSM over the period through 2022 for the “Med DSM” case, assuming a slower ramping up of such savings. We will also correct for the presence of PHP mill load in computing how the 2% energy savings per year affects total load, as noted by NSPI. This will result in higher energy and firm peak levels than were seen in the Input Assumptions memo.

- We will incorporate NSPI's assumptions for natural gas prices for volumes above "opportunistic" natural gas amounts, and incorporate their revisions to solid fuel prices.
- We have applied cost curves to battery, solar, and wind cost projections. We are using the real cost decline values included in our memo for solar and wind for 10 years, and then a flat real cost thereafter. We are using a revised 5% per year cost decline for batteries (not 9%), over a 15-year period, with flat real costs thereafter.
- At this time, we are not including an "electrification" scenario beyond the increased heat pump loads considered in NSPI's reference load scenario.
- We will run ST scenarios for each of the (now two) retirement path bookend scenarios, for all years (2022-2040).

Additional Comments

- The Industrial Group makes recommendations for both scenarios and input assumptions.
  - At this time, we will continue with just two load scenarios. It is our sense that the current reference load forecast already incorporates potentially less energy efficiency than is actually being obtained through Efficiency One's efforts (see Synapse comments on the 2017 Load Forecast matter), and thus constitutes a lower energy efficiency scenario.
  - We are modifying the sustaining capital "high" case to 25% higher than NSPI's 2017 projections, but due to the number of scenarios we can run in this initial step, we are not able to reflect effects of lower sustaining capital costs; it is also our sense that there is a greater likelihood of higher, rather than lower, sustaining capital costs given the changes in cost projections by NSPI between the 2014 IRP and the 2017 10-year System Outlook report.
  - Synapse continues to rely on GE integration study ELCC results and the use of higher wind capacity contribution values in New Brunswick, Quebec and Northern Maine (winter peaking systems) to underlie our concern that NSPI's methodology underestimates true resource adequacy contribution from wind. This exercise will test whether or not use of a higher value results in material differences for consideration of thermal fleet retention.
  - The exercise is not intended to capture all rate effects, such as what is best for ATL vs. BTL loads. At this time, we are attempting to ensure PLEXOS captures the effect of all energy consumption in the Province, but we are not conducting any sector-specific analyses.
  - Natural gas price sensitivities will be considered after our initial set of scenario runs if or as time is available. This decision will also depend on the results seen with the initial

runs. If significant natural gas builds occur under "reference" scenario prices, e.g., then we will further investigate a "high gas" price effect.

- Selection Criteria: NSPI notes that the memo does not articulate selection criteria for a reference plan. We note that we will tabulate the revenue requirements for the full period of model run (2018-2042) for all scenarios, and that the NPV of those revenue requirements will be an important metric to use when comparing results across scenarios; but we are not "selecting" any particular plan. The aim of the exercise is to examine how costs vary under different resource formulations. We will include the full 2018-2042 period data in our report.

- The SBA notes its concern with short-term period effects. The exercise objective is primarily to ascertain the longer-term economics of thermal fleet retention over the next decade, and beyond. While our analysis will provide some near-term revenue requirement effects, it is a planning study, not a rate effects study, and as such care must be taken in interpreting the results for the purposes of ascertaining short-term effects. We note that the "optimization parameter" PLEXOS uses is essentially the production costs plus the new build capacity costs. We also note that the present value of revenue requirements will be available from the analysis. We are not anticipating any rate effects assessment other than a very high-level sense of how revenue requirements change over time.

- Port Hawkesbury Paper provides extensive comments on load forecasts, sustaining capital, retirement path bookends, and suggests more natural gas price scenarios. As noted, we will consider additional gas price scenarios if or as merited. We note that the use of "retirement path" bookend scenarios is solely to gauge overall economics, and does not indicate any policy considerations. We have reduced the number of load scenarios to be used. As noted, it is our sense that the reference forecast already has some electrification load, and in a sense reflects what we might consider a "high" forecast.