Proposed Terms of Reference

Plexos Optimization Analysis

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

Synapse Energy Economics

July 7, 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[1] 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

[1] 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 the model run. 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"[2] would result from running Plexos with different combinations of the input assumption sets illustrated below.

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.

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.

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

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, specifying input parameters, 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, 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. This phase, and the underlying research to inform the key analytical inputs, will include NS UARB input and review of stakeholder TOR 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. Prepare final report post technical conference, addressing feedback.

e. 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.[3]
- 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.).

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

- 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 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.

Milestone	Estimated Date	Comments/Deliverables
Terms of Reference	Early July	Document.
Input Assumptions	July	Assumes early July receipt of modeling files from NSPI – Memo.
Model Execution - Start	July-Early August	
Model Execution – Finish	Late September into October	Requires efficient development of modeling plan, scenario/sensitivity specification, and execution.
Model Post Processing and Results	Late October	Memo.
Draft Report	Mid-November	Report.
Technical Conference	Late November	Presentation Slides.
Final Report	December	Report w/ appendices as necessary.

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[4] 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>

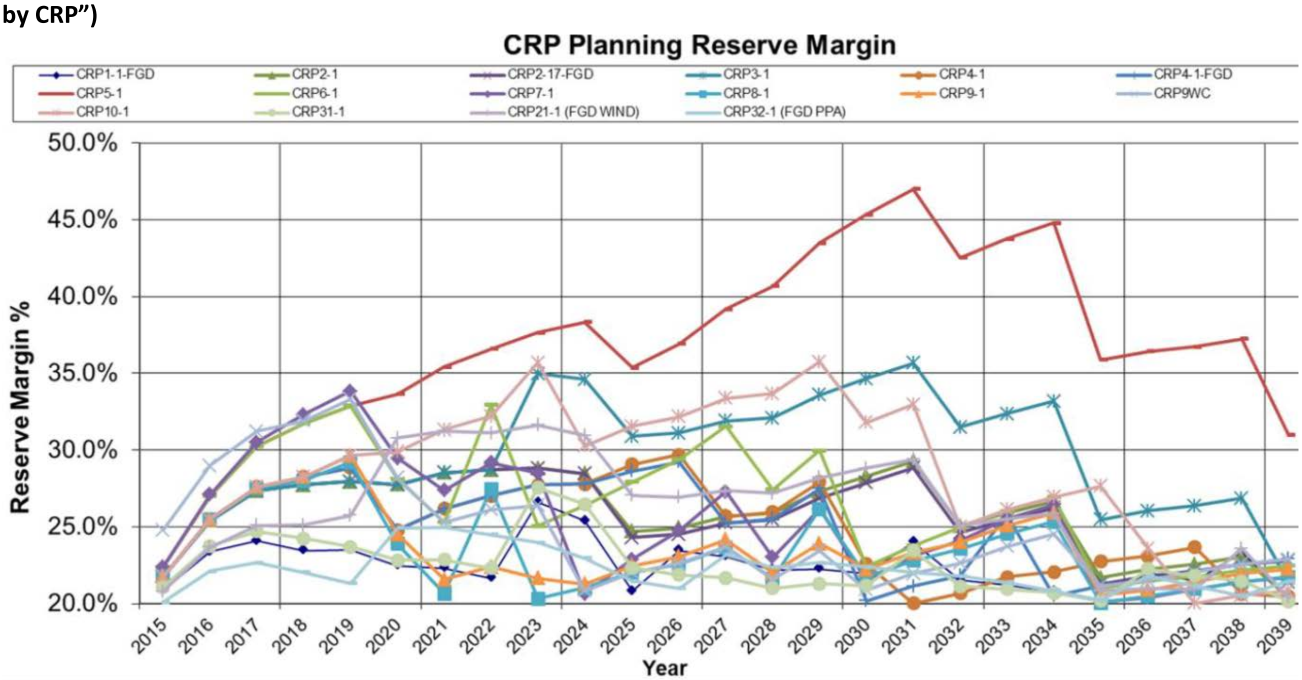
NSPI has not yet conducted a rigorous quantitative analysis of the economically optimal path for sustaining capital investment in the thermal fleet. NSPI stated that "The 2014 IRP results concluded that

[4] 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.[5]

---

[5] 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.[6] 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.[7] 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[8] 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.[9] However, this conclusion was based on an assessment of the Levelized Electricity Cost to Grid,[10] and did not capture the value

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.

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

[7] 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.

[8] 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.

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

[10] Ibid.

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".[11]

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**)

3- Regional Coordination Options

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.

4 – Wind Resources – Capacity Contribution

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%.[12] 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%

[11] 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.
[12] 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.

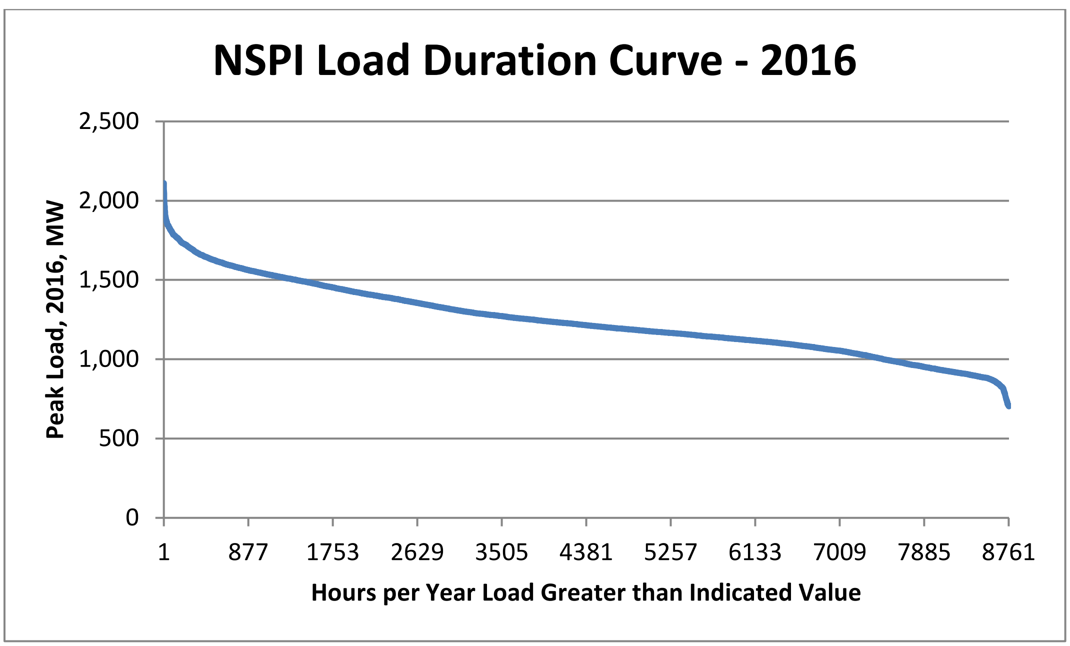
for all its wind resources, the overall increase in contribution towards resource adequacy requirements would be on the order of 48 MW.[13]

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.

[13] 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",[14] 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,[15] 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.[16] 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.

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

[15] 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.

[16] 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)