Comments in Response to NSPI 4/13/2017 Technical Conference on Future Plan for Thermal Resources

Synapse Energy Economics

April 28, 2017

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[1] 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>

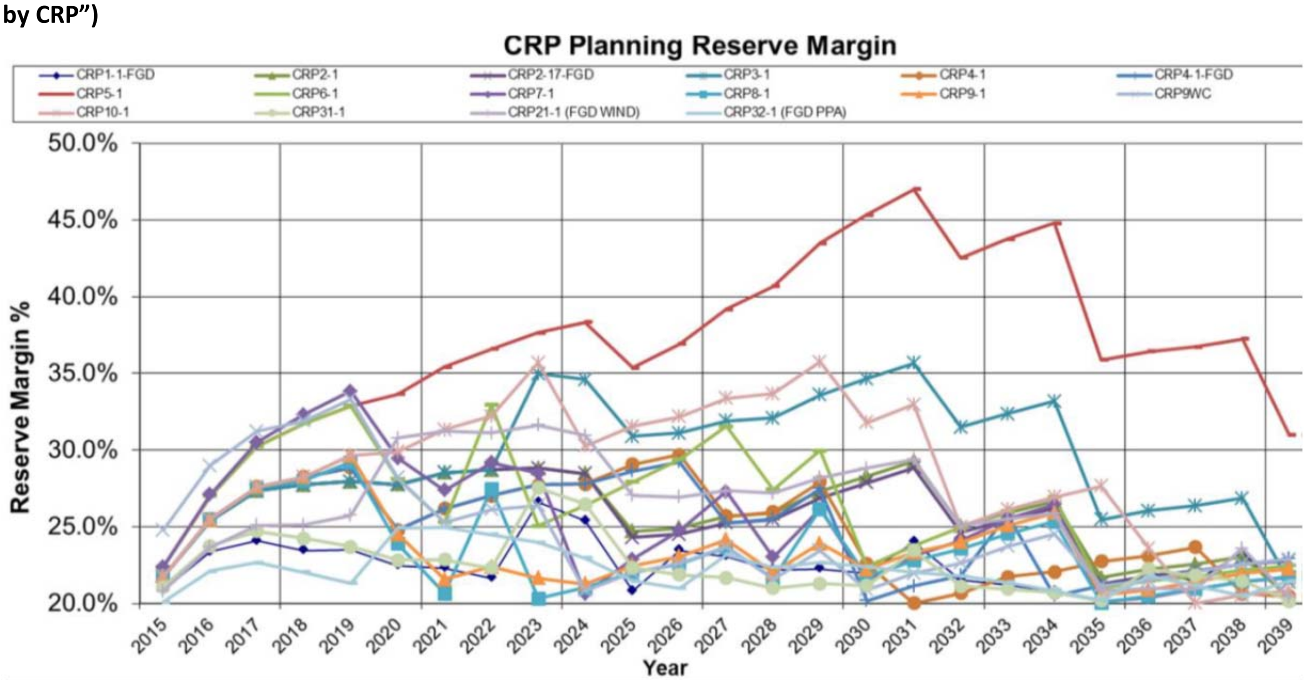
NSPI has not yet conducted a rigorous quantitative analysis of the economically optimal path for sustaining capital investment in the thermal fleet. NSPI stated that "The 2014 IRP results concluded that

[1] 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.[2]

[2] 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.[3] 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.[4] 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[5] 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.[6] However, this conclusion was based on an assessment of the Levelized Electricity Cost to Grid,[7] 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.

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

[4] 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.

[5] 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.

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

[7] 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".[8]

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%.[9] 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%

---

[8] 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.

[9] 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.

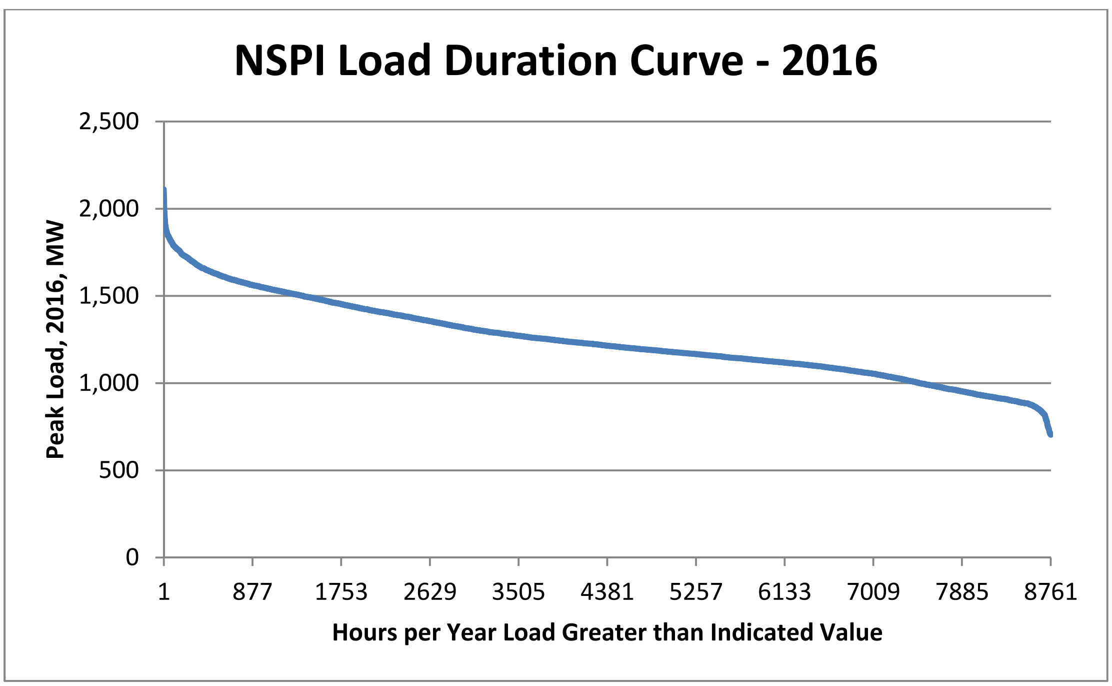
for all its wind resources, the overall increase in contribution towards resource adequacy requirements would be on the order of 48 MW.[10]

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.

[10] 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",[11] 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,[12] 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.[13] 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.

---

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

[12] 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.

[13] 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)