Analysis of Nova Scotia Power's 2020 Integrated Resource Plan

Recommendations on Key Findings, Action Plan, and Roadmap Elements

Prepared for Counsel to Nova Scotia Utility and Review Board

December 23, 2020

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1. INTRODUCTION

Synapse was engaged in 2019 by the Nova Scotia Utility and Review Board (Board) Counsel to provide analytical assessment of Nova Scotia Power Inc.'s (NSPI) 2020 Integrated Resource Plan (IRP).

The scope of work included review of NSPI pre-IRP studies, collaboration with Board staff and NSPI on scenario development and input assumptions, and computer modeling using PLEXOS software (incremental to modeling conducted by NSPI to test other scenarios). The analytical assessment included document review, informal discovery development, defining the Terms of Reference, and research related to modeling inputs including energy efficiency and demand response alternatives. Synapse's scope also included review of IRP assumptions developed by NSPI—including its load forecast, wind power costs and performance, and transmission issues that affect the resource plan—and communications with NSPI to further an in-depth understanding of NSPI's approach to developing its resource plan. A core part of Synapse's scope of work included detailed review of NSPI Plexos results.

Synapse's role spanned the period from Fall 2019 through the end of 2020 and included on-site visits to Halifax for initial stakeholder conferences prior to the onset of COVID-19-related travel restrictions.

Regular (generally, weekly) collaborative telephone meetings between NSPI IRP development staff, Board staff, Synapse, and Board consultant Bates Whites allowed for ongoing technical discussion across many of the issues addressed in the IRP process. The issues extensively discussed during these meetings included the treatment of carbon emissions in modeling, reflecting Nova Scotia's burgeoning implementation of its Sustainable Development Goals Act (SDGA) and the related impact of the Province's Equivalency Agreement with the federal government; the role of a possible "reliability tie" or increased transmission connection to New Brunswick; and the presence of new wind power in the resource plan.

Our comments in this report reflect technical disagreements between Synapse and NSPI's technical staff on the approaches used to determine a resource plan, the value of input assumptions, or the weighting afforded to different outcomes. In our opinion the process itself allowed for a full vetting of the myriad of technical issues that have the greatest impact on finding a least-cost resource plan. NSPI's approach, which allowed for more extensive stakeholder input to the discussions than Synapse has seen in past IRP processes, was transparent, professional, and led to a reasonable set of possible resource plans. We identify and explain a few core technical disagreements which lead to our suggestions for modifications to certain Action Plan and Roadmap elements.

This report presents Synapse's findings with respect to NSPI's filed IRP. It first addresses the pre-IRP analyses conducted by NSPI and an assessment of the modeling scenarios examined. It presents observations on NSPI's modeling results and summarizes Synapse's modeling exercises. Lastly, we provide comments on key findings and suggest changes to certain of NSPI's Action Plan and Roadmap elements.

2. Scenario Planning and Modeling Assumptions

2.1. Overview

NSPI describes its process for determining the set of scenarios to directly model in PLEXOS in its IRP Report.[1] In March, 2020 Synapse provided comments to NSPI addressing and generally supporting its overall approach to defining a set of candidate scenarios, and then using the PLEXOS LT modeling platform to determine an optimal capacity expansion and retirement result for each scenario.[2] In this section we summarize the salient aspects of the scenario planning step, provide a summary of pre-IRP observations, and note important aspects of the load forecast assumptions used by NSPI.

Generally, NSPI's process around reviewing and determining which scenarios to analyze in PLEXOS is commendable.[3] NSPI considered an extensive array of options such as different load levels, different emissions constraints, and sensitivity to input assumptions that can understandably be subject to uncertainty (sometimes considerable uncertainty such as forecasting the pace of increased electrification in the Province).

However, defining an eventual final set of scenarios to evaluate does not confer any particular degree of certainty that this set of scenarios comprehensively represents all possible worlds in which NSPI will plan and operate. While it is reasonable to identify a set of scenarios to bound the overall process, it is critical that interpretation of the results arising from the selected set of scenarios accounts for the fact that not all permutations can be directly modeled. For example, NSPI modeled two scenarios with low wind cost assumptions, but it did not model a low wind cost assumption with an earlier retirement path for the coal fleet. Nonetheless, one can still glean important and valid insights from even this reduced set, and in general NSPI's modeling results and Action Plan reflect this. In Section 4 of this report, however, we indicate some exceptions.

We note that NSPI uses both the "Scenario" terminology and the "Sensitivity" terminology. While the term "sensitivity" is often used to connote running a modeling exercise while changing just a single input, it is also sometimes understood to imply freezing a resource buildout prior to changing an assumption, and then re-running the model. For this IRP analysis, NSPI essentially treats all modeling runs as scenarios (different scenarios result in different resource build results) even when NSPI's naming convention calls it a "sensitivity."

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[1] IRP report, pages 78-81.

[2] The PLEXOS modeling platform is used first in "long term" or LT mode to optimize the new resource builds and retirement of old uneconomic resources. It then uses the "medium term" and "short term" models (MT/ST) to conduct more granular (temporally) and sequential unit commitment and dispatch modeling.

[3] NSPI describes this in Section 5 (page 78) of its IRP Report.

NSPI declined to directly incorporate as part of its scenario definitions or assumptions the effect of NSPI marginal emission reduction beyond the levels scripted in the SDGA. Excluding this aspect of the SDGA technically implies that the modeling runs conducted are sub-optimal, since it is possible that NSPI scenarios with some level of overachievement of emissions reductions could be less costly than another scenario with "less overcompliance." But for technical optimality, explicit valuation of such overcompliance by NSPI would need to be incorporated into the overall capacity expansion optimization algorithm. It was not for this exercise.[4] We address the effect of this choice by NSPI in Section 3 and Section 4 of this report. NSPI also did not test the effect of a more stringent emission reduction trajectory, such as one that would align with the Ecology Action Center's 1 million tons/year of carbon dioxide (CO_2) emissions for the electric sector by 2030.

NSPI incorporated use of E3's RECAP tool in the "Reliability Screening" phase to assess the overall reliability of a preliminary portfolio.[5] This part of the analytical process set out to resolve any issues that might arise concerning whether a preliminary portfolio exhibits loss-of-load-expectation (LOLE) values that are well below (or well above) the accepted one-day-in-ten-years (or 0.1 days/year LOLE) reliability/resource adequacy criteria. For example, if the parameters used as inputs to the PLEXOS LT module lead to an economic "overbuild" of capacity resources, testing the portfolios via RECAP could lead to a need for input parameter adjustments. For instance, such adjustment might be needed to ensure the resulting PLEXOS build does not result in excessive economic resource adequacy (as measured by the LOLE metrics). NSPI did not iterate PLEXOS modeling to reflect RECAP findings but used the RECAP modeling to confirm that PLEXOS scenarios met (or, in this case, exceeded) reliability criteria. The resulting findings suggest that the scenarios considered by NSPI may be slightly more reliable than necessary. This implies that, for any application for additional resources to meet peak load needs, NSPI should revisit the fundamental need requirements to ensure it does not overbuild going forward, and instead fully utilizes any surplus capacity (above minimum needs) that exists, however small, since the surplus is already roughly 20 percent greater than NSPI's peak load.

2.2. Pre-IRP

In 2019, NSPI conducted three major studies prior to undertaking the scenario specification, assumptions vetting, and PLEXOS modeling exercises that comprised the essential analytical effort during the main phase of the 2020 IRP process. Those studies, released by NSPI in July and August 2019,

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[4] NSPI did not ignore this. As seen in Section 4 of this report, and at page 47 of the IRP Report, NSPI's perspective on the market for such overcompliance with electric sector emissions standards is different from Synapse's perspective. NSPI chose to exclude this consideration apparently based on its assessment of the quantitative impact.

[5] NSPI noted its planned use of this tool (subsequent to initial use by E3 in the pre-IRP phase as part of the capacity value study) in the 2/27/2020 stakeholder meeting presentation. Also, in the Pre-IRP Deliverables Report, NSPI notes the reasons why such iteration may be important: "The PRM is dependent on the composition of a portfolio; changes in the resource mix can trigger changes in the PRM requirement. Accordingly, NS Power plans to incorporate a proposal for iterating on the PRM calculation in the Analysis Plan, particularly for portfolios with significant resource differences (e.g. high levels of renewables or major unit retirements), to provide insight on how the required PRM may change with different resource mixes." Page 11.

included (i) a Renewable Integration Study,[6] (ii) a Planning Reserve Margin and Capacity Value study,[7] and (iii) a Supply Options study.[8] The findings from these studies were used in part to inform the input assumptions used in the PLEXOS analyses.

Generally, we supported the primary recommendation of PSC to expand the existing study (PSC study, page 63) and provide enhancements to that study (PSC Study, page 64). Roadmap item #2 addresses ongoing stability study needs, and Synapse provides comments to that item in Section 4.3 of this report. An expansion of the study, reflected in the Roadmap item #2, could include a matrix of additional scenarios, in line with PSC's recommendations and to capture concerns that an insufficient array of combinations of reactive support, battery installation, and new 345 kV tie effects are represented in the existing study results. The new studies could use the results from different IRP scenarios to inform the resource mix.

While the E3 study described appropriate methodologies to test capacity contributions (e.g., ELCC effects), we recommend as part of Roadmap items #3 and #4 the ongoing analysis of the ELCC effect of additional portfolio offerings. For example, different combinations of wind, storage, demand response, and solar PV resources can exhibit higher portfolio ELCC values, reflecting supply diversity effects. As part of ongoing "evergreen" IRP processes NSPI should continue to examine, and refine as necessary, the underlying analytical approach using the most current data available.

2.3. Load Forecast, Demand-Side Management, and Electrification

The NSPI IRP analysis considers three load scenarios, two of which represent significant electrification futures. While provincial electrification is probably essential to meet the greenhouse gas (GHG) emission goals, the precise form that this might take is uncertain.

The forecasts used in the IRP represent just some possible paths that future loads might take. Three cases are highlighted in the report: (1) Low Electrification / Base DSM (demand-side management), (2) Mid Electrification / Base DSM and (3) High Electrification / Max DSM. In all cases, energy growth remains modest or declining until 2030. But after 2030, it increases at 0.54 percent per year in the Mid Electrification case and 0.89 percent per year in the High Electrification case. For the Low Electrification case, the load increases after 2030 at a rate of 0.23 percent, but the load is below 2021 levels in 2045. The total increase by 2045 in the High Electrification case is 16 percent above 2021 loads.[9]

However, a different pattern is observed for the peak loads. For the Low Electrification case, peak loads remain at current levels and then increase modestly after 2035. However, for both the Mid and High

[6] PSC North America, "Nova Scotia Power Stability Study for Renewable Integration Report," July 24, 2019.

[7] E3, "Planning Reserve Margin and Capacity Value Study," July 2019.

[8] E3, "NSPI Resource Options Study," July 2029.

[9] NSPI's load forecast detail is provided in the March 11, 2020 Integrated Resource Plan Final Assumptions Set, a slide deck and associated excel files posted on the NSPI IRP website.

Electrification cases the peak loads increase substantially by 2030, and then increase at a lower rate thereafter. The overall rates of increase range from 0.26 to 1.51 percent per year. The total peak load increase from 2021 to 2045 is 9 percent in the Low case, 23 percent in the Mid case, and 43 percent in the High case. These are relatively much more than the energy increases and produce a greater need for peak capacity resources. This is represented by a change in the system load factor (average / peak load) which is currently a little over 60 percent but declines by 2030 to about 48 percent in the High Electrification case.

However, these are not the only possible scenarios. Provincial and NSPI actions can shape what happens and moderate the growth in the peak loads. For example, Provincial promotion of electric vehicles will affect how fast that load increases, and NSPI implementation of time-of-use rates will affect how much the peak load grows relative to that of energy for both transportation and heating end use electrification. The use of battery storage either on the grid or in electric vehicles could shave the peak load. DSM programs focusing on peak load reduction could lower the need for and the cost of new capacity, using targeted programming. Both Roadmap item #7 and our recommendations for the Action Plan step for electrification strategy emphasize the need to mitigate any increases in peak period—especially critical peak period—load, while encouraging "beneficial electrification" of the electrification of end uses currently served with fossil fuels.

3. MODELING RESULTS

3.1. NSPI

NSPI presents its final modeling results in Section 6 of its 2020 IRP Report. The full set of modeling results is also presented in NSPI's November 27, 2020 Updated Modeling Results Release, included as Appendix E to the 2020 IRP Report. Appendix F to the report contains a series of modeling results tables listing Installed Capacity Changes, Annual Energy Balances, and Annual Emissions by scenario for each of the 15 scenarios and 18 sensitivities modeled by NSPI.

Synapse provided initial comments on the results of NSPI's modeling in late September 2020. We supplement those comments briefly here with a focus on how the modeling results should affect the development of NSPI's Action Plan, for which we suggest modifications in Section 4 of this report. Ongoing "evergreen" IRP processes will likely lead to updating the effect of the modeling results for resource changes occurring during the second half of the planning horizon.

Wind

NSPI modeling results show a dramatically different optimal build path for new Nova Scotia wind resources using the "low wind cost" assumption of $1,500/kW for wind, compared to NSPI's baseline Scenario 2.1C, which uses a value of $2,100/kW. The scenario with low wind cost assumptions shows a build-out of 631 MW by 2025, compared to NSPI's baseline Scenario 2.1C, which shows 112 MW by

2026. (NSPI's "reference" case Scenario 2.0C shows zero wind build-out until 2030; no "low cost" wind scenario was modeled for Scenario 2.0C and thus no direct comparison can be made reflecting a low wind sensitivity for the "reference" case.) The second "low wind cost" Scenario 2.1C, which includes an assumption for low battery costs also, shows an even earlier build-out of 600 MW by 2024, and 676 MW of wind by 2025, along with 61 MW (firm capacity rated) of battery builds by 2025.[10] This finding illustrates the importance of NSPI determining the true going-forward cost of wind in Nova Scotia, since it is the most important variant of optimal resource expansion seen from NSPI's modeling results. Notably, and not unexpectedly, under the scenario with earlier coal plant retirement (3.1C), the model builds 186 MW of wind by 2025, instead of the lower value of 112 MW by 2026 in Scenario 2.1C. (There is no Scenario 3.0C to compare to 2.0C, the "reference" plan.)

Synapse suggests a modification to NSPI's Action Plan item for wind procurement to allow for the capture of any economies of scale that might be associated with obtaining lower cost wind resources. The modification would involve a procurement plan that seeks to procure up to 631 MW of wind resources by 2025, in line with the optimal build-out for Scenario 2.1C low wind cost.

Carbon Emission Modeling and Valuation of Overcompliance of SDGA Limits

NSPI modeling of all scenarios directly incorporates the CO_2 emission limits associated with the SDGA.[11] NSPI has permission—in the form of allowances—to emit a declining level of CO_2 from its fossil fuel plants. If NSPI were to emit more than allowed, it would need to secure additional CO_2 emission allowances, either bilaterally or through the Cap and Trade auctions.[12] Conversely, if NSPI "over-complies" or emits less than its allowance, it can sell excess allowances. Generally, NSPI's modeling results for all scenarios show that NSPI generally over-complies with its requirement to reduce CO_2 emissions, because it is economic to do so. This is the case even without direct valuation or monetization of NSPI's "excess" emission reduction, or overcompliance with the SDGA-imposed emission limits. Significantly, NSPI's modeling does ***not*** credit the value of any overcompliance for any given scenario.[13] Thus, NSPI is undervaluing any benefit associated with a further reduction in CO_2 emissions.

We analyzed the effect of valuing incremental carbon reductions (beyond those reflected in NSPI's actual optimization, which uses a fixed, declining carbon constraint but doesn't assign any value to

[10] All of the wind resource build-outs can be seen in the IRP Report, Appendix F, Final Portfolio Study resource plan; for these Scenarios listed here, see pages 7, 8, 9 and 12.

[11] IRP, page 47. "While the specific application of the SDGA to Nova Scotia Power has yet to be determined, these targets were integrated into the development of emissions assumptions for IRP modeling purposes."

[12] Cap and Trade regulations and auction information, see e.g. https://climatechange.novascotia.ca/cap-trade-regulations/.

[13] IRP, page 47: "Similarly, significant uncertainty regarding the depth, liquidity, pricing and duration of the Cap and Trade market, Nova Scotia Power has not modeled the ability to sell credits into the market as part of the IRP optimization model so as not to develop resource plans which rely on that revenue for optimality."

further CO_2 emission reductions) on the resource builds and the net present value of revenue requirements (NPVRR) differences across comparable scenarios.

NSPI did not model a scenario that directly valued incremental carbon emission reductions (beyond those associated with the SDGA's allowances for CO_2 emissions for NSPI) at any estimated price or value for such further emission reductions. Thus, the only means of assessing the effect from this exercise is to review NSPI's modeling results and compare CO_2 emissions between scenarios. The value of CO_2 emissions reduction between any two scenarios can be estimated by assuming a value, in $/ton, of any differences in emitted CO_2. NSPI declines to assume any value for such reductions because it does not project any certainty for such revenues. However, for planning purposes, it is useful to understand at least a range of values for additional carbon emission reduction.

From a planning perspective, the analytical exercise is straightforward; although as NSPI indicates, the possible or eventual reality of such incremental value from a revenue perspective is uncertain.

Table 1 and Table 2 below show the effect for two separate scenario comparisons, respectively: (1) between Scenarios 2.1C and 2.1C with "low wind" costs, which results in an earlier expansion of wind energy in the Province, and a corollary reduction in emissions, and (2) between Scenarios 2.1C and 3.1C. Scenario 3.1C includes (by design) an earlier retirement path for the coal fleet in Nova Scotia, resulting in lower carbon dioxide emissions (and includes, per the optimization, increased earlier wind builds also).

As seen in Table 1, placing a value on the carbon emission reduction that comes with an earlier installation of wind results in a cumulative incremental value of roughly $250 million (at a price of $24/ton) or $520 million (at a price of $50/ton). This is for the scenario where wind is installed earlier in the decade, i.e., Scenario 2.1C "low wind cost" with a total of 631 MW of new wind by 2025. This is an increase of more than 600 MW by 2025 over that seen in Scenario 2.1C (i.e., 12 MW by 2025).

As seen in Table 2, placing a value on the carbon emission reduction that comes from earlier retirement of the coal fleet (by 2030, instead of by 2040) results in a cumulative incremental value of roughly $374 million (at a price of $24/ton) or $779 million (at a price of $50/ton), if all of the emissions reduction is valued at the price indicated. Table 2 also shows the breakeven point: if all of the incremental CO_2 emission reductions were valued at a price point of $38/ton, the NPVRR of the two scenarios would be equal. In other words, either of the two options results in the same NPVRR to ratepayers over the 25-year horizon.

Table 1. Effect of Valuation of “Overcompliance” Carbon Emission Reduction on NPVRR Comparison – Scenario 2.1C vs. Scenario 2.1C Low Wind Cost

Value of "overcompliance" CO2 reduction at current SDGA auction market price																	
Scenario 2.1C vs. 2.1C "Low Wind" cost	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2040**	**2045**
Sc. 2.1C CO2 emissions ('000 tons)	5,031	4,189	4,223	4,258	4,260	4,194	4,193	4,207	4,181	3,067	2,910	2,317	2,342	2,407	2,451	1,006	1,125
Sc. 2.1C low wind cost CO2 emissions ('000 tons)	5,031	4,189	3,919	3,945	2,042	2,280	2,302	2,353	2,298	2,131	2,146	2,186	2,206	2,254	2,235	980	1,114
CO2 emissions savings ('000 tons)	0	0	304	313	2,219	1,914	1,892	1,854	1,883	937	764	131	136	153	216	26	11
Cumulative CO2 emission savings ('000 tons)	0	0	304	616	2,835	4,749	6,640	8,494	10,377	11,313	12,077	12,209	12,345	12,498	12,714	14,225	14,332
Value at price of $24/ton																	
Delta Value at $24/ton (real) ($millions)	$ -	$ -	$ 7.3	$ 7.5	$ 53.2	$ 45.9	$ 45.4	$ 44.5	$ 45.2	$ 22.5	$ 18.3	$ 3.1	$ 3.3	$ 3.7	$ 5.2	$ 0.6	$ 0.3
NPV (4.42%) 2022-2045, $2021 Millions	**$249.5**																
Value at price of $50/ton																	
Delta Value at $50/ton (real) ($millions)	$ -	$ -	$ 15.2	$ 15.6	$ 110.9	$ 95.7	$ 94.6	$ 92.7	$ 94.1	$ 46.8	$ 38.2	$ 6.6	$ 6.8	$ 7.6	$ 10.8	$ 1.3	$ 0.6
NPV (4.42%) 2022-2045, $2021 Millions	**$519.7**																

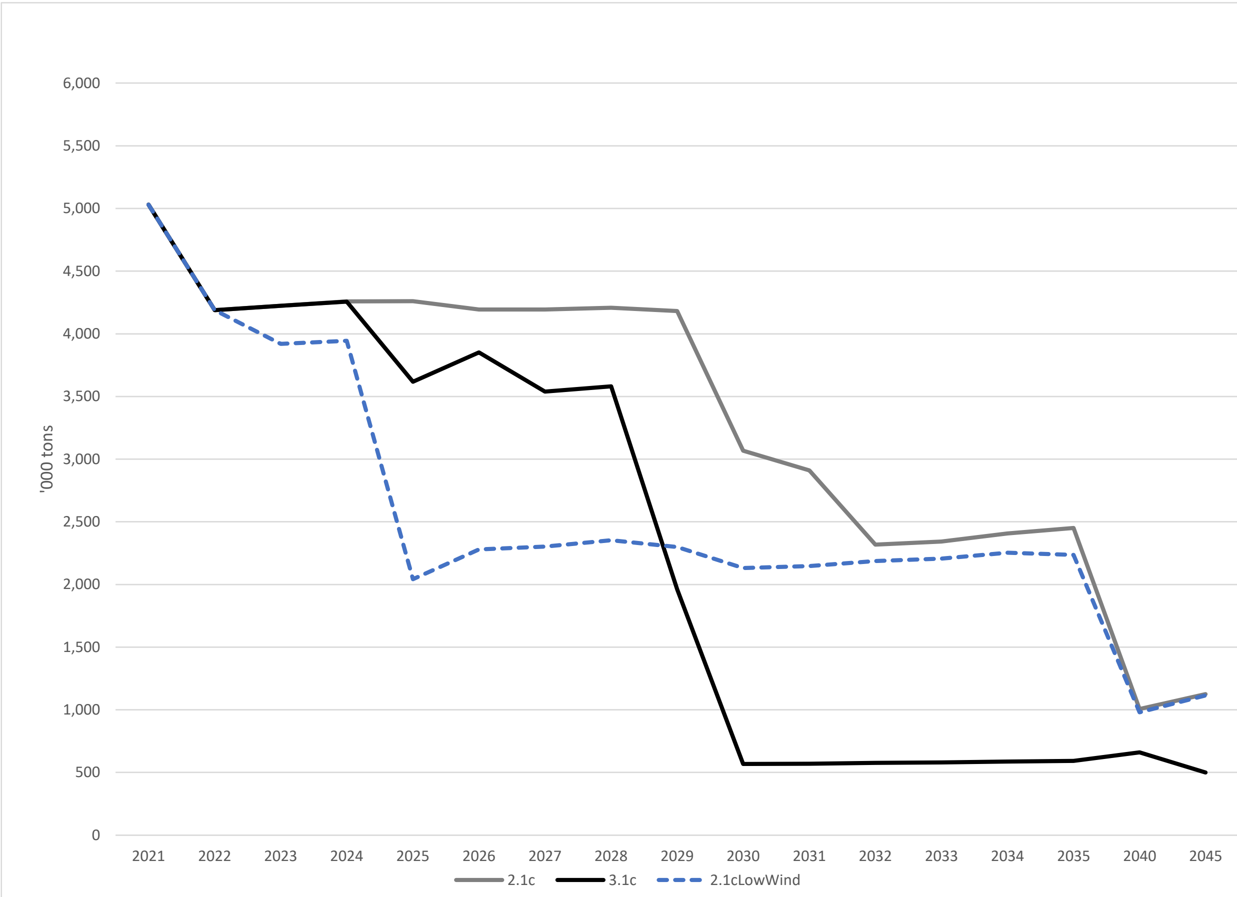
Table 2. Effect of Valuation of “Overcompliance” Carbon Emission Reduction on NPVRR Comparison – Scenario 2.1C vs. Scenario 3.1C

Value of "overcompliance" CO2 reduction at current SDGA auction market price																	
Scenario 2.1C vs. 3.1C	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2040**	**2045**
Sc. 2.1C CO2 emissions ('000 tons)	5,031	4,189	4,223	4,258	4,260	4,194	4,193	4,207	4,181	3,067	2,910	2,317	2,342	2,407	2,451	1,006	1,125
Sc. 3.1C CO2 emissions ('000 tons)	5,031	4,189	4,223	4,256	3,618	3,851	3,539	3,581	1,962	568	569	577	580	586	593	660	500
CO2 emissions savings ('000 tons)	0	0	0	1	642	342	655	626	2,219	2,499	2,341	1,741	1,762	1,820	1,859	346	625
Cumulative CO2 emission savings ('000 tons)	0	0	0	1	644	986	1,641	2,267	4,486	6,986	9,327	11,067	12,830	14,650	16,509	24,639	26,908
Value at price of $24/ton																	
Delta Value at $24/ton (real) ($millions)	$ -	$ -	$ -	$ 0.0	$ 15.4	$ 8.2	$ 15.7	$ 15.0	$ 53.3	$ 60.0	$ 56.2	$ 41.8	$ 42.3	$ 43.7	$ 44.6	$ 8.3	$ 15.0
NPV (4.42%) 2022-2045, $2021 Millions	**$374.2**																
Value at price of $50/ton																	
Delta Value at $50/ton (real) ($millions)	$ -	$ -	$ -	$ 0.1	$ 32.1	$ 17.1	$ 32.7	$ 31.3	$ 111.0	$ 125.0	$ 117.1	$ 87.0	$ 88.1	$ 91.0	$ 92.9	$ 17.3	$ 31.3
NPV (4.42%) 2022-2045, $2021 Millions	**$779.5**																
Estimation of CO2 emissions price at which 2.1C NPVRR equals 3.1C NPVRR inclusive of delta emission value																	
Delta 2.1C vs. 3.1C, NPVRR from Modeling Results	593.4	millions															
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2040**	**2045**
Delta Value at $24/ton (real) ($millions)	$ -	$ -	$ -	$ 0.1	$ 24.4	$ 13.0	$ 24.9	$ 23.8	$ 84.5	$ 95.1	$ 89.1	$ 66.2	$ 67.1	$ 69.3	$ 70.7	$ 13.2	$ 23.8
NPV (4.42%) 2022-2045, $2021 Millions	**$593.4**																
Carbon Price: ($2021 real)	**38.06**																

Source, Tables 1 and 2: NSPI modeling results and Synapse computation.

Figure 1 below reproduces the emission trajectory results shown in Tables 1 and 2 above. It shows the different CO_2 trajectories for three Scenarios: 2.1C, 2.1C low wind cost, and 3.1C.

Figure 1. Carbon Emissions by Selected Scenarios – 2.1C, 2.1C Low Wind, 3.1C – 2021-2045



Source: NSPI modeling results.

For any comparison made between scenarios, if there is a difference in CO_2 emissions then the scenario with the lower level of emissions will result in a relative reduction in overall revenue requirements (compared to NSIP's modeled NPVRR), if it is assumed that overcompliance with the SDGA's emissions limits for NSPI can be monetized through the sale of carbon reduction credits. This applies for any factor that lowers emissions, not just earlier wind installations or earlier coal plant retirement. As another example, valuing incremental carbon emission reduction from increased levels of DSM can be estimated by comparing two scenarios with different levels of DSM, where the scenario with more DSM leads to lower energy needs and lower CO_2 emissions.

One key observation seen in Table 1 above is that the order of magnitude of additional carbon reduction value for scenarios with earlier wind investment (the baseline Scenarios 2.1C vs. 2.1C "low wind") is roughly $250 million (NPVRR) if all of the incremental CO_2 emission reduction is valued at the June 2020 Cap and Trade clearing price of $24/ton. And, when considering the effect between earlier (by 2030) and later (by 2040) coal steam plant retirement, seen in Table 2 above (Scenario 2.1C vs. 3.1C) the carbon reduction value is roughly $374 million, also assuming a value of $24/ton for all incremental CO_2 reduction.

A similar comparative exercise can be done for the Base and Mid DSM scenarios. Table 3 below shows the different CO_2 emissions levels for the four 2.0C scenarios, each with different levels of DSM. The difference in CO_2 emissions between the Base and Mid DSM scenarios is seen to be $82 million (NPV) if valued at $24/ton and $171 million under a sensitivity where carbon was valued at $50/ton.[14]

Table 3. Carbon Emissions under Different DSM Scenarios

		CO2, '000 tons												
DSM Level / Scenario	**Sum CO2 2021-2045, '000 tons**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2035**	**2040**	**2045**
Low / 2.0C Low DSM	72,107	5,022	4,161	4,194	4,212	4,040	4,262	4,090	4,077	4,036	3,830	2,527	996	1,068
Base / 2.0C Base DSM	64,970	5,023	4,162	4,148	4,121	4,088	4,277	4,221	4,176	4,098	2,383	2,195	667	903
Mid / 2.0C Mid DSM	59,434	4,828	4,084	4,039	3,967	3,868	3,856	3,778	3,702	3,584	2,256	1,880	620	654
Max / 2.0 Max DSM	62,082	4,771	4,076	3,980	3,870	3,712	3,822	3,722	3,625	3,504	3,347	1,826	592	620
Scenario Deltas	**Delta CO2 ('000 tons), 2021-2045**	**CO2, '000 tonnes**												
Low - Savings from Base (Base minus Low)	-7,137	1	1	-46	-91	48	15	130	100	63	-1,447	-332	-329	-164
Mid - Savings from Base (Base minus Mid)	5,536	195	77	108	154	220	420	442	474	515	127	315	47	249
Max - Savings from Base (Base minus Max)	2,887	252	86	168	251	376	454	499	551	595	-963	369	75	284
Value of CO2 Emissions Delta (+ is credit to DSM; - is debit), $ millions ($ real), at $24/ton	**NPV 2021-2045, $ millions**	**Value, $ millions (2021 real)**												
Low - Savings from Base (Base minus Low)	-92	0	0	-1	-2	1	0	3	2	2	-35	-8	-8	-4
Mid - Savings from Base (Base minus Mid)	82	5	2	3	4	5	10	11	11	12	3	8	1	6
Max - Savings from Base (Base minus Max)	43	6	2	4	6	9	11	12	13	14	-23	9	2	7
Sensitivity - at $50/ton	**NPV 2021-2045, $ millions**	**Value, $ millions (2021 real)**												
Mid - Savings from Base (Base minus Mid), $ millions	171	9.8	3.9	5.4	7.7	11.0	21.0	22.1	23.7	25.7	6.3	15.7	2.3	12.5

Source: NSPI modeling results and Synapse computation.

This exercise demonstrates that to the extent additional carbon reductions are seen beyond the CO_2 emissions allocations given to NSPI (and reflected in the modeling), if those are explicitly valued the magnitude of the benefit is potentially appreciable. As such, this should be considered when weighing resource plan alternatives. It also illustrates that the Max DSM result is increased overall emissions. This is an artifact of greater use of the coal fleet for energy production and delayed increased in wind energy in the 2030–2033 period.

[14] In these valuations, a $24/ton value, in $2021 real dollars was used. The NPV computation corrects for the use of real currency by using a 4.42% real discount rate, a rough approximation based on the 6.62% nominal WACC and a 2% inflation rate.

The overall takeaway from these quantitative examples taken from the modeling results is that differences in NPVRR values (that do not reflect additional carbon value) are of an order of magnitude that, when considering carbon value, could affect the resource choices. For example, the Low Wind Cost scenario, leading to an earlier build-out of wind resources with attendant carbon reductions potentially valued at $250 million, is premised on wind costs that are roughly $360 million lower than Base wind costs ($600/kW difference between baseline and low wind resource costs, for roughly 600 MW of wind). Thus, even if procurement processes reveal wind costs that do not reach as low a value as is assumed in the modeled "low wind cost" Scenario 2.1C (i.e., $1,500/kW), the presence of additional benefit from potential sale of "excess" carbon reduction could offset any shortfall and validate the economics of earlier installations of more wind.

More broadly, for scenarios with earlier retirement of coal steam plants, the CO_2 emission reduction benefit could be of an order of magnitude of $375 million (NPV basis), assuming all "excess" carbon reduction is valued at $24/ton. Comparing the "raw" NPVRR values for 2.1C vs. 3.1C leads to a change in NPV cost difference such that 3.1C is no longer 4.5 percent more costly (NPVRR basis) than 2.1C. Instead, it is only 1.7 percent more costly.

This analytical exercise shows that the overall differences in cost exposure for ratepayers between earlier retirement of the coal fleet and later retirement of the coal fleet is relatively small. It also demonstrates that earlier wind resource installations (even with longer timelines for coal fleet retirement) can easily be seen as more beneficial to ratepayers (i.e., lower NPVRR) if either or both of (1) incremental carbon emission reduction valuation, or (2) lower cost wind through capturing of economies of scale, come to fruition.

Reliability Tie

All resource plans show inclusion of the Reliability Tie, generally by or before 2030. Notably some scenarios show economic benefit to having it in place earlier (2024 or 2025, for 2.1C "low wind" and 2.1C "non-firm import limited") and as early as 2023 (Scenario 2.1C "low wind and low battery cost"). The overall benefits of the Reliability Tie include allowing earlier, reliable installation of additional wind. In general, completion of a second 345 kV circuit at least as far as Salisbury (reflecting the $360 million Reliability Tie) as soon as is practically feasible is reasonable. The Action Plan should support concerted efforts by NSPI to expedite processes required to allow the tie to be completed.

Mersey

The planning horizon scenario (2021–2045) shows greater value in retirement of Mersey, by $44 million. Only the use of an extension of end effects achieves an economic indication of greater value with Mersey retention, but even in that instance the $78 million NPV benefit assumes $227 million in decommissioning costs. Any circumstance that would presume lower decommissioning costs (on the order of $150 million or less) would lead to the conclusion that, even considering end effects, it is not reasonable to retain the Mersey units. At this point it appears more reasonable to exclude Mersey investment from the resource plan.

Coal Steam Plant Retirement

Based on the above discussion concerning incremental carbon emission reductions, we recommend consideration of a retirement path that looks to close all units in the earlier part of the planning horizon, closer to 2030 than 2040. NSPI's Action Plan and Roadmap elements analyzing thermal plant retirement issues (Action Plan item #3 and Roadmap elements #6 and #3) and the overall evergreen process (Roadmap element #8) should continuously review cost and benefit assumptions concerning the retention timeline for the coal units.

Demand Response

We support all efforts to obtain all cost-effective demand response resources, including the magnitude of demand response reflected in most of the resource scenarios. As electrification efforts proceed in the province, additional demand response options to minimize peak period consumptions should be prioritized. We note that the IRP assumptions exclude incremental demand response that may be available under the higher electrification scenarios seen in the modeling, and additional demand response may be available after full consideration of the form of time-of-use and critical peak pricing rate design that will be in place commencing 2021.

3.2. Synapse PLEXOS Modeling

Synapse conducted a series of PLEXOS modeling runs to determine the extent to which alternative scenarios may result in materially different results than what was found in NSPI's modeling results, or indicate a need to expand the horizon for NSPI's determined scenarios. We also ran most of the same scenarios as are included in NSPI's analysis plan to confirm the results seen by NSPI.

Generally, our findings aligned with the PLEXOS modeling results seen in NSPI's analyses with respect to the overall differences in NPVRR across scenarios, and with respect to the overall capacity expansion results. While minor numerical differences occurred, this is expected given different machines used for the modeling execution.

Additional Synapse modeling scenarios included a number of scenarios that tested the effects of a more stringent emission limit (approximating the EAC (Ecology Action Center) trajectory), modifying the ELCC values for wind and battery storage, and combining lower wind costs and ELCC levels for batteries and wind. Generally, those results led to a slightly earlier retirement trajectory for coal steam plants (one additional unit during the first decade), and some additional early builds of battery energy storage resources, but no appreciable changes to wind build patterns. The purpose of these additional efforts was to test the more extreme edges of the modeling envelope and determine if additional scenarios should be run by NSPI. After our initial findings, NSPI did add more modeling runs to its set of scenarios, including those that modified the inertia parameters, and to directly incorporate low cost wind and low cost battery scenarios.

All of our comments on major findings from the IRP process and suggested changes for the Action Plan and Roadmap arise from our analysis of NSPI's modeling runs, although our insights reflect perspectives gained from conducting our own modeling runs. The final results from Synapse's modeling did not materially change our overall perspective on the most important aspects of NSPI's Action Plan and Roadmap direction.

4. Comments and Recommendations on Key Findings, Action Plan, and Roadmap

Synapse presents the following specific comments on NSPI's findings from its IRP analyses. We then suggest a series of improvements to the Action Plan and Roadmap, primarily based on incorporating the observations and modeling results interpretations we discuss in the above sections of this report.

Generally, while NSPI lays out a reasonable set of steps for action over the next five years, some steps insufficiently address key factors explained in our Findings comments below. In a related manner, incremental changes to—and re-prioritizing of—elements in the Roadmap will ensure that supporting analytical steps going forward meet the observed needs arising from the IRP analyses. In particular, the type of nimble responses that may be required by NSPI in the face of determinations made during the first few years of implementing the Action Plan will be better supported by the suggested modifications we recommend below.

4.1. Key Findings

NSPI lists its Key Findings in Section 7.1 of the IRP report. Generally, many of NSPI's key findings appropriately follow from the extensive analytical processes employed during IRP development throughout 2019 and 2020. However, for certain critical areas the findings as listed reflect NSPI's interpretations of modeled outcomes but exclude or minimize the potential importance of relevant factors surrounding any given scenario, or in respect of multiple modeling scenarios. We list those areas below and provide further context and explanation. In the Action Plan and Roadmap subsections that follow, we make recommendations based on those explanations.

- **Finding 2b**. **Wind as Lowest Cost Domestic Energy Resource**. We strongly agree with NSPI that wind is Nova Scotia's lowest cost domestic energy resource. However, we note that only two "low cost" wind scenarios were modeled, both for the underlying Scenario 2.1C, and thus we have no modeling results that demonstrate the effect of this important cost sensitivity assumption on other scenarios, especially on "3.x" scenarios that could show the combination of lower cost wind and a 2030 coal fleet retirement timeline.

  However, these low cost wind scenarios nonetheless provide critical information for resource planning, as they show that the optimal resource plan involves essentially a doubling of Nova

Scotia installation of wind resources by 2025, or a doubling by 2024 if battery storage resources are also seen to be lower cost than the baseline assumption.

Both of the low cost wind scenarios modeled show earlier installation of sizable amounts of additional wind power: 631 MW of new wind by 2025 (Scenario 2.1C low wind cost), or 600 MW of new wind by 2024 and 676 MW by 2025 (Scenario 2.1C low wind and low battery cost).

This single set of sensitivities demonstrates the importance of determining if market-based wind costs are likely to be in the range of the "low cost" values presumed. NSPI relegates to a Roadmap item what should be an explicit part of the Action Plan: when soliciting for wind resources, clearly include a request for prices or costs if a greater amount of wind was to be installed in the Province, in line with the amounts found to be optimal in these scenarios.

And, as reflected in the analysis shown above in Section 3 of this report, if additional value is included for incremental carbon emission reductions achieved with a more rapid installation of wind, then an optimal resource plan could involve the high level of wind resources seen in Scenario 2.1C "low wind" or Scenario 2.1C "low wind and low battery costs" even if the actual costs are not as low as used in the modeling assumptions ($1,500/kW, vs. $2,100/kW in the base case assumptions). This is the case because the presence of any incremental carbon reduction value attributed to earlier (than NSPI's "reference" Scenario 2.0C)[15] installations of the wind resource can be considered as a credit to the actual cost of such earlier installations.

- **Finding 2a. Reliability Tie as Key Enabling Transmission Resource**. NSPI states that the Reliability Tie has value, even separate from an eventual "Regional Interconnection" landscape. NSPI states "the Reliability Tie could be constructed as the first phase of a larger Regional Interconnection transmission investment."[16] Building a Reliability Tie allows Nova Scotia to increase its in-Province wind generation without having to rely on external energy or capacity sources. While most of the scenarios modeled do clearly show value in importing additional energy and firm capacity from external regions, the modeling also clearly shows this first step of constructing the Reliability Tie is crucial to support any number of possible outcomes across the Province.
- **Findings 1c, 2c, and 4b. Coal Retirement Timeline.** NSPI states in Finding 1c, "Earlier emissions reductions are possible at incremental cost relative to the lowest cost plans;" in Finding 2c, "Coal units are generally sustained economically until their model-imposed retirement date, …"; and in Finding 4b, "The earlier retirement scenarios are less economic on an NPV basis but have similar cumulative rate implications by 2045."

[15] IRP Report, page 86.

[16] Id., page 106.

In reference to earlier retirement than the model-imposed date for "2.x" scenarios, NSPI's statements above may not be valid under scenarios where the additional carbon reduction associated with over-compliance of SDGA CO_2 emission targets for the electric power sector is monetized. This will depend on the value presumed for such incremental reductions. NSPI in its IRP analyses did not monetize any such over-compliance with emissions targets.[17] **NSPI's results as presented presume this value is zero** for all scenarios modeled as they effectively assign a zero probability to policy or market outcomes that would value electric power sector carbon reductions beyond those listed in the SDGA targets for NSPI. NSPI provided its rationale for this approach in the IRP Report:

> "Similarly, significant uncertainty regarding the depth, liquidity, pricing, and duration of the Cap-and-Trade market, Nova Scotia Power has not modeled the ability to sell credits into the market as part of the IRP optimization model so as not to develop resource plans which rely on that revenue for optimality. Nova Scotia Power's current assessment is that the revenue stream of this market is not sufficiently well understood to, in isolation, justify incremental capital spending or programs given the current limited level of market certainty (2022 termination) and practical experience (one auction conducted to date). Nova Scotia Power believes that participating in the GHG allowance market in the short term and monitoring developments that could provide long-term certainty sufficient for resource planning decisions are appropriate next steps as this market continues to develop and evolve" (pages 47-48).

Synapse notes that resource planning in many jurisdictions historically has excluded a carbon emission reduction value. However, Nova Scotia does have in place an explicit mechanism, under the SDGA, for multi-sector emissions reductions that would allow the lowest-cost emissions reductions to substitute for higher-cost reductions. For example, this would be allowed if the electric sector can reduce overall emissions at lower cost than the other sectors.

Whether or not Scenario 3.1C as developed would end up at a lower NPVRR than Scenario 2.1C (or, more generally, whether any 3.x Scenario would exhibit a lower NPVRR than any analogous 2.x Scenario) does depend on the level assumed for the valuation of the additional carbon reductions. It also depends on the extent to which there is economic demand for additional carbon reductions. Currently, that economic demand occurs as part of the Cap and Trade regulatory framework and reflects whether those mandatory Cap and Trade participants[18] can

[17] Synapse explicitly included a request for such modeling consideration in our comments on NSPI's Analysis Plan and Assumptions, and on several occasions during stakeholder conferences. As stated in our comments on March 3, 2020: "In all cases, the effect of the Cap and Trade Regulations will be to provide an effective shadow price on incremental carbon emissions (beyond NSPI's free allocation of carbon emission allowances). Critically, we recommend this effect be directly incorporated in the model as pricing for any NSPI increased emissions, and an allowance sales opportunity for any decreased NSPI emissions, for all years of the analysis. While the structure of the regulations, and the level of the 'cap', is uncertain for out years, some form of 'floor' price should be considered for all years."

[18] The Cap and Trade regulations define mandatory Cap and Trade market participants, and reflects wholesale oil product providers (e.g., gasoline, diesel) and other large industry emitters. Cap and Trade program details including a list of mandatory participants is available here https://climatechange.novascotia.ca/cap-trade-regulations#auctions.

meet their sectors' emission reduction targets through direct actions, or through purchase of allowances either bilaterally or at Cap and Trade auctions.

As seen in the analysis we present above in Section 3 of this report, a direct comparison between Scenario 2.1C and Scenario 3.1C shows that earlier reductions of emissions (under Scenario 3.1C) result in a **lower** cost than later reduction of emissions (under Scenario 2.1C) **if** the additional CO_2 emissions saved are directly valued at just above a "breakeven" point of roughly $38/ton (real, $2021) of additional CO_2 emission reduction, for the specific scenarios developed.[19]

- **Finding 3d and 3e. Battery Storage and Demand Response as Capacity Resources.** NSPI appropriately notes the importance of demand response as a capacity resource, and the role that battery storage can also play in providing peak period capacity supply. NSPI indicates that duration attributes of battery resources limit the role it can play as an economic option in Nova Scotia to provide capacity in response to eventual coal fleet retirement. As part its Roadmap element #4, NSPI suggests ongoing monitoring of "low/zero carbon fuels" that could substitute for the natural gas combustion turbine resources currently present as replacement capacity in most resource plans. Synapse notes that the overall portfolio diversity of demand response resources, coupled with battery storage resources, and capacity contributions from new wind resources should be further analyzed to ensure that overall diversity effects across a portfolio of substitute resources is comprehensively analyzed. While this was addressed to some extent in the pre-IRP studies of capacity value,[20] a more in-depth revisiting of the ability for a combination of resources to support capacity needs is warranted.

- **Finding 1b and 2e. DSM and Electrification**. These findings appropriately note the importance of energy efficiency provision and assessment of the trajectory of electrification in the Province. Synapse notes that under scenarios where DSM costs to NSPI are lower than those projected by Efficiency One, the IRP results using higher levels of DSM remain relevant to ongoing planning efforts. NSPI appropriately notes that "future DSM program development should incorporate the learnings obtained from the full range of sensitivities and metrics considered in the IRP."[21] NSPI also developed its Mid and High Electrification scenarios without testing the effect of higher energy requirements coupled with more aggressive mitigation of peak load increases. Many options are available to NSPI over the next decade and beyond to mitigate peak period load increases while still encouraging beneficial electrification. Continued study of

[19] Note that there is no modeled Scenario 3.1 Low Wind, and thus we do not have a comparison point for the 2.1C Low Wind scenario.

[20] E3, "Planning Reserve Margin and Capacity Value Study," July 2019.

[21] IRP Report, page 109.

mechanisms to promote off-peak period consumption for electrifying end-uses is required.

- **Finding 2d. Mersey Retention or Retirement.** NSPI's sensitivity run excluding the Mersey system ("2.1C Mersey") was $44 million lower cost (NPVRR + decommissioning cost) than 2.1C with Mersey included. This is the result when using the 25-year NPVRR metric and directly including as an explicit adder the estimated $227 million decommissioning cost associated with a full decommissioning.[22] It was only when end effects and the estimated full decommissioning costs are included that the modeling results indicate a benefit to retaining Mersey (estimated at $78 million NPVRR including end effects). NSPI states, "The results of this sensitivity indicate that redevelopment of that hydro system is economic relative to decommissioning when comparing the 25-year NPVRR with end effects." This is only the case if it is presumed the full $227 million in decommissioning will be required. The breakeven point when using the full "end effects" computation would be if actual decommissioning costs associated with any final scope of decommissioning were roughly 66 percent of their currently estimated cost.

4.2. Action Plan

NSPI presents its Action Plan in Section 7.2 of the IRP report, consisting of five multi-part action steps. Suggested changes, if any, for those steps are itemized below. Synapse's suggestions are based on the findings we describe above, and on the analyses discussed in earlier sections of this report.

i. Regional Integration Strategy

- Synapse recommends initial prioritization be given to NSPI's item 1b, commencement of the development of a Reliability Tie, because it likely will take longer than item 1a (efforts to identify opportunities for near-term firm imports over existing transmission infrastructure). Developing the Reliability Tie is potentially complex (because it involves new construction and a neighboring jurisdiction), and it should be afforded a very high priority because it critically supports both economic new wind—potentially a doubling of the Province's existing wind capacity—and a deeper regional interconnection strengthening with New Brunswick. Furthermore, this item of the Action Plan should include more specific timelines and tasks for NSPI to adhere to, such as the following (subject to administrative requirements):

[22] IRP Report, Appendix E, IRP Modeling Results, pages 58-59.

- Initialize a regulatory proceeding for this resource in the first half of 2021.
- Report to the Board on the current status of securing right-of-way for the Reliability Tie in Nova Scotia.
- On an aggressive a timeline as is possible, engage with Canadian Federal departments and other Nova Scotia agencies to determine possible sources of joint funding for development of the Reliability Tie.
- Report to the Board on the current status of discussions with New Brunswick on all elements associated with development of a Reliability Tie, including routing, electrical modeling, timing, cost allocation approaches between the Provinces and potentially the Federal government, and any other relevant issue.

ii. Initiate Thermal Plant Retirement, Redevelopment and Replacement Plan

- NSPI should prioritize element 3d, initiation of a wind procurement strategy. This strategy should target potential procurement of up to 631 MW of wind deployment by 2025. This is in line with the findings of Scenario 2.1C low wind cost, and roughly in line with the findings of Scenario 2.1C low wind cost and low battery cost. To the extent that market outcomes do not find costs or price offerings in line with the low wind cost assumptions, and estimated incremental carbon reduction valuation does not offset the difference, NSPI can utilize this procurement process to obtain the lower levels of economic wind seen in its other scenarios. Ongoing Roadmap analysis can address any concerns with the ultimate level of wind resource integration allowed, which is premised in part on the status of the Reliability Tie and other assets that may be deployed to ensure reliable operation.[23]

  The potential for capturing any economies of scale that may exist, if developers were aware of a potential deployment totaling roughly 631 MW by 2025, must be ensured through broadcast of the upper end of possible procurement. NSPI's current action item 3d is potentially self-defeating: by targeting only 50–100 MW of new wind, NSPI could be directly foreclosing capture of the economics of scale associated with higher levels of new wind installations. Targeting only a smaller level of new wind could miss the economic opportunity to accelerate the deployment of

[23] The PSC study indicated requirements for reliable operation of increased levels of wind integration. Notably, some stakeholder comments also indicated that the larger levels of wind power could be installed, but operational limitations may need to be used for those periods when stability or related concerns matter to reliability. The implication is that there will be many periods when actual wind operation from a fleet of roughly 1,200 MW (installed) will not pose a reliability concern (e.g., in the summer when loads are lower, and wind output from the wind resource is predictably much lower than winter output, when loads are higher and the system can more easily absorb higher levels of wind).

in-Province resources. NSPI should also further publicize the already-public assumptions made in the "low wind" cost Scenario 2.1C, to provide to the market a clear signal as to the level of wind cost expected if procurements of as much as 631 MW by 2025 are to be entertained.

- As with all elements of the Action Plan, NSPI should be expected to report to the Board with a specific timeline and procurement plan approach.

iii. Demand Response Strategy

- NSPI should prioritize development of resources that enable deployment of demand response during winter peak periods. Demand response resources generally at levels up to 81 MW by 2026 are seen in all Low and Mid Electrification scenarios, and up to 103 MW are seen in High Electrification scenarios. Roadmap item # 4 includes monitoring of "low/zero carbon fuels" that could provide incremental capacity; to the extent that additional demand response resources are available in the Province, in part (for example) as a result of successful implementation of time-of-use rate strategies,[24] the efforts planned as part of the Roadmap would be better elevated to Action Plan status.

iv. Electrification Strategy

- Item # 2 of NSPI's Action Plan includes encouragement of beneficial electrification and data collection on the nature of incremental load (e.g., hourly load shapes) from electrifying end-uses such as heating and transportation. Item 2c appropriately requires NSPI to address electrification impacts on the transmission and distribution system; Synapse suggests the nature of analysis associated with this element needs significant expansion to assess the extent to which potential peak load increases associated with beneficial electrification can be mitigated.

  The input assumptions associated with all scenario analysis used a single trajectory of peak load growth for each of the Low, Mid, and High Electrification scenarios. Peak impacts associated with newly electrifying transportation sector load can be mitigated through rate structures that recognize the ability of electric vehicles to utilize managed charging, and thus shrink peak impacts on system peak loads. Time-

[24] It is our understanding that the estimated level of demand response resources included in NSPI's IRP assumptions does not include the potential for additional market/behavioral response that could arise from implementation of time-of-use and critical peak pricing rates after deployment of automatic metering infrastructure (AMI) and commencement of any time-of-use or critical peak pricing rates pursuant to NSPI's Time Varying Pricing Application.

of-use pricing, and the use of critical peak pricing tariff structures coupled with the Province's deployment of automatic metering infrastructure presents an opportunity to ensure significant mitigation of peak load increases from heating electrification. As noted in Section 3 of this report, identifying and deploying peak shaving tools can allow for high electrification paths with a greater proportion of off-peak period consumption than NSPI had indicated in its High Electrification forecasts used in this IRP process. Going forward, NSPI must give much greater attention to identifying programs and investments that can minimize peak load addition (at least during critical peak periods) while maximizing off-peak and non-critical peak period consumption arising from beneficial electrification.

v. Carbon Emission Valuation from Overcompliance with SDGA Emission Targets

- Synapse suggests elevating a Roadmap step to a sixth Action Plan element for NSPI to include as part of this IRP: ongoing, at-least-annual direct valuation of any incremental (beyond SDGA targets) carbon emission reductions arising from NSPI system operation and planning. This could be included in NSPI's annual *System Outlook* report generally filed with the NS UARB at mid-year. Synapse suggests that the first reporting in 2021 for this element should include a detailed analysis of the market potential for excess emission allowances and estimated prices for those allowances.

  NSPI includes in its Roadmap item #6 a tracking of the ongoing Nova Scotia Cap-and-Trade Program. Synapse suggests this element be moved to the Action Plan and made more specific, as noted above.

  Additionally, obtaining better information on the near-term value associated with increased emission reductions from new wind resources would require NSPI to perform more immediate analyses associated with near-term policy developments and Cap-and-Trade auction results. The results of such analyses would inform the results of initial wind procurement processes. Use of these results would ensure that any additional value from the sale of carbon emission over-compliance arising from earlier installation of wind resources—such as seen in Scenario 2.1C "low wind cost"—be factored into decisions on early deployment of wind after determining the costs of such wind in response to procurement offers.

  Lastly, such analyses should also be used to regularly inform any evergreen IRP planning processes, as laid out in Roadmap item #8. As part of such use, the analyses should be used when assessing the extent to which "[s]ignificant changes in the value of incremental GHG reductions could influence resource plan components including non-emitting generation procurement, DSM levels, and coal retirement trajectories."[25]

4.3. Roadmap

NSPI presents its Roadmap in Section 7.3 of the IRP report, consisting of eight elements. Suggested changes for three steps are itemized below. Synapse suggestions for modifications to NSPI's Action Plan also address the role for some of the issues identified in NSPI's Roadmap.

i. Elevate Roadmap item #6 to Action Plan status, as described above in Section 4.2 of this report.

ii. Roadmap item #2 suggests completing a detailed system stability study under various current and future system conditions. Synapse suggests that a portion of this work was already completed as part of the pre-IRP PSC Renewable Integration Study but recognizes that additional detailed studies continue to be required to support new renewable resource installation.

    This Roadmap item should focus first on the practical effects of system operation, and any required specification of operational limitations that may be needed under circumstances that see increases in wind on NSPI's system at levels up to 631 MW by 2025 (as seen in Scenario 2.1C low wind). The studies should recognize that, under higher levels of new wind connected to NSPI's system, there may be limited hours where system stability concerns or other technical concerns give rise to requirements to restrict output or otherwise posture new (or existing) resources to ensure reliable operation. The studies should identify these circumstances, with specificity on the number and duration of hours requiring curtailment (for example), and the conditions giving rise to the limitations. The original studies focused on analyzing limiting conditions, rather than identifying the duration and mitigation needs under circumstances with large levels of interconnected new wind.

    The studies should assume a Reliability Tie in place, with sensitivities reflecting different timelines for likely installation (e.g., fast (2023), medium (2025), slow (2027-2029) completion of Tie) to test what form of alternative resource requirements (e.g., synchronous condensing) might be necessary to limit operational restrictions on new wind resources.

iii. Roadmap items #3 and #4 include monitoring unit reliability, and potentially conducting an ELCC (equivalent load carrying capability) calculation if necessary, and monitoring the development of low/zero carbon fuels that could be used as capacity resources to substitute for natural gas combustion

[25] IRP Report, page 115.

turbines. Synapse suggests that this Roadmap item be expanded to include more in-depth analyses and computation of the ELCC for a future resource portfolio combining wind, battery storage, demand response, and possibly solar PV. A large part of the reason that gas combustion turbine units, rather than a combination of storage resources charged with wind energy, are economic in the modeling process is due to the poor ELCC performance of battery and wind resources, as input to the model. However, portfolio combinations that include the ability of demand response, and potentially solar PV, may result in higher overall ELCC and reduction of need for new gas combustion turbine units to substitute for capacity provided by the steam resources expected to retire during the planning horizon. Also, any updated information on the performance attributes of existing or new wind resources could be incorporated into ongoing analyses.

iv. Roadmap item # 7 indicates NSPI's plan to monitor electrification growth in Nova Scotia. As part of any monitoring of electrification, as noted above in the Action Plan element for NSPI's Electrification Strategy, NSPI must give much greater attention to identifying programs and investments that can minimize peak load addition (at least during critical peak periods) while maximizing off-peak and non-critical peak period consumption arising from beneficial electrification.