NS Power IRP

Comments received from Participants in response to Modeling Results

July 2020

Resource Insight Inc.

MEMORANDUM

To: Linda Lefler, Senior Project Manager, Regulatory Affairs
Nova Scotia Power

From: John D. Wilson and Paul Chernick

Date: July 17, 2020

Subject: Comments on Initial Modeling Results

Thank you for a very informative report and presentation on July 9th. We appreciate the opportunity to comment on the results so far. Our comments below are divided into three sections. First, we request some further documentation or potentially modification to methods. Second, we suggest some enhancements to the scenarios or sensitivities to address emerging findings. Third, we make some observations regarding the initial results.

At a high level, the analysis so far suggests that the IRP will set up some significant decisions for NS Power and the Board, but that additional work may be needed to reach those decisions. Those key pre-2030 decisions appear to be whether to retire some coal units, whether to build more than 100 MW of wind, whether to plan and build the reliability tie, and whether to start the inter-provincial process of siting and planning the reliability tie and regional interconnection.

We also recognize that there are many other significant decisions that the IRP may inform, including the level of DSM investment, approaches to distributed resources, life extension for the Mersey hydro system, and planning for electrification.

None of these decisions are so time-sensitive that NS Power must be conclude its work within the current schedule for submitting a final IRP report to the Board. We strongly encourage NS Power to take the time necessary to explore these key issues thoroughly, whether by seeking a delay in the final IRP or by supplemental analyses and consultation following that filing.

I. Methods

Reserve margin: During the discussion of the new ELCC factors (slide 7), NS Power explained that instead of a planning reserve margin of 21% of installed capacity (with downward adjustments to the effective capacity for wind and some other resources), NS Power was imposing a minimum reserve of 9% in ELCC terms. Our understanding was that one MW of ELCC would support one MW of firm load. We are unable to locate any documentation for the conclusion that reliable supply requires capacity with a cumulative ELCC of 109% of peak load. We suggest that NS Power should provide that derivation and identify what drives the need for an ELCC reserve margin of 9%.

End effects: During the explanation of the end effects, we learned that NS Power was calculating end effects as the present value of 25 years of the 2045 revenue requirements. Those end effects are included in the objective function for the model optimization. The end effects are quite large and vary significantly by portfolio. For example, in the portfolios that include medium electrification and base DSM, the end effects range from $3.5 to $4.7 billion.

We are concerned that this end-effects calculation may significantly distort the differences among cases. For example, the regional interconnection has a cost of $1.7 billion (Assumptions Set, p. 74) and its various portfolios add the interconnection between 2030 and 2045. The 2045 net plant (and hence the annual revenue requirements) of the connection will be much higher if it is built in 2045 than if it is built in 2030. The 2045 revenue requirements of the 2030 connection would be lower than those of the 2045 tie because (1) the 2030 tie would be less expensive in nominal dollars and (2) it would be substantially depreciated by 2045. It seems to us that holding post-2045 revenue requirements at the 2045 level for 25 years overstates the end-effects costs of the plans with large capital investments near the end of the modeling period, compared to plans dominated by higher fuel or other expenses.

We would like to see an analysis of whether the differences in end effects among the initial IRP results reasonably reflect differences in costs between options. If the variation in end effects among cases appears to be correct, but the magnitude is overstated, NS Power should consider shifting to a shorter end effect period (e.g., 10 or 15 years), or eliminating it altogether.

Distributed resource costs: As we commented in February, we are concerned by NS Power's decision to ignore the costs for the distributed energy resources in cases 2.1B and 3.1B. Determining the value to customers of DERs (especially storage, which adds resiliency) is difficult, so it would be hard to estimate the net cost of the DERs. We suggest that NS Power be careful to indicate each time it presents costs for these cases to indicate that they do not include any allowance for BTM costs.

Those BTM costs do not fit neatly into the NPVRR calculation, since they do not represent utility revenue requirements. Nor should the full cost of DERs comparable to the utility costs, since DERs (especially paired solar and storage) provide additional benefits, particularly resiliency. If NS Power decides to incorporate some BTM costs into its reported cost metric, we suggest using a modest placeholder value. If Plexos produces marginal hourly energy costs, those could be used for the assumed DER load shape. Otherwise, NS Power might use some appropriate forecast estimate (average fuel cost, monthly marginal energy cost).

Bill metric: As the discussion with the stakeholders demonstrated, it is very difficult to compare plans with divergent load forecasts. NPVRR may be low for cases with high DSM and high for cases with lots of electrification, since the NPVRR does not reflect the benefit of fossil fuels avoided by electrification. The other economic metric in the interim results, the partial generation cost per MWh, does not provide much information about rate effects, since it does not reflect the spreading of sunk generation costs and all T&D and administrative costs over fewer MWh of sales with high DSM and more sales with high electrification.

As we suggested previously, a typical bill metric might be more meaningful than the partial cost per kWh. A typical bill metric should not include end effects. Clearly, the report will need to explain that the estimation of residual revenue requirements and any class cost allocation is drastically simplified from what might be presented in a rate case but is useful in terms of comparing portfolios to each other.

T&D costs: NS Power staff explained that the projection of revenue requirements excludes T&D costs, which would be affected by electrification and DSM. Please consider providing a rough estimate of the potential sensitivity of T&D costs to these scenarios in the IRP report even if estimates cannot be provided by scenario.

Capital cost: In conjunction with our concerns about the end-effects treatment, we would like more detail on the manner in which the "revenue requirement profiles" for the "supply-side options that represent a capital investment" are computed in the objective function of the long-term Plexos model (2020 IRP: Financial Assumptions, March 11, 2020). In particular, we are interested in whether you use annual, nominally-levelized or real-levelized revenue requirements, and how income taxes are reflected in the revenue requirements computation, in addition to book depreciation and return (which we assume is included at the 6.62% pre-tax rate). A display of the assumed revenue requirements from a combustion turbine, a wind installation and the reliability tie would be useful to ensure that we understand what you are doing.

II. Scenarios & Sensitivities

We suggest four changes to the scenarios (or sensitivities) that will be run for the IRP.

Natural gas price capacity plan sensitivity: The most recent FAM report suggests that there has been a shift from coal to gas driven by changes in fuel price. We suggest that NS Power should develop a capacity expansion plan that explores what level (or duration) of fuel price changes might trigger an economic decision to implement early coal retirements or otherwise affect the capacity build.

No-transmission sensitivity: Since the reliability tie and regional interconnection were selected in every scenario (except the comparator case), we suggest that there should be a capacity plan with steam retirements but without the major transmission options, to identify what resources would be selected.

It may be appropriate to study the interactions of the natural gas price and transmission sensitivities with the wind analysis discussed below. We observed that early coal retirements occurred in the net zero 2050 scenarios with distributed resources or low wind costs, indicating that coal plants are at least somewhat sensitive to low-cost energy.

Hydro avoided costs sensitivity: We understand that there will be a specific "without Mersey" case. In addition, we suggest that NS Power develop three additional expansion plans in order to develop avoided costs for Wreck Cove and the two small hydro system groups. These avoided costs would them be used in future economic assessment model (EAM) runs during capital project filings. This could be completed after all other modeling is done, as we do not believe these model runs are likely to have any other significant role in the final IRP analysis.

III. Observations

HalifACT 2050 plan: The HalifACT 2050 plan was discussed on the stakeholder call. A participant pointed out that the IRP should provide adequate study of plans that would be consistent with the HalifACT 2050 plan, particularly the 2030 goals. NS Power indicated that its scenarios at least roughly covered the goals of HalifACT 2050.

Our understanding of the HalifACT 2050 plan is that it includes four main elements that are relevant to the IRP.

- CO_2 emissions target: roughly 0.5 $MtCO_2e$ by 2030[1]
- Rooftop and other HRM solar, with storage: 1,600 MW by 2030 (also 200 MW wind)[2]

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[1] Halifax Regional Municipality, *Low-Carbon Technical Report* (March 2020), p. 28.

[2] Halifax Regional Municipality, *Low-Carbon Technical Report* (March 2020), p. 45. We understand the 1,300 MW of rooftop solar to be a technical feasibility estimate, and that HRM would view other resources as potentially replacing this component.

- 100% EV sales by 2030
- Every building retrofitted (electrified and efficient) by 2040

With the partial exception of the electrification goals, our review of the IRP modeling indicates that NS Power is correct that it has scenarios that address these points.

With respect to the CO_2 emissions target, all of the accelerated zero 2045 scenarios (e.g., 3.1B) appear to have emissions at or below 1 MtCO2e in 2030, which is consistent with the HRM goal, since HRM represents roughly half of Nova Scotia electric demand.[3]

With respect to the renewable energy goals, the IRP modelling suggests it will be more economical to rely on wind and firm imports than on solar.[4] NS Power will allow the model to select either both emitting and non-emitting resources (Assumptions Set, p. 75); the results reported to date do not break down that split. Scenarios 3.1C, 3.2B, and 3.2C have capacity builds that are consistent with the HRM goal, given the energy production from wind and firm energy imports (assuming those are renewable).

However, with respect to the electrification goals in HaliFACT 2050, it does not appear that NS Power's electrification scenarios in the load forecast are as ambitious as the HRM's goals. The limited description of the high-electrification scenario in the IRP make it difficult to determine how closely the two plans track. But the divergence in the electrification assumptions appears to occur mostly after 2030, so the high-electrification scenarios are likely to be adequate to develop an action plan consistent with HRM's electrification goals. Even a fairly aggressive program (whether sponsored by HRM, NS Power or some other entity) is unlikely to substantially exceed the levels of EVs and building electrification in the high electrification scenario before NSP's next IRP, which we assume will be completed around 2025. At that time, if vehicle and building electrification were progressing consistent with HRM's goals, then NS Power would need to adopt significantly higher assumptions for building electrification.

Whether NS Power commits resources reach the levels of electrification in HaliFACT 2050 is a matter for the Board to determine.

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[3] A precise comparison is not possible because neither the draft IRP modeling results nor the HalifACT 2050 plan include specific CO_2 emissions figures for 2030.

[4] Of course, the IRP does not reflect the benefits of distributed solar in reducing the T&D loads in summer-peaking Halifax, nor the resiliency benefits of solar plus storage.

Wind costs and constraints: NS Power's assumptions and modeling methods may be unreasonably constraining near-term wind builds in the model. The issues relate to NSP's cost assumptions for wind and the reliability constraints imposed during modeling.

Regarding costs, we noted in our previous comments that NS Power's 2019 capital cost of $2,100 per kW is outside the cost envelope suggested by Lazard. Synapse and Natural Forces also indicated that the $2,100 per kW cost was not reflective of the market. NS Power's response includes a single scenario in which the 2019 capital cost is reduced from $2,100 per kW to $1,500 per kW. This scenario results in a significantly higher near-term wind capacity procurement (118 MW in 2.1C.S2 vs 57 MW in 2.1C).

We understand that New Brunswick is adding wind resources; if those costs are available, NS Power should compare its assumptions to the contract prices in New Brunswick. If New Brunswick costs are lower than NS Power's assumption, then either the model cost assumption should be revised, or NS Power should explain how Nova Scotia conditions (mostly wind resources, but perhaps other cost drivers) would differ from New Brunswick conditions and justify the higher cost assumption.

Second, NS Power caps the wind build at 100 MW (700 MW total installed) unless either reliability tie or a battery + synchronous condenser capital investment (referred to as domestic integration) is made to support reliability. The model selects the less expensive reliability tie. This limitation is derived from the PSC study, which found that during periods of high wind and high imports, the loss of an intertie could cause stability issues.

NS Power's use of the PSC study finding to require a reliability tie or domestic integration ignores two alternative operational responses to accommodate additional wind. First, under hourly conditions of high wind and high imports without the reliability tie, wind generation could be capped at 700 MW. Second, under conditions of high wind, a minimum conventional (thermal or hydro) online capacity requirement could be established,[5] which would both provide additional local inertia and reduce imports, avoiding the high wind/high import combination. NS Power may be able to model these operational constraints (curtailments or minimum commitment requirements) in its planning models, in which case the model could directly compare the cost of the operational constraints to the reliability tie and to the benefit of higher wind capacity. Alternatively, NS Power may need to exogenously estimate the amount of curtailment or uneconomic

[5] Or, if an existing minimum conventional capacity requirement exists, then it could be increased during high wind hours.

commitment to deal with extreme conditions, and the cost of those actions, and use that cost in lieu of the reliability-tie cost.

The combination of the cost assumption and reliability requirements may be resulting in misleading model results. In the low wind cost scenario (2.1C.S2), the reliability tie is built in 2029, the earliest year of tie construction in any scenario, to allow addition of 20 MW of additional wind in 2030.[6] If the model were allowed to build additional wind with operational constraints, it might well choose to add that wind earlier than 2029 and defer the reliability tie until later in the study period.

This seems to be a critical policy question that the IRP should frame properly in the following sequence. The various scenarios include roughly 50–100 MW of wind in 2021, so NS Power should soon have market price bids for wind.

a) Under the assumption that operational restraints are used, and low wind costs are available in the market, at what dates does the model suggest building more wind than the operational constraints can accommodate, requiring the reliability tie?
b) What additional reliability and operational studies are needed to verify the performance and cost-effectiveness of using operational constraints to address the high wind/high import issue?
c) If wind prices are attractive enough to go beyond the wind capacity that can be facilitated with the operational constraints, how long a lead time would NS Power require to make a build or defer decision for the reliability tie?

Since the IRP process does not include an opportunity to further investigate the cost of wind resource development or further study the practicality of operational constraints, it is essential that the final modeling scenarios appropriately examine these questions to provide the Board with the context it needs to evaluate the need for and potential scheduling of the reliability tie.

DSM impacts – There are two case pairs that contrast base and mid DSM. The 2.0A pair has a NPVRR difference of $337m and the 2.1C pair has a difference of $544m. Why is the difference so substantial based on the electrification level? Why is the mid DSM incremental cost more than the supply resources it replaces? Would the avoided T&D costs associated with a higher level of DSM potentially offset the cost difference?

The model is making changes that seem counter-intuitive when shifting from base to mid DSM. The shift from base to mid DSM in case 2.1C (vs S1) results in an

[6] This raises a question not addressed in the Assumption Set: In what year has NS Power allowed the model to build the reliability tie?

early build of an NGCC unit, reducing gas peaker capacity, and reducing firm imports. Is there something about the way firm imports are characterized that needs to be reconsidered? Why is the model suggesting that it is economic to build a unit that produces more energy when there is less energy to serve?

Regional Interconnection – It appears that the regional interconnection is built in 2030 if the more aggressive climate policy is selected, except in the mid-electrification case with high distributed resources. Otherwise, it is built in 2038–2045. Perhaps a sensitivity to one of the 2040 or 2045 build cases should be run that forces the build in 2030. It would be interesting to see if the cost difference is significant. Building or postponing this upgrade well beyond 2030 is a significant near-term decision point, and NS Power should determine whether it should move forward with planning on this project, since it would require cooperation with New Brunswick and possibly Quebec.

Storage – It appears that in most cases with near-term wind procurement over 100 MW, there is a relatively large amount of 4 hr battery storage selected as well. If that is correct, the final plan should recommend that wind procurement should generally proceed in combination with a storage procurement.

Combined Cycle Gas – It is surprising to see a combined cycle built so late in the 2.2A and 2.2C cases, as well as being built in the 3.1 and 3.2 cases. We are concerned because it is our understanding that the objective function of the model includes costs and benefits at 2045 operational levels through 2070 via end effects. Given the 2050 climate targets assumed in these cases, but not really represented in the model, we believe there may need to be modifications to the model to ensure that combined cycle plants are financially viable without an assumption that the plants will operate beyond 2050.

Ideally, NS Power would simply limit the useful life of a combined cycle to 2050. However, there are at least two reasons why this simple approach may not be practical in the current modeling environment. First, this may result in creating a unique resource for each year in the model, which may result in too much model complexity. Second, the end effects associated with a gas plant retirement in 2050 may result in the model considering costs and benefits of the gas plant in 2045 continuing through 2070 – which is clearly inconsistent with the net zero carbon scenarios.

NS Power should identify a workable approach that allows the benefits and costs of a combined cycle plant to be reflected in a way that approximates retirement by 2050. As discussed above, it may make sense to limit or eliminate end effects calculations as part of the objective function. If that was done, then the number of resource options could be limited by offering units with 25, 20, and 15-year lifetimes, with no combined cycle plants built after 2039.

Resource Insight Inc.

MEMORANDUM

To: Linda Lefler, Senior Project Manager, Regulatory Affairs
Nova Scotia Power

From: John D. Wilson and Paul Chernick

Date: August 4, 2020

Subject: Comments on modeling of wind and hydro in the IRP

This comment letter supplements our prior comments on the IRP assumptions and initial modeling results. These comments respond to understandings we have developed as NS Power has shared additional details about its reliability constraints and based on our analysis of four years of operating history for the NS Power system. Specifically, the Consumer Advocate has commissioned a review of NSP's renewable integration report, and we have analyzed some operational data provided by NS Power.

Renewable Integration

First, we attach a review of the reliability constraints that NS Power has derived from the Power Systems Consulting, Inc. (PSC) Renewable Integration report. Telos Energy recommends that "*NSP should conduct capacity expansion plan modeling with no inertia constraint and/or with a 1500MW-s inertia constraint to show the sensitivity to the inertia constraint.*"

Telos Energy's findings raise important substantive questions about how NS Power is viewing the potential for near- and mid-term expansion of wind energy. As demonstrated by the low wind-cost scenario, the model results are very sensitive to the cost of wind. The cost of adding wind above the 700-MW threshold is greatly affected by the cost of the reliability tie; the need and timing of the tie depend entirely on NS Power's application of the PSC report's reliability findings.

We recommend that NS Power provide results in its final report that apply alternative inertia constraints. Assuming the differences are significant, further study after the final IRP report is issued could clarify the inertia constraint and other relevant reliability considerations so that NS Power can determine the appropriate level of wind development that may be supported prior to investing in the reliability tie.

Effective Load Carrying Capability

Second, wind development is also affected by the ELCC values assumed in the IRP. Our analysis of the historical generation data recently provided by NS Power to the Consumer Advocate does not seem consistent with the ELCC values being assumed in the IRP for wind and hydro. The wind plants appear to contribute more output at high-load periods than implied by the ELCC results, and the various hydro resources appear to contribute less output lower than the assumed ELCC.

Our findings suggest that the assumed ELCC values for wind and hydro understate and overstate, respectively, the UCAP Firm Capacity estimates for existing resources. If appropriate to revise or consider alternate ELCC values in the final IRP, then we recommend that the final IRP include modeling that reflects those adjustments.

Our Analysis

We calculated four metrics from hourly dispatch data supplied by NS Power for 2016 through 2019. These data are shown by type of plant in Table 1.

- **Annual Capacity Factor** – The average ratio of hourly generation to operating capacity. To calculate capacity factors, we did not have unit capacities matched to the units in the hourly generation data, except for the wind capacity which was provided in the heading. For the remaining units and resource categories, we sourced the operating capacity values from the E3 Capacity Study, pp. 42-43.
- **Winter Capacity Factor** – Average of the monthly capacity factors for December – March.
- **Average Capacity Factor for Peak Events** – Average capacity factor for all hours during peak events. Peak Events are defined as one or more consecutive days in which the load for one hour is in the top 1.1% of all hours.
- **Average Capacity Factor for Peak Hours** – Average capacity factor, top 1.1% of hours (386 hours over the four years), and top 0.1% (35 hours). The average capacity factor for the top 1.1% of hours is a recognized metric for calculating capacity credit from historical data.[1]

[1] The average capacity factor is equivalent to the load duration curve method for a marginal resource increment. The equivalency of the load duration curve method to ELCC is discussed in: Andrew D. Mills and Pia Rodriguez, *Drivers of the Resource Adequacy Contribution of Solar and Storage for Florida Municipal Utilities*, Lawrence Berkeley National Laboratory (October 2019).

Table 1: NS Power Generating Unit Capacity Factors

	Annual	Winter	Peak Events	Peak 1.1% Hours	Peak 0.1% Hours
Coal	60.0 %	79.6 %	89.1 %	95.9 %	98.8 %
Gas CC	46.0 %	37.2 %	31.7 %	48.4 %	33.2 %
Gas/HFO Steam	34.7 %	28.3 %	38.6 %	46.6 %	62.4 %
Diesel CT	0.5 %	0.6 %	1.9 %	3.7 %	4.5 %
Biomass	40.5 %	44.2 %	48.0 %	55.4 %	60.4 %
Wind	36.1 %	43.6 %	51.1 %	55.8 %	61.3 %
Wreck Cove	16.0 %	19.2 %	20.2 %	39.1 %	48.2 %
Mersey	58.4 %	74.2 %	73.7 %	70.6 %	66.2 %
Annapolis	10.3 %	11.5 %	20.8 %	45.9 %	69.6 %
Other Hydro	30.8 %	46.3 %	44.9 %	45.7 %	39.1 %

For each type of capacity, Table 2 shows the operating capacity from the E3 study, the maximum hourly output from the data provided by NS Power, operating capacity from the IRP Assumptions document, UCAP Firm Capacity (which NS Power defines as ELCC × IRP capacity) from the IRP Assumptions document, and Capacity Credit, calculated as the IRP capacity × capacity factor for the top 1.1% hours. The first two columns of data include Lingan 2 in the coal category.

Table 2: Operating and Firm Capacity (MW) for NS Power Units

	Operating Capacity (E3)	Max Hourly Generation [2]	Operating Capacity (IRP)	UCAP Firm Capacity	Calculated Capacity Credit
Coal	1,234	1,299	1,081	976	1,037
Gas CC	144	146	144	133	70
Gas/HFO Steam	318	337	318	232	148
Diesel CT	231	172	231	178	9
Biomass	43	50	43	41	24
Wind	404	387	595	113	332
Wreck Cove	212	207	212	201	83
Mersey	43	42	43	40	30
Annapolis	19	23	-	-	-
Other Hydro	121	98	121	115	55
Total	2,769	2,762	2,788	2,030	1,787

[2] Max Hourly Generation is the hourly dispatch for the single highest hour that the group of units is dispatched, i.e. a coincident maximum. It is presented as a reference to compare with the operating capacity values.

Observations and Questions

1. Unlike the thermal plants, the wind plants operate almost any time they are available. According to the E3 Capacity Value Study, wind resources only offer a 19% ELCC and the capacity factor for wind is generally in the 10-40% range during high load factor hours, as illustrated in that report's Figure 13.

Figure 13: Maintenance of Correlations Between Load and Renewable Production in RECAP's Day-Matching Algorithm

Time-Synchronous Load & Renewable Profiles

Load Factor (% of 1-in-2 Peak)	Wind Capacity Factor (% of Nameplate) 0-10%	10-20%	20-30%	30-40%	40-50%	50-60%	60-70%	70-80%	80-90%	90-100%
30-40%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
40-50%	3.3%	4.3%	4.7%	4.6%	4.1%	2.9%	2.2%	1.2%	0.4%	0.1%
50-60%	5.9%	6.6%	6.6%	6.3%	5.6%	4.1%	3.2%	2.2%	1.0%	0.3%
60-70%	3.3%	3.1%	3.0%	3.2%	2.7%	2.1%	1.6%	0.8%	0.3%	0.0%
70-80%	1.1%	1.0%	1.0%	1.1%	1.0%	0.8%	0.4%	0.1%	0.0%	0.0%
80-90%	0.4%	0.4%	0.5%	0.5%	0.5%	0.3%	0.1%	0.0%	0.0%	0.0%
90-100%	0.1%	0.2%	0.3%	0.2%	0.1%	[illegible]	0.0%	0.0%	0.0%	0.0%
100-110%	0.0%	0.0%	0.0%	0.0%	0.0%	[illegible]	0.0%	0.0%	0.0%	0.0%

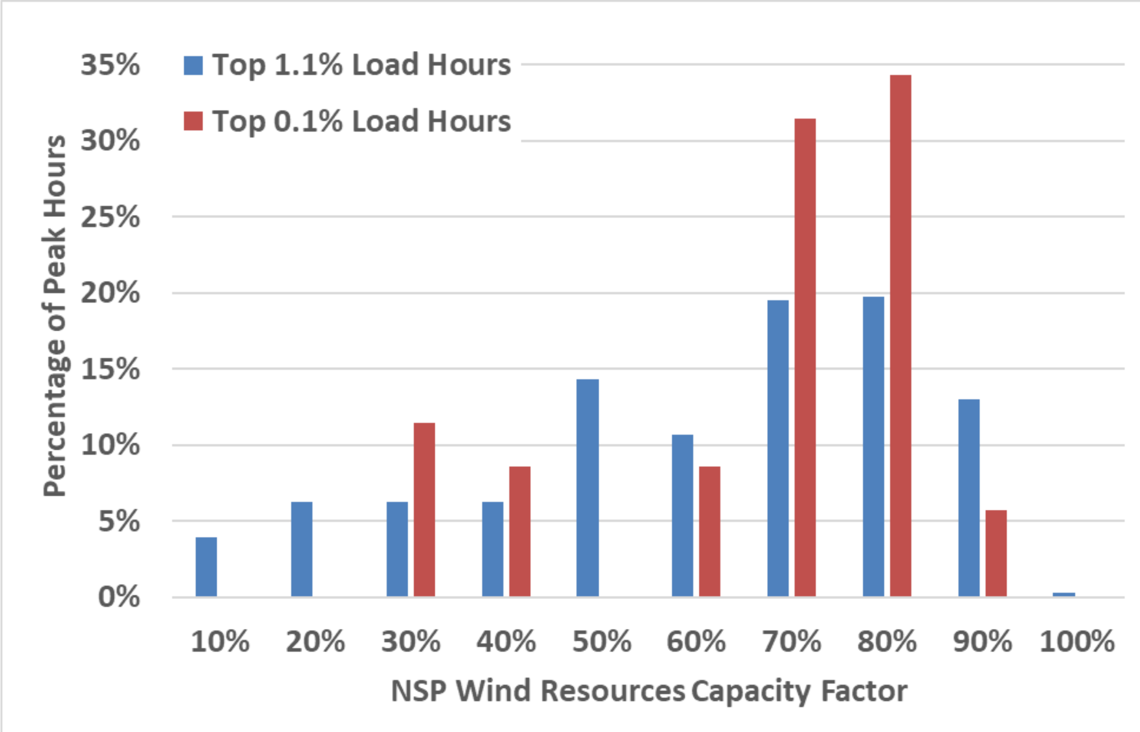
RECAP Synthetic Load & Renewable Profiles

Load Factor (% of 1-in-2 Peak)	Wind Capacity Factor (% of Nameplate) 0-10%	10-20%	20-30%	30-40%	40-50%	50-60%	60-70%	70-80%	80-90%	90-100%
30-40%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%
40-50%	3.5%	4.7%	5.2%	5.2%	4.4%	3.2%	2.3%	1.4%	0.5%	0.1%
50-60%	5.9%	6.5%	6.5%	6.4%	5.4%	4.2%	3.4%	2.3%	1.1%	0.3%
60-70%	2.9%	2.7%	2.5%	2.8%	2.5%	2.0%	1.5%	0.8%	0.3%	0.1%
70-80%	0.8%	0.8%	0.8%	1.0%	1.0%	0.8%	0.4%	0.1%	0.0%	0.0%
80-90%	0.2%	0.3%	0.4%	0.4%	0.4%	0.3%	0.1%	0.0%	0.0%	0.0%
90-100%	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
100-110%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

RECAP's day-matching algorithm captures key correlations between load and renewable production, including (1) tendency of wind to produce at low levels of output during very high load events, and (2) low loads during periods of high wind output

The generation data supplied by NS Power are significantly different from those presented in Figure 13 of the E3 Capacity Value Study. As shown in Table 1 and Figure 1, the generation data supplied by NS Power indicates that the average capacity factor during those hours was over 50% in the years for which data was provided, and at or below the 19% ELCC Factor assumed by NS Power for the IRP only about 10% of the time.

Figure 1: Wind Resources Capacity Factor Histogram



The IRP relies on the ELCC for two related purposes, valuing the capacity provided by existing wind generation and valuing the capacity provided by incremental wind resources. It is important to get both correct, since the existing wind generation counts towards meeting the planning reserve margin.

The E3 Capacity Value study indicates that the wind ELCC drops from 38% at near-zero capacity to 19% at NSP's current wind capacity (E3 Capacity Value Study, p. 58). We agree with the E3 report that the capacity credit for wind and other renewable resources should decrease as additional wind is installed. This strongly implies that existing resources should receive a higher credit that incremental resources. However, the current IRP assumptions appear to give an ELCC value of 19% for both installed and incremental wind capacity.

With respect to the installed wind capacity, we believe that the ELCC should be higher for three reasons.

- As noted above, the wind resource modeled by E3 performs far worse during peak hours than indicated by the data provided by NS Power.
- Our calculations, following the LBNL method (see footnote 1), suggest existing resources should have an ELCC of about 25%, as described below.
- E3's calculation of a 19% ELCC at current wind levels may be a marginal value (reflecting incremental system resources), not an average value (reflecting existing system resources).

With respect to incremental resources, the capacity credit calculation should be performed based on net demand, considering the top net peak hours after deducting wind resources.[3] Our findings using this analysis are compared to the net peak hour analysis in Table 3.

Table 3: NS Power Generating Unit Capacity Factors

	Peak Hours		**Net Peak Hours**	
	Top 1.1%	**Top 0.1%**	**Top 1.1%**	**Top 0.1%**
Coal	95.9 %	98.8 %	99.2 %	97.5 %
Gas CC	48.4 %	33.2 %	55.4 %	59.1 %
Gas/HFO Steam	46.6 %	62.4 %	51.4 %	62.5 %
Diesel CT	3.7 %	4.5 %	8.1 %	12.3 %
Biomass	55.4 %	60.4 %	62.9 %	65.1 %
Wind	55.8 %	61.3 %	19.7 %	14.8 %
Wreck Cove	39.1 %	48.2 %	45.7 %	57.6 %
Mersey	70.6 %	66.2 %	71.6 %	77.3 %
Annapolis	45.9 %	69.6 %	42.3 %	39.3 %
Other Hydro	45.7 %	39.1 %	47.6 %	53.6 %

As Table 3 indicates, after taking into consideration the capacity credit associated with wind, the capacity factor for wind in the top 1.1% of peak hours drops from 61.3% to 19.7% in the top 1.1% of net peak hours.

In the 4-year dataset provided by NS Power, the top 1.1% hours are those hours with load of 1,840 MW or with a net load of 1,697 MW. This indicates that the 595 MW of wind reduced load by about 143 MW, or a 25% capacity credit.

Thus, while our analysis supports the use of a 19% ELCC for incremental resources, *we find that the existing wind resources should have a UCAP Firm Capacity of 143 MW rather than 113 MW*.

2. The E3 study assessed hydroelectric capacity as a dispatchable resource using a net dependable capacity of 95% (E3 Capacity Value Study, Table 17). This appears to have been retained for the IRP. However, as shown in Table 1 and Table 3, this is not well supported by the historical generation data.

3. While Wreck Cove's capacity factor increases somewhat as demand peaks, the average capacity factor is only 58% for the top 0.1% net peak hours, as shown in Table 3. In fact, during the top 1.1% net peak hours, Wreck Cove was

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[3] Arguably, the net peak hours should also take into consideration must-run hydro resources. However, we lack sufficient information about the must-run requirements of specific hydro resources to make this adjustment.

dispatched over 75% in only 39 out of the 386 hours. In contrast, Mersey was dispatched at over 75% in 247 hours of those 386 hours.

We understand that Wreck Cove serves multiple functions on the NS Power system and has limited storage capacity, both of which may require that it be dispatched sparingly in many high-load hours.

Can NS Power explain why Wreck Cove operates so little in high-load hours? Does NS Power normally hold a large portion of Wreck Cove in reserve at peak? Does Wreck Cove have available energy resources to support a 95% ELCC value, given the long evening winter peaks?

While the Mersey units are dispatched more reliably than Wreck Cove in high-load hours, its dispatch does not match the UCAP/ELCC that NS Power claims for this system. Its capacity factor also declines from the winter, to peak days, and to net peak hours. *Does Mersey have enough flexibility in dispatch to be held in reserve at peak, or does the system simply produce less energy in the hours that tend to have high loads?*

4. The smaller run-of-the-river units are also dispatched well below their 95% ELCC factor during peak and net peak hours. As shown in Table 3, these hydro units have an average capacity credit of 48%, and were dispatched above a 75% capacity factor in only 3 of the top 1.1% net peak hours. We understand these units to have limited flexibility, so they would not appear to be held in reserve as is Wreck Cove. We also understand their capacity and energy output to be limited in low-water years.

   Why would these units merit a 95% ELCC value?

Nova Scotia IRP Technical Review and Commentary

Prepared for the Nova Scotia Consumer Advocate

August 4, 2020

Introduction

The purpose of this document is to capture the commentary from a technical review of materials prepared by and for Nova Scotia Power (NSP) as part of their Integrated Resource Plan (IRP). The focus is on grid reliability, grid stability, and grid services and their impact on IRP modeling and conclusions, with emphasis on the Power Systems Consulting, Inc. (PSC) Renewable Integration report.

The materials reviewed for this effort include:

- Nova Scotia Power Stability Study for Renewable Integration Report, PSC North America (NOTE: Tables A-D and figure C were not available in the version of the report reviewed)
- NSP IRP Modeling Results - Grid Services Representation in RESOLVE and PLEXOS
- NSP IRP Modeling Results - June 26, 2020
- NSP IRP Modeling Results - July 9, 2020

Organization of this document is as follows:

1. Summary of Key Points
2. Observations, Clarifications, and Commentary on the PSC Study by topic area

Summary of Major Points

Overall, NSP's application of the PSC report appears to place unreasonable constraints on wind resource deployment in the IRP. As discussed below, the initial conditions in the four cases selected by NSP for evaluation by PSC, certain assumptions in the modeling, and constraints on potential solutions combine in a manner that is very unfavorable to wind. The report does not provide sufficient analysis to provide alternate conclusions. For purposes of IRP analysis, NSP should conduct capacity expansion plan modeling with no inertia constraint and/or with a 1500MW-s inertia constraint to show the sensitivity to the inertia constraint.

- The four cases selected by NSP for evaluation represent a very narrow set of grid operations that is particularly severe. The dispatch conditions are not likely representative of actual system dispatch conditions and the contingencies evaluated appear to be inconsistent across the four cases evaluated. The initial conditions and simulated events directly impact the resulting inertia requirement for the system.
- The case selection did not consider the probability of occurrence of operating conditions. The scenarios evaluated should be viewed as highly conservative and it is likely that the stability

challenges could be avoided with small changes to operations rather than new investment or a moratorium on new wind development.

- The frequency stability and inertia evaluation considered wires, battery storage, and synchronous condensers, and it failed to consider many other effective alternatives, including use of the Maritime HVDC Link for frequency response, synthetic inertia from wind turbines, and fast demand-side response.
- The PSC report did not state the status (commitment and dispatch) of the Wreck Cove Hydro Plant in the cases evaluated. It is our understanding based on prior modeling analysis of NSP's grid that Wreck Cove is a large (~218 MW) and flexible plant that is routinely utilized for grid services like regulation reserves, inertia (424 MW-s), and primary frequency response. It is recommended to explicitly state how this plant was modeled and dispatched in this analysis.
- The grid strength analysis was not available (Figure C not included in the version of the report reviewed) or inadequately documented in the PSC report for drawing any conclusions. The apparent interpretation of the grid strength requirement of 0.67MVAr synchronous condensers per 1 MW of wind diverges significantly from current industry practices on evaluating and mitigating grid strength.

Identification and Explanation of Findings

Case Selection & Clarity

Case 1: The contingency event considers a simultaneous loss of both AC ties (345kV and 138kV). This is not N-1, but N-2 (the "N-X" denotes X elements of the power system are placed out-of-service, and typical planning criteria is for N-1). However, the PSC report also states that there's a remedial action scheme to prevent loss of the 138kV in the loss of the 345kV by adjusting transfer over the Maritime Link (as described in Section 5.1, case 3, page 41). This indicates that there is a special scheme already implemented to avoid the simultaneous loss of both 345kV and 138kV AC links to New Brunswick. Further, Section 7 (page 59) states that the thermal line limits have been "...set based on the loss of a single tie to New Brunswick..." The contingency event involving the AC lines to New Brunswick should be clarified, assessed for validity, and held consistent across all cases and simulations.

Case 1: At the time of event, the power flowing through the AC links from New Brunswick is 250 MW importing and 200 MW is being exported to Newfoundland via the HVDC link, according to Table 5-2. A reduced import (and similarly reduced export) would have substantially reduced the severity of the event where all AC connections to New Brunswick are lost. The reasons for selecting this initial condition, or why NSP would be willing to operate in this combination of imports and exports, are not provided. The behavior of the HVDC link following the event is not discussed. These aspects are critical, as a fast run-back of the HVDC link during this event could have mitigated instability of the grid. Furthermore, the PSC report states that "the only synchronous machines in the island are small hydro units" with an aggregate online inertia of 387 MW-s. It appears that the Wreck Cove Hydro unit (at 424 MW-s) was not online, as it would have more than doubled the system inertia online. It is not clear why a stabilizing and economic plant like Wreck Cove (or if Wreck Cove was not available, some thermal capacity) was not committed.

Case 2: The contingency evaluated was the loss of 1 of 2 poles of Maritime HVDC link at its maximum import (~240 MW). Section 5.1 (page 41) states that “Although NPCC requires the system to survive the loss of both poles of the Maritime Link (475 MW or 39% of total load), this study included loss of one pole only.” The report later recommends that the loss of both poles be evaluated. Absent other changes to the system, the loss of both poles simultaneously would be far worse for the system. This lends further doubt as to the reasons for -- and validity of -- the cases selected for evaluation. If it is determined that loss of only one pole of the HVDC link is considered credible for evaluation (and not the simultaneous loss of both poles), then it is expected that the power flow on both poles will be balanced (50% power flow on each), which will reduce the maximum contingency size if one pole is lost.

Case 2: This case assumes that NS is already disconnected and islanded from the NB grid. A trip of the largest generator would constitute an N-2 contingency and should not be considered in the same comparison as the N-1 contingency analysis.

Case 1 and Case 4: Both cases assume high imports from New Brunswick even during high wind events, and this is particularly extreme in Case 1 where system load is also very low. This level of import is unlikely during high wind and low load conditions and appears overly challenging to system operations. Reduced imports via utilization of generation within Nova Scotia would likely be the most prudent operational strategy.

Probability of Occurrence of Scenarios

There is no context or reasoning provided for the selection of the four cases evaluated: why NSP would operate in this fashion, how frequently these conditions might be expected to occur, or how frequently similar conditions (recognizing that large imports from NL have not been possible) have occurred in the past. To evaluate mitigations, it is important to understand the frequency and duration for which the grid would be operated in the pre-event conditions. (Note that an additional probability factor would be multiplied, representing the probability that the contingency event actually occurs during the time the grid is operating in the specified condition.) The answer may range from very infrequent and short-duration conditions to frequent and long-duration conditions. The answer can dominate the economic cost/benefit of proposed mitigations. For instance, infrequent (worst-case) scenarios that happen for a few hours a year and can be operationally mitigated at very low cost would not justify large investments. On the other hand, conditions that would occur very frequently (100s or 1000s hours/year) and require expensive or unreliable operational mitigation may warrant a significant capital expenditure.

Frequency Stability & Inertia Requirements

Existing System (Section 5.1)

Case 1: This case is key because it was used to determine the 2766 MW-s inertia minimum, which was later used in NSP's IRP modeling. However, the resulting minimum inertia from this simulation is highly suspect for the reasons described in the Case Selection section for Case 1.

Case 4: The results of the simulation show that after the contingency event, there is a relatively slow dynamic sequence of increasing voltage, leading to increasing load, which leads to a system frequency instability. If there was a means of better regulating voltage during this time frame (for instance, utilizing the reactive capabilities of wind turbines and/or augmenting that capability with other assets like shunts, STATCOMs, or SVC), it is possible interrupt this sequence of events and improve system stability with a relatively economic mitigation alternative.

With Added Wind (End of Section 5.1)

Case 3: The simulation fails to run, presumably due to non-convergence of the software algorithm. While non-convergence of the software algorithm is often associated with an infeasible operating point of the power system, this is not necessarily so. It could simply be a problem with the model and/or the simulation parameters. No comments were provided to indicate if additional checks were performed to try to confirm that the result was indeed due to an infeasible operating condition. Therefore it is difficult to draw a defendable conclusion here.

Case 4: Additional wind was added by backing down the Maritime HVDC link. The report states that the tripping of the AC tie (apparently both 345kV and 138kV as it states the Nova Scotia becomes islanded) results in all load-shedding stages to be triggered and "this major issue requires additional system reinforcements to accommodate increase [sic] of wind beyond present levels." There are several issues with this:

- The contingency appears to be a loss of both AC (345kV and 138kV) ties simultaneously, which is N-2 (simultaneous loss of two elements of the power system)
- The contingency size (in this case, power flowing through the AC ties when tripped) is unstated. However, if the power flowing through were reduced, for instance, by not backing down the Maritime HVDC link as much, then the load shedding impact would be reduced.
- The resulting load shedding is stated to be a "major issue" and "requires additional system reinforcements" but the level of acceptable load shedding for a contingency of the severity simulated is not defined.

System with Additional 345kV Line (Section 5.2)

This section was not given a high level of scrutiny at this time because the base cases (covered in Section 5.1, "Existing System") on which this analysis is based raises so many questions.

System with Synchronous Condenser and BESS (Section 5.3)
This section was not given a high level of scrutiny at this time because the base cases (covered in Section 5.1, "Existing System") on which this analysis is based raises so many questions.

However, the proposed mitigations of a 200 MVA synchronous condenser and a 200 MW BESS were not sufficiently justified because they were not tied to any performance criteria and not evaluated with adequate clarity. Further, the synchronous condenser was noted to have little impact on the load shedding incurred and its rating and rationale were not supported by analysis, like a grid strength study.

Meanwhile, the analysis did not mention Wreck Cove Hydro, which is a relatively large (218 MW) and flexible hydro asset that could be effectively used to mitigate load shedding and grid-strength concerns simultaneously as it is function similar, but larger than the combined proposed mitigation of 200 MVA synchronous condenser and 200 MW BESS.

Alternative Mitigations Not Considered:
Many alternative mitigations were not considered beyond the use of a synchronous condenser and BESS:

- Utilization of the Maritime HVDC Link for short-term contingency support -- HVDC systems are exceptionally fast-responding and can provide critical fast-frequency response (FFR) services. The Maritime HVDC system also has a very high rating (475MW) and even a partial allocation of its capability for emergency grid services can be very effective. The report noted that remedial action schemes (RAS) with the HVDC are already in use. It is acknowledged that any such schemes will have an impact on the Newfoundland power system, which would need to be considered.
- Utilization of synthetic inertia from wind power plants should be considered. The use of synthetic inertia does not require pre-curtailment of the resource. Ireland has introduced a market for grid services like synthetic inertia (called FFR, POR) as part of their DS3 Program, which has been operating since 2018 [1]. HydroQuebec has mandated the use of synthetic inertia for new wind plants on their system [2].
- Utilization of curtailment from wind power plants. When the curtailment is implemented as a fast-frequency response (FFR) function for over-frequency, wind plants can quickly and automatically reduce power output in the event of a contingency (for instance, a sudden loss of export capability or loss of load) to help the grid remain stable. Nearly all new wind plants offer this capability, and many modern wind plants installed in recent years may be able to adopt this functionality through software upgrades. The Electric Reliability Council of Texas (ERCOT) has been requiring this functionality for many nears from its wind turbine fleet.
- Utilization of under-frequency FFR from wind power plants that are curtailed. This functionality enables wind turbines which have already been curtailed to respond quickly and automatically to contingency events like a loss of import or loss of generation to improve stability and mitigate under-frequency load-shedding. Like FFR for over-frequency response (fast curtailment), this

functionality is available on nearly all new wind plants and most modern wind plants (perhaps with upgrades), and has been routinely used in ERCOT for many years.
- Utilization of demand-side resources to provide frequency response. Demand response has been around for decades, and more recently, there has been a growing segment providing very fast demand response, which is capable of acting quickly to mitigate or avoid load shedding. ERCOT has been operating a responsive reserve market for several years, and has introduced a fast-response (FFR) version open to load resources earlier in 2020 [3].
- Utilization of the Wreck Cove Hydro Plant -- It is not clear to what degree the Wreck Cove Hydro Plant was considered in the dispatch scenarios, but this plant is sufficiently large (~218MW, 424MW-s of inertia) and flexible as to have a substantial impact on the stability of the power system. Its status and utilization in the study work should be made explicit because of its potential importance to the system.

Short-Circuit Strength

Short-circuit strength was only discussed qualitatively and did not appear to be a binding constraint for the Nova Scotia system. The report version reviewed did not quantify that support for grid strength is needed.

In the "Wind Integration" line item from NSP's "Grid Services and Renewable Integration -- Modeling Requirements" slide, it appears that NSP arrived at a ratio of 0.67MVAr of synchronous condensers for every MW of wind turbines installed based on a section of the PSC report that analyzed 300MW of additional wind with the addition of 200MVAr of synchronous condensers [4]. But there is no connection or attributed causation here. The apparent interpretation (ratio method) by NSP of a poorly constructed simulation scenario is technically unsubstantiated and far from industry-accepted methods and practices for assessing and mitigating risks associated with low grid strength. Industry-accepted methods involve a screening process, potentially followed by a detailed study, which PSC alludes to in their report. The physics of weak grid instability issues is highly non-linear and cannot be reduced to a simple ratio for extrapolation to significantly different grid conditions or resource mixes.

Power Quality

Power quality is mentioned in the PSC report and recommended for further study. However, power quality is generally not considered a systemic issue but rather an application-specific issue with application-specific mitigations. There is no evidence to suggest that power quality analysis is warranted as part of long-range planning efforts. While it's correct that weak grids can exacerbate the problem, it often is in conjunction with resonances on the system, for instance due to long, high-voltage cable.

Regulation Reserve

It is unclear why PSC included a regulation reserve analysis at all, as it does not significantly influence the transient stability analysis, the minimum inertia levels, or the need for synchronous machines. The timeframe of regulation reserves (several minutes) is longer than the timeframe analyzed by the PSC simulations. Nova Scotia is part of the much larger Eastern Interconnection and thus will not see fluctuations in frequency due to wind variability when it is interconnected to New Brunswick.

It should be noted that all power systems require some level of regulation reserves, regardless of installed wind capacity, to cover normal load variability. The introduction of wind variability can increase the amount of regulation reserves required. Overall, the PSC analysis included a reasonable analysis of historical net load variability to develop a regulation requirement, but there are a couple limitations.

First, PSC utilized a 3-sigma standard deviation for variability, which covers 99.7% of all wind variability on the system. There was limited discussion on how three standard deviations were selected; that level is potentially conservative. For example, a 95% confidence interval could significantly reduce the amount of regulation required. For example, the National Renewable Energy Laboratory's (NREL) *Eastern Renewable Generation Integration Study* (ERGIS),[5] used *"confidence intervals that covered 95% of the forecast errors. These requirements approximate levels of coverage used in past integration studies.* The 95% confidence interval is also supported by Ibanez, et al.,*"The regulation reserves were calculated using 10-min time and 95% confidence intervals for the entire footprint."*[6] Limiting wind output to the 95th percentile may have very small costs.

Second, the PSC analysis assumed a proportional increase in variability for wind additions to 1,000 MW. In reality, there would be at least some increased diversity of the wind profile as new wind is added to the system. However, Nova Scotia is relatively small with over 500 MW of wind currently installed, so this effect is likely relatively small.

Overall, the assumed regulation requirement is relatively small, will not influence the PSC stability analysis, and will have a relatively small effect on the IRP modeling. It should be given lower priority than the other stability analysis comments.

Curtailment

The second phase of the study, beginning with Section 5.2 states that "Under the base cases of Case 01 and 02, adding wind to Nova Scotia is not feasible assuming the wind needs to be curtailed due to lack of enough load or export limit." However, the level of curtailment is not quantified. While high levels of curtailment are not economic, some curtailment is likely and can be used for productive purposes when necessary.

None of the cases were evaluated with curtailed wind, which could occur when wind is added to the system. This is especially true during light-load, high-wind conditions where transient stability is most challenged. When curtailed, wind can be a highly flexible and fast responding resource to respond to a loss-of-generation event. In addition, wind can also be used during over-frequency events (loss of the tie-line during export conditions) to rapidly curtail and provide fast frequency response.

References

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2. HydroQuebec: Technical Requirements for the Connection of Generating Stations to the Hydro-Québec Transmission System, January 2019 http://www.hydroquebec.com/transenergie/fr/commerce/pdf/2_Requirements_generating_stations_D-2018-145_2018-11-15.pdf
3. ERCOT NPRR863: Creation of ERCOT Contingency Reserve Service and Revisions to Responsive Reserve http://www.ercot.com/mktrules/issues/NPRR863#summary
4. NSP IRP Grid Services and Renewable Integration - Modeling Requirements (see Appendix)
5. Bloom, et al., *Eastern Renewable Generation Integration Study,* National Renewable Energy Laboratory, August 2016, *available at* https://www.nrel.gov/grid/ergis.html.
6. Ibanez, et al., *A Solar Reserve Methodology for Renewable Energy Integration Studies Based on Sub-Hourly Variability Analysis, National Renewable Energy Laboratory, November 2012, available at* *https://www.nrel.gov/docs/fy12osti/56169.pdf*.

Appendix

Slide excerpts for NSP IRP Grid Services and Renewable Integration - Modeling Requirements:

GRID SERVICES AND RENEWABLE INTEGRATION – MODELING REQUIREMENTS

	RESOLVE Modeling			PLEXOS Modeling		
Requirement Category	**Requirement in RESOLVE**	**Can be provided by**	**Renewables role**	**Requirement in PLEXOS**	**Can be provided by**	**Renewables role**
10-min non-spin reserve	Not modeled*			168 MW (Spinning reserve counts towards 10-min reserve)	Same as for Spinning. Only CTs, Recips and Hydro can count towards reserve if off-line. Other units must be on-line.	Can't be provided by renewables
30-min non-spin reserve	Not modeled*			75 MW	Same as for Spinning.	Can't be provided by renewables
Inertia	3266 MW.sec	All existing thermal; new gas plants; pumped hydro; batteries; CAES; large hydro + SC + Synchronized AC interties	Can't be provided by renewables	3266 MW.sec	All existing thermal; new gas plants; pumped hydro; batteries; CAES; large hydro + SC + Synchronized AC interties	Can't be provided by renewables
Wind Integration	2nd AC 345 kV tie or 0.67 MVAR of SC + 0.67 MW of 4-hour battery for each MW of wind capacity over 100 MW new build			2nd AC 345 kV tie or 0.67 MVAR of SC + 0.67 MW of 4-hour battery for each MW of wind capacity over 100 MW new build		

*Spinning reserve can be counted toward 10-min non-spin. Non-spinning reserves are not modeled in RESOLVE because existing diesel peakers can provide those.

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Viewing CHRIS MILLIGAN's s...

GRID SERVICES AND RENEWABLE INTEGRATION – MODELING REQUIREMENTS

	RESOLVE Modeling			PLEXOS Modeling		
Requirement Category	Requirement in RESOLVE	Can be provided by	Renewables role	Requirement in PLEXOS	Can be provided by	Renewables role
Regulation up	13.455 MW + 0.028 * installed capacity (MW) for wind and solar	Most existing thermal; new gas plants; pumped hydro; batteries; CAES; and Wreck Cove hydro	Can't be provided by renewables	15 MW	Most existing thermal; new gas plants; pumped hydro; batteries; CAES; and Wreck Cove hydro	Can't be provided by renewables
Regulation down	13.455 MW + 0.028 * installed capacity (MW) for wind and solar	All of the above + renewables	Up to 50% of renewables installed capacity	15 MW	All of the above	Can't be provided by renewables
Ramp Reserve	Incorporated into regulation constraint			0.028 * Hourly Wind Generation (MW) for wind	New Recips, Aero CTs, Batteries	Can't be provided by renewables
Spinning reserve	64 MW	All existing thermal; new gas plants; pumped hydro; batteries; CAES; Wreck Cove hydro; other hydro plants	Can't be provided by renewables	64 MW	All existing thermal; new gas plants; pumped hydro; batteries; CAES; Wreck Cove hydro; other hydro plants	Can't be provided by renewables

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July 17, 2020

Jennifer Ross
Manager Regulatory Strategy
Nova Scotia Power **via email**

Canadian Renewable Energy Association submission to Nova Scotia Power re: Integrated Resource Plan Modelling

Dear Ms. Ross,

The Canadian Renewable Energy Association is pleased to present this submission in response to the Nova Scotia Power Inc. (NSPI) 2020 Integrated Resource Plan (IRP). We appreciate the efforts that NSPI has taken to provide stakeholders an opportunity to comment on its 2020 IRP, including the detailed modeling presentation provided on July 9, 2020.

On July 1, 2020, the members of the Canadian Wind Energy Association and the Canadian Solar Industries Association, merged to become the Canadian Renewable Energy Association (CanREA), with a new mandate representing companies active in the wind energy, solar energy and energy storage industries in Canada.

Our technologies are uniquely positioned to deliver clean, low-cost, reliable, flexible and scalable solutions for Canada's energy needs and as such we are well positioned to put forward this submission to NSPI, responding to the 2020 IRP.

We are providing this input with a view to ensuring that the IRP analysis and results can be a strong foundation for future policy development or electricity sector infrastructure investment in Nova Scotia.

Wind represents an Attractive Resource for Nova Scotia

NSPI's 2020 IRP has consistently shown that wind represents the most attractive clean energy resource for Nova Scotia. Slide 20 in NSPI's July 9th presentation indicated that "Onshore wind energy selected in all scenarios as the most economic type of domestic renewable generation".[1] The July 9th presentation indicates that near term (by 2026) wind additions range from 51 to 148 MW and long term (2045) additions range from about 125 to 1,300 MW , recognizing that approximately 600 MW of wind generation capacity is currently available in Nova Scotia.[2]

NSPI has noted that there are challenges associated with integrating additional volumes of onshore wind in Nova Scotia. The PSC Renewable Integration study, which was conducted for NSPI's pre-IRP work, was performed in part to assess how much additional wind could be developed in Nova Scotia with and without additional investment to support its integration.[3] The PSC study objective was identified in its report as being:

> "To assess the integration of increased levels of renewable generation in Nova Scotia and to form recommendations for reinforcement and/or for further investigations required to enable this

[1] NSPI, 2020 IRP Modeling Results Workshop, July 9, 2020, (July 9th Presentation)
[2] July 9th Presentation, p. 14-15.
[3] *Nova Scotia Power Stability Study for Renewable Integration Report*, July 2019. (PSC Study)

integration. The Nova Scotia power system like any other power system is limited in its ability to accommodate an increasing number of power electronic interfaced generation"[4]

CanREA believes that in addition to the positive outlook for wind presented in the IRP modeling, wind energy can provide additional benefits to the grid that help address the subsequent concerns associated with integrating more wind, particularly as noted in the PSC work. It is likely that additional analysis would demonstrate that the need for more infrastructure investment to support wind integration is less a deterrent because the benefits provided by the procurement of the additional services would lessen the need for such infrastructure investments. As such, we are recommending that additional analysis be conducted to consider how these specific capabilities of wind energy, coupled with other technologies like storage, will in fact, enable more, cost effective wind energy to be integrated to the grid without significantly more infrastructure investment. Some of these additional benefits are outlined below.

Wind Integration in NSPI's IRP

At the July 9th, 2020 stakeholder session, NSPI reviewed some of the high-level modeling assumptions. One of these slides (presented below) reviewed the inertia constraint that was an element of the PSC work that was used to assess how much wind could be added to the Nova Scotia electricity system. The PSC study noted that "the main question that was answered by the simulations in this study was if the Nova Scotia system, upon disconnecting from the AC interconnection or losing one DC pole, will be able to survive the transients and remain stable."[5]

The PSC modeling indicates that the Nova Scotia electricity system requires a certain level of inertia to maintain system frequency and avoid under-frequency load shedding due to the loss of Nova Scotia's intertie when it is importing energy from New Brunswick. As indicated below, the 2,766 MW.sec estimated in the PSC Study was increased to 3,266 MW.sec to cover the contingency of the loss of a generating unit representing an estimated 500 MW.sec. CanREA notes that one stakeholder questioned the reasonableness of the resulting stringency of this 3,266 MW.sec intertia threshold. We do not address that issue here.

INERTIA CONSTRAINT

- The kinetic inertia constraint is modeled at 3266 MW.sec minimum online requirement
  - This is derived as allowing an approximate contingency of 500 MW.sec (~1 unit) above the level of 2766 MW.sec that was found to be required for stability in the 2019 PSC Study
- Unit provisions are shown in the table on the right for existing and new resource types available to the model

Source	Inertia Contribution (MW.sec)
Generators (01 - Lingan 1)	814
Generators (02 - Lingan 2)	814
Generators (03 - Lingan 3)	797
Generators (04 - Lingan 4)	797
Generators (05 - Point Aconi)	933
Generators (06 - Point Tupper)	777
Generators (07 - Trenton 5)	620
Generators (08 - Trenton 6)	771
Generators (11 - Tufts Cove 1)	403
Generators (12 - Tufts Cove 2)	412
Generators (13 - Tufts Cove 3)	768
Generators (14 - Tufts Cove 4)	245
Generators (15 - Tufts Cove 5)	245
Generators (16 - Tufts Cove 6)	245
Generators (270 - New_50MW Pump Strg)	100
Generators (320 - New_Tre 5 NGas)	620
Generators (321 - New_Tre 6 NGas)	771
Generators (322 - New_TUP NGas)	777
Generators (040 - New_RECIP - 9.3 MW)	45
Generators (050 - New_ CT 50 MW Aero)	250
Generators (052 - New_CC 145 MW)	750
Generators (054 - New_CC 253 MW)	1265
Generators (056 - New_CT 34 MW Aero)	170
Generators (058 - New_CT 33 MW Frame)	165
Generators (059 - New_CT 50 MW Frame)	250
Generators (CAES_Air Component)	100
Generators (H01 - Wreck Cove)	424
Generators (Sync Cond _1)	5 (per MVA of SC)
Lines (670-NB 2nd 345kV Intertie_Basic)	3266

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[4] PSC Study, p. 1
[5] PSC Study, p. 5

Recognizing the Contribution that Wind can Play in Reducing Inertia Requirements

In response to a question by Dan Roscoe regarding this slide and why it didn't reflect the fact that synthetic inertia can be provided by wind projects, Chris Milligan noted that the synthetic inertia that inverter based projects (i.e., wind generation) provide is effectively Fast Frequency Response (FFR) and is distinct from synchronous inertia.

CanREA notes that these issues are the subject of concurrent work that was initiated by the Offshore Energy Research Association (OERA) on behalf of the Nova Scotia Department of Energy and Mines. CanREA offered comments to the consultant that OERA engaged to perform this study (Power Advisory LLC) and as part of this effort reviewed work in other jurisdictions on the role that existing non-synchronous/inverter-based resources such as wind can play in providing frequency response services and by so doing reduce Nova Scotia's inertia constraint.

CanREA agrees that FFR and synchronous inertia are technically distinct services given that they respond in different timescales. However, as the Australian Energy Market Operator (AEMO) noted when developing an FFR specification for its market, "FFR can compensate for, and help to mitigate, the effects of reduced synchronous inertia on power system frequency control by providing a wider range of options for meeting the frequency operating standards (depending upon a co-optimised consideration of the availability and costs of both services)".[6] AEMO noted that "This suggests that enabling FFR services in the NEM [Australia's National Energy Market] may allow the frequency operating standards to be met with a lower level of synchronous inertia." CanREA notes that the same is true for Nova Scotia. The provision of FFR by inverter-based generating resources and energy storage can play a significant role in helping to meet Nova Scotia's system reliability needs in the context of diminishing synchronous inertia.

In a recent report from the US National Renewable Energy Laboratory (NREL)[7] on maintaining system reliability in a low synchronous-generation power grid, Denholme et al. note that while a higher penetration of inverter-based generating resources and energy storage reduces available inertia, an increased proportion of these resources also reduce the need for inertia, noting that the rapid response of inverter-based resources can in effect supersede traditional frequency-responsive reserves. The authors note the well-established use of extracted wind kinetic energy from the rotating mass of the blades, shaft, and generator to rapidly inject real power into the grid (as has been utilized in the Hydro Quebec transmission system since 2009), along with the proven ability of inverter-based variable generation to provide FFR much faster than conventional generators.

CanREA members understand that one issue being evaluated in this IRP process is whether such obligations (e.g., the provision of FFR and Primary Frequency Response) should be placed on new and existing non-synchronous/inverter-based resources in Nova Scotia. Based on experience elsewhere and input from various CanREA members (e.g., wind turbine manufacturers who were able to advise on the costs of such requirements), we understand that such obligations are likely to be placed on these resources, including wind.

ERCOT has required wind generators to have frequency-responsive capability beginning since 2012[8], and in 2018, the Federal Energy Regulatory Commission (FERC) required new utility-scale wind and solar PV plants to have frequency-responsive capabilities[9]. The net result of such an obligation could

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[6] Australian Energy Market Operator, *Fast Frequency Response Specification*, 2017, p. 1.
[7] Denholm, Paul, Trieu Mai, Rick Wallace Kenyon, Ben Kroposki, and Mark O'Malley. 2020. Inertia and the Power Grid: A Guide Without the Spin. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6120-73856. https://www.nrel.gov/docs/fy20osti/73856.pdf.
[8] NERC Essential Reliability Services Task Force Report (2015)
[9] FERC (2018). Order No. 842: Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response, Issued February 15, 2018. https://cdn.misoenergy.org/2018-02-15%20162%20FERC%20%C2%B6%2061,128%20Docket%20No.%20RM16-6-000133298.pdf.

be reduced requirements for synchronous generating units during specific operating conditions, with an increased ability to integrate additional wind generation, with corresponding reductions in costs to customers. In fact, this is likely to be a primary objective of placing such an obligation on these resources – the added benefit of enhanced decarbonization should also be noted.

As the slide from the July 9th Presentation shown below indicates, NSPI estimates that under current conditions approximately 100 MW of additional wind can be reliably integrated without major infrastructure investment (i.e., Reliability Tie or Batteries and Synchronous Condenser). However, with the implementation of an obligation on new and existing wind projects to provide FFR, it may be economic and feasible to add additional wind generation well beyond 100 MW without major infrastructure investment.

Therefore, CanREA believes that it is critical to consider these changes in this IRP. Specifically, the potential implications of such obligations of wind resources and the consequent impact on Nova Scotia's ability to accommodate additional volumes of wind without major system investments (e.g., a Reliability Tie such as identified in the slide shared below).

The importance of considering the impact of this obligation on Nova Scotia's inertial constraint is reinforced by the fact IRPs are conducted in Nova Scotia on a somewhat sporadic basis. Furthermore, one potential purpose of the IRP could be to inform policymakers regarding appropriate targets for near-term renewable resource procurements.

RENEWABLE GENERATION

- Onshore wind energy selected in all scenarios as the most economic type of domestic renewable generation
- Construction of a Reliability Tie (new 345kV line from Onslow, NS to Salisbury, NB) is preferentially selected as a method of wind integration
  - This option was offered to the model in all scenarios, including "A" (Current Landscape)
- Domestic integration (batteries + synchronous condensers) was selected when the limits of what could be integrated using the Reliability Tie were reached
- The combination of Reliability Tie integration and domestic integration was not examined in the PSC reliability study as part of the Pre-IRP work but was selected in several scenarios after 2030; this will need to be studied further

Available Wind (Nameplate MW)	No Integration Requirements*	Reliability Tie*	Domestic Integration* (Batteries + Sync. Condenser)	Total Available
Low Electrification	100	400	400	900
Mid Electrification	100	500	500	1,100
High Electrification	100	600	600	1,300

Next Steps: Consider New Obligations to Provide FFR on Wind Integration

Chris Milligan indicated that one of the next steps in the IRP process was to assess the operability of different portfolios. We understand that this operability analysis is likely to be test scenarios that were evaluated in PLEXOS to ensure that they do not adversely affect reliability.

CanREA encourages NSPI to ensure that these analyses consider at minimum the impact of new frequency response provision requirements for non-synchronous/inverter-based resources in terms of enabling additional wind generation in Nova Scotia in the near term without major infrastructure investments.

Forecasted near-term reductions in both the levelized cost of wind generation[10], and competitive system costs of inverter-based generating resources and energy storage as compared to a synchronous generation-based system[11], suggest that increased volumes of these resources could reduce costs for Nova Scotia consumers while advancing the Province's environmental goals.

Additional Considerations: Importance of Increased Transparency with respect to Analysis

NSPI has shared summary information regarding the results on the underlying model runs. This includes the capacity mix of the various resource portfolios, partial revenue requirements and case summaries. The limited details make it difficult for stakeholders to discern key drivers of modeling results. This undercuts the transparency of the analysis and undermines confidence in the results. Key unexplained results that are surprising and appear counter-intuitive are the high levels of gas turbine build and relatively low levels of battery build.

This raises a number of questions:

- How were ancillary service provision by various resources modeled?
    - Does this modeling reflect the underlying higher performance of ancillary service provision that batteries and other non-synchronous/inverter-based resources can achieve relative to conventional resources including thermal generation? Experience in other electricity markets (e.g., PJM etc.) indicates that the quality of AGC service provided by batteries is such that it can reduce the underlying requirements for these resources to provide this service, reducing costs to customers.
- Does the end effects analysis adequately consider additional costs of fossil-based resources relative to renewable resources recognizing that carbon constraints and costs associated with exceeding these are likely to become increasingly significant?
    - Does the end effects analysis adequately reflect future operating constraints on fossil-based resources?
    - How were the prospects of increasingly stringent carbon constraints imposed after fossil investments are made considered in the analysis?
    - How was the loss of flexibility or these cost penalties considered?
- Where the potential benefits of hybrid projects (wind/energy storage or solar/energy storage with storage embedded behind the meter) adequately considered? Experience in other markets shows that hybrid projects can provide required ancillary services (e.g., frequency response services) at lower cost by avoiding opportunity costs associated with the provision of some frequency response services as well as provide a desired capacity resource at a relatively low effective cost.

The Canadian Renewable Energy Association appreciates the opportunity to provide feedback to the NSPI 2020 IRP modeling presentation. Please do not hesitate to contact the undersigned for additional clarity or required follow-up. We remain available as an engaged stakeholder and look forward to the next steps on this file.

Sincerely,

Brandy Giannetta
Senior Director, Ontario and Atlantic Canada
Canadian Renewable Energy Association

[10] Lazard's Levelized Cost of Energy Analysis – Version 13.0
[11] Denholm *et al*.

Memorandum

To: IRP Development Team, Nova Scotia Power

From: EfficiencyOne

Date: July 17, 2020

Re: 2020 IRP – June 26 Modelling Results Comments

On June 26th, 2020, NS Power released its IRP Modelling Results. This followed the release of interim modelling results on April 27th, 2020, on which EfficiencyOne (E1) provided comments in a previous memorandum.

On July 9th, 2020, a technical session was hosted related to release of 2020 IRP modelling results. E1 appreciates the opportunity for the discussion and clarity provided during this session, as well as the effort NS Power has put forth in demonstrating a concern for issues as they arise in responding to E1 feedback over the course of the IRP process to-date. The efforts made to accommodate requests for meetings as well as information sharing in separate technical meetings has been very helpful for enhancing the ongoing understanding of approaches and providing clarity throughout the IRP process.

As a summary, E1 has the following recommendations and requests:

The need for additional sensitivities with respect to DSM

1. Model additional sensitivities with respect to differing DSM cases. Modelling additional sensitivities is required to adequately test DSM's impact in the context of the various 2020 IRP scenarios. The requested sensitivities in each scenario are detailed on pages 3-4 of this memo.
2. Confirmation that full resource re-optimization is occurring for all sensitivity runs, including re-optimization of the planning reserve margin.

Limited Value of Distributed Generation Cases

3. Continue to refine the cost estimates for Distributed Resources, as they currently span a wide uncertainty range. Existing and planned data, including

costs, from Smart Grid Atlantic and NS Power's Smart Grid project may be useful in doing so.

4. With respect to Distributed Resources cases, define the portion of the NPV revenue requirement that will be ratepayer-funded, and include it within NPV revenue requirements.

Levelization of DSM Costs

5. Re-run DSM scenarios with an amortized capital cost stream, similar to the treatment for supply-side resources. The rationale for this is described further in this memo.

Demand Response

6. Allow the introduction of Demand Response (DR) in 2021, 2025, 2030, and 2035. This would provide a better balance and consistency in model runs, and more accurately estimate the value of DR in Nova Scotia.
7. Re-run all scenarios allowing DR to economically compete against new and existing natural gas peaking infrastructure.

The Availability of Detailed Information

8. Provide quantitative inputs and outputs from Plexos in tabular format, as initially requested on May 12, 2020 with a priority for the Comparator cases 1.0A and 1.0C. To note, requests for release of data have been addressed by NS Power through an alternative arrangement for a technical session with E1 and its consultant, where PLEXOS model parameters and data can be examined.

Critical Importance of Transparent Evaluation Process

9. With respect to the remaining evaluation of Candidate Resource Plans:
    a. Provide findings for each evaluation category for each candidate resource plan considered.
    b. When selection decisions are being made regarding specific candidate resource plans, or groups of similar plans, justification should be provided on the basis of evaluation criteria, and the relative importance of each criterion in making such a determination.

Capacity Value of Non-Firm Imports

10. Clarify any ongoing modelling impacts associated with the use of non-firm imports in RESOLVE. Confirm that the PLEXOS LT runs do not count any non-firm imports as capacity.
11. Provide additional information and support regarding firm import assumptions to allow stakeholders to assess the reasonableness of these assumptions.
12. Clarify which candidate resource plans depend on the addition of 450 MW of firm imports from Quebec, or portions of this capacity if Plexos did not take the entire volume in any given scenario.
13. Include a sensitivity analysis run that limits market imports (both firm and non-firm) to 110% of recent historical averages, excluding the Maritime Link NS block. This inclusion would provide the benefit of a view with limited expansion of market opportunities, which E1 believes warrants consideration.

New Natural Gas Capacity and Pricing

14. A proxy for new gas supply should also include a sensitivity relating to the Algonquin City Gates Hub (AGT) as the commodity price for new winter (and summer) natural gas capacity, with the inclusion of energy cost and tolls reflecting transport from AGT to Tufts Cove, as it would address some of the uncertainties associated with the current approach of acquiring gas and transportation from Alberta (AECO), Dawn or LNG via Amsterdam (TTF).
15. Sensitivity analyses that explores the constrained availability of natural gas for the NS electricity system should be included, at least in terms of incremental capacity additions beyond 20,000 MMBtu per day. Put another way, constrain the model to only allow for consumption of 20,000MMBtu per day, thus allowing the model to economically select other resources other than natural gas beyond the currently contracted firm supply.

The above requests and recommendations are described in more detail below.

The need for additional sensitivities with respect to DSM

Two key sensitivities with respect to DSM levels have been modelled to date. These two sensitivities represent:

- A variation of energy efficiency levels from the Base DSM trajectory to the Mid DSM trajectory, within case 2.1C. This case represents a net-zero emissions trajectory (non-accelerated), with mid-level electrification and a regional integration resource strategy.

- A variation of energy efficiency levels from the Base DSM trajectory to the Mid DSM trajectory, within case 2.0A. This case represents a net-zero emissions trajectory (non-accelerated), with reference-level electrification and a "current landscape" resource strategy.

While these results do provide insight on mid-DSM levels in these two specific cases, these runs do not provide a full set of expected sensitivities as presented in slide nine of the materials released on June 26, 2020.[1] Additional sensitivities will provide further and necessary insight on the appropriate DSM trajectory for Nova Scotia. At minimum, results should be provided from:

- Completion of a DSM sensitivity examining Mid-DSM levels within case 2.0C (Net-Zero, Reference Electrification, Regional Integration). This plan is currently outperforming 2.0A in terms of both Planning Period, and Planning Period with End-Effects, NPV revenue requirement, and exploration of Mid-DSM in this case may be valuable, as it is a seemingly high-value candidate resource plan.
- A DSM sensitivity examining Mid-DSM levels within case 3.1C (Accelerated Net-Zero, Mid-Electrification, Regional Integration) would be useful to test Mid-DSM levels in an accelerated net-zero context under intermediate increased loading from electrification.
- A DSM sensitivity examining Mid-DSM levels within case 3.2C (Accelerated Net-Zero, High-Electrification, Regional Integration) would be useful to test Mid-DSM levels in an accelerated net-zero context under the most aggressive increased load from electrification.
- A DSM sensitivity examining Mid-DSM levels within case 2.2C (Net-Zero, High-Electrification, Regional Integration) would be useful. With a less restrictive GHG profile as compared to other high-electrification cases, this candidate resource plan may well form the most competitive view of a high-electrification world. Testing Mid-DSM in this case may further improve the competitiveness of this plan, due to the high incentives required by the Max-DSM case.

In addition, should the distributed energy versions (X.XB) of the above remain in consideration following further analysis, they should also receive similar sensitivity treatment as outlined in the bulleted list above.

Also, please confirm that full resource re-optimization is occurring within the context of sensitivity runs, including re-optimization of the planning reserve margin to levels that satisfy, but do not greatly exceed NERC requirements.

Limited Value of Distributed Generation Cases

[1] NS Power 2020 IRP Modeling Results Release, June 26, 2020, at slide 9.

Numerous cases in the IRP depend on a large growth in renewable distributed energy resources. It is understood that there are two scenarios being examined for distributed energy resources:

- Cases with the notation X.XA and X.XC have levels of distributed energy resources consistent with the 2019 NS Power load forecast.
- Cases with the notation X.XB employ a Distributed Resource resource strategy. This is understood to represent additional solar PV integration beyond the levels envisioned in the 2019 Load Forecast.

Basic information has been provided relating to the envisioned costs for these additional resources – described as "$1.6-2.5B" on an NPV basis.[2] These costs have not been directly included in the NPV revenue requirement of any modelling scenario.

These cost estimates should continue to be refined, and existing and planned data from Smart Grid Atlantic and NS Power's Smart Grid project may be useful in doing so.

The difficulty in estimating which portion of the NPV costs will be attributable to ratepayers is understandable – current solar PV offerings in Nova Scotia do not leverage ratepayer investment, and no such programs have been planned to date.

Given that there already exist three differing and incomparable sets of revenue requirements within the IRP (reference, mid and high levels of electrification), having three incomparable cases through DER levels is cumbersome, and will likely stifle clear determinations about effective resource strategies.

Some portion of the NPV revenue requirement should be defined as ratepayer related and included within NPV revenue requirements. The current SolarHomes rebate limit of 25% of installed costs could provide a reasonable proxy for the portion of investment sourced from ratepayers. The limitation in this method is that current rebate levels may produce a trajectory more consistent with reference levels of DER, which already include considerable growth in PV to 2030, as opposed to the higher levels envisioned by the High DER case.

Levelization of DSM Costs

At the July 9, 2020 technical session, it was confirmed that supply-side resources are being amortized as part of the methodology associated with modelling within the IRP. The amortization of supply-side assets may not be especially impactful, since WACC is being used for both the amortization of assets, as well as the calculation of NPV revenue requirements.

Where amortization does have material effect on the NPV revenue requirement is in the domain of the end of planning period, as well as the end-effects calculations

[2] *Ibid.*, at slide 62.

performed as part of the broader study period (25-year Planning period + 20 year End Effects period).

In an illustrative example, a $100M investment in a combined-cycle (CC) Natural Gas generator is introduced in year 2040 of the IRP. Table 1 below shows the financial treatment of that generator under an amortization model and one without amortization, with a 50-year life estimated for the generator and WACC as the discount rate:

Table 1 - Amortization Effects in IRP

Year	Cost with Amortization ($M)	Cost without Amortization ($M)
2040	$3.89	$100
2041	$3.89	$0
2042	$3.89	$0
2043	$3.89	$0
2044	$3.89	$0
2045	$3.89	$0
Planning Period Costs	$23.32	$100
NPV Planning Period Costs (2021)	$5.66	$28.27

Very large financial differences exist as a result of the interaction of the planning period's finite duration and the existence of resource additions later in the planning period. For longer-lived supply-side measures, any resource addition will not have its full costs included due to the duration of the study period.

To reinforce the point, these differences are not a result of the amortization itself, rather the interaction of amortization and the planning period of the IRP.

Presently, DSM is being modelled within the IRP on an expensed basis, as opposed to an amortized basis. Based on the treatment of supply-side resources on an amortized basis, the DSM scenarios should be re-run with this similar treatment. E1 can assist in this by providing an amortized cost stream which reflects the amortization across the average measure life of each year's potential DSM activities (this cost stream would extend into the end effects period).

Through this revision, stakeholders can be provided with more accurate information regarding the true competitiveness of DSM, as opposed to a result which may include artifacts from the differing financial treatment of DSM.

The amortization of DSM in the context of the IRP does not need to speak to appropriateness of amortizing DSM in reality, since amortization itself does not affect

NPV revenue requirements (rather the interaction of amortization and the conclusion of the planning period does).

This change could be rapidly implemented without extensive effort, since DSM costs are included in the analysis through an extrinsic set of values.

Demand Response

Two aspects of the Demand Response (DR) modelling require further analysis:

1) DR was only allowed to compete at two discrete points in time (2021 and 2030).
2) DR was not permitted to retire or replace natural gas peaking resources in the analysis.

Both of the above issues constrain the competitiveness of DR and create a bias favouring supply-side peaking capacity. These treatments were justified to stakeholders on the basis that they reduced complexity in the model.

With respect to DR being constrained to two time periods, E1 appreciates the complexity that offering DR to the model in each year would produce. However, a more appropriate balance would be to allow its introduction in 2021, 2025, 2030, and 2035. This would provide a better balance in model complexity and a more consistent application of DR while more accurately reflecting the value of DR in Nova Scotia.

It is understood that the continued operation of peaking capacity against DR and other approaches was tested in the Resolve modelling before hard-coding the continued operation of the combustion turbine fleet in NS.

This method:

1) Prevents inspection of the detailed RESOLVE analysis by Stakeholders, as no modelling information has been made available.
2) Prevents the investigation of combustion turbine retirements in the Plexos LT environment.

The scenarios should be re-run without a fixed trajectory for combustion CTs, and allow DR to compete against those assets.

Additionally, please clarify on the following points relating to how DR was modelled:

1) In scenarios where DR is selected, it appears that 82MW of capacity is in place in year 1 (2030).
    a) Does the model assume that level of DR remains in place until 2045 with no changes in capacity?
    b) What is the DR profile for the remaining years?

c) Is there a ramp-up built into the DR assumptions as is the case with the 2019 DSM Potential Study?

2) Was DR available to the model in place of selecting the build-out of ~37MW capacity of new gas combustion turbines and reciprocating units in 2021?

The Availability of Detailed Information

In its May 12th Letter of Comment, E1 requested detailed inputs and outputs relating to a sample candidate resource plan, or at minimum those inputs and outputs related to DSM.[3]

Quantitative data regarding candidate resource plans' energy balances and new capacity additions was released on June 26, alongside the modelling results presentation – E1 appreciates this additional data.

E1 also appreciates that NS Power has made arrangements for a technical session with E1, where PLEXOS model parameters and data can be examined. This session may reduce or eliminate concerns that E1 and its consultant have regarding the release of data.

The availability of detailed quantitative information associated with IRP modelling results continues to be concerning. The graphical presentation of IRP modelling results is useful in a presentation context, but insufficient for the review of key findings by stakeholders and technical consultants. The Regulatory Assistance Project states:

> A proper IRP will include discussion of the inputs and results, and appendices with full technical details. Only items that are truly sensitive business information should be treated as confidential, because such treatment can hinder important stakeholder input processes.[4]

A full set of inputs and outputs associated with the 2019 DSM Potential Study, in the context of the work product being a single input to the broader IRP process. This level of transparency is needed for effective stakeholder input on the broader effort represented by the 2020 IRP itself.

Inputs and outputs from Plexos in tabular format for at least the Comparator cases (1.0A and 1.0C) are being requested. These data would allow for the quantitative review of items such as planning reserve margin (no results have been presented), the modelled costs of resources, model settings and other important factors.

Critical Importance of Transparent Evaluation Process

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[3] EfficiencyOne memorandum to NS Power – Interim Modelling Results, May 12, 2020.
[4] Wilson, R et al, Best Practices in Electric Utility Integrated Resource Planning, Prepared by Synapse Energy Economics for the Regulatory Assistance Project, June 2013, at Page 32.

The Analysis Plan[5] evaluation metrics included:

1. Minimization of the cumulative present value of the annual revenue requirements over the planning horizon (adjusted for end-effects);
2. Magnitude and timing of electricity rate effects;
3. Reliability requirements for supply adequacy;
4. Provision of essential grid services for system stability and reliability;
5. Plan robustness (the ability of a plan to withstand plausible potential changes to key assumptions);
6. Reduction of greenhouse gas and/or other emissions; and,
7. Flexibility (limitation of constraints on future decisions arising from the selection of a particular path).

With the latest information release, stakeholders now possess information relating to items one, four and seven. The remaining items appear to be part of the next phase of analysis planned, the reliability screening phase.

A large amount of analysis is yet to be undertaken on the candidate resource plans presented in this current release of information, and that analysis may be quite time-consuming and subjective.

To avoid a challenging, qualitative evaluation process that stakeholders may not be able to fully recreate, it is recommended that:

1. Within the written deliverables (Draft Findings, Roadmap & Action Plan) to be released (per the Terms of Reference), provide findings for each evaluation category for each candidate resource plan considered. This will allow stakeholders to better follow the more qualitative aspects of the evaluation process
2. When selection decisions are being made regarding specific candidate resource plans, or groups of similar plans, justification should be provided on the basis of evaluation criteria, and the relative importance of each criteria in making such a determination.

Additionally, stakeholders should be notified of the remaining planned dates for stakeholder consultation up to the end of September, and if any further overall extension to the process is being considered. The IRP process is behind schedule based on the Terms of Reference (due to beneficial additional length of comment periods) and several sensitivities are yet to be tested and released for stakeholder consideration. Please confirm whether the current IRP schedule is to be revised.

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[5] 2020 IRP Analysis Plan – Draft, Provided January 20th, 2020 at Slide 4. *Note: No final version of this document exists, per EfficiencyOne's understanding.*

Capacity Value of Non-Firm Imports

The modelling results appear to indicate that non-firm resources are being modelled as a source of capacity. Slide 30 of the Modelling Results information package (2045 Installed Capacity Across Current Landscape and Regional Integration Cases) shows material additions in system capacity associated with non-firm imports.

Since the Resolve models as presented on slide 30 are intended to represent those fed to Plexos LT to be further refined, this foundational work is seemingly important to overall flow of information within the IRP.

Given that it was clarified at the Technical Session that no particular source or market was being targeted for imports, it is difficult to make any assessment regarding the availability of capacity and energy from non-firm imports.

With this in mind, E1 requests:

1. Clarify any ongoing modelling impacts associated with the use of non-firm imports in RESOLVE.
2. Confirmation that the PLEXOS LT runs do not count any non-firm imports as capacity.
3. Clarify which candidate resource plans depend on the addition of 450 MW of firm imports from Quebec, or portions of this capacity if Plexos did not take the entire volume in any given scenario.
4. A sensitivity analysis run that limits market imports (both firm and non-firm) to 110% of recent historical averages, excluding firm commitments from Muskrat Falls. This inclusion would provide the benefit of a view with limited expansion of market opportunities, which E1 believes warrants consideration.

Given the significant volumes that firm and non-firm imports have within this IRP, the additional sensitivity will provide further information to all stakeholders to allow them to determine whether reasonable assumptions are in place for this aspect of the analysis.

New Natural Gas Capacity and Pricing

All candidate resource plans contain large amounts of new natural gas capacity, and associated energy production from these facilities. The minimum energy production in the year 2045 from incremental new natural gas facilities (not existing today) is 388 GWh, but many scenarios (70%) have in excess of 1000 GWh of energy production in 2045 from natural gas, with the average across candidate resource plans being 1679 GWh.

Given that the use of new natural gas generators is featured so prominently in the 2020 IRP, additional information and analysis is warranted on future natural gas pricing assumptions.

On the general topic of natural gas pricing in the 2020 IRP:

> With the shutdown in production from domestic sources (Sable Island and Deep Panuke), Nova Scotia will be reliant on natural gas imported via U.S. pipelines, LNG tankers, or an all-Canadian Path, via Western Canada.[6]

Additionally, it is stated that additional Baseload Gas pricing from would be based on "up to an additional 100,000 MMBtu/day firm contract"[7] from AECO.

The above reflects continued uncertainty regarding the future availability and pricing of natural gas in general, and especially in the case of incremental gas supply that is currently not contracted. This risk and uncertainty are not currently reflected in natural gas fuel price projections.

In the final assumptions set state that Peaking Winter Gas Pricing would be based on the following:[8]

1. TTF Spot Commodity Pricing (4Q2019).
2. Fuel & Tolls for delivery from Baileyville to Tufts Cove.
3. A market premium of $2.50/MMBtu for regasification.

No cost estimate has been made associated with the transportation of LNG from its point of title transfer to the Canaport facility in Saint John, NB.

In addition, the use of TTF Spot commodity pricing and future pricing is difficult to contextualize, given the likely requirement of a long-term supply agreement for the incremental new gas generation in each IRP scenario, even for use as Winter Peaking Gas.

For Baseload Gas, the following supply pricing structures are assumed:[9]

1. Henry Hub Commodity Pricing
2. AECO Basis
3. Tolls from Nova to Tufts Cove

Given that no contracts have been established, aside from precedent agreements associated with an initial 20,000 MMBtu/day of gas from Alberta for existing facilities, it is unclear as to the availability of pipeline capacity and commodity pricing certainty for such an analysis to be made.

The 2020-2022 Fuel Stability Plan submission indicates:

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[6] 2020 IRP Final Assumptions Set, March 11, 2020, at Slide 8.
[7] *Ibid,* at slide 88.
[8] *Ibid.,* at slide 90.
[9] *Ibid,* at slide 91.

> The primary driver for the [Natural Gas] requirements is supply availability at prices competitive with solid fuel, the availability of imports via the Maritime Link and gas being a lower emitting fuel than solid fuel. Gas Swap contracts are financial instruments used to lower volatility in pricing terms for a supply contract. Forward price curves refer to a graph of future prices decided upon by both buyer and seller for any given commodity.
>
> Gas supply either has to be sourced from the TransCanada Pipeline Ltd. (TCPL) system and shipped across multiple pipelines or sourced from the Algonquin system once the Atlantic Bridge expansion is fully placed in service, which is forecast to occur in 2021 and provides a limited amount of additional capacity into the Maritimes & Northeast Pipeline.[10]

As an illustration of the complexity and risk associated with sourcing gas from the TCPL system, as of August 2019, supply contracts for gas assuming to be flowing in 2021 had not been secured, nor included the costs of transportation in modelling associated with the 2020-2022 Fuel Stability Plan.[11]

The assumption that new gas plant infrastructure will be constructed with a combination of TTF sourced LNG and uncommitted AECO gas introduces a large degree of risk, both in terms of using spot-sourced LNG (an IRP and operational risk) and uncommitted AECO gas (an IRP risk). Assumption sets which possess less risk should be examined, as suggested below:

1. An appropriate additional proxy for new gas supply, due to its physical location and connection to the Maritimes and Northeast natural gas pipeline system, and its presence in the 2020-2022 Fuel Stability Plan, would be to use the Algonquin Gates (AGT) as the commodity price for new natural gas capacity (both peaking and baseload), with the inclusion of energy and tolls reflecting transport from AGT to Tufts cove.

   Figure 1 below provides a comparison of AGT and AECO historical spot prices:[12]

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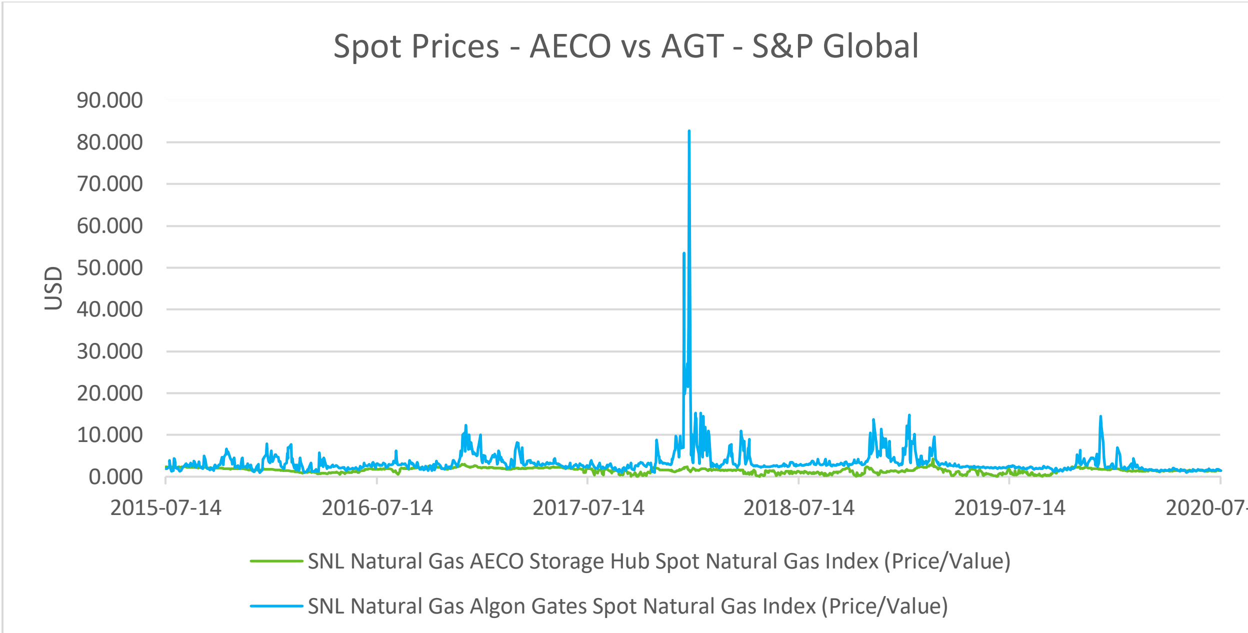
[10] 2020-2022 Fuel Stability Plan at Pages 52-53.
[11] M09288, N-3, NSPI to Bates White RIRs, Filed August 8, 2019, at RIR-08 a).
[12] S&P Market Intelligence – Spot Nat Gas Index



The historical AGT prices are generally higher than AECO spot prices, especially so during periods of higher winter pipeline demand in the US Northeast. The use of future pricing from AGT may provide higher overall gas prices than the Canaport LNG/AECO combination, but this source of supply should be considered. The pipeline demand and availability for 100,000 MMBtu of AECO gas will also likely be an issue, but these challenges are not precisely understood by stakeholders. The use of AGT pricing would provide greater transparency to a source of supply that is already being assessed based on the Rate Stability Plan, with less dependence on forward-looking complexity of obtaining gas supply from AECO and TTF.

2. In addition, sensitivity analyses that explores the constrained availability of natural gas for the NS electricity system should be included, at least in terms of incremental capacity additions beyond 20,000 MMBtu per day. Put another way, constrain the model to only allow for consumption of 20,000MMBtu per day, thus allowing the model to economically select other resources other than natural gas beyond the currently contracted firm supply.
3. Gas price sensitivities can then appropriately explore higher or lower pricing scenarios that impact future capacity additions to the system, and differing limits on the availability of gas.

   The Final Assumptions set indicate that:

   If the IRP Action Plan indicates new investment in natural gas resources, [Dual Fuel Capability, Natural Gas Storage, and LNG Alternatives] would be considered in a more detailed analysis.[13]

[13] *Ibid.,* at slide 92.

These fundamental questions regarding natural gas pricing and availability must be answered in the context of the IRP prior to it being finalized, if the IRP results are to show the degree of sensitivity to commodity costs. They will fundamentally affect pricing and the selection of resources, which will not be reflected in an after-the-fact analysis.

E1 appreciates the opportunity to provide ongoing comments in relation to the 2020 IRP, and is available for discussion on any of the comments made.

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Submitted Comments Regarding 2020 IRP Modelling Results

July 17, 2020

The Ecology Action Centre (EAC) welcomes the opportunity to participate as a stakeholder in the 2020 Integrated Resource Plan process. We submit the below comments and questions in response to the Modelling Results released for stakeholder comment, and discussed at the IRP stakeholder session on July 9, 2020. Specifically, this submission is in response to the below documents:

i) *NS Power 2020 IRP Modeling Results Release*
ii) *2020 IRP Final Assumption Set*

It is also important to note in this submission that the capacity of EAC to engage in this process is greatly reduced due to the design and process of the 2020 IRP, and the lack of availability for stakeholder funding and support through the NSUARB, through the NSPI-led process, or through the Nova Scotia Department of Energy and Mines.

The EAC feels very strongly that this process should not be considered just another Integrated Resource Plan. Nova Scotia Power Incorporated (NSPI) is the third most polluting energy utility in Canada. We have the opportunity to make NSPI one of the least polluting energy utilities in Canada and limited time to make these decisions with significant long term consequences for emissions and especially for utility ratepayers.

.
Two significant gaps remain in the scenarios undergoing analysis.

Firstly, the study is inconsistent with GHG trajectories needed to align with international, federal, provincial, and local emissions reductions plans. No zero emission scenarios are studied, although the study mentions that mid- and high-electrification scenarios follow SDGA 2050 end points, and there are delayed zero emission targets; perhaps never achieving zero emissions will limit the opportunities for other sectors to rapidly decarbonize.

Secondly, the study restricts the model's ability to add firm imports and as such biases the result towards gas turbine construction, continued natural gas purchases and GHG emissions from both direct combustion and upstream fugitive methane emissions (which are not currently accounted for under this process). Long decarbonization trajectories endorse the replacement of coal generation with natural gas resources and it is not clear if these generators will be cost effective when utility emissions are regulated to zero. Faster trajectories to zero electric utility emissions may be more cost effective over the study period and the related end-effects time frame.

The EAC welcomes the opportunity to submit written comments to this process, and acknowledges the time and effort of Nova Scotia Power staff in answering our questions in the pre-IRP and IRP periods.

Thank you,

Ben Grieder

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The Roadmap for our Future

We are not continuing the long-term planning process from 2007 and 2017. There are many external influences that are occurring right now in Nova Scotia that we have never encountered before. There are federal and provincial greenhouse gas emission targets that must be considered in this integrated resource plan and adhered to in order for our province to thrive. In the last five months, we have encountered increased instability in energy consumption and production, and a global pandemic that will shape the future of energy production in our province. We have restricted this consultation process to a timeline that requires a submission to the Utility and Review Board by September 30, 2020. Considering the exceptional circumstances that the world is in right now, we urge all stakeholders involved in this process to consider an extended timeline that would allow more stakeholder consultation and a final submission deadline to the UARB of **November 30, 2020.**

To address gaps in GHG trajectory analysis and modelling bias, the EAC recommends the following actions to close these gaps and yield an IRP that can provide input to GHG planning activities beyond the electrical utility landscape rather than react as GHG requirements become increasingly strict. Proactive planning will, in the long run, minimize costs to ratepayers.

Action 1) Model scenarios that achieve zero GHG emissions.

Consider examining cases for 2050, 2045 and 2035. Zero emission cases will provide an assessment of the costs required to operate from imports, sequestered carbon emissions and renewable energy. Increased costs to the utility add value to efforts across the regional GHG reductions landscape by maximizing the impact of electrification. The modeled scenarios, at present, all incorporate a replacement fleet of combined cycle natural gas infrastructure. A zero emissions study enables the model to compare the costs of adding carbon sequestration to these generators against the costs of increased clean imports. It is not clear from the scenarios studied that replacement of coal thermal plants with natural gas infrastructure is the lowest long-term pathway to a zero emission state. Modelling accelerated zero emission timelines may well reveal lower long-term cost solutions. Accelerated net zero timelines can and should analyze multiple energy mixes.

Description (New Transmission)	Total Capital Cost ($2021) [1]	NB-NS Tieline Gross Capacity (MW)
345kV Onslow-Salisbury-Coleson Cove	$600M	700
345kV Onslow-Salisbury ; HVDC to QC [2]	$1.7B	1000

- Assumptions presented here would be subject to additional feasibility study if selected during the IRP modeling.
- The transmission costs above are the assumed total capital cost of the builds and do not reflect potential cost sharing. Opportunities for cost sharing may depend on forecast utilization and will be examined during the resource screening phase.

1) Earliest in-service date is 2026
2) Costing to Quebec Border.

Nova Scotia POWER An Emera Company

2020 IRP FINAL ASSUMPTIONS SET 74

Source: Page 74- https://irp.nspower.ca/files/key-documents/assumptions-and-analysis-plan/20200311-IRP-Assumptions-Final.pdf

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Action 2) Report the detailed operational profiles of natural gas and diesel generation assets (number of operations per year, their durations and power and energy associated with each unit).

This data will be useful in using these model choices as proxies for identifying cost effective alternate generation or storage solutions in the future. These may include long duration battery storage or tidal power, among others, as technologies mature. One specific example would be the recent announcement of a 150 hour duration battery demonstration by Form Energy and Great River Energy in Minnesota (https://www.electric.coop/great-river-energy-co-op-test-groundbreaking-battery-energy-storage-system/). Industry is working across a broad technological landscape and the utility, regulator and stakeholders must be in a position to evaluate emerging solutions.

Action 3) Ensure that the model's portfolio of assets always includes the ability to add an additional transmission line through New Brunswick to Quebec as identified in the IRP assumptions set (IRP Update Appendix C Page 75 of 136).

Action 4) Call upon the Board and the Provincial Government to fund a Sustainability Advocate to participate in future hearings with resources similar to those available to the Consumer Advocate and Small Business Advocate.
There is no dispute that controlling costs for consumers and small business is important but without well resourced review from a regional sustainability perspective, net costs to consumers and small businesses may not be fully understood.

These actions will ensure that this 2020 IRP positions the utility, the regulator and citizens of Nova Scotia to make informed and timely choices in the immediate future.

Gaps and Opportunities in IRP 2020.

Zero Emission Planning and Planning Alignment
While the models address several so-called net zero scenarios, the term is simply aspirational. No carbon credit purchase costs are included to bring these cases to net zero. As such, these cases should be labeled Near-Zero rather than Net-Zero.

The declining slopes of the emissions curves all cross zero outside the planning window. While a regulatory plateau may come to pass, it is more likely that the lines will ultimately reach zero and reserve economy wide emissions for more intractable fossil fuel applications. Moreover, it is entirely possible that future GHG regulations may encourage negative emission curves to incentivize atmospheric capture of carbon. For example, carbon sequestration of the CO_2 emissions from biomass could create a negative emissions condition. In any event, the slopes in the planned trajectories will all cross zero between 2065 (Comparator case) and 2052 (Net Zero 2050) but the modeled scenarios do not consider this near certainty.

What will the utility look like when actual emissions must be zero (or less)? Do the trailing end effect costs include carbon sequestration from the operational gas plants at the end of the study period? Because no zero emissions case within the study period has been considered and all near zero cases build combined cycle gas to work with intermittent wind resources, these predictable costs are not identified.

It is clear that in the face of dramatically reduced emissions limits, the model first chooses interconnection over generation. It is entirely plausible that a zero emissions limit at 2050, 2045 or 2035 would react the same provided it had access within the model to more regional interconnection. It may be that greatly reduced generation is built and that zero emissions are achieved faster for limited additional expense to the utility and avoided rate base costs to the ratepayer. The last thing this process should plan for is a new life cycle of generation that will require expensive upgrades or premature retirement. Only a zero emission scenario can fully determine if this is truly cost effective.

The costs to the ratepayer are not fully comparable between scenarios. High electrification cases presume that consumers are replacing fossil fuel costs for heating and transport with electrical costs and there is substantial potential that this transition will provide significant savings to consumers.

Present electric vehicles provide 100 km of electric transport for 15 – 20 kWh of electricity and for a cost of less than $3.20. At a Canadian average of 8.9 liters of gasoline per 100 km (https://www.cer-rec.gc.ca/nrg/ntgrtd/mrkt/snpsht/2019/07-05hwdscndrnk-eng.html), and today's depressed prices (97.8 cents per liter 2020/07/10), the same 100 km using gasoline costs $8.70. For a 16,000 km per year consumer the savings today amount to $880.00 per year. While the consumer would see an additional $85.33 per bi-monthly electricity bill, they would avoid a $231.99 gasoline expense over the same time period.

Accounting for the difference in average generation cost summarized on page 30 of the results, the cost of 100 km of electric transport rises to $3.52 and the annual net savings to a consumer declines to $828.80 per year. For an estimated annual use of 15,000 kWHr/year, an added 1.6 cents per kWHr would add $240 in costs, still well below the savings from operating an electric vehicle. The scenarios with high electrification envisage substantial vehicle electrification. Page 8 of the E3 study reports the values in the excerpt (Figure 5, below). 150,000 EV's on the road in 2030, 590,000 in 2050. Direct consumer financial benefit will be substantial. Further accounting of health benefits would likewise represent long term financial savings to the province.

Clearly, a structured and measured assessment of this benefit is an important part of the net present value to ratepayers.

The same high electrification rate conditions likewise underestimate benefits and projected savings from building heating and electrification. While the E3 Pathways report contemplates electrification of heating systems, it does not account for improved building quality beginning in 2030 from new construction, nor is there an assumption around the rate at which older building stock may be renovated as cladding and window systems approach replacement age.

These measures form an integral part of Canada's Building Strategy as currently envisioned by the federal government under the Pan-Canadian Framework on Clean Growth and Climate Change (https://www.nrcan.gc.ca/energy-efficiency/energy-efficiency-buildings/canadas-building-strategy/20535).

These federal initiatives have the stated goal:

"Federal, provincial, and territorial governments will work to develop and adopt increasingly stringent model building codes, starting in 2020, with the goal that provinces and territories adopt a "net-zero energy ready" model building code by 2030."

https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/emmc/pdf/Building_Smart_en.pdf

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Assumptions aligned with these goals are included in modelling efforts such as those used for HalifACT planning and can dramatically reduce energy demand and also present an opportunity for cost effective demand response.

The distinction is critical. These structures require substantially reduced heating load, so the high electrification scenarios may overstate load growth. Likewise a high performance structure's low heat requirements enable demand response in heating systems. Measurements on winter loss of heat conditions in high performance buildings regularly take several weeks for the internal temperature to drop to stable values near 12C. Low heat rate losses enable cost effective demand response using hot water and existing ETS technology. None of these opportunities are represented in these cases.

The recently issued HalifACT report plans for reduced emissions sooner and most transition strategies frontload emissions reductions on electrical utilities to enhance the impact of electrification. This has been our experience in the past where diverse governments across the political spectrum turned to the electrical sector to lead emissions transition

The IRP must consider scenarios that align with these goals, if for no other reason, to advise Halifax on the implicit costs (or savings).

Import and Natural Gas Trade-offs:

Scenarios that modeled regional integration indicate that the Reliability Tie (345 kV Onslow - Salisbury) and the Regional Interconnection (345 kV Salisbury to Coleson Cove) are selected early when seeking solutions to declining GHG limits. The proposed March 11, 2020 IRP Assumptions (IRP Update Appendix C Page 75 of 136) listed a third interconnection (Salsbury - Quebec HVDC) and it is not clear that this was an active option in all of the modeled scenarios or just the regional integration scenarios. If it were available, it is not clear that, if presented with a zero emissions case in the study window, the model might well choose it over gas generation with carbon sequestration.

In addition, there is a risk that planning gas turbine construction and continued natural gas purchases will ultimately carry a higher carbon emissions factor. The North American natural gas supply has additional emissions associated with upstream fugitive methane emissions. While not currently accounted for under this IRP process, there is a clear risk that at some point in time they will be included as regulators seek to achieve real emissions reductions. Multiple studies indicate that fully accounting for these emissions brings the natural gas supply close to emissions intensities associated with coal combustion. (Assessment of Methane Emissions From the U.S. Oil and Gas Supply Chain, By Ramón A. Alvarez, Daniel Zavala-Araiza, David R. Lyon, David T. Allen, Zachary R. Barkley, Adam R. Brandt, Kenneth J. Davis, Scott C. Herndon, Daniel J. Jacob, Anna Karion, Eric A. Kort, Brian K. Lamb, Thomas Lauvaux, Joannes D. Maasakkers, Anthony J. Marchese, Mark Omara, Stephen W. Pacala, Jeff Peischl, Allen L. Robinson, Paul B. Shepson, Colm Sweeney, Amy Townsend-Small, Steven C. Wofsy, Steven P. Hamburg, Science13, Jul 2018 : 186-18) (https://www.bloomberg.com/news/articles/2020-01-23/gas-exports-have-dirty-secret-a-carbon-footprint-rivaling-coal-s)

There is risk that the emissions ratings of combined cycle natural gas systems will be raised.

Non-zero emissions allowances and optimistic emissions factors for natural gas create conditions where building natural gas fired systems is the most cost effective response to declining GHG levels. The concern is that when emission limits fall to absolute zero, significant (approximately doubling - IRP Update Appendix C Page 39 of 136) costs will be incurred to sequester the carbon output of these plants.

Please ensure that all models can add multiple interconnections and run scenarios that study zero GHG conditions.

It is critical that this IRP fully assess the import options available to Nova Scotia.

Generation Operational Data

The combined cycle and regular gas turbine systems that are frequently selected in the studied scenarios are selected for their functional characteristics and low costs. As mature technology, these systems represent the best in class low emissions fossil fuel generation equipment today. It is not clear that this will be the case over the full extent of the study period. Already solar dominated utilities are choosing utility solar and battery systems over natural gas systems. While these systems benefit from low battery durations and matched renewable resource and loads (Hot sunny days store more energy to power evening air conditioning), Long duration energy storage employing low cost battery materials, flow batteries and other concepts are active development areas. Tidal resources within Nova Scotia are substantial and it remains a possibility that these systems will mature within the time frame of the study period as well. It is entirely likely that viable alternatives to lithium battery systems will emerge within the first half of the study period.

For this reason, it is important to characterize the operation of the gas combustion resources selected by the model as a proxy for the cost threshold and performance that alternate systems will be required to meet. Knowing the cost, typical operational profile and duration of these systems will provide ready early evaluation of emerging solutions as applied to specific operational conditions in Nova Scotia.

Sustainability Advocate

The capacity of EAC to engage in this process is greatly reduced due to the design and process of the 2020 IRP, and the lack of availability for stakeholder funding and support through the NSUARB, through the NSPI-led process, or through the Nova Scotia Department of Energy and Mines. This is true for other organizations who advocate on behalf of climate mitigation, environmental concerns and energy affordability concerns, who do not have staff regulatory or legal counsel capacity to engage in this important energy planning process. Rather these organizations rely on a patchwork of volunteers over a multi-year timeline.

Although NSPI has made every effort to make the 2020 IRP process accessible to stakeholders, we regret the lack of financial and structural support for organizations to participate. The EAC feels that this problem is ongoing. NSPI and NSUARB processes will continue with ad hoc sustainability oversight until the Department of the Environment, Department of Energy and Mines, or Nova Scotia Power create an updated mandate to support climate change and environmental concerns in a way similar to the Consumer Advocate or the Small Business Advocate.

Moving Forward

The EAC believes that Nova Scotia still has an opportunity to set long-term ambition, and commit to phasing out coal-fired electricity in Nova Scotia. This IRP process will determine the future of our electricity grid in ways that will hinder or facilitate a just transition in Nova Scotia.

We need to ensure that low and middle-income Nova Scotians, coal workers and communities all benefit from this change in our electricity system, and the EAC believes that this transition is possible in an affordable, just and timely way.

The EAC looks forward to continued participation in the 2020 IRP stakeholder process, and ongoing conversations regarding Nova Scotia's electricity future.

Ecology Action Centre is committed to continuing to ensure Nova Scotia sets a pathway to phasing out coal-fired electricity generation, and looks forward to working with all partners toward the just transition to a prosperous, green economy.

Thank you for your consideration,

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See Also:
Ecology Action Centre's Electricity Report and Ongoing Work on Coal Phase-Out:
https://ecologyaction.ca/electricityreport

Setting Expectation for Robust Equivalency Agreements in Canada (April 2019)
Climate Action Network Canada | Canadian Association of Physicians for the Environment | Centre québécois du droit de l'environnement | Ecology Action Centre | Environmental Defence | Pembina Institute
https://ecologyaction.ca/sites/ecologyaction.ca/files/images-documents/CAN-Rac-Equivalency-Paper-2019-web.pdf

The Just Transition Task Force on Coal Workers and Communities Final Report:
https://www.canada.ca/en/environment-climate-change/news/2019/03/government-of-canada-welcomes-report-from-just-transition-task-force-for-canadian-coal-power-workers-and-communities.html

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July 17, 2020

Re: M08929 – Integrated Resource Planning – Response to Initial Run of Scenarios

Dear Ms. Godbout and Ms. Fris:

Envigour Policy Consulting Inc. has been retained by QUEST and Marine Renewables Canada as their Consultant in this matter. We have participated in the discussions regarding the initial outcomes from the scenarios.

We have found the information and discussion to be useful and insightful. To maintain the value of this extensive planning process, we suggest the following matters be explored before closing the IRP and developing the Roadmap.

1. DERs are considered a reduction in system demand without a cost to the system. We would want to understand how this assumption fits within the requirement to allow for Enhanced Net-metering by customers. Also, to simply assume DERs as reduced demand for system electricity, likely undervalues the potential positive contribution to the system that could come from a combination of DERs such as solar PV and storage by customers. We understand NS Power is exploring this potential through the NS Smart Grid project and related initiatives.

   The benefits from resiliency and reliability offered by DERs may be part of your planned next step runs and scenario testing. If so, information from that process may help gain insights into the value of DERs, especially when combined with storage. However, we believe there will likely be the need for additional discussions on these matters, and how to incorporate them into the Roadmap.

   Also, several NS Municipalities have expressed interest in Community Solar PV Gardens. It would be useful to discuss whether this concept is the same as DERs from the model's perspective and, if not, how it may be considered as well.

2. The model did not select several potential technologies such as offshore wind, tidal or hydrogen. It would be useful to know what the gap was between these technologies and the ones are chosen. It would help us understand the degree price reduction required to make them competitive in the future. Furthermore, it would be useful to know how the model would have valued any of the unique properties associated with these technologies, such as the predictability of tidal. If they were not valued, what process or opportunity might we see in the future to gain better insight?

3. Several runs chose natural gas solutions. It is difficult to see precisely what was selected as the options are shown in 5 shades of grey. Nevertheless, the narrative suggests a CCGT solution appears in several runs. We recommend there be a fuller discussion of the costs and benefits associated with an investment in this area. We would consider what kind of pathways/solutions would be necessary to achieve a net-zero electricity system by 2050 with a CCGT investment to be a priority. We would also want to identify and quantify the risk to electricity reliability from a dependence on a single natural gas pipeline. Identifying the risk of not being able to have local storage of natural gas should also be explored from a reliability perspective.

4. Each of the scenarios has a different impact on the NS GDP. Will the IRP process be able to differentiate which scenarios would more likely use NS sourced goods and services on a CAPEX and an OPEX basis?

Bruce Cameron
Principal Consultant,
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c.c. Tonja Leach, Executive Director QUEST
Via Email: tleach@questcanada.org

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Heritage Gas

July 17, 2020

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RE: M08929 – NSPI Integrated Resource Planning – Modeling Results Comments

Heritage Gas is the regulated provider of natural gas distribution service to Nova Scotia residents and businesses. Heritage Gas has been attending stakeholder meetings and workshops with Nova Scotia Power Inc. ("NSPI"), Energy+Environmental Economics ("E3") and other stakeholder groups. Heritage Gas is interested in understanding NSPI's Integrated Resource Plan ("IRP") and its interplay with long-term overall energy planning for the province over the next 25 years.

Natural gas has played an important role in electrical generation in the province for many years beginning with capital investments at Tufts Cove in 1999 that facilitated the use of natural gas as a fuel for the three generating units at that station. Reliance on natural gas further increased with the addition of the combined cycle combustion turbines at Tufts Cove. The modeling results distributed to interested stakeholders on June 26, 2020 and presented on July 9, 2020 indicate reliance on natural gas will continue to increase over the next 25-year period. The results show that increased natural gas capacity will be necessary to meet peak energy requirements and environmental targets while also providing critical ancillary services. The use of natural gas is robust across all scenarios in the Modeling Results.

Increased Reliance on Natural Gas and Planning Reserve Margin Issues

Heritage Gas notes that near-term resource changes in 2026 have included the need for "*New Gas CTs & Recips*" in every scenario provided by NSPI[1]. The more aggressive environmental targets being modeled

[1] Page 14 –IRP Modeling Results Workshop – 2020/07/09.

within various scenarios increase the demand for natural gas given the intermittent nature of more renewables.

At least one Combined Cycle ("CC") gas unit has been selected in each scenario in the late 2020's and early 2030's (slide 22). Heritage Gas notes that "late 2020s-early 2030s" is very close in the planning horizon. As NSPI is aware, assets were constructed by Heritage Gas for the purpose of providing service to NSPI that can provide various options for items identified throughout the modeling in the IRP.

As well, the long-term resource changes emphasize the need for additional natural gas resources, where some additional coal-to-gas conversions have been selected by the model[2].

Finally on this point, NSPI identified ~30MW deficiency in Planning Reserve Margin ("PRM") remains and NSPI has identified that a "*small early build of CT / Reciprocating resources resolves existing PRM deficiency*"[3].

Reliability of Liquid-Fueled Combustion Turbines ("CTs")

The liquid-fueled CT's provide a variety of critical ancillary services including 10- and 30-minute operating reserve, voltage support and black start capability in the event of a partial or total loss of the electrical grid[4]. The units are now over 40 years old. The model scenarios include the continued use of these units to 2045[5], by which time they will have been in service for over 60 years. Heritage Gas understands that fuel delivery to these units is by tanker trucks and, as a result, replenishment of the tanks that support these units is reliant on the availability of a limited pool of tanker trucks. This pool is further constrained in winter months when the units are more likely to be called upon. Availability of fuel supply has decreased following the closure of local refineries. Reliability issues associated with maintaining units out to their

[2] Page 16 – IRP Modeling Results Workshop #4 – 2020/07/09.
[3] Page 22 – IRP Modeling Results Workshop #4 – 2020-07-09.
[4] M09560 – NSUARB Decision – NSPI Approval of 2020 Capital Work Order (March 23, 2020).
[5] Page 15 – IRP Modeling Results Workshop #4 – 2020/07/09.

sixth decade of operation should be considered independently of the economics of replacement vs sustaining capital costs. Reliability test results should be made available to IRP stakeholders.

<u>Electrification Contribution to Peak Load & Associated Transmission & Distribution ("T&D") Costs</u>

NSPI's Modeling shows the potential for large increases in peak energy demand[6]. Increased electric load and increases in peak demand will have significant cost implications for NSPI's transmission and distribution ("T&D") assets. Heritage Gas understands that these are issues that have not had to be significantly considered in previous IRPs. NSPI's consideration of T&D cost implications appears limited to avoided T&D Costs with respect to DSM[7] and regional integration.

Given that IRP outcomes can influence long-term capital investments and policy directions, the total cost implications of IRP outcomes for rate payers should be examined in the Action Plan. Increased electrification (e.g. building heat, transportation) will contribute to peak energy demand. A number of studies have shown that natural gas distribution systems can cost effectively assist in meeting peak energy demand while still meeting GHG targets. The nature of the results of the IRP analysis and the significant reliance on natural gas going forward in all scenarios provides an opportunity for Heritage Gas to work with all stakeholders to ensure the most cost-effective energy supply system in the province going forward.

Heritage Gas appreciates the continued open and collaborative process with all stakeholders to date on this IRP. While various other issues related to the above matters were discussed with NSPI, Heritage Gas felt it appropriate to highlight the foregoing points for all stakeholders. We look forward to the continued dialogue with all stakeholders throughout the remaining elements of the IRP, including the development of the Action Plan.

[6] Page 9 – 2020 IRP Assumptions Set (January 20, 2020).
[7] E-ENS-R-19– M09471 – Efficiency One – 2019 Historical Rate and Bill Impact Analysis (March 27, 2020 Letter).

Regards,

HERITAGE GAS LIMITED

John Hawkins
Cc: M08929 Participants

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To: Linda Lefler P.Eng, Senior Project Manager - Regulatory Affairs, Nova Scotia Power

From: Jon Sorenson, Executive Consultant, Hydrostor Inc.

Date: 17th of July 2020

Re: A-CAES as a Solution for Nova Scotia

Memorandum

As we have communicated to the Nova Scotia Power team, Hydrostor is a Canadian technology provider and global developer of energy storage facilities that uses commercially proven Advanced Compressed Air Energy Storage (A-CAES) technology. We have been following Nova Scotia Power's IRP process with great interest and were disappointed to learn that long duration energy storage technology was not included in the preferred portfolio. We note that Nova Scotia Power has instead opted for a portfolio that calls for new transmission and fossil fuel assets to meet balancing and peaking requirements. We believe that long duration Energy Storage, and A-CAES in particular, is a credible, market-ready solution that can address the issues solved by these assets in a cleaner and more cost-effective way.

Nova Scotia Power's A-CAES Cost Assumptions

Based on our review of Nova Scotia Power's IRP assumptions, we believe that A-CAES's capital costs were inaccurately modelled. We believe that this played a decisive factor in it not being selected as a preferred resource. In particular, we found that in your cost analysis, the model used a $/kW cost of CAD $2,200. This was in effect, the mid point of our $/kW cost estimates for a 200MW facility with a duration of 12 hours that we had previously provided to you (See Appendix 1). This was then compared to the cost of a lithium-ion system with 1 and 4 hours of duration. (See Figure 1 below).

Technology	Subtechnology	Capital Cost (2019 CAD $/kW) 2019	2030	% Change
Wind	Onshore	$2,100	$1,691	-19%
	Offshore	$4,726	$3,429	-27%
Solar PV[a]	Tracking	$1,800	$1,416	-21%
Biomass	Grate	$5,300	$5,146	-3%
	Municipal Solid Waste	$8,470	$8,470	0%
Tidal	n/a	$10,000	$10,000	0%
Storage	Li-Ion Battery (1 hr)	$764	$385	-50%
	Li-Ion Battery (4 hr)	$2,125	$1,071	-50%
	Compressed air	$2,200	$2,200	0%
	Pumped Storage	$2,700	$2,700	0%

[a] Solar PV costs reported in $/kW-ac, reflecting an inverter loading ratio of 1.3

Figure 1

Our concern is that this was not an apples-to-apples comparison as it accounts for the additional cost of a longer duration facility but ignores the additional value such a system provides. Additionally, by choosing to use the costs for a 200MW system, this did not account for the significant economies of scale that come with larger sized A-CAES facilities. If you consider a 500MW facility with a 4-hour duration, the cost works out to an average of US$1125/kW[1]. We believe that this is a much fairer comparison to a 4-hour lithium-Ion system for the short duration market.

However A-CAES's cost advantage is most apparent in the long-duration market where it can act as a non-wires alternative to traditional transmission for improving reliability or as a solution for integrating and time-shifting Nova Scotia's wind resources onto the grid. To illustrate this point, we compared the bid prices that we recently submitted for a 300MW 6 hour and 12 hour facility to a utility in California to what an equivalent lithium system would cost based on prices provided by Lazard's Levelized Cost of Storage Analysis 5.0. For the 6-hour system we found that lithium ion prices would have to drop 7%-50% from 2019 in order to achieve cost parity. Whereas, for the 12-hour facility we found that lithium ion would have to decrease their cost by a further 41%-70% in order to achieve cost parity.

A-CAES is a Reliable Solution for Nova Scotia's Needs

Advanced Compressed Air Energy Storage, uses equipment, construction techniques and technology proven and optimized in the oil and gas sector to deliver a bankable and market-ready solution that can be delivered at scale. The technology benefits from large economies of scale which allow it to offer the lowest per kwh cost the energy storage

[1] [1] We also note there was a conversion error as our costs were presented to Nova Scotia power in US$ but were displayed here in $CA. We therefore question whether this conversion error applied to other technologies listed here.

market for system sizes larger than 250MW and at durations ranging from 4 to 12 hours or more. Because of our exclusive use of equipment produced by Tier 1 manufacturers such as Baker Hughes, Hydrostor can deliver facilities backed by global supply chains, comprehensive maintenance packages and performance guarantees. With no degradation or disposal liabilities, flexible expansion options, and a service life of 50+ years that give it unique advantages over batteries and makes it the ideal storage solution for integrating Nova Scotia's considerable wind resources into the grid.

It is also important to note that since A-CAES uses spinning turbines it can meet the grid's need for inertia and synchronous generation that is currently provided by Nova Scotia Power's coal fired generation facilities. Furthermore, unlike pumped hydro or fossil assets, A-CAES can be flexibly sited where the grid needs it. It is a benign technology that has minimal impact on its local environment while producing major economic benefits for local communities, reducing permitting risk and allowing it to be safely sited close to population centres. Furthermore, Hydrostor has studied the geology of Nova Scotia and New Brunswick and found the region to be highly suitable for A-CAES, making it even easier to site. For these reasons, we believe A-CAES is the right solution for accelerating the retirement of coal assets and avoiding further investment into fossil fuels.

We note that Nova Scotia Power intends to make considerable investment in transmission infrastructure to improve the reliability of the system. Again, we believe that A-CAES should be seriously considered by Nova Scotia Power as a lower-cost alternative that could save the utility 10's to 100's of millions of dollars. We have proposed this kind of solution to regulators and transmission companies in Chile, Australia, and California and would be happy to provide you with an indication of what the cost savings could look like for an A-CAES facility sited near the source or load instead of build a new transmission line.

In short, we believe that a Canadian designed A-CAES facility built to a scale of 300 to 500MW with a long duration of 6, 8,10, 12 hours or beyond can assist Nova Scotia Power in its Integrated Resource Plan in the following areas:

- Be a cost-effective non-wire alternative solution for transmission that is easier to permit and more cost effective than large transmission projects
- Be a clean source of synchronous generation capacity with similar system benefits and operating characteristics as coal that can be used to advance coal retirements and be located on or near the sites of former plants while retaining many of the plant's employees
- Be used to balance intermittent resources such as wind and solar or instead of natural gas fired plants, as a peaking asset

We would be very interested to better understand your thoughts on A-CAES and hope to address any questions or concerns. We would also invite Nova Scotia Power and its consultants to take part in a virtual or in-person tour (situation permitting) at our soon-to-be officially commissioned Goderich, Ontario facility soon. I thank you for your consideration and look forward to working with you further to explore this option for Nova Scotia's energy future.

Please do not hesitate to reach out.

Thank you and Best Regards,

Jon Sorenson
Executive Consultant
Hydrostor Inc

Appendices

Appendix 1: A-CAES Technical Inputs Summary (Previously submitted to NS Power)

HYDROSTOR

ADVANCED COMPRESSED AIR ENERGY STORAGE

Hydrostor Introduction

April 2020

About Hydrostor

Hydrostor is the global leader in Advanced Compressed Air Energy Storage (A-CAES)

Founded 2010

Offices Toronto, Canada (primary)
Adelaide, Australia (satellite)

Headcount 35

Operating Facilities
2 (Canada – Toronto Hydro; Canada – IESO)

Facilities Under Construction
1 (Australia – NEM)

Project Pipeline
~400 MW commercially bid, 4 GW project pipeline (focused on US, Canada, Australia, Chile)

A-CAES is a breakthrough for large-scale energy storage:

- Uses only water, pressurized air and standard equipment with proven supply chain to provide long-duration, emissions-free storage.
- Provides similar characteristics to pumped hydro storage, but with the key advantage of being able to flexibly site where the grid needs it.

Compressed Air Energy Storage

Compressed Air Energy Storage is a utility-scale electrical energy storage solution with a history of over 40 years of successful operation.

- There are two large-scale examples of compressed-air energy storage in operation:
  - 290-MW Huntorf CAES Plant (Germany, commissioned in 1978)
  - 110-MW McIntosh CAES Plant (Alabama, commissioned in 1991)
- Hydrostor builds on the CAES platform and improves it with well-established systems that are innovatively deployed for storage: 1) a proprietary thermal management system, and 2) purpose-built hard-rock air-storage caverns. This enables both **emission-free operation** and **siting flexibility**.

Huntorf CAES Plant in Elsfleth, Germany

McIntosh CAES Plant in McIntosh, Alabama

How Advanced-CAES Works

A-CAES integrates proven technologies and construction approaches in innovative ways to produce a superior long-duration grid-scale energy storage solution.

Step 1

Compress air using electricity

Electricity runs a compressor to produce heated compressed air

Unique to Hydrostor

Step 2

Capture heat in thermal store

Heat is extracted from the air stream and stored in a proprietary thermal store

Unique to Hydrostor

Step 3

Store compressed air in purpose-built cavern

Air is stored in a purpose built cavern using water to maintain constant pressure

Step 4

Convert the air to electricity

Water forces air to the surface where recombined with heat and expanded through a turbine

- ***Electrical Conversion:*** Relies on off-the-shelf synchronous generating equipment, including compressors, expanders, heat exchangers, available in a variety of sizes and configurations and that have decades run-time experience across multiple industry applications (e.g., oil & gas).
- ***Underground:*** Simple and cost-effective purpose-built underground cavern construction using industry standard and well-proven mining techniques with large precedent in hydrocarbon storage industry (i.e., 100s of rock caverns, dozens with hydrostatic compensation).

A Proven and Bankable Solution

Significant Precedent:

- 200+ MW conventional-CAES plants reliably operated for over 30 years.
- 100+ rock caverns storing hydrocarbons with dozens using hydrostatic compensation.
- All major equipment proven for intended application with long reliability histories.

Backed by Proven A-CAES Facilities and Significant Engineering:

- Hydrostor projects – 3 A-CAES plants in Canada and Australia with directly analogous operations to pipeline.
- Independent engineering complete.
- Supply chain partners in-place experienced delivering sub-systems at all system scales.
- Bonding and performance guarantees for full-scale systems in place.

Technical due diligence already cleared with Tier 1 development companies, government-funded entities, and supply chain partners


Goderich A-CAES Facility


Australia project - Photo within air storage section


Storage cavern construction, India, accessed by a mine shaft in a gallery configuration with a water curtain


Storage cavern construction, Portugal, accessed by a helical decline in a gallery configuration

HYDROSTOR

Full Delivery Capabilities

Curtis VanWalleghem
CEO, Co-Founder, Board Member
Bruce Power
Deloitte

Jon Norman
President & COO
Brookfield
Ontario Ministry of Energy

Jordan Cole
Chief Commercial Officer
Brookfield
Enwave

Sid Meloney
EVP Engineering & Projects
Williams Energy
TransCanada

Greg Allen
Managing Director, Australia
Carnegie Clean Energy
Wesfarmers Energy

Development Project Finance Partner

meridiam infrastructure

Equipment Supply Partner

Baker Hughes

Design & Construction Relationships

AECOM

TMCC THYSSEN MINING

wsp

Agapito Associates, Inc. Mining & Civil Engineers & Geologists

GEOSTOCK ENTREPOSE

Project Bonding & Warranty Partners

EDC

NEW ENERGY RISK

A-CAES Compelling for Long Duration

This provides a strong advantage over competing solutions, especially given A-CAES flexible siting capability:

	Hydrostor A-CAES	Gas Turbine	Traditional CAES	Pumped Hydro	Li-Ion Battery	Flow Battery
Size (MW)	50 – 500+	>100	150 – 500+	>100	1 – 100+	1 – 20
Duration (hours)	>6	N/A	>6	>6	1–4	4–6
Efficiency	>60%	N/A	30 – 40%	70 – 85 %	85%	70%
Emissions	None	Emitting	Emitting	None	None	None
Lifecycle (cycles)	>20,000	>20,000	>20,000	>20,000	5,000	10,000
CAPEX (US$/kW)	$1,000–$3,000	$1,000	$1,500–$2,500+	>$2,500	$3,000+**	$5,000
CAPEX (US$/kWh)*	$150–$300*	N/A	$150–$250+	>$250	$300+**	$500
Operating Costs	Low -Medium	High (fuel costs)	High (fuel costs)	Low -Medium	Medium	Low -Medium
Siting Flexibility	Medium-High	Medium (emissions)	Low (salt, emissions)	Low (topography)	High	High

** Assumes 10-hour discharge for storage, fully-delivered system with BOP. Additional cost reductions possible where infrastructure can be repurposed.*
*** Li-ion costs based on Lazard LCOS v4.0 adjusted to 10-hour discharge using CPUC methodology in order to show equivalency with 10-hour A-CAES*

Hydrostor has strong advantages in situations with the following conditions:

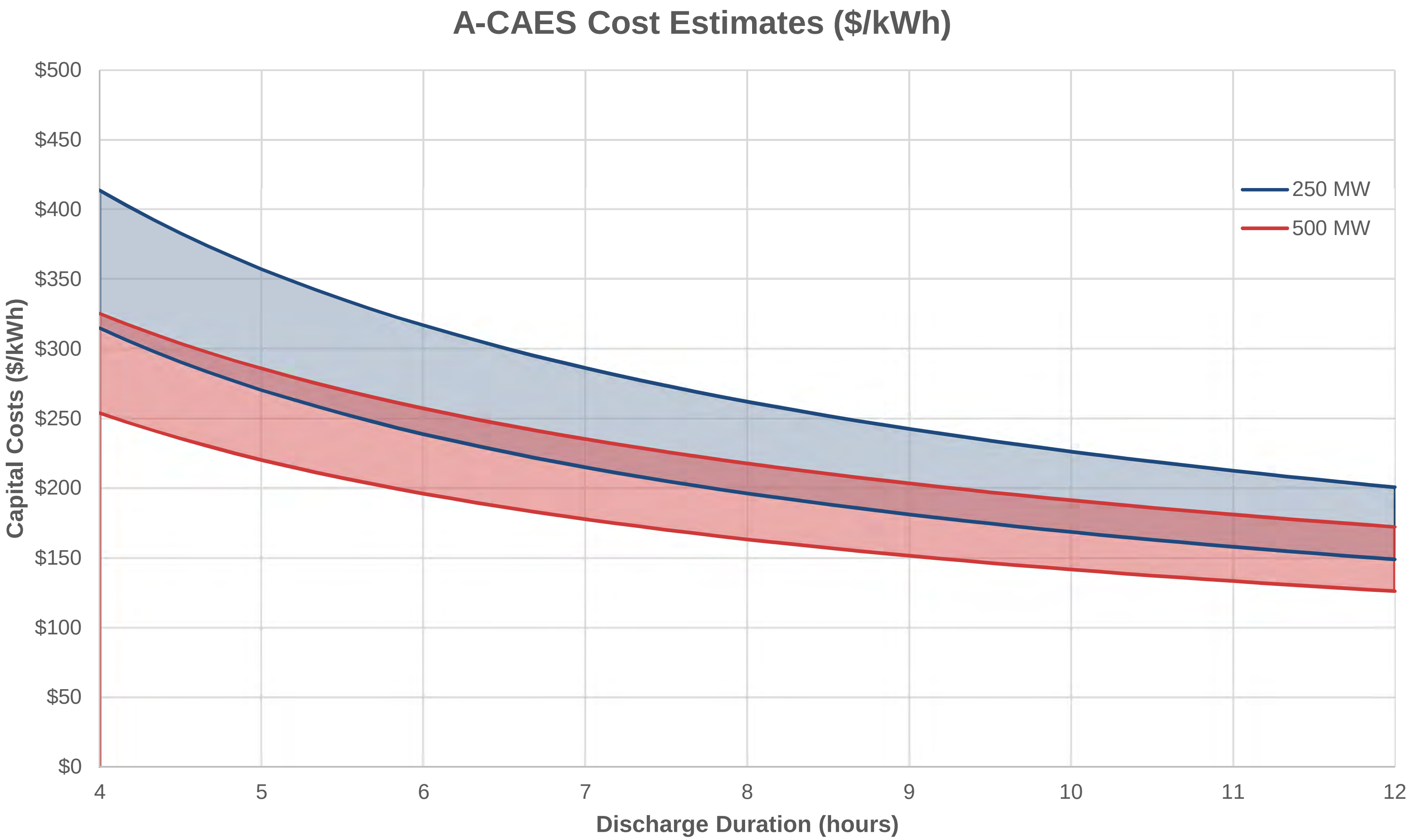
a) Difficulty permitting gas (e.g. California, urban centers) or high-cost gas markets (e.g. Australia),

b) Requirement for long-duration >4 hours (e.g. transmission deferral, capacity/reliability, high renewable),

c) Scale in excess of 200 MW

HYDROSTOR

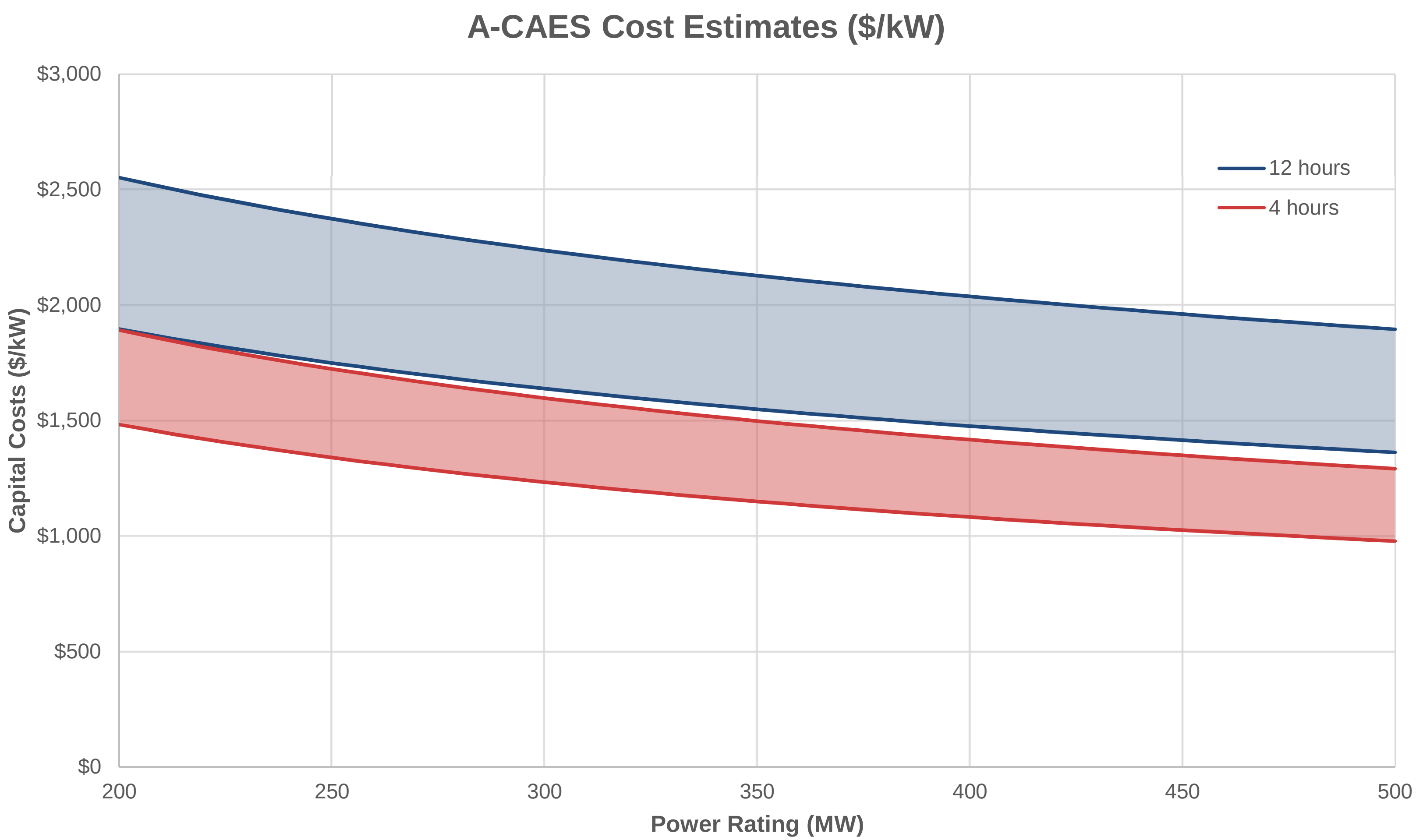
Lower Cost & Longer Life vs Li-Ion



Installed cost at scale significantly below all-in delivered costs for Li-ion batteries. The levelized cost for A-CAES is even further below that of Li-ion for long duration applications due greater life of A-CAES (i.e. A-CAES more than 4x cycle life of Li-ion, which can be cost-effectively extended even longer to allow a 30-50+ asset life).

** Note: Costs shown are overnight costs for an open loop system.*

Emission-Free & Similar Cost vs Gas



The levelized cost for A-CAES is often similar to new natural gas (CCGT) given the ongoing fuel costs of natural gas relative to the off-peak electricity rate in many markets. Most importantly, A-CAES is emission-free and often can be sited where natural gas cannot be permitted.

HYDROSTOR

** Note: Costs shown are overnight costs for an open loop system.*

A-CAES Value Proposition

	**Fossil Plant Replacement**	• Synchronous dispatchable generation, and A-CAES long duration enables reliable capacity replacement, with flexible siting at the exact location needed. • Alternative to new natural gas (no emissions and often less permitting hurdle, lower fuel costs in many markets with high RE, access additional ancillary services on charging) • Can leverage existing interconnection & infrastructure and defer fossil plant remediation costs
	**Transmission Deferral**	• Non-wires alternatives to defer grid network investment • Long-duration alleviates grid congestion during peak periods, and enables transmission alternatives requiring longer-term outage management • Locatable reliable power for critical areas and infrastructure
	**Renewable Integration**	• Provide dispatchable or baseloaded renewables at rates ~$70-120/MWh • Optimize large solar/wind project economics through time-shifting to reduce curtailment

- Ability to Site Where Needed
- Low Cost at Scale; Long Life
- Flexible Design
- Bankable
- Emission Free
- Ancillary Services

Growing Project Pipeline

Hydrostor has three projects in operation or under construction in Canada and Australia that total more than 25 MWh of storage capacity.

The Company is continually developing its pipeline of future opportunities which currently includes 15+ projects in various development stages across North America, Australia and Chile that range in size up to 500 MW, 4 gigawatt hours (GWh) per project.

1

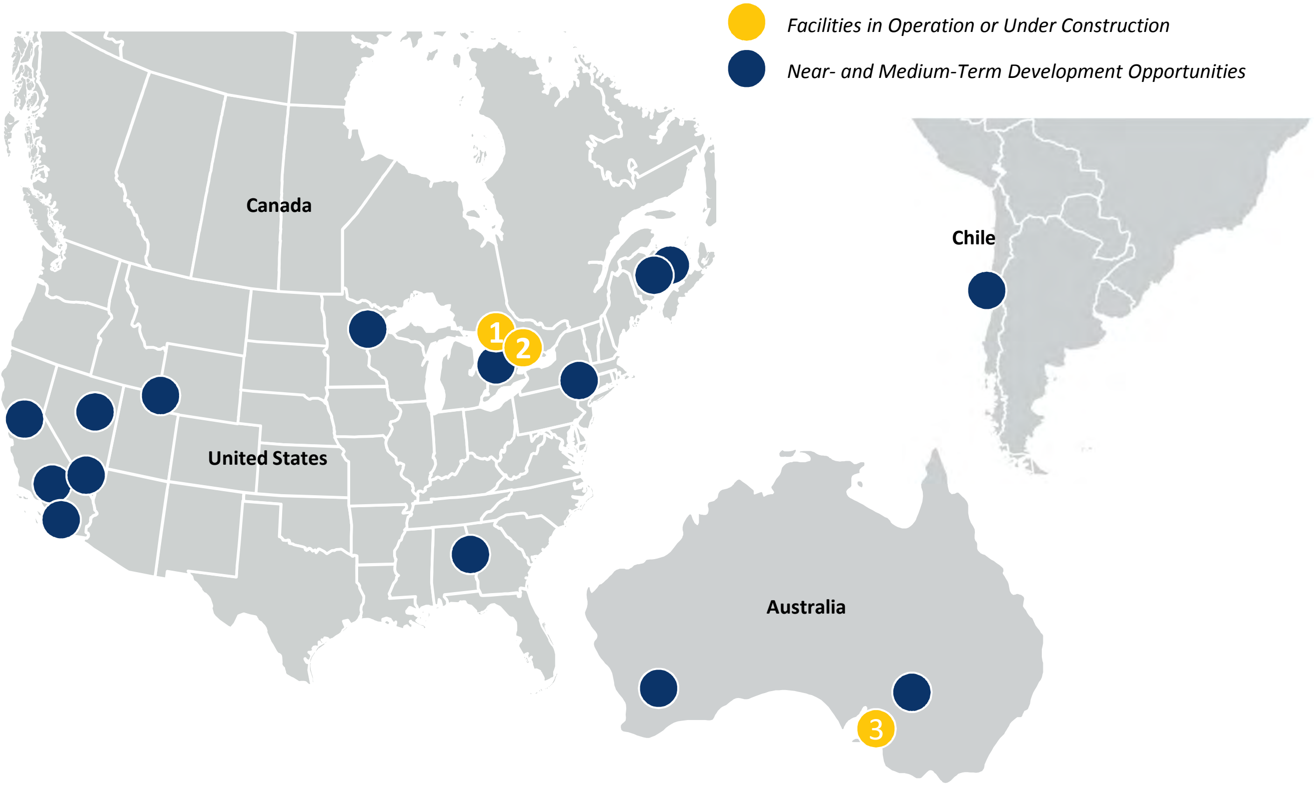

Goderich A-CAES Facility

2

Toronto A-CAES Facility

3


Angas A-CAES Project



HYDROSTOR

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natural forces
Natural Forces Services Inc. | 1801 Hollis Street | Suite 1205 | Halifax | NS | B3J 3N4 | T: (902) 422 9663 | F: (902) 422 9780

Doreen Friis, July 17, 2020
Regulatory Affairs Officer/Clerk
Nova Scotia Utility and Review Board
1601 Lower Water Street, 3rd Floor
P.O. Box 1692, Unit "M"
Halifax, NS B3J 3S3

-SENT VIA EMAIL-

RE: 2020 Integrated Resource Plan Initial Modelling Review

Dear Ms. Friis,

Natural Forces Services Inc. welcomes the opportunity to input comments on the IRP process. We note that again the time for comments to this process are extremely tight and it makes it very difficult for us to fully process the information that is being submitted by NSPI.

In general, there are two large issues we would like to comment on and several smaller issues. The key issues are

- The Cost of wind (capex, opex and capacity factor)
- The limits on wind installed capacity

As well we would comment on

- Synchronous Inertia minimum requirement
- Demand projections
- Requirement for transitioning plan
- Interconnector Flows; treatment of exports
- ELCC contribution from interconnectors

We have for convenience, set out our comments below under several headings.

The Cost of Wind

This point has been brought up several times by several stakeholders, however NSPI staff still feel that the pricing that they are using for wind energy is correct. NSPI's assumption is that

Wind

- Capital cost $1691 / kW

- O&M $59 / kW / year

This is not close to what current pricing would suggest is for wind in Canada. Natural Forces is currently building medium sized project across the country and these prices are not reflective of our data. From recent public calls of power, Alberta is currently pricing wind between 3 and 4 c/kWh. While the capital cost is high as well as the O&M, it is really the capacity factor that is estimated to be much too low which leads to a false number This is a fundamental issue in the IRP and presents a bias in the results that are coming from the modelling. NSPI has strong opinion on this issue and it is suggested that it would make sense to test the sensitivity of this pricing. The model should be run with a sensitivity of a reduction in cost of 30% at a minimum.

Hard limit on Wind installed capacity

It is our understanding from the presentation of the modelling results on 9th July, that in effect, a "hard cap" of 700 MW has been applied to wind installed capacity, i.e. that no increase in wind installed capacity is permitted without the addition of major capital investment in a second AC intertie and/or in battery storage and synch condensers. The capital cost of the associated investments have the effect of making wind a non-viable proposition for at least the first ten years or so of the model period.

If this understanding is correct, firstly, this is contradictory from our previous understanding based on direct discussions on the modelling approach and assumptions. More importantly, we believe this approach to be fundamentally flawed and biased towards less renewables and higher costs.

PSC study

The 700 MW "limit" on installed capacity is derived from the PSC study[1].

As we noted before, the PSC study analysed the performance and stability of the Nova Scotia system under four scenarios, specifically selected to examine the resilience of the system under the most stressful conditions likely to be encountered. It is fairly typical for technical studies of this nature, to include scenarios that represent more stressful system conditions, thus giving insights on the operation of the system at or near to its operational limits. This might include for example, minimum system demand cases, as is "Case 01" in the PSC study. The PSC Report itself acknowledges that the Study covers:

"simulations of 4 different cases that represent stressed conditions in the Nova Scotia power system and applying several severe contingencies, it was concluded that the existing Nova Scotia power system can support 600 MW of wind generation." [emphasis added]

What must be remembered though is that such scenarios are not representative of more "normal" system conditions that exist for the vast majority of the time. There is arguably nothing wrong with that, as that is not the primary purpose of the such studies. However, it also means that the findings of the studies must be recognised for what they are. Specifically the findings cannot be extrapolated or implied to apply

[1] "Nova Scotia Power Stability Study for Renewable Integration Report", prepared by PSC North America on behalf of Nova Scotia Power Inc. (24th July 2019).

to the more normal or typical system conditions that will exist the remainder of the time. A finding that the system is reaching limits of operation with 600 or 700 MW of wind generation in some or all of the "stressed conditions" scenarios, certainly does not mean that much higher levels of wind could not be accommodated at other times. In contrast, significantly greater levels of wind could be accommodated under other, more typical system conditions.

The wind "limit" identified from the PSC study derives mainly from two study cases:

- Case 1: minimum demand case; high wind; 250 MW import on AC intertie;
- Case 4: high demand case; high wind; 417 MW import on AC intertie.

In both cases, the loss of the AC intertie at high import appears (not surprisingly) to be the most severe contingency. The high wind output coupled with the high import is "squeezing" the space for conventional (synchronous) generation needed on-line to provide SIR and other services. The assumed remedial action is to reduce or limit the wind, whereas <u>reducing the AC import would be a more effective remedy</u>; reduction of the import level has the double benefit of creating more space for conventional generation, while at the same time reducing the severity of the contingency.

In effect, wind is being limited in order to facilitate high levels of import. In most jurisdictions tie lines are regularly limited when there are stressful events on the system and internal resources (particularly renewables) are prioritized. This should be considered from a policy perspective.

Installed wind capacity vs. operational limitations

In the section above we have made a number of observations on the PSC study scenarios and findings, which indicate that more wind could potentially be accommodated even in the "stressed conditions" selected for the study. However even accepting the PSC study findings to be broadly correct, it is critical that the study findings are recognised for what they are (and what they are not).

The Study findings <u>do not conclude that the wind installed capacity must be limited to 700 MW.</u> All that they conclude, is that in <u>certain stressed system conditions, the output of the wind should be temporarily limited to 700 MW.</u> [2]

These scenarios will only arise for a few hours per year. Even when the system conditions (demand, import levels) apply, it may or may not be the case that wind output will be high at the same time[3]. It is common practice (in fact one could say almost universal) in systems with RES ambitions, to accept that wind output will have to be operationally curtailed from time to time, specifically in the small number of hours when <u>stressed system conditions</u> and <u>high wind output</u> coincide.

[2] Notwithstanding the fact that reducing the import level would be a more effective means of ameliorating the problems.

[3] In fact evidence suggests that there is a positive correlation between wind output and demand, reducing the likelihood of occurrences of high wind output at time of low demand.

It was mentioned in the discussion on the 9th July webinar, that the occurrence of these stressful events was unpredictable. It is correct to say that the occurrence of contingencies (such as the loss of the AC intertie) is unpredictable. However the system conditions under which the contingencies are problematic, are entirely predictable. The stressful cases are a combination of demand conditions and high imports on the AC intertie. These conditions will be known and identified in operational planning and dispatch timescales, and mitigating actions (e.g. curtailment of wind, or curtailment of imports) can be implemented to ensure that the contingencies, should they occur, do not unacceptably impact on system security. This is that approach commonly adopted in all power systems with renewable ambitions.

International practice

As noted, all systems with high RES ambitions which we are aware of, adopt the approach of accepting that wind output will be curtailed from time to time, when stressed system conditions and high wind outputs coincide. The alternative approach of limiting the amount of wind which can be installed to the amount of wind output that the system can safely accommodate in the most stressful system conditions would, quite frankly, not even enter consideration.

To take Ireland as an example; both Ireland and Northern Ireland, operate as an integrated synchronous system and market. The total wind connected is currently about 5,200 MW, and further wind projects have network connection agreements and are currently in development. Ireland is expected to meet its 2020 target of 40% of generation from renewable sources in 2020 (of which over 90% is from wind).

Wind in Ireland can reach up to 70% of the system demand on an instantaneous basis. It is necessary to curtail wind output at times, particularly when high wind output coincides with low demand.

If lreland imposed a limitation on wind installed capacity in the manner contemplated in the IRP study (i.e. limiting installed capacity to the amount of wind that could be accommodated under all system conditions, including "stress" cases), then the installed capacity would be limited to somewhere in the region of 1700 MW (compared to the current installed capacity of 5,200 MW). Note that Ireland is not unique in this regard; the approach of accepting additional renewable installed capacity and limiting the output at times when necessary to ensure security of system against plausible contingencies, is fairly universal.

Synchronous Inertial Response (SIR) minimum requirement

The IRP model is set to require a minimum of 3,266 MW-sec of SIR. This is stated to be based off the PSC study but adds in a safety margin of 500 MW-sec, approximating to a requirement for one additional generation unit. The figure of 2,766 MW-sec from the PSC study is from Case 01 (revised), which had three thermal generation units on-line. However the PSC report also notes that the system would be stable with only two units.

It is also worth noting once more, that the contingency event which is driving the SIR requirement in the PSC study, is the loss of the AC intertie at high levels of import. If the flow on the AC intertie was reduced, this level of SIR would not be required. In this regard PSC study Case 2 is very informative; in Case 2 the

AC intertie is out of service, and the Nova Scotia system is noted to be stable with only 1,788 MW-sec of SIR. The PSC report state that:

"Therefore, it seems that once Nova Scotia is operating in an islanded mode, two thermal units can provide enough inertia for it to survive the transients caused by the studied internal contingencies."

Of course, it is almost certainly not the fact of islanding that make the system stable with much lower SIR, but rather the fact that there is no large import on the AC intertie to deal with as a contingency event. If the AC intertie were in service but at a lower MW level, the results would be at least as good, or indeed better.

In summary, in relation to the minimum SIR requirement:

- The minimum level of 3,266 MW is not well substantiated based on the PSC study. It appears that there is a safety margin of one thermal generation unit included in the PSC study, and then a further safety margin approximating to one thermal generator added in the IRP study. This appears on face value, to be unduly conservative.
- The SIR requirement is arising from high imports on the AC intertie. At times of lower import levels, the SIR requirement would be expected to be much lower.

Demand projections

The slide deck distributed on 27th June includes revised demand projections, apparently based on revisions due to the COVID-19 pandemic. The changes in demand assumptions appear to be quite severe and certainly prolonged, with an assumption that it will take 10 years to return to the original demand trajectories. Of course, there is inevitable a degree of uncertainly regarding COVID, but this is certainly much longer than would be assumed in other countries. To our knowledge, most countries are predicting recovery to earlier trajectories within two to five years.

Requirement for transitioning plan

As way of a comment, it is understood that the IRP model does not address the complexity of adding units instantaneously to the system or quickly retiring units, so it can be forgiven for the large swings in generation sources in 2030 and 2040. As the new plant cannot realistically be added "instantaneously", as it is in the current model, there will be a need for a transition plan where the new plant is brought on progressively over a period of up to ten years. This may lead to more quickly retiring coal plants and adding more renewable sources sooner. It may serve to force the model to ramp the coal plants down over multiple years so that it can take this into account, or it will have to be manually estimated, which may be problematic if we are looking for the best solution.

As a second part to this issue, as any transition plan is likely to involve adding wind year-by-year over the period up to 2030, determining the correct results from the SIR requirement and the hard cap on wind until a 2nd intertie is of crucial importance. If the position is maintained that wind installed capacity in excess of 700 MW must be accompanied by either the 2nd AC intertie or by BES/synch comps, then these would have to be built out in tandem with the wind. This could result in a premature and/or unnecessary level of capital expenditure, increasing costs to consumers.

Interconnector Flows; treatment of exports

The spreadsheet provided by NSPI showing the modeling results, contains interconnector energy flows by year for each scenario, under the headings of “Maritime Link Blocks”, “Firm Imports” and “Non-form market”. For each of these, only an aggregate quantity is given; we assume that in at least some cases, there are both import and export quantities underlying the data. Can the import and export energy flows be provided?

We would also appreciate clarity on the assumptions regarding pricing of exports. It may be that this is covered somewhere within earlier documents, but we have been unable to identify it.

ELCC contribution from interconnectors

It is our understanding that in the IRP model, only firm imports are assumed to contribute to ELCC. There was mention at the 9th July webinar of this being due to NERC rules. If this is the case and it is a mandatory requirement that non-firm imports cannot be considered to contribute ELCC, it may not be open to amendment at this time.

It is worth noting that the approach in other regions, for example in Europe , is very different. The ability to share capacity resources is accepted as one of main benefits of interconnection, and need not be underpinned by “firm” imports. By way of example, the two 500 MW HVDC interconnectors from Ireland to GB, are credited with an ELCC quantity in each interconnected system. In Ireland, each of the 500 MW interconnectors is credited with 220 MW ELCC, even though there are no firm import arrangements (interconnector flows follow the market). This approach significantly reduces the generation installed capacity requirement in each system, and in aggregate.

Emulated or Synthetic inertia

The points brought up to NSPI during the workshop discussing Emulated or Synthetic inertia is of great interest. We agree that HVDC interconnectors and also energy sources connected through power electronics (such as wind, solar, batteries) do not provide SIR. However it is worth noting that there is currently a great deal of effort going in to getting HVDC and RES connected through power electronics to provide “inertia-like” services (typically referred to as “synthetic” or “emulated” inertia). Developments in this area could be a significant “game-changer” in the future, so it is important to continue to monitor progress closely.

Sincerely,

Presented for, and on behalf of, Natural Forces Services Inc. Halifax, Nova Scotia.

Blackburn Law

VIA EMAIL

July 17, 2020

Linda Lefler
Nova Scotia Power

Dear Ms. Lefler,

Re: M08929 – July 9, 2020 Stakeholder Session – SBA Comments

The Small Business Advocate (SBA) participated in the online IRP Stakeholder meeting on July 9th, 2020, along with its experts from Daymark Energy Advisors, John Athas and Jeff Bower. Please find a memo from Mr. Athas and Mr. Bower attached, setting out comments and questions regarding the modeling results that were presented.

Please let me know if you have any questions or require any clarification.

Yours truly,

BLACKBURN LAW

Melissa

E.A. Nelson Blackburn, Q.C.
Small Business Advocate

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DAYMARK®
ENERGY ADVISORS

TO: Nelson Blackburn and Melissa MacAdam, Nova Scotia Small Business Advocate

FROM: John Athas and Jeff Bower

DATE: July 17, 2020

SUBJECT: Comments on NSPI modeling results

This memo summarizes Daymark's comments regarding NSPI's IRP modeling results, dated June 26, 2020. We have included questions associated with areas of uncertainty, and highlighted areas in which additional analysis should be provided by the Company so the conclusions can be fully evaluated by stakeholders. Finally, we provided some suggestions related to how the Company can continue the valuable stakeholder engagement process it has maintained thus far in the IRP process.

I. Modeling Questions, Concerns and Suggestions

a. **System Inertia-Based Generation Requirements:** Since the system inertia requirement is a constraint in the modeling, the Company should provide more analysis and detail supporting the assumptions. The PSC study provided initial results, but the Company acknowledged several shortcomings at the time. The IRP analysis would be more complete with the following:
   - More information on derivation of requirements and cost of alternatives to generation such as synchronous condensers, and information on any limitations on the amount of these that the system can rely upon.
   - Additional analysis supporting the inertia benefits ascribed to the Reliability Tie. The modeling currently assumes the reliability tie would provide all system inertia requirements for system. Are there limitations to this assumption, or are there system conditions (in NS or NB) under which the tie would not provide the claimed inertia benefits?
   - NSPI should conduct additional analysis to identify the minimum amount of inertia requirements in province under different system conditions. The 3266 MW.sec requirement was based on specific load conditions resulting in a 2766 MW.sec requirement, plus a 500 MW.sec generic additional requirement. Additional analysis would allow for more dynamic modeling of this requirement and provide additional insight on the inertial need over time as load, DSM, and supply-side portfolio mix changes. Since ascribing this benefit of providing all the inertia requirements is uncertain and very valuable to the evaluation we would like to see a sensitivity if the inertia benefits of the tie is substantially lower than assumed, such as providing only half of system inertia need.

- Provide information regarding whether the battery + synchronous condenser option for system inertia would also provide system capacity.

b. **Reliability Tie and Regional Integration – Treatment of risk:** The Reliability Tie and Regional interconnection are significant components of the initial modeling results and would represent substantial investments. Given the scope of the investment it is important to understand the risks associated with the investment, and the cost of alternatives.
   - What additional studies will be required if the reliability tie or regional integration plan is selected? What would be the schedule for those studies?
   - For each portfolio that selects a transmission upgrade as part of a least-cost plan, NSPI should provide results demonstrating the incremental cost of the non-transmission option so the Board can balance the cost against the risk if the transmission investment is not fully utilized or if a lower cost option becomes available. This should be clearly considered within the decision process to choose a preferred portfolio.

c. **Renewable resource selection:** The Company assumes onshore wind is the primary renewable resource as part of the future portfolio. Other areas on the Atlantic coast of North America are focusing on offshore wind to provide resource diversity.
   - Did the Company's analysis fully incorporate the benefits of diversity of timing of production (e.g. through the ELCC analysis)?
   - If the costs of offshore wind come down considerably over the study period, are there planning decisions (such as transmission investments or conventional capacity additions) included in this IRP that would be rendered unnecessary? The Company should provide sensitivity modeling that would help understand this issue.

II. **Metrics**

a. **Stakeholder Input:** The metrics used for evaluating portfolios are critical assumptions to the IRP process. Now that the initial modeling is complete and stakeholders have greater understanding of the inputs and analysis, it would be useful to have a stakeholder exchange or technical session and the opportunity for written comments specifically focused on proposed metrics from NS Power. We offers the following additional comments:
   - Current proposed metrics appear to be revenue requirement minimization over a long horizon since the modeling calculated PVRR utilizing a real levelized capital cost recovery factor in modeling. We would like to see the corresponding values utilizing nominal accounting cost recovery or revenue requirements.
   - GHG metrics presented with initial modeling results include totals over the study period and includes some GHG Marginal abatement cost. The Company should provide annual GHG production metrics in tons and in percent of a baseline historical year emissions.

- The preliminary results included a metric calculating an average cost of generation, but the Company was uncertain as to whether it would be used going forward. The Company should provide metrics to help provide insight on affordability of each portfolio, perhaps showing annual cost of electricity impacts utilizing nominal capital cost carrying charges.
- Generally, the more capital a company commits to invest in a portfolio the greater the risk. The Company should provide a metric calculating total average capital investment requirements over the first five years, ten years and twenty years.
- It is important to have visibility on how much NS Power will be relying upon imported power as a metric, such as average annual imports over the first five years, ten years and twenty years.

b. **Metric Definitions:** The Company should provide written formulas and examples for the calculation of each metric used in the portfolio analysis.

c. **Scoring or Metric Trade-off Analysis:** The portfolio analysis will likely utilize some method of weighing (explicitly or implicitly) the various metrics when choosing or creating a preferred portfolio. The Company should provide a detailed description of how the various metrics will be used.

III. Stakeholder engagement: The Company has maintained extensive communication and stakeholder engagement efforts during the development of the pre-IRP deliverables, and we hope that going forward the process will remain transparent and collaborative. To that end, we recommend technical sessions or the opportunity for written comments on the following areas:

a. Metrics choice – Recommend written comments exchange after distribution of NS Power proposal. It is critical to finalize the metrics collaboratively before reviewing modeling results for findings.

b. Detailed review of analytical results – Recommend technical session, in particular detailing results of any analysis of system operations.

c. NS Power initial findings and conclusions – Recommend the Company issue findings and conclusions, solicit comments, and hold a stakeholder feedback and discussion session.

d. Road Map & Action Plan - Recommend the Company issue drafts, solicit comments, and perhaps hold a stakeholder discussion session. Assure that road map lays out all studies and approvals necessary and key decision points.

e. Report – Recommend the Company issue draft receive comments, incorporate comments into final and have all comments in an Appendix.

July 17th, 2020

Linda Lefler, P.Eng.
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RE: Comments on initial IRP modeling results

The following are comments from the Verschuren Centre for Sustainability in Energy and the Environment regarding the Initial Modeling results of the 2020 Integrated Resource Plan.

Stranded Assets

It seems counterintuitive that in modeling various net zero scenarios that the model has determined that building 764-1170MW of additional fossil fuel capacity is most appropriate. It should be expected that all of these assets would have minimal economic value in a zero carbon system, or after 2050.

Question:

1. Does the plexus model consider stranded assets in 2050 (beyond the planning horizon), especially for those units installed in 2040 in 2.x Scenarios?

Inertia

It seems that satisfying the inertia requirement of 3266 MW.sec minimum online requirement is a binding constraint in much of the IRP model decision making. The table on Page 8 of the modeling results indicates that inertia factors for wind energy and energy storage were not considered in the model. As wind energy and batteries are low cost sources of energy and carbon free capacity, the decision to exclude them will have negative impacts for customers. There is a growing body of evidence that suggests both technologies can contribute to system inertia.

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For Wind Energy, Hydro Quebec has been using wind turbines to provide synthetic inertia since 2015. [1] Many of the existing fleet of Nova Scotia wind turbines, including some of those owned by NS Power, are inverter-based machines that could provide this service. There are other examples of gearbox-based turbines being able to provide more physical inertia as well. Future requests for renewable energy could provide an adder for turbines that can provide this service going forward.

Since all Lithium Ion Battery systems would also have an inverter-based interface with the grid, they too would be able to provide synthetic inertia to the grid. Some utilities in North America are already seeing proven results from this effort, and others are starting additional testing:

- **Pacific Gas and Electric Company (PG&E) – NREL[2]**
    - EPIC 2.05 report – February 2019
    - From Page 10: "*The EPIC 2.05 project gave a more definitive form to a looming issue facing the evolving power system. A high penetration level of renewable energy significantly decreases the inertia of the PG&E transmission system and increases the occurrence of frequency violations during contingency scenarios. The project demonstrated great potential for novel control methods to enable inverter-based renewables to address this problem.*"
- **North America Electricity Reliability Corporation[3]**
    - Fast Frequency Response Concepts and Bulk Power System Reliability Needs – White Paper
    - Simulation results showing fast reaction response of inverters can provide enhanced frequency control in a low inertia environment compared to a synchronous resources system. – Page 11.
- **Independent Electricity System Operator – IESO – Ontario[4]**

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[1] IEEE Spectrum – "Can Synthetic Inertia from Wind Power Stabilize Grids?" – 2016 https://spectrum.ieee.org/energywise/energy/renewables/can-synthetic-inertia-stabilize-power-grids -

[2] EPIC Final Report – PG&E – March 2019 https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-2.05.pdf .

[3] Fast Frequency Response Concepts and Bulk Power System Reliability Needs - NERC Inverter-Based Resource Performance Task Force (IRPTF) - White Paper March 2020 https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf

[4] IESO - http://www.ieso.ca/en/Get-Involved/Innovation/Projects

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- Demonstration Project- Alternative technologies for regulation (ATR) program
- Purpose: Use ongoing work of ATR program to determine the merits of two new wholesale market products that leverage the fast-ramping capabilities of energy storage: fast regulation service and synthetic inertia service.

Questions/Requests:

2. Please provide indication of where in the modelling the Inertia Constraint was binding and resulted in a choice of fossil fuel generator over batteries
3. Did the inertia constraint impact the decision process of the Diesel CT Screening?
4. Please consider a screening, which evaluates a 3.x scenario with inertia qualities applied to existing wind turbines, future wind turbines, demand control and battery resources.

Thank you in advanced for the continued opportunity to contribute to this Integrated Resource Plan process, and we look forward to continuing the process later this summer,

Sincerely,

Daniel Roscoe, P.Eng
Lead – Renewable Energy
Verschuren Centre for Sustainability in Energy and the Environment