NS Power IRP

Comments received from Participants in response to Interim Modeling Results

May 2020

Resource Insight Inc.

MEMORANDUM

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

From: John D. Wilson and Paul Chernick

Date: May 7, 2020

Subject: Comments on Interim Modeling Progress

1. NS Power's planned reflection of the recession is inadequate.

The current economic downturn will reduce NS Power's load this year. Already, FAM data show that NS Power's retail sales are down by roughly 5%, which is consistent with impacts across the North American power sector.

North American utilities are seeing residential loads increase, while commercial and industrial loads are seeing sharp decreases. As the recession deepens, residential loads may be maintained at above-average levels but the impact on commercial and industrial loads is only likely to worsen.

NS Power will not be able to directly observe the effect of the recession on peak demand until next winter. But it is possible to infer the range of likely outcomes from current trends and historical reactions to economic shocks.

Residential contribution to system peak loads are not likely to increase by the same percentage as energy use. Anecdotal evidence suggests that most increased residential demand is due to end uses such as plug load, hot water, and other uses that tend to be spread broadly through the day, rather than being concentrated in the evening winter peak. Home-heating loads, which are the peakiest residential load, are unlikely to increase substantially due to stay-at-home orders (since most people would be home in the evening, anyway, and additional afternoon occupancy will tend to leave homes warmer going into the evening peak) and unemployment (since tighter budgets will encourage customers to reduce thermostat settings).

In contrast, commercial and industrial load decreases will likely reduce peak demand. Since many theatres, restaurants, stores, offices and factories will be closed, their loads (whether for lighting, space heating, or other equipment) will tend to fall at system peak hours, along the rest of the day. Business closures, many of which may be permanent, will radically reduce or even eliminate customer loads.

Absent an unlikely full medical and economic recovery by late fall, we cannot expect peak demand to return to pre-recession levels this winter. Experience indicates that load does not bounce back rapidly from deep downturns. The Great Recession's impacts on North American electric demand are particularly instructive as to how the post-COVID economic recovery might unfold.

The residential sector was the least affected by the Great Recession, but it took several years for residential electricity use to return to pre-recession levels. Today, the impact of the recession on demand is obscured by the demand bump due to stay-at-home guidance. When people return to work and other activities, the impact of the recession on residential loads will become more apparent, and residential demand will likely drop below pre-recession levels, at least until there is a significant economic recovery.

Commercial sales, which had been growing quickly before the Great Recession, bounced back, but then remained stable at roughly pre-recession levels. The much steeper downturn in business activity in the pandemic is likely to result in significant numbers of business closures, as well as depleted cash reserves for businesses and customers, even when economic recovery begins.

Industrial demand dropped the most during the Great Recession and never recovered. There is no reason to assume the current recession is not likely to be similar, leaving industrial demand below pre-recession levels for some years.[1]

In summary, each customer class appears likely to remain below pre-recession levels at least until the economy has substantially recovered. In total, probably for at least several years after the economic growth restarts.

NS Power's proposed approach to the recession's impact on load consists of the following:

- Selecting portfolios based on (among other options) the previously defined lower-load forecast cases, without any adjustment for the economic decline.
- Late in the process, evaluate the portfolios with even lower load sensitivities, to "validate" the results.

We do not believe these process adjustments are adequate.

[1] Efforts to shorten and diversify supply chains may shift the location of some manufacturing; it is not clear how this trend might affect Nova Scotia.

It is going to take a long time for electricity demand to recover to any of the three forecasts being used to develop resource portfolios in the IRP. Given the impact of the recession on electricity demand, the "Mid Electrification / Base DSM" and "High Electrification / Mid DSM" forecasts are unlikely to provide useful guidance for the next 5-10 years, at least. Without modification, the effort to model these two forecasts could be wasted effort.

Even the "Low Electrification/Base DSM" forecast may not be relevant to near- or mid-term resource planning decisions. A 5% drop in annual energy in 2020, followed by a 1% per year growth rate, would return to the low forecast in roughly 2026. A 10% drop in annual energy in 2020 would require a 2% per year growth rate to return to that path in 2026. At best, peak demand could return to the "Low Electrification / Base DSM" path within a 2-3 years.

If no changes are made to the three load forecasts, the resulting resource portfolios will not be optimized to the most plausible electricity demand in the near- and mid-term. Sensitivity runs to validate these portfolios under even lower load conditions could entirely miss a more optimal resource plan.

It could be argued that heating-driven peaks will be more resistant to economic downturn than energy use. In this scenario, system load factors would be different. Some generating units would be used much less. This could alter the cost-effectiveness of continuing to invest sustaining capital and fixed O&M in some existing units. It may be more cost-effective to meet capacity needs by advancing future resource investments.

If peak loads also remain significantly below pre-recession levels, then the resulting excess capacity could create conditions that would favor retiring existing units, especially coal units and the Mersey hydro system.

In either case, with unrealistic load forecasts, the portfolios may have uneconomic, excessive generation which will lead to inaccurate, low avoided costs. For that reason, the model is unlikely to provide useful guidance for near- and mid-term DSM investment decisions.

Accordingly, we recommend that NS Power develop a more expansive response to the impacts of the recession on present and future load.

2. *Further concerns about the load forecast.*

Based on information NS Power shared with us on April 8 and during the April 28 workshop, we continue to be concerned about the load shapes associated with electrification. Based on the graph shared on April 28, it appears that the energy added to shift from mid to high electrification has a load factor of roughly 50%. This seems appropriate for building electrification, but for transportation, there would likely be very little on-peak generation during a winter peak event, especially if rate design is updated to utilize the smart meters NS Power is installing.

Based on an email exchange with Chris Milligan following up on the April 8 call, we understand that NS Power is relying on a 2015 NYSERDA report to develop its peak load assumptions for some EVs, and the general system load shape for the rest.

It is difficult to understand how NS Power is applying the NYSERDA study to the load forecast. The load forecast states that there will be an average on-peak load of 1.3 kW/vehicle without mitigation measures and 0.6 kW/vehicle with some mechanism to discourage charging on peak.

According to the NYSERDA study, EV charging peaks in the early evening at about 1 kW per vehicle (p. 56). The 1.3 kW / vehicle figure corresponds to the off-peak scenario (p. 66) with the EV charging peak occurring in the hour ending at 1 AM. Off-peak charging levels in the NYSERDA that are coincident with NS Power's early winter evening peak would be around 0.25 kW per vehicle.

Furthermore, the 0.6 kW/vehicle figure doesn't seem to correspond to any of the aggregate charging load profiles in the NYSERDA study. Figure 25 shows a 0.6 kW/vehicle peak load for PHEVs a controlled charging scenario, with the peak occurring in the hour ending 6 PM. If this is the source for the 0.6 kW/vehicle figure, we don't understand the relevance.

We would like to see the load shape graph(s) for EV charging compared to the NS Power peak day load shape. The load forecast (Figure 13) gives two columns of peak data but there really isn't a clear explanation of how NS Power has mapped this to the baseline forecast, and definitely not an explanation of how this will be used in the electrification scenarios.

We also note that in its response to comments on IRP assumptions, NS Power did not respond to our suggestion to consider electrification in the industrial and marine sectors. **As NSP continues to refine the electrification assumptions, it should also evaluate electrification in the industrial and marine sectors.**

3. Flexible solar and hybrid resource technology options should be added to the model.

Previously, NSP declined to adopt our recommendation to add flexible solar and hybrid (RE+storage) resources to the model. This reduces the reliability and operational flexibility of renewable and storage resources, resulting in a greater preference for gas-fueled resources.

Flexible solar (e.g., solar that is curtailed in advance in order to provide upward dispatch flexibility in addition to downward dispatch), provides operational reserves that may be less expensive than operation of peaker units. In terms of reliability, NS Power's system inertia constraint will affect evaluation of must-take, uncoupled renewables, which do not provide inertia. More advanced wind and solar technologies would likely provide inertia.

We raised this issue in discussion with NS Power on April 8 and NS Power agreed to speak with Arne Olsen, their E3 consultant who happens to be the authority on flexible solar. **NSP should update intervenors as it explores this topic further.** We appreciate NS Power's willingness to explore this topic further and look forward to an update.

On a related note, we also raised the issue of the potential for wind and solar to be screened out in the initial capacity expansion modeling due their low assumed capacity benefit. Even though the "diversity benefit" will be assessed during the Reliability and Operability phases, it is not clear that there is a process for considering higher levels of wind and solar at that point if they have already been screened out. In the April 8 discussion, we received some assurance that NS Power will be sensitive to this point during the evaluation. **We request that this issue be explicitly tracked and documented as the evaluation proceeds.**

4. ELCC for other units.

During discussion, NS Power indicated that it has calculated ELCC values such that renewable and non-renewable resources are handled on an equivalent basis. We request that NS Power share these assumptions as soon as feasible.

On a related note, NSP previously declined to adopt our recommendation to use a longer averaging period for TUC DAFOR "to avoid subjectivity." We don't see the question as being one of subjectivity, but of realism. If the recent experience is a good predictor for the future, the recent DAFOR should be used in modeling. If the cause of recent reliability issues at TUC is unlikely to be repeated in any particular future year, a longer averaging period should be used. Overestimating DAFOR may result in an unnecessarily high reserve requirement, accelerated retirement of the gas steam plants, and excessive capacity acquisition. We raised this issue in discussion with NS Power on April 8 and NS Power indicated that this could be explored in a sensitivity test. **Unless NS Power has some reason for treating the recent high DAFOR as the base case, a longer base line should be used, and the recent anomaly should be treated as a sensitivity.**

5. Minimum inertia constraint.

In the follow-up from the April 8 call, NS Power explained that the minimum system inertia constraint is provided on p. 111 of the assumptions document. (We had interpreted that box as referring to the performance requirement for the synchronous condenser.) **Now that we have that clarification about the constraint, it would be useful for NS Power to provide the modeling assumptions for the inertia constraint**, especially how much each resource contributes to meeting this requirement and the nature of any operational restrictions (such as ramp rates, or the effect of generation output on inertia contribution) on that limit the contribution of each resources to meeting the constraint.

To: Nicole Godbout

From: John Esaiw

Date: May 12, 2020

Re: 2020 IRP - Interim Modelling Update Comments

On April 27th, 2020, NS Power released materials relating to an interim modelling update, as listed in the approved Terms of Reference for the 2020 Integrated Resource Plan ("IRP"). On April 28, 2020, NS Power hosted a technical session relating to these materials, which provided a forum for stakeholders and NS Power to discuss these interim results.

EfficiencyOne is pleased to provide comments relating to the interim modelling results released by NS Power in the sections below, together with comments on key issues.

The following recommendations and requests are detailed in relation to the information provided by NS Power:

1. Provide further updates on scenario modelling with draft results at such point as they become available, which would allow for a more substantive review in advance of the next stakeholder session.
2. Provide stakeholders with all inputs and outputs for Plexos LT for a sample Candidate Resource Plan, as part of the June 5 release of IRP modelling results.
3. NS Power draft, and provide, a schedule of engagement to the DSMAG for the facilitation of the Avoided Costs of T&D process. It is recommended the process meet certain minimum requirements in terms of stakeholder engagement, as further detailed in the body of this memorandum.
4. Modify qualitative assumptions for the contents of the DSM Potential Study, clarifying that the DSM Potential Study contains only estimates of programmatic DSM. NS Power's current assumptions do not reflect the methodology used to develop the 2019 DSM Potential Study.
5. Confirm the scope contemplated for energy efficiency (EE) through sensitivity analyses will include in many cases Mid DSM. In the event EfficiencyOne's understanding is incorrect, we request that NS Power use a sensitivity analysis methodology that, at minimum, meets the characteristics set out in the body of this document.
6. A recommendation that only one demand response (DR) case be permitted for selection for each eligible Candidate Resource Plan.

7. A recommendation against the use of small fragments of the DR cases (e.g. operation for a few years, cessation, restart), on the basis that costs and potential estimated were reflective of continuous operation as opposed to frequent starts and stops.
8. A recommendation that cost estimates be put in place for DER resource strategies.
9. Confirmation from NS Power that it will avoid cost comparisons across differing electrification scenarios, and to provide their stated means of selection amongst scenarios for the purposes of generating the avoided costs of capacity and energy – key inputs for DSM in Nova Scotia.

Substantive Modelling Progress and the Opportunity for Comment

NS Power has begun the modelling process associated with the 2020 IRP, and the 2020 IRP is leveraging new modelling software and analysis methods, which presumably increase the amount of time required for front-end model configuration, and other related tasks.

It is understood that the comparator case is substantially complete, and that some draft results for that case have been developed as part of the interim modelling update.

Given the lack of draft or interim modelling results available at this point in time, EfficiencyOne is requesting that NS Power provide scenario outputs and results to stakeholders as they become available.

Timely provision of this information would allow stakeholders to assess results from cases within the IRP, and to contemplate any potential desired revisions well in advance of the release of full modelling results, which form the quantitative core of the 2020 IRP. EfficiencyOne is concerned that without this interim provision of data, the time allotted for review, comment and discussion in June will not be sufficient to allow stakeholders to provide constructive and meaningful feedback to this process.

Data Transparency

Subject to the comments above regarding modelling progress, EfficiencyOne requests that all inputs and outputs for a sample Candidate Resource Plan be made available to stakeholders, accompanying any other data intended to be reviewed starting on that date. In particular, the requested information comprises all Plexos LT input and output data for a sample Candidate Resource Plan modelled and a sample treatment of DSM (based on Potential Study input scenarios). Any data that is considered proprietary can be treated on a confidential basis within the stakeholder group, or redacted in cases where required.

The release of input and output data will provide greater transparency to stakeholders regarding the fidelity of modelling relative to published assumptions, and allow for detailed review of modelling results. EfficiencyOne understands from its consultants that release of modelling data in a transparent fashion is common in other IRP related settings.

Development of T&D Avoided Costs

In its interim modelling update, NS Power has provided an update on its proposal for next steps with respect to the development of revised estimates for Transmission and Distribution Avoided Costs. As directed by the NSUARB[1], it is understood that the DSM Advisory Group (DSMAG) is intended to be the main forum for discussion of the development of these revised estimates, as clarified during the April 28 technical session.

In keeping with the process set out by the NSUARB, EfficiencyOne requests that NS Power provide a draft schedule of engagement to the DSMAG, as soon as reasonably practical, to aid in the facilitation of this process. EfficiencyOne is prepared to work with NS Power to assist in coordination of the process through the DSMAG.

The following key activities are recommended to be included in such a process:

1. Establishment of Terms of Reference for the development of T&D Avoided Costs, with direct input of the DSMAG.
2. Opportunity for substantive DSMAG discussion and a comment period leading to a consensus agreement of the DSMAG (if possible) in relation to the appropriate methodology for development of these avoided costs. Such a methodology should be reflective of broader industry practices, or best practices where possible.
3. All candidate methodologies to be presented prior to adoption (i.e. all quantitative details, calculations, etc.), in a manner where they can be recreated using publicly available information (e.g. ACE Plans).
4. The methodology also should include a defined process and timing for future updating and the administration of the new methodology for avoided costs of T&D.

Adoption of these measures in the development of avoided costs of T&D will provide stakeholder confidence in the use of these inputs in future regulatory proceedings including development of future DSM Resource Plans.

Interpretation of the DSM Potential Study

[1] M09471, 80788, Board Letter Re: Revised Methodology Should not Await Completion of IRP Process, Issued April 2, 2020, at Page 2.

EfficiencyOne remains concerned that NS Power's assumptions, surrounding what is, and what is not, contained in the scope of the 2019 DSM Potential Study, are not accurate and do not align with the development of the DSM Potential Study.

Page 55 of NS Power's Draft Assumptions Slide Deck, released January 20, 2020, notes the following:

- *The [2019 DSM Potential Study] scenarios are assumed to include all DSM, including:*
    - *Cost-effective electricity efficiency and conservation activities provided by the franchise holder*
    - *Initiatives that may be pursued by NS Power as permitted under the Public Utilities Act*
    - *Consumer behaviour and investments*
    - *Energy efficiency codes and standards*
    - *Initiatives undertaken by other agencies*
    - *Technological and market developments.*

On February 14th 2020, EfficiencyOne provided comments regarding this assumption. These comments were intended to correct this assumption and be reflective of the 2019 DSM Potential Study, which limits quantified impacts to programmatic DSM, and specifically excludes "natural DSM" (e.g. customer behaviour and investments, technological and market developments) and codes and standards.

In the final assumptions document, released March 11, 2020, there is reference to the same statement on page 59. This assumption is incorrect and should be updated to include only "Cost-effective electricity efficiency and conservation activities provided by the franchise holder" as part of the DSM Potential Study energy efficiency cases. Similarly, for demand response cases, the results should also be assumed to include "Initiatives that may be pursued by NS Power as permitted under the Public Utilities Act"; recognizing the role both parties have in pursuing demand response activities.

Inclusion of Mid-DSM in Scenarios

On March 6, 2020, in response to the Scenarios and Pathways documents released on February 14th, 2020, EfficiencyOne provided its suggested combinations of EE and DR cases from the 2019 DSM Potential Study associated with each scenario as proposed by NS Power. Related to those suggestions was the recommendation that enhanced analysis of DSM cases should be completed for high-performing DSM Resource Plans.

In response to our suggested inclusions, NS Power produced some modifications to the scenarios and cases initially proposed for modelling. The changes made are appreciated, however there remains a concern with respect to the lack of inclusion of the Mid-DSM energy efficiency scenario in any of the proposed cases. Mid-DSM is viewed as a more competitive scenario relative to Max DSM. Similar to the low-case scenario, Max-DSM serves as a "bookend" case. Max-DSM requires very high incentives and marketing activity to achieve the results found in the scenario.

NS Power advised stakeholders that it intends to perform a substantial portion of the exploration of DSM through a sensitivity analysis. In particular, that energy efficiency cases from the DSM potential study will be adjusted "up and down" by one level for each IRP scenario analyzed (i.e. for scenarios that contain Base EE, Low and Mid EE will be examined through sensitivity).

The approach addresses our concerns in terms of the exploration of DSM in the IRP, however, without any additional margin for further reductions to the scope of analysis.

It is understood that the sensitivity analysis methodology will have the following characteristics:

- Allow for the replacement of the original DSM (EE) case within the analysis with another explicitly defined DSM case (e.g. Base);
- Allow for optimization of the supply mix and reserve margin with each differing DSM (EE) case.
- Allow for the production of the avoided costs of energy and capacity using EE cases and scenarios as explored in the sensitivity analyses.
- Allow for the identification of a lowest NPV revenue requirement Candidate Resource Plan from within the sensitivity analysis (for a given electrification and distributed generation 'world').

Simply scaling costs and benefits by a multiplier is not deemed an adequate approach as it would involve the analysis of DSM levels not analyzed or provided by the 2019 DSM Potential Study, and without the support of the coherent analysis that the Potential Study was intended to provide. Without this validation, any conclusions founded on the sensitivity analysis results would not be reliable.

It is requested that the use a sensitivity analysis methodology, at minimum, meets the characteristics outlined above.

DR as a Resource Option

EfficiencyOne notes that NS Power plans to model the DR cases within the DSM Potential Study as a resource option rather than a load modifier. Clarification is requested on the following:

- Is NS Power maintaining the continuous (25-year) nature of the DR cases from the 2019 DSM Potential Study? If not, is there any tolerable bound to how fragmented DR operation is 'allowed' to become?
- How will the NS Power generated cases compete against cases from the Potential Study?
- Will all DR cases be allowed to compete in every scenario?
- Can multiple DR cases be allowed to stack? (e.g. one NS Power case, and one Potential Study case).

DR cases from the 2019 DSM Potential Study were intended to be used "one-at-a-time", as opposed to with any other DR activity present (e.g. the Base and High DR cases were not intended to be 'stacked'). For this reason, we are recommending only one DR case be allowed to be selected for each eligible Candidate Resource Plan.

In addition, we recommend against the use of small fragments of the DR cases (e.g. operation for a few years, cessation, restart), as the costs and potential estimated were reflective of continuous operation as opposed to frequent starts and stops.

Electrification and DG

EfficiencyOne is seeking clarification concerning inclusion of costs relating to Distributed Generation. In its final assumption set, NS Power indicated that "DERs will be accounted for in the model as a load modifier, with costs and benefits separately evaluated/discussed in the evaluation of each resource portfolio."

This assumption seemingly contradicts a comment from April 28, 2020, responding to a query, which indicated that such costs would not be included for DERs.

Clarification is requested on the approach to be used.

Should cost information not be included within DER resource strategies, this will likely require similar treatment as used for electrification scenarios, as revenue requirements will be incomparable for any case containing differing levels of DERs or electrification scenarios.

Having one of three resource strategies (i.e. DERs) incomparable to the other two (in-province generation, regional integration) within each incomparable scenario has the potential to void useful insights from the IRP modelling. For this reason, we strongly recommend that some form of cost estimate be included for DER resource strategies.

Confirmation is requested that NS Power will avoid cost comparisons across differing electrification scenarios, and to provide their stated means of selection amongst scenarios for the purposes of generating the avoided costs of capacity and energy – key inputs for DSM in Nova Scotia.

EfficiencyOne appreciates this opportunity to provide input to the development of the 2020 Integrated Resource Plan and looks forward to NS Power's response to the issues raised in these submissions.

Blackburn Law

VIA EMAIL

May 14, 2020

Linda Lefler
Nova Scotia Power

Dear Ms. Lefler,

Re: M08929 – April 28th, 2020 Stakeholder Session – SBA Comments

The Small Business Advocate (SBA) participated in the online IRP Stakeholder meeting on April 28th, 2020 and has the following comments about the update slideshow that was presented.

Slide 7 – Key Modeling Scenarios

The Comparative Scenario is a good scenario from which to start the planning. It should be thought of as more than just a comparison. It is important to have a scenario to evaluate resource options (multiple portfolios evaluated) that is not driven by any particular carbon reduction strategy beyond compliance with known regulations. The best portfolio under that scenario would be the pure least cost portfolio (the "Least Cost Portfolio").

Slide 8 – Key Modeling Scenarios (Table)

Consistent with our concern that there needs to be a Least Cost Portfolio developed under the Comparator Scenario, there is something lacking if there is no evaluation of the full use of economic DSM and economic Regional Integration under these scenario assumptions. Without a Comparator Scenario Least Cost Portfolio, NS Power will not be able to communicate the cost or value of the alternate strategies as well as making a fully informed decision.

It is unclear why is there no cases in in Scenario 2 or Scenario 3 without Regional Integration. Without a case that does not use Regional Integration we will not know the cost or value of Regional Integration. Is it that NSPI cannot meet the objectives of these Scenarios without Regional Integration? If so, that should be explicitly stated and an explanation provided as to why that is. We also require that details be provided about all costs performance and potential amounts of the various distributed generation that are assumed to be available when NSPI refers to Distributed Generation. It may have already provided, so if you could provide a direction to where that information is located, that would be of assistance.

T: 902-835-8544 F: 902-835-4310 E: info@blackburnlaw.ca www.blackburnlaw.ca
SUITE 231 BEDFORD HOUSE, SUNNYSIDE MALL, 1595 BEDFORD HIGHWAY, BEDFORD, NOVA SCOTIA B4A 3Y4

Slide 12 – Resolve Model Structure

The SBA is concerned that we do not fully understand how Resolve co-optimizes investments and operations. Over what period of years are the economics tested? If you could point to materials that describe this process in detail, as per the manner in which NSPI are setting its models to run, that would be beneficial.

Slides 17& 18 – T & D Avoided Cost Methodology Update/Next Steps

It appears that the next time we will see the T&D Avoided Cost analysis results is September, as per the bottom of slide 18. This is problematic. Stakeholders must see this information in the June modeling review sessions.

We believe these items are crucial in order to have the most informative IRP analysis possible. Please let me know if you have any questions or require any clarification.

Yours truly,

BLACKBURN LAW

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