wickwire holm
BARRISTERS SOLICITORS

April 7, 2014

VIA EMAIL

#55246-GAS

Nicole Godbout
Regulatory Counsel
Nova Scotia Power
1223 Lower Water Street
Halifax NS, B3J 3S8

Dear Ms. Godbout:

Re: M05522-2014 IRP Assumptions (DSM and Additional Details)

Efficiency Nova Scotia Corporation (ENSC) has reviewed the DSM and DR Assumptions – Levels and Costs, released by Nova Scotia Power Inc. (NSPI) on March 28, 2014. We appreciate the opportunity to respond and provide these written comments. For convenience, we set out below excerpts from your document, followed by our comments.

1. **NS Power proposes to model candidate resource plans that include various levels of DSM and Demand Response (DR).**

ENSC agrees with NSPI's approach.

2. **DSM levels. NS Power proposes to model a range of different candidate resource plans that have one of three different levels of DSM:**
   - **High Case from ENSC/Navigant January 2014 DSM Potential Study**
   - **Low Case from ENSC/Navigant January 2014 DSM Potential Study**
   - **50% Low Case from ENSC/Navigant January 2014 DSM Potential Study**

ENSC strongly objects to NSPI's selection of an inappropriate scenario to be modelled. ENSC was not consulted during the process of selecting which three scenarios would be proposed, despite the UARB's letter of January 9, 2014 to ENSC and copied to NSPI, stating that the Board "expects NSPI will consult with ENSC at various stages throughout the IRP development process to ensure that DSM input assumptions are appropriately included within the Strategist modelling scenarios."

1801 Hollis Street
Suite 2100, PO Box 1054,
Halifax, NS B3J 2X6

Tel 902.429.4111
Fax 902.429.8215
wickwireholm.com

The three DSM scenarios proposed by NSPI do not include ENSC's least-cost DSM scenario, and one of the scenarios was created by NSPI instead of coming from ENSC's DSM Potential Study.

The least-cost DSM scenario is ENSC's Base Case, which has a first-year unit cost of \$0.419/kWh; this translates into a conservative lifetime unit cost of \$0.032/kWh (using the portfolio average measure life of 12.96 years as calculated by Navigant's EERAM tool based on the DSM Potential Study). ENSC would make this Base Case the highest priority for inclusion in IRP scenario planning. The Low and High scenarios selected by NSPI have lifetime unit costs of \$0.034 and \$0.042, respectively, and should also be included.

If NSPI believes it is necessary to limit the number of levels of DSM included in the candidate resource plans, ENSC agrees with modeling the Low and the High Case, which would provide a broad range of options. However, ENSC strongly disagrees with the inclusion of a scenario (i.e., 50% of Low Case) that has not been researched, benchmarked, and modelled and as a result, is not part of the DSM Potential Study. For the third level of DSM, ENSC recommends the inclusion of the Base Case, as it contains a future consistent with ENSC's past performance and is viewed by ENSC to be the most robust, as well as cost-effective, case.

To minimize the utility's revenue requirements, the IRP analysis must be constructed to select all DSM that is more cost effective than the supply side alternatives, which could include capital expenditures to extend the life of thermal generating units. To ensure this requirement is met, ENSC recommends that the IRP analysis include scenarios for early retirement of generation assets, where sustaining those assets is not the most cost effective alternative for ratepayers.

3. **NS Power believes that the ENSC/Navigant January 2014 DSM Potential Study warrants review and vetting by stakeholders in a separate regulatory process at a future date. NS Power considers this data to be sufficient for IRP purposes.**

ENSC agrees that the data from the DSM Potential Study is sufficient for IRP purposes.

ENSC filed its DSM Potential Study in January with the primary purpose of providing relevant data for the IRP to fully consider Achievable Demand-Side Resources as an alternative to Supply-Side Resources. The study identifies four varying levels of Achievable DSM Potential and presents each of these scenarios in components of Residential, Commercial and Industrial, along with costs, peak demand savings and energy savings for each year of the IRP Planning Period.

The Base scenario presented in the Study is based on ENSC's proven track record of cost effectively achieving energy savings in Nova Scotia, and the alternate scenarios presented use the Base as a starting point, analyzing the impacts of varying incentive levels for DSM.

ENSC disagrees with the notion that its DSM Potential Study should be reviewed in a separate regulatory process at a future date. The purpose of its DSM Potential Study is to inform this current IRP process. ENSC will use the IRP to guide the direction of its future DSM Plans. These future Plans will involve separate processes that incorporate new inputs resulting from the 2014 IRP.

4. **DR levels. In addition to the reductions in peak demand associated with each of the DSM levels, NS Power proposes to model several direct load control solutions to mitigate peak demand and provide some ancillary services. These DR assumptions do not preclude the utilization of other customer solutions as a resource in the future.**

ENSC agrees with the general proposal to model DR within the IRP. However, we agree with the Consumer Advocate and the Industrial Group that NSPI should provide more detail on the various DR options for stakeholders to comment on, including detailed assumptions and sources, as ENSC provided in its DSM Potential Study.

ENSC also notes that NSPI's promotion of heat pumps to convert oil heat customers to electric heat is both increasing the system peak demand and increasing electrical energy consumption. With NSPI's new concern over Capacity and Demand Response Initiatives, ENSC expects that this would translate into upward pressure on avoided costs once the new Avoided Costs are developed through a stakeholder consultation process during this IRP. If the rationale for DR is to mitigate the effect that intermittent supply resources have on regulating system capacity, then the IRP should consider that the costs of such intermittent supply resources are directly linked to the associated DR costs.

5. **NS Power proposes to calculate the revenue requirements of candidate resource plans that include DSM using the total cost of that DSM. These costs, referred to as Total Resource Costs (TRC), consist of the DSM program administrator costs plus the customer costs, i.e., costs paid by participants in those programs.**

   NS Power is proposing this approach consistent with the TRC, previous IRPs and with the IRP treatment of DSM in other jurisdictions that use TRC as a primary test. The TRC is the predominant cost effectiveness test used for screening in North America. The TRC is the test currently accepted by the UARB.

> **For information purposes, NS Power will also calculate the revenue requirements of candidate resource plans that include DSM without customer costs.**

ENSC disagrees with NSPI's proposed approach of inflating the total utility costs of DSM by adding customer costs.

- Such an approach is in direct violation of the objective function of the approved Terms of Reference for the 2014 IRP. The Terms of Reference identifies the objective function as the minimization of the cumulative present worth of the annual revenue requirements over the planning period.

- Revenue requirements, by their very definition, are the amounts that must be recovered from customers to cover the utility's costs.

- For Demand Side Management resources, the DSM Program Administrator costs fully represent those amounts that must be recovered from the utility's customers and, as such, are the full utility revenue requirements associated with DSM.

- Participation in DSM programs is voluntary. Only the DSM Rate Rider is mandatory and this alone represents the utility's investment in Demand Side Management resources to offset the need for Supply Side Resources.

- When individuals or businesses volunteer to participate in DSM programs they are doing so for their own personal or business interests. The fundamental concept of DSM programming is to provide incentives to program participants that are just enough to cause them to decide to implement an energy efficiency measure. The clear distinction here is that the utility's portion of the cost (i.e. incentive amounts plus program administrator costs) is the amount invested by the utility to offset electricity system supply-side costs, and the participant's portion of the cost (above and beyond their rate rider cost) is the amount invested voluntarily by them for a wide variety of their own reasons; examples include increasing the insulation of their home for comfort, improving the quality of lighting in their commercial building, or improving the efficiency of their industrial processes. For certain, the individuals and businesses participating in DSM programs are not investing their own dollars (above and beyond their rate rider cost) for the purpose of offsetting the utility's cost of supply-side resources.

- It would be fundamentally and logically flawed, as well as mathematically incorrect, to proceed with the approach that NSPI has proposed to calculate its revenue requirements associated with DSM resources.

- Customers actually incur a net benefit as opposed to a net cost. Their costs of participating in DSM programs are significantly more than offset by their savings of lower power bills, as provided for in Attachment A. ENSC is providing these net customer benefits for illustration purposes only and asserts that it would also

> be incorrect for NSPI to deflate their total utility costs of providing DSM by subtracting customer net benefits.

NSPI is correct that its proposed approach is consistent with the approach taken in the 2007 and 2009 IRPs. However, these should not be taken as appropriate precedents because of the reasons the TRC approach was addressed by NSPI in 2009. In 2009, the Ecology Action Centre pointed out that "If the IRP only wishes to optimize with respect to the electric system, then the IRP should use a utility cost test rather than a TRC test which counts all resources." NSPI's response was that "since DSM is a cost-effective option compared to supply alternatives, the model will pick DSM over other alternatives. The suggestion to either enhance the benefits associated with DSM or to use the utility costs instead of total costs would increase the attractiveness of DSM versus supply options. The DSM as projected will be in the Reference plan and increasing the economic attractiveness of DSM will not change that outcome" (NSPI's 2009 Integrated Resource Plan Update Final Report. Appendix F, Attachment 1, p.6). In other words, NSPI's only argument was that including customer costs did not matter, not that it was correct. Including a calculation that is incorrect but doesn't matter is not one that ENSC believes should be incorporated within this IRP, and it is not one that should be used to set a precedent.

NSPI is correct that TRC is the predominant cost-effectiveness test used for screening DSM programming in North America. However, the traditional TRC test is not predominant among leading DSM jurisdictions in North America.[1] Over the past year, ENSC has engaged Dunsky Energy Consulting to help advise on best practices and has been working closely with the DSM Advisory Group in advancing our thinking on such concepts and methodologies. ENSC agrees that the TRC test is the one currently accepted by the UARB. ENSC also agrees that this is an item that warrants further review and full vetting by stakeholders in a UARB regulatory process at a future date rather than during the IRP. However, ENSC wishes to reiterate that there is a distinction between cost-effectiveness screening, which takes place within DSM modeling software, and least-cost analysis, which takes place within IRP modeling software.

It should be pointed out that all of the "Achievable DSM Potential" put forward in the Scenarios of ENSC's DSM Potential Study has already been screened for cost-effectiveness using the TRC test within the DSM modeling software. In addition, should NSPI include customer costs for DSM (despite the fact that doing so is in opposition to the IRP Terms of Reference and provides an inconsistent comparison between supply and demand-side options), the unit costs of the Low and High scenarios would be the two highest costs of ENSC's four scenarios: they are $0.070/kWh and $0.078/kWh, as compared to the Base scenario of $0.056/kWh.

---

[1] As provided in Dunsky Energy Consulting's report, "Appropriate Treatment of DSM in Integrated Resource Planning (IRP)", filed on January 29, 2014 as part of ENSC's comments on NSPI's 2014 IRP Terms of Reference.

In contrast, for Supply-Side resources, the notion of cost-effectiveness pre-screening does not exist. It does not exist because the IRP analysis is one that inherently determines the least- cost of viable resource alternatives for the utility.

6. **For information purposes, NS Power will also calculate the revenue requirements of candidate resource plans that include DSM without customer costs.**

ENSC requests confirmation that the calculation of revenue requirements of candidate resource plans will occur at a point in the process in which stakeholders can provide input that may influence which revenue requirement calculation (with or without customer costs) is included in the IRP outputs.

7. **Consistent with the treatment of supply side options, NS Power will apply its after-tax WACC as the discount rate for DSM.**

ENSC agrees with NSPI's approach for the purpose of this IRP. ENSC believes that this issue warrants review and full vetting by stakeholders in a DSM regulatory process at a future date.

8. **Slides 5 & 6**

ENSC requests that NSPI provide the detailed assumptions, including all source data, references, documents and spreadsheets that were used in preparing the graphs on Slides 5 and 6 and provide stakeholders with an opportunity to comment on them.

Summary of ENSC's Comments

1. ENSC recommends that NSPI use the DSM scenarios of ENSC's DSM Potential Study that have been researched, benchmarked and modelled by ENSC for input to the IRP analysis. ENSC's DSM Potential Study should not be deferred to a separate regulatory process. If NSPI needs to limit the number of scenarios to three, ENSC recommends the Base, Low and High Case DSM potential scenarios.

2. In order to minimize utility revenue requirements, ENSC recommends that the IRP analysis be constructed to select all DSM that is more beneficial to ratepayers than supply-side expenditures, including those expenditures intended to avoid retirement of NSPI assets, as well as an examination of the cost-effectiveness of early retirement of existing generation.

3. NSPI is requested to provide detailed assumptions and sources for the direct load control solutions intended to mitigate peak demand or to provide ancillary

services, and that stakeholders be given adequate opportunity to assess and direct the selection of these options.

4. The stakeholder consultation process on the development of Avoided Capacity Costs, to be conducted in accordance with the IRP Terms of Reference and ENSC's 2013-2014 DSM Plan Settlement Agreement, is expected to allow for appropriate reflection of NSPI's acknowledgement of the value provided by demand response and customer peak reduction initiatives.

5. NSPI should not inflate the total utility costs of DSM by adding customer costs.

6. ENSC requests confirmation that the calculation of revenue requirements of candidate resource plans will occur at a point in the process in which stakeholders can provide input that may influence which revenue requirement calculation (with or without customer costs) is included in the IRP outputs.

7. NSPI is requested to provide the detailed assumptions, including all source data, references, documents and spreadsheets that were used in preparing the graphs on Slides 5 and 6 and provide an opportunity for stakeholders to comment on them.

As always, we appreciate the opportunity to provide our comments and look forward to our continued involvement in the IRP process.

Yours very truly,

WICKWIRE HOLM

Geoffrey A. Saunders

Direct Dial: 902.482.7005
gsaunders@wickwireholm.com

GAS/

c. Participant List

ATTACHMENT A

Total All Sectors Achievable Potential (Net-at-Generator) with Net Customer Costs[1]

	Base Scenario									
	Program Administrator Costs ($ millions)		Customer Costs ($ millions)		Energy Savings GWh		Customer Power Bill Savings ($ millions)		Net Customer Costs ($ millions)	
Year	Incremental	Cumulative	Incremental	Cumulative	Incremental	Cumulative	Incremental	Cumulative	Incremental	Cumulative
2015	$50.70	$50.70	$37.90	$37.90	137.8	137.8	$ (16.8)	$ (16.8)	$ 21.1	$ 21.1
2016	$50.50	$101.20	$39.90	$77.80	139.9	226.1	$ (27.6)	$ (44.4)	$ 12.3	$ 33.4
2017	$50.00	$151.20	$41.20	$119.00	141.7	360.8	$ (44.0)	$ (88.4)	$ (2.8)	$ 30.6
2018	$52.40	$203.60	$41.60	$160.60	136.2	480.3	$ (58.6)	$ (147.0)	$ (17.0)	$ 13.6
2019	$57.00	$260.60	$32.20	$192.80	134.8	597.4	$ (72.9)	$ (219.9)	$ (40.7)	$ (27.1)
2020	$61.50	$322.10	$28.00	$220.80	133.9	708.9	$ (86.5)	$ (306.4)	$ (58.5)	$ (85.6)
2021	$56.90	$379.00	$28.40	$249.20	130.1	817.1	$ (99.7)	$ (406.1)	$ (71.3)	$ (156.9)
2022	$54.10	$433.20	$28.40	$277.60	127.6	932.3	$ (113.7)	$ (519.8)	$ (85.3)	$ (242.2)
2023	$51.50	$484.70	$29.20	$306.80	126.6	1,040.9	$ (127.0)	$ (646.8)	$ (97.8)	$ (340.0)
2024	$50.80	$535.50	$28.60	$335.40	127.4	1,155.4	$ (141.0)	$ (787.8)	$ (112.4)	$ (452.4)
2025	$50.60	$586.10	$29.90	$365.30	130.1	1,257.1	$ (153.4)	$ (941.1)	$ (123.5)	$ (575.8)
2026	$52.10	$638.30	$33.80	$399.10	135.6	1,371.0	$ (167.3)	$ (1,108.4)	$ (133.5)	$ (709.3)
2027	$54.80	$693.00	$36.80	$435.90	143.5	1,509.5	$ (184.2)	$ (1,292.5)	$ (147.4)	$ (856.6)
2028	$58.50	$751.50	$41.40	$477.30	153.4	1,644.6	$ (200.6)	$ (1,493.2)	$ (159.2)	$ (1,015.9)
2029	$60.70	$812.20	$34.00	$511.30	163.3	1,797.6	$ (219.3)	$ (1,712.5)	$ (185.3)	$ (1,201.2)
2030	$63.10	$875.30	$37.20	$548.50	170.7	1,956.3	$ (238.7)	$ (1,951.2)	$ (201.5)	$ (1,402.7)
2031	$62.60	$937.90	$40.60	$589.10	173.5	2,112.9	$ (257.8)	$ (2,208.9)	$ (217.2)	$ (1,619.8)
2032	$61.40	$999.40	$40.80	$629.90	171.4	2,266.2	$ (276.5)	$ (2,485.4)	$ (235.7)	$ (1,855.5)
2033	$59.30	$1,058.70	$41.40	$671.30	166.0	2,415.4	$ (294.7)	$ (2,780.1)	$ (253.3)	$ (2,108.8)
2034	$56.70	$1,115.40	$41.70	$713.00	159.3	2,560.6	$ (312.4)	$ (3,092.5)	$ (270.7)	$ (2,379.5)
2035	$47.70	$1,163.10	$48.40	$761.40	153.0	2,699.4	$ (329.3)	$ (3,421.8)	$ (280.9)	$ (2,660.4)
2036	$46.50	$1,209.60	$48.00	$809.40	147.0	2,833.1	$ (345.6)	$ (3,767.4)	$ (297.6)	$ (2,958.0)
2037	$45.40	$1,254.90	$47.60	$856.90	141.5	2,955.0	$ (360.5)	$ (4,128.0)	$ (312.9)	$ (3,271.0)
2038	$44.40	$1,299.30	$46.80	$903.70	136.1	3,080.8	$ (375.9)	$ (4,503.8)	$ (329.1)	$ (3,600.0)
2039	$43.50	$1,342.80	$46.30	$950.00	131.6	3,197.5	$ (390.1)	$ (4,893.9)	$ (343.8)	$ (3,943.8)
2040	$42.30	$1,385.00	$46.30	$996.30	127.9	3,308.7	$ (403.7)	$ (5,297.6)	$ (357.4)	$ (4,301.2)

[1]For illustrative purposes only, so no escalation has been applied to 2013 rates.