STEWART McKELVEY
LAWYERS • AVOCATS

Purdy's Wharf Tower One, 900 – 1959 Upper Water Street, P.O. Box 997
Halifax NS B3J 2X2 Canada tel: 902.420.3200 fax: 902.420.1417 stewartmckelvey.com

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Nancy G. Rubin, Q.C.
Direct Dial: 902.420.3337
nrubin@stewartmckelvey.com

September 19, 2014

Delivered by E-mail – tim.wood@nspower.ca

Tim Wood
Nova Scotia Power Inc.
P.O. Box 848
Halifax, NS B3J 2V5

Dear Mr. Wood:

Re: M05522 Integrated Resource Plan (IRP)

This letter and the attached comments from Drazen Consulting Group are submitted on behalf of the Industrial Group with respect to the draft Analysis Results. NSPI has requested input on the relative weighting to be assigned to the factors to select the "preferred plan" (or any additional factors) and comments on the proposed "Action Plan". In addition, NSPI indicated it would be receptive to requests for additional analyses or comparisons.

At the outset, we commend NSPI's efforts to compile the extensive information in an understandable graphic format which facilitates comparisons across the various CRPs. That said, distribution of the Analysis Results did not occur until two days before the Technical Conference and there has been insufficient time on our part to fully evaluate and understand the modeling and assumptions. Our impression is that both NSPI and stakeholders would benefit from additional time to have some questions addressed and for NSPI to carry out some of the studies identified as part of its Action Plan before selecting a course of conduct and preferred Plan.

"No Regrets"

It is noted that many of the CRPs look the same for a number of years before they diverge. It would be helpful for NSPI to produce an analysis and graphic to demonstrate the point of divergence i.e. the year and what decision needs to be made at that point. The Industrial Group supports NSPI's "no regrets" approach given that the only certainty is that there is no certainty in the long term.

It is expected that NSPI will be continuing to carry out regular (5-6 year) updates to the IRP, so the Industrial Group recommends a focus on the CRPs which yield the lowest costs out to 2020; these are characterized by maximum coal, currently committed levels of wind and Base Case or Low Case DSM (or some optimum combination discussed further below). Assuming there are no regrets, this would provide sufficient opportunity in future to re-evaluate and change course if some assumptions do not bear out or there is a significant change in the market.

The Industrial Group does not believe that there is sufficient certainty in the long term to place any weight on the NPV over the Study Period (to infinity). Examples of events that could alter the fuel outlook considerably would be the reopening of the Donkin mine in Sydney (potentially requiring the addition of a scrubber at Lingan), the potential for a significant offshore gas discovery by Shell/Chevron and expansion of the Tennessee pipeline with large volumes of Marcellus shale gas being made available.

Demand Side Management (DSM)

At slide 11 of the Analysis Results, NSPI has observed (#11) that a variable DSM spending profile has the potential to lower rate pressure in the near term (five years) while being competitive on a planning period NPV basis. In making observation #11, it is unclear whether NSPI has considered the scalability of DSM from the perspective of ENSC and its service delivery.

It appears from the results that there are near term cost benefits to a lower level of DSM but higher costs in the long term if this lower level is sustained (slide 26). There are, however, clear operational advantages to lower levels of DSM investment as identified in the Plexos work through to 2030 (slides 46-48) – minimum curtailment and uneconomic exports of excess energy and maximum economic Maritime Link and NB energy purchases.

The Industrial Group requests that NSPI model an optimum DSM spending profile on a variable basis, having regard to any operational constraints (on the part of NSPI and ENS). It is understood that NSPI and ENS will be negotiating an agreement for the delivery of efficiency programs on three year terms so the ultimate level of DSM will be determined in that process and approved by the Board; nonetheless, for planning purposes, it would be helpful to understand the implications of an optimum variable DSM spend.

Secondly, with respect to DSM, in NSPI's memo to IRP stakeholders of July 30, 2014, NSPI stated that it would be modeling a sensitivity in relation to higher DSM costs i.e. an S8 sensitivity analysis would be performed by increasing the cost of the DSM program and run across all CRPs. Nowhere in the Analysis Results of September 12, 2014, does it show this sensitivity.

The Industrial Group requests that NSPI run a sensitivity of both higher and lower costs of DSM per MWh and also higher and lower achievable energy and demand savings for the same DSM dollar investment (Base, Half Low).

Combining CRPs

NSPI noted at slide 13 that "the best performing aspects of several CRPs may be combined to inform development of a robust Resource Plan that is adaptable to future regulatory supply, and demand side requirements, while being sensitive to accuracy of system assumptions in the outer years." Please clarify how NSPI proposes to combine the CRPs, which have been identified as "best performing".

Action Plan

While the Industrial Group does not take issue with the items listed, insofar as we concur they should be completed and many are simply compliant with legislative requirements, the timelines for completion should be clarified.

With respect to "Renewable Resources" (slide 19), it notes that the Mersey redevelopment capital application will be undertaken for filing with the Board. This seems to presuppose that such an application will be filed but the Mersey upgrade is not a component of all CRPs. NSPI should clarify its operational necessity and the costs as part of its evaluation of the IRP.

A number of items are proposed to form part of the 10 Year System Outlook report (tidal energy; operational challenges regarding variable generation; need for flexible resources to integrate additional variable generation; regional market opportunities, balancing and interconnection; retirement forecast for existing thermal fleet; planning reserve margin). Historically, this has never involved a stakeholder component. The Industrial Group recommends that stakeholders be offered the opportunity to comment before finalization of the Report.

Thank you for the opportunity to submit these comments and we look forward to the additional analysis requested.

Yours truly,

Nancy G. Rubin

NGR/lmc

cc IRP Stakeholders

att. – Drazen Consulting Group Comments

NOVA SCOTIA POWER

Comments of the Industrial Group Comments on 2014 IRP

NSPI's presentation leaves some issues unclear or unanswered.

Slide 4: Developments Since Previous IRPs

This slide shows:

Loss of industrial load ~165 MW – 1,100 GWh
Industrial load on LR tariff: ~185 MW – 1,050 GWh

Comments:

Does lost load include NewPage, Bowater, Michelin and Imperial? Anything else? Is LR all PHP? If so, why is it nearly equal to the loss of industrial load?

The treatment of LR load for planning and operating purposes was left unclear. The response to the question at the meeting was that the LR load is included during the LR contract period and zero thereafter. The CRPs should assume zero LR load throughout.

Slide 10: Key Observations

Point 4: *If DSM delivery beyond 2020 does not meet the DSM forecast then the system will experience reliability and environmental/emissions challenges.*

Comment:

What does "not meet the DSM forecast" mean? (1) That less-than-forecast DSM is installed? Or (2) That installed DSM does not reduce usage as much as expected? Or?

Slide 15: Comparison of Partial Revenue Requirements Graphs (graphs on Slide 16)

1st bullet: *NS Power believes customers are concerned with affordability particularly in the short term.*

4th bullet: *These costs do not encompass NS Power's total revenue requirement. They include only a portion of the costs such as fuel and purchased power, thermal and hydro unit O&M, capital costs for new resources added in the CRP and DSM program administrator costs.*

5th bullet: *The graphs do not include other cost items that would be common among all CRPs such as remaining O&M, regulatory adjustments/amortizations, interest and tax impacts.*

Comment:

What are the dollars in each case? Since NSPI recognizes that customers are concerned with affordability, it would make sense to get a feel for the potential levels of rates.

Slide 21: Draft Action Plan Items (cont'd)

2nd major bullet: Planning Reserve Margin

> *Report on the ongoing evaluation of the appropriate planning reserve margin for the power system in the 10 Year System Outlook Report*

Comments:

What will NSPI evaluate? NSPI stated that it uses the "1 day in 10 years" criterion. (Presumably, it means that NPCC uses it.) We are aware that NPCC currently specifies a 20% reserve margin for the Maritimes. However, it is not clear whether NSPI (or any other Maritimes utility) has ever questioned this or raised the issue with NPCC. It appears that there has been no evaluation of whether this is the best criterion (there are others, such as EENS – Expected Energy Not Served or LOLH – Loss of Load Hours), nor whether it translates into a 20% reserve margin.

Has NSPI reviewed other utilities' analysis of the economically-appropriate reserve margin?

How would the CRPs be affected by different levels (e.g., 15%)?

Background:

Reliability is fundamentally an economic concept—the cost to customers of outages versus the cost of extra capacity--so it is logical to analyze the potential cost savings of a lower reserve margin.

A 2012 study by The Brattle Group for the Electric reliability Council of Texas (ERCOT) explained:

> Consistent with industry practice, ERCOT's reliability target for the bulk power system is based on LOLE, or the frequency of expected firm load shed events caused by supply shortages. For decades, the utility industry has used a 1-day-in-10-years bulk power standard for setting target reserve margins and capacity requirements. While the origin of the 1-in-10 metric is unclear, references to the standard appear as early as the 1940s. **Usually, utilities and system operators offer no justification for the reasonableness of 1-in-10 other than that it is the industry standard or that it is consistent with NERC guidelines.** Because customers rarely complain about bulk power reliability under the 1-in-10 standard and system operators and policymakers generally are not faulted if they adhere to long-term industry practices, few question 1-in-10 as an appropriate standard.
>
> It is also helpful to understand that the 1-in-10 standard is not applied uniformly throughout the industry. For example, ERCOT and many other system operators interpret the 1-day-in-10-years standard as "1 outage event in 10 years," while other

system operators such as SPP interpret the 1-day-in-10-years standard as "24 outage hours in 10 years." While the two interpretations sound semantically similar, the level of reliability they impose differs significantly. As shown in a recent case study of a 40,000 MW power system, the former definition requires a 14.5% reserve margin, while the latter requires only 10%.

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Despite these considerations, **little empirical work has been done in the industry to quantify the economics of the 1-in-10 criterion** to confirm that it reasonably balances the tradeoffs between the economic value of reliability and the system capital costs imposed.

http://www.ercot.com/content/news/presentations/2012/Brattle%20ERCOT%20Resource%20Adequacy%20Review%20-%202012-06-01.pdf

Other utilities that have studied the issue have found that a reserve margin lower than 20% is appropriate. An example is Southern Company's 2010 IRP analysis:

1.10 RESERVE MARGINS

After an analysis of load forecast and weather uncertainty as well as the current and near-term projected generation reliability of the System, the Company has selected a target reserve margin of 15 percent in the long term, which is near the minimum total cost but carries less risk than the absolute minimum cost point. For the short-term horizon, the Company will maintain a 13.5 percent planning reserve margin guideline, but may periodically review the availability and cost of resources in the market and adjust short-term resource procurement decisions accordingly.

http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=125981