Introduction

EfficiencyOne appreciates the opportunity to provide comments on NS Power's 2020 Integrated Resource Plan (IRP) draft Analysis Plan and Assumptions Set.

EfficiencyOne submits the following comments, questions and recommendations. The comments of Energy Futures Group, consultant to EfficiencyOne are included as Attachment "A" and are incorporated by reference to EfficiencyOne's submissions.

1. Evaluation Criteria

Slide four of the draft Analysis Plan described seven proposed evaluation criteria that NS Power will use to rank Candidate Resource Plans (CRPs). EfficiencyOne understands that minimizing the 25-year NPV revenue requirement will be the primary metric for evaluation. However, it is unclear how the remaining metrics will be utilized or what importance will be given to them. Before moving into the modelling stage, it is critical that all stakeholders have a clear understanding of exactly how the evaluation criteria will be measured, when resource plans will be screened out, and what the criteria for screening will be. EfficiencyOne does not advocate for weightings to be applied to any criteria. NS Power weighting each criterion would be inherently arbitrary and therefore should not be used in this process.

EfficiencyOne strongly recommends the following:

- NS Power defines how each evaluation criteria metric will be quantified, so that it is clear to all stakeholders how the resource plans will be scored.
- NS Power commit to quantitively scoring all CRPs that pass the operability and reliability screening phases on all of the evaluation criteria so that stakeholders can have a complete view of resource plans.
- NS Power provides alongside the ranking of all CRPs the rationale for the ranking, detailing how the scores of the evaluation criteria were considered.

EfficiencyOne's comments on specific evaluation criteria as proposed by NS Power are as follows:

I. <u>Minimization of NPV of the annual revenue requirements over 25 years (slide four, row one)</u>

EfficiencyOne agrees that this is an appropriate evaluation criterion.

II. <u>Magnitude and timing of electricity rate effects (slide four, row two)</u>

EfficiencyOne is unclear how the stated evaluation metric of the 10-year NPV revenue requirement assesses the timing and magnitude of rate effects. Further, EfficiencyOne is unclear why a 10-year NPV revenue requirement is an important metric to evaluate, and if it is the best proxy for the magnitude and timing of electricity rate effects.

EfficiencyOne requests the following:

- Detail why a simple 10-year NPV of revenue requirement be used to evaluate rate impacts of the IRP.

III. <u>Reliability requirements for supply adequacy (slide four, row three)</u>

EfficiencyOne recommends the following:

- all CRPs that do not meet reliability requirements should be eliminated at the reliability screening stage; i.e., if they are truly "requirements" they should be evaluated on a pass/fail basis and not included in evaluation criteria.

The description for this evaluation criteria lists a number of metrics for consideration "PRM, resource capacity, operating reserve requirements, etc."

EfficiencyOne requests the following:

- NS Power confirm whether all metrics to be considered for this evaluation criteria are listed on slide 4, row three of the Draft Analysis Plan document. If not, please list all metrics that will be considered.

IV. Provision of essential grid services for system stability and reliability (slide four, row four)

E1 recommends the following:

- all CRPs that do not meet requirements for essential grid services be eliminated at the reliability and/or operability screening stages; i.e. if they are truly "essential" they should be evaluated on a pass/fail basis and not included in the post-analysis evaluation criteria.
- Any required integration costs (e.g. requirements for additional or supplementary grid services) to be considered in the cost of the IRP NPV.
- All grid services being assessed to be listed, and the specific evaluation criteria or thresholds assigned to each to be clearly defined.

V. Plan robustness (slide four, row five)

It is unclear how 'robustness' will be measured via a sensitivity analysis.

EfficiencyOne submits the following question:

- NS Power to confirm if it is possible to combine this metric with the 25-year NPV revenue requirement metric by assessing the NPV revenue requirement under both a high and low sensitivity analysis?

VI. Reduction of greenhouse gas and/or other emissions (slide four, row six)

EfficiencyOne agrees the emissions performance of plans is relevant, although some additional clarity is required if a comparative analysis is contemplated.

EfficiencyOne recommends the following:

- Total emissions for each CRP to be quantified and presented.
- Total emissions for each CRP be considered rather than the reductions compared to some undefined base case.
- If other types of emissions are to be considered as criteria such as mercury, SOx, NOx, these emission types to be listed, and metrics assigned.

VII. Flexibility

It is unclear how a "qualitative assessment of timing of investments" will be used as an evaluation criterion. EfficiencyOne appreciates that there may be benefit in not being locked into one path for investment timing; however there is a risk that this could simply push all major decisions to 25-

years out, and delay benefits of grid modernization and GHG emission reductions that cannot be captured in a revenue requirement.

DSM is a flexible resource in terms of the ability to adjust activity levels in response to changes in current conditions. It is unclear to EfficiencyOne how DSM is being considered in terms of its flexibility.

EfficiencyOne requests the following:

- NS Power clarify the specific metric that will be used to evaluate flexibility.
- NS Power clarify how flexibility will be scored for DSM (including energy efficiency and demand response).

2. Analysis Plan

EfficiencyOne requests the following additional detail on the draft Analysis Plan shared by NS Power:

- Clarify at which steps in the analysis, potential CRPs are being assessed for removal. For ease of reference, the stages of the analysis EfficiencyOne is referencing are found on slide one of the draft Analysis Plan document.
- Define the long-term strategy, roadmap, and near-term action plan in terms of their objective and how they will be used by NS Power for planning purposes.
- Clarify the data relationship between the long-term strategy, roadmap, and near-term action plan (i.e. how will the analysis results, and predecessor documents, "feed" into the subsequent documents described.) Does NS Power plan to base these reports on the quantitative findings of the modelling phase?
- Describe the process NS Power will follow in the event government passes more stringent environmental regulations relating to GHG emissions after the IRP is complete. How will it be determined if this change is a "decision gate"? If it is determined to be a "decision gate" would this lead to a reassessment of CRPs and a change in the Preferred Resource Plan?

3. Environmental

EfficiencyOne requests clarification on the following questions regarding NS Power's environmental assumptions:

- Does NS Power expect to sell excess GHG credits resulting from lower emissions? If yes, how will the cost of carbon (e.g. the market price of carbon reductions) be captured in the modeling process. Will revenues from the sale of carbon credits be accounted for in the revenue requirement calculation for each scenario?
- Is NS Power considering the CO2 emission hard caps as laid out in slide 17 of the assumptions set as business-as-usual? Will the Sustainable Development Goals Act be considered in a business-as-usual scenario?
- EfficiencyOne's understanding is that current air quality regulations go out to 2030. What causes the drop in emission hard caps for SO2 (slide 24) and mercury (slide 25) in 2035?

4. Calculation of DSM Avoided Costs Through a Preferred Resource Plan

EfficiencyOne understands that avoided costs due to DSM will be handled in the IRP as follows:

- Avoided energy and avoided capacity costs will be an output of the IRP, calculated through a difference-in-revenue-requirements (DIRR) method;
- Avoided transmission and distribution (T&D) costs will be an input to the IRP, extrapolating values calculated based on historical growth-related T&D expenditures; and
- Avoided costs of environmental compliance will be inherently included in the avoided energy costs, as any revenues or expenses associated with the sale or purchase of carbon credits would be included in the IRP as fuel-related costs.

If any part of the above description is incorrect or undecided, EfficiencyOne requests that NS Power provide clarification before the IRP modelling process proceeds.

<u>Importance of the Preferred Resource Plan</u>

It is critical that an output of the IRP is a Preferred Resource Plan. EfficiencyOne presumes this would be the highest ranked CRP based on the evaluation criteria NS Power has provided. EfficiencyOne understands the selection of a Preferred Resource Plan to be one of the primary objectives of an IRP. In correspondence to NS Power in the course of the 2014 IRP process, the Nova Scotia Utility and Review Board stated:

> "The value in conducting a long term IRP exercise is its ability to consider the potential impact of all decisions both to add capital and to add DSM over the longer term. The reference to test that in future decisions is the Preferred Resource Plan. Without a Preferred Resource Plan against which to test decisions, there is a risk uneconomic decisions may be made. That is the whole point of the exercise."[1]

Importantly, the selection of a Preferred Resource Plan is necessary for the calculation of DSM avoided costs of energy and capacity. During the stakeholder session on 7 February 2020 (Q&A Session – Assumptions), NS Power clarified that a) the Reference Plan, referenced in their Draft Analysis Plan is not the Preferred Resource Plan , but a business-as-usual resource plan, and b) this Reference Plan would be used to calculate the avoided costs of DSM, by comparison to the highest-ranked plan. Since DSM would be included in a business-as-usual plan, this will drastically underestimate the avoided costs of DSM, which play a critical role in the approval and evaluation of DSM investments.

This problem is clearly illustrated by the example of the business-as-usual CRP being the winning CRP. If this were the case, the DSM energy and demand savings, as well as annual revenue requirements would be identical in both the Preferred and Reference plans. In any given year, the avoided costs would be calculated as the difference in revenue requirement between the plans (a difference of $0) divided by the difference in savings (a difference of 0 GWh and 0 MW). Therefore, the avoided costs would be zero, which is clearly producing a flawed outcome.

EfficiencyOne strongly recommends the following:

- A single Preferred Resource Plan is an outcome of the 2020 IRP.

EfficiencyOne requests the following:

- NS Power to clarify whether or not there will be one highest-ranked CRP identified as an outcome of the 2020 IRP process.
- If there will not be one winning CRP (i.e. a single Preferred Resource Plan) as an outcome of the 2020 IRP process, please describe how DSM avoided costs will be calculated.

[1] M05522, November 5, 2014 Board correspondence to NSPI.

Difference-in-Revenue-Requirements Method

Avoided energy and avoided capacity costs were calculated through a DIRR method in the 2014 IRP and is the standard industry practice.[2] Two CRPs are necessary for the calculation using this method– the 'winning' Preferred Resource Plan, which presumably will include DSM as it is the lowest-cost energy resource, and a Reference Plan that contains no new DSM. Persistent load effects of past DSM should be present in all CRPs in equal proportion, so any plan with "no DSM" should be interpreted as no *new* DSM.

This method requires selection of a comparator CRP that does not include DSM. In theory this should be the highest-ranking CRP that does not contain any DSM, as it would be the optimal resource plan if all DSM activities were halted and would therefore provide the best estimate of the avoided costs. An alternative is to back out any DSM from the Preferred Resource Plan and re-run the generation optimization within, but this is less desirable as it will not produce an optimized No New DSM plan, and will therefore overestimate the avoided costs of DSM.

EfficiencyOne recommends the following:

- DSM avoided costs of energy and capacity to be calculated through a DIRR method through comparison of the Preferred Resource Plan and the highest-ranked CRP without any DSM.

Avoided Transmission and Distribution Costs

EfficiencyOne understands that the transmission and distribution systems are not being modeled in the IRP, and thus their avoided costs cannot be produced via a DIRR method. EfficiencyOne further understands that transmission and distribution costs will be an input for the IRP modelling. As of 2016, NS Power has calculated avoided transmission and avoided distribution costs and shared them with EfficiencyOne and the DSMAG. Along with the figures themselves, NS Power has shared a general description of the method to develop the estimates, but not the calculations themselves.

[2] Baatz, B. Everyone Benefits: Practices and Recommendations for Utility System Benefits of Energy Efficiency, ACEEE June 2015, at Page 5, para. 2.

As of February 2019, NS Power has been aware of an error in the avoided T&D calculations it had been providing to EfficiencyOne and the DSMAG since 2016, which appears to result in the avoided costs being understated by a factor of 30 to 100, as estimated by Paul Chernick in February 2019[3]. Multiple requests by EfficiencyOne and Synapse in filings before the UARB have requested the error to be addressed.[4] To date, NS Power has not addressed the issue, other than to say that "the methodology for calculating the avoided costs of transmission and distribution due to DSM will be discussed during the IRP process, but NS Power expects the outputs of this calculation will be outside of the IRP model".[5]

Excerpts from EfficiencyOne's reply to stakeholder comments on its 2019 RBIA are included here, which explain the significance of the problem, and its relationship to the 2020 IRP. To be clear, unless this issue with respect to T&D avoided costs is addressed urgently in the context of the IRP, there exists the strong potential for sub-optimal amounts of DSM to be selected through the IRP process, by virtue of an underestimation of avoided costs.

> "EfficiencyOne estimates that with avoided T&D costs on the low end of Paul Chernick's estimate, an additional 15 MW of DR potential would be economic and achievable by 2045 (including behind-the meter battery control and behavioural DR). Additionally, for energy efficiency measures, these potentially more accurate avoided T&D costs would produce total avoided costs on the order of 50 percent higher overall (energy, capacity, and T&D combined), with the result that current achievable potential may be underestimated in a material manner. This would translate to the four Potential Study scenarios used as an input to the 2020 IRP potentially being higher, with the result that more DSM be included in the Preferred Resource Plan. This, in turn, would inform and result in a higher target level of investment for future DSM Plans."

> "Through discussions with NS Power, EfficiencyOne understands that the error in avoided

[3] Resource Insight Inc., *Memorandum Re: Comments on RBIA Enhancements*, 11 February 2019.
[4] M09471, E-1, 2019 Rate and Bill Impact Analysis, Filed October 31, 2019, at Pages 31-33. M09471, E-3, Comments of Synapse Energy Economics, Filed December 5, 2019, at Page 1. M09471, E-6, 2019 Rate and Bill Impact Analysis Reply to Stakeholder Comments, Filed December 19, 2019, at Pages 1-5.
[5] M08929, NS Power, Integrated Resource Planning (IRP) Draft Terms of Reference

T&D costs identified by Paul Chernick exists. As stated in EfficiencyOne's 2019 RBIA: "If they cannot be produced through the upcoming 2020 IRP it is recommended that NS Power update and correct the values produced outside of the IRP and provide the full calculations to the DSMAG for review".[6] EfficiencyOne supports Synapse and Resource Insight's view that NS Power must provide the corrected avoided T&D costs, as well as their full calculations. EfficiencyOne urges that these corrections be addressed and reviewed by all stakeholders prior to the initiation of modelling the 2020 IRP."

EfficiencyOne strongly recommends the following:

- NS Power correct the error in their current calculation of T&D avoided costs described above, prior to them being used as an input in the 2020 IRP.
- NS Power provide stakeholders the calculations and full description of the methodology of the corrected T&D avoided costs to be used in the 2020 IRP.

5. DSM

On slide 11 of the Assumptions deck, NS Power proposes to shift the DSM Potential Study scenarios ahead to a starting year of 2023 and replace 2020-2022 with the current 3-year supply agreement.

EfficiencyOne understands the motivation to align the near-term years of the IRP to current expectations. EfficiencyOne recommends an alternative approach, wherein in lieu of "shifting" DSM ahead – the 2021 and 2022 years of the Potential Study scenarios are replaced by their respective amounts contained within the 2020-2022 Supply Agreement, and the remaining years are held constant (on an incremental basis, as opposed to cumulative). This is due to the sensitivity the DSM Potential Study has to predicted temporal conditions. For example, building stock forecasts that drive participation (in part), are based on temporally sensitive Statistics Canada data that varies by year.

[6] M09471, Exhibit 1, EfficiencyOne, 2019 Rate and Bill Impact Analysis and Model [October 31, 2019] at page 33, line 7-9.

To maintain the fidelity of the DSM Potential Study, EfficiencyOne strongly recommends NS Power consider the above approach.

On slide 11, NS Power also indicates that the DSM Potential Study cases are assumed to include:

- 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

EfficiencyOne wishes to clarify that the DSM Potential Study contains only the impacts that result from programmatic DSM (bullet one, and potentially bullet two above in the case of Demand Response).

“Consumer behaviour and investments”, as well as “technological and market developments” are removed from DSM Potential Study through the use of net energy savings (i.e. free-riders are excluded from savings estimates). The aforementioned factors are reflected within base load forecast quantification via the NS Power Load Forecast.

Savings attributed to “energy efficiency codes and standards” are also explicitly subtracted from DSM Potential Study savings through a sub-model within the broader DSMSim model. This sub-model allows for the calculation of effects on programmatic DSM as a result of likely future Codes and Standards.

As EfficiencyOne has the exclusive franchise for certain DSM activities in Nova Scotia, other agency direct involvement in electricity DSM is considered immaterial in Nova Scotia, outside of the regulated environment.

As described above consumer behaviour and investments, energy efficiency codes and standards, initiatives undertaken by other agencies, and technological and market developments are part of NS Power's Before DSM load forecast, which EfficiencyOne understands is currently the case. EfficiencyOne requests that NS Power confirm these factors or alternatively provide appropriate support for any contrary position.

EfficiencyOne recommends the following:

- The 2021 and 2022 years of the Potential Study scenarios are replaced by their respective amounts contained within the 2020-2022 Supply Agreement, and the remaining years are held constant (on an incremental basis, as opposed to cumulative).

6. "Before DSM" Load Forecast

For the purposes of the IRP, EfficiencyOne understands that NS Power is using a 2019 "Before DSM" Load Forecast. EfficiencyOne is unclear whether the 2019 "Before DSM" Load Forecast as filed by NS Power with the NSUARB on April 30, 2019 is being used directly or if it has been modified in some way.

EfficiencyOne has concerns if NS Power is using the as filed 2019 "Before DSM" Load Forecast because it does not exclude all DSM.

Each year NS Power produces a load forecast that includes a scenario called "Before DSM". NS Power has stated on the record that its "Before DSM" scenario includes roughly half of DSM but continues to use the term "Before DSM".[7]

In NS Power's annual "Before DSM" Load Forecast, EfficiencyOne understands that forward-looking DSM has been introduced through the use of USEIA data from the US Northeast in the NS Power Load Forecast, a geographic area with high levels of DSM activity. Precedent exists for the process of removing future DSM influences (from USEIA data) from the load forecast of a

[7] M09191, N-1, 2019 Load Forecast, Filed April 30, 2019, at Pages 38-40.

Canadian utility, namely through work undertaken by BC Hydro in 2011, which may be useful to review.[8]

In addition, EfficiencyOne has reviewed the base load forecast NS Power presented in slide 8 of the assumptions set, and has the following questions:

- In comparing the "Before DSM" scenario to the 2019 load forecast it appears that load has been increased (i.e. 2029 load increased from 11,797 GWh in the 2019 load forecast to ~12,300 GWh). Please fully describe all modifications that were made to the 2019 load forecast for use in the IRP. Please clarify in particular, whether all embedded DSM has now been removed from the "Before DSM" scenario (our position is that it must be removed, or the load forecast will be artificially low).
- Have the DSM Potential Study scenarios been modified in any way, other than the "shift" that has been applied to account for approved DSM activity in 2021 and 2022?
- Please provide an excel version of the base load forecast including DSM scenarios (slide 8) and peak demand forecast including DSM scenarios (slide 9) from the assumptions set.

7. DSM and Risk

At the IRP Analysis Plan Technical Conference, there was a discussion regarding conducting a sensitivity analysis around DSM performance; namely, investigating a scenario where DSM savings were reduced and spending was held constant.

EfficiencyOne submits that the notion of DSM as a "risky" resource option is antiquated, and not supported by modern experiences. Moreover, DSM can serve to mitigate risk from supply-side options, making it a valuable risk reduction tool, as described below:

> "DSM evolved during the 1970s as economic, political, social, technological, and resource supply factors combined to change the electricity sectors' operating environment and its outlook for the future. Ever since then there have been staggering capital requirements for new plants, significant fluctuations in demand and energy growth rates, declining financial performance of electric utilities, power

[8] BC Hydro IRP Appendix 2B – DSM/Load Forecast Integration, August 29, 2011, at page 17.

> producers and energy service providers, and regulatory and consumer concern about rising prices. DSM has been viewed as an effective way of mitigating these risks when it was invented and still viewed so today."[9]

NERC also provides comments relating to the issue:

> "DSM resources lead to reductions in supply-side and transmission requirements to meet total internal demand. They can be considered in long term planning exercises as a supplement to long-term planning reserves, and provide operational reliability through operating reserves and flexibility. DSM resources can also be used to manage the risk associated with construction and operations of traditional supply-side resources as well as a variety of new operating characteristics associated with variable renewable resources."[10]

In addition, at the energy consumer-level, DSM can serve as a hedging mechanism to exposure to future energy price risk.

EfficiencyOne requests that DSM variability be excluded from sensitivity runs exploring supply-side risk. Although complex, it may be beneficial to explore its risk mitigation effects through examining the effects of supply-side risk with and without DSM as part of the IRP as well.

8. Resource Options Study

EfficiencyOne requests the following:

- Please provide details on the assumption "access to firm capacity via new transmission build up to ~800 MW firm". What is the basis for this assumption, what are the estimated costs, and will the costs be included in modelling? Will this assumption be used in all scenarios or only a high transmission scenario? EfficiencyOne assumes that significantly different scenarios such as this one will produce a broad range of transmission and distribution costs which should be considered in the overall cost of each study.

[9] Gellings, Clark, Evolving practice of demand-side management, Journal of Modern Power Systems and Clean Energy 5, 1-9 (2017).

[10] NERC, Data Collection for Demand-Side Management for Quantifying its Influence on Reliability, December 2007, at Page 1.

9. Demand Response

Upon reviewing the Assumptions for Demand Response (DR), EfficiencyOne has concern associated with separating individual DR options from each of three DR cases analyzed as part of the DSM Potential Study, as suggested in the assumptions methodology. Each of the three market potential cases for DR should be treated as one trajectory for DR spending and savings. DR programs are highly interrelated, as described by Navigant in their DSM Potential Study Report:

> For achievable potential estimates, Navigant accounted for participation overlaps among different DR options offered to the same customer class through a participation hierarchy represented in Figure 10-17.
>
> The participation hierarchy helps avoid double counting of potential through common load participation across multiple programs and is necessary to arrive at an aggregate potential estimate for an entire portfolio of DR programs. CPP is considered lower in the hierarchy than the incentive-based options. The hierarchy order is based on the dispatchability of the options and the reliability around the load reductions, with the most reliable and dispatchable resource placed at the top and the least reliable resource at the bottom.[11]

This interdependence produces unreliable estimates of potential when scenarios are disaggregated, or aggregated with other resource options. This, in combination with the temporal continuity of the DR Potential cases (i.e. marketing and recruitment phases, steady-state phases, re-marketing phases present) results in the diminished utility of modelling the DR cases as a resource option (or some DR options as resource options, some as load modifiers).

EfficiencyOne recommends the following:

- modelling the three DR Potential Study cases as load modifiers throughout the entirety of the period, potentially as “drivers” within the analysis plan context.

10. Other Questions

[11] M08929, N-1, 2019 DSM Potential Study, Filed August 14, 2019, at Page 98.

Following is a list of additional questions, some of which were previously raised in the TOR stage and deferred by NS Power to the Analysis Plan stage:

- Does NS Power plan to do any stochastics and if so, on which variables?
- How will end effects be handled in the IRP model?
- How are Municipal Electric Utilities modeled? How much load and peak demand is included in the load forecast for MEUs, and will any adjustments need to occur?

Closing

EfficiencyOne thanks NS Power for the opportunity to comment on the draft Analysis Plan and Assumptions Set and looks forward to continued work with NS Power and stakeholders.

Attachment A: Comments from Energy Futures Group

NSP 2020 IRP Draft Analysis Plan

1. How NSP will use E3's RESOLVE model in combination with PLEXOS LT Plan

We're unclear how NSP intends to use both PLEXOS LT Plan and RESOLVE. Both models perform capacity expansion modeling and both models have their limitations, especially with respect to storage resources. Specifically, our questions are:

- Is there a particular situation in which NSP expects to use RESOLVE and why?
- If both models are used in a given scenario, how will each be used?
- How would the results of both models be combined, if at all?

2. Use of PLEXOS ST Schedule

Since PLEXOS is a market model, resources are dispatched against a market price rather than against load. Since there is no meaningful market for energy in Nova Scotia NSP has said to us in prior conversations that it intended to arrive at a market price that is akin to the shadow price of each portfolio it models. We understood this to be an iterative process that would necessitate the use of PLEXOS ST Schedule to derive an accurate shadow price. Further, NSP acknowledged the issues that PLEXOS LT Plan has with simulating resources, particularly highly chronologically dependent ones and said it would rerun all portfolios in ST Schedule. We'd like to clarify that this is still indeed what NS Power intends to do and, if so, clarify why the "operability screening" is a necessary additional step.

3. Release of modeling information

Does NSP plan to provide modeling information to stakeholders after the conclusion of all analysis phases or will modeling be shared in between the phases? We believe that in order for this process to be a collaborative one with stakeholders, NSP can't wait until the end of the process to share input/output files with stakeholders. Sharing modeling files early on will help ensure that stakeholders' concerns and questions can be addressed while the modeling is being finalized.

4. Proposed evaluation criteria

Based on the information NSP provided for its proposed evaluation criteria, it is not clear how NSP intends to use the different metrics to evaluate the different portfolios or what each metric is measuring. EFG believes that NSP should not assign weights or color codes to the evaluation criteria. Doing so is inherently arbitrary – weights can be assigned to make any portfolio rise to the top and are entirely subjective. It would be much more meaningful to stakeholders to provide the actual values measured by each metric so stakeholders can see explicitly how each portfolio compares. Furthermore, if any of the evaluation criteria are going to be used to screen out portfolios, NSP should advise stakeholders of this now, rather than waiting for the conclusion of the modeling. In order to ensure clarity on the meaning of the metrics we also seek more information regarding the 10 year NPV Revenue Requirement to look at the magnitude and timing of electricity rate effects. Will NSP attempt to calculate rate impacts by class and if not, why not? And will system costs be translated into annual revenue requirements instead of, for example, carrying charges which would smooth out the rate impact?

5. Unit sizing and derivation of avoided costs

We view the IRP as fundamental to the construction of the avoided costs for screening future DSM. NSP doesn't intend to run PLEXOS so that it captures all the benefits of DSM, e.g, avoided transmission and distribution costs and non-energy benefits. But it can give an avoided energy and capacity stream of costs that can be used for DSM screening. Therefore, it is very important that each scenario also have a concomitant run with no future DSM, i.e. no incremental DSM additions. It is also important that the model inputs be flexible enough to "right-size" supply-side additions as additional DSM is added. This can be done by modeling new resources in small chunks, e.g. 10 – 25 MW or by iterating runs to arrive at the portfolio that least overbuilds NSP's system.

NSP 2020 IRP Draft Assumptions

6. Natural gas pricing

We're interested in some additional specifics around NSP's gas pricing:

- In the past, PIRA has refused to allow stakeholders to see its price forecasts even under NDA, will that be an issue here too?
- What are the specific assumptions around pricing and timing for a new pipeline in Nova Scotia?
- What are the specific assumptions are liquefaction and transportation costs for LNG?
- Will the gas price forecast capture the seasonal differences (winter versus summer) in natural gas prices?
- Why wouldn't NSP model at least a sensitivity that is pegged to New England gas prices since that is the primary way it can currently procure natural gas?