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

Doreen Friis, February 14, 2020
Regulatory Affairs Officer/Clerk
Nova Scotia Utility and Review Board
1601 Lower Water Street, 3rd Floor
P.O. Box 1692, Unit "M"
Halifax, NS B3J 3S3

-SENT VIA EMAIL-

RE: 2020 Integrated Resource Plan Terms of Reference

Dear Ms. Friis,

Natural Forces Services Inc. welcomes the opportunity to input comments on the IRP process and Draft Assumption Set (DAS). We note that at this point of the process, there are clearly a lot of details still to be worked out; accordingly, our comments in some areas are of necessity also at a more general level. We look forward to continuing to engage in the process with NSPI and other stakeholders, as more details of the methodology and assumptions are developed. We have for convenience, set out our comments below under several headings.

Electricity Demand projections

The demand projections (DAS page 8) are mostly clustered around an assumption of demand regression, based on DSM/efficiency measures. DSM scenarios range from around a 17% reduction in the "Low" case, to approaching 30% in the "Maximum Achievable" case. While DSM is an important objective, these assumptions appear ambitious.

It is also important to consider the potential (as seen in other countries) for electricity demand growth through increased electrification of transport and heat sectors (as the electricity sector is decarbonised, it becomes a vehicle to assist decarbonisation of the transport and heat sectors). Increased electrification of the transport and heat sectors has the potential to significantly increase electricity demand.

It is also important in general in an IRP process, that the selected scenarios represent a spread of credible, but significantly different possible futures. This supports assessment of the robustness of different portfolio outcomes to different possible futures.

We strongly recommend that a wider spread of demand projections is included, potentially retaining some of the "demand regression" scenarios but adding scenarios with significant demand growth.

Emissions modelling and limits

Emissions modelling (DAS page 13 and later) appears to relate to meeting specific emissions limits, rather than ascribing any value to further reductions. Further reductions are not monetised (e.g. \$/tonne CO_2 or similar), nor is any strategic benefit recognised.

Additional emissions savings within the alternative scenarios, even if beyond the current legislative requirements, does have a value (either as a general "public good" or as a step to meeting likely future emissions restrictions). Additional emissions savings should be captured as a benefit, and potentially monetised.

Risk premium

There should be some recognition - even if not initially directly monetised - of the risk premium (e.g. implementation risk) associated with different scenarios. For example, scenarios which rely on new/unproven technology, or very ambitious DSM achievements, may carry additional risk regarding implementation and risk of failure.

Operational Constraints associated with Renewable Integration (Ref. DAS page 96 and later.)

There are several important elements in modelling operational constraints in the IRP process, including:

1. Identifying the key operational constraints (or required "grid services") to include in the model;
2. Setting appropriate parameters (or limits) for the selected operational constraints;
3. Setting assumptions regarding the capability of the resource pool (existing and new) to provide system services;
4. Assessing the resultant portfolios to determine if they provide adequate operational flexibility and security (or indeed to see if they are unnecessarily conservative). This step is described in the IRP Draft Analysis Plan as "Operability Screening".

The proposed Grid Services to be included in the model are set out in the DAS (page 99), as follows:

> *For the NS Power system, the following has been identified as the grid services that need to be addressed to accommodate additional inverter-based generation to maintain stable and secure operation of the system.*
>
> - *Ramping reserve and net load following capabilities*
> - *System strength and short circuit ratio*
> - *Volt-Ampere-Reactive support*
> - *Kinetic energy and synchronous inertia requirement*
>
> *A value for the minimum requirement of each of these essential grid services will be represented in the model as dynamic constraints, which will enable the model to integrate renewable resources at any level by ensuring provision of the services.*

We suggest inclusion of VAR support as a key operational parameter should be reconsidered. While we are not questioning its importance, if it is in fact a binding constraint in some portfolios, it can usually be resolved by other solutions which are at relatively low costs and easy to implement (e.g. installation of SVCs or synchronous condensers).

The parameterisation (i.e. setting the required minimum levels) for the remaining requirements will be of critical importance. In reality, most are not "static" requirements, for example the synchronous inertia requirement will depend significantly on the largest system infeed (or outfeed) at a point in time. It will be presumably not be possible to model this degree of sophistication within the IRP model; more likely, single static values will be adopted.

We note the references in the DAS to (page 98) drawing on the Nova Scotia Power Stability Study for Renewable Integration Report (the "Stability Study"), prepared by PSC North America on behalf of Nova Scotia Power Inc. (24th July 2019), as a source for determining the relevant levels of grid services. This is somewhat concerning as the Stability Study, by its nature, examined a small number of "stressed" system conditions, and applied severe contingencies in order to test the limits of the system. Therefore, while there may be learnings that can be taken from it, care must be applied as the scenarios modelled in the Stability Study do not reflect "normal" system conditions and normal grid service requirements.

We would appreciate further understanding of the proposed levels/limits of Grid Services to be included in the IRP model. We strongly suggest that if anything the limits should be set low rather than high; if they are set too high, potential economic portfolio options may be excluded from consideration; on the other hand is they are set too low, this will be picked up at the "operability screening" stage. If some shortfalls are identified at that stage, there may indeed be other solutions to fill any gaps or shortfalls (such as SVCs or synch comps, as mentioned above).

Regarding the capability of the portfolio of potential resources to contribute to Grid Services requirements, it is important not to automatically default to assuming existing levels of performance. Experience in other systems has shown that:

- existing generation plant can often significantly improve its flexibility and contribution to system services, in areas such as ramping, minimum stable output, start times and reserves.
- new generation plants can be configured to optimally provide certain grid services, depending on the specific needs of the system;
- renewable plants in other systems are also an important source of grid services (some examples are described in the Stability Study); and,
- widening of the supply base for grid services has also been very successful (e.g. demand side contribution to short-term operating reserves has been very successful. This can also offset or contribute to ramping requirements.).

We would welcome further information on the assumptions proposed in regard to Grid Service capability. If this cannot be provided for specific plants, at least description of the assumptions for different classes of plant would be helpful.

Interconnectors

Treatment of interconnectors in the IRP modelling will be critically important. There is currently little information in the DAS on this aspect. It is noted that imports (particularly firm imports) could support a transition to lower GSG emissions, but on the other hand fixed import schedules can cause reduction in wind output/capacity as it "squeezes" the space available for RES and local thermal/synchronous plants. Also, with the current interconnection arrangements, the AC interconnector to New Brunswick can often be (depending on its flow) the most severe contingency on the Nova Scotia system, thus determining the grid services requirements (for at least some grid services) within Nova Scotia. Further description of the proposed modelling of interconnector flows would be appreciated.

We hope you find these helpful and that they will receive due consideration, and please revert to us at any time if we can provide further clarification or elaboration. We look forward to working closely with you in the continuing stages of the IRP process.

Sincerely,

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

Halifax, Nova Scotia.