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VIA ELECTRONIC MAIL to engagement@ieso.ca

Independent Electricity System Operator (IESO)
1600-120 Adelaide Street West
Toronto, ON M5H 1T1

RE: "Enabling System Flexibility: Stakeholder Engagement" Presentation dated August 16, 2016 ("Presentation")

Dear IESO,

Thank you very much for the Presentation. As noted in earlier correspondence, the Nipissing First Nation and FN Power are developing a power development partnership that could potentially meet the needs of the IESO as described in the Presentation. As requested per the Presentation we are providing our feedback as follows.

Issue

Minimizing the impact of Variable Generation ("VG") forecast uncertainty on the Ontario power system (the "Issue")

Information Provided to Date

To date, the IESO has provided materials as highlighted per the Presentation and the Previous Presentation. Currently, we understand that the VG forecast uncertainty is as follows:

Table 1 (Per Previous Presentation by IESO)

Year			2013	2014	2015	2016	2017	2018	2019	2020
Installed Capacity (MW)			3506	5266	6952	7814	8152	9050	9640	9940
Exposure % of time	Exposure hours/year	Error %	Error (MW)	Error (MW)	Error (MW)	Error (MW)	Error (MW)	Error (MW)	Error (MW)	Error (MW)
30%	2634	4.8%	169	254	335	377	393	436	465	479
20%	1752	7.0%	244	366	484	544	567	630	671	692
10%	876	10.5%	370	555	733	824	859	954	1016	1048
5%	438	13.7%	481	722	953	1071	1117	1240	1321	1362
2%	175	17.4%	609	914	1207	1357	1416	1572	1674	1726
1%	88	20.1%	704	1058	1397	1570	1638	1818	1937	1997

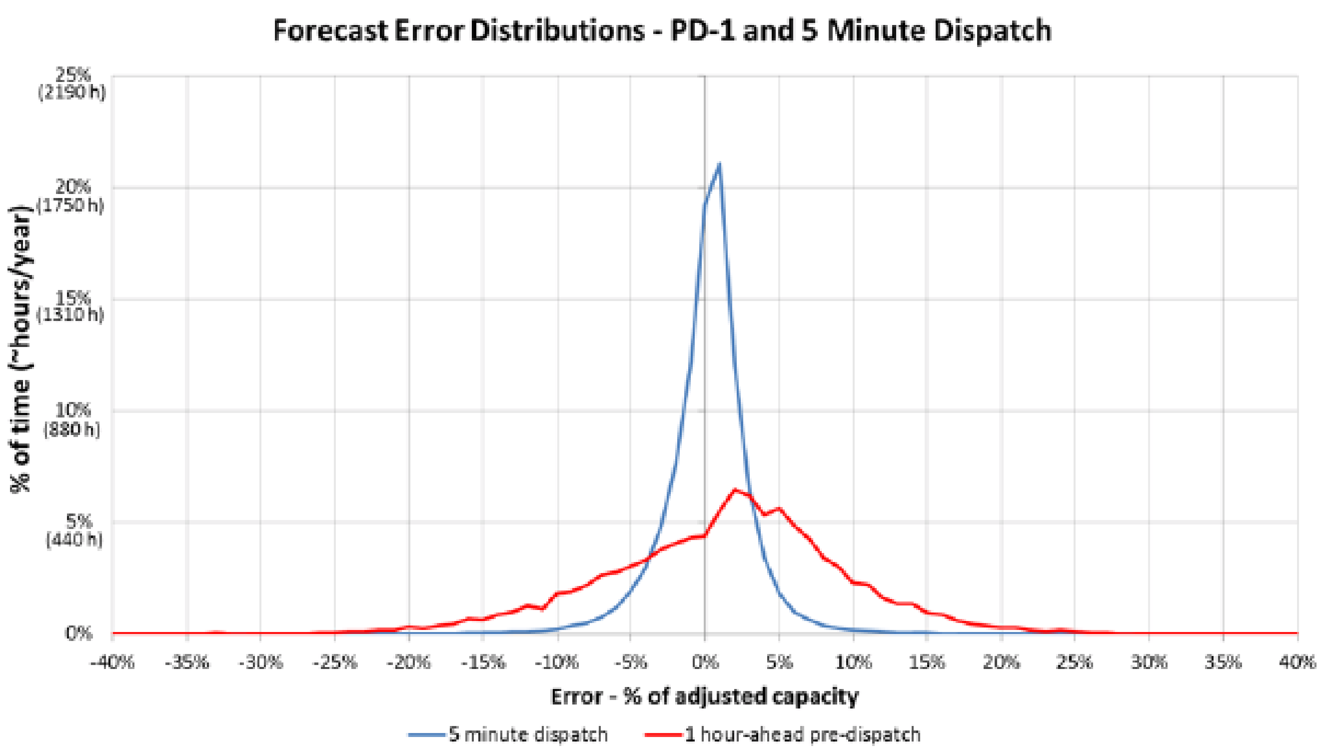
Per the Presentation, we understand that the IESO is targeting 1000MW of additional flexible resources by 2018.

Framing the Issue

Based on our approach, we break down the Issue of minimizing the impact of VG forecast uncertainty on the Ontario power system into two components:

1. Dealing with acceptable VG forecasting uncertainty which we define as when the VG forecasting error versus actual generation is below a level as defined by the IESO (the "Acceptable VG Forecasting Error"). Currently, we do not know what the Acceptable VG Forecasting Error would be for the IESO but for the purposes of our feedback we assume that the IESO believes that it is a more normal distributed VG forecasting error and would be similar to that of the VG forecasting error as per the 5-minute dispatch interval (the blue line per the chart below).

   Chart 1 (Per Previous Presentation)



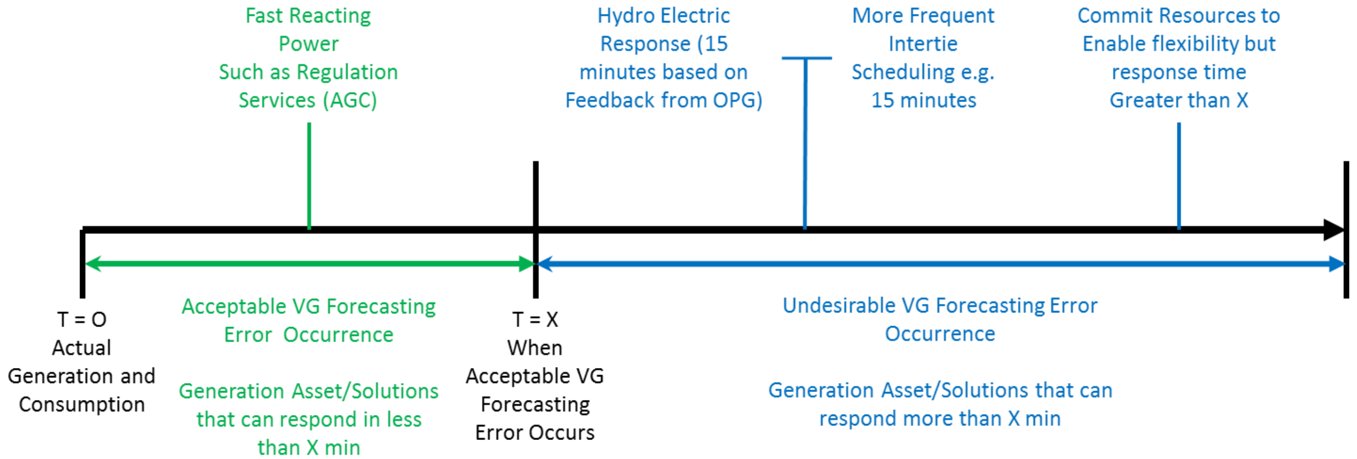
2. Dealing with undesirable VG forecasting uncertainty which we define as when the VG forecasting error versus actual generation is higher than the acceptable level as defined by the IESO ("Undesirable VG Forecasting Error"). Currently, we do not know what the Undesirable VG Forecasting Error is but based on discussions we understand that the VG forecasting error at the 1 hour pre-dispatch is undesirable (red line per char above from Previous Presentation) and for the purposes of our feedback we assume that the IESO desires a more normal distributed VG forecasting error similar to that of the 5 minute dispatch (blue line).

Further, we understand based on the discussion per August 16, 2016 that the IESO is primarily concerned with insufficient supply of power and over generation is not the main concern as generation assets can be curtailed to balance the Ontario power system.

Discussion of the Issue

As noted, we believe the Issue is really made up of two components and we would characterize the components as follows:

Chart 2 – Description of Timing and Acceptable VG Forecasting Error and Undesirable VG Forecasting Error



Acceptable VG Forecasting Error

Characteristics:

- Errors that are normally distributed and are generally applicable for forecast that are done X minutes before actual need. For the purposes of this feedback, we will assume that any forecast done 5 minute or less before dispatch generates a normally distributed VG forecasting error that is acceptable to the IESO.
- Typically to deal with Acceptable VG Forecasting Error, the IESO will need assets that can respond in a short time frame. Based on current forecasting techniques utilized, we understand that an Acceptable VG Forecasting Error occurs at 5min before dispatch and thus assets that can respond/ramp-up in under 5 minutes would be utilized to deal with such errors.
- Quick responding generation required such as peaking power generation or generators that provide the same characteristics as Regulations Services (with automatic generation control, AGC) as procured in the ancillary services market.

Thoughts:

- Depending on when VG forecasting error becomes acceptable, it will dictate how fast of a response time required by assets. Worst case scenario is assets with the quality of Regulation Services (with AGC) will need to be employed to resolve Acceptable VG Forecasting Error to ensure system reliability.
  - If Acceptable VG Forecasting Error occurs at a time greater than 15 minutes it would indicate that solutions such as allocating Hydro Electric generation or intertie scheduling can be utilized to solve Acceptable VG Forecasting Error.
  - If Acceptable VG Forecasting Error occurs less than 15 minutes it would indicate a quicker responding tool is required with characteristics similar to that of the Regulated Reserve Market for AGC or synched Operating Reserves in addition to what is being procured.
- IESO should understand this error to determine the amount of quick responding assets it requires to deal with Acceptable VG Forecasting Error. Based on Chart 1, it appears that if you measure it for 5% error of adjusted capacity for when insufficient generation occurs (if our math is correct it would be 5% X 9940 MW of Installed Capacity of VG by 2020 it would equal 497 MW) or 497MW error for circa 220 hours a year for a supply shortfall (so reading the right side of the chart). It appears reasonable that

circa 100MW to 300 MW of assets with the characteristics of Regulated Reserve (with AGC) should be procured to meet most needs.

- In general, if the response time required is quick it will eliminate the number of assets that can be repurposed or potential solutions that can be utilized to solve Acceptable VG Forecasting Error.
- Amount of power required to solve Acceptable VG Forecasting Error can be reduced depending on how much resources is committed to deal with Undesirable VG Forecasting Error (as probability of Acceptable VG Forecasting Error is likely to decrease).
- Regardless it would appear that IESO will need to procure some quick responding generation to deal with Acceptable VG Forecasting Error.

Undesirable VG Forecasting Error

Characteristics:

- Errors that are fat tailed and are generally applicable for forecast that are done X minutes before actual need. For the purposes of this discussion we will assume that any forecast done more than 5 minute before dispatch generates a fat tailed error (based on information available to date, Chart 1, and as per discussion on August 16, 2016 presentation as there are currently no time intervals examined between 60 minutes before dispatch and 5 min before dispatch)
- To deal with Undesirable VG Forecasting Error, the Ontario power system would procure/commit additional resources to reduce the probability of insufficient supply. This would also result in more occurrences of excess power generation which would be dealt with via curtailment.

Thoughts:

- Typically to deal with Undesirable VG Forecasting Error, it appears that a solution can come from multiple sources but in essence involves committing/procuring resources to meet a pre determined Undesirable VG Forecasting Error amount. For the purpose of this discussion let's assume that the IESO procures 1000MW of resources that are somewhat flexible but cannot ramp up/respond in 5 minutes or less is utilized (e.g. hydro, intertie, etc.). A simple analysis of the general results would be as follows:
  - Forecast +1000 MW = Actual + 1000 MW – The additional 1000 MW of committed resources would result in a 1000MW of extra power being generated and as a result a 1000MW would need to be curtailed. Cost to IESO is the cost to procure 1000MW and any cost associated to curtailing generation.
  - Forecast + 1000 MW = Actual– The additional 1000 MW of committed resources would be utilized and no power needs to be curtailed. Based on the information from Table 1 (and that errors are both equally under and over estimates) and that the IESO is not concerned with over generation, the IESO would be covered for almost 95% of the time if a 1000 MW was procured.
  - Forecast + 1000 MW = Actual - 300 MW – The additional 1000 MW of committed resources is utilized but is insufficient and another 300 MW of additional power is required (from solution identified to solve Acceptable VG Forecasting Error). Based on the information from Table 1 (and that errors are equal for under and over estimates) and that the IESO is not concerned with over generation, for about 5% of the time the IESO would need to procure additional power (in addition to the 1000 MW procured) to meet VG forecast error. For about 1% of the year or 88 hours the IESO would need to procure and additional 726MW (above the 1000 MW) to deal with forecasting error per Table 1.
- The cost to deal with Undesirable VG Forecasting Error in general should be lower on a per MW basis than that of Acceptable VG Forecasting Error as the assets/solutions have more time to react and would include a greater number of generators that would qualify.

- A costing analysis would need to be done to determine where the 'tipping point' is for optimal allocation of power procured to deal with Undesirable VG Forecasting Error and Acceptable VG Forecasting Error.

Potential Solutions

We believe a solution that meets the reliability and principles identified by the IESO per the Previous Presentation involves the following:

Per Slide 28 A) Improvements to, or increased use of, existing market mechanisms

1. Improvement in VG Forecasting – critical as it drives corresponding assumptions to develop the appropriate solutions. By improving forecasting, it lowers the error and the scope of solutions needed to solve VG forecasting errors (thus IESO needs best in class forecasting tools and utilize it on a more frequent basis to limit errors).
    a. Examine and determine if VG forecasting can be improved. We would suggest benchmarking the performance of the model used by IESO to others used in other jurisdictions and backward test the models to determine if improvements can be made. The IESO needs/wants the best in class forecasting tool. A model that generates smaller error will simply save more money.
    b. Increase frequency of VG Forecasting – the error rate should drop as time gets closer to actual time of dispatch. Based on feedback from the Presentation, we believe a forecast should occur right before the 15 minute to dispatch period such that it can utilize assets such as Hydro electricity (as per Ontario Power Generation response) and match the intertie scheduling frequency of other jurisdictions which have gone to a more frequent basis.
2. Per the Presentation, it appears that part of the answer must be increasing frequency of intertie scheduling as it provides another tool to meet VG forecasting error and if the frequency increases it provide more flexibility/options for the IESO to deal with VG forecasting errors while meeting the principles desired by the IESO.
    a. The increase in flexibility is useful but to get a better handle as to potential usefulness, we recommend the IESO to examine how much power was being exported via the intertie during periods of forecasting errors where insufficient generation occurred. We believe that their could be underlying factors which would indicate some sort of correlations that may limit how useful the intertie is in terms of completely solving issues.
3. Per the Presentation, we believe some sort of commitment to resources to account for VG forecasting error is required to ensure reliability of the system especially in the short term. A cost benefit analysis with some backward testing should be done to determine a potential tipping point where the cost over a year of procuring the additional committed power equals the incremental cost of dealing with forecasting error experienced to date. This would provide some data points to the IESO in terms of what could be a feasible amount to procure in terms of dealing with VG forecasting error (or a benchmark business case). Using a model similar/increasing the amount procured via the operating reserve (10 min non-sync and 30 minute) should be considered and examining those data points (especially for those bids not accepted up to a certain value threshold where the values don't make sense) should examined to determine i) how deep the market is of potential solutions and ii) the potential cost of providing committed resource (as it should be cheaper than actual market procurement as the standby rate is a fraction of market power prices but the cost of activation will need to be factored in to determine best value).
4. Another consideration is that the IESO should examine the cost of curtailing VG assets. We understand that the PPA for some of the VG assets have limits in term of ability to curtail production. We recommend that the IESO identify how much curtailment is utilizes annually and how much space is left before the limit is hit. This would better inform the IESO the amount of resources the IESO should commit to in order to

deal with VG forecasting error (in essence there are two different pricing curves relating to the curtailment of resources when over production occurs and there maybe other solutions viable before curtailing with additional payments are considered from a costing structure minimization exercise).

5. Procure additional generation to deal with Acceptable VG Forecasting Error with characteristics similar to that of Regulated Reserves (with AGC) as that is the most responsive tool that the IESO has and it would be used to deal with forecasting errors that occur in the shortest time frame. For simplicity and ease, we would recommend increasing the procurement of Regulated Reserves that is scheduled to come out in Q4 2016 which would help ensure system reliability to deal for Acceptable VG Forecasting Errors as detailed earlier. We believe that a procurement of 100 MW to 300 MW to deal with VG forecasting error would make sense based on Table 1 and the suggested 1000MW procurement per the Presentation. This is critical to maintain system relatability.

Per Slide 28 B) Introduction of a new market product(s), which could be co-optimized with energy and reserve /Increased use of/Existing Market Mechanisms

Per Slide 28 C) Development of other incentives to increase flexibility in the system

1. In general, we do not support co-optimizing energy and reserves, especially as it relates to Regulated Reserves and Operating Reserves. Those mechanisms exist to deal with other issues in terms of reliability of the Ontario power system. However, we are supportive of increasing the Regulated Reserves and Operating Reserves to meet the pre-existing needs in terms of reliability and VG forecasting errors. In essence the Ontario power system needs to be robust enough to deal with the contingencies which the Regulated Reserves and Operating Reserves is set up for and for VG forecasting error. Basically we don't want the IESO to be caught in a situation where two unlikely events occur that brings down the power system as reliability is paramount.
2. In general, we support introduction of new products/incentives when new infrastructure/assets are required to be built. If new infrastructure/assets are required to be built to provide a product required to meet VG forecasting error they should be structured as an hourly standby availability payment (which would be competitively bid upon such that it is transparent) and a cost plus activation rate (so a premium over the cost of the fuel burned plus marginal maintenance/operations cost) over a long term period. This is because:
    - Dramatically reduces the cost of financing which is your largest variable price for bids
        - The price of equipment competitively procured should be within a small range but the price of risk that is applied by all financiers will vary dramatically depending on risk.
        - To obtain cheapest source of capital the key is to reduce risk and the biggest risk is the pricing for the service (as that is what makes the financial model go for financiers). If the price is fixed, the projects could obtain leverage as high as 80% (given the low debt service coverage ratio which allows for more debt) and debt pricing in cdor +200's (low/mid single digits think 4% to 5% in current markets) and equity pricing in the 10%-12% range prior to any development fee that maybe charged on the project. This would suggest a Weighted Average Cost of Capital (WACC) of circa 6.2%. The amount of capital and competitiveness of returns is the highest for low risk projects.
        - In a merchant market (so pricing for providing the service is not stable/predictable with high degree of confidence) leverage is substantially reduced and cost associated with reducing risk is substantial. We have some antidotal evidence in Alberta regarding merchant procurement
            - For prices exposed to merchant risk lenders will examine the market and the average power prices. In Alberta prices are low (in the teens per MWH and a large range over the past 5 years), which implies risk to lenders and their view of the amount to lend against merchant prices will be low as they are conservative which

dramatically changes leverage and raises the WACC dramatically. Equity providers will take a similar view as most investors require a minimum return in a down side scenario. Using the assumption that leverage drops to 30% (which was suggested by RBC at a recent Alberta Power Conference for financing merchant risk projects) and cost of equity is 17% (based on returns hurdles seen for some merchant risk projects in Alberta) it would translate to a WACC of 13.1%. The net cost difference from a financing perspective using an example of 1000 MW financed at a capital cost of $1M per MW (as an example), it would increase annual financing cost of $69M per year (WACC increases 6.9%) which is a Present Value of circa $882M (assuming a 6% rate for 25 years) which is dramatic for a total capital cost of $1B (or 88%).
- Lenders will require projects to hedge the risk for fuel prices which is detrimental from a value for money perspective as there is a sizeable transaction cost for security (as required by financial institutions for hedge transactions) and the hedges are not perfect as there are gaps as it is unknown the number of activations on a go forward basis (thus for activation rates the cost minimizing approach would be a cost plus basis over market natural gas rates). This creates a nightmare from a netting perspective and lenders still apply an incremental risk premium for the mismatch in risk.

Ultimately, the financing market will push projects to ideally eliminate merchant and commodity risk to provide the most competitive pricing. We would ultimately note that investment demand for low risk projects are extremely high given the number of pension funds, insurance funds, and banks that are trying to match liabilities based on our experiences. As risk increases the demand dramatically decreases as competition is significantly reduced from a capital perspective. Further it hurts the value for money offering to the IESO

We understand the above maybe a bit unclear and would more than welcome a discussion or emails to clarify anything contained within this letter or to explore the above matters further. We thank you for including us as part of this engagement process.

Sincerely

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