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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 June 24, 2016 ("Presentation")

Dear IESO,

Thank you very much for the Presentation in advance of the meeting. 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. Due to personal matters not all of our team could make it in person. However, we did take the time to review the materials and wanted to provide our feedback as requested on slide 56 of the Presentation.

Issues Identified

Variable Generation (VG) and the impact on system operations. Specifically, we noted the following:

1. When should the IESO make a decision on variable generation to limit the errors for the next hour going forward?
    - The issue is most pronounced from the 1 hour ahead pre-dispatch to the 5-minute dispatch period where the error for the 1 hour ahead pre-dispatch is fat tailed (so higher rate of larger errors) as compared to the 5-minute dispatch period where the errors are more normally distributed (so lower rate of large errors). Per slide 15 of presentation
    - We are curious as to how many minutes before the hour when the error rate becomes more normally distributed or at an acceptable level (i.e. the question of when should you make a decision on variable generation to limit errors when predicting for the next hour forward)? We suspect it is probably more than 5 minutes but less than 30 minutes (we have no evidence but just a guess). As answering this questions will dictate the response times required for reacting to VG on a go forward basis.
2. Regardless, the IESO needs a quick reacting generation that can ideally react short intervals (depending on answer above). The IESO likely needs additional asset that can generate and consume power (as errors are either a shortfall or too much power) quickly, which would be critical to maintain system reliability.
    - To date many jurisdictions would meet energy generation shortfall by one of several methods including (basically the same assets utilized to meet the 10-minute synch Operating Reserve (OR) requirements):
        - Dam Hydro -fast response time but can be limited due to environmental factors (reservoir requirements, once used it is gone until replenished, global warming, seasonality, availability, etc.), which limits performance seasonally.

        - Peaking natural gas – can sort of meet the needs (so not cogeneration or combined cycle but rather simple cycle) but depends on ramping rates and keeping the asset warm to respond in tight frames (basically idling the turbines which has an operating cost and environmental impact). We are aware that Ontario only has one simple cycle peaking generation facility which is the York Energy Centre (http://www.powerauthority.on.ca/current-electricity-contracts/sc-cc) that is based on two Siemens SGT6-PAC 5000F turbines and per the website requires 10-30 minutes to meet full capacity and capable of operating between 260 to 1300 hours annually (which may not be sufficient to meet VG forecasting errors)
        - Other assets could potentially serve a larger window of the 30 minute standby (such as other base load generators that run a generator on idle specifically to meet this need or run an asset sub-optimally (not at full capacity) to meet this need). This comes at a cost as the incentive/revenue to provide this service has to overcome the marginal cost for running an asset (thinking of cogeneration, combined cycle, etc) in a non-optimal manner which incurs more operational cost and environmental cost (as you're basically idling a generator so emitting emissions when it isn't really needed).
        - The key here is understanding the response and ramping requirements required by VG but in general the faster the better.
    - We are not aware of many jurisdictions dealing with the other aspect of energy consumption to keep the system stable (so when the system is generating to much power). This would likely take the form of grounding the power or some sort of energy storage in the most efficient manner (pump, batteries, etc.) but an effective solution will depend on the cost/benefit.
3. How many MW are required deal with VG forecast uncertainty? Per slide 17 of the Presentation, the quantum by 2020 ranges for 479MW to 1,997MW for an error that occurs 30% of the time to 1% of the time. Could OR help deal with this?
    - Based on the OR requirements per Q4 2015 of 1600MW (http://www.ontarioenergyreport.ca/pdfs/5806_IESO_OntarioEnergyReportQ42016_Electricity_EN_FA.pdf) this exceeds it by a significant margin for the 1% of the time or 88 hours a year and OR was really designed to deal with unexpected issues with the system not VG. As OR is the amount of supply resources required to handle the loss of the largest contingency on the grid, plus the loss of half the amount of the second largest contingency. If OR is dispatched to deal with VG, it can create a perfect storm where there is a VG error and a contingency occurs which would threaten the stability of the system. Further, potentially only some of the OR could truly meet the VG error (given the time it takes to ramp-up and bring online).
    - Could use 10-minute synch OR to meet the gap but how much will that cost given frequency of activation (basically are the assets in use today designed to provide that service in a cost effective manner) and are there sufficient assets within the Ontario grid to provide such services in a meaningful manner.

Potential Technical Solution Description

Proven modular natural gas generation plant with a grounding grid that can consume power in periods where excess generation is occurring. Specifically, we note the following (collectively the "Potential Technical Solution"):

1. Quick start times of circa 10 minutes from notification.
2. Modular in design (multiple generator sets) which provide for high availability rates (low probably that all generator sets are down) and a large variety of power output with a higher efficiency over a wider load (for a single turbine generator the generation choice is typically binary…on/off.. but a modular generator s has

numerous generator and the increment of additional power is smaller (so if generators are sized at 10MW/each you can go in 10MW intervals) so you only procure exactly what you need). .

3. Environmental - emit 15% less CO_2 than the standard (July 2015) for new power plants per the Canadian Environmental Protection Act and 22% less CO_2 than the new US EPA Standards (Aug 2015) (contemplated generator set would generate 0.354t/MWH) and limited water consumption depending on configuration (as little as ~3L/MWH).
4. Efficient/Competitive cost with electrical efficiencies ranging from 42% to 50% and upfront project cost (note not capital but overall project cost) of circa $XM per MW for plant for plant sizes above XMW.
5. Versatile as it can provide a whole host of other services including operating reserves, ancillary services (such as standby power, voltage control, black start) and given its modular design it can be located in many locations to limit transmission and upgrade cost. The modular design of the facility can facilitate it being upsized or downsized (adding or removing generator sets) to meet the changing needs of the IESO. The IESO needs are likely to change as the VG is likely to increase over time and hopefully VG forecasting error improves as better techniques are adopted with time.
6. We would recommend the inclusion of a grounding grid that is capable of consuming power in a meaningful quantity during periods of over production (so when to much power is in the system the grounding grid can be activated to consume power from the system alleviate the strain). Ideally and depending on the cost of other solutions can be examined to consume power with ancillary benefits (some sort of energy storage).

Rationale for Potential Technical Solution

We believe the Potential Technical Solution could be deployed in a manner that meets the principles outlined in slide 50 of the Presentation. Specifically, we would note the following:

1. Maintain the reliability of the system:
    - Provides fast responding capacity (start times within 10 minutes from notification).
    - Could consume excess generation if required (grounding grid) as VG could also result in the generation of excess power in the system.
    - Given modular design, would generally provide high level of availability (dependable).
    - Flexible and can provide other desired Ancillary Services (operating reserves, voltage control, black start, etc.).
2. Cost-effective, competitive, transparent and stable
   Highly dependent on how it is implemented as per slide 52 of the Presentation because each option has a different cost and level of transparency/stability. That being said we can make some comments on cost effectiveness and they are as follows:
    - In general, the cost for providing such services depends on the marginal cost of the process, technology, operations, and upfront capital.
    - Existing assets within IESO with the exception of dam hydro are likely inefficient at providing rapid response from a generation perspective given:
        - Gas/nuclear require long ramp up times to deliver power and likely cannot act in the tight time frame as described in the Presentation.
        - New dam power assets take a long time to develop (so cannot be implemented in a timely manner to meet the issue is right now) and have effectiveness constraints given that its location is dependent on geography and may not service an area of need (when you factor in line loses and etc.)

    - Efficient/Competitive cost with electrical efficiencies ranging from 42% to 50% and upfront project cost (note not capital but overall project cost) of circa $XM per MW for plant sizes above XMW which are competitive compared to gas generation assets.
    - Given its modular design, the Proposed Technical Solution offers a higher efficiency across a larger range of output and a more discrete range of outputs. Given the number of generators it can turn on generation in smaller intervals (e.g. 10 MW at a time) which better meets the actual requirement (instead of operating another asset such as a turbine (which typically generate power in larger blocks) in a non optimal format or having it produce more power than is required).
    - If implemented appropriately the Proposed Technical Solution can be targeted for specific areas to reduce the cost associated with upgrades (transmission/substation) or troublesome transmission areas (areas with voltage problems) or limit impact of line loses.
    - In general, we believe Option C is the most cost effective way of providing The Proposed Technical Solution. In general, the cost of a solution depends on 3 factors i) upfront capital cost ii) operational model and iii) financing cost. Refer to the section "Getting There with the Potential Technical Solution" for additional discussion.
3. Send efficient price signals
    - Highly dependent on how it is implemented as per slide 52 of the Presentation as each option will send a different price signal. Refer to the section "Getting There with the Potential Technical Solution" for additional discussion.
4. Scalable to system need changes over time
    - Given modular design, the facility can be scaled to increase in size easily or decrease in size and be updated with more modern generator sets as time goes by (improve efficiency and lower emissions)
    - Flexible and can provide other desired services such as Ancillary Services (reserves, voltage control, black start, etc.).
5. Technology neutral, allowing for the development of new technology and/or maximizing capability from existing assets
    - We believe that the Proposed Technical Solution allows for the IESO to utilize VG in a more effective manner while maintaining system reliability. If new technology emerges the Proposed Technical Solution can be scaled up or down and doesn't preclude new technology from being integrated to the power system.

Getting There with the Potential Technical Solution

We believe the solution to address flexibility needs in the system will involve a combination of the options indicated on slide 52 of the Presentation. A potential approach could be as follows:

- Determine a range of response times that are suitable to deal with VG (same approach as dealing with OR)
- Each response time category will require certain number of MW (suitability can be determined by simulations and scenario testing)
- Through testing and setting up a range of requirements similar to that of OR (we believe VG forecasting error is in essence having reserves to deal with the unexpected VG)
- We suspect that there will be at least two categories with 1) being a rapid response time below 10 min and 2) response time between 10 minute and X minute (as determined by Item 1 in "Issues Identified" section)

The issue is that the market / power system likely does not have sufficient generation capacity to meet the additional MW generation required for 1) rapid response below 10 minutes and 2) the response time between 10 minute and X minute. Some generation capacity can likely be "re-purposed" such as dam hydro and the York Energy Centre but with that said the IESO still has to meet existing OR requirements. Based on the simple review of slide 17 of the presentation it appears that reserves required for VG could be somewhere from 479 MW to 1997MW by 2020. We believe that the IESO should procure enough VG reserves that equate to at least 5% (or less) of the time exposure or 1,362MW (or more) for 2020. Anything beyond that could potentially be covered by the OR market but that would be putting more strain on OR. We recommend various scenarios be simulated to determine the probability that a VG forecasting error occurs that is greater than 13.7% and that an event occurs that requires OR (such as largest contingency event + something else) to be dispatched and if sufficient reserves existing within the power system. From a big picture perspective and using the above approach to deal with VG, the IESO may need to procure power reserves (1,362 MW suggested above) that is similar in size to the OR market (Q4 2015 at 1,600MW), which is a lot of additional generation with potentially few incremental assets being able to meet such technical requirements. Thus we believe some additional generation will be required to be built to in essence balance VG. Timing of when this is built is critical as well as 2020 is not far off so a quick construction solution is also preferred.

Factors	Option A – Improvement to Existing Market Mechanism	Option B – Introduction of New Market Products	Option C – Development of Other Incentives to Increase Flexibility
Upfront Capital Cost	- Likely can repurpose some generation assets - New generation assets will be required given the technical requirement to provide "VG Reserves" - The Upfront Cost of the Proposed Technical Solution is likely to be similar in all three options	- Likely can repurpose some generation assets - New generation assets will be required given the technical requirement to provide "VG Reserves" - The Upfront Cost of the Proposed Technical Solution is likely to be similar in all three options	- Likely can repurpose some generation assets - New generation assets will be required given the technical requirement to provide "VG Reserves" - The Upfront Cost of the Proposed Technical Solution is likely to be similar in all three options
Operational Model	- Assume payments mirror that of OR market - IESO will pay for a market determined standby and activation rate	- Unknown and depends on structure	- Assume a long term hourly availability payment plus a cost plus activation rate (with the plus aspect being the cost above the cost of natural gas) - IESO cost is in essence a monthly rent plus an activation cost
Financing Cost	- High financing cost as uncertainty surrounding pricing of standby and activation rate	- Depends on structure and predictability /risk of cash flow stream. - More risk equates to higher financing cost	- Low financing cost as highly predictable cash flow streams
Notes/Thoughts	- It will likely take time for the market to adapt to the new demand and building of new generation assets will be	- Depends on structure but a less predictable the cash flow stream will result in higher financing cost / difficulties which	- See discussion below but we believe that this will result in the lowest cost solution to the IESO as cash flows are highly

	slow given uncertainty surrounding market - This would result in high cost of procuring such services in the short term - Likely to result in higher cost as build out of required assets slow	will slow down the number of assets that can be brought on in a timely manner	predicable which results in optimal financing costs.

Additional considerations to "Getting There":

- We believe that Option C is likely the most cost effective way of procuring "VG reserves" but 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 natural gas burned but assuming an efficiency that is predefined by IESO) 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 $1.5M per MW (as an example), it would increase annual financing cost of $103.5M per year (WACC increases 6.9%) which is a Present Value of circa $1,323M (assuming a 6% rate for 25 years) which is dramatic for a total capital cost of $1.5B (or 88%).
      - Lenders will require projects to hedge the risk for natural gas 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 pricing 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.

- Suggest that the IESO examine the costing impact of VG and potential solutions by examining the costing over a X time horizon (assume 25 years for below purposes to match the conservative asset life of the Proposed Technical Solution) to the system:
  - Determine the cost of "current approach" (so basically the cost of not dealing with the situation) which could be measured as the incremental cost of power during the periods which additional power needs to be activated during a VG forecasting error (average change in market power prices multiplied by the total market power procured multiplied by number of occurrences during a year). Note it is our understanding that when the market power price changes all market producers get the new market clearing price. So when a VG forecasting error shortfall occurs you have to pay the new market price to all market producers as well as procure the shortfall generation. The answer to this analysis would be great to know now to determine how much money could be saved using the solution chosen by the IESO.
  - Get some insight in regards to "OR approach". We believe that there will be some additional assets that can be re-purposed and provide OR / VG Reserves. A way of potentially determining this is examining how deep the OR market is for the various OR classes (so looking at the non accepted bids) to determine i) how much additional capacity exist and ii) the cost of the additional capacity. We believe this would represent additional capacity that could be re-purposed to provide VG reserves. How much to accept would ultimately depend on the cost benefit analysis.
  - Determine the cost of the "Option C approach"
    - Contracted standby rate plus
    - Cost of activation multiplied by hours activated

A well thought out process of measuring net cost will be important versus other proposed solutions. Ultimately value and reliability needs to demonstrated to all rate payers.

Other Considerations

In reviewing the information provided, we had the following other considerations for the IESO to consider:

1. Suggest that the IESO determine the time prior to the beginning of the new hour where the error associated with VG forecasting is more normally distributed. By determining this time (we suspect it is somewhere between 5 minutes and 30 minutes before the hour) it would provide the IESO the following:
   - Additional time to deal with VG forecasting errors and act earlier to deal with VG errors (such as calling up generators with longer ramp up times prior to the 5-minute dispatch).
   - It may allow for the IESO to apply the same methodology of OR to VG in the sense that the IESO has X MW quantity of "rapid response" generation and Y MW quantity of "slower response" generation (maybe like 30 minutes) that still manage VG variability.
2. Suggest that the IESO provide more information to the market to react to VG. Specifically, some thoughts would be as follows:

- Let the market know if VG forecast error (for the 1 hour ahead pre-dispatch) exceeds X% (say 5%) as we know that once a forecast error occurs it could lead to a higher probability of a forecast error for the next hour (not sure if this is the case but suspect it is if you were to look at the data on an ex-post basis). If that is the case it would provide information to the market that there may be a higher opportunity to be turned on and to potentially get themselves "at the ready" (the thought is that if market participants see this occurring and understand there maybe a chance to generate power at a higher market price that they would get their generation asset at the ready which would hopefully reduce ramp up time and bring in more participants to meet that need).
- If a VG forecast error does occur and exceeds X% (say 5%), we would recommend that the IESO provide some details of what the error looks like. We would think that providing the market a series of confidence intervals (much like slide 17) for P(70) to P(99) (so basically 70% of the time VG generation would exceeds X MW and 99% of the time VG would exceed X MW for the upcoming forecasted hour) for that hour and the subsequent hour it would educate the market at the range of possible outcomes for the next hour to help them decide if they want to get an asset "at the ready".
- If a VG forecast error does occur and exceeds X% (to be determined by simulation and modeling), we would recommend that the IESO for the time being procure additional OR (beyond the requirement) for the next hour in the meantime as a stop gap measure.

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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