Feedback Form

Long-Term 2 (LT2) RFP – February 15, 2024

Feedback Provided by:

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To promote transparency, feedback submitted will be posted on the Long-Term RFP engagement page unless otherwise requested by the sender. If you wish to provide confidential feedback, please mark "Confidential".

Following the LT2 RFP February 1, 2024, engagement webinar, the Independent Electricity System Operator (IESO) is seeking feedback from stakeholders on specific items discussed during the webinar. The webinar presentation and recording can be accessed from the engagement web page.

Please submit feedback to engagement@ieso.ca by February 15, 2024.

Revenue Model

Topic	Feedback
Do you have any additional comments regarding the revenue model, particularly with regards to the following: Deeming energy market revenues based on real-time locational marginal prices (LMP), as opposed to the IESO's recommendation of basing this on the day-ahead LMP. (Slides 19-21) • The optionality of using either a simple average day-ahead price or weighted average LMP, with the latter including hours where the resource was scheduled day-ahead in a given month. (Slides 22-23) • Including monthly production factors that on average equate to the annual production factor, in order to further account for seasonality. (Slides 24-26)	No comment on simple average day-ahead price vs weighted average LMP. The proposed grid reliability payment as described should not be implemented since it removes some risk from project owners and places that risk on ratepayers. This would give project owners the higher of two possible rates, with the ratepayers paying for the difference. If the IESO plans to have ratepayers pay for any curtailments, that should only apply to curtailed output that is actually available; it should not apply to hours when a facility is not able to provide any output. **Annual production factor (PF) vs monthly production factor**: There is insufficient room in this section for all my comments on this issue. Please see the note in the General Comments/Feedback section at the end of this document.

DERs

Topic	Feedback
Do you have any comments regarding eligibility requirements for DERs of other general comments?	No comment

Capacity Resources

Topic	Feedback
Do you have any comments regarding considerations for acquiring additional capacity resources, and utilizing a multi-stream approach (energy and capacity streams)?	No comment

LT2 Deliverability

Topic	Feedback
Do you have any comments on early deliverability data and evaluation stage deliverability?	No comment

Repowering

Topic	Feedback

Do you have any comments around repowering participation?	There should be a distinction made between extending existing contracts and replacement of existing project infrastructure. Some of the earliest wind projects predate the current regulations in O.Reg. 359/09 and would not be approved today. These projects should not be considered for contract extensions. Replacement of infrastructure should be treated as new projects, and meet current regulations including municipal support. When O.Reg. 359/09 was drafted, the average wind turbine nameplate capacity was 2 - 2.5 MW. Current, on-shore wind turbines have nameplate capacities of 4.0 - 5.0 MW. Design work on 6 MW wind turbines is already underway. The suitability of O.Reg. 359/09 for new turbine models should be reviewed by an independent body, such as the Council of Canadian Academies, and open to a public comment period, prior to any acceptance of any new wind project proposals.

Long Lead-Time Resources

Topic	Feedback
Do you have any comments on enabling long-lead time resources?	No comment

General Comments/Feedback

Annual production factor vs monthly production factors.

With intermittent sources, such as wind projects, there are serious issues with using the annual production factor and dividing the estimated yearly revenue into approximately 12 monthly payments.

With the proposed revenue model (using annual PF applied monthly); during months with low wind availability, the project owners would be reimbursed as if the project operated at the annual production factor for all calendar hours in each month.

As an example; a 100 MW wind project with an annual PF of 0.30 would have an annual output of 262,800 MWh (0.30 x 100 x 8760 hours).

Using simple arithmetic, the data in IESO's Reliability Outlook dated December 2023, shows that, with the proposed revenue model, during the low wind months of May to September, when the wind project could not reach a production factor of 0.30, the 100 MW project owner would receive payment for approximately 45,000 MWh of electricity that were not produced during those months. This is about 17% of the annual production.

During the high wind months, when wind projects operate at production factors greater than a yearly average of 0.30, a similar amount of MWh output, (17% or 45,000 MWh) above the calculated monthly average output for those months, would be produced. Since the ratepayers have already prepaid for 17% of the annual production that was not delivered in May to September, it would be a reasonable assumption that the 'surplus' production above the calculated monthly average would be available to the ratepayers at no additional cost.

However, the proposed revenue model, as described in the IESO's Feb 1, 2024 presentation appears to suggest that any market revenue from a project's production would remain with the project owner.

The following comments appear in Slide 9 in the IESO Feb 1, 2024 presentation:

> Step 2a: the facility participates in the IESO administered market and earns revenues associated with their production. **All energy market revenues, including make whole payments, will remain with the supplier.** (my emphasis)

If the 100 MW project owner is allowed, and is able to sell all of this 'surplus' 45,000 MWh, at a low price of $25/ MWh and keep all revenues, that would amount to a 'double-dipping' of over $1Million each year, or $20Million over the 20 year contract. At a sale price of $50/MWh, that would amount to $2Million each year, and $40Million over a 20 year contract.

If the IESO is able to obtain contracts for 3000 MW of wind capacity; even at the low prices of $25/MWh or $50/MWh, that 'double-dipping' could add up to an unnecessary, and unjustified, $600Million to $1.2Billion cost burden to ratepayers/taxpayers over the 20 year contracts, for electricity that was not delivered.

That would be tantamount to a hidden subsidy for project owners financed through a hidden tax on ratepayers/taxpayers.

RECOMMENDATIONS

1. Averaged monthly payment based on 1/12 of a yearly annual production factor, in its current form, should not implemented. Project owners should NOT be reimbursed twice for a portion of a project's annual production output.

2. If the IESO wishes to proceed using the proposed revenue model based on yearly production factors to generate an averaged monthly output; the total payment to project owners during high wind months should be limited to:

- No more than the calculated MWh determined by the yearly production factor x the calendar hours in each month.
- Additional payment for curtailment during high wind months should be limited such that the total monthly payment is not greater than the yearly production factor x the calendar hours in each month.
- For high wind months, any additional output above the amount determined by the average yearly production factor x the calendar hours in the month should be considered as pre- paid and available to the IESO without any cost.

3. Rather than averaged monthly payments based on the yearly average production factor, the IESO should require ACCURATE monthly production factors and a proposed $MWh price from proponents. This would allow the IESO to calculate the the available output capacity of a specific project.
4. Actual monthly payment to project owners should be based on electricity actually delivered, plus any IESO directed curtailment, during each month.
5. Both the initial annual, or monthly production factors, would be estimates. There will likely be variations due to project design/layout; unpredictability of wind resources at the actual site, or optimistic specifications by the turbine manufacturers. The IESO should require wind project owners to recalculate and resubmit production factors after 1 year after commercial start up.
6. Project owners should NOT be encourage to engage in creative pricing and/or production factors in order to improve project acceptance or increase revenues.