Feedback Form

Long-Term RFP – November 7, 2022

Feedback Provided by:

Name: Daryl Scheerer, Jesse Shopa

Title: Director, Project Engineering; Corporate Development Analyst

Organization: BluEarth Renewables Inc.

Email: [redacted]

Date: November 11, 2022

Following the November 7th public meeting on the Long-Term RFP, the Independent Electricity System Operator (IESO) is seeking feedback from participants on the proposed deemed generation model.

The referenced presentation can be found on the Long-Term RFP webpage.

Please provide feedback by November 14, 2022 to **engagement@ieso.ca**.

Please use subject header: ***Long-Term RFP***. To promote transparency, this feedback will be posted on the Long-Term RFP webpage unless otherwise requested by the sender.

The IESO will work to consider and incorporate comments as appropriate.

Thank you for your contribution.

Deemed generation model

Topic	Feedback
Do you support the proposed approach with fixed VOM and CRE value? Please explain why or why not.	We understand why IESO would want to fix these two values in support of proper bid evaluation between projects/proponents. However, proponents are using different BESS suppliers and technologies and so likely have different VOM and CRE factors than what will end up being "fixed" under the contract. This creates a fundamental mismatch between the operational reality of the project and the contractual reality of the project. Proponents with VOM and CRE values that differ from what is fixed under the contract will likely bid in higher capacity prices to reflect this risk or to reflect the operational reality that this will either lower revenue or increase costs. It is challenging to comment fully on this topic with these two values not yet being determined (e.g. is VOM $1/MWh or $10/MWh).
Do you have any feedback on the use of non-continuous 4 hours in the model?	The use of continuous is preferable to non-continuous on the basis that non-continuous will exacerbate the issue caused by perfect hindsight vs. imperfect foresight (as outlined below). However, a 4 hour factor fails to appropriately capture different battery sizes. Some proponents may bid in battery storage technology with a 6 or 8 hour charge duration which creates an inherent mismatch between the operational reality of the project and the
Is there anything further you recommend be considered with respect to the implementation of this alternative model?	The Daily Energy Adjustment assumes that the battery will be discharged daily, which is likely not going to be the case. This then exposes the capacity price revenue to adjustment rather than exposing the energy arbitrage revenue to adjustment, creating volatility and variability in a capacity revenue stream that should be constant month-over-month. This has negative financing implications (see below). Deducting the Daily Energy Adjustment is also a backwards looking function and will be calculated using "perfect hindsight" of how the market performed in that day. Even the most sophisticated operator will not be able to capture the highest peak prices and charge during the lowest cost hours. A recent study by

Topic	Feedback
	WoodMac/DNV ("Financing the Next Generation of Merchant Energy Storage Projects") suggests that BESS operators in California operate at a >25% reduction to perfect foresight on a daily basis. This will result in the Adjustment being outsized relative to the net revenue proponents generate in the wholesale electricity market (not a true 1-for-1). This uncertainty and risk will result in higher capacity price bids as a means for proponents to hedge against this exposure. We hope the example on page five helps contextualize this commentary. Additionally, the Adjustment will force proponents to operate daily to minimize the impact of the Adjustment which will distort market pricing and may ultimately be disadvantageous to ratepayers. The Daily Energy Adjustment also creates a fundamental risk/reward mismatch for equity providers. Equity providers now have no ability to capture upside through prudent and efficient operation in the wholesale energy market, yet they still bear all of the risk associated with future augmentation (materials costs, foreign exchange, technology supply, etc.). We believe this will ultimately result in higher capacity prices as this is now the only lever that proponents can pull to fund future augmentation capital and ensure they are meeting their required equity hurdle rates. A Daily Energy Adjustment is also incredibly challenging to (i) model, (ii) administrate, and (iii) audit. The need for IESO to validate ~30 adjustments 12x a year is burdensome and will likely become a source of frustration for both parties. We would advocate and recommend that the alternative revenue model be eliminated.

Topic	Feedback
Do you have any general feedback on the two models presented, including any feedback on financeability?	The Daily Energy Adjustment assumes that the battery will be discharged daily, which is likely not going to be the case. This then exposes the capacity price revenue to adjustment rather than the adjustment being applied to what the proponent earned in the wholesale energy market (e.g. the energy arbitrage revenue). This exposes the capacity revenue stream to variability and volatility. Lenders will, in turn, charge a higher cost of debt that is commensurate with this increased risk which will then be passed through to ratepayers via a higher capacity price. Removal of the DEA/alternative model will eliminate the potential risk of adjustment to the capacity revenue stream which will improve the financeability of projects and the lower the cost of debt. Through our previous consultation with financiers, we know that the previous contract construct is financeable. Financiers have expressed material concerns with the Daily Energy Adjustment/alternative model.
Do you have any feedback on potential market and operational impacts between the two models?	The alternative models does not promote efficient operations by proponents and results in market distortion. Additionally, the alternative model is fundamentally mismatched to how the BESS will be operated in practice by proponents (please see the discussion above re: perfect hindsight vs. imperfect foresight). We would also appreciate clarification on if the Regulatory Charge Credit will be maintained if the new model is adopted or if the IESO is considering changes to the RCC as well.

Materials Cost Index Adjustment (MCIA): Lithium

Topic	Feedback
Do you have any feedback on the appropriate weighting for lithium in the MCIA?	We have no specific feedback on the weighting at this time and support the changes IESO has made thus far.

General Comments/Feedback

Daily Energy Adjustment Examples

Scenario - Sufficient Volatility to Incentivize Discharge

	Contract			Operations	
	Perfect Hindsight			Imperfect Foresight	
	Actual Lowest & Highest HOEP Clearing prices			Hours Dispatched	
	Hrs	$/MWh		Hrs	$/MWh
Non-QHs Charging	1	$ 20.0	Non-QHs Charging	3	$ 22.0
	2	$ 21.0		4	$ 20.0
	3	$ 22.0		5	$ 24.0
	4	$ 20.0		6	$ 25.0
QHs - Discharging	7	$ 70.0	QHs - Discharging	7	$ 70.0
	8	$ 65.0		8	$ 65.0
	18	$ 90.0		9	$ 60.0
	19	$ 80.0		10	$ 55.0
	HBAP	$ 76		HBAP	$ 63
	LBAP	$ 21		LBAP	$ 23
	VOM	$ -		VOM	$ -
	CRE	0.75		CRE	0.75
	Hrs	4.00		Hrs	4.00
	DEA	$ 194.33		DEA	$ 128.67

Contact Capacity	[MW]	50.00
Capacity Price Per MW	[$/MW]	1,500.00
Capacity Revenue	[$/Business Day]	75,000.00
Wholesale Market Revenue	[$/Business Day]	6,433.33
DEA	[$/Business Day]	(9,716.67)
Net Revenue	[$/Business Day]	**71,716.67**

Operator dispatched the full four hours too early in the day, missing high prices during hours 18 and 19

Lenders believed they were financing $75,000 of revenue but in actuality were financing less due to the DEA

Scenario - Insufficient Volatility to Incentivize Discharge

	Contract			Operations	
	Perfect Hindsight			Imperfect Foresight	
	Actual Lowest & Highest HOEP Clearing prices			Hours Dispatched	
	Hrs	$/MWh		Hrs	$/MWh
Non-QHs Charging	1	$ 20.0	Non-QHs Charging	3	$ 22.0
	2	$ 21.0		4	$ 20.0
	3	$ 22.0		5	$ 21.0
	4	$ 20.0		6	$ 21.0
QHs - Discharging	7	$ 27.0	QHs - Discharging	7	$ 27.0
	8	$ 28.0		8	$ 28.0
	18	$ 29.0		9	$ 25.0
	19	$ 27.0		10	$ 25.0
	HBAP	$ 28		HBAP	$ 26
	LBAP	$ 21		LBAP	$ 21
	VOM	$ -		VOM	$ -
	CRE	0.75		CRE	0.75
	Hrs	4.00		Hrs	4.00
	DEA	$ 0.33		DEA	$ -

Contact Capacity	[MW]	50.00
Capacity Price Per MW	[$/MW]	1,500.00
Capacity Revenue	[$/Business Day]	75,000.00
Wholesale Market Revenue	[$/Business Day]	0.00
DEA	[$/Business Day]	(16.67)
Net Revenue	[$/Business Day]	**74,983.33**

Spreads were too thin to incentivize discharging so proponent did not generate any wholesale market revenue

Lenders believed they were financing $75,000 of revenue but in actuality were financing less due to the Daily Energy Adjustment

Interconnection

We understand the IESO's position and argument with respect to projects with advanced queue positions being better suited for E-LT1 for other proponents. However, we believe our suggestions made in the previous comment period would promote increased supplier diversity in E-LT1 with limited impact to the IESO. Additionally, those proponents with current queue positions likely understand their enhanced competitive positioning in the process relative to the rest of the applicant field – this lack of competitive tension may in fact lead to higher capacity prices bid in by these proponents.

As such, we would like to reiterate our proposal which creates more reasonable risk sharing between the parties while also not providing a contractual offramp.

1. Interconnection Schedule

Day-for-day extension of the Milestone COD caused by interconnection delays **without liquidated damages** for a period of up to 12 months, after which liquidated damages would become effective.

2. Interconnection Costs

Proponents submit their interconnection cost estimates to the IESO as part of their bid submission, with a contractual mechanism to adjust the capacity price upwards or downwards once the true cost is known in the future. Such true cost would also be submitted to IESO and subject to audit etc. For example:

	Interconnection Cost	Capacity Price Adjustment
Estimate at Submission	$5,000,000	None
True Cost (Range)	$4,000,000 - $4,999,999	-$Y/MW-Biz Day
True Cost (Range)	$5,000,001 - $6,000,000	+$Z/MW-Biz Day

(and so on and so forth…)

Additional considerations for the IESO on this point:

a. Rather than a distinct dollar value, percentages could be utilized
b. There could be a range ($ or %) that would not trigger an adjustment. In the above example, an adjustment would **not** be triggered on any change below 20% (+/- $1,000,000).

Without these forms of relief, proponents **will** bid in higher capacity prices to reflect the increased risk they are bearing in their E-LT1 submissions.

Municipal Support Resolutions

All municipalities that we have engaged with to date have been unwilling to provide a letter or resolution evidencing municipal support in accordance with the required timeline, which each municipality has highlighted as "unreasonable" and "unrealistic". One municipality was willing to provide a signed letter to such effect which we have provided to IESO as part of the last feedback period. While adjusting the rated criteria to be based on "consultation" versus "resolution" likely does not meet the goals of the IESO, we feel this rated criteria needs adjustment given the feedback received from municipalities to date. We believe we are not the only proponent to have received such feedback to date. If true, that will result in few-to-no scored points in the criteria category for all proponents which increases the weighting/importance to the other three scoring criteria categories which may not be in the best interest of the IESO.

Reimbursement Reference Efficiency

We appreciate the IESO's revision to the RRE factor but we believe it should be lower as 0.75 still does not give adequate consideration to parasitic load, losses, and day-to-day discharge variability. The embedded assumption in the 0.75 factor seems to be that the battery will be discharged daily which likely will not be the case. There will be more standby/idle periods than as estimated in the 0.75 factor which will result in a gap between Delivered Electricity and Withdrawn Electricity over the three month measurement period, resulting in the Regulatory Charge Credit being lower than the total cost it intends to reimburse. **Proponents will subsequently pass this cost through to ratepayers via a higher capacity price proposal** than would otherwise be the case if the RCC truly did make proponents "whole" with respect to Global Adjustment and other such costs. We hope the example below helps demonstrate this issue more clearly. This is presented on a simplified 2 month basis:

		Month 1	Month 2	
Idle Parasitic Load	[MWh AC/Idle Hr]	1.8	1.8	a
Total Hours in Month	[Hours]	744.00	720.00	b
Charge Duration	[Hours]	5.00	5.00	c
Number of Charge Events in Month	[#]	14.00	30.00	d
Hours Spent Charging	[Hours]	70.00	150.00	e=c*d
Discharge Duration	[Hours]	4.00	4.00	f
Number of Charge Events in Month	[#]	14.00	30.00	g
Hours Spent Discharging	[Hours]	56.00	120.00	h=f*g
Hours Spent Idle	[Hours]	618.00	450.00	i=b-e-h
Parasitic Load When Idle	MWh/AC]	1,112.40	810.00	j=a*i
MW Capacity	[MW]	100.00	100.00	k
Discharge Duration	[Hours]	4.00	4.00	l
Number of Discharge Events in Month	[#]	14.00	30.00	m
Delivered Energy in Month		5,600.00	12,000.00	n=k*l*m
Discharge Capacity at POI	[MW]	100.00	100.00	k
Discharge Losses from Battery to POI	[MW]	10.00	10.00	o
Charge Duration	[Hours]	5.00	5.00	p
Number of Discharge Events in Month	[#]	14.00	30.00	m
Withdrawn Electricity for Purposes of Charging	[MWh/AC]	7,700.00	16,500.00	q=((k+o)*p)*m
Withdrawn Electricity from Parasitic Load	[MWh/AC]	1,112.40	810.00	j
Total Withdrawn Electricity in Month	[MWh/AC]	8,812.40	17,310.00	r=q+j
Delivered Energy in Month	[MWh/AC]	5,600.00	12,000.00	n
Withdrawn Electricity in Month	[MWh/AC]	8,812.40	17,310.00	r
Round Trip Efficiency	[RTE%]	63.5%	69.3%	s=n/r

Federal Refundable Tax Credit

We would like to highlight that the tax credit will not be "law" by the time of proposal submission and is still subject to material change between now and the time the 2023 budget is passed. Industry is still consulting with the Ministry of Finance on this point and materials points to the credit are still subject to change. Additionally, there are labour condition requirements as part of accessing a significant portion of the tax credit which are still undefined. This has a two pronged impact – one is in respect of accessing this portion of the credit and the other is in respect of the impact to this requirement on project capital costs. As the condition is still undefined, it is impossible to determine how accessible it is and what the dollar impact to project budget(s) may be. This makes determining a capacity price incorporative of the tax credit difficult.

What we initially thought of proposing was that proponents provide two prices – one that includes the impact of the tax credit and one that excludes the impact of the tax credit. However, by the time of proposal submission it may be such that the labour condition requirements are still not yet defined and therefore proponents are unable to provide a confident capacity price that is based on a crystallized set of assumptions re: the tax credit.

Therefore, we would propose that the contract include a provision that requires the parties to convene and renegotiate (in good faith) the capacity price upon the refundable tax credit being signed into law. Otherwise, IESO runs the risk of proponents bidding higher capacity prices given the uncertainty associated with (a) the tax credit being passed into law, (b) the impact of the labour condition requirements on project capital costs, and (c) other potential changes to the credit.

Regulatory Charge Credit

We would recommend IESO clarify, within Exhibit R, that the 3-month rolling average does not begin until the third settlement month.

COD Timing

The new proposed contract award date elevates regulatory schedule risk due to the increased possibility of being unable to complete wildlife surveys within the required spring timing windows, which will consequently impact the timing of permitting applications and the overall ability of proponents to achieve COD within the current timeframes.

We understand the IESO is working to amend these dates and that will be reflected in the Dec 6th version of the contract and are appreciative of this recognition in light of the above concern that is likely shared across the applicant pool.

Proposal Security

We support IESO's current proposal security amount. We believe this is an important mechanism for the IESO to create a pool of projects and proposals that are committed to achieving COD within the provided framework.