Powerex appreciates the opportunity to submit additional comments respecting the proposed revisions to the Business Practice Manual ("BPM") for Market Instruments to implement a default energy bid structure for hydro resources participating in the energy imbalance market ("EIM").

While Powerex believes that the proposed business practice generally reflects the framework set out in the draft tariff language that CAISO has submitted to the Federal Energy Regulatory Commission ("FERC") to implement the local market power ("LMPM") enhancements, Powerex believes that the specific application approach proposed for weighting prices within the long-term component of the hydro DEB has the potential to result in a default energy bid that does not appropriately reflect the opportunity cost of a hydro resource participating in the EIM.

Currently, the proposed language added to the BPM to accommodate the default energy bid option for hydro states that "*[r]esources with less firm transmission rights than resource maximum capacity will only be eligible for a weighted blend of electricity prices between the hub with transmission rights and the default electric hub."* This statement is also supported by illustrative calculations later in the document.

Powerex understands the BPM's calculation would proceed as follows. Assume a resource with a PMax of 100 MW and three hubs:

		Transmission Rights	Weighting Factor	Hub Price	*Proposed Blended Price for DEB Calc*
Default Hub	Mid-C	n/a	n/a	$10	$10
Additional Hub 1	NP-15	50 MW	0.5	$40	**$25**
Additional Hub 2	SP-15	25 MW	0.25	$50	**$20**

Effectively, the calculation would consider three possible scenarios for the sale of the 100 MW PMax of the resource:

1. Sell all 100 MW of the output at the Default Hub (Mid-C) at a price of $10/MWh.
2. Sell 50 MW of the output at Additional Hub 1 (NP-15) at a price of $40/MWh, with all of the remaining 50 MW sold at the Default Hub at a price of $10/MWh. This yields a blended price of $25/MWh.
3. Sell 25 MW of the output at Additional Hub 2 (SP-15) at a price of $50/MWh, will all of the remaining output (75 MW) sold at the Default Hub at a price of $10/MWh. This yields a blended price of $20/MWh.

The draft BPM calculation would use the highest of the three "blended prices" calculated above. This results in hub price used in the long-term component being calculated as:

MAX ($10, $25, $20) = **$25**

Powerex's concern with the draft BPM approach is that it assumes that *all* of the output that is not sold at a given Additional Hub must be sold at the Default Hub, even if the Default Hub price is lower than the price at a second (or third) Additional Hub. This is simply not realistic or reasonable.

Based on the hub prices and transmission rights, the resource in this example would be expected to be able to sell:

- 25 MW of its output at the highest-price location (SP-15), at a price of $50/MWh;
- 50 MW of its output at the next highest-price location (NP-15), at a price of $40/MWh; and
- 25 MW of its output at the lowerst-price location (the Default Hub of Mid-C), at a price of $10/MWh

The transmission weighted-average geographic hub price that should be used in the long-term/geographic component is (.25 * $50 + .5 * $40 + .25 * $10) **= $35**

Powerex believes that calculating the transmission-weighted average price for each pricing term included in the long-term component is most consistent with CAISO's proposed tariff language, which references the use of a proportional weighted average of the "bilateral pricing hub ***prices***" in the long-term component:

> *For resources that Scheduling Coordinators demonstrate a quantity of firm transmission rights to a requested electric pricing hub or similarly priced location that is less than the hydro resource's capacity, the CAISO will include the requested electric pricing hub up to the quantity demonstrated transmission rights,* ***and apply a proportional weighting of the resource's transmission rights to calculate a weighted average of those bilateral electric pricing hub prices*** *when calculating the value of the long-term/geographic component of the Hydro Default Energy Bid.*[2]

In order to ensure consistency with the proposed tariff language, Powerex requests that the draft BPM and technical solution be modified in a manner consistent with the alternative calculation set out below.

Proposed Solution

1. As currently proposed, CAISO should maintain a matrix of electric pricing hubs and associated transmission rights in the Master File. The transmission rights for the Default Hub should be set to the PMax of the resource:

Hub	Transmission Rights
Mid-C (Default Hub)	100 (set to PMax)
NP-15	50
SP-15	25

2. On a daily basis, and separately for each pricing term used in the long-term/geographic component, CAISO should retrieve the relevant hub prices and sort from highest price to lowest price:

Hub	Transmission	Price
SP-15	25	$50
NP-15	50	$40
Mid-C (Default)	100	$10

3. On a daily basis, and separately for each pricing term used in the long-term/geographic component, CAISO should use the transmission rights to weight the index futures prices at each location by starting with the highest price and working down until the resource's PMAX is depleted:

    1. SP-15 = 25 MW at $50
    2. NP-15 = 50 MW at $40
    3. Mid-C = 25 MW at $10

Where the weighted price = ((25 * $50) + (50 * $40) + (25 * 10)) / 100 = **$35**

[2] Cal. Indep. Sys. Operator Corp., CAISO Tariff Amendments to Enhance Local Market Power Mitigation and Reflect Hydroelectric Resource Opportunity Costs in Default Energy Bids, Docket No. ER19-2347-000, Proposed Section 39.7.1.7.2(b) (filed July 2, 2019).

4. CAISO should repeat steps 2 and 3 for the DA Index, the BOM Index, and each month M_{+1} through M_{+N}.

5. CAISO should insert the results into the long-term component using the elements within the applicable storage horizon**:**

$$LT\ Geo\ Floor = MAX(DA\ Index, BOM\ Index, M\ Index_{+1}, \ldots, M\ Index_{+N}) * 1.1$$