Comments of Powerex Corp. on Local Market Power Mitigation Tariff Language

Submitted by	Company	Date Submitted
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Powerex appreciates the opportunity to submit comments on CAISO's draft tariff language respecting the local market power mitigation ("LMPM") enhancements. Powerex strongly supports CAISO's efforts to proceed with enhancements to its LMPM mechanism to make participation in the Western Energy Imbalance Market ("EIM") significantly more workable for storage hydro resources located outside of the CAISO Balancing Authority Area ("BAA"). Powerex appreciates the significant time and effort that CAISO has spent in evaluating how to modify the existing LMPM framework to take into account the costs of storage hydro resources and the responsiveness that CAISO has exhibited to stakeholder comments and feedback throughout this proceeding. Powerex believes that the draft tariff language posted by CAISO generally reflects the proposal outlined in the draft final proposal in this proceeding and establishes a workable framework to better accommodate the participation of storage hydro resources in the EIM.

In Sections I and II of these comments, Powerex provides suggestions regarding how the draft tariff language can be modified to more fully align with CAISO's draft final proposal in this proceeding and provide greater clarity to market participants regarding the inputs into the calculation of the default energy bid ("DEB") for storage hydro resources. For CAISO's convenience, Powerex also is providing a mark-up (and clean version) of the draft tariff language as Attachment A to these comments reflecting Powerex's proposed revisions. In addition, in order to provide greater certainty to market participants regarding the level of demonstration that must be made to obtain a hydro DEB, Powerex respectfully requests that CAISO confirm that the information provided in Attachment B to these comments is sufficient to substantiate a request for a hydro DEB as discussed in Section III below.

I. Powerex Supports CAISO's Revisions to Address Flow Reversal and Economic Displacement

Powerex supports CAISO's proposed enhancements to address flow reversal and economic displacement. As CAISO explained in the draft final proposal, "[f]low reversal occurs in cases when an EIM BAA or group of BAAs are import-constrained in a market interval, triggering mitigation, which results in the BAA shifting to export at mitigated prices in the subsequent market run."[1] In Powerex's experience, the result of the existing LMPM framework in these situations has been to force hydroelectric resources within the import-constrained BAA to make sales at a DEB that does not accurately reflect their costs. Powerex believes that the proposed tariff revisions will address the potential for flow reversal by eliminating tariff provisions that currently prevent determination of the need for mitigation separately for each interval and within each market timeframe. In addition, in order to provide further assurances against the possibility of

[1] CAISO Draft Final Proposal at 5.

flow reversal, CAISO's proposed tariff revisions would apply a nominal adder to the calculation of the competitive price for EIM entity areas.

Powerex also supports CAISO's proposed revisions to its tariff to limit the potential magnitude of economic displacement resulting from bid mitigation (*i.e*., an increase in EIM transfers out of a mitigated entity to another EIM entity). Under CAISO's proposal, an entity participating in the EIM would have the ability to request that CAISO limit transfers between entities participating in the EIM to prevent transfers from increasing beyond a specified amount between the market power mitigation run and the market run for a specific interval. Powerex believes that CAISO's proposed revisions will help reduce the potential quantity of forced sales of energy from a mitigated resource voluntarily offered into the EIM.

Although Powerex supports CAISO's proposed tariff language, Powerex believes that one passage in Section 29.39(e)(3) is ambiguous and requires clarification. That section states that, "[t]he incremental net EIM Transfer limit will be the sum of the Flexible Ramping Up awards in the EIM Entity Balancing Authority Area *prior to the RTM process for the interval to which the MPM process applies*[.]" Powerex believes that the intent of the italicized language is unclear and should be clarified.

II. Powerex Supports Implementation of the Proposed Hydro Resource DEB Framework

Powerex strongly supports CAISO's proposal to implement a new DEB option available to hydro resources with storage capability. Powerex believes that the framework set out in the draft tariff language represents a reasonable framework for the calculation of a DEB for storage hydro resources, and should be workable in most circumstances. In particular, Powerex believes that the proposed framework reflects key concepts that are relevant to the opportunity cost of storage hydro resources, as the proposed formula:

- Takes into account a resource's maximum storage horizon;
- Includes short-term and long-term components, reflecting the range of trade-offs that a storage hydro resource faces over time;
- Is based on the maximum of the short-term and long-term components;
- Applies different scalars to short-term and long-term factors;
- Considers multiple geographic market locations that can be accessed by a resource in the calculation of the long-term component; and
- Incorporates a floor price to protect against the inefficient depletion of hydro resources.

Powerex strongly supports the inclusion of the aforementioned elements in the design of the DEB option for storage hydro resources and believes that they reflect the types of considerations faced by storage hydro resources when determining the most efficient allocation of their supply. By establishing a DEB option that incorporates these elements, CAISO's proposal will help ensure that the opportunity costs of storage hydro resources are more accurately reflected in the DEB for these resources and will address a potential barrier to the voluntary participation of such resources in the CAISO markets.

While Powerex believes that the draft tariff language that CAISO has posted generally aligns with CAISO's draft final proposal in this proceeding, Powerex believes that CAISO should consider modifying the draft tariff language in several respects to more fully align with CAISO's draft final proposal and to provide additional clarity to market participants.

1. CAISO Should Modify The Draft Tariff Language To Reflect The Availability Of Alberta As An Eligible Electric Pricing Hub

In CAISO's draft final proposal, CAISO explained that it had included Alberta in the list of available geographic hubs for the proposed DEB. CAISO further added that the "Alberta hub will be available for entities that can demonstrate that the hub is robust enough to be used in these calculations."[2] The draft tariff language posted by CAISO, however, did not expressly identify the Alberta hub as a potential electric pricing hub available to storage hydro resources.

Powerex respectfully requests that CAISO add the Alberta hub to the list of potential electric pricing hubs in order to align the draft tariff language with CAISO's draft final proposal in this proceeding. As Powerex explained in detail in its earlier comments in this proceeding, the availability of the Alberta hub is *critical* to ensuring that the DEB framework permits certain storage hydro resources to reflect their opportunity costs in their DEB. Notably, it would be incorrect to view Powerex's sales opportunities as being limited exclusively to Mid-Columbia ("Mid-C") (even if Powerex did not hold transmission rights to more distant regions). To the contrary, the physical generation capability that supports Powerex's participation in the EIM is located entirely within British Columbia and, as a result, is effectively located between Mid-C and the Alberta hub. Moreover, Powerex has secured, and regularly uses, long-term transmission rights to deliver incremental hydro energy from British Columbia to Alberta. As a result, in any given period, market conditions at *both* Mid-C and the Alberta hub are relevant to determining the potential current and future sales opportunities available to Powerex and, ultimately, Powerex's opportunity costs. Powerex notes that other potential EIM participants may be in a similar position.[3]

For the foregoing reasons, Powerex suggests modifying Section 39.7.1.7.3 to expressly identify the Alberta hub as an electric pricing hub that is available to storage hydro resources. In order to avoid the need to update this tariff language as new market participants are added to the EIM, Powerex also recommends modifying Section 39.7.1.7.3 to provide that the Default Trading Hub and any additional electric pricing hubs approved for a given hydro resource will be set out in the CAISO's Master File.

2. CAISO Should Modify The Attestation Requirement To Reflect The Reasonable Expectations Of A Scheduling Coordinator

Under Section 39.7.1.7.2.1(a), a Scheduling Coordinator seeking to add an electric pricing hub to the list of hubs that will be included in the calculation of the long-term component of its DEB must attest that it "will use the full quantity of the transmission rights to deliver incremental sales from the hydro resource." Powerex believes that this language must be modified, in keeping with feedback in the stakeholder process, to only require that a Scheduling Coordinator attest that it "reasonably expects to use the demonstrated transmission rights to deliver incremental sales from the hydro resource." As was discussed during the stakeholder process, hydro resources with

[2] Draft Final Proposal at 17.

[3] For example, NorthWestern Energy's system interconnects directly with the transmission system operated by the Alberta Electric System Operator.

storage have limited energy and must make trade-offs between many market opportunities, including selling limited supply during the highest priced hours and days and at the highest priced locations. As a practical matter, it is thus not feasible that an entity would use *all* of its transmission rights to deliver its hydro energy to every location to which it has transmission rights during each and every hour of the year. Powerex therefore believes that any attestation requirement should only require that the Scheduling Coordinator affirm that the relevant transmission rights are reasonably expected to enable potential market opportunities for the resource during the applicable year.

3. CAISO Should Clarify The Granularity Of The Transmission Rights Showing

Currently, Section 39.7.1.7.2.1 states that a Scheduling Coordinators must make an annual demonstration that they have firm transmission rights and/or a historical practice of purchasing firm transmission rights to a given electric pricing hub. In order to take into account the fact that the transmission reservations currently held or historically acquired by a market participant may vary over the course of the year, Powerex requests clarification that Scheduling Coordinators that make such a submission may provide a month-by-month breakdown of their transmission rights to relevant electric pricing hubs. Powerex believes that allowing Scheduling Coordinators to submit a showing that includes monthly transmission availability strikes an appropriate balance between ensuring that the DEB represents the opportunity costs of a resource while limiting the additional data collection and computational burden imposed on the CAISO.

4. CAISO Should Clarify The Calculation Of The Hydro DEB

In addition to the issues raised above, Powerex is proposing revisions to the draft tariff language that are designed to further clarify the calculation of the hydro DEB in a manner consistent with the draft final proposal. More specifically, as reflected in Attachment A, Powerex suggests that CAISO revise the language of Section 39.7.1.7 to:

- Clarify that the DEB will be calculated on a daily basis;
- Make clear that the calculation of the short-term component and long-term component will take into account on-peak prices at the relevant trading hubs;
- Make clear that the option to make a demonstration regarding the transmission rights held by an entity applies to the calculation of the long-term component of the DEB;
- Clarify that a resource may substantiate the relevance of a particular trading hub by demonstrating that they "hold" – rather than have purchased – firm transmission rights in order to reflect that transmission may be obtained through assignment or other arrangements, such as through legacy ownership rights; and
- Clarify the use of weighted pricing for resources that have firm transmission rights to a requested electric pricing hub that is less than the resource's capacity.

III. Powerex Requests Confirmation Of The Required Transmission And Maximum Storage Horizon Requirements

Powerex strongly supports CAISO's proposal to require Scheduling Coordinators requesting the hydro DEB option to submit information regarding their transmission reservations and the maximum storage horizon of their resources. Powerex believes, however, that stakeholders

would benefit from further clarification regarding the level of information and demonstration that CAISO will require in order to comply with the obligations set out in the draft tariff language.

In the interest of receiving guidance regarding the demonstration that is required, Powerex is providing a draft of information to support a hydro DEB for Powerex as Attachment B. This draft includes detailed information regarding Powerex's transmission rights and the storage capability of resources, the residual capability of which support Powerex's participation in the EIM. Powerex respectfully requests that CAISO confirm that the information included in Attachment B is sufficient in scope and detail to meet the demonstration requirements set out in the proposed tariff language.

Attachment A

Draft Tariff Language

29.39 EIM Market Power Mitigation.

(a) **EIM Market Power Mitigation Procedure.** The CAISO shall apply the Real-Time Local Market Power Mitigation procedure in Section 39.7 to the Energy Imbalance Market, including EIM Transfer constraints into an EIM Entity Balancing Authority Area on an EIM Internal Intertie, except as provided in Section 29.39.

(b) **Competitive Path Assessment.** The CAISO shall conduct the competitive path assessment to determine for each EIM Entity Balancing Authority Area whether a path is competitive or non-competitive, consistent with Section 39.7.2, except that –

(1) EIM Participating Resource Scheduling Coordinators shall submit information required by the CAISO to perform the competitive path assessment;

(2) the competitive path assessment shall not exclude EIM Participating Resources from the test used to determine the competitiveness of Transmission Constraints on the basis that they may be net buyers of Energy in the Real-Time Market; and

(3) the CAISO may establish different Reference Buses for each Balancing Authority Area, which need not be within the Balancing Authority Area, for calculating the LMP decomposition which is used to trigger Bid mitigation, based on the topology of each Balancing Authority Area and consideration of the bus at which the Marginal Cost of Congestion component of Locational Marginal Prices is least influenced by market power.

(c) **Locational Marginal Price Decomposition.** The CAISO shall perform the Locational Marginal Price decomposition for each EIM Entity Balancing Authority Area using the results of the competitive path assessment and the Congestion pricing results of the pre-market run to determine which resources may have local market power due to Congestion on a non-competitive Transmission Constraint, consistent with Section 34.2.3 and 39.7.

(d) **Default Energy Bids.** The CAISO shall use the methods and standards set forth in Section 39.7 to determine Default Energy Bids for EIM Participating Resources, except that the CAISO will use the Market Services Charge and System Operations Charge

reflected in the EIM Administrative Charge.

(e) **Incremental Net EIM Transfer Limit.**

(1) **Election.** An EIM Entity Scheduling Coordinator may elect for the CAISO to limit the incremental net EIM Transfer from above after the MPM process for the EIM Entity Balancing Authority Area pursuant to the election procedures and timelines established in the Business Practice Manual for the Energy Imbalance Market.

(2) **Application.** ~~Incremental~~In the applicable RTM process, incremental net EIM Transfers from an EIM Entity Balancing Authority Area that has made the election in Section 29.39(e)(1) will be limited when the MPM process triggers mitigation and EIM Transfers in the MPM process are constrained in the import direction to that EIM Entity Balancing Authority Area, or a group of EIM Entity Balancing Authority Areas that includes that EIM Entity Balancing Authority Area.

(3) **Limit.** The incremental net EIM Transfer limit in the RTM process will be the sum of the Flexible Ramping Up awards in the EIM Entity Balancing Authority Area prior to the RTM process for the interval to which the MPM process applies, which is in excess of the EIM Entity Balancing Authority Area's corresponding Flexible Ramping Up requirement, plus the greater of—

(A) the net EIM Transfer in the MPM process described in Section 34.1.5 prior to the RTM process for the interval to which the MPM process applies; or

(B) the net EIM Transfer represented by the EIM Base Schedules at each EIM Internal Intertie for the interval to which the MPM process applies.

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31.2.3 Bid Mitigation

If the non-competitive Congestion component of an LMP calculated in an MPM process is greater than zero (0), then any resource at that Location that is dispatched in that MPM process is subject to Local Market Power Mitigation. Bids on behalf of any such resource, to the extent that they exceed the Competitive LMP plus the Competitive LMP Parameter at the resource's Location for the DAM and RTM process interval for which the MPM process applies, will be mitigated to the higher of the resource's Default Energy Bid, as specified in Section 39, or the Competitive LMP plus the Competitive LMP Parameter at the resource's Location for the DAM and RTM process interval for which the MPM process applies. To the extent a Multi-Stage Generating Resource is dispatched in the MPM process and the non-competitive Congestion component of the LMP calculated at the Multi-Stage Generating Resource's Location is greater than zero, for purposes of mitigation, all the MSG Configurations will be mitigated similarly and the CAISO will evaluate all submitted Energy Bids for all MSG Configurations based on the relevant Default Energy Bids for the applicable MSG Configuration. The CAISO will calculate the Default Energy Bids for Multi-Stage Generating Resources by submitted MSG Configuration. Any market Bids equal to or less than the Competitive LMP plus the Competitive LMP Parameter will be retained in the DAM and RTM process.

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34.1.5 Mitigating Bids in the RTM

34.1.5.1 Generally

After the Market Close of the RTM, after the CAISO has validated the Bids pursuant to Section 30.7 and Section 34.1.4, and prior to conducting any other RTM processes, the CAISO conducts a MPM process. The results are used in the RTM optimization processes. Bids on behalf of Demand Response Resources, Participating Load, and Non-Generator Resources are considered in the MPM process but are not subject to Bid mitigation. Bids from resources comprised of multiple technologies that include Non-Generator Resources will remain to be subject to all applicable market power mitigation under the CAISO Tariff, including Local Market Power Mitigation.

34.1.5.2 Fifteen Minute Market MPM

The MPM process for each fifteen-minute (15) interval for a Trading Hour starts with the unmitigated Bid set as validated pursuant to Section 30.7 and Section 34.1.4. The MPM process produces results for each fifteen (15) minute interval of the Trading Hour and thus may produce up to four mitigated Bids for any given resource for the Trading Hour. The determination as to whether a Bid is mitigated is made based on the non-competitive Congestion component of each LMP for each fifteen (15) minute interval of the applicable Trading Hour, using the methodology set forth in Section 31.2.3 above. If a Bid is mitigated in the MPM process for ~~an~~a fifteen (15) minute interval for a Trading Hour, the mitigated Bid will be utilized in the RTM process for that fifteen (15) minute interval. If a Bid is not mitigated in a fifteen (15) minute interval, the CAISO will still mitigate that Bid in subsequent fifteen (15) minute intervals of the Trading Hour if the MPM runs for the subsequent intervals determine that mitigation is needed.

34.1.5.3 Real-Time Dispatch MPM

The RTD MPM process produces results for each five (5) minute interval of a Trading Hour. The determination as to whether a Bid is mitigated is made based on the non-competitive Congestion component of each LMP for each five (5) minute interval, using the methodology set forth in Section 31.2.3 above. The RTD MPM process is performed for each advisory interval within a configurable time frame from the binding RTD interval to mitigate bids used in the following RTD for these intervals.

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34.1.5.5 Competitive LMP Parameter

When a Bid is mitigated, the CAISO will add a cost, not to exceed $0.01, to the Competitive LMP used in the MPM process prior to the DAM and RTM process. The CAISO will set the Competitive LMP Parameter as low as possible while reasonably creating price separation in the DAM and RTM process between the area where mitigation applies and other areas where mitigation does not apply. The CAISO will publish the value of the Competitive LMP Parameter in the Business Practice Manual.

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39.7.1.7 Hydro Default Energy Bid

Scheduling Coordinators may request a Hydro Default Energy Bid for a hydro ~~resources~~resource with storage capability ~~located in the CAISO Balancing Authority Area or any EIM Entity Balancing Authority Area~~that is subject to bid mitigation.

39.7.1.7.1 Computation

~~The~~For each Trading Day, the CAISO will calculate the Hydro Default Energy Bid as the maximum of the gas floor, the short-term component ~~or~~and the long-term/geographic component as specified in the subsections below.

39.7.1.7.1.1 Gas Floor

The CAISO will calculate the gas floor as the average tested heat rate for a ~~typical peaking~~ gas turbine resource, as published by the Energy Information Administration (EIA), multiplied by the gas price for the fuel region applicable for the location of the hydro resource, multiplied by 1.1.

39.7.1.7.1.2 Short-Term Component

The CAISO will calculate the short-term component as the maximum of the Day-Ahead on-peak price at the applicable ~~electric pricing hub~~Default Trading Hub, the balance of the month on-peak futures ~~prices~~price for the current month at the applicable ~~electric pricing hub~~Default Trading Hub, and the monthly ~~index~~on-peak futures price at the applicable ~~electric pricing hub~~Default Trading Hub for one (1) month after the current month, multiplied by 1.40.

39.7.1.7.1.3 Long-Term/Geographic Component

The CAISO will calculate the long-term/geographic component as the maximum of the Day-Ahead on-peak price at the applicable electric pricing hub, the balance of the month on-peak futures ~~prices~~price for the current month at the applicable electric pricing hub, and the monthly ~~index~~on-peak futures price at the applicable electric pricing hub for all future months up to the maximum storage horizon after the current month, multiplied by 1.1.

39.7.1.7.2 Requirements

As part of its request for a Hydro Default Energy Bid, the Scheduling Coordinator must submit the following information to the CAISO -

39.7.1.7.2.1 Transmission Rights Showing for Multiple Electric Pricing Hubs in Long-Term/ Geographic Component

A Scheduling Coordinator may request that the long-term/geographic component be calculated based on multiple electric pricing hubs (in addition to the Default Trading Hub) to the extent the Scheduling Coordinator demonstrates that it has transmission rights to each of the requested additional electric pricing hubs consistent with this section.

(a) Annually, and for each electric pricing hub requested that is not the Default Trading Hub, the Scheduling Coordinator must demonstrate that (1) they ~~have purchased~~hold firm transmission rights to enable delivery from the hydro ~~resource location~~resource's default market region to the requested electric pricing hub or ~~hubs or~~to a ~~similarly priced location~~delivery point that is represented by such pricing hub, or (2) provide documentation that supports a historical practice of purchasing qualifying firm transmission rights. Scheduling Coordinators may demonstrate transmission rights to multiple locations and, based on the CAISO's evaluation of such information, the CAISO may include ~~multiple~~additional electric pricing hubs (in addition to the Default Trading Hubs specified in Section 39.7.1.7.3) in the long-term/geographic component of the Hydro Default Energy Bid for the affected resources. The Scheduling Coordinator must attest in ~~their~~its submission that ~~they will~~it reasonably expects to use the ~~full quantity of the~~demonstrated transmission rights to deliver incremental sales from the hydro resource.

(b) For resources ~~with less~~ that demonstrate a quantity of firm transmission rights to a requested electric pricing hub that is less than the hydro resource's capacity~~, the~~ CAISO will ~~use~~include the requested electric pricing hub up to the quantity of demonstrated transmission rights , and apply a proportional weighting of ~~those bilateral~~the electric pricing hub prices when calculating ~~values in~~the value of the long-term/geographic component of the Hydro Default Energy Bid.

(c) In the absence of supporting transmission rights information when calculating the Hydro Default Energy Bid, the CAISO will revert to the ~~default bilateral electric pricing~~

~~hub~~Default Trading Hub specified in Section 39.7.1.7.3.

(d) If during the term of the annual period the Scheduling Coordinator no longer has the firm transmission rights previously demonstrated, the Scheduling Coordinator must inform the CAISO within 5 Business Days.

(e) The CAISO may audit the Scheduling Coordinator and request additional information in support of the Scheduling Coordinator's assertions.

(f) If the CAISO determines the Scheduling Coordinator has submitted inaccurate information, the CAISO may revert the resource to the ~~default~~Default Trading ~~Hubs~~Hub as specified in Section 39.7.1.7.3.

39.7.1.2.2 Maximum Storage Horizon. The maximum hydro resource storage horizon submitted by the Scheduling Coordinator must –

(a) Reflect the ~~typical~~maximum storage duration of a hydro resource's reservoir, defined as the length of time when cycling from its maximum reservoir elevation to a new maximum reservoir elevation during ~~typical~~a hydro year, and should be computed comparing historic reservoir elevations for multiple years for the hydro resource and observing typical cycling times for the hydro resource.

(b) Be supported by (1) a written attestation by a representative that can legally bind the company stating that the value submitted to the CAISO as the maximum storage horizon is consistent with the requirements specified in this section 39.7.1.7.2 (b), or (2) corroborating information submitted to the CAISO, which may include several years of historic reservoir levels for the specific hydro resource and regulatory filings related to the operations of the hydro resource.

39.7.1.7.3 Eligible Hubs

A Scheduling Coordinator may elect one or more of the following as a Default Trading ~~Hubs~~

~~The default Trading Hubs for each hydro resource area shall be designated as:~~

~~(a) PacifiCorp West, Portland, Powerex, Puget Sound will be in the~~ Hub or an electric pricing hub: Mid-Columbia Trading Hub~~.~~

~~(b) Arizona, Idaho, PacifiCorp East, NV Energy will be in the~~ ; Alberta; Palo Verde~~.~~

~~(c) Northern California will be in the ;~~ North-of-path 15~~.~~

~~(d) Southern California will be in the;~~ and South-of-path 15. Each resource's Default Trading Hub and any approved electric pricing hubs shall be reflected in the CAISO Master File for the relevant resource.

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- Competitive LMP Parameter

A cost added to the Competitive LMP used in the MPM process in accordance with Section 34.1.5.5.

- Hydro Default Energy Bid

A Default Energy Bid for a hydro resource calculated in accordance with Section 39.7.1.7.

29.39 EIM Market Power Mitigation.

(a) **EIM Market Power Mitigation Procedure.** The CAISO shall apply the Real-Time Local Market Power Mitigation procedure in Section 39.7 to the Energy Imbalance Market, including EIM Transfer constraints into an EIM Entity Balancing Authority Area on an EIM Internal Intertie, except as provided in Section 29.39.

(b) **Competitive Path Assessment.** The CAISO shall conduct the competitive path assessment to determine for each EIM Entity Balancing Authority Area whether a path is competitive or non-competitive, consistent with Section 39.7.2, except that –

(1) EIM Participating Resource Scheduling Coordinators shall submit information required by the CAISO to perform the competitive path assessment;

(2) the competitive path assessment shall not exclude EIM Participating Resources from the test used to determine the competitiveness of Transmission Constraints on the basis that they may be net buyers of Energy in the Real-Time Market; and

(3) the CAISO may establish different Reference Buses for each Balancing Authority Area, which need not be within the Balancing Authority Area, for calculating the LMP decomposition which is used to trigger Bid mitigation, based on the topology of each Balancing Authority Area and consideration of the bus at which the Marginal Cost of Congestion component of Locational Marginal Prices is least influenced by market power.

(c) **Locational Marginal Price Decomposition.** The CAISO shall perform the Locational Marginal Price decomposition for each EIM Entity Balancing Authority Area using the results of the competitive path assessment and the Congestion pricing results of the pre-market run to determine which resources may have local market power due to Congestion on a non-competitive Transmission Constraint, consistent with Section 34.2.3 and 39.7.

(d) **Default Energy Bids.** The CAISO shall use the methods and standards set forth in Section 39.7 to determine Default Energy Bids for EIM Participating Resources, except that the CAISO will use the Market Services Charge and System Operations Charge

reflected in the EIM Administrative Charge.

(e) **Incremental Net EIM Transfer Limit.**

(1) **Election.** An EIM Entity Scheduling Coordinator may elect for the CAISO to limit the incremental net EIM Transfer from above after the MPM process for the EIM Entity Balancing Authority Area pursuant to the election procedures and timelines established in the Business Practice Manual for the Energy Imbalance Market.

(2) **Application.** In the applicable RTM process, incremental net EIM Transfers from an EIM Entity Balancing Authority Area that has made the election in Section 29.39(e)(1) will be limited when the MPM process triggers mitigation and EIM Transfers in the MPM process are constrained in the import direction to that EIM Entity Balancing Authority Area, or a group of EIM Entity Balancing Authority Areas that includes that EIM Entity Balancing Authority Area.

(3) **Limit.** The incremental net EIM Transfer limit in the RTM process will be the sum of the Flexible Ramping Up awards in the EIM Entity Balancing Authority Area prior to the RTM process for the interval to which the MPM process applies, which is in excess of the EIM Entity Balancing Authority Area's corresponding Flexible Ramping Up requirement, plus the greater of—

(A) the net EIM Transfer in the MPM process described in Section 34.1.5 prior to the RTM process for the interval to which the MPM process applies; or

(B) the net EIM Transfer represented by the EIM Base Schedules at each EIM Internal Intertie for the interval to which the MPM process applies.

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31.2.3 Bid Mitigation

If the non-competitive Congestion component of an LMP calculated in an MPM process is greater than zero (0), then any resource at that Location that is dispatched in that MPM process is subject to Local Market Power Mitigation. Bids on behalf of any such resource, to the extent that they exceed the Competitive LMP plus the Competitive LMP Parameter at the resource's Location for the DAM and RTM process interval for which the MPM process applies, will be mitigated to the higher of the resource's Default Energy Bid, as specified in Section 39, or the Competitive LMP plus the Competitive LMP Parameter at the resource's Location for the DAM and RTM process interval for which the MPM process applies. To the extent a Multi-Stage Generating Resource is dispatched in the MPM process and the non-competitive Congestion component of the LMP calculated at the Multi-Stage Generating Resource's Location is greater than zero, for purposes of mitigation, all the MSG Configurations will be mitigated similarly and the CAISO will evaluate all submitted Energy Bids for all MSG Configurations based on the relevant Default Energy Bids for the applicable MSG Configuration. The CAISO will calculate the Default Energy Bids for Multi-Stage Generating Resources by submitted MSG Configuration. Any market Bids equal to or less than the Competitive LMP plus the Competitive LMP Parameter will be retained in the DAM and RTM process.

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34.1.5 Mitigating Bids in the RTM

34.1.5.1 Generally

After the Market Close of the RTM, after the CAISO has validated the Bids pursuant to Section 30.7 and Section 34.1.4, and prior to conducting any other RTM processes, the CAISO conducts a MPM process. The results are used in the RTM optimization processes. Bids on behalf of Demand Response Resources, Participating Load, and Non-Generator Resources are considered in the MPM process but are not subject to Bid mitigation. Bids from resources comprised of multiple technologies that include Non-Generator Resources will remain to be subject to all applicable market power mitigation under the CAISO Tariff, including Local Market Power Mitigation.

34.1.5.2 Fifteen Minute Market MPM

The MPM process for each fifteen-minute (15) interval for a Trading Hour starts with the unmitigated Bid set as validated pursuant to Section 30.7 and Section 34.1.4. The MPM process produces results for each fifteen (15) minute interval of the Trading Hour and thus may produce up to four mitigated Bids for any given resource for the Trading Hour. The determination as to whether a Bid is mitigated is made based on the non-competitive Congestion component of each LMP for each fifteen (15) minute interval of the applicable Trading Hour, using the methodology set forth in Section 31.2.3 above. If a Bid is mitigated in the MPM process for a fifteen (15) minute interval for a Trading Hour, the mitigated Bid will be utilized in the RTM process for that fifteen (15) minute interval. If a Bid is not mitigated in a fifteen (15) minute interval, the CAISO will still mitigate that Bid in subsequent fifteen (15) minute intervals of the Trading Hour if the MPM runs for the subsequent intervals determine that mitigation is needed.

34.1.5.3 Real-Time Dispatch MPM

The RTD MPM process produces results for each five (5) minute interval of a Trading Hour. The determination as to whether a Bid is mitigated is made based on the non-competitive Congestion component of each LMP for each five (5) minute interval, using the methodology set forth in Section 31.2.3 above. The RTD MPM process is performed for each advisory interval within a configurable time frame from the binding RTD interval to mitigate bids used in the following RTD for these intervals.

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34.1.5.5 Competitive LMP Parameter

When a Bid is mitigated, the CAISO will add a cost, not to exceed $0.01, to the Competitive LMP used in the MPM process prior to the DAM and RTM process. The CAISO will set the Competitive LMP Parameter as low as possible while reasonably creating price separation in the DAM and RTM process between the area where mitigation applies and other areas where mitigation does not apply. The CAISO will publish the value of the Competitive LMP Parameter in the Business Practice Manual.

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39.7.1.7 Hydro Default Energy Bid

Scheduling Coordinators may request a Hydro Default Energy Bid for a hydro resource with storage capability that is subject to bid mitigation.

39.7.1.7.1 Computation

For each Trading Day, the CAISO will calculate the Hydro Default Energy Bid as the maximum of the gas floor, the short-term component and the long-term/geographic component as specified in the subsections below.

39.7.1.7.1.1 Gas Floor

The CAISO will calculate the gas floor as the average tested heat rate for a gas turbine resource, as published by the Energy Information Administration (EIA), multiplied by the gas price for the fuel region applicable for the location of the hydro resource, multiplied by 1.1.

39.7.1.7.1.2 Short-Term Component

The CAISO will calculate the short-term component as the maximum of the Day-Ahead on-peak price at the applicable Default Trading Hub, the balance of the month on-peak futures price for the current month at the applicable Default Trading Hub, and the monthly on-peak futures price at the applicable Default Trading Hub for one (1) month after the current month, multiplied by 1.40.

39.7.1.7.1.3 Long-Term/Geographic Component

The CAISO will calculate the long-term/geographic component as the maximum of the Day-Ahead on-peak price at the applicable electric pricing hub, the balance of the month on-peak futures price for the current month at the applicable electric pricing hub, and the monthly on-peak futures price at the applicable electric pricing hub for all future months up to the maximum storage horizon after the current month, multiplied by 1.1.

39.7.1.7.2 Requirements

As part of its request for a Hydro Default Energy Bid, the Scheduling Coordinator must submit the following information to the CAISO -

39.7.1.7.2.1 Transmission Rights Showing for Multiple Electric Pricing Hubs in Long-Term/ Geographic Component

A Scheduling Coordinator may request that the long-term/geographic component be calculated based on multiple electric pricing hubs (in addition to the Default Trading Hub) to the extent the Scheduling Coordinator demonstrates that it has transmission rights to each of the requested additional electric pricing hubs consistent with this section.

(a) Annually, and for each electric pricing hub requested that is not the Default Trading Hub, the Scheduling Coordinator must demonstrate that (1) they hold firm transmission rights to enable delivery from the hydro resource's default market region to the requested electric pricing hub or to a delivery point that is represented by such pricing hub, or (2) provide documentation that supports a historical practice of purchasing qualifying firm transmission rights. Scheduling Coordinators may demonstrate transmission rights to multiple locations and, based on the CAISO's evaluation of such information, the CAISO may include additional electric pricing hubs (in addition to the Default Trading Hubs specified in Section 39.7.1.7.3) in the long-term/geographic component of the Hydro Default Energy Bid for the affected resources. The Scheduling Coordinator must attest in its submission that it reasonably expects to use the demonstrated transmission rights to deliver incremental sales from the hydro resource.

(b) For resources that demonstrate a quantity of firm transmission rights to a requested electric pricing hub that is less than the hydro resource's capacity CAISO will include the requested electric pricing hub up to the quantity of demonstrated transmission rights , and apply a proportional weighting of the electric pricing hub prices when calculating the value of the long-term/geographic component of the Hydro Default Energy Bid.

(c) In the absence of supporting transmission rights information when calculating the Hydro Default Energy Bid, the CAISO will revert to the Default Trading Hub specified in Section 39.7.1.7.3.

(d) If during the term of the annual period the Scheduling Coordinator no longer has the firm transmission rights previously demonstrated, the Scheduling Coordinator must inform the CAISO within 5 Business Days.

(e) The CAISO may audit the Scheduling Coordinator and request additional information in

support of the Scheduling Coordinator's assertions.

(f) If the CAISO determines the Scheduling Coordinator has submitted inaccurate information, the CAISO may revert the resource to the Default Trading Hub as specified in Section 39.7.1.7.3.

39.7.1.2.2 Maximum Storage Horizon. The maximum hydro resource storage horizon submitted by the Scheduling Coordinator must –

(a) Reflect the maximum storage duration of a hydro resource's reservoir, defined as the length of time when cycling from its maximum reservoir elevation to a new maximum reservoir elevation during a hydro year, and should be computed comparing historic reservoir elevations for multiple years for the hydro resource and observing typical cycling times for the hydro resource.

(b) Be supported by (1) a written attestation by a representative that can legally bind the company stating that the value submitted to the CAISO as the maximum storage horizon is consistent with the requirements specified in this section 39.7.1.7.2 (b), or (2) corroborating information submitted to the CAISO, which may include several years of historic reservoir levels for the specific hydro resource and regulatory filings related to the operations of the hydro resource.

39.7.1.7.3 Eligible Hubs

A Scheduling Coordinator may elect one or more of the following as a Default Trading Hub or an electric pricing hub: Mid-Columbia Trading Hub; Alberta; Palo Verde; North-of-path 15; and South-of-path 15. Each resource's Default Trading Hub and any approved electric pricing hubs shall be reflected in the CAISO Master File for the relevant resource.

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- Competitive LMP Parameter

A cost added to the Competitive LMP used in the MPM process in accordance with Section 34.1.5.5.

- Hydro Default Energy Bid

A Default Energy Bid for a hydro resource calculated in accordance with Section 39.7.1.7.

Attachment B

Information Substantiating Hydro DEB

In accordance with Section 39.7.1.7.2 of the CAISO Tariff, Powerex hereby submits information regarding its long-term firm transmission rights and maximum storage horizon to support its request for a Hydro Default Energy Bid for use in connection with its participation in the CAISO Energy Imbalance Market.

I. Transmission Rights

As discussed further below, Powerex holds firm transmission reservations that warrant inclusion of the NP-15, SP-15, and Alberta electric pricing hubs in the calculation of the Long-Term/Geographic Component of Powerex's Hydro Default Energy Bid.

A. NP-15 and SP-15

Tables 1 and 2 below provide an overview of firm transmission rights that are currently held by Powerex and that can be used to support deliveries to NP-15 and SP-15.[1] These rights represent forward firm and conditional firm[2] transmission service agreements to enable deliveries from the boundary of its default market region (*i.e.*, the BPA primary network) to these electric trading hubs.

Table 1: Transmission Reservations Supporting Delivery To NP-15

POR	POD	Product	2019	2020
JohnDay	COB	FIRM	870	870(1)
JohnDay	COB	CONDITIONAL FIRM	200	200
Total			**1070**	**1070**

(1) 200 MW of Powerex's firm transmission rights expire in August 2020. Powerex has a contractual right to renew service and may do so approximately 12 months prior to expiration.

Table 2: Transmission Reservations Supporting Delivery To SP-15

POR	POD	Product	2019	2020
BigEddy	NOB	FIRM	1437	1437
Total			**1437**	**1437**

B. AESO

Table 3 depicts transmission rights supporting delivery to the AESO electric pricing hub. These rights represent Powerex's forward firm and conditional firm transmission service agreements to enable deliveries to Alberta.

Table 3: Transmission Reservations Supporting Delivery To AESO[3]

POR	POD	Product	2019	2020
GMS.MCA.REV	AB.BC	FIRM	330	330
GMS.MCA.REV	AB.BC	CONDITIONAL FIRM	300	300
Total			**630**	**630**

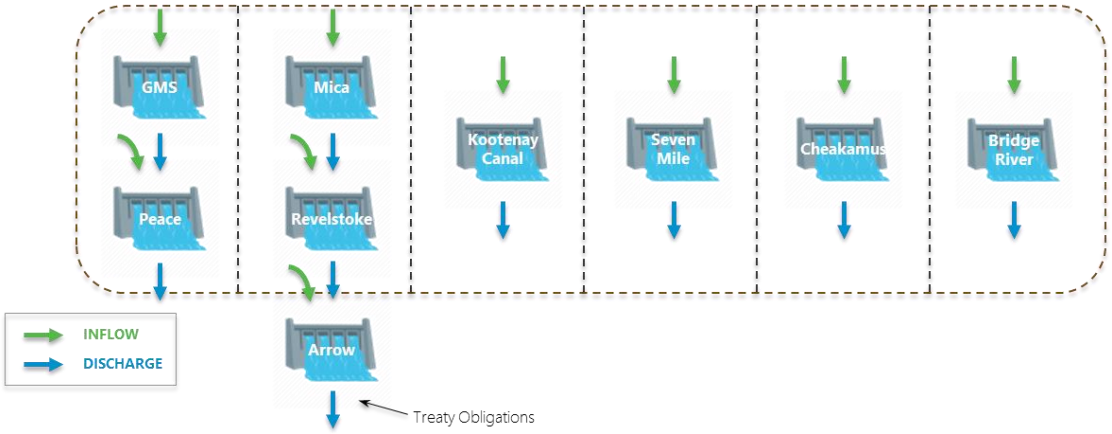
[1] The quantities listed are based on Powerex's transmission service agreements and do not include the impact of transmission outages or de-rates.

[2] Powerex has included conditional firm service because such service is only subject to curtailment in certain limited conditions and otherwise generally maintains a firm transmission priority.

[3] Values are based on executed service agreements, as well as service agreements received and currently being finalized, with execution expected on or before May 15, 2019.

II. Support for a Maximum Storage Horizon of 12 Months

Powerex's EIM Aggregate Participating Resource ("APR") represents surplus capability from 8 resources owned by Powerex's parent, BC Hydro:

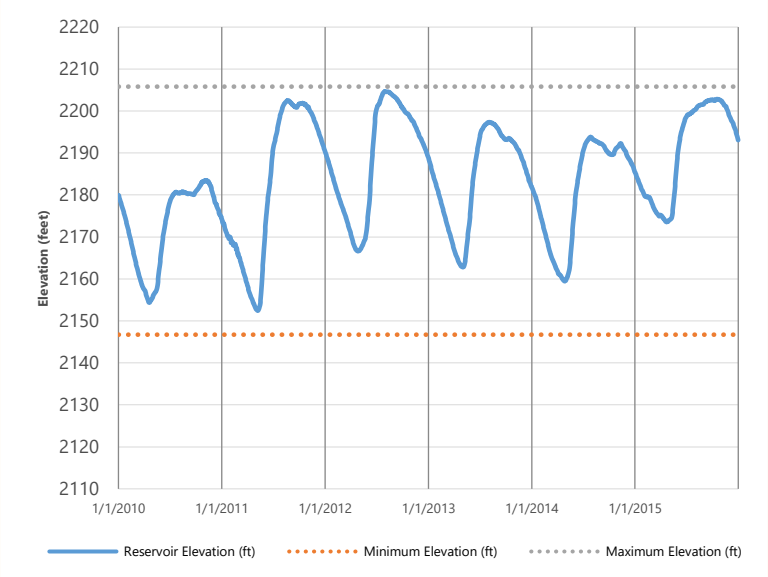


Powerex requests a Maximum Storage Horizon that is based on the maximum potential storage capabilities at the GMS reservoir (Williston Lake) and Mica reservoir (Kinbasket Lake), both of which have multi-year storage capabilities. Peace, Revelstoke, Kootenay Canal, Seven Mile, Cheakamus, Bridge River have shorter-term storage reservoirs. Peace and Revelstoke facilities benefit, however, from upstream storage capabilities at GM Shrum and Mica.

The following sections provide information relevant to determining the Maximum Storage Horizon of Powerex's EIM APR.

A. Public Data Shows Annual Cycling Of Largest BC Hydro Reservoirs

Williston Reservoir (2010-2015)

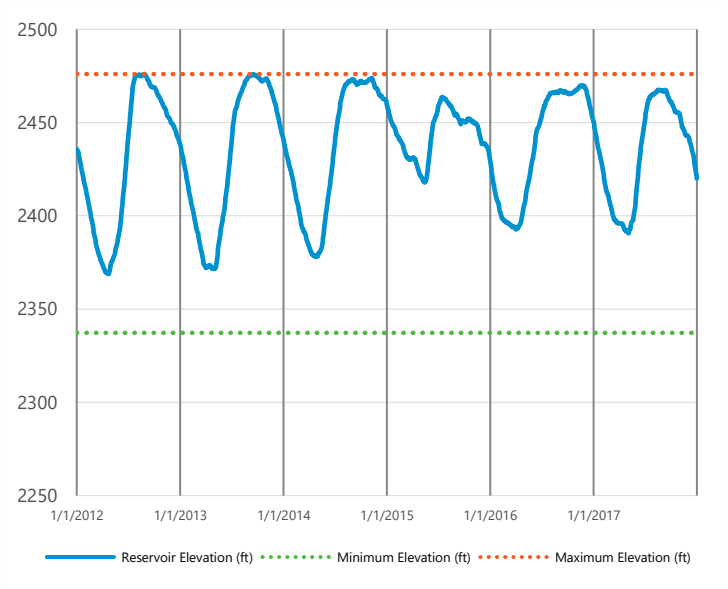


Source: *Daily Water Level Data for WILLISTON LAKE AT LOST CABIN CREEK*
https://wateroffice.ec.gc.ca/report/historical_e.html?stn=07EF002

Notes:

Elevation data are adjusted for datum at 2067.06 feet (630.040 m)
Elevations are converted from meters to feet
Minimum and maximum elevations are from 1976 to 2015
CAISO to verify Powerex analysis using data from above noted link

Kinbasket Reservoir (2012–2017)



Source: Daily Water Level Graph for KINBASKET LAKE AT MICA DAM
https://wateroffice.ec.gc.ca/report/historical_e.html?stn=08ND017

Notes:
Elevation data are absolute values and are not adjusted for a datum
Elevations are converted from meters to feet
Minimum and maximum elevations are from 1976 to 2017
CAISO to verify Powerex analysis using data from above noted link

B. Public Information Describing Storage Capabilities of BC Hydro System

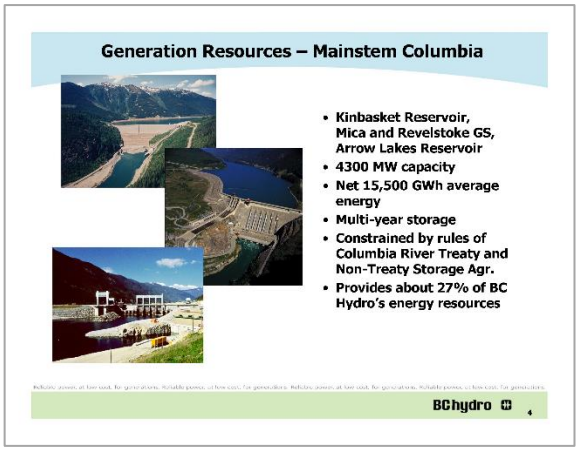
1. Excerpt from BC Hydro Provincial Integrated Electricity Planning Committee Information Sheet #4, Introduction to BC Hydro's Integrated Electric System

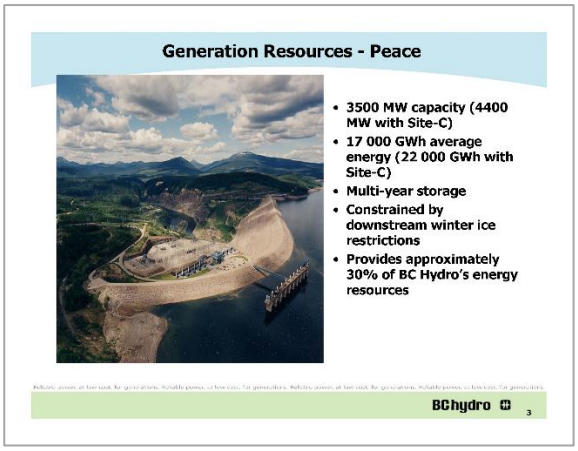
"The hydroelectric facilities on the Peace and Columbia Rivers also provide a significant portion of the energy capability of BC Hydro's Heritage resources. The GM Shrum and Peace Canyon generating stations on the Peace River produce 29 per cent of BC Hydro's Heritage energy, while Mica and Revelstoke hydroelectric plants on the Columbia River together produce 25 per cent. ***Both of the hydroelectric systems on the Columbia and the Peace River have large reservoirs that provide multi-year storage.*** Williston Reservoir on the Peace River is 1773 km^2 while the Kinbasket Reservoir behind Mica Dam on the Columbia is 425 km^2.

The generation system must be operated in a way that protects consumers from a shortage of electricity in periods of low inflows and makes the best use of the water available when inflows are at average or higher levels. In general, ***BC Hydro's storage reservoirs are drawn down in the winter months*** and are at their lowest point in the spring before the freshet. The large water volume from ***snowmelt in the spring and summer then refills the reservoirs***. The large storage reservoirs on the Peace and Columbia Rivers ***allow water from wet years (above average snow and rain) to be stored and used in subsequent drier years.*** Operation of reservoirs on the Columbia River is partly constrained by the

Columbia River Treaty, which is a treaty between Canada and the U.S. signed in 1961 when the hydroelectric development of the Columbia basin was initiated."[4]

2. Excerpt from January 2013 BC Hydro Presentation[5]





3. BC Hydro, Peace Project Water Use Plan[6]

"Because ***Williston Reservoir has multi-year storage capability*** annual inflow/discharge volumes may vary. For example, in years of high inflows, extra water may be stored to fill or recharge the reservoir resulting in the discharge for those years being less than the inflow. The ***available storage at Williston Reservoir is approximately 14 per cent greater than the average annual inflow***."

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[4] Available at: https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/info/pdf/info_iep_pre_reading_4.pdf.

[5] Available at: https://www.usea.org/sites/default/files/event-/BC_Generation_Overview_REV.pdf.

[6] Available at: https://www.acee-ceaa.gc.ca/050/documents/p63919/97604E.pdf.