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From: Greene,Richard A (BPA) - LP-7
Sent: Wed Apr 11 12:17:17 2018
To: Olive,J Courtney (BPA) - LP-7
Subject: FW: Strategy Negotiations Documents for EIM IMPORTANT
Importance: High
Attachments: Federal Resource Participation ADF v2.docx; Legal Memo-Fed Resource ADF.PDF; Excerpts from Oct 2017 Legal Analysis For FRP ADF.pdf; Negotiation Strategy Proposal.docx

(b)(5) [redacted]

From: Davis,Thomas E (BPA) - LT-7
Sent: Tuesday, March 27, 2018 11:39 AM
To: Herrin,Janet C (BPA) - K-7; Cathcart,Michelle M (BPA) - TO-DITT-2; Mantifel,Russell (BPA) - TSQM-DITT-2; Manary,Michelle L (BPA) - TS-DITT-2; Cooper,Suzanne B (BPA) - PT-5; Cook,Jeffrey W (BPA) - TP-DITT-2; Connolly,Kieran P (BPA) - PG-5; Symonds,Mark C (BPA) - BD-3; Federovitch,Eric C (BPA) - PTM-5; Kerns,Steven R (BPA) - PGS-5; Cook,Joel D (BPA) - P-6; Shaheen,Richard L (BPA) - T-DITT-2; Miller,Todd E (BPA) - LP-7; Zimmerman,Nita M (BPA) - B-3; Jensen,Mary K (BPA) - L-7
Subject: Strategy Negotiations Documents for EIM IMPORTANT
Importance: High

Attached below, please find the following documents for Friday's meeting regarding Bonneville's negotiation strategy for EIM participation.

The first three documents include the ADF for Federal resource participation in the EIM (led by Steve Kerns) and supporting legal analysis. There are two legal analyses attached for this ADF. The first is the analysis for the specific ADF itself and the second includes relevant excerpts from OGC's comprehensive EIM legal analysis done back in October 2017.

The next document is staff's Negotiation Strategy proposal for the other topics not addressed in the ADFs addressing Federal resource participation and utilization of transmission for EIM transfers.

Staff is still finalizing the ADF regarding utilization of transmission for EIM transfers (led by Russ Mantifel) today. I will send it out this evening along with the legal analysis for that ADF.

The expectation is that Friday's meeting will be a discussion of these documents, not a presentation of them, so please read them beforehand and come prepared to discuss.

If you have any questions, please do not hesitate to communicate with me or Todd Miller.

Tom

Negotiation Strategy Proposal

This document follows up the Negotiation Strategy document embedded in Bonneville staff's "Proposal for Grid Modernization" presented to the Front Office on January 24, 2018. This document is a companion to two ADFs being prepared by staff regarding Federal resource participation in the EIM and utilization of transmission in the EIM.

Purpose:

In this document, staff proposes negotiation strategies on the topics not addressed by the ADFs and solicits management feedback and approval of staff's proposals. Management direction and approval is necessary so that staff can move forward with negotiating with the CAISO as well as interfacing with other external entities. As negotiations progress and more information on the topics set forth below is known, Bonneville may have to change or modify its strategy for negotiations. Thus, staff's positions set forth below should be considered "starting" positions to allow the initiation of negotiations. This document follows the organization of the topics included in the Negotiation Strategy document.

High-Level Negotiating Criteria:

Staff proposes the following "high-level" criteria to generally guide how Bonneville negotiates with the CAISO. Most of these criteria are reflected in the substantive discussion below.

1. Bonneville's participation in the EIM must provide financial benefits to Bonneville and its customers.
2. The EIM must provide operational and reliability benefits to Bonneville's transmission system and the region.
3. Cost shifts between Bonneville's customers caused by participation in the market should be minimized or mitigated to the extent possible.
4. Participation in the EIM must comply with the applicable statutory authorities for the Federal power and transmission systems. More specifically, the market operator or market rules shall not cause Bonneville to violate operational requirements of the Federal hydro or transmission systems.
5. The EIM should recognize and monetize the environmental attributes (low carbon value) of the Federal hydro system.

Section 1: Assumptions Regarding Bonneville's Participation in the EIM

This section identified three key assumptions that Bonneville needs to settle on before starting negotiations.

A. Load Zones: Staff proposed that Bonneville will only have one load zone in its balancing authority area (BAA) for the EIM and not to consider additional load zones unless there are studies showing significant benefit to Bonneville from using multiple load zones that exceed implementation costs. Multiple load zones may help manage cost allocation and rate design issues among PF rate customers but that risk appears to be very low and would introduce significant settlement complexity that staff believes is unwarranted at this time.

Staff Proposal: Move forward assuming that Bonneville will only have one load zone. Bonneville may revisit this decision later if new analysis or negotiations indicate a demonstrable benefit that exceeds the cost of having more than one load zone.

B. Federal Generation: Concurrent with the preparation and presentation of this document to management, staff is preparing and presenting a separate ADF on this topic for Bonneville management's direction and decision. Therefore, no staff proposal is made here.

C. Transmission: Concurrent with the preparation and presentation of this document to management, staff is preparing and presenting a separate ADF on this topic for Bonneville management's direction and decision. Therefore, no staff proposal is made here.

Section 2: Bonneville EIM Participation Requirements Outside of CAISO Negotiations

A. Carbon Markets and Legislation: [redacted] Hence Bonneville avoids making direct power sales to the CAISO by marketing ("sleeving") through a third party. Oregon is considering joining California's carbon market, which will elevate the issue.

Participation in the EIM through a third party is unprecedented. Thus, Bonneville's participation in the EIM would likely be very difficult if it must participate through a third party. Moreover, the additional cost imposed by third-party participation may eliminate any benefit to Bonneville from market participation. In the absence of legislation, Bonneville would need some sort of modified arrangement to provide sales directly to California through the EIM.

WAPA was able to get waiver language in an appropriations bill that allows it to pay the state carbon tax. Bonneville staff has drafted similar legislation and gained support from public power for moving forward with a similar approach, but DOE removed the language from legislation in 2017.

Staff Proposal: *Aggressively pursue legislation* that allows Bonneville to participate in CAISO's markets without having to sleeve power through a third party. Assume, for purposes of negotiation, that Bonneville will be able to participate directly in the CAISO's markets without having to sleeve through a third party. This should be a *high priority* item.

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B. <u>Tariff Process</u>: Bonneville will have to revise its Open Access Transmission Tariff (Tariff) to include EIM-specific provisions (including a new EIM market rules attachment) before joining the EIM. There are two issues regarding Bonneville's Tariff that Bonneville must address before it can join the EIM.

First, Bonneville must implement a process to revise its Tariff that will enable Bonneville to update its Tariff with EIM specific provisions. Under Bonneville's current Tariff, Section 9 of requires Bonneville to seek FERC approval of any changes to its Tariff. Bonneville no longer plans to seek FERC approval of prospective changes to its Tariff and has taken several steps to revise section 9 and to adopt a process for future Tariff changes. On January 10, 2018, Bonneville announced to the region that a new Bonneville Tariff will be developed through a hearing process conducted under Section 212 of the Federal Power Act. This process follows Bonneville's rate making procedures, but allows for the hearing officer to make a recommendation to the Administrator regarding general terms and conditions for transmission service. Staff is preparing to conduct a 212 process starting in 2018. However, if Bonneville fails to adopt a process to revise its Tariff, Bonneville cannot participate in the EIM because it cannot update its Tariff to reflect EIM requirements..

Second, the 212 Tariff process will only change the tariff for new service and all customers with existing contracts will the have option to convert to the new tariff. If there are existing transmission customers that are unwilling to convert to the new tariff, Bonneville would be forced to provide transmission and ancillary services under two separate tariffs with materially different terms and conditions. This would be complicated and costly to administer under a pre-EIM participation scenario, but when Bonneville makes the tariff changes to join the EIM, those changes will only exist in the new tariff and will not be applicable to customers that did not convert.

Joining the EIM when Bonneville has customers taking transmission service under two different tariffs would be very difficult and presents some significant financial and legal risks. For example, the EIM will provide imbalance service to Bonneville's entire load, but Bonneville would not be able to pass through any EIM imbalance costs to transmission customers under the old tariff. In the case of a slice customer under the old tariff, Bonneville's financial exposure could be significant and needs additional analysis to determine the level of exposure. Billing and settlements will be incredibly complicated under two tariffs because Bonneville will have to determine how EIM costs and charges are allocated to customers under each tariff. Moreover, all loads and resources, regardless of whether they are EIM participating resources, will have to provide certain data in order for EIM to operate properly. Therefore, to some degree, all customers with resources in Bonneville's balancing authority area will likely have to comply with EIM rules, but, for those customers still under the old tariff, Bonneville would have to compel compliance through business practices or rate schedules. Finally, customers under the old tariff that would not be eligible to participate in the EIM but potentially exposed to certain EIM charges either directly or indirectly could assert unduly discriminatory treatment. All of these issues will need to be further explored in more detail as Bonneville moves forward.

Staff Proposal: Staff notes that if Bonneville is going to join an EIM, running a *successful* section 212 process must be a top agency priority. In this context, success includes motivating customers to convert their transmission service to the new tariff through settlement. A two-tariff paradigm must be avoided or Bonneville's ability to join the EIM is significantly jeopardized.

C. Cost Shifts Among Bonneville Transmission Customers: Bonneville should aim to equitably allocate the costs of participating in the EIM to the beneficiaries of EIM participation. One possible outcome of Bonneville's participation in the EIM is a shift by certain point-to-point customers to optimize their transmission usage by reducing their purchases of long-term firm point-to-point rights. In doing so, there could be cost shifts to transmission customers taking network service that are not directly participating in the EIM. Bonneville must strive to balance market participation and the impacts to network customers. This risk is present today, but may be exacerbated by Bonneville joining the EIM.

Staff Proposal: The avoidance of cost shifts to network customers should be a major consideration and evaluation criteria in the development of Bonneville policy regarding the EIM and negotiations with the CAISO.

D. Balancing Authority Principles: Does Bonneville want to come up with an enforcement approach for ensuring that all resources meet the BA reliability tests? Do we want to ensure resource sufficiency through the BA provision of balancing reserves or do we require that all resources and load self-supply?

Staff Proposal: This requires a revisit of the Red Box ADF, which staff is beginning to start.

Section 3: Bonneville "Must Haves" in CAISO Negotiation

A. Dynamic Transfer Capability (DTC): Bonneville must retain its discretion as to how much DTC is made available for EIM transactions. To mitigate the risk of reliability impacts due to EIM transfers, Bonneville limits the use of DTC by the EIM on its system through rate of change (ROC) limitations on the network and specifying an amount of available DTC on the southern intertie. (DTC in this context is used to refer to both limitations.) DTC acts as a constraint on the amount of EIM transfers that can flow on the system. It is assumed that in an EIM, Bonneville as the BAA would continue to set and utilize DTC limits.

The CAISO and other EIM entities utilizing Bonneville's transmission system have advocated for expanding access to DTC in the past and will likely do so again if Bonneville joins the EIM. Bonneville is currently working on tools that will allow for assessing real-time voltage visibility that will inform Bonneville operators as to the total amount of DTC that can reliably be made available. These tools may result in more DTC being offered.

Staff Proposal: With any consideration of expanding the usage of DTC for the EIM, the primary uses of DTC historically—serving load following customers, delivering ancillary services, and maintaining an appropriately conservative margin to protect reliability—must be prioritized over allowing additional EIM transfers across the Bonneville system.

B. Reliability Tools: When the FCRPS is the only network resource on response, Power Services requires operational tools, such as Operational Controls for Balancing Reserves (OCBR), to limit balancing reserves deployed to that which Bonneville agreed to be set aside as Generation Inputs determined by the BP-22 rate case. Without operational tools like OCBR, deployment of balancing reserves or other uncontrolled use of FCRPS flexibility on the system could absorb all of the flexibility that Bonneville could bid into the EIM leading to negative financial and operational consequences.

Another set of system reliability tools is identified in section 5 of the Coordinated Transmission Agreement. Those tools will include the management of real-time EIM flows on our transmission system to manage dynamic impacts as well as total impacts on our flowgates. Bonneville is implementing the management of EIM flows when we are curtailing and is developing tools to more efficiently implement curtailments through market redispatch and also to respond to reliability events. These tools will be implemented over the next few years.

Staff Proposal: Bonneville must retain its ability to implement operational controls, such as OCBR (fka DSO 216), those identified in section 5 of the Coordinated Transmission Agreement, and others to maintain reliability of the FCRTS. Staff believes a white paper should be prepared of Bonneville's reliability tools and how they could be impacted by joining the EIM.

C. Resource Sufficiency Standards: Resource sufficiency is a tool to help demonstrate a plan for reliable operations in Bonneville's BAA and ensure that parties are coming to the EIM with enough resources to meet their obligations before the hour so that they can equitably benefit from the EIM within the hour. This raises two specific questions that need further analysis and decision:

1. Depending on the decision after revisiting the decision in the "Red Box" Agency Decision Framework (discussed above), can Bonneville meet the existing CAISO EIM resource sufficiency tests, and can Bonneville satisfactorily demonstrate resource sufficiency to the CAISO for its entire BAA? An internal team needs to evaluate the CAISO EIM resource

sufficiency test for the Bonneville BAA and results will be monitored on an ongoing basis to support our negotiation posture.

2. Are the existing CAISO EIM resource sufficiency tests adequate to meet Bonneville resource sufficiency principles and commercial concerns stemming from potential leaning? There are anecdotes leading to some concern in both areas. Refer to CAISO market performance and planning materials which articulate their own concerns about CPS 1 and 2 compliance. Refer to the Powerex write-up on resource sufficiency regarding commercial concerns due to potential leaning.

Because Bonneville has more independent power producers embedded in its BAA than any other EIM entity, the resource sufficiency rules and standards that apply to participating and non-participating resources are very important to Bonneville.

Staff Proposal: Staff does not have a specific proposal regarding resource sufficiency at this time other than Bonneville should ensure that resource sufficiency rules are sufficient for all parties in the market (EIM/ISO) to reliably meet their obligations.

D. EIM Local Power Mitigation and Default Energy Bid (DEB) Requirements: Market power to a seller is the ability to profitably maintain prices above competitive levels for a significant period of time. In economics, market power is defined as the ability to alter profitably price away from competitive level and market efficiency. For the purposes of this paper, market power references a limited number of suppliers at a specific grid locality due to transmission congestion or voltage constraints that are able to set the locational marginal price above opportunity cost without sufficient competition. The CAISO runs a market power test before each hour to ensure a competitive market. If an entity is found to have market power both the offer to sell price and the bid to buy price are changed from the entity's bid to a default energy bid (DEB). The market solution is then recalculated, which could lead to substantive changes to awards, power flows, and de-optimization of the FCRPS. The DEB is set ahead of time via negotiations with the CAISO's Department of Market Monitoring. The current DEB options will need expansion to reflect the opportunity cost for energy limited hydro systems.

Staff is working on an internal white paper addressing the likelihood of market power in Bonneville's BAA and the unique nature of flexible hydro systems within this context. The current potential stakeholder process regarding a DEB option sought by Powerex may address this issue for Bonneville, by precluding any bid mitigation where the economic bid is below a certain threshold (like $100, or 300% above the ICE Mid-C Day-Ahead price). Lack of mitigation below these kind of reasonably high price thresholds would almost always result in Bonneville still dispatching at a level that would satisfy internal opportunity cost estimates. It should be noted that there is potential for a transmission product like 0-NX (bid award) to mitigate potential market power findings, by expanding the available transmission and increasing supply of generation provided by others.

Staff Proposal: Bonneville should continue to track and participate in the CAISO stakeholder processes related to DEB and to coordinate these efforts with other Northwest hydro generators. The CAISO assured Powerex that the DEB issues would be resolved before Powerex's EIM start date, but that has not happened. Bonneville needs to learn from Powerex's experience and ensure that market power mitigation rules will not undercut the value Bonneville expects to realize by joining the EIM. This is a *high* priority issue, and if it is not satisfactorily resolved, Bonneville's participation in the EIM should be reevaluated.

E. Bonneville's Oversupply Management Protocol (OMP): Bonneville requires the ability to replace a base schedule sourced by a non-Federal resource in our BAA with a base schedule sourced by the FCRPS to manage total dissolved gas (TDG) in negative priced markets. If the non-Federal resource base schedule was submitted to Bonneville as an EIM resource with an offer curve, Bonneville will submit the base schedule to the market operator.[1]

Bonneville needs to retain its negative pricing policy and not be required to bid or accept DEBs for sales/INCs that are negative. The "As-Is" OMP paradigm allows hydro duty schedulers to initiate a request for OMP as late as 10 minutes prior to the hour of delivery. In the EIM, data elements must be submitted to the market operator earlier, so the hydro duty scheduler will need to make the OMP decision earlier. While it's true that more may be learned between data submission and 10-min prior to the hour, this is more of a refinement of the amount rather than a determination of whether or not OMP is needed. As a result, there is a risk that we could over request OMP (incur additional OMP costs) or under request OMP (incur additional spill), but the magnitude to dollars and TDG are likely pretty small.[2]

Staff Proposal: Bonneville must retain the ability to meet all mandatory non-power objectives without being forced to be a price-taker in the EIM. Bonneville must retain control over OMP and its negative pricing policy. The EIM dispatch must honor OMP directives, and the EIM must not cause Bonneville to incur additional oversupply costs. Bonneville should encourage the market operator to move the data submission closer to the operating hour and/or to allow changes for this purpose as part of the auto-matching process.

Section 4: Bonneville "Wants" in CAISO Negotiations

A. CAISO Settlements Simplification: A large consensus of entities participating in or otherwise impacted by the EIM (including Power Services) believe the current EIM settlements structure is

[1] The assumption is that all resources in Bonneville's BAA will be submitted by the generation owner to the BA prior to the data being submitted to the market operator so that there will be an opportunity to replace the source of a non-Federal resource's base schedule. If the non-Federal resource submits directly to the market operator, we will need to figure out a way to signal to the market operator to change the source.
It's also worth noting that VERs could very well have no base schedule and go to the market as a price taker. If this is the case, the amount and costs of OMP could drop but at the consequence of higher TDG levels.
[2] It's worth pointing out that Bonneville has decided to initiate mandatory waiver of loss returns in preschedule which also results in greater risk to the magnitude of OMP and spill.

overly complex, non-transparent, reliant on manual exchanges of voluminous amounts of data, and often results in a rebilling/dispute resolution process that can continue for 3 years after the initial billing.

As an EIM Entity, Bonneville will settle all EIM transaction for the EIM Entity area with the CAISO and then Bonneville will pass through the appropriate charges to its customers that are subject to energy or generation imbalance charges. With the current complicated non-transparent settlements paradigm, Bonneville will face billing disputes with its customers and will become the middleman in disputes with the CAISO.

Additionally, Bonneville has some unique settlements challenges compared to other participating BAs, due to the comparatively high amount of non-federal generation within its BAA, as well as the amount of Power Services' load obligation that lies in 4-5 EIM participating BAAs. These factors magnify the complexity and expose Bonneville to significant workload and risk of inaccurate EIM settlements validation and continuous billing disputes.

Staff Proposal: Bonneville should seek changes that simplify and streamline the EIM settlement process. There are two potential non-exclusive paths for changing the CAISO settlements process: 1) Bonneville can join other EIM Entities and advocate for changes to the settlements process through the EIM governance process; and/or 2) Bonneville can make its participation in the EIM contingent on changes to the settlements process as part of negotiations with the CAISO. In either case, Bonneville needs to assign staff to learn and understand the current EIM settlements paradigm and then have the same staff benchmark and identify best practices of settlements in other organized markets that can be used to support changes to the EIM settlements process. Other EIM Entities will likely support improvements to the settlements process, and Bonneville will need to build a coalition of support for specific changes. If Bonneville wants to get these changes in place before joining, the discussion needs to be addressed early in the negotiation process. Bonneville should also advocate that CAISO become the centralized repository of EIM data such that all parties that incur EIM charges from a participating BA can rely on existing tools and processes to perform settlements validation.

Proposed Priority Level: High

B. Governance: Bonneville's participation in the EIM decision-making process under the current governance paradigm is legally permissible. However, the current governance structure would provide only marginal representation to Bonneville through a seat on the Regional Issues Forum (an advisory board) whose agenda is set by the CAISO staff and shared with other public power and investor-owned utility interests. While the interest of the Investor Owned Utilities is currently also supported by the Body of State Regulators advisory committee, there is currently no comparable representation of public power or PMA interests in the EIM governance structure.

Staff Proposal: Bonneville should negotiate certain changes to the EIM governance structure and bylaws described below to ensure better representation of Bonneville's interests. Bonneville's leverage to realize its desired concessions regarding governance from the CAISO will likely be at its highest during the negotiations of the EIM Implementation Agreement. Staff has identified two possible negotiation points.

1. *Enhanced Representation in an Advisory Capacity*: Bonneville could negotiate the creation of separate advisory body comprised of public power that includes Bonneville that is similar to the current Body of State Regulators, which represents the interest of the retail aspects of investor owned utilities and their retail customers in the EIM footprint. Currently, there is no separate but comparable body representing the interests of public power in the EIM footprint as there is for state jurisdictional retail interests. Another solution is expanding the Body of State Regulators to include public power representation that includes Bonneville's interests. However, expanding the Body of State Regulators to include a public power seat may still dilute Bonneville's representation. Staff believes a separate advisory body comprising public power would be more effective.

2. *Enhanced Representation on EIM Governing Body Nominating Board*: Bonneville could also ask for a position on the nominating committee for the EIM Board of Governors. FERC-jurisdictional entities have representation on the nominating committee. It is only fair that non-jurisdictionals and Federal Power Marketing Administrations participating in the EIM also have representation on the committee.

Proposed Priority Level: High

C. Carbon Value: It is important that the EIM dispatch and associated market prices accurately reflect the incremental value of emitted carbon. There are currently two working approaches on how to reflect carbon value in the EIM—a two pass solution, which tries to measure the incremental carbon emissions caused by the EIM market, or a hurdle rate construct that raises the EIM price by the identified threshold, in this case the emissions from a combined cycle gas plant.

A two pass solution more accurately reflects the incremental emissions caused by the EIM dispatch. Some potential gaming implications have been identified with this approach, but some version of a multi pass run appears to be the best identified option to accurately reflect the variable cost of emissions versus a flat adder in the hurdle rate construct. This approach would increase price volatility which would generally make EIM participation more valuable, leading to higher revenue from participation.

It is important that the EIM dispatch and associated market prices accurately reflect the incremental value of emitted carbon. There is concern that beyond the required bid adder to reflect the carbon value of the resource, the emissions from secondary dispatch is not accurately reflected. To mitigate for this, a hurdle rate construct is being considered. Still under development, this hurdle rate would apply to non emitting resources transferred into California. This would require Bonneville to be responsible for compliance which could include purchasing allowance.

Staff Proposal: Advocate for consistent treatment of emission rates for Asset Controlling Suppliers (ACS). This will ensure that ACS supply is equally incented to participate in all California markets.

Proposed Priority Level: High

D. Late-Breaking Constraints: Currently, the market operator requires data submission at T-75. However, changes to non-power constraints, Slice obligations and Trading Floor products can occur after this time.

   Staff Proposal: Bonneville should explore shortening this time window to be closer to the scheduling hour and/or developing a way to accommodate changes to the dispatchable range of the EIM resources and the associated bid curves. Not resolving this issue could result in unforeseen imbalance costs imposed on Power Services.

   Proposed Priority Level: Medium

E. Contingency Reserves Deployments: The NWPP Reserve Sharing Program (RSG) pools contingency reserve needs for BAs throughout the NWPP footprint and allows each RSG member to carry a lower amount that they would absent the RSG. The methodology used by the EIM to track contingency reserve deployments should consider the use of RSG members' resources to respond to qualifying events from other RSG members. In addition, the current method in the EIM for tracking outages is overly manual. Since the FCRPS has over 150 generating units, automation of this process would be beneficial.

   Staff Proposal: Bonneville and CAISO staff will discuss and document how the EIM will deal with contingency reserve deployments originate from the RSG. Bonneville staff will meet with other existing and soon-to-join EIM entities with hydro resources to discover how they deal with the outage process and discuss whether or not there are opportunities for automation.

   Proposed Priority Level: Medium

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From: Pettinger,Rebekah S (BPA) - LP-7
Sent: Wed Mar 21 08:23:09 2018
To: Hulett,Jimmy D (BPA) - LT-7; Chong Tim,Marcus H (BPA) - LT-7; Davis,Thomas E (BPA) - LT-7; Sigurdson,Ryan M (BPA) - LT-7; Johnson,Tim A (BPA) - LP-7; Greene,Richard A (BPA) - LP-7; Griffen,Christian W (BPA) - LT-7; Jensen,Mary K (BPA) - L-7; Miller,Todd E (BPA) - LP-7; Chan,Allen C (BPA) - LT-7; Schaeffer,Virginia K (BPA) - LG-7; Adams,Hub V (BPA) - LN-7; Cox,Tiffany L (BPA) - LP-7
Cc: Sigurdson,Ryan M (BPA) - LT-7
Subject: Federal Resource Participation ADF--Draft legal analysis
Importance: Normal
Attachments: MEMORANDUM--ADF on Gen3-20-18.docx

Here is our current draft of the Legal Analysis on the Federal Resource Participation ADF. It includes comments from Tim, which we are working to incorporate.

Rebekah

From: Hulett,Jimmy D (BPA) - LT-7
Sent: Tuesday, March 13, 2018 1:30 PM
To: Chong Tim,Marcus H (BPA) - LT-7; Davis,Thomas E (BPA) - LT-7; Pettinger,Rebekah S (BPA) - LP-7; Sigurdson,Ryan M (BPA) - LT-7; Johnson,Tim A (BPA) - LP-7; Greene,Richard A (BPA) - LP-7; Griffen,Christian W (BPA) - LT-7; Jensen,Mary K (BPA) - L-7; Miller,Todd E (BPA) - LP-7; Chan,Allen C (BPA) - LT-7; Schaeffer,Virginia K (BPA) - LG-7; Adams,Hub V (BPA) - LN-7; Cox,Tiffany L (BPA) - LP-7
Cc: Sigurdson,Ryan M (BPA) - LT-7
Subject: EIM Transmission Provision ADF--Draft legal analysis

Hi all,

Attached is our draft legal analysis for staff's ADF regarding how BPA will make transmission available to support EIM transfers.

I think we are a bit ahead of staff is at this point, so this may be subject to change. That said, it seems they have come to a consensus around the identified alternatives and hopefully there won't be new major revelations in the next week. So please edit and comment as you see fit.

I am also attaching staff's most recent draft of the ADF for reference.

Thanks,
Jimmy

Jimmy Hulett
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From: Greene,Richard A (BPA) - LP-7
Sent: Mon Mar 26 17:55:29 2018
To: Kerns,Steven R (BPA) - PGS-5 (srkerns@bpa.gov); Federovitch,Eric C (BPA) - PTM-5; Chang,Elsa (BPA) - PGST-5; Symonds,Mark C (BPA) - BD-3; Truong,Mai N (BPA) - PGST-5; Messemer,Clarisse M (BPA) - PGST-5
Cc: Pettinger,Rebekah S (BPA) - LP-7
Subject: Legal Analysis on Fed Resource ADF
Importance: Normal
Attachments: Legal Memo-Fed Resource ADF.pdf; Excerpts from Legal Analysis.pdf

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From: Johnson,Tim A (BPA) - LP-7
Sent: Tue Mar 20 13:28:35 2018
To: Greene,Richard A (BPA) - LP-7; Pettinger,Rebekah S (BPA) - LP-7
Subject: MEMORANDUM--ADF on Gen3-14-18
Importance: Normal
Attachments: MEMORANDUM--ADF on Gen3-14-18.docx

My edits and comments. Thanks for all your efforts on this stuff.

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[redacted]

(b)(5)

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(b)(5)

[redacted]

(b)(5)

[redacted]

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[redacted]

From: Chong Tim,Marcus H (BPA) - LT-7
Sent: Wed Mar 21 16:42:37 2018
To: Pettinger,Rebekah S (BPA) - LP-7; Greene,Richard A (BPA) - LP-7
Subject: MEMORANDUM--ADF on Gen3-20-18
Importance: Normal
Attachments: MEMORANDUM--ADF on Gen3-20-18.docx

This is nice work. I just caught a few nits. Thanks for the opportunity to review.

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[redacted]

(b)(5)

[redacted]

(b)(5)

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[redacted]

(b)(5)

[redacted]

From: Kochheiser,Todd W (BPA) - TOI-DITT-2
Sent: Tue Mar 06 09:57:13 2018
To: Messemer,Clarisse M (BPA) - PGST-5; Chang,Elsa (BPA) - PGST-5; Truong,Mai N (BPA) - PGST-5; Polsky,Cynthia H (BPA) - PGST-5; Will,Garland L (BPA) - PGST-5; Siewert,Christopher W (BPA) - PGSD-5; Van Calcar, Pamela M (BPA) - PGSP-5; Kerns,Steven R (BPA) - PGS-5; King,Eric V (BPA) - TSPP-TPP-2; Mantifel,Russell (BPA) - TS-DITT-2; Puyleart,Frank R (BPA) - TOOC-DITT-2; Sanford,Chris T (BPA) - TOR-DITT-1; Gaube,Stephen J (BPA) - PTF-5; Haraguchi,Kelii H (BPA) - PTM-5; Federovitch,Eric C (BPA) - PTM-5; Davis,Thomas E (BPA) - LT-7; Simpson,Troy D (BPA) - TOI-DITT-2; Dernovsek,David K (BPA) - PTKP-5; Greene,Richard A (BPA) - LP-7; Pettinger,Rebekah S (BPA) - LP-7; Symonds,Mark C (BPA) - BD-3; Hawkins,Robert E (BPA) - PGSD-5; Pedersen Mainzer,Margaret E (BPA) - PTL-5; Kitchen,Larry (BPA) - PTL-5
Cc: Stermer,Anna M (BPA) - PGSP-5
Subject: RE: ADF on the number of generation points - Todd's "Electrically Similar" and "Congestion Risk" documents
Importance: Normal
Attachments: 20180305_Congestion_Risk_v03_Draft.docx

All:

I found a problem with the pivot table I used to count up all the firm (priority 7) curtailments. Attached is an updated report and below is a copy of the updated table. As one would expect, the number of firm curtailments is much lower than the total.

CURTAILMENT F					
Row Labels	**2008**	**2009**	**2010**	**2011**	**2012**
NJD					
NOEL					
NOH					
NOH_SN					2
P-A					
R-P				2	
SOA					
SOA_SN					
SOC					
WOCN			2		

WOJD					
WOM					5
WOM - MAIN-GRID					
WOMSG					
Grand Total			**2**	**2**	**7**

Bonneville Power Administration | Transmission Operations
5411 NE Hwy 99 | TOK-DITT2 | Vancouver, WA 98663
Direct: (360) 418-8752 | **twkochheiser@bpa.gov**

From: Kochheiser,Todd W (BPA) - TOI-DITT-2
Sent: Monday, March 05, 2018 3:01 PM
To: Messemer,Clarisse M (BPA) - PGST-5; Chang,Elsa (BPA) - PGST-5; Truong,Mai N (BPA) - PGST-5; Polsky,Cynthia H (BPA) - PGST-5; Will,Garland L (BPA) - PGST-5; Siewert,Christopher W (BPA) - PGSD-5; Van Calcar, Pamela M (BPA) - PGSP-5; Kerns,Steven R (BPA) - PGS-5; King,Eric V (BPA) - TSPP-TPP-2; Mantifel,Russell (BPA) - TS-DITT-2; Puyleart,Frank R (BPA) - TOOC-DITT-2; Sanford,Chris T (BPA) - TOR-DITT-1; Gaube,Stephen J (BPA) - PTF-5; Haraguchi,Kelii H (BPA) - PTM-5; Federovitch,Eric C (BPA) - PTM-5; Davis,Thomas E (BPA) - LT-7; Simpson,Troy D (BPA) - TOI-DITT-2; Dernovsek,David K (BPA) - PTKP-5; Greene,Richard A (BPA) - LP-7; Pettinger,Rebekah S (BPA) - LP-7; Symonds,Mark C (BPA) - BD-3; Hawkins,Robert E (BPA) - PGSD-5; Pedersen Mainzer,Margaret E (BPA) - PTL-5; Kitchen,Larry (BPA) - PTL-5
Cc: robhawkins1@gmail.com; Stermer,Anna M (BPA) - PGSP-5
Subject: ADF on the number of generation points - Todd's "Electrically Similar" and "Congestion Risk" documents
Sensitivity: Private

Here are the latest version based on today's conversation.

Todd

Bonneville Power Administration | Transmission Operations
5411 NE Hwy 99 | TOK-DITT2 | Vancouver, WA 98663
Direct: (360) 418-8752 | **twkochheiser@bpa.gov**

From: Kochheiser,Todd W (BPA) - TOI-DITT-2
Sent: Monday, March 05, 2018 2:03 PM
To: Messemer,Clarisse M (BPA) - PGST-5; Chang,Elsa (BPA) - PGST-5; Truong,Mai N (BPA) - PGST-5; Polsky,Cynthia H (BPA) - PGST-5; Will,Garland L (BPA) - PGST-5; Siewert,Christopher W (BPA) - PGSD-5; Van Calcar, Pamela M (BPA) - PGSP-5; Kerns,Steven R (BPA) - PGS-5; King,Eric V (BPA) - TSPP-TPP-2; Mantifel,Russell (BPA) - TS-DITT-2; Puyleart,Frank R (BPA) - TOOC-DITT-2; Sanford,Chris T (BPA) - TOR-DITT-1; Gaube,Stephen J (BPA) - PTF-5; Haraguchi,Kelii H (BPA) - PTM-5; Federovitch,Eric C (BPA) - PTM-5;

Davis,Thomas E (BPA) - LT-7; Simpson,Troy D (BPA) - TOI-DITT-2; Dernovsek,David K (BPA) - PTKP-5; Greene,Richard A (BPA) - LP-7; Pettinger,Rebekah S (BPA) - LP-7; Symonds,Mark C (BPA) - BD-3; Hawkins,Robert E (BPA) - PGSD-5; Pedersen Mainzer,Margaret E (BPA) - PTL-5; Kitchen,Larry (BPA) - PTL-5
Cc:
robhawkins1@gmail.com; Stermer,Anna M (BPA) - PGSP-5
Subject: RE: ADF on the number of generation points bid into the EIM
Sensitivity: Private

Here is a quick curtailment risk analysis. I will go over it today.

Todd

Bonneville Power Administration | Transmission Operations
5411 NE Hwy 99 | TOK-DITT2 | Vancouver, WA 98663
Direct: (360) 418-8752 | **twkochheiser@bpa.gov**

-----Original Appointment-----
From: Messemer,Clarisse M (BPA) - PGST-5
Sent: Thursday, February 08, 2018 12:57 PM
To: Messemer,Clarisse M (BPA) - PGST-5; Chang,Elsa (BPA) - PGST-5; Truong,Mai N (BPA) - PGST-5; Polsky,Cynthia H (BPA) - PGST-5; Will,Garland L (BPA) - PGST-5; Siewert,Christopher W (BPA) - PGSD-5; Van Calcar, Pamela M (BPA) - PGSP-5; Kerns,Steven R (BPA) - PGS-5; King,Eric V (BPA) - TSPP-TPP-2; Mantifel,Russell (BPA) - TS-DITT-2; Puyleart,Frank R (BPA) - TOOC-DITT-2; Sanford,Chris T (BPA) - TOR-DITT-1; Gaube,Stephen J (BPA) - PTF-5; Haraguchi,Kelii H (BPA) - PTM-5; Federovitch,Eric C (BPA) - PTM-5; Davis,Thomas E (BPA) - LT-7; Simpson,Troy D (BPA) - TOI-DITT-2; Kochheiser,Todd W (BPA) - TOI-DITT-2; Dernovsek,David K (BPA) - PTKP-5; Greene,Richard A (BPA) - LP-7; Pettinger,Rebekah S (BPA) - LP-7; Symonds,Mark C (BPA) - BD-3; Hawkins,Robert E (BPA) - PGSD-5; Pedersen Mainzer,Margaret E (BPA) - PTL-5; Kitchen,Larry (BPA) - PTL-5
Cc: robhawkins1@gmail.com; Stermer,Anna M (BPA) - PGSP-5
Subject: ADF on the number of generation points bid into the EIM
When: Monday, March 05, 2018 2:00 PM-3:00 PM (UTC-08:00) Pacific Time (US & Canada).
Where: HQ 418 x4000 ID: (b)(2)
Sensitivity: Private

Rescheduling the 3/2 instance only. Moving to 3/5

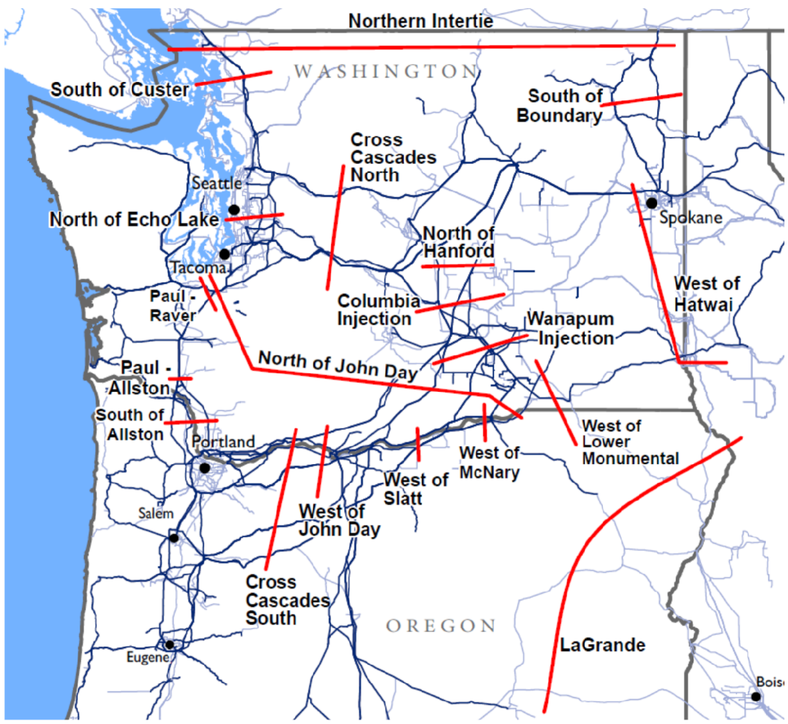
Objective & Approach:

Provide a high-level assessment of the risk of congestion on BPA internal flowgates

Methodology:

- Analyzed historical in-hour curtailments events between 2008 and present.
- Analyzed excursion minutes (flows > TTC) for CY2015 – FY2018 (YTD)
- Note: SOL Methodology changed 4/2017 where curtailments no longer occur when actual flows exceed the TTC
    - SOL must be exceeded on an element (thermal)
    - RTCA used as a real-time tool
    - Still curtail when MaxTTC or SSOL is reached
- Results have not been peer reviewed – draft results!

Flowgates:



Summary:

- The number and duration of actual flows exceeding TTC has been increasing
- The number curtailments has been decreasing
- Trends are likely due to new SOL methodology that went into effect on 4/1/2017
- Overall risk of curtailments is low on most flowgates
- These trends may or may not continue – hard to predict the future!
- Very few N-1 contingencies have occurred recently – curtailments may be higher when they occur since we are running the system at higher loading than we have historically
- As of November, 2014, 15-minute intervals are curtailed – they used to be hourly

Curtailment Trends:

CURTAILMENT EVENTS - ALL PRIORITIES (1,2,6,7)											
Row Labels	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**Grand Total**
NJD			4	4	11		21		2	2	**44**
NOEL						12	5	17		3	**37**
NOH				3							**3**
NOH_SN		11		1	7	1					**20**
P-A		2									**2**
R-P			1	4	1				7		**13**
SOA	11	1		3		2	2				**19**
SOA_SN	3	2		1		3					**9**
SOC								1	21		**22**
WOCN		1	4			1					**6**
WOJD					4				6		**10**
WOM					5		3				**8**
WOM - MAIN-GRID									2		**2**
WOMSG								4			**4**
Grand Total	**14**	**17**	**9**	**16**	**28**	**19**	**31**	**22**	**38**	**5**	**199**

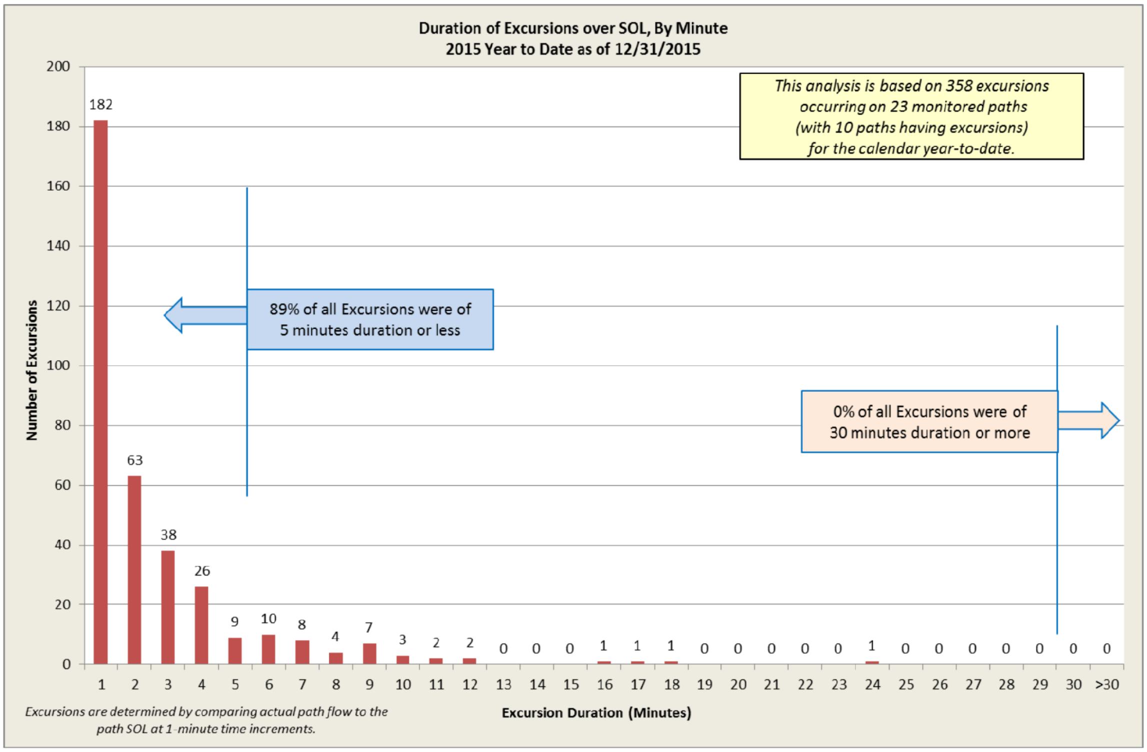
CURTAILMENT EVENTS - FIRM (7)											
Row Labels	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**Grand Total**
NJD							5				**5**
NOEL						4	1	2		1	**8**
NOH											
NOH_SN					2						**2**
P-A											
R-P				2					4		**6**
SOA											
SOA_SN											
SOC											
WOCN			2			1					**3**
WOJD									4		**4**
WOM					5		1				**6**
WOM - MAIN-GRID									2		**2**
WOMSG								1			**1**
Grand Total			**2**	**2**	**7**	**5**	**7**	**3**	**10**	**1**	**37**

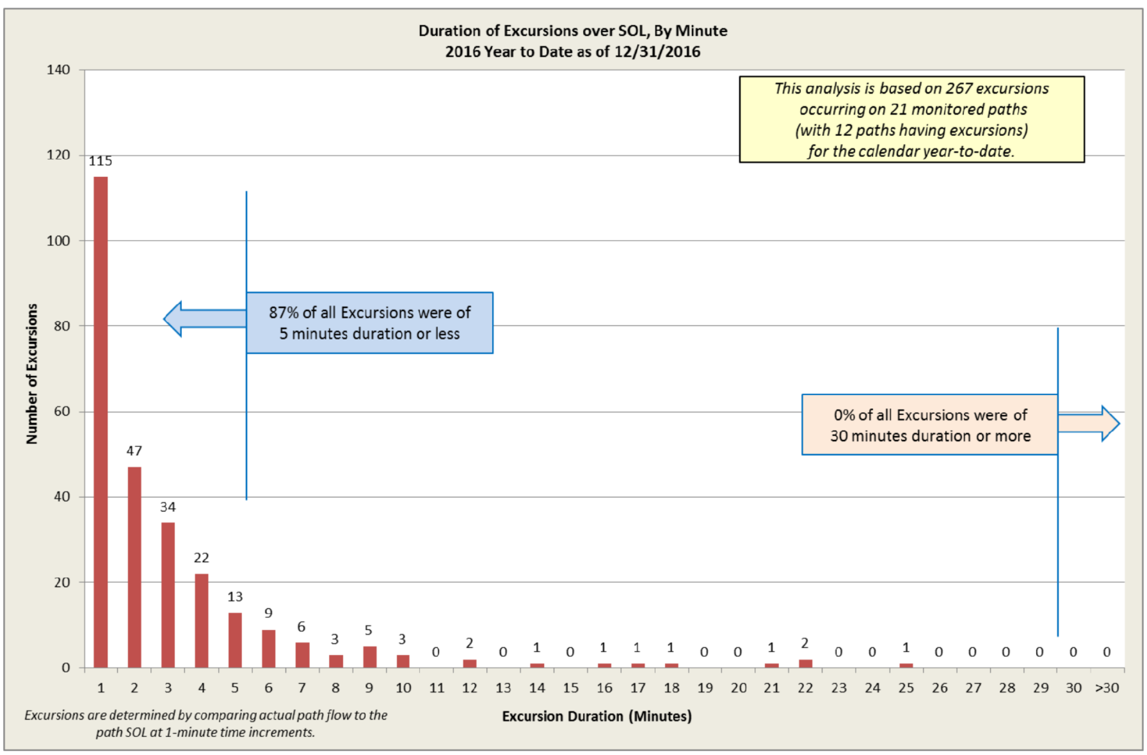
MWs CURTAILED - ALL PRIORITIES (1,2,6,7)											
FLOWGATE	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**Grand**

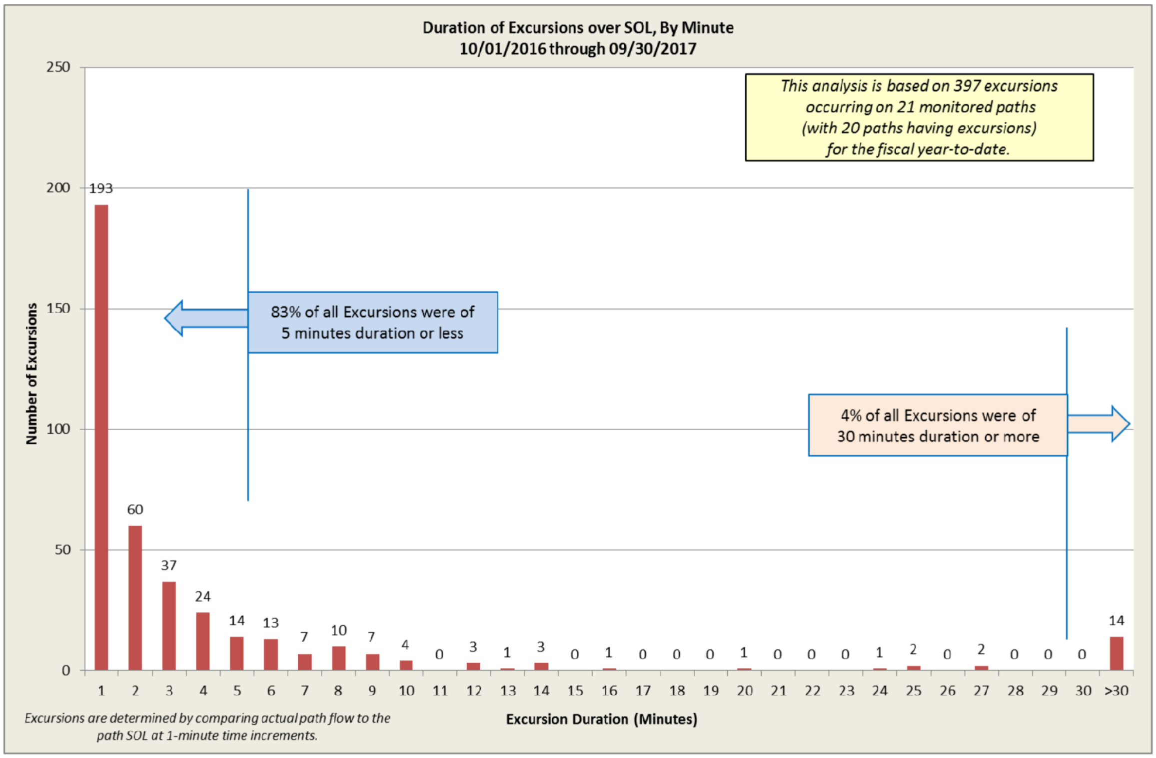
											Total
NJD			1814	930	2649		6862		632	318	**13205**
NOEL						2193	1468	4469		997	**9127**
NOH				1325							**1325**
NOH_SN		6612		215	4889	317					**12033**
P-A		1598									**1598**
R-P			709	4028	621				3232		**8590**
SOA	5369	739		1539		797	1683				**10127**
SOA_SN	1599	719		491		1830					**4639**
SOC								133	6720		**6853**
WOCN		346	2618			1298					**4262**
WOJD					1294				3388		**4682**
WOM					12590		468				**13058**
WOM - MAIN-GRID									3011		**3011**
WOMSG								1044			**1044**
Grand Total	**6968**	**10014**	**5141**	**8528**	**22043**	**6435**	**10481**	**5646**	**16983**	**1315**	**93554**

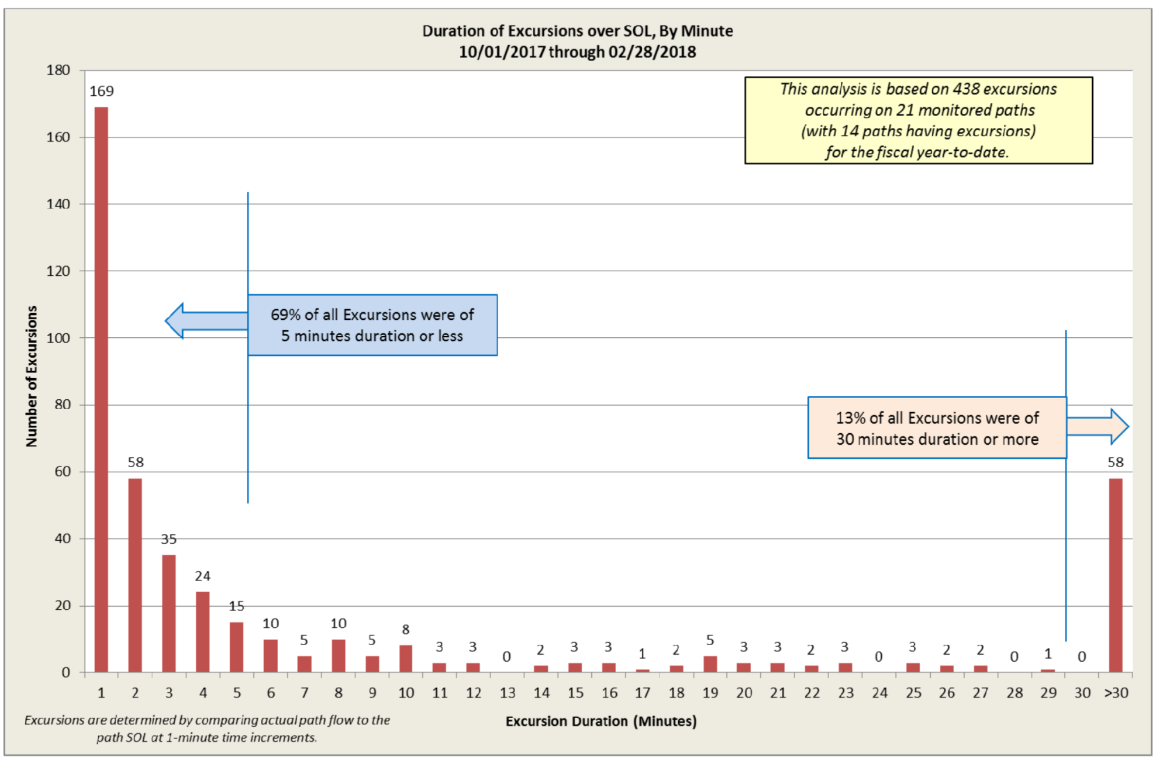
** In the graph above, this shows the total number of MWs that were requested during a curtailment. All curtailments are sub-hourly, but multiple curtailments could occur during the same hour.

Duration of Excursions:






Duration of Excursions over SOL, By Minute
10/01/2016 through 09/30/2017
This analysis is based on 397 excursions occurring on 21 monitored paths (with 20 paths having excursions) for the fiscal year-to-date.
83% of all Excursions were of 5 minutes duration or less
4% of all Excursions were of 30 minutes duration or more
Number of Excursions
Excursion Duration (Minutes)
Excursions are determined by comparing actual path flow to the path SOL at 1-minute time increments.
193
60
37
24
14
13
7
10
7
4
0
3
1
3
0
1
0
0
0
1
0
0
0
1
2
0
2
0
0
0
14


Duration of Excursions over SOL, By Minute
10/01/2017 through 02/28/2018
This analysis is based on 438 excursions occurring on 21 monitored paths (with 14 paths having excursions) for the fiscal year-to-date.
69% of all Excursions were of 5 minutes duration or less
13% of all Excursions were of 30 minutes duration or more
Number of Excursions
Excursion Duration (Minutes)
Excursions are determined by comparing actual path flow to the path SOL at 1-minute time increments.
169
58
35
24
15
10
5
10
5
8
3
3
0
2
3
3
1
2
5
3
3
2
3
0
3
2
2
0
1
0
58

Excursion Minutes Trends:

Note: FY2018 numbers are YTD (~3/5/2018)

EXCURSION MINUTES (>TTC)					
PATH	CY2015	CY2016	FY2017	FY2018	Grand Total
AC INTERTIE (COI)	148	205	178	24	555
COLUMBIA INJECTION			14		14
DC INTERTIE (PDCI)	18				18
JOHN DAY WIND	16	2	3	6	27
MONTANA-NORTHWEST		1	1		2
NORTH-OF-ECHOLAKE	34	2	25	377	438
NORTH-OF-HANFORD	1	3	3		7
NORTH-OF-JOHN-DAY		8	25	1	34
NORTHWEST-BC	108	9	77	14	208
PAUL-ALLSTON			3	1	4
RAVER-PAUL	1	2	6	1	10
ROCK CREEK WIND			3		3
SOUTH-OF-ALLSTON	2		2		4
SOUTH-OF-BOUNDARY	14	9	15		38
SOUTH-OF-CUSTER	16	18	14	2	50
WEST-OF-CASCADES-NORTH			3	1	4
WEST-OF-CASCADES-SOUTH		2	2	1	5
WEST-OF-HATWAI			6	1	7
WEST-OF-JOHN-DAY		6	10	3	19
WEST-OF-LOWER-MONUMENTAL			3	2	5
WEST-OF-SLATT			4	4	8
Grand Total	358	267	397	438	1460

From: Kochheiser,Todd W (BPA) - TOI-DITT-2
Sent: Wed Mar 07 12:59:34 2018
To: Truong,Mai N (BPA) - PGST-5; Messemer,Clarisse M (BPA) - PGST-5; Chang,Elsa (BPA) - PGST-5; Polsky,Cynthia H (BPA) - PGST-5; Siewert,Christopher W (BPA) - PGSD-5; Van Calcar, Pamela M (BPA) - PGSP-5; Kerns,Steven R (BPA) - PGS-5; King,Eric V (BPA) - TSPP-TPP-2; Mantifel,Russell (BPA) - TS-DITT-2; Puyleart,Frank R (BPA) - TOOC-DITT-2; Sanford,Chris T (BPA) - TOR-DITT-1; Gaube,Stephen J (BPA) - PTF-5; Haraguchi,Kelii H (BPA) - PTM-5; Federovitch,Eric C (BPA) - PTM-5; Davis,Thomas E (BPA) - LT-7; Simpson,Troy D (BPA) - TOI-DITT-2; Dernovsek,David K (BPA) - PTKP-5; Greene,Richard A (BPA) - LP-7; Pettinger,Rebekah S (BPA) - LP-7; Symonds,Mark C (BPA) - BD-3; Will,Garland L (BPA) - PGST-5; Schaffroth,John T (CONTR) - PGL-5; Pedersen Mainzer,Margaret E (BPA) - PTL-5; Kitchen,Larry (BPA) - PTL-5; Stermer,Anna M (BPA) - PGSP-5; Eaton,Sara L (BPA) - PTM-5
Subject: RE: ADF on the number of generation points bid into the EIM
Importance: Normal
Attachments: 20180305_Congestion_Risk_v04_Draft.docx

Steve asked me to add a risk column to the curtailment tables. The % risk is simply the number of events over 10 years divided by the number of hours in 10 years. Attached is an updated document.

Todd

Bonneville Power Administration | Transmission Operations
5411 NE Hwy 99 | TOK-DITT2 | Vancouver, WA 98663
Direct: (360) 418-8752 | twkochheiser@bpa.gov

From: Truong,Mai N (BPA) - PGST-5
Sent: Wednesday, March 07, 2018 10:38 AM
To: Messemer,Clarisse M (BPA) - PGST-5; Chang,Elsa (BPA) - PGST-5; Polsky,Cynthia H (BPA) - PGST-5; Siewert,Christopher W (BPA) - PGSD-5; Van Calcar, Pamela M (BPA) - PGSP-5; Kerns,Steven R (BPA) - PGS-5; King,Eric V (BPA) - TSPP-TPP-2; Mantifel,Russell (BPA) - TS-DITT-2; Puyleart,Frank R (BPA) - TOOC-DITT-2; Sanford,Chris T (BPA) - TOR-DITT-1; Gaube,Stephen J (BPA) - PTF-5; Haraguchi,Kelii H (BPA) - PTM-5; Federovitch,Eric C (BPA) - PTM-5; Davis,Thomas E (BPA) - LT-7; Simpson,Troy D (BPA) - TOI-DITT-2; Kochheiser,Todd W (BPA) - TOI-DITT-2; Dernovsek,David K (BPA) - PTKP-5; Greene,Richard A (BPA) - LP-7; Pettinger,Rebekah S (BPA) - LP-7; Symonds,Mark C (BPA) - BD-3; Will,Garland L (BPA) - PGST-5; Schaffroth,John T (CONTR) - PGL-5; Pedersen Mainzer,Margaret E (BPA) - PTL-5; Kitchen,Larry (BPA) - PTL-5; Stermer,Anna M (BPA) - PGSP-5; Eaton,Sara L (BPA) - PTM-5
Subject: RE: ADF on the number of generation points bid into the EIM
Sensitivity: Private

Updated NGR illustration attached.
<< File: FCRPS_Config_EIM.PPTX >>

There's a week and a half left to complete a rough draft.....

3/7 Agenda:

1. Quick review of the curtailment risk analysis - Todd
    a. Is there a need for a 4th alternative based on this analysis - All
2. NGR functionality illustration – Elsa
3. Identify outstanding item /assign action items – All

<< File: FCRPS_Config_EIM.PPTX >>
-----Original Appointment-----
From: Messemer,Clarisse M (BPA) - PGST-5
Sent: Thursday, February 08, 2018 12:22 PM
To: Messemer,Clarisse M (BPA) - PGST-5; Chang,Elsa (BPA) - PGST-5; Truong,Mai N (BPA) - PGST-5; Polsky,Cynthia H (BPA) - PGST-5; Siewert,Christopher W (BPA) - PGSD-5; Van Calcar, Pamela M (BPA) - PGSP-5; Kerns,Steven R (BPA) - PGS-5; King,Eric V (BPA) - TSPP-TPP-2; Mantifel,Russell (BPA) - TS-DITT-2; Puyleart,Frank R (BPA) - TOOC-DITT-2; Sanford,Chris T (BPA) - TOR-DITT-1; Gaube,Stephen J (BPA) - PTF-5; Haraguchi,Kelii H (BPA) - PTM-5; Federovitch,Eric C (BPA) - PTM-5; Davis,Thomas E (BPA) - LT-7; Simpson,Troy D (BPA) - TOI-DITT-2; Kochheiser,Todd W (BPA) - TOI-DITT-2; Dernovsek,David K (BPA) - PTKP-5; Greene,Richard A (BPA) - LP-7; Pettinger,Rebekah S (BPA) - LP-7; Symonds,Mark C (BPA) - BD-3; Will,Garland L (BPA) - PGST-5; Schaffroth,John T (CONTR) - PGL-5; Pedersen Mainzer,Margaret E (BPA) - PTL-5; Kitchen,Larry (BPA) - PTL-5; Stermer,Anna M (BPA) - PGSP-5
Subject: ADF on the number of generation points bid into the EIM
When: Wednesday, March 07, 2018 3:00 PM-4:00 PM (UTC-08:00) Pacific Time (US & Canada).
Where: HQ 470EW(40) x4000 ID: (b)(2) [redacted]
Sensitivity: Private

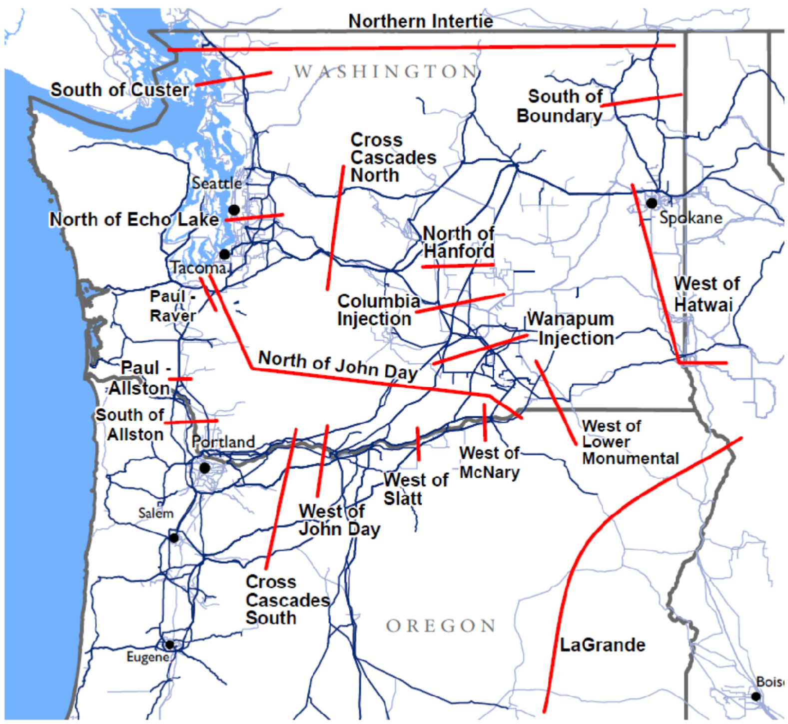
Objective & Approach:

Provide a high-level assessment of the risk of congestion on BPA internal flowgates

Methodology:

- Analyzed historical in-hour curtailments events between 2008 and present
- Discretionary Redispatch events were not analyzed
- Analyzed excursion minutes (flows > TTC) for CY2015 – FY2018 (YTD)
- Note: SOL Methodology changed 4/2017 where curtailments no longer occur when actual flows exceed the TTC
    - SOL must be exceeded on an element (thermal)
    - RTCA used as a real-time tool
    - Still curtail when MaxTTC or SSOL is reached
- Results have not been peer reviewed – draft results!

Flowgates:



Summary:

- The number and duration of actual flows exceeding TTC has been increasing
- The number curtailments has been decreasing
- Trends are likely due to new SOL methodology that went into effect on 4/1/2017
- Overall risk of curtailments is low on most flowgates
- These trends may or may not continue – hard to predict the future!
- Very few N-1 contingencies have occurred recently – curtailments may be higher when they occur since we are running the system at higher loading than we have historically
- As of November, 2014, 15-minute intervals are curtailed – they used to be hourly

Curtailment Trends:

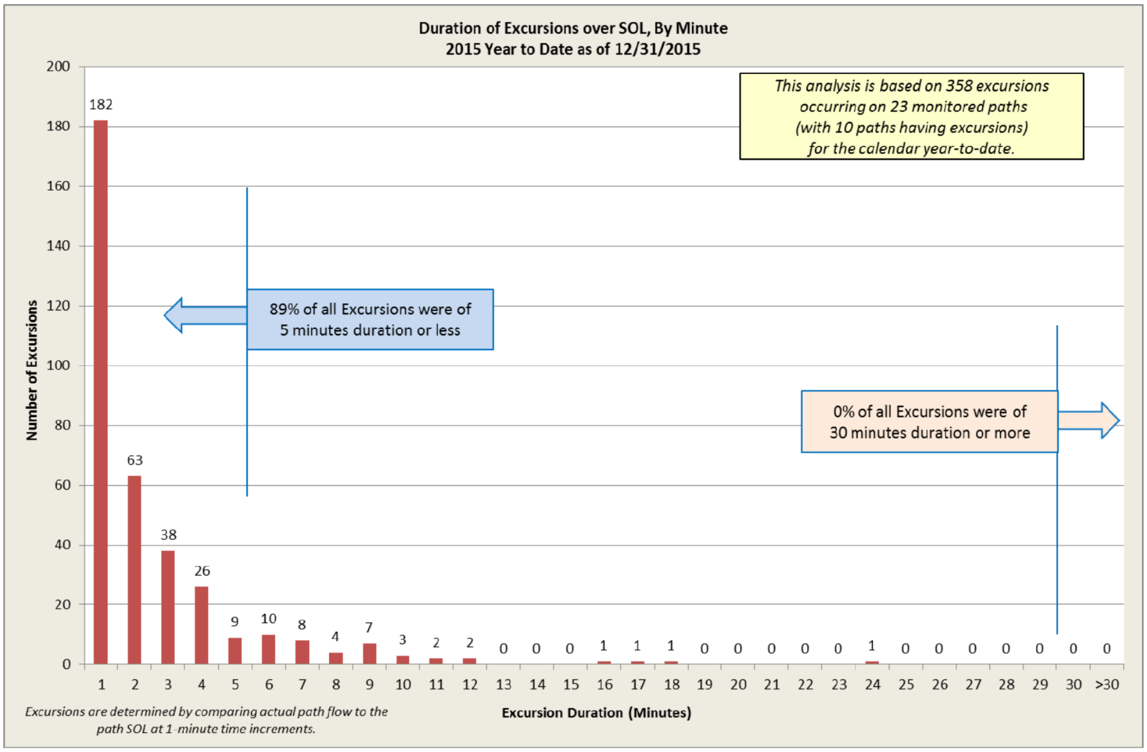
CURTAILMENT EVENTS - ALL PRIORITIES (1,2,6,7)												
Flowgate	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**Grand Total**	**Risk (10yr)**
NJD			4	4	11		21		2	2	**44**	**0.050%**
NOEL						12	5	17		3	**37**	**0.042%**
NOH				3							**3**	**0.003%**
NOH_SN		11		1	7	1					**20**	**0.023%**
P-A		2									**2**	**0.002%**
R-P			1	4	1				7		**13**	**0.015%**
SOA	11	1		3		2	2				**19**	**0.022%**
SOA_SN	3	2		1		3					**9**	**0.010%**
SOC								1	21		**22**	**0.025%**
WOCN		1	4			1					**6**	**0.007%**
WOJD					4				6		**10**	**0.011%**
WOM					5		3				**8**	**0.009%**
WOM - MAIN-GRID									2		**2**	**0.002%**
WOMSG								4			**4**	**0.005%**
Grand Total	**14**	**17**	**9**	**16**	**28**	**19**	**31**	**22**	**38**	**5**	**199**	**0.227%**

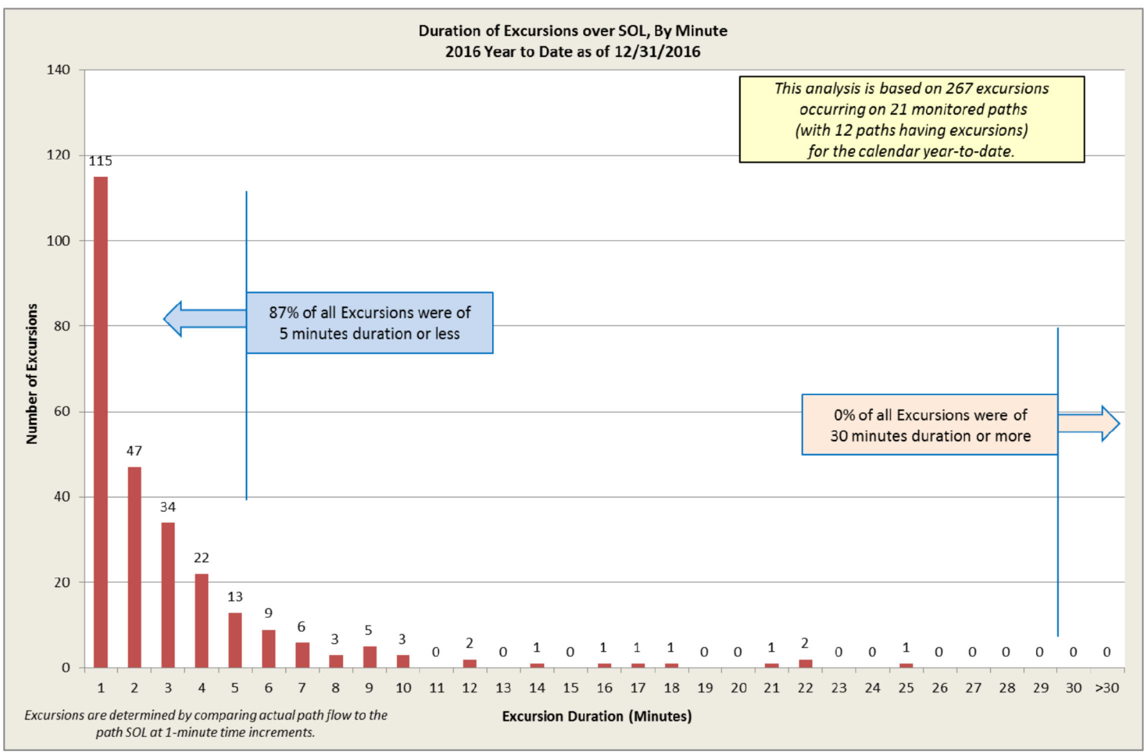
CURTAILMENT EVENTS - FIRM (7)												
Flowgate	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**Grand Total**	**Risk (10yr)**
NJD							5				**5**	**0.006%**
NOEL						4	1	2		1	**8**	**0.009%**
NOH												**0.000%**
NOH_SN					2						**2**	**0.002%**
P-A												**0.000%**
R-P				2					4		**6**	**0.007%**
SOA												**0.000%**
SOA_SN												**0.000%**
SOC												**0.000%**
WOCN			2			1					**3**	**0.003%**
WOJD									4		**4**	**0.005%**
WOM					5		1				**6**	**0.007%**
WOM - MAIN-GRID									2		**2**	**0.002%**
WOMSG								1			**1**	**0.001%**
Grand Total			**2**	**2**	**7**	**5**	**7**	**3**	**10**	**1**	**37**	**0.042%**

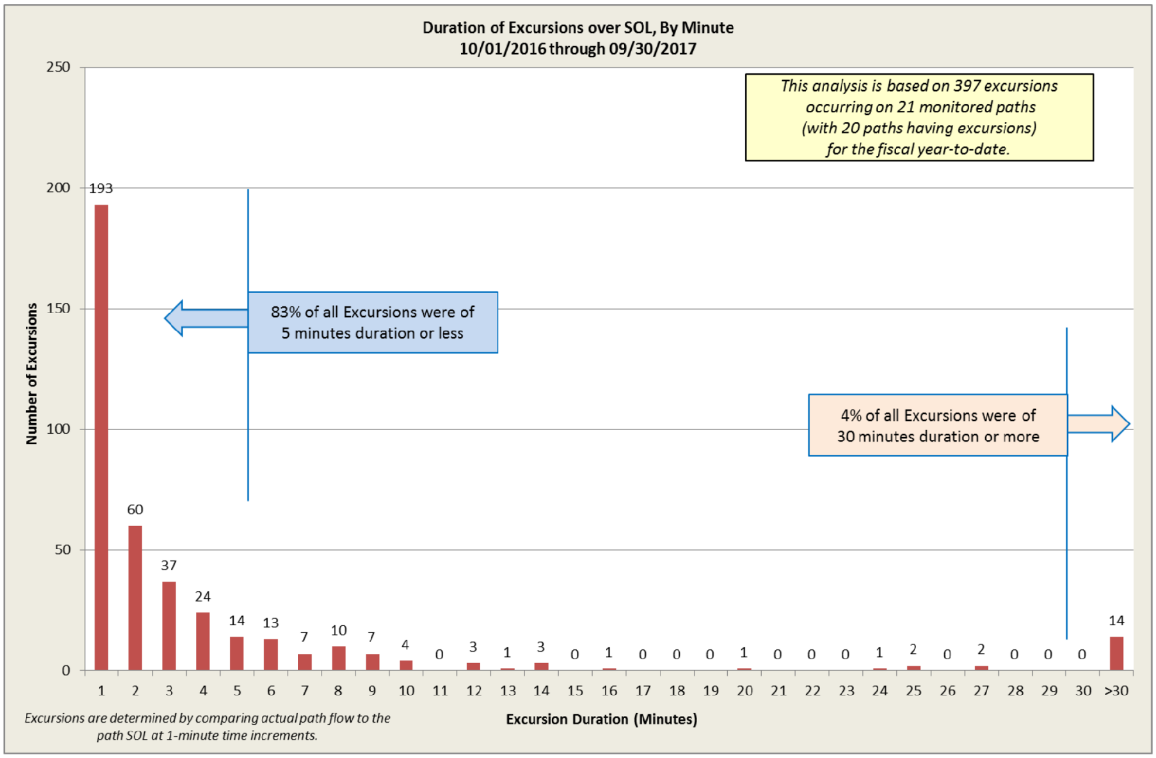
MWs CURTAILED - ALL PRIORITIES (1,2,6,7)											
FLOWGATE	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**Grand Total**
NJD			1814	930	2649		6862		632	318	**13205**
NOEL						2193	1468	4469		997	**9127**
NOH				1325							**1325**
NOH_SN		6612		215	4889	317					**12033**
P-A		1598									**1598**
R-P			709	4028	621				3232		**8590**
SOA	5369	739		1539		797	1683				**10127**
SOA_SN	1599	719		491		1830					**4639**
SOC								133	6720		**6853**
WOCN		346	2618			1298					**4262**
WOJD					1294				3388		**4682**
WOM					12590		468				**13058**
WOM - MAIN-GRID									3011		**3011**
WOMSG								1044			**1044**
Grand Total	**6968**	**10014**	**5141**	**8528**	**22043**	**6435**	**10481**	**5646**	**16983**	**1315**	**93554**

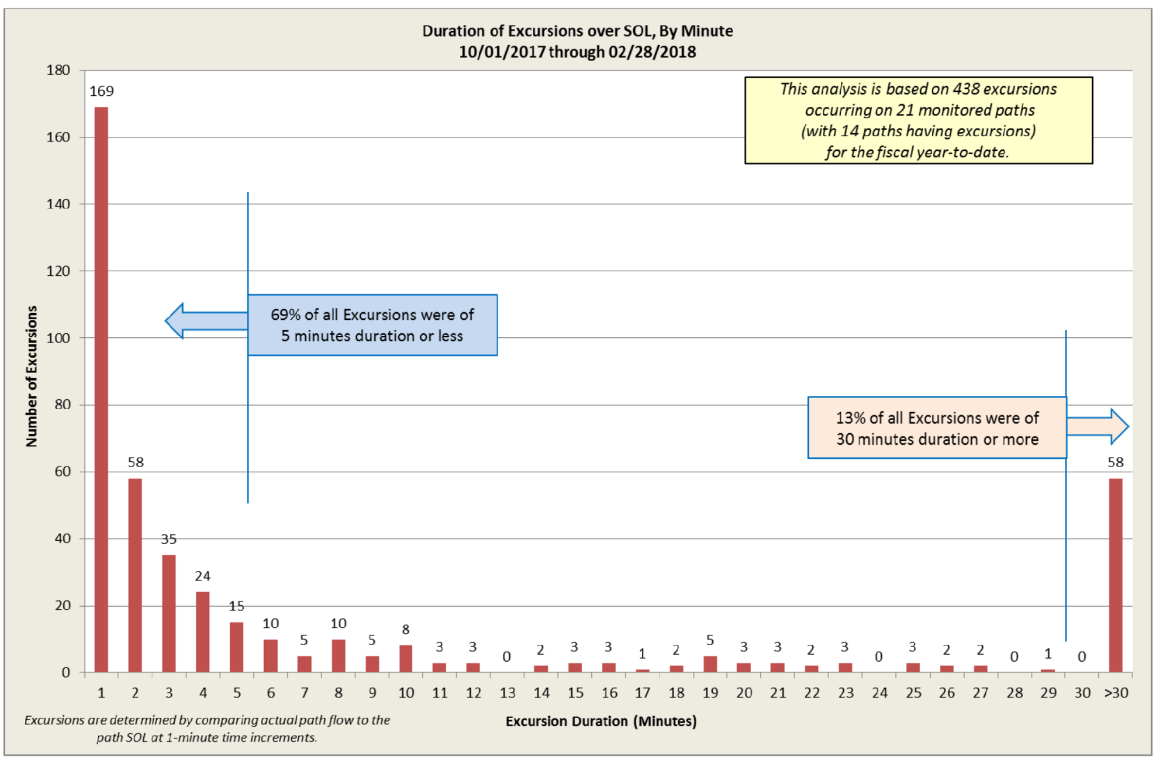
** In the graph above, this shows the total number of MWs that were requested during a curtailment. All curtailments are sub-hourly, but multiple curtailments could occur during the same hour.

Duration of Excursions:






Duration of Excursions over SOL, By Minute
10/01/2016 through 09/30/2017
This analysis is based on 397 excursions occurring on 21 monitored paths (with 20 paths having excursions) for the fiscal year-to-date.
83% of all Excursions were of 5 minutes duration or less
4% of all Excursions were of 30 minutes duration or more
Number of Excursions
Excursion Duration (Minutes)
Excursions are determined by comparing actual path flow to the path SOL at 1-minute time increments.


Duration of Excursions over SOL, By Minute
10/01/2017 through 02/28/2018
This analysis is based on 438 excursions occurring on 21 monitored paths (with 14 paths having excursions) for the fiscal year-to-date.
69% of all Excursions were of 5 minutes duration or less
13% of all Excursions were of 30 minutes duration or more
Number of Excursions
Excursion Duration (Minutes)
Excursions are determined by comparing actual path flow to the path SOL at 1-minute time increments.

Excursion Minutes Trends:

Note: FY2018 numbers are YTD (~3/5/2018)

EXCURSION MINUTES (>TTC)					
PATH	CY2015	CY2016	FY2017	FY2018	Grand Total
AC INTERTIE (COI)	148	205	178	24	**555**
COLUMBIA INJECTION			14		**14**
DC INTERTIE (PDCI)	18				**18**
JOHN DAY WIND	16	2	3	6	**27**
MONTANA-NORTHWEST		1	1		**2**
NORTH-OF-ECHOLAKE	34	2	25	377	**438**
NORTH-OF-HANFORD	1	3	3		**7**
NORTH-OF-JOHN-DAY		8	25	1	**34**
NORTHWEST-BC	108	9	77	14	**208**
PAUL-ALLSTON			3	1	**4**
RAVER-PAUL	1	2	6	1	**10**
ROCK CREEK WIND			3		**3**
SOUTH-OF-ALLSTON	2		2		**4**
SOUTH-OF-BOUNDARY	14	9	15		**38**
SOUTH-OF-CUSTER	16	18	14	2	**50**
WEST-OF-CASCADES-NORTH			3	1	**4**
WEST-OF-CASCADES-SOUTH		2	2	1	**5**
WEST-OF-HATWAI			6	1	**7**
WEST-OF-JOHN-DAY		6	10	3	**19**
WEST-OF-LOWER-MONUMENTAL			3	2	**5**
WEST-OF-SLATT			4	4	**8**
Grand Total	**358**	**267**	**397**	**438**	**1460**

From: Kochheiser,Todd W (BPA) - TOI-DITT-2
Sent: Fri Feb 23 08:18:44 2018
To: Messemer,Clarisse M (BPA) - PGST-5; Chang,Elsa (BPA) - PGST-5; Truong,Mai N (BPA) - PGST-5; Polsky,Cynthia H (BPA) - PGST-5; Will,Garland L (BPA) - PGST-5; Siewert,Christopher W (BPA) - PGSD-5; Van Calcar, Pamela M (BPA) - PGSP-5; Kerns,Steven R (BPA) - PGS-5; King,Eric V (BPA) - TSPP-TPP-2; Mantifel,Russell (BPA) - TS-DITT-2; Puyleart,Frank R (BPA) - TOOC-DITT-2; Sanford,Chris T (BPA) - TOR-DITT-1; Gaube,Stephen J (BPA) - PTF-5; Haraguchi,Kelii H (BPA) - PTM-5; Federovitch,Eric C (BPA) - PTM-5; Davis,Thomas E (BPA) - LT-7; Simpson,Troy D (BPA) - TOI-DITT-2; Dernovsek,David K (BPA) - PTKP-5; Greene,Richard A (BPA) - LP-7; Pettinger,Rebekah S (BPA) - LP-7; Symonds,Mark C (BPA) - BD-3; Hawkins,Robert E (BPA) - PGSD-5; Pedersen Mainzer,Margaret E (BPA) - PTL-5; Kitchen,Larry (BPA) - PTL-5
Subject: RE: ADF on the number of generation points bid into the EIM
Importance: Normal
Attachments: 20180223_Electrically_Similar_Analysis_v0_Draft.pdf

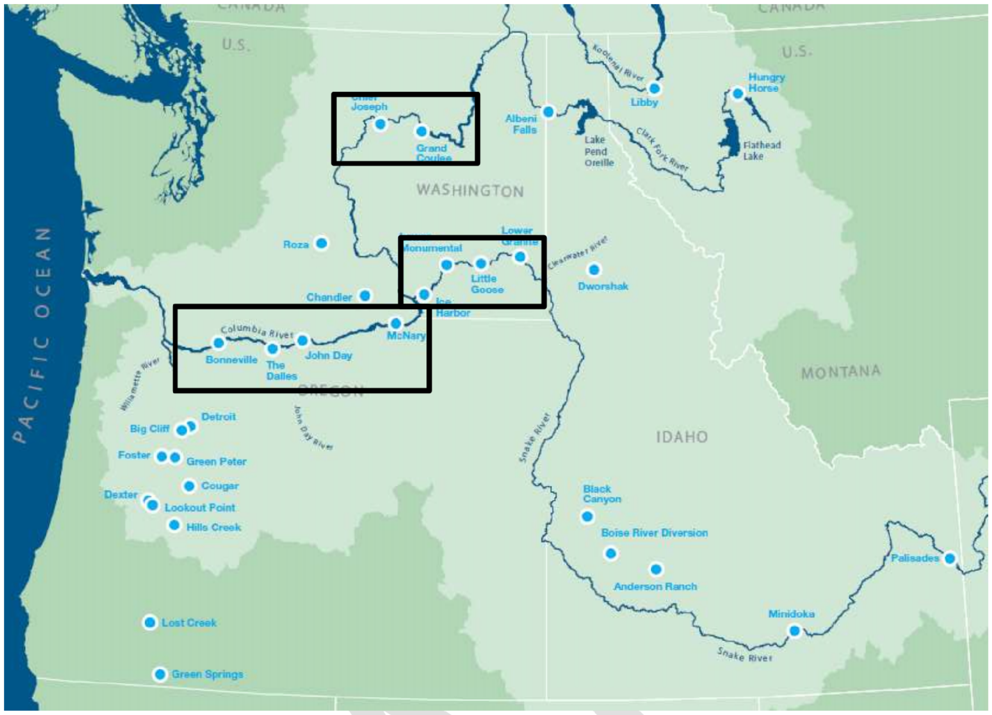
All:

Attached is my first attempt at trying to more objectively define "electrically similar." I rushed the analysis so we could have something to discuss today, so this is very preliminary and draft material. Based on our discussion today we can refine the analysis or perform some sensitivities.

Todd

Bonneville Power Administration | Transmission Operations
5411 NE Hwy 99 | TOK-DITT2 | Vancouver, WA 98663
Direct: (360) 418-8752 | **twkochheiser@bpa.gov**

-----Original Appointment-----
From: Messemer,Clarisse M (BPA) - PGST-5
Sent: Thursday, February 08, 2018 12:57 PM
To: Messemer,Clarisse M (BPA) - PGST-5; Chang,Elsa (BPA) - PGST-5; Truong,Mai N (BPA) - PGST-5; Polsky,Cynthia H (BPA) - PGST-5; Will,Garland L (BPA) - PGST-5; Siewert,Christopher W (BPA) - PGSD-5; Van Calcar, Pamela M (BPA) - PGSP-5; Kerns,Steven R (BPA) - PGS-5; King,Eric V (BPA) - TSPP-TPP-2; Mantifel,Russell (BPA) - TS-DITT-2; Puyleart,Frank R (BPA) - TOOC-DITT-2; Sanford,Chris T (BPA) - TOR-DITT-1; Gaube,Stephen J (BPA) - PTF-5; Haraguchi,Kelii H (BPA) - PTM-5; Federovitch,Eric C (BPA) - PTM-5; Davis,Thomas E (BPA) - LT-7; Simpson,Troy D (BPA) - TOI-DITT-2; Kochheiser,Todd W (BPA) - TOI-DITT-2; Dernovsek,David K (BPA) - PTKP-5; Greene,Richard A (BPA) - LP-7; Pettinger,Rebekah S (BPA) - LP-7; Symonds,Mark C (BPA) - BD-3; Hawkins,Robert E (BPA) - PGSD-5; Pedersen Mainzer,Margaret E (BPA) - PTL-5; Kitchen,Larry (BPA) - PTL-5
Cc: robhawkins1@gmail.com
Subject: ADF on the number of generation points bid into the EIM
When: Friday, February 23, 2018 9:00 AM-10:00 AM (UTC-08:00) Pacific Time (US & Canada).
Where: HQ 418 x4000 ID: [redacted]
Sensitivity: Private



- Used 2019 planning case – all lines in service
- Analyzed impacts of each plant relative to one another
- Used 10% threshold
- Not verified – draft results!

ELECTRICALLY SIMMILAR @ 10%				
FLOWGATE	UPPER	LOWER	SNAKE	NOTES
CCN	YES	MAYBE	YES	Bonneville slightly above 10% in Lower
CCS	YES	NO	YES	Bonneville much higher than 10% in Lower
NOEL	YES	YES	YES	
NOH	YES	MAYBE	YES	Bonneville slightly above 10% in Lower
NJD	YES	YES	NO	Ice Harbor much higher than 10%
PA	YES	MAYBE	YES	Bonneville slightly above 10% in Lower
RP	YES	MAYBE	YES	Bonneville slightly above 10% in Lower
SOA	YES	MAYBE	YES	Bonneville slightly above 10% in Lower
SOC	YES	YES	YES	
WOJD	YES	NO	YES	
WOLM	YES	YES	NO	
WOM	YES	NO	MAYBE	Ice Harbor a little less than 20%
WOS	YES	MAYBE	YES	Impacts range from 5-32%

FLOWGATE:		CROSS CASCADES NORTH E>W														
PERCENT:		10.0%														
		LOW1	LOW2	LOW3	LOW4	OTH	OTH	OTH	OTH	OTH	SNK1	SNK2	SNK3	SNK4	UP1	UP2
		MCN	JDA	TDA	BON	ALF	DWR	HGH	LIB	BLK	LWG	LGS	LMN	IHR	GCL	CHJ
LOW1	MCN	0.0%	1.7%	3.5%	14.8%	2.2%	4.6%	3.5%	3.2%	2.2%	4.6%	4.7%	4.7%	3.2%	15.6%	17.9%
LOW2	JDA	1.7%	0.0%	1.8%	13.1%	0.5%	6.3%	5.2%	4.9%	0.5%	6.3%	6.3%	6.4%	4.9%	17.3%	19.6%
LOW3	TDA	3.5%	1.8%	0.0%	11.3%	1.3%	8.1%	7.0%	6.7%	1.3%	8.1%	8.2%	8.2%	6.7%	19.1%	21.4%
LOW4	BON	14.8%	13.1%	11.3%	0.0%	12.6%	19.4%	18.3%	18.0%	12.6%	19.4%	19.4%	19.5%	18.0%	30.4%	32.7%
OTH	ALF	2.2%	0.5%	1.3%	12.6%	0.0%	6.8%	5.7%	5.4%	0.0%	6.8%	6.9%	6.9%	5.4%	17.8%	20.1%
OTH	DWR	4.6%	6.3%	8.1%	19.4%	6.8%	0.0%	1.1%	1.4%	6.8%	0.0%	0.0%	0.1%	1.5%	11.0%	13.3%
OTH	HGH	3.5%	5.2%	7.0%	18.3%	5.7%	1.1%	0.0%	0.3%	5.7%	1.1%	1.1%	1.2%	0.3%	12.1%	14.4%
OTH	LIB	3.2%	4.9%	6.7%	18.0%	5.4%	1.4%	0.3%	0.0%	5.4%	1.4%	1.4%	1.5%	0.0%	12.4%	14.7%
OTH	BLK	2.2%	0.5%	1.3%	12.6%	0.0%	6.8%	5.7%	5.4%	0.0%	6.8%	6.9%	6.9%	5.4%	17.8%	20.1%
SNK1	LWG	4.6%	6.3%	8.1%	19.4%	6.8%	0.0%	1.1%	1.4%	6.8%	0.0%	0.0%	0.1%	1.4%	11.0%	13.3%
SNK2	LGS	4.7%	6.3%	8.2%	19.4%	6.9%	0.0%	1.1%	1.4%	6.9%	0.0%	0.0%	0.0%	1.5%	11.0%	13.3%
SNK3	LMN	4.7%	6.4%	8.2%	19.5%	6.9%	0.1%	1.2%	1.5%	6.9%	0.1%	0.0%	0.0%	1.5%	10.9%	13.3%
SNK4	IHR	3.2%	4.9%	6.7%	18.0%	5.4%	1.5%	0.3%	0.0%	5.4%	1.4%	1.5%	1.5%	0.0%	12.4%	14.8%
UP1	GCL	15.6%	17.3%	19.1%	30.4%	17.8%	11.0%	12.1%	12.4%	17.8%	11.0%	11.0%	10.9%	12.4%	0.0%	2.3%
UP2	CHJ	17.9%	19.6%	21.4%	32.7%	20.1%	13.3%	14.4%	14.7%	20.1%	13.3%	13.3%	13.3%	14.8%	2.3%	0.0%

FLOWGATE:		CROSS CASCADES SOUTH E>W														
PERCENT:		10.0%														
		LOW1	LOW2	LOW3	LOW4	OTH	OTH	OTH	OTH	OTH	SNK1	SNK2	SNK3	SNK4	UP1	UP2
		MCN	JDA	TDA	BON	ALF	DWR	HGH	LIB	BLK	LWG	LGS	LMN	IHR	GCL	CHJ
LOW1	MCN	0.0%	0.1%	2.4%	76.8%	12.8%	8.5%	11.1%	11.3%	12.8%	5.8%	5.1%	4.7%	3.3%	14.0%	15.2%
LOW2	JDA	0.1%	0.0%	2.2%	77.0%	12.9%	8.7%	11.2%	11.5%	12.9%	5.9%	5.2%	4.8%	3.4%	14.1%	15.3%
LOW3	TDA	2.4%	2.2%	0.0%	79.2%	15.1%	10.9%	13.5%	13.7%	15.1%	8.1%	7.4%	7.0%	5.7%	16.3%	17.5%
LOW4	BON	76.8%	77.0%	79.2%	0.0%	64.1%	68.3%	65.7%	65.5%	64.1%	71.1%	71.7%	72.2%	73.5%	62.9%	61.7%
OTH	ALF	12.8%	12.9%	15.1%	64.1%	0.0%	4.2%	1.6%	1.4%	0.0%	7.0%	7.7%	8.1%	9.5%	1.2%	2.4%
OTH	DWR	8.5%	8.7%	10.9%	68.3%	4.2%	0.0%	2.6%	2.8%	4.2%	2.8%	3.5%	3.9%	5.2%	5.4%	6.6%
OTH	HGH	11.1%	11.2%	13.5%	65.7%	1.6%	2.6%	0.0%	0.2%	1.6%	5.3%	6.0%	6.4%	7.8%	2.9%	4.1%
OTH	LIB	11.3%	11.5%	13.7%	65.5%	1.4%	2.8%	0.2%	0.0%	1.4%	5.6%	6.2%	6.7%	8.0%	2.6%	3.8%
OTH	BLK	12.8%	12.9%	15.1%	64.1%	0.0%	4.2%	1.6%	1.4%	0.0%	7.0%	7.7%	8.1%	9.5%	1.2%	2.4%
SNK1	LWG	5.8%	5.9%	8.1%	71.1%	7.0%	2.8%	5.3%	5.6%	7.0%	0.0%	0.7%	1.1%	2.5%	8.2%	9.4%
SNK2	LGS	5.1%	5.2%	7.4%	71.7%	7.7%	3.5%	6.0%	6.2%	7.7%	0.7%	0.0%	0.4%	1.8%	8.9%	10.1%
SNK3	LMN	4.7%	4.8%	7.0%	72.2%	8.1%	3.9%	6.4%	6.7%	8.1%	1.1%	0.4%	0.0%	1.4%	9.3%	10.5%
SNK4	IHR	3.3%	3.4%	5.7%	73.5%	9.5%	5.2%	7.8%	8.0%	9.5%	2.5%	1.8%	1.4%	0.0%	10.7%	11.9%
UP1	GCL	14.0%	14.1%	16.3%	62.9%	1.2%	5.4%	2.9%	2.6%	1.2%	8.2%	8.9%	9.3%	10.7%	0.0%	1.2%
UP2	CHJ	15.2%	15.3%	17.5%	61.7%	2.4%	6.6%	4.1%	3.8%	2.4%	9.4%	10.1%	10.5%	11.9%	1.2%	0.0%

DRAFT – ELECTRICALLY SIMILAR ANALSYS - DRAFT

FLOWGATE:	NORTH OF ECHO LAKE S>N															
PERCENT:		10.0%														
		LOW1	LOW2	LOW3	LOW4	OTH	OTH	OTH	OTH	OTH	SNK1	SNK2	SNK3	SNK4	UP1	UP2
		MCN	JDA	TDA	BON	ALF	DWR	HGH	LIB	BLK	LWG	LGS	LMN	IHR	GCL	CHJ
LOW1	MCN	0.0%	0.4%	0.4%	0.7%	10.7%	3.2%	5.9%	6.4%	10.7%	1.2%	0.6%	0.3%	0.3%	3.2%	10.3%
LOW2	JDA	0.4%	0.0%	0.0%	0.3%	11.1%	3.6%	6.3%	6.8%	11.1%	1.6%	1.0%	0.7%	0.7%	3.6%	10.7%
LOW3	TDA	0.4%	0.0%	0.0%	0.2%	11.2%	3.7%	6.3%	6.8%	11.2%	1.6%	1.1%	0.8%	0.8%	3.6%	10.7%
LOW4	BON	0.7%	0.3%	0.2%	0.0%	11.4%	3.9%	6.6%	7.1%	11.4%	1.8%	1.3%	1.0%	1.0%	3.9%	10.9%
OTH	ALF	10.7%	11.1%	11.2%	11.4%	0.0%	7.5%	4.9%	4.3%	0.0%	9.6%	10.1%	10.4%	10.4%	7.5%	0.5%
OTH	DWR	3.2%	3.6%	3.7%	3.9%	7.5%	0.0%	2.7%	3.2%	7.5%	2.1%	2.6%	2.9%	2.9%	0.0%	7.0%
OTH	HGH	5.9%	6.3%	6.3%	6.6%	4.9%	2.7%	0.0%	0.5%	4.9%	4.7%	5.2%	5.6%	5.6%	2.7%	4.4%
OTH	LIB	6.4%	6.8%	6.8%	7.1%	4.3%	3.2%	0.5%	0.0%	4.3%	5.2%	5.8%	6.1%	6.1%	3.2%	3.9%
OTH	BLK	10.7%	11.1%	11.2%	11.4%	0.0%	7.5%	4.9%	4.3%	0.0%	9.6%	10.1%	10.4%	10.4%	7.5%	0.5%
SNK1	LWG	1.2%	1.6%	1.6%	1.8%	9.6%	2.1%	4.7%	5.2%	9.6%	0.0%	0.5%	0.8%	0.8%	2.0%	9.1%
SNK2	LGS	0.6%	1.0%	1.1%	1.3%	10.1%	2.6%	5.2%	5.8%	10.1%	0.5%	0.0%	0.3%	0.3%	2.6%	9.6%
SNK3	LMN	0.3%	0.7%	0.8%	1.0%	10.4%	2.9%	5.6%	6.1%	10.4%	0.8%	0.3%	0.0%	0.0%	2.9%	9.9%
SNK4	IHR	0.3%	0.7%	0.8%	1.0%	10.4%	2.9%	5.6%	6.1%	10.4%	0.8%	0.3%	0.0%	0.0%	2.9%	9.9%
UP1	GCL	3.2%	3.6%	3.6%	3.9%	7.5%	0.0%	2.7%	3.2%	7.5%	2.0%	2.6%	2.9%	2.9%	0.0%	7.1%
UP2	CHJ	10.3%	10.7%	10.7%	10.9%	0.5%	7.0%	4.4%	3.9%	0.5%	9.1%	9.6%	9.9%	9.9%	7.1%	0.0%

FLOWGATE:	NORTH OF HANFORD N>S															
PERCENT:		10.0%														
		LOW1	LOW2	LOW3	LOW4	OTH	OTH	OTH	OTH	OTH	SNK1	SNK2	SNK3	SNK4	UP1	UP2
		MCN	JDA	TDA	BON	ALF	DWR	HGH	LIB	BLK	LWG	LGS	LMN	IHR	GCL	CHJ
LOW1	MCN	0.0%	4.2%	0.1%	12.2%	38.1%	14.8%	29.0%	30.7%	38.1%	1.7%	5.9%	8.4%	1.5%	56.3%	55.6%
LOW2	JDA	4.2%	0.0%	4.1%	16.3%	42.3%	18.9%	33.1%	34.8%	42.3%	2.5%	1.7%	4.2%	5.6%	60.4%	59.7%
LOW3	TDA	0.1%	4.1%	0.0%	12.2%	38.2%	14.8%	29.1%	30.8%	38.2%	1.6%	5.8%	8.3%	1.6%	56.3%	55.6%
LOW4	BON	12.2%	16.3%	12.2%	0.0%	26.0%	2.6%	16.8%	18.5%	26.0%	13.8%	18.0%	20.5%	10.7%	44.1%	43.4%
OTH	ALF	38.1%	42.3%	38.2%	26.0%	0.0%	23.4%	9.2%	7.5%	0.0%	39.8%	44.0%	46.5%	36.7%	18.1%	17.4%
OTH	DWR	14.8%	18.9%	14.8%	2.6%	23.4%	0.0%	14.2%	15.9%	23.4%	16.4%	20.6%	23.1%	13.3%	41.5%	40.8%
OTH	HGH	29.0%	33.1%	29.1%	16.8%	9.2%	14.2%	0.0%	1.7%	9.2%	30.7%	34.8%	37.4%	27.5%	27.3%	26.6%
OTH	LIB	30.7%	34.8%	30.8%	18.5%	7.5%	15.9%	1.7%	0.0%	7.5%	32.4%	36.5%	39.0%	29.2%	25.6%	24.9%
OTH	BLK	38.1%	42.3%	38.2%	26.0%	0.0%	23.4%	9.2%	7.5%	0.0%	39.8%	44.0%	46.5%	36.7%	18.1%	17.4%
SNK1	LWG	1.7%	2.5%	1.6%	13.8%	39.8%	16.4%	30.7%	32.4%	39.8%	0.0%	4.2%	6.7%	3.2%	57.9%	57.2%
SNK2	LGS	5.9%	1.7%	5.8%	18.0%	44.0%	20.6%	34.8%	36.5%	44.0%	4.2%	0.0%	2.5%	7.3%	62.1%	61.4%
SNK3	LMN	8.4%	4.2%	8.3%	20.5%	46.5%	23.1%	37.4%	39.0%	46.5%	6.7%	2.5%	0.0%	9.8%	64.6%	63.9%
SNK4	IHR	1.5%	5.6%	1.6%	10.7%	36.7%	13.3%	27.5%	29.2%	36.7%	3.2%	7.3%	9.8%	0.0%	54.8%	54.1%
UP1	GCL	56.3%	60.4%	56.3%	44.1%	18.1%	41.5%	27.3%	25.6%	18.1%	57.9%	62.1%	64.6%	54.8%	0.0%	0.7%
UP2	CHJ	55.6%	59.7%	55.6%	43.4%	17.4%	40.8%	26.6%	24.9%	17.4%	57.2%	61.4%	63.9%	54.1%	0.7%	0.0%

FLOWGATE:	NORTH OF JOHN DAY N>S														
PERCENT:	10.0%														
		LOW1	LOW2	LOW3	LOW4	OTH	OTH	OTH	OTH	OTH	SNK1	SNK2	SNK3	SNK4	UP1	UP2
		MCN	JDA	TDA	BON	ALF	DWR	HGH	LIB	BLK	LWG	LGS	LMN	IHR	GCL	CHJ
LOW1	MCN	0.0%	4.4%	1.2%	4.4%	71.3%	73.3%	69.3%	69.8%	71.3%	81.1%	83.7%	85.3%	0.5%	75.1%	74.5%
LOW2	JDA	4.4%	0.0%	3.2%	8.8%	75.7%	77.7%	73.7%	74.2%	75.7%	85.5%	88.1%	89.7%	4.9%	79.5%	78.9%
LOW3	TDA	1.2%	3.2%	0.0%	5.6%	72.5%	74.5%	70.5%	71.0%	72.5%	82.3%	84.9%	86.5%	1.7%	76.3%	75.7%
LOW4	BON	4.4%	8.8%	5.6%	0.0%	66.9%	68.9%	64.9%	65.4%	66.9%	76.7%	79.3%	80.9%	3.9%	70.7%	70.1%
OTH	ALF	71.3%	75.7%	72.5%	66.9%	0.0%	2.0%	2.0%	1.5%	0.0%	9.8%	12.4%	13.9%	70.8%	3.7%	3.1%
OTH	DWR	73.3%	77.7%	74.5%	68.9%	2.0%	0.0%	4.0%	3.5%	2.0%	7.8%	10.4%	11.9%	72.8%	1.7%	1.1%
OTH	HGH	69.3%	73.7%	70.5%	64.9%	2.0%	4.0%	0.0%	0.5%	2.0%	11.8%	14.4%	15.9%	68.8%	5.7%	5.1%
OTH	LIB	69.8%	74.2%	71.0%	65.4%	1.5%	3.5%	0.5%	0.0%	1.5%	11.3%	13.9%	15.4%	69.3%	5.2%	4.6%
OTH	BLK	71.3%	75.7%	72.5%	66.9%	0.0%	2.0%	2.0%	1.5%	0.0%	9.8%	12.4%	13.9%	70.8%	3.7%	3.1%
SNK1	LWG	81.1%	85.5%	82.3%	76.7%	9.8%	7.8%	11.8%	11.3%	9.8%	0.0%	2.6%	4.2%	80.6%	6.0%	6.6%
SNK2	LGS	83.7%	88.1%	84.9%	79.3%	12.4%	10.4%	14.4%	13.9%	12.4%	2.6%	0.0%	1.6%	83.2%	8.6%	9.2%
SNK3	LMN	85.3%	89.7%	86.5%	80.9%	13.9%	11.9%	15.9%	15.4%	13.9%	4.2%	1.6%	0.0%	84.7%	10.2%	10.8%
SNK4	IHR	0.5%	4.9%	1.7%	3.9%	70.8%	72.8%	68.8%	69.3%	70.8%	80.6%	83.2%	84.7%	0.0%	74.5%	73.9%
UP1	GCL	75.1%	79.5%	76.3%	70.7%	3.7%	1.7%	5.7%	5.2%	3.7%	6.0%	8.6%	10.2%	74.5%	0.0%	0.6%
UP2	CHJ	74.5%	78.9%	75.7%	70.1%	3.1%	1.1%	5.1%	4.6%	3.1%	6.6%	9.2%	10.8%	73.9%	0.6%	0.0%

FLOWGATE:	PAUL TO ALLSTON N>S														
PERCENT:	10.0%														
		LOW1	LOW2	LOW3	LOW4	OTH	OTH	OTH	OTH	OTH	SNK1	SNK2	SNK3	SNK4	UP1	UP2
		MCN	JDA	TDA	BON	ALF	DWR	HGH	LIB	BLK	LWG	LGS	LMN	IHR	GCL	CHJ
LOW1	MCN	0.0%	1.8%	3.3%	12.4%	10.7%	6.7%	8.7%	9.0%	10.7%	4.9%	4.4%	4.2%	2.8%	12.5%	13.6%
LOW2	JDA	1.8%	0.0%	1.6%	10.7%	12.5%	8.5%	10.5%	10.8%	12.5%	6.6%	6.2%	6.0%	4.6%	14.3%	15.4%
LOW3	TDA	3.3%	1.6%	0.0%	9.1%	14.1%	10.1%	12.0%	12.4%	14.1%	8.2%	7.8%	7.5%	6.2%	15.9%	16.9%
LOW4	BON	12.4%	10.7%	9.1%	0.0%	23.1%	19.2%	21.1%	21.5%	23.1%	17.3%	16.9%	16.6%	15.2%	24.9%	26.0%
OTH	ALF	10.7%	12.5%	14.1%	23.1%	0.0%	4.0%	2.0%	1.7%	0.0%	5.9%	6.3%	6.5%	7.9%	1.8%	2.9%
OTH	DWR	6.7%	8.5%	10.1%	19.2%	4.0%	0.0%	2.0%	2.3%	4.0%	1.9%	2.3%	2.6%	3.9%	5.8%	6.9%
OTH	HGH	8.7%	10.5%	12.0%	21.1%	2.0%	2.0%	0.0%	0.3%	2.0%	3.8%	4.3%	4.5%	5.9%	3.8%	4.9%
OTH	LIB	9.0%	10.8%	12.4%	21.5%	1.7%	2.3%	0.3%	0.0%	1.7%	4.2%	4.6%	4.9%	6.2%	3.5%	4.6%
OTH	BLK	10.7%	12.5%	14.1%	23.1%	0.0%	4.0%	2.0%	1.7%	0.0%	5.9%	6.3%	6.5%	7.9%	1.8%	2.9%
SNK1	LWG	4.9%	6.6%	8.2%	17.3%	5.9%	1.9%	3.8%	4.2%	5.9%	0.0%	0.4%	0.7%	2.1%	7.7%	8.7%
SNK2	LGS	4.4%	6.2%	7.8%	16.9%	6.3%	2.3%	4.3%	4.6%	6.3%	0.4%	0.0%	0.3%	1.6%	8.1%	9.2%
SNK3	LMN	4.2%	6.0%	7.5%	16.6%	6.5%	2.6%	4.5%	4.9%	6.5%	0.7%	0.3%	0.0%	1.4%	8.3%	9.4%
SNK4	IHR	2.8%	4.6%	6.2%	15.2%	7.9%	3.9%	5.9%	6.2%	7.9%	2.1%	1.6%	1.4%	0.0%	9.7%	10.8%
UP1	GCL	12.5%	14.3%	15.9%	24.9%	1.8%	5.8%	3.8%	3.5%	1.8%	7.7%	8.1%	8.3%	9.7%	0.0%	1.1%
UP2	CHJ	13.6%	15.4%	16.9%	26.0%	2.9%	6.9%	4.9%	4.6%	2.9%	8.7%	9.2%	9.4%	10.8%	1.1%	0.0%

DRAFT – ELECTRICALLY SIMILAR ANALSYS - DRAFT

FLOWGATE:	RAVER TO PAUL N>S															
PERCENT:	10.0%															
		LOW1	LOW2	LOW3	LOW4	OTH	OTH	OTH	OTH	OTH	SNK1	SNK2	SNK3	SNK4	UP1	UP2
		MCN	JDA	TDA	BON	ALF	DWR	HGH	LIB	BLK	LWG	LGS	LMN	IHR	GCL	CHJ
LOW1	MCN	0.0%	1.3%	2.6%	10.2%	8.2%	5.2%	6.7%	6.9%	8.2%	3.9%	3.6%	3.4%	2.2%	9.8%	10.6%
LOW2	JDA	1.3%	0.0%	1.3%	8.9%	9.5%	6.6%	8.0%	8.2%	9.5%	5.2%	4.9%	4.7%	3.6%	11.1%	12.0%
LOW3	TDA	2.6%	1.3%	0.0%	7.6%	10.8%	7.9%	9.3%	9.5%	10.8%	6.5%	6.2%	6.0%	4.9%	12.4%	13.3%
LOW4	BON	10.2%	8.9%	7.6%	0.0%	18.4%	15.5%	16.9%	17.1%	18.4%	14.1%	13.8%	13.6%	12.5%	20.0%	20.9%
OTH	ALF	8.2%	9.5%	10.8%	18.4%	0.0%	2.9%	1.5%	1.3%	0.0%	4.3%	4.6%	4.8%	5.9%	1.6%	2.5%
OTH	DWR	5.2%	6.6%	7.9%	15.5%	2.9%	0.0%	1.4%	1.7%	2.9%	1.4%	1.7%	1.9%	3.0%	4.6%	5.4%
OTH	HGH	6.7%	8.0%	9.3%	16.9%	1.5%	1.4%	0.0%	0.2%	1.5%	2.8%	3.1%	3.3%	4.4%	3.1%	4.0%
OTH	LIB	6.9%	8.2%	9.5%	17.1%	1.3%	1.7%	0.2%	0.0%	1.3%	3.0%	3.3%	3.5%	4.7%	2.9%	3.7%
OTH	BLK	8.2%	9.5%	10.8%	18.4%	0.0%	2.9%	1.5%	1.3%	0.0%	4.3%	4.6%	4.8%	5.9%	1.6%	2.5%
SNK1	LWG	3.9%	5.2%	6.5%	14.1%	4.3%	1.4%	2.8%	3.0%	4.3%	0.0%	0.3%	0.5%	1.6%	5.9%	6.8%
SNK2	LGS	3.6%	4.9%	6.2%	13.8%	4.6%	1.7%	3.1%	3.3%	4.6%	0.3%	0.0%	0.2%	1.3%	6.2%	7.1%
SNK3	LMN	3.4%	4.7%	6.0%	13.6%	4.8%	1.9%	3.3%	3.5%	4.8%	0.5%	0.2%	0.0%	1.1%	6.4%	7.3%
SNK4	IHR	2.2%	3.6%	4.9%	12.5%	5.9%	3.0%	4.4%	4.7%	5.9%	1.6%	1.3%	1.1%	0.0%	7.6%	8.4%
UP1	GCL	9.8%	11.1%	12.4%	20.0%	1.6%	4.6%	3.1%	2.9%	1.6%	5.9%	6.2%	6.4%	7.6%	0.0%	0.9%
UP2	CHJ	10.6%	12.0%	13.3%	20.9%	2.5%	5.4%	4.0%	3.7%	2.5%	6.8%	7.1%	7.3%	8.4%	0.9%	0.0%

FLOWGATE:	SOUTH OF ALLSTON N>S															
PERCENT:	10.0%															
		LOW1	LOW2	LOW3	LOW4	OTH	OTH	OTH	OTH	OTH	SNK1	SNK2	SNK3	SNK4	UP1	UP2
		MCN	JDA	TDA	BON	ALF	DWR	HGH	LIB	BLK	LWG	LGS	LMN	IHR	GCL	CHJ
LOW1	MCN	0.0%	2.1%	4.0%	16.0%	13.2%	8.3%	10.7%	11.2%	13.2%	6.0%	5.5%	5.2%	3.5%	15.4%	16.8%
LOW2	JDA	2.1%	0.0%	2.0%	13.9%	15.3%	10.4%	12.8%	13.2%	15.3%	8.1%	7.6%	7.2%	5.6%	17.4%	18.8%
LOW3	TDA	4.0%	2.0%	0.0%	11.9%	17.3%	12.4%	14.8%	15.2%	17.3%	10.1%	9.5%	9.2%	7.5%	19.4%	20.8%
LOW4	BON	16.0%	13.9%	11.9%	0.0%	29.2%	24.3%	26.7%	27.1%	29.2%	22.0%	21.5%	21.2%	19.5%	31.4%	32.7%
OTH	ALF	13.2%	15.3%	17.3%	29.2%	0.0%	4.9%	2.5%	2.1%	0.0%	7.2%	7.7%	8.1%	9.7%	2.2%	3.5%
OTH	DWR	8.3%	10.4%	12.4%	24.3%	4.9%	0.0%	2.4%	2.8%	4.9%	2.3%	2.8%	3.2%	4.8%	7.1%	8.4%
OTH	HGH	10.7%	12.8%	14.8%	26.7%	2.5%	2.4%	0.0%	0.4%	2.5%	4.7%	5.2%	5.6%	7.2%	4.7%	6.0%
OTH	LIB	11.2%	13.2%	15.2%	27.1%	2.1%	2.8%	0.4%	0.0%	2.1%	5.1%	5.7%	6.0%	7.7%	4.2%	5.6%
OTH	BLK	13.2%	15.3%	17.3%	29.2%	0.0%	4.9%	2.5%	2.1%	0.0%	7.2%	7.7%	8.1%	9.7%	2.2%	3.5%
SNK1	LWG	6.0%	8.1%	10.1%	22.0%	7.2%	2.3%	4.7%	5.1%	7.2%	0.0%	0.5%	0.8%	2.5%	9.4%	10.7%
SNK2	LGS	5.5%	7.6%	9.5%	21.5%	7.7%	2.8%	5.2%	5.7%	7.7%	0.5%	0.0%	0.3%	2.0%	9.9%	11.3%
SNK3	LMN	5.2%	7.2%	9.2%	21.2%	8.1%	3.2%	5.6%	6.0%	8.1%	0.8%	0.3%	0.0%	1.7%	10.2%	11.6%
SNK4	IHR	3.5%	5.6%	7.5%	19.5%	9.7%	4.8%	7.2%	7.7%	9.7%	2.5%	2.0%	1.7%	0.0%	11.9%	13.3%
UP1	GCL	15.4%	17.4%	19.4%	31.4%	2.2%	7.1%	4.7%	4.2%	2.2%	9.4%	9.9%	10.2%	11.9%	0.0%	1.4%
UP2	CHJ	16.8%	18.8%	20.8%	32.7%	3.5%	8.4%	6.0%	5.6%	3.5%	10.7%	11.3%	11.6%	13.3%	1.4%	0.0%

FLOWGATE:	SOUTH OF CUSTER N>S															
PERCENT:		10.0%														
		LOW1	LOW2	LOW3	LOW4	OTH	OTH	OTH	OTH	OTH	SNK1	SNK2	SNK3	SNK4	UP1	UP2
		MCN	JDA	TDA	BON	ALF	DWR	HGH	LIB	BLK	LWG	LGS	LMN	IHR	GCL	CHJ
LOW1	MCN	0.0%	0.3%	0.4%	0.8%	15.1%	3.6%	7.0%	7.7%	15.1%	1.3%	0.8%	0.5%	0.2%	0.3%	1.5%
LOW2	JDA	0.3%	0.0%	0.1%	0.5%	15.3%	3.8%	7.3%	8.0%	15.3%	1.6%	1.1%	0.7%	0.4%	0.1%	1.2%
LOW3	TDA	0.4%	0.1%	0.0%	0.4%	15.4%	3.9%	7.4%	8.1%	15.4%	1.7%	1.2%	0.8%	0.6%	0.0%	1.1%
LOW4	BON	0.8%	0.5%	0.4%	0.0%	15.9%	4.4%	7.8%	8.5%	15.9%	2.1%	1.6%	1.3%	1.0%	0.5%	0.7%
OTH	ALF	15.1%	15.3%	15.4%	15.9%	0.0%	11.5%	8.1%	7.4%	0.0%	13.7%	14.3%	14.6%	14.9%	15.4%	16.5%
OTH	DWR	3.6%	3.8%	3.9%	4.4%	11.5%	0.0%	3.4%	4.1%	11.5%	2.2%	2.8%	3.1%	3.4%	3.9%	5.0%
OTH	HGH	7.0%	7.3%	7.4%	7.8%	8.1%	3.4%	0.0%	0.7%	8.1%	5.7%	6.2%	6.5%	6.8%	7.3%	8.5%
OTH	LIB	7.7%	8.0%	8.1%	8.5%	7.4%	4.1%	0.7%	0.0%	7.4%	6.4%	6.9%	7.2%	7.5%	8.0%	9.2%
OTH	BLK	15.1%	15.3%	15.4%	15.9%	0.0%	11.5%	8.1%	7.4%	0.0%	13.7%	14.3%	14.6%	14.9%	15.4%	16.5%
SNK1	LWG	1.3%	1.6%	1.7%	2.1%	13.7%	2.2%	5.7%	6.4%	13.7%	0.0%	0.6%	0.9%	1.2%	1.7%	2.8%
SNK2	LGS	0.8%	1.1%	1.2%	1.6%	14.3%	2.8%	6.2%	6.9%	14.3%	0.6%	0.0%	0.3%	0.6%	1.1%	2.3%
SNK3	LMN	0.5%	0.7%	0.8%	1.3%	14.6%	3.1%	6.5%	7.2%	14.6%	0.9%	0.3%	0.0%	0.3%	0.8%	1.9%
SNK4	IHR	0.2%	0.4%	0.6%	1.0%	14.9%	3.4%	6.8%	7.5%	14.9%	1.2%	0.6%	0.3%	0.0%	0.5%	1.7%
UP1	GCL	0.3%	0.1%	0.0%	0.5%	15.4%	3.9%	7.3%	8.0%	15.4%	1.7%	1.1%	0.8%	0.5%	0.0%	1.1%
UP2	CHJ	1.5%	1.2%	1.1%	0.7%	16.5%	5.0%	8.5%	9.2%	16.5%	2.8%	2.3%	1.9%	1.7%	1.1%	0.0%

FLOWGATE:	WEST OF JOHN DAY E>W															
PERCENT:		10.0%														
		LOW1	LOW2	LOW3	LOW4	OTH	OTH	OTH	OTH	OTH	SNK1	SNK2	SNK3	SNK4	UP1	UP2
		MCN	JDA	TDA	BON	ALF	DWR	HGH	LIB	BLK	LWG	LGS	LMN	IHR	GCL	CHJ
LOW1	MCN	0.0%	22.3%	56.4%	33.2%	10.4%	7.3%	8.7%	9.1%	10.4%	6.0%	5.7%	5.5%	3.1%	12.4%	12.9%
LOW2	JDA	22.3%	0.0%	78.6%	55.4%	32.7%	29.5%	31.0%	31.3%	32.7%	28.2%	27.9%	27.8%	25.3%	34.6%	35.2%
LOW3	TDA	56.4%	78.6%	0.0%	23.2%	46.0%	49.1%	47.6%	47.3%	46.0%	50.4%	50.7%	50.8%	53.3%	44.0%	43.4%
LOW4	BON	33.2%	55.4%	23.2%	0.0%	22.7%	25.9%	24.4%	24.1%	22.7%	27.2%	27.5%	27.6%	30.1%	20.8%	20.2%
OTH	ALF	10.4%	32.7%	46.0%	22.7%	0.0%	3.1%	1.7%	1.4%	0.0%	4.4%	4.7%	4.9%	7.3%	2.0%	2.5%
OTH	DWR	7.3%	29.5%	49.1%	25.9%	3.1%	0.0%	1.4%	1.8%	3.1%	1.3%	1.6%	1.8%	4.2%	5.1%	5.6%
OTH	HGH	8.7%	31.0%	47.6%	24.4%	1.7%	1.4%	0.0%	0.3%	1.7%	2.8%	3.0%	3.2%	5.7%	3.6%	4.2%
OTH	LIB	9.1%	31.3%	47.3%	24.1%	1.4%	1.8%	0.3%	0.0%	1.4%	3.1%	3.4%	3.5%	6.0%	3.3%	3.9%
OTH	BLK	10.4%	32.7%	46.0%	22.7%	0.0%	3.1%	1.7%	1.4%	0.0%	4.4%	4.7%	4.9%	7.3%	2.0%	2.5%
SNK1	LWG	6.0%	28.2%	50.4%	27.2%	4.4%	1.3%	2.8%	3.1%	4.4%	0.0%	0.3%	0.4%	2.9%	6.4%	7.0%
SNK2	LGS	5.7%	27.9%	50.7%	27.5%	4.7%	1.6%	3.0%	3.4%	4.7%	0.3%	0.0%	0.2%	2.6%	6.7%	7.2%
SNK3	LMN	5.5%	27.8%	50.8%	27.6%	4.9%	1.8%	3.2%	3.5%	4.9%	0.4%	0.2%	0.0%	2.5%	6.8%	7.4%
SNK4	IHR	3.1%	25.3%	53.3%	30.1%	7.3%	4.2%	5.7%	6.0%	7.3%	2.9%	2.6%	2.5%	0.0%	9.3%	9.9%
UP1	GCL	12.4%	34.6%	44.0%	20.8%	2.0%	5.1%	3.6%	3.3%	2.0%	6.4%	6.7%	6.8%	9.3%	0.0%	0.6%
UP2	CHJ	12.9%	35.2%	43.4%	20.2%	2.5%	5.6%	4.2%	3.9%	2.5%	7.0%	7.2%	7.4%	9.9%	0.6%	0.0%

FLOWGATE:	WEST OF LOWER MONUMENTAL E>W															
PERCENT:	10.0%															
		LOW1	LOW2	LOW3	LOW4	OTH	OTH	OTH	OTH	OTH	SNK1	SNK2	SNK3	SNK4	UP1	UP2
		MCN	JDA	TDA	BON	ALF	DWR	HGH	LIB	BLK	LWG	LGS	LMN	IHR	GCL	CHJ
LOW1	MCN	0.0%	1.1%	1.5%	2.4%	25.0%	53.3%	33.7%	32.2%	25.0%	78.9%	86.0%	90.3%	3.2%	9.0%	8.2%
LOW2	JDA	1.1%	0.0%	0.4%	1.4%	23.9%	52.2%	32.6%	31.2%	23.9%	77.8%	84.9%	89.2%	4.3%	7.9%	7.2%
LOW3	TDA	1.5%	0.4%	0.0%	1.0%	23.5%	51.8%	32.2%	30.8%	23.5%	77.4%	84.5%	88.8%	4.7%	7.5%	6.8%
LOW4	BON	2.4%	1.4%	1.0%	0.0%	22.6%	50.9%	31.3%	29.8%	22.6%	76.4%	83.5%	87.8%	5.6%	6.6%	5.8%
OTH	ALF	25.0%	23.9%	23.5%	22.6%	0.0%	28.3%	8.7%	7.2%	0.0%	53.9%	61.0%	65.3%	28.2%	16.0%	16.8%
OTH	DWR	53.3%	52.2%	51.8%	50.9%	28.3%	0.0%	19.6%	21.1%	28.3%	25.6%	32.7%	36.9%	56.5%	44.3%	45.1%
OTH	HGH	33.7%	32.6%	32.2%	31.3%	8.7%	19.6%	0.0%	1.5%	8.7%	45.2%	52.3%	56.6%	36.9%	24.7%	25.5%
OTH	LIB	32.2%	31.2%	30.8%	29.8%	7.2%	21.1%	1.5%	0.0%	7.2%	46.6%	53.7%	58.0%	35.4%	23.2%	24.0%
OTH	BLK	25.0%	23.9%	23.5%	22.6%	0.0%	28.3%	8.7%	7.2%	0.0%	53.9%	61.0%	65.3%	28.2%	16.0%	16.8%
SNK1	LWG	78.9%	77.8%	77.4%	76.4%	53.9%	25.6%	45.2%	46.6%	53.9%	0.0%	7.1%	11.4%	82.1%	69.9%	70.6%
SNK2	LGS	86.0%	84.9%	84.5%	83.5%	61.0%	32.7%	52.3%	53.7%	61.0%	7.1%	0.0%	4.3%	89.2%	77.0%	77.7%
SNK3	LMN	90.3%	89.2%	88.8%	87.8%	65.3%	36.9%	56.6%	58.0%	65.3%	11.4%	4.3%	0.0%	93.4%	81.3%	82.0%
SNK4	IHR	3.2%	4.3%	4.7%	5.6%	28.2%	56.5%	36.9%	35.4%	28.2%	82.1%	89.2%	93.4%	0.0%	12.2%	11.4%
UP1	GCL	9.0%	7.9%	7.5%	6.6%	16.0%	44.3%	24.7%	23.2%	16.0%	69.9%	77.0%	81.3%	12.2%	0.0%	0.8%
UP2	CHJ	8.2%	7.2%	6.8%	5.8%	16.8%	45.1%	25.5%	24.0%	16.8%	70.6%	77.7%	82.0%	11.4%	0.8%	0.0%

FLOWGATE:	WEST OF MCNARY E>W															
PERCENT:	10.0%															
		LOW1	LOW2	LOW3	LOW4	OTH	OTH	OTH	OTH	OTH	SNK1	SNK2	SNK3	SNK4	UP1	UP2
		MCN	JDA	TDA	BON	ALF	DWR	HGH	LIB	BLK	LWG	LGS	LMN	IHR	GCL	CHJ
LOW1	MCN	0.0%	72.5%	70.4%	67.4%	52.4%	47.1%	50.9%	51.1%	52.4%	43.6%	42.8%	42.3%	23.8%	55.5%	55.8%
LOW2	JDA	72.5%	0.0%	2.1%	5.1%	20.1%	25.4%	21.6%	21.4%	20.1%	28.9%	29.7%	30.2%	48.7%	17.0%	16.7%
LOW3	TDA	70.4%	2.1%	0.0%	3.0%	18.0%	23.3%	19.5%	19.3%	18.0%	26.8%	27.6%	28.1%	46.6%	14.9%	14.6%
LOW4	BON	67.4%	5.1%	3.0%	0.0%	14.9%	20.3%	16.5%	16.3%	14.9%	23.8%	24.6%	25.1%	43.6%	11.9%	11.6%
OTH	ALF	52.4%	20.1%	18.0%	14.9%	0.0%	5.3%	1.5%	1.4%	0.0%	8.9%	9.6%	10.1%	28.6%	3.0%	3.3%
OTH	DWR	47.1%	25.4%	23.3%	20.3%	5.3%	0.0%	3.8%	3.9%	5.3%	3.6%	4.3%	4.8%	23.3%	8.4%	8.7%
OTH	HGH	50.9%	21.6%	19.5%	16.5%	1.5%	3.8%	0.0%	0.2%	1.5%	7.3%	8.1%	8.6%	27.1%	4.6%	4.9%
OTH	LIB	51.1%	21.4%	19.3%	16.3%	1.4%	3.9%	0.2%	0.0%	1.4%	7.5%	8.3%	8.7%	27.3%	4.4%	4.7%
OTH	BLK	52.4%	20.1%	18.0%	14.9%	0.0%	5.3%	1.5%	1.4%	0.0%	8.9%	9.6%	10.1%	28.6%	3.0%	3.3%
SNK1	LWG	43.6%	28.9%	26.8%	23.8%	8.9%	3.6%	7.3%	7.5%	8.9%	0.0%	0.8%	1.3%	19.8%	11.9%	12.2%
SNK2	LGS	42.8%	29.7%	27.6%	24.6%	9.6%	4.3%	8.1%	8.3%	9.6%	0.8%	0.0%	0.5%	19.0%	12.7%	13.0%
SNK3	LMN	42.3%	30.2%	28.1%	25.1%	10.1%	4.8%	8.6%	8.7%	10.1%	1.3%	0.5%	0.0%	18.5%	13.2%	13.5%
SNK4	IHR	23.8%	48.7%	46.6%	43.6%	28.6%	23.3%	27.1%	27.3%	28.6%	19.8%	19.0%	18.5%	0.0%	31.7%	32.0%
UP1	GCL	55.5%	17.0%	14.9%	11.9%	3.0%	8.4%	4.6%	4.4%	3.0%	11.9%	12.7%	13.2%	31.7%	0.0%	0.3%
UP2	CHJ	55.8%	16.7%	14.6%	11.6%	3.3%	8.7%	4.9%	4.7%	3.3%	12.2%	13.0%	13.5%	32.0%	0.3%	0.0%

FLOWGATE:		WEST OF SLATT E>W														
PERCENT:		10.0%														
		LOW1	LOW2	LOW3	LOW4	OTH	OTH	OTH	OTH	OTH	SNK1	SNK2	SNK3	SNK4	UP1	UP2
		MCN	JDA	TDA	BON	ALF	DWR	HGH	LIB	BLK	LWG	LGS	LMN	IHR	GCL	CHJ
LOW1	MCN	0.0%	32.4%	27.7%	22.3%	10.7%	8.0%	10.4%	10.4%	10.7%	5.0%	4.2%	3.7%	2.2%	11.3%	11.6%
LOW2	JDA	32.4%	0.0%	4.6%	10.1%	21.7%	24.4%	22.0%	22.0%	21.7%	27.4%	28.2%	28.7%	30.2%	21.1%	20.7%
LOW3	TDA	27.7%	4.6%	0.0%	5.5%	17.0%	19.7%	17.3%	17.4%	17.0%	22.7%	23.5%	24.0%	25.5%	16.5%	16.1%
LOW4	BON	22.3%	10.1%	5.5%	0.0%	11.6%	14.3%	11.9%	11.9%	11.6%	17.3%	18.1%	18.6%	20.1%	11.0%	10.7%
OTH	ALF	10.7%	21.7%	17.0%	11.6%	0.0%	2.7%	0.3%	0.3%	0.0%	5.7%	6.5%	7.0%	8.5%	0.6%	0.9%
OTH	DWR	8.0%	24.4%	19.7%	14.3%	2.7%	0.0%	2.4%	2.4%	2.7%	3.0%	3.8%	4.3%	5.8%	3.3%	3.6%
OTH	HGH	10.4%	22.0%	17.3%	11.9%	0.3%	2.4%	0.0%	0.1%	0.3%	5.4%	6.2%	6.7%	8.2%	0.8%	1.2%
OTH	LIB	10.4%	22.0%	17.4%	11.9%	0.3%	2.4%	0.1%	0.0%	0.3%	5.4%	6.2%	6.7%	8.2%	0.9%	1.3%
OTH	BLK	10.7%	21.7%	17.0%	11.6%	0.0%	2.7%	0.3%	0.3%	0.0%	5.7%	6.5%	7.0%	8.5%	0.6%	0.9%
SNK1	LWG	5.0%	27.4%	22.7%	17.3%	5.7%	3.0%	5.4%	5.4%	5.7%	0.0%	0.8%	1.3%	2.8%	6.2%	6.6%
SNK2	LGS	4.2%	28.2%	23.5%	18.1%	6.5%	3.8%	6.2%	6.2%	6.5%	0.8%	0.0%	0.5%	2.0%	7.1%	7.4%
SNK3	LMN	3.7%	28.7%	24.0%	18.6%	7.0%	4.3%	6.7%	6.7%	7.0%	1.3%	0.5%	0.0%	1.5%	7.5%	7.9%
SNK4	IHR	2.2%	30.2%	25.5%	20.1%	8.5%	5.8%	8.2%	8.2%	8.5%	2.8%	2.0%	1.5%	0.0%	9.1%	9.4%
UP1	GCL	11.3%	21.1%	16.5%	11.0%	0.6%	3.3%	0.8%	0.9%	0.6%	6.2%	7.1%	7.5%	9.1%	0.0%	0.4%
UP2	CHJ	11.6%	20.7%	16.1%	10.7%	0.9%	3.6%	1.2%	1.3%	0.9%	6.6%	7.4%	7.9%	9.4%	0.4%	0.0%

From: Pettinger,Rebekah S (BPA) - LP-7
Sent: Wed Mar 14 15:31:57 2018
To: Greene,Richard A (BPA) - LP-7
Subject: RE: Draft Memo
Importance: Normal
Attachments: MEMORANDUM--ADF on Gen3-14-18.docx

I like the changes you made—I think this is shaping up. I first accepted your changes then made some additional edits and added several citations. All my new stuff is in redline.

From: Greene,Richard A (BPA) - LP-7
Sent: Wednesday, March 14, 2018 9:29 AM
To: Pettinger,Rebekah S (BPA) - LP-7
Subject: Draft Memo

Here you go…

From: Jensen,Mary K (BPA) - L-7
Sent: Fri Mar 23 14:53:53 2018
To: Pettinger,Rebekah S (BPA) - LP-7; Hulett,Jimmy D (BPA) - LT-7; Chong Tim,Marcus H (BPA) - LT-7; Davis,Thomas E (BPA) - LT-7; Sigurdson,Ryan M (BPA) - LT-7; Johnson,Tim A (BPA) - LP-7; Greene,Richard A (BPA) - LP-7; Griffen,Christian W (BPA) - LT-7; Miller,Todd E (BPA) - LP-7; Chan,Allen C (BPA) - LT-7; Schaeffer,Virginia K (BPA) - LG-7; Adams,Hub V (BPA) - LN-7; Cox,Tiffany L (BPA) - LP-7
Cc: Sigurdson,Ryan M (BPA) - LT-7
Subject: RE: Federal Resource Participation ADF--Draft legal analysis
Importance: Normal
Attachments: MEMORANDUM--ADF on Gen3-20-18 Mary's edits.docx

Here are a few tweaks from me. Note that most of the *italics* are gone. I didn't read the last part since Tim thought it needed a lot more work.

From: Pettinger,Rebekah S (BPA) - LP-7
Sent: Wednesday, March 21, 2018 8:23 AM
To: Hulett,Jimmy D (BPA) - LT-7; Chong Tim,Marcus H (BPA) - LT-7; Davis,Thomas E (BPA) - LT-7; Sigurdson,Ryan M (BPA) - LT-7; Johnson,Tim A (BPA) - LP-7; Greene,Richard A (BPA) - LP-7; Griffen,Christian W (BPA) - LT-7; Jensen,Mary K (BPA) - L-7; Miller,Todd E (BPA) - LP-7; Chan,Allen C (BPA) - LT-7; Schaeffer,Virginia K (BPA) - LG-7; Adams,Hub V (BPA) - LN-7; Cox,Tiffany L (BPA) - LP-7
Cc: Sigurdson,Ryan M (BPA) - LT-7
Subject: Federal Resource Participation ADF--Draft legal analysis

Here is our current draft of the Legal Analysis on the Federal Resource Participation ADF. It includes comments from Tim, which we are working to incorporate.

Rebekah

From: Hulett,Jimmy D (BPA) - LT-7
Sent: Tuesday, March 13, 2018 1:30 PM
To: Chong Tim,Marcus H (BPA) - LT-7; Davis,Thomas E (BPA) - LT-7; Pettinger,Rebekah S (BPA) - LP-7; Sigurdson,Ryan M (BPA) - LT-7; Johnson,Tim A (BPA) - LP-7; Greene,Richard A (BPA) - LP-7; Griffen,Christian W (BPA) - LT-7; Jensen,Mary K (BPA) - L-7; Miller,Todd E (BPA) - LP-7; Chan,Allen C (BPA) - LT-7; Schaeffer,Virginia K (BPA) - LG-7; Adams,Hub V (BPA) - LN-7; Cox,Tiffany L (BPA) - LP-7
Cc: Sigurdson,Ryan M (BPA) - LT-7
Subject: EIM Transmission Provision ADF--Draft legal analysis

Hi all,

Attached is our draft legal analysis for staff's ADF regarding how BPA will make transmission available to support EIM transfers.

I think we are a bit ahead of staff is at this point, so this may be subject to change. That said, it seems they have come to a consensus around the identified alternatives and hopefully there won't be new major revelations in the next week. So please edit and comment as you see fit.

I am also attaching staff's most recent draft of the ADF for reference.

Thanks,

Jimmy

Jimmy Hulett
Office of General Counsel
Bonneville Power Administration
P.O. Box 3621, LT-7
Portland, OR 97208-3621
503.230.3121 (o)
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Email: jdhulett@bpa.gov

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From: Pettinger,Rebekah S (BPA) - LP-7
Sent: Thursday, March 22, 2018 9:16 AM
To: Greene,Richard A (BPA) - LP-7
Subject: RE: Fed Resource ADF - Draft Legal Analysis
Attachments: MEMORANDUM--ADF on Gen3-22-18b.docx

Use this version please. I caught a couple of typos in the final section.

From: Pettinger,Rebekah S (BPA) - LP-7
Sent: Thursday, March 22, 2018 9:12 AM
To: Greene,Richard A (BPA) - LP-7
Subject: Fed Resource ADF - Draft Legal Analysis

Hi Rich. I incorporated Tim and Marcus's edits into the legal analysis (accepted most edits and got rid of comments I thought were taken care of). I also made a few additional adjustments, shown in redline.

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From: Greene,Richard A (BPA) - LP-7
Sent: Fri Sep 28 16:53:41 2018
To: Pettinger,Rebekah S (BPA) - LP-7; Chong Tim,Marcus H (BPA) - LT-7; Davis,Thomas E (BPA) - LT-7; Hulett,Jimmy D (BPA) - LT-7; Sigurdson,Ryan M (BPA) - LT-7; Johnson,Tim A (BPA) - LP-7; Griffen,Christian W (BPA) - LT-7; Jensen,Mary K (BPA) - L-7; Chan,Allen C (BPA) - LT-7; Miller,Thomas (BPA) - LP-7
Subject: RE: EIM Legal Team Meeting
Importance: Normal
Attachments: Legal Memo-Fed Resource ADF.docx; Paper on LMPs and System Resource - Examples.docx

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-----Original Appointment-----
From: Pettinger,Rebekah S (BPA) - LP-7
Sent: Wednesday, September 05, 2018 9:53 AM
To: Pettinger,Rebekah S (BPA) - LP-7; Chong Tim,Marcus H (BPA) - LT-7; Davis,Thomas E (BPA) - LT-7; Hulett,Jimmy D (BPA) - LT-7; Sigurdson,Ryan M (BPA) - LT-7; Johnson,Tim A (BPA) - LP-7; Greene,Richard A (BPA) - LP-7; Griffen,Christian W (BPA) - LT-7; Jensen,Mary K (BPA) - L-7; Chan,Allen C (BPA) - LT-7
Subject: EIM Legal Team Meeting
When: Friday, September 28, 2018 1:00 PM-2:00 PM (UTC-08:00) Pacific Time (US & Canada).
Where: HQ 761 VP(20) Call-in in invite

503-230-4000
PW: (b)(2) [redacted]

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From: Davis,Thomas E (BPA) - LT-7
Sent: Tue Mar 27 11:38:48 2018
To: Herrin,Janet C (BPA) - K-7; Cathcart,Michelle M (BPA) - TO-DITT-2; Mantifel,Russell (BPA) - TSQM-DITT-2; Manary,Michelle L (BPA) - TS-DITT-2; Cooper,Suzanne B (BPA) - PT-5; Cook,Jeffrey W (BPA) - TP-DITT-2; Connolly,Kieran P (BPA) - PG-5; Symonds,Mark C (BPA) - BD-3; Federovitch,Eric C (BPA) - PTM-5; Kerns,Steven R (BPA) - PGS-5; Cook,Joel D (BPA) - P-6; Shaheen,Richard L (BPA) - T-DITT-2; Miller,Todd E (BPA) - LP-7; Zimmerman,Nita M (BPA) - B-3; Jensen,Mary K (BPA) - L-7
Subject: Strategy Negotiations Documents for EIM IMPORTANT
Importance: High
Attachments: Federal Resource Participation ADF v2.docx; Legal Memo-Fed Resource ADF.PDF; Excerpts from Oct 2017 Legal Analysis For FRP ADF.pdf; Negotiation Strategy Proposal.docx

Attached below, please find the following documents for Friday's meeting regarding Bonneville's negotiation strategy for EIM participation.

The first three documents include the ADF for Federal resource participation in the EIM (led by Steve Kerns) and supporting legal analysis. There are two legal analyses attached for this ADF. The first is the analysis for the specific ADF itself and the second includes relevant excerpts from OGC's comprehensive EIM legal analysis done back in October 2017.

The next document is staff's Negotiation Strategy proposal for the other topics not addressed in the ADFs addressing Federal resource participation and utilization of transmission for EIM transfers.

Staff is still finalizing the ADF regarding utilization of transmission for EIM transfers (led by Russ Mantifel) today. I will send it out this evening along with the legal analysis for that ADF.

The expectation is that Friday's meeting will be a discussion of these documents, not a presentation of them, so please read them beforehand and come prepared to discuss.

If you have any questions, please do not hesitate to communicate with me or Todd Miller.

Tom

1. Describe problem or opportunity

The key driver for this ADF is the need to develop a negotiation strategy prior to starting negotiations with the CAISO. The specific resource participation model that we establish for joining the Western EIM with CAISO will influence the requirements for Grid Modernization projects including developing new systems, business processes, and governance. The decision on the general structure of how FCRPS within hour flexibility will be marketed in the EIM, along with the Transmission participation model will likely influence other decisions as we learn more about what Grid Modernization and participating in organized markets means for BPA (from a one-BPA perspective). Collectively, these decisions on market participation choices will balance reliability, efficiency, and control of generation in the balancing authority (BA).

As the team learns more, as additional decisions are made, and as Grid Modernization projects progress, the decisions in this ADF will likely be revisited.

There are two questions for decision laid out in this ADF:

1. How to aggregate (or not) the FCRPS for BPA to participate in the Western EIM and
2. Whether to adopt the Powerex model to split each aggregate resource into: (1) a participating portion for the CAISO to dispatch (surplus power) and (2) a nonparticipating portion for the BA to dispatch (load and ancillary services).

Assumptions:

1. The BPA BA maintains its autonomy; contingency reserves and regulation (for load and generators) will not be dispatched by the market operator.
2. Power Services retains the autonomy on how hydro projects respond to market signals.
3. Power Services will still be able to make system sales and purchases outside of the EIM.
4. Current tagging and scheduling practices will remain.
5. A participating EIM resource will be used to reference the type of resource that the market operator sees and is limited to the dispatchable "Big10" FCRPS hydro projects.
6. Power Services retains the ability to determine how much and which, if any, of the "Big10" FCRPS hydro project to offer bid curves for any given hour.
7. A bid curve will be created for each aggregated participating resource (APR). An individual bid curve will be created for each participating resource that is not part of an aggregate.
8. Non-dispatchable FCRPS projects will be non-participating resources in an EIM.
9. Participation decisions by non-federal generators in the BPA BA are independent of this ADF decision.
10. The outcome of the "Transmission Provision in an EIM" ADF does not impact the outcome of this ADF.
11. Power Services will meet all NT load obligations.
12. All FCRPS dispatches are deliverable and feasible without violating FCRPS non-power constraints.
13. Transmission is available for dispatch instructions from the CAISO.
14. The EIM will not cause the BA to violate reliability standards.
15. EIM approved meters are in place to capture the FCRPS resource (aggregated or not) responses.

2. Define governance, scope & constraints

Name of Initiative: Federal Resource Participation in an EIM
Client Organization: Power Services, Transmission Services
POC Manager: Steve Kerns (PGS)
Decision Maker(s): Joel Cook, Richard Shaheen

Consult - Tier II steering committee: Kieran, Suzanne, Michelle M., Michelle C., Jeff C., Todd M. – Currently meets monthly (last Tuesday of every month) for one hour on March 27th at 1pm.

Executive Sponsors: Kieran Connolly, Suzanne Cooper, Michelle Cathcart, Michelle Manary, Jeff Cook (?)
ADF Lead: Steve Kerns (PGS)
Core ADF team members: Clarisse Messemer (PGST), Todd Kochheiser (TOI), Dave Dernovsek (PTKP), Eric Federovitch (PTM), Rich Greene (LP), Rebekah Pettinger (LP), Kelii Haraguchi (PTM), Eric King (TSPP), Russ Mantifel (TS), Tom Davis (LT), Mark Symonds (BD), Chris Siewert (PGSD) , Elsa Chang (PGST), Cindy Polsky (PGST), Pam Van Calcar (PGSP), Frank Puyleart (TOOC), Chris Sanford (TOR), Steve Gaube (PTF), Troy Simpson (TOI), John Schaffroth (Utilicast), Margaret Pedersen Mainzer (PTL), Mai Truong (PGST), Rob Hawkins (PGSD), Garland Will (PGST), Anna Stermer (PGSP), Sara Eaton (PTM), Dave Kirsch (TOOC)
Draft due: March 15, 2018
Final due: March 31, 2018
Decision Deadline: March 31, 2018

3. Status quo context

FCRPS Aggregation:
Since the BPA is not currently a participating entity, there is no status quo context for how the FCRPS will participate in the Western EIM. However, there is a status quo of current operations that has elements of all the alternatives. So no one alternative can be considered the status quo.

Of the 31 dams and one nuclear plant that BPA markets the energy for, only 10 projects (the Big10) are capable of being armed for Automatic Generation Control (AGC) response. This means that they are connected via AGC and can be automatically dispatched by the transmission operator to maintain reliability.

The Big10, AGC responsive projects are:
Upper Columbia:
- Grand Coulee (GCL)
- Chief Joe (CHJ)

Lower Snake:
- Lower Granite (LWG)
- Little Goose (LGS)
- Lower Monumental (LMN)
- Ice Harbor (IHR)

Lower Columbia:
- McNary (MCN)
- John Day (JDA)
- The Dalles (TDA)
- Bonneville (BON)

BPA operates these projects individually and as an aggregate depending upon the hydraulic, power, or non-power constraint that is binding. The entire system (the Big10 as well as all the remaining generators marketed by Power Services) is marketed as if coming from a single resource (system sales) at the Mid-C hub. Operationally, the Hydro Duty Scheduler generally manages the hydraulic nature of the system as three groups: Upper Columbia, the Lower Snake, and the Lower Columbia. In addition, the Hydro Duty Scheduler sets basepoints for each project individually and sets response factors for each of the projects on response individually.

Upper Columbia projects are hydraulically independent from Lower Snake projects since they are on different river reaches and from the Lower Columbia projects due to the long travel time and nonfederal projects that are in between. Assessing hydraulic linkage between Lower Snake and Lower Columbia projects is a little trickier since the travel time between water discharged from Ice Harbor and McNary is only a couple of hours. However, absent special operations or unusual outage conditions, the Lower Snake projects tend to operate in a similar manner so aggregating these projects is rational. Of the four Lower Columbia river projects, McNary, John Day and The Dalles tend to be operated in a similar manner except during high flows when McNary (which is the most turbine limited of the three) tends to run at flat generation. Bonneville dam can, at times, also operate in a similar manner, but it has frequent special operations and non-power constraints that limit operational flexibility.

Looking at hourly response factors over a ten year period (2008 – 2017), there are at least two aggregations of projects that provide a substantial amount of the within-hour FCRPS flexibility. Group 1 is GCL and CHJ. These projects are often operated in tandem such that one project will have a relatively high response factor while the other one will be lower and vice versa. Group 2 is JDA and TDA. They routinely account for an important amount of within-hour flexibility, with their response factors commonly being at similar levels. The other Big10 projects sometimes have flexibility. Depending on water conditions MCN can be limited in flexibility, but at other times MCN can be an important source of flexibility. The Lower Snake is also important as during certain periods of the year, there is flexibility and response carried on the Lower Snake projects.

Electrically similar:
In order for the Western EIM to dispatch around congested flowgates, only resources that affect a flowgate similarly are considered electrically similar enough to be considered for aggregation.

In order to determine which of the Big10 FCRPS resources are electrically similar[1] to one another relative to BPA's internal/network flowgates, a set of Generation Shift Factors (GSFs) were calculated from a 2019 all lines in service planning case. In the context of any specific flowgate, resources that have very similar GSFs are considered to be electrically similar for that flowgate - in this analysis, if the difference between any two GSFs were less than 10%, the resources were considered to be electrically similar. Three separate aggregations of resources were specifically considered: Upper Columbia (Grand Coulee and Chief Joe), the Lower Snake projects (Lower Granite, Little Goose, Lower Monumental, Ice Harbor), and the Lower Columbia projects (McNary, John Day, The Dalles, Bonneville).

Based on the preliminary/draft results[2], Upper Columbia resources can be considered electrically similar at every flowgate. For the Lower Columbia projects, Bonneville and McNary would ideally not be included in an aggregation. However, the West of John Day flowgate (WOJD) is problematic for the Lower Columbia projects in total and doesn't lend itself to any Lower Columbia aggregation - additional analysis will be required to determine if an aggregation can be allowed. For the Lower Snake projects, excluding Ice Harbor from the aggregation would probably be acceptable, pending further analysis.

ELECTRICALLY SIMILAR @ 10%

[1] There is an element of subjectivity to defining "electrically similar". This must be defined likely via path-transfer distribution factors (PTDFs, aka impacts on the transmission grid).
[2] See the Electrically Similar analysis paper is included in the Appendix of this ADF

FLOWGATE	UPPER	LOWER	SNAKE	NOTES
CCN	YES	MAYBE	YES	Bonneville slightly above 10% in Lower
CCS	YES	NO	YES	Bonneville much higher than 10% in Lower
NOEL	YES	YES	YES	
NOH	YES	MAYBE	YES	Bonneville slightly above 10% in Lower
NJD	YES	YES	NO	Ice Harbor much higher than 10%
PA	YES	MAYBE	YES	Bonneville slightly above 10% in Lower
RP	YES	MAYBE	YES	Bonneville slightly above 10% in Lower
SOA	YES	MAYBE	YES	Bonneville slightly above 10% in Lower
SOC	YES	YES	YES	
WOJD	YES	NO	YES	
WOLM	YES	YES	NO	Ice Harbor has a large impact (>80%)
WOM	YES	NO	MAYBE	Ice Harbor a little less than 20%
WOS	YES	MAYBE	YES	Impacts range from 5-32%

Congestion in the BPA BA:

For the flowgates where the aggregations considered above do not allow the market to dispatch around congestion, an analysis of congestion risk was performed. It concluded with the following:

- The number and duration of actual flows exceeding TTC has been increasing
- The number curtailments has been decreasing
- Trends are likely due to new SOL methodology that went into effect on 4/1/2017
- Overall risk of curtailments is low on most flowgates
- These trends may or may not continue – hard to predict the future!
- Very few N-1 contingencies have occurred recently – curtailments may be higher when they occur since we are running the system at higher loading than we have historically
- As of November, 2014, 15-minute intervals are curtailed – they used to be hourly

CURTAILMENT EVENTS - ALL PRIORITIES (1,2,6,7)												
Flowgate	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	Grand Total	Frequency (10yr)
NJD			4	4	11		21		2	2	**44**	**0.050%**
NOEL						12	5	17		3	**37**	**0.042%**
NOH				3							**3**	**0.003%**
NOH_SN		11		1	7	1					**20**	**0.023%**
P-A		2									**2**	**0.002%**
R-P			1	4	1				7		**13**	**0.015%**
SOA	11	1		3		2	2				**19**	**0.022%**
SOA_SN	3	2		1		3					**9**	**0.010%**
SOC								1	21		**22**	**0.025%**
WOCN		1	4			1					**6**	**0.007%**
WOJD					4				6		**10**	**0.011%**
WOM					5		3				**8**	**0.009%**
WOM - MAIN-GRID									2		**2**	**0.002%**
WOMSG								4			**4**	**0.005%**
Grand Total	**14**	**17**	**9**	**16**	**28**	**19**	**31**	**22**	**38**	**5**	**199**	**0.227%**
CURTAILMENT EVENTS - FIRM (7)												

Flowgate	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	Grand Total	Frequency (10yr)
NJD							5				**5**	**0.006%**
NOEL						4	1	2		1	**8**	**0.009%**
NOH												**0.000%**
NOH_SN					2						**2**	**0.002%**
P-A												**0.000%**
R-P				2					4		**6**	**0.007%**
SOA												**0.000%**
SOA_SN												**0.000%**
SOC												**0.000%**
WOCN			2			1					**3**	**0.003%**
WOJD									4		**4**	**0.005%**
WOM					5		1				**6**	**0.007%**
WOM - MAIN-GRID									2		**2**	**0.002%**
WOMSG								1			**1**	**0.001%**
Grand Total			**2**	**2**	**7**	**5**	**7**	**3**	**10**	**1**	**37**	**0.042%**

Powerex EIM Resource Aggregation Participation Model:

Powerex (PWX) has signed an agreement with CAISO to become the first non-U.S. participant in the Western EIM. PWX markets the surplus generation of parent BC Hydro, which operates large cascading hydro systems. The company's role is similar to that of BPA. Learning from PWX's EIM implementation plan and understanding the differences between PWX and BPA's systems can help us make well-informed decisions about FCRPS' participation model in EIM.

The BC Hydro BAA is largely radial to the US with a single BC-USA intertie and there is very little temporal and spatial variation in terms of reserve carrying within their BA. Under these conditions, the large 8 hydro projects are considered electrically similar and grouped into one aggregate in the EIM. PWX takes that aggregation and makes the 8 hydro projects a participating resource and makes the same 8 hydro projects a non-participating resource: 1) aggregate participating resource (APR) to respond to the EIM bids/offers and (2) aggregate non-participating resource (ANPR) to respond to load and ancillary and control area services (ACS). Separate sets (one for APR, one for ANPR) of hourly generating response factors (GDF) are submitted to CAISO to control the proportions of energy distribution among the projects. The use of APR/ANPR with GDF enables the separation of market bids/dispatches from load/ACS obligations for transparency and effective usages of system flexibility. It could also allow BPA to retain control of the congestion management and the hydraulic coordination in the BA.

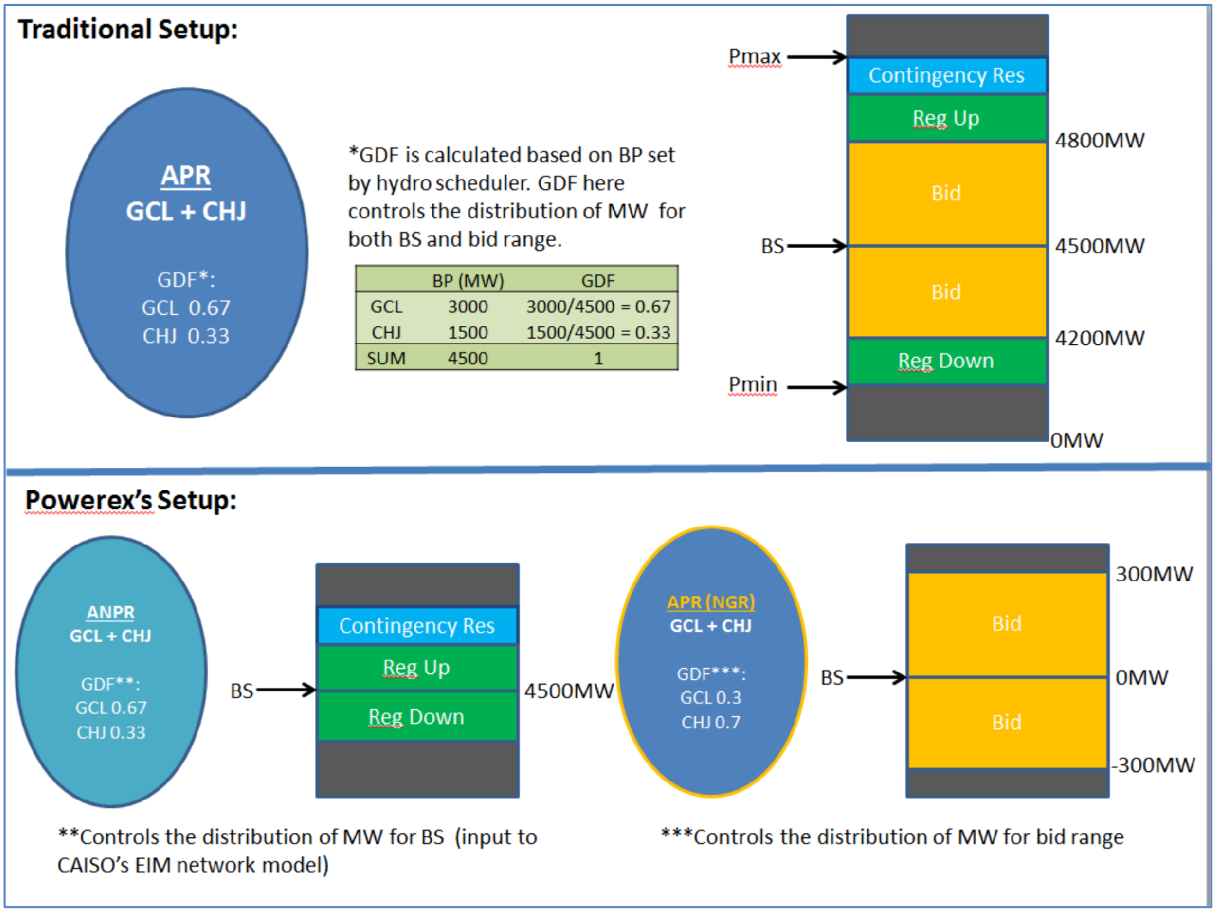
The illustration below (using the Upper Columbia aggregate resources as an example) compares the traditional and PWX's participation models.

- The traditional set-up considers the entire aggregate as a participating resource. The PWX model explicitly partitions the resource and allocates the EIM bids/offers to the APR and load and ancillary services obligations to the ANPR.

- In the traditional set-up, a base schedule (load and ancillary services) and a bid range (market bids/dispatches) are submitted to CAISO. In PWX's set-up, a base schedule for the ANPR and a bid range (zero base schedule) for the APR are submitted.

- In the traditional set-up, a base point (BP) for each project is submitted and GDF's would be computed based on those base points.

- In the traditional setup, a single set of GDFs is used to control the MW distribution for the base schedule (BS) and bid range. The GDFs are computed as the proportion of the base schedule of the individual resource to the aggregated sum. These computed GDFs are then used to determine how individual projects respond to market dispatches, which implies that the proportion of project flexibility to aggregate flexibility offered to the market would have to match these computed GDFs. PWX's set-up uses these computed GDFs (base GDF) for the ANPR's base schedule and allows the use of a different set of GDFs to respond to market dispatches.



Stakeholders:

Internal Stakeholders (Please Describe in Appropriate Detail)	What They Want or Need (& Why, if helpful)	What They Will Resist
Power Operations (PG)	• Ability to meet high-priority non-power obligations and constraints placed on the FCRPS • Discretion to operate the FCRPS in the most efficient manner • Cost recovery	• Difficulty in managing risk of de-optimization[3] • More manual processes
Bulk Marketing (PT)	• Maintain control over how much dispatch control at any given moment is given to the CAISO • Minimize the opportunity for CAISO to de-optimize (in revenue terms) FCRPS operations • Ability to shape *limited* energy into highest-value periods • Ability to have algorithmic/automated bid curve creation and submission	• Alternatives that limit access to other high-valued CAISO markets • Exclusion of manual processes, such that innovation is limited • Alternatives that result in local market power mitigation • Undue scheduling complexity
Transmission Operations (TO)	• The ability for the market to manage congestion proactively and in real-time • The visibility of EIM market dispatches and the impacts on the transmission system	• Participation framework that unduly limits the ability of the market to manage congestion or adversely impacts congestion.
Transmission Sales & Marketing (TS)	• Maintain/improve system reliability through enhanced congestion management • Maintain benefits of firm transmission rights to transmission customers, thus minimizing revenue loss (shift).	• Aggregation that is too big to allow for the EIM to help solve congestion.
Negotiations Team		
Legal	• Maintain compliance with all statutory requirements	• Any action that conflicts with statutory requirements

[3] For purposes of this discussion, de-optimization of the FCRPS refers to EIM dispatches that result in an un-anticipated reduction in future flexibility. For example, with the same bid curve, Lower Columbia projects could be given dispatch instructions that drafts or fills some of the projects without touching other projects. This could leave some projects too full (which risks spill) or too empty (which limits fuel).

External Stakeholders (Please Describe in Appropriate Detail)	What They Want or Need (& Why, if helpful)	What They Will Resist
CAISO	• Generator level visibility for most efficient market dispatch	• Aggregations that are not electrically similar
EIM Entities	• Enable better market liquidity for their own operations	• BPA receiving special treatment
Corps/Bureau	• Better visibility on expected generation	• Risk to BiOP or other statutory obligations. • Wear and tear on equipment. • Changes to their staffing?

4. Define objectives & decision criteria

Describe the desired end state to be accomplished or achieved:

Decision #1: Aggregation of resources

Objectives:

1. Preserve and enhance the value of Northwest hydropower and transmission operations for our customers and the region by making more efficient use of the FCRPS and FCRTS.
    a. Ability to mitigate risks of de-optimization of the FCRPS
    b. Maximize transmission congestion management benefits
    c. Capture revenue benefits from joining the CAISO EIM
2. Implementation should be straightforward with little to no manual work-arounds for submitting hourly bids to the CAISO.
3. Following the market dispatch instructions will be straightforward with little to no manual work-arounds.
4. Settlements will be as straightforward as possible.

Decision Criteria:

1. Maximum flexibility of the FCRPS offered into the market[4]
2. Maximize the value to the FCRPS of differential locational marginal pricing (LMP) generally caused by congestion
3. Maximize the value to the FCRPS from participation through explicit reflection of different opportunity costs across the system
4. Maximum transmission congestion relief
5. Systems and processes that are necessary to participate are simplest as possible to implement
6. Likely to be accepted as a model of participation from the CAISO
7. Ability to mitigate the risk of FCRPS de-optimization due to market dispatch instructions
8. Settlements are easy to implement[4]
9. Prevent unintentional cost shifts among Transmission and Power customers[4]
10. Minimize risk of local market power mitigation[4]
11. Flexibility to evolve FCRPS participation as more is learned about EIM implementation and negotiation

[4] These criteria will not be scored until more is known about EIM implementation

5. Assess risks of status quo

The status quo for EIM participation does not exist. This section is intentionally left blank.

6. Identify alternatives

Decision #1: Aggregation of resources

Alternative A – one aggregate: all "Big10" projects' data will be aggregated into one *resource*

Alternative B – Three aggregates: **"**Big10" projects will be aggregated into three resources each corresponding to a subset of the Big10 (Upper Columbia, Lower Snake, and Lower Columbia)

Alternative C – Project level: each "Big10" project will be a participating resource at the project level, no aggregation

Alternative D – Hybrid: Resource #1: Upper Columbia Resource; #2: John Day and The Dalles; Resource#3: Lower Granite, Little Goose, Lower Monumental. Ice Harbor, McNary, and Bonneville will be individual participating resources

Decision #2: Partition resource into APR and ANPR or Not

Alternative 1 – Utilize the APR/ANPR set-up: When each resource or aggregated resource is partitioned into an APR and ANPR, BPA will be able to use different GDFs to separate market bids/dispatches and load/ACS obligations.

Alternative 2 – Do Not Utilize the APR/ANPR set-up

7. Assess risks of alternatives

Decision #1: Aggregation of resources

Alternative A – one aggregate (System): all "Big10" projects' data will be aggregated into one *resource*. The risk of Alternative A is that the projects are not electrically similar enough for the CAISO to accept the proposal. BPA will get no congestion relief with this alternative nor will BPA be able to take advantage of additional revenue associated with differential LMPs.

Alternative B – Three aggregates: **"**Big10" projects will be aggregated into three resources each corresponding to a subset of the Big10 (Upper Columbia, Lower Snake, and Lower Columbia). The risk of this alternative is that it is an in-between solution meaning that it potentially has all the complexity of Alternative C but not all of the congestion relief or revenue benefits of Alternative C.

Alternative C – Project level: The biggest risk to this alternative is the difficulty in managing the risk of de-optimization of the FCRPS. In this alternative, dispatch signals will come directly from the market operator and will not reflect hydraulic optimization. For example, absent mitigation, a run-of-river project (like The Dalles) could get a dispatch from the market operator that is greater than the dispatch from the upstream storage project (John Day in this example) which would empty the run-of-river project. While this risk may be mitigated by using market tools and/or finessing the bid curve, it could be more complex than in other alternatives. In addition, there could be increased workload in managing multiple bid curves.

Alternative D – Hybrid: This alternative has all of the risks of B (congestion relief) and C (de-optimization) since it is a hybrid.

Decision #2: Partition resource into APR and ANPR or Not

The risk of Alternative 1 is unknown; it has yet to be implemented by CAISO and PWX.

The risk of Alternative 2 is artificially limited flexibility.

8. Analyze & rank alternatives

Decision #1: Aggregation of resources

Each alternative is evaluated 1-5 against the criteria above which are measures of the objectives. 1 is the lowest (least likely to meet the objective) and 5 is the highest (most likely to meet the objective). Alternative can be equally likely to meet the objective (which means ties along a row are allowed)

Decision Criteria	Alternative A 1 aggregate (System)	Alternative B 3 aggregates (GCL/CHJ, LSN, LCOL)	Alternative C Project Level	Alternative D Hybrid
Maximum flexibility (most amount) of the FCRPS offered into the market[5]				
Maximize the value to the FCRPS of differential locational marginal pricing (LMP) generally caused by congestion	1	3	5	4
Maximize the value to the FCRPS from participation due to different opportunity costs across the system	1	4	4	4
Maximum transmission congestion relief	1	3	5	4
Systems and processes that are necessary to participate are simplest as possible to implement	5	4	3	2
Likely to be accepted as a model of participation from the CAISO	1	3	5	4
Ability to mitigate the risk of FCRPS de-optimization due to market dispatch instructions	4	4	2	3
Settlements are easy to implement[5]				
Prevent unintentional cost shifts among Transmission and Power customers[5]				
Minimize risk of local market power mitigation[5]				
Flexibility to evolve FCRPS participation as more is learned	5	4	1	3

Alternative A: All projects aggregated into one resource

- This aggregation includes resources which are electrically dissimilar which provides the least efficient congestion relief, therefore, unlikely to be accepted by the CAISO.
- Duty Scheduling Center (DSC) will manage GDFs manually at the project-level in real-time; modest impact to DSC workload and manageable with no additional BFTE.
- Market operator dispatch instructions can be translated to project-level in a manner closest to the current real-

[5] These criteria will not be scored until more is known about EIM implementation

time process.

- A single price curve would need to be developed which is closest to current real-time process.
- The tools and processes to mitigate de-optimization are the most similar to current tools and processes today.
- This option decreases the ability to use market tools and information provided in advisory/future market runs.
- This alternative offers the most optionality for shifting the aggregation participation model in the future towards an un-aggregated resource participation model as we learn more (shift to Alternative B, C or D).

Alternative B: Three aggregates

- This aggregation includes resources that are *mostly* electrically similar which allows the market to dispatch around congestion. This is most similar to how redispatch is done today and adequate in most cases. There is not enough disaggregation in this alternative to relieve WoJD flowgate; moreover, WoJD congestion is expected to increase with 15 minute PDCI scheduling.
- This alternative has a greater chance than Alternative A for CAISO to accept as a participation model due to the congestion benefits mentioned in the above bullet.
- DSC will manage GDFs manually in real-time, similar to Alternative A, yet would have to manage three bid curves, one for each aggregation. Any impact to DSC workload should be marginal.
- Market operator dispatch instructions can be translated to project-level in a manner similar to the current real-time process.
- This option has potential to use market tools and information provided in advisory/future market runs.
- Has the potential to be the "sweet spot" for the starting participation model because it blends the current real-time adjustment process and new market tools in order to mitigate de-optimization between projects while providing incremental congestion relief. BPA still has the ability to further disaggregate participating resources in the future (shift to Alternative C or D).

Alternative C: No aggregations, the Big10 projects are individual resources

- This alternative would provide the most efficient market dispatches to relieve congestion on most flowgates, such as WoJD. Congestion at WoJD is expected to increase with 15 minute PDCI scheduling.
- Alternative C is CAISO's preferred participation model (individual participating resources).
- The development of the bid curve data has the greatest complexity of all the alternatives and potentially the greatest increase to DSC workload that could require additional BFTE especially if managing 10 different bid curves is required.
- Market operator dispatch instructions can be directly translated to project-level operations (no GDFs).
- Mitigation of hydraulic de-optimization would have to be managed at the project level requiring proficient use of new market tools and processes.
- If no aggregation is our beginning participation model, it will be difficult to persuade CAISO to incorporate an aggregation model in the future.

Alternative D: Hybrid

- This aggregation includes resources that are mostly electrically similar which allows the market to dispatch around congestion.
- This alternative has a greater chance than Alternative A or B for CAISO to accept as a participation model due to the congestion benefits mentioned in the above bullet.
- DSC will manage GDFs manually in real-time, similar to Alternative A, yet would have to manage multiple bid curves, one for each aggregation and one for each individual project. Any impact to DSC workload should be

marginal.

- This option has potential to use market tools and information provided in advisory/future market runs.
- This alternative blends the current real-time adjustment process and new market tools to mitigate hydraulic de-optimization which is incrementally more complex than Alternative B. For example, if the EIM participating resources operating in isolation cause downstream problems at relatively small reservoirs.

Decision #2: Partition resource into APR and ANPR or Not

Alternative 1 – Utilize the APR/ANPR set-up

- Implementation of this approach provides transparency for how the aggregated resources are allocated for base operations and for market bids/dispatches.
- BPA will be able to use different GDFs to separate market bids/dispatches and load/ACS obligations.

Alternative 2 – Do Not Utilize the APR/ANPR set-up

- Implementation of this approach would likely result in very conservative hydraulic operation and limited EIM market participation because one cannot delineate the flexibility required for base operations from the flexibility offered for market dispatches.

9. Recommendation

Decision #1: Aggregation of resources

The team recommends beginning negotiations with Alternative B, recognizing that Alternative D and possibly Alternative C may be preferred if the benefits of doing so become apparent as we learn more about the market and engage the CAISO and stakeholders. Alternative C and D might be necessary for congestion management if WoJD and WoLM flowgates are more congested in the future. Alternative B provides a reasonable "starting point" to evaluate the use of multiple APRs and adjustments to our participation model can be made as warranted by new information.

Opportunity costs within the proposed aggregates of Alternative B are likely similar. Opportunity costs across aggregates would likely differ. For these reasons, Alternative B likely captures higher revenue benefits than Alternative A, but has not been judged to be significantly less than Alternatives C and D.

An additional benefit to Alternative B is that while it is possible to disaggregate in the future, it is unlikely the CAISO will allow us to aggregate if we enter the market as individual resources (Alternative C).

Decision #2: Partition resource into APR and ANPR or Not

The team recommends Alternative 1. Pursuing the ability to adopt PWX's aggregate participation model for aggregated resources mitigates the risk of artificially limited flexibility by allowing different GDFs for the portion of the aggregated resource dispatched by the balancing authority and that dispatched by the CAISO and is consistent with how we set basepoints and response factors today.

10. Present findings & document decision

- Develop briefing package.
- Present results to the decision maker(s), including decision insights, minority opinions, and preliminary implementation plan assumptions.
- Document decision, supporting information, high level planning estimates, and performance expectations informed by decision criteria.

See also Additional Guidance and Resources for Step 9.

11. Transition to implementation

- Decision maker assigns management accountability for implementation.
- Form implementation team.
- Implementation team debriefs with ADF team.
- Management ensures that monitoring and reporting process is established.

See Additional Guidance and Resources for Step 10 for an implementation charter template.

12. Appendix

Definitions

Aggregate Non-Participating Resource (ANPR):

- ANPR is a defined portion of an actual physical resource used to respond to base schedules and reserve requirements. A set of base Generation Distribution Factors (GDF) is determined by the entity to distribute the energy among the projects within the aggregation. An ANPR can be AGC capable (this may be done, it is a choice, therefore the ANPR could be a mix of AGC-capable and non-AGC-capable resources)
- GDFs for the ANPR are set at t-75 minutes with bid submission for the operating hour (this must be done, it is not a choice); BA / EIM Entity may change the GDF until T-40 min.
- ANPR is "electrically similar" (this must be defined likely via path-transfer distribution factors (PTDFs, aka impacts on the transmission grid), there is an element of subjectivity to defining "electrically similar")
- An ANPR will have a base schedule quantity for every hour that adds up to the load and obligation forecast for that hour per the Resource Sufficiency check (this must be done, it is not a choice)
- ANPRs will not receive CAISO dispatches (this happens, it is not a choice)
- Physical deviation from the base schedules will result in uninstructed imbalance charges and create imbalance that will be subject to financial settlement via the CAISO EIM (this happens, it is not a choice)

Aggregate Participating Resource (APR):

- APR is a defined portion of an actual physical resource used to respond to EIM bids/offers. A set of Generation Distribution Factors (GDF) is submitted by the Entity to distribute energy among projects within the aggregation.
- APR is AGC capable (this must be done, it is not a choice)
- GDFs for the APR are set at T-75 minutes with bid submission for the operating hour (this must be done, it is not a choice); BA / EIM Entity may change the GDF until T-40 min
- APR is "electrically similar" (this must be defined likely via path-transfer distribution factors (PTDFs, aka generating resource impacts on the transmission grid), there is an element of subjectivity to defining "electrically similar")
- APR will have a base schedule quantity for every hour (this must be done, it is not a choice but it could be 0 as would likely be the case for Powerex every interval)

- APR will receive a financially binding dispatch from CAISO – Dispatch Operating Target (DOT) – every 5-minute market interval that may create imbalance which will be subject to financial settlement via the CAISO EIM (this must be done; however, how the DOT is passed to the resource is a choice, i.e. CAISO>project(PAC) or CAISO>BCH>project (PWX))
- ANPR is split into two resources: Generating Resource and Non-generating Resource
  - Generating Resource (GR):
    - GR will submit base schedules and will be carrying various ancillary services (regulation, contingency reserves, etc.)
    - GR do not submit GDFs or bid curves

  - Non-Generating Resource (NGR): Resources that operate as either Generation or Load and that can be dispatched to any operating level within their entire capacity range but are also constrained by a MWh limit to (1) generate energy; (2) curtail the consumption of energy in the case of demand response; or (3) consume energy. More generally, NGRs have a continuous operating range from a negative to a positive power injection (they can operate continuously by ether consuming energy or providing energy and can seamlessly switch between generating and consuming).
    - NGRs can provide ancillary services.
    - CAISO's NGR (Non-Generating Resource) model was originally developed to allow energy storage devices to participating in their market (e.g., Flywheels, Electric Cars, Batteries, Pumped Hydro, etc.)
    - PWX's APR is modeled as an NGR. NGR will have a base schedule of 0 MW and bids will be +/-, for example ± 250 MW.
    - GDFs for NGR will be determined for each upcoming hour

Generation Distribution Factor (GDF): The Bid template component that indicates the proportions of how the Bid is distributed for the resources participating in Physical Scheduling Plants, System Units, or Distributed Energy Resource Aggregations.

Base Generation Distribution Factor (Base GDF): A factor that indicates the proportions of how the energy is distributed among generators within an aggregated resource for a base schedule.

Non-Generating Resource Functionality: CAISO developed the concept of non-generating resources (NGRs) to allow energy storage devices to participate in their market (e.g., Flywheels, Electric Cars, Batteries, Pumped Hydro, etc.). NGRs are resources that operate as either Generation or Load and that can be dispatched to any operating level within their entire capacity range but are also constrained by a MWh limit to (1) generate energy; (2) curtail the consumption of energy in the case of demand response; or (3) consume energy.

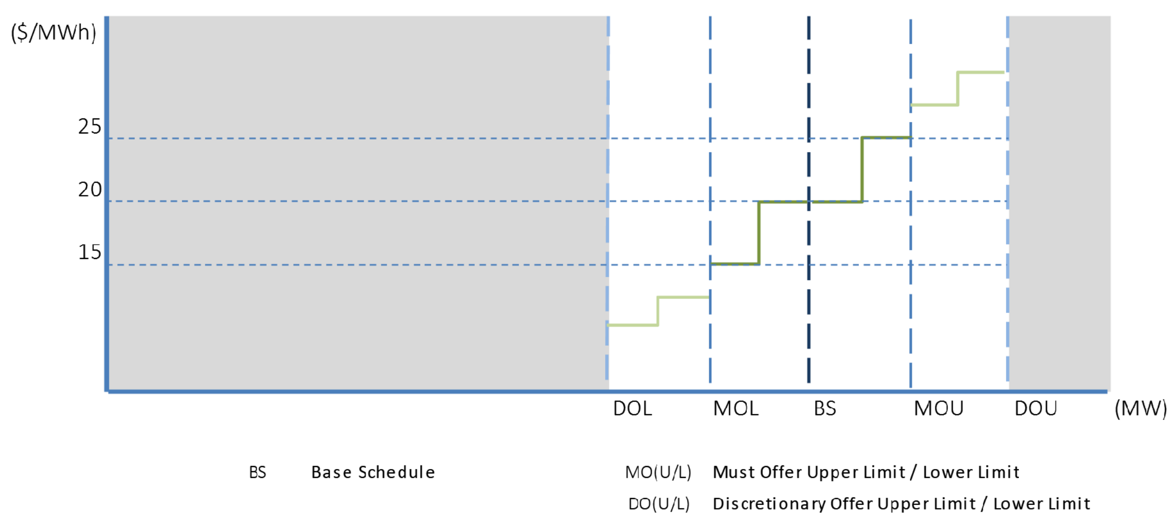
Bid Curve

Initial thoughts:

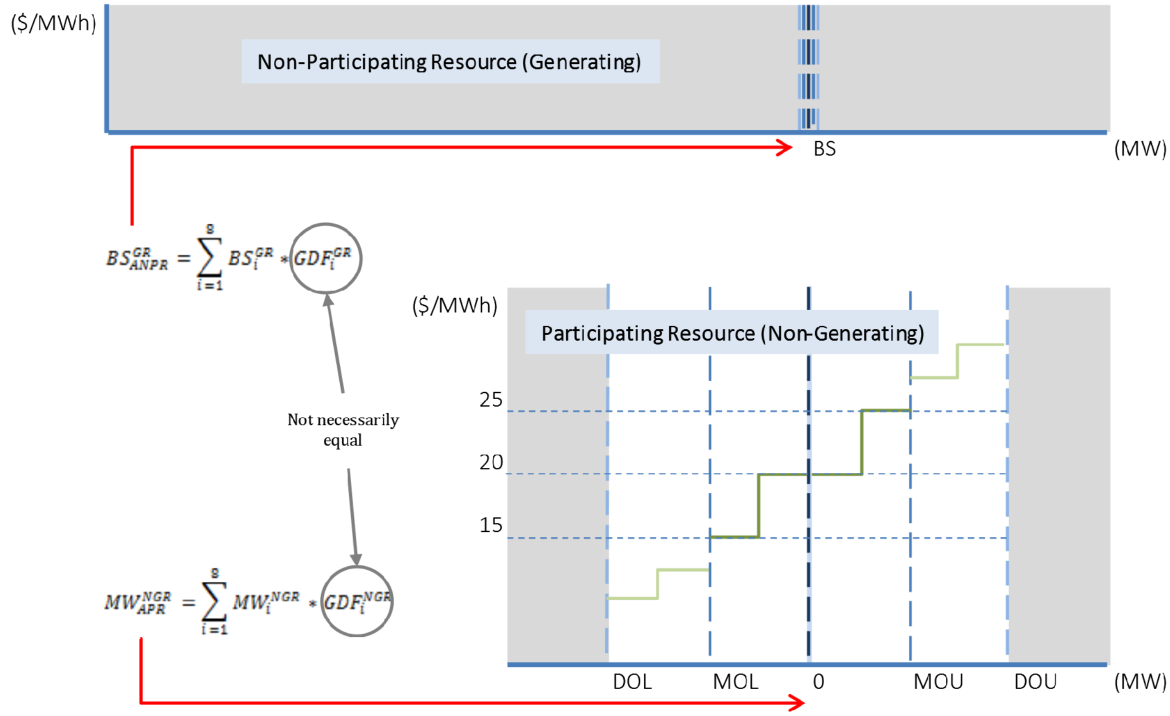
Headwater projects, the Willamettes, and CGS carved off as non-participating resources. Here, still, there is a decision regarding how to aggregate the non-participating resources. Since there are still data –submission requirements for non-participating resources, it may be advantageous to aggregate these carved-off resources into a single non-participating resource.

For the balance of the system there is an advantage to aggregation, due to improved discretion for water management within the group of aggregated projects. Further, within the aggregation scheme chosen, BPA may have the option to partition each aggregate resource into participating and non-participating portions (i.e., the Powerex model). With respect to current BPA practice, there may be intuitive appeal to this strategy, since it represents an explicit reflection of which resources are meeting FCRPS obligations (load service, fish obligations, etc.) and which entity is making FCRPS dispatch decisions (kind of) and distinguishing these resources from those that are used for EIM marketing purposes. There is further intuitive appeal to treating the participating portion of an aggregate resource as a non-generating resource (NGR). As stated above (or in the appendix or whatever), an NGR is modeled as having a base schedule of zero. In this way, a single aggregate participating resource (with a strictly positive base schedule and surrounding dispatchable range) becomes two resources – one with a strictly positive base schedule and no EIM-dispatchable range and the other with zero-valued base schedule and the entire dispatchable range of the underlying resources. Finally, treatment of BPA's participating resource as a non-generating resource may be advantageous in avoiding mitigation of BPA's bids due to a finding of market power. The BPM on Market Operations, Appendix, Section B.1.3 states that NGR capacity is not included in the calculation of withheld capacity in determining the set of potentially pivotal suppliers. However, the Tariff, Section 34.1.5.1, states "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." This latter statement appears more applicable to our participation, but may warrant verification with the CAISO.

Single Aggregate Participating Resource



Partitioned Aggregate Resource



Beyond aggregation, there may be an advantage to partitioning participating resources into generating resources and non-generating resources (i.e., the PWX model)

- Explicit reflection of which resources are meeting FCRPS obligations (load service, fish obligations, etc.) and which resources are used for EIM marketing purposes, explicit reflection of entity that is making FCRPS dispatch decisions
- Is there an advantage from a legal perspective in explicitly demonstrating that the FCRPS is meeting its own load?
- Simple aggregation into multiple resources (APR/ANPR) and partitioning multiple aggregated resources (PWX model) may achieve the same operational outcomes.

FCRPS Participation in EIM White Paper

FCRPS EIM v5.docx

Electrically Similar Analysis

Electrically_Similar_Analysis_v03.docx

Congestion Risk Analysis

Congestion_Risk_v04.docx

Parking Lot

Additional Considerations:

1. A more granular approach than Alternative B would allow Transmission to develop tools based on the base schedules and bids to accurately calculate ATC available to the market. This would help avoid market assumptions that strand FCRPS bid generation due to perceived congestion.
2. In lieu of a multi-state generator forbidden zone (in the outage card), BPA will have to handle deadbands via GDF.

Questions:

3. Are you able to outage card GDFs in real-time? If not, the implication is that aggregating resources severely limits your ability to make changes in real-time.
4. Automation of manual dispatches during contingency events?
5. Are GDFs submitted with bids? (We know it is not part of the master file)
6. Should Banks Lake be considered part of GCL or a "separate" resource? Banks Lake is unique in that it is a generator and a load and is non-dispatchable (cannot respond fast enough for market dispatches).

More information about EIM implementation is needed to score the decision criteria below:

A. <u>Maximum flexibility (most amount) of the FCRPS offered into the market</u>

It's unclear how much flexibility the FCRPS can offer without precedence of aggregate cascading hydro resources in the EIM. PWX will be the first EIM entity to have aggregate participating resources with an April 2018 "go-live" date.

B. <u>Settlements are easy to implement</u>

BPA does not understand the current CAISO EIM settlement process.

C. <u>Prevent unintentional cost shifts among Transmission and Power customers</u>

Unclear where the cost shifts will take place under any alternative.

D. <u>Minimize risk of local market power mitigation</u>

Broadly speaking, the likelihood that BPA's participating resource bids are mitigated in the CAISO's local market power mitigation (LMPM) process is dependent on several key factors. We currently have insufficient information to determine how (if at all) our choice of alternatives in this ADF will affect these key factors:

- The likelihood that transmission constraints (either between EIM BAAs or within BPA's EIM BAA) bind.
- The proximity (via associated shift factors) of BPA participating resources to the binding transmission constraint
- The amount of participating capacity from BPA and other EIM participating resource scheduling coordinators

At issue for the particular decision of how to aggregate our participating resources is how (or whether) the CAISO disaggregates aggregated resources for the LMPM market run. For an EIM participating resource's bid to be mitigated, it must be deemed to be "effective" at relieving congestion on a non-competitive path. Its effectiveness in achieving such relief is a function of the resource's proximity (via its associated shift factors) to the congested path and the amount of participating capacity offered by others into the market that is also effective in achieving relief on the congested path. It is currently unclear how GDFs of an aggregated resource will interact with the shift factors of the individual projects in the course of determining BPA's pivotal supplier status for binding transmission constraints in the EIM.

Background:

The following describes the challenge of managing the risk of EIM dispatches de-optimizing the FCRPS:

Let's assume that we have a set of hydro projects that are close to each other such that the outflow of an upstream project impacts the inflow of a downstream project in an hour or two. The FCRPS has three of these sets: Coulee/Chief, the Lower Columbia projects, and the Lower Snake projects (i.e., the Big10). The real-time operation of these projects is closely monitored by hydro duty schedulers to avoid projects getting too full (risk of spill and lost generation), getting too empty (loss of storage and generating/ramping capability), or operating inefficiently (less MWs per unit of flow). Any of these three conditions are generally referred to as "de-optimizing" the hydraulic operation.

Currently, within hour movement of load and intermittent resources in our BA are accommodated by setting aside flexibility (balancing reserves) at these Big10 projects. The deployment of balancing reserves is accomplished by "response factors" that are manually set by hydro duty schedulers. For example, if Grand Coulee's response factor is .4, then Coulee will move 40 MW for every 100 MW of balancing reserves that are required to balance load and generation in the BA. Manually adjusting these response factors in real-time is the mitigation tool for dealing with de-optimization that results from reserve deployments.

Since Balancing Reserve deployment generally INCs and DECs within an hour, there tends to be little energy impact. However, if the EIM dispatches more consistently either INCs or DECs across the hour, then the energy impact would be greater as well as the risk of de-optimizing the FCRPS' operation. The method for mitigating the risk of de-optimizing the FCRPS depends on how participation of our resources is implemented.

Participation of FCRPS hydro projects in an EIM will require a decision on how these resources will be bid and how dispatch instructions from the market operator will be implemented. The intent of this paper is to discuss options on how FCRPS resources can participate in an EIM as well as pros/cons with each approach.

For discussion purposes in this paper, the term *EIM resource* will be used to reference the type of resource that the market operator sees and are limited to the dispatchable "Big10" FCRPS hydro projects. The assumption about the other non-dispatchable FCRPS projects is that they will be self-scheduled (as is the current practice) and not considered by the market operator for EIM dispatches. Data that is required to be submitted to the market operator for the *EIM resources* include base generation, minimum generation, maximum generation, and a bid curve for the upcoming hour, as well as an indication of the regulation, load following and contingency reserve requirements. The market operator will perform a calculation every five minutes and send a dispatch instruction to each *EIM resource* depending upon their submitted flexibility and the cleared price.

The fundamental question is how granular should FCRPS "Big10" resources be bid into the EIM, and there appear to be four options:

1. **BIG10 Level:** all "Big10" projects' data will be aggregated into one *EIM resource*.
2. **Zonal Level: "**Big10" projects' data will be aggregated into zones each corresponding to an *EIM resource* (Coulee/Chief, Lower Snake, and Lower Columbia, for example)
3. **Project Level:** all "Big10" projects' data will each be submitted as individual *EIM resources*.
4. **Hybrid:** Big10 will be broken up into self-scheduled resources and individual *EIM resources*. (Coulee/John Day as individual *EIM resources*, the rest of the "Big10" self-scheduled, for example)

Considerations:

As pros/cons of each of the alternatives are developed, there are a few things to keep in mind:

- For purposes of grid reliability and congestion management, there is a desire for as much granularity as possible for the *EIM resources.*
- The current practice in BPA's BA of dispatching balancing reserves to manage load and generation imbalance is market price-insensitive and generally fairly random within an hour. However, EIM market dispatches are price-driven and tend to dispatch *EIM resources* in a similar manner throughout the hour except for the *EIM resource* that is setting the price on the 5-minute interval. The result is that FCRPS *EIM resources* could be consistently dispatched at the minimum or maximum generation levels[1] that are submitted to the market operator.
- Moving to a market dispatch that is more granular than the **Big10 Level** risks de-optimizing the FCRPS[2] unless we figure out a way to reflect the costs of de-

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[1] Minimum and maximum levels that are submitted to the market operator are at the discretion of the hydro duty scheduler and not necessarily the absolute generation limits.

[2] For purposes of this discussion, *de-optimization of the FCRPS* refers to EIM dispatches that result in an un-anticipated reduction in future flexibility. For example, with the same bid curve, Lower Columbia projects could be given dispatch instructions that drafts or fills some of the projects without touching other projects. This could leave some projects too full (which risks spill) or too empty (which limits fuel).

optimizing the FCRPS in the development of the price curves, limit the FCRPS flexibility that is being submitted, and/or develop a hydro-optimization post-processor. The level of complexity of how this risk is mitigated is an important consideration.

- The CAISO is exploring an *auto-matching* function as part of the EIM which, in effect, would allow for late breaking changes[3] sourced from the EIM market participants (like Slice right-to-power). As we gain more understanding of this proposal, and how BPA could use, this will inform additional thinking.
- The CAISO runs a market power test before each hour to ensure a competitive market[4]. If a market participant is found to have market power and their bid sets the price, the price awarded is changed from their bid to a default energy bid (DEB) which is negotiated ahead of time. This could adversely impact any financial benefit to Power Services unless the current DEB options are expanded to reflect the opportunity cost for energy-limited hydro systems
- Hydro duty scheduling workload will be impacted by the path that is chosen – perhaps significantly.

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[3] Current market rules require the submission of base schedules, dispatchable ranges and offer curves 75 minutes prior to the hour. A *late-breaking change* then is any change to a non-power requirement, load or obligation (such as Slice RTP or a Trading Floor product)

[4] Market power to a seller is the ability to profitably maintain prices above competitive levels for a significant period of time. In economics, market power is defined as the ability to alter profitably price away from competitive level and market efficiency. For the purposes of this paper, market power references horizontal market power in which generation concentration from two or more firms is perceived to conspire to act more or less like a monopolist.

Alternatives:

1. **BIG10 Level:** all "Big10" projects' data will be aggregated into one *EIM resource*. From an implementation perspective, this is probably the easiest since the market operators' dispatch instructions could be post-processed by using the existing (or an improved version) of response factors. However, there is very little, if any, benefits to grid reliability or congestion management from this approach

   Pros:

   - Hydro and price curve data submission is fairly straight-forward
   - Market operator dispatch instructions can be translated to project-level in a manner close to status quo
   - No increased risk of hydraulic de-optimization
   - While still a potential, this option is likely has the smallest risk of market power and mitigation of bids
   - Modest impact to DSC workload and manageable with no additional BFTE

   Cons:

   - Little, if any, benefit to grid reliability or congestion management
   - No financial benefit to Power Services beyond what is expected in the cost/benefit analysis

2. **Zonal Level: "**Big10" projects' data will be aggregated into zones each corresponding to an *EIM resource.* At first blush, using three zones (GCL/CHJ, LSN, LCOL) would seem doable (but more challenging) from an implementation perspective and would allow for some benefits for grid reliability and congestion management. This approach could also potentially allow for some additional financial benefits for Power Services since the bid curves could be tuned to reflect more refined opportunity costs in each of the zones (for example, the opportunity costs of moving water around at Grand Coulee could be different than moving water around on the Lower Snakes). A challenge would be developing a methodology to post-process market operator zonal dispatch instructions to project-level.

   Pros:

   - Some benefit to grid reliability or congestion management
   - Potential of some additional financial benefit to Power Services

   Cons:

   - Hydro and price curve data creation and submission is fairly complex
   - Mitigation of hydraulic de-optimization could be complex
   - Market operator dispatch instructions translation to project-level could be fairly complex
   - More zones, increase the risk of market power findings and mitigation of bids
   - Depending on the zones chosen, there could be a large impact to DSC workload that could require additional BFTE

3. **Project Level:** all "Big10" projects' data will be submitted as individual *EIM resources*. From a hydro data submission perspective, this approach is not much different from the **Big10 Level** alternative since the data exists. However, there is a wild card in how complex the development of the bid curve data will be. This approach would maximize the benefit for grid reliability and congestion management. This approach could also potentially allow for some additional financial benefits for Power Services since the bid curves could be tuned to reflect more refined opportunity costs in the same manner as the **Zonal Level** alternative. While there is no need to develop a methodology to post-process the market instructions since they are already at the project level, there is risk of hydraulic de-optimization if we aren't careful in how the hydro and price data are constructed.

   Pros:

   - Hydro data submission is fairly straight-forward
   - Maximum benefits to grid reliability or congestion management
   - Potential of some additional financial benefit to Power Services
   - Minimizes need to post process market operator dispatch instructions

   Cons:

   - Price curve data construction and submission could be very complex
   - Mitigation of hydraulic de-optimization could be complex
   - More zones, increase the risk of market power findings and mitigation of bids
   - Large impact to DSC workload that would likely require additional BFTE

4. **Hybrid:** Big10 will be broken up into self-scheduled resources and individual *EIM resources*. The idea here is find a way that preserves the potential benefits while minimizing the risk of hydraulic de-optimization. The mix of *EIM resources* and self-scheduled resources would be set going into the EIM and would not change. Suppose we picked just a couple projects from the "Big 10" (Grand Coulee and John Day being the most obvious, but using small zones like John Day/The Dalles is also worth considering) and only offered them as *EIM resources*, and the remaining "Big 10" projects would be self-scheduled. We could also envision this approach as allowing the change of groupings and projects that define EIM resources as conditions change. Using the most operationally flexible and isolated projects minimizes the risk of hydro de-optimization within the hour and maintaining the project granularity that maximizes the grid reliability and congestion management benefits. However, to do this, we would have to completely change how we allocate regulation, load following and contingency reserves[5] so that these *EIM resources* can have maximum flexibility offered to the market operator to preserve the financial benefits for Power Services. In addition, there is a risk of incurring imbalance at the remaining "Big 10" projects.

   Pros:

   - Hydro and price curve data submission is fairly straight-forward
   - Maximum benefits to grid reliability or congestion management
   - Potential of some additional financial benefit to Power Services
   - No need to post process market operator dispatch instructions

   Cons:

   - Risk of incurring imbalance from the self-scheduled "Big10" projects
   - Mitigation of hydraulic de-optimization could be complex if the *EIM Resources* operating in isolation cause downstream problems at relatively small reservoirs.
   - Depending on the approach, there could be a large impact to DSC workload that could require additional BFTE

Information Gathering

Information gathering from the CAISO on the following topics is necessary in order for this team to give a recommendation on the "must-haves".

[5] This is part of the Reserves Enhancement Commercial Operations project.

Tools:

Currently it is unclear what operational tools will be available to mitigate de-optimization. One must have already discussed is the ability to change base schedules in response to late-breaking changes. These changes can be anything from weather and emergency ops for barge passage or Slice. Will all of the actions we take in response to these late-breaking changes be charged as imbalance? If these are all treated as imbalance, we will have to choose the bidding structure that minimizes these charges.

Settlements and Pricing:

Are INCs and DECs priced similarly to how the BPA BA charges today? ie we pay for the DEC but are paid for the INC. If there is no congestion and therefore no difference in the locational marginal price across the nodes, then redispatching to mitigate the de-optimization could be straightforward.

Reserves, self-schedules, and projects on response:

We need flexibility in how we carry reserves regardless of what option we choose and we need to know how the CAISO will treat the imbalance created by deploying those reserves.

Can the projects change from a participating resource to a self-scheduled one each hour? If things were going off the rails, would BPA self-schedule the projects that are in trouble? What is the “cons” of periodic self-scheduling individual projects?

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1. Describe problem or opportunity

- Describe the situation and circumstances creating the need for a decision. This should be a brief statement that gives the reader enough context to get started.
- The problem statement should be reviewed with decision makers to confirm the correct problem is being addressed.
- Do not treat the initial problem statement as a final product; as you go through the ADF steps, the problem statement may need to be revised and reviewed again.

See Additional Guidance and Resources for Step 1

The key driver for this ADF is the need to develop a negotiation strategy prior to starting negotiations with the CAISO. The specific, Western EIM, participation model that we establish with CAISO will influence the requirements for Grid Modernization projects including developing new systems, business processes, and governance. The decision on the general structure of how the FCRPS will be marketed in the EIM, along with the Transmission participation model will likely influence other decisions as we learn more about what Grid Modernization and participating in organized markets means for BPA (from a one-BPA perspective). Collectively, these decisions on market participation choices will balance reliability, efficiency, and control of generation in the balancing authority (BA).

As the team learns more, as additional decisions are made, and as Grid Modernization projects progress, we will likely revisit the decisions in this ADF.

There are two questions for decision laid out in this ADF:

1. How to aggregate (or not) the FCRPS to be a participating resource in the Western EIM and
2. Whether to adopt the Powerex model to split each participating, aggregate resource into two resources: one for the CAISO to dispatch (surplus power) and one for the BA to dispatch (load and ancillary services).

Assumptions:

1. Contingency reserves and regulation (for load and generators) will not be dispatched by the market operator.
2. Power Services retains the autonomy on how hydro projects respond to market signals
3. Power Services will still be able to make system sales and purchases outside of the EIM.
4. Current tagging and scheduling practices will remain.
5. A participating EIM resource will be used to reference the type of resource that the market operator sees and is limited to the dispatchable "Big10" FCRPS hydro projects.
6. Individual bid curves will be created for each participating resource (aggregate or not).
7. Locational marginal prices (LMP) are resource specific or meter specific, regardless of the decision to aggregate.
8. Non-dispatchable FCRPS projects will be non-participating resources in an EIM.
9. Independent Power Producer (IPP) participation decision is independent of this ADF decision.
10. FCRPS will be able to access all interchanges in the balancing authority area.
11. FCRPS will meet all of NT load obligations
12. All FCRPS dispatches are deliverable, dispatches are feasible
13. Transmission is available for dispatch instructions from the CAISO

2. Define governance, scope & constraints

- List the decision makers for this ADF
- Describe the decision process for the ADF, including when decision makers will be engaged.
- Define the timeline for analysis and making this decision
- List the ADF team members and any key supporting resources
- Describe any notable scoping requirements or constraints on this analysis (if any)

A more complex or formal ADF should include a project charter, which describes the above information. See Additional Guidance and Resources for Step 2 for a Project Charter template.

Name of Initiative: Federal Resource Participation
Client Organization: BTO
POC Manager: Steve Kerns (PGS)
Decision Maker(s):

Consult - Tier II steering committee: Kieran, Suzanne, Michelle M., Michelle C., Jeff C., Todd M. – Currently meets monthly (last Tuesday of every month) for one hour on March 27th at 1p.

Responsible - Tier I decision makers: Joel, Richard, Janet

Executive Sponsors: Kieran Connolly
ADF Lead: Steve Kerns (PGS)
Core ADF team members: Clarisse Messemer (PGST), Todd Kochheiser (TOI), Dave Dernovsek (PTKP), Eric Federovitch (PTM), Rich Greene (LP), Rebecakah Pettinger (LP), Kelii Haraguchi (PTM), Eric King (TSPP), Russ Mantifel (TS), Tom Davis (LT), Mark Symonds (BD), Chris Siewert (PGSD) , Elsa Chang (PGST), Cindy Polsky (PGST), Pam Van Calcar (PGSP), Frank Puyleart (TOOC), Chris Sanford (TOR), Steve Gaube (PTF), Troy Simpson (TOI), John Schaffroth (Utilicast), Margaret Pedersen Mainzer (PTL), Mai Truong (PGST), Rob Hawkins (PGSD)
Key SMEs/Orgs for Input:
Draft due: March 15, 2018
Final due: March 31, 2018
Decision Deadline: March 31, 2018

3. status quo context

- Collect relevant background information about the current state of affairs and relevant history for this issue and decision (Status Quo).
- Describe the external environment and the goals and interests of external stakeholders.
- Describe the internal structure, culture, and capabilities of the organization and the goals and interests of internal stakeholders.
- Describe the strategic context by identifying relationships to agency-level and business-line objectives, policies, top risks, and/or strategic issues.

See Additional Guidance and Resources for Step 3 for worksheets on Context, Internal Stakeholders, and External Stakeholders

Since the BA is not currently a participating entity, there is no status quo context for how the FCRPS will participate in the Western EIM. However, there is a status quo of current operations that has elements of all the alternatives. So no one alternative can be considered the status quo.

Of the 31 dams and one nuclear plant that BPA markets the energy for, only 10 projects (the Big 10) are on response. This means that they are connected via AGC and can be dispatched by the transmission operator to maintain reliability.

The Big-10 projects on response are:
Grand Coulee
Chief Joe
John Day
The Dalles
Bonneville
McNary
Lower Granite
Little Goose
Lower Monumental
Ice Harbor

Bonneville operates these projects individually and as an aggregate depending upon the hydraulic, power, or non-power constraint that is binding. The entire system (the Big 10 as well as all the remaining generators marketed by Power Services) is marketed as if coming from a single resource (system sales) at Mid-C. Operationally, the Hydro Duty Scheduler manages the system in three buckets: the Upper Columbia, the Lower Columbia, and the Lower Snakes. In addition, the Hydro Duty Scheduler sets base points for each project individually and sets response factors for each of the projects on response individually.

Looking ahead to participating in an organized market, instead of aggregating or not depending upon the relevant constraint or the leading objective, we assume that the FCRPS will have to pick whether to participate as an aggregate resource or as individual projects. Since the status quo allows us to be flexible around this decision, any of the alternatives will likely not be as optimal as the status quo from a purely Power Services perspective.

Other than hydraulic and power marketing objectives, BPA is also interested in the congestion revenue rents and congestion relief associated with participating in the Western EIM. As a result, these considerations as well as ease of implementation will need to be considered among the alternatives available for participating in the Western EIM.

Congestion in the BPA BA:
There are 13 network flowgates in the balancing authority. None of the flowgates experience congestion to the point of curtailments more than 2% of the time. However, congestion revenue rents can accrue on flowgates even when a flowgate is not so congested as to warrant curtailments. Therefore, while we have historically low probabilities of curtailments, any of the flowgates can be candidates to capture congestion revenue rents and we would want to have participating resources available on either side of the flowgates in order to capture those rents.

Electrically similar:
In order for the Western EIM to dispatch around congested flowgates, only resources that affect a flowgate similarly are considered electrically similar enough to be considered for aggregation.

In order to determine which of the big-10 FCRPS resources are electrically similar to one another relative to BPA's internal flowgates, a set of Generation Shift Factors (GSFs) were calculated from a 2019 all lines in service planning case. In the context of any specific flowgate, resources that have very similar GSFs are considered to be electrically similar for that flowgate - in this analysis, if the difference between any two GSFs were less than 10%, the resources were considered to be electrically similar. Three separate aggregations of resources were specifically considered: Upper Columbia (Grand Coulee and Chief Joe), Lower Columbia (McNary, John Day, The Dalles, Bonneville), and the Snake River projects (Lower Granite, Little Goose, Lower Monumental, Ice Harbor).

Based on the preliminary/draft results, Upper Columbia resources can be considered electrically similar at every flowgate. For the Lower Columbia resources, Bonneville and McNary would ideally not be included in an aggregation. However, the West of John Day flowgate (WOJD) is problematic for the Lower Columbia resources in total and doesn't lend itself to any Lower Columbia aggregation - additional analysis will be required to determine if an aggregation can be allowed. For the Lower Snake resources, excluding Ice Harbor from the aggregation would probably be acceptable, pending further analysis.

Internal Stakeholders (Please Describe in Appropriate Detail)	**What They Want or Need** (& Why, if helpful)	**What They Will Resist**	**Their stake in the decision and likely role in supporting or opposing it**
Power Operations (PG)	• Ability to meet high-priority non-power obligations and constraintsplaced on the FCRPS • Flexibility to operate the FCRPS in the most efficient manner • Cost recovery •	• Difficulty in managing risk of de-optimization • More manual processes	
Bulk Marketing (PT)			
Transmission Operations (TO)			
Transmission Sales & Marketing (TS)			
Business Transformation Office (BTO)			
Legal			

External Stakeholders (Please Describe in Appropriate Detail)	**What They Want or Need** (& Why, if helpful)	**What They Will Resist**	**Their stake in the decision and likely role in supporting or opposing it**
CAISO			
EIM Participants			

4. Define objectives & decision criteria

- Describe the desired end state to be accomplished or achieved.
- Define the decision criteria (i.e. key evaluation factors) that will be used to determine whether and how well proposed alternatives (Step 6) deliver on the stated objectives and create value for BPA.
- Decision criteria should be considered in such categories as: Economic/Finance, Legal/Regulatory, Environment, Customer/stakeholder, BPA's people and processes, etc.
- Decision Criteria should be updated to address unacceptable risks from Steps 5 and 7.

See *Additional Guidance and Resources for Step 4* for further guidance on defining Objectives and Decision Criteria

Describe the desired end state to be accomplished or achieved:

Objectives:

1. Preserve and enhance the value of Northwest hydropower and transmission operations for our customers and the region by making more efficient use of the FCRPS and FCRTS.
   a. Minimize de-optimization[1] of the FCRPS
   b. Maximize transmission congestion management benefits
   c. Capture revenue benefits from joining the CAISO EIM
2. Implementation should be straightforward with little to no manual work-arounds for submitting hourly bids to the CAISO.
3. Following the market dispatch instructions will be straightforward with little to no manual work-arounds.
4. Settlements will be as straightforward as possible.

Decision Criteria:

Maximum flexibility of the FCRPS
Maximum transmission congestion relief
Maximum transmission congestion revenue rents
Simplest to implement
Likely to be accepted as a model of participation from the CAISO
Market dispatch instructions are hydraulically feasible
Market dispatch instructions do not violate any non-power objectives

5. Assess risks of status quo

The status quo for EIM participation does not exist. This section is intentionally left blank.

[1] For purposes of this discussion, de-optimization of the FCRPS refers to EIM dispatches that result in an un-anticipated reduction in future flexibility. For example, with the same bid curve, Lower Columbia projects could be given dispatch instructions that drafts or fills some of the projects without touching other projects. This could leave some projects too full (which risks spill) or too empty (which limits fuel).

6. Identify alternatives

- Brainstorm significantly different, creative, feasible alternatives to the status quo that achieve the objectives (Step 4) and mitigate risks (Step 5) based on the decision criteria.
- Narrow down the alternatives to manageable set of (at least two) alternatives.
- Ensure the alternatives are sufficiently defined and estimates based on preliminary planning assumptions.
- Test feasibility of selected alternatives with SMEs/Stakeholders as needed.

See *Additional Guidance and Resources for Step 6* *for further assistance with this step.*

Decision #1: Aggregation of resources

Alternative A – one APR: all "Big10" projects' data will be aggregated into one *APR*

Alternative B – Three APRs: "Big10" projects will be aggregated into three APRs each corresponding to a subset of the Big10 (Coulee/Chief, Lower Columbia, and Lower Snake)

Alternative C – Project level: all "Big10" projects will be participating resources at the project level, no aggregation

Alternative D – Hybrid: APR #1: Coulee/Chief Joe APR #2: The Dalles and John Day APR #3: Lower Granite, Little Goose, Lower Monumental, and McNary. Bonneville and Ice Harbor will be individual participating resources

Decision #2: Do we want to follow Powerex's participation model for aggregated resources? Aggregated Participating Resources (APR) and Aggregated Non-Participating Resources (ANPR) Strategy

For any alternative other than Alternative C, Power Services will have to manage how the aggregated signal will be broken up and relayed to the individual projects. The Powerex model allows Power Services to set a separate Generation Dispatch Factor (GDF) for base schedules and for flexibility (ranges that the market operator can move the project up and down). The optics of this participation model might also be preferred from a legal perspective since the CAISO is only dispatching surplus energy.

7. Assess risks of alternatives

- Identify the risks associated with the alternative actions or approaches.
- Assess effectiveness of existing controls for mitigating the risks identified.
- Analyze the likelihood and consequences of each risk.
- Evaluate the risks to determine whether they are acceptable or must be mitigated.

See Additional Guidance and Resources for Step 7 for assistance with scenario development and scoring/rating risks

Decision #1: Aggregation of resources

Alternative A – one APR: all "Big10" projects' data will be aggregated into one *APR*. The risk of Alternative A is that the projects are not electrically similar enough for the CAISO to accept the proposal. BPA will get no congestion relief with this alternative nor will BPA be able to capture congestion revenue rents with this alternative.

Alternative B – Three APRs: "Big10" projects will be aggregated into three APRs each corresponding to a subset of the Big10 (Coulee/Chief, Lower Columbia, and Lower Snake). The risk of this alternative is that it is an in-between solution meaning that it potentially has all the complexity of Alternative C but not all of the congestion relief or revenue benefits of Alternative C.

Alternative C – Project level. The biggest risk to this alternative is the de-optimization of the FCRPS.

Participation of FCRPS hydro projects in an EIM will require a decision on how these resources will be bid and how dispatch instructions from the market operator will be implemented. Data that is required to be submitted to the market operator for the EIM resources include base generation, minimum generation, maximum generation, and a bid curve for the upcoming hour, as well as an indication of the regulation, load following and contingency reserve requirements. The market operator will perform a calculation every five minutes and send a dispatch instruction to each EIM resource depending upon their submitted flexibility and the cleared price. Moving to a market dispatch that is more granular than the Big10 level risks de-optimizing the FCRPS unless Bonneville figures out a way to 1) reflect the costs of de-optimizing the FCRPS in the development of the price curves, 2) limit the FCRPS flexibility that is being submitted, and/or 3) develop a hydro-optimization post-processor. The level of complexity of how these risks are mitigated are all important considerations.

Alternative D – Hybrid This alternative has all of the risks of A,B, and C since it is a hybrid of all of them.

Decision #2: Aggregated Participated Resources (APR) and Aggregated Non-Participating Resources (ANPR) Strategy

Adopting Powerex's participation model for aggregated resources mitigates the risk of not meeting hydraulic objectives or artificially limited flexibility by allowing different generation distribution factors for the portion of the aggregated resource dispatched by the balancing authority and that dispatched by the CAISO.

8. Analyze & rank alternatives

- Analyze status quo and alternatives using decision criteria from Step 4.
- Rank order status quo and alternatives based on the analysis and insights.
- Based on the analysis, consider hybrid alternatives that may be more effective.
- Formulate the recommendation, explaining why the recommended alternative is the best.

See Additional Guidance and Resources for Step 6 for further guidance on evaluation of alternatives.

Decision #1: Aggregation of resources

Each alternative is ranked 1-4 against the criteria above which are measures of the objectives. 1 is the highest and 4 is the lowest.

Alternative A: All participating projects aggregated into one resource

Maximum flexibility of the FCRPS - 1
Maximum transmission congestion relief - 4
Maximum transmission congestion revenue rents - 4
Simplest to implement - 1
Likely to be accepted as a model of participation from the CAISO - 4
Market dispatch instructions are hydraulically feasible - 1
Market dispatch instructions do not violate any non-power objectives - 1

Explanation to follow

- Probably the easiest from an implementation perspective. Market operator dispatch instructions can be translated to project-level in a manner close to status quo; hydro and price curve data submission is fairly straight-forward.
- Modest impact to DSC workload and manageable with no additional BFTE.

Alternative B: Three aggregated, participating resources

Maximum flexibility of the FCRPS - 2
Maximum transmission congestion relief - 3
Maximum transmission congestion revenue rents - 3
Simplest to implement - 2
Likely to be accepted as a model of participation from the CAISO -3
Market dispatch instructions are hydraulically feasible - 2
Market dispatch instructions do not violate any non-power objectives -2

Explanation to follow

GCL/CHJ is hydraulically independent from Lower Snake projects since they are on different river reaches and from the Lower Columbia projects due to the long travel time and nonfederal projects that are in between. Assessing hydraulic linkage between Lower Snake and Lower Columbia projects is a little trickier since the travel time between water discharged from Ice Harbor and McNary is only a couple of hours. However, absent special operations or unusual outage conditions, the Lower Snake projects tend to operate in a similar manner so aggregating these projects is rational. Of the four Lower Columbia river projects, McNary, John Day and the Dalles tend to be operated in a similar manner except during high flows when McNary (which is the most turbine limited of the three) tends to run at flat generation. Bonneville dam can, at times, also operate in a similar manner, but it has frequent special operations and nonpower constraints that limit operational flexibility.

Looking at hourly response factors over a ten year period (2008 – 2017), there are at least two aggregations of projects that provide a substantial amount of the FCRPS within hour flexibility. Group 1 is GCL and CHJ. These projects are often operated in tandem such that one project will have a relatively high response factor while the other one will be lower and vice versa. Group 2 is JDA and TDA. They routinely account for an important amount of within hour flexibility, with their response factors commonly being at similar levels. The other Big 10 projects sometimes have flexibility. Depending on water conditions MCN can be limited in flexibility, but at other times MCN can be an important source of flexibility. The Lower Snake is also important as during certain periods of the year, there is flexibility and response is carried on these projects.

- Market operator dispatch instructions translation from APR to project-level could be fairly complex, for example, the determination of GDFs to allocate EIM dispatches among the APRs
- Potentially an increase to DSC workload that could require additional BFTE especially if the determination of GDFs is manual

Alternative C: no aggregations, bid curves submitted for each project individually

Maximum flexibility of the FCRPS -4
Maximum transmission congestion relief -1
Maximum transmission congestion revenue rents -1
Simplest to implement - 3
Likely to be accepted as a model of participation from the CAISO - 1
Market dispatch instructions are hydraulically feasible - 4

Market dispatch instructions do not violate any non-power objectives – 4

Explanation to follow

Opportunity costs from varying levels of aggregation

Relative to aggregating all of BPA's "Big10" generators in one grouping, smaller aggregations are likely to increase BPA's ability to maximize revenue from EIM participation. In the presence of transmission congestion within BPA's BA, disaggregation allows BPA to respond more appropriately to the different price signals provided by the EIM dispatch. In the absence of transmission congestion (where LMPs in BPA's BA are likely very similar), BPA may still benefit from disaggregation if we wish to specify differing levels of flexibility or reflect different opportunity costs at different geographic locations (for example, if hydrological conditions implied that we would only dispatch GCL upward at a price that is well above recent market prices but that also implied that we would be willing to dispatch the LSN upward or downward at price levels near recent market prices). Such differing opportunity costs could perhaps be reflected by modifying PTDFs/GDFs or more explicitly through bidding-in disaggregated resources. Benefits from increasing the number of aggregations are expected to exhibit diminishing returns (e.g. more benefits going from Big10 to Big3 than going from Big3 to individual generators).

- This may be similar to Alternative 1 from an implementation perspective because the data exists. However, the the development of the bid curve data will be much more complex.
- Hydro data submission is fairly straight-forward; participating resources will only need to submit bid curves.
- May facilitate transparency by separating projects for BAA regulation and EIM dispatches explicitly. Conversely, BPA will have the option to use the same projects for EIM and regulation.
- Potentially an increase to DSC workload that could require additional BFTE especially if managing 10 different bid curves is required

Alternative D: Hybrid

Maximum flexibility of the FCRPS - 3
Maximum transmission congestion relief - 2
Maximum transmission congestion revenue rents - 2
Simplest to implement - 3
Likely to be accepted as a model of participation from the CAISO - 2
Market dispatch instructions are hydraulically feasible - 3
Market dispatch instructions do not violate any non-power objectives – 3

Explanation to follow

- This may completely change how Bonneville allocates regulation, load following and contingency reserves so that the EIM resources can have maximum flexibility offered to the market operator
- Has to potential to be the "sweet spot" that preserves the potential benefits while minimizing the risk of hydraulic de-optimization. Using the most operationally flexible and isolated projects minimizes the risk of hydro de-optimization within the hour. Yet, mitigation of hydraulic de-optimization could be complex if the EIM participating resources operating in isolation cause downstream problems at relatively small reservoirs.
- This alternative allows the change of groupings and projects that define EIM resources as conditions change.
- There is a risk of incurring imbalance at the non-participating "Big 10" projects

Decision #2: Aggregated Participated Resources (APR) and Aggregated Non-Participating Resources (ANPR) Strategy

Non-Generating Resource Functionality

CAISO developed the concept of non-generating resources (NGRs) to allow energy storage devices to participate in their market (e.g., Flywheels, Electric Cars, Batteries, Pumped Hydro, etc.). NGRs are resources that operate as either Generation or Load and that can be dispatched to any operating level within their entire capacity range but are also constrained by a MWh limit to (1) generate energy; (2) curtail the consumption of energy in the case of demand response; or (3) consume energy.

Adopting Powerex's participation model for aggregated resources mitigates the risk of not meeting hydraulic objectives or artificially limited flexibility by allowing different generation distribution factors for the portion of the aggregated resource dispatched by the balancing authority and that dispatched by the CAISO.

9. Present findings & document decision

- Develop briefing package.
- Present results to the decision maker(s), including decision insights, minority opinions, and preliminary implementation plan assumptions.
- Document decision, supporting information, high level planning estimates, and performance expectations informed by decision criteria.

See also Additional Guidance and Resources for Step 9.

10. Transition to implementation:

- Decision maker assigns management accountability for implementation.
- Form implementation team.
- Implementation team debriefs with ADF team.
- Management ensures that monitoring and reporting process is established.

See Additional Guidance and Resources for Step 10 for an implementation charter template.

Last Updated: February 15, 2018

1. Describe problem or opportunity

- Describe the situation and circumstances creating the need for a decision. This should be a brief statement that gives the reader enough context to get started.
- The problem statement should be reviewed with decision makers to confirm the correct problem is being addressed.
- Do not treat the initial problem statement as a final product; as you go through the ADF steps, the problem statement may need to be revised and reviewed again.

See Additional Guidance and Resources for Step 1

Bonneville's grid modernization and EIM participation program is a huge undertaking that will require making key assumptions. These assumptions address fundamental questions which Bonneville should decide prior to negotiating with the CAISO, because they impact how Bonneville will negotiate as well as proceed with developing its systems/automation and tariff and business practice changes to enable EIM participation. These assumptions may change over time as negotiations and stakeholder engagement progress.

There are multiple models in the CAISO EIM to set-up participating resources. BPA needs to understand these models, describe the alternatives applicable to BPA and make an initial recommendation on how to set-up EIM participating resources to begin facilitating a collection of mutually dependent high-level market participation choices that balance reliability, efficiency and control of the resources to support power and non-power objectives.

2. Define governance, scope & constraints

- List the decision makers for this ADF
- Describe the decision process for the ADF, including when decision makers will be engaged.
- Define the timeline for analysis and making this decision
- List the ADF team members and any key supporting resources
- Describe any notable scoping requirements or constraints on this analysis (if any)

A more complex or formal ADF should include a project charter, which describes the above information. See Additional Guidance and Resources for Step 2 for a Project Charter template.

Name of Initiative: Federal Resource Participation
Client Organization: BTO ?
POC Manager: Steve Kerns (PGS)
Decision Maker(s):

Consult - Tier II steering committee: Kieran, Suzanne, Michelle M., Michelle C., Jeff C., Todd M. – Currently meets monthly (last Tuesday of every month) for one hour on March 27th at 1p.

Responsible - Tier I decision makers: Joel, Richard, Janet

Executive Sponsors: Kieran?
ADF Lead: Steve Kerns (PGS)
Core ADF team members: Clarisse Messemer (PGST), Todd Kochheiser (TOI), Dave Dernovsek (PTKP), Eric Federovitch (PTM), Rich Greene (LP), Rebecakah Pettinger (LP), Kelii Haraguchi (PTM), Eric King (TSPP), Russ Mantifel (TS), Tom Davis (LT), Mark Symonds (BD), Chris Siewert (PGSD) , Elsa Chang (PGST), Cindy Polsky (PGST), Pam Van Calcar (PGSP), Frank Puyleart (TOOC), Chris Sanford (TOR), Steve Gaube (PTF), Troy Simpson (TOI), John Schaffroth (Utilicast), Margaret

Pedersen Mainzer (PTL), Mai Truong (PGST), Rob Hawkins (PGSD)
Key SMEs/Orgs for Input:
Draft due: March 15, 2018
Final due: March 31, 2018
Decision Deadline: March 31, 2018

3. status quo context

- Collect relevant background information about the current state of affairs and relevant history for this issue and decision (Status Quo).
- Describe the external environment and the goals and interests of external stakeholders.
- Describe the internal structure, culture, and capabilities of the organization and the goals and interests of internal stakeholders.
- Describe the strategic context by identifying relationships to agency-level and business-line objectives, policies, top risks, and/or strategic issues.

See Additional Guidance and Resources for Step 3 for worksheets on Context, Internal Stakeholders, and External Stakeholders

Background: The status quo is an aggregation of all the "Big 10" dispatchable resources operated and scheduled as one system. The Big 10 dispatchable projects are the following:

Grand Coulee
Chief Joe
Lower Granite
Little Goose
Lower Monumental
Ice Harbor
McNary
John Day
The Dalles
Bonneville

Operating the FCRPS as one system maximizes the flexibility characteristics of the FCRPS. Monetizing this flexibility is one way that we keep power rates low in the region. However, this aggregation level minimizes the revenue enhancement associated with monetizing the opportunity cost of the system at a more granular level (Kelii and Steve G., please help here). In addition the aggregation level of the status quo minimizes the transmission congestion relief that could be achieved by the EIM if the projects were bid into the market at a more granular level. The bidding strategy decided in this ADF will have to balance these objectives to achieve the best revenue and operations outcomes for BPA from a one BPA perspective.

Possible aggregations:
These projects are hydrolically linked by their locations relative to the river: Upper Columbia, Lower Columbia and Lower Snakes. A further consideration comes from where the resources are located in relation to the transmission flowgates and defines how electrically similar they are (define electrically similar here).

Some of these projects are highly linked (Grand Coulee and Chief Joe for example) while the link for others is less obvious (Bonneville could be aggregated with John Day and The Dalles but often is operated in a different way to either of those projects in order to meet non-power constraints) (Pam and Chris please help here). And while there is minimal flexibility in the projects on the Snake River with the current Fish Operating Plan (and hence no loss to monetizing that flexibility with de-aggregation) bidding these projects in independently may not add any revenue or congestion relief since these projects may have to become non-participating resources during spill season.

Since we are looking for a balance of transmission and power objectives, the status quo does not seem to be optimal. In addition, a natural aggregation from a hydrolic perspective (Upper Columbia, Lower Columbia and Lower Snakes) may not be feasible either if these aggregations span across congested flowgates. Finally, bidding in the projects individually minimizes the flexibility of the FCRPS system and will not be optimal from a power revenue perspective. Some alternative grouping will have to arise out of this decision framework for an initial bidding strategy when negotiating with the CAISO.

Internal Stakeholders (Please Describe in Appropriate Detail)	**What They Want or Need** (& Why, if helpful)	**What They Will Resist**	**Their stake in the decision and likely role in supporting or opposing it**
Power Operations (PG)	• Ability to meet high-priority non-power obligations and constraintsplaced on the FCRPS • Flexibility to operate the FCRPS in the most efficient manner • Cost recovery •	• Difficulty in managing risk of de-optimization • More manual processes	
Bulk Marketing (PT)			
Transmission Operations (TO)			
Transmission Sales & Marketing (TS)			
Business Transformation Office (BTO)			
Legal			

External Stakeholders (Please Describe in Appropriate Detail)	**What They Want or Need** (& Why, if helpful)	**What They Will Resist**	**Their stake in the decision and likely role in supporting or opposing it**

CAISO			
EIM Participants			

4. Define objectives & decision criteria

- Describe the desired end state to be accomplished or achieved.
- Define the decision criteria (i.e. key evaluation factors) that will be used to determine whether and how well proposed alternatives (Step 6) deliver on the stated objectives and create value for BPA.
- Decision criteria should be considered in such categories as: Economic/Finance, Legal/Regulatory, Environment, Customer/stakeholder, BPA's people and processes, etc.
- Decision Criteria should be updated to address unacceptable risks from Steps 5 and 7.

See *Additional Guidance and Resources for Step 4* for further guidance on defining Objectives and Decision Criteria

Describe the desired end state to be accomplished or achieved:

Objectives:

1. Preserve and enhance the value of Northwest hydropower and transmission operations for our customers and the region by making more efficient use of the FCRPS and FCRTS. (Goldilocks sweet spot; balance the following):
    a. Minimize de-optimization[1] of the FCRPS
    b. Maximize transmission congestion management benefits
    c. Capture revenue benefits from joining the CAISO EIM
2. Power Services retains the autonomy on how hydro projects respond to market signals
3. Reliable operations.
4. FCRPS must be able to access all interchanges in the balancing authority area.
5. FCRPS will meet all of our NT load obligations
6. All FCRPS dispatches are deliverable
    a. Dispatches are feasible
    b. Transmission is available for dispatch instructions from the CAISO

Decision Criteria:

Economic/Finance:

Legal/Regulatory: Ensure Bonneville meets its statutory obligations

Environment:

Customer/stakeholder:

BPA's people and processes: Simple implementation (Goldilocks – just right)

[1] For purposes of this discussion, de-optimization of the FCRPS refers to EIM dispatches that result in an un-anticipated reduction in future flexibility. For example, with the same bid curve, Lower Columbia projects could be given dispatch instructions that drafts or fills some of the projects without touching other projects. This could leave some projects too full (which risks spill) or too empty (which limits fuel).

5. Assess risks of status quo

- Identify events or conditions that would impact achievement of the objectives (from Step 4).
- Assess effectiveness of existing controls for mitigating the risks identified.
- Analyze the likelihood and consequences of each risk.
- Explain which risks are unacceptable and why.

See Additional Guidance and Resources for Step 5 for agency risk scales, guidance on risk assessment, and other tools.

Identify events or conditions that would impact achievement of the objectives:

The status quo is one aggregated resource, the Big10. If Bonneville decides the level of aggregation for the Big10 should be one aggregate EIM resource, CAISO may reject it and require more granularities because CAISO's full network model will group resources that are "electronically similar".

Assess [effectiveness] of existing controls for mitigating the risks identified:

6. Identify alternatives

- Brainstorm significantly different, creative, feasible alternatives to the status quo that achieve the objectives (Step 4) and mitigate risks (Step 5) based on the decision criteria.
- Narrow down the alternatives to manageable set of (at least two) alternatives.
- Ensure the alternatives are sufficiently defined and estimates based on preliminary planning assumptions.
- Test feasibility of selected alternatives with SMEs/Stakeholders as needed.

See *Additional Guidance and Resources for Step 6 for further assistance with this step.*

Decision #1: Aggregation of resources

Assumptions:

1. The "Provision of Transmission in an EIM" ADF and transmission scheduling practices (including zonal scheduling) are agnostic to the decision of this ADF.
2. Power Services will still be able to make system sales and purchases outside of the EIM.
3. NWHub – Eric F.
4. Current tagging and scheduling practices will remain. Russ
5. Non-dispatchable FCRPS projects will be non-participating resources in an EIM and may or may not be aggregated.
6. A participating EIM resource will be used to reference the type of resource that the market operator sees and are limited to the dispatchable "Big10" FCRPS hydro projects.
7. An aggregate participating resource (APR) will be some combination of the Big10 projects.
8. An aggregate non-participating resource (ANPR) will be some combination of the non-dispatchable FCRPS projects.
9. Independent Power Producer (IPP) participation decision is independent of this ADF decision.
10. Within the BPA BA there are multiple interconnection points.
11. Individual bid curves will be created for each participating resource (aggregate or not). Eric F to clarify
12. Locational marginal prices (LMP) are resource specific or meter specific, regardless of the decision to aggregate.
13. Contingency reserves and regulation (for load and generators) will not be dispatched by the market operator.

Considerations:

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1. CAISO's network model defines the electronically similar resources (Todd and Russ to define electronically similar)
2. The current practice in Bonneville's BAA of dispatching balancing reserves to manage load and generation imbalance is market price-insensitive and generally fairly random within an hour. However, EIM market dispatches are price-driven and tend to dispatch EIM resources in a similar manner throughout the hour except for the EIM resource that is setting the price on the 5-minute interval. The result is that APRs could be consistently dispatched at the minimum or maximum generation levels that are submitted to the market operator.

Alternative A – Big 10 level: all "Big10" projects' data will be aggregated into one *APR*

Alternative B – Multiple APRs (more than 1, less than 10): **"**Big10" projects' data will be aggregated into multiple APRs each corresponding to a subset of the Big10 (Coulee/Chief, Lower Snake, and Lower Columbia, for example)

Alternative C – Project level: all "Big10" projects' data will each be submitted as individual *participating resources*.

Decision #2: Aggregated Participated Resources (APR) and Aggregated Non-Participating Resources (ANPR) Strategy

Assumptions:

1. Each resource could be divided into two resources: a non-generating resource and a generating resource.
   a. The generating resource would have a base schedule; the non-generating resource would have a bid curve
   b. This is the only way that a bid curve can include both a positive and negative values in its range, for example, ± 300 MW.

Alternative 1 – Develop APR/ANPR strategy

Alternative 2 – Do not develop APR/ANPR strategy

7. Assess risks of alternatives

- Identify the risks associated with the alternative actions or approaches.
- Assess effectiveness of existing controls for mitigating the risks identified.
- Analyze the likelihood and consequences of each risk.
- Evaluate the risks to determine whether they are acceptable or must be mitigated.

See Additional Guidance and Resources for Step 7 for assistance with scenario development and scoring/rating risks

Address for each alternative: ability to meet load and non-power objectives, bid curve development/opportunity costs, different incentives due to financial consequences (more explicit, informed decision if part of EIM?), are we handing over the system, ability to mitigate risk of de-optimization, ease of implementation (systems, processes, staff, policy development/business practices), etc

Decision #1: Aggregation of resources

Alternative A – Big 10 level
Alternative B – Multiple APRs
Alternative C – Project level

Decision #2: Aggregated Participated Resources (APR) and Aggregated Non-Participating Resources (ANPR) Strategy

Alternative 1 – Develop APR/ANPR strategy
Alternative 2 – Do not develop APR/ANPR strategy

Depending on the outcome of the transmission ADF, the objective to be able to access all interchange points may be at risk. However, there is no risk to that objective depending on which alternative is chosen for this ADF.

Depending on the outcome of the transmission ADF, the objective of being able to meet all of our NT load obligations may be at risk. However, there is no risk to that objective depending on which alternative is chosen for this ADF.

There should be no risk to deliverability of our bids depending on the outcome of the transmission ADF.

Defining physically feasible (master file and bid curves) will be more difficult the less aggregated the FCRPS projects are.

8. Analyze & rank alternatives

- Analyze status quo and alternatives using decision criteria from Step 4.
- Rank order status quo and alternatives based on the analysis and insights.
- Based on the analysis, consider hybrid alternatives that may be more effective.
- Formulate the recommendation, explaining why the recommended alternative is the best.

See Additional Guidance and Resources for Step 6 for further guidance on evaluation of alternatives.

Decision #1: Aggregation of resources

Insert transient time table for hydraulically linked projects / electronically linked projects – Mark

As Bonneville currently operates, having a single group of the entire big 10 makes the most sense from the perspective of reserves. We currently do not know how many spinning reserves we will have at any project 75 minutes in the future. In this paradigm, the single big 10 group provides the most flexibility divvying up EIM dispatch based on where reserves are in fact available.

To be more granular, knowledge about the amount of spinning reserves that can be made available is needed when formulating the bid curve and associated min and max values. If there was the situation where Bonneville sent an advisory forecast of basepoints for the next couple (perhaps 2 or 3) hours, and received back from projects the dispatch pattern and associated amount of spinning reserves that would be available at any project a more granular solution is viable.

Insert electronically similar matrix – Todd, Russ, Mark

Relative to aggregating all of BPA's "Big10" generators in one grouping, smaller aggregations are likely to increase BPA's ability to maximize revenue from EIM participation. In the presence of transmission congestion within BPA's BA, disaggregation allows BPA to respond more appropriately to the different price signals provided by the EIM dispatch. In the absence of transmission congestion (where LMPs in BPA's BA are likely very similar), BPA may still benefit from disaggregation if we wish to specify differing levels of flexibility or reflect different opportunity costs at different geographic locations (for example, if hydrological conditions implied that we would only dispatch GCL upward at a price that is well above recent market prices but that also implied that we would be willing to dispatch the LSN upward or downward at price levels near recent market prices). Such differing opportunity costs could perhaps be reflected by modifying PTDFs/GDFs or more explicitly through bidding-in disaggregated resources. Benefits from increasing the number of aggregations are expected to exhibit diminishing returns (e.g. more benefits going from Big10 to Big3 than going from Big3 to individual generators).

Decision #2: Aggregated Participated Resources (APR) and Aggregated Non-Participating Resources (ANPR) Strategy

Insert "Decide whether generating or non-generating resources were appropriate for the FCRPS or whether a bid curve can accomplish the same" – Pam, Kelii

9. Present findings & document decision

- Develop briefing package.
- Present results to the decision maker(s), including decision insights, minority opinions, and preliminary implementation plan assumptions.
- Document decision, supporting information, high level planning estimates, and performance expectations informed by decision criteria.

See also Additional Guidance and Resources for Step 9.

10. Transition to implementation:

- Decision maker assigns management accountability for implementation.
- Form implementation team.
- Implementation team debriefs with ADF team.
- Management ensures that monitoring and reporting process is established.

See Additional Guidance and Resources for Step 10 for an implementation charter template.