BP-24 Rate Case & TC-24 Tariff Proceeding Workshop

May 25, 2022

Agenda

TIME*	TOPIC	Presenter
9:00 to 9:05 a.m.	Introduction, Meeting Protocols and Agenda	Rebecca Fredrickson Daniel Fisher
9:05 to 9:15 a.m.	Customer Logistics and Norms	Rebecca Fredrickson
9:15 to 9:45 a.m.	Power Rates/Generation Inputs • EIM Benefits in Power Rates (steps 1-4)	Steve Gaube Eric Graessley
9:45 to 10:10 a.m.	Power Rates/Generation Inputs • EIM Impact on Balancing Services Cost (steps 1-4)	Jonathan Ramse
10:10 to 10:30 a.m.	Power Rates/Generation Inputs • Customer concerns regarding EIM and Generation Inputs (steps 1-4)	Jonathan Ramse
10:30 to 10:45 a.m.	**BREAK**	
10:45 to 11:00 a.m.	Transmission Rates • EIM Charge Code Allocation (steps 1-2)	Bill Hendricks
11:00 to 11:30 a.m.	Transmission Rates • Segmentation Study	Miranda McGraw
11:30 to 12:30 p.m.	**LUNCH**	
12:30 to 1:25 p.m.	Tariff • Attachment C: Short-Term ATC (steps 1-4)	Margaret Olczak
1:25 to 1:30 p.m.	Wrap-up and Next Steps	

** Times are approximate*

Approach to Customer Engagement

Most identified issues will be presented according to the following process at workshops (multiple steps might be addressed in a single workshop):

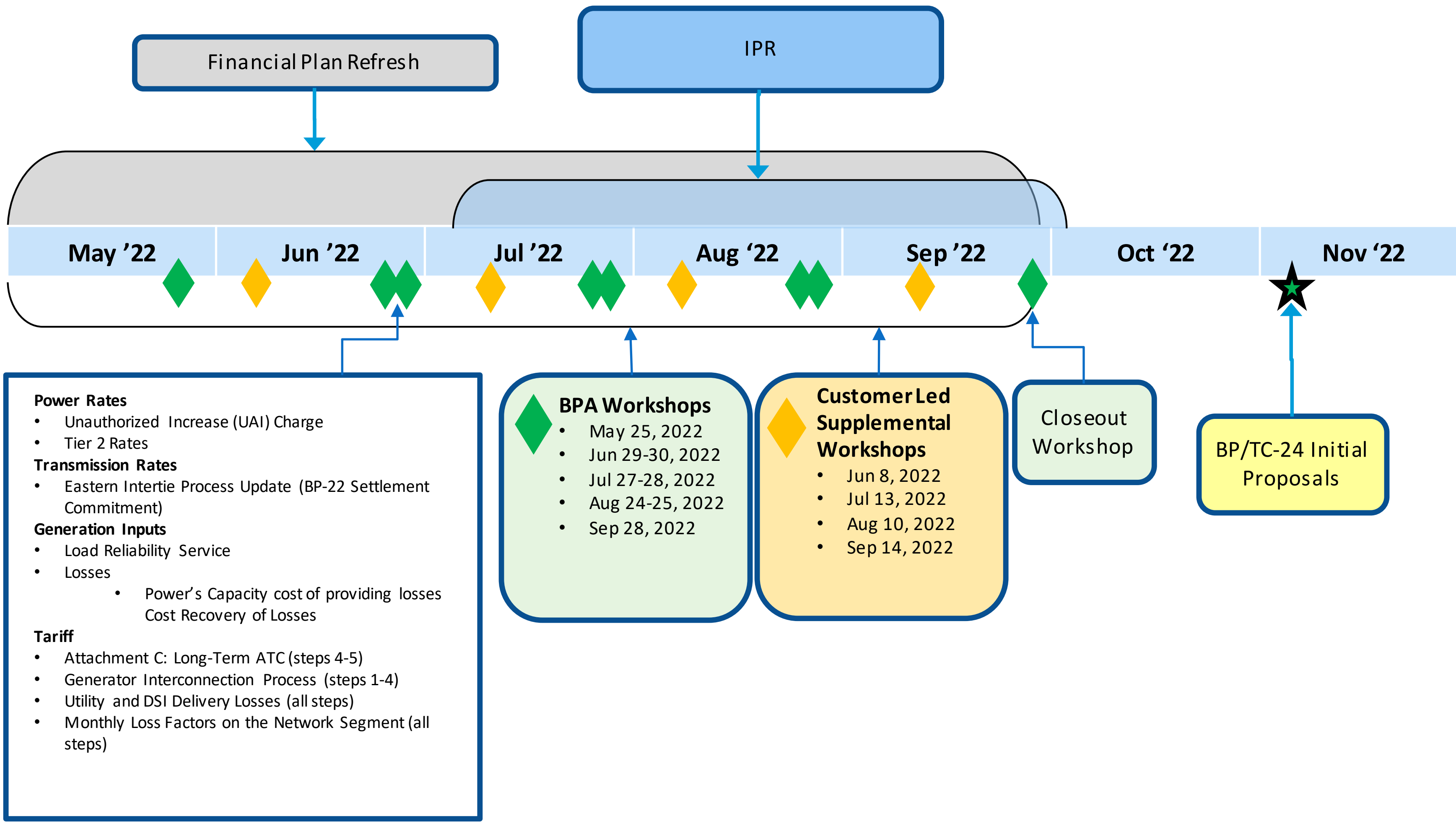
Phase One: Approach Development	Phase Two: Evaluation	Phase Three: Proposal Development
Step 1: Introduction & Education	**Step 3: Analyze the Issue**	**Step 5: Discuss Customer Feedback**
Step 2: Description of the Issue	**Step 4: Discuss Alternatives**	**Step 6: Staff Proposal**

- Teams will follow the steps that may be covered in one workshop or more based on the complexity of the issue.

Customer Comment Process

- Thank you to everyone who submitted comments.
- In order to be as transparent and responsive as possible, BPA is developing a comment tracking and response process that includes the following:
  - All customer comments will be posted to the BP-24/TC-24 website.
  - BPA will be posting a consolidated customer response (CCR) document for each workshop that will be posted/updated at the same time as other workshop materials.
  - The CCR is organized to address comments listed by the workshop date where the comments were received.
  - The CCR will provide direct responses or identify other forums or future BP/TC-24 workshops where BPA expects to provide a response.
    - To the extent possible, BPA will endeavor to provide responses prior to the next workshop on the BP-24 website (updated CCR will be posted with workshop materials)
    - All comments will have a response

BP/TC-24 Pre-Proceeding Timeline



BP-24 Topics

Power Rates/Generation Inputs

- EIM Benefits in Power Rates
- EIM Impact on Balancing Services Cost
- Customer concerns regarding EIM and Generation Inputs

Transmission Rates

- EIM Charge Code Allocation
- Segmentation Study

BP-24 Topic
EIM Benefits in Power Rates

- Step 1: Introduction and Education
- Step 2: Description of the Issue
- Step 3: Data and/or analysis that supports the issue
- Step 4: Discussions on possible alternatives to solve issue

Steps 1: Introduction and Education

Background

- The EIM Cost Benefit Study (modeled by E3) indicating annual net EIM benefits of $36-$40M/year.
- For reasons discussed in the BP-22 rate proceedings, BP-22 rates assume incremental benefits equal to costs (zero net benefit).
- BPA committed to working with stakeholders on a BP-24 proposal that would better reflect expected benefits, and BPA has a desire to fully integrate EIM participation in modeling, avoiding the false precision that results from itemized credits to the NSR Forecast.
- According to the E3 study, EIM dispatch benefits accrue in 2 key areas, with the vast majority being attributed to #1:

  1) Additional Load Factoring
     - Previously undeployed reserves can be monetized in EIM, allowing more sales (INCs) in high-value periods and more purchases (DECs) in low-value periods.

  2) Volatility
     - Significant real-time volatility allows participants to market at triggers more effectively than bilateral hour-ahead trading.

Steps 2-3: Description of Issue & Data and/or Analysis

Initial Approach

- Recognizing that most EIM dispatch benefits come from additional load factoring, evaluate whether we can model increases to NSR by allowing hydro modeling to assume a lower level of required reserves, freeing up additional flexibility to shape into high-value periods.

- This process involves rerunning RiverWare using BP-22 assumptions, but relaxing the amount of non-reg balancing reserves held in RiverWare.
  - ~370 MW INC
  - ~500 MW DEC

- The difference between hourly generation in the rate case and the test case are then valued at the corresponding Aurora hourly Mid-C price (BP-22 final proposal prices).

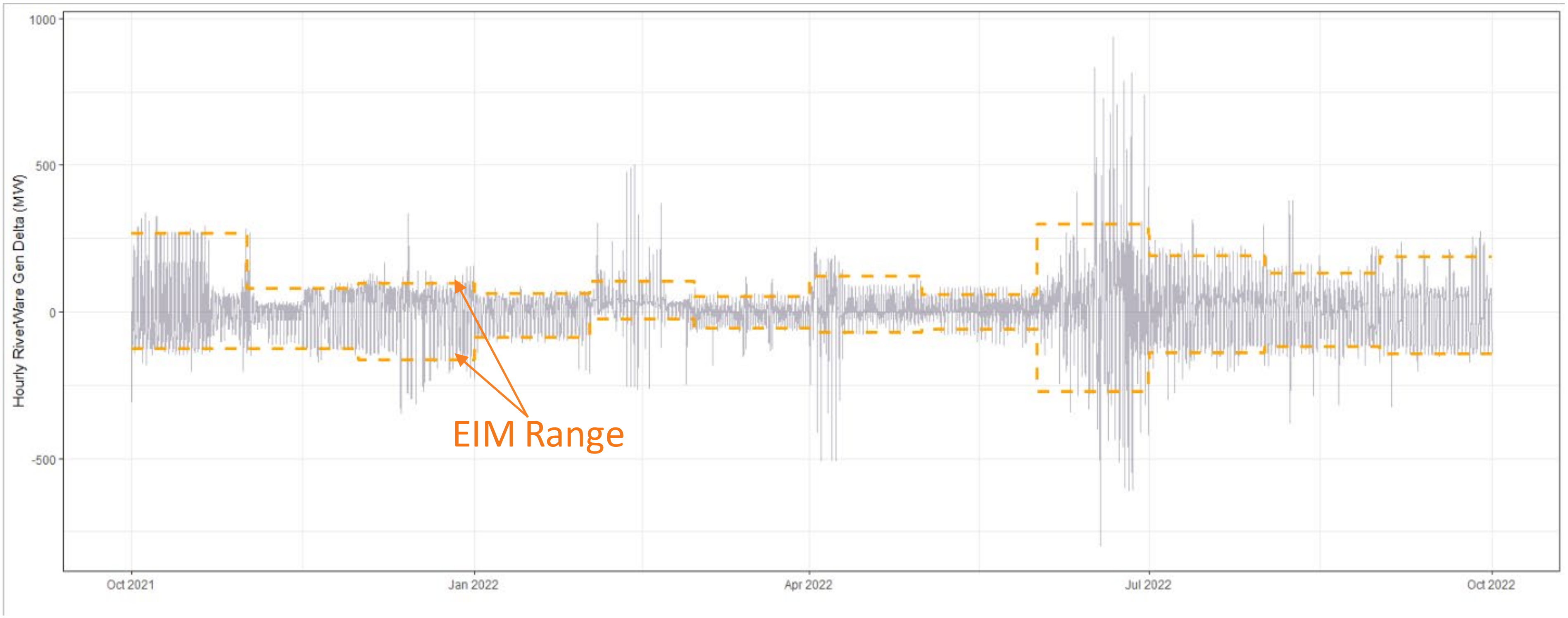
Initial Approach: Problem

- Hourly RiverWare generation deltas coupled with BP-22 hourly Aurora prices produce an annual average EIM benefit of about **$4M**.
- This low value is not reflective of our expected EIM benefits or of our expected operations as the flexibility is not responsive to EIM price signals.
  - RiverWare shapes using heuristics informed by recent historical behavior, which tends to load factor in a way that maximizes HLH and super-peak generation.
  - EIM prices reflect hourly load-net-of-resource needs across the region, requiring shaping that is more flexible and dynamic in order to produce benefits.

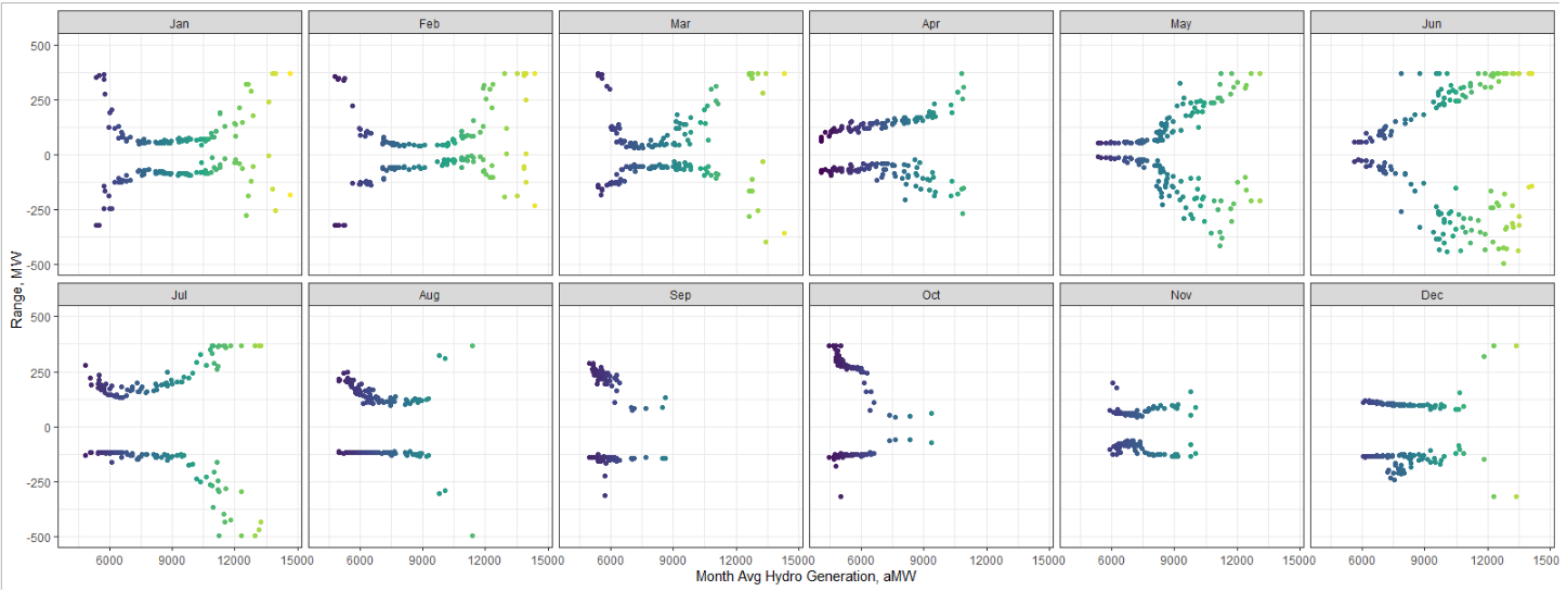
Alternative Approach

1) Leverage the RiverWare hourly generation deltas from the initial approach to estimate a range of EIM flexibility and participation.
   - The full range of hourly generation deltas could contain a number of extreme outcomes, which could result in overestimating a reasonable range of EIM flexibility and participation.
   - Instead, we use 5th and 95th percentiles of the RiverWare hourly generation deltas for each month and each water year to establish a reasonable range of expected EIM participation. *See next two slides*

Monthly EIM Ranges from RiverWare 5th and 95th Percentiles FY22, WY 1963



Monthly EIM Ranges from RiverWare 5th and 95th Percentiles FY22, All 80-Water Years

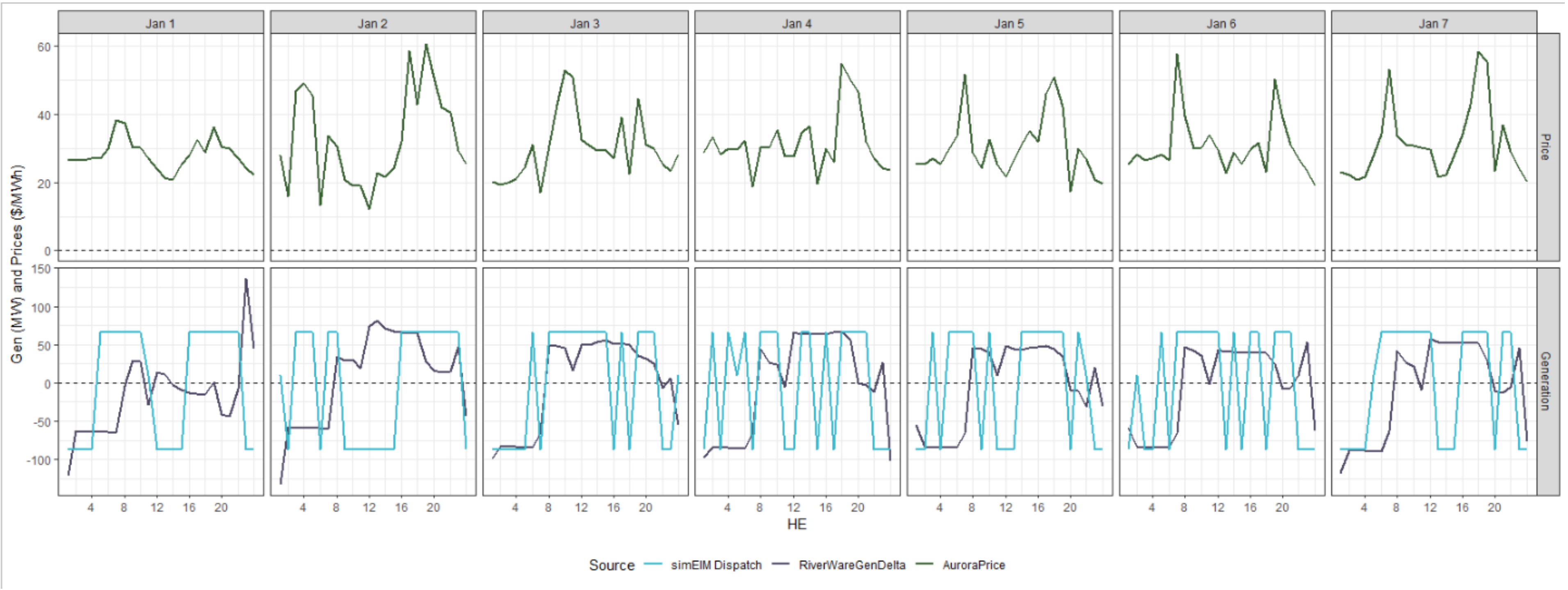


Alternative Approach, Cont'd

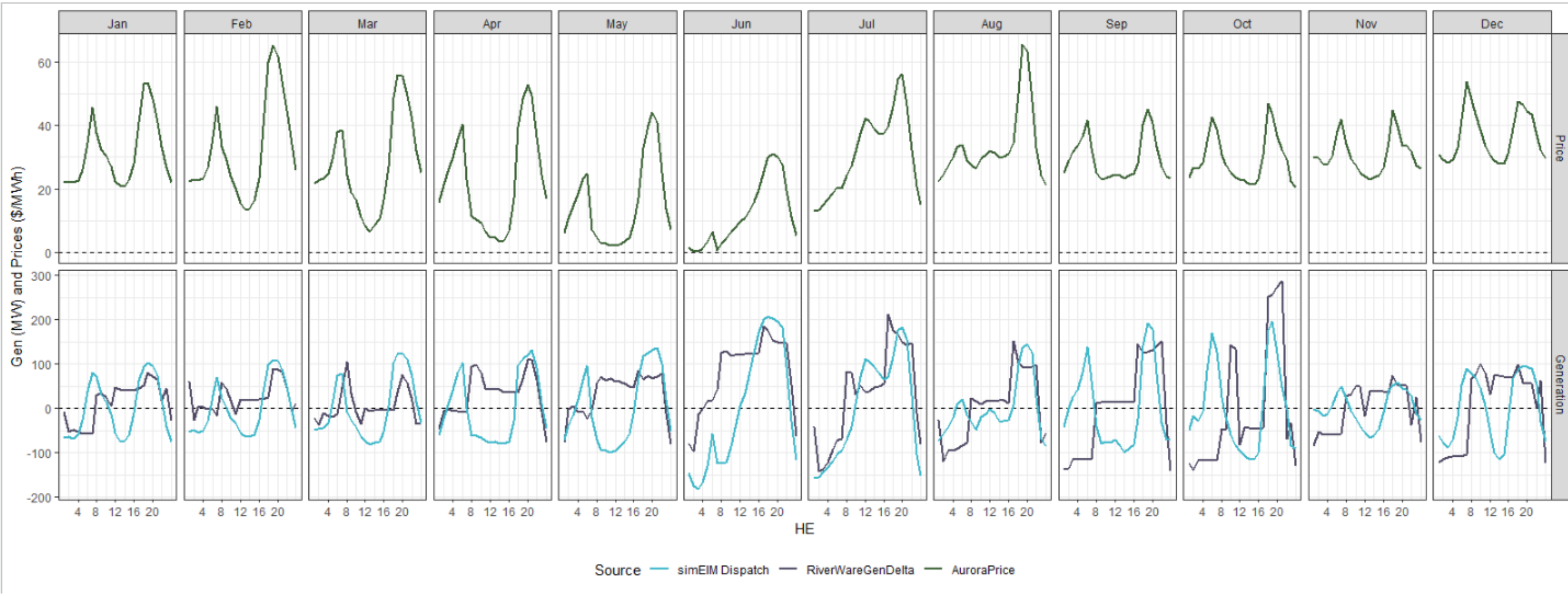
2) Once we've used the RiverWare generation deltas to produce ranges of expected EIM participation and operations by month and water year, we then simulate EIM dispatch associated with the corresponding hourly Aurora prices with the following objective and constraints:
   - Assume perfect price knowledge and aggressively dispatch the system to maximize revenue
   - Maintain daily energy neutrality
   - Operations must remain within the expected ranges for all hours of the year

See next two slides

Aurora Prices and Simulated EIM Dispatch
Jan 2022 Week 1, Iteration 1865

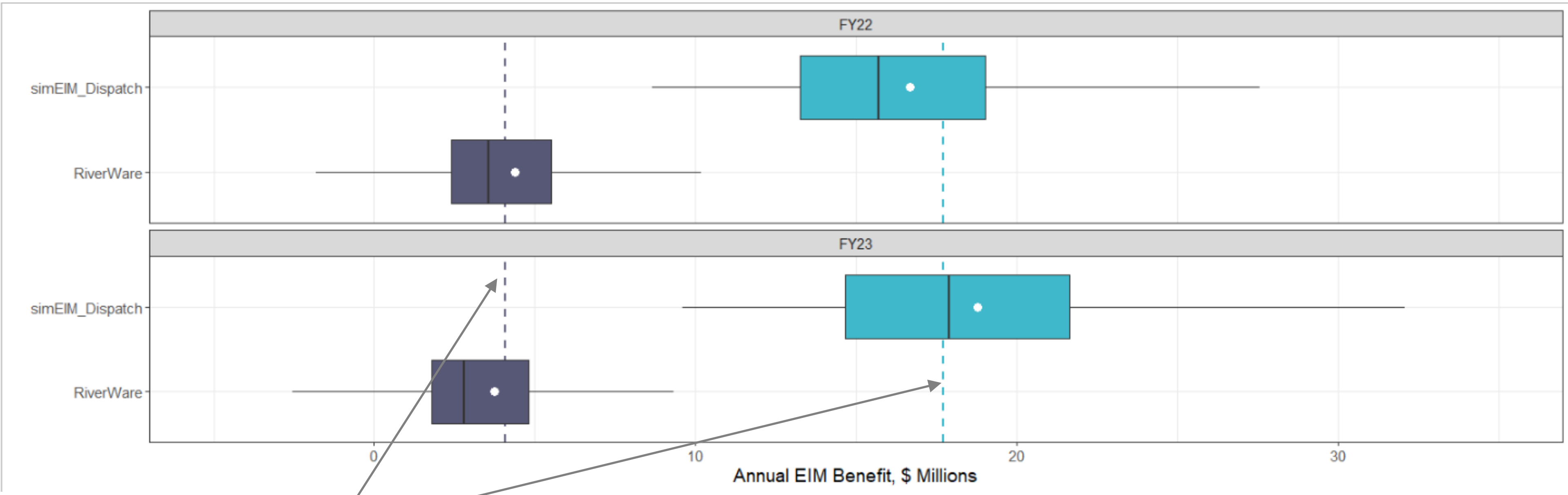


Aurora Prices and Simulated EIM Dispatch
FY22 Averages by Hour and Month



Alternative Approach: Results

- Simulated EIM dispatch using the ranges from RiverWare and BP-22 Aurora prices produces an annual average EIM benefit of about **$18M**. **Results for BP-24 will differ.**



The dashed lines are rate period annual averages ($4M with RiverWare versus $18M with simulated EIM dispatch)

Step 4: Discuss additional considerations and possible alternatives to solve issue

Further Considerations

The potential to **overestimate** benefits

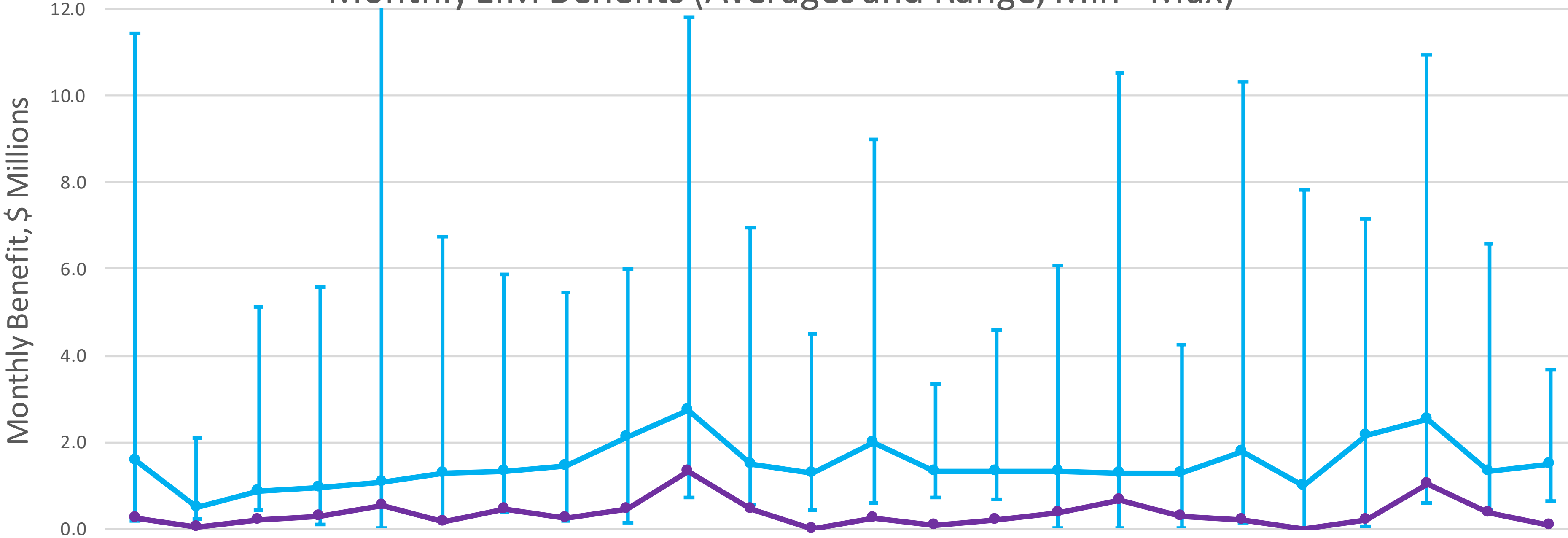
- Actual EIM ranges could be lower because:
  - Forecasts will be imperfect.
  - Increased ramping may incur additional costs which could lead to more conservative bids that reduce responsiveness.
  - The potential to fail sufficiency tests.
  - Potential transmission limitations.
  - We employ more sophisticated or conservative marketing strategies that result in lower levels of EIM participation.
- Actual EIM prices will respond to dispatch and our generation levels, but this approach holds prices constant for each iteration (exogenous prices).

The potential to **underestimate** benefits

- Actual EIM ranges could be higher because:
  - We employ more sophisticated marketing strategies that result in greater levels of EIM participation.
- Actual EIM prices may be more variable than the Aurora hourly price forecasts.
- We expect to gain additional benefits from sub hourly variability and responsiveness that are not included in the alternative approach.
- BPA expects to eventually participate in EIM with more reserves than just non-reg reserves (E3's study assumed all spinning capability).

Appendix - Power

Monthly EIM Benefits (Averages and Range, Min - Max)



	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23
Riverware	0.2	0.0	0.2	0.3	0.5	0.2	0.5	0.2	0.4	1.3	0.4	0.0	0.2	0.1	0.2	0.4	0.7	0.3	0.2	0.0	0.2	1.0	0.4	0.1
SimEIM	1.6	0.5	0.9	1.0	1.1	1.3	1.3	1.5	2.1	2.7	1.5	1.3	2.0	1.3	1.3	1.3	1.3	1.3	1.8	1.0	2.2	2.5	1.3	1.5

BP-24 Topic
EIM Impact on Balancing Services Cost

- Step 1: Introduction and Education
- Step 2: Description of the Issue
- Step 3: Data and/or analysis that supports the issue
- Step 4: Discussions on possible alternatives to solve issue

Steps 1 & 2: Introduction, education and description of issue

EIM associated Cost Reductions for Generation Inputs

- During the BP-22 rate case, BPA acknowledged the potential for EIM participation to offset variable costs of holding non-reg balancing reserves.
  - The BP-22 settlement includes a 50% cost offset for non-reg variable costs that is triggered upon BPA's entry into the EIM.
  - BPA committed to readdressing this issue during BP-24.
- We have limited EIM experience to inform a permanent approach to measure the true cost offset that EIM revenue has on the variable cost of holding non-reg reserves.
- The potential to offset costs arises from BPA's EIM participation because the variable costs incurred due to holding reserves and deoptimization of the Federal System, may be partially reoptimized through EIM operations utilizing the non-reg reserves.

GARD and EIM Cost Offset

- The Generation and Reserves Dispatch (GARD) Model forecasts the variable costs of holding reserves on the Federal system.
- Stand-ready energy costs are incurred due to changes in efficiency. These general costs are categorized into three buckets: energy shift, spill and efficiency.
- Under the EIM we are still required to hold all reserves, including the non-reg portion of the Balancing Reserves. Because of this, the costs of deoptimizing the Federal system need to be calculated.
- The EIM provides a new opportunity to economically dispatch capacity that would have otherwise been dispatched based solely on forecast error. This provides BPA the ability to maintain some control over the non-regulation capacity it is holding, which – *subject to market conditions* – would result in the ability to offset most if not all its stand-ready energy costs.
  - This approach is consistent with the assumptions made in modeling used to forecast EIM benefits in Power rates.

Steps 3 & 4: Analyze and discuss the issue

GARD and EIM Cost Offset Results

	Reg Balancing INC	Reg Balancing DEC	Non-reg Balancing INC	Non-reg Balancing DEC	Operating Reserves INC	Total:
Energy shift	1.91	1.71	2.30	2.61	5.38	13.91
Spill	0.49	0.44	0.59	0.67	1.38	3.57
Efficiency	-0.78	-0.70	-0.94	-1.07	-2.20	-5.68
Total	1.62	1.45	1.95	2.21	4.56	11.79
EIM Cost Offset	*0.00*	*0.00*	***1.95***	***2.21***	*0.00*	***4.16***
Adjusted Total	*1.62*	*1.45*	***0.00***	***0.00***	*4.56*	***7.63***

Values in $ Millions

- All values are from BP-22 Final Proposal
- The total EIM variable cost offset of **$4.16M** assumes the full quantity of non-reg reserves being available for EIM dispatch.
- Staff believe that up to a 100% variable cost offset for non-reg balancing reserves may be justified for the BP-24 rate period.

Results Summary and EIM Benefits in Power Rates Crosswalk

	Alternative Approach
Estimated EIM Benefits:	~ $18M
Gen Inputs EIM Cost Reduction:	~ $4M
Net EIM Benefit in Power Rates:	**~ $14M**

- Estimated EIM benefits are pre-Slice estimates and shared across Slice and Non-Slice products.
- Approximately 50% of revenue received for balancing services is from BPA Power Preference customers.

BP-24 Topic
Customer concerns regarding EIM and Generation Inputs

- Step 1: Introduction and Education
- Step 2: Description of the Issue
- Step 3: Analyze the Issue
- Step 4: Discuss Alternatives

Objectives

- Background education on Generation Inputs and capacity costs
- Understand the relationship between Generation Inputs and the EIM
- Address customer concerns regarding Generation Inputs cost allocations and EIM benefits
- Provide staff responses to customer concerns

Generation Inputs

- Generation Inputs are the reserve generation capacity and other services needed for Ancillary and Control Services (ACS) and transmission.
- BPA holds two types of reserve capacity:
  - Balancing (INCs and DECs): Regulation and Non-regulation
  - Operating Reserves (INCs): Spinning and Supplemental

Generation Inputs Costs

- BPA Power allocates the total power revenue requirement (excluding conservation costs) as either:
  - Energy (approx. $2 Billion) or,
  - Capacity (approx. $1 Billion)
- Generation Inputs costs are composed of two parts:
  - **Embedded unit costs** are calculated by dividing the revenue requirement allocated to capacity divided by the 1-hour peaking capacity of the federal system. For BP-22 this was:

$$\frac{\$1.004\ Billion}{14{,}249\ MW} = \$5.87\ kW/month$$

  - **Variable unit costs** are calculated for each reserve type in the Generation and Reserve Dispatch (GARD) Model. For BP-22, total variable costs were $11.8 Million.
- Incremental capacity unit costs = embedded unit cost + variable unit cost
- Decremental capacity unit costs = variable unit cost

Generation Inputs and the EIM

- In BP-22, BPA allocated both the costs and benefits of the EIM to Energy. None of the implementation costs or benefits of the EIM were allocated to Capacity.
- BPA anticipates offering most, if not all, of the non-reg balancing reserves in the EIM.
- Variable costs of holding non-reg balancing reserves
  - During the BP-22 rate case, BPA acknowledged the potential for EIM participation to offset variable costs of holding non-reg balancing reserves. As a result, BPA reduced GARD costs associated with non-reg balancing reserves by 50% for the BP-22 rate period when in the EIM.
  - For the BP-24 rate period, staff believe up to a full (100%) non-reg balancing variable cost offset may be appropriate assuming BPA will have the opportunity to bid most, if not all, of the non-reg balancing reserves in the EIM.
  - See EIM Benefits in Power Rates presentation, above, for full discussion of this topic.

Outstanding Customer Concerns

- It is our understanding that NIPPC believes that a portion of the capacity costs allocated to non-reg balancing reserves should be borne by customers other than ACS customers. This is because this capacity is a key component of realizing EIM benefits.
- Specifically, NIPPC is arguing that while all Generation Input customers gain the benefits of more efficient and lower cost energy for imbalance, BPA's Power customers (who are also ACS customers) receive incremental EIM-related revenue benefit from non-reg balancing capacity without directly being allocated a portion of the costs of that capacity.
- BPA staff's analysis of this issue is presented in the following slides.

Ingredients that make EIM benefits possible and EIM benefactors

EIM Ingredients:	Source:	Paid for by ACS customers:
Capability	Operational costs (IT systems, staff, etc.)	✗
Energy	Federal Hydro System	✗
Capacity	• Any entity bidding INC/DEC capacity into EIM ➢ BPA non-reg balancing reserves INC ➢ BPA non-reg balancing reserves DEC ➢ Additional capacity provided by BPA ➢ Additional capacity provided by Non-federal sources	 ✓ ✗ ✗ ✗
Transmission	BPA Transmission donation	✗

EIM Benefit:	Benefactors:	Received by ACS customers:
Efficient Energy Deployment	• Any entity that is offering INC or DEC balancing capacity into the EIM. • Any entity that has energy imbalance in the EIM.	✓

Staff Response

- **EIM does not reduce Bonneville's capacity costs.** Bonneville recovers its embedded cost of capacity associated with having to hold balancing reserves through ACS rates. This cost is incurred in or out of an EIM.
- **The existence of forecast error creates the need to hold capacity.** This balancing capacity is used to manage that error. The EIM re-optimizes resource generation in response to that forecast error and thus provides benefits (reduces the cost of meeting forecast error) compared to the alternative (meeting forecast error with resources that are deployed out of merit order).

Staff Response

- **Energy benefits flow to ACS rates through GARD:** Bonneville calculates the energy de-optimization cost of holding balancing reserve capacity through GARD. This variable cost is minimized, or potentially eliminated, when in an EIM. This is consistent with staff leaning to remove up to 100% of the variable cost for balancing capacity that can be offered into the EIM.
- **EIM benefits are a result of several ingredients.** Bonneville's non-reg balancing reserves is only one and energy benefits are realized by all entities in the EIM footprint. Importantly, Bonneville's requirement to hold non-reg balancing reserves is both the cause of BPA's balancing cost as well as a source of potential energy to more efficiently meet the forecast error across the EIM footprint.

Staff Response

- **Taken together, we believe that:**
  - Basing the unit cost of non-reg balancing reserves on the entire embedded capacity cost is appropriate.
  - It is appropriate to reduce the de-optimization costs allocated to non-reg balancing reserves because the EIM allows for that capacity to be re-optimized.
  - All entities in the EIM footprint will receive energy benefits from an efficient dispatch of resources. These benefits flow through EIM settlements. This includes those that offer in INC or DEC balancing capacity into the EIM as well as any entity that has energy imbalance in the EIM.

Next Steps: EIM & Gen Inputs

- Stakeholders to provide comments.
- Discuss stakeholder comments (Step 5)
- Staff Proposal (Step 6)

BP-24 Topic
EIM Charge Code Allocation

- Step 1: Introduction and Education
- Step 2: Description of the Issue

Issue: Introduction and Education

Objectives

- Review the BP-22 EIM Charge Code Allocations
- Update the rolled-in charges for BP-24

Context

- In the EIM, BPA will receive charges and credits from the CAISO. BPA will need to, in turn, recover these charges or distribute these credits through sub-allocating them to customers or rolling them into rates.
- There is no *pro forma* method for allocating the various charge codes.
- While most EIM entities have followed similar cost allocation methodologies, that is not always the case.
  - For example, PGE sub-allocates the real time cost of marginal loss offset charges based on measured demand, but PAC does not sub-allocate these charges.
- While FERC-approved methods are considered as a starting point, there may be rationale to modify methods to align with cost-causation.

Phased In Approach

BP-22

Begin Charge Code Allocation and Modify Existing Rate Structures (as needed)

BP-24

Review and Leverage Preliminary Data to Modify Charge Code Allocation and/or Rate Structures (as needed)

BP-26

Utilize Two Years of Data to Complete Refinement of Charge Code Allocation and/or Rate Structures (as needed)

Approach implementation is subject to change by rate period, given factors such as information availability and market changes.

SUB-ALLOCATED CODES

Sub-Allocated Charge Codes for BP-22

Base Codes	Neutrality Codes	Over/Under Scheduling Codes

Base Codes

Code Number	Description	Transmission Rates Schedule	FERC Allocation Method
64750	Uninstructed Imbalance Energy (Schedule 4 and Schedule 9)	§4(A) §4(B)	Direct Assignment
64600	FMM Instructed Imbalance Energy (Energy Imbalance)	§4(A) §4(B)	Direct Assignment
64700	Real-Time Instructed Imbalance Energy (Energy Imbalance)	§4(A) §4(B)	Direct Assignment

Method for All Codes : Direct Assignment

Rationale: Aligned with cost-causation, consistent with other entities/approved approach.

Definition: Direct allocation of the charges and credits to customers based on customer behavior in the CAISO EIM. The charges and credits are based on granular customer level detail behind the CAISO settlements to the EESC.

Neutrality Codes

Code Number	Description	Transmission Rates Schedule	FERC Allocation Method
64770	Real-Time Imbalance Energy Offset EIM	§4(D)(1)	Measured Demand
64740	Real-Time Unaccounted For EIM Energy Settlement (UFE)	§4(D)(5)	Measured Demand
69850	EIM Entity Real-time Marginal Cost of Losses Offset	§4(D)(3)	Measured Demand
6478	Real-Time System Imbalance Energy Offset	§4(D)(4)	Measured Demand
67740	EIM Entity BAA Real-Time Congestion Offset	§4(D)(2)	Measured Demand

Method for All Codes: Measured Demand by Magnitude

Rationale: Consistent with other entities/approved approach, mirrors CAISO BAA allocation.

Definition: Takes each customer's load ratio share, measured as the customer's Measured Demand (Metered Demand + Export Schedules) divided by the Total BAA Measured Demand multiplied by the amount billed to the BAA under each neutrality charge code. The Metered Demand for each customer is their metered load, including losses.

Over/Under Scheduling Codes

Code Number	Description	Transmission Rates Schedule	FERC Allocation Method
6045	Under/Over Schedule Load Charge	§4(C)(1) §4(C)(2)	Imbalance by Direction
6046	Under/Over Schedule Load Allocation	§4(C)(3)	Metered Demand by Magnitude

Method for 6045: Imbalance by Direction

Rationale: Allocates costs only to those that caused the penalty.

Definition: Takes each customer's imbalance in the same direction as the BAA imbalance, divided the sum of the customer imbalances in the same direction as the BAA multiplied by the amount billed to the BAA under code 6045.

Method for 6046: Metered Demand by Magnitude with Imbalance Threshold

Rationale: In addition to mirroring CAISO BAA Allocation, incentivizes individual customer scheduling accuracy in order to receive share of credit.

Definition: Same as metered demand by magnitude, but only allocates to those customers with imbalance at or below a predetermined imbalance tolerance (within 5-percent / 2 MW of schedule). Note that code 6046 is a credit to EIM entities on days in which they did not receive any penalty charges associated with code 6045, but other EIM entities did.

UNALLOCATED CODES

Rationale for Unallocated Codes

Administrative

- Not directly tied to customer behavior
- Some fees could be forecast
- Some codes would not be forecast (e.g. penalty fees or rarely used administrative codes)

Flexible Ramping

- EESCs are billed costs to fund resources to address future interval forecast ramp needs (interchange schedule ramps, change in net load forecast) and uncertainty (net load forecast error).
- Payments to resources respects the opportunity cost of awarding flexible ramping, so prices are marginal or the delta between resource's bid and LMP.

Real Time Bid Cost Recovery

- Recovers daily "Shortfalls" (net non-zero positive amounts) for units dispatched in the RTM.
- Charges to the EESC are based on non-zero positive amounts for units within the BAA and the BAA's pro-rata share of EIM transfers in.

Unallocated charge codes do not impact financial settlement chains of proposed set of sub-allocated charge codes. While these codes are not primary drivers of customer behavior in the EIM, they warrant review in this rate case and will be further reviewed as part of BP-26 once more data is available.

Recovering Unallocated Codes

- Unallocated codes with fixed charges are forecast within revenue requirement and segmented to the Network, Southern Intertie, and Eastern Intertie, using the O&M percentages.
- Unallocated codes without fixed charges are not forecast, however, BPA will continue to review available data to assess ability to incorporate in revenue requirement and/or risk assessment.

Ability to Forecast

CC #	Charge Code Name	CC #	Charge Code Name	CC #	Charge Code Name
701	Forecasting Service Fee	5900	Shortfall Receipt Distribution	7087	Daily Flexible Ramp Down Uncertainty Award Allocation
1592	EP Penalty Allocation Payment	5901	Shortfall Allocation Reversal	7088	Monthly Flexible Ramp Down Uncertainty Award Allocation
2999	Default Invoice Interest Payment	5910	Shortfall Allocation	7989	Invoice Deviation Interest Distribution
3999	Default Invoice Interest Charge	5912	Default Loss Allocation	7999	Invoice Deviation Interest Allocation
4564	GMC-EIM Transaction Charge	7070	Flexible Ramp Forecast Movement Settlement	8526	Generator Interconnection Process GIP Forfeited Deposit Allocation
4575	SMCR -Settlements, Metering, and Client Relations	7071	Daily Flexible Ramp Up Uncertainty Capacity Settlement	8989	Daily Neutrality Adjustment
4989	Daily Rounding Adjustment	7076	Flexible Ramp Forecast Movement Allocation	8999	Monthly Neutrality Adjustment
4999	Monthly Rounding Adjustment	7077	Daily Flexible Ramp Up Uncertainty Award Allocation	66200	Bid Cost Recovery EIM Settlement
5024	Invoice Late Payment Penalty	7078	Monthly Flexible Ramp Up Uncertainty Award Allocation	66780	Real Time Bid Cost Recovery Allocation EIM
5025	Financial Security Posting (Collateral) Late Payment Penalty	7081	Daily Flexible Ramp Down Uncertainty Capacity Settlement		

- Codes highlighted in green are ones that BPA would not forecast.
  - 701 is for a service that BPA already performs at lower cost and was granted an exemption.
  - 7071 & 7081 are charged directly to the PRSC.
  - The rest are penalty charges or rarely used administrative charges.
- The remaining codes could, theoretically, be forecast.

Codes with Fixed Charges (BP-22)

- Of the forecastable codes, two are based on fixed monthly charges or posted rates.
- 4575 (Settlements, Metering & Client Relations) is a flat $1,000/month charge.
- 4564 (Grid Management Charge) has two defined rates:
  - EIM Market Service Charge Rate: $0.0841/MWh (2019 Rate)
  - EIM System Operations Charge Rate: $0.1091/MWh (2019 Rate)
    - The EIM ROD includes estimates of the 5 minute and 15 minute purchases and sales as simulated by E3.
    - The base scenario estimates a total of 791.9 aMW or about 6.9 million MWh.
    - This would produce an annual cost of $1.34 million.
- Total charges for these codes = $1.35 million/year in BP-22:
  - Network $1,173k
  - S. Intertie $ 156k
  - E. Intertie $ 22k

Codes with Fixed Charges (BP-24)

- Of the forecastable codes, two are based on fixed monthly charges or posted rates.
- 4575 (Settlements, Metering & Client Relations) is a flat $1,500/month charge.
- 4564 (Grid Management Charge) has two defined rates:
  - EIM Market Service Charge Rate: $0.0935/MWh (2022 Rate)
  - EIM System Operations Charge Rate: $0.1002/MWh (2022 Rate)
    - The EIM ROD includes estimates of the 5 minute and 15 minute purchases and sales as simulated by E3.
    - The base scenario estimates a total of 791.9 aMW or about 6.9 million MWh.
    - This would produce an annual cost of $1.34 million.
- Total charges for these codes = $1.36 million/year in BP-24:
  - Distribution of these costs have not been finalized.

Codes Without Fixed Charges

- There is limited data on the remaining codes.
- CAISO provided data on the range of monthly costs of other EESCs of our size.

		Maxium Monthly Average	Minimum Monthly Average
7070	Flexible Ramp Forecast Movement Settlement	$49,000.00	($7,000.00)
7076	Flexible Ramp Forecast Movement Allocation	$7,000.00	($13,000.00)
7077	Daily Flexible Ramp Up Uncertainty Award Allocation	$34,000.00	$0.00
7087	Daily Flexible Ramp Down Uncertainty Award Allocation	$8,000.00	($1,000.00)
66780	Real Time Bid Cost Recovery Allocation EIM	$510,000.00	$0.00
	Total	$608,000.00	($21,000.00)

- Continuing to further evaluate these codes to determine the best approach with CAISO.
- Working to receive updated information as there have been changes in the market structure since the original data was provided by the CAISO.

Outstanding Items

- For August 24/25 Workshop:
  - Review what market activity is available to determine if better forecasts are possible for rolled-in costs
  - Discuss any charge codes that are not currently sub-allocated that may be better suited as sub-allocated
- For BP-26:
  - Review 2 years of market data for further discussion to complete refinement of charge code allocation and/or rate structures

QUESTIONS

BP-24 Topic Segmentation Study

BP-24 FY21 Segmentation

- BPA is proposing no methodology changes or changes to segment definitions.
- The Segmentation Study assigns plant investment to segments based on their function.
- Segmented net plant is used to allocate capital related costs in the revenue requirement to specific segments.
- Existing plant in service is updated with actuals through FY 2021 for the BP-24 Initial Proposal.

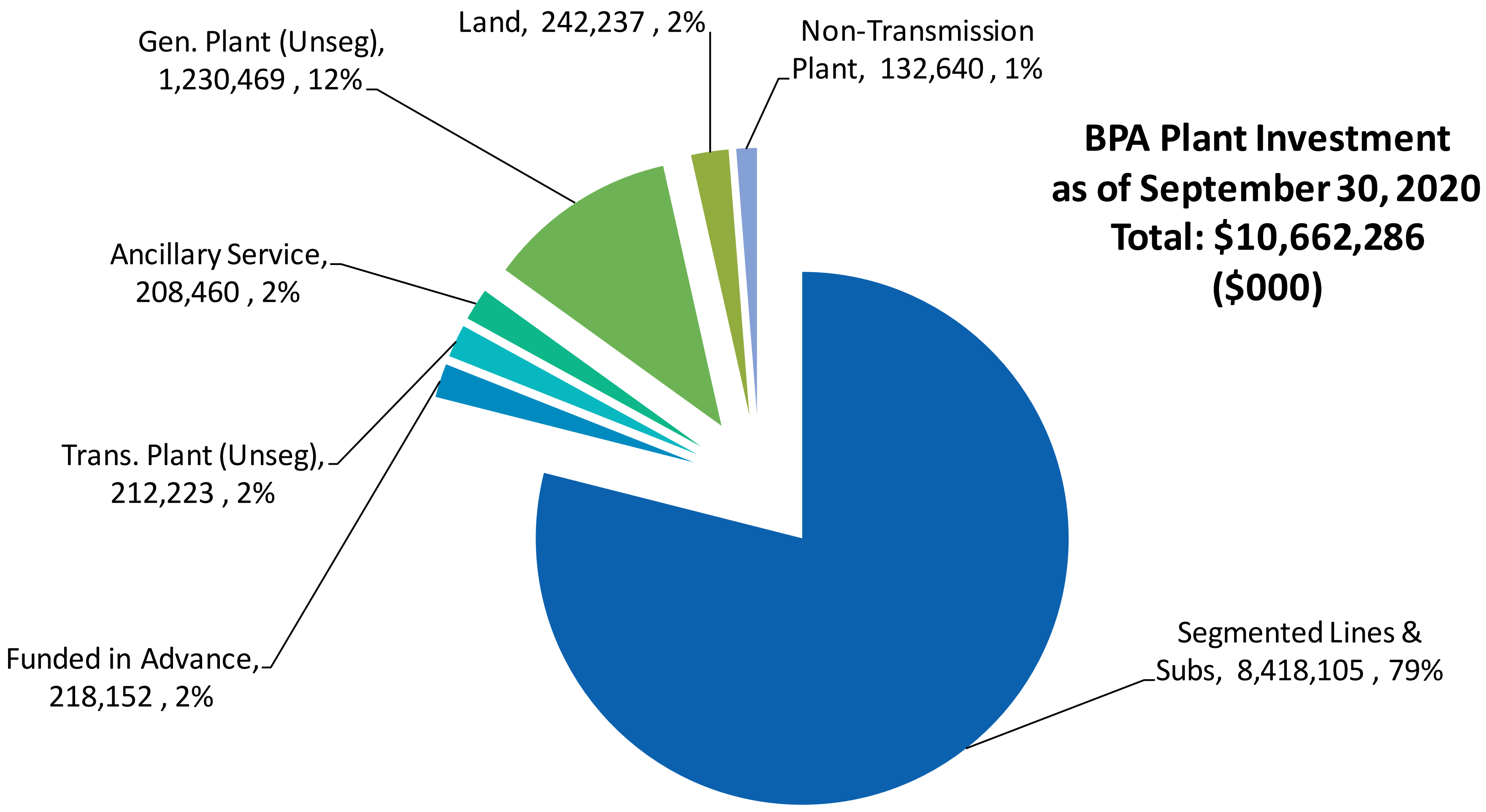
Description of Segments

- ***Generation Integration*** – Transmission facilities that connect Federal generation to BPA's transmission facilities.
- ***Network*** – Core of BPA's transmission system. Transmission facilities that transmit power from Federal and non-federal generation sources or interties to the load centers of BPA's transmission customers in the PNW or other segments.
- ***Southern Intertie*** – Transmission facilities used primarily to transmit energy between the PNW and California.
- ***Eastern Intertie*** – Transmission facilities connecting network facilities in the PNW to Eastern Montana, primarily to transfer energy from Colstrip to the PNW (these facilities were constructed pursuant to the Montana Intertie Agreement).
- ***Utility Delivery*** – Low voltage transmission lines and substation equipment associated with supplying power directly to utility customers' distribution systems (below 34.5 kV).
- ***DSI Delivery*** – Transformers and low-side switching equipment and protection equipment necessary to step down power to DSI customers at industrial voltages (6.9 or 13.8 kV).
- ***Ancillary Service*** – Communications and control equipment necessary for BPA to provide Scheduling, System Control and Dispatch (SCD) service.

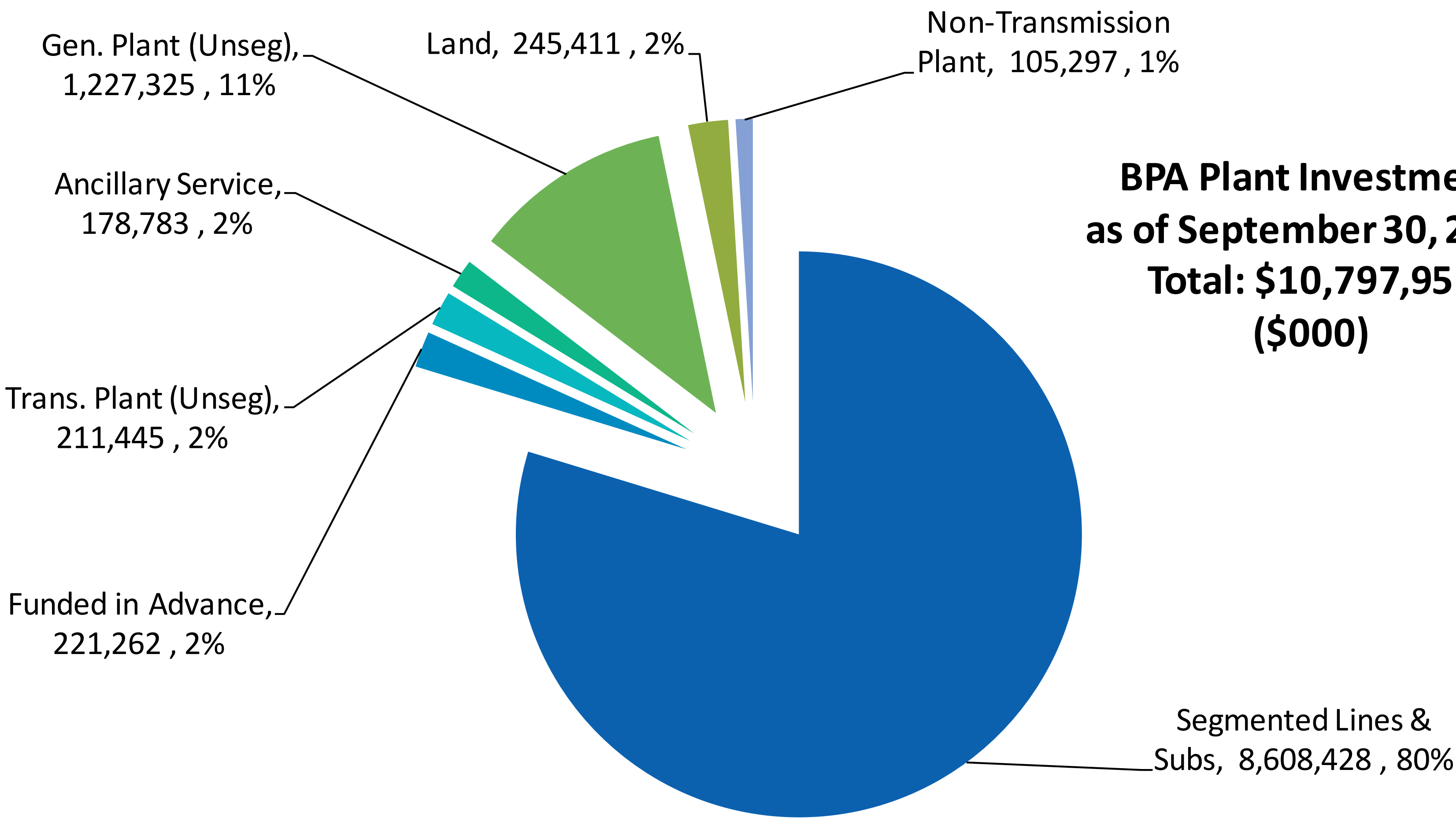
Segments

Segments	Corresponding Rates
Network	PTP, NT, FPT
Utility Delivery	UDC
DSI Delivery	UFT
Southern Intertie	IS
Eastern Intertie	IE, IM, TGT
Generation Integration	Assigned to power rates
Ancillary Services	ACS

BP-22 FY20 Plant Investment Summary



BP-24 FY21 Plant Investment Summary



BPA Plant Investment as of September 30, 2021 Total: $10,797,951 ($000)

Segmented Lines and Substations Investment

($000)

BPA Plant Investment Investment, through Sept. 30, 2020								
A	B	C	D	E	F	G	H	I
	Generation Integration	Network	Southern Intertie	Eastern Intertie	Utility Delivery	DSI Delivery	Segmented Total	Ancillary Services
Stations	110,562	3,807,908	815,595	28,449	18,846	8,279	4,789,638	
Lines	31,610	3,394,543	319,103	95,021	412	-	3,840,690	
Sub Total	142,172	7,202,451	1,134,698	123,470	19,258	8,279	8,630,328	208,460
% of Segmented Total	**1.6%**	**83.5%**	**13.1%**	**1.4%**	**0.2%**	**0.1%**	**100.0%**	

BPA Plant Investment Investment, through Sept. 30, 2021								
A	B	C	D	E	F	G	H	I
	Generation Integration	Network	Southern Intertie	Eastern Intertie	Utility Delivery	DSI Delivery	Segmented Total	Ancillary Services
Stations	124,684	3,895,356	823,742	28,419	18,917	8,256	4,899,375	
Lines	32,978	3,475,249	316,676	95,006	590	-	3,910,940	
Sub Total	157,662	7,370,605	1,140,418	123,425	19,508	8,256	8,819,874	178,783
% of Segmented Total	**1.8%**	**83.6%**	**12.9%**	**1.4%**	**0.2%**	**0.1%**	**100.0%**	

Station and Line Totals Tie to Segmented Lines and Subs plus Unsegmented Transmission Plant from Prior Slide

O&M Segmentation Methodology

- Consistent with prior O&M methodology
- Based on a 7 year historical average
- Direct O&M are historical O&M costs associated with a specific asset
  - The O & M is directly charged to the asset.
  - The O & M is then assigned to the different segments based on the segmented investments.
- Non-direct O&M are historical O&M costs not associated with a specific asset
  - These costs are allocated to Lines, Substations, and Metering stations in proportion to the direct O&M in each respective group
  - Transmission Line and Right-of-way Maintenance, and Vegetation Management (all non-direct) are allocated to Lines only

Segmented Historical O&M

($000)

BPA Historical Operations and Maintenance (O&M)
Fiscal years 2014 through 2020 (Seven Years)

A	B	C	D	E	F	G	H		
	Generation Integration	Network	Southern Intertie	Eastern Intertie	Utility Delivery	DSI Delivery	Total	Ancillary Services	Overhead
Stations	3,338	108,436	18,653	791	1,118	401	132,737		
Lines	618	48,833	2,252	2,107	13	-	53,823		
Sub Total	3,956	157,268	20,905	2,898	1,131	401	186,560	64,539	58,627
% of Segmented Total	2.1%	84.3%	11.2%	1.6%	0.6%	0.2%	100.0%		

BPA Historical Operations and Maintenance (O&M)
Fiscal years 2015 through 2021 (Seven Years)

A	B	C	D	E	F	G	H		
	Generation Integration	Network	Southern Intertie	Eastern Intertie	Utility Delivery	DSI Delivery	Total	Ancillary Services	Overhead
Stations	3,325	110,131	18,868	1,027	1,065	413	134,828		
Lines	621	49,531	2,120	1,150	16	-	53,437		
Sub Total	3,945	159,662	20,988	2,176	1,081	413	188,266	66,126	59,680
% of Segmented Total	2.1%	84.8%	11.1%	1.2%	0.6%	0.2%	100.0%		

Segmentation – Future Plant in Service

- The Segmentation Study reflects historic plant in service through FY 2021.
- A future plant in service forecast will be used for FY 2022-25 in the Initial Proposal to project segmented net plant investment during the rate period.
  - The plant in service forecast will be based on proposed capital spending levels slated for discussion in the 2022 IPR process.

Next Steps: Segmentation

- The future plant in service will be updated based on IPR capital projections.
- The segmentation study will be updated for the BP-24 Final Proposal to reflect plant placed into service and retirements through FY 2022.

TC-24 Topics

- Attachment C: Short-Term ATC

TC-24 Topic
Attachment C: Short-Term ATC

- Step 1: Introduction and Education
- Step 2: Description of the Issue
- Step 3: Data and/or analysis that supports the issue
- Step 4: Discussions on possible alternatives to solve issue

Introduction and Education

- In the meeting today, Bonneville is discussing our Attachment C for the ATC methodology covering Bonneville's ATC calculations for the 0-13 month horizon
  - Bonneville refers to these calculations as ST ATC
- Bonneville's Attachment C approach for the ATC methodology covering the beyond 13 month horizon, referred to as Long-Term ATC, is being addressed as a separate topic in these workshops

Introduction and Education (cont.)

- The following requirements outline where Transmission Providers (TPs) need to document their ATC and Transmission Reliability Margin (TRM) methodologies:
  - Attachment C, required the by Federal Energy Regulatory Commission (FERC)
  - TRM Implementation Document (TRMID), required by NERC MOD-008
  - ATC Implementation Document (ATCID), required by NERC MOD-001
  - NAESB WEQ-023, mirrors the NERC ATC MOD requirements for a TRMID and ATCID
- Unlike other parts of the tariff, FERC only has pro forma guidance for Attachment C and not specific language
  - This means that not all *jurisdictional* TPs' Attachment Cs are identical, however, are all approved by FERC

Introduction and Education (cont.)

- The pro forma requires TPs to include the following in their Attachment C:
  - Mathematical algorithm used to calculate firm and non-firm ATC for scheduling, operating and planning horizons
  - Process flow diagram that illustrates the steps through which ATC is calculated
  - Explanation of how the ATC components are calculated for the operating and planning horizons
  - For Total Transfer Capability (TTC), definition of TTC, calculation methodology, list of databases used in TTC assessments, and the assumptions used in TTC assessments regarding load levels, generation dispatch, and modeling of planned and contingency outages

Introduction and Education (cont.)

- For Existing Transmission Commitments (ETC), definition of ETC, calculation methodology used to determine the transmission capacity set aside for native load (including network load) and non-OATT customers, how point-to-point transmission service requests are incorporated, how rollover rights are accounted for, processes for ensuring that non-firm capacity is released properly
- For TRM, definition of TRM, calculation methodology (e.g., assumptions on load forecast errors, forecast errors in system topology or distribution factors and loop flow sources), databases used in TRM assessments, and the conditions under which the transmission provider uses TRM
- Explanation of practices for Capacity Benefit Margin (CBM); statement if CBM is not used

Description of the Issue

- Bonneville's current Attachment C is over a decade old
  - Current Attachment C was approved by FERC
  - However, it is outdated and does not correctly reflect Bonneville's current ST ATC methodology
  - It is also high-level, and although Bonneville provides all the ST ATC methodology information required by the pro forma Attachment C, the information is provided in other documents posted on our website rather than in Attachment C itself
- Bonneville sees benefits to making updates to Attachment C in TC-24 as the current document is outdated
- We need to determine the level of detail that is appropriate for our Attachment C

Data and/or Analysis

- Bonneville staff have benchmarked the Attachment Cs and ATCIDs/TRMIDs of other TPs
  - Although there is a range of approaches, other TPs generally include more detail in their Attachment Cs than Bonneville
  - Also, generally speaking, other TPs include less detail in their ATCIDs than Bonneville
  - TRM is not being widely used by the TPs Bonneville benchmarked
  - Bonneville observed that some TPs are breaking out their Attachment Cs into separate sections, one covering their 0-13 month ATC methodology and one covering their beyond 13 month methodology

Possible Alternatives

- Bonneville staff have considered three alternatives for the ST ATC Attachment C within TC-24
- The alternatives are outlined in the following slides, and differ based on:
  - How much content to update in the current Attachment C
  - What level of detail to provide in Attachment C

Alternative #1

- In this alternative, Bonneville would ***not*** update the current Attachment C to align with our current ST ATC methodology
  - Although this does not require any work, Attachment C would remain out of date and out of alignment with Bonneville's ATCID
- Bonneville does not believe this is a viable alternative

Alternative #2

- Under Alternative #2, outdated information in Attachment C would be revised to reflect Bonneville's current ST ATC methodology
- Attachment C would be expanded to include information on TTC, ETC and TRM calculations that are not updated regularly, such as the ATC formulas, TTC and ETC definitions, and process flow diagram
  - Adding this information to Attachment C would bring Bonneville more in line with pro forma

Alternative #2 (cont.)

- Bonneville would continue to provide all the information required by the pro forma Attachment C
  - Attachment C would continue to direct customers to Bonneville's TRMID and ATCID for details on Bonneville's TTC, ATC and TRM methodologies (such as load and generation assumptions)
  - Bonneville has an established process for customer engagement on our ST ATC methodology and would continue to use this process for any future ST ATC methodology changes being considered by Bonneville

Alternative #3

- Under Alternative #3, Bonneville would have a fully updated and pro forma Attachment C
  - Outdated information in Attachment C would be revised to reflect Bonneville's current ST ATC methodology
  - Attachment C would include detailed information on Bonneville's TTC, ETC and TRM calculations, including such details as load and generation assumptions used in the studies
  - BPA would continue to maintain ATCID and TRMID, as required by other regulatory requirements

Alternative #3 (cont.)

- Including details of the ATC, TTC and ETC methodologies in Attachment C has several limitations for the region
  - Decreases region's flexibility to change Bonneville's ST ATC and TRM methodologies, as changes would require a Tariff proceeding
    - This limits Bonneville's ability to have an accurate and up to date ST ATC methodology
    - Posting too much ST ATC due to inaccuracies in the methodology can result in overselling when the capacity is not there. Conversely, not making capacity available to customers when it's actually there impedes the market. Both outcomes are detrimental.
    - Bonneville can most nimbly achieve ST ATC accuracy by making improvements as they're identified, without the time needed for a tariff proceeding

Alternative #3 (cont.)

- Could negatively impact reliability needs
  - Example: Bonneville staff recognizes the need for TRM on a path and Bonneville has to go through a tariff proceeding before one can be implemented to allow for TRM methodology to be included in Attachment C
  - Makes it harder to stay compliant with NERC standards, as the timeline for running a tariff proceeding could be in conflict with timelines for updating documentation related to TTC methodologies

Staff Leaning on Alternatives

- Staff leans towards Alternative #2
  - Brings Attachment C up to date
  - Brings Attachment C more in line with FERC pro forma
  - Allows Bonneville to engage with customers using existing processes for portions of the ST ATC Methodology that require more frequent changes than is practical for a Tariff proceeding
- We want to hear leanings from customers on this issue

Next Steps: Attachment C

- Bonneville would like feedback on this issue
- Please send your comments and thoughts to techforum@bpa.gov with a copy to your Account Executive
- Comments are due by June 8th, 2022
- Bonneville will review comments as we draft the ST ATC portion of Attachment C
- We will be presenting the draft Attachment C at the August workshop on this topic

Next Steps: BP/TC-24

- **Wednesday, June 1**
  - Deadline for requests for June 8 customer-led workshop, including specific topics and amount of time.
- **Wednesday, June 8**
  - Deadline for feedback and comments on May 25 materials. Please submit feedback and comments to techforum@bpa.gov, with a cc to your Power and/or Transmission Account Executive.
- **June 29 & 30**
  - Next BP/TC-24 workshops

Appendix

Customer Led Workshops

- Within one week after every workshop, customers can request a Customer Led workshop that would focus on topics presented in the previous workshop.
- Customers should provide the topic and estimated time needed for discussion with BPA SMEs.
- BPA will not create new content – this is an opportunity to ask further questions on materials previously presented.
- Opportunities for customers to present on topics of interest, where BPA will be in listening mode.

BP-24 & TC-24 Workshops: Proposed Dates for Rate and Tariff Topics

Date	Rate/Tariff Topics
April 27 (Wed)	**Generation Inputs** • Operating Reserves with Western Power Pool (WPP) **Tariff** • Attachment C: Long-Term ATC (steps 1-5) • Conditional Reservation Deadline for Daily Firm PTP (all steps)
May 25 (Wed)	**Power Rates/Generation Inputs** • EIM Benefits in Power Rates • EIM Impact on Balancing Services Cost • Customer concerns regarding EIM and Generation Inputs **Transmission Rates** • EIM Charge Code Allocation • Segmentation Study **Tariff** • Attachment C: Short-Term ATC (steps 1-4)
June 7 (Tues)	• *RHWM Process Workshop*

BP-24 & TC-24 Workshops: Proposed Dates for Rate and Tariff Topics (cont.)

Date	Rate/Tariff Topics
Jun 14-16	• *IPR (pre-rate case process)*

Jun 29-30
(Wed-Thu)
	Power Rates
	• EIM Benefits in Power Rates
	• Unauthorized Increase (UAI) Charge
	• Tier 2 Rates
	Transmission Rates
	• Eastern Intertie Process Update (BP-22 Settlement Commitment)
	Generation Inputs
	• EIM Impact on Balancing Services Cost
	• Load Reliability Service
	• Losses
	    • Power's Capacity cost of providing losses (if needed)
	    • Cost Recovery of Losses
	Tariff
	• Attachment C: Long-Term ATC (steps 4-5)
	• Generator Interconnection Process (steps 1-4)
	• Utility and DSI Delivery Losses (all steps)
	• Monthly Loss Factors on the Network Segment (all steps)

BP-24 & TC-24 Workshops: Proposed Dates for Rate and Tariff Topics (cont.)

Date	Rate/Tariff Topics
Jul 27-28 (Wed-Thu)	**Agency (P&T)** • Revenue Requirements • Risk **Power Rates** • UAI and Tier 2 follow-up (if needed) • Transfer Service • Washington Cap-and-Invest Program **Transmission Rates** • Sales Forecast (includes LGIA Forecast and Load Forecast) **Generation Inputs** • Persistent Deviation/ Intentional Deviation Review • VERBS, DERBS, and Load Balancing Services (BP-22 Settlement commitment) **Tariff** • Attachment C: Short-Term ATC (steps 5-6) • EIM Resource Sufficiency (inform) • Order 881: Transmission Line Ratings (inform)

BP-24 & TC-24 Workshops: Proposed Dates for Rate and Tariff Topics (cont.)

Date	Rate/Tariff Topics

Aug 24-25 (Wed-Thu)	**Power Rates**
	• Loads & Resources
	• Gas & Market Price Forecast
	• Secondary Revenue Forecast
	Transmission Rates
	• EIM Charge Code Allocation
	Generation Inputs
	• Losses
	  • Power's Capacity cost of providing losses (if needed)
	  • Cost Recovery of Losses
	• Load Reliability Service
	Tariff
	• Attachment C: Long-Term ATC (steps 5-6)
	• Generator Interconnection Process (steps 5-6)
	• Proposed Draft Tariff (redline), including miscellaneous clean-up

Sept 28 (Wed)	Workshop Close-out and Summary of Staff Leanings

Meeting topics and workshop dates are subject to change. Please check the BPA Event Calendar for the most up-to-date information.

Proposed Procedural Schedules

	BP-24	TC-24
Federal Register Published (estimated)	Nov 10	Nov 10
Pre-Hearing Conference/BPA Direct Case	Nov 17	Nov 17
Clarification of BPA's Direct Case	Dec 7-8	Dec 6
Parties File Direct Cases	Jan 24	Jan 20
Litigants File Rebuttal	Mar 7	Mar 1
Cross Examination	Apr 6-7	Mar 23-24
Initial Briefs	Apr 25	April 13
Hearing Officer's Recommendation	n/a	May 23
Draft ROD	Jun 13	Jun 23
Briefs on Exceptions	Jun 27	Jul 7
Final ROD	Jul 26	Jul 26

Preliminary proposal subject to change.