TC-22, BP-22 and EIM Phase III Customer Workshop

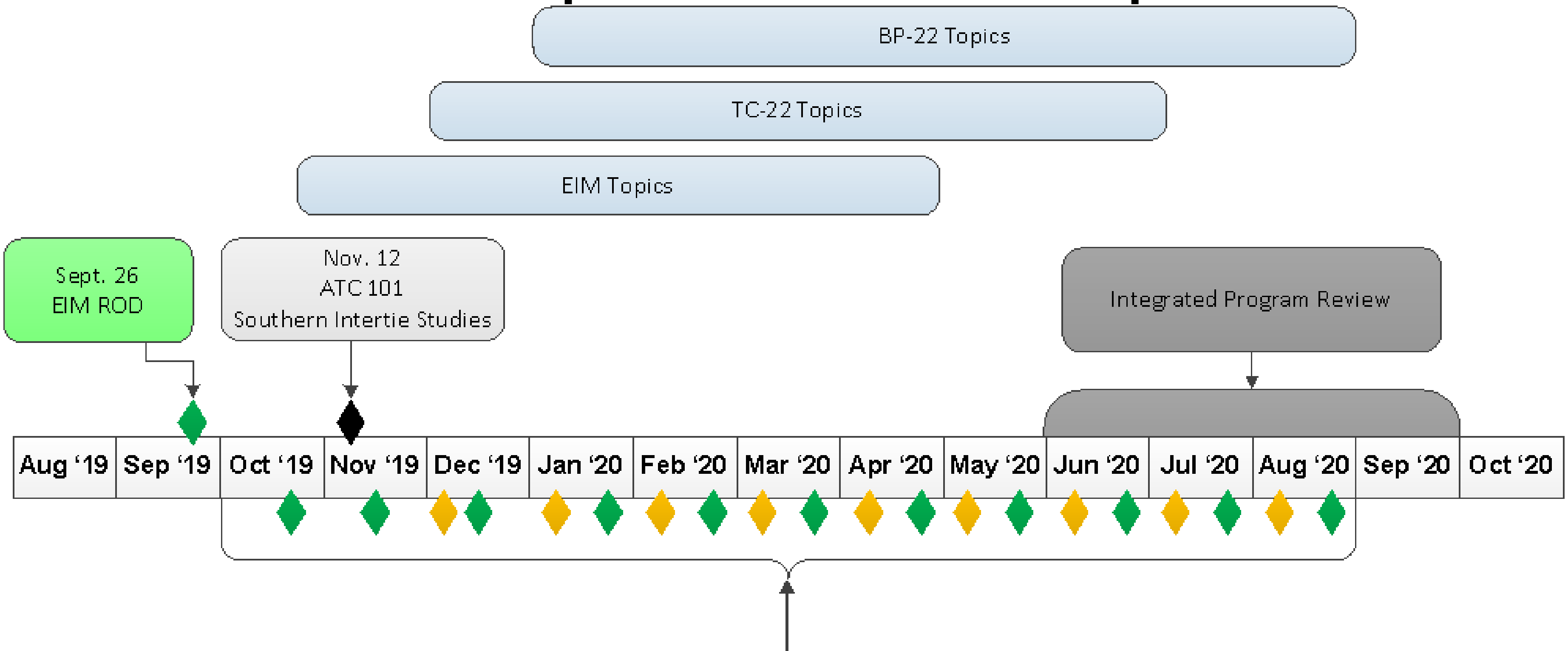
December 12, 2019

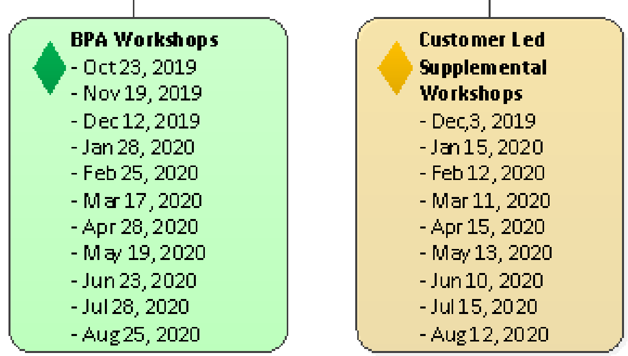
Agenda

TIME	TOPIC	Presenter
9:30 to 9:40 a.m.	Agenda Review, Prior Workshop Feedback & Safety	Rebecca Fredrickson Rachel Dibble
9:40 to 10:45 a.m.	Transmission Losses	Mike Bausch Katie Sheckells Doug Johnson Andy Meyers
10:45 to 11:00 a.m.	BREAK	
11:00 to 12:00 p.m.	EIM Losses	Todd Kocheiser
12:00 pm to 1:00 pm	LUNCH	
1:00 to 2:00 p.m.	EIM Charge Code Allocation	Miranda McGraw Derrick Pleger
2:00 to 3:30 pm	TC-20 Settlement Update • Short Term ATC • Hourly Firm	Katie Sheckells Kevin Johnson Margaret Olczak

Agenda Review and Feedback from Prior Workshop

BP/TC-22 Proposed Workshop Timeline





Just as a reminder: The Customer led workshops are reserved for customer collaboration or time that could be used to receive clarification on BPA workshop materials.

Engaging the Region on Issues

- After every workshop, BPA will provide a two-week feedback period for customers.
  - Input can be submitted via email to techforum@bpa.gov. Please copy your Power or Transmission Account Executive on your email.
- 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 2: Description of the Issue	Step 3: Analyze the Issue Step 4: Discuss Alternatives	Step 5: Discuss Customer Feedback Step 6: Staff Proposal

EIM Priority Issues

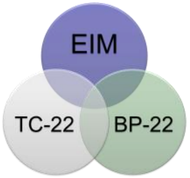
EIM
TC-22
BP-22

#	Issue	BP-22	TC-22	Future BP/TC
1	EIM Charge Code Allocation	X	?	X
2	EIM Losses	X	X	?
3	Resource Sufficiency	X	X	?
3a	- Balancing Area Obligations	X	X	?
3b	- LSE Performance & Obligations	X	X	?
3c	- Gen Input Impacts	X	X	?
4	Development of EIM Tariff Changes		X	?
5	Transmission Usage for Network	X	X	?
6	Non-federal Resource Participation	X	X	?
7	Metering & Data Requirements		X	?
8	Evaluation of Operational Controls	X	X	?

Rates & Tariff Topics

#	Topics	BP-22	TC-22	Future BP/TC
9	Transmission Losses	X	X	
10	Ancillary Services	X		?
11	Debt Management (Revenue Financing)	X		
12	Generator Interconnection		X	
13	Regional Planning		X	
14	Creditworthiness		X	
15	Incremental/Minor Changes to Agreement Templates		X	
16	Seller’s Choice		X	
17	Loads	X		
18	Sales	X		
19	Generator Interconnection (assumed for BP-22)	X		
20	Risk	X		
21	Revenue Requirements	X		
22	Review of Segments	X		
23	Review of Sale of Facilities	X		
24	Financial Leverage Policy Implementation	X		
25	Power-Only issues	X		

Potential Future Rates & Tariff Issues



#	Issue	BP-22	TC-22	Future BP/TC
26	Simultaneous Submission Window			**?**
27	Study Process			**?**
28	Attachment C (Short-term & Long-term ATC)			**?**
29	Hourly Firm (TC-20 Settlement – Attachment 1: section 2.c.ii)			**?**
30	Required Undesignation			**?**
31	Reservation window for Hourly non-firm			**?**
32	Non-federal NT Redispatch			**?**
33	PTP/NT Agreement Templates			**?**

Feedback Summary

Themes	BPA's Response: Updated 12/12
Provide a detailed summary timeline with topics for each workshop	We will keep an agile schedule and adjust as we hear feedback from customers.
Customers concurred with BPA's proposal for engagement for certain topics	No change
Customers want early discussions on the following topics: • Transmission Usage • Creditworthiness • EIM Metering and Data Requirements • EIM Non Federal Resources	Based on customer feedback, we have started discussion on the identified topics from customers in Jan. and Feb. This is reflected in the schedule on the Meetings and Workshops page
Provide customers information on where/if there will be changes for Rate Case topics	We recognize rates have dependencies on EIM policy topic decisions and we will stay coordinated with the topics. We also recognize their dependencies on charge code, gen inputs and Priority Firm Load; therefore, we will begin these discussions in Dec. and Jan.
Provide an explanation of why the proposed future tariff topics are not part of TC-22	The future deferred tariff topics are due to possible changes in industry standards and developing markets. As we discussed in the Oct. 23 workshop, we are focusing on EIM for this proceeding.
Identify early in steps 1 & 2 where there are dependencies for other topics	We will identify the steps and to the extent we know the dependencies, will include them.
Provide a crosswalk of the Tariff issues from TC-20 to TC-22	Please see appendix at workshop in Nov. 19.

Feedback Summary (cont.)

Themes	BPA's Response: Updated 12/12
EDAM impact on rates and tariff	EDAM policy is out of scope in the rates and tariff. Customers have the ability to participate directly in the CAISO's EDAM policy initiative process. Bonneville's evaluation of whether and how to join EDAM is anticipated to be another decision process – much like EIM – including the development of principles for our evaluation. We also anticipate that process would then be followed by rates and tariff cases.
Green House accounting	Green house gas accounting is out of scope in the rates and tariff process. The policy was discussed in the following workshop: https://www.bpa.gov/Projects/Initiatives/EIM/Doc/20190312-March-13-2019-EIM-Stakeholder-Mtg.pdf
EIM governance	EIM governance is out of scope in the rates and tariff process. Customers have the ability to participate in CAISO's governance review process.
Leverage customer led workshops to share experiences and challenges	We worked with other participants to get a better understanding of their experiences and challenges. We also agree the monthly customer led workshops are an excellent forum to share experiences and challenges with other customers.
Carry larger ancillary services reserves	This will be addressed in the Gen Inputs discussion.
More discussion is needed on steps 1 & 2 for resource sufficiency. Customers provided several questions to gain a better understanding.	We will look at the schedule and update it to address these questions.

Feedback Summary (cont.)

Themes	BPA's Response: Updated 12/12
Develop a roadmap of how future deferred tariff topics are addressed.	The future deferred tariff topics are due to possible changes in industry standards and developing markets. We don't have roadmaps at this time. We would look to develop roadmaps after the conclusion of TC-22 if warranted.
Regional Planning Organization may have a couple of options	This will be addressed in steps 3-6 of the RPO discussion.
Oversupply discussion and if it is needed in EIM	As noted in the EIM discussions at https://www.bpa.gov/Projects/Initiatives/EIM/Doc/20190312-March-13-2019-EIM-Stakeholder-Mtg.pdf BPA believes OMP is compatible with EIM. As we gain experience with EIM operations, we will continue to evaluate implementation and consider any potential changes in future tariff cases.

Transmission Losses #9

Step 1: Introduction and Education
Step 2: Description of the Issue
Step 3: Data and/or Analysis that Supports the Issue

Agenda

- Introduction and education (Step 1)
- Description of the issue (Step 2)
- Data and/or analysis that supports the issue (Step 3)
  - Value
  - Actual vs Expected Returns
  - Administrative Burden

Objective

- Update the BPA process for the provision and settling of losses which captures the value of capacity and energy used to provide losses and minimizes load uncertainty, the administrative burden of system administration, maintenance, and reconciliation of deviations

Current Loss Energy Return Options

BPA provides customers with three methods for returning their loss energy obligations to BPA:

- In-Kind (168 Hours later) – 88.77%
- Financial Settlement – 0.82%
- Slice – 10.41%

*Percentage breakdown of MW Obligations year to date 2019.

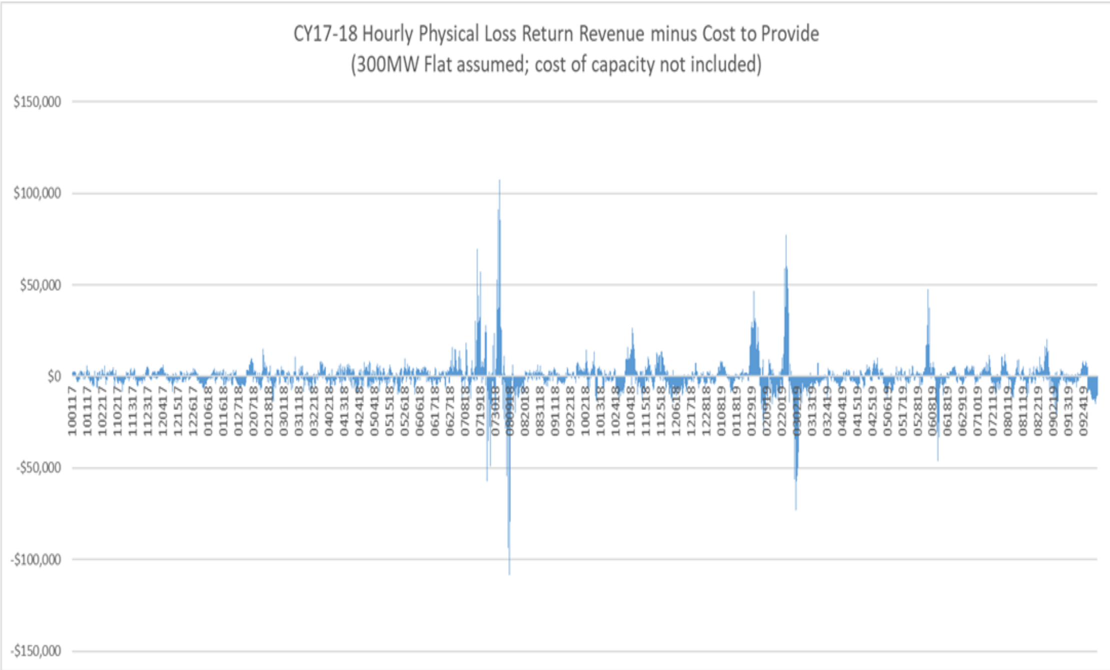
In-Kind Challenges

In-Kind is the most challenging option due to:

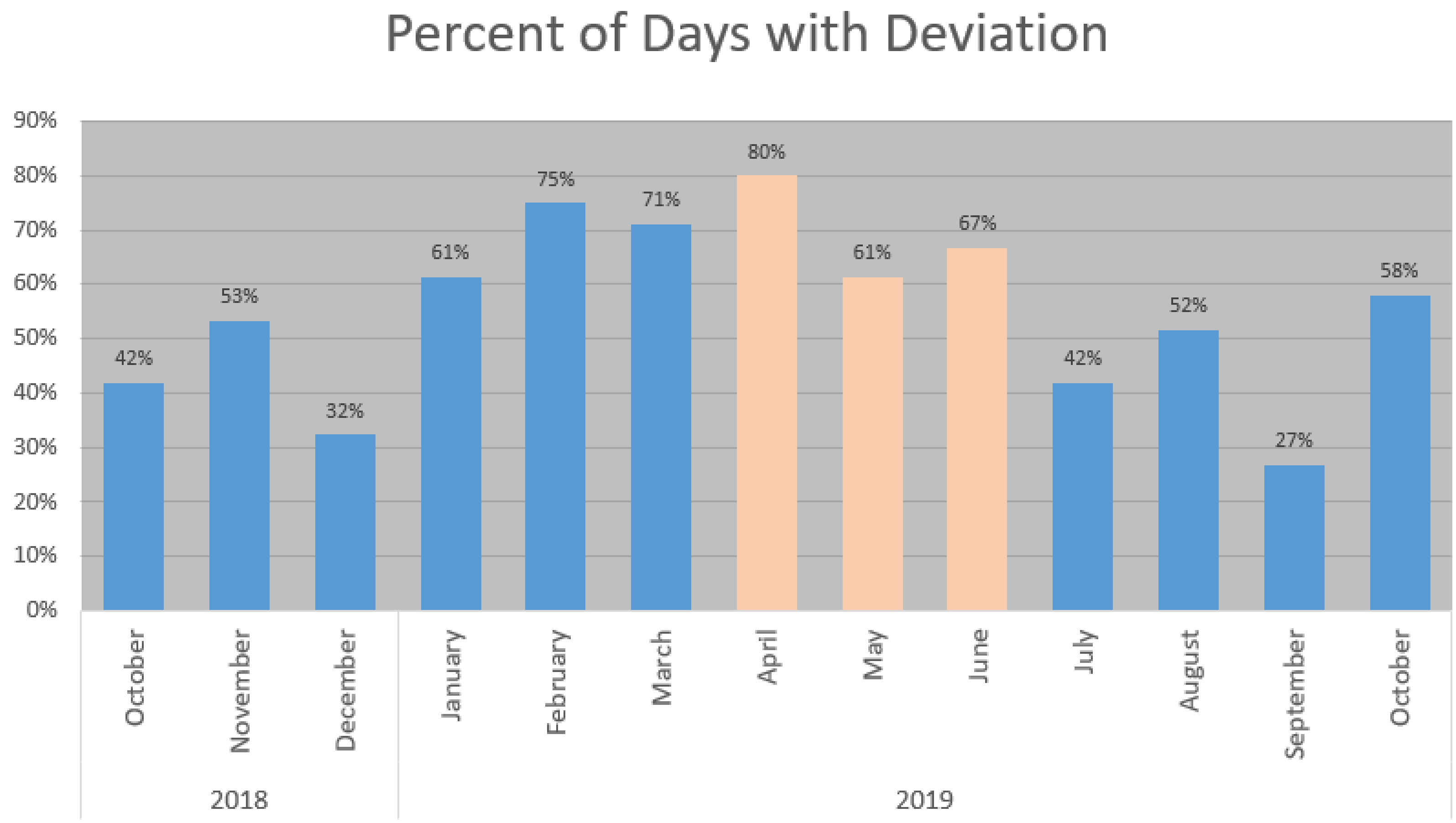
- **Value**: In-kind replacement of losses results in mismatches in value between the time the losses occur and the time the energy is returned 168 hours later.
- **Actual vs. expected returns**: BPA receives losses from the parties where parties do not schedule the entire loss obligation or schedule the incorrect amounts of losses
- **Administrative Burden**: Current process requires significant FTE time to manage routine daily processes and system maintenance. Losses app requires a monthly maintenance fee.

Value: Physical Loss Returns Compensation

- Returning physical losses at t+168 hours results in roughly neutral energy-related revenue for the loss provider
  - Assuming flat MW quantities
  - Energy values fluctuate but generally equalize over time
- The loss provider (Power Services) is not compensated for holding out capacity necessary to provide losses.



Actual vs Expected Returns



April, May, June monthly totals including losses waived by Power Services during over supply season.

Actual vs Expected Returns

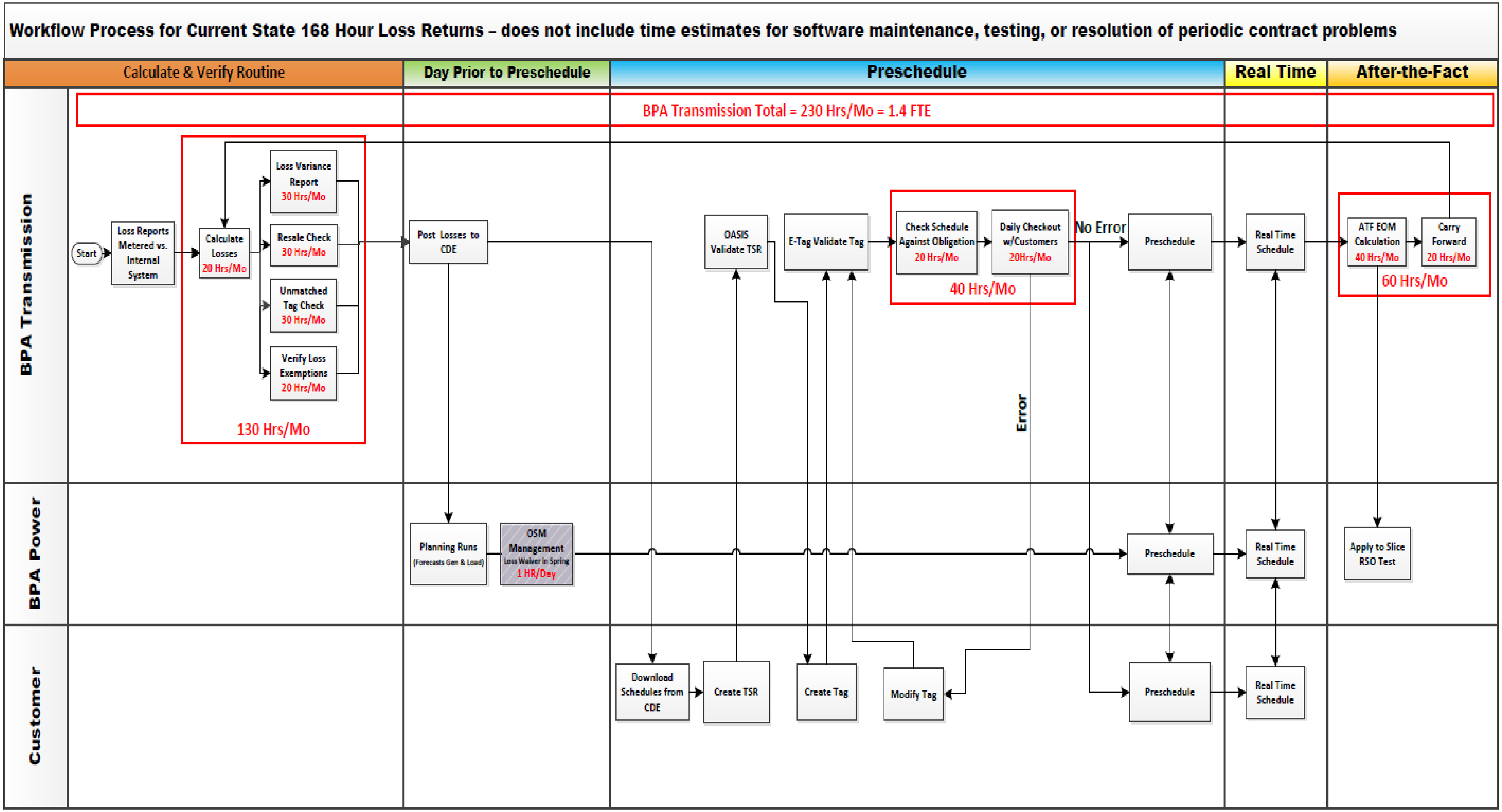
Year:	Month:	Total Obligation MWh	Return Total MWh	MWh Difference	Days Reviewed	Days With Difference	Percent of Days with Deviation
	October	200,010	199,770	240	31	13	42%
	November	187,305	186,896	409	30	16	53%
2018	December	218,803	218,869	-66	31	10	32%
	January	246,744	246,674	70	31	19	61%
	February	194,324	194,132	192	28	21	75%
	March	213,126	213,028	98	31	22	71%
	April	207,187	206,656	531	30	24	80%
	May	225,901	212,846	13,055	31	19	61%
	June	235,718	235,478	240	30	20	67%
	July	259,763	259,605	158	31	13	42%
	August	275,905	275,564	341	31	16	52%
	September	266,291	266,053	238	30	8	27%
2019	October	207,522	207,312	210	31	18	58%

Monthly totals including losses waived by Power Services during over supply season.

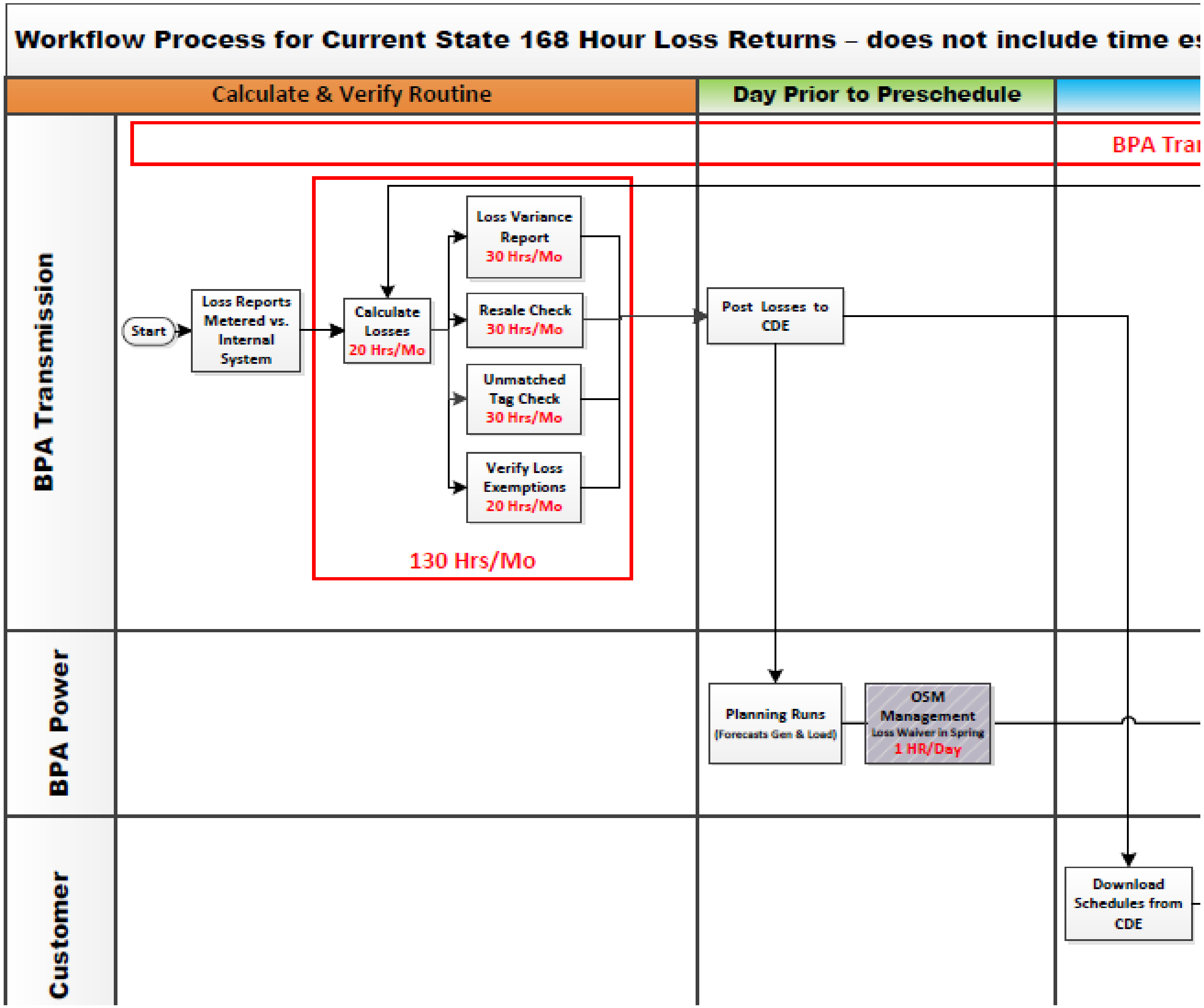
Administrative Burden

- Current State Daily Process - ~1.4 FTE
  - Calculation Review
  - Obligations vs Actuals
  - Checkout & Carry Forward
- Software
  - Recurring maintenance of customized loss module
  - Application Regression Testing
- Management and resolution
  - Issues around changes in loss return elections
  - Uncollected/unreturned loss obligations

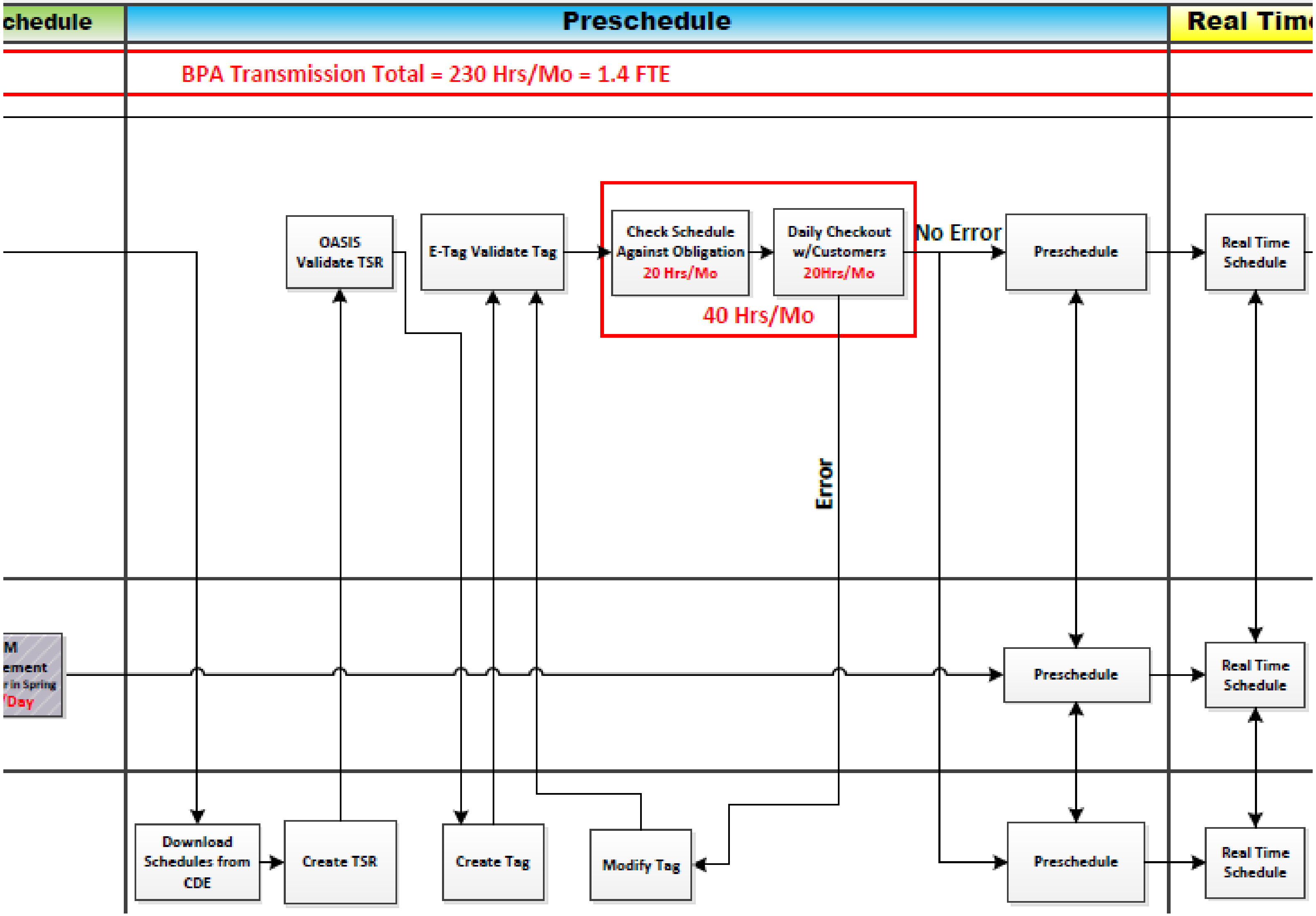
Administrative Burden



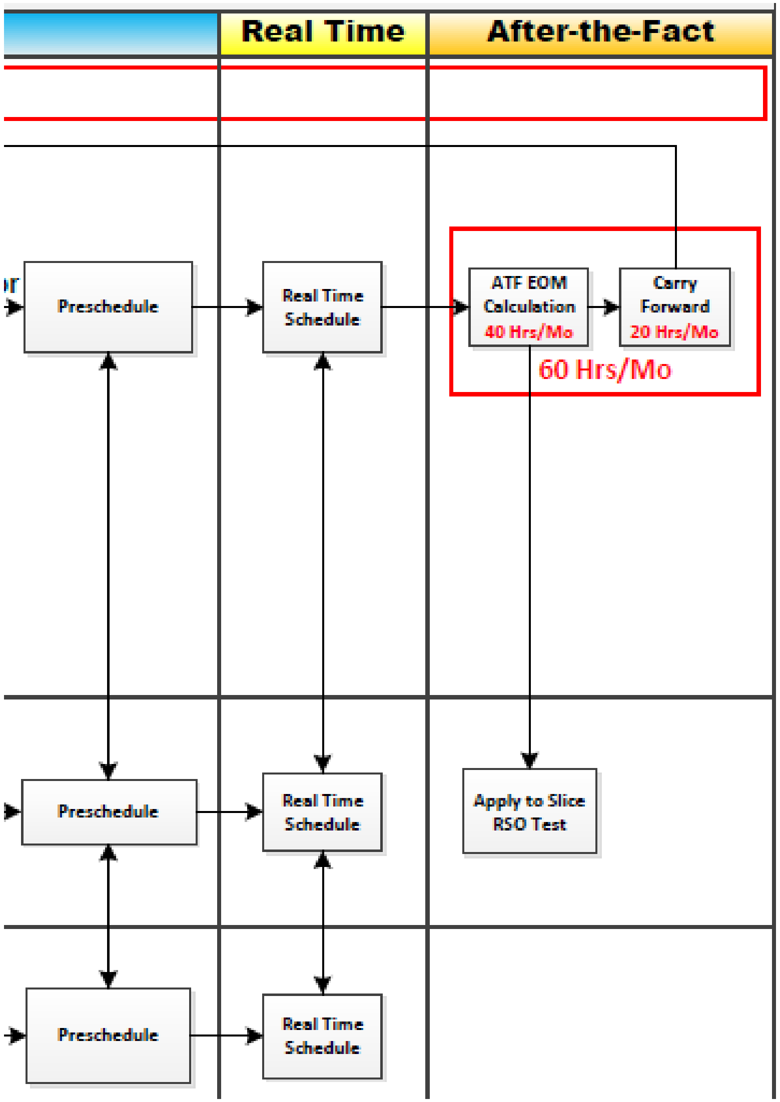
Administrative Burden



Administrative Burden



Administrative Burden



Software Maintenance/Testing

- FTE impacts not included on process diagram
  - App is prone to errors/software variances
  - App needs testing during monthly software upgrades even when not included.
- Financial
  - Monthly maintenance fee

Uncollected Obligations

- BPA engages customers when physical losses are not returned on time – this can be the result of:

  - A customer allowing its loss return agreement to lapse after repeated attempts from BPA to renew;
  - A PTP agreement expiring before a replacement agreement can be signed for a contract to be in place to bill losses against;
  - A generator returning losses in-kind ceases operation before an "in-kind" loss obligation is satisfied.

Consequences

- BPA Transmission AEs work with the BPA Power Services Trading Floor to make alternate arrangements to make BPA whole.
- Trading Floor performs a “lookback” to calculate the financial value of the losses.
- BPA Transmission AE executes a Letter Agreement allowing for the one-time financial settlement of losses.
- Customer is billed for losses.
- This process is labor intensive and takes all involved off task for a one-off solution.
  - In the last calendar, year we have had multiple instances which have required review, analysis and resolution.
  - These issues arise each year.

EIM Losses #2

Step 1: Introduction and Education

Objective

- Inform BPA stakeholders of how losses are handled in the EIM
- Identify EIM charge codes that are impacted by losses
- Determine Bonneville's current practices regarding transmission losses

  "Bonneville will discuss with stakeholders the extent to which the EIM's handling of losses should lead to changes in Bonneville's current practices regarding transmission losses, or what new opportunities are available for more efficient repayment of losses. This may include the potential for moving to a practice which losses are only settled financially instead of a physical repayment. Decision in this process will likely influence and/or be memorialized in the BP-22 and TC_22 cases." (Excerpt from ROD)

Transmission vs. EIM Losses

- **Transmission Losses:** Losses produced by the use of the FCRTS and recovered based on scheduled demand
- **EIM Losses:** A mechanism to account for and ensure that 1) the total Balancing Authority Area (BAA) losses have been planned and provided for prior to each hour and 2) that the impact of the EIM market awards/dispatches on losses are taken into considering in the market solution and Locational Marginal Prices (LMP)

EIM Base Losses

- In the EIM, each participating Balancing Authority Area (BAA) is expected to submit hourly base schedules for resources and interchange to meet the expected demand forecast *(a.k.a. load forecast)* of the BAA
- The demand forecast for the BAA includes load and losses
- Similar to today, the majority of BAA losses (i.e., base losses) are planned for and supplied prior to the hour as part of the base scheduling activity

EIM Incremental Losses

- The Locational Marginal Prices (LMP) produced by the EIM include the Marginal Cost of Losses (MLC) at each pricing node, relative to the cost of providing energy to the weighted/distributed load reference bus
- As such, as the market is running, it is taking into consideration the cost of marginal (incremental) losses at each LMP node in its optimization

EIM Load Base Schedule

- For settlement of load imbalance, an hourly Load Base Schedule (LBS) is calculated by the market

LBS = Sum(GENbase) – Sum(INTbase) – Demand Forecast * Loss%

Where:

- **GENbase:** Generation Base Schedules
- **INTbase:** Interchange Base Schedules
- **Loss%:** Provided by each EIM Entity for their BAA - can be a static value or a lookup table that contains different values for hour of day and day of week

EIM Load Meter

- A Load Meter (LM) for the BAA must be submitted by the EIM Entity (EESC) ATF
- A “top down” approach is generally used

LM = Sum(GEN$_{\text{meter}}$) – Sum(INTmeter) – Losses

Where:

- **GENmeter:** Generator/Resource meter
- **INTmeter:** Interchange meter
- **Losses:** Typically calculated using the same loss% that was used when establishing the Load Base Schedule (LBS)

Uninstructed Imbalance Energy (UIE)

- Uninstructed Imbalance Energy (CC64750) for Load is calculated as follows:

UIEload = LBS – LM ← Hourly Settlement

- Hourly Load Aggregation Point (LAP) LMP is used for load UIE settlement
- If the same loss% is used for both the LBS calculation and the LM submittal, it should help minimize the UIE for load charges and allow them to be more easily shadowed

Unaccounted for Energy (UFE)

- Unaccounted for Energy (CC64740) uses the hourly LAP LMP and is calculated as follows:

$$\mathbf{UFE = Sum(GEN_{meter}) - Sum(INT_{meter}) - LM - NALosses}$$

- NALosses: actual losses calculated using an AC Power Flow (ACPF) from the EIM's Network Analysis application
- Differences between the loss% used in the LBS and LM calculations and actual losses (via ACPF) will be captured in UFE.

Real-Time Marginal Losses Offset

- Marginal Loss Charges are implicitly collected by the CAISO in the Real-Time settlement
- There are no holders of rights to receive Real-Time Marginal Loss revenues so they are accumulated in special and separate BAA neutrality accounts
- Allocated to the associated EESC of an EIM BAA in Real Time Marginal Losses Offset (CC 69850)

* The product of (1) the contribution of that BAA's Transmission Constraints to the marginal Loss component of the LMP at each resource location in the EIM Area and (2) the imbalance energy at that resource location

Imbalance Energy Offset(RTIEO)

- Real-Time Imbalance Energy Offset (CC64770) is intended to help ensure that the EESC is revenue neutral
- RTIEO: If the Sum(IIE, UIE, UFE, GHG) less Congestion and Losses does not = $0, charges or payments will be made to the EESC
- Large errors in UIEload or UFE will ultimately be reconciled for in 64770
- The financial value of EIM Transfers is also included in RTIEO, unless an EIM Entity has chosen to settle ETSRs through the market

EIM Losses Summary

- The EIM does not provide system or BAA losses, but takes them into consideration when ensuring each BAA is balanced prior to the hour
- The EIM also takes into consideration marginal (a.k.a. incremental) losses that result from market awards and dispatches
- Losses are embedded in load UIE, UFE, and RTIEO
- Bonneville will need to determine how it calculates the loss percentages used by the EIM

Next Steps

- Feedback on Transmission and EIM Losses
  - Please submit to techforum@bpa.gov (with copy to your account executive)
  - Comments will close Jan. 3, 2020
- Transmission Losses:
  - Step 4: Discussion of Alternatives March 17th customer workshop
  - BPA plans to evaluate methodology for calculating Loss percentage this spring and incorporate into decision making
- EIM Losses
  - Steps 2-4: Issue, Analysis and Alternatives March 17th customer workshop

EIM Charge Code Allocation #1

Step 1: Introduction and Education

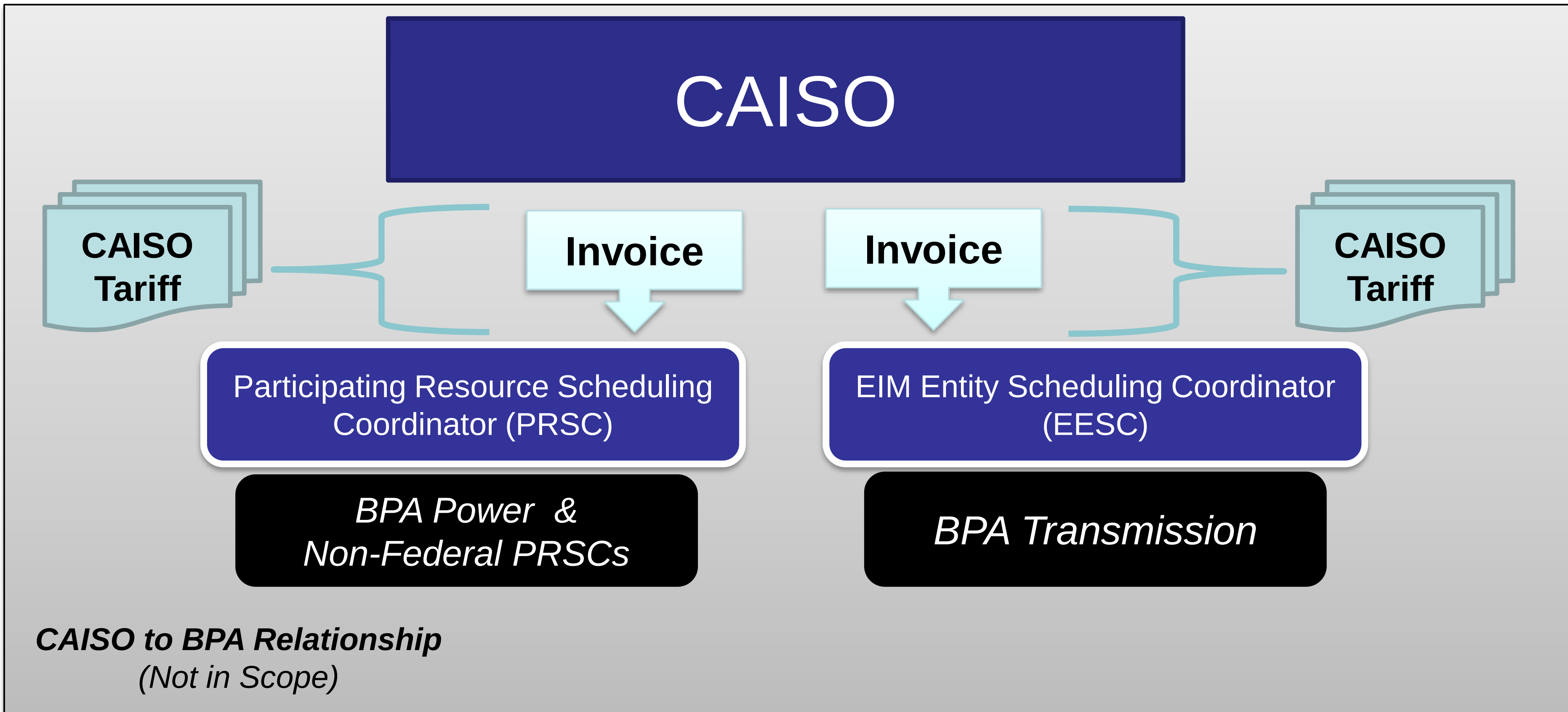
Step 2: Description of the Issue

Objective

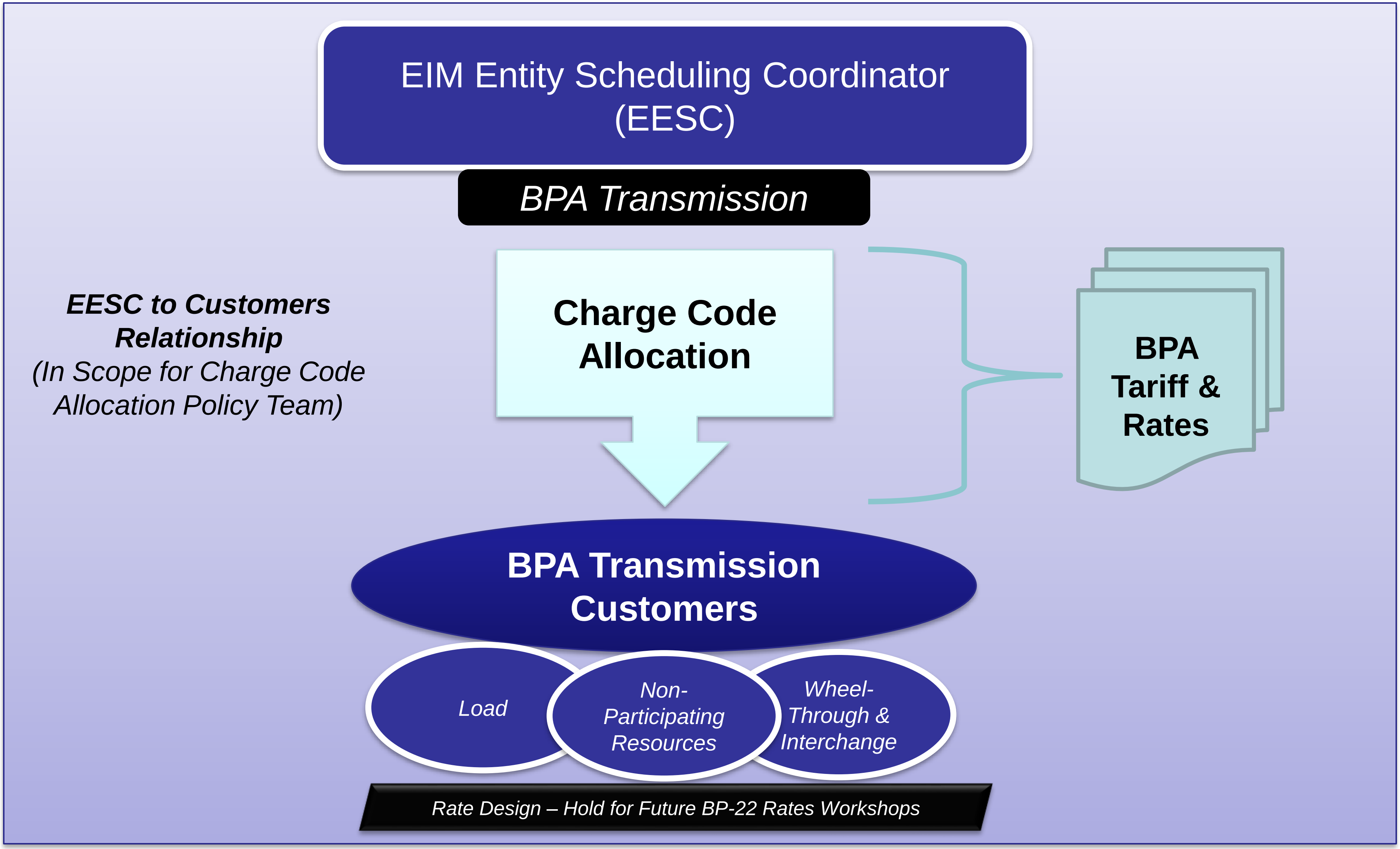
- Address charge code allocation policy issues to determine the approach Bonneville should adopt to recover its costs (or distribute credits) for charge codes it receives as an EIM Entity.

Note: Settlement mechanics (e.g. frequency or type of BPA customer billing) will be addressed separately in future workshops, if there is a sub-allocation methodology adopted.

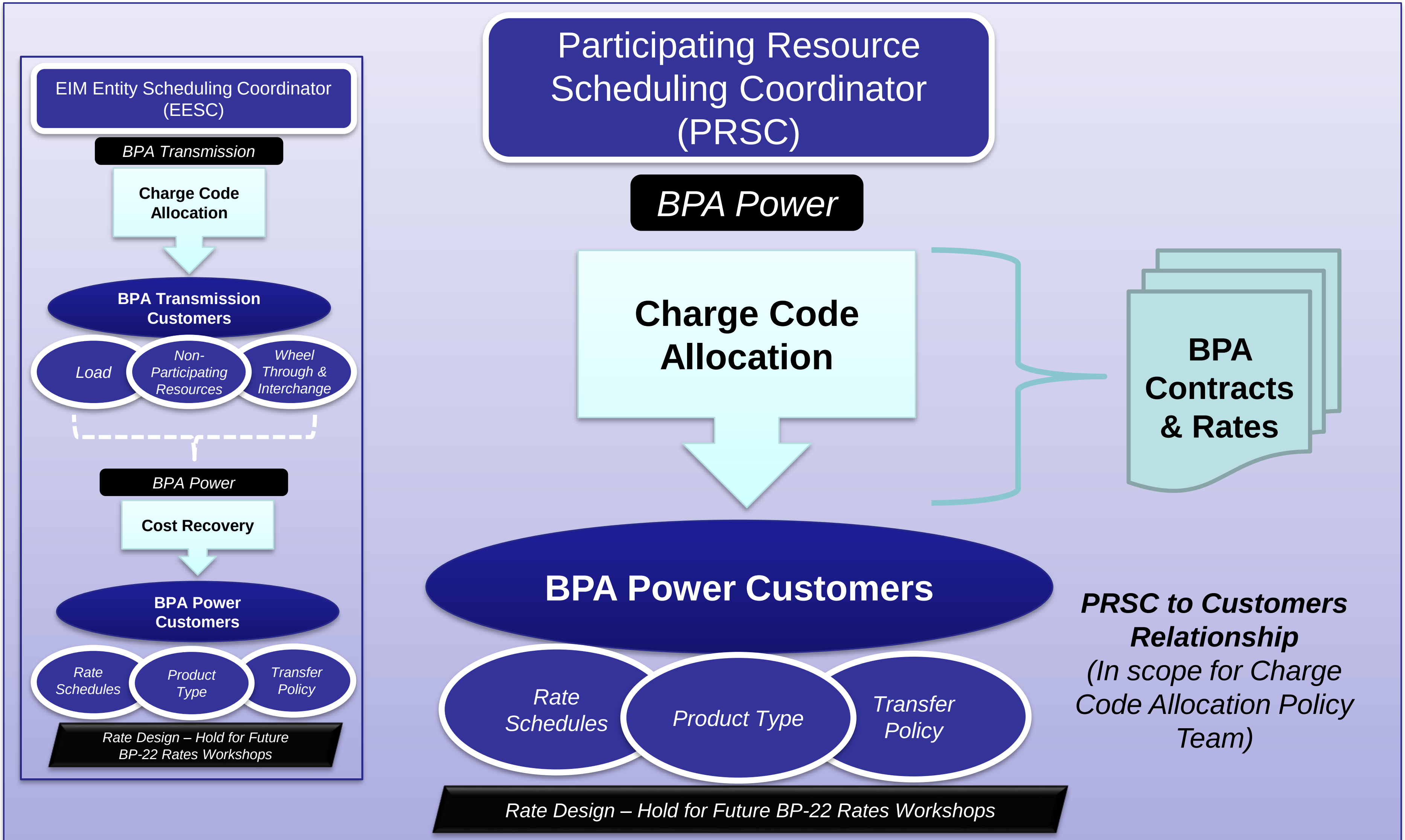
Organizational Relationships: CAISO



Organizational Relationships: EESC



Organizational Relationships: PRSC



CAISO Settlement Process Consideration

- Direct sub-allocation of EIM Charge Codes to customers would indirectly expose customers to CAISO Settlement process.
- CAISO Settlement Process is Complex and Administratively Burdensome
  - CAISO bills weekly; re-calculates Charge Codes multiple times for up to 3 years.
  - Disputes over sub-allocated EIM Charge Codes would have to be submitted to Bonneville; could lead to Bonneville bringing customer dispute to CAISO.

Bonneville is still considering settlement mechanics, which will be addressed in a future workshop. While developing the charge code allocation methodology, there is awareness that if a sub-allocation methodology is adopted, it could have broad administrative impacts on customers' and Bonneville's billing.

CAISO Charge Code Overview

Primary Charges

- Imbalance Energy
  - Instructed
  - Uninstructed
- Ancillary Services

Penalty Charges

- Over Scheduling
- Under Scheduling

Market Clearing / Neutrality / Cost Recovery

- Real-Time Energy Offsets
- Congestion Offsets
- Bid Cost Recovery

Administrative

- Grid Management
- Forecasting Service Fee
- Administrative Penalties

The following slides provide lists of the charge codes by category for context. The charge code lists contain information on Bonneville's experience with other EIM entities as examples to illustrate the range and volatility that can exist. Examples of Bonneville's experience focused on the largest EIM balancing authorities that Bonneville has load in.

CAISO EIM Charge Code List

Primary Imbalance Charges

CC #	Charge Code Name	CAISO > EIM Entity Allocation		EIM Entity Sub Allocation	PacifiCorp		Idaho Power		NV Energy	
					BPA Peak Load 400+		BPA Peak Load 300+		BPA Peak Load 100<>	
					Monthly		Monthly		Monthly	
					Min Charge	Max Charge	Min Charge	Max Charge	Min Charge	Max Charge
64600	FMM Instructed Imbalance Energy EIM Settlement	EESC	PRSC	Yes	Varies	Varies	Varies	Varies	Varies	Varies
64700	Real Time Instructed Imbalance Energy EIM Settlement	EESC	PRSC	Yes	Varies	Varies	Varies	Varies	Varies	Varies
64750	Real Time Uninstructed Imbalance Energy EIM Settlement	EESC		Yes	Varies	Varies	Varies	Varies	Varies	Varies
64740	Real Time Unaccounted for Energy EIM Settlement	EESC		No						

Primary Ancillary Service Charges

CC #	Charge Code Name	CAISO > EIM Entity Allocation		EIM Entity Sub Allocation	PacifiCorp		Idaho Power		NV Energy	
					BPA Peak Load 400+		BPA Peak Load 300+		BPA Peak Load 100<>	
					Monthly		Monthly		Monthly	
					Min Charge	Max Charge	Min Charge	Max Charge	Min Charge	Max Charge
7070	Flexible Ramp Forecast Movement Settlement	EESC	PRSC	Yes						
7071	Daily Flexible Ramp Up Uncertainty Capacity Settlement		PRSC	No						
7076	Flexible Ramp Forecast Movement Allocation	EESC		Yes						
7077	Daily Flexible Ramp Up Uncertainty Award Allocation	EESC	PRSC	Yes	(950)	56,701	(1,064)	5,995	(24,740)	13,918
7078	Monthly Flexible Ramp Up Uncertainty Award Allocation	EESC	PRSC	Yes						
7081	Daily Flexible Ramp Down Uncertainty Capacity Settlement		PRSC	No						
7087	Daily Flexible Ramp Down Uncertainty Award Allocation	EESC	PRSC	Yes						
7088	Monthly Flexible Ramp Down Uncertainty Award Allocation	EESC	PRSC	Yes						

CAISO EIM Charge Code List

Market Clearing / Neutrality / Cost Recovery Charges

CC #	Charge Code Name	CAISO > EIM Entity Allocation		EIM Entity Sub Allocation	PacifiCorp		Idaho Power		NV Energy	
					BPA Peak Load 400+		BPA Peak Load 300+		BPA Peak Load 100<>	
					Monthly		Monthly		Monthly	
					Min Charge	Max Charge	Min Charge	Max Charge	Min Charge	Max Charge
6478	Real Time Imbalance Energy Offset - System	EESC		Yes					381	1,939
64770	Real Time Imbalance Energy Offset EIM	EESC		Yes	(114,282)	133,420	(79,394)	461,270	(32,986)	16,279
67740	Real Time Congestion Offset EIM	EESC		Yes	(45,581)	359,509	(25,288)	(3,683)	(37,911)	2,173
69850	Real Time Marginal Losses Offset EIM	EESC		Yes			(59,009)	18,121	(6,825)	1,348
66200	Bid Cost Recovery EIM Settlement	EESC	PRSC	Yes			(32)	7	(78,549)	133,216
66780	Real Time Bid Cost Recovery Allocation EIM	EESC		Yes	951	31,738	1,093	36,584	(56,642)	3,476
8989	Daily Neutrality Adjustment	EESC		Yes						
8999	Monthly Neutrality Adjustment	EESC		Yes						

Penalty Charges

CC #	Charge Code Name	CAISO > EIM Entity Allocation		EIM Entity Sub Allocation	PacifiCorp		Idaho Power		NV Energy	
					BPA Peak Load 400+		BPA Peak Load 300+		BPA Peak Load 100<>	
					Monthly		Monthly		Monthly	
					Min Charge	Max Charge	Min Charge	Max Charge	Min Charge	Max Charge
6045	Overscheduling and Under scheduling Charge	EESC		Yes					(0)	8,217
6046	Under Scheduling and Over Scheduling Allocation	EESC		Yes	(5,369)	368			(511)	776

CAISO EIM Charge Code List

Administrative Charges

					PacifiCorp		Idaho Power		NV Energy	
					BPA Peak Load 400+		BPA Peak Load 300+		BPA Peak Load 100<>	
		CAISO > EIM Entity Allocation		EIM Entity Sub Allocation	Monthly		Monthly		Monthly	
CC #	Charge Code Name				Min Charge	Max Charge	Min Charge	Max Charge	Min Charge	Max Charge
491	Green House Gas Emission Cost Revenue		PRSC	No						
701	Forecasting Service Fee		PRSC	Yes						
1592	EP Penalty Allocation Payment	EESC	PRSC	No						
2999	Default Invoice Interest Payment	EESC	PRSC	No						
3999	Default Invoice Interest Charge	EESC	PRSC	No						
4515	GMC Bid Transaction Fee		PRSC	No						
4564	GMC-EIM Transaction Charge	EESC	PRSC	Yes			2,130	4,026	398	12,353
4575	SMCR -Settlements, Metering, and Client Relations	EESC	PRSC	Yes			-	121	-	10,870
5024	Invoice Late Payment Penalty	EESC	PRSC	No						
5025	Financial Security Posting (Collateral) Late Payment Penalty	EESC	PRSC	No						
5900	Shortfall Receipt Distribution	EESC	PRSC	No						
5901	Shortfall Allocation Reversal	EESC	PRSC	No						
5910	Shortfall Allocation	EESC	PRSC	No						
5912	Default Loss Allocation	EESC	PRSC	No						
7989	Invoice Deviation Interest Distribution	EESC	PRSC	No						
7999	Invoice Deviation Interest Allocation	EESC	PRSC	No						
8526	Generator Interconnection Process GIP Forfeited Deposit Allocation	EESC		No						

Policy Question

- What approach should Bonneville adopt in recovering its costs (or distributing credits) for charge codes that it will receive as an EIM Entity from the CAISO?
  - Should Bonneville roll-in the costs/benefits to its current transmission rates? (completely insulating customers from direct CAISO costs/credits)
  - If not, how should Bonneville recover from customers? (partial insulation, no insulation from costs/credits)
    - E.g. Sub-allocation by each charge code or sub-allocation by charge code grouping

Potential Bonneville Charge Code Allocation Principles

- Full and timely cost recovery, considering cost causation while balancing with simplicity.
- Develop understandable and transparent methodology that we can build upon as we gain experience in the market.
- Feasibility of implementation, recognizing forecasting constraints and administrative implications.

Potential Transmission Charge Code Allocation Principles

- Equitable cost allocation between Federal and non-Federal users of the transmission system.
- Behavior-driven cost causation where practical, to incentivize appropriate market behaviors.
- Mitigate seams and potential for charge code allocation misalignments with other EIM Entities.

Potential Power Charge Code Allocation Principles

- Costs and benefits are allocated among cost pools consistent with the Tiered Rates Methodology and power product purchased from BPA.
- To the extent possible, treat directly connected and transfer customers comparably.
- Maintain similar level of exposure to actual market conditions as is included in power products today.

Methodology Spectrum

Factors to Evaluate:	Complete Insulation	Partial Insulation	No Insulation
Charge Code Allocation	No Allocation of Charge Codes	Sub-Allocate Some Charge Codes	Pass-through All Charge Codes
Forecast in Rates	Full Costs Forecast	Some Costs Forecast	No Costs Forecast
Cost Recovery Mechanism	Risk Mechanism within Rate Structure	Combination of Direct Assignment and Rate Structure	Direct Assignment
Potential Structural Changes	Minimal Changes to Product / Rate Structure	Some Changes to Product / Rate Structure	Changes to Product / Rate Structure
Billing Implications	Minor Changes to Billing	Some Changes to Billing	Re-structuring of Billing
Customer Impact	Low Impact	Moderate Impact	High Impact

Phase Two (Issue Analysis and Alternative Development) will evaluate the feasibility of the factors across the methodology spectrum, which will lead to identifying feasible alternatives.

Complete Insulation

Advantages

- No charge code sub-allocation
- No settlement re-calculation process with customers
- Limited rate schedule changes
- No significant change to customer bills
- Disassociates customer/BPA disputes from BPA/CAISO disputes
- Customers would not need resources to verify CAISO data
- BPA gains experience in the market to provide understanding for future charge code allocation development

Potential Challenges

- Separation of market behavior and cost causation, reducing customer visibility
- Cost recovery would not occur through the EIM design and a financial cost recovery mechanism would need to be determined
- BPA's existing behavioral price signals may not fully align with CAISO's structure for the same action
- Unable to pass on EIM-specific price signals
- Potential seams issues between EIM BAAs

Partial Insulation

Advantages

- Incentivize appropriate market behaviors through charge code allocation
- Enables BPA to develop experience in the market, but begins to stage implementation of sub-allocating
- Customers begin developing experience with CAISO price signals
- Potential for closest alignment with other EIM entities, may reduce seams issues

Potential Challenges

- Opens up potential customer exposure to EIM settlement process, potentially increasing need for customers to validate data
- Begins to create billing complexity, given the volume of settlements
- Bonneville takes on risk of consolidating and allocating charge codes

No Insulation

Advantages

- Cost causation incentivizes appropriate market behavior
- Allocation of costs tie closely to behaviors
- Close alignment with other EIM entities, may reduce seams issues
- Reduces need to design risk mechanisms
- Greatest transparency in the allocation of specific charge codes from CAISO to BPA to customers

Potential Challenges

- Significant change to customer bills to address CAISO settlement processes
- Aligning disputes between CAISO/BPA and Customer/BPA would be complex to administer
- BPA and customers would need to consider increasing resources to validate EIM data
- Not all EIM settlements with BPA will be 100% verifiable, which could create challenges when passed to customers
- With direct assignment, may create greater uncertainty for customers in bills
- May go beyond structure other EIM entities use today, increasing settlement complexity

EIM Charge Code Next Steps

- Feedback on policy questions and charge code allocation principles
  - Please submit to techforum@bpa.gov (with copy to your account executive) by Friday, January 3
- Next Charge Code Allocation Workshop: February 25
  - Phase 2
    - Step 3: Analysis of the Issue
    - Step 4: Alternatives

WRAP UP & NEXT STEPS

Next Steps

- By Jan. 3, please provide feedback on the following via techforum@bpa.gov (with copy to your account executive):
  - Transmission Losses
  - EIM Losses
  - Charge code allocation policy questions and principles

- Next workshop is on Jan. 28, 2020.

Proposed January Workshop Agenda

- Proposed TC-22, BP-22 & EIM Topics
  - EIM Transmission Network Usage
  - Metering Policies for EIM
  - Non-Federal Resources Participation in EIM
  - Exploring Section 7(f) Rate Options
  - Debt Management
- Proposed BP-20 Settlement Update Topics
  - Attachment 2, Generation inputs
- Proposed TC-20 Settlement Update Topics
  - NT Roadmap
  - Intertie Studies

Customer Led Workshop Protocol

- Submit a workshop request no later than one week before the scheduled date (see slide 4 for dates).
- Requests must include a list of topics/issues you wish to cover if you are requesting Bonneville SME support.
- Discussions/workshops will only cover previously reviewed materials.
- Customers must inform BPA if A/V resources are required to include remote participants and/or present materials within the Rates Hearing Room.
- BPA will verify that it will staff for the requested topics within three business days via Tech Forum.