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

September 29, 2020

AGENDA REVIEW AND FEEDBACK FROM PRIOR WORKSHOP

Agenda

Day 1 – September 29, 2020		
TIME*	**TOPIC**	**Presenter**
9:00 to 9:05 a.m.	Summary and Update	Rebecca Fredrickson Rachel Dibble
9:05 to 10:05 a.m.	Update on Losses	Mike Bausch Andy Meyers Eric Taylor Daniel Fisher
10:05 to 10:30 a.m.	Real Power Losses on EIM Transfers	Tracey Salazar Todd Kochheiser Derrick Pleger
10:30 to 12:30 p.m.	Financial Planning	Daniel Fisher Nadine Coseo Alex Lennox Zach Mandell
12:30 to 1:30 p.m.	**LUNCH**	
1:30 to 3:00 p.m.	Transmission GRSP for EIM Discussion	Rich Green Allen Chan Miranda McGraw Derrick Pleger Libby Kirby Frank Puyleart Eric Taylor
3:00 to 4:00 p.m.	PowerEx Presentation: • EIM Cost Allocations	Jeff Spires

** Times are approximate*

8/25 & 8/26 Workshop - Customer Comments

Topic	Comment Summary	BPA Response
Risk	• General support to maintain current practice of business line-based TPP • Additional information is needed before benefits of BPA proposal to move to agency-based TPP can be understood	• Thank you for your comments

Transmission Losses	• Strong support to maintain in-kind option for BP-22
	• General support to move to concurrent as soon as practicable after BP-22
	    • move to implement concurrent for BP-24
	• Concerns with applying a capacity charge for losses
	    • 15% capacity proposal is arbitrary
	    • no other TX provider applies a capacity charge to losses
	    • capacity cost inconsistent with industry standard and cost-causation principles
	    • FCRPS should be appropriately compensated
	• Strong support to update network loss factor and update more regularly moving forward
	    • Support for seasonal loss factors and possibly a shaped loss factor
	• Retain ability to switch loss return options within the rate period
	• Strong support for an FFI
		• Thank you for your comments. The team appreciates all the comments they received on the transmission losses topic. The team believes the capacity charge is appropriate and believes the monthly loss factor is also appropriate.

8/25 & 8/26 Workshop - Customer Comments Cont.

Topic	Comment Summary	BPA Response
Transmission Donation	• Allow donation until T-57 • Consider allocating ETSR congestion rents to interchange rights holders donating transmission • Seek clarity on which parties will be charged for losses on EIM transmission • Firm transmission should be minimally impacted to allow non-firm donations • Monitor quarterly to identify any unintended consequences	• Thank you for your comments • Regarding congestion rents: • CAISO does not provide settlement data to distinguish congestion rents for EIM Transfer congestion and BPA internal physical congestion. • Because of this lack of settlement data, BPA cannot sub allocate congestion rent for EIM Transfer congestion differently than BPA internal physical congestion. • Congestion rents for EIM Transfers are always a credit. • Internal congestion rents may be charges or credits and typically results in higher load imbalance settlement pricing than generation LMPs. • Sub allocating congestion rents to measured demand helps return those costs equitably. • If BPA sub allocated congestion rents to customers that donate transmission, non-donating load and exporting generation would be left exposed without the measured demand sub allocation. • If BPA sub allocated congestion rents to customers that donate transmission, those customers could to exposed to charges for their donations instead of credits due to the inclusion of internal physical congestion in congestion rents.

8/25 & 8/26 Workshop - Customer Comments Cont.

Topic	Comment Summary	BPA Response
EIM General	• All resources should have option to participate in EIM and not have to face a six-month delay • EIM implementation issues raised by BPA are the same as what other resources will face and there could be efficiencies working with eligible non-fed resources sooner • BPA should monitor impacts of implementation and participation on a quarterly basis leading up to BP-24 to ensure appropriate transparency • Support for phased process as outlined in letter	• Thank you for your comments. These comments were forwarded to the EIM phase III draft letter to be addressed
EIM Losses	• BPA proposal seems reasonable	• Thank you for your comments
EIM Tariff	• Attachment P should be modified to request reimbursement of EIM charges resulting from OMP • Suggests removal of “Firm” from Attachment A as will apply to both firm and non-firm	• Thank you for your comments. At this time the team did not see any comments that would change their staff leaning

8/25 & 8/26 Workshop - Customer Comments Cont.

Topic	Comment Summary	BPA Response
Real Power Losses on EIM Transfers	• Supports not charging for losses on EIM transfers • Concerns with allocating EIM losses through RTEIO charge code • RTEIO charge code should only be allocated to those contributing to incremental losses	• Thank you for your comments, these comments will be addressed in this presentation.
Resource Sufficiency	• Supports no sub-allocation of RS obligations • Supports not establishing an RS pass target	• Thank you for your comments
Operational Controls	• Cautious support for continued use • Request a workshop to review potential EIM impacts as additional layer of complexity	• Thank you for your comments

8/25 & 8/26 Workshop - Customer Comments Cont.

Topic	Comment Summary	BPA Response
Gen Inputs	• General support for removing EI & GI deviation bands • Don't retain the PD penalty. If retained, consider adjustments • ID penalty should adapt to new paradigm • Consider pilot that allows use of alternative forecasts to stimulate improvement to generation forecasting. • Reconsider how total reserve requirement is allocated. • Concerns with "rate shock" of updated BPA proposal • Request additional information on non-wind/solar ACE rates (equal to or less than current rates) • Request accommodation/uplift for customers currently using 30/15 committed scheduling • Track how BPA reserves compare to CAISO supplied flex reserve and dispatch of resources and earned revenues • Consider modeling MISO forecasting workshops to improve VER forecasting • Support for proposed changes to reserve pricing methodology	• Thank you for your comments. At this time the team did not see any comments that would change their staff leaning
Charge Code Allocation	• General support for proposed EIM charge code sub-allocation • Reconsider allocating load-based charge codes to the non-Slice cost pool • Concern for using Measured Demand with respect to Export Schedules and EIM Neutrality Codes • Neutrality codes should not be allocated to customers not contributing to EIM transfers/transactions • Confirm how other EIM entities allocate • Request additional details on implementation of "measured demand by magnitude" • Concerns with cost exposure due to schedule changes after T-57 • Proposal for allocation of EESC and PRSC seem appropriate but should be tracked quarterly	• Thank you for your comments. At this time the team did not see any comments that would change their staff leaning

8/25 & 8/26 Workshop - Customer Comments Cont.

Topic	Comment Summary	BPA Response
Power Rates	• Staff leanings seem a reasonable starting point for EIM benefits & charges in Power rates • Commit to making data available ahead of BP-24 for collaborative approach on including EIM benefits in future rate cases • Net dispatch benefits should be shared with Slice customers • Add fourth bucket to EIM costs to capture share of capacity used to meet resource sufficiency test • General support for Section 7(f) proposal • Secondary revenue o Secondary revenue proposal submitted by EWEB o Proposed compromise on FRP Surcharge and annual base rate is not acceptable. o Support current secondary revenue construct o NT (PPC/NRU) does not support BPA proposal as resulting in higher base rates	• Thank you for your comments.
Leverage Policy	• Additional opportunities for exploring implementation details would be appreciated	• Thank you for your comments
GridMod Cost Functionalization	• Allocation should be based on cost-causation, not on traditional 65/35 allocation practice • Power is the primary beneficiary and as such a more equitable cost split must be implemented	• Thank you for your comments
Interconnection Reform	• Proposed implementation of Repowering and Generator Replacement are appreciated	• Thank you for your comments
Intertie Studies	• Concerns with implementation of staff leaning	• Thank you for your comments

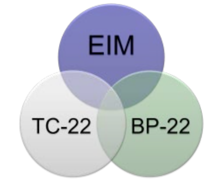
EIM Priority Issues

#	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	Requirements for Participating & Non-Participating Resources	X	X	?
6a	- Participating Resources: Base Scheduling Timeline			
7	Metering & Data Requirements		X	?
8	Evaluation of Operational Controls	X	X	?

Rates & Tariff Topics

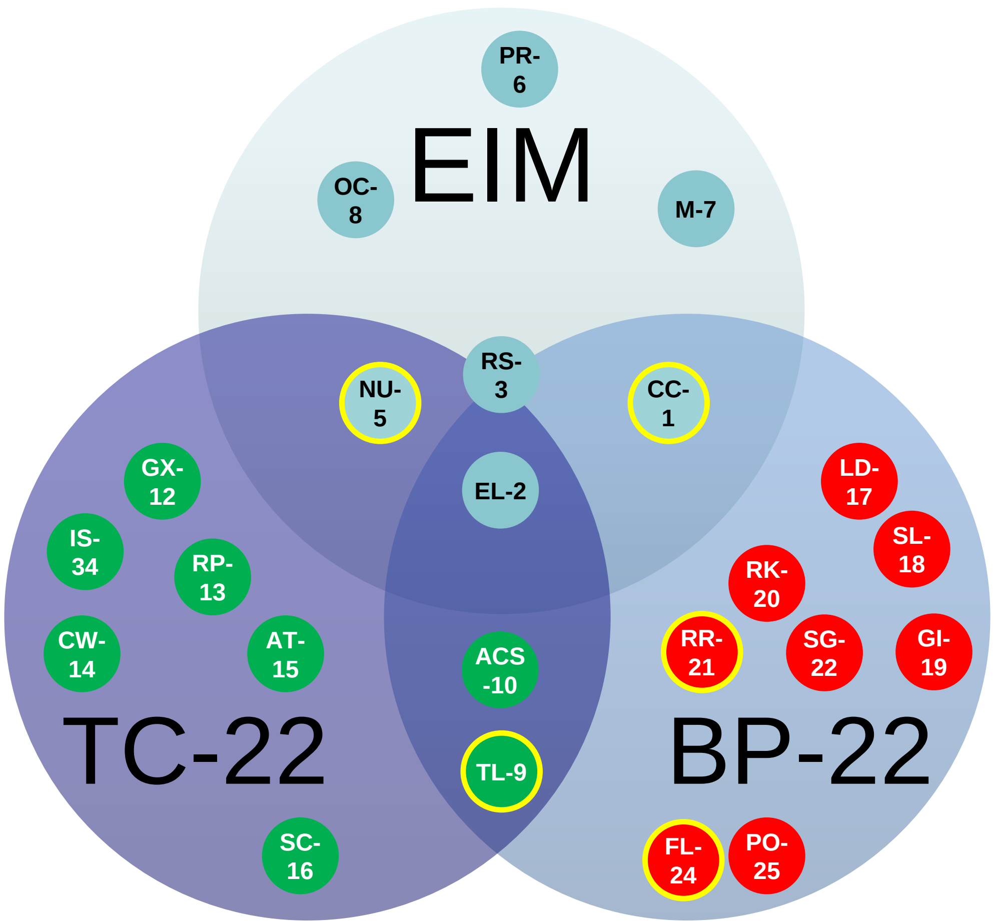
#	Topics	BP-22	TC-22	Future BP/TC
9	Transmission Losses	X	X	
10	Ancillary Services (Gen Inputs)		X	?
11	Debt Management (Revenue Financing)	X		
12	Generator Interconnection		X	
13	Regional Planning		X	
14	Creditworthiness		X	
15	Incremental/Minor Changes to Agreement Templates		X	
16	Seller's Choice		X	
17	Loads	X		
18	Sales	X		
19	Gen Inputs (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			?
34	Southern Intertie Studies			?
35	De minimus (TC-20 Settlement)			?

BP-22, TC-22 & EIM Integrated Scope



TC	
TL-9	Transmission Losses
ACS-10	Ancillary Services
GX-12	Generator Interconnection
RP-13	Regional Planning
CW-14	Creditworthiness
AT-15	Agreement Templates
SC-16	Seller's Choice
IS-34	Intertie Studies

BP	
LD-17	Loads
SL-18	Sales
GI-19	Gen Inputs
RK-20	Risk
RR-21	Revenue Requirements
SG-22	Segmentation
FL-24	Financial Leverage
PO-25	Power-only

EIM	
CC-1	Charge Code Allocation
EL-2	EIM Losses
RS-3	Resource Sufficiency
NU-5	Network Usage
PR-6	Participating Resources
M-7	Metering
OC-8	Operational Controls

XX-# Yellow Outline Denotes Current Workshop Topics

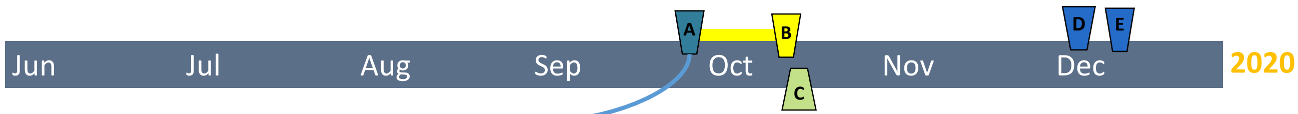
WORKPLAN AND PROPOSAL

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

Workplan Completion



September 29, 2020

- Update on Losses
- Real Power Losses on EIM Transfers
- CRFM
- Financial Planning
- Transmission GRSP for EIM Discussion
- PowerEx Presentation
    - EIM Cost Allocation

Timeline Key

A. 9/29: September Workshop

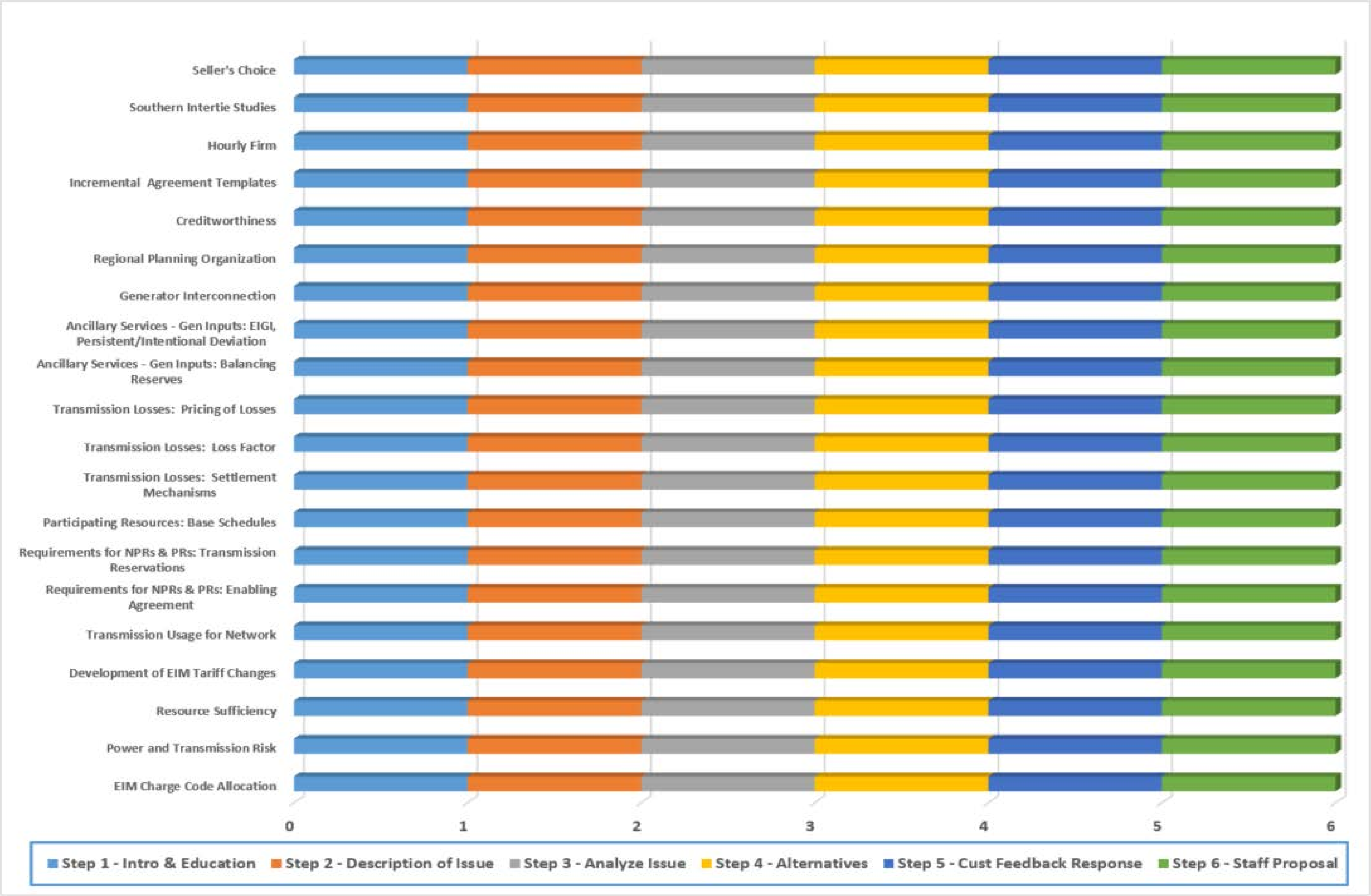
B. 10/13 Customer Comment on September Workshop

C. 10/14: Final-EIM Phase III Letter

D. 12/1: Federal Register Notice (Ex Parte Start)

E. 12/7: TC-22 & BP-22 Initial Proposal

Status of Topics Through September Workshops



ISSUE #9: TRANSMISSION LOSSES:

- Update on Losses

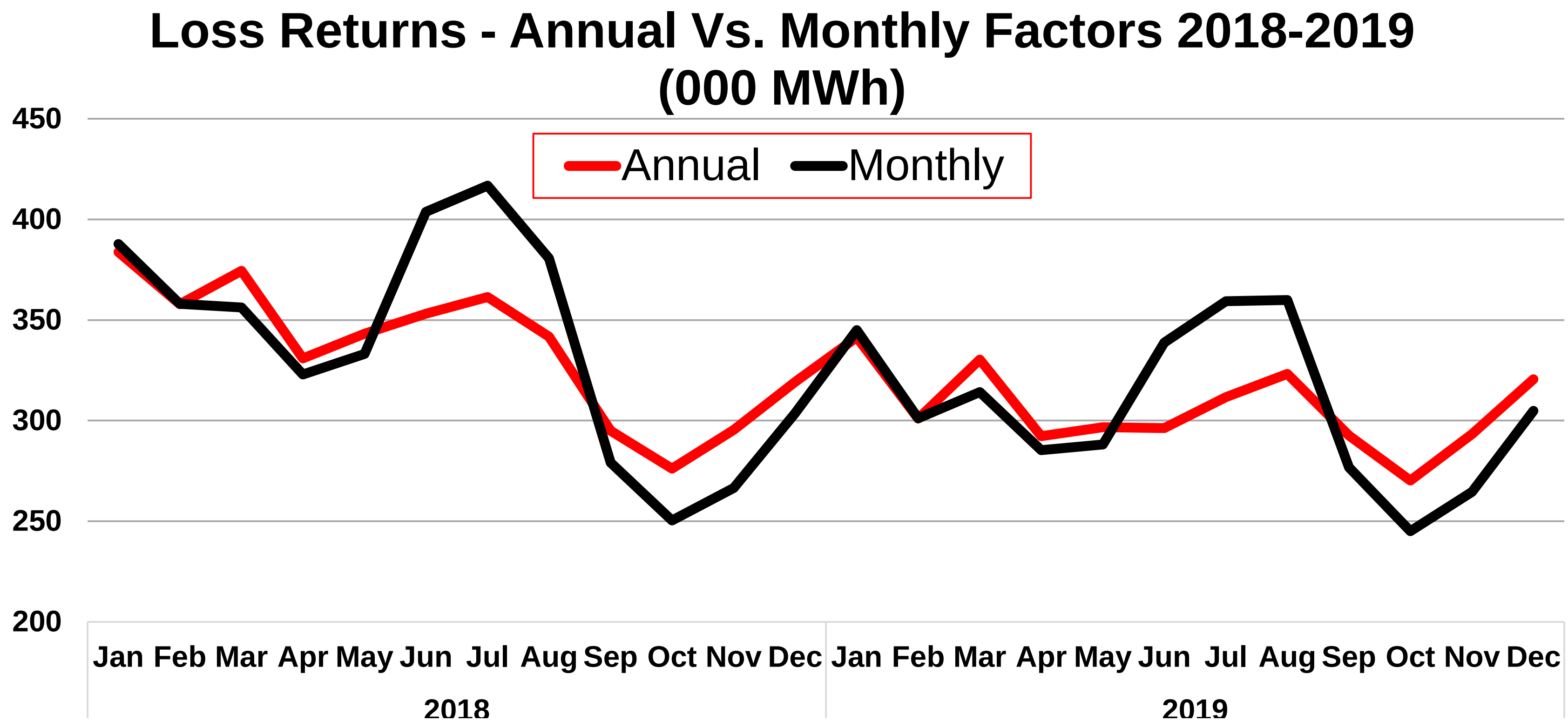
Items

1. Loss Factor
   - Granularity
2. Pricing
   - (a) Capacity Costs
   - (b) Transmission Cost Recovery
   - (c) Financial For Inaccuracy (FFI)

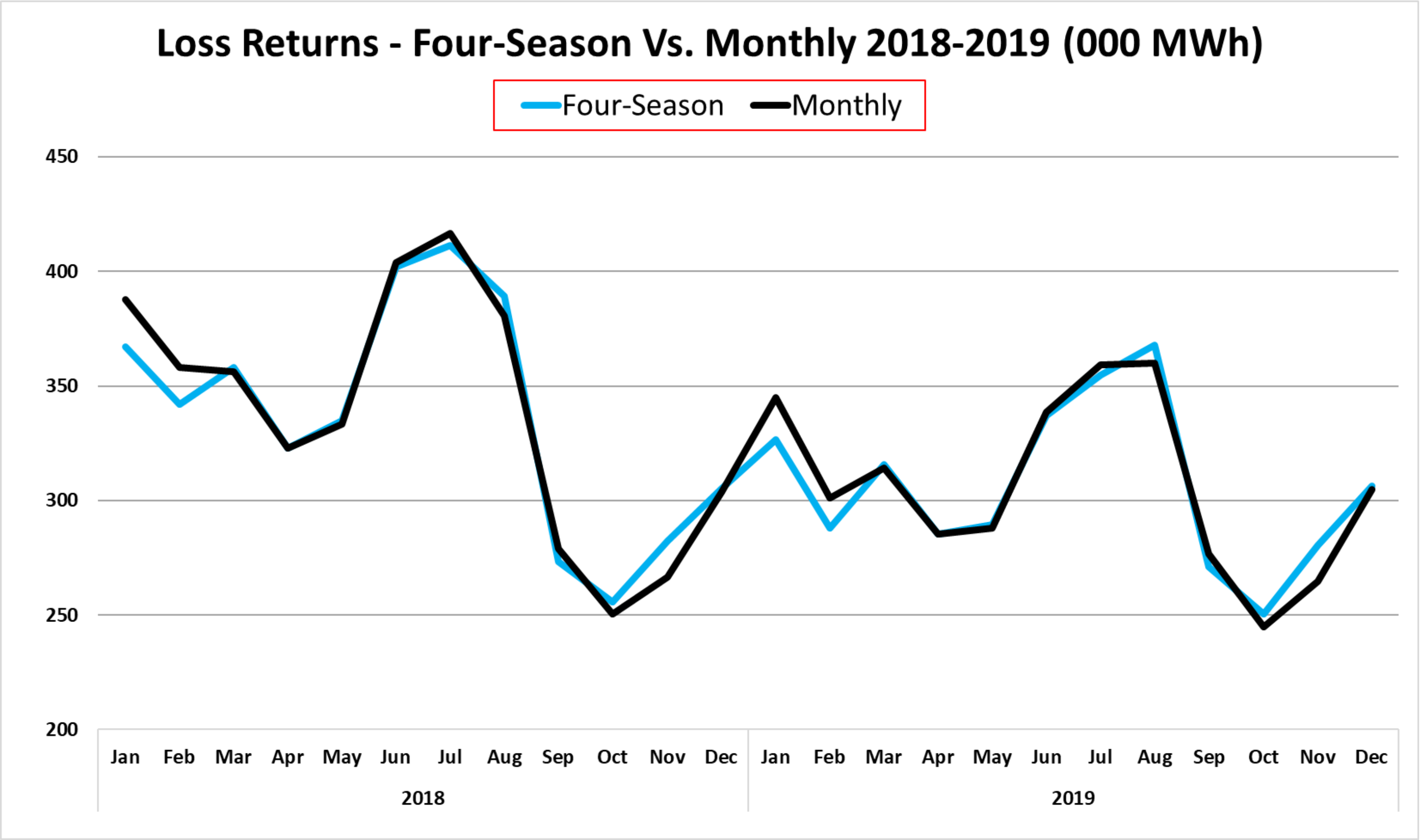
Item 1 - Loss Factor

- August workshop BPA staff discussed granularity of Loss Factor
  - Annual/Seasonal/Monthly
- Customer Comments generally support more granularity than annual but disagree with BPA staff on how granular
  - BPA staff are seeking better understanding of customers' comments surrounding administrative burden due to the potential adoption of monthly Loss Factor

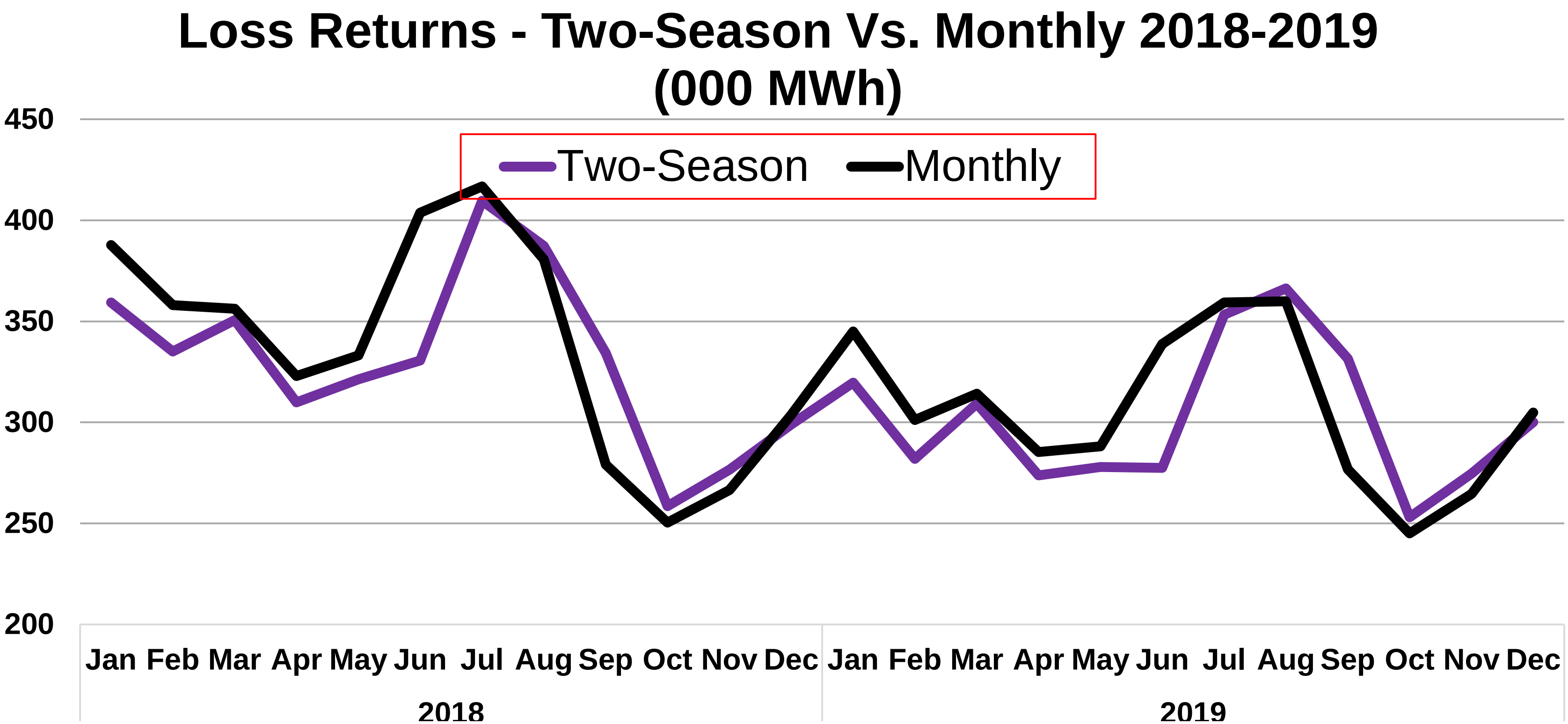
Annual Vs Monthly Factor



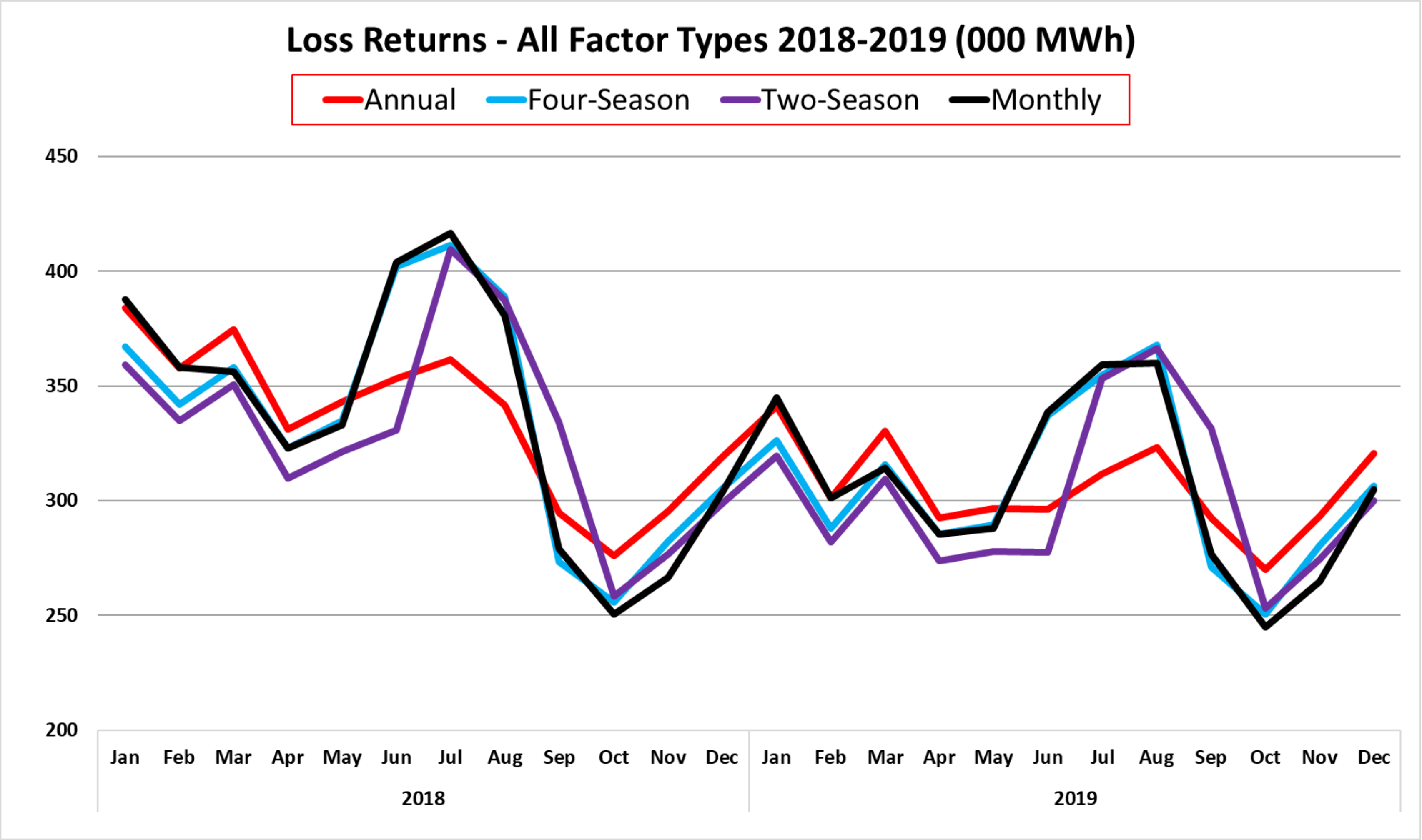
Four-Season Vs Monthly Factor (updated to use four seasons with correct months)



Two-Season Vs Monthly Factor



All Factor Types (updated to use four seasons with correct months)



Monthly Loss Factor - Discussion

- BPA staff's leaning is to propose Monthly Loss Factors in initial Tariff offering
- Monthly Loss Factors will be included in BPA's Tariff – Schedule 11
- Draft Tariff language for monthly Loss Factors has been provided to customers

Item 2(a) – Capacity Costs

- August workshop BPA staff proposed the following capacity costs associated with wheeling loss service for BP-22
  - In-Kind -168 hour delay including Slice - $3.53/MWH
  - Financial - $6.65/MWH

  Note – calculated dollar values only utilized one year of data.
- Customer comments received following the August workshop
  - – Expand data set used in calculations to three years
  - – Remove the charge for capacity costs for wheeling loss service
  - – Continue to explore and pursue a transition to In-kind concurrent returns
- BPA staff will expand the data set used in calculating proposed fees to include three years of data
- BPA staff continue to believe the charging of a capacity cost for wheeling loss service is appropriate and intend to propose inclusion of a capacity cost in the initial proposal of the Rate Schedule
- Concurrent loss returns continue to be under evaluation as we work towards future rate periods

Item 2(a) – Capacity Costs

- Delayed Loss Returns – Capacity Services
  - BPA provides INCs when the amount returned by customers in an hour (based on an obligation incurred 168-hours ago) is less than the losses incurred in the same hour.
  - BPA provides DECs (stores generation) when the returned loss amounts are greater than the losses incurred in the same hour.
  - Customers have stated in workshops that they provide DECs to BPA when BPA waives loss returns due to over supply

Item 2(a) – Capacity Costs

- Valuing Capacity, INCs and DECs

Loss Service A - Capacity to support delayed returned losses								
	BPA provided INCs		BPA provided DECS		Customer provided DECS: Option A		Customer provided DECS: Option B	
	Max (Actual Loss Obligaton less Returned Losses)	$5.82 kW-mo	Min (Actual Loss Obligaton less Returned Losses)	$0.91 kW-mo	Average Hourly Loss Waiver (only hours with loss waivers)	$0.91 kW-mo	Max Hourly Loss Waiver (monthly max of 3 years)	$0.91 kW-mo
	MW	INC charge $	MW	DEC charge $	MW	DEC credit $	MW	DEC credit $
Oct	82	$477,240	-157	$142,870		$0		$0
Nov	153	$890,460	-137	$124,670		$0		$0
Dec	123	$715,860	-119	$108,290		$0		$0
Jan	166	$966,120	-110	$100,100		$0		$0
Feb	187	$1,088,340	-176	$160,160		$0		$0
Mar	158	$919,560	-131	$119,210		$0		$0
Apr	123	$715,860	-117	$106,470	369	($335,335)	453	($412,230)
May	146	$849,720	-144	$131,040	376	($342,245)	467	($424,970)
Jun	128	$744,960	-112	$101,920	385	($350,657)	469	($426,790)
Jul	188	$1,094,160	-153	$139,230	361	($328,868)	441	($401,310)
Aug	123	$715,860	-106	$96,460		$0		$0
Sep	91	$529,620	-142	$129,220		$0		$0
Total		**$9,707,760**		**$1,459,640**		**($1,357,105)**		**($1,665,300)**

- Based on customer feedback, BPA staff now leans to include DECs in the capacity calculation. On the customer provided DECs, staff is leaning to Option B (using maximum waived loss amounts.)
- In the analysis above, BPA provided INCs and DECs are based on FY 2019 losses data and loss waiver data is based on FY 2018 through FY 2020 data and a preliminary $0.91/kW/mo cost of DECs.
- For the Initial Proposal, the BPA provided INCs and DECs will be updated using FY 2018 through FY 2020 losses data. The capacity rates will also be updated.

Item 2(b) - Transmission Rate Recovery

- Power Services capacity costs for customers who elect in-kind loss returns (including Slice) will be passed through Transmission Services
  - Transmission Services will calculate the in-kind capacity charge by multiplying the capacity price established by Power Services by the applicable Billing Factor
  - Billing Factor
    - Schedules and eTags for NT and PTP
      - NT customers with non-federal resources who elect to return losses in-kind
      - NT Slice customers who elect to return losses in-kind
- Customers who elect financial loss returns will be charged for capacity costs through the FPS power rate schedule

Item 2(c) - Financial For Inaccuracy (FFI)

- Penalty Pricing
  - Under Delivery
    - Applicable to the delta between expected and scheduled return when schedule is lower than expected
    - Capacity – Difference between Financial capacity price and In-Kind capacity price
    - Energy 125% index price (floor of zero)
  - Over Delivery
    - Bonneville expects customers to accurately return their losses
    - Curtailments may be made to reduce the etag to the expected return
    - Penalty Structure
      - Applicable to the delta between the expected return and the scheduled return when schedule is higher than expected
      - Zero or Positive priced market
        - Capacity penalty -- Difference between Financial capacity price and In-Kind capacity price
        - No credit will be provided to customers for over delivered energy
      - Negative price market
        - Capacity penalty -- Difference between Financial capacity price and In-Kind capacity price
        - An energy penalty fee of 125% of negative index value for the delta between the expected obligation and scheduled energy returned
- FFI will zero out imbalances in CDE and loss obligation will be deemed “met in full”
- No proposed strikes or tracking of strikes
- Customers will be provided opportunity to dispute FFI penalties
- Customers retain their settlement election even if they are charged an FFI penalty

Item 2(c) FFI – Penalty Example

- Under Delivery
  - Expected Return = 100 MWh
  - Actual Return = 95 MWh
  - Hourly Index Price $32/MWh
  - Customer Bill
    - Capacity Fee = 100 X $3.53 = $353
    - FFI
      - FFI applicable to 5 MWh (100-95 = 5)
      - Capacity Penalty = 5 X $3.12 = $15.60
      - Energy Penalty = 5 X $40 = $200
  - Total $568.60 = ($353.00 + $15.60 + $200.00)

Item 2(c) FFI – Penalty Example

- Over Delivery (Positive Price Market)
  - Expected Delivery = 100 MWh
  - Actual Delivery 105 MWh
  - Hourly Index Price = $25/MWh
  - Customer Bill
    - Capacity Fee = 100 X $3.53 = $353
    - FFI
      - Capacity Penalty = 5 MWh X $3.12 = $15.60
      - Energy Penalty = $0.00
    - Total $368.60 = ($353.00 + $15.60)

Item 2(c) FFI – Penalty Example

- Over Delivery (Negative Price Market)
  - Expected Delivery = 100 MWh
  - Actual Delivery 105 MWh
  - Hourly Index Price = ($10.00)/MWh
  - Customer Bill
    - Capacity Fee (100 X $3.53) = $353
    - FFI
      - Capacity Penalty = 5 MWh X $3.12 = $15.60
      - Energy Penalty = 5 MWh X (1.25 X $10.00) = $62.50
    - Total $431.10 = ($353.00 + $15.60 + $62.50)

Real Power Loss Return - Business Practice

- Areas of anticipated change
  - Dispute Process for FFI
    - BPA staff are recommending the inclusion of a process for customers to dispute Financial For Inaccuracy charges
  - Settlement Elections
    - Practice currently allows four changes per calendar year with 60 day notice
    - BPA staff recommending a reduction of elections to once a year
      - Election period would be prior to the start of the rate period
      - A mid-rate period option would be used to update election with 30 or 60 day notice prior to the start of BPA's fiscal year

Next Steps

- Customer written responses are due on October 13th to Tech Forum
- Initial Proposal
- Rate Case
- Tariff Proceeding
- Initiate BP Process Changes

Appendix - Monthly Average Loss Factors

MONTH	LOSS FACTOR
January (based on 24402 MW average hour) =	2.05%
February (based on 24109 MW average hour) =	2.03%
March (based on 22688 MW average hour) =	1.93%
April (based on 21792 MW average hour) =	1.98%
May (based on 21590 MW average hour) =	1.97%
June (based on 22847 MW average hour) =	2.32%
July (based on 23183 MW average hour) =	2.34%
August (based on 21866 MW average hour) =	2.26%
September (based on 20282 MW average hour) =	1.92%
October (based on 18547 MW average hour) =	1.84%
November (based on 20919 MW average hour) =	1.83%
December (based on 22690 MW average hour) =	1.93%

Appendix - Seasonal Average Loss Factors (updated with correct months for seasons)

- **Summer has highest losses**
- **Winter has highest loads**
- **Discrepancy due to system optimization for winter**

SEASONAL AVERAGE LOSS FACTORS	LOSS FACTOR
Spring (April, May) (based on 21691 MW average hour) =	1.98%
Summer (June, July, Aug) (based on 22632 MW average hour) =	2.31%
Fall (Sept, Oct) (based on 19414 MW average hour) =	1.88%
Winter (Nov, Dec, Jan, Feb, Mar) (based on 22962 MW average hour) =	1.94%

Appendix - Annual Average Loss Factor

ANNUAL AVERAGE LOSS FACTOR	2.03%

ISSUE #2: REAL POWER LOSSES ON EIM TRANSFERS

- Update on EIM Transfers

Definition of Measured Demand

- In the August workshop, BPA proposed the following definition of Measured Demand: Metered Demand + Export Schedules (see slide 111 from the 8/25/20 customer meeting).
- This definition of Measured Demand is consistent with that of other EIM Entities and the CAISO
- EIM Entities and the CAISO exclude EIM Transfers in the calculation of Measured Demand
- Consistent with other EIM Entity Tariffs and the CAISO, BPA proposes to clarify the definition of Measured Demand as follows:
  - **Measured Demand includes (1) Metered Demand, plus (2) e-Tagged export volumes from the BPA BAA (excluding EIM Transfers)**

Review of Issue

- In the August workshop, BPA proposed two alternatives for the treatment of losses on EIM transfers.

- **Alternative 1: Do Not Charge Losses on EIM Transfers**
  - Customers with load, exports and wheeling customers would be allocated a share of RTIEO, assuming Export Schedules are defined to include wheels.
  - Creates an incentive to donate transmission for EIM
  - Avoids the potential for double-recovery of losses

- **Alternative 2: Charge Losses on All EIM Transfers**
  - Creates the potential for double-recovery of losses
  - Creates a disincentive for customers to donate transmission for EIM since that customer will have to pay losses on the transmission it donated if used but may not necessarily benefit from that EIM transfer

Suballocation of RTIEO

- At the August workshop, BPA proposed to sub-allocate RTIEO to its customers by Measured Demand by Magnitude.
- Measured Demand by Magnitude was defined as Metered Demand + Export Schedules.
- Export Schedules in the context of Measured Demand had not yet been defined by the BPA Settlement team.
- Regarding charging for losses for EIM transfers, BPA concluded the following: *Assuming Export Schedules are defined to include the export leg of wheels, which would capture EIM transfers that "pass-through" BPA's BAA,* customers with load and/or exports, and wheeling customers would be allocated a share of RTIEO.

Staff Recommendation from August

- *Assuming Measured Demand includes exports associated with wheels (including EIM)*, BPA recommends Alternative 1, do not charge losses on EIM transfers.
- This settlement approach ensures that the cost of EIM losses is recovered from all customers, not just customers with load in the BAA.
- If the Settlement Team determines that Measured Demand will not include exports associated with wheels, BPA will reevaluate the recommendation on losses on EIM transfers.

Customer Comments on Proposal

- BPA received comments in support of its proposal to not charge losses on EIM transfers.
  - BPA Response: Thank you for your comments.
- Several customer also commented that customers wheeling through the BPA system should not be allocated any costs associated with imbalance created by EIM transfers if they do not benefit from those transfers
  - BPA Response: Any imbalance created by wheel-through EIM transfers will be settled through RTIEO, as prescribed in the CAISO tariff. BPA proposes to sub-allocate RTIEO through Measured Demand. Please see slide 3 for BPA's rationale for including exports in Measured Demand.

BPA Proposal on Losses on EIM Transfers

- Since BPA proposed to exempt EIM transfers from real power losses, the definition of measured demand has been clarified to exclude EIM transfers.
- BPA's proposal to exempt EIM transfers from real power losses was contingent on measured demand including all exports, even EIM transfers.
- BPA staff have reaffirmed the proposal to exempt EIM transfers from real power losses despite the exclusion of EIM transfers from Measured Demand.
  - Measured Demand will only be slightly reduced by the exclusion of EIM transfers.
  - There will be little impact on customers with load and exports.

Proposed Tariff Language

- 15.7 Real Power Losses:
  - Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service, excluding EIM participation, as calculated by the Transmission Provider under Schedule 11.

- 28.5 Real Power Losses:
  - Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Network Customer is responsible for replacing losses associated with all transmission service, excluding EIM participation, as calculated by the Transmission Provider. The applicable loss factors are listed under Schedule 11.

Next Steps

BPA requests customer feedback on:

- Recommendation and proposed tariff language
- Please submit to techforum@bpa.gov (with a copy to your account executive) by October 13.

FINANCIAL PLANNING

Long Term Strategic Financial Issues

September 2020

#1 STRENGTHEN FINANCIAL HEALTH

Background & Objective

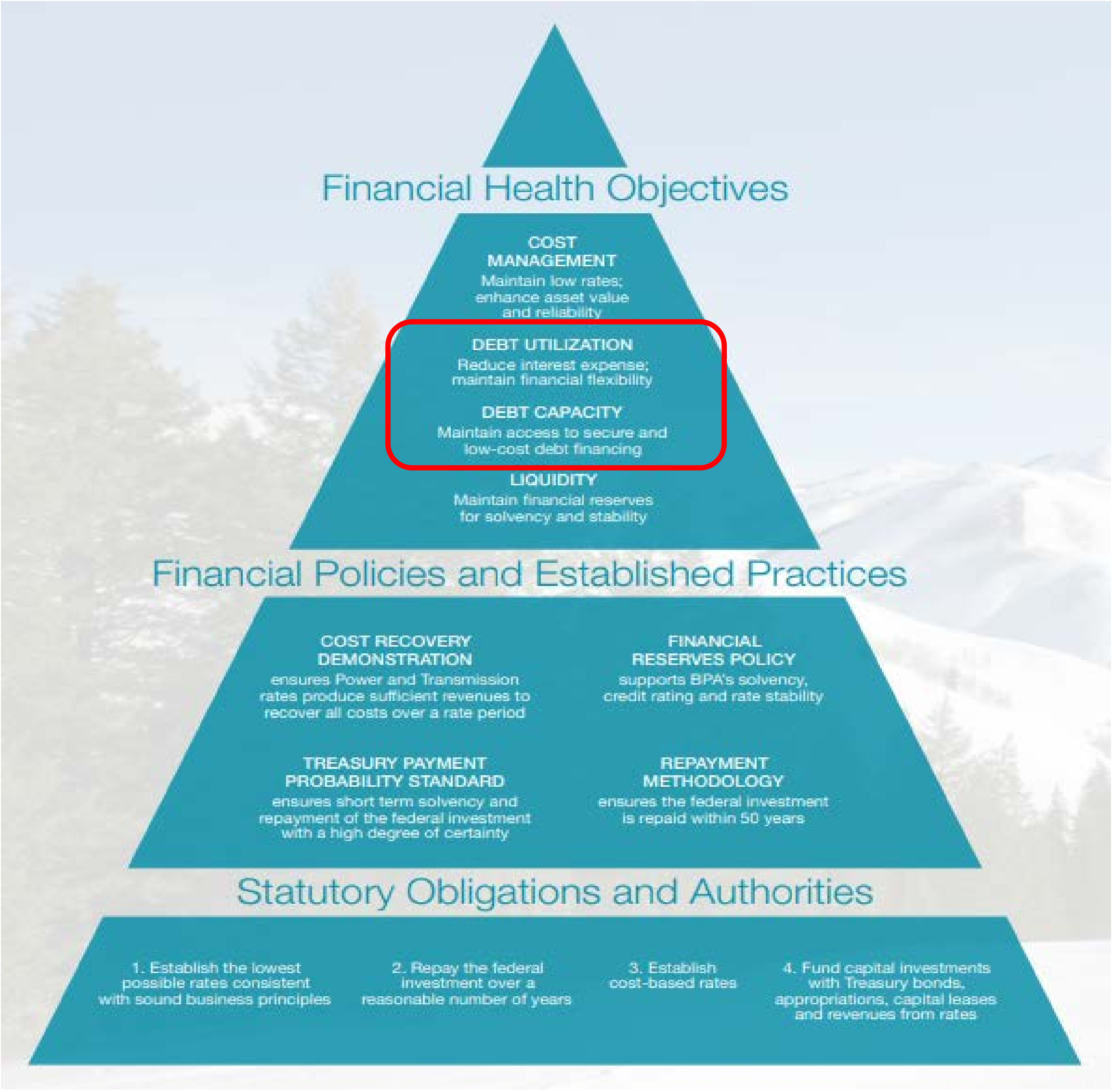
Setting the context:

- The 2018 Financial Plan was foundational in helping to focus financial policies that move BPA toward a more solid financial position.
- The goals of the Financial Plan are still valid. Additional actions and measures are necessary to further our progress toward those goals.

Today's objective:

- Discuss why BPA must further refine its financial polices to ensure long term financial health and why we must take action in BP-22.
- Share approaches for BP-22 initial proposal -- the starting point.
- Share next steps on building the longer term plan.

BPA's 2018 Financial Plan



- The Financial Plan is organized in order of flexibility, beginning with the foundational and least flexible elements, followed by financial polices and practices, and ending with financial health objectives.
- The financial health objectives of debt utilization, debt capacity and liquidity relate to financial resiliency.
- Debt utilization and debt capacity are the prime focus of the "why" today.

Financial Plan Health Objectives

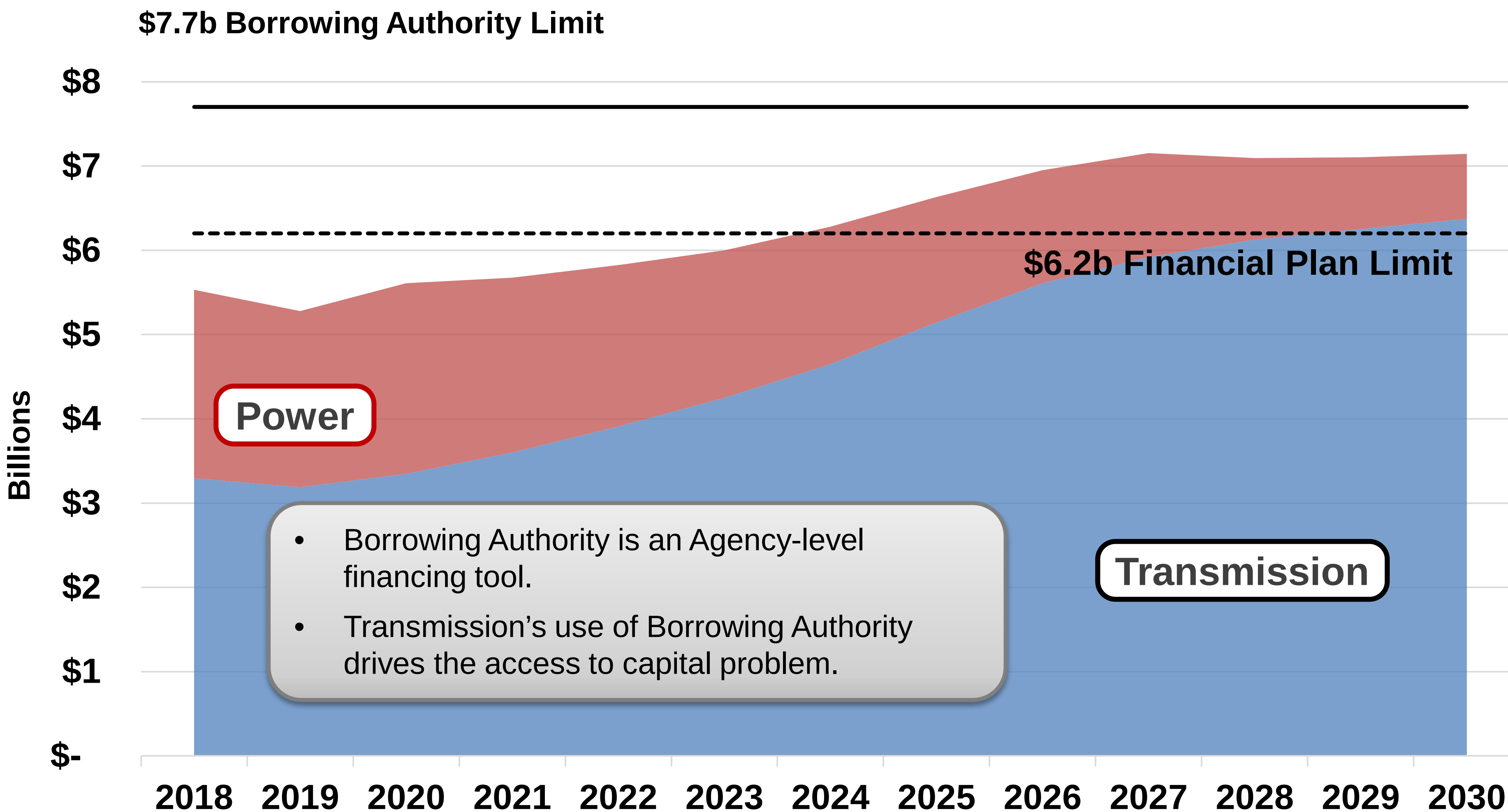
Financial Resiliency-Related Financial Health Objectives			
Health Objective	**Purpose**	**Metric**	**Target**
Liquidity	Solvency and stability	Days cash on hand and Treasury Payment Probability (TPP)	Maintain a minimum of 60 days cash on hand for each business line and a 97.5% annual TPP
Debt Utilization	Low interest expense and financial flexibility	***Debt to asset ratio***	Achieve a debt to asset ratio of 75% -85% within 10 years and 60% - 70% in the long term
Debt Capacity	Secure and low-cost debt financing available to fund capital program	***Remaining borrowing authority***	Maintain sufficient debt capacity to fund BPA's capital program on a rolling 10-year basis and preserve $1.5B of available US Treasury borrowing authority

What is the Issue?

- BPA has made progress on decreasing its leverage.
  - The Financial Plan target was to achieve a debt to asset ratio of 75% - 85% in the near term and a ratio of 60% in the long term.
  - At the end of FY19, BPA's debt to asset ratio was at 82%, down from 88% the year before.
- Borrowing Authority Issue: BPA is not on track to meet is borrowing authority goal of maintaining $1.5b of available borrowing authority.
  - The forecast shows that in 2024, BPA falls short of this objective.
  - Without action the problem only worsens.
- Debt Outstanding Issue: Achieving the near term leverage policy target alone, does not address other debt-related issues.
  - BPA's debt to asset ratio is still significantly higher than its peers in the industry.
  - A debt to asset ratio at this level or even at the 75% level does not equate to a declining debt outstanding balance.
  - Transmission has and continues to be a net borrower, resulting in large fixed costs and reduced financial flexibility.

Borrowing Authority – Current Forecast

U.S. Treasury Bonds Outstanding – Historical & Forecast (BP-22 IPR Capital)



- Borrowing Authority is an Agency-level financing tool.
- Transmission's use of Borrowing Authority drives the access to capital problem.

Assumes FY18 Actuals, Adjusted Leverage calculation, RCD2 through 2030, no new Lease Purchase

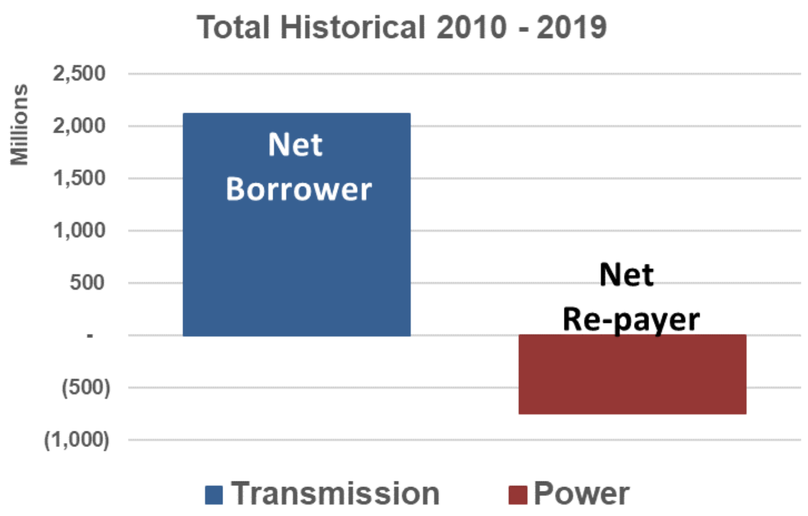
Borrowing Authority Details

- Our current forecast shows that in 2024, BPA has less than the $1.5b goal. Starting in 2025 the problem grows significantly, driven by Transmission's net borrowing position.
- While the problem is driven by Transmission, ***this is an Agency issue***. Regardless of which business line uses the borrowing authority, once depleted, both business lines are impacted.
- BPA has limited tools to ensure adequate access to capital.
  - The Lease Purchase program that Transmission has relied on may not be available in the same capacity as before. Moreover, relying entirely on 3rd party tools to solve the problem is not prudent.
  - In this latest forecast, ***Transmission leverage payments have decreased by ~$1.0B due to aligning the forecast ratio calculation to the actuals calculation.***

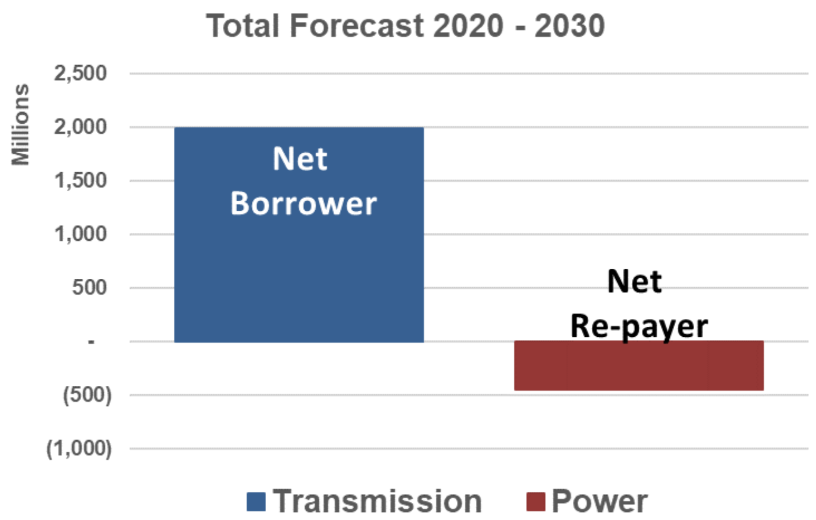
FY20 Plan	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	
Transmission													
UST Bond Payments		(200)	(205)	(220)	(223)	(217)	(199)	(214)	(266)	(291)	(376)	(391)	(2,802)
UST Bond Issuances		357	457	530	563	616	697	678	573	500	502	513	5,986
Trans. UST Bonds Outstanding	3,190	3,347	3,599	3,909	4,249	4,648	5,146	5,610	5,917	6,126	6,252	6,374	
Power													
UST Bond Payments		(151)	(519)	(493)	(517)	(474)	(502)	(501)	(467)	(641)	(496)	(466)	(5,228)
UST Bond Issuances		325	332	332	353	355	356	355	363	372	379	387	3,910
Power UST Bonds Outstanding	2,089	2,263	2,076	1,915	1,751	1,632	1,486	1,340	1,236	967	850	771	
Agency UST Bonds Outstanding	**5,280**	**5,611**	**5,676**	**5,825**	**6,000**	**6,281**	**6,632**	**6,951**	**7,154**	**7,093**	**7,102**	**7,146**	

Key Driver: Net Borrowing Position

- Transmission is and has been a net debt borrower.
  - Net borrowed approximately $2.1b since 2010.
  - Forecast to net borrow approximately $2.1b in the next ten years. This is the case even with additional leverage payments.
- Why is this important?
  - Net borrowing takes from BPA's limited remaining borrowing authority that is jointly used by Power and Transmission Services.
  - Net borrowing adds significant future fixed costs (interest expense) that will be recovered through transmission rates.



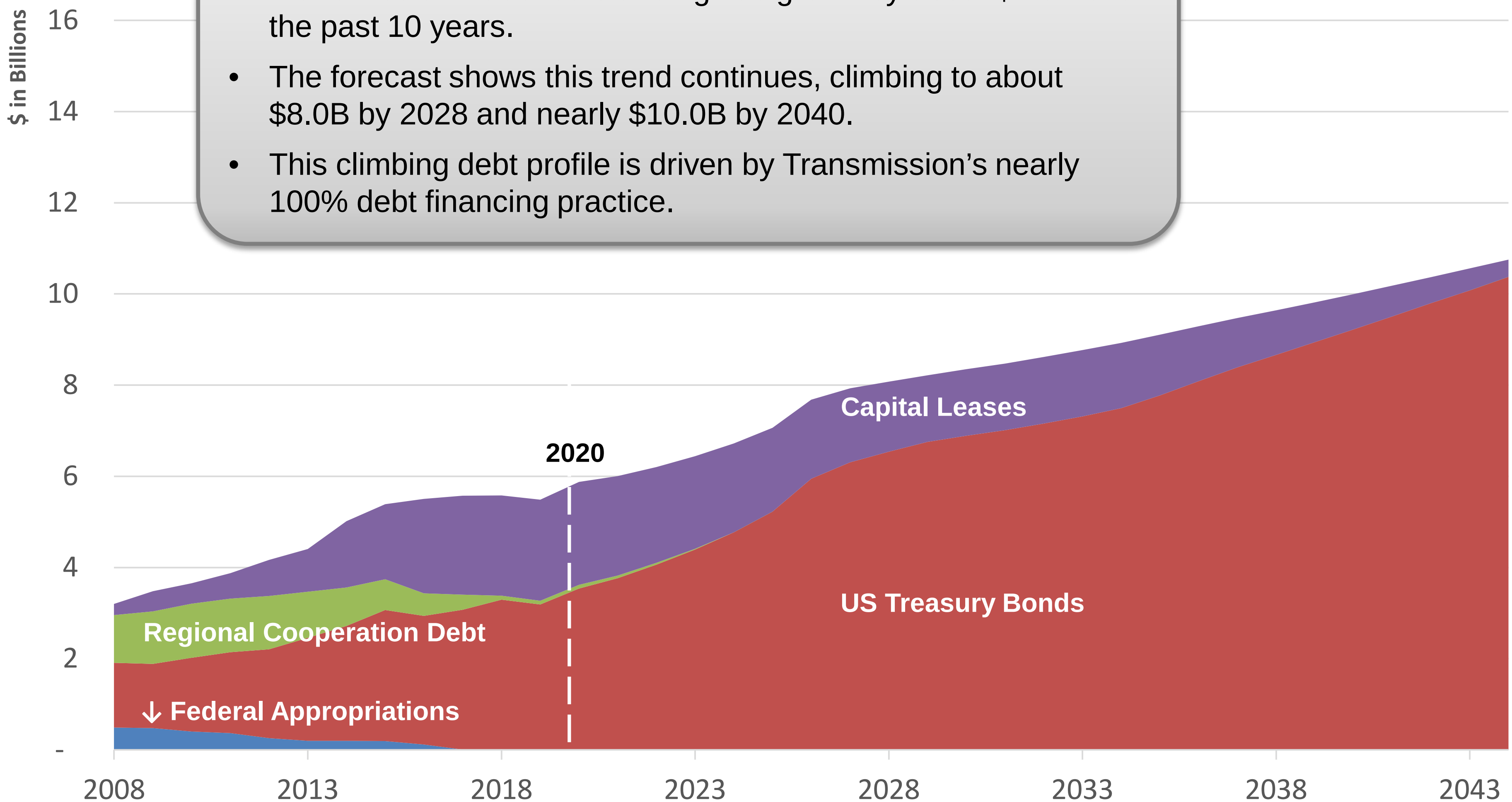
Source: Based on FCRPS audited financial statements



Source: Based on BP-22 IPR

Transmission's Increasing in Debt Profile

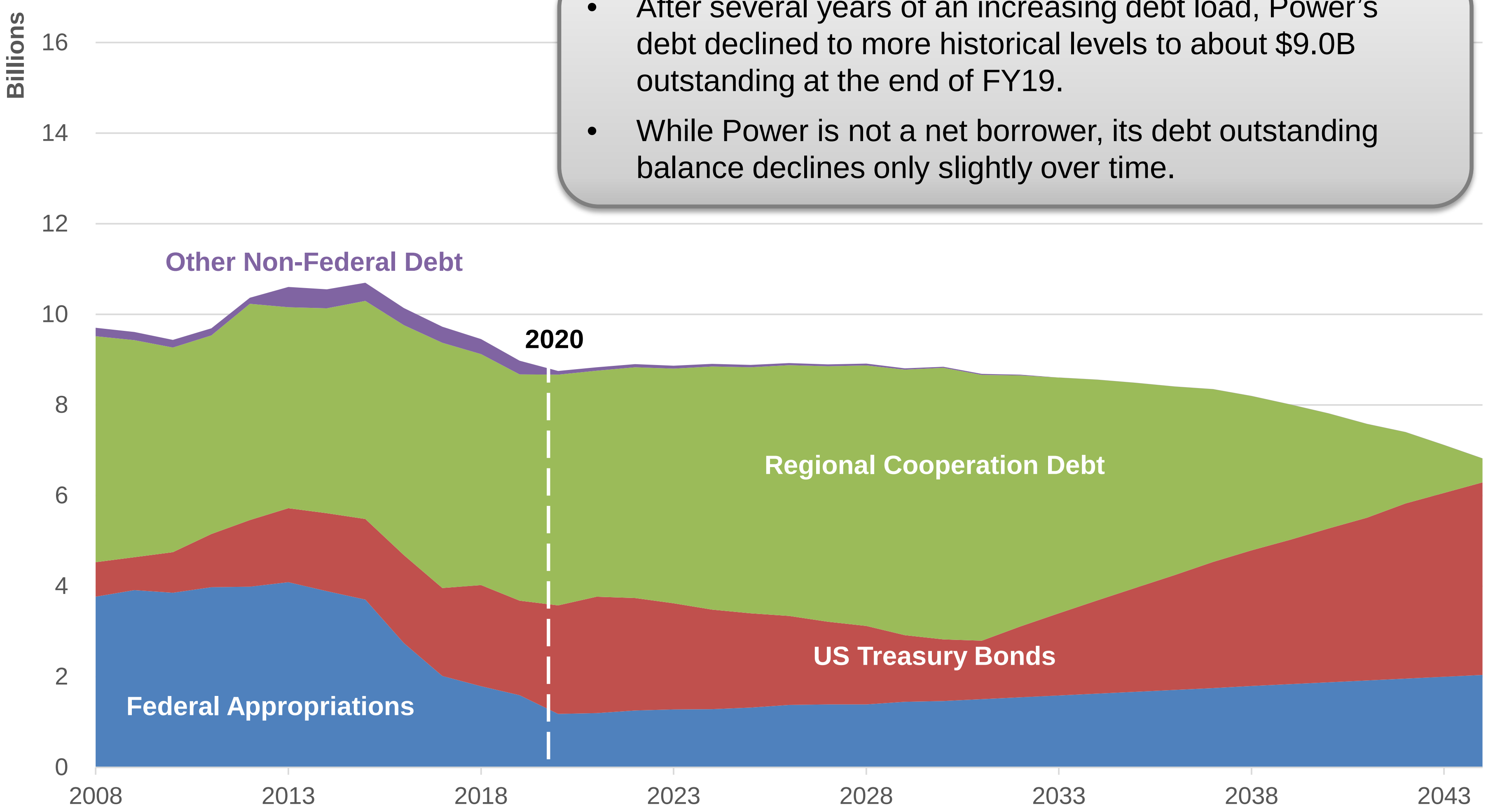
- Transmission's debt outstanding has grown by about $2.0B over the past 10 years.
- The forecast shows this trend continues, climbing to about $8.0B by 2028 and nearly $10.0B by 2040.
- This climbing debt profile is driven by Transmission's nearly 100% debt financing practice.



Source: BPA Audited Financial Statements FY 2008-FY2019

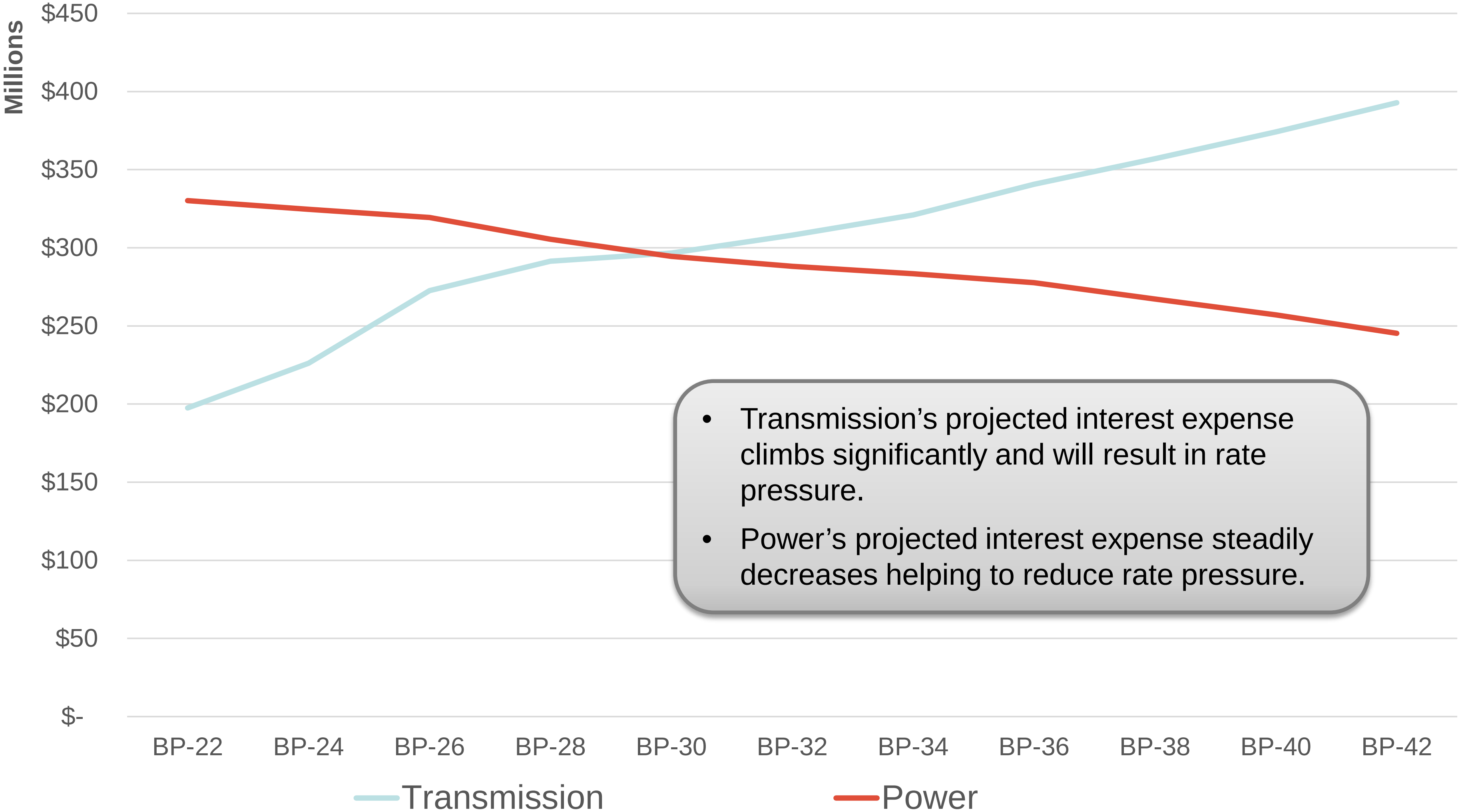
Power's Flat Debt Profile

- After several years of an increasing debt load, Power's debt declined to more historical levels to about $9.0B outstanding at the end of FY19.
- While Power is not a net borrower, its debt outstanding balance declines only slightly over time.



Source: BPA Audited Financial Statements FY 2008-FY2019

Total Projected Interest Expense



- Transmission's projected interest expense climbs significantly and will result in rate pressure.
- Power's projected interest expense steadily decreases helping to reduce rate pressure.

Source: BP-22 IPR

Rating Agency Leverage Perspective

- Moody's June2020 rating: "***Borrowing ability under the US Treasury line*** and the ability to defer debt service payments to the US Treasury are two of the most critical support features from the US government." "BPA's ratings could be lowered…if the adjusted availability under the US Treasury line declines significantly below $1.25 billion on a sustained basis…"

- From Fitch June 2020 rating, regarding the revision of BPA's Outlook to Negative from Stable: "***Bonneville's already high debt, together with its nearly 100% debt-financed capex plans*** and weak liquidity profile could limit its financial flexibility to respond to increased economic uncertainty."

- From Fitch June 2020 rating: "Factors that Could, Individually or Collectively, Lead to Positive Rating Action/Upgrade: Outperformance to budget in fiscal 2021 that increases reserves and improves financial flexibility. ***Rate case 2021–2023 approval that improves trajectory toward Bonneville's adopted financial reserves and leverage policies***."

What is the Proposed Solution?

- BPA projects to have less than $1.5B of remaining borrowing authority in 2024. We must take action in BP-22 to bend the curve.

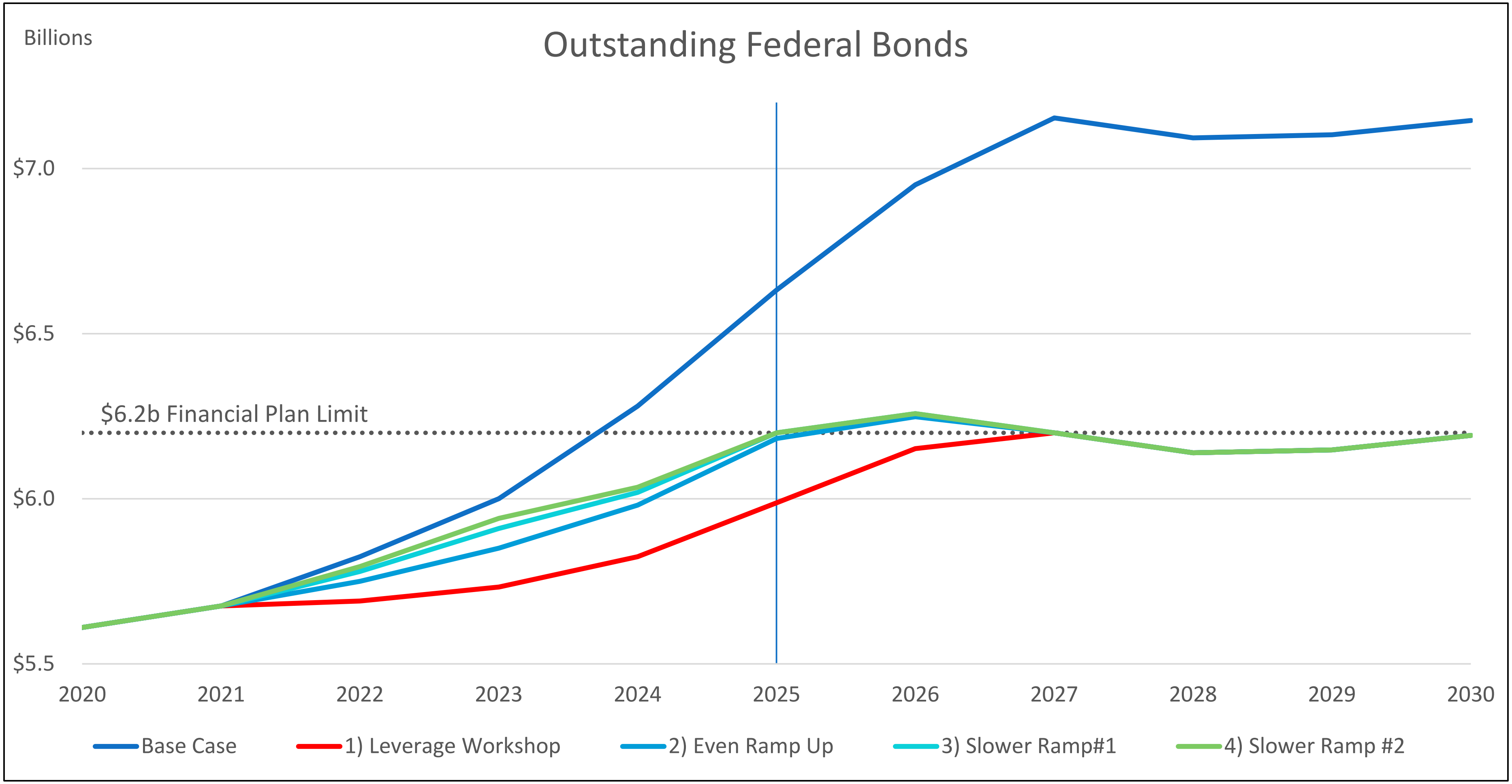
- Over the longer term, BPA must move toward a more net neutral borrowing position and declining debt position to:
  - Aid the access to capital challenge and adopt more sustainable capital funding practices that ensure we are not continually bumping up against borrowing authority constraints.
  - Ensure future rate periods are not unduly impacted by ever increasing interest expense costs.
  - Improve financial flexibility enabling BPA to respond during times of financial stress and uncertainty.

Approaches for Transmission BP-22

- Without action now, BPA falls short of maintaining $1.5b available borrowing authority and faces a tremendous challenge in BP-24.
- Doing nothing now means facing a borrowing authority shortfall of $432m in BP-24. If this is managed entirely with revenue financing in BP-24, it would create approximately 22% rate pressure in BP-24.

Approach	BP-22	BP-24
1) 2018 Leverage Policy Workshop	$134m/year ≈ 13.4% rate pressure	$188m/year ≈ 5.4% rate pressure
2) Even Ramp Up Start at 25% of Replacements	$75m/year ≈ 7.5% rate pressure	$150m/year ≈ 7.5% rate pressure
3) Slower Ramp #1 Start at 15% of Replacements	$45m/year ≈ 4.5% rate pressure	$171m/year ≈ 12.5% rate pressure
4) Slower Ramp #2 Start at 10% of Replacements	$30m/year ≈ 3% rate pressure	$186m/year ≈ 15.5% rate pressure

Borrowing Authority Impacts



Under each scenario, BP-26 includes revenue financing needed to retain $1.5b at the end of the rate period.

BP-22 Next Steps

- BPA seeks customer feedback on options that can mitigate this near term access to capital issue, while also recognizing that we will be discussing the longer term and overall debt management picture after BP22.

- Please submit to techforum@bpa.gov (with copy to your account executive) by **October 13, 2020**.

- Initial Proposal is in development and will be released later this year.

Post BP-22 Next Steps

- Prior to BP-24, BPA will develop and lay out an approach to capital financing that ensures BPA maintains at least $1.5b of available borrowing authority. The plan will include the trajectory and pace at which we achieve this objective.
- At the same time, BPA may consider additional enhancements to the financial plan. Likely topics include:
  - Additional financial metrics to track financial health and performance.
  - Liquidity needs of the agency and business units.
- Topics will be shared with customers via a series of public workshops, with comment periods.

Issue: Secondary Revenue and Revenue Financing for Power

Objective

- Power should take actions that provide substantial longer-term benefits to customers.
- As always, longer-term objectives need to be balanced with short-term objectives – specifically the immediate impact on rate level and affordability.

Short-Term Perspective

- BPA has worked hard over the last five years to “bend the cost curve” and deliver meaningful and measurable results that have reduced power rates.
- With 2022/23 IPR costs expected to be flat in nominal terms (decreasing in real terms), rate pressures that are a result of cost increases are expected to be minimal – **about 1%** for the rate period due, in large part, to the escalation of benefits built into the REP Settlement Agreement.
- Non-cost related rate pressure is also expected to be minimal, currently estimated at about 1% as a result of changes in forecast loads and resources.
- We also expect the BP-22 secondary revenue forecasts to be rate decreasing.
- Considering the above, BPA staff believes that the short-term objective is being, and will continue to be, met and that BPA should begin taking a longer-term perspective and consider actions that would result in longer-term benefits.

Rate Level in Perspective

- At what point is the short-term objective met?
- The answer to this question is certainly subjective and would need to be grounded on historical rate levels, the current landscape, expectations for the future, and available benchmarks.
- BPA staff currently believes a rate change of 1% or less would conservatively meet the short-term objective. Why?
  - Setting aside the potential increase in secondary revenue, the rate change would have been about 1% based on costs alone.
  - BPA's IPR costs are expected to be flat and thus are not contributing to the 1% increase in costs.
  - 1% is well below the rate of inflation, which means BPA's rates would be decreasing in real terms.
  - BPA's 10-year power rate change (roughly 24%) is now very close to the increase historical inflation alone would have produced (roughly 20%).

Actions with Longer-Term Benefits

- There are two obvious areas of potential action that BPA could take that would provide longer-term benefits to customers.
  - **Rate stability** - reduce reliance on uncertain revenue for purposes of collecting BPA's costs.
    - The secondary revenue concept we shared at the last few workshops.
  - **Debt** - reduce debt costs and ease future borrowing constraints.
    - Early amortization of existing debt.
    - Revenue financing new debt.

Customer Comments

- Public customers provided feedback that the secondary revenue construct, as proposed by BPA staff, was not appealing.
- Public customers have not yet had an opportunity to provide feedback on the idea of Power early-amortizing debt or revenue financing during the BP-22 rate period.

Secondary Revenue Concept

- We heard resistance to leaving the Reserves Distribution Clause (RDC) unchanged until a comprehensive evaluation could be done for BP-26.
- We remain open to ideas that would make the secondary revenue concept palatable to customers.
- That said, customers may be more amenable to the concept of revenue financing as the preferred action. It would provide longer-term, direct benefits to customers by not increasing future debt obligations and alleviate customer concerns associated with BPA building financial reserves until Power had the equivalent of 120-days cash on hand.

Revenue Financing

- The concept would be to include revenue financing in power rates with a cap of up to 1% of rate pressure above base rates.
- The maximum amount of revenue financing would be determined in the rate case based on the expected financial performance through the rate period.
- When financial performance is expected to be strong, Power would likely do revenue financing up to the maximum amount established in the final proposal.
- When financial performance is expected to be weak, Power could forego revenue financing entirely.
- The cost of revenue financing would be included in the Composite Cost pool and be subject to the Slice True-up.
- Due to its simplicity and the customer response to our secondary revenue concept, BPA is currently leaning towards this concept to provide direct and longer-term benefits to customers.

Next Steps

- Customer feedback on the revenue financing concept to provide longer-term benefits to customers by accelerating repayment of existing debt repayment and easing future debt obligations.
- Although Public customers were not initially supportive of BPA's secondary revenue proposal, are there modifications to the proposal that could be made to alter their perspective?

Customer Comments

- Please submit to techforum@bpa.gov (with copy to your account executive) by **October 13, 2020**.

Power Regulatory Assets

Power Regulatory Assets

- Two decisions have been made about Power regulatory assets.
- BPA will discontinue regulatory asset treatment of Columbia River Fish Mitigation (CRFM) program studies starting in FY 2022.
  - Spending in BP-22 averages $5 million/year, dropping to about $3 million/year starting in 2024. It will be expensed in each year.
  - Initial Proposal repayment study results are lower than in IPR, offsetting in full the increase in expense due to this change.
  - This only affects spending starting in FY 2022. It does not affect historical spending.
- The amortization period for the existing CRFM regulatory asset will be shortened from 75 years to 50 years.
  - This would align the repayment period and the amortization period.
  - Any change would only affect future amortization. No restatement of the past.
  - Amortization expense would go up (approximately $7 million/year) but would be offset by a matching reduction in MRNR.

Customer Comments

- Please submit to techforum@bpa.gov (with copy to your account executive) by **October 13, 2020**.

ISSUE #4: TRANSMISSION GRSP FOR EIM AND GENERATION INPUTS

EIM
Rate Schedule Language

Guiding Principles

- Start with Existing language used by other entities
- Clarifications / Modifications
  - Adding clarifying language where Tariff description of charge was not clear or could not be determined.
  - Removed language that was inapplicable or unnecessary
  - Added new language to address BPA specific issues

Scope of Changes

- Changes to Existing Schedules 4 (Energy Imbalance) and 9 (Generator Imbalance)
- New Schedule provisions to implement EIM cost allocation among BPAT Transmission customers.

Changes to Schedules 4 (Energy Imbalance) and 9 (Generator Imbalance)

- Changes to *existing* Schedules 4 and 9.
  - Traditional EI/GI will be in place *until* BPA joins EIM.
  - Traditional EI/GI will *toggle* on if EIM is suspended (per OATT terms).
  - Need rate schedule language to do this.

Changes to *existing* EI/GI (Schedule 4/9)

D. ENERGY IMBALANCE SERVICE (SCHEDULE 4T)

The rates below apply to Transmission Customers taking Energy Imbalance Service from BPA and shall apply until BPA joins the EIM and begins financial settlements for Energy Imbalance Service pursuant to Section IV. After BPA joins the EIM, all charges and credits for Energy Imbalance Service shall be settled in accordance with Section IV. This Section II.D shall also apply in the event the EIM is suspended pursuant to section 10 of Attachment Q of the BPA Tariff.

B. GENERATION IMBALANCE SERVICE (SCHEDULE 9T)

The rates below apply to generation resources in the BPA Control Area if Generation Imbalance Service is provided for in an interconnection agreement or other arrangement. The rates below shall apply until BPA joins the EIM and begins financial settlements for Generation Imbalance Service pursuant to Section IV. After BPA joins the EIM, all charges and credits for Generation Imbalance Service shall be settled in accordance with Section IV. This Section III.B shall also apply in the event the EIM is suspended pursuant to section 10 of Attachment Q of the BPA Tariff.

Structure of EIM Rate Schedule

1. EIM Imbalance Charges
   a. Energy Imbalance Service (Schedule 4E)
   b. Generator Imbalance Service (Schedule 9E)
      (1) GI When No Changes Made After T-57
      (2) GI When Changes Made After T-57
2. Interchange and Intrachange Imbalance
3. Charges for Under-Scheduling or Over-Scheduling Load
4. EIM Neutrality and Uplift Charges and Credits
5. Rolled In Charges
6. Other Charges and Provisions

Energy Imbalance Charges

- Energy Imbalance Service (Schedule 4E)
  - Follows same as EIM Entities language

1. Energy Imbalance Service (Schedule 4E) (EIM)

A Transmission Customer shall be charged or paid for Energy Imbalance Service measured as the deviation of the Transmission Customer's metered load compared to the load component of the Transmission Customer Base Schedule (as determined

pursuant to Section 4.2.4 of Attachment Q of Bonneville's Tariff) settled as UIE for the period of the deviation at the applicable LAP price where the load is located as determined by the MO under Section 29.11(b)(3)(C) of the MO Tariff.

Generator Imbalance Charge

Structure of EIM Schedule 9E…

2. Generator Imbalance Service (Schedule 9E)
   - a. Generator Imbalance Service When No Schedule Changes Occur to Resource After T-57
     - UIE (Metered Gen – Scheduled Output at RTD)
   - b. Generator Imbalance Service When Schedule Changes Occur to Resource After T-57
     - (1) GI – Uninstructed Imbalance Energy Charges / Credits
     - (2) GI – Instructed Imbalance Energy Charges/Credits
       - (a) FMM IIE (Scheduled Output at FMM-TCBS)
       - (b) RTD-IIE (Scheduled Output at RTD-FMM)
       - (c) Intrachange Imbalance Adjustment

Generator Imbalance Service (Schedule 9E)

2. Generation Imbalance Service (Schedule 9E) (EIM)

a. Generation Imbalance Service When No Schedule Changes Occur to Resource After T-57.

~~The Transmission Provider shall establish charges for Generator Imbalance Service as follows (the following provisions do not apply to Transmission Customers which have received a Manual Dispatch or EIM Available Balancing Capacity dispatch, or which have communicated physical changes in the output of resources to the MO):~~

Except as provided for in section 2(B) below, Transmission Customer shall be charged or paid for Generator Imbalance Service measured as the deviation of the Transmission Customer's metered generation compared to the resource component of the Transmission Customer Base Schedule settled as UIE for the period of the deviation at the applicable PNode RTD price where the generator is located, as determined by the MO under Section 29.11(b)(3)(B) of the MO Tariff.

Generator Imbalance Service (Schedule 9E)

~~B~~b.~~-~~ Generation Imbalance Service When Changes Occur To Resource Schedule After T-57.

For Transmission Customers that have received a Manual Dispatch or EIM Available Balancing Capacity dispatch, or if the scheduled output of a resource changes after T-57, ~~which have communicated physical changes in the output of resources to the MO,~~ the following provisions shall apply:

Generator Imbalance Service (Schedule 9E)

(1) GI - Uninstructed Imbalance Energy Charges/Credits.

~~(1) (a) A Transmission Customer shall be charged or paid for Generator Imbalance Service measured as the deviation of the Transmission Customer's metered generation compared to the Manual Dispatch amount, the EIM Available Balancing Capacity dispatch amount, or physical changes in the output of resources incorporated by the MO in the FMM, settled as UIE for the period of the deviation at the applicable PNode RTD price where the generator is located, as determined by the MO under Section 29.11(b)(3)(B) of the MO Tariff; or~~

~~(b)~~ *UIE/RTD (Metered Gen - Scheduled Output at RTD)*

A Transmission Customer shall be charged or paid for Generator Imbalance Service measured as the deviation of the Transmission Customer's metered generation compared to the Manual Dispatch amount, the EIM Available Balancing Capacity dispatch amount, or the scheduled output of a resource ~~physical changes in the output of resources~~ incorporated by the MO in RTD, settled as UIE for the period of the deviation at the applicable PNode RTD price where the generator is located, as determined by the MO under Section 29.11(b)(3)(B) of the MO Tariff.

Can this occur?

Generator Imbalance Service (Schedule 9E)

(2) GI - Instructed Imbalance Energy Charges/Credits

~~(2)~~ (a) *FMM-IIE (Scheduled Output at FMM - TCBS)*
A Transmission Customer shall be charged or paid for Generator Imbalance Service measured as the deviation of ~~either~~ the Manual Dispatch amount, the EIM Available Balancing Capacity dispatch amount, or the scheduled output of a resource ~~physical changes in the output of resources~~ incorporated by the MO in the FMM ("FMM Schedule"), compared to the resource component of the Transmission Customer Base Schedule, settled as IIE for the period of the deviation at the applicable PNode FMM price where the generator is located, as determined by the MO under Section 29.11(b)(1)(A)(ii) of the MO Tariff; or

(b) *RTD-IIE (Scheduled Output at RTD –FMM)*
A Transmission Customer shall be charged or paid for Generator Imbalance Service measured as the deviation of ~~either~~ the Manual Dispatch amount, the EIM Available Balancing Capacity dispatch amount, or the scheduled output of a resource ~~physical changes in the output of resources~~ incorporated by the MO in RTD, compared to the FMM S~~s~~chedule, as IIE for the period of the deviation at the applicable PNode RTD price where the generator is located, as determined by the MO under Section 29.11(b)(2)(A)(ii) of the MO Tariff.

Generator Imbalance Service (Schedule 9E)

- We will talk about this more in a bit, but the IIE payments for resources may change if there are intra-changes…
- We have this last part in Schedule 9E…

(c) *Intrachange Imbalance Adjustment.*
If a Transmission Customer elects to receive Intrachange Imbalance pursuant to the BPA EIM BP, then the FMM-IIE and RTD-IIE associated with such Intrachange shall be settled with the resource in accordance with Section IV.C.2.b. of this section.

Interchange / Intrachange Imbalance and IIE

- Definition of IIE for most EIM Entities.

1.38 **Instructed Imbalance Energy (IIE)**: There are three scenarios that can lead to settlement of imbalance as IIE: (1) operational adjustments of the Transmission Customer's affected Interchange or Intrachange, which includes changes by the Transmission Customer after T-57, (2) resource imbalances created by Manual Dispatch or an EIM Available Balancing Capacity dispatch, or (3) an adjustment to resource imbalances created by adjustments to resource forecasts pursuant to Section 11.5 of the MO Tariff.

- NOTE: Most EIM Entities include **Intrachange** in definition of IIE…

Interchange/Intrachange EIM Entities

"interchange imbalance" (in code)

8.1 Instructed Imbalance Energy (IIE)

The PGE EIM Entity shall settle as IIE imbalances that result from (1) operational adjustments of a Transmission Customer's affected Interchange, which includes changes by a Transmission Customer after T-57, (2) resource imbalances created by Manual Dispatch or an EIM Available Balancing Capacity dispatch, or (3) an adjustment to resource imbalances created by adjustments to resource forecasts pursuant to Section 11.5 of the MO Tariff and using the RTD or FMM price at the applicable PNode. Any allocations to the PGE EIM Entity pursuant to Section 29.11(b)(1) and (2) of the MO Tariff for IIE that is not otherwise recovered under Schedule 10 of this Tariff shall be settled directly with each Transmission Customer according to this Section 8.1.

Already covered by Sch. 9

??? Schedule 9

- PGE Tariff says IIE can be assessed to Interchange, does not mention Intrachange. (although it mentions intrachange in BP?)
- PSE includes intrachange in above language.
- IPC excludes intrachange, but also adds a catchall for IIE at end.
  - (But mentions IPC *can* settle Intrachange in BP?)

BPA's Proposed language

BPA's Definition of IIE.

A type of Imbalance Energy that occurs when changes are made to a resource, Interchange, or Intrachange schedule after the submission of the TCBS. IIE will be settled at either the FMM or RTD price at the applicable PNode depending on the nature and timing of the imbalance.

Structure of BPA's proposed language:

C. INTERCHANGE AND INTRACHANGE IMBALANCE

1. Interchange Imbalance
   a. Calculation of Interchange Imbalance – FMM-IIE
   b. Calculation of Interchange Imbalance – RTD-IIE
2. Intrachange Imbalance
   a. Calculation of Intrachange Imbalance – FMM-IIE
   b. Calculation of Intrachange Imbalance – RTD-IIE
   c. Adjustment to IIE Settlement for Resources that Supply Energy For an Intrachange

Interchange Imbalance

1. Interchange Imbalance.

Interchange Imbalance is assessed when deviations occur between the Interchange portion of a Transmission Customer's Base Schedule and the schedule value at the applicable FMM or RTD market interval. Transmission Customers with Interchange Imbalance shall be assessed IIE at either the Fifteen Minute Market (FMM) LMP, the Real-Time Dispatch (RTD) LMP, or both, depending upon when the changes to the Transmission Customer's Interchange are incorporated by the MO into the applicable EIM market run. Interchange Imbalance shall be calculated as follows:

- Interchange Imbalance calculates deviations between TCBS and either FMM market run or RTD market run (or between FMM and RTD market run).
- Price assessed is the FMM LMP or RTD LMP (or both).
- Whether you get charged is dependent on when your change is incorporated by the MO into the applicable EIM market run.
  - This is important!
  - Whether your change will affect your IIE depends on
    - (1) when you make a change;
    - (2) when Bonneville communicates that change to the MO; and
    - (3) when the MO takes BPA's data and includes it in a market run.

Interchange Imbalance – FMM-IIE

a. Calculation of Interchange Imbalance - FMM-IIE

A Transmission Customer shall be charged or paid for Interchange Imbalance measured as the deviation of the Interchange /portion of the Transmission Customer's Base Schedule compared to the Interchange /schedule incorporated by the MO in the FMM ("FMM Schedule"). Such imbalance shall be settled as FMM-IIE for the period of the deviation at the applicable PNode FMM price where the Interchange is located, as determined by the MO under Section 29.11(b)(1)(A)(ii) of the MO Tariff.

- TCBS – FMM Schedule. FMM schedule is your Interchange at the FMM interval which is communicated to MO by BPA and incorporated into the FMM run by the CAISO.

Interchange Imbalance – RTD-IIE

b. Calculation of Interchange Imbalance - RTD-IIE

A Transmission Customer shall be charged or paid for Interchange Imbalance measured as the deviation of the FMM Schedule compared to the Interchange schedule incorporated by the MO in the RTD. Such imbalance shall be settled as RTD-IIE for the period of the deviation at the applicable PNode RTD price where the Interchange ~~/~~is located, as determined by the MO under Section 29.11(b)(2)(A)(ii) of the MO Tariff.

- FMM Schedule – RTD. Calculates the difference between the FMM Schedule from (a) with the last schedule change captured in the RTD.

Intrachange Imbalance

2. Intrachange Imbalance.

Intrachange Imbalance is assessed when deviations occur between the Intrachange portion of a Transmission Customer's Base Schedule and the Transmission Customer's Intrachange schedule at an applicable FMM or RTD market interval. BPA will assess Intrachange Imbalance when requested by Power Services or a Transmission Customer and upon meeting the requirements in the BPA EIM BP. Intrachange Imbalance shall be assessed IIE at either the Fifteen Minute Market (FMM) LMP, the Real-Time Dispatch (RTD) LMP, or both, depending upon when the changes to the Transmission Customer's Intrachange occurs. Intrachange Imbalance shall be calculated as follows:

- Voluntary. Requires Transmission customer request.
- Designed to assign IIE Credits/debits from resource to load.

Why need Intrachange?

- CAISO does not settle Intrachange. CAISO only sees resource schedules and Interchange.
  - Applies when resource *not owned by load* sells load power, and delivers within BPA's BAA.
- Intrachange is a part of Transmission Customer's Base Schedule
  - See 4.2.4.3. Transmission customer WILL be charged/paid UIE for deviations between Intrachange at TCBS and actual.
- Changes to resource *for* Intrachange is charged to Resource as IIE (under Schedule 9).
- Unless costs/credits reassigned, resource will get IIE, load will get UIE.

IIE Credits to Resource

- Example.
  - Load has contract from resource to purchase up to 210 MW from NPR2. Load does NOT own NPR2.
  - Load owns NPR1.
  - Load schedules 200 MW at T-57, and then 210 MW at T-30.
  - Load gets UIE charge (Schedule 4) of $406.70
  - But… Load met its imbalance. Why charged? Where did the offsetting Credit go?
  - It went to NPR2 under Schedule 9 as IIE.

						LMP	LMP	LAP
						$ 40.00	$ 40.00	$ 40.67
		T-57	**T-40**	**T-30**	**Actual Meter**	**FMM-IIE**	**RTD-IIE**	**UIE**
Schedule 4	***Load TCBS***							
	Resources (NPR1)	150	150	150				
	Intrachange (NPR2)	200	200	210				
	Total	350	350	360	360			$ 406.70
Schedule 9	NPR 1	150	150	150	150	$ -	$ -	$ -
	NPR2	200	200	210	210	$ -	$ (400.00)	
Intrachange IIE (GRSP)	Intrachange					$ -	$ -	

Load's Final Position		
UIE	$	406.70
Intrachange IIE		0
NPR1 Resource IIE	$	-
NPR1 Resource UIE	$	-
Total	$	406.70

NPR Gen2's Final Position		
Resource UIE		0.00
Resource IIE	$	(400.00)
Total	$	(400.00)

IIE Debits to Resource

- Same facts… but now Load is DECing its Intrachange Schedule.
- Load gets credits… (as UIE)
- NPR2 gets Debits (as IIE)

						LMP	LMP	LAP
						$ 40.00	$ 40.00	$ 40.67
		T-57	T-40	T-30	Actual Meter	FMM-IIE	RTD-IIE	UIE
Schedule 4	***Load TCBS***							
	Resources (NPR1)	150	150	150				
	Intrachange (NPR2)	210	210	200				
	Total	360	360	350	350			$ (406.70)
Schedule 9	NPR 1	150	150	150	150	$ -	$ -	$ -
	NPR2	210	210	200	200	$ -	$ 400.00	

Load's Final Position	
UIE	$ (406.70)
Intrachange IIE	0
NPR1 Resource IIE	$ -
NPR1 Resource UIE	$ -
Total	$ (406.70)

NPR Gen2's Final Position	
Resource UIE	0.00
Resource IIE	$ 400.00
Total	$ 400.00

Intrachange can align Credits/Debits

- Inc example… NPR2 is zeroed out… no IIE for Intrachange
- The credit/debit is assigned to Load through the Intrachange Imbalance… offsetting credit.
- Net difference that load pays is congestion between LAP and LMP.

						LMP	LMP	LAP
						$ 40.00	$ 40.00	$ 40.67
		T-57	T-40	T-30	Actual Meter	FMM-IIE	RTD-IIE	UIE
Schedule 4	***Load TCBS***							
	Resources (NPR1)	150	150	150				
	Intrachange (NPR2)	200	200	210				
	Total	350	350	360	360			$ 406.70
Schedule 9	NPR 1	150	150	150	150	$ -	$ -	$ -
	NPR2	200	200	210	210	$ -	$ (400.00)	
	Intrachange Adj.	-200	-200	-210	-210		$ 400.00	
Intrachange IIE (GRSP)	Intrachange IIE	200	200	210	210	$ -	$ (400.00)	

Load's Final Position	
UIE	$ 406.70
Intrachange IIE	$ (400.00)
NPR1 Resource IIE	$ -
NPR1 Resource UIE	$ -
Total	$ 6.70

NPR Gen2's Final Position	
Resource UIE	0.00
Resource IIE	$ -
Total	$ -

Intrachange can align Credits/Debits

- Same Facts, but DEC example. Same answer.

						LMP	LMP	LAP			
						$ 40.00	$ 40.00	$ 40.67			
		T-57	**T-40**	**T-30**	**Actual Meter**	**FMM-IIE**	**RTD-IIE**	**UIE**		Load's Final Position	
Schedule 4	***Load TCBS***									UIE	$ (406.70)
	Resources (NPR1)	150	150	150						Intrachange IIE	$ 400.00
	Intrachange (NPR2)	210	210	200						NPR1 Resource IIE	$ -
										NPR1 Resource UIE	$ -
	Total	360	360	350	350			$(406.70)		Total	$ (6.70)
Schedule 9	NPR 1	150	150	150	150	$ -	$ -	$ -		NPR Gen2's Final Position	
	NPR2	210	210	200	200	$ -	$ 400.00			Resource UIE	0.00
	Intrachange Adj.	-210	-210	-200	-200		$(400.00)			Resource IIE	$ -
										Total	$ -
Intrachange IIE (GRSP)	Intrachange IIE	210	210	200	200	$ -	$ 400.00				

Intrachange Rate Schedule Language

a. Calculation of Intrachange Imbalance - FMM-IIE

A Transmission Customer shall be charged or paid for Intrachange Imbalance measured as the deviation of the Intrachange portion of the Transmission Customer's Base Schedule compared to the Transmission Customer's Intrachange schedule at the applicable FMM interval ("FMM Schedule"). Such imbalance shall be settled as FMM-IIE for the period of the deviation at the applicable PNode FMM price where the source resource responsible for the Intrachange is located, as determined by the MO under Section 29.11(b)(1)(A)(ii) of the MO Tariff.

b. Calculation of Intrachange Imbalance – RTD-IIE

A Transmission Customer shall be charged or paid for Intrachange Imbalance measured as the deviation of the FMM Schedule compared to the Transmission Customer's Intrachange schedule at the applicable RTD interval. Such imbalance shall be settled as RTD-IIE for the period of the deviation at the applicable PNode RTD price where the source resource responsible for the Intrachange is located, as determined by the MO under Section 29.11(b)(2)(A)(ii) of the MO Tariff.

- Follows same FMM-IIE and RTD-IIE as Interchange.

Intrachange Adjustment

c. Adjustment to IIE Settlement for Source Resource Responsible for an Intrachange

The source resource responsible for an Intrachange shall be charged or paid an amount of Intrachange Imbalance that exactly offsets the Intrachange Imbalance paid or charged the Transmission Customer under Sections IV.C.2.a and b above.

- Explains the "setoff" so resource does not get IIE credits/debits for Intrachange Schedule.
- NOTE: Resource will still get UIE for any deviations from RTD schedule value (which makes sense).

Under/Over Scheduling Charges

- Adopting Other EIM Entities' language, except for distribution of proceeds.
  - Under/Over Scheduling… (Imbalance by Direction)
- Distribution of credits from other BAAs

3. Distribution of Under-Scheduling or Over-Scheduling Proceeds

Any payment to the ~~PGE~~BPA EIM Entity pursuant to Section 29.11(d)(3) of the MO Tariff shall be distributed to Transmission Customers ~~that were not subject to underscheduling or overscheduling charges during the Trading Day~~ on the basis of Metered Demand whose daily average absolute imbalance is less than 5 percent or 2 MW (whichever is greater) of its daily average schedule. ~~and in accordance with the procedures outlined in the PGE EIM BP~~.

Measured Demand

- Current Definition used by ALL EIM Entities

1.50 **Measured Demand**

Includes (1) Metered Demand, plus (2) e-Tagged export volumes from the PGE BAA (excluding EIM Transfers).

- BPA intends to use this definition in GRSP.

--. Measured Demand:
Includes (1) Metered Demand, plus (2) e-Tagged export volumes from the ~~PGE~~ BPA BAA (excluding EIM Transfers).

Other Provisions

- EIM Entities list out charges that are not sub allocated…
- BPA will include following provision instead…

F. ROLLED IN CHARGES

All other charges or credits assessed by the MO to the BPA EIM Entity that are not otherwise allocated by this Section IV shall be rolled in and recovered through base Transmission rates.

- Other Charges and Provisions
  - Tax liability (?)
  - Resettlement
- Not including provisions related to…
  - EIM transmission service (unnecessary)
  - VER Forecast Charge (see BPA decision on VER forecasting)
  - EIM Payment Calendar (in Tariff)
  - EIM Residual Balancing Account (does not apply)
  - Allocation of Operating Reserves (rolling this in)

Next Steps

- Redline rate schedules are available on the Meetings and Workshop page.
- Please submit to techforum@bpa.gov (with copy to your account executive) by **October 13, 2020**.

Gen Inputs
Rate Schedule Language

Scope of Changes

- Changes to VERBS, PD, and ID
- Changes designed to accommodate EIM participation, but apply both in and out of the EIM

Changes to VERBS Rate

- Change from existing three components to two
  - Previously provided for Regulation, Following, and Imbalance
  - Change to Regulation and Non-Regulation
- Elimination of Scheduling Elections
  - Previously provided for 30/60, 30/15, and Uncommitted scheduling options
  - Change to use of Forecast scheduling only

Changes to VERBS Rate

a. BALANCING SERVICE RATES FOR WIND RESOURCES

Customers taking Balancing Service will receive BPA's Variable Energy Resource reliability forecast) and submit schedules that are consistent with the signal or that result in less imbalance for the scheduling period.

(a)	Regulating Reserves	$X.XX per kilowatt per month
(b)	Non-Regulating Reserves	$X.XX per kilowatt per month

Changes to Intentional Deviation

- Previous language designed to accommodate scheduling elections
- New language designed to:
  - Measure ID based on the hourly forecast, and account for schedule changes made after T-57
  - Exclude market dispatches from the measurement of Station Control Error

Changes to Intentional Deviation

3. BILLING FACTOR

The Billing Factor in MWh shall be:

ABS(Intentional Deviation Measurement Value – Resource Schedule) – 1

~~*Multiplied by*~~

~~Minutes of schedule divided by 60 minutes~~

Where:

ABS = the absolute value of the term in parentheses.

Intentional Deviation Measurement Value = one of the following:

1) for wind generating customers taking VERBS under rate schedule section 2.a., the applicable schedule value provided by BPA;

2) for solar generating customers taking VERBS under rate schedule section ~~3.a.~~ 2.b, the applicable schedule value provided by BPA.

Resource Schedule = for each wind or solar resource, the amount in megawatts of generation that is scheduled by the customer ~~for the scheduling period~~ integrated over the hour.

~~Minutes of schedule = 15 if a 15-minute schedule, 30 if a 30-minute schedule, or 60 if a 60-minute schedule.~~

Changes to Intentional Deviation

4. OTHER PROVISIONS

EXEMPTION FROM INTENTIONAL DEVIATION PENALTY CHARGE

A customer that schedules its resource to a value other than the Intentional Deviation Measurement Value is exempt from the Intentional Deviation Penalty Charge for a scheduling period if

ABS(Station Control Error) ≤ ABS(Intentional Deviation Measurement Value Error) + 1 MW

Where:

ABS(Intentional Deviation Measurement Value Error) = the absolute value of the Station Control Error that *would have resulted* from a schedule that was set equal to the resource's applicable Intentional Deviation Measurement Value. Any interval in which a Variable Energy Resource that is a Participating Resource in the Energy Imbalance Market receives an instructed dispatch from the Market Operator is excluded from the calculation of Station Control Error and Intentional Deviation Measurement Value Error.

Changes to Persistent Deviation

- Moved PD into its own rate schedule provision consistent with other penalty rates
- Language changes designed to accommodate schedule changes after T-57
- Limits the application of PD to only the UIE portions of EI and GI

Changes to Persistent Deviation (GI)

L. Persistent Deviation Penalty Charge

1. GENERATION IMBALANCE SERVICE

a. APPLICABILITY

For Dispatchable Energy Resources taking Generation Imbalance Service pursuant to ACS III.B and IV.B.2, the Persistent Deviation Penalty Charge applies to all hours or scheduled periods in which either a negative deviation (actual generation greater than scheduled) or positive deviation (generation is less than scheduled) exceeds:

(1) both 15 percent of the integrated hourly schedule and 20 MW in each scheduled period for four consecutive hours or more in the same direction;

(2) both 7.5 percent of the integrated hourly schedule and 10 MW in each scheduled period for six consecutive hours or more in the same direction;

(3) both 1.5 percent of the integrated hourly schedule and 5 MW in each scheduled period for twelve consecutive hours or more in the same direction; or

(4) both 1.5 percent of the integrated hourly schedule and 2 MW in each scheduled period for twenty-four consecutive hours or more in the same direction.

For Generation Imbalance Service pursuant to ACS IV.B.2, positive or negative deviations will be based on the measurement value used for determining Uninstructed Imbalance Energy pursuant to that section.

Changes to Persistent Deviation (GI)

b. RATE

No credit is given for negative deviations (actual generation greater than scheduled) for any hour(s) that the imbalance is a Persistent Deviation (as determined by BPA).

For positive deviations (actual generation less than scheduled) that are determined by BPA to be Persistent Deviations, the charge is the greater of (i) 125 percent of either BPA's highest incremental cost that occurs during that day for service under ACS III.B, or the LMP for service under ACS IV.B.2, or (ii) 100 mills per kilowatthour.

If the energy index is negative in any hour(s) in which there is a negative deviation (actual generation greater than scheduled) that BPA determines to be a Persistent Deviation, the charge is the energy index for that hour.

If BPA assesses a Persistent Deviation Penalty charge in any scheduled period for a positive deviation, BPA will not also assess a charge pursuant to ACS II.B or ACS.IV.B.2. New generation resources undergoing testing before commercial operation are exempt from the Persistent Deviation penalty charge for up to 90 days.

Changes to Persistent Deviation (EI)

1. ENERGY IMBALANCE SERVICE

a. APPLICABILITY

For customers taking Energy Imbalance Service pursuant to ACS II.D and IV.B.1, the Persistent Deviation Penalty Charge applies to all hours or scheduled periods in which either a negative deviation (energy taken is less than the scheduled energy) or positive deviation (energy taken is greater than energy scheduled) exceeds:

(1) both 15 percent of the integrated hourly schedule and 20 MW in each scheduled period for four consecutive hours or more in the same direction;

(2) both 7.5 percent of the integrated hourly schedule and 10 MW in each scheduled period for six consecutive hours or more in the same direction;

(3) both 1.5 percent of the integrated hourly schedule and 5 MW in each scheduled period for twelve consecutive hours or more in the same direction; or

(4) both 1.5 percent of the integrated hourly schedule and 2 MW in each scheduled period for twenty-four consecutive hours or more in the same direction.

For Energy Imbalance Service pursuant to ACS IV.B.1, positive or negative deviations will be based on the measurement value used for determining Uninstructed Imbalance Energy pursuant to that section.

Changes to Persistent Deviation (EI)

RATE

No credit is given when energy taken is less than the scheduled energy.

(2) When energy taken exceeds the scheduled energy, the charge is the greater of (i) 125 percent of either BPA's highest incremental cost that occurs during that day for service under ACS II.D, or the LAP for service under ACS IV.B.1, or (ii) 100 mills per kilowatthour.

If the energy index is negative in any hour(s) in which there is a negative deviation (energy taken is less than the scheduled energy) that BPA determines to be a Persistent Deviation, the charge is the energy index for that hour.

If BPA assesses a persistent deviation penalty charge in any scheduled period for a positive deviation, BPA will not also assess a charge pursuant to ACS II.D or IV.B.1.

Next Steps

- Redline rate schedules are available on the Meetings and Workshop page.
- Please submit to techforum@bpa.gov (with copy to your account executive) by **October 13, 2020**.

Final Workshop Steps

- Feedback on all Topics:
  - Please submit to techforum@bpa.gov (with copy to your account executive) by October 13, 2020

APPENDIX

PROPOSED BP-22/TC-22 Procedural Schedule

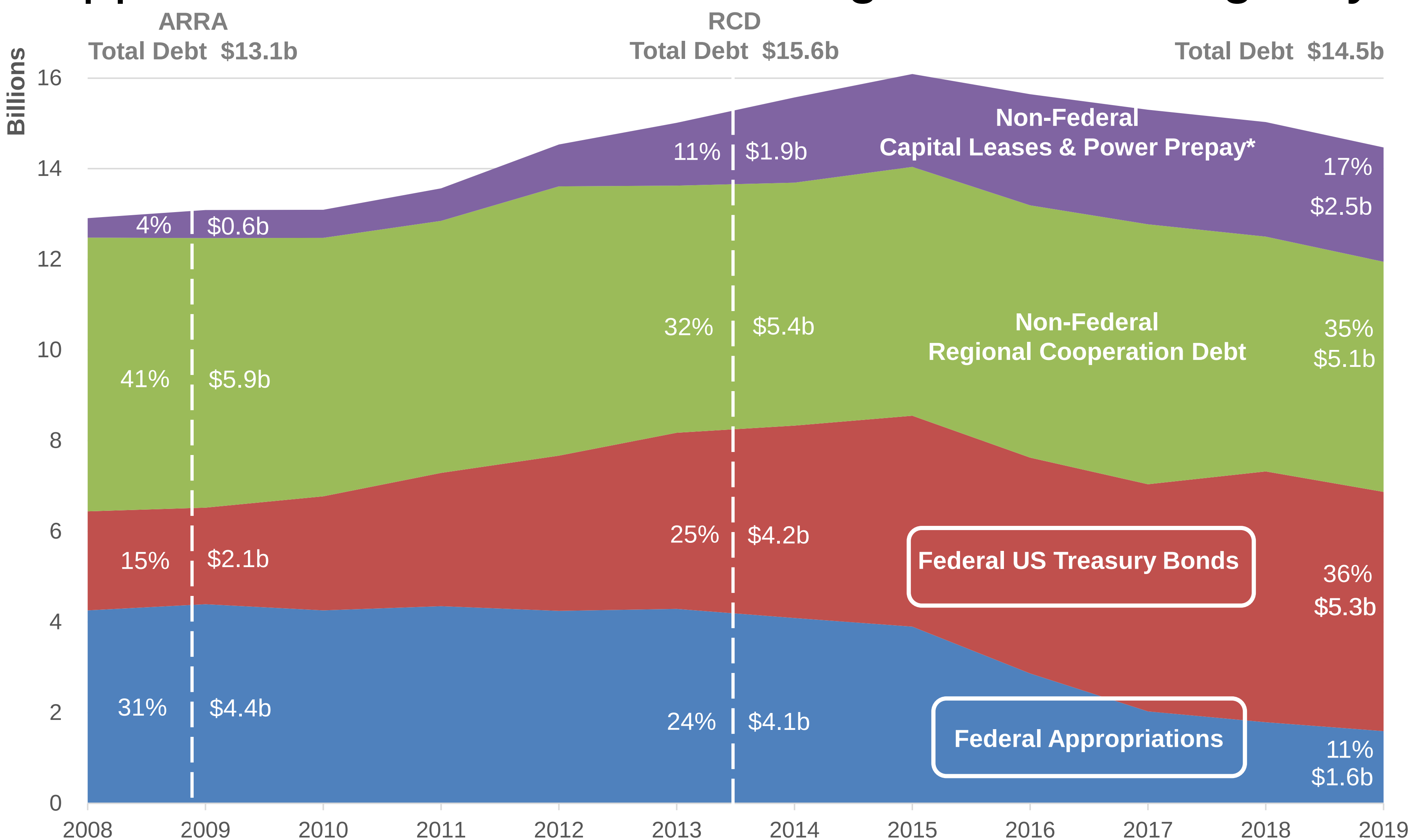
PROPOSED BP-22/TC-22 Procedural Schedule

	BP-22 (2020-2021)	TC-22 (2020-2021)
FRN Published	**Dec 1 (Tues)**	**Dec 1 (Tues)**
BPA Initial Proposal/ Prehearing Conference	**Dec 7 (Mon)**	**Dec 7 (Mon)**
Clarification	Dec 18 (F) Jan 6-7 (W-Th)	Dec 16-17 (W-Th)
Data Response Deadline	Jan 22 (Fri)	Jan 18 (Mon)
Parties File Direct Cases	**Feb 3 (Wed)**	**Jan 29 (Fri)**
Clarification	Feb 9-10 (T-W)	Feb 8-9 (M-T)
Data Response Deadline	Feb 23 (Tues)	Feb 22 (Mon)
Litigants File Rebuttal Cases	**Mar 16 (Tues)**	**March 8 (Mon)**
Clarification	Mar 22 (Mon)	March 12 (Fri)
Data Response Deadline	April 2 (Fri)	March 23 (Tues)
Cross-Examination	**April 8-9 (Th-F)**	**March 29-30 (M-T)**
Initial Briefs Filed	**April 27 (Tues)**	**April 16 (Fri)**
Oral Argument	**May 4 (Tues)**	**April 26 (Mon)**
Hearing Officer's Recommended Decision	**(N/A)**	**May 25 (Tues)**
Draft Record of Decision	**Jun 11 (Fri)**	**June 30 (Wed)**
Briefs on Exceptions	**Jun 25 (Fri)**	**July 14 (Wed)**
Final ROD/Studies	**Jul 28 (Wed)**	**July 28 (Wed)**

APPENDIX

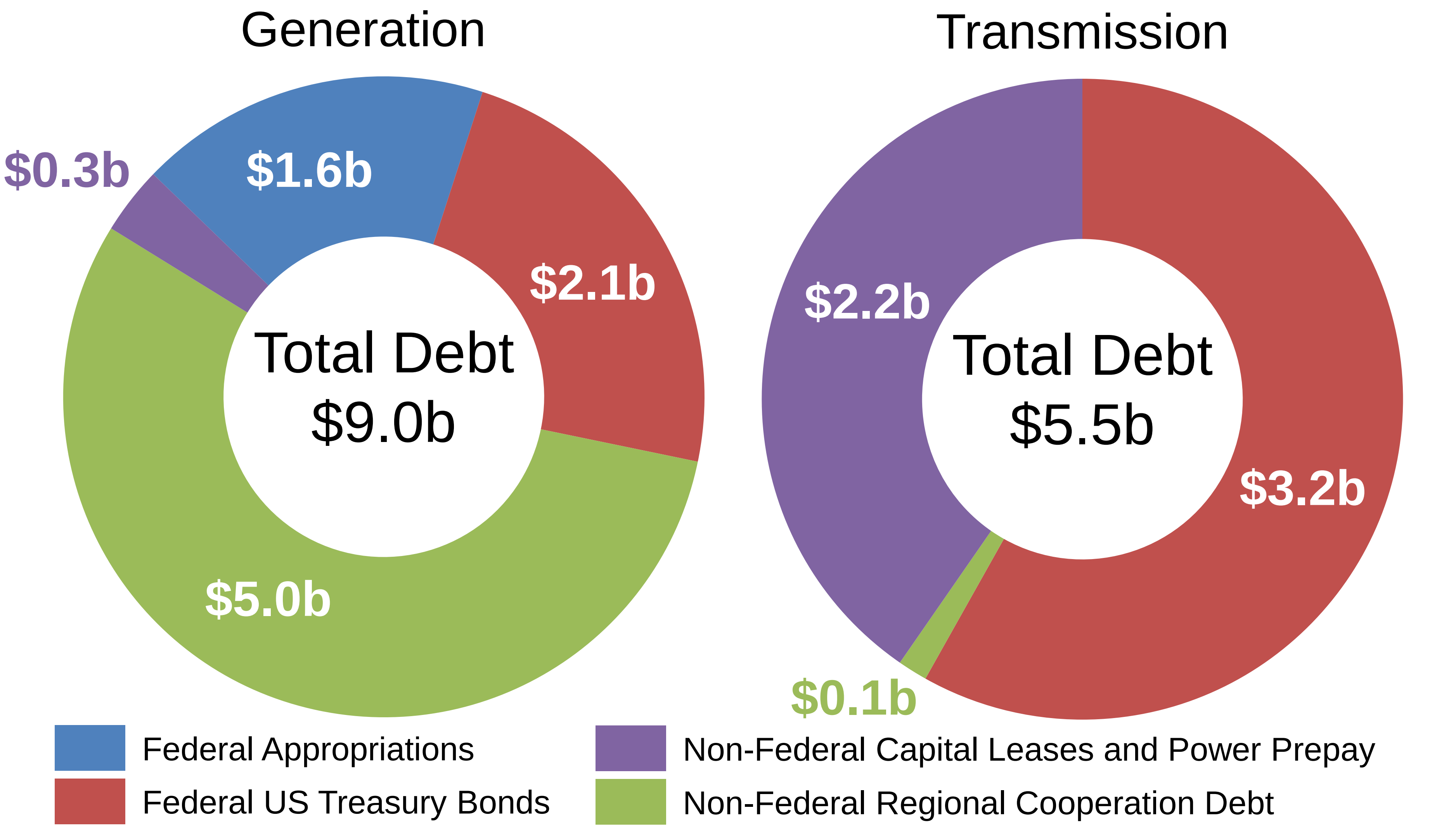
Long Term Strategic Financial Issues

Appendix: Historical Outstanding Liabilities - Agency



Source: BPA Audited Financial Statements FY 2008-FY2019
** FY14 and prior includes conservation bonds (Tacoma, CARES, and Emerald)*

Appendix: Outstanding Debt at 9/30/2019



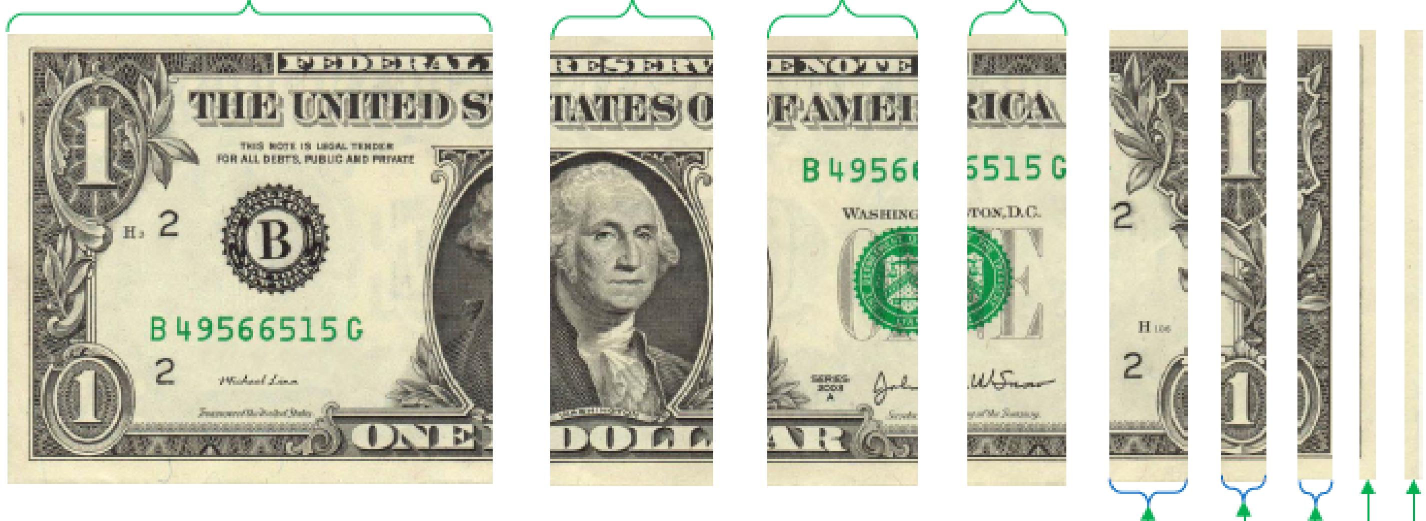
Appendix: Transmission Revenues

Long Term Network PTP (45 cents)
Revenue from the sale of long-term point to point transmission service on BPA's network.

Network (NT) Load Service (15 cents)
Revenue from the sale of transmission service for customer's designated network load.

Ancillary Services (14 cents)
Revenue from the sale of scheduling, system control and dispatch service to support transmission of energy.

Generation Inputs (9 cents)
Revenue from service to meet reliability obligations of a party with resources or load in the BPA control area.



Intertie PTP (7 cents)
Revenue from long-term point to point service on the Southern and Montana interties.

Miscellaneous (4 cents)
Revenue from TGT contracts, utility delivery, land and equipment leases, and other miscellaneous services.

Short Term PTP (3 cents)
Revenue from the sale point to point service of less than 1 year on BPA's network and interties.

Fiber and PCS Wireless (2 cents)
Revenue from leased communications equipment that exceed BPA's needs

Legacy Products (2 cents)
Revenue from pre OATT FPT contracts.

Appendix: Transmission Expenses

How Bonneville spends a dollar of its transmission revenue

O&M Expense (45 cents)*
Operation and
Maintenance Expense

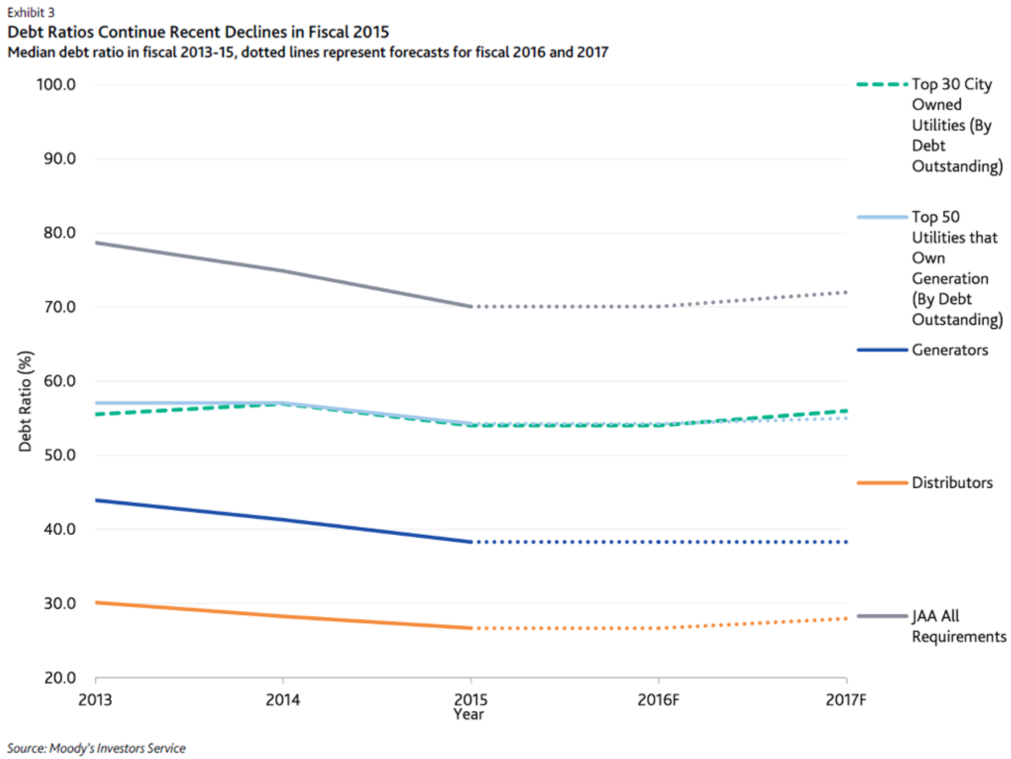
Depreciation and Amortization (31 cents)
Capital related costs for capital
investments for sustain and commercial

*Note: Other expenses are included in O&M Expense

Net Interest Expense (14 cents)
Interest expense for the capital
related costs

Transmission Ancillary (10 cents)
Expenses related to balancing
reserves and SCD

Financial Metrics: Rating Agency View



Ratings	Top 30 City Owned Generators (By Debt Outstanding) All	Aa	A	Baa	Top 50 Utilities that Own Generation (By Debt Outstanding) All	Aaa/Aa	A	Baa
Debt Ratio (%)	54.0	53.5	45.0	95.7	54.3	51.9	55.0	84.1
Days Cash on Hand	214	214	269	115	207	214	254	109
Adjusted Days Liquidity on Hand	242	242	269	115	241	242	262	109

Source: Moody's Investors Service, Sector In-Depth, September 15, 2016, Public Power Medians – "Finances Hold Steady with Transition to Lower Carbon Environment"

APPENDIX

Summary of Customer Feedback

7/28 & 7/29-30 Workshop - Customer Comments

Topic	Comment Summary	BPA Response
Work Plan & Schedule	• Please add a second customer-led workshop the week of August 31 • Please move the 9/22 meeting out at least two weeks to allow adequate time for staff to consider customer comments submitted by 9/18 • If any new concepts are delivered at August workshops, suggest delaying customer comment deadline	• We are looking at additional customer led workshop and will send out a tech forum. • We will move the workshop to September 29 from Sept 22
PR & NPR Requirements	• Support staff recommendation of Alternative 1 • Continue to monitor the issue to better understand changes to transmission purchasing behavior or other unintended consequences	• Thank you for your comments • BPA will be monitoring transmission purchase behavior.
Base Schedule Timeline	• Supports staff recommendation of T-57 submission deadline • Consistent/aligns with neighboring EIM BAAs	• Thank you for your comments
Southern Intertie Studies	• Differing entities voiced support for all three alternatives • Support for Alts 2 and 3 noted consistency with FERC OATT • Support for Alt 1 noted opposition to any alternative that allows lower queued requests to clear the queue.	• Thank you for your comment. Based on customers comments we are leaning towards alternative #3
Seller's Choice	• Customer group proposes to maintain through FY23 that includes an annual MW cap • Continued uncertainty around planning and Mid-C impacts	• Thank you for your comments, we will be addressing the comments in a customer led workshop on 9/9

7/28 & 7/29-30 Workshop - Customer Comments

Topic	Comment Summary	BPA Response
Gen Inputs: General	• T-57 will likely result in increased imbalances • How will OCBR and OMP be handled in an EIM? • Adopt policies that incent accurate scheduling behaviors • Sharing of EIM revenues would be another incentive for scheduling accurately. • Need to avoid duplicate charges. • Further clarification on how charges would be allocated would be helpful. • Commit to reviewing scheduling accuracy prior to BP-24	• These comments will be addressed in the Gen Inputs presentation on 8/26
Gen Inputs: EI/GI Bands	• General support for alternative 3., removal of existing EI/GI deviation bands • FERC doesn't support EI/GI bands • Concerns with financial impacts to renewables if adopt LMP pricing without removing bands	• Thank you for your comments
Gen Inputs: PD/ID Penalties	• Some support for removing PD/ID penalties • Some support for Alts 2 or 3, based on continued development of details. • Penalties should not necessary if EIM appropriately incentives good scheduling behavior.	• Thank you for your comments
Revenue Requirements	• Leverage policy should continue to be clarified, possibly through a separate stakeholder process • BPA should further clarify its assets and debts. • Clarify how higher expenses might qualify for regulatory asset treatment.	• Thank you for your comments we will address the leverage policy in a separate stakeholder process.

7/28 & 7/29-30 Workshop - Customer Comments

Topic	Comment Summary	BPA Response
Transmission Rates: EIM Charge Code	• Scenario analysis was helpful but seek additional clarifications around relationship between base codes and neutrality codes • General support for BPA approach to delaying sub-allocation of certain codes until more data is available. • Clarify impact to sub-BAAs within the BPA BAA • To the extent possible, the basic principle of cost-causation should be applied. • EIM revenues should be leveraged to cover EIM costs • Consider extension of interim period to acquire additional information. • Be conscientious of too many changes too soon creating unintended consequences • Non-firm schedules should not create undue financial costs to firm customers • Preserve priority and value of long-term rights • How can improved information from CAISO improve sub-allocation policies? • Further clarification on direction of allocation for Over/Under Scheduled Load • Better address feasibility of both BPA and customer implementation of EIM settlements	• These comments will be addressed in the presentation on 8/26

7/28 & 7/29-30 Workshop - Customer Comments

Topic	Comment Summary	BPA Response
Power Rates: Tier 2	• Support no carbon adder for BP-22	• BPA will not propose a carbon adder in BP-22 Tier 2 rates.
Power Rates: EIM Benefits	• General support for Off the Top option 1 • Surprise and concern by BPA's $2.4M annual benefit analysis compared to E3 evaluation of $36-40M that drove BPA's recommendation to pursue EIM • Support BPA using a benefit level higher than $2.4M in BP-22. Benefit estimate should be re-examined prior to BP-24.	• Staff also supports Off-the-top option 1 • E3 study is a reasonable representation of BPA's future-state EIM benefits, with mature participation and market experience. E3 study does not reflect BPA's expected near-term benefits in BP-22, due to our new entrance into market, more conservative participation as we gain experience with market mechanics, the partial rate period, and other uncertainties. • BPA's BP-22 proposal is to set EIM dispatch benefits equal to EIM costs. BPA plans a more robust evaluation for BP-24.

6/23 & 6/24 Workshop - Customer Comments

Topic	Comment Summary	BPA Response
General Comments	• Provide further examples of how EIM charges and rates will impact certain classes of customers. • Failure to appropriately sub-allocate charge codes could result in bad behaviors that may result in substantial costs and negative consequences • EIM can provide financial and renewable integration benefits but wary of contentious adoption and missing win-win opportunities. • Consider additional time to July agenda and wherever else necessary to ensure adequate time to discuss the issues • Clearly identify implementation issues not being addressed prior to rates/tariff cases	• Thank you for your comments. Going forward we will start at 9 a.m. and will give enough time to address the issues • EIM Imbalance Scenarios will be discussed in this workshop • We are working to identify implementation issues as soon as possible
Resource Sufficiency	• Support for Status Quo for balancing BAA • Support for Status Quo for not setting Ramp Sufficiency pass target • How will gaps in balancing tests be covered? • Pursue further balance between cost to transmission customers and benefits to load customers.	• Thank you for your comments
Participating Resource Requirements	• Confirm that requirements only apply to 3 MW or greater • Concerns with lack of requirements for PR to hold transmission rights • Evaluate impacts to EDAM • Encourage BPA to address demand response participation before BP-24 if possible • T-75 deadline not feasible for resources in non-EIM BAAs • Supports consistent policies and implementation across the EIM footprint	• Thank you for your comments, these comments will be addressed in the later in the workshop

6/23 & 6/24 Workshop - Customer Comments (cont.)

Topic	Comment Summary	BPA Response
Transmission Donation	• General support for staff recommendation • Staff recommendation not consistent with BPA ROD or other EIM tariffs • Please provide further analysis supporting EIM limitations resulting from firm-only donations. • Aggregate all transmission donations on a single ETSR/Export tag • Provide examples of donations, including redirects of existing reservations • Further evaluate impact of return of losses on donated transmission • Concerned that current loss provisions may be a disincentive to donate transmission • Carefully evaluate rules and approaches for donations • Provide further details on BPA's analysis and how it influenced the staff recommendation. • Unlimited non-firm should be further evaluated. • Provide clarification on how non-firm donations will not impact quality of how long-term rights are used. • Clarify how ETSRs might help reduce likelihood of curtailments	• Thank you for your comments. These comments will be considered for the initial proposal

Base Schedule Timeline	• Support for both T-50 and T-57
	    • T-50 may minimize exposure to congestion costs
	    • T-57 is consistent with other EIM entities
	• Not clear if additional seven minutes outweighs the potential complexity, costs and burdens
	• Clarify impacts and risks of changes up to T-20
		• Thank you for your comments. The risks and comments will be considered for the initial proposal

6/23 & 6/24 Workshop - Customer Comments (cont.)

Topic	Comment Summary	BPA Response
Gen Inputs	• Would proposed DERS reserves framework be adopted if BPA does not join EIM? • New method for pricing balancing reserves must show that it is revenue neutral compared to current methodology • Customers should have option to use their meteorological forecast • Show impact to BP-22 ancillary rates be if committed scheduling were retained. • Supports pricing different types of capacity with industry standards & market values • Further discuss impacts to OCBR & OMP if BPA joins EIM • Supports a timeline that allows wind resources adequate time to manage and schedule their resource portfolio • BPA super forecast struggles with handling outages, improvement is needed.	• Thank you for your comments more discussion of the DERS and the Gen Inputs rates will be later this workshop and in August • OMP and OCBR will be discussed as part of the Business Practice Change Processes for the EIM (the Oversupply Management BP and the Balancing Reserves Capacity BPA for OCBR)
Transmission Losses	• General support for maintaining the status quo, both in-kind and financial • General support for monetizing the value of capacity used by Power Services but should reflect BPA's capacity cost • General support for the FFI which should be established in tariff proceedings • Eliminating "In-kind" is non-negotiable and should not be part of TC-22 or TC-24 • Acknowledge that how losses are treated in an EIM may be different than network • Any financial settlement rate should be a transmission rate and should be based in embedded costs. • General support of returning losses sooner than 168 hours. • General support for updating transmission loss factor and updating on a regular basis and using seasonal values. • Is there a loss factor for Montana or Southern interties? • BPA should provide further information on administrative and implementation costs and challenges that support staff alternative.	• Thank you for your comments. These will be considered as for the August workshop

6/23 & 6/24 Workshop - Customer Comments (cont.)

Topic	Comment Summary	BPA Response
Generator Interconnection	• Supportive of Alt 4 to update Attachment L with both Repower and Replacement provisions	• Thank you for your comments

Power Rates	• Support further exploration of proposal on secondary revenues
	  • Meets customer needs
	  • Reduces agency reliance on secondary revenues
	  • Time is now
	  • There should be no immediate rate impact
	• Secondary revenue construct should be further considered utilizing customer proposed principles
		• Thank you for your comments

Hourly Firm & ST ATC	• Supports retaining Hourly Firm in TC-22 • Continue to improve ATC and other factors that could mitigate existing limitations to Hourly Firm • Revisit allowing Hourly Firm reservations within the operating day	• Thank you for your comments • BPA has not identified any of the conditions necessary to reconsider its current Hourly Firm service • There is not sufficient data to warrant a reconsideration of the status quo • The status quo recommendation allows staff more time to evaluate prior to TC-24, which is in alignment with the settlement agreement

5/19 Workshop - Customer Comments

Topic	Comment Summary	BPA Response
Workshop Schedule	• Ensure sufficient time to engage customers in iterative process on important issues and if more time is necessary consider additional workshops. • Continue to notify customers of any procedural, topical or timeline changes in advance. • Ensure schedules are aligned on all documentation.	• Thank you for the comments we have added time and dates to give customers time to provide comments in the work plan proceeding these slides

Seller's Choice	• Clarify process for encumbering/unencumbering ATC for NT service, particularly for Seller's Choice.
	    • Clarify Reservation and Scheduling process for Seller's Choice
	• Clarify how an FTSR goes through the ATC process
	• Provide further examples of how impacts/effects of Seller's Choice are calculated.
	    • This analysis is important for any decision to extend.
	• Provide examples/analysis of how Seller's Choice impacts Hourly Firm ATC
	• Evaluate impacts of the NT MOA on ATC and propose to include in TC-22 proceedings.
	• Additional analysis is important to determining whether to support or oppose
	• Seller's Choice is a vital market alternative for NT customers for Mid-C market purchases
	    • Hourly Firm no longer reliable
	• Seller's Choice mitigates impacts resulting from limited Hourly Firm and absence of Preemption & Competition
		• Thank you for your comments the team is reviewing the comments are planning to have a customer meeting on July 15 to respond to customer comments during the customer led workshop.

5/19 Workshop - Customer Comments (cont.)

Topic	Comment Summary	BPA Response
RPO	• Support Attachment K referencing NorthernGrid planning process to be most efficient and avoid discrepancies	• Thank you for your comments
Intertie Studies	• Both alternatives appear viable • Consider modification of Alt 1 to include option for customer to request a study • Some concerns with level of "BPA discretion in Alt 1	• Thank you for your comments. The team will consider your comments for alternative #1
Tariff Language	• Supports a separate service agreement for participation in EIM • Supports minor amendments to Attachment A for e-signature and such	• Thank you for your comments, they have been forwarded to the SMEs for consideration.
BP-22 Rates	• If possible, provide materials for Revenue Requirements and Risk as soon as possible to allow for internal vetting prior to workshops • Concerns with degradation of FBS, need to work with region to develop ways to improve value of FBS • DERBS service should be re-evaluated during BP-22 • Functionalization and assignment of GridMod and EIM costs should be addressed in BP-22 • Consider customer input on principles and requirements for a 7(f) rate discussion • 200 kW threshold for SGIP should be addressed in BP-22	• Thank you for your comments. The comments and suggestions are being considered and we will share with you at our next meeting when these topics are scheduled to be discussed.

5/19 Workshop - Customer Comments (cont.)

Topic	Comment Summary	BPA Response
General Comments	• Provide an update on Preemption and Competition with regards to BPA's plan to comply with Order 676-I and associated NAESB standards. • BPA must pursue policies that are fair and equitable to both NT and PTP customers.	• Thank you for your comments. We have an update at the customer let workshop on July 15
	• Undesignation of NT Resources should be included in TC-22	• The undesignation of is currently prioritized to be discussed in TC-24
	• No policy decisions on charge code allocation should be made until there is more data to support allocation and price signals.	• Thank you for your comments on the charge code cost allocation. The team will consider this and the PowerEx presentation in its evaluation.
	• Provide requirements for small, non-participating resources if BPA joins the EIM	• Thank you for your comments on the requirements for the small and non participating resources. The requirements are included in today's presentation.

4/28 Workshop - Customer Comments

Customer	Comment Summary	BPA Response
Charge Code Allocation	• Existing transmission usage should be preserved to the extent possible to minimize unintended consequences of existing use of the FCRTS and BPA's transmission business model • Per BPA's own criteria, to the extent possible, maintain alignment with FERC-approved allocation methods, particularly to avoid seams issues • Allocation of charges/credits should be consistent with cost causation to avoid uneconomic price signals and increased costs and included in evaluation criteria • Clarify how charges attributable to load following customers will be allocated and accounted for. • Concerned with unintended shift of costs to transmission customers and with revenues only benefiting BPA Power • Revenues should be allocated to transmission customers to offset costs with any surplus to Power • Request further clarification on certain charge codes that are excluded from initial sub-allocation (bid cost recovery, flexible ramp, grid management, enforcement protocol, administrative) • Operational experience will mitigate inappropriate allocation of charges/credits. Until such experience is attained, consider no sub-allocation. • If proceeding with sub-allocation, develop a framework to guide charge/credit allocation. • If proceeding with sub-allocation, all charge codes should be well understood	• Thank you for your comments. BPA will continue to evaluate the impacts and consider the concerns expressed as we approach the implementation phase.

4/28 Workshop - Customer Comments (Cont.)

Customer	Comment Summary	BPA Response
Proposed Workplan	• Provide clarification on status of 7(f) options and grandfathered Green Exception • Undesignation of DNR should be addressed in TC-22	• See BP-22 Rate Case Kickoff presentation. • BPA does not calculate its ST ATC frequently enough for ST undesignations to be reflected in ST ATC. • The systems are not in place at this time to recognize ST undesignations of NT resources and release the corresponding ST ATC to the market. • The full implementation of NITS on OASIS will include this functionality. However, the recent FERC Order 676-I makes extensive changes to the NITS on OASIS module that OATI needs to build over the next several months. • BPA still offers unlimited non-firm transmission, which mitigates the impact of not releasing ST ATC to the non-firm market after ST undesignation of a network resource.

4/28 Workshop - Customer Comments (Cont.)

Customer	Comment Summary	BPA Response
Solar Study (BP-20 Settlement)	• Don't support decision to delay development of a shaped quantity of reserves • Study should be expanded to include wind resources • BPA should be prepared to revisit should circumstances change	• Thank you for your comment. Should circumstances change significantly, BPA is prepared to revisit.
Creditworthiness	• Support alignment with structure of pro forma approach	• Thank you
Agreement Templates	• Proposed clarifying language regarding service commencement	• Thank you. We will review consider it our next workshop in June
Tariff Language Review	• Inter-related issues should be presented together to ensure complete picture of tariff edits is understood	• BPA will share tariff language with customers as it's available. At the final workshop a complete draft tariff will be shared with customers with an opportunity to provide feedback before that language goes into the Initial Proposal.
General Comments	• EIM must support the Northwest's current shift to low carbon resources and not result in negative financial impact to VERS • Requests a workshop to educate CAISO on tools that BPA and renewables have used to reduce integration costs	• Thank you
Timeline for Base Schedules	• T-57 scheduling deadline may increase VERBS exposure to balancing reserves • Supports exploration of possibly reducing balancing reserve requirements • Entities may be forced to make decisions to use transmission to support within hour scheduling versus EIM participation.	• This will be considered in the June presentation

3/17 Workshop - Customer Comments

Customer	Comment Summary	BPA Response
Work Plan & Workshops	• More information and clarity needed on EIM Phase III Decision Document • Clarify where all policy issues will be documented • Identify topics that could be delayed or simplified to allow focus on priority issues • Support additional workshops • Continue to use the VENN diagram to highlight topics	• BPA has included a detail policy questions and proposal on where those decisions will be made in the presentation
Seller's Choice	• Support access to non-federal resources at Mid-C • Clarify whether there is an impact to ATC due to NT encumbrance. • Be careful with any policies that deviate from the OATT. • Provide additional analysis of reservations/schedules/flow impacts at Mid-C.	• These concerns will be considered and addressed in May, when Seller's choice will be discussed
Transmission Losses	• General support for Alternative 3 and 5, maintain both options with financial rate developed in rate case. • This issue should be able to be resolved quickly • Support financial for inaccuracy charge • Additional details needed on financial pricing including impacts by customer type • Additional details needed on customer impacts/benefits • Administrative costs may be worthwhile/appropriate • Consider additional decision criteria (per submissions)	• Thank you for your feedback. These comments will be considered and addressed in the May workshop
EIM Transmission Usage	• Support for modifications to scope and objective • Support non-firm donations • Concerns with donation deadlines misaligned with market intervals • Evaluate impacts to dynamic transfers as compared to ETSRs. • Cost recovery mechanisms must be in place to follow cost-causation principles	• Thank you for your feedback, your concerns will be considered and addressed in the June workshop
Intertie Studies	• Support updating the tariff • Maximize flexibility and minimize financial exposure • Work with customers, regional stakeholders and partners on expansion needs	• Thank you for your comments. BPA staff will consider these comments as we address the tariff discussion for the Intertie studies at the May workshop.

2/25 Workshop - Customer Comments

Customer	Comment Summary	BPA Response

Charge Code Allocation	• Comments received reflected support for both a phased in sub-allocation approach as well as a "direct-assigned" approach that would utilize CAISO charge codes.
	  • Develop more examples of how different customer types would be treated under the different alternatives.
	  • Provide additional estimates on the administrative costs.
	  • Provide a cost-benefit analysis for each alternative that weighs benefits against administrative costs.
	• If no sub or sub-allocation:
	  • Balance cost-causation with simplicity
	  • Imbalance service should be developed as a separate rate
	  • Will better ensure existing transmission rights are respected
	  • Focus on Base Codes and Scheduling Entity Codes
	• If direct assigned (FERC-approved allocation method):
	  • Maintain incentives for customers to schedule accurately within the BAA
	  • Consistency across EIM footprint
	  • Maintains consistency with FERC, one of BPA's tariff principles
	  • Insulation of costs will create risk of hiding EIM market signals
	  • A phased in approach could be applied
	  • Concerned that development of rate mechanisms will not capture granularity
	  • Experiences with EIM suggest more administrative burden up front but ease of that burden moving forward.
	  • Administrative burden to insulate customers is not a justifiable argument and eventually will be same level as other EIM entities
	  • Customers need transparency for market signals and disputes
	  • Ensures better adaptability and response to future changes from CAISO instead of every two years.
		• Direct assignment, sub allocation will be discussed in the alternatives in Steps 5 and 6 on April 28.

2/25 Workshop - Customer Comments (Cont.)

Customer	Comment Summary	BPA Response
Resource Sufficiency	• Don't establish a target • Develop financial mitigation for the t-20 to t-55 window • Develop a matrix of 4 alternatives for better comparative capability	• The target and the alternatives will be discussed in steps 5 and 6 in the April 28 workshop.
Gen Inputs	• Develop principles for Gen Inputs • EIM benefits should be part of Gen Input rate design • Maintain close association with Charge Code discussion • Schedules 9 and 10 might benefit from transitioning to EIM methodology • Need a more robust conversation about ID, PD, EI, and GI rates relative to the charge code sub-allocation alternatives • Eliminating the 30/60 and 30/15 committed scheduling elections options will increase the capacity that BPA must set aside for reserves and increase the rates that ancillary services customers will have to pay	• The team will consider the customer request and respond at the April workshop • The alternatives will be considered in the development of steps 3 and 4 in the April workshop.
Creditworthiness	• Attachment to the OATT	• Attachment to the OATT will be considered the review of the alternatives in steps 3 to 4 in the April workshop
Section 7(f) Power Rates	• Customers have requested we explore contractual solutions such as the grandfathered Green Exception."	• The team will address this in our next workshop on service under 7(f).
Regional Planning	• Revise Attachment K to ensure future changes must go through tariff process	• We will consider this alternative in steps 3 and 4 which will be reviewed in the May workshop
Generator Interconnection	• Support for implementation of Order 845 • Need more information regarding "streamlining" proposal to ensure no queue discrimination	• Thank you

1/28 Workshop - Customer Comments

Customer	Comment Summary	BPA Response
Objective Statement	• Clarify that BPA will not negatively impact existing rights or existing uses in favor of EIM • Costs associated with EIM should be allocated to those benefiting • Alternatives should consider the sub-elements of the objective statement.	• These suggestive changes to the objective statement will be considered
Network Usage	• Concerns that EIM will reduce capacity used to support bilateral transactions • Encourage BPA to pursue solutions that would allow use of ATC Methodology. Admittedly may be most appropriate in EDAM • BPA needs to ensure rights and expectations of existing customers under the tariff and in some cases may need to eliminate adverse commercial impacts. • EIM reciprocity transmission framework is an essential principle. Align with requirements utilized by other EIM entities	• The concerns and considerations will be evaluated in steps 3 and 4. Some of these concerns were addressed in the other forums and we will address these concerns in our evaluation.
Deviation Policies	• Evaluate persistent deviation and intentional deviation penalties with respect to EIM dispatch • How does EIM dispatch impact Intentional Deviation policies?	• The penalties are discussed in the presentation 2/25 and will be evaluated in steps 3 and 4
Ancillary Services	• NIPPC posed several questions addressing concerns around how BPA will address ancillary services in EIM. • Penalties/Negative Prices: Review ACS rate schedules for appropriate modifications	• The ancillary services questions as it relates to rates are discussed in the Gen Inputs of the 2/25 workshop and will continue the discussion in future rate case workshops

1/28 Workshop - Customer Comments (Cont.)

Customer	Comment Summary	BPA Response
Participating & Non-participating Resources	• Non-participating Resources: Concerned with requirements for co-gen resources • Participating Resources: BPA should present preliminary evaluation along with pros and cons on what types of transmission products for EIM transfers. • External-BA Resources: will BPA allow dynamic schedules? • Participating Resources: NIPPC poses several questions regarding type of transmission donations and the donation process. o Survey and share findings of how existing EIM participant approaches to these questions. o How will BPA manage exposure to EIM prices?	• The concerns and the evaluation will be discussed during the steps 3 and 4
Un-designation of DNR	• Un-designation of DNR o Require the Un-designation of DNRs being used to make Firm network sales o Address this issue in TC-22 including review of the NT MOA	• The NT team is reviewing these comments and will have a response at the next TC-20 settlement workshop.
Solar Study (BP-20)	• Solar Study (BP-20): Material value to exploring shaped reserve option. • Gen Inputs: limited input to reach conclusions	• The concerns and considerations will be evaluated in steps 3 and 4

1/28 Workshop - Customer Comments (Cont.)

Customer	Comment Summary	BPA Response
7f Rate Design	• Clarify the timing, availability and market risk as a discretionary Tier 1 obligation o Also include terms & conditions, methodology for new rate and customer obligations o New firm surplus rate could be explored with similar clarification per above • Support continued exploration as long as available to all preference customers among other considerations. • Any new proposal for serving load following customers should be win-win for all preference customers and not create any new material risks or cost shifts • There is potential merit deserving further exploration based on initial customer benefits and BPA revenues	• The 7f rates team are reviewing these comments and will consider them as part of their evaluation and alternatives in upcoming rates workshop
Financial Planning	• Concerned of disproportionate burden on transmission • use of MRNR per previous filings and testimony o Accounting policies should be considered outside of a rate case o Amortize short-lived regulatory assets for greatest ratepayer benefits o More strategic approach at regulatory accounting and MRNR • include long-term cost and rate forecasting. Customers will want greater visibility	• These concerns and comments were forwarded to the financial planning process
General Comments	• BPA should demonstrate how it will track how the new processes will affect other topics. • EIM charges: incremental transmission charges would be problematic and upset the reciprocity transmission framework o FERC expressly disapproved of PAC's proposal of an incremental transmission rate for EIM • VERBS: 30/15 option will most likely be eliminated. What other changes might be needed? • In general, avoid seams issues • Encourage BPA to work with stakeholders across EIM footprint	• These comments will be considered by the affected teams moving forward

12/12/19 Feedback Summary

Themes	BPA's Response
Transmission Losses concerns on pricing and capacity adder	The review of the pricing and the value for transmission losses will be discussed in the rate case
Customers would like to have a better understanding of the objective and reason for change for Transmission Losses.	Losses will return in the March workshop to address this request.
Customers would like to have choices for settling transmission losses (i.e. physical vs financial). For example one choice could be to consider an option of returns in like kind with a penalty for customers who fail to return the loss obligation	Losses will return in the March workshop to begin sharing options.
Transmission loss factor should be established in Tariff proceedings	The Tariff does contain the annual average system loss factor for the network and intertie. We do not intend to suggest removing it from the Tariff.
Transmission losses should be included in the Transmission rates and rates schedule and should be equitably allocated	Bonneville intends to have any rate discussions during the upcoming rate case proceedings. Any discussion regarding the location (i.e. Power or Transmission Rates Schedules) will be discussed during the rate proceeding. Options of transmission losses pricing will be discussed in the rate case in steps 4 and 5.
The EIM losses are important and BPA is in the the best position to determine the appropriate transmission loss percentage for OATT service	In the workshops, steps 4 and 5 will discuss the option for the EIM Losses
Provide more information on the value lost to BPA from a customer's failure to deliver In Kind	This will be addressed in steps 4 and 5.
Costs are inevitable so develop cost/benefit analysis (administrative burden) for financial returns (similar to what was developed for In Kind). In other words, realize that certain administrative costs may be worthwhile due to the market value they deliver – such costs should be appropriately allocated.	This will be addressed in steps 4 and 5
Be clearer of the strategic interplay between EIM Losses and Transmission Losses both in implementation and long-term	We will continue to look for opportunities to share interplay between EIM losses and Transmission losses if applicable. At this point, we do not see any interplay between EIM Losses and Transmission Losses.
Maintain separation between EIM Losses and Transmission Losses	We agree there is a separation of EIM Losses and Transmission Losses

12/12/19 Feedback Summary (cont.)

Themes	BPA's Response
Customer proposed changes to EIM Charge Code principles	The team will consider the proposed principles and will give feedback to customers at the February workshop
Include a glossary of EIM charge codes and a crosswalk to current BPA rates where applicable	We will continue discussing the EIM charge code s and cross walk to current BPA rates where applicable in the February workshop materials
EIM charge code cost allocation should include wheel through , preference customers and interchange and non-participating resources. How are customers outside the BA considered?	Analysis and alternatives will be discussed in steps 4 and 5.
EIM charge code cost allocation should be initially based on cost causation and should be phased in with a partial insulation	Cost allocation is an important issue and the feedback on a phased in and partial insulation will be considered in the alternatives development
As the EIM charge code cost allocation (and other EIM policy issues) is discussed, one consideration is to ensuring customers existing OATT rights are fully respected and that customers maintain the ability to use their rights without facing new costs.	In the evaluation phase, there will be consideration of OATT rights and how to recover new costs . In the steps 5 and 6 the consideration of OATT rights will be evaluated
More clearly tie Ancillary Services to EIM Charge Codes	In the rates discussion, there will be an in-depth discussion of tying the Ancillary Services to EIM Charge Codes where it is applicable.

12/15/19 Feedback Summary

Themes	BPA's Response: Updated 1/28
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. We have discussions on rate case issue in the Jan workshop and will continue those discussions through the summer.
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.

12/15/19 Feedback Summary (cont.)

Themes	BPA's Response: Updated 1/28
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. Our first requested customer led workshop was 1/15.
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.

12/15/19 Feedback Summary (cont.)

Themes	BPA's Response: Updated 1/28
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. An RPO update will be discussed at the 2/25 workshop and step 3 will be addressed in the 4/28 workshop.
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.

EIM Issue Inter-Dependencies Identified