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

August 26, 2020

AGENDA REVIEW

Agenda

Day 2 – August 26, 2020		
TIME*	**TOPIC**	**Presenter**
9:00 to 10:30 a.m.	Transmission Rates Gen Inputs: Steps 5 & 6 • EI/GI PD/ID • VERs Forecasting/Scheduling • Balancing Reserve Pricing	Miranda McGraw Libby Kirby Frank Puyleart Eric King Danny Chen Daniel Fisher
10:30 to 10:50 a.m.	Functionalization of Grid Modernization Costs	Allie Mace
10:50 to 11:30 a.m.	Risk	Zach Mandell
11:30 to 12:00 p.m.	Power Rates • Loads and Resources	Reed Davis Peggy Racht Steve Bellcoff John Stalnaker
12:00 pm to 1:00 p.m.	**LUNCH**	
1:00 to 4:30 p.m.	Power Rates • Gas, Electricity Price and Secondary Revenue Forecast • Transfer Service • EIM Benefits and Charges in Power Rates • Follow-up: Section 7(f) Power Rate Options • Secondary Revenue Proposal	James Vanden Bos Eric Graessley Kevin Mozena Derrick Pleger Jeff Hurt Emily Traetow Daniel Fisher Derrick Pleger Paulina Cornejo Daniel Fisher Daniel Fisher
4:30 to 5:00 p.m.	Summary of Staff Leanings • Rates • Tariff	Rebecca Fredrickson

** Times are approximate*

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	?

EIM
TC-22
BP-22

Rates & Tariff Topics

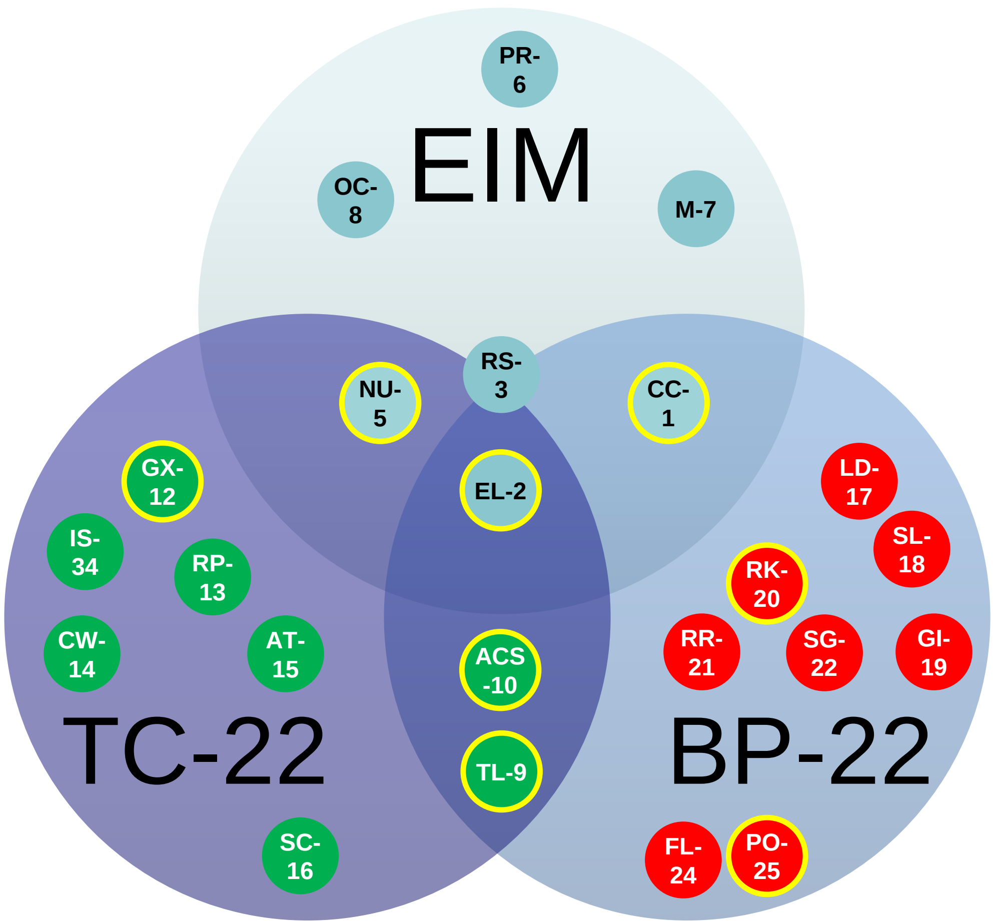
#	Topics	BP-22	TC-22	Future BP/TC
9	Transmission Losses	X	X	
10	Ancillary Services	X		?
11	Debt Management (Revenue Financing)	X		
12	Generator Interconnection		X	
13	Regional Planning		X	
14	Creditworthiness		X	
15	Incremental/Minor Changes to Agreement Templates		X	
16	Seller's Choice		X	
17	Loads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

Potential Future Rates & Tariff Issues

EIM
TC-22
BP-22

#	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	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

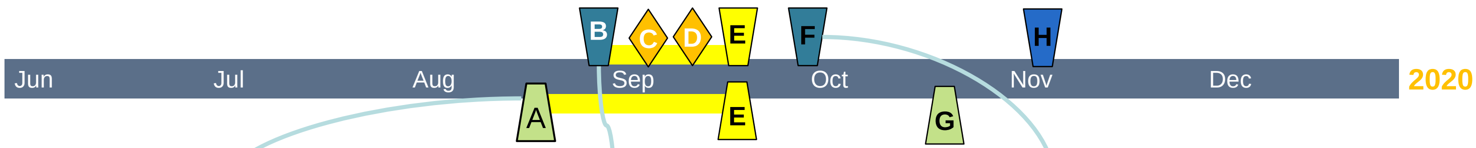
XX-# Yellow Outline Denotes Current Workshop Topics

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 3: Analyze the Issue	Step 5: Discuss Customer Feedback
Step 2: Description of the Issue	Step 4: Discuss Alternatives	Step 6: Staff Proposal



Phase III EIM Draft Letter (8/14):

Decision Finalized in EIM Letter
- Sub Allocation of Resource Sufficiency
- Non Federal Resource Participation
- Metering
- EIM Losses

Other decisions that will be part of the Tariff or Rate Case

August 25-26, 2020

- Summary of Topics & Policy – Staff Leaning through the end of August
- EIM Tariff Update
- Real Power Losses on EIM Transfers
- Donation Timing for ETSR
- Generation Interconnection
  - Steps 5 & 6
- Transmission Losses Steps 5 & 6
  - Loss Factor
  - Pricing
- Transmission Rates
  - EIM Charge Code Implementation
- Ancillary Services: Generation Inputs
  - Steps 5-6
- Functionalization of Grid Modernization Costs
- Risk
- Power Rates
  - Loads & Resources
  - Gas and Market Price
  - Transfer Service
  - Follow-up: Treatment of EIM Charge Codes
  - Follow-up: Section 7(f) Power Rate Options
  - Forecasts
  - Secondary Revenue Forecast
  - Net Secondary Revenue Proposal

EL-2
NU-5
GX-12
TL-9
CC-1
ACS-10
RK-20
PO-25

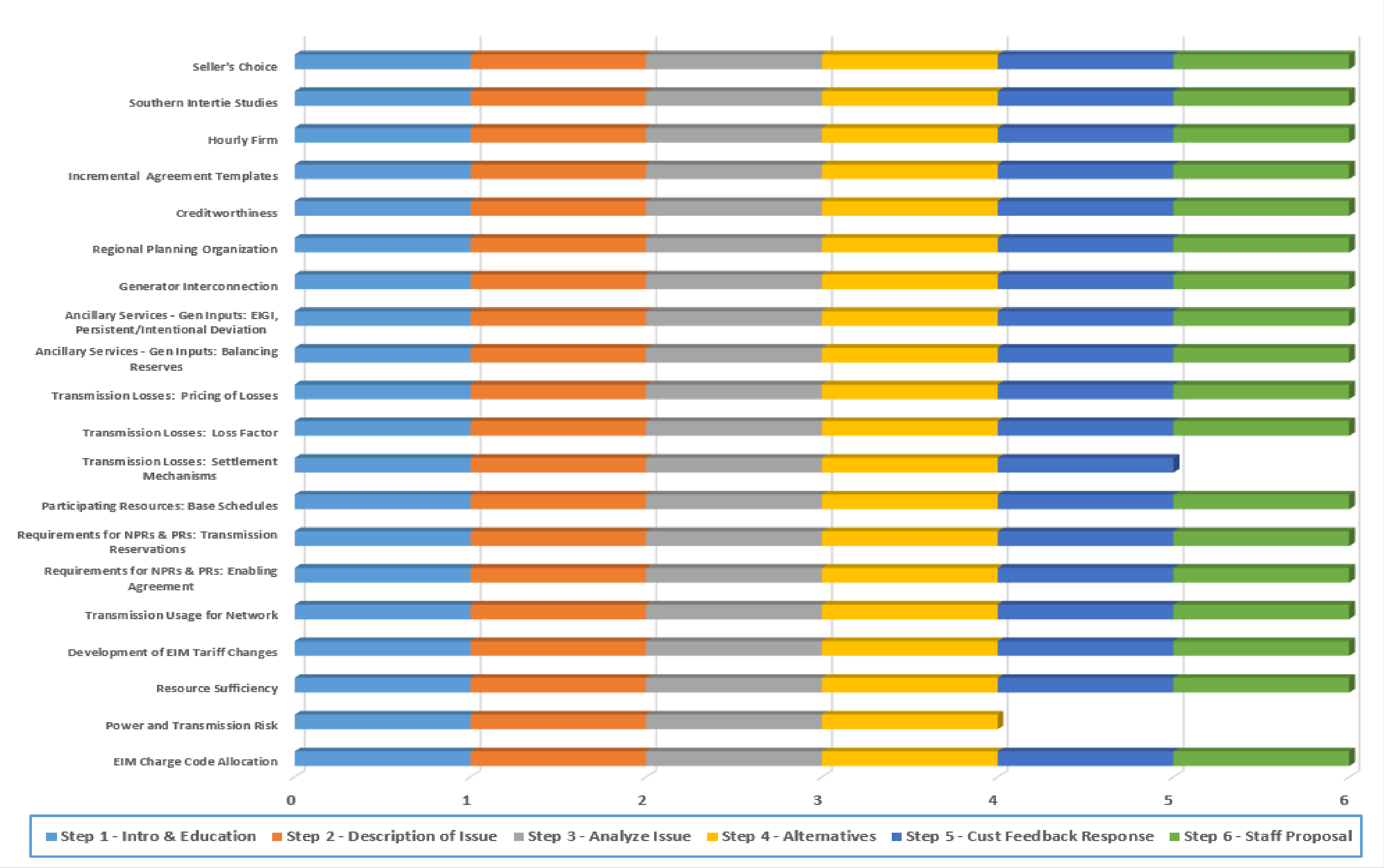
September 29, 2020

- Update on Losses
- Update on Risk
- Power Rates Wrap up
- Losses schedules
- EIM Charge Code GRSP Language
- Generation Inputs GRSP Language for Select Sections (EI/GI and PD/ID)
- Tariff update

Timeline Key

A. 8/14: EIM Phase III Draft
B. 8/25-26: August Workshop
C. 9/1: Customer Led Workshop
D. 9/9: Customer Led Workshop
E. 9/18: Customer Comment Deadline
F. 9/29: (September Workshop)
G. 10/14: EIM Phase III Letter
H. November: TC-22 & BP-22 Initial Proposal

Status of Topics Through August Workshops



TRANSMISSION RATES

Issue #3C: Gen Inputs:

- EI/GI and PD/ID
- VERs Forecasting/Scheduling
- Balancing Reserve Pricing

Step 5: Discuss Customer Feedback

Step 6: Staff Proposal

TRANSMISSION RATES

EI/GI and PD/ID

Objective

- BPA currently uses the following mechanisms to incentivize proper scheduling behavior:
  - Energy Imbalance (EI) Bands,
  - Generation Imbalance (GI) Bands,
  - Intentional Deviation Penalty (ID), and
  - Persistent Deviation Penalty (PD)

- If BPA joins the EIM, BPA must decide whether to keep, remove, or modify these existing incentive mechanisms.

Timeline

Phases One and Two:
Approach and Evaluation

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

July Workshop

Phase Three:
Proposal Development

Step 5: Customer Feedback
Step 6: Staff Proposal

Today's Workshop

EI/GI Alternatives

Given EIM Charge Code Policy Direction, ALL alternatives assume sub-allocation of the base codes for the EIM. Therefore, in alternatives where the EI/GI Deviation Bands are retained, bands would be in addition to the sub-allocated charges/credits.

- **<u>Alternative 1:</u> Retain Status Quo EI/GI Deviation Bands and Existing Pricing (Mid-C Index)**
- **<u>Alternative 2:</u> Retain EI/GI Deviation Bands and Adopt CAISO EIM Pricing (LAP and LMP)**
- **<u>Alternative 3:</u> Remove Existing EI/GI Deviation Bands**

Note: The EI/GI Deviation Bands will be maintained as the contingency plan if BPA is outside the EIM market due to EIM market failure or suspension from market.

Customer Feedback: EI and GI

- Remove the deviation bands and rely on the EIM sub-allocation structure.
  - Consistent with other EIM entities and FERC rulings.
  - Mid-C index may not reflect the “true” value of energy once more entities join the EIM.
  - Removal of the bands would mitigate the impact to customers of the earlier scheduling deadline.
  - Customers would face additional charges if maintaining EI/GI bands with the sub-allocation of EIM imbalance codes.
- One customer suggested retaining the existing pricing structure, without EIM pricing.
  - However, if adopting EIM LMP, no longer apply deviation bands.

Staff Proposal for EI and GI

- **<u>Alternative 3:</u> Remove Existing EI/GI Deviation Bands**
  - Relies on sub-allocation of EIM codes to manage EI/GI.
  - Aligns with other EIM Entities.
  - Removes price index risk, as it moves away from Mid-C Index.
  - Imbalance may increase due to updated EIM scheduling timelines, but removal of EI/GI deviation bands would reduce the impact of transitioning to the timeline.
    - Customers will still have charges/credits associated with the EIM imbalance charge codes.

Note: The EI/GI Deviation Bands will be maintained as the contingency plan if BPA is outside the EIM market due to EIM market failure or suspension from market.

PD/ID Penalty Alternatives

- **<u>Alternative 1:</u> Status Quo: Keep the ID and PD penalties**
- **<u>Alternative 2:</u> Remove one or both of the ID and PD penalties**
- **<u>Alternative 3:</u> Modify the ID and PD penalties**

Customer Feedback: PD and ID

- Remove PD and ID penalties
  - Other entities have not used these pre or post EIM.
  - Rely on the market signals directly from the EIM.
    - Expect that EIM will provide sufficient incentive to schedule accurately.
  - If there are trends in the future regarding inaccurate scheduling, revisit incorporate ID/PD later.
  - Passing resource sufficiency tests should not be part of rationale for penalties, should be focused on meeting reliability obligations.
  - Consider incentivizing accurate scheduling through sharing EIM revenues.
- Open to removing or modifying penalties
  - Requesting BPA monitor the issue and review prior to BP/TC-24.
- If retaining, modify to recognize the EIM environment that customers are participating in.

Staff Proposal for PD and ID

- **<u>Alternative 3:</u> Modify the ID and PD penalties**
  - Apply modifications in BP-22 to adapt to EIM model, may need to revisit if further adjustments are needed in BP-24.
  - BPA sets Balancing Reserves Capacity based on expected variability of scheduling practices, and PD/ID penalties incentivize customers to schedule within that expected variability.
  - ID/PD penalties directly incentivize loads and generators to schedule accurately and not accumulate imbalance energy.
    - The EIM's O/U scheduling penalty is at the BAA-level, and doesn't apply if the BAA balances to the CAISO's Area Load Forecast (ALF). Therefore, O/U scheduling penalty does not address the same concerns as the ID/PD structure.
  - If EIM is sufficient to incentivize accurate scheduling, then would not anticipate that the PD and ID penalties would trigger. If the EIM is not sufficient, the mitigation tools are still in place.

Existing Construct for PD

- Designed to discourage load and DERs from leaning on the BPA BAA and prevent accumulated imbalance energy on the FCRPS.
- Biased scheduling errors (in the same direction for consecutive hours) or consistent patterns of scheduling errors cause energy accumulation on FCRPS.
  - Energy accumulation can require changes to hydro operations plans and/or taking market actions that could have been avoided.
  - PD includes ability to penalize for patterns of scheduling errors occurring generally or at specific times of day.
- Incentivizes load and DERs to monitor scheduling error.
- Customers can mitigate the charge by making changes in future hours to correct scheduling deviations.

Staff Proposed Modifications for PD

- Propose to move first tier from 3 hours to 4 hours to account for scheduling being due at T-57 instead of T-20.
- Propose to move to 100 mills per kWh instead of the greater of 125% of BPA's highest incremental cost during that day or 100 mills per kWh.
- Considering adjustments for participating resources
  - A DER participating resource with continual Uninstructed Imbalance Energy (UIE) would still be impacting the FCRPS, whereas Instructed Imbalance Energy (IIE) would be handled in the market and should not be penalized.
  - Continuing to consider the system implementation ability to support the adjustments.

Existing Construct for ID

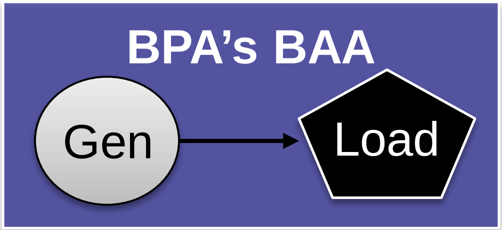
- Designed to discourage VERs from leaning on the BAA.
- Incentivizes proper scheduling behavior.
- Reduces impact of VERs on the balancing capacity provided by BPA, aiming to have accuracy and certainty in forecasts.
- If VERs schedule to the BPA-supplied forecast, VERs are not subject to ID penalties.
- If scheduling error from self-supplied schedule is greater than the error from the BPA-supplied forecast, VERs are subject to the ID penalty.

Staff Proposed Modifications for ID

- Intentional Deviation Measurement Value will be equal to the forecast value BPA supplies to the customer prior to T-57.
- Not anticipating adjustments for participating resources, but still under review.
  - ID is based on the forecast comparison to what is scheduled.
  - Unclear if there would be an impact for the EIM dispatch.

APPENDIX

Example Related to PD Patterns of Behavior Potential: Actual Output Above Schedule



- RS Timeframe (by T-57):
  - NPR Base schedule = 200 MW
- Pre-Real time:
  - No changes
- Real time:
  - Output = 10 MW above schedule
- ATF:
  - Gen. Imbalance Credit – UIE (difference between 5-minute market expectation and actual output)

<table>
<tr><th></th><th colspan="12">Non-Participating Resource Generation – Assumed LMP = $40</th></tr>
<tr><td>BPA Base Schedule</td><td colspan="12">200</td></tr>
<tr><td>FMM Market Run Occurs</td><td colspan="3">T-37.5</td><td colspan="3">T-22.5</td><td colspan="3">T-7.5</td><td colspan="3">T+7.5</td></tr>
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<tr><td>RTD Market Run Occurs</td><td>T-2.5</td><td>T+2.5</td><td>T+7.5</td><td>T+12.5</td><td>T+17.5</td><td>T+22.5</td><td>T+27.5</td><td>T+32.5</td><td>T+37.5</td><td>T+42.5</td><td>T+47.5</td><td>T+52.5</td></tr>
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<tr><td>FMM IIE</td><td colspan="3">$ -</td><td colspan="3">$ -</td><td colspan="3">$ -</td><td colspan="3">$ -</td></tr>
<tr><td>RTD IIE</td><td>$ -</td><td>$ -</td><td>$ -</td><td>$ -</td><td>$ -</td><td>$ -</td><td>$ -</td><td>$ -</td><td>$ -</td><td>$ -</td><td>$ -</td><td>$ -</td></tr>
<tr><td>RTD UIE</td><td>-$33.33</td><td>-$33.33</td><td>-$33.33</td><td>-$33.33</td><td>-$33.33</td><td>-$33.33</td><td>-$33.33</td><td>-$33.33</td><td>-$33.33</td><td>-$33.33</td><td>-$33.33</td><td>-$33.33</td></tr>
<tr><td>Total Imbalance</td><td colspan="12">-$400</td></tr>
</table>

- Footnote 1: Note that, while PRs will receive charges and credits directly from the market operator, and likely will not have their FMM and RTD awards equal to their base schedule, the concept that actual output differing from 5-minute market expectation results in UIE applies to PRs as well as NPRs

VER FORECAST/SCHEDULING

Review of Issues

Review of VER Forecast/Scheduling Issues

- Under the EIM scheduling timeline, current BPA-offered scheduling elections of 30/60 Committed and 30/15 Committed are no longer feasible, as hourly base schedules are finalized significantly earlier.

- The level of Balancing Reserve Capacity need for the BPA BA is linked to the accuracy of the VER forecast and schedules.
  - In order to achieve the reduction in Balancing Reserve Capacity BPA presented at the June workshop, BPA needs to replacing the Uncommitted Wind 45/60 Proxy with the “true Wind Forecast”. BPA is able to do so because the level of error of the BPA supplied forecast is known.
  - It is uncertain what the level of error would be in the Market Operator-produced forecast or a forecast supplied by the customer. BPA would need to continue using the Uncommitted Wind 45/60 Proxy

Baseline: Terms of EIM Entity Tariff

A Transmission Customer with a Non-Participating Resource that is a Variable Energy Resource shall submit resource Forecast Data to the BPA EIM Entity consistent with this Section 4.2.4.2 using any one of the following methods:

(1) The Transmission Customer may elect to use the BPA EIM Entity's Variable Energy Resource reliability forecast prepared for Variable Energy Resources within BPA's BAA, which shall be considered to be the basis for physical changes in the output of the resource communicated to the MO, for purposes of settlement pursuant to Schedule 9 of this Tariff;

(2) The Transmission Customer may elect to self-supply the Forecast Data and provide such data to the BPA EIM Entity, which shall be considered to be the basis for physical changes in the output of the resource communicated to the MO, for purposes of settlement pursuant to Schedule 9 of this Tariff. The BPA EIM BP will specify the manner in which Transmission Customers may self-supply Forecast Data; or

(3) The Transmission Customer may elect that the MO produce Forecast Data for the Variable Energy Resource, made available to the Transmission Customer in a manner consistent with Section 29.11(j)(1) of the MO Tariff, which shall be considered to be the basis for physical changes in the output of the resource communicated to the MO, for purposes of settlement pursuant to Schedule 9 of this Tariff.

A Transmission Customer with a Non-Participating Resource that is a Variable Energy Resource must elect one of the above methods prior to commencement of the EIM or prior to such other date in accordance with the procedures set forth in the BPA EIM BP…

Areas and Risks to Be Analyzed

- Scheduling accuracy
  - As accurate schedules as possible
- Ensure the BA has sufficient Balancing Capacity to maintain the 99.7% level of service
  - While Trying to keep the capacity needed for balancing as low as possible to minimize impacts to FCRPS and to cost of service
- Meet customer need
- Minimize impacts to VERBs rates
- Minimize cost and implementation complexity

Review of Step 4: Alternatives

Alternatives

- Alternative #1: Status Quo – Three Options for Forecast
  - Allow customers to elect which forecast they will use VER schedules
- Alternative #2: BPA Supplied Forecast
  - Require customers to use the BPA supplied forecast for VERs
  - This is similar to how Intentional Deviation penalties apply to Uncommitted Schedules today

Step 5: Customer Feedback to Alternatives and BPA Responses

Question from June Workshop

BPA's leaning -
Require VER Schedules to use the BPA supplied Hourly Meteorological Forecast.

BPA is asking for customer input: Is there a need or desire for BPA to allow VER customers to use a self supplied or Market Operator-supplied forecast?*

* *NOTE: Self supplied forecast must meet all CAISO requirements for timing, frequency and performance.*

Customer Feedback on Alternatives

Topic	Comment Summary	BPA Response
Forecast Options	We received comments from a number of customers encouraging BPA to not foreclose the option to use self-supplied or Market Operator-suppled forecasts for VERs.	Thank you for your comments. BPA has addressed the pros and cons/risks of the alternatives as part of Step 6, Staff Proposal for Solution.

Step 6: Staff Proposal for VER Forecast/Scheduling

Cost of CAISO Produced Forecast

Analysis of increased costs to VERs if they do not use the BPA supplied forecast (Note – this is BPA's understanding of how the costs work):

Cost of CAISO Produced Forecast

- Producing the forecast (the equation for the price for a year) is:
  - CAISO VER FC Charge = $0.10/MWh
  - Charge ($/MWh) * Nameplate (MW) * CF * 8760hrs/year = $/year

- Example:
  - For a 100 MW wind plant with a 30% capacity factor, the result is $0.10 * 100MW*0.3*8760= $26280/yr for the MO supplied forecast

Increase in VERs Capacity BPA Holds

- It is uncertain what the level of error would be in the Market Operator-produced forecast or a forecast supplied by the customer. Therefore BPA would propose to use the Uncommitted Wind 45/60 Proxy used in past rate cases to hedge against the uncertain accuracy of the non-BPA produced forecast, when determining the balancing reserve capacity need.

- Analysis shows a 13% increase to wind's balancing reserve capacity requirement and about a 30% increase to solar's balancing reserve capacity requirement over the amount needed if the BPA supplied forecast is used.

Additional Costs

There would be an increase in costs for VERS if the BPA forecast is not used:

- Cost of the Forecast Vendor
  - CAISO or
  - Other vendor/forecast system
- Higher VERBS rate
  - Use of the Uncommitted Wind 45/60 Proxy used in past rate cases to set Balancing Capacity needs
- Cost to any BPA system to enable use on non-BPA supplied forecast

Evaluation of Alternatives – VERs Scheduling

Decision Criteria	Alternative 1: Status Quo, Three Options	Alternative 2: BPA Supplied Forecast
BPA tariff language is aligned with the pro forma tariff and/or industry standard or Industry Best Practices • **Does not create seams issues between BPA and other EIM Entities** • **That is conducive to EIM participation**	Consistent with what other EIM Entities allow • Does not create seems issues • Conducive to EIM participation	Is not consistent with what other EIM Entities allow • Does not create seems issues • Conducive to EIM participation • Does not create seems issues • Conducive to EIM participation
Accurate schedules as possible	Introduces unknown variability when the MO forecast or a self-supplied forecast is used.	• Balancing Reserve Capacity based on the known variability of the BPA vendor supplied forecast. • Reduces uncertainty

Evaluation of Alternatives – VERs Scheduling

Decision Criteria	Alternative 1: Status Quo, Three Options	Alternative 2: BPA Supplied Forecast
Ensure the BA has sufficient Balancing Capacity to maintain the 99.7% level of service • **Try and keep the capacity needed to balance as low as possible**	Based on customer election, BPA may have to hold more capacity to maintain the 99.7% level of service. • Introduces unknown variability since if the MO forecast or a self-supplied forecast is used. • BPA would need to use the 45/60 proxy for any customers electing to use other than the BPA supplied forecast - results in 13% more BR capacity.	Able to use the True wind forecast approach while ensuring BPA has sufficient Balancing Capacity to maintain the 99.7% level of service. • Lowers the amount of capacity needed on a planning basis • Balancing Reserve Capacity based on the known variability of the BPA vendor supplied forecast. • Reduces uncertainty
Minimize impacts to VERBs rates	It is expected that customer that do not elect the BPA forecast would pay: • a higher VERBS rate, and • Assign cost of MO supplied forecast, and • Assign cost of implementing MO or self-supplied forecast to the customer	• Lower amount of Capacity should result in lower VERB rate, all else equal

Evaluation of Alternatives – VERs Scheduling

Decision Criteria	Alternative 1: Status Quo, Three Options	Alternative 2: BPA Supplied Forecast
Meet customer need	• Consistent with what customers asked for in their comments • Provides the balancing service as defined	• Not consistent with what customers asked for in their comments • Provides the balancing service as defined • Reduces the cost to customers
Minimize cost and implementation complexity	Increased work • Develop rates for non-BPA forecast use • Set up system to deal with non-BPA forecast • BPA is concerned about potentially putting a lot of work and dollars in order to allow optionality, only to not have anyone use the option.	Only need develop rate for BPA supplied forecast

BPA Staff Recommendation

BPA staff recommends Alternative 2: BPA Supplied Forecast.

Considerations:

- Benefits for Customers
  - Concern about cost to VERs if BPA joins the EIM
    - Lower Balancing Reserve Capacity need – lower VERBS rate
    - Lower cost of forecast data
      - Avoids the direct assignment of the costs associated with the MO or other vendor supplied meteorological data
      - Avoids the direct assignment of BPA's cost to implement
- Benefits for BPA
  - Ease of implementation – one set of VERBS rates
  - Less system modifications needed
  - Lower Balancing Reserve Capacity need – less impact on FCRPS

Proposed Tariff Language

A Transmission Customer with a Non-Participating Resource that is a Variable Energy Resource shall submit resource Forecast Data to the BPA EIM Entity consistent with this Section 4.2.4.2 using ~~any one of the following methods:~~

~~(1) The Transmission Customer may elect to use~~ the BPA EIM Entity's Variable Energy Resource reliability forecast prepared for Variable Energy Resources within BPA's BAA, which shall be considered to be the basis for physical changes in the output of the resource communicated to the MO, for purposes of settlement pursuant to Schedule 9 of this Tariff;

~~(2) The Transmission Customer may elect to self-supply the Forecast Data and provide such data to the BPA EIM Entity, which shall be considered to be the basis for physical changes in the output of the resource communicated to the MO, for purposes of settlement pursuant to Schedule 9 of this Tariff. The BPA EIM BP will specify the manner in which Transmission Customers may self-supply Forecast Data; or~~

~~(3) The Transmission Customer may elect that the MO produce Forecast Data for the Variable Energy Resource, made available to the Transmission Customer in a manner consistent with Section 29.11(j)(1) of the MO Tariff, which shall be considered to be the basis for physical changes in the output of the resource communicated to the MO, for purposes of settlement pursuant to Schedule 9 of this Tariff~~.

~~A Transmission Customer with a Non-Participating Resource that is a Variable Energy Resource must elect one of the above methods prior to commencement of the EIM or prior to such other date in accordance with the procedures set forth in the BPA EIM BP~~…

GENERATION INPUTS: RESERVES CAPACITY PRICING & ACS RATES

Daniel Fisher
Miranda McGraw
Danny Chen

Overview

- Address stakeholder comments on embedded cost pricing.
- Review BPA staff leaning for the Initial Proposal.
- Indicative ACS rates that reflect correction and updates.

Stakeholder Comments

- **Stakeholder comment:** Demonstrate that the new method of pricing regulation and non-regulation balancing reserves produces the same revenue.

COST ALLOCATION				
	Unit Cost/kW/mo	Quantity of INC Balancing Reserves	Cost Allocation	
Embedded Cost	$ 5.80	774	$ 53,884,811	
Variable Cost	$ 0.75	774	$ 6,942,389	
Base Capacity Cost	$ 6.55	Total	$ 60,827,200	

RATE DESIGN				
		Cost Delta between Regulation and Non-Regulation	$ 3.41	$/kW/mo
		Revenue Neutral Adjustment	$ 0.30	$/kW/mo
	Unit Cost/kW/mo	Quantity of INC Balancing Reserves	Cost Allocation	
Regulation	$ 8.56	319	$ 32,740,138	
Non-Regulation	$ 5.15	455	$ 28,087,062	CHECK
Delta	$ 3.41	Total	$ 60,827,200	TRUE

Stakeholder Comments

- **Stakeholder comment:** What would the BP-22 rates be if committed scheduling were still an option?
- **Response:**

Hypothetical	BP-20	BP-22 Hypothetical	Units
Wind Uncommitted	1.09	1.00	$/kW/month
Wind 30/60	0.93	0.90	$/kW/month
Wind 30/15	0.63	0.54	$/kW/month
Wind (Weighted Avg) vs. New	0.98	0.93	$/kW/month
Solar Uncommitted	0.91	0.55	$/kW/month
Solar 30/60	0.69	0.57	$/kW/month
Solar 30/15	0.37	0.38	$/kW/month
Solar New Forecast	0.71	0.62	$/kW/month

Stakeholder Comments

Stakeholder comment:

- BPA's generation inputs customers pay for more than half of BPA's total reserve requirement all of which will be used to support BPA's participation in the EIM. Yet, no EIM benefits are proposed to be allocated to generation inputs. Why?

Response:

- The classification of costs used in generation inputs separates capacity costs from energy costs.
- Considering we do not allocate energy costs to generation inputs, we do not believe it is appropriate to allocate energy benefits.
- The unit cost of balancing capacity is constructed using roughly a third of Power's total revenue requirement.
- Said another way, if BPA sold all of its capacity capability through generation inputs, it would collect roughly $1 billion of its $3 billion revenue requirement and would need to collect another $2 billion in revenue from the use of that capacity to fully recover its costs.
- Therefore, we do not believe it is appropriate to credit energy revenue to capacity products under this type of cost classification method.

- *Reminder:* Regulation Frequency Response service, Variable Energy Resource Balancing Service, and Dispatch able Energy Resource Balancing Service are pooled services that are supported by the use of capacity but are not a purchase of the capacity itself.

Initial Proposal Preview

- Staff has selected "Method B" (presented at the June 23, 2020 workshop) as the preferred method for applying rate design to the cost of balancing reserves.
- In summary, Method B used the fixed costs of an LMS100 combustion turbine (fast flexible aeroderivative) and a 7HA.02 CT(slower, less expensive heavy duty turbine) to create a cost delta between providing regulating and non-regulating capacity.
- The delta is preliminarily estimated at $3.41/kW/mo (i.e., the LMS100 is $3.41/kW/mo more expensive).

	Capital	Debt Payments	Fixed O&M	Insurance	Fixed Fuel	Total Annual Cost	Monthly Fixed Cost ($/kw/mo)	Delta
LMS100	1000	$65.39	$ 12.53	$ 2.80	$ 42.29	$123.01	$10.25	
7HA02	550	$31.58	$ 6.89	$ 1.35	$ 42.29	$82.11	$6.84	($3.41)

Update on Preliminary ACS Rate

- Corrected inadvertent exclusion of relevant solar data.
- Fix caused the **preliminary** rates to change relative to the June 23rd workshop with the solar rate changing the most.

Solar update only	BP-20	BP-22	Units
RFR	0.49	~~0.55~~ 0.53	mills/kWh
Operating Reserves: Spinning	9.53	9.96	mills/kWh
Operating Reserves: Supplemental	8.32	7.94	mills/kWh
Wind Uncommitted	1.09		$/kW/month
Wind 30/60	0.93		$/kW/month
Wind 30/15	0.63		$/kW/month
Wind (Weighted Avg) vs. New	0.98	0.91	
Solar Uncommitted	0.91		$/kW/month
Solar 30/60	0.69		$/kW/month
Solar 30/15	0.37		$/kW/month
Solar New Forecast	0.71	~~0.47~~ 0.60	
DERBS INC	15.11	~~21.76~~ 21.68	mills/kW (max hourly deviation)
DERBS DEC	1.59	~~1.95~~ 1.93	mills/kW (max hourly deviation)

DERBS Update

- Billing determinants updated

June Update			
Derbs inc Forecast Quantity	Monthly MW max hrly deviation	4159	
Derbs dec Forecast Quantity	Monthly MW max hrly deviation	3758	
August Update			Change
Derbs inc Forecast Quantity	Monthly MW max hrly deviation	2729	-34%
Derbs dec Forecast Quantity	Monthly MW max hrly deviation	3102	-17%

Applying DERBS billing determinant update to the updated rates with the solar adjustment as provided on previous slide.	**BP-20**	**BP-22**	**Units**
DERBS INC	15.11	~~21.68~~ 33.04	mills/kW (max hourly deviation)
DERBS DEC	1.59	~~1.93~~ 2.34	mills/kW (max hourly deviation)

ACS Rates Update

- The rates below reflect our latest estimate of the ACS rates with the previously discussed updates (solar and forecast DERBS billing determinant) and updated variable costs.
- These are still **preliminary** rates as several components still need to be updated for the Initial Proposal.

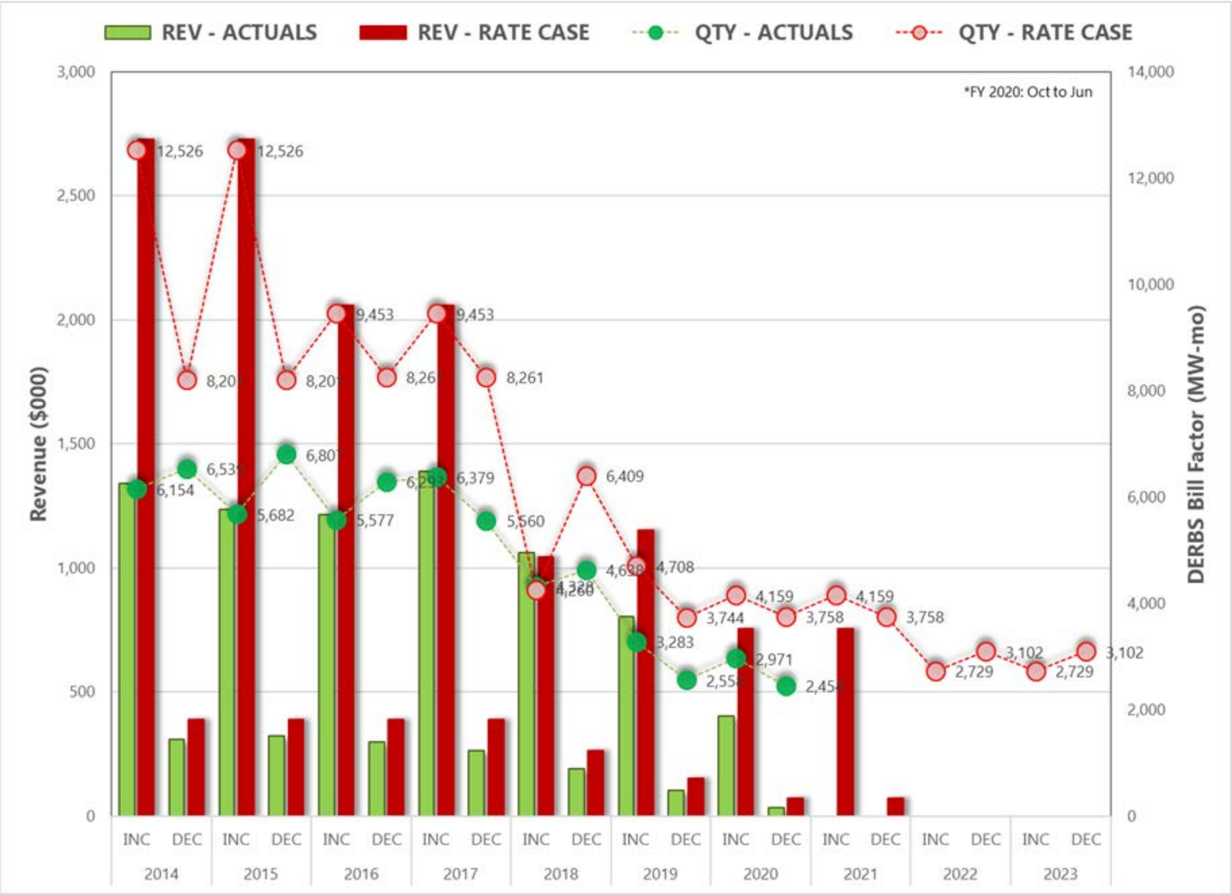
Preliminary	**BP-20**	**BP-22**	**Units**
RFR	0.49	~~0.53~~ 0.54	mills/kWh
Operating Reserves: Spinning	9.53	~~9.96~~ 8.97	mills/kWh
Operating Reserves: Supplemental	8.32	7.95	mills/kWh
Wind Uncommitted	1.09		$/kW/month
Wind 30/60	0.93		$/kW/month
Wind 30/15	0.63		$/kW/month
Wind (Weighted Avg) vs. New	0.98	~~0.91~~ 0.93	$/kW/month
Solar Uncommitted	0.91		$/kW/month
Solar 30/60	0.69		$/kW/month
Solar 30/15	0.37		$/kW/month
Solar New Forecast	0.71	~~0.60~~ 0.62	$/kW/month
DERBS INC	15.11	~~33.04~~ 31.43	mills/kW (max hourly deviation)
DERBS DEC	1.59	~~2.34~~ 4.02	mills/kW (max hourly deviation)

Stakeholder Feedback

- **Stakeholder comment:** The DERBS rate is increasing a lot as a percentage; will BPA mitigate this rate shock?
- **Response:** While the DERBS rates may increase by 108% for INC and 153% for DEC, we do not currently believe that this is rate shock once the larger context is considered.
  - Historical under-collection of costs is also a factor. All else equal, the rate would need increase to simply collect the same amount of money because response to price signal is not causing a one for one decrease costs.
  - Generally, the total amount of revenue collected as a result of these two DERBS rates is small relative to a customer's overall bill. The % increase of a single rate cannot alone be used to determine rate shock.
  - The new DERBS rates are forecast to collect a total of roughly $1.2 million.

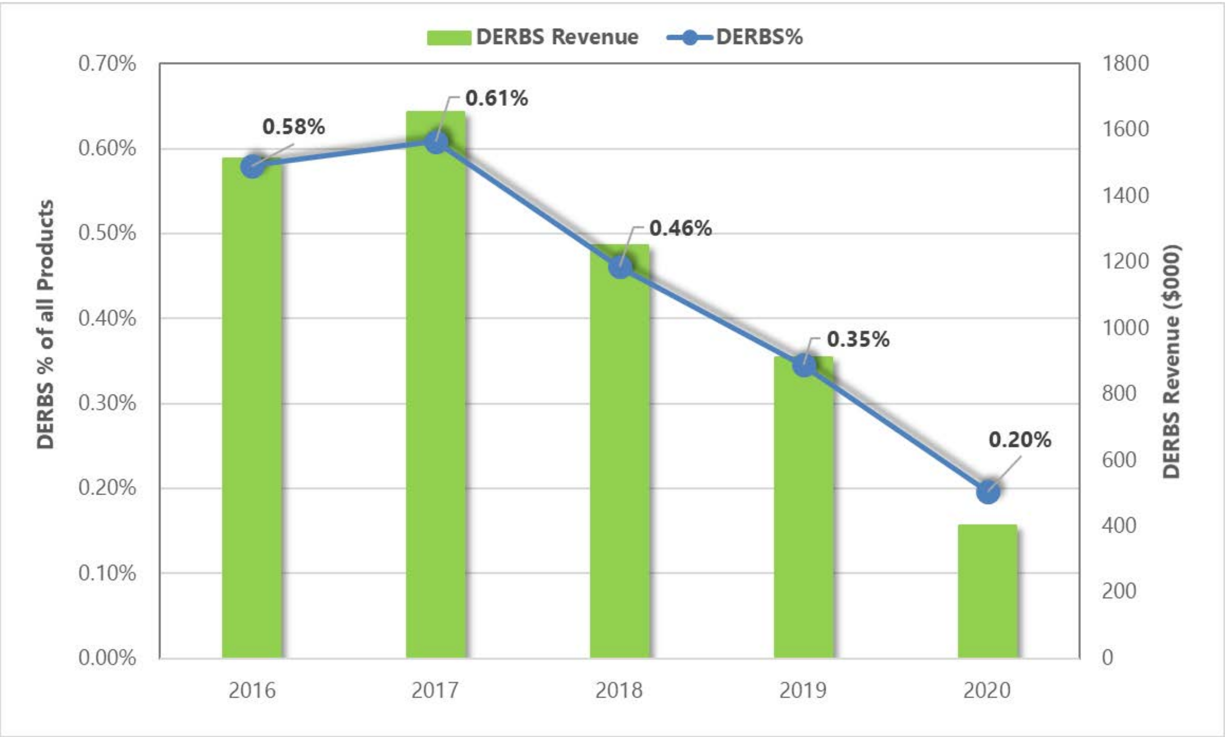
DERBS Variance to Rate Case

- A portion of the rate increase is due to historical under collection of costs.



- Billing Factor: 5-min max SCE each hour (summed for month)
- Historical over-forecast of DERBS revenues.
- Large non-fed thermal plants have been departing the BPA BAA.
- Actively have been improving forecasts as seen in BP-18.
- Leads to lower values in BP-22.
- Note: FY 2020 is Oct to June.

DERBS Revenue compared to total



- Revenues for DERBS customers compared to total revenues for DERBS customers < 1%.
- Majority of customers have DERBS revenue at less than 2%.
- There are a limited number of customers that only purchase ancillary services and for those customers they would experience a higher percentage impact.

CAISO EIM v Powerdex Comparison

- We have received a request to compare Powerdex energy rates to potential CAISO EIM energy rates.
- While we understand the desire for this information, it is a comparison that is extremely difficult to quantify.
  - Essentially, it requires trying to predict how BPA's participation in the EIM would change WECC-wide operations and the impact on the market clearing price across two different markets functioning in different timeframes (one before the hour and frozen and one in five minute increments during the hour). It would also require knowledge of the amount of transmission entities may decide to donate by path.
- Qualitatively, the EIM is designed to solve for a more efficient and lower cost dispatch of energy.
- Given this, we expect that the EIM will better reflect the least-cost source of energy during an hour as compared to the Powerdex index that is a market snapshot prior to the hour of operation.
  - If more energy is needed, that energy should reflect the most cost-effective source of the energy offered to the EIM.
  - If less energy is needed, that excess will be available to others and dispatched in least cost order after constraints are considered.
- Further, BPA staff leaning is to remove the EI/GI bands if in the EIM. With that change, if the clearing prices were similar, customers would pay less for energy needed or receive more for energy sold.
- Lastly, historical CAISO EIM prices are publically available for stakeholders to consider, analyze, and evaluate, which can be found here:
  - CAISO EIM prices: http://www.caiso.com/TodaysOutlook/Pages/prices.aspx

FUNCTIONALIZATION OF GRID MODERNIZATION COSTS

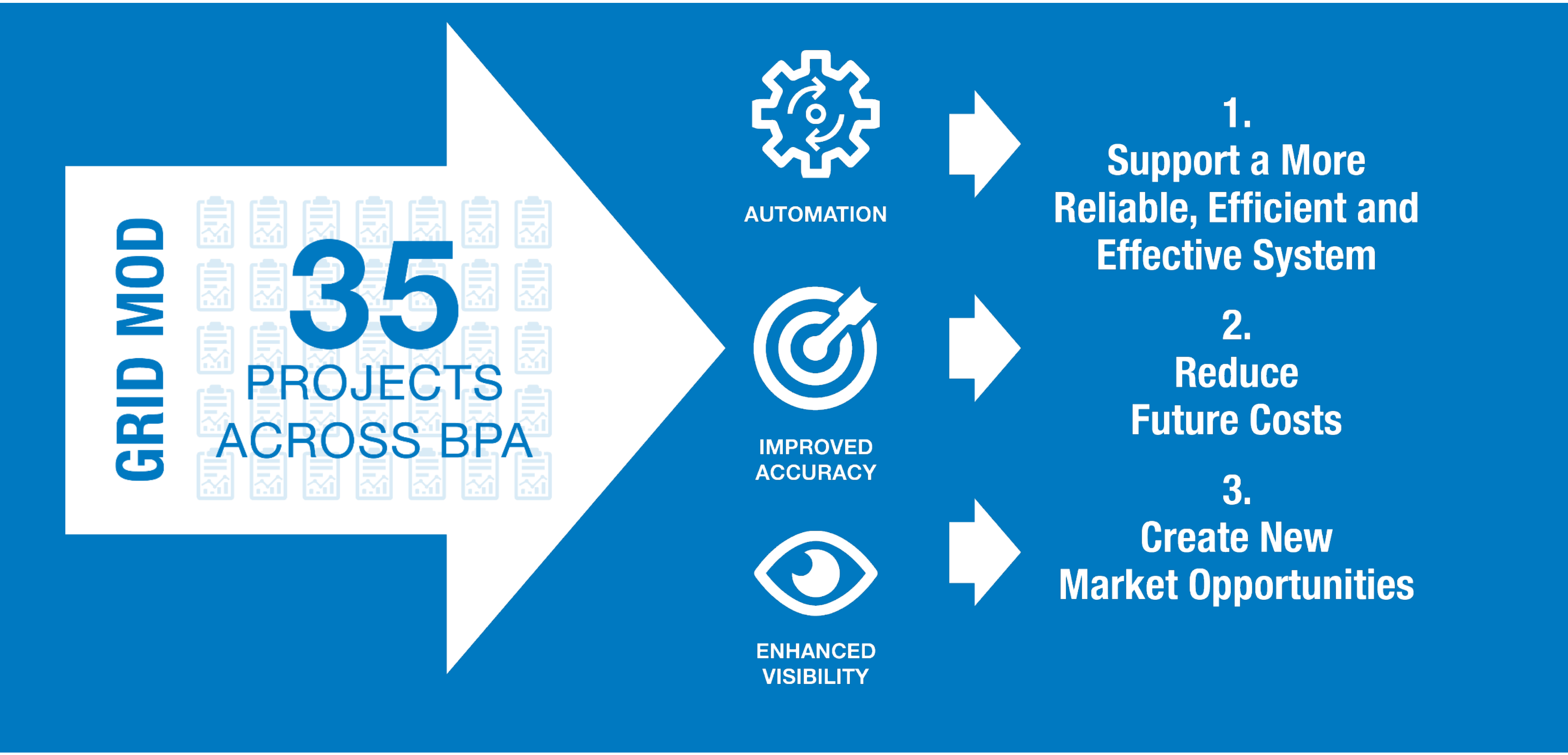
Allison Mace

Background

Customers requested additional information on the functionalization of Grid Modernization costs:

- The amounts functionalized to each function;
- Which projects are functionalized to each function; and
- The rationale for the 65/35 functionalization.

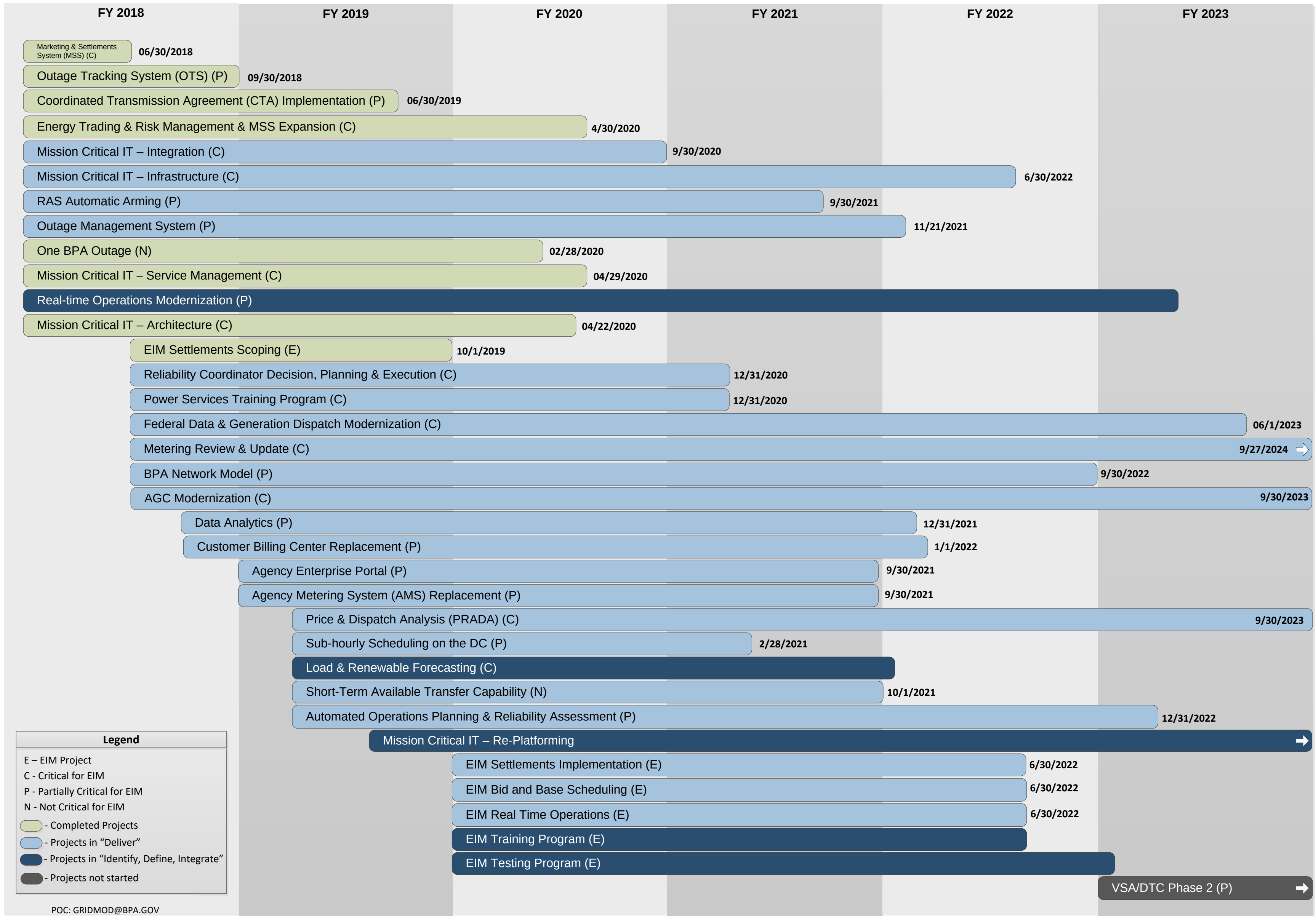
What is Grid Modernization?



Grid Modernization Roadmap

FY20 Q4

As of 08/06/2020 – Subject to Change



Bonneville POWER ADMINISTRATION

Functionalization of Grid Modernization Costs

- The Grid Modernization Key Strategic Initiative has proposed an expense budget of $25 million for BP-22.
  - Budget includes EIM implementation costs.
  - It does not include ongoing costs of any Grid Mod projects including participation in EIM.
- Individual project costs were not directly functionalized to specific business lines.

2022-2023 Grid Mod Costs

- In IPR, the annual costs for Grid Mod are functionalized as:
  - 65% to Transmission: $8,125,000
  - 35% to Power: $4,375,000
- Within those Grid Mod costs, $6,752,000 are for EIM-specific projects, which are functionalized as:
  - 65% to Transmission: $4,388,800
  - 35% to Power: $2,363,200

FY17-19 Functionalization

FY17-19 Grid Mod IPR Expense				Notes
Corp	Power	Transmission	Total (Less Corp)	Corporate (39% of total) is excluded in the total because they are the costs that need to be functionalized after the P&T split is determined.
$6,901,078	$2,966,595	$7,977,055	$10,943,650	
Allocation	**27%**	**73%**	**100%**	

- Functionalization shown is based on Grid Mod IPR costs only only, not including costs borne by the business line.
- Total expenditure in this period was $17.8 Million

Considerations:

- Corporate costs represent 39% of the spend.
    - IT and program support.
- Mix of projects was more heavily weighted towards Transmission.

Evaluation of Grid Mod Functionalization

- Staff recommends retaining the 65/35 functionalization applied to Grid Mod projects in BP-18 and BP-20.
- Staff evaluated whether 65/35 continued to reasonably approximate cost causation based on which organization would be completing the work.
- Reviewed historical (2017-2019) actual costs billed to projects and concluded that the project costs in that time period are not representative of the cost split going forward.

ISSUE #20: POWER AND TRANSMISSION RISK

Zach Mandell

Issue: Introduction and Education

Risk Study Overview

The Power and Transmission Risk Study serves to ensure that BPA meets the Treasury Payment Probability (TPP) Standard and implements BPA's Financial Reserves Policy (FRP)

TPP Standard: BPA must set rates high enough to have at least a 95% probability of making all payments to the Treasury over the two-year rate period.

FRP Implementation: BPA must establish tools to meet FRP objectives for managing business line and agency financial reserves.

Risk Study Overview (continued)

- The Risk Study defines and evaluates the tools used to implement the FRP and ensures BPA meets the TPP standard. The Study uses probabilistic modeling of revenues, expenses, and Reserves for Risk (RFR) to measure TPP and the effectiveness of the risk mitigation tools.
- For BP-20, BPA included three risk mechanisms for each business line. These were the Cost Recovery Adjustment Clause (CRAC), the FRP Surcharge, and the Reserves Distribution Clause (RDC). The trigger metric for each of these mechanisms was set based on end-of-year actuals. If a risk mechanism triggered it would adjust rates for December-September of the following fiscal year.
- Staff plan to propose these same tools for the BP-22 Initial Proposal. An additional tool, Planned Net Revenue for Risk (PNRR), is available to meet the TPP standard, but is not expected to be needed for BP-22.

Risk Study Overview, Risk Mechanisms

- Cost Recovery Adjustment Clause (CRAC): increases rates for the following fiscal year when below a threshold (generally $0 in RFR) at the end of a fiscal year.
    - For Transmission, the CRAC triggers "dollar for dollar" up to maximum of $100 million. For Power, it triggers dollar for dollar up to $100 million, then "50¢ on the dollar" up to $300 million.
- FRP Surcharge: increases rates for the following fiscal year when below 60 days cash on hand at the end of a fiscal year.
    - The maximum annual surcharge is proposed to be $40 million for Power and $15 million for Transmission.
- Reserves Distribution Clause (RDC): A mechanism for identifying reserves the Administrator shall consider for rate reduction, debt repayment, incremental capital investment, or any other high-value purpose when a business line is above 120 days cash *and* the agency is above 90 days cash at the end of a fiscal year.
- Planned Net Revenue for Risk (PNRR): A fixed amount of additional revenue added to the Revenue Requirement which increases reserves over the rate period.

Issues

There are two notable issues which we would like to discuss in this workshop:

1. The trigger metric for the risk mechanisms
2. Business Line vs Agency TPP

Issue 1: Risk Mechanism Trigger Metric

Overview

- During BP-20 workshops, we discussed changing the risk mechanism trigger metrics from Forecast Accumulated Calibrated Net Revenue (ACNR) to either Actual Accumulated Net Revenue (ANR) or Actual Reserves for Risk (RFR). Ultimately, we ended up using of ACNR Actuals in BP-20 rates.
  - Shortly after the release of the BP-20 Initial Proposal, BPA discovered a reserves allocation issue related to the Business Unit Split model. This issue was a key factor in the decision to stay with the use of ACNR in final BP-20 rates.
- The issue was discussed in the BP-20 risk workshop on 8/8/2018. The presentation can be found at: https://www.bpa.gov/Finance/RateCases/BP-20/Meetings/RateCase/2018.08.08_BP20Wrkshp_Px-Tx-Risk.pdf

Trigger Metric Decision Criteria

In the BP-20 workshop, we laid out the following criteria and considerations for choosing the risk mechanism trigger metric:

- Decision criteria:
  1. *Verifiable:* process and calculations are repeatable and can be reviewed by others
  2. *Simplicity:* metric is easy to explain and understand
  3. *Aligns with BPA's goals regarding financial reserves*: metric should reasonably reflect end of year reserves for risk since it is the basis of the Financial Reserves Policy

- Other considerations:
  1. Low error potential: consider input, calculation, and forecast errors
  2. Low staff workload: consider workload for standing up process and routine execution
  3. Cost effectiveness: consider combined implementation and ongoing costs
  4. Low impact on Business Decisions: consider potential for undesirable financial choices in order to keep metric from "misbehaving"
  5. Impact on customer rates: consider recovery period and time for customers to react

Proposal

- Currently, staff proposes to use Reserves for Risk (RFR) Actuals as the trigger metric for the CRAC, FRP Surcharge, and RDC in the BP-22 Initial Proposal.
- In BP-20, we converted from using forecast values for the risk mechanism trigger to end-of-year actuals. We intend to continue the use of actuals for BP-22.
- This proposal aligns closely with the Decision Criteria listed on the prior slide; in particular, the use of RFR-based thresholds aligns very closely with the FRP targets.

The above outlines BPA staff's current intent for the BP-22 Initial Proposal. We welcome feedback on this approach.

Issue 2: Business Line vs Agency TPP

Overview

- The TPP standard requires that BPA maintain a 95% probability of making *both* treasury payments in a two-year rate period when setting rates. BPA's payments to the US Treasury are the first to be missed if financial reserves are insufficient. Therefore, TPP is a measure of BPA's ability to meet its overall financial obligations over a rate period.
- The TPP Standard was first adopted by BPA in 1993 as part of BPA's 10-year Financial Plan and remains in place in BPA's most recent 2018 Financial Plan.
- In 2002, BPA began measuring TPP for each business line individually. Measurement of TPP on a business line basis has continued through BP-20.
- In 2010, BPA began relying on the $750 million Treasury Facility as a source of liquidity to meet the TPP standard.

Issue

- Business line TPP has led to the need to attribute Agency liquidity tools to individual business lines in order to demonstrate that the agency is meeting the TPP standard.
  - The $750 million Treasury Note has been attributed to Power for rate setting since 2010
  - In 2007, $55 million of Transmission RFR were attributed to Power for TPP purposes. These reserves remained attributed to Transmission for all other purposes, including interest earning.
- BPA's Treasury Payment is an obligation of the agency. The TPP policy is meant to provide a very high probability that BPA is able to meet its financial obligations.
- Prior to BPA adopting the FRP, business line TPP set implicit minimum RFR levels for each business line. With the FRP in place, each business line has an explicit lower reserves target.

Proposal

- Develop the Risk Study to use an Agency TPP test in place of business line specific TPP tests.
- Only in the event that Agency TPP is below 95%, would we fall back to business line-specific TPP tests to calculate the appropriate amount of PNRR to add to each business line's revenue requirement in order to meet the Agency TPP test.
- Measuring TPP at the Agency level would align better with TPP policy and eliminate unnecessary attribution of liquidity.

The above outlines BPA staff's current intent for the BP-22 Initial Proposal. We welcome feedback on this approach.

Next Steps

- To complete customer feedback on Power and Transmission Risk proposal:
  - Please submit to techforum@bpa.gov (with copy to your account executive) by Tuesday, September 9

POWER RATES

LOAD & RESOURCES

Post RHWM Load Updates
Loads & Resources
Flex Spill Implementation

Reed Davis
Peggy Racht
Steve Bellcoff
John Stalnaker

Post RHWM Load Updates

BPA is changing Initial Proposal loads

- Industrial announcements not commented on in RHWM process are impacting loads requiring BPA to make adjustments to load.
  - Pulp & Paper Industry impacts
  - Airlines industry
- Uncertainty of the COVID 19 recovery continues but some things are less murky.
  - Beginning of school season
  - End of 1st stimulus package
  - State revenue collections

Load changes from RHWM values

- Changes are not widespread, much is continuing as it has.
  - Urban area recovery continues into 2021 and beyond.
  - Isolated industrial impacts are occurring as expected.

Amount of aMW change by year

2021	2022	2023	2024
-110	-96	-64	-45
-1.1%	-0.9%	-0.6%	-0.4%

BPA is changing normal weather assumption

- To better align with climate, we are changing normal weather assumptions.
  - Moving away from a 35-year fixed average to a 15-year rolling average updated every 5 years.
  - Adding a few new weather stations due to the availability of quality data during this period.
- Doing so now lets up implement change while impacts are smaller.
- Starting after September, forecast updates will use normal based on 2005-2019 average.
- Slight decrease in winter temperatures and increase in summer temperatures.
- Current normal is 35 year from 1970-2004.

Loads & Resources

General Hydro Updates (RHWM and IP Studies)

Pacific Northwest Coordination Agreement (PNCA) Project Data

- Update based on 2019 PNCA data, with latest Coulee pumping data from upcoming 2020 PNCA submittal

Canadian Operations

- Update based on the 2022 Assured Operating Plan (AOP22) completed under the Columbia River Treaty. AOP22 provides the same Canadian Operation for FY20 – FY24.

Project Outages

- Update based on the latest long term maintenance and capital program forecasts from PGAF. This will use the same methodology as the last rate case.

Reserves

- Update FCRPS reserve assumptions consistent with Generation Inputs forecasts.

Loads

- Update based on latest forecasts produced by KSL and aggregated by PGPR in LORA.

CRSO EIS Preferred Alternative Updates

Water Supply Forecast

- Include the Corps' Water Supply Forecast, uses consistent forecasting methodology

Project Operations

- Update Flood Risk Management inputs based on new Water Supply Forecast
- Minimum Operating Pool at John Day raised April-May to disrupt salmonid predators
- Implement sliding scale summer draft at Libby and Hungry Horse
- Allow Dworshak to draft slightly deeper for hydropower (winter/early-spring)
- Set lower Grand Coulee September and October targets to maintain power flexibility

Updates affecting Hydro availabilities obtained from PGAF

- Contingency reserves can include unused turbine capacity (Lower Snake, Lower Columbia projects)
- Allow turbine operation within and above 1% of peak efficiency
- Allow each Lower Snake project to carry up to 5% reserves during fish passage season

Updates Affecting H/K values of plant data input

- Installation of "fish-friendly" turbines at IHR (slightly increases H/K)

Spill Updates

Spring Spill Season

- Begins - Lower Snake Projects: April 3, Lower Columbia Projects: April 10
- 125% Flex Spill: LWG, LGS, LMN, IHR, MCN, BON (with 150 kcfs max spill) - applies 125% TDG spill caps (16 hrs), Performance Standard Spill (8 hrs)
- 120% Flex Spill: JDA - applies 120% TDG spill caps (16 hrs), Performance Standard Spill (8 hrs)
- TDA – 40% Performance Standard Spill (24 hrs)

Summer Spill Season

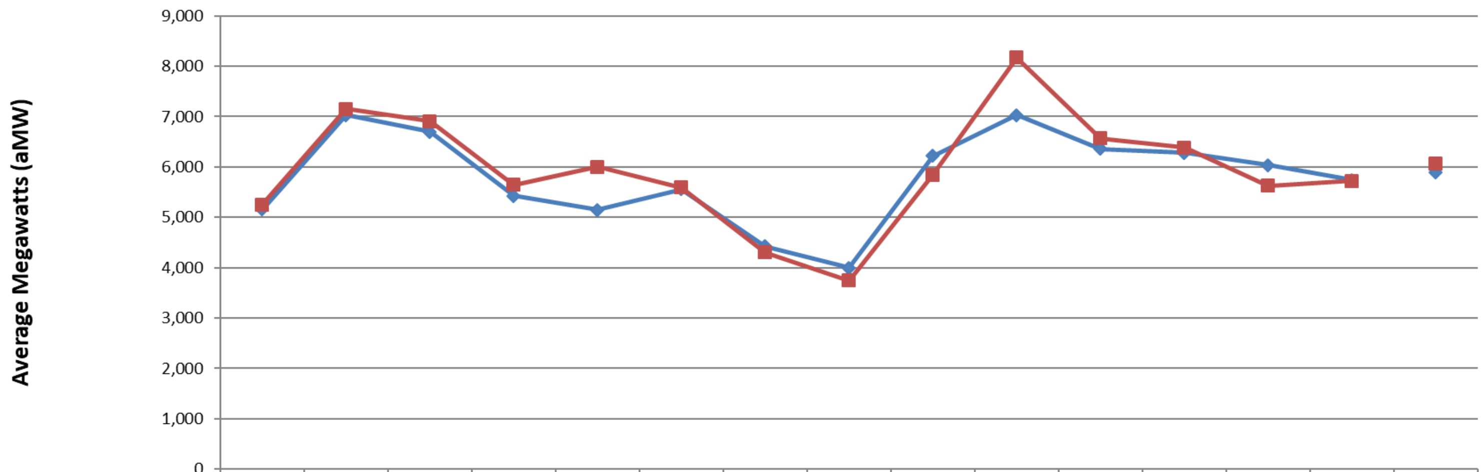
- Begins – Lower Snake Projects: June 21, Lower Columbia Projects: June 16
- Performance Standard Spill at all eight projects
- Ends – August 14, and transitions into reduced spill amounts through August 31

Includes Overshoot Spill (5-10 cfs) outside spill season for adults

Firm Hydro Comparison

1937 Firm Federal Regulated Hydro Generation

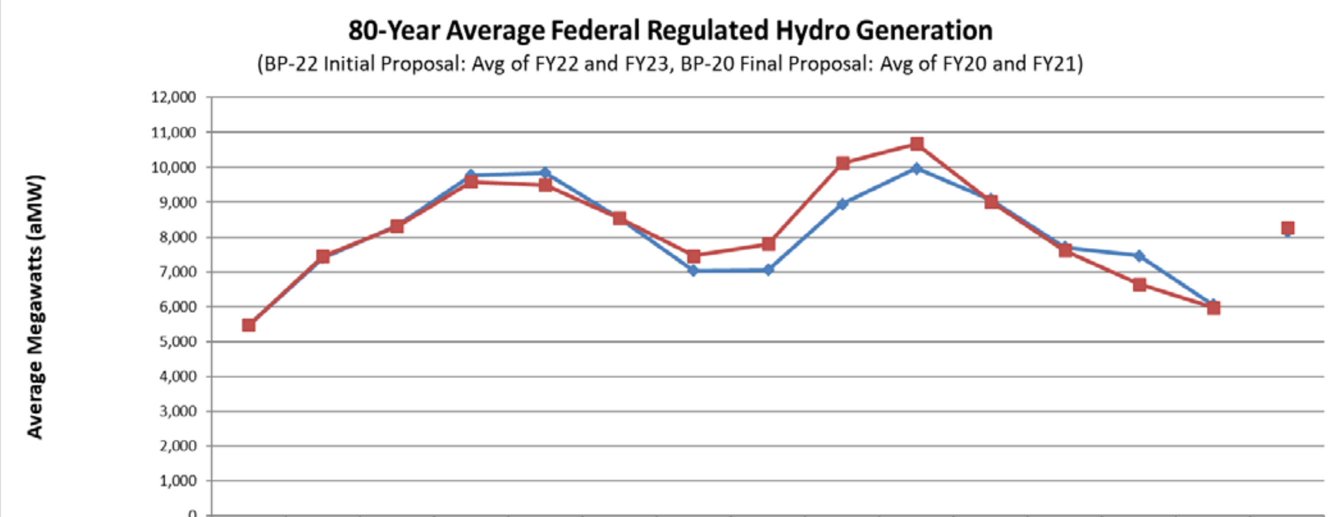
(BP-22 Initial Proposal: Avg of FY22 and FY23, BP-20 Final Proposal: Avg of FY20 and FY21)



	Oct	Nov	Dec	Jan	Feb	Mar	AprI	AprII	May	Jun	Jul	AugI	AugII	Sep	Annual
BP-22 Initial Proposal	5,157	7,031	6,700	5,429	5,149	5,553	4,424	3,996	6,219	7,026	6,360	6,277	6,031	5,736	5,898
BP-20 Final Proposal	5,252	7,154	6,904	5,640	6,000	5,592	4,298	3,744	5,843	8,170	6,564	6,383	5,628	5,721	6,070
BP-22 IP - BP-20 FP	-96	-124	-204	-212	-851	-40	126	252	377	-1,145	-204	-106	403	15	-172

The - 172 aMW decrease in annual 1937 generation compared to BP20 Final Proposal is attributable to including the net CRSO FEIS Preferred Alternative measures implemented in FY22 & FY23 (-110 aMW), including the 125% Flex Spill operation (about -50 aMW), and a combination of including 5 to 10 cfs of overshoot spill outside spill season (from the CRSO FEIS) and several hydro availability refinements (-12 aMW).

80-Year Average Hydro Comparison



	Oct	Nov	Dec	Jan	Feb	Mar	AprI	AprII	May	Jun	Jul	AugI	AugII	Sep	Annual
BP-22 Initial Proposal	5,480	7,407	8,323	9,771	9,840	8,544	7,033	7,059	8,948	9,975	9,077	7,703	7,461	6,052	8,163
BP-20 Final Proposal	5,476	7,450	8,308	9,583	9,498	8,543	7,463	7,798	10,117	10,682	9,020	7,614	6,648	5,980	8,278
BP-22 IP - BP-20 FP	4	-43	16	189	342	1	-430	-739	-1,170	-708	57	89	813	72	-115

- The -115 aMW decrease in 80-year average hydro generation was attributable to including the 125% Flex Spill operation (about -100 aMW), the CRSO FEIS Preferred Alternative measures implemented in FY22& FY23 (about -5 aMW), and a combination of including 5 to 10 cfs of overshoot spill outside spill season (from the CRSO FEIS) and several hydro availability refinements (about -10 aMW).

BP-22 Preliminary Load Forecast

2-Year Average Comparison (1937 Critical Water):
BP-22: FY22 and 23; BP-20 Final Rate Case: FY20 and 21

- **Total Federal Firm Load Obligation are lower by -239 aMW**
  - **Firm Obligations lower by -254 aMW**
    - Reduced Load Following obligations (-92 aMW)
    - Reduced Federal Agency obligation (-23 aMW)
    - Reduced Tier 1 Block (-100 aMW)
    - Reduced Slice obligations (-38 aMW)
  - **Other Contract Obligations lower by -77 aMW**
    - Expiration BPA/PAC Wind Shaping
    - Expiration of misc. Power Sales Contracts
  - **Uncommitted Firm Surplus Sales increased by +92 aMW**
    - Tier 2 load service (166 aMW)
      - Tier 2 load service is new in L&R reporting and shows the use of any surplus to serve T2 load before being sold as a firm surplus sale
    - Firm Surplus Sales after T2 Load Service (109 aMW)

BP-22 Preliminary Resource Forecast

2-Year Average Comparison (1937 Critical Water):

BP-22: FY22 and 23; BP-20 Final Rate Case: FY20 and 21

- **Total Federal firm resources are lower by -239 aMW**
  - **Total Hydro Generation forecast lower by -171 aMW**
    - Net reduction due to CRSO FEIS PA changes (-110 aMW)
    - Reduction from including the 125% Flex Spill operation (-50 aMW)
    - Other typical hydro updates (about -11 aMW)
  - **Non-Hydro Renewables forecast lowered by -16 aMW**
    - Expiration of Foote Creek 4 wind (-4 aMW)
    - Expiration of Klondike Wind 1 (-5 aMW)
    - Expiration of Condon wind (-6 aMW)
  - **Contract Purchase forecast lower by -61 aMW**
    - Expiration of Contracts
    - Inclusion on new SILS Contracts
  - **Reserves and Transmission losses lowered by 9 aMW**
  - **Uncommitted Purchases - No change**
    - No Tier 1 Augmentation
    - No Tier 2 Augmentation
      - Tier 2 Augmentation is new in L&R reporting due to addition of Tier 2 Obligations in report

BP-22 Preliminary Load Forecast

Detailed 2-Year Average Comparison (1937 Critical Water):

BP-22: FY22 and 23; BP-20 Final Rate Case: FY20 and 21

Comparison BP-22 Preliminary and BP-20 Final Proposals *(Energy in aMW)*		BP-22 Preliminary (Avg FY22-23)	BP-20 Final Proposal (Avg FY20-21)	Difference	Comment
Federal Load Obligations					
1.	**Firm Obligations**	**6,592**	**6,845**	**-254**	**Firm obligation changes:** - Load Following obligations -92 aMW - Federal Agencies Obligation -23 aMW - Tier 1 Block -100 aMW - Slice obligations -38 aMW
2.	*Load Following*	*2,987*	*3,079*	*-92*	
3.	*Federal Agencies*	*109*	*132*	*-23*	
4.	*USBR*	*177*	*178*	*-1*	
5.	*Tier 1 Block*	*472*	*573*	*-100*	
6.	*Slice Block*	*1,328*	*1,301*	*27*	
7.	*Slice Output from T1 System*	*1,506*	*1,571*	*-65*	
8.	*DSI Obligations*	*12*	*12*	*0*	
9.	**Other Contract Obligations** *(w/o Firm Surplus Sales)*	**498**	**575**	**-77**	**Other contract obligaton changes:** - Expiration of wind shaping and other contracts - Includes SILS and Other Sales Obligations
10.	*Exports*	*487*	*516*	*-28*	
11.	*Intra-Regional Transfers (Out)*	*11*	*59*	*-49*	
12.	**Uncommitted Sale**	**275**	**183**	**92**	**Uncommitted sales changes:** - specifically called out share of surplus serving T2 Load
13.	*Tier 2 Load Service*	*166*	*NA*	*166*	
14.	*Firm Surplus Sale*	*109*	*183*	*-74*	
15.	**Total Firm Obligations** *(Sum lines 1+9+12)*	**7,365**	**7,604**	**-239**	

BP-22 Preliminary Resource Forecast

Detailed 2-Year Average Comparison (1937 Critical Water): BP-22: FY22 and 23; BP-20 Final Rate Case: FY20 and 21

Comparison BP-22 Preliminary and BP-20 Final Proposals *(Energy in aMW)*		BP-22 Preliminary (Avg FY22-23)	BP-20 Final Proposal (Avg FY20-21)	Difference	Comment
Federal Resources					
16.	**Net Hydro**	**6,296**	**6,468**	**-171**	**Hydro generation changes:** - CRSO PA measures (-110 aMW) - 125% Flex Spill Operations (-50 aMW) - overshoot/availabilities (-12 aMW)
17.	*Regulated Hydro - Net*	*5,945*	*6,117*	*-172*	
18.	*Independent Hydro - Net*	*348*	*348*	*0*	
19.	*Small Hydro Resources*	*3*	*3*	*0*	
20.	**Non-Hydro Renewable**	**40**	**56**	**-16**	**Non Hydro Renewable changes:** - Experation of Foote Creek 4 wind (-4 aMW) - Expiration of Klondike Wind 1 (-5 aMW) - Expiration of Condon wind (-6 aMW)
21.	*Wind*	*40*	*56*	*-16*	
22.	*Solar*	*0*	*0*	*0*	
23.	*Other*	*0*	*0*	*0*	
20.	**Thermal**	**1,055**	**1,055**	**0**	
21.	*Nuclear*	*1,055*	*1,055*	*0*	
24.	**Contract Purchases** *(w/o Augmentation)*	**199**	**260**	**-61**	**Contract purchase changes:** - Expiration of contracts - Includes SILS
25.	*Imports*	*1*	*82*	*-81*	
26.	*Intra-Regional Transfers (In)*	*34*	*13*	*21*	
27.	*Non-Federal CER*	*135*	*135*	*0*	
28.	*Slice Transmission Loss Return*	*29*	*30*	*-1*	
29.	**Reserves & Losses**	**-225**	**-235**	**9**	**Changes in Federal resource stack**
30.	*Transmission Losses*	*-225*	*-235*	*9*	
31.	**Total Net Resources** *(Sum lines 14+18+22+27)*	**7,365**	**7,604**	**-239**	
20.	**Uncommitted Purchases**	**0**	**0**	**0**	**Uncommitted purchases changes:** - inclusion of Tier 2 loads requires Tier 2 Augmentation if needed
21.	*Tier 1 Augmentation*	*0*	*0*	*0*	
23.	*Tier 2 Augmentation*	*0*	*NA*	*0*	
33.	**Total Resources w/Augmentation** *(Sum lines 29+30)*	**7,365**	**7,604**	**-239**	
33.	**Federal Surplus/Deficit** *(Sum lines 31 less line 13)*	**0**	**0**	**0**	

Flex Spill Implementation

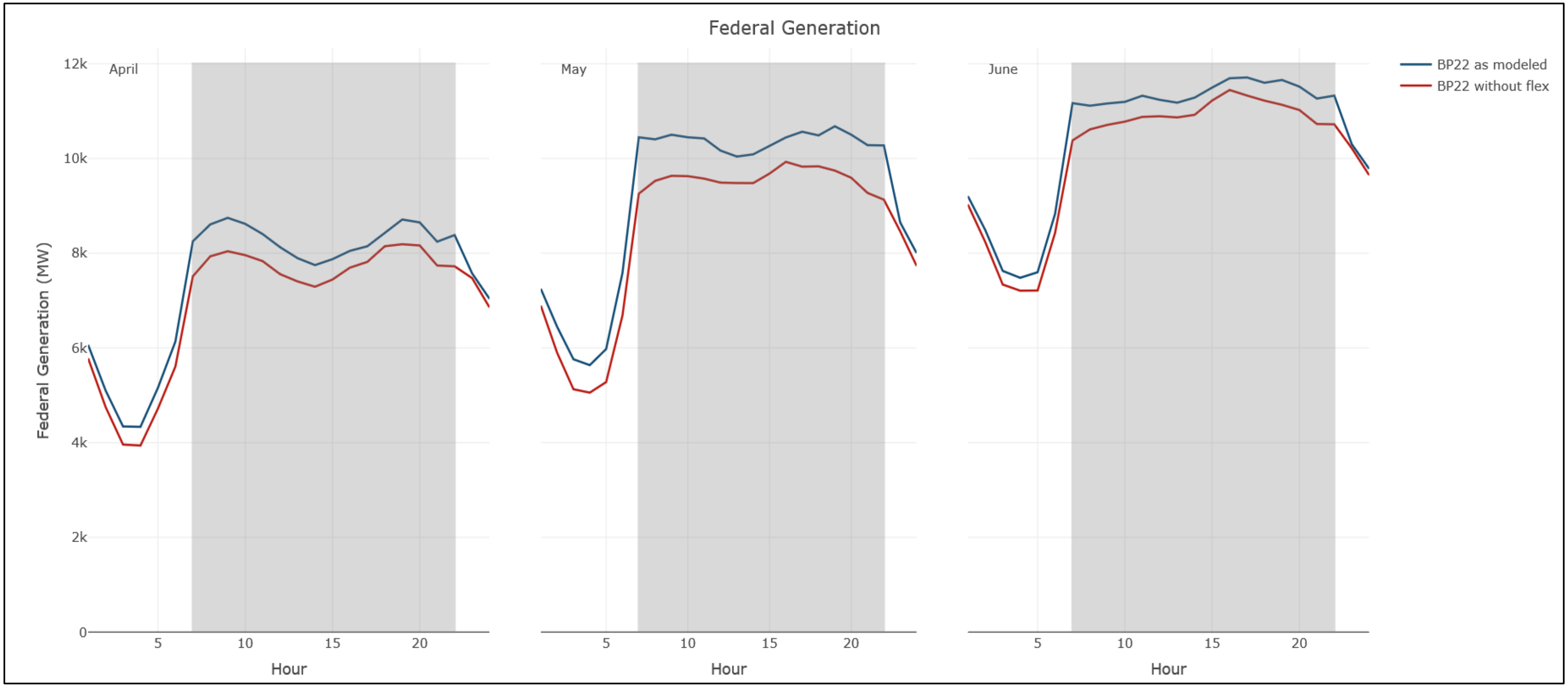
Background

- BPA agreed to implement flexible spill in 2018 under the 2019-2021 Spill Operation Agreement (spill agreement).
- To support agreement negotiations, Columbia Vista was used to show that additional spill with the option to reduce spill for up to 8 hours a day would be, under a value-of-energy perspective, revenue neutral with 2018 fish passage spill operations.
- However, flex spill disproportionately lowers generation under 1937 water conditions, which lowers Tier 1 loads and has upward pressure on rates due to rate design.
  - This is offset, to some degree by reduced spill in August under the spill agreement, as well as additional secondary inventory forecast to be sold on the trading floor in rate case models for the net secondary energy credit.
  - Additional value for within-day shaping is the subject of this presentation

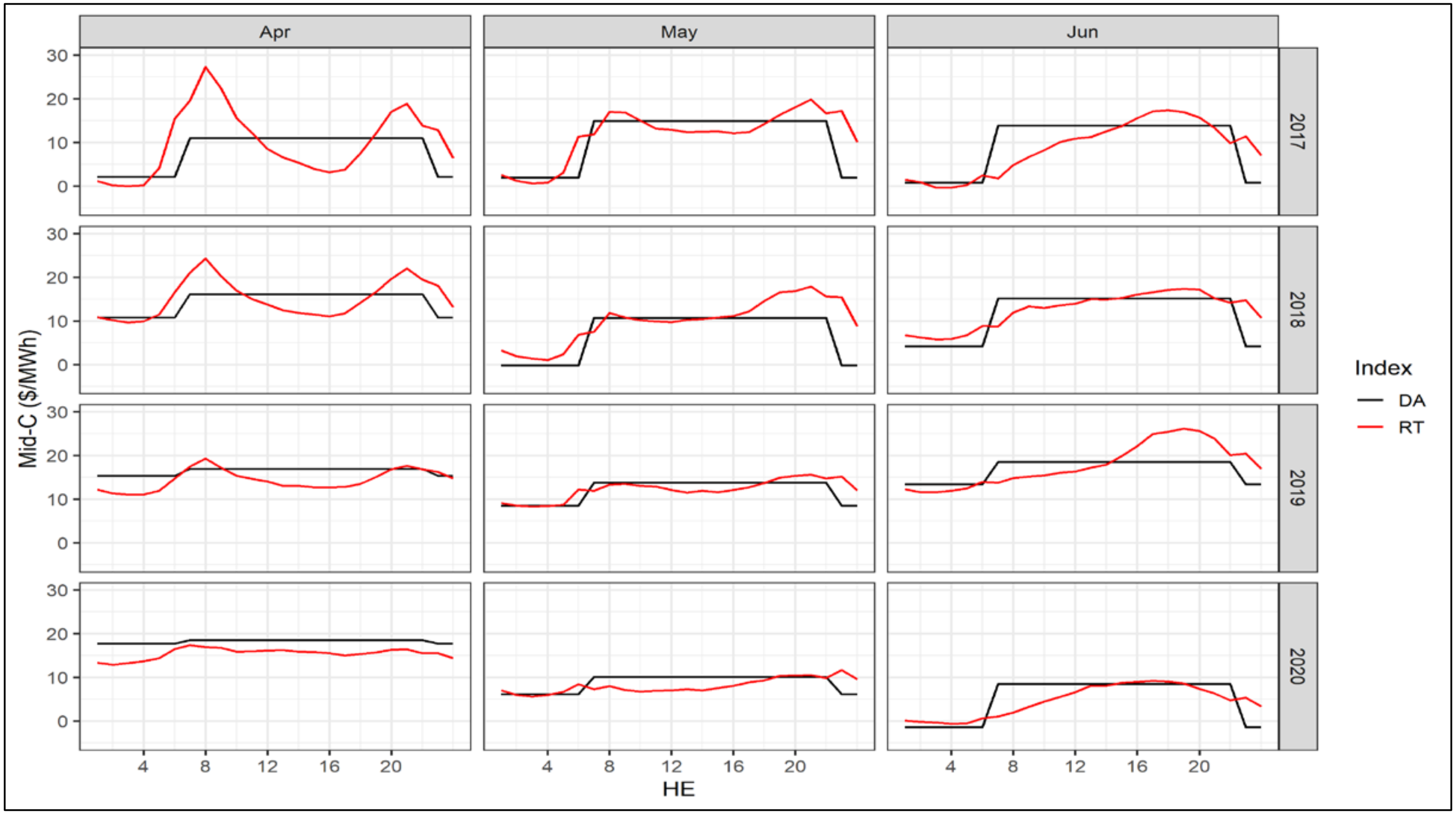
Valuing Within-Day Shaping Benefits

- We evaluated whether our rate case models were capturing the benefits of a flexible spill operation.
    - Used HOSS to model flexible spill valuation as benefits *spread over the entire HLH period*. HOSS load factors the FCRPS to all constraints and produces HLH and LLH generating values used net secondary forecast.
    - This produced significantly more HLH generation.
    - Given today's market conditions (spreads between super peak and HLH blocks) and our current operational practices, we believe this approach captures the full benefit of the flexible spill operation.
    - Under different market conditions, it's possible that flexible spill could provide up to another $1-2 million in additional benefits.
    - Until we start observing those type of market conditions, we do not believe rates should be set assuming this additional value.

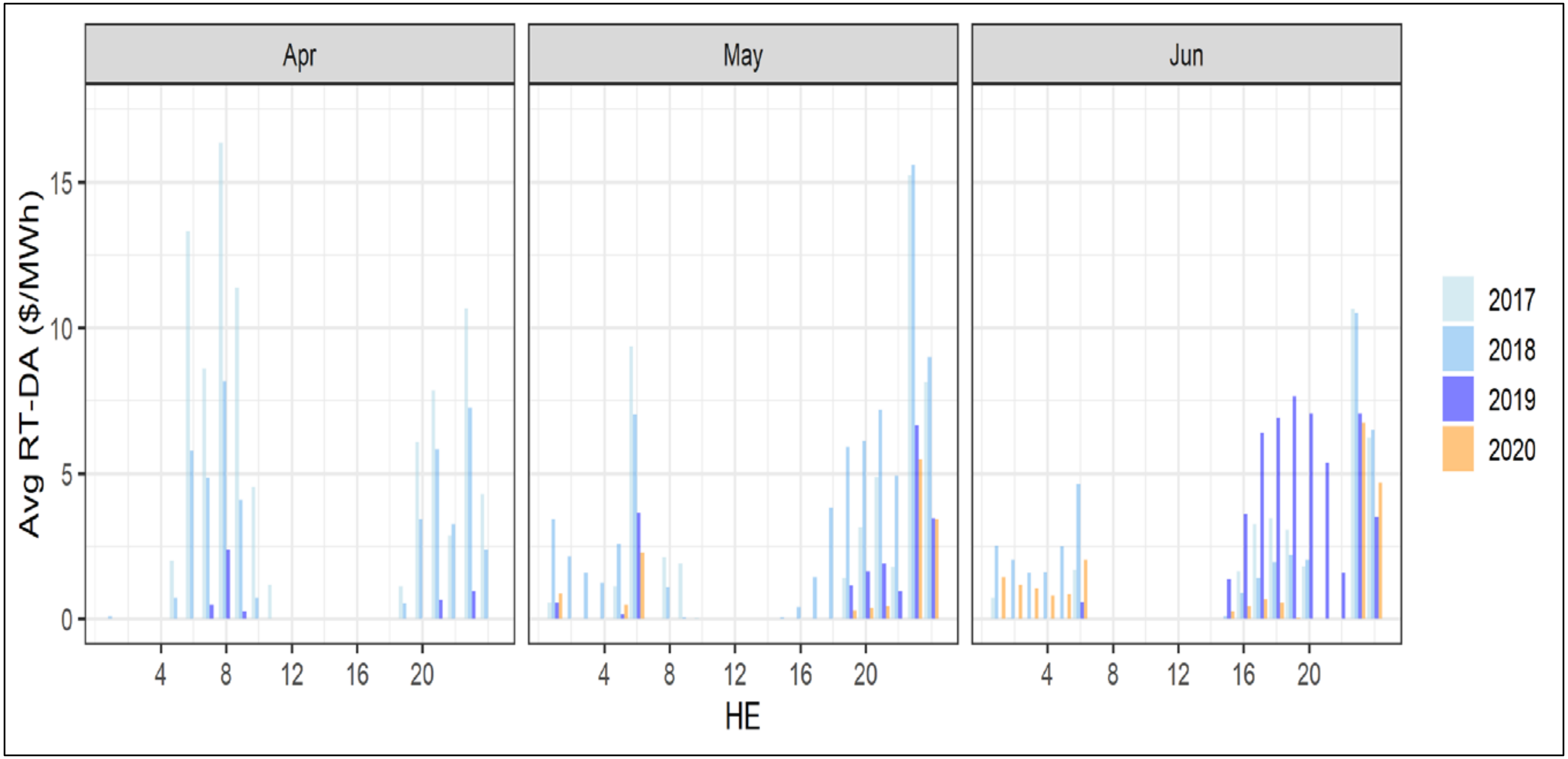
BP-22 Federal Generation



Mid-C Forecast – Day Ahead and Real-Time



Day Ahead vs. Real-Time Spreads Declining at Mid-C



NATURAL GAS, ELECTRICITY MARKET PRICE, AND NET SECONDARY REVENUE FORECASTS

James Vander Bos
Eric Graessley

Natural Gas Forecast

Forecasting Gas Prices

- Aurora™ takes natural gas forecasts as input to electricity price forecasts
- BPA's gas forecast is prepared using information from:
  - S&P Global Platts
  - IHS Markit
  - Henry Hub and Sumas futures contract pricing
  - EIA energy outlook data

Pacific Northwest Region

- The gas forecast provides monthly prices for Henry Hub and basis values for 11 other hubs in the PNW, SW US, and Western Canada
- These inform the fuel costs for gas plants in Aurora™

- What are we seeing?

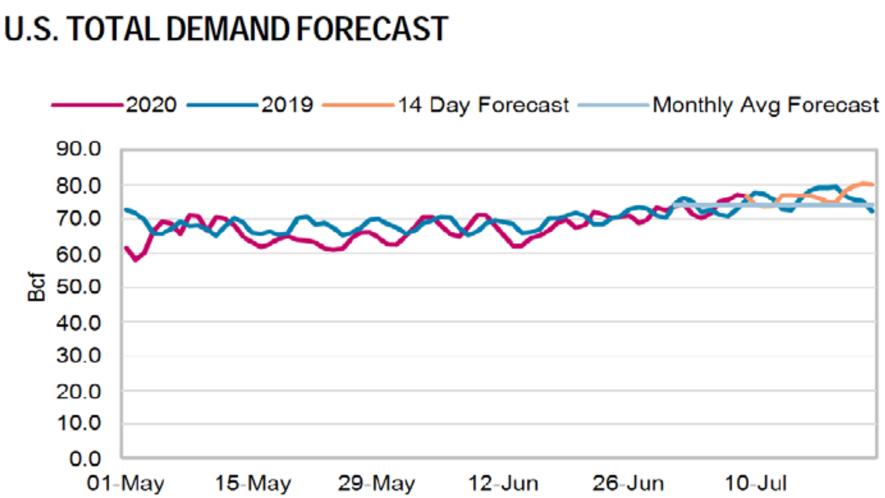
Prices Look Higher for BP-22

- A bit of déjà vu from BP-20's Final Proposal when we were seeing "higher prices"
  - BP-20 Anticipated low storage inventories heading into *next* winter
    - This is the same for BP-22
  - BP-20 PNW regional import constraints
    - A similar phenomena for BP-22
  - BP-20 Might be leaning more heavily on Rockies gas
    - This is the same for BP-22

- New trends
  - Large expected declines to associated gas production (maybe 7 Bcf lower, from previous estimates, during BP-22 timeframe)
  - Declines to production and LNG export capacity utilization tie US to global gas prices

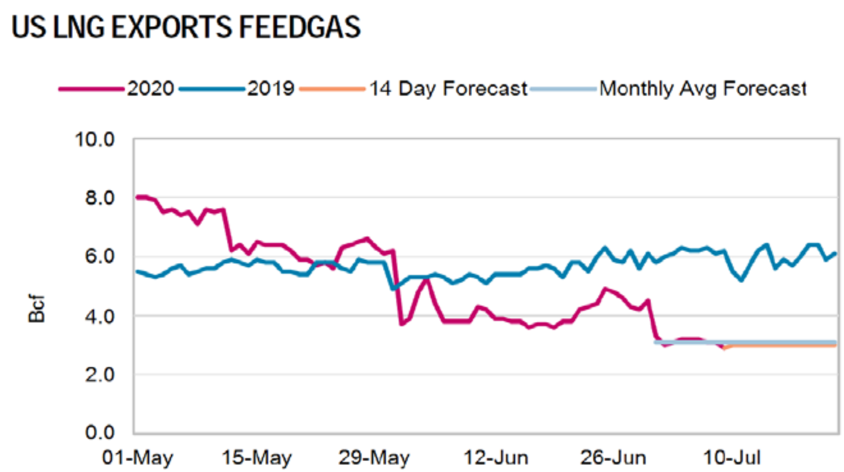
Covid-19 Impacts on Demand (near-term impacts)

Overall Demand



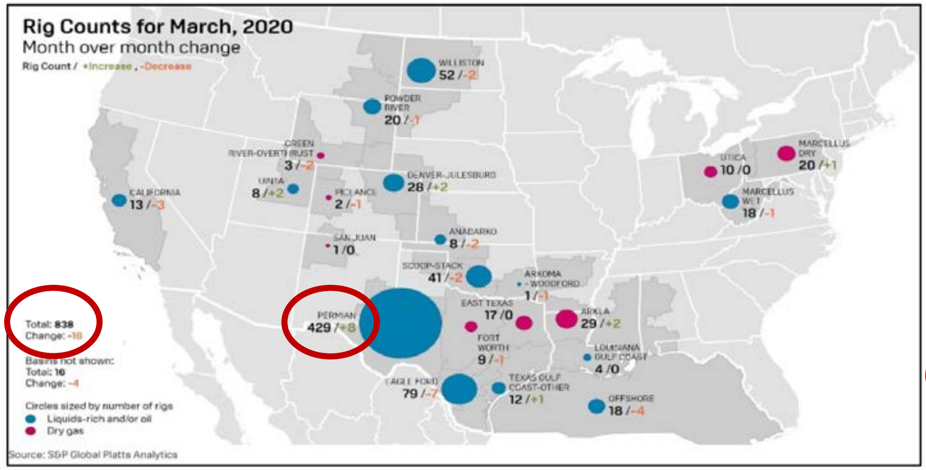
- Total demand not far off 2019
- Reductions to Ind, Com muted, partially offset by increases to Res

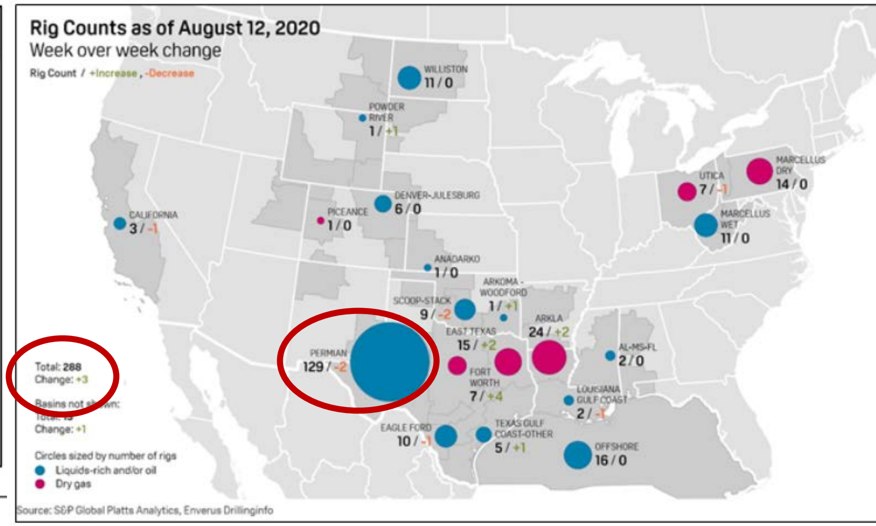
LNG Export Demand

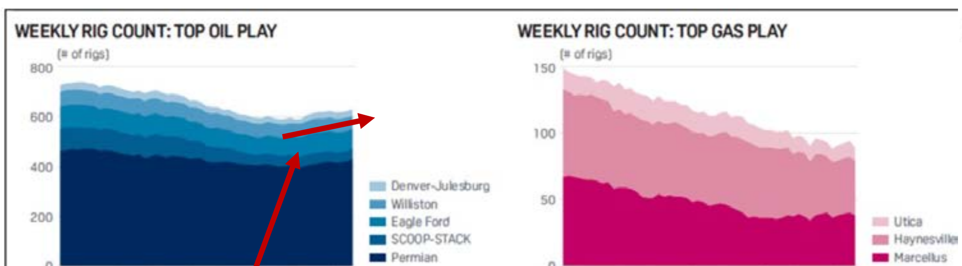


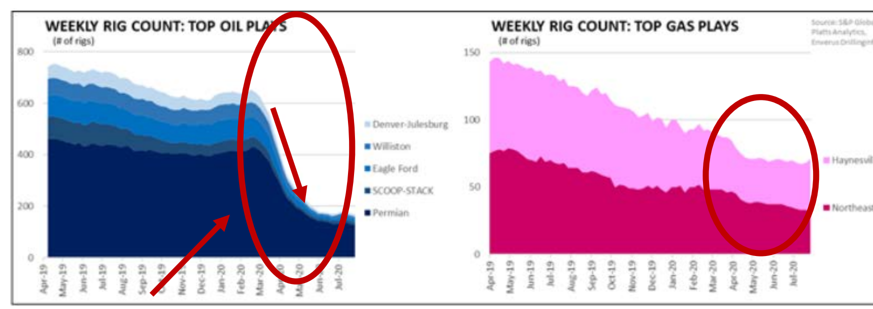
- LNG, however, was expected to add LOTS of demand vs 2019
- Instead it has decreased from 8 to 3 Bcf/d due to global oversupply

Where is Supply Headed? (medium-term impacts)









Previously expected associated gas growth

What happens to the "free" gas?

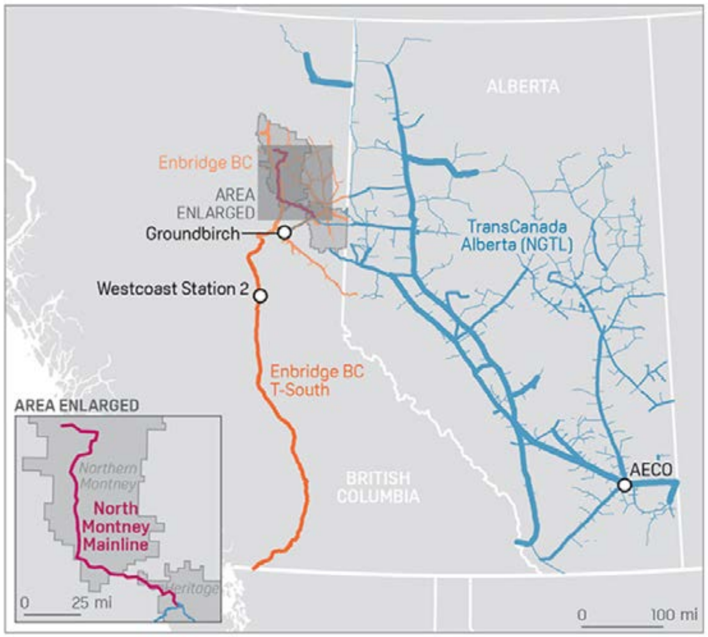
What about the PNW? (longer-term impacts)

- For the past few years, the PNW has been insulated (but not separate) from the macro movements
- A quote from S&P Global Platts:

  "***PNW loses its captive BC supplier***

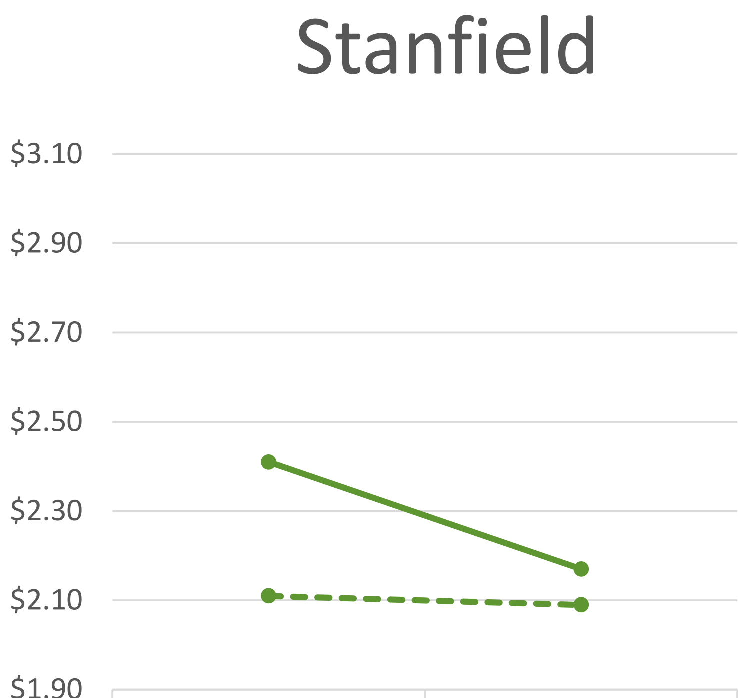
  With the startup of TC Energy subsidiary NGTL's North Montney Mainline, the Pacific Northwest no longer has a captive supplier with the cheapest source of gas in North America…This will put upward pressure on prices in the PNW."
- More gas can now move east to other markets
- Increased Canadian demand from coal to gas conversions

NORTH MONTNEY MAINLINE



Source: S&P Global Platts Analytics

A Recent Forecast



	First Year	Second Year
preIP (May)	2.41	2.17
BP-20	2.11	2.09

- There was a mild increase above the BP-22 price for a recent forecast:

Stanfield	1st Year	2nd Year	Annual Avg.
Change	0.30	0.08	0.19

- All indications point to a further increase in the expected prices in the PNW for the Initial Proposal

Electricity Market Price Forecast

Preliminary BP-22 Initial Proposal (IP) Forecast

1. Refresher
2. Updates
3. What will likely change for the actual IP
4. Any preferences for what goes into the rate case study / documentation?

Aurora Refresher

- Aurora is a third party production cost model used globally by utilities, regulators, system operators, planning entities, consultants, and investment firms to model the economics of wholesale electricity grids

- BPA has used Aurora to forecast electricity prices in every rate case since 2000

- Aurora uses a linear program to minimize the cost of meeting load in the Western Interconnection on an hourly basis, subject to a number of operating constraints. Given the solution (an output level for all generating resources and a flow level for all interties), the price at any hub is the cost, including wheeling and losses, of delivering a unit of power from the least-cost available resource. **It is assumed that the marginal cost of producing and delivering electricity approximates the price.**

Aurora Refresher

- **Limitations:**
  - No market design differentiation (no: forward curves / contracts / day-ahead / real-time markets, forecast error, source & sink, local commitment considerations), **all of the WECC is effectively modeled as a single ISO**
  - No behavioral components of power markets (in reality, bids may differ from actual marginal cost)
  - No AC flows / nodal prices, and transmission system is fixed (AURORA has the capability, not yet implemented)
  - No ancillary services (again, AURORA has the capability, not yet implemented)
  - No thermal resource duct firing / peak heat rate

- AURORA is a deterministic model**, we produce a distribution of price forecasts** by using a Monte Carlo of input distributions using historical variation for: loads, hydro generation, gas prices, transmission capability, wind generation, and CGS availability

Aurora and the EIM

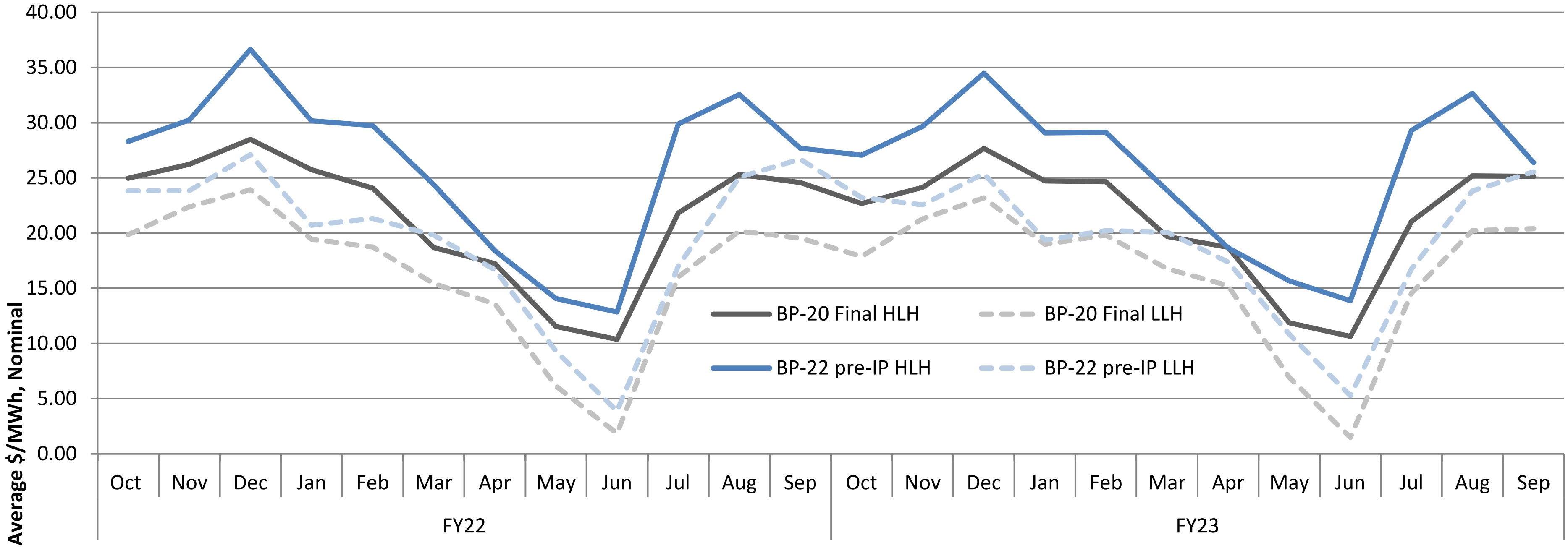
- Aurora does not account for differences in market structure (futures, DA, RT, bilateral vs ISO). It simulates the interconnect **as if the WECC were centrally dispatched in a single ISO**, and we assume that all prices will tend to converge on the marginal cost of generating electricity.

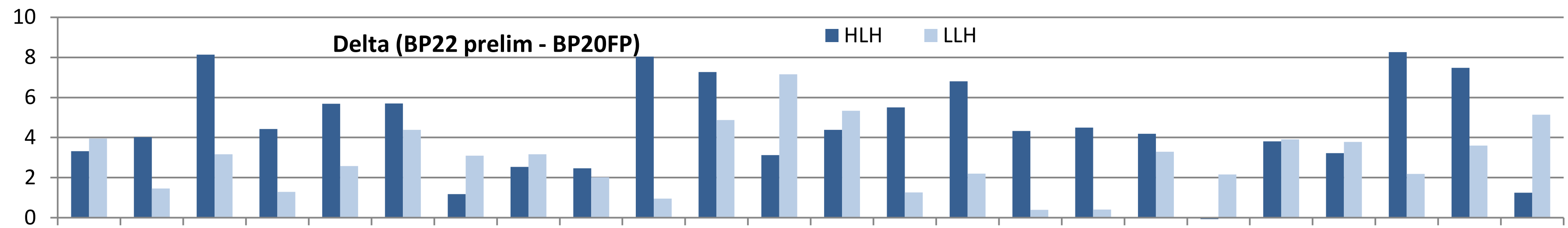
- Aurora has capabilities to model components of the EIM, but these tend to be computationally prohibitive and incompatible with existing models and methodologies. For example:
  - Sub-hourly (incompatible with risk and rate case models, requires significant investment)
  - Nodal topography (produces Locational Marginal Prices—LMPs, including congestion, this change requires significant investment)
  - Can use commitment logic to lock in Day Ahead commitment, and add deviations to loads and renewable resources better capturing DA vs RT price dynamics (computationally prohibitive)

- Alternatively, attempting to better reflect the current bilateral market structure in the Northwest is both highly speculative and likely computationally prohibitive

- **Ultimately, we are not planning on making any adjustments to account for possible differences in EIM pricing for the BP-22 rate period.**
  - BPA will continue to review market dynamics and forecasting tools to develop electricity price forecasts for future rate cases.

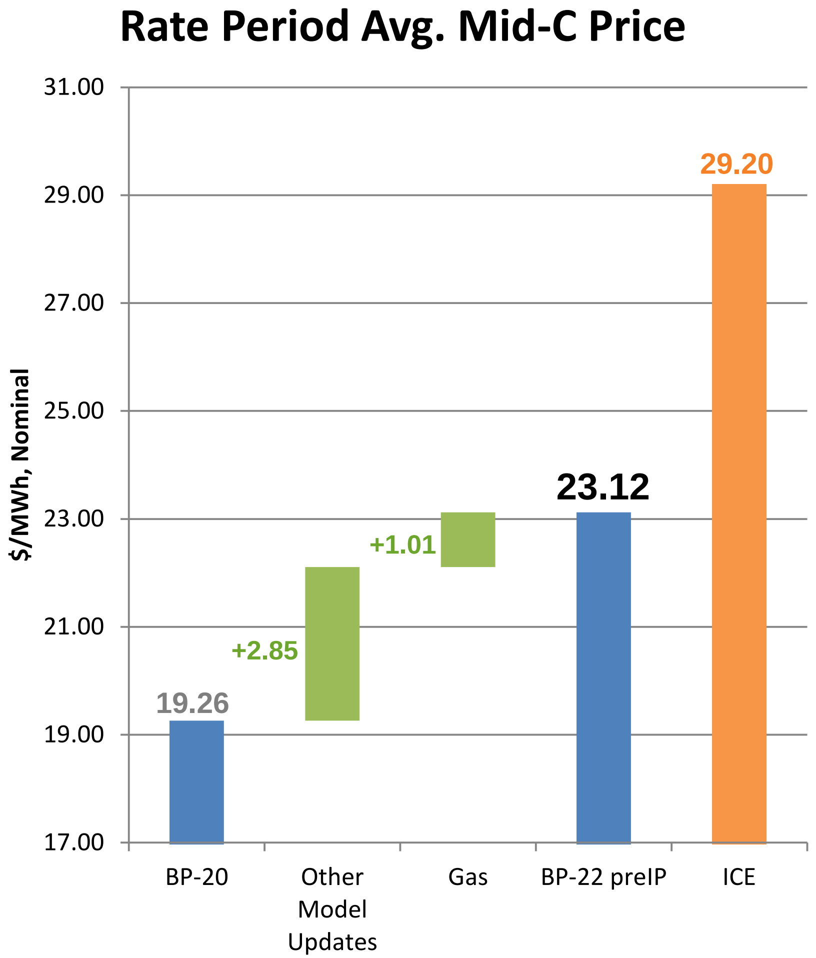
Average Mid-C Prices, BP22 preIP vs BP20





Average Rate Period Mid-C Flat Price Change Summary

$/MWh, Nominal	FY1	FY2	Avg.
BP-20	19.34	19.17	19.26
BP-22 preIP	**23.33**	**22.92**	**23.12**
Delta	**+3.99**	**+3.75**	**+3.86**

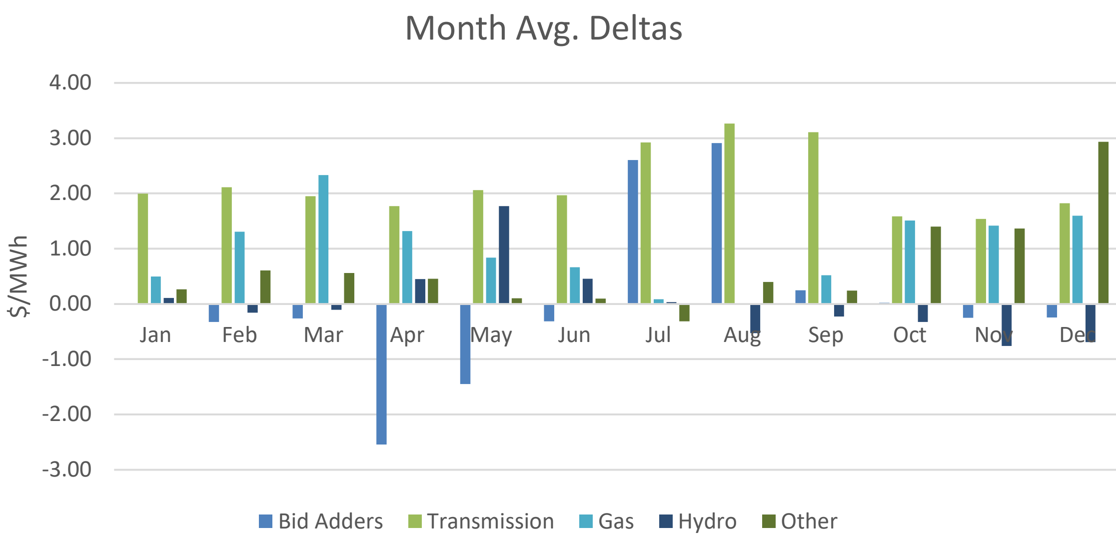


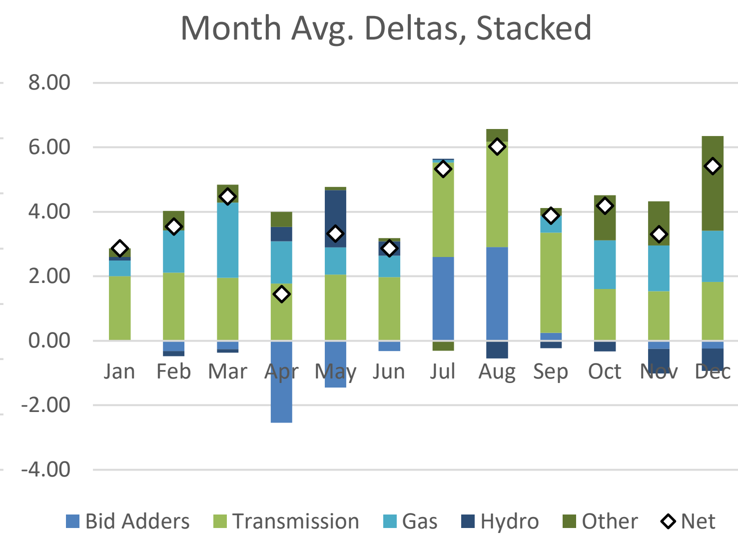
ICE Futures averaged over last 3 months (15 April to 15 July, 2020)

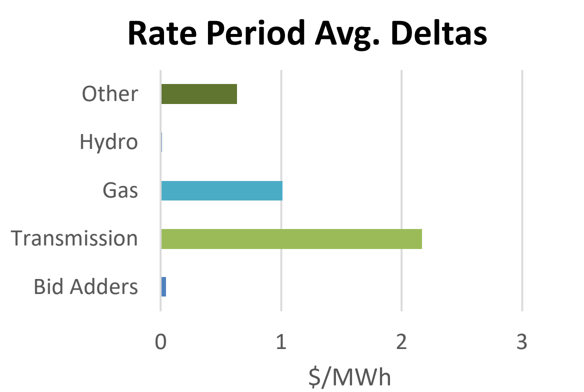
Major Updates since BP-20:

- Updates from benchmark runs
  - Elimination of carbon adders on Southern Intertie
  - Resource Bid adders
- Refreshed new builds, retirements, and RPS policies, and updated resource build
- Natural gas prices
- PNW hydro generation
- WECC BA load forecast

Decomposition of Price Impacts, Mid-C







"Other" represents price impacts from all other updates, including:

- Changes to the resource build
- New load forecast
- CA Carbon prices (forecast remains close to the auction floor but still escalates)
- New Aurora version
- Any other changes in the latest database (usually some minor fluctuations in resource characteristics and other parameters)

Benchmarking

- There are two main reasons Aurora price forecasts are wrong:

  1) Get the fundamentals wrong

  2) Get the relationship between fundamentals and prices wrong (not capturing important details of how markets work / behavioral effects)

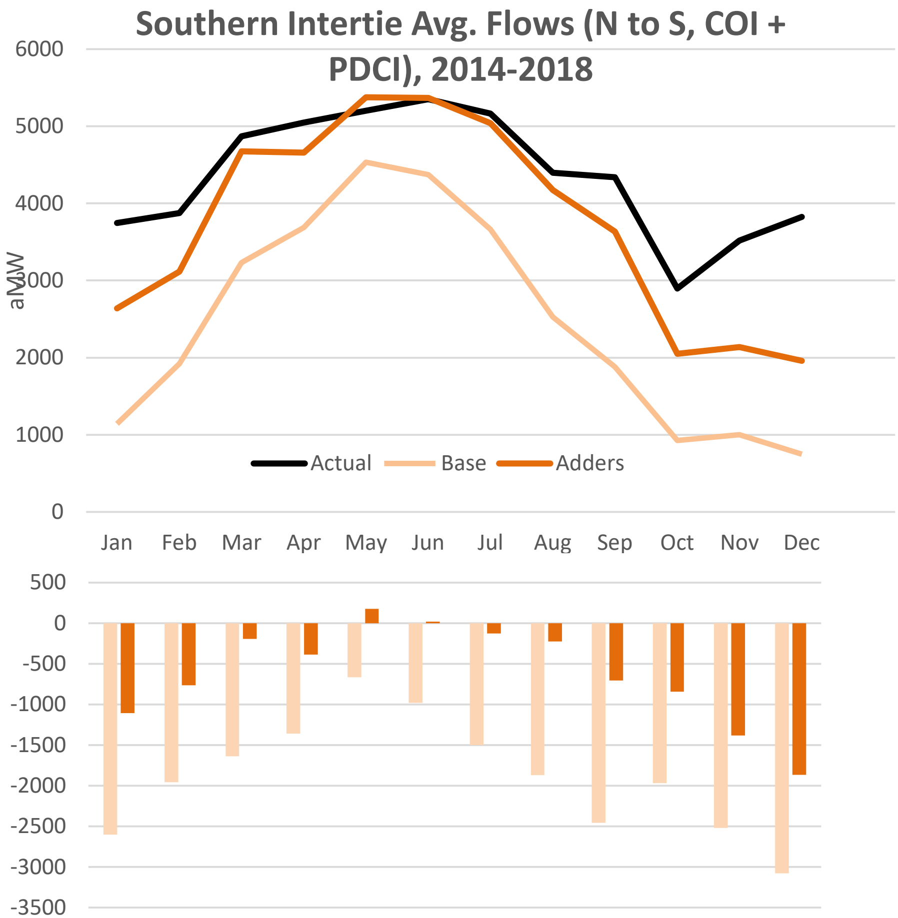
- Benchmarking (running Aurora with actual fundamentals and comparing results to actual prices) allows us to isolate and address the 2nd problem

- Primarily rely on Mid-C ICE day-ahead prices, and CAISO NP-15 and SP-15 day-ahead LMPs
- **Lead to 2 significant updates:**
  - **Eliminated carbon price component of wheeling adders on the Southern Intertie (COI & PDCI)**
  - **Applied bid adders to resources**

Main Shortcomings:

- No historical BC Hydro
- Limited hourly output data for renewables outside of California

Southern Intertie



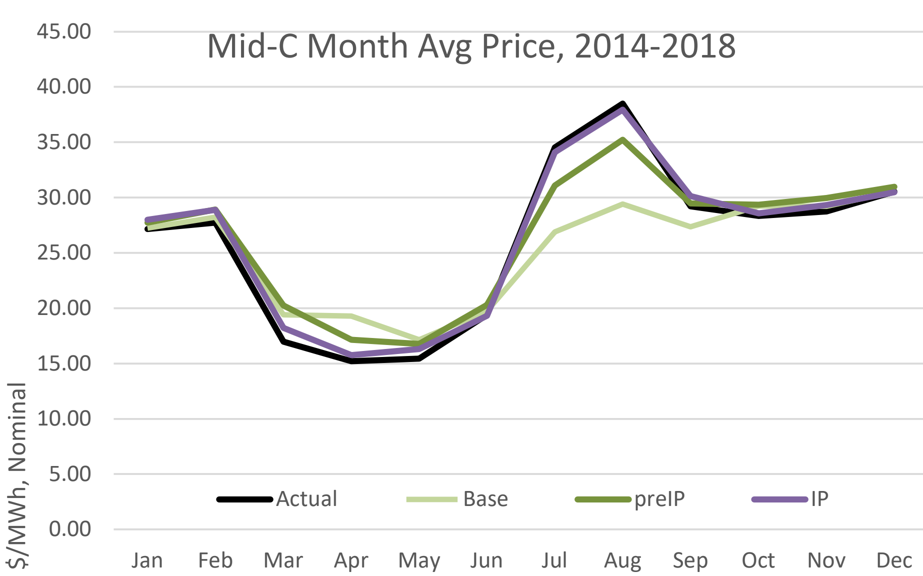
Base:

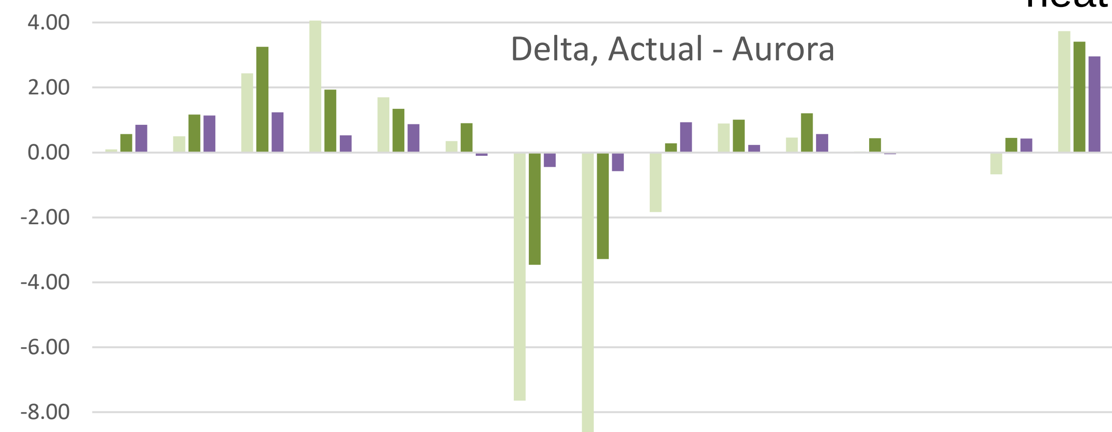
- Our Aurora base case logic using actual fundamentals. Unspecified resource emission rates and carbon prices are applied to a substantial share of North to South flows on the COI and PDCI
- The benchmark run shows that this significantly reduces modeled flows on the lines, relative to actual flows

"Adders":

- Reflects impacts of both the resource bid adders and the elimination of the carbon price adders on the COI and PDCI transmission lines

Bid Adders: 2014-2018 Mid-C, Month Avg. Prices





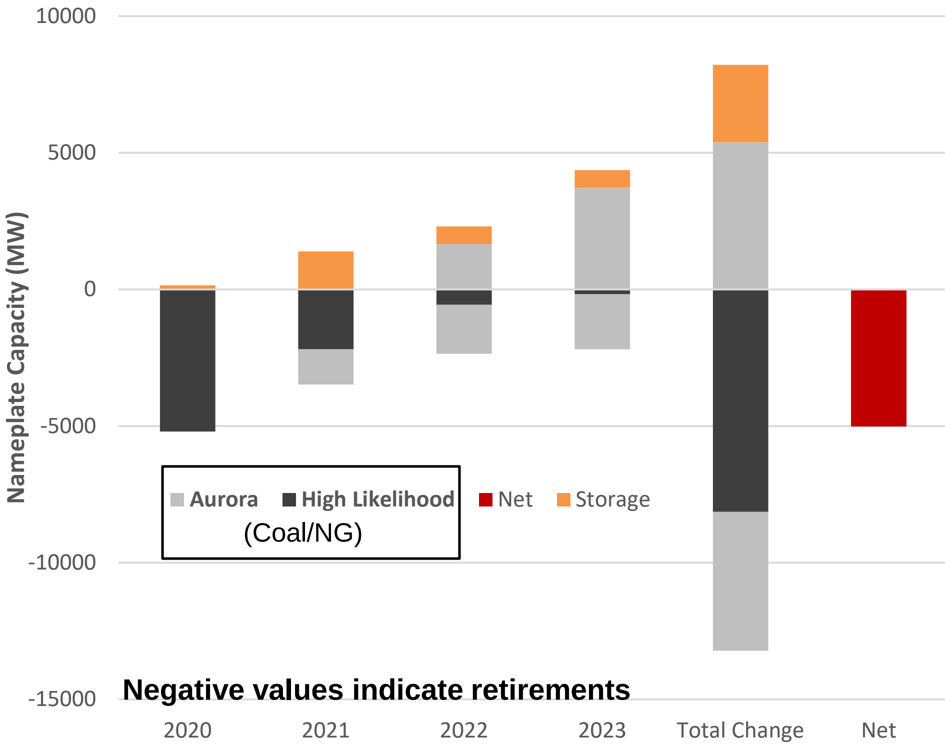
Lower values (in absolute terms) indicate that Aurora is closer to actuals

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		ME	MAE
Base	0.09	0.50	2.44	4.06	1.70	0.35	-7.65	-9.10	-1.83	0.90	0.46	0.02		-0.67	3.74
preIP	0.57	1.17	3.26	1.94	1.34	0.90	-3.46	-3.28	0.28	1.02	1.20	0.44		0.45	3.41
IP	0.85	1.14	1.23	0.53	0.87	-0.10	-0.45	-0.57	0.93	0.23	0.57	-0.05		0.43	2.96

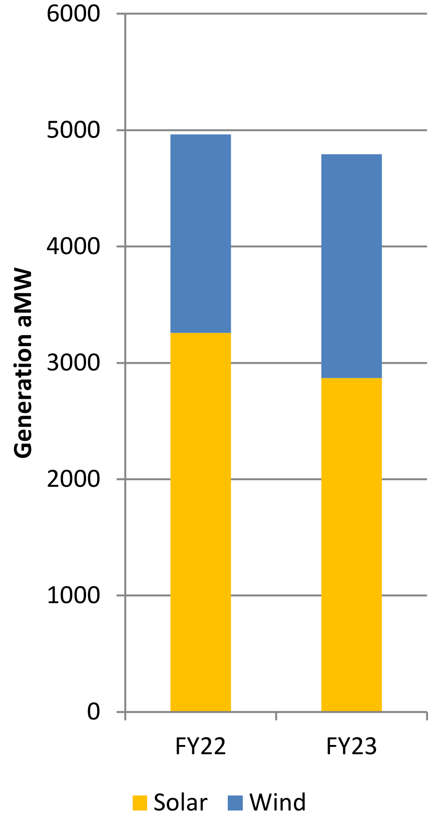
- Bid adders change the marginal cost of resource used for dispatch and the calculation of prices
  - For example, we assign wind and solar resources bid adders of -$23/MWh
- Bid adders are applied to all resources but have the most significant impact on high heat rate resources in July and August
- Bid adder values are adjusted in an effort to calibrate Aurora output prices to actual prices
- Bid adders reflect a combination of missed fundamentals (such as resource outages, ancillary services, forecast error, possibly some scarcity premiums) and behavior (risk preferences, marketing strategies, etc.)

Changes in the WECC Resource Fleet

Dispatchable *Capacity* (Coal/NG, and Storage)



RPS *Generation*



Dispatchable build:

- Increased retirements
- Reduction of generic thermal additions
- Now including solar + storage as a new resource option
- Generally produces upward price pressure

RPS:

- Most significant changes result from moving forward in time. Relative to previous LT forecasts, RPS build has been reduced (with lower loads). **The IP will have more renewables**
- Exerts substantial downward price pressure

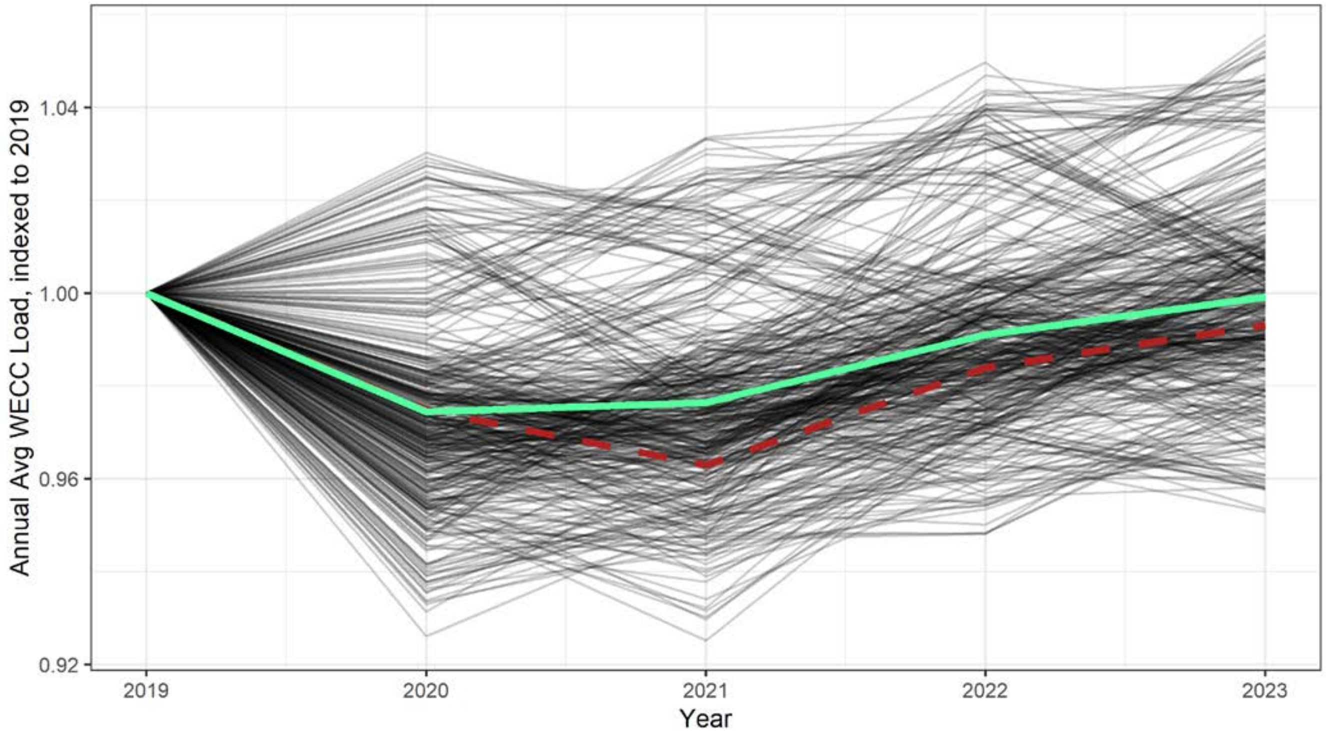
COVID-19 and WECC Loads

- IHS Markit forecasted a significant economic decline starting in Q2-2020 due to COVID-19. After bottoming out in 2020, economic recovery was assumed to take place through 2021 and reaching pre-COVID levels in 2022. *Non-Farm Employment is a main economic driver for the WECC BA Load Forecasts.*

- Consequently, **IHS employment forecasts with COVID-19 impacts were used in the modeling process.** The employment forecasts followed the same pattern as the overall economic outlook.

- **At this point, the economic future has a high level of uncertainty. However, the economic assumptions used in the WECC BA Load Forecasts continue to remain reasonable at this time (no change for the IP).**

COVID-19 and WECC Loads



The bright green is our annual average total WECC load forecast.
The gray lines are traces from the load risk distribution.
The dashed red line represents the 2008 financial crisis if it began at the end of 2019.

All values are indexed to 2019 (the load forecast is indexed to the 2019 pre-COVID-19 forecast value)

Modeling Changes for Initial Proposal

- Resource build
  - Capture latest updates to IRPs and new construction, **more renewables**
- Inflation correction
  - Adds ~3-4% to prices
- Aurora Version **13.5.1010** update
  - low impact

Considered but not implemented

- New gas risk model
  - Previous testing indicated surprisingly minor price effects
  - Still significant automation work
  - May still consider implementation between IP and FP

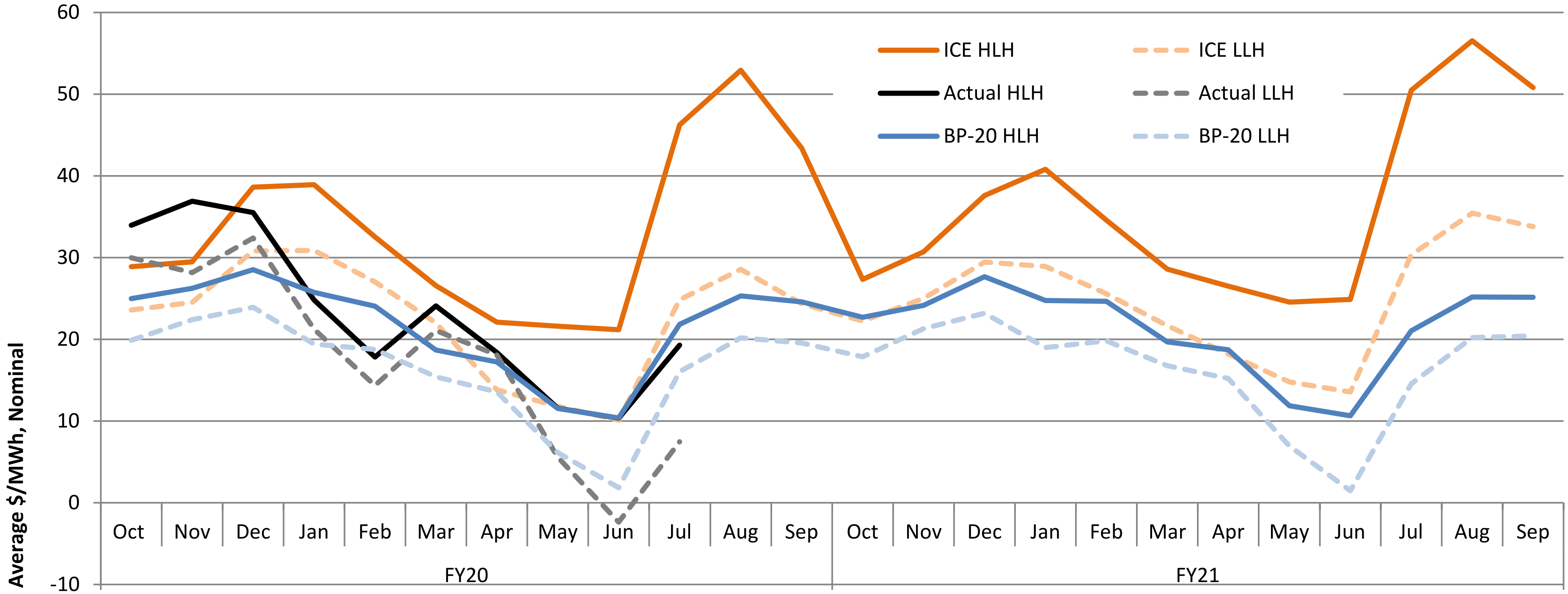
- Improved hydro shaping (modest increase LLH and decrease HLH)
- Bid adder refinement (higher July & August prices)
- **Most likely, prices will be modestly higher for IP on average, possible downward movement in spring**

Rate Case Documentation?

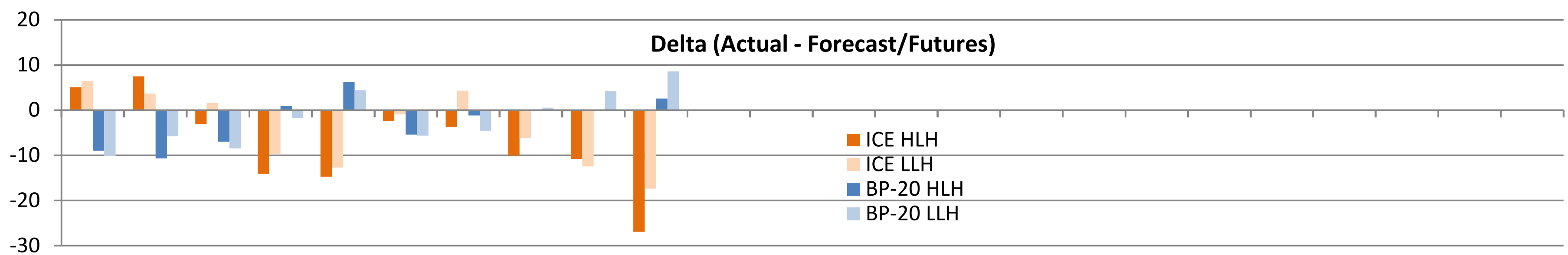
- What would be most helpful?
- Planning on a new section that summarizes changes from previous model versions
- Note the IP Aurora archive will be available upon request, provided that you have an active Aurora license

Other Questions?

Average Mid-C Prices, BP-20 & ICE Futures vs Actual



ICE Futures averaged over 3 months (~February through April 2019)



Net Secondary Revenue Forecast

Method

- Net Secondary Revenue (NSR) is forecast using RevSim
- RevSim helps assign an expected value to BPA’s ability to generate energy in excess of its firm obligations to serve load
- Calculated as the mean of the 3,200 game distribution
  - Note: The largest source of variation in the NSR distribution is the water year

No Major Changes to RevSim

- Anticipated updates
  - New forward sales/purchases
    - Including another capacity sale
  - BPA can now sell directly into the California ISO
    - Can now simply forecast incremental transaction costs
  - Treatment of new Southern Idaho Load Service forward transactions

TRANSFER SERVICE

Kevin Mozena
Derrick Pleger
Jeff Hurt

Transfer Service Updates

BPA's Transfer Service group acquires transmission across third-party transmission systems for service to loads outside Bonneville's BAA. The current annual cost to provide this service to all transfer customers is roughly $85 million. The following looks at three separate items that impact Transfer Service customers:

- Update on Market Differential for Southeast Idaho loads under the second interim service plan.
- Updated Estimate of the Transfer Service Delivery Charge (TSDC). The TSDC is recovered through a calculated rate applied to all Transfer Customers who take low-voltage service from a third-party transmission provider.
- Transfer Service Regional Compliance Enforcement Charge.

Second Interim SE Idaho Load Service Plan

Recap of Assumptions to Finish FY 2021

- No renewal of fixed long-term market purchases to serve load needed at this time.
- Local generation combined with current transmission rights and augmented by short-term market purchases are expected to be sufficient to reliably serve Southeast Idaho load during the last three months of FY 2021.
- If, through analysis performed during preparations for the second Interim Service Plan, it appears that long-term market purchases may provide a more economic solution than long-term transmission rights, Bonneville will consider that option.
- For the BP-20 rate period, BPA is allocating to the Composite Cost Pool a Market Differential of $5.4 million for FY 2020 and $4.2 million for FY 2021.

Second Interim SE Idaho Load Service Plan

Second Interim Service Plan

- Bonneville has entered into a second round of five-year market purchases to serve its customers in SE Idaho.
- Market purchases will terminate on July 1, 2026.
- Bonneville has also elected to retain the 200 MWs of point-to-point transmission across Idaho Power's BAA.

Impacts to Transfer Service's Budget

- There will be no Market Differential applied to the Transfer Service budget due to the five-year purchases being transacted at index rather than a fixed market price.
- Transfer Service will retain the cost of the 200 MWs of point-to-point transmission in the budget.

Transfer Service Delivery Charge

- Current Transfer Service Delivery Charge (TSDC) is $1.27 per kW-Month.
- Likely no change for BP-22.

Transfer Service Regional Compliance Enforcement Charge

- Current Transfer Service Regional Compliance Enforcement Charge is 0.03 mills/kWh.
- Likely no change for BP-22.
- No Reliability Coordinator charges for transfer customers.

EIM BENEFITS AND CHARGES IN POWER RATES

Emily Traetow
Daniel Fisher
Derrick Pleger

Agenda

- Discuss staff leaning for the treatment of EIM benefits and charges within power rates in BP-22:
  - Dispatch benefits for Participating Resources
  - Costs (from CAISO, from Transmission Services, and internal to BPA)
- Discuss costs and credits for Transfer Service customers in BAAs that have joined the EIM

Dispatch benefits

- Power Services can use its Participating Resources to bid surplus power and balancing reserves into the EIM market.
- In BP-22, staff proposes to include a revenue credit for EIM net dispatch benefits in the net secondary revenue (NSR) forecast to account for non-Slice customers' share of dispatch benefits (from surplus power and/or balancing reserves).
- Staff proposes to set the revenue credit equal to EIM costs included in power rates.
- Staff is also proposing a method that would provide net dispatch benefits to Slice customers during the BP-22 rate period.

Slice customers and dispatch benefits

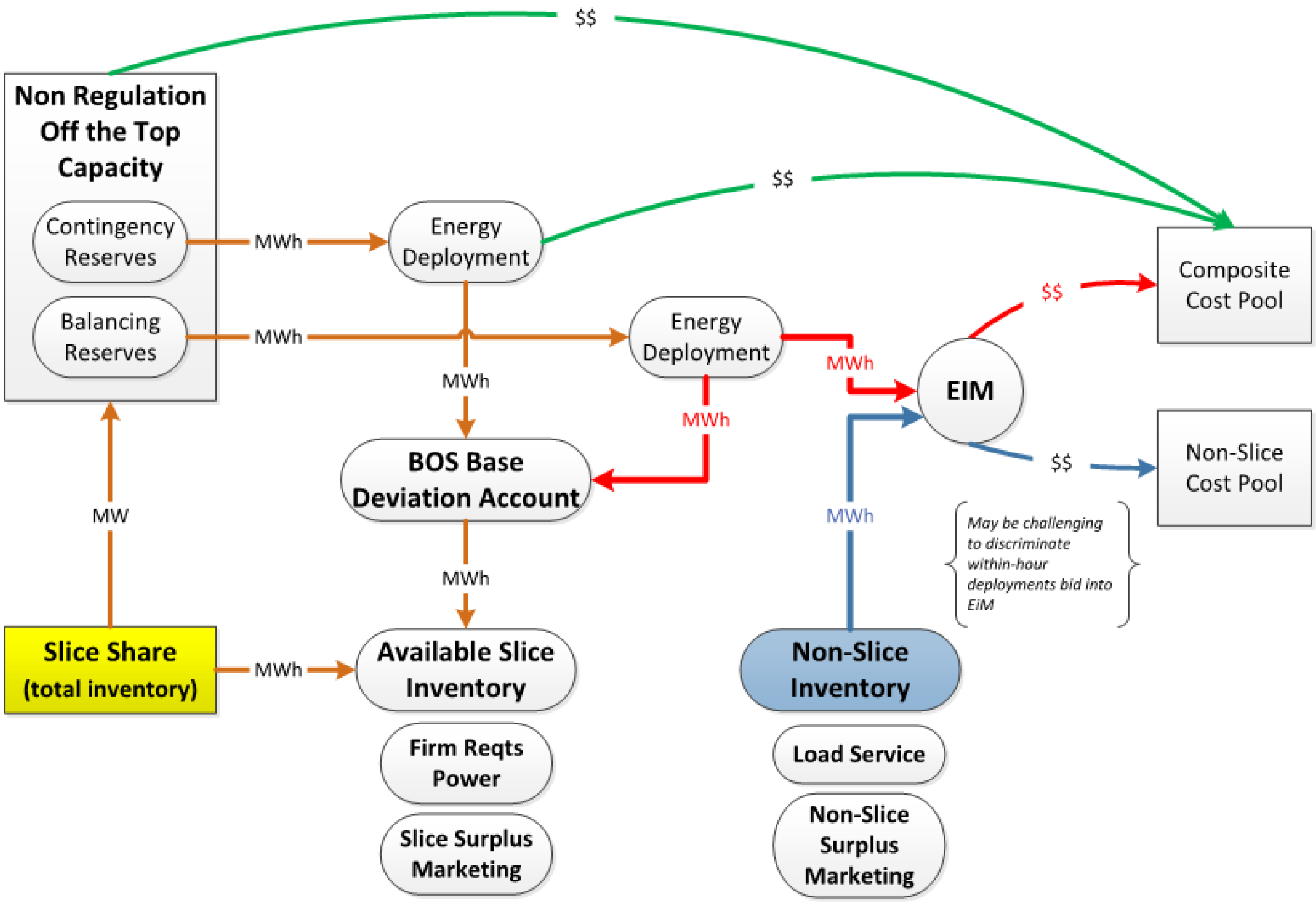
- Reserves (balancing and contingency) are "off-the-top" obligations for the FCRPS, with the revenue credit going to Slice and non-Slice customers in the composite cost pool.
- Energy associated with contingency reserve deployments is tracked and accounted for, then deducted (pro-rata) from each Slice customer's energy account (BOS Deviation Account). Energy associated with balancing reserve deployments currently nets to zero, but may not if offered into the EIM.
- Staff and customers developed several options for how to account for balancing reserves if BPA joins the EIM. Staff has focused on the following two options as both seem equitable and in accordance with the TRM:
  - Option 1 shares EIM net dispatch benefits and energy impacts associated with balancing reserves with Slice customers;
  - Option 2 does not share EIM net dispatch benefits with Slice customers and does not impact Slice customers' energy accounts for energy associated with balancing reserves.

❖ See appendix for all three options (including status quo information) shared in the July workshop.

OFF THE TOP OPTION 1

Treat capacity and energy as off the top

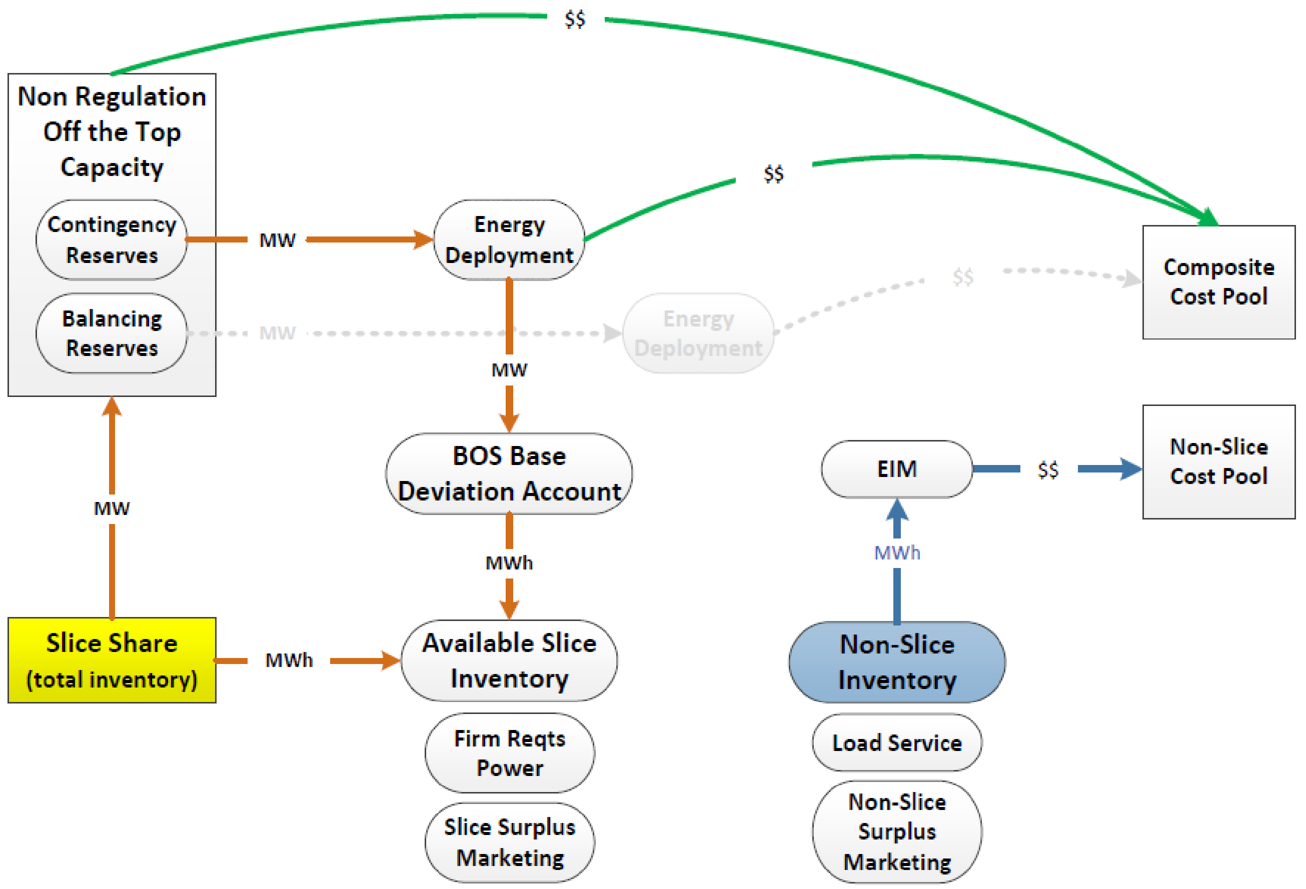
The Gen Res Inc constraint includes the non-reg capacity, BOS deviation account is adjusted for associated energy, customers receive revenue associated with capacity and energy



OFF THE TOP OPTION 2

Treat capacity as off the top, and status quo deployment of contingency reserves

The Gen Res Inc constraint includes the non-reg capacity, energy accounting is done for deployment of contingency reserves, customers receive revenue associated with non-reg capacity and deployment of contingency reserves



Implementing Off-the-top Option 1

- Need to determine a method that separates EIM net dispatch benefits associated with balancing reserves from net dispatch benefits associated with non-slice inventory. Considered the following:
  - Pro-rata share based on actual deployments of balancing reserves and non-slice inventory. This would require data to determine share. Split could be based on monthly planning assumptions for reserves or actual operations data.
  - Priority deployment and allocation assuming non-slice inventory is used first, then balancing reserves.
  - Priority deployment and allocation assuming balancing reserves are used first, then non-slice inventory.

Examples

Option 1 Pro-Rata Balancing Reserves

	NonReg Bal. Res. INC (MW)	NonReg Bal. Res. DEC (MW)	NonSlice Inventory INC (MW)	NonSlice Inventory DEC (MW)	Total INC Offered (MW)	Total DEC Offered (MW)	Total INC Deployed (MWh)	Total DEC Deployed (MWh)	Total INC Net Revenue ($)	Total DEC Net Revenue ($)	Composite Share INC (%)	Composite Share DEC (%)	BOS Base Adjustment (MWh)	Composite Cost Pool EIM Line ($)
Hour 1	400	600	0	0	400	600	400	0	$ 8,000	$ -	100%	100%	-400	$ 8,000
Hour 2	400	600	0	0	400	600	0	300	$ -	$ (6,000)	100%	100%	300	$ (6,000)
Hour 3	400	600	400	600	800	1200	400	0	$ 8,000	$ -	50%	50%	-200	$ 4,000
Hour 4	400	600	400	600	800	1200	800	1200	$ 16,000	$ (24,000)	50%	50%	200	$ (4,000)

Option 2 Balancing Reserves First

	NonReg Bal. Res. INC (MW)	NonReg Bal. Res. DEC (MW)	NonSlice Inventory INC (MW)	NonSlice Inventory DEC (MW)	Total INC Offered (MW)	Total DEC Offered (MW)	Total INC Deployed (MWh)	Total DEC Deployed (MWh)	Total INC Net Revenue ($)	Total DEC Net Revenue ($)	Composite Share INC (%)	Composite Share DEC (%)	BOS Base Adjustment (MWh)	Composite Cost Pool EIM Line ($)
Hour 1	400	600	0	0	400	600	400	0	$ 8,000	$ -	100%	100%	-400	$ 8,000
Hour 2	400	600	0	0	400	600	0	300	$ -	$ (6,000)	100%	100%	300	$ (6,000)
Hour 3	400	600	400	600	800	1200	400	0	$ 8,000	$ -	100%	100%	-400	$ 8,000
Hour 4	400	600	400	600	800	1200	800	1200	$ 16,000	$ (24,000)	50%	50%	200	$ (4,000)

Option 3 Balancing Reserves Last

	NonReg Bal. Res. INC (MW)	NonReg Bal. Res. DEC (MW)	NonSlice Inventory INC (MW)	NonSlice Inventory DEC (MW)	Total INC Offered (MW)	Total DEC Offered (MW)	Total INC Deployed (MWh)	Total DEC Deployed (MWh)	Total INC Net Revenue ($)	Total DEC Net Revenue ($)	Composite Share INC (%)	Composite Share DEC (%)	BOS Base Adjustment (MWh)	Composite Cost Pool EIM Line ($)
Hour 1	400	600	0	0	400	600	400	0	$ 8,000	$ -	100%	0%	-400	$ 8,000
Hour 2	400	600	0	0	400	600	0	300	$ -	$ (6,000)	0%	100%	300	$ (6,000)
Hour 3	400	600	400	600	800	1200	400	0	$ 8,000	$ -	0%	0%	0	$ -
Hour 4	400	600	400	600	800	1200	800	1200	$ 16,000	$ (24,000)	50%	50%	200	$ (4,000)

3 Buckets of EIM Costs

1. Internal to BPA (costs in IPR associated with EIM)

2. Invoice from CAISO to Power Services as a Participating Resource Scheduling Coordinator (PRSC)
   - Settlement invoice from CAISO to Power Services will include costs associated with bidding Participating Resources into the EIM.
   - Any dispatch benefits provided to customers will be net these costs.

3. Invoice from Transmission Services to Power Services
   - Transmission Services will be an EIM Entity Scheduling Coordinator (EESC) and will receive a BAA level invoice from CAISO. Some charges from the CAISO invoice will be sub-allocated from Transmission Services to its customers (including Power Services.)
   - Transmission Services has proposed to sub-allocate imbalance, over/under scheduling, and neutrality charges to its customers.

1. Internal to BPA EIM costs

- Internal costs associated with participating in the EIM allocated to Power Services (current forecast is $2.4 million for BP-22 rate period)
- These costs will be included in Power Services' revenue requirement and should be allocated to customers receiving net dispatch benefits from the EIM.
- If BPA shares net dispatch benefits with Slice customers (Off-the-top Option 1) as well as non-Slice customers, then allocate these internal costs to the composite cost pool.
- If all net dispatch benefits go to non-Slice customers (Off-the-top Option 2), then allocate these costs to the non-Slice cost pool.

2. Participating Resource Costs

- All charges associated with BPA's Participating Resources will be invoiced directly to Power Services from CAISO. These invoices will include costs and credits.
- Dispatch benefits (the credits) that Power Services allocates to its customers should be net any costs associated with its participating resources.
- If BPA shares dispatch benefits with Slice customers (Off-the-top Option 1) as well as non-Slice customers, then allocate a commensurate amount of PRSC costs to Slice customers with remaining costs going to non-Slice customers.
- If all dispatch benefits go to non-Slice customers (Off-the-top Option 2), then allocate all PRSC costs to the non-Slice customers.

3. EESC Costs from Transmission Services

- Transmission Services has proposed to sub-allocate imbalance, over/under scheduling, and neutrality charges to its customers.
- Some charges will be sub-allocated to Power Services due to load imbalance (managing non-Slice load) and some charges will be allocated due to non-participating resource (NPR) imbalance.
- For BP-22, staff is proposing to allocate any charges associated with load to the non-Slice cost pool and any charges associated with NPR to the composite cost pool.
  - Non-Slice cost pool would be allocated UIE for load imbalance, over/under scheduling charges, and neutrality charges (for Load Following and Block).
  - Composite cost pool would be allocated UIE/IIE/RTIIE for NPR imbalance.
  - These costs would likely be forecast as $0 in power rates, with differences between actuals and forecast impacting the annual Slice true-up calculation and financial reserves.

Staff Leaning

- Staff is leaning towards the following treatment of EIM benefits and costs in Power Rates:
  - Include NSR revenue credit for net dispatch benefits in the non-Slice cost pool equal to EIM costs attributed to non-Slice customers in power rates
  - Implement Off-the-top Option 1 of sharing net dispatch benefits associated with balancing reserves with Slice customers
  - Allocate to the composite cost pool: internal to BPA EIM costs, costs associated with participating resource deployment of balancing reserves, and sub-allocated EESC costs associated with non-participating resources
  - Allocate to the non-Slice cost pool: costs associated with participating resource deployment of surplus power, sub-allocated EESC costs associated with load

Transfer Service - today

- Load Following Transfer Service Customers
  - BPA currently treats EIM Charge Code costs/credits (UIE, IIE, neutrality) incurred for Transfer Service for Load Following customers as a Transfer Service Cost in Composite Cost Pool.
- Slice Transfer Service Customers
  - BPA directly assigns to Slice Customer UIE and IIE.
  - BPA pays neutrality charges for Slice customers served by Transfer Service and includes these costs/credits as Transfer Service Cost in Composite Cost Pool.

Transfer Service – BP-22 proposal

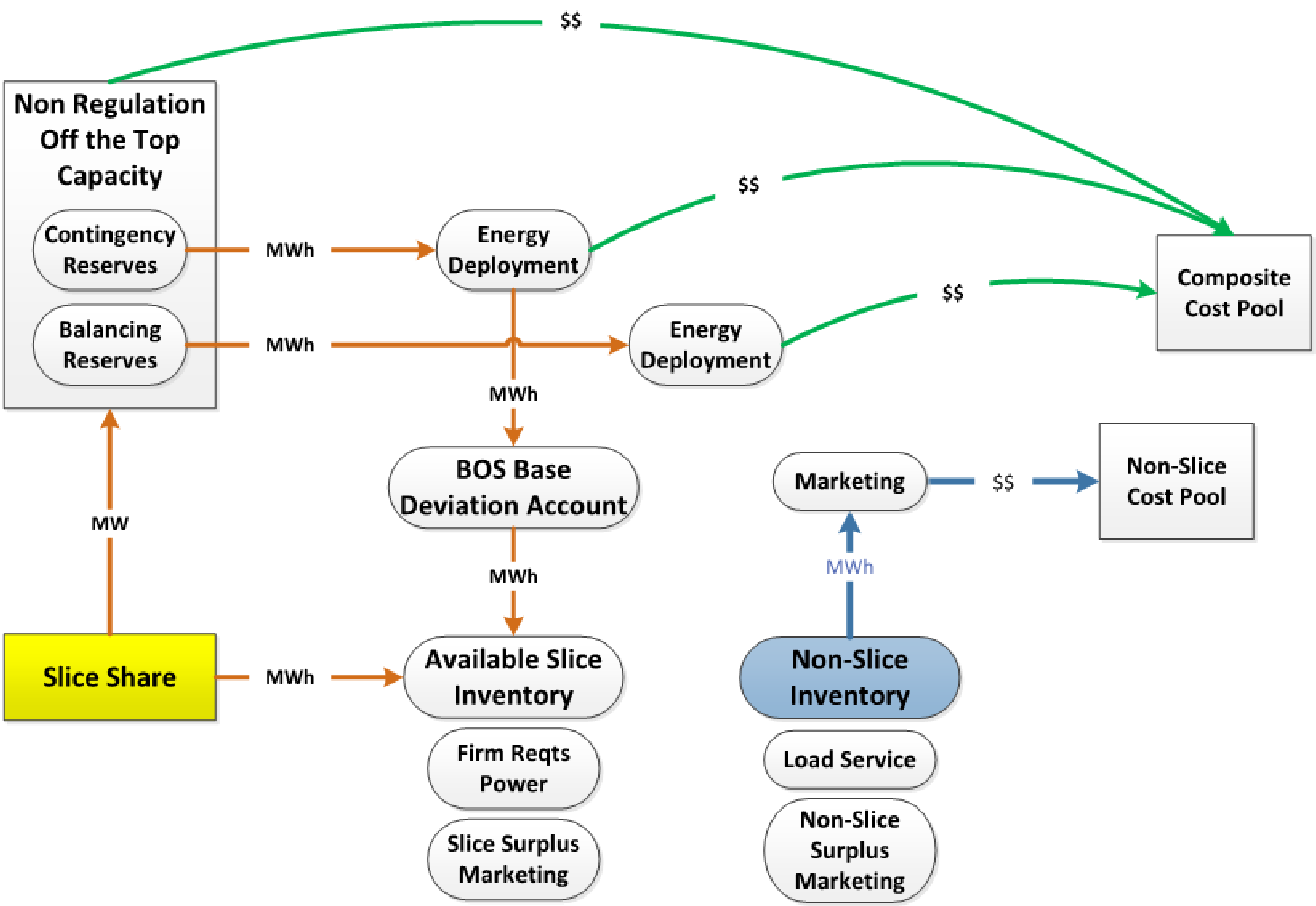
- Staff Proposal: EIM Charge Code Comparability for Transfer Customers
  - Load Following and Slice transfer customers should receive same *type* of charges that Load Following and Slice customers would receive on BPAT's system.
  - Key Point: Not same *amount of charge…*same *type* of charge.
- Example:
  - If Slice Customer on BPA's system would be subject to Bonneville's Congestion Offset (CC 64700) on Bonneville's system, a Transfer Slice Customer on PacifiCorp's system would be allocated <u>PacifiCorp's</u> Congestion Offset.
- Comparability would apply to load calculations
  - If BPAP agrees to not apply EIM Neutrality charges related to Block on BPAT's system directly to the customer, we would do the same for EIM Neutrality incurred for Block served by Transfer Service.

Appendix
(off-the-top Slice options shared at July workshop)

Balancing reserves and Slice customers

- Reserves (balancing and contingency) are “off-the-top” obligations for the FCRPS, with the revenue credit going to Slice and non-Slice customers in the composite cost pool.
- An “off-the-top” obligation for Slice customers means the Slice “capability” is reduced accordingly. Slice customers share in the operational obligation and receive a share of the associated revenue.
  - Energy associated with Contingency Reserve deployments is tracked and accounted, then deducted (pro-rata) from each Slice customer’s energy account (BOS Deviation Account). We expect this would continue under the EIM.
  - Energy associated with Balancing Reserve activity nets to roughly zero over time, so as a simplifying procedure energy is not tracked for the purpose of Slice customer energy accounts. If BPA joins the EIM, the non-regulating portion of Balancing Reserves will be offered into the market so this “net zero” energy accumulation may not continue. Any associated energy would need to be tracked and accounted accordingly if the energy revenue and cost is shared with the Slice product.

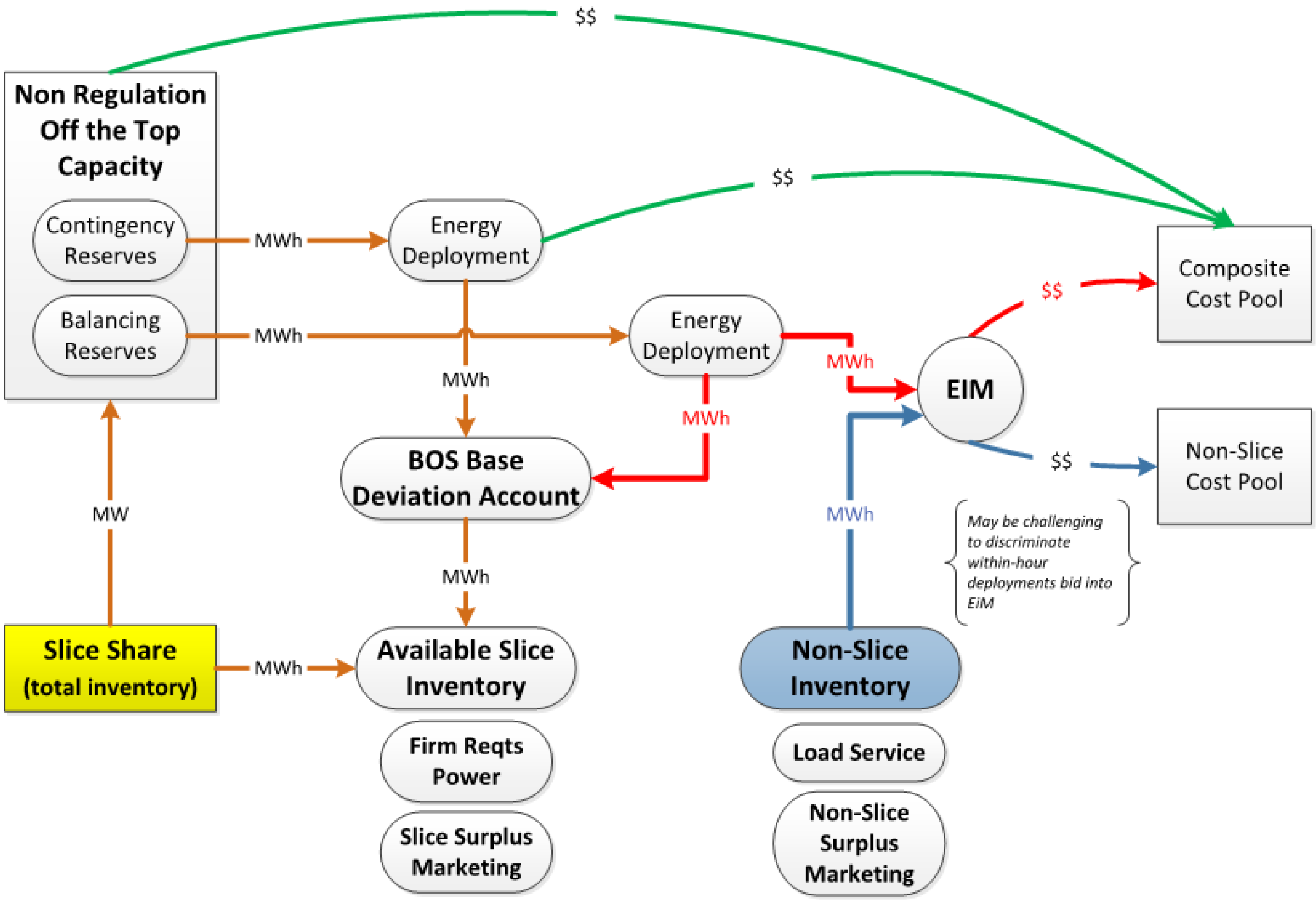
OFF THE TOP STATUS QUO



OFF THE TOP OPTION 1

Treat capacity and energy as off the top

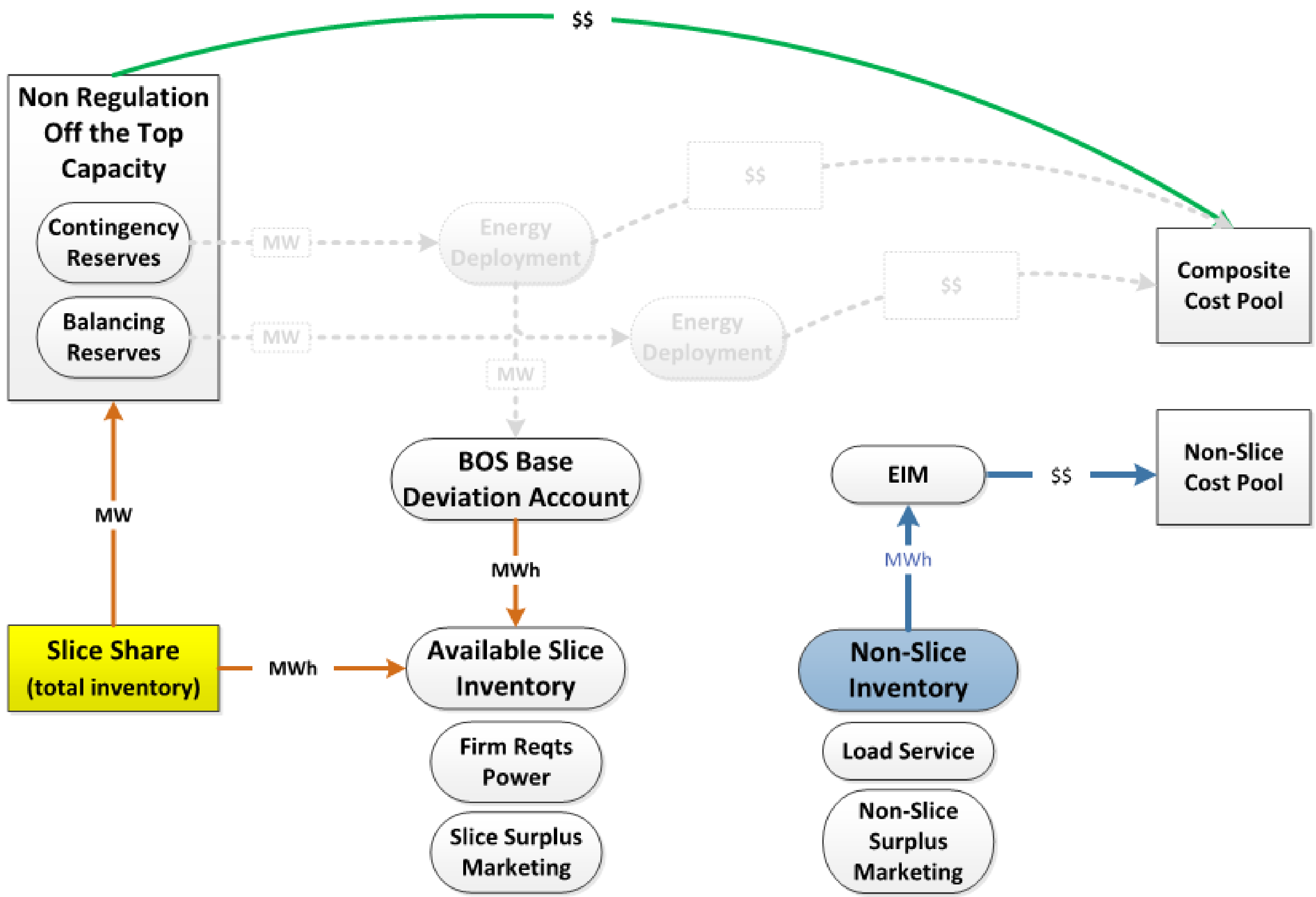
The Gen Res Inc constraint includes the non-reg capacity, BOS deviation account is adjusted for associated energy, customers receive revenue associated with capacity and energy



OFF THE TOP OPTION 2

Treat capacity as off the top, but not the energy

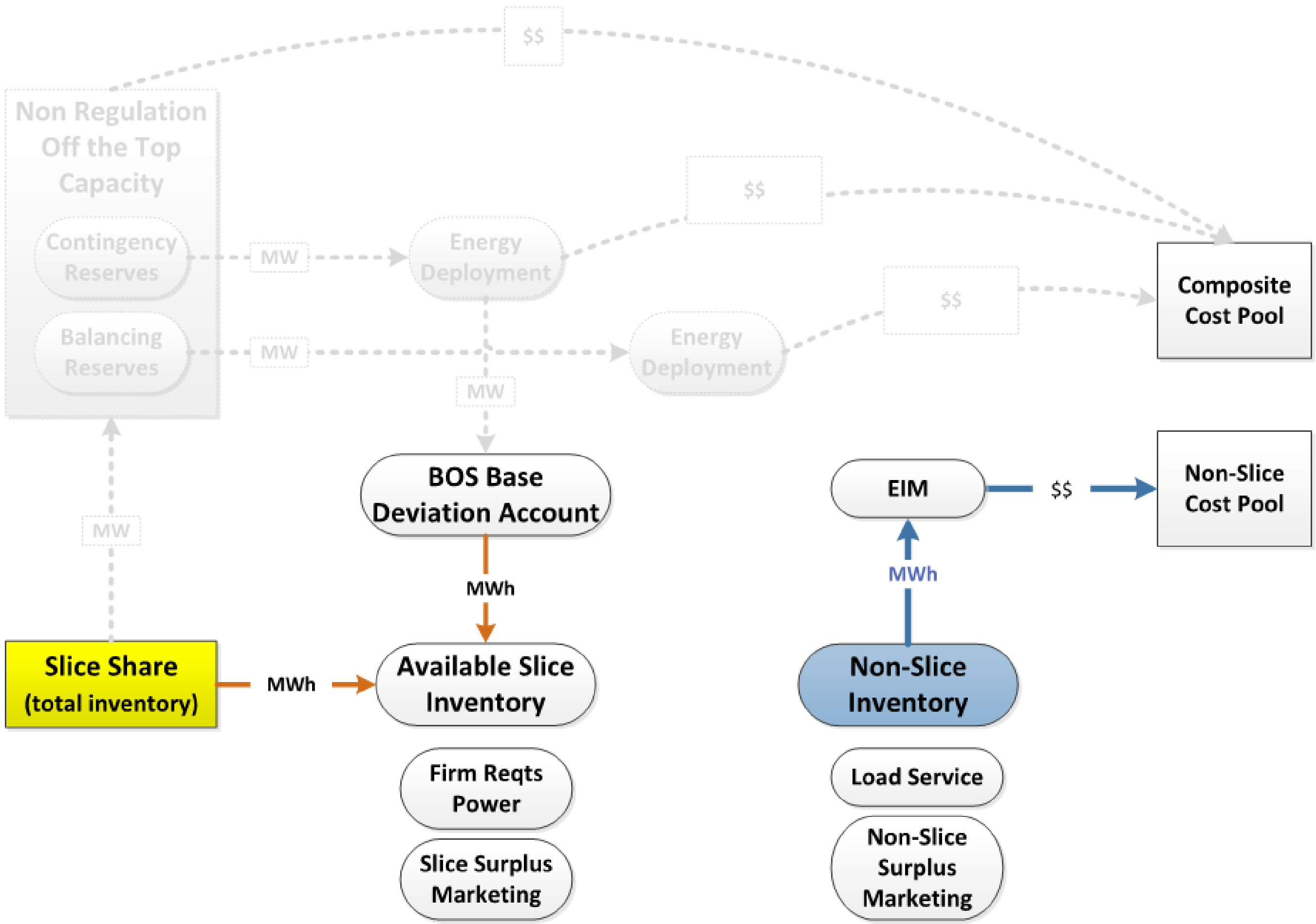
The Gen Res Inc constraint includes the non-reg capacity, no energy accounting is done, customers receive revenue associated with non-reg capacity only



OFF THE TOP OPTION 3

Treat neither capacity or energy as off the top

The Gen Res Inc constraint excludes the non-reg capacity, no energy accounting is done, customers receive no capacity or energy revenue for non-reg capacity needs and use



SECTION 7(F) POWER RATE TO SERVE NEW LARGE SINGLE LOADS

Paulina Cornejo
Daniel Fisher

Background

In BP-20, preference customers requested that BPA identify New Large Single Load (NLSL) service alternatives:

- Currently available NLSL service options are:
  - BP-20 New Resource (NR) Rate of $79.80/MWh;
  - Self-supply with non-federal resources, and/or market purchases;
  - NLSL Policy – Green Exception Option:
    - If an NLSL applies its consumer-owned onsite renewable or co-gen resource to reduce its load below 10 aMW, then BPA may serve the remaining load below 10 aMW at the PF rate. Prior to Regional Dialogue, BPA offered an offsite option that was sunset in the RD policy and ROD.
- Section 7(f) of the Northwest Power Act permits BPA to establish rates “for all other firm power sold” including NLSLs. BPA sells such power under two rate schedules:
  - NR Rate schedule.
  - Firm Power and Surplus Products and Services rate (FPS rate) schedule.

Concept Idea to serve NLSLs

- In response to customer requests, BPA staff presented a new service concept to customers at the January 28th workshop.
  - A new discretionary rate under the NR rate schedule.
    - Priced as a function of PF rate
    - Permits BPA to augment to serve an NLSL load obligation, if needed
    - Contractually limited to certain customers
  - A fixed FPS rate under the FPS schedule.
    - Also priced as a function of PF rate
    - Available to all NLSL customers
    - However, limited to available firm surplus

Jan 28th Customer Workshop Feedback

- Provide price stability and certainty; consider that pricing above the PF Tier 1 rate eliminates the product’s appeal.
- Contain load following services.
- Offer capacity product, in addition to energy.
- Term of service to exceed a two-year period.
- Make available to all customers, including IOUs.
- Create energy caps/limitations for individual customers (if offering a limited product amount).
- Coordination with Transmission Services to ensure timely response to interconnection requests.
- Be consistent with Exhibit H of the Regional Dialogue contract regarding environmental attributes.
- Resurrect the offsite Green Exception option with more flexibility for customers.
- With regard to market risk:
  - Address how BPA will limit risk and/or cost shifting between rate classes.
  - Consider the option that doesn’t necessitate planned augmentation.

Staff Concept Summary

- BPA staff designed an NR Rate product that appeared to have the best chance of shared support and explored different pricing outcomes consistent with the REP Settlement.
  - Augmentation prices plus 7(b)(3) surcharge, but no higher than the PF Tier 1 rate plus 7(b)(3) surcharge, and no lower than the PF Tier 1 rate.
  - Rate was a collared design with a floor of the PF Tier 1 rate and a ceiling of roughly the Industrial Firm Power (IP) rate ($35 to $42/MWh depending on market conditions).
- Quantity of offering would be based on BPA Administrator’s discretion.
  - Either meet all customer demand or offer a specific limited amount to allocate among eligible customers.
  - Both options would have likely required the **purchase of system augmentation** as BPA expects very little headroom under critical water conditions.
- Available to all PF customers – Load Following, Slice/Block and Block with Existing and Planned NLSLs (no IOUs).
- Contain load following services.
- Limited to a 2-year duration, or one Rate Period.

Summary of Implications

- Likely requires purchase of system augmentation, which:
  - Increases BPA's market risk exposure if prices deviate from rate case expectations.
  - Incurs Mark-to-Market risk – if the 3rd party supplier is not able to fulfill obligation.
  - Increase of carbon content in BPA's fuel mix - unspecified market purchases are considered to have carbon content in WA and CA markets.
- Potential for incremental transfer service costs in the Composite Cost pool due to servicing transfer customers' NLSLs.
- Subject to – Power CRAC, Power RDC, and Power FRP Surcharge.
- Requires substantial contract modifications.

Staff Position

- BPA Staff does not plan to turn the concept of offering an additional NLSL product into a proposal for BP-22.
- Why?
  - Proposal increases BPA’s risk exposure. Specifically, it increases market risk if BPA is required to purchase system augmentation to meet this additional obligation.
  - As before, customers still have the option of purchasing surplus power directly from BPA’s Trading Floor.

SECONDARY REVENUE PROPOSAL

Daniel Fisher

Agenda

- Current status
- Options
- BPA Staff Recommendation

Overview

- At the June 24th TC/BP/EIM workshop, BPA Staff shared a secondary revenue construct that would reduce over time the amount of secondary revenue included in base rates.
- BPA received comments from some stakeholders that supported the concept.
- Public power customers expressed a willingness to consider the proposal but only if it was in the context of a larger package.
- This presentation provides a proposal for a larger package for further consideration by all stakeholders.

BPA Staff's Goal

- Our goal is to support stable rates by reducing BPA's dependence on secondary revenue for cost recovery.
- Ideally, we would like the Initial Proposal to include the "lower of BP-20 and BP-22 secondary revenue" feature to support this goal.
- There are two other somewhat related components of BP-22 rates that should also be considered in the context of a new method of setting secondary revenue - specifically, the FRP Surcharge and the EIM benefits.
- While we agree that each of these two components can influence, or be influenced by, financial reserves, we believe there is merit in having each stand on its own.
  - A rate mechanism, like the FRP Surcharge, that would begin building financial reserves before hitting zero financial reserves, remains important. That said, under the lower of secondary concept, it would make that rate mechanism less likely to be needed.
  - There is a lot of uncertainty in the amount of EIM benefits BPA would actually see during the BP-22 rate period. For this reason, we are proposing to handle it as a side issue. Any benefits larger than expectation would benefit customers through a reduced likelihood of needing the FRP Surcharge. In future rate periods, we expect we will capture these benefits in the overall secondary revenue forecast.

BPA Staff Perspective

- Given this, BPA staff believes the following would be a strong and positive initial proposal, but it would not be without contention:

	BP-22
Years with FRP Surcharge Mechanism	2
Secondary Revenue in Base Rates	Lower of BP-20 and BP-22 forecast
EIM Benefits	Equal to costs

- However, we want our initial proposal to be broadly supported and believe there is room for compromise.
- In exchange for limited contention and general support for our long-term plan to reduce dependence on secondary revenue for cost recovery, we could support this proposal:

	BP-22
Years with FRP Surcharge Mechanism	1 (2023 only)
Secondary Revenue in BP-22 Base Rates	Dial used to attempt to reach Base Rate Change capped at 50th percentile
EIM Benefits	Equal to costs
Base Rate Change	1%

Long-term plan

- The long-term plan would be captured in the BP-22 rate case.
- It would state the intent that in all future rate periods through 2028, BPA would use as a secondary revenue amount in base rates equal to the lesser of (1) the previous rate period's secondary revenue amount included in base rates and (2) the updated secondary revenue forecast.
- The dial to solve for a base rate would not be applied in BP-24 and beyond as this is a good transition choice but would defeat the entire purpose in the long-run.
- Although the "lesser of" rate design could be contested when it is proposed in future rate cases, BPA would expect to retain this construct as an effective means to achieve long-term rate stability.

Benefits of our Proposal

- **Timely**
  - The amount of secondary revenue included in BP-20 rates is the lowest it has been in over a decade. We've already experienced the rate impact of including less secondary in base rates. Let's hold that line and not move in the opposite direction.
  - Power financial reserves are nearing the level when the FRP Surcharge would stop triggering.
  - Implemented after BPA has proven its ability to "bend the cost curve" and deliver competitive rates.
  - Proposed after BPA has demonstrated its ability to be nimble and collaborate with customers to provide expedited rate relief in response to the COVID-19 pandemic.
- **"Modest change" (direct quote from several power stakeholders) with the potential to deliver large future benefits**.
- **Responsive to credit agency concerns and maintains BPA's commitment to its policies and financial health.**
- **A solid step in making the CRAC and FRP Surcharge dormant components of BPA's risk mitigation.**
  - Benefits of more stable rates realized near instantly as financial reserves are more likely to stay above rate-increasing thresholds.
- **COVID-19 aware:**
  - In light of COVID-19 financial strain, a dial is used (to the extent there is room) to dial back the BP-22 financial impact of the proposal if the Final Proposal base power rate increase ends up being higher than 1%.
  - FRP Surcharge is suspended one more year (2023) to give more distance from COVID-19 financial impacts as well as a year for the proposal to start working (assuming, of course, less than the expected amount of secondary revenue is included in BP-22 base rates).

SUMMARY OF STAFF LEANINGS

- Rates
- Tariff

Final Workshop Steps

- Feedback on all Topics Except Power and Transmission Risk & Losses Methodology has an extended comment period:
  - Please submit to techforum@bpa.gov (with copy to your account executive) by September 18, 2020

APPENDIX

Customer Led Workshop Protocol

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