B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

BP-20 Generation Inputs Workshop

April 24, 2018

Corrected slides 16, 25-27

Agenda

- Solar Summary and Non-rate Exploration of Balancing Reserve Capacity – Rebecca Fredrickson
- Reserve Cost – Jarek Hunger
  - Cost Allocation for Reserve Capacity
  - Load Balancing Reserves
  - Combined Impacts
- Next Steps

Solar Summary and Non-rate Exploration of Balancing Reserve Capacity

Summary of Findings from Solar Study

- On February 13, 2018, BPA presented solar studies as contemplated in the BP-18 Generation Inputs settlement agreement.
- In the studies that were presented, BPA considered several methodologies to appropriately scale solar irradiance data, and settled on a rolling average methodology as the best balance between complexity and accuracy.
- BPA's current reserve allocation practice employs the Incremental Standard Deviation (ISD) methodology to allocate the net total reserve amount among generation types, which captures the diversity of the various generation profiles. By considering the net error, and employing ISD to allocate out the reserve amount, all parties receive the benefits of the group diversity. The presentation demonstrated the way in which the ISD allocation incorporates time-of-generation diversity with respect to the generation profile of solar plants.

Observations

- Solar reserves under a diurnally-split reserve analyses were also presented. Because time-of-generation diversity is respected by ISD, the studies did not show significant solar reserve reduction on average when compared with the non-split reserve analysis.
- Currently, BPA has 8 MW of utility-scale solar in our BAA and expects to see an additional 70 MW come online during the BP-20 rate period.
- At this time BPA does not see any need to include diurnal pricing or any other price signals for rate design. If we were to explore using diurnal pricing for solar, BPA would explore similar pricing for all balancing capacity. BPA will continue to monitor this issue as solar grows within our BA to better determine when price signals may be appropriate.
- BPA is devoting its limited resources to grid modernization, including exploring EIM.
- How EIM may effect BPA balancing reserves will be part of the future EIM consideration and will be discussed with stakeholders as the EIM discussion develops.

Potential Exploration

- BPA is considering offering a 30/60 committed scheduling option for solar, consistent with the options provided to wind customers.
- Some other examples of exploration:
  - Elimination of CSGI
  - Reviewing our current scheduling election options

Cost Allocation for Reserve Capacity

Basic Framework

$$\frac{Cost\ of\ Capacity}{Amount\ of\ Capacity} = Embedded\ Unit\ Cost\ of\ Capacity$$

$$Embedded\ Cost + Variable\ Cost = Total\ Cost$$

What We Have Done Previously (simplified)

1. For Balancing Reserves:
   - Embedded Cost is calculated by dividing the big 10 hydro resource costs (project costs + share of costs/credits) by the capacity of the big 10 projects.
   - This embedded cost is multiplied by the amount of capacity for each reserve product being held to get a total embedded cost.
   - The embedded cost is added to the variable cost produced by the GARD model to get a total cost for each service (DERBS, VERBS (Wind, Solar), and Regulating).

2. For Operating Reserves, a similar calculation is done that uses all regulated hydro instead of only the big 10, and a different percentage of costs/credits.

Concerns with the Existing Method

1. Debt management decisions such as Regional Cooperation Debt actions can change the amount of debt associated with the Big 10 and thereby change the embedded cost value even if the total amount of debt hasn't changed.

2. Risk -- Stakeholders have expressed concerns that exposure to CRACs and PNRR is not balanced by a secondary energy credit.

Proposed Alternative: The Variable-Fixed Method

The Variable-Fixed Method is based on the basic cost-of-service model of cost classification, whereby fixed costs are allocated to capacity and variable costs are allocated to energy.

By classifying costs in this way we can address the debt management problem since all debt would be classified as a fixed cost.

Since BPA has several statutory costs which are not ‘obviously’ fixed or variable, in a classic ratemaking sense -- we refer to the collection of allocated costs as “Capacity Costs” not “Fixed Costs.”

Proposed Alternative: Variable-Fixed Method

Old/Existing Method

Balancing Embedded Cost =

$$\frac{Big\ 10\ Cost + Share\ of\ other\ costs}{Big\ 10\ Capacity\ (120hr\ avg)}$$

Operating Embedded Cost =

$$\frac{Regulated\ Hydro\ Cost + Share\ of\ other\ costs}{Regulated\ Hydro\ Capacity\ (120hr\ avg)}$$

New Method

Embedded Cost =

$$\frac{Capacity\ Costs}{1\ hr\ critical\ Capacity}$$

Approach to Risk

The goal of this method is to use only critical water values and remove exposure to both positive and negative risk. Thus:

- Critical Water (1 Hour Peak) is used for the capacity value, instead of average water (120 Hour Peak).
  - Using the 1 hour peak better aligns with other power rates, which happens to mostly negate the effect of using critical water.
    - In BP-18: 1 Hour Critical Capacity averaged 12,722 MW; where 120 Hour Average Capacity averaged 12,702 MW.
- Exposure to PNRR and CRACs is removed

Which Costs are Tagged for Capacity?

A cost is added to the capacity costs attributed to reserves if <u>the cost is or was incurred to establish our current level of capacity</u>. In particular there are three main categories of costs that are tagged as capacity costs:

- Debt/Amortization/Depreciation/etc. (classic "fixed costs")
- Firm annual energy purchases which increase BPA's capacity (Augmentation, Tier 2)
- Statutory Obligations which impact our capacity

Which Credits are Tagged for Capacity?

The included credits are the same as they were previously which are:

- 4(h)(10)(C)
- Colville and Spokane Settlements
- Synchronous Condensing

After costs and credits are tagged, capacity costs are 45.5% of BPA's revenue requirement in BP-18.

Process to Calculate the Embedded Cost of Capacity (for BP-18)

- Take the allocated capacity cost: $1.143 Billion
- Divide it by the capacity amount: 13,503 MW
- This results in an embedded cost of capacity of $7.07/kW/month

- For comparison: BP-18 with the old method would have been:
  - $7.03 for Balancing Capacity
  - $7.39 for Operating Capacity

Corrected 5/2/2018

Summary of Benefits to the New Method

- Simpler
  - Uses one set of values to calculate embedded cost, instead of two
  - Includes all debt/financing costs
  - Doesn't use percentage allocators for costs/credits
- More Consistent
  - 1 Hour capacity maximum is a more classic rate-setting measurement of capacity than 120 Hour, which is partially energy constrained (but not impossibly high like nameplate capacity)
  - Critical capacity is consistent with all other power rate design
  - Same treatment of positive and negative financial risks across different power rates and services.
- More Stable & Predictable
  - Excludes CRAC/PNRR/Secondary Revenue Credit, which will result in a more predictable and stable rate.

Resulting Power Reserve Costs by Type (for BP-18)

Weighted Average Cost of $8.34/kW/mo broken out by reserve type

	New Proposed Tariff Schedules	Reserve Types	**Total Cost (inc+dec)**	**Component Cost $/kW/mo**		**Quantity Forecast for BP-18 (MW)** Gen	Load
Balancing Reserves	**Schedules 3, 4, 9, and 10**	Regulation (100% Spin)	$ 9.22	$ 8.60	Inc	51	64
				$ 0.62	Dec	50	64
		Following (50% Spin)	$ 8.81	$ 8.20	Inc	141	132
				$ 0.62	Dec	142	134
		Imbalance (0% Spin)	$ 8.44	$ 7.83	Inc	185	61
				$ 0.62	Dec	284	93
Operating Reserves	**Schedule 5**	Contingency (Spinning)	$ 8.55			277	
	Schedule 6	Supplemental (Non-Spinning)	$ 7.07			277	

Load Balancing Reserves

Load Balancing Reserves – The Current Allocation

Who Pays for Balancing Reserves?	*For Supporting...*	
Type	Generation	Load
Regulation	Transmission	Transmission
Following	Transmission	Power
Imbalance	Transmission	Power

Concerns with this method:

1. Balancing the BAA is a Transmission function and so should be a Transmission cost.
2. These costs are in the PF Tier 1 Rate which creates two equity issues:
   - Customers have load that isn't charged for it's impact on the BAA (Above RHWM Load, Resources counted against net requirement)
   - Customers not in the BAA are being charged to balance it

Proposed alternative

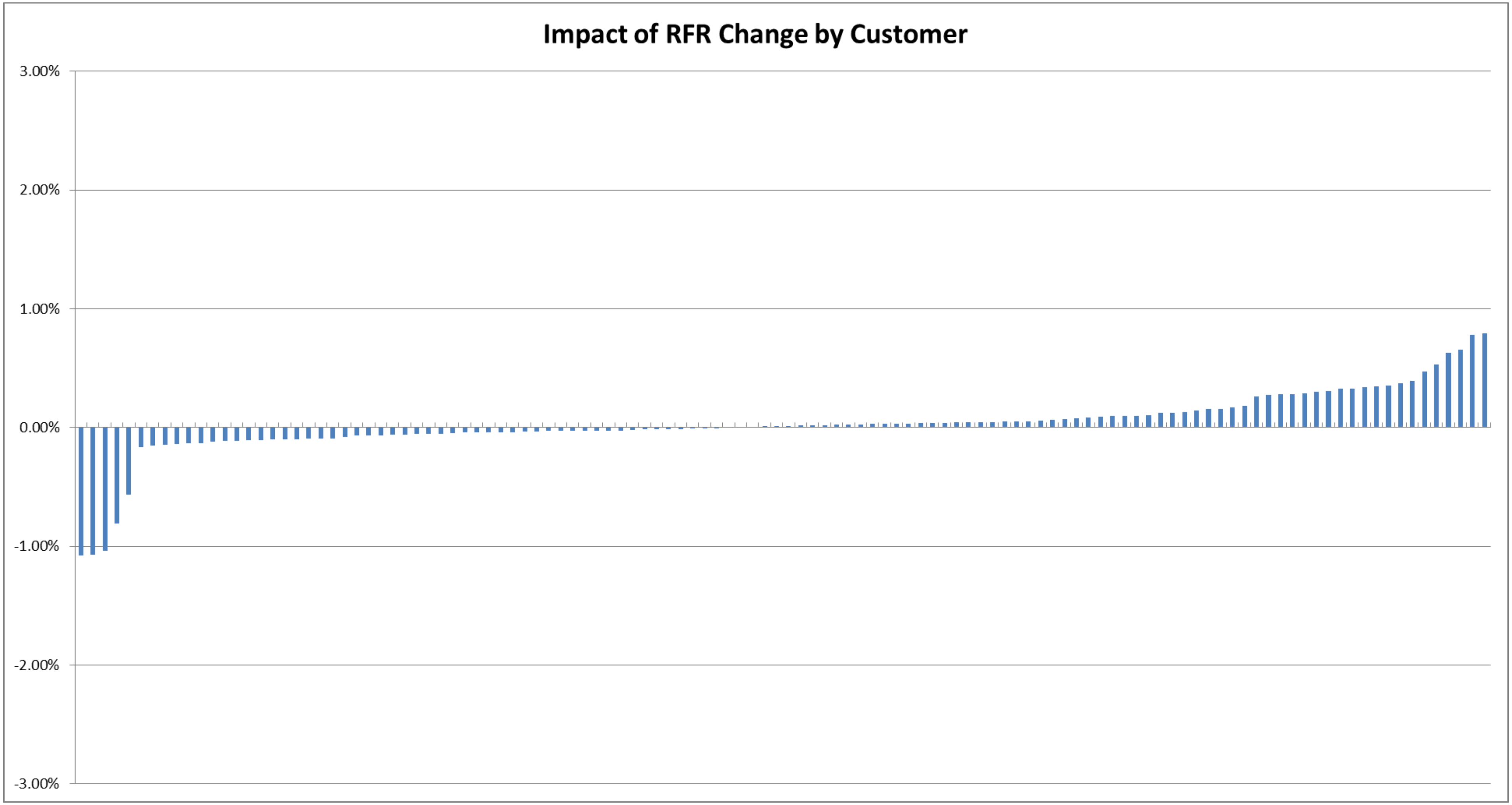
The proposed alternative is that Transmission pays for all load balancing reserves, instead of just the regulating component; and recovers these costs in their ACS rates instead of recovering it in the PF Tier 1 rate.

In BP-18, this alternative would have resulted in around $22M more collected by Power through the generation inputs credit and a commensurate increase in ACS Rates.

Expected Impact

The proposed allocation results in small net effect on many customers combined Power and Transmission bills. Their Transmission bill goes up and their Power bill goes down by nearly equal and opposite amounts. Of the 118 PF customers considered, 98 of them had net impacts of between -0.3% and 0.3%.

The exceptions to this are the customers that are in one of the groups listed previously who have lots of Above RHWM load, lots of non-federal resources, or are outside the BAA.


Impact of RFR Change by Customer
3.00%
2.00%
1.00%
0.00%
-1.00%
-2.00%
-3.00%

Combined Impacts

BP-18 ACS Rates

BP-18	Settlement	Old Methdology	New Methodology	Q (MW)
DERBS				14
Inc	$20.42	$24.93	$25.43	
Dec	$3.43	$2.69	$1.61	
Solar Avg	**$0.24**	**$0.38**	**$0.36**	**1**
Wind				364
Wind 30-15	**$0.71**	**$0.70**	**$0.69**	
Wind 30-60	**$1.01**	**$1.00**	**$1.00**	
Wind Uncommitted	**$1.22**	**$1.20**	**$1.11**	
Wind CSGI	**$0.49**	**$0.45**	**$0.45**	
OR				454
OR Spinning	$11.98	$12.01	$11.00	
OR Supplemental	$9.92	$9.93	$9.09	
RFR	**$0.13**	**$0.14**	**$0.14**	**64**

BP-18 Revenue to Power

			$/kW/mo
Settlement			
Normal Components	$	92,023,453	
Estimated Total	**$**	**92,023,453**	**$ 8.56**
Old Method			
Normal Components	$	91,237,858	
Estimated Total	**$**	**91,237,858**	**$ 8.48**
New Method			
Normal Components	$	89,663,161	
Estimated Total	**$**	**89,663,161**	**$ 8.34**

Corrected 4/25/2018

BP-18 ACS Rates

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OR				454
OR Spinning	$11.98	$12.01	$11.00	
OR Supplemental	$9.92	$9.93	$9.09	
RFR	**$0.13**	**$0.14**	**$0.14**	**64**
**RFR With Load Portion Added*			$ 0.51	*192.8*

BP-18 Revenue to Power

			$/kW/mo
Settlement			
Normal Components	$	92,023,453	
Estimated Total	**$**	**92,023,453**	**$ 8.56**
Old Method			
Normal Components	$	91,237,858	
Estimated Total	**$**	**91,237,858**	**$ 8.48**
New Method			
Normal Components	$	89,663,161	
*Adding Load Portion**	*$*	*20,365,456*	
Estimated Total	**$**	**110,028,617**	**$ 8.42**
Transfer Revenue	*$*	*3,350,000*	

Corrected 4/25/2018

BP-18 ACS Rates

BP-18	Settlement	Old Methdology	New Methodology	Q (MW)
DERBS				14
Inc	$20.42	$24.93	$25.43	
Dec	$3.43	$2.69	$1.61	
Solar Avg	**$0.24**	**$0.38**	**$0.36**	**1**
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Wind CSGI	**$0.49**	**$0.45**	**$0.45**	
OR				454
OR Spinning	$11.98	$12.01	$11.00	
OR Supplemental	$9.92	$9.93	$9.09	
RFR	**$0.13**	**$0.14**	**$0.14**	**64**
**RFR With Load Portion Added*			$ 0.51	*192.8*

BP-18 Revenue to Power

			$/kW/ mo
Settlement			
Normal Components	$	92,023,453	
Other Generation Inputs	*$*	*12,949,876*	
Estimated Total	**$**	**104,973,329**	**$ 8.56**
Old Method			
Normal Components	$	91,237,858	
Other Generation Inputs	*$*	*12,949,876*	
Estimated Total	**$**	**104,187,734**	**$ 8.48**
New Method			
Normal Components	$	89,663,161	
*Adding Load Portion**	*$*	*20,365,456*	
Other Generation Inputs	*$*	*12,949,876*	
Estimated Total	**$**	**122,978,493**	**$ 8.42**

Total Change to Power Revenue Credit		
Transfer Revenue	*$*	*3,350,000*
Gen Inputs Credit	$	18,790,759
Total	$	22,140,759

Corrected 4/25/2018

Next Steps

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By Friday, May 4:

- Please send any comments regarding this BP-20 Gen Inputs presentation to BPA's Tech Forum at techforum@bpa.gov with the subject line: "BP-20 Gen Inputs."
- Next BP-20 Gen Inputs workshop: May 30