Generation Inputs Workshop

March 29, 2016

(Slides 13 and 14 corrected 4/1/16)

BP-18 Generation Inputs Workshop Agenda

Topic	Presenter
Generation Imbalance	Scott Winner Chris Gilbert
Spring Acquisition Process	Andy Meyers Matt Schroettnig
DERBS Rate	Lauren Tenney Denison
Mock Election	Eric King
Cost Allocation	Daniel Fisher

Wind Generation Imbalance Preliminary FY 2016 Study

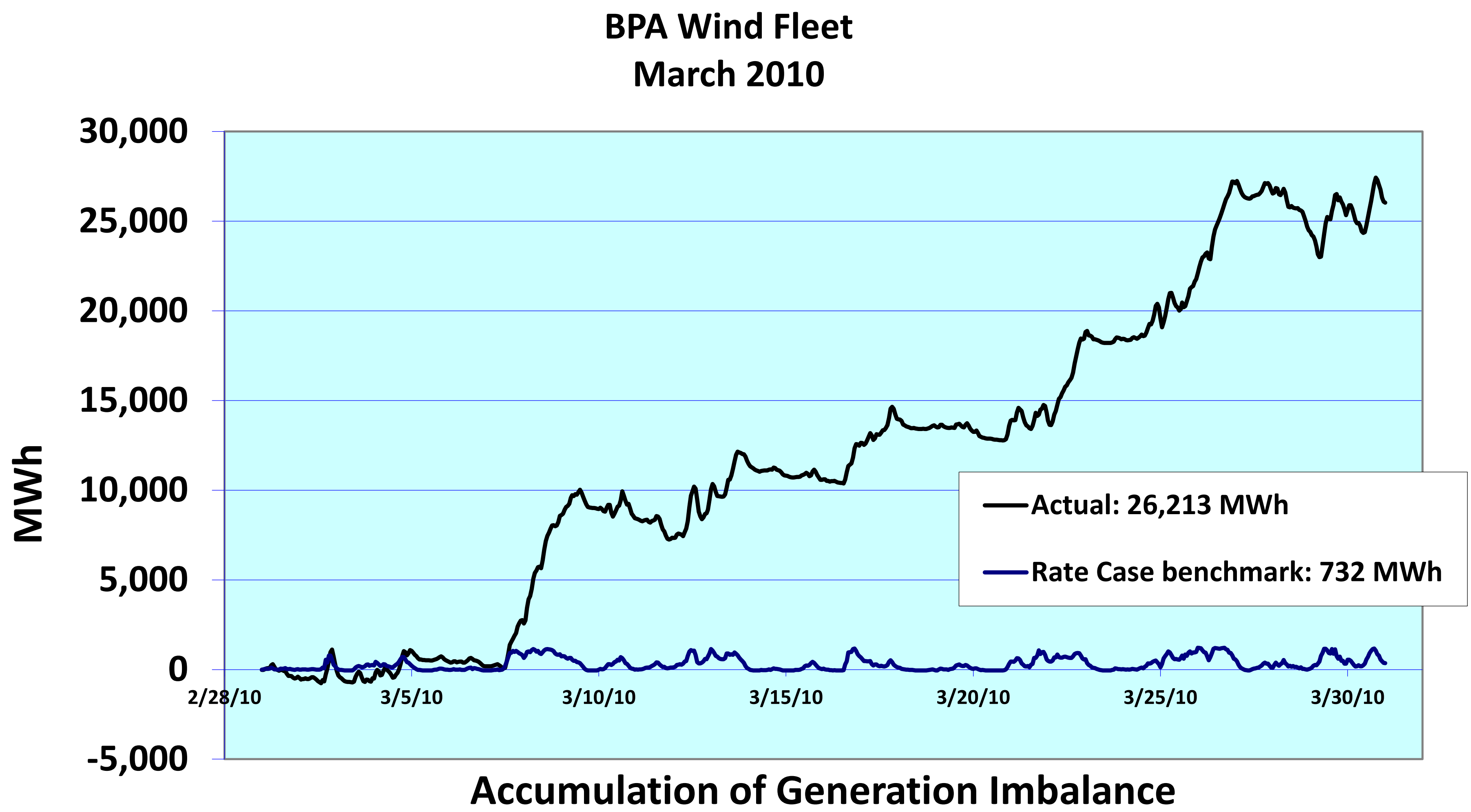
Scott Winner

Chris Gilbert

Introduction

- Generation Imbalance (GI) Charge
  - For wind generators it can be up to +/- 10% of the energy market price
- Accumulation of Generation Imbalance
  - When wind schedule error is random and un-biased, the monthly accumulation of imbalance can be small
- This study/presentation looks into the impact of accumulation of imbalance by the FY 2016 Wind Scheduling elections
  - Study looks at FY 2016 Q1 (Oct-Dec) and FY 2016 Q2 (Jan & Feb)

Why is managing Imbalance important?

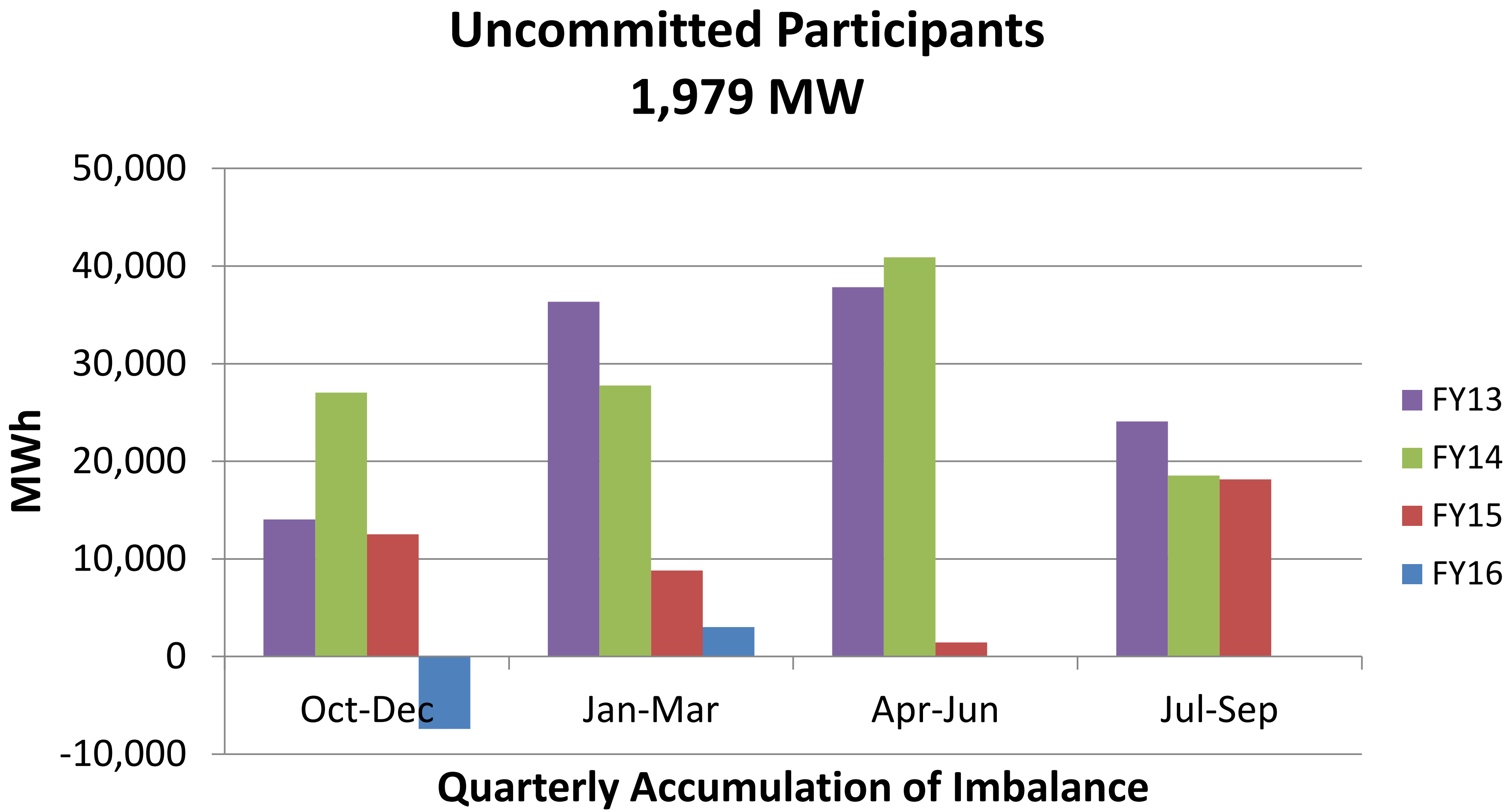


FY 2016 Scheduling Elections

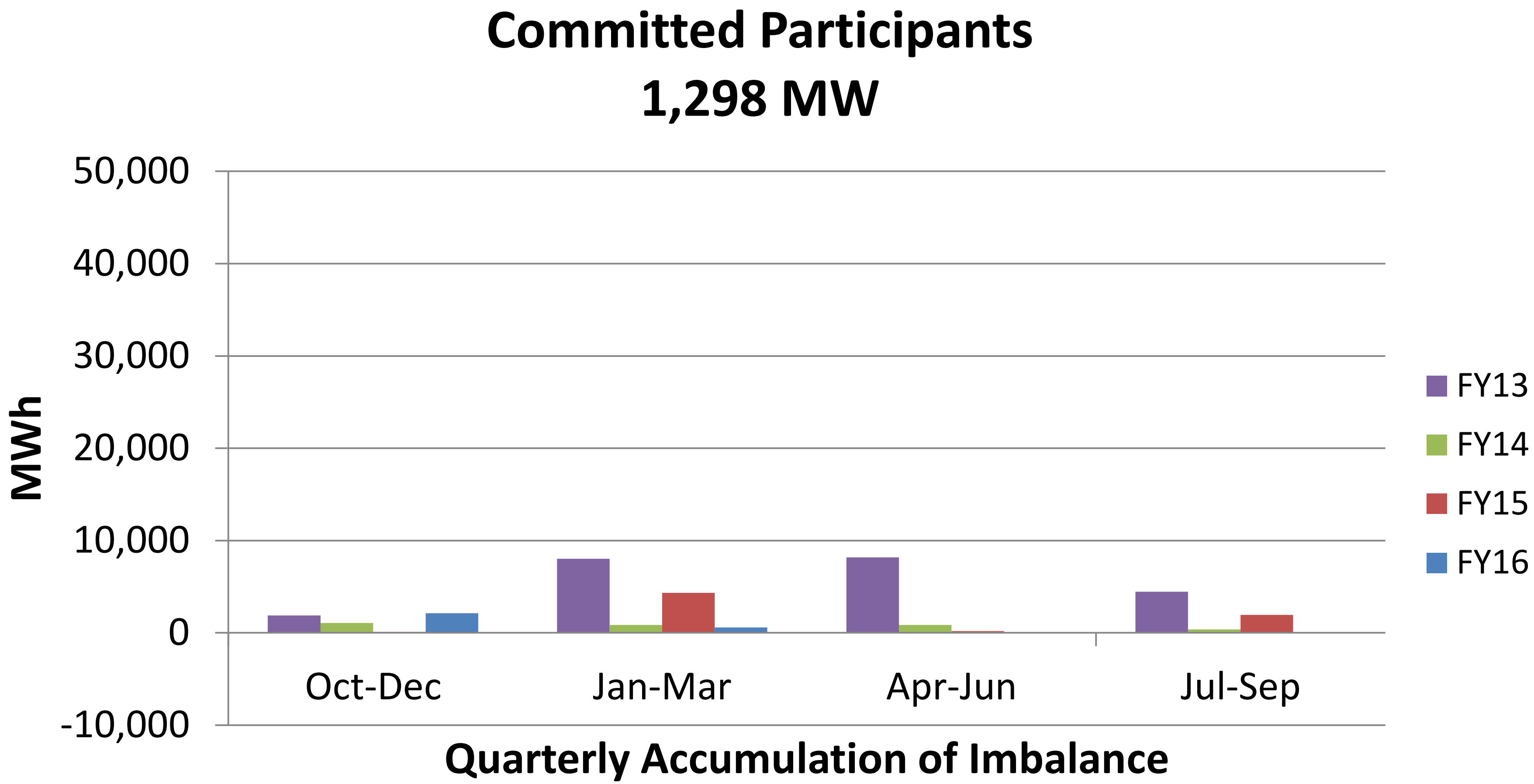
- CSGI with PD — $0.40 KW/month
  - 1,391 MW elected
- Committed 30/15 with ID — $0.73 KW/month
  - 792 MW elected
- Committed 40/15 with ID — $0.94 KW/month
  - 0 MW elected
- Committed 30/60 with ID — $1.20 KW/month
  - 506 MW elected
- Uncommitted with ID — $1.48 KW/month
  - 1,979 MW elected
- Uncommitted with PD — $1.68 KW/month
  - 114 MW elected

PD = Persistent Deviation

ID = Intentional Deviation



- Scheduling to the BPA Official wind power forecasts for the Uncommitted Participants is showing a lower impact to BPA System draft/storage
- FY16 Jan-Mar includes only Jan and Feb 2016 data



- Scheduling to a persistent value results in considerably less accumulation of imbalance energy compared to scheduling to the BPA Official Wind Power Forecast
- FY16 Jan-Mar includes only Jan and Feb 2016 data

Intentional Deviation Penalty Charge

- 2016 Transmission, Ancillary, and Control Area Service Rate Schedules and General Rate Schedule Provisions, GRSP II.H
  - Intentional Deviation Penalty Charge rate shall be $100 per MWh
  - An Intentional Deviation event occurs when:

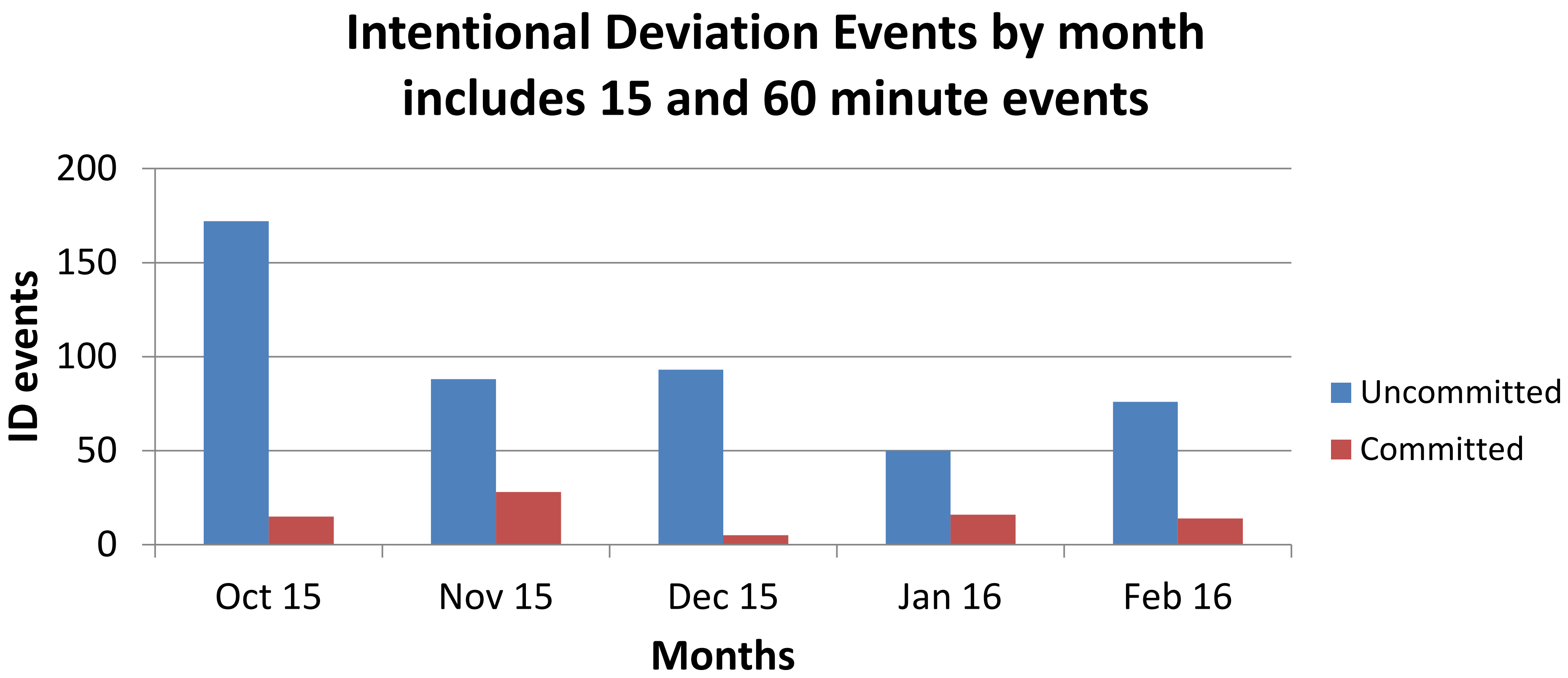
    ABS(Intentional Deviation Measurement Value – Resource Schedule) > 1
  - Intentional Deviation Measurement Value is

    Committed Election – committed schedule value provided by BPA

    Uncommitted Election – 40-minute forecast schedule value
  - Intentional Deviation Exemption

    Actual error ≤ Intentional Deviation event error +1 MW

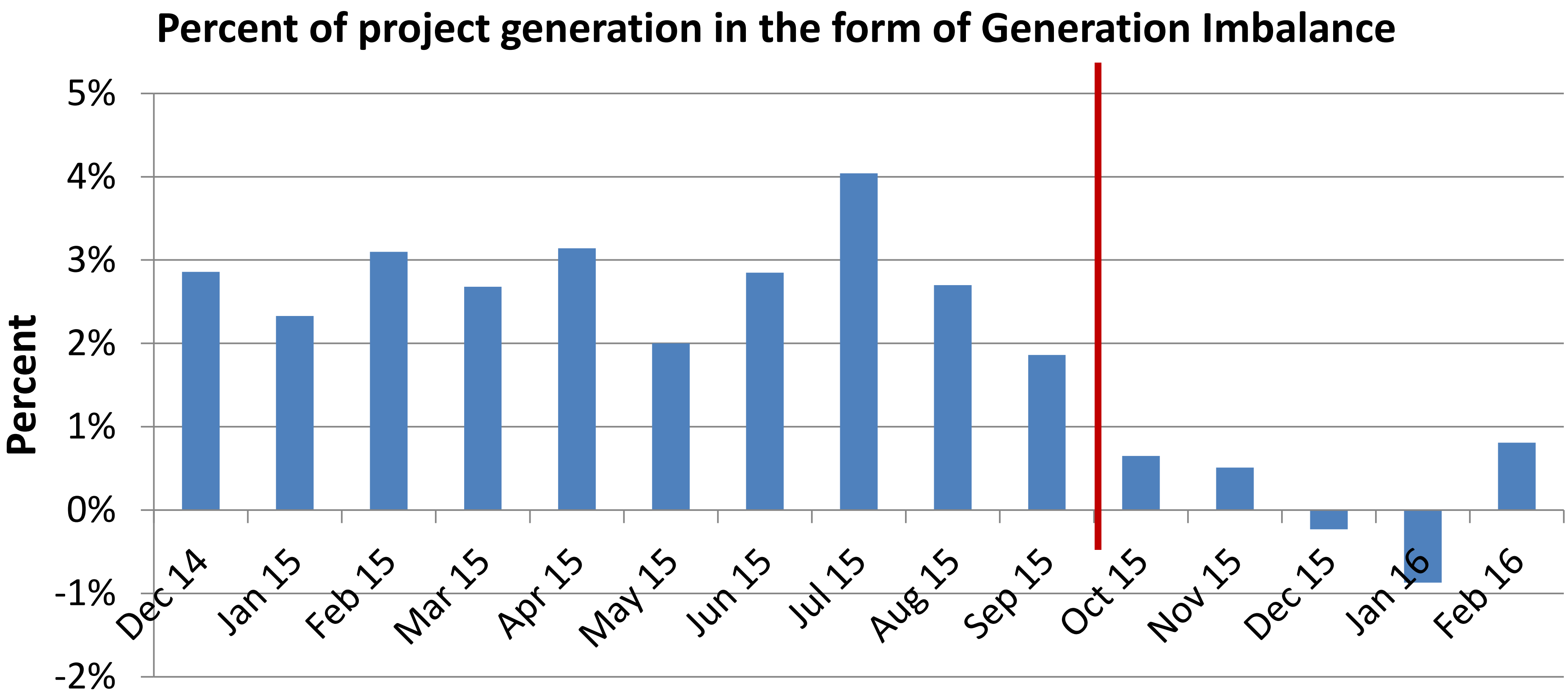
ABS = Absolute value of the term in parentheses



ID events are on the decline

Some customers were not prepared for the new scheduling requirements that started Oct 2015

By Q2, events have dropped off as customer's systems and procedures have been finalized



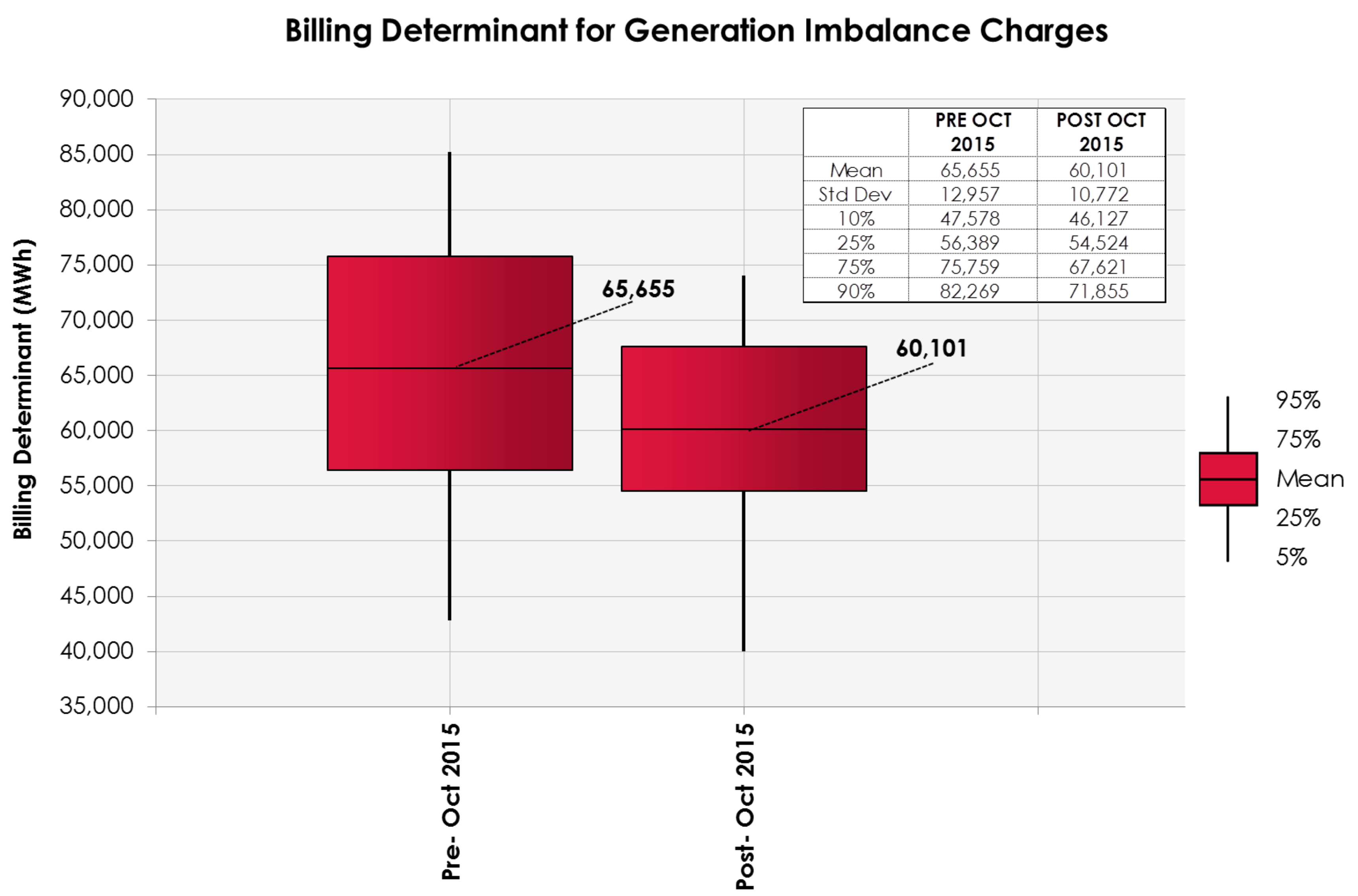
Graph represents a single uncommitted wind plant

Prior to Oct 2015, project regularly under-scheduled

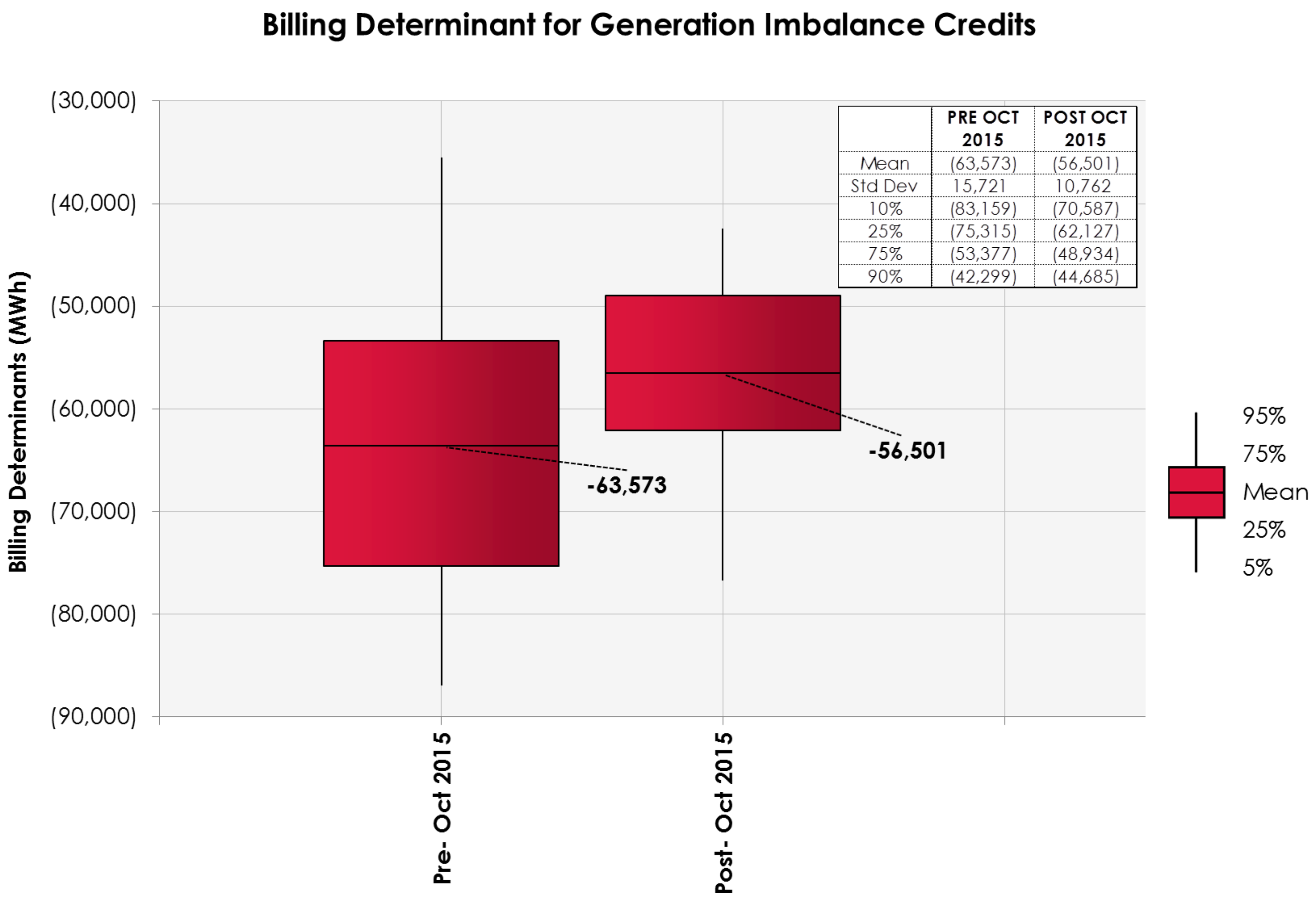
Beginning Oct 2015, project GI is less and more random

Generation Imbalance Charges and Credits

- Data:
  - October 2011 through February 2016
  - Generation imbalance charges for wind generators
  - Excludes CSGI plants and energy billed as Persistent Deviation
- Approach:
  - Separated data into pre- and post-October 2015.
  - Observed generation imbalance billing trends before and after the implementation of the Intentional Deviation Penalty Charge.
- Summary:
  - GI charges post-October 2015 decreased slightly and variability remained mostly unchanged. (Under-generation)
  - GI credits post-October 2015 reduced significantly and variability decreased significantly. (Over-generation)
  - Scheduling accuracy under ID has improved dramatically, especially for over-generation situations.



	PRE OCT 2015	POST OCT 2015
Mean	65,655	60,101
Std Dev	12,957	10,772
10%	47,578	46,127
25%	56,389	54,524
75%	75,759	67,621
90%	82,269	71,855



	PRE OCT 2015	POST OCT 2015
Mean	(63,573)	(56,501)
Std Dev	15,721	10,762
10%	(83,159)	(70,587)
25%	(75,315)	(62,127)
75%	(53,377)	(48,934)
90%	(42,299)	(44,685)

Spring Acquisition Process

Andy Meyers

Matt Schroettnig

Objectives of Discussion

- Highlight changes for BP-16 spring acquisitions from BP-14
- Provide an overview of our proposed implementation strategy for third party supply (3PS) acquisitions.
  - Long term spring acquisitions
  - Preschedule spring acquisitions
- Explain process using the R3T reserve forecast model

What's new for BP-16 spring acquisitions

- 210 MW is targeted to be purchased ahead for the months of April, May & June per the rate case settlement.
  - All 210 MW has now been purchased for 2016
- The purchasing budget has increased from $2 million/yr to $17.5 million/yr
- We will no longer attempt to purchase up to 910 MW of *incs* each preschedule period. Rather, we will buy based on the following:

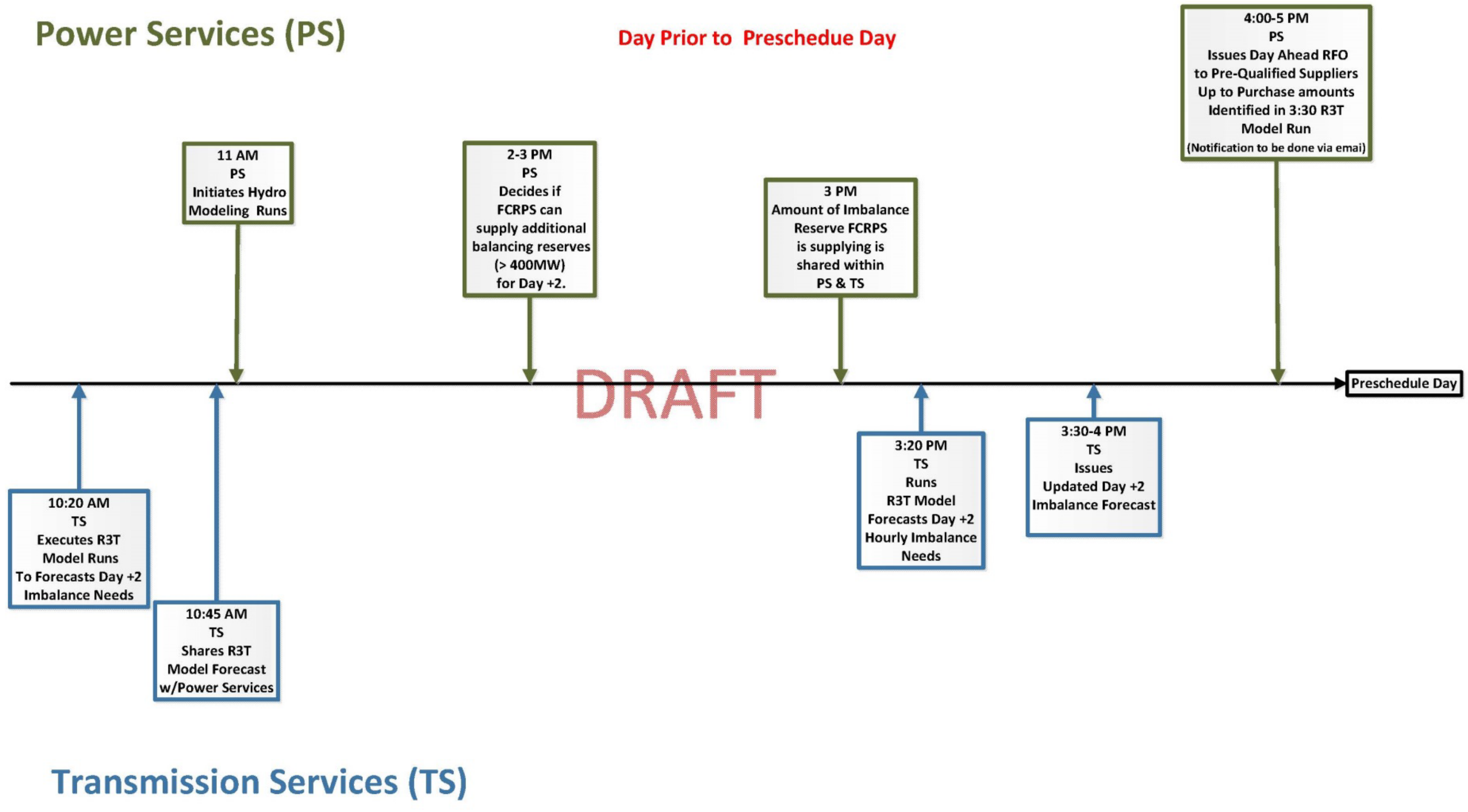
  Acquisition Target = R3T projected need – 400 MW (base FCRPS amount) – 210 MW (3PS) – FCRPS (additional output)
- Based on supplier feedback, minimum bid amounts have been reduced from 50 MW to 25 MW with diurnal bids also being allowed.
- A bidders conference was held on March 18th.
- We will manage the yearly budget based on previous monthly or quarterly purchases, remaining budget, projected reserve needs and expected operational impacts during each spring preschedule purchasing period.

Implementation Process

- "Up to" buying targets will be identified at the 3:30 pm R3T model run on the day prior to the Preschedule day.
  - The RFO will be issued this same day between 4:00-5:00 pm using the above "up to" purchasing targets.
  - On the following morning, once the 7:00 am R3T refresh model runs are done, the actual buying targets will be adjusted to these new numbers.
  - If final buying targets are higher, we will attempt to buy to that target even if they are above the "up to" targets given in the RFO.
  - If final buying targets are at or less than the RFO "up to" targets, we will attempt to purchase to these amounts.

FY16/17 Preschedule Third Party Supply (3PS) Balancing Reserve Acquisitions
Spring Operational Acquisitions (April – July)

(Acquisitions made one day at a time in 25MW Flat/LHL/LLH blocks)
Imbalance Deployments made in 50MW chunks



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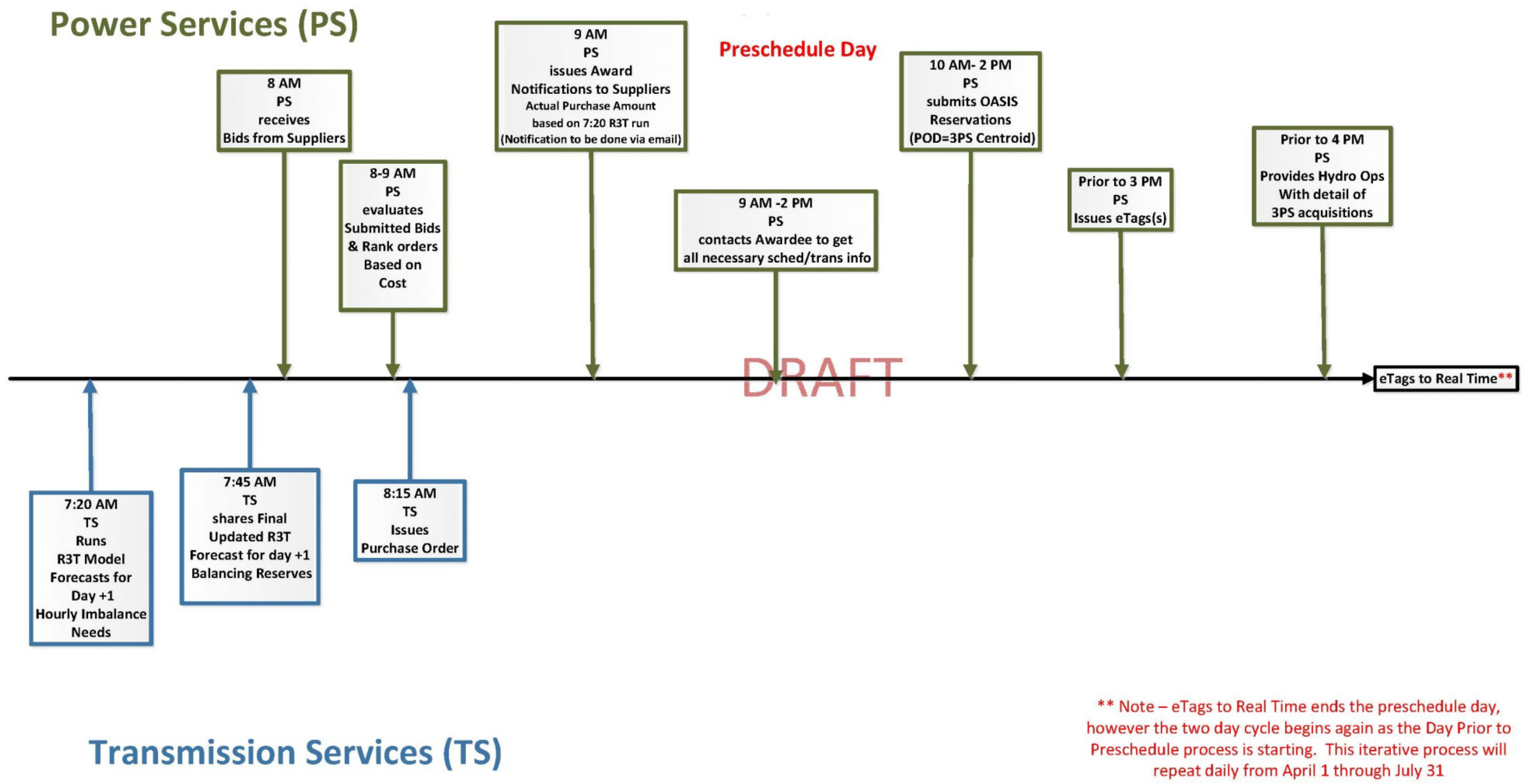


Dispatchable Energy Resource Balancing Service Rate

Lauren Tenney Denison

Introduction

- Dispatchable Energy Resource Balancing Service (DERBS) applies to all non-Federal thermal resources with nameplate 3 MW or over.
- Error deadband of +/- 3 MW
- Separate rates for Inc and Dec, with Inc rate substantially higher (4.5x)
- BP-16 rates held to BP-14 rates to achieve settlement
  - Inc: 18.15 mills per kW maximum hourly deviation
  - Dec: 3.94 mills per kW maximum hourly deviation
- Rate based on use
  - Billed based on max five-minute average deviation (above and below) from the schedule each hour
  - This deviation is called the Station Control Error (SCE)

DERBS Rate Under-Recovery

- In the past have had issues of under-recovery with DERBS

	FY 2012	FY 2013	FY 2014	FY 2015
Actual Revenues	$4.08	$3.10	$1.65	$1.55
Rate Case Forecast	$5.75	$5.76	$3.12	$3.12
Actual less Rate Case	***-$1.66***	***-$2.66***	***-$1.47***	***-$1.56***

- Recent changes may have improved recovery
  - Large thermal facilities have moved out of the Balancing Authority (BA) reducing SCE for DERBS
  - DERBS use has largely stabilized since 2013 which would help create improved forecasts based on historical data
- Difficult to assess under-recovery of DERBS rate in BP-16 since rates were not updated
  - Estimate revenue requirement for BP-16 using $8.65 per kW-mo x 18 MW of reserves x 12 x 1000 = $1.9M per year
  - Latest forecast is $1.5M in DERBS revenues for FY 2016
  - Expected deviation of around $400k

If DERBS Rates Had Been Updated In BP-16…

- Forecast use was not updated to reflect stabilization of use and removal of plants

	BP-16 Mock Calculation*		BP-16 Settled Rate
INC	Revenue Requirement	$ 1,670,644	
	Monthly Sales (MW)	5,419	
	Estimated Rate (mills per kW)	25.69	18.15
DEC	Revenue Requirement	$ 152,084	
	Monthly Sales	6,054	
	Estimated Rate	2.09	3.94

- Estimate of updated rates indicates customers would be impacted differently. The update would benefit those who rely more heavily on Decs.
- Applying these “mock rates” to FY 2016 actual DERBS billing determinants results in $200k additional revenues compared to BP-16 settled rates.

*Mock calculation includes 5% inflator to costs from BP-14, DERBS billing factor from FY 2016 Start-of-Year forecast.

Potential Changes In BP-18 Impacting DERBS Rate

- Drivers that may impact DERBS rates:
  - Wind farms moving out of the BPA Balancing Authority may reduce diversity of SCE, increase costs for DERBS
  - BAL changes may reduce total reserves, decrease costs for DERBS

Next Steps

- Continue to monitor cost recovery. Is under-recovery still an issue?
- At a future workshop bring data showing historical behavior of remaining DERBS plants.
- Seeking customer feedback
  - Are customers interested in exploring alternative rate designs?
  - Specific proposals to discuss in future workshops?

Mock Election for FY 2018-FY2019 Balancing Service

Eric King

Mock Election

- Non-binding elections for balancing service for BP-18 rate period received by March 15, 2016

- Default for projects that did not submit:
  - Existing Variable Energy Resources (VERs): assume current BP-16 election
  - New VERs: assume Uncommitted
  - Existing Dispatchable Energy Resources (DERs) taking Dispatchable Energy Resource Balancing Service (DERBS) and New DERs: assume both taking DERBS from BPA

Results of Mock Election (If Projects Not Able to Leave 10/1/2017)

Scheduling Election	MW End of BP-16	MW End of BP-18
▪ CSGI*	1,390 MW	0 MW
▪ Committed 30/15	1,586 MW	870 MW
▪ Committed 40/15	0 MW	0 MW
▪ Committed 30/60	654 MW	155 MW
▪ Uncommitted	1,148 MW	1,348 MW
Total Wind Capacity Taking Service	4,778 MW	2,373 MW
Wind Capacity leaving the BAA**	*1,216 MW* ***	2,606 MW

*Customer-Supplied Generation Imbalance Pilot Program

**Balancing Authority Area

*** Requesting to leave on 10/1/2017

Direct Assignment Charges for VERBS

Cost of incremental balancing reserve capacity purchases that are necessary to provide Variable Energy Resource Balancing Service (VERBS) to customers if:

- Unable to self-supply one or more components of VERBS;
- Project's interconnection date is earlier than projected interconnection date;
- Unable to conform to committed scheduling criteria;
- Unable to transfer its resource out of BPA's BA on schedule.

Customers subject to direct assignment charges will be billed for all costs incurred above $0.29 per kilowatt-day for any incremental balancing reserve capacity acquisition. Customers billed for direct assignment charges will also be billed at the applicable VERBS rate.

Reference: 2016 Transmission, Ancillary, and Control Area Service Rate Schedules, ACS-16 Rate, Section III.E.4

Direct Assignment Charges for DERBS

Cost of incremental balancing reserve capacity purchases that are necessary to provide Dispatchable Energy Resource Balancing Service (DERBS) to customers if:

- Unable to self-supply DERBS;
- Project's interconnection date is earlier than projected interconnection date;
- Customer operating in another BA chooses to dynamically transfer in to the BPA BA;
- Unable to transfer its resource out of BPA's BA on schedule.

Customers subject to direct assignment charges will be billed for all costs incurred above $0.29 per kilowatt-day for any incremental balancing reserve capacity acquisition. Customers billed for direct assignment charges will also be billed at the applicable DERBS rate.

Reference: 2016 Transmission, Ancillary, and Control Area Service Rate Schedules, ACS-16 Rate, Section III.F.4

Cost Allocation Concepts

Daniel Fisher

Today's Discussion

- Discuss the history of revisiting BPA's method of calculating its embedded cost and why we want to revisit it again for potential application in BP-18.
- Explore three different methods of assigning system costs to energy and capacity services (cost classification).
  - Warm Up: Apply two cost classification methods to a simplified example problem.
  - Warm Up Over: Apply a third cost classification method to the more complex BPA system.
  - Review five different cost classification scenarios with the three cost classification methods previously introduced.
- Begin the DEC discussion - Discuss the history of the amount of DECs BPA has held, the financial tradeoff of carrying DECs, and the historically observed feather events.

Revisiting BPA's Calculation of Embedded Capacity Cost

- A portion of the BP-14 settlement included a commitment to explore potential new ways to calculate BPA's embedded capacity cost.
- Several workshops were held to explore the concept, but no conclusions were reached – largely because the BP-16 settlement was based on BP-14 settled rates.
- We believe it is time to revisit this topic for potential use in the BP-18 rate case.
- One reason for the revisit is due to debt management actions BPA has made over the past few years and the unintended impact they have on BPA's Big 10 embedded cost methodology.
  - Generally, the BPA's Big 10 embedded cost methodology parcels out the cost of BPA's Big 10 hydro projects from the overall BPA revenue requirement and divides that cost by the capacity uses of the Big 10 hydro projects to calculate a capacity unit cost per use.

Debt Refinancing and Gen Inputs Costing

- BPA has been managing its Federal and non-Federal debt as a single portfolio. In particular, the recent Regional Cooperation Debt (RCD) refinancings involve the refinancing of Energy Northwest debt which frees up funds for BPA to accelerate the repayment of Federal appropriations repayment.
- The current costing methodology is not designed to capture the effects of these transactions.
  - The methodology only looks at capital-related costs (depreciation, interest, minimum required net revenues) directly associated with the Federal hydro system.
  - These costs are allocated to the Big 10 hydro projects based on their share of the net investment in the hydro system.
  - The methodology does not capture any non-Federal costs associated with the RCD transactions.
- Without change to the current costing methodology, gen inputs will receive the benefits from the RCD transactions without any of the offsetting costs.

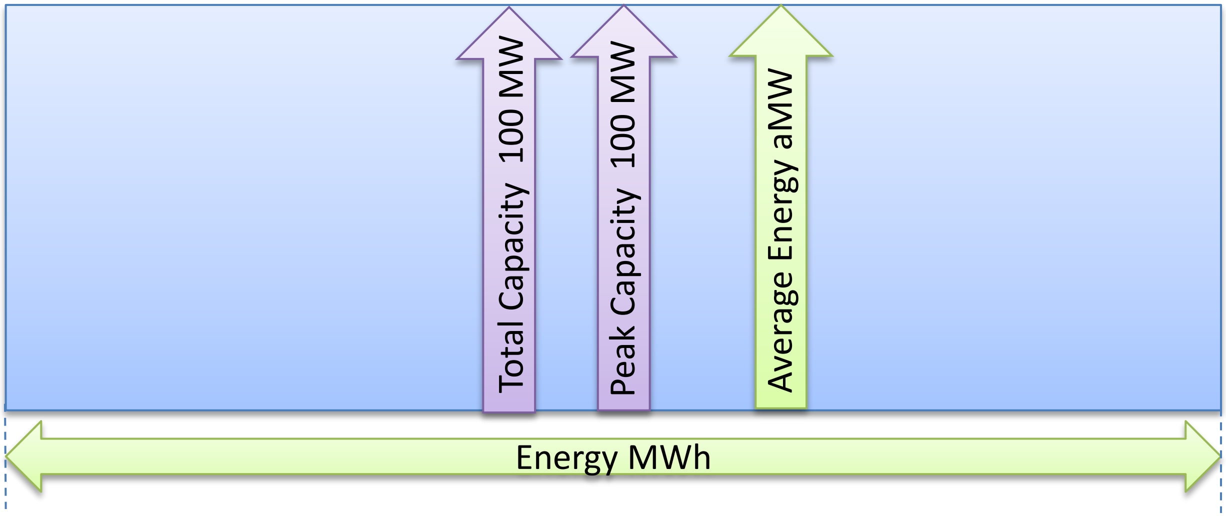
Warm Up

Simple Cost Classification Example

Hypothetical cost classification (e.g., assignment of costs to energy and capacity) problem:
How to allocate a 100% fixed cost system to two customers that purchase two different services?

System and Service Facts:

- 100% fixed costs = $20,000,000
- The system produces a 100 MW flat annual block of power (*i.e.*, 100% load factor system.)
- Customer 1 needs to power a pump to move water up a hill. The pump can be turned on and off at anytime with little to no notice. The customer has no preference when the pump runs and is reasonably flexible with how often it runs (an energy only product).
- Customer 2 needs a power supply to manage extreme events that last for a relatively short amount of time (mostly capacity only product).



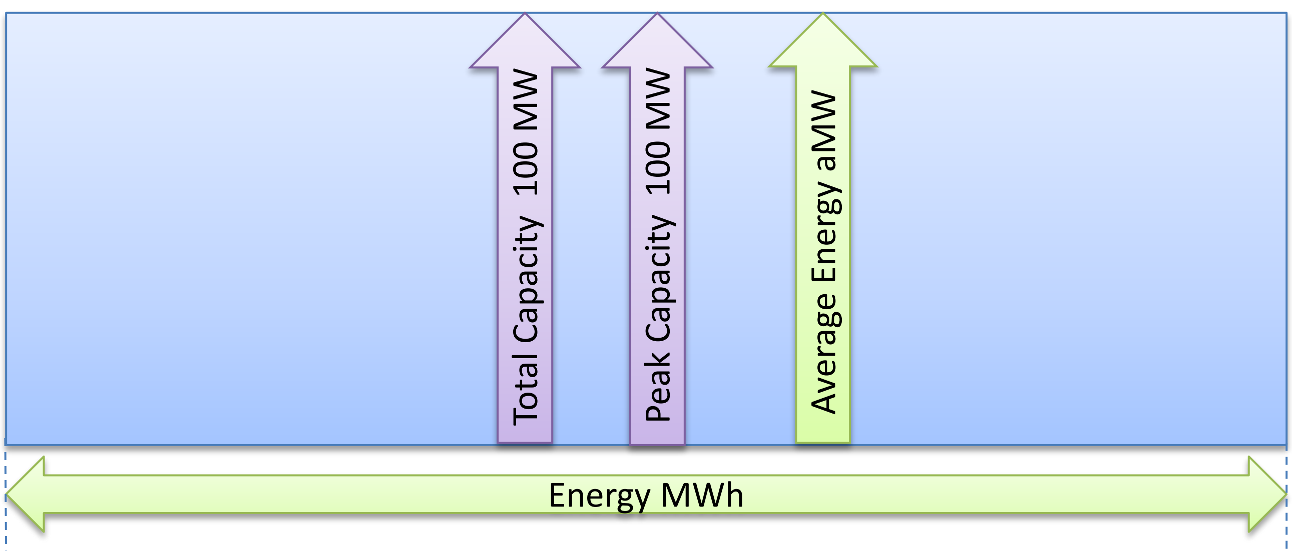
Peak Capacity = Forecast Highest Hourly Generation Amount

Total Capacity = Peak Capacity + Reserve Capacity

Max and Average Method

$$\frac{\text{Total Capacity MW}}{\left\{\text{Average Energy aMW} + \text{Total Capacity MW}\right\}} = \text{Capacity Allocation \%}$$

Capacity Allocation	50%
Energy Allocation	50%
Capacity Cost ($/kW/mo)	$ 8.33
Energy Cost ($/MWh)	$ 11.42
Energy and Capacity Cost ($/MWh)	$ 22.83

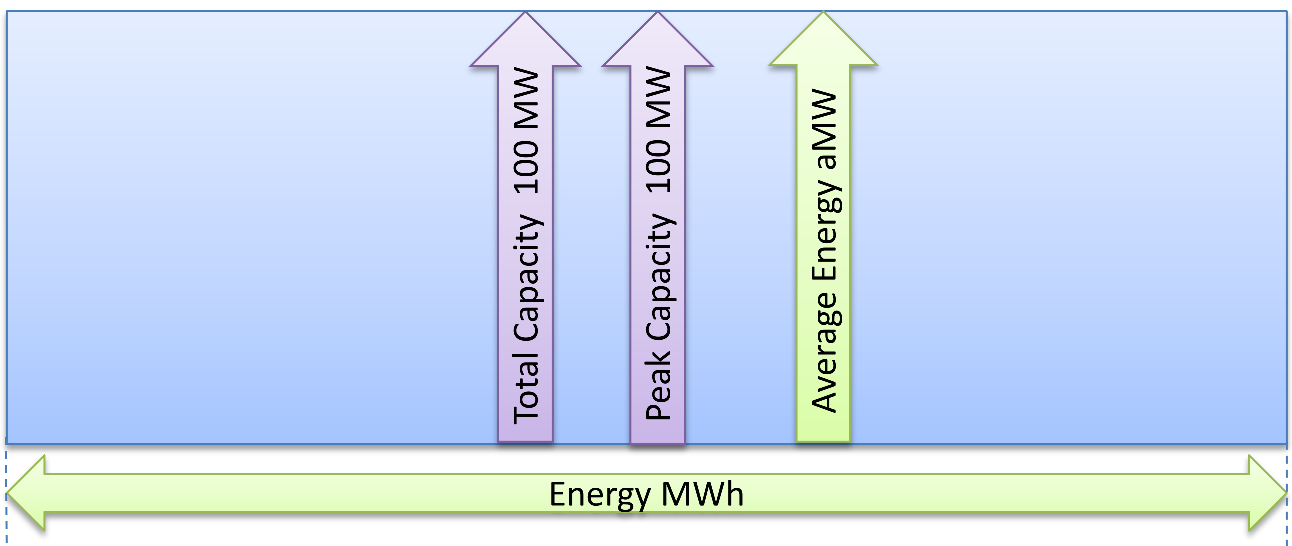


Load Factor Method

$$\frac{\text{Average Energy aMW}}{\text{Peak Capacity MW}} = \text{Energy Allocation \%}$$

$$\text{100 \%} - \text{Energy Allocation \%} = \text{Capacity Allocation \%}$$

Capacity Allocation		0%
Energy Allocation		**100%**
Capacity Cost ($/kW/mo)	$	-
Energy Cost ($/MWh)	$	22.83
Energy and Capacity Cost ($/MWh)	$	22.83



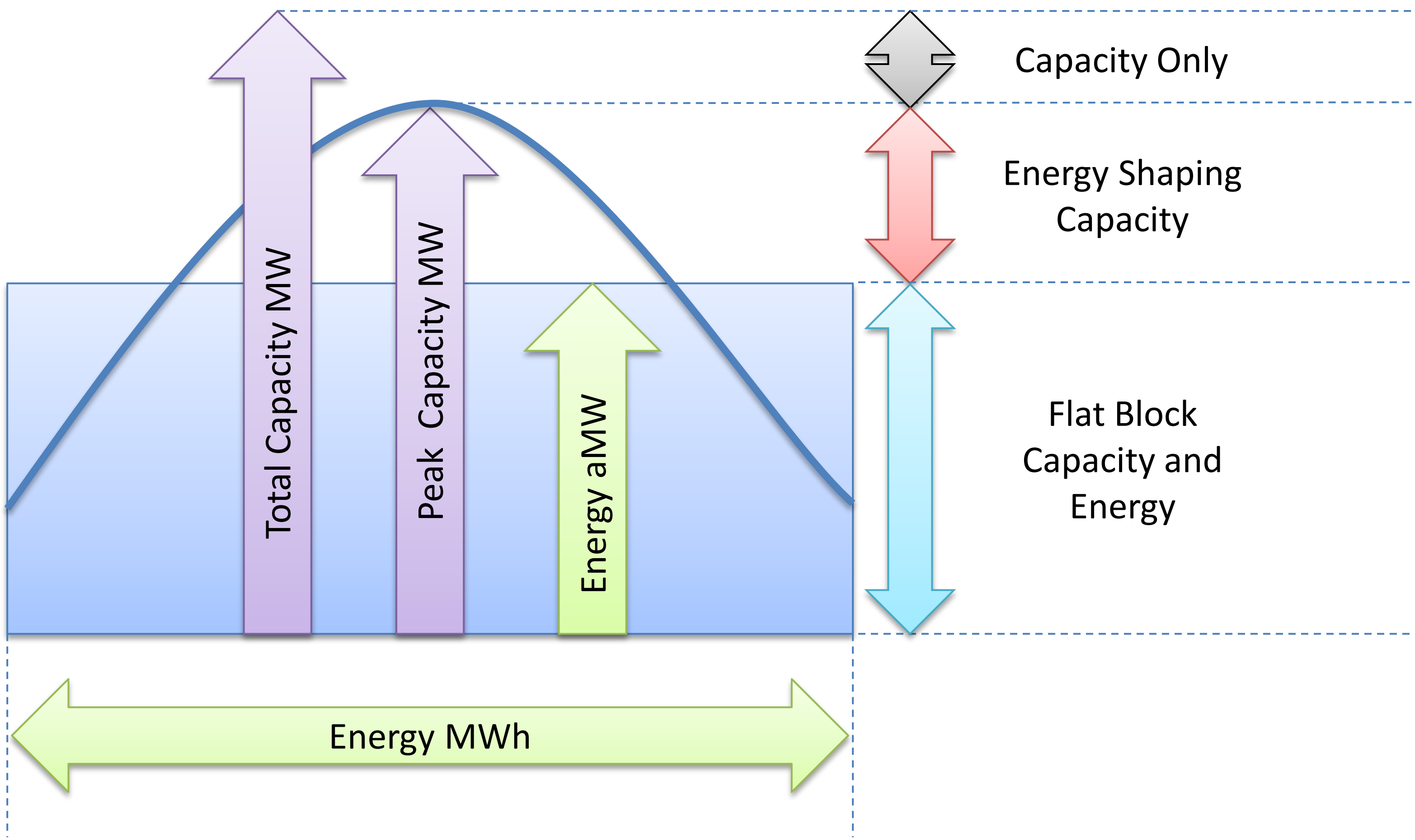
Methods Applied to Various Generation Load Factors

Revenue Requirement	$ 20,000,000							
Max and Average Method								
Peak (MW)	Energy (aMW)	Load Factor	Energy Allocation	Capacity Allocation	Energy Cost $/MWh	Capacity Cost ($/kW/mo)	Energy and Capacity Cost ($/MWh)	Delta from Load Factor Method
100	100	100%	50%	50%	$ 11.42	$ 8.33	$ 22.83	$ -
100	90	90%	47%	53%	$ 12.02	$ 8.77	$ 24.03	$ (1.08)
100	80	80%	44%	56%	$ 12.68	$ 9.26	$ 25.37	$ (2.03)
100	70	70%	41%	59%	$ 13.43	$ 9.80	$ 26.86	$ (2.82)
100	60	60%	38%	63%	$ 14.27	$ 10.42	$ 28.54	$ (3.42)
100	50	50%	33%	67%	$ 15.22	$ 11.11	$ 30.44	$ (3.81)
100	40	40%	29%	71%	$ 16.31	$ 11.90	$ 32.62	$ (3.91)
100	30	30%	23%	77%	$ 17.56	$ 12.82	$ 35.12	$ (3.69)
100	20	20%	17%	83%	$ 19.03	$ 13.89	$ 38.05	$ (3.04)
100	10	10%	9%	91%	$ 20.76	$ 15.15	$ 41.51	$ (1.87)
Load Factor Method								
Peak (MW)	Energy (aMW)	Load Factor	Energy Allocation	Capacity Allocation	Energy Cost $/MWh	Capacity Cost ($/kW/mo)	Energy and Capacity Cost ($/MWh)	
100	100	100%	100%	0.00%	$ 22.83	$ -	$ 22.83	
100	90	90%	90%	10.00%	$ 22.83	$ 1.67	$ 25.11	
100	80	80%	80%	20.00%	$ 22.83	$ 3.33	$ 27.40	
100	70	70%	70%	30.00%	$ 22.83	$ 5.00	$ 29.68	
100	60	60%	60%	40.00%	$ 22.83	$ 6.67	$ 31.96	
100	50	50%	50%	50.00%	$ 22.83	$ 8.33	$ 34.25	
100	40	40%	40%	60.00%	$ 22.83	$ 10.00	$ 36.53	
100	30	30%	30%	70.00%	$ 22.83	$ 11.67	$ 38.81	
100	20	20%	20%	80.00%	$ 22.83	$ 13.33	$ 41.10	
100	10	10%	10%	90.00%	$ 22.83	$ 15.00	$ 43.38	

Warm Up Over

Applying Cost Classification to BPA

How to equitably allocate BPA's Net Power Revenue Requirement to services that use **Capacity Only** and services that use both **Capacity and Energy**?

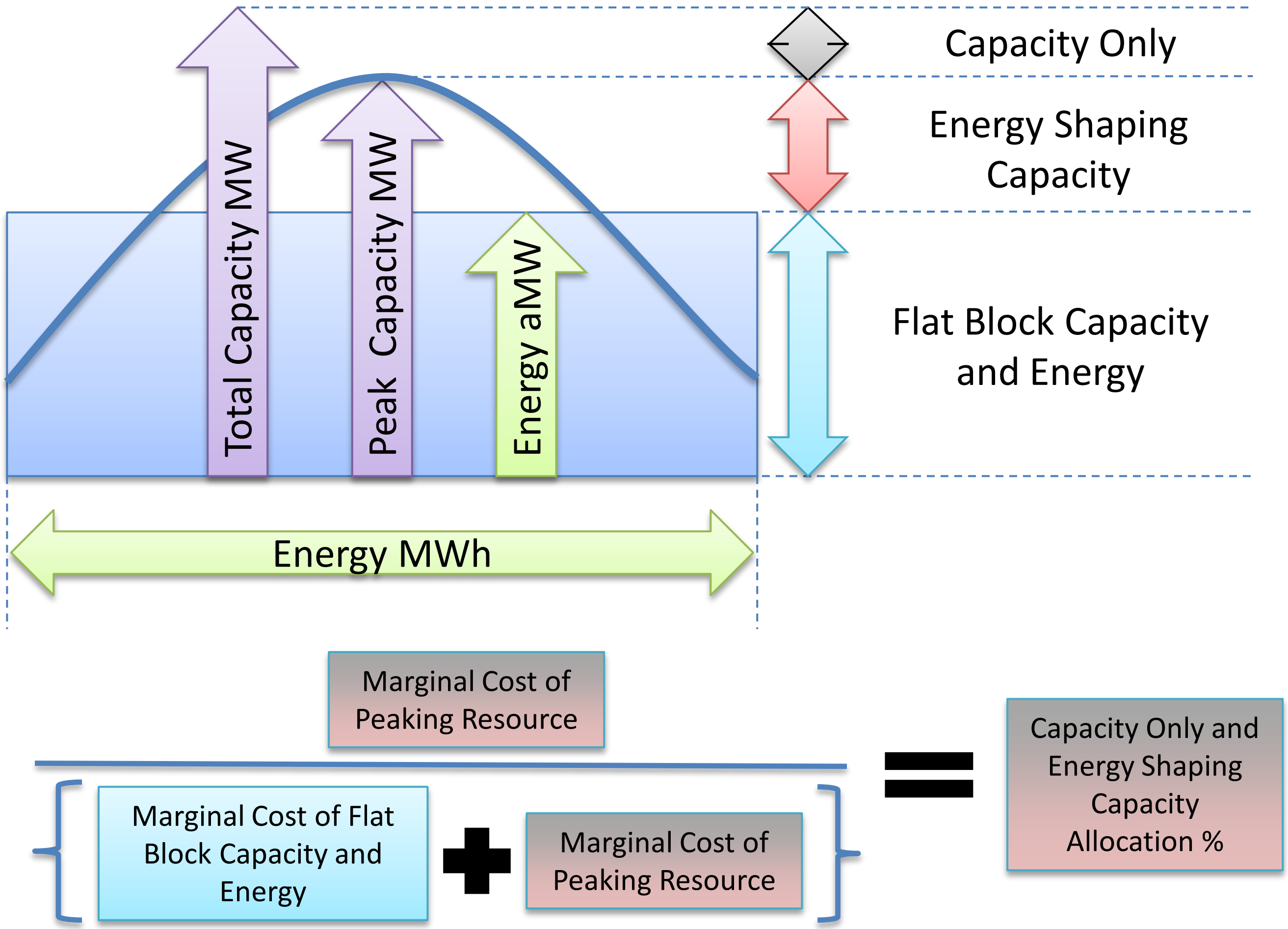


More Methods!?

- Yes, lots more. This is where the art of rate making comes into play.
- There are a wide range of acceptable cost classification methods – each tailored to the industry trend and utility situation at time of establishment.
- In addition to the **Max and Average Method** and **Load Factor Method**, BPA could use a **Marginal Cost Ratio Method** to classify its revenue requirement into capacity and energy costs.

Marginal Cost Ratio Approach

What would the proportion of costs be if we served with marginal resources?



Applying These Methods to Calculate BPA's Embedded Cost

- Method Status Quo – **Big 10 as revised** to accommodate debt refinancings – at this time it is unclear how this would be accomplished.
- Method A – **Max and Average** – Capacity and energy allocation set using ratio of:
  - Max monthly 1-hour critical water capacity + gen. input reserve capacity.
  - Average annual firm power sales not otherwise monetized.
- Method B – **Load Factor** without secondary energy credit and balancing purchase costs.
  - System load factor used to set energy allocation. Residual cost allocated to capacity.
  - This method is used by several other utilities with hydro resources to classify capacity and energy costs. Many of these utilities classify secondary energy sales and balancing purchases as energy-related credits and costs.
- Method C – **Load Factor** with secondary energy credit and balancing purchase costs.
  - Same as Method B, but with secondary energy revenue and balancing purchase costs allocated to energy and capacity services.
- Method D – **Marginal Cost Ratio** Independent Power Producer (IPP). Capacity cost allocation set on ratio of:
  - IPP financed General Electric LMS100 to value Capacity Only and Energy Shaping Capacity.
  - IPP financed Combined Cycle Gas Turbine to value Flat Block Capacity and Energy.
- Method E – **Marginal Cost Ratio** BPA Study. Capacity cost allocation set on ratio of:
  - BPA demand rate (public financed General Electric LMS100) to value Capacity Only and Energy Shaping Capacity.
  - BPA Aurora market price forecast to value Flat Block Capacity and Energy.

Potential Classification of Energy and Capacity Cost Methods

		A	B	C	D	E	
1	Method	Max and Average	Load Factor	Load Factor	Marginal Cost Ratio (LMS100 + CC)	Marginal Cost Ratio (Demand Rate + Aurora)	
2	Peak Capacity (Max Monthly 1-Hour Critical) (MW)	12,660	12,660	12,660	12,660	12,660	Input
3	Capacity Only (Reserve Provided by FCRPS) (MW)	1,242	-	-	1,242	1,242	Input
4	Total (A,D & E) or Peak Capacity (B & C) (MW)	13,902	12,660	12,660	13,902	13,902	Row2 + Row3
5	Average Energy (Critical) (aMW)	6,989	6,989	6,989	6,989	6,989	Input
6	(MW)	6,913	5,671	5,671	6,913	6,913	Row4 - Row5
7	Energy Allocation	33.5%					Row5 / (Row4 + Row5)
8	Capacity Allocation	66.5%					Row4 / (Row4 + Row5)
11							
12	BPA System Load Factor - Energy Allocation		55.2%	55.2%			Row5 / Row4
13	Capacity Allocation		44.8%	44.8%			100% - Row12
16							
17	Marginal Peaking Capacity ($/kW/mo)				$ 12.97	$ 9.88	Input
18	Marginal Flat Block Energy and Capacity ($/MWh)				$ 60.17	$ 25.36	Input
21	Marginal Peaking Cost (Energy Shaping Capacity & Capacity Only)				$ 1,075,939,320	$ 819,605,280	Row6 * Row17 * 12000
22	Marginal Cost Flat Block Energy and Capacity				$ 3,688,872,756	$ 1,554,758,403	Row5 * Row18 * 8772
23	Total Marginal Cost Denominator				$ 4,764,812,076	$ 2,374,363,683	Row21 + Row22
24	Marginal Flat Block Allocation %				77.4%	65.5%	Row22 / Row23
25	Marginal Energy Shaping Capacity and Capacity Only Allocation %				22.6%	34.5%	Row21 / Row23

* Method B and C include only Energy Shaping Capacity

		A	B	C	D	E		
	Method	Max and Average	Load Factor	Load Factor	Marginal Cost Ratio (LMS100 + CC)	Marginal Cost Ratio (Demand Rate + Aurora)		
	EMBEDDED COST ALLOCATION							
1	Total Power Revenue Requirement	$ 2,836,776,226	$ 2,836,776,226	$ 2,836,776,226	$ 2,836,776,226	$ 2,836,776,226	BP-16 Final Proposal	
2	Revenue Credits/1	$ (160,620,701)	$ (160,620,701)	$ (160,620,701)	$ (160,620,701)	$ (160,620,701)	Input	
3	Conservation Cost	$ (140,468,500)	$ (140,468,500)	$ (140,468,500)	$ (140,468,500)	$ (140,468,500)	Input	
4	Secondary Energy Credit	$ (469,175,060)	$ (469,175,060)		$ (469,175,060)	$ (469,175,060)	Input	
5	Balancing Purchase Costs			$ (14,002,066)			Input	
6	Remaining Revenue Requirement	$ 2,066,511,965	$ 2,066,511,965	$ 2,521,684,959	$ 2,066,511,965	$ 2,066,511,965	Sum(Row1 : Row5)	
7	Capacity Allocation	66.5%	44.8%	44.8%	22.6%	34.5%	Calculated on Classification Sheet	
8	Revenue Requirement Allocated to Capacity	$ 1,375,168,701	$ 925,656,324	$ 1,129,542,761	$ 466,637,811	$ 713,338,117	Row6 * Row7	
9	Unit Cost Denominator (MW)	13,902	12,660	12,660	6,913	6,913	Calculated on Classification Sheet	
10	Unit Cost of INC Capacity ($/kW/mo)	$ 8.24	$ 6.09	$ 7.44	$ 5.63	$ 8.60	Row8 / (Row9 * 12000)	
11	**RISK ALLOCATION**							
12	Subject to Proportional Share of Power Risk Mitigation	Yes	Yes	Maybe	Yes	Yes		
13	Balancing Reserves provided by FCRPS (MW)	733	733	733	733	733	Input	
14	Contingency Reserves provided by FCRPS (MW)	509	509	509	509	509	Input	
15	Balancing Reserves Self-Supplied by Power Services (MW)	-288	-288	-288	-288	-288	Input	
16	Revenue producing Gen Input Capacity (MW)	954	954	954	954	954	Sum(Row13 : Row15)	
17	Transmission Services or ACS Power DDC/CRAC Share	4.6%	3.4%	3.4%	3.1%	4.8%	Row16 / Row9 * Row7	
18	**VARIABLE COST ALLOCATION**							
19	DEC Variable Unit Cost $/kW/mo	$ 0.80	$ 0.80	$ 0.80	$ 0.80	$ 0.80		Method
20	Embedded INC and Var DEC Total Unit Cost $/kW/mo	$ 9.04	$ 6.89	$ 8.24	$ 6.43	$ 9.40	Row10 + Row19	1
21	INC Variable Unit Cost $/kW/mo	$ 0.99	$ 0.99	$ 0.99	$ 0.99	$ 0.99		
22	Embedded INC and Var DEC & INC Total Unit Cost $/kW/mo	$ 10.03	$ 7.88	$ 9.23	$ 7.42	$ 10.39	Row10 + Row19 + Row21	2
23			Embedded Cost	Variable + Direct	Overall	ACS Risk Share		
24	BP-14 Initial Proposal INC and DEC Unit Cost $/kW/mo		$ 6.93	$ 1.72	$ 8.65	8.20%		
25	BP-16 Final Proposal blind crank turn INC and DEC Unit Cost $/kW/mo		$ 7.41	$ 1.79	$ 9.20	8.20%		

/1 Equal to sum of (Downstream Benefits, Colville/Spokane Settlements, Green Tags, 4h10c, Contract Obligation Revenues, GTA revenues, WNP#3 settlement/Slice Adjustment, and Other Long-term Contract Revenues

Amount of DECs for BP-18

Beginning the Discussion

How Many DECs Should BPA Hold?

- In the process of settling the BP-16 Generation Inputs and ACS rates, BPA provided customers a table that estimated that financial tradeoff between paying BPA to hold DECs versus lost generation due to feathering events (limit events). *Note: We may also need to take into consideration the impact holding lower amounts of Dec reserves has on hydro operations, specifically the increased potential for over deployment under the current Operational Controls for Balancing Reserves (OCBR) protocol.*

- BPA had been holding 1,100 MW of DECs during the BP-14 rate period.

- In response to the financial tradeoff table (and settlement as a whole), customers agreed to lower the amount of DECs BPA would hold to 900 MW.

- The following tables refresh the costs of DEC table based on BP-16 Final Proposal values (energy shift, efficiency loss, cycling loss, deployment loss, spill loss, and market price forecast).

- The estimated number of feathering events ("limits") remain the same as the original tables shared during the BP-16 settlement discussions.

Economics of DECs

				Assumed Value $/MWh		$50		
Reserve Level	Limits Per Year (#)	Limits Per Month (#)	Average Limit Capacity (MW)	Average Limit Energy (MWh)***	Total Lost Gen(MWh)	Cost of Lost Gen Decs	Cost of FCRPS Decs	Total Cost of Decs
-700	198	17	395	198	39,204	$ 1,960,200	$ 1,141,686	$ 3,101,886
-750	154	13	401	201	30,954	$ 1,547,700	$ 1,506,106	$ 3,053,806
-800	120	10	396	198	23,760	$ 1,188,000	$ 1,870,526	$ 3,058,526
-850	94	8	393	196	18,424	$ 921,200	$ 2,234,946	$ 3,156,146
-900	**79**	**7**	**385**	**193**	**15,247**	**$ 762,350**	**$ 2,599,366**	**$ 3,361,716**
-950	68	6	372	186	12,648	$ 632,400	$ 2,963,786	$ 3,596,186
-1000	58	5	358	179	10,382	$ 519,100	$ 3,328,206	$ 3,847,306
-1050	43	4	348	174	7,482	$ 374,100	$ 3,692,626	$ 4,066,726
-1100	35	3	338	169	5,915	$ 295,750	$ 4,057,046	$ 4,352,796

*** Assumes Limit events last 45 minutes of the hour and the average generation lost is 2/3 of max.

				Assumed Value $/MWh		$100		
Reserve Level	Limits Per Year (#)	Limits Per Month (#)	Average Limit Capacity (MW)	Average Limit Energy (MWh)***	Total Lost Gen(MWh)	Cost of Lost Gen Decs	Cost of FCRPS Decs	Total Cost of Decs
-700	198	17	395	198	39,204	$ 3,920,400	$ 1,141,686	$ 5,062,086
-750	154	13	401	201	30,954	$ 3,095,400	$ 1,506,106	$ 4,601,506
-800	120	10	396	198	23,760	$ 2,376,000	$ 1,870,526	$ 4,246,526
-850	94	8	393	196	18,424	$ 1,842,400	$ 2,234,946	$ 4,077,346
-900	**79**	**7**	**385**	**193**	**15,247**	**$ 1,524,700**	**$ 2,599,366**	**$ 4,124,066**
-950	68	6	372	186	12,648	$ 1,264,800	$ 2,963,786	$ 4,228,586
-1000	58	5	358	179	10,382	$ 1,038,200	$ 3,328,206	$ 4,366,406
-1050	43	4	348	174	7,482	$ 748,200	$ 3,692,626	$ 4,440,826
-1100	35	3	338	169	5,915	$ 591,500	$ 4,057,046	$ 4,648,546

*** Assumes Limit events last 45 minutes of the hour and the average generation lost is 2/3 of max.

Historical Feather Events

Rate Period	Dec Reserves Held (MW)	Year	Month	Events
BP14	1,100	2014	July	2
BP14	1,100	2014	August	5
BP14	1,100	2014	September	1
BP14	1,100	2014	October	3
BP14	1,100	2014	November	0
BP14	1,100	2014	December	0
BP14	1,100	2015	January	1
BP14	1,100	2015	February	1
BP14	1,100	2015	March	2
BP14	1,100	2015	April	1
BP14	1,100	2015	May	1
BP14	1,100	2015	June	1
BP14	1,100	2015	July	0
BP14	1,100	2015	August	2
BP14	1,100	2015	September	0
BP16	900	2015	October	6
BP16	900	2015	November	3
BP16	900	2015	December	5
BP16	900	2016	January	7
BP16	900	2016	February	14

Source: https://www.bpa.gov/Projects/Initiatives/Wind/Pages/operational-controls.aspx

Total Events = 35
Average per month = 7