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-18 Power Rates Workshop

August 9, 2016

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Agenda Topic	Presenter
Loads & Resources and associated topics • Loads and Resources • Firm Surplus • Product Switching • Lost Creek/Green Springs Error	Tim Misley Tyler Llewellyn Steve Bellcoff Peter Stiffler
Gas and Market Price Forecast and Secondary Revenue Forecast	Eric Graessley James Vanden Bos Mitchell R. Green
Transmission Curtailment Management Service for Non-Firm Transmission	Annamarie Weekley Daniel Fisher
PNGC's Power Unauthorized Increase Charge Proposal (under separate cover)	Greg Mendonca, PNGC
Proposed BP-18 GRSP Clarification • Low Density Discount • Forced Outage Reserve Service and Resource Shaping Service • Unauthorized Increase (Appendix to Proposed BP-18 GRSP Clarification is under separate cover)	Annamarie Weekley Daniel Fisher Doug Gilmore
Transfer Service • Southeast Idaho Load Service • GTA Delivery Charge Rate • Transfer Service WECC Charge	Dan Yokota Derrick Pleger Jeff Hurt

Load & Resources
and associated topics

Tim Misley
Tyler Llewellyn
Steve Bellcoff
Peter Stiffler

General Hydro Updates

Pacific Northwest Coordination Agreement (PNCA) Project Data

- Updated based on 2016 PNCA data, with a couple of additional updates that will be part of next year's PNCA data. These updates include:
  - Grand Coulee storage table
  - Hungry Horse H/K table
  - Grand Coulee pumping

Canadian Operations

- Updated based on the 2018 Assured Operating Plan (AOP18) completed under the Columbia River Treaty. AOP19 is a roll-over year. These were the first AOPs created using the 80-year Modified Flows.

Project Outages

- Updated based on the latest long-term maintenance and capital program forecasts.

Reserves

- Updated FCRPS reserve assumptions based on input from the Generation Inputs panel.

Loads

- Updated based on latest forecasts produced by Agency Load Forecasting.

Spill Updates

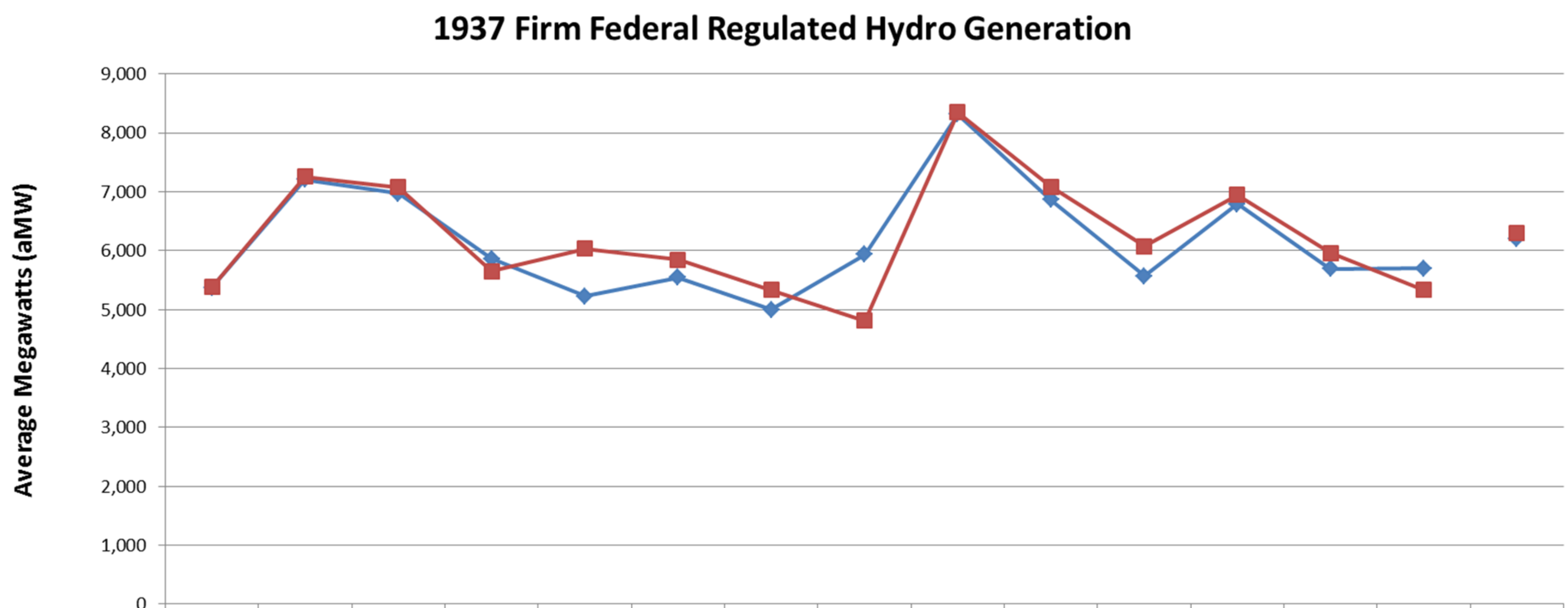
Early August Spill Curtailment

- Updated to reflect the most recent dates provided by the Corps:
  - Lower Granite: August 13th
  - Little Goose: August 19th
  - Lower Monumental: August 21st
  - Ice Harbor: August 22nd
- These dates are one to four days later than the dates in the last rate case (i.e., they extend the spill period).

Spring Maximum Transport in Dry Years

- Removed this no-spill assumption, which increases spill in 1937 and seven other water years.

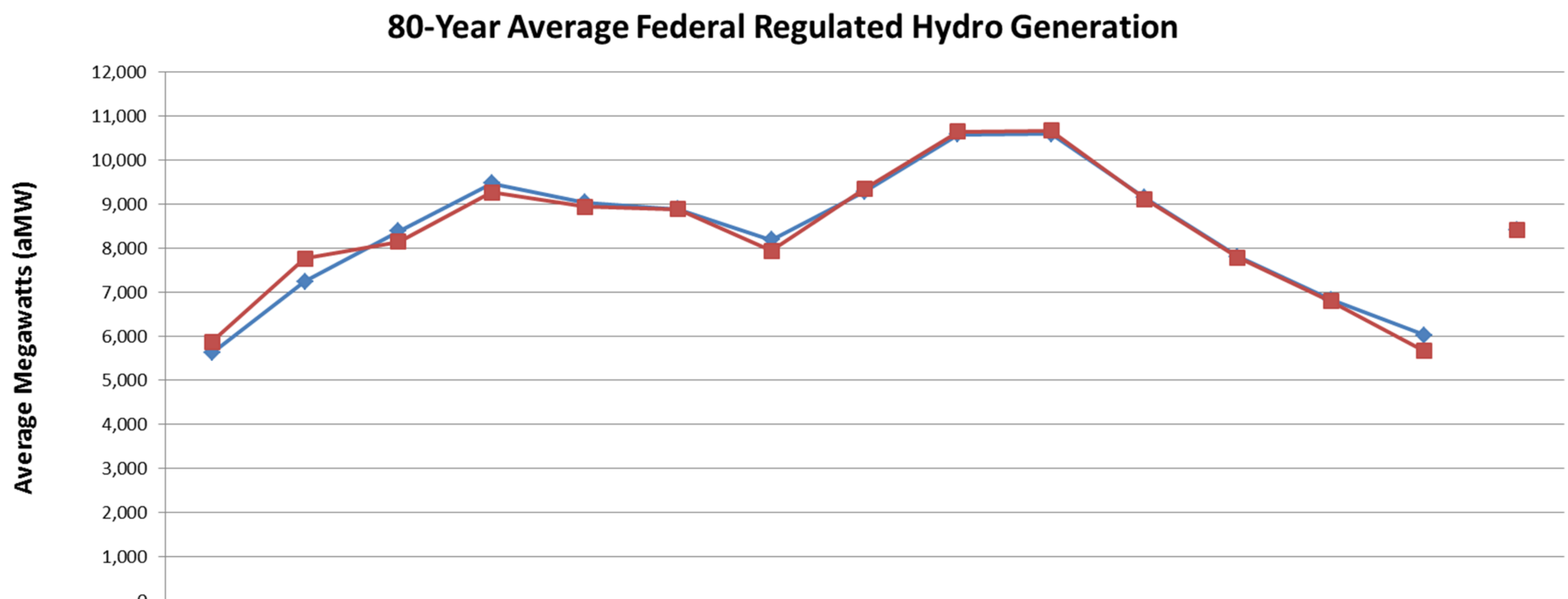
Firm Hydro Comparison



	Oct	Nov	Dec	Jan	Feb	Mar	AprI	AprII	May	Jun	Jul	AugI	AugII	Sep	Annual
BP-18 Initial	5,371	7,210	6,973	5,863	5,228	5,546	4,998	5,936	8,310	6,861	5,571	6,792	5,691	5,702	6,201
BP-16 Final	5,381	7,258	7,072	5,651	6,030	5,848	5,335	4,813	8,349	7,080	6,071	6,946	5,961	5,334	6,302
Difference	-10	-49	-99	212	-801	-302	-337	1,124	-39	-219	-500	-154	-270	369	-102

- The loss of just over 100 aMW of firm energy is primarily caused by less outflow from Canadian projects in 1937, more Grand Coulee pumping, and the removal of the maximum transport no-spill assumption. Further, due to the changes in inflow, Grand Coulee drafts deeper November through February, resulting in head losses.

Average Hydro Comparison



	Oct	Nov	Dec	Jan	Feb	Mar	AprI	AprII	May	Jun	Jul	AugI	AugII	Sep	Annual
BP-18 Initial	5,631	7,250	8,395	9,482	9,041	8,895	8,193	9,294	10,590	10,598	9,154	7,817	6,840	6,029	8,425
BP-16 Final	5,879	7,771	8,147	9,268	8,944	8,886	7,947	9,360	10,651	10,670	9,116	7,791	6,801	5,675	8,410
Difference	-248	-522	248	214	97	9	245	-66	-62	-72	39	26	39	355	15

- There is a slight gain of 15 aMW in 80-year average energy. Dworshak has the largest increase in generation of 20 aMW, which is due to higher availabilities that reduce forced spill in some months.

BP-18 Preliminary Load Forecast
2-Year Average Comparison:
FY 2018-2019 & BP-16 Final Rate Case (FY 2016-2017)

- **Total Federal Firm Load Obligation are lower by -130 aMW**
  - **Firm Obligations lower by -134 aMW**
    - Lower Tier 1 contract obligations (-95 aMW)
    - Reduced Tier 1 Block (-15 aMW)
    - Reduced Slice obligations (-8 aMW)
    - Decreased DSI Alcoa obligation (-17 aMW)
  - **Other Contract Obligations lower by -50 aMW**
    - Expiration BPA/BHEC (-6 aMW)
    - Expiration BPA/PG&E wind shaping (-17 aMW)
    - Expiration BPA/AVWP WNP-3 Set. (-35 aMW)
    - Updated BPA/PSE WNP-3 Set. (+9 aMW)
  - **Contract Firm Surplus Sales increased by +53 aMW**
    - Updated Firm Surplus Sales (+53 aMW)

BP-18 Preliminary Resource Forecast

2-Year Average Comparison (1937 Critical Water): FY 2018-2019 & BP-16 Final Rate Case (FY 2016-2017)

- **Total Federal firm resources are lower by -130 aMW**
  - **Hydro Generation forecast lower by -115 aMW**
    - Lower outflows from Canadian project, more GCL pumping, the removal of max transport no spill assumption in second year of study; and changes in GCL outflows drafting deeper in Nov-Feb resulting in head losses (-101 aMW)
    - Removal of Idaho Falls Bulb turbines (-14 aMW)
  - **Other Resource forecast increased by +16 aMW**
    - Expiration of Wauna purchase (-5 aMW)
    - CGS generation forecast (+23 aMW)
    - Wind generation forecast (-2 aMW)
  - **Contract Purchase forecast lower by -18 aMW**
    - Expiration BPA/RVSD CNX/SNX (-7 aMW)
    - Expiration BPA/PG&E wind shaping (-10 aMW)
  - **Reserves and Transmission losses forecast increased by +2 aMW**
  - **System augmentation forecast decreased by -15 aMW**

BP-18 Preliminary Load Forecast
Detailed 2-Year Average Comparison: FY 2018-2019 & BP-16 Final Rate Case (FY 2016-2017)

	2-Year Average Comparison BP-18 Initial 8/3/2016 and BP-16 Final 5/21/2015 *(Energy in aMW)*	BP-18 Initial Study (FY18-19)	BP-16 Final Study (FY16-17)	Difference 2-Year Average	Comment
	Federal Load Obligations				
1.	**Firm Obligations**	**6,997**	**7,131**	**-134**	**Firm obligation changes:** - Lower Tier 1 contract obligations (-95 aMW) - Reduced Tier 1 Block (-15 aMW) - Reduced Slice obligations (-8 aMW) - Decreased DSI Alcoa obligation (-17 aMW)
2.	*Load Following*	*2,984*	*3,080*	*-95*	
3.	*Federal Agencies*	*119*	*117*	*3*	
4.	*USBR*	*183*	*184*	*-1*	
5.	*Tier 1 Block*	*0*	*15*	*-15*	
6.	*Slice Block*	*1,790*	*1,798*	*-8*	
7.	*Slice Output from T1 System*	*1,847*	*1,847*	*0*	
8.	*DSI Obligations*	*74*	*91*	*-17*	
9.	**Other Contract Obligations** *(w/o Firm Surplus Sales)*	**551**	**601**	**-50**	**Other contract obligaton changes:** - Expiration BPA/BHEC (-6 aMW) - Expiration BPA/PG&E wind shaping (-17 aMW - Expiration BPA/AVWP WNP-3 Set. (-35 aMW) - Updated BPA/PSE WNP-3 Set. (+9 aMW)
10.	*Exports*	*491*	*515*	*-24*	
11.	*Intra-Regional Transfers (Out)*	*60*	*86*	*-26*	
12.	**Firm Surplus Sale**	**90**	**37**	**53**	**Combination of load and resource updates**
13.	**Total Firm Obligations** *(Sum lines 1+9+12)*	**7,639**	**7,769**	**-130**	

BP-18 Preliminary Resource Forecast

Detailed 2-Year Average Comparison (1937 Critical Water): FY 2018-2019 & BP-16 Final Rate Case (FY 2016-2017)

	2-Year Average Comparison BP-18 Initial 8/3/2016 and BP-16 Final 5/21/2015 *(Energy in aMW)*	BP-18 Initial Study (FY18-19)	BP-16 Final Study (FY16-17)	Difference 2-Year Average	Comment
	Federal Resources				
14.	**Net Hydro**	**6,590**	**6,705**	**-115**	**Hydro generation forecased were reduced:** - Lower outflows from Canadian porject, more GCL pumping, the removal of max transport no spill assuption in second year of study; and changes in GCL outflows drafting deeper in Nov-Feb resulting in head losses (-101 aMW) - Removal of Idaho Falss Bulb turbines (-14 aMW)
15.	*Regulated Hydro - Net*	*6,248*	*6,349*	*-101*	
16.	*Independent Hydro - Net*	*339*	*353*	*-14*	
17.	*Small Hydro Resources*	*3*	*3*	*0*	
18.	**Other Resources**	**1,077**	**1,061**	**16**	**Other Resouces changes:** - Expiration of Wauna purchase (-5 aMW) - CGS generation forecast (+23 aMW) - Wind generation forecast (-2 aMW)
19.	*Cogeneration Resources*	*0*	*5*	*-5*	
20.	*Large Thermal Resources*	*1,019*	*996*	*23*	
21.	*Renewable Resources*	*58*	*60*	*-2*	
22.	**Contract Purchases** *(w/o Augmentation)*	**193**	**210**	**-18**	**Contract purchase changes:** - Expiration BPA/RVSD CNX/SNX (-7 aMW) - Expiration BPA/PG&E wind shaping (-10 aMW)
23.	*Imports*	*1*	*8*	*-7*	
24.	*Intra-Regional Transfers (In)*	*20*	*30*	*-10*	
25.	*Non-Federal CER*	*136*	*137*	*-1*	
26.	*Slice Transmission Loss Return*	*35*	*35*	*0*	
27.	**Reserves & Losses**	**-236**	**-238**	**2**	**Changes in Federal resource stack (+2 aMW)**
28.	*Transmission Losses*	*-236*	*-238*	*2*	
29.	**Total Net Resources** *(Sum lines 14+18+22+27)*	**7,624**	**7,738**	**-115**	
30.	**System Augmentation**	**15**	**31**	**-15**	
31.	**Total Resources w/Augmentation** *(Sum lines 29+30)*	**7,639**	**7,769**	**-130**	
32.	**Federal Surplus/Deficit** *(Sum lines 31 less line 13)*	**0**	**0**	**0**	

Firm Surplus

- In BP-16, firm surplus was embedded in the net secondary calculation for the FY 2016-2017 rate period.
- While this modeling results in correct allocation of costs and credits, a more straightforward approach would be to assume a firm surplus sale at the weighted-average secondary price (as a flat block) to get to load-resource balance.
  - Such an approach would be consistent with modeling of a system augmentation purchase when critical generation is less than load obligations.
- BPA expects to be firm-surplus again for the FY 2018-2019 rate period, and plans to assume a firm surplus sale in getting to load-resource balance before computing net secondary allocated to the Non-Slice Customer Charge.
- The firm surplus sale will be allocated to the Non-Slice Customer Charge, since the existence of firm surplus does not affect the amount of secondary energy the Slice product receives in kind.

Product Switching

- Three customers have indicated an intent to switch products. Under the terms of the Regional Dialogue Power Sales Agreements, the anticipated start date is October 1, 2019.
- Klickitat PUD and Seattle City Light requested an early change in their purchase obligations. These customers requested that the change be effective October 1, 2017.
- BPA previously stated in its October 2008 Long-Term Regional Dialogue Contract Policy Record of Decision that it would consider requests to change purchase obligations outside of the timing in section 11 of the Agreement on a case-by-case basis as long as it does not shift costs or risks to BPA and its other customers.
- BPA performed rate and risk analysis of the customers' request to change purchase obligations.
- BPA has determined that if Klickitat PUD and Seattle City Light were allowed to convert to their requested purchase obligations in October 2017, the conversion would neither impose added financial risks on BPA nor create undue cost shifts to other customers.
- As a result, BPA:
  - Proposes to allow these two customers to switch their purchase obligations early; and
  - Proposes not to assess charges to the customers per section 11.1.1 of the Agreement except those charges determined in the rate case to be necessary to ensure that debt actions BPA has taken with timing impacts that differ between products are accounted for properly.

Product Switching and Timing

- The decision to allow an early switch for Klickitat PUD and Seattle City Light is pending.
  - The Customer Comment period recently ended on August 1.
  - BPA is evaluating the comments and plans to issue a decision by the end of August.
- Given the timing, BPA therefore plans to assume no product switching in the Initial Proposal modeling.
- If BPA decides to allow customers to switch products beginning FY 2018, BPA will address any associated issues in testimony. BPA will incorporate these final determinations in Final Proposal modeling and rates.
  - If customers are allowed to switch products beginning FY 2018, BPA anticipates it will propose a mechanism in the BP-18 rate case so that the two former Slice customers will not receive the benefits of Regional Cooperation Debt actions that they had already received as Slice customers in the BP-14 rate period.
  - It is estimated that this proposed customer-specific charge will be about ~$4 million for Seattle City Light and less than ~$300,000 for Klickitat PUD.

Lost Creek/Green Springs Error

- For BP-12, BP-14 and BP-16, BPA allocated “Third Party Transmission & Ancillary Services” in the revenue requirement to the Non-Slice cost pool.
- This allocation is consistent with the initial allocation determinations made in the TRM, Table 2.
- However, to be consistent with cost causation principles in the TRM, these costs should have been allocated to the Composite cost pool.
  - These costs are largely associated with federal generation located outside BPA’s balancing authority area, and delivered to BPA under OATT.

Lost Creek/Green Springs Error

- The dollar value of the misallocation totals ~$2.1 million per year for FY 2012-2017, for a total of ~$12.8 million.
- Slice customers should have paid 27% of the total ~$12.8 million, or $3.5 million.
- BPA currently proposes either:
  - A one-time Slice Adjustment Charge, similar to the charge implemented in BP-16 to correct for the misallocation of PGE WNP#3 Settlement revenues for FY 2012-2015, or
  - To make a correction moving forward only, with no Slice Adjustment Charge.
- The decision will be largely determined by the outcome of the Error Correction Policy discussions.

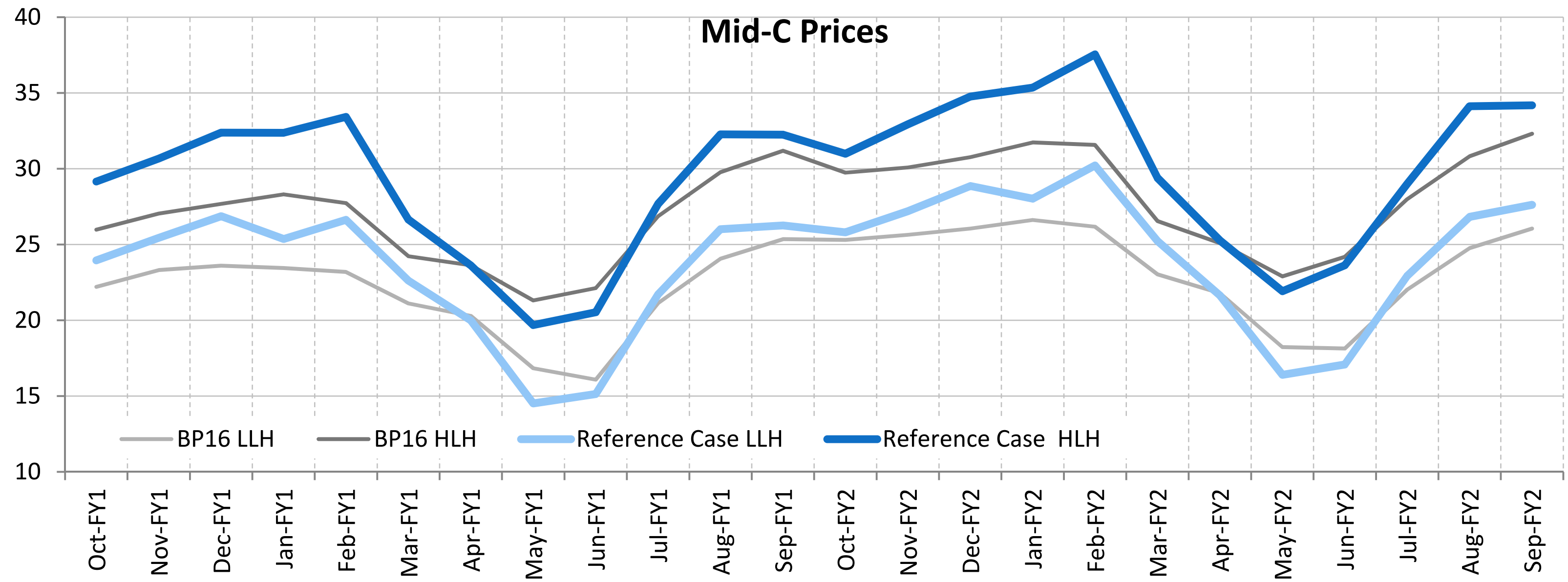
Gas and Market Price Forecast and Secondary Revenue Forecast

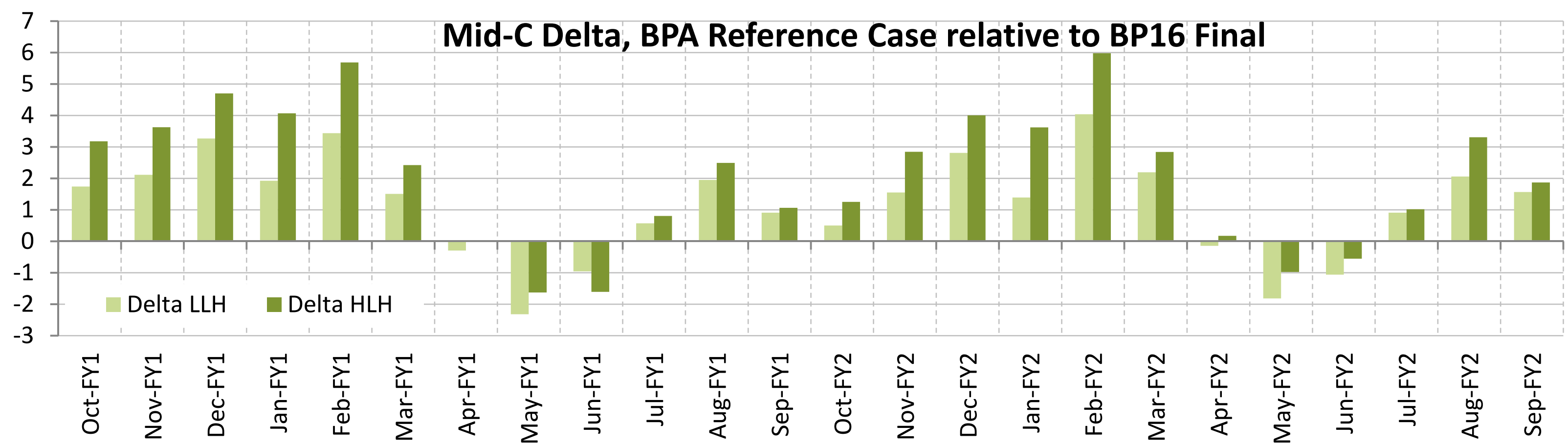
Eric Graessley
James Vanden Bos
Mitchell R. Green

Electricity Market Prices

- Continue to use AURORA to value secondary market energy
- Model changes from BP-16 Final Proposal:
  - Natural gas forecast
  - Long-term resource build (including recent changes to RPS targets)
  - Incorporated California carbon pricing
  - New AURORA zonal topology
  - Hydro generation

BPA Reference Case (Spring 2016) compared to BP-16 Final (nominal $/MWh)

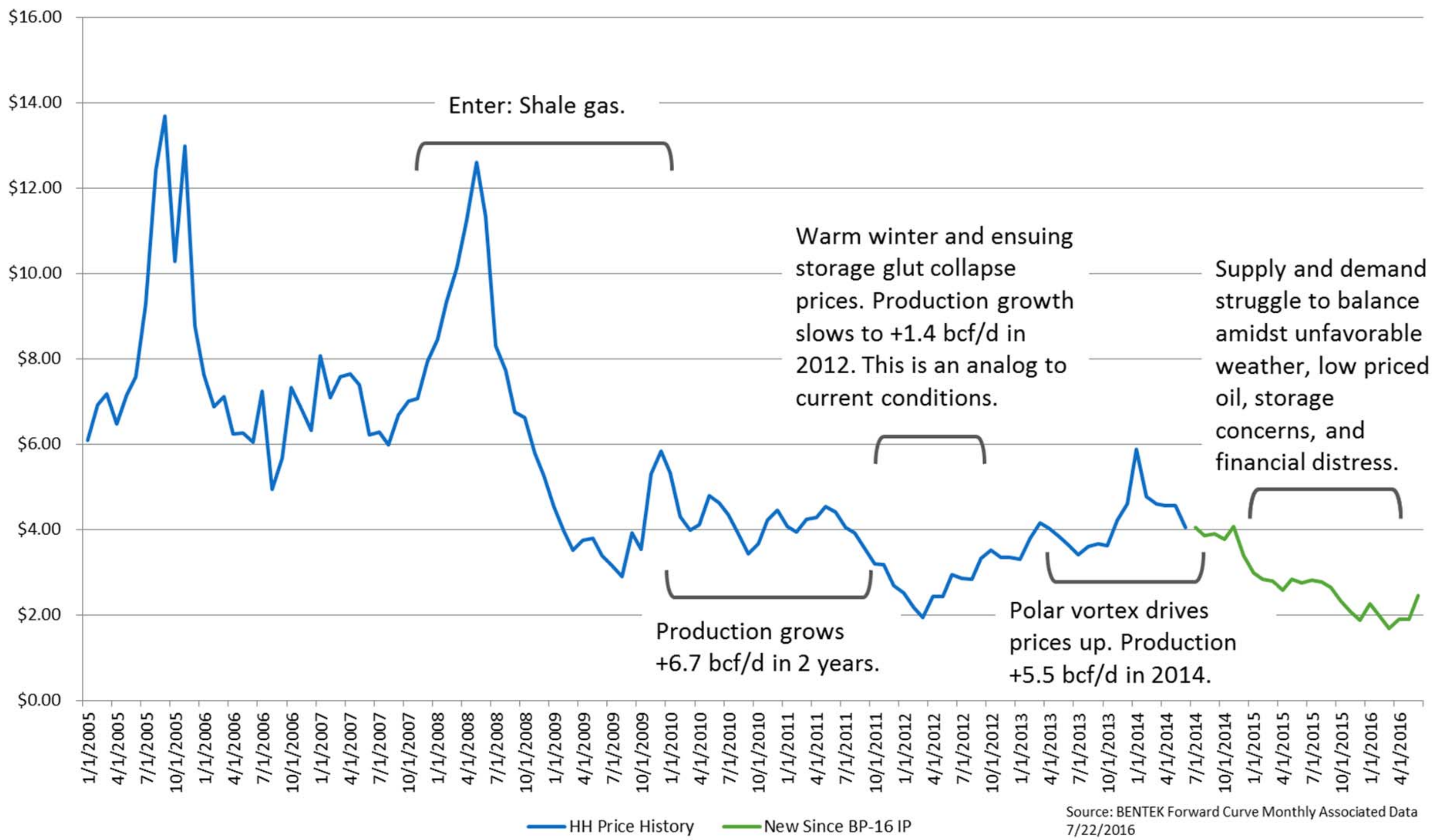




Anticipated Updates for BP-18 Initial Proposal

- Natural Gas Forecast
- New AURORA version
- Under consideration:
  - Negative prices for renewables throughout WECC
  - Modifications to California market
    - Load forecast
    - Distributed generation forecast
    - RPS buildout (composition and solar capacity factors)
- Routine updates to ensure risk model inputs are up to date

Context – Henry Hub Price History



Key Drivers for Next 3 Years

Demand

- LNG Exports: Incremental exports of 3.0 - 3.5 bcfd by FY 2019. (Actual capacity is higher, utilization is price sensitive.)
- Industrial Demand: Incremental demand of 1.7 - 2.4 bcfd by FY 2019.
- Mexican Exports: Incremental export of 1.0 - 1.5 bcfd by FY 2019.
- Power Burn should also remain a strong contributor. **Coal retirements and new installed gas capacity should counteract higher prices.**

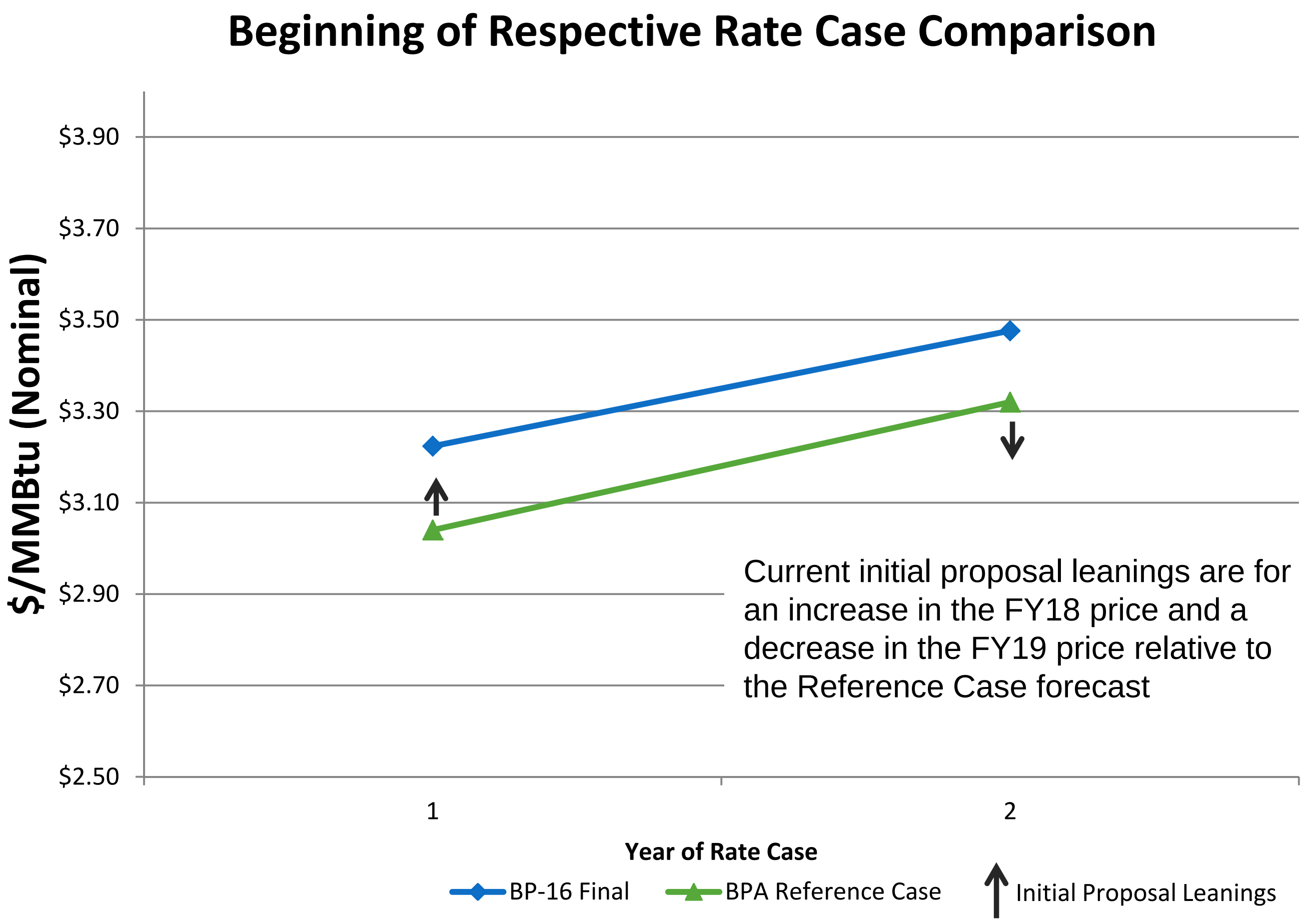
Supply

- **Rig counts have plummeted, but seem to have bottomed out.**
- Supply has remained astoundingly resilient. **However, the February record peak (74.6 bcfd) has transitioned to Y/Y declines (-1.4 bcfd for June).**
- US Production is expected to rebound in FY 2017 and grow by 9+ bcfd by FY 2019.

Uncertainty

- Weather: For sake of modeling and planning, assume normal weather.
- Rate of technological advancement: What can the industry do with these low rig counts? How far have production costs fallen?
- What does the production rebound look like?
- Take-away capacity constraints in the NE.
- Utilization rate of LNG export terminals.

Henry Hub Price Outlook



Secondary Revenue Forecast

Accounting for value of extra-regional sales

Background

- Parties to the BP-16 rate case challenged the practice of modeling NSR on Mid-C prices alone.
- Parties to the BP-16 rate case also argued for a $25 million credit to NSR.
- The BP-16 Record of Decision allowed for an ad hoc $10 million credit and agreed to a public process to explore modeling changes to NSR forecasts.

Public Process

- Oct 22, 2015 – Explained forecasting methodology
- Feb 17, 2016 – Considered stakeholder proposals

PPC/ICNU Proposal

- Summary: Adds a dispatch procedure that seeks to maximize revenues, subject to transmission constraints and available inventory, by prioritizing sales at hubs (Mid-C, COB, NOB) with highest relative value.

PPC/ICNU Proposal

Mechanics

For each iteration of a given AURORA run:

1. Determine the relative price-spread combinations between four pricing nodes: Mid-C, NP15, SP15, and COB.
2. Determine whether inventory exists for surplus sales.
3. Determine transmission capacity along PDCI and COI.
4. Given the results of items 1-3, carve out surplus inventories to be sold at merit-order until all surpluses are exhausted.

BPA Evaluation

- BPA intends to reflect the value of extra-regional sales in the secondary revenue forecast used for the BP-18 initial proposal.

- BPA will include the proposed PPC/ICNU methodology, or some variant, as an enhancement to RevSim.

Transmission Curtailment Management Service for Non-Firm Transmission (TCMS)

Annamarie Weekley
Daniel Fisher

TCMS

As part of the Resource Support Services available to customers using non-Federal resources, Power Services provides Transmission Curtailment Management Service (TCMS) to qualifying customers taking Transmission Scheduling Service from BPA.

- TCMS is a service option within TSS that BPA provides when a customer’s scheduled resource cannot be delivered to the customer’s load as planned due to congestion or a transmission outage (either full or partial).
- When there is a transmission event that affects the path the customer is using to deliver its non-Federal resource, BPA will “buy around” the outage or curtailment.
  - BPA will either procure (or source from the Federal system) replacement energy (for a curtailment) or procure replacement transmission (for an outage).

TCMS

- The TCMS rate has only been available to customers delivering non-Federal resources on firm transmission or to customers in the process of obtaining firm transmission.
- During the recent Transmission Load Service discussions, Load Following customers requested TCMS for non-firm transmission schedules as well.

TCMS

- In response to customers' request, during BP-18 BPA will propose to make this service available to Load Following customers using non-Federal purchases delivered at Mid-C on non-firm NT transmission schedules.
  - The proposed rate structure will be similar to the current Transmission Services' Energy Imbalance charge (index plus bands depending on the amount of energy).
  - Currently, customers receiving TCMS rarely use it and it is anticipated that changing the pricing structure to align with Transmission Services' EI charges would have a very minimal cost impact on the customers currently taking this service.

TCMS

BPA is proposing a TCMS pricing structure based on BPA's Transmission Services EI Charge:

- Band 1: deviations equal to or less than 1.5 percent of the scheduled amount of energy, or 2MW (whichever is greater) = BPA's incremental cost* based on the applicable average HLH and LLH incremental costs for the month.
- Band 2: deviations greater than 1.5 percent of the scheduled amount of energy, or 2MW (whichever is greater), up to and including 7.5 percent of the scheduled amount of energy or 10MW = 110 percent of BPA's incremental cost.
- Band 3: deviations greater than 7.5 percent of the scheduled amount of energy, or greater than 10MW (whichever is greater) = 125 percent of BPA's incremental cost.

* BPA's incremental cost will be based on an hourly energy index in the Pacific Northwest (typically Powerdex Mid-C). This would be the same index used for the EI rate.

Proposed BP-18 GRSP Clarification

Annamarie Weekley
Daniel Fisher
Doug Gilmore

Proposed BP-18 GRSP Clarification

- Low Density Discount language will be updated to more clearly reflect the application of the phase-in adjustment.
- Forced Outage Reserve Service and Resource Shaping Service billing determinant descriptions will be updated to clarify types of planned generation and align more clearly with language in the RD contracts.
- Unauthorized Increase will be updated to clarify when the charge applies to Block customers, or the Block portion of the Slice/Block product, and to align with the RD contract terms.
- See Appendix for proposed language.

Transfer Service

Dan Yokota
Derrick Pleger
Jeff Hurt

Changes or New Issues for Transfer Service in BP-18

- No major policy or ratemaking changes from BP-16 for Transfer Service.

- Cost of full SILS service will be experienced for first time.
  - On July 1, 2016, Bonneville's service to its customers in Southern Idaho converted to PacifiCorp's Open Access Transmission Service (OATT).
  - Bonneville now will pay PAC's OATT transmission charges for service to these loads.
  - Bonneville acquisition costs for market purchases (SILS, see next slide).

Southeast Idaho Load Service (SILS)

- Reminder that for the first time, the full annual cost of the market purchases used to serve South Idaho Loads will be reflected in FY 2018-2019 rates.

- Composite cost pool will be allocated the delta between the ICE forward market at the time of the purchase and the cost of the five (5) year market purchases.
  - ~$11 million or ~$5.5 million in each FY.

- Non-Slice cost pool will be allocated the remainder.
  - ~$77 million or ~$38.5 million in each FY.

Forecast of the Transfer Service Budget

- **Transfer Service General Costs**
  - In FY 2016-2017, Transfer Services' budget was forecasted to be $78.2M on an annual average basis.

  - For FY 2018-2019, Transfer Services' budget is forecasted to be $89.2M on an annual average basis. This is an increase of 14%.
    - The main drivers of the increase are:
      - Avista ancillary service rate increase.
      - Idaho Power increase due to PAC/IPC asset exchange.
      - SILS full application through the FY 2018-2019 rate period.

GTA Delivery Charge Rate

- Background
  - First applied in 2002 and designed to recover costs associated with low voltage and distribution level transmission facilities that BPA pays to third party transmission providers for service to Transfer Customers below 34.5 kV points of delivery (low voltage).
  - Applies to all transfer customers that take low voltage delivery unless costs are directly assigned to customers.
  - Prior to the BP-14 rate case, the GTA Delivery Charge rate was set to mirror BPA Transmission Services' Utility Delivery (UD) Rate.
  - Since the BP-14 rate case, Power Services has established the GTA Delivery Charge rate independent of the UD Rate.
    - The rate is based on low voltage transfer costs.
    - The billing determinant was changed to the customer system peak.

GTA Delivery Charge Rate Calculation

- Methodology
  - No proposed changes from the methodology used in the BP-16 rate case.
  - **GTA Delivery Charge Revenue Requirement** – Computed using FY 2014 and FY 2015 transmission provider invoices (for Initial Proposal) for low voltage distribution, delivery charges, and contract exhibits. Values are then computed to generate an annual average for the two years. This average serves as the numerator in the GTA Delivery Charge rate calculation.
  - **GTA Delivery Charge Billing Determinant** – The FY 2014 and FY 2015 Customer System Peaks are determined by reviewing customer bills and extracting customer load data for the low voltage PODs at customer system peak. The annual average is then computed for the two-year period. This average serves as the denominator in the GTA Delivery Charge rate calculation.
  - The calculation of the BP-18 GTA Delivery Charge rate in the Final Proposal will use FY 2015 and FY 2016 data.

GTA Delivery Charge Rate Comparison

- Comparison of preliminary BP-18 to BP-16 rate

Comparison	**FY16-17**	**FY18-19**	**Difference**	**% Change**
Distribution and Low Voltage Costs Average	$2,109,973	$2,971,178	$861,205	41%
BPA Customer System Peak Average	2,235,919	2,285,320	49,402	2%
Proposed Rate	**$0.94**	**$1.30**	**$0.36**	38%

- Factors behind the difference:
  - Increase in costs
    - Avista $720,000 cost increase due to first rate increase since 1998.

Transfer Service WECC Charge

- No change, will remain at 0.03mills/kWh.
- No Peak Dues Rate for Transfer Customers.
  - Peak funded through agreements with each Balancing Authority Area.