BP-20 Rate Case Workshop: Transmission Rates

June 14, 2018

Agenda

- May 30 Workshop Follow-up Items
- Load Forecasting Overview
- Overview of Unauthorized Increase Charge
- Segmentation: Future Plant
- Proposed Rate Schedule Changes
- Next Steps

May 30 Workshop Follow-up Items

Follow-up Items from May 30 Meeting

Description	Where it will be Addressed	Due Date
Reconciliation of Total Plant with Segmented Historical Investment	Addressed in current presentation	6/14/2018
Direct labor costs by segment in the segmentation study	The detailed direct labor costs by segment were not studied and would take extensive resources to produce. We have provided the detail used to develop the O&M table. See the BP-20 Meetings and Workshops page.	6/14/2018
Detailed segmentation investment	See BP-20 Meetings and Workshops page	6/14/2018
Detailed segmented O&M costs	See BP-20 Meetings and Workshops page	6/14/2018
Comparison of Future Plant FY 17 Forecast to Actuals	Addressed in current presentation	6/14/2018
FY 17 Tag Data for Scheduling, System Control and Dispatch (schedule data)	See BP-20 Meetings and Workshops page. Customers will have until June 28 to submit SCD rate design alternatives for consideration.	SCD rate design alternatives due 6/28/2018

Segmentation Follow-up: Segmentation Components

Description	$ in Millions	
Non-Transmission Plant	193	Assets not used for investment allocation factor for segements
Land	221	
Gen Plan (unsegmented)	1,091	
Funded in Advance	191	
Segmented Lines and Substations	7,623	====>>>>> Used for as the total then segmented to get allocation factors by segments
Ancillary Services	213	====>>>>>> Stand alone investment segment not used for allocation
Transmission Plant (unsegmented)	179	====>>>>>> Allocated based on Segmented Lines and Substation allocation factors
Total BPA Transmission Plant	$ 9,711	

O&M Direct Labor Costs by Segment

- Currently we do not have O&M direct labor by segment.
- The direct labor is included in the program costs
  - It would take extensive resources to produce and analyze this information
  - We do not use the direct labor detail by segment in our study
- We have included the O&M cost details on the rate case website for customer review

Segmentation Follow Up:
Example of Lines and Subs Investments

Sub-Stations							
Location	**FY 17 Investment**	**FY 16 Investment**	**Delta**	**% Change**	**17 Inv Ntw**	**17 Inv IS**	**Notes**
MCNARY SUBSTATION	126,075,896	87,957,229	38,118,667	43%	114,272,704		$25M for 3 new Transformers, 2.5 M for new foundations, 2.2M for Limit Reactors, 1.5 M for new BUS, 1.1M for new Circuit breaker. Other smaller investments
ALVEY SUBSTATION	69,903,517	54,224,662	15,678,856	29%	61,333,694	8,569,823	5.1M for 2 limit reactors, 2.6M for swtchbrds, 2.6 for 2 circuit breakers, 900k for foundations. Other smaller investments.
Lines							
Location Name	**FY 17 Investment**	**FY 16 Investment**	**Delta**	**% Change**	**17 Inv Ntw**	**17 Inv IS**	**Notes**
CELILO-SYLMAR NO 1 (ML LAKE CO)	30,857,739	-	30,857,739	100%		30,857,739	30M for a new line and hardware
CELILO-SYLMAR NO 1	54,618,487	27,022,357	27,596,130	102%		54,618,487	32M for a road
CELILO-SYLMAR NO 1 (ML WASCO CO)	13,513,878	-	13,513,878	100%		13,513,878	13.5M for a new line.
CELILO-SYLMAR NO 1 (ML CROOK CO)	8,116,987	-	8,116,987	100%		8,116,987	8M for a new line
CELILO-SYLMAR NO 1 (ML DESCHUTES CO)	7,152,331	-	7,152,331	100%		7,152,331	6.8M for a new line
CELILO-SYLMAR NO 1 (ML JEFFERSON CO)	6,979,118	-	6,979,118	100%		6,979,118	6.9M for a new line

Segmentation Follow Up:
Plant in Service Forecast vs. Actuals

FY16 Actuals	Generation Integration	Network	Southern Intertie	Eastern Intertie	Utility Delivery	DSI Delivery	Segmented Total
Lines & Subs Total	111,279	6,203,536	989,009	123,264	13,691	8,297	7,449,074

FY17 Actuals	Generation Integration	Network	Southern Intertie	Eastern Intertie	Utility Delivery	DSI Delivery	Segmented Total
Lines & Subs Total	131,505	6,416,142	1,106,924	123,398	15,024	8,581	7,801,574
FY17 Additions	20,226	212,606	117,915	134	1,333	284	352,500

PIS Forecast	Generation Integration	Network	Southern Intertie	Eastern Intertie	Utility Delivery	DSI Delivery	Total
Lines & Subs BP16 RC for FY17	-	307,620	322,753	87	46	-	630,506
Delta	(20,226)	95,014	204,838	(47)	(1,287)	(284)	278,006

Scheduling, System Control and Dispatch Data

- The FY 2017 tag data for SCD is posted
- Customers will have until June 28, 2018 (two week extension) to review the data and suggest SCD rate design alternatives for us to consider.
- Customers are encouraged to suggest other alternatives.
- Staff aims to present the customer impact and evaluation of each rate design alternative, along with staff’s leaning for the Initial Proposal at the July 18, 2018 workshop.
  – Customers are welcome to present their alternatives and their own evaluation. Please contact Rebecca Fredrickson at refredrickson@bpa.gov if you would like time on the July 18 workshop agenda.

Load Forecasting Overview

Transmission Peak Types

(graph referenced throughout the presentation)

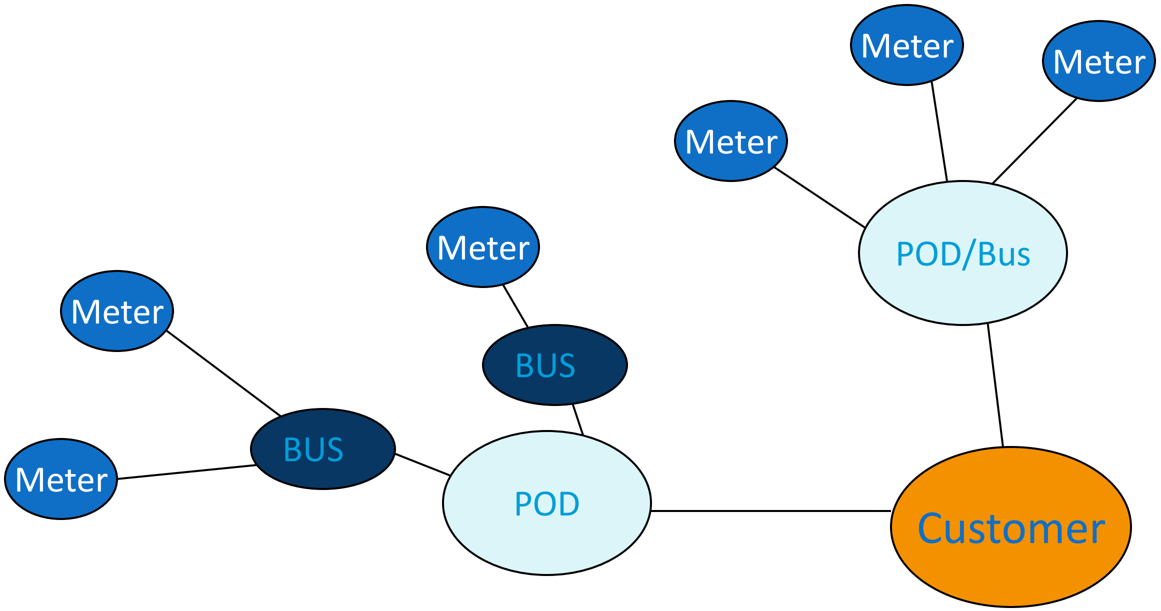
Terminology – Keeping All the Terms Straight

- What does Coincident Peak (CP) load mean?
  - Generally, coincident peak is a measure of load at the same time (coincident) that another measure is highest.
  - For Rate purposes, a customer's CP load is the sum of the customer's individual meters, integrated over the hour of the Federal Columbia River Transmission System (FCRTS) Monthly Transmission System Peak Load. *(point D on graph)*
- What is the Monthly Transmission System Peak Load?
  - The peak load on the FCRTS during the designated billing month, determined by the largest hourly integrated demand produced from the sum of the Federal and non-Federal generating plants in BPA's Control Area and net metered flow into BPA's Control Area (aka Total Transmission System Load or TTSL). *(red vertical line on graph)*
- What does Non-Coincident Peak (NCP) load mean?
  - For Rate purposes, any method that looks at customer metered load at a time other than (non-coincidental with) the Monthly Transmission System Peak Load. *(any of points A, B, C's, E)*

Peak Forecasts used by Transmission

The Forecasts used in Rates and Planning are developed at the POD or WECC Bus level.

- Non-coincidental peak POD load forecast models are developed from historical meter detail. *(points A & B)*
- The sum of the Non-coincidental peak POD load forecasts for a customer is represented by the dashed horizontal blue line on the Peak Types chart on the previous slide. *(point E)*



Peak Forecasts used by Transmission, continued

- Each Non-coincidental POD forecast is scaled to reflect the POD load at the time of the Customer Peak as represented by the points where the POD load crosses the vertical black line on the chart. *(points C1 and C2)*
  - The sum of these POD loads for a customer is the Non-coincident Customer Peak *(point C)*
- Each Non-coincidental POD forecast is also scaled to reflect the POD load at the time of the Transmission System Peak Load as represented by the points where the POD load crosses the vertical red line on the chart. *(points D1 and D2)*
  - The sum of these POD loads for a customer is the Customer Peak coincident with the transmission system peak (CP). *(point D)*

Overarching Forecast Assumptions

- Normal weather conditions exist
  - 34 year average value
- Continuation of trends with known changes
  - Known changes identified through customer visits
- Numerous elements are forecasted from the same assumptions
  - kWh
  - customer peak
  - Generation System Peak (GSP)
  - Transmission System Peak (TSP)
  - Control Area (CA) peak
  - Etc.

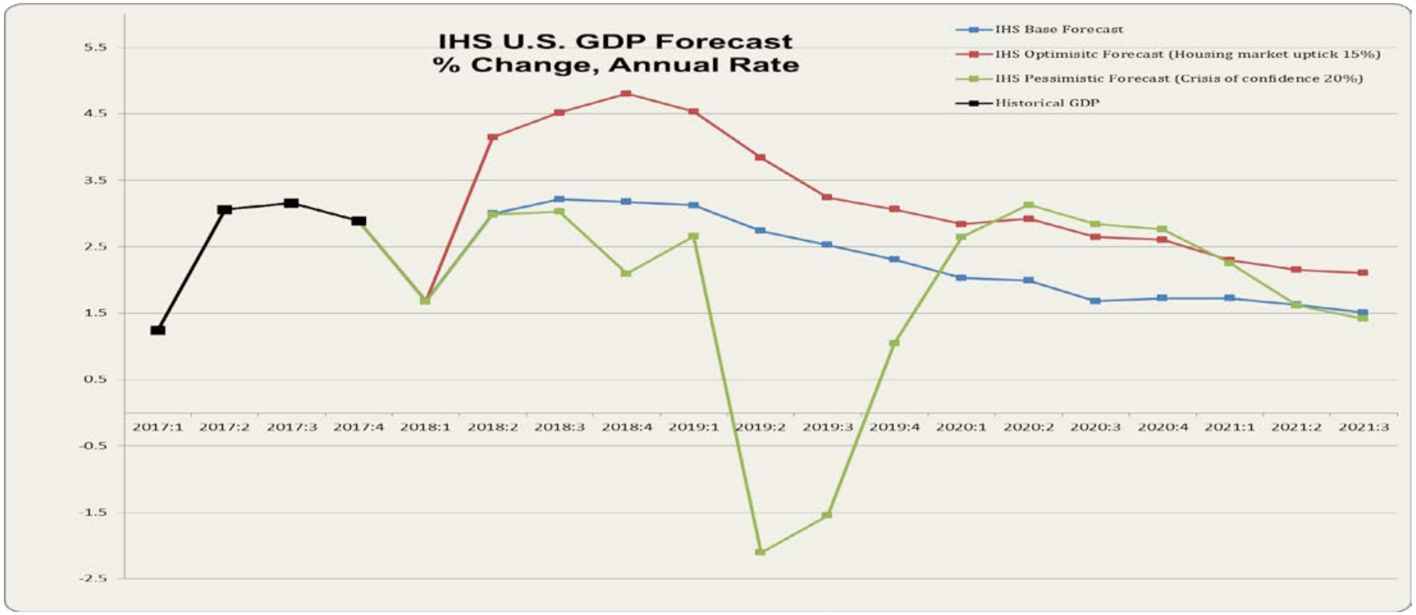
Load Forecasting Process

- Forecasts are developed within the Agency Load Forecasting tool (ALF)
- Updates are prepared annually
- Each customer/POD/Bus element is individually forecasted
  - Statistical based regression models using up to 10 years of historical data
  - All Energy models are independent models
  - Non-coincidental customer peak and POD non-coincidental peaks each have their own independent model *(points A, B, C)*
  - Customer non-coincidental POD peaks and all Coincidental peaks are dependent on Customer non-coincident peak model using historical factors *(points C1, C2, D1, D2, D)*

Load Forecasting Process, continued

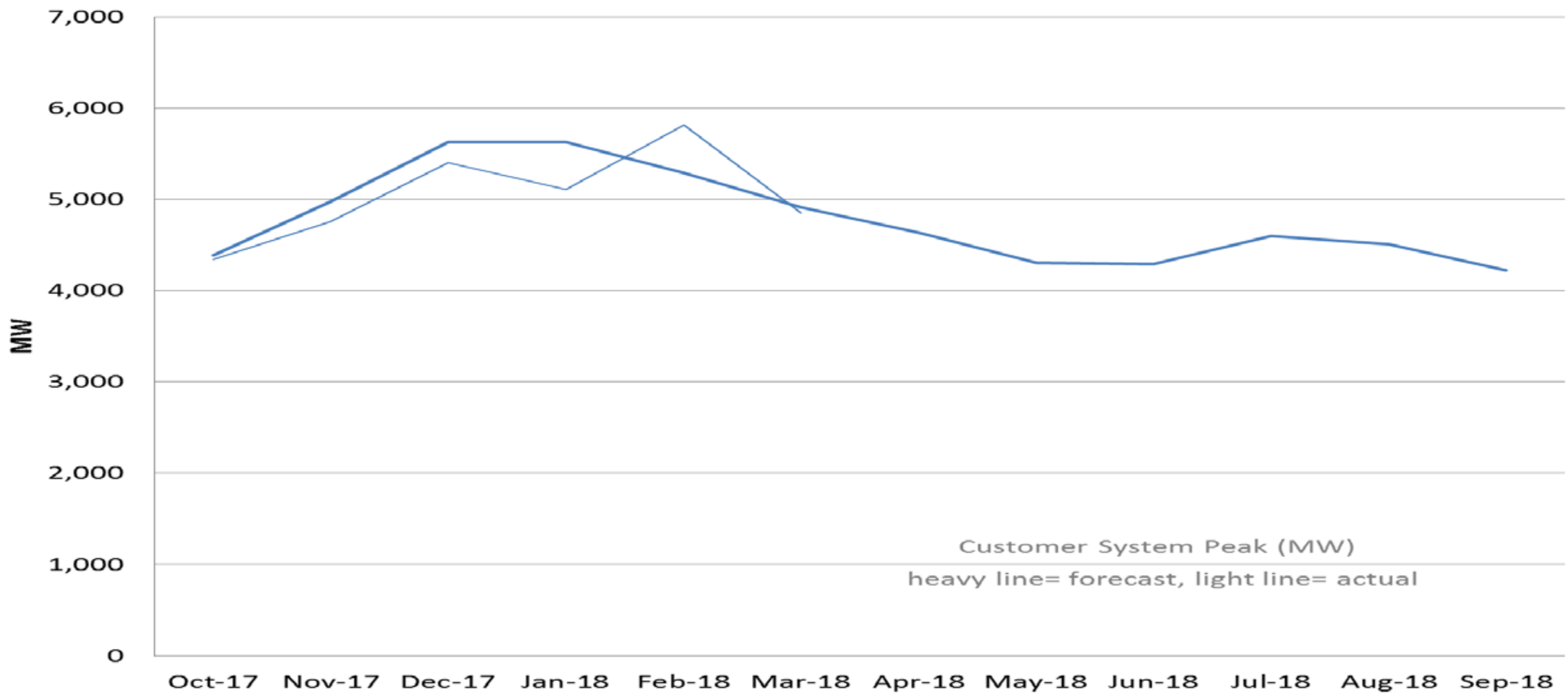
- Preliminary forecast reviewed by Customer, and other interested parties
  - Regional economic conditions
    - Migration patterns
    - Individual industrial plant activity
    - Changing consumer behavior
  - Demographic conditions
    - Birth and Death Rates
    - Age and Gender
  - Off trend growth is added to trend
  - Off trend examples
    - New large industrial or commercial loads
    - New large subdivision additions

Forecasted Economic Conditions Continue from Last Year



- Positive GDP growth is still expected for the nation
- Regional unemployment has improved slightly
- Load continues small growth
- World economic concerns continue

Current Models - Peaks



- Demand models are performing well after compensating for the ups and downs of the weather.

Forecasted Agency Loads Continue as Planned Last Year

	Mwa				
	2018	2019	2020	2021	2022
Prior Forecast (April 2017)	9,133	9,248	9,441	9,598	9,732
Current Forecast (April 2018)	8,974	9,171	9,272	9,514	9,711
change	-159	-77	-169	-84	-21
% change	-1.7%	-0.8%	-1.8%	-0.9%	-0.2%

- Downward bias in forecast adjustments
  - ~55% of the customers increased forecast over last year levels, ~45% reduced forecasts
  - Average change about 1aMW per customer
- Bulk of changes are the results of anticipated specific large customer adjustments with most of the change coming from a few customers

Overview of Unauthorized Increase Charge

UIC Current Status

- BPA imposes an Unauthorized Increase Charge (UIC) whenever a Point-To-Point customer's schedule exceeds its capacity reservation at any Point of Receipt (POR) or Point of Delivery (POD). The UIC is assessed as defined in Section II.F.1.a of the BPA Transmission Services GRSPs, which states:

  > The UIC rate shall be the lesser of (i) 100 mills per kilowatthour plus the price cap established by FERC for spot market sales of energy in the WECC, or (ii) 1000 mills per kilowatthour. If FERC eliminates the price cap, the rate will be 500 mills per kilowatthour.

- Prior to the current rate, customers were charged based on the duration of their transmission reservation. This could result in the long-term firm rate being applied for one UIC while a daily rate was applied for another.

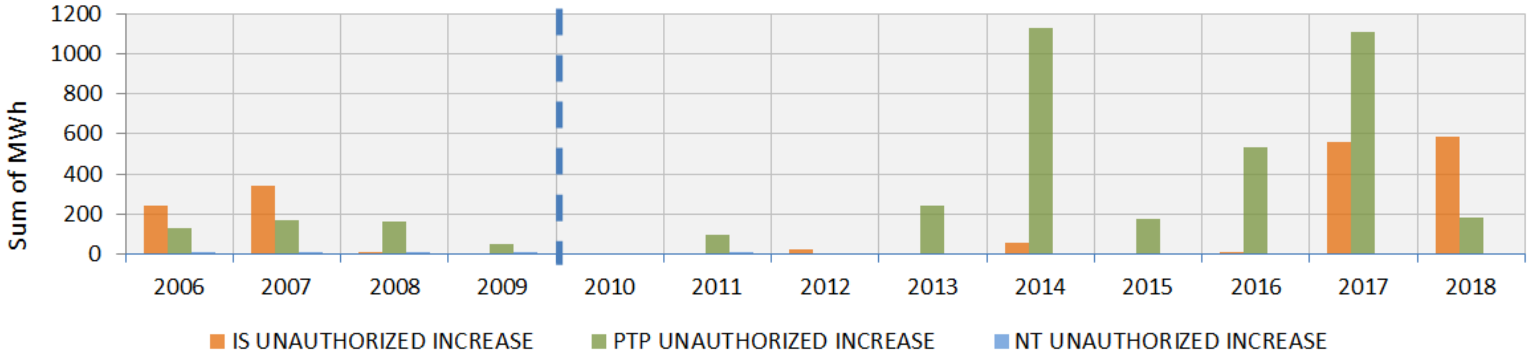
- The motivation to change the rate was to create a more consistent UIC and to ensure customers have no economic incentive to schedule in excess of their reserved capacity. The current rate was adopted in the 2010 Transmission Rate Case Settlement.

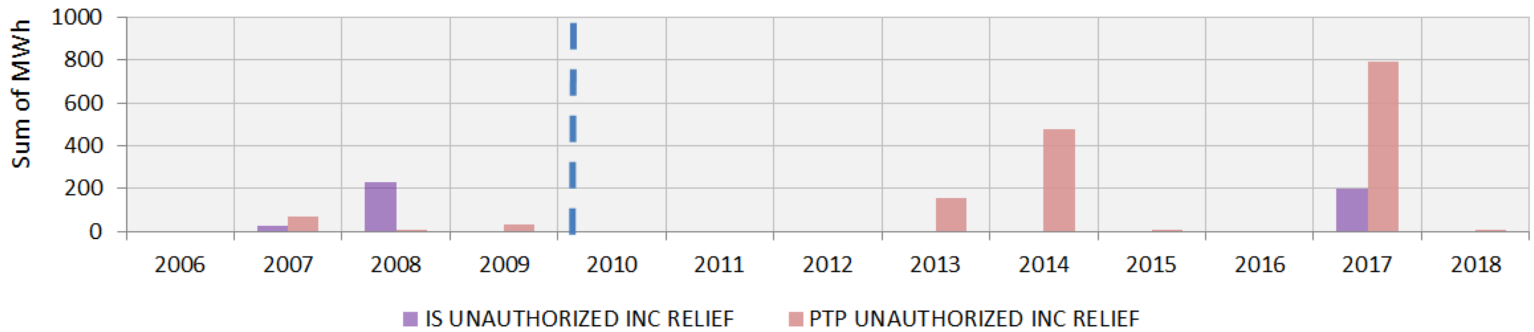
- Since the implementation of the current UIC rate design, BPA continues to see some customers scheduling in excess of their reserved capacity.

- The WECC price cap is still $1000/MWh.

- The UIC still creates an important economic incentive for customers to not schedule beyond their reserved transmission capacity.

UIC Historical Volumes by Fiscal Year





	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
IS UIC MWh	240	340	2	-	-	-	24	-	54	-	4	558	585
PTP UIC MWh	127	171	158	47	-	97	-	242	1,131	178	530	1,110	180
NT UIC MWh	1	2	0	6	-	3	-	-	-	-	-	-	-
IS Relief MWh	-	25	227	-	-	-	-	-	-	-	-	200	-
PTP Relief MWh	-	72	6	31	-	-	-	155	479	8	-	794	1
Net UIC MWh	368	417	(73)	22	-	100	24	87	706	170	534	674	764

- Fiscal Year 2018 is a partial year through April.

Segmentation: Future Plant in Service

Segmentation – Future Plant in Service

- The Segmentation Study and Revenue Requirement reflect historical plant in service through FY 2017.
- A future Plant in Service forecast is used for FY 2018-21 in the Initial Proposal to project segmented net plant investment during the rate period.
- Segmented net plant is used to allocate capital related costs in the revenue requirement to specific segments.
- The Plant in Service forecast is based on initial capital spending levels currently being discussed in the 2018 IPR.

Future Plant in Service Forecast

- Consistent with past practices, the Final Proposal will be updated to reflect plant placed into service and retirements that occurred in FY 2018.
  - The Plant in Service forecast will also be updated to reflect any updates in proposed capital spending for FY 20-21.

Future Plant in Service

($000)

A	B	C	D	E	F	G	H
	Generation Integration	Network	Southern Intertie	Eastern Intertie	Utility Delivery	DSI Delivery	Total
Stations							
FY 2018	-	148,076	2,829		-	-	**150,906**
FY 2019	-	194,978	2,403		-	-	**197,381**
FY 2020	-	251,696	2,109		-	-	**253,805**
FY 2021	-	201,128	2,265		-	-	**203,393**
Lines							
FY 2018	-	81,715	70	-	-	-	**81,784**
FY 2019	-	82,954	58	-	-	-	**83,012**
FY 2020	-	116,330	3	-	-	-	**116,332**
FY 2021		127,012	37				**127,049**
Lines & Subs							
FY 2018	-	229,791	2,899		-	-	**232,690**
FY 2019	-	277,932	2,461		-	-	**280,393**
FY 2020	-	368,025	2,112		-	-	**370,137**
FY 2021	-	328,140	2,303		-	-	**330,442**

	Ancillary Services	General Plant
Other		
FY 2018	25,489	95,871
FY 2019	43,941	122,690
FY 2020	34,583	115,083
FY 2021	34,966	105,557

Proposed Rate Schedule Changes

Proposed Rate Schedule Changes

- A draft redline version of the proposed changes to the BP-20 Transmission Rate Schedules is posted on the BP-20 Rate Case Meetings and Workshops page.
  - Changes to the NT SDD language to limit the SDD to be no more than the power load
  - Reliability Services name change
  - Reference to the correct website for the operating reserves

Next Steps

Comment Period

- Please send comments on the proposed rate schedule changes or additional rate case topics you'd like to discuss during the workshops by June 28, 2018.

Upcoming Workshops

- The Next BP-20 Rate Case workshop will be on July 18, 2018. Transmission rates topics will include:
  - LGIA Forecast
  - Sales Forecast
  - SCD

Appendix

Future Customer Meetings

Date	BP-20 Rate Case Workshops	Other Meetings
June 18-21		• 2018 IPR
June 26 (T)		• TC-20 Tariff Workshop
June 27 (W)	*Cancelled*	
Jul 18 (W)	• Transmission Rates o LGIA o Sales o SCD • ACS Practices Workshop	

Future Customer Meetings, continued

Date	BP-20 Rate Case Workshops	Other Meetings
July 23 (M)		• TC-20 Tariff Workshop
July 25 (W)	• Power Rates o Tier 2 pricing o Transmission Scheduling Service • Transmission Rates o Rates Model o Rate Schedule Changes • Revenue Requirements	• RHWM Process (9am-10am)
Aug 8 (W)	• Risk • Power Rates • ACS Practices Workshop (tentative)	
Aug 22 (W)	• BP-20 Rate Case (if needed)	

Workshop dates and topics are subject to change. Please check the BPA Event Calendar for the most up-to-date information.

What is Segmentation?

- Segmentation is a categorization of BPA’s transmission assets into groups (called segments) to develop allocation factors based on gross investment and historical operations and maintenance (O&M) expenses.
- These allocation factors are then used to assign the total transmission revenue requirement to the various segments.
- This results in the segmented revenue requirement that is used to calculate transmission rates.

Segments

Segments	Corresponding Rates
Network	PTP, NT, IR, FPT
Utility Delivery	UDC
DSI Delivery	UFT
Southern Intertie	IS
Eastern Intertie	IE, IM, TGT
Generation-Integration	Assigned to power rates
Ancillary Services	ACS

Description of Segments

- ***Generation Integration*** – Transmission facilities that connect Federal generation to BPA's transmission facilities.
- ***Network*** – Core of BPA's transmission system. Transmission facilities that transmit power from Federal and non-federal generation sources or interties to the load centers of BPA's transmission customers in the PNW or other segments.
- ***Southern Intertie*** – Transmission facilities used primarily to transmit energy between the PNW and California.
- ***Eastern Intertie*** – Transmission facilities connecting network facilities in the PNW to Eastern Montana, primarily to transfer energy from Colstrip to the PNW (these facilities were constructed pursuant to the Montana Intertie Agreement).
- ***Utility Delivery*** – Low voltage transmission lines and substation equipment associated with supplying power directly to utility customers' distribution systems.
- ***DSI Delivery*** – Transformers and low-side switching equipment and protection equipment necessary to step down power to DSI customers at industrial voltages (6.9 or 13.8 kV).
- ***Ancillary Service*** – Communications and control equipment necessary for BPA to provide Scheduling, System Control and Dispatch (SCD) service.

BP-20 Segmentation Investment

- BPA is proposing no methodology changes from the BP-18 final proposal or segment definitions.
- The Segmentation Study assigns plant investment to segments based on their function.
- Existing plant in service is updated with actuals through FY 2017 for the BP-20 Initial Proposal.
  - The final proposal will be updated through FY 2018
- Future plant in service will be forecasted for FY 2018 – FY 2021 for the BP-20 Initial Proposal.

Segmented Lines and Substations Investment

($000)

Plant Investment Through September 30, 2016 (BP18 Final)

A	B Generation Integration	C Network	D Southern Intertie	E Eastern Intertie	F Utility Delivery	G DSI Delivery	H Segmented Total	I Ancillary Services
Stations	92,969	3,111,799	784,841	28,412	13,383	8,297	4,039,701	
Lines	18,310	3,091,737	204,168	94,851	308	-	3,409,374	
Sub Total	111,279	6,203,536	989,009	123,264	13,691	8,297	7,449,074	185,654
% of Segmented Total	1.5%	83.3%	13.3%	1.7%	0.2%	0.1%	.	

Plant Investment Through September 30,2017 (BP20 Initial Proposal)

A	B Generation Integration	C Network	D Southern Intertie	E Eastern Intertie	F Utility Delivery	G DSI Delivery	H Segmented Total	I Ancillary Services
Stations	100,634	3,269,967	803,783	28,552	14,707	8,581	4,226,223	
Lines	30,872	3,146,175	303,141	94,846	318	-	3,575,351	
Sub Total	131,505	6,416,142	1,106,924	123,398	15,024	8,581	7,801,574	212,601
% of Segmented Total	1.7%	82.2%	14.2%	1.6%	0.2%	0.1%	100.0%	

O&M Segmentation Methodology

- Consistent with BP-18 Final Proposal Methodology
- Based on a 7 year historical average
- Direct O&M are historical O&M costs associated with a specific asset
  - The O&M is directly charged to the asset.
  - The O&M is then assigned to the different segments based on the segmented investments
- Non-direct O&M are historical O&M costs not associated with a specific asset
  - These costs are allocated to Lines, Substations, and Metering stations in proportion to the direct O&M in each respective group
  - Transmission Line and Right-of-way Maintenance, and Vegetation Management (all non-direct) are allocated to Lines only

Segmented Historical O&M

($000)

Historical O&M FY2010-2016 (BP18 Final)									
A	B Generation Integration	C Network	D Southern Intertie	E Eastern Intertie	F Utility Delivery	G DSI Delivery	H Segmented Total	I Ancillary Services	I Overhead
Stations	2,822	95,923	16,064	593	788	491	116,681		
Lines	468	45,547	2,369	1,956	9	-	50,349		
Sub Total	3,290	141,470	18,433	2,549	797	491	167,030	52,418	48,688
% of Segmented Total	2.0%	84.7%	11.0%	1.5%	0.5%	0.3%	100.0%		

Historical O&M FY2011-2017 (BP20 Initial Proposal)									
A	B Generation Integration	C Network	D Southern Intertie	E Eastern Intertie	F Utility Delivery	G DSI Delivery	H Segmented Total	I Ancillary Services	I Overhead
Stations	2,983	100,123	17,243	628	843	476	122,296		
Lines	471	46,265	2,454	1,915	15		51,120		
Sub Total	3,454	146,388	19,697	2,543	858	476	173,416	55,579	50,993
% of Segmented Total	2.0%	84.4%	11.4%	1.5%	0.5%	0.3%	100.0%		