BP-18 Transmission Rates Workshop

May 6, 2016

Agenda

- Load Forecasting
- Planning the Transmission System
- Rate Case Implications of Load Forecast
- Segmentation

Load Forecasting

Terminology – Keeping All the Terms Straight

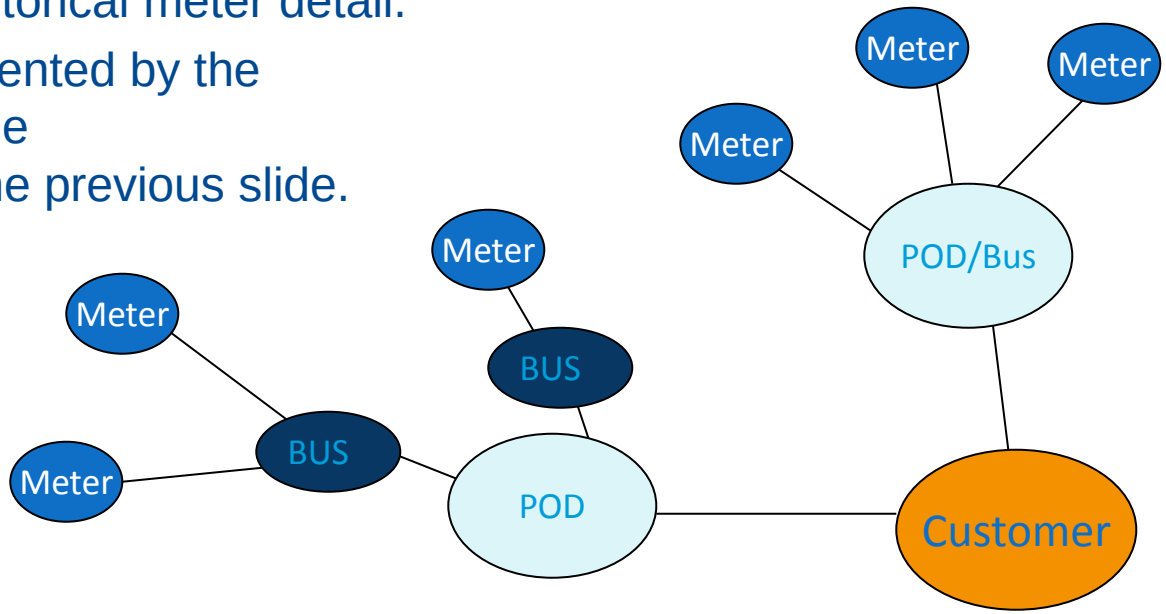
- What does Coincident Peak (CP) load mean?
  - Generally, coincident peak is a measure of load at the same time (coincident) that another measure is highest.
  - For Rate purposes, a customer's CP load is the sum of the customer's individual meters, integrated over the hour of the FCRTS Monthly Transmission System Peak Load.
- What is the Monthly Transmission System Peak Load?
  - The peak load on the Federal Columbia River Transmission System (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).
- 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.

Transmission Peak Types

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.
- POD Peaks are represented by the vertical blue lines on the Peak Types chart on the previous slide.



- 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.

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.
  - The sum of these POD loads for a customer is the Customer Peak non-coincident with the transmission system peak (NCP).
- 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.
  - The sum of these POD loads for a customer is the Customer Peak coincident with the transmission system peak (CP).

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
  - GSP
  - TSP
  - CA peak
  - Etc.

Load Forecasting Process

- Forecasts developed within the Agency Load Forecasting tool (ALF)
- Updates 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
  - Customer Peaks and POD/Bus Peaks each have their own independent model
  - POD/BUS coincident peak and TTSL coincident peak are dependent on Customer coincident peak model using historical factors

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

Planning the Transmission System

Load Forecasts used in Planning the Transmission System

- BPA does not use the Monthly Transmission System Peak Load in planning the system.
  - Because there is diversity in the timing when constraints occur across the system, BPA does not determine system reinforcements by a single snapshot of system usage as indicated by a Monthly Transmission Peak Load.
- The system is planned for **Non-Coincidental Peak** loads.
  - BPA Transmission Planning considers the maximum load (by season) on individual PODs for each customer. Transmission Planning refers to this as a Customer's Non-Coincidental Peak Load.
  - Transmission Planning may also consider the maximum load for the sum of the customer's PODs during the month. Planning refers to this as a Customer's Coincidental Peak load.
  - While Transmission Planning may consider the Customer's Coincidental Peak load along with the Customer's Non-Coincidental Peak load, any of the loads BPA uses for planning the system are still Non-Coincidental Peak (NCP) loads relative to the Monthly Transmission System Peak Load.

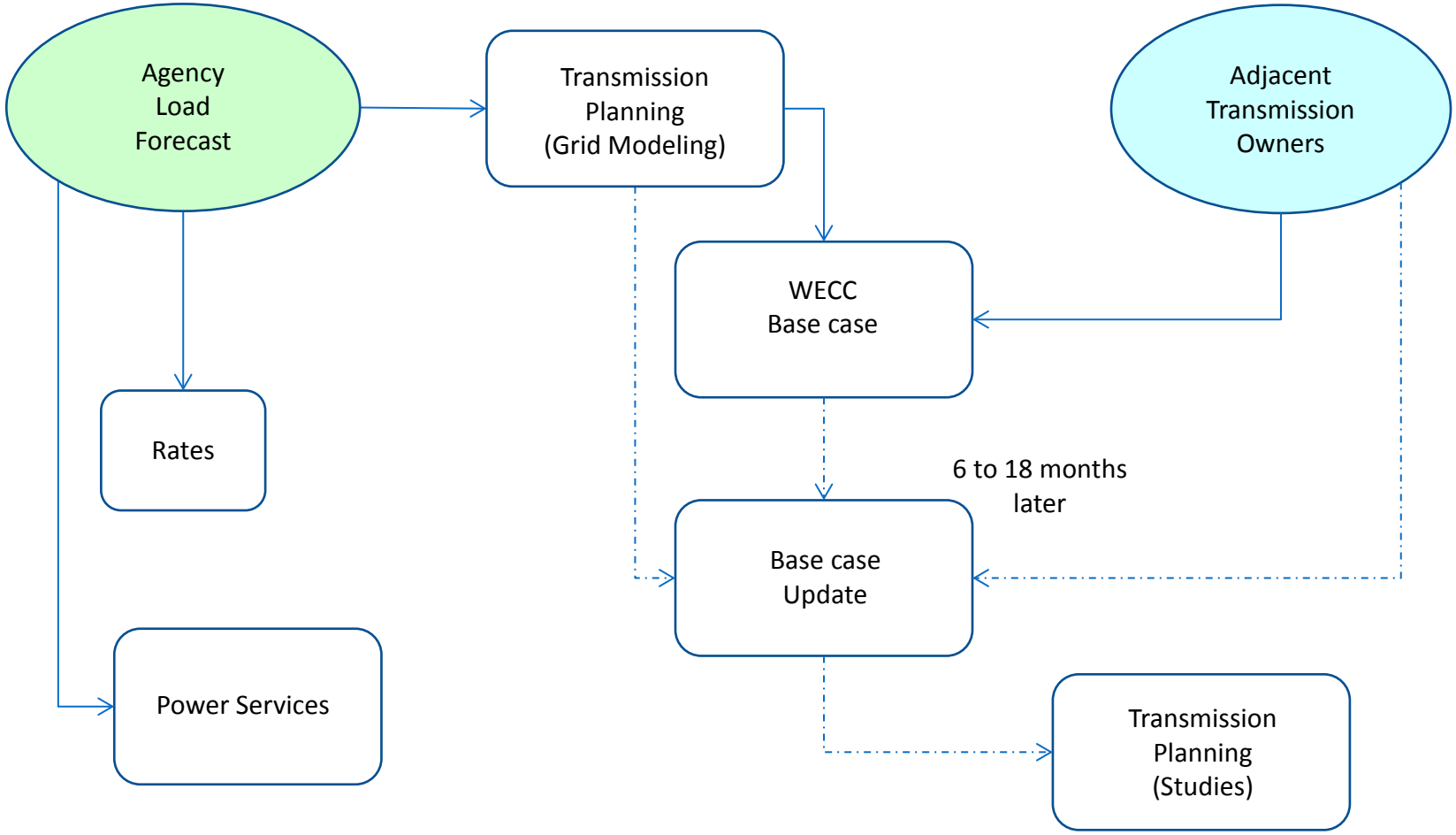
How Loads are Utilized in Planning the System

- Loads forecasts are developed in the Agency Load Forecast System.
  - Forecasts created for all customer PODs – both PTP and/or NT
  - Forecasts also produced for IOU's and for entities beyond the BPA Network
  - Same base forecasts provided to Power Services and Transmission Services
- Transmission Planning (Grid Modeling) validates forecasts and submits appropriate peak loads for all BPA customers to WECC for use in developing regional planning models (base cases).
  - Forecasts submitted as part of the Annual WECC Study Plan
  - Other load serving entities may also submit their own forecasts to WECC which replace the forecasts provided by BPA
- The WECC base cases are reviewed by all planning organizations in the WECC and then approved by WECC.
- Before using the approved WECC cases for planning studies BPA Transmission Planning updates the load forecasts to reflect the most current information available.
  - Updated information from the Agency Load Forecast
  - Updates based on recent coordination with specific customers

Development of WECC Base Cases

- WECC Base Cases are developed on an annual basis
  (examples based on 2016 calendar year development)
  - Typical Operating Base Cases (developed Spring time frame)
    - Upcoming year Heavy Winter (e.g. 2016/2017 winter)
    - Upcoming year Light Winter (e.g. 2016/2017 winter)
    - Following year Heavy Spring (e.g. 2017 spring)
    - Following year Heavy Summer (e.g. 2017 summer)
    - Following year Light Summer (e.g. 2017 summer)
  - Five-year Base Cases (developed Summer time frame)
    - Five to Six years out Heavy Winter (e.g. 2021/2022 winter)
    - Five or Six years out Heavy Summer (e.g. 2022 summer)
  - Ten-year Base Cases (developed Summer time frame)
    - Ten to Eleven years out Heavy Winter (e.g. 2026/2027 winter)
    - Ten or Eleven years out Heavy Summer (e.g. 2027 winter)
  - Scenario Base Cases (developed in the Autumn/Winter time frame)
    - As needed (e.g. 2018 Light Autumn in Northwest)

Planning Load Forecast Data Flow



Cases Used to Plan the System

- Planning prepares study cases for two primary uses:
  - System assessments – Reliability Based Studies
    - Generally uses Five-year and Ten-year WECC Base Cases, updated to reflect recent load forecast information
    - Planning develops additional cases and scenarios designed to simulate expected utilization for twenty four Load Service Areas and seven Transfer Path Areas
    - Supports identification of system reinforcement to maintain reliable operation of the system
  - Requested Service
    - Interconnection Studies – Cases selected to assess expected utilization – five-year and ten-year cases, typically.
      - Generator Interconnection
      - Line & Load Interconnection
    - Requests for Long Term Firm Transmission Service
      - ATC – Use a two year case
      - Cluster Study – Use an out-year case (typically five-year)

In summary, the forecasts used for the two-year rate case process will never match the planning forecasts exactly due to timing and updates to the load forecasts in the planning process.

Rate Case Implications of Load Forecast

Relationship of Peak load forecasts to Network Cost Allocation

- In BP-14 and BP-16, BPA allocated Network costs between NT and PTP using forecast reserved capacities for PTP and forecast monthly non-coincidental customer peak loads for NT as the allocation factors (12 NCP method).
- The NT non-coincidental loads used were the non-coincidental **customer peaks**—the sum of the POD loads on the hour of the customer peak.
- As explained earlier, BPA uses non-coincidental peaks by **POD (not by customer)** and other considerations in its planning studies.
- **Issue:** What forecast of NT non-coincidental peak loads should be used as the Network allocation factor for NT?
  - Customer peaks
  - POD peaks

Segmentation Overview

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	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

How Is Segmentation Used?

- Segmented plant investment and segmented historical O&M are used for allocating costs among the segments in the transmission revenue requirement.
- Segmented plant investment, which includes current investment and future plant in service projections, is the allocator for:
  - Transmission line and substation depreciation
  - Net interest expense
  - Planned net revenue
- Segmented historical O&M costs is the allocator for:
  - O&M costs during the rate period
  - Overhead expenses
  - General plant depreciation

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-18 Segmentation

- BPA is proposing no changes from the BP-16 final proposal methodology or segment definitions.
- The Segmentation Study assigns plant investment to segments based on their function.
- Plant in service is updated through FY 2015 for the BP-18 Initial Proposal.
  - The final proposal will be updated through FY 2016
- Future plant in service will be forecast for FY 2016 – FY 2019 for the BP-18 Initial Proposal.

Segmented Lines and Substations Investment

($000)

	A	B	C	D	E	F	G	H	I
		Generation Integration	Network	Southern Intertie	Eastern Intertie	Utility Delivery	DSI Delivery	Segmented Total	Ancillary Services
	Plant Investment Through September 30, 2014 (BP-16 Final Proposal)								
1	Stations	81,760	2,678,554	636,189	23,289	11,304	10,331	3,441,428	
2	Lines	17,992	2,663,166	199,264	94,891	170	-	2,975,484	
3	**Sub Total**	**99,752**	**5,341,721**	**835,453**	**118,181**	**11,474**	**10,331**	**6,416,911**	**147,353**
4	% of Total	1.6%	83.2%	13.0%	1.8%	0.2%	0.2%		
	Plant Investment Through September 30, 2015 (BP-18 Draft Initial Proposal)								
5	Stations	86,336	2,851,872	638,530	28,121	11,353	10,362	3,626,573	
6	Lines	18,321	2,775,689	200,359	94,906	170	-	3,089,444	
7	**Sub Total**	**104,656**	**5,627,560**	**838,890**	**123,026**	**11,523**	**10,362**	**6,716,017**	**164,586**
8	% of Total	1.6%	83.8%	12.5%	1.8%	0.2%	0.2%		

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							
1	FY 2015	-	185,004	26,797	208	54	-	**212,064**
2	FY 2016	-	241,608	23,593	91	63	-	**265,355**
3	FY 2017	-	177,918	288,417	87	46	-	**466,468**
	Lines							
4	FY 2015	-	147,123	1,762	-	-	-	**148,886**
5	FY 2016	-	182,584	1,754	-	-	-	**184,339**
6	FY 2017	-	129,702	34,336	-	-	-	**164,038**
	Lines & Subs							
7	FY 2015	-	332,127	28,560	208	54	-	**360,950**
8	FY 2016	-	424,192	25,347	91	63	-	**449,694**
9	FY 2017	-	307,620	322,753	87	46	-	**630,506**

	Other	Ancillary Services	General Plant
10	FY 2015	52,109	116,239
11	FY 2016	64,789	118,691
12	FY 2017	40,038	119,561

This table is from Final Proposal BP-16. Updated forecasts for FY 2016 – FY 2019 will be shared in July and finalized after the CIR/IPR concludes this summer.

Draft IPR Numbers will be shared in July Workshops

O&M Segmentation Methodology

- Consistent with BP-16 Final Proposal Methodology
- Based on a 7 year historical average
- Direct O&M are historical O&M costs associated with a specific asset
  - These are assigned to the segments based on how that asset is segmented
- 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)

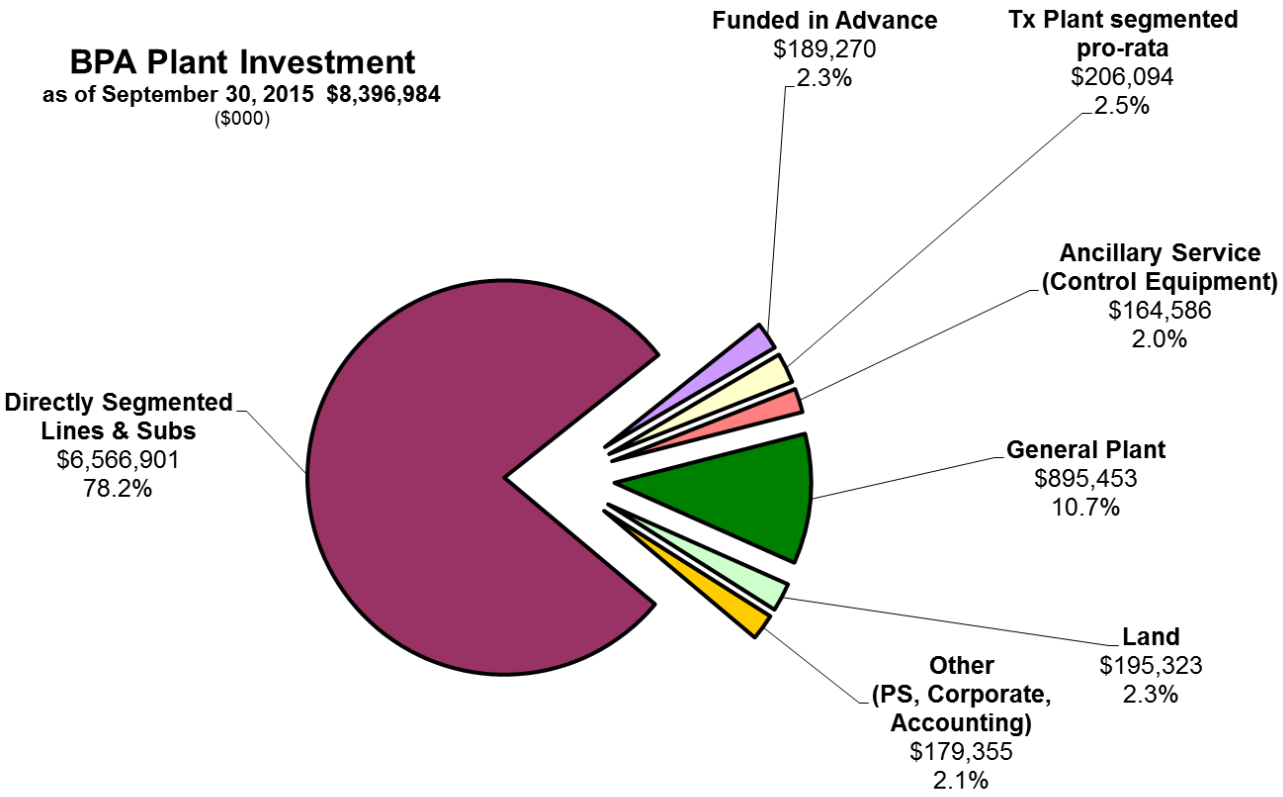
	A	B	C	D	E	F	G	H	I	
		Generation Integration	Network	Southern Intertie	Eastern Intertie	Utility Delivery	DSI Delivery	Segmented Total	Ancillary Services	Overhead
					Historical O&M FY 2008 through FY 2014 (BP-16 Final Proposal)					
1	Stations	2,450	83,961	15,497	497	731	454	103,590		
2	Lines	412	45,595	2,810	1,873	9	-	50,699		
3	**Sub Total**	**2,862**	**129,556**	**18,306**	**2,370**	**740**	**454**	**154,289**	**45,935**	**44,434**
4	% of Total	1.9%	84.0%	11.9%	1.5%	0.5%	0.3%			
					Historical O&M FY 2009 through FY 2015 (BP-18 Draft Initial Proposal)					
5	Stations	2,603	90,629	15,924	520	755	535	110,966		
6	Lines	445	46,178	2,582	2,053	8	-	51,266		
7	**Sub Total**	**3,048**	**136,807**	**18,506**	**2,573**	**763**	**535**	**162,232**	**48,795**	**46,128**
8	% of Total	1.9%	84.3%	11.4%	1.6%	0.5%	0.3%			

Next Steps

- The next BP-18 Transmission Rates Workshop is **May 24** (1:00p.m. - 4:00p.m.)
  - Southern Intertie HNF rate
  - Rate impact of the alternative load forecasts for Network cost allocation
- **By Friday, June 3** – BPA requests customer comments on which load forecast should be used for the NT cost allocation. Please send comments to techforum@bpa.gov with the title "BP-18 Transmission Forecast Comments."
- We will share the updated future plant in service in July after the IPR/CIR.

Appendix

BP-18 Draft Initial Proposal: Segmentation Study – Plant Investment Summary



Future Customer Meetings

Date	BP-18 Rate Case	Other Workshops
May 10 (T)		• RHWM Process • Financial Reserves Policy
May 24 (T)	• Gen Inputs • Transmission Rates o Short Distance Discount o Southern Intertie HNF	
June 7 (T)		• Financial Reserves Policy
June 8 (W)	• Transmission Rates o Loads and Planning o Segmentation	

Future Customer Meetings, continued

Date	BP-18 Rate Case	Other Workshops
June 29 (W)	• Transmission Rates o Southern Intertie HNF • Gen Inputs	
~~June 28 (T)~~ June 30 (Th)		• RHWM Process (if needed) • Small Generation Integration
Jul 13 (W)	• Transmission Rates o Load Forecasting o LGIA o Sales	
Jul 27 (W)	• Revenue Requirement • Transmission Rates o Southern Intertie HNF o SDD • Gen Inputs	

Future Customer Meetings, continued

Date	BP-18 Rate Case	Other Workshops
Aug 9 (T)	• Power Rates o Overviews: Market Prices/Loads & Resources o TCMS for NT Secondary o Other	• RHWM Process
Aug 10 (W)	• Risk • Transmission Rates o Rates Models o Wrap-up	
Aug 24 (W)	• Transmission Rates • Power Rates	
Sept 7 (W)	• Transmission Rates	