BP-14 Transmission Pre-Rate Case

August 22, 2012

Agenda

- Customer Presentations
- Reservation Fee Follow up
- Use of Reserves Follow up
- Transmission Rate Schedules Proposed Changes
- NT Proposal - Utility Delivery Charge
- Redispatch 101

Rates Workshop Follow-Up Items

#	A	B	C
1	**Customer Request**	**BPA Response**	**Date Completed**
2	**8/9/12 – PTP Customer Coalition, via Electronic Submission:**		
3	What would be the rate treatment (functionalization, allocation, direct assignment, ect.) of BPA costs of paying, supporting, or reimbursing customers for NERC or WECC fines or penalties?		
4	For FY 14-15, how much does BPA expect to receive – for the two most recent FYs, how much did BPA receive- in revenues as direct charges for its activities included above (such as revenues under O&M Agreements with respect to compliance with NERC or WECC reliability requirements and such as reimbursements by any customer under any Delegation Agreement)?		
5	Please describe any efforts BPA is making to work with one or more customers to develop information on such expenditures and analyze or propose how the costs of demand response might be functionalized or allocated?		
6	**8/8/12 - Transmission pre-rate case workshop follow-up items:**		
7	Have a Redispatch 101 presentation	Will be discussed at the Pre-Rate Case Workshop on 8/22/12.	
8	Why are Reserves growing?	Will be discussed at the Pre-Rate Case Workshop on 8/22/12.	
9	**7/25/12 - Transmission pre-rate case workshop follow-up items:**		
10	What are the differences in “use” compared to “demand”?		
11	What is the aggregate of total system load by month?		

Rates Workshop Follow-Up Items, cont.

#	A	B	C
12	**Customer Request**	**BPA Response**	**Date Completed**
13	If we were to use the FERC "Brightline" test, 1) how much would be directly assigned and 2) how much would stay in the network in the past and in the future?	Will be discussed in NOS.	
14	Provide an updated wind forecast.		
15	Why is the segmented O&M changing from $112 million to $178 million? What are the drivers?	The historical O&M avg of $112M identified from the segmentation study only includes O&M segmented to lines and subs. It did not include O&M segmented to Ancillary Services or the amount left unsegmented (e.g. O&M associated with General Plant). If these were included, the total historical O&M would be much closer to the future O&M forecast of $178M as identified in the revenue requirement. For the initial proposal all historical O&M will be identified and the future O&M allocated to Ancillary Services will align with the historical O&M allocated to Ancillary Services.	
16	Include variability for creditworthiness and resales, in revenue assumptions.		

Rates Workshop Follow-Up Items, cont.

#	A	B	C
17	**Customer Request**	**BPA Response**	**Date Completed**
18	Is Method 1 for NT LGIA Transmission repayment industry standard?	We haven't found any clear industry standard for how credits are repaid to NT customers, but we have found a couple of instances where the transmission provider repaid credits to an NT customer differently than the way BPA does. We are evaluating whether to revise our BP to adopt the method that they used or something similar.	
19	What are the benefits for Redispatch?	Will be discussed at the Pre-Rate Case Workshop on 8/22/12.	

Reservation Fee Analysis Follow Up

Reservation Fee Issue

- In the 2014 Rate Case workshops, BPA shared with customers it is expecting a large amount of deferred revenues in the future.
- The forecast deferrals are based on generation inter-connection forecasts and information from Account Executives.
- The forecast indicates that $6.4M in revenue is likely to defer in FY 14 and $40.0M in FY 15. Beyond the rate period, the deferred revenues are expected to peak at $45.2M in FY 16 and stay at over $30M through FY 18.

Actual (for FY 2010-2011) and Forecast (for FY 2012-2020)
Deferred Revenues (in $M)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
		Actuals		Forecast								
		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020
1	Non-NOS Requests	$ 16.07	$ 13.51	$ 6.34	$ 0.94	$ 0.81	$ 0.39	$ 0.05	$ -	$ -	$ -	$ -
2	NOS - No Build Required (includes CF)	$ 3.96	$ 8.73	$ 7.38	$ 5.78	$ 4.54	$ 3.47	$ 1.41	$ 0.19	$ 0.09	$ 0.10	$ 0.01
3	NOS - Build Required	$ -	$ -	$ 1.45	$ 1.44	$ 1.03	$ 36.13	$ 43.75	$ 40.01	$ 35.37	$ 28.77	$ 6.62
4	**Total**	**$ 20.03**	**$ 22.24**	**$ 15.17**	**$ 8.16**	**$ 6.38**	**$ 39.99**	**$ 45.21**	**$ 40.19**	**$ 35.46**	**$ 28.87**	**$ 6.63**

Note: No assumptions are made in this forecast for PTSA Reform changes. If customers are allowed to terminate or modify their requests the expected deferrals could be reduced significantly, depending on the amount of terminations and modifications.

Deferrals Related to NOS

- The majority of forecast deferrals in FY 15 and beyond are due to requests associated with NOS builds, specifically Big Eddy-Knight and CF-LoMo.
- The timing of these builds will affect the amount of deferred revenue BPA can expect.

Revenue Deferred On NOS Builds Due to Deferrals

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		FY 2012	**FY 2013**	**FY 2014**	**FY 2015**	**FY 2016**	**FY 2017**	**FY 2018**	**FY 2019**	**FY 2020**
1	**John Day - McNary**	$ 1.45	$ 1.44	$ 0.98	$ 0.92	$ 0.03	$ 0.00	$ 0.00	$ 0.00	$ -
2	**Big Eddy - Knight**	$ -	$ -	$ 0.05	$ 29.84	$ 36.66	$ 32.99	$ 28.63	$ 24.46	$ 5.82
3	**Central Ferry - LoMo**	$ -	$ -	$ -	$ 5.37	$ 7.06	$ 7.01	$ 6.74	$ 4.31	$ 0.80
4	**Total**	**$ 1.45**	**$ 1.44**	**$ 1.03**	**$ 36.13**	**$ 43.75**	**$ 40.01**	**$ 35.37**	**$ 28.77**	**$ 6.62**

Deferrals of Cash vs. Deferral of Credits

- The majority of customers deferring have Large Generation Interconnection Agreements which means, in the absence of deferrals, BPA would be granting revenue credits for their transmission service.
- Only a small amount of the forecast deferrals, $0.25M in FY 14 and $0.12M in FY 15, would result in deferred cash payments to BPA.

Actual (for FY 2010-011) and Forecast (for FY 2012-2020) Deferred Revenues Related to Cash and Transmission Credits

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
		Actuals		Forecast								
		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020
1	Cash	$ 4.68	$ 6.87	$ 2.02	$ 0.76	$ 0.25	$ 0.12	$ 0.04	$ 0.06	$ 0.09	$ 0.10	$ 0.01
2	Credits	$ 15.34	$ 15.37	$ 13.15	$ 7.40	$ 6.13	$ 39.87	$ 45.17	$ 40.13	$ 35.37	$ 28.77	$ 6.62
3	**Total**	**$ 20.03**	**$ 22.24**	**$ 15.17**	**$ 8.16**	**$ 6.38**	**$ 39.99**	**$ 45.21**	**$ 40.19**	**$ 35.46**	**$ 28.87**	**$ 6.63**

Cash vs. Credit Effects on Rate Pressure

- Deferral of credits results in little rate effect in the near-term.
- There is some effect in the long-term since customers earn interest on their credits while in deferral status and BPA must pay off the larger balance eventually.
- Rate pressure resulting from deferral of cash payments:

	FY 14	FY 15	Rate Period Average
Forecast Deferrals of Cash Payments	$ 0.25	$ 0.12	$ 0.19
Rate Pressure	**0.04%**	**0.02%**	**0.03%**

- When reservation fees are considered deferrals may even have a downward rate effect. Below are the rate pressuring resulting from deferral of cash payments when considering reservation fees:

	FY 14	FY 15	Rate Period Average
Forecast Deferrals of Cash Payments	$ 0.25	$ 0.12	$ 0.19
-less Forecast Reservation Fees	$ 0.32	$ 4.18	$ 2.25
Resulting Deferred Cash	$ (0.07)	$ (4.06)	$ (2.07)
Rate Pressure	**-0.01%**	**-0.60%**	**-0.30%**

Note: These effects are somewhat simplified because they do not account for the increased interest paid during the rate period which has cash effects. Over the two-year term the effect of deferrals on interest is minimal.

Mitigation of Deferred Revenues

- Successful mitigation of deferred revenues is difficult to track. The below estimate gives a risk adjusted range for the expected deferred revenues that would not be mitigated by BPA's current efforts.
- See appendix for assumptions.

Deferred Revenue Expected After Mitigation Through Short Term Sales & Competitions

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		FY 13	FY14	FY 15	FY 16	FY 17	FY 18	FY 19	FY 20
1	**Reduced for Short Term Sales**								
2	High Estimate	$ 8.98	$ 7.26	$ 39.92	$ 44.86	$ 39.80	$ 35.27	$ 28.93	$ 7.04
3	Low Estimate	$ 6.92	$ 5.71	$ 35.16	$ 39.26	$ 34.82	$ 30.35	$ 24.40	$ 5.27
4	**Reduced for Competitions**								
5	High Estimate	$ 8.34	$ 4.81	$ 37.83	$ 43.42	$ 38.02	$ 32.13	$ 24.31	$ 5.84
6	Low Estimate	$ 4.90	$ 2.15	$ 33.39	$ 38.16	$ 32.51	$ 26.06	$ 17.85	$ 3.63
7	**Reduced for Short Term Sales & Competitions**								
8	High Estimate	$ 8.05	$ 4.62	$ 35.94	$ 41.19	$ 35.97	$ 30.19	$ 22.68	$ 5.25
9	Low Estimate	$ 4.60	$ 1.98	$ 30.44	$ 34.47	$ 29.34	$ 23.35	$ 15.79	$ 3.09

Note:High and Low Estimates include 90% of the modeled distribution. Basd on the assumptions there is a 5% chance that the amount of deferred revenues would be outside these ranges.

Next Steps

- Looking for customer comments on:
  - Reservation Fee
- Comments due by September 5, 2012:
  - techforum@bpa.gov
  - Please include in subject line: “BP14 Transmission Rate Case – Reservation Fee”.

Use of Reserves
Follow Up

Why are Financial Reserves Growing?

- Since 2006 Rate Case the reserves for Transmission have been growing due to three major areas;
  - Revenues have been higher than forecasted (or an average of 48%), and
  - Transmission Credits (LGIA) have been lower than forecast (or an average of 15%).
  - Interest expense has been lower than forecast (or an average of 36%).
- Revenue forecast variance has been decreasing in the more recent years and we expect the revenues will be relatively close to forecasts in the future.
- Transmission credits have been consistently less than forecast due to wind resource interconnection forecasts that have been moving around. Since we have more experience, the rates team is looking at risk analysis to get to an expected value based on historical and future outlook on the RPS.
- Interest Expense has been consistently lower than Rate Case, however, Finance and Transmission is exploring revisions to forecast assumptions and methodologies.

Transmission Rate Schedules Proposed Changes

PROPOSED CHANGES FOR THE BP-14 RATE PERIOD

- A number of changes or clarifications have been identified for discussion and implementation for the 2014 Rate Period.
- Most of the changes are related to Network Integration Rate, Point To Point Rate, General Rate Schedule Provisions and Definitions. More specifically:
  - NT
    - Replacement of Monthly Transmission Peak Load also referred as Total Transmission System Load (TTSL) with Customer System Peak.
    - Metering Adjustment

PROPOSED CHANGES FOR THE BP-14 RATE PERIOD, cont.

- PTP
  - PTP and SDD.
  - Interruption of Non Firm PTP Transmission Service. Same language applies for Southern Intertie Rate and Montana Intertie Rate.
- Changes on Ancillary Services language.
  - SCD Network Integration Transmission Service.
  - GSR Network Integration Transmission service.
- General Rate Scheduling Provisions
  - Delivery Charge
  - Customer System Peak – Recovery Peak Billing Adjustments
- Definitions

NT-12 Billing Factors Change

- The current rate schedule, NT-12, Section II.A, provides that the billing factor for the Base Charge and the Load Shaping is the customer's Network Load on the hour of the Monthly Transmission Peak Load.
- The proposed change to the Billing Factor language in the rate schedule tracks the proposed adoption of the 12 NCP network cost allocation mechanism for the Initial Proposal.
- This method would compute the customer's system peak for a given month and eliminates the Load Shaping charge and the use of TTSL.
- Specific proposed changes to the NT Rate Schedule:
  - Section II (B) Load Shaping charge is eliminated.
  - Section III. BILLING FACTORS
  - Delete the existing language and insert the following:
  - The monthly Billing factor shall be the customer's Network Load on the hour of the Customer's System Peak (CSP).

NT METERING ADJUSTMENT

- Delete the existing language and insert the following:
  - For those meters that cannot record hourly readings but record the meter's peak demand, the meter's peak demand will be the Billing demand on the hour of the Customer's System Peak (CSP)."

PTP-12 and SDD for System Sales - Clarification

- Background: The current Rate schedule, PTP-12 Sec. G. Short Distance Discount (SDD) identifies the various requirements to meet the criteria in order to qualify for the SDD.
  - The intent of the rate schedule is to exclude system sales coming out of the Federal Generation, or other system sales. Note that up to now, SDD was not applied to system sales.
- Proposal: Add the following language to Section III.G of the Point –To-Point rate schedule:
  - "system sales (not purchased from a specific generating source) do not qualify for SDD"

PTP Interruption of Non Firm PTP Transmission Service - Clarification

- Background. PTP, Section IV.D, second paragraph.
  - Current rate schedule states that “When Reserved Capacity becomes the Billing Factor for Hourly Non Firm service, the following shall apply”.
- This paragraph is replaced by the following:
  - “When Reserved Capacity becomes the Billing Factor for Hourly Non Firm service, the rates charged under Section II.B.2. shall apply as follows”.
- The same wording will replace the existing paragraph for Southern Intertie, Section C.
- The same wording will replace the existing paragraph for Montana Intertie Rate, Section C.

ANCILLARY SERVICES RATES

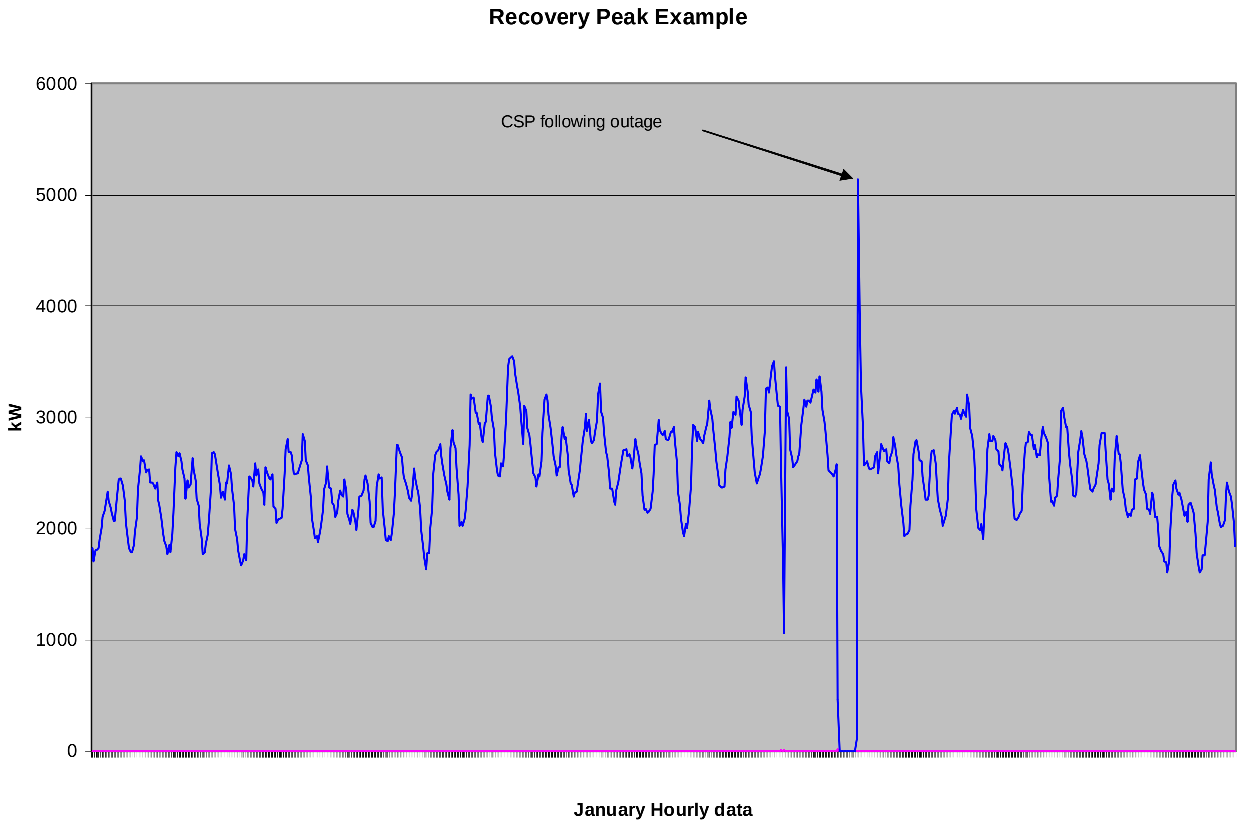
- Scheduling System Control And Dispatch Service A.2(b)
  - For Transmission Customers taking Network integration Transmission service, the Billing Factor for the rate specified in section 1.a. shall equal the NT Billing factor determined pursuant to section III, of the Network Integration Rate Schedule (NT-14)
- Reactive Supply And Voltage Control From Generating Sources Service B.2(b)
  - For Transmission Customers taking Network integration Transmission service, the Billing Factor for the rate specified in section 1.a. shall equal the NT Billing factor determined pursuant to section III, of the Network Integration Rate Schedule (NT-14)

SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

- Delivery Charge.
  - Section A.2.a. Current rate schedule states that the monthly Billing Factor shall be the total load on the hour of the Monthly Transmission Peal Load at the Points of Delivery specified at Utility Delivery facilities. This is deleted and replaced by the following:
    - The monthly Billing Factor for the Utility Delivery Rates shall be the monthly peak load at the Points of delivery specified as Utility Delivery facilities.
- Billing Adjustments to Customer System Peak (CSP)

Recovery Peak

- Issue: Power restoration events that affect Load Following utilities' Demand Billing Determinant.
- A few power restoration events occurred in January 2012 where utilities experienced system outages caused by a winter storm. When power was restored, the utilities experienced "recovery peaks" which set their Customer System Peak (CSP) for the month and created significantly higher Demand Charges than they otherwise would have seen.

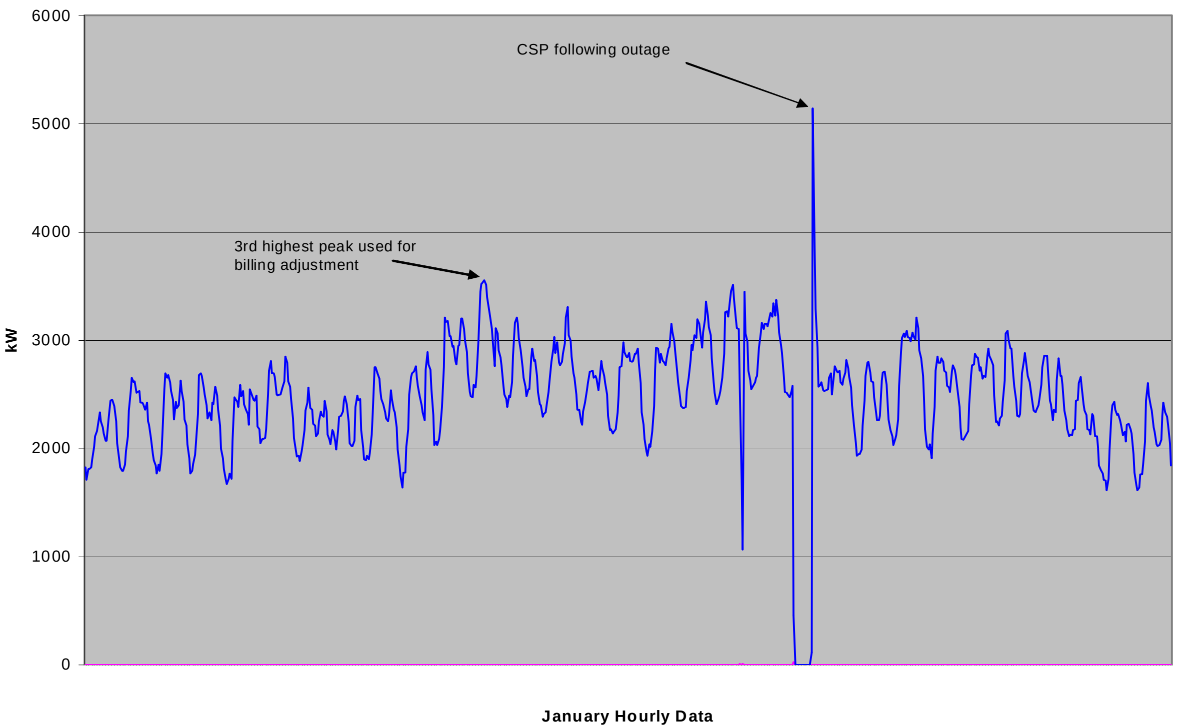


Proposed Qualifying Parameters

- BPA staff proposes to provide billing accommodations when recovery peaks occur.
- Proposed qualifying parameters for Demand Charge relief:
  - The outage must have occurred due to an Uncontrollable Force. The outage must have been for two hours or more (An outage of at least two hours provides a level of confidence that the measured peak was caused by a system recovery).
  - The outage must have reduced the utility’s total system load by 25 percent or more (This provides some assurance that the outage was significant for the customer).
  - The Demand Billing Determinant resulting from the recovery peak must have been ten percent or more of the recovery peak kW.

Proposed Billing Adjustments

- If a utility does experience a system outage that results in a recovery peak, they would have 45 days after the event to notify their BPA Account Executive that they are seeking relief.
- Provide relief to the Demand charge by reducing the Demand CSP by the kW difference between the CSP set immediately following an outage and the next highest HLH peak not following an outage.
- Assume recovery events affect peaks for 2 hours following an outage. If more than one recovery event occurs, use the highest HLH peak hour **not** following an outage (e.g., the 3rd hour, the 5th hour, the 7th hour, etc.).



SECTION III DEFINITIONS

- No. 31 “Monthly Transmission Peak Load” Delete the term “Monthly Transmission Peak Load” and its definition.
- Add a new definition:
  - Customer System Peak (CSP)
    - For NT customers: The monthly Billing Factor shall be the customer’s Network Load on the hour of the CSP. The CSP is the largest hourly average load amount, in kilowatts, for the billing period.
  - Station Control Error (SCE)
    - The SCE measured in MWs, is the difference between the plant generation request that BPA’s AGC sends to the plant and the actual generation reported back to BPA by the plant.
      - In the case of generators that are not controlled by BPA’s AGC, SCE is the difference between actual generation for the generator and the scheduled generation. SCE is measured in MW.

Next Steps

- Looking for customer comments on:
  - the Rate Schedules proposed changes .

- Comments due by August 29, 2012:
  - techforum@bpa.gov
  - Please include in subject line: “BP14 Transmission Rate Case – Rate Schedules Proposed Changes”.

NT Customers’ Utility Delivery Charge (UDC) Proposal

NT Customers' Utility Delivery Charge (UDC) Proposal

- At the June 13 rates workshop, NT Customers (represented by NRU, PNGC, and WPAG) submitted a proposal for the Utility Delivery Charge (UDC).
- NT Customer Proposal
  - Any increase in the UDC should be the same as the percentage change in the NT rate.
  - This UDC policy to remain the same for the next three rate periods.
  - At the end of three rate periods, the UDC will be eliminated and charges for any unsold UD substations will be converted to Use Of Facilities (UFT) charges.

NT Customers' UDC Proposal, cont.

- At the June 27 rates workshop, NT Customers (again represented by NRU, PNGC, and WPAG) responded to the PTP Coalition's proposal to use FERC's Seven-Factor Test in redefining the Network segment.
- NT Customers' Response:
  - BPA should not redefine the Network segment.
  - All facilities at 34.5 kV or above should remain in the Network segment.
  - Redefining the Network segment as proposed by the PTP Coalition is inconsistent with BPA's organic statutes and Congressional intent.

NT Customers' UDC Proposal, cont.

- How will the under-recovery be collected?
  - NT customers stated that this should be recovered from the entire Network segment.
    - Under-recovery will be offset by the revenue generated as these Utility Delivery facilities are sold and the funds used to benefit all Transmission customers and future O&M expenses reduced, as was done in prior rate cases.
    - The $2.5 million under-recovery has a de minimis impact on the Network rate segment (0.3%) (these values calculated by the NT customer representatives, not BPA).
    - Many costs that benefit a limited number of customers are included in the Network segment, e.g., NOS builds and PTSA reform).

Next Steps

- Looking for customer comments on:
  - the NT Customers' UDC proposal.

- Comments due by September 5, 2012:
  - techforum@bpa.gov
  - Please include in subject line: "BP14 Transmission Rate Case – NT Customers' UDC Proposal".

Redispatch 101

(Slides will be sent separately on Monday, August 20)

Timeline for the Workshops

- Upcoming Workshops
  - Sep 12 - Transmission Pre-Rate Case - AM
    - Montana Intertie
  - Sep 26 - Transmission Pre-Rate Case - AM
  - http://www.bpa.gov/corporate/ratecase/bp14_meeting_ws.cfm

Appendix

- Assumptions
- Forecast and actual deferrals in MW
- Forecast and actual reservation fees
- Deferral Statistics

Assumptions

- For FY 14 – FY 20 assumed current rates.
- Risk analysis was performed to produce an expected value. The assessed risk was based on BPA's Wind Interconnection Forecast and Account Executive input based on customer discussions.
- Reservation fees are assumed to be received in the first month of deferral.
- Does not reflect potential terminations.
- Deferrals only forecast for current offers. No assumptions are made about requests currently in the queue.
- Forecast NOS Project Start Dates:
  - Big Eddy – Knight: January 2015
  - Central Ferry – LoMo: January 2015

Mitigation Analysis Assumptions

- Competitions.
  - Up to four competitions were competed per year.
  - Which TSRs were competed were selected at random.
  - If a TSR was competed, the chance of a successful competition (that revenues would be received earlier) was:
    - 30% if a Non-NOS request or NOS 2008 request.
    - 80% if a NOS 2009 or NOS 2010 request.
- Short Term Sales.
  - Assumed short-term sales was based on the highest ATC held on BPA's most congested 4 flowgates: South of Alston, Cross Cascades North, West of Slatt, and West of John Day.
  - This amount was assumed to be resold for the full period of the deferral.
  - Based on the past year of short-term MWh scheduled (excluding hourly and loss returns) the resold assumed as follows (all were risk adjusted):
    - 89% Redirects (results in no additional revenues).
    - 10% Daily sales (rate of $60 per MW day).
    - 1% Monthly sales (rate of $48.30).
  - For the combination competition and short-term sales forecast, short-term sales were not considered if a successful competition occurred.

Actual and Forecast Deferrals (MW)

Actual (for FY 2010-2011) and Forecast (for FY 2012-2020) Deferred MW

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
		Actuals		Forecast								
		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020
1	Non-NOS Requests	12,379	10,411	4,883	724	624	304	42	-	-	-	-
2	NOS - No Build Required (includes CF)	3,049	6,725	5,685	4,452	3,501	2,670	1,085	145	69	76	6
3	NOS - Build Required	-	-	1,120	1,110	794	27,837	33,703	30,821	27,252	22,168	5,101
4	**Total**	**15,428**	**17,136**	**11,688**	**6,286**	**4,918**	**30,810**	**34,830**	**30,966**	**27,321**	**22,244**	**5,107**

MW Deferred On NOS Builds

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020
1	John Day - McNary	1,120	1,110	759	709	20	2	0	0	-
2	Big Eddy - Knight	-	-	35	22,988	28,244	25,416	22,056	18,847	4,484
3	Central Ferry - LoMo	-	-	-	4,140	5,439	5,403	5,196	3,322	616
4	**Total**	**1,120**	**1,110**	**794**	**27,837**	**33,703**	**30,821**	**27,252**	**22,168**	**5,101**

Actual (for FY 2010-2011) and Forecast (for FY 2012-2020) Deferred MW

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
		Actuals		Forecast								
		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020
1	**Cash**	**3,606**	**5,293**	**1,560**	**582**	**194**	**90**	**33**	**48**	**70**	**76**	**6**
2	**Credits**	**11,822**	**11,843**	**10,128**	**5,704**	**4,725**	**30,720**	**34,797**	**30,918**	**27,251**	**22,168**	**5,101**
3	**Total**	**15,428**	**17,136**	**11,688**	**6,286**	**4,918**	**30,810**	**34,830**	**30,966**	**27,321**	**22,244**	**5,107**

Actual and Forecast Reservation Fees

Actual (for FY 2010-2011) and Forecast (for FY 2012-2020)
Reservation Fees (in $M)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
		Actuals		Forecast								
		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020
1	Non-NOS Requests	$ 0.35	$ 1.46	$ 0.73	$ 0.03	$ 0.03	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00
2	NOS - No Build Required (includes CF)	$ 0.55	$ 1.12	$ 0.53	$ 0.26	$ 0.25	$ 0.23	$ 0.10	$ 0.01	$ 0.01	$ 0.00	$ 0.00
3	NOS - Build Required	$ 0.00	$ 0.00	$ 0.13	$ 0.09	$ 0.08	$ 4.08	$ 3.52	$ 3.18	$ 2.66	$ 2.15	$ 0.00
4	**Total**	**$ 0.90**	**$ 2.57**	**$ 1.39**	**$ 0.38**	**$ 0.37**	**$ 4.32**	**$ 3.62**	**$ 3.19**	**$ 2.67**	**$ 2.15**	**$ 0.00**

Forecast Reservation Fees Related to NOS Projects

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020
1	John Day - McNary	$ 0.13	$ 0.09	$ 0.08	$ 0.01	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00
2	Big Eddy - Knight	$ 0.00	$ 0.00	$ 0.01	$ 3.48	$ 2.94	$ 2.59	$ 2.24	$ 1.89	$ 0.00
3	Central Ferry - LoMo	$ 0.00	$ 0.00	$ 0.00	$ 0.60	$ 0.58	$ 0.58	$ 0.41	$ 0.26	$ 0.00
4	**Total**	**$ 0.13**	**$ 0.09**	**$ 0.08**	**$ 4.08**	**$ 3.52**	**$ 3.18**	**$ 2.66**	**$ 2.15**	**$ 0.00**

Forecast Reservation Fees Related to Service Paid with Cash or Credits

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020
1	Cash	$ 0.36	$ 0.49	$ 0.17	$ 0.01	$ 0.00	$ 0.01	$ 0.00	$ 0.01	$ 0.01	$ 0.00	$ 0.00
2	Credits	$ 0.54	$ 2.09	$ 0.42	$ 0.37	$ 0.32	$ 4.17	$ 3.52	$ 3.18	$ 2.66	$ 2.15	$ 0.00
3	Total	$ 0.90	$ 2.57	$ 0.58	$ 0.38	$ 0.32	$ 4.18	$ 3.52	$ 3.19	$ 2.67	$ 2.15	$ 0.00

FY 10 – FY 20 Deferral Statistics

		(A) Average # of Deferrals[1]	(B) Average Deferral Length (years)[1]
1	Non-NOS Requests	4	3.79
2	NOS - No Build Required (includes CF)	2	2.16
3	NOS - Build Required	3	3.54
4	Overall Average	4	3.46

		(A) % of MW offered expected to defer	(B) % of MW offered expected to defer 2 or more years
1	John Day - McNary	47%	22%
2	Big Eddy - Knight	88%	67%
3	Central Ferry - LoMo	84%	82%
4	NOS Build %	78%	60%

[1]Note: Averages are weighted by MW