2012 BPA Rate Case
Customer Workshop

Transmission Rate Development

September 15, 2010

Transmission Rates Workshop Agenda
9:00 A.M. – 5:00 P.M.

- **Opening and Introduction**
- **Preliminary Transmission Rate Development for FY12-13 Rate Case**
  - Transmission Parking Lot Issues:
    - Failure to Comply Penalty Charge
    - NT Unauthorized Increase Charge
    - Power Factor Penalty Charge
  - Segmentation Study
  - Revenue Requirement
  - LGIA Credits
  - Revenue Forecasting
    - Load Forecasting
  - Transmission Rate Study
  - Snohomish presentation on Transmission Rate Development
- **Next Steps**

Acronym List

- AGC – Automatic Generation Control
- BAA – Balancing Authority Area
- CA – Control Area
- CF – Conditional Firm
- COB – California-Oregon Border
- COE – Corps of Engineers
- CSL – Customer Served Load
- DNR – Designated Network Resource
- FCRTS – Federal Columbia River Transmission System
- FPT – Formula Power Transmission
- GI – Generation Interconnection
- GSP – Generation System Peak
- HLH – Heavy Load Hour
- IM – Montana Intertie
- IPR – Integrated Program Review
- IR – Integration of Resources
- IS – Southern Intertie
- LGIA – Large Generator Interconnection Agreement
- MRNR – Minimum Required Net Revenues
- NEPA – National Environmental Policy Act
- NOS – Network Open Season
- NT – Network Transmission
- OATT – Open Access Transmission Tariff
- OR – Operating Reserve

Acronym List (Cont.)

- PCB – Polychlorinated Biphenyl
- POD – Point of Delivery
- POR – Point of Receipt
- PTP – Point to Point
- PV – Present Value
- SDD – Short Distance Discount
- SI – Southern Intertie
- RFR – Regulation and Frequency Response
- SCD – Scheduling, System and Dispatch
- TRS – Transmission Rate Study
- TSA – Transmission Service Agreement
- TSP – Transmission System Peak
- TSR – Transmission Service Request
- UD – Utility Delivery
- UFT – Use of Facilities
- WI – Within Hour Balancing Service
- USBR – Bureau of Reclamation

Objective

- Our objective today is to continue discussion of the transmission parking lot issues. We will focus on recent customer submitted transmission parking lot issues and provide preliminary transmission rate levels and assumptions today.
- The alternatives discussed for each parking lot topic do not reflect BPA commitment to adopt any particular proposal in the Initial Proposal. To the extent possible, we are interested in hearing customer's perspective on rate alternatives discussed.
- Today's discussion is **preliminary** and **pre-decisional**.
- We look forward to working together toward development of the Initial Proposal.

Rate Making Principles

- Full and timely cost recovery
- Lowest possible rates consistent with sound business principles
- Cost causation—fairly allocate costs to customers based on proportionate use
- Statutory requirement of equitable allocation
- Simplicity, understandability, public acceptance, and feasibility of application
- Avoidance of rate shock and rate stability from rate period to rate period (e.g., magnitude of rates and rate design)
- Meet Treasury Payment Probability (TPP) standard where financial reserves achieve 95% TPP of making US Treasury Payments in full and on time each year of the two year rate period

TR-12 Transmission Parking Lot Topics

	Parking Lot Topic	Status of Workshop Meetings
1	Incremental Cost Rates	See Meeting Handouts on: 4/14, 7/14
2	Delivery Charge	See Meeting Handouts on: 4/14, 6/17, 8/18
3	Short Distance Discount Added to Southern Intertie	See Meeting Handouts on: 4/14, 7/14
4	Reservation Fee	See Meeting Handouts on: 4/14, 7/14, 8/18
5	CSL Replacement (Short Distance Discount)	See Meeting Handouts on: 4/14, 7/14, 8/18
6	Transmission Segmentation	See Meeting Handouts on: 4/14, 6/17, 7/14, 9/15
7	Revenue Requirement	See Meeting Handouts on: 9/15
8	Revenue/Load Forecasting/LGIA Credits	See Meeting Handouts on: 9/15
9	Risk Analysis	See Meeting Handouts on: 9/15
10	Use of Cash Reserves	See Meeting Handouts on: 5/26, 7/14
11	Montana/Eastern Intertie	See Meeting Handouts on: 6/17, 7/14, 8/18
12	Overall Transmission Rates (No Surprises)	To Be Scheduled
13	Power Factor Penalty: Transfer Service, Ratchet Demand	See Meeting Handouts on: 7/14, 8/18
14	Customer Reasons for Unsold UD Facilities	See Meeting Handouts on: 6/17
15	Does rolling-in the Montana Intertie into the Network mean that Generators Interconnecting at Townsend would be in the Bonneville BAA and take Control Area services from BPA?	See Meeting Handouts on: 8/18
16	Unauthorized Increase Charge	See Meeting Handouts on: 7/14, 8/18
17	Failure to Comply Penalty Charge	See Meeting Handouts on: 9/15

Failure to Comply Penalty Charge

Failure to Comply Objective

- We plan to review relevant background and policy supporting the Failure to Comply Penalty charge.
- Discuss recent customer-submitted proposed rate alternatives and invite other customers to weigh in on the proposals.
- Discuss additional rate alternatives.

Failure to Comply

- If a party fails to comply with the BPA-TS's dispatch, curtailment, redispatch, or load shedding orders, the party will be assessed the Failure to Comply Penalty Charge.
- Currently, the Failure to Comply Penalty Charge is 1000 mills per kilowatthour.
- Please refer to the Failure to Comply Business Practice for additional processes and procedures regarding the application of the Failure to Comply Penalty.

Background

- The Failure to Comply Penalty Charge is designed to incentivize and encourage compliance with BPA-TS dispatch, curtailment, redispatch, and load shedding orders.
- Due to the increased non-compliance with its orders, BPA-TS increased the Failure to Comply Penalty Charge during the 2010 Transmission Rate Case.
  - A penalty of 1000 mills per kilowatthour is designed to avoid economic considerations and encourage full compliance with BPA-TS orders.
- Currently, the Rate Schedule does not provide for a dead-band related to the Failure to Comply Penalty Charge.

Failure to Comply Penalty Charge- Rate Level Alternatives

1. **Retain BPA's existing $1000/MWh Failure to Comply Penalty Charge**.
   - The $1000/MWh charge is designed to encourage compliance with BPA-TS orders to maintain system reliability and to avoid any economic incentives involved with whether or not to comply with such orders.
   - The penalty rate has been effective in incentivizing compliance with BPA-TS orders.
   - The current penalty is 2.5 times the current WECC price cap.

2. **TransAlta proposes to decrease the Failure to Comply Penalty Charge to $250/MWh or 150% of the hourly MIDC index (whichever is greater during the curtailment hour).**
   - The rate level, $250/MWh may provide some incentive to comply with BPA-TS orders.
   - Compared to the WECC price cap ($400/MWh), the rate nevertheless does not appear to remove economic considerations of compliance with BPA-TS orders.
   - **Please refer to the separate handout for the customer proposal**.

Failure to Comply Penalty Charge – Rate Level Alternatives

3. **BPA staff are considering whether or not to propose to modify the Failure to Comply Penalty Charge to be the greater of $1000/MWh or the effective WECC price cap.**
   - Currently, the WECC price cap is set at $400/MWh.
   - The WECC price cap may increase beyond the current rate of $1000/MWh. If so, a change in price would potentially compromise the underlying rate objectives of sending a clear price signal to encourage compliance with dispatch orders to maintain system reliability.
   - The proposed revised penalty charge also preserves the avoidance of any potential economic considerations of whether or not to comply with BPA-TS orders.

Failure to Comply Penalty Charge – Rate Design Alternatives

1. **Retain BPA's No Dead-Band / Tolerance-Band Rate Design.**
   - Maintains the ***reliability*** of the transmission system by requiring full compliance with curtailment orders to relieve congestion on the system.
   - Sends clear signal to comply with orders at all times and under all circumstances.

2. **TransAlta's proposes to establish a dead-band at 1.5% of sum of schedules**.
   - If the generator output remains within 1.5% of sum of schedules during a curtailment, the generator will not be assessed a Failure to Comply Penalty Charge.
   - **Please refer to the separate handout for the customer proposal.**

   <u>A few staff questions to consider</u>:
   - Does this proposal create the potential for deeper curtailments in order to effectively relieve constraints? What are unintended consequences might we be overlooking (eg. large generator)?

Failure to Comply Penalty Charge – Rate Design Alternatives

3. **Puget proposes to establish a "de-minimus" exemption based on a specific MW deadband.**
   - For example: generators maintaining generation to within 2 MW of the sum of the schedules will not be assessed a Failure to Comply Penalty.
   - **Please refer to the separate handout for the customer proposal.**

<u>A few staff questions to consider regarding above proposals</u>:

- Will deeper curtailments be needed to effectively relieve constraints?
- Are there unintended consequences introduced such as penalty avoidance for low generation levels?
- Are we sending mixed messages with regard to compliance with orders necessary to relieve constraints?

NT Unauthorized Increase Charge (UIC)

NT Unauthorized Increase Charge (UIC)-Background

- Customer Served Load (CSL) will expire at midnight on September 30, 2011.
- Transmission Customers taking Network Integration (NT) Transmission Service under the NT Rate Schedule are assessed the UIC if the Actual CSL is less than the Declared CSL.
- As CSL expires, BPA Transmission Services is considering alternatives to replace the NT UIC.
- FERC guidance supports a UIC for both PTP and NT Service. See Order No. 890, para. 838 and Order No. 890-A, para. 437.

NT Unauthorized Increase Charge Rate Alternatives

1. **Do not establish an NT UIC for 2012-2013 Rate period.**
   - Monitor unreserved use of the transmission system and revisit this proposal in the next rate case.

2. **Establish an NT UIC for Behind the Meter Generation exceeding a customer's Network Load for any given hour.**
   - Behind the Meter Resources, by definition, do not use BPA transmission facilities.
   - Behind the Meter generation exceeding Network Load flows onto the BPA Transmission System.
   - Output from Behind the Meter Resources is not scheduled.

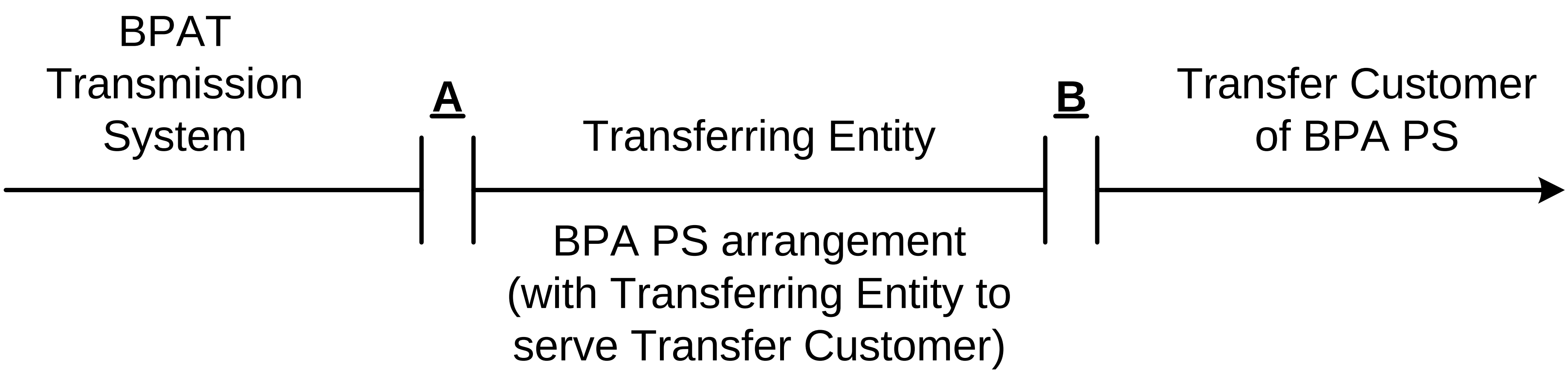
3. **Establish an NT UIC for Scheduling NT Firm transmission, from designated Network Resources, above contractually designated capacity.**
   - Customer can submit additional schedules for secondary non-firm service to Network Load.

4. **Establish an NT UIC based on a combination of the above alternatives 2 and 3.**

Power Factor Penalty – Transfer Service

BPA Transmission Services Power Factor Penalty Charge - Transfer Service

- Since the last workshop, we considered the need to add supplemental language to the Power Factor Penalty charge rate schedule.
- We are proposing to maintain existing rate schedule language.
  - Pursuant to the Rate Schedule, each point of interconnection or point of delivery is monitored and billed independently.
  - Current provisions do not preclude Transferring Utilities from assessing power factor penalties to the transfer contract holders.



Segmentation

Segmentation Study Purpose

- The rate development includes segmentation and revenue requirements and concludes with rate design.
- The primary purpose of the segmentation study is to provide the cost basis for segmenting the revenue requirements used to develop transmission rates.
- The output of the segmentation study provides capital investment and historical O&M costs.
- Segments are defined primarily by voltage and function, or, for some segments, by voltage and contract.
- Investment and O&M costs are based on historical costs.

Segmentation Background

- In workshops for the 2010-2011 Rate Case, BPA presented segmentation information, in addition to the results to date of the segmentation process.
- On September 9th of last year, BPA presented in-depth information on the segmentation methodology, including a detailed description of how multi-purpose assets were allocated among the segments, how overhead is allocated, etc.
- For the purposes of today's preliminary discussion, the definition of transmission segments and the segmentation methodology previously established remain unchanged. The inputs however have been updated with more recent information to produce newer results that will be discussed today.
- BPA-TS is open to other customer suggested alternatives.
- More segmentation information is provided in the Appendix.

Summary of Segment Investments

	Asset Investment as of 09/30/07		Asset Investment as of 09/30/09	
Segment	Investment ($)	% of Total	Investment ($)	% of Total
Generation Integration	61,366,601	1%	61,535,536	1%
Network	3,703,930,733	79%	3,945,565,443	↑ 81%
Southern Intertie*	712,121,650	15%	685,150,049	↓ 14%
Eastern Intertie	118,137,417	3%	118,137,417	↓ 2%
Utility Delivery	25,826,076	1%	25,517,732	1%
DSI Delivery	62,625,014	1%	15,557,383	↓ 1%
Totals**	4,684,007,492	100%	4,851,463,560	100%
Ancillary Services	552,352,183	N/A	586,398,809	N/A

*The Southern Intertie assets investments ($) can be further broken down into:	**09/30/07**	**09/30/09**
AC Intertie	325,146,229	326,237,856
DC Intertie	386,975,421	358,912,193

**Totals may not add due to rounding

Other Segmentation Considerations

Here are key drivers to changes in investments from FY07 to FY09:

1. The absolute size of the Network segment has grown by ~$242 million, or about 6.5%, increasing the relative size from 79% to 81% of total investment in lines and substations.

2. The total gross investment in the Southern Intertie segment at the end of FY09 was approximately $27 million less than it was at the end of FY07, a decrease of about 1% in the Southern Intertie's relative size.

3. The Ancillary Services investment grew by ~$34 million or ~6%. Investment in Ancillary Services assets increased in all categories, but the largest relative increase was in the "Computer Hardware and Software for Control Systems" category. This equipment is used for control of the system and is located at the control centers. Examples include the scheduling system and updates to automatic generation control system (AGC).

Other Segmentation Considerations (cont.)

- In order to reflect modifications to the asset base during the rate period, BPA also forecasts plant investment and reflects these assumptions in the segmentation study.

- The Corps of Engineers (COE) and Bureau of Reclamation (USBR) transmission assets at Federal hydroelectric projects are segmented in the same way as other BPA assets.
  - However, these transmission costs are included in the Power Service's Revenue Requirement and are then charged back to Transmission through inter-business line transfers.
  - This approach is consistent with prior rate cases.

- Customer comments and suggestions are welcome at this time.

FY 2012-13
Transmission Rate Case
Revenue Requirement

Assumptions

- Program spending levels are consistent with data presented in Integrated Program Review (IPR) workshops.
- Generation input costs are a placeholder and will be revised for the Initial Proposal.
- Net interest and amortization are consistent with the debt management workshops.
- BPA proposes to use $15 million per year of reserves for capital investments which is consistent with the last two rate cases.
- Changes to be expected in the Initial Proposal
  - Updates for final IPR decisions
  - Updates for actual FY 2010 results, e.g., actual capital borrowing, actual ending reserves
  - Adjustments to ensure consistency with other forecasts and studies, such as updates to Large Generation Interconnection Agreement (LGIA) credits and generation input costs

Income Statement

($thousands)

		A FY 2012	B FY 2013	C Average	D TR-10 Final	E Difference
1	OPERATING EXPENSES					
2	TRANSMISSION OPERATIONS	137,348	140,956	139,152	118,584	20,568
3	TRANSMISSION MAINTENANCE	150,425	154,468	152,447	129,826	22,620
4	TRANSMISSION ENGINEERING	34,522	35,579	35,051	23,607	11,443
5	TRANSMISSION ACQ & ANCILLARY SERVICES	132,171	152,580	142,376	109,875	32,501
6	BPA INTERNAL SUPPORT	72,973	74,382	73,678	65,514	8,163
7	OTHER INCOME, EXPENSES & ADJUSTMENTS				(20,000)	20,000
8	DEPRECIATION & AMORTIZATION	205,469	224,398	214,934	195,619	19,315
9	TOTAL OPERATING EXPENSES	732,908	782,363	757,636	623,025	134,610
10	INTEREST EXPENSE					
11	INTEREST EXPENSE					
12	FEDERAL APPROPRIATIONS	23,087	11,115	17,101	30,259	(13,158)
13	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)	(18,968)	(18,968)	0
14	ON LONG-TERM DEBT	120,253	158,699	139,476	101,660	37,816
15	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	561	561	561	725	(164)
16	DEBT SERVICE REASSIGNMENT INTEREST	56,773	54,868	55,821	56,781	(960)
17	NON-FEDERAL INTEREST	50,442	57,516	53,979	36,846	17,133
18	AFUDC	(36,883)	(41,442)	(39,162)	(19,574)	(19,588)
19	INTEREST INCOME	(20,658)	(20,579)	(20,619)	(23,840)	3,221
20	NET INTEREST EXPENSE	174,607	201,769	188,188	163,888	24,300
21	TOTAL EXPENSES	907,515	984,132	945,824	786,913	158,910
22	MINIMUM REQUIRED NET REVENUES 1/	70,026	55,256	62,641	75,079	(12,438)
23	PLANNED NET REVENUES FOR RISK	0	0	0	0	0
24	TOTAL PLANNED NET REVENUES	70,026	55,256	62,641	75,079	(12,438)
25	**TOTAL REVENUE REQUIREMENT**	**977,541**	**1,039,388**	**1,008,464**	**861,992**	**146,472**

1/ SEE NOTE ON CASH FLOW TABLE.

Statement of Cash Flows

($thousands)

		A FY 2012	B FY 2013	C Average	D TR-10 Final	E Difference
1	CASH FROM CURRENT OPERATIONS:					
2	MINIMUM REQUIRED NET REVENUES 1/	70,026	55,256	62,641	75,079	(12,438)
3	EXPENSES NOT REQUIRING CASH:					
4	DEPRECIATION & AMORTIZATION	205,469	224,398	214,934	195,619	19,315
5	TRANSMISSION CREDIT PROJECTS NET INTEREST	20,000	27,082	23,541	11,877	11,664
6	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	561	561	561	725	(164)
7	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)	(18,968)	(18,968)	0
8	DRAWDOWN OF CASH RESERVES FOR CAPITAL FUNDING	15,000	15,000	15,000	15,000	0
9	ACCRUAL REVENUES (LGIA/AC INTERTIE/FIBER)	(45,789)	(52,532)	(49,161)	(44,317)	(4,844)
10	CASH PROVIDED BY CURRENT OPERATIONS	246,299	250,797	248,548	235,014	13,534
11	CASH USED FOR CAPITAL INVESTMENTS:					
12	INVESTMENT IN:					
13	UTILITY PLANT	(584,403)	(632,808)	(608,606)	(449,266)	(159,339)
14	CASH USED FOR CAPITAL INVESTMENTS	(584,403)	(632,808)	(608,606)	(449,266)	(159,339)
15	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:					
16	INCREASE IN LONG-TERM DEBT	569,403	617,808	593,606	434,266	159,339
17	DEBT SERVICE REASSIGNMENT PRINCIPAL	(41,118)	(165,628)	(103,373)	(83)	(103,290)
18	REPAYMENT OF LONG-TERM DEBT	(25,000)	0	(12,500)	(120,126)	107,626
19	REPAYMENT OF CAPITAL APPROPRIATIONS	(165,181)	(70,169)	(117,675)	(99,806)	(17,869)
20	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	338,104	382,011	360,058	214,252	145,806
21	ANNUAL INCREASE (DECREASE) IN CASH	0	0	0	0	0
22	PLANNED NET REVENUES FOR RISK	0	0	0	0	0
23	TOTAL ANNUAL INCREASE (DECREASE) IN CASH	0	0	0	0	0

1/ Line 21 must be greater than or equal to zero, otherwise net revenues will be added so that there are no negative cash flows for the year.

Segmented Revenue Requirement

($thousands)

		A	B	C	D	E	F	G	H
	FY 2012	TOTAL	Generation Integration	NETWORK	Southern Intertie	Eastern Intertie	Utility Delivery	DSI Delivery	Ancillary Services
1	Operations & Maintenance	395,268	4,149	258,811	35,781	2,546	3,723	1,445	88,813
2	Transmission Acquisition & Ancillary Services	132,173	63	17,369	1,933	18	444	30	112,316
3	Depreciation	205,470	2,414	155,309	23,198	3,065	1,280	633	19,571
4	Net Interest Expense	174,607	1,979	136,346	15,625	2,535	707	415	17,000
5	Planned Net Revenues	70,025	739	49,917	11,653	947	264	155	6,350
6	Total Transmission Revenue Requirement	977,543	9,344	617,752	88,190	9,111	6,418	2,678	244,050
	FY 2013								
7	Operations & Maintenance	405,387	4,252	265,655	36,652	2,609	3,815	1,481	90,923
8	Transmission Acquisition & Ancillary Services	152,581	63	17,124	1,933	18	762	30	132,651
9	Depreciation	224,400	2,613	171,832	24,366	3,120	1,373	664	20,432
10	Net Interest Expense	201,768	2,088	162,719	15,754	2,387	690	393	17,737
11	Planned Net Revenues	55,255	569	38,356	10,552	650	188	107	4,833
12	Total Transmission Revenue Requirement	1,039,391	9,585	655,686	89,257	8,784	6,828	2,675	266,576

LGIA Credits and Expenses

- The revenue credits that customers receive in return for the funding of Network upgrades currently serve as a net cost for other transmission customers.
- These accrual revenues provide no cash for cost recovery. However, they are offset to a certain extent by the associated costs of these transactions, which are part of the revenue requirement. These costs are also non-cash elements.
- Plant investment associated with the Network upgrades is depreciated like all other plant, adding to depreciation expense.
- Interest on the outstanding LGIA deposits is part of non-Federal interest component of net interest expense.
- On the revenue requirement's cash flow statement, these expenses are netted against the revenues as part of the Minimum Required Net Revenues (MRNR) calculation. MRNR is the amount that cash requirements (bond and appropriation repayment) exceed non-cash elements in the revenue requirement.
- To the extent that LGIA revenues exceed associated expenses, it creates additional costs to be recovered through rates because the credit is based on rates for service that must provide cash cost recovery.

Repayment Model Conversion

Repayment Model

- The primary purpose of the repayment model is to determine a schedule of Federal principal payments that satisfies the statutory requirement to set rates to assure timely repayment of the Federal investment at the lowest cost to consumers consistent with sound business principles.
- The repayment model is also used for managing BPA's debt portfolio. For example, the repayment model assisted with the debt restructuring scenarios that were presented at the public Debt Management meetings this summer.
- Annual debt service streams for non-Federal payment obligations are included as fixed requirements that the study must take into account in establishing the overall levelized debt service for the agency. BPA's non-Federal debt currently consists primarily of Energy Northwest debt and debt associated with the Lease Financing program.
- The model uses an iterative methodology to find the lowest level of combined non-Federal and Federal interest and principal payments such that all debts are paid within the repayment period (50 yrs for Generation; 35 yrs for Transmission).

Repayment Model

- For the TR-04 initial rate proposal, BPA converted from the Fortran repayment model to the Ferrand Jordan (Munex) repayment model. BPA will convert from the Munex repayment model to a new repayment model for the WP-12 and TR-12 rate case.
- Replacing Munex was necessary because:
  - Munex repayment model was developed by the Ferrand Jordan Company and written in APL, to work in conjunction with the Munex debt database, an off-the-shelf software package.
  - Ferrand Jordan no longer supports this custom model.
  - The APL language is obscure and programmers are hard to find.
- BPA examined several alternatives for the debt database software and determined that the widely used, off-the-shelf DBC Debt Manager product would best meet our database needs. However, we also needed a repayment model that would be compatible with DBC.

C# Repayment Model

- The new repayment model, that was developed in house and written in the C# (pronounced "C Sharp") programming language, incorporates and interfaces with the data from the DBC debt database.
  - The new model offers more flexibility as well as an interface that uses all of the benefits of a Windows-based approach.
  - It is also fully supported by BPA without relying on outside maintenance. This was a major objective since the repayment model is critical to BPA's financial operations.
- The new C# model offers the same methodology as the Munex model, with full replication of the original repayment model used for regulatory repayment runs. It determines which bonds to call based on highest coupon adjusted for the call premiums.
  - One enhancement in the C# model is that it can reflect make-whole call terms that BPA now incorporates in compliance with the Treasury Memorandum of Understanding, in addition to the coupon scale-down call terms that the Munex model handled.
  - A second enhancement of the C# model is in the way the input data is formatted and manipulated, which saves staff time and reduces input errors.

C# Repayment Model Testing Process

- In order to confirm that the C# repayment model replicates the same methodology as Munex, we ran both models using the same data and compared the results.

- Generation:
  - At the June 18th public Debt Management workshop, Finance presented two debt restructuring scenarios. Scenario B restructured callable bonds in 2011 & 2012 (Projects 1&3) and extended maturing and callable CGS principal in 2011 and 2012.
  - The Munex model was used for the Debt Restructuring analysis. The data used to create Scenario B in Munex for the Debt Management workshop was replicated in the C# model.

- Transmission:
  - A Munex repayment study was created with the Transmission capital spending levels from the IPR process. Again, the data used to create the Transmission IPR study in Munex was replicated in the C# model.

Comparison of Results

Generation (Debt Management Scenario B)

Fiscal Year	Total Debt Service			Non-Federal Debt Service			Federal Interest			Federal Amortization			Irrigation		
	Munex	C#	Delta	Munex	C#	Delta	Munex	C#	Delta	Munex	C#	Delta	Munex	C#	Delta
2010	1,027,629	1,027,629	-	527,086	527,086	-	255,870	255,870	-	244,673	244,673	-	-	-	-
2011	981,350	981,350	-	559,990	559,990	-	259,197	259,197	-	162,163	162,163	-	-	-	-
2012	1,001,837	1,001,837	-	531,962	531,962	-	275,693	275,693	-	193,000	193,000	-	1,182	1,182	-
2013	1,070,085	1,070,085	-	592,765	592,765	-	295,697	295,697	-	122,800	122,800	-	58,822	58,822	-
2014	1,016,897	1,016,897	-	601,268	601,268	-	326,263	326,263	-	36,940	36,940	-	52,426	52,426	-
2015	1,031,528	1,031,528	-	577,476	577,476		357,064	357,064	-	45,000	45,000	-	51,987	51,987	-
2016	1,048,866	1,048,866	-	559,056	559,056	-	389,260	389,260	-	39,737	39,737	-	60,813	60,813	-
2017	1,065,670	1,065,670	-	562,122	562,122	-	421,652	421,652	-	30,618	30,618	-	51,277	51,277	-

Transmission

Fiscal Year	Total Debt Service			Non-Federal Debt Service			Federal Interest			Federal Amortization		
	Munex	C#	Delta	Munex	C#	Delta	Munex	C#	Delta	Munex	C#	Delta
2010	401,202	401,203		73,059	73,059	-	112,987	112,987	-	215,156	215,156	
2011	422,629	422,629		76,268	76,268	-	121,654	121,654	()	224,707	224,707	
2012	447,446	447,446	-	118,551	118,551	-	138,714	138,714	()	190,181	190,181	
2013	478,579	478,579	-	241,730	241,730	-	166,680	166,680	()	70,169	70,169	
2014	510,478	510,478	-	244,131	244,131	-	201,167	201,167	()	65,180	65,180	
2015	529,245	529,245	-	251,837	251,837	-	232,628	232,628	()	44,780	44,781	
2016	543,917	543,917	-	245,836	245,836	-	259,533	259,533	()	38,548	38,548	
2017	570,830	570,830	-	252,432	252,432	-	285,529	285,529	()	32,869	32,869	

Summary

- Lack of support for the Munex repayment model required BPA to find an alternative.
- DBC Debt Manager was the best debt database software that met BPA's needs.
- The C# repayment model was developed to work in conjunction with the DBC Debt Manager program and offers flexibility, in house support and added enhancements.
- The repayment methodology used by Munex and C# is identical.
- BPA will use the new C# repayment model in the WP-12 and TR-12 rate cases.

Overview of Large Generator Interconnection Agreement (LGIA) Forecasting and Methodology and Calculation of Credits

Transmission Credits Overview

- Customers select one of two methods to recover funds advanced for the construction of Network Upgrades necessary to enable generation interconnection. (The methods below are also defined in our Business Practice for Transmission Credits-Generator Large, V6)
  - Method 1-Application of transmission credits against eligible transmission bills.
    - PTP Service: Transmission credit applied in a given month is based on the amount of transmission capacity reserved at the generator.
    - NT Service: Transmission credit applied in a given month is based on a ratio of the customer's MW share of a generating resource to their maximum Network load set on the hour of the transmission peak over the last twelve months.
  - Method 2-Cash payment based on the estimated output of the facility multiplied by the PTP Long-Term rate.
- Customers earn interest on the funds advanced for Network Upgrades. Interest accrues monthly from date of deposit.
  - For LGIAs signed prior to July 15, 2009, the interest rate is either specified in the contract or is the FERC rate.
  - For LGIAs signed on or after July 15, 2009, the interest rate is the rate for ten-year bonds posted on Bloomberg, L.P. under the United States Government Agency fair market yield curve (yield curve number 84 - the Bloomberg rate) per our Business Practice for Transmission Credits-Generator Large, V6

Transmission Credits Rate Case Process

- The Generation Interconnection (GI) Queue was assessed to determine which generation projects were likely to be completed prior to or during the rate period.
- To the extent possible, each GI project was tied to requests in the Transmission Queue to forecast sales eligible to receive Transmission Credits.
  - When a request in the GI queue could not be tied to requests in the Transmission Queue, 50% of the nameplate of the generator was used to forecast the sales eligible to receive credits.
- Projects begin receiving Transmission Credits on the later of the forecasted commercial operation date or their TSR start date (if applicable).
- The dollar value of the Transmission Credits was determined by multiplying Transmission's current rates by the forecasted sales eligible for credits.
- Interest expense was calculated based the applicable interest rate and on the projected remaining funds advanced for Network Upgrades (the cost of the Network Upgrades less Transmission Credits repaid). The GI Queue was also assessed to determine what funds were expected to be advanced for Network Upgrades during the rate period.

Transmission Credits Rate Analysis Results

- BPA currently holds $131 million in funds advanced for Network Upgrades for projects that are now receiving Transmission Credits, and BPA holds an additional $137 million in funds advanced for Network Upgrades for projects that have not yet begun receiving Transmission Credits.
- For FY 11 through FY 13, BPA is forecasting approximately $324 million in additional funds advanced for Network Upgrades for continuing and future interconnection projects.
- Interest expense associated with Transmission Credits is forecast to be $22.8 million and $29.7 million in FY 12 and FY 13, respectively. The average interest expense over the rate period is $26.3 million per year.
- The current forecast shows that Transmission will issue Transmission Credits in the amounts of approximately $39.0 million and $46.0 million in FY 12 and FY 13, respectively. The average Transmission Credits issued during the rate period is $42.5 million per year.

Transmission Credit and Interest Forecast

The chart below shows credit and interest forecasts for GI projects in four different groups:

1) Projects where customers are currently receiving Transmission credits (rows 1 – 24)
2) Projects where the credit repayment forecast is based on TSRs (rows 25-50)
3) Projects where the credit repayment forecast is based on 50% of forecast capacity (row 51)
4) Projects forecast to earn interest during the rate period, but not to receive credit repayments (row 52)

   * Totals for all GI projects are shown on row 53

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	Request	Credit Start Date	Credit Balance as of 6/30/10 (Deposits prior to rate period)	Network Upgrade Cost During FY11 - FY13 Period	FY 11 Credit Repayment Forecast	FY 12 Credit Repayment Forecast	FY 13 Credit Repayment Forecast	FY 11 Interest Forecast	FY 12 Interest Forecast	FY 13 Interest Forecast
1	Currently Taking Credits (as of 6/30/10)									
2	GI Request 1	FY 2006	$ 4,020	$ 500	$ 2,445	$ 1,871	$ -	$ 138	$ 39	$ -
3	GI Request 2	FY 2006	$ 986		$ 674	$ -	$ -	$ 9	$ -	$ -
4	GI Request 3	FY 2006	$ 264	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	GI Request 4	FY 2008	$ 461		$ 180	$ -	$ -	$ 1	$ -	$ -
6	GI Request 5	FY 2008	$ 7,894		$ 4,362	$ 2,779	$ -	$ 217	$ 59	$ -
7	GI Request 6	FY 2008	$ 11,428	$ 200	$ 6,757	$ 4,330	$ -	$ 342	$ 89	$ -
8	GI Request 7	FY 2008	$ 15,014	$ -	$ 4,673	$ 4,673	$ 4,673	$ 527	$ 469	$ 234
9	GI Request 8	FY 2008	$ 9,041		$ 1,051	$ 1,051	$ 1,051	$ 373	$ 469	$ 477
10	GI Request 9	FY 2008	$ 1,469	$ -	$ 835	$ 485	$ -	$ 40	$ 9	$ -
11	GI Request 10	FY 2008	$ 871	$ -	$ 298	$ 298	$ 271	$ 30	$ 24	$ 9
12	GI Request 11	FY 2008	$ 3,396		$ 243	$ 243	$ 243	$ 145	$ 192	$ 208
13	GI Request 12	FY 2008	$ 3,396		$ 243	$ 243	$ 243	$ 145	$ 192	$ 208
14	GI Request 13	FY 2008	$ 261		$ 19	$ 19	$ 19	$ 11	$ 15	$ 16
15	GI Request 14	FY 2008	$ 6,009		$ 430	$ 430	$ 430	$ 256	$ 340	$ 368
16	GI Request 15	FY 2009	$ 10,264	$ -	$ 863	$ 863	$ 863	$ 433	$ 567	$ 604
17	GI Request 16	FY 2009	$ 2,348	$ -	$ 292	$ 292	$ 292	$ 69	$ 81	$ 74
18	GI Request 17	FY 2009	$ 1,667	$ -	$ 779	$ 779	$ 3	$ 50	$ 25	$ 0
19	GI Request 18	FY 2009	$ 229	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	GI Request 19	FY 2009	$ 2,885	$ -	$ 336	$ 336	$ 336	$ 119	$ 150	$ 152
21	GI Request 20	FY 2009	$ 40,756	$ 1,060	$ 15	$ 175	$ 175	$ 48	$ 68	$ 68
22	GI Request 21	FY 2010	$ 7,935	$ -	$ 966	$ 966	$ 966	$ 326	$ 407	$ 410
23	GI Request 22	FY 2010	$ 532	$ 400	$ 696	$ -	$ -	$ 5	$ -	$ -
24	GI Request 23	FY 2010	$ 84	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Transmission Credit and Interest Forecast

	Request	Credit Start Date	Credit Balance as of 6/30/10 (Deposits prior to rate period)	Network Upgrade Cost During FY11 - FY13 Period	FY 11 Credit Repayment Forecast	FY 12 Credit Repayment Forecast	FY 13 Credit Repayment Forecast	FY 11 Interest Forecast	FY 12 Interest Forecast	FY 13 Interest Forecast
25	Credits Repaid During the Rate Period Based on TSR									
26	GI Request 24	FY 2010	$ 101	$ -	$ 37	$ -	$ -	$ 0	$ -	$ -
27	GI Request 25	FY 2010	$ -	$ -	$ 779	$ 490	$ -	$ 40	$ 9	$ -
28	GI Request 26	FY 2011	$ 23,749	$ 24,000	$ 649	$ 4,543	$ 10,696	$ 1,509	$ 2,099	$ 2,728
29	GI Request 27	FY 2010	$ 2,317	$ -	$ 2,389	$ -	$ -	$ 53	$ -	$ -
30	GI Request 28	FY 2011	$ 11,118	$ 7,700	$ 519	$ 779	$ 779	$ 836	$ 1,153	$ 1,292
31	GI Request 29	FY 2012	$ 49,540	$ 57,200	$ -	$ 2,336	$ 4,130	$ 3,585	$ 6,501	$ 7,571
32	GI Request 30	FY 2012	$ 274	$ 22,750	$ -	$ 195	$ 779	$ 340	$ 1,346	$ 1,619
33	GI Request 31	FY 2012	$ 190	$ -	$ 193	$ -	$ -	$ 2	$ -	$ -
34	GI Request 32	FY 2012	$ 2,016	$ 4,500	$ -	$ 389	$ 1,168	$ 81	$ 100	$ 216
35	GI Request 33	FY 2013	$ 903	$ 700	$ -	$ -	$ 1,090	$ 71	$ 103	$ 102
36	GI Request 34	FY 2013	$ 5,728	$ -	$ -	$ -	$ 1,817	$ 257	$ 368	$ 399
37	GI Request 35	FY 2013	$ 840	$ -	$ -	$ -	$ 454	$ 38	$ 54	$ 55
38	GI Request 36	FY 2013	$ -	$ 9,900	$ -	$ -	$ 454	$ 87	$ 475	$ 562
39	GI Request 37	FY 2013	$ -	$ 3,000	$ -	$ -	$ -	$ 21	$ 96	$ 165
40	GI Request 38	FY 2013	$ -	$ 2,000	$ -	$ -	$ 909	$ 21	$ 96	$ 103
41	GI Request 39	FY 2012	$ 7,236		$ -	$ 1,552	$ 1,552	$ 352	$ 335	$ 276
42	GI Request 40	FY 2012	$ 7,236		$ -	$ 1,552	$ 1,552	$ 352	$ 335	$ 276
43	GI Request 41	FY 2012	$ 2,813		$ -	$ 605	$ 605	$ 135	$ 128	$ 106
44	GI Request 42	FY 2012	$ 7,214		$ -	$ 1,552	$ 1,552	$ 346	$ 329	$ 271
45	GI Request 43	FY 2012	$ 5,338		$ -	$ 1,148	$ 1,148	$ 256	$ 243	$ 200
46	GI Request 44	FY 2012	$ 216		$ -	$ 47	$ 47	$ 10	$ 10	$ 8
47	GI Request 45	FY 2012	$ 3,604		$ -	$ 776	$ 776	$ 173	$ 164	$ 135
48	GI Request 46	FY 2012	$ 3,604		$ -	$ 776	$ 776	$ 173	$ 164	$ 135
49	GI Request 47	FY 2012	$ 1,081		$ -	$ 233	$ 233	$ 52	$ 49	$ 41
50	GI Request 48	FY 2012	$ 865		$ -	$ 186	$ 186	$ 41	$ 39	$ 32
51	*Totals for Customers Whose Credits Repaid During the Rate Period is Based on 50% Capacity*		$ 713	$ 64,150	$ 779	$ 1,999	$ 5,697	$ 1,322	$ 2,359	$ 3,372
52	*Totals for Customers Not Yet Receiving Credits During the Rate Period*		$ 709	$ 125,800	$ -	$ -	$ -	$ 484	$ 3,084	$ 7,226
53	***Total Credits and Interest During the Rate Period***		**$ 268,615**	**$ 323,860**	**$ 31,502**	**$ 38,990**	**$ 45,963**	**$ 13,919**	**$ 22,836**	**$ 29,719**

FY2012-13 Transmission Rate Case Revenues and Sales Forecast

FY 2012-13 Rate Case
Revenue Forecast at Current Rates

	($ in millions)	(A) FY 2008 Actuals	(B) FY 2009 Actuals	(C) FY 2010 3rd Quarter	(D) FY 2011 Start of Year	(E) FY 2012 TR12 Init Prop	(F) FY 2013 TR12 Init Prop
	Network						
1	Formula Power Transmission (FPT)	30.3	30.2	25.9	25.6	25.6	25.6
2	Integration of Resources (IR)	72.6	74.9	38.3	8.8	4.9	4.8
3	Network Integration (NT)	121.5	118.9	121.7	125.9	131.3	133.0
4	Long-Term Point-to-Point (PTP)	274.9	289.4	337.3	382.4	383.9	392.4
5	**Sub-total Long-Term Network**	**499.3**	**513.4**	**523.2**	**542.7**	**545.8**	**555.8**
6	Short-Term Point-to-Point (PTP ST)	39.3	24.1	20.0	27.4	27.9	28.1
7	**Total Network**	**538.5**	**537.4**	**543.2**	**570.1**	**573.6**	**583.8**
	Intertie						
8	Long-Term Intertie South (IS)	85.1	83.9	83.7	83.8	92.3	92.2
9	Short-Term Intertie South (IS ST)	5.5	2.9	2.8	3.9	4.3	4.5
10	Montana Intertie (IM)	0.3	0.3	0.3	0.3	0.3	0.3
11	**Total Intertie**	**90.9**	**87.0**	**86.8**	**88.0**	**96.8**	**96.9**
	Ancillary Services						
12	Operating Reserves - Spinning & Supplemental[1]	37.9	35.6	36.6	35.2	36.1	36.4
13	Regulation & Frequency Response	17.2	13.9	7.3	7.5	7.6	7.7
14	Within-Hour Balancing for Wind	0.0	15.0	41.1	51.1	69.2	89.2
15	Energy & Generation Imbalance[2]	6.8	4.7	6.8			
16	Scheduling, Control & Dispatch	78.1	77.5	85.1	94.5	98.2	99.9
17	**Total Ancillary Services**	**140.1**	**146.7**	**176.8**	**188.4**	**211.0**	**233.3**
18	Utility Delivery (UD)	2.6	2.6	2.8	2.6	2.8	2.8
19	**Total Adjustable Transmission Rates**	**772.1**	**773.8**	**809.6**	**849.1**	**884.3**	**916.8**
20	Revenue Credits	51.6	53.5	53.4	53.3	51.2	52.3
21	**Total Revenues** (excl. reimbursable revenue)	**823.6**	**827.3**	**863.0**	**902.3**	**935.5**	**969.1**

1 Contingency energy is not forecasted (FY09-11), but is included in actuals (FY06-FY08).
2 Energy & Generation Imbalance is not forecasted (FY11-13), but is included in actuals (FY08-10).
3 FY08/09 actuals do not include prior year billing and accrual accounting which are not forecasted.

FY 2012-13 Rate Case Sales Forecast

		Units	(A) FY 2008 Actuals	(B) FY 2009 Actuals	(C) FY 2010 3rd Quarter	(D) FY 2011 Start of Year	(E) FY 2012 TR12 Init Prop	(F) FY 2013 TR12 Init Prop
	Network							
1	Formula Power Transmission (FPT)	aMW	1,893	1,887	1,611	1,570	1,570	1,570
2	Integration of Resources (IR)	aMW	2,763	2,763	2,186	488	272	268
3	Network Integration (NT)	aMW	6,283	6,150	6,306	6,514	6,573	6,656
4	Long-Term Point-to-Point (PTP)	aMW	17,844	18,627	21,655	24,525	24,590	25,085
5	Short-Term Point-to-Point (PTP ST)	aMW	1,643	1,047	757	1,162	1,183	1,186
6	**Total Network**	aMW	**30,426**	**30,474**	**32,515**	**34,259**	**34,188**	**34,765**
	Southern Intertie							
7	Long-Term Intertie South (IS) CONFIRMED	aMW	5,480	5,408	5,375	5,402	5,949	5,943
8	Short-Term Intertie South (IS ST)	aMW	216	125	105	162	177	187
9	**Total Southern Intertie**	aMW	**5,696**	**5,533**	**5,480**	**5,564**	**6,126**	**6,130**
10	Montana Intertie (IM)	aMW	16	16	16	16	16	16
11	Utility Delivery (UD)	aMW	194	196	208	197	207	209
	Ancillary Services							
12	Operating Reserves - Spinning & Supplemental[1]	aMW	240	234	229	226	232	234
13	Regulation & Frequency Response	aMW	5,941	4,807	5,590	5,721	5,801	5,893
14	Within-Hour Balancing for Wind	aMW	0	1,838	2,653	3,302	4,467	5,761

1 Contingency energy is not forecasted (FY11-13), but is included in actuals (FY08-10).

2 Energy & Generation Imbalance is not forecasted (FY11-13), but is included in actuals (FY08-10).

FY 2012-13 Rate Case
Long-term Network Sales Forecast Assumptions

- Formula Power Transmission (FPT) are expected to remain static. Although conversions significantly reduced these legacy sales from FY 2009 to FY 2010, no additional conversions are expected during the upcoming rate period.
- Integration of Resources (IR) sales are expected to decrease slightly. One to two conversions, for a total of 6 MW, are expected during the upcoming rate period.
- Network Integration (NT) sales are expected to increase slightly based on load forecasts at a growth rate of 1%.
- Point-to-Point (PTP) sales are expected to increase as a result of Network Open Season (NOS). As a result of the 2008 and 2009 NOS processes, BPA assumed:
  - An average of 1831 MW additional PTP sales including 668 MW of conditional firm service over FY 2012-13
  - An increasing number of deferrals (an average of 804 MW over the rate period)
- PTP reservations for 800 MW will end during the rate period because they have no rollover rights.

FY 2012-13 Rate Case
Long-term Intertie Sales Forecast Assumptions

- Southern Intertie (IS) sales are forecast to increase due to the COI upgrade. An additional 530 aMW in sales from the COI upgrade is forecast in the rate period.
- Montana Intertie (IM) sales are expected to remain static.

FY 2012-13 Rate Case
Short-term Sales Forecast Assumptions

- Short-term sales on the Network (PTP) are based on:
  - Recent historical usage
  - Adjustments to better reflect normal water conditions which are higher than conditions in recent years
  - Forecast market trends of differences between the Mid-Columbia (MIDC) and California (NP-15) markets.
- Short-term sales on the Intertie (IS) are based on historical trends of differences between the Mid-Columbia (MIDC) and California (NP-15) markets.

FY 2012-13 Rate Case
Ancillary Services Sales Forecast Assumptions

- Scheduling, System Control, and Dispatch service (SCD) sales are directly tied to the NT, PTP, IM and IS sales.
- Operating Reserve (OR) sales are based on the assumption of the effective WECC Standard, BAL-002-0, where 5% is applied to hydro and wind and 7% is applied to thermal resources. If firm contingent tags are adopted for exports out of the BPA BA area, they are assumed to reduce the reserve obligation.
- Regulation and Frequency Response (RFR) sales are based on load forecasts of the loads in the BPA BA area.
- Within-hour Balancing service (WI) sales are based on the forecast of installed capacity of variable generation sources in the BPA BA area.

Load Forecasting

Load Forecasting Goals

- Customer Services Load Forecasting group (KSL) established in 2007
- Same forecast basis and assumptions are used for forecasts provided to Power and to Transmission
- Consistency for all planning processes
  - In accuracy levels
  - In methods
  - In assumptions
- Goal is seamless integration of planning from next day to the next twenty years forecasted accurately

Load Forecasting Process

- Bottom up approach where each customer is individually forecasted
- Statistical based models using 10 or more years of historical data
- Known changes identified through customer visits
- Known changes are for specific off trend customer growth
  - New large industrial or commercial loads
  - New large subdivision additions
- Economic assumptions obtained from Global Insight.
- Numerous elements are forecasted from the same assumptions (ie. kWh, customer peak, GSP, TSP, CA peak)
- Updates prepared annually followed with quarterly refinement as necessary
- Final forecast reviewed by Customer, AE, and other interested parties

Load Forecasting Assumptions

- Normal weather conditions exist (34 year average value)
- Continuation of recent trends with known changes identified through customer visits
  - Precious metals production (increases)
  - Federal stimulus funding (increases)
  - Mill closures (decreases)
- Continuing slow economy expected with growth returning in first quarter of calendar year 2011
- Expected average growth per year in the BPA Balancing Authority Area of approximately 1.0% FY 2010 through FY 2013 compared to an average of 3.7% historically FY 2003 to FY 2009

Transmission Rate Study

What is the "Transmission Rate Study"?

- The Transmission Rate Study (TRS) is an integral part of the Transmission Rate Case.
- The TRS consists of the study documentation, a rates model, and appendices of detailed inputs into the rates model.
- The last published TRS was for the 2002 Transmission Rate Case.
- The TRS model is a spreadsheet used to calculate rates.
  - Proposed rates are set to recover the cost of providing service
  - Cost recovery is segment by segment, where possible
  - The model compares proposed rates to existing rates
  - Compares revenues forecasted at current and proposed rates
- The information shared today assumes no change to the established transmission rates methodology. To the extent practical, we are open to exploring different rate development methods and alternatives.

Inputs to the Transmission Rate Study Model

- Revenue Requirement Study Data
  - Yearly segmented FCRTS investment base (Net Plant)
  - Yearly segmented Revenue Requirement
  - Yearly Generation Input costs from BPA Power Services
- Sales Forecast Information
  - Yearly Forecast of Revenue from sources other than sales of transmission capacity. These are identified as "Revenue Credits" against the segmented costs for rate making purposes.
  - Monthly Forecast of Transmission Sales quantities, typically expressed in MegaWatts (MW) or KiloWatts (kW) for capacity, or in terms of energy such as kW-mo.

Current Transmission Rate Model Methods and Assumptions

- The Segmented Revenue Requirement is reduced by Revenue Credits to establish costs to be recovered by rates. Revenue Credits allocated to segments based on direct assignment of contract facilities where applicable, or by segmented net plant for general revenues.

- The cost of the segments with none or minimal customer base (Montana Intertie, Industry Delivery) are allocated to remaining segments based on Net Plant.

- The generation input ancillary services are a pass-through to Power Services.

Current Transmission Rate Model Methods and Assumptions - Continued

- Network Integration (NT) allocation based on annual peak forecasted load at transmission system peak. Load-shaping Charge is applied to recover difference from average monthly billing factor to annual peak.
- Point-to-Point (PTP), Integration of Resources (IR), and Formula Power Transmission (FPT) allocation based on nominal forecasted contract demand. Where appropriate, existing Short Distance Discounts are included in allocation.
- FPT rate components adjusted by network base rate percentage change, rather than computing each component individually.
- Southern Intertie (IS) based on nominal forecasted contract demand.
- Utility Delivery based on forecasted load at transmission system peak.
- BPA-TS is open to other rate study and rate design alternatives.

Preliminary Rate Projection FY 2012 - 13

- BPA recognizes how difficult the current economic situation is for customers and consumers
- Committed to hold proposed rate increases to the absolute lowest level consistent with sound financial operations
- BPA continues to make very significant investments in the region's transmission infrastructure and habitat restoration / improvement

Key Assumptions for Preliminary Rate Projection FY 2012 - 13

- Assume no change in approach to LGIA and associated Transmission Service Requests (TSRs).
- Assume average revenues during the rate period are $953 million.
- Assume average interest and expenses during the rate period are $945 million.

How Does BPA Get to Preliminary Rate Projection FY 2012 - 13

Using assumptions outlined above:

- Minimum Required Net Revenues (MRNR) average during the rate period is $63 million.
- Based on June IPR numbers, BPA projects an average shortfall of $55 million; this would yield an overall general rate increase of about 8%.
- BPA will update cost and revenue projections for the IPR closeout letter.
- We expect the projected rate impact to decrease an amount in the 2% to 3% range.

Preliminary TS Rate Projection FY 2012 - 13

Rate Impact due to Cash Shortfall During Rate Period

($'s in Millions)

	(A) Average TR-10	(B) 2012	(C) 2013	(D) Average TR-12
1 **Revenues**	**866**	936	969	953
2 **Expenses**	**623**	732	781	757
3 **Net Interest**	**164**	175	202	189
4 **Net Revenues**	**79**	29	(14)	8
5 **MRNR**	**75**	70	55	63
6 **Over-run/Under-run**	4	(41)	(69)	(55)
7 **Estimated Rate Impact** ($6.7 million = 1% rate impact)				8.2%

Based on the June IPR numbers; these will be updated based on the IPR closeout letter. We expect the rate impact to decrease by about 2% to 3%.

Wrap Up

- Thank you for your contributions throughout our transmission rates workshop meetings. Your input has been useful in shaping transmission rate development alternatives for consideration in the initial proposal.

- Meeting participants that desire to post other rate-related materials to our external rates website should submit a written request to techforum@bpa.gov

- See 2012 Rate Case website for additional information, workshop postings and handouts, and the BPA Calendar: http://www.bpa.gov/corporate/ratecase/2012. The BPA Calendar is also located at http://www.bpa.gov/corporate/public_affairs/calendar/.

- We are tentatively planning the No Surprises workshop for November 1, 2010. A Tech Forum notice announcement will be sent out to confirm the “No Surprises” workshop date.

Appendix

Segmentation Process

- Classify the facilities of the FCRTS and assign them to different segments (categories of service) according to the type of services they provide.
- Project investment and O&M costs associated with these segments over the rate period.
- The final Segmentation Study is an input to the Revenue Requirements Study, which is used to develop transmission rates.

Segment Categories

- Generation Integration (GI) – Facilities to connect Federal generation to the Network.
- Integrated Network (Network) – Facilities to provide bulk power transmission.
- Southern Intertie – AC and DC connections to California.
- Eastern Intertie –Townsend- Garrison 500 kV line and equipment.
- Utility Delivery (UD) – Facilities to deliver power to public customers at <34.5 kV.
- Industrial Delivery (DSI) – Facilities to deliver power to Direct Service Industries (DSIs) at <34.5 kV.
- Ancillary Services – FERC-defined facilities and operations necessary for reliable transmission service.

Generation Integration Segment

- Consists of all facilities that connect the Federal generating plants to the integrated BPA transmission network.
- Includes transmission lines and equipment between the Federal generator bus and the first BPA transmission system substation encountered by the generated power.
- The costs associated with this segment are assigned to Power Services.

Integrated Network Segment

- Consists of facilities that:
  - Transfer bulk power from generation to load, including to the Delivery and Southern and Eastern Intertie segments.
  - Provide voltage regulation and overall reliability resulting from multiple transmission pathways.
- Consists of line and substation equipment at voltages from 34.5 kV to 500 kV owned and operated by BPA.
- By far the biggest segment

Southern Intertie Segment

- This segment is a system of transmission lines that interconnect the PNW and California power systems.
- The Southern Intertie consists of:
  - The Celilo Converter Station and 1,000 kV direct-current transmission line originating at The Dalles, Oregon (the DC Intertie).
  - A set of 500 kV alternating-current lines and substations originating in North Central Oregon (the AC Intertie)

Eastern Intertie Segment

- Consists of the Garrison-Townsend 500 kV line and the associated substation facilities at Garrison.
- The facilities are used to connect power generated at Colstrip to the BPA network and to transfer power between the Northwest and Montana

Delivery Segments

- The two delivery segments consist primarily of substation facilities required to "step down" (reduce) from prevailing transmission voltages for delivery to customers at voltages below 34.5 kV. Consists of two sub-segments:
  - Utility Delivery Segment: Consists of the facilities required to supply power at delivery voltages to BPA's public utility customers.
  - Industrial Delivery (DSI) Segment: Consists of facilities required to supply BPA's industrial customers.

Ancillary Services Segment

- Services that the Transmission Provider are required by FERC order to supply
- Required for reliable transmission service.
- Transmission equipment that supports ancillary services are certain communications and control systems, SCADA equipment, and computer hardware and software located at the control centers.
- These costs are assigned to various Ancillary Services

Segmentation Methodology

- BPA's transmission facilities are grouped as lines or substations and are assigned to segments on the basis of voltage and function.
- A number of technical sources are relied on to identify facilities for specific segments.
- In some cases, as for Interties, contracts define some or all of the facilities in a segment.

Segmentation Methodology (cont.)

- After the facilities are identified by segment, the investment cost of each segmented facility is determined from accounting records.
- Some facilities are common to more than one segment.
  - For substations, the facility costs are divided among the segments based on the use of each major component of the substation or, in some cases by contract
  - For lines, allocation is based on the miles in each segment, except for Buckley-Summer Lake, which has remained unchanged from the 1985 rate filing
- Historical investment is though September 30, 2009

Segmentation Methodology

- Direct O&M expenses for each transmission line and substation are obtained from plant and maintenance records for the latest 3 years (data available FY07-09)
- The historical segmented direct O&M costs are then used in the Revenue Requirements Study to allocate forecasted O&M costs and overhead to the test years
- Investment and O&M associated with providing the FERC-defined Ancillary Services are Identified

Appendix: Background on PTP and NT Service

Point to Point Transmission Service

From the OATT preamble for Point-To-Point Transmission Service:

II. **Point-To Point Transmission Service**
Preamble

The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service pursuant to the applicable terms and conditions of this Tariff. Point-To-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transfer of such capacity and energy to designated Point(s) of Delivery. If and to the extent that the Transmission Provider has established separate rates for Transmission Service over one or more segments, separate rates shall be charged for Transmission Service over such separate segments.

Network Integration Transmission Service

From the OATT preamble for Network Integration Transmission Service:

III. **Network Integration Transmission Service**
Preamble

The Transmission Provider will provide Network Integration Transmission Service pursuant to the applicable terms and conditions contained in the Tariff and Service Agreement. Network Integration Transmission Service allows the Network Customer to integrate, economically dispatch and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which the Transmission Provider utilizes its Transmission System to serve its Native Load Customers. Network Integration Transmission Service also may be used by the Network Customer to deliver energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Bonneville Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Part II of the Tariff. If and to the extent that the Transmission Provider has established separate rates for Transmission Service over one or more intertie segments, Network Integration Transmission Service will not be available over such intertie segments, and the terms and conditions for Transmission Service over such intertie segments will be provided under Part II of this Tariff.