2010 BPA Rate Case

Pricing Methodology for Generation Inputs for Operating Reserves and Other Services

Customer Workshop

October 22, 2008

Agenda

- 1:00 Welcome and Introductions
- 1:15 Generation Inputs for Operating Reserves
- 2:00 Other Generation Inputs
  - Generation Dropping
  - Redispatch
  - Segmentation of Corps and Bureau of Reclamation Network and Delivery Facilities
  - Station Service

    Other

  - Segmentation of Corps and Bureau of Reclamation Network and Delivery Facilities Synchronous Condensing
- 2:45 Next Steps

Key Messages

- We are sharing this material in the spirit urged by regional parties--that of sharing and discussing technical analysis before it is completed--in the interest of a better final product.
- In that spirit, the material we are sharing is very much a work in progress. We are very open to input and willing to make changes based on that input if warranted.

Generation Inputs for Ancillary Services and Other Services

- Operating Reserves
- Generation Inputs
  - Generation Dropping for Remedial Action Scheme
  - Redispatch
  - Station Service
  - Synchronous Condensing
- Other
  - Segmentation of Corps of Engineers and Bureau of Reclamation Network and Delivery Facilities

Pricing Principles for Generation Inputs

- Consistent Allocation of Costs for All Uses of Similar Products/Services
  - Energy priced at the risk-adjusted AURORA prices
- Cost Causation
- Since forecasted revenue from generation inputs is a credit to the revenue requirement, generation inputs must allocate an equitable amount of costs to BPA Transmission Services.

OPERATING RESERVES

Operating Reserves Definition

- Operating Reserves in this presentation are the contingency reserves (not regulating reserves) as currently defined by the Western Electricity Coordinating Council (WECC) Regional Reliability Standard.
- Operating Reserve –Spinning Reserve is needed to serve load immediately in the event of a system contingency. The service is provided under Schedule 5 of the tariff. Spinning Reserve Service may be provided by units that are on-line and loaded at less than maximum output.
- Operating Reserve –Supplemental Reserve is needed to serve load in the event of a system contingency. The service is provided under Schedule 6 of the tariff; however, it is not available immediately to serve load but rather within 10 minutes. Supplemental Reserves may be provided by generating units that are on-line but unloaded, by quick-start or by interruptible load.

Preliminary Reserve Need Quantities from BPA Transmission Services to BPA Power Services

- The analysis for the initial considering will use Operating Reserve generation input amounts based on the current WECC standard. The current standard determines the Balancing Authority reserve requirement from 5% of the hydro and wind generation on line plus 7% of other generation on line. This is a reliability based requirement that the Balancing Authority must satisfy at all times.
- The operating reserves forecast based on the current WECC standard is:
  - FY2010:   504 MW
  - FY2011:   522 MW
  - Rate Period Average: 513 MW

Preliminary Reserve Need Quantities from BPA Transmission Services to BPA Power Services

- WECC is in the process of getting approval from FERC for a new Standard titled BAL-002-WECC-1 Contingency Reserves. If FERC adopted, this will change the calculation of the requirement and needed amount of generation inputs to be: 3% times BA load ***plus*** 3% times BA net generation (generation minus station service).
- The new WECC standard is expected to be approved by FERC for implementation by the beginning of the 2010 rate period. Therefore, BPA TS is considering to revise the forecasted amount of generation inputs for the Final Proposal.
- The preliminary operating reserves forecast based on the new WECC standard is:
  - FY2010: 375 MW
  - FY2011: 387 MW
  - Rate Period Average: 381 MW

Operating Reserves

- Forecasted quantity of Generation Inputs Power Services provides to Transmission Services
- Preliminary Approach is to Use Embedded Price Methodology for Operating Reserves from 2007 Power Rate Case
- Explain Pricing Methodology from 2007 Power Rate Case
- Example of Applying a Method similar to the 2007 Pricing Methodology Using Preliminary Reserve Need Quantities and Preliminary Costs for FY2010-2011
- FY2010-2011 operating reserves allocation
  - Embedded Costs are treated the same as 2007
  - With efficiency costs for Spinning Operating Reserves

Generation Inputs – Overview of FY2007-2009 Embedded Cost Pricing Methodology

- Method used for Operating Reserves
  - Calculate the costs associated with all the hydro projects and divide those costs by the average annual capacity amount of those same hydro projects (adjusted for other requirements)

FY2007-2009 Operating Reserve Embedded Cost Calculating the Capacity Value

(WP-07-FS-BPA05B, Page 15)

	Operating Reserve Assumptions	FY 2007-2009 Average MWs
1	**Regulated + Independent Hydro**	**9,217**
2	Total BPA Control Area Reserve Obligation (Line 3+4)	690
3	Total Self-Supply and Third-Party-Supply Reserve Obligation	310
4	**Total BPA Reserve Obligation**	**380**
5	**Control Area Regulation Requirement**	**350**

Regulated Hydro:	20,252.0	*Installed Capacity*
Independent Hydro:	724.0	*Installed Capacity*
Operational Peaking Adjustment:	7,901.0	
Hydro Reserves:	1,049.0	
Federal Hydro Maintenance:	2,202.0	
Spinning Reserves:	277.0	
Federal Transmission Losses:	329.0	
Total 12 Month Period:	**9,217.8**	

Components in Calculating the Capacity Value

- Regulated Hydro is the Instantaneous Peak Capability we are adjusting to get to 120-hour capacity (6 hours/day, 5 days/week, 4 weeks/month)
- Independent Hydro are federal Non-Columbia River Projects
- Operational Peaking Adjustment includes
  - Regulation
  - Load Following Capacity
  - Supplemental (Non-Spinning) Capacity
  - And reflects water conditions such as the new BI-OP (Biological Opinion) and other operating requirements
- Hydro Reserves includes Forced Outage Reserve
- Federal Hydro Maintenance includes Planned Outage Reserve
- Spinning Reserve is based on the White Book assumptions at the time
- Federal Transmission Losses

FY2007-2009 Operating Reserve Embedded Cost Calculating the Capacity Value

(WP-07-FS-BPA05B, Page 15)

- Operating and Regulating Reserves Added Back In

		FY 2007-2009
	Operating Reserve Assumptions	**Average MWs**
	Forecast of Average Hydro Generation System Uses	
6	Average Hydro Generation (Line 1)	9,217
7	Total PBL Reserve Obligation (Line 4)	380
8	Control Area Regulation Requirement (Line 5)	**350**
9	**Total Average Hydro Generation System Uses**	**9,947**

FY2007-2009 Operating Reserve Embedded Cost Allocating the Costs

(WP-07-FS-BPA05B, Page 15)

- Allocate Costs

	Operating Reserve Assumptions	FY 2007-2009 Average MWs
	Per Unit Rate	
10	Total PBL Reserve Obligation (Line 4)	380
11	Total Average Control Area Generation (Line 9)	9,947
12	**Multiplication Factor for Revenue Requirement (Line 10 / Line 11)**	**$ 0.03820**

	Operating Reserve Assumptions	FY 2007-2009 Average MWs
	Annual Revenue Forecast for Operating Reserves	
13	Power Revenue Requirement for ALL Hydro Projects	$ 771,201,466
14	Multiplication Factor (Line 12)	3.8202%
15	**Adjusted Revenue Requirement for Operating Reserves**	**$ 29,461,803**

FY2007-2009 Operating Reserve Embedded Cost Allocating the Costs (WP-07-FS-BPA-05B, page 15)

- Calculating the Per Unit Price
- Calculating the Operating Reserve Revenue Forecast

	Operating Reserve Assumptions		FY 2007-2009 Average MWs
	Per Unit Rate		
16	Adjusted Revenue Requirment for Operating Reserves (Line 15)	$	29,461,803
17	Total PBL Reserve Obligation (Line 4) * 12 * 1,000	$	4,560,000
18	**Per Unit Rate Express Kw-Mo (Line 16 / Line 17)**	**$**	**6.46**

	Operating Reserve Assumptions		FY 2007-2009 Average MWs
	Annual Revenue Forecast for Operating Reserves		
19	Total PBL Reserve Obligation (Line 4)		380
20	Per Unit Generation Input Rate	$	6.46
21	**Annual Revenue Forecast (Line 19 * Line 20 * 12 * 1,000)**	**$**	**29,461,803**

FY2007-2009 Operating Reserve Embedded Cost Settling the Costs

- Partial Resolution of Issues for the 2007 Power Rate Case
  - Per Unit Price settled at $5.63 per kW per month

- Revised revenue forecast was 380 MW at $5.63 per kW per month for $25,672,800 per year.

Example of Applying 2007 Pricing Methodology to Preliminary Reserve Need Quantities and Preliminary Costs for FY2010-2011

- Preliminary Costs for Hydro Projects
- Preliminary Quantities of Reserve Need for Operating Reserves
- Changes
  - Hydro Projects Located in the BPA Balancing Authority (BA)
  - Transmission Losses on Hydro Projects in the BPA BA

FY2010-2011 Operating Reserves Embedded Cost Preliminary Update to Assigned Cost

- Current expense estimates are from Power Services Integrated Program Review (IPR) 2010 and 2011 forecasts (pre-decisional).
- Associated plant investment of hydro projects is from original WP-07 forecasts, updated to 2007 actual investment.
- All costs are subject to change for IPR final decisions as well as updates for 2008 actual investments and revised forecasts of plant additions.

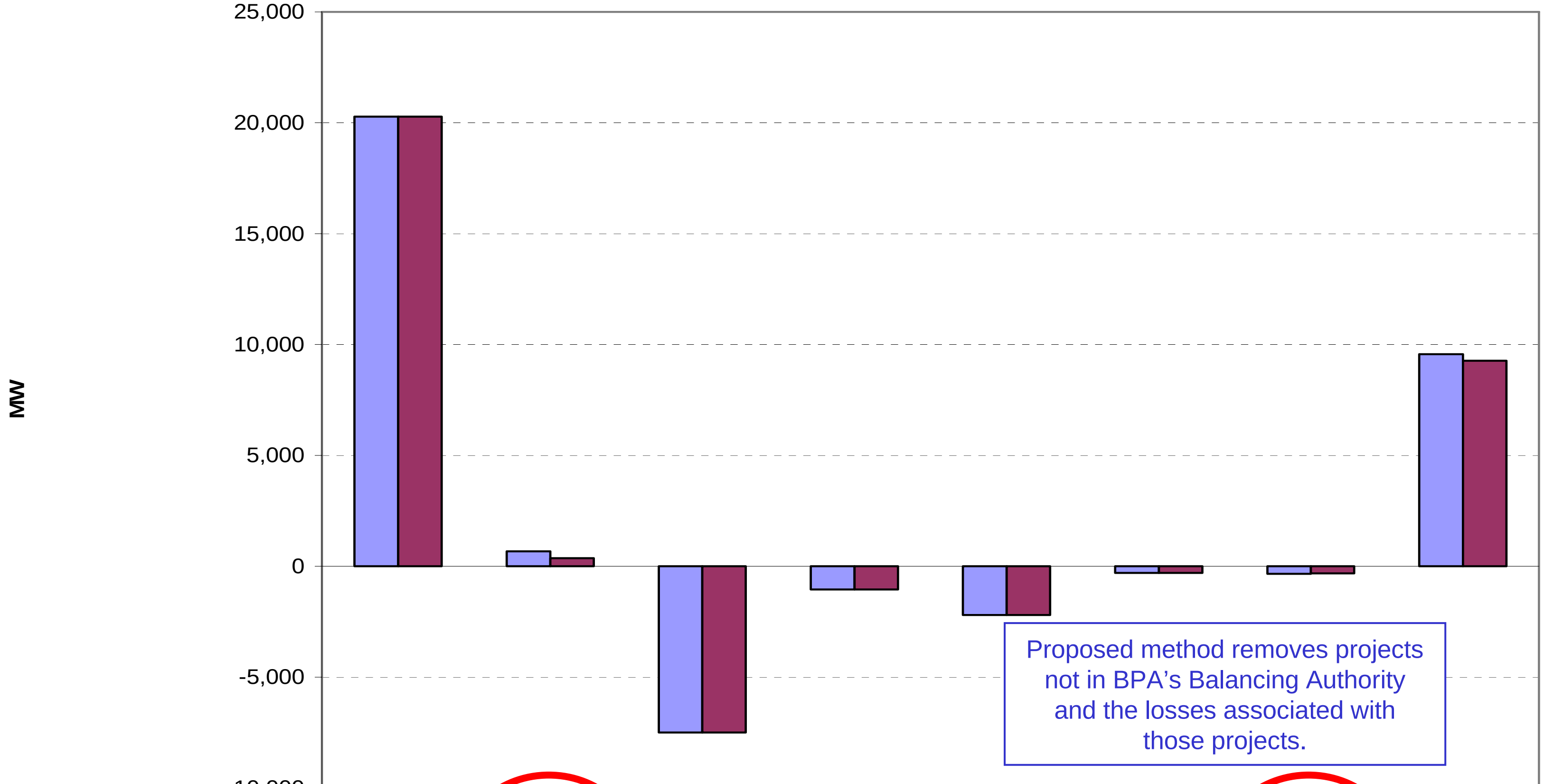
FY2010-2011 Operating Reserves Embedded Cost Preliminary Update to Assigned Cost

Operating Reserves
Power Revenue Requirement for
All Hydroelectric Projects in BPA Balancing Authority and F&W
($in thousands)

		2010	2011	2010-2011 Average
1	**All Hydro Projects 1/**			
2	O&M	193,742	205,213	199,477
3	Depreciation	88,622	89,407	89,015
4	Net Interest	106,810	112,833	109,822
5	Planned Net Revenues	12,622	0	6,311
6	Total Revenue Requirement	401,796	407,453	404,624
7	**Fish & Wildlife**			
8	O&M	301,929	309,891	305,910
9	Amortization/Depreciation	42,926	46,680	44,803
10	Net Interest	39,362	45,123	42,243
11	Planned Net Revenues	6,040	0	3,020
12	Subtotal	390,256	401,694	395,975
13	A&G Expense 2/	100,126	101,684	100,905
14	Total Revenue Requirement	892,178	910,831	901,504
15	Revenue Credits			
16	4h10C (non-operations)	66,900	66,008	66,454
17	Colville payment Treas. Credit	4,600	4,600	4,600
18	**Net Revenue Requirement**	**820,678**	**840,223**	**830,450**

1/ Excludes Boise, Minidoka-Palisades, Green Springs (USBR) and Lost Creek (COE).
2/ Power Marketing Sales & Support, Power Scheduling, Generation Oversight, Corporate Expense and 1/2 Planning Council

Proposed Update to Federal Transmission Losses and Treatment of Independent Hydro



	Regulated Hydro	Independent Hydro	Operational Peaking Adj.	Hydro Reserves	Federal Hydro Maint.	Spinning Reserves	Federal Trans. Losses	Total 12 Month Average Capacity
FY10-11 using old method	20268	674	-7497	-1047	-2202	-293	-341	9562
Proposed FY10-11	20268	362	-7497	-1047	-2202	-293	-322	9269

Preliminary Reserve Need Quantities from BPA Transmission Services to BPA Power Services

- Operating Reserves Amounts Used in the Cost Allocation Example
  - FY2010: 504 MW
  - FY2011: 522 MW
  - Rate Period Average: 513 MW

Example for Illustrative Purposes
Embedded Cost Component of Operating Reserves
Using 2007 Pricing Methodology

		FY10-11 MWs
	Operating Reserve Assumptions	
1	Regulated + Independent Hydro	**9,269**
2	Regulating Reserves	**106**
3	Operating Reserves	**513**
4	Load Following Capacity	**628**
5	Wind Integration	**1,045**
	Forecast of Hydro Capacity System Uses	**MWs**
6	Hydro Projects Capacity (Line 1)	**9,269**
7	Total PBL Reserve Obligation (Line 2+3+4+5)	**2,292**
8	Hydro Project Capacity System Uses (Line 6+7)	**11,561**
	Adjusted Revenue Requirement	
9	Power Revenue Requirement for Hydro Projects	**$830,450,500**
10	Hydro Project Capacity System Uses (Line 8)	**11,561**
11	Total kW/month Hydro Project Capacity (Line 10 * 12MO * 1000kW/MW)	**138,732,000**
12	**Per Unit Allocation $/kW/month (Line 9 / Line 11)**	**$5.98**

Example for Illustrative Purposes
Embedded Cost Component of Operating Reserves
Using 2007 Pricing Methodology

- Applying preliminary revenue requirement (preliminary Integrated Program Review) and preliminary reserve need quantity
  - Amount of Operating Reserves
    - 513 MW
  - Embedded Component Per Unit Reserve
    - $5.98 per kW per month
  - Embedded Cost Portion of the Operating Reserves Allocation
    - 513 MW X 12 months X 1000 kW/MW X $5.98/kW/month = $36,812,880

Stand Ready Cost Component

- For Operating Reserves Need Forecast
  - Half is spinning reserves
  - Half is supplemental (non-spinning) reserves

Operational Cost of Reserves

- Costs associated with setting up the system to stand ready and respond to reserve need.
- All reserves are referred to as “inc” obligations.
  - Inc Reserve: ability to increase generation in order to maintain load-resource balance in the Balancing Authority Area (BAA).
- All costs are operations related and do not include items such as operations and maintenance (O&M).

Stand Ready

- Stand ready: Those costs associated with making the reserve available such that the system is capable of instantaneously maintaining load-resource balance 99.5% of the time. Stand ready costs consist of:
  - Efficiency Loss: Efficiency losses are the losses incurred when a project needs to alter its unit dispatch in order to have enough inc and dec capability standing ready to respond.
  - Cycling Cost: The cost of synchronizing and ramping additional units in order to have enough inc and dec capability standing ready to respond.
  - Spill Cost: Costs realized when a project must spill energy in order to have enough inc capability standing ready to respond.

Stand Ready: Efficiency Loss

- Efficiency losses are incurred when projects alter their unit dispatch in order to have enough inc and dec capability standing ready to respond.
- Projects are standing ready to respond; not responding at this point.
- The loss is determined by finding the most efficient unit dispatch for each controller project meeting both the generation request and reserve obligation for a base case and a test case. The loss is determined by taking the efficiency difference between the test and base case.
- The loss is valued at the risk-adjusted AURORA HLH price.

Stand Ready: Cycling Cost

- In addition to the losses in efficiency are costs associated with cycling more units on/off line.
- Per-cycle cost calculations are project specific costs associated with synchronization and ramping losses.
- Costs are functions of the unit specific efficiency characteristics.

Stand Ready: Spill Cost

- Spill costs are realized when an inc obligation combined with a generation request results in all available units being online and still unable to meet the inc reserve obligation.

- In this case the units are unloaded to just meet the inc obligation and the project spills the remaining energy.

- Spilled energy is valued at the risk-adjusted AURORA HLH price.

Stand Ready Cost Component

- Only inc for operating reserves amounts
- Stand ready charge for the spinning portion
- Since deployments are infrequent and, at most, for a duration of 90 minutes, deployments costs are not considered

Stand Ready Cost Component

- Applicable stand ready charges are:
  - Efficiency loss
  - Cycling
  - Spill

Results: Stand Ready Components

- The following table shows the efficiency loss component for various combinations of inc and dec reserve obligation:

EFFICIENCY LOSS	0 MW	500 MW	1000 MW	1500 MW	2000 MW
0 MW	0	-3,133,845	-14,046,439	-31,495,783	-51,085,832

Results: Stand Ready Components

- The following table shows the cycling cost component for various combinations of inc and dec reserve obligation:

CYCLING COST	0 MW	500 MW	1000 MW	1500 MW	2000 MW
0 MW	0	-690,880	-1,459,722	-2,267,595	-3,819,462

Results: Stand Ready Components

- The following table shows the spill cost component for various combinations of inc and dec reserve obligation:

SPILL	0 MW	500 MW	1000 MW	1500 MW	2000 MW
0 MW	0	-81,689	-380,387	-1,727,079	-4,964,172

Results: Stand Ready Components

- From the previous tables for Efficiency Loss cost , Cycling cost, and Spill cost at the 256 MW estimate for Operating Reserves – Spinning
  - Efficiency Loss
    - $1,566,922
  - Cycling
    - $345,440
  - Spill
    - $0
  - Total
    - $1,964,631
- Preliminary estimate of per-unit-cost is $0.64 per kW per month. ($1,964,631 / 256 MW * 12 months * 1000 kW/MW = $0.64

Operating Reserves

- Spinning Reserves
  - $6.62 per kW per month
  - Embedded Cost Component is $5.98 per kW per month
  - Stand Ready Cost Component is $0.64 per kW per month
- Supplemental Reserves
  - $5.98 per kW per month
  - Embedded Cost Component is $5.98 per kW per month

Embedded Cost Portion of Operating Reserves

- Key Drivers for Changes:
  - Increased Costs in the Revenue Requirement
  - Higher proportion of reserve need quantity to system capacity
  - Stand Ready costs for spinning reserves portion

GENERATION DROPPING

Generation Dropping Definition

- Generation Dropping is a controlled and coordinated action implemented by Transmission Services that instantaneously disconnects increments of generation from the interconnected transmission system so that reliable operations can be maintained during an emergency situation. This service is provided when Transmission Services requests Power Services to instantaneously drop large increments of generation to maintain loads and voltages within acceptable levels.

Generation Dropping Cost Allocation Methodology

- The preliminary cost method is from the 2007 Power Rate Case and is based on project costs, adjusted for inflation.
- Costs fell into three components:
  - Equipment Deterioration Costs
  - Operation and Maintenance Costs
  - Lost revenue in the event of replacement
- The key assumption is that Grand Coulee Third Powerhouse hydroelectric units (each exceed 600 MW) represents Power Services' costs of dropping large units.

Generation Dropping for Remedial Action Scheme

- Original study prepared by Harza Engineering in August 1998
- Estimated costs of generation dropping at Unit 22, 23 or 24 at Grand Coulee Third Powerhouse
- Updated to year 2010/2011 from Handy-Wittman Index calculate cost multiplier
- Energy priced at the risk-adjusted AURORA market price forecast
- 1.5 average number of drops per year

Generation Dropping for Remedial Action Scheme Preliminary Forecast for 2010 Rate Case

Equipment	Equipment Deterioration Costs	Operation and Maintenance Costs	Lost Revenue In The Event of Replacement	Total Cost/Drop
	Cost/Drop	Cost/Drop	Cost/Drop	
550kV Circuit Breaker	$278	$2	$0	$280
Main Power Transformer	$1,192	$9	$554	$1,755
Generator (Re-winding)	$125,523	$3,195	$393,639	$522,357
Turbine	$3,341	$1,080	$24,579	$29,000
Total:	$130,334	$4,286	$418,773	$553,393

$553,393 cost/drop * 1.5 drops/year = $830,090/year

REDISPATCH

Types of Redispatch

- Open Access Transmission Tariff (OATT) Attachment M Discretionary Redispatch:
  - Transmission Services can request at their discretion
  - Price and quantity offered at time of request
- OATT Attachment M Network Transmission (NT) Redispatch:
  - Used to protect NT firm schedules
  - BPA Power Services must provide; priced at time of request
- OATT Attachment M Emergency Redispatch:
  - Used for system reliability in response to an emergency
  - BPA Power Services must provide; priced at time of request
- Transmission Services Reliability Redispatch Program:
  - Provided through advance bidding process
  - Used for same purposes as Attachment M Discretionary Redispatch

Redispatch
FY 2008-2009 Redispatch Forecasts and 2008 Actuals

- In the 2008 Transmission Rate Case, Transmission Services forecast $4.5 million per year in expected redispatch costs for all purposes. This amount was included in the overall revenue requirement.
- Actual costs for June 2007 through May 2008 totaled $307,500. We had one large, expensive redispatch event in July 2008, but we believe this event was an anomaly and new dispatch procedures should reduce the likelihood of similar events.
- We believe that a forecast of $600,000 per year in redispatch costs for FY2010 and FY2011 is reasonable, with $400,000 the expected payments to Power Services. Given the size of the expected costs, we propose to include this costs as part of the overall Transmission Services' revenue requirement.

Redispatch

- Billing Methodology:
  - BPA Transmission Services will pay for each redispatch request provided by BPA Power Services at a bid price quoted at the time of the BPA Transmission Services' request.
  - BPA Transmission Services can choose to either accept the redispatch at the bid price or choose another congestion management solution.
- BPA Power Services expected revenue : $400,000 per year during the rate period:
  - The expected revenue is based on historical usage
  - Due to decreased flexibility in operation of the Federal Columbia River Power System it is unlikely that more redispatch capability will be made available then has been historically provided.
- BPA Transmission expected costs are greater than BPA Power Services expected revenue because BPA Power Services is not the only redispatch provider.

CORPS OF ENGINEERS & BUREAU OF RECLAMATION SEGMENTATION

Segmentation Background

- The overwhelming majority of the transmission assets (e.g., substations and transmission lines) of the Federal Columbia River Transmission System (FCRTS) are owned by BPA
- A notable exception to this is substation equipment at some of the federal hydroelectric projects owned by the Corps of Engineers and the Bureau of Reclamation
- For ratemaking purposes, the investment in these transmission assets must be allocated to one or more of the Transmission Segments (details on the various segments was covered at the September 23rd customer workshop)

Background on Process

- The process followed for segmenting Corps/Bureau assets is identical to that for assets owned by BPA: Classify the facilities of the FCRTS and assign them to different segments (categories of service) according to the type of services they provide.

Facilities Segmented

- **Corps of Engineers:**
  - With the exception of the Bonneville project, all the substation equipment at Corps of Engineers projects is owned by BPA and is already reflected in the Transmission System's asset base
  - Substation equipment at the Bonneville project, amounting to about $32.5 million, was owned by the Corps of Engineers at the end of FY 2007 (the base year for the Segmentation Study)
- **Bureau of Reclamation:**
  - The Bureau of Reclamation retains ownership of all substation equipment at its projects
    - Therefore this equipment must be segmented

Segmentation Effects

- Costs assigned to segments are included in the cost recovery responsibility for either Power Services or Transmission Services
  - Costs associated with the Generation Integration segment are included in Power rates
  - Costs associated with the Network and Utility Delivery segments are included in Transmission rates

Summary of Segment Investments

Segment	2007 Power Rate Case		Preliminary 2010 Rate Case	
	Investment	%	Investment	%
Generation Integration	153,602,100	76%	118,942,202	67%
Network	48,629,167	24%	57,283,439	32%
Utility Delivery	998,145	0%	1,161,039	1%
TOTALS:	203,229,415	100%	177,386,680	100%

Segmentation Summary

- Preliminary estimate of Network and Utility Delivery Costs allocated to Transmission Services are $7.5 million per year.
- Corps and Reclamation Network and Delivery Annual Costs are derived from Power revenue requirement components:
  - Operations and Maintenance Expense - At project level, allocated based on investment
  - Depreciation Expense - At project level, calculated from investment
  - Net Interest Expense - Suballocated by average net investment from Cost of Service Analysis' (COSA's) Federal Base System (FBS) Hydro
  - Minimum Required Net Revenues - Suballocated by average net investment from COSA's FBS Hydro

STATION SERVICE

Station Service

- Definition:
  - Station Service is real power that Transmission Services takes directly off the BPA power system for use at substations and other facilities like Big Eddy/Celilo Complex and the Ross Complex.
- Key Factors:
  - The key factors to consider for station service are the amount of primary station service transformation installed at each substation location, and historic usage data (where metering is available).

Station Service (continued)

- Proposed methodology to quantify station service:
  - This methodology is unchanged from the prior rate case.
  - Since there are very few locations where station service is metered, the methodology to quantify station service is based on the average load factor times the amount of primary station service transformation installed at each substation times the number of hours in a month.
  - The historic station service usage is used for the Ross Complex and Celilo/Big Eddy Complex.
  - Transmission Services excludes its purchases of station service from other utilities.
- Estimated amount of station service:
  - Based on the proposed methodology, the estimated amount of station service is 6,615,846 kWh per month.

Station Service Revenue Forecast

- Energy was priced at average annual PF rate in 2007 Power Rate Case
- Energy will be priced at the risk-adjusted AURORA prices for 2010 Rate Case
- 6,615,846 kWh per month quantity forecasted by Transmission Services
- 6,615,846 kWh per month X 12 months = 79,390,152 kWh per year
- Preliminary sample calculation:
  - 79,390,152 kWh X 1 MWh/1000 kWh X $55 per MWh = $4,366,458 per year

SYNCHRONOUS CONDENSING

Synchronous Condensing Definition

- A synchronous condenser is essentially a motor with an exciter system that enables it to dynamically provide voltage support as needed by the transmission system.
- Some Federal Columbia River Power System (FCRPS) generating units are capable of operating in synchronous condenser or “condense” mode, and are requested to do so at times by BPA Transmission Services.
- As with any motor, synchronous condensers consume real power. In the case of FCRPS generators operating in condense mode, the energy consumed is supplied by the FCRPS.

Synchronous Condensing

- Distinction between generators and generators operated as synchronous condensers
  - Generators operated in condense mode perform the same voltage control function as when producing real power.
  - Normally, generating units are operated to produce real power and, at the same time, provide voltage control. However, at certain times some units are not needed at a project for real power production. At such times having units idle at particular locations may degrade reliability, so the transmission system operator will request that certain units be operated in condense mode.

Synchronous Condensing (Continued)

- Two components to costs assigned to Transmission Services:
  - The cost of energy consumed by FCRPS hydro units operating in condense mode for voltage control
  - The cost of upgrades at John Day and The Dalles hydro projects to enable synchronous condenser operation.
- When a generator is operated as a synchronous condenser, real power is consumed. The cost of the energy consumed is assigned to BPA Transmission Services when the condensing is for voltage control. The forecast of energy consumed assigned to BPA TS is based on an average of the most recent three years of data available, for fiscal years 2005, 2006 and 2007.
- The energy consumed for condensing operation is energy not available to sell; therefore, it is appropriate to price the energy at risk-adjusted AURORA prices rather than PF.

Synchronous Condensing (Continued)

- What FCRPS projects are capable of providing Synchronous Condensing Support?
  - A summary of all projects capable of providing this support and the energy they consume when motoring is listed to the right. While Hungry Horse has not been utilized for synchronous support for many years, it has been listed for completeness since this project is set up to condense.

Project	Units	Power Consumption
Grand Coulee	19-24	11 MWs (19-21) 13 MWs (22-24)
Dworshak	1-3	4.0 MWs (1 & 2) 8.0 MWs (3)
Hungry Horse	1-4	2.5 MWs
Palisades	1-4	0.6 MWs
The Dalles	15-20	1.5 MWs
John Day	11-14	3.0 MWs
Lookout Point	1-3	1.1 MWs
Green Peter	1 & 2	1.2 MWs
Detroit	1 & 2	2.0 MWs

Generation Inputs for Ancillary *and* Other Services (Synchronous Condensing)

- On average, how much energy is projected to be consumed by each project utilized for TS support in FY2010 and FY2011?
  - Current estimates by TS on the amount of time required for synchronous condensing is shown in the attached table. Amounts are broken down by projected motoring hours per year, hourly energy consumption and annual MWhrs.

Project	Motoring hrs/yr	MW's/hr consumed	Total MWhr/yr
Grand Coulee	2,387	11.0	26,253
John Day	2,691	3.0	8,072
Green Peter	3,606	1.2	4,327
Detroit	1,958	2.0	3,917
The Dalles	1,815	1.5	2,723
Dworshak	24 204	4.0 8.0	1,724
Palisades	2,549	0.6	1,529
Lookout Point	331	1.1	364
TOTALS:	15,565	32.4	48,909

Synchronous Condensing (Continued)

- Power Services' proposed revenue forecast of costs allocated to Transmission Services for Synchronous Condensing is $2,984,495 each year. Costs are based on risk-adjusted Aurora prices of $55/MWhr. Proposed costs are calculated as shown below.
  - 48,909 MWhrs/yr X $55/MWhr = $2,689,995/yr
  - The investment in plant modifications allocated to TS average $294,500/year
- Therefore the total projected revenue for Power Services is $2,689,995 + $294,500 = $2,984,495/yr

Summary of Generation Inputs for Operating Reserves and Other Services

- Preliminary estimates of annual generation input costs for 2010 BPA Rate Case:

Generation Input	Amount	Per Unit Cost	Annual Revenue Forecast
Operating Reserves - Spinning	256.0	$ 6.62	$ 20,336,640
Operating Reserves - Supplemental	256.0	$ 5.98	$ 18,370,560
Generation Dropping	1.5	$ 553,393	$ 830,090
Redispatch			$ 400,000
Segmentation of COE/BOR Network and Delivery Facilities			$ 7,500,000
Station Service	79,390	$ 55.00	$ 4,366,458
Synchronous Condensing	48,909		$ 2,984,495

Above does not include regulating reserves, following reserves, imbalance or wind integration costs.

Next Steps

- Summary of issues raised during the workshop