Power Function Review II Technical Workshop

February 13, 2006

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PFR II: Current Areas Of Priority Focus

Capital Recovery

(-/+) Longer amortization period for conservation acquisition
(-) Longer amortization period for fish and wildlife investments
(-) Use BPA borrowing authority for land and water acquisitions for fish
(-$16M) Extend existing CGS debt to 2024
(-$1.5M) Longer maturity (to 2024) on debt for new CGS investments
(-$12M) Update to reflect 2005 actuals in repayment studies
(+$5M) Columbia River Fish Mitigation plant-in-service schedule -- DOD IG decision
(+$2.5M) Potential increases for deferred maintenance (capital)

CGS O&M

(+$14M) Potential increases for deferred maintenance (expense)
(-) Consider increasing CGS generation forecast

Corps & Reclamation O&M

(-/+) Benchmarking federal projects O&M against other regional hydro projects
(-) Review process used to approve CRFM investments

Residential Exchange

None

Transmission expenses

(-) Review transmission expense for secondary sales

PFR II: Current Areas Of Priority Focus

Fish and Wildlife

(-/+) Re-examine timing for Snake River spill tests
(-/+) F&WL Monitoring and Evaluation (M&E)

"Other"

(-$53M) DSI $59 million annual support ($53M/yr is expected value in I.P. with risk)
(+) Review Spokane settlement status

Internal Operations

(-) Examine potential for additional EPIP savings

Conservation

(-) Consider conservation done by utilities "on their own nickel"
(-/+) Increase BPA funding for conservation

Renewables

(-$7M) Remove Calpine geothermal costs from 2009
(+$4M) Consider increasing facilitation costs

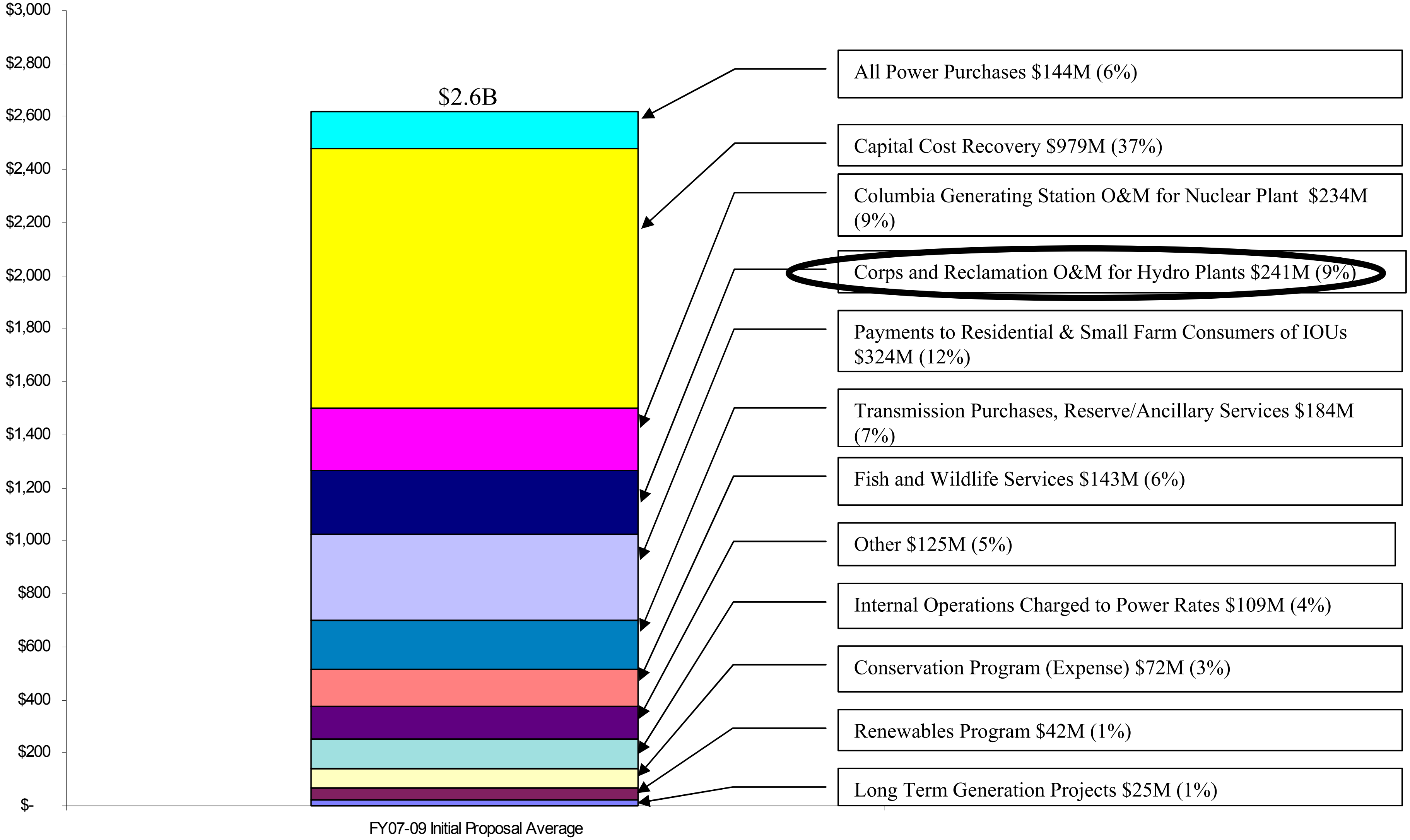
Long Term Generating Projects

None

Power Function Review II

Corps and Reclamation O&M

Average Annual Power Expenses for FY07-09



Hydro Benchmarking

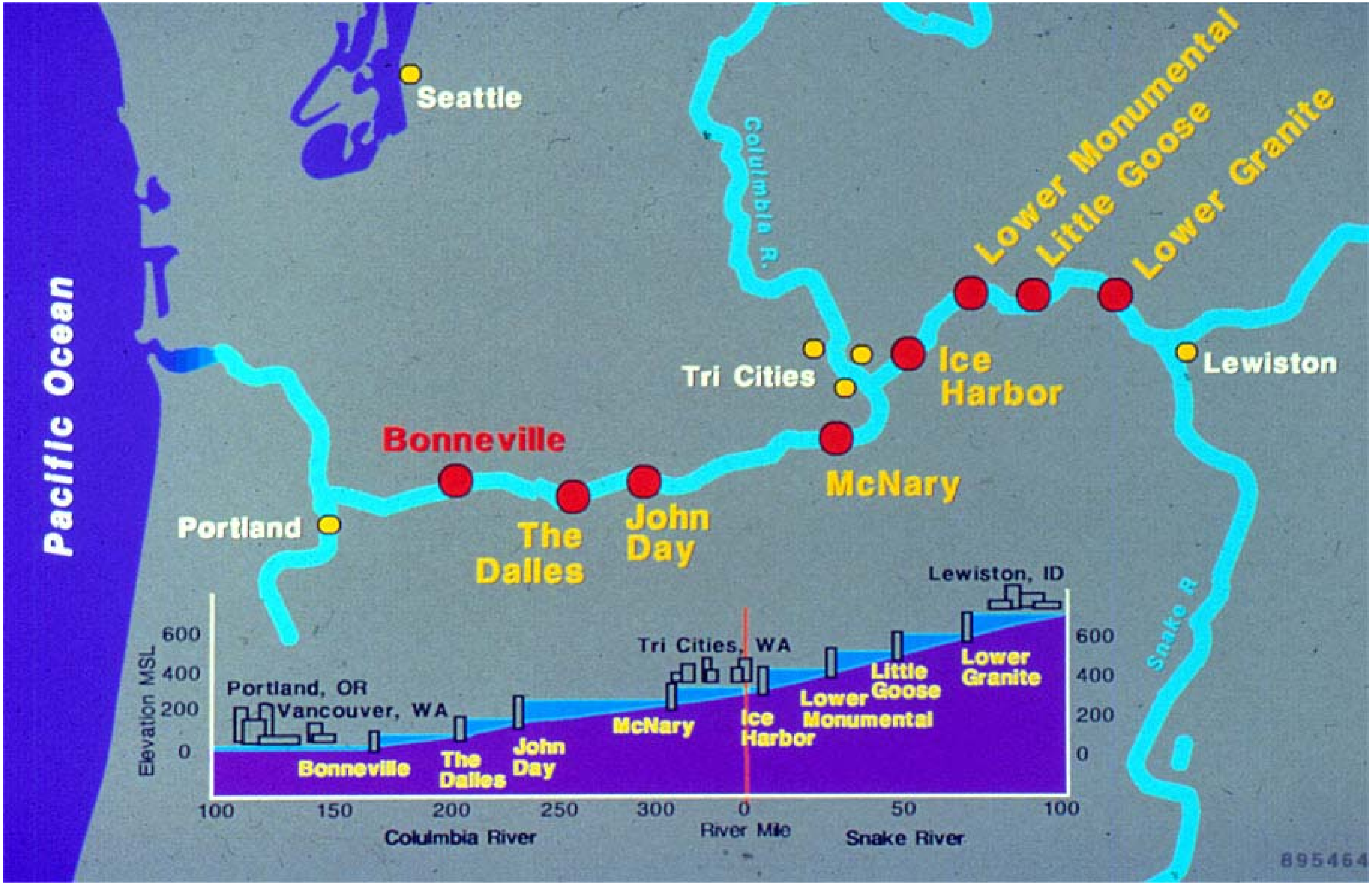
Corps & Reclamation O&M
NW Regional Benchmarking: Preliminary Findings

- General
  - Similar wage rates at NW hydro stations.
  - Similar staffing levels within peer groups.
- Operations (11 percent of benchmarked expenses)
  - All NW Large stations have similar cost per unit and are at the HJA Consulting North American panel average cost.
  - For FCRPS stations with staffed control rooms the cost per unit is higher than other regional stations that have been automated. This difference is larger with smaller stations.
- Plant Maintenance (13 percent of benchmarked expenses)
  - NW stations generally have lower maintenance costs than the North American panel.
  - Tacoma was identified as a leading performer for maintenance at Medium and Small stations. Tacoma attributes this success to two factors: 1) small workforces with a great deal of knowledge of and ownership in the facility, and; 2) continuous improvement of work processes for managing the maintenance program.
- Support (18 percent of benchmarked expenses)
  - 70 percent of NW stations are in the Lower-Mid to Lowest cost quartile of the North American panel.
  - The analysis suggests that supporting multiple functions (i.e., power, navigation, recreation, etc.) results in lower support cost per function than when serving a single function.
- Waterways and Dams / Buildings and Grounds Maintenance (8 percent of benchmarked expenses)
  - NW stations have low cost relative to the North American panel.
  - Generally, FCRPS stations have low cost within the region.
- Public Affairs and Regulatory (50 percent of benchmarked expenses)
  - 70 percent of NW stations are in the High to Upper-Mid quartiles of the North American panel.
  - Boundary and Skagit have the lowest PA&R costs within the region.

Columbia River Fish Mitigation
Plant-in-Service Update

Columbia River Fish Mitigation

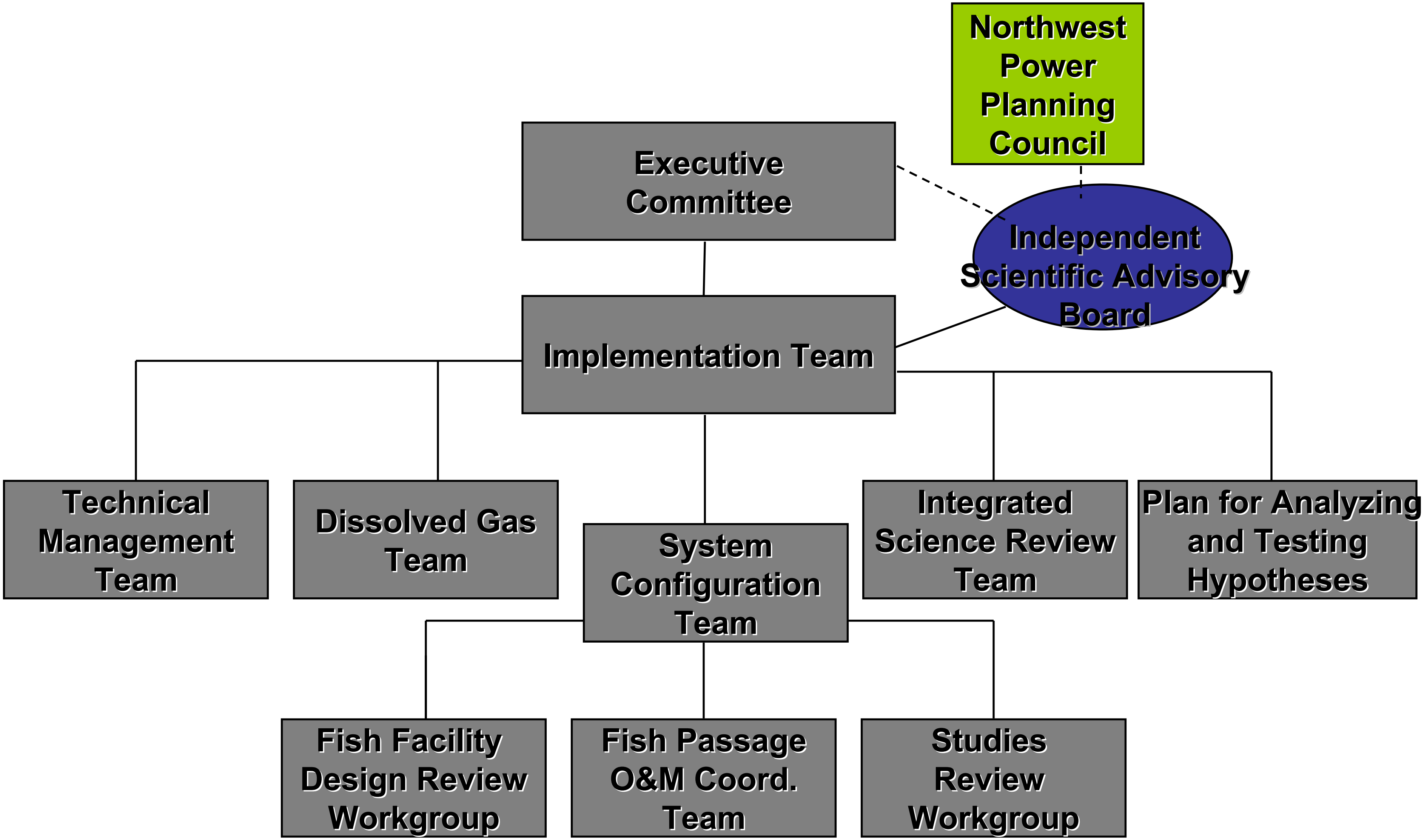
- **Purpose**: Mitigate impacts to anadromous fish passage at the Columbia/Snake River run-of- river dams
- **Authority**: Original Congressional dam construction and operation authorities
- **Project initiation**: 1991
- **Funding source**: Congressional appropriations
- **Estimated project cost**: $1.5 - $1.6 Billion
- **Estimated completion date**: 2014



Seattle
Pacific Ocean
Columbia R.
Lower Monumental
Little Goose
Lower Granite
Tri Cities
Ice Harbor
Lewiston
Bonneville
McNary
Portland
The Dalles
John Day
Snake R.
Lewiston, ID
Tri Cities, WA
Portland, OR
Vancouver, WA
Elevation MSL
600
400
200
0
Bonneville
The Dalles
John Day
McNary
Ice Harbor
Lower Monumental
Little Goose
Lower Granite
100 150 200 250 300 0 50 100
Columbia River
River Mile
Snake River
895464

- **Primary focus - passage facility configuration and operations at the dams**
  - Evaluate project and system fish passage & survival
  - Identify/develop/construct passage improvements
  - Seek cost effective alternatives
  - Implement Biological Opinions
  - Regional coordination
    - Biological/technical review &input
    - Advise on priorities

Regional Forum



- **Regional Priorities**
  - Ongoing construction
  - Dams/facilities with most significant passage and survival issues
  - Key system or project passage uncertainties
  - Highest risk facility reliability issues (primarily associated with adult ladder systems)

- **2006 Program Highlights**

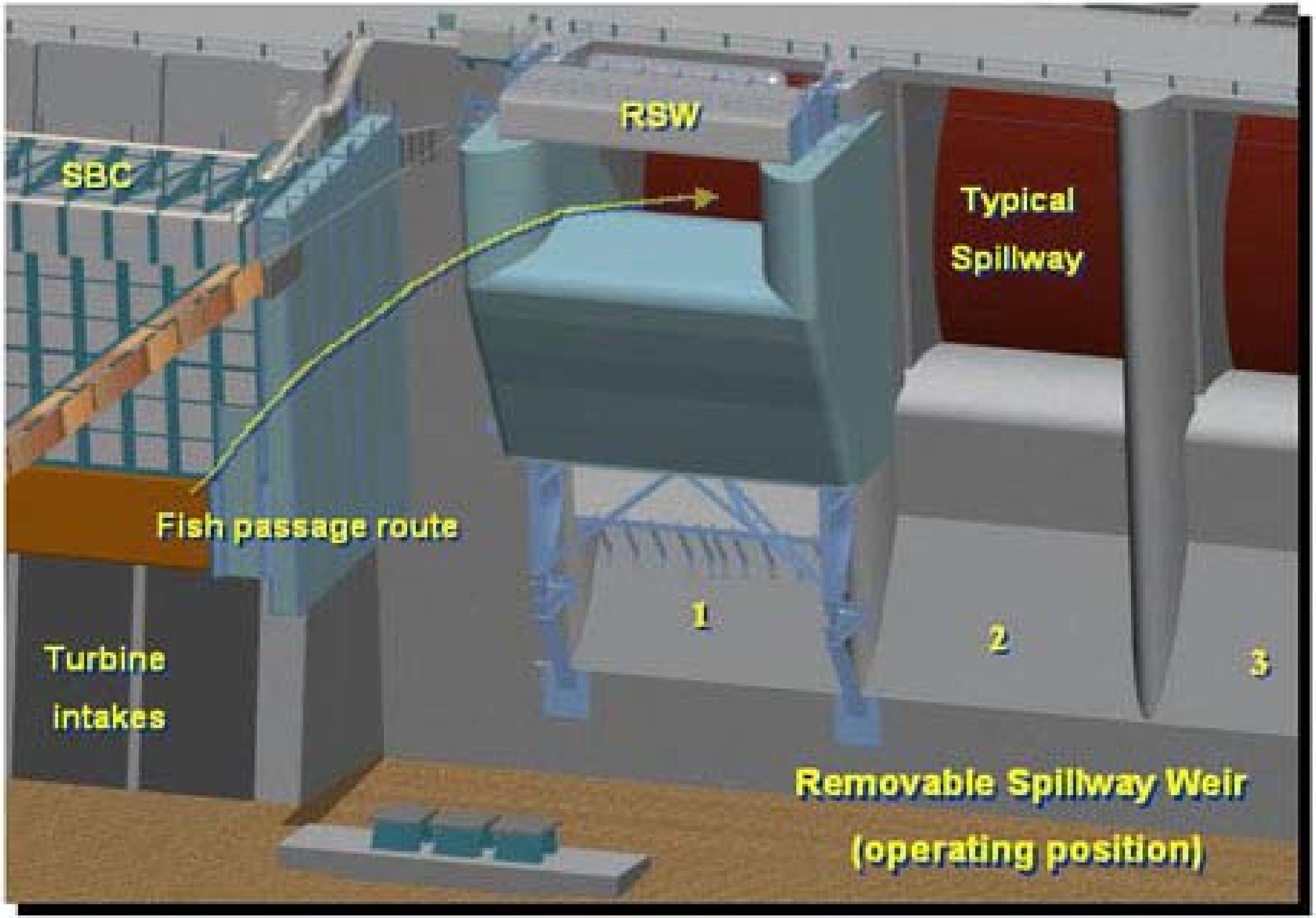
  – Initiate Removable Spillway Weir construction for Lower Monumental

  – Juvenile bypass improvements at Bonneville 2nd Powerhouse

  – Sea lion controls at Bonneville Dam

  – Continue surface bypass/configuration developments at The Dalles, John Day, McNary and Little Goose

Removable Spillway Weir



- **Repayment**
  - BPA repays “power share” of costs
  - Transfers to Plant-in-Service
    - Costs transferred when a new facility goes into operation
    - Prior Congressional guidance for “mitigation analysis” costs within the project
      - Hold until mitigation analysis “completed”
    - *Tentative* new guidance for “mitigation analysis”
      - Transfer backlog of completed studies
      - Transfer current/future studies when completed

Effect on PBL Expenses

- Including the current estimate of the plant-in-service schedule will alter the calculus of the revenue requirement. BPA does not have repayment study analysis of this change.
- The table below shows only the estimated depreciation and interest expense changes associated with the revised schedule. It is shown in comparison to the information presented during the Power Function Review last Spring.
- The effect on the revenue requirement will depend on how this change interacts with other new assumptions that will be used in the final proposal repayment study.
- Note that the expense effects are delayed by one year because plant goes into service at the end of the fiscal year. So, moving plant into service in 2006 will result in interest and depreciation expenses in 2007, not in 2006.

Estimated Interest and Depreciation Expense Changes ($ in millions)

	2006	2007	2008	2009
PFR Plant-in-Service Schedule	**$ 22**	**$ 76**	**$ 136**	**$ 6**
Interest Expense	$ 28	$ 31	$ 36	$ 40
Depreciation Expense	7	8	9	10
Cumulative Total	$ 35	$ 39	$ 45	$ 50

	2006	2007	2008	2009
Revised Plant-in-Service Estimate	**$ 284**	**$ 91**	**$ 86**	**$ 62**
Interest Expense	$ 23	$ 37	$ 41	$ 45
Depreciation Expense	6	10	11	12
Cumulative Total	$ 29	$ 47	$ 52	$ 57

F&W Hydro Operations Effects

F&W Hydro Operations Effects

How are river and reservoir operations for fish reflected when establishing BPA rates?

BPA uses a hydro-system computer model (HYDSIM) to identify the period-by-period average energy production we can expect in 50 water conditions while operating to fish criteria for each year of the rate case period.

Energy production is compared to our estimated firm load period-by-period.
Deficits cause the purchase of secondary energy and surplus can be sold.
The resulting revenue (Net Secondary Energy Revenue) is used as input to establish the level of our rates.
It is important to note that in the rate process there is no line-item expense for fish operations as there is for the Integrated Program.

What are fish operation criteria?

Reservoir elevation objectives
Juvenile bypass spill objectives
Flow augmentation targets

F&W Hydro Operations Effects

Surface Passage Improvements

NONE	= no improvement
TEST	= improvement in place in test mode 50% of the time
FULL	= improvement fully implemented 100% of the time

	Initial Proposal Assumption 2007	Initial Proposal Assumption 2008	Initial Proposal Assumption 2009	Final Proposal Assumption 2007	Final Proposal Assumption 2008	Final Proposal Assumption 2009
LWG	FULL	FULL	FULL	FULL	FULL	FULL
LGS	NONE	TEST	TEST	NONE	NONE	TEST
LMN	TEST	TEST	FULL	TEST	TEST	FULL
IHR	FULL	FULL	FULL	FULL	FULL	FULL
MCN	NONE	TEST	TEST	NONE	NONE	TEST
JDA	NONE	NONE	NONE	NONE	NONE	NONE
TDA	TEST	TEST	FULL	NONE	TEST	TEST
BON	NONE	NONE	NONE	NONE	NONE	NONE

Note: These are planning dates and are subject to change based on regional input, research results, annual flow conditions, and funding availability.

Fall Chinook Transport Study

Initial Proposal Assumption 2007	Initial Proposal Assumption 2008	Initial Proposal Assumption 2009	Final Proposal Assumption 2007	Final Proposal Assumption 2008	Final Proposal Assumption 2009
NO	YES	YES	YES	YES	?

F&W Hydro Operations Effects

50-Year Average Generation Change from Initial Proposal to Final Proposal due to Surface Passage Improvements
(in aMW)

	April	May	June	July	August
2007	-88	-135	-119	-130	-97
2008	-29	-32	-30	0	0
2009	-69	-69	-69	-69	-69

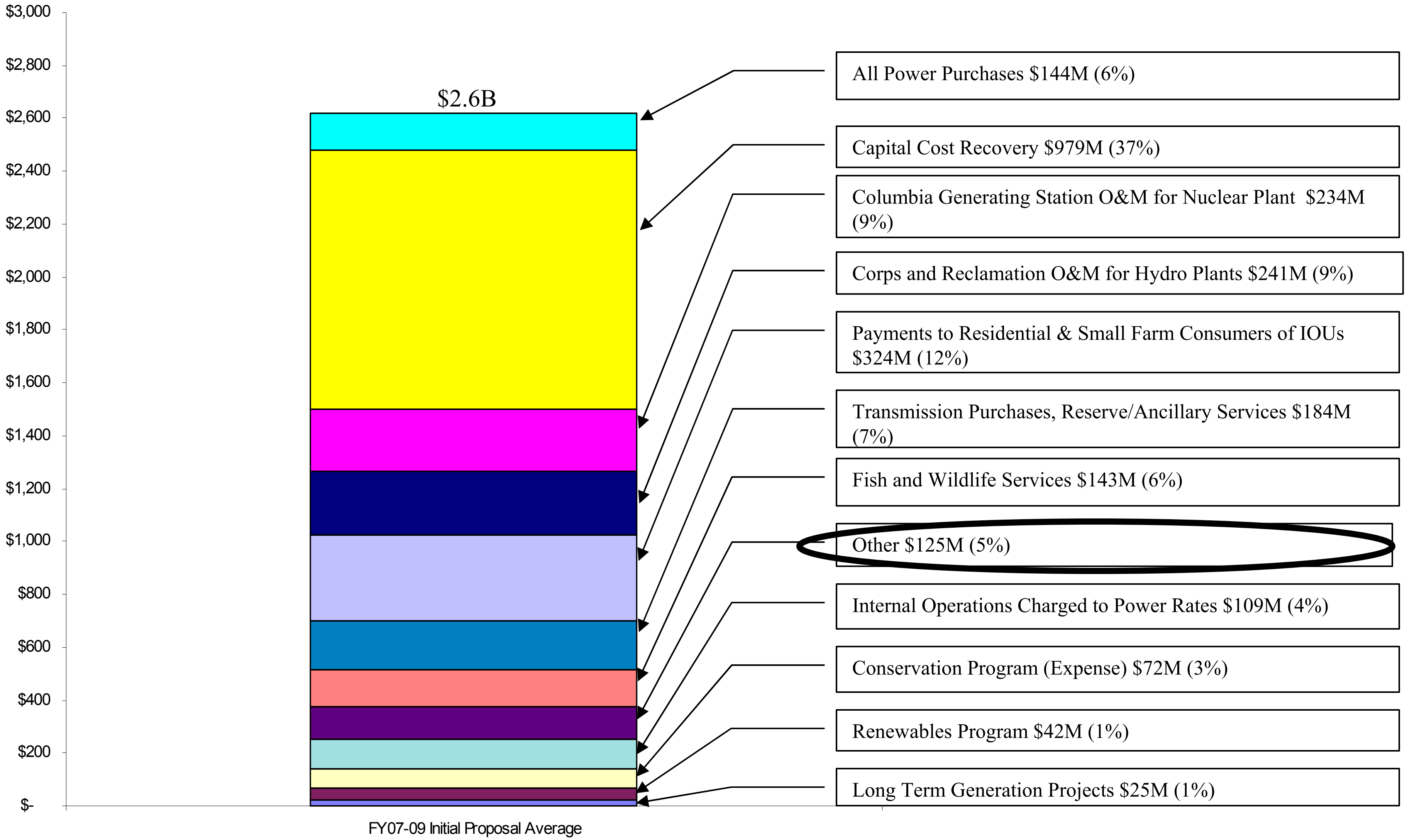
50-Year Average Generation Change from Initial Proposal to Final Proposal due to Fall Chinook Transport Study
(in aMW)

	July		August	
2007	-545		-592	
2008	-72		-144	
2009	None 473	Yes -72	None 448	Yes -144

Power Function Review II

Other (DSI Benefits)

Average Annual Power Expenses for FY07-09



DSI Benefits FY2007-2009 - History

Previous Process --- *2/4/05 Short-Term Regional Dialogue ROD*

<u>Decisions Made:</u>

- Creditworthy DSIs would be provided some level of service benefits.
- Another regional process would be conducted to take comment on the level of benefits to be offered, the eligibility criteria for receiving benefits, and the mechanism for delivering benefits.
- A supplemental ROD deciding those issues would be issued following the conclusion of the comment period.
- Mechanism or mechanisms to deliver DSI benefits would be developed through contract negotiations during the summer of 2005.

DSI Benefits FY2007-2009 – History (cont.)

Previous Process --- *DSI Straw Proposal Feb 2005 - June 2005*

<u>Proposals:</u>

- Would provide up to 500 aMW of service benefits to the DSIs.
- Service benefits would be capped at $40 million/year.
- Financial benefits by monetizing the financial value of a physical power sale contract.
- Service through local utilities would be the preferred path.

DSI Benefits FY2007-2009 – History (cont.)

Previous Process --- *6/30/05 DSI ROD on FY2007-2011 DSI Service*

<u>Decisions Made:</u>

- Provide 560 aMW of service benefits to DSI smelters (Alcoa 320 aMW, CFAC 140 aMW, GNAH 100 aMW) and benefits will not provide DSIs equivalent power costs lower than PF.
- Based on comments on straw proposal on DSI needs the cap on costs for providing benefits to the aluminum smelters increased to $59 million/year.
- Port Townsend Paper Corporation to be provided a 17 aMW surplus firm power sale at a rate approximately equivalent to the PF rate.
- BPA will attempt to deliver all service benefits through the local utility.
- BPA will review its ability to deliver proposed service benefits prior to signing contracts based on more current information about the implications of the US District Court’s decision and its impact on future hydro system operations.

DSI Benefits FY2007-2009 – History (cont.)

Previous Process --- *11/05-1/06 Regional Review of DSI Prototype Contracts*

<u>Proposed Contract Decisions:</u>

- Fulfilled promised review of DSI prototype contracts designed to implement 6/05 DSI ROD. Contracts developed by BPA, DSIs and DSI Partner Utilities.
- Embodied delivery mechanism for DSI ROD benefit level, allocation, and the concept of physical power versus financial benefits along with implementation details and flexibilities.
- Determined BPA would be unable to provide physical power within $59 million cost cap ($12/MWh). Monetized the power sale to provide financial benefits FY07-09 with a BPA option to convert to a physical sale FY10-11.
- Provided flexibility to allow smelter to operate at one half of its financial benefit allocation and receive up to $24/MWh; provided the resultant cost for power is not less the equivalent PF rate.

DSI Benefits FY2007-2009 – History (cont.)

Proposed Contract Decisions: (cont.)

- In order for a smelter to receive any benefits at all it must operate no lower than one half of its allocation.
- The Maximum Monetary Benefit Rate is established prior to the beginning of the fiscal year and is based on numbers developed for the IOU Settlement. The rate for FY2007 will likely be $24/MWh using this methodology.
- Amounts retained by DSIs are further limited such that DSIs can only keep benefits equal to the actual amount their costs exceed actual PF during the year. DSIs must demonstrate these costs which are also reviewable by BPA.
- Any benefits that go unused for 12 consecutive months will be offered to the other two smelters. Any such unused benefit not utilized within 6 months after being offered will go away and will no longer be available for use.

DSI Benefits FY2007-2009 – Benefit Level?

- **DSI Service Included in PFR II:**
  - Based on comments on DSI prototypes BPA has decided to review DSI service costs for the FY2007-2009 period in the PFR II
  - Otherwise BPA would have intended to sign contacts in mid-February. BPA now plans to sign contracts at the end of April when the PFR II is expected to be completed.
  - But BPA may pull DSI service out of PFR II and make decisions on DSI benefit levels sooner than with the rest of the process if it becomes necessary for DSIs to know the BPA benefit level in order to make decisions in a timely business-like matter. A month ago power prices were too high for DSIs to make such decisions but prices have been dropping.

DSI Benefits FY2007-2009 – Benefit Level?

- **Benefit Amount Proposed in the Initial Proposal:**
  - $59 million/year was included in the Initial Proposal as a cost for providing aluminum smelters service benefits.
  - BPA's risk modeling indicates that the average DSI benefits during FY 2007-2009 are $58.9 million, $47.2 million, and $52.8 million.
  - Risk Modeling above assumes DSIs take full benefit available until power prices become prohibitive. Benefit levels differ based on power price expectations. For example if market prices are less than $12/MWh above PF the annual $59 million becomes lower.
  - The reduction in the DSI benefits accounted for in BPA's risk modeling reduces the amount of dollars that needs to be collected via BPA's risk mitigation tools (PNRR/CRACs).

DSI Benefits FY2007-2009 – Benefit Level?

- **Reasons Why Proposed Benefit Amount May be Less than the $59 Million in the Initial Proposal:**
  - GNAH has a 100 aMW allocation, is currently shutdown, and coming out of bankruptcy; so there is some question about its ability to even restart to qualify for financial benefits.
  - This benefit concept was never intended to allow aluminum smelters to operate under all market conditions. Under very high power prices it is likely some smelters will shut down.
  - With low market prices maximum yearly benefits will be reduced below the $59 million cap since DSIs cannot receive better value than PF
  - When acquiring unused benefits an aluminum smelter may not increase its allocation above the power amount specified in its current Subscription Contract.
  - Financial benefits unused for 18 months disappear and are no longer available for any aluminum smelter.

DSI Benefits FY2007-2009 – Benefit Level?

The benefit level was never intended to enable aluminum smelting under all market conditions but is an attempt to strike the right balance between supporting aluminum jobs and the cost incurred by BPA's other customers.

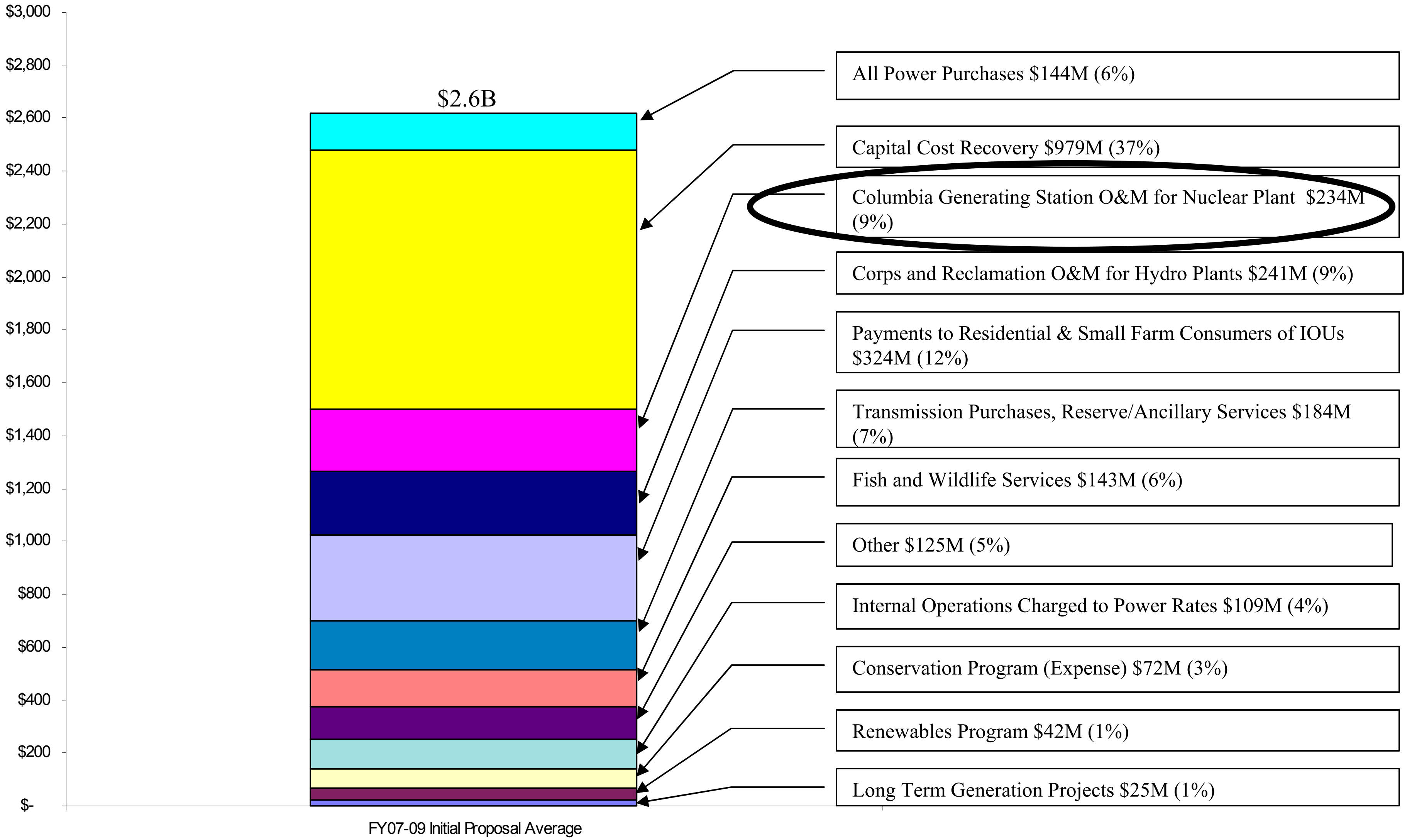
Options for Final Proposal:

- Do not change the level of service benefits proposed in the Initial Proposal. Maintain the $59 million/year cost cap.
- Sell Power amounts at PF instead of using the capped financial approach.
- Cut the $59 million/year cap in half.
- Eliminate all benefits.

Power Function Review II

Columbia Generating Station O&M

Average Annual Power Expenses for FY07-09



Outline

- BPA Introduction
  - Columbia Generating Station (CGS) Operating Costs
- Energy Northwest Presentation
- Financial Impacts to CGS
  - Operating Costs
  - Capital Additions Debt Service
- License Extension
- Generation Forecasts

CGS Operating Costs

PFR

- CGS operating costs in the BPA FY07-09 Initial Proposal Revenue Requirement are an average of $234M.
- This is down an average of $22M per year from the PFR Base Forecast.
- Capital is assumed to be 100% debt financed.

PFR II

- Since last year's PFR meetings, Energy Northwest has determined that additional funding is needed to do maintenance and equipment replacements on CGS.
- This effort will begin in Energy Northwest FY 2007 and continue through BPA's upcoming rate period.

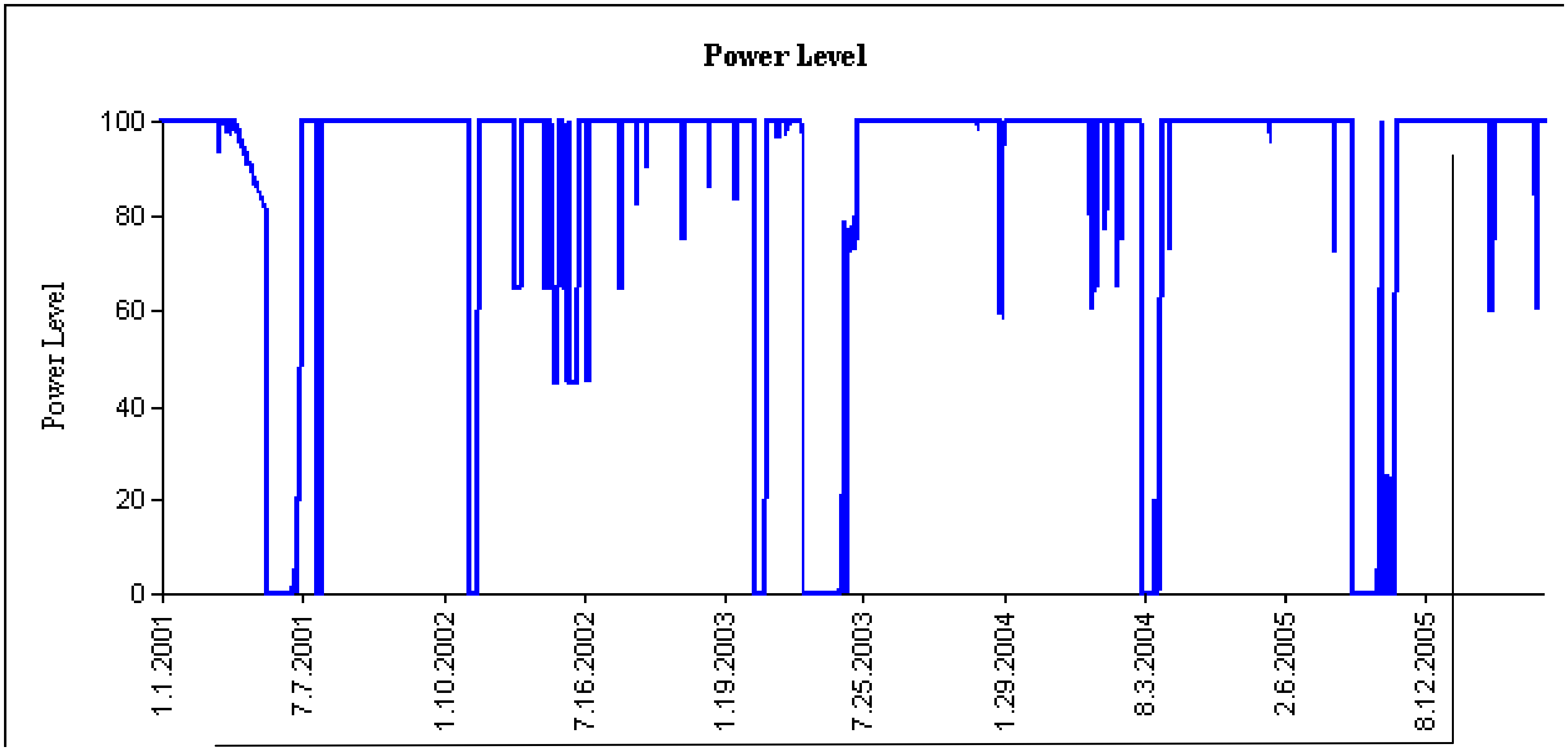
Columbia Generating Station Long Range Plan

Vic Parrish

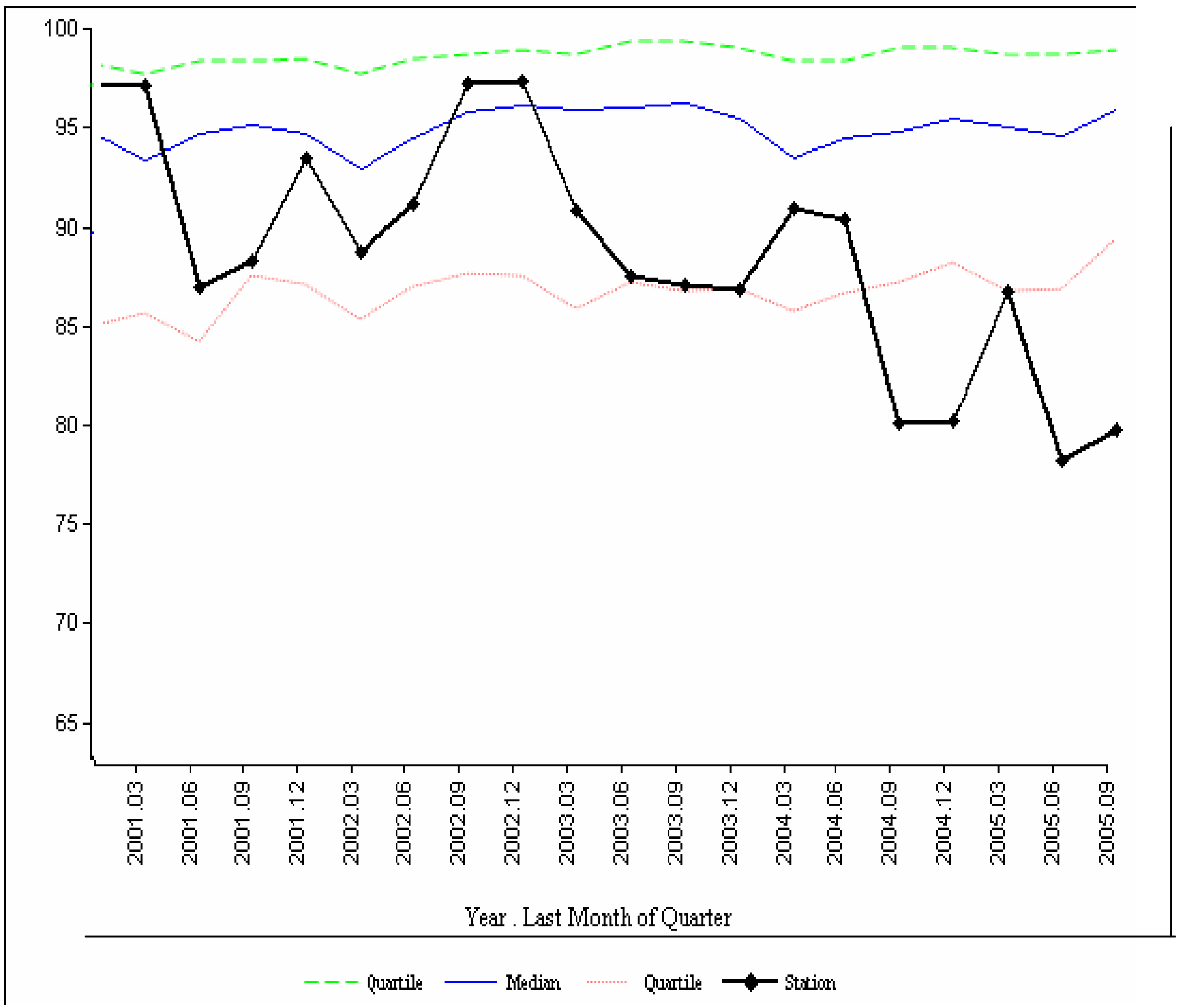
CEO/CNO

Energy Northwest

Columbia Generating Station Power History



Columbia Performance Indicator



Capital Projects
($ in Millions)

Fiscal Year	Delta from LRP	Major Projects
2007	$24.9	Turbine Digital Electro-Hydraulic Control System Main Transformer Large Pumps and Motors Process Radiation Monitoring System Refueling Floor Upgrades Plant Life Extension
2008	$17.1	Main Conderser (Planning) Large Pumps and Motors Plant Life Extension Primary Access Area Search Equipment
2009	$19.4	Main Condenser (Replacement) Large Pumps and Motors Plant Life Extension
2010	$18.0	Large Pumps and Motors Main Transformer Supplemental Spent Fuel Pool Cooling (Planning) Plant Life Extension
Total	$79.5	

O&M Projects

($ in Millions)

Fiscal Year	Delta from LRP	Major Projects
2007	$8.2	Chemical Decontamination Main/Auxialliary Jet Pump Wedges
2008	$1.2	Design Basis Upgrade
2009	$16.0	Spent Fuel Pool Cleanup Feedwater Drive Turbine Overhaul
2010	$2.2	Spent Fuel Pool Cleanup
Total	$27.6	

Incremental Outage

($ in Millions)

Fiscal Year	Delta from LRP	Major Impacts
2007	$7.6	Support for additional projects
2008	$0.0	No Outage
2009	$8.1	Support for additional projects
2010	$0.0	No Outage
Total	$15.7	

Estimated Change to FY07-09 Revenue Requirement for CGS

Operating Costs

BPA FYs - Dollars in Millions

	2007	2008	2009		Average 2007-2009
Initial Proposal Revenue Requirement	$256.5	$206.5	$239.0		$234.0
Latest Revised Estimate	$268.4	$213.2	$261.9		$247.8

- The current Rate Case and the Initial Proposal for FYs 2007 through 2009 assume that CGS capital will be debt financed. The estimates above reflect this assumption.
- NEIL insurance and CGS Decommissioning Trust Fund contributions are included in the estimates.
- The Latest Revised Estimate (LRE) is a draft. Energy Northwest and BPA are continuing to review the forecasts. Changes in the estimates are expected prior to the Final Rate Proposal.

Estimated Change to FY07-09 Revenue Requirement for CGS

BPA FYs - Dollars in Millions
Total Capital

	2007	2008	2009		Average 2007-2009
Initial Proposal Revenue Requirement	$18.0	$15.8	$28.8		$20.0
Latest Revised Estimate	$41.8	$36.8	$50.1		$42.9

Debt Service on Capital

	2007	2008	2009		Average 2007-2009
Initial Proposal Revenue Requirement	$3.8	$5.7	$8.2		$5.9
Latest Revised Estimate	$4.8	$8.2	$12.1		$8.4

•The estimates provided in this table will change prior to the Final Rate Proposal as the capital amounts get finalized and the Repayment Model is run.

•The estimates assume that 100% of capital will be debt financed.

•We are considering expensing the taxable portion (5% of capital) of the FY 06 financing due to the negative impacts it would have on the entire 2006 financing/refinancings.

CGS License Extension

BPA Fiscal Years -
Dollars in Millions

	2007	2008	2009
Initial Proposal	$3.9	$2.6	$2.0
Current Estimate	$1.4	$3.0	$3.2

- Estimated Total Project Costs approximate $15M
- The project will begin in Energy Northwest FY 2007 and continue through FY 2012.
- The estimate above is a draft and may change prior to the Final Rate Proposal.

Columbia Generating Station Generation Forecast

CGS Generation Forecasts

PNCA Operating Years – Gigawatt Hours

	2002	2003 Outage Year	2004	2005 Outage Year	2006	2007 Outage Year	2008	2009 Outage Year
Actual Generation	9,025	7,589	9,608	7,597				
PNCA Target - Rate Case input	8,760	7,680	8,784	7,680	8,760	7,680	8,760	7,680
(Under)/Over Target	265	(91)	824	(83)				
Energy Northwest Budgeted Generation	9,478	8,574	9,627	8,266	9,556	8,452	9,582	8,717

- In operating year 2004, CGS set a generation record.
- 1,000 aMW (877 aMW outage year) is a conservative estimate that has been reasonably accurate in previous years.
- CGS has completed its second two year refueling cycle. Additional experience with the two year refueling cycle is needed to support increased generation forecasts.
- Future outage lengths are uncertain at this time as Energy Northwest is reviewing projected maintenance and project plans, and implementation schedules.

BPA Financial Disclosure Information

- The information on the effect on the revenue requirement is a derived estimate for presentation purposes and may not be found in Agency Financial Information releases but is provided for discussion or exploratory purposes only as *projections of program activity levels, etc.* Such information should be used only for the purpose for which it was provided and should not be recommunicated by the recipient without the foregoing qualification.

- All FY '06-'09 information was provided in February 2006 and cannot be found in BPA-approved Agency Financial Information but is provided for discussion or exploratory purposes only as projections of program activity levels, etc.

- All FY '97-'05 information was provided in January 2006 and is consistent with audited actuals that contain BPA-approved Agency Financial Information.