Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

POWER BUSINESS LINE

May 2, 2002

In reply refer to: P-6

To: BPA Customers, Tribes, Constituents, and Interested Parties:

This letter is to follow up on a recent letter from BPA Administrator, Steve Wright, in which he reviewed the agency's current financial situation. In what follows we describe what we are doing to keep power rates as low as possible, provide detail on our costs and cost management actions, and invite your input.

As Steve said, the distress caused to utilities, businesses, and families by increased rates is very clear to us. We know that strong longstanding relationships between utility managers and their members are at risk. We know that businesses and jobs are strained because of high electricity rates – in a region with the nation's highest unemployment rates. We know that some families are struggling to pay their electricity bills. We know that our rates are a significant contributor to many retail rate increases. We have no greater priority than to manage this situation to keep rates as low as possible, and we are working hard to do that.

The following outlines our current plan to minimize power rates and manage costs for FY 2002. More detailed information is provided in the enclosures. This is a summary of an effort that is ongoing and is not yet complete. We will be sharing a complete 5-year plan with you later, but I wanted to get this progress report in your hands now. After you have had time to review this material, I encourage you to discuss it with your PBL Account Executive or Constituent Account Executive. He or she will be prepared to answer specific questions, and has direct access to those of us who are developing and managing the plan.

Our Current Action Plan to Minimize Power Rates

Aggressively managing costs. This is our primary focus. Excluding the costs of augmentation purchases, we have brought expense budgets for 2002 down to the aggressive targets in the rate case, which are based on the 1998 Cost Review, through net reductions of $102 million relative to the start-of-year estimates. This is progress, but it is not enough. We are continuing to work to bring down FY 2002 and out-year costs. Attachments 1 and 2 show the line item changes in forecasted expenditures for FY 2002 relative to the rate case (which embodied the 1998 assumptions) and to start-of-year forecasts. See Attachment 3 for line item descriptions.

Examining staff levels. Since FY 1995, the PBL has reduced its full time equivalent employment by over 26 percent. We are looking for ways to further reduce staff levels and/or make more efficient use of the staff that we have. However, the PBL has increased staffing levels somewhat over the past year for reasons described in the attachments. Staffing trends are shown in Attachment 4. We are continuing to look for ways to keep essential work on track while limiting hiring.

Limiting new long-term financial commitments. While we are examining our out-year costs, we have put interim financial controls in place to limit new financial commitments, both capital and expense, to ensure that we don't make commitments now that we later might conclude we cannot afford.

Minimizing augmentation costs. The cost of our total 5-year portfolio of over 2,400 average megawatts of augmentation power purchases and load buy-downs averages approximately $35 per megawatt-hour (MWh). A package of more detailed information on our augmentation costs is available on request. These costs are the basis for the Load-Based Cost Recovery Adjustment Clause (LB CRAC). Considering the market price extremes of 2000 and 2001, we view $35/MWh as a reasonable average price for these purchases. However, there are individual purchases in our portfolio that are higher-priced, and we are actively seeking opportunities within our contractual rights to reduce the costs of those individual purchases.

Maximizing surplus sales revenues. In this near-average water year, we have significant seasonal surplus power to sell. The quantity and price of these sales is the single largest driver of our net revenues this year, and hence the single largest driver of the probability of a Financial-Based Cost Recovery Adjustment Clause (FB CRAC) triggering in October. We are working hard to maximize revenues from these sales, and to optimize river operations within the various non-power constraints to make power available during the highest-value periods.

Standing firm on take-or-pay obligations. So far this year, spot market prices have been lower than our firm power rates much of the time. All of our customers have contracts which obligate them to take certain amounts of power from BPA, or to pay BPA the difference between our rates and the spot market (where we would have to resell any power that our customers failed to take). We are continuing to insist that customers meet this obligation, because to do otherwise would cause a net revenue loss that could drive our rates up.

Residential exchange settlement. We are encouraging certain of our investor-owned and public utility customers to reach a settlement of litigation challenging the investor-owned utilities' residential exchange settlement agreements. A settlement would avoid adding $50 million per year to BPA rates, beginning in October 2002.

Fish and Wildlife: BPA remains committed to meeting the performance standards of the 2000 Biological Opinion governing endangered salmon recovery efforts, and intends to seek the most cost-effective means of doing so. We intend to step up our focus on ensuring that we are implementing all actions that are needed to meet Endangered Species Act and Northwest Power Act requirements. We intend to continue to work with Federal agencies, Tribes, customers, and other stakeholders in these efforts.

Cost Management

As noted already, managing our costs is a cornerstone of this plan. In what follows you will find specific information concerning PBL's costs for the current fiscal year and a description of the actions we are taking to manage costs this year. We are also working hard on out-year cost reductions through FY 2006, and plan to share our cost management plan for those years with you within the next 90 days.

We have grouped PBL costs into three broad categories: Program costs, Fixed costs, and Subscription costs. The discussion below provides information on these costs and what we are doing to manage them.

Program and Fixed Costs

Program costs cover items such as operations and maintenance of the Federal Columbia River Power System (FCRPS), Columbia Generating Station expenses, and our fish and wildlife obligations. Of the three cost categories, these costs are the ones PBL is most able to influence. Since we first developed initial estimates of costs at the start of the fiscal year, we have thoroughly examined our expected costs for FY 2002. As a result, we have identified over $95 million in program expense reductions for this fiscal year relative to start-of-year budgets. Some of these reductions, however, are offset by increases in such things as security costs at the Corps of Engineers and Bureau of Reclamation hydro projects due to more stringent security requirements required since the events of September 11, 2001.

Fixed costs are primarily Federal and non-Federal debt service. Since the start of the year, we have achieved about $19 million in non-Federal debt service savings. These savings have occurred for a variety of reasons, including reduced capital spending, and lower interest rates.

Therefore, relative to start-of-year targets, these program and fixed cost reductions together total about $102 million, net of increases in some categories. Attachment 1 provides details concerning the changes in our expense forecasts for FY 2002 that we have identified thus far.

The result of these cost management actions is that current estimates of expenses in these two categories are $3 million less than projected in June 2001 (see Attachment 2). These Rate Case projections, included in both the May 2000 and June 2001 rate proposals, were based on the very aggressive cost control targets put forward by the regional Cost Review in 1998. Attachment 3 provides brief explanations of the line items that show changes in their expense forecasts since the June 2001 Rate Case.

The 1998 Cost Review made assumptions about BPA's post-2001 operating environment that turned out to be wrong, as just about everything projected from the 1990s turned out to be. The upheaval in our industry – in law, regulation, markets, supply obligations, and institutional structures – has been huge, and we and our customers have been struggling to adjust to the new realities. Most of this change has created large additional requirements on BPA. In this context, bringing costs down to Cost Review levels in 2002 is progress, but we are looking to do more. This letter provides a snapshot of an ongoing concerted effort to bring costs down.

Subscription Costs

Subscription costs are those costs associated with serving additional load beyond that which can be served by the FCRPS. Most of these costs are recovered through the LB CRAC. However, the LB CRAC does not cover the following subscription-related items:

- Additional residential exchange settlement costs of about $60 million resulting from an increase in the market price forecast between the May 2000 and June 2001 Rate Case studies.
- Difference in the shape of the load BPA serves which has resulted in additional costs compared to those forecast in the rate case.
- Augmentation power was purchased in 6-month blocks using conservative assumptions about water availability for hydropower production. Actual month-to-month loads are sometimes less than the amount of augmentation power we have purchased so these augmentation costs are not covered by the LB CRAC. Because spot market prices are now substantially lower than the augmentation contract prices, we are currently selling any excess augmentation power at a loss.

We may have opportunities to reduce the cost of augmentation, and we are working constantly on that front. But, we will have additional augmentation purchases to make over the next 4 years if public and DSI loads recover. We are looking for every opportunity to minimize the costs of those purchases.

FB CRAC Outlook

We will be providing a broader update of our overall financial outlook in about 2 weeks when our second quarter financial results are posted on our web site. That update will include prospects for the FB CRAC in October.

Your Input

This letter and the attachments are a progress report on the plan we are pursuing to minimize rates. Within 90 days, we will be sharing an extension of this plan that will address FY 2003-2006. I very much welcome your input on this plan. Our PBL Account Executives and Constituent Account Executives are very knowledgeable about this plan and I encourage you to discuss it with them.

Sincerely,

/s/ Paul E. Norman

Paul E. Norman, Senior Vice President
Power Business Line

4 Enclosures:
Attachment 1: Changes to Start-of-Year Expense Forecasts for the PBL for FY 2002
Attachment 2: Expense Comparison of FY 2000 through April 2002
Attachment 3: Descriptions of Major Cost Categories and Key Drivers
Attachment 4: FY 1995-2002 Power Business Line FTE

ATTACHMENT 1

Changes to Start-of-Year Expense Forecasts for the PBL for FY 2002

$ in Millions

	Program Cost Reductions		FY 2002 Delta (April 2002 - Start of Year)
1	Columbia Generating Station (WNP-2) O&M	$	(37.3)
5	Power Business Operations	$	(8.5)
8	Shared Services	$	(3.4)
9	Corporate General & Administrative	$	(5.9)
12	Corps of Engineers Operation & Maintenance	$	(1.0)
13	Bureau of Reclamation Operation & Maintenance	$	(2.0)
17	Conservation and Energy Efficiency	$	(8.4)
21	PBL Efficiencies Program	$	(6.9)
24	Generation Development & Coordination	$	(1.4)
28	Renewable Projects	$	(0.8)
29	Long-Term Generating Projects	$	(4.0)
30	Fish and Wildlife Program 1/	$	(15.0)
34	Trojan Operation & Maintenance	$	(1.0)
	Sub-Total of Program Cost Reductions	**$**	**(95.6)**

	Fixed Cost Reductions		Amount
39	Energy Northwest Debt Service 2/	$	-
40	Trojan Debt Service	$	(7.7)
41	Renewables Debt Service	$	-
42	Conservation Financing	$	-
43	Long-Term Generating Debt Service	$	-
45	Amortization	$	(1.6)
46	Misc. Income Deductions	$	-
47	Net Interest	$	(10.0)
	Sub-Total of Fixed Cost Reductions	**$**	**(19.3)**
	Sub-Total of all Cost Reductions	***$***	***(114.9)***

	Program Cost Increases		Amount
12	Corps of Engineers Security	$	5.1
13	Bureau of Reclamation Security	$	1.7
24	Generation Development and Coordination correction 3/	$	0.6
25	Colville Generation Settlement	$	1.3
28	Renewable Wind Project	$	1.2
	Sub-Total of Program Cost Increases	**$**	**9.9**

	Fixed Cost Increases		Amount
44	Depreciation	$	3.1
	Sub-Total of Fixed Cost Increases	**$**	**3.1**
	Sub-Total of all Cost Increases	***$***	***13.0***
	FY 2002 Net Expense Reductions For Program and Fixed Categories	**$**	**(101.9)**

Specific Actions:

- **Capitalized the Columbia Generating Station spent fuel storage system which reduced expenses by $37 M**
- **Cut travel, support services and consulting contracts, and all overtime in all departments**
- **Major reduction to Energy Web/Technology Leadership initiatives**
- **Reduced and deferred PBL Efficiencies projects without jeopardizing work done to date**
- **Capitalized major Information Technology (IT) projects as well as IT in PBL Efficiencies**
- **Revised several generation output contracts yielding significant savings**
- **Agency-wide reductions in Corporate G&A and Shared Services including: cuts in travel, support service contracts, furniture replacement, and IT upgrades**
- **Corps of Engineers and Bureau of Reclamation O&M reductions, partially offset by rising costs for increased security since 9/11/2001**
- **Reduced Market Transformation spending in the Conservation program**
- **Scaled back Renewables project predevelopment work**
- **Revised Fish and Wildlife costs to reflect more realistic estimates based on past experience**
- **Utilized reserve fund free-ups associated with Trojan debt service to pay for Trojan decommissioning (O&M) costs**
- **Reduced PBL staffing by 10 FTE relative to annual target, mainly by deferring hiring for approved positions**

1/ BPA is continuing to plan and obligate at planned spending levels. However, expenses reflected in the April 2002 Forecast are re-estimated accruals based on past experience.
2/ The April 2002 Forecast for Energy Northwest debt service does not reflect savings from ongoing refinancing because the savings will be used to pay Federal debt, and cannot be used in the Financial Based Cost Recovery Adjustment Clause calculation.
3/ This increase resulted from a data entry correction.

ATTACHMENT 2

Expense Comparison of FY 2000 through April 2002

(See Attachment 3 for descriptions of these cost categories)

$ in Millions

#	Detailed Expenses By Category 1/	FY 2000 Actuals	FY 2001 Actuals	FY 2002 June 2001 Rate Case Forecast 2/	FY 2002 April 2002 Forecast 3/	FY 2002 Delta (April 2002 - June 2001)
	Program Expenses					
1	Columbia Generating Station (formerly WNP-2)	$ 182.4	$ 209.5	$ 154.1	$ 173.1	$ 19.0
2	NORM - PNRR 4/			$ 17.9	$ -	$ (17.9)
3	Revenue Offsets from Increased Output			$ -	$ (10.0)	$ (10.0)
4	**Total CGS Expenses**	**$ 182.4**	**$ 209.5**	**$ 172.0**	**$ 163.1**	**$ (8.9)**
5	Power Business Operations 5/	$ 52.6	$ 49.3	$ 36.9	$ 53.1	$ 16.2
6	NORM - PNRR 4/			$ 4.5	$ -	$ (4.5)
7	**Total Power Business Operations Expenses**	**$ 52.6**	**$ 49.3**	**$ 41.4**	**$ 53.1**	**$ 11.7**
8	Shared Services (estimate for FY 2000) 6/	*$ 14.1*	$ 15.2	$ 7.4	$ 19.6	$ 12.2
9	Corporate G&A (estimate for FY 2000) 6/	*$ 20.6*	$ 22.3	$ 10.0	$ 25.7	$ 15.7
10	NORM - PNRR 4/			$ 3.0	$ -	$ (3.0)
11	**Total Expenses for SS and Corporate G&A**	**$ 34.7**	**$ 37.5**	**$ 20.4**	**$ 45.3**	**$ 24.9**
12	Corps of Engineers O&M	$ 104.1	$ 115.0	$ 108.0	$ 127.3	$ 19.3
13	Bureau of Reclamation O&M	$ 46.1	$ 53.2	$ 47.0	$ 57.1	$ 10.1
14	NORM - PNRR 4/			$ 2.7	$ -	$ (2.7)
15	Revenue Offsets from Generation Investments			$ -	$ (7.5)	$ (7.5)
16	**Total Corps and Bureau Expenses**	**$ 150.2**	**$ 168.2**	**$ 157.7**	**$ 176.9**	**$ 19.2**
17	Conservation and Energy Efficiency	$ 32.7	$ 30.5	$ 29.4	$ 38.0	$ 8.6
18	NORM - PNRR 4/			$ -	$ -	$ -
19	Revenue Offsets from Reimbursable Contracts			$ -	$ (10.0)	$ (10.0)
20	**Total Expenses for Conservation and EE**	**$ 32.7**	**$ 30.5**	**$ 29.4**	**$ 28.0**	**$ (1.4)**
21	PBL Efficiencies Project	$ 0.5	$ 5.7	$ -	$ 4.1	$ 4.1
22	Revenue Offsets from System Efficiencies			$ -	$ -	$ -
23	**Total Expenses for PBL Efficiencies Project**	**$ 0.5**	**$ 5.7**	**$ -**	**$ 4.1**	**$ 4.1**
24	Generation Development & Coordination	$ 6.7	$ 4.2	$ 3.0	$ 9.1	$ 6.1
25	Colville Settlement	$ 14.8	$ 19.7	$ 16.0	$ 21.3	$ 5.3
26	Planning Council	$ 7.4	$ 7.3	$ 5.1	$ 8.3	$ 3.2
27	Telemetering & Equipment Replacement	$ -	$ -	$ -	$ 2.0	$ 2.0
28	Renewables	$ 3.9	$ 7.9	$ 20.3	$ 19.9	$ (0.4)
29	Long-Term Generating Projects	$ (3.8)	$ 20.0	$ 26.8	$ 23.9	$ (2.9)
30	Fish & Wildlife Including Augmentation Initiative 7/	$ 108.2	$ 102.9	$ 131.7	$ 129.4	$ (2.3)
31	WNP-1, 3 & 4 O&M/Decommissioning	$ (0.3)	$ -	$ 3.5	$ 0.1	$ (3.4)
32	Between Business Expenses	$ -	$ -	$ 4.0	$ -	$ (4.0)
33	Ancillary & Reserve Services	$ 30.2	$ 28.6	$ 8.0	$ -	$ (8.0)
34	Trojan O&M Decommissioning	$ 13.9	$ 2.6	$ 9.6	$ 0.6	$ (9.0)
35	GTA Wheeling	$ 32.8	$ 34.2	$ 52.0	$ 35.2	$ (16.8)
36	US Fish and Wildlife	$ 12.4	$ 12.7	$ 15.4	$ 15.4	$ -
37	CSRS Pension	$ 2.4	$ 3.2	$ 27.6	$ 27.6	$ -
38	**Total Program Expenses**	**$ 681.7**	**$ 744.0**	**$ 743.9**	**$ 763.3**	**$ 19.4**
	Fixed Expenses					
39	Energy Northwest Debt Service 8/	$ 525.4	$ 445.1	$ 528.9	$ 528.9	$ -
40	Trojan Debt Service	$ 10.3	$ 10.2	$ 9.9	$ 2.2	$ (7.7)
41	Renewables Debt Service	$ -	$ -	$ 2.9	$ -	$ (2.9)
42	Conservation Financing	$ 9.5	$ 5.3	$ 5.6	$ 5.6	$ -
43	Long-Term Generating Debt Service	$ 15.7	$ 16.5	$ 15.9	$ 12.2	$ (3.7)
44	Depreciation	$ 88.6	$ 88.3	$ 97.6	$ 94.8	$ (2.8)
45	Amortization	$ 77.3	$ 76.1	$ 79.1	$ 77.2	$ (1.9)
46	Misc. Income Deductions	$ 1.0	$ 19.7	$ -	$ -	$ -
47	Net Interest	$ 169.3	$ 168.3	$ 203.7	$ 199.7	$ (4.0)
48	**Total Fixed Expenses**	**$ 897.1**	**$ 829.5**	**$ 943.6**	**$ 920.6**	**$ (23.0)**
	Total Net Change of <u>Program and Fixed Expense</u> Categories - April 2002 Forecast Compared to June 2001 Rate Case Forecast					**$ (3.6)**

Footnotes for Attachment 2

1/ The Program expense reductions in Steve Wright's letter of April 2002 erroneously included Fixed expense reductions of $18M. This table reflects this correction. Additionally, all expense forecasts have been updated since that time (labeled April 2002 Forecast).

2/ The June 2001 Rate Case Forecast is the same as the May 2000 rate proposal, which is based on the 1998 Cost Review.

3/ The April 2002 Forecast of Program and Fixed expenses reflects both offsetting revenues and expense reductions of $101.9M for FY 2002 compared to the FY 2002 Start-of-Year Forecast in Program costs (see Attachment 1 for the detailed expense reductions compared to the FY 2002 start-of-year forecast).

4/ NORM refers to Non-Operating Risk Model as used in the June 2001 Power Rate Case to calculate a component of Planned Net Revenues for Risk. Planned Net Revenues for Risk (PNRR) were included to cover the risk of not meeting those aggressive targets.

5/ Includes expenses from the following organizations: Sales & Support; Operations Planning; Scheduling; Strategy, Finance & Risk; Human Resource Management; Process Automation & IT; Communication & Liaison; Billing; Rates; Trading Floor; Transmission & Reserve Services; and Pricing and Transaction Analysis.

6/ The June 2001 Rate Case assumed efficiency savings across all administrative functions.

7/ Fish and Wildlife expenditures of $24.4 million in FY 2002 are being used to mitigate the impacts of last year's power emergency. BPA is continuing to plan and obligate at planned spending levels. However, expenses reflected in the April 2002 Forecast are re-estimated accruals based on past experience.

8/ The April 2002 Forecast for Energy Northwest debt service does not reflect savings from ongoing refinancing because the savings will be used to pay Federal debt, and cannot be used in the Financial-Based Cost Recovery Adjustment Clause (FB CRAC) calculation.

Attachment 3

Descriptions of Major Cost Categories and Key Drivers

1. Columbia Generating Station (WNP-2) includes the costs for the operation and maintenance of Energy Northwest's nuclear power plant. There is no refueling outage in 2002, reducing costs compared to a refueling year.

5 and 24. Power Business Operations and **Generation Development & Coordination** consist primarily of Federal and Contractor employee costs such as salaries and benefits, and related costs, such as travel, training, supplies, and information technology equipment. The June 2001 Power Rate Case, reflecting the FTE (Full Time Equivalent) levels of the 1998 Cost Review, had PBL FTE much lower than current FY 2002 levels, and declining further over time. The Cost Review based the reduced FTE levels on greatly simplified contracts with basic products, greatly reduced sales support, and automated scheduling transaction systems. PBL reduced staff levels through 2000; however, increases over the past few years have been necessary. The fundamental driver for increases in PBL staff levels has been the additional functions PBL has had to take on in the current market environment including the need to staff Scheduling and the Trading Floor on a 24-hour/7-day-a-week basis. The renewed and reinforced commitment to energy efficiency has also placed some upward pressure on staffing needs. BPA's strategy has been to attempt to offset the higher staffing needs with greater cost reductions elsewhere.

8. Shared Services represents BPA costs for information technology services, purchasing services, personnel services, mail, media support, building lease and management services, library and printing services. Two major drivers since Cost Review have been the development and implementation of an enterprise software system for work management and finance (the costs of this system appear in the Shared Services and Corporate categories, while the efficiencies expected from the system are spread over all BPA organizations) and information technology infrastructure investments to replace aging and non-integrated computer systems. Another major driver is a change in the methodology for distributing costs, which has shifted a larger share of costs to Power from Transmission.

9. Corporate General & Administration includes Contracts & Property Management, Security, Safety, Human Resources/Diversity Management, and Finance. The major driver has been the change in methodology for distributing this cost. At the time of Cost Review, the allocation was approximately 30% Power and 70% Transmission. Today, the cost is allocated 50/50 between both business lines hence Power receives a greater share of these costs.

12 and 13. Corps of Engineers and Bureau of Reclamation includes the direct operating and maintenance expenses of all power generating projects in the Federal Columbia River Power System. Major cost drivers have been the change in operations stemming from subsequent Biological Opinion(s), no inflation assumptions in the Cost Review, and the change in the allocation of costs (increase) to the power component from other project purposes at Grand Coulee dam. In addition, there have been increased security costs since September 11, 2001. Availability at the projects is up 5% and overall efficiencies are increasing, thus creating off-setting revenues from additional generation.

17. Conservation and Energy Efficiency reflect legacy conservation programs as well as reimbursable agreements (Market Development), Conservation & Renewables Discount, Market Transformation, and Energy Web/Technology Leadership programs. A major cost driver has been the Agency's strategy to invest more in conservation activities, especially after 2001's record drought and energy crisis.

21. PBL Efficiencies is a set of projects started in 1999 in response to the Cost Review to improve overall efficiencies to maximize performance and meet the challenges in rapidly changing markets. They consist of **Near Real Time Optimization** to more accurately optimize the Federal hydro system generation; **Columbia Vista** software which will make more efficient use of water thus resulting in added net revenues; **Enterprise Application Integration** which will provide a seamless integration of applications across BPA networks which will reduce interface development, maintenance costs, and staff time associated with introducing new application into the PBL application architecture; **Generation Management System** is a real-time system to better manage generating resources, maintain inventories, implement zonal generation management, transition to Regional Transmission Organization (RTO), and update systems to industry standards; this will allow duty schedulers to have increased control of the hydro system and depend less on manual processes; **Information Factory** to access, query, and analyze information from multiple sources, including PBL processes, agency financial systems, and the Corporate InfoFactory**; Load Forecasting** project to improve all aspects of generating or using load information which will improve revenue, rates, and risk predictions as well as improved operations planning procedures; **Transaction Scheduling System** will facilitate the power/transmission transaction process from contract signing to billing eliminating the need for multiple, manual processes. These are significant system investments with a high rate of return in optimized system operations.

25. Colville Settlement is the settlement program with the Colville Nation regarding lands lost due to the construction of Grand Coulee dam and is based on an algorithm of actual generation from Grand Coulee with sales revenue. Until recently, the average annual payment has been approximately $16 million but high market prices last year caused the payment to increase to over $21 million.

26. Planning Council pays for the staff and associated expenses of the Northwest Power Planning Council.

27. Telemetering/Equipment Replacements are for transmission engineering services, including equipment, to provide transmission support for General Transfer Agreement (GTA) customers.

28. Renewables are generating projects fueled by renewable energy resources, such as wind, geothermal, methane gas, solar, and "fish friendly" small hydro projects.

29. Long-Term Generating Projects consist of output contracts for generating resources, such as Cowlitz Falls, Billing Credits, Wauna, etc.

30. Fish & Wildlife including Augmentation Initiative reflects costs incurred to mitigate the impacts of the drought and low water in 2001 as well as the annual recurring program costs.

31. WNP-1/3/4 O&M/Decommissioning reflects costs for the decommissioning or restoration of sites for three incomplete nuclear power plants.

32. Between Business Expenses reflects costs for services provided by the Transmission Business Line except the wheeling of power (e.g., aircraft services, engineering design services, etc.).

33. Ancillary & Reserve Services represent costs associated with services necessary to support the transmission of energy from resources to loads: reliability, scheduling and dispatch, spinning reserves, emergency reserves, load following and regulation, automatic generation control, energy imbalance, transmission losses, control area reserves for resources and for interruptible purchases.

34. Trojan O&M Decommissioning reflects the costs associated with the decommissioning of the Trojan nuclear power plant.

35. GTA (General Transfer Agreements) Wheeling reflects the costs for wheeling power over a second utility's line to a customer of the first utility in the second utility's control area.

36. U.S. Fish and Wildlife Service reflects the costs for the Lower Snake River Compensation Plan, a series of 13 fish hatcheries on the Lower Snake to mitigate the damage done to fish by the construction of Lower Monumental, Little Goose, Lower Granite, and Ice Harbor dams. Authorized by Congress in the mid-1970s, constructed by the U.S. Army Corps of Engineers, operated and maintained by the U.S. Fish and Wildlife Service. Expenses are directly funded by BPA from power sales revenues, except one hatchery with shared funding.

37. CSRS Pension reflects the costs for the unfunded liability of the Civil Service Retirement and Disability Fund, the Employees Health Benefits Fund, and the Employees Life Insurance Fund that has not been covered prior to FY 1998. This cost is split 50/50 between Power and Transmission. Cost estimates also include the power related portion of Corps of Engineers, Bureau of Reclamation, and the U.S. Fish and Wildlife pension and post-retirement benefits.

39. Energy Northwest Debt Service reflects the interest and principal for three shut down and one operating nuclear power plant.

40. Trojan Debt Service reflects the interest and principal for the Trojan nuclear power plant.

41. Renewables Debt Service reflects the expected principal and interest costs for capital funding renewable projects.

42. Conservation Financing reflects third party financing of Conservation programs.

43. Long-Term Generating Debt Service reflects the interest and principal of the Cowlitz Falls generation plant.

44. Depreciation: the cost of recognizing or allocating the non-cash expense of a long-lived asset to a particular year (e.g., Corps of Engineers and Bureau of Reclamation capital projects).

45. Amortization: The depreciation for intangible assets associated with capital investments in Fish and Wildlife, and Conservation programs.

46. Misc. Income Deductions: The costs associated with military buybacks, insurance, and travel advancement recapture.

47. Net Interest: The interest costs of borrowing funds for capital investments in Power programs including the repayment to the U.S. Treasury by BPA of principal on the Federal investment in the Federal Columbia River Power System (FCRPS), which includes BPA bonds and appropriations, and Army Corps of Engineers and Bureau of Reclamation appropriations that are part of the FCRPS.

Attachment 4

Power Business Line FTE
FY 1995 - FY 2002