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WASHINGTON PUBLIC POWER SUPPLY SYSTEM

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March 2, 1995
GO2-95-044

Docket Nos: 50-460
50-397
50-508

U.S. Nuclear Regulatory Commission
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Gentlemen:

Subject: **NUCLEAR PROJECTS 1, 2, & 3 ANNUAL FINANCIAL REPORT**

Enclosed for your information, as required by 10 CFR 50.71(b), are three copies of the Washington Public Power Supply System's 1994 Annual Report.

Should you have any questions or desire additional information regarding this matter, please call me or D. W. Coleman at (509) 377-4342.

Sincerely,

J. V. Parrish (Mail Drop 1023)
Vice-President, Nuclear Operations

AGC/ml
Enclosure: Washington Public Power Supply System Annual Report 1994

cc: LJ Callan - NRC RIV
JW Clifford - NRC w/o
MM Mendonca - NRC w/o
KE Perkins, Jr. - NRC RIV, Walnut Creek Field Office
NS Reynolds - Winston & Strawn w/o
DL Williams - BPA/399 w/o
NRC Site Inspector - 927N

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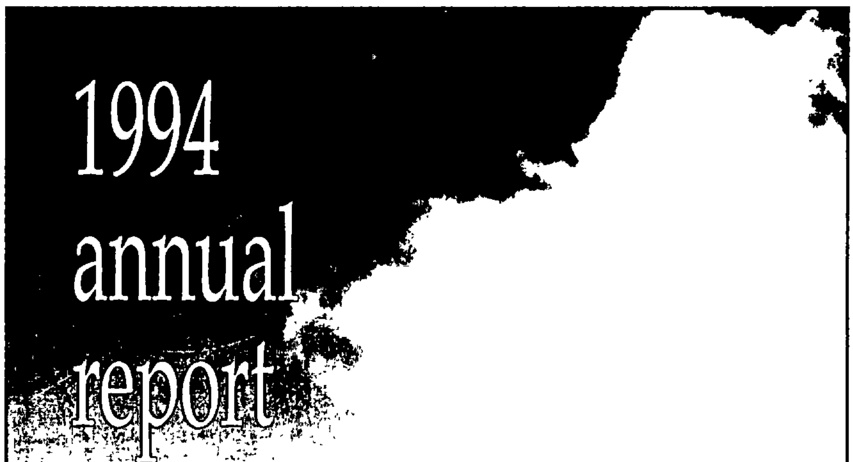
10 YEARS OF SERVICE
PLANT 2

WASHINGTON PUBLIC
POWER SUPPLY SYSTEM



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1994 annual report

Meeting the Challenge

FINANCIAL AND OPERATING HIGHLIGHTS

For the year ended June 30, 1994 *(Dollars in millions)*

BONDS OUTSTANDING

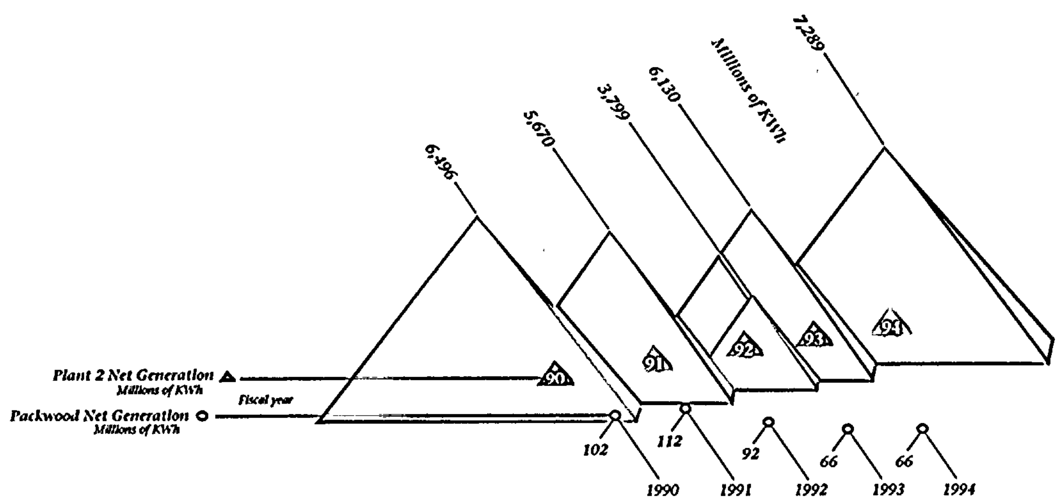
Amount*/Weighted Average Coupon Rate	FY 1994	FY 1993	CHANGE
WNP-1 amount	$2,246.3	$2,406.3	-6.6%
weighted average	6.2%	6.6%	-6.1%
variable	$153.3	$0.0	NA
average rate	2.4%	NA	NA
WNP-2 amount	$2,612.2	$2,507.4	4.2%
weighted average	6.1%	6.6%	-7.6%
WNP-3 amount	$1,738.4	$1,868.1	-6.9%
weighted average	6.0%	6.1%	-1.6%
variable	$202.1	$0.0	NA
average rate	2.4%	NA	NA

*Excludes Compound Interest Bond Accretion

INVESTMENT PERFORMANCE	FY 1994	FY 1993	CHANGE
Income	$ 50.1	$ 46.8	7.1%
Average Balance	$894.2	$839.2	6.6%
Rate of Return	5.6%	5.6%	0.0%

OPERATING STATISTICS	NUCLEAR PROJECT NO. 2 FY 1994	NUCLEAR PROJECT NO. 2 FY 1993	NUCLEAR PROJECT NO. 2 CHANGE	PACKWOOD LAKE PROJECT FY 1994	PACKWOOD LAKE PROJECT FY 1993	PACKWOOD LAKE PROJECT CHANGE
Total production costs *	$ 155.9	$ 138.6	12.5%	$ 0.4	$ 0.3	33.3%
Net generation (millions of kWh)	7,288.8	6,129.7	18.9%	65.6	65.8	-0.3%
Cost in mills/kWh	21.4	22.6	-5.3%	6.7	4.4	52.3%
Plant availability	79.5%	68.8%	15.6%	90.0%	100.0%	-10.0%
Plant capacity	76.6%	63.7%	20.3%	27.3%	27.3%	0.0%

*Includes operation and maintenance costs per FERC report



Electric utilities have experienced many significant changes in recent years. Energy shortages, increasing costs, additional regulatory pressures, and the heightened demand for electricity, have challenged the industry to move toward more cost-competitive and customer-oriented operations.

The rapid emergence of competing energy providers and resources also is challenging established energy providers to become more flexible and innovative in their relations with their customers.

These factors challenged the Supply System and its employees during fiscal year 1994 in the operation of its two generating facilities—the 1,112-megawatt Plant 2 nuclear power plant and the Packwood Lake Hydroelectric Project—and in the preservation of two partially complete nuclear projects, WNP-1 and WNP-3.

As one of the Pacific Northwest's largest electrical energy resources, Plant 2 staff helped the region's electricity users surmount several energy hurdles this year by significantly improving its operating performance and providing the region with nearly 7.4 million megawatt-hours of electricity.

During a year when the Pacific Northwest continued to experience drought conditions and resulting increased pressures on its hydroelectric system, Plant 2's increased generation was acclaimed by its customer, the Bonneville Power Administration (BPA), for saving them millions of dollars in avoided outside power purchases.

The Supply System's responsiveness to BPA was illustrated in May 1994, when our Board of Directors acknowledged BPA's recommendation and approved a resolution to terminate the Supply System's two partially complete nuclear power plants, WNP-1 and WNP-3. After thorough study, Board members concluded that there was little regional support for bringing on line either of the two projects (more than 1,200 megawatts each). Termination brings to a close more than a decade of the Supply System preserving the two plants as future energy resources for the region.

Termination also ends certain provisions of contracts between the Supply System and BPA for the two projects and abandons the possibility of the Supply System completing either of the projects as commercial power plants for BPA. Termination does not, however, affect the Supply System's ability to continue net billing for ongoing debt service and termination costs from BPA.

The Supply System further pursued this year its proposal to construct and operate a combustion turbine-powered electrical generating complex at the WNP-3 power plant site in western Washington State. In October 1993, BPA signed an agreement with the Supply System authorizing us to proceed with preliminary development work for the natural gas-fueled power plant.

We continued our successful bond refunding program during the year with a series of four bond sales that increased present value savings to $1.62 billion. This means a significant reduction in debt service payments by the Supply System.

The program's thirteenth, and most recent issue of $662 million in bonds were sold in January 1994 at a true interest rate of 5.31 percent.

The refinancing program continues to increase BPA's competitive position by providing substantial debt service savings, dollars that are ultimately saved by the ratepayers served by the federal power marketing agency.

Whether it's Plant 2 operations, the future of WNP-1 and WNP-3, or refinancing activity, the Supply System will continue to rely on the ingenuity and resourcefulness of its employees to confront the challenges in today's competitive energy marketplace.

Carl M. Halvorson
Executive Board Chairman

Successful organizations establish appropriate goals and objectives and focus on efforts that will achieve the desired outcome. The Supply System focused during fiscal year 1994 on improving Plant 2 operations. Our success showed our customer, the Bonneville Power Administration (BPA), that we are committed to providing the Pacific Northwest with a reliable and cost-competitive supply of electricity.

In today's economic environment, reliability and cost-effectiveness are crucial. In the nuclear industry, both must be accomplished without sacrificing safety. This year, Plant 2 performed remarkably well, as evidenced by a record 257-day run and a significant increase in electrical generation. Coupled with other improvements, these accomplishments enabled the Supply System to meet its goal of generating electricity at a regional cost of 37 mills (3.7 cents) per kilowatt-hour. When the cost of power was calculated from an industry perspective, it was 21.4 mills per kilowatt-hour, about one mill (0.1 cents) over budget.

I attribute Plant 2's improved operating performance to a shift in philosophy for the organization. In years past, the Supply System tended to over commit itself to a whole host of challenges and opportunities. The resulting strain on our resources sometimes led to mediocre performance. Our intent this year, and in years to come, is to better control our commitment of resources so we can concentrate on improving Plant 2 operations to the point that we are recognized as an industry leader.

To that end, we have implemented several new initiatives. In correlation with the Supply System's strategic objectives, a new *Plant 2 Business Plan* outlines specific work initiatives and identifies senior management sponsors and key managers who are accountable for achieving the desired results. We also developed and distributed a series of *Standards for Success* that provide each of our 1700 employees with expectations and values to guide their day-to-day work activities.

Complementing the nuclear utility industry's high standards are the expectations of the Nuclear Regulatory Commission (NRC). In the NRC's most recent assessment of Plant 2 performance, which covered the period from March 1, 1993, through March 31, 1994, the NRC noted our implementation of numerous improvement initiatives and described Plant 2 performance as improved. The Systematic Assessment of Licensee Performance (SALP) report includes NRC evaluations in four functional areas including plant operations, maintenance, engineering, and plant support.

We place considerable emphasis on meeting the NRC's expectations and requirements, and maintain an open and candid communications link with NRC representatives.

Measuring up to community expectations continues to be a top priority for the Supply System and its employees, many of whom are involved in civic groups, charitable organizations, education committees, youth activities, and more. This volunteer work and participation in community activities demonstrates the Supply System's commitment to the public power concept of improving the quality of life in those communities of which we are a part.

And that commitment extends beyond the local communities. The Supply System continues to support state and local taxing districts with annual generation tax payments made on the wholesale value of the electricity generated by Plant 2. This year alone, the Supply System paid the state treasurer \$2.8 million — the highest payment made since Plant 2 began operating in 1984. The state general fund and fund for schools, as well as counties, cities, fire protection districts, and library districts within 35 miles of Plant 2, share these dollars. More than \$18.7 million in generation taxes have been paid by the Supply System to the state of Washington during the past 10 years.

As our perception that we can excel becomes firmly rooted, those dedicated to building the future of the Supply System will take the steps necessary to ensure our continued success.

William G. Counsil
Managing Director

EXECUTIVE BOARD

Washington Public Power Supply System

From top left to right:

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Consultant, Economic & Technical Analysis Group, Seattle, WA

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Commissioner, Grant County PUD, Ephrata, WA (Board Assistant Secretary)

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Superintendent, Tacoma Public Utilities, Tacoma, WA

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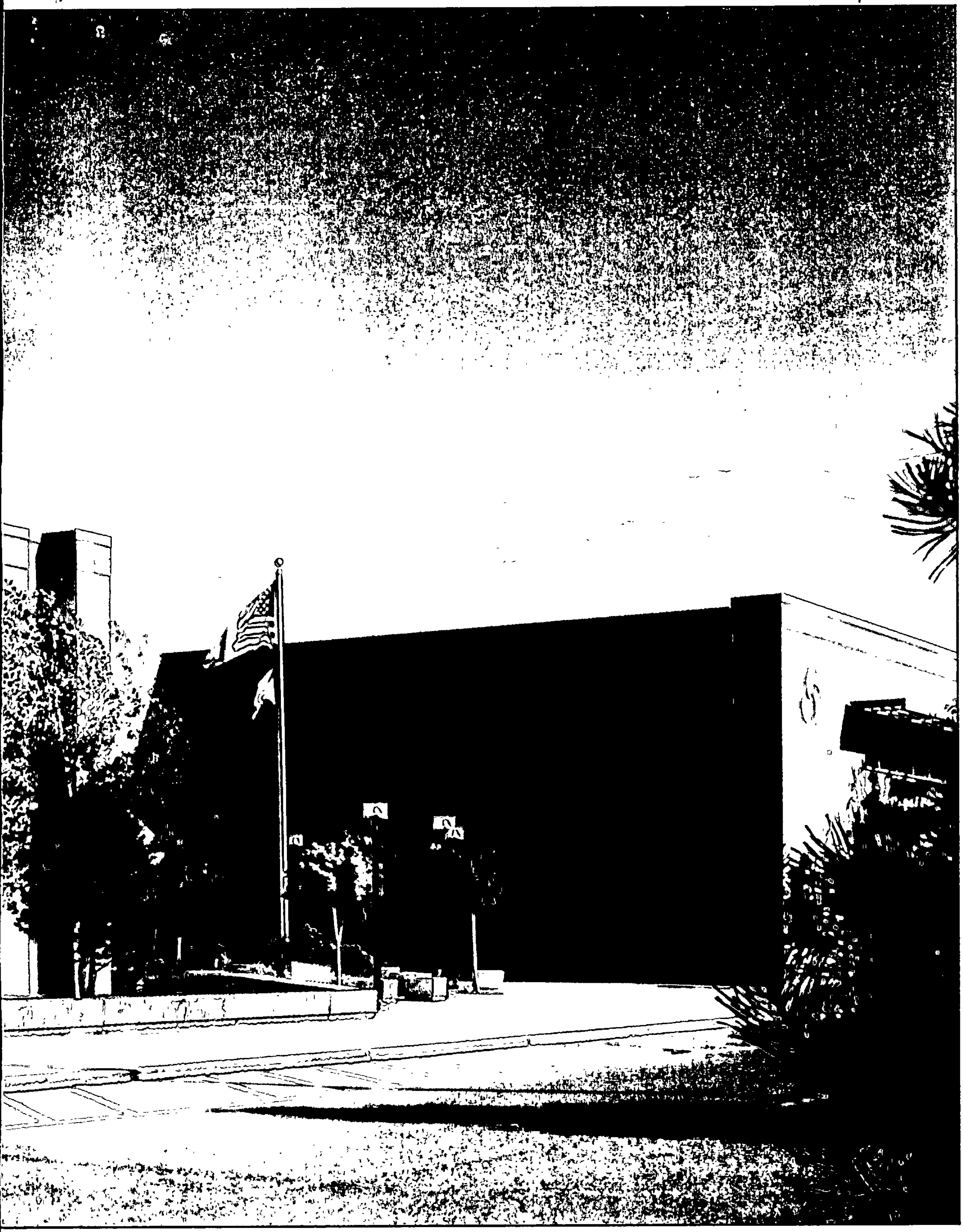


Plant 2's improved performance

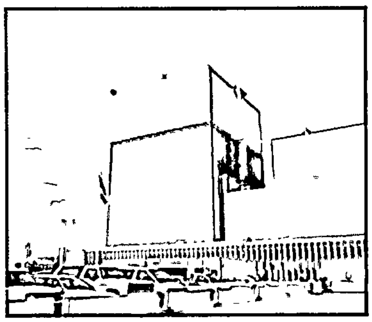
Plant 2 operations during fiscal year 1994 clearly demonstrated the progress being made by the Supply System to improve the plant's overall performance and reliability. Operational improvements are producing increased electrical generation and lowering the cost of power produced by the 1,112-megawatt nuclear plant for Pacific Northwest ratepayers.

Plant staff in recent years have refocused their attention and efforts to improving procedures, plant systems, equipment, and work practices that have direct impact on plant safety and reliability. The objective is to maintain Plant 2 in a safe and efficient operating mode and minimize problems that in the past tended to interrupt plant operations.

An exceptional year of operation for Plant 2 is evidence that this objective is being met. Plant 2 this year achieved a capacity factor of 76.6 percent, representing considerable improvement over past years and nearing the Supply System's capacity factor goal of 80 percent. Capacity factor is the ratio of energy actually produced to the energy that could have been produced had the plant operated continuously at its rated capacity during the same time period.

The Supply System's customer, the Bonneville Power Administration (BPA), also reported that for the period from March 1993 through March 1994, Plant 2 achieved a capacity factor of 80.2 percent, the highest ever in any 12-month period.

Contributing to an improved capacity factor was a 257-day record generating run which ended with the start of plant's annual maintenance and refueling outage on April 26, 1994. Registered as the longest period of continuous electrical generation in the plant's nine-year operating history, the 257-day run surpassed the plant's previous record of 203 days, set in 1990.



The Institute for Nuclear Power Operations (INPO), in a summary of thermal performance for the nation's 31 boiling water reactor plants, listed Washington Public Power Supply's Plant 2 as the best in the United States in this category.

Plant 2 continued to maintain an excellent thermal efficiency, or heat rate, throughout the year. The Institute for Nuclear Power Operations (INPO), in a summary of thermal performance for the nation's 31 boiling water reactor plants, listed Plant 2 as the best in the United States in this category. Calculated in British Thermal Units (BTUs), thermal efficiency is a measure of the plant's efficiency in converting heat energy into electrical energy. The smaller the number, the more efficiently the power plant converts heat energy into electrical energy. In INPO's September 1993 report, Plant 2 used an average of 9,916 BTUs to generate one kilowatt-hour of electricity. The industry average for boiling water reactors is 10,351 BTUs. Plant 2's success in thermal efficiency sets a standard for performance that can be achieved in all aspects of plant operations.

Overall operating performance during fiscal year 1994 demonstrated that increased emphasis on improving Plant 2 operations is producing results that benefit BPA and electricity users throughout the region. With a record production of nearly 7.4 million megawatt-hours of electricity, Plant 2 was able to provide BPA with 765,000 megawatt-hours, or the equivalent of one month, more generation than planned by BPA. The extra month of generation provided by Plant 2 saved BPA, and ultimately regional ratepayers, about $20 million that otherwise would have been spent to purchase power from outside the region.

On average, Plant 2 provides BPA with more than 11 percent of its firm power load. This generation has helped BPA in its continued struggle with with the effect of a regional drought and other pressures on the Pacific Northwest's hydroelectric system. Plant 2's generation of 6.7 million megawatt-hours of electricity during BPA's fiscal year, Oct. 1, 1993, through Sept. 30, 1994, provided the federal agency with about 400,000 megawatt-hours, or two and one-half weeks, more generation than BPA anticipated. That extra electricity was enough to power about 25,000 Pacific Northwest homes.

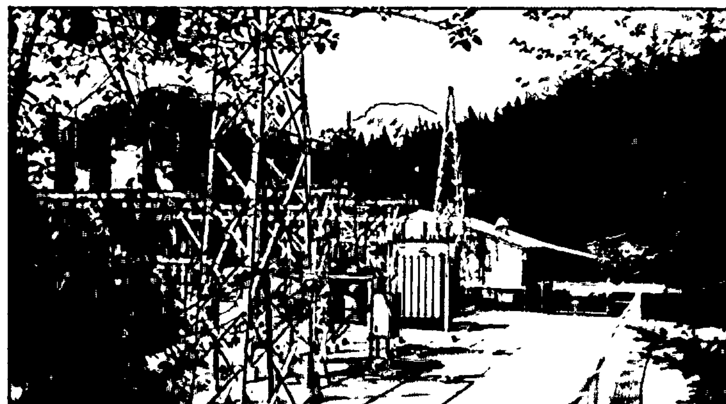
Plant 2 also was recognized by BPA as placing fourth among the agency's 33 regional generating facilities for highest generation during federal fiscal year 1994. Grand Coulee Dam at 17 million megawatt-hours, Chief Joseph Dam at 9.6 million megawatt-hours, and John Day Dam at 8.3 million megawatt-hours, were the only facilities that generated more electricity than Plant 2, which is the Federal Columbia River System's largest single-generator facility.

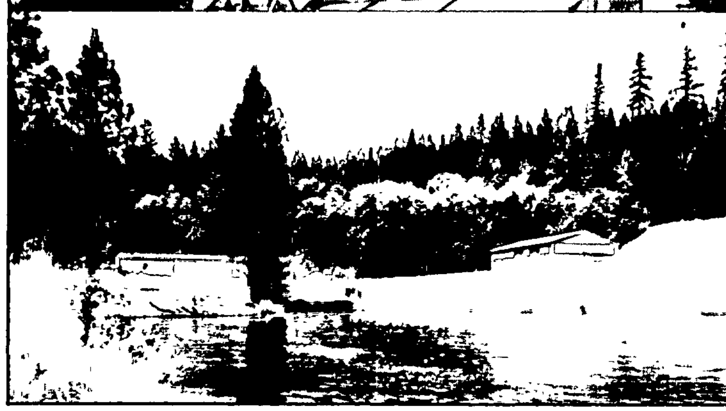
The Supply System is proud of this year's achievements and intends to continue improving Plant 2 operations and maintaining the plant as a cost-effective regional resource in succeeding years.

30 years at Packwood Lake

Situated in the Gifford Pinchot National Forest amidst Washington's Cascade Mountain range, the Supply System's Packwood Lake Hydroelectric Project this year celebrated 30 years of economic, reliable electricity generation.

Dry weather conditions and lower than average water flow into Packwood Lake this year were less of a cause for celebration for the Supply System's first operating power plant. Packwood's generation during fiscal year 1994 totalled 65,600 megawatt-hours. Although a year with normal precipitation results in Packwood generating about 84,000 megawatt-hours, high water years have seen production rise to more than 100,000 megawatt-hours.





Only four full-time employees have been stationed at the Packwood Project since it went into operation in 1964. While the plant is designed to operate in a somewhat automatic mode, operators with knowledge and experience in electrical, mechanical, instrumentation and power plant operations are required to assure continued safe and reliable operations. Any major repair work is typically scheduled for October each year, when the Project is shut down for its annual maintenance outage.

Among the various maintenance activities completed during this year's outage, Packwood staff repainted the 191-foot-tall surge tank which accepts water from Packwood Lake as it is channeled through two tunnels and around a mountain in a 22,000-foot pipeline.

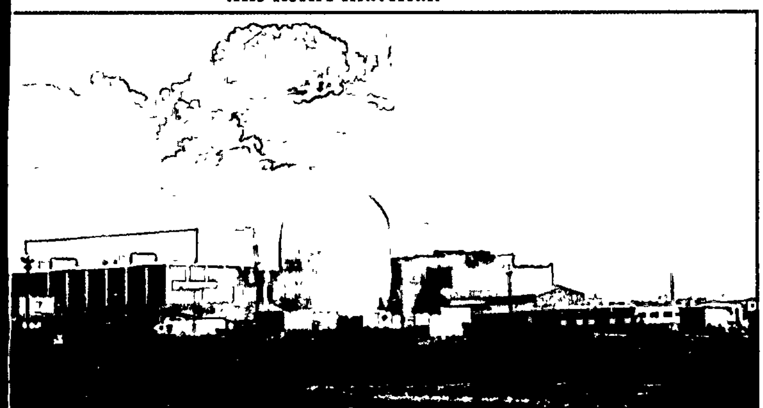
Electrical energy from the Packwood Project is distributed by the Bonneville Power Administration (BPA) for use by 12 Public Utility Districts (PUDs) in Washington state. Packwood supplies enough electricity to meet the annual needs of nearly 4,000 Pacific Northwest residences.

In addition to low-cost electricity, the utilities that are participants in the project receive funds each fall when revenues gained from the Packwood Project exceed costs. This year, more than $1 million in revenue was distributed to Packwood participants under power sales contracts based on member purchasers' power allocation shares.

Dual Purpose Concept

The Supply System in January 1994 proposed a concept that involves using Plant 2 and WNP-1 to dispose of the nation's stockpiled weapons-grade plutonium while providing the Pacific Northwest with competitively priced electricity. The partially complete WNP-1 is situated about one mile from Plant 2, both within the federal government's Hanford Site.

The concept addresses the United States' need to use readily available and technologically proven means to reduce worldwide supplies of this fissile material.



The Department of Energy is evaluating several possible disposal methods, and in the spring of 1996 is expected to determine the most desirable and cost-effective means of plutonium management and disposition.

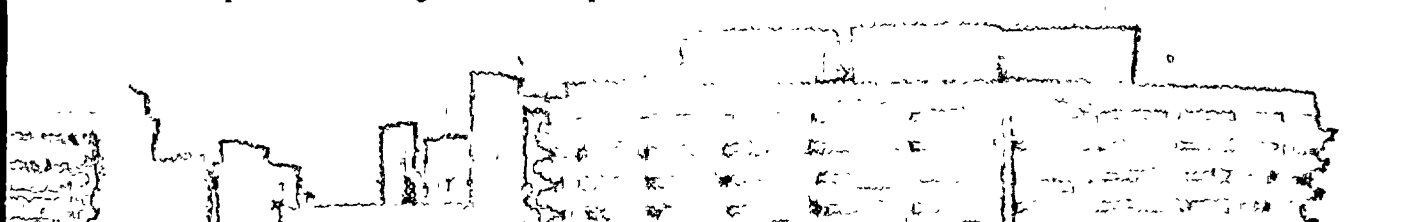
Combustion Turbine Proposal

The Supply System has responded to the region's recent call for low-capital-intensive projects to meet growing electricity needs. One response is a proposal to construct twin combined cycle combustion turbine power plants at its Satsop site, located 30 miles west of Olympia, the capitol of Washington state.

Fueled by natural gas, the combustion turbine plants would each have a generating capacity of 227 megawatts. Plans are to construct both plants on 20 acres that were used to store construction materials for two of the Supply System's partially complete nuclear power plants. Several site conditions make these projects advantageous to potential purchasers. They include an existing connection to the regional power transmission grid, its close proximity to a natural gas line, its license for electric generating facilities, and its location in western Washington, where the need for additional generation is the greatest.

One of the combustion turbine units is committed to the Bonneville Power Administration's (BPA's) resource contingency program. The program involves BPA acquiring resource options like the Satsop combustion turbine to reduce the time it takes to bring new electric generating resources on line when needed. While two other proposed combustion turbine projects are included in BPA's resource options, BPA is not obligated to call for completion of any or all of the projects unless the power is needed and the resource is deemed to be the most cost-effective and timely option available.

The Supply System is working to identify a power purchaser for the second combustion turbine unit by marketing the plant to regional utilities and other potential customers.



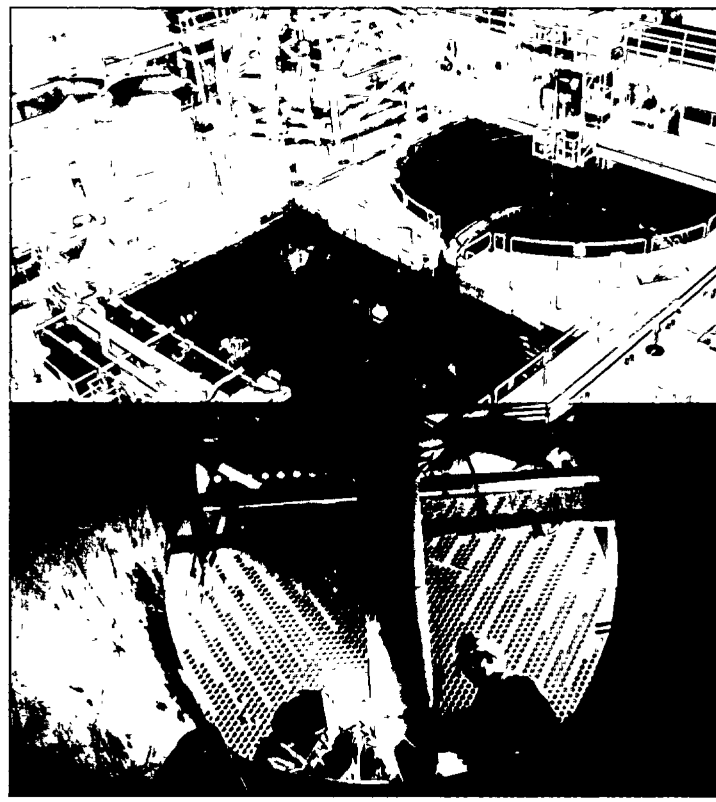
Plant 2's annual outage

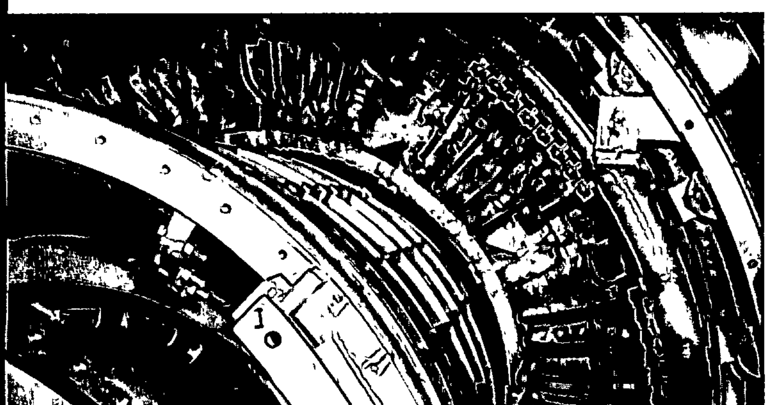
The Supply System entered into Plant 2's 10th annual refueling and maintenance outage with a comprehensive and highly detailed plan for completing the large volume of work required to prepare the power plant for another successful operating cycle. Early into the outage, a problem with a number of electrical modules in the plant's containment building caused outage workers to devote considerable time and attention to test and replace a significant number of modules. Although much time and attention was devoted to this issue, Supply System staff worked hard to minimize its impact on other critical work tasks. The electrical module problem was estimated to add about 18 days onto the original 60-day outage schedule.

Extra time also was needed for plant staff and outage workers to resolve several other issues that arose during the outage's extensive maintenance and inspection activities. The unplanned work involved detailed analysis of a crack detected in one of the jet pump sensing lines, which serves to maintain accurate measurements of reactor coolant flow; the overhaul of control rod mechanisms; repair of two valves in the reactor shutdown cooling system; and replacement of dozens of aged electrical relays. The additional outage tasks delayed Plant 2 restart activities until July 26 — three weeks beyond schedule.

While challenged with unexpected work activity, plant staff remained committed to successfully completing the work originally scheduled to ready the plant for safe, reliable operation. Among the outage work accomplished this year was the replacement of 156 of the reactor plant's 764 nuclear fuel assemblies; the inspection of the reactor vessel and associated piping systems; work on the plant's 20 jet pumps, which are used to sustain reactor coolant flow; replacement of several valves in containment used to control atmospheric conditions; and inspection of the main electrical generator.

The individuals involved in outage work activity each demonstrated a sense of dedication and the ability to work as a team toward a common goal. That goal is to improve Plant 2 performance and reliability to the point that it routinely will operate continuously from the end of one annual outage to the beginning of the next one. By doing so, the region's ratepayers will receive the best possible return on their investment in Plant 2.

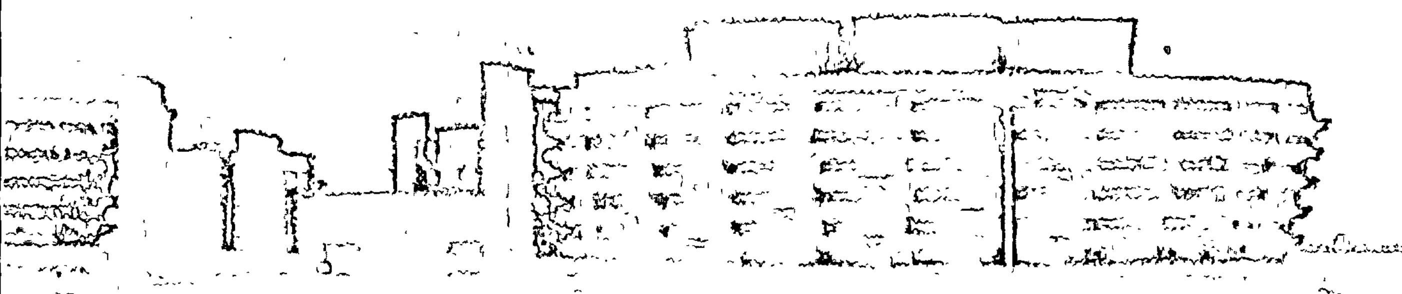




New Plant 2 Simulator

After years of working to develop a highly accurate training tool for Plant 2 reactor operators, the Supply System this year received its new Plant 2 simulator. Designed as a full-scale, computerized replica of the Plant 2 control room, the new simulator accurately mimics plant conditions and enables reactor operators to get hands-on training in an environment that duplicates the appearance and operation of the actual Plant 2 control room instrumentation.

The simulator replaces Plant 2's original simulator, which in 1988 was determined to need improvement to meet increasing high standards of performance required by the Nuclear Regulatory Commission (NRC) for training and examining reactor operators throughout the nuclear industry.



BOARD OF DIRECTORS

Pictured from left:

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Commissioner
Skamania County PUD

Beverley Cochrane Fitzgerald
Commissioner
Franklin County PUD

Roger C. Sparks (President)
Commissioner
Kittitas County PUD

Don Carter
Deputy City Manager
City of Richland

Dan G. Gunkel
Commissioner
Klickitat County PUD

William G. Kuehne
Commissioner
Ferry County PUD

Arne Torget (Assistant Secretary)
Commissioner
Wahkiakum County PUD

Robert Graves
Commissioner
Benton County PUD

Seated:

William D. Scott
Commissioner
Chelan County PUD

Absent from photo:

Roberta P. Bradley
Superintendent
Seattle City Light

Darrel Bunch
Commissioner
Okanogan County PUD

Vera Claussen (Secretary)
Commissioner
Grant County PUD

Mark Crisson
Superintendent
Tacoma Public Utilities

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Administrative and Public Responsibility Committee
- Vera Claussen, Chairman
- Mark Crisson
- Ray Foleen
- Paul J. Nolan
- Bob Royer
- Carl M. Halvorson, Ex Officio

Audit, Legal and Finance Committee
- William D. Scott, Acting Chairman
- Vera Claussen
- Paul J. Nolan
- Carl M. Halvorson, Ex Officio

Operations and Construction Committee
- Parker L. Knight, Chairman
- Mark Crisson
- Ray Foleen
- William D. Scott
- Carl M. Halvorson, Ex Officio

1994 ANNUAL REPORT

FINANCIAL INFORMATION

WASHINGTON PUBLIC POWER SUPPLY SYSTEM

MANAGEMENT REPORT ON RESPONSIBILITY FOR FINANCIAL REPORTING

The management of the Supply System is responsible for preparing the accompanying financial statements and for their integrity. The statements were prepared in accordance with generally accepted accounting principles applied on a consistent basis, and include amounts that are based on management's best estimates and judgments.

The financial statements have been audited by Deloitte & Touche LLP, the Supply System's independent auditors. Management has made available to Deloitte & Touche LLP all financial records and related data, and believes that all representations made to Deloitte & Touche LLP during its audit were valid and appropriate.

Management has established and maintains internal control procedures that provide reasonable assurance as to the integrity and reliability of the financial statements, the protection of assets from unauthorized use or disposition, and the prevention and detection of fraudulent financial reporting. These control procedures provide for appropriate division of responsibility and are documented by written policies and procedures.

The Supply System maintains an ongoing internal auditing program that provides for independent assessment of the effectiveness of internal controls, and for recommendations of possible improvements thereto. In addition, Deloitte & Touche LLP has considered the internal control structure in order to determine their auditing procedures for the purpose of expressing an opinion on the financial statements. Management has considered recommendations made by the internal auditor and Deloitte & Touche LLP concerning the control procedures and has taken appropriate action to respond to the recommendations. Management believes that, as of June 30, 1994, internal control procedures are adequate.

W.G. Counsil　　　　J.D. Perko

W. G. Counsil
Managing Director

J. D. Perko
Chief Financial Officer

AUDIT, LEGAL AND FINANCE COMMITTEE CHAIRMAN'S LETTER

The Executive Board's Audit, Legal and Finance Committee is composed of three independent directors. Members of the Committee are William D. Scott, Acting Chairman; Vera Claussen; Paul J. Nolan; and Carl M. Halvorson, Ex Officio. The Committee held seventeen meetings during the fiscal year ended June 30, 1994.

The Committee oversees the Supply System's financial reporting process on behalf of the Executive Board. In fulfilling its responsibility, the Committee discussed with the internal auditor and the independent auditors the overall scope and specific plans for their respective audits, and reviewed the Supply System's financial statements and the adequacy of the Supply System's internal controls.

The Committee met regularly with the Supply System's internal auditor and independent auditors to discuss the results of their examinations, their evaluations of the Supply System's internal controls, and the overall quality of the Supply System's financial reporting. The meetings were designed to facilitate any private communication with the Committee desired by the internal auditor or independent auditors.

William D. Scott

William D. Scott
Acting Chairman, Audit, Legal and Finance Committee

INDEPENDENT AUDITORS' REPORT

Executive Board
Washington Public Power Supply System
Richland, Washington

We have audited the accompanying individual balance sheets of Washington Public Power Supply System's (the Supply System) Nuclear Project No. 2, Packwood Lake Hydroelectric Project, Hanford Generating Project, Nuclear Project No. 1, Nuclear Project No. 3, and Nuclear Projects Nos. 4 and 5 as of June 30, 1994, and the related statements of operations and cash flows for the year then ended. These financial statements are the responsibility of the Supply System's management. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of the Supply System's individual projects at June 30, 1994, and the results of their operations and cash flows for the year then ended in conformity with generally accepted accounting principles.

As discussed in Note F to the financial statements, Nuclear Projects Nos. 1 and 3 are involved in disputes concerning costs shared with Nuclear Projects Nos. 4 and 5. The ultimate amount of additional costs, if any, to be borne by Nuclear Projects Nos. 1 and 3 due to this matter is presently indeterminable. As further discussed in Notes A and F, the Supply System's Board has authorized the termination of Nuclear Projects Nos. 1 and 3 and the ultimate utilization of these projects is uncertain.

Deloitte & Touche LLP

Seattle, Washington
September 1, 1994

BALANCE SHEETS

As of June 30, 1994 *Dollars in thousands*

	NUCLEAR PROJECT NO. 2	PACKWOOD LAKE PROJECT	HANFORD GENERATING PROJECT**	NUCLEAR PROJECT NO. 1	NUCLEAR PROJECT NO. 3*	NUCLEAR PROJECTS NOS. 4/5**
ASSETS						
UTILITY PLANT (NOTE B)						
In service	$3,302,506	$12,520		$ 13,637	$ 1,580	
Allowance for depreciation	(1,010,584)	(8,949)		(5,011)	(807)	
	2,291,922	3,571		8,626	773	
Nuclear fuel, net of accumulated amortization	118,804					
Construction work in progress	116,677			2,236,260	2,449,467	
Less joint owners' share					(615,956)	
	2,527,403	3,571		2,244,886	1,834,284	
RESTRICTED ASSETS (NOTE B)						
Special funds						
Cash	7	1		257	1,113	$ 136
Investments	45,695	290	$ 1	143,708	17,081	9,816
Accounts receivable				1,471	6,317	1
Due from other projects				419	2	19,217
Due from other funds					654	
Prepayments and other				38	77	1
Debt service funds						
Cash	59	6		139	141	
Investments	165,817	721		217,036	179,521	46,016
	211,578	1,018	1	363,068	204,906	75,187
LONG-TERM RECEIVABLE (NOTE B)	50,230					
CURRENT ASSETS						
Cash	3,170	6	22	360	765	
Investments	22,931	1,034	8,203	9,239	8,024	
Accounts receivable	6,407	224		2		
Due from other projects	27		5	163		
Due from other funds	28,083	22		27,372	6,399	
Materials and supplies	50,853	1				
Prepayments and other	1,804	1	1			
Nuclear fuel held for sale				81,604	11,652	
Plant & equipment held for sale			3,900			
	113,275	1,288	12,131	118,740	26,840	
DEFERRED CHARGES						
Costs in excess of billings		3,571				
Unamortized regulatory studies	16,736					
Unamortized debt expense	19,161	10		24,835	20,296	
Other deferred debits				749	748	
	35,897	3,581		25,584	21,044	
TOTAL ASSETS	$2,938,383	$ 9,458	$12,132	$2,752,278	$2,087,074	$75,187

* Supply System's ownership share (Note A)

** Project recorded on a liquidation basis

See notes to financial statements

	NUCLEAR PROJECT NO. 2	PACKWOOD LAKE PROJECT	HANFORD GENERATING PROJECT**	NUCLEAR PROJECT NO. 1	NUCLEAR PROJECT NO. 3*	NUCLEAR PROJECTS NOS. 4/5**
LIABILITIES						
DEFICIENCY IN ASSETS						$(4,161,106)
BILLINGS IN EXCESS OF COSTS	$ 225,944		$ 5,233	$ 262,204	$ 47,081	
LONG-TERM DEBT (NOTE E)						
Revenue bonds payable	2,689,895	$7,916		2,399,640	2,347,120	
Unamortized discount on bonds - net	(111,385)	(39)		(34,017)	(388,428)	
	2,578,510	7,877		2,365,623	1,958,692	
DEBT IN DEFAULT, CURRENTLY PAYABLE (NOTES E & F)						
Revenue bonds payable						2,155,755
Subordinated revenue notes						19,237
						2,174,992
LIABILITIES - PAYABLE FROM RESTRICTED ASSETS (NOTE B)						
Special funds						
Accounts payable and accrued expenses	25,600			6,846	3,142	4,083
Due to other projects				40	19,102	8,489
Due to other funds	16,703	9		19,076		
Debt service funds						
Accrued interest payable		99		71,211	47,741	2,039,215
Accounts payable						9,514
Due to other funds	11,380	12		8,297	7,053	
	53,683	120		105,470	77,038	2,061,301
OTHER NONCURRENT LIABILITIES	13,281	6	3			
CURRENT LIABILITIES						
Current maturities of long-term debt	8,515	220		16,900		
Accounts payable and accrued expenses	53,153	151	6,733		(5)	
Due to participants	4,713	1,012	-	2,081	4,268	
Due to other projects	584	5	163			
	66,965	1,388	6,896	18,981	4,263	
DEFERRED CREDITS						
Deferred gain on redemption of revenue bonds		67				
COMMITMENTS AND CONTINGENCIES (NOTE F)						
TOTAL LIABILITIES	$2,938,383	$9,458	$12,132	$2,752,278	$2,087,074	$ 75,187

STATEMENTS OF OPERATIONS

For the year ended June 30, 1994 *Dollars in thousands*

	NUCLEAR PROJECT NO. 2	PACKWOOD LAKE PROJECT	HANFORD GENERATING PROJECT**	NUCLEAR PROJECT NO. 1	NUCLEAR PROJECT NO. 3*	NUCLEAR PROJECTS NOS. 4/5**
OPERATING REVENUES	$ 583,217	$1,677				
OPERATING EXPENSES						
Nuclear fuel	29,652					
Fuel disposal fee	6,869					
Decommissioning	5,197					
Depreciation and amortization	107,092	438				
Operations and maintenance	134,064	891				
Administrative & general	43,594	108				
Generation tax	3,015	1				
Total operating expenses	329,483	1,438				
NET OPERATING REVENUES	253,734	239				
OTHER INCOME & EXPENSE						
Non-operating revenues - net			$ (117)	$362,245	$231,797	$ 2,840
Investment income	16,774	68	278	20,508	10,211	1,964
Interest expense and discount amortization	(171,111)	(307)		(153,228)	(121,058)	(195,977)
Maintenance of projects in extended construction delay				(4,902)	(3,944)	
Maintenance of plant held for disposition			(161)			
Termination and asset disposition expenses						(8,442)
Other	2,872			(171,332)	(18,081)	
NET REVENUES BEFORE EXTRAORDINARY ITEM	102,269	0	0	53,291	98,925	(199,615)
EXTRAORDINARY ITEM						
Loss on bond refunding (Note E)	(102,269)			(53,291)	(98,925)	
Gain on write-off of liabilities (Note F)						189,519
NET REVENUES	$ 0	$ 0	$ 0	$ 0	$ 0	$ (10,096)

* Supply System's ownership share (Note A)

** Project recorded on a liquidation basis

See notes to financial statements

STATEMENTS OF CASH FLOWS

For the year ended June 30, 1994 *Dollars in thousands*

	NUCLEAR PROJECT NO. 2	PACKWOOD LAKE PROJECT	HANFORD GENERATING PROJECT**	NUCLEAR PROJECT NO. 1	NUCLEAR PROJECT NO. 3*	NUCLEAR PROJECTS NOS. 4/5**
CASH FLOWS FROM OPERATING AND OTHER ACTIVITIES						
Operating revenue receipts	$ 358,537	$ 2,746				
Cash payments for operating expenses	(193,530)	(967)				
Non-operating revenue receipts				$ 166,327	$ 129,010	$ 2,797
Cash payments for maintenance of projects in extended construction delay				(3,210)	(4,989)	
Cash payments for other expenses	572		(118)	(1,092)	(1,533)	(9,601)
Distributions of operating and non-operating surplus		(1,105)	(592)	592		
Net cash provided/(used) by operating and other activities	165,579	674	(710)	162,617	122,488	(6,804)
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES						
Proceeds from bond refundings	888,505			510,418	1,007,388	
Refunded bonds escrow requirement	(854,694)			(512,942)	(994,857)	
Bond issuance costs paid	(7,833)			(7,874)	(9,135)	
Capital and nuclear fuel acquisitions	(52,035)	(11)		(566)	1,094	
Cash payments for deferred programs	(3,802)					
Interest paid on revenue bonds	(161,024)	(305)		(156,512)	(102,577)	
Principal paid on revenue bond maturities	(14,413)	(304)		(35,050)	(31,545)	
Net cash used by capital and related financing activities	(205,296)	(620)	(0)	(202,526)	(129,632)	0
CASH FLOWS FROM INVESTING ACTIVITIES						
Purchases of investment securities	(1,115,837)	(8,333)	(13,080)	(839,802)	(668,437)	(238,399)
Sales of investment securities	1,137,989	8,204	13,525	845,666	665,917	239,478
Interest on investments	18,355	63	262	21,228	10,255	482
Receipts from sales of nuclear fuel				13,141		
Net cash provided/(used) by investing activities	40,507	(66)	707	40,233	7,735	1,561
NET INCREASE/(DECREASE) IN CASH	790	(12)	(3)	324	591	(5,243)
CASH AT JUNE 30, 1993	2,446	25	25	432	1,428	5,380
CASH AT JUNE 30, 1994 (NOTE B)	$ 3,236	$ 13	$ 22	$ 756	$ 2,019	$ 137

* Supply System's ownership share (Note A)
** Project recorded on a liquidation basis
See notes to financial statements

STATEMENTS OF CASH FLOWS (continued)

For the year ended June 30, 1994 Dollars in thousands

	NUCLEAR PROJECT NO. 2	PACKWOOD LAKE PROJECT	HANFORD GENERATING PROJECT**	NUCLEAR PROJECT NO. 1	NUCLEAR PROJECT NO. 3*	NUCLEAR PROJECTS NOS. 4/5**
RECONCILIATION OF NET OPERATING REVENUES TO NET CASH PROVIDED BY OPERATING AND OTHER ACTIVITIES						
CASH FLOWS FROM OPERATING AND OTHER ACTIVITIES						
Net operating revenues	$ 253,734	$ 239				
Adjustments to reconcile net operating revenues to cash provided by operating activities:						
Amortized revenues	(224,680)	(418)				
Depreciation and amortization	132,613	428				
Decommissioning	5,197					
Other	2,872					
Change in operating assets and liabilities:						
Accounts receivable	(4,637)	140				
Materials and supplies	(6,425)					
Prepaid and other assets	(1,311)	(1)				
Due from/to other projects, funds and participants	(1,110)	255				
Accounts payable	9,326	31				
Non-operating revenue receipts				$ 166,327	$ 129,010	$ 2,797
Cash payments for maintenance of projects in extended construction delay				(3,210)	(4,989)	0
Cash payments for other expenses			(118)	(1,092)	(1,533)	(9,601)
Distributions of non-operating surplus			(592)	592	0	0
Net cash provided/(used) by operating and other activities	$ 165,579	$ 674	$ (710)	$ 162,617	$ 122,488	$ (6,804)

* Supply System's ownership share (Note A)

** Project recorded on a liquidation basis

See notes to financial statements

OUTSTANDING LONG-TERM DEBT

As of June 30, 1994 *Dollars in thousands*

SERIES	DATE OF SALE	TRUE INTEREST COST (A)	INITIAL OFFERING PRICES	COUPON RATE	SERIAL OR TERM MATURITIES	AMOUNT
NUCLEAR PROJECT NO. 2 REVENUE BONDS						
1973	6-26-73	5.65%	100	5.70%	7-1-2012	$ 110,450
						110,450
1976A	11-18-76	5.86	(B)	5.50-5.75	7-1-94/2000	29,400
			100	6.00	7-1-2007	44,815
			99.50	6.00	7-1-2012	60,990
						135,205
1981A	9-4-81	14.67	100	14.375	7-1-2001	30,000
			59.958	8.25	7-1-2003	100,000
						130,000
1990A	3-15-90	7.77	99.75	7.25	7-1-2003	73,705
			97.125	7.25	7-1-2006	35,790
						109,495
1990B	6-7-90	7.69	94.135	7.00	7-1-2012	200,840
						200,840
1990C	11-1-90	7.84	(B)	7.00-7.50	7-1-97/2003	204,870
			(B)	(C)	7-1-04/2005	18,054
						222,924
1991A	9-26-91	6.81	(B)	5.40-6.60	7-1-96/2005	135,260
			90.375	6.00	7-1-2012	105,940
			(B)	(C)	7-1-06/2007	13,431
						254,631
1992A	10-2-92	6.19	(B)	4.65-6.30	7-1-96/2009	193,360
			97.230	6.25	7-1-2012	66,780
			98.875	6.30	7-1-2012	50,000
			(B)	(C)	7-1-2010/2011	9,084
						319,224
1993A	5-20-93	5.76	(B)	3.75-6.00	7-1-1995/2010	208,230
			96.404	5.75	7-1-2012	42,105
						250,335
1993B	7-15-93	5.64	(B)	3.60-5.65	7-1-95/2008	122,825
			100	5.55	7-1-2010	51,000
			97.775	5.625	7-1-2012	43,455
						217,280

(A) Based on original issue
(B) Various prices
(C) Compound interest bonds
(D) Excludes amounts due July 1,1994
(E) Includes amounts due July 1, 1994
(F) The estimated fair value shown has been reported to meet the disclosure requirements of SFAS 107 and does not purport to represent the amounts at which these obligations would be settled.

OUTSTANDING LONG-TERM DEBT (continued)

As of June 30, 1994 *Dollars in thousands*

SERIES	DATE OF SALE	TRUE INTEREST COST (A)	INITIAL OFFERING PRICES	COUPON RATE	SERIAL OR TERM MATURITIES	AMOUNT
NUCLEAR PROJECT NO. 2 REVENUE BONDS (Continued)						
1994A	1-27-94	5.31%	(B)	3.00-6.00%	7-1-95/2011	$ 556,855
			100	5.40	7-1-2012	100,200
			100	(C)	7-1-2009	4,776
						661,831
Compound interest bonds accretion						86,195
Revenue bonds payable						$2,698,410 (D)
Estimated fair value at June 30, 1994						$2,661,627 (F)
PACKWOOD LAKE PROJECT REVENUE BONDS						
1962	3-20-62	3.66	99.425	3.625	3-1-2012	6,171
1965	11-4-65	3.76	100.5	3.75	3-1-2012	1,965
Revenue bonds payable						$ 8,136
Estimated fair value at June 30, 1994						$ 6,944 (F)
NUCLEAR PROJECT NO. 1 REVENUE BONDS						
1989A	9-14-89	7.76	100	6.80-7.30	7-1-94/2002	27,525
			98.185	7.00	7-1-2004	27,385
			99.017	7.50	7-1-2007	62,105
			97.759	7.50	7-1-2011	116,195
			82.083	6.00	7-1-2017	95,110
						328,320
1989B	12-7-89	7.44	100	6.70-7.25	7-1-96/2003	31,095
			98.375	7.00	7-1-2005	2,100
			100	7.40	7-1-2009	5,180
			98.553	7.125	7-1-2016	41,070
						79,445
1990A	3-15-90	7.73	(B)	6.60-7.60	7-1-94/2005	70,375
			92.75	7.00	7-1-2011	56,770
			81.75	6.00	7-1-2017	55,635
						182,780

(A) Based on original issue
(B) Various prices
(C) Compound interest bonds
(D) Excludes amounts due July 1, 1994
(E) Includes amounts due July 1, 1994
(F) The estimated fair value shown has been reported to meet the disclosure requirements of SFAS 107 and does not purport to represent the amounts at which these obligations would be settled.

SERIES	DATE OF SALE	TRUE INTEREST COST (A)	INITIAL OFFERING PRICES	COUPON RATE	SERIAL OR TERM MATURITIES	AMOUNT
NUCLEAR PROJECT NO. 1 REVENUE BONDS (Continued)						
1990B	6-7-90	7.75%	(B)	7.00-7.20%	7-1-99/2003	$ 24,495
			97.979	7.25	7-1-2009	72,770
			98.913	7.25	7-1-2012	56,000
						153,265
1990C	9-27-90	7.85	(B)	7.00-7.75	7-1-94/2003	160,075
			99.50	7.75	7-1-2008	22,085
						182,160
1991A	9-26-91	7.02	(B)	5.40-6.80	7-1-94/2008	51,360
			98.375	6.875	7-1-2017	92,965
						144,325
1992A	10-2-92	6.51	(B)	3.80-6.40	7-1-94/2011	56,440
			99.375	6.50	7-1-2015	137,820
			98	6.25	7-1-2017	78,815
						273,075
1993A	5-20-93	5.86	(B)	2.90-7.00	7-1-94/2008	215,485
			100	5.75	7-1-2011	80,000
			99.75	6.05	7-1-2012	35,705
			96.306	5.75	7-1-2013	37,970
			96.566	5.70	7-1-2017	176,180
						545,340
1993B	7-15-93	5.64	(B)	3.00-7.00	7-1-94/2010	94,825
			98.138	5.60	7-1-2015	94,885
						189,710
1993C	9-10-93	5.47	(B)	2.70-5.30	7-1-94/2010	25,840
			100	5.40	7-1-2012	66,400
			98.166	5.375	7-1-2015	75,650
						167,890
1993-1A	12-15-93	NA	NA	Variable	7-1-94/2017	153,330
						153,330
Revenue bonds payable						$2,399,640 (E)
1993A NOTES	5-20-93	4.975	100	4.70	7-1-1995	16,900
						16,900
Revenue bonds/notes payable						$2,416,540
Estimated fair value at June 30, 1994						$2,462,100 (F)

OUTSTANDING LONG-TERM DEBT (continued)

As of June 30, 1994 *Dollars in thousands*

SERIES	DATE OF SALE	TRUE INTEREST COST (A)	INITIAL OFFERING PRICES	COUPON RATE	SERIAL OR TERM MATURITIES	AMOUNT
NUCLEAR PROJECT NO. 3 REVENUE BONDS						
1989A	9-14-89	7.43%	100	6.80-7.30%	7-1-94/2002	$ 26,705
			(B)	(C)	7-1-2003/2014	18,668
			84.75	6.00	7-1-2018	54,570
						99,943
1989B	12-7-89	7.39	100	6.50-7.15	7-1-94/2001	81,080
			(B)	(C)	7-1-2004/2014	71,321
			98.375	7.00	7-1-2005	85,690
			100	7.40	7-1-2009	29,235
			98.533	7.125	7-1-2016	76,145
			79.755	5.50	7-1-2017	62,560
			79.525	5.50	7-1-2018	65,905
						471,936
1990B	6-7-90	7.57	(B)	6.50-7.25	7-1-94/2000	117,040
			(B)	(C)	7-1-2001/2010	39,210
			98.923	7.375	7-1-2004	55,920
						212,170
1991A	9-26-91	6.97	(B)	5.40-6.80	7-1-94/2008	50,040
			97.75	6.75	7-1-2011	20,790
			94.552	6.50	7-1-2018	66,065
						136,895
1992A	10-2-92	4.86	100	3.80-5.10	7-1-1994/1998	12,345
						12,345
1993B	7-15-93	5.64	(B)	3.00-7.00	7-1-94/2010	146,465
			97.775	5.625	7-1-2012	28,295
			98.138	5.60	7-1-2015	49,095
			98.058	5.60	7-1-2018	37,795
			97.719	5.70	7-1-2018	20,605
						282,255
1993C	9-10-93	5.47	(B)	2.70-7.50	7-1-94/2010	183,445
			100	5.40	7-1-2012	105,000
			(B)	(C)	7-1-2013/2018	25,248
			98.166	5.375	7-1-2015	188,355
			99.5	5.50	7-1-2018	20,805
						522,853

(A) Based on original issue
(B) Various prices
(C) Compound interest bonds
(D) Excludes amounts due July 1, 1994
(E) Includes amounts due July 1, 1994
(F) The estimated fair value shown has been reported to meet the disclosure requirements of SFAS 107 and does not purport to represent the amounts at which these obligations would be settled.

SERIES	DATE OF SALE	TRUE INTEREST COST (A)	INITIAL OFFERING PRICES	COUPON RATE	SERIAL OR TERM MATURITIES	AMOUNT
NUCLEAR PROJECT NO. 3 REVENUE BONDS (Continued)						
1993-3A	12-15-93	NA	NA	Variable	7-1-94/2018	$ 202,140
						202,140
Compound interest bonds accretion						406,583
Revenue bonds payable						$2,347,120 (E)
Estimated fair value at June 30, 1994						$1,985,596 (F)

DEBT-SERVICE REQUIREMENTS

As of June 30, 1994 *Dollars in thousands*

	NUCLEAR PROJECT NO. 2			PACKWOOD LAKE PROJECT		
FISCAL YEAR	PRINCIPAL	INTEREST	TOTAL	PRINCIPAL	INTEREST	TOTAL
6/30/94 Balance*	$ 972	$ 0	$ 972	$ 116	$ 99	$ 215
1995	8,515	155,993	164,508	333	293	626
1996	51,643	155,722	207,365	347	281	628
1997	68,390	153,296	221,686	367	269	636
1998	72,050	149,283	221,333	387	255	642
1999	120,375	144,980	265,355	422	241	663
2000	131,390	136,978	268,368	473	226	699
2001	168,235	127,944	296,179	498	208	706
2002	92,835	116,371	209,206	523	190	713
2003	212,190	110,467	322,657	548	171	719
2004	158,249	107,591	265,840	573	151	724
2005	115,395	111,007	226,402	598	130	728
2006	131,896	93,684	225,580	623	108	731
2007	165,470	86,216	251,686	648	86	734
2008	192,780	64,100	256,880	674	62	736
2009	189,086	59,365	248,451	572	37	609
2010	202,629	52,718	255,347	274	16	290
2011	166,750	41,673	208,423	122	6	128
2012	363,365	21,904	385,269	38	2	40
2013						
2014						
2015						
2016						
2017						
2018						
*Adjustment***	86,195	(86,195)				
	$ 2,698,410	$ 1,803,097	$ 4,501,507	$ 8,136	$ 2,831	$ 10,967

* Bond account balances less accrued investment income.

** Adjustment for compound interest bonds accretion; compound interest bonds are reflected at their face amount less discount on the balance sheet

FISCAL YEAR	NUCLEAR PROJECT NO. 1			NUCLEAR PROJECT NO. 3			NUCLEAR PROJECTS NOS. 4/5	
	PRINCIPAL	INTEREST	TOTAL	PRINCIPAL	INTEREST	TOTAL	PRINCIPAL	TOTAL
6/30/94 Balance*	$ 40,930	$ 71,211	$ 112,141	$ 40,735	$ 47,740	$ 88,475	$ 0	$ 0
1995	60,400	147,641	208,041	41,760	101,648	143,408	2,174,992	2,174,992
1996	46,565	144,701	191,266	47,475	99,327	146,802		
1997	50,770	142,092	192,862	36,490	96,563	133,053		
1998	53,020	139,117	192,137	34,555	94,524	129,079		
1999	67,275	135,965	203,240	68,150	92,615	160,765		
2000	71,325	131,737	203,062	73,025	88,247	161,272		
2001	76,105	127,203	203,308	71,585	90,107	161,692		
2002	75,705	122,205	197,910	76,257	86,234	162,491		
2003	66,375	117,220	183,595	78,522	84,568	163,090		
2004	78,065	113,019	191,084	62,396	96,206	158,602		
2005	70,345	108,016	178,361	63,621	94,365	157,986		
2006	87,770	103,463	191,233	64,457	92,640	157,097		
2007	93,630	97,693	191,323	59,381	92,903	152,284		
2008	100,135	91,265	191,400	61,196	91,181	152,377		
2009	104,070	84,282	188,352	63,648	88,827	152,475		
2010	111,285	77,352	188,637	66,117	86,461	152,578		
2011	135,355	70,067	205,422	84,464	75,450	159,914		
2012	144,565	61,213	205,778	98,062	71,717	169,779		
2013	156,210	52,609	208,819	95,410	74,630	170,040		
2014	165,535	43,397	208,932	98,355	71,817	170,172		
2015	175,530	33,534	209,064	129,220	41,108	170,328		
2016	186,925	23,424	210,349	133,834	36,663	170,497		
2017	198,650	11,848	210,498	142,027	28,643	170,670		
2018				149,796	21,047	170,843		
*Adjustment***				406,582	(406,582)			
	$2,416,540	$2,250,274	$4,666,814	$2,347,120	$1,538,649	$3,885,769	$ 2,174,992	$2,174,992

Refer to Note F under Nuclear Projects Nos. 4 and 5 Termination, Bond Default, and Litigation and Nuclear Projects Nos. 4 and 5 Bridge and Termination Loans

Note A - General

ORGANIZATION

The Washington Public Power Supply System (Supply System), a municipal corporation and joint operating agency of the State of Washington, was organized in 1957. It is empowered to finance, acquire, construct and operate facilities for the generation and transmission of electric power. On June 30, 1994, its membership consisted of 10 public utility districts and the cities of Richland, Seattle, and Tacoma. All members own and operate electric systems within the State of Washington. The Supply System has no taxing authority.

SUPPLY SYSTEM PROJECTS

The Supply System operates Nuclear Project No. 2, a 1,120 MWe (DER net) generating plant completed in 1984, and the Packwood Lake Hydroelectric Project (Packwood), a 27.5 MWe plant completed in 1964.

The Hanford Generating Project (HGP), an 860 MWe plant, previously used by-product steam from the Department of Energy's (DOE) dual-purpose New Production Reactor (N-Reactor) and has not operated since the shutdown of the N-Reactor in 1987. As a result of the Secretary of Energy's decision to place the N-Reactor in permanent shutdown, the Supply System has evaluated alternative energy uses for the plant and anticipates eventual termination of HGP and subsequent removal and site restoration (see Note F - Hanford Generating Project).

Nuclear Project No. 1, a 1,250 MWe plant, is 65 percent complete and has been in an extended construction delay status since 1982. Nuclear Project No. 3, a 1,240 MWe plant, is 75 percent complete and has been in an extended construction delay status since 1983. On May 13, 1994, the Supply System's Board of Directors adopted resolutions terminating Nuclear Projects Nos. 1 and 3. The Supply System has entered into an agreement with the Bonneville Power Administration (BPA) to provide continued funding for the existing preservation programs, including the maintenance of all federal and state licenses and permits until January 13, 1995, or such other date as may be mutually agreed upon by BPA and the Supply System (see Note F - Nuclear Projects Nos. 1 and 3 Termination). Nuclear Project No. 1 is wholly-owned by the Supply System. Nuclear Project No. 3 is jointly-owned, 70 percent by the Supply System and 30 percent by four investor-owned utilities (PacifiCorp, Portland General Electric Company, Puget Sound Power & Light Company, and The Washington Water Power Company).

Nuclear Projects Nos. 4 and 5 were terminated in January 1982, and substantially all of the utility plant assets have been sold. Eighty-eight project participants in Nuclear Projects Nos. 4 and 5 were originally obligated by contract to pay annual costs of Nuclear Projects Nos. 4 and 5, including debt service, whether or not the projects were completed. However, these contracts were declared invalid. Nuclear Project No. 4 is wholly-owned by the Supply System. Nuclear Project No. 5 is jointly-owned, 90 percent by the Supply System and 10 percent by PacifiCorp (see Note F - Nuclear Projects Nos. 4 and 5 Termination, Bond Default, and Litigation).

Each Supply System project is financed and accounted for as a utility system separate from all other current or future projects with the exception of Nuclear Projects Nos. 4 and 5 which are treated as one utility system.

All electrical energy produced by Supply System projects is delivered to electrical distribution facilities owned and operated by BPA as part of the Federal Columbia River Power System. BPA in turn distributes the electricity to electrical utility systems throughout the Northwest, including participants in Supply System projects, for ultimate distribution to consumers. BPA is obligated by law to establish rates for electric power which will recover the cost of acquisition and BPA's other costs. See Note E, Security - Nuclear Projects Nos. 1, 2 and 3, for discussion of BPA's obligations with respect to Nuclear Projects Nos. 1, 2 and 3. BPA has no obligations with respect to Nuclear Projects Nos. 4 and 5.

Note B - Summary of Significant Accounting Policies

BASIS OF ACCOUNTING

The Supply System has adopted accounting policies and practices that are in accordance with generally accepted accounting principles applicable to governmental utilities. Accounts are maintained in accordance with the uniform system of accounts of the Federal Energy Regulatory Commission. Separate funds and books of account are maintained for each utility system. Payment of obligations of one utility system with funds of another utility system is prohibited, and would constitute violation of bond resolution covenants.

UTILITY PLANT

Utility plant is stated at original cost. Plant in service is depreciated by the straight-line method over the estimated useful lives of the various classes of plant.

During the normal construction phase of a project, the Supply System's policy is to capitalize all costs relating to the project,

including interest expense (net of interest income), and administrative and general expense.

HGP has been reduced to its net realizable value in anticipation of project termination in fiscal year 1995 (see Note F - Hanford Generating Project).

Because of the extended delay of Nuclear Projects Nos. 1 and 3, the Supply System discontinued capitalizing interest expense and preservation costs. Interest expense, termination expenses and asset disposition costs for Nuclear Projects Nos. 4 and 5 are charged to current operations.

NUCLEAR FUEL

All expenditures related to the purchase of nuclear fuel are capitalized and carried at cost. When the fuel is placed in the reactor, the fuel cost is amortized to operating expense on the basis of quantity of heat produced for generation of electric energy. Accumulated nuclear fuel amortization as of June 30, 1994 for Nuclear Project No. 2 is $94 million. Current period operating expense for Nuclear Project No. 2 includes a charge for future spent nuclear fuel storage and disposal to be provided by DOE in accordance with the Nuclear Waste Policy Act of 1982, and a charge by DOE for clean-up of its nuclear enrichment facilities, in accordance with the Energy Policy Act of 1992. No provision has been made for additional storage and disposal costs which may be incurred by the Supply System prior to the transfer of spent fuel to DOE.

On October 28, 1993, the Supply System's Executive Board declared Nuclear Project No. 1's nuclear fuel reload uranium to be excess to the current needs of the project and approved the sale or other disposal of such uranium. On December 15, 1993, the Supply System executed a contract with Nuxeco Trading Corporation to sell the excess reload uranium (approximately 1.6 million KgU as UF6). As a result of this sale, the Supply System reduced the book value of the uranium for financial reporting purposes from $183.9 million to a contract value of $52.8 million.

On July 28, 1994, the Supply System's Executive Board declared the Nuclear Projects Nos. 1 and 3 uranium acquired for nuclear fuel to be surplus and excess to the needs of the projects and authorized the sale of all Nuclear Project No. 1's uranium hexaflouride and enriched uranium product and Nuclear Project No. 3's uranium. As a result of this decision, the Supply System has reduced the book value of nuclear fuel for financial reporting purposes from $79.6 million to a market value of $41.9 million and from $34.8 million to a market value of $11.7 million for Nuclear Projects Nos. 1 and 3, respectively. This amount has been reclassified to Nuclear Fuel Held for Sale.

Under certain exchange agreements, the Supply System can transfer to third parties approximately 3.2 million pounds of Nuclear Project No. 1 uranium (equivalent U_3O_8) and 2 million pounds of Nuclear Project No. 2 uranium (equivalent U_3O_8). In return, the Supply System will receive equivalent quantities of uranium in future years. Additionally, the Supply System receives usage fees for the transferred uranium. These exchange agreements have been secured by bank letters of credit at current market value, adjusted semiannually. The cost of this uranium, $29.9 million, is included in the carrying amount of Nuclear Project No. 2 Nuclear Fuel. The contract value of the uranium, $39.7 million, is included in the carrying amount of Nuclear Project No. 1 Nuclear Fuel Held for Sale.

RESTRICTED ASSETS

In accordance with project bond resolutions, related agreements, or state law, separate restricted funds have been established for each project. The assets held in these funds are restricted for specific uses including construction, debt service, capital additions, extraordinary operation and maintenance, termination, decommissioning, and workers' compensation claims.

LONG-TERM RECEIVABLES

Long-term receivables include minimum guaranteed amounts pertaining to future discounts for certain goods and services to be provided to Nuclear Project No. 2 as the result of a litigation settlement.

DECOMMISSIONING

Estimated Nuclear Project No. 2 decommissioning costs are accrued based on current funding requirements. Monthly payments are made into a sinking fund which, with accumulated interest, is expected to be adequate to fund decommissioning costs at the end of the 40-year plant operating life. Decommissioning costs are currently estimated at $357 million (in 1987 dollars). Payments to the decommissioning fund for the year ended June 30, 1994 aggregated $3.1 million and the balance of the fund at June 30, 1994 was $25.6 million.

MATERIALS AND SUPPLIES

Materials and supplies are valued at cost, using weighted-average methods.

FINANCING EXPENSE, BOND DISCOUNT, AND DEFERRED GAIN

Financing expense, bond discounts, and deferred gain on redemption of revenue bonds are amortized over the terms of the respective bond issues.

REGULATORY STUDIES

Expenses associated with regulatory studies for Nuclear Project No. 2 are deferred and amortized by the straight-line method over the estimated operating life of the plant.

CURRENT MATURITIES OF REVENUE BONDS

Current maturities of revenue bonds payable from restricted assets are reflected in Long-Term Debt. Current maturities of bonds for which funds have not yet been restricted are reflected in Current Liabilities.

FAIR VALUE OF FINANCIAL INSTRUMENTS

The fair value of financial instruments has been estimated using available market information and appropriate valuation methodologies. Considerable judgment is required in interpreting market data to develop fair value estimates and such estimates are not necessarily indicative of the amounts that could be realized in a current market exchange. The following methods and assumptions were used to estimate the fair value of each of the following financial instruments.

Cash, accounts receivable, accounts payable and accrued expenses, other noncurrent liabilities and due to and from participants, other projects and other funds: The carrying amount approximates fair value.

Investments and revenue bonds payable: The fair value is based on quoted market prices for such instruments or similar instruments. The fair value of revenue bonds payable currently in default is not determinable due to litigation contingencies.

REVENUES

With the exception of Nuclear Projects Nos. 4 and 5, the Supply System recovers, through various agreements, actual cash requirements for operations and debt service for each project over the life of that project. Accordingly, the Supply System recognizes revenues equal to operating costs for each period. No net income or loss is recognized, and no equity is accumulated.

The difference between cumulative revenues received and cumulative operating costs is recorded as either billings in excess of costs (liability) or as costs in excess of billings (asset), as appropriate. Such amounts will be recognized as revenues, or costs, during future operating periods.

STATEMENTS OF CASH FLOWS

For purposes of the statements of cash flows, cash includes unrestricted and restricted cash balances. Short-term, highly-liquid investments are not considered cash equivalents.

Note C - Cash and Investments

Cash and investments for each utility system are separately maintained. The Supply System's deposits are insured by federal depository insurance or through the Washington Public Deposit Protection Commission. Supply System investment policies limit investment authority to obligations of the United States Treasury, Federal National Mortgage Association, Federal Home Loan Banks, Farm Credit System, and Federal Home Loan Mortgage Corporation, as well as repurchase agreements. Collateral for repurchase agreements must be authorized investments under Supply System investment policies. The Supply System did not invest in repurchase agreements during fiscal year 1994. All investments are held in the Supply System's name by safekeeping agents, custodians, or trustees.

Investments are stated at amortized cost and include accrued interest. The Supply System's investments are categorized below to give an indication of the types and amounts of investments held by each project at year-end.

Note D - Retirement Benefits

Substantially all Supply System full-time employees participate in the statewide local government Public Employees' Retirement System (PERS). PERS is a contributory multi-employer cost-sharing retirement system established by the Washington State Legislature and administered by the State of Washington through the

INVESTMENTS *(Dollars in thousands)*	U.S. Gov't Securities	U.S. Gov't Agencies	Total	Accrued Interest	Carrying Amount
NUCLEAR PROJECT NO. 2					
Amortized cost	$ 152,249	$ 78,954	$ 231,203	$ 3,240	$ 234,443
Fair value	147,200	78,656	225,856		
PACKWOOD LAKE PROJECT					
Amortized cost	2,045	-0-	2,045	-0-	2,045
Fair value	2,044	-0-	2,044		
HANFORD GENERATING PROJECT					
Amortized cost	8,204	-0-	8,204	-0-	8,204
Fair value	8,199	-0-	8,199		
NUCLEAR PROJECT NO. 1					
Amortized cost	163,483	202,166	365,649	4,334	369,983
Fair value	246,206	133,769	379,975		
NUCLEAR PROJECT NO. 3					
Amortized cost	82,588	119,575	202,163	2,463	204,626
Fair value	77,566	119,587	197,153		
NUCLEAR PROJECTS NOS. 4/5					
Amortized cost	54,167	30	54,197	1,635	55,832
Fair value	54,154	30	54,184		

Department of Retirement Systems. For the year ended June 30, 1994, the Supply System's payroll covered under PERS was $94 million, representing 94 percent of total payroll.

PERS contains two plans. Plan I members (employed on or before September 30, 1977) may retire with full benefits at age 60 with at least five years of credited service, at age 55 with 25 years of service, or upon reaching 30 years of service regardless of age. Plan II members (employed after September 30, 1977) may retire with full benefits at age 65 with at least five years of credited service, or with actuarially reduced benefits at age 55 with 20 years of service. The annual pension benefits are generally based on a percentage of final average salary.

Required employer contributions for both plans, and PERS II employee contributions, are determined each biennium by the Legislature. Employee contribution rates for Plan I are established by legislative statute. Employer rates for Plan I are not necessarily adequate to fully fund the system. The employer and employee contribution rates for Plan II are developed by the Office of State Actuary to fully fund the system. The methods used to determine the contribution requirements were established under state statute.

As of December 31, 1992 (the latest actuarial valuation date), the pension benefit obligation of PERS, which is the actuarial present value of credited projected benefits adjusted for the effects of projected salary increases, was $9.758 billion and the value of net assets available to satisfy present and future pension benefit obligations was $8.344 billion. The pension benefit obligation is a standardized measure which enables readers of financial statements to assess the funding status of each system and progress made in accumulating sufficient assets to pay benefits when due, and to make comparisons with other retirement systems. The standardized disclosure method is independent of the actuarial funding method used to determine contributions.

Supply System contributions for the year ended June 30, 1994, expressed both in dollar amounts and percentages of current-year covered payroll, are shown in table below.

The Supply System's actuarially determined employer contribution requirement represents approximately 2.1 percent of the total for all employers covered by PERS.

Historical trend information showing PERS' progress in accumulating sufficient assets to pay benefits when due is presented in the State of Washington's June 30, 1993 comprehensive annual financial report.

	Plan I		Plan II	
	Rate	Amount	Rate	Amount
Employer Contributions				
Actuarially determined requirement	7.41%	$ 986,041	7.41%	$5,976,341
Actual Supply System contributions	7.56%	$1,005,622	7.56%	$6,098,816
Employee Contributions				
Actuarially determined requirement	6.00%*	$ 798,239	5.20%	$4,193,924
Actual employee contributions	6.00%	$ 798,239	4.98%	$4,014,852

* Fixed at 6.00%

In addition to the pension benefits available through PERS, the Supply System offers postemployment life insurance benefits to retirees who are eligible to receive pensions under PERS Plan I and Plan II. Currently, 188 retirees are eligible to receive life insurance benefits and 141 retirees have elected to participate in this insurance. The life insurance benefit is equal to the employee's annual rate of salary at retirement for non-bargaining unit employees and one-half of the employee's annual rate of salary at retirement, with a minimum benefit of $22,000, for bargaining unit employees. Retirees contribute $6.60 per $1,000 of coverage annually for life insurance, and the Supply System funds the death benefit claims on a pay-as-you-go basis.

At the time each employee retires, the Supply System accrues a liability for the actuarial present value of estimated claims, net of retiree contributions. The total liability recorded at June 30, 1994 was $2.6 million for these benefits.

During fiscal years 1994 and 1993, pension costs for Supply System employees and postemployment life insurance benefit costs for retirees were calculated and allocated to each project based on direct labor dollars. Approximately 93 and 92 percent of all such costs were allocated to Nuclear Project No. 2 during fiscal years 1994 and 1993, respectively.

Note E - Long-Term Debt

Except for Nuclear Projects Nos. 4 and 5, which were financed together as one utility system, each Supply System project is financed separately. The resolutions of the Supply System authorizing issuance of revenue bonds for each project provide that such bonds are payable solely from the revenues of that project.

During the year ended June 30, 1994, the Supply System issued $2.4 billion in net-billed bonds for Nuclear Projects Nos. 1, 2 and 3 to refund $2.131 billion of outstanding bonds with an average interest rate of 6.36 percent. The net proceeds of the new issues were deposited in separate irrevocable trusts under the control of escrow agents to provide for all future debt service payments on the refunded bonds. As a result, the refunded bonds are considered to be defeased and the liability for those bonds has been removed from long-term debt.

Although the advance refundings resulted in the recognition of an accounting loss for the year ended June 30, 1994, the change in the aggregate debt service payments for Nuclear Projects Nos. 1, 2 and 3 and changes to debt service reserve fund balances resulted in an economic gain of $74.5 million, $68.3 million, and $116.4 million, respectively. The range of the economic gain for the variable rate debt (Series 1993-1A/3A) as defined by Statement No. 7 of the Governmental Accounting Standards Board is $51.5 million to $(58.8) million and $71.2 million to $(80.6) million for Nuclear Projects Nos. 1 and 3, respectively.

FISCAL YEAR 1994 BOND REFUNDINGS

(Dollars in Thousands)

NUCLEAR PROJECT NO. 1	Series 1993B	Series 1993C	Series 1993-1A/3A	Series 1994A	All Series
Size of issue	$189,710	$167,890	$153,330		$510,930
Amount of bonds refunded	175,075	137,240	153,330		465,645
Accounting loss	21,660	27,732	3,899		53,291
Reduction in aggregate debt service	22,015	7,058	32,870*		61,943
NUCLEAR PROJECT NO. 2					
Size of issue	$219,435			$661,831	$881,266
Amount of bonds refunded	203,175			558,785	761,960
Accounting loss	7,161			95,108	102,269
Reduction in aggregate debt service	11,808			39,600	51,408
NUCLEAR PROJECT NO. 3					
Size of issue	$ 282,255	$522,853	$202,140		$1,007,248
Amount of bonds refunded	268,635	432,455	202,140		903,230
Accounting loss	7,897	85,474	5,554		98,925
Reduction in aggregate debt service	17,663	20,222	44,582*		82,467

*Variable rate assumed at 4.5 percent annual rate for reduction in aggregate debt service.

In prior fiscal years, the Supply System defeased certain revenue bonds by placing the proceeds of new bonds in irrevocable trusts to provide for all future debt service payments on the old bonds. Accordingly, the trust account assets and the liability for the defeased bonds are not included in the financial statements. Including the fiscal year 1994 defeasements, approximately $708.7 million, $890.7 million, and $685.6 million of bonds outstanding are considered defeased at June 30, 1994 for Nuclear Projects Nos. 1, 2 and 3, respectively.

A summary of fiscal year 1994 Series 1993B, 1993C, 1993-1A/3A and 1994A bond refundings by project is presented above.

The Supply System expects to continue the refunding of high-interest bonds when economically feasible.

Outstanding revenue bonds of the various projects as of June 30, 1994, are presented on pages 21 through 25, and debt service requirements for these bonds are presented on pages 26 through 27.

SECURITY - NUCLEAR PROJECTS NOS. 1, 2 AND 3

Project participants and five investor-owned utilities for Nuclear Project No. 1 have purchased all of the project capability of Nuclear Projects Nos. 1 and 2 and the Supply System's 70 percent ownership share of project capability of Nuclear Project No. 3. BPA has in turn acquired the entire project capability from the project participants under contracts referred to as net-billing agreements. Under the net-billing agreements for each of the projects, project participants are obligated to pay the Supply System their pro rata share of total annual costs of the respective projects, including debt service on bonds relating to each project, and BPA in turn is obligated to pay the participants identical amounts by reducing amounts due to BPA by participants under BPA power sales agreements. The net-billing agreements provide that project participants and BPA are obligated to make such payments whether or not the projects are completed, operable or operating and notwithstanding the suspension, interruption, interference, reduction or curtailment of the projects' output. The validity of the net-billing agreements was challenged in November 1982. In May 1983, the U.S. District Court of Oregon declared that the net-billing agreements were binding, and this decision was upheld on appeal.

On May 13, 1994, the Supply System's Board of Directors adopted resolutions terminating Nuclear Projects Nos. 1 and 3. The Nuclear Projects Nos. 1 and 3 project agreements and the net-billing agreements, except for certain sections which relate only to billing processes and accrued liabilities and obligations under the net-billing agreements, ended upon termination of the projects. The Supply System has entered into an agreement with BPA to provide continued funding for the existing preservation program until January 1995 and for continuation of the present budget approval, billing and payment processes. With respect to Nuclear Project No. 3, the ownership agreement among the Supply System, Puget Sound Power & Light Company, PacifiCorp, Portland General Electric Company and The Washington Water Power Company remains in effect following termination.

SECURITY - NUCLEAR PROJECTS NOS. 4 AND 5

In connection with the issuance of the generating facilities revenue bonds for Nuclear Projects Nos. 4 and 5, the Supply System pledged the revenues to be derived under participants' agreements with 88 utilities operating principally in the Northwest. The participants' agreements provided that each participant pay its respective share of annual costs, including debt service on the bonds, whether or not the projects were completed, operable, or

operating and notwithstanding the suspension, interruption, interference, reduction or curtailment of the projects' output. Payments from the participants for Nuclear Projects Nos. 4 and 5 termination costs and debt service were due beginning on January 25, 1983. As a result of a ruling by the Washington State Supreme Court declaring the participants' agreements invalid, payments due under the participants' agreements were not made and an event of default, as defined in the bond resolution, occurred on July 22, 1983 (see Note F - Nuclear Projects Nos. 4 and 5 Termination, Bond Default, and Litigation).

SECURITY - HANFORD GENERATING PROJECT

It was initially intended that Nuclear Project No. 1 be constructed next to HGP to provide the energy source to operate the project when DOE ceased operation of the N-Reactor. To allow for construction of Nuclear Project No. 1, it would have been necessary to shut down HGP on October 31, 1977. Because studies at that time indicated that generating resources in the Pacific Northwest would be inadequate in the late 1970s and early 1980s, the Supply System and BPA determined that HGP should be kept available for power production. Therefore, the Nuclear Project No. 1 net-billing, exchange and project agreements were amended to provide for the separation of Nuclear Project No. 1 from HGP.

The amended agreements provided for the payment of all HGP debt service costs, net of investment income, by Nuclear Project No. 1 participants, beginning July 1, 1980, regardless of continued operation of the N-Reactor, and that other costs, to the extent not otherwise provided for, be treated as Nuclear Project No. 1 costs, with HGP having a first claim on the revenues of that project.

SECURITY - PACKWOOD LAKE HYDROELECTRIC PROJECT

Under power sales agreements, 12 public utility districts have purchased all of the project capability of Packwood. The purchasers are obligated to pay annual costs of the project, including debt service, whether or not the project is operable, until outstanding bonds are paid or provision is made for the retirement in accordance with provisions of the bond resolution.

Note F - Commitments and Contingencies

NUCLEAR PROJECTS NOS. 1 AND 3 TERMINATION

In April 1982, the Supply System commenced a construction delay of Nuclear Project No. 1, and in July 1983, it commenced a construction delay of Nuclear Project No. 3. On May 13, 1994, the Supply System's Board of Directors adopted a resolution terminating Nuclear Projects Nos. 1 and 3. Additionally, the Board of Directors recommended to the Executive Board that the Supply System enter into an agreement with BPA to provide continued funding for the existing preservation programs, including the maintenance of all federal and state licenses and permits until January 13, 1995, or such other date as may be mutually agreed upon by BPA and the Supply System. The Supply System and BPA executed post termination agreements for Nuclear Projects Nos. 1 and 3 on June 14, 1994, in which BPA agreed to continue funding for preservation of the projects to evaluate alternative uses for and to facilitate the marketing of the projects until January 13, 1995.

The project agreements end upon termination of the projects, as do the net-billing agreements, except for certain sections which relate only to billing processes and accrued liabilities and obligations. The post termination agreement provides for an assured period of funding for asset preservation and for continuation of the present budget approval, billing and payment processes. The ownership agreement among the Supply System, Puget Sound Power & Light Company, PacifiCorp, Portland General Electric Company and The Washington Water Power Company remains in effect following termination.

COST-SHARING LITIGATION

Nuclear Projects Nos. 1 and 4 are of substantially the same design and are referred to as "twin units." Nuclear Projects Nos. 3 and 5 are also twin units of substantially the same design. As costs of architect/engineer services, construction management services, certain common equipment used in the construction of twin units and other costs incurred by the Supply System benefited both units, it was concluded that those costs should be shared by the twin units. The Supply System allocated such shared costs on the basis of respective benefit to the projects involved in accordance with a policy statement adopted by the Supply System's Executive Committee.

In August 1982, the Participants' Committee for Nuclear Projects Nos. 4 and 5, on behalf of the project participants, demanded that the Supply System reallocate $161 million, plus interest, in shared costs previously paid by Nuclear Projects Nos. 4 and 5, based on a revised formula for sharing of costs which it prepared. The demand indicated this was not the total extent of claims which could be made by the Nuclear Projects Nos. 4 and 5 participants. The investor-owned utilities (IOUs) owning 30 percent of Nuclear Project No. 3 asserted that they are entitled to set off the amounts owed by the Supply System on bridge and termination loans made for Nuclear Projects Nos. 4 and 5 in 1981, totaling $12 million plus interest, against any cost-sharing reallocation obligation.

In October 1982, the Supply System filed a complaint for declaratory judgment in Federal District Court for Western Washington, naming the participants in Nuclear Projects Nos. 1, 2, 3, 4 and 5, BPA, the four IOUs owning shares of Nuclear Project No. 3, and the bond fund trustees for Nuclear Projects Nos. 1 and 3 as defendants, and asked the court to declare the rights and obligations of the parties with regard to the allocation of costs among the projects. Certain other claims have been filed as part of this action. In May 1983, the court designated BPA as the plaintiff and all other parties as defendants. The case is captioned BPA v. Supply System, et al.

In June 1983, Chemical Bank intervened as bond fund trustee on behalf of the Nuclear Projects Nos. 4 and 5 bondholders. Chemical Bank alleged that the Supply System's allocations of costs among the twinned projects were improper and that repayment to the Nuclear Projects Nos. 4 and 5 bond fund was required for such costs allegedly improperly allocated.

In May 1989, the District Court ruled that the cost allocation procedures used were improper and that Chemical Bank has a lien in an amount of any funds which may be determined in the future to have been improperly expended as a result of costs misallocated to Nuclear Projects Nos. 4 and 5. The court stated that any enforcement of the lien must await resolution of the issue of whether there was any improper allocation. In October 1990, the District Court ruled that the Nuclear Projects Nos. 4 and 5 Bond Resolution required the application of cost allocation principles similar to those espoused by Chemical Bank. The court stated that because such principles were not applied, Nuclear Projects Nos. 4 and 5 apparently bore more than their fair and equitable share of construction costs. The court granted Chemical Bank's motion for an accounting of all uses of bond proceeds of Nuclear Projects Nos. 4 and 5.

The Supply System and other parties in the case appealed this order to the U.S. Court of Appeals for the Ninth Circuit, and in February 1992, the Court of Appeals reversed both the May 1989 and October 1990 rulings. The Court of Appeals upheld the proportional cost sharing method implemented by the Supply System's Policy Statement, reversed the lower court's finding of a lien on misallocated funds, and remanded the case to the District Court for resolution of the remaining issues in accordance with the Court of Appeals' decision.

Prior to the reversal, counsel for Chemical Bank had publicly estimated the potential recovery for Nuclear Projects Nos. 4 and 5 at up to $1 billion, including interest. If a judgment were awarded in favor of Chemical Bank and costs previously allocated to Nuclear Projects Nos. 4 and 5 were allocated to other Supply System projects, such amounts would be treated as construction costs of such projects.

The case is still in the discovery phase and in April 1994 a settlement master was assigned to the case. The order appointing the settlement master provides that all communications with the settlement master be kept confidential and that the parties may not disclose any information relating to the status of settlement activities.

The Supply System is unable to predict the outcome of this litigation.

NUCLEAR PROJECT NO. 3 DELAY LITIGATION

In July and August 1983, the four IOUs owning 30 percent of Nuclear Project No. 3 filed claims against BPA, the Supply System and the Nuclear Project No. 3 participants asserting that they suffered damages as a result of the extended construction delay of Nuclear Project No. 3.

The Supply System executed agreements in September 1985 to settle the construction delay claims with BPA and with each of the IOUs owning shares of Nuclear Project No. 3. A number of the Nuclear Project No. 3 participants have opposed the settlement and dismissal of claims. In October 1985, the participants filed pleadings in the U.S. District Court asserting challenges to the Nuclear Project No. 3 settlement agreements between BPA and the IOUs. None of the agreements executed by the Supply System has been challenged. However, the pleadings filed by some participants also include claims against the Supply System, the IOUs and BPA unrelated to the validity of the settlement. In July 1986, the district court dismissed the claims challenging BPA's authority to enter into the Nuclear Project No. 3 settlement agreements with the IOUs and stayed all other claims relating to or arising out of the construction delay or the settlement.

An original proceeding also was filed in the U.S. Court of Appeals for the Ninth Circuit, challenging BPA's settlements with the IOUs. In January 1989, the Court of Appeals rejected all statutory challenges to BPA's settlements, affirmed BPA's authority to enter the settlements, and dismissed other claims, including claims against the IOUs and the Supply System, for lack of jurisdiction.

In May 1989, the District Court dismissed the claims of all but nine of the Nuclear Project No. 3 participants against the Supply System, BPA and the IOUs relating to or arising out of the construction delay of Nuclear Project No. 3 or the settlement, pursuant to a stipulation of the parties. No action has been taken by these nine non-stipulating participants since the May 1989 district court ruling.

The four IOUs owning 30 percent of Nuclear Project No. 3 also filed complaints in state courts in King County, Washington, and Multnomah County, Oregon, in May 1983 seeking declarative and equitable relief and damages because of the Nuclear Project No. 3 construction delay as claimed by them in <u>BPA v. Supply System, et al.</u> These cases were filed as a precaution against any determination that the Federal District Court lacked jurisdiction to try the Nuclear Project No. 3 construction delay claims. The Washington case was dismissed without prejudice in March 1992. Proceedings in the Oregon case are stayed by stipulation of the parties. The parties have agreed to dismiss the Oregon case after final dismissal of the parallel claims in the Federal Court and the final dismissal of any claims challenging the Nuclear Project No. 3 Settlement Agreements.

If the settlement agreements between BPA and the IOUs are determined to be invalid or unenforceable, the IOUs might renew their claim that they are entitled to rescission of the Nuclear Project No. 3 ownership agreement. However, the IOUs have agreed in their settlement agreements with the Supply System not to assert any claim against the Supply System for money damages, restitution or injunctive relief.

The Supply System is unable to predict what results will be reached with respect to these claims.

HANFORD GENERATING PROJECT

HGP, completed in 1966, previously used by-product steam from DOE's N-Reactor, and has not operated since the shutdown of the N-Reactor in 1987. The federal government's decision to place the N-Reactor in permanent shutdown eliminated the N-Reactor as an energy source for HGP. The Supply System has evaluated alternative energy uses for the plant to no avail. Current options include a transfer to DOE for removal and site restoration, or removal and site restoration by the Supply System. At this time, it is unknown what the eventual disposition of HGP will be. The Supply System has reduced the assets of HGP to their net realizable value and has accrued for the estimated cost of removal and site restoration.

Certain preservation costs of HGP have been funded by DOE since 1989 under a supplemental agreement between the Supply System and DOE. This agreement expired June 30, 1992. Preservation costs were funded by Nuclear Project No. 1 between June 30, 1992 and September 30, 1993, at which time preservation of physical assets was discontinued.

NUCLEAR PROJECTS NOS. 4 AND 5 TERMINATION, BOND DEFAULT, AND LITIGATION

In January 1982, the Supply System's Nuclear Projects Nos. 4 and 5 were terminated prior to completion. The Supply System had previously issued $2.25 billion of bonds to pay costs of the projects.

The participants' agreements (discussed in Note E - Security-Nuclear Projects Nos. 4 and 5) provided that each participant pay its respective share of the debt service on the bonds and termination costs beginning January 25, 1983. In 1983, and again in 1984, the Washington State Supreme Court ruled that Washington municipal utilities did not have statutory authority to enter into the participants' agreements, thus invalidating the agreements. This decision became final when the U.S. Supreme Court denied a writ of certiorari.

On July 22, 1983, the Supply System acknowledged that it could not pay Nuclear Projects Nos. 4 and 5 obligations as they became due. This was an event of default under the Nuclear Projects Nos. 4 and 5 bond resolution. On July 25, 1983, Chemical Bank, as bond fund trustee, demanded that all remaining project funds be transferred to it for holding in a special account. On August 18, 1983, Chemical Bank declared the principal of all Nuclear Projects Nos. 4 and 5 revenue bonds and interest accrued thereon to be due and payable immediately.

Beginning in 1983, a number of lawsuits were filed by and on behalf of purchasers and holders of Nuclear Projects Nos. 4 and 5 bonds ("the securities litigation"). The defendants named in the lawsuits included the Supply System, its member utilities, Nuclear Projects Nos. 4 and 5 participants, BPA, the architect/engineers and the lead underwriters for Nuclear Projects Nos. 4 and 5 and the Supply System's former bond counsel, special counsel and financial advisor. The lawsuits alleged violations of federal and state securities law, fraud, misrepresentation, negligence and breach of contract, and sought monetary damages, rescission and restitution. The lawsuits sought to recover the bondholders' investment in the principal amount of $2.25 billion, plus unspecified damages, interest, costs and attorneys' fees.

In September 1988, the Supply System's Executive Board approved an agreement to settle the securities litigation. The agreement called for the Supply System to consent to entry of a judgment on the contract claim on the Nuclear Projects Nos. 4 and 5 bonds brought on behalf of bondholders. All other claims against the Supply System were to be dismissed with prejudice. The amount of the judgment was to equal the aggregate unpaid principal amount of the Nuclear Projects Nos. 4 and 5 bonds and accrued interest thereon at the time the judgment was entered. Recourse for satisfaction of the judgment was expressly limited to the funds and assets of the Supply System pledged to secure the Nuclear Projects Nos. 4 and 5 bonds. The settlement agreement provided that judgment would be entered upon final judgment or final settlement of all suits covered by the settlement.

All other defendants in the securities litigation and the State of Washington, a nonparty, settled all of the claims against them for aggregate payments of more than $850 million. All of the settlements were approved by the District Court on September 5, 1989. The court found that the settlements were binding on all Nuclear Projects Nos. 4 and 5 bondholders in the litigation. On February 4, 1992, the Court of Appeals affirmed, in its entirety, the settlement of those claims; and a petition for certiorari was denied by the U.S. Supreme Court on November 2, 1992.

Accordingly, the District Court's ruling now permanently bars Chemical Bank and all Nuclear Projects Nos. 4 and 5 bond purchasers and bondholders from commencing, prosecuting, or continuing any action against the Supply System arising out of or relating to the allegations or subject matter of the securities litigation. However, based on the terms of the Supply System's settlement with Chemical Bank, the ruling does not preclude Chemical Bank from continuing with the cost-sharing litigation described above.

In March 1994, Nuclear Projects Nos. 4 and 5 received a $2.8 million settlement as a reimbursement to the Bond Fund Reserve Account and recorded the reimbursement as non-operating revenue.

NUCLEAR PROJECTS NOS. 4 AND 5 BRIDGE AND TERMINATION LOANS

In late 1981, 68 Nuclear Projects Nos. 4 and 5 participants and others loaned the Supply System $60 million to pay project costs until an alternative source of financing could be found. None was found, and after the projects were terminated in January 1982, 42 Nuclear Projects Nos. 4 and 5 participants loaned the Supply System additional amounts of approximately $8 million to pay termination costs. The first set of loans were called bridge loans, and the second termination loans. All of these loans were subordinate to the $2.25 billion of bonds payable, and were payable

solely from the revenues of Nuclear Projects Nos. 4 and 5. The Supply System defaulted on all of the loans at the same time it defaulted on Nuclear Projects Nos. 4 and 5 bonds in 1983.

Most of the lenders have sued the Supply System and all but three of the suits (those brought by certain investor-owned utilities) have been reduced to judgment. The Washington State Supreme Court has held that the terms of the loans limited the source of recovery to funds and assets of Nuclear Projects Nos. 4 and 5. Due to the expiration of the statute of limitations, the Supply System wrote off $46.2 million of principal and $114.5 million of accrued interest for bridge/termination loans during the year ended June 30, 1994. Interest on these loans in the amount of approximately $65.3 million remains accrued and unpaid at June 30, 1994.

INTER-PROJECT CLAIMS AGAINST REVENUES AND OTHER ASSETS

Some creditors of Nuclear Projects Nos. 4 and 5 have attempted, and others have threatened to attempt, to obtain payment from the physical assets of other projects of the Supply System or from the revenues pledged as security for the Supply System bonds issued in connection with, and revenues pledged for the payment of costs of, such other projects. Such creditors include present and former holders of the Nuclear Projects Nos. 4 and 5 bonds and others who may assert claims in the future against the Supply System and/or its projects.

The Supply System had recognized certain Nuclear Projects Nos. 4 and 5 contract claims as accrued expenses. At June 30, 1994, the Supply System wrote off all contract claims, $23.4 million and $5.5 million for Nuclear Projects Nos. 4 and 5, respectively, due to the expiration of the statute of limitations.

The Supply System's management and legal counsel are of the opinion that such creditors will only be able to realize upon the net assets of Nuclear Projects Nos. 4 and 5 and will not be able to realize upon any net assets or future revenues of the Supply System and/or its other projects.

NUCLEAR PROJECT NO. 5 TERMINATION CLAIM

In August 1983, PacifiCorp, owner of 10 percent of Nuclear Project No. 5, filed a counterclaim in BPA v. Supply System, et al. asserting that termination of Nuclear Project No. 5 was a breach of the ownership agreement between PacifiCorp and the Supply System. PacifiCorp seeks damages in an unspecified amount. Such amount would presumably be approximately $150 million, and could be a general claim against assets of the Supply System. Actions on that claim have been stayed since 1983. The Supply System is unable to predict the outcome of this litigation, but counsel is of the opinion that a successful claim against assets of other than Nuclear Projects Nos. 4 and 5 is remote.

OTHER LITIGATION AND COMMITMENTS

The Supply System is involved in various claims, legal actions and contractual commitments not mentioned above as both plaintiff and a defendant and in certain claims and contracts arising in the normal course of business. Although some suits, claims and commitments are significant in amount, final disposition is not determinable. In the opinion of management, the outcome of such litigation, claims or commitments will not have a material adverse effect on the financial positions of the projects or the Supply System as a whole. The estimated cost of the projects, however, may either be increased or decreased as a result of the outcome of these matters.

NUCLEAR PROJECTS NOS. 4 AND 5 SITE RESTORATION

No provisions have been made for site restoration of Nuclear Projects Nos. 4 and 5, which is governed by the site certification agreement between the Supply System and the State of Washington and regulations adopted by the Washington Energy Facility Site Evaluation Council (EFSEC) and, with respect to Nuclear Project No. 4, the lease agreement with DOE. It is not known at this time what actions will be necessary to comply with these requirements. Because the site certification agreement for Nuclear Project No. 1 also covers Nuclear Project No. 4, and the agreement for Nuclear Project No. 3 also covers Nuclear Project No. 5, EFSEC might assert that Nuclear Projects Nos. 1 and 3 are obligated to pay the cost of site restoration for Nuclear Projects Nos. 4 and 5. Such costs are estimated to be in the range of $31 to $54 million (in January 1994 dollars).

NUCLEAR LICENSING AND INSURANCE

The Supply System is a licensee of the Nuclear Regulatory Commission and is subject to routine licensing and user fees, to retrospective premiums for nuclear liability insurance, and to license modification, suspension, or revocation or civil penalties in the event of violations of various regulatory and license requirements.

The Price Anderson Act currently provides for nuclear liability insurance over $9.1 billion per incident, which is covered by a combination of commercial nuclear insurance and mandatory industry self-insurance. The Supply System has purchased the maximum commercial insurance available of $200 million, which is the first layer of protection. The second layer of protection is provided through a mandatory industry self-insurance plan wherein each licensed nuclear facility required to participate in the plan (currently 113) may be assessed up to $79.275 million per incident, subject to a maximum annual assessment of $10 million per year.

Nuclear property damage and decontamination liability insurance requirements are met through a combination of commercial nuclear insurance policies purchased by the Supply System and BPA. The total amount of insurance purchased is currently $1.2 billion. The deductible for this coverage is $10 million per occurrence.

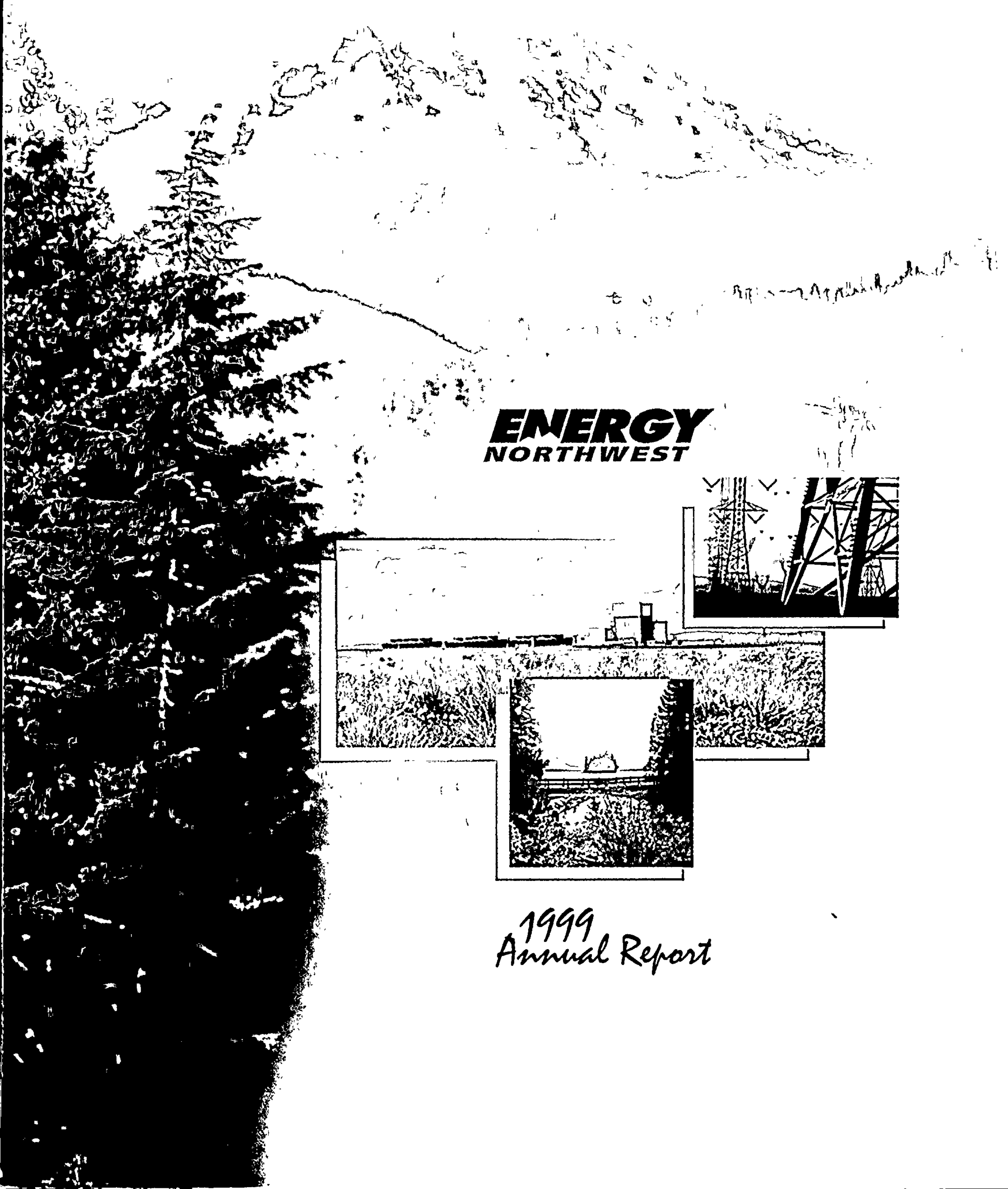
For the year ended June 30, 1994

	FY 1994	FY 1993		
BOND RATINGS - SUPPLY SYSTEM				
Fitch Investor Service, Inc.	AA	AA		
Moody's Investors Service, Inc. (Moody's)	Aa	Aa		
Standard and Poor's (S & P)	AA	AA		
VARIABLE RATE LETTER OF CREDIT BANKS			S & P	MOODY'S
Long Term				
Series 1993-1A/3A-1			A+	Aa3
Series 1993-1A/3A-2			A+	A1
Series 1993-1A/3A-3			AA	Aa2
Short Term				
Series 1993-1A/3A-1			A-1	VMIG1
Series 1993-1A/3A-2			A-1	VMIG1
Series 1993-1A/3A-3			A-1+	VMIG1

WASHINGTON PUBLIC POWER
SUPPLY SYSTEM

3000 George Washington Way, P.O.Box 968, Richland, Washington 99352 (509) 372-5000

940205

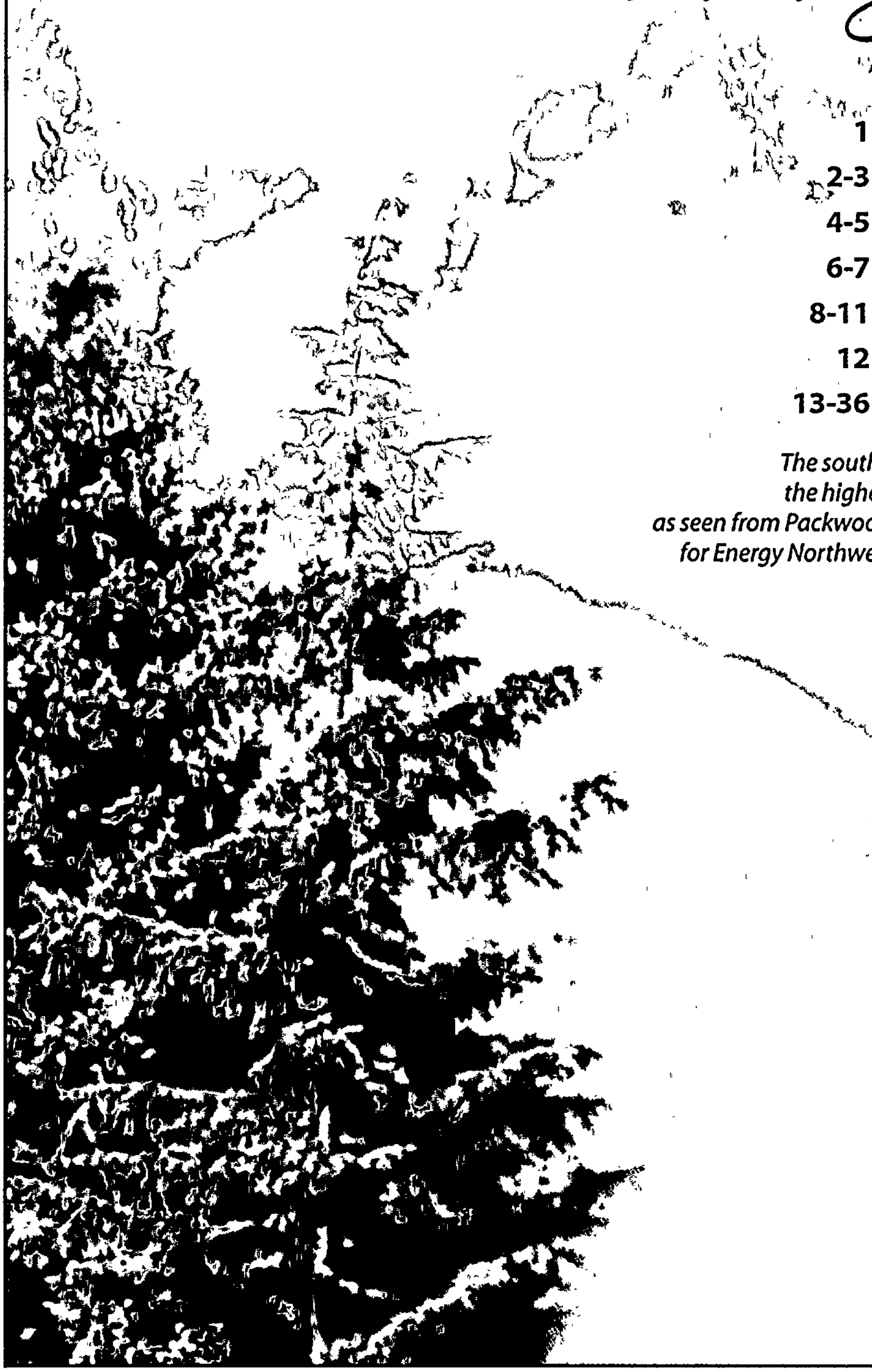


ENERGY NORTHWEST

1999 Annual Report

ENERGY NORTHWEST

Pursuing Excellence



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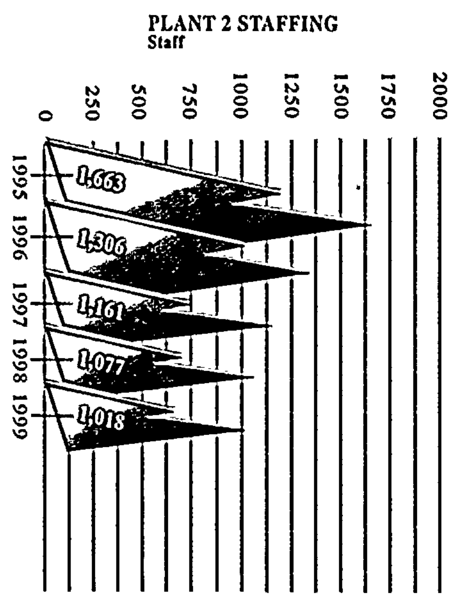
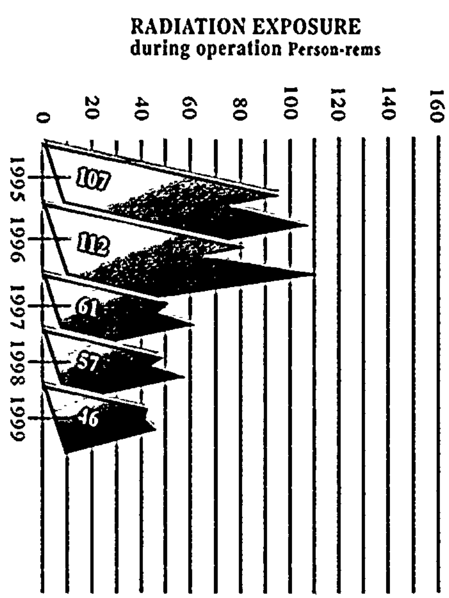
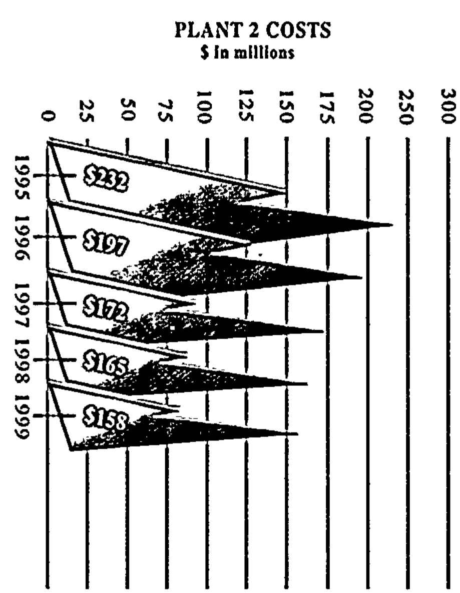
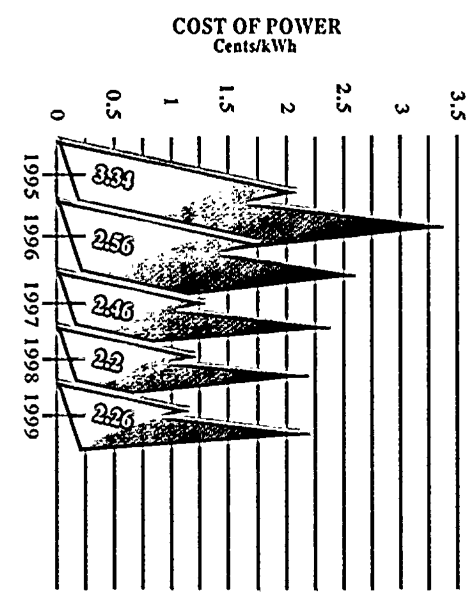
The southern flank of Mt. Rainier, at 14,410 feet the highest mountain in the Pacific Northwest, as seen from Packwood Lake. The lake is the source of water for Energy Northwest's 27-megawatt hydroelectric plant.

OPERATING HIGHLIGHTS









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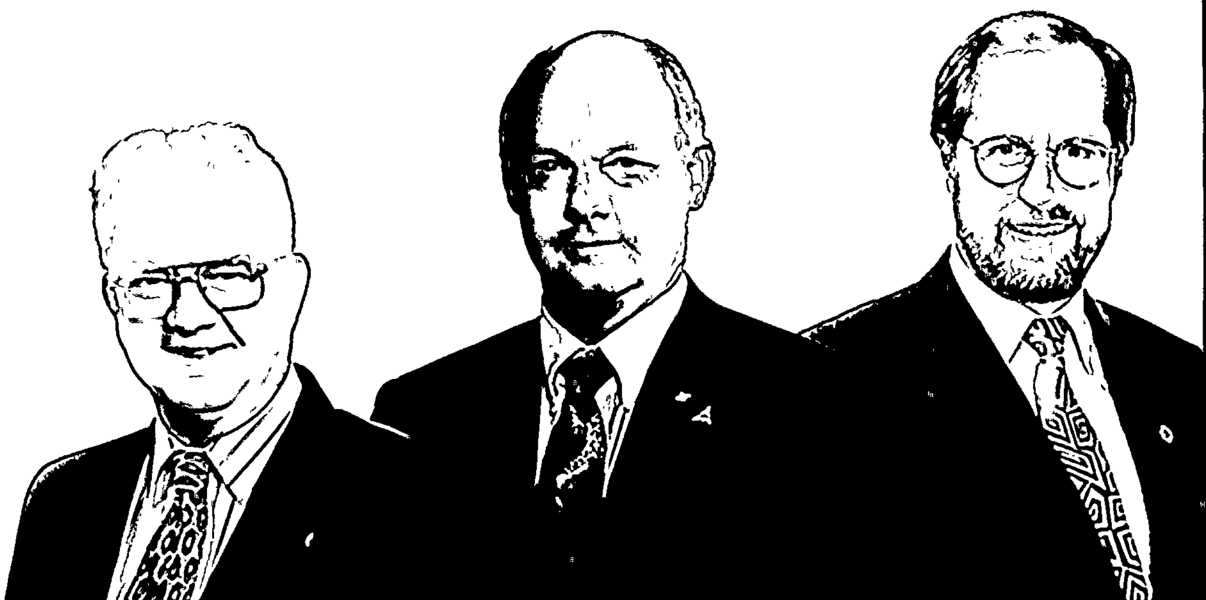
Leading the way



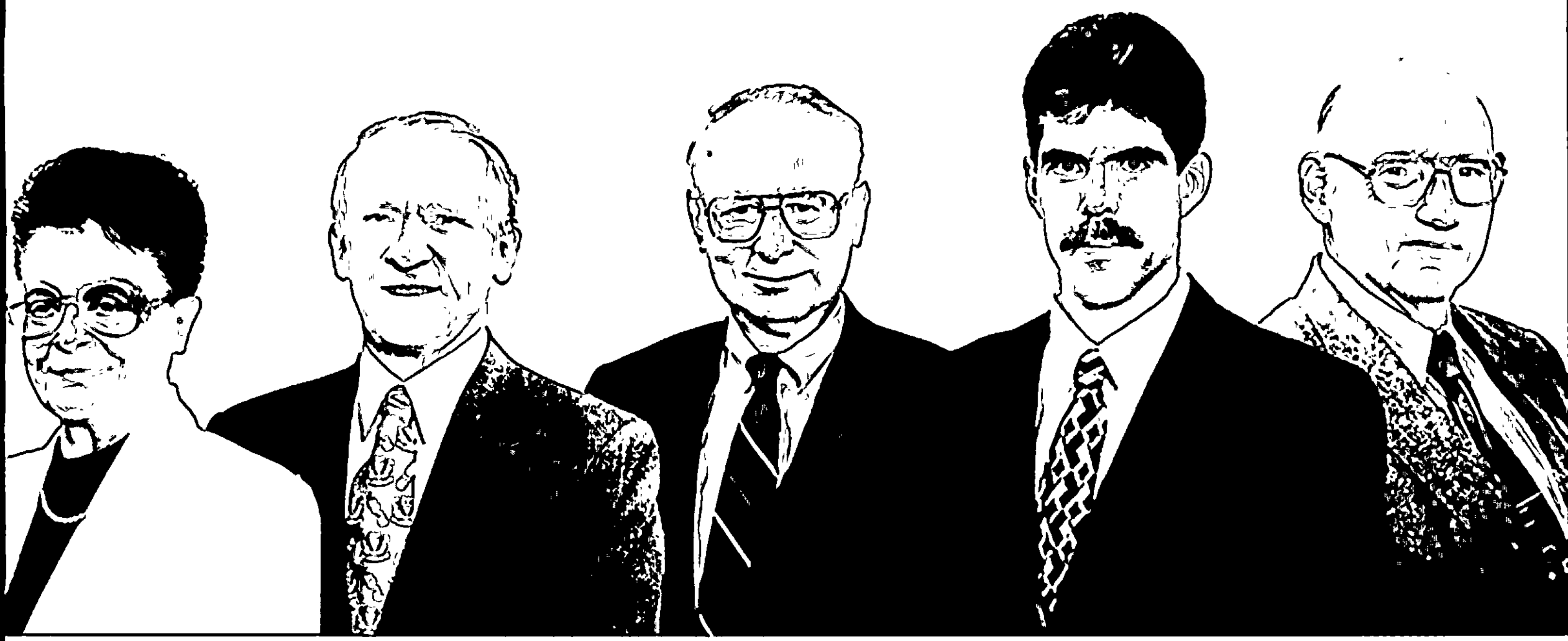
Darrel Bunch
Commissioner
Okanogan County PUD
Okanogan, WA

Don Carter
Deputy City Manager for
Utilities and Physical Services.
City of Richland, WA

Rudi Bertschi
(Vice Chairman)
Consultant
Economic & Technical
Analysis Group
Seattle, WA

Executive Board

Louis H. Winnard
Chairman
Consultant
Windsor, CA



Vera Claussen
(Assistant Secretary)
Commissioner
Grant County PUD
Ephrata, WA

Edward E. "Ted" Coates
(Secretary)
Retired
Utility Executive
Tacoma, WA

John Cockburn
Retired
Bank Executive
Seattle, WA

Dan Gunkel
Commissioner
Klickitat County PUD
Goldendale, WA

Roger Sparks
Commissioner
Kittitas County PUD
Ellensburg, WA

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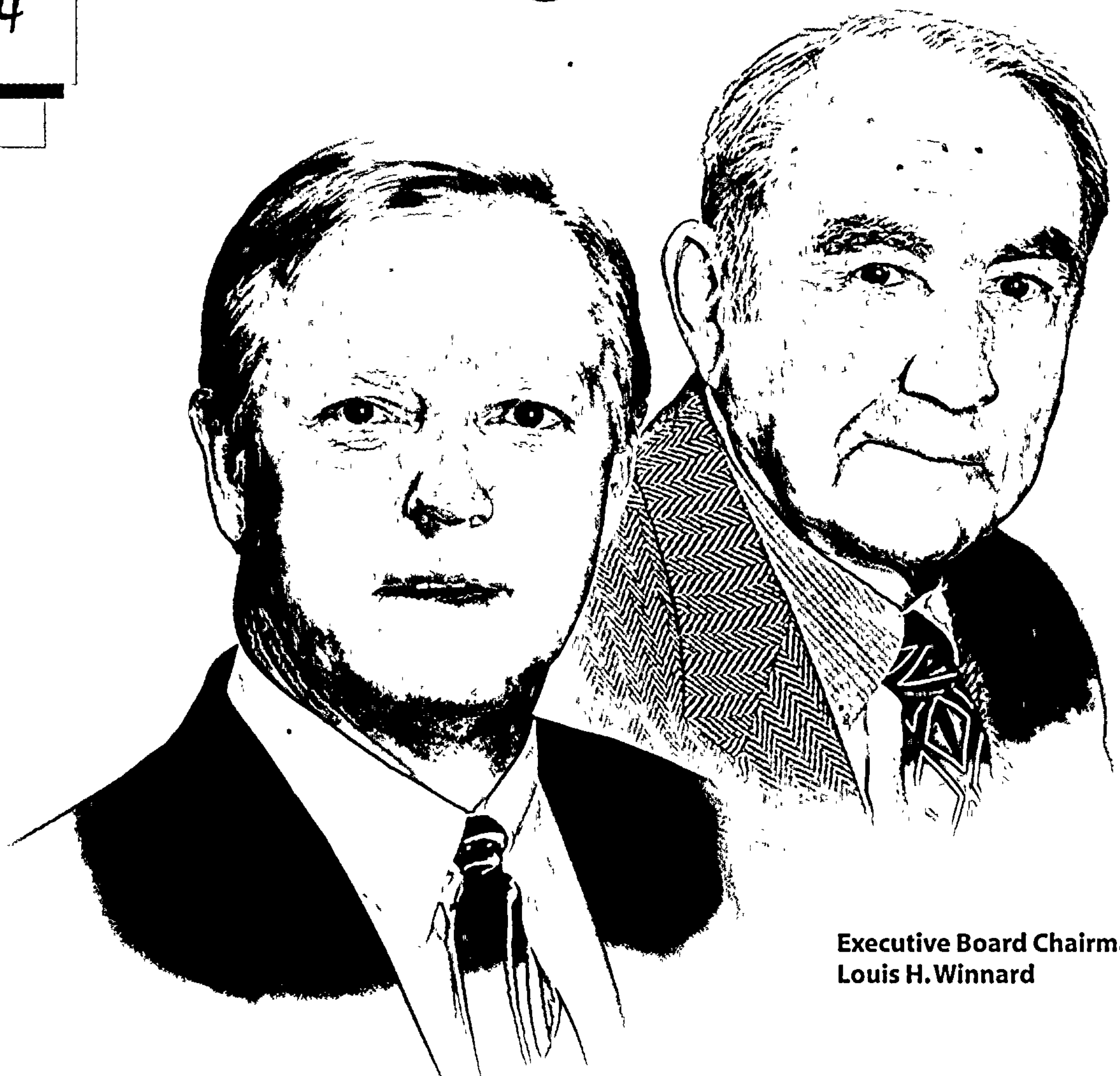
ENERGY NORTHWEST

Pursuing Excellence



Executive Board Chairman
Louis H. Winnard

Chief Executive Officer
J. V. Parrish

After four decades of doing business as the Washington Public Power Supply System, sometimes marked by turbulence and turmoil, we are ready to enter the new millennium with a new name: Energy Northwest. This change signifies the end of one era of our journey, and the beginning of a new one in our pursuit of excellence.

We are not fleeing from our past. Rather, we are running toward our future.

Five years ago our journey almost ended prematurely. Plant 2, our sole operating nuclear generating station, was over-staffed, over-priced, and under-productive. The cost of power was too high, at 3.34 cents per kilowatt-hour, to be competitive. The plant was unreliable, worker radiation exposure was too high, and our staff was wasting far too much time trying to keep the plant running, rather than operating it reliably. We were faced with a clear choice: cut costs and increase reliability, or terminate the plant.

Here is what has been accomplished since 1995:

- Lowered the cost of power from 3.34 cents per kilowatt-hour to 2.26 cents in fiscal 1999 and met the market test benchmark established by the Bonneville Power Administration.
- Cut the plant budget from $232 to $158 million.
- Downsized our staff by 36 percent while cutting overtime expenditures from $10.9 million in fiscal 1994 to $1.5 million in fiscal 1999.
- Reduced worker radiation exposure, a key indicator of safety and efficiency, by 67 percent.

Increased reliability and availability, rather than continued drastic budget reductions, will ensure a strong future for Plant 2 and Energy Northwest. Reducing the price of power is still a key goal (the fiscal 2000 target is 2.15 cents a kilowatt-hour), but increased generation is the principle tool we will use to achieve our goal.

The budget is only one side of the cost equation. A recent report by an independent consultant commissioned by the Bonneville Power Administration praised our cost-cutting efforts, with one caveat: continued cost-cutting could hurt the reliability of our nuclear station and actually increase the cost of its power. A number of U.S. nuclear utilities have made that very mistake. We don't intend to follow their example.

We are following the industry in making a major change in Plant 2's operating cycle. This year was the first time in its 15-year history that Plant 2 was not refueled in the spring. Refueling was put off until September as we transition the plant from an annual to a 24-month refueling schedule. This transition will result in a relatively small increase in fuel costs, but it will be more than offset by increased generation, reliability and availability.

Here is why that is important: In the past, when Plant 2's power output wasn't needed as the runoff from mountain snowpacks powered the region's numerous hydroelectric generators, it made sense to shut the plant down every spring.

That is no longer the case.

The Bonneville Power Administration has warned the region that, under certain circumstances, the Pacific Northwest might see a shortfall of up to 7,000 megawatts of electrical capacity in the winter of 2001.

Generation in the Northwest hasn't met the pace of increasing demand and, even more troubling, is the possibility of removing existing hydroelectric resources. Hydropower no longer is bountiful, nor is it cheap. Fish protection measures have increased the cost of running the Northwest's hydro system tremendously while fish passage and spawning regimens have cut generation.

But Plant 2 doesn't hurt fish, and fish protection measures don't impact Plant 2. When the water is low in the Columbia River system, we generate vast amounts of power. When the water is high, but the dams are forced to spill huge amounts of water to help migrating salmon, we continue to produce power.

We generate about 10 percent of Bonneville's firm power, and provide the federal agency with the flexibility to operate the river system in a way that balances the competing needs of fish protection, flood control, irrigation, transportation and recreation.

This added flexibility has been instrumental in Bonneville's resurgence as the region's preferred electricity provider. A few years ago critics predicted the demise of Bonneville. They said BPA was too expensive, too bureaucratic, and would be unable to meet its fish-recovery obligations without large increases in the wholesale price of electricity. They said Bonneville was doomed. Utilities began searching for other, lower-cost sources of power.

But the critics were wrong.

Bonneville tightened its belt and cut the wholesale price of electricity sold to its public power customers by 20 percent. Customers that a few years ago were scrambling to abandon BPA now are competing fiercely for their share of low-cost BPA power.

BPA's progress has also been helped by Energy Northwest's bond refinancing program. Early planning paid off handsomely as we, with Bonneville's cooperation, took advantage of favorable credit ratings and low interest rates, thereby cutting the average interest rate on billions of dollars in outstanding bonds nearly in half since 1989, from 10.5 percent to 5.3 percent.

The result: Northwest consumers will save $1.83 billion over the life of the bonds.

This Annual Report details other ways in which we are supporting Bonneville and our member public power utilities. Among them is our Packwood Hydroelectric Project, one of three of the region's "green" resources marketed by BPA.

We also hold two licenses on combustion turbine sites in Western Washington and are marketing energy services to public power utilities statewide. We are also embarking on several new business initiatives that will diversify our operations and cut the overhead costs charged to Plant 2.

These new endeavors, coupled with the changing face of Plant 2, convinced our Executive Board that a new name for the organization was needed. They selected Energy Northwest because in two words it says who we are, where we are and what we do.

We belong to the Northwest because we're a public power agency, created by the people. We belong in the Northwest because our roots are here. We're going to stay in the Northwest because ratepayers in the region made an investment in us over the years. Now they are collecting the dividends on that investment: energy services and inexpensive power.

The entire Energy Northwest team of employees, management and its governing boards pledge their best efforts to continue to serve the future best interests of our owners — the Northwest ratepayers.

OPERATIONAL HIGHLIGHTS

Energy Northwest is on a journey; a journey to excellence that began in 1995 when the cost of power from Plant 2 was not competitive at 3.34 cents a kilowatt-hour.

By reducing costs and increasing reliability, Plant 2 delivered electricity to the Bonneville Power Administration in fiscal year 1999 at a price — 2.26 cents a kilowatt-hour — that is competitive with other available resources.

ENERGY NORTHWEST

Increasing Reliability and Availability

Getting to this point of the journey was difficult. Gaining control of costs required setting priorities, fixing problems in the plant and motivating the staff to realize its potential.

Innovative ways were found to give employees incentives to take ownership for plant performance. Energy Northwest employees are paid a portion of their compensation in the form of incentive payments based on meeting key Plant 2 cost and efficiency goals. The concept is simple: If Plant 2 runs well and remains within budget, employees are rewarded at the end of the year. If the plant fails to meet its goals, some or all of the incentive payment is forfeited.

With budgets down and reliability up Energy Northwest is continuing to look for ways to decrease the cost of power. This year's major initiative is transitioning Plant 2 from an annual to a 24-month refueling cycle.

Plant 2 was the last of the nation's nuclear power plants still on a 12-month refueling cycle. Most plants operate on an 18-month cycle and about 20 percent run two years before refueling. Because Plant 2 is nestled among some of the greatest hydroelectric dams in the world, the nuclear station has always followed the ebb and flow of the Columbia River system. In the past, each spring when water was high, the region was awash with hydropower. Bonneville would meet the region's needs while selling huge amounts of surplus power in the West Coast market for less than a cent per kilowatt-hour.

From left:

Vice President, Operations Support/PIO *Rod Webring*
Vice President, Generation/Plant General Manager *Greg Smith*
Vice President/General Counsel *Al Mouncer*
Vice President, Adminsitration/Chief Financial Officer *Jerry Kucera*
Vice President, Resource Development *Jack Baker*

Then it made sense to have Plant 2 off line and refueling. The plant simply couldn't compete with hydropower during the spring runoff.

The situation is different now, for three reasons. First, efforts to restore runs of endangered salmon have dramatically altered the way hydroelectric dams are operated. More water for fish means less water to run turbines.

Second, the booming Northwest economy has caught up with the power surplus the region has enjoyed for the past two decades: Utilities that a few years ago were turning away from BPA and looking for lower-cost suppliers are now flocking back to the federal marketing agency.

Third, the incremental cost to Bonneville of running Plant 2 — the cost for fuel, generation taxes and contributions to the federal spent fuel fund — are about a half-cent a kilowatt-hour. In the spring of 1999, Bonneville could have realized millions of dollars in additional revenue if Plant 2 had been operating.

Plant 2 was not refueled this spring for the first time in its 15-year operating history. The plant was shut down, not for refueling, but to conserve fuel to meet the high power demand in the summer. Refueling was put off until September, when enough fuel was loaded in the reactor to run the plant non-stop until the spring of 2001.

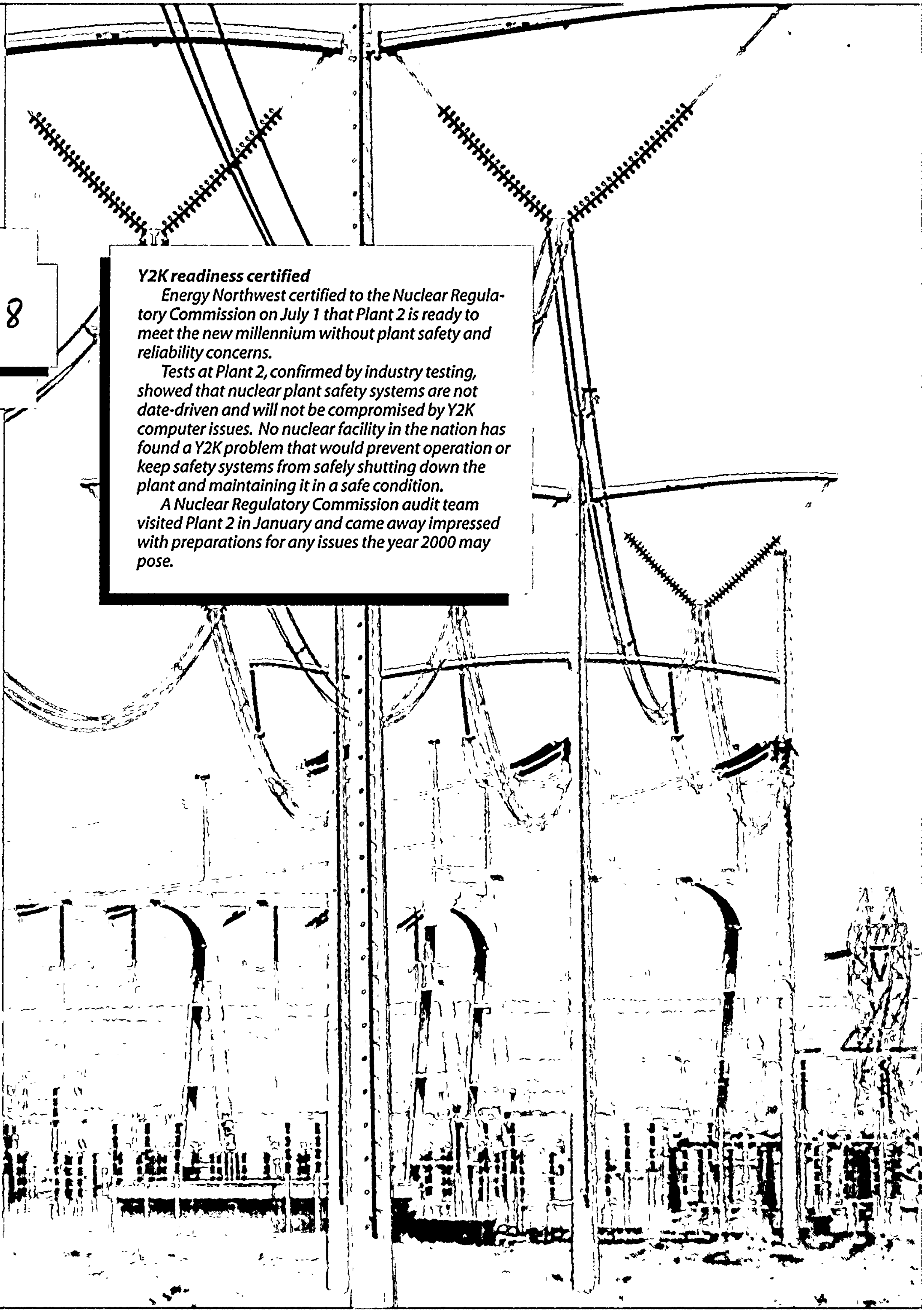
Changing to a 24-month refueling cycle will increase fuel costs somewhat, but the expense will be relatively small compared to the benefits. And Plant 2 already has among the lowest fuel costs in the industry. Last year Energy Northwest had the lowest costs for conversion and enrichment services and beat out all other boiling water reactors in its cost for fuel fabrication services.

Moving to a 24-month fuel cycle is expected to save between $100 million and $120 million over the life of Plant 2. The transition will cost about $22 million but, if Plant 2 skips an outage every other spring, the yearly average price for its power is likely to drop because the plant will generate more electricity over the two-year period. And, by skipping every other outage, Plant 2 will save about $15 million for each one missed.

Another initiative that is expected to help reduce the cost of power from Plant 2 is a plan to partner with the Omaha Public Power District (OPPD) to establish a service company that will use shared resources to provide centralized support functions to Plant 2 and OPPD's Fort Calhoun Station.

The objective of the service company is to lower costs by identifying efficiencies and sharing common services with OPPD's 514 megawatt pressurized water reactor located about 25 miles north of Omaha, Nebraska.

Plant 2 has come a long way in its pursuit of excellence. It has developed into a valued resource that is a counterpoint to the Pacific Northwest's traditional reliance on low-cost hydroelectric dams.



Y2K readiness certified

Energy Northwest certified to the Nuclear Regulatory Commission on July 1 that Plant 2 is ready to meet the new millennium without plant safety and reliability concerns.

Tests at Plant 2, confirmed by industry testing, showed that nuclear plant safety systems are not date-driven and will not be compromised by Y2K computer issues. No nuclear facility in the nation has found a Y2K problem that would prevent operation or keep safety systems from safely shutting down the plant and maintaining it in a safe condition.

A Nuclear Regulatory Commission audit team visited Plant 2 in January and came away impressed with preparations for any issues the year 2000 may pose.

ENERGY NORTHWEST

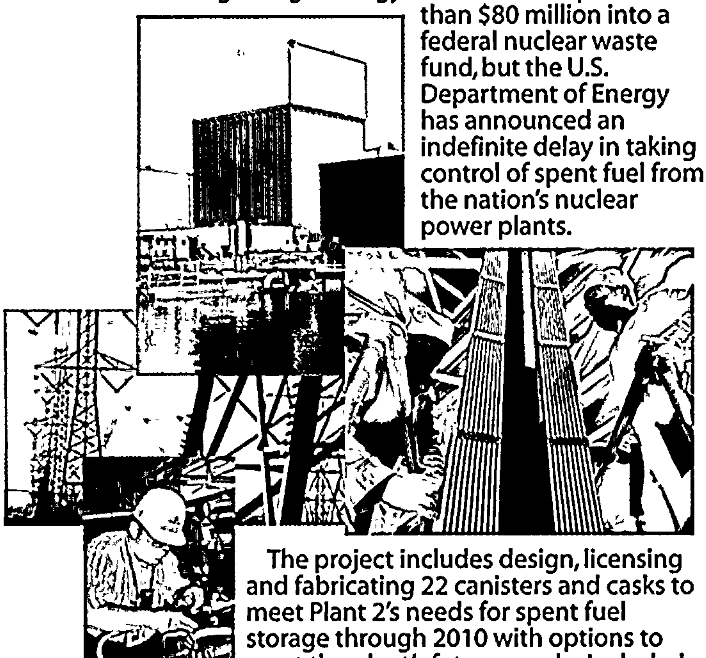
Energizing the new Millennium

Energy Northwest's Y2K readiness team spent about $6 million over two years testing and updating plant systems to ensure they were Y2K ready. Overall, Energy Northwest spent about $17 million on testing and upgrades. One benefit to this effort was upgrades made to application systems, including moving from a mainframe to a client-server environment.

Spent fuel storage contract signed

Energy Northwest's Executive Board approved a $25 million contract in May for a spent nuclear fuel dry-storage system to Holtec, International. The contract provides for the design, licensing, fabrication, and furnishing of an independent spent fuel storage installation.

Plant 2 is expected to run out of storage space in its spent fuel storage pool, located on the top floor of the Reactor Building, after its spring 2003 refueling outage. Energy Northwest has paid more than $80 million into a federal nuclear waste fund, but the U.S. Department of Energy has announced an indefinite delay in taking control of spent fuel from the nation's nuclear power plants.



The project includes design, licensing and fabricating 22 canisters and casks to meet Plant 2's needs for spent fuel storage through 2010 with options to meet the plant's future needs. Included are auxiliary equipment for loading, sealing and moving the canisters and casks to the storage site, and engineering support for required storage site evaluation.

Regulatory reform becoming a reality

The Nuclear Regulatory Commission has made substantial strides towards regulatory reform.

A major element in the reform is a change to the enforcement policy to expand use of non-cited violations at nuclear power plants. Under the new policy, which went into effect in March, most instances of non-compliance that in the past would have been treated as level IV violations are instead treated as non-cited violations, provided the licensee takes corrective actions.

Packwood Hydroelectric Project goes green

Energy Northwest's 27-megawatt Packwood Lake Hydroelectric Project is one of three regional generating projects marketed as "green power" by the Bonneville Power Administration on behalf of its Environmental Foundation.

The foundation is made up of the Renewable Northwest Project, the Northwest Energy Coalition, and the National Resource Defense Council. The environmental groups have teamed with Bonneville in a unique arrangement to market "green power" from Packwood, the Idaho Falls Hydroelectric Project and a Wyoming wind farm.

Northwest consumers voluntarily pay a premium for this green power, with most of the extra revenue going to the foundation to finance future environmental projects. If all the output from Packwood is sold by BPA as "green," the foundation stands to gain about $750,000 a year. Energy Northwest and its Packwood participants stand to gain up to $300,000 a year.

Another benefit to Packwood may come down the road. The project is up for relicensing in 2010. The recognition of Packwood as environmentally friendly could pay future dividends during the relicensing process.

Applied Process Engineering Laboratory

The Applied Process Engineering Laboratory (APEL) celebrated its first anniversary in April. The $6 million lab, located in a former Energy Northwest warehouse in Richland, exceeded projections for tenants and revenue in its first year.

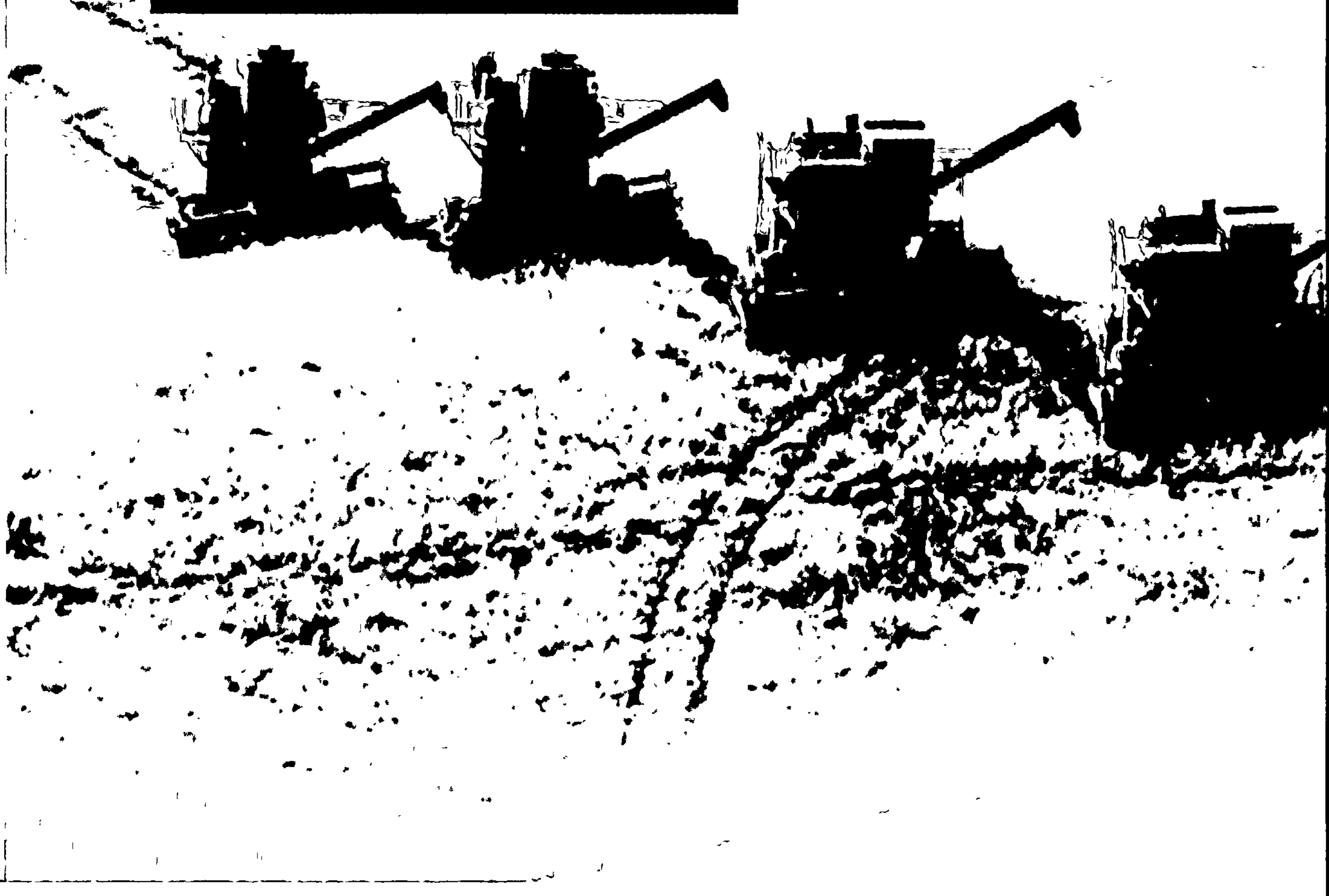
The lab is the only high-tech business incubator of its kind in North America. It will create jobs in the Northwest and address some of the most vexing environmental problems facing the planet, such as disposal of toxic wastes. APEL is a joint venture of Energy Northwest, the Port of Benton, the City of Richland, the Pacific Northwest National Laboratory, the U.S. Department of Energy and others.

After a year of operation, APEL hosts a diverse array of technologies, from a waste vitrification pilot plant to chemical warfare detection devices to a robotic arm used to remove debris from underground nuclear waste storage tanks.

Hometown Connections

To expand into the energy services industry, Energy Northwest last year became a marketing affiliate of Hometown Connections, a subsidiary of the American Public Power Association. Hometown Connections is a collection of services designed to make local public power retailing utilities more competitive by using combined buying power to leverage better arrangements from vendors. Energy Northwest is marketing such services and products as customer surveys, customer information software, advanced meter-reading products, surge protection, workshops and energy services.

Energy Northwest is selling a wide variety of products and services offered by APPA's subsidiary directly to its 13 member utilities and other public power systems in the Northwest. Hometown Connections uses the market leverage of the nation's 2,000 public power systems to negotiate better financial and service arrangements from vendors than utilities can obtain on their own.



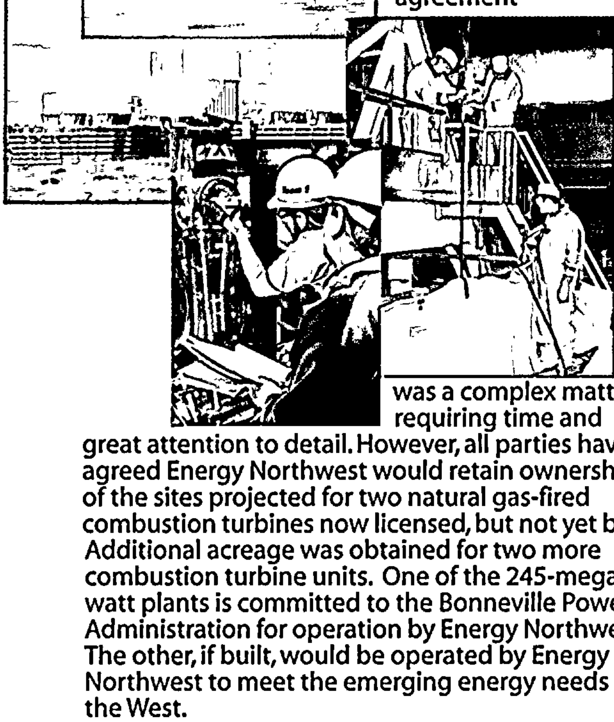
ENERGY NORTHWEST

Expanding our Horizons

Satsop Redevelopment Project

Energy Northwest continues to work with the Satsop Redevelopment Project (SRP) following the transfer of most of the assets and real estate associated with terminated Nuclear Projects 3 and 5 for economic development in Grays Harbor County, in coastal Washington State.

The Bonneville Power Administration provided about $25 million to take over the site. That is far less than if Energy Northwest had retained ownership and was required, under terms of its Energy Facility Site Evaluation Council license, to return the site to its natural state. In return, the SRP assumed liability for the site. Because of the complex nature of past ownership contracts, reaching a transfer agreement was a complex matter, requiring time and great attention to detail. However, all parties have agreed Energy Northwest would retain ownership of the sites projected for two natural gas-fired combustion turbines now licensed, but not yet built. Additional acreage was obtained for two more combustion turbine units. One of the 245-megawatt plants is committed to the Bonneville Power Administration for operation by Energy Northwest. The other, if built, would be operated by Energy Northwest to meet the emerging energy needs of the West.



Benton Redevelopment Initiative

The feasibility of a similar arrangement is being investigated for Energy Northwest's terminated Nuclear Projects 1 and 4 in Benton County in southeast Washington. The Port of Benton, Benton County, Benton County Public Utility District and the City of Richland have banded together to assess the economic development potential of the project site.

Energy Northwest is supporting this initiative, both for its potential to stimulate the local economy by attracting industry to the project site, and because of the substantial cost of site restoration. A 1995 site restoration plan, updated in June, estimates that WNP-1/4 site restoration costs could run as high as $100 million. This cost would be included in the Bonneville Power Administration's rates and would be borne by the region's electric ratepayers.

New Business Initiatives

Energy Northwest is pursuing several new business initiatives to diversify the organization as well as reduce the costs of operating Plant 2.

A contract was signed this spring with a contractor on the U.S. Department of Energy's Hanford Site to provide instrument calibration services that will mean about $1 million in new business for the utility. Other new business initiatives being investigated include:

- Supporting the development and deployment of new cost-effective renewable energy technologies, including a wind project to provide green power to regional utilities;
- Supporting development and deployment of new cost effective distributed generation technologies, including establishing a Center for Energy Innovation in Renewable and Distributed Generation Technologies to provide financial, technical and business planning support to clients with new technologies;
- Developing new or acquiring existing thermal generation projects to benefit members and other public power entities;
- Providing hydroelectric facility engineering, technical, modification and maintenance services to the Federal Columbia River Power System and public power agencies in the Northwest; and
- Participating in the development and operation of a public power/public purpose communications network serving a variety of needs across the Northwest by making use of the dark fiber that Bonneville has built on 2,000 miles of its transmission system.

(left to right)

Robert Graves (President)
Commissioner, Benton County PUD

Darrel Bunch (Assistant Secretary)
Commissioner, Okanogan County PUD

Board of Directors

Charles Buennagel
Commissioner, Wahkiakum County PUD

James Todd (Alternate)
Seattle City Light

Beverley Cochrane (Vice President)
Commissioner, Franklin County PUD

Roger Sparks
Commissioner, Kittitas County PUD

Vera Claussen (Secretary)
Commissioner, Grant County PUD

Dan Gunkel
Commissioner, Klickitat County PUD

Don Carter
Deputy City Manager for Utilities and Physical Services,
City of Richland

Parker Knight
Commissioner, Skamania County PUD

Dale Bly (Alternate)
Commissioner, Ferry County PUD

Tom Casey
Commissioner, Grays Harbor County PUD

Not pictured: ***Mark Crisson***
Director of Utilities, Tacoma Power

. *FINANCIAL OPERATING HIGHLIGHTS*

For the year ending June 30, 1999 *(Dollars in millions)*

OPERATING STATISTICS

NUCLEAR PROJECT NO. 2

	FY 1999	*FY 1998*	*FY 1997*	*FY 1996*	*FY 1995*
Total production costs*	$ 111.4	$ 119.1	$ 119.5	$ 133.3	$ 139.9
Net generation (millions of kWh)**	6,975.0	7,502.0	6,965.3	7,703.6	6,942.7
Cost in cents/kWh*	1.60	1.59	1.72	1.73	2.02
Plant availability***	76.3%	77.9%	83.7%	79.7%	75.0%
Plant capacity****	71.9%	71.9%	60.0%	61.3%	67.9%
Regional cost of power cents/kWh*****	2.26	2.20	2.46	2.56	3.34

PACKWOOD LAKE PROJECT

	FY 1999	*FY 1998*	*FY 1997*	*FY 1996*	*FY 1995*
Total production costs*	$ 0.2	$ 0.3	$ 0.4	$ 0.1	$ 1.0
Net generation (millions ofkWh)	89.8	98.4	123.1	125.4	60.7
Cost in cents/kWh*	.23	.25	.33	.09	1.63
Plant availability***	91.4%	92.2%	88.5%	90.1%	60.0%
Plant capacity****	37.3%	37.4%	51.9%	51.9%	22.9%

INVESTMENT PERFORMANCE	*FY 1999*	*FY 1998*	*CHANGE*
Income	$ 39.9	$ 41.8	- 4.5%
Average Balance	$ 659.0	$ 627.6	+ 5.0%
Rate of Return	6.05%	6.65%	- 9.0%

BONDS OUTSTANDING

	FY 1999	*FY 1998*	*CHANGE*
PROJECT -1 fixed	$ 2,081.9	$ 2,137.3	-2.6%
weighted average	5.8%	5.8%	0.0%
variable	$ 134.5	$ 138.7	-3.0%
average rate	3.2%	3.6%	-11.1%
PROJECT-2 fixed#	$ 2,207.8	$ 2,335.1	-5.5%
weighted average##	5.6%	5.6%	0.0%
variable	$ 120.9	120.9	0.0%
average rate	3.2%	3.7%	-13.5%
PROJECT-3 fixed #	$ 1,573.1	$ 1,605.6	-2.0%
weighted average##	5.7%	5.7%	0.0%
variable	$ 184.9	$ 185.6	-0.4%
average rate	3.2%	3.6%	-11.1%
PACKWOOD			
fixed	$ 6.3	$ 6.7	-6.0%
weighted average	3.7%	3.7%	0.0%

\# *Excludes compound interest bonds accretion.*

\## *Excludes compound interest bonds.*

* *Includes operating, maintenance, and fuel amortization costs per FERC report.*

** *Includes BPA economic dispatch generation (millions of kWh) credit of 0; 532; 1,150.9; 1,759.2; and 480 in FY 1999, FY 1998, FY 1997, FY 1996 and FY 1995, respectively.*

*** *Plant availability is defined as the ratio of the sum of source hours and reserve shut down hours to total period hours.*

**** *Plant capacity factor is the ratio of the actual energy production over a given period of time to the maximum energy production capability.*

***** *Regional cost of power uses a broader measure of cost and is primarily used by BPA and the Supply System to evaluate cost competitiveness.*

MANAGEMENT REPORT ON
RESPONSIBILITY FOR FINANCIAL REPORTING

The management of Energy Northwest is responsible for preparing the accompanying financial statements and for their integrity. The statements were prepared in accordance with generally accepted accounting principles applied on a consistent basis, and include amounts that are based on management's best estimates and judgments.

The financial statements have been audited by PricewaterhouseCoopers LLP, Energy Northwest's independent accountants. Management has made available to PricewaterhouseCoopers LLP all financial records and related data, and believes that all representations made to PricewaterhouseCoopers LLP during its audit were valid and appropriate.

Management has established and maintains internal control procedures that provide reasonable assurance as to the integrity and reliability of the financial statements, the protection of assets from unauthorized use or disposition, and the prevention and detection of fraudulent financial reporting. These control procedures provide for appropriate division of responsibility and are documented by written policies and procedures.

Energy Northwest maintains an ongoing internal auditing program that provides for independent assessment of the effectiveness of internal controls, and for recommendations of possible improvements thereto. In addition, PricewaterhouseCoopers LLP has considered the internal control structure in order to determine their auditing procedures for the purpose of expressing an opinion on the financial statements. Management has considered recommendations made by the internal auditor and PricewaterhouseCoopers LLP concerning the control procedures and has taken appropriate action to respond to the recommendations. Management believes that, as of June 30, 1999, internal control procedures are adequate.

J. Vic Parrish
Chief Executive Officer

G.J. Kucera
Vice President, Administration/
Chief Financial Officer

AUDIT, LEGAL AND FINANCE COMMITTEE
CHAIRMAN'S LETTER

The Executive Board's Audit, Legal and Finance Committee is composed of five independent directors. Members of the Committee are John F. Cockburn, Chairman; Rudi Bertschi; Vera Claussen; Roger Sparks; and Louis Winnard, Ex Officio. The Committee held 12 meetings during the fiscal year ended June 30, 1999.

The Committee oversees Energy Northwest's financial reporting process on behalf of the Executive Board. In fulfilling its responsibility, the Committee discussed with the internal auditor and the independent accountants, the overall scope and specific plans for their respective audits, and reviewed Energy Northwest's financial statements and the adequacy of Energy Northwest's internal controls.

The Committee met regularly with Energy Northwest's internal auditor and independent accountants to discuss the results of their examinations, their evaluations of Energy Northwest's internal controls, and the overall quality of Energy Northwest's financial reporting. The meetings were designed to facilitate any private communication with the Committee desired by the internal auditor or independent accountants.

John F. Cockburn
Chairman, Audit, Legal and Finance Committee

Report of Independent Accountants

To the Executive Board of
Energy Northwest

In our opinion, the accompanying individual balance sheets and related statements of operations and comprehensive income and of cash flows present fairly, in all material respects, the financial position of Energy Northwest Nuclear Project No. 1, Nuclear Project No. 2, Nuclear Project No. 3 and Packwood Hydroelectric Project at June 30, 1999, and the results of each of their operations and each of their cash flows for the year then ended in conformity with generally accepted accounting principles. These financial statements are the responsibility of Energy Northwest's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with generally accepted auditing standards, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for the opinion expressed above.

The Year 2000 information, shown as required supplementary information on page 35, is not a required part of the basic financial statements but is supplementary information required under Technical Bulletin 98-1, as amended, issued by the Governmental Accounting Standards Board, and we did not audit and do not express an opinion on such information. Further, we were unable to apply to the information certain procedures prescribed by professional standards because the disclosure criteria specified by Technical Bulletin 98-1, as amended, are not sufficiently specific and, therefore, preclude the prescribed procedures from providing meaningful results. In addition, we do not provide assurance that the Projects are or will become year 2000 compliant, that the Projects' year 2000 remediation efforts will be successful in whole or in part, or that parties with which the Projects do business are or will become year 2000 compliant.

PricewaterhouseCoopers LLP

Portland, Oregon
September 10, 1999

BALANCE SHEETS

As of June 30, 1999 *(Dollars in thousands)*

	NUCLEAR PROJECT NO.2	PACKWOOD LAKE PROJECT	NUCLEAR PROJECT NO.1#	NUCLEAR PROJECT NO.3#
ASSETS				
UTILITY PLANT (NOTE B)				
In service	$ 3,465,569	$ 12,895		$ 1,047
Allowance for depreciation	(1,520,069)	(10,865)		(504)
	1,945,500	2,030		543
Nuclear fuel, net of accumulated amortization	123,924			
Construction work in progress	7,931			
	2,077,355	2,030		543
RESTRICTED ASSETS (NOTE B)				
Special funds				
Cash	2,916	4	$ 2,704	2,957
Available-for-sale investments	28,248	295	80,246	18,312
Accounts and other receivables	62,642		363	13
Due from other projects			1,819	
Prepayments and other			9	
Debt service funds				
Cash	49	10	205	501
Available-for-sale investments	146,745	756	203,452	181,932
Other receivables	1,585		1,030	1,096
	242,185	1,065	289,828	204,811
LONG-TERM RECEIVABLES (NOTE B)	30,070			
CURRENT ASSETS				
Cash	331	2	921	77
Available-for-sale investments	33,614	505	21,237	17,324
Accounts and other receivables	7,336	325	8	24
Due from participants	180		51	72
Due from other projects	2,575	181	9	1,574
Due from other funds	24,589	45	24,781	16,885
Materials and supplies	58,296			
Prepayments and other	959	31		74
Nuclear fuel held for sale			9,304	
Plant & equipment held for sale			9,515	
	127,880	1,089	65,826	36,030
DEFERRED CHARGES				
Costs in excess of billings		3,018	1,933,882	1,675,059
Unamortized debt expense	15,679	5	19,561	14,462
Other deferred charges	1			
	15,680	3,023	1,953,443	1,689,521
TOTAL ASSETS	$ 2,493,170	$ 7,207	$ 2,309,097	$ 1,930,905

 # Project recorded on a liquidation basis

See notes to financial statements

BALANCE SHEETS

As of June 30, 1999 (Dollars in thousands)

	NUCLEAR PROJECT NO.2	PACKWOOD LAKE PROJECT	NUCLEAR PROJECT NO.1#	NUCLEAR PROJECT NO.3#
LIABILITIES				
BILLINGS IN EXCESS OF COSTS	$ 27,625			
UNREALIZED INVESTMENT LOSSES	(287)		$ (1,206)	$ (357)
LONG-TERM DEBT (NOTE E)				
Revenue bonds payable	2,254,875	$ 6,016	2,216,430	2,159,635
Unamortized discount on bonds - net	(33,373)	(20)	(9,678)	(284,154)
Unamortized loss on bond refundings	(53,954)		(61,151)	(20,413)
	2,167,548	5,996	2,145,601	1,855,068
LIABILITIES- PAYABLE FROM RESTRICTED ASSETS (NOTE B)				
Special funds				
Accounts payable and accrued expenses	66,124	8	76,679	4,078
Due to other funds	22,438	12	19,875	15,290
Debt service funds				
Accrued interest payable	378	77	61,134	42,594
Due to other funds	2,151	33	4,906	1,595
	91,091	130	162,594	63,557
OTHER NONCURRENT LIABILITIES	8,368	5		
CURRENT LIABILITIES				
Current maturities of long-term debt	142,630	310		
Accounts payable and accrued expenses	49,137	141		12,182
Due to participants	1,616	577	1,392	455
Due to other projects	5,442		716	
	198,825	1,028	2,108	12,637
DEFERRED CREDITS				
Deferred gain on redemption of revenue bonds		48		
		48		
COMMITMENTS AND CONTINGENCIES (NOTE F)				
TOTAL LIABILITIES	$ 2,493,170	$ 7,207	$ 2,309,097	$ 1,930,905

STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

For the year ended June 30, 1999 (Dollars in thousands)

	NUCLEAR PROJECT NO.2	PACKWOOD LAKE PROJECT	NUCLEAR PROJECT NO.1 #	NUCLEAR PROJECT NO.3 *#
OPERATING REVENUES	$ 401,980	$ 1,185		
OPERATING EXPENSES				
Nuclear fuel	23,978			
Fuel disposal fee	6,613			
Decommissioning	10,299			
Depreciation and amortization	105,212	348		
Operations and maintenance	95,354	566		
Administrative & general	27,437	91		
Generation tax	2,442	19		
Total operating expenses	271,335	1,024		
NET OPERATING REVENUES	130,645	161		
OTHER INCOME & EXPENSE				
Non-operating revenues			$ 139,319	$ 99,553
Investment income	16,077	63	13,753	10,375
Gain/(loss) on current bond redemption	(924)	17		(376)
Interest expense and discount amortization	(144,525)	(241)	(134,310)	(111,199)
Plant preservation and termination costs			(5,145)	(18,956)
Site Restoration			(13,800)	25,500
Write off assets and liabilities			29	(5,241)
Write off MOX Fuel	(763)			
Fuel settlement cost recovery	13		193	
Joint owners' share of costs				176
Other	(523)		(39)	168
NET REVENUES	$ 0	$ 0	$ 0	$ 0
OTHER COMPREHENSIVE INCOME:**				
Net revenue	$ 0	$ 0	$ 0	$ 0
Unrealized holding investment losses arising during period	(611)		(1,206)	(358)
TOTAL COMPREHENSIVE INCOME (LOSS)	$ (611)	$ 0	$ (1,206)	$ (358)

* *Energy Northwest's ownership share (Note A)*

** *As described in Note B*

Project recorded on a liquidation basis

See notes to financial statements

STATEMENTS OF CASH FLOWS

For the year ended June 30, 1999 *(Dollars in thousands)*

	NUCLEAR PROJECT NO.2	PACKWOOD LAKE PROJECT	NUCLEAR PROJECT NO.1 #	NUCLEAR PROJECT NO.3 * #
CASH FLOWS FROM OPERATING AND OTHER ACTIVITIES				
Net operating revenues	$ 130,645	$ 161		
Adjustments to reconcile net operating revenues to cash provided by operating activities:				
Cash received in excess of costs	24,120	(330)		
Depreciation and amortization	127,647	346		
Decommissioning	6,773			
Other	(509)			
Change in operating assets and liabilities:				
Accounts receivable	(673)	(229)		
Materials and supplies	(1,069)			
Prepaid and other assets	(69)			
Due from/to other projects, funds and participants	8,949	947		
Accounts payable	(6,082)	93		
Non-operating revenue receipts			$ 181,128	$ 168,893
Cash payments for preservation and termination expenses			(877)	(13,989)
Cash payments for other expenses				217
Net cash provided by operating and other activities	289,732	988	180,251	155,121
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES				
Payment for bond issuance and financing costs	(548)		(855)	(190)
Hanford Generating Project funds transferred to NP-1			9,612	
Capital and nuclear fuel acquisitions	(25,279)			
Cash payments for deferred programs	(121)			
Interest paid on revenue bonds	(132,375)	(241)	(127,491)	(86,227)
Principal paid on revenue bond maturities	(131,965)	(383)	(59,490)	(34,036)
Net cash used by capital and related financing activities	(290,288)	(624)	(178,224)	(120,453)
CASH FLOWS FROM INVESTING ACTIVITIES				
Purchases of investment securities	(1,147,762)	(5,976)	(802,926)	(618,413)
Sales of investment securities	1,133,298	5,553	785,494	576,267
Interest on investments	16,482	60	13,507	9,766
Receipts from sales of plant assets			193	654
Net cash provided(used) by investing activities	2,018	(363)	(3,732)	(31,726)
NET INCREASE(DECREASE) IN CASH	1,462	1	(1,705)	2,942
CASH AT JUNE 30, 1998	1,834	15	5,535	593
CASH AT JUNE 30, 1999 (NOTE B)	$ 3,296	$ 16	$ 3,830	$ 3,535

* *Energy Northwest's ownership share (Note A)*

\# *Project recorded on a liquidation basis*

See notes to financial statements

OUTSTANDING LONG-TERM DEBT

As of June 30, 1999 (Dollars in Thousands)

SERIES	COUPON RATE	SERIAL OR TERM MATURITIES	AMOUNT
NUCLEAR PROJECT NO. 2 REFUNDING REVENUE BONDS			
1990A	7.25%	7-1-2006	$ 35,790
1990C	7.00-7.50	7-1-2000/2002	122,260
	(A)	7-1-2004/2005	18,054
			140,314
1991A	6.25-6.60	7-1-2000/2004	90,415
	(A)	7-1-2006/2007	13,431
			103,846
1992A	5.45-6.30	7-1-2000/2009	129,785
	6.25	7-1-2012	14,525
	6.30	7-1-2012	50,000
	(A)	7-1-2010	1,359
			195,669
1993A	5.10-6.00	7-1-2000/2010	165,810
	5.75	7-1-2012	42,105
			207,915
1993B	5.00-5.65	7-1-2000/2008	86,295
	5.55	7-1-2010	51,000
	5.625	7-1-2012	43,455
			180,750
1994A	4.30-6.00	7-1-2000/2011	524,835
	5.40	7-1-2012	100,200
	(A)	7-1-2009	4,776
			629,811
1996A	5.00-6.00	7-1-2000/2012	205,630
1997A	5.00-6.00	7-1-2000/2012	204,095
1997B	5.00-5.50	7-1-2000/2011	74,925
1998A	4.50-5.75	7-1-2000/2012	229,115

(A) Compound interest bonds

(B) Excludes amounts due July 1, 1999 which were paid as of June 30, 1999

(C) Includes amounts due July 1, 1999

(D) The estimated fair value shown has been reported to meet the disclosure requirements of Statement of Financial Accounting Standards (SFAS) 107 and does not purport to represent the amounts at which these obligations would be settled

OUTSTANDING LONG-TERM DEBT

As of June 30, 1999 (Dollars in Thousands)

SERIES	COUPON RATE	SERIAL OR TERM MATURITIES	AMOUNT	
NUCLEAR PROJECT NO. 2 REFUNDING REVENUE BONDS (Continued)				
1997-2A-1,2	Variable	7-1-2000/2012	$ 120,865	
Compound interest bonds accretion			68,780	
Revenue bonds payable			$ 2,397,505	(B)
Estimated fair value at June 30, 1999			$ 2,545,418	(D)
PACKWOOD LAKE PROJECT REVENUE BONDS				
1962	3.625%	3-1-2012	$ 4,791	
1965	3.75	3-1-2012	1,535	
Revenue bonds payable			$ 6,326	
Estimated fair value at June 30, 1999			$ 5,968	(D)
NUCLEAR PROJECT NO. 1 REFUNDING REVENUE BONDS				
1989A	7.10-7.30	7-1-1999/2001	$ 10,380	
1989B	7.00-7.15	7-1-1999/2001	14,855	
	7.125	7-1-2016	41,070	
			55,925	
1990A	7.25-7.50	7-1-1999/2002	27,690	
1990B	7.00-7.20	7-1-1999/2003	24,495	
	7.25	7-1-2009	72,770	
			97,265	
1990C	7.25-7.75	7-1-1999/2003	95,765	
1991A	6.20-6.60	7-1-1999/2004	22,080	
1992A	5.30-6.25	7-1-1999/2007	13,140	
	6.25	7-1-2017	68,015	
			81,155	

(A) Compound interest bonds
(B) Excludes amounts due July 1, 1999 which were paid as of June 30, 1999
(C) Includes amounts due July 1, 1999
(D) The estimated fair value shown has been reported to meet the disclosure requirements of SFAS 107 and does not purport to represent the amounts at which these obligations would be settled

OUTSTANDING LONG-TERM DEBT

As of June 30, 1999 (Dollars in Thousands)

SERIES	COUPON RATE	SERIAL OR TERM MATURITIES	AMOUNT
NUCLEAR PROJECT NO. 1 REFUNDING REVENUE BONDS (Continued)			
1993A	4.75-7.00%	7-1-1999/2008	$ 162,710
	5.75	7-1-2011	80,000
	6.05	7-1-2012	35,705
	5.75	7-1-2013	37,970
	5.70	7-1-2017	176,180
			492,565
1993B	4.75-7.00	7-1-1999/2010	74,030
	5.60	7-1-2015	94,885
			168,915
1993C	4.25-5.30	7-1-1999/2010	19,505
	5.40	7-1-2012	66,400
	5.375	7-1-2015	75,650
			161,555
1993-1A-1,2,3	Variable	7-1-1999/2017	134,505
1996A	5.00-6.00	7-1-1999/2012	351,890
1996B	5.00-6.00	7-1-1999/2005	29,970
1996C	5.00-6.00	7-1-1999/2015	90,460
	5.50	7-1-2017	24,860
			115,320
1997A	4.75-6.00	7-1-1999/2008	20,905
1997B	5.00-5.125	7-1-1999/2017	255,990
1998A	4.50-5.75	7-1-1999/2017	94,555
Revenue bonds payable			$ 2,216,430 (C)
Estimated fair value at June 30, 1999			$ 2,285,305 (D)

(A) Compound interest bonds

(B) Excludes amounts due July 1, 1999 which were paid as of June 30, 1999

(C) Includes amounts due July 1, 1999

(D) The estimated fair value shown has been reported to meet the disclosure requirements of SFAS 107 and does not purport to represent the amounts at which these obligations would be settled

OUTSTANDING LONG-TERM DEBT

As of June 30, 1999 (Dollars in Thousands)

SERIES	COUPON RATE	SERIAL OR TERM MATURITIES	AMOUNT
NUCLEAR PROJECT NO. 3 REFUNDING REVENUE BONDS			
1989A	7.10-7.30%	7-1-1999/2001	$ 10,070
	(A)	7-1-2003/2014	18,668
			28,738
1989B	7.00-7.15	7-1-1999/2001	56,125
	(A)	7-1-2004/2014	70,580
	7.125	7-1-2016	76,145
	5.50	7-1-2017	62,560
	5.50	7-1-2018	65,905
			331,315
1990B	7.20-7.25	7-1-1999/2000	48,200
	(A)	7-1-2001/2010	38,685
	7.375	7-1-2004	55,920
			142,805
1991A	6.20-6.60	7-1-1999/2004	24,775
1993B	4.75-7.00	7-1-1999/2010	114,755
	5.625	7-1-2012	28,295
	5.60	7-1-2015	49,095
	5.60	7-1-2017	37,795
	5.70	7-1-2018	20,605
			250,545
1993C	4.25-7.50	7-1-1999/2010	155,265
	5.40	7-1-2012	105,000
	(A)	7-1-2013/2018	25,248
	5.375	7-1-2015	188,335
	5.50	7-1-2018	20,805
			494,653
1993-3A-3	Variable	7-1-1999/2018	25,420
1996A	5.00-6.00	7-1-1999/2009	32,110
1997A	4.75-6.00	7-1-1999/2018	111,480
1997B	5.00	7-1-2002	4,075

(A) Compound interest bonds

(B) Excludes amounts due July 1, 1999 which were paid as of June 30, 1999

(C) Includes amounts due July 1, 1999

(D) The estimated fair value shown has been reported to meet the disclosure requirements of SFAS 107 and does not purport to represent the amounts at which these obligations would be settled

OUTSTANDING LONG-TERM DEBT

As of June 30, 1999 (Dollars in Thousands)

SERIES	COUPON RATE	SERIAL OR TERM MATURITIES	AMOUNT	
NUCLEAR PROJECT NO. 3 REFUNDING REVENUE BONDS (Continued)				
1998A	4.50-5.125%	7-1-1999/2018	$ 152,620	
1998-3A	Variable	7-1-1999/2018	159,500	
Compound interest bonds accretion			401,599	
Revenue bonds payable			$ 2,159,635	(C)
Estimated fair value at June 30, 1999			$ 2,120,028	(D)

(A) Compound interest bonds

(B) Excludes amounts due July 1, 1999 which were paid as of June 30, 1999

(C) Includes amounts due July 1, 1999

(D) The estimated fair value shown has been reported to meet the disclosure requirements of SFAS 107 and does not purport to represent the amounts at which these obligations would be settled

DEBT SERVICE REQUIREMENTS

As of June 30, 1999 (Dollars in Thousands)

FISCAL YEAR	NUCLEAR PROJECT NO. 2 PRINCIPAL	NUCLEAR PROJECT NO. 2 INTEREST	NUCLEAR PROJECT NO. 2 TOTAL	PACKWOOD LAKE PROJECT PRINCIPAL	PACKWOOD LAKE PROJECT INTEREST	PACKWOOD LAKE PROJECT TOTAL
6/30/99 Balance:*	$ -	$ 378	$ 378	$ 155	$ 77	$ 232
2000	142,630	127,427	270,057	473	226	699
2001	178,580	119,206	297,786	498	208	706
2002	96,750	108,480	205,230	524	190	714
2003	155,225	102,989	258,214	548	171	719
2004	163,609	106,211	269,820	573	151	724
Balance Through 2012	1,591,931	502,027	2,093,958	3,555	447	4,002
Adjustment **	68,780	(68,780)	0			
	$ 2,397,505	$ 997,938	$3,395,443	$ 6,326	$ 1,470	$ 7,796

FISCAL YEAR	NUCLEAR PROJECT NO. 1 PRINCIPAL	NUCLEAR PROJECT NO. 1 INTEREST	NUCLEAR PROJECT NO. 1 TOTAL	NUCLEAR PROJECT NO. 3 PRINCIPAL	NUCLEAR PROJECT NO. 3 INTEREST	NUCLEAR PROJECT NO. 3 TOTAL
6/30/99 Balance:*	$ 70,355	$ 61,134	$ 131,489	$ 66,275	$ 42,594	$ 108,869
2000	83,395	123,009	206,404	76,940	85,787	162,727
2001	84,255	118,083	202,338	74,950	86,787	161,737
2002	79,635	112,668	192,303	78,457	82,994	161,451
2003	70,280	107,709	177,989	80,057	81,837	161,894
2004	81,710	103,760	185,470	63,311	94,095	157,406
Balance Through 2017	1,746,800	788,417	2,535,217			
2018				1,318,046	944,761	2,262,807
Adjustment **				401,599	(401,599)	0
	$ 2,216,430	$ 1,414,780	$ 3,631,210	$ 2,159,635	$ 1,017,256	$ 3,176,891

* Bond Fund Account balances less accrued investment income

** Adjustment for Compound Interest Bonds accretion; Compound Interest Bonds are reflected at their face amount less discount on the balance sheet

NOTES TO FINANCIAL STATEMENTS

NOTE A - GENERAL

Organization

Energy Northwest, a municipal corporation and joint operating agency of the State of Washington, was organized in 1957. It is empowered to finance, acquire, construct and operate facilities for the generation and transmission of electric power. On June 30, 1999, its membership consisted of 10 public utility districts and the cities of Richland, Seattle, and Tacoma. All members own and operate electric systems within the State of Washington. Energy Northwest is exempt from federal income tax. Energy Northwest has no taxing authority.

Energy Northwest Projects

Energy Northwest operates Nuclear Project No. 2, a 1,153 MWe (Design Electric Rating, net) generating plant completed in 1984, and the Packwood Lake Hydroelectric Project (Packwood), a 27.5 MWe generating plant completed in 1964. Energy Northwest has obtained all permits and licenses required to operate Nuclear Project No. 2 including a Nuclear Regulatory Commission (NRC) operating license which expires in December 2023. Packwood operates under a fifty-year license from the Federal Energy Regulatory Commission (FERC) that expires on February 28, 2010.

Nuclear Project No. 1, a 1,250 MWe plant, was placed in extended construction delay status in 1982, when it was 65 percent complete. Nuclear Project No. 3, a 1,240 MWe plant, was placed in extended construction delay status in 1983, when it was 75 percent complete. On May 13, 1994, Energy Northwest's Board of Directors adopted resolutions terminating Nuclear Projects Nos. 1 and 3 (see Note F - Nuclear Projects Nos. 1 and 3 Termination). In fiscal year 1999 the assets and liabilities of Hanford Generating Project were consolidated into Nuclear Project No. 1. The Hanford Generating Project site is being restored and all funding requirements are net billed obligations of Nuclear Project No. 1. Nuclear Project No. 1 is wholly-owned by Energy Northwest. Nuclear Project No. 3 was jointly-owned, 70 percent by Energy Northwest and 30 percent by four investor-owned utilities until fiscal year 1999. In fiscal year 1999 the ownership agreements were terminated and the ownership of real and personal property interests was transferred to Energy Northwest. The financial affect of the termination of the ownership agreement was a write-off for Nuclear Project No. 3 of a $3.7 million receivable from the joint owners.

Each Energy Northwest project is financed and accounted for as a utility system separate from all other current or future projects.

All electrical energy produced by Energy Northwest projects is ultimately delivered to electrical distribution facilities owned and operated by the Bonneville Power Administration (BPA) as part of the Federal Columbia River Power System. BPA in turn distributes the electricity to electric utility systems throughout the Northwest, including participants in Energy Northwest projects, for ultimate distribution to consumers. Participants in Energy Northwest projects consist of 104 publicly-owned utilities and rural electric cooperatives located in the western United States who have entered into net-billing agreements with Energy Northwest and BPA for participation in one or more of Energy Northwest projects. BPA is obligated by law to establish rates for electric power which will recover the cost of electric energy acquired from Energy Northwest and other sources as well as BPA's other costs. See Note E, Security - Nuclear Projects Nos. 1, 2 and 3, for discussion of BPA's obligations with respect to Nuclear Projects Nos. 1, 2 and 3.

NOTE B - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

Energy Northwest has adopted accounting policies and practices that are in accordance with generally accepted accounting principles. Accounts are maintained in accordance with the uniform system of accounts of the FERC. Separate funds and books of account are maintained for each utility system. Payment of obligations of one utility system with funds of another utility system is prohibited, and would constitute violation of bond resolution covenants.

Pursuant to statement No. 20 of the Governmental Accounting Standards Board (GASB), "Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities That Use Proprietary Fund Accounting," Energy Northwest has elected to apply all Financial

Accounting Standards Board statements and interpretations except for those that conflict with or contradict GASB pronouncements. Specifically, Statement of Governmental Accounting Standard No. 7 and No. 23 conflict with Statement of Financial Accounting Standard No. 125. As such, the guidance under Statement of Governmental Accounting Standard No. 7 and No. 23 is followed. Such guidance governs the accounting for bond defeasances and refundings.

SFAS No. 130, "Reporting Comprehensive Income," defines comprehensive income during the applicable period as a change in equity of a business enterprise from transactions and other events and circumstances from nonowner sources. SFAS No. 130 requires that an enterprise report all components of comprehensive income in the period in which the enterprise recognizes these components.

Components of comprehensive income are net income and other comprehensive income. Net income includes income from continuing operations, discontinued operations, extraordinary items and cumulative effects of changes in accounting principles. Other comprehensive income includes foreign currency translations, adjustments of minimum pension liability and unrealized gains or losses on certain investments in debt and equity securities.

For the year ended June 30, 1999 Energy Northwest's only item of other comprehensive income was unrealized gains and losses on investments as detailed in Note C – Cash and Investments.

The preparation of Energy Northwest financial statements in conformity with generally accepted accounting principles necessarily requires management to make estimates and assumptions that directly affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from these estimates. Certain assets and incurred expenses are allocated to the projects based on specific allocation methods and management considers the allocation methods to be reasonable.

Utility Plant

Utility plant is stated at original cost. Plant in service is depreciated by the straight-line method over the estimated useful lives of the various classes of plant, which range from five to 40 years.

During the normal construction phase of a project, Energy Northwest's policy was to capitalize all costs relating to the project, including interest expense (net of interest income), and related administrative and general expense.

Nuclear Projects Nos. 1 and 3 have been reduced to their net realizable values due to termination. A loss on the write-down of Nuclear Projects Nos. 1 and 3 was recorded in fiscal year 1995 and is included in Cost in Excess of Billings. Plant and equipment held for sale includes management's best estimate of the net realizable value of the remaining inventories, buildings, equipment, tools, materials and consumables, common and operational spares, moveable equipment and land. Interest expense, termination expenses and asset disposition costs for Nuclear Projects Nos. 1 and 3 have been charged to operations.

Internal Service Fund assets are shared by all projects and they are allocated to each project's balance sheet based on direct labor cost incurred.

Nuclear Fuel

All expenditures related to the purchase of nuclear fuel, including interest, are capitalized and carried at cost. When the fuel is placed in the reactor, the fuel cost is amortized to operating expense on the basis of quantity of heat produced for generation of electric energy. Accumulated nuclear fuel amortization (the amortization of the cost of nuclear fuel assemblies in the reactor used in the production of energy) is $90 million as of June 30, 1999 for Nuclear Project No. 2. Current period operating expense for Nuclear Project No. 2 includes a charge for future spent nuclear fuel storage and disposal to be provided by the Department Of Energy (DOE) in accordance with the Nuclear Waste Policy Act of 1982. Current operations only includes a small charge for escalation of the clean-up of DOE enrichment facilities. The Enrichment Clean-up Assessment was costed years ago and a payable is charged when annual assessments are paid. Energy Northwest is currently planning to utilize dry cask storage until the national repository is available. No provisions have been made in fiscal year 1999 for additional storage and disposal costs which may be incurred in the future by

Energy Northwest prior to the transfer of spent fuel to DOE.

Energy Northwest has entered into an agreement to transfer enriched uranium to General Electric Company in exchange for equivalent amounts of uranium at reload enrichments in future years and usage/loan fees. Energy Northwest has transferred approximately 240,966 pounds of UF6 and 113,503 SWU of Nuclear Project No. 2 uranium. The exchange agreement has been secured by an irrevocable letter of credit issued in the amount of the replacement value of the loaned uranium product, adjusted semiannually. The cost of the loaned uranium, $19 million, is included in the carrying amount of Nuclear Project No. 2 Nuclear Fuel.

Until June 30, 2002 Nuclear Project No. 2 has an option to purchase the remaining fuel at Nuclear Project No. 1 for $9.3 million plus escalation.

Restricted Assets

In accordance with project bond resolutions, related agreements, or state law, separate restricted funds have been established for each project. The assets held in these funds are restricted for specific uses including construction, debt service, capital additions, extraordinary operation and maintenance, termination, decommissioning and workers' compensation claims.

Long-Term Receivables

Long-term receivables include minimum guaranteed amounts adjusted annually pertaining to future discounts for certain goods and services to be provided to Nuclear Project No. 2 as the result of a litigation settlement and subsequent revisions.

Decommissioning

Energy Northwest established a decommissioning fund for Nuclear Project No. 2 and moneys are being deposited each year in accordance with an established funding plan.

The NRC has issued rules to provide guidance to licensees of operating nuclear plants on decommissioning the plants at the end of each plant's operating life. In addition, in September 1998, the NRC approved and published its "Final Rule on Financial Assurance Requirements for Decommissioning Power Reactors." As provided in this rule, each power reactor licensee is required to report to the NRC the status of its decommissioning funding for each reactor or share of reactor it owns. This reporting requirement began on March 31, 1999 and reports are required every two years thereafter. Energy Northwest submitted its initial report to the NRC on March 26, 1999.

Energy Northwest's current estimate of Project 2 decommissioning costs is approximately $340 million (in 1998 dollars). This current estimate is based on the NRC minimum amount required to demonstrate reasonable financial assurance for a boiling water reactor with the power level of Project 2. The estimate continues to be based on the NRC report (NUREG-1307) revised and published annually which provides regional adjustment factors which are applied to a formula for estimating decommissioning costs that are acceptable to the NRC.

The funding plan requires annual deposits through fiscal year 2024, the estimated end of commercial operation of Nuclear Project No. 2. The plan for annual deposits calls for incremental increases of 4% per year. The plan assumes that such deposits will grow at a 2% real rate of return and that the Project will be placed in a 60 year safe storage until 2085, at which time decontamination and dismantlement will be initiated. Over the life of the fund, deposits and the earnings related to the reinvestment thereof, are expected to provide sufficient funds to cover the cash flow requirements to decommission Nuclear Project No. 2. This plan will be reexamined every year and modified to assure that the projected fund balance complies with the then current estimates and NRC requirements. Payments to the decommissioning fund have been made since January 1985, and the balance of cash and investment securities in the fund as of June 30, 1999 totaled approximately $62.6 million. Since July 1990 these amounts have been held and managed by BPA in an external decommissioning trust fund in accordance with NRC requirements. Because it is held by BPA, the balance sheet reflects a receivable from BPA for $62.6 million.

Materials and Supplies

Materials and supplies are valued at cost, using weighted-average methods.

Financing Expense, Bond Discount, and Deferred Gain and Losses

Financing expenses and bond discounts are amortized over the terms of the respective bond issues using the bonds outstanding method.

In accordance with the Statement of Governmental Accounting Standard No. 23 effective for periods after June 15, 1994, losses on debt refundings have been deferred and amortized as a component of interest expense over the shorter of the remaining life of the old or new debt. The balance sheet includes the original deferred amount less recognized amortization expense and is included as a reduction to the new debt.

Current Maturities of Revenue Bonds

Current maturities of revenue bonds payable from restricted assets are reflected in Long-Term Debt. Current maturities of bonds for which funds have not yet been restricted are reflected in Current Liabilities.

Accounts Payable

Accounts payable and accrued expenses include payroll and benefits related accruals for Nuclear Project No. 2 of \$16.6 million. Nuclear Project No. 2 includes a Personal Time Bank accrual of \$10.6 million. Packwood includes an accrual for FERC Administrative charges of \$21,600. Nuclear Project No. 2 includes an accrual for \$2.6 million for Arbitrage Rebate and \$19.2 million for operating and capital expenses.

Fair Value of Financial Instruments

The fair value of financial instruments has been estimated using available market information and certain assumptions. Considerable judgment is required in interpreting market data to develop fair value estimates and such estimates are not necessarily indicative of the amounts that could be realized in a current market exchange. The following methods and assumptions were used to estimate the fair value of each of the following financial instruments.

Financial instruments for which the carrying value is considered a reasonable approximation of fair value include: cash, accounts receivable, accounts payable and accrued expenses, other noncurrent liabilities and due to and from participants, other projects and other funds. The fair values of investments and revenue bonds payable have been estimated based on quoted market prices for such instruments or based on the fair value of financial instruments of a similar nature and degree of risk.

Revenues

Energy Northwest accounts for revenue on an accrual basis and recovers, through various agreements, actual cash requirements for operations and debt service for each project over the life of that project. Accordingly, Energy Northwest recognizes revenues equal to expenses for each period. No net income or loss is recognized, and no equity is accumulated.

The difference between cumulative billings received and cumulative expenses is recorded as either billings in excess of costs (liability) or as costs in excess of billings (asset), as appropriate. Such amounts will be recognized as revenues, or expenses, during future operating periods.

Concentration of Credit Risk

Financial instruments which potentially subject Energy Northwest to concentrations of credit risk consist of available-for-sale investments, accounts receivable, other receivables, long-term receivables and costs in excess of billings. Energy Northwest invests exclusively in U.S. Government securities and agencies. Energy Northwest's projects accounts receivable and costs in excess of billings are concentrated with project participants and BPA through the net billing agreements. See Note E, Security - Nuclear Projects Nos. 1, 2, and 3 and Security - Packwood Lake Hydroelectric Project. The long-term receivable is with a large and stable company which Energy Northwest considers to be financially strong. Other receivables are secured through the use of letters of credit and other similar security mechanisms or are with large and stable companies which Energy Northwest considers to be financially strong. As a consequence, Energy Northwest considers the exposure of the projects to concentration of credit risk to be limited.

Statements of Cash Flows

For purposes of the statements of cash flows, cash includes unrestricted and restricted cash balances. Short-term, highly liquid investments are not considered cash equivalents.

NOTE C - CASH AND INVESTMENTS

Cash and investments for each utility system are separately maintained. Energy Northwest's deposits are insured by federal depository insurance or through the Washington Public Deposit Protection Commission. Energy Northwest resolutions and investment policies limit investment authority to obligations of the United States Treasury, Federal National Mortgage Association and Federal Home Loan Banks. All investments are held for the benefit of the individual Energy Northwest projects, by safekeeping agents, custodians, or trustees.

Investments are classified as available-for-sale and are stated at fair value with unrealized gains and losses excluded from earnings and reported on the balance sheet as unrealized investment gains/(losses). Available-for-sale investments at June 30, 1999 are categorized below to give an indication of the types and amounts of investments held by each project at year end. (See table below)

AVAILABLE-FOR-SALE INVESTMENTS
(Dollars in Thousands)

	Amortized Cost	Unrealized Gains	Unrealized Losses	Fair Value
Nuclear Project No. 2				
U.S. Government Securities	$64,556	$ 318	$ <392>	$ 64,482
U.S. Government Agencies	144,638	197	<710>	144,125
Total	$209,194	$ 515	$ <1,102>	$208,607
Packwood Lake Project				
U.S. Government Securities	$ 1,556	$ 0	$ 0	$ 1,556
U.S. Government Agencies	0	0	0	0
Total	$ 1,556	$ 0	$ 0	$ 1,556
Nuclear Project No. 1				
U.S. Government Securities	$ 37,147	$ 204	$ <335>	$ 37,016
U.S. Government Agencies	268,994	86	<1,161>	267,919
Total	$306,141	$ 290	$<1,496>	$304,935
Nuclear Project No. 3				
U.S. Government Securities	$ 24,348	$ 103	$<137>	$ 24,314
U.S. Government Agencies	193,578	159	<483>	193,254
Total	$217,926	$ 262	$<620>	$217,568

	< 1 Year	1-5 Years	6-10 Years	> 10 Years	TOTAL
Nuclear Project No. 2					
U.S. Government Securities	$ 9,062	$ 26,031	$ 14,634	$ 14,755	$ 64,482
U.S. Government Agencies	$ 92,218	$ 26,769	$8,864	$ 16,274	$ 144,125
Maturities at Fair Value	$ 101,280	$ 52,800	$ 23,498	$ 31,029	$ 208,607
Packwood Lake Project					
U.S. Government Securities	$ 1,556				$ 1,556
Maturities at Fair Value	$ 1,556				$ 1,556
Nuclear Project No. 1					
U.S. Government Securities	$ 10,374	$ 24,447	$ 0	$ 2,195	$ 37,016
U.S. Government Agencies	$ 217,328	$ 38,658	$ 11,487	$ 446	$ 267,919
Maturities at Fair Value	$ 227,702	$ 63,105	$ 11,487	$ 2,641	$ 304,935
Nuclear Project No. 3					
U.S. Government Securities	$ 4,929	$ 15,430	$ 3,955	$ 0	$ 24,314
U.S. Government Agencies	$ 150,280	$ 30,866	$ 9,912	$ 2,196	$ 193,254
Maturities at Fair Value	$ 155,209	$ 46,296	$ 13,867	$ 2,196	$ 217,568

•NOTE D - RETIREMENT BENEFITS

Substantially all full-time and qualifying part-time employees participate in one of the following statewide retirement systems administered by the Washington State Department of Retirement Systems, under cost-sharing multiple-employer defined benefit public employee retirement plans. The Department of Retirement Systems (DRS), a department within the primary government of the State of Washington, issues a publicly available comprehensive annual financial report (CAFR) that includes financial statements and required supplementary information for each plan. The DRS CAFR may be obtained by writing to: Department of Retirements Systems, Administrative Services Division, P.O. Box 48380, Olympia. WA 98504-8380. The following disclosures are made pursuant to GASB Statement No. 27, Accounting for Pensions by State and Local Government Employers.

Public Employee's Retirement System (PERS)
Plans 1 and 2

Plan Description

PERS is a cost-sharing multiple-employer defined benefit pension plan. Membership in the plan includes: elected officials; state employees; employees of the Supreme, Appeals, and Superior courts (other than judges in a judicial retirement system); employees of legislative committees' college and university employees not in national higher education retirement programs; judges of district and municipal courts; non-certificated employees of school districts; and employees of local government. The PERS system includes two plans. Participants who joined the system by September 30, 1977 are Plan 1 members. Those joining thereafter are enrolled in Plan 2. Retirement benefits are financed from employee and employer contributions and investment earnings. Retirement benefits in both Plan 1 and Plan 2 are vested after completion of five years of eligible service.

Plan 1 members are eligible for retirement at any age after 30 years of service, or at age 60 with five years of service, or at age 55 with 25 years of service. The annual pension is two percent of the average final compensation per year of service, capped at 60 percent. If qualified, after reaching age 66 a cost-of-living allowance is granted based on years of service credit and is capped at three percent annually.

Plan 2 members may retire at age 65 with five years of service, or at age 55 with 20 years of service, with an allowance of two percent per year of service of the average final compensation. Plan 2 retirements prior to 65 are actuarilly reduced. There is no cap on years of service credit and a cost-of-living allowance is granted, capped at three percent annually.

Funding Policy

Each biennium, the state Pension Funding Council adopts Plan 1 employer contribution rates needed to fully amortize the total costs of the plan. Employee contribution rates for Plan 1 are established by statue at six percent and do not vary from year to year. The employer and employee contribution rates for Plan 2 are set by the director of the Department of Retirement Systems based on recommendations by the Office of the State Actuary to continue to fully fund the plan. All employers are required to contribute at the level established by state law. The methods used to determine the contribution rates are established under state statute in accordance with chapters 41.40 and 41.45 RCW.

The required contribution rates expressed as a percentage of current year covered payroll, as of June 30, 1999 were:

	PERSPlan 1	PERS Plan 2
Employer	7.32%*	7.32%*
Employee	6.00%	4.65%

*The employer rates do not include the employer administrative expense fee currently set at 0.18%.

Both Energy Northwest and the employees made the required contributions. Energy Northwest's contributions for the years ended June 30 were:

	PERSPlan 1	PERS Plan 2
1999	$718,527	$4,697,392
1998	$754,672	$4,513,332
1997	$776,582	$4,486,119

In addition to the pension benefits available through PERS, Energy Northwest offers post-employment life insurance benefits to retirees who are eligible to receive pensions under PERS Plan I and Plan II. One hundred thirty-six

retirees have elected to participate in this insurance. Energy Northwest's Board of Directors in 1994 approved provisions which continued the life insurance benefit to retirees at 25 percent of the premium for employees who retire prior to January 1, 1995 and charged the full 100 percent premium to employees who retired after December 31, 1994. The life insurance benefit is equal to the employee's annual rate of salary at retirement for non-bargaining employees retiring prior to January 1, 1995. The cost of coverage for employees who retired after January 1, 1995 is $2.33 per $1,000 of coverage. Employees who retired prior to January 1, 1995 contribute $.58 per $1,000 of coverage while the Energy Northwest pays the remainder. Premiums are paid to the insurer on a current period basis.

At the time each employee retires, Energy Northwest accrues a liability for the actuarial value of estimated future premiums, net of retiree contributions. The total liability recorded at June 30, 1999 was $2 million for these benefits.

During fiscal year 1999, pension costs for Energy Northwest employees and post-employment life insurance benefit costs for retirees were calculated and allocated to each project based on direct labor dollars. Approximately 95 percent of all such costs were allocated to Nuclear Project No. 2 during fiscal year 1999.

NOTE E - LONG-TERM DEBT

Each Energy Northwest project is financed separately. The resolutions of Energy Northwest authorizing issuance of revenue bonds for each project provide that such bonds are payable solely from the revenues of that project. All bonds issued under Resolution Nos. 769, 640 and 775 for Nuclear Projects Nos. 1, 2 and 3, respectively, have the same priority of payment within the projects. The variable rate debt issued for Nuclear Projects Nos. 1, 2 and 3 is subordinate to the bonds stated above.

In prior fiscal years, Energy Northwest defeased certain revenue bonds by placing the proceeds of new bonds in irrevocable trusts to provide for all future debt service payments on the old bonds. Accordingly, the trust account assets and the liability for the defeased bonds are not included in the financial statements, in accordance with GASB No. 7 and No. 23. Approximately $1,313.3 million, $1,214.9 million and $739.2 million of defeased bonds were not called or had not matured at June 30, 1999 for Nuclear Projects Nos. 1, 2 and 3, respectively.

Outstanding revenue bonds of the various projects as of June 30, 1999, are presented on pages 5 through 9, and debt service requirements for these bonds are presented on pages 20 through 25.

Energy Northwest expects to continue the refunding of higher interest rate bonds when economically feasible.

Security - Nuclear Projects Nos. 1, 2 and 3

Project participants have purchased all of the project capability of Nuclear Projects Nos. 1 and 2 and 3. BPA has in turn acquired the entire project capability from the project participants under contracts referred to as net-billing agreements. Under the net-billing agreements for each of the projects, project participants are obligated to pay Energy Northwest their pro rata share of total annual costs of the respective projects, including debt service on bonds relating to each project, and BPA in turn is obligated to pay the participants identical amounts by reducing amounts due to BPA by participants under BPA power sales agreements. The net-billing agreements provide that project participants and BPA are obligated to make such payments whether or not the projects are completed, operable or operating and notwithstanding the suspension, interruption, interference, reduction or curtailment of the projects' output.

On May 13, 1994, Energy Northwest's Board of Directors adopted resolutions terminating Nuclear Projects Nos. 1 and 3. The Nuclear Projects Nos. 1 and 3 project agreements and the net-billing agreements, except for certain sections which relate only to billing processes and accrued liabilities and obligations under the net-billing agreements, ended upon termination of the projects. Energy Northwest entered into an agreement with BPA to provide for continuation of the present budget approval, billing and payment processes. With respect to Nuclear Project No. 3, the ownership agreement among Energy Northwest, Puget Sound Power & Light Company, PacifiCorp, Portland General Electric Company and The Washington Water Power Company was terminated in fiscal year 1999. The ownership of all real and personal property interests was transferred to Energy Northwest.

Security - Packwood Lake Hydroelectric Project

Energy Northwest and BPA signed an agreement which became effective on October 1, 1996 for the period through July 1, 2001, and states that BPA will pay Energy Northwest in exchange for the project's total output of electric capacity and energy delivered from the project. BPA will pay 17.5 mills per kWh for the first 86,750 megawatt hours delivered to the interconnections and 5 mills per kWh for any energy delivered to the interconnections in excess of 86,750 megawatt hours during the fiscal year. In addition, BPA pays to Energy Northwest their Lewis County PUD No. 1 transmission costs and Energy Northwest receives generation credit for spill requested by BPA. Packwood is now a "certified resource" in BPA's environmental foundation pool. When Packwood's generation is marketed as "green" power, a stipend of 2.5 mills per kWh will be received from BPA. The Packwood participants are obligated to pay annual costs of the project including debt service, whether or not the project is operable, until the outstanding bonds are paid or provision is made for the retirement in accordance with provisions of the bond resolution.

NOTE F - COMMITMENTS AND CONTINGENCIES

Nuclear Project No. 1 Termination

On May 13, 1994, Energy Northwest's Board of Directors adopted a resolution terminating Nuclear Project No. 1. Since that date, Energy Northwest has been planning for the demolition of Nuclear Project No. 1 and restoration of the site recognizing the fact that there is no market for the sale of the Project in its entirety and to date no viable alternative use has been found. Funding for the Project has continued for administrative efforts associated with termination and planning of demolition activities for the Project. Preservation activities have been continued for certain high-value assets to maximize the return on their expected resale. At this time, the eventual disposition of the Project is unknown. Energy Northwest has reduced the assets to their estimated net realizable value and has accrued for the estimated cost of removal and site restoration.

Nuclear Project No. 3 Termination

On May 13, 1994, Energy Northwest's Board of Directors adopted a resolution requesting that the Nuclear Project No. 3 Owners Committee declare the termination of the Project. The Owners Committee voted unanimously to terminate the Project in June 1994. Since that date, Energy Northwest has been planning for the demolition of the Project and restoration of the site under its obligations to the State of Washington if no bona fide purchase offers are received. Funding for the Project has continued for administrative efforts associated with termination and planning of demolition activities for the Project. Preservation activities have been continued for certain high-value assets to maximize the return on their expected resale. In February 1999, Energy Northwest entered into a transfer agreement with the Satsop Redevelopment Project to transfer the real and personal property at the site of Nuclear Project No. 3 and Nuclear Project No. 5. For further discussion, see information contained under ("Nuclear Project Nos. 1, 3, 4, and 5 Site Restoration").

Inter-Project Claims Against Revenues and Other Assets

Some creditors of Nuclear Projects Nos. 4 and 5 have attempted, and others have threatened to attempt, to obtain payment from the physical assets of other projects of Energy Northwest or from the revenues pledged as security for Energy Northwest bonds issued in connection with, and revenues pledged for the payment of costs of, such other projects. Such creditors include present and former holders of the Nuclear Projects Nos. 4 and 5 bonds and others who may assert claims in the future against Energy Northwest and/or its projects.

Energy Northwest's management and legal counsel are of the opinion that such creditors will only be able to realize upon the net assets of Nuclear Projects Nos. 4 and 5 and will not be able to realize upon any net assets or future revenues of Energy Northwest and/or its other projects.

Nuclear Projects Nos. 1, 3, 4 and 5 Site Restoration

Site restoration requirements for Nuclear Projects Nos. 1, 3, 4 and 5 are governed by site certification agreements between Energy Northwest and the State of Washington and regulations adopted by the Washington Energy Facility Site Evaluation Council (EFSEC), and additionally for Nuclear Projects Nos. 1 and 4, by a lease agreement with DOE. Energy Northwest submitted a site restoration plan for Nuclear Projects Nos. 1, 3, 4 and 5 to EFSEC on March 8, 1995, which complied with EFSEC requirements to

remove the assets and restore the sites by demolition, burial, entombment, or other techniques such that the sites pose minimal hazard to the public. EFSEC approved Energy Northwest's site restoration plan on June 12, 1995. In its approval, EFSEC recognized that there is uncertainty associated with Energy Northwest's proposed plan. Accordingly, EFSEC's conditional approval provides for additional reviews once the details of the plan are finalized.

Based on current estimates for site restoration, Energy Northwest has accrued liabilities of $59.8 million for Nuclear Project No. 1 and $10.5 million for Nuclear Project No. 3. Funding for these liabilities will be provided by BPA. No source of funding has been identified for site restoration of Nuclear Project No. 4 which is located approximately one-half mile from Nuclear Project No. 1. Energy Northwest believes that although Nuclear Project No. 1 has no legal obligation to fund Nuclear Project No. 4, it is possible that claims may be asserted against Nuclear Project No. 1 to pay the costs of site restoration for Nuclear Project No. 4. Energy Northwest currently estimates that the cost of site restoration for Nuclear Project No. 4 is $38.9 million.

During 1995, a group from Grays Harbor County, Washington, which is interested in economic development, formed the Satsop Redevelopment Project (SRP). The Satsop Redevelopment Project introduced legislation with the State of Washington under Senate Bill No. 6427 which passed and was signed by the Governor of the State of Washington on March 7, 1996. The legislation enables local governments and Energy Northwest to negotiate an arrangement allowing such local governments to assume an interest in the site on which Nuclear Project No. 3 and Nuclear Project No. 5 exists for economic development by transferring ownership of all or a portion of the site to local government entities. This legislation also provides for the local government entities to assume regulatory responsibilities for site restoration requirements and control of water rights.

In February 1999, Energy Northwest entered into a transfer agreement with the Satsop Redevelopment Project to transfer the real and personal property at the site of Nuclear Project No. 3 and Nuclear Project No. 5. The real property was actually transferred on August 12, 1999. As part of the agreement Energy Northwest transferred $15 million to the SRP and the SRP agreed to assume regulatory responsibility for site restoration. Energy Northwest has agreed to accept a demolition and restoration obligation to bring the site into suitable condition for transfer. This obligation is estimated to cost $10.5 million in addition to the $15 million transferred to the SRP and a formal Request for Proposal is being prepared to complete the specified work. Each estimate has been recorded as Accounts Payable and accrued expenses. Energy Northwest will retain ownership of the combustion turbine property.

Other Litigation and Commitments

Energy Northwest is involved in various claims, legal actions and contractual commitments not mentioned above and in certain claims and contracts arising in the normal course of business. Although some suits, claims and commitments are significant in amount, final disposition is not determinable. In the opinion of management, the outcome of such litigation, claims or commitments will not have a material adverse effect on the financial positions of the projects or Energy Northwest as a whole. The future annual cost of the projects, however, may either be increased or decreased as a result of the outcome of these matters.

Nuclear Licensing and Insurance

Energy Northwest is a licensee of the Nuclear Regulatory Commission and is subject to routine licensing and user fees, to retrospective premiums for nuclear liability insurance, and to license modification, suspension, or revocation or civil penalties in the event of violations of various regulatory and license requirements.

The Price Anderson Act currently provides for nuclear liability insurance of over $9.51 billion per incident, which is covered by a combination of commercial nuclear insurance and mandatory industry self-insurance. Energy Northwest has purchased the maximum commercial insurance available of $200 million, which is the first layer of protection. The second layer of protection is provided through a mandatory industry self-insurance plan wherein each licensed nuclear facility required to participate in the plan (currently 108) may be assessed up to $88.095 million per incident, subject to a maximum annual assessment of $10 million per year.

Nuclear property damage and decontamination liability insurance requirements are met through a combination of commercial nuclear insurance policies purchased by Energy Northwest and BPA. The total amount of insur-

ance purchased is currently $1.06 billion. The deductible for this coverage is $10 million per occurrence.

Required Supplemental Information

"Year 2000" {Unaudited}

Energy Northwest was ready for the year 2000 by July 1 - six months before the millennial deadline. This effort consumed the efforts of at least 16 men and women for a year and a half - as well as costing Energy Northwest $17.6 million.

Energy Northwest first addressed year 2000 issues in 1996, when replacement and upgrading major business computer and software programs began. In January of last year the Year 2000 Project was formally launched - an examination of all computer systems and software programs used in and around Plant 2. More that 2,200 embedded systems were identified. Some were not time or calendar sensitive, and hence left alone. Some were easily fixed. Many were replaced. No computer or software problems have been found that would have presented nuclear safety issues – problems that would have incapacitated emergency systems or prevented continued operation of the plant.

In May 1998, the Nuclear Regulatory Commission issued a letter to all commercial nuclear plants, ordering that they establish year 2000 programs and report in writing by July 1 of this year. Energy Northwest reported by the deadline that Plant 2 was ready for the year 2000.

Contingency plans were prepared. External risks have been identified and a multi-discipline team formed to address them. Examples of contingency plans include stockpiling consumables – such as diesel fuel for emergency generators – in case there are potential supplier disruptions. There will also be extra staffing during sensitive time periods.

As for the actual move into the year 2000, suggestions from the Western Systems Coordinating Council, which recommends standards for an electrical grid covering 14 western states and two provinces, have been followed. Plant 2 will be at 80 percent power as the clock ticks toward midnight. This posture has been communicated to Bonneville for integration into the Western Systems Coordinating Council's contingency plan. At 80 percent, Plant 2 will be in a position to rapidly increase power in case there is a problem with other generating stations or with the grid.

The cost or consequences of a material incomplete or untimely resolution of the Year 2000 problem could adversely affect future operations, however, any costs related to such results would remain obligations of the project participants and BPA as discussed in Note E, Security - Nuclear Projects Nos. 1, 2, and 3.

JAN 1 1 2001

CURRENT DEBT RATINGS (Unaudited)

ENERGY NORTHWEST (Long-Term)	RATING	OUTLOOK
Fitch IBCA, Inc.	AA-	Stable
Moody's Investors Service, Inc. (Moody's)	Aa1	
Standard and Poor's Rating Services (S & P)	AA-	Stable

VARIABLE RATE DEBT	S & P	MOODY'S
Letter of Credit Banks		
Bank of America		
Long-Term	AA-	Aa2
Short-Term	A-1+	P-1
Morgan Guaranty Trust Company		
Long-Term	AA+	Aa1
Short-Term	A-1+	P-1
Bond Insurance (Long-Term)		
MBIA Insurance Corporation	AAA	Aaa
Bank Credit Facility (Short-Term)		
Credit Suisse First Boston	A-1+	P-1

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NUREG-0892
Supplement No. 3

Safety Evaluation Report
related to the operation of WPPSS Nuclear Project No. 2

Docket No. 50-397

Washington Public Power Supply System

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

May 1983

ABSTRACT

This report, Supplement No. 3 to the Safety Evaluation Report (SSER 3) for Washington Public Power Supply System's application for a license to operate WNP-2 (Docket No. 50-397), located in Benton County, Washington, approximately 12 miles north of Richland, Washington, has been prepared by the Office of Nuclear Reactor Regulation of the U.S. Nuclear Regulatory Commission. This supplement reports the status of certain items that had not been resolved at the time of publication of the Safety Evaluation Report and Supplements No. 1 and 2.

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1 INTRODUCTION AND GENERAL DESCRIPTION

1.1 Introduction

In March 1982, the Nuclear Regulatory Commission staff (hereinafter referred to as the NRC staff) issued its Safety Evaluation Report (NUREG-0892) regarding the application by the Washington Public Power Supply System (hereinafter referred to as the applicant or WPPSS) for a license to operate the Washington Public Power Supply System Nuclear Project Number 2 (hereinafter referred to as WNP-2 or facility), Docket 50-397. The NRC staff Safety Evaluation Report (SER) on WNP-2 was issued in March 1982. Supplement No. 1 (SSER 1) to the SER was issued in August 1982 and included the staff evaluation of the WNP-2 geology and seismology. SSER 2, which was issued in December 1982, addressed several outstanding licensing issues as well as the report of the Advisory Committee on Reactor Safeguards (ACRS) to the Chairman of the NRC on the WNP-2 operating license (OL) application. This report is Supplement No. 3 to the Safety Evaluation Report.

The purpose of this supplement is to provide the results of the NRC staff's review of additional information submitted by the applicant in regard to outstanding issues identified in Sections 1.7, 1.8, and 1.9 of SSER 2.

Each section of this supplement is numbered and titled to correspond to the sections of the SER and the supplements that have been affected by the NRC staff's additional evaluation and, except where specifically noted, does not replace the corresponding section of those documents. Appendix A is a continuation of the safety review chronology and lists additional documents used in this supplement. Appendix B is an updated bibliography. Appendix E is a list of principal contributors to this supplement.

Copies of this SER supplement are available for inspection at the NRC Public Document Room, 1717 H Street, NW, Washington, D.C., and at the Richland City Library, Swift and Northgate Streets, Richland, Washington. Single copies may be purchased from the sources indicated on the inside front cover.

The NRC Project Manager assigned to the operating license application for WNP-2 is Dr. Rajender Auluck. Dr. Auluck may be contacted by calling (301) 492-9778 or writing:

Dr. Rajender Auluck, P.E.
Division of Licensing
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

1.7 Summary of Outstanding Items

In Section 1.7 of the SER, SSER 1, and SSER 2, the NRC staff identified outstanding items that were not resolved at the time of issuance of those documents. In this supplement, the NRC staff discusses the resolution of a number of these items. The outstanding items list in Section 1.7 of the SER is reproduced

below, with the current status of each item. For items discussed in this supplement, the specific section is identified. The resolution of the remaining outstanding items will be discussed in future supplements to the SER.

Item	Status	Section(s)
(1) Geology and seismology	Resolved	--
(2) Internally generated missiles	Resolved	3.5.1
(3) Tornado-missile protection for diesel generator (DG) exhaust	Resolved	3.5.2
(4) Turbine missiles	Awaiting further information	--
(5) Component supports	Resolved	
(6) Equipment qualification	Awaiting further information	3.10, 3.11
(7) Condensation oscillation and chugging load specifications	Resolved	
(8) Pressure interlocks on emergency core cooling injection valves	Resolved	--
(9) Modification of automatic depressurization system logic	Awaiting further information	--
(10) Standby service water system instrumentation and control (I&C) design	Resolved	7.3.2.4
(11) Engineered safety feature reset control	Resolved	--
(12) Remote shutdown system I&C design	Resolved	--
(13) Control system failures	Awaiting further information	--
(14) Adequacy of station electric distribution system	Resolved	--
(15) Quality group classification for the DG auxiliary systems	Resolved	--
(16) Diesel engine cooling heater preheat	Resolved	--
(17) Diesel engine lube oil system's ability to preclude dry starting	Resolved	--

Item	Status	Section(s)
(18) Blockage of the DG combustion air intake and exhaust system	Resolved	9.5.8
(19) Shift support supervisor training program	Resolved	--
(20) Administrative procedures: limitation on working hours	Resolved	--
(21) Criteria for testing hot pipe containment penetrations	Resolved	--
(22) Emergency planning program (offsite)	Awaiting further information	--
(23) Control room design review	Under review	--
(24) Anticipated transients without scram (ATWS)	Combined with confirmatory item 15	--
(25) General Design Criterion (GDC) 51	Resolved	--
(26) TMI II.E.4.2 (operability of purge valves only)	Under review	--
(27) TMI II.K.3.28, qualification of accumulators on automatic depressurization system (ADS) valves	Resolved	--
(28) Pipe break in the boiling water reactor (BWR) scram system	Resolved	4.6
(29) Steam bypass from a stuck open wetwell-to-drywell vacuum breaker	Awaiting further information	--
(30) Heavy load handling system	Under review.	--
(31) Sprinkler and standpipe system	Resolved	9.5.1
(32) Organizational changes	Resolved	13.1.1
(33) Cable separation criteria	Resolved	--

1.8 Confirmatory Issues

In Section 1.8 of the SER, SSER 1, and SSER 2, the NRC staff listed confirmatory items that were not resolved at the time of issuance of those documents. That list is reproduced and updated below.

Item	Status	Section
(1) Break location	Awaiting further information	--
(2) Preoperational testing of snubbers	Under review	--
(3) Reactor internals analysis under faulted conditions	Under review	--
(4) Hydrodynamic loads	Under review	--
(5) Class 1 fatigue evaluations for the safety/relief valve (SRV) discharge piping and downcomers	Resolved	3.9.3.1
(6) Method for combining dynamic responses	Resolved	3.9.3.1
(7) Design of component supports	Awaiting further information	--
(8) Systems drawings for inservice testing	Resolved	--
(9) Fuel rod mechanical fracturing	Under review	--
(10) Fuel assembly structural damage from external sources	Under review	--
(11) Fuel rod bowing	Resolved	4.2.3.1
(12) Overheating of gadolinia fuel pellets	Under review	--
(13) Automatic restart capability for reactor core isolation cooling (RCIC) system	Awaiting further information	--
(14) Modification to prevent spurious isolation of RCIC system	Awaiting further information	--
(15) Emergency procedures review	Awaiting further information	--
(16) ADS, low pressure cooling system (LPCS), and low pressure coolant injection (LPCI) setpoint	Awaiting further information	--
(17) RCIC system	Awaiting further information	--
(18) SRV position indications	Awaiting further information	--
(19) Additional accident monitoring instrumentation	Awaiting further information	--

Item	Status	Section
(20) Rod block monitor	Resolved	7.6.2.3
(21) Mitigating core damage training	Awaiting further information	--
(22) Assurance of engineered safety features (ESF) functioning and safety-related system operability status	Under review	--
(23) General plant guidance--building design	Resolved	9.5.1.5
(24) Design-basis volcanic ash	Resolved	2.5.1.3

1.9 License Conditions

Section 1.9 of the SER, SSER 1, and SSER 2 listed several probable license conditions. The updated list of these conditions is as follows:

Item	Section
(1) Ultimate heat sink	--
(2) Channel box deflection	Deleted (4.2.3.1)
(3) Effects of high-burnup fission gas release on loss-of-coolant accident (LOCA) analysis	--
(4) Inadequate core cooling (ICC) instrumentation analysis	--
(5) Conditions for operations beyond cycle 1	--
(6) IE Bulletin 80-06, "Engineered Safety Features Reset Control"	--
(7) Post-accident sampling	--
(8) Relocations of engine-mounted controls	--
(9) Conformance of diesel generator fuel oil system	Deleted
(10) BWR startup or operating experience	--
(11) Physical security	--
(12) Prohibition of operations with partial feedwater heating	--
(13) Remote shutdown system	--

2 SITE CHARACTERISTICS

2.5 Geology, Seismology, and Geotechnical Engineering

2.5.1 Basic Geologic and Seismic Information

2.5.1.3 Volcanic Hazards

2.5.1.3.1 Ashfall

In the SER-OL, Supplement No. 1 (SSER-1) Appendix G, the staff and the United States Geological Survey (USGS) indicated that the FSAR estimates of the uncompacted thickness of ashfall and the rate of fall fell short of more recently developed estimates by the USGS based on experience with the May 18, 1980 Mt. St. Helens eruption. In accordance with the Standard Review Plan (SRP) (NUREG-0800), Section 2.5.1, concerning operating license reviews, all new information on the regional and site geology developed after issuance of the construction permit (CP) SER must be included and evaluated in the determination of site suitability and design criteria. The applicant, therefore, was asked to evaluate the ashfall considerations discussed in the following paragraphs.

Although the compacted design thickness chosen (7.4 cm or 3 inches) was considered conservative, the uncompacted thickness was based on earlier estimates of 20% to 40% compaction of loose ash. As was pointed out by the USGS (SSER-1, page G-11), a compaction factor of up to 75% was measured for the May 18, 1980 Mt. St. Helens eruption. Although the validity of this latter figure had not been determined when SSER-1 was written, it was considered prudent to use a more conservative estimate than 20% to 40%--somewhere between 50% to 60%. This higher estimate would result in a maximum of 18.5 cm (7.4 inches) of loose ash.

The rate of ashfall for a 20-hour period, based on the earlier FSAR percent compaction estimates of 0.37 cm/hr (0.15 inch/hr) would result from the compacted thickness of 7.4 cm (3 inches). Therefore a higher rate based on the more recent uncompacted ash estimates was suggested, the average being 0.92 cm/hr (0.36 inch/hr) and the maximum 1.1 cm/hr (0.44 inch/hr) for the Katmai volcano rate.

Based on these differences between the applicant's estimates on the one hand, and those of the NRC staff and the USGS on the other, the applicant committed to set up a task force to evaluate and recommend a plan to incorporate the new information.

In a letter dated October 4, 1982, the applicant evaluated the WNP-2 plant systems and equipment with regard to operability and reliability during a design-basis ashfall. The more conservative values of maximum compacted (3-inch) and uncompacted (7.4-inch) ashfall thicknesses and the average and maximum rates (0.35 inch/hr and 0.44 inch/hour, respectively) were used, coincident with loss of offsite power for 2 hours. As a result of this analysis, the applicant proposed several plant procedures and equipment modifications to ensure that the

plant could operate safely and achieve safe shutdown following a design-basis ashfall.

The NRC staff has reviewed the submittal and concludes that the applicant has adequately addressed the consequences of the volcanic event and that the proposed plant procedures and equipment modifications will provide adequate assurance of safe plant operation and shutdown following such an event. This resolves confirmatory item 24.

3 DESIGN CRITERIA FOR STRUCTURES, SYSTEMS, AND COMPONENTS

3.5 Missile Protection

3.5.1 Missile Selection and Description

3.5.1.1 Internally Generated Missiles (Outside Containment)

In the SER, the NRC staff stated that the FSAR analysis did not include the air accumulators and the gas bottles as potential missile sources. Furthermore, the applicant had indicated that a new FSAR Section 3.5.1.1 would be provided to reflect a more complete analysis. The applicant provided the revised analysis by Amendment 27 to the FSAR. The revised analysis included air accumulators and gas bottles as potential missile sources.

The primary means of providing protection to safety-related equipment from damage resulting from internally generated missiles is through the plant physical arrangement. Safety-related systems are physically separated from nonsafety-related systems, and redundant components of safety-related systems are physically separated so that potential missiles could not damage both trains of safety-related equipment. Stored spent fuel is protected from damage by internally generated missiles by the fuel pool walls and by preventing the location of high-energy piping systems or rotating machinery in the vicinity of new or spent fuel.

The applicant provided an evaluation of potential missile sources on the basis that a single failure could result in their becoming potential missiles. The evaluation indicated that there were no credible potential missile sources, including air accumulators and gas bottles, that could cause adverse effects on safety-related systems and components, except for the motor-generator set. The applicant has installed a barrier that the NRC staff considers adequate to prevent any internally generated missile from the motor-generator set from damaging the nearby safety-related cables and cabinets. The staff reviewed the applicant's assumptions and evaluation for potential missiles outside containment and agrees with the conclusion that adequate protection is provided.

Based on the above, the NRC staff concludes that the design of the facility is in conformance with the requirements of General Design Criterion (GDC) 4 as it relates to protection against internally generated missiles and is, therefore, acceptable with respect to internally generated missiles outside containment. The design of the facility for providing protection from such internally generated missiles meets the applicable acceptance criteria of SRP 3.5.1.1 (NUREG-0800).

3.5.1.2 Internally Generated Missiles (Inside Containment)

In the SER, the NRC staff noted that the applicant's analysis of potential missiles and the effects of the internally generated missiles was not complete. The applicant has provided a revised analysis by Amendment 27 to the FSAR. The

revised analysis includes missile characteristics, trajectory, and impact area, as applicable. The NRC staff has reviewed the results of the applicant's missile analysis for internally generated missiles inside containment and agrees with the conclusion that unacceptable damage to safety-related equipment will not occur; thus the requirements of GDC 4 are satisfied with respect to such missiles.

The staff has reviewed the adequacy of the applicant's design to maintain the capability for a safe plant shutdown and to prevent unacceptable radiological release in the event of internally generated missiles inside containment. Based on the above, the staff concludes that the design is in conformance with the requirements of GDC 4 as it relates to protection against internally generated missiles inside containment; therefore, this aspect of the plant's design is acceptable. The design of the facility for providing protection from internally generated missiles meets the applicable acceptance criteria of SRP 3.5.1.2 (NUREG-0800). This finding, together with the finding in Section 3.5.1.1 above, resolves outstanding issue 2.

3.5.2 Structures, Systems, and Components To Be Protected from Externally Generated Missiles

In the SER, the staff stated that except for the diesel generator exhausts, the safety-related structures, systems, and components were acceptably protected from tornado missiles. Regarding the diesel generator exhausts, the NRC staff was concerned that the diesel exhaust openings of one of the two engineered safety feature (ESF) diesels might be blocked by tornado-borne missiles (e.g., utility poles). Each ESF diesel has two exhaust openings. The applicant stated that, with one diesel exhaust opening blocked, the corresponding diesel would not accept its required load. Assuming a single failure in the redundant diesel (failure to start), neither diesel would be available in the case of a loss of offsite power resulting from a tornado.

As guidance in evaluating the site for the source(s) of such missiles, the NRC staff used SRP 3.5.1.4 (NUREG-0800), which states that a utility pole should be considered as a missile source at elevations up to 30 feet above all grade levels within 1/2 mile of the facility structure. For this plant, the exhaust openings are more than 30 feet above grade; however, there is a bluff due south of the diesel generator building. The NRC staff was concerned that this area might be used as a lay down area and that utility poles or other construction materials might be stored there.

The NRC staff recommended that the applicant provide administrative control over the bluff. In a submittal dated July 23, 1982, the applicant stated that it was extremely improbable that a tornado would lift a utility pole and transport it to the diesel generator building. The applicant provided a limited probabilistic risk assessment (PRA) to support this statement that indicates that the probability of a tornado generating a utility pole missile that would plug one of the ESF diesel generator exhausts at the same time the redundant diesel generator would fail to start from an independent cause is on the order of 10^{-12} per year.

The NRC staff has reviewed the applicant's PRA. Based on this NRC staff review, and on the NRC staff's independent determination of the tornado frequency at the WNP-2 site, the staff finds that the probability of a utility

pole missile plugging one diesel generator exhaust at the same time the second diesel generator fails to start is very low. The NRC staff has also examined the site terrain and concludes that the possible sources of missiles are limited. Further, between the bluff and the diesel exhausts are six forced draft cooling towers and a pumphouse. A utility pole lifted from the bluff would have to traverse a very limited path between the intervening cooling towers to reach the diesel exhaust openings. The NRC staff, therefore, concludes, based on the low probability, that there is reasonable assurance that missiles resulting from a tornado will not prove to be a danger to the diesel generator exhausts. The NRC staff concludes that conformance to the requirements of GDC 4 has been demonstrated in that, through the use of probabilistic risk assessment, there is reasonable assurance that tornado missiles will not endanger the diesel generator exhausts, and, therefore, the risk to the public is acceptable. This resolves outstanding issue 3.

3.9 Mechanical Systems and Components

3.9.3 ASME Code Class 1, 2, and 3 Components, Component Supports, and Core Support Structures

3.9.3.1 Loading Combinations, Design Transients, and Stress Limits

In SER Section 3.9.3.1, the NRC staff stated that the applicant committed to demonstrate that a square root of the sum of the squares (SRSS) combination of dynamic responses for WNP-2 achieves the 84% nonexceedence probability level. The staff has reviewed the information in the following referenced documents: Bouchey, 1983; Bouchey, 1982a; GE SMA 12109.01-R001; and NEDE-24010-P (see Appendix B). In Bouchey, 1983, the applicant performed a study that included 96 samples of combinations of dynamic responses resulting from safety/relief valve (SRV) discharge and seismic loadings. The results of the study indicated that the nonexceedence probabilities (NEPs) of SRSS combination of responses at selected sample locations are at or exceed 50%, and the NEPs of 1.2 SRSS are at or exceed 85%. Based on a review of this study and information in Bouchey, 1982a; GE SMA 12109.01; and NEDE-24010-P, the NRC staff has determined that the SRSS method for combining dynamic responses is applicable to the WNP-2 nuclear plant and satisfies the requirements of "Methodology for Combining Dynamic Responses," NUREG-0484, Revision 1 (July 1981). This resolves confirmatory item 6.

In the SER, the NRC staff also stated that the applicant committed to perform a plant-unique American Society of Mechanical Engineers "Boiler and Pressure Vessel Code (ASME Code), Section III, Class 1 fatigue evaluation for the SRV discharge pipings and downcomers. The NRC staff has reviewed the information on the fatigue analysis on these lines described in the WNP-2 Design Assessment Report dated January 21, 1983. The fatigue evaluation of 24- and 28-inch downcomer lines and all 18 SRV lines in the wetwell air volume was performed using ASME Code, Section III, Class 1 rules. The results of these analyses indicated that the maximum fatigue usage factor for both downcomers and all 18 SRV lines was below ASME Code-allowable limits. The NRC staff finds that the applicant's evaluation satisfies the ASME Code, Section III, Class 1 fatigue evaluation requirement and is acceptable. This resolves confirmatory item 5.

The NRC staff contracted with the Energy Technology Engineering Center to perform an independent analysis of the main steam relief line 10" MS(18)-2 SRV

analysis verified that the piping system met the applicable ASME Code acceptance requirements. The detailed results of this analysis are documented in the Energy Technology Engineering Center report, "WPPSS No. 2 Confirmatory Piping Analysis," dated July 6, 1982 and its attachment dated November 2, 1982.

3.10 Seismic and Dynamic Qualification of Seismic Category I Mechanical and Electrical Equipment

3.10.1 Seismic and Dynamic Qualification

The staff evaluation of the applicant's program for qualification of safety-related electrical and mechanical equipment for seismic and dynamic loads consists of (1) a determination of the acceptability of the procedures used, standards followed, and the completeness of the program in general, and (2) an audit of selected equipment items to develop the basis for the staff judgment on the completeness and adequacy of the implementation of the entire seismic and dynamic qualification program. The Seismic Qualification Review Team (SQRT) consists of NRC staff engineers and personnel from the Idaho National Engineering Laboratory (INEL, EG&G). The SQRT has reviewed the equipment dynamic qualification information in FSAR Sections 3.9.2 and 3.10 and visited the plant site on November 16 through November 19, 1982 to determine the extent to which the qualification of equipment as installed at WNP-2 meets the current licensing criteria as described in Institute of Electrical and Electronics Engineers (IEEE) Standard 334-1975; RGs 1.92 and 1.100; and SRP 3.10. Conformance with these criteria is required to satisfy the applicable portions of GDC 1, 2, 4, 14, and 30, as well as Appendix B to 10 CFR 50 and Appendix A to 10 CFR 100. A representative sample of safety-related electric and mechanical equipment, as well as instrumentation, included in both the nuclear steam supply system (NSSS) and the balance of plant (BOP) scopes of review, was selected for the audit. The plant site visit consisted of field observations of the actual final equipment configuration and its installation. This was immediately followed by the review of the corresponding test and/or analysis documents that the applicant maintains in his central files.

Observing the field installation of the equipment is required to verify and validate equipment modeling employed in the qualification program. Based on the audit, the SQRT concluded the applicant has properly implemented the seismic and dynamic qualification program. However, some concerns, both plant generic and equipment-specific remain; these are delineated in Subsections 3.10.1.2 and 3.10.1.3. These concerns must be satisfactorily resolved before fuel loading. The plant generic concerns are more significant, in that they apply to all safety-related equipment and potentially can affect a large number of components and systems. The applicant must develop an acceptable approach and plan to resolve the plant generic findings.

The audit identified the need to provide additional information on certain plant generic findings as well as to clarify the details of qualification for some pieces of equipment. These findings are summarized below.

3.10.1.1 Plant Generic Findings

A unique feature of the containment design is that the reactor building foundation is not integral with the containment foundation. Hydrodynamic loads inside containment are included in the qualification of equipment. Outside containment, but inside the reactor building, hydrodynamic loads are not considered, because the unique design of containment is alleged to attenuate these loads. The staff review in this area is continuing and will be completed in additional meetings with the applicant.

When the valve operator BOP-12 was qualified, an assumed g value was used. Later, in the as-built and as-installed condition, an analysis confirmed that the g value used in the qualification was indeed adequate. This is also the case with other equipment in this category as far as loads are concerned. The applicant indicated that a procedure is in place to verify assumed g values for each case. For the motor operator, the g value was confirmed to be adequate. The applicant is to confirm the adequacy of all assumed g values and inform the NRC in writing of the results when this confirmation is completed.

The motor control center was qualified through single frequency, biaxial input tests. The motor control center has more than one natural frequency below 33 Hz. This technique, in the absence of adequate justification, is not acceptable. The applicant is to review the cases in which single frequency tests have been used in spite of the presence of multiple natural frequencies of the system within the range of 33 Hz. In each case, the applicant is to provide a justification for single frequency testing.

All safety-related equipment should be qualified and installed before fuel loading. At the time of the audit, some safety-related equipment remained to be qualified and installed. Before fuel loading the applicant must state in writing that all (100%) of the plant safety-related equipment is qualified and installed.

3.10.1.2 Specific Issues

Pressure Switch (BOP-14)

The panel on which this item is mounted was qualified by test. The test consisted of multifrequency, multi-axis, random inputs. Test Response Spectra (TRS) from these tests enveloped the initial Required Response Spectra (RRS). Subsequently, based on further investigation, the RRS were changed, with the result that the TRS did not envelope the RRS in different regions. An effort was made to analyze this apparent inadequacy based on the natural frequency of the system. From this analysis, the lowest natural frequency of the system is estimated as 7.5 Hz. One unenveloped region is around 6.5 Hz, which is too close to the system frequency. As a result, the adequacy of the qualification test is in doubt. The applicant is to justify his present qualification or requalify the equipment.

3.10.1.3 Summary

Based on the SQRT audit findings as well as on submittals from the applicant, with the exception of the concerns mentioned, the staff concludes that an

appropriate seismic and dynamic qualification program has been defined and substantially implemented. This provides adequate assurance that such equipment will function properly during and after the excitation from vibratory forces imposed by the safe shutdown earthquake.

Resolution of the specific and generic plant items as they progress will be reported in a future supplement to the SER.

3.10.2 Operability Qualification of Pumps and Valves

To ensure that the applicant has provided an adequate program for qualifying safety-related pumps and valves to operate under normal and accident conditions, the NRC staff performs a two-step review. The first step is a review of FSAR Section 3.9.3.2 for the description of the applicant's pump and valve operability assurance program against SRP 3.10. Because the information in the FSAR is general and not sufficient to evaluate the applicant's overall pump and valve operability qualification program, the Pump and Valve Operability Review Team (PVORT) also conducts an onsite audit.

The onsite.audit includes a plant inspection to observe the as-built configuration and installation of the equipment, a discussion of the system in which are located and of the normal and accident conditions under which the component must operate, and a review of the qualification documentation (stress reports, test reports, etc.).

The two-step review is performed to determine the extent to which the qualification of equipment, as installed, meets SRP 3.10, as well as GDC 1, 2, 4, 14, and 30 and Appendix B to 10 CFR 50.

The onsite audit for WNP-2 was performed November 16 to 19, 1982. A representative sample consisting of seven valves and three pumps was chosen for review. The sample included both NSSS and BOP equipment. During the review, a number of concerns were raised. Some of these concerns were satisfactorily resolved by the applicant during the audit either by supplying additional information or by providing additional commitments, as appropriate. The remaining concerns and generic findings are summarized below.

3.10.2.1 Generic Findings

No generic operability concerns resulted from the evaluation of the WNP-2 qualification program for pump and valve operability.

The results of reviewing the document packages for the unannounced components indicate that the applicant has a good central file system from which he can retrieve documents in a relatively short time, as required by SRP 3.10. This conclusion was further substantiated after a review of the applicant's quality assurance filing system.

The PVORT was given an orientation lecture on the WNP-2 computer-based maintenance and surveillance program by the supervisor of maintenance. The program appears to be very comprehensive and incorporates many excellent features. Some of these include: (1) performing maintenance on all components before pre-operational testing; (2) integrating all pertinent qualification

information (e.g., aging information for age degradable parts) into the maintenance program, and (3) analyzing subcomponents upon removal to aid in determining changes in replacement schedules. In keeping with the third idea, the applicant is voluntarily participating in the Nuclear Plant Reliability Data System (NPRDS).

The NRC staff concludes that the WNP-2 supply system equipment qualification group is dealing with the equipment qualification issue in a positive manner, and the results of the group's efforts are evident in the applicant's pump and valve operability assurance program.

3.10.2.2 Specific Concerns

Suppression Pool Outlet Valve, HPCS-V-15, High Pressure Core Spray Suction Isolation Valve

During plant walk-down, reviewers observed that the horizontal clearance between the actuator and an adjacent pipe restraint was possibly too small, so that it might affect the operability of the valve under dynamic loads. A review of the documentation revealed that the valve was originally qualified to the interim piping criteria. When the final piping analysis was completed and compared to the interim load, a review by the applicant found that the loads for this component exceeded those calculated using the interim criteria. The valve is currently being reanalyzed to the loads specified by the final piping analysis.

Confirmation that the valve has been requalified to the new loads must be provided to the staff before fuel load. In addition, the applicant must provide justification that clearance between the valve actuator and the adjacent pipe restraint will not affect valve operability during dynamic loads.

Rockwell 26-inch Globe Valve, MS-V-22C, Main Steam Isolation Valve

During the valve inspection, NRC staff reviewers found: (1) the accumulator was not installed, (2) the installed solenoid valves were not qualified for the environment, and (3) the valve was scheduled to be completely disassembled for cleaning. These problems were discussed with the startup engineer, and it was determined that the valve, as viewed, was obviously not ready for operation. The valve, which had been on site for a number of years (the valve was built in 1973), was to be completely refurbished before testing. This refurbishing would include installation of environmentally qualified solenoid valves.

The documentation review revealed that the qualification of the assembly for operability under accident conditions was based on two analyses by Rockwell, RAL-2006, Revision 1, and RAL-1002, Revision 2. A test report (RAL-1004, Revision 0) was also provided for a similar valve (a 20-inch Rockwell Model 1612Y). RAL-1004 stated that the valve had operated with a 0.820-inch deflection. An analysis of the WNP-2 valve calculated a maximum deflection of only 0.270 inches. In addition, it was learned that a seismic test on a similar actuator for a Rockwell 24-inch valve was being reviewed by General Electric to determine if the results of that test could be used to qualify the WNP-2 actuator by similarity. The engineer in charge of power ascension testing commented

on the operability of the valve assembly under design conditions. He stated that the valve is to be tested (closed against flow) at three different power levels--approximately 30%, 50%, and 85%. In addition, all the main steam isolation valves (MSIVs) will be closed simultaneously at 100% steam flow. A complete report on the results of the power ascension tests will be available 3 months after completion of the tests.

Although MS-V-22C is presently not operable, the NRC staff's findings indicate that adequate plans are in place to ensure that the valve assembly will be qualified for operability before the power ascension tests. The power ascension tests will then verify operability under normal plant conditions. However, the applicant must provide the results of the ongoing review of a Rockwell seismic test on a similar 24-inch actuator before fuel load. In addition, confirmation that the solenoid valves for the actuators on all MSIVs have been replaced with qualified units must be provided before fuel load.

The qualification program for the safety-related pumps and valves was not complete for a number of components at the time of the audit. In addition to responding to the concerns addressed above, the applicant should provide a schedule for completion of this program.

3.10.2.3 Summary

The staff will complete its review when the applicant has provided the required information as stated above and has documented the completion of his pump and valve operability program. The documentation required to close each of the open items addressed in this report is discussed above. Satisfactory resolution of all the open items discussed must be accomplished before fuel load. A final evaluation of the pump and valve operability program will be performed following satisfactory resolution of the open items discussed above as well as notification that the pump and valve operability assurance program has been completed for all safety-related pumps and valves. The staff will report on the results of its final evaluation of the applicant's program in a future supplement to the SER.

3.11 Environmental Qualification of Electric Equipment Important to Safety and Safety-Related Mechanical Equipment

3.11.1 Introduction

Equipment that is used to perform a necessary safety function must be demonstrated to be capable of maintaining functional operability under all service conditions postulated to occur during its installed life for the time it is required to operate. This requirement, which is embodied in GDC 1 and 4 and in Sections III, XI, and XVII of Appendix B to 10 CFR 50, is applicable to equipment located inside as well as outside containment. More detailed requirements and guidance relating to the methods and procedures for demonstrating this capability for electrical equipment have been set forth in 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants," and NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment." NUREG-0588 supplements IEEE Standard 323 and various NRC Regulatory Guides and industry standards.

3.11.2 Background

NUREG-0588 was issued in December 1979 to promote a more orderly and systematic implementation of electrical equipment qualification programs by industry and to provide guidance to the NRC staff for use in ongoing licensing reviews. The positions contained in this section provide guidance on (1) how to establish environmental service conditions, (2) how to select methods that are considered appropriate for qualifying equipment in different areas of the plant, and (3) other areas such as margin, aging, and documentation.

In February 1980, the NRC requested certain near-term operating licence (OL) applicants to review and evaluate the environmental qualification documentation for each item of safety-related electric equipment and to identify the degree to which their qualification programs comply with the staff positions described in NUREG-0588. IE Bulletin 79-01B, "Environmental Qualification of Class 1E Equipment," issued January 14, 1980, and its supplements dated February 29, September 30, and October 24, 1980, established environmental qualification requirements for operating reactors. This bulletin and its supplements were provided to OL applicants for consideration in their review.

A final rule on environmental qualification of electric equipment important to safety for nuclear power plants became effective on February 22, 1983. This rule, Section 50.49 of 10 CFR 50, specifies the requirements to be met for demonstrating the environmental qualification of electrical equipment important to safety located in a harsh environment. In accordance with this rule, equipment for WNP-2 may be qualified to the criteria specified in Category II of NUREG-0588.

The qualification requirements for mechanical equipment are principally contained in Appendices A and B of 10 CFR 50. The qualification methods defined in NUREG-0588 can also be applied to mechanical equipment.

In response to the above requirements, the applicant has provided equipment qualification information in letters dated January 14, 1982, September 15, 1982, and January 31, 1983 to supplement the information in FSAR Section 3.11.

The following subsections evaluate the adequacy of the WNP-2 environmental qualification program for electric equipment important to safety as defined in 10 CFR 50.49 and for safety-related mechanical equipment. The staff review includes an evaluation of the completeness of the list of systems and equipment to be qualified, the criteria which they must meet, the environments in which they must function, and an assessment of the qualification documentation for the equipment. It is limited to electric equipment important to safety within the scope of 10 CFR 50.49, and safety-related mechanical equipment. Equipment required to mitigate scram discharge volume (SDV) breaks as described in NUREG-0803, "Generic Safety Evaluation Report Regarding Integrity of BWR Scram System Piping," will be evaluated separately.

3.11.3 Staff Evaluation

The staff evaluation of the applicant's environmental qualification program included an onsite examination of electrical equipment, audits of qualification documentation, and a review of the applicant's submittals for completeness and

acceptability of systems and components, qualification methods, and accident environments. The criteria described in SRP 3.11 (NUREG-0800) and NUREG-0588, Category II, form the basis for the staff evaluation of the adequacy of the applicant's qualification program. Revision 1 of NUREG-0588 was utilized to clarify staff positions as required.

The staff performed an audit of the applicant's qualification documentation and installed electrical equipment on February 15 through 17, 1983. The audit consisted of a review of 10 files containing equipment qualification documentation. The staff's findings during the audit are discussed in detail in Section 3.11.4.2 below. Mechanical equipment environmental qualification was also reviewed.

3.11.3.1 Completeness of Equipment Important to Safety

The applicant was directed to (1) establish a list of systems and components that are required to prevent or mitigate a loss-of-coolant accident (LOCA) or a high-energy line break (HELB) and (2) identify components needed to perform the functions of safety-related display instrumentation, post-accident sampling and monitoring, and radiation monitoring.

The applicant's systems list for the environmental qualification program was compared to FSAR Table 3.2-1. Omissions from the harsh environment program were adequately justified by the applicant. Appendix 3D, appended to this section, lists the systems identified and their safety function.

Based on information in the applicant's submittal, the staff has verified and determined that the systems included in the applicant's submittal are those required to achieve or support: (1) emergency reactor shutdown, (2) containment isolation, (3) reactor core cooling, (4) containment heat removal, (5) core residual heat removal, and (6) prevention of significant release of radioactive material to the environment.

The applicant has identified the equipment required by NUREG-0737, "Clarification of TMI Action Plan Requirements," but the qualification status has not been established for all items. Before an operating license is granted, the applicant should identify the qualification status for all TMI Action Plan equipment. For any TMI Action Plan equipment not yet installed and that will not be installed prior to operation, a description of the plans for qualification, including the schedule for completion of qualification, must be submitted. (All TMI Action Plan equipment currently installed or that will be installed before operation must be qualified, or justifications for interim operation provided before an operating license is issued, in accordance with 10 CFR 50.49.)

To comply with 10 CFR 50.49, the following information must be submitted by the applicant before an operating license for WNP-2 can be granted:

(1) A list of all nonsafety-related electrical equipment, located in a harsh environment, whose failure under postulated environmental conditions could prevent satisfactory accomplishment of safety functions by the safety-related equipment. A description of the methods used to identify

this equipment must be included. The nonsafety-related equipment identified must be included in the environmental qualification program.

(2) A statement that all safety-related electrical equipment in a harsh environment, as defined in the scope of 10 CFR 50.49, is included in the list of equipment identified in the September 1982 submittal.

(3) A list of all post-accident monitoring equipment currently installed, or that will be installed before plant operation begins, that is specified as Category 1 and 2 in Revision 2 of RG 1.97 and is located in a harsh environment. The equipment identified must be included in the environmental qualification program.

3.11.3.2 Qualification Methods

3.11.3.2.1 Electrical Equipment in a Harsh Environment

Detailed procedures for qualifying safety-related electrical equipment in a harsh environment are defined in NUREG-0588. The criteria in NUREG-0588 are also applicable to other equipment important to safety as defined in 10 CFR 50.49. Type testing of equipment in a sequence consisting of pre-aging (thermal, radiation, and mechanical), seismic and dynamic loading, and exposure to LOCA/HELB conditions (where applicable) is the preferred method of qualification. However, in a number of cases the applicant has extrapolated partial test data to establish the equipment qualfication. The staff has reviewed this analysis and finds the approach to be adequate except as noted in this report.

3.11.3.2.2 Safety-Related Mechanical Equipment in a Harsh Environment

Although there are no detailed requirements for mechanical equipment, GDC 1 and 4; Sections III and XVII of Appendix B to 10 CFR 50; and SRP 3.11, Revision 2, contain the following requirements and guidance related to equipment qualification:

- Components shall be designed to be compatible with the postulated environmental conditions, including those associated with LOCAs.
- Measures shall be established for the selection and review for suitability of application of materials, parts, and equipment that are essential to safety-related functions.
- Design control measures shall be established for verifying the adequacy of design.
- Equipment qualification records shall be maintained and shall include the results of tests and materials analyses.

The staff review is concentrated on materials that are sensitive to environmental effects (for example, seals, gaskets, lubricants, fluids for hydraulic systems, and diaphragms). Qualification documentation was reviewed by the staff to verify conformance with the above criteria. The results of the staff review are in Section 3.11.4.3 below.

3.11.3.3 Service Conditions

NUREG-0588 defines the methods to be utilized for determining the environmental conditions associated with LOCAs or HELBs, inside or outside of containment. The review and evaluation of the adequacy of these environmental conditions are described below. The staff has reviewed the qualification documentation to ensure that the qualification conditions envelop the conditions established by the applicant.

3.11.3.3.1 Temperature, Pressure, and Humidity Conditions Inside the Primary Containment

The applicant provided the LOCA/main steamline break (MSLB) profiles used for equipment qualification program submittals. The peak values in the drywell resulting from these profiles are as follows:

	Maximum temperature, °F	Maximum pressure, psig	Humidity, %
LOCA/MSLB	340	45	100

The staff has reviewed these profiles and finds them acceptable for use in equipment qualification; i.e., there is reasonable assurance that the actual pressures and temperatures will not exceed those profiles anywhere within the specified environmental zone (except in the break zone).

3.11.3.3.2 Temperature, Pressure, and Humidity Conditions Outside the Primary Containment

The applicant has provided the temperature, pressure, and humidity conditions associated with HELBs in the secondary containment. The staff has used a screening criterion of saturation temperature at the calculated pressure to verify that the parameters identified by the applicant are acceptable. The applicant should indicate that the postulated environmental conditions associated with moderate-energy line breaks are no more severe than the conditions associated with high-energy line breaks.

3.11.3.3.3 Submergence

The maximum submergence level established by the applicant in the environmental qualification program is 12 inches above the drywell floor. The applicant has stated that there are no exposed connections or equipment located between the diaphragm floor and the top of the downcomer vent pipes inside the wetwell, except for the wetwell level system, which is totally enclosed in watertight conduit.

The effects of flooding on equipment located in the reactor building have been evaluated to ensure that safe shutdown can be achieved. All impacted equipment will either be protected, relocated, or qualified.

The applicant should indicate that any equipment important to safety that could be subjected to flooding will not affect the safety function of any other equipment or system and will not mislead the operator.

3.11.3.3.4 Demineralized Water Spray

A demineralized water spray could be used inside primary containment to mitigate the effects of an accident. Spray impingement on affected equipment has been evaluated by the applicant and has been included in the qualification program.

3.11.3.3.5 Aging

NUREG-0588, Category II delineates two aging-program requirements. Valve operators committed to IEEE Standard 382-1972 and motors committed to IEEE Standard 334-1971 must meet the Category I requirments of NUREG-0588. This requires the establishment of a qualified life, with maintenance and replacement schedules based on the findings. All other equipment must be subjected to an aging program that identifies aging-susceptible materials within the component.

In addition to the above, a maintenance/surveillance program should be implemented to identify and prevent significant age-related degradation in electrical and mechanical equipment. The applicant has committed to follow the recommendations in RG 1.33, Revision 2, "Quality Assurance Program Requirements (Operation)," which endorses American National Standard ANS-3.2/ANSI N18.7-1976, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants," as noted in SER Section 17. This standard defines the scope and content of a maintenance/surveillance program for safety-related equipment. Provisions for preventing or detecting age-related degradation in safety-grade equipment are specified and include (1) utilizing experience with similar equipment, (2) revising and updating the program as experience is gained with the equipment during the life of the plant, (3) reviewing and evaluating malfunctioning equipment and obtaining adequate replacement components, and (4) establishing surveillance tests and inspections based on reliability analyses, frequency and type of service, or age of the items, as appropriate. The applicant must commit to implementation before an operating license is granted.

3.11.3.3.6 Radiation (Inside and Outside Containment)

The applicant has provided values of the radiation levels postulated to exist following a LOCA. The accident radiation environments in primary containment have been defined according to Section II.B.2 of NUREG-0737 and NUREG-0588, Revision 1. For this review, the staff has assumed that the values provided have been determined in accordance with the prescribed criteria. The staff review determined that the values to which the equipment was qualified enveloped the requirements identified by the applicant, except as noted in Section 3.11.4.2 below.

The radiation service condition specified by the applicant for primary containment are: 7.0×10^7 rads in the drywell; 9×10^7 rads in the wetwell; and 3.7×10^6 rads in the suppression pool. In the secondary containment, required values of up to 1.2×10^7 rads gamma were used in the evaluation of equipment in areas exposed to recirculating fluid lines. These values are acceptable for use in the qualification of equipment.

In addition the applicant was directed to evaluate any possible radiation-induced damage to solid state devices and the effect of beta radiation on

equipment important to safety. The applicant has indicated that an investigation is under way and corrective action will be taken as required.

3.11.3.4 Outstanding Equipment

For items not having complete qualification documentation, the applicant must provide a commitment for corrective action and schedules for completion. For items that will not have full qualification before an operating license is granted, analyses must be performed in accordance with paragraph (i) of 10 CFR 50.49 to ensure that the plant can be operated safely pending completion of environmental qualification. These analyses must be submitted for consideration before the granting of an operating license.

In his list of equipment, the applicant has identified a manual control switch, General Electric type CR 2940. This switch has recently been identified as having failed after exposure to radiation aging. The applicant should review the specific use of this switch in the plant and ascertain that this equipment is suited for its application.

The applicant also has stated that the required minimum operating time margin of 1 hour was not applied in certain specific cases. The specific equipment should be identified by the applicant for staff review.

3.11.4 Qualification of Equipment

The following subsections present the staff assessment based on the applicant's submittal, audits of documentation at the plant site, information in the NRC Equipment Qualification Data Bank, and previous staff evaluations of equipment in other plants.

3.11.4.1 Electric Equipment in a Harsh Environment

The applicant has committed to completing several analyses important to the validity of the equipment qualification program, as stated in Section 3.11.3.3.6 above. The applicant has also committed to provide an updated Environmental Equipment Qualfication Report to reflect any changes in the qualification status and information provided to the staff. Because of these expected revisions, Appendices 3A, 3B, and 3C, which would normally list the equipment items and their qualification status, will not be included in this SER. These appendices will be provided in a future supplement after the revised submittal is reviewed.

3.11.4.2 Environmental Qualification Audit

The staff, with assistance from EG&G Idaho, Inc., performed an audit of the applicant's qualification files on February 15 through 17, 1983. The audit consisted of a review of 10 files containing information regarding the qualification status of the equipment. There were a number of exceptions taken with the findings of the applicant regarding the qualification status of the equipment. Based on the results of the audit, the staff has determined the following:

(1) For 3 of the 10 items reviewed that were classified by the applicant as qualified, the required accuracy had not been developed and compared with the demonstrated accuracy during testing. These itmes should be reclassified as not fully qualified until the demonstrated accuracy under accident conditions is shown to envelop the required accuracy. The staff may select several pieces of equipment for detailed review of the resolution of this item before licensing.

(2) Modifications to installed transmitters resulting from IE Bulletin 80-16 had not been considered in the evaluation of the qualification information. Although the applicant satisfactorily addresses the effects of these modifications, he should address how changes to other equipment items resulting from IE Bulletins, Circulars, and Information Notices have been or will be evaluated for their impact on qualification.

(3) For the same transmitter, the applicant determined by the Arrhenius equation that an "O-ring" sealing the electronics housing had an expected life of 40 years. However, the applicant was unable to address the type and frequency of surveillance to be performed to determine if unanticipated age-related degradation is occurring. Recent information has revealed that a failure was observed during qualification tests of Rosemount transmitters as a result of the inability of the seal to prevent steam ingress into the electronics housing. Based on this, the staff will not accept analysis in lieu of testing to address the effects of age-related degradation on the seals of any equipment containing susceptible electronic components, unless there are valid reasons to the contrary (environmental conditions, etc.).

One other file, for a level switch, did not contain aging data to support a calculated life of 40 years and only selected pages of a referenced test report were included in the file. The complete test report was provided at the end of the audit but was not made part of the qualification file. A cursory review of the report revealed that maintenance was required at 1- and 5-year intervals to obtain a 40-year life. The applicant did not address these requirements.

Because aging was addressed exclusively by analysis in the majority of the files reviewed, the applicant should describe the approach that will be taken to account for material degradation.

(4) During the plant walk-down it was noted that flexible conduit connected to electrical equipment had not been included in the environmental qualification program. Failure of this conduit under accident conditions could permit steam to enter sealed portions of instruments and cause equipment failures. This item should be added to the program and qualified for the postulated environments.

Also noted during the walk-down were several instances where the installed equipment was not representative of the tested equipment, specifically

- An electronics housing for a transmitter did not contain a threaded metal plug for sealing but instead used a plastic insert intended only to protect the threads. The insert does not provide leaktight

integrity and could permit steam from a high-energy line break to enter the housing.

- A pressure switch was described as being sealed with RTV silicone rubber at the lead wire entrance cavity to exclude moisture from the device internals during qualification tests. This type of sealing was not evident at plant installation, and the applicant could not determine if the same type of sealing was provided in the installed configuration.

Because of the discrepancies identified, the applicant should reevaluate the adequacy of the plant walk-down performed before the staff's audit. From the information in the qualification files on installed equipment and the results of the staff's walk-down, it is apparent that environmental qualification concerns were not adequately addressed. The staff will review the applicant's approach to the resolution of this item prior to licensing.

(5) One item that could be exposed to elevated temperatures and 100% relative humidity from a high-energy line break was qualified by evaluation of tests for individual components in the device; type testing of the assembled device had not been utilized as required by NUREG-0588. Although additional review by the applicant established that the item, a transformer, was not required to function during line break conditions, other equipment in the program may have been similarly reviewed and considered to be qualified. The applicant indicated during the audit that all other equipment has been qualified for steam conditions by type testing. To verify this, the staff will review the applicant's revised list of equipment and compare qualification methods with those described in the staff's Equipment Qualification Data Bank.

(6) During the plant walk-down and review of the qualification files, it was evident for one item that traceability and similarity between the tested piece of equipment and the installed equipment was not established. The applicant has not demonstrated conclusively that the material data reported in the files apply to the component materials of the installed equipment. The applicant should review the qualification program and establish that all data reported are applicable.

3.11.4.3 Environmental Qualification of Mechanical Equipment

Three mechanical equipment qualification files were reviewed by the staff. In general the same comments made for electrical equipment apply to the mechanical equipment. Qualification is based on analysis to a great extent, especially to demonstrate radiation and aging resistance. For example, radiation resistance of the "O-rings" on a "qualified" air operator on the main steamline is achieved by a vague referenced statement that in one test the "seals perform acceptably." Similarity of material compound and similarity of application were not demonstrated. For another material, the required radiation dose was not enveloped by the reported qualification dose. A replacement interval was not specified to justify the lower value.

The applicant should review the mechanical equipment qualification files to ascertain that all deficiencies are removed. The staff may select additional pieces of equipment for detailed review. Additionally, the applicant should submit the results of his review for all safety-related mechanical equipment located in a harsh environment. For any equipment that will not be demonstrated fully qualified before an operating license is granted, justification for interim operation should be submitted, along with proposed corrective actions and a schedule for completion.

3.11.5 Conclusions

On the basis of its review, the staff finds that the applicant must provide the required information, identified above, to demonstrate full compliance with 10 CFR 50.49 and all applicable regulations. The qualification information should be provided to allow sufficient time for staff review and approval before an operating license is issued. The staff's evaluation will be addressed in a future supplement.

APPENDIX 3D

SAFETY-RELATED SYSTEMS
IN THE ENVIRONMENTAL QUALIFICATION PROGRAM

A. Emergency Reactor Shutdown

Reactor Protection System
  Average Power Range Monitor
  Local Power Range Monitor System
Control Rod Drive System

B. Primary Containment Isolation

Containment Instrument Air System
Isolation Valves in the following systems:

RRC Hydraulic Control
Main Steam System
Reactor Feedwater System
Reactor Recirculation System
High Pressure Core Spray System
Low Pressure Core Spray System
Standby Liquid Control System
Residual Heat Removal System
Reactor Core Isolation Cooling System
Containment Atmosphere Control
Containment Supply Purge System
Containment Exhaust Purge System
Reactor Closed Cooling System
Reactor Water Cleanup System
Equipment Drain System
Floor Drain System
Containment Instrument Air System
Process Instrumentation System
Control Air System
Fuel Pool Cooling System
Traversing In-Core Probe System

C. Reactor Core Cooling (Short Term)

High Pressure Core Spray System
Low Pressure Core Spray System
Main Steam System
Residual Heat Removal System
Containment Instrument Air System
Standby Service Water System

D. Containment Integrity

Containment Atmosphere Control System
Containment Return Air System
Containment Vacuum Breaker System
Residual Heat Removal System
Standby Service Water System

E. Core Residual Heat Removal

Residual Heat Removal System
Standby Service Water System

F. Prevent Release of Radioactive Material

Standby Gas Treatment System
Main Steam Leakage Control System
Standby Service Water System
Leak Detection System
Miscellaneous Drain System
Reactor Building Exhaust Air System (Reactor Building Isolation)
Reactor Building Outside Air System (Reactor Building Isolation)

4 REACTOR

4.2 Fuel System Design

4.2.3 Design Evaluation

4.2.3.1 Fuel System Damage Evaluation

(4) External Corrosion and Crud Buildup

Waterside Corrosion

Corrosion problems associated with stainless steel cladding in boiling water reactors (BWRs), together with a desire to improve neutron economy, led to a change some years ago from stainless steel to Zircaloy cladding material, which has good resistance to the hot water and steam environment encountered under typical BWR operating conditions (Garzarolli et al., 1978). In several recent cases, however, cladding failures have been associated with external "waterside" corrosion (GE Projects Division Memorandum, 1979, and Manry, 1981), and these occurrences have been characterized by GE as "crudinduced local corrosion failure" (NEDE-24343-P). The corrosion is reportedly associated with a variably high copper concentration in the core coolant water and a minor anomaly in the Zircaloy cladding metallurgy (Charnley, 1979; Engel, 1980; Smith, 1980; Smith, 1981; and DelGeorge, 1980). The source of the copper contamination in the affected plants appears to be the copper-bearing main condenser tubes (DelGeorge, 1980). All the plants affected have copper alloy condenser tubing. It is notable also that virtually all the BWR waterside corrosion failures have involved gadolinia burnable poison rods.

The NRC staff has been following this issue generically, and in a recent meeting with the staff, GE identified (Tokar, 1982) what were believed to be some factors responsible for the corrosion failures and stated that a change had been made in the manufacturing process to ensure that such failures will not occur in newly manufactured fuel bundles. GE's presentation provided an explanation of the problem, and the solution appears plausible (ibid). Further documentation on this subject has been provided in a recent letter from the applicant (Bouchey, 1982c). This letter confirmed that all susceptible cladding will be eliminated from the WNP-2 environment. The staff, therefore, concludes that this issue should be considered resolved for WNP-2.

Crud Buildup

The buildup of a corrosion film and a crud layer on the outer surface of a fuel rod during irradiation causes gradual flow reductions and impedes heat transfer to the coolant. The effects of crud buildup on flow are discussed in SER Section 4.4.5. As indicated in Section 2.4.2.2 of NEDE-24011, GE calculates the cladding surface temperature using the cladding surface heat flux at a given

axial position of a fuel element in conjunction with an overall cladding-to-coolant film coefficient that is taken to represent the combined effects of crud and oxide resistances and a liquid film resistance based on the Jens-Lottes wall superheat equation (Jens and Lottes, 1951). The impact of high cladding temperatures, such as decreased yield strength and reduced cladding thickness due to oxidation, was considered in GE's design evaluation (NEDE-24011). GE's methods for analyzing the effects of oxidation and crud on fuel cladding temperatures were reviewed and approved in connection with NEDE-24011, and the NRC staff, therefore, finds that approach acceptable for WNP-2.

(5) Dimensional Changes

Channel Box Deflection

Boiling water reactor (BWR) fuel channels provide structural stiffness for the fuel assemblies and distribute the coolant flow between the assemblies and channel bypass regions. The channels are subject to time-dependent, permanent dimensional changes (i.e., deflections) that result from irradiation, creep, and stress-relaxation effects. The resultant bulge (resulting from long-term creep) or bow (resulting from differential irradiation-induced axial growth) reduces the size of the gap available for control blade insertion. Channel box deflection is thus a phenomenon that can limit channel life because of the potential adverse effects on the ability of the control blades to move freely.

In a generic topical report (NEDE-21354-P), General Electric (GE) describes a channel lifetime prediction method and a backup recommendation for periodic channel deflection measurements that consist of settling friction tests. Upon consideration of the factors involved, the NRC staff concluded that the settling friction tests or an acceptable alternative (such as channel dimensional deflection measurements) should be performed, and in a memorandum (Rubenstein, 1981) the staff outlined a method that could be used to resolve the channel box deflection issue for several near-term BWR operating license applications, including WNP-2. Basically, the staff advocated a multistep procedure that had been proposed bv the Zimmer applicant. The key ingredient of the Zimmer plan was a commitment to (1) perform some control rod settling friction tests, which would provide an exact profile of control rod drive friction versus position at refueling outages, or (2) make some actual channel dimensional measurements. Several plants agreed to the Zimmer proposal. Subsequently, the BWR Licensing Review Group (LRG-II) submitted a position paper (Holtzscher, 1982) on channel box deflection that incorporated several of the same features as the Zimmer proposal (the settling friction test was simplified). The LRG-II position was approved (Rubenstein, 1982) for the LRG-II plants (i.e., River Bend and Perry), and a letter (Schwencer, 1982) was sent to WPPSS indicating the NRC staff's position on this issue at that time.

In response to the Schwencer letter, WPPSS stated (Bouchey, 1982b) that a channel management program for WNP-2 has been initiated that includes the following features:

(1) Compiling complete operating history records for each channel. Data to be collected include channel location, orientation of welded sides, exposure, and control history.

(2) Compiling complete analytical history records for each channel including fast fluence (>/MeV) and flux gradient history.

(3) Measurement of post-operation channel box deflection.

Items 1 and 2 are consistent with the Zimmer and LRG-II proposals. The main difference in the WPPSS program lies in the emphasis on channel box deflection measurements. WPPSS proposes to measure channel box deflection after each refueling outage for selected channels that are discharged to the spent fuel pool. The reuse of discharged channels (the nominal design lifetime of BWR fuel channels is one fuel assembly lifetime, which currently is about 4 or 5 years) would be determined based upon those measurements as compared to predetermined criteria. Other items to be addressed in this program include development of channel manufacturing history data and analytical prediction capability.

In support of its proposed channel management program, WPPSS referred to some recently available data from Commenwealth Edison measurements that indicate that major channel bowing may be a strong function of channel manufacturing history rather than location of the channel within the core. The Commonwealth Edison data alluded to in the WPPSS letter are probably the same as that described in detail in a recent Electric Power Research Institute (EPRI) report (EPRI NP-2483) on a rather exhaustive study funded by EPRI. As indicated in the Bouchey letter (1982b) (and in Section 4 of the EPRI report), the Commonwealth Edison data indicate that prime candidates for channel bowing are those manufactured from mismatched halves; i.e., channels manufactured from two pieces of stock material not from the same original batch. It is notable that Car Tech channels avoid this potential problem because the channels are made by rolling and welding single sheets of material. The GE fabrication process, on the other hand, does not preclude use of unmatched halves. WPPSS has identified which of the WNP-2 channels are manufactured from mismatched halves (75 out of 764) and has set up special plans to manage the use of these channels to minimize potential bowing. Those measures will include taking advantage of core locations that are not adjacent to control blades and identifying locations of minimal exposure and fast flux tilt. In addition, WPPSS is proposing to take a number of operational actions to monitor channel distortion in the core, including scram time and rod notch testing prior to startup after each reload. For control rods that fail those tests, the settling friction test described in Section 4.4.2 of NEDE-21354-P would be performed.

The above described channel box management program committed to by the applicant for WNP-2 reflects the latest state-of-the-art information on this issue and is supported by results of a comprehensive study funded by EPRI. Based on the information from that study, the NRC staff concludes that the proposed program is eminently sound and that its implementation by WPPSS will provide adequate assurance that channel box deflection will not become a problem in WNP-2. This removes the need for potential license condition 2.

Fuel Rod Bowing

A 1977 version of a GE fuel experience report (NEDE-21660-P) stated that BWR fuel operating experience, testing, and analysis indicate that there is no significant problem with rod bowing. The staff recently completed (Rubenstein,

1983) a review of a GE generic topical report (NEDE-24289-P) that is intended to update the GE rod bowing experience. On the bases of (1) the reported GE data base and GE's statement that "To date, no significant fuel rod bowing has been detected in GE BWR fuel assemblies" [sic, excluding segmented-rod designs] and (2) the NRC staff's calculations using other vendors' proprietary information, the NRC staff concludes that significant fuel rod bowing in GE BWR fuel is not anticipated and no operational penalties on GE BWR fuel are warranted at this time. If adverse rod bowing behavior (gap closures greater than 50%) is observed in GE-supplied fuel in the future, NRC should be notified to ascertain the need for critical power ratio penalties. This resolves confirmatory item 12.

4.6 Functional Design of Control Rod Drive System

In the SER, the NRC staff stated that its review of the applicant's response to the Office of Analyses and Evaluation of Operational Data (AEOD) May 3, 1981 report entitled "Safety Concerns Associated with a Pipe Break in the BWR Scram System" was not complete. The NRC staff has completed its review of the applicant's submittal and the additional information provided by submittals dated December 9, 1982 and February 3, 1983. The results of the applicant's analysis indicated that the scram system pipe break identified in the AEOD report would not result in flooding of safety-related equipment and would not produce any adverse environmental effects. The applicant provided a discussion of the procedure needed to isolate such a reactor coolant system leak and verified that the effects of the escaping reactor coolant would not prevent personnel from entering the area and isolating the leak. Thus the applicant has adequately addressed the May 3, 1981 AEOD report concerns, and the NRC staff agrees with the applicant's conclusions.

Based on the above, the NRC staff concludes that the applicant has adequately addressed the concerns expressed by AEOD in its May 5, 1981 report. The design of the control rod drive system meets the applicable acceptance criteria of SRP 4.6 (NUREG-0800). This resolves outstanding issue 28.

7 INSTRUCTIONS AND CONTROL

7.3 Engineered Safety Features Systems

7.3.2 Specific Findings

7.3.2.4 Standby Service Water System

The standby service water (SSW) system was designed to use multiplexed signals to operate associated pumps and valves. The NRC staff raised several concerns regarding the use of multiplexing in this Class 1E application. Of particular concern were the potential effects of electromagnetic interference (EMI) on the SSW multiplexer systems, and the inability to manually operate SSW system components remotely, independent of the multiplexer systems.

The applicant has since committed to implement design modifications that will remove all safety-related functions from the multiplexers. This will allow (1) the functioning of the SSW pumps and valves in the primary flow path without the multiplexer, and (2) manual initiation/control capability for SSW components from the control room, independent of the multiplexers. The multiplexers will remain operational, providing the operator with supplementary information from the SSW pumphouse. Examples of this information are spray pond level and temperature, pump discharge pressures, and pump motor and bearing temperatures. Sufficient instrumentation independent of the multiplexers is provided in the control room to allow the operators to verify SSW system operability. This instrumentation includes valve position and pump running status lights, SSW flow through the RHR heat exchangers, and low flow alarms for the components served by the SSW system. The applicant plans to complete these modifications before fuel load.

The NRC staff has determined (based on its review of the SSW system as described and on supporting information provided in WPPSS letters G02-83-167 dated February 23, 1983, and G02-83-266 dated March 28, 1983) that the SSW system instrumentation and controls are acceptable. This resolves outstanding item 10. The applicant will be required to submit the final drawings (electrical schematics) for the affected components for confirmatory review when the design modifications are completed. This resolves outstanding issue 10.

7.6 All Other Instrumentation Systems Required for Safety

7.6.2 Specific Findings

7.6.2.3 Rod Block Monitor

The NRC staff identified four concerns regarding the WNP-2 rod block monitor (RBM) function as stated in the SER. These are

(1) The four flow monitors are interconnected by armored cable and shielded cables, and there are open spaces around the cables that penetrate fire barriers between redundant channels.

(2) Both RBM channels are connected by data buses that are enclosed in a metal shield and run along the top of the cabinet.

(3) The wiring of the RBM bypass switch may not satisfy the separation criterion (minimum separation of 6 inches).

(4) The RBM is a modified design and contains multiplexing circuitry that interfaces with the new reactor manual control system.

The WNP-2 RBM is identical to other RBM designs for which the above four concerns were identified and subsequently resolved. The applicant was to confirm that similar plant modifications to resolve these concerns have been implemented. The applicant has submitted information indicating that corrective actions to resolve these concerns have been or will be implemented as follows:

(1) As stated in the NRC staff's fire protection review (SER Section 9.5.1), the applicant has committed to inspect all fire barriers within the plant and to seal any unsealed penetrations with an approved fire resistant material with a rating equivalent to that of the barrier itself. Any deficiencies regarding the open spaces identified above will be corrected, according to the applicant's commitment. This resolution is acceptable to the NRC staff.

(2) The NRC staff reviewed the tests performed on the devices used to isolate the redundant RBM channels from each other in the Zimmer design and concluded that these devices provide adequate isolation. The applicant has indicated that these same devices are used in the WNP-2 RBM design. Therefore, the NRC staff considers this item resolved.

(3) The applicant has stated that the wiring of the WNP-2 RBM bypass switch is being rerouted to provide acceptable separation. The NRC staff considers this item resolved.

(4) The multiplexing circuitry employed in the WNP-2 RBM and reactor manual control system processes and transmits information about reactor status, control rod position, rod block logic, and rod control logic through common electrical circuits. In earlier BWR designs this was accomplished by individual circuits. The new design has a self-testing capability to ensure that this information is being processed correctly. The NRC staff believes that the new multiplexing design is acceptable, provided this self-testing capability is formally implemented through Technical Specifications. The Technical Specifications will require that this is done.

On the bases discussed above, the NRC staff has concluded that the WNP-2 RBM is acceptable. This resolves confirmatory item 20.

9 AUXILIARY SYSTEMS

9.5 Other Auxiliary Systems

9.5.1 Fire Protection Program

In the SER, two open items concerning fire protection were identified: verification of unlabeled fire doors, and deletion of a fire suppression system in fire areas.

By letters dated April 22, June 30, September 20, October 4, and October 5, 1982, the NRC staff received additional information concerning these open items.

In the SER, the NRC staff also stated that the applicant proposed to equip all manual hose stations in the plant with 150 feet of hose. At the request of the NRC staff, by letter dated January 28, 1983, the applicant agreed to modify the standpipe hose system to provide enough hose stations so that effective water streams can reach any area of the plant with a maximum of 100 feet of 1 1/2-inch hose, in accordance with Section C.6.c of BTP CMEB 9.5-1. By letter of March 4, 1983, the applicant proposed to deviate from the NRC staff guidelines by equipping hose stations in the reactor building with 150 feet of hose. This deviation was justified on the basis of water distribution system hydraulics, the capabilities of the plant fire brigade, and the cost and potential repercussions of a fire on safety-related equipment.

SER Sections 9.5.1.5(1), 9.5.1.6(3), 9.5.1.8, and 9.5.1.9 have been revised to reflect the results of the NRC staff evaluation of this information.

9.5.1.5 General Plant Guidelines

(1) Building Design

Fire areas are defined by walls and floor/ceiling assemblies. Walls that separate buildings and walls between rooms containing safe shutdown systems are 3-hour-fire rated. Floor/ceiling assemblies are 1-1/2-, 2-, or 3-hour-fire-rated assemblies. In cases where the fire rating is less than 3 hours, the staff has evaluated the fuel loading and fire protection provided and found the fire rating acceptable. By letter dated December 9, 1981, the applicant has committed that all fire-rated walls and floors/ceilings will be qualified in accordance with ASTM E-119. Based on its review, the NRC staff concludes that the fire-rated walls and floor/ceiling assemblies are provided in accordance with the guidelines of Branch Technical Position (BTP) CMEB 9.5-1, Section C.5.a, and are, therefore, acceptable.

By letter dated December 9, 1981, the applicant has also committed to provide 3-hour-fire-rated penetration seals. The penetration seals are verified by a 3-hour-fire test in accordance with the ASTM E-119 fire test procedure. Based on this, the NRC staff concludes that the fire seal ratings meet the guidelines of BTP CMEB 9.5-1, Section C.5.a, and, therefore, are acceptable.

Door openings in rated fire barriers are provided with labeled fire doors, except for several doors that are nonrated airtight doors. By letter dated April 22, 1982, the applicant provided additional information to verify that the airtight doors are similar in construction to labeled fire doors. The doors and frames are constructed of heavy gauge welded steel, with 2-1/4 inches of internal insulating material. The doors, when closed, will be able to withstand the anticipated fire exposure, represented by burning in situ and transient combustibles, and prevent the passage of smoke as well as convective and radiant heat as effectively as a labeled fire door. This resolves confirmatory item 23.

The applicant, in Amendment 19, has committed that the fire doors will satisfy the requirements of Appendix R to 10 CFR 50, Section N, which pertains to self-closing or administrative-closing procedures. With the commitment the NRC staff finds that the fire doors meet the guidelines of BTP CMEB 9.5-1, and are, therefore, acceptable.

The applicant has provided 3-hour- and 1-1/2-hour-fire door dampers in ducts penetrating fire-rated walls. Where duct penetrations have less than a 3-hour-fire rating, the NRC staff has evaluated the fuel loading and fire protection provided and found the fire rating acceptable. Based on its review, the NRC staff concludes that the fire doors and dampers will be provided in accordance with the guidelines of BTP CMEB 9.5-1, Section C.5.1, and are, therefore, acceptable.

The use of plastic materials, in particular halogenated plastics, has been minimized. No flammable liquids (with the exception of the diesel generator oil day tanks covered in Section 9.5.4.2 of the SER) as defined by National Fire Protection Association (NFPA) Standard 30 are stored in the plant. The NRC staff finds that this conforms to the guidelines of BTP CMEB 9.5-1, Section C.5, and is, therefore, acceptable.

Interior walls and structural components, thermal insulation materials and components, and radiation shielding materials are noncombustible. Decontaminable coatings and finish painting materials have a flame spread of less than 25. The NRC staff finds this to be within the guidelines of BTP CMEB 9.5-1, Section C.5.a, and, therefore, acceptable.

All high-voltage transformers located inside safety-related building areas are insulated or cooled with noncombustible liquid. There are no oil-filled transformers located within 50 feet of the exterior wall of a building containing safety-related equipment. This meets the guidelines of BTP CMEB 9.5-1, Section C.5.a, and is, therefore, acceptable.

9.5.1.6 Fire Detection and Suppression

(3) <u>Sprinkler and Standpipe Systems</u>

The wet pipe sprinkler system and standpipe hose system are connected to common risers from the underground water supply loop. Looped interior headers are provided. This design is in compliance with BTP CMEB 9.5-1, Section C.5.c, and is, therefore, acceptable.

The automatic sprinkler systems (wet pipe sprinkler systems, pre-action sprinkler system, and deluge water spray systems) are designed to the provisions of NFPA Standards 13, "Standard for the Installation of Sprinkler Systems," and 15, "Standard for Water Spray Fixed Systems."

The areas that are being equipped with automatic water suppression systems are listed in FSAR Amendment 24.

By letter dated January 21, 1982, the applicant stated that 15 fire areas contain cables associated with redundant shutdown systems. To ensure post-fire shutdown capability, these cables must be protected. In FSAR Amendment 24, and in a letter dated October 4, 1982, the applicant revised this number from 15 to 10. The reduced number reflects the establishment of redundant shutdown capabilities in fire areas separate from those plant locations originally identified as containing redundant safety divisions.

The following three areas will be completely protected by an automatic sprinkler system:

(1) cable spreading room (RC-11)
(2) cable chase (RC-111)
(3) corridor (TG-1)

In the following seven areas, the applicant proposes to deviate from the staff guidelines to the extent that they require automatic fire suppression systems:

(1) remote shutdown room (RC-IX)
(2) switchgear room #2 (RC-XIV)
(3) general floor area (R-1) - elevation 471'-0"
(4) general floor area (R-1) - elevation 501'-0"
(5) general floor area (R-1) - elevation 522'-0".
(6) general floor area (R-1) - elevation 548'-0"
(7) general floor area (R-1) - elevation 572'-0"

In lieu of an automatic sprinkler system, the applicant proposes to completely protect one safety division with a subliming and insulating coating that is capable of withstanding a 3-hour-fire exposure as defined in American Society for Testing and Materials (ASTM) Standard 119. The material has been demonstrated to protect the cable from visible fire damage and to maintain circuit integrity during fire exposure. The material is not adversely affected by a water hose stream and is capable of limiting temperature rise on the unexposed side to not more than 250°F above ambient, which is well below the temperature at which similar Institute of Electrical and Electronics Engineers (IEEE)-qualified cabling began to fail in tests conducted independently for NRC at Underwriters' Laboratories. The NRC staff concludes that this protection, coupled with the smoke detection systems in these areas, provides an equivalent level of fire safety to that achieved by the installation of a sprinkler system.

The NRC staff finds the deletion of automatic sprinkler systems in the proposed areas an acceptable deviation from Section C.6.c. of BTP CMEB 9.5-1. Therefore, the fire protection provided for these rooms is acceptable.

Manual hose stations are provided in stairwell enclosures throughout the plant except in containment. With the exception of the reactor building, all hose stations are equipped with 100 feet of 1.5-inch hose, in accordance with Section C.6.c of BTP CMEB 9.5-1. By letter dated March 4, 1983, the applicant proposed to deviate from the NRC staff guidelines by utilizing 150 feet of hose to protect all areas of the reactor building. One hundred feet of hose will be pre-connected to the hose outlets. The remaining 50 feet of hose will be connected only if required to suppress a fire in a remote area.

The configuration of the reactor building is such that it is possible to protect most of the floor area with 100 feet of hose. The remaining areas that necessitate the use of the additional 50 feet of hose contain the following systems:

Elevation 606'-10.5"
no safety-related equipment

Elevation 572'
"A" train systems associated with the emergency core cooling system and the residual heat removal (RHR) heat exchanger

Elevation 548'
"A" train systems associated with the RHR heat exchanger and three motor-operated valves

Elevation 522'
power supply for the RHR, reactor core isolation cooling (RCIC), and reactor water cleanup systems and the main steam drain valve

Elevation 501'
main steam isolation valve

Elevation 471'
RHR piping valves and the dc power supply to motor-operated valves

Elevations 441' and 444'
"A" train systems associated with the RCIC and severe water systems and dc-operated valves

Elevation 422'3"
no safety-related equipment

If a fire damages any of the above-listed equipment, an alternate capability exists in a separate fire area, or compensating actions could be taken, such as manual operation of valves. Consequently, there is no safety significance to the proposed deviation.

The plant water distribution system is capable of supplying hose streams in the reactor building with the required quantity of water and pressure (125 gpm, 65 psi) through 150 feet of hose. In addition, the plant fire brigade is capable of deploying the hose lines quickly enough to suppress postulated fires.

Based on the above evaluation, the NRC staff concludes the use of 150 feet of hose in the reactor building represents an acceptable deviation from Section C.6.c of BTP CMEB 9.5-1. This resolves outstanding issue 31.

The applicant has not identified the seismic design of standpipe systems, which is recommended in BTP CMEB 9.5-1, Section C.6.c.(1). For plants for which construction permits were issued prior to July 30, 1976, the guidelines in Appendix A to BTP ASB 9.5-1 have no requirement for seismic design for standpipe systems. Therefore, this is an acceptable deviation from the guidelines of BTP CMEB 9.5-1, Section C.6.c.(1).

9.5.1.8 Summary of Deviations from BTP CMEB 9.5-1

Five deviations from the guidelines of BTP CMEB 9.5-1 have been identified. Those items have been approved, and they are

(1) control room vent closure
(2) seismic design of standpipe systems
(3) floor drains in day tank room
(4) deletion of a fire suppression system in the following seven plant areas:

    remote shutdown room (RC-1X)
    switchgear room #1 (RC-XIV)
    general floor area (R-1) - elevation 471'-0"
    general floor area (R-1) - elevation 501'-0"
    general floor area (R-1) - elevation 522'-0"
    general floor area (R-1) - elevation 548'-0"
    general floor area (R-1) - elevation 572'-0"

(5) the use of 150 feet of hose at hose stations in the reactor building

9.5.1.9 Conclusion

Based on its evaluation, the NRC staff concludes that the fire protection program with the accepted deviations listed in Section 9.5.1.8 above meets the guidelines of BTP CMEB 9.5-1 and GDC 3 and is, therefore, acceptable.

9.5.8 Emergency Diesel Engine Combustion Air Intake and Exhaust System

As stated in the SER, the applicant had not adequately addressed potential blockage of the combustion air intake structure as a result of the design worst case dust storm and volcanic ashfall and blockage of the diesel engine exhaust stack as a result of severe meteorological events such as freezing rain, snow, dust storms, heavy rain, and volcanic ashfall. (The evaluation and acceptability of the tornado-missile protection for the diesel engine exhaust stack are addressed in Section 3.5.2 of this supplement.)

In letters dated August 5 and December 28, 1982, the applicant provided information on the capabilities of the diesel engine to operate under adverse meteorological conditions (snow, freezing rain, heavy rain, dust storms, and volcanic ashfall). The applicant stated that if any blockage did occur as a result of adverse meteorological conditions, the diesel engine air intake and

exhaust structures would only be partially blocked and engine operation would not be affected. The NRC staff has reviewed the submitted information and concurs with the applicant.

Based on its review, the NRC staff concludes that the emergency diesel engine intake and exhaust system meet the requirements of GDC 2, 4, 5, and 17; meets the guidance of the cited RGs and SRP 9.5.8; can perform its design safety function; and meets the recommendations of NUREG/CR-0660 and industry codes and standards. It is, therefore, acceptable. This resolves outstanding issue 18.

13 CONDUCT OF OPERATIONS

13.1 Organization Structure of Applicant

13.1.1 Management and Technical Support Organization

13.1.1.1 General

The applicant has made organizational changes that establish the new positions of Director of Operations, Director of Support Services, and Director of Licensing and Assurance, reporting to the Managing Director.

Reporting to the Director of Operations will be the Director Power Generation, Director WNP-4/5 Termination Program, Director WNP-3 Program, Director WNP-2 Program, Director WNP-1 Program, and Director Technology. These directors formerly reported directly to the Managing Director, Washington Public Power Supply System (WPPSS). D. W. Mazur has been appointed to the position of Director of Operations. He has about 19 years of nuclear experience and was formerly the Director WNP-1/4 project.

The Director of Support Services picks up the functions of administrative, security, health physics, industrial safety, emergency preparedness, fire protection, and technical training support services. These functions, except for administrative, were formerly under the Director, Safety and Security. J. W. Shannon has been appointed to the position of Director, Support Services. He has about 30 years of nuclear experience and was formerly the Director, Safety Security.

The Director, Licensing and Assurance will be responsible for licensing support, quality assurance, and nuclear safety assurance. Licensing support and nuclear safety assurance were formerly under the Director, Safety and Security, and quality assurance was a separate organization. The Directors of Safety and Security and Quality Assurance formerly reported directly to Managing Director, WPPSS. R. B. Glasscock has been appointed to the position of Director, Licensing and Assurance. He has about 24 years of nuclear experience and formerly was the Director, Quality Assurance.

The NRC staff has reviewed these changes and finds that they meet the "Guidelines for Utility Management Structure and Technical Resources (NUREG-0731) and meet the criteria of SRP 13.1.1 (NUREG-0800). Therefore, the NRC staff concludes that the changes are acceptable.

Figure 13.1 has been revised to reflect the corporate reorganization. This resolves outstanding issue 32.

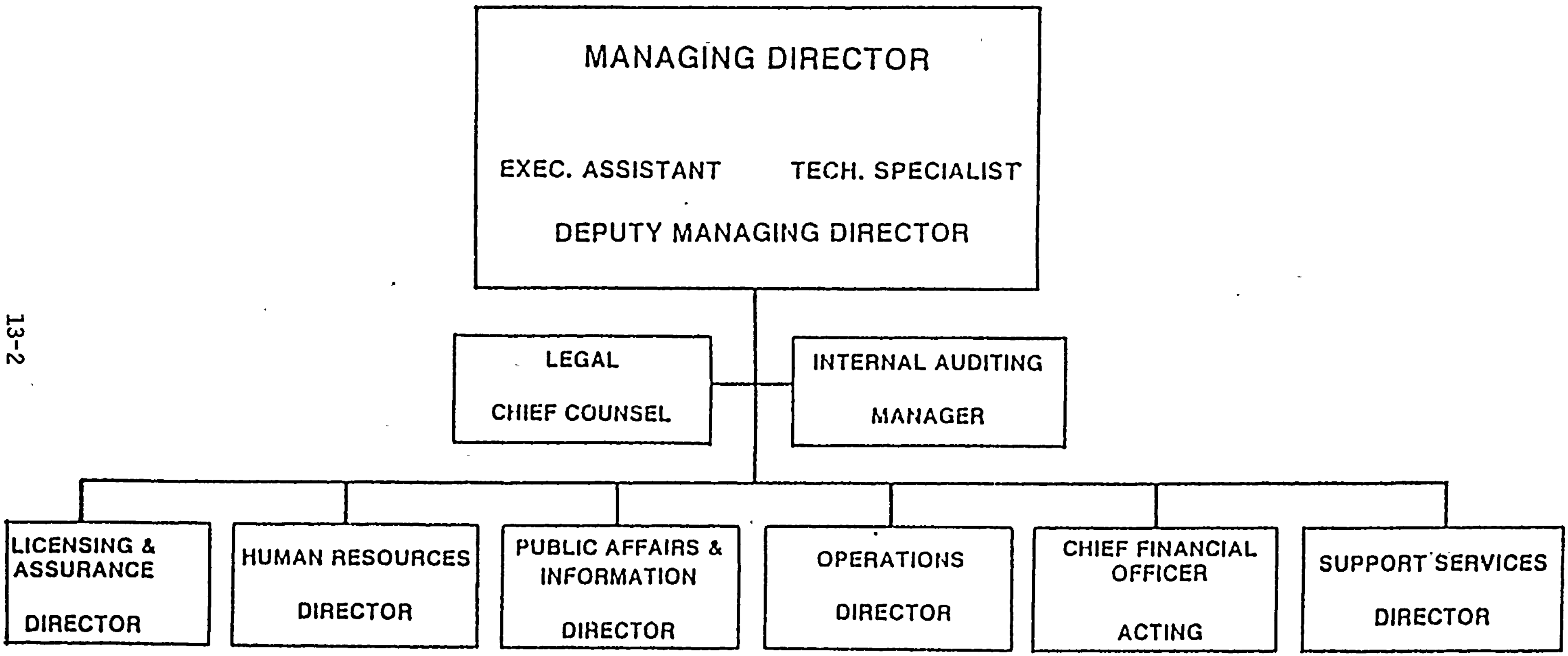

Figure 13.1 Washington Public Power Supply System organization

APPENDIX A

CONTINUATION OF CHRONOLOGY
WPPSS NUCLEAR PROJECT NO. 2

December 21, 1982	Issuance of SER Supplement No. 2.
December 23, 1982	Letter from applicant regarding request for additional information on fuel rod corrosion measures.
December 28, 1982	Letter from applicant regarding clarification of diesel generator capability to withstand severe meteorological events.
December 28, 1982	Letter from applicant regarding FSAR Section 8.3.
December 29, 1982	Letter from applicant regarding SER confirmatory issue 17.
December 29, 1982	Letter from applicant regarding confirmatory issue 7.
January 7, 1982	Submittal of Amendment No. 27 to the FSAR.
January 10, 1983	NRC letter requesting additional information regarding standby service water multiplexer system.
January 13, 1983	Letter from applicant regarding qualifications of engineers assigned to the WNP-2 design reverification reviews.
January 17, 1983	Letter from applicant regarding visual examination acceptance criteria for reverification inspection of welded structures (QVI-09, revision 0).
January 18, 1983	Letter from applicant regarding Hanford Site Evacuation Time Assessment Study.
January 18, 1983	Letter from applicant regarding GDC 51 clarification.
January 20, 1983	Letter from applicant regarding plant verification program third TAA audit.
January 21, 1983	Letter from applicant regarding emergency plant coordination with the Yakima Indian Nation.
January 26, 1983	Letter from applicant regarding engineering evaluation of the sacrificial shield wall.
January 27, 1983	Letter from applicant regarding modifications to restricted area boundary.

February 1, 1983	Letter from applicant regarding control room chiller installation deferral.
February 3, 1983	Letter from applicant regarding SRSS combination of dynamic responses confirmatory issue 6.
February 3, 1983	Letter from applicant regarding preservice inspection program scram discharge system.
February 3, 1983	Letter from applicant regarding response to NRC question 010.066, NUREG-0803.
February 8, 1983	Letter from applicant regarding GDC 51 clarification.
February 8, 1983	Letter from applicant regarding additional information on the "out-of-roundness" of the containment.
February 9, 1983	Letter from applicant transmitting annual financial report.
February 14, 1983	Letter from applicant regarding addition of diesel starting air dryers.
February 15, 1983	Submittal of Amendment No. 28 to the FSAR.
February 23, 1983	Letter from applicant regarding control of heavy loads, revision 2.
February 23, 1983	Letter from applicant regarding NRC question 010.068.
February 23, 1983	Letter from applicant regarding SER outstanding issue 10 standby service water instrumentation and control design.
February 25, 1983	Letter from applicant regarding solid waste management system, FSAR Section 11.4.
March 1, 1983	Letter from applicant regarding emergency plan implementation procedures.
March 4, 1983	NRC letter regarding modifications to restricted area boundary.
March 8, 1983	Letter from applicant regarding new loads update, complete rewrite of FSAR Section 3.9.
March 9, 1983	NRC letter regarding fire hose-standpipe modifications.
March 15, 1983	Letter from applicant regarding pipe whip restraint installation.
March 16, 1983	NRC letter regarding turbine maintenance commitment for turbine missile issue.

March 18, 1983	Letter from applicant regarding draft Envirnmental Technical Specifications.
March 21, 1983	Letter from applicant regarding rewrite of FSAR Sections 4.1 through 4.4.
March 23, 1983	NRC letter requesting additional information on SER confirmatory issue 7.
March 23, 1983	Letter from applicant regarding project visual examination acceptance criteria for reverification inspection of welded structures (QVI-09, revision 1).
March 23, 1983	Letter from applicant regarding emergency operating procedures generation package.
March 23, 1983	Letter from applicant regarding confirmatory issue 22--assurance of ESF functioning (II.K.1.5) and safety-related system operability status (II.K.1.10).
March 28, 1983	Letter from applicant regarding control of heavy loads.
March 28, 1983	Letter from applicant regarding fuel rod corrosion measures.
March 28, 1983	Letter from applicant regarding closure of SER outstanding issue 10.
March 28, 1983	Letter from applicant regarding deferred shielding walls.
April 6, 1983	Letter from applicant regarding draft Technical Specification, revision 2.
April 13, 1983	NRC letter regarding staff evaluation of the BWR owners group response to TMI action plan, Item II.K.3.18, "Modifications to Automatic Depressurization System Logic."
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April 14, 1983	Letter from applicant regarding control room design review, submittal of preliminary report.
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APPENDIX B

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APPENDIX E

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16. ABSTRACT *(200 words or less)*

Supplement No. 3 to the Safety Evaluation Report on the application filed by Washington Public Power Supply System for a license to operate the WPPSS Nuclear Project No. 2, located in Richland, Washington, has been prepared by the Division of Licensing, Office of Nuclear Reactor Regulation of the U. S. Nuclear Regulatory Commission. This supplement reports the status of certain items that had not been resolved at the time of publication of the Safety Evaluation Report and Supplement Nos. 1 and 2.

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