1993 Electric Integrated Resource Plan

Technical Information

The Washington Water Power Company
April 1993

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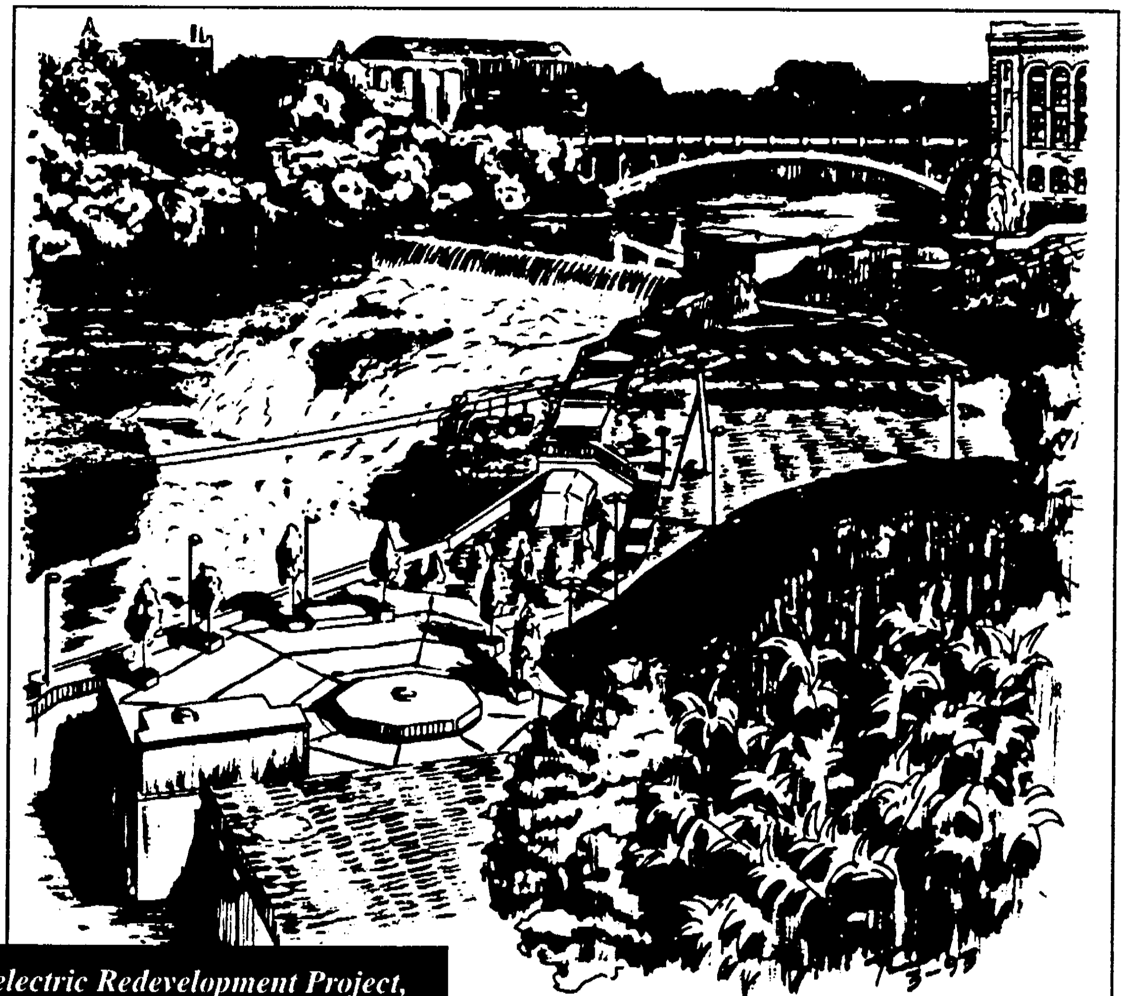

Monroe Street Hydroelectric Redevelopment Project, Completed November 1992

The Washington Water Power Company

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Technical Information

This Technical Information appendix serves as a companion document to WWP's 1993 Electric Integrated Resource Plan Summary Report. It is intended to provide additional detail. The reader may find that it contains some of the same text as the Summary Report. The author took this approach so that the Technical Information volume may stand alone.

Appendix A

1991 Action Plan Report

1991 Action Plan Report

In the 1991 Least Cost Plan, WWP listed specific action plan activities which were to be accomplished during the past two-year planning cycle. This appendix reports the company's progress on these individual action items. A summary is followed by additional detail for each action item.

Summary

Load Forecasting

Complete development of the economic model for Kootenai County.	This enhancement is reflected in the current long-term energy forecast.
Analyze the effects of wind on the peak forecast.	Primarily on the basis of qualitative analysis, the company concluded that specifically incorporating wind as a peak forecast variable is currently not feasible.
Refine peak forecast equations.	The results of this activity were applied to the peak forecast and to estimates of demand-side management capacity savings.
Assess the feasibility of developing an end-use forecasting model for the commercial sector.	WWP is currently implementing the Commercial Energy Demand Modeling System (CEDMS). Full use of the model is planned for the 1993 forecast.

Demand-Side Management Programs

Complete Initial Demand-Side Management (DSM) Assessment.	Initial technical evaluation and pilot programs were completed in 1991.
Develop Long-Term Goals & Objectives.	Near-term (5 year) goals were developed as part of the 1992 DSM tariffs filed with the WUTC and IPUC. Long-term conservation targets are determined as part of the ongoing integrated resource planning process.
Conduct a Commercial/Industrial Customer Energy Survey.	A comprehensive survey of WWP customers was completed in 1991.
Revise the DSM Assessment (using 1991 Commercial/Industrial Survey results).	Survey results, and preliminary results from the commercial end-use forecasting model (CEDMS) supplied input to the first revision of the commercial sector assessment.
Conduct and Evaluate Residential Fuel Efficiency Test Programs	WWP's $witch $aver test program was completed in 1991. Evaluation results were documented in "$witch $aver Test Program, Impact and Evaluation Report", dated November 1991.
Implement an Updated Residential Weatherization Program.	Updated electric weatherization programs (Schedule 61) became effective under WWP's 1992 DSM tariff approved by the WUTC and the IPUC.
Develop and Implement Large and Small Commercial / Industrial Programs.	New Commercial/Industrial programs (Schedule 91) became effective under the 1992 DSM tariff.

System Efficiency Programs

Implement a Distribution System Loss Savings Program.	Distribution system losses are being reduced on an ongoing basis. Loss savings are realized gradually as low loss transformers, compensating capacitors and new conductors are selected and installed as warranted by system needs.
Determine the potential for Transmission System Loss Savings.	Transmission loss savings associated with near-term (5-year) plans to meet system reliability and growth requirements have been estimated.
Implement Hydro Improvements which optimize WWP's supply of renewable energy.	Preliminary engineering and economic evaluations identified potential additions or upgrades at all existing hydroelectric facilities. The Monroe Street rebuild project was completed in 1992. Capability upgrades are being actively pursued at the Nine Mile and Cabinet Gorge plants.

Competitive Bidding

Evaluate resource proposals submitted under WWP's 1991 Request for Proposal (RFP).	WWP determined not to pursue any proposals submitted under the RFP. In December 1992, WWP petitioned the WUTC to accept its closure of the 1991 competitive bidding process.

Transmission Interconnections

Finalize economic evaluations for the WWP-BC Hydro Interconnection.	In early 1993, WWP received a Presidential Permit for the proposed transmission project. Final economic evaluations will consider the new British Columbia government's electricity export policy.
Analyze potential WWP participation in Other Interconnection projects.	The company is currently not involved in the development of any other transmission interconnections.

Purchase and Sales

Evaluate Purchase and Sales Opportunities with other utilities as they become available.	Long-term agreements were signed with two utilities. WWP is selling 50 MW of energy and capacity to the Northern California Power Agency and 150 MW of capacity to Portland General Electric. These and similar wholesale marketing activities are guided by WWP's "Electric Wholesale Guidelines".

Cogeneration Development

Implement a Cogeneration Development program within WWP's service territory.	Studies to determine the feasibility of cogeneration facilities focused on industrial facilities and state universities in WWP's service area. No cogeneration development projects are currently being pursued.

Additional Action Plan Items

Review the feasibility of maintaining the Creston Generating Site as a regional resource option.	No longer considered a preferred regional option, WWP allowed the Creston license (Site Certificate Agreement) to expire in February 1993. The company will seek to recover $11.2 million of Creston investment in future electric rate adjustments.
Identify potential constraints which limit the energy transfer capability of the WWP transmission system.	In 1991, WWP and BPA determined a plan of service to reduce a transmission bottleneck between Montana and the Pacific Northwest. Both parties will share in the cost of facilities required to increase the transfer capability between the two regions. Ongoing studies will seek to eliminate any additional transmission constraints.
Enhance the analytical capabilities of the least-cost planning effort.	The company's annual simulation model, called the Strategic Resource Planning Model (SRPM), received significant modification. Specifically, these modifications enhance SPRM's ability to reflect actual system operation and to incorporate risk into resource selection decisions. This enhanced capability is reflected in the development of this plan. Preliminary development of an additional planning tool was completed in early 1993. The capacity planning model will be used to study daily peak and energy requirements under extreme weather conditions.
Refine prior evaluations of a Firming Nonfirm resource strategy.	Detailed analysis examined the feasibility of installing simple-cycle combustion turbines to back-up the production of nonfirm energy from WWP's existing hydro system. Results indicated that up to 92 MW of nonfirm hydro energy could be converted to a firm energy resource and would provide a $30 million dollar net present value benefit. This effort provides the basis for an ongoing evaluation of a potential firming nonfirm strategy.
Pursue extension of the existing Mid-Columbia power purchase agreements.	WWP is currently participating in negotiations with Grant County PUD for the purchase of energy produced by the existing Priest Rapids and Wanapum hydroelectric facilities.

Load Forecasting:

• Economic Model

Complete development of the economic model of Kootenai County and re-specify the load equations in Idaho in order to better capture varying economic impacts in the service territory.

This activity was implemented during 1991. The growth patterns in Idaho changed somewhat, reflecting the different economic growth patterns. This information has been provided to the Technical Advisory Committee. The forecasts being prepared for the 1993 Plan will incorporate this activity.

• Peak Variables

Analyze the effects of wind on peak.

The impetus for this action plan item was a direct result of the fierce windstorms that occurred during the winter of 1989/90, followed by another "Siberian Express" during the winter of 1990/91. Unfortunately, actually quantifying the impact of wind on peak load falls within the range of the standard error of the regression. In other words, our ability to statistically estimate electric peak demand for an average design day is somewhat restricted. Peak is affected by temperature, cloud cover, snow cover, wind direction, and wind speed. The impacts of these climatological events are affected by hours of daylight, whether the peak occurs on a weekend or a weekday, and even on which day of the week. Temperature is the dominant variable accounting for most of the variation in peak load, illustrated by an R-squared value of 93 percent. The standard error of the regression is 48 MW. Establishing "normals" for these additional variables is a further complexity, particularly since these models are specified at monthly frequency. Fundamentally, we can observe some contributions by these climatological events when evaluating a specific event, suggesting a qualitative interpretation of the actual peak. Statistically, by using 10 years of monthly data, we are in effect taking the average values of these not included climatological variables to estimate the most likely peak. This basic analysis has lead us to the conclusion that incorporation of wind as a specific variable in the peak forecasting model is not feasible at this time.

• Peak Forecast Equations

Refine peak forecast equations and include additional data for the 1990/91 and 1991/92 heating season.

This activity has been completed. In addition, peak savings estimates from DSM programs have been estimated for each planned program.

• Model Assessment

Prepare an assessment of the cost and feasibility of developing an integrated natural gas and electric end-use forecasting model for the commercial class.

During 1991, we conducted this assessment. Because of the advantages of modeling the commercial class with this approach, as well as the difficulty of assessing the DSM potential in this heterogeneous sector, we have purchased the Commercial Energy Demand Modeling System (CEDMS) from Jerry Jackson and Associates, of Chapel Hill, NC. The first commercial survey will be used to calibrate the model, and the model will be used to perform a DSM assessment including supply curves. Calendar year 1992 is the implementation year, with full forecasting planned for the forecast to be prepared in 1993. A series of three workshops on the model, data, and supply curves will occur in order to allow staff and interested parties a full public airing of the model process.

Source: Randy Barcus, WWP Marketing & Sales-Forecast & Research, 1992

Demand-Side Resource Programs:

• Complete Initial DSM Assessment

This activity covers completing the first comprehensive DSM assessment which was initiated in 1990. Assessment to be completed in the first quarter of 1991. Assessment results will be used to begin implementation of DSM programs.

WWP's initial assessment of DSM potential was prepared by Synergic Resources Corporation and was completed in April 1991. The results were presented in a report entitled "Evaluation of Demand Side Management Options for Washington Water Power." This report evaluated 68 DSM options and identified approximately 72 aMW of cost-effective measures.

• Develop Long-Term DSM Goals and Objectives

From the results of the initial DSM assessment, long-term goals and objectives for the acquisition of DSM will be developed. This action plan item will be completed by the end of the second quarter of 1991.

Long-term goals and objectives were developed as part of the comprehensive DSM filing which was filed in the spring of 1992 with the WUTC and the IPUC. Five year budgets and savings were presented within the DSM filings. Longer term goals were developed for integrated resource planning. WWP has identified 54 aMW of DSM savings from its tariff program through 1996 and roughly 130 aMW by the year 2012.

• Conduct 1991 Commercial/Industrial Energy Survey

This survey will be conducted to update our survey information on commercial and industrial customers. The primary goal is to gain energy use information in the small C/I customers which have not been surveyed to date. Survey planning, implementation and analysis of results are planned during the first and second quarters of 1991.

A comprehensive survey of WWP's commercial and industrial customers was completed in 1991. The survey was designed to support a wide range of program planning, forecasting, and marketing activities through helping WWP better understand its commercial and industrial customers. The survey instrument was mailed to 8,635 WWP commercial/industrial customers. The survey instruments were designed to collect information including physical attributes of the premise structure, type of major electric/gas using equipment, conservation activities already undertaken, and attitudes towards WWP.

• Revise DSM Assessment

This revision will provide an update to the initial DSM assessment to incorporate results of the 1991 Commercial/Industrial Energy Survey. The revision will be conducted in the third and fourth quarters of 1991.

WWP is using the results of the 1991 commercial/industrial survey to revise the assessment of DSM potential in the commercial sector. WWP has hired the consulting firm of Jerry Jackson and Associates to develop a commercial end-use forecasting model of the commercial sector and also perform an assessment of the DSM potential in the commercial sector. This project will provide improved estimates of the electric and gas DSM potential in the commercial sector. This project is scheduled to be completed by December 1992, with DSM supply curves available for WWP's electric and gas least-cost plans.

The decision to implement the commercial end-use forecasting model, as a tool to evaluate DSM potential, greatly increased the comprehensiveness of the results but significantly delayed how quickly this project could be completed.

- **Conduct Electric to Natural Gas Residential Water Heating and Space Heating Equipment Change Test Programs.**

Test programs will be conducted to convert residential customers from electric to gas. A Water Heat Conversion Program will target existing gas customers who have electric water heaters. A Space Heat Conversion program will target electric-only customers to encourage them to replace electric space and water heating equipment with gas equipment. The test programs will be conducted March 1 through June 30, 1991.

WWP conducted the $witch $aver test program in the spring and summer of 1991. This program's purpose was to encourage customers to replace electric space and water heating equipment with gas equipment. The program was run in Coeur d'Alene and Lewiston/Clarkston. In the Coeur d'Alene area, customers were offered significant incentives to change electric equipment to gas. In the Lewiston/Clarkston area, customers were offered only easy market rate financing. Both areas used similar promotional materials.

- **Evaluate Electric to Gas Equipment Change Programs**

A detailed evaluation of the conversion test programs will be conducted in the third and fourth quarters of 1991.

WWP presented a report entitled "$witch $aver Test Program, Impact Evaluation Report, Volumes I & II" to the Idaho Public Utilities Commission in November 1991. This report evaluated the market penetration in the two test areas, and evaluated the costs, savings and cost-effectiveness of the program.

- **Update Residential Weatherization Programs**

Revise and update the existing residential weatherization program. This will be done during the first and second quarters of 1991.

WWP's electric weatherization program was updated as part of the company's comprehensive DSM filing. In addition, a gas weatherization program was also proposed. Both the electric and gas programs became effective on April 30, 1992, in Washington and July 17, 1992, in Idaho. WWP chose not to update the weatherization program in 1991, but rather to update it along with all of the new programs filed for in 1992.

- **Implement Residential Weatherization Changes**

Make the planned changes to the program. This task includes obtaining necessary regulatory approvals. Implementation activities are planned to begin July 1, 1991.

Implementation of the updated electric weatherization program became effective when the Washington and Idaho tariffs were approved. WWP is currently implementing the programs based on the new tariffs. WWP chose not to update the weatherization program in 1991, but rather to update it along with all of the new programs filed for in 1992.

- **Develop Large Commercial/Industrial Program**

Plan and develop a program to capture large commercial and industrial DSM opportunities. This action plan item will be done during the first and second quarters of 1991.

WWP filed a tariff for a large commercial/industrial electric efficiency program in the fall of 1991. The tariff was approved in Washington and Idaho in December 1991. The tariff allows WWP to pay incentives for any cost-effective DSM measures the customer may have available to them. Under the tariff, WWP will pay the customer up to 75 percent of the avoided cost savings, or an amount which provides the customer with a two-year payback, or up to the measure cost. This action was undertaken at the planned time, but took longer than anticipated to complete.

- **Implement Large Commercial/Industrial Program**

Implement the program. Begin offering to customers. This task includes obtaining necessary regulatory approvals. Implementation activities begin July 1, 1991.

The commercial/industrial efficiency program based on the Schedule 91 tariff began implementation in early 1992. The program has over 100 participants to date. Implementation of this program was delayed about a half-a-year due to longer than anticipated time to develop program parameters.

- **Develop Small Commercial/Industrial Program**

Plan and develop program to capture small commercial and industrial DSM opportunities. This action plan item is scheduled for the first and second quarters of 1992.

WWP modified its originally approved commercial/industrial tariff during its comprehensive filing to eliminate the size limitation under Schedule 91. As it now stands, any size customer can participate in the existing commercial/industrial program. WWP, however, recognizes the conditions that may limit participation by smaller customers in the existing program. WWP plans to develop a commercial lighting program to target the smaller commercial customer who may have cost-effective lighting options but does not have enough savings to justify an independent audit. This program would be based on set rebates for specific lighting measures. Lighting contractors would perform the majority of the program delivery.

This plan development was planned for as early as July 1992, but has been delayed due to later than anticipated implementation of other programs and a change in projected resource needs.

- **Implement Small Commercial/Industrial Program**

Implement the program. Begin offering to customers. This task includes obtaining necessary regulatory approvals. Implementation is scheduled to begin July 1, 1992.

WWP anticipates having a small commercial lighting program developed and ready to implement sometime in the first half of 1993. Implementation was planned for as early as July 1992, but has been delayed due to the later than anticipated implementation of other programs and a change in projected resource needs.

Source: Bill Johnson, WWP Marketing & Sales-DSM Planning & Evaluation, 1992

System Efficiency Programs:

• Distribution

The company has determined through a distribution loss study that it can save 10 aMW at below our avoided cost. These savings will be developed gradually over time as they are tied to ongoing operations. The best estimate of savings for the next two years from these programs is 0.4 aMW.

WWP is continuing to reduce distribution line losses by installing low loss transformers, compensating capacitors and conductors chosen for lifetime economic value. Savings will be realized gradually as old facilities are replaced and the system expands. Over the next 40 years, the savings will increase to about 120,770 MWh/year equaling 13.8 aMW at a cost less than the avoided cost. Program acceleration would require replacement of existing operating facilities before the end of their useful lives. This cannot be accomplished for less than the avoided cost.

Capacitors

The majority of WWP's distribution system is already compensated by fixed capacitor banks. Line capacitor installations have been reviewed to establish the current status of all banks. Additional savings can be achieved with switched banks and compensation at customer motor terminals. A study will determine whether additional fixed banks can be economically justified and whether switched banks should be considered. The present Reactive Power Adjustment (KVAR Penalty) may need revision to encourage industrial customers to invest in secondary capacitors.

WWP will review the placement and sizing of its primary capacitors during normal feeder design and analysis. WWP will review the Reactive Power Adjustment.

Over the next twenty years, an additional savings (more than the current savings due to capacitors) of about 5,000 MWH/year equaling 0.6 aMW can be developed.

Conductors

WWP has evaluated the use of larger conductors to reduce lifetime operating costs. The analysis identified the economic conductor sizes for all current levels and showed that nearly all of the losses occur on the three-phase trunks. Economic conductor is the least expensive choice of conductor considering the original installed cost and the cost of losses over a lifetime of 40 years. As the size of the conductor is increased, the installation cost rises but the present worth cost of losses drops. A plot of all conductors over the normal range of distribution currents shows the best choice for each current-- the economic conductor.

The economic conductor is used on new construction and rebuilds when the higher investment fits within budget restrictions and the lifetime cost is less than the avoided cost. It is not cost-effective to replace existing conductor solely to reduce losses.

Increased emphasis has been placed on economic conductor size by reorganizing the Distribution Design section to create a distribution planning position. This engineer's duties include recommending the routes and sizes of feeder trunks to reduce losses and provide reliable service.

Over the next 40 years, the installation of economic conductors will gradually reduce losses by about 36,000 MWH/year equaling 4.1 aMW.

Distribution Upgrades

The company evaluates three alternatives for economic conductor and chooses the one that is the lowest cost.

1. The cost of increasing the size of a conductor that is being replaced for other reasons is the lifetime cost of the larger conductor (installation plus losses) less the lifetime cost of the smaller conductor.

2. The cost of replacing a conductor that is not being replaced for other reasons is the lifetime cost of the new conductor less the lifetime cost of the existing conductor. The lifetime cost of the new conductor is the installed cost of the new conductor, plus the cost of any structure changes to accommodate the new conductor, plus the removal cost of the existing materials less the salvage of the existing materials, plus any maintenance required on the job, plus the lifetime cost of losses on the new conductor. The lifetime cost of the existing conductor is the cost of losses for the remainder of its useful life, plus the present worth of the future replacement costs.

3. The avoided cost.

Annual Replacements

Out of 270 distribution feeders in the WWP system, portions of ten were budgeted for replacement or additions of three-phase circuits in 1992. This included over 22 miles of reconductoring and nearly three miles of new lines. These figures do not include the many miles of single-phase line installed to serve new residential customers.

WWP had 8,713 miles of overhead line (1-, 2- and 3-phase) at the end of 1991.

Transformers

WWP has been purchasing low-loss transformers for over ten years. About 10 percent of the 82,255 transformers in service (12/9/89) are low-loss units.

The economic formula for the purchase of high-efficiency transformers is reviewed annually and revised if necessary. The interest in natural gas has resulted in the installation of smaller transformers in developments, reducing the no-load losses in the system. This reduction may become significant if the trend continues for a long enough time and spreads to enough existing customers through electric to gas conversions. The company is evaluating used transformers as they are returned for repairs. If the remaining lifetime costs, including losses and repair cost, exceed the cost to purchase a new high-efficiency transformer, the unit is scrapped. Losses are being tested on the company's transformer test set.

Over the next 30 years, all transformers that fail will be replaced with low-loss units. When all older units are replaced, the added savings will be about 79,770 MWH/year equaling 9.1 aMW. It is not cost-effective to replace operating transformers.

Source: Tim Rahman, WWP Distribution Engineering, January 1992

- **Transmission**

Implement a study effort (utilizing preliminary results currently being developed) to determine the potential for loss savings in WWP's transmission system. A program for transmission loss improvement will be developed and implementation started, if cost-effective.

WWP is continuing to reduce transmission losses by installing conductors and other facilities chosen for lifetime economic value. In addition, WWP is embarking upon an examination to determine the most efficient transmission system configuration(s). Savings will be realized gradually as old facilities are replaced and the system expands, although an initial decrease in losses should be realized by system reconfiguration. Over the next 40 years, the savings should increase to about 15.0 aMW at a cost less than WWP's avoided cost.

Program acceleration would require replacement of existing operating facilities before the end of their useful lives. Generally, this cannot be accomplished for less than the avoided cost.

Conductors

New Construction:

The economic conductor is used on new transmission construction when the higher investment fits within budget restrictions and the lifetime cost is less than the avoided cost.

The economic conductor is used to integrate new generation into the transmission system when the lifetime costs is less than the avoided cost.

Reconductoring of Existing Facilities:

Increasing conductor size to the most economic conductor is examined when transmission lines require rebuilding due to:

1. normal aging of facilities, or

2. when system changes due to load shifts or additions, or power transfers through the transmission system requires additional transmission system facilities.

While it is generally not cost-effective to replace the existing conductor solely to reduce losses, WWP investigates that potential in areas of the system where there may be economic loss savings.

Transformation

In addition to examining additional transformation as a solution to system deficiencies, adding transformation is also examined for promotion of transmission system efficiency. Although it not generally cost-effective to install additional transformation to reduce losses, it may be applicable in specific instances.

Source(s): Scott Waples, WWP System Planning, December 1991

• Hydro Improvements

Implement hydro system improvement programs to optimize system renewable energy supplies. WWP is continuing to evaluate the cost-effectiveness of redevelopment or replacement of old facilities to increase the efficiency and generating outputs at all WWP hydro plants. The determination to proceed with the hydro improvement programs depends upon economics in concert with other factors affecting comprehensive development of the waterway and stewardship of the associated natural resources. There is an estimated potential to increase the hydro system's firm energy by 36 aMW, total energy (firm plus nonfirm energy) by 84 aMW, and peak by 265 MW. The total preliminary cost of these programs is approximately $284 million.

Description of Activities:

Work is essentially complete on the program to evaluate each of the company's hydroelectric developments for additions and upgrades that may be economically pursued now or in the near future. For each site, a set of alternatives was developed, and if any were found to be promising, a preliminary engineering study was performed to determine specific design details and a more accurate cost estimate. The development alternatives still showing promise were presented to the company for authorization to proceed or to put on the shelf for development when additional resources are called for. Additional analysis will be done at each site if the company decides to proceed with that site option.

Each of the company's hydroelectric sites has been screened for developable additions and upgrades. The current status of these studies and subsequent actions follows.

Cabinet Gorge and Noxon Rapids
(Clark Fork River; Completed 1959 and 1963)

A feasibility study of the Cabinet-Noxon plants focusing on Cabinet was done in 1991 by Acres, a consultant engaged by WWP. The study showed that even though discharges at Noxon (51,400 cfs) were larger than Cabinet (36,000 cfs), a fifth unit at Cabinet could not be justified because of a low plant factor. The study did show that rehabilitation alternatives are economically viable. In recent months, cracks have developed in the blades of the Cabinet No.1 turbine. Repeated efforts of welding these cracks have not shown lasting success. Additional studies have shown that upgrading the turbine, generator and transformers will improve efficiency, capacity and reliability. This work is in progress and scheduled for completion in the first quarter of 1994. WWP engineering is developing preliminary rehabilitation alternatives for Noxon and additional units at Cabinet Gorge.

Post Falls
(Spokane River; Constructed 1906)

The Post Falls plant was addressed in overview by the Spokane River Optimization Study. Both generation additions and upgrades were reviewed. Preliminary economic screening shows the replacement of units with more efficient units and units of higher capacity to be the most promising. The replacement of two units would potentially increase the capacity of the plant from 18 MW to 25 MW. No further evaluation is planned until a need for the energy is foreseen.

Upper Falls
(Spokane River; Constructed 1922)

Upper Falls has been addressed in overview by the Spokane River Optimization Study (SROS) and has been studied in detail by vendors who are developing detailed costs and benefits of feasible upgrades. The vendors have studied the replacement of either or both the turbine and generator. Replacement of the turbine and rewind of the generator appears to be the best alternative. The incremental cost today is estimated at two to three million dollars, which would produce an additional output of 5,000 to 10,000 MWh of firm energy and 10,000 to 20,000 MWh of secondary (nonfirm) energy annually. WWP is continuing with a review of the vendor's study and a recommended plan for project development.

Monroe Street
(Spokane River; Constructed 1891; Rebuilt 1992)

WWP has replaced the old five-unit plant with a new single vertical Kaplan unit rated at 2,900 cfs and 14.75 MW. The project was budgeted for $23.6 million. The project essentially doubles the capacity of the plant (from 7.2 MW nameplate to 14.75 MW). Annual energy increases are expected to be 46,000 MWh of firm energy and 15,000 MWh of secondary (nonfirm) energy.

On July 7, 1992, during the open-circuit stator test, one of the 243 coils shorted and failed. The damaged coil was removed from service and the plant was put on-line on July 15 at 5:52 p.m. The plant ran for several days in a test mode and produced 327 MWh of energy. Disassembly of the machine began on August 3 to repair the damaged coil. The rebuilt Monroe Street Hydroelectric Development became operational in December 1992.

Nine Mile
(Spokane River; Constructed 1908)

WWP is proceeding with the redevelopment of the Nine Mile Project, which includes the replacement of two of the four units with more efficient units of "similar" design. The company is deferring plans to raise the forebay elevation five feet by installation of a rubber spillgate. The deferral of this work will allow WWP to pursue a public involvement process for the pool raise portion of the project. This is another plant where major work is required in the next five years. On-line date for unit 3 is now scheduled for mid 1994, with unit 4 on line by the first quarter of 1995.

Long Lake
(Spokane River; Constructed 1915)

Completed engineering study indicates the feasibility of installing a second powerhouse beside the existing powerhouse. The new powerhouse could be sized for one or two new 60 MW units. The project will be further evaluated as a means of meeting future capacity needs.

Little Falls
(Spokane River; Constructed 1910)

The Spokane River Optimization Study identified upgrade alternatives involving the replacement of the existing turbines with units of higher efficiency. The most promising alternative replaces two of the existing 1,800 cfs units with higher efficiency units rated at 2,650 cfs. The company has no plans to pursue redevelopment at this time.

Meyers Falls
(Colville River; Constructed 1915)

The company has evaluated redevelopment opportunities at this 1.3 MW plant. None of the upgrades are financially viable. The plant is being maintained as-is, and the application for a renewed FERC license was filed in late 1991. Various recreational and historical enhancements are planned for the area. No changes in the operation of the plant are being proposed.

Source(s): Bob Mansfield, WWP Corporate Communications, January 1993
Tom Johns, WWP Power Resources, February 1993

Competitive Bidding:

• 1991 Request For Proposals (RFP)

Complete the competitive bidding process of evaluating, ranking and selecting the winning bid proposals from WWP's "Request For Proposals" (RFP). The company will evaluate all bid proposals selecting those that have the greatest benefits for WWP's customers. The RFP will be issued for bid proposals in 1991. Negotiations with the winning bidder for a power purchase agreement will also be finalized, for a total acquisition of not less than 30 aMW, with deliveries commencing in 1995.

Following is a summary of the WWP's first competitive bidding process conducted from September 1991 through July 1992. The bidding process was completed in accordance with regulations issued by the Washington Utilities and Transportation Commission (WUTC) in Chapter 480-107 WAC (Purchases of Electricity from Qualifying Facilities and Independent Power Producers and Purchases of Electrical Savings from Conservation Suppliers).

WWP's 1991 RFP: In September 1991, Washington Water Power (WWP) issued a Request for Proposal[1] for 30 aMW of firm energy to be delivered beginning July 1, 1995. Resources sought under the 1991 RFP were consistent with needs as determined in WWP's 1991 Least Cost Plan. Under the RFP, both conservation (DSM) and supply-side resource proposals were accepted.

Issuance: Subsequent to WUTC approval, WWP's RFP was issued September 26, 1991. Advertisement and other communications resulted in a distribution of 187 copies of the RFP.

A Pre-Bid Conference was conducted on October 29, 1991, in Spokane, Washington. At this conference, WWP responded to questions about the RFP from approximately thirty participants. A question and answer document was developed and distributed to all parties who had received an RFP.

Bid Submittal: Along with a representative of the WUTC staff, bids were opened January 7, 1992. WWP received a total of sixteen bids; five conservation bids from three bid sponsors, ten supply-side proposals and one system efficiency bid. Since the RFP specifically excluded system efficiency bids for WWP-owned facilities, that bid was eliminated from further evaluation. As shown in Figure A-1, the remaining proposals were distributed to members of WWP's RFP Work Group for continued evaluation.

Figure A-1: Summary of All Bids Submitted Under the 1991 RFP

Resource Type	Number of Proposals	Capacity (MW)	Energy (aMW)
Conservation	5	15	11
Renewable (Hydro, Geothermal and Biomass)	3	80	39
Gas Turbines (Combined-Cycle Cogeneration and IPP)	7	200	187
Total	15	295 MW	237 aMW

1 WWP Document: "Request for Proposals - Long-Term Purchase of Resources from Electric Conservation and/or Generating Facilities" dated September 1991.

Bid Evaluation Process and Criteria: WWP's evaluation process consisted of a three step process:

1. Initial Review
2. Determination of a Preliminary Short List
3. Determination of a Final Short List

As projects were eliminated from continued evaluation, WWP notified project sponsors of these results. The status of the evaluation process was also communicated to the WUTC and IPUC staffs and to WWP's Technical Advisory Committee (TAC) at their scheduled meetings.

As described in more detail below, scoring and ranking of resource proposals was based solely on the criteria outlined in the RFP.

Initial Review: In the initial review, WWP identified those projects which did not meet minimum RFP criteria or requested clarifying information. As a result of this review, which was completed on February 11, 1992, three projects were eliminated from continued evaluation. The average price of the remaining projects was calculated to be 95% of WWP's Washington Avoided Cost.

Determination of a Preliminary Short List: Following the initial review, the RFP Work Group scored the remaining proposals in three categories. The value of each category, and the list of associated attributes, is consistent with the information outlined in the RFP. Figure A-2 summarizes the RFP scoring criteria.

Figure A-2: RFP Scoring Criteria Summary

Category	Value	Attributes
Price	50%	Comparison to Washington Avoided Cost and pricing risk.
Viability	30%	Sponsor ability, project design, fuel supply and host facility, financial plan, electrical system impact, and licensing and environmental impact.
Non-Price Factors	20%	Operation date and contract term, dispatch, compatibility with system resources, and other potential benefits.

Based on the scoring and ranking of available projects, the Preliminary Short List was announced on March 5, 1992. The preliminary short list consisted of three supply-side and one conservation project as shown in Figure A-3. The average price of these projects was calculated to be 92% of WWP's Washington Avoided Cost.

As part of the determination of a Preliminary Short List, WWP's trial method to account for environmental externalities was applied[2]. While this analysis had some minor impact on the individual project scores, it did not change the overall ranking and preliminary short list recommendation.

2 In considering environmental externalities, WWP applied price adders to specific resource "types" according to the following schedule: Conservation = 0.0 \$/MWh, Renewables = 2.0 \$/MWh, Gas-fired Cogeneration = 4.0 \$/MWh, Stand-alone Gas-fired Generation = 6.0 \$/MWh, and Coal = 8.0 \$/MWh.

Figure A-3: RFP Preliminary Short-List

Resource Option	Energy	Project Sponsor
Gas Turbine - IPP	30 aMW	J. Makowski Associates, Inc.
Gas Turbine - Cogeneration	25 aMW	Powerlink-Morrow, Inc.
Gas Turbine - Cogeneration	23 aMW	Benchmark Power Corporation
Residential Conservation	4.6 aMW	SESCO, Inc.

Determination of a Final Short List: Project scoring, based on the above criteria, combined with a review of WWP's current forecast for energy needs was used to determine a final short list. Information gained from clarification meetings with each bid sponsors was also incorporated. Results of this evaluation supported the selection of the residential conservation bid, sponsored by SESCO, Inc., as the only project on the final short list. This final short list decision was announced to all bidders in July 21, 1992, correspondence. In additional July 22 correspondence, WWP offered all bidders who participated in the RFP process an opportunity to meet in a debriefing session.

WWP's decision to select SESCO as the only final short list member was announced to the public in a July 22, 1992, press release. After further analysis, WWP rejected the SESCO bid and petitioned the WUTC to accept its closure of the 1991 competitive bidding process.

Figure A-5: WWP 1991 Request For Proposal (RFP)
Process and Evaluation Summary

WWP RFP Issued:
September 26,1991

- Request for 30 aMW beginning July 1,1995.
- All source bid.
- Pre-Bid Conference held October 29,1991.

Bids Opened:
January 7,1992

Resource Type	Bids	Energy aMW
Conservation	5	11
Renewable	3	39
Gas-Fired	7	187
Total *	15	237 aMW

*Total excludes 1 rejected system efficiency bid.

Weighted Average Bid Price 104%
(% of Avoided Cost)

Initial Review Completed:
February 11,1992

Resource Type	Bids	Energy aMW
Conservation	5	11
Renewable	1	3
Gas-Fired	7	187
Total	13	201 aMW

Weighted Average Bid Price 95%
(% of Avoided Cost)

Preliminary Short List Announced:
April 15,1992

Resource Type	Bids	Energy aMW
Conservation	1	4.6
Gas-Fired	3	78
Total	4	83 aMW

Weighted Average Bid Price 92%
(% of Avoided Cost)

- **RFP Evaluation**

Evaluate the RFP bid proposals to gain information to be used for input to the next planning cycle. Utilize the RFP results and the least-cost plan to determine the avoided cost estimates and other criteria for future competitive bidding programs. The resulting winning bid resources will be included in future planning activities and reports.

The RFP provided WWP with some information about the type, location, availability and price associated with new resources. Through the RFP, the company had access to approximately 200 aMW of new resource options available at a price of five percent or more below the Washington avoided cost. This information gives WWP a benchmark that can be used in evaluating future resource acquisition plans.

The RFP information, in conjunction with other new resource costs, can be used in determining what adjustments are needed for future avoided cost estimates. This information can be used as inputs in the SRP model to develop a weighted average incremental resource cost for the various resource scenarios.

WWP's RFP included a ceiling price at which the bid prices had to be less for acceptance. This did not result in a true market-based pricing of resources. Eliminating the ceiling price would allow bid sponsors an opportunity to submit true resource cost, including a return on investment, instead of working their prices to be slightly under the established avoided cost.

The 1991 RFP provided WWP with experience in conducting a bidding process for new resources. It also provided the company the availability of non-utility demand-side and supply-side resources. The company feels it would be helpful to allow some flexibility with the bid price in negotiations with bid sponsors in order to achieve the best resource products for the company.

Source(s): Doug Young & Robert Pierce, WWP Power Resources, August 1992

Transmission Interconnections:

• WWP-BC Hydro Interconnection

Finalize the economic evaluations for the WWP/B.C. Hydro transmission interconnection. Pursue cost-effective commercial arrangements with Canadian utilities. Assess other utility participation in the interconnection. Evaluate the cost factors of the best proposal and, if cost-effective, proceed with project in compliance with the least-cost planning process.

In October 1987, WWP filed an application with the Department of Energy (Office of Fuels Programs) for a Presidential Permit for a proposed WWP-BC Hydro Transmission Interconnection. The permit is required to construct an international interconnection. In 1993, the Department of Energy (DOE) issued a Presidential Permit for the proposed interconnection.

During the Presidential Permit process, WWP reduced the scope of the original interconnection project. Initial project transfer capability was reduced from 1000 MW to 800 MW. The selection of WWP's existing Beacon substation as the preferred Spokane area terminal provides the following project benefits:

- Eliminate the construction of 25 miles of new high-voltage transmission line.
- Delay the need to construct a new Marshall switching station.
- Substantially reduce the capital cost of the project.
- Provide increased flexibility for staged project construction.

If constructed, the WWP-BC Hydro Interconnection would provide additional transmission capability between Canada and the Pacific Northwest. This additional capability would allow WWP and other regional utilities direct access to resources in British Columbia and Alberta.

WWP is continuing to evaluate the need and potential benefits of the proposed Canadian interconnection. Among these benefits are the access to new resources and additional coordination of the Canadian and Northwest reservoir systems. Economic evaluations of the interconnection must consider the impact of the new British Columbia government and its development of an energy export policy. Study results will determine the future of the interconnection project.

• Other Interconnections

Analyze WWP's participation in other transmission projects that will allow the company access to additional electrical markets and supplies.

The company has studied and evaluated other interconnection opportunities but the economics for the company, so far, have not justified further activities.

Source: Brent Guyer, WWP Power Resources, February 1993

Purchase/Sales With Other Utilities:

Evaluate purchase and sale opportunities from other electric utilities as they become available to WWP. Power purchase arrangements will be executed if there is an opportunity to add value by integration with other company resources or utilizing the changed product, either short-term or long-term, to displace other more expensive resources. Power supply purchases will be evaluated against other alternatives for cost-effectiveness and compatibility within the least-cost planning process.

Focus

Since the last revision of WWP's Resource Management Report, April 1991, WWP has continued to be an active participant in the wholesale electric market.

Over the last two years, the wholesale market in the western United States has become very volatile. The trend is toward a quicker acting more flexible marketplace.

Activities

WWP has responded to the demand of increased flexibility by creating a new FERC tariff that allows for the sale of energy, capacity and storage for contract terms up to one year long. Also, in the last two years, the Western Systems Power Pool (WSPP) went from an experiment to a permanent arrangement.

Both the WSPP and FERC tariff Volume 4 have improved WWP's ability to be more flexible and responsive to the wholesale market. This flexibility has allowed WWP to maximize its opportunities in the wholesale arena and has resulted in better opportunities to maximize the value of its system.

During the last two years, WWP has been actively seeking out new opportunities in the Pacific Northwest and Southwest. Through its efforts, WWP was able to complete two long-term and numerous short-term contracts that have been, and will be, beneficial to WWP's customers.

In September 1991, WWP signed an agreement with the Northern California Power Agency (NCPA) for the sale of 50 MW of energy and capacity. Also, in June 1992, WWP signed an agreement for the sale of 150 MW of capacity to Portland General Electric.

In the 1991 report, WWP said it will "Evaluate purchase and sale opportunities from other electric utilities as they become available to WWP. Power purchase arrangements will be executed if there is an opportunity to add value by integration with other resources or utilizing the changed product.". These two contracts represent exactly this strategy. In both cases, WWP will be adding a resource to its system (by contract or construction) and combining it with its existing system to increase the value for a sale.

Results

The results of WWP's long-term and short-term transactions have been to more fully utilize its existing resources' base, improve its relationship with other utilities, and reduce the revenue needs of its customers.

Source: Doug Young , WWP Power Resources, December 1992

Cogeneration Development Program:

Implement a cogeneration development program within WWP's service territory. The company has a commitment to encourage cost-effective cogeneration development with its customers through assistance with studies and potentially with investment dollars. Potential opportunities will be evaluated as to their cost-effectiveness, and the cogeneration business unit of the company will develop those projects in conjunction with host facilities as warranted. The goal is to have cogeneration on-line by 1993 in an amount up to 30 aMW. This level of generation and future generation additions will be used by WWP, if needed, or sold off-system. This decision as to the generation output will be made at the time the decision is made to proceed with the cogeneration development. This effort is not linked to the RFP process, but is a separate part of the dual effort of the Company in promoting cost-effective cogeneration.

The company's commitment to encourage cost-effective cogeneration development with its customers has resulted in a number of project evaluations since 1991. The company, with the assistance of consultants retained at Company expense, performed comprehensive feasibility studies in cooperation with Inland Empire Paper, Kaiser Aluminum, and with a major food processor in Grant County. The work with Inland Empire Paper (IEP) resulted in submission of a formal bid to the Bonneville Power Administration to construct a generating facility at IEP and provide a long-term source of power for BPA. In addition to these studies sponsored by the company, WWP has also worked closely with the University of Idaho, Washington State University and Eastern Washington University providing input to their ongoing evaluation of the feasibility of cogeneration at their facilities.

To date, the relatively high cost of installing cogeneration and the relatively low price of electricity in the Pacific Northwest have worked against extensive development. However, favorable prices for natural gas and the passage of the region into a period of electric power deficiency will increase cogeneration development activity. The company will continue to work with its customers to ensure timely development of this resource.

Source: Alan Meyer, WWP Power Supply, February 1993

Additional Action Activities:

- **Creston**

Review the feasibility of maintaining the Creston generating site as a regional resource option. If the analysis shows the Creston site should be maintained, WWP will continue the land options, licensing permits and state site certification agreement in order to keep this site available for future resource needs.

Creston was kept as a regional option for the construction of a coal-fired plant when and if the need became apparent. The company has now decided to focus its future resource options on lower cost alternatives other than coal. BPA and the Power Council considered preservation of the Creston site, but recently concluded that a new coal plant was not as attractive as other energy options. WWP has decided to let the Creston license expire (The Site Certificate Agreement for the Creston Generating Station will expire February 25, 1993) and dispose of any property at that location. WWP will ask the WUTC, the IPUC and the FERC for $11.2 million of investment recovery in the next general electric rate filing.

Source: Doug Young , WWP Power Resources, December 1992

- **Transmission System Reconfiguration**

Study WWP's transmission system as it relates to future resource additions. The result will be a list of potential bottlenecks and what can be done to solve the problem to the transmission system as it relates to getting resources into and out of WWP's system. Work has begun on a current bottleneck between the WWP and BPA systems.

As part of the transmission planning process, WWP studies measures that do not necessarily involve facility additions but may result in system loss savings. Some of these measures involve reconfiguration of the transmission system. This reconfiguration may include the opening of existing transmission circuits or re-routing of transmission lines to different substations. By changing how power flows through the electric network, the company may be able to reduce losses for the system as a whole.

WWP has recently embarked upon an examination of reconfiguring the transmission system to provide the "most efficient" transmission system configuration(s) Recognizing that there may be seasonal variations in system configuration to achieve the maximum benefits, reconfiguration of the transmission system has the potential for recovering up to 10 aMW over the next five to ten years.

Source: Scott Waples, WWP System Planning, December 1992

- **Strategic Resource Planning Model (SRPM)**

Continue to enhance the analytical capabilities in the least-cost planning efforts. Review the least-cost planning model capabilities for further enhancements.

The SRP model was recently upgraded to include considerably more sophisticated algorithms controlling new resource decisions, annual operating hours, and the interaction between secondary energy prices and thermal resource dispatch. While still an annual simulation model, SRP now offers the ability to make economic resource additions and operation decisions. Moreover, SRPM now has the ability to run on-line resources in a manner that reflects secondary energy markets.

Other specific enhancements include the correlation of load growth and non-production plant O&M costs, capability for program-specific demand-side resource options, an algorithm to iteratively incorporate price elasticity of demand, and the conversion of SRPM to PC based EXCEL from LOTUS 123. For further information on the SRPM model upgrades, please refer to Appendix H.

Source: Dennis Vermillion,WWP Power Resources, January 1993

- **Firming Nonfirm Hydroelectric Resources**

Using the analysis done previously regarding firming nonfirm hydro energy, evaluate the impacts on WWP's system based on up-to-date information and knowledge in refining the variables and assumptions.

A study was completed in October 1992, using just WWP's nonfirm hydro capability, that showed an economic justification to firm up to 92 aMW of secondary energy. This analysis was based using simple-cycle combustion turbines as the back-up resource. The study results showed WWP could expect to earn over a twenty-year period $30 million on a net present value (NPV)(basis, with an investment of $43 million. The analysis resulted in a range of NPVs from a low of minus $10 million to a high of $66 million over the 5,000 iterations performed. Further analysis will need to be done to determine the greatest economic benefit of this resource, whether it should be used to serve retail loads or sold on the wholesale market. The results of other work being done in the region on this subject will also be reviewed and used. Study details appear in Appendix J.

Source: Mike Griswold, WWP Business Analysis, January 1993

- **Mid-Columbia Agreements**

Begin the process of discussing extension of the Mid-Columbia power purchase agreements with the appropriate public utility districts.

The company desires to complete renewals of these Mid-Columbia contracts so that licensing efforts can proceed smoothly and a long-term supply of power can be assumed. Negotiations have begun on the Grant PUD contracts affecting the output of Priest Rapids and Wanapum hydro facilities. The company is optimistic that the negotiated term and conditions of the new contract will be beneficial to both WWP and Grant PUD.

Source: Doug Young , WWP Power Resources, December 1992

Appendix B

Public Involvement

Public Involvement

WWP's 1993 Electric IRP reflects the company's efforts to expand both the nature and the scope of its public involvement activities. This appendix reviews the company's public participation activities completed or initiated during this planning cycle, including the following:

- Public Forums
- Technical Advisory Committee (TAC)
- Technical Workshops
- Demand-Side Management Issues Group (DIG)

As part of the ongoing design of the public process, WWP is developing its policy for "social responsibility." This policy is summarized here as well.

Summary

WWP believes the public has a right to be involved in business decisions that directly influence their lives. Moreover, the company believes the most effective way to reach balanced business decisions is by working with the public, utility commission staffs and other key audiences. An effective public involvement process creates the opportunity to build credibility and trust for the company.

Currently, the company is involved in a broad range of public involvement efforts. Public meetings, open houses, customer surveys and advisory groups are all being used to explain the company's position, receive input from constituency groups, gauge public concerns and accommodate group needs.

WWP realizes public participation will play an increasingly important role in resource planning and other business decisions. That's why the company has created an emerging public involvement function that will enable the company to continue to grow in a manner that fosters public trust. Internally, the company is building a broad-based team to guide and support public involvement efforts of teams and departments.

The initial public involvement focus is on on-going projects and areas of immediate opportunity and need. The company is also identifying planned intermediate and long-term activities and projects and the level of public involvement they warrant.

Public Forums

WWP held evening forums in late 1992 and early 1993. The goals of these workshops were to:

- Educate the public about the company's integrated resource planning activities.
- Develop better understanding of community needs and values on critical issues.
- Obtain feedback on the company's draft plan and incorporate this input as appropriate.
- Build the basis for more comprehensive public involvement efforts.

The first forums were held November 5, 1992, in Spokane, Washington, and November 18, 1992, in Lewiston, Idaho. Publicized by advertisements, news releases and personal letters, the workshops focused on future energy resource options including energy-efficiency programs, hydroelectric upgrades and fuel-efficiency programs.

Citizens who attended the meetings asked a wide variety of questions. Here is a sampling of the questions asked at the meetings:

- What is the company's position regarding alternative energy resources such as wind and solar?
- Are future political developments taken into consideration when predicting future natural gas supplies?
- What factors determine whether a project is economical now or put on the shelf?
- Are environmental externalities weighed in the least-cost planning process?
- Are any of WWP's hydro projects affected by the salmon recovery programs?
- Is the Rathdrum combustion turbine being considered because of the way our customers use energy or as a way to gain profit by changing from firm to nonfirm energy?
- Why do efficiency resources go up and level off?
- Are there incentives to encourage large commercial users to switch to natural gas?

Two additional forums were held in early 1993--March 15 in Coeur d'Alene, Idaho, and March 16 in Spokane, Washington. These workshops focused on a summary of the preferred electric resource strategy, peak resource planning and the natural gas integrated resource plan.

Questions asked by customers include:

- What type of upgrades is WWP considering on the Spokane River?
- Will the proposed WWP-BC Hydro Interconnection be used as a resource to meet WWP's peak needs?
- There are differing efficiencies related to electric versus natural gas. How does WWP see that shifting through time?
- What DSM programs besides fuel switching is WWP pursuing?
- Could direct control of water heaters be used to flatten out peaks?
- How will the proposed BTU energy tax affect WWP's resource planning?
- Has WWP looked at time of day rates to help meet long-term deficiencies?

WWP is committed to providing the public with various opportunities to get involved in energy resource decisions. Public meetings are one way to encourage an open exchange of information and ideas. As the company continues the integrated resource planning process, it will evaluate the most effective methods to discuss resource options and listen to community comments and concerns.

Source: John Gustafson, WWP Public and Community Relations, April 1993

Technical Advisory Committee

WWP's Technical Advisory Committee (TAC) is comprised of customer groups, governmental agencies and environmental organizations. Through the TAC, the company receives valuable input from a group of experts who represent other than the company's perspective.

TAC Participants (1991-1992)

Name	Organization	Phone
Andre, Don	Spokane Neighborhood Action Programs (SNAP)	(509) 456-7111
Bell, Kevin	Northwest Conservation Act Coalition (NCAC)	(206) 784-4585
Benjamin, Craig	Washington State University (WSU)	(509) 335-9017
Byers, Dick	Washington State Energy Office (WSEO)	(206) 956-2022
DeBusk, David	Northwest Conservation Act Coalition (NCAC)	(206) 784-4585
Dodds, Dan	Washington State Energy Office (WSEO)	(206) 956-2142
Domanski, Gary	North Idaho Community Action Agency	(208) 666-2407
Eastlake, Bill	Idaho Public Utilties Commission (IPUC)	(208) 334-0359
Fry, Susan	Intermountain Gas	(208) 377-6127
Gardner, Margie	Northwest Power Planning Council (NWPPC)	(503) 222-5161
Garvey, Gerald	North Idaho Community Action Agency	(208) 664-3114
Hall, Montie	Eastern Washington University (EWU)	(509) 359-6465
Jackson, Jerry	Jerry Jackson & Associates	(919) 967-9000
Jordan, David	Tuscon Economic Consulting (TEC)	(602) 742-6014
McDonald, Craig	Synergic Resources Corporation	(206) 624-8508
McGrath, Mike	Intermountain Gas	(208) 377-6168
Minow, George	Intermountain Gas	(208) 377-6118
Moast, Patrick	Washington Utilities and Transportation Commission (WUTC)	(206) 664-0834
Morlan, Terry	Northwest Power Planning Council (NWPPC)	(503) 635-3216
Mueller, Jon	Spokane Legal Services	(509) 838-6773
Nelson, Karen	Northwest Power Planning Council (NWPPC)	(208) 334-3593
Nicholson, William J.	Potlatch Corporation	(415) 956-2973
Renz, Don	Black's Industrial, Inc.	(509) 535-1503
Riding, Clay	Northwest Pipeline	(206) 244-6605
Roberts, Richard M.	Habitat for Humanity	(509) 327-9447
Sawyer, Tom	University of Idaho (UI)	(208) 885-6603
Sorrells, Diane	Washington Utilities and Transportation Commission (WUTC)	(206) 753-1096
Spinney, Peter	Charles River Associates, Inc.	(617) 266-0500
Sproule, Leon	City of Spokane	(509) 625-6641
Van Hersett, David	Northwest Energy Services	(509) 838-9190
Whaley, Wes	Spokane County	(509) 456-2255
Winters, Kevin	Washington State Attorney General's Office	(206) 464-6907

As listed below, WWP sponsored nine meetings of the TAC during the 1991-1992 planning cycle. Each meeting was held in Spokane, Washington.

TAC Meeting Dates

May 8, 1991	January 16, 1992	September 10, 1992
September 12, 1991	April 7, 1992	October 22, 1992
November 19, 1991	June 18, 1992	December 4, 1992

Over the course of these meetings, the company presented information and study results related to many aspects of resource planning. The breadth and complexity of the issues listed below speaks directly to the capabilities and commitment of the participants. The company looks forward to the continued opportunity to involve all interested parties in the planning process.

TAC Meeting Topics

Demand-Side Management
- 1991 Assessment Report
- Current Program Activities
- $witch $aver Test (Pilot) Evaluation Review
- 1992 Tariff Filing Overview and Results
- Issues Group Activities

1993 Planning Cycle
- Integrated Resource Plan Improvements
- Future TAC Meetings and Objectives.

WWP Hydroelectric Improvement Opportunities
- Status
- Cost effectiveness Determination
- Licensing and Environmental Constraints

Clean Air Act Amendments

Salmon Recovery Issues
- Overview
- Hydroelectric System Impacts

Electric and Magnetic Fields (EMF)

Environmental Externalities

Electric Load Forecast
- Results
- Scenarios

Commercial End-Use Forecasting Model

Cogeneration Development Overview

Resource Needs

Resource Options and Supply Curves

Potential Planning Scenarios

Strategic Resource Planning Model (SRPM)
- Upgrades and Enhancements
- Model Results

1991 Request For Proposal Results

Public Involvement Plans

WWP-PGE Capacity Contract

Proposed Rathdrum Combustion Turbines

WWP's Resource Clearinghouse

Source: Doug Young, WWP Power Resources April 1993

Firming Nonfirm Hydroelectric Resources Study

Two-Year Action Plan Items

Potential Natural Gas Price Increases

Electric Wholesale Marketing
- Current Activity
- Guidelines

Capacity Planning Model Development

Draft IRP Report

Technical Workshops

CEDMS

WWP sponsored four workshops regarding the company's commercial end-use forecasting model (CEDMS). These workshops provided participants with details about CEDMS inputs, assumptions and results.

SRPM

A one day workshop was dedicated to a technical review of the company's Strategic Resource Planning Model (SRPM). The workshop was attended by representatives from the WUTC, the Washington State Attorney General's Office, the Northwest Power Planning Council and the consulting firm of Charles River and Associates. Some model modifications were made as a result of this workshop. Other recommendations will be considered for future SRPM enhancements..

Source: Robert Pierce, WWP Power Resources, April 1993

Demand-Side Management Issues Group

The Demand Side Management Issues Group (DIG) is the result of filings by the Washington Water Power Company (WWP) to implement gas and electric demand side management programs, along with corresponding accounting treatment in the states of Idaho and Washington. During the course of these proceedings, WWP and other parties suggested that the discussion of certain related issues be delayed and more thoroughly examined by a "DSM issues group." This suggestion was incorporated into both the WUTC and the IPUC orders issued on April 30, 1992 and July 16, 1992, respectively. The orders directed WWP to facilitate the formulation and operation of the DIG and to provide periodic update reports to the respective commissions.

DIG Purpose

As ordered by both the WUTC and the IPUC and as earlier agreed to by WWP and other parties, the "DSM Issues Group" (DIG) will address, but not be limited to, the following issues (not necessarily in order of priority or importance):

- DSM program evaluation and measurement of savings.
- Needed modifications and/or mid-course program corrections.
- Cost-effectiveness methods and criteria.
- Updating avoided cost especially with regard to gas.
- Appropriateness and level of incentive for DSM.
- Lost and found margins as a result of DSM.
- Issues related to low income participation.
- Amortization periods for various measures and programs.
- The interaction of these programs and gas main extension policies.
- The appropriateness of decoupling for WWP.
- A revised or new DSM assessment.

DIG Membership

Initial membership was determined by active involvement in WWP's original DSM filings. Current membership is as follows:

- Washington Water Power Company (WWP)
- Spokane Neighborhood Action Program (SNAP).
- Washington Utilities & Transportation Commission Staff (WUTC)
- Idaho Public Utilities Commission Staff (IPUC)
- Washington Attorney General, Public Counsel Section (PC)

- Washington State Energy Office (WSEO)
- Northwest Power Planning Council (NWPPC)
- Washington Industrial Customers for Fair Utility Rates (WICFUR)
- Northwest Conservation Act Coalition (NCAC)

Source: Kelly Norwood, WWP Rates and Tariff Administration, February 1993

Social Responsibility

As an electric and natural gas utility, WWP is invariably linked with the communities in which it serves. As such, the company recognizes that business and society interests cannot be viewed independently. To provide corporate social responsibility direction, WWP established a philosophy statement to serve as a foundation upon which the company maintains and builds public trust. Company employees are held accountable to apply the principles as a routine element of all planning activities. Here is the social responsibility philosophy statement:

It is our belief that the success of our business relies on the goodwill and consent of society, and we demonstrate our social responsibility by operating ethically and in harmony with the public interest.

We will address society's needs and concerns in a manner consistent with the financial interests of our company. We will encourage collaborative efforts that focus on issues of mutual benefit to our communities and company.

We meet our commitment to social responsibility as:
Advocates
for efficient and safe use of electricity and natural gas;
Stewards
of the natural resources which we affect in the course of our businesses; and
Leaders
and partners in enhancing the prosperity of our communities.

To raise awareness and understanding of the social responsibility principles throughout the company, a development plan was created and implemented. The plan includes:

- Ongoing identification and analysis of key social issues that are of mutual interest and benefit to area communities and businesses.

- An inventory of corporate resources, programs and activities in support of priority social issues to determine what additional corporate support may be necessary.

- Development of a social responsibility management tool that can help determine if planned corporate projects and activities are compatible with society's values, the company's business goals and available resources.

The social responsibility principles are designed to commit the company to planning and operating as a good corporate neighbor. In so doing, the company will continue to provide long-term economic and social value to the communities in which it serves.

Source: John Gustafson, WWP Public and Community Relations, April 1993

Appendix C

Existing Resources and Contracts

Existing Resources and Contracts

This appendix describes WWP's existing resource base. It includes the following information:

- Nameplate and maximum capability for each WWP generating plant.
- A summary of WWP's past conservation efforts.
- Performance data for WWP-owned generation.
- A monthly tabulation of economy purchases and sales.
- A summary of existing purchase and sales contracts with other utilities.

Summary

WWP's existing resource base consists of a diverse mix of both demand-side and supply-side resources. The existing resource base consists primarily of:

- **WWP-owned hydroelectric and thermal generation.** WWP began generating electricity in 1890 when the Monroe Street hydroelectric plant became operational. The company entered the thermal plant era in 1971 when the Centralia coal-fired plant became operational. WWP now owns 1,476 MW of electric generating capability (peak capability).
- **The effect of WWP's past conservation efforts.** The company's experience with acquiring demand-side resources began in 1978.
- **Contract resources.** Existing agreements include utility purchases and exchanges, cogeneration and PURPA contracts, and the purchase of generation from four existing Columbia River hydroelectric projects.

These resources combine to provide WWP with a reliable and flexible supply of electrical generation[1].

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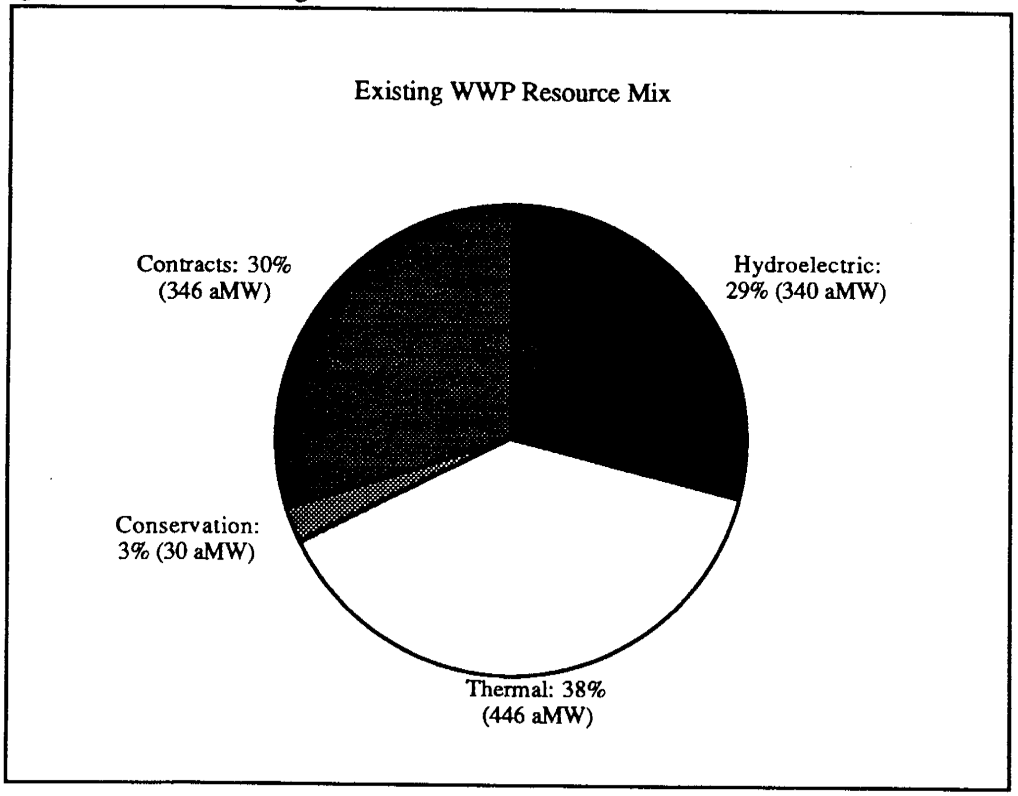
1 The actual energy output from existing resources depends on several factors. For hydroelectric generation, the predominant factor is streamflow conditions. In this report, hydroelectric generation output is based on critical water conditions. For thermal generation, the predominant factors are the length (amount of time) that the project is out for planned maintenance and the expectant downtime due to forced outages. In this report the thermal plant factors are: Centralia 87% (based on 192 MW capability), Kettle Falls 87% and Colstrip 85% (based on 216 MW capability).

Figure C-1: WWP's existing resource base.



As of November 1992, this existing resource base includes a rebuilt Monroe Street hydroelectric project. The original project consisted of five small generators with a peak capability of 6 MW. The rebuilt facility consists of an underground powerhouse and a single, more efficient unit that can produce more than 14 MW.

Existing WWP Generating Capability

Maximum Plant/Unit Generating Capability and Nameplate Rating[2]:

Year	Plant	Maximum Capability (kW)	Nameplate Capability (kW)
1890	Monroe Street	14,700	14,750
1906	Post Falls	18,000	14,750
1908	Nine Mile	18,000	12,000
1910	Little Falls	36,000	32,000
1915	Long Lake	72,500	70,000
1922	Upper Falls	10,200	10,000
1952	Cabinet Gorge	230,000	200,000
1959	Noxon Rapids	554,000	466,720
1961	Meyers Falls	1,300	1,200
1974[3]	Centralia[4] (15% ownership coal-fired)	196,950	199,469
1978	Northeast (gas/oil)	68,000	61,200
1983	Kettle Falls (wood waste)	46,500	50,700
1984	Colstrip[5] (15% ownership coal-fired)	210,000	233,400

2 WWP has no resource scheduled for retirement in the next 20 years.

3 The Centralia plant became operational in 1971, The power was surplus to the company and was sold to other utilities for three years. WWP took delivery of Centralia generation starting in 1974.

4 The Centralia coal-fired plant has a 24-hour state certified test capability of 1,313 MW. At 15 percent, WWP's share is 196.95 MW. Although this is the maximum plant capability. The plant operator (Pacificorp) has stated that for prolonged production periods a more reasonable capability is 1,280 MW. At 15 percent, WWP's share is 192 MW. For load and resource tabulations, WWP's share of Centralia is listed as 192 MW. For reporting purposes, the maximum capability is listed as 196.95 MW.

5 The Colstrip coal-fired plant has a test capability of 1,400 MW (total for units No.3 and No.4.) At 15 percent, WWP's share of the project is 210 MW. The plant operator (Montana Power) operates the units in an over pressure mode that results in the plant exceeding its tested capability. Recent history indicates the plant operating consistently above 1,400 MW. For load and resource tabulations, WWP's share of Colstrip is listed as 216 MW, a realistic figure based on past operations. For reporting purposes, the maximum capability is still listed at 1,400 MW, or 210 MW for WWP's share.

Past WWP Demand-Side Management Program Savings

WWP has been involved with demand-side management since 1978. Following is a description of past WWP programs and associated energy savings through 1991.

Residential Weatherization

The company provided no-interest loans or upfront cash grants to the customer to finance the installation of ceiling, wall, floor insulation, storm windows and doors, and weatherstripping. Approximately 31,000 homes were weatherized over the period 1978 through 1991 resulting in estimated savings of 19.3 aMW.

The company has also made payments for weatherization of low-income homes. The low-income weatherization program has been operated by CAP agencies who receive reimbursement by WWP for each home weatherized. Reliable records of job completions are not available prior to 1987. From 1987 through 1991, 2,369 homes have been weatherized under the program resulting in estimated savings of 0.8 aMW.

Water Heater Insulation Kits

The company provided installation of an R-11 vinyl covered fiberglass blanket free of charge on all customer-owned electric water heaters up to 82 gallons. Company employees canvassed customers' homes and solicited customers to call for appointments through door hangers, post cards and newspaper ads. Approximately 140,000 water heaters were wrapped over the period 1981 through 1983 resulting in estimated savings of 6.9 aMW. This program was operated under a conservation agreement with BPA.

Shower Flow Restrictor Packages

The company distributed kits which contained shower flow restrictors and outlet and switch plate gaskets. Approximately 220,000 kits were distributed over the period 1981 through 1983 resulting in estimated savings of 1.3 aMW. This program was operated under a conservation agreement with BPA.

Street Light Retrofit

The purpose of this program was to convert mercury vapor street lamps to high pressure sodium lamps. During 1982 and 1983, 11,302 lamps were converted resulting in estimated savings of 0.7 aMW. This program was operated under a conservation agreement with BPA.

Residential Fuel-Efficiency

In the spring of 1991, WWP ran a test program to evaluate different approaches to encourage customers to replace electric space and water heating equipment with natural gas equipment. The $witch $aver program was offered in to three cities in WWP's service territory (Coeur d'Alene, Lewiston and Clarkston). In Coeur d'Alene, electric space and water heat customers were given significant grants toward purchase and installation of new natural gas equipment. In Lewiston and Clarkston, the company offered financing but no cash grant for customers who chose to switch to natural gas. In both areas, targeted customers were mailed promotional and informational material explaining the benefits of switching from electricity to natural gas.

The results of the test were a high rate of participation in Coeur d'Alene (greater than 20 percent) versus a low rate of participation in Lewiston and Clarkston (less than one percent). Overall the program resulted in the conversion of 617 customers who converted both space and water heating equipment, and 309 customers who converted only water heat equipment. The company estimates that the program resulted in a net savings of approximately 1.0 aMW of energy and 3.0 MW of peak capacity.

Generation Performance Data

This section includes five years of historical data relating to WWP's generation and power purchased from independent developers under PURPA regulations. It also includes a monthly summary of economy exchanges, purchases and sales. Resources are identified within one of the following categories.

1. Hydroelectric
   - Noxon Rapids
   - Cabinet Gorge
   - Post Falls
   - Upper Falls
   - Monroe Street
   - Nine Mile
   - Long Lake
   - Little Falls
   - Meyers Falls
2. Coal-Fired
   - Colstrip
   - Centralia
3. Oil- or Gas-Fired
   - Northeast
4. Transmission Resources
   - N/A
5. Other
   - Kettle Falls (wood)
6. PURPA[6] Hydroelectric
   - Upriver Power Project
   - Big Sheep Creek Hydroelectric Project
   - Jim Ford Creek Power Project
   - John Day Creek Hydroelectric Project
7. PURPA Thermal
   - Wood Power Project
   - Vaagen Brothers Power Project
   - Potlatch Corporation - Lewiston
8. Economy Exchanges
   - N/A
9. Economy Purchases/Sales
   - Based on hydro and load conditions at time of purchase or sale.
10. Contract Purchases/Exchanges/Sales

[6] PURPA facilities that provide fewer than 500 MWh per year are not listed.

Hydroelectric Plants:

Plant: Noxon Rapids

Rated Capacity: (Peak in MW)	Total	No. 1	No. 2	No. 3	No. 4	No. 5
	554	107.5	107.5	107.5	107.5	124.0

FERC License expiration date: April 30, 2005

Year	Month	Forced Outage Rate	Equivalent Availability Factor	Year	Month	Forced Outage Rate	Equivalent Availability Factor
1988	Jan	0.00	100.00	1991	Jan	0.00	100.00
	Feb	0.00	80.00		Feb	0.00	99.00
	Mar	0.60	80.00		Mar	0.00	100.00
	Apr	8.70	90.70		Apr	0.00	99.60
	May	0.00	100.00		May	0.00	100.00
	Jun	0.00	98.00		Jun	0.00	100.00
	Jul	0.00	80.00		July	0.00	94.00
	Aug	0.00	93.30		Aug	0.00	81.00
	Sep	0.00	88.00		Sep	0.40	60.00
	Oct	0.00	80.00		Oct	0.10	74.00
	Nov	0.00	86.70		Nov	0.00	99.40
	Dec	12.30	83.20		Dec	0.00	94.00
1989	Jan	0.00	86.00	1992	Jan	0.00	99.70
	Feb	0.00	80.00		Feb	0.00	100.00
	Mar	0.00	79.00		Mar	0.00	90.20
	Apr	0.00	87.00		Apr	0.00	99.00
	May	0.00	99.00		May	0.00	100.00
	Jun	0.00	99.00		Jun	0.00	99.80
	Jul	0.00	98.00		Jul	23.00	69.00
	Aug	0.00	80.00		Aug	0.00	72.60
	Sep	0.00	84.00		Sep	0.00	91.50
	Oct	3.60	80.00		Oct	0.00	100.00
	Nov	16.70	80.00		Nov	0.00	100.00
	Dec	7.70	92.00		Dec	2.30	99.00
1990	Jan	0.00	100.00				
	Feb	0.00	83.20				
	Mar	0.00	82.70				
	Apr	0.00	85.50				
	May	0.00	99.90				
	Jun	0.00	100.00				
	Jul	0.70	96.40				
	Aug	1.65	91.00				
	Sep	0.00	61.00				
	Oct	0.00	60.00				
	Nov	0.00	80.00				
	Dec	0.00	81.50				

*Equivalent Availability Factor = Availability Factor = (Available Unit Days/Period Unit Days) x 100.

**Forced Outage Rate = (Forced Outage Unit Days/(Service Unit Days + Forced Outage Unit Days)) x 100.

Plant: Cabinet Gorge

Rated Capacity: (Peak in MW)	Total	No. 1	No. 2	No. 3	No. 4
	230	57.5	57.5	57.5	57.5

FERC License expiration date: January 9, 2000

Year	Month	Forced Outage Rate	Equivalent Availability Factor	Year	Month	Forced Outage Rate	Equivalent Availability Factor
1988	Jan	0.00	100.00	1991	Jan	0.00	94.00
	Feb	0.00	82.80		Feb	0.00	97.00
	Mar	0.00	86.30		Mar	0.00	98.00
	Apr	0.00	100.00		Apr	0.00	100.00
	May	0.00	100.00		May	0.00	100.00
	Jun	0.00	100.00		Jun	0.00	100.00
	Jul	0.00	83.90		Jul	0.00	98.00
	Aug	0.00	75.00		Aug	0.00	87.00
	Sep	0.00	88.30		Sep	2.00	98.00
	Oct	0.00	96.00		Oct	2.00	99.00
	Nov	0.00	75.00		Nov	0.00	96.00
	Dec	0.00	96.00		Dec	1.00	99.00
1989	Jan	0.00	99.20	1992	Jan	0.00	100.00
	Feb	0.00	99.60		Feb	0.00	100.00
	Mar	1.20	98.80		Mar	0.00	79.00
	Apr	0.00	99.90		Apr	0.00	99.00
	May	0.00	100.00		May	0.30	99.00
	Jun	0.00	100.00		Jun	0.50	99.70
	Jul	6.70	91.80		Jul	0.01	96.00
	Aug	6.70	92.70		Aug	0.00	76.00
	Sep	0.00	92.70		Sep	0.01	75.00
	Oct	0.00	85.80		Oct	0.02	75.00
	Nov	0.20	77.10		Nov	0.00	98.00
	Dec	0.00	96.00		Dec	0.00	100.00
1990	Jan	0.00	99.00				
	Feb	0.00	100.00				
	Mar	0.00	100.00				
	Apr	0.00	100.00				
	May	0.00	100.00				
	Jun	0.00	100.00				
	Jul	0.40	98.00				
	Aug	0.00	97.00				
	Sep	28.00	60.00				
	Oct	28.00	72.00				
	Nov	17.00	80.00				
	Dec	0.00	78.00				

*Equivalent Availability Factor = Availability Factor = (Available Unit Days/Period Unit Days) x 100.

**Forced Outage Rate = (Forced Outage Unit Days/(Service Unit Days + Forced Outage Unit Days)) x 100.

Maintenance and outage records for the following plants are not computerized and exist in log style handwritten form. It would take many man-hours to obtain the necessary data to determine accurate forced outage and availability data. Because of this, five years of data is not included. The data is available for inspection or recording at any time.

Plant: Post Falls

Rated Capacity: (Peak in MW)	Total	No. 1	No. 2	No. 3	No. 4	No. 5	No. 6
	18.0	2.9	2.9	2.9	2.9	2.9	3.5

FERC License expiration date: July 31, 2007

Plant: Upper Falls

Rated Capacity: (Peak in MW)	Total	No. 1
	10.2	10.2

FERC License expiration date: July 31, 2007

Plant: Monroe Street

Rated Capacity: (Peak in MW)	Total	No. 1
	14.7	14.7

FERC License expiration date: July 31, 2007

Monroe Street (redevelopment) became operational in December 1992.

Plant: Nine Mile

Rated Capacity: (Peak in MW)	Total	No. 1	No. 2	No. 3	No. 4
	18.0	4.5	4.5	4.5	4.5

FERC License expiration date: July 31, 2007

Plant: Long Lake

Rated Capacity: (Peak in MW)	Total	No. 1	No. 2	No. 3	No. 4
	72.5	18.12	18.12	18.12	18.12

FERC License expiration date: July 31, 2007

Plant: Little Falls

Rated Capacity: (Peak in MW)	Total	No. 1	No. 2	No. 3	No. 4
	36.0	9.0	9.0	9.0	9.0

FERC License expiration date: (Not Applicable - License not required)

Plant: Meyers Falls

Rated Capacity: (Peak in MW)	Total	No. 1	No. 2
	1.3	0.4	0.9

FERC License expiration date: December 31, 1993

Steam Plants:

Colstrip No. 3

Rated Capacity = 700 MW
Service Date = 1/10/84
Design Plant Life = 35 years
WWP's Share = 15%
Note: WWP uses 108 MW/unit based on an over pressure mode of operation.

Year	Month	Forced Outage Rate	Equivalent Availability Factor	Year	Month	Forced Outage Rate	Equivalent Availability Factor
1988	Jan	16.04	82.87	1991	Jan	3.48	94.84
	Feb	12.55	85.63		Feb	9.27	86.23
	Mar	7.88	90.77		Mar	0.00	99.97
	Apr	3.41	95.74		Apr	0.00	100.16
	May	0.00	41.49		May	0.00	52.51
	Jun	28.43	52.79		Jun	2.13	29.41
	Jul	9.66	89.13		Jul	5.99	89.86
	Aug	13.32	84.98		Aug	0.00	99.37
	Sep	14.33	83.77		Sep	0.00	100.04
	Oct	0.08	99.04		Oct	1.77	96.95
	Nov	0.13	99.56		Nov	0.00	99.53
	Dec	5.84	93.48		Dec	2.73	96.40
1989	Jan	8.40	89.64	1992	Jan	0.00	100.03
	Feb	11.33	82.51		Feb	0.00	99.75
	Mar	5.85	92.69		Mar	0.00	99.00
	Apr	25.55	73.02		Apr	4.02	82.28
	May	1.02	59.88		May	5.30	42.82
	Jun	51.41	12.28		Jun	0.12	99.69
	Jul	9.65	84.50		Jul	0.16	90.79
	Aug	0.28	98.86		Aug	0.00	96.05
	Sep	5.34	93.22		Sep	1.24	97.35
	Oct	0.55	99.50		Oct	19.29	76.27
	Nov	12.21	86.01		Nov	0.00	100.44
	Dec	0.00	100.48		Dec	0.00	100.25
1990	Jan	11.19	79.40				
	Feb	0.08	100.04				
	Mar	1.62	94.25				
	Apr	0.18	65.59				
	May	23.95	56.17				
	Jun	0.62	96.95				
	Jul	67.14	32.26				
	Aug	100.00	0.00				
	Sep	30.78	59.87				
	Oct	0.00	91.24				
	Nov	13.01	86.63				
	Dec	0.00	100.32				

* Forced Outage Rate: Forced Outage Hours/(Service Hours + Forced Outage Hours) x 100 (%).

** Equivalent Availability Factor: $\frac{\text{Available Hours - [(Derated Hours x Size of Reduction)/Maximum Capacity] x 100 (\%)}}{\text{Period Hours}}$.

Colstrip No. 4

Rated Capacity = 700 MW
Service Date = 4/6/86
Design Plant Life = 35 years
WWP's Share = 15%
Note: WWP uses 108 MW/unit based on an over pressure mode of operation.

Year	Month	Forced Outage Rate	Equivalent Availability Factor	Year	Month	Forced Outage Rate	Equivalent Availability Factor
1988	Jan	5.41	91.21	1991	Jan	0.43	98.55
	Feb	0.00	99.44		Feb	4.14	95.30
	Mar	27.04	60.55		Mar	0.00	100.15
	Apr	3.53	63.05		Apr	10.91	56.35
	May	0.00	99.97		May	1.20	75.01
	Jun	1.61	94.96		Jun	2.80	95.09
	Jul	0.00	99.62		Jul	30.10	92.76
	Aug	4.84	93.68		Aug	0.00	93.64
	Sep	0.60	98.32		Sept	4.35	88.36
	Oct	0.94	97.76		Oct	0.00	99.86
	Nov	11.96	86.05		Nov	0.00	99.81
	Dec	0.00	99.60		Dec	5.04	94.46
1989	Jan	10.76	88.40	1992	Jan	6.89	92.41
	Feb	0.06	99.31		Feb	0.00	100.00
	Mar	4.57	94.23		Mar	0.00	99.79
	Apr	0.00	42.61		Apr	0.00	99.43
	May	0.13	99.01		May	0.00	92.16
	Jun	1.02	96.85		Jun	0.00	0.00
	Jul	2.65	92.10		Jul	2.29	90.82
	Aug	5.84	90.19		Aug	0.39	99.52
	Sep	6.07	93.41		Sep	0.00	100.42
	Oct	16.01	81.72		Oct	0.00	100.53
	Nov	10.50	88.44		Nov	0.00	100.52
	Dec	4.79	94.65		Dec	0.33	99.65
1990	Jan	3.02	96.41				
	Feb	1.78	96.96				
	Mar	0.08	99.44				
	Apr	0.32	95.27				
	May	41.04	58.06				
	Jun	5.63	25.24				
	Jul	17.13	80.34				
	Aug	9.28	87.73				
	Sep	0.26	99.41				
	Oct	8.32	88.71				
	Nov	9.00	90.52				
	Dec	2.78	96.36				

Centralia No. 1

Rated Capacity =656.5 MW (based on plant tested capability of 1313 MW)
=640 MW (based on plant operational capability of 1280 MW)
Service Date = 12/31/72
Design Plant Life = 35 years
WWP's Share = 15%

Year	Month	Forced Outage Rate	Equivalent Availability Factor	Year	Month	Forced Outage Rate	Equivalent Availability Factor
1988	Jan	6.21	93.00	1991	Jan	0.00	98.02
	Feb	0.00	100.00		Feb	0.00	100.00
	Mar	4.46	95.00		Mar	0.00	100.00
	Apr	0.00	47.00		Apr	0.00	100.00
	May	0.00	66.00		May	0.32	99.67
	Jun	9.93	89.00		Jun	0.00	100.00
	Jul	8.83	91.00		Jul	7.17	89.65
	Aug	0.00	99.00		Aug	0.00	98.34
	Sep	28.09	64.00		Sep	5.98	93.88
	Oct	0.00	86.00		Oct	9.65	90.25
	Nov	0.00	90.00		Nov	0.00	99.80
	Dec	0.00	89.00		Dec	0.00	99.96
1989	Jan	0.00	85.00	1992	Jan	13.30	84.50
	Feb	0.00	86.00		Feb	0.00	99.80
	Mar	0.00	86.00		Mar	0.00	100.00
	Apr	0.00	37.00		Apr	0.00	99.48
	May	52.08	3.00		May	0.00	48.30
	Jun	26.95	69.00		Jun	2.43	41.95
	Jul	0.00	98.00		Jul	0.13	99.27
	Aug	0.00	100.00		Aug	0.00	99.95
	Sep	0.00	100.00		Sep	3.05	96.95
	Oct	9.20	89.00		Oct	11.00	88.75
	Nov	0.00	100.00		Nov	0.00	99.99
	Dec	13.95	86.00		Dec	8.17	91.67
1990	Jan	2.84	97.00				
	Feb	9.12	91.00				
	Mar	3.31	96.00				
	Apr	0.00	43.00				
	May	0.00	19.00				
	Jun	0.00	97.00				
	Jul	1.02	99.00				
	Aug	10.89	89.00				
	Sep	2.26	98.00				
	Oct	0.00	100.00				
	Nov	0.00	100.00				
	Dec	0.00	100.00				

Centralia No. 2 Rated Capacity =656.5 MW (based on plant tested capability of 1313 MW)
=640 MW (based on plant operational capability of 1280 MW)
Service Date = 7/11/73
Design Plant Life = 35 years
WWP's Share = 15%

Year	Month	Forced Outage Rate	Equivalent Availability Factor	Year	Month	Forced Outage Rate	Equivalent Availability Factor
1988	Jan	3.37	95.00	1991	Jan	0.00	99.95
	Feb	0.00	99.00		Feb	7.35	94.86
	Mar	2.59	96.00		Mar	1.12	98.95
	Apr	2.70	97.00		Apr	0.00	100.00
	May	0.00	38.00		May	0.00	5.06
	Jun	0.00	62.00		Jun	2.16	96.05
	Jul	0.00	98.00		Jul	15.18	83.58
	Aug	1.40	98.00		Aug	0.00	99.91
	Sep	0.00	100.00		Sep	16.56	82.19
	Oct	0.00	99.00		Oct	0.00	99.65
	Nov	0.00	100.00		Nov	0.00	99.76
	Dec	5.34	91.00		Dec	0.00	99.98
1989	Jan	0.00	100.00	1992	Jan	0.00	99.16
	Feb	0.00	99.00		Feb	20.38	78.94
	Mar	0.22	95.00		Mar	0.00	100.00
	Apr	7.40	92.00		Apr	0.00	99.71
	May	0.00	58.00		May	0.00	99.90
	Jun	0.00	0.00		Jun	0.00	100.00
	Jul	6.01	89.00		Jul	0.00	99.91
	Aug	0.00	100.00		Aug	0.00	99.73
	Sep	4.16	95.00		Sep	0.00	99.39
	Oct	2.23	96.00		Oct	0.00	99.22
	Nov	22.43	77.00		Nov	7.99	91.77
	Dec	1.13	98.00		Dec	0.00	99.92
1990	Jan	0.00	100.00				
	Feb	30.39	68.00				
	Mar	5.06	95.00				
	Apr	0.00	100.00				
	May	0.00	100.00				
	Jun	1.19	99.00				
	Jul	1.32	99.00				
	Aug	10.04	89.00				
	Sep	43.53	56.00				
	Oct	0.32	100.00				
	Nov	0.00	100.00				
	Dec	0.00	100.00				

Transmission and Other Resources:

Kettle Falls

Rated Capacity = 46.5 MW
Service Date = 12/1/83
Design Plant Life = 35 years

Year	Month	Forced Outage Rate	Availability Factor	Year	Month	Forced Outage Rate	Availability Factor
1988	Jan	0.75	99.25	1991	Jan	0.08	99.93
	Feb	0.09	99.91		Feb	0.00	100.00
	Mar	0.00	100.00		Mar	0.00	100.00
	Apr	0.00	100.00		Apr	0.00	100.00
	May	0.00	26.61		May	0.00	88.04
	Jun	0.77	83.94		Jun	0.00	57.92
	Jul	0.00	100.00		Jul	0.31	99.85
	Aug	0.00	100.00		Aug	0.51	99.49
	Sep	0.00	100.00		Sep	0.00	100.00
	Oct	0.00	100.00		Oct	0.00	100.00
	Nov	0.00	100.00		Nov	0.19	99.81
	Dec	0.19	99.81		Dec	0.07	99.93
1989	Jan	0.00	100.00	1992	Jan	0.15	99.85
	Feb	0.00	100.00		Feb	0.00	100.00
	Mar	0.00	100.00		Mar	0.00	100.00
	Apr	0.00	96.69		Apr	0.15	99.92
	May	3.46	64.67		May	0.00	16.94
	Jun	0.79	99.21		Jun	0.81	98.06
	Jul	0.39	99.61		Jul	0.07	99.93
	Aug	3.91	96.09		Aug	0.25	99.75
	Sep	0.00	100.00		Sep	0.04	99.96
	Oct	0.00	100.00		Oct	0.13	99.87
	Nov	0.00	100.00		Nov	0.00	100.00
	Dec	0.00	100.00		Dec	0.12	99.88
1990	Jan	0.00	100.00				
	Feb	0.00	100.00				
	Mar	0.00	100.00				
	Apr	0.00	93.16				
	May	0.00	45.07				
	Jun	0.00	100.00				
	Jul	0.00	100.00				
	Aug	1.59	92.69				
	Sep	0.09	99.91				
	Oct	2.69	97.31				
	Nov	0.09	99.93				
	Dec	0.18	99.82				

* Availability Factor: (Available Hours/Period Hours) x 100 (%)).

PURPA Plants:

1. Upriver Power Project/City of Spokane

Rated Capacity = 15,700 kW
Hours Connected to System = Not Available
Level of Dispatchability = None
Expiration Date = 7/1/2004

Year	Month	Generation - kWh
1988	Jan	4,500,000
	Feb	4,300,000
	Mar	5,500,000
	Apr	5,400,000
	May	5,200,000
	Jun	5,400,000
	Jul	2,800,000
	Aug	1,200,000
	Sep	1,900,000
	Oct	2,000,000
	Nov	2,800,000
	Dec	4,000,000
1989	Jan	4,721,000
	Feb	3,679,000
	Mar	8,214,000
	Apr	7,600,000
	May	8,839,000
	Jun	8,446,000
	Jul	2,372,000
	Aug	1,299,000
	Sep	1,553,000
	Oct	2,343,000
	Nov	5,410,000
	Dec	9,485,000
1990	Jan	9,604,000
	Feb	9,494,000
	Mar	11,147,000
	Apr	8,270,000
	May	9,590,000
	Jun	8,656,000
	Jul	4,926,000
	Aug	2,118,000
	Sep	2,381,000
	Oct	3,472,000
	Nov	6,218,000
	Dec	10,111,000

Year	Month	Generation - kWh
1991	Jan	9,630,000
	Feb	8,836,000
	Mar	10,165,000
	Apr	9,176,000
	May	8,840,000
	Jun	10,093,000
	Jul	6,303,000
	Aug	1,990,000
	Sep	2,363,000
	Oct	2,991,000
	Nov	3,803,000
	Dec	5,298,000
1992	Jan	4,984,000
	Feb	9,198,000
	Mar	11,240,000
	Apr	9,421,000
	May	8,514,000
	Jun	3,677,000
	Jul	1,754,000
	Aug	955,000
	Sep	1,662,000
	Oct	3,374,000
	Nov	4,098,000
	Dec	5,126,000

2. Big Sheep Creek Hydroelectric Project/Sheep Creek Hydro, Inc.

Rated Capacity = 1,500 kW
Hours Connected to System = Not Available
Level of Dispatchability = None
Expiration Date = 6/4/2021

Year	Month	Generation - kWh	Year	Month	Generation - kWh
1988	Jan	142,893	1991	Jan	228,689
	Feb	130,977		Feb	667,926
	Mar	584,550		Mar	914,367
	Apr	1,055,931		Apr	1,174,015
	May	1,204,784		May	1,192,392
	Jun	1,120,599		Jun	1,056,586
	Jul	746,363		Jul	1,209,404
	Aug	203,989		Aug	549,192
	Sep	123,758		Sep	213,182
	Oct	127,085		Oct	141,150
	Nov	236,764		Nov	156,752
	Dec	195,300		Dec	122,230
1989	Jan	169,335	1992	Jan	142,691
	Feb	146,874		Feb	393,378
	Mar	504,507		Mar	1,143,057
	Apr	1,040,289		Apr	1,140,503
	May	1,258,520		May	1,153,699
	Jun	1,118,455		Jun	1,069,927
	Jul	862,861		Jul	1,063,276
	Aug	362,169		Aug	491,843
	Sep	234,172		Sep	175,118
	Oct	195,325		Oct	135,655
	Nov	466,011		Nov	181,269
	Dec	490,050		Dec	153,847
1990	Jan	400,878			
	Feb	251,837			
	Mar	702,491			
	Apr	1,182,872			
	May	479,477			
	Jun	1,078,499			
	Jul	1,114,331			
	Aug	542,671			
	Sep	272,271			
	Oct	208,461			
	Nov	268,185			
	Dec	302,130			

3. Jim Ford Creek Power Project/Ford Hydro Limited Partnership

Rated Capacity = 1,500 kW
Hours Connected to System = Not Available
Level of Dispatchability = None
Expiration Date = 4/14/2023

Year	Month	Generation - kWh	Year	Month	Generation - kWh
1988	Jan	0	1991	Jan	47,686
	Feb	0		Feb	599,450
	Mar	0		Mar	791,142
	Apr	164,910		Apr	651,392
	May	0		May	514,397
	Jun	0		Jun	520,018
	Jul	0		Jul	15,120
	Aug	0		Aug	0
	Sep	0		Sep	0
	Oct	0		Oct	0
	Nov	53,550		Nov	0
	Dec	97,249		Dec	240,551
1989	Jan	29,915	1992	Jan	145,958
	Feb	146,472		Feb	728,647
	Mar	285,835		Mar	382,064
	Apr	0		Apr	496,072
	May	0		May	24,156
	Jun	0		Jun	0
	Jul	0		Jul	0
	Aug	0		Aug	0
	Sep	0		Sep	0
	Oct	61		Oct	745
	Nov	677		Nov	94,488
	Dec	60,786		Dec	12,352
1990	Jan	236,411			
	Feb	244,710			
	Mar	221,666			
	Apr	321,427			
	May	0			
	Jun	0			
	Jul	0			
	Aug	0			
	Sep	0			
	Oct	0			
	Nov	0			
	Dec	0			

4. John Day Creek Hydroelectric Project/David Cereghino

Rated Capacity = 900 kW
Hours Connected to System = Not Available
Level of Dispatchability = None
Expiration Date = 9/21/2022

Year	Month	Generation - kWh	Year	Month	Generation - kWh
1988	Jan	57,850	1991	Jan	75,050
	Feb	57,800		Feb	106,590
	Mar	99,170		Mar	86,690
	Apr	156,610		Apr	64,240
	May	351,320		May	289,780
	Jun	474,820		Jun	455,130
	Jul	362,160		Jul	440,940
	Aug	242,260		Aug	248,520
	Sep	154,510		Sep	142,780
	Oct	119,640		Oct	97,330
	Nov	115,920		Nov	161,100
	Dec	107,780		Dec	116,080
1989	Jan	78,480	1992	Jan	77,220
	Feb	55,630		Feb	82,840
	Mar	217,830		Mar	122,800
	Apr	312,620		Apr	77,230
	May	451,070		May	261,980
	Jun	455,030		Jun	157,640
	Jul	436,660		Jul	94,050
	Aug	325,270		Aug	76,860
	Sep	232,300		Sep	42,420
	Oct	186,780		Oct	40,950
	Nov	182,820		Nov	0
	Dec	131,110		Dec	0
1990	Jan	104,380			
	Feb	84,250			
	Mar	131,530			
	Apr	223,660			
	May	329,230			
	Jun	451,140			
	Jul	378,790			
	Aug	277,800			
	Sep	155,790			
	Oct	148,440			
	Nov	130,700			
	Dec	84,700			

5. Wood Power Project/Wood Power, Inc.

Rated Capacity = 6,250 kW
Hours Connected to System = Not Available
Level of Dispatchability = None
Expiration Date = 1/26/2019

Year	Month	Generation - kWh	Year	Month	Generation - kWh
1988	Jan	3,599,000	1991	Jan	3,596,000
	Feb	3,315,000		Feb	3,108,000
	Mar	3,560,000		Mar	2,969,000
	Apr	3,697,000		Apr	3,836,000
	May	3,367,000		May	3,253,000
	Jun	763,000		Jun	2,658,000
	Jul	879,000		Jul	3,664,000
	Aug	3,478,000		Aug	3,253,000
	Sep	4,427,000		Sep	3,216,000
	Oct	3,431,000		Oct	3,438,000
	Nov	3,627,000		Nov	3,151,000
	Dec	4,145,000		Dec	3,488,000
1989	Jan	3,560,000	1992	Jan	3,636,000
	Feb	3,128,000		Feb	2,875,000
	Mar	3,360,000		Mar	3,739,000
	Apr	3,498,000		Apr	3,213,000
	May	3,667,000		May	3,296,000
	Jun	2,768,000		Jun	2,659,000
	Jul	2,687,000		Jul	3,579,000
	Aug	3,742,000		Aug	3,630,000
	Sep	3,557,000		Sep	3,463,000
	Oct	3,767,000		Oct	3,196,000
	Nov	3,279,000		Nov	3,441,000
	Dec	3,841,000		Dec	3,554,000
1990	Jan	3,753,000			
	Feb	3,349,000			
	Mar	3,381,000			
	Apr	3,519,000			
	May	3,380,000			
	Jun	1,934,000			
	Jul	3,435,000			
	Aug	3,485,000			
	Sep	3,632,000			
	Oct	3,458,000			
	Nov	3,647,000			
	Dec	3,465,000			

6. Vaagen Brothers Power Project/Vaagen Brothers Lumber

Rated Capacity = 4,000 kW
Hours Connected to System = Not Available
Level of Dispatchability = None
Expiration Date = 5/30/1994

Year	Month	Generation - kWh	Year	Month	Generation - kWh
1988	Jan	2,394,000	1991	Jan	2,632,000
	Feb	2,115,000		Feb	2,634,000
	Mar	2,217,000		Mar	2,536,000
	Apr	2,245,000		Apr	2,943,000
	May	2,318,000		May	3,078,000
	Jun	2,217,000		Jun	2,695,000
	Jul	2,393,000		Jul	2,371,000
	Aug	1,878,000		Aug	3,164,000
	Sep	0		Sep	3,051,000
	Oct	0		Oct	2,522,000
	Nov	0		Nov	3,035,000
	Dec	2,120,000		Dec	2,371,000
1989	Jan	3,066,000	1992	Jan	2,916,000
	Feb	2,998,000		Feb	2,619,000
	Mar	3,113,000		Mar	2,597,000
	Apr	3,265,000		Apr	2,047,000
	May	2,480,000		May	3,132,000
	Jun	2,988,000		Jun	3,035,000
	Jul	3,170,000		Jul	1,727,000
	Aug	3,198,000		Aug	2,975,000
	Sep	3,251,000		Sep	2,047,000
	Oct	2,397,000		Oct	3,191,000
	Nov	3,078,000		Nov	2,138,000
	Dec	3,223,000		Dec	2,921,000
1990	Jan	3,217,000			
	Feb	2,867,000			
	Mar	3,229,000			
	Apr	3,186,000			
	May	2,468,000			
	Jun	2,905,000			
	Jul	3,177,000			
	Aug	3,153,000			
	Sep	2,759,000			
	Oct	2,316,000			
	Nov	2,924,000			
	Dec	2,781,000			

7. Potlatch Corporation[7] - Lewiston

Rated Capacity = 59,000 kW (contracted amount)
Hours Connected to System = Not Available
Level of Dispatchability = None
Expiration Date = 12/31/2001

Note:

Year	Month	Generation - kWh
1992	Jan	37,405,000
	Feb	40,670,000
	Mar	43,214,000
	Apr	42,074,000
	May	42,571,000
	Jun	10,876,000
	Jul	41,266,000
	Aug	43,562,000
	Sep	31,271,000
	Oct	42,732,000
	Nov	41,527,000
	Dec	43,360,000

7 WWP negotiated a special contract with Potlatch to buy a portion of their generation for ten years, starting 1/1/92.

Economy Purchases and Sales:

		Total Secondary Sales-MWh	Average Cost Mills/kWh	Total Secondary Purchases-MWh	Average Cost Mills/kWh
1988	Jan	130,836	21.1	57,535	18.6
	Feb	108,367	19.8	60,345	17.4
	Mar	121,280	20.5	57,389	17.9
	Apr	215,653	20.2	38,713	18.3
	May	218,423	19.0	70,382	16.3
	June	227,807	20.3	83,459	17.5
	July	144,789	19.6	74,129	16.3
	Aug	185,870	20.4	134,354	17.9
	Sep	138,685	22.1	80,720	18.6
	Oct	102,491	21.5	111,400	21.1
	Nov	91,692	19.5	85,587	16.4
	Dec	96,509	20.2	92,985	17.1
1989	Jan	196,971	21.0	155,060	14.7
	Feb	116,143	37.0	92,761	28.8
	Mar	78,689	26.7	62,513	16.7
	Apr	232,681	15.7	99,466	15.7
	May	264,685	11.8	74,174	8.9
	June	209,050	15.4	38,802	13.9
	July	155,709	25.7	61,572	22.6
	Aug	136,670	24.8	45,257	21.2
	Sep	159,622	26.2	70,237	20.6
	Oct	92,507	26.4	80,972	20.2
	Nov	198,574	27.4	97,477	22.4
	Dec	128,469	29.2	40,671	21.7
1990	Jan	258,519	29.8	87,982	22.4
	Feb	196,133	29.1	88,564	19.0
	Mar	116,187	18.5	117,677	15.4
	Apr	297,739	17.2	41,339	14.7
	May	272,861	18.8	68,383	14.4
	June	410,796	15.5	195,018	8.1
	July	226,884	18.8	83,718	12.9
	Aug	77,708	27.8	106,403	17.2
	Sep	80,023	28.0	93,615	19.3
	Oct	75,325	27.6	95,308	17.5
	Nov	129,404	22.0	107,329	13.1
	Dec	102,689	22.0	147,491	15.2

		Total Secondary Sales-MWh	Average Cost Mills/kWh	Total Secondary Purchases-MWh	Average Cost Mills/kWh
1991	Jan	162,923	17.65	105,889	14.34
	Feb	153,466	13.11	50,776	8.83
	Mar	168,227	13.25	97,500	10.86
	Apr	153,949	13.76	48,825	10.80
	May	291,659	10.39	86,052	8.07
	June	315,699	9.29	108,472	6.96
	July	185,297	9.36	67,488	8.34
	Aug	59,950	14.84	131,294	12.86
	Sep	48,314	20.51	92,137	17.05
	Oct	178,411	25.03	183,550	20.62
	Nov	141,643	31.96	73,919	23.81
	Dec	81,912	22.97	35,117	20.35
1992	Jan	91,907	19.57	41,524	18.33
	Feb	72,536	24.90	54,391	18.05
	Mar	81,963	15.91	58,721	13.43
	Apr	88,518	19.34	20,332	18.18
	May	186,052	20.03	93,154	18.61
	June	67,872	17.68	167,727	13.90
	July	91,075	20.34	30,110	21.22
	Aug	34,538	22.36	79,098	26.95
	Sep	83,130	24.05	95,676	25.19
	Oct	131,361	24.64	74,702	26.36
	Nov	127,553	27.09	83,201	25.73
	Dec	89,461	30.14	53,414	26.54

Contract Purchases/Exchanges/Sales

WWP's existing contracts include the following agreements. Contract details appear in the individual summaries.

Bonneville Power Administration - Contract No. 39216
Bonneville Power Administration - WNP No. 3 Settlement
Bonneville Power Administration - Peak
Bonneville Power Administration - Energy
Columbia Storage Power Exchange
Douglas County PUD
Entitlement and Supplemental Capacity
Mid-Columbia Purchasers:
- Chelan County Public Utility District - Chelan and Rocky Reach Hydroelectric Plants
- Douglas County Public Utility District - Wells Hydroelectric Plant
- Grant County Public Utility District - Priest Rapids and Wanapum Hydroelectric Plants

Montana Power Company
Northern California Power Agency
Pacific Gas and Electric Company
Pacific Power & Light Company
Pacific Power & Light Company - Sandpoint
Pend Oreille County PUD
Portland General Electric No. 1
Portland General Electric No. 2
Puget Sound Power & Light No. 2
San Diego Gas & Electric
Seattle City Light

BONNEVILLE POWER ADMINISTRATION (BPA) - WNP No. 1

(Contract No. 39216)

The private utilities, Washington Public Power Supply System (WPPSS) and BPA entered into an agreement to replace the present Hanford NPR with a new nuclear steam supply and generating facility. This agreement resulted from the company's rights to power from the debt service portion of WPPSS costs on the Hanford NPR. The new plant is called WNP No. 1 and has a capability of 1,250 megawatts. The company will receive 80 megawatts at 85 percent plant factor for the period July 1980 through June 1996. For the first ten-year period, power was purchased at BPA rates, and for the balance of the contract the company will pay a fixed rate negotiated by the parties. This rate as shown below does not include any transmission costs/losses or relocation costs.

1991-92 (July - June)	43.98 mills/kWh
1992-93	45.01
1993-94	46.09
1994-95	47.22
1995-96	48.42

	Deliveries to WWP	
	Capacity (MW)	Energy (Average MW)
July 1980 through June 1996	80	68

BONNEVILLE POWER ADMINISTRATION - WNP No. 3 SETTLEMENT

On September 17, 1985, the company signed settlement agreements with BPA and the WPPSS in which the company agreed not to proceed further on the construction delay claims. In addition to settling the construction delay litigation, the BPA Settlement includes agreements for an exchange of energy, an agreement to reimburse the company for certain WNP No. 3 preservation costs and an irrevocable offer of WNP No. 3 capability for acquisition under the Regional Power Act.

Under the energy exchange portion of the BPA Settlement, the company expects to receive from BPA approximately 32 average megawatts for a period of up to 32.5 years, subject to a contract minimum of 5.8 million MWh. The company is obligated to pay BPA operating and maintenance costs associated with the energy exchange, determined by a formula in an amount not less than 1.6 cents per kWh nor more than 2.9 cents per kWh expressed in 1987 dollars, unless WNP No. 3 is completed in which case, under certain circumstances, the operating and maintenance costs may be measured by actual WNP No. 3 costs. The company began receiving power from BPA on January 1, 1987.

With the BPA Settlement, the company continues as an owner of WNP No. 3 under the Ownership Agreement and will continue to pay its ownership share of preservation costs. BPA is required to reimburse the company for the preservation costs and other costs of WNP No. 3 paid on or after February 1, 1985, through the date that WNP No. 3 is restarted or terminated. The reimbursement will be applied against the operating and maintenance costs which the company will pay BPA under the energy exchange portion of the BPA Settlement.

BONNEVILLE POWER ADMINISTRATION

BPA is selling to the company long-term firm capacity of 50 MW for the period starting as early as May 1, 1993, (based on the availability of the California-Oregon Transmission Project) through September 30, 2010. There is a provision for termination upon five years' notice by either party. BPA shall make the capacity available ten hours a day and fifty hours a week. The company shall return the energy associated with the capacity deliveries the following day.

COLUMBIA STORAGE POWER EXCHANGE

In 1968, the company was entitled to receive power from the Columbia Storage Power Exchange (CSPE), a nonprofit Washington corporation, which purchased Canada's share of the downstream benefits resulting from the Columbia River Treaty. The company's share of the power is 5 percent. It is obligated to pay 5 percent of CSPE's costs which are almost entirely debt interest and repayment charges. This contract will be in effect until the year 2003.

In conjunction with CSPE arrangements, the company has purchased Entitlement and Supplemental Capacity commencing April 1977. This is strictly a capacity purchase with the amount decreasing until 2003 when the agreement terminates.

	Deliveries to WWP			
	Capacity (MW)		Energy (Average MW)	
CSPE	Gross	Net	Gross	Net
April 1, 1991 - March 31, 1992	47	45	16	15
April 1, 1992 - March 31, 1993	42	40	15	15
April 1, 1993 - March 31, 1994	38	36	15	14
April 1, 1994 - March 31, 1995	33	32	14	14
Entitlement and Supplemental Capacity				
April 1, 1991 - March 31, 1992	24	24	0	0
April 1, 1992 - March 31, 1993	22	21	0	0
April 1, 1993 - March 31, 1994	19	19	0	0
April 1, 1994 - March 31, 1995	17	17	0	0

MID-COLUMBIA PURCHASES

I. CHELAN COUNTY PUD

Chelan Plant

The company signed a 40-year contract in 1955 for the entire 58 megawatt capacity of Lake Chelan Hydro Plant by paying the district all costs associated with this plant including interest on and repayment of revenue bonds. The company sells back to Chelan PUD about 50 percent of the output to supply the requirements of the Chelan service area. The contract terminates June 21, 1995.

Rocky Reach Plant

The company has been receiving 3.9 percent or 32 megawatts of capacity from Rocky Reach Hydro Plant since 1961, but the debt interest and repayment charges were not a cost factor until 1963. The contract is in effect until 2011, and WWP's participation was reduced to 2.9 percent on July 1, 1977, for the remainder of the contract.

The company signed an amendment to the Rocky Reach Power Sales Contract June 1, 1968, which provides for company participation in the power output of four additional generating units at Rocky Reach. The company began receiving generation from these additional units in the fall of 1971. The company's percentage share in these additional units will be the same as the initial seven units and currently is 2.9 percent or 14 megawatts.

	Capacity - WWP Share (MW)
July 1, 1977 - November 1, 2011	37

II. DOUGLAS COUNTY PUD

Wells Plant

The company has a 50-year contract for 5.6 percent of the Wells Hydro Plant power. The power became available in 1967; however, it was assigned to other utilities until September 1, 1972, at which time the company started receiving this power. The PUD may withdraw, within certain limits, a portion of the plant output but cannot reduce the company's share below 3.5 percent. WWP's participation was 3.8 percent on September 1, 1992, and will be 3.9 percent on September 1, 1993. The contract is in effect until August 31, 2018.

	Capacity - WWP Share (MW-Based on 840 Total Plant)
September 1, 1992 - August 31, 1993	32
September 1, 1993 -	33

III. GRANT COUNTY PUD

Priest Rapids Plant

The company first received power from Priest Rapids Hydro Plant in 1959, but debt interest and repayment charges didn't become a factor until 1961. The company's share of this plant's power was initially 11 percent or 98 megawatts of capacity. Reductions in the company's share were made by the PUD in predetermined maximum amounts on five years' notice. The company's share was reduced to 6.1 percent on September 1, 1983, and will remain 6.1 percent until the end of the contract. The contract is in effect until 2005.

	Capacity - WWP Share (MW)
September 1, 1983 - October 31, 2005	55

Wanapum Plant

The company received 13.1 percent or 118 megawatts of capacity commencing in 1964 but paid only its share of the operating charges. However, debt interest and repayment charges commenced January 1, 1965. Similar to the Priest Rapids Contract, the company's share was reduced to 8.2 percent on September 1, 1983 until the end of the contract. The contract is in effect until 2009.

	Capacity - WWP Share (MW)
September 1, 1983 - October 31, 2009	75

MONTANA POWER COMPANY

The company and Montana Power entered into a firm agreement for the period January 1, 1991, through December 31, 1994. Montana Power will deliver to the company 319,650 MWh in 1991, 318,300 MWh in 1992, 317,400 MWh in 1993, and 233,925 MWh in 1994. Most of this energy will be delivered during the off-peak hours, although if requested by the company, some or all of the energy can be delivered during the heavy load hours for an additional charge of two mills/kWh.

NORTHERN CALIFORNIA POWER AGENCY (NCPA)

The company is selling to NCPA capacity and energy for an 18-year term starting as early as May 1, 1993, (based on the availability of the California-Oregon Transmission Project) and ending September 30, 2010. Either party may terminate upon five years' notice but not earlier than June 30, 2001. NCPA shall purchase 50 MW capacity and associated energy from WWP at up to 100% daily load factor. WWP will purchase nonfirm energy on the daily spot market to support the energy portion of the sale.

PACIFIC GAS AND ELECTRIC COMPANY (PG&E)

The company and PG&E signed a 20-year 150 MW seasonal exchange agreement for service beginning May 25, 1991. The agreement provides for flexible starting dates, November 11 - 27 for the company and May 24 - June 9 for PG&E. Each session will have 18 weeks duration with 95,700 MWh of Peak Energy and 120,960 MWh of Base Energy per exchange period. The Base Energy delivery rate is 40 MW. Peak Energy may be scheduled at a rate of delivery equal to 110 MW, for up to 24 hours per day, and will be delivered at a uniform rate in a sequence of consecutive hours each day.

In addition, the delivering party may request ramping service. The receiving party may refuse Base Energy, however, the delivering party shall be relieved of its obligation to supply Peak Energy during the next two peak days. A Base Energy Account and a Peak Energy Account will be established for each party each year. For termination, a five-year notice is required. However, termination will not be effective prior to May 24, 2011. The agreement may also be terminated if third party transmission is unavailable or unacceptable.

PACIFIC POWER & LIGHT COMPANY (PP&L)

The company will sell power to PP&L company for the period February 13, 1989, through December 31, 1995. PP&L has elected to extend the agreement through 1997. The amounts of capacity and energy sold to PP&L are shown below:

Year	Capacity-MW	Energy-aMW
1992	150	50
1993	150	50
1994	150	50
1995	150	50
1996	100	33
1997	50	17

PACIFIC POWER & LIGHT COMPANY - SANDPOINT

The company has an agreement with PP&L to sell five megawatts of peak and an annual total of 20,100 MWh to be used for resale for their Sandpoint load. The term is from January 1, 1986, through December 31, 1995. The payment is computed at the rates set forth in the company's Rate Schedule 61.

PEND OREILLE COUNTY PUD

In February 1991, the company agreed to a four-year power sale to the PUD starting July 1, 1991, and ending July 31, 1995. The PUD can schedule the energy up to the capacity rate stated in the contract. In addition, under a separate contact, the company is selling to the PUD firm capacity and energy for the term of August 1, 1996, through July 31, 1997, and amending the current schedule from August 1, 1993, through July 31, 1996. Listed below is the current schedule:

Year	Capacity - MW	Energy - aMW
8/1/92 - 7/31/93	13	13
8/1/93 - 7/31/94	9	9
8/1/94 - 7/31/95	11	11
8/1/95 - 7/31/96	4	4
8/1/96 - 7/31/97	4	4

PORTLAND GENERAL ELECTRIC (PGE)

The company is selling to PGE 100 MW of capacity, ten hours per day, fifty heavy load hours per week for the term March 1, 1992 through October 31, 1994. Within 168 hours the energy associated with the capacity deliveries shall be returned. In June 1992 the company signed a long-term capacity sale with PGE for an additional 50 MW beginning November 1992 through October 1994, and 150 MW for the period starting November 1, 1994, through December 31, 2016.

PUGET SOUND POWER & LIGHT COMPANY (PSP&L) No. 2

The company, on January 1, 1988, entered into an agreement with PSP&L to sell a block of power for 15 years. The contract demand is 100 MW for contract years 1988 through 2000 and 67 MW for 2001 and 33 MW for contract year 2002, unless the contract is extended for two years. The two-year extension is dependent on whether the company has minimal load growth. Energy will be delivered to PSP&L based on 75 percent annual load factor. Energy shall not be scheduled for any hour at a rate higher than 100 MW or less than 30 MW. The price for energy starts at 31.5 mills/kilowatt-hour and is calculated each year based on the company's average power cost.

SAN DIEGO GAS & ELECTRIC (SDG&E)

The company signed a firm capacity and energy purchase agreement with SDG&E to begin June 8, 1992, through March 31, 1993. The company will purchase 216,660 MWh of firm energy from June 8, 1992, through October 11, 1992. 120,960 MWh of base energy will be delivered at a rate of 40 MW for each hour and 95,700 MWh of Peak Energy will be delivered at a rate of 110 MW for up to 24 hours per day. Firm winter capacity will be delivered from December 1992 through March 1993 in amounts ranging from 25 MW to 275 MW.

The company will sell to SDG&E 216,660 MWh of firm energy from June 1, 1993 through October 18, 1993. 120,960 MWh of base energy will be delivered at a rate of 36 MW for each hour and 95,700 MWh of peak energy at a rate not to exceed 104 MW for each hour.

SEATTLE CITY LIGHT (SCL)

The company entered into a five-year Ross Reservoir Overdraft Protection Sales Agreement with SCL. SCL requires overdraft protection for its Ross reservoir for the period January 1 through June 30 of each operating year 1990-91 through 1994-95. This energy is made available up to 130,000 MWh each year at a rate not to exceed 100 MW. The company has the option to not deliver energy during any six hours each day.

For energy delivered, SCL shall pay 2.5 mills/kWh plus the incremental cost of the least costly thermal resource available, the weekly weighted average price of any non-firm sales, the incremental cost of running combustion turbines, or 1.0 mill/kWh plus the purchase price of energy to the company.

Source(s): Doug Young & Sandee Warne, WWP Power Resources, February 1993

Appendix D

Electric Load Forecast

Electric Load Forecast

WWP's electric forecast provides the basis for many of the company's planning and budgeting activities. This appendix describes the inputs and results of the electric load forecast as it is applies to the 1993 IRP. It contains a summary of the following information:

- Economic assumptions for the nation and the service territory.
- Large-load customer forecast.
- Electricity and natural-gas price forecasts.
- Forecast methodology.
- Forecast results for the medium, high and low energy forecasts.
- Peak forecast methodology and results.

Summary

WWP's 20-year energy forecast is prepared annually. Results of the official forecast are used internally and also distributed to external entities. While the annual forecast focuses on projections of the most likely (or medium) load growth, high and low growth scenarios are developed biennially to meet IRP objectives. Figure D-1 illustrates the current projections for high, medium and low load growth as determined by the forecast. Note that this information relates WWP's energy forecast prior to any load reductions associated with demand-side management. Annual average growth rates are calculated for the period 1993 through 2011.

Figure D-1: WWP long-term electric energy forecast.

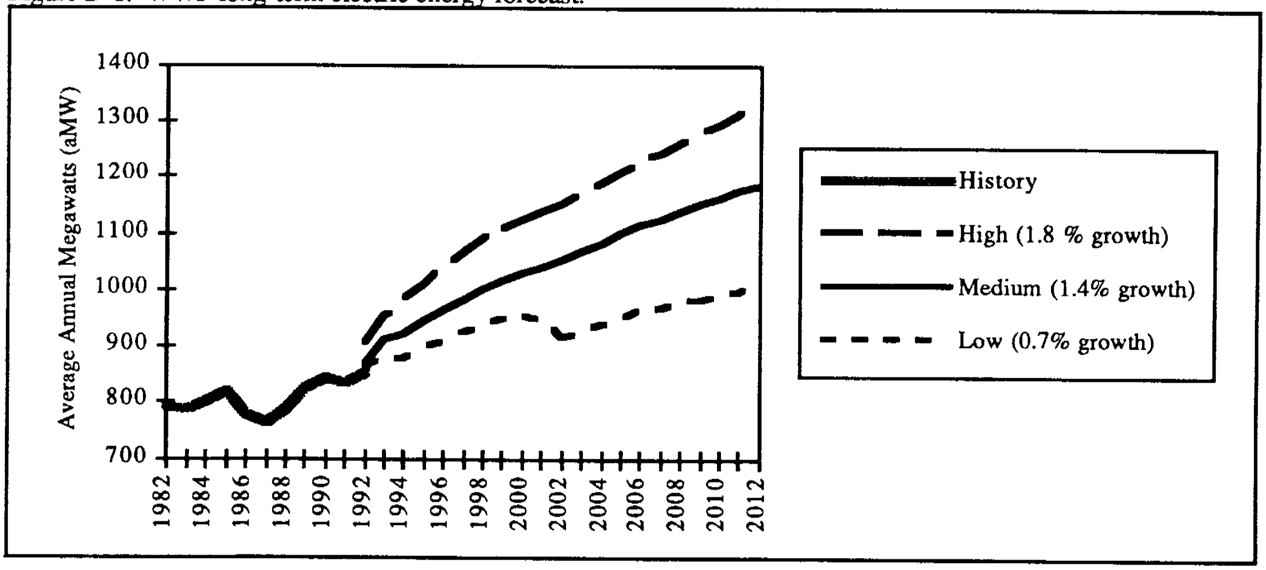


Figure D-1 (continued): WWP long-term electric energy forecast.

Year	High (aMW)	Medium (aMW)	Low (aMW)
1993	954	912	878
1994	983	921	879
1995	1011	944	896
1996	1040	961	907
1997	1067	981	922
1998	1088	998	934
1999	1108	1014	946
2000	1121	1026	954
2001	1135	1039	950
2002	1151	1052	915
2003	1168	1067	923
2004	1186	1082	937
2005	1205	1097	949
2006	1225	1112	960
2007	1242	1124	967
2008	1259	1136	974
2009	1276	1148	981
2010	1294	1160	989
2011	1312	1172	996
2012	1329	1184	1003

In addition to the forecast of annual energy requirements, the company produces a peak load forecast. WWP projects monthly peak demand over the 20-year planning period and uses the forecast results in its capacity planning efforts. WWP's January peak load forecast, as produced for the medium growth scenario only, is shown in Figure D-2. Similar to the tabulation of annual energy requirements, the peak demand forecast is shown absent the effects of any demand-side management activities.

Figure D-2: WWP long-term peak electric forecast.

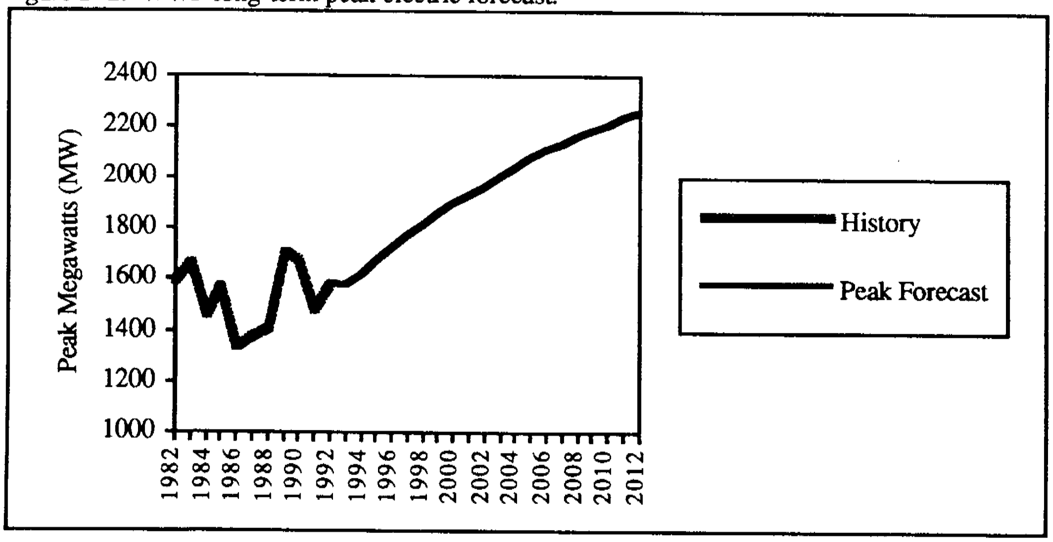


Figure D-2 (continued): WWP long-term peak electric forecast.

Year	January Peak Demand (MW)
1993	1576
1994	1613
1995	1668
1196	1719
1197	1768
1998	1814
1999	1856
2000	1893
2001	1929
2002	1963
2003	1998
2004	2033
2005	2068
2006	2101
2007	2130
2008	2153
2009	2177
2010	2201
2011	2226
2012	2250

Forecast Assumptions

National Economic Assumptions

The company contracts to a national economic forecasting company, McGraw-Hill/Data Resources Inc. (DRI). DRI provides through this contract three alternative economic scenarios. The DRI "Review of the U.S. Economy (Long-Range Focus), Winter 1991-92" is the document source.

The general outlook for the TREND alternative is that the economy exhibits mild variations in growth and approaches its balanced-growth path. The TREND scenario is used to produce economic and electric forecasts for the medium case.

The OPTIMISTIC alternative is characterized by higher growth in population, productivity and investment, with low inflation. The OPTIMISTIC scenario is used in the high case scenario development.

The PESSIMISTIC alternative contains low growth in population, productivity and investment, combined with high inflation. The PESSIMISTIC scenario is used in the low case scenario development.

A full description of the principal exogenous assumptions, policy dimensions, behavior of economic agents and other parameters is contained in Figure D-3, "Capsule Summary of National Long-Term Projections."

Capsule Summary Of National Long-Term Projections

	Trend	Optimistic	Pessimistic
General Outlook	The economy exhibits mild variations in growth and approaches its balanced-growth path. Inflation rises slowly, averaging 4.2%.	High growth; low inflation.	Low growth; high inflation.
		For both the high and low growth projections, deviations from the trend are due to differences in labor-force participation, productivity, growth and investment.	
I. Principal Exogenous Assumptions			
Demographic	Projections consistent with Census Bureau middle-growth estimates, which assume a leveling off of the fertility rate at 1.8 births and a further reduction of the mortality rate.	Projection above the trend are a result of higher fertility rate, higher immigration rate , and lower mortality rate assumptions.	Projections below the trend due to lower fertility rate, lower immigration rate, and higher mortality rate assumptions.
Energy Imports	Oil prices rise by an average 6.3% per year. No embargos assumed. Oil imports bill exceeds $475 billion by 2016.	Oil prices rise by an average 4.5% per year. Oil imports bill rises above $320 billion by 2016.	Oil prices rise by an average 8.2% per year. Oil imports bill surpasses $730 billion by 2016.
Food Prices	Wholesale farm prices average 3.8% annual increases.	Wholesale farm prices average 2.8% annual increases.	Wholesale farm prices average 5.4% annual increases.

Source: DRI/McGraw-Hill, Review of the U. S. Economy, Long-Range Focus, Winter 1991-92
Prepared by: Ann Carey, Washington Water Power, August 1992

Capsule Summary Of National Long-Term Projections

	Trend	Optimistic	Pessimistic
II. Principal Policy Dimensions			
Tax Changes	Steady increases in personal income tax rate through 2016.	Small, steady increases through 2002, then lower through 2010, but rising thereafter.	Rate increases late in the period as budget deficit threatens to get out of control.
Growth of Federal Government Purchases	Real, -.04% per year; nominal, 4.5%. Real military purchases fall through 2002, then resume slow growth.	Real, -.03% per year; nominal, 3.7%.	Real, -.06% per year; nominal, 5.9%.
Transfers Budget Deficit	Real growth of 2.2% per year. The federal budget deficit averages only 1.4% of GDP.	Real growth of 2.2% per year. Deficit falls to $186 billion in 1994 and hits slight surplus by 2001; budget remains in surplus thereafter. Deficit averages 0.1% of GDP.	Real growth of 2.2% per year. Deficit continues to worsen in nominal terms throughout the projection period, hitting $631 billion in 2016. Deficit averages 2.4% of GDP
Average Federal Government Share of GDP	22.1%	20.3%	23.9%
Monetary Policy	Sufficient funds made available to promote stable credit growth. Money (M2) growth averages 6.3%	For both the high and low growth projections, real interest rates remain close to the trend values throughout forecast period.	

Source: DRI/McGraw-Hill, Review of the U. S. Economy, Long-Range Focus, Winter 1991-92
Prepared by: Ann Carey, Washington Water Power, August 1992

Capsule Summary Of National Long-Term Projections

	Trend	Optimistic	Pessimistic
III. Behavior of Economic Agents			
Consumers	Stable inflation rate and job security boost consumer confidence.	Stable inflation rate and job security boost consumer confidence.	Lower real incomes depress consumer expenditures, especially on durable goods.
Average Annual Real Consumption Growth	1.8%	2.2%	1.8%
Business	Decisions made in relatively stable environment.	High demand expectations plus low inflation and interest rates enhance the business environment.	Higher inflation, cyclical interest rates, and greater uncertainty make investors more cautious.
Average Fixed Investment Share in GDP	10.7%	11.4%	10.2%
State and Local Government	Real expenditures dictated by demographics and ability to raise taxes. Average real growth in purchases of 1.4% per year.	Average real growth in purchases of 1.8% per year.	Average real growth in purchases of 0.9% per year.
International - Average annual wholesale price inflation for major trading partners	3.9%	2.8%	5.6%
U.S. Exchange Rate	Remains stable through 1995. Small declines occur thereafter.	Level through 2004, with small declines thereafter.	Peaks at 89% of 1980-82 parity in 1994. Declines thereafter as inflation remains a problem. Eventually falls to 67% of 1980-82 parity.
IV. Other Parameters			
Average Annual Productivity Growth	1.5%	1.7%	1.4%

Source: DRI/McGraw-Hill, Review of the U. S. Economy, Long-Range Focus, Winter 1991-92
Prepared by: Ann Carey, Washington Water Power, August 1992

Capsule Summary Of National Long-Term Projections

	Trend	Optimistic	Pessimistic
Consumer Price Inflation	Demand pressures and a return of moderate oil and food price inflation gradually push consumer price increases from 3.2% in 1992 to 4.5% in 2001. Price increases hold steady until 2010, when they begin to accelerate again.	Supply-side growth keeps inflation well below 4.0% throughout most of the projection period.	Inflation worsens 6.8% by 2016.
Consumer Price Index			
Average Annual Increases	4.2%	3.4%	5.9%
Peak Annual	5.1% (2016)	4.1% (2016)	6.8% (2016)
Hourly Earnings			
Average Annual Rise	5.1%	4.4%	6.6%
Peak Annual	5.9% (2016)	4.9% (2015-16)	7.5% (2003)
Housing Market	Demographics dictate slower growth of the housing stock.	The higher populations projection push housing stock 4.2% above the trend by 2016.	Lower real income and high cost of funds depress housing starts, but demographic pressures prevent sustained decline.
Average Unemployment Rate	5.8%	5.7%	5.9%

Source: DRI/McGraw-Hill, Review of the U. S. Economy, Long-Range Focus, Winter 1991-92
Prepared by: Ann Carey, Washington Water Power, August 1992

Service Area Economic Forecasts

The company has developed and maintains econometric forecasting models for both Spokane County, Washington, and Kootenai County, Idaho, under contract with Tucson Economic Consulting (TEC), a contractor specializing in regional economic modeling and forecasting.

Since about 90 percent of the company's service area's economic activity occurs in the two-county area, Spokane County is used as the proxy for the Washington portion of the company's service area, and Kootenai County is used as the proxy for the Idaho portion. Historical economic data for each area is obtained from official county and state sources.

Each county model produces separate detailed forecasts of population, employment and income, including components. The population forecasts are the result of net forecasted changes in births, deaths and net migration. Employment is split into manufacturing and non-manufacturing and is forecasted by the major standard industrial classification (SIC) code. The personal income forecast is composed of forecasts of labor and proprietor's income, social security contributions, transfer payments, and dividends, interest, and rental income.

Population

For the medium case, the two-county population in 1992 is estimated to be 453,351, with 83.0 percent residing in Spokane, 17.0 percent in Kootenai. By 2002, the population is estimated to expand to 518,450, an increase of 65,099, or 14.4 percent. Kootenai County growth is faster than Spokane, resulting in population shares of 80.7 percent in Spokane, and 19.3 percent in Kootenai. During the second decade, population grows by the year 2012 to 560,162, an increase of 41,712. This smaller increase in population in this ten-year period is consistent with an overall slowing at the national level. Over the 20-year period, the two-county population growth rate averages 1.1 percent per year, compounded.

In 1982, the two-county population was 409,740. Between 1982 and 1992, the population increased 43,611, or only 10.6 percent.

The high case scenario exhibits faster population growth. By 2002, the population is estimated to be 531,606, and by 2012, it is 584,886. The 20-year compound growth rate is 1.3 percent.

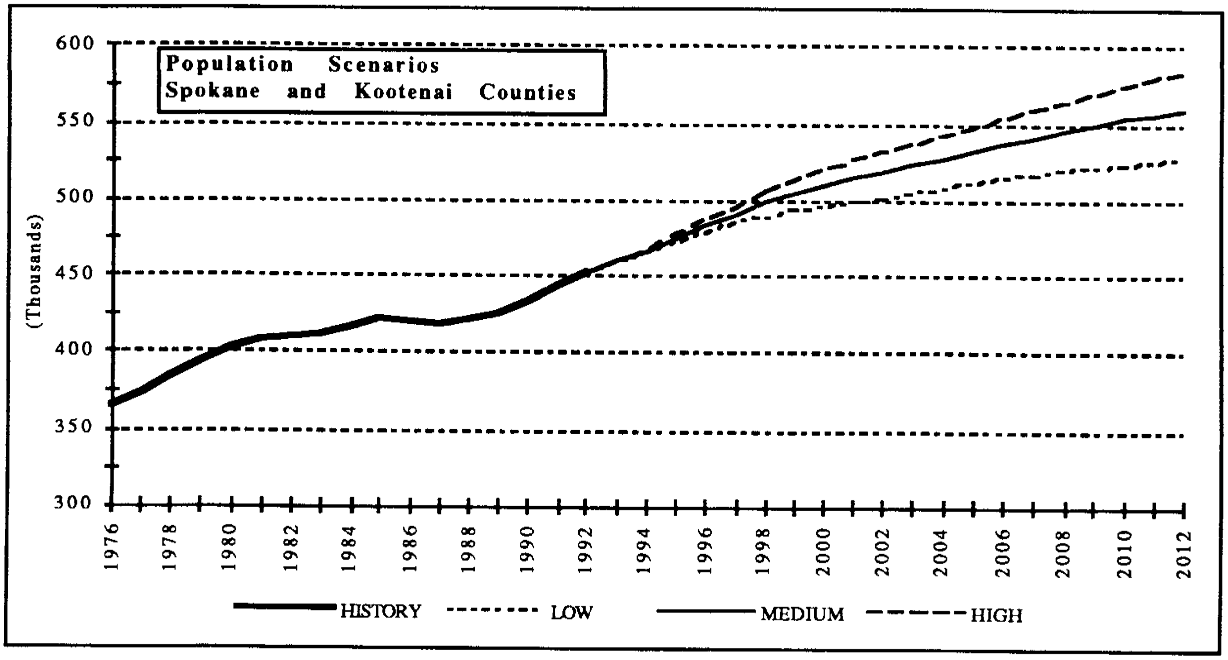
The low case scenario, predictably, has slower population growth. By 2002, the population is estimated to be only 501,360, and by 2012, only 527,020. The 20-year compound growth rate is only 0.8 percent.

Migration is a component of population change. Although the high scenario has higher births and lower deaths, and the low scenario the opposite, the patterns are relatively smooth or well-behaved. In-migration is the component which makes up the shortfall associated with labor force shortages, and out-migration is usually a result of labor force surplus.

In the base case, total migration between 1992 and 2012 is estimated to be 62,754 persons. In the high case, a 67,542 person change is 8 percent higher than the base case. In the low case, 51,172 persons is 18 percent lower than the base case.

Figure D-4 charts the historical period population from 1976 and illustrates the three scenario alternatives for the forecast period through 2012 for the two-county area.

Figure D-4: Population Scenarios for Spokane and Kootenai Counties



Employment

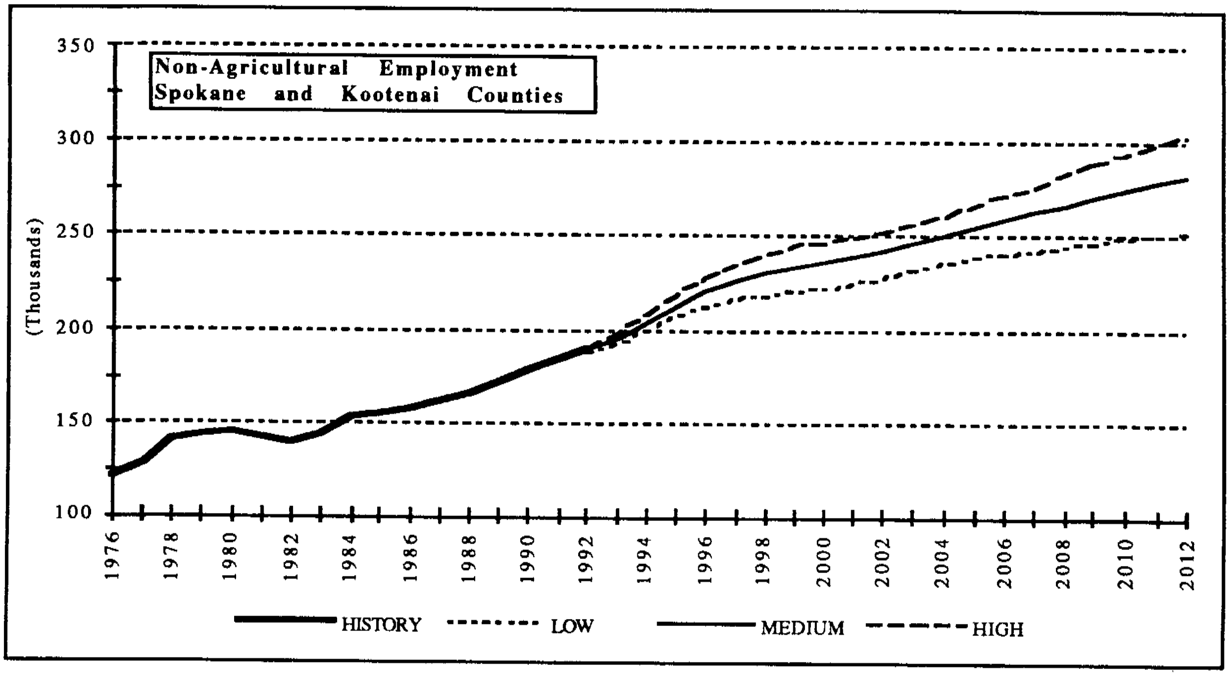
Non-agricultural employment is the sum of the components of manufacturing and non-manufacturing employment. Each of the available components of employment are forecast separately for Spokane County and for Kootenai County. The combined employment level in the two-county area in 1992 is 189,949, with 85 percent in Spokane County, 15 percent in Kootenai County. In 2002, non-agricultural employment is forecast to increase by 55,219 jobs, to 242,168 jobs, an increase of 27.5 percent. The employment share in Spokane decreases to 83 percent, and in Kootenai increases to 17 percent. By 2012, total non-agricultural employment is forecast to be at 281,670 jobs, an increase of another 39,502 jobs. Over the 20-year period, the two-county non-agricultural employment growth rate averages 2.0 percent per year, compounded.

In 1982, the two-county non-agricultural employment level was 138,830. Between 1982 and 1992, employment increased by 51,119 jobs, or by 3.2 percent per year, compounded.

The high case scenario exhibits faster employment growth over the 20-year period, averaging 2.4 percent per year, compounded. The low case scenario growth rate for 20 years is only 1.4 percent per year compounded.

Figure D-5 charts the historical period of employment from 1976 and illustrates the three scenario alternatives for the forecast period through 2012 for the two-county area.

Figure D-5: Non-Agricultural Employment for Spokane and Kootenai Counties



Income

For the medium case, personal income in Spokane County is estimated to be $6.61 billion, and in Kootenai County, $1.29 billion in nominal dollars. Two-county income in 1992 is $7.90 billion. By 2012, Spokane County personal income increases to $22.93 billion, and Kootenai County to $5.38 billion, for a combined total of $28.31 billion. The average annual growth in personal income is 6.6 percent, compounded. Inflation averages 4.2 percent, as measured by the U.S. GDP Personal Consumption Deflator. Therefore, inflation adjusted personal income in the two-county area averages 2.3 percent, compounded. Per capita income in Spokane County increases from $17,565 in 1992 to $51,454 in 2012, averaging 5.5 percent per year, compounded, during the 20-year forecast. In Kootenai County, per capita income grows from $16,717 to $47,003 in 20 years, averaging 5.3 percent, compounded.

The high case forecast for personal income for 2012 in Spokane County is $21.02 billion, and in Kootenai County is $5.07 billion. At first glance, combined personal income of only $26.09 billion seems inaccurate, when compared to the base case since it averages only 6.2 percent, compounded, over the 20-year period. However, the high case inflation averages only 3.4 percent, compounded, so inflation adjusted personal income in the high case at 2.7 percent, compounded, is actually higher than the medium case, which was 2.3 percent, compounded.

The low case forecast for personal income for 2012 in Spokane County is $28.17 billion, and for Kootenai County is $6.50 billion, a combined total of $34.67 billion. The 20-year average annual increase is 7.7 percent per year, which again seems inaccurate. However, the low case scenario inflation averages 5.9 percent, compounded, for 20 years. Therefore, inflation adjusted personal income in the low case exhibits an average increase of only 1.7 percent per year, compounded.

Figure D-6 charts the historical period of personal income from 1976 and illustrates the three scenario alternatives for the forecast period through 2012 for the two-county area.

Figure D-6: Personal Income Scenarios for Spokane and Kootenai Counties

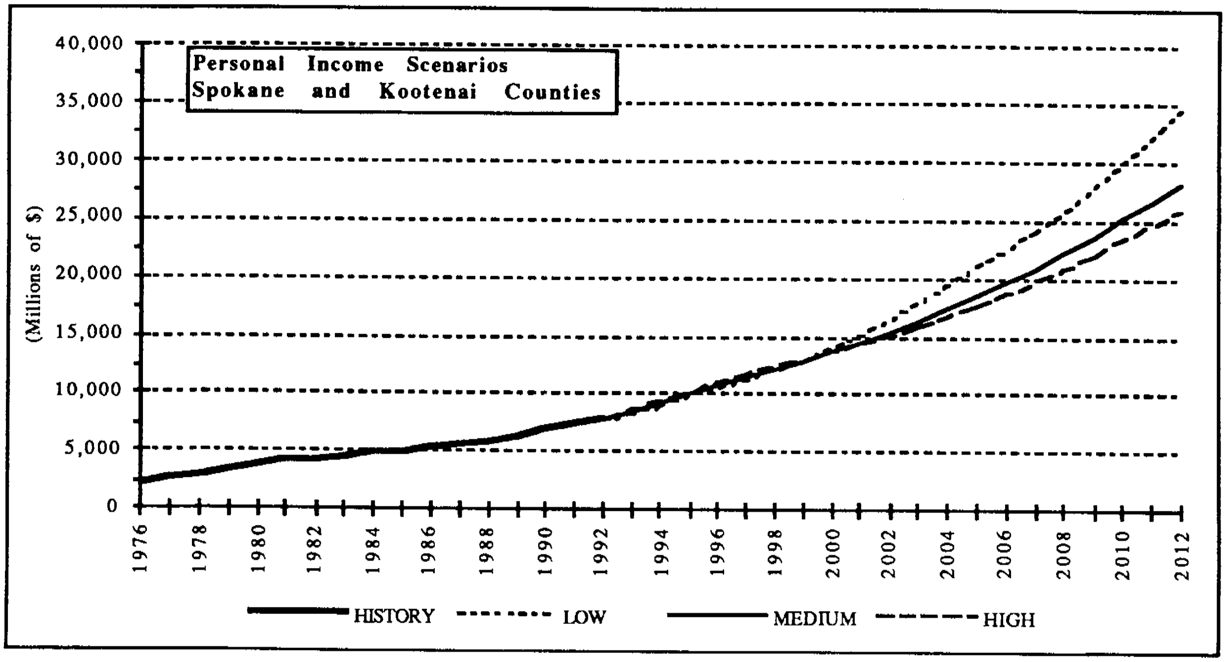
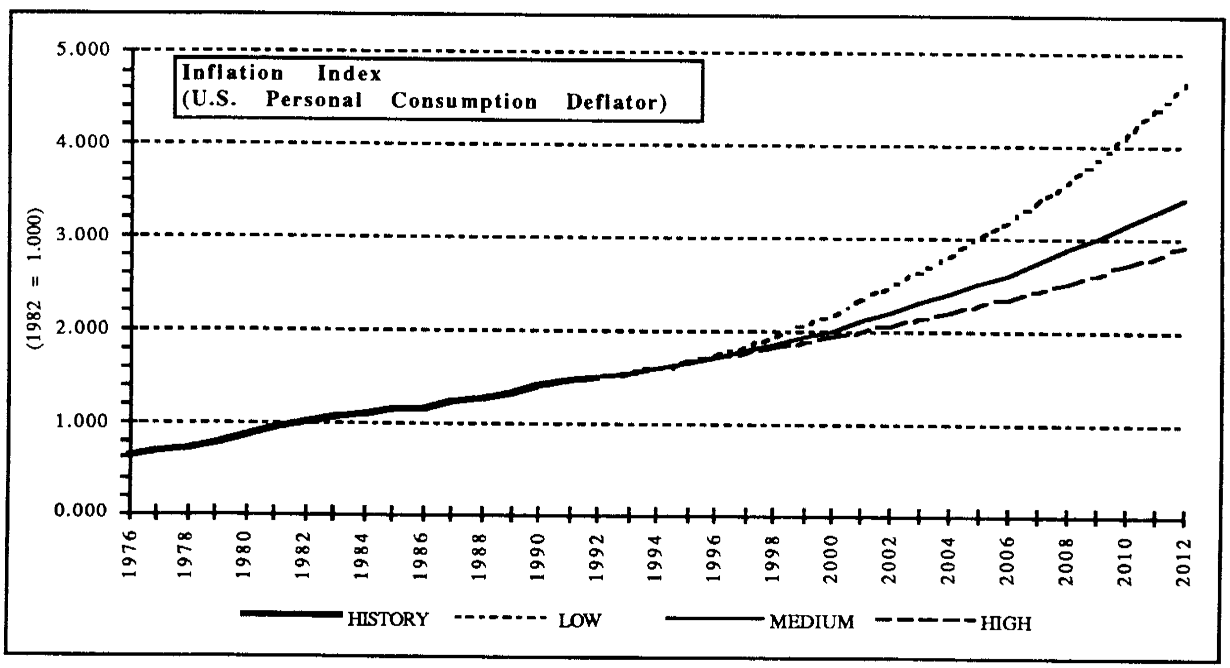


Figure D-7 charts the historical period of inflation, using the index for Personal Consumption Expenditures (1982=100) from 1976, and illustrates the three scenario alternatives for the forecast period through 2012 for the two-county area.

Figure D-7: Inflation Index



Large Load Customer Forecasts

A survey is conducted each spring of all existing large commercial and industrial customers, typically those on Schedule 25. We ask customers to indicate planned load increases or decreases over the next five years. The customer responses are reviewed with the account managers for accuracy and reasonability. The survey responses are extended to ten years by the account managers, who also develop high and low scenarios for each customer. No new customers were explicitly added to these projected sales forecasts. In the low case, some customers sales do go to zero. The low case zero customers are forecast to either go out of business, bypass, or self-generate. The Northwest Power Planning Council's regional forecasts by industry are used to escalate the second ten-year period of the forecast. Individual customer survey responses and forecasts are confidential.

Large load sales are estimated to be 1,400 million kWh in 1992. In the medium scenario, sales increase to 1,520 million kWh in 2002, and to 1,640 million kWh in 2012. In the high case scenario, sales are forecast to increase to 2,060 million kWh in 2002, and to 2,420 million kWh in 2012. In the low case scenario, sales are forecast to decrease to only 660 million kWh in 2002, and to decline further to 610 million in 2012.

Price

Electric prices are expected to increase 2.2 percent per year, compounded, over the forecast horizon, before taking into account the effects of inflation. This translates into an inflation adjusted price decline of about 1.9 percent per year, compounded, for the medium case. For the high case, inflation adjusted price declines of 1.2 percent per year, compounded, are forecast. For the low case, inflation adjusted price declines of 3.5 percent, compounded, are forecast. Since the nature of the electric business is generally high fixed cost, changes in inflation produce opposing results in inflation adjusted prices. However, since inflation adjusted incomes are much higher in the high case, and much lower in the low case, the forecasts of electric costs relative to income in the high case indicates electricity is relatively more affordable, while in the low case, it is relatively less affordable, when compared to the medium case. This is an intuitively plausible result, particularly when incomes are used to pay the bill.

In the medium case, natural gas prices are expected to grow at 5.2 percent per year, compounded, before taking into account the effects of inflation. Compared to the 1991 Least-Cost Plan, forecasts for commodity costs for natural gas prices have been reduced considerably by DRI. Although natural gas prices are expected to increase at a faster rate than electric prices, in the competitive fuel area, principally electric space heat and electric water heat, natural gas continues its comparative price advantage over electricity throughout the forecast period.

Other

Demand-side management (DSM) activities: These are handled as having been implemented when the roll-up of the sales forecast for the budget is produced. For least-cost planning purposes, DSM is handled as a resource during the forecast time frame.

Weather: Weather is assumed to be normal in the medium case, 105 percent of normal in the high case, and 95 percent of normal in the low case. The weather effect in the sales forecast is reflected in annual usage.

Forecast Methodology

The company's sales forecasting methodology integrates econometric and end-use techniques. Some electric consumption behavior lends itself to economic relationships, while some special relationships do not.

The econometric part of the model relates electric consumption to weather, economic and price variables. Residential, small commercial and small industrial electric sales are examples of economic relations that are forecasted with the electric econometric regression model. The forecast system is PC based, using econometric software from Alphametrics Corp., and is built on an historical data base beginning in 1978. The electric model is actually two models, model A and model B. Model A has 72 econometric equations representing customer, use, and sales forecasts by state, by rate schedule and by customer class. Results of model A feed into model B, which has 56 equations. Model B transforms the results from model A to account for the impacts of DSM programs, as well as it produces the schedule 61 forecasts for our four wholesale-for-resale customers, which are under the jurisdiction of the FERC. These four customers are in the WWP control area, and these customers are treated as firm loads. These schedule 61 contracts expire at the end of 1993. The forecast assumes that Citizens Utilities' contract is renewed, but that the other three contracts expire. Power Supply will handle any contract extensions in the resource and requirements tabulation.

As the needs and requirements associated with the forecast change, alternative methodologies need to be explored. The company's 1991 Plan contained a two-year action plan item assessing the cost and feasibility of developing an end-use forecasting model for the commercial class. WWP reported the results of its assessment in late 1991 to technical advisory committee members. At that time, the company recommended and received budget approval to proceed with the acquisition of a commercial end-use forecasting model. WWP executed a contract with Jerry Jackson and Associates in early 1992 to purchase and implement the Commercial Energy Demand Modeling System (CEDMS). During 1992, a series of four workshops were held in Seattle and Spokane describing the model, data, supply curves and forecast results. These workshops were attended by utility commission staff from Idaho and Washington, utility forecasting staff from most Northwest utilities, the Northwest Power Planning Council and Bonneville Power Administration forecasting staff, and interested parties from the Washington State Attorney General's office and the Northwest Conservation Act Coalition. The evolution of forecasting's requirement to consistently integrate large scale market intervention activities is addressed by this end-use method. The forecasting two-year action plan provides detailed plans for integration of CEDMS into the company's business plans, as well as plans to pursue similar methodological improvements in the residential class.

Forecast Scenarios

Three alternative forecast scenarios have been developed. In summary, they are as follows:

High: Uses cold weather (105 percent of average), the high estimate for large customer sales, 25 percent higher penetration of DSM activities than the budget (where applicable), and the DRI optimistic forecast impact on the local economy, including an additional add-factor of 600 employees in transportation equipment manufacturing. The probability of occurrence is subjectively estimated to be 20 percent. The company estimates a 5 percent chance of exceeding the high scenario.

Medium: Uses normal weather (100 percent of average), the expected estimate for large customer sales, the planned and filed DSM implementation, and the DRI trend forecast impact on the local economy. This scenario is the most likely scenario. The probability of occurrence is subjectively estimated to be 50 percent.

Low: Uses warm weather (95 percent of average), the low estimate for large customer sales, 50 percent lower penetration of DSM activities than the medium case (where applicable), and the DRI pessimistic forecast impact on the local economy. The company estimates a 5 percent chance of not reaching the low scenario (further reduction).

Results

Below is a table comparing average compounded growth rates in percent from 1993 to 2011 by customer class for each scenario excluding DSM implementation. The table provides the baseline forecasts for demand and supply-side resource acquisition:

	High	Medium	Low
Residential	2.0 %	1.8 %	1.6 %
Commercial	3.1 %	2.7 %	2.3 %
Industrial	2.6 %	0.9 %	-3.3 %
Total*	1.8 %	1.4 %	0.7 %

*Also includes street lights and Schedule 61 sales.

Elasticities

The electric forecasting model has price variables in the residential, small- and medium-sized commercial and industrial customer classes, corresponding to schedules 1, 11, and 21. Simulating the model to estimate price own-price elasticities produces a residential class elasticity of -0.20, a commercial class elasticity of -0.25, and an industrial class elasticity of -0.15 in Washington and -0.35 in Idaho. Cross-price elasticities are not modeled. The number of new customers choosing electric space and water heat is assumed to continue to follow present patterns, namely that natural gas will be the fuel of choice in the residential sector where available, and electric heat will be utilized in new homes where gas is not available. At present, about 60 percent of all new customers are using natural gas, and that assumption is continued throughout the forecast period. The DSM program market intervention is based on estimated program implementation for the budget forecast. The resource planning forecast treats DSM programs as selectable resources.

Energy and Peak Forecasts

The monthly net system energy forecast is determined using a regression equation of actual energy to actual retail sales. The monthly peak demand forecast is determined using a regression equation with actual monthly peak to actual monthly energy. Net system loads are provided by the Power Supply department, which exclude transfer customer loads and scheduled transmission losses from wholesale sales to other utilities. Net system peak load is the result of similar deductions from area peak load. Although some reporting stations do not have instantaneous metering equipment and are thus estimates of loadings at the border of the WWP control area, the net system peak and energy reported loads provide a high quality data base for producing load forecasts.

Both regression equations use a linear specification. The regressions were calibrated over the period January 1982 to May 1992 for both energy and peak. Since the energy forecast leads the retail load forecast on average by one-half month, the energy model looks ahead one month to produce regressors with the correct frequency. Qualitative variables for representative months were utilized where statistically significant. For example, in the peak regression, a qualitative variable for February accommodates the short month, October handles the seasonal transition to winter and December deals with holiday seasonal activities.

Results

The following illustrates the energy forecast scenarios produced by using the high, medium and low sales forecasts discussed previously. A word of caution is advised when examining these results. The specific treatment of demand-side management programs, including energy efficiency improvements and space and water heat conversions, are not contained in these forecasts. These programs are treated as demand-side resources. Actual expected sales and energy requirements, assuming all programs are cost-effective and implemented, are considerably lower than these estimates, as are the power generating resources required to meet the peak and energy needs of customers.

With this in mind, the 1993-2011 energy growth rates are 1.8 percent compounded for the high case scenario, 1.4 percent for the medium case and 0.7 percent for the low case. Medium case energy requirements for system firm loads increases from 869 aMW in 1992, to 1,052 aMW in 2002, and to 1,184 aMW in 2012. Using the medium case as the baseline, the following differences in total energy requirements is forecast:

	Year 2002	Year 2012	Year 2012 Spread
High Case	+99 aMW	+145 aMW	+12.2 %
Low Case	-104 aMW	-181 aMW	-15.5 %

The inputs and results of WWP's electric forecast are summarized in Figure D-8.

Figure D-8: Forecast Input and Results Summary

	High	Medium	Low
The Nation	DRI Optimistic Scenario Inflation: 3.40%	DRI Trend Scenario Inflation: 4.20%	DRI Pessimistic Scenario Inflation: 5.9%
The Inland Northwest			
Population	1.30%	1.10%	0.8%
Employment	2.40%	2.00%	1.40%
Personal Income	2.70% (Real)	2.30% (Real)	1.70% (Real)
Per Capita Income			
Spokane County		5.50%	
Kootenai County		5.30%	
Weather	105% of Normal	Normal	95% of Normal
Price Elasticity			
Residential	-0.20	-0.20	-0.20
Commercial	-0.25	-0.25	-0.25
Industrial (Washington)	-0.15	-0.15	-0.15
Industrial (Idaho)	-0.35	-0.35	-0.35
Electric Prices			
Nominal	2.16%	2.20%	1.86%
Real	-1.20%	-1.90%	-3.50%
Electric Sales			
Residential	2.00%	1.80%	1.60%
Commercial	3.10%	2.70%	2.30%
Industrial	2.60%	0.90%	-3.30%
Combined Sales[1]	1.80%	1.40%	0.70%

[1] Combined Sales forecast includes street lights and projected Schedule 61 sales.

Appendix E

Resources and Requirements Tabulation

TABULATION OF FIRM REQUIREMENTS & RESOURCES

	-1992-		-1993-		-1994-		-1995-		-1996-		-1997-		-1998-	
Figures are megawatts.	Peak	Average	Peak	Average	Peak	Average	Peak	Average	Peak	Average	Peak	Average	Peak	Average
FIRM REQUIREMENTS														
1 System Firm Loads	1345	869	1576	912	1613	921	1668	944	1719	961	1768	981	1814	998
2 Puget #2	100	75	100	75	100	75	100	75	100	75	100	75	100	75
3 PG&E Exchange	0	25	0	25	0	25	0	25	0	25	0	25	0	25
4 PP&L Sandpoint	5	2	5	2	5	2	5	2	0	0	0	0	0	0
5 PGE #1	0	0	50	0	50	0	150	0	150	0	150	0	150	0
6 PGE Short-Term	200	0	100	0	100	0	0	0	0	0	0	0	0	0
7 Pend Oreille 4-yr	9	11	13	13	13	13	13	10	6	4	0	0	0	0
8 PP&L 1989	150	50	150	50	150	50	150	50	100	33	50	17	0	0
9 BPA Sale	0	17	0	0	0	0	0	0	0	0	0	0	0	0
10 San Diego Exchange	0	0	0	25	0	0	0	0	0	0	0	0	0	0
11 NCPA	0	0	0	0	52	0	52	0	52	0	52	0	52	0
12 Sch. 61 two-year extension	0	0	0	0	44	25	50	28	0	0	0	0	0	0
13 **TOTAL REQUIREMENTS**	1809	1049	1994	1102	2127	1111	2188	1134	2127	1098	2120	1098	2116	1098
RESOURCES														
14 System Hydro	915	328	915	328	915	328	915	328	915	328	915	328	915	328
15 Contract Hydro	220	106	220	106	220	106	220	97	188	87	188	87	188	87
16 Canadian Entitlement Return	-12	-4	-12	-4	-10	-4	-8	-3	-7	-3	-7	-3	-7	-2
17 Restoration	0	4	0	4	0	4	0	4	0	4	0	4	0	4
18 Small Hydro	8	7	8	7	8	7	8	7	8	7	8	7	8	7
19 Monroe Street Improvement	0	6	15	12	15	12	15	12	15	12	15	12	15	12
20 Total Hydro	1131	447	1146	453	1148	453	1150	445	1119	435	1119	435	1119	436
21 Cogeneration	69	64	69	64	69	62	75	69	75	69	75	69	75	69
22 Northeast Combustion Turbine	68	54	68	54	68	54	68	54	68	54	68	54	68	54
23 Rathdrum Combustion Turbine	0	0	0	0	0	0	176	0	176	0	176	0	176	0
24 CSPE	45	15	40	14	36	14	32	13	28	13	23	12	23	11
25 PG&E Exchange	150	25	150	25	150	25	150	25	150	25	150	25	150	25
26 Montana Purchase	0	36	0	36	0	27	0	0	0	0	0	0	0	0
27 Entitlement & Supplemental Cap	24	0	21	0	19	0	17	0	14	0	12	0	11	0
28 BPA #39216	79	67	79	67	79	67	79	67	79	28	0	0	0	0
29 BPA-WNP #3	82	31	82	27	82	27	82	27	82	27	82	29	82	32
30 Douglas Capacity Purchase	50	0	0	0	0	0	0	0	0	0	0	0	0	0
31 BPA Capacity Purchase	0	0	0	0	50	0	50	0	50	0	50	0	50	0
32 San Diego Exchange	0	25	150	0	0	0	0	0	0	0	0	0	0	0
33 Short-Term Peak Purchases	100	0	100	0	100	0	0	0	0	0	0	0	0	0
34 Short-Term Energy Purchases	0	0	0	0	0	0	0	42	0	50	0	50	0	50
35 Thermal Centralia	192	167	192	167	192	167	192	167	192	167	192	167	192	167
36 Kettle Falls	47	41	47	41	47	41	47	41	47	41	47	41	47	41
37 Colstrip	216	184	216	184	216	184	216	184	216	184	216	184	216	184
38 **TOTAL RESOURCES**	2253	1156	2360	1132	2256	1121	2334	1134	2296	1093	2210	1066	2209	1069
39 Reserves	-225	0	-246	0	-246	0	-247	0	-248	0	-250	0	-251	0
40 **NET RESOURCES**	2028	1156	2114	1132	2010	1121	2087	1134	2048	1093	1960	1066	1958	1069
41 **SURPLUS OR DEFICIT**	219	107	120	30	-117	10	-101	0	-79	-5	-160	-32	-158	-29

TABULATION OF FIRM REQUIREMENTS & RESOURCES

	-1999-		-2000-		-2001-		-2002-		-2003-		-2004-		-2005-	
Figures are megawatts.	Peak	Average	Peak	Average	Peak	Average	Peak	Average	Peak	Average	Peak	Average	Peak	Average
FIRM REQUIREMENTS														
1 System Firm Loads	1856	1014	1893	1026	1929	1039	1963	1052	1998	1067	2033	1082	2068	1097
2 Puget #2	100	75	100	75	100	75	100	75	67	50	33	25	0	0
3 PG&E Exchange	0	25	0	25	0	25	0	25	0	25	0	25	0	25
4 PP&L Sandpoint	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 PGE #1	0	0	50	0	50	0	150	0	150	0	150	0	150	0
6 PGE Short-Term	200	0	100	0	100	0	0	0	0	0	0	0	0	0
7 Pend Oreille 4-yr	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 PP&L 1989	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 BPA Sale	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 San Diego Exchange	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11 NCPA	52	0	52	0	52	0	52	0	52	0	52	0	52	0
12 Sch. 61 two-year extension	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13 **TOTAL REQUIREMENTS**	2158	1114	2195	1126	2231	1139	2265	1152	2267	1142	2268	1132	2270	1122
RESOURCES														
14 System Hydro	915	328	915	328	915	328	915	328	915	328	915	328	915	328
15 Contract Hydro	188	87	188	87	188	87	188	87	188	87	188	87	188	66
16 Canadian Entitlement Return	-5	-2	-9	-4	-9	-4	-9	-4	-8	-5	-14	-5	-14	-5
17 Restoration	0	4	0	4	0	4	0	4	0	1	0	0	0	0
18 Small Hydro	8	7	8	7	8	7	8	7	8	7	8	6	1	6
19 Monroe Street Improvement	15	12	15	12	15	12	15	12	15	12	15	12	15	12
20 Total Hydro	1121	436	1117	434	1117	434	1117	434	1118	430	1112	428	1105	407
21 Cogeneration	75	69	75	69	75	69	75	69	75	69	75	69	75	69
22 Northeast Combustion Turbine	68	54	68	54	68	54	68	54	68	54	68	54	68	54
23 Rathdrum Combustion Turbine	176	0	176	0	176	0	176	0	176	0	176	0	176	0
24 CSPE	20	8	10	5	9	5	9	5	8	1	0	0	0	0
25 PG&E Exchange	150	25	150	25	150	25	150	25	150	25	150	25	150	25
26 Montana Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27 Entitlement & Supplemental Cap	10	0	5	0	4	0	4	0	4	0	0	0	0	0
28 BPA #39216	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29 BPA-WNP #3	82	32	82	32	82	32	82	32	82	32	82	32	82	32
30 Douglas Capacity Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31 BPA Capacity Purchase	50	0	50	0	50	0	50	0	50	0	50	0	50	0
32 San Diego Exchange	0	0	0	0	0	0	0	0	0	0	0	0	0	0
33 Short-Term Peak Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34 Short-Term Energy Purchases	0	50	0	50	0	50	0	50	0	50	0	50	0	50
35 Thermal Centralia	192	167	192	167	192	167	192	167	192	167	192	167	192	167
36 Kettle Falls	47	41	47	41	47	41	47	41	47	41	47	41	47	41
37 Colstrip	216	184	216	184	216	184	216	184	216	184	216	184	216	184
38 **TOTAL RESOURCES**	2207	1066	2188	1061	2186	1061	2186	1061	2186	1053	2168	1050	2161	1029
39 Reserves	-251	0	-252	0	-253	0	-254	0	-256	0	-258	0	-260	0
40 **NET RESOURCES**	1956	1066	1936	1061	1933	1061	1932	1061	1930	1053	1910	1050	1901	1029
41 **SURPLUS OR DEFICIT**	-202	-48	-259	-65	-298	-78	-333	-91	-337	-89	-358	-82	-369	-93

TABULATION OF FIRM REQUIREMENTS & RESOURCES

Figures are megawatts.	-2006- Peak	-2006- Average	-2007- Peak	-2007- Average	-2008- Peak	-2008- Average	-2009- Peak	-2009- Average	-2010- Peak	-2010- Average	-2011- Peak	-2011- Average	-2012- Peak	-2012- Average
FIRM REQUIREMENTS														
1 System Firm Loads	2101	1112	2130	1124	2153	1136	2177	1148	2201	1160	2226	1172	2250	1184
2 Puget #2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 PG&E Exchange	0	25	0	25	0	25	0	25	0	25	0	3	0	0
4 PP&L Sandpoint	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 PGE #1	0	0	50	0	50	0	150	0	150	0	150	0	150	0
6 PGE Short-Term	200	0	100	0	100	0	0	0	0	0	0	0	0	0
7 Pend Oreille 4-yr	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 PP&L 1989	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 BPA Sale	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 San Diego Exchange	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11 NCPA	52	0	52	0	52	0	52	0	52	0	0	0	0	0
12 Sch. 61 two-year extension	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13 **TOTAL REQUIREMENTS**	2303	1137	2332	1149	2355	1161	2379	1173	2403	1185	2376	1175	2400	1184
RESOURCES														
14 System Hydro	915	328	915	328	915	328	915	328	915	328	915	328	915	328
15 Contract Hydro	133	57	133	57	133	57	133	32	58	22	58	10	21	5
16 Canadian Entitlement Return	-10	-4	-10	-4	-10	-4	-10	-4	-4	-4	-4	-3	-4	-3
17 Restoration	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18 Small Hydro	1	6	1	6	1	6	1	6	1	6	1	6	1	6
19 Monroe Street Improvement	15	12	15	12	15	12	15	12	15	12	15	12	15	12
20 Total Hydro	1054	399	1054	399	1054	399	1054	374	985	364	985	353	948	348
21 Cogeneration	75	69	75	69	75	69	75	69	75	69	75	69	75	69
22 Northeast Combustion Turbine	68	54	68	54	68	54	68	54	68	54	68	54	68	54
23 Rathdrum Combustion Turbine	176	0	176	0	176	0	176	0	176	0	176	0	176	0
24 CSPE	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25 PG&E Exchange	150	25	150	25	150	25	150	25	150	25	150	14	0	0
26 Montana Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27 Entitlement & Supplemental Cap	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28 BPA #39216	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29 BPA-WNP #3	82	32	82	32	82	32	82	32	82	32	82	32	82	32
30 Douglas Capacity Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31 BPA Capacity Purchase	50	0	50	0	50	0	50	0	50	0	0	0	0	0
32 San Diego Exchange	0	0	0	0	0	0	0	0	0	0	0	0	0	0
33 Short-Term Peak Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34 Short-Term Energy Purchases	0	50	0	50	0	50	0	50	0	50	0	50	0	50
35 Thermal Centralia	192	167	192	167	192	167	192	167	192	167	192	167	192	167
36 Kettle Falls	47	41	47	41	47	41	47	41	47	41	47	41	47	41
37 Colstrip	216	184	216	184	216	184	216	184	216	184	216	184	216	184
38 **TOTAL RESOURCES**	2110	1021	2110	1021	2110	1021	2110	996	2041	986	1991	964	1804	945
39 Reserves	-262	0	-264	0	-267	0	-269	0	-271	0	-274	0	-276	0
40 **NET RESOURCES**	1848	1021	1846	1021	1843	1021	1841	996	1770	986	1717	964	1528	945
41 **SURPLUS OR DEFICIT**	-455	-116	-486	-128	-512	-140	-538	-177	-633	-199	-659	-211	-872	-239

Source: Sandee Warne, WWP Power Resources, August 10, 1992 (R-3)

Appendix F

Resource Assessment

Resource Assessment

This appendix discusses the cost and availability of demand-side and supply-side resources that may be selected to meet WWP's long-term energy needs. It contains the following information:

- Supply curve information for demand-side and supply-side resources.
- An overview of WWP's current demand-side management programs, measurement and evaluation plan and cost-effectiveness tests.
- Levelized cost calculations for supply-side resources.

Summary

The supply curve shown in Figure F-1 illustrates the availability and price of firm energy produced by both demand-side and supply-side options. Resource cost data is based on WWP evaluations as well as information from the Northwest Power Planning Council. Levelized energy rates are calculated in 1992 dollars[1]. They reflect utility costs and are levelized over the individual life of each resource. Figure F-1 indicates that approximately 200 aMW are available at a rate of 4.0 ¢/kWh or below.

While cost is the primary criteria used to screen potential alternatives, other factors help to select the best resources. The portfolio of preferred options includes resources that match customer needs, add value to the existing system, represent a proven technology and can be successfully licensed and permitted.

The company's commitment as a low-cost provider of energy services makes an ongoing resource assessment an important part of the planning process. New information regarding capital and operational costs, as well as the risks associated with each resource option, is evaluated as it beomes available.

1 Unless otherwise specified, all resource costs are in 1992 dollars. Rates are nominally levelized using a discount rate of 8.97%.

Figure F-1: New Energy Resource Supply Curve

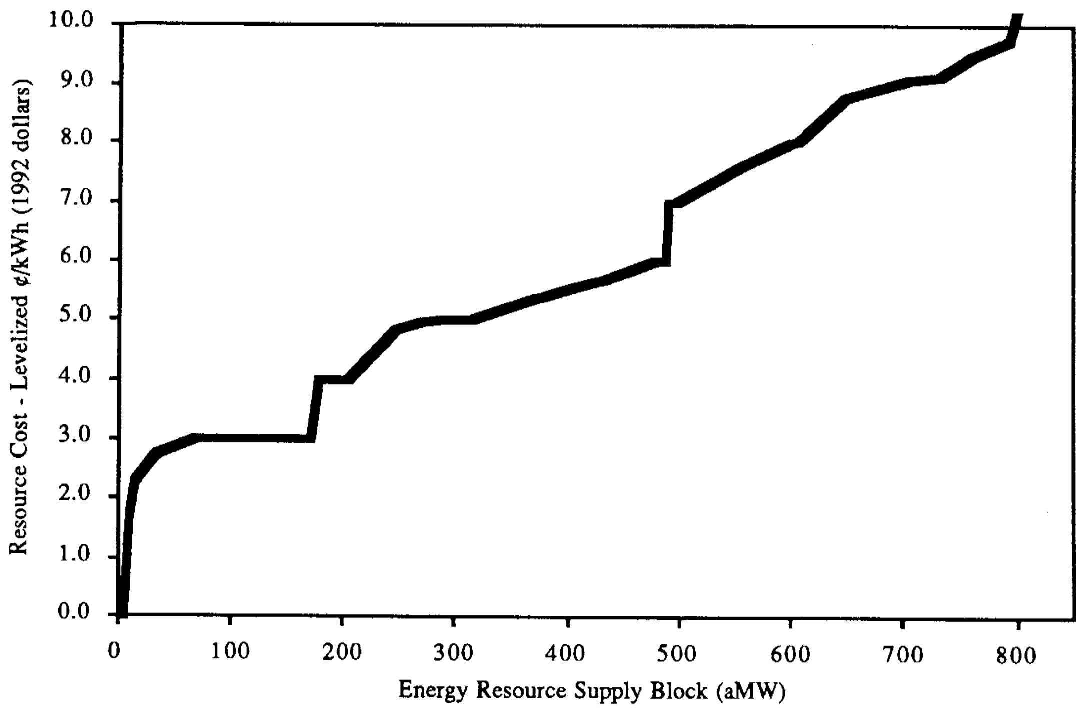


Figure F-1 (continued): New Energy Resource Supply Curve

Resource / Project Name	Project aMW	Cumulative aMW	Levelized Cost ¢/kWh
Cabinet #1 - (Replace Turbine Runner)	5.1	5.1	0.00
Colstrip Upgrade	5.2	10.3	1.60
Upper Falls - (Replace Turbine Runner)	0.8	11.1	1.72
Nine Mile - (Replace 2 Turbine Generators)	3.1	14.2	2.28
Transmission and Distribution	20.0	34.2	2.73
Residential Fuel Efficiency - Space Heat	35.0	69.2	3.00
Residential Fuel Efficiency - Water Heat	40.0	109.2	3.00
Residential Conservation - Weatherization	1.0	110.2	3.00
Residential Conservation - Low Flow Shower Heads	4.5	114.7	3.00
Residential Conservation - Compact Fluorescent Lighting	0.5	115.2	3.00
Commercial / Ind. Fuel Efficiency - Combined Space and Water Heat	6.5	121.7	3.00
Commercial / Industrial Conservation	48.5	170.2	3.00

Figure F-1 (continued): New Energy Resource Supply Curve

Residential Fuel Efficiency - Space Heat	8.0	178.2	4.00
Residential Fuel Efficiency - Water Heat	3.0	181.2	4.00
Residential Conservation - Weatherization	2.0	183.2	4.00
Residential Conservation - Compact Fluorescent Lighting	0.5	183.7	4.00
Residential Conservation - Residential New Construction	0.5	184.2	4.00
Commercial / Ind.Fuel Efficiency - Combined Space and Water Heat	1.5	185.7	4.00
Commercial / Industrial Conservation	14.5	200.2	4.00
Cabinet #2 - (Replace Turbine Runner)	3.5	203.7	4.00
Noxon #1 - (Replace Turbine Runner)	0.9	204.6	4.00
Combined Cycle Combustion Turbine	42.0	246.6	4.83
Cogen #1	25.0	271.6	4.98
Cogen #2	23.0	294.6	4.99
Residential Fuel Efficiency - Space Heat	5.0	299.6	5.00
Residential Fuel Efficiency - Water Heat	2.0	301.6	5.00
Residential Conservation - Weatherization	2.0	303.6	5.00
Residential Conservation - Low Flow Shower Heads	0.5	304.1	5.00
Residential Conservation - Compact Fluorescent Lighting	0.5	304.6	5.00
Residential Conservation - Manufactured Home Acquisition (MAP)	0.6	305.2	5.00
Commercial / Ind. Fuel Efficiency - Combined Space and Water Heat	2.0	307.2	5.00
Commercial / Industrial Conservation	6.0	313.2	5.00
Noxon #3 - (Replace Turbine Runner)	1.6	314.8	5.00
IPP #1	30.0	344.8	5.21
IPP #2	27.0	371.8	5.35
Renewable #1	3.0	374.8	5.38
IPP #3	30.0	404.8	5.54
Cogen #3	29.0	433.8	5.69
Simple Cycle CT	44.0	477.8	5.99
Residential Fuel Efficiency - Space Heat	3.0	480.8	6.00
Residential Fuel Efficiency - Water Heat	1.0	481.8	6.00
Residential Conservation - Weatherization	1.0	482.8	6.00
Residential Conservation - Compact Fluorescent Lighting	0.5	483.3	6.00
Commercial / Ind.Fuel Efficiency - Combined Space and Water Heat	1.0	484.3	6.00
Commercial / Industrial Conservation	5.0	489.3	6.00
Residential Fuel Efficiency - Space Heat	1.0	490.3	7.00
Residential Fuel Efficiency - Water Heat	1.0	491.3	7.00
Residential Conservation - Weatherization	1.0	492.3	7.00
Residential Conservation - Low Income Weatherization	2.0	494.3	7.00
Residential Conservation - Compact Fluorescent Lighting	0.5	494.8	7.00
Commercial / Ind. Fuel Efficiency - Combined Space and Water Heat	1.0	495.8	7.00
Commercial / Industrial Conservation	1.0	496.8	7.00
Large Pulverized Coal	60.0	556.8	7.60
Geothermal (Cascade)	45.0	601.8	7.99

Figure F-1 (continued): New Energy Resource Supply Curve

Residential Fuel Efficiency - Space Heat	1.0	602.8	8.00
Residential Fuel Efficiency - Water Heat	1.0	603.8	8.00
Residential Conservation - Weatherization	1.0	604.8	8.00
Residential Conservation - Compact Fluorescent Lighting	0.5	605.3	8.00
Commercial / Ind. Fuel Efficiency - Combined Space and Water Heat	0.5	605.8	8.00
Commercial / Industrial Conservation	0.5	606.3	8.00
Coal Gasification (IGCC)	42.0	648.3	8.77
Fluidized Bed (AFBC)	59.0	707.3	9.10
Small Pulverized Coal	25.0	732.3	9.13
Wind (Blackfoot Hills)	29.0	761.3	9.48
Renewable #2	33.0	794.3	9.73
Biomass	22.0	816.3	11.31
Solar (Photovoltaic)	4.0	820.3	26.30

The levelized firm energy costs shown in Figure F-1 are used to compare various resource options. Figures F-2 and F-3 provide the data and methodology used to calculate these costs[2].

Figure F-2: Escalation and Financial Assumptions

		Fixed Charge Rates (FCR)	
Nominal Capital Cost Escalation	3.10%		
		5 Years	30.57%
Nominal O&M Cost Escalation	4.20%	10 Years	20.09%
		15 Years	16.60%
Nominal Fuel Cost Escalation		20 Years	14.89%
Coal	4.90%	25 Years	13.94%
Natural Gas	7.50%	30 Years	13.41%
Biomass	4.20%	35 Years	13.10%
		40 Years	12.92%
Inflation Rate	4.20%	45 Years	12.81%
		50 Years	12.75%
Discount Rate	8.97%		

2 The firm energy cost for each hydroelectric upgrade opportunity reflect credits for incremental capacity and nonfirm energy available from the project. In the case of Cabinet Gorge Unit No.1, these benefits completely outweigh the cost of the project, thereby yielding a firm energy cost of zero.

Figure F-3: Life -cycle levelized cost example calculation.

Step 1:
Levelized Capital Cost = (Total Capital Cost per kW * FCR)/(hours per year * Annual Availability)

Step 2:
Levelized Fixed O&M = (1991 Fixed O&M Cost * Levelizing Factor)/(hours per year * Annual Availability)

Step 3:
Levelized Variable O&M = 1991 Variable O&M Cost * Levelizing Factor

Step 4:
Levelized Fuel Cost = 1991 Fuel Cost * Levelizing Factor

Levelizing Factor Calculation:
Levelizing Factor = $[(1+esc.)/(d-esc.)] * [1-((1+esc.)^n/(1+d)^n)] * [d(1+d)^n/((1+d)^n-1)]$

where:
d = Discount Rate
esc. = Assumed Escalation Rate
n = Operating Life of Resource

Step 5:
Add steps 1-4 for Total Life-Cycle Levelized Cost

Combined-cycle combustion turbine example for illustrative purposes only.

Step 1:
Total Capital Cost = $860/kW (incl. AFUDC)
FCR = 13.41% (30 year life)
Annual Availability = 83%
Hours per Year = 8,760

Levelized Capital Cost = (860*.1341)*1000/(8760*.83) = 15.86 mills/kWh

Step 2:
1991 Fixed O&M Cost = $6.06/kW
Annual Availability = 83%
Hours per Year = 8,760
Levelizing Factor = 1.5669 (d =8.97%, esc. = 4.20%, and n = 30 years)

Levelized Fixed O&M = (6.06*1.5669)*1000/(8760*.83) = 1.31 mills/kWh

Step 3:
1991 Variable O&M Cost = 0.41 mills/kWh
Levelizing Factor = 1.5669 (d =8.97%, esc. = 4.20%, and n = 30 years)

Levelized Variable O&M = 0.41 * 1.5669 = 0.64 mills/kWh

Step 4:
1991 Fuel Cost = 12.83 mills/kWh
Levelizing Factor = 2.3758 (d =8.97%, esc. = 7.50%, and n = 30 years)

Levelized Fuel Cost = 12.83 * 2.3758 = 30.48 mills/kWh

Step 5:
Total Life-Cycle Levelized Cost = 15.86 + 1.31 + 0.64 + 30.48 = 48.29 mills/kWh

Demand-Side Resource Assessment

The supply curve information shown in Figure F-4 represents WWP's current estimates of electric demand-side potential over the next 20 years. The levelized rates, which range from 3.0 ¢/kWh to 8.0 ¢/kWh, reflect WWP's net costs to acquire the electric savings from each demand-side opportunity. Resource costs reflect a 10 percent conservation credit for all measures. Fuel-efficiency measures receive an additional credit that represents incremental capacity benefits.

Figure F-4: Demand-side resources supply curve (cumulative aMW).

Demand-Side Activity by Sector	3 ¢/kWh	4 ¢/kWh	5 ¢/kWh	6 ¢/kWh	7 ¢/kWh	8 ¢/kWh
Residential						
Electric to Natural Gas Fuel Efficiency						
Space Heat	35.0	43.0	48.0	51.0	52.0	53.0
Water Heat	40.0	43.0	45.0	46.0	47.0	48.0
Electric Conservation						
Weatherization	1.0	3.0	5.0	6.0	7.0	8.0
Low-Income Weatherization	0.0	0.0	0.0	0.0	2.0	2.0
Low-Flow Shower Heads	4.5	4.5	5.0	5.0	5.0	5.0
Compact Fluorescent Lighting	0.5	1.0	1.5	2.0	2.5	3.0
Residential New Construction	0.0	0.5	0.5	0.5	0.5	0.5
Manufactured Home Acquisition (MAP)	0.0	0.0	0.6	0.6	0.6	0.6
Commercial / Industrial						
Electric to Natural Gas Fuel Efficiency						
Combined Space & Water Heat	6.5	8.0	10.0	11.0	12.0	12.5
Electric Conservation	48.5	63.0	69.0	74.0	75.0	75.5
Total Demand-Side Resource Potential (Cumulative aMW)	136.0	166.0	184.6	196.1	203.6	208.1

WWP's current programmatic efforts, and future resource assessments, will be used to refine supply curves for individual resources. The current information provides input to the company's resource planning model. The current assessment of the demand-side potential in the residential, commercial and industrial sectors is described below.

Residential

For 1993, WWP projects residential electric sales of approximately 3.2 million MWh. Space heating, water heating and lighting/convenience account for the majority of electric consumption in this sector. These uses respectively represent approximately 22 percent, 25 percent and 35 percent of WWP's electric system load. Electricity is used by approximately 78,000 residential customers for space heat and by approximately 180,000 customers for water heat.

DSM potential in the residential sector is in space heating, water heating, lighting and appliance end uses. Space heat savings can be achieved by reducing the need for space heat or increasing the efficiency of heating equipment. Water heat savings can be achieved by decreasing water heat usage or increasing the efficiency of water heaters. Lighting savings can be achieved with efficient light products. Appliance savings can be achieved by encouraging the use of high-efficiency appliances.

WWP's initial assessment of residential sector potential was completed in 1991. It identified estimated demand-side resource potential of approximately 42 aMW.

Commercial

WWP projects commercial sales of approximately 2.4 million MWh in 1993. Lighting and HVAC each account for approximately 36 percent of electrical load in the commercial sector. The remaining consumption is for refrigeration, cooking, water heating and miscellaneous other end uses.

The 1991 assessment included savings estimates for several commercial end uses. This initial assessment identified approximately 26 aMW of potential energy savings in the commercial sector.

In 1992, the company hired Jerry Jackson and Associates to implement the Commercial Energy Demand Modelling System (CEDMS) for WWP's service territory. The purpose of this project is to:

- Develop an end-use forecasting model of the commercial sector.
- Perform an assessment of the commercial sector demand-side resource potential for both electric and gas.

CEDMS DSM forecasting and demand-side assessment applications provide the following output options:

- "Frozen efficiency" forecast (continuation of current efficiencies).
- Base case forecast (with customer's natural adoption of higher efficiency end uses).
- Base case forecast with utility DSM programs.
- Achievable demand-side potential (savings that can be achieved with current market imperfections).
- Economic demand-side potential (savings that cost less than avoided cost).
- Technical demand-side potential (maximum savings with the most efficient technologies).

Preliminary results from the CEDMS assessment have been used to develop a supply curve of commercial sector potential. Figure F-5 represents the net demand-side savings that could be achieved by the year 2012, assuming a continuation of current WWP programs. The savings include both electric efficiency and fuel efficiency measures.

Figure F-5: CEDMS Estimated Commercial Sector Savings

	2 ¢/kWh	3 ¢/kWh	4 ¢/kWh	5 ¢/kWh	6 ¢/kWh	7 ¢/kWh
Estimated Commercial Sector Demand-Side Savings by the Year 2012 (Cumulative aMW)	19	50	66	73	78	80

Industrial

For 1993, WWP projects firm industrial sales of approximately 1.5 million MWh. Interruptible sales are projected to add another 220,00 MWh.

WWP's 1991 assessment of industrial demand-side resource potential estimated savings of 12.2 aMW over a 20-year period at a levelized utility cost of 3.4 ¢/kWh. This study evaluated the savings from process efficiency in general. It did not focus on any specific measures.

WWP's commercial/industrial program is expected to help identify and confirm cost-effective conservation potential in the industrial sector. In addition, this program is expected to help to identify and overcome barriers that keep customers from implementing conservation measures.

Current WWP Demand-Side Activity

In 1992, WWP received regulatory approval for new tariffs that allowed the company to implement comprehensive demand-side management programs that provide all customers the opportunity to reduce their electric bills. Consistent with the 1992 tariff filing, WWP is currently operating the following demand-side management programs.

Residential Energy Exchanger Program

The Energy Exchanger program is designed to encourage customers to replace their existing electric space and water heat equipment with natural gas equipment. The program is available to all customers who use WWP electricity as their primary source for space and water heating. The company pays up to $2,700 ($3,400 for zoned electric heat in Idaho) for a customer to change both space and water heating equipment and $650 to change out only water heating. A customer must already have gas service to qualify for the program to change only the water heater. The customer makes 60 monthly payments of $15 and $4 ($15 and $5 in Idaho) for a space heat equipment change and water heat equipment change, respectively. These payments are designed to allow the company to recover lost electric margins associated with the conversion of a customer from electricity to natural gas.

Residential Weatherization

WWP has offered weatherization incentives to its electric space heat customers since 1978. The revised weatherization program offers customers grants toward the installation of many energy saving measures including insulation, energy-efficient windows, water heater wraps and set-back thermostats. The grant level is set at 100% of the avoided cost value up to 80% of the measure cost (70% of measure cost in Idaho).

This weatherization incentive is also offered to customers who participate through the low-income community action program (CAP) agencies. WWP pays agencies $1,600 for each electrically heated low-income home that is weatherized.

Low-Flow Shower Head and Faucet Aerator Distribution

Energy-efficient shower heads and faucet aerators are being made available to all electric and gas water heating customers in Washington and Idaho. Residential customers are sent promotional materials that offer up to two energy-efficient shower heads and three aerators at no charge. Customers are asked to return a response card indicating the number of shower heads they need. Customers receive the requested shower heads and three aerators through the mail.

Compact Fluorescent Light Bulb Rebates

Under this program, customers who purchase compact fluorescent light bulbs can receive a rebate of up to $7 per bulb. Bulbs can be purchased at many retail outlets in the region. To receive their rebates, customers submit completed rebate forms along with their receipts and UPC codes. Customers can receive a rebate form for up to 12 compact fluorescent bulbs.

Residential New Construction

The residential construction program supports the implementation of the applicable Washington state residential energy codes. In Idaho, the program supports jurisdictions that have adopted the Northwest Energy Code.

WWP makes payments to builders of electrically heated homes within the Washington and Idaho electric service area. Payments for efficient, electrically heated homes will be made under tariff schedule 67 filed with each state utility commission. Payments in Washington are $900 for single-family homes having 2,000 square feet or less of finished floor area and $390 per multi-family unit. Payments in Idaho are 40 cents per square foot with a $720 maximum for single-family homes and 20 cents per square foot with a $255 maximum for multi-family units.

Manufactured Home Acquisition

The Manufactured Home Acquisition program (MAP) is a regional program that supports manufactured home builders who produce and distribute energy-efficient, electrically heated homes.

Through the BPA, WWP pays manufacturers $2,500 for each manufactured home that is constructed to MAP standards and installed in the WWP service territory.

Commercial/Industrial Electric Efficiency

This program targets commercial and industrial customers who install energy-efficiency measures. The program is structured such that any electric-savings measure qualifies for an incentive payment from the company. It allows the company to proceed with site specific demand-side opportunities that exist within the commercial and industrial sector. The program will pay customers the lower of 75 percent of the avoided cost value or whatever amount is necessary to give the customer a two-year simple payback.

Commercial/Industrial Fuel Efficiency

The commercial/industrial fuel-efficiency program is designed to encourage customers to replace electric end uses with natural gas end uses. To qualify for the program, the new gas end use must be at least 40 percent efficient. The customer is paid an incentive up to the measure cost or the net avoided cost value, whichever is less. The net avoided cost is the difference in the present value between the saved electricity avoided cost and the consumed gas avoided cost over the measure life. The customer makes 60 monthly payments of the lost margin which is computed by subtracting WWP's energy production cost from the customer's retail energy rate plus the reduced demand charges.

WWP's 1992 tariff filing included demand-side savings targets for program activity through 1996. Detailed capital budgets and savings goals have been developed for 1993 and 1994 program activities. This information, along with actual 1992 program results, is shown in Figure F-6.

Figure F-6: 1992-1994 Detailed demand-side management activities.

WWP Demand-side Program	1992		1993		1994	
	Dollars ($ 000's)	Energy Savings (aMW)	Dollars ($ 000's)	Energy Savings (aMW)	Dollars ($ 000's)	Energy Savings (aMW)
Residential						
Energy Exchanger						
Combined Space and Water Heat	5,997	3.79	15,000	7.47	15,000	7.86
Water Heat Only	1,258	0.73	1,958	1.03	2,057	1.08
Energy Exchanger: Low-Income						
Combined Space and Water Heat	63	0.02	396	0.15	416	0.16
Water Heat Only	15	0.00	108	0.05	114	0.05
Weatherization	100	0.01	750	0.20	288	0.07
Low-Income Weatherization	359	0.07	480	0.11	480	0.11
Low-Flow Shower Heads	286	0.43	949	2.55	968	2.42
Compact Fluorescent Lighting	106	0.03	534	0.29	551	0.29
Residential New Construction	317	0.13	506	0.19	354	0.14
Manufacture Home Acquisition	166	0.01	844	0.21	848	0.21
Commercial / Industrial						
Fuel-Efficiency	84	0.05	1,139	0.79	1,274	0.81
Electric-Efficiency	1,084	0.51	4,500	2.26	6,000	2.94
Totals	9,835	5.78	27,164	15.30	28,350	16.14

Demand-Side Resource Measurement and Evaluation

The measurement of the company's 1993 demand-side management programs is described in WWP's 1993 Demand-Side Management Measurement and Evaluation Plan. This plan is the result of a cooperative effort between the company and its DSM Issues Group (DIG). It outlines the comprehensive evaluation of eight WWP electric and gas demand-side programs. Goals of the plan are to:

- Provide for counting of program savings as soon as participants complete installations and before the company conducts detailed evaluations of savings impacts.
- Estimate the capacity and energy savings actually achieved for the demand-side programs.
- Provide data necessary for performing cost-effectiveness tests from a total resource cost and utility cost perspective.
- Supply information essential to the company for making changes to various aspects of ongoing programs.

While the measurement and evaluation plan considers each demand-side program separately, the individual plans contain the following components:

- Program Description
- Pre-evaluation Estimates of Program Savings
- Evaluation Goals
- Impact Analysis
- Process Analysis
- Evaluation Issues
- 1993 Evaluation Budget
- Evaluation Schedule
- Data Elements Required for Impact Analyses.

The two key components of this evaluation effort are the impact and process analyses. The impact analysis quantifies the energy impacts of each program. It answers the question, "How much energy savings did the program achieve?" In contrast, the process evaluation answers the question, "How well did the program operate?" Both analyses will provide valuable information about the near-term success of WWP's demand-side management efforts.

Demand-Side Resource Cost-Effectiveness

Cost-effectiveness tests provide a means of comparing the price to be paid for demand-side resources with the cost of the company's alternative resource. WWP uses two types of tests to evaluate the cost-effectiveness of demand-side opportunities. The "Utility Cost Test" (Utility Test) and the "Total Resource Cost Test" (TRC Test) provide different types of information. Both are important. The application of each test may vary depending upon the type of resource or type of program being evaluated.

Utility Test

From the utility perspective, the determination of cost-effectivenes is a direct calculation, involving only the company's costs associated with the demand-side resources. These costs primarily include the utility rebate or contribution (grant), program administrative costs and measurement and evaluation costs.

The total costs paid by the utility for the energy savings are compared with the value of these savings as represented by the utility avoided cost. Other types of utility benefits, such as electrical system loss savings or incremental capacity benefits, may upwardly adjust the avoided cost or be credited against the cost of the demand-side resource.

Figure F-7: Utility Test Components

WWP Program	Costs	Benefits
Fuel-Efficiency	• Utility Grant • Utility Administrative Cost • Measurement & Evaluation Cost	• Commission Approved Avoided Cost • 10% Conservation Credit • Capacity Savings Credit
Conservation	• Utility Grant • Utility Administrative Cost • Measurement & Evaluation Cost	• Commission Approved Avoided Cost • 10% Conservation Credit

A demand-side resource passes the Utility test as long as the total cost paid by the utility is equal to or less than the avoided cost.

TRC Test

A TRC test compares the cost paid by all parties for the demand-side resource with the cost of the alternative resource, as represented by the utility avoided cost. The TRC test captures any additional costs paid by the customer or any other third party. Participant costs are generally represented by measure (equipment) costs that remain after payment of the utility grant.

Customers who install demand-side measures receive the benefits of increased comfort, reduced electric bills and new energy-saving equipment. Depending upon the type of demand-side program, the TRC test may quantify some or all of these benefits. In quantifying these benefits, the TRC test recognizes the customer, to some extent, is willing to pay for these benefits.

The TRC test views cost-effectiveness from a societal perspective. The total price paid by all parties should not exceed the value of the resource as represented by the avoided cost. The TRC test is used to determine the maximum cost-effective funding level for each WWP program. The details of the TRC test, as it applies to WWP, are currently being developed through the company's DSM Issues Group (DIG).

Folowing is a general description of the TRC test that is currently being discussed by the DIG participants.

- As long as the total demand-side measure cost, paid by all parties, is less than the avoided cost, then the measure passes the TRC test.
- If the total measure cost exceeds the avoided cost, then it would be necessary to determine whether there are other quantifiable benefits associated with the measure, such as reduced operating costs. If the quantifiable benefits plus the avoided cost value are greater than the total measure cost, then the measure would pass the TRC test.
- If the demand-side measure has other benefits that are identifiable but not easily quantified, then TRC test will estimate the customers' willingness to pay for the energy savings (or electric bill savings). The customers' willingness to pay for energy savings plus the utility's payment for the energy savings should be equal to or less than the avoided costs. The details for estimating the customers' willingness to pay for energy savings are not yet completed by the DIG participants.

Not every demand-side measure will pass these cost-effectiveness tests. However, special conditions, such as regulatory requirements or the need to raise conservation awareness and maintain program infrastructure, may direct the company to pursue these resources.

Supply-Side Resource Assessment

Supply-side resources may be developed by the company, by another utility or by an independent power producer. As shown in Figure F-8, WWP's current development opportunities include hydroelectric upgrades, Colstrip efficiency and electric system energy savings (loss savings). Firm energy resource costs are levelized over a 35-year life for each project. These system efficiency and upgrade opportunities will help the company meet long-term energy and capacity needs. A proposed simple-cycle combustion turbine facility is being considered primarily to meet the company's capacity needs.

Figure F-8: WWP hydroelectric upgrade, thermal and electric system efficiency opportunites.

WWP Resource Opportunity	Incremental Capacity (MW)	Incremental Firm Energy (aMW)	Firm Energy Levelized Cost (¢/kWh)
Hydroelectric Plant Upgrade			
Monroe Street (completed in 1992)	8.9	5.8	3.3
Upper Falls	1.7	0.8	1.7
Nine Mile Falls			
Without Incremental Pool Raise	11.1	1.7	2.4
With Incremental Pool Raise	13.1	3.1	1.8
Cabinet Gorge			
Unit No.1	10.0	5.1	0.0
Unit No.2	10.0	3.5	4.0
Noxon Rapids			
Unit No.1	10.0	0.93	5.0
Unit No.3	10.0	1.63	4.0
Colstrip Thermal Efficiency			
Turbine rotor replacement for Units No.3 and No.4	6.0	5.0	1.6
Electric System Efficiency			
Transmission and distribution system loss savings.	20.0	20.0	2.7

WWP Hydroelectric Plant Improvements

In 1992, WWP essentially completed the program to evaluate each of the company's hydroelectric developments for additions and/or upgrades that may be economically pursued now, or in the future. For each site, a set of alternatives was developed. If any were found to be promising, a preliminary engineering study was performed to determine specific design details and a more accurate cost estimate. The development alternatives still showing promise were presented to the company for authorization to proceed or put on the shelf for future development. Each of the company hydroelectric sites has been screened for developable additions and/or upgrades. Figure F-9 summarizes the results of this screening process.

Figure F-9: WWP hydroelectric plant improvement opportunities.

WWP Hydro Plant	Potential Capacity Increase (MW)	Potential Firm Energy Increase (aMW)	Potential Total Energy Increase (aMW)	Estimated Total Investment ($Millions)	Estimated Incremental Investment ($Millions)	Net Firm Energy Levelized Cost (¢/kWh)
Upper Falls	1.7	0.8	1.2	4.2	2.3	1.7
Nine Mile Falls						
Without Pool Raise	11.1	1.7	3.3	22.2	11.4	2.4
With Pool Raise	13.1	3.1	5.5	26.3	14.9	1.8
Cabinet Gorge						
Unit No.1	10.0	5.1	5.6	8.7	5.5	0.0
Unit No.2	10.0	3.5	3.9	6.7	4.5	4.0
Noxon Rapids						
Unit No.1	10.0	0.93	1.27	6.5	4.5	5.0
Unit No.3	10.0	1.63	2.25	6.5	4.5	4.0

The following paragraphs provide additional detail on the current status of WWP's hydroelectric plant improvement studies. For all of WWP's hydro improvement opportunities, the scope and cost of each project is refined as new information becomes available.

Monroe Street

(Spokane River; Constructed 1891; Rebuilt 1992)

WWP has replaced the old five-unit plant with a new single vertical Kaplan unit rated at 2,900 cfs and 14.75 MW. The project was budgeted for $23.6 million. The project essentially doubles the capacity of the plant (from 7.2 MW nameplate to 14.75 MW). Annual energy increases are expected to be 46,000 MWh of firm energy and 15,000 MWh of secondary (nonfirm) energy. The rebuilt Monroe Street Hydroelectric Development became operational in December 1992.

Upper Falls

(Spokane River; Constructed 1922)

Upper Falls has been addressed in overview by the Spokane River Optimization Study (SROS) and has been studied in detail by vendors who are developing detailed costs and benefits of feasible upgrades. The vendors have studied the replacement of either or both the turbine and generator. Replacement of the turbine and rewind of the generator appears to be the best alternative. The incremental cost today is estimated at two to three million dollars, which would produce an additional output of 5,000 to 10,000 MWh of firm energy and 10,000 to 20,000 MWh of secondary (nonfirm) energy annually. WWP is continuing with a review of the vendor's study and a recommended plan for project development.

Nine Mile

(Spokane River; Constructed 1908)

WWP is proceeding with the redevelopment of the Nine Mile Project, which includes the replacement of two of the four units with more efficient units of "similar" design. The company is deferring plans to raise the forebay elevation five feet by installation of a rubber spillgate. The deferral of this work will allow WWP to pursue a public involvement process for the pool raise portion of the project. This is another plant where major work is required in the next five years. On-line date for unit 3 is now scheduled for mid 1994, with unit 4 on line by the first quarter of 1995.

Post Falls

(Spokane River; Constructed 1906)

The Post Falls plant was addressed in overview by the Spokane River Optimization Study. Both generation additions and upgrades were reviewed. Preliminary economic screening shows the replacement of units with more efficient units and units of higher capacity to be the most promising. The replacement of two units would potentially increase the capacity of the plant from 18 MW to 25 MW. No further evaluation is planned until a need for the energy is foreseen.

Long Lake

(Spokane River; Constructed 1915)

Completed engineering study indicates the feasibility of installing a second powerhouse beside the existing powerhouse. The new powerhouse could be sized for one or two new 60 MW units. The project will be further evaluated as a means of meeting future capacity needs.

Little Falls

(Spokane River; Constructed 1910)

The Spokane River Optimization Study identified upgrade alternatives involving the replacement of the existing turbines with units of higher efficiency. The most promising alternative replaces two of the existing 1,800 cfs units with higher efficiency units rated at 2,650 cfs. The company has no plans to pursue redevelopment at this time.

Meyers Falls

(Colville River; Constructed 1915)

The company has evaluated redevelopment opportunities at this 1.3 MW plant. None of the upgrades are financially viable. The plant is being maintained as-is, and the application for a renewed FERC license was filed in late 1991. Various recreational and historical enhancements are planned for the area. No changes in the operation of the plant are being proposed.

Cabinet Gorge and Noxon Rapids

(Clark Fork River; Completed 1959 and 1963)

A feasibility study of the Cabinet-Noxon plants focusing on Cabinet was done in 1991 by Acres, a consultant engaged by WWP. The study showed that even though discharges at Noxon (51,400 cfs) were larger than Cabinet (36,000 cfs), a fifth unit at Cabinet could not be justified because of a low plant factor. The study did show that rehabilitation alternatives are economically viable. In recent months, cracks have developed in the blades of the Cabinet No.1 turbine. Repeated efforts of welding these cracks have not shown lasting success. Additional studies have shown that upgrading the turbine, generator and transformers will improve efficiency, capacity and reliability. This work is in progress and scheduled for completion in the first quarter of 1994. WWP engineering is developing preliminary rehabilitation alternatives for Noxon and additional units at Cabinet Gorge.

Source(s): Bob Mansfield, WWP Corporate Communications, January 1993
Tom Johns, WWP Power Resources, February 1993

Colstrip Thermal Efficiency

An opportunity exists to replace the high and low pressure turbine rotors at Colstrip Units No.3 and No.4. If this work is completed, these Colstrip units would produce additional output with no increase in fuel (coal) consumption. WWP's share of the incremental Colstrip resource would be approximately 5 aMW. WWP and the other Colstrip owners are currently evaluating the timing and scope of this and other potential plant improvements. A levelized resource cost of 1.6 ¢/kWh has been used for planning purposes. The results of WWP's preliminary detailed economic studies are summarized in the following report:

Preliminary Financial Analysis of Colstrip Units 3 & 4 Upgrade
Prepared by Mike Griswold, WWP Business Analysis, October 1992

A financial analysis of a proposal to upgrade the low and high pressure rotors for Colstrip's units 3 and 4 has been completed. The analysis was based on an economic evaluation prepared by the Montana Power Company (MPC). The analysis examined two options, 4 and 15, selected by MPC as the most economical. Option 4 entails installing all new low and high pressure rotors on units 3 &4 and option 15 would use less expensive rebuilt low-pressure rotors for units 3&4. All variables were provided by MPC except the power values and the AFUDC rate, both of which were the current values used by WWP.

Using the construction schedule included in the MPC memo, total project costs, including AFUDC, were computed. The analysis assumed 6.5% construction escalation, the same rate used by MPC. Cash flows were charged to WWP in the month that MPC incurred the expenditure. Allowance For Funds Used During Construction (AFUDC) was compounded annually based upon the weighted average cumulative monthly construction expenditures using WWP's AFUDC rate of 10.67%. The capital was then totaled by year and charged against cash flows in the year incurred.

Revenues were based upon the projected increased generation that would arise from the more efficient turbines. It was assumed that both rebuilt units would generate an additional 20 MW of capacity for the unit's projected 25 year lives. The post-outage equivalent availability factor was 87% for both units throughout their lives except unit 3 had an EAF of 94% during its first seven months of operation. The use of more efficient rotors will also decrease the operating costs since the units would have a lower heat rate. It was determined that the first year annual O&M savings would be $56,372. Although Option 15 utilizes rebuilt rotors, no incremental O&M was assessed against Option 15.

Property taxes were charged against the net book value of the plant at a rate of 1.728%. The new additions to plant were assumed to have a 35 year book life. The additions were recovered for income tax purposes using 20 year MACRS tax rates. Net cash flows were charged federal income taxes at 34%. Capital was charged against cash flows in the year spent. Net after-tax cash flows were discounted back to 1992 using the Company's discount rate of 8.97%. Figure F-10 summarizes the results of the analysis:

Figure F-10: Preliminary Colstrip thermal efficiency study results.

Option	Value of Power	Months of Transmission Curtailment	Capital	NPV	IRR	Cost of Power	Discounted Payback
4	Firm	1	$6,961,663	$8,234,382	20.93%	$19.79	10 Yrs
4	Firm	0	$6,961,663	$9,419,085	22.45%	$19.79	9 Yrs
4	NonFirm	1	$6,961,663	$2,198,276	12.68%	$19.79	17 Yrs
4	NonFirm	0	$6,961,663	$2,834,243	13.68%	$19.79	16 Yrs
15	Firm	1	$6,533,313	$8,566,044	22.10%	$18.44	9 Yrs
15	Firm	0	$6,533,313	$9,750,748	23.70%	$18.44	9 Yrs
15	NonFirm	1	$6,533,313	$2,529,939	13.47%	$18.44	16 Yrs
15	NonFirm	0	$6,533,313	$3,165,905	14.51%	$18.44	15 Yrs

The above values reflect WWP's 15% of the project. A power value sensitivity was run against each case by using projected nonfirm prices. To test the sensitivity to transmission capacity, it was assumed that the incremental power could not be wheeled out of Colstrip for one month a year. This power was assumed to be lost. Based upon this analysis, Option 15 has the greatest return to the Company with an NPV of $9,750,748 assuming firm energy prices and no transmission curtailment. However, option 15 has the greatest risk since rebuilt equipment would be used instead of all new under Option 4. The sensitivity analysis suggests that even at secondary prices with one month of transmission curtailment the project would provide economic benefits to the participants.

Source: Mike Griswold, WWP Business Analysis, October 1992

Electric System Efficiency (System Loss Savings)

The company's electric distribution and transmission system is designed to provide service reliability to all customers. Ongoing studies determine economic and reliable means of serving new customers and integrating new resources. The results are decisions to construct new facilities, replace existing equipment or reconfigure the existing network. As part of these studies, WWP also investigates the potential to reduce losses on the electrical distribution and transmission system.

For planning purposes, WWP estimates that 10 aMW of system loss savings can be acquired at a levelized rate of 2.7 ¢/kWh.

Distribution System Loss Savings

Long-term Distribution Savings Estimate

WWP's distribution system generally consists of electrical facilities that operate below 60,000 volts (60 kV). Distribution system losses are reduced by installing low-loss transformers, compensating capacitors and conductors chosen for lifetime economic value. Energy savings will be realized gradually as old facilities are replaced and the system expands.

Over the next 40 years, WWP expects to save approximately 13.8 aMW of distribution system losses. The cost of these distribution savings is estimated to be below WWP's current Washington avoided cost.

Figure F-11 Distribution loss savings estimate.

Distribution System Activity	Estimated Energy Savings (aMW)
Low-loss transformers installations for new and failed equipment.	9.1
Economic conductor selection for new construction, upgrades and replacements.	4.1
Additional capacitor installations.	0.6
Total	13.8

Distribution Savings Assessment

Distribution Transformers: WWP has been purchasing low-loss transformers for over ten years. As of 1989, approximately 10 percent of the 82,255 transformers in service are low-loss units.

The economic formula for the purchase of high-efficiency transformers is reviewed annually and revised if necessary. The increased use of natural gas for space and water heating has resulted in the installation of smaller transformers in housing developments which, in turn, has reduced the no-load losses on the distribution system. This reduction may become significant if the widespread conversion from electricity to natural gas continues over the long-term.

The company is evaluating used transformers as they are returned for repairs. If the remaining lifetime costs, including losses and repair cost, exceed the cost to purchase a new high-efficiency transformer, the unit is scrapped. Losses are being tested on the company's transformer test set.

Over the next 30 years, all transformers that fail will be replaced with low-loss units. When all older units are replaced, the added savings will be approximately 9.1 aMW. It is not considered cost-effective to replace operating transformers.

Distribution Conductors: At the end of 1991, WWP's overhead distribution line (1-, 2- and 3-phase circuits) totalled 8,713 miles.

WWP has evaluated the use of larger conductors to reduce lifetime operating costs. The analysis identified the economic conductor sizes for all current levels and showed that nearly all of the losses occur on the three-phase trunks (i.e. main distribution feeder lines). Economic conductor is the least expensive choice of conductor considering the original installed cost and the value of losses evaluated over a 40-year life.

The economic conductor is used on new construction and rebuilds when the higher investment fits within budget restrictions and the lifetime cost is less than the avoided cost. In most cases, it is not cost-effective to replace existing conductor solely to reduce losses.

Increased emphasis has been placed on economic conductor size by reorganizing the Distribution Design section to create a distribution planning position. This engineer's duties include recommending the routes and sizes of feeder trunks to reduce losses and provide reliable service.

Out of 270 distribution feeders in the WWP system, portions of 10 feeders were budgeted for replacement or additions of three-phase circuits in 1992. This included over 22 miles of reconductoring and nearly three miles of new lines. These figures do not include the many miles of single-phase line installed to serve new residential customers.

Over the next 40 years, the installation of economic conductors will gradually reduce losses by approximately 4.1 aMW.

Distribution Capacitors: The majority of WWP's distribution system is already compensated by fixed capacitor banks. Line capacitor installations have been reviewed to establish the current status of all banks.

Additional savings can be achieved with switched banks and compensation at customer motor terminals. Further study will determine whether additional fixed banks can be economically justified and whether switched banks should be considered. The present Reactive Power Adjustment (kVAR Penalty) may need revision to encourage industrial customers to invest in secondary capacitors at their individual sites.

Over the next 20 years, an additional savings (more than the current savings due to capacitors) of approximately 0.6 aMW (5,000 MWH per year can be realized.

Source: Tim Rahman, WWP Distribution Engineering, January 1992

Transmission System Loss Savings

WWP's bulk transmission system primarily consists of 230 kV and 115 kV facilities. Electric resources produced at WWP generating facilities and throughout the region are transferred on the 230 kV grid and delivered through power transformers to the 115 kV network.

Figure F-12: Current WWP transmission line miles.

Transmission System Voltage	Line Miles (As of January 1993)
60 kV	6
115 kV	1,490
230 kV	545
Total	2,041

Transmission system losses are reduced by installing conductors and other facilities chosen for their lifetime economic value. System reconfiguration that redirects power flows over the most efficient transmission paths can also result in system energy savings. System planning studies determine the need for new transmission facilities, as well as the most efficient system configuration. Through these detailed near-term studies, WWP is able to refine long-term estimates of transmission system loss savings.

Long-term Transmission Savings Estimate

Over the next 40 years, WWP expects to save approximately 15.0 aMW of transmission system losses. The cost of these transmission savings is estimated to be below WWP's current Washington avoided cost. Savings will be realized by selecting economic conductors for new construction and reconductor projects and proper siting and specification of new power transformers.

Transmission Savings Assessment

Transmission Conductor: The economic conductor is used on new transmission construction when the higher investment fits within budget restrictions and the lifetime cost is less than the avoided cost. Although it is generally not cost-effective to replace the existing conductors solely to reduce losses, increasing conductor size to the most economic conductor is also examined when existing facilities are being upgraded or replaced due to:

- normal aging, or
- changing power flow patterns resulting from new or shifting loads or increased power transfers.

System Additions and Reconfiguration: In most cases, the addition of new transmission facilities results in reduced transmission system losses. These facilities may include new high-voltage transmission lines, system capacitors and power transformers. When located near load centers, new generation plants can also reduce transmission system losses.

System reconfiguration is one of the alternatives considered to solve potential reliability problems. Reconfiguration primarily involves the opening of existing ties and the construction of new facilities to redirect power flows across the transmission network. In addition to addressing the reliability concerns, system reconfiguration may also result in a more efficient (lower loss) transmission system. Some reconfiguration alternatives are considered as operational solutions for the short-term until long-term solutions can be determined and implemented. Detailed system analysis is required to completely evaluate each reconfiguration alternative.

Near-Term Transmission Savings Study Results

In early 1993, WWP completed preliminary system studies to determine the transmission loss savings associated with system additions and reconfiguration proposed for the next five years (through 1997). These facilities are being planned to meet growth, maintain reliability and integrate new generation. These projects primarily include the completion and construction of:

- Three 115 kV substations.
- Three 115 kV switching stations.
- New 115 kV and 230 kV transmission lines.

In addition to these projects, WWP and BPA have determined a plan of service to eliminate a transmission system bottleneck between Montana and the Pacific Northwest. Facility upgrades and reconfiguration will reduce the "West of Hatwai" transmission constraints and result in increased power transfer capability between Montana and the Northwest.

System study results indicate that these system additions, upgrades and reconfiguration planned for the next five years will result in approximately 3.7 aMW of transmission loss savings.

Source(s): Scott Waples, WWP System Planning, December 1991
Warren Clark, WWP System Planning, February 1993

Purchases and Exchanges

The company reviews unsolicited proposals for power purchases on an ongoing basis. These proposals are typically sponsored by other utilities or by developers of independent power projects. By maintaining an active involvement in regional wholesale energy markets, the company is able to pursue power purchase and sales opportunities as they become available. Each of these opportunities is considered as a potential means of meeting WWP's energy and capacity needs or the needs of the region.

Mid-Columbia Contract Extensions

WWP currently has long-term purchase rights to power output from four mid-Columbia River hydroelectric plants owned by three Public Utility Districts. The company's purchase rights and contract termination dates are shown in Figure F-13.

Figure F-13: Contract termination dates for mid-Columbia contract power purchases.

Mid-Columbia Plant	Plant Owner	WWP Purchase Rights (MW / aMW)	Contract Termination Date
Priest Rapids	Grant County PUD	55 / 29	2005
Wanapum	Grant County PUD	75 / 36	2009
Rocky Reach	Chelan County PUD	37 / 17	2011
Wells	Douglas County PUD	33 / 14	2018

Each of the mid-Columbia contract purchases represents a very low-cost and flexible resource for WWP. Contracts with Grant County PUD are the first to expire. WWP is actively pursuing a Grant County offer to extend the sale of Priest Rapids and Wanapum output. Terms and conditions of a contract extension are currently being negotiated.

For planning purposes, WWP currently estimates that successful extension of the Grant County contracts will provide a resource with the following characteristics.

- Available long-term (estimated 20-30 years).
- Priced between current contract rates and a new low-cost generating resource.
- Based on the fact that Grant County will "take back" power to serve their own loads, energy available to WWP is estimated to decline from the current 65 aMW to approximately 45 aMW in the year 2012.

Negotiations for the Grant County contract extension are expected to be completed sometime in 1994.

Source: Doug Young and Sandee Warne, WWP Power Resources, February 1993

Cogeneration Opportunities Within WWP's Service Territory

Cogeneration is the use of one primary fuel source for simultaneous generation of both thermal and electrical energy. The technology typically includes combustion turbines, steam turbines and reciprocating engines. Cogeneration is a fully developed technology that can be implemented in some industrial and commercial facilities. Cost for cogenerated power tends to be driven by the competitive marketplace. In addition, the price and availability of cogeneration is strongly influenced by the customer's forecasted fuel (natural gas) prices.

WWP's initial assessment of customer generation potential was completed by Resource Management International (RMI). Results of this investigation indicated that within WWP's service territory, there is 60 MW to 140 MW of cogeneration potential. Levelized resource costs range in the order of 60 $/MWh.

Since 1991, studies to refine this initial assessment focused on industrial facilities and state universities located in WWP's electric and gas service territories. Comprehensive studies were completed with:

- Inland Empire Paper
- Kaiser Aluminum
- A major food processor in Grant County.

The work at Inland Empire Paper resulted in the submission of resource proposal to BPA's recent competitive bidding process. In addition to these studies, the company has worked closely with the University of Idaho, Washington State University and Eastern Wasthington University providing input to their ongoing evaluation of cogeneration opportunities.

Source: Alan Meyer, WWP Power Supply, February 1993

Competitive Bidding

WWP's 1991 Request for Proposals (RFP) competitive bidding process provided the company some information about the type, availability and price associated with new resources. Supply-side resource options were dominated by proposals to produce energy from natural-gas-fired combustion turbines. These projects also represented the lowest cost supply-side proposals. Only one small renewable resource was offered at a price below WWP's Washington avoided cost ceiling. Figure F-14 summarizes the type of projects that passed the company's initial project review. Because of the confidential nature of the RFP process, bid prices are combined and represented by a range rather than on an individual project basis.

Figure F-14: 1991 Competitive bidding process: Supply-side project summary.

Resource Type	Proposals	Firm Energy (aMW)	Levelized Cost ¢/kWh
Renewable	1	3.3	
Natural Gas-Fired			5.0 - 5.7
Cogeneration Facility	4	100.0	
Independent Power Producer	3	87.3	
Total	8	190.6	

PURPA

The Public Utilities Regulatory Policies Act (PURPA) of 1978 requires utilities to purchase power from cogeneration and small power production facilities that qualify under PURPA rules. WWP's existing PURPA contracts are described in Appendix C. Active discussions regarding new PURPA projects are limited to one small project (300 kW) to be located in North Idaho.

Regional Resource Data

Published by the Northwest Power Planning Council (NWPPC), the 1991 Northwest Conservation and Electric Power Plan, provides regional data regarding the costs for a variety of resource options. WWP uses this data to complete a generic assessment of these supply-side resources. Figure F-15 and the following paragraphs summarize the nature and cost of these various technologies.

Figure F-15: Generic resource cost information.

Generic Resource Type	Total Capital Cost $/kW	Fixed O&M $/kW/Yr	Variable O&M $/MWh	Fuel Cost $/MWh	Const. Lead Time	Oper. Life	Fixed Charge Rate (FCR)	Annual Avail.	Life Cycle Lev. Cost $/MWh
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1. Large Pulverized Coal	$1,743	$25.47	2.17	17.91	72 Mos	40 Years	12.92%	75%	76.0
2. Small Pulverized Coal	$2,317	$38.83	3.26	18.16	60 Mos	40 Years	12.92%	77%	91.3
3. Fluidized Bed (AFBC)	$2,521	$43.53	5.54	16.31	63 Mos	30 Years	13.41%	82%	91.0
4. Coal Gasification	$2,543	$70.57	0.87	13.90	39 Mos	30 Years	13.41%	80%	87.7
5. Combined Cycle CT	$860	$6.31	0.43	13.79	24 Mos	30 Years	13.41%	83%	48.3
6. Simple Cycle CT	$740	$2.36	0.11	20.78	24 Mos	30 Years	13.41%	85%	59.9
7. Biomass	$1,924	$47.51	4.02	42.00	36 Mos	30 Years	13.41%	87%	113.1
8. Geothermal (Cascade)	$2,951	$112.92	5.43	N/A	36 Mos	30 Years	13.41%	90%	79.9
9. Wind (Blackfoot Hills)	$1,275	$17.37	13.14	N/A	24 Mos	40 Years	12.92%	30%	94.8
10. Solar (Photovoltaic)	$4,471	$26.36	1.49	N/A	24 Mos	30 Years	13.41%	28%	263.0

All figures in 1992 dollars

Column Description

(a) Generic resource type.
(b) Capital cost includes AFUDC and siting and licensing costs.
(c) First year fixed O&M costs.
(d) First year variable O&M costs.
(e) First year variable cost, including fuel (natural gas prices based on WWP estimates).
(f) Construction lead time (excludes siting and licensing lead time).
(g) Typical resource operating life.
(h) Fixed Charge Rate.
(i) Annual Availability (amount of time resource is available to run).
(j) Life-cycle levelized cost.

Resource Descriptions:

"Resource Data Source: Unless noted, data is based on 1991 Northwest Conservation and Electric Power Plan, Volume II - Part II, NPPC."

1. Pulverized Coal-Fired Power Plant: two 605 MW units located near Hermiston, Oregon.
2. Pulverized Coal-Fired Power Plant: two 250 MW units located near Hermiston, Oregon.
3. Atmospheric Fluidized Bed Combustion: one 197 MW unit (rated capacity) near Hermiston, Oregon.
4. Coal Gasification Combined-Cycle: one 419 MW plant (rated Capacity), consisting of two 139 MW GE MS7001 CT, one heat recovery steam generator and one 141 MW steam turbine-generator located at Creston, WA.).
5. Combined Cycle Combustion Turbine: one 420 MW power plant consisting of two 139 MW GE MS7001F GTG's and one 141 MW steam turbine-generator.
6. Simple Cycle Combustion Turbine: two 139 MW GE MS7001F GTG units located near Hermiston, Oregon.
7. Biomass: 25 MW wood or agricultural waste plant (rated capacity).
8. Generic Geothermal: One 50 MW unit located in the Cascade geologic province. Assumes flashed steam plant and wellfield.
9. Representative Wind Power Station: 96 MW Capacity (29 MW energy) farm in Blackfoot Hills, MT. area (150 to 200 kW units), horizontal axis," 82 foot diameter blades. Includes transmission and access roads as per NPPC data. Assumed 30% capacity factor for levelizing calculation.
10. Solar Photovoltaic: Generic data from NPPC data. Assumed 28% capacity factor for levelizing calculation. Fixed & variable O&M estimated.

Conventional Coal Plants

Coal-fired generating plants are a commercially proven resource and should continue to be a viable resource option for the company. Although a supply of low cost, low sulfur coal is available to the Northwest, siting difficulties, public concern about new transmission lines and atmospheric emissions may constrain the development of new coal-fired power plants. Environmental risks include ash and sludge disposal and concerns of possible acid rain and "greenhouse effect" problems. Scrubbers added to a coal-fired facility reduce particulates and SO_2 emissions to regulated levels. Capital expenditures continue to be a concern because of the long lead time for construction and high capital cost.

Because of low load growth projections in the company's service territory, a large coal plant doesn't fit the company's requirements unless the company participates in a coal plant built for regional need.

Fluidized Bed

Fluidized bed combustion technology is in a period of refinement and development with several plants under construction or operation. Because of its claimed versatility, excellent emissions control and fuel utilization characteristics, fluidized bed generation could be a promising energy resource for the future.

The Atmospheric Fluidized-Bed Combustion (AFBC) concept involves a process in which crushed and ground material (such as coal) is held in suspension with a cushion of air blown through a porous floor. The sulphur recovery is performed right in the fluidized bed with the addition of limestone to the bed. This may eliminate the need for large, expensive scrubber systems downstream from the combustion area used in conventional plants today. AFBC technology is in the early stages of commercialization. Several small plants, producing less than 100 MW each, have been built and are now operating. A number of larger systems are currently under construction. The technology should be available in sizes up to 250 MW by 1995.

Combustion Turbines

Combustion turbines are versatile forms of power generation. They are capable of burning conventional fuels such as natural gas and various grades of petroleum products. The units can be installed for peaking or intermediate/base operation and can also be used to firm nonfirm hydro energy. Combustion turbines are attractive for many reasons. The units have short construction lead times, low capital costs and are available in several sizes that can fit a utility's power needs. They also have reasonable fuel efficiency (heat rate), are reliable and have low maintenance costs. The units are relatively environmentally benign, especially when using natural gas as the fuel. Because of their operating characteristics, combustion turbines can add flexibility to the electrical system.

The environmental impact of combustion turbine operation is low, with the primary emittent being nitrogen oxide (NOx). Methods of controlling NOx emissions include steam injection, dry low nitrogen oxide burners or selective catalytic reduction. There are basically three types of combustion turbine applications, as described below.

Simple-Cycle Combustion Turbine:

The simple-cycle combustion turbine represents a relatively inexpensive power resource to construct. Its total cost, including capital recovery of fixed costs, is primarily made up of fuel (depending upon the capacity factor).

In early 1993, WWP selected a site near Rathdrum, Idaho, as the preferred location to install 176 MW of simple-cycle combustion turbine capacity. The proposed Rathdrum Combustion Turbine Project involves the installation of two natural-gas-fired simple cycle combustion turbines and associated equipment. Natural gas has been selected as the primary fuel with leased gas storage proposed as a back-up fuel source. Each unit is a General Electric 7111EA combustion turbine with a wintertime rating of 88 MW. Actual project output depends on fuel type and atmospheric conditions.

The estimatated capital cost of the turbine project is $70 million, or $350 per kilowatt. The company anticipates receiving all necessary permits and approvals by July 1993. Based on this timing, ground breaking for site preparation will take place in the 3rd quarter 1993 with the majority of construction activity scheduled for 1994. Commercial operation would begin in January 1995. Although the cost and availability of fuel supplies will ultimately determine how Rathdrum is operated, the project could be utilized for up to approximately 4,500 hours per year based on restrictions of the air quality permit that is being requested by the company.

Combined-Cycle Combustion Turbine

A combined-cycle combustion turbine power plant is a combustion turbine with the addition of a heat recovery boiler and a steam turbine to capture the energy in the turbine exhaust. The addition of combined-cycle equipment to a combustion turbine results in a more capital intensive power plant. However, because of more efficient use of fuel under normal operating conditions, the total cost of the electricity will be lower.

Coal Gasification:

A coal gasification combined-cycle power plant adds fuel flexibility to combined-cycle units. The Integrated Gasification Combined Cycle (IGCC) uses pulverized coal fed into a gasifier where it reacts with oxygen to produce an intermediate BTU gas. After the gas passes through a cooling section, sulfur and nitrogen compounds are removed and clean gas is used as the combustion turbine fuel.

Renewable Resources

Biomass

Biomass fuels are defined as any organic matter that is available on a renewable basis. This material includes: forest residues, wood product mill residues, agricultural field residues, waste products from animals and food processing, agricultural and forest crops grown for fuel and municipal solid wastes (i.e., garbage collected from residences, commercial buildings and industrial firms). The heat content, moisture levels and other physical characteristics of biomass resources differ widely.

Large quantities of biomass residues are produced by the forest products industry in the Inland Northwest. Some of this material is now used for industrial process heating, residential heating and electric power generation. There are two large facilities within WWP's service territory that are using wood waste to generate electrical power. One is the Kettle Falls generating station owned by the company, located in northeastern Washington, and the second is located near Lewiston, Idaho, and is owned by the Potlatch Corporation.

The City of Spokane owns and operates a large municipal solid waste facility. The electrical output from the facility is sold to Puget Sound Power & Light. Within WWP's service area, Spokane is the only city of sufficient size that could support a plant using solid waste as a fuel. Because of the present use of biomass within its service territory, WWP doesn't view this fuel as a viable alternative for new electrical facilities, except for small units that can be acquired under a bidding program or as a QF under PURPA.

Geothermal

The geothermal resource comes from underground reservoirs of hot water-steam mixtures which can be tapped for energy production. The binary plants can provide the most efficient use of geothermal resources in terms of net power per unit of fluid mass. Binary plant designs also tend to have lower costs and shorter implementation periods. The main disadvantage of geothermal systems is the cost of the geothermal working fluid. In addition, the long-term reliability of the working fluid can be uncertain. Geothermal energy may be attractive from an environmental point of view, but the number of suitable sites is limited.

Geothermal energy is currently being used for the production of electricity at many locations throughout the world. Although there are estimates of vast amounts of geothermal resources in the Pacific Northwest, there are no potential geothermal sites in WWP's service territory.

Wind

A wind turbine is a renewable resource that utilizes the energy in a moving air stream to drive a turbine generator that produces electricity. The capital related costs of a wind farm have declined since the mid-1980s. Wind is also becoming more attractive due to increased turbine generator reliability. A third generation of wind machines is currently under development and promises even greater reliability, efficiency and cost-effectiveness.

Wind power is appealing due to its low variable costs and zero air emissions. However, wind power lacks load shaping capability, which is the ability to follow loads. Therefore, additional resources may be necessary as backup facilities to provide firm peaking capability and to shape wind energy production to daily load variations. The fact that wind power is usually available in remote locations may lead to transmission access uncertainties and concerns.

The wind energy resources of the Pacific Northwest have the potential to produce several hundred megawatts of electrical energy at costs generally competitive with electrical energy from new coal plants. A strong benefit of wind is the fact that it is a renewable energy resource. The bulk of the region's wind resources are found in Montana, east of the Rocky Mountains. To access this resource would require high voltage transmission lines that are expensive and cause environmental concerns. The company will continue to monitor this potential resource.

Solar

Solar photovoltaics offer good potential for future application in the Northwest. But because of high costs, the deployment of these and other solar technologies will follow that of geothermal and wind resources in the Northwest, except for certain remote applications of photovoltaics that currently are cost-effective.

Hydroelectric (New)

Hydroelectric power is a renewable energy resource that involves the production of electricity from generators driven by hydraulic turbines. The Pacific Northwest streams and rivers have the ability to provide abundant opportunities for small hydroelectric generation. This includes numerous potential sites located above natural barriers to anadromous fish (i.e., salmon). Hydropower continues to be an attractive, proven, long-term energy resource with low environmental effects and low costs. Development and operation are essentially free from toxic emissions and solid waste problems with the majority of project expenditures related to capital costs. Therefore, after the initial investment, uncertainties surrounding future energy costs are virtually eliminated, offering significant protection against rising fuel prices.

Environmental impacts pose the greatest constraint to the development of new hydropower projects. Hydropower projects may cause biological, aesthetic, recreational and socioeconomic impacts that can be difficult to mitigate. Compliance with the Northwest Power Planning Council's protected areas policies is expected to help minimize the environmental impact of new hydropower development. Upgrades, expansions and improvements to the efficiency of existing projects generally pose few environmental problems.

Ocean

Ocean power technologies eventually may provide electrical energy to the Pacific Northwest. The most promising of Northwest oceanic energy resources appears to be ocean wave energy. But ocean power technologies are at an early stage of development. Much additional technological research, development and demonstration must occur before ocean power resources can be considered sufficiently reliable and cost-effective to be included in the preferred resources of WWP. Moreover, there will be significant environmental constraints to large scale deployment of wave and other ocean energy devices.

Other Resource Types

Energy Storage

The company is monitoring information as it becomes available on all systems that have a potential to be used to ease peak load conditions in our service territory. Some of the energy storage systems include fuel cells, batteries and compressed air storage. The company will evaluate the cost-effectiveness of using these systems as more information becomes available and operating experience is gained. Pumped storage is another storage technology that may be used to supplement WWP's existing resource base.

Fuel Cell

A fuel cell is a device that converts the chemical energy of a hydrocarbon based fuel directly to usable energy in the form of electricity and heat without fuel combustion as an intermediate step. The fuel cell characteristics are quiet and relatively pollution-free operation, ease of siting, modularity and high efficiency (50 percent efficient when producing electricity and up to 80 percent efficient in a cogeneration mode). The cost of energy from a fuel cell is very high due to high capital cost. With improvements of the technology and mass production, the costs are expected to decline, allowing perhaps in 10 years for the fuel cell to become a part of WWP's resource alternatives.

Nuclear

Although the company has been involved with nuclear energy production of electricity since 1966, at the present time WWP is not considering future nuclear generation options. However, the conditions that caused unacceptable problems with nuclear power (high construction costs, uncertain regulatory treatment of those costs and difficulty in licensing) could be solved by the module nuclear units now under development. Both General Electric and Westinghouse are developing a modular nuclear production plant in the 500 MW range with a standardized design acceptable to the regulatory entities that could be constructed in five years. Additional emphasis will be placed on using nuclear energy for the production of electricity if the environmental concerns of burning fossil fuels cannot be resolved and the nuclear waste disposal problem is resolved.

Source(s): Doug Young & Dennis Vermillion, WWP Power Resources, June 1992

Appendix G

Resource Management Issues

Resource Management Issues

Throughout the planning process, WWP identifies issues that may affect the operation of the existing system or the resource selection process. This appendix provides a discussion of these current and emerging issues. As much as practicable, pertinent technical information is also included.

Summary

The following resource management issues are discussed in the 1993 IRP:

- 1992 National Energy Policy Act
- Transmission Access
- Clean Air Act Amendments of 1990
- Proposed National Energy Tax
- Endangered Species Act
- Hydroelectric Plant Relicensing
- Competitive Bidding
- PURPA
- Avoided Cost
- Demand-Side Resource Acquisition
- Environmental Externalities
- Global Warming
- Electric and Magnetic Fields (EMF)
- Regional Power Supplies
- Firming Nonfirm Hydroelectric Resources
- Transmission Opportunities

The status and impact of each these resource management issues determines how they are addressed in the planning process. Some are addressed directly through scenario planning. Others are identified as future action plan items or as part of ongoing activities.

1992 National Energy Policy Act

In October 1992, energy bill HR 776 became the first major energy legislation in fifteen years to become law. While the Energy Act covers specific subjects ranging from energy-efficiency to nuclear plant licensing, major objectives are to promote:

- Competition in power generation: The goal is to make bulk power supply markets more competitive.
- Alternative fuels and fuel sources: Supports the advancement of fuel cells, renewable resources, nuclear power, clean-coal technology and electric vehicles.
- Energy efficiency and conservation. The goal is to increase efficiency in the end use of electricity.
- Environmental protection. Enhances protection of the environment by supporting integrated resource planning, renewable resources, alternative fuels and energy efficiency.

To fully understand potential impacts, a complete review of the Energy Act is required. Based on a cursory review, WWP will closely monitor developments in the following areas:

Alternate Fuel Vehicles	A proportion of new fleet vehicles will require alternative fuel capability. Of 1999 model year vehicles, 90% will require alternate fuel capability. Tax rebates for electric cars could increase electric load. Rebates of up to $2,000 are available for individuals; businesses get a $100,000 incentive to install battery recharging stations.
Exempt Wholesale Generators	A new class of independent power plant, that would be exempted from PUCHA regulation and PURPA restrictions, is created.
Transmission Access	FERC is provided with broader authority to order transmission access and to set transmission wheeling rates.
Integrated Resource Planning	Current Northwest practices for integrated resource planning are basically reinforced. States are asked to give incentives for conservation resource acquisition. Energy-efficiency standards are outlined. A least-cost energy strategy for the federal government will be developed. National targets for energy efficiency, renewable resources and oil consumption are outlined.
Resource Development	Clean-coal technologies are supported. Renewable energy development is supported through federal incentives and permanent tax credits. Certain renewable energy sources could receive a federal payment of 1.5 ¢/kWh. The development of new hydroelectric resources faces higher regulatory and economic barriers.

As the implementation of the Energy Act unfolds, future planning activities will address those issues that specifically affect WWP's ability to manage existing and future resources.

Source: Doug Young, WWP Power Resources, January 1993

Transmission Access

One of the most controversial aspects of the National Energy Act gives the Federal Energy Regulatory Commission (FERC) the authority to order a transmitting utility to provide transmission access (wheeling) to another utility, independent power producer or PURPA qualifying facility when such transmission access is determined by the FERC to be in the public interest. The transmitting utility may be required by the FERC to expand the capacity of its transmission system to accommodate a request for transmission access.

WWP doesn't expect the transmission access provisions of HR776 to have any immediate adverse impact on the company for the following reasons:

- WWP has received no formal requests for long-term firm wheeling service in the past three years.
- The Bonneville Power Administration (BPA) owns the majority of the bulk power transmission lines in the Pacific Northwest. BPA has operated its system on an open access basis for many years. As a result, BPA provides most new transmission service. Rather than deny transmission access, WWP often competes with BPA to provide wheeling services.
- Although WWP has three full requirements wholesale for resale utility customers (Modern Electric, Village of Plummer, City of Chewelah), WWP would not be adversely affected financially by lost revenue or stranded investment if these customers chose to buy power from BPA. Modern Electric and City of Chewelah requested a BPA Sales Contract prior to the passage of HR776.

Although WWP expects no immediate impacts from the transmission access legislation, the company is participating in the formation of a regional transmission group (RTG). The RTG will allow utilities to address transmission access issues through coordinated transmission planning, dispute resolution mechanisms, and data collection activities. The RTG may provide a local alternative to the FERC should transmission access disputes arise.

Source: Steve Fisher, WWP Power Resources, January 1993

Clean Air Act Amendments of 1990

Legislation passed in 1990 included substantial amendments to the federal Clean Air Act. Title IV of the 1990 Clean Air Act Amendments (CAAA) deals with Acid Deposition Control. It will have major impacts on utilities who rely on coal-fired generation. Goals to significantly reduce emissions of sulphur dioxide (SO_2) and nitrous oxide (NOx) will occur in two phases. Phase I affects 110 plants nationwide. Phase II affects over 2000 sources, including the Centralia coal-fired plant of which the company is part owner. The following report describes the potential impacts of the CAAA on WWP.

Impacts of the 1990 Clean Air Act Amendments on WWP

Prepared by Doug Pottratz, WWP Licensing and Environmental Affairs, December 1992

The primary impact of the 1990 Clean Air Act Amendments on WWP will be the company's share of the costs of removing or reducing sulfur dioxide (SO_2) from the Centralia coal-fired generating station. Pacificorp is the operator and largest percent owner of the plant. WWP owns 15 percent. There are a total of eight utilities that make up the plant owners.

Centralia

Centralia is a "Phase II" plant that will be required to meet a 1.2 lb SO_2 per mmbtu emission standard by the year 2000. This means a reduction of SO_2 of approximately 30 percent over current emission rates or sufficient allowances to operate at its current rate. There are several ways in which compliance with this standard could be met. Some of these methods include conventional scrubbing, lower-sulfur coal, clean-coal technology, reduction in output, reduction in the capacity factor and the purchase of SO_2 allowances. Conventional scrubbing costs are estimated to be between $600 - $800 million dollars. The most likely scenarios in meeting the standard will be some combination of lower-sulfur coal, SO_2 reduction through clean coal-technology, the use of natural gas and SO_2 allowances either purchased or pooled among owners. Costs are being developed for these scenarios at this time.

Phase I compliance strategies are developing at a very rapid pace and will have a significant impact on how Phase II plants will achieve cost-effective compliance. The Centralia owners recognize the need to be involved in acid rain decision-making now. A committee has been established to begin making decisions now on how compliance with acid rain regulations will be achieved for the Centralia plant by the year 2000.

The National Park Service (NPS) in October 1990 completed its study of the impact of Centralia on visibility in the Northwest's national parks. Results of the study, entitled *PREVENT*, were presented by the NPS at the annual meeting of the Air & Waste Management Pacific Northwest International Section in Bellevue, Washington, in November 1992. Based on chemical fingerprinting, the NPS estimated that Centralia may have a 13 percent visual reduction impact on Mount Rainier. However, the study had no visibility measurements to correlate with this determination. Given the fact that local federal land managers were faced with more obvious and documented visibility concerns from urban pollution and slash burning, no further action on Centralia is likely. There is a general feeling that compliance with the Clean Air Act Amendments will address some of the public's concerns about visibility as a result of reduced SO_2 emissions.

Colstrip

WWP is a 15 percent owner in Colstrip units No.3 and No.4 in Montana. Both Colstrip units will have sufficient SO_2 allowances to operate.

Reduction in NOx emissions will be required by both the Centralia and Colstrip plants prior to the year 2000. The technology used to meet the new NOx emission standards will be burner design. Costs will run approximately $15 per KW or $10 million dollars for each of the two units at both plants. At 15 percent ownership, WWP's share of this cost would be approximately $6,000,000 for both plants.

The CAAA establishes a new operating permit program that will assess a permit fee of at least $25 for each regulated pollutant up to a maximum of 4000 tons for each pollutant. This translates into combined annual permit fees for the owners of approximately $800,000 for the Centralia plant and units No.3 and No.4 at Colstrip. WWP's share of this would be approximately $120,000. Washington state air pollution agencies are also assessing a fee based on emissions. This will affect both the Centralia and the Kettle Falls plants.

The impact of air toxics on coal-fired thermal generation sources is uncertain at this time. EPA will present a report to Congress next year on results of a study of hazardous air pollutants from coal plants.

Creston Generating Station (Proposed)

The Creston coal-fired project was terminated on Nov. 6, 1992. The reason for this decision was based on a region-wide opinion that a large coal-fired project no longer appeared to have substantial continued value as an energy option.

Kettle Falls Generating Station

The Kettle Falls wood-fired generating station was listed in the proposed Dec. 3, 1991, Federal Register as an affected unit under the acid deposition regulations. It was listed because the unit is a utility unit, is greater than 25 MW, and has the capability of burning fossil fuel (natural gas). Natural gas is currently used, however, only in plant start-up and shut-down. The Kettle Falls plant was issued 92 SO_2 allowances by EPA in 1992. The number of allowances are sufficient to allow the plant to operate 100 percent on natural gas, if this should ever occur.

The state of Washington is currently involved in reviewing new air operating permit rules and evaluating more stringent emission standards. The existing emission control system at the Kettle Falls plant may be adequate enough to meet any new state-wide particulate emission standard. Current actual particulate emissions are 10 times less than the existing allowable (permit) emission limits. Permit fees will run approximately $10,000. It does not appear at this time that the new state air toxics regulation will affect the Kettle Falls plant.

Proposed National Energy Tax

In February 1993, President Bill Clinton proposed a national energy tax as a means of reducing the federal deficit. The proposed broad-based energy tax is expected to curb U.S. oil imports by some 350,000 barrels per day by the year 2000, but not hinder the domestic production of fossil fuels and other energy sources. The proposed plan would impose a tax based on the heat content of fuels, as measured in British Thermal Units, or BTUs. The tax promotes conservation and is geared toward reducing the consumption of imported oil and fuels with a greater environmental impact, such as coal. The "BTU tax" would be phased in over three years, beginning on July 1, 1994.

For WWP, the proposed energy tax would mean increases in the cost of natural gas, coal, and hydroelectric generation. Although it is too early to predict the specific impact, these additional production costs would lead to some increase in the retail price of natural gas and electricity.

Source: Pat Lynch, WWP Corporate Communications, February 1993

Endangered Species Act

Actions to save the Snake River salmon, as well as any future ESA activity, could affect the company's hydroelectric resources. While these ESA impacts are largely unknown, the company will continue to monitor and participate in all regional ESA activities. Efforts will focus on meeting fish and wildlife needs, while minimizing generation and economic impacts.

Snake River Salmon

In 1990, five salmon runs located within the Snake and Columbia river basins were petitioned for protection under the Endangered Species Act (ESA). These actions resulted in the listing of the Snake River sockeye as "endangered" and the Snake River spring/summer chinook as "threatened."

In response to these actions, the Northwest Power Planning Council, initiated a four-part process to amend its Columbia River Basin Fish and Wildlife Program. This process was to provide the National Marine Fishery Service (NMFS) with a comprehensive regional recovery plan for the listed Snake River salmon and to provide protection for other threatened Pacific Northwest fish runs.

Thus far, measures which have been adopted and implemented through the Planning Council's amendment process have not directly affected generation levels at WWP-owned-and-operated hydroelectric facilities. However, generation levels at each of the four Mid-Columbia projects, from which the company receives power under long-term purchase agreements, are being affected. The size of this current impact is less than one percent of the company's total hydro generating capability.

A long-term recovery plan for the Snake River salmon is scheduled for completion by late 1993. The results of the recovery plan will determine the nature of any further impacts to WWP's hydroelectric capability.

Kootenai River White Sturgeon

In June 1992, the Kootenai River white sturgeon was petitioned for protection under the ESA. The U.S. Fish and Wildlife Service (USFWS) has stated that there is sufficient biological evidence to continue the listing process. In an attempt to remove the sturgeon from further ESA review, the Idaho Department of Fish and Game is leading the development of a pre-listing "conservation plan" for the Kootenai River sturgeon.

Bull Trout

In October 1992, the bull trout was petitioned for listing under the ESA. The petition cites over 30 streams located in the western U.S. and Canada that are currently experiencing declining bull trout populations. The USFWS has until early February 1993 to make a determination whether the information contained within the petition warrants further action or review under the ESA.

Source: Steve Kern, WWP Power Resources, January 1993

Hydroelectric Plant Relicensing

WWP is now planning for the successful relicensing of its existing hydroelectric generating facilities. Over the next 10 to 15 years, the company will be involved in efforts to relicense facilities on the Spokane and Clark Fork rivers.

WWP Facilities	Location	Peak Capability	FERC Expiration
Cabinet Gorge	Clark Fork River, Northern Idaho	230 MW	2001
Noxon Rapids	Clark Fork River, Northwestern Montana	555 MW	2005
Spokane River Plants: Post Falls Upper Falls Monroe Street Nine Mile Falls Long Lake	Spokane River, Northern Idaho and Eastern Washington	132 MW	2007

As a result of the Electric Consumers Protection Act of 1986, the FERC must give equal consideration to energy conservation, fish and wildlife protection, the enhancement and preservation of recreational opportunities, and other aspects of environmental quality. WWP's relicensing activities will focus on balancing environmental concerns with the need to preserve resource capabilities. As described in the following consultant report, preliminary investigations indicate that mitigative measures which become a condition of the FERC license could result in a loss of both generating capability and operational flexibility.

Lost Generation: Data developed by the Electric Power Research Institute (EPRI) in a study of licenses through 1989 shows an average generation loss of 8 percent. Unpublished data since 1989 indicates the 8 percent figure will only go higher.

Lost Flexibility: Required operational changes may have dramatic impact on hydro peaking capability. EPRI study results indicate that projects with the ability to deliver peak power lost, on average, 7 percent of that ability.

WWP's relicensing activities will attempt to mitigate these potential losses of generating capability and flexibility. At the same time, the company will look to comply with FERC requirements for maximizing the efficiency of each facility. These efforts could determine a need to schedule hydroelectric plant improvements ahead of the company's overall requirements for new resources.

Even though WWP's first major FERC license does not expire until the year 2001, the company has already begun its relicensing planning efforts, including environmental impact assessments, agency consultation and public involvement. Completion of these activities are expected to culminate in the successful relicensing of WWP's valuable hydroelectric resources. (Note: WWP is currently in a relicensing process for its 1.2 MW Meyers Falls plant on the Colville River. A new license for this small project is expected by mid-1993).

Source: Dan Pfeiffer, WWP Licensing and Environmental Affairs, January 1993

Competitive Bidding

Competitive bidding is one of the ways that WWP can evaluate potential resources. Completed under the WUTC bidding rule, the 1991 Request for Proposal (RFP) was the company's first competitive bidding experience. This first process provided the company with:

- Some knowledge of the cost and availability of new generating resources.
- Experience with treating environmental externalities.

WWP's 1991 RFP also provided some insight into potential improvements to the bidding process. Suggested improvements to the WUTC competitive bidding process include:

- Eliminate the requirement to include a price ceiling. This would promote the true market pricing of proposed resource developments or programs.
- Allow some utility flexibility to negotiate the bid price of resource proposals. This would allow the utility to pursue the best resources at the lowest cost.
- Allow separate evaluation procedures for demand-side and supply-side resources. Final evaluation would compare all proposals, but separate criteria would address the nature of the different resource types.
- Eliminate the requirement for utilities to issue an RFP on a strict two-year schedule. RFP's should coincide with the utility's need for resources.

Under the current WUTC rule, WWP's next RFP is scheduled for 1993. Bid resources would need to compete with resource the company intends to add to meet future needs. Under WWP's preferred resource strategy, these resources include demand-side resources and hydroelectric plant upgrades. Assuming the company proceeds on schedule, an RFP would be issued in September 1993. There is no competitive bidding process in the state of Idaho.

Source: Robert Pierce, WWP Power Resources, February 1993

PURPA

The Public Utilities Regulatory Policies Act (PURPA) of 1978 requires utilities to purchase power from cogeneration and small power production facilities which qualify under PURPA rules. These facilities are commonly known as qualifying facilities or QFs. Implementation of the PURPA legislation, including the price to be paid a prospective QF developer, is different for each of WWP's two state jurisdictions.

State	Project Size	PURPA Obligation	Purchase Price
Washington	< 1 MW	Yes	Washington avoided cost rates as determined for the WUTC competitive bidding process (RFP).
	> 1 MW	Requirements are satisfied under the WUTC competitive bidding process.	The Washington avoided cost rates as filed with the RFP represent the price ceiling used for project evaluation.
Idaho	< 10 MW	Yes	Idaho avoided cost rates as determined by an IPUC methodology.
	> 10 MW	Yes There is no competitive bidding process in the state of Idaho.	Subject to special hearing before the IPUC.

As shown below, WWP has existing contracts with several independent power producers and QFs. A contract with a northeast Washington wood-waste cogeneration facility expires in May of 1994. Any extension of this contract will depend upon the cost of the resource compared with available WWP alternatives.

Type	Project*	State	Peak Capability	Expiration
Hydroelectric	Upriver Power	Washington	6,000 kW	2004
	Big Sheep Creek	Washington	1,000 kW	2021
	Jim Ford Creek	Washington	100 kW	2022
	John Day Creek	Washington	100 kW	2022
Thermal	Wood Power	Idaho	6,000 kW	2019
	Vaagen Brothers	Washington	4,000 kW	1994
	Potlatch Corporation	Idaho	59,000 kW	2001

* Excludes projects which deliver less than 500 MWh per year.

There is currently no new QF activity in WWP's Washington service area. In Idaho, active discussions are limited to the potential development of a small QF (300 kW) to be located in northern Idaho.

Source(s): Dennis Vermillion & Sandee Warne, WWP Power Resources, January 1993

Avoided Cost

In general, the avoided cost is meant to represent the incremental cost of new electric resources available to the utility. Avoided cost rates reflect the price of power from the avoided resource or resource mix. These rates are often applied to the purchase of energy from PURPA qualifying facilities. In some cases the avoided cost is used to determine the cost-effectiveness of potential resource alternatives.

Currently, WWP calculates a separate avoided cost for its Washington and Idaho jurisdictions. In Washington the avoided cost is filed as part of the competitive bidding process. The Idaho avoided cost is calculated and updated according to IPUC regulation. Because of the different methodologies, current Idaho avoided cost rates are somewhat higher than the Washington rates.

Based on the recent energy forecast and the availability of economic resource alternatives, WWP's deficit period has been delayed. This result combined with resource cost information gained from the 1991 bidding process will be incorporated into revised avoided costs for the company. The new avoided cost rates will reflect the company's current energy surplus and the market price of available new resources. Initial investigations based on these factors indicate that the current rates will be reduced.

Avoided costs are one indicator of the incremental cost of new resources. WWP's strategic resource planning model (SRPM) produces another type of indicator. The SRPM calculates the incremental cost of new resources weighted by resource type for potential resource strategies. Unlike the avoided costs based on a surrogate resource, the SRPM calculates a rate based on actual resources selected to meet projected load. For WWP's preferred strategy for meeting medium load growth, SRPM calculates a 20-year levelized resource cost of approximately 3.4 ¢/kWh.

The company intends to file new Washington and Idaho avoided cost rates by mid-1993. For the state of Washington (pursuant to WAC 480-107-050), the new avoided cost rates will be based on a combined-cycle combustion turbine when firm energy resources are needed and nonfirm rates until the company's near-term surplus is exhausted. The assumptions used in calculating the avoided cost schedule are consistent with the sample calculation for a combined-cycle combustion turbine found in Appendix F. Based on preliminary calculations and SRPM results, 20-year levelized rates are expected to fall somewhere between 3.4 ¢/kWh to the current Washington rate of 4.6 ¢/kWh[1].

Source: Dennis Vermillion, WWP Power Resources, January 1993

1 1992 levelized rate based on an annual discount rate of 8.97%.

Demand-Side Resource Acquisition

WWP's preferred long-term energy strategy calls for the acquisition of approximately 136 aMW of demand-side resources. Over half of the company's new resource requirements will come from conservation and fuel efficiency programs Careful management of these programs is expected to result in the acquisition of cost-effective and environmentally benign energy supplies.

The pursuit of demand-side resources presents some special challenges to all utilities. Through its DSM Issues Group (DIG), WWP is working now with state regulators and other interested parties to address important topics such as:

- Resource evaluation and measurement.
- Program review and modification.
- Utility financial incentives.
- Resource cost-effectiveness.
- Low-income programs.
- Continued resource assessment.

To ensure these issues are addressed in a timely manner, WWP and the DIG participants have agreed to complete their efforts by March of 1994. Significant progress has already been made in many of these areas.

The company recently completed its 1993 Demand Side Management Measurement and Evaluation Plan. This plan outlines the comprehensive evaluation of eight WWP electric and gas programs.

WWP's concern for resource efficiency is applied to the design and delivery of the company's demand-side programs. Ongoing program review identifies the need for any modifications that will reduce costs, improve customer satisfaction and eliminate market barriers. Several program adjustments have been identified.

A total resource cost methodology is being developed as part of the DIG process. This methodology ensures that the total price paid for the demand-side resource is less than or equal to the cost of alternative resources.

A primary challenge for WWP, and its DIG advisors, will be continual management of the company's demand-side programs. Adjusting programs to match demand-side acquisitions to resource needs will be an ongoing process.

The pursuit of cost-effective demand-side resources can provide benefits to the utility and its customers. However, along with the benefits of improved end-use efficiency comes a reduction in utility electric revenues which cover utility fixed costs. The company's Energy Exchanger fuel efficiency program requires that participants make a monthly payment to WWP for a 60 month period. These payments are designed to to help WWP recover this lost margin. For other WWP programs, the lost margin is deferred for later recovery.

As part of DIG process, the involved parties are working together to determine financial incentives that will encourage the utility to make the acquisition of cost-effective demand-side resources an even higher priority.

Source: Tom Dukich & Kelly Norwood, WWP Rates and Tariff Administration, February 1993

THE DEMAND-SIDE MANAGEMENT ISSUES GROUP (DIG)
FOR THE WASHINGTON WATER POWER COMPANY

PURPOSE AND GUIDELINES
Adopted April 1, 1993

BACKGROUND

The Demand Side Management Issues Group (DIG) is the result of filings by the Washington Water Power Company (WWP) to implement gas and electric demand side management programs, along with corresponding accounting treatment in the states of Idaho and Washington. During the course of these proceedings, WWP and other parties suggested that the discussion of certain related issues be delayed and more thoroughly examined by a "DSM issues group." This suggestion was incorporated into both the WUTC and the IPUC orders issued on April 30, 1992 and July 16, 1992, respectively. The orders directed WWP to facilitate the formulation and operation of the DIG and to provide periodic update reports to the respective commissions.

PURPOSE

As ordered by both the WUTC and the IPUC and as earlier agreed to by WWP and other parties, the "DSM Issues Group" (DIG) will address, but not be limited to, the following issues (not necessarily in order of priority or importance):

- DSM program evaluation and measurement of savings.
- Needed modifications and/or mid-course program corrections.
- Cost-effectiveness methods and criteria.
- Updating avoided cost especially with regard to gas.
- Appropriateness and level of incentive for DSM.
- Lost and found margins as a result of DSM.
- Issues related to low income participation.
- Amortization periods for various measures and programs.
- The interaction of these programs and gas main extension policies.
- The appropriateness of decoupling for WWP.
- A revised or new DSM assessment.

Discussion will have the goal of reaching a consensus on issues. However, the parties agree that any consensus is not meant to be a substitute for the judgment of the respective commissions. In addition, any consensus will have a well documented and understood basis and will not simply be a "black box" settlement.

MEMBERSHIP

Initial membership was determined by active involvement in WWP's original DSM filings. New members may be added to the extent the DIG views the new member as providing needed representation that is currently lacking on the DIG. Current membership is as follows:

- Washington Water Power Company (WWP)
- Spokane Neighborhood Action Program (SNAP).
- Washington Utilities & Transportation Commission Staff (WUTC)
- Idaho Public Utilities Commission Staff (IPUC)
- Washington Attorney General, Public Counsel Section (PC)
- Washington State Energy Office (WSEO)
- Northwest Power Planning Council (NWPPC)
- Washington Industrial Customers for Fair Utility Rates (WICFUR)
- Northwest Conservation Act Coalition (NCAC)

DIG OPERATING PRINCIPLES AND GUIDELINES

To promote open and honest discussion, certain principles and guidelines will be followed:

- All parties agree to negotiate in good faith.
- General DIG meeting notes will be taken, but exact transcriptions and attributions will be avoided.
- A dissenting position by any participant will be specifically noted in the meeting notes.
- No party is bound to follow the majority.
- Positions dissenting from the consensus decision are acceptable as long as that rejection is clearly articulated and noted in the meeting notes or through a letter, memo or other written means.
- On any issue, all parties reserve the right to take independent positions in formal regulatory proceedings as long as that intent is made very clear at the time the issue is being discussed by the DIG.
- Any dissenting member has the obligation to make their position clear to all members of the DIG.
- Except by group agreement, all comments are considered confidential and given in the spirit of negotiation.
- All members are obligated to reveal conflicts of interest or the appearance of conflict of interest as this notion is generally understood, with further participation determined by the DIG membership.
- All parties have an equal say in discussions, and the goal of all discussions is consensus, but the responsibility for decisions is ultimately borne by WWP.
- Members commit to be actively involved as evidenced by consistent attendance, doing their "homework", voluntarily offering rather than withholding candid opinions at appropriate times, etc.
- Members are spokespersons for their individual organizations and will honestly represent their organizations to the best of their abilities even though they may not be able to formally represent each of their members or sign official documents, e.g., NWPPC and WUTC and IPUC staffs, respectively.
- On certain issues, DIG members may need to consult their respective organizations before committing to an action or position.
- Members are interested in being action oriented rather than engaging in theoretical debates.
- DIG members are committed to developing a sound basis for proposed actions.
- Where appropriate, consultants may be retained by the DIG.
- The DIG will consider providing travel assistance when appropriate.
- The parties agree to make a good faith effort to examine all issues by March of 1994 and, to the extent justified, incorporate findings of the DIG into WWP's probable refilling of its DSM programs in April of 1994 for an effective date of January 1, 1995.
- Periodic updates on the progress of discussions will be provided to both Washington and Idaho Commissioners.

Environmental Externalities

Environmental costs in the utility industry are the economic value of damages to the ecosystem not paid for directly by the utility or the utility's customers. These costs are external to the pricing system. Examples of environmental costs include reduced visibility, adverse human health effects, reduction in crop and timber yields, acidification of lakes and streams, damage to materials and buildings, and reductions in fish and wildlife populations. Environmental cost estimates are subject to more uncertainty than other cost estimates. These costs are typically used during resource selection but are not passed on to customers.

The consideration of environmental impacts has always been a significant element of WWP's resource planning activities. However, environmental assessment which specifically includes the treatment of environmental externalities is a relatively new and complex input to the planning process. In general, the goal of addressing externalities is to more accurately reflect the full cost to society of utility resource decisions.

There is currently no consensus as to the best methodology for treating externalities. Within the utility community, most efforts followed a two-step method that attempts to:

- Quantify any harmful production effects that are not included in the direct costs of producing electricity.
- Apply the cost of these negative externalities to the cost of new resource alternatives.

Application of this method is intended to further balance the societal cost associated with electric power production and the private cost paid by consumers. Beyond the arguments over specific methodologies, there is also disagreement as to whether or not current utility efforts and environmental regulations, such as the 1990 Clean Air Act Amendments, will provide the same benefits.

The current focus on environmental externalities presents additional challenges for WWP in maintaining the delicate balance between economics and the environment. The company's past experience with externalities is primarily the result of WUTC regulations associated with the state's competitive bidding process. This experience is summarized in a WWP report that was prepared for a broader PNUCC Environmental Cost Committee review. The result of this review is a 1993 PNUCC report that summarizes regional utility experience in treating environmental externalities[2].

Environmental costs are being investigated at different levels by various entities. In response to Executive Order 90-06, the Washington State Energy Office (WSEO) has completed some studies of the environmental costs of energy resource development. In 1992, WWP reviewed the WSEO reports listed below.

- WSEO Issue Paper ITF-1; Summary of State Actions to Incorporate Residual Costs Associated with Energy Resource Development
- WSEO Issue Paper ITF-2; Accounting for the Economic Impacts of Energy Resource Development: Issues and Recommendations
- WSEO Issue Paper ITF-3; Appropriate Use of Numeric and Monetary Values for Environmental Impacts of Energy Resource Development and Use Decisions

In its assessment of new demand-side and supply-side resources, WWP has identified a full menu of resource options which can be developed economically and with minimal environmental impact. For new demand-side resources, the company will continue to apply a 10 percent conservation credit as well as recognize their electric system loss savings benefits. For other types of resources, WWP will continue to monitor and participate in state and regional efforts to clarify the externalities issue.

Source: Robert Pierce, WWP Power Resources, January 1993

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[2] PNUCC Report: "Environmental Effect of Resources: The Northwest Experiment,", March 1993

WWP 1991 Request for Proposal:
Environmental Externalities Methodology, Analysis and Results Summary

Prepared by Robert Pierce, WWP Power Resources, for PNUCC Environmental Cost Committee, August 1992

Introduction:

WWP has always made consideration of the environment an important part of resource acquisition and management. The company takes pride in its record of providing low cost supplies of energy while maintaining an exemplary environmental record[3]. The current focus on environmental impacts, specifically on environmental externalities, presents additional challenges for the company in maintaining the delicate balance between economics and the environment. Following is a summary of WWP's recent experience in dealing with environmental externalities.

Background:

WWP's recent experience with environmental externalities is primarily the result of Washington state regulation regarding the purchase of electricity from non-utility suppliers. Guidelines for such purchases, and for development of the associated competitive bidding process, are defined in Washington state regulation WAC 480-107[4]. Under the "bidding rule" the criteria used to rank project proposals must address environmental effects including those associated with resources that emit carbon dioxide.

Method:

In its 1991 Request for Proposals[5] (RFP), WWP described guidelines for evaluating, ranking and selecting resource options offered under the competitive bidding process. These guidelines included a one-time trial mechanism to account for environmental externalities. Under this procedure, externalities are considered by:

- Applying a 10 percent cost credit to conservation resources, and
- Applying an "externality cost adjustment" to the levelized price of each supply option, depending on the resource type:

Resource Type	Externality Adjustment
Conservation	None
Renewable	0.2 ¢/kwh
Cogeneration (Gas-fired)	0.4 ¢/kwh
Stand-Alone (Gas-fired)	0.6 ¢/kwh
Coal	0.8 ¢/kwh

3 WWP is the only company in Washington state to receive four state environmental awards.

4 The purpose of WAC 480-107 is to provide rules for determining rates, terms and conditions governing purchases by electric utilities of non-utility sponsored resources. The intent is to provide an opportunity for conservation and generating resources to compete on a fair and reasonable basis to fulfill a utility's new resource needs.

5 WWP document: "Long-Term Purchase of Resources from Electric Conservation and/or Generating Facilities," dated September 1991.

Analysis:

While the intent of this methodology was primarily to address the impacts associated with different resource options, it also provided developers with information about which types of resources are preferred by the company.

Development of this methodology was qualitative in that no original research was completed by WWP to determine the externality adjustment factors listed above. However, the methodology is based on a review of a number of qualitative studies completed by other entities, including BPA and Pace University[6]. By virtue of the fact that much of the available analysis regarding environmental externalities has focused on emissions, WWP's methodology also reflects the relative impacts of air polluting resources. The 10 percent cost credit allowed conservation resources is consistent with the methodology recommended by the 1980 Northwest Power Planning Act.

Application:

Externalities represent one of the many inputs that WWP considers in evaluating potential supplies of electricity. Other environmental effects of resource development, such as land and water use requirements, are considered in the evaluation of individual resources. However, these effects are included as part of the overall environmental review of each potential project and not specifically as part of the externalities evaluation. System considerations, such as the reliability and flexibility of a resource and the potential impact to the integrating transmission network, are also evaluated, but once again separately from externalities.

In the 1991 RFP evaluation process, WWP did not attempt to quantify any positive externalities in terms of a positive price adjustment factor. This is not to say that potential project benefits were not considered in the scoring and ranking process. WWP's methodology also did not apply any types of weighting to distinguish between project locations. For example, the externality adjustment for a gas-fired plant located in Nevada is the same as for a similar plant located in Washington state.

<u>Results</u>:

WWP completed its 1991 RFP process in August of 1992[7]. Project scoring, based on the RFP criteria, was used to rank and select resource alternatives. In addition to this scoring, the above method to account for environmental externalities was applied. As a result of this analysis, WWP found that the inclusion of externalities had some impact on individual project scores, but did not change the overall ranking of resources. In other words, WWP's ranking of projects based on pricing and other factors also resulted in an environmental ranking, even without consideration of environmental externalities.

6 Pace University study: "Environmental Costs of Electricity", dated 1990.

7 Results of WWP's 1991 RFP were presented to the Washington Utilities and Transportation Commission (WUTC) on August 12, 1992.

Global Warming

As defined by the 1991 Clean Air Act, all U.S. industries must comply with national efforts to reduce emissions of certain pollutants. While the Clean Air Act identifies acceptable limits for emissions of sulphur dioxide (SO_2) and nitrous oxide (NOx), the environmental impact of other air pollutants, such as carbon dioxide (C02), are still being investigated

Efforts to determine the effects of carbon dioxide on the global climate are being studied in many international arenas. At the federal level, consideration has been given to assessing a tax on CO_2 emissions. Regional utility efforts to examine a "carbon tax" have found that even modest tax on carbon dioxide could overwhelm the effects of all other externalities. The result could have significant impact on the selection of new resources.

For purposes of this plan, WWP's scenario analysis also investigates the potential effect of a carbon tax. Until this controversial issue is scientifically resolved, quantifying the environmental impact of CO_2 emissions will continue to be difficult.

Source: Doug Young, WWP Power Resources, January 1993

Electric and Magnetic Fields (EMF)

The issue of whether exposure to power-frequency electric and magnetic fields (EMFs) could result in adverse health effects has received considerable attention. These fields are present virtually everywhere in our society, since they are associated with the operation of electrical transmission and distribution facilities, as well as with the use of home and office appliances.

The issue of potential health effects resulting from EMFs is one of where public concern exceeds scientific evidence available to date. The concern is often at variance with the consensus of the scientific community. This controversial issue has been reviewed by over 20 major scientific groups since 1975, with several major evaluations (in the U.S. and abroad) completed and released in 1992. The available research does not demonstrate that a hazard to human health exists from exposure to these fields.

WWP recognizes its public obligation to become openly and actively involved in this issue. The company's activities include:

- Support of independent scientific research.
- Monitoring of scientific and regulatory developments.
- Using the resources of its EMF task force for the collection and distribution of comprehensive and up-to-date information.
- Developing responsible policies related to this issue.

As one example of these activities, WWP's EMF task force, with the assistance of scientific consultants, provides annual updates to the City of Spokane on the state-of-the-art of scientific research relevant to the EMF issue.

Source: Larry LaBolle, WWP Licensing and Environmental Affairs, March 1993

Regional Power Supplies

In early 1993, Portland General Electric (PGE) decided to permanently close its Trojan Nuclear Plant. Efforts to replace this 1,100 MW of regional power supply could affect both near-term and long-term energy markets. In 1992, WWP entered into an agreement to sell 150 MW of electrical capacity to PGE. Under this long-term agreement, WWP will supply PGE with energy during peak load hours and, in exchange, receive return energy during light load hours.

Operational requirements placed on the federal hydroelectric system to support fish and wildlife recovery may also constrain regional power supplies. Through additional wholesale marketing efforts, WWP may be able to help meet any regional needs for energy and capacity.

Share-the-Shortage Agreement

Regional coordination to meet unexpected power shortages is outlined in the proposed Share-the-Shortage Agreement. This agreement outlines operating procedures, including the allocation of available energy surpluses and load curtailments, which could be implemented in response to regional deficits.

The proposed Share-the-Shortage Agreement would be implemented in three phases, depending upon the severity of the energy deficit.

Phase 1: Any party in a deficit situation would request offers of sale from parties with surplus energy. Parties could then enter into agreements for the sale of such energy on terms mutually agreeable to them.

Phase 2: Each party in a deficit situation would have to take actions that would help meet the load in its service area, including activating voluntary load curtailment programs with its customers and cutting sales to interruptible loads. If, after taking such actions, a party continues to be in a deficit situation, it could request offers of sale as under Phase 1. Parties with surplus energy would be allocated, on a pro rata basis, a portion of each deficit party's shortage. The proposed agreement provides incentives to parties with surplus energy to offer the entire amount of their allocations for sale to parties in a deficit situation. Agreements between parties for the sale of surplus energy will be on terms mutually agreeable to them.

Announcement by the government of the four Northwest states of the need for energy use curtailment of at least 5 percent throughout the region would implement the third phase of the proposed agreement.

Phase 3: Each party, whether it is in a deficit situation or not, would be obligated to take curtailment actions. Parties that continue to be in a deficit situation could request offers of sale from parties with surplus energy. As under Phase 2, parties with surplus energy would be allocated a portion of each deficit party's shortage.

Source: Brent Guyer and Robert Pierce, WWP Power Resources, February 1993

Firming Nonfirm Hydroelectric Energy

WWP's existing hydroelectric facilities provide a significant portion of the company's annual energy requirements. Depending upon streamflow conditions, annual production from these facilities can fluctuate over a wide scale. For planning purposes, the company defines hydroelectric production based on streamflows recorded for a specific four-year period of low-water conditions. This critical period[8] is used to calculate the amount of firm energy production from existing and proposed hydroelectric projects. Generation which exceeds this firm capability is defined as secondary, or nonfirm energy.

The objective of firming non-firm energy is to turn the lesser-valued nonfirm energy into firm energy through a back-up power source. Since the availability of nonfirm hydroelectric energy is contingency upon rainfall, snowpack and the operability of the region's thermal plants, its deliverability cannot be guaranteed without a firm resource as a back-up.

As a hydroelectric based utility, WWP has the opportunity to pursue "firming nonfirm" strategies. In 1992, the company completed a detailed feasibility study. This study assumed 92 aMW of nonfirm energy would be firmed and sold under a long-term contract. Depending upon availability and cost, this contract would be supplied by either existing WWP hydroelectric resources or by the operation of a 100 MW simple-cycle combustion turbine. Results of this analysis indicated that by firming its own hydroelectric resources, the company could potentially realize an economic benefit of approximately $30 million on a net present value basis. Future investigations will provide additional information on the cost and need for this potential resource, as well as the risks associated with its development.

Source: Mike Griswold, WWP Business Analysis, January 1993

Transmission Opportunities

WWP must expand its electric transmission system to maintain reliable service to new and existing customers. Through interconnections with other utilities, WWP may also use transmission facilities to access low-cost resources, new energy markets or both. These interconnections are carefully planned so as to maintain or improve the reliability of the interconnecting utility systems.

WWP's geographic location and existing interconnections allow the company to pursue the purchase and sale of energy on a short-term and long-term basis. Through these types of transactions, WWP can reduce resource costs for the company and for the region. The company has existing transmission interconnections with the following utilities:

- Chelan County PUD
- Grant County PUD
- Bonneville Power Administration
- Montana Power Company
- Idaho Power Company
- Puget Power Company
- Pacificorp

Depending on its cost, a new transmission interconnection may eliminate the need to develop a new generating resource. WWP will continue to evaluate and promote the development of new interconnections that allow for the reliable transfer of low-cost energy supplies. Current activity is summarized below:

[8] The "Critical Period" is currently defined as the 42 month period from September 1928 to February 1932.

WWP-BC Hydro Transmission Interconnection

In October 1987, WWP filed an application with the Department of Energy (Office of Fuels Programs) for a Presidential Permit for a proposed WWP-BC Hydro Transmission Interconnection. The permit is required to construct an international interconnection. Following this application, WWP completed environmental[9] and system reliability studies which address permit requirements. In 1993, the Department of Energy (DOE) issued a Presidential Permit for the proposed interconnection.

The proposed WWP-BC Hydro Interconnection consists of approximately 110 miles of double circuit 230kV transmission line connecting the BC Hydro system in southeastern British Columbia with WWP's system in northeastern Washington. Planned project terminations are BC Hydro's existing Selkirk 500/230kV substation and WWP's existing Beacon 230kV substation. Figure G-1 illustrates the proposed route for the transmission project.

During the Presidential Permit process, WWP reduced the scope of the original interconnection project. Initial project transfer capability was reduced from 1000 MW to 800 MW. The selection of WWP's existing Beacon substation as the preferred Spokane area terminal provides the following project benefits:

- Eliminate the construction of 25 miles of new high-voltage transmission line.
- Delay the need to construct a new Marshall switching station.
- Substantially reduce the capital cost of the project.
- Provide increased flexibility for staged project construction.

If constructed, the WWP-BC Hydro Interconnection would provide additional transmission capability between Canada and the Pacific Northwest. This additional capability would allow WWP and other regional utilities direct access to resources in British Columbia and Alberta.

WWP is continuing to evaluate the need and potential benefits of the proposed Canadian interconnection. Among these benefits are the access to new resources and additional coordination of the Canadian and Northwest reservoir systems. Economic evaluations of the interconnection must consider the impact of the new British Columbia government and its development of an energy export policy. Study results will determine the future of the interconnection project.

Pacific Intertie

In mid-1993, participants in the California-Oregon Transmission Project (COTP) will complete construction of a third 500kV interconnection between the Pacific Northwest and California. This project will increase the north to south transfer capability of the existing Pacific AC Intertie (PACI) from 3200 MW to 4800 MW. WWP's evaluation determined that participation in the COTP project was not a cost-effective option for the company at this time.

To the extent that it is economically available, WWP will pursue opportunities to gain transmission capability on the existing Pacific Intertie.

Other Opportunities

WWP evaluates other interconnection opportunities as they are proposed. As a result of these investigations, the company is currently not participating in the development of any other transmission projects.

Source: Brent Guyer, WWP Power Resources, February 1993

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9 Environmental studies for the proposed WWP-BC Hydro Transmission Interconnection are contained in the Department of Energy's "Final Environmental Impact Statement", published in October 1992.

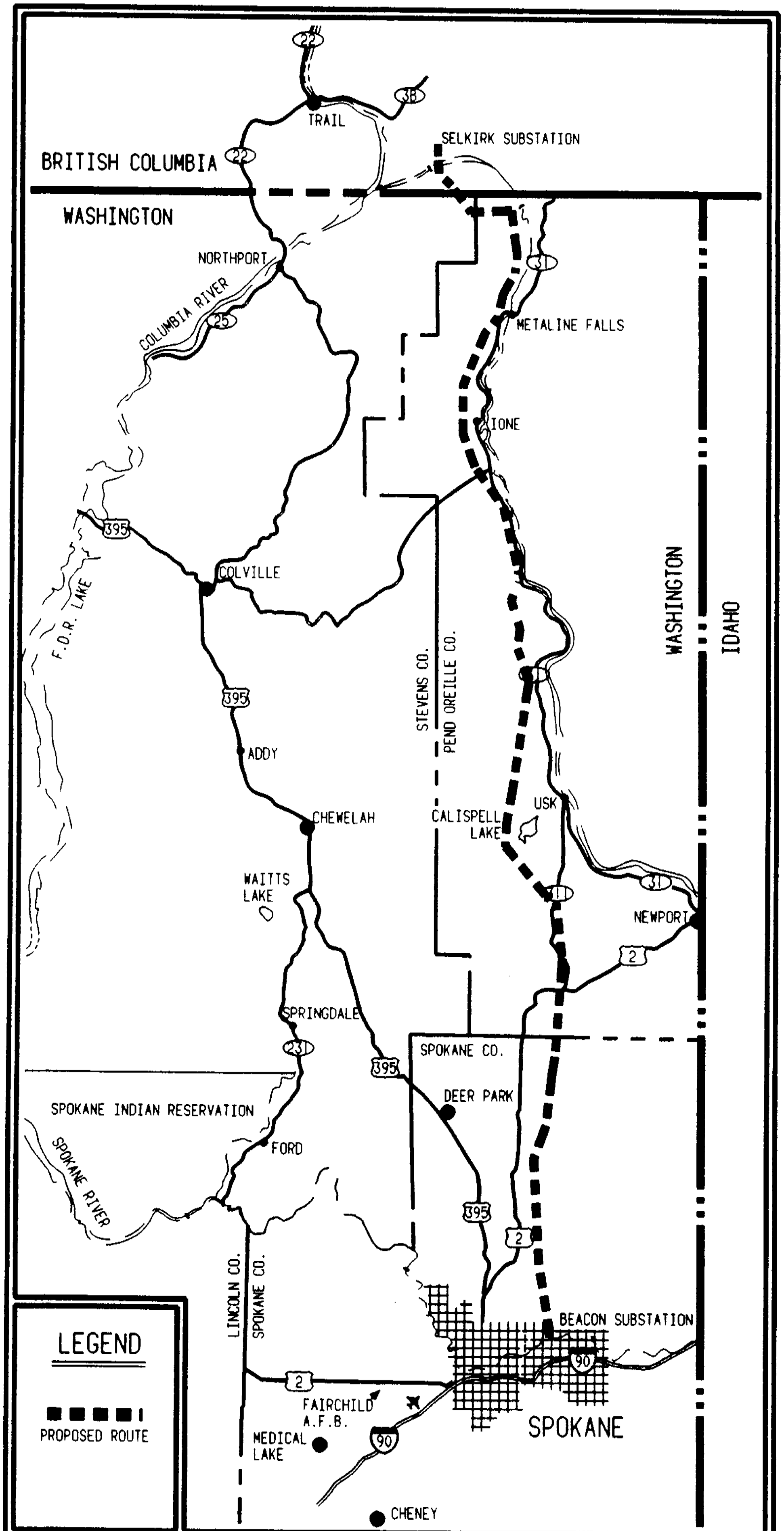


FIGURE G-1: PROPOSED WWP-BC HYDRO TRANSMISSION INTERCONNECTION

Appendix H

Resource Plan Evaluation

Resource Plan Evaluation

This appendix provides additional detail regarding WWP's determination of the low-cost energy plan. It contains the following information:

- A summary of WWP's preferred energy strategy.
- A description of WWP's Strategic Resource Planning Model (SRPM) and its recent enhancements.
- Key inputs, including resource options and their costs, as input into SRPM.
- Inputs and results of WWP's risk and scenario analysis.

Summary

With a relatively modest level of long-term energy needs, and a large menu of cost-effective resource options, the company is currently in a good position to choose the general direction for future resource acquisitions. WWP's preferred energy strategy represents a balance of demand-side and supply-side options that focus on improving the efficiency of the existing resource base.

The company's evaluation of alternative resource plans identified the timing of demand-side resource acquisition as having the primary influence on individual plan performance. Risk analysis results indicate that careful management of WWP's demand-side programs will have a key role in supporting the company's commitment to rate stability. Scenario analysis results reinforce the need to maintain flexibility and diversity within the new resource portfolio and to protect the capability of the existing resource base. Given these results, selection of the company's preferred resource plan was primarily based on the following considerations:

- Revenue Requirements: The preferred strategy is one of the lowest-cost options. It is not the lowest-cost plan. The lowest-cost strategy is one that would require the company to stop and then restart demand-side management activities.
- Demand-side Resource Acquisition: The preferred resource strategy reflects a level of demand-side aquisition that best tracks WWP's resource needs without having to temporarily terminate program activity.
- Risk and Uncertainty: The preferred plan performs reasonably well under all conditions. It provides the necessary flexibility to respond to changing load and resource needs.

Figure H-1 lists the cumulative resource acquisitions as outlined by WWP's preferred strategy.

Figure H-1: WWP's preferred energy resource strategy (cumulative aMW).

Resource Acquisition Activity	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Colstrip Thermal Efficiency (Units No.3 & No.4)	0	0	0	0	0	0	0	0	0	5
Conservation	2	7	14	16	18	19	21	22	24	26
Fuel-Efficiency	5	15	25	29	32	34	36	38	40	42
Planned Hydroelectric Upgrades (Cabinet No.1, Nine Mile & Upper Falls)	0	0	5	8	8	8	8	8	8	8
Clark Fork Hydroelectric Upgrades (Cabinet No.2, Noxon No.3 & No.4)	0	0	0	0	0	0	0	0	0	0
Electric System Efficiency (Transmission & Distribution Loss Savings)	0	0	0	0	0	0	0	0	0	0
Mid-Columbia Extension (Grant County PUD Contract)	0	0	0	0	0	0	0	0	0	0
Total	**7**	**22**	**44**	**53**	**58**	**61**	**65**	**68**	**72**	**81**

Resource Acquisition Activity	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Colstrip Thermal Efficiency (Units No.3 & No.4)	5	5	5	5	5	5	5	5	5	5
Conservation	27	29	30	32	34	37	41	45	50	55
Fuel-Efficiency	44	46	48	50	53	57	62	68	74	81
Planned Hydroelectric Upgrades (Cabinet No.1, Nine Mile & Upper Falls)	8	8	8	8	8	8	8	8	8	8
Clark Fork Hydroelectric Upgrades (Cabinet No.2, Noxon No.3 & No.4)	0	0	0	0	0	3	3	6	6	6
Electric System Efficiency (Transmission & Distribution Loss Savings)	0	0	0	0	0	2	4	6	8	10
Mid-Columbia Extension (Grant County PUD Contract)	0	0	0	10	17	17	17	40	47	47
Total	**84**	**88**	**91**	**105**	**117**	**129**	**140**	**178**	**198**	**212**

The Strategic Resource Planning Model

The Strategic Resource Planning Model (SRPM) is an analytical model used by WWP to facilitate long-term integrated resource planning (IRP). SRPM calculates the economic and financial implications of utility resource acquisition decisions. Using an analytical technique called *Monte Carlo simulation*, SRPM also explicitly accounts for key planning uncertainties, and allows for examination of tradeoffs between expected costs and risk. For any given set of planning assumptions and resource decisions, the model provides outcome indicators such as rates, revenue requirements, new resource costs, plus other key financial indicators. SRPM effectively addresses the following objectives:

- Accommodates the full range of potential supply- and demand-side resources;
- Allows explicit treatment of key sources of planning uncertainties and risks;
- Combines the benefits of simulation and optimization modeling approaches;
- Accommodates scenario analysis and risk assessment;
- Captures sufficient operational detail to result in realistic resource operation and system expansion decisions;
- Provides sufficient output detail to capture tradeoffs among key planning criteria; and
- Accomplishes these objectives with a software package that is well documented, user-friendly and easy for WWP to maintain and/or enhance.

Figure H-2 illustrates the basic structure of the SRPM. A preliminary resource balance is derived based on existing demand forecasts and information on resource costs and availability. A detailed description of existing generation, purchase contracts, and in-place DSM is provided by the user, prompted by a menu system. The existing demand and energy use profiles are input, and a future demand growth rate is estimated in terms of average escalation rates or discrete annual values. The capital requirements, O&M costs and energy/capacity profiles of planned and discretionary resources are entered into the SRPM screens. Nonfirm power costs are included to allow for planning flexibility. Any exogenous factors, such as imposition of a carbon tax, are also represented at this stage of the analysis.

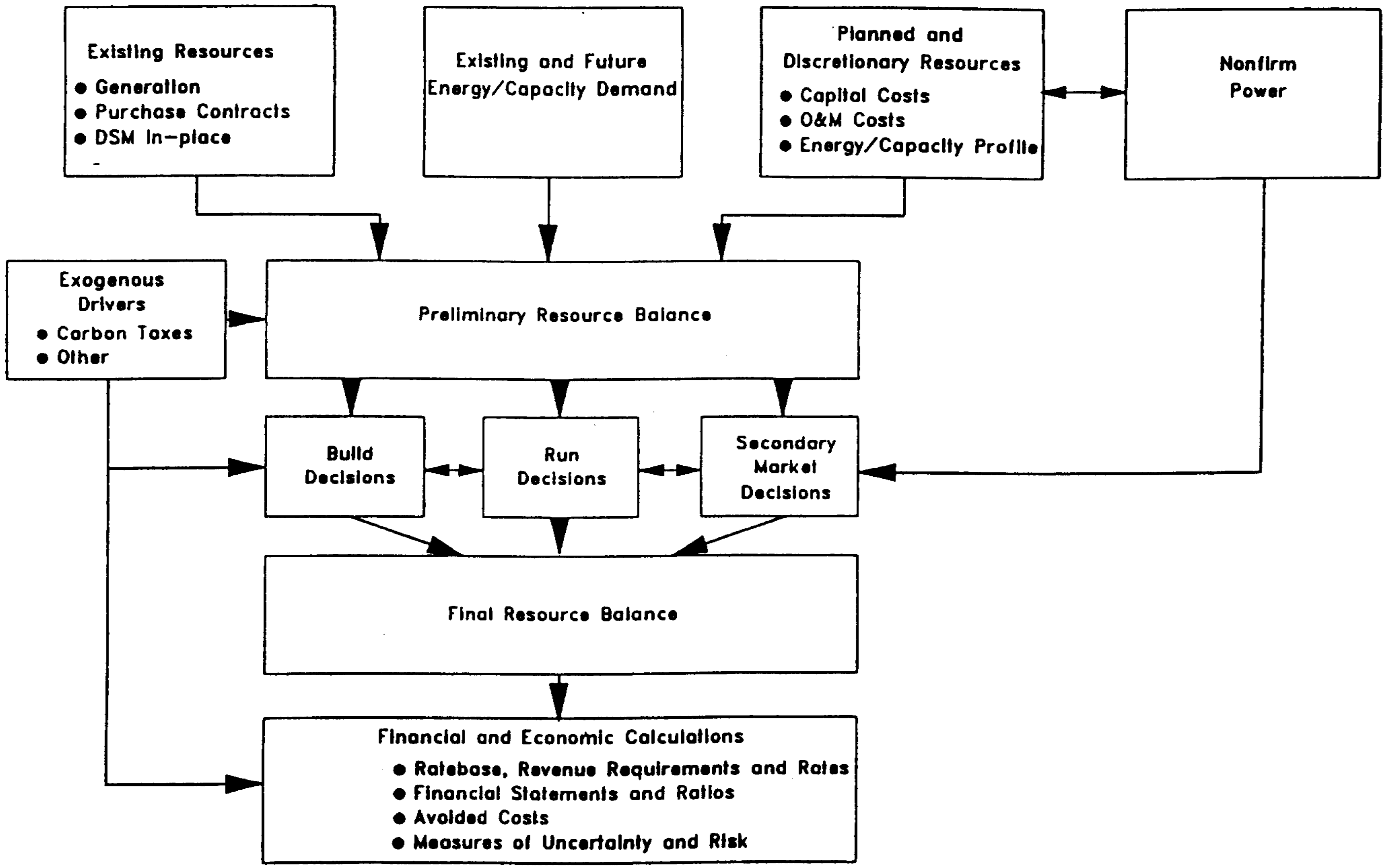
SRPM proceeds through operating, new construction and secondary market power purchasing decisions. A final resource balance is determined, comprised of the supply-side and demand-side resources that will meet projected loads. These resources have either been *specified* by the user as an intended resource plan or *selected* by the model as a result of user input evaluation, depending on whether or not they are discretionary or non-discretionary in nature. The rate base, revenue requirements, rates, new resource costs and other pertinent implications of this resource plan are calculated in the financial/economic module. A tabular and graphical profile of critical indicators of the final plan and its economic and financial implications is produced as model output. SRPM allows the user to input a wide range of financial and technical characteristics of the utility and the power resources. SRPM is menu-driven and is based on Microsoft Excel 4.0 running in the Windows environment on IBM compatible computers.

SRPM's Monte Carlo simulation module allows key assumptions such as fuel costs, load growth and interest rates to be treated as uncertain variables. The module allows potential discrete events, such as the imposition of a carbon tax, to be explicitly represented. When used in this mode, the model draws inputs from user-specified probability distributions for each input specified as such[1]. The model then stores the results of multiple iterations and conveys key outputs as probability distributions with specific means, shapes and standard deviations. Resource plans can in this manner be examined in terms of the potential variability of long-term outcomes; conclusions can be drawn about the risks associated with these uncertainties. Correlations between input assumptions can also be specified. For example, annual non-production O&M costs are currently linked to sales so that higher load scenarios result in higher non-production costs based on observed statistical relationships.

1 Latin Hypercube sampling partitions probability distributions so that "convergence" can be obtained with fewer iterations of the model. Convergence is defined as the point where the observed means equal the *a priori* expected values for a given distribution.

Figure H-2:

SRP Flow and Logic



Key SRPM Features

SRPM simulates the energy and financial operations on an annual basis. A series of user controlled input screens accept data on existing and future generation, demand-side management, and purchase resource options, utility system and financial data, base case assumptions, and the mix of resources (generation, power purchases, and DSM) to be used for meeting loads.

Existing and potential new generation resources are described in terms of their financial characteristics, operations and maintenance (O&M) costs, and expected operational profile. These resources can be represented in "must-run" mode; or can be scheduled by SRPM on the basis of variable costs and secondary energy prices, as described in more detail below. Purchases can be short- or long-term, and are described with planned capacity and energy quantities, as well as the expected prices associated with each.

Demand-side resources can be addressed in a variety of ways. One option is to define supply curves, where the resource *cost* is determined as a function of the cumulative quantity obtained at any given point on the planning horizon. The user can specify individual measures, single programs, or aggregate groups of DSM programs and/or purchases. DSM resources can also be modeled as discrete additions: such additions can be capitalized in the same manner as a utility power plant, or expensed like a power purchase.

SRPM is not primarily intended to be an optimization model. The purpose of the model is to examine the implications of selecting a specific resource mix under varying conditions. SRPM will, however, endogenously perform economically rational resource scheduling. As described below, SRPM will build the minimum cost discretionary resource when planned load exceeds planned resources by a user-defined threshold; and will operate plants in accordance with available resources, minimum-run constraints, maximum availability factors, variable costs, and the price of secondary energy.

Thus, SRPM combines elements of both *simulation* and *optimization* resource planning models. Simulation models illustrate the consequences or implications of a set of decisions given assumptions about future trends and events. Optimization models choose a set of decisions that maximize or minimize a given objective function given a similar set of assumptions. Because both approaches have advantages and drawbacks, resource planning is best served by a model that performs both functions. Since the distinction between the approaches is important, both approached are briefly discussed.

An IRP simulation model requires the user to specify a set of supply- and demand-side resources to meet projected demand growth. The benefit of such an approach is that explicit judgments about resource mix and quantity are required. Different choices can be tested, and their implications can be clearly seen. Unlike optimization models, where the choices depend on a single *objective function* (such as the present value of revenue requirements), it is possible to examine tradeoffs, such as those between rate impacts and revenue requirements.

A second benefit is the ability to address uncertainty in a simulation model in a relatively simple and straightforward manner. The Monte Carlo simulation capabilities of SRPM allow for examination of tradeoffs between expected costs and reliability risks for key resource choices. For example, this modeling approach allows for *cumulative probability curves* that illustrate price-risk tradeoffs between relying on relatively low capital cost gas-fired combined cycle plants and higher capital cost coal technologies with lower potential fuel price variability.

The biggest drawback to simulation models is that the way resource options are specified can be somewhat arbitrary. There is no guarantee of testing the optimal set for a given set of assumptions, and the mix of resources will not necessarily change when other input assumptions are changed. An optimization model will choose a set of resources that provide the best objective function, given the input assumptions that are specified. This approach accomodates the possibility of advantageous resource combinations that are not necessarily obvious on the basis of common sense and informed judgment.

In view of the importance of these IRP "drivers," it is important that any modeling approach address them systematically. While there are methods of incorporating uncertainties into optimization models, the computational complexity and associated problems (development costs, maintenance costs, error detection, ease-of-use, etc.) can be significant.

Recent SRPM Enhancements

As part of this IRP cycle, WWP has upgraded SRPM to include considerably more sophisticated algorithms controlling new resource decisions, annual operating hours, and the interaction between secondary energy prices and thermal resource dispatch. While still an annual simulation model, SRPM now offers the ability to make economic resource addition and operation decisions. Moreover, SRPM now has the ability to (on the basis of exogenously derived chronological dispatch analyses) run on-line resources in a manner that reflects secondary energy markets and other bulk power market parameters.

Generating Resource Dispatch:

The first set of algorithms, which we refer to as *dispatch* algorithms, control the operation of existing resources, both those on-line at the beginning of the planning horizon and those added over the course of the study period. By incorporating the results of chronological or load-duration-based production costing models as input parameters, SRPM now offers a degree of operational realism not found in most annual IRP models.

The **Minimum Equivalent Availability Factor (EAF)** table determines the minimum and maximum amounts a particular on-line resource can operate, subject to secondary prices and technical characteristics. The minimum is determined by the lesser of: 1) the user-specified "minimum-run threshold"; and 2) the EAF derived from the user inputs in the secondary price thermal dispatch table[2]. In other words, a resource can under no circumstances run less than the minimum value, but will run more if secondary prices make doing so economically rational.

The **Available for Dispatch** table determines the maximum average MW available for dispatch[3] in response to the resource balance net of planned resources and sampled load. This number equals the difference between the maximum available hours (peak capacity * maximum capacity factor) minus the minimum EAF. The implication is that SRPM will sell energy for a particular resource on the secondary (non-firm) market if the EAF (as determined above) is greater than the energy production needed to meet loads in a given year. This table also sorts all resources on-line in decreasing order of variable cost.

The **Dispatch Quantity** table, in the case of a resource surplus in a given year, first looks at the **Available for Dispatch** table for the most expensive variable cost resource. Hours of energy production are reduced by the lesser of 1) the reduction needed to obtain resource balance for the year; and 2) total available dispatch for the resource. If this total is reached and a surplus remains for the year, the process is repeated for the next most expensive variable cost resource and so on down the "stack."

The Net Annual Dispatch table re-sorts resources by account number. This table finds the corresponding resource in the sorted Dispatch Quantity table, reduces the maximum capacity factor by the amount of hours determined in that table and displays the net capacity factor for each resource. This capacity factor reflects the actual hours of operation for each resource, after the resource balance, average annual price of secondary energy, resource-specific variable costs, and minimum-run levels have been taken into account for the year in question.

New Resource Scheduling Algorithms:

SRPM will add new resources on the basis of 1) resource balance; 2) resource-specific present value (fixed and variable) revenue requirements (PVRR); and 3) user-specified constraints. The model still allows the user to specify a set of planned resources to capture the effects of specific resource decisions. Each planned resource can be designated as *discretionary* or *non-discretionary*.

Discretionary resources are added or removed from the resource mix in accordance with resource needs, unit size, present value of revenue requirements and the constraints discussed below. Non-discretionary resources remain in the mix as specified by the user, regardless of conditions over the planning horizon.

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2 These inputs relate expected hours of operation for dispatchable thermal plants to the average annual price of secondary energy. These values are derived by running our 50 year regional dispatch model.

3 *Dispatch* as defined here refers to the allowable deviation from the user-input *planned capacity factor*.

SRPM determines the energy (aMW) available in a year for each resource type. For non-discretionary resources, this amount is simply the quantity in the planned resource mix. For discretionary resources, this quantity represents the largest number of specified units that is less than the user-defined maximum cumulative percentage of total new resources, based on average MW. The model then sorts all available resource types by the long-run present value combined fixed and variable costs, expressed on a per kW basis.

In a deficit condition, the model adds the least expensive resource in the terms expressed above, until the deficit is satisfied or the maximum from the *Available New Resources* table is reached. In this case, the next resource in the stack is added, and so on, until the deficit is met. Since many resources are "lumpy", this algorithm will often result in a surplus condition. In this case, the model will use the dispatch algorithms to 1) sell excess energy on the secondary market; or 2) back off existing resources on the basis of secondary prices and variable costs.

In a surplus year, the model will drop the most expensive planned discretionary resource out of the mix. While this event is similar to resource "deferral" as depicted in many IRP models, there is an important difference. A resource thus dropped out of the mix will only be added later if it is *still the most cost-effective option.*

Decision rules for responding to both deficit and surplus conditions are subject to user-defined thresholds. A second constraint limits the *cumulative* amount of a given resource type to a user-specified percentage of the total cumulative new resource additions since the beginning of the planning period.

The model combines the results of the dispatch and build algorithms discussed above for a final resource balance. Any residual surpluses or shortfalls, as explained above, are treated as secondary energy sales (negative values) or purchases (positive values). These final resource-specific operating profiles are passed on to the revenue requirements and financial modules. These modules account for construction work in progress (CWIP), expenses, capitalization, depreciation and taxes. These financial parameters are ultimately reflected as changes to the annual average rates, revenue requirements, new resource costs and summary financial indicators.

Risk Analysis Module:

The risk analysis module allows the user to specify probability distributions for load growth, capital cost escalation, fuel prices, and the incremental cost of capital. These are typically specified as normal or lognormal distributions, with a given mean and standard deviation. Many other types of mathematical distributions are possible. Some uncertainties, such as discrete changes in load or resource availability, are better modeled with discrete distributions where each possible state is assigned a specific probability.

Different types of power resources are subject to different types of risks. Some of these risks are inherent to the type of technology involved. Other risks involve the interaction of the technology (*endogenous*, resource-specific risk) and the environment in which the utility operates (*exogenous* risk).

Monte Carlo simulation entails the following steps:

- Identification of key uncertain model *input* variables, which are assumptions about both resource options and the environment in which they will operate;

- Statistical description of the uncertainty for these key inputs with probability distributions;

- Identification and statistical description of any relationships (covariance) between key inputs;

- Multiple iteration, where sets of input assumptions are drawn from each specified input variable probability distributions and used for each model iteration; and

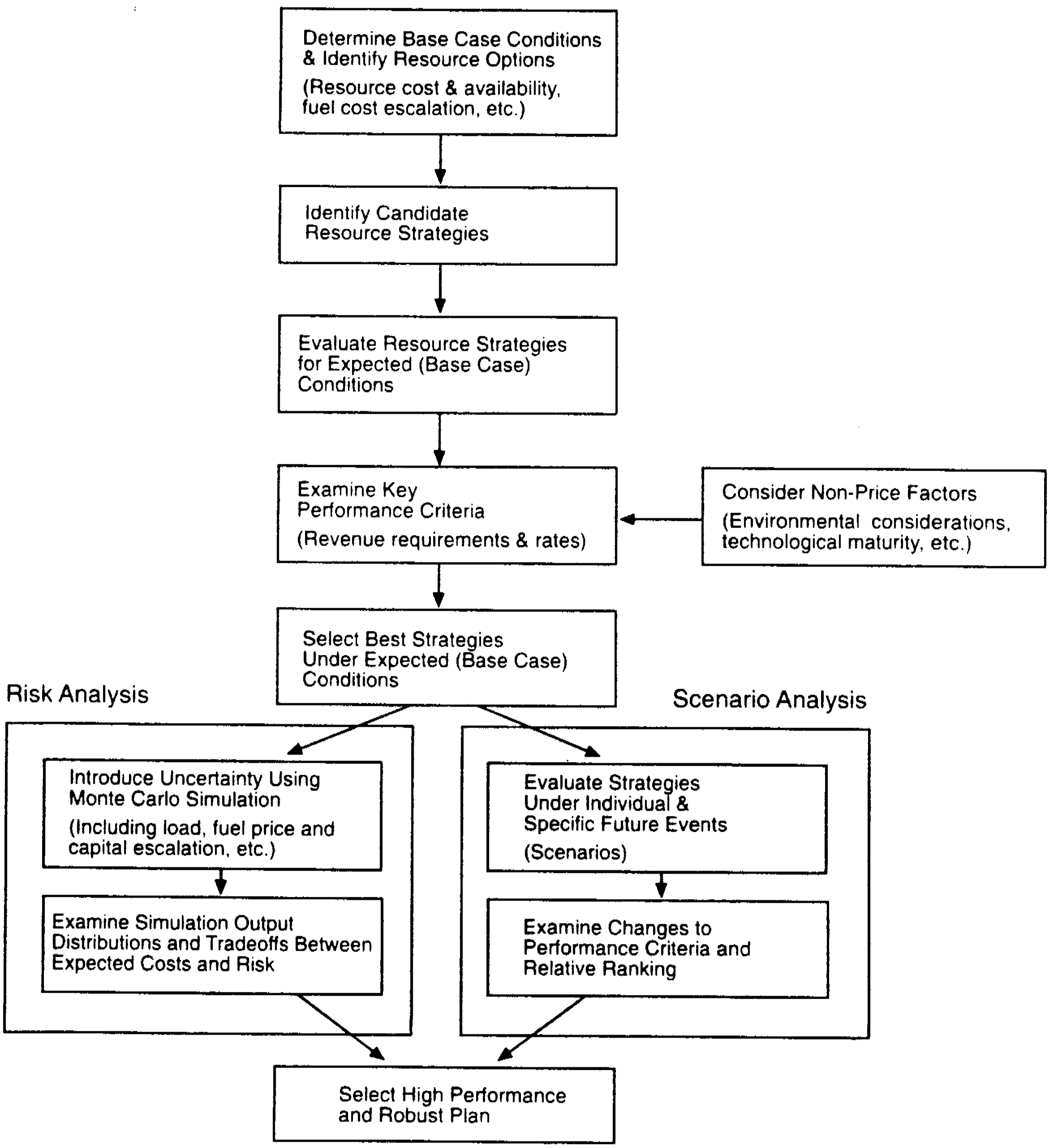
- Description of key model *outputs* with probability distributions that convey the range of possible outcomes in terms of the "central tendency" (e.g. mean or median) outcome and the probability associated with outcomes both higher and lower than the central tendency.

As discussed above, this type of analysis is contrasted against a decision analysis methodology which assigns a weight to each of multiple possible inputs and derives a single value to represent a given input parameter. This value is then used to calculate a resultant figure of merit that is also estimated as a single value. The Monte Carlo method produces an output distribution and not a single value.

Resource Evaluation Process

Figure H-3 illustrates how the SRPM model is used to evaluate the best resource strategies and select the preferred resource plan.

Figure H-3: WWP's resource evaluation process using SRPM.



Expected Conditions and Resource Strategies

The resource evaluation process begins with the development of base case study conditions.

Figure H-4: Base case study conditions.

Input Parameter	Base Case Value ($1992 dollars)
Medium Forecast Energy Load Growth Rate	1.40%
Inflation: Average Annual Rate	4.20%
Natural Gas	
Fuel Cost	1.81 $/MMBtu
Fuel Price Escalation: Average Annual Rate	7.50 % (Nominal) 3.07 % (Real)
Coal	
Fuel Cost	1.65 $/MMBtu
Fuel Price Escalation: Average Annual Rate	4.90 % (Nominal) 0.58 % (Real)
Capital Escalation : Average Annual Rate	3.10 % (Nominal) -1.15 % (Real)
Weighted Average Cost of Capital	10.50%

SRPM requires inputs describing new demand-side and supply-side resources, as well as potential energy purchases. Expected costs for these alternatives are based on the company's resource assessment. A wide array of potentially cost-effective energy resource options were identified for model analysis. With a finite number of inputs available, the cost and capability of some options were combined to provide more modeling flexibility. All of the resource options listed in Figures H-5 through H-8 were input for the SRPM analysis.

Figure H-5: Conservation Supply Curve - Includes weatherization, compact fluorescent lighting, low-flow shower heads and energy-efficiency measures for all customer sectors.

Cumulative aMW	¢/kWh
55	3.0
74	4.0
81	5.0
88	6.0
93	7.0
95	8.0

Figure H-6: Fuel-Efficiency Supply Curve - Includes electric to natural-gas space and water heating conversions for all customer sectors.

Cumulative aMW	¢/kWh
60	2.0
82	3.0
93	4.0
103	5.0
108	6.0
111	7.0
114	8.0

Figure H-7: Supply-side resource options.

	Small Cogeneration	CCCT	Colstrip Upgrade	Planned Hydro Upgrades	Clark Fork Upgrades	System Efficiency
Maximum Availability Factor	93%	83%	87%	100%	100%	60%
Coal/Gas Fired Resource (C/G/H)	Gas	Gas	Coal	Hydro	Hydro	–
Capital Cost (Installed $/kW)	$1,181	$788	$759	$463	$2,694	$1,062
Capital Cost Escalation (Real)	-1.15%	-1.15%	-1.15%	-1.15%	-1.15%	-1.15%
Total Required Lead Time (Years)	2	2	3	2	2	1
Economic Life	30	30	35	35	35	35
Fixed O & M ($/kW)	$6.05	$6.05	$0.00	$0.00	$0.00	$0.00
Fixed O & M Escalation (Real)	-0.10%	-0.10%	0.00%	0.00%	0.00%	0.00%
Variable O & M (mills/kWh)	11.41	13.22	0	0	0	0
Variable O & M Escalation (Real)	3.07%	3.07%	0.00%	0.00%	0.00%	0.00%

Notes:

Costs in 1991 dollars.

Small Gas Cogeneration: A new 25 MW natural-gas-fired combined-cycle combustion turbine cogeneration facility.

Combined-Cycle Combustion Turbine (CCCT): A new natural-gas-fired unit.

Colstrip Thermal Efficiency: Turbine rotor replacement for Colstrip Units No.3 and No.4.

Planned Hydroelectric Upgrades: Includes upgrades at WWP's Cabinet Gorge, Nine Mile and Upper Falls plants.

Clark Fork Upgrades: Includes hydroelectric upgrades at WWP's Cabinet Gorge and Noxon Rapids plants.

Figure H-8: Potential power purchase rates.

Year	Secondary Energy ($/MWh)	BPA New Resources (NR) Rate Demand Charge ($/kW/month)	BPA New Resources (NR) Rate Energy Charge ($/MWh)	1991 RFP Avoided Cost Energy Charge ($/MWh)	Idaho Avoided Cost Energy Charge ($/MWh)
1992	16.0	$4.40	$24.03	$17.40	$41.27
1993	17.2	$4.40	$24.03	$18.60	$43.18
1994	19.0	$4.59	$25.09	$20.00	$45.17
1995	21.8	$4.82	$26.36	$40.20	$47.26
1996	22.9	$5.23	$28.62	$43.40	$49.45
1997	24.1	$5.51	$30.17	$48.00	$51.75
1998	25.3	$5.78	$31.65	$50.80	$54.14
1999	26.2	$6.10	$33.42	$54.00	$56.64
2000	27.0	$6.44	$35.26	$55.21	$59.27
2001	28.0	$6.70	$36.67	$57.29	$62.01
2002	28.9	$7.10	$38.86	$59.46	$64.89
2003	29.9	$7.44	$40.70	$61.72	$67.90
2004	30.4	$7.76	$42.47	$64.07	$71.04
2005	32.0	$8.11	$44.38	$66.52	$74.33
2006	33.1	$8.70	$47.63	$69.07	$77.78
2007	34.2	$9.47	$51.87	$71.73	$81.38
2008	35.3	$9.73	$53.28	$74.50	$85.16
2009	36.5	$10.27	$56.25	$77.38	$89.11
2010	37.8	$10.91	$59.78	$80.39	$93.25
2011	39.1	$11.27	$61.76	$83.52	$97.57

Notes:
WWP's estimate of secondary energy rates used for planning purposes.
BPA NR rate is current WWP estimate.
Extension of mid-Columbia purchase contracts (with Grant County PUD) is currently in negotiation; rates are not shown.

Candidate resource strategies were developed from the above menu of resource alternatives. Each potential strategy represents a different combination of new resource options with respect to mix and timing. Each strategy includes total resources sufficient to meet long-term energy needs. An "all supply-side mix," or "an all demand-side mix," represent extreme examples of potential strategies. For the initial analysis, WWP examined over 50 different resource strategies. The company's resource needs were met by either allowing SRPM to choose the best options or by fixing the timing for acquisition of specific resources. One of the advantages of this approach is that it allows a comparison of strategies dependent upon large supply-side resources with those based more heavily on the acquisition of demand-side resources.

Plan Performance Under Expected Conditions

Each potential resource strategy was evaluated under base case conditions. Key performance results, including rates and revenue requirements, were examined for each alternative. The lowest cost resource strategies are those which have the lowest net present value of revenue requirements (NPVRR). Figure H-9 lists the revenue requirement and rate[4] results for the lowest cost plans. The list is sorted from lowest to highest revenue requirement.

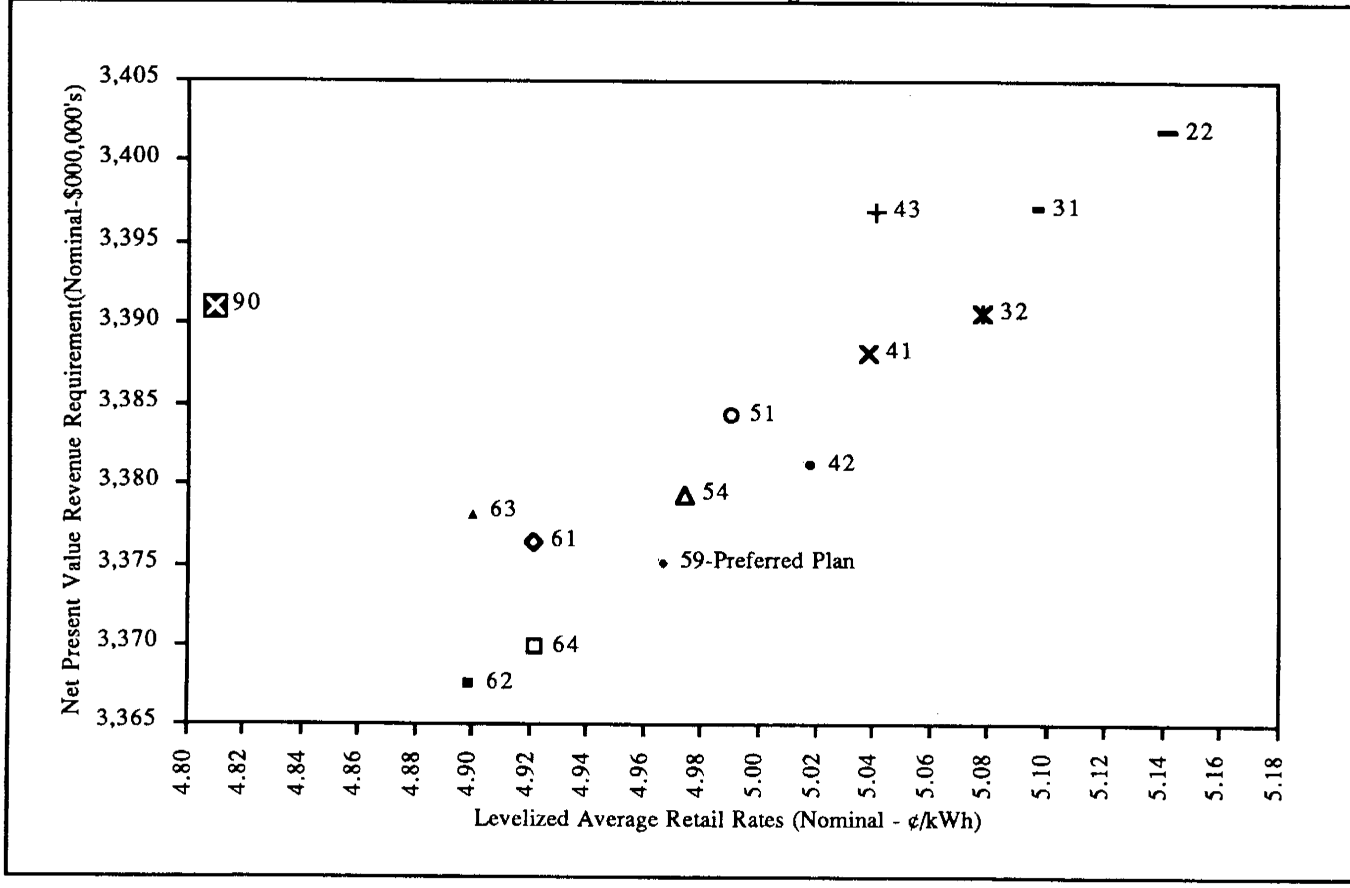
Figure H-9: Revenue requirement and rate results for the lowest cost resource plans.

CASE #	Net Present Value Revenue Requirement (Nominal $000,000)	Levelized Rates (Nominal ¢/kWh)
CASE 62	$3,368	4.90
CASE 60	$3,368	4.90
CASE 64	$3,370	4.92
CASE 56	$3,375	4.97
CASE 59	$3,375	4.97
CASE 52	$3,375	4.97
CASE 58	$3,375	4.97
CASE 50	$3,376	4.97
CASE 61	$3,376	4.92
CASE 63	$3,378	4.90
CASE 54	$3,379	4.97
CASE 57	$3,380	4.97
CASE 42	$3,381	5.02
CASE 40	$3,382	5.02
CASE 51	$3,384	4.99
CASE 65	$3,386	4.94
CASE 53	$3,388	4.99
CASE 41	$3,388	5.04
CASE 44	$3,388	5.03
CASE 32	$3,391	5.08
CASE 90	$3,391	4.81
CASE 30	$3,392	5.08
CASE 43	$3,397	5.04
CASE 31	$3,397	5.10
CASE 34	$3,398	5.09
CASE 55	$3,399	5.01
CASE 22	$3,402	5.14
CASE 20	$3,402	5.14
CASE 45	$3,406	5.07
CASE 33	$3,407	5.10
CASE 21	$3,408	5.16
CASE 24	$3,409	5.15

4 The rate information output by SRPM is used only to compare the performance of alternative strategies and not as a forecast of actual electric rates.

Figure H-10 plots the NPVRR and levelized average rates for the lowest cost plans.

Figure H-10: Rates and revenue requirements for potential resource strategies.



The primary difference between the resource strategies shown in Figure H-10 is the timing of demand-side resource acquisition. For example, Cases 61 through 64 represent one level of acquisition. Cases 51, 54 and 59 correspond to another level, and so on. With the exception of Case 90, each plan acquires approximately 130 aMW of demand-side resources over the planning period.

Case 90 emphasizes supply-side resources. It assumes demand-side management activities completely terminate after 1993 and the acquisition of only 22 aMW of demand-side resources. Although Case 90 is not the lowest cost plan, it does result in the lowest rates. Case 22 represents the other extreme. Compared to the other plans, it represents accelerated acquisition of demand-side resources. It results in the highest costs and the highest rates.

The evaluation of rates and revenue requirements compares resource strategies and determines common resource elements. The analysis indicates that the level of demand-side resource acquisition has the most significant affect on plan performance. WWP's hydroelectric and Colstrip upgrades, electric system efficiencies and mid-Columbia contract extensions are common to each low-cost plan. The timing of these supply-side resources is impacted by the level of demand-side acquisition.

The purpose of this base case analysis is to identify resource strategies which minimize both rates and revenue requirements under expected conditions. Although Cases 62 and 64 best satisfy these criteria, they would require the company to stop and then restart its demand-side management programs. The preferred plan, Case 59, is the lowest cost plan that allows the company to maintain program activity over the planning period. On a net present value basis, the cost of this preferred plan exceeds the lowest cost plan by less than $10 million.

While revenue requirements and rates are the key financial information used to determine this preferred resource plan, the SRPM calculates other parameters. Figure H-11 summarizes the performance of the preferred strategy under expected conditions.

Figure H-11: Performance results for WWP's preferred energy strategy.

Nominal Net Present Value Revenue Requirement ($ 000,000's)	Real Net Present Value Revenue Requirement ($ 000,000's)	Nominal Revenue Requirement Growth (%)	Levelized Nominal Rates (¢/kWh)	Nominal Rate Growth (%)	Real Rate Growth (%)	Incremental New Resource Cost (Levelized ¢/kWh)
3,375	1,454	2.97	4.97	2.03	-1.97	3.41

Based on SRPM results, Figure H-11 indicates that nominal rates are expected to grow at an average of about 2.0 percent per year. Absent the effects of inflation, real rates are expected to decrease. The incremental new resource cost reflects the mix of resources selected to meet forecast loads. Its low value indicates that WWP's moderate energy needs can be met with a combination of low-cost demand-side and supply-side resources.

Risk and Uncertainty

Because of the impact that demand-side resources have on plan performance, the company focused its risk and scenario analysis on varying levels of demand-side acquisition. In addition to the preferred plan, three other resource strategies were selected for these studies that introduce risk and uncertainty into the resource plan evaluation. Figure H-12 illustrates the levels of demand-side resource acquisition that correspond to these four strategies. Figures H-13 through H-16 list the complete resource acquisition schedule for each of these four strategies.

Figure H-12: Potential demand-side resource acquisition strategies.

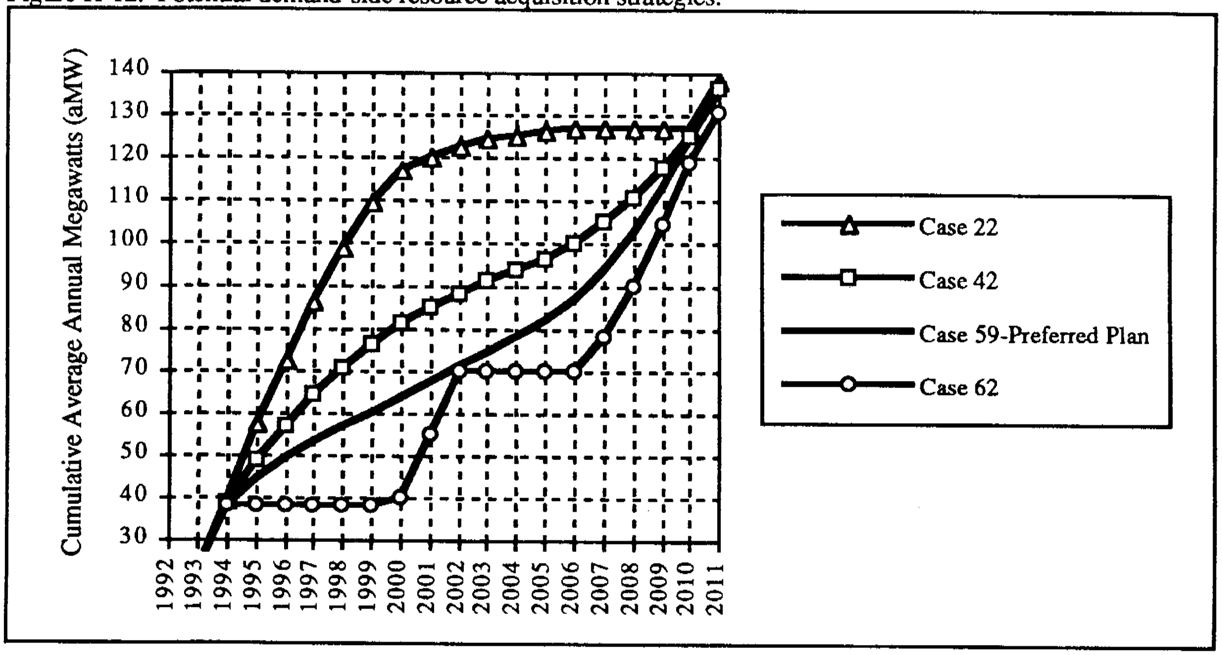


Figure H-13: Case 22 resource acquisition schedule (cumulative aMW).

Resource Acquisition Activity	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Colstrip Thermal Efficiency (Units No.3 & No.4)	0	0	0	0	0	0	0	0	0	0
Conservation	2	7	15	23	29	34	38	42	45	47
Fuel-Efficiency	5	15	25	35	44	53	60	67	72	73
Planned Hydroelectric Upgrades (Cabinet No.1, Nine Mile & Upper Falls)	0	0	5	8	8	8	8	8	8	8
Clark Fork Hydroelectric Upgrades (Cabinet No.2, Noxon No.3 & No.4)	0	0	0	0	0	0	0	0	0	0
Electric System Efficiency (Transmission & Distribution Loss Savings)	0	0	0	0	0	0	0	0	0	0
Mid-Columbia Extension (Grant County PUD Contract)	0	0	0	0	0	0	0	0	0	0
Total	7	22	45	66	81	95	106	117	125	128

Resource Acquisition Activity	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Colstrip Thermal Efficiency (Units No.3 & No.4)	0	0	0	0	0	0	0	0	5	5
Conservation	48	48	48	48	49	49	49	49	49	53
Fuel-Efficiency	75	76	77	78	78	78	78	78	78	78
Planned Hydroelectric Upgrades (Cabinet No.1, Nine Mile & Upper Falls)	8	8	8	8	8	8	8	8	8	8
Clark Fork Hydroelectric Upgrades (Cabinet No.2, Noxon No.3 & No.4)	0	0	0	0	0	0	0	0	0	0
Electric System Efficiency (Transmission & Distribution Loss Savings)	0	0	0	0	0	0	0	2	12	20
Mid-Columbia Extension (Grant County PUD Contract)	0	0	0	10	17	17	17	40	47	47
Total	131	132	133	144	152	152	152	177	199	211

Figure H-14: Case 42 resource acquisition schedule (cumulative aMW).

Resource Acquisition Activity	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Colstrip Thermal Efficiency (Units No.3 & No.4)	0	0	0	0	0	0	0	0	0	0
Conservation	2	7	14	18	21	24	27	29	31	33
Fuel-Efficiency	5	15	25	31	36	40	44	47	50	52
Planned Hydroelectric Upgrades (Cabinet No.1, Nine Mile & Upper Falls)	0	0	5	8	8	8	8	8	8	8
Clark Fork Hydroelectric Upgrades (Cabinet No.2, Noxon No.3 & No.4)	0	0	0	0	0	0	0	0	0	0
Electric System Efficiency (Transmission & Distribution Loss Savings)	0	0	0	0	0	0	0	0	0	0
Mid-Columbia Extension (Grant County PUD Contract)	0	0	0	0	0	0	0	0	0	0
Total	7	22	44	57	65	72	79	84	89	93

Resource Acquisition Activity	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Colstrip Thermal Efficiency (Units No.3 & No.4)	0	0	0	0	0	0	5	5	5	5
Conservation	34	35	36	37	39	41	44	47	50	53
Fuel-Efficiency	54	56	57	59	61	64	67	71	76	80
Planned Hydroelectric Upgrades (Cabinet No.1, Nine Mile & Upper Falls)	8	8	8	8	8	8	8	8	8	8
Clark Fork Hydroelectric Upgrades (Cabinet No.2, Noxon No.3 & No.4)	0	0	0	0	0	0	0	0	0	0
Electric System Efficiency (Transmission & Distribution Loss Savings)	0	0	0	0	0	0	0	6	14	18
Mid-Columbia Extension (Grant County PUD Contract)	0	0	0	10	17	17	17	40	47	47
Total	96	99	101	114	125	130	141	177	200	211

Figure H-15: Case 59 (Preferred Plan) resource acquisition schedule (cumulative aMW).

Resource Acquisition Activity	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Colstrip Thermal Efficiency (Units No.3 & No.4)	0	0	0	0	0	0	0	0	0	5
Conservation	2	7	14	16	18	19	21	22	24	26
Fuel-Efficiency	5	15	25	29	32	34	36	38	40	42
Planned Hydroelectric Upgrades (Cabinet No.1, Nine Mile & Upper Falls)	0	0	5	8	8	8	8	8	8	8
Clark Fork Hydroelectric Upgrades (Cabinet No.2, Noxon No.3 & No.4)	0	0	0	0	0	0	0	0	0	0
Electric System Efficiency (Transmission & Distribution Loss Savings)	0	0	0	0	0	0	0	0	0	0
Mid-Columbia Extension (Grant County PUD Contract)	0	0	0	0	0	0	0	0	0	0
Total	7	22	44	53	58	61	65	68	72	81

Resource Acquisition Activity	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Colstrip Thermal Efficiency (Units No.3 & No.4)	5	5	5	5	5	5	5	5	5	5
Conservation	27	29	30	32	34	37	41	45	50	55
Fuel-Efficiency	44	46	48	50	53	57	62	68	74	81
Planned Hydroelectric Upgrades (Cabinet No.1, Nine Mile & Upper Falls)	8	8	8	8	8	8	8	8	8	8
Clark Fork Hydroelectric Upgrades (Cabinet No.2, Noxon No.3 & No.4)	0	0	0	0	0	3	3	6	6	6
Electric System Efficiency (Transmission & Distribution Loss Savings)	0	0	0	0	0	2	4	6	8	10
Mid-Columbia Extension (Grant County PUD Contract)	0	0	0	10	17	17	17	40	47	47
Total	84	88	91	105	117	129	140	178	198	212

Figure H-16: Case 62 resource acquisition schedule (cumulative aMW).

Resource Acquisition Activity	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Colstrip Thermal Efficiency (Units No.3 & No.4)	0	0	0	0	0	0	0	0	0	0
Conservation	2	7	14	14	14	14	14	14	14	19
Fuel-Efficiency	5	15	25	25	25	25	25	25	27	37
Planned Hydroelectric Upgrades (Cabinet No.1, Nine Mile & Upper Falls)	0	0	5	8	8	8	8	8	8	8
Clark Fork Hydroelectric Upgrades (Cabinet No.2, Noxon No.3 & No.4)	0	0	0	0	0	0	0	0	0	0
Electric System Efficiency (Transmission & Distribution Loss Savings)	0	0	0	0	0	0	0	2	17	17
Mid-Columbia Extension (Grant County PUD Contract)	0	0	0	0	0	0	0	0	0	0
Total	7	22	39	47	47	47	47	49	66	81

Resource Acquisition Activity	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Colstrip Thermal Efficiency (Units No.3 & No.4)	0	0	0	0	5	5	5	5	5	5
Conservation	24	24	24	24	24	24	28	32	37	42
Fuel-Efficiency	47	47	47	47	47	53	63	73	83	84
Planned Hydroelectric Upgrades (Cabinet No.1, Nine Mile & Upper Falls)	8	8	8	8	8	8	8	8	8	8
Clark Fork Hydroelectric Upgrades (Cabinet No.2, Noxon No.3 & No.4)	0	0	0	0	0	0	0	0	0	6
Electric System Efficiency (Transmission & Distribution Loss Savings)	17	17	17	17	17	20	20	20	20	20
Mid-Columbia Extension (Grant County PUD Contract)	0	0	0	10	17	17	17	40	47	47
Total	96	96	96	106	118	127	141	178	200	212

Risk Analysis

The base case analysis described in Figure H-10 identifies the best resource strategies under expected conditions. Risk analysis that employs Monte Carlo simulation techniques incorporates uncertainty into the resource plan evaluation. For Monte Carlo analysis, base case input parameters are replaced by ranges of values. Each input range is identified by high and low limits or by statistical distributions. For example, energy loads are bounded by the high and low forecast. Secondary energy rates, fuel price and capital escalation rates are represented by normal probability distributions. Figure H-17 describes the input variable assumptions used for risk analysis.

Figure H-17: SRPM input variable assumptions for risk analysis.

Secondary Energy Price: Also termed economy or non-firm energy. Secondary energy is market priced energy which is available for purchase by WWP and other utilities to meet short-term needs. For conditions when available generation exceeds load, WWP will try to sell this energy into the secondary market. Secondary energy price is represented by a truncated normal distribution with the following parameters:

Parameter	Assumption/Basis
Mean	Equal to WWP estimate (15.6 mills in 1992).
Standard Deviation	8.0 mills - Based on WWP review of historical data.
Minimum Value	7.0 mills - Based on typical price for BPA "thermal displacement power".
Maximum Value	53.0 mills - Based on WWP review of historical data.

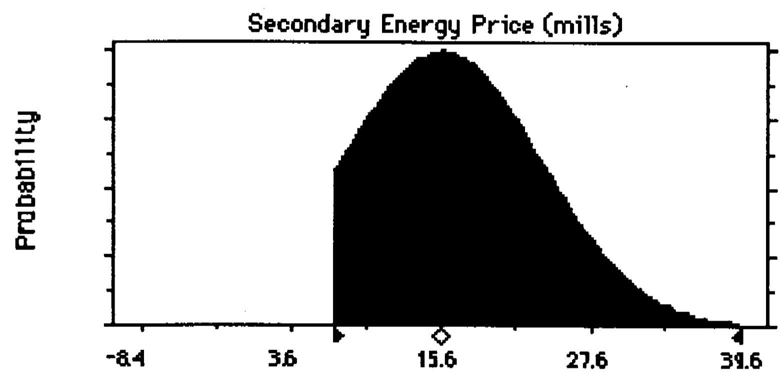
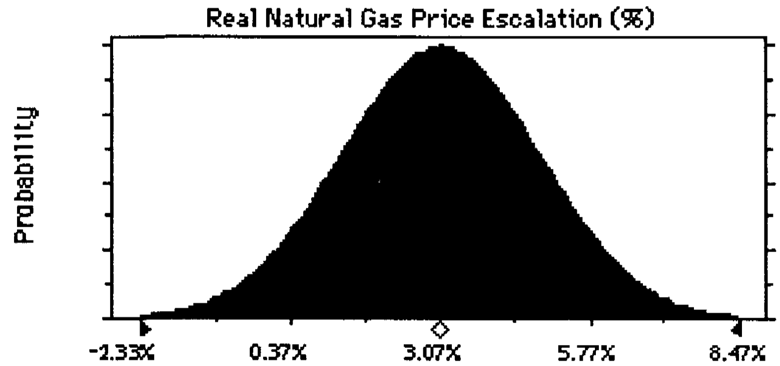


Figure H-17 (continued): SRPM input variable assumptions for risk analysis.

Real Natural Gas Price Escalation: Long-term estimate of natural gas available to fuel power production. Distribution parameters were selected to encompass the pricing assumptions applied in the Northwest Power Planning Council's 1991 Plan.

Parameter	Assumption/Basis
Mean	3.07% - WWP estimate of 25 year average.
Standard Deviation	1.80% - WWP estimate.
Minimum Value	0.60% - NWWPP "low" value.
Maximum Value	6.74% - WWP estimate.



Real Coal Price Escalation: Long-term estimate of coal available to fuel power production. Distribution parameters were selected to encompass the pricing assumptions applied in the Northwest Power Planning Council's 1991 Plan.

Parameter	Assumption/Basis
Mean	0.58% - WWP estimate of 25 year average.
Standard Deviation	0.29% - WWP estimate.
Minimum Value	-0.90% - NWWPP "low" value.
Maximum Value	2.4% - NWWPP "high" value.

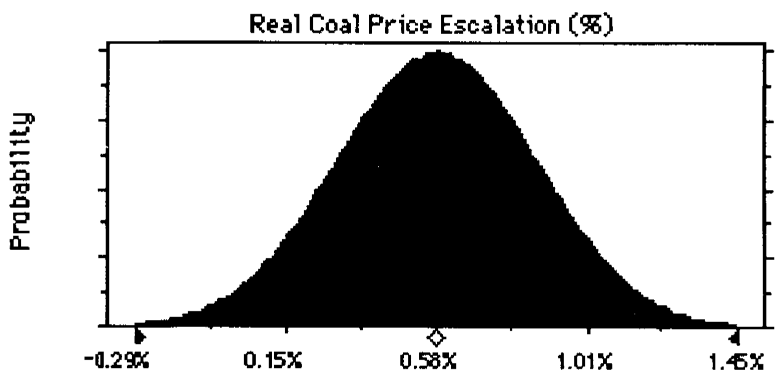
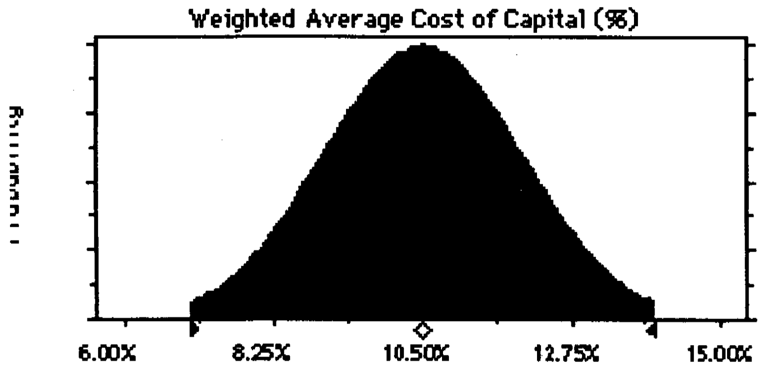


Figure H-17 (continued): SRPM input variable assumptions for risk analysis.

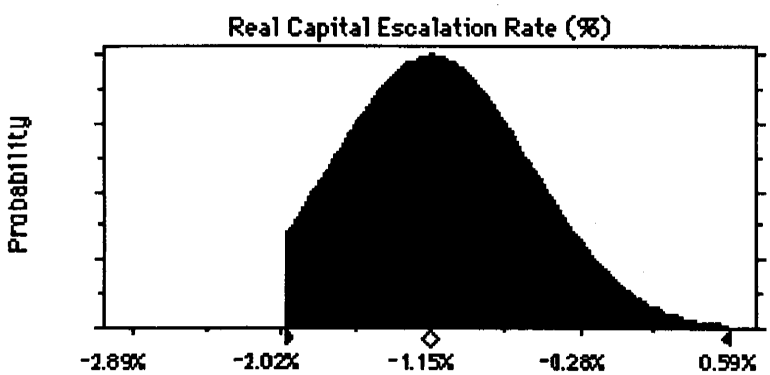
Weighted Average Cost of Capital: Long-term projection of WWP's cost of capital including debt and common and preferred stock. A truncated normal distribution is selected with the following parameters.

Parameter	Assumption/Basis
Mean	10.50% - WWP projection.
Standard Deviation	2.00% - WWP estimate.
Minimum Value	8.00% - WWP estimate.
Maximum Value	14.00% - WWP estimate.



Real Capital Escalation Rate: Long-term rate used to escalate capital costs associated with new resource construction. A truncated normal distribution is selected with the following parameters.

Parameter	Assumption/Basis
Mean	-1.15% - WWP projection.
Standard Deviation	0.58% - WWP estimate.
Minimum Value	-2.00% - WWP estimate.
Maximum Value	2.00% - WWP estimate.



Given these ranges of uncertainties, SRPM uses Monte Carlo techniques to generate a random value for each input parameter. Based on these inputs, rate and revenue requirement results are calculated for each simulation. The results of 500 simulations were evaluated for each of the four resource strategies. This analysis allows examination of tradeoffs between expected costs and associated risk. By examining the results shown in Figures H-18 and H-19, the company can identify the resource plan that is considered to be the most robust[5].

Figure H-18: Risk analysis results - Revenue requirements.

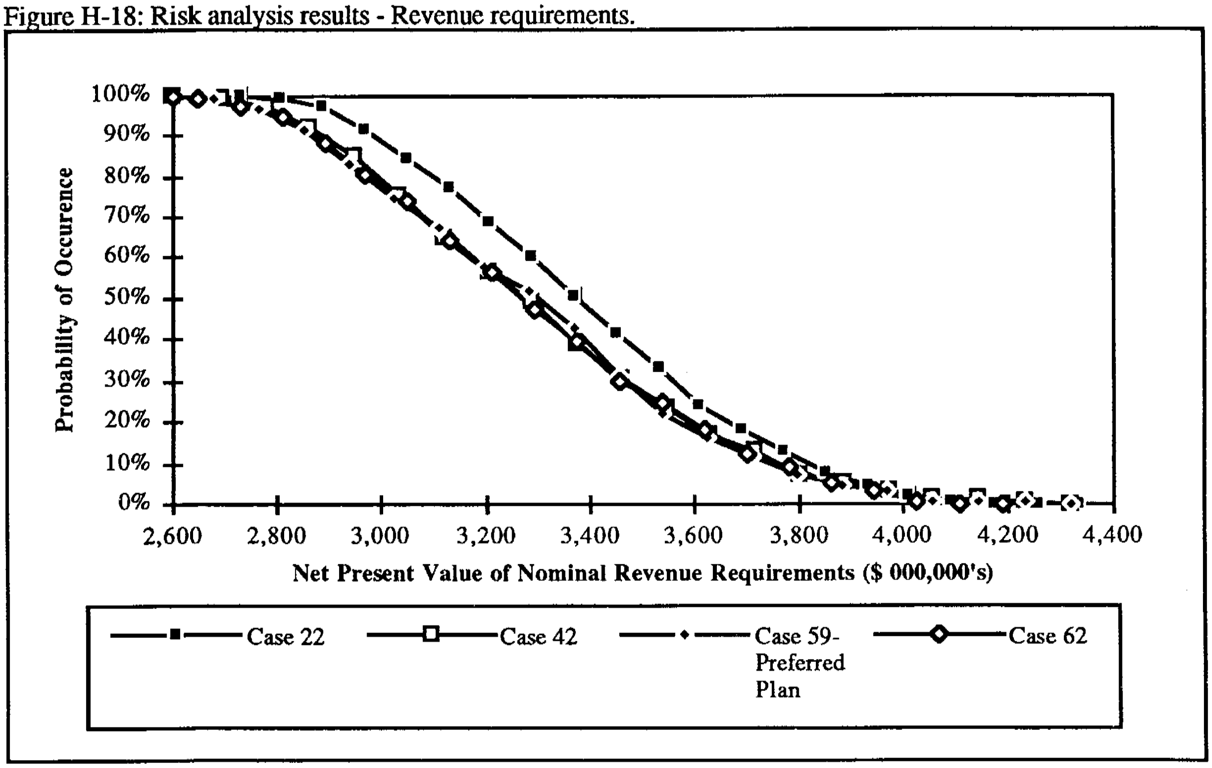
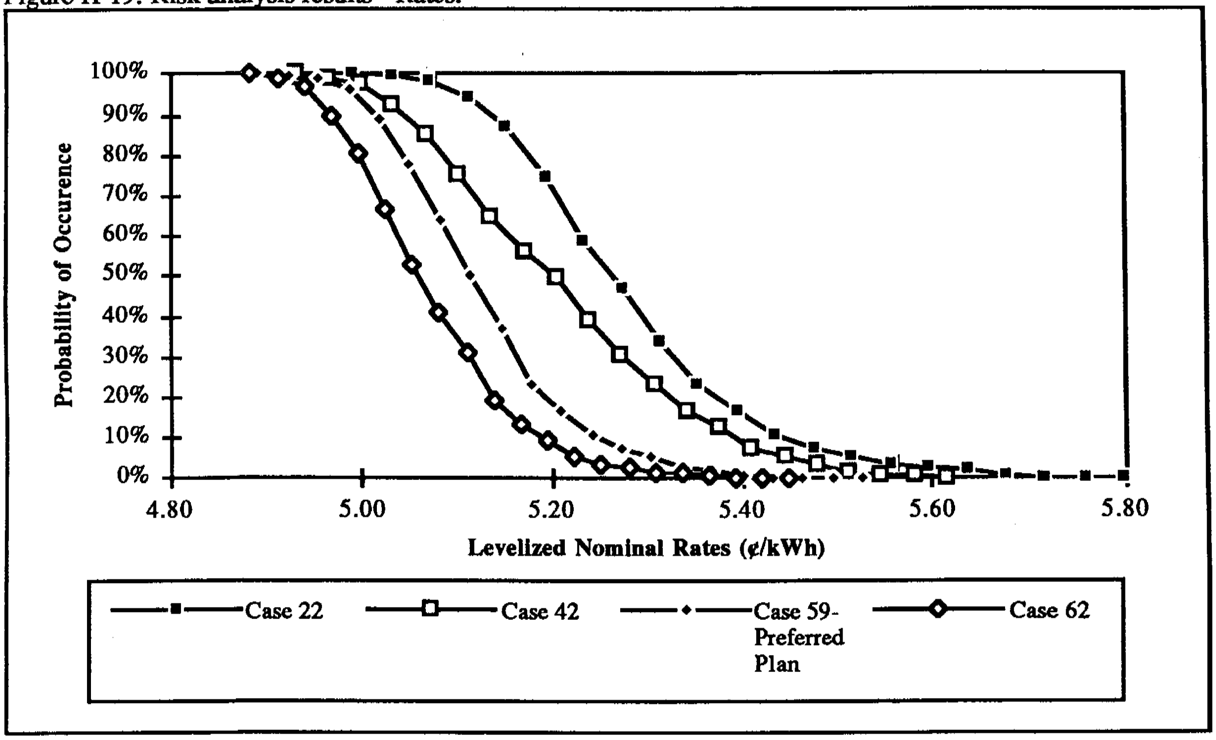


Figure H-18 indicates that uncertainty has a similar effect on the cost of each resource plan. Since each plan consists of low-cost hydroelectric and demand-side resources, capital cost and fuel price escalation does not substantially affect the relative performance of these strategies. Case 22 reflects accelerated demand-side acquisition. It exhibits higher costs, but similar risks than the alternative plans.

5 In this context, robust is defined as a strategy that provides good outcomes over a broad range of potential future conditions.

The effects of uncertainty on long-term rates is shown in Figure H-19. Cases 59 and 62 exhibit lower rates for all potential conditions. Even though it results in higher rates, Case 59 is once again preferred over Case 62 because it does not require WWP to temporarily terminate its demand-side management activities.

Figure H-19: Risk analysis results - Rates.



Scenario Analysis

Scenario analysis is another way to incorporate risk and uncertainty into the planning process. Scenario analysis allows the potential impacts of specific parameters such as high load growth or the loss of a resource to be examined in isolation. If a resource strategy retains a high ranking over a set of diverse set of scenarios, it can be viewed as a high performance and robust plan.

For this evaluation, the company selected scenarios that test resource plan performance under potential and extreme events. In the case that one of these events becomes a reality, the scenario analysis results provide the company with some insight as how to best respond to the new conditions. WWP's analysis included examination of low and high load growth, loss of resource, high natural-gas prices, a carbon tax and loss of load. Figure H-20 lists the results. These results are also shown graphically in Figures H-21 and H-22.

Figure H-20: SRPM scenario study results.

Scenario / Case #	Net Present Value of Nominal Revenue Requirements ($000,000)	Levelized Nominal Rates (¢/kWh)
LOW LOAD GROWTH		
CASE 22	$3,492	5.79
CASE 42	$3,470	5.63
CASE 59	$3,460	5.56
CASE 62	$3,448	5.49
HIGH LOAD GROWTH		
CASE 22	$3,506	4.94
CASE 42	$3,518	4.93
CASE 59	$3,532	4.93
CASE 62	$3,548	4.93
LOSS OF 25 MW RESOURCE IN 1998		
CASE 22	$3,435	5.19
CASE 42	$3,420	5.08
CASE 59	$3,421	5.05
CASE 62	$3,425	5.03
LOSS OF 150 MW RESOURCE IN 1998		
CASE 22	$3,679	5.60
CASE 42	$3,680	5.53
CASE 59	$3,679	5.45
CASE 62	$3,702	5.41
HIGH NATURAL GAS		
CASE 22	$3,367	5.01
CASE 42	$3,364	4.94
CASE 59	$3,364	4.92
CASE 62	$3,367	4.87
CARBON TAX @ $22/TON		
CASE 22	$3,559	5.38
CASE 42	$3,538	5.25
CASE 59	$3,532	5.20
CASE 62	$3,528	5.15
CARBON TAX @ $100/TON		
CASE 22	$3,827	5.79
CASE 42	$3,780	5.62
CASE 59	$3,762	5.54
CASE 62	$3,750	5.48
LOSS OF 100 MW LOAD IN 1996		
CASE 22	$3,273	5.33
CASE 42	$3,252	5.19
CASE 59	$3,244	5.12
CASE 62	$3,232	5.05

- **Low Load Growth:** WWP's low load estimate (0.7 percent annual growth) serves as the basis for this scenario. In the case that energy loads grow at the slower rate, the company would remain in a surplus condition over the entire planning period. In response, the company could adjust demand-side resource acquisitions and delay the timing of some hydroelectric and other system efficiencies. To the extent possible, remaining energy surpluses would be marketed to other utilities. Cases 59 and 62 are the low-cost plans under both the medium-growth and low-growth forecast scenarios.

- **High Load Growth:** The forecast of high load growth (1.8 percent annual growth) serves as the basis for this scenario. For higher than expected load growth, WWP would need to add some new resources. To the extent possible, the schedule for hydroelectric upgrades and system efficiencies would be accelerated. Demand-side management activities would focus on capturing high levels of cost-effective conservation and fuel-efficiency opportunities. A natural-gas-fired combined-cycle combustion turbine would be added in the 2009-2010 time frame. Case 22 includes the highest level of planned demand-side resource acquisition. It represents a sound strategy for meeting high load growth and emphasizes the need to maintain flexibility in the company's demand-side management activities. In all cases, additional customer growth would help offset the company's fixed costs.

- **Loss of Resource:** The loss of resource scenario assumes that in 1998 the company could experience some loss of generating capability. The resource loss could be the result of environmental factors, such as the Endangered Species Act, the Clean Air Act or mitigation measures associated with hydroelectric plant relicensing. As the specific nature and scope is unknown, WWP evaluated the loss of 25 aMW and 150 aMW from the existing resource base.

  The early acquisition of demand-side resources helps to mitigate the loss of 25 aMW from the existing resource base. While maintaining the capability of existing resources is the lowest cost strategy, the flexibility to accelerate demand-side activities and supply-side options is also very important. If the company foresees a high probability of losing this amount of resource capability, adding demand-side resources is an attractive option. Case 42 represents such a strategy.

  The second scenario assumes that the company loses 150 aMW of existing resource capability. In all cases, this scenario represents an extreme and severe event. Beginning in 1998, the company is required to acquire additional resources. These resources would likely be purchased on the short-term market. For the long-term, all cost-effective conservation and fuel-efficiency resources would be pursued, along with available hydroelectric and other system efficiencies. A natural-gas-fired combined-cycle combustion turbine would be added in the year 2000. Although this scenario is considered a low probability event, the early acquisition of demand-side resources is one way to help mitigate the consequences.

- **High Natural Gas Prices:** This scenario assumes that a one-time doubling of natural-gas prices occurs in the year 1997. These higher prices are assumed to affect the company's electric to natural-gas fuel-efficiency programs. Program activity is halted after 1997.

  Without fuel-efficiency as a long-term option, new electric conservation and system efficiencies would help meet future growth. By maintaining diversity within the resource portfolio, the company can mitigate some of this price risk.

- **Carbon Tax:** Although the environmental effects of carbon dioxide (CO_2) are still under study, the federal government has considered a "carbon tax" as a way to reduce CO_2 emissions. Potential effects were evaluated by taxing CO_2 emissions on existing and planned resources beginning in 1996. Tax levels of $22 and $100 per ton were considered.

  A proposed carbon tax would increase the cost of thermal generation and secondary energy prices. Because no new base-load thermal plants are being considered by WWP, existing resources would be the most affected. The company's long-term strategy alternatives remain sound, but increased production costs associated with existing resources could lead to higher rates.

- **Loss of Load:** This scenario examines the effects of losing a large block of retail electric load. The probability of such an occurrence is most likely in the industrial sector and could result from a customer's decision to implement cogeneration, seek another supplier or otherwise bypass WWP.

  In this study, the company assumed a loss of 100 MW of load beginning in 1996. For each resource strategy, the company would be in a long-term surplus condition. To the extent possible, the timing of demand-side and supply-side acquisitions would be adjusted to better match resource needs. The company would focus on wholesale marketing efforts as a means of eliminating any remaining surplus energy. Cases 59 and 62 reflect lower demand-side acquisitions under the expected forecast. They represent the best plans under the loss of load scenario.

The effect of each of these scenarios is summarized in Figures H-21 and H-22. These figures illustrate the potential impacts to revenue requirements and rates for each of the four resource strategies.

Figure H-21: Scenario analyis results-Revenue requirements.

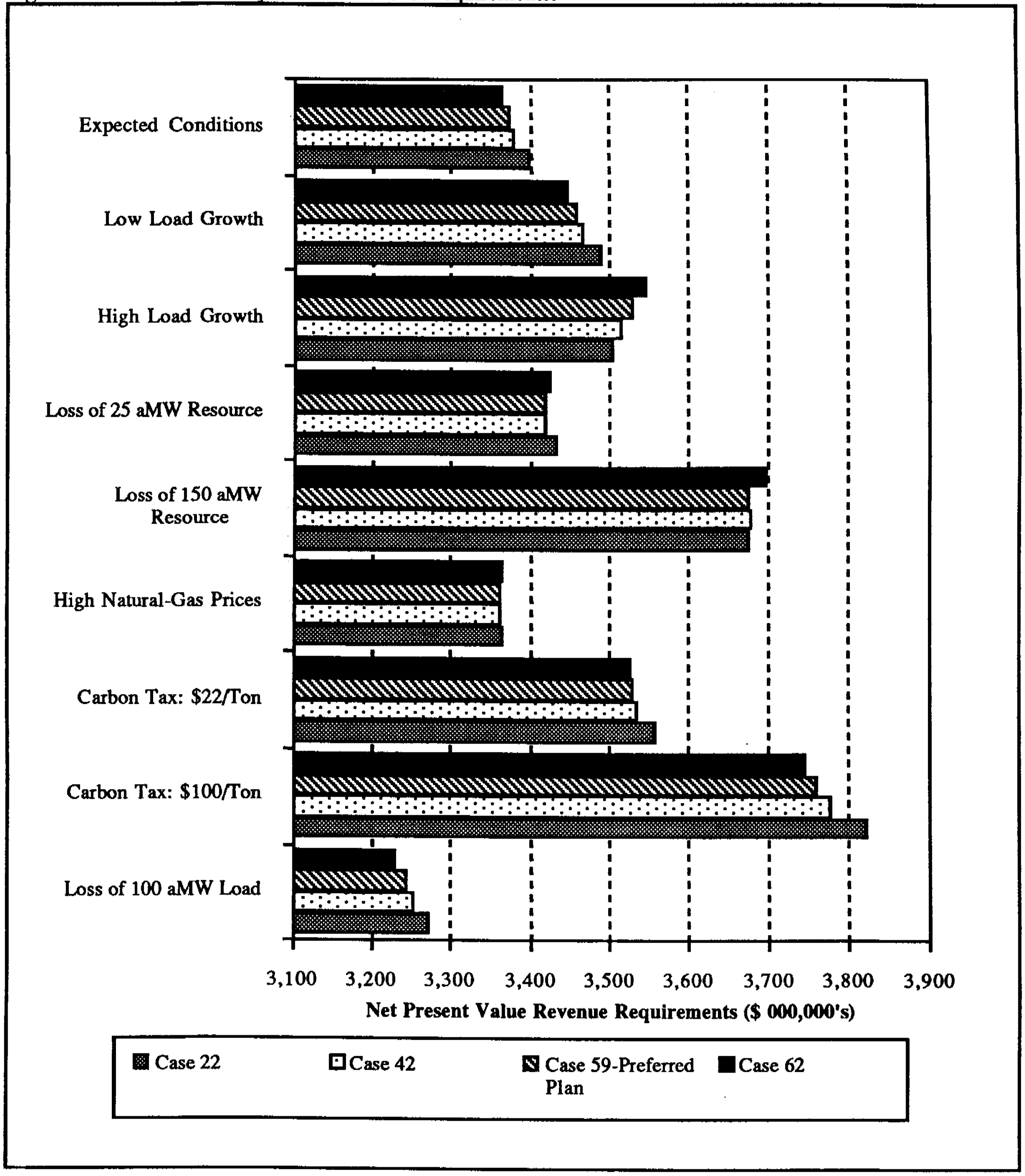


Figure H-21 shows that the preferred plan is the lowest cost plan under the loss of resource and high natural gas price scenarios. It is never the highest cost plan. Case 62 is lowest cost plan for the low load growth, loss of load and carbon tax scenarios. However, it is highest cost plan under the high load growth and loss of resource scenarios. Figure 39 also indicates that in all cases the loss of a large block of the company's existing resources or a high carbon tax would have the most significant effect on long-term revenue requirements. This result points out the importance of protecting the capability of existing resource base.

Figure H-22: Scenario analyis results-Rates.

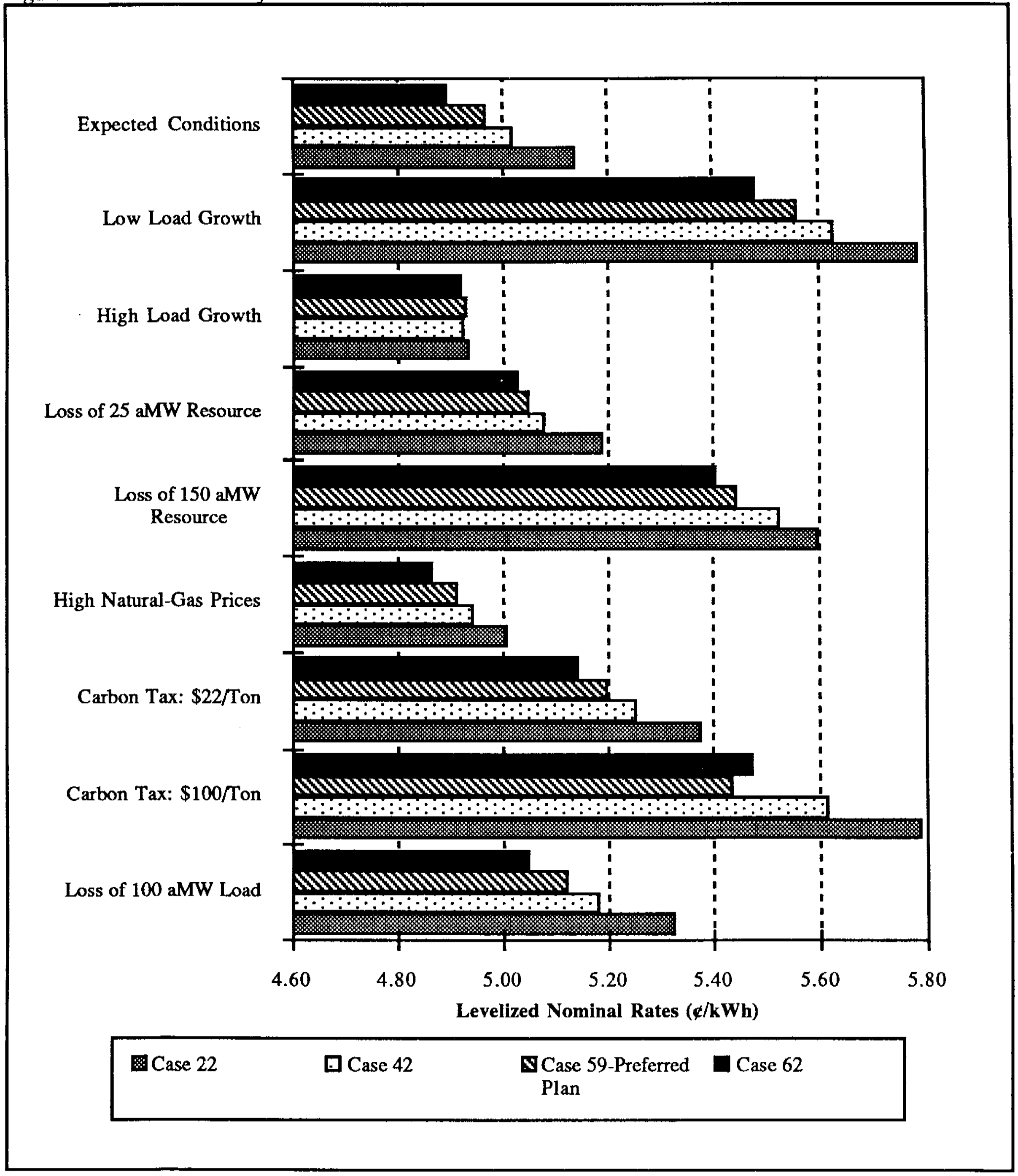


Figure H-22 shows the variability of rates resulting from each of the scenarios. For all but one scenario, Case 62 results in the lowest rates. The preferred plan ranks next in terms of rate performance. Low load growth, the loss of a large resource and a high carbon tax have the most effect on rates. In order to maintain the commitment as a low-cost provider of energy services, the company must be able to respond to such events. The preferred resource strategy is expected to provide the necessary flexibility to adjust to future conditions.

Appendix I

Capacity Planning

Capacity Planning

This appendix provides additional detail regarding WWP's capacity planning efforts. It contains information about the following topics:

- The current peak demand forecast and capacity resource needs.
- WWP's current plan to meet capacity needs.
- The proposed Rathdrum Combustion Turbine Project.
- Preliminary results from a new capacity planning tool.

Summary

The combination of the forecast peak loads, contract obligations and reserve requirements represents the company's long-term capacity requirements. These total capacity requirements are compared with WWP's existing peak-resource capability and contract rights to determine a capacity surplus or deficit for each year. Figure I-1 shows the current

Figure I-1: WWP's long-term capacity surplus/deficit (without new resources).

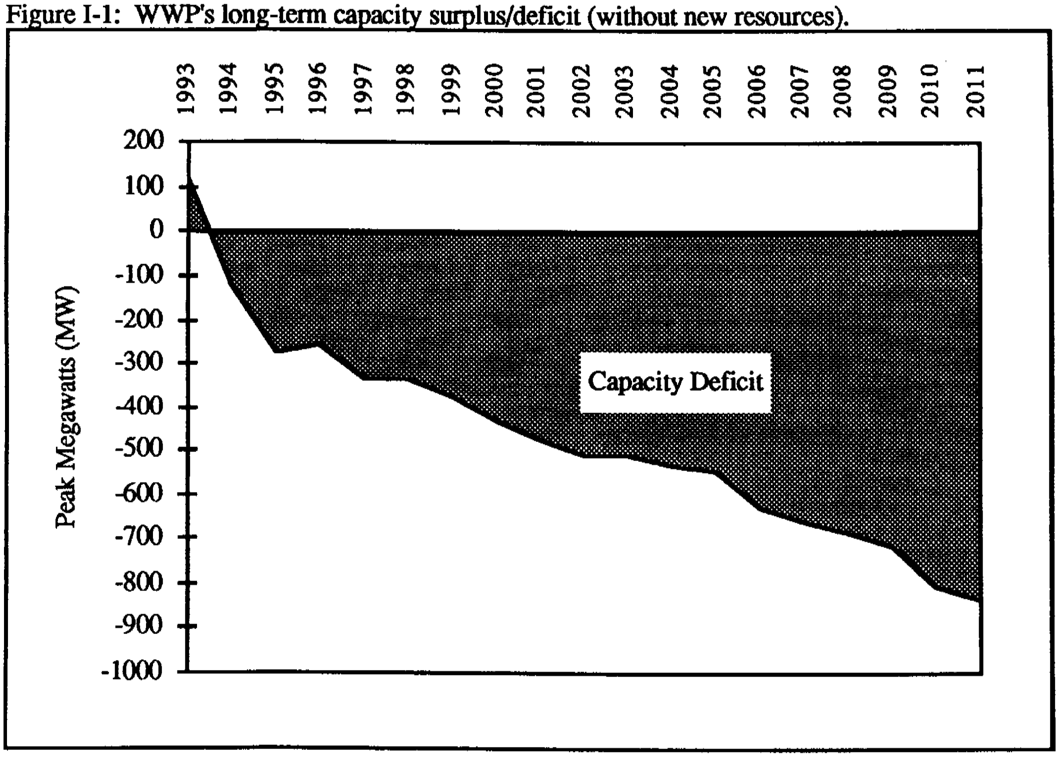


Figure I-1 (continued): WWP's long-term capacity surplus/deficit (without new resources).

Year	Total Capacity Requirements (MW)	Existing Generating Capacity (MW)	Capacity Surplus(+)/Deficit(-) (MW
1993	2240	2360	120
1994	2373	2256	-117
1995	2435	2158	-277
1996	2375	2120	-255
1997	2370	2034	-336
1998	2367	2033	-334
1999	2409	2031	-378
2000	2447	2012	-435
2001	2484	2010	-474
2002	2519	2010	-509
2003	2523	2010	-513
2004	2526	1992	-534
2005	2530	1985	-545
2006	2565	1934	-631
2007	2596	1934	-662
2008	2622	1934	-688
2009	2648	1934	-714
2010	2674	1865	-809
2011	2650	1815	-835

Without new resources, WWP is facing some immediate peak deficits. To meet these capacity needs, the company will rely on a mix of demand-side and supply-side resources. In addition to resources planned to meet the company's energy needs, WWP has proposed the installation of a pair of natural-gas-fired simple-cycle combustion turbines. A shown in Figure I-2, these planned energy resources and the Rathdrum combustion turbines will have a significant effect on the company's capacity deficits.

Figure I-2: WWP's plans to meet long-term capacity needs.

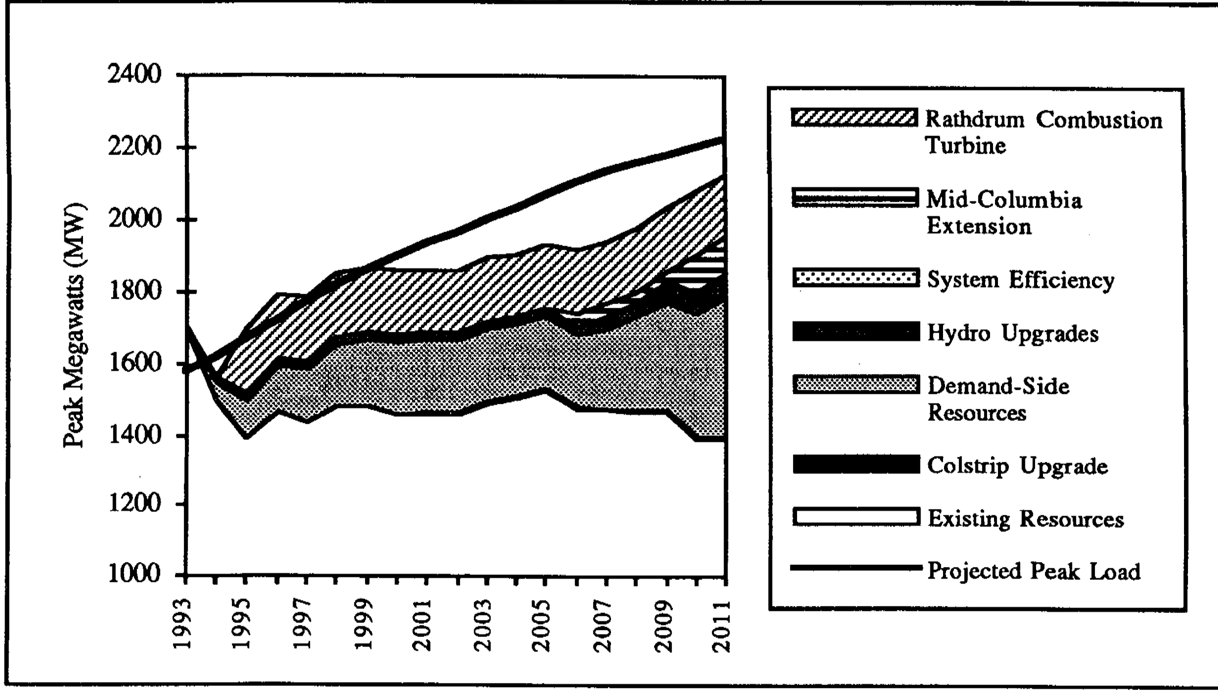


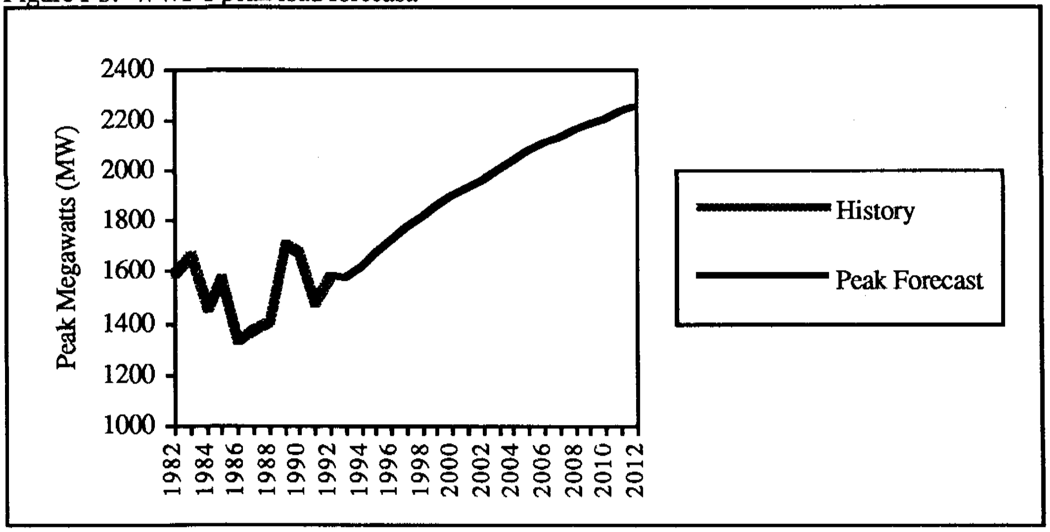
Figure I-2 shows how WWP's planned demand-side, hydroelectric and other resources contribute to meeting a portion of the projected peak load. The addition of the Rathdrum combustion turbine facility ensures that that the company has adequate generating capability until the year 2000.

Capacity Requirements

Capacity requirements include a forecast of the company's native peak load, contract obligations and reserve requirements. WWP projects monthly peak demand over the 20-year planning period. The peak-load forecast is produced for the medium-growth scenario only. The company's highest peak load typically occurs during the winter months of November through February. This peak, one-hour demand, which is forecast to occur sometime during this period, is based on an average daily temperature[1] of eight degrees Fahrenheit. Although WWP's service territory may experience colder temperatures, the company forecast needs are determined by the eight degree day. This forecast of peak loads is shown in Figure I-3.

1 Average daily temperature is the average of the high and low temperatures recorded for the day.

Figure I-3: WWP's peak load forecast.



Year	Peak Demand (MW)
1993	1576
1994	1613
1995	1668
1996	1719
1997	1768
1998	1814
1999	1856
2000	1893
2001	1929
2002	1963
2003	1998
2004	2033
2005	2068
2006	2101
2007	2130
2008	2153
2009	2177
2010	2201
2011	2226

Weather has a significant effect on peak loads. Based on recent analysis of historical temperature data for the Spokane area, the forecast temperature falls in the 97th percentile. In other words, 97 percent of the winter days are expected to average eight degrees or warmer. This cold spell analysis also indicates that Spokane experiences about three days per year when daily temperatures average eight degrees or colder[2].. An average daily temperatures of 32 degrees corresponds to the 50th percentile. This weather information is used to determine a relationship between temperature and peak loads. As average temperatures drop below eight degrees, peak loads are expected to increase at a rate of about 11 MW per degree

2 In winter 1992-93, WWP recorded three days with average temperatures at or below 8 degrees fahrenheit.

WWP's obligation to provide capacity to other utilities primarily includes contracts with Puget Power, Pacific Power and Portland General Electric (PGE). The agreements with Pacific Power and Puget Power expire in 1997 and 2004, respectively. The PGE contract began in 1992 and terminates in the year 2016. Under a seasonal exchange agreement with Pacific Gas & Electric (PG&E), WWP provides energy and capacity to PG&E in the summer and receives a like amount during the winter months. This exchange agreement ends in 2011.

A reasonable level of planning reserves helps the company ensure adequate generating capacity during periods of extreme weather or unexpected plant outages. WWP's capacity reserves include components for cold weather, generator forced outages and contingencies such as river freeze-up at hydroelectric plants. Although they vary by year, capacity reserves are approximately 12 percent of the company's total resources.

Meeting Capacity Needs

Resources planned to meet the company's energy load will have some impact on the WWP's ability to meet peak demand. Figure I-4 lists the capability of these planned resources as well as the capability of the proposed Rathdrum combustion turbines.

Figure I-4: Planned resource additions and their affect on capacity needs.

Year	New Resources						Capacity Surplus/Deficit (MW)
	Demand-Side Resources (MW)	Hydro Upgrades (MW)	Transmission & Distribution Savings (MW)	Colstrip Upgrade (MW)	Grant Cty. PUD Contract Extension (MW)	Rathdrum Combustion Turbine (MW)	
1993	3	0	0	0	0	0	123
1994	52	10	0	0	0	0	-55
1995	103	23	0	0	0	176	25
1996	129	23	0	0	0	176	73
1997	152	23	0	0	0	176	15
1998	171	23	0	0	0	176	36
1999	189	23	0	0	0	176	10
2000	200	23	0	0	0	176	-36
2001	201	23	0	6	0	176	-68
2002	201	23	0	6	0	176	-103
2003	202	23	0	6	0	176	-106
2004	202	23	0	6	0	176	-127
2005	204	23	0	6	0	176	-136
2006	206	23	0	6	36	176	-184
2007	222	33	2	6	36	176	-187
2008	258	33	4	6	36	176	-175
2009	297	53	6	6	36	176	-140
2010	341	53	8	6	105	176	-120
2011	388	53	10	6	105	176	-97

Demand-Side Resources

Demand-side resources are a key element of the company's strategy to meet long-term energy needs. The preferred plan calls for the acquisition of 50 aMW through 1996 and 136 aMW through 2011. A significant portion of these energy savings are expected to come from the company's fuel-efficiency programs. Under the preferred plan, the company plans to acquire approximately 81 aMW of fuel-efficiency savings. According to the demand-side assessment in Chapter 5, this represents all but 12 aMW of the 93 aMW of fuel-efficiency savings available at or below a levelized cost of 5 ¢/kWh.

WWP's demand-side management programs will also have a significant impact on the company's coincident peak load. Because they completely remove electrical equipment capacity from the system, fuel-efficiency programs that replace electric heating equipment with natural- gas equipment will have the most effect. Since fuel-efficiency program savings will be at the same load factor as the prior electric load, every 1 aMW of energy reduction is expected to provide a coincident peak reduction of about 3.6 aMW.

Conservation programs like weatherization provide electric efficiency and will also achieve some coincident peak reduction. However, for demand-side measures where existing electric equipment is not removed, the company is uncertain that coincident peak reduction will be as great as expected under the fuel-efficiency programs.

To date, regional efforts to estimate demand-side resource potential have focused primarily on energy savings and less on peak load reduction. For planning purposes, WWP has estimated the peak reduction associated with demand-side resources planned under the preferred resource strategy. WWP's measurement and evaluation activities will include a review of available utility research into the capacity impacts of demand-side resources. This review is expected to help the company refine its own estimates.

Hydroelectric Resources

Hydroelectric resources are sources of both energy and capacity. Their peaking capability is dependent upon the amount of water available. Storage projects that have the ability to draft reservoirs have more flexibility than run-of-river type projects that rely strictly on river flows. Noxon Rapids and Long Lake are WWP's primary storage projects. This ability to store water, and utilize it when most needed, is called shaping. The ability to shape the hydroelectric system adds great flexibility and value to the company's resource portfolio.

WWP recently investigated the costs associated with maximizing the output of the company's existing hydroelectric resources. Many of these plant modernization and efficiency improvement opportunities represent cost-effective energy supply alternatives. Each project will also add some amount of new hydroelectric capacity. Hydroelectric upgrades planned between 1994 and 2009 will provide approximately 14 aMW of energy and 53 MW of capacity.

Figure I-5: WWP hydroelectric upgrades will meet capacity and energy needs.

WWP Hydro Plant	Potential Capacity Increase (MW)	Installed Capacity Cost ($/kW)	Potential Firm Energy Increase (aMW)	Firm Energy Levelized Cost (¢/kWh)	Estimated On-line Date
Upper Falls	1.7	1,353	0.8	1.7	1995
Nine Mile Falls					
Without Pool Raise	11.1	1,027	1.7	2.4	1995
Cabinet Gorge					
Unit No.1	10.0	550	5.1	0.0	1994
Unit No.2	10.0	450	3.5	4.0	2007
Noxon Rapids					
Unit No.1	10.0	450	0.9	5.0	2009
Unit No.3	10.0	450	1.6	4.0	2009
Total	52.8		13.7		

Efforts are currently under way to extend the existing mid-Columbia purchase agreements with Grant County PUD. The company estimates that new Grant County contracts will provide 47 aMW of energy and 105 MW of capacity. The final results will depend on the terms and conditions negotiated. WWP also intends to negotiate the extension of existing agreements with Douglas County PUD and Chelan County PUD. All of these mid-Columbia contract extensions will help WWP meet long-term energy and capacity needs.

Combustion Turbines

Combustion turbines are often considered as capacity resources. Compared to other supply-side alternatives, they have lower capital installation costs and shorter licensing and construction times. Natural gas and oil are typical combustion turbine fuels. Many units have dual-fuel capability. Relatively short start-up times and high ramp-rates allow the units to be used for load-following. Technology advances associated with the combustion process have improved turbine fuel efficiencies and reduced emissions.

Operating costs and primary fuel are important considerations for all resources. These costs are more critical for facilities that would operate to serve base or intermediate load needs. Combined-cycle units that have a lower heat rate (higher fuel efficiency) than simple-cycle units are better suited to serve these base load needs.

Simple-cycle turbines are less expensive to construct than combined-cycle facilities. Because they are installed primarily as a system back-up to meet peaking needs, a higher heat rate (lower fuel efficiency) is acceptable. Dual-fuel capability provides resource reliability and can help offset fuel-cost increases.

WWP currently owns and operates one natural-gas-fired simple-cycle combustion turbine facility. The Northeast Combustion Turbine, located in northeast Spokane, provides the company with 68 MW of peaking capability. In early 1993, WWP selected a site near Rathdrum, Idaho, as the preferred location to install 176 MW of simple-cycle combustion turbine capacity. Following is a summary of the Rathdrum Combustion Turbine Project development.

Rathdrum Combustion Turbine Project

The proposed Rathdrum Combustion Turbine Project involves the installation of two natural-gas-fired simple-cycle combustion turbines and associated equipment. Natural gas has been selected as the primary fuel with leased gas storage proposed as a back-up fuel source. Each unit is a General Electric 7111EA combustion turbine with a winter rating of 88 MW. Actual project output depends on fuel type and atmospheric conditions and will range from approximately 68 MW to 88 MW.

Figure I-6: Rathdrum combustion turbine as a function of ambient air temperature.

Ambient Temperature	8.0 º F	10.0 º F	30.0 º F	90.0 º F
100% Output/Unit *	88.2 MW	87.7 MW	83.3 MW	68.4 MW
* "Dry-Low NOx Combustor" operating on natural gas.				

The estimated capital cost of the turbine project is $70 million, or $350 per kilowatt. The current schedule calls for commercial operation beginning in January 1995. Although the cost and availability of fuel supplies will ultimately determine how Rathdrum is operated, the project could be utilized for up to approximately 4,500 hours per year based on restrictions of the air quality permit that is being requested by the company.

Siting

WWP evaluated several sites in the region prior to selecting Rathdrum as the preferred location. In addition to being near the company's largest load centers, the Rathdrum site offered other advantages. Adjacent to a major WWP electrical substation (Rathdrum), the site eliminates the need to construct any significant new electrical transmission. The site is served by an abundant water supply and a municipal sewer system. It is less than one mile from a major natural-gas pipeline, near two state highways and adjacent to land zoned for industrial use.

Permits and Construction

Prior to the beginning of construction, the company's proposal must receive approval from several agencies.

- In January 20, 1993, the City of Rathdrum approved annexation of the plant site and zoned it for industrial use.
- The company's application to the Idaho Division of Environmental Quality (DEQ) for a Permit to Construct is currently pending.
- The Panhandle Health district must approve the design of the hazardous material containment facilities. This includes the diesel fuel storage system.
- The Idaho Public Utilities Commission must grant a Certificate of Public Convenience and Necessity.

The company anticipates receiving all necessary permits and approvals by August 1993. Based on this timing, ground-breaking for site preparation will take place in 3rd quarter 1993 with the majority of construction activity scheduled for 1994.

Environmental Considerations

The development and design of the Rathdrum turbine project involves the consideration of environmental impacts including air quality, sound, aesthetics and groundwater protection. All environmental considerations associated with development of the proposed project are being addressed through the permitting process. Each of these concerns will be addressed by the company's commitment to exceed requirements of all pertinent environmental regulations.

Air Quality: Idaho state air quality standards are virtually identical to national standards established by the federal Environmental Protection Agency (EPA). To limit emissions from the Rathdrum plant, WWP is committed to using the best proven combustion technology available.

Natural gas is the cleanest burning fossil fuel. The results of technical evaluations indicate that expected air emissions from the facility are well below Idaho and federal standards[3]. Nitrogen oxide (NOx) and Carbon Monoxide (CO) are the primary pollutants created during the combustion of natural gas. The planned combustor design would limit NOx to levels below 15 parts per million (ppm) and CO emissions below 25 ppm. NOx and CO emissions from the plant will each be less than 240 tons/year. This is defined by EPA and the state of Idaho as a Non-PSD (or minor) industrial source. Particulate levels would actually decrease because of planned road paving near the facility.

Groundwater Protection: The current fuel strategy for the Rathdrum facility calls for the use of diesel oil as a back-up fuel source only as a contingency plan. However, the potential storage of diesel oil on the Rathdrum site makes protection of the Spokane-Rathdrum Prairie Aquifer a major project development objective. Should on site storage ultimately be required, proposed oil containment measures would establish a new standard for protecting the aquifer from contamination. Four out of five finalist sites are located over the aquifer.

Preliminary design of the diesel oil containment system includes a steel storage tank protected by an impervious berm and a state-of-the-art leak detection system. Underlying the berm area would be a high-density, self-sealing and chemical resistant composite liner system. The proposed containment system would far exceed that required by both state and federal laws.

Sound: The Rathdrum combustion turbine facility would be located in an area zoned for industrial purposes. Sound emissions from the site are not expected to be problematic. The nearest residential property is more than 3/4 mile away. At these distances, the sound emission from the project will be barely audible.

Aesthetics: The company has assembled a Citizen's Site Development Committee. This volunteer group, which is comprised of nearby property owners, has been given responsibility for design of the site contouring and landscaping. Primary emphasis has been placed on screening the plant from the view of neighboring properties.

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3 Technical studies were completed by Woodward-Clyde Consultants, an internationally known environmental consulting firm. The information is contained in a Permit to Construct application filed with the Division of Environmental Quality in Boise, Idaho.

Public Involvement: Through an extensive public education and involvement process, the company hopes to address public concerns prior to the final design and construction phases of the turbine project. WWP has sought public input through a variety of activities and forums including:

- Open houses in the Rathdrum area.
- Presentations to various service clubs.
- Meetings with numerous public and state agencies, individual citizens and citizen groups.
- A local site development committee.
- Meetings with various local environmentalist groups.

These activities have had a direct impact on the project's development. Public input has influenced the design and technology of the natural-gas combustors and oil containment measures, as well as the landscaping of the overall plant site.

Project Benefits

The proposed project represents a cost-effective way for WWP to meet its combined capacity needs . The simple-cycle turbine is a proven technology which enhances the flexibility of the company's hydroelectric system. In addition to satisfying immediate and future capacity needs, the Rathdrum project as it is currently proposed offers many other benefits including:

- Approximately $1 million per year in property tax revenue for the taxing districts in Kootenai County, Idaho.
- More than $130 million in direct benefits for WWP customers. Revenues from a contract with Portland General Electric will offset the cost of the project and eliminate the need to recover the project capital costs through customer electric rates.
- Between 80 and 100 construction jobs and at least 3 permanent jobs.
- Infrastructure improvements for the local community that include the paving of roads and improvements to Rathdrum municipal water and sewer systems.

Other Capacity Resources

The planned resources described above will satisfy the company's immediate capacity needs. Alternatives that were considered are more expensive and do not have the same type of flexibility and reliability offered by the Rathdrum combustion turbine. Some options, like the proposed BC Hydro Transmission Interconnection, can not be developed in time to meet the immediate needs. This project and other resources will be considered as alternatives for meeting future capacity needs.

Long Lake Redevelopment

An additional hydroelectric upgrade opportunity exists at the company's Long Lake plant. This project involves the construction of a second powerhouse for the installation of one or two new 60 MW generators. Additional Long Lake generating capacity would allow the company to more fully utilize the existing hydraulic resource. Detailed studies have focused on the development of a single 60 MW unit project. The Long Lake expansion project may be considered as a future capacity alternative. Capacity costs for the this project are estimated at $1,000 per kilowatt.

WWP-BC Hydro Transmission Interconnection

In March 1993, the Department of Energy (DOE) issued a Presidential Permit authorizing a license to construct a 230,000 volt (230 kV) transmission line connecting the BC Hydro system in southeastern British Columbia with WWP's system in northeastern Washington. The proposed WWP-BC Hydro Transmission Interconnection consists of approximately 110 miles of new 230kV transmission line and would have an initial transfer capability of 800 MW. The capital cost of the interconnection is estimated to be $150 per kilowattt but does not include the cost of resources that would have to be purchased from Canadian suppliers.

In conjunction with the proposed interconnection, WWP has signed a Memorandum of Understanding (MOU) to purchase 200 MW of capacity from BC Hydro. The delivery of 200 MW of capacity depends on the construction of the interconnection. A contingency agreement calls for the purchase of 50 MW of capacity and is subject to the availability of firm transfer capability on the existing transmission system.

The decision to proceed with construction of the interconnection project depends on several factors including a policy recommendation by the British Columbia government regarding the long-term export of firm electricity. Project approval is also required by Canadian regulatory agencies.

Utility Purchases

WWP assesses the cost and availability of capacity from other utilities on a regular basis. The existing capacity exchange with Pacific Gas & Electric (PG & E) allows both utilities to take advantage of seasonal load diversity. WWP's ability to enter into additional exchange agreements is limited by low summertime hydroelectric conditions and maintenance requirements.

The surplus capacity available from other utilities, especially outside the Northwest, is often based on the cost to operate oil and gas-fired combustion turbines. A typical capacity purchase may also include the purchase of a minimum amount of energy. The cost to acquire these resources also includes the cost of electrical transmission (wheeling) and losses.

The company continually monitors capacity purchase opportunities. These potential purchases are compared with other capacity alternatives and pursued when they prove to be a cost-effective option.

Time-of-Use Rates

Time-of-use rates are based on the concept that there is a significant differential in the cost to supply power during peak-load hours versus off-peak load hours. Time-of-use rates are designed to discourage energy usage during heavy-load hours. Because time-of-use rates require the utility to install additional metering equipment, implementation for residential customers is considered costly. If the peak- and off-peak differential becomes significant, industrial and commercial time-of-use rates may become feasible. The company intends to further assess the feasibility of time-of-use rates in order to meet future capacity needs.

Load Control

Load control is being implemented by some utilities in the eastern United States. It involves the periodic switching of appliances, such as water heaters, during periods of peak demand. It requires the utility to install special control equipment. WWP's current fuel-efficiency program is considered a more cost-effective way of reducing peak demand associated with residential space and water heating equipment.

Hydroelectric Pumped Storage

Across the nation, there has been a renewed interest in pumped storage opportunities. Individual projects are being promoted in Washington, Oregon and Idaho. Pumped storage facilities rely on water stored in reservoirs to generate electricity during heavy-load hours. During the light-peak hours, the water is pumped back to the reservoirs. The disadvantage is 50% more energy is required to fill the reservoir than is generated. Capital costs for pumped storage are also significant. Although these costs are very site-specific, most fall in the range of $1,000 to $1,500 per kilowatt.

A New Capacity Planning Tool

In 1992, WWP began development of an additional planning tool that allows the company to evaluate capacity needs and resources on a daily basis. By incorporating variables that affect both load and generation, the model approximates operation of the company's resources. Inputs for daily load shape, river flows, reservoir draft limits and maintenance outages help to evaluate resource capability and needs under extreme conditions. Additional model development of the new planning tool is scheduled for 1993. Figure I-7 illustrates model results from a preliminary study.

The study results shown in Figure I-7 reflect how WWP resources might be operated to meet peak loads forecast for a January 1995 day. Resources are stacked according to typical operating procedures. Thermal resources and contract rights serve the base-load needs WWP's mid-Columbia purchase and run-of-river hydroelectric resources are used to serve intermediate needs. To the extent possible, the company's Clark Fork river plants (Cabinet Gorge and Noxon) are primarily shaped to follow peak loads. Combustion turbine capability, including the Northeast plant and planned Rathdrum facility, is used to meet any remaining peaks.

The conditions studied in Figure I-7 are fairly extreme. Total capacity requirements include the January 1995 peak-load forecast of 1,573 MW. The daily load shape is based on actual data recorded for a January 1993 day that had an average daily temperature of 5 degrees Fahrenheit. All contract obligations are assumed to be met over the peak-load hours. Each of the company's thermal plants are operating to full capacity, but streamflows reflect the average of the lowest flows over the last ten years.

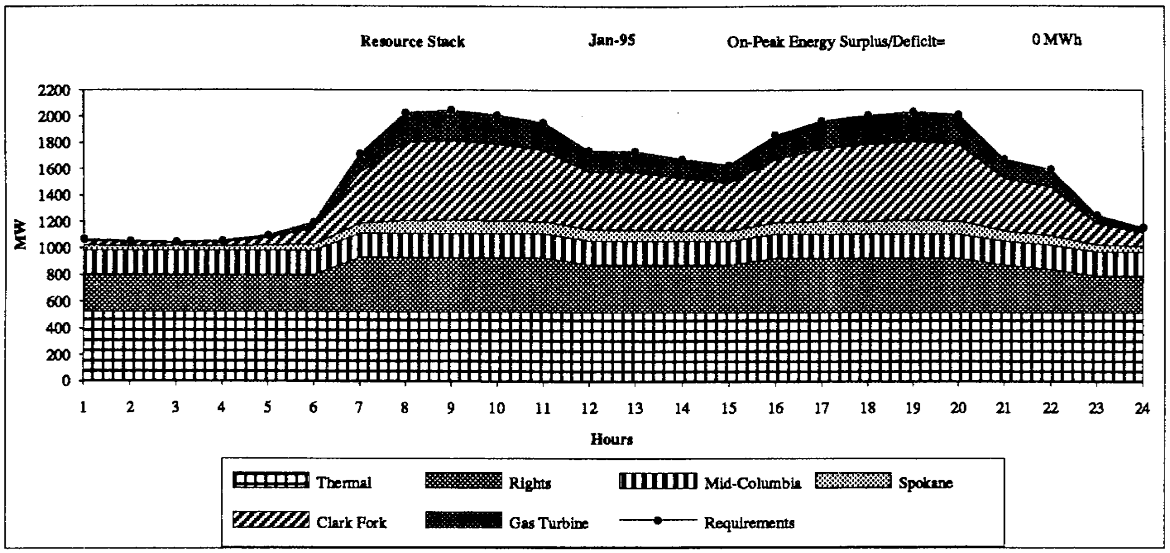
Under the conditions studied, the company's Noxon reservoir would be drafted to its current limits. WWP would rely on its combustion turbine peaking capability to meet loads during the peak hours. For the peak hour of the day, 231 MW of the total available 244 MW of turbine capability would be utilized. Under less severe conditions, the combustion turbines would be required to operate much less, if at all.

Figure I-7: Capacity Planning Model-Preliminary Study Results

Assumptions

Load	
Forecast Period	*Jan-95*
Peak Load	*1573 MW*
Average Load	1372 MW
Demand Period Day(1-5)	*1*
Saturation Factor	0 MW
Saturated Load	1573 MW
Load Shape (1-6)	*4*
Shape Day	1/7/93
Average Daily Temperature	5 °F
Daily Load Factor	87%
@Risk Load	
@Risk Adjusted Load	
Hydro	
Mid-Columbia Generation	*199 MW*
Mid-Columbia Maintenance	*20 MW*
Spokane River Flow	*2,200 cfs*
Run-of-River H/K	*15.50*
Reservoir H/K	*17.80*
Spokane River Maintenance	*0 MW*
Spokane River Generation	2,805 MWh
Long Lake Draft	*1 ft/day*
Noxon Inflow	*11,900 cfs*
Noxon Draft	*2 ft/day*
Noxon H/K	*11.40*
Noxon Maintenance	*0 MW*
Noxon Generation	5,319 MWh
Cabinet H/K	*7.00*
Cabinet Maintenance	*0 MW*
Cabinet Generation	3,077 MWh
Thermal	
Centralia On-Line	*192 MW*
192 MW Maintenance	*0 MW*
Colstrip On-Line	*216 MW*
216 MW Maintenance	*0*
Kettle Falls On-Line	*47 MW*
47 MW Maintenance	*0 MW*
Northeast Max. On-Line	55 MW
68 MW Maintenance	*0 MW*
Rathdrum Max. On-Line	176 MW
176 MW Maintenance	*0 MW*
Reserves	
Other	*0 MW*
ICP Reserves	*140 MW*
Total Reserves	140 MW
New	
Peak Purchase	*0 MW*
Off-Peak Purchase	*0 MW*
Total New	0 MW
Results	
Total Peak Hr Surplus/Deficit	0 MWh
1-Hour Peak Surplus/Deficit	0 MW
Total Off-Peak Hr Surplus/Deficit	0 MWh
1-Hour Off-Peak Surplus/Deficit	0 MW

Chart1



Summary

Hour	Load Forecast Jan-95 1573 MW	Contract Obligations Peak MW	Baseload Thermal Generation Peak MW	Contract Resources Peak MW	Mid-Columbia Hydro Peak MW	Spokane River Hydro Peak MW	Clark Fork Hydro Peak MW	Peaking Thermal Generation Peak MW	Total Resources Jan-95 Peak MW	Net System Load plus Obligations Day 1 Peak MW	Peak Demand Surplus/Deficit Jan-95 Peak MW	%ofTime Duration Hour	Total Resources Duration Peak MW	Net System Load plus Obligations Duration Peak MW
Hour	Net Load	Obligations	Thermal	Rights	Columbia	Spokane	Clark Fork	Gas Turbine	Resources	Requirements	Surplus/Deficit	%ofTime	Resources	Requirements
1	1120	-53	524	279	179	38	34	13	1067	1067	0	4%	2051	2051
2	1110	-53	524	279	179	37	27	10	1057	1057	0	8%	2038	2038
3	1101	-53	524	279	179	37	21	8	1048	1048	0	13%	2031	2031
4	1112	-53	524	279	179	37	29	11	1060	1060	0	17%	2016	2016
5	1151	-52	524	279	179	40	56	21	1099	1099	0	21%	2014	2014
6	1243	-50	524	279	179	47	119	45	1194	1194	0	25%	2010	2010
7	1463	255	524	410	179	77	382	146	1719	1719	0	29%	1970	1970
8	1554	478	524	410	179	100	592	226	2031	2031	0	33%	1957	1957
9	1573	478	524	410	179	102	605	231	2051	2051	0	38%	1860	1860
10	1537	477	524	410	179	99	580	222	2014	2014	0	42%	1744	1744
11	1481	476	524	410	179	95	542	207	1957	1957	0	46%	1741	1741
12	1420	324	524	360	179	83	433	165	1744	1744	0	50%	1719	1719
13	1417	324	524	360	179	82	431	165	1741	1741	0	54%	1683	1683
14	1360	323	524	360	179	78	392	150	1683	1683	0	58%	1678	1678
15	1313	322	524	360	179	74	360	137	1635	1635	0	63%	1635	1635
16	1387	474	524	410	179	88	477	182	1860	1860	0	67%	1601	1601
17	1494	476	524	410	179	96	551	210	1970	1970	0	71%	1258	1258
18	1533	477	524	410	179	99	578	221	2010	2010	0	75%	1194	1194
19	1560	478	524	410	179	101	596	228	2038	2038	0	79%	1165	1165
20	1539	477	524	410	179	99	582	222	2016	2016	0	83%	1099	1099
21	1502	176	524	360	179	78	389	149	1678	1678	0	88%	1067	1067
22	1426	175	524	329	179	74	358	137	1601	1601	0	92%	1060	1060
23	1306	-48	524	279	179	52	162	62	1258	1258	0	96%	1057	1057
24	1216	-50	524	279	179	45	100	38	1165	1165	0	100%	1048	1048

Capacity Planning Model Definitions, Assumptions and Logic Summary

Load Information

Peak Load: Forecast January peak load forecast.

Average Load: Average load over the 24-hour period (Peak load x hourly load shape).

Load Shape: The nature of electric loads experienced on the WWP system. For a cold winter day, loads begin to increase at 6:00 a.m. and peak around 8:00 a.m. or 9:00 a.m. Loads drop off during mid-day until a second peak occurs later in the day. The load shape used for WWP's preliminary studies was based on actual data recorded for January 7, 1993, when the average temperature was 5 degrees Fahrenheit.

Hydroelectric Generation

Mid-Columbia hydroelectric generation is assumed to be base loaded during periods of cold weather.

Generation from WWP's Spokane and Clark Fork river plants is conservative. River flows were based on the average of the lowest January daily flows for the last ten years.

H/K: Water to power conversion factors for Spokane run-of-river plants, and Spokane and Clark Fork river reservoir plants. The values assumed in the study represent the expected performance of WWP hydroelectric plants for a winter period.

Thermal Generation

Centralia, Colstrip and Kettle Falls plants are operated to meet base load needs. Northeast and Rathdrum simple-cycle combustion turbines are available to meet peak loads that cannot be met by WWP's hydroelectric system.

Reserves

Represent an estimate of WWP's contractual reserve obligation. In the model, these reserves are netted against available hydroelectric generation from the Noxon plant.

Resource Stack Logic

Base load resources includes thermal generation, contract rights and run-of-river hydroelectric plants. Operation of these resources is generally flat for all hours.

Intermediate and peak loads are first met by shaping the company's storage hydroelectric resources (Cabinet Gorge and Noxon Rapids on the Clark Fork River and Long Lake and Little Falls on the Spokane River). The output from these plants is shaped in proportion to the resource needs remaining after operation of the base load resources.

Peaking thermal resources include WWP's gas-fired combustion turbines (Northeast and the proposed Rathdrum facility). They are operated to meet any peak loads that cannot be met by the company's base load thermal and hydroelectric resources.

Appendix J

Wholesale Marketing

Wholesale Marketing

Summary

WWP has the tools and the expertise to selectively take advantage of wholesale market opportunities that reduce the total cost of resources for its retail customers. Active involvement in wholesale marketing allows WWP to understand available resource opportunities and to take advantage of those resources which enhance its existing resource mix. The company will continue to investigate all new opportunities they become available.

Firming nonfirm hydroelectric resources is one example of a potential WWP wholesale marketing opportunity.
This appendix contains a summary of the company's firming nonfirm study that was completed in 1992.

Firming Nonfirm Hydroelectric Energy

Prepared by Mike Griswold, WWP Business Analysis, January 1993

A study has been completed on the feasibility of converting nonfirm hydroelectric energy into firm energy. This study was originally undertaken by Finance and Power Supply in June 1989. This earlier study was a conceptual study that identified the circumstances that would have to exist in order to economically firm nonfirm hydroelectric energy. The objective of the current analysis is to determine an actual projected value of firming nonfirm utilizing the company's most recent operating and construction data. In preparing the study, assistance was provided by Gas Supply on projected gas prices and Power Supply on available nonfirm energy, energy rates, and on both combustion turbine (C-T) capital costs and operating characteristics.

The objective of firming nonfirm is to turn the lesser valued nonfirm energy into firm energy via a back-up power source. Since the availability of nonfirm hydroelectric energy is contingent upon rainfall, snowpack, and the operability of the region's thermal plants, its deliverability cannot be guaranteed without a firm resource. This analysis assumed that the firming resource would a 100 MW simple cycle combustion turbine with operating characteristics similar to a GE Frame 7EA.

The analysis used a software program called @Risk that utilizes simulation technology which incorporates risk analysis. All material variables subject to a significant degree of risk were assigned ranges of values with corresponding probabilities of attaining those values. The simulation model randomly assigns a number for each variable based upon the probabilities given to that variable. These values are then input into the monthly cash flows, which are summarized in an annual cash flow analysis. The results, as expressed by the NPV (Net Present Value) and IRR (Internal Rate of Return), are recorded as outputs for that iteration of the simulation. The process is repeated for a preset number of iterations, with the final output being an expected value NPV and IRR. This analysis was based upon 5,000 iterations. A minimum of 350 samples is recommended when using the Monte Carlo method of sampling employed in this analysis. The expected value is defined as the summation of the output (NPV or IRR) times the probability of it occurring for all iterations. The probability of achieving any one result is equal to one divided by the number of iterations.

The initial step in the analysis was to determine how much of WWP's nonfirm hydro energy was available. WWP's available nonfirm hydro was based upon the fifty year water period from July 1928 through June 1978. For each water month, total generation was computed based upon WWP's projected hydro capacity in 1995 which included the Monroe Street Rebuild and the Nine Mile and Cabinet Gorge turbine upgrades. Excluded from total capacity was Chelan (contract terminates by 1995) and a 30 aMW fish adjustment. A water-year trend was calculated by applying a normal distribution with July's 50 year median as the mean and July's 50 year standard deviation as the standard deviation. The percentage variance from the median was then applied for the subsequent 11 months. This is based upon the premise that there is a discernible annual trend in water conditions.

From total energy capability both critical water capability and the Northeast Turbine capability were deducted. If the remaining value was positive it was assumed that WWP had available nonfirm energy. The analysis did not include any reduction to available nonfirm energy arising from the company's future interchange obligations under the Pacific Northwest Coordination Agreement. It was assumed that the company would make a purchase from the region at market prices for 100% of its interchange liabilities. No other regional purchases were assumed in the analysis, although the company would make regional nonfirm purchases as long as the price was less than the dispatch price of the thermal back-up unit.

The predicted nonfirm energy price was correlated with WWP's available hydro energy during the months of February through July. The correlation was computed by Power Supply and was based upon the historical period from 1982 through 1992. Power Supply's forecasted wholesale secondary prices were used as the mean price which was then adjusted inversely for available water and randomly based upon the monthly standard deviation. Using the nonfirm price and the actual water availability as the X-Y data points, a least squares regression analysis was performed that computed a Y intercept, a standard deviation and the slope of the line. It was found that there was an inverse relationship between price and water in the months of February through July and no correlation in the remaining months.

Nonfirm prices for all months with a correlation between price and water were computed by starting with the forecasted wholesale price, adding a hydro availability bias, and then adding a randomly generated value based upon a normal distribution around 0 with the appropriate monthly calculated standard deviation. The hydro availability bias is defined as the slope of the line times the difference between the predicted water minus the month's median water. The result of the calculation was subject to a floor that was defined as the incremental cost to operate the cheapest thermal unit, which was estimated to be 7 mills in 1995. For months without a price-water correlation (August through January), the calculation of the secondary price was identical to the above, but did not include the hydro availability bias adjustment.

The forecasted nonfirm price was then compared to the cost of production for the month. If the nonfirm price was cheaper and there was available nonfirm energy, the model would purchase the lesser of the available nonfirm energy or the firm requirement. The cost of production was based upon fuel costs and variable O&M. Fuel costs were calculated based upon a combustion turbine with an average heat rate of 11,682 Btu/kWh and natural gas priced at $2.00/mmbtu in 1995. Annual fuel prices were seasonally adjusted by using actual monthly gas prices provided by Gas Supply. Fuel inflation was predicted by using a normal distribution with 7% as the mean and a 3% standard deviation not subject to a floor or a ceiling. Variable nonfuel O&M was assumed to be 7.66 mills/kWh in 1995 dollars and was subject to annual inflation with a normal distribution having a mean of 4.2% and a standard deviation of 1%. Total variable costs were converted to $/MWh in order to make a comparison to nonfirm prices.

A separate decision to run the thermal unit or purchase secondary energy was made for each month. The expected value for the percentage of energy purchased was determined to be 49.2% with 50.8% of the total energy coming from the thermal back-up unit. The thermal utilization arises from the unavailability of WWP's nonfirm hydro energy and not from price dispatching since the price of nonfirm was determined to exceed the cost of production only 1.9% of the time.

Monthly costs were totaled by year and summarized in the annual cash flow analysis. Revenues were based upon selling 100 MW with a 95% plant factor for the months of October through April and 92 MW with a 95% plant factor for the months of May through September. Total annual sales equaled 803,100 MWH/year. The sales price was assumed to be 90% of the company's Washington Avoided Cost rate which levelized to $52.38/MWh over the 1995-2014 contract period. Offsetting these revenues were the variable expenses associated with the purchased and generated energy. An annual fixed O&M based upon the projected fixed O&M from two GE Frame 7EAs was assessed against the cash flows. The fixed O&M was estimated by assuming that 60% of the total annual fixed O&M would vary based upon the size of the unit, and 40% of the fixed O&M would not vary. Included in fixed O&M are salaries, carrying costs for the backup fuel supply, and other miscellaneous charges.

Property taxes were charged against net book value, subject to a minimum floor of 50% of original book value, at 1.25%. This assumes that the thermal unit would be sited in Idaho. The asset was recovered for both book and tax purposes over a 20 year life using straight-line and MACRS depreciation schedules, respectively. Income taxes were assessed against net taxable income at a rate with a discrete distribution having an 85% probability of being 34%, a 10% probability of being 40%, and a 5% probability of being 50%. The expected value of this variable is 36%. Capital was assumed to be expended over a four year period and was charged against cash flows in the year incurred. Total capital was estimated to be $42,798,604 and was calculated by taking the ratio of the plant size to the Rathdrum turbines plus 10% [(100/168)*1.1]. After-tax cash flows were totaled by year and discounted at 8.97% to compute the net present value.

The following table summarizes the results of the analysis:

Plant Size	Capital Cost	Expected Value NPV	Expected Value IRR	Discounted Payback	% of Energy Purchased
100MW	$42,798,604	$30,323,012	20.06%	8 Yrs	49.20%

The results of the analysis indicate that there are economic benefits to the company from firming in its own nonfirm hydro energy. This analysis, based upon the inputs identified above, indicates that WWP could expect to earn $30,323,012 on an investment of $42,798,604. This investment would earn a return of 20.06% and would be fully recovered in eight years. If the company was able to purchase secondary energy from the region for less than the cost of production these benefits would increase. As shown in Figure J-1, the analysis resulted in a range of NPVs from a low of minus $10 million to a high of plus $66 million over the 5,000 iterations performed.

Figure J-1: Firming nonfirm study results.