MANAGING ELECTRICAL RESOURCE OPTIONS FOR THE FUTURE

LEAST-COST PLAN

Washington Utilities and Transportation Commission

RESOURCE MANAGEMENT REPORT

Idaho Public Utilities Commission

THE WASHINGTON WATER POWER COMPANY
APRIL 1991

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INTRODUCTION

This report is an update of the "least-cost plan" report published by The Washington Water Power Company (WWP) in April 1989. As indicated by the title, "Managing Electrical Resource Options for the Future," the company is developing resource acquisition plans to manage resource options in such a way as to meet the future electrical requirements of its customers at the lowest possible cost. This report is also used to meet the planning requirements of both the Washington Utilities and Transportation Commission and the Idaho Public Utilities Commission.

The least-cost resource planning process is an ongoing process. This planning effort cannot predict the future, but it does help provide an understanding of the future implications of current decisions. There have been many changes over the past few years which have affected resource planning and point to the need for flexibility in planning. Some of these changes are competition among supplies and suppliers of energy, concerns for the environment, regulatory activities, and customers' service demands.

Resource planning provides no simple answers. Major uncertainties are necessarily encountered in any planning process involving a 20-year planning horizon. For this reason, the plan examines numerous resource scenarios against a variety of assumptions which are designed to minimize the impacts of the uncertainty of future events by covering a broad range of potential futures. This effort provides an opportunity for WWP, state regulators, and the public to collaborate in developing a reliable low-cost electric resource plan.

The company has begun two new processes which affect its planning and resource acquisition efforts. One is the development of a competitive bidding program, or "Request for Proposals" (RFP) procedure, in connection with the acquisition of new resources. The RFP is consistent with WWP's least-cost plan with regard to the size of the resource block to be met with bid proposals and the use of the calculated avoided cost schedule. It is anticipated that the bid proposals received from WWP's RFP will influence future resource acquisition plans of the company, as well as the determination of future avoided cost calculations. The second new process affecting planning efforts is the use of scenario planning, which is a process within which "what if" analysis can be performed. This process is designed to increase planners' awareness of alternative futures and WWP's subsequent ability to react appropriately. Scenario planning involves the selection of probable future scenarios from a number of possible alternative futures.

The purpose of this planning effort is to develop and implement strategies that will assure future customers' needs are met with efficient electric energy services. These energy services need to be reliable and attainable at reasonable cost, both now and in the future. This can only be achieved if all parties involved in the planning process recognize the uncertainties the company faces in future electric energy sources and requirements.

This report is an accumulation of the efforts of many individuals both inside and outside the company. It is a 20-year resource plan for WWP which attempts to consider various future events and develop a series of power cost scenarios to meet the company's resource planning objectives. Future revisions and resource development plans will continue to include input from the public and the staffs of utility commissions in both Washington and Idaho.

SUMMARY

As the 1990s begin and WWP embarks on its second century of service, the company's commitment is to provide its customers with the lowest-cost energy available. As a low-cost producer and competitive supplier of energy services, the company plans to continue its position as the customers' preferred supplier of energy service in the 1990s. The objective of least-cost planning is to accomplish that goal.

Least-cost planning is the process of planning for and selecting resources from both supply-side and demand-side options in such a way as to minimize costs to the company and its customers. It is WWP's expectation that least-cost planning will be achieved in a manner consistent with system reliability objectives and the need to maintain an adequate rate of return.

WWP's current (medium) base electric load-growth forecast indicates the company will need long-term firm energy resources starting in 1995, given existing resource and contract termination dates. By the year 2009, the energy deficit is 166 average megawatts (aMW) and the peak deficit is 355 megawatts (MW). These anticipated deficits will be met by both demand-side and supply-side resources.

The integrated resource planning process needs to be flexible to take into account a wide range of uncertainties in both load projections and available resources. Through programs and studies conducted over the past two years, the company has attempted to position itself to make the decisions which now need to be made relating to the acquisition of electrical resources.

WWP's current long-term strategy is to rely on five resource types to meet future requirements. These resource types are energy efficiency programs, residential space and water heat conversion programs, hydro system improvements, a Request for Proposals (competitive bidding program) and combustion turbines. By the year 2009, WWP expects demand-side resource options to provide 30 aMW from energy efficiency programs and 31 aMW from fuel conversion programs. Direct firing of natural gas for space and water heating is a much more efficient use of natural gas than is generating electricity with the gas and selling electricity to customers for those end uses. It is also more cost-effective. The space and water heat conversion program will encourage customers to replace electric space and water heating equipment with natural gas equipment.

WWP could realize 36 aMW from hydro system improvements, if the presently identified improvements prove to be cost effective. The company plans to issue a Request for Proposals in 1991 for 30 aMW of resources in 1995. Combustion turbines will be used as a backup for planned resources if those resources cannot be realized. Combustion turbines could also be used as a supply of firm electrical energy in the year 2006, if the forecasted need develops and if the operational cost can be shown to be cost effective.

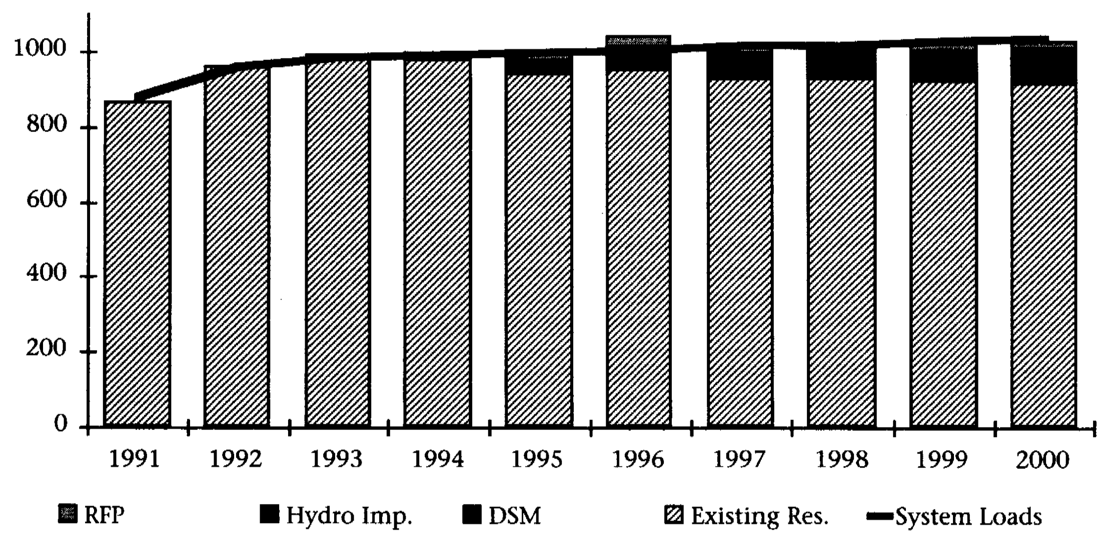
During the next two years, the company will begin acquiring resources identified in the previous paragraph. WWP will also pursue all cost-effective system efficiency savings currently being identified in the distribution and transmission systems. In addition, the company is implementing a cogeneration development program within its service territory. This generation will be used by WWP, if needed, or sold off-system. As a result of the scenario planning done in this report, it became apparent of the need for pursuing transmission interconnections to allow the company access to additional electrical markets and supplies. Other studies will also be done to enhance the company's ability to acquire cost-effective resources, if and when the need develops. These resource acquisitions and studies will allow the company to meet its projected system requirements and maintain the flexibility needed to handle changing conditions.

Planning for the next two to five years is a worthwhile endeavor and can be done with a fair degree of certainty. Planning for 10 years involves a multitude of questions that can't be answered with a high degree of precision. Undertaking a planning horizon of 20 years is next to impossible. There are just too many changes that occur in both the requirements and resources. WWP relies on short term sales and purchases to satisfy changes that occur in the short term. The long term planning is revised annually or more often if known conditions have changed.

The company's existing resources, load forecasts, and planned resources based on the medium (most probable) energy forecast for the next 10 years, are shown below:

WWP's Requirements and Resources

Figure 1.



Chapter 1

THE COMPANY

Company Profile

The Washington Water Power Company (WWP) is an investor-owned electric and natural gas utility serving a 26,000-square-mile area in eastern Washington and northern Idaho. The company is based in Spokane, Washington, the largest community served in the area. Electric service is supplied to approximately 246,000 customers, and natural gas is supplied to approximately 90,000 customers. In late 1990 WWP reached an agreement to purchase CP National Corporation's natural gas distribution system in Oregon, California, and Nevada.

In addition, the company owns one subsidiary, Pentzer Corporation, a parent company to its diversified operations. The diversified operations include real estate (e.g., Spokane Industrial Park), telecommunications (e.g., NW Telco), energy (e.g., WP Energy), solid waste (e.g., Solganic Services), and investments (e.g., ITRON). In 1990, WWP sold its 50 percent ownership of a coal mining operation called Washington Irrigation and Development Company to Pacific Power & Light Company.

At the end of 1989, WWP had 36,968 shareholders of common stock located in all 50 states, as well as in 22 countries. A total of 39 percent of company shareholders live in the Pacific Northwest, with 28 percent residing in the state of Washington.

Current Issues

As the company begins the 1990s, WWP's framework for future growth has been clearly established. WWP will continue to build on the foundation provided by its successful energy business. The position as a low-cost producer and supplier of energy services will be reinforced. We will continue to focus on opportunities for further development of subsidiary operations. The company will remain a leader in regional economic development activities and will continue the tradition of service excellence to customers, communities, and shareholders.

Retaining the position as a low-cost producer and supplier of energy services strengthens WWP's position in an increasingly competitive marketplace and has allowed WWP to become more aggressive in the wholesale and retail markets. Much of the improvement in utility operating revenues for 1989 is a direct result of our wholesale marketing efforts, which produced an increase of $15 million in wholesale electric revenues. The company continues to promote the efficient use of electricity where electricity is a good value for the customer. In 1989 we added approximately 3,000 new customers, most of them residential, to each of the electric and gas systems, and we signed long-term natural gas supply contracts with a number of large volume customers, assuring retention of this important gas load.

While the primary focus of our plans for future growth remains on our utility operations, the expansion of subsidiary businesses will have a stabilizing influence on future earnings.

In the past year, WWP pursued a business opportunity which we believe will provide an excellent return on our investment. WWP acquired Northwest Telecommunications, Inc., a world-wide long-distance telephone service company.

In a short period of time, WWP has witnessed a turn-around in the regional economy. The economic outlook for the region just a few years ago was not very encouraging. Today the report is a much brighter outlook. We are proud to have been involved in a number of programs, such as Momentum in Spokane and Jobs Plus in northern Idaho, which have helped stimulate economic development throughout the Inland Northwest. These programs have contributed to a renewed feeling of enthusiasm that prevails throughout the region, and also provide the foundation for a new era of economic growth and expanded levels of demand for energy services.

A companion strategy to economic development efforts is our commitment to education. The challenges of today's global economy require the talents of a well-educated highly motivated work force. The company, through its education initiative, is committed to helping provide the Inland Northwest with the leadership to meet these challenges. The commitment extends to all levels of education, and the programs will benefit students and educators in every community we serve.

Driving all our strategies, of course, is our ongoing commitment to service excellence. Providing outstanding service has been our business for 100 years, and excellent customer service will be the one element that will set us apart from our competitors as we begin the second century. While planning for the future energy requirements of our customers remains important, the company has also recognized the importance of offering services which enhance the lives of its customers.

In the area of demand-side management, which is considered by the company as the number one resource option, the company began to staff an energy management section in its marketing department in 1989. The purpose of this section is to assess the potential and cost of demand-side resources on our system and to implement programs to acquire this resource. Preliminary information regarding demand-side management will be available in early 1991, and is included for informational purposes as appendix C of this report. Those DSM programs providing the lowest cost energy will have first priority.

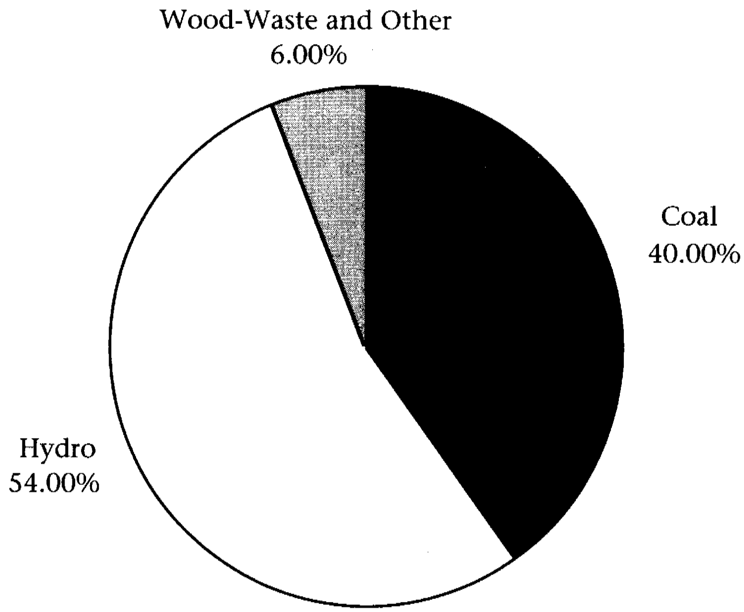
Generating Capacity

WWP was incorporated in 1889, and was entirely hydroelectric based until 1971, when the Centralia coal-fired plant in western Washington came on-line (WWP has a 15 percent ownership). The company's largest hydroelectric plants (Noxon Rapids and Cabinet Gorge) are located on the Clark Fork River in northwestern Montana and northern Idaho, respectively. The remainder of WWP's hydroelectric capacity is on the Spokane River in eastern Washington and northern Idaho.

The company owns 946 megawatts (MW) of hydroelectric generating capacity (peak). WWP also purchases a total of 221 MW (peak) of hydroelectric generation from four projects located on the mid-section of the Columbia River (Priest Rapids, Wanapum, Rocky Reach and Wells) and the Chelan Falls project.

WWP's thermal plant ownership, consisting of 521 MW (peak), exists at the Centralia coal-fired plant in western Washington, the Kettle Falls wood-fired plant in northeastern Washington, the Colstrip coal-fired plant in eastern Montana, and the oil/gas-fired combustion turbine (Northeast) in eastern Washington.

In 1989, the generating resources owned by the company produced a total of 7,180.4 million kilowatt-hours (the hydro generation figures vary depending on streamflow conditions). The figure below shows the breakdown of generation by fuel type for 1989:



Percent of 1989 Kilowatt-hours Generated

Figure 1-1. Distribution of WWP's generating resources in kilowatt-hours for 1989.

Also in 1989, the company received 1,287.2 millions of kilowatt-hours of generation from long-term hydro purchase agreements with the Mid- Columbia hydro projects. This amount of power is 33 percent of the total hydro generation received from company owned hydro facilities, and if combined with the generating resources of WWP, would give hydro 61 percent of the total generating energy capability of WWP for 1989.

Transmission and Distribution

The company's transmission system consists of 230 kV and 115 kV circuits extending from Hot Springs, Montana west of the Columbia River in Washington, south to north-central Idaho, and north to the Canadian border. The transmission system circuit mileage is 2,046. WWP also owns 10,757 miles of distribution lines.

During 1991, WWP will receive the Presidential Permit on the proposed transmission line interconnection with British Columbia Hydro and Power Authority. This interconnection would have the capability of delivering a maximum of 1,200 megawatts of power into WWP's electric system. At 1,200 MW, the line far exceeds WWP's needs. To maximize the use of the line, WWP will need to have other utilities participate. To get the power to other utilities would require some strengthening of WWP's transmission system. The facility is a 128-mile, 230-kilovolt, double-circuit transmission line. After state and local permitting is completed and the line is found to be a cost-effective way of meeting future power needs, the line could be operational by 1996.

Arrangements with Other Utilities

WWP frequently purchases, sells or exchanges power with Canadian and United States entities including BPA, municipalities, public utility districts, and other investor-owned utilities. In the past, a significant part of the company's wintertime capacity used to meet customer requirements came from firm power contracts with other utilities.

Wholesale Business

On a day-to-day basis, WWP is continually buying and selling energy on the secondary market. Other services, such as load factoring and storage is also purchased and sold on a daily and seasonal basis in order to maximize the highest value for the energy. WWP also uses this marketing strategy on a firm commitment basis for a longer period of time (one to four years).

The company will buy firm power if there is an opportunity to mix that energy with other services producing a product that is salable in the firm marketplace. In addition, WWP is willing to purchase cost-effective resources that are surplus to its needs, if it is felt that there is a good possibility of selling the firm power to other utilities. These cost-effective surplus resources could come from a wide range of altervatives including cogeneration development, hydro improvements and purchases from utilities outside the region. The resource possibilities are a business opportunity for the Company and would be evaluated from both a rate base and subsidiary application.

The company is also a member of various regional entities that provide various coordinating functions on a multi-utility basis and regional planning perspective. Some of these entities include the Western System Coordinating Council (WSCC), Pacific Northwest Utilities Conference Committee (PNUCC), Northwest Power Pool (NWPP), Pacific Northwest Coordinating Group, and the Intercompany Pool (ICP).

Other Considerations

Power sale contracts entered into with other electric utilities essentially ended the company's period of power surplus. The company will be in a relative load-resource balance through 1993, although some short-term deficits will need to be covered with short-term purchases. We anticipate the greatest portion of the company's power supply needs from 1994 through 2005 will be covered by a combination of hydro system redevelopment, demand-side management programs and purchases. The purchases will be from utilities and nonutility power developers. Some of these purchases will be facilitated through a bidding process. WWP expects to issue a Request for Proposals in 1991 for long-term purchase of resources.

Include short-term resources in L/R as planned resources to meet future loads.

One of the company's planning policies in the past has been to refrain from acquiring long-term firm resources unless the need for energy on an annual basis is greater than 50 aMW. The need for firm energy less than 50 aMW is planned to be met by purchases on the short-term market and/or by better than critical hydro conditions. WWP's analyses show short-term purchases to be available at reasonable cost. This policy for planning resource acquisitions remains in effect at the present time but will be reviewed periodically or as conditions change.

Actual determination of WWP's long-term resource acquisition strategy will come from this least-cost planning process. The goal of the least-cost plan is to identify a mix of resource options which provide reliable electric service and minimize the cost of electrical energy to the customer. WWP has also developed a least-cost plan for gas activities.

Hydro Facility Improvements

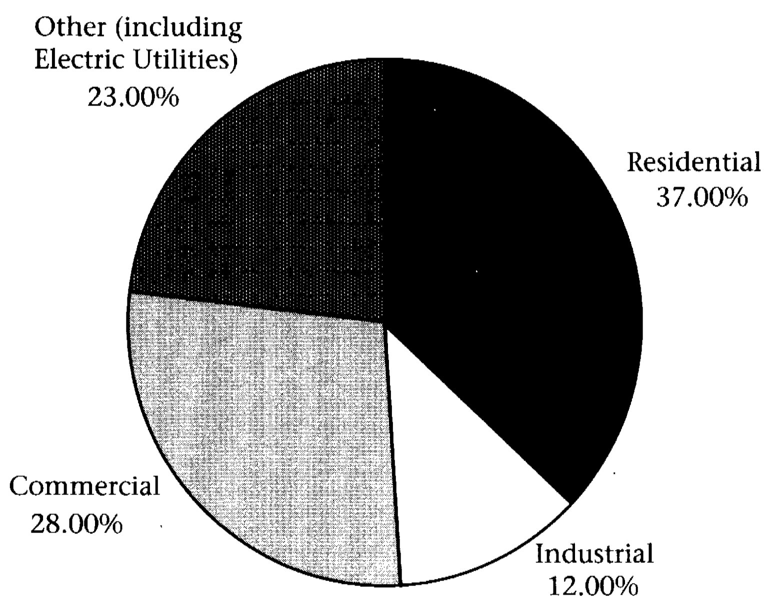
In August 1989, the company announced plans to more than double the generating capacity of its Monroe Street Hydroelectric Project. The redevelopment of the Monroe Street facility, which has been in operation since late 1890, involves removing the existing powerhouse and five turbine generators and replacing them with a single turbine-generator housed in a predominantly underground structure. The new generator will increase generating capacity from six to 14.7 megawatts. The old facility was shut down July 1, 1990 and the reconstruction work, which has an estimated cost of $26.5 million, will take from 12 to 18 months to complete.

Demolition of the Monroe Street powerhouse began on August 11. WWP donated the station's century-old No. 5 turbine-generator to the Henry Ford Museum in Dearborn, Michigan. In preparing the site for construction of the new powerhouse, a wall of sandbags was built along the Spokane River. In order to temporary seal the site from the river channel, the contracting firm installed a temporary concrete cofferdam against the sandbags. The cofferdam will not interrupt the flow of the Spokane River and will be removed after the generating unit is in place. Work has now begun on constructing the new powerhouse. The facility is expected to be on-line in April 1992.

The company is also in the process of evaluating ways to enhance the generating capacity of its Nine Mile and Long Lake hydroelectric developments. While final decisions regarding the study at Nine Mile have not been made, some conclusions about the alternatives are apparent. Any alternatives involving a new powerhouse are not economical, and a reservoir level increase of 10 feet is neither economical nor environmentally acceptable. Engineering studies will continue to optimize the turbine generator size and number, and to determine whether the reservoir level should be raised as much as five feet above the existing level. A feasibility study on Long Lake was completed in 1990 and basically included a new powerhouse of various production capabilities, with or without the existing powerhouse. The most economic options at this time would include retention of the old powerhouse, plus the addition of a new one or two unit powerhouse immediately downstream from the existing one. Further studies will have to be completed before a final decision is reached. A summary of the consultant's studies can be found in Appendix E.

Customer Information

The company's net system energy load is composed of three main categories: residential, commercial and industrial. Also included are losses (distribution and transmission), street lighting and four wholesale for resale customers. The percent of 1989 revenues for the company by categories is shown below:



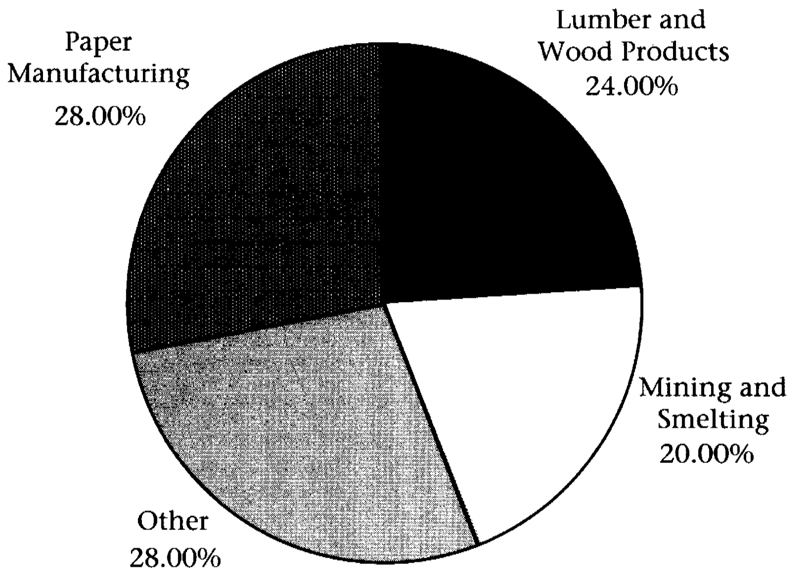
Percent of 1989 Dollar Revenues

Figure 1-2. Distribution of WWP's electric revenues in dollars for 1989. Total revenues that year amounted to $384.8 million.

Industrial revenue comes from three main manufacturing industries; lumber, paper and mining. The revenues as a percent of manufacturing processes are:

Percent of 1989 Dollar Revenues

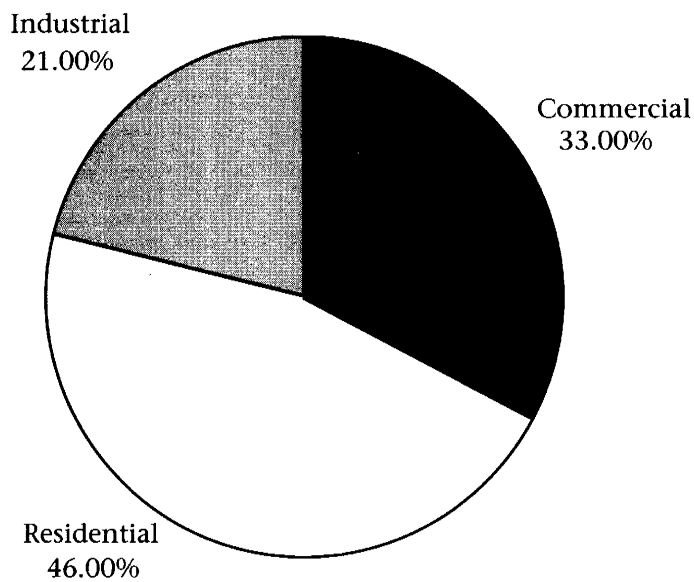
Figure 1-3. Distribution of WWP's industrial revenue in dollars for 1989. Total revenues that year amounted to $44.1 million.



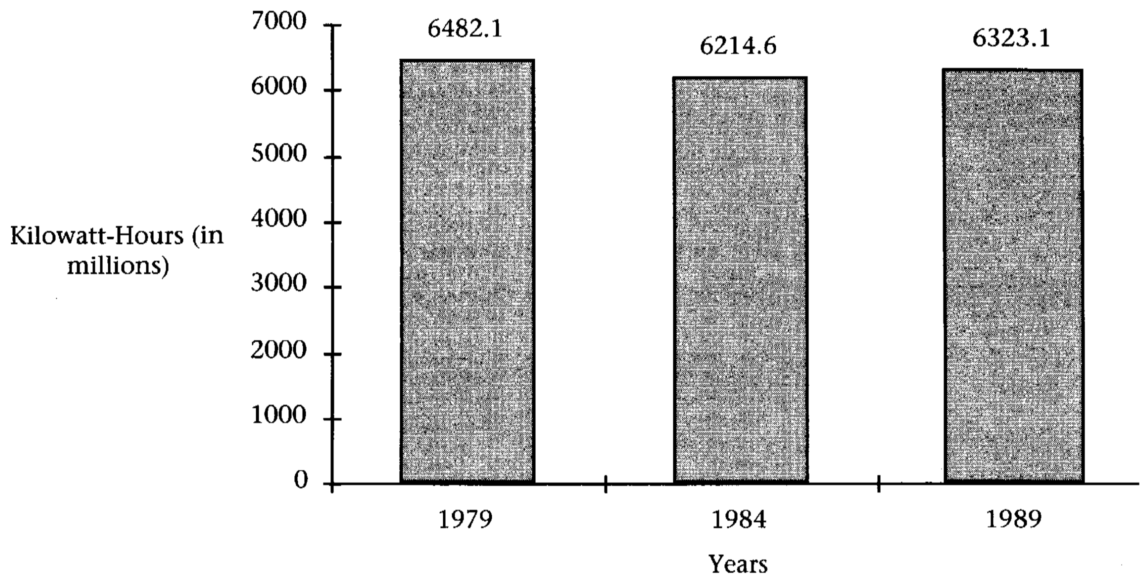
Total kilowatt-hour sales (in millions) for 1989 were 9,969.4, of which 3,646.3 were to other electric utilities. Total retail kWh sales (in millions) for 1989 were 6,323,1:

Percent of 1989 Kilo-watt-hours Sold

Figure 1-4. Distribution of WWP's kilowatt hours sold for 1989.



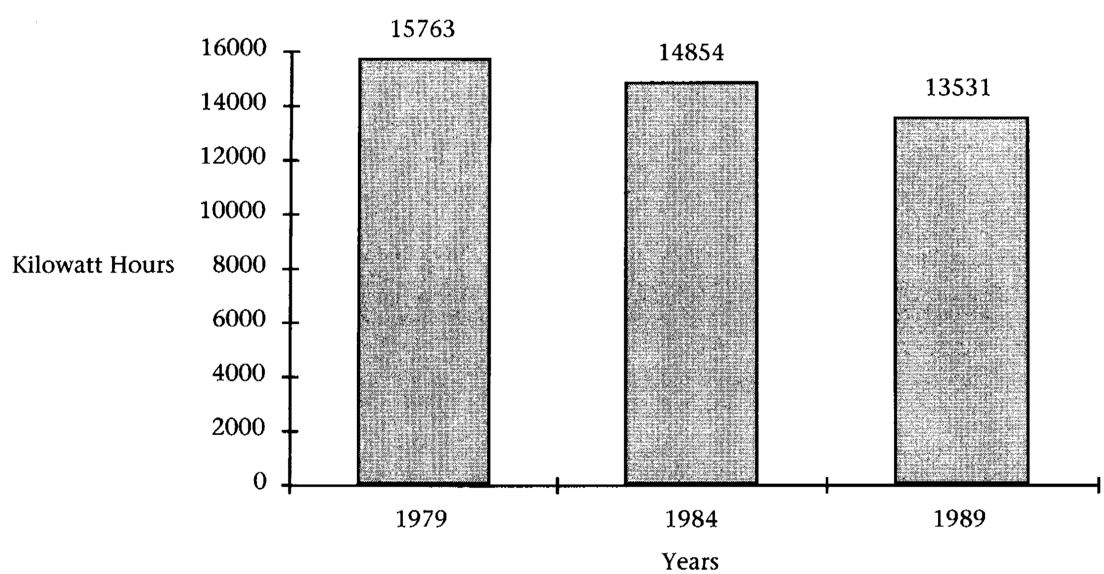
The company has experienced a decline in electricity sales since 1979, although a slight increase was noted in 1988 and 1989. The total retail kilowatt-hours sold for 1979, 1984 and 1989 are shown below:



Total Retail Sales

Figure 1-5. WWP's retail kilowatt hours sold.

The average electrical use per residential customer has also been declining, although some increase has been noted in the last two years. The average use per residential customer is shown below:



Average use per residential customer

Figure 1-6. WWP's residential electric usage in kilowatt-hours.

During the extreme cold spell of February 1989, the company had a record one-hour system peak load. The record adjusted peak load of 1660 MW occurred on February 2, 1989. The previous peak record occurred on January 29, 1980 and was 1614 MW. WWP's net system energy load for 1989 was 7,208,271 megawatt hours or 822.9 aMW.

The February 1989 situation is a good example of the difficulty in planning for the future. Our peak load estimate of 1989 showed a peak load requirement of 1661 in the year 1999, although after adjusting the 1660 MW figure for weather the February peak was close to the estimate. If the company had not had peak reserves, which are also used to cover cold weather contingencies, or been able to purchase on-peak energy in the short-term market, WWP would not have been able to meet its load requirements. Providing a margin of surplus through peak reserves is an expensive undertaking but viewed in the long-term perspective can be a preferred option for the utility customers in meeting the uncertainties of planning.

New Developments

In the latter part of 1990, the company made three purchase arrangements that affected our surplus (deficit) situation. These purchases are cost-effective opportunities that were pursued by WWP.

Two of the purchases are contract arrangements with other electric utilities. The first is a four-year purchase of firm energy from the Montana Power Company, delivered mostly during light load hours. During the four years, 1991 through 1994, WWP will purchase a total of 1,190,400 MWh. The second is a winter power purchase from B.C. Hydro. WWP has an option to purchase 75-100 MW of capacity and associated energy for each of the three winter months of December 1990 through February 1991.

The third purchase is a resource acquisition. WWP purchased two 60 MW gas-fired combustion turbines that had recently been refurbished and placed on the market for $14.5 million. A decision as to their ultimate use has not been determined. There are many available options ranging from their use as a resource for firming non-firm hydro to being placed in a cogeneration application. After various alternatives have been studied and analyzed, a final decision will be made as to their ultimate use and location.

WWP's Strategy For The Future

The continued success of WWP's energy business will depend on our ability to retain the position as a low-cost producer and supplier of energy services. With programs like demand-side management, redevelopment of the Monroe Street Hydroelectric Project, and the plans to access Canadian resources, WWP should be able to assure both low-cost production and supply through the next decade and beyond.

WWP's strategy in serving its customers' requirements is to maintain flexibility in its planning to account for changing conditions and needs. The uncertainty in planning for the long-term requires the company to be flexible enough to adjust its resource acquisition plans to meet those uncertainties. WWP's long-standing goal has been to select resources that are reliable and which have the lowest overall cost.

The company is proceeding with resource acquisition plans. Although WWP's needs are small compared to other electric utilities in the Northwest, we are proceeding with a variety of resource types as determined through the least-cost planning effort. WWP hopes to acquire a mixture of resources that will provide the stability and reliability needed to meet our customers requirements in the most cost-effective manner. The issuance of the Request for Proposals (RFP) should provide another tool or method in assessing the resource potential, especially in our service area, at a price dictated by market conditions.

The company has not placed any limitations on wheeling QF or IPP generation in our service territory to other users. WWP views the use of its transmission system by others, if line capacity is not a concern, as a way to increase revenues. WWP therefore encourages wheeling transactions.

The company has also continued in its pursuit of acquiring cost-effective lost opportunity resources as they become available. These resources could be either demand- or supply-side. WWP also views resource options as a way to minimize the long lead time of resource permitting and construction. The company has maintained its option on the Creston site for the development of a potential regional coal-fired facility and is pursuing the option of the transmission interconnection with B.C. Hydro.

WWP has a multitude of options that can be chosen to supply electrical power for the future. The company will continue to choose a mixture of resource options to meet its needs in order to have diversity in supply. Some of the options presently being considered are demand-side management, hydro upgrades and redevelopment, power purchases from other utilities and nonutility generators and gas-fired combined cycle combustion turbines.

The least-cost planning and RFP efforts are viewed by WWP as being tools in developing planning strategies and acquiring the most cost-effective resources presently available. The company expects to issue an RFP during the 1991 year under the guidelines of the WUTC bidding order. The company will request resources, available to the company in 1995. The goal of the first RFP is to acquire firm resources and to assess the market supply and cost of resources that the company can acquire when compared to other alternatives.

As competition intensifies on both the demand- and supply-sides of the electrical business, strategies must also change. To succeed, electric utilities will have to think and behave more competitively. Service is the key. We must remember that customers are not obligated to buy. We need to tailor service packages for customers that make the utility's service the most attractive option. WWP needs to anticipate how its plans will change in the future in response to shifting markets, customer behavior and regulatory outcomes.

WWP's forecasts indicate a need for additional electric resources in the long-term. This need for additional resources comes from a combination of increasing requirements and decreasing available resources. These resource needs can be met with a combination of demand- and supply-side options. Because of future uncertainties, the company needs a portfolio of resource options which provide flexibility in meeting these uncertainties. The company does not want to tie itself down in meeting future needs through one type of resource addition. Flexibility in resource planning needs to be maintained in order that planning can be adopted to assure that the company can acquire new resources in the most effective manner possible.

Chapter 2

EXISTING RESOURCE STACK

Maximum Plant/Unit Generating Capability and Nameplate Rating:

Year	Plant	Capability - kW	Nameplate - kW
1890	Monroe Street (under redevelopment)	6,000	7,200
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	Centralia (15% ownership coal-fired)	196,950	199,469
1978	Northeast (gas/oil)	68,000	61,200
1983	Kettle Falls (wood)	46,500	50,700
1984	Colstrip (15% ownership coal-fired)	210,000	233,400

Note: (1) WWP has no resource scheduled for retirement in the next 20 years.

(2) The actual energy outputs from existing resources depends on several factors. For hydro the predominant factor is hydro (streamflow) conditions and the hydro generation numbers for this report are based on critical water. For thermal, 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. For this report the thermal plant factors are: Centralia 82% (based on 192 MW capability), Kettle Falls 85% and Colstrip 73%.

All existing power supply 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. **PURPA Hydroelectric**
   Upriver Power Project
   Big Sheep Creek Hydroelectric Project
   Jim Ford Creek Power Project
   John Day Creek Hydroelectric Project
   Note: Those facilities providing fewer than 500 MWh per year are not listed.

5. **PURPA Thermal**
   Woodpower Power Project
   Vaagen Brothers Power Project
   Note: Those facilities less than 500 MWh per year are not listed.

6. **Economy Exchanges**
   N/A

7. **Economy Purchases**
   Based on hydro and load conditions at time of purchase.

8. **Contract Purchases/Exchanges**
   Bonneville Power Administration - Contract No. 39216
   Bonneville Power Administration - WNP No. 3 Settlement
   British Columbia Hydro and Power Authority
   Columbia Storage Power Exchange
   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
   Pacific Gas and Electric Company

9. **Transmission Resources**
   N/A

10. **Other**
    Kettle Falls (wood)

Hydro 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
1986	Jan	0.00	100.00
	Feb	0.00	87.10
	Mar	0.00	87.10
	Apr	3.30	96.00
	May	0.00	100.00
	Jun	0.00	100.00
	Jul	0.00	93.50
	Aug	0.00	86.00
	Sep	0.00	98.00
	Oct	0.00	88.40
	Nov	0.00	80.00
	Dec	0.00	98.10
1987	Jan	0.00	88.40
	Feb	0.00	80.00
	Mar	0.00	80.00
	Apr	0.00	85.30
	May	0.00	100.00
	Jun	0.00	100.00
	Jul	4.50	95.50
	Aug	0.00	100.00
	Sep	0.00	94.00
	Oct	0.00	65.80
	Nov	0.00	80.00
	Dec	0.00	80.60
1988	Jan	0.00	100.00
	Feb	0.00	80.00
	Mar	0.60	80.00
	Apr	8.70	90.70
	May	0.00	100.00
	Jun	0.00	98.00

Year	Month	Forced Outage Rate	Equivalent Availability Factor
1988	Jul	0.00	80.00
	Aug	0.00	93.30
	Sep	0.00	88.00
	Oct	0.00	80.00
	Nov	0.00	86.70
	Dec	12.30	83.20
1989	Jan	0.00	86.00
	Feb	0.00	80.00
	Mar	0.00	79.00
	Apr	0.00	87.00
	May	0.00	99.00
	Jun	0.00	99.00
	Jul	0.00	98.00
	Aug	0.00	80.00
	Sep	0.00	84.00
	Oct	3.60	80.00
	Nov	16.70	80.00
	Dec	7.70	92.00
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

Do we not track deratings?

*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
1986	Jan	0.00	100.00	1988	Jul	0.00	83.90
	Feb	0.00	83.90		Aug	0.00	75.00
	Mar	0.00	75.00		Sep	0.00	88.30
	Apr	5.00	91.70		Oct	0.00	96.00
	May	9.70	90.30		Nov	0.00	75.00
	Jun	0.00	100.00		Dec	0.00	96.00
	Jul	4.80	81.50				
	Aug	11.30	63.70	1989	Jan	0.00	99.20
	Sep	0.00	90.00		Feb	0.00	99.60
	Oct	0.00	75.00		Mar	1.20	98.80
	Nov	0.00	95.80		Apr	0.00	99.90
	Dec	0.00	97.60		May	0.00	100.00
					Jun	0.00	100.00
1987	Jan	0.00	100.00		Jul	6.70	91.80
	Feb	0.00	75.90		Aug	6.70	92.70
	Mar	0.00	75.00		Sep	0.00	92.70
	Apr	0.00	84.20		Oct	0.00	85.80
	May	0.00	100.00		Nov	0.20	77.10
	Jun	0.00	100.00		Dec	0.00	96.00
	Jul	0.00	79.00				
	Aug	0.00	75.00	1990	Jan	0.00	99.00
	Sep	0.00	75.00		Feb	0.00	100.00
	Oct	0.00	75.00		Mar	0.00	100.00
	Nov	0.00	75.00		Apr	0.00	100.00
	Dec	0.00	75.00		May	0.00	100.00
					Jun	0.00	100.00
1988	Jan	0.00	100.00		Jul	0.40	98.00
	Feb	0.00	82.80		Aug	0.00	97.00
	Mar	0.00	86.30		Sep	28.00	60.00
	Apr	0.00	100.00		Oct	28.00	72.00
	May	0.00	100.00		Nov	17.00	80.00
	Jun	0.00	100.00		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:	Total	No. 1	No. 2	No. 3	No. 4	No. 5	No. 6
(Peak in MW)	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:	Total	No. 1
(Peak in MW)	10.0	10.0

FERC License expiration date:
July 31, 2007

Plant: Monroe Street

FERC License expiration date:
July 31, 2007

In August 1989, the company announced plans to more than double the generating capacity of its Monroe Street Hydroelectric Project. The redevelopment of the Monroe Street facility, which has been in operation since late 1890, involves removing the existing powerhouse and five turbine generators and replacing them with a single turbine generator housed in a predominately underground structure. The new generator will increase generating capacity from six to 14.7 megawatts. On July 1, 1990, the facility was shut down to allow the start of redevelopment. The reconstruction work, which has an estimated cost of $26.5 million, will take a year to 18 months to complete. The facility is expected to be on-line in April of 1992.

Plant: Nine Mile

Rated Capacity:	Total	No. 1	No. 2	No. 3	No. 4
(Peak in MW)	18.4	4.6	4.6	4.6	4.6

FERC License expiration date:
July 31, 2007

Plant: Long Lake

Rated Capacity:	Total	No. 1	No. 2	No. 3	No. 4
Peak in MW)	72.8	18.2	18.2	18.2	18.2

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%

Year	Month	Forced Outage Rate	Equivalent Availability Factor	Year	Month	Forced Outage Rate	Equivalent Availability Factor
1986	Jan	1.10	96.40	1988	Jul	9.66	89.13
	Feb	0.39	98.82		Aug	13.32	84.98
	Mar	17.04	68.59		Sep	14.33	83.77
	Apr	0.00	0.00		Oct	0.08	99.04
	May	0.00	0.00		Nov	0.13	99.56
	Jun	9.77	0.05		Dec	5.84	93.48
	Jul	8.19	84.55				
	Aug	4.62	92.18	1989	Jan	8.40	89.64
	Sep	0.15	99.28		Feb	11.33	82.51
	Oct	0.06	99.63		Mar	5.85	92.69
	Nov	0.30	98.44		Apr	25.55	73.02
	Dec	0.08	89.32		May	1.02	59.88
					Jun	51.41	12.28
1987	Jan	0.38	71.72		Jul	9.65	84.50
	Feb	0.00	50.57		Aug	0.28	98.86
	Mar	23.89	75.42		Sep	5.34	93.22
	Apr	100.00	0.00		Oct	0.55	99.50
	May	100.00	0.00		Nov	12.21	86.01
	Jun	100.00	0.00		Dec	0.00	100.48
	Jul	100.00	0.00				
	Aug	11.99	79.77	1990	Jan	11.19	79.40
	Sep	4.54	93.52		Feb	0.08	100.04
	Oct	3.03	96.31		Mar	1.62	94.25
	Nov	21.09	60.34		Apr	0.18	65.59
	Dec	0.23	97.56		May	23.95	56.17
					Jun	0.62	96.95
1988	Jan	16.04	82.87		Jul	67.14	32.26
	Feb	12.55	85.63		Aug	100.00	0.00
	Mar	7.88	90.77		Sep	30.78	59.87
	Apr	3.41	95.74		Oct	0.00	91.24
	May	0.00	41.49		Nov	13.01	86.63
	Jun	28.43	52.79		Dec	0.00	100.32

Forced Outage Rate:

Forced Outage Hours/(Service Hours + Forced Outage Hours) x 100 (%)

Equivalent Availability Factor:

$$\frac{\text{Available Hours - [(De-rated Hours x Size of Reduction)/Maximum Capacity] x 100 (\%)}}{\text{Period Hours}}$$

Colstrip No. 4

Rated Capacity = 700 MW
Service Date = 4/6/86
Design Plant Life = 35 years
WWP's Share = 15%

Year	Month	Forced Outage Rate	Equivalent Availability Factor	Year	Month	Forced Outage Rate	Equivalent Availability Factor
1986	Jan	27.50	57.60	1988	Jul	0.00	99.62
	Feb	26.74	62.99		Aug	4.84	93.68
	Mar	0.08	54.87		Sep	0.60	98.32
	Apr	0.81	93.14		Oct	0.94	97.76
	May	0.44	99.56		Nov	11.96	86.05
	Jun	16.30	80.36		Dec	0.00	99.60
	Jul	10.80	85.54				
	Aug	2.08	93.58	1989	Jan	10.76	88.40
	Sep	0.12	97.17		Feb	0.06	99.31
	Oct	5.97	92.47		Mar	4.57	94.23
	Nov	0.00	99.26		Apr	0.00	42.61
	Dec	56.05	43.67		May	0.13	99.01
					Jun	1.02	96.85
1987	Jan	100.00	0.00		Jul	2.65	92.10
	Feb	100.00	0.00		Aug	5.84	90.19
	Mar	100.00	0.00		Sep	6.07	93.41
	Apr	100.00	0.00		Oct	16.01	81.72
	May	100.00	0.00		Nov	10.50	88.44
	Jun	97.22	0.63		Dec	4.79	94.65
	Jul	9.74	76.42				
	Aug	0.50	89.02	1990	Jan	3.02	96.41
	Sep	11.44	85.73		Feb	1.78	96.96
	Oct	0.00	100.02		Mar	0.08	99.44
	Nov	0.07	99.56		Apr	0.32	95.27
	Dec	0.71	98.07		May	41.04	58.06
					Jun	5.63	25.24
1988	Jan	5.41	91.21		Jul	17.13	80.34
	Feb	0.00	99.44		Aug	9.28	87.73
	Mar	27.04	60.55		Sep	0.26	99.41
	Apr	3.53	63.05		Oct	8.32	88.71
	May	0.00	99.97		Nov	9.00	90.52
	Jun	1.61	94.96		Dec	2.78	96.36

Centralia No. 1

Rated Capacity = 656.5 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
1986	Jan	0.00	96.00	1988	Jul	8.83	91.00
	Feb	0.00	100.00		Aug	0.00	99.00
	Mar	0.00	100.00		Sep	28.09	64.00
	Apr	0.00	100.00		Oct	0.00	86.00
	May	0.00	100.00		Nov	0.00	90.00
	Jun	0.00	43.00		Dec	0.00	89.00
	Jul	0.00	94.00				
	Aug	0.00	99.00	1989	Jan	0.00	85.00
	Sep	8.11	91.00		Feb	0.00	86.00
	Oct	0.00	94.00		Mar	0.00	86.00
	Nov	0.00	99.00		Apr	0.00	37.00
	Dec	7.09	92.00		May	52.08	3.00
					Jun	26.95	69.00
1987	Jan	1.88	97.00		Jul	0.00	98.00
	Feb	0.00	99.00		Aug	0.00	100.00
	Mar	3.62	96.00		Sep	0.00	100.00
	Apr	0.00	100.00		Oct	9.20	89.00
	May	0.00	45.00		Nov	0.00	100.00
	Jun	33.16	46.00		Dec	13.95	86.00
	Jul	1.62	98.00				
	Aug	4.96	95.00	1990	Jan	2.84	97.00
	Sep	4.22	96.00		Feb	9.12	91.00
	Oct	0.00	98.00		Mar	3.31	96.00
	Nov	7.50	91.00		Apr	0.00	43.00
	Dec	3.65	96.00		May	0.00	19.00
					Jun	0.00	97.00
1988	Jan	6.21	93.00		Jul	1.02	99.00
	Feb	0.00	100.00		Aug	10.89	89.00
	Mar	4.46	95.00		Sep	2.26	98.00
	Apr	0.00	47.00		Oct	0.00	100.00
	May	0.00	66.00		Nov	0.00	100.00
	Jun	9.93	89.00		Dec	0.00	100.00

Centralia No. 2

Rated Capacity = 656.5 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
1986	Jan	0.00	98.00	1988	Jul	0.00	98.00
	Feb	0.00	99.00		Aug	1.40	98.00
	Mar	0.00	90.00		Sep	0.00	100.00
	Apr	0.00	0.00		Oct	0.00	99.00
	May	0.00	0.00		Nov	0.00	100.00
	Jun	46.07	80.00		Dec	5.34	91.00
	Jul	23.93	76.00				
	Aug	0.69	98.00	1989	Jan	0.00	100.00
	Sep	0.00	100.00		Feb	0.00	99.00
	Oct	0.00	100.00		Mar	0.22	95.00
	Nov	0.00	100.00		Apr	7.40	92.00
	Dec	0.00	99.00		May	0.00	58.00
					Jun	0.00	0.00
1987	Jan	0.00	99.00		Jul	6.01	89.00
	Feb	3.75	95.00		Aug	0.00	100.00
	Mar	0.00	100.00		Sep	4.16	95.00
	Apr	0.00	99.00		Oct	2.23	96.00
	May	0.00	98.00		Nov	22.43	77.00
	Jun	0.00	100.00		Dec	1.13	98.00
	Jul	0.00	100.00				
	Aug	0.00	100.00	1990	Jan	0.00	100.00
	Sep	3.34	95.00		Feb	30.39	68.00
	Oct	0.00	100.00		Mar	5.06	95.00
	Nov	0.68	99.00		Apr	0.00	100.00
	Dec	0.30	99.00		May	0.00	100.00
					Jun	1.19	99.00
1988	Jan	3.37	95.00		Jul	1.32	99.00
	Feb	0.00	99.00		Aug	10.04	89.00
	Mar	2.59	96.00		Sep	43.53	56.00
	Apr	2.70	97.00		Oct	0.32	100.00
	May	0.00	38.00		Nov	0.00	100.00
	Jun	0.00	62.00		Dec	0.00	100.00

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	Year	Month	Generation - kWh
1986	Jan	4,500,000	1988	Jul	2,800,000
	Feb	4,300,000		Aug	1,200,000
	Mar	5,500,000		Sep	1,900,000
	Apr	5,400,000		Oct	2,000,000
	May	3,187,000		Nov	2,800,000
	Jun	0		Dec	4,000,000
	Jul	0			
	Aug	0	1989	Jan	4,721,000
	Sep	0		Feb	3,679,000
	Oct	0		Mar	8,214,000
	Nov	0		Apr	7,600,000
	Dec	0		May	8,839,000
				Jun	8,446,000
1987	Jan	4,065,000		Jul	2,372,000
	Feb	4,300,000		Aug	1,299,000
	Mar	5,500,000		Sep	1,553,000
	Apr	5,400,000		Oct	2,343,000
	May	5,200,000		Nov	5,410,000
	Jun	5,400,000		Dec	9,485,000
	Jul	2,800,000			
	Aug	1,200,000	1990	Jan	9,604,000
	Sep	1,900,000		Feb	9,494,000
	Oct	2,000,000		Mar	11,147,000
	Nov	2,800,000		Apr	8,270,000
	Dec	4,000,000		May	9,590,000
				Jun	8,656,000
1988	Jan	4,500,000		Jul	4,926,000
	Feb	4,300,000		Aug	2,118,000
	Mar	5,500,000		Sep	2,381,000
	Apr	5,400,000		Oct	3,472,000
	May	5,200,000		Nov	6,218,000
	Jun	5,400,000		Dec	10,111,000

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
1986	Jan	0
	Feb	0
	Mar	0
	Apr	0
	May	0
	Jun	862,907
	Jul	912,710
	Aug	266,401
	Sep	203,832
	Oct	214,665
	Nov	222,848
	Dec	236,457
1987	Jan	159,073
	Feb	164,117
	Mar	477,445
	Apr	889,960
	May	1,048,213
	Jun	1,032,137
	Jul	692,445
	Aug	251,100
	Sep	114,724
	Oct	91,311
	Nov	105,554
	Dec	179,501
1988	Jan	142,893
	Feb	130,977
	Mar	584,550
	Apr	1,055,931
	May	1,204,784
	Jun	1,120,599
1988	Jul	746,363
	Aug	203,989
	Sep	123,758
	Oct	127,085
	Nov	236,764
	Dec	195,300
1989	Jan	169,335
	Feb	146,874
	Mar	504,507
	Apr	1,040,289
	May	1,258,520
	Jun	1,118,455
	Jul	862,861
	Aug	362,169
	Sep	234,172
	Oct	195,325
	Nov	466,011
	Dec	490,050
1990	Jan	400,878
	Feb	251,837
	Mar	702,491
	Apr	1,182,87
	May	479,477
	Jun	1,078,499
	Jul	1,114,331
	Aug	542,671
	Sep	272,271
	Oct	208,461
	Nov	268,185
	Dec	N/A

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
1986	Jan	0
	Feb	0
	Mar	0
	Apr	0
	May	0
	Jun	0
	Jul	0
	Aug	0
	Sep	0
	Oct	0
	Nov	0
	Dec	0
1987	Jan	0
	Feb	0
	Mar	0
	Apr	0
	May	0
	Jun	0
	Jul	0
	Aug	0
	Sep	0
	Oct	0
	Nov	0
	Dec	0
1988	Jan	0
	Feb	0
	Mar	0
	Apr	164,910
	May	0
	Jun	0

Year	Month	Generation - kW
1988	Jul	0
	Aug	0
	Sep	0
	Oct	0
	Nov	53,550
	Dec	97,249
1989	Jan	29,915
	Feb	146,472
	Mar	285,835
	Apr	0
	May	0
	Jun	0
	Jul	0
	Aug	0
	Sep	0
	Oct	61
	Nov	677
	Dec	60,786
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	N/A

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
1986	Jan	0	1988	Jul	362,160
	Feb	0		Aug	242,260
	Mar	0		Sep	154,510
	Apr	0		Oct	119,640
	May	0		Nov	115,920
	Jun	0		Dec	107,780
	Jul	0			
	Aug	0	1989	Jan	78,480
	Sep	0		Feb	55,630
	Oct	0		Mar	217,830
	Nov	0		Apr	312,620
	Dec	0		May	451,070
				Jun	455,030
1987	Jan	0		Jul	436,660
	Feb	0		Aug	325,270
	Mar	0		Sep	232,300
	Apr	0		Oct	186,780
	May	0		Nov	182,820
	Jun	0		Dec	131,110
	Jul	0			
	Aug	0	1990	Jan	104,380
	Sep	9,060		Feb	84,250
	Oct	82,020		Mar	131,530
	Nov	74,630		Apr	223,660
	Dec	71,290		May	329,230
				Jun	451,140
1988	Jan	57,850		Jul	378,790
	Feb	57,800		Aug	277,800
	Mar	99,170		Sep	155,790
	Apr	156,610		Oct	148,440
	May	351,320		Nov	130,700
	Jun	474,820		Dec	N/A

5. Woodpower Power Project/Woodpower, 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
1986	Jan	2,730,000	1988	Jul	879,000
	Feb	3,245,000		Aug	3,478,000
	Mar	3,345,000		Sep	4,427,000
	Apr	3,516,000		Oct	3,431,000
	May	3,590,000		Nov	3,627,000
	Jun	3,345,000		Dec	4,145,000
	Jul	2,817,000			
	Aug	3,606,000	1989	Jan	3,560,000
	Sep	3,268,000		Feb	3,128,000
	Oct	4,025,000		Mar	3,360,000
	Nov	3,320,000		Apr	3,498,000
	Dec	3,409,000		May	3,667,000
				Jun	2,768,000
1987	Jan	3,330,000		Jul	2,687,000
	Feb	3,357,000		Aug	3,742,000
	Mar	3,483,000		Sep	3,557,000
	Apr	4,070,000		Oct	3,767,000
	May	3,197,000		Nov	3,279,000
	Jun	2,593,000		Dec	3,841,000
	Jul	4,152,000			
	Aug	3,334,000	1990	Jan	3,753,000
	Sep	3,627,000		Feb	3,349,000
	Oct	3,927,000		Mar	3,381,000
	Nov	3,053,000		Apr	3,519,000
	Dec	3,534,000		May	3,380,000
				Jun	1,934,000
1988	Jan	3,599,000		Jul	3,435,000
	Feb	3,315,000		Aug	3,485,000
	Mar	3,560,000		Sep	3,632,000
	Apr	3,697,000		Oct	3,458,000
	May	3,367,000		Nov	3,647,000
	Jun	763,000		Dec	3,465,000

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

Month	Generation - kWh	Year	Month	Generation - kWh	Generation - kWh
Jan	0	1988	Jul	362,160	2,393,000
Feb	0		Aug	242,260	1,878,000
Mar	0		Sep	154,510	0
Apr	0		Oct	119,640	0
May	0		Nov	115,920	0
Jun	0		Dec	107,780	2,120,000
Jul	0				
Aug	0	1989	Jan	78,480	3,066,000
Sep	0		Feb	55,630	2,998,000
Oct	0		Mar	217,830	3,113,000
Nov	0		Apr	312,620	3,265,000
Dec	0		May	451,070	2,480,000
			Jun	455,030	2,988,000
Jan	0		Jul	436,660	3,170,000
Feb	0		Aug	325,270	3,198,000
Mar	0		Sep	232,300	3,251,000
Apr	0		Oct	186,780	2,397,000
May	0		Nov	182,820	3,078,000
Jun	0		Dec	131,110	3,223,000
Jul	0				
Aug	0	1990	Jan	104,380	3,217,000
Sep	9,060		Feb	84,250	2,867,000
Oct	82,020		Mar	131,530	3,229,000
Nov	74,630		Apr	223,660	3,186,000
Dec	71,290		May	329,230	2,468,000
			Jun	451,140	2,905,000
Jan	57,850		Jul	378,790	3,177,000
Feb	57,800		Aug	277,800	3,153,000
Mar	99,170		Sep	155,790	2,759,000
Apr	156,610		Oct	148,440	2,316,000
May	351,320		Nov	130,700	2,924,000
Jun	474,820		Dec	N/A	2,781,000

Economy Purchases and Sales:

		Total Secondary Sales-MWh	Average Cost Mills/kWh	Total Secondary Purchases-MWh	Average Cost Mills/kWh
1986	Jan	236,615	24.9	61,724	17.2
	Feb	229,536	19.2	24,183	15.0
	Mar	249,603	9.3	38,231	6.9
	Apr	202,034	10.3	106,180	7.8
	May	187,801	10.2	205,828	7.1
	June	181,946	9.6	82,258	7.2
	July	111,811	11.0	124,843	8.0
	Aug	28,996	12.9	121,038	10.2
	Sep	136,720	12.5	14,540	11.2
	Oct	176,768	12.0	22,310	9.3
	Nov	234,600	11.3	13,486	9.9
	Dec	188,553	12.2	2,464	10.1
1987	Jan	189,731	13.8	16,417	11.4
	Feb	173,946	15.0	11,176	12.5
	Mar	207,988	15.0	28,321	12.8
	Apr	185,260	15.9	27,488	14.2
	May	209,478	13.5	130,867	9.8
	June	51,786	14.4	118,145	14.6
	July	84,259	16.0	44,858	15.6
	Aug	109,918	16.1	94,107	14.3
	Sep	189,443	14.1	66,717	15.1
	Oct	146,424	14.2	58,065	15.4
	Nov	260,349	18.4	22,218	15.1
	Dec	285,493	21.7	59,763	16.5
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

		Total Secondary Sales-MWh	Average Cost Mills/kWh	Total Secondary Purchases-MWh	Average Cost Mills/kWh
	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

Purchases and Exchanges:

BONNEVILLE POWER ADMINISTRATION - (WNP NO. 1) Contract No. 39216

The investor-owned 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 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 10-year period, power will be 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 or relocation costs.

1990 - 91 (July - June)	43.00 mills/kWh
1991 - 92	43.98
1992 - 93	45.01
1993 - 94	46.09
1994 - 95	47.22
1995 - 96	48.42

	DELIVERIES TO WWP	
	Capacity (MW)	Energy (Avg 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 Supply System 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 Project 3 preservation costs and an irrevocable offer of Project 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 periods 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 Project 3 is completed in which case, under certain circumstances, the operating and maintenance costs may be measured by actual Project 3 costs. The company began receiving power from BPA on January 1, 1987.

With the BPA Settlement, the company continues as an owner of Project 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 Project 3 paid on or after February 1, 1985, through the date that Project 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.

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

The company agreed to purchase from B.C. Hydro 146,400 MWh per year for four years, starting in 1985 at 20 mills/kWh and increasing to 23 mills/kWh in the fourth year.

In addition, both parties signed in April 1987, a "Joint Licensing and Presidential Permit Intertie Agreement." This Agreement allows the company to begin the licensing and permitting phase of an intertie between the company and the system of B.C. Hydro. Included in the Agreement is a two-year purchase of 146,400 MWh per year at market prices, with a discount of two mills to offset the company's expenses on the intertie licensing effort. The purchase years are 1989 and 1990.

In 1990, both parties signed a capacity purchase agreement in which the company has rights to receive 75 MW of capacity in December 1990 and 100 MW in both January and February of 1991. The company will pay B.C. Hydro a capacity reservation fee of $1.00/kW-month and if requested and delivered a usage fee of $0.60/kW-week. The energy may be purchased at 21 mills/kWh or returned within 168 hours, at the company's option.

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 five percent. It is obligated to pay five 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

CSPE	Capacity (MW)		Energy (Avg MW)	
	Gross	Net	Gross	Net
April 1, 1990 - March 31, 1991	51	49	16	16
April 1, 1991 - March 31, 1992	47	45	16	16
April 1, 1992 - March 31, 1993	42	40	15	15
Entitlement and Supplemental Capacity				
April 1, 1990 - March 31, 1991	27	26	0	
April 1, 1991 - March 31, 1992	24	24	0	
April 1, 1992 - March 31, 1993	22	21	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 30 percent of the output to supply the requirements of the Chelan service area.

Chelan Plant Capacity = 58 MW

Rocky Reach Plant

The company has been obtaining 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 our 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 - End of Contract	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. Our participation dropped to 3.9 percent on September 1, 1985; 3.7 percent on September 1, 1987; and 3.6 percent from September 1, 1988, until the end of the contract. The Contract is in effect until 2018.

	Capacity - WWP Share (MW-Based on 820 Total Plant)
September 1, 1985 -	32
September 1, 1987 -	30
September 1, 1988 -	30

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 - End of Contract	55

Wanapum Plant

1964 ?

The company received 13.1 percent or 118 megawatts of capacity commencing in 1974 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 - End of Contract	75

MONTANA POWER COMPANY

The company and Montana entered into a firm energy agreement for the period January 1, 1991, through December 31, 1994. Montana will deliver to the company 319,650 MWh in 1991, 318,300 MWh in 1992, 317,400 MWh in 1993, and 235,050 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 2 mills/kWh. The price for the energy delivered all four years is 22.25 mills/kWh.

PACIFIC GAS AND ELECTRIC COMPANY

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 MWh. 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. The delivering party may request ramping. 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.

DELIVERIES TO WWP

CSPE	Capacity (MW)		Energy (Avg MW)	
	Gross	Net	Gross	Net
April 1, 1990 - March 31, 1991	51	49	16	16
April 1, 1991 - March 31, 1992	47	45	16	16
April 1, 1992 - March 31, 1993	42	40	15	15
Entitlement and Supplemental Capacity				
April 1, 1990 - March 31, 1991	27	26	0	
April 1, 1991 - March 31, 1992	24	24	0	
April 1, 1992 - March 31, 1993	22	21	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 30 percent of the output to supply the requirements of the Chelan service area.

Chelan Plant Capacity = 58 MW

Rocky Reach Plant

The company has been obtaining 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 our 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 - End of Contract	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. Our participation dropped to 3.9 percent on September 1, 1985; 3.7 percent on September 1, 1987; and 3.6 percent from September 1, 1988, until the end of the contract. The Contract is in effect until 2018.

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Chapter 3

FUTURE DEMAND FOR ELECTRICITY

Load, Energy and Peak Demand Forecast

The narrative that follows discusses the electric load forecast, including assumptions, methodology, and results, followed by a similar description of energy and peak requirements.

Electric Load Forecast

The company's electric forecast is developed each year, with a forecast horizon of 20 years. The forecast provides the basis for the revenue budget, supply planning activities, and least cost planning efforts. The results of the forecast become the official forecast information used internally, as well as supplied to external entities.

Forecast Assumptions

National Economic Assumptions

Over the last two years, the company has developed an econometric forecasting model of the Spokane County economy using national economic forecasts purchased from McGraw-Hill/Data Resources, Inc. (DRI). Spokane County and Washington State data are obtained from various state and local sources. Spokane is the center of economic activity and, as such, is used as the proxy for the service area economy.

The DRI Review of the U.S. economy for the winter 1989-90 provided the underlying macroeconomic input to the Spokane County economic model. The highlights of the DRI trend projections incorporated in the medium case economic forecast are as follows:

- National economic growth will be significantly slower than experienced in the past. Growth in GNP is expected to average 2.0% over the next 25 years compared with 3.0% in the prior 25 years.

- Inflation is expected to increase, and the consumer price index is projected to rise at an annual average rate of 5.1% over the next 25 years.

- Energy prices are expected to outpace inflation, but there is little likelihood prices will reach the crisis levels experienced during the OPEC oil embargo. Incremental or average?

- Labor markets will slowly improve and unemployment rates will average 5.5%.

A more detailed summary of the medium, high, and low assumptions used in the scenarios are presented on Table 3-1.

Least Cost Planning Scenario Assumptions

Figure 3-1.

Assumption		Medium Case	High Case	Low Case
U. S. Macroeconomic		DRI TREND25YR0190	DRI OPTIM25YR0190	DRI PESSIM25YR0190
1	Demographic	Census middle-growth, with 1.8 fertility rate, & declining mortality	Higher fertility, lower mortality, & higher immigration	Lower fertility, higher mortality, & lower immigration
2	Inflation	GNP deflator averages 4.9%, CPI at 5.1%	GNP deflator averages 3.8%, CPI at 4.0%	GNP deflator averages 6.5%, CPI at 6.6%
3	Oil Prices	Oil prices rise 8.1% per year nominal, 3.0% real	Oil prices rise 6.0% per year nominal, 2.1% real	Oil prices rise 9.8% per year nominal, 3.1 % real
4	Natural Gas Prices	Natural gas 3.4% real	Natural gas 2.4% real	Natural gas 3.5% real
5	Productivity Growth	1.2%	1.3%	1.1%
6	Gross National Product	2.0% real	2.4% real	1.6% real
7	Industrial Production	2.5%	2.9%	2.0%
8	Unemployment	5.5%	5.3%	5.9%
Spokane/Service Area Specific				
9	Econ. Model add-factors	None	Boeing +600 new jobs	FAFB loses 200 civilian, 1,500 military jobs
10	Large Load Forecasts	Most expected, from customer surveys	High case, except mining low case	Low case, except mining high case
11	DSM Programs*	Most likely initial plan	Space and water heat conversion accelerates	Space and water heat conversion decelerates
	•Water Heat Conversions in Gas Heat Homes	33,625 by 1999 79% market potential	38,161 by 2000 90% market potential	25,440 in 1997 60% market potential
	•Prog. Space & Water Heat Conversions from Electric	9,210 in 1999 40% market potential	14,233 in 2002 60% market potential	5,050 in 1995 22% market potential
	•Nat. Space & Water Conversions from Electric	4,908 by 2010 Base	6,060 by 2010 125% of base	3,756 by 2010 75% of base
	•Conversion Factors			
	Electric Water Heat Use	4,800 kwh	4,800 kwh	4,800 kwh
	Gas Water Heat Use	252 therm	252 therms	252 therms
	Electric FA Space Heat	10,000 kwh	10,000 kwh	10,000 kwh
	Gas Space Heat from Electric HP & Resist.	528 therms	528 therms	528 therms
	Gas Space Heat from Other Fuels	474 therms	474 therms	474 therms
12	New Customer Forecasts	Assumes 60% of new customers space heat with gas, 40% electric	Add-factor applied from population differential in economic forecast	Add-factor applied from population differential in economic forecast
13	Results of Spokane Economic Model Scenario Alternatives			
	•Manufacturing Employment vs. medium case		13% above in 2010	12% below in 2010
	•Population vs. medium case		6% above in 2010	6% below in 2010
	•Inflation vs. medium case		13% below in 2010	34% above in 2010
	•Real Personal Income vs. medium case		10% above in 2010	13% below in 2010

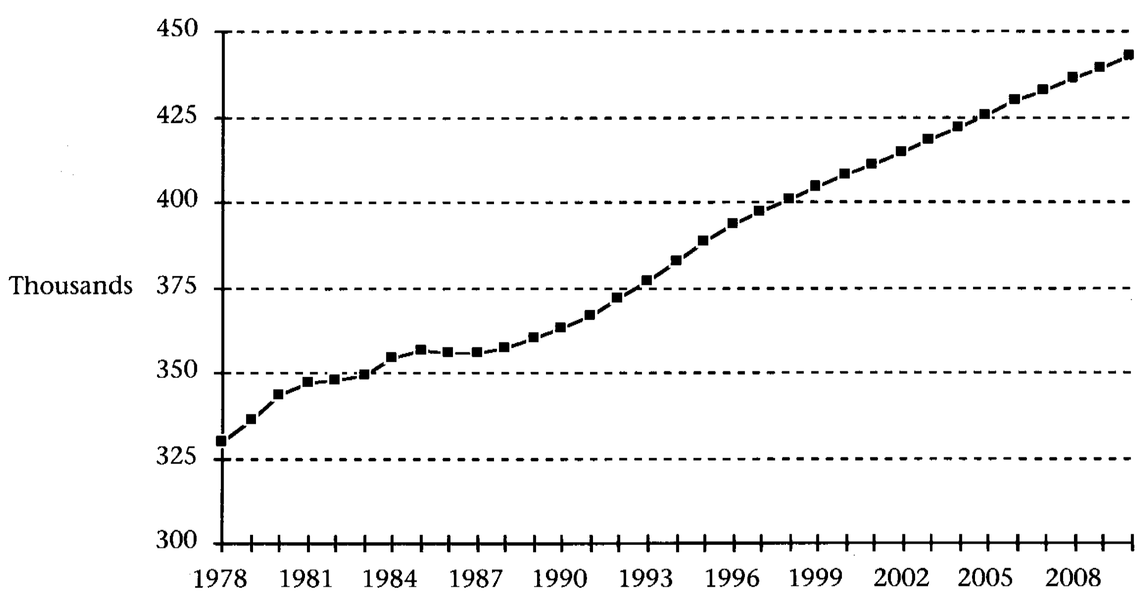
* Programmatic resources are not included in the load forecast.

The Spokane County Economic forecast model is an econometric regression model developed for WWP by Tucson Economic Consulting to provide local economic input to the energy forecast models. In addition to DRI, inputs to this model are provided by Spokane County, the state of Washington, and by various other state and local sources. The model forecasts population, employment, and income for Spokane County.

The population forecasts are the result of the net forecasted change in births, deaths, and net migration. Employment is split into manufacturing and nonmanufacturing and is forecasted by major grouping, or 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.

In summary, the results of the Spokane County Economic forecast model in the medium case show the rebound of the Spokane economy continuing for the next few years, then it begins to slow, consistent with national forecasts. Specific medium case assumptions are as follows:

Population: Changes are caused by natural increases and net migration. The forecast continues the stable historical trend of natural increase (about 2,000 per year). Historically, net migration has been influenced by several key events. After the 1974 World's Fair the county experienced high growth. Out migration occurred following the '81-82 recession, and currently people are moving back into the county. The forecast continues this growth trend because of a brighter employment outlook in the near term. Growth is expected to slow somewhat in later years, consistent with national trends. Shown in the following two charts are total population and the explicit migration included within this forecast:

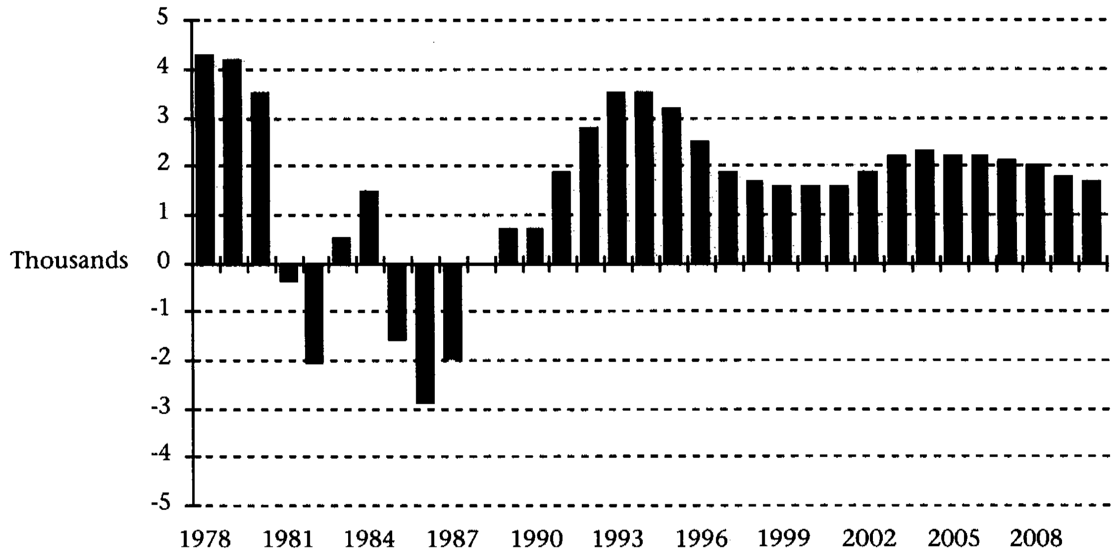


Spokane County Population

Figure 3-2.

Spokane County Net Migration

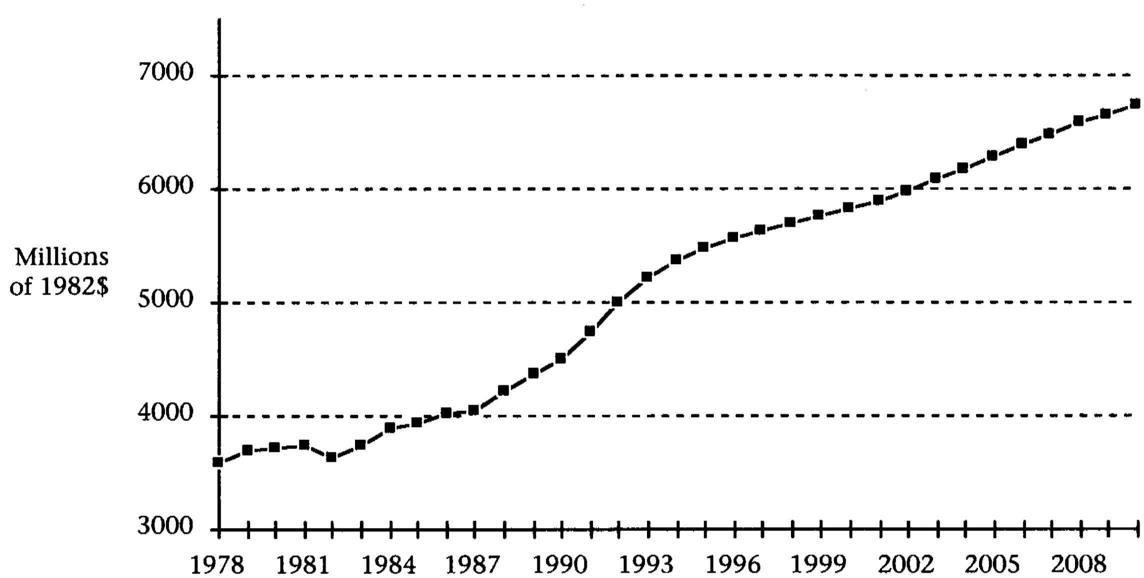
Figure 3-3.

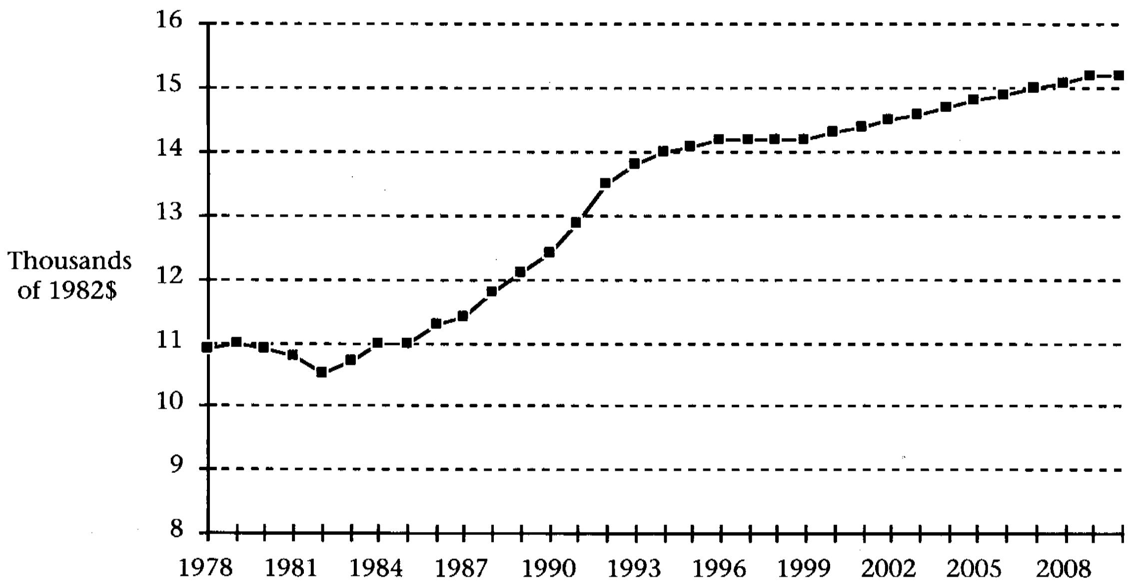


Income: Real income growth is healthy for the next five years because of expected stable inflation and moderately strong employment growth. Real per capita income, based on 1982 dollars, is expected to increase an average 2.2% over the next five years and remain nearly flat in subsequent years. Shown in the next three charts are total personal income, per capita income, and the inflation rate applied to convert the data into inflation adjusted dollars:

Spokane County Personal Income (inflation adjusted)

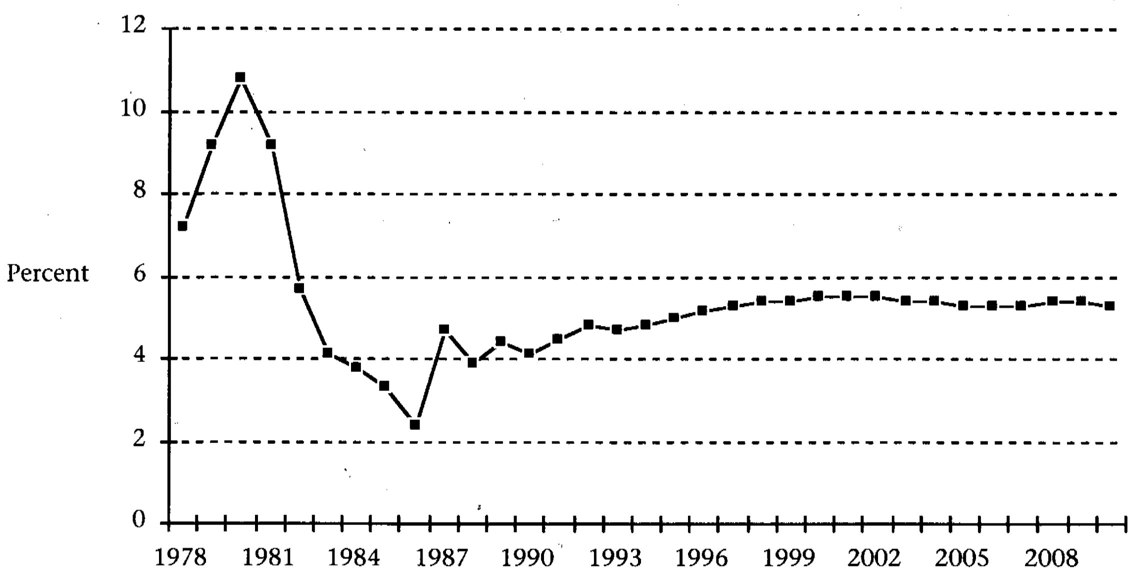
Figure 3-4.





Spokane County Per Capita Income (inflation adjusted)

Figure 3-5.



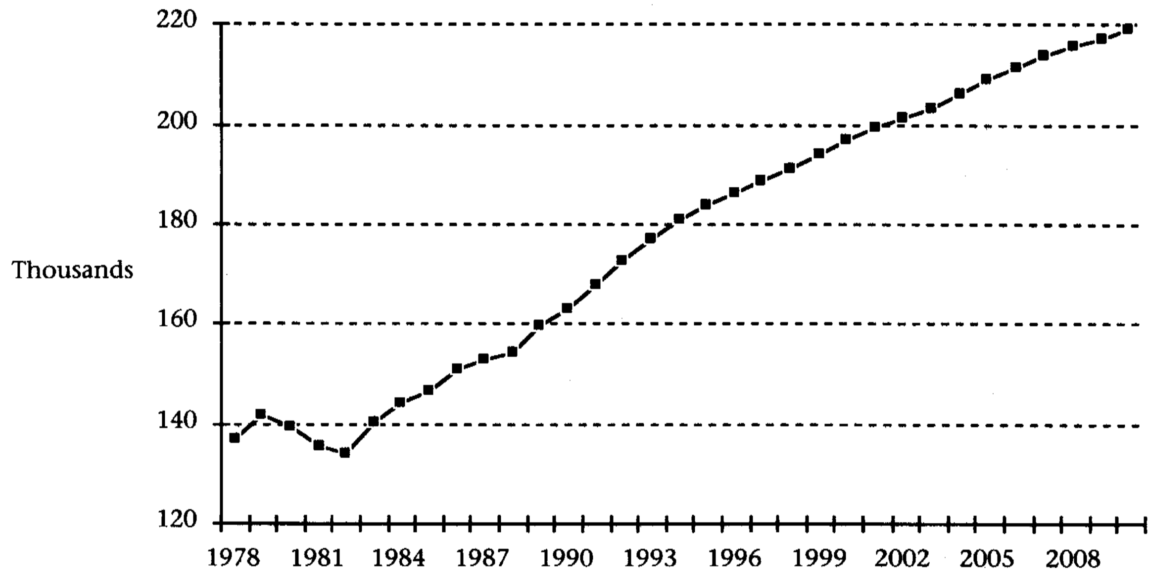
Inflation Rate (U.S. Personal Consumption Deflator)

Figure 3-6.

Employment: The total employment outlook in the near term for Spokane County is good, growing a healthy 2-3% through 1994. Employment is then expected to back off somewhat in response to slowing national trends. Unemployment is expected to remain moderate at around 6%. Total employment in Spokane County is essentially non-agricultural and consists of manufacturing and non-manufacturing employment segments, as shown on the next page:

Spokane County Total Employment

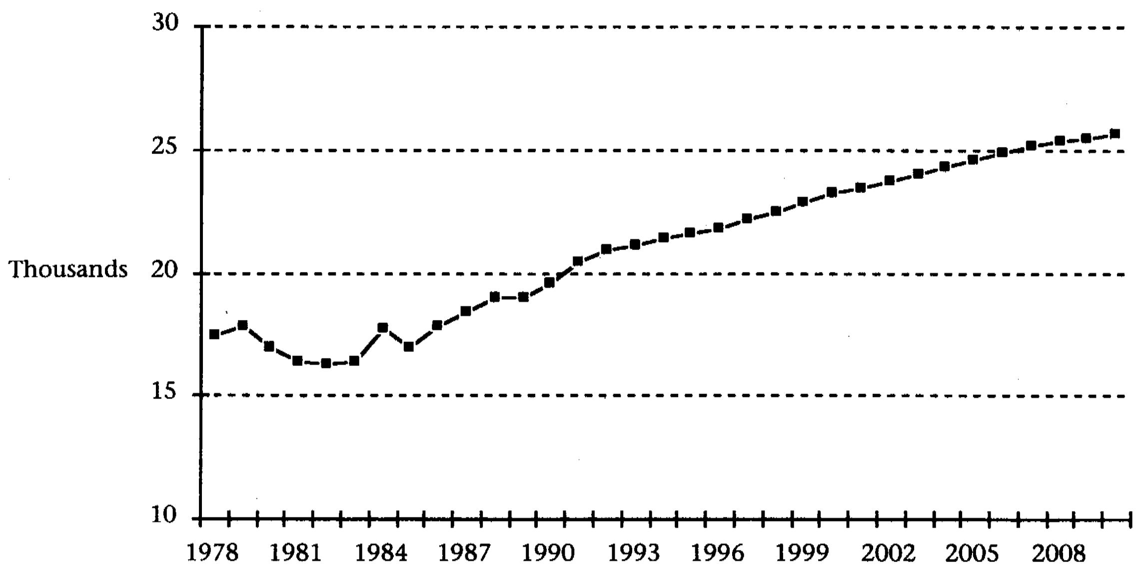
Figure 3-7.



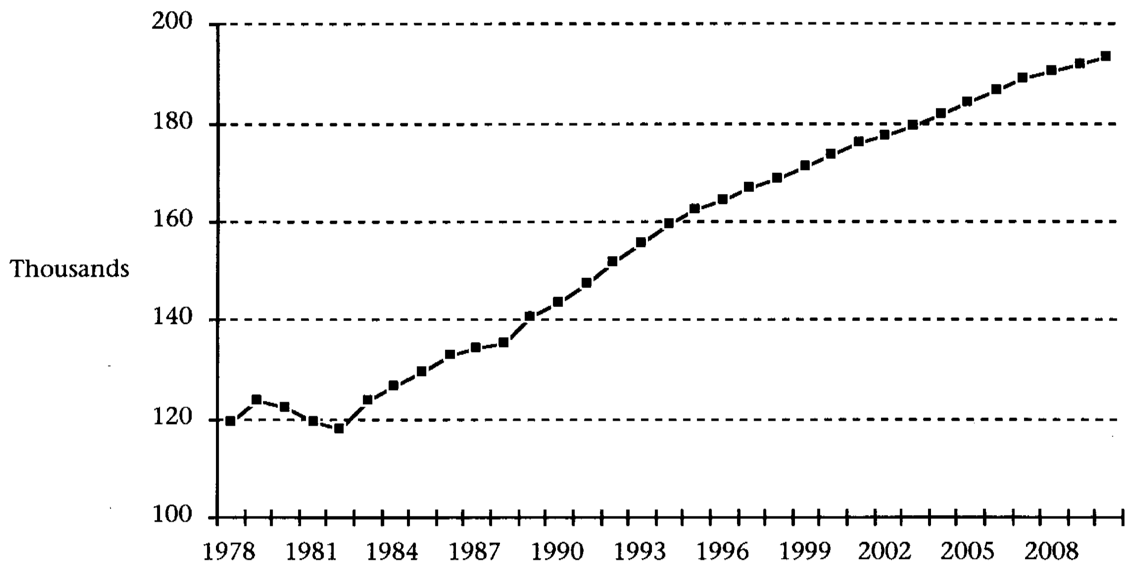
The manufacturing component of Spokane County employment was forecasted in five parts so high growth and low growth industries could be considered separately. The high growth manufacturing industries include electric and transportation equipment. Low growth industries consist mainly of aluminum smelters. After considering each particular industry outlook, manufacturing employment is is expected to grow at a robust 2-5% in the near nerm, backing off to about 1% after 1992. Total manufacturing employment is shown below:

Spokane County Manufacturing Employment

Figure 3-8.



The non-manufacturing component of the county's employment is about seven times larger than manufacturing, and was also forecasted in sectors. Those employment sectors include construction, transportation, trade, services, government, and the financial group. In recent years the local economy, as in other metropolitan areas in the U.S., has increasingly shifted toward a service based economy. Nonmanufacturing employment is forecasted to grow at a robust 3-5% in the next five years, then backing off consistent with national trends.



Spokane County Non-Manufacturing Employment

Figure 3-9.

Large Load Customer Forecasts

A survey is conducted each spring of all existing large commercial and industrial customers, typically those on Schedule 25, covering five years of responses to customer surveys. No new customers were explicitly added to these projected loads. The latest Northwest Power Planning Council regional forecasts by industry are used to escalate the remaining years.

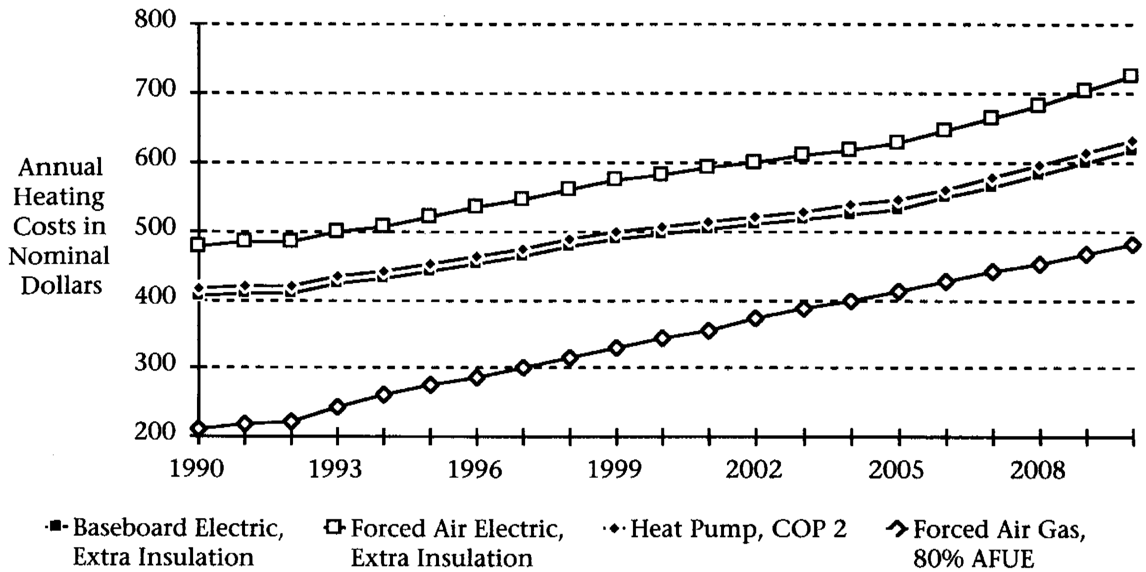
Price

Electric prices are expected to increase an average of 2.3% per year over the forecast horizon, before taking into account the effects of inflation. This translates into a real price decline of about 2.5% per year.

Even though natural gas prices are expected to grow at 8.4% per year, natural gas is forecasted to continue its comparative price advantage over electricity throughout the forecast period, as the graph below illustrates.

Estimated Heating Costs for New Residential Dwellings (based on forecasts of electric and gas rates)

Figure 3-10.



Price forecasts are produced by the WWP resource evaluation model. Prices used in the medium case are consistent with the prices used to produce the load forecast. Price forecasts for the alternative forecasts produce different estimates. By incorporating price elasticity impacts estimated in the load forecasting model, the load forecasts for these alternatives was calibrated.

Conversions

The company is committed to implementing a variety of demand-side management (DSM) programs beginning in 1991. Following are the estimates in the medium case forecast. The medium, high and low scenarios are detailed inFigure 3-1. A more detailed discussion of DSM assumptions may be found in chapter 4 on resource options. The programmatic and natural conversions incorporated in the medium case forecast are as follows:

- Electric Water Heat Conversion Program: The company is currently planning to offer a program to existing gas coustomers to allow them to remove their electric water heaters and replace them with efficient gas models. In the base case, we estimate that 33,625 customers (79% of the 42,400 gas heat customers having electric water heat) will convert to gas water heating. The load impact is considered a resource, and as such, the reduction to electric load due to program activity is not included in the forecast.

- Space and Water Heat Conversion Program: Incorporates estimates that 12,486 (40%) of the 31,496 electric heat customers who have electric forced air equipment will be converted to gas space and water heat. Programmatic conversions are estimated at 9,210, while natural conversions are estimated at 3,276 customers through 1999 (4,908 natural conversions through 2010). Preliminary research indicates that at least 9,900 customers have either forced air resistance or heat pumps for their main heat equipment and live in an area where gas is immediately available.

- Conversions to gas from other fuel sources (primarily wood and oil) are expected to be 19,200 customers of the 30,500 customers who currently use oil or wood as a main heat source in WWP electric service territory, through 2010. We expect that when these customers convert to gas heat, they will also convert their electric water heater to gas. This impact is taken into account in the load forecast.

Other

- Model Conservation Standards: An annual adjustment of 5,000 kWh per customer was deducted from all new construction electric residential customer usage to account for improved building codes. This assumption is the same in all scenarios.

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

Forecast Methodology

The Company's load 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, commercial, and small industrial electric loads are examples of economic relationships 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 made up of 119 equations that forecast usage and customers by class, by schedule, and by state jurisdiction.

Large industrial customers are special relationships which were dealt with on an individual basis through surveys and in-depth analysis by the affected account executive. Escalation rates after the fifth year were applied consistent with regional industry forecasts. In all three scenarios, no closures of existing customers nor addition of any major new large load customers were assumed.

Schedule 61 customers, under the jurisdiction of the FERC, are retail electric customers in the WWP control area served wholesale power by the company as a firm load. These customers represent about 4% of net system sales, which excludes sales to other utilities outside the WWP control area. The model used to forecast these mostly residential and commercial loads is based upon the growth expected in the WWP sales area.

Forecast Scenarios

Three alternative forecast scenarios are presented in this section. Three additional scenarios are in progress. The specifics are detailed in Figures 3-15 through 3-18. These assumptions do not apply to the Peak forecast, except as noted in that section. In summary they are as follows:

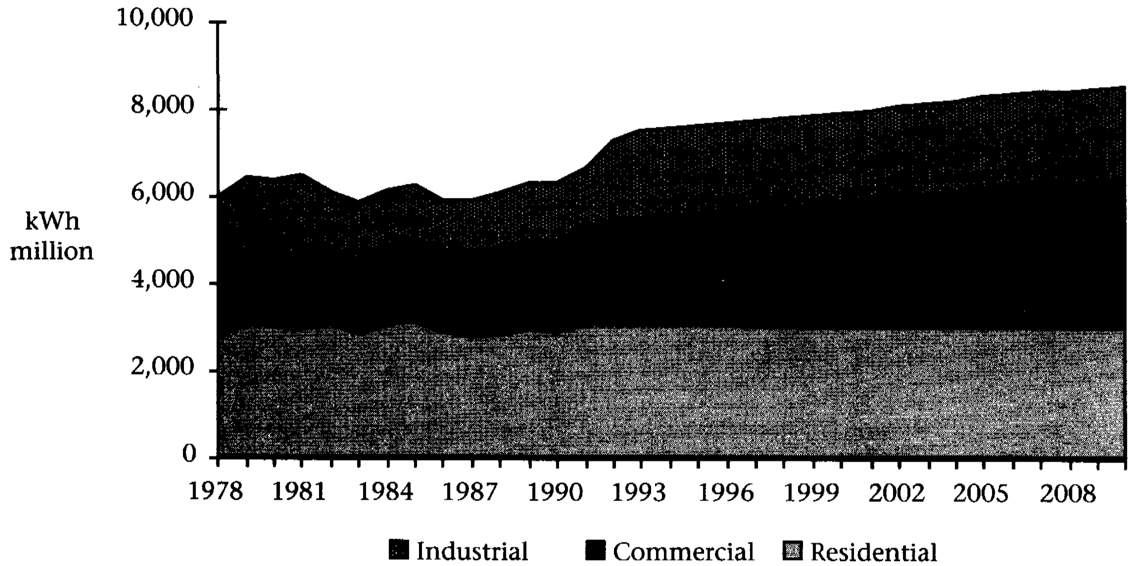
High: Uses a cold weather scenario (105% of normal), includes a high estimate for large load customers, lower natural gas prices, higher conversion estimates, addition of another 600 jobs at Boeing, and the DRI Optimistic economic forecast.

Medium: Uses a normal weather scenario, includes the most likely estimate for large load customers, most likely gas prices and demand-side management and conversion estimates, and DRI Trend economic forecast.

Low: Uses a warm weather scenario (95% of normal), includes a low estimate for large load customers, higher natural gas prices, lower demand-side management and conversion estimates, a loss of 200 civilian and 1,500 military personnel at Fairchild Air Force Base, and the DRI Pessimistic economic forecast.

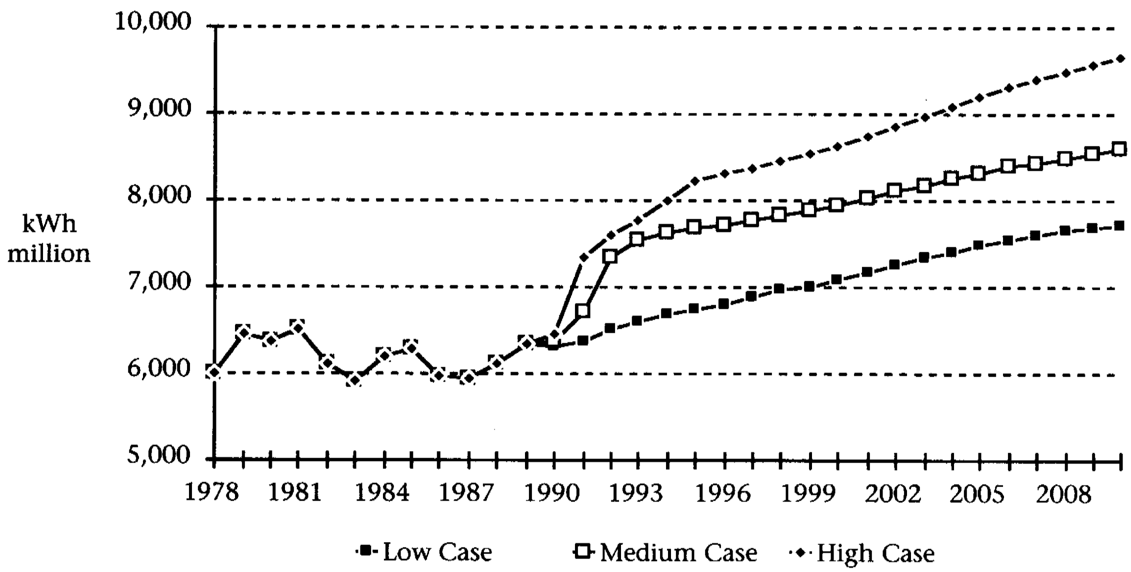
Medium Case Load Customer Class

Figure 3-11. Forecast Results



Alternate Load Cases

Figure 3-12. Forecast results.



Below is a table comparing ten year (1990-2000) growth rates by customer class for each scenario:

	High	Medium	Low
Residential	0.2%	0.3%	0.6%
Commercial	3.5%	3.1%	2.7%
Industrial	6.8%	4.5%	-0.4%
Total Sales	3.0%	2.2%	1.1%
Schedule 61 (FERC)	1.1%	1.1%	1.1%
Total System	2.9%	2.2%	1.2%

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. By simulating a 10 percent price increase for the medium case scenario, a change in usage for these customer classes has been determined. The reduction in residential customer use caused by this 10 percent price change is 1.9 percent, implying an elasticity of -0.19. The reduction in commercial use is 2.5 percent, implying an elasticity of -0.25. The reduction in small-sized industrial customer sales is 1.6 percent in Washington and 3.3 percent in Idaho, implying an elasticity of -0.16 to -0.33. The reduction in medium-sized industrial customer sales in Idaho is 3.7 percent, implying an elasticity of -0.37. These elasticities are termed own-price elasticities.

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 in not available, and be used exclusively in apartments. Presently, about 60 percent of all new customers are using natural gas, and that assumption is continued throughout the forecast period.

Energy & Peak Forecasts

The monthly net system energy load forecast is derived using a regression equation with the WWP retail load and the Schedule 61 (FERC) load forecast. The monthly peak demand forecast is derived using a regression equation with monthly net system energy loads All energy and peak load data is taken from monthly actual information reported by the Power Supply department. Net system load is calculated by removing transfer customer load and scheduled transmission losses from wholesale sales to other utilities from the reported and metered area load totals. 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 estimates provide a high quality data base for producing load forecasts.

Both regression equations are log-log specified. The regressions were calibrated over the period July 1982 to June 1990 for energy, and July 1981 to June 1990 for peak. Since the energy forecast leads the retail load forecast on average by one-half month, the retail load forecasts were adjusted by one-half month, using a simple average, in order to produce a regressor with the correct frequency. Qualitative variables for representative months were utilized where statistically significant. For example, a qualitative variable for February accommodates the short month, while a qualitative variable for December relates holiday seasonal activities.

The following table and chart indicate the results of the energy and peak forecasting models using the high, medium, and low retail load forecast scenarios. A word of caution is advised when viewing 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 retail sales, assuming all programs are cost-effective and implemented, are lower than these estimates, as are the power generating resources required to meet the peak and energy needs of customers.

Results

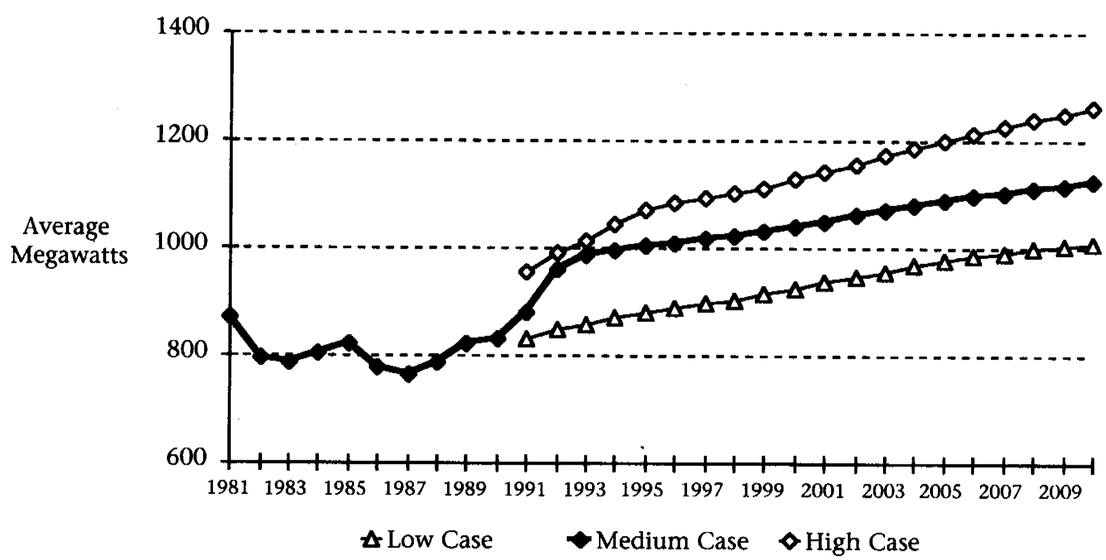
The resulting patterns of load growth follow the retail load paths described earlier. The increase apparent in 1992 is offset by the acquisition of a cogeneration facility currently serving needs of the customer. Chapter 5 describes the resource acquisition concurent with the increased load. Peak forecasts have prepared for the medium case in order to provide documentation for the information in chapter 5 as well.

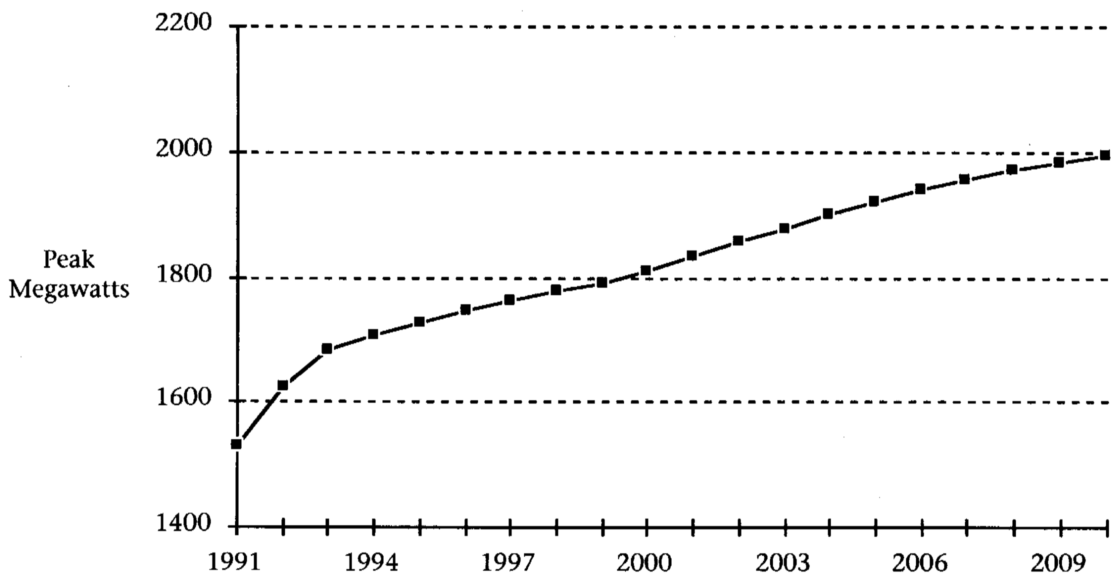
The twenty year compound growth rates (1990-2010) indicated below:

	High	Medium	Low
Net System Load	2.0%	1.5%	1.0
Peak Demand	n.a.	1.4%	n.a.

Net System Energy Load (No DSM Programs)

Figure 3-13.





Medium Case Peak Demand Forecast For January

Figure 3-14.

Forecasting Two Year Action Plan

- 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
- Analyze the effects of wind on peak
- Refine peak forecast equations and include additional data for the 1990/91 and 1991/92 heating season
- Prepare an assessment of the cost and feasibility of developing an integrated natural gas and electric end-use forecasting model for the commercial class

1991 WWP Electric Load Forecast (Medium Case)

Figure 3-15.

1991 WWP ELECTRIC LOAD FORECAST (MEDIUM CASE) FOR
LEAST COST PLANRETAIL LOADS WITH 100% OF NORMAL
WEATHER AND NO DSM PROGRAMS

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
RESIDENTIAL CUSTOMER CLASS												
TOTAL SALES (000 KWH) ...	2930495	3075886	3100768	3106026	3094338	3082439	3067251	3052948	3040945	3029963	3026574	3030402
% CHANGE	0.9	5.0	0.8	0.2	-0.4	-0.4	-0.5	-0.5	-0.4	-0.4	-0.4	-0.1
NUMBER OF CUSTOMERS ..	218914	220576	222885	224774	226253	227652	228925	230040	231020	231907	232726	233493
% CHANGE	0.8	0.8	1.0	0.8	0.7	0.6	0.6	0.5	0.4	0.4	0.4	0.3
NEW CUSTOMERS (AVG) ...	1750	1662	2309	1890	1478	1399	1273	1115	981	887	818	767
USE PER CUSTOMER (KWH)	13387	13945	13912	13818	13676	13540	13399	13271	13163	13065	13005	12979
% CHANGE	-1.7	4.2	-0.2	-0.7	-1.0	-1.0	-1.0	-0.9	-0.8	-0.7	-0.5	-0.2
COMMERCIAL CUSTOMER CLASS												
TOTAL SALES (000 KWH) ...	2127911	2255250	2368163	2463379	2532052	2594686	2655818	2714987	2763116	2821464	2887063	2951773
% CHANGE	3.1	6.0	5.0	4.0	2.8	2.5	2.4	2.2	1.8	2.1	2.3	2.2
NUMBER OF CUSTOMERS ..	26525	27016	27489	27897	28257	28598	28933	29255	29523	29819	20100	30349
% CHANGE	1.8	1.8	1.8	1.5	1.3	1.2	1.2	1.1	0.9	1.0	0.9	
USE PER CUSTOMER (KWH)	80222	83478	86149	88303	89608	90730	91791	92805	93592	94619	95917	97259
% CHANGE	1.3	4.1	3.2	2.5	1.5	1.3	1.2	1.1	0.8	1.1	1.4	1.4
INDUSTRIAL CUSTOMER CLASS												
TOTAL SALES (000 KWH) ...	1314713	1378778	1876174	1973879	1995662	1999978	2008227	2016741	2025495	2034386	2043665	2053116
% CHANGE	0.2	4.9	36.1	5.2	1.1	0.2	0.4	0.4	0.4	0.4	0.5	0.5
TOTAL STREET & HIGHWAY LIGHTING												
TOTAL SALES (000 KWH) ...	21556	21247	21247	21247	21247	21247	21247	21247	21247	21247	21247	21247
TOTAL RETAIL CUSTOMER CLASS SALES												
TOTAL SALES (000 KWH) ...	6395450	6731390	7365538	7563927	7642167	7696793	7750671	7803857	7848706	7904788	7976274	8054295
% CHANGE	0.7	5.3	9.4	2.7	1.0	0.7	0.7	0.7	0.6	0.7	0.9	1.0

1991 WWP ELECTRIC LOAD FORECAST (MEDIUM CASE) FOR LEAST COST PLAN
RETAIL LOADS WITH 100% OF NORMAL WEATHER AND NO DSM PROGRAMS

	2002	2003	2004	2005	2006	2007	2008	2009	2010
RESIDENTIAL CUSTOMER SALES									
TOTAL SALES (000 KWH) ...	3035620	3039273	3041505	3043597	3042441	3037512	3032927	3027634	3022367
% CHANGE	0.2	0.1	0.1	0.1	0.0	-0.2	-0.2	-0.2	-0.2
NUMBER OF CUSTOMERS ..	234228	234966	235706	236425	237111	237760	238368	238938	239470
% CHANGE	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2
NEW CUSTOMERS AVG) ...	736	738	740	719	687	649	608	570	532
USE PER CUSTOMER (KWH)	12960	12935	12904	12873	12831	12776	12724	12671	12621
% CHANGE	-0.1	-0.2	-0.2	-0.2	-0.3	-0.4	-0.4	-0.4	-0.4
COMMERCIAL CUSTOMER CLASS									
TOTAL SALES (000 KWH) ...	3015254	3076798	3136604	3195519	3249545	3299085	3347113	3392976	3237970
% CHANGE	2.2	2.0	1.9	1.9	1.7	1.5	1.5	1.4	1.3
NUMBER OF CUSTOMERS ..	30581	30809	31040	31280	31516	31742	31945	32128	32313
% CHANGE	0.8	0.7	0.8	0.8	0.8	0.7	0.6	0.6	0.6
USE PER CUSTOMER (KWH)	98600	99868	101049	102158	103108	103934	104777	105609	106397
% CHANGE	1.4	1.3	1.2	1.1	0.9	0.8	0.8	0.8	0.7
INDUSTRIAL CUSTOMER CLASS									
TOTAL SALES (000 KWH) ...	2062418	2071594	2080665	2089833	2098856	2107585	2116192	2124548	2132874
% CHANGE	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
TOTAL STREET & HIGHWAY LIGHTING									
TOTAL SALES (000 KWH) ...	21247	21247	21247	21247	21247	21247	21247	21247	21247
TOTAL RETAIL CUSTOMER CLASS SALES									
TOTAL SALES (000 KWH) ...	8132335	8206737	8277890	8348118	8410078	8463491	8515619	8564602	8612689
% CHANGE	1.0	0.9	0.9	0.8	0.7	0.6	0.6	0.6	0.6

1991 WWP Electric Load Forecast (High Case)

Figure 3-16.

1991 WWP ELECTRIC LOAD FORECAST (HIGH CASE) FOR LEAST COST PLAN
RETAIL LOADS WITH 105% OF NORMAL WEATHER AND NO DSM PROGRAMS

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
RESIDENTIAL CUSTOMER SALES												
TOTAL SALES (000 KWH) ...	2950477	3144651	3172129	3173355	3152032	3130212	3104575	3075858	3046729	3019791	3004391	2998463
% CHANGE	-0.2	6.6	0.9	0.0	-0.7	-0.7	-0.8	-0.9	-0.9	-0.9	-0.5	-0.2
NUMBER OF CUSTOMERS ..	218971	220552	222851	225193	227528	229816	232013	234407	236918	239246	241239	243011
% CHANGE	0.8	0.7	1.0	1.1	1.0	1.0	1.0	1.0	1.1	1.0	0.8	0.7
NEW CUSTOMERS (AVG) ...	1807	1581	2299	2342	2334	2288	2198	2393	2511	2328	1994	1771
USE PER CUSTOMER (KWH)	13474	14258	14234	14092	13853	13621	13381	13122	12860	12622	12454	12339
% CHANGE	-1.0	5.8	-0.2	-1.0	-1.7	-1.7	-1.8	-1.9	-2.0	-1.8	-1.3	-0.9
COMMERCIAL CUSTOMER CLASS												
TOTAL SALES (000 KWH) ...	2137907	2281831	2400840	2498558	2574793	2647059	2719217	2792253	2857839	2934913	3018963	3101293
% CHANGE	3.6	6.7	5.2	4.1	3.1	2.8	2.7	2.7	2.3	2.7	2.9	2.7
NUMBER OF CUSTOMERS ..	26532	27014	27485	27946	28411	28865	29320	29806	30274	30763	31206	21597
% CHANGE	1.8	1.8	1.7	1.7	1.7	1.6	1.6	1.7	1.6	1.6	1.4	1.3
USE PER CUSTOMER (KWH)	80579	84469	87351	89408	90627	91705	92741	93680	94398	95403	96742	98153
% CHANGE	1.7	4.8	3.4	2.4	1.4	1.2	1.1	1.0	0.8	1.1	1.4	1.5
INDUSTRIAL CUSTOMER CLASS												
TOTAL SALES (000 KWH) ...	1343541	1885100	1999119	2068951	2252946	2429561	2462971	2497082	2531876	2567255	2603476	2640337
% CHANGE	2.4	40.3	6.0	3.5	8.9	7.8	1.4	1.4	1.4	1.4	1.4	1.4
TOTAL STREET & HIGHWAY LIGHTING												
TOTAL SALES (000 KWH) ...	21156	21247	21247	21247	21247	21247	21247	21247	21247	21247	21247	21247
TOTAL RETAIL CUSTOMER CLASS SALES												
TOTAL SALES (000 KWH) ...	6454316	7333234	7592422	7761023	7999118	8225761	8305263	8383199	8454232	8539731	8644804	8758196
% CHANGE	1.6	13.6	3.5	2.2	3.1	2.8	1.0	0.9	0.8	1.0	1.2	1.3

1991 WWP ELECTRIC LOAD FORECASE (HIGH CASE) FOR LEAST COST PLAN
RETAIL LOADS WITH 105% OF NORMAL WEATHER AND NO DSM PROGRAMS

	2002	2003	2004	2005	2006	2007	2008	2009	2010
RESIDENTIAL CUSTOMER SALES									
TOTAL SALES (000 KWH) ...	2994619	2989825	2984516	2979864	2972999	2963313	2954910	2945908	2935560
% CHANGE	-0.1	-0.2	-0.2	-0.2	-0.2	-0.3	-0.3	-0.3	-0.4
NUMBER OF CUSTOMERS ..	244749	246460	248115	249635	251005	252211	253316	254300	255512
% CHANGE	0.7	0.7	0.7	0.6	0.5	0.5	0.4	0.4	0.5
NEW CUSTOMERS (AVG) ...	1739	1711	1655	1520	1370	1205	1106	984	1212
USE PER CUSTOMER (KWH)	12235	12131	12029	11937	11844	11749	11665	11584	11489
% CHANGE	-0.8	-0.9	-0.8	-0.8	-0.8	-0.8	-0.7	-0.7	-0.8
COMMERCIAL CUSTOMER CLASS									
TOTAL SALES (000 KWH) ...	3182472	3261891	3339516	3415752	3485732	3549575	3610946	3669300	3728864
% CHANGE	2.6	2.5	2.4	2.3	2.0	1.8	1.7	1.6	1.6
NUMBER OF CUSTOMERS ..	31967	32331	32693	33050	33387	33699	33978	34226	34508
% CHANGE	1.2	1.1	1.1	1.1	1.0	0.9	0.8	0.7	0.8
USE PER CUSTOMER (KWH)	99554	100890	102147	103353	104403	105332	106273	107210	108059
% CHANGE	1.4	1.3	1.2	1.2	1.0	0.9	0.9	0.9	0.8
INDUSTRIAL CUSTOMER CLASS									
TOTAL SALES (000 KWH) ...	2677519	2715058	2753993	2791498	2830377	2869479	2907983	2948770	2989073
% CHANGE	1.4	1.4	1.4	1.4	1.4	1.4	1.3	1.4	1.4
TOTAL STREET & HIGHWAY LIGHTING									
TOTAL SALES (000 KWH) ...	21247	21247	21247	21247	21247	21247	21247	21247	21247
TOTAL RETAIL CUSTOMER CLASS SALES									
TOTAL SALES (000 KWH) ...	8872726	8984944	9096289	9205531	9307684	9401123	9492703	9583034	9671581
% CHANGE	1.3	1.3	1.2	1.2	1.1	1.0	1.0	1.0	0.9

1991 WWP Electric Load Forecast (Low Case)

Figure 3-17.

1991 WWP ELECTRIC LOAD FORECASE (LOW CASE) FOR LEAST COST PLAN
RETAIL LOADS WITH 95% OF NORMAL WEATHER AND NO DSM PROGRAMS

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
RESIDENTIAL CUSTOMER SALES												
TOTAL SALES (000 KWH) ...	2912053	3021256	3047772	3048479	3048601	3058471	3065575	3069682	3071594	3073262	3081162	3092474
% CHANGE	-1.5	3.8	0.9	0.0	0.0	0.3	0.2	0.1	0.1	0.1	0.3	0.4
NUMBER OF CUSTOMERS ..	218823	219944	221792	223060	223448	223223	223098	223285	223685	224079	224451	224903
% CHANGE	0.8	0.5	0.8	0.6	0.2	-0.1	-0.1	0.1	0.2	0.2	0.2	0.2
NEW CUSTOMERS AVG) ...	1658	1122	1848	1267	389	-225	-126	188	400	394	372	452
USE PER CUSTOMER (KWH)	13308	13736	13742	13667	13643	13701	13741	13748	13732	13715	13728	13750
% CHANGE	-2.3	3.2	0.0	-0.5	-0.2	0.4	0.3	0.0	-0.1	-0.1	0.1	0.2
COMMERCIAL CUSTOMER CLASS												
TOTAL SALES (000 KWH) ...	2115225	2211593	2314697	2391016	2450184	2503015	2554161	2606809	2650830	2707331	2770734	2832755
% CHANGE	2.5	4.6	4.7	3.3	2.5	2.2	2.0	2.1	1.7	2.1	2.3	2.2
NUMBER OF CUSTOMERS ..	26515	26942	27357	27686	27911	28047	28198	28390	28572	28796	29010	29211
% CHANGE	1.7	1.6	1.5	1.2	0.8	0.5	0.5	0.7	0.6	0.8	0.7	0.7
USE PER CUSTOMER (KWH)	79774	82088	84612	86362	87786	89244	90580	91823	92777	94019	95509	96975
% CHANGE	0.7	2.9	3.1	2.1	1.6	1.7	1.5	1.4	1.0	1.3	1.6	1.5
INDUSTRIAL CUSTOMER CLASS												
TOTAL SALES (000 KWH) ...	1274405	1126434	1121040	1127129	1156652	1158816	1170461	1182266	1194631	1207450	1220713	1234115
% CHANGE	-2.9	-11.6	-0.5	0.5	2.6	0.2	1.0	1.0	1.0	1.1	1.1	1.1
TOTAL STREET & HIGHWAY LIGHTING												
TOTAL SALES (000 KWH) ...	21156	21247	21247	21247	21247	21247	21247	21247	21247	21247	21247	21247
TOTAL RETAIL CUSTOMER CLASS SALES												
TOTAL SALES (000 KWH) ...	6323948	6381118	6504168	6587729	6676375	6741128	6810524	6878590	6936649	7007463	7091953	7178632
% CHANGE	-0.5	0.9	1.9	1.3	1.3	1.0	1.0	1.0	0.8	1.0	1.2	1.2

1991 WWP ELECTRIC LOAD FORECASE (LOW CASE) FOR LEAST COST PLAN
RETAIL LOADS WITH 95% OF NORMAL WEATHER AND NO DSM PROGRAMS

	2002	2003	2004	2005	2006	2007	2008	2009	2010
RESIDENTIAL CUSTOMER SALES									
TOTAL SALES (000 KWH) ...	3102923	3110038	3116304	3124546	3133546	3141406	3149227	3156925	3160674
% CHANGE	0.3	0.2	0.2	0.3	0.3	0.3	0.2	0.2	0.1
NUMBER OF CUSTOMERS ..	225453	226060	226492	226593	226334	225887	225396	224847	224130
% CHANGE	0.2	0.3	0.2	0.0	-0.1	-0.2	-0.2	-0.2	-0.3
NEW CUSTOMERS (AVG) ...	550	606	433	100	-259	-446	-492	-548	-718
USE PER CUSTOMER KWH)	13763	13758	13759	13789	13845	13907	13972	14040	14102
% CHANGE	0.1	0.0	0.0	0.2	0.4	0.4	0.5	0.5	0.4
COMMERCIAL CUSTOMER CLASS									
TOTAL SALES (000 KWH) ...	2893536	2951630	3005235	3054017	3093973	3126870	3156440	3183829	3201355
% CHANGE	2.1	2.0	1.8	1.6	1.3	1.1	0..9	0.9	0.6
NUMBER OF CUSTOMERS ..	29410	29615	29802	29956	30063	30138	30187	30213	30223
% CHANGE	0.7	0.7	0.6	0.5	0.4	0.2	0.2	0.1	0.0
USE PER CUSTOMER (KWH)	98384	99668	100841	101949	102916	103753	104563	105380	105925
% CHANGE	1.5	1.3	1.2	1.1	0.9	0.8	0.8	0.8	0.5
INDUSTRIAL CUSTOMER CLASS									
TOTAL SALES (000 KWH) ...	1247448	1260502	1273158	1285773	1298320	1310774	1323387	1336134	1348667
% CHANGE	1.1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9
TOTAL STREET & HIGHWAY LIGHTING									
TOTAL SALES (000 KWH) ...	21247	21247	21247	21247	21247	21247	21247	21247	21247
TOTAL RETAIL CUSTOMER CLASS SALES									
TOTAL SALES (000 KWH) ...	7263128	7341409	7414137	7484087	7545897	7599257	7649328	7697261	7731332
% CHANGE	1.2	1.1	1.0	0.9	0.8	0.7	0.7	0.6	0.4

1991 WWP Electric Load Historical Actuals

Figure 3-18.

1991 WWP ELECTRIC LOAD HISTORICAL ACTUALS
RETAIL LOADS WITH ACTUAL WATHER (NOT WEATHER CORRECTED)

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
RESIDENTIAL CUSTOMER SALES												
TOTAL SALES (000 KWH) ...	2800952	3060393	3006568	2959321	3093976	2881984	3107748	3154576	2924976	2823618	2871278	2956690
% CHANGE	NA	9.3	-1.8	-1.6	4.6	-6.9	7.8	1.5	-7.3	-3.5	1.7	3.0
NUMBER OF CUSTOMERS ..	188325	194237	198847	201465	203444	205533	208574	210811	212865	214479	215610	217164
% CHANGE	NA	3.1	2.4	1.3	1.0	1.0	1.5	1.1	1.0	0.8	0.5	0.7
NEW CUSTOMERS (AVG) ...	NA	5912	4610	2618	1979	2089	3041	2237	2054	1614	1131	1554
USE PER CUSTOMER (KWH)	14873	15756	15120	14689	15208	14022	14900	14964	13741	13165	13317	13615
% CHANGE	NA	5.9	-4.0	-2.9	3.5	-7.8	6.3	0.4	-8.2	-4.2	1.2	2.2
COMMERCIAL CUSTOMER CLASS												
TOTAL SALES (000 KWH) ...	1449429	1551363	1563154	1613157	1664026	1675591	1805139	1880355	1885446	1975417	2001254	2064515
% CHANGE	NA	7.0	0.8	3.2	3.2	0.7	7.7	4.2	0.3	4.8	1.3	3.2
NUMBER OF CUSTOMERS ..	21541	22222	22899	23120	23310	23555	24003	24390	24871	25346	25772	26069
% CHANGE	NA	3.2	3.0	1.0	0.8	1.0	1.9	1.6	2.0	1.9	1.7	1.1
USE PER CUSTOMER (KWH)	67287	69811	68262	69774	71386	71136	75205	77094	75809	77937	77651	79195
% CHANGE	NA	3.8	-2.2	2.2	2.3	-0.4	5.7	2.5	-1.7	2.8	-0.4	2.0
INDUSTRIAL CUSTOMER CLASS												
TOTAL SALES (000 KWH) ...	1742754	1834649	1812928	1934464	1354096	1349333	1285583	1237875	1168696	1129511	1235316	1312085
% CHANGE	NA	5.3	-1.2	6.7	-30.0	-0.4	-4.7	-3.7	-5.6	-3.4	9.4	6.2
TOTAL STREET & HIGHWAY LIGHTING												
TOTAL SALES (000 KWH) ...	NA	NA	NA	NA	NA	NA	NA	NA	21992	20561	20849	20999
TOTAL RETAIL CUSTOMER CLASS SALES												
TOTAL SALES (000 KWH) ...	5994322	6447369	6384339	6508504	6115698	5908510	6199320	6274755	6001437	5949217	6129130	6353444
% CHANGE	NA	7.6	-1.0	1.9	-6.0	-3.4	4.9	1.2	-4.4	-0.9	3.0	3.7

Chapter 4

LEAST-COST PLANNING

Least-cost planning is the process of planning for and selecting resources from both supply-side and demand-side options in such a way as to minimize costs to the company and its customers. It is WWP's expectation that least-cost planning will be achieved in a manner consistent with system reliability objectives and the need to maintain an adequate rate of return.

As the 1990s begin and WWP embarks on its second century of service, the company's commitment is to provide its customers with the lowest-cost energy available. As a low-cost producer and supplier of energy services, we plan to ensure our position as our customers' preferred energy supplier in the 1990s. While planning for the future energy requirements of its customers remains important, the company has also recognized the importance of offering services which enhance the lives of its customers.

WWP's future resource needs can be met with a combination of demand- and supply-side options. Uncertainties can be mitigated somewhat by providing a diverse mix of available resource options. Providing the appropriate combinations of resource options will allow the company to maintain flexibility, reliability, low rates and profitability.

Resource Decisions

The WWP plans long term firm resource acquisitions to serve system requirements based on critical water conditions. In addition the company plans to serve a small portion of the requirements (up to 50 aMW) with its own hydro generation, when hydro conditions are better than critical, or with short-term purchases from other utilities. (For further information on the 50 aMW planning criteria, see Appendix A.)

Resource decisions are based on several factors. The two most significant factors are availability and cost. If an analysis shows that the resource can be acquired and that the financial impacts of the resource demonstrate it to be a least-cost alternative, then that resource is pursued. A determination of availability would address the effects of the resource as it relates to the environment (societal), a ranking effort only with no numerical values, regulatory activities and compatibility with WWP's electrical system.

All available resources that can be acquired by the company and are compatible to WWP's system are evaluated against each other on a total cost basis (capital and operating costs). Because of uncertainty of future events that may affect different resource types and fuels the company's policy has been to not rely on one single type of resource but to have diversity in its resource acquisition mix. In addition all resource decisions need to be compatible with its integrated resource plan as stated in WWP's least-cost planning reports. The least-cost planning model is used as one tool in evaluating resources for long term planning and acquisition.

WWP evaluates the impacts to the company of future events using scenario or "what if" planning. But the most probable or medium case is used for short-term and long-term resource acquisition. If conditions change, either in the requirements or resources of the company, then a new evaluation of WWP's power supply needs is made. This new study or forecast then becomes WWP's most probable or "base" forecast. A new resource acquisition plan is made based on the new forecast, which is now the most probable. These new forecasts and resource plans are made at least annually or more often if conditions so warrant. WWP's many resource options that are maintained allows the company to meet changing conditions with a minimum amount of risk.

Need for Energy

During the 1980s, the company experienced a drop in customer demand while at the same time saw the completion of new generating plants such as Colstrip which WWP has 15 percent ownership. The result was a large surplus on WWP's system requiring a concentrated marketing effort in order to stabilize rates.

The company, through sales to other Northwest utilities, has essentially brought the requirements and resources into balance. This marketing strategy was designed to help keep energy costs lower during the period of surplus than they would be were the company to make only non-firm sales. The company has entered into a period of load-resource balance. The need for firm resources starts in 1995 and increases until the year 2000, at which time additional resource needs terminate until the year 2006.

The company has many options available to meet this need for additional energy supply, which comes from a combination of increased loads and a decrease in available resources. The decrease in existing resources is partially due to the expiration of a contract for energy from the Chelan hydro plant (1995) and the gradual termination of various contract purchase rights from the Mid-Columbia hydro facilities (2005). Another significant reduction occurs in 1996 with the termination of a contract with BPA for power deliveries (80 MW) associated with the Hanford NPR/WNP-1 Nuclear projects.

For the medium case, the power supply needs from 1994 through 2005 will be covered by a combination of energy efficiency programs, residential space and water heat conversion programs, hydro system redevelopment and purchases. The purchases will be from utilities and non-utility power developers. Some of these purchases are expected to be facilitated through a bidding process. If, at the time of installment, the energy is not available for some reason, combustion turbines are shown to be a cost-effective back-up of these resources. The resource options which appear to have the most potential for WWP in the short-term and long-term are discussed below.

Resource Options

The company has a multitude of options available to handle the projected peak and energy requirements for the next 20 years. WWP plans to continue to rely on a diverse mixture of resource options for the future. These combinations of resource options are being evaluated continually using a multitude of planning tools in order to determine the least-cost path of resource acquisitions. Not all of these resource options will be needed by WWP based on the most probable (medium) forecast. The company will be pursuing these resources identified in the base case to meet projected system requirements. The other resource options will be used by WWP if planned resources do not materialize or WWP finds itself on a load forecast higher than the medium forecast. Some of the more promising options available to WWP are:

1. Demand Side Resources. Demand side resources include any company sponsored program which encourages customers to change the way they use electricity. Types of demand side resources include: energy efficiency (conservation), space and water heat conversion, and load management. The company is aggressively pursuing the implementation of energy efficiency and fuel conversion programs to defer the need to construct new generating resources. The company is currently staffing its Energy Management section to assess, design, implement, and evaluate demand side resource programs.

1A. Energy Efficiency. The company has been involved with energy efficiency programs in the residential sector with its residential weatherization program. Opportunities in the commercial and industrial sectors for energy efficiency improvements will be developed.

1B. Space and Water Heat Conversion. Opportunities exist for WWP to promote the direct use of natural gas by customers for heating. One example is a program to promote the replacement of electric hot water heaters with gas models for WWP's residential customers already using gas for space heating.

2. Cogeneration. WWP is pursuing the opportunities for cost-effective cogeneration development within its service territory. The company will encourage cost-effective cogeneration development through studies and capital investment. Utilizing cogeneration results in a higher efficiency use of thermal energy which correlates to better economics for both the host facility (steam source) and the utility (electrical generation). At the time the decision is made to develop a cogeneration site, then WWP will determine if it is useable to serve system requirements or will be sold off system.

   Cogen Section

   To the extent that these cogeneration resources are jointly developed with WWP's retail customers, we anticipate a three-way sharing of benefits between the host facility, WWP's customers, and WWP's shareholders. If rate basing of the cogeneration resource is denied, there will be a sharing of costs and benefits between the host facility and WWP's shareholders. When cogeneration resources are developed to meet company's native load, such resources must be cost effective when compared to other resource alternatives.

3. Hydro Improvements. Hydro generation is the backbone of WWP's power supply and the reason for its low retail rates. In order to fully utilize this resource, the company has begun a program of improvements and/or redevelopments of all its hydro plants. Each hydro site will be individually evaluated and then a decision will be made on whether or not to proceed with the improvement.

   The hydro improvements contemplated to meet WWP's native load will not be approved by company management unless it is clear that the economics show that a particular site improvement is cost effective when compared to other alternatives. An exception would be if the power can be sold to another entity. One of the alternatives that the site improvement will be measured against is the resource costs received under WWP's RFP.

4. Request For Proposals (RFP). The company has prepared an RFP which will request firm energy proposals for both generation and conservation. Bids can come from all sources except WWP's subsidiaries. The RFP will hopefully provide innovative resource alternatives at competitive prices that can be used by WWP. The first RFP will request 30 aMW of firm energy starting delivery to WWP in 1995. Based on WWP's first RFP, other RFPs will be evaluated for the future.

5. Firming Non-Firm Hydro. A feasibility study was completed by WWP to determine the maximum amount of non-firm hydro that could be firmed up by other low capital, high operating cost resources, "A Sample Approach to Analyze Firming Non-firm Hydro Energy" dated July 1989. There is a potential for the company to pursue this option up to firming between 90 and 100 MWs of non-firm hydro energy, based on values used in 1989. The uncertainty of future conditions make this number hard to quantify. These future conditions are the value of firm to non-firm energy and the cost of fuel to operate the back-up resource under low water conditions. The company is already firming up over 60 aMW based on NE combustion turbine operation and reliance on short term purchases. The 60 aMW is one half of the way between critical and medium water energy production on WWP's system.

6. Resource "Options." The company is still maintaining the licensed site for a future coal plant at Creston, Washington. The licensing and permitting have been maintained, so that if the need develops in the region, a generating facility can be built without the delay of site evaluation and certification.

   WWP is still pursuing the licensing of the transmission interconnection with B.C. Hydro and possible power purchase arrangements. This intertie would enable WWP to gain firm access to Canadian electrical supplies. The final decision to build the intertie will be decided based on the project being cost-effective when compared to other resources, and it is shown to be beneficial to the company's customers. The analysis would include a comparison to other alternatives including resources from the RFP.

7. Long-term Purchases. The company's long-term power purchase agreements for power from public utility district-owned hydroelectric facilities on the mid-Columbia River begin to expire in 2005. WWP plans to actively negotiate for extensions of these agreements which will allow for a continuation of the benefits theagreements currenlt provide to both the company and the PUDs. Such extensions would make long-term purchases from these facilities significant resources beginning in 2006, when system requirements are projected to begin exceeding available new resources.

Capacity Needs

The need for capacity occurs every year, even though WWP's hydro system is basically energy constrained, not capacity constrained. With the ongoing hydro system improvements and redevelopments, additional capacity will be acquired. Resource acquisitions to satisfy energy needs will also contribute to our capacity capability. These two activities should satisfy our capacity deficiencies. If additional peak capability is needed in the future, then the company will pursue a peak purchase from another utility, install a combustion turbine and/or implement a load management program.

If all the hydro improvements can be justified for implementation, then the excess capacity not needed by WWP to serve loads will be sold off system.

Peak Requirements and Resources

Figure 4-1. Medium Peak Load Forecast (figures are MW)

Year	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Surplus (Deficit)	331	-42	-4	-57	-89	-119	-14	-118	-138	-158
Peak Efficiency	0	0	1	1	2	3	5	6	8	10
Space and Water Heat Conversion	0	1	3	12	25	41	55	67	74	78
Hydro Improvements	0	0	1	1	3	54	200	210	210	210
Request for Proposals	---	---	---	---	---	30	30	30	30	30
Combustion Turbines	---	---	---	---	---	---	---	---	---	---
Adj. Surplus (Deficit)	331	-41	1	-43	-59	9	276	195	184	170

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Surplus (Deficit)	-198	-191	-183	-178	-217	-237	-311	-328	-344	-355
Peak Efficiency	12	14	16	17	19	21	22	24	26	27
Space and Water Heat Conversion	79	78	77	77	76	75	75	74	73	72
Hydro Improvements	255	255	255	255	255	255	255	255	255	255
Request for Proposals	30	30	30	30	30	30	30	30	30	30
Combustion Turbines	---	---	---	---	---	---	40	40	40	40
Adj. Surplus (Deficit)	178	186	195	201	163	144	111	95	80	69

Uncertainty

The only future certainty is that the future will differ from our expectations. The ability to forecast what resources and loads the region and WWP will have 20 years from now is not very precise. For the long term, we need to maintain enough flexibility that the utility can accommodate future changes. The primary focus for WWP will be on what we expect will happen in the next few years. WWP will develop those resources that have a demonstrated profitability and/or are justified as being cost-effective for the long-term. Some resources might be acquired even though they are not the least cost due to other factors such as reliability, compatibility with power system needs, peak reserve obligations, environmental acceptance, etc.

There are additional complexities introduced in least-cost planning that are difficult to quantify and to be remembered in the total evaluation of the resource acquisition plans. The inclusion of demand-side resources into the resource planning framework increases the complexity of the planning process. When only supply-side resources are evaluated for resource acquisition, no direct rate impact evaluation is done to determine which resources to choose. Rather resources were chosen on the basis of total cost to own and operate. The lowest cost options among supply resources have the lowest impacts on rates. However, with the inclusion of demand-side resources in the planning process, the comparison of resources becomes more complex. Because demand-side resources impact the customers' purchases from the utility, there are rate impacts due to the reduced sales which affect customers differently than do supply resources. Therefore, in integrated resource planning, rate impacts are one of many factors used.

In addition, the consideration of demand-side options requires information, not only on WWP's programs, but also on the customer's choice of energy consumption as well as some non-energy related decisions. The company's planning process also needs to be in step with regional planning criteria such as from the Northwest Power Planning Council. Due to the passage by Congress of the Clean Air Act, the company has set up a special team to assess the impact to WWP. These impacts will be inputs to the next planning process.

WWP has completed its preliminary review of the new 1990 Clean Air Act Amendment, but much of what we understand is interpretive at this time. We will continue to study the language of the Act and maintain discussions with state officials and other utility representatives. The cost to WWP in meeting new clean air standards at Centralia coal plant may be significant. Industry will be faced with stricter standards that may require increased energy usage or changes to cleaner fuels such as electricity and natural gas. The utility must be prepared to meet this need and recover its costs. It is important that a dialogue be established on the impact of new clean air legislation as Federal rulemaking and state legislative sessions begin.

In any resource acquisition decision, the environmental effects have been taken into account by increasing the supply-side resource cost to cover the expense of addition equipment for pollution control or modifications to the facilities to mitigate environmental concerns. Environmental impacts are not new to energy planning. The electric utilities have continued to work on environmental problems such as nuclear waste, the effects of dams on fish and acid rain. Global warming is now being hotly-debated as to the timing and magnitude of the problem. Over the next two to three decades, global warming could reshape the way we produce and use energy. Global warming is the phenomenon produced by increased carbon dioxide and other gases in the earth's atmosphere. A major contributor to increased carbon dioxide is the burning of fossil fuels, like coal, to produce electricity. The atmospheric changes are believed to be producing a long-term increase in the earth's temperature and climate, hence the name global warming. Although the issues of global warming are being debated within the scientific community, the relationship of carbon dioxide and temperature is not known. But beyond that, there is no agreement as to the timing, the effects or the magnitude of this environmental problem.

In the past, any attempts to cost out non-quantifiable effects of resources have never been very successful. To quantify these factors would require a judgment call by WWP. There is presently no consensus as to the magnitude of the hard costs or even how to develop the methodology. It would appear to WWP that the conclusions and the programs to mitigate the non-quantifiable environmental effects should be decided by the scientific and political communities. These environmental problems affect all of society and, therefore, should be addressed by society as a whole. WWP stands ready to support these endeavors. It is the company's intention to rank resources based on judgement as to preference to the environment, although WWP has not placed numerical value on resource types. WWP, in the past, has always worked to protect the environment, and will continue to do so in the future.

Critical Water

The capability of the company's hydroelectric resources is based on critical (low) water conditions. Better than critical water conditions result in higher annual energy production figures, although the distribution could vary throughout the year. Attempting to base hydroelectric capability on conditions better than critical water would result in trying to carry more load than the critical capability of the system, which is inherently risky. Also, planning on critical water does not guarantee that demands will always be met. Even worse water conditions could occur. The region and WWP use the 1928-78 historical water sequence for planning, and the critical period currently being used is the worst four-year sequence of flows during that period. The numbers in WWP's Requirements and Resources tabulations for the hydro energy production reflect the critical period monthly hydro energy generation averaged over that period.

Excess hydro generation, which is seasonally available in most years even under low water conditions, offers the company a resource which can be used in a variety of ways. This non-firm energy (so-called because it is not always available) can be used to back off higher cost thermal plants, can be sold to other utilities in the Northwest and Southwest, or in conjunction with other resources can be firmed up to serve firm loads. The revenues from the non-firm sales can be used to offset company costs and, thereby, help reduce retail rates. The difference for the company between the average annual output of the hydro power system and the critical annual output is approximately 125 aMW.

50 aMW planning criteria

WWP's planning policy is to not commit to long-term firm resources for about the last 50 aMW of requirements. Last does not mean in time, but means the last resources to be obtained. WWP fully intends to serve all its load including firm contracts under all water conditions, including critical. However, for approximately 50 aMW of our energy needs under critical water planning, the company will wait to insure that the requirement actually exists before committing to a resource and then probably obtaining a short-term resource. Our resource plans are based on estimates of future requirements. Those estimates contain uncertainty. WWP has been particularly hard hit by loss of load in the past, and we need to protect our customers and investors from that risk in the future. When future uncertainty increases, we need more flexibility in our resource mix. Waiting before committing to a resource gives us that flexibility. It also gives us more risk. But in today's electric energy market, in our judgment, that risk is manageable and moderate. This planning policy will be reviewed periodically to judge changes in future uncertainty and market availability/price.

Planning Model

The company's least-cost planning model, named "Strategic Resource Planning (SRP) Model", was used by WWP to evaluate alternative resource additions to the company. The model produces total revenue requirements, resulting retail rates and a weighted average incremental resource cost indicator. These results help narrow down the range of possibilities resource planners face in deciding on a future course of action relating to demand-side and supply-side resource options. As the decision point approaches in resource acquisitions, utility planners will use least-cost analysis along with experience and judgment to decide a prudent course of action.

By utilizing WWP's SRP model, several variations of the base case can be developed, and assessments can be made of the financial impacts of each variation on the company. The variations deal with changes in future resource additions, as well as changes in real price escalation of fuels, changes in financial parameters and changes in load growth. Having a multitude of "what if" scenarios gives utility planners a chance to assess the impacts of a number of possible futures by changing the input variables. In the face of future uncertainty, the resulting outputs allow the company to assess the financial impact of each scenario and determine which is most likely to provide the lowest cost to the company and its customers.

The planning process must take into account a wide range of uncertainties. To do this, flexibility needs to be stressed in order that the planning process becomes the key and not the plan itself. In addition, non-economic factors (e.g., environmental factors, reliability, dispatchability, contributions to peak, seasonal output, uncertainty, fuel mix, impact on local economy, capital requirements, rate stability and daily load matching capability) need to be reviewed, as well.

Description of WWP Model

The WUTC developed a computerized model for use in least-cost planning and other regulatory forums where accessibility, ease-of-use, and rapid turnaround times are important. WWP hired a consultant to provide program modifications to the WUTC model in order to enhance model effectiveness and ease of use. The WWP model (SRP) calculates financial and rate implications of a utility resource acquisition plan. The model also allows the user to generate multiple scenarios in order to examine the sensitivity of a resource plan to variations in parameters such as fuel costs and load growth.

The SRP model has several purposes. At the most basic level, the model is simply a "fill-in-the-blanks" spreadsheet that establishes the data requirements and planning assumptions the WUTC will require from each company. At its more sophisticated level, the model is a set of methodologies which takes this basic planning information and produces a number of financial statements.

The spreadsheet is not an "optimization" model, in that it does not attempt to produce a plan that minimizes or maximizes some objective. It does not search for the "best" least-cost plan. Rather, it records the results from an assumed plan and reports the power planning and rate implications of those assumptions. In other words, the model is of the "what if" variety. The model makes it possible to change the planning assumptions and test the results by examining the subsequent changes to the rates and revenue requirements.

The SRP model is developed for determining relative impacts on revenue requirements and rates, and does not determine the expected level of those two outputs. The model also determines the weighted average incremental resource costs for each plan as another method of comparison. Costs of transmission and distribution upgrades, and of power plant upgrades and life extensions, cannot be estimated for 20 years, and can be expected to be largely independent of resource mix.

The SRP model is intended to help do three things:

1. Organize and present the data. The model relies on the information developed by WWP in consultation with the public participation process. The model helps standardize the presentation of least-cost planning information much in the same way that income statements and balance sheets help to standardize financial information.

2. Allow "what if" analysis. The model helps in identifying and measuring the uncertainties affecting the future choices facing the utility. Key assumptions can then be changed and power planning, rate and financial results compared.

3. Improve the state commission's ability to evaluate certain type of regulatory decisions. Some areas where the results from the model could have future uses are: (1) the setting of avoided costs for PURPA-type resources; (2) the determination of the cost-effective level for demand-side management programs; (3) the setting of rate design policies; and (4) the evaluation of purchased power contracts.

The model is menu-driven, flexible and fairly easy to use. New and existing energy resources can be described as specific projects or generic types. Users can specify as many resources and projection years as they desire. Input options are carefully tailored to the form and level of detail characterizing real world utility data. An output module produces a user-specified combination of balance sheets, key financial and rate indicators, and graphic comparison of indicator performance under different scenarios.

WWP hired a consultant (Charles River Associates) to provide program modifications to the model in order to enhance model effectiveness and ease of use. One of the modifications was to incorporate the use of the software program @RISK. The program @RISK integrated into the model will allow the framework to handle uncertainty. The incorporation of @RISK addresses the input parameters of loads, fuel costs, capital escalation, costs of capital and purchase price costs. In addition, we now have the ability to base new resource additions on discrete plants of known capacity and energy output.

Figure 4-2 gives an overview of the general structure of the model, including the input data required and the resulting output.

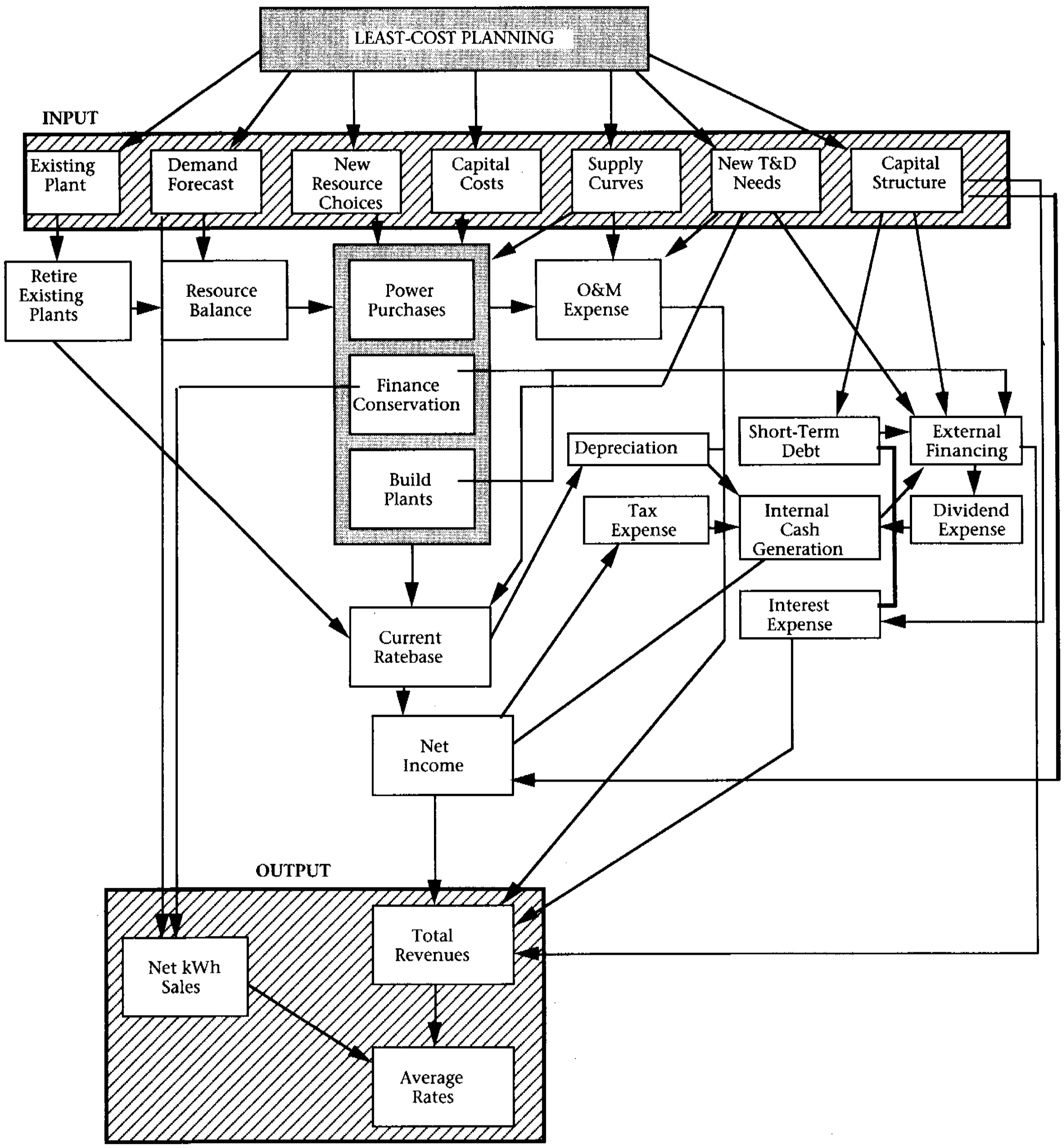
Requirements and Resources

WWP has projected a medium load estimate (the most probable estimate) that is used in determining the future resource needs of the company. Two other load forecasts (high and low) were made that require a different resource acquisition plan. In addition, each resource acquisition plan will vary depending on what assumptions for the future are used (such as fuel escalation). The model was used to evaluate these assumptions and their expected range on future rates, revenue requirements and incremental resource costs.

WWP's planning is based on the medium forecast. A new forecast is done at least annually, which reflects changing conditions such as population changes, economic growth, inflation, etc. It is the company's expectation that long term trends would be picked up in WWP's load forecast and that over a one to two year period adjustments in the load forecast would reflect changing conditions. The new forecast published by the company would then become the medium forecast and WWP would plan resources accordingly. The company assumes the magnitude of load changes for the future is driven primarily by the industrial activity within its service territory. The company keeps close contact with its industrial customers through visits and surveys throughout each year. The information received would be an indication of the industrial activity and correspondingly an indication if WWP is experiencing load growths that approximate the medium, low, or high forecasts used in the report. If deviation from the medium forecast occurs and appears permanent, the company's annual load forecast will reflect the deviation and the resource plan will be adjusted accordingly.

Medium Load Estimate:

The company's medium load estimate or base load forecast is used by WWP as the most probable load growth projection that might occur on its system (see Chapter 3 for load information). The resource planning of the company is based on this estimate. The other estimates are used in assessing the magnitude of the financial impact to the company if



WWP Least Cost Planning Model (Version 2.0)

Figure 4-2.

the actual loads come in higher or lower than the medium. From the model results, it is the company's determination that these magnitudes are manageable.

Using the medium load estimate, the surplus (deficit) situation of the company for 20 years was determined using known conditions. The known conditions are firm contracts, both imports and exports, that WWP has executed with other entities, the expected hydro generation based on critical water conditions, and the planned thermal plant annual generation. Figure 4-3 shows the requirements and resources of WWP based on these conditions with the corresponding surplus (deficit) figures. The energy deficit grows from 0 aMW to 202 aMW in the year 2010. The energy deficit starting in the year 1998 levels off until 2005 due to termination of power sale agreements. The peak numbers are January peaks and the average is a 12-month annual average. The peak number for 1990 is the actual January peak which is lower than the yearly actual peak.

Requirements and Resources

Figure 4-3.

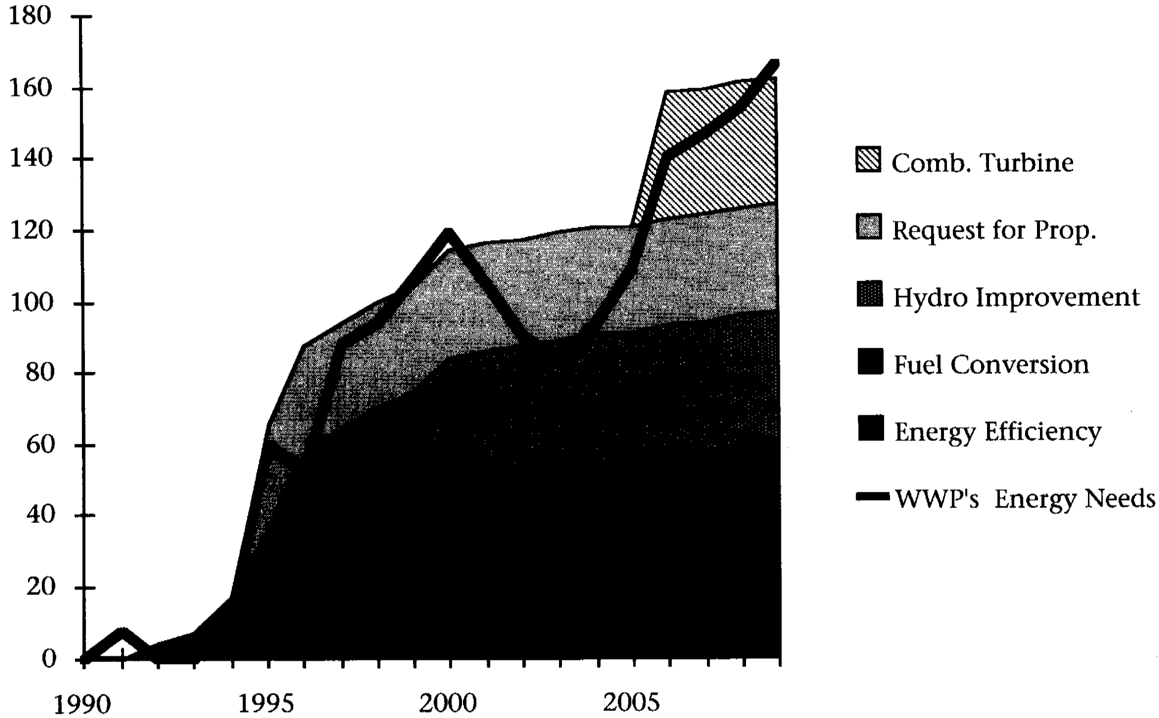
Figures are megawatts.	-1990- Peak	-1990- Average	-1991- Peak	-1991- Average	-1992- Peak	-1992- Average	-1993- Peak	-1993- Average	-1994- Peak	-1994- Average	-1995- Peak	-1995- Average	-1996- Peak	-1996- Average
REQUIREMENTS														
1 System Firm Loads	1264	833	1530	879	1626	961	1684	986	1709	996	1728	1003	1746	1010
2 Puget #1	55	28	55	14	0	0	0	0	0	0	0	0	0	0
3 Puget #2	100	75	100	75	100	75	100	75	100	75	100	75	100	75
4 Seattle City Light	0	15	0	15	0	15	0	15	0	15	0	15	0	0
5 PG&E Exchange	0	0	0	25	0	25	0	25	0	25	0	25	0	25
6 PP&L Sandpoint	5	2	5	2	5	2	5	2	5	2	5	2	0	0
7 PP&L WIDCO	9	5	9	5	0	0	0	0	0	0	0	0	0	0
8 BPA-WNP #3	0	27	0	27	0	27	0	27	0	27	0	27	0	27
9 PP&L 1989	50	50	150	50	150	50	150	50	150	50	150	50	0	0
10 LADWP	0	0	0	11	0	0	0	0	0	0	0	0	0	0
11 Interruptible Load	0	0	0	0	-25	-25	-25	-25	-25	-25	-25	-25	-25	-25
12 TOTAL REQUIREMENTS	1483	1035	1849	1103	1856	1130	1914	1155	1939	1165	1958	1172	1821	1112
RESOURCES														
13 System Hydro	922	341	922	341	922	341	922	341	922	341	922	341	922	341
14 Contract Hydro	221	108	221	108	221	108	221	108	221	108	221	97	197	85
15 Canadian Entitlement Return	-14	-4	-13	-4	-12	-4	-11	-4	-9	-4	-8	-3	-7	-3
16 Restoration	0	4	0	4	0	4	0	4	0	4	0	4	0	4
17 Small Hydro	7	7	8	8	8	8	8	8	8	8	8	8	8	8
18 Monroe Street Upgrade	0	-3	-6	-5	-6	7	10	11	10	11	10	11	10	11
19 Total Hydro	1136	453	1132	452	1133	464	1150	468	1152	468	1153	458	1130	446
20 Cogeneration	10	9	10	9	75	64	75	64	75	61	71	60	71	60
21 Northeast Combustion Turbine	68	54	68	54	68	54	68	54	68	54	68	54	68	54
22 CSPE	49	16	49	16	45	15	40	14	36	14	32	13	28	13
23 PG&E Exchange	0	0	0	10	150	25	150	25	150	25	150	25	150	25
24 S Cal Edison	80	4	0	0	0	0	0	0	0	0	0	0	0	0
25 Grant Peaking	50	0	0	0	0	0	0	0	0	0	0	0	0	0
26 Entitlement & Supplemental Cap	26	0	26	0	24	0	21	0	19	0	17	0	14	0
27 BPA #39216	80	68	79	67	79	68	80	68	80	68	80	68	80	28
28 BPA-WNP #3	82	27	82	27	82	27	82	27	82	27	82	27	82	27
29 B C Hydro	0	22	100	11	0	0	0	0	0	0	0	0	0	0
30 Montana	0	0	0	36	0	36	0	36	0	27	0	0	0	0
31 Storage Arrangements	0	0	55	6	0	0	0	0	0	0	0	0	0	0
32 Short-Term Purchases	0	25	0	50	0	20	0	42	0	50	0	50	0	50
33 Thermal Centralia	192	163	192	163	192	163	192	163	192	163	192	163	192	163
34 Kettle Falls	47	40	47	40	47	40	47	40	47	40	47	40	47	40
35 Colstrip	210	154	210	154	210	154	210	154	210	154	210	154	210	154
36 TOTAL RESOURCES	2030	1035	2050	1095	2105	1130	2115	1155	2111	1151	2102	1112	2072	1060
37 Reserves	-216	0	-243	0	-253	0	-258	0	-261	0	-263	0	-265	0
38 NET RESOURCES	1814	1035	1807	1095	1852	1130	1857	1155	1850	1151	1839	1112	1807	1060
39 SURPLUS OR DEFICIT	331	0	-42	-8	-4	0	-57	0	-89	-14	-119	-60	-14	-52
LCP MODEL INPUTS:														
Net Contracts without N.E., Thermals or System Hydro		81		119		209		234		230		191		206
Net Resources		833		871		961		986		982		943		958

	-1997-		-1998-		-1999-		-2000-		-2001-		-2002-		-2003-	
Figures are megawatts.	Peak	Average	Peak	Average	Peak	Average	Peak	Average	Peak	Average	Peak	Average	Peak	Average
REQUIREMENTS														
1 System Firm Loads	1762	1017	1779	1023	1792	1031	1812	1040	1834	1051	1857	1061	1879	1071
2 Puget #1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 Puget #2	100	75	100	75	100	75	100	75	67	50	33	25	0	0
4 Seattle City Light	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 PG&E Exchange	0	25	0	25	0	25	0	25	0	25	0	25	0	25
6 PP&L Sandpoint	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 PP&L WIDCO	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 BPA-WNP#3	0	29	0	32	0	32	0	32	0	32	0	32	0	32
9 PP&L 1989	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 LADWP	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11 Interruptible Load	-25	-25	-25	-25	-25	-25	-25	-25	-25	-25	-25	-25	-25	-25
12 TOTAL REQUIREMENTS	1837	1121	1854	1130	1867	1138	1887	1147	1876	1133	1865	1118	1854	1103
RESOURCES														
13 System Hydro	922	341	922	341	922	341	922	341	922	341	922	341	922	341
14 Contract Hydro	197	85	197	85	197	85	197	85	197	85	197	85	197	85
15 Canadian Entitlement Return	-7	-3	-7	-2	-9	-3	-12	-4	-12	-4	-12	-4	-15	-5
16 Restoration	0	4	0	4	0	4	0	4	0	4	0	4	0	1
17 Small Hydro	8	8	8	8	8	8	8	8	8	8	8	8	8	8
18 Monroe Street Upgrade	10	11	10	11	10	11	10	11	10	11	10	11	10	11
19 Total Hydro	1130	446	1130	447	1128	446	1125	445	1125	445	1125	445	1122	441
20 Cogeneration	71	60	71	60	71	60	71	60	71	60	71	60	71	60
21 Northeast Combustion Turbine	68	54	68	54	68	54	68	54	68	54	68	54	68	54
22 CSPE	23	12	23	11	20	8	10	5	9	5	9	5	8	1
23 PG&E Exchange	150	25	150	25	150	25	150	25	150	25	150	25	150	25
24 S Cal Edison	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25 Grant Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26 Entitlement & Supplemental Cap	12	0	11	0	10	0	5	0	4	0	4	0	4	0
27 BPA #39216	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28 BPA-WNP #3	82	29	82	32	82	32	82	32	82	32	82	32	82	32
29 B C Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30 Montana	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31 Storage Arrangements	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32 Short-Term Purchases	0	50	0	50	0	50	0	50	0	50	0	50	0	50
33 Thermal Centralia	192	163	192	163	192	163	192	163	192	163	192	163	192	163
34 Kettle Falls	47	40	47	40	47	40	47	40	47	40	47	40	47	40
35 Colstrip	210	154	210	154	210	154	210	154	210	154	210	154	210	154
36 TOTAL RESOURCES	1985	1033	1984	1036	1978	1032	1960	1028	1958	1028	1958	1028	1954	1020
37 Reserves	-266	0	-268	0	-269	0	-271	0	-273	0	-276	0	-278	0
38 NET RESOURCES	1719	1033	1716	1036	1709	1032	1689	1028	1685	1028	1682	1028	1676	1020
39 SURPLUS OR DEFICIT	-118	-88	-138	-94	-158	-106	-198	-119	-191	-105	-183	-90	-178	-83
LCP MODEL INPUTS:														
Net Contracts without N.E., Thermals or System Hydro		177		177		173		169		194		219		236
Net Resources		929		929		925		921		946		971		988

Figures are megawatts.	-2004- Peak	-2004- Average	-2005- Peak	-2005- Average	-2006- Peak	-2006- Average	-2007- Peak	-2007- Average	-2008- Peak	-2008- Average	-2009- Peak	-2009- Average	-2010- Peak	-2010- Average
REQUIREMENTS														
1 System Firm Loads	1900	1080	1920	1090	1940	1098	1955	1105	1970	1112	1984	1118	1997	1125
2 Puget #1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 Puget #2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4 Seattle City Light	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 PG&E Exchange	0	25	0	25	0	25	0	25	0	25	0	25	0	25
6 PP&L Sandpoint	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 PP&L WIDCO	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 BPA-WNP#3	0	32	0	32	0	32	0	32	0	32	0	32	0	32
9 PP&L 1989	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 LADWP	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11 Interruptible Load	-25	-25	-25	-25	-25	-25	-25	-25	-25	-25	-25	-25	-25	-25
12 TOTAL REQUIREMENTS	1875	1112	1895	1122	1915	1130	1930	1137	1945	1144	1959	1150	1972	1157
RESOURCES														
13 System Hydro	922	341	922	341	922	341	922	341	922	341	922	341	922	341
14 Contract Hydro	197	85	197	80	142	56	142	56	142	56	142	50	67	21
15 Canadian Entitlement Return	-19	-5	-17	-5	-14	-4	-14	-4	-14	-4	-10	-4	-10	-4
16 Restoration	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17 Small Hydro	8	8	8	8	8	8	8	8	8	8	8	8	8	8
18 Monroe Street Upgrade	10	11	10	11	10	11	10	11	10	11	10	11	10	11
19 Total Hydro	1118	440	1120	435	1068	412	1068	412	1068	412	1072	406	997	377
20 Cogeneration	71	60	71	60	71	60	71	60	71	60	71	60	71	60
21 Northeast Combustion Turbine	68	54	68	54	68	54	68	54	68	54	68	54	68	54
22 CSPE	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23 PG&E Exchange	150	25	150	25	150	25	150	25	150	25	150	25	150	25
24 S Cal Edison	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25 Grant Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26 Entitlement & Supplemental Cap	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27 BPA #39216	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28 BPA-WNP #3	82	32	82	32	82	32	82	32	82	32	82	32	82	32
29 B C Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30 Montana	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31 Storage Arrangements	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32 Short-Term Purchases	0	50	0	50	0	50	0	50	0	50	0	50	0	50
33 Thermal Centralia	192	163	192	163	192	163	192	163	192	163	192	163	192	163
34 Kettle Falls	47	40	47	40	47	40	47	40	47	40	47	40	47	40
35 Colstrip	210	154	210	154	210	154	210	154	210	154	210	154	210	154
36 TOTAL RESOURCES	1938	1018	1940	1013	1888	990	1888	990	1888	990	1892	984	1817	955
37 Reserves	-280	0	-282	0	-284	0	-286	0	-287	0	-288	0	-290	0
38 NET RESOURCES	1658	1018	1658	1013	1604	990	1602	990	1601	990	1604	984	1527	955
39 SURPLUS OR DEFICIT	-217	-94	-237	-109	-311	-140	-328	-147	-344	-154	-355	-166	-445	-202
LCP MODEL INPUTS:														
Net Contracts without N.E., Thermals or System Hydro		234		229		206		206		206		200		171
Net Resources		986		981		958		958		958		952		923

New Resource Additions (Medium Case 1A)

Figure 4-4.



	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Energy Efficiency	0	0	1	1	2	4	6	7	9	11	14	16	18	20	22	23	25	26	28	30
Fuel Conversion	0	0	2	5	11	18	24	29	32	34	34	34	33	33	33	32	32	32	32	31
Hydro Improvement	0	0	1	1	4	13	27	28	29	29	36	36	36	36	36	36	36	36	36	36
Request for Prop.	0	0	0	0	0	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Comb. Turbine	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	35	35	35	35
Total	0	0	4	7	17	65	87	94	100	104	114	116	117	119	121	121	158	159	161	162

With the resource options available to WWP, there are a significant number of resource acquisition plans that could be used to meet the energy deficits. Using the least-cost planning model to evaluate the alternatives (see Chapter 5 for model results) and combined with judgment, a resource acquisition plan was selected. This resource plan appears to have the greatest overall benefits for WWP. The resource plan will be used in formulating short-term action items and long-term guidelines. Figure 4-4 shows WWP's energy needs (from figure 4-3) and the preferred resource acquisition plan for the future. These resource additions are a combination of energy efficiency programs, space and water heat conversion programs, system hydro improvements, purchases from non-utility entities (RFP) and combustion turbines. A decision regarding the combustion turbines will not be made for 10 to 12 years since the need for that energy is in the year 2006. At that decision time all resources available to WWP will be evaluated against each other and the resource that fits WWP's needs and is the lowest in cost will be selected. If a decision had to be made now a combustion turbine (CCCT) would be the best option.

Under the medium case, the company shows a small peak and energy deficit in 1991 which is planned to be covered with short-term purchases, if and when these deficits materialize. The energy surplus/deficit numbers in the Requirements and Resources tabulation (Figure 4-3) shown on line 39 is also shown on Figure 4-4 as WWP's energy needs.

The resources to be acquired under the medium case are a reflection of price and nonprice factors. The company is committed to evaluating DSM resources. Those that have the most benefits for WWP's customers, are shown to be cost effective, and meet the business objectives of the company will be selected. The company intends that all of its customers have an opportunity to participate in one or more of the planned energy efficiency programs. These programs give WWP another way of being a true energy service company. These reasons and the fact that these programs are environmentally preferable give this resource the number one ranking. The energy figures shown from the energy efficiency programs are WWP's best estimates at this time. Cost figures used in this report can be found in Appendix A. These megawatt numbers and prices will be refined as the consultant recommendations are evaluated and implemented in WWP's service territory. WWP expects to have at least 30 aMW from energy efficiency programs in the year 2009.

Low income weatherization has been and will continue to be a part of WWP's DSM programs and as such is included in the least-cost plan. Savings for low income DSM was included in the total residential DSM savings and was not accounted for separately. The cost of those savings from WWP's perspective may or may not differ from the cost of other weatherization depending on the relative funding for each program and the total cost and savings.

The next resource in the resource stack is fuel conversions, which is the process of converting electric water and space heat to natural gas. Although not as environmentally benign as energy efficiency programs, it does improve the environment by being more thermal efficient. The benefit to our customers is lower energy bills. The benefit to WWP is delaying the need for higher cost electrical resources allowing the capital to be used in a more productive way. It also allows WWP to increase its natural gas load within its service territory. Everyone should benefit from the conversion program. WWP expects to have 34 aMW from fuel conversion programs by the year 2000. Appendix C describes the consultant's report on DSM programs.

There has been some discussion about weatherizing converted customers' homes and how to account for the weatherization savings of converted electric customers. From an electric DSM standpoint, conversions are clearly much more cost effective than weatherization measures. Therefore, conversions should be promoted over electric weatherization programs in homes that have not already been weatherized. Conversion program participants whose homes have not already been weatherized will be eligible for weatherization under the soon-to-be-revised residential weatherization program, which will be available to both gas heat and electric heat customers.

The next resource being used to meet its needs under the medium case is hydro improvements. Hydro improvements started with Monroe Street, which is reflected in the existing resource figures. WWP is now in the process of evaluating all of its hydro sites. The numbers shown are what is potentially available. This does not mean that all hydro site programs will be done. Each hydro site will be closely evaluated as to the benefits and costs. Appendix E describes the consultant's reports on Long Lake and Nine Mile, which are being studied presently. These are redevelopments or improvements to existing hydro sites, so the impact to the environment is negligible. These programs would give WWP an opportunity for capital investment in resources that optimize system renewable energy supplies. In addition these programs affect the comprehensive development of the waterway and stewardship of the associated natural resources. By showing the public and FERC that the company is willing to invest dollars to maximize the power output of its hydro sites, WWP will be in a better position when it comes time to renew its FERC hydro licenses. All parties should benefit in this activity. WWP will maintain its resources for the long term in a manner that is cost effective and efficient, customers will benefit by rate stability through having resources that are not subject to escalating fuel supply costs and the public will benefit by having resources that are not detrimental to the environment. If a hydro improvement project has a benefit/cost ratio greater than one, then in most cases it will be pursued. Each site scenario will need to be studied to determine that qualification. If all potential hydro improvement sites were done that have been preliminarily identified, then WWP could expect to have by the year 2000 36 aMW of additional firm energy. The secondary energy and excess capacity would be sold to other utilities.

The fourth resource to be acquired under the medium case is a 30 aMW firm purchase through a Request for Proposal (RFP). WWP would ask for long term firm resources to be available in 1995. These resources could come from QFs, IPPs, other utilities or DSM programs. With this RFP, the energy needs for WWP would be satisfied until the year 2006. It is expected by WWP that these resources acquired through the bidding process will be able to be constructed, comply with all known environmental requirements, and sold at below WWP's administratively determined avoided cost. It is also hoped that there will be some innovative resources bid and that the bid prices will set the stage for future avoided cost determinations. This activity will also give our customers an opportunity to work with us in the development of resources. The 30 aMW is about 2.5% of our existing resources in the year 1995.

The combustion turbines (CCCT prices) in the year 2006 were added to round out the resource scenario for the 20 year time frame. In reality WWP doesn't know what will be done in 2006 because of the constantly changing conditions in loads and resources. When the company gets closer to that decision point (10-12 years from now) then an analysis will be done to see what is needed and what resource option is the most cost effective. By then the resource options selected could be anything from photovoltaics to wind generation or another resource option not even contemplated at this time. WWP will not foreclose on any resource option for future considerations.

Figure 4-5 is a tabulated result of our existing resources, new resource additions under medium case load forecasts, for both energy and peak.

WWP's Preferred Plan Medium Case

Figure 4-5. (figures are megawatts)

Energy	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Surplus (Def.) from Fig. 4-3	0	-8	0	0	-14	-60	-52	-88	-94	-106
New Resources (from Fig. 4-4):										
Energy Efficiency	0	0	1	1	2	4	6	7	9	11
Space and Water Heat Conversion	0	0	2	5	11	18	24	29	32	34
Hydro Improvement	0	0	1	1	4	13	27	28	29	29
Request for Proposals	0	0	0	0	0	30	30	30	30	30
Combustion Turbines	0	0	0	0	0	0	0	0	0	0
Short Term Purchases	0	8	0	0	0	0	0	0	0	0
Adjusted Surplus (Def.)	0	0	4	7	3	5	35	6	6	-2

Energy	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Surplus (Def.) from Fig. 4-3	-119	-105	-90	-83	-94	-109	-140	-147	-154	-166
New Resources (from Fig. 4-4):										
Energy Efficiency	11	16	18	20	22	23	25	26	28	30
Space and Water Heat Conversion	34	34	33	33	33	32	32	32	32	31
Hydro Improvement	36	36	36	36	36	36	36	36	36	36
Request for Proposals	30	30	30	30	30	30	30	30	30	30
Combustion Turbines	0	0	0	0	0	0	35	35	35	35
Short Term Purchases	0	0	0	0	0	0	0	0	0	0
Adjusted Surplus (Def.)	-8	11	27	36	27	12	18	12	7	-4

Peak	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Surplus (Def.) from Fig. 4-3	331	-42	-4	-57	-89	-119	-14	-118	-138	-158
New Resources (from Fig. 4-4):										
Energy Efficiency	0	0	1	1	2	3	5	6	8	10
Fuel Conversion	0	1	3	12	25	41	55	67	74	78
Hydro Improvement	0	0	1	1	3	54	200	210	210	210
Request for Proposals	0	0	0	0	0	30	30	30	30	30
Combustion Turbines	0	0	0	0	0	0	0	0	0	0
Short Term Purchases	0	42	0	40	60	0	0	0	0	0
Adjusted Surplus (Def.)	331	0	1	-3	1	9	276	195	184	170
Peak Sale		0	0	0	0	0	270	190	180	170
Adjusted Surplus (Def.)	331	0	1	-3	1	9	6	5	4	0

Peak	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Surplus (Def.) from Fig. 4-3	-198	-191	-183	-178	-217	-237	-311	-328	-344	-355
New Resources (from Fig. 4-4):										
Energy Efficiency	12	14	16	17	19	21	22	24	26	27
Fuel Conversion	79	78	77	77	76	75	75	74	73	72
Hydro Improvement	255	255	255	255	255	255	255	255	255	255
Request for Proposals	30	30	30	30	30	30	30	30	30	30
Combustion Turbines	0	0	0	0	0	0	40	40	40	40
Short Term Purchases	0	0	0	0	0	0	0	0	0	0
Adjusted Surplus (Def.)	178	186	195	201	163	144	111	95	80	69
Peak Sale	170	170	170	170	170	140	110	100	80	70
Adjusted Surplus (Def.)	8	16	25	31	-7	4	1	-5	0	-1

The model runs as shown in Chapter 5 for the base case show the best resource acquisition scenario to be utility purchases. The price WWP used in this report was BPA projected medium NR rate. Relying on short term purchases from other utilities to serve a small portion of WWP's total needs is prudent planning at this time. But the company has been adverse to relying on other utilities for long term firm resources for any significant portion of its needed requirements. In addition a long term purchase agreement usually has significant price escalators that tend to make a purchase uneconomical. The price escalators for the long term are needed to cover the unknown conditions facing the utilities in the future. No one knows what the impacts will be for the long term as a result of changes that can affect both load requirements and resource operations. Therefore as a hedge utilities price their long term sale arrangements extremely high in the later years. A purchase from BPA would be very risky because of the price unknowns in future years. The purchasing utilities have no assurance of rate stability or ways to influence the price escalations of BPA's NR rate, which is the rate WWP would be subject to for long term firm purchases after a 7 year notification. The company would use firm purchases as a resource acquisition option only if the term and conditions, such as purchase price, can be determined and the total cost of the purchase agreement can be shown to be the lowest cost when compared to other resource options.

Under all the cases analyzed under the medium forecast, the nominal revenue requirements average growth rate per year only varied from a low of 3.27% to a high of 3.78% over the 20 years. This variance is only 16% of the low value which would demonstrate that the financial impacts of the various resources have small implications to WWP and other factors need to be considered when making a preferred resource acquisition plan.

Under the three load projections the selected resource acquisition plans show a nominal revenue requirements average growth rate per year of 3.41%, 3.56% and 3.53%. These are minimal differences. The real rates average growth rate per year are -2.36%, -1.47% and -3.34% for the medium, high and low cases. Real rates decline over the 20 year planning term for all load growth projections. The risks of the financial impacts to the company based on different load projections and resource acquisition plans are not significant when compared to each other and can be managed.

Scenario Load Planning

These additional load estimates (low and high) allow the company to evaluate the impact and risks associated with higher and lower loads. WWP views these as "what if" type scenarios of having load growth different than the medium case but starting at the same point in time. The resource plans are based on knowing that higher or lower load growth than medium is occurring on WWP's system and this is the resource acquisitions that the company would pursue. The company's resource acquisition plan is based on the medium (load forecast) case and the two-year action plan reflects this effort. Within the two-year action plan are resource options that provide flexibility for the company to meet changing loads. If the loads come in higher than the medium projection, WWP has activities (e.g. cogeneration development program) that will allow the company to acquire additional electrical resources. If the loads come in lower than the medium projection, WWP would terminate, if legally possible, resource acquisitions (including RFP resources). Existing power contracts would be terminated either through contract termination rights or renegotiations. All efforts would be made to eliminate the highest cost resources from the resource stack. WWP would implement additional sales programs as a further implementation to its action plan item "Purchase/Sales with other Utilities." Although these load scenarios allow the company to assess the financial impact and risks to changing load projections, they are not used in mapping out a resource acquisition strategy for the company. The company is planning resources under the medium case and providing flexibility through resource options to handle changing conditions.

Low Load Estimate:
The company's low load estimate is used by WWP as the pessimistic load forecast for its service territory (see Chapter 3 for load information). The low load estimate has an annual growth rate of 1.04 percent. The company is not using this estimate to plan resources, but is using it as a "what if" condition to determine the impacts on WWP if loads grow at a slower rate than the medium case. The RFP shown in the medium estimate is not shown in this scenario. It is anticipated that by 1992 WWP would know if loads are coming in under the medium load forecast and therefore would terminate the negotiations with the bid developers.

Adjusting the base case surplus (deficit) numbers with the differential change in load estimate, results in a projected surplus (deficit) for the low load case. See Figure 4-6 for this data.

Using the least-cost planning model as one of the inputs (see Chapter 5 for model results), WWP has determined that the preferred resource acquisition planned for the low load projection is to rely on energy efficiency programs, fuel conversion programs and system hydro improvements. Figure 4-8 shows WWP's energy needs (from Figure 4-6) and the preferred resource acquisition plan for the future.

Under this scenario WWP does not need any additional energy resources until the year 2006. Although the need is not there WWP feels that activity in the three areas of energy efficiency, space and water heat conversions and hydro improvements should be continued, but at a significantly reduced rate. This will allow WWP to provide those programs that are environmentally benign but have a significant impact on our customers and existing system facilities. WWP will then be able to continue to be active in working with our customers through energy service activities. The company will also be able to improve on the stewardship given to us by FERC regarding our hydro sites. By 1995 WWP would have through the three resource programs 16 aMW of firm energy from new resource additions. But this 16 aMW is only 1.4% of WWP's existing resource base, a fairly small amount. Figure 4-7 shows the adjusted energy surplus (deficit) figures (from Figure 4-6) with the new resources added. WWP would need to market its excess firm energy to other utilities.

Low Load Estimate

Figure 4-6. (figures are aMW)

Year	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Surplus (Def.) Base Case	0	-8	0	0	-14	-60	-52	-88	-94	-106
Differential in Load Est.	11	48	114	128	126	125	122	120	119	117
Adjusted Surplus (Def.)	0	-10	94	86	62	15	20	0	0	0

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Surplus (Def.) Base Case	-119	-105	-90	-83	-94	-109	-140	-147	-154	-166
Differential in Load Est.	115	114	113	113	112	113	113	113	113	113
Adjusted Surplus (Def.)	-4	0	0	0	0	0	-27	-34	-41	-53

Note: The final surplus (deficit) figures are adjusted to handle the 50 aMW planning criteria.

The following table (Figure 4-7) shows WWP's surplus (deficit) under low loads adjusted for new resource acquisitions. Almost all of the surplus figures in the earlier years are from the reduced loads and not from new resources.

WWP's Energy Situation Under Low Case Projections

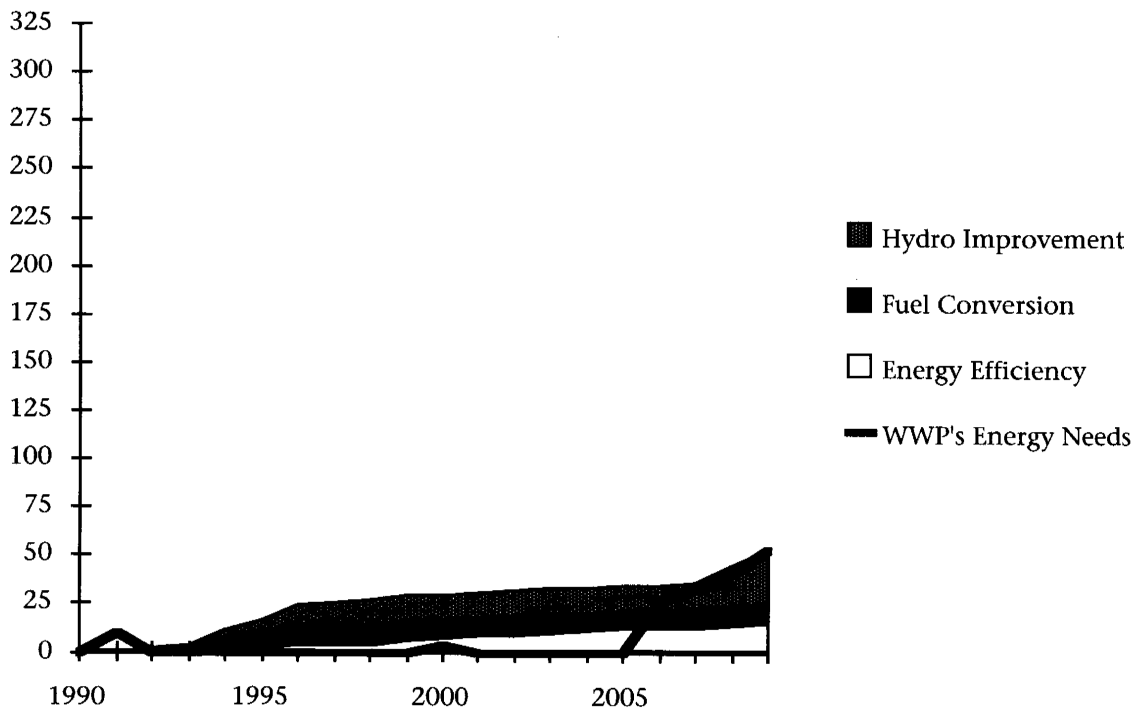
Figure 4-7. (figures are aMW)

Year	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Surplus (Def.) from Fig. 4-6	0	-10	94	86	62	15	20	0	0	0
Energy Efficiency	0	0	0	0	1	2	3	4	4	6
Space and Water Heat Conversion	0	0	1	2	6	9	10	10	10	10
Hydro Improvement	0	0	1	1	4	5	11	12	13	13
Adj. Surplus (Def.)	0	-10	96	89	73	31	44	26	27	29

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Surplus (Def.) from Fig. 4-6	-4	0	0	0	0	0	-27	-34	-41	-53
Energy Efficiency	7	8	9	10	11	12	12	13	14	15
Space and Water Heat Conversion	10	10	10	10	10	10	10	10	10	10
Hydro Improvement	13	13	13	13	13	13	13	13	21	28
Adj. Surplus (Def.)	26	31	32	33	34	35	8	2	4	0

New Resource Additions (Low Case 3A)

Figure 4-8.



	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Energy Efficiency	0	0	0	0	1	2	3	4	4	6	7	8	9	10	11	12	12	13	14	15
Fuel Conversion	0	0	1	2	6	9	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Hydro Improvement	0	0	1	1	4	5	11	12	13	13	13	13	13	13	13	13	13	13	21	28
Total	0	0	2	3	11	16	24	26	27	29	30	31	32	33	34	35	35	36	45	53

High Load Estimate:

The company's high load estimate is used by WWP as the optimistic load forecast for its service territory (see Chapter 3 for load information). The high load estimate has an annual growth rate of 2.04 percent. The company is not using this estimate to plan resources, but is using it as a "what if" condition to determine the impacts on WWP if loads grow at a higher rate than the medium case.

Adjusting the base case surplus (deficit) numbers with the differential change in load estimate, results in a projected surplus (deficit) for the high load case. See Figure 4-9 for this data.

Using the least-cost planning model as one of the inputs (see Chapter 5 for model results), WWP has determined what the preferred resource acquisition plan is for the high load projection. WWP's resource plan is to rely on the resources identified under medium load forecast plus additional cogeneration acquisitions, which might include new RFP submittals and possible CCCT installations. There is enough flexibility in WWP's Action Plan to allow the company to acquire additional resources if load growth exceeds the medium forecast. Figure 4-11 shows WWP's energy needs and the resource acquisition plan under high load growth. Additional resources under an RFP could not be obtained until 1997. Short-term energy purchases would have to be negotiated by WWP until long-term energy resources could be brought on line.

Under this scenario WWP needs additional resources above the medium case resource acquisition plan. If WWP was on this load growth forecast it would pursue several resource options. In Figure 4-11 the additional resources are shown as cogeneration, but would probably include not only cogeneration facilities, but also additional RFP's and CCCT installations, depending on the need and cost. A significant part of the cogeneration additions would be facilitated through WWP's in-house cogeneration program that is part of the company's action plan. Having various resource options being developed allows WWP the ability to exercise those options depending on their costs when and if the need has been demonstrated and shown to be necessary. If the amount of energy is not available from cogeneration facilities, RFP's and CCCT's because of fuel supplies and/or costs, then WWP would pursue its transmission option to Canada and enter into purchase arrangements with Canadian utilities. The financial impacts on WWP is shown in Chapter 5. Figure 4-10 shows the adjusted energy surplus (deficit) figures (from Fig. 4-9) with the new resources added. The company would have to enter into a one-year purchase to cover the shortage in 1991.

High Load Estimate

Figure 4-9. (figures are aMW)

Year	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Surplus (Def.) Base Case	0	-8	0	0	-14	-60	-52	-88	-94	-106
Differential in Load Est.	11	76	29	27	48	69	73	76	79	83
Adjusted Surplus (Def.)	0	-84	0	-19	-62	-129	-125	-164	-173	-189

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Surplus (Def.) Base Case	-119	-105	-90	-83	-94	-109	-140	-147	-154	-166
Differential in Load Est.	88	92	97	102	108	112	118	123	128	134
Adjusted Surplus (Def.)	-207	-197	-187	-185	-202	-221	-258	-270	-282	-300

Note: The final surplus (deficit) figures are adjusted to handle the 50 aMW planning criteria.

The following table (Figure 4-10) shows WWP's surplus (deficit) under high loads adjusted for new resource acquisitions.

WWP's Energy Situation Under High Case Projections

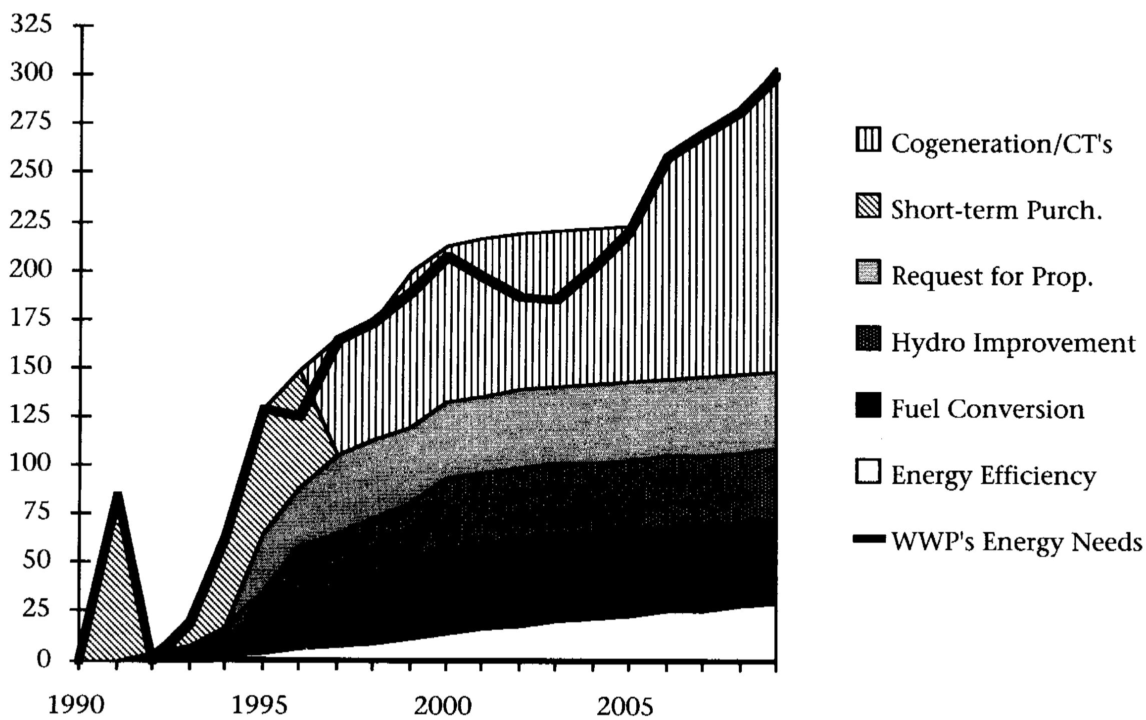
Figure 4-10.
(figures are aMW)

Year	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Surplus (Def.) from Fig. 4-9	0	-84	0	-19	-62	-129	-125	-164	-173	-189
Energy Efficiency	0	0	1	1	2	4	6	7	9	11
Space and Water Heat Conversion	0	0	2	5	11	18	25	30	35	40
Hydro Improvement	0	0	1	1	4	13	27	28	29	29
Requests for Proposals	0	0	0	0	0	30	30	40	40	40
Short-Term Purchases	0	84	0	12	45	64	60	0	0	0
Cogeneration / CTs	0	0	0	0	0	50	50	60	60	80
Adj. Surplus (Def.)	0	0	4	0	0	0	23	1	0	11

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Surplus (Def.) from Fig. 4-9	-207	-197	-187	-185	-202	-221	-258	-270	-282	-300
Energy Efficiency	14	16	18	20	22	23	25	26	28	30
Space and Water Heat Conversion	43	44	45	45	44	44	44	44	43	43
Hydro Improvement	36	36	36	36	36	36	36	36	36	36
Requests for Proposals	40	40	40	40	40	40	450	40	40	40
Short-Term Purchases	0	0	0	0	0	0	0	0	0	0
Cogeneration / CTs	80	80	80	80	80	80	115	125	135	155
Adj. Surplus (Def.)	6	19	32	36	20	2	2	1	0	4

New Resource Additions (High Case 2A)

Figure 4-11.



	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Energy Efficiency	0	0	1	1	2	4	6	7	9	11	14	16	18	20	22	23	25	26	28	30
Fuel Conversion	0	0	2	5	11	18	25	30	35	40	43	44	45	45	44	44	44	44	43	43
Hydro Improvement	0	0	1	1	4	13	27	28	29	29	36	36	36	36	36	36	36	36	36	36
Request for Prop.	0	0	0	0	0	30	30	40	40	40	40	40	40	40	40	40	40	40	40	40
Short-term Purch.	0	84	0	12	45	64	60	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogeneration/CT's	0	0	0	0	0	0	0	60	60	80	80	80	80	80	80	80	115	125	135	155
Total	0	84	4	19	62	129	148	165	173	200	213	216	219	221	222	223	260	271	282	304

Medium Load and Median Hydro Conditions:
The company's medium load estimate is used in conjunction with median hydro conditions. This situation was requested by some members of WWP's TAC. WWP does not plan firm resources under median water but under critical water conditions. Therefore no resource acquisition plan for median water has been developed.

Under median water conditions, several line items in WWP's requirements and resources tabulation need to be adjusted. The items adjusted are as follows:

a. Additional energy generation is shown in the hydro figures (line no. 18).

b. Some of the contracts under requirements would go to zero with median conditions (lines no. 8 and no. 9).

c. With excess energy available from the hydro generation, Centralia with the highest incremental cost would be backed down (line no. 33).

d. If more energy is needed to carry system requirements, then the combustion turbine output is increased up to base load operation (line no. 22).

Under these assumptions, the company needs additional energy resources starting in 2005. The 20-year median water requirements and resources can be found in Fig. 4-12.

Scenario Planning

Least-cost planning is viewed by the company as a tool in managing resource options for the future, taking into account that the only certainty about the future is change. In order to manage change, the planning process needs to be flexible. The company's planning should respond efficiently to change, as opposed to predicting future events.

The company is preparing for future uncertainties by maintaining resource options as defined in its two-year action plan. Scenario planning was used as another way to evaluate uncertainties and their impact on the company. It should be understood that scenario planning is in no way trying to predict the future. WWP is facing several potential futures dealing with supply side events that could have significant impacts. These futures should be analyzed and evaluated in lieu of others that have lesser probability of occurrence. The result is three scenarios (handling not business as usual concepts), in addition to the range of three possible futures using conventional demand growth forecasting. Again, as in the two load scenarios (high and low) the magnitude of the financial impact to the company is determined and addressed for manageability. It is the company's judgement that the impacts are manageable.

Through the development of these three scenarios, the company assessed the impact of significant changes in the business and social environment. By analyzing the impact of these scenarios, WWP is able to assess the effects on its electric business. Scenarios help visualize the impacts of possible changes, corresponding cost of resulting programs, and impacts on customer rates.

The three scenarios selected were Loss of Electrical Generation, Loss of Electrical Load and Excess Electrical Generation. These three scenarios had electrical energy resource impacts on WWP's system of from 60 aMW to 200 aMW. These impacts have a percentage effect of seven percent through 23 percent, based on annual energy customer requirements. The task for each scenario, as part of its analysis, was to forecast electricity sales as they relate to changing rates, and to formulate a least-cost integrated resource mix necessary to serve the customer needs.

The three scenarios ask questions in terms of "what if". WWP does not expect these events to happen, but these cases allow management to assess the impacts on the company if events of this magnitude were actually to occur. The three scenarios are take-offs from the base case, or most probable forecast utilizing the medium load estimates. The common risk among the three is the financial impact on the company and the corresponding impact on customers rates. Each scenario would require WWP to implement new programs to mitigate the financial impacts. These programs would address the short-term and long-term effect of these conditions. To facilitate the handling of these events, the company needs to maintain and improve its transmission interactions with other utilities. Each of these scenarios are described below with their corresponding results.

Scenario 1 - Loss of Electrical Generation

This scenario assumes, due to environmental regulations, that WWP and the other owners would have to curtail operations of the Centralia coal-fired plant because of concerns relating to the environment. The environmental concerns could be either, or a combination of, CO_2 discharges (and other greenhouse gases), acid rain or air visibility quality. With curtailment of the plant operations, it becomes uneconomical to continue to run the facility and the plant is shut down. Centralia is unable to operate economically and meet the new environmental regulations. WWP is aware by 1994 that Centralia will be shut down in 1996. With this 2 year lead time plus the two years of energy purchases allows WWP enough time to get the cogeneration and CCCT unit licensed, constructed and operational. This loss of generation requires WWP to acquire additional resources (192 MW of peak and 163 aMW of energy) which impacts capital expenditures and purchase expenses in 1996 and beyond.

Results: The company is required to acquire additional resources to fill the loss of Centralia generation (resource replacement). All space and water heat conversion potential has already been developed and additional energy efficiency is being acquired on a yearly basis. Most of the hydro system improvements have been done or are being done. The capital costs of Centralia are still incurred by WWP but the fuel (coal) costs and O&M expenses are eliminated. It is assumed that the shut-down costs equal the salvage costs. To cover the deficit on a short-term basis, a wholesale purchasing effort is implemented. Enough energy is purchased from Canada and California to cover the deficit for the first two years, but at very high costs. For the long-term, the energy needs can be met with cogeneration plants being brought on in an accelerated manner of 60 aMW by 1998 through in-house efforts of the company. The additional 100 aMW of energy and corresponding peak is acquired through the addition of an CCCT unit at WWP's NE combustion turbine site. One result is an increase of revenue requirements because Centralia capital component still has to be paid off and the company is purchasing higher cost replacement resources. The increasing revenue requirements causes rates to increase resulting in a price elasticity adjustment resulting in a lower load requirement on WWP's system (see Chapter 5). With the loss of Centralia, the region is affected by the loss of approximately 1100 aMW of their generation. This would have an effect on both firm and non-firm prices. The supply of non-firm energy would be affected because the replacement resources would be high cost incremental resources and the utilities could use non-firm to back those resources down. This scenario assumes non-firm prices would go up 20 percent. The risk is the reliance placed on natural gas as the fuel source for the cogeneration and combustion turbines. The natural gas supply and/or price might not be acceptable to WWP or its customers.

Median Water

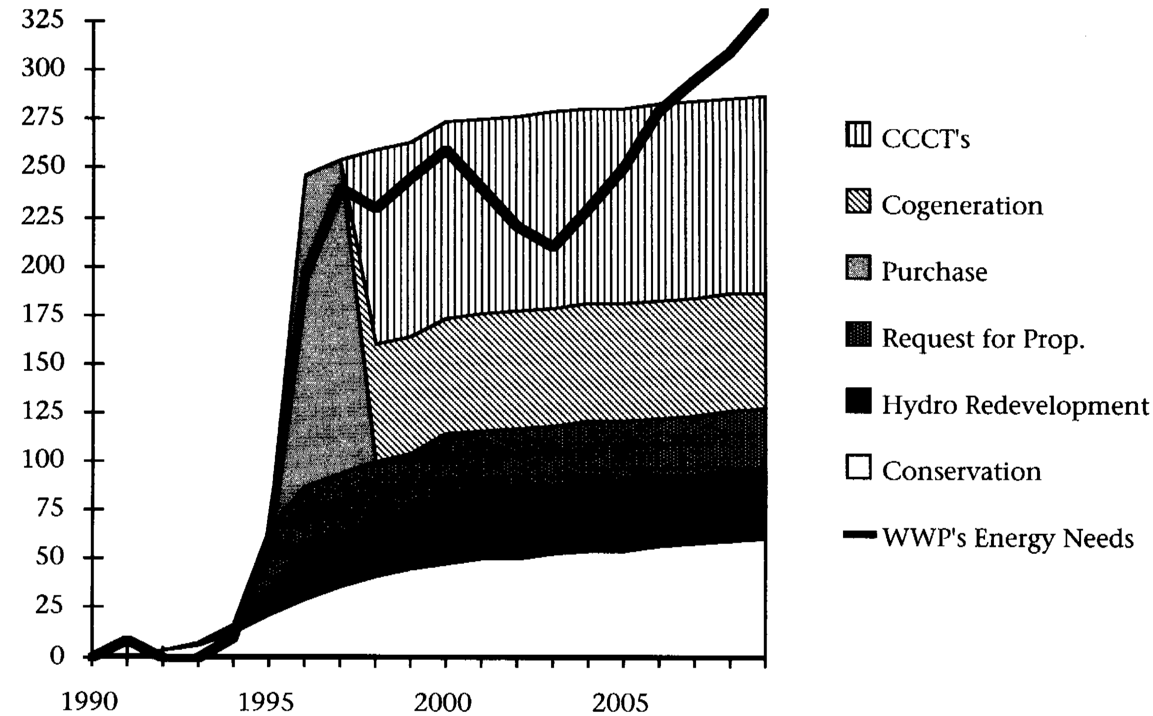
Figure 4-12.

Figures are megawatts.	-1990- Peak	-1990- Average	-1991- Peak	-1991- Average	-1992- Peak	-1992- Average	-1993- Peak	-1993- Average	-1994- Peak	-1994- Average	-1995- Peak	-1995- Average	-1996- Peak	-1996- Average
REQUIREMENTS														
1 System Firm Loads	1264	833	1530	879	1626	961	1684	986	1709	996	1728	1003	1746	1010
2 Puget #1	55	28	55	14	0	0	0	0	0	0	0	0	0	0
3 Puget #2	100	75	100	75	100	75	100	75	100	75	100	75	100	75
4 PG&E Exchange	0	0	0	25	0	25	0	25	0	25	0	25	0	25
5 PP&L Sandpoint	5	2	5	2	5	2	5	2	5	2	5	2	0	0
6 PP&L WIDCO	9	5	9	5	0	0	0	0	0	0	0	0	0	0
7 PP&L 1989	50	50	150	50	150	50	150	50	150	50	150	50	0	0
8 Seattle City Light	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 BPA-WNP #3	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 LADWP	0	0	0	11	0	0	0	0	0	0	0	0	0	0
11 Interruptible Load	0	0	0	0	-25	-25	-25	-25	-25	-25	-25	-25	-25	-25
12 TOTAL REQUIREMENTS	1483	993	1849	1061	1856	1088	1914	1113	1939	1123	1958	1130	1821	1085
RESOURCES														
13 System Hydro	922	341	922	341	922	341	922	341	922	341	921	341	921	341
14 Contract Hydro	221	108	221	108	221	108	221	108	221	108	221	97	197	85
15 Canadian Entitlement Return	-14	-4	-13	-4	-12	-4	-11	-4	-9	-4	-8	-3	-7	-3
16 Restoration	0	4	0	4	0	4	0	4	0	4	0	4	0	4
17 Small Hydro	7	7	8	8	8	8	8	8	8	8	8	8	8	8
18 Median Hydro (incl. System, Chelan Net, & M/C)	0	125	0	125	0	125	0	125	0	125	0	122	0	114
19 Monroe Street Upgrade - Median	0	-3	-6	-5	-6	10	10	13	10	13	10	13	10	13
20 Total Hydro	1136	578	1132	577	1133	592	1150	595	1152	595	1152	582	1129	562
21 Cogeneration	10	9	10	9	75	64	75	64	75	61	71	60	71	60
22 Northeast Combustion Turbine	68	1	68	1	68	1	68	1	68	1	68	1	68	13
23 CSPE	49	16	49	16	45	15	40	14	36	14	32	13	28	13
24 PG&E Exchange	0	0	0	10	150	25	150	25	150	25	150	25	150	25
25 S Cal Edison	80	4	0	0	0	0	0	0	0	0	0	0	0	0
26 Grant Peaking	50	0	0	0	0	0	0	0	0	0	0	0	0	0
27 Entitlement & Supplemental Cap	26	0	26	0	24	0	21	0	19	0	17	0	14	0
28 BPA #39216	80	68	79	67	79	68	80	68	80	68	80	68	80	28
29 BPA-WNP #3	82	27	82	27	82	27	82	27	82	27	82	27	82	27
30 B C Hydro	0	22	100	11	0	0	0	0	0	0	0	0	0	0
31 Montana	0	0	0	36	0	36	0	36	0	27	0	0	0	0
32 Storage Arrangements	0	0	55	6	0	0	0	0	0	0	0	0	0	0
33 Thermal Centralia	192	74	192	107	192	66	192	89	192	111	192	160	192	163
34 Kettle Falls	47	40	47	40	47	40	47	40	47	40	47	40	47	40
35 Colstrip	210	154	210	154	210	154	210	154	210	154	210	154	210	154
36 TOTAL RESOURCES	2030	993	2050	1061	2105	1088	2115	1113	2111	1123	2101	1130	2071	1085
37 Reserves	-216	0	-243	0	-253	0	-258	0	-261	0	-263	0	-265	0
38 NET RESOURCES	1814	993	1807	1061	1852	1088	1857	1113	1850	1123	1838	1130	1806	1085
39 SURPLUS OR DEFICIT	331	0	-42	0	-4	0	-57	0	-89	0	-120	0	-15	0

	-1997-		-1998-		-1999-		-2000-		-2001-		-2002-		-2003-	
Figures are megawatts.	Peak	Average	Peak	Average	Peak	Average	Peak	Average	Peak	Average	Peak	Average	Peak	Average
REQUIREMENTS														
1 System Firm Loads	1762	1017	1779	1023	1792	1031	1812	1040	1834	1051	1857	1061	1879	1071
2 Puget #1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 Puget #2	100	75	100	75	100	75	100	75	67	50	33	25	0	0
4 PG&E Exchange	0	25	0	25	0	25	0	25	0	25	0	25	0	25
5 PP&L Sandpoint	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6 PP&L WIDCO	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 PP&L 1989	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Seattle City Light	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 BPA-WNP#3	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 LADWP	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11 Interruptible Load	-25	-25	-25	-25	-25	-25	-25	-25	-25	-25	-25	-25	-25	-25
12 TOTAL REQUIREMENTS	1837	1092	1854	1098	1867	1106	1887	1115	1876	1101	1865	1086	1854	1071
RESOURCES														
13 System Hydro	921	341	921	341	921	341	922	341	922	341	922	341	922	341
14 Contract Hydro	197	85	197	85	197	85	197	85	197	85	197	85	197	85
15 Canadian Entitlement Return	-7	-3	-7	-2	-9	-3	-12	-4	-12	-4	-12	-4	-15	-5
16 Restoration	0	4	0	4	0	4	0	4	0	4	0	4	0	1
17 Small Hydro	8	8	8	8	8	8	8	8	8	8	8	8	8	8
18 Median Hydro (incl. System, Chelan Net, & M/C)	0	114	0	114	0	114	0	114	0	114	0	114	0	114
19 Monroe Street Upgrade - Median	10	13	10	13	10	13	10	13	10	13	10	13	10	13
20 Total Hydro	1129	562	1129	563	1127	562	1125	561	1125	561	1125	561	1122	557
21 Cogeneration	71	60	71	60	71	60	71	60	71	60	71	60	71	60
22 Northeast Combustion Turbine	68	47	68	50	68	54	68	54	68	54	68	46	68	39
23 CSPE	23	12	23	11	20	8	10	5	9	5	9	5	8	1
24 PG&E Exchange	150	25	150	25	150	25	150	25	150	25	150	25	150	25
25 S Cal Edison	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26 Grant Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27 Entitlement & Supplemental Cap	12	0	11	0	10	0	5	0	4	0	4	0	4	0
28 BPA #39216	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29 BPA-WNP #3	82	29	82	32	82	32	82	32	82	32	82	32	82	32
30 B C Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31 Montana	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32 Storage Arrangements	0	0	0	0	0	0	0	0	0	0	0	0	0	0
33 Thermal Centralia	192	163	192	163	192	163	192	163	192	163	192	163	192	163
34 Kettle Falls	47	40	47	40	47	40	47	40	47	40	47	40	47	40
35 Colstrip	210	154	210	154	210	154	210	154	210	154	210	154	210	154
36 TOTAL RESOURCES	1984	1092	1983	1098	1977	1098	1960	1094	1958	1094	1958	1086	1954	1071
37 Reserves	-266	0	-268	0	-269	0	-271	0	-273	0	-276	0	-278	0
38 NET RESOURCES	1718	1092	1715	1098	1708	1098	1689	1094	1685	1094	1682	1086	1676	1071
39 SURPLUS OR DEFICIT	-119	0	-139	0	-159	-8	-198	-21	-191	-7	-183	0	-178	0

Scenario 1 - Loss of Generation

Figure 4-13.



Cumulative:	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Conservation	0	0	3	6	13	22	30	36	41	45	48	50	51	53	55	55	57	58	60	61
Hydro Redevelopment	0	0	1	1	4	13	27	28	29	29	36	36	36	36	36	36	36	36	36	36
Request for Prop.	0	0	0	0	0	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Purchase	0	0	0	0	0	0	160	160	0	0	0	0	0	0	0	0	0	0	0	0
Cogeneration	0	0	0	0	0	0	0	0	60	60	60	60	60	60	60	60	60	60	60	60
CCCT's	0	0	0	0	0	·0	0	0	100	100	100	100	100	100	100	100	100	100	100	100
Total	0	0	4	7	17	65	247	254	260	264	274	276	277	279	281	281	283	284	286	287

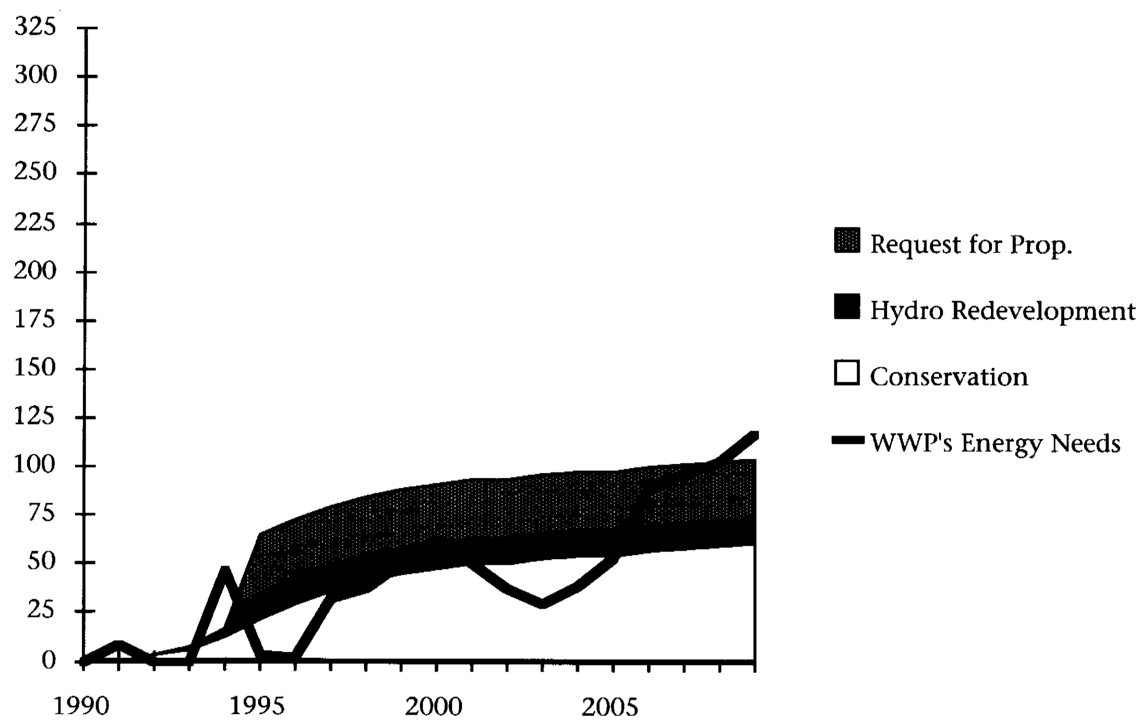
Scenario 2 - Loss of Electrical Load

This scenario assumes that other electrical suppliers are less expensive than WWP and/or customers use other electrical supplies such as cogeneration, fuel cells, etc. Whatever the reason, WWP loses electrical load resulting in a surplus condition on its system. This scenario happened to WWP in the early 1980s. We need to understand the risks of acquiring resources during a period when customers are leaving our system. The effects of this load loss would be mitigated somewhat by selling the surplus on the wholesale market. WWP would institute efforts to sell this surplus by negotiating firm sales agreements with other utilities. The total effect of this load loss would be 60 aMW starting in 1994. There is no foreknowledge of this event. All resource acquisitions are ongoing as planned under the medium forecast scenario. Approximately one half of this load loss would be the result of losing WWP's wholesale customers to another supplier, and the other half would be the loss of industrial/commercial load due to alternative supplies.

Results: The company is facing another situation as it did in the early 1980s, when load was lost due to economic business reasons. This situation is slightly different in that WWP is not now experiencing large thermal unit additions to its system in conjunction with the load loss. All company efforts in hydro system improvements and cogeneration installations would be slowed down or stopped unless there was a known market for the firm energy outside WWP's service territory. It was company policy at this time to continue all DSM programs which included energy efficiency and conversions. A rejuvenated wholesale marketing plan is formed to sell off the surplus as a firm sale for four to eight years. If a firm sale was not able to be negotiated, then WWP would have to sell on the secondary market at a lesser price resulting in a shortfall of revenues for the company causing increasing revenue requirements with corresponding increasing rates and a drop in load growth. It was determined that because of the timing, the first year of surplus had to be sold on the secondary market. This then allowed the company to negotiate a long-term sale to another utility for 10 years. This allowed the company to obtain a sale price halfway between secondary prices and BPA's NR rate. The result was financial stability for the early years of the start of the scenario and continued low revenue requirements and rates (see Chapter 5) resulting in a higher load requirement on WWP's system. Any short-fall in the latter years of electrical energy was met with a resource priced at WWP's avoided cost. The risk is the assumption that there would be markets and/ or transmission available to facilitate the firm sale.

Scenario 2- Loss of Load

Figure 4-14.



Cumulative:	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Conservation	0	0	3	6	13	22	30	36	41	45	48	50	51	53	55	55	57	58	60	61
Hydro Redevelopment	0	0	1	1	4	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
Request for Prop.	0	0	0	0	0	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Total	0	0	4	7	17	65	73	79	84	88	91	93	94	96	98	98	100	101	103	104

Scenario 3 - Excess Electrical Generation

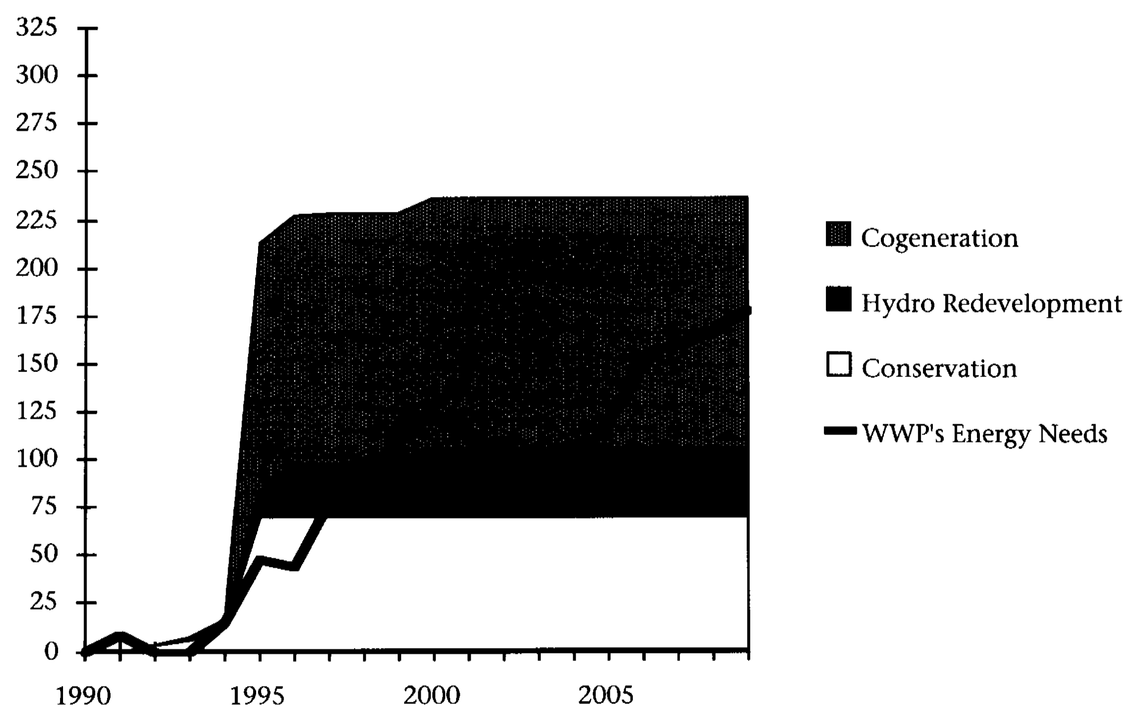
This scenario assumes that through efforts within WWP, the company DSM and cogeneration programs result in a significant increase in the amount of energy available to WWP. This scenario also assumes that these are cost-effective programs that should be pursued by the company. These programs are less than WWP's avoided cost and would be lost to WWP if the acquisition was delayed (lost opportunity resources). These programs would provide an additional 200 aMW of energy starting in 1995, with increasing amounts each year through the year 2000. The result is no need for new company-built resources (including the B.C. Hydro transmission line), or for an RFP (resources acquired through bidding) or for purchases from other utilities. It is apparent by early 1992 that these resources can be acquired at costs less than the resources bid under WWP's RFP. All negotiations with bid developers are terminated. The result is a net resource addition of 170 aMW after the reduction of the RFP resources. The resulting energy would be required to be sold off-system until needed by WWP's increasing load requirements. A breakdown of company programs resulting in additional generation and savings in 1995 are as follows:

DSM Programs - (on and off system)	70 aMW
Cogeneration development	130
Total	200 aMW

Results: The company is facing a surplus condition due to the acquisition of lost opportunity resources. All other resource acquisition programs are placed on hold. The increasing amounts that can be made available each year through these programs would supply WWP's increasing energy requirements through the year 2010. The company would have to initiate sales on both the firm and secondary markets to sell off excess generation until needed by WWP. Since these firm sales would be for a long-term period, (energy would not be needed until after the year 2010), the company could command a higher price. This scenario would eliminate the need for resource acquisitions as the amount of excess energy would supply WWP's needs for 20-30 years. The result is an increase in rates for the first four years due to increasing revenue requirements in order to purchase these additional cost-effective, lost opportunity resources (the market prices of secondary and firm energy would not be enough to equal the purchase price in the short term). By the fifth year these acquired resources, or higher cost resources that they displace on WWP's system, would be sold off at prices in excess of costs because the sale would be available for the long-term (20 years). In essence WWP would be in the power brokering business, buying electrical resources and selling generation at the same time. The long term result is lower rates and increasing loads due to price elasticity (see Chapter 5). The risk is that WWP would not have transmission access to market its surplus and this would place the company in a difficult marketing position.

Scenario 3- Excess Generation

Figure 4-15.



Cumulative:	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Conservation	0	0	3	6	13	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
Hydro Redevelopment	0	0	1	1	4	13	27	28	29	29	36	36	36	36	36	36	36	36	36	36
Cogeneration	0	0	0	0	0	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130
Total	0	0	4	7	17	213	227	228	229	229	236	236	236	236	236	236	236	236	236	236

CHAPTER 5

MODEL OUTPUTS

The Strategic Resource Planning (SRP) Model was used by WWP to evaluate alternative resource acquisition plans for the company. This model was used to analyze the total revenue requirements, resulting retail rates, and the weighted average incremental new resource costs associated with each alternative plan. The model was not used as a forecasting tool, but rather a tool to evaluate the relative impacts on these factors from one plan to the next. The weighted average incremental new resource cost is determined by taking the resource amounts acquired each year, weighted by their proportion of the total amounts to produce a weighted cost for each year. New resource capital costs and supply curve resources are entered as nominal costs in determining the weighted cost for each year. The resulting yearly weighted cost indicators are levelized over the 20-year planning period to obtain the weighted average incremental new resource costs. The specific resource plans tested, and associated model results, are summarized below.

Expected Result Analysis

The SRP model was used to evaluate the different resource plans based on assumptions relating to uncertainty in certain key variables. The key variables used were load growth, inflation, and the real escalation of fuel prices. The expected result of inflation and real fuel escalation associated with the low/medium/high load growth scenarios used in the analysis are as follows:

Key Variables Used in the Expected Result Analysis

Key Variable	Low	Medium	High
Average annual load growth	1.0%	1.5%	2.0%
General inflation rate	6.5%	4.9%	3.8%
Coal cost real escalation rate	1.3%	1.3%	1.3%
Gas cost real escalation rate	3.5%	3.4%	2.4%

Figure 5-1. Real Annual Values

All variables are consistent with those used in developing the alternative load growth scenarios in Chapter 3.

Separate resource acquisition plans formulated to meet load under the alternative load scenarios were studied to determine an expected range of future rates, revenue requirements, and weighted resource costs. Resource acquisitions to meet system requirements were taken from both supply-side and demand-side. The estimated costs of these resources are summarized in Appendix A.

Medium Load Growth

Under the medium load growth scenario, the company will institute several resource acquisition programs. As the future unfolds these resource programs will be adjusted and changed to meet changing conditions. Resource plans with various resource emphases were evaluated using the SRP model, each using a realistic combination of new resources available to WWP. Each acquisition plan emphasized the acquisition of energy efficiency programs, fuel conversion programs and hydro system improvements. The remaining load was then met with purchases (QFs, IPPs, or utility), combustion turbines/CCCT or a coal-fired plant.

The specific resource plans tested and resource emphasis are shown below in Figure 5-2 (plans Medium 1A through Medium 1E):

Resource Acquisition Plans under Medium Load Growth

Figure 5-2.

CASE: MEDIUM 1A
Megawatts Acquired under Medium Load Growth with RFP/CT Emphasis

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
DSM Programs	0	0	3	6	13	22	30	36	41	45
Hydro Improvements	0	0	1	1	4	13	27	28	29	29
RFP	0	0	0	0	0	30	30	30	30	30
Combustion Turbine	0	0	0	0	0	0	0	0	0	0
Total Acquisition	0	0	4	7	17	65	87	94	100	104

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
DSM Programs	48	50	51	53	55	55	57	58	60	61
Hydro Improvements	36	36	36	36	36	36	36	36	36	36
RFP	30	30	30	30	30	30	30	30	30	30
Combustion Turbine	0	0	0	0	0	0	35	35	35	35
Total Acquisition	114	116	117	119	121	121	158	159	161	162

CASE: MEDIUM 1B
Megawatts Acquired under Medium Load Growth with RFP/Cogeneration Emphasis

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
DSM Programs	0	0	1	2	7	11	15	18	20	23
Hydro Improvements	0	0	1	1	4	5	11	12	13	13
RFP	0	0	0	0	0	50	50	50	50	50
Cogeneration	0	0	0	0	0	0	0	0	30	30
Total Acquisition	0	0	2	3	11	66	76	80	113	116

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
DSM Programs	24	25	25	26	27	28	28	29	30	31
Hydro Improvements	13	13	13	13	13	13	13	13	13	13
RFP	50	50	50	50	50	50	50	50	50	50
Cogeneration	30	30	30	30	30	30	60	60	60	70
Total Acquisition	117	118	118	119	120	121	151	152	153	164

CASE: MEDIUM 1C
Megawatts Acquired under Medium Load Growth with Utility Purchase Emphasis

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
DSM Programs	0	0	1	2	7	11	15	18	20	23
Hydro Improvements	0	0	1	1	4	5	11	12	13	13
Utility Purchases	0	0	0	0	0	50	50	50	80	80
Total Acquisition	0	0	2	3	11	66	76	80	113	116

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
DSM Programs	24	25	25	26	27	28	28	29	30	31
Hydro Improvements	13	13	13	13	13	13	13	13	13	13
Utility Purchases	80	80	80	80	80	80	120	120	120	120
Total Acquisition	117	118	118	119	120	121	161	162	163	164

CASE: MEDIUM 1D
Megawatts Acquired under Medium Load Growth with Combustion Turbine Emphasis

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
DSM Programs	0	0	1	2	7	11	15	18	20	23
Hydro Improvements	0	0	1	1	4	5	11	12	13	13
Combustion Turbine	0	0	0	0	0	50	50	50	50	75
Total Acquisition	0	0	2	3	11	66	76	80	83	111

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
DSM Programs	24	25	25	26	27	28	28	29	30	31
Hydro Improvements	13	13	13	13	13	13	13	13	13	13
Combustion Turbine	75	75	75	75	75	75	120	120	120	120
Total Acquisition	112	113	113	114	115	116	161	162	163	164

CASE: MEDIUM 1E
Megawatts Acquired under Medium Load Growth with Coal Plant Emphasis

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
DSM Programs	0	0	1	2	7	11	15	18	20	23
Hydro Improvements	0	0	1	1	4	5	11	12	13	13
Combustion Turbine	0	0	0	0	0	0	0	0	0	0
Coal Plant	0	0	0	0	0	75	75	75	75	75
Total Acquisition	0	0	2	3	11	91	101	105	108	111

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
DSM Programs	24	25	25	26	27	28	28	29	30	31
Hydro Improvements	13	13	13	13	13	13	13	13	13	13
Combustion Turbine	0	0	0	0	0	0	50	50	50	50
Coal Plant	75	75	75	75	75	75	75	75	75	75
Total Acquisition	112	113	113	114	115	116	166	167	168	169

As shown in Figure 5-2, each resource plan, after acquiring DSM programs and hydro improvements, emphasized other resources. The SRP Model expected results, shown below in Figure 5-3, indicate that plans 1A and 1B have similar key results, with plans 1D and 1E being higher cost, and plan 1C lower cost. These key results are expected since acquisition of higher cost resources result in higher cost plans.

The key results suggest the resource strategy that appears to be the best suited for the company at this time is a combination of several resource types. Demand-side management programs should be acquired because of these programs' low cost and environmental benefits. Cost-effective hydro system improvements should be acquired because of its environmental and other benefits. A combination of purchases from QFs, IPPs, or a utility and combustion turbines could be used to meet additional requirements.

It is important to note that the resulting rates and revenue requirements in Case Medium 1A could be lowered with the substitution of a utility purchase for a CT in 2006, making it competitive with plan Medium 1C. Since the need for these resources is not immediate, the company will be active in these areas to ensure that, when additional resource acquisition is required, the company will be in a position to acquire the most cost-effective resources, whatever they may be.

It is also important to note that the difference in nominal rates compared to highest and lowest results shown below in the last study year is only approximately 0.65¢/kWh. This implies that since the company's need for resources over the next 20 years is only approximately 200 aMW, rates and revenue requirements will not be greatly impacted by alternative resource acquisition strategies.

Key Results from Medium Case Expected Result Analysis

Figure 5-3.

Key Result	Case Medium 1A (RFP/CT)	Case Medium 1B (RFP/Cogen)	Case Medium 1C (Utility Purch)	Case Medium 1D (CT)	Case Medium 1E (Coal Plant)
Weighted Average New Resource Cost (mills/kWh)	46.36	46.60	45.33	48.81	67.48
Nom. Revenue Requirements Avg. Growth Rate per Year	3.41%	3.49%	3.27%	3.72%	3.78%
Nominal Rates Average Growth Rate per Year	2.18%	2.12%	1.91%	2.35%	2.41%
Real Rates Average Growth Rate per Year	-2.36%	-2.41%	-2.62%	-2.20%	-2.14%

High Load Growth Scenario

Under the high load growth scenario, it is assumed that in 1992 it is determined the company is on the high load growth path and that action must be taken to acquire additional resources that are identified in the two year action plan. Resource acquisition plan High 2A, shown below, assumes that additional resources from the company's RFP and cogeneration resources in our service territory cannot be acquired until 1997. Resource plan High 2B assumes that long-term firm utility purchases cannot be put in place until 1995. Resource plan High 2C assumes that the company is able to install a combustion turbine at its existing Northeast site in under three years. Resource plan High 2D assumes that the company is able to install a coal-fired unit at its licensed Creston site by 1997. In all plans short-term purchases are acquired to meet the near-term deficits. The specific resource plans tested under high loads are summarized in Table 5-4.

Resource Acquisition Plans under High Load Growth

Figure 5-4.

CASE: HIGH 2A

Megawatts Acquired under High Load Growth with RFP/Cogeneration Emphasis

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
DSM Programs	0	0	3	6	13	22	31	37	44	51
Hydro Improvements	0	0	1	1	4	13	27	28	29	29
RFP	0	0	0	0	0	30	30	40	40	40
Short-Term Purchase	0	84	0	12	45	64	60	0	0	0
Cogeneration	0	0	0	0	0	0	0	60	60	80
Total Acquisition	0	84	4	19	62	129	148	165	173	200

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
DSM Programs	57	60	63	65	66	67	69	70	71	73
Hydro Improvements	36	36	36	36	36	36	36	36	36	36
RFP	40	40	40	40	40	40	40	40	40	40
Cogeneration	80	80	80	80	80	80	115	125	135	155
Total Acquisition	213	216	219	221	222	223	260	271	282	304

CASE: HIGH 2B

Megawatts Acquired under High Load Growth with Utility Purchase Emphasis

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
DSM Programs	0	0	3	6	13	22	31	37	44	51
Hydro Improvements	0	0	1	1	4	13	27	28	29	29
Short-Term Purchase	0	84	0	12	45	0	0	0	0	0
Purchases	0	0	0	0	0	100	100	100	100	100
Total Acquisition	0	84	4	19	62	135	158	165	173	180

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
DSM Programs	57	60	63	65	66	67	69	70	71	73
Hydro Improvements	36	36	36	36	36	36	36	36	36	36
Purchases	100	100	100	100	100	120	150	160	180	190
Total Acquisition	193	196	199	201	202	223	255	266	287	299

CASE: HIGH 2C

Megawatts Acquired under High Load Growth with Combustion Turbine Emphasis

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
DSM Programs	0	0	3	6	13	22	31	37	44	51
Hydro Improvements	0	0	1	1	4	13	27	28	29	29
Short-Term Purchase	0	84	0	12	45	0	0	0	0	0
Combustion Turbine	0	0	0	0	0	100	100	100	100	100
Total Acquisition	0	84	4	19	62	135	158	165	173	180

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
DSM Programs	57	60	63	65	66	67	69	70	71	73
Hydro Improvements	36	36	36	36	36	36	36	36	36	36
Combustion Turbine	100	100	100	100	100	100	175	175	175	175
Total Acquisition	193	196	199	201	202	203	280	281	282	284

CASE: HIGH 2D

Megawatts Acquired under High Load Growth with Coal Plant Emphasis

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
DSM Programs	0	0	3	6	13	22	31	37	44	51
Hydro Improvements	0	0	1	1	4	13	27	28	29	29
Short-Term Purchase	0	84	0	12	45	94	67	0	0	0
Combustion Turbine	0	0	0	0	0	0	0	0	0	0
Coal Plant	0	0	0	0	0	0	0	120	120	120
Total Acquisition	0	84	4	19	62	129	125	185	193	200

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
DSM Programs	57	60	63	65	66	67	69	70	71	73
Hydro Improvements	36	36	36	36	36	36	36	36	36	36
Combustion Turbine	0	0	0	0	0	0	50	50	50	50
Coal Plant	120	120	120	120	120	120	120	120	120	120
Total Acquisition	213	216	219	221	222	223	275	276	277	279

The SRP Model expected results, shown below in Figure 5-5, indicate that the real rates growth rate range from -1.13% to -1.54%. The resource strategy that appears to be the best suited for the company under the high load path is again a combination of several resource types. Demand side management programs and cost-effective hydro system improvements should be aggressively acquired with a combination of purchases from utilities, QFs, and IPPs, and combustion turbines used to meet additional requirements. With the resource strategy outlined under the medium load growth and the action plans detailed in Chapter 6, the company is positioning to react quickly if high load growth occurs.

Key Results from High Case Expected Result Analysis

Figure 5-5.

Key Result	Case High 2A (RFP/Cogen)	Case High 2B (Utility Purch)	Case High 2C (CT)	Case High 2D (Coal Plant)
Weighted Average New Resource Cost (mills/kWh)	45.95	44.74	45.57	56.78
Nom. Revenue Requirements Avg. Growth Rate per Year	3.56%	3.49%	3.69%	3.93%
Nominal Rates Average Growth Rate per Year	2.08%	2.01%	2.21%	2.44%
Real Rates Average Growth Rate per Year	-1.47%	-1.54%	-1.35%	-1.13%

Low Load Growth Scenario

Under the low load growth scenario, it is assumed that in 1992 it is determined the company is on the low load growth path and the company does not need additional resources until the year 2006. Negotiations with resource developers under the company's RFP are terminated. The decision is made to maintain the continuation of programs that are beneficial to the company and its customers. Efforts in resource acquisitions will continue for demand-side management programs, and cost-effective hydro system improvements, although at a reduced level.

The resource acquisition plans under low loads acquire varying amounts of DSM programs and hydro system improvements. The specific resource plans tested are summarized in Figure 5-6 below.

Resource Acquisition Plans under Low Load Growth

Figure 5-6.

CASE: LOW 3A

Megawatts Acquired under Low Load Growth with Smaller Amounts of DSM Programs and Hydro Improvements

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
DSM Programs	0	0	1	2	7	11	13	14	14	16
Hydro Improvements	0	0	1	1	4	5	11	12	13	13
Total Acquisition	0	0	2	3	11	16	24	26	27	29

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
DSM Programs	17	18	19	20	21	22	22	23	24	25
Hydro Improvements	13	13	13	13	13	13	13	13	21	28
Total Acquisition	30	31	32	33	34	35	35	36	45	53

CASE: LOW 3B

Megawatts Acquired under Low Load Growth with Larger Amounts of DSM Programs and Hydro Improvements

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
DSM Programs	0	0	3	6	13	22	26	28	30	32
Hydro Improvements	0	0	1	1	4	13	27	28	29	29
Total Acquisition	0	0	4	7	17	35	53	56	59	61

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
DSM Programs	35	37	39	40	42	43	45	46	48	49
Hydro Improvements	36	36	36	36	36	36	36	36	36	36
Total Acquisition	71	73	75	76	78	79	81	82	84	85

The SRP Model expected results, shown below in Figure 5-7, indicate that both plans tested yield the same results. The resource strategy that appears to be the best suited for WWP under the low load path is the acquisition of cost-effective demand-side management programs and hydro system improvements even though there is not an immediate resource need. The amount of cost-effective resource acquisition is small and surplus energy is marketed successfully, allowing rates and revenue requirements to remain low.

Key Results from Low Case Expected Result Analysis

Key Result	Case Low 3A (Low DSM/Hydro)	Case Low 3B (High DSM/ Hydro)
Weighted Average New Resource Cost (mills/kWh)	55.14	55.13
Nom. Revenue Requirements Avg. Growth Rate per Year	3.53%	3.42%
Nominal Rates Average Growth Rate per Year	2.62%	2.64%
Real Rates Average Growth Rate per Year	-3.34%	-3.32%

Figure 5-7.

Alternative Scenario Planning Results

The company is preparing for future uncertainties by evaluating the impacts of different load growth scenarios and the resource acquisition strategies for each. In addition, scenario planning was used as another way to evaluate uncertainties and their impact on the company. As a result, WWP has selected three scenarios (handling not business as usual concepts) to analyze, in addition to the range of three possible futures using conventional demand growth forecasting.

The three scenarios selected were Loss of Electrical Generation, Loss of Electrical Load and Excess Electrical Generation. These three scenarios had electrical energy resource impacts on WWP's system of from 60 aMW to 200 aMW. These impacts have a percentage effect of seven percent through 23 percent, based on annual energy customer requirements. The task for each scenario, as part of its analysis, was to forecast electricity sales as they relate to changing rates, and to formulate a least-cost integrated resource mix necessary to serve the customer needs. Each of these scenarios are briefly described below with their corresponding results (see Chapter 4 for a more detailed discussion on scenario planning and the scenarios selected).

Scenario 1. Loss of Electrical Generation

This scenario assumes, due to environmental regulations, WWP and other owners would have to curtail operations of the Centralia coal-fired plant. WWP is aware by 1994 that Centralia will be shut down in 1996. With a 2 year lead time plus two years of energy purchases, WWP is allowed enough time to get a cogeneration and CCCT unit licensed, constructed and operational. This loss of generation requires WWP to acquire additional resources (192 MW of peak and 163 aMW of energy) which impacts capital expenditures and purchase expenses in 1996 and beyond.

Results: The company is required to acquire additional resources to fill the loss of Centralia generation. All conversions have already been developed and additional energy efficiency is being acquired. Most cost-effective hydro system improvements have been done or are being done. To cover the deficit on a short-term basis, a wholesale purchasing effort is implemented but at high costs. Non-firm prices are assumed to increase 20 percent. For the long-term, cogeneration plants can be installed in an accelerated manner of 60 aMW by 1998 through in-house efforts. The additional 100 aMW is acquired through the addition of an CCCT unit at WWP's NE combustion turbine site. One result is an increase on revenue requirements because Centralia capital component still has to be paid off and the company is purchasing higher cost replacement resources. The increasing revenue requirements causes rates to increase resulting in a price elasticity adjustment resulting in a lower load requirement on WWP's system (see Figure 5-8 below). The risk is the reliance placed on natural gas as the fuel source for the cogeneration and combustion turbines. The natural gas supply and/or price might not be acceptable to WWP or its customers.

Scenario 1 - Loss of Electrical Generation

Figure 5-8.

Key Result	
Weighted Average New Resource Cost (mills/kWh)	47.71
Nom. Revenue Requirements Avg. Growth Rate per Year	3.77%
Nominal Rates Average Growth Rate per Year	2.66%
Real Rates Average Growth Rate per Year	-1.90%

The results shown in Figure 5-8, when compared to the results in Figure 5-3, show that WWP is adversely impacted. As expected with the loss of Centralia, higher rates and revenue requirements would result due to higher cost replacement resources. These impacts, however, are not severe. The difference in nominal rates compared to the base case in the last study year is only approximately 0.6 ¢/kWh.

Scenario 2. Loss of Electrical Load

This scenario assumes WWP loses electrical load resulting in a surplus condition on its system. WWP would institute efforts to sell this surplus by negotiating firm sales agreements with other utilities. The total effect of this load loss would be 60 aMW starting in 1994. There is no foreknowledge of this event. All resource acquisitions are ongoing as planned under the medium forecast scenario.

Results: All company efforts in hydro system improvements and cogeneration installations would be slowed or stopped unless there was a known market for the energy elsewhere. All cost-effective DSM programs would be continued. A rejuvenated wholesale marketing plan is formed to sell off the surplus as a firm sale for four to eight years. It was determined that because of the timing, the first year of surplus had to be sold on the secondary market. This then allowed the company to negotiate a long-term sale to another utility for 10 years. This allowed the company to obtain a sale price halfway between secondary prices and BPA's NR rate. The result was financial stability for the early years of the start of the scenario and continued low revenue requirements and rates (see

Figure 5-9 below) resulting in a higher load requirement on WWP's system. Any shortfall in the latter years of electrical energy was met with a resource priced at WWP's avoided cost. The risk is the assumption that there would be markets and/or transmission available to facilitate the firm sale.

Scenario 2- Loss of Electrical Generation

Figure 5-9.

Key Result	
Weighted Average New Resource Cost (mills/kWh)	45.77
Nom. Revenue Requirements Avg. Growth Rate per Year	3.01%
Nominal Rates Average Growth Rate per Year	2.03%
Real Rates Average Growth Rate per Year	-2.50%

The results shown in Figure 5-9, when compared to the results in Figure 5-3, show that WWP is not adversely impacted with loss of load. Rates and revenue requirements continue to remain low because the company is able to successfully market its surplus. This scenario suggests that the company is now in better position to handle loss of load than it was in the early 1980's when loss of load actually occurred because no high cost resources are planned or currently under construction.

Scenario 3. Excess Electrical Generation

This scenario assumes that company DSM and cogeneration programs result in a significant increase in the amount of cost-effective energy available to WWP. These programs are less than WWP's avoided cost and all would be lost if the acquisition was delayed (lost opportunity resources). These programs would provide an additional 200 aMW of energy starting in 1995, with increasing amounts each year through the year 2000. The result is no need for new company-built resources, for an RFP, or for utility purchases. The resulting energy would be sold off-system until needed by WWP's increasing load requirements. A breakdown of company programs resulting in additional generation and savings in 1995 are as follows:

DSM Programs - (on and off system)	70 aMW
Cogeneration development	130
Total	200 aMW

Results: The company is facing a surplus condition due to the acquisition of cost-effective lost opportunity resources which would eliminate the need for resource acquisitions as the amount of excess energy would supply WWP's needs for 20-30 years. The result is an increase in rates and lower demand for the first four years due to increasing revenue requirements in order to purchase these additional cost-effective, lost opportunity resources (the market prices of secondary and firm energy would not be enough to equal the purchase price in the short term). By the fifth year these acquired resources would be sold off at prices in excess of costs. In essence WWP would be in the power brokering business, buying electrical resources and selling generation at the same time. The long term result is lower rates and increasing loads due to price elasticity (see Figure 5-10 below). The risk is that WWP would not have transmission access to market its surplus and this would place the company in a difficult marketing position.

Scenario 3- Excess Electrical Generation

Figure 5-10.

Key Result	
Weighted Average New Resource Cost (mills/kWh)	55.06
Nom. Revenue Requirements Avg. Growth Rate per Year	3.25%
Nominal Rates Average Growth Rate per Year	2.00%
Real Rates Average Growth Rate per Year	-2.54%

The results shown in Figure 5-10, when compared to the results in Figure 5-3, show that WWP is not adversely impacted with excess generation over the long term. Rates and revenue requirements could actually be lower than those from the base case. This scenario suggests that it may be beneficial to the company and its customers to pursue cost-effective resources in excess of system needs and market the excess to other utilities. Transmission access and cost would have to be evaluated to see if these markets could be reached.

@RISK ANALYSIS

Risk analysis can be a powerful tool to help resource planners manage situations subject to uncertainty. For the current LCP process, the company has retained the consulting firm Charles River & Associates to perform enhancements to the existing WUTC LCP model. The key enhancement has been the incorporation of a software application called @RISK developed by the Palisade Corporation. The @RISK software is used in conjunction with Lotus 1-2-3 for the analysis of situations impacted by risk. The company is just beginning to use this tool in its resource planning.

Traditionally, utility modeling analysis has combined single point estimates of a model's variables to predict a single result. The old WUTC model does vary certain input variables for the low, medium, and high cases, but still uses a combination of single point estimates to predict a single result. Estimates of the model variables must be used because the values are not known with certainty. In reality, the estimates rarely turn out as planned. When estimating several input variables, the combined errors often lead to a real life result much different from the estimated result. With @RISK, the user can explicitly include the uncertainty in the input estimates to give results that show all possible outcomes. @RISK combines all the uncertainties identified in the model inputs, such as load growth, coal and gas escalation, etc. Instead of inputting single estimates for a variable, the user includes all information on the variable, including its full range of possible values and the likelihood of occurrence for each possible value (i.e., its expected probability distribution). @RISK uses this information with the model to run hundreds of "what if" scenarios allowing the user to test a more complete range of possible outcomes. @RISK gives results and inputs in graphical form which can be easily understood and explained.

@Risk integrated into the SRP model allows WWP to calculate the degree of statistical uncertainty for a specified variable based on input variables selected from given distributions. The input distributions selected for this analysis include real natural gas escalation, real coal escalation, load growth, capital escalation, and weighted average cost of capital. Other input distributions will be added for future studies. The range of values examined in the @RISK analysis are shown below in Figure 5-11;

Range of Values for Input Distributions to @RISK Analysis

Figure 5-11.

Input Variable	Low	High
Average Annual Load Growth		
-Medium Load Scenario	0.9%	2.1%
Real Natural Gas Escalation Rate		
-Medium Load Scenario	0.7%	6.3%
Real Coal Escalation Rate	-0.1%	1.9%
Real Capital Escalation Rate	0.9%	1.9%
Weighted Average Cost of Capital	9.0%	14.0%

The input variables described above were input as distributions within the limits set by the low and high values. The SRP model was then run for 300 iterations, a number found to be sufficient. The resulting input distributions are shown below:

Input Load Distribution Under medium Load Scenario

Figure 5-12.

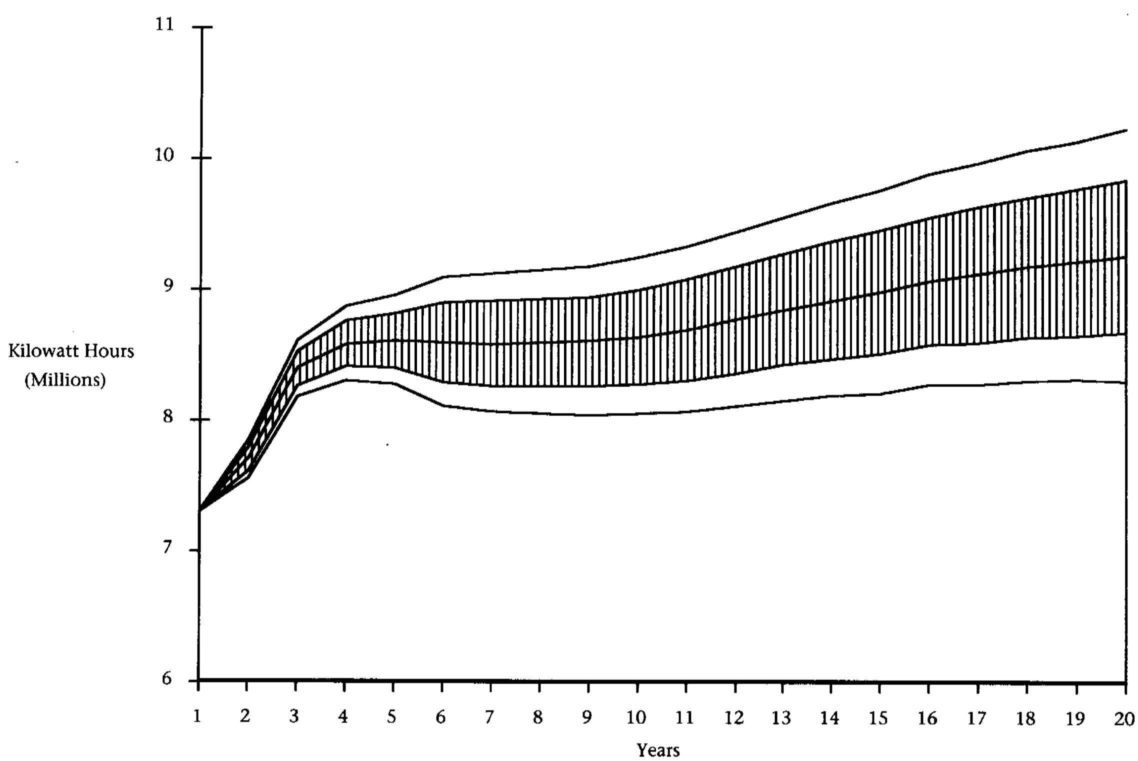


Figure 5-12: This figure is the input distribution for the medium load growth scenario in megawatthours (x1,000,000) for years 1-20 (1990-2009). The line in the middle of the shaded area is the respective load forecast and most likely case. @RISK varies the load around the base forecast within the bounds shown. The load falls within the shaded area 68 percent of the time and within the two outer bounds 95% of the time.

Real Natural Gas Escalation Input Under Medium Load Scenario

Figure 5-13.

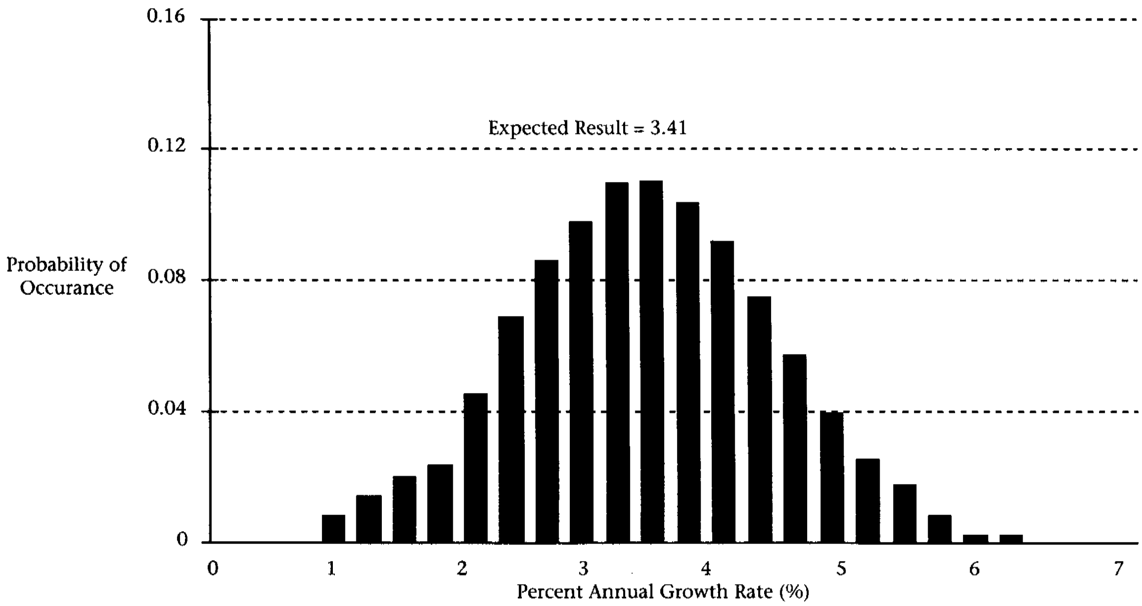


Figure 5-13: This figure shows the real natural gas escalation input distribution for the median load growth scenario. The bounds of this distribution is described above in Figure 5-8.

Real Coal Escalation Input Distribution

Figure 5-14.

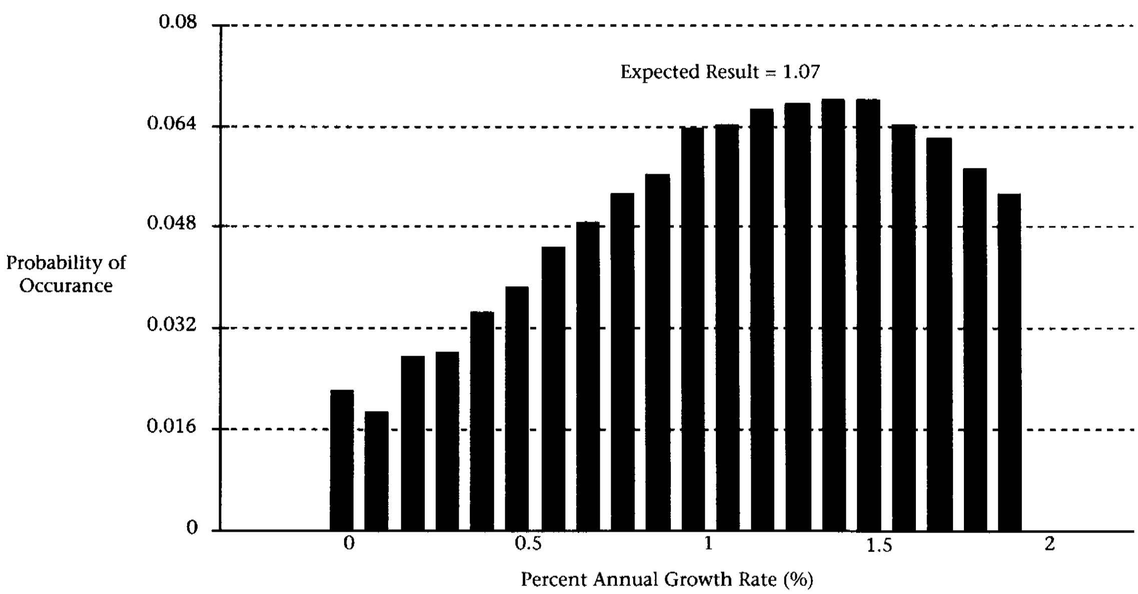


Figure 5-14: This figure shows the real coal escalation input distribution for the median load growth scenario. Notice the truncated distribution indicating that although the expected result is a 1.1% real annual escalation rate, the rate is not expected to be greater than 1.9% and could be as low as -0.1%.

Real Capital Escalation Input Distribution

Figure 5-15.

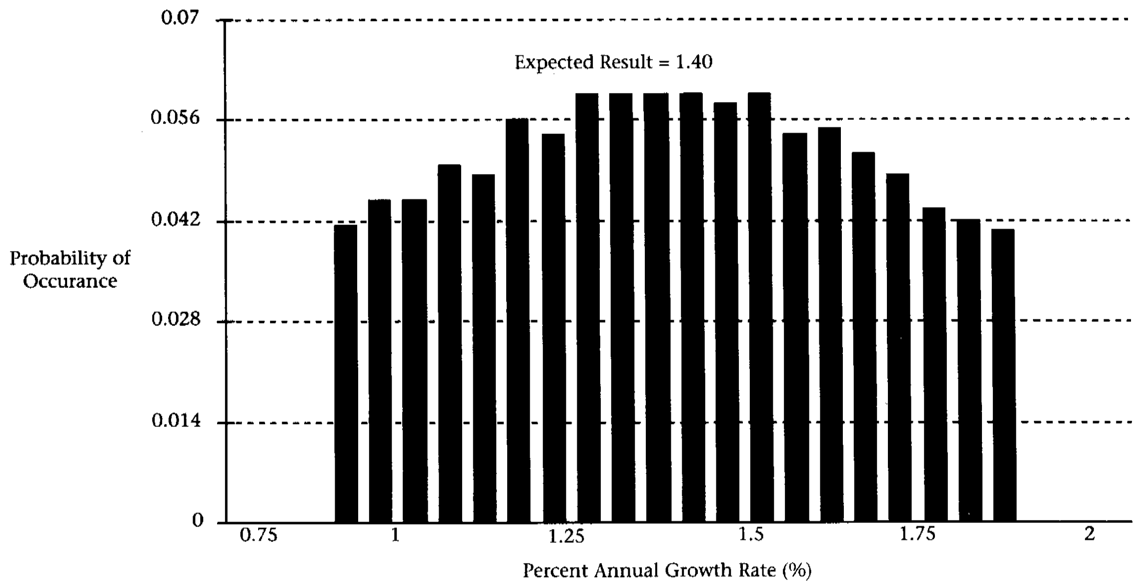


Figure 5-15: This figure shows the capital escalation input distribution for the median load growth scenario. This is the annual escalation rate applied to the capital costs of new resources.

Weighted Average Cost of Capital Input Distribution

Figure 5-16.

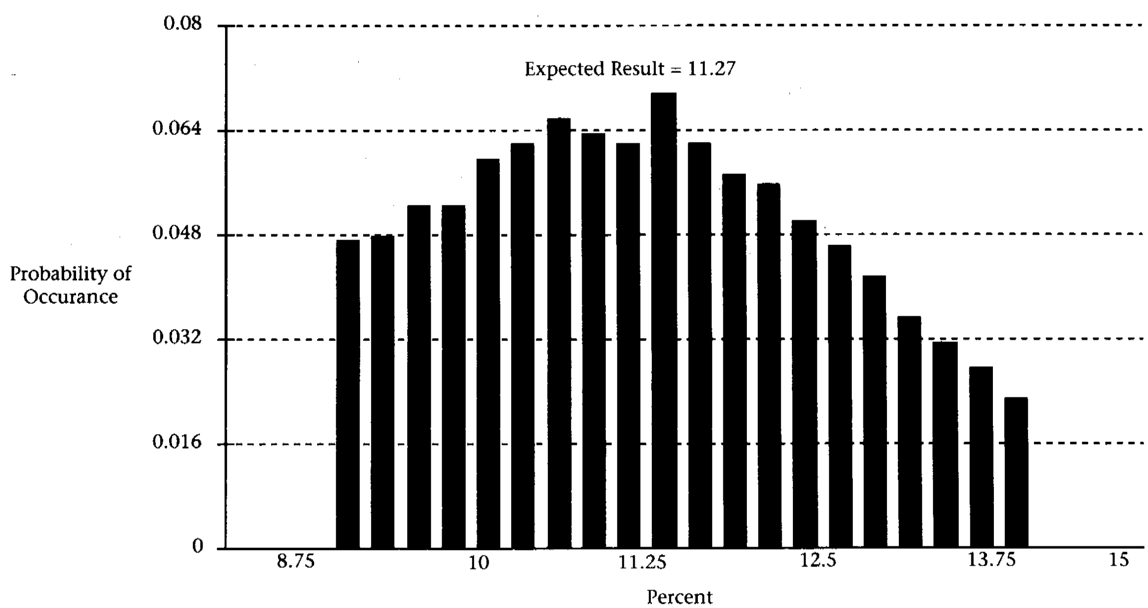


Figure 5-16: This figure shows the weighted average cost of capital input distribution for the median load growth scenario. This distribution is also truncated showing an expected result of 11.26%, with high and low values of 14% and 9% respectively.

Summary of Results

At the start of each iteration, @Risk randomly chose new values for the variables from within their specified input distributions described above. The new combination of load growth, real fuel escalation, etc. produced a new weighted average incremental resource cost value, new growth rates for real and nominal rates, and new growth rates for nominal revenue requirements for that iteration. A histogram of these outputs was produced at the end of 300 iterations (one simulation). The results of simulations for medium load growth resource plan Medium 1A are shown below.

Medium Load Growth Scenario

Resource plan Medium 1A shown in Figure 5-2 was analyzed in an @RISK simulation under the medium load growth scenario. The range of results are presented in the figures below:

Medium Case Weighted Average Incremental Resource

Figure 5-17.

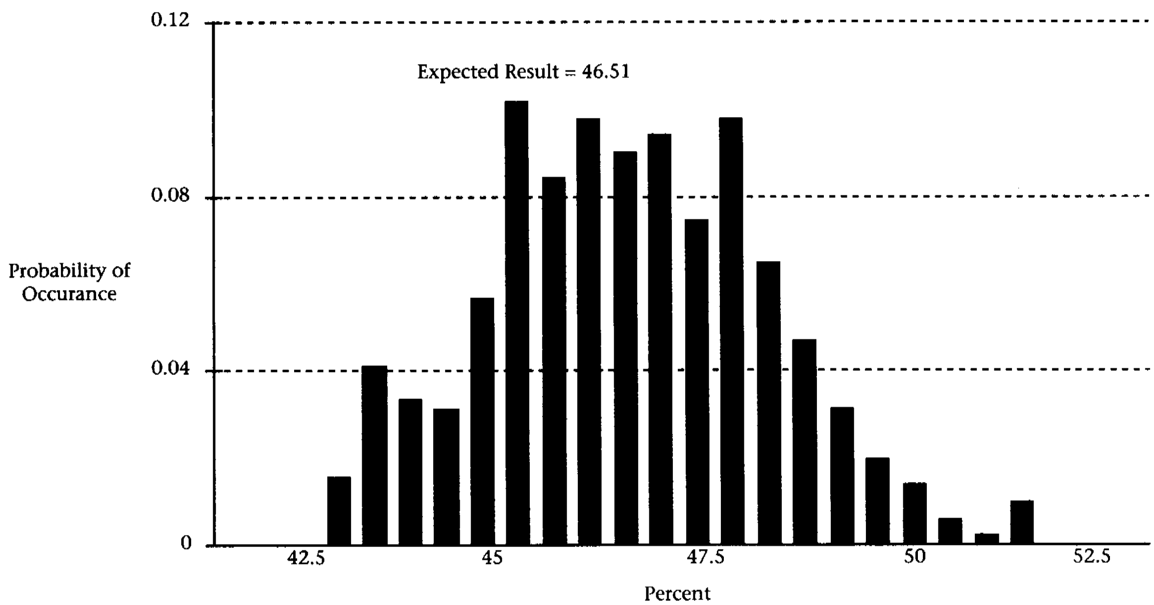


Figure 5-10: This output distribution shows a weighted average incremental resource cost ranging from 42.5 to 52 mills/kWh with an expected result of 46.5 mills/kWh. This distribution is slightly skewed reflecting more high side risk in new resource costs, although the overall range between the high and low values is not great.

Medium Case Real Rates Average Growth Per Year

Figure 5-18.

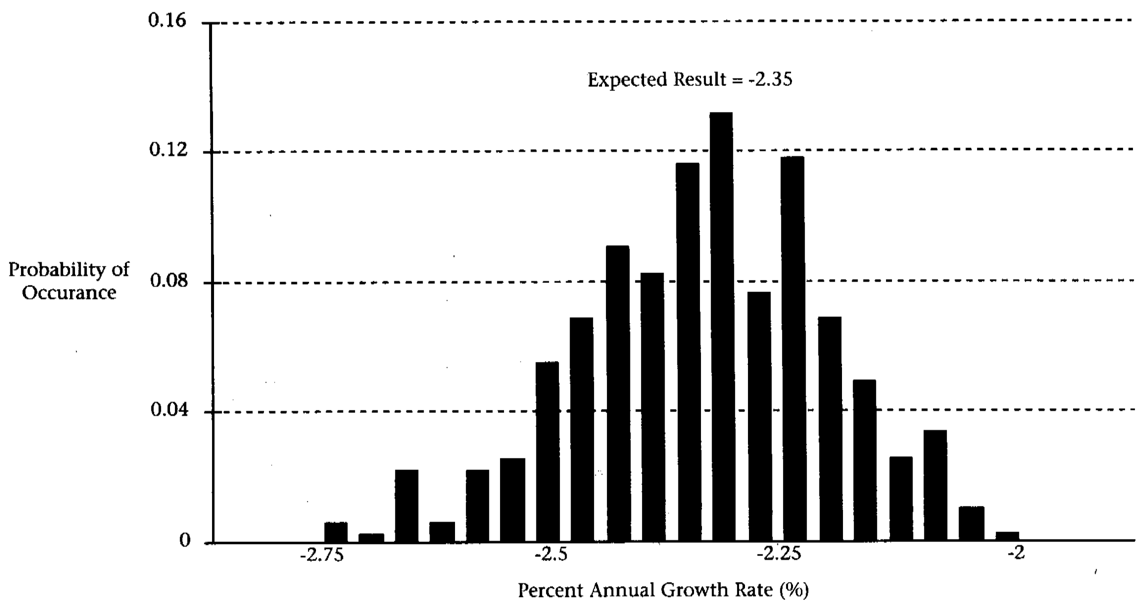


Figure 5-11: This output distribution shows a real rate growth rate ranging between -2.0% and -2.8% per year with an expected result of -2.35% per year. This range only amounts to a magnitude of roughly 0.5 ¢/kWh in the year 2009.

Medium Case Nominal Rates Average Growth Per Year

Figure 5-19.

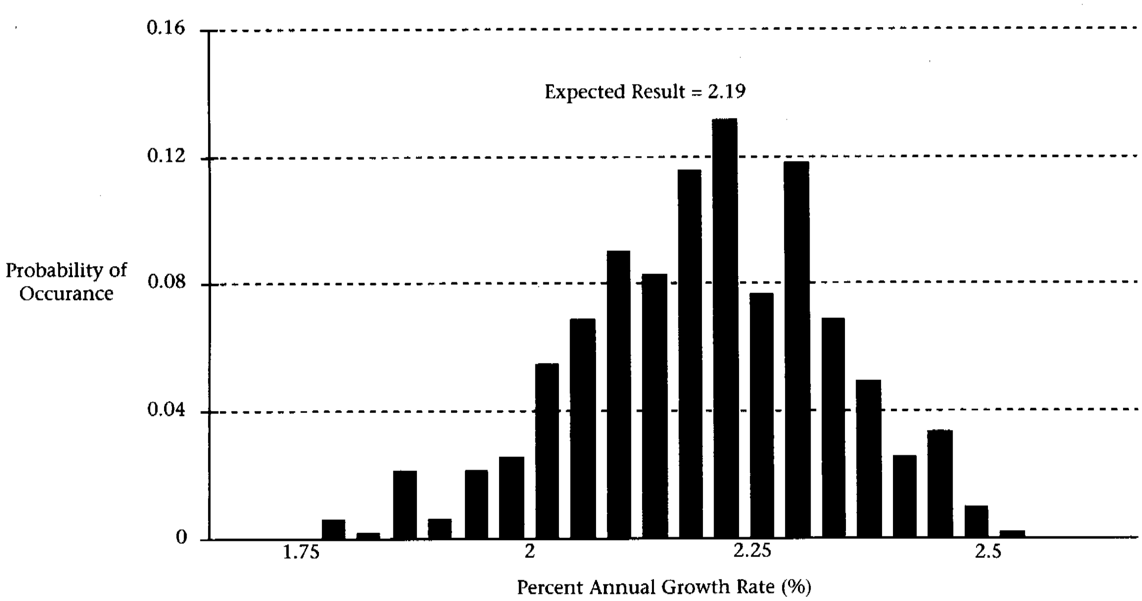


Figure 5-12: This output distribution shows a nominal rate growth rate ranging between 1.75% and 2.55% per year with an expected result of 2.19% per year.

Medium Case Nominal Revenue Require-ments Growth

Figure 5-20.

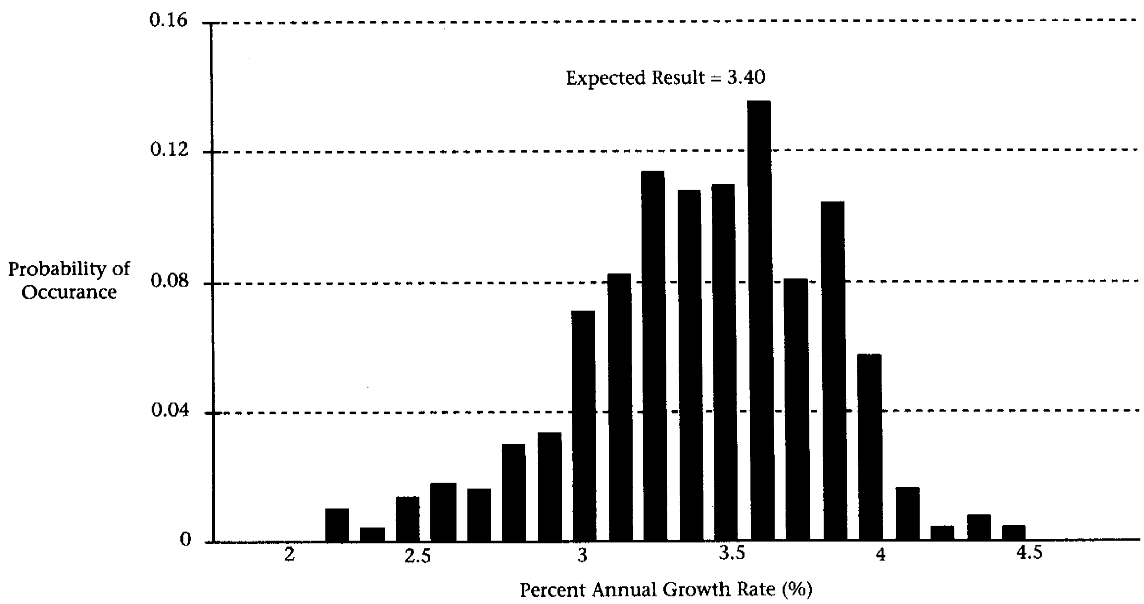


Figure 5-13: This output distribution shows a nominal revenue requirement growth rate ranging between 2.0% and 4.5% per year with an expected result of 3.4% per year.

These results indicate that, based on the input distributions defined, the Medium 1A resource plan does not have large variability around the most likely results and therefore would have a lower amount of risk compared to other resource plans. Resource plans that acquire more combustion turbines and coal plants, i.e. plans with capital intensive resources and/or resources with greater fuel volatility, would expect to have a greater range of possible outcomes, and therefore greater risk.

Chapter 6

ACTION PLAN

As part of the least-cost planning effort, the company in April 1989 proposed a "two-year action plan" outlining specific measures to be taken during that two-year period. Those actions have been completed to various degrees. Additional measures or objectives have been proposed for the next "two-year action plan" as part of this report. These proposed actions will be for the period April 1991 through March 1993.

In the 1989 report, the action plan identified several areas where additional information was needed. To accomplish this objective, several consultants were hired to perform the work. The consultants worked in the areas of conservation, cogeneration, hydro improvements and least-cost planning model enhancement. The "1989 Action Plan Summary" explains the results of WWP's efforts during the past two years in the activities designated by the company as action items.

1989 Action Plan Summary

Figure 6-1. Short-Term Action Plan (April 1991 - March 1993)

Title	Actions (1989-91)	Results (1989-91)
I. Customer Energy Efficiency Programs	A. Industrial and Commercial Conservation: Develop an industrial and commercial conservation program for WWP, including costs.	The Marketing Department has hired staff to deal with this action (see Appendix C for WWP's DSM Business Plan.) A consultant has also been hired to determine the potential and cost of various programs in these sectors (including residential). The demand-side management options screening assessment was done by Synergic Resources Corporation at a cost of $125,000. The summary of their report can be found in Appendix C.

Title	Actions (1989-91)	Results (1989-91)
	B. Model Conservation Standards: Promote the adoption of MCS within WWP's service territory.	WWP participated in the statewide MCS effort The MCS was adopted fully in the state of Washington and at a 60 percent level in Idaho (Idaho's first state-wide energy code). WWP has successfully provided "early" adoption of the Northwest energy code by the majority of the local jurisdictions in the Washington and Idaho service territory.
	C. Conservation Activities: Monitor conservation activities, methods and programs within the Northwest.	This is an ongoing effort of attending meetings and reviewing reports.
II. System Improvements	A. Transmission and Distribution Savings: Complete a study to determine the potential for savings in this area.	The Engineering Department completed a distribution savings study and determined that 10 aMW could be saved at less than avoided cost. These savings will be obtained over a period of several years as distribution upgrades are done. Since these savings are spread over several years resulting in small numbers, they are not included as a specification line item in the resource plan. The transmission analysis study is currently under way with preliminary results expected by mid-1991.
	B. Hydro System Improvement: Evaluate the benefits of proceeding with hydro plant improvements.	WWP determined that it was cost effective to replace the old powerhouse at the Monroe Street hydro site. The new powerhouse is scheduled to be completed in 1992. Preliminary studies have been completed for Long Lake and Nine Mile, with the help of consultants. A summary of the consultant's findings for Long Lake and Nine Mile can be found in Appendix E. The consultant's cost of this study effort was approximately $627,500. Other hydro sites will be evaluated with the help of consultants.

Title	Actions (1989-91)	Results (1989-91)
III. Marketplace Opportunities	A. Biomass and Cogeneration: Assess the potential of cogeneration and biomass generation in WWP's service territory	WWP has hired a manager of cogeneration development to determine the potential and corresponding costs of specific projects. A consultant has been hired at a cost of $39,500 to conduct a reconnaissance level customer generation assessment in WWP's service territory. Resource Management International's summary report can be found in Appendix D.
	B. Competitive Bidding (RFP): Integrate the LCP with the RFP.	The company has developed an RFP and will be submitting it to the WUTC for approval. The timing and size of the request is a result of the LCP effort and report.
	C. B.C. Hydro Interconnection: The proposed interconnection will be licensed and the option to build will be analyzed.	The company expects to receive a Presidential Permit for this line by early 1991 Other licensing permits are proceeding. An MOU between Powerex and WWP was finalized and power purchases from Canada are being evaluated.
IV. Additional Information	A. Capacity Planning: Incorporate capacity planning into the LCP process.	Capacity needs have been evaluated and incorporated into the 1991 LCP Report. The capacity component of those resources added for firm energy has been determined and inserted into the figures for capacity resources.
	B. Economic Variables: Evaluate and use financial and economic variables in the LCP process.	The financial and economic variables were updated and used as inputs wherever appropriate.

Title	Actions (1989-91)	Results (1989-91)
	C. Computer Models: A comparison of various models and their benefits to WWP will be evaluated.	A comprehensive comparison of models for planning was not done. At this time the cost and implementation of other models did not appear to be beneficial. A decision was made to enhance the existing model used in the 1989 LCP Report. WWP hired Charles River Associates to provide program modifications to the model in order to enhance model effectiveness and ease of use at a cost of approximately $11,000.
	D. Power Council Activities: Continue to utilize information developed by the Power Council.	WWP has utilized Council's data and has monitored their planning activities.

This (two-year) short-term action plan is a list of activities that will provide additional resources, both supply-side and demand-side, for the short-term and will position the company for long-term resource acquisitions. As future events unfold, the company will make appropriate adjustments to these activities so that the resource plans will fit WWP's needs. The company plans to maintain its flexibility by keeping open all possible resource options. Some of these resource options in the Action Plan (e.g., cogeneration development) will be used by the Company to meet system requirements if WWP finds itself on a higher load growth than the medium load projection. This will allow us to act in a positive and cost-effective way to future changes. By maintaining and developing resource options beyond those needed under the medium (most probable) forecast provides the flexibility to handle changes. WWP will also continue during the next two years to acquire lost opportunity resources, if cost-effective, and will continue to develop options to minimize the long lead times of resource construction. The company's short-term action plan includes the following activities:

Demand Side Resource Programs

1. a. **Complete Initial DSM Assessment.** This activity covers completing the first comprehensive DSM assessment which was initiated in 1990. Assessment to be completed in 1st quarter of 1991. Assessment results will be used to begin implementation of DSM programs.

   b. **Develop Long Term DSM Goals & Objectives.** From the results of the initial DSM assessment, long-term goals and objectives for the acquisition of DSM will bedevel oped. This action plan item will be completed by the end of 2nd quarter 1991.

2. **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 1st and 2nd quarters of 1991.

3. **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 3rd and 4th quarters of 1991.

4. a. **Conduct Electric to Gas Residential Water Heating and Space Heating Conversion 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 of 1991.

   b. **Evaluation of Conversion Program Tests.** A detailed evaluation of the conversion test programs will be conducted in the 3rd and 4th quarters of 1991.

5. a. **Update Residential Weatherization Program.** Revise and update the existing resi dential weatherization program. This will be done during the 1st and 2nd quarter of 1991.

   b. **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.

6. a. **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 1st and 2nd quarter of 1991.

   b. **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.

7. a. **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 1st and 2nd quarters of 1992.

   b. **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.

Demand Side Resource Action Plan

Figure 6-2.

		1991				1992			
1a.	Complete Initial DSM Assessment	■							
1b.	Develop Long Term DSM Goals & Objectives		■						
2.	1991 Comm/Ind Energy Survey	■	■						
3.	Revise DSM Assessment			■	■				
4.a	Residential Conversion Program Test		■						
4.b	Evaluation of Conversion Program Tests			■	■				
5.a	Update Res. Weatherization Program	■	■						
5.b	Implement Res. Weatherization Changes			■	■	■	■	■	■
6.a	Develop Large C/I DSM Program	■	■						
6.b	Develop Large C/I Program			■	■	■	■	■	■
7.a	Develop Small C/I DSM Program					■	■		
7.b	Implement Small C/I Program							■	■

System Efficiency Programs

1. Implement distribution loss savings programs. 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.

2. 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.

3. 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.

Competitive Bidding

1. 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 agreements will also be finalized, for a total acquisition of not less than 30 aMW, with deliveries commencing in1995.

2. 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.

B.C. Hydro Interconnection and Other Interconnections

1. 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.

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

Purchases/Sales with other Utilities

Wholesale Business

1. 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.

Cogeneration Development Program

1. 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.

Wholesale Business Cogen.

Additional Action Activities

1. 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.

2. 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.

3. Continue to enhance the analytical capabilities in the least-cost planning efforts.

Review the least-cost planning model capabilities for further enhancements.

4. 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.

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

GLOSSARY OF TERMS

aMW
Average Megawatts (energy).

Assured net energy resources
The amount of energy from a resource which can be used to serve load.

B.C. Hydro
British Columbia Hydro and Power Authority.

Base loaded
A resource which operates more efficiently without being cycled.

BPA
Bonneville Power Administration.

Capacity
The maximum power that a machine or system can produce or carry under specified conditions.

Capacity constrained
A system or resource which has restrictions on peak output resulting from external factors.

Cogeneration
A facility that generates electricity and uses the waste steam for other purposes.

Combined-Cycle
Combustion turbine with the addition of a heat recovery boiler and a steam turbine.

Conservation
Spending dollars on capital improvements to reduce electrical consumption.

Contributions to peak
A resource added for energy which also provides capacity.

Critical Period
The sequence of low water conditions during which the region's hydro power system's lowest amount of energy can be generated while drafting storage reservoirs from full to empty.

Cycling Mode
A resource which is operated in a manner which allows variation in output.

Daily load-matching capability
Availability of adequate resources to meet load changes during the day.

Demand-Side Management (DSM)
The activity of acquiring demand-side resources.

Demand-Side Resources
Resources that can be added to a utility system by utility-sponsored programs that reduce customer electric usage.

Dispatchability
The ability to operate or not operate a resource for economic reasons.

DSI
Direct Service Industries of Bonneville Power Administration.

Energy
The amount of electrical usage or output average over a specified period.

Energy constrained
A resource which provides limited output for some period of time as a result of limited fuel or water.

FERC
Federal Energy Regulatory Commission.

Firm load
Customer load served by a utility without a contractual provision for curtailment.

Frequency distribution
An assortment of data based on probabilities.

Fuel mix
The make-up of resources used to serve load by fuel type.

IAP
Intertie Access Policy.

ICP
Intercompany Pool.

Inland Northwest
The area of eastern Washington and northern Idaho.

IOU
Investor-Owned Utility.

IPPs
Independent Power Producers.

IPUC
Idaho Public Utilities Commission.

kW
1000 watts.

kWh
Kilowatt-hour = 1000 watt-hours.

LCP
Least-Cost Plan or least-cost planning.

Levelized Cost
The present value of a cost stream converted into a stream of equal annual payments.

Net system load
The total load of a system, including both firm and interruptible.

Lost Opportunities
Resources, which if not acquired or developed within a certain time, could be lost to WWP.

MCS
Model Conservation Standards.

Mill
The cost of electricity expressed as a tenth of a cent.

MW
Megawatts (peak).

MWh
Megawatt-hour = 1000 kilowatt-hours.

Nominal Dollars
Dollars that include the effects of inflation.

Non-firm interruptible load
Load which can be curtailed in response to a system emergency.

NPPC
Northwest Power Planning Council.

NR
BPA's New Resource Rate.

NWPP
Northwest Power Pool.

O&M
Operation and Maintenance Costs.

Pacific Northwest
States of Idaho, Washington and Oregon.

Pacific Southwest
States of California and Nevada.

Peak
The one hour maximum load usage or resource output.

PNUCC
Pacific Northwest Utilities Conference Committee.

Present Value
The worth of future returns or costs in terms of their value now.

PURPA
Public Utility Regulatory Policies Act.

QFs
Qualifying Facilities under PURPA (cogeneration and small power production facilities).

Real Dollars
Dollars that do not include the effects of inflation.

Reliability
A measurement of the percent of time a resource is available to meet load.

Seasonal output
Electrical output from a resource which varies in amount according to the season.

Supply-Side Resources
Resources that generate an electrical output into the utility system.

TAC
Technical Advisory Committee.

Weatherization
Home Insulation Program.

Weighted average resource cost indicator
The value used in fixing resource costs based on incremental expenditures (i.e., part of the LCP model output).

WNP
Washington Public Power Supply System Nuclear Project.

WSCC
Western System Coordinating Council.

WUTC
Washington Utilities and Transportation Commission.

WWP
The Washington Water Power Company.

For further information relating to this LCP/RMR, please contact:

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Doug graduated from the University of Idaho in 1965 with a Bachelor of Science Degree in Electrical Engineering. In December 1967 he was employed by WWP as an assistant electrical engineer, with responsibilities in load and resource projections of the company. In 1974 he received an advancement to Power Resource Engineer and became involved with coordination of utility operation under the Pacific Northwest Coordination Agreement, and with the development and publication of company and regional publications of long-range load and resource planning. He was promoted to Supervisor of Planning and Contracts in 1982, and in 1988 received his present title of Contracts and Resource Administrator.

or

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Dennis graduated from Washington State University in 1985 with a Bachelor of Science Degree in Electrical Engineering. In May 1985 he was employed by WWP as an assistant Power Resource Engineer, with responsibilities in resource planning activities for the company. In 1990 he received an advancement to Power Resource Engineer and continues to have responsibilities in long-range load and resource planning.

APPENDIX A

DEMAND-SIDE AND SUPPLY-SIDE RESOURCES

WWP will select resources from both the demand-side and supply-side options resulting in a least-cost plan compatible with its energy needs. The resources that have been evaluated are discussed in this Appendix A. Each is briefly described in the following paragraphs along with specific assumptions used in this report.

From the demand-side resource options, energy efficiency programs and space and water heat conversion programs are utilized up to the estimated amounts that can be obtained in WWP's service territory at costs comparable with supply-side resources. Cogeneration and purchases from other utilities are also utilized in the resource mix. Hydro upgrades are also considered, if they are cost-effective. Additional supply-side generating resources that could be used by WWP in future resource scenarios, along with costs in mills/kWh, are shown in Figure A-1.

Levelized Life Cycle Power Cost of New Resources

Figure A-1. (Mills/Kilowatt-Hour in 1990 Dollars)

Plant Type	Capital	O & M Fixed	O &M Variable	Fuel Fixed	Fuel Variable	Total
Pulverized Coal Fired	44.67	9.49	4.37	3.12	26.00	87.65
Atmospheric Fluidized Bed	48.73	10.58	9.76	2.37	21.81	93.25
Single Cycle Combustion Turbine (capacity factor = 40%)	25.68	1.08	0.17	0.00	72.90	99.83
Combined Cycle Combustion Turbine	14.57	1.40	0.57	0.00	48.39	64.93
Coal Gasification Combined Cycle	45.12	17.68	0.41	2.40	20.45	86.06
Generic Cogeneration	29.14	11.55	0.00	0.00	12.07	52.16
BPA New Resource Rate Projection	N/A	N/A	N/A	N/A	N/A	47.77
Combined DSM Options	35.60	N/A	N/A	N/A	N/A	35.60

Note: The power costs in Figure A-1 are calculated using the expected total annual cost of an isolated generating unit, including AFUDC and both the operating costs and annual, level fixed charges required to support the new unit investment. The costs are levelized over the life of the facility. The following equation demonstrates how the capital cost is levelized for comparison purposes:

$$COE = \frac{(\text{Capital Cost \$/kW}) \times (\text{FCR}) \times (1000 \text{ mills/\$})}{\text{CF} \times 8760 \text{ Hours/Year}}$$

Where: COE = Cost of Energy (mills/kWh)
FCR = Fixed Charge Rate (levelizing factor)
CF = Capacity Factor

The first year O&M and Fuel costs are escalated over the plant life-time using planning assuptions contained in this study, then levelized for comparison purposes. Variations in escalation assumptions would change the total resource cost.

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, intermediate/base load operation and as a resource option in firming 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 and reliability which results in low maintenance costs.

Environmental emissions are minimized when using natural gas, although the possibility that gas-fired turbines may contribute to the "greenhouse effect" has not been ruled out, which effect is relative to other fuels. The main concern in using combustion turbines as an energy resource is the uncertain future supply and cost of fuel. Please see discussion in this Appendix under "Fossil Fuel Price and Availability". Both General Electric and Westinghouse are proceeding towards commercial development of an Advanced High Temperature Turbine design. Both are predicting combined cycle efficiencies of 50 percent or greater with availability by the early 1990s.

Simple Cycle: The simple cycle combustion turbine represents a relatively inexpensive power resource to construct. Its total cost, including capital recovery, is primarily made up of fuel (depending on capacity factor). The following information is used in this report for a simple cycle combustion turbine power plant (1990 dollars).

• Capital Cost (including siting and licensing cost and fuel inventory)		\$587/kW
• Annual Availability	85%	
• Construction Lead Time	24 Months	
• Siting and Licensing Lead Time		24 Months
• Fuel Cost	Variable	\$2.57/MMBTU
	Fixed	Included in Capital Cost
• O&M Cost	Variable	0.1 mills/kWh
	Fixed	\$2.20/kW/year
• Heat Rate		11,480 BTU/kWh
• Operating Life		30 years

Note: Data based on two 139 MW units (rated capacity).

Combined Cycle: 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 capacity factors, the total cost of the electricity will be lower. This report uses the following information for a combined cycle combustion turbine power plant (1990 dollars).

• Capital Cost (including siting and licensing cost and fuel inventory)		$686/kW
• Annual Availability	83%	
• Construction Lead Time	36 months	
• Siting and Licensing Lead Time		24 months
• Fuel Cost	Variable	$2.57/MMBTU
	Fixed	Included in Capital Cost
• O&M Cost	Variable	0.33 mills/kWh
	Fixed	$5.93/kW/year
• Heat Rate		7,620 BTU/kWh
• Operating Life		30 years

Note: Data based on one 420 MW unit (rated capacity).

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 the clean gas is used as the combustion turbine fuel. Coal gasification technologies continue to evolve and IGCC is rapidly approaching a commercial status. The following information is used in this report for a coal gasification combined cycle power plant (1990 dollars).

• Capital Cost (including siting and licensing cost and fuel inventory)		$2,016/kW
• Annual Availability	80%	
• Construction Lead Time	39 Months	
• Siting and Licensing Lead Time		48 Months
• Fuel Cost	Variable	$1.17/MMBTU
	Fixed	$8.92/kW/year
• O&M Cost	Variable	0.22 mills/kWh
	Fixed	$67.24/kW/year
• Heat Rate		9,270 BTU/kWh
• Operating Life		30 years

Note: Data based on one 419 MW Plant (rated capacity).

Demand-side Resources

In 1990, the Company retained a consultant to help perform a demand-side resource assessment. This assessment provides the basis for Company estimates of achievable demand-side potential. In the assessment process, 20 demand-side options were evaluated in detail. 13 of those were electric DSM options, and 7 were gas DSM options. The 13 electric options evaluated in detail were:

1. New home construction
2. Conversion of electric water heat to gas/residential
3. Conversion of electric space heat to gas/residential
4. Energy efficient new commercial and industrial construction
5. Industrial process efficiency improvements
6. Comprehensive residential weatherization
7. High efficiency reflectors/commercial and industrial lighting
8. High efficiency commercial and industrial refrigeration
9. Fluorescent ballasts/commercial and industrial lighting
10. Energy efficient motors/industrial
11. Lighting occupancy controls/commercial and industrial
12. High efficiency air conditioning/commercial and industrial
13. LEPA irrigation/agricultural sector

These options were selected as most likely to have the greatest opportunity for cost-effective savings. WWP's intention is to pursue all cost-effective demand-side resources whether or not they were evaluated in detail for the 1990 assessment. As the Company increases its demand-side resource activities, new options will be added to the list of those evaluated in detail. Periodic reevaluations will also be performed.

It is estimated that demand-side resources savings by the year 2000 will be 34 aMW from residential fuel conversion programs, and 14 aMW from energy efficiency programs. The weighted cost of these DSM options was assumed to be 35.6 mills/kWh. This cost is a preliminary estimate designed for modeling purposes only. Detailed cost information is included in the consultant report found in Appendix C.

Competitive Bidding

The company has prepared an Request For Proposal (RFP) that will request firm energy from generation and cogeneration proposals. This first RFP expects 30 aMW to be available in 1995. As the need for additional resources becomes evident, further RFPs will be developed. Hopefully the competitive bidding process will be an important element in assuring that marketplace-based resources are acquired at the least-cost subject to several nonprice criteria. Some of the nonprice criteria include viability of the project developer, reliability of the generation/savings, financial stability of the developer, dispatchability, environmental concerns, etc. These criteria are important to assure that the resources acquired actually produce the promised energy service.

Conventional Coal Plants

Coal-fired generating plants are a commercially proven resource and should continue to be a viable resource option for the company. However, they do pose some environmental risks with ash and sludge disposal, and concerns of possible acid rain and "greenhouse effect" problems. 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. WWP is still maintaining the Creston site as a fully licensed resource option for future construction of a coal-fired generating station. The report uses the following information for a pulverized coal-fired power plant (1990 dollars).

• Capital Cost (including siting and licensing cost and fuel inventory)		\$1,446/kW
• Annual Availability	70%	
• Construction Lead Time	72/84 months	
• Siting and Licensing Lead Time		Acquired
• Fuel Cost	Variable	\$1.17/MMBTU
	Fixed	\$8.92/kW/year
• O&M Cost	Variable	2.10 mills/kWh
	Fixed	\$34.56/kW/year
• Heat Rate		10,370 BTU/kWh
• Operating Life		40 years

why not ? 75%

Note: Data based on two 605 MW units (rated capacity).

Distribution System Design

Through appropriate distribution system design modifications, energy savings can be realized but at an increased installation cost. For example, using a larger conductor on a distribution feeder can result in lower resistive losses. These energy savings can be realized in new feeder construction and rebuilds of the distribution system.

The company has determined that there is a potential to save an additional (above existing programs) 10 aMW at below WWP's avoided cost. This effort will require several years of implementation and will be reflected in the company's load estimate.

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. Additional hydro capability, such as pump storage, could also be used.

Fluidized Bed

Fluidized bed combustion technology is in a period of refinement/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. Commercial availability is expected in mid-1990s.

The fluidized bed 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 as in conventional plants today. The following information is used in this report for an atmospheric fluidized bed combustion power plant (1990 dollars).

• Capital Cost (including siting and licensing cost and fuel inventory)		$2,318/kW
• Annual Availability	81%	
• Construction Lead Time	64 Months	
• Siting and Licensing Lead Time		48 Months
• Fuel Cost	Variable	$1.17/MMBTU
	Fixed	$8.92/kW/year
• O&M Cost	Variable	5.30 mills/kWh
	Fixed	$40.75/kW/year
• Heat Rate		9,885 BTU kWh
• Operating Life		30 years

Note: Data based on one 419 MW unit (rated capacity).

Fossil Fuel Price and Availability

The price and availability of fuel has a significant impact on the overall cost effectiveness of generating resources. In its resource planning, the company must incorporate these impacts when evaluating new generating resources. For this study, the company recognizes two primary fossil fuels as fuels for new resources. These fuels are coal and natural gas. It is generally agreed that there is an abundance of both coal and natural gas for the long term. The price of these fuels over the long term, however, is uncertain. Increasing concerns over environmental effects of fossil fuel use, especially coal, also creates some uncertainty on the role of fossil fuel use in the Northwest and the nation.

Coal prices used in this study are based on Northwest Power Planning Council data and in-house knowledge. Delivered coal prices begin at $1.17/MMBTU in 1990, and escalate at an average nominal rate of 6.3% over the 20-year planning period. This price is based on East Kootenai coal from British Columbia delivered by unit train to an inland Northwest site.

Natural gas is considered to be environmentally cleaner than other fossil fuels. The advantages of natural gas are environmental improvement, economic competitiveness and energy security. These advantages over oil and in some cases coal makes natural gas the fuel choice for now and the future for electric generation and cogeneration. The Department of Energy has projected a 60-year supply of natural gas in the lower 48 states, assuming conventional production technologies and foreseeable economics. The addition of new, nonconventional supply technologies in the years ahead points to a natural gas supply base that numbers in the hundreds of years.

Kuwait Impact:
The turmoil in the Middle East has demonstrated the desirability of natural gas over other fuel choices. WWP is in a unique position to take advantage of natural gas for its fuel choice. The following is an assessment of the natural gas impacts due to the invasion of Kuwait:

Short-term impact: After an initial panic reaction by the natural gas futures market and some industrial customers, prices have stayed even to slightly higher on the spot market. Increased demand by current major industrial and electric generation customers is limited, both because many are already using gas and others (such as in the Northeast and Southern California) are constrained by the delivery system until further pipeline capacity can be added.

Near-term impact: The one-to-three-year horizon is expected to be generally unaffected by the invasion as long as it doesn't escalate into a full-blown war with major destruction to Middle East oil production and delivery capabilities. Natural gas has been beating oil and coal as the preferred fuel lately, and that trend will continue for environmental and economic reasons as well as national security reasons. Natural gas prices are expected to be only slightly above current levels due to gas on gas competition.

Long-term impact: The current scare, even if short-lived, should contribute to increases in research and development of natural gas vehicles, accelerated approval of competing pipeline applications, investment in more mobile delivery such as LNG facilities, and increased domestic natural gas drilling and production. All of these will have an impact on the country's environment, its economic competitiveness and its shifting reliance on North American instead of Middle East energy.

Customer Gas Supply:
WWP is in an unique situation as far as the access and supply of natural gas. From all indications natural gas service will continue to be a great energy value to our customers. These same indications will also be reflected on the use of natural gas for electrical generation. WWP's customers are as immune from the short-term impact of the Middle East situation as any gas consumers in the United States due to the following reasons:

1. Water Power has gas supplies which are mainly insulated from short-term price swings. These include storage gas purchased at low summer prices, pipeline sales gas which is based on contracts which are not generally tied to the price of oil, fixed price annual and winter contracts which are being signed at or below last year's prices. Recent strategic efforts to reduce gas costs, to diversify supply through PGT pipeline access to Alberta gas, and to take advantage of seasonal price swings despite the company's winter load are now paying off.

2. Tracking mechanisms for rates will ease any gas price increase beyond the short-term and reduce the impact of more expensive gas. If prices go up only briefly, the weighted average cost of gas will blend away the major impact of any possible price spikes. Therefore, prices to customers will reflect actual gas costs, avoiding any feeling of customers being "gouged" like many feel oil and gasoline companies have done by pricing all of their products previously in the distribution system at current production prices.

3. The main impetus for price hikes will be from increases in general demand, which will lead to a normal demand/supply reaction by producers of higher prices. Gas on gas competition and a limited opportunity for increased industrial gas use in the Northwest and California will mitigate substantial increases in demand in the near-term. This will mainly impact the natural gas spot market, which WWP is less exposed to than most utilities.

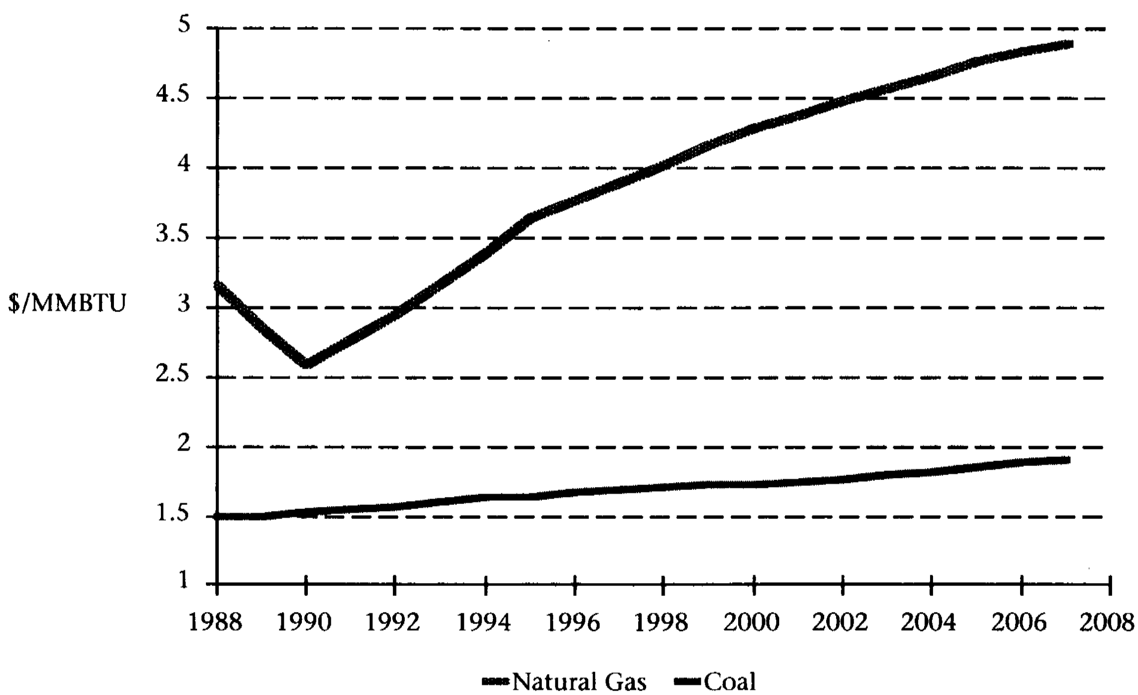
4. Current industrial customers with fuel switching capabilities are already using gas as their fuel of preference from a pricing and efficiency standpoint. The higher costs of oil as an alternative and the fluctuations in the gas spot prices may in fact encourage some of these industrial customers to switch to firm WWP sales gas service.

Combustion Turbine Gas Supply:
The company is in a good position regarding natural gas to be able to serve additional combustion turbines if selected as a necessary resource to serve load. In addition, any fuel switching programs done by the company should have sufficient natural gas supplies at reasonable costs. Using natural gas fired generation, including new combustion turbine installations, to firm nonfirm hydro generation appears to be a viable alternative to other incremental sources of generation. WWP has the advantage of having access to two natural gas transportation systems with supplies available from both the U.S. and Canada. This backup generation could be done with interruptible gas because WWP could use its reservoirs to shape the need for energy off of heavy gas load days, when all the gas is needed to serve existing markets.

The natural gas prices used for this study are based on data received from external sources and in-house knowledge. The price begins at $2.57/MMBTU in 1990, and escalates at a medium case average nominal rate of 8.5% over the 20-year planning period. We are assuming that the Company would be purchasing gas to fire new electric generating facilities under tariffs and that the escalation rate imbedded in the electric assumptions reflect tariff increases and not gas commodity escalation rates, inherent in the Company's gas Least Cost Plan. As such the Company electric operations are customers of the Company's gas operations.

Nominal Natural Gas and Coal Price Forecast ($/MMBTU)

Figure A-2.



Fuel Cells

A fuel cell is a device which 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 should decline, allowing perhaps in 10 years for the fuel cell to become a part of WWP's resource alternatives.

Geothermal

Geothermal energy is currently being used for the production of electricity at many locations throughout the world. Unfortunately, there are no potential geothermal sites in WWP's service territory, although these are estimates of vast amounts of geothermal resources in the Pacific Northwest. However, since there no proven natural steam or hot water reservoirs for an assured fuel supply and there is a lack of local operating experience, geothermal energy in the Northwest cannot be considered at this time to be a viable option to meet future electrical requirements. As the region's geothermal resources are confined and better understood, electrical generation from geothermal should become a cost-effective alternative to other generating resources. Geothermal energy will continue to be monitored, but for this report it is not considered a viable option.

Hydro

Most of the large scale hydro power sites that are environmentally acceptable have been developed in our region. There is a potential for small scale development, but there are problems of small hydro without storage capabilities. Most of the energy produced is during the period April through July when the value of power is less. WWP does not plan to develop new hydro sites but will continue to purchase hydro development that is offered as a QF facility.

Hydro System Improvements

The company has been actively engaged in assessing the improvement potential of its hydro system. Monroe Street hydro facility was the oldest on our system and was the first facility to receive an in-depth study as to what cost-effective improvements could be done to increase the generating capability and efficiency of the site. After extensive study, it was determined that the old facility of five units for a total capability of six MW should be torn down and a new facility (mostly underground) should be built utilizing the existing head gates and penstock. The new facility will have one turbine generator unit rated at 14.7 MW. The new facility should be available for electrical generation production around April 1992.

Nine Mile and Long Lake hydro facilities are now being studied by WWP in conjunction with hired consultants. A summary of the consultants' findings are found in Appendix E of this report. We are assuming that once the studies are finalized, any hydro system improvement will be completed if it is shown to be cost-effective.

Nine Mile and Long Lake Redevelopments

Long Lake and the Nine Mile Hydroelectric Developments are a part of Washington Water Power's Spokane River Project, which is licensed under the Federal Power Act as FERC Licensed Project Number 2545. The licensed project as a whole includes developments at Long Lake, Nine Mile, Monroe Street, Upper Falls and Post Falls.

The Nine Mile Development (18 MW) is northwest of the city of Spokane. From the intersection of Division Street and Francis Street it is nine miles along Francis Street and Nine Mile Road to the plant. Construction of the Nine Mile development was initiated in 1906 by the Spokane and Inland Empire Railway. Two generating units were placed in operation in 1908 and an additional two units in 1910. WWP acquired the development in July 1925.

The Long Lake Development (72 MW) is about 25 miles northwest of Spokane. By road, it is 40 miles from WWP's main office in Spokane to the plant. Long Lake was designed and constructed between 1910 and 1915 when the first two generating units came on-line. The final two penstocks and generating units were added in 1919 and 1924. The design was performed by the engineering department of WWP. It's interesting to note that the main, or spillway dam, at 213 feet above foundation, was the world's highest concrete gravity dam when it was completed in 1915. The turbines were also said to be the largest of their type when installed.

Due to the age of these plants and because of technological improvements currently available, it is advisable to investigate possible opportunities for these developments. In July of 1989, WWP entered into technical service agreements with engineering consultants to perform engineering and economical studies of these hydroelectric facilities. These studies identified renovation and development alternatives to ensure a reliable long-term generating resource, as well as make use of river flows which are currently spilled due to the limitation of the hydroelectric capacity of the existing system.

"Long Lake"

The Long Lake Development consists of a gravity dam and powerhouse. Actually, there are two dams joining each other at right angles in the middle. The main, or spillway dam is 213 ft. high. The spillway dam has a crest length of 353 feet and consists of eight gated bays. The intake dam is a non-overflow gravity section with a crest length of 148 feet. It contains four penstocks which supply flow to the four units in the powerhouse below. The turbines are horizontal Francis types. Each unit has a hydraulic capacity of 1575 cfs under a gross head of 175 feet for a combined total of 6300 cfs. The generators have a combined net capacity of 72.5 MW. There is a third dam, known as the cutoff dam, located in a saddle about 600 feet upstream from the intake dam. This dam is about 100 feet high by 250 feet long.

The magnitude of available Spokane River flows and the physical configuration of the project combined to suggest the basic approach used in this study. That is, to construct a totally new intake, penstock and powerhouse system which will be physically independent from the existing powerhouse. The project layout is ideally suited to this. In fact, it should be possible to construct the entire new system without any significant shutdown of the existing plant. It is, therefore, expected that the program may be completed with no energy lost during construction.

The new powerhouse system is envisioned as including a new intake structure located approximately 300 ft downstream from the present cutoff dam in the natural saddle now blocked by that dam. It will replace the present cutoff dam, which will be breached after the new intake is complete. The intake will contain gates and a trashrack system. It will direct flow form Long Lake into a penstock or penstocks which will convey water to the new powerhouse.

Construction cost estimates and power production studies are currently being done to determine the exact size and number of turbine-generator units. Engineering work is now in progress to determine the cost of one and two unit 50 or 60 MW powerplants. An economic analysis will be done on January 1991 to quantify the differences in cost and benefits for each powerhouse arrangement.

Engineering cost estimates for a powerhouse with two 60 MW units is $98.3 million. A $7.5 million credit is realized because money is saved on the existing powerhouse refurbishment by virtue of the construction of the new facility. This reduces the net project cost to $90.8 million. These costs include sales tax, escalation, and AFUDC but do not include owner's administrative costs.

The proposed Long Lake expansion has several benefits. One of the most important is the increase in energy production. For a powerhouse with one 60 MW unit, the increase in energy production is about 38 percent. If two 60 MW units are installed in the powerhouse, energy production increases by about 60 percent.

In the very practical area of operation, expansion at Long Lake will have another important advantage to WWP. It is clear that addition of two new units in a new powerhouse will improve the reliability of the Long Lake facility as a whole. The existing units will operate fewer hours per year, and can supply stand-by capabilities at other times. In addition, scheduling of annual maintenance will be simplified as forced outage rates are reduced.

Finally, any long-term concern WWP may have about the longevity of the existing cutoff dam will certainly be answered by expanding Long Lake, since doing so will result in the replacement of the cutoff dam with a totally new structure: the new power intake.

It is apparent that virtually no other project will be so benign environmentally as the proposed Long Lake expansion. The project's operation and effects on the river will be virtually unchanged from present conditions. In effect, the only change will be to generate power with water now spilled during periods of high river flow.

"Nine Mile"

The Nine Mile dam is a concrete gravity structure 459 feet long that includes a 225-foot spillway, a 139-foot powerhouse, and a 95-foot wingwall section. The spillway section is 58 feet high with an additional 10 feet of flashboards. There are no penstocks in this plant. The turbine shaft extends through a steel bulkhead and the runners are in a large chamber which is located on the upstream side of the dam.

The turbines are a horizontal Francis type with four sets of runners. The generators have a nameplate capability of 12 MW but have been rewound and are capable of 18 MW. The project has very little storage capacity and is operated as run-of-river.

An engineering consultant was contracted by WWP to perform a study of alternative methods for increasing the development's power generation. These alternatives included 1) upgrading the existing units; 2) replacing the existing units with new more efficient units; and, 3) constructing a new powerhouse downstream of the existing project.

Improving efficiency of the station by upgrading the four existing turbines is not as effective as replacement, because the turbine manufacturer's quoted prices for exchanging present parts with more efficient ones were equal to or above the cost of new, more efficient replacement machines.

Increasing the station capacity by installing a Kaplan unit in a new powerhouse on the left bank just downstream of the existing station did not prove viable. In combination with the existing or upgraded units, incremental power production of the additional unit does not justify the capital investment.

The existing units can be replaced without major changes to the powerhouse structure. The existing units can be replaced with horizontal Francis turbines, designed to discharge into the existing dual draft tube with only minor rework of the concrete. The generators and major electrical equipment will have to be replaced to utilize the higher shaft output of the upgraded turbines.

An economic analysis will be done in March 1991 after the construction cost estimates and power production studies are completed. Preliminary investigations show that capacity can be increased to 27.8 MW and average annual energy can be increased from 110.5 Gwh/year to 151.5 Gwh/year for a total project cost of $19.3 million. Net project benefits have not been finalized but preliminary indications are on the order of $7.0 million dollars.

In Figure A-3 we show the hydro projects presently being evaluated or considered for evaluation for improvement potential including plant and site modifications. The figures shown are based on very preliminary estimates and are subject to change. The improvements vary from additional powerhouses to turbine upgrades depending on the hydro site.

WWP's Hydro System Improvement Potential (in 1990 dollars)

Figure A-3.

Hydro Plant Name	Potential Firm Capacity Increase MW	Potential Annual Firm Energy Increase MWh	Potential Annual Total Energy Increase MWh	Estimated Investment Dollars $(000)
Noxon Rapids	0	2	2	10,000
Cabinet Gorge	60	10	15	51,340
Post Falls	15	3	6	15,000
Upper Falls	1	1	1	250
Monroe Street (2nd Unit)	55	7	20	90,000
Nine Mile		4	4	6
12,800				
Long Lake	120	8	30	99,800
Little Falls	10	1	4	5,260
Total	265	36	84	284,450

Any changes in the hydro facilities will require an amended license from FERC. Environmental studies will be conducted as part of the licensing process. The Monroe Street redevelopment had negligible effect on the environment and in fact enhanced public access to this part of the Spokane River. In addition money and work were contributed to the Centennial Trail Committee to enhance the trail construction efforts through the City of Spokane.

Interruptible Rates

The application of electrical retail interruptible rates on WWP's system has been evaluated. Being able to interrupt an electrical load could substitute for an electrical resource. Depending on the terms and conditions of the interruptible contract would dictate what the interruption could be used for. For example, an interruption could cover a portion of the utilities need for peaking reserves or could back up the system for low water conditions or other adverse circumstances. WWP has offered interruptible rates to some of its customers in the past but was turned down. Most customers do not want to take a chance on interrupting their manufacturing process even for a reduction in their rates. At the present time the company is negotiating a service agreement with one of its customers that includes a provision to serve part of the load on an interuptible basis. There could be opportunities in the future with some of our other industrial customers and these will be evaluated and pursued as they arise.

Load Management

Load management programs are helpful tools in shifting energy load from heavy on-peak hours to off-peak hours. These tools include specialty rates, interruptible rates, and direct load control devices. As resources are added for energy needs, the company also receives from those resources a contribution to peak needs. The amount of peak depends on the energy resource acquired. From all indications, our peak needs are being satisfied through the energy resource additions. If in the future additional peak resources are needed, then load management programs will be evaluated against other peaking resources and those that are the most cost-effective will be selected.

Nuclear

Although the company has been involved with nuclear energy production of electricity since 1966, at the present time we are not considering future nuclear generation options. However, the conditions that caused unacceptable problems with nuclear power (long lead times required to construct, extremely high construction costs, and excessive regulation) could be solved by the module nuclear units now being developed. Both General Electric and Westinghouse are developing a modular nuclear production plant in the 500 MW range that will be standardized design acceptable to the regulatory entities and able to be constructed in five years. Additional emphasize will be placed on using nuclear energy for the production of electricity if the environmental concerns of burning fossil fuels cannot be resolved.

Options

WWP utilizes the concept of resource "options", first proposed by the NPPC, to add flexibility to the scheduling of those resources which take a great deal of time from inception to completion. Under the resource option concept, a resource proceeds through the time-consuming, but relatively inexpensive, siting, design and licensing stages. After completing those stages, it can be placed in a standby condition. In that condition, the project could be constructed, placed on hold or terminated, depending on the demand for electricity. Such options would provide a relatively low-cost resource inventory that would allow the company to be ready for high growth rates without prematurely committing to build for those growth rates.

The company has two such options available. The first option is a licensed site available for future construction of coal-fired generating units, four miles southeast of Creston, Washington. The second option currently being licensed is the B.C. Hydro-WWP 230 kV Transmission Interconnection. If constructed it will provide a transmission intertie between the company's system at Spokane and the B.C. Hydro system near Trail, British Columbia, Canada. The purpose of the line is to provide access to Canadian electrical power sources.

Creston Generating Station Site:

Washington Water Power has available a licensed site for future construction of coal-fired generating units located four miles southeast of Creston, Washington. Land options, a federal permit and a state Site Certification Agreement are being maintained by the company in order to keep this site available for future resource needs. The company worked with the Energy Facility Site Evaluation Council (EFSEC) to extend, for five years, the Site Certification Agreement. The company has received extensions to the Prevention of Significant Deterioration Permit (PSD) for Creston. To accommodate Creston's Air Contaminant Permit, WWP will provide new BACT (Best Available Control Technology) analyses to be approved by EFSEC at the time a decision is made to construct the project. The Creston Generating Station Site is located close to a major transmission facility.

Creston is the only fully licensed coal-fired plant site within the region. There are concerns with every type of resource, but there is an abundance of coal in the western states and the region should maintain its coal option for future resources. Also the license for Creston could be amended to accommodate new technologies such as coal gasification or fluidized bed designs. This would position Creston to be a more environmentally acceptable energy resource within the region.

Washington Water Power Company and Puget Sound Power & Light Company are currently maintaining the Creston site as an option for future regional resource needs. Its viability as an option should be maintained to provide maximum flexibility to the region to meet future electrical needs.

B.C. Hydro - WWP Transmission Interconnection:

Another option currently being developed is the B.C. Hydro-WWP 230 kV Transmission Interconnection. It will provide a transmission intertie between the company's system at Spokane and the B.C. Hydro system near Trail, British Columbia, Canada. The main purpose of the proposed transmission line is to provide the customers of WWP and other northwest utilities with access to a future source of economic power.

The intertie with B.C. Hydro is tentatively planned for completion in late 1995. However, construction will not begin until all power purchase contracts have been finalized and signed with B.C. Hydro, and the company is assured of a long-term power supply at a favorable cost. The favorable cost will include not only the purchase price of power, but also the recovery of capital costs of the intertie associated with the company's ownership share. If this resource option proves to be less cost effective than other alternatives, then this option will be placed on hold.

On October 15, 1987 the company filed an application with the Economic Regulatory Administration within the Department of Energy for a Presidential Permit to construct, operate, maintain and connect the double-circuit 230 kV transmission line with B.C. Hydro. Under the direction of the Department of Energy, an Environmental Impact Statement on the intertie is being prepared. Licensing is planned for completion by Spring 1991.

On March 2, 1991, the company filed an amendment to the original application, reducing the the length of the proposed line from 127.9 miles to 102.2 miles and establishing the company's Beacon substation, rather than the proposed Marshall substation, the southern terminus of the proposed line. The preferred route generally parallels existing BPA and WWP rights-of-wayfrom the international boundary to the Beacon substation. The estimated cost of the U.S. portion of the project is $123,000,000 in 1988 U.S. dollars.

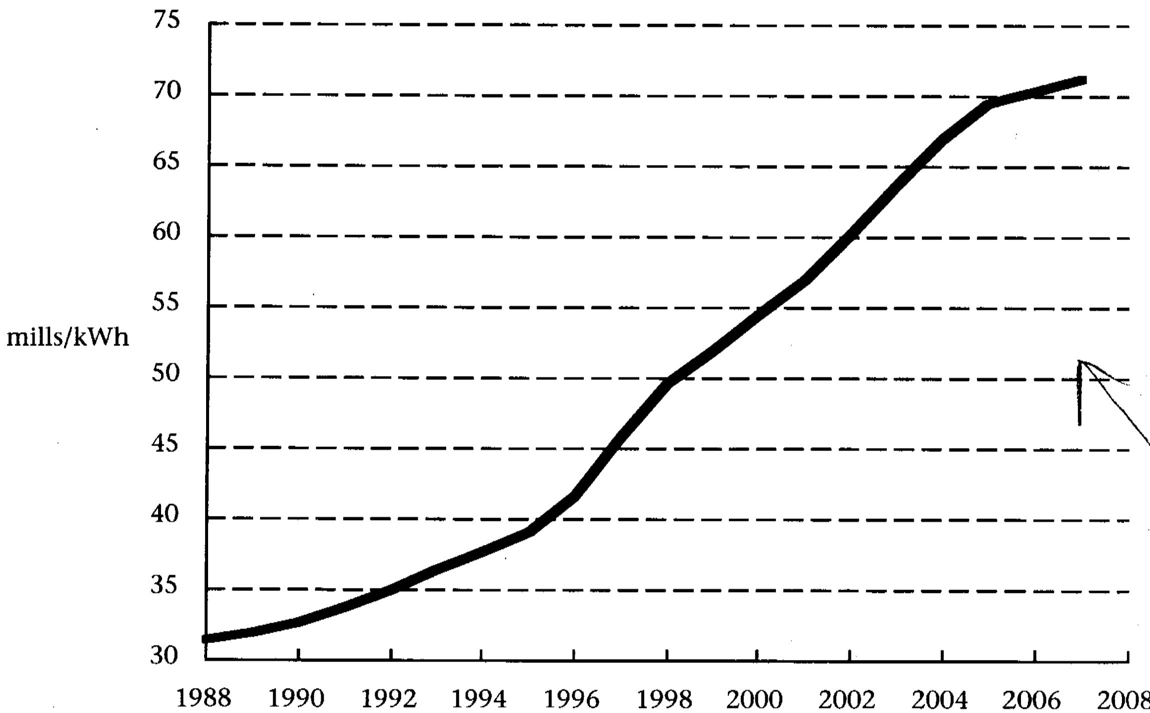
In 1990 the company and Powerex, a subsidiary of B.C. Hydro, entered into a Memorandum of Understanding (MOU) for the purchase and sale of power and construction of an interconnection. The MOU provides the framework for a capacity and energy sale to WWP when the interconnection construction has been completed. There is no obligation on the part of either party to proceed with the interconnection.

The parties' decisions regarding construction of the interconnection will be dependant on obtaining timely regulatory approvals and completing commercial arrangements to justify building the interconnection. In recognition of the risk associated with licensing cost of the planned interconnection and in the event that the interconnection is not completed, Powerex will enter into a 50 MW capacity sale agreement to WWP for a term of 15 years.

Purchases

The company is constantly purchasing and selling energy on the wholesale market on a day by day basis. In the past purchases on a long term basis have been used by WWP to meet system requirements. Purchases have also been made for intermediate periods of from one to five years to cover short-term deficits. In the fall of 1990, WWP entered into two purchase arrangements. One purchase was for one year (1991) from B.C. Hydro and provided WWP with access to capacity and associated energy. The other purchase was for firm energy delivered mostly during off-peak hours from Montana Power Company during a four year period (1991 through 1994).

For this report, the company is assuming that any firm purchases available to it in the 1990s will be priced at or below BPA's New Resource (NR) rate. The NR power is available to WWP and other investor-owned utilities from BPA after seven years' notification. Purchases from other utilities will have to be below the NR rate to offset transmission costs in wheeling the power into WWP's system. One problem with the NR power is the uncertainty of what the NR rate will be in the future and the required seven-year lead time. As demand for purchases from BPA increases, the NR rate will increase as new generating resources are added to the NR resource pool. Figures A-4 and A-5 below shows the NR rate forecast at 75 percent load factor based on a revised BPA estimate and in-house data.



BPA New Resource Rate Projection ($/MWh at 75% Load Factor)

Figure A-4.

does not appear to match?

Year	($/MWh)	Year	($/MWH)
1990	32.42	2000	55.04
1991	33.59	2001	57.70
1992	34.78	2002	60.71
1993	36.09	2003	65.60
1994	37.40	2004	68.63
1995	38.83	2005	74.04
1996	42.51	2006	80.22
1997	46.48	2007	83.97
1998	48.98	2008	90.37
1999	51.76	2009	93.42

BPA New Resource Rate Projection ($/MWh at 75% Load Factor)

Figure A-5.

The 50 aMW Planning Criteria:

For planning purposes the company will use up to 50 aMW of short term purchases to serve its requirements. The 50 aMW criteria is a flexible criteria. WWP may rely on more or less short term purchases depending on the company's assesment of availability, cost and alternatives.

WWP plans to serve all the load placed on its system by a combination of company owned resources and power purchases of various lengths. The lengths of the power purchases will vary depending on our judgement as to the risks and costs of those purchases. Planning to fill 50 aMW of energy deficits with unidentified off system resources is reasonable for planning purposes, especially for such a small proportion of total load.

In short term planning, as the need approaches, the deficit will be met with better than critical water conditions on WWP's own system hydro production or when that production is inadequate, by purchases from other utilities.

Resources are generally available on a short-term basis at considerably less cost than on a long-term basis. WWP has chosen to include in its resource mix, some short-term and long-term purchases. The amount depends on our judgement based on experience and knowledge of the WSCC area load and resource balance and expected cost. Short-term purchases provide flexibility benefits such as limiting the purchases to only the amount of needs, minimizing the effects of error of estimates by not acquiring expensive surpluses if actual loads fail to materialize, and only purchasing the energy needed in excess of actual production. Short-term purchases will be at market prices, which normally are significantly below the cost of gas-fired generation. This strategy provides the least-cost resource mix for WWP.

There is a risk that resources will not be available but risk is inherent in any reasonable resource plan. Using a modest amount of short-term resources in the resource mix will not measurably change the supply risk. WWP will periodically review the probable cost and availability of short-term purchases to see if conditions have changed which may warrant a change in reliance on short-term purchases.

The amount of power from coal-fired steam, gas- and oil-fired steam and combined cycle resources that is available from the southwest and desert southwest for export, based on WSCC load and resource reports, is 16,800 aMW in 1990 and 15,239 aMW in 1998. This energy is from thermal plants and is considered firm energy that can be purchased by WWP.

The Southwest-Northwest Intertie transmission system is not a material constraining factor for importing energy to the northwest. Also energy from the desert SW can be delivered through PacifiCorp and Idaho Power to WWP's system.

With the large quantities of energy and transmission available, WWP has a high degree of assurance that energy can be imported to serve its modest needs for short-term purchases.

Qualifying Cogeneration and Small Power

The Public Utility Regulatory Policies Act (PURPA) of 1978 requires utilities to purchase power from cogeneration and small power production facilities which qualify under PURPA and FERC's implementing rules. These facilities are commonly known as "qualifying facilities" or "QFs".

The company purchases QFs power at calculated avoided costs set by both the WUTC and the IPUC. WWP is not adverse to purchasing QF power if the published avoided cost reflects the true avoided cost of the company. The concern is that if WWP is required to purchase a larger quantity of power than needed or at prices in excess of alternate resource acquisition programs, then its customers will be asked to bear an unjustified financial burden through increased electrical rates. In pursuing a bidding system (RFP), WWP hopes to verify what is the price of supply- and demand-side resources as determined by the marketplace.

Some of the benefits of QF power are the facility can usually be built at the fuel source and the excess steam can be used at the host facility, they can be added in small increments to match load growth and they also have the benefit of short construction lead times. Some of the disbenefits are usually no economic dispatch, a question of reliability, interconnection concerns and considerable contract administration efforts.

The company has a program in effect to help its customers develop cogeneration facilities if physically possible and is shown to be cost-effective. Several large industrial and commercial customers are presently contemplating the addition of cogenerating units. These customers will either sell cogenerated energy to WWP, off-system to other utilities, or use the energy to reduce their load. WWP hired a consultant (Resource Management International) to help in the assessment of customer generation potential. A summary of the consultant's report is found in Appendix D of this report.

For this report, WWP has estimated that there is a large potential of QFs in its service territory from industrial and commercial customers. These numbers are slightly different than the consultant data because the final assessment data was not available at the time of this study effort. This report also assumes that the majority of this cogeneration will be available at a levelized nominal priceat WWP's avoided cost, although it is recognized that cost estimates for cogeneration facilities are highly site-specific.

Solar

There are currently two solar power conversion systems available to convert radiant energy from the sun into usable electrical power. The first type consists of a field of heliostats (mirrors) that reflect the sun's rays to a central receiver point for indirect conversion to electricity. The second type utilizes a field of photovoltaic (solar cells) panels used to absorb the sun's rays for direct conversion to electricity. Each of these conversion technologies is proven and is commercially available, although the cost are high.

Photovoltaic (PV) systems have recently decreased in price and increased in efficiency. Currently PV systems efficiencies are around 13 percent with production costs of approximately $300 per square meter. It is anticipated that significant cost reductions will occur in solar electric generation technologies in the future. As this scenario unfolds, solar electric generation could become a portion of WWP's new resource acquisition programs.

Wind

The process of converting power from the wind to useful energy has been around for many years. There are some areas in the company's service territory that have marginal wind resources that could be used for the operation of wind turbines. There are some sites within the Northwest region that have good potential for wind generation. However, because of the high cost of energy produced from wind resources, this option is not considered a feasible resource at this time. As technological improvements are made over time, the cost of wind generation will decline allowing WWP to re-evaluate this source of energy as a potential resource.

APPENDIX B
PUBLIC INVOLVEMENT

This report is used by WWP as a plan for resource acquisitons and to meet the planning requirements of both the Washington Utilities and Transportation Commission and the Idaho Public Utilities Commission. As part of its planning efforts, WWP has been active in obtaining public involvement. The company feels that this least-cost planning effort provides an opportunity for WWP, state regulators and the public to collaborate together in developing a reliable low-cost electric plan.

Resource planning is a continuous effort at WWP, but on a formal basis this second effort of integrated resource planning was started on February 15, 1990, through an internal memo. The memo alerted the various departments as to the time frame and need for input data. Initial work had already been done prior to that time outlining the 1991 report and formulating resource scenarios.

A mailing was made on March 16, 1990 to WWP's Technical Advisory Committee (TAC) members, asking for their help in this second formal planning effort. Three committee meetings were scheduled to be held in Spokane. The first meeting to be held on June 12 was to discuss basic planning concepts. The second meeting, September 11, was to discuss resource scenarios and review draft chapter write-ups. The third meeting on December 18 was to review the draft report.

The following is a list of those invited to participate in WWP's TAC meetings:

Mr. Fred Adair
Research Analyst
House Energy & Utilities Committee
205 House Office Building
Campus Mail AS-33
Olympia, WA 98504

Mr. Steve Aos
Washington Utilities and Transportation Commission
Chandler Plaza Building
1300 Evergreen Park Drive South
Olympia, WA 98504

Mr. Kevin Bell
Executive Director
Northwest ConservationAct Coalition
3429 Freemont Place North, No. 308
Seattle, WA 98103

Mr. Craig Benjamin
McCklusky Services
Washington State University
Pullman, WA 99164-1150

Mr. John Bjork
City of Spokane
W. 808 Spokane Falls Boulevard
Spokane, WA 99204

Mr. Kevin Winters
Office of Public Counsel
900 4th Ave. #2000
Seattle, WA 98104

Mr. Bill Campion
Associate Dean
School of Business
Eastern Washington University
c/o Mail Stop 46
Cheney, WA 99004

Mr. Ken Canon
IndustrialCustomers of Northwest Utilities
700 NE Multnomah Street, Suite 1200
Portland, OR 97232

Mr. Bob Cooper
President
Spokane Area Economic Development Council
Box 203
Spokane, WA 99210

Ms. Anne Cowles
Washington Trust Bank
W. 717 Sprague
Spokane, WA 99201

Mr. Bill Eastlake
Idaho Public Utilities Commission
Statehouse Mail
W. 472 Washington
Boise, ID 83720

Mr. Bruce Folsom
Washington Utilities and Transportation Commission
Chandler Plaza Building
1300 Evergreen Park Drive South
Olympia, WA 98504

Mr. Tom Faull
Idaho Public Utilities Commission
Statehouse Mail
W 472 Washington
Boise, ID 83720

Mr. Ken Hall
Budget Officer
University of Idaho
Moscow, ID 83843

Mr. Jonathan Lesser
Energy Policy Specialist
Washington State Energy Office
809 Legion Way SE #FA-11
Olympia, WA 98504

Mr. Jim Litchfield
Northwest Power Planning Council
851 SW Sixth #1100
Portland, OR 97204

Mr. David Van Hersett
W 222 33rd
Spokane, WA 99204

Ms. Stephanie Miller
Idaho Public Utilities Commission
Statehouse Mail
W. 472 Washington
Boise, ID 83720

Mr. Phil Moeller
Senate Energy & Utilities Committee
415 JAC Building
Mail Stop MSQW11
Olympia, WA 98504

Mr. William Nicholson
Manager Coprorate Energy Services
Potlatch Forest Industries
P O Box 3591
San Francisco, CA 94119-3591

Mr. Terry Novak
City Manager
City of Spokane
W. 808 Spokane Falls Boulevard
Spokane, WA 99204

Ms. Deborah Ross
Washington Utilities and
Transportation Commission
Chandler Plaza Building
1300 Evergreen Park Drive South
Olympia, WA 98504

Mr. Bob Sallee
Technical Assistant to the President
Inland Empire Paper Company
N. 3320 Argonne Road
Spokane, WA 99212

Mr. Marc Sullivan
Executive Director
Northwest Conservation Act Coalition
3429 Freemont Place North, No. 308
Seattle, WA 98103

Mr. Phil Welker
Energy Policy Specialist
Northwest Power Planning Council
450 West State
Boise, ID 83720

Mr. David Weitzel
Senior Consultant
National Economic Research
Associates
3411 One Union Square

The June 12, 1990 meeting had an attendance of 26 people, of which 11 were from the company. The scope and timing of the report was discussed and a current requirements and resources 20-year tabulation was distributed. Other items discussed were WWPs demand-side activities, supply-side resource costs, financial data, load forecasting activities, plans to revise the WUTC least-cost planning model, scenario planning and the company's study on firming non-firm hydro.

On June 20, 1990 WWP held a public meeting on resource planning. The meeting was advertised in the local newspaper and nearly 200 individual letters inviting participation in the public meeting were mailed. We had nine non-WWP people in attendance. A short presentation was made on both supply-side and demand-side resources and questions were answered. A survey was also given for the participants to complete. The survey showed the following results: WWP should acquire resources in the following order, conservation, solar with small hydro and nuclear tied for third. The participants were evenly split on whether they would be willing to raise rates to pay for conservation programs.

The September 11, 1990 TAC meeting had 22 in attendance, of which 11 were from the company. A review of work being done by WWPs consultant on screening of DSM options was presented to the group. Thirteen DSM options were selected from those studied to do a more detailed analysis. The load (base) forecast inputs and outputs were also explained to the group. Other items discussed were the draft chapters, resource planning and scenarios, and the least-cost planning model status.

On December 18, 1990, a TAC meeting was held in Spokane. In attendance were 16 people of which 5 were from the Company. An update was given as to the progress of WWP in the various areas of planning. A review of the draft was done and comments taken that should improve the report. The main emphasis of the TAC members was that WWP should be more specific in explaining why certain resource acquisitions were done.

The Spokane public meeting was held on January 15, 1991. Almost 400 letters were sent out inviting people to the meeting. A notice of the meeting was published in the local newspapers. In addition we received publicity from the newspapers and one radio station that encouraged people to come out to the public meeting and participate with WWP in its planning process. There were over 50 people in attendance, which included 10 WWP people. At the meeting WWP explained the DSM programs to be implemented in 1991 and the planning process, with the outlook on what resource acquisitions there would be for the future.

The public meeting was a success in two ways. First, it gave the company an opportunity to explain what we were doing to assure an adequate future supply of electrical energy at the lowest cost for our customers. Second, it gave our customers an opportunity to voice their comments and concerns regarding various activities of WWP. some of the subjects brought up as questions from the public were DSM programs, rate impacts, BPA's energy surplus, Spokane's garbage plant, B.C. Hydro/WWP interconnection, weatherization programs, relationship of gas prices to electric, fuel conversion programs, incentives, cogeneration opportunities, wind, solar, environmental costs, peek needs, RFP and future public participation.

Notice Of Least Cost Planning Meeting Advertisement

Figure B-1.

Notice of Public Planning Meeting

Least-Cost Electrical Supply Plan

WWP invites participation and input from individuals and organizations in developing a plan to acquire reliable low-cost energy supplies to meet future electrical demands.

Least-cost planning is a planning process that utilizes demand-and supply-side resources to develop a least-cost electrical supply strategy for an uncertain future. The Washington Water Power Company is working on its second formal least-cost planning report, in cooperation with the Washington Utilities and Transportation Commission, and a related program, Resource Management Report, for the Idaho Public Utility Commission.

The complete draft of the WWP Least-Cost Plan, "Managing Resource Options for the Future," will be available at the meeting.

A brief presentation on the plan will be made, and then comments will be solicited from those in attendance. Written comments can be submitted at any time prior to or during the meeting. Public comments will be incorporated into the final report.

Meeting Time **7:00 pm**

Tuesday, January 15, 1991

Audubon Room

Cavanaugh's Inn at the Park
West 303 North River Drive

Direct written comments or questions to Doug Young, (509) 482-4521 at Washington Water Power, Spokane.

WWP

The Washington Water Power Company

P.O. Box 3727, Spokane, WA 99220

APPENDIX C

ANALYSIS OF DEMAND-SIDE RESOURCE OPTIONS

INTRODUCTION

In keeping with its objectives to acquire least cost energy resources, provide high quality energy services, maintain low energy service costs, and assure shareholder value, in 1990 the company embarked on an effort to identify cost-effective demand-side management (DSM) options. This effort is the first comprehensive effort by the company to assess DSM options. To assist in the effort, the company retained Synergic Resources Corporation (SRC) of Bala Cynwyd, Pennsylvania. SRC has a significant amount of expertise in DSM planning and implementation and has provided DSM consulting to many utilities both nationally and internationally.

The following are the major objectives established for this first DSM assessment:

- Develop end-use sales estimates and load shapes consistent with WWP's billing data to provide an information base for estimating end-use load shape impacts of DSM options.
- Through an initial screening process identify the DSM options with the greatest potential to provide benefits to WWP and its customers. (The effort resulted in 13 electric and 7 gas DSM options studied.)
- Complete detailed evaluation of the most promising DSM options to estimate market potential, and the costs and benefits of each option from the perspective of WWP, the participating customer, all customers and society.
- Develop implementation and monitoring guidelines for those options identified to be cost-effective.

At the time of printing of this 1991 version of the company's electric integrated resource plan, the final report on the results of the DSM assessment was not yet available. The report in this appendix provides some of the draft results of this initial effort to develop data, identify, and evaluate DSM options for WWP's service area. Specifically, the report discusses the initial list of DSM options which was then screened to provide the 13 electric DSM options evaluated in detail. A brief description of each of the programs evaluated is presented, and summary draft results of the evaluations are shown.

With the exception of the impacts of the residential space and water heat conversion programs, none of the results of this assessment have been explicitly included in the specific resource scenarios developed in this integrated resource planning report. Estimates of energy efficiency programs included in the resource scenarios developed were estimates generated prior to this DSM assessment. The company derived those estimates from regional conservation estimates generated by the Northwest Power Planning Council.

OPTIONS SCREENING

A subjective screening process was used to identify the DSM options with the greatest potential. An initial, comprehensive list was developed. Then each option was evaluated relative to a set of screening criteria to identify those with the greatest potential. The list of options considered is shown in Figure C-1. The 13 options shown in bold text are the ones selected for detailed evaluation.

DSM Options Screening List

Figure C-1.

Sector
End Use
DSM Option

Residential

All End Uses

1. **New Home Construction, Shell and Appliances,**
2. **Comprehensive Weatherization.**
3. Whole House Load Control

Space Heating

4. Advanced Heat Pump
5. High Efficiency Heat Pumps
6. Ground Source Heat Pumps
7. Electric Thermal Storage
8. **Convert Electric Space Heat to Natural Gas Space Heat**
9. Promote Heat Pumps

Space Cooling

10. High Efficiency Air Conditioning
11. Window Films and Treatments
12. Air Conditioner Load Control
13. Whole House Fans
14. Evaporative Air Conditioning
15. Gas Air Conditioning
16. Storage Air Conditioning

Water Heating

17. Heat Pump Water Heaters
18. Water Heater Load Control
19. **Convert Electric Water Heat to Natural Gas Water Heat**
20. Heat Recovery Water Heating

Lighting

21. Fluorescent Lamps
22. High Pressure Sodium (HPS) Outdoor Lighting

Swimming Pools

23. Pool Pump Timers

Clothes Dryers

24. Convert Electric Dryers to Natural Gas Dryers

Refrigeration

25. High Efficiency Refrigerators

Freezers

26. High Efficiency Freezers

Cooking

27. Convert Electric Ranges/Ovens to Natural Gas Ranges/Ovens

Commercial/Industrial

All End Uses

28. **Energy Efficient New Construction**
29. Energy Management Control Systems (EMCS)

Sector
End Use
DSM Option

Space Heating

30. Convert to Gas Heat
31. High Efficiency Ground Source Heat Pump
32. High Efficiency Air Source Heat Pump

Space Cooling

33. Cool Storage
34. Indirect/Direct Evaporative Cooling
35. Gas Air Conditioning
36. Air Conditioning Maintenance
37. **High-Efficiency Air Conditioning**
38. Economizers

Water Heating

39. Convert Electric Water Heat
40. Heat Pump Water Heaters
41. Water Heating Load Controls

Lighting

42. **High-Efficiency Fluorescent Ballasts**
43. **High-Efficiency Reflectors**
44. **Occupancy Controls**
45. High Pressure Sodium Lamps (HPS)
46. Metal Halide Light Fixture and Lamp
47. Low Pressure Sodium Street Lights

Ventilation

48. High-Efficiency Motors
49. Low Temperature Air
50. Variable Air Volume Systems
51. Adjustable Speed Drives for ventilation

Refrigeration

52. **High-Efficiency Refrigeration**
53. Case Covers and Doors
54. Gas Driven Mechanical Refrigeration

Industrial Process

55. **Customized Process Efficiency options**
56. **Energy Efficient Motors**
57. Process Heat Recovery
58. Adjustable Speed Drives
59. Compressed Air Systems Efficiency Upgrade
60. Pumping System Efficiency Upgrades
61. Install High-Efficiency Particulate Air (HEPA) Filters
62. Refrigeration System Efficiency Upgrades
63. Gas Engine Driven Pumping
64. Thermal Storage Heating
65. Infrared Heat Drying
66. Thermal Product Storage

Agricultural

67. **Low Energy Precise Application (LEPA) Irrigation**
68. Pump Test Program

Program concepts were developed for the selected DSM options. The program concepts include the marketing approach, the target markets, the estimated load impacts and costs. Umbrella programs were developed that included multiple DSM options. The use of umbrella programs minimizes program marketing and administrative costs and provides the customers with a range of options to best meet their energy service requirements. The 13 DSM options were consolidated into 10 programs which were evaluated. The programs are:

- **Residential Electric Space Heat Conversion** — promotes installation of natural gas space heating equipment and water heating equipment in the residences of electric heat customers of the company (option 8).
- **Residential Electric Water Heat Conversion** — promotes installation of natural gas water heating equipment in the residences of existing gas customers of the company also served by company electric service and having electric water heat (option 19).
- **Residential New Construction** — promotes measures that are more efficient than required by the Model Conservation Standards (MCS) including high efficiency heat pumps, air conditioners, furnaces and water heaters; low flow shower heads; compact fluorescent lamps; set-back thermostat and gas cooking (screened option 1). Insulation and other shell measures exceeding MCS levels are currently not cost effective, so have not been included.
- **Residential Weatherization** — provides a blower door test with infiltration control measures, water heater tank wraps, set-back thermostat, furnace retrofits, low flow shower heads and compact fluorescent lamps to existing households (option 2).
- **Commercial Lighting** — promotes the installation of high efficiency lighting systems in commercial buildings (options 42, 43, and 44).
- **Commercial Air Conditioning** — promotes the installation of air conditioning equipment that exceeds the efficiency requirements of current building codes (option 37).
- **Energy Efficient Commercial New Construction** — provides design assistance and incentives to incorporate energy efficiency into the design of new commercial buildings (option 28).
- **Energy Efficient Commercial Refrigeration** — provides audits and incentives to identify and install measures to improve the energy efficiency in commercial refrigeration in supermarkets, grocery stores, and warehouses (option 52).
- **Industrial Process Efficiency Improvement** — provides audits and incentives to identify and install measures to improve the energy efficiency in industrial facilities (options 55, and 56).
- **Irrigation System Efficiency Upgrade** — provides audits and incentives to identify and install measures to improve the energy efficiency of irrigation systems (option 67).

EVALUATION PROCESS

The costs and benefits of alternative DSM program concepts were evaluated using the COMPASS demand-side planning software, a proprietary software product of SRC. The COMPASS model integrates customer load impact and rate calculations with market size data, program design parameters and utility characteristics data to provide forecasts of the annual net effect of a DSM program on customer adoption of the DSM option and the resultant net impact upon utility loads and costs.

The major steps used to evaluate the DSM program concepts in the COMPASS model are described below:

Evaluate Customer Level Load Impacts and Economics

The load shape characteristics of the base (i.e., current, typical practice) and DSM options are compared to estimate energy and demand savings by hour for the peak weekday, typical weekday, and typical weekend (including holidays) day for each month. Base load shapes for the residential sector were obtained from Bonneville Power Administration End-Use Load and Consumer Assessment Program (ELCAP) data. For the commercial sector, load shapes were developed through the engineering simulations of prototypical buildings using Spokane weather. The customer bills (electric and gas) are also computed using actual rate schedules and the monthly energy and demand usage by rating period.

Determine the Eligible Market Size

The eligible market size depends upon the program design which defines the market segments that are targeted, the customer characteristics including the percent that are eligible for the DSM option net of customers who have already installed the option, and forecasted changes in the size of the customer population. Company survey data was used to estimate the size of eligible markets and current penetration of DSM measures. A stock accounting model is used to determine the new construction and replacement market size in each year.

Forecast Market Penetration

The portion of the eligible market adopting the DSM option in each year is forecasted. Adoption rates with and without the utility program are forecasted. In the benefits calculations, only the net load impacts from the incremental participation induced by the program are included. In the cost calculations, costs associated with all adopters are included regardless of whether they would have adopted the option without the utility program.

The share of the market adopting a given DSM option in each year is forecasted using either the experience of other utilities with similar programs or a payback-acceptance approach. For the payback-acceptance approach, the percent of the market accepting a DSM option is based upon the simple payback. The shorter the simple payback, the greater the market adoption. For instance, 71% of the market would adopt an option with a 1 year payback, while only 26% of the market would adopt an option with a three year payback. Thus, a program that reduced the payback for a DSM program from three years to one year would result in a net increase in market share of 45%, the difference in the 1 and 3 year market. The 26% of the market willing to adopt the measure without the utility program (i.e., with the three year payback) are called free riders.

The payback-acceptance curve only provides estimates of the long-run market share. The long-run market share is generally attained only over a period of time. Diffusion curves have been developed to describe the portion of the long-run market that is attained in each year after the product is adopted. They are incorporated into the analysis of measure adoption.

Determine Program Costs and Benefits

The program costs and benefits are calculated based upon the estimated load impacts, the utility's cost structure and the number of participants. The energy and demand savings by time period times the company's avoided costs for the corresponding time periods provide the estimated capacity and fuel savings. The benefits and costs are used to calculate annual net benefits, rate impacts and bill impacts. Standard benefit cost ratios are also computed including the following:

- **Utility Test** — Compares utility costs of fuel and capacity with utility program costs. Values greater than one indicate that the life-cycle fuel and capacity savings exceeds the life-cycle program costs. Values greater than one indicate that the net present value of revenue requirements will be reduced.

- **Rate Impact Test** — Includes the lost revenue from the reduced electricity sales as a cost. Values less than one indicate that average rates may increase over the life of the program.

- **Total Resource** — Compare the capacity and fuel savings with the utility program costs plus customer costs. This is probably the most widely used test for evaluating DSM programs.

- **Societal** — Adds the externalities from fuel use to generate electricity to the benefit term. Sometimes, a lower discount rate is used for the societal test then the total resource test, thus the societal benefit cost ratios are generally higher than the total resource test.

The programs have been evaluated assuming that the cost of the measures are split 50/50 between the utility and the participants. The company is assumed to pick up the program administration costs.

RESULTS

The summary results of the detailed evaluation for the electric DSM programs are summarized in Figure C-2. Shown for each of the 1 program "packages" described are the four benefit/cost ratios and the levelized costs of the programs from the utility and total resource perspectives.

Summary Cost-Effectiveness Results

Figure C-2.

	Benefit/Cost Ratios				Lifecycle Costs	
Program Name	Utility Test	Participants Test	Total Resource Cost Test	Societa Test	Utility Perspective (¢/kWh)	TRC Perspective (¢/kWh)
Residential Electric Space Heat Conversion	4.31	1.19	1.43	1.48	2.13	2.93
Residential Electric Water Heat Conversion	4.02	1.31	1.17	1.21	1.53	2.61
Residential New Construction	0.92	2.35	0.83	0.85	11.27	12.93
Residential Weatherization	1.83	3.42	1.90	1.92	4.72	4.73
Commercial Lighting	3.53	2.99	3.30	3.43	2.54	2.84
Commercial Air Conditioning	1.51	1.75	1.07	1.08	3.37	5.16
Energy Efficient Commercial New Construction	1.75	0.97	1.05	1.10	6.07	10.53
Energy Efficient Commercial Refrigeration	4.31	1.81	1.94	1.93	1.48	3.46
Industrial Process Efficiency Improvement	3.31	1.46	2.07	2.14	1.83	3.03
Irrigation System Efficiency Upgrade	0.16	1.12	0.15	0.14	15.90	18.64

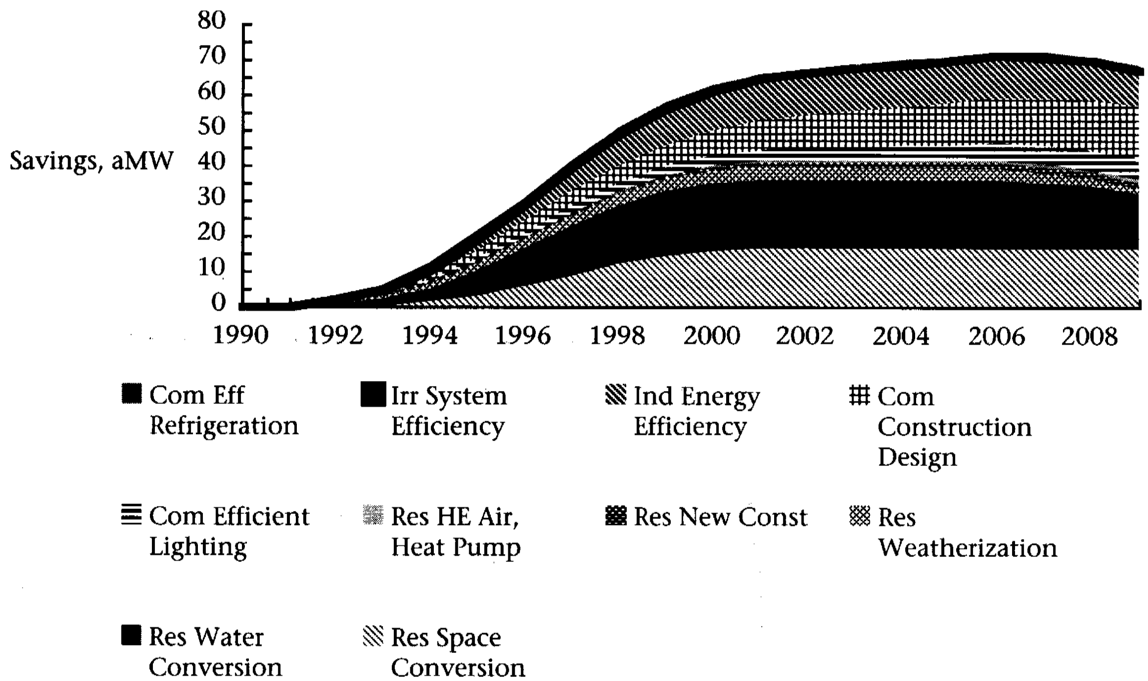
Note that the levelized lifecycle costs shown are calculated by COMPASS as 30-year values. However, they are not directly comparable to a 30-year "avoided cost." One of the main reasons is that the savings for any given program plan vary over the life of the plan. The benefit/cost ratios in Figure C-2 indicate how a program's costs per kilowatt-hour compare to avoided costs.

Benefit/cost ratios of 1.00 indicate a program's costs equal avoided costs. Ratios greater than 1.00 indicate that a program's costs are lower than avoided costs, and ratios less than 1.00 indicate costs greater than avoided costs. In this evaluation, no credit has been given for the environmental benefits of demand-side resources over supply resources, so the societal test cost/benefit ratio is very nearly equal to the total resource cost test.

Figure C-3 below summarizes the load impacts of the programs if implemented.

Electric DSM Load Impacts

Figure C-3.



APPENDIX D
COGENERATION ACTIVITIES

COMMERCIAL AND INDUSTRIAL CUSTOMER
COGENERATION ASSESSMENT

Prepared for
WASHINGTON WATER POWER

Prepared by
RESOURCE MANAGEMENT INTERNATIONAL, INC.

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APPENDICES

EXECUTIVE SUMMARY

Resource Management International, Inc. (RMI) was retained by Washington Water Power (WWP) to perform a reconnaissance-level assessment of the potential for cogeneration and customer generation within WWP's service territory. WWP made some preliminary estimates of cogeneration potential in its service area for its April 1989 Least Cost Plan but noted that those cogeneration estimates should be further refined. RMI proposed to WWP a reconnaissance-level assessment with the following objectives: evaluate cost-effective cogeneration technologies, assess the cost effectiveness of cogeneration at avoided cost prices or displacement of WWP retail sales, and identify customer groups most suited for cogeneration application. Additional objectives were to determine the potential range of cogeneration development in WWP's service territory in order to allow the utility to better assess the cogeneration resource in its future least cost planning and to identify steps necessary to further refine the cogeneration estimates.

WWP's planning estimates show for the medium and high growth scenarios that the utility will need to add additional power resources over the next 20 years. The utility's planning documents go on to indicate that conservation and cogeneration are anticipated to be two likely new sources of power. Additionally, regional planning efforts by the Bonneville Power Administration (BPA) and the Northwest Power Planning Council (NPPC) show cogeneration is a cost-effective resource for Pacific Northwest power supplies. There are a number of customers in WWP's service area that have developed cogeneration projects at their facilities, all of which use wood waste as a fuel. WWP is interested in knowing whether additional cogeneration potential exists and whether the cogeneration will be limited to wood waste-fueled plants only, or if other fuels (like natural gas) will play a significant role in development. This study assesses these issues, identifies commercial and industrial customer types most suited for cogeneration development, and provides a reconnaissance-level estimate of the range of cogeneration development reasonably anticipated by those customer types.

APPROACH TO COGENERATION ASSESSMENT

This assessment was conducted in three primary parts. First, WWP supplied information on commercial and industrial customers' electric load, gas load, thermal load size and availability, and hours of facility operation. That data allowed a categorization of the customer information based on those key factors. By screening the customer groups, those customer types that are unlikely to develop cogeneration were eliminated. The remaining customer groups were: food processors, hotels, universities and colleges, hospitals, and wood products industries. These customer groups were identified as likely candidate classes for future cogeneration potential.

Second, RMI tested the various size and types of cogeneration systems for cost effectiveness under a range of economic, fuel cost, electric rate, and financial parameters to determine their potential application for WWP's commercial and industrial customers. Seven cogeneration systems ranging in size from 20 kilowatts (kW) to 10 megawatt (MW) were selected for evaluation. The evaluation of these units were predicated on fuel type (natural gas and wood residue being the most likely fuel sources), type of purchase/sale arrangement, anticipated WWP retail gas and electric rates, avoided costs, financing and economic assumptions, and cogeneration system operating factors. In addition, the economic sensitivity of a range of avoided cost rates for the sale of cogeneration project output to WWP was tested. Under the avoided cost pricing scenarios, the case with 200-kW internal combustion engines were considered to be potentially feasible and the 1.4-MW, 4.2-MW and 10-MW gas-fired combustion turbines (CT) are likely to be cost effective. Ten MW wood-fired cogeneration facilities also appeared cost effective and it would be difficult to rule out their use for site-specific cogeneration development in the wood products industry.

As a final step, the likely candidate customer classes were matched with the economically viable and cost-effective cogeneration technologies for WWP's service area. This allowed an evaluation of the applicability of generically viable cogeneration technologies to specific customers and an estimate of the range of cogeneration potential to be developed.

FINDINGS

The key findings in this assessment are:

1. Based on WWP's current retail electric rate structure for small commercial, medium commercial and industrial, and large industrial users, it is unlikely that a customer will seek to install or develop cogeneration purely to displace WWP's service. The exception may be in the wood products industry where volumes of wood residue provide fuel sources at sufficiently low costs to make displacement of electric sales from WWP potentially cost effective. It is more likely that cogeneration must be induced by nominal levelized "avoided cost" rates greater or equal to $.06 per kilowatthour (kWh).

2. The thermal load and hours of daily and weekly operation appear to be the most important factors in determining the likelihood of a WWP customer installing cogeneration, since cogeneration development is unlikely to be induced by a desire to displace WWP sales.

3. WWP customers in the wood products and related industries, large universities (i.e. Washington State and the University of Idaho), and high thermal requirement food processing plants provide the best cogeneration opportunities. The health services sector, primarily hospitals, shows some potential for the development of smaller amounts of cogeneration. Figure I-1 provides the low and high case estimates of cogeneration potential in the five most likely customer categories.

4. Based on this reconnaissance-level assessment, the potential for cogeneration in WWP's service area ranges from a low of 61 MW to a high case of 141 MW.

CONCLUSIONS

Key factors which will affect the potential for cogeneration development in WWP's service area include:

- Cogeneration development will be influenced by the continued economic growth in the Pacific Northwest, the relative cost of natural gas and electric power rates offered by WWP, and the volatility of the agricultural and forest products sector of the economy in Eastern Washington.

- WWP can develop policies that will encourage and induce cogeneration development in their service area. However, it is unlikely that the current rate structure will be sufficient inducement to encourage cogeneration by itself.

- The estimated range of cogeneration potential in WWP's service area can be refined by developing a feasibility-level assessment of the cogeneration potential at a group of specific customer sites selected from the current data base.

ESTIMATION OF SYSTEM-WIDE COGENERATION POTENTIAL

The cogeneration technology screening results and the customer characterization can be combined to determine which customer types may have potential for application of the cogeneration technologies and sizes considered to be economically viable based on the preliminary screening. The evaluation of each of the five customer types, combined with experience of the project team in evaluating cogeneration projects, provides a basis for estimating the range of cogeneration application throughout the WWP system.

As noted in Section IV based on WWP's forecast of retail electric rates, none of the natural gas-fired cogeneration technologies are expected to be sufficiently economically promising to warrant development if power produced by the cogeneration project were used at the cogeneration host facility to displace a WWP customer's retail electric power purchases, with the possible exception of wood waste-fired facilities. All new cogeneration potential for the 1991 to 2000 planning period is assumed to be sold to WWP. As a result, the electrical loads of the major customer groups did not enter into the evaluation of potential technical or economic viability of the cogeneration applications.

The matching of customer type and cogeneration technology is primarily based on type, amount and likely pattern of thermal energy use by the customer, and the consistency of the customer's thermal energy use with the thermal energy available from cogeneration technologies.

The following presents the results of the evaluation of cogeneration potential for each of the five major customer groups considered most likely to include facilities which could host cogeneration development.

FOOD PRODUCTS

Thermal energy use data for ten of the largest food products related customers in the WWP natural gas and electric customer service territory were compared to the available cogeneration technologies. All but three of these ten larger food products customers were rejected as likely cogeneration applications for one of the following reasons:

- thermal energy requirements were for direct firing of ovens, with insufficient apparent opportunity for application of heat recovery through steam or hot water;
- the operation was too seasonal to achieve economic electric capacity factor operation;
- the thermal energy use was at the level suitable for development of cogeneration technologies of a size smaller than the 200-kW internal combustion engine application. These smaller units are expected to be uneconomic based on the generic technology screening performed earlier; or
- the total thermal energy requirements were too low for any reasonable cogeneration application (such as some of the large commercial greenhouse operations).

Three of the ten food products customers evaluated are yearlong food processors, all believed to be primarily potato processors with annual thermal energy requirements in excess of ten times the thermal requirements of the seven customers rejected from further consideration. All three are served natural gas by WWP, but two of the three are provided electricity by public utility districts (PUD). Also considered for evaluation were several food processors located outside WWP's gas and electric service area and served entirely by other utilities. Their location and service makes it difficult to assess the overall likelihood that WWP would be able to purchase this generation. In these cases, the PUDs are assumed to be willing to wheel power from the cogeneration plants to WWP.

Based on annual and single-month peak use data, two of three food products customers appear to have a potential for up to approximately 10 MW of gas-fired cogeneration and another is estimated to have a potential of up to approximately 4 MW. Each of the operations presently use multiple steam boiler systems, run nearly yearlong, and operate two to three shifts per day. Stable thermal loads are necessary to make cogeneration economic when natural gas is used to fuel the operation.

POTENTIAL OTHER FOOD PRODUCTS APPLICATIONs

The extent of other existing or future new food products operations similar to the three more promising customers evaluated above is not known with certainty. Since WWP industrial customer representatives provided the customer data, it is unlikely that other large potato or other yearlong food processor customers in the 10-MW cogeneration range exist that have not been considered. There may be potential for an existing or future new food products operation with a thermal energy load to support a 4-MW cogeneration plant.

To estimate WWP system-wide cogeneration potential, a single 10 MW application for the single largest, most stable yearlong thermal load customer would be a reasonable assumption for the low end of the projection. Development of an additional 10 MW at some other food processing candidate and development of another approximately 4 MW (at the other known customer estimated at this size, or a similar customer not on the sample list), would be a reasonable high case scenario. This yields a high case scenario of 24 MW.

COLLEGES AND UNIVERSITIES

Thermal energy use data for ten high schools, colleges, and universities were evaluated for possible cogeneration application. The thermal energy use for the three high school examples provided by WWP indicate the use is too low on a total annual basis, and the thermal load factor is expected to be too low to be cost effective. Education Services customers generally will need yearlong attendance and some on-site residential use to achieve thermal load factors that could support cogeneration. This requirement generally limits colleges and universities to candidates within this customer group.

Thermal energy use data from seven colleges and universities were reviewed to evaluate the college and university customer subgroup. One college and one university were eliminated because the thermal load was too small to be served by a CT and heat recovery boiler. The appropriate form of thermal energy (steam) needed to operate the space conditioning system cannot be produced by an internal combustion engine.

Two other colleges could be candidates for a 200-kW to 500-kW internal combustion engine application if hot water systems can be used to serve the thermal loads (more facility-specific data would be required to confirm the applicability). Another university could potentially have a steam demand sufficient to support a 2.5-MW to 4.3-MW gas turbine heat recovery boiler set, depending upon the amount of the total gas use attributable to steam use on campus (more facility-specific investigation would be required).

Two special cases are WSU and the University of Idaho. A detailed study is underway by others for WSU and previous reconnaissance-level analyses have been performed for the

University of Idaho. Depending upon assumptions and future campus expansions, WSU could support a 23-MW to 40-MW CT heat recovery boiler system and University of Idaho could potentially support a similar 10-MW to 20-MW facility.

Cumulatively, the colleges and universities could represent a meaningful cogeneration resource. Under a low scenario, the WSU and University of Idaho campuses could support approximately 33 MW. Under a higher case development scenario, the larger size facilities could be feasible at these two universities and up to approximately 4 MW may be feasible at up to two of the other colleges or smaller universities, for a cumulative development range of approximately 33 MW to 64 MW.

HEALTH SERVICES CUSTOMERS

Hospitals and medical centers tend to be candidates for cogeneration applications in the 300 kW to 3 MW range. Thermal energy use for eight hospitals and medical centers was reviewed to assess the potential for cogeneration applications. Annual natural gas use for the customers ranged from a low of approximately 170,000 therms annually to approximately 1.5 million therms annually. Based on thermal energy use, most of the hospitals on the list would be potential candidates for 300 kW to approximately 1.4 MW of capacity. The largest hospital on the list could have potential in the 2.5 to 4.3 MW range.

Two of the eight projects are planned for heating plant renovation or replacement — one in 1991 and one in 1992. It is likely that the facility with a 1991 replacement schedule is too far advanced in development to change the renovation to cogeneration. Changing the 1992 planned renovation to cogeneration would require a decision in the near future. If these two facilities are renovated without adding cogeneration, it is unlikely they would be modified further within the 1991 to 2000 planning horizon relevant to this study.

The list of eight hospitals is not assumed to be an exhaustive list, but any other hospitals within WWP's gas or electric territory are assumed to be similar to the smaller thermal energy use size of the eight examples, presumably in the 500-kW cogeneration application range.

A service area-wide low and a high case scenario for cogeneration development at hospitals can be estimated from the sample of facilities. The low development scenario assumes there are no other similar sized hospitals than those on the list evaluated in this report. This scenario also assumes that the two hospitals planning for near-term heating plant renovation are too far advanced for the revisions to include cogeneration. The low development estimate assumes that approximately 3 MW of cogeneration is developed and that at only the largest of the eight hospitals. A high case scenario assumes the hospital planning renovations in 1992 can modify these renovations to include 3 MW of cogeneration. The largest hospital develops 4.3 MW of cogeneration and up to three other hospitals throughout WWP's service territory develop an average of 1.0 MW each. The health services cogeneration contribution is estimated to range from 3 to 10 MW.

HOTELS AND RESORTS

Four hotel and resort facilities were reviewed for cogeneration potential. These facilities have annual gas usage in the 200,000 to 450,000 therm range. Most facilities of this type operate on hot water systems, although one of the facilities evaluated uses a steam system. These customer types, if they are feasible for cogeneration application, will tend to be 200 kW to 500 kW applications, and will use internal combustion engine/hot water systems. The steam system used for space heating and cooling in one of the facilities would require a small CT in the 500 kW range to provide thermal energy in the proper form.

All of these facilities are expected to be on the marginal edge of economic feasibility unless WWP's power purchase rates increase faster than assumed in the screening analysis performed in this study. There may be other hotels in WWP's gas or electric service territory which approximate the smaller size on the sample list of four hotel/resorts, but larger hotel facilities are not expected to exist.

On a system-wide basis under a low development scenario, no cogeneration capacity would be expected at hotels or resorts. Under a high development scenario, the two larger hotel/resorts are assumed to be developed for a cumulative capacity of approximately 1 MW.

LUMBER AND WOOD PRODUCTS

Cogeneration development at lumber and wood products customers of WWP requires a facility-specific assessment to provide estimates with any confidence, due to the unique nature of individual facilities — both in terms of types and quantities of wood waste and use of steam. Virtually all of the existing cogeneration in WWP's service territory uses wood waste related fuel and the economic screening of wood waste-fired plants shows a high expected economic return for these facilities generically. In the event the wood waste from existing plants is not used for on-site cogeneration, it is possible that the waste would be marketed to an independent power producer to fuel a wood waste-fueled plant, with or without cogeneration.

Sixteen existing lumber and wood products customers of WWP were reviewed. Of the facilities evaluated, several were considered unlikely due to apparent seasonal operations based on the customer's electrical load factor and an annual electrical energy requirement of less than one third of the next largest plant on the list. The remaining projects are all considered reasonable candidates for cogeneration or wood-fired power plant development with or without cogeneration. Estimated capacity of the potential plants ranged from about 2.5 to 7.5 MW for a potential cumulative combined capacity of 27.5 MW. However, many of the facilities, sawmills for example, are highly dependent on business cycles and have been further discounted in this analysis to account for this fact. The estimate for the wood products sector is based on comparing the individual facilities to similar existing cogeneration facilities at wood products plants within or outside of WWP territory.

These facilities are perhaps the most promising opportunities for cogeneration of all customer types due to the favorable economics from use of high quality waste wood products fuel. A low scenario assumes that only the two largest customers would develop a total of 15 MW of capacity. A high development scenario would assume expansion of the existing customer facilities and development of cogeneration capacity at several of the customers' plants for approximately 42 MW. This latter scenario assumes the Eastern Washington wood products industry maintains or expands its present volume of business to increase the volume of product processed by existing plants.

CUMULATIVE COGENERATION DEVELOPMENT POTENTIAL

The future of cogeneration potential within WWP's service territory will be influenced by several factors. One of the most significant influences will be the extent to which WWP encourages cogeneration through pricing structures as well as the institutional considerations such as interconnection, customer education, and technical evaluation guidance. The extent to which WWP would provide encouragement would depend upon the impact on total and average system revenue requirements and stockholder return as compared to the level of development that could occur without any encouragement. Such analysis would need to be performed as part of a total system power supply study.

If the current situation of relatively low cost of retail power supply and incremental new power supply continue, it is likely to mean there will be little cogeneration development. It is possible that only the wood products customers who have access to wood waste fuel would develop cogeneration. In this scenario, capacity in the range of 15 to 20 MW, would approximate the additional system-wide cogeneration potential.

Assuming some effort is made to institutionally foster cost-effective cogeneration, and if WWP's purchase price for new capacity is in the $.06/kWh nominal levelized cost range, the following is a reasonable estimate of the range of cogeneration potential in WWP's gas and electric service area:

These estimates are shown graphically on Figure D-1.

CAPACITY IN MW		
Customer Group	Low Case	High Case
Lumber & Wood Products	15	42
Colleges & Universities	33	64
Food Products	10	24
Hospitals & Medical Centers	3	10
Hotels & Resorts	0	1
Total	61	141

Estimated Cogeneration Potential—WWP Service Area

Figure D-1.

KEY FACTORS AFFECTING COGENERATION DEVELOPMENT

The prospects for cogeneration development within WWP's territory will be influenced most by:

- the relative cost of natural gas and power purchase rates offered by WWP;
- the rate of economic growth in the region;
- the volatility of the agricultural economic sector of Eastern Washington and Northern Idaho; and
- the extent to which timber supply and the pulp and paper industry maintains or expands its present rate of production and processing of products.

These more broad based economic factors will influence cogeneration development in the following manner:

1. The relative cost of natural gas versus the price at which WWP will purchase cogeneration output is perhaps the largest factor to influence cogeneration potential. The economic analyses shows that financial viability of typical projects increases substantially when the nominal levelized sale price is between the $.06/kWh and $.07/kWh.

2. Continued economic growth in the region will provide increased demand for new power supplies which will tend to increase the cost of power supply additions more rapidly than they would increase under slow economic growth conditions. In addition, strong economic growth will result in greater use of existing facilities which could be thermal hosts for cogeneration, making them more financially viable for cogeneration development.

3. Since food processing related industries comprise a significant percentage of the potential cogeneration capacity, any expansion of the agricultural economy will provide more opportunities for cogeneration.

4. Wood products related waste fuel-fired cogeneration represents a major percentage of the potential cogeneration additions. Uncertainty over regional timber supply and demand for housing related products could influence the startup of new facilities or the willingness of wood products plant owners to make major capital investments in existing plants to add cogeneration.

APPENDIX E

HYDRO IMPROVEMENT ACTIVITIES

Washington Water Power

INTEROFFICE MEMORANDUM

Hydro Project Development

To: Doug Young

January 4, 1991

From: Joe Kurrus

Subject: Nine Mile HED Redevelopment
Feasibility Study and Preliminary Engineering

Enclosed is a summary of the feasibility study, completed in February 1990, and a copy of the Scope of Work for the preliminary engineering for the above referenced project. It should be noted that the preliminary engineering is not yet complete. Completion is expected by the end of March 1991.

This information is provided in response to your request.

If you need any additional information about this project, please call me on extension 4461.

JAK:kbl

Enclosures

FEASIBILITY STUDY

NINE MILE HED REDEVELOPMENT

1.0 SUMMARY

1.1 PURPOSE

Ebasco was contracted by the Washington Water Power Company (WWP) to perform a study of alternative methods of upgrading and rehabilitating the Nine Mile Hydroelectric Development located on the Spokane River 5 miles northwest of Spokane, Washington. A kick-off meeting was held in Spokane on July 25, 1989 at which the objectives and scope of the study were defined.

This rehabilitation study had two main purposes. The first was to identify and evaluate alternatives for stabilizing the dam structures (spillway, powerhouse, and left abutment). The second was to identify and evaluate alternatives for increasing the development's power generation.

The study was conducted in two phases. This Final Report summarizes the results of Phase I and presents a complete discussion of Phase II. The objectives of Phase I were to identify practical alternatives for stabilizing the dam, assess the benefits and costs of these alternatives, and recommend the most appropriate alternative(s) for evaluation in Phase II. During Phase I, the structural condition of the existing concrete features was also evaluated, assisted by a nondestructive testing program performed by Olson-Wright, Inc.

Phase I also included an initial identification and evaluation of alternatives for increasing power generation. These included 1) upgrading the existing units, 2) replacing the existing units with new more efficient units, 3) constructing a new powerhouse downstream from the existing project, 4) raising the normal reservoir elevation 10 feet, and 5) combinations of the above.

The objectives of Phase II were to further define and develop the "shortlisted" alternatives, provide feasibility-level estimates of their benefits and costs, and recommend one or more economically attractive alternatives for future development. Under consideration during Phase II were 1) improving spillway water level control for the dam at present or higher reservoir levels, 2) upgrading or replacing existing units, 3) constructing a new single-unit powerhouse downstream from the existing project, and 4) combinations of the above. An intermediate (5-foot) raised reservoir level was added to the scope of studies when property acquisition and relocation costs estimated for the 10-foot increase were higher than initially anticipated.

1.2 SCOPE

The Phase I Studies included a reconnaissance level inspection of the Nine Mile dam, powerhouse and all major equipment to assess the condition of these facilities and thereby establish a base case operating condition from which improvements and changes could be evaluated. The visual inspection was supplemented by a microseismic survey of concrete conditions in all structures, a core boring program initiated by WWP which produced information on both concrete quality in the structures and geotechnical conditions in the rock foundations below, and a resurvey of the left abutment area at, and immediately downstream, of the dam.

Additional data was acquired from perusal of plant technical files, drawings, old construction photographs, records of O&M costs and major equipment overhauls, and interviews with WWP's key personnel. WWP furnished survey and hydrology data; plans and budgets for future major overhauls and improvements; evaluation parameters including energy, capacity cost and financial data; and estimates of land and relocation costs associated with raised reservoir levels.

This Final Report consists of four parts. The first part is the Summary (Section 1.0). The second part is a description of the Phase I studies (Sections 2.0 through 9.0) and the third part is a presentation of Phase II (Sections 10.0 through 19.0). The fourth part, included at the end of the report, contains all figures. Appendices A and B, under separate covers, contain detail on cost estimates, power studies, and economic calculations.

SCHEDULE A-1

NINE MILE PRELIMINARY ENGINEERING

SECTION 1: SCOPE OF WORK

Consultant shall perform the services identified in Section 1.1 through Section 1.9 required to complete and deliver preliminary design for WWP's Nine Mile Hydroelectric Redevelopment Project, in a manner consistent with the requirements stated below. The results of this will be used by WWP for the economic analysis to determine the project feasibility.

1.1 Identify Components to be Replaced

1.1.1 Consultant will recommend and identify the major components to be replaced for this project. This will include all electrical, mechanical and structural items associated with the powerhouse and spillway. This shall be done considering replacement of two, three and four turbine/generator units. The reasons for replacement, sequence of replacement and the type of replacement component will be included for each component.

1.1.2 Consultant will prepare a draft report which presents this information in a concise format for onetime WWP review. Upon receipt of WWP's comments, the Consultant will incorporate these comments and prepare the final report. Four (4) bound copies of the final report will be submitted to WWP.

1.2 Evaluate Turbine Centerline Elevation and Reservoir Pool Elevation

1.2.1 The Consultant shall evaluate the possibility of lowering the centerline elevation of the turbines and generators, and raising the reservoir elevation. These changes may result in increased energy production as well as increased construction costs to do the related work. This evaluation shall consist of the following sub tasks:

1.2.1.A Conduct inquiries and discussions with equipment manufacturers (Barber, American Hydro, Voith and Hydro West) to determine the increased flow capacity of each manufacturer's unit if the turbine centerline is lowered by two to four feet.

1.2.1.B Estimate all construction costs associated with lowering the centerline including removing and replacing concrete in the powerhouse to accommodate a lower turbine centerline and/or generator centerline for each manufacturer's unit.

Estimate the incremental equipment costs associated with the increased turbine and generator size resulting from the lowered centerline.

Estimate the installed costs, life expectancy, and maintenance costs associated with a gear box or inclined shaft. Estimate the associated reduction in generator and construction costs for using a gear box.

1.2.1.C The Consultant shall evaluate the possibility of raising the forebay water surface level from 1606.6 feet to 1611.6 feet. The Consultant will estimate all costs associated with raising the reservoir. Items to be considered include the rubber dam, headgate and headgate lifting devices, all structures, all equipment and systems, land and environmental and licensing costs. (WWP will provide land, environmental and licensing cost estimates.)

Estimate the incremental equipment costs associated with the increased turbine and generator size resulting from the raised forebay.

1.2.1.D Estimate the annual energy production for each alternative using the energy model prepared under Task 1.8.

1.2.1.E Identify the impacts of reservoir level and centerline elevation changes on turbine efficiency over the proposed range of hydraulic head.

1.2.1.F Prepare a draft report for onetime WWP review which describes the results of this study. The report shall include the following information:

1) A total net project benefit analysis comparing the alternatives with lowered centerline to the alternatives with the present centerline, for both existing and raised reservoir elevations.

2) Cost estimate details which support the net project benefit analysis.

3) Back up documentation from manufacturers such as letters, memos, etc.

The WWP review comments will be incorporated into the final report, four (4) bound copies of which will be submitted to WWP.

1.3 Prepare Design Criteria

1.3.1 Consultant will prepare civil, mechanical, electrical and instrumentation and control design criteria documents covering the new features, systems, and equipment. Design criteria will identify all equipment that is affected or modified by the installation of new turbine generator units. Design criteria will be prepared for all components identified in Task 1.1 "Identify Components to be Replaced". In general, the mechanical design criteria will address the new turbines, governors, piping, and generator cooling systems. Electrical design criteria will address the generators and excitation system, switchgear, station service system, protective relays, and grounding. Instrumentation and Control design criteria will cover the instrumentation and control systems and philosophy for the power plant operation. Civil design criteria will address demolition, structural stability and hydraulic considerations, construction techniques and stages, and project operation during construction. Consultant shall prepare a draft report which presents this design criteria for onetime review by WWP. Consultant will incorporate WWP's comments and submit four (4) bound copies to WWP.

1.4 Prepare General Arrangement Drawings

1.4.1 Consultant shall prepare the following preliminary design drawings:

Drawing No.	Drawing Title
1042-001	Project Location Map
1042-002	General Plan Existing Structures
1042-003	Transverse Section Through Powerhouse Existing Units
1042-004	Powerhouse Plan Turbine & Generator Floors

Drawing No.	Drawing Title
1042-005	Powerhouse Plans At EL 1594.57 & EL 1584.07 Access Bay & Switch Room Floors
1042-006	Transverse Section Through Powerhouse New Units
1042-007	Existing Draft Tubes

1042-011 Main One Line Diagram

The drawings will show sufficient detail to be included in the bid packages. The drawings will also be used as the basis for the detailed construction cost estimate (Task 1.7). The drawing set shall be submitted for onetome review by WWP. Consulatnt shall incorporate WWP's comments and provide one full-size and one half size set of mylar originals.

1.5 Prepare Specifications and Bid Packages

1.5.1 Consultant will prepare a complete bid package including bid documents and the technical specifications for the following equipment:

A) Turbines, Generators and Governors;
B) Switchgear.

The technical specifications will provide sufficient detail for bidding purposes. The Consultant shall prepare a draft set of bid documents for onetime review by WWP. The Consultant shall incorporate WWP's comments and issue the bid package. Consultant will make all necessary copies of the bid documents and issue them to the approved vendors.

1.6 Technical Support During Bidding Phase

1.6.1 Consultant will respond to questions from bidders, prepare addenda, and assist with the evaluation of bids. This will include evaluation of alternative equipment and materials or substitutions that may be included in the proposal(s). Consultant will support and participate at WWP's direction in pre-bid meetings and contract negotiations.

1.7 Prepare a Detailed Construction Cost Estimate, Schedule and Quarterly Cash Flow

1.7.1 Consultant will prepare a detailed construction cost estimate for the project modifications. The estimate will include the selected bidders' equipment quotes and all other construction costs for this project. This cost estimate will be prepared in such detail as to have a stated accuracy of plus or minus 10 percent.

1.7.2 Consultant will revise the construction schedule prepared for the "Nine Mile Rehabilitation Final Report January 1990" based on the selected bidders' vendor commitments of equipment fabrications and delivery.

1.7.3 Consultant will prepare a quarterly cash flow estimate without AFUDC for the selected bidder based on the construction cost estimates and construction schedule developed herein. Consultant will also estimate the escalation rate to be used during the construction period.

1.8 Estimate Annual Energy Production

1.8.1 Consultant will prepare an energy production computer model to estimate the annual energy generation on a monthly basis for all water years of record. For each month the firm energy, secondary energy, shaping capacity and differential energy shall be estimated. A copy of the model will be supplied to WWP on magnetic media.

1.8.2 This shall be done using the selected bidder's proposed equipment certified performance data. This study will be performed for A) the existing flashboard system and reservoir; B) for a rubber dam replacement of the flashboards (reservoir El. 1606.6); and C) for a rubber dam replacement of the flashboards (reservoir El. 1611.60). Cases A), B) and C) need to be done for i) the existing turbine-generator units; ii) two replacement and two existing units; and iii) four replacement units.

Bechtel

50 Beale Street
San Francisco, CA 94105-1895
Mailing address: P.O. Box 193965
San Francisco, CA 94119-3965

November 30, 1990

BLW-015

Mr. Steven J. Schultz, P.E.
The Washington Water Power Company
East 1411 Mission Avenue
P. O. Box 3727
Spokane, Washington 99220-3727

Re: Long Lake Expansion
Final Plan Report Transmittal

Dear Steve:

We are very pleased to transmit herewith 24 copies of the Long Lake Expansion Final Plan Report and eight copies of the associated Appendices.

As this report indicates, the cost of the new powerhouse as estimated at the preliminary design level is $99.2 million. This cost compares favorably with the $98.3 million cost reported in the Feasibility Report last February. As the Final Plan Report also shows, appropriate operating refinements at Long Lake and at the Little Falls plant will result in an increase of net new energy from the two projects of nearly six percent over the net new energy reported in the Feasibility Report. Long Lake's incremental new production will average 273.244 GWh/yr.

Our conclusion is that the addition of a new two-unit, 120 MW powerhouse at Long Lake is a technically and economically attractive concept which should be pursued vigorously.

We are prepared to discuss the Final Plan Report with you, and to present it to your staff or management at your convenience, should you wish us to do so.

It has, once again, been a real pleasure to work with you and the other members of the WWP staff in the preparation of this work. We believe, as we did during the feasibility study, that the expansion of Long Lake is an exciting prospect. We are happy to have been part of its development to date, and we sincerely hope to be able to participate in the next stages of the implementation of this important project.

If there are further questions or comments on the work, please don't hesitate to call.

Very truly yours,

F. A. Hamill
Project Manager

FAH/to

Enclosure

Bechtel Corporation

Section 2

Introduction and Scope

2.1 INTRODUCTION

On February 1, 1990, Bechtel issued the Long Lake Renovation Study Feasibility Report to The Washington Water Power Company (WWP). The report outlined studies of several alternatives for the renovation and expansion of the existing Long Lake Hydroelectric Development of the Spokane River Project (FERC Project No. 2545).

The recommendation of the Feasibility Report was to study the addition of a new intake, penstocks, and powerhouse at Long Lake at the preliminary design level.

On May 8, 1990, Bechtel entered into an agreement with WWP covering the preparation of a preliminary design and cost estimate for the Long Lake Expansion Final Plan. The scope of the expansion includes a new intake structure, two new steel penstocks, and a new powerhouse containing two 60 MW vertical Francis turbines driving two synchronous generators.

This report summarizes the results of the preliminary design studies undertaken for the Final Plan.

2.2 SCOPE

This report contains the engineering definition of the Long Lake Expansion Project, a description of the construction sequence and schedule to build the project, and a cost estimate for the project. In addition, appendices are included which describe: a geotechnical exploration program undertaken in support of the preliminary design; an abbreviated set of technical specifications for turbines and generators; power operation studies undertaken to demonstrate the effects of re-regulation at the Little Falls Project downstream; and the civil, structural, mechanical, and electrical design criteria established for the project.

The engineering definition of the project is displayed in a set of 44 drawings and related engineering documents. In addition, a brief functional description is given to aid in understanding the project concept.

In contradistinction to the Feasibility Report, this report is limited to the expansion project alone. This scope does not include any work to existing facilities at Long Lake, unless such work will be performed only in support of the new expansion. Thus, all costs associated with the Feasibility Report Base Case are excluded here. Note that WWP has re-evaluated the Base Case and expanded it somewhat from what was described in the Feasibility Report.

Economic evaluation of the expansion project reported herein should be performed on a purely incremental basis. That is, energy and capacity produced above and beyond what is available from the existing system should be weighed against the cost of this expansion. In this way, it is unnecessary to revisit the costs associated with refurbishing the existing plant.

2.3 SELECTION OF STUDY CASE

The Feasibility Report showed a number of alternatives for increased generating capacity at Long Lake to be economically attractive. All attractive alternatives involved retaining the existing plant as a backup to the new plant. The table below summarizes comparative results from the Feasibility Report for the attractive alternatives:

New Units	Average Incremental New Energy (GWh/yr)	Average Cost of Incremental Energy Production (Mills/kWh*)	Incremental B/C Ratio Compared with Base Case*
One 40 MW	118.631	50.8	1.053
One 50 MW	142.620	47.6	1.130
One 60 MW	167.729	45.9	1.186
Two 40 MW	206.269	49.5	1.102
Two 50 MW	238.896	49.1	1.093
Two 60 MW	267.064	49.3	1.075
Three 40 MW	265.327	53.1	1.002

* Costs are based on estimates given in the Feasibility Report. The base case is the existing plant.

As the table indicates, the apparent best alternative is the addition of a single 60 MW unit. It can be seen, however, that the second 60 MW unit increases the average incremental energy by 59 percent (from 167.729 to 267.064 GWh/yr), and it is only slightly less attractive than the one-unit addition. It will also provide more operational flexibility, more reserve capacity, and more plant reliability than the single unit case. These advantages led to the decision to proceed with study of two additional 60 MW units.

Table 5-1
Cost Estimate Summary

FERC Acc. No.	Description		Cost Amounts $
330	Land and Land Rights		–
331	Powerhouse		
	Civil		$5,844,234
	Mechanical		3,664,182
	Electrical		3,080,279
332	Waterway		
	Intake Channel	360,191	
	Intake Structure	2,036,294	
	Penstocks-Civil	542,982	
	Tailrace	365,527	
	Training Work	–	
	Subtotal - Civil		3,304,994
	Mechanical		3,188,982
	Electrical		–
333	Turbines and Generators		
	Mechanical		22,564,338
	Electrical		–
334	Accessory Electrical Equipment		–
335	Miscellaneous Power Plant Equipment		775,964
336	Access Road to Powerhouses		138,430
353	Substation and Switching Station		1,142,268
354	Steel Towers and Fixtures		410,000
355	Wood Poles and Fixtures		–
356	Overhead Conductors and Devices		–
359	Roads and Trails (related to transmission lines)		–
•	Total Direct Cost		44,113,671
700	Construction Indirect Costs		13,689,523
•	Total Specific Construction Cost		57,803,194
•	Engineering		4,000,000
•	Construction Management		4,600,000
•	Subtotal		66,403,194
•	Sales Tax @ 7.9% of Specific Const. Cost		4,566,452
•	Subtotal		70,969,646
•	Contingency @ 12%		8,516,358
•	Subtotal		79,486,004
•	Escalation		6,399,700
•	Subtotal		85,885,704
•	Allowance for Funds Used During Construction		13,315,729
•	Total Project Investment Cost		99,201,433
•	Transmission System Upgrade Cost Allocation		4,595,000
•	Credit for Existing Powerhouse		(7,479,000)
•	Net Cost		$96,317,433

STATUS OF LONG LAKE REDEVELOPMENT WORK AND SUMMARY OF CONSULTANT'S FINDINGS FOR FINAL PLAN

On February 1, 1990, Bechtel issued the Long Lake Renovation Study Feasibility Report to The Washington Water Power Company (WWP). The report outlined studies of several alternatives for the renovation and expansion of the existing Long Lake Hydroelectric Development of the Spokane River Project (FERC Project No. 2545).

The recommendation of the Feasibility Report was to study the addition of a new intake, penstocks, and powerhouse at Long Lake at the preliminary design level.

On May 8, 1990, Bechtel entered into an agreement with WWP covering the preparation of a preliminary design and cost estimate for the Long Lake Expansion Final Plan. The scope of the expansion includes a new intake structure, two new steel penstocks, and a new powerhouse containing two 60 MW vertical Francis turbines driving two synchronous generators. This work represents the next stage of development after the feasibility study and is called the Final Plan.

The present work has concentrated on incremental work and costs required to add a new two-unit, 120 MW powerhouse to the existing facilities at Long Lake. This incremental cost may then be measured against the incremental capacity and energy revenues which the new works will produce.

The present project definition is supported by the following work:

- An aerial survey of the jobsite with a ground control survey to tie the work into the Washington State plane coordinate system;
- A subsurface exploration program including nine core-drilled exploratory holes, six seismic refraction survey lines, and laboratory evaluation of rock samples;
- Civil engineering design and layout work resulting in 20 general arrangement drawings;
- Mechanical design and scoping work resulting in 19 mechanical documents, including schematic diagrams, and equipment and device lists;
- Electrical design and scoping work resulting in a project one-line diagram, a bill of materials for all electrical equipment, and a complete switchyard layout;
- Vendor quotes (non-firm) for turbines and generators based on an abbreviated set of technical specifications;
- Design criteria for the new work;
- Construction sequencing to produce a summary-level schedule for the work;
- A cost estimating program targeted to produce a very reliable estimate consistent with the preliminary design level reported herein; and
- Ongoing coordination with WWP technical staff.

At the preliminary design level, total project investment cost is $129.2 million; the cost includes engineering, management, sales taxes, escalation through construction, a 12 percent contingency, and Allowance for Funds Used During Construction. This cost compares favorably with the values reported in the feasibility report of $121.3 million. The cost represents the new powerhouse installation and rehabilitation of the old powerhouse to improve reliability. Totaldirect costs to rehabilitate the old perhouse are $12.1 million. Items requiring significant costs for improvement are the turbines, generators, and headgates. Another significant item is the tendoning or other remedial measures which may be required for the cutoff dam. The new project will render this unnecessary. Transmission system reinforcement will be required to accommodate the expansion. The $4.2 million cost of this will be charged to the project.

The power operation studies reported in the Feasibility Report reflected a very restrictive operating criterion. The criterion was that the Little Falls plant downstream from Long Lake be operated as near as possible as it is currently. This meant that the Little Falls pool would be kept as full (to the top of the flashboards) as possible. Under the existing restrictive operating criterion, peaking operation at Long Lake to make use of the 5,000 A-F of pondage in the top 12 inches of the Long Lake pool will cause a substantial amount of spill at Little Falls when the new powerhouse at Long Lake is operating. This is due to the fact that the Little Falls plant hydraulic capacity is only about 7,400 cfs, whereas the new plant at Long Lake will have a 12,000 cfs capacity in addition to the existing plant capacity of 6,300 cfs. The loss of energy due to spill at Little Falls may be minimized by adopting a new, less restrictive operating criterion. Specifically, Little Falls will be operated in a re-regulating mode. This involves drawing the Little Falls pond down as much as 11 ft during off-peak hours when Long Lake outflows permit. Thus, spill will be minimized because the pond will refill during peak hours.

This proposed re-regulation operation at Little Falls will yield an increase of 12,300 MWh in average annual energy over the amounts reported for the two projects in the Feasibility Report.

In addition, curtailment of the annual 14 ft winter drawdown of Long Lake to the period of 1 February to 1 April is being considered instead of the period from 15 December to 1 April which is presently observed. This will result in an additional increase of 3,189 MWh.

The Table 1-1 below summarizes the average energy production expected for the two plants under these conditions.

Average Annual Energy (GWh/yr)

Figure E-1.

Case	Long Lake	Little Falls
Existing Plants, Existing Operation	445.795	210.649
Long Lake Expansion, Existing Little Falls Operation and Existing Winter Drawdown	713.950	183.155
Long Lake Expansion, Little Falls Re-regulation and Existing Winter Drawdown	714.935	189.763
Long Lake Expansion, Little Falls Re-regulation and Short Winter Drawdown	719.038	188.849

WWP will review the results of the Final Plan as submitted by Bechtel in December 1990. Further economic analysis will be made before a recommendation is made to management. Subject to management approval, final design is expected to be begin in March 1991. Construction is scheduled to begin in June 1992 with plant start-up in November 1994.

All project costs identified in the summary are the consultant's estimates and do not include owner's cost of administration and licensing.